2016 State of the Market Report for the MISO Electricity Markets

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Independent Market Monitor
for the Midcontinent ISO

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Guide to Acronyms

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
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 *2016 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 encompasses a geographic area from Montana east to Michigan and south to Louisiana. 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 2016

The MISO energy and ancillary services markets generally performed competitively in 2016. The most notable factor affecting market outcomes in 2016 was the continuing decline in fuel prices through the first half of the year, with natural gas prices falling to their lowest levels since the commencement of the MISO markets in 2005. The 10 percent decrease in natural gas prices from 2015 and declines in other fuel prices led to a 3 percent reduction in energy prices throughout MISO, which averaged $26.56 per MWh in 2016.

Energy prices did not fall as much as fuel prices because relatively hot conditions during the summer in 2016 resulted in higher loads and prices in these months. Nonetheless, 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.

In addition to this overall correlation, we 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 0.5 percent, or effectively zero, in 2016. This indicates that the MISO markets were highly competitive in 2016.

- The "output gap" is a measure of potential economic withholding. It remained unchanged from 2015, averaging 0.11 percent of load, which is *de minimus*. Consequently, market power mitigation measures were applied infrequently.

Although system-wide energy prices fell slightly, prices often varied substantially throughout MISO, reflecting congestion on the MISO transmission network. The value of real-time congestion increased by four percent to $1.4 billion, partly due to hot conditions and storms during the summer and high levels of outages in the spring and fall. We recommend a number of improvements in this Report to lower the cost of managing congestion on MISO's system.

MISO implemented several market design changes in 2016 that should improve the efficiency and competitiveness of the MISO markets.

- On February 1, MISO implemented a settlement agreement with its neighbors and created the Regional Dispatch Transfer (RDT) constraint that allows 3,000 MW of flow in the North-to-South direction and 2,500 MW of flow in the South-to-North direction.
  - This allowed much higher interregional flows from the prior 1,000 MW constraint.
  - Net interregional flows between the MISO South and MISO Midwest regions were predominantly in the South-to-North direction early in the year.
  - The flows reversed to be prodominantly in the North-to-South direction in the summer and in the fall because of high levels of generation outages in the South.
- On May 1, MISO implemented the ramp product, which contributed to low price volatility and slightly lower prices in the real-time market.
- In July, emergency pricing was implemented to ensure that additional supply or demand reductions acquired through emergency actions are priced at appropriate shortage levels.
- In September, the Real-Time Offer Enhancement (RTOE) capability was introduced to allow resources to update offers intra-hour to reflect short-term operating limitations.

Long-Term Economic Signals and Resource Adequacy

Capacity Levels and Summer Capacity Margins

In 2016, MISO lost 6.8 GW of resources to retirement, suspension, or because they were pseudo-tied out of MISO to PJM. MISO added 3.6 GW of resources, but 1.4 GW were renewable resources whose capacity value is relatively low. 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 2017 if the peak conditions are not substantially hotter than normal.

- We estimate a planning reserve margin of 18.9 percent, which exceeds MISO's planning reserve requirement of 15.8 percent.
- Under hotter than normal summer conditions and realistic assumed performance of MISO's demand response (DR) capability, the planning margin would be 10 percent. This margin should be sufficient given typical forced outage rate of 5 to 8 percent.

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 2016, and found:

- Net revenues increased at locations in MISO Central and North compared to last year and decreased in locations in MISO South;
- However, net revenues continue to be substantially less than necessary for new investment to be profitable in any area (i.e., the annual cost of new entry, or "CONE").

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. This has led some suppliers that own nuclear resources to announce plans to retire their units. Late in 2016, the State of Illinois passed legislation to subsidize two nuclear units to extend their operations for 13 years.

Capacity market design issues described in this report 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. In 2016, approximately three GW of MISO's coal-fired resources retired or pseudo-tied into PJM, largely due to the combined effects of low gas prices, costly retrofits required by environmental regulations, and low capacity prices in MISO. Although most of MISO is vertically integrated, it still has may resources owned by competitive suppliers and loads served by competitive load-serving entities. These participants rely on the economic signals from MISO's markets to guide their long-term decisions. Decisions of regulated suppliers are also informed by these economic signals. Hence, establishing efficient capacity and energy prices remains essential to ensuring resource adequacy in the MISO region.

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 to 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 2016/2017, the auction cleared at $72 per MW-day throughout most of the Midwest subregion and $2.99 per MW-day in MISO South.
- In 2017/2018, decreased capacity requirements and increased assumed transfer capability between subregions contributed to a MISO-wide clearing price of essentially zero ($1.50 per MW-day).

The extremely low clearing price in the most recent auction and the price volatility more broadly is a result of the capacity market design issues we discuss below.

PRA Design Issues

Several PRA design issues continue to undermine the efficiency of the PRA and contributed to the price volatility in MISO's capacity prices in the past few years. The most significant design flaw relates to how the demand for capacity is represented. Demand in the PRA is modeled as a single MISO-wide 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.

Understated capacity prices is a particular problem in Competitive Retail Areas (CRAs) where unregulated suppliers rely on the market to retain resources MISO needs to ensure reliability. In 2016, MISO developed a proposal to improve the capacity pricing in CRAs that we did not support. We offered an alternative proposal that would establish prices for CRAs that reflect the marginal reliability value of MISO's unregulated resources. While FERC rejected MISO's proposed solution, we believe FERC would approve an efficient proposal. Hence, we continue to encourage MISO to pursue a reasonable solution to ensure efficient capacity prices, if only for competitive loads and suppliers.

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

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

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 settlements occur through the day-ahead market, most congestion costs are collected in this market.

Congestion Costs in 2016

The value of real-time congestion increased by four percent from last year to $1.4 billion. Congestion levels were highest during the summer months, when real-time congestion rose 35 percent from last summer (to $464 million), which was due to high loads and key generation and transmission outages, particularly in the South. High network flows from wind resources in MISO and PJM contributed to the congestion in the spring and fall. These factors more than offset the reductions in natural gas prices that tend to reduce the costs of managing congestion in MISO, as well as the much lower congestion costs in early 2016 because of mild winter weather.

During 2016, MISO continued to pursue improvements to lower the cost of congestion and improve dispatch efficiency.

- In October 2015, MISO reached a settlement with SPP and other parties to increase the constraint on flows between the MISO South and Midwest subregions from 1,000 MW up to levels ranging from 2,500 MW to 3,000 MW. This increased economic transfers between regions and allowed MISO to capture substantial dispatch savings.
- MISO and the IMM have worked with transmission owners to improve the utilization of the transmission system by obtaining more accurate facility ratings. This included a pilot program with one transmission owner to expand the use of temperature-adjusted, emergency ratings. This program has been successful and we recommend that MISO expand it to include more constraints and other transmission owners.

Although improvements have been made, we are concerned that a significant amount of congestion could have been avoided or managed more efficiently. For example, we found that more than $450 million of the congestion from January 2016 to May 2017 was incurred on constraints in cases where more than one planned outage was scheduled that affected the same constraint. Some of these planned outages were also scheduled when planned transmission outages were occurring. We believe congestion could have been reduce significantly in 2016 if MISO had expanded authority to coordinate planned outages.

Not all of the $1.4 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 $737 million in 2016, down two percent from last year. These congestion costs are used to fund MISO's FTRs.

FTR Shortalls and Balancing Congestion Shorfalls

FTRs represent the economic property rights associated with the transmission system. FTRs are acquired in MISO-administered auctions 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 2016. FTR shortfalls arise when insufficient day-ahead congestion is collected to fully fund the FTRs. Under-funding FTRs degrades the value of the FTRs. Ultimately, this harms transmission customers that receive reduced revenues from the sale of the FTRs. Therefore, the full funding in 2016 is a good outcome and MISO should ultimately consider guaranteeing full funding of FTRs.

Balancing congestion shortfalls (negative balancing congestion revenue) occurs when the transmission capability available in the real-time market is less than the capability scheduled in the day-ahead market. In other words, the network was over-scheduled in the day-ahead market, which tends to be caused by real-time transmission outages, derates, or loop flows that were not anticipated in the day-ahead market. Balancing shortfalls are uplifted to MISO's customers. Balancing congestion costs increased 47 percent in 2016 to nearly $41 million. These levels of balancing congestion costs indicate that consistency between the day-ahead and real-time market models and assumptions could likely be improved.

Market-to-Market Coordination and External Congestion

MISO incurs a substantial amount of congestion on external constraints located in PJM or SPP, which are coordinated through the market-to-market processes. Likewise, there are many MISO constraints that are coordinated with PJM and SPP because generation in these areas affect the flows on these constraints. The number of MISO constraints that need to be coordinated with PJM are growing rapidly as PJM has taken dispatch control of increasing numbers of MISO generators via pseudo-ties. Over the past year, more than one-hundred new market-to-market constraints in MISO have been defined because of the MISO units that have been pseudo-tied to PJM.

Congestion on MISO's market-to-market constraints grew 26 percent in 2016 to $377 million, which is more than one fourth 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 the market-to-market coordination operate as effectively as possible. To that end, we evaluated whether the RTOs are defining new market-to-market constraints when warranted and activating existing market-to-market constraints in a timely manner. We found $238 million in congestion on MISO constraints that: a) likely should have been defined as market-to-market constraints ($192 million), b) were delayed in being defined ($41 million), or c) were delayed in being activated after they were defined ($5 million). These results indicate that the RTOs should improve the automation of their testing process to ensure that constraints are appropriately tested and activated to coordinate congestion efficiently.

Lastly, some of the most costly market-to-market constraints are constraints that are dominated by generation in the non-monitoring RTO area (e.g., SPP or PJM constraints dominated by MISO or vice versa). This situations have sometimes caused the RTOs to abandon economic coordination and seek other means to manage the constraint. In these cases, substantial savings can be achieved by transferring the monitoring responsibility for the constraint to the non-monitoring RTO. Hence, we recommend MISO continue working with SPP and PJM to implement a procedure to transfer the monitoring responsibility when appropriate.

Day-Ahead Market Performance

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 2016:

- The difference between day-ahead and real-time prices was 0.4 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, particularly in MISO South.

Virtual transactions provided essential liquidity and improved the convergence of day-ahead and real-time energy prices. Cleared virtual transactions increased by more than 50 percent in 2016, resulting in lower overall profitability of virtual trades. Most of this virtual trading is by financial participants and the report shows that roughly 60 percent of this virtual trading improved price convergence and economic efficiency in the day-ahead market. Hence, virtual trading continues to be a vital component of the MISO's market. The improvements MISO has made in the allocation of RSG costs have resulted in more active virtual trading and a more liquid day-ahead market than any other market we monitor.

Price convergence was worst at congested locations in 2016, as in prior years. Price-insensitive transactions continued to frequently be placed to establish an energy-neutral (balanced) positions (offsetting virtual supply and demand at different locations) to arbitrage congestion-related price differences. These positions are valuable in improving the convergence of congestion between the day-ahead and real-time markets but would be more effective if they could be submitted price-sensitively through a virtual spread product. Participants today must submit these transactions with prices that compel both sides of the position to clear, which increases the risk of the positions. Accordingly, we continue to recommend MISO develop a virtual spread product that may be submitted price sensitively, which should improve the convergence of day-ahead and real-time congestion patterns.

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 2016, as indicated above, falling 3 percent relative to 2015.

Real-Time Price Formation

In March 2015, MISO implemented the Extended Locational Marginal Pricing (ELMP) algorithm. ELMP is intended to improve price formation in the real-time energy and ancillary services markets by allowing prices to better reflect the true marginal costs of supplying the system at each location. ELMP reforms pricing by allowing:

- Online, inflexible fast-start resources to set the LMP when they are economic.[2] These are online "Fast-Start Resources" and demand response resources.
- Offline fast-start resources to be eligible to set prices during transmission or energy shortage conditions.

MISO's initial ELMP rules permitted only five percent of the online peaking resources to set prices. In May 2017, MISO implemented Phase 2 of ELMP that would have allowed 16 percent of peaking resources dispatched in 2016 to set prices. While this is an improvement, the vast majority of the peaking resources utilized by MISO are still ineligible to set real-time prices. Therefore, we recommend that ELMP be extended to most of the remaining peaking resources, which would have reduced the $17 million in RSG payments made to these units.

2 Fast-Start Resource is a term defined in the MISO Energy Markets Tariff term 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…."

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. Our evaluation revealed that only seven percent of the offline resources that set prices under ELMP appeared to be both feasible and economic. Accordingly, we conclude that ELMP's offline pricing is inefficiently changing real-time prices during shortage conditions and recommend that MISO disable the offline pricing logic.

Real-Time Generator Performance

Our greatest concern regarding the real-time market is the poor performance of some of the generators in following MISO's dispatch instructions. Accounting for poor performance over a period of an hour, the accumulated dragging by MISO's generators (producing less output than had they followed MISO's instructions) in 2016 averaged 158 MW and averaged almost 600 MW in the worst 10 percent of the intervals. Although this is an improvement over 2015, it 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 greatly improve incentives for generators to follow dispatch signals. We have also recommended better tools for operators to identify poor generator performance and State-Estimator model errors that are contributing to inefficient dispatch. These changes will improve generators' performance and would have lowered DAMAP by one third (more than $12 million) in 2016.

Wind Overforecasting

We determined that average deviations by wind units are larger than any other class of resource. These deviations occur because a number of wind units tend to substantially overforecast their output. The forecast is used by MISO to establish wind units' dispatch maximum, and because their offer prices are low, also usually their dispatch level. These results raise concerns because they undermine the efficiency of MISO dispatch and may lead to unjustified payments to the wind resources. The wind deviations contributed to increased congestion and under-utilization of the transmission system, 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
- Day-Ahead Margin Assurance Payments (DAMAP) settlement rules can allow wind resources to earn more revenue by deliberately overforecasting their output than by forecasting accurately.

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.

Real-Time Settlements

MISO's real-time market produces new dispatch instructions and prices every five minutes, but settlements are based on hourly-average prices. This inconsistency can create incentives for suppliers to be inflexible. For this reason, MISO instituted Price Volatility Make-Whole Payments (PVMWP) to ensure that suppliers are not harmed when they respond to MISO's five-minute dispatch instructions. Total PVMWPs, the vast majority of which are DAMAP, rose 1.6 percent in 2016 as price volatility at the resources' locations increased by two percent.

PVMWPs will be substantially reduced and generators will have stronger incentives to be flexible and follow MISO's dispatch instructions when MISO implements five-minute settlements for generators in early 2018. We have recommended this important change for a number of years because better generator performance will produce production cost savings for the system and improve reliability. FERC endorsed this by issuing a rulemaking that requires RTOs to settle with generators in the same time increments as their dispatch (i.e., five-minute settlements for MISO).[3]

In addition to this change, our evaluation in this report indicates that roughly one-third of MISO's DAMAP is paid to units because they are not following MISO's dispatch instructions or to wind resources that are not forecasting their output accurately. The wind resources are only eligible for these DAMAP revenues because of the flaw in MISO's tariff that we recommend they correct as quickly as possible. To address the broader issue, we recommend that MISO reform its DAMAP and RTORSP formulas to only make payments to resources that are performing reasonably well in following MISO's dispatch instructions. This will not only lower the costs of these payments, but improve the incentives for generators to perform well.

Uplift (RSG) Costs

Revenue Sufficiency Guarantee (RSG) payments are made in both the day-ahead and real-time markets to ensure suppliers' offered costs are recovered when a unit is dispatched.

- Real-time RSG payments fell 1.6 percent to $5.2 million per month.
- Day-ahead RSG costs fell by almost 50 percent to $3.4 million per month. Slightly more than half of these payments. Almost 60 percent of the day-ahead RSG costs were associated with Voltage and Local Reliablity (VLR) commitments in MISO South.

3 FERC Order 825, Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators, issued June 16, 2016.

Most of these RSG reductions were due to lower fuel prices and improvements in the procedures for satisfying the VLR needs in MISO South. The RSG associated with VLR requirements in MISO South is attributable to reliability needs that are not reflected in the market. We have recommended that MISO develop a new operating reserve product that would reflect these needs and establish prices that incent participants to provide it in both the short-term (by committing of resources in the area) and long-term (by building new resources in the area).

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 on its network efficiently. Our analysis in this report shows that congestion on the constraints affected by these units have increased by 152 percent on a monthly average basis from before the pseudo-ties were implemented. Our analysis in this Report 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 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. Earlier this year, 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 MISO capacity resources to PJM, 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 2016, importing an average of 5.3 GW per hour in real time. MISO remained a net importer of energy from PJM in 2016, with imports averaging roughly 1.2 GW per hour. Price differences between MISO and neighboring areas create incentives to schedule imports and exports that alter the net interchange between the areas. If interface prices accurately reflect the relative cost difference between the neighboring RTOs (including congestion costs), then scheduling between the RTOs that are consistent with the price differences is efficient and desirable. However, efficient interchange is currently compromised by several shortcomings in the market design, including:

- Flawed interface pricing on market-to-market and other external constraints, and
- Suboptimal and poorly-coordinated interchange scheduling.

Addressing these issues is important because they can lead to inefficient transactions that 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. For example, when MISO calculated congestion prices at the PJM interface for imports from PJM, it previously assumed the power would come from all over PJM's system (i.e., all generator locations). This was a good methodology because, in most cases, the marginal generators are located throughout an RTOs footprint. However, PJM has generally assumed that the power sources from a limited number of points near the seam, which is not accurate and tends to inflate the congestion pricing at the interface. MISO recently implemented PJM's approach for the MISO-PJM interface. Unfortunately, our analysis indicates that the PJM approach will result in less efficient imports and exports and raise costs for customers in both regions, but we will monitor the actual results.

Ultimately, we continue to recommend that MISO implement an efficient interface pricing framework by: a) removing all external constraints from its interface prices (i.e., including only MISO constraints), and b) adopting accurate assumptions regarding where imports source and exports sink when when calculating interface congestion.

Interchange Coordination. The most promising means to improve interchange coordination is to allow participants to submit offers to transact within the hour if the spread in the RTOs' real-time interface prices is greater than the offer price (i.e., Coordinated Transaction Scheduling or CTS). MISO worked with PJM to develop and file a CTS proposal and it is scheduled for implementation later this year. Although we support the CTS proposal, we requested that FERC order PJM to eliminate all fees charged to CTS transactions because this will limit its effectiveness. Additionally, we remain concerned that the interface pricing issues described above may diminish the savings achieved by the CTS process.

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 10.7 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 (referred to as "load-modifying resources" or LMRs). MISO does not directly control LMRs and they cannot set energy prices when they are called.

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.

Table of Recommendations

Although the markets performed competitively in 2016, we make 25 recommendations in this report intended to further improve their performance. Nine of the recommendations are new this year, while 16 were recommended in prior reports. This is not unexpected because many of our recommendations require software changes that can require years to implement. MISO addressed three of our recommendations in 2016 and early 2017, 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.[4]

SOM Number	Focus Area	Recommendations	High Benefit	Feasible in ST
Energy Pricing and Transmission Congestion				
2015-1	3	Expand eligibility for online units to set prices in ELMP and suspend offline pricing.	✓	
2015-2	2,3	Expand utilization of temperature-adjusted and short-term emergency ratings for transmission facilities	✓	
2014-3	2	Improve external congestion related to TLRs by developing a JOA with TVA.		
2012-5	1,2	Introduce a virtual spread product.		
2016-1	1,3,7	Improve shortage pricing by adopting an improved contingency reserve demand curve that reflects the expected value of lost load.	✓	
2016-2	3,4	Improve procedures for M2M Activation and Coordination including identifying, testing, and transferring control of M2M Flowgates.	✓	
2016-3	2,7	Enhanced Transmission and Generation Planned Outage Approval Authority.		

4

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	Feasible in ST
Operating Reserves and Guarantee Payments				
2014-2	1,3,7	Introduce a 30-Minute reserve product to reflect VLR requirements and other local reliability needs.	✓	
2016-4	1,3,7	Establish regional reserve requirements and cost allocation.		
2016-5	1,5	Reform DAMAP and RTORSGP rules to improve performance incentives, and reduce gaming opportunities and unjustified costs.	✓	
Improve Dispatch Efficiency and Real-Time Market Operations				
2012-12	1,5	Improve thresholds for uninstructed deviations.	✓	✓
2012-16	1,3	Re-order MISO's emergency procedures to utilize demand response efficiently.		✓
2015-4	1	Enhanced tools and procedures to address poor dispatch performance.		✓
2016-6	1	Improve the accuracy of the LAC recommendations.		✓
2016-7	1,5	Improve forecasting incentives for wind resources by modifying deviation thresholds and settlement rules.		
2016-8	1,7	Validation of wind suppliers' forecasts and use results to correct dispatch instructions.		✓
Resource Adequacy				
2010-14	7	Introduce a sloped demand curve in the RAC to replace the current vertical demand curve.	✓✓	
2013-4	7	Improve alignment of the PRA and the Attachment Y process governing retirement and suspensions.		✓
2014-5	7	Transition to seasonal capacity market procurements.		
2014-6	7	Define local resource zones primarily based on transmission constraints and local reliability requirements.		
2015-5	7	Implement Firm Capacity Delivery Procedures with PJM.	✓✓	
2015-6	7	Improve the modeling of transmission constraints in the PRA.	✓	
2015-7	7	Improve the physical withholding mitigation measures for the PRA by addressing uneconomic retirements.		✓
2015-8	7	Improve the limit on the transfer constraint between MISO South and Midwest in the PRA.		✓
2016-9	7	Qualification of planning resources.		✓

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 initially encompassed parts of 12 states in the Midwest. In 2013, MISO integrated the MISO South region in Texas, Louisiana, Mississippi, and Arkansas. The MISO markets include:

Day-ahead and real-time energy markets. They 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 by MISO through its markets fund FTRs. FTRs allow participants to hedge congestion costs by entitling holders to the congestion price difference between locations in the day-ahead energy market.

Ancillary Services Markets (ASM). These include operating reserves and regulation markets. 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 any capacity market – to facilitate efficient investment and retirement decisions.

A number of key market improvements were implemented in 2016 and early 2017, including:

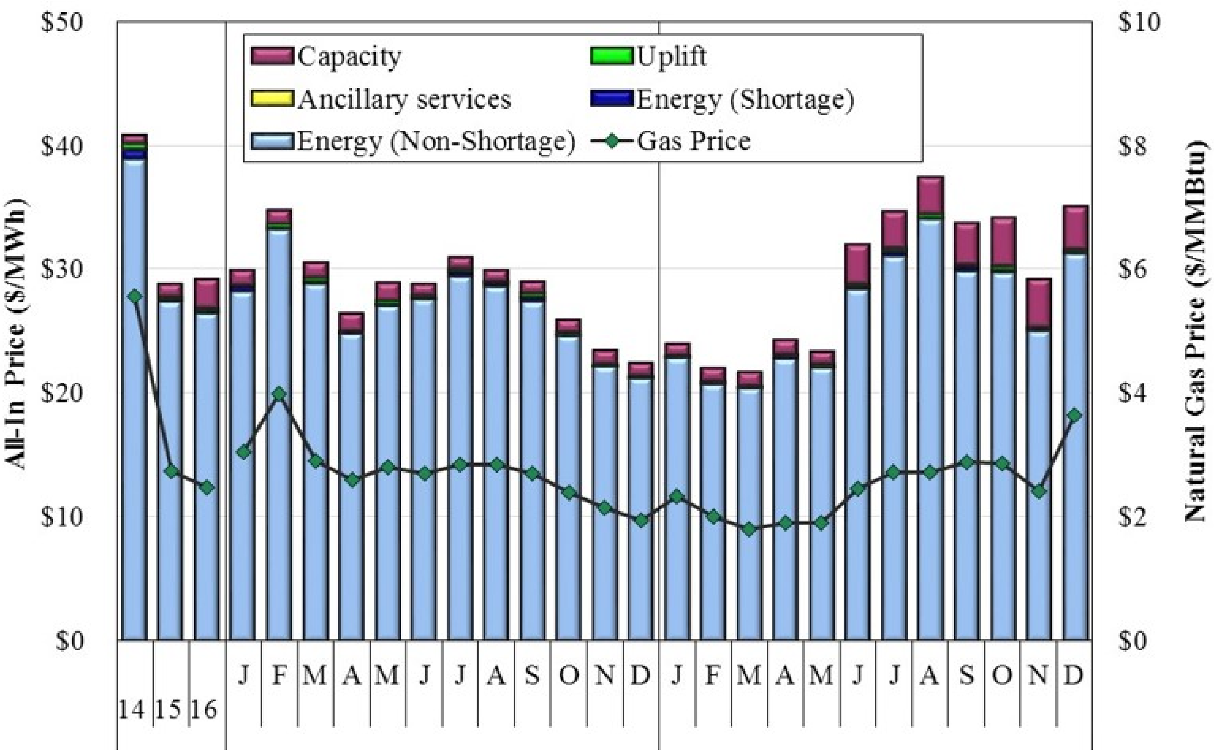
- Settling with SPP and others to create the Regional Dispatch Transfer (RDT) constraint, allowing larger transfers (2500 to 3000 MW) between the Midwest and South subregions;
- Introducing a ramp product in May to allow the system to reduce the costs of satisfying fluctuating system needs;
- Implementing Real-Time Offer Enhancement (RTOE) capability in September, allowing resources to update offers intra-hour to reflect short-term operating limitations.
- Shifting the day-ahead market in November to better align the electricity and gas markets.
- Implementing emergency pricing in July to ensure that additional supply or demand reductions acquired through emergency actions are priced at appropriate shortage levels.
- Modifying the ELMP pricing model to allow more peaking resources to set energy prices.

II. PRICE AND LOAD TRENDS

A. Market Prices in 2016

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
2015–2016



The all-in price increased by one percent in 2016 to an average of $29.27 per MWh. The slight increase was driven by increases in capacity clearing prices from the 2016/2017 Planning Resource Auction (PRA). The energy and ancillary services components of the all-in price actually fell 3 percent relative to 2015, largely because of declining fuel prices in the first half of the year and increases in wind production. The average price of natural gas decreased 10 percent from 2015, while Powder River Basin coal prices were virtually unchanged from 2015 to 2016.

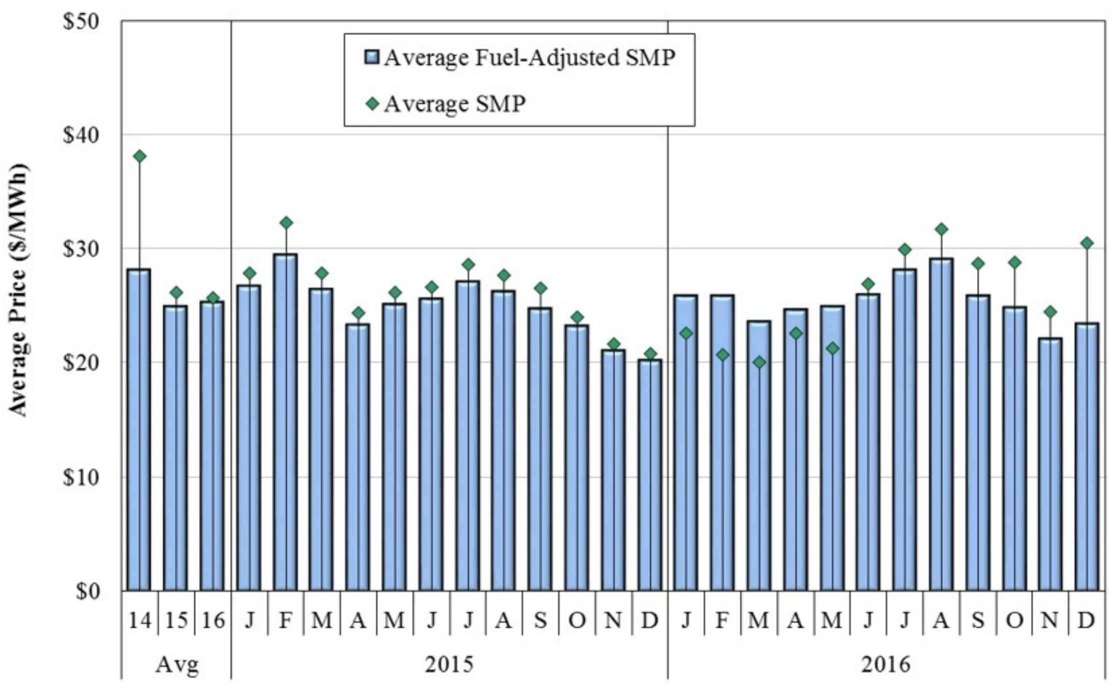
As in prior years, the real-time energy component constituted most of the all-in price. The figure indicates that natural gas prices continued to be a primary driver of energy prices. This correlation is expected in a well-functioning, competitive market because fuel costs are the majority of most suppliers' marginal production costs. Since suppliers in competitive markets have an incentive to offer marginal cost, fuel price changes should result in comparable offer price changes. However, the figure shows that energy prices rose faster than fuel prices in the summer months because the summer temperatures and loads were higher than normal in 2016.

Higher capacity prices in the Midwest subregion added 8 percent ($2.43 per MWh) to the all-in price in 2016. The PRA clearing price in the 2016/2017 delivery year was $72 per MW-day for most zones in the Midwest versus $2.99 per MW-day in the South, because the transfer constraint between subregions was binding. Despite the higher prices in the Midwest, capacity remains undervalued due to shortcomings in the PRA design that we discuss in this report.

Uplift payments include Revenue Sufficiency Guarantee (RSG) payments made to ensure resources cover their as-offered costs and Price Volatility Make Whole Payments (PVMWPs) made to ensure resources are not harmed when following MISO's dispatch instructions. Lower fuel prices led to lower uplift payments in 2016 and reduced the uplift contribution to the all-in price to 20 cents per MWh. Ancillary services costs remained modest at 9 cents per MWh.

To estimate the price 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. To calculate this metric, each real-time interval's SMP is indexed to the three-year average of the price of the marginal fuel during the interval.[5]

Figure 2: Fuel-Adjusted System Marginal Price
2015–2016



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

The average nominal SMP in 2016 fell three percent from 2015. However, the fuel-adjusted SMP *increased* by two percent because of the higher summer loads in 2016. The highest fuel-adjusted SMP occurred in August 2016 when MISO experienced several high-temperature periods and declared a Maximum Generation Alert for the North and Central regions at the end of the month. The fuel-adjusted SMP was also high in July, when MISO declared Hot Weather Alerts throughout the Central and North regions and a Maximum Generation Event (Step 1) on one day. A week later, MISO experienced an Operating Reserve Shortage.

B. Fuel Prices and Energy Production

The continuing decline in fuel prices during 2016 contributed to changes in the generation mix in MISO. In particular, low natural gas prices throughout 2016 increased MISO's output from natural gas-fired units and decreased the generation from coal-fired resources. The following table shows how these changes affected the share of energy produced by fuel type and which generators set real-time energy prices in 2016.

Table 1: Capacity, Energy Output, and Price-Setting by Fuel Type
2015–2016

	Unforced Capacity				Energy Output		Price Setting			
	Total (MW)		Share (%)		Share (%)		SMP (%)*		LMP (%)	
	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
Nuclear	12,432	12,432	9%	9%	16%	16%	0%	0%	0%	0%
Coal	59,181	53,471	42%	41%	50%	46%	62%	55%	95%	85%
Natural Gas	58,013	55,367	42%	42%	24%	27%	37%	44%	94%	85%
Oil	2,063	1,832	1%	1%	0%	0%	0%	0%	0%	0%
Hydro	3,603	3,478	3%	3%	1%	1%	1%	1%	2%	2%
Wind	2,412	2,796	2%	2%	7%	8%	1%	1%	45%	32%
Other	1,688	2,076	1%	2%	1%	2%	0%	0%	4%	3%
Total	**139,391**	**131,452**								

** In 2016, we updated our methodology for SMP price-setting to allow for multiple fuels to be marginal in the same interval.*

The lowest-cost resources (coal and nuclear) operate at the highest capacity factors and coal continued to produce the greatest share of energy. Natural gas-fired output grew from 24 percent in 2015 to 27 percent in 2016, yet remains lower than its 42 percent share of capacity. Coal-fired resources now constitute a slightly smaller share of MISO's capacity than last year, and they produced 46 percent of MISO's output in 2016, down from 50 percent in 2015.

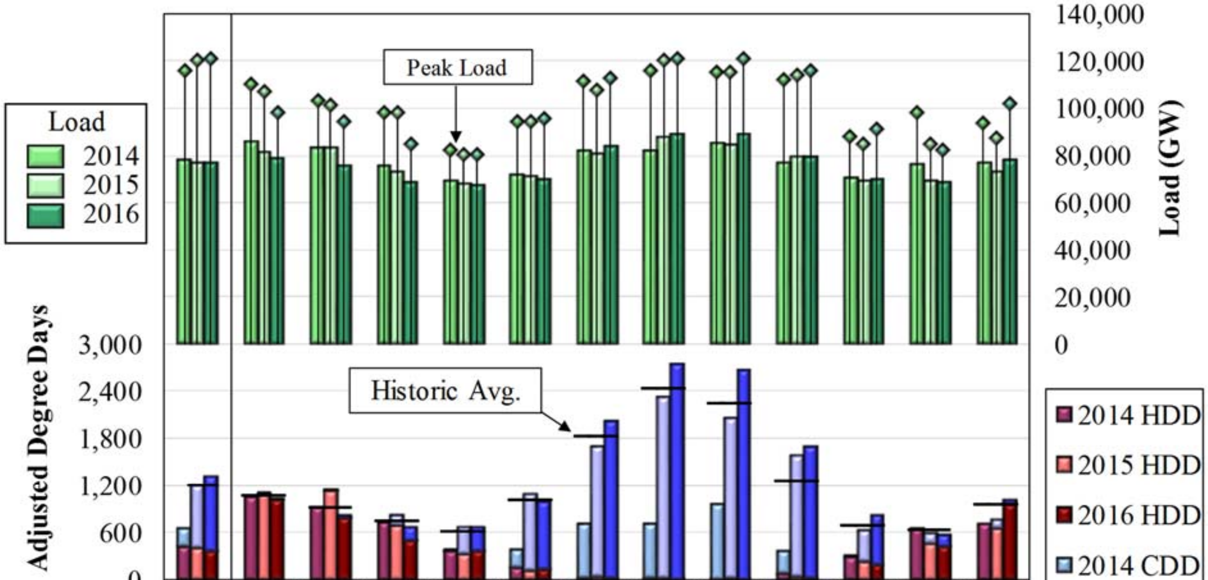
Although natural gas-fired units produce a modest share of the energy in MISO, they play an important role in setting energy prices. Gas-fired units set the system-wide price in 44 percent of all intervals for the year, up from 37 percent in 2015. Gas-fired resources effectively set the system-wide prices in almost all peak hours, because gas rarely sets prices overnight when prices are lower. Congestion frequently causes gas-fired units to set prices in local areas when lower-cost units may be setting the system-wide price. Hence, natural gas-fired resources set LMPs in local areas in 85 percent of all intervals, highlighting why natural gas prices are an important driver of energy prices. Coal-fired resources set the system-wide price in 55 percent of intervals, down from 62 percent in 2015.

The capacity values in Table 1 are planning values, so they are derated from the nameplate level by more than 13 GW. This derating has the largest effect on wind resources that are only two percent of MISO's planning capacity. Although wind resources' share of both energy and capacity is well below 10 percent, wind resources set LMPs in local areas (generally at negative prices) in almost one third of all intervals because they were frequently ramped down to manage congestion.

C. Load and Weather Patterns

Long-term load trends are driven by economic and demographic changes in the region, but short-term load patterns are 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.[6]

Figure 3: Heating- and Cooling-Degree Days
2014–2016



% Chg 15-16	Avg	J	F	M	A	M	J	J	A	S	O	N	D
Avg. Load	0%	-3%	-10%	-5%	-1%	-2%	4%	1%	5%	0%	1%	-1%	7%
Degree Days	9%	-6%	-27%	-20%	-1%	-8%	19%	18%	30%	7%	30%	-4%	30%

6 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.

Although the degree days increased in 2016, the average load in MISO remained unchanged compared to 2015 levels. Total degree days increased by nine percent, primarily because the summer and early fall in 2016 were warmer than in recent years. Winter conditions early in the year were significantly milder than normal in most MISO areas, leading to fewer heating-degree days during typically colder months.

Annual Peak Load on July 21

MISO set its annual peak load of 121.0 GW on July 21, which was one GW higher than the peak load in 2015. Actual peak load was roughly five GW lower than the forecasted peak of 125.9 GW from MISO's *2016 Summer Resource Assessment.* On July 21:

- MISO declared a Maximum Generation Event and remained in Conservative Operations through the evening of July 22 because it had forecasted load of nearly 125 GW.
- The real-time load was substantially below the day-ahead and mid-term forecasts (made on the morning of July 21), because storms in Wisconsin, Michigan, and Northern Indiana reduced temperatures and loads in those areas. Additionally, market participants voluntarily curtailed loads of nearly 1,600 MW during the emergency event.
- The day-ahead load forecast was 121.2 GW, and the mid-term load forecast (MTLF) called for approximately 125.5 GW. Given that the MTLF informs commitment decisions, MISO committed resources in real time based on a higher forecast load than actually materialized.
- MISO committed 195 turbines, most of which were ultimately unnecessary because the peak load was much lower than the forecast, causing them to lower real-time prices and leading to $1.6 million in real-time RSG.
- The turbines committed did not set prices because very few were eligible under Extended Locational Marginal Pricing (ELMP). We conducted a simulation that showed that expanding the eligibility rules would have raised peak hour prices by 38 percent on July 21 and lowered real-time RSG by 14 percent.
- Emergency Pricing rules implemented on July 1 called for MISO to apply a proxy offer floor price to all emergency MWs, but the emergency MWs did not set the price because they were not deemed necessary by ELMP.

Other Peak Load Days in 2016

MISO experienced several other weather-related events during the summer months in 2016. In June, high loads and outages in MISO South resulted in substantial congestion into the South, when the RDT constraint was binding. MISO declared Severe Weather Alerts and Conservative Operations and Local Transmission Operators declared emergency conditions on several days. On June 17, MISO issued a Maximum Generation Alert in the South. MISO also experienced several hot periods in August and declared local Conservative Operations for severe flooding conditions in the Amite South and DSG load pockets. On August 29, MISO issued a Maximum Generation Alert for the North and Central regions due to weather conditions.

D. 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 2016.

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 sufficient to meet the system's needs. Figure 4 and Figure 5 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).

Figure 4: Net Revenue Analysis

Midwest Region, 2014–2016

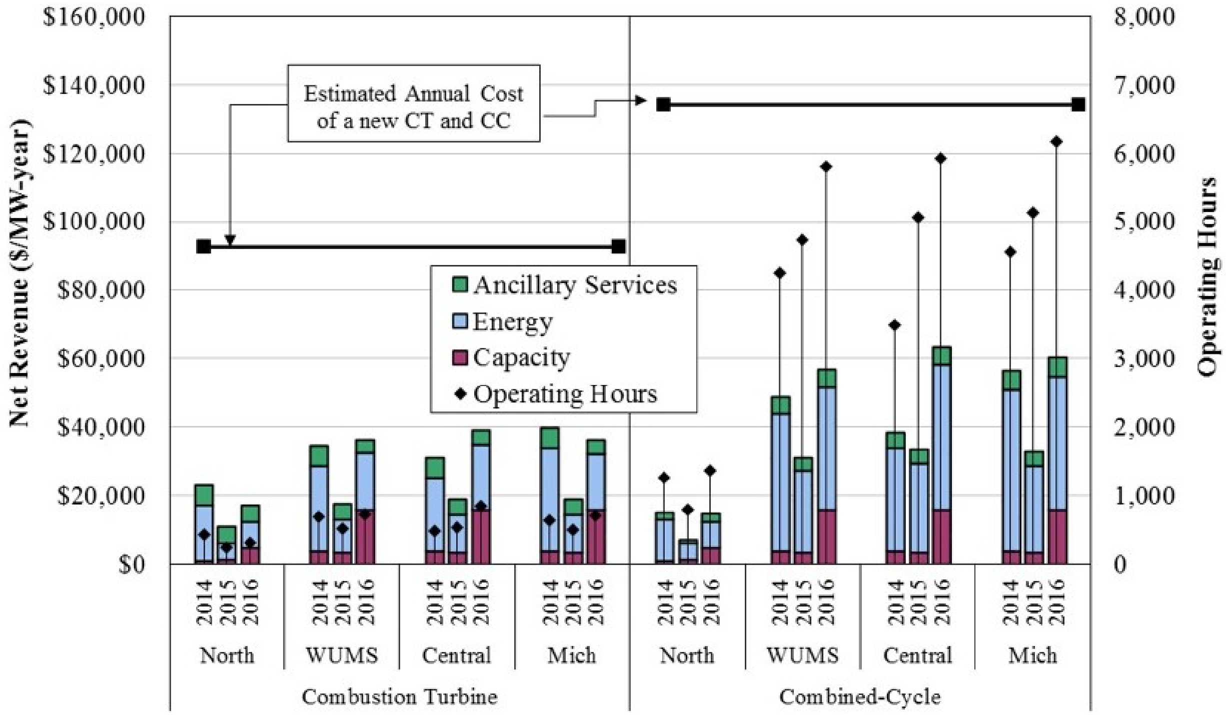
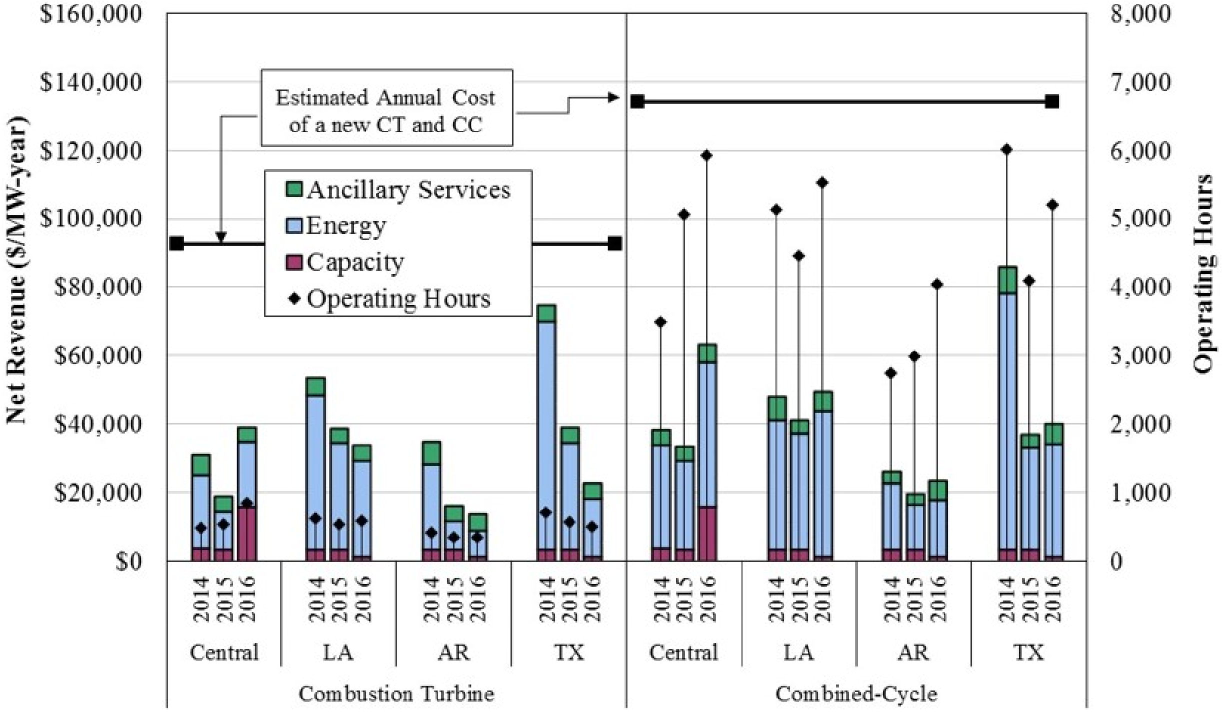


Figure 5: Net Revenue Analysis
South Region, 2014–2016



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

Net revenues for combustion turbines in the South region generally decreased as capacity prices and congestion levels fell in 2016. Estimated net revenues in the Midwest Region for both types of units increased substantially in 2016 because of higher capacity prices and higher prices during the summer months. Nonetheless, net revenues continue to be substantially less than CONE in all regions. The relatively low net revenues are consistent with expectations, because of the small prevailing capacity surplus and capacity market design issues that we describe in this report.

Capacity market design issues continue to undermine MISO's economic signals. This raises particularly timely concerns, because MISO's capacity surplus is dissipating as resources are facing substantial economic pressure and competitive suppliers are incented to export capacity to PJM. To improve these price signals, we recommend a number of changes to both the energy and capacity markets in this Report. The next section discusses the supply in MISO in more detail and evaluates the design and performance of the capacity market.

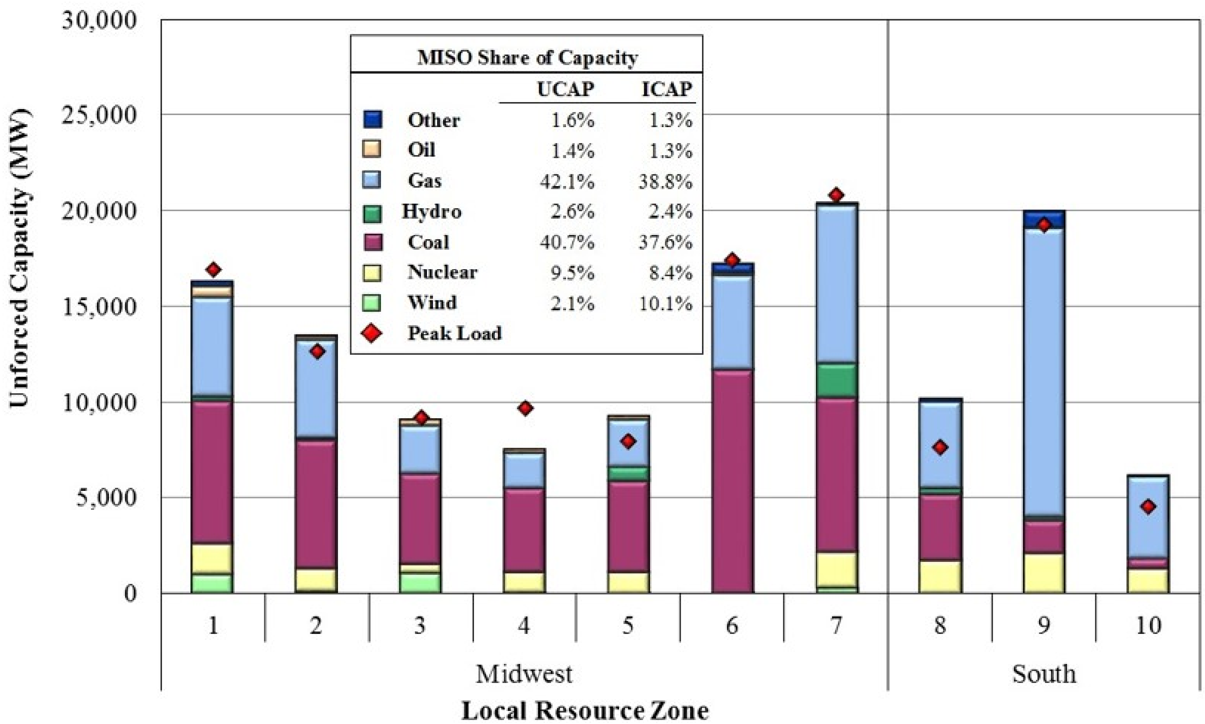
III. Resource Adequacy

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 capacity distribution of existing generating resources by Local Resource Zone. Figure 6 shows the distribution of Unforced Capacity (UCAP) at the end of 2016 by zone and fuel type, along with the 2016 coincident peak load in each zone. UCAP was based on data from the MISO PRA for the 2016/2017 Planning Year. UCAP values account for forced outages and intermittency; therefore, UCAP values for wind units are lower than Installed Capacity (ICAP) values (as shown in the inset table). Hence, although wind is 10 percent of MISO's ICAP, it is only two percent of its UCAP.

Figure 6: Distribution of Existing Generating Capacity
By Fuel Type and Zone, December 2016



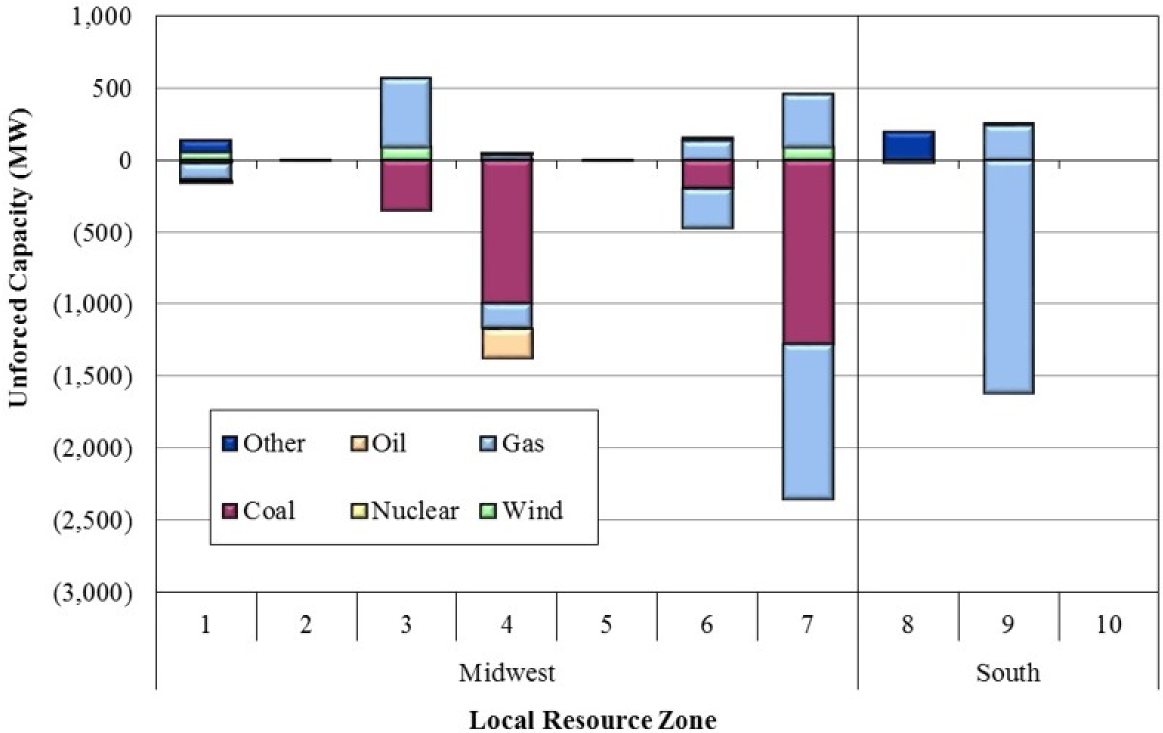
This figure shows that gas-fired resources now account for a larger share of MISO's capacity than any other capacity type including coal-fired resources. The figure also shows that the gas-fired capacity shares are largest in MISO South, which tends to result in large interregional flows from the South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

Additionally, because the average energy output from wind units in the western zones (i.e., zones 1 and 3) is generally greater than those units' UCAP credit, the western areas produce substantial surplus energy when wind output is high, resulting in large west-to-east flows and congestion.

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 and retirements during 2016.

Figure 7: Distribution of Additions and Retirements of Generating Capacity
By Fuel Type and Zone, 2016



Capacity Losses

In 2016, 6.8 GW of resources exited MISO, of which nearly 4 GW was gas-fired capacity that retired, suspended, or pseudo-tied out of MISO. More than half of these resources were located in the South. In total, more than three GW of lost capacity consisted of coal-fired resources, two-thirds of which was sold into PJM. Capacity exports to PJM have grown rapidly where the price of capacity has been more reflective of its reliability value.

In recent years, the U.S. Environmental Protection Agency (EPA) has issued several environmental regulations that required older coal units to install costly retrofits in order to continue operating, and multiple resources retired in order to avoid incurring those costs. Additional resources have announced their intentions to suspend or retire in 2017.

New Additions

Most new capacity additions in MISO were natural gas-fired resources, totaling more than 2.2 GW. In 2016, 1.4 GW of renewables entered in the Midwest region, including a 100-MW solar farm that entered on December 1, 2016. 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 estimatd to cost more than $6.6 billion. Four of these projects are completed, five are underway and expected to be completed between 2017 and 2019, and the remaining eight are pending. In April 2017, a new gas-fired combined-cycle unit entered MISO.

C. Planning Reserve Margins

This subsection summarizes capacity levels in MISO and their adequacy for satisfying the forecasted peak loads for summer 2017. We have worked closely with MISO to ensure that our Base Case planning reserve level is consistent with MISO's assumptions in its *2017 Summer Resource Assessment,* with one notable exception. MISO assumes a transfer limit assumption of 1,500 MW (consistent with the 2017/2018 PRA). We assume a probabilistic derated transfer capability of 2,000 MW, which results in a slightly higher planning reserve margin. 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		
			High Temperature Cases	
	Base Case	Realistic DR	Full DR	Realistic DR
Load				
Base Case	125,020	125,020	125,020	125,020
High Load Increase	-	-	7,211	7,211
Total Load (MW)	125,020	125,020	132,231	132,231
Generation				
Internal Generation	140,850	140,850	140,850	140,850
BTM Generation	4,009	4,009	4,009	4,009
Hi Temp Derates*	-	-	(4,900)	(4,900)
Adjustment due to Transfer Limit**	(2,157)	(2,157)	-	-
Total Generation (MW)	142,701	142,701	139,958	139,958
Imports and Demand Response				
Demand Response***	6,112	4,890	6,112	4,890
Capacity Imports****	3,483	3,483	3,483	3,483
Capacity Exports	(3,636)	(3,636)	(3,636)	(3,636)
Margin (MW)	23,640	22,417	13,686	12,464
Margin (%)	**18.9%**	**17.9%**	**10.9%**	**10.0%**

Notes:
* Based on an analysis of quantities offered into the day-ahead market on the three hottest days of 2012 and on August 1, 2006. Quantities can vary substantially based on ambient water temperatures, drought conditions, and other factors.
** The MISO Base Case Reserve Margin assumes that 2,157 MW (50/50 scenario) of capacity in MISO South cannot be accessed due to the 2,000 MW Transfer Limit (applying probabalistic derates on the 2,500 MW Transfer Limit) so this reduces the overall MISO Capacity Margin.
*** Demand Response reflects cleared Demand Response for 2017/2018 planning year.
**** Capacity imports reflects cleared imports for 2017/2018 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: Base case with a "realistic DR" assumption 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 capability from LBAs, and penalties for failing to respond have all improved. Hence, we believe an 80 percent assumed response is realistic.
- Columns 3 and 4: Assuming "Full DR" and "realistic DR" scenarios under hotter than normal summer peak conditions. These cases are based on 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.[7] In its *2017 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 nearly 19 percent, which substantially exceeds the Planning Reserve Margin Requirement of 15.8 percent.
- 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 due to correlated factors (e.g., during periods of extreme temperatures).

Overall, these results indicate that the system's resources should be adequate for summer 2017 if the peak demand conditions are not substantially hotter than normal. However, planning reserve margins have been decreasing and will likely continue to fall as resources retire and suppliers continue to export capacity to PJM. 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.

7 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.

D. Attachment Y and SSR Status Designations

Attachment Y to the MISO Tariff requires suppliers seeking to retire or suspend a unit to notify MISO 26 weeks in advance. Based on a reliability study, MISO may then designate a resource as a System Support Resource (SSR), which it granted for the first time in 2012. A SSR cannot retire or be suspended until a reliability solution, such as transmission upgrades, can be implemented or the reliability condition no longer exists. The SSR agreement provides for compensation to the market participant during this period of delayed retirement.

In 2016, only one unit in MISO was classified as a SSR and in November 2016, FERC approved the termination of the SSR agreement. This resulted in an estimated savings of $9 million through April 2018, because the resource received more than $0.5 million in gross recovery per month while the agreement was active. On April 1, 2017, MISO entered a SSR agreement with one unit in MISO South.

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

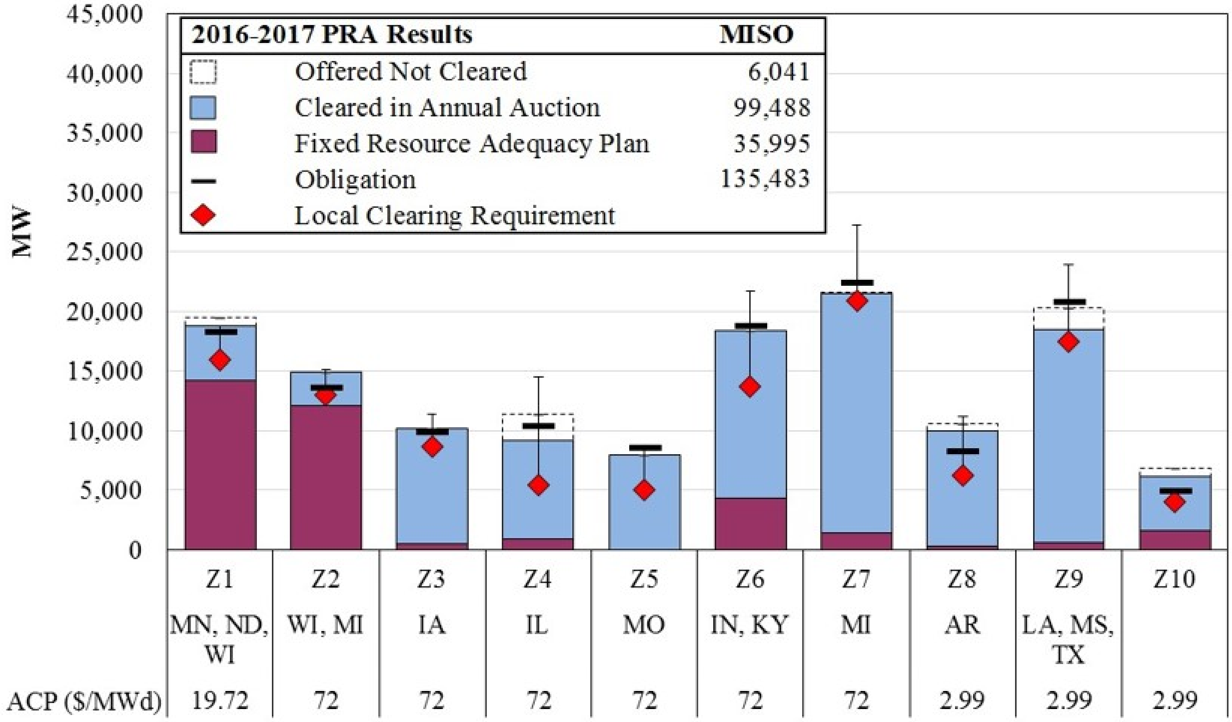
E. Capacity Market Results

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 Planning Resource Auction (PRA). Resources clearing in MISO's PRA earn a revenue stream that, in addition to energy and ancillary services market revenues, should signal when and where new resources are needed.

Figure 8 shows the combined outcome of the PRA held in April 2016 for the 2016-2017 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.

The auction for the 2016-2017 planning year cleared at $72 per MW-day in most zones in the Midwest Regions, which is more than 25 percent of the Cost of New Entry (CONE), while Zone 1 remained export constrained and cleared at $19.72 per MW-day. The 876 MW transfer limit between the Midwest (Zones 1-7) and South (Zones 8 - 10) regions was binding and resulted in a significantly lower clearing price in MISO South of $2.99 per MW-day.

Figure 8: Planning Resource Auctions
2016–2017 Planning Year



As part of the Settlement Agreement with SPP,[8] MISO may normally schedule up to 2,500 MW of transfer capability from MISO South to MISO Midwest in real time, and this amount has been reliably available. 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 and would have affected prices on both sides of the transfer constraint in the PRA. Hence, we recommend MISO adopt a new methodology for establishing the transfer limit in future PRAs.

The 2016/2017 PRA was affected by a number of changes. In particular, MISO:

- Set the initial reference levels for all units to $0 and made other changes to the market power mitigation rules in response to a December 2015 Order from FERC (Resources can still request facility-specific reference levels based on going-forward costs);
- Adjusted the zonal import limits so that they now account for capacity exports from a zone, which is in line with our recommendation made in the 2014 SOM; and
- Reduced the transfer limit between the South and Midwest regions to 876 MW, well below the reasonably expected transfer capability under the RDT; and
- Allowed Attachment Y suspended units to offer into the capacity auction.

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

Additional changes were approved by FERC for the 2017/2018 PRA, which include:

- Imposing physical withholding at the affiliate level, as opposed to 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, which is currently contested on the issue of amortizing capital expenses.

In the 2017/2018 capacity auction, the transfer constraint between MISO South and Midwest was expanded to 1,500 MW. This change, together with the PRA's vertical demand curve, led to a historically low auction clearing price of $1.50 per MW-day throughout the entire MISO footprint. This price is close to zero and fails to reflect the true value of capacity in MISO. In addition, the year-over-year volatility in MISO's auction clearing prices creates uncertainty, leading to highly unpredictable expected future revenue streams for long-term investment decisions. These concerns are discussed in the next subsection.

F. Capacity Market Design

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. Three design flaws undermine the performance of the PRA capacity market: (1) the current "vertical 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. In addition to these three design flaws, we discuss MISO's proposal to reform the capacity market in competitive retail areas at the end of this subsection.

Sloped Demand Curve

The PRA includes a single capacity requirement for each LSE and a deficiency price if the market is short, which is effectively a vertical demand curve. The marginal cost of selling capacity for most units is close to zero, so a vertical demand curve will predictably establish clearing prices close to zero (if supply is not withheld). In addition, the vertical demand curve is inconsistent with the underlying reliability value of excess capacity beyond the planning requirement. The implication of the 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 will improve reliability and lower energy and ancillary services costs for consumers (although these effects diminish as the surplus increases).

To address this flaw, we provided comments to FERC and recommended in prior *State of the Market Reports* that Module E of the Tariff be modified to implement a sloped demand curve.[9] 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 as a result of significant amounts of capacity exiting MISO.

LSEs and their ratepayers should benefit from a sloped demand curve. LSEs in MISO have generally built resources to achieve a small surplus over the minimum requirement because:

- Investment in new resources is "lumpy," occurring in increments larger than necessary to match the gradual growth in a LSE's requirement; and
- The costs of being deficient are large.

Under a vertical demand curve, the cost of the surplus must entirely be borne by the LSEs' retail customers because LSEs will generally receive very little capacity revenue to offset the costs that they incurred to build the resources. This additional capacity provides reliability value to MISO, so the fact that LSEs receive no capacity revenues is inefficient. Adopting a sloped demand curve would benefit most regulated LSEs. Table 3 illustrates this conclusion.

The table shows how hypothetical LSEs are affected by a sloped demand curve when they hold varying levels of surplus capacity beyond the minimum capacity requirement. The scenarios share the following assumptions: (1) a LSE with 5,000 MW of minimum required capacity; (2) net CONE of $65,000 per MW-year and demand curve slope of -0.01 (matching the slope of the NYISO curve); and (3) a market-wide surplus of 1.5 percent, which translates to an auction clearing price of $4.74 per kW-month ($54.85 per kW-year).

For each of the scenarios, we show the amount that the LSE would pay to or receive from the capacity market, along with the carrying cost of the resources the LSE built to produce the surplus. Finally, in a vertical demand curve regime where the LSE will not expect to receive material capacity revenues for its surplus capacity, all of the carrying cost of the surplus must be paid by the LSE's retail customers. The final column shows the portion of the carrying cost borne by the LSE's retail customers under a sloped demand curve.

9 See "Motion to Intervene Out of Time and Comments of the Midwest ISO's Independent Market Monitor," filed September 16, 2011, in Docket No. ER11-4081.

Table 3: Costs for a Regulated LSE Under Alternative Capacity Demand Curves

LSE Surplus	Market Surplus	Capacity Market Revenues ($Million)	Carrying Cost of Surplus ($Million)	Carrying Cost Borne by Retail Load	Surplus Cost: Sloped Demand Curve	Surplus Cost: Vertical Demand Curve
1.0%	1.5%	$-1.43	$3.25	100%	$4.68	$3.25
2.0%	1.5%	$1.41	$6.50	78%	$5.09	$6.50
3.0%	1.5%	$4.25	$9.75	56%	$5.50	$9.75
4.0%	1.5%	$7.10	$13.00	45%	$5.90	$13.00

These results illustrate three important dynamics associated with the sloped demand curve:

- *The sloped demand curve does not raise the expected costs for most regulated LSEs*. In this example, if a LSE fluctuates between a surplus of one and two percent, its costs will be virtually the same under the sloped and vertical demand curves.
- *The sloped demand curve reduces risk for the LSE* by stabilizing the costs of having differing amounts of surplus. The table shows that the total costs incurred by the LSE for surpluses between one and four percent vary by only 26 percent, compared to 300 percent under the vertical demand curve.
- *A smaller share of the total costs are borne by retail customers*. Because wholesale capacity market revenues play an important role in helping the LSE recover the costs of new resources, the LSE's retail customers will bear a smaller share of these costs when the LSE's surplus exceeds that of the market.

The example above shows that a sloped demand curve will not raise the costs for the vertically-integrated LSEs that dominate the MISO footprint. In fact, it will likely reduce the costs and long-term risks facing MISO's LSEs in satisfying their planning reserve requirements, in addition to providing efficient market signals to other types of market participants, such as unregulated suppliers, competitive retail providers, and capacity importers and exporters.

Coordination with Attachment Y Process

The second issue with MISO's current capacity market concerns the participation of resources with Attachment Y applications to retire. Resources that have submitted Attachment Y filings for retirement with effective dates during the planning year may lose their interconnection rights and cannot satisfy their capacity obligations after the effective date by deferring retirement.

The PRA should be a process that assists suppliers in making efficient decisions regarding their resources, including whether to retire their units. In order to do this, MISO would need to modify the PRA rules to allow:

- Units with Attachment Y retirement requests to participate in the PRA and, if they clear, to either a) defer the effective date of the retirement, or b) retire the unit during the planning year if MISO determines it is not needed during the period when it would be unavailable. Absent this flexibility, such units would have to procure substitute capacity for the balance of the planning year. This risk is an inefficient barrier to participating in the PRA.
- Units under SSR contracts to participate in the PRA as price takers without undue risk. There should be an assurance that either a) the SSR contract will not be terminated prior to the end of their capacity obligation, or b) if the SSR contract is terminated prior to the end of the capacity obligation period, a unit's capacity obligation will also terminate.

These changes to the RAC and the Attachment Y processes will allow MISO's capacity market to operate more efficiently and facilitate better decisions by market participants. The latter change to allow units to be unavailable for a portion of the planning year is consistent with the precedence for several other types of capacity resources that are only available during the summer season, including units that are not winterized, units that operate with PPAs that are considered "Diversity Contracts," and load-modifying resources.

One recommended change that would substantially mitigate these concerns is the adoption of a seasonal capacity market. This would better align the revenues and requirements of capacity with the value of the capacity. In this construct, there should be consistently applied requirements that resources are available for the duration of the season.

Local Capacity Zone and Seasonal Issues

The third issue with MISO's current capacity market relates to definitions of local resource zones. Currently, a local resource zone 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.

Additionally, MISO is proposing to procure capacity on a seasonal basis, which we believe would be beneficial. MISO's latest proposal would define two seasons, summer and winter. We have recommended that MISO define four seasons, which would facilitate savings for participants. First, it would allow 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. Second, it would allow suppliers to retire or suspend units at four points in time during the year (between seasons) without having to purchase replacement capacity. This reduces the risks and costs of supplying capacity and should, therefore, ultimately reduce costs to MISO's consumers.

Proposed Capacity Market Changes in Competitive Retail Areas

A well-functioning capacity market that provides efficient price signals would produce sizable benefits for MISO by:

- Coordinating efficient capacity imports and preventing inefficient exports;
- Supporting a vibrant forward market (bilateral contracts);
- Facilitating low-cost merchant investment; and
- Ultimately, generating substantial savings for MISO's consumers.

Ideally, the MISO capacity market should be structured to achieve these benefits in all areas. In competitive retail areas (CRAs) and for competitive suppliers, however, the capacity market is particularly important to facilitate investment and retirement decisions that will maintain adequate resources (i.e., satisfy planning reserve requirements). Competitive suppliers whose resources are key for satisfying the resource adequacy needs in CRAs rely on the market to decide whether to build, retire, or export resources. However, the current PRA is not designed to provide efficient long-term economic signals for competitive suppliers and loads.

In November 2016, MISO filed a capacity market design for CRAs to address this problem. We found this proposal to be unsound and ultimately FERC agreed with our concerns and rejected it in February 2017. However, we worked with MISO to develop a prompt auction alternative that would produce efficient prices for competitive suppliers and loads. This alternative is based on MISO's existing PRA. It would optimize the procurements and prices in the CRAs, while allowing the procurements and prices outside of the CRAs to be determined by MISO's existing market rules. We encourage MISO to reconsider this alternative or similar design improvements to improve the economic signals provided to MISO's competitive suppliers and loads.

IV. Day-Ahead Market Performance

MISO's spot markets for electricity operate in two time frames: real time and 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.[10] Resources that clear in the day-ahead receive commitment and scheduling instructions based on day-ahead results, and they must perform these contractual obligations or be charged the real-time price for any products not supplied.[11] Both the day-ahead and real-time markets continued to perform competitively in 2016.

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;[12]
- 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 its outcomes converge with those of 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).

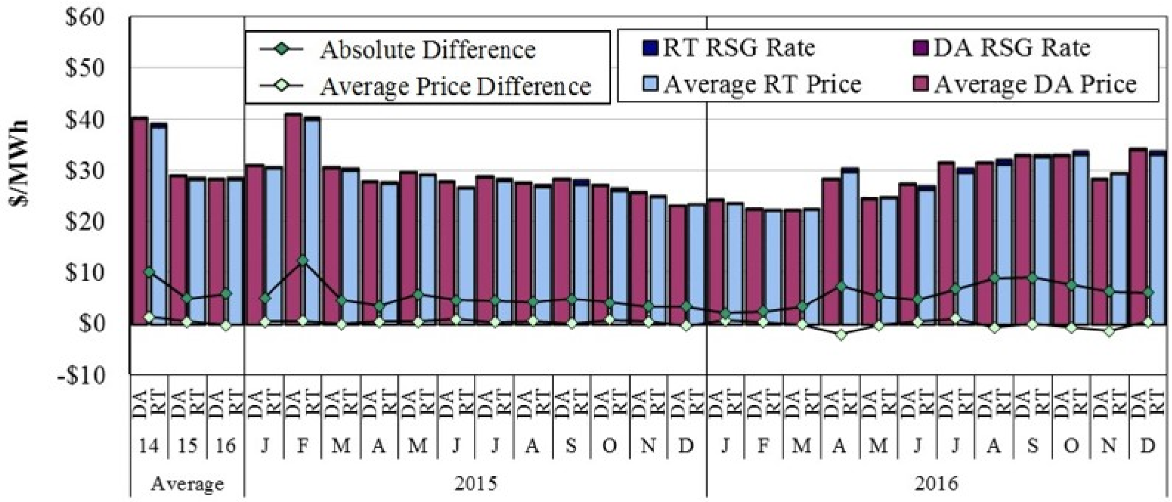
10 In addition to the normal day-ahead commitment, MISO utilizes the Multi-Day Forward Reliability Assessmement Commitment process to commit resources in the day-ahead in order to satisfy reliability requirements in certain load pockets that may require long-start-time resources.

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

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

Figure 9 shows monthly and annual price convergence statistics. The upper panel shows the results for only the Indiana Hub, while the table below shows Indiana Hub and six other hub locations in MISO. Because real-time RSG charges (allocated partly to deviations between real-time and day-ahead schedules) tend to be much larger than day-ahead RSG charges (allocated to day-ahead energy purchases), the table shows the average price difference adjusted to account for the difference in RSG charges.

Figure 9: Day-Ahead and Real-Time Prices
2015–2016



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

	14	15	16	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
	Average			2015												2016											
Indiana Hub	3	1	-1	1	1	0	1	2	3	1	2	0	3	2	-2	2	1	-1	-7	-1	1	3	-2	0	-2	-5	1
Michigan Hub	7	1	0	7	6	-1	2	0	0	0	0	-3	2	3	0	4	3	-1	-6	4	0	5	-9	-2	4	-1	2
Minnesota Hub	1	2	-1	-1	0	-1	2	3	-1	3	0	-2	14	5	3	4	5	-3	2	6	-5	0	-6	-2	-2	2	-6
WUMS Area	2	1	-1	1	0	2	4	1	3	3	0	1	1	-1	0	4	3	0	0	1	-3	-5	-7	1	4	1	-6
Arkansas Hub	-3	1	0	-3	3	-3	4	3	3	-3	0	0	0	6	4	2	2	-3	-3	7	4	-1	0	-3	-2	-6	0
Louisiana Hub	-6	-2	-2	0	2	-10	-2	0	-10	1	-5	0	0	-1	4	2	3	-2	2	1	-14	-1	-4	-3	1	0	1
Texas Hub	-1	-4	1	-1	1	-5	4	-10	4	0	-7	-2	-12	-15	3	1	6	3	-18	13	2	-3	1	2	3	-1	2

Day-ahead premiums in 2016 averaged negative 0.4 percent, or essentially zero, after adjusting for the Day-Ahead and Real-Time Deviation Charges (DDC), which averaged $0.06 and $0.48 per MWh respectively. However, there were a number of congestion episodes that resulted in substantial transitory divergence:

- Increases in planned and unplanned outages of transmission and generation contributed to significant congestion in the spring. Two market-to-market constraints that are primarily affected by inflexible wind in PJM contributed to more than half of the total congestion in the spring. Unplanned outages contributed to congestion on both of these constraints.
- Generator and transmission outages in the South led to a large amount of real-time congestion in Texas at the end of April and congestion in Louisiana and Texas during the summer months.
- High quantities of generator outages and increased wind output contributed to periods of substantial congestion in the fall.

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 would allow a participant to make price-sensitive offers in the day-ahead market to buy or sell only the flow over the network between two locations. This would lower the risk of arbitraging the congestion-related differences between the two markets and improve convergence of the congestion in the day-ahead and real-time 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 10 shows the average cleared and offered amounts of virtual supply and virtual demand in the day-ahead market. It also shows components of daily virtual bids and offers in the day-ahead market in 2015 and 2016. The virtual bids and offers that did not clear are shown as the transparent areas.

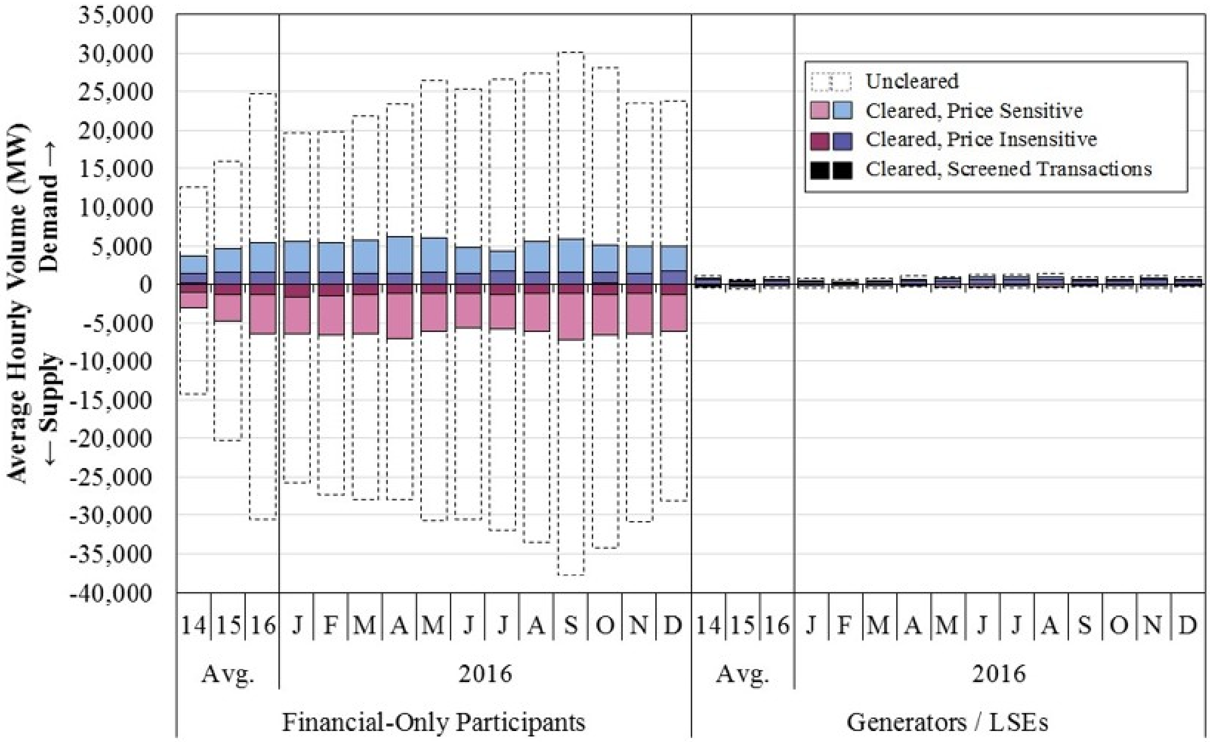
Figure 10 distinguishes between bids and offers that are price-sensitive and those that are price insensitive (i.e., those that are very likely to clear), because price-sensitive transactions are much more valuable in providing liquidity in the day-ahead market and facilitating price convergence. Bids and offers are considered price-insensitive when demand is bid at more than $20 above an "expected" real-time price or supply is offered at $20 below an expected real-time price.[13] In such instances, the participants are effectively indicating a preference for the transaction to clear regardless of the price.

Price-insensitive bids and offers that contribute to a significant difference in congestion at a location between the day-ahead and real-time markets are labeled "Screened Transactions." We routinely investigate these because they generally do not appear rational and lead to price divergence. Therefore, they may represent an attempt to manipulate the day-ahead market.

Figure 10 shows that offered volumes increased by more than 50 percent from last year. Several market participants submitted "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.

13 The "expected" real-time price is based on an average of recent real-time prices in comparable hours.

Figure 10: Virtual Load and Supply in the Day-Ahead Market
2015–2016



Cleared transactions rose 24 percent to 12.6 GW per hour. The increase in both offers and cleared transactions was largely driven by the activity of financial traders. Financial participants, who tend to offer more price-sensitively than physical participants, provided key liquidity to the day-ahead market. The also continued to help moderate the effects of under-scheduled wind in the day-ahead market.

The share of Screened Transactions, which are transactions that may constitute manipulation, fell to less than one percent. In most cases, such transactions do not ultimately raise manipulation concerns. However, we did find conduct from one participant in 2016 that warranted the imposition of virtual bidding restrictions at specific locations. The restrictions remained in place for three months per Module D of the MISO Tariff.

Price-insensitive transactions overall continued to constitute a substantial share of virtual transactions. These transactions 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; 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.

We identify “matched” virtual transactions, which are the subset of price-sensitive transactions whereby the participant clears both insensitive supply and insensitive demand that offset one another in a particular hour. The average hourly volume of matched transactions in 2016 fell by 11 percent from 2015. To the extent that matched transactions are attempting to arbitrage congestion-related price differences, we believe that a virtual spread product that would allow participants to engage in these transactions price-sensitively would be more efficient.

Therefore, we continue to recommend that MISO implement a virtual spread product. Participants using such a spread product would specify the maximum congestion difference between two points that they are willing to pay (i.e., schedule a transaction). This product would settle only on the difference in the congestion and loss components of the LMP, so the participant would bear no energy price risk and would not create a deviation that could cause MISO to be capacity-deficient. Comparable products exist in both PJM and ERCOT.

C. Virtual Profitability

The rate of gross virtual profitability fell from $0.76 per MWh in 2015 to $0.63 per MWh in 2016, which is consistent with increased liquidity and good price convergence. The transactions by financial participants were more profitable than those participants that own generation or serve load, which actually lost $0.11 per MWh on average. Transactions that promote convergence are generally profitable (e.g., selling virtual supply at high day-ahead prices), while those that lead prices to diverge are generally unprofitable.

Virtual supply profitability averaged $0.95 per MWh, although more than half of these profits were offset by real-time RSG costs allocated to net virtual supply. Virtual demand profitability was lower at $0.29 per MWh, which reflects good convergence in 2016 and the fact that it is not allocated real-time RSG charges because vitual demand is generally 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 are improving day-ahead market outcomes.

D. Benefits of Virtual Trading in 2016

We conducted an empirical analysis of virtual trading in MISO in 2016 that evaluated virtuals’ contribution to the efficiency of the market outcomes. We determined that 57 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 (nine 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 total MWhs of cleared virtual transactions that were and were not efficiency-enhancing by market participant type.

Table 4: Efficient and Inefficient Virtual Transactions by Type of Participant
2016

	Financial Participants		Physical Participants		Total	
	Average Hourly MWh	Share of Class	Average Hourly MWh	Share of Class	Average Hourly MWh	Share of Total
Efficiency - Enhancing Virtuals	6,790	*58%*	400	*47%*	7,190	*57%*
Non - Efficiency - Enhancing Virtuals	4,956	*42%*	456	*53%*	5,412	*43%*

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 $65 million in 2016, a 15 percent increase over 2015.

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.
- The losses of inefficient virtual transactions get larger as prices diverge.
- Hence, the total net benefit of virtual transactions were much larger than $65 million in 2016.

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 2016.

Some have argued that virtual transactions can sometimes profit but not produce efficiency benefits. We agree and 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 $34.7 million, roughly two-thirds of which 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 modeling between the day-ahead and real-time markets.

V. Real-Time Market

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 slightly in 2016, which was due in part to severe weather patterns throughout the summer, as well as the increase in transmission congestion (which is a source of volatility). Figure 11 compares 15-minute price volatility at representative locations in MISO and in three neighboring RTOs.

Figure 11: Fifteen-Minute Real-Time Price Volatility
2016

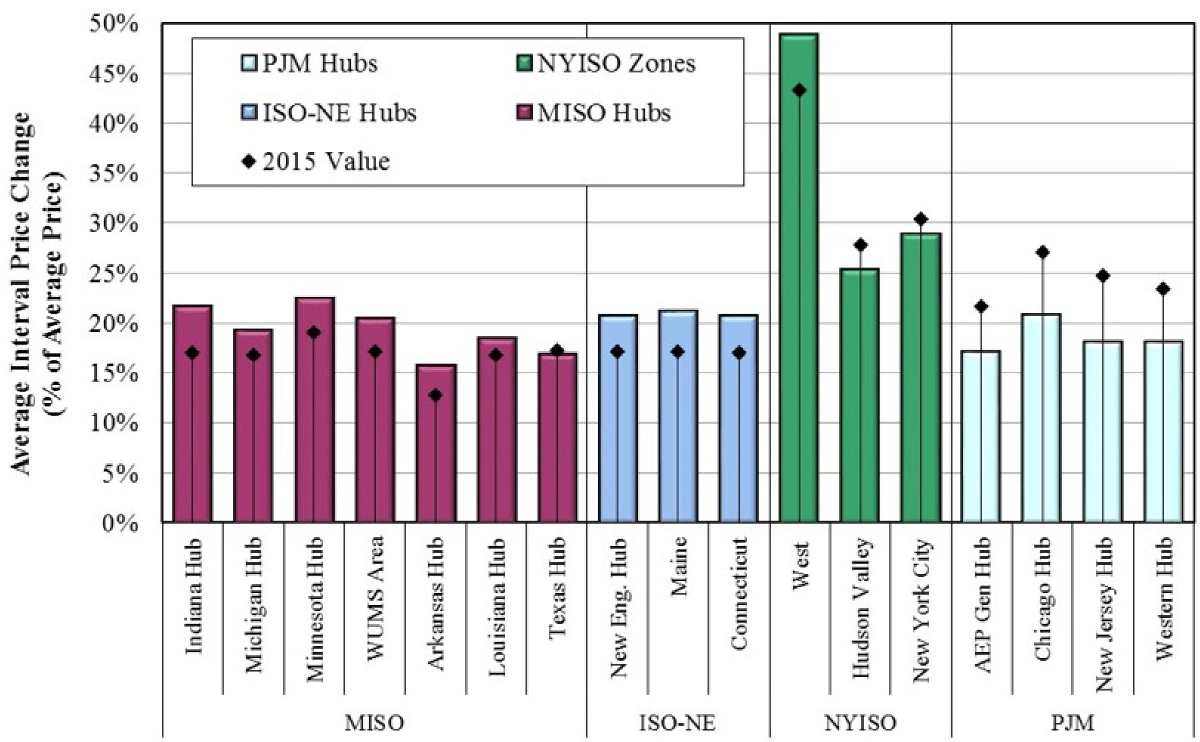


Figure 11 shows that MISO generally had similar price volatility as compared to PJM and ISO New England in 2016, which is impressive because:

- MISO runs a true five-minute real-time market (producing a new real-time dispatch every five minutes).
- PJM and ISO New England dispatch their systems every 10 to 15 minutes, which tends to provide more flexibility and lower volatility (although it is not as effective in balancing supply and demand).
- NYISO dispatches the system every five minutes like MISO, but it has a look-ahead dispatch system that optimizes multiple intervals. All else equal, the multi-period optimization reduces 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 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. The efficiency of real-time commitments improved with the introduction of a Look-Ahead Commitment (LAC) tool. MISO also implemented a "Ramp Capability" product in the spring of 2016, which has resulted in the real-time market holding additional ramp capability when the projected benefits exceed its cost. This product has improved MISO's ability to manage the system's ramp demands and contributed to lower price volatility.

B. Evaluation of ELMP Price Effects

In March 2015, MISO implemented the Extended Locational Marginal Pricing algorithm (ELMP). ELMP is intended to improve price formation in the day-ahead and real-time energy and ancillary services markets by causing prices to better reflect the true marginal costs of supplying energy and ancillary services at each location. ELMP is a reform of the current price-setting engine that affects prices but does not affect the dispatch. ELMP reforms pricing by allowing Fast-Start Resources,[14] some Demand Response resources, and emergency resources to set prices when they are:

- *Online* and deemed economic by the ELMP model; or

14 Fast-Start Resource is a term defined in the MISO Energy Markets Tariff term 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…."

- *Offline* and deemed economic to set prices during transmission or energy shortage conditions.

The first of these reforms was intended to remedy issues that we first identified shortly after the start of the MISO energy markets in 2005. The pricing algorithm in MISO's UDS dispatch software does not always reflect the true marginal cost of the system. This is because inflexible high-cost resources are frequently not recognized as marginal even though they are needed to satisfy the system's needs. The most prevalent class of such units is online natural gas-fired turbines that often have a narrow dispatch range. Because it is frequently not economic to turn them off since they are the lowest cost means to satisfy the energy needs of the system, it is appropriate for the energy prices to reflect the running cost of these units. It undermines real-time prices when these resources are economic, but not refected in prices. Ultimately, this will:

- Increase the need to make RSG payments to cover these units' as-offered costs;
- Not provide efficient incentives to buy in the day-ahead market when lower-cost resources could be scheduled that would reduce reliance on high-cost peaking units in real time;
- Not provide efficient incentives for participants to schedule exports or imports, which can prevent lower-cost energy from being imported to displace the higher-cost peaking units.

Accordingly, the objective of the online pricing reforms in ELMP is to address these inefficiencies and improve price formation in MISO's energy markets.

The second reform allows *offline* fast-start resources to set prices under shortage conditions. Shortages include transmission violations and operating reserves shortages. 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 2016:

- ELMP lowered market-wide real-time prices by $0.01 per MWh on average.
  - The online pricing component of ELMP has raised real-time prices in 7.1 percent of intervals market-wide, resulting in an average increase of $0.09 per MWh.
  - The offline pricing component has affected prices in only 0.6 percent of intervals, but the effects are larger because this component mitigates shortage pricing. On average, it lowered real-time energy prices in 2016 by $0.11 per MWh.
- At congested locations, ELMP affected real-time prices in roughly 10 percent of the intervals and had effects ranging from -$0.81 to $1.34 per MWh on a monthly average basis at the most affected locations.
- As expected, ELMP had almost no effect in the day-ahead market because the overall supply is much more flexible, including virtual transactions.

Evaluation of Online Pricing

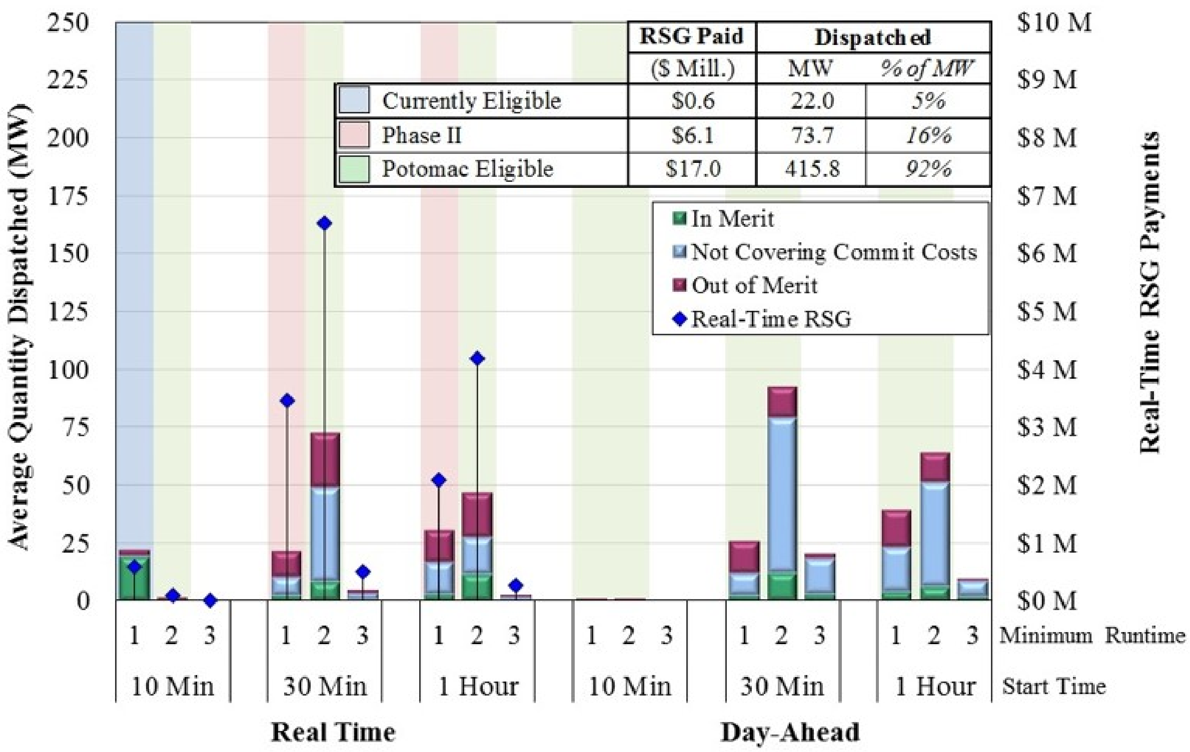
Our prior evaluations concluded that the relatively small effects of the online pricing was attributable to the fact that a very small share of MISO's resoures were initially eligible to set prices. This was expanded somewhat when MISO implemented ELMP Phase 2 in May 2017.

Figure 12 shows all of the energy produced by online peaking resources, separated by:

- Whether they were scheduled in the day-ahead market or after the day-ahead market (i.e., in real time);
- Their start-up time; and
- Their minimum run-time.

Up until May 2017, the only online units eligible to set prices in ELMP are those that: a) can start in 10 minutes or less, b) have a minimum runtime of one hour or less, and c) are not scheduled in the day-ahead market. These units are shown to the far left of the figure (the column shaded in blue), which include only five percent of the peaking resources dispatched by MISO. The additional units that are eligible to set prices under Phase 2 of ELMP are shown by the columns shaded in light red. Although an improvement, the Phase 2 changes only allow 16 percent of MISO's peaking resources to set prices so the effects have been modest.

Figure 12: Eligibility for Online Peaking Resources in ELMP
January 2016 to December 2016



The IMM is recommending that additional units be eligible to set prices, which are shown in the figure by the columns shaded in light green. The IMM proposal would allow 92 percent of all of the peaking resources to set prices, which accounted for $17 million in RSG in 2016.

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 utilize 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 are either not feasible or not economic, the resulting prices will be inefficiently low.

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

Table 5: Evaluation of Offline ELMP Price Setting
2016

	Economic*	Started	Economic & Started
Operating Reserve Shortages	20%	14%	**7%**
Transmission Shortages	33%	7%	**6%**

** Does not include units that were never started, which would increase the values to: 26% for OR shortages and 54% for Tx shortages.*

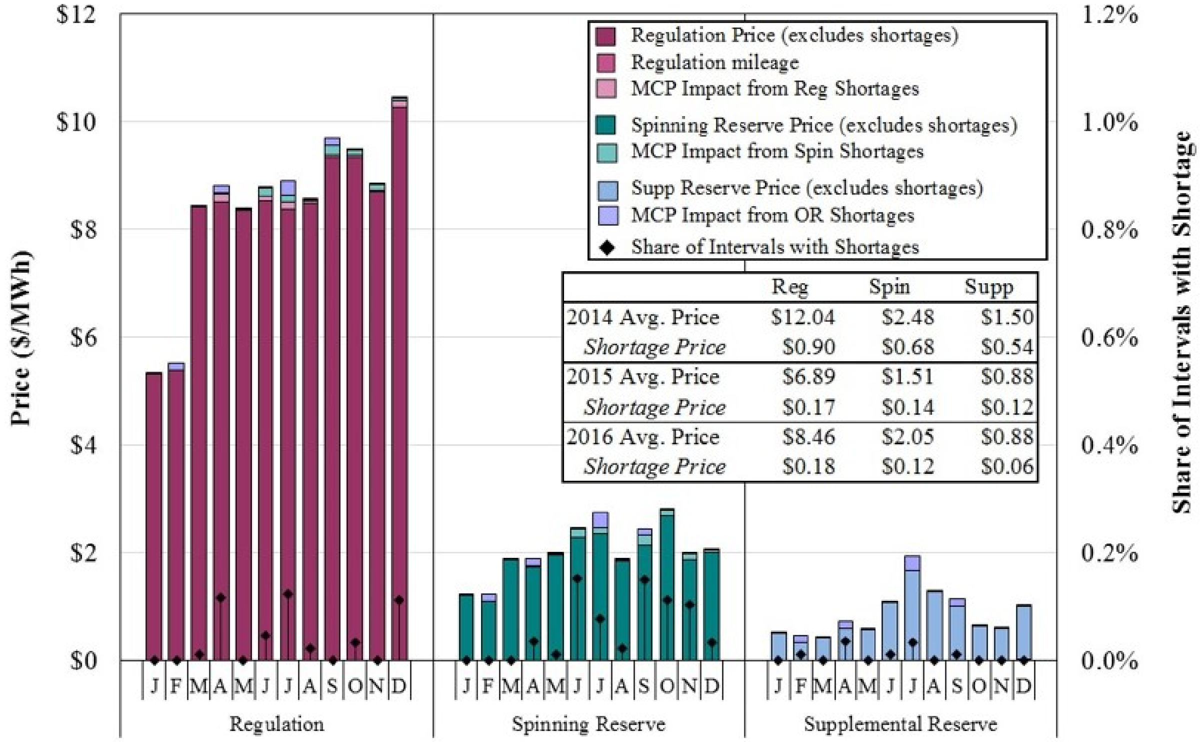
This table shows that the offline units that set prices during both operating reserve and transmission shortages are rarely economic and feasible (less than 7 percent of intervals). Based on these results, we conclude that ELMP's offline pricing component is not satisfying the economic principles outlined above and is leading prices to be less efficient during shortage conditions. As the Commission has recognized, efficient shortage pricing is essential for good market performance. Therefore, we recommend that MISO disable the offline pricing logic.

C. Ancillary Services Markets

ASM continued to perform as expected with no significant issues in 2016. 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 13 shows monthly average real-time prices, the contribution of shortage pricing to each product's price in 2016, and the share of intervals in shortage. MISO's demand curves specify the value of all of its reserve products.[15] When the market is short of one or more of its reserve products, the demand curve for the product will set the price and also be included in the prices of higher-valued reserves and energy through the co-optimized market clearing.

Figure 13: Real-Time ASM Prices and Shortage Frequency
2016



The supplemental reserve prices are for the market-wide operating reserve requirement (the only requirement supplemental reserves can satisfy). Spinning reserves can satisfy the operating reserve requirements, so the spinning reserve price will include a component for the operating reserve shortages. In other words, operating reserves shortages will be included in the price of higher-value reserves and energy. Likewise, regulation prices will include components associated with both spinning reserve and operating reserve shortages.

Monthly average clearing prices for regulating reserves and spinning resources rose slightly in 2016, but remain reasonable. The price for supplemental reserves remained virtually unchanged from 2015.

15 The demand curve for regulation, which is indexed to natural gas prices, averaged $112.01 per MWh in 2016. 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 $3,400 per MWh, depending on their severity.

D. 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 required rather than not serving the energy demand). When an RTO is short of its required 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. Therefore, efficient shortage pricing requires properly-valued reserve demand curves. Efficient shortage prices play a key role in establishing economic signals for new investment, facilitating optimal interchange between markets, and balancing the value of holding reserves subject to the cost of violating transmission constraints. An efficient RDC should abide by three principles:

- Reflect the marginal reliability value of reserves at each shortage level;
- Consider all significant supply-side contingencies, including the risk of multiple contingencies occurring simultaneously; and
- Have no 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 is not consistent with this valuation because:

- Only a small portion of it 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 14 shows the current ORDC and a curve that illustrates the IMM's proposed economic ORDC. Small shortages of less than 4 percent are priced at the lowest step of $200, but as reserve levels fall (and shortages increase) the current ORDC will price 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.[16]

In comparison, the IMM's economic ORDC reflects the expected value of lost load, which we illustrate in Figure 14 based on an assumed VOLL of $12,000 per MWh. We estimated the probability of losing load using a Monte Carlo simulation.[17] The figure also shows that almost all shortages have been modest and priced in the green range shown on the figure.

16 "Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators,"FERC RM16-5-000, Order No. 831, issued November 17, 2016.

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

Figure 14: Comparison of IMM Economic RDC to Current ORDC

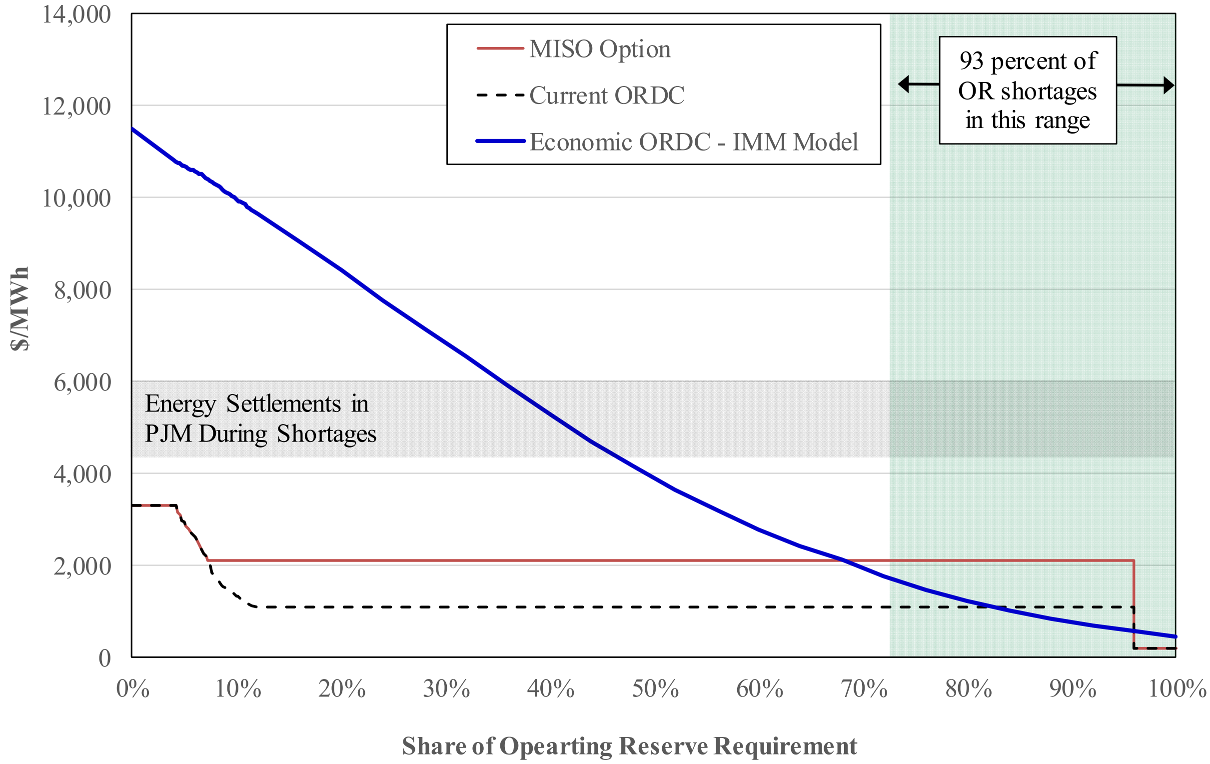


Figure 14 shows that the current curve will set inefficiently high shortage prices under some conditions and inefficiently low shortage prices under others. The sharp increase in the curve at 96 percent of MISO's reserve requirement leads to excessive price volatility at low shortage levels. An economic ORDC aligns shortage pricing with the marginal reliability value of the foregone reserves. This will result in more efficient reserve and energy prices during shortages, which will improve MISO's short-term economic signals to improve generator performance, day-ahead load scheduling, and import/export scheduling. It will also improve MISO's long-term investment signals.

E. Settlement and Uplift Costs

Uplift costs are very important because they are costs that are difficult for customers to 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:

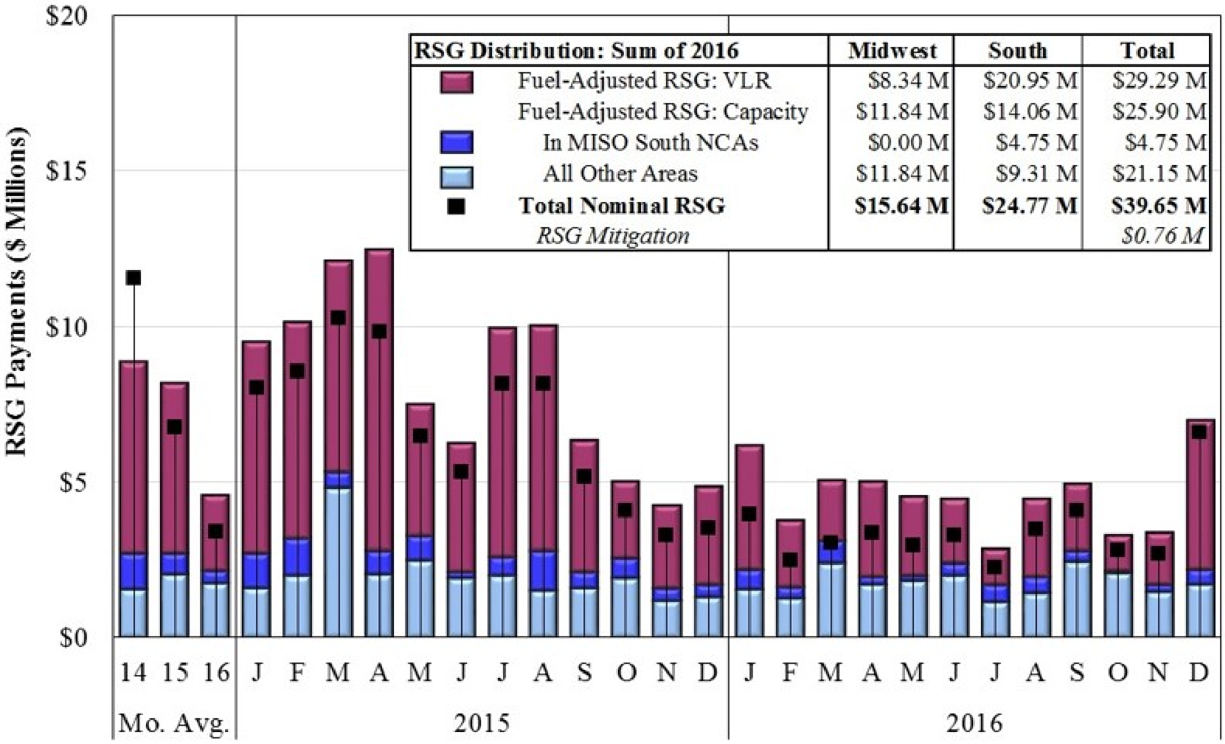
- RSG payments ensure that the total market revenue a generator receives when economically committed is at least equal to its as-offered costs over its commitment period.
- Price Volatility Make Whole Payments ensure suppliers will not be financially harmed by following the five-minute dispatch signals.

Resources committed after the day-ahead market receive a "real-time" RSG payment to ensure they recover their as-offered costs. 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, and FERC proposed that other RTOs adopt a comparable cost allocation method in a recent Notice of Proposed Rulemaking (NOPR).[18]

Day-Ahead and Real-Time RSG Costs

Figure 15 and Figure 16 show monthly day-ahead and real-time RSG payments, respectively. 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.[19] The maroon bars show the RSG paid to units started before the day-ahead for VLR, while the blue bars show the amounts that we determined were paid to units likely commited for VLR by the day-ahead model (but not designated as VLR).

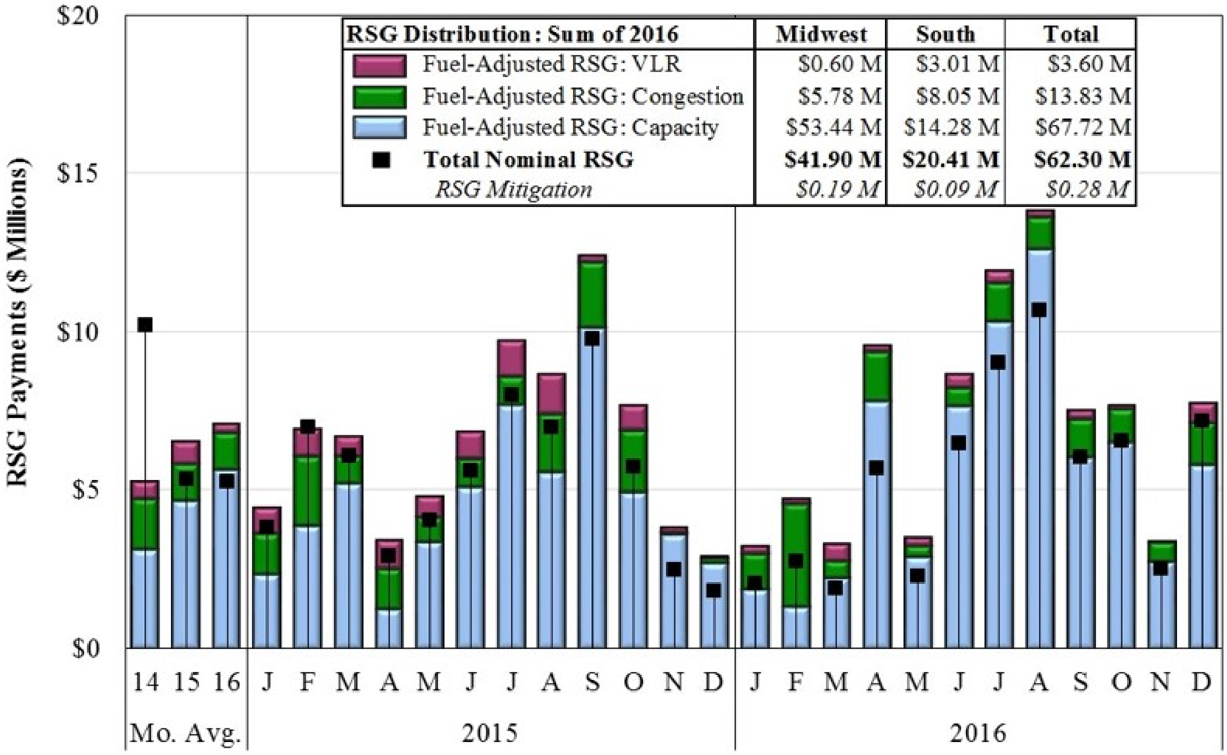
Figure 15: Day-Ahead RSG Payments
2015–2016



18 "Uplift Cost Allocation and Transparency in Markets Operated by Regional Transmission Organizations and Independent System Operators," FERC RM17-2-000, issued January 19, 2017.

19 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.

Figure 16: Real-Time RSG Payments
2015–2016



Nominal day-ahead RSG costs decreased by almost 50 percent to $3.4 million per month in 2016. Fuel-adjusted day-ahead RSG costs fell to comparable amounts, indicating that most of the cost reductions were due to better utilization of the transmission system and improvements in the process of committing resources to satisfy VLR requirements.

Additionally, MISO completed construction of several local projects in the Southern load pockets that reduced the need for some VLR commitments. Nonetheless, if one includes the RSG amounts likely caused by the VLR requirements in the day-ahead market, nearly 60 percent of day-ahead RSG payments were were caused by VLR needs in the South. To achieve further reductions, we have recommended that MISO improve its modeling of the VLR requirements in the day-ahead market, and MISO is pursuing approaches to address this recommendation.

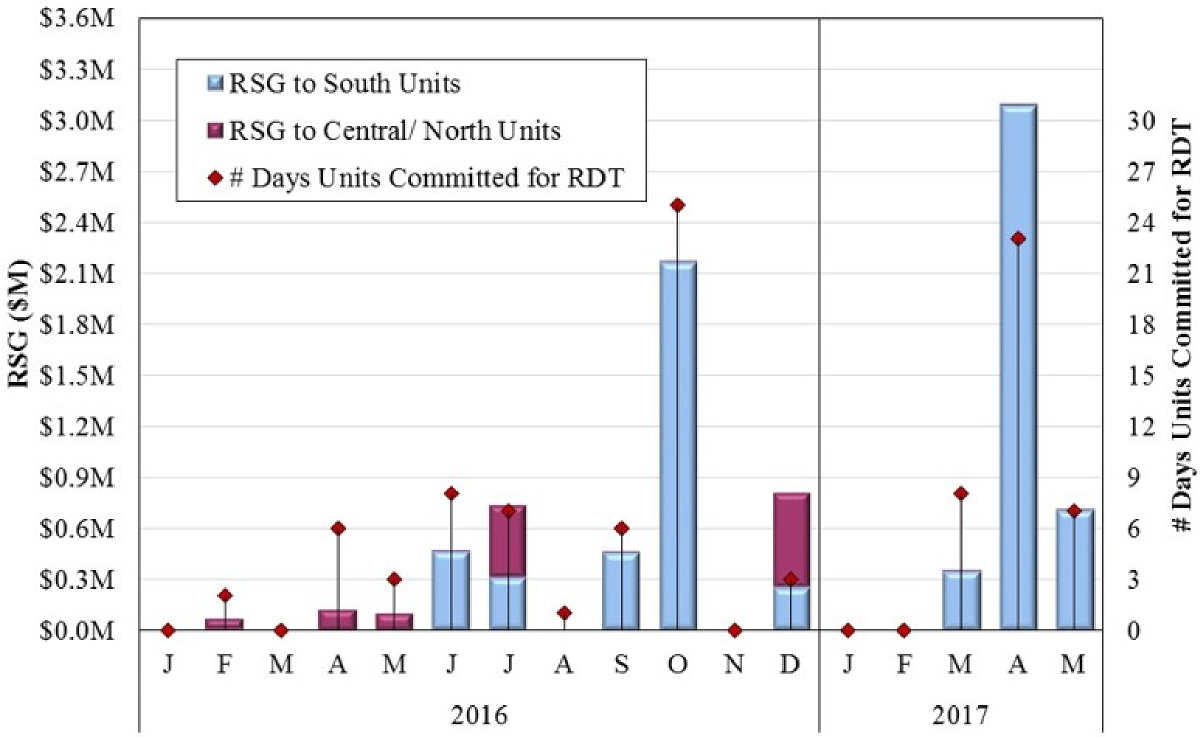
Figure 16 shows that nominal real-time RSG payments fell slightly (1.6 percent) from 2015, primarily because of lower fuel prices. Adjusting for changes in fuel prices, real-time RSG actually increased by nine percent in 2016. This increase occurred in April and in the summer months when hotter summer conditions resulted in increased use of peaking resources. Despite implementation of ELMP in 2015, most peaking resources utilized by MISO were not eligible to set energy prices, so they required RSG payments to cover their as-offered costs. MISO expanded eligibility modestly in May 2017, but we are recommending expanding the eligibility further, which will lower real-time RSG (see Section V.B for a more detailed discussion).

RSG Incurred to Satisfy Regional Capacity (Reserve) Needs

We have identified a substantial number of commitments and associated RSG made in MISO Midwest or MISO South to satisfy regional capacity needs when the Regional Dispatch Transfer (RDT) constraint is binding or potentially binding. These commitments are not generally needed to manage the dispatch flows over the RDT, but they ensure that sufficient capacity is available in the importing region. These commitments are made outside of the market because MISO's markets do not include subregional capacity requirements.

In more recent months, particularly during periods of high generator outages in MISO South, MISO has incurred significant RSG for these types of commitments, and the costs of the commitments are largely spread across the entire MISO footprint. Figure 17 below illustrates the total RSG that MISO has incurred for these commitments since June 2016 and in which region (Midwest or South) the commitments were located. The maroon segment of the bars shows RSG payments to resources in the Midwest, and the blue bar segments indicate the resources that were turned on in the South region.

Figure 17: RSG Incurred to Satisfy Regional Capacity (Reserve) Needs

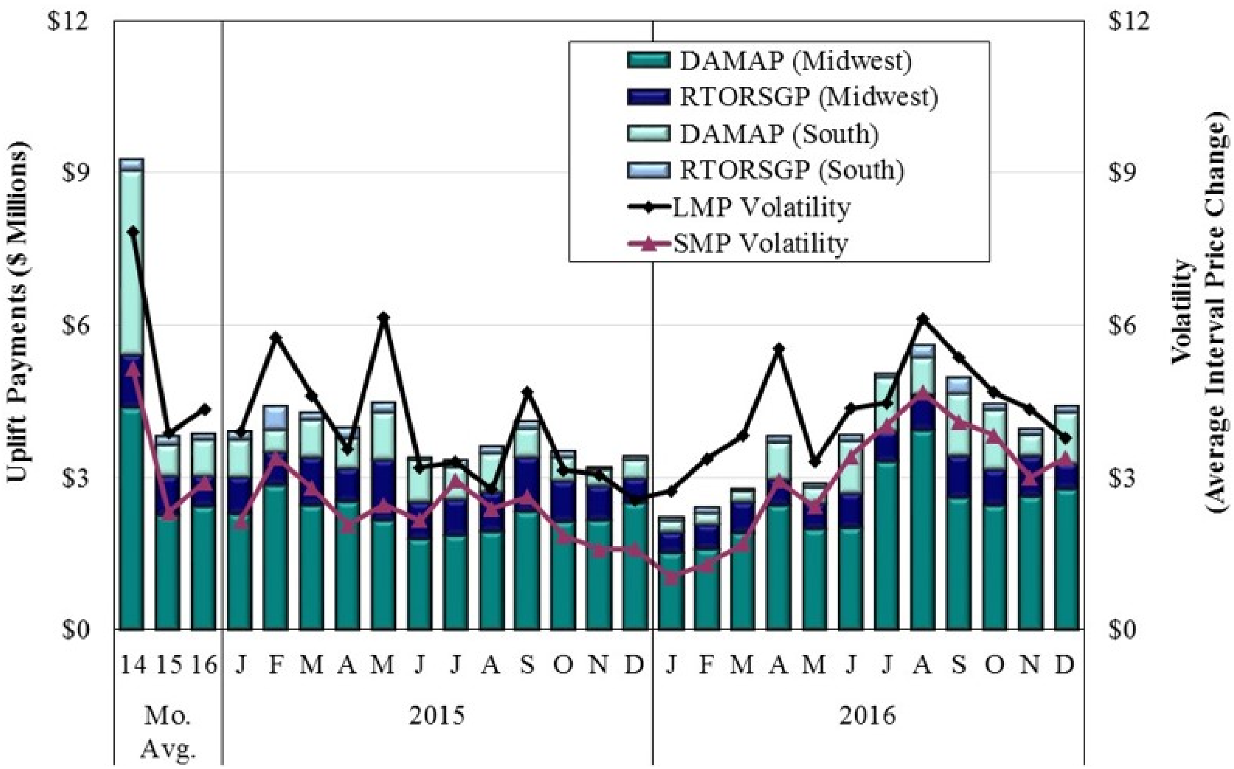


Since June 2016, MISO has incurred $9 million in RSG for subregional capacity commitments. Of this more than half was incurred in October 2016 and April 2017 when MISO South experienced very high generation outage rates. We are recommending that MISO establish subregional reserve requirements and regional cost allocation to allow its markets to satify and price local capacity requirements that are being satisfied currently through out-of-market commitment and reflected only in RSG costs. This could likely be addressed by the same product that MISO is developing to address the reserve needs in the VLR areas.

Price Volatility Make-Whole Payments

PVMWPs address the concerns that resources that respond flexibly to volatile five-minute price signals can be harmed by doing so because their settlement is based on the hourly average price. Hence, these payments provide suppliers the incentive to offer flexible physical parameters and follow dispatch instructions. 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 generators produce output at a level that is below their day-ahead schedule and the level that is economic given the hourly settlement price and their offer prices. RTORSGP payments are made when a unit operates above the level that would be economic given the hourly energy price. Figure 18 shows the monthly totals for the two components of PVMWP, along with measures of price volatility at the system level (System Marginal Price, or SMP, volatility) and at the locations where units are receiving the payments (LMP volatility).

Figure 18: Price Volatility Make-Whole Payments
2015–2016

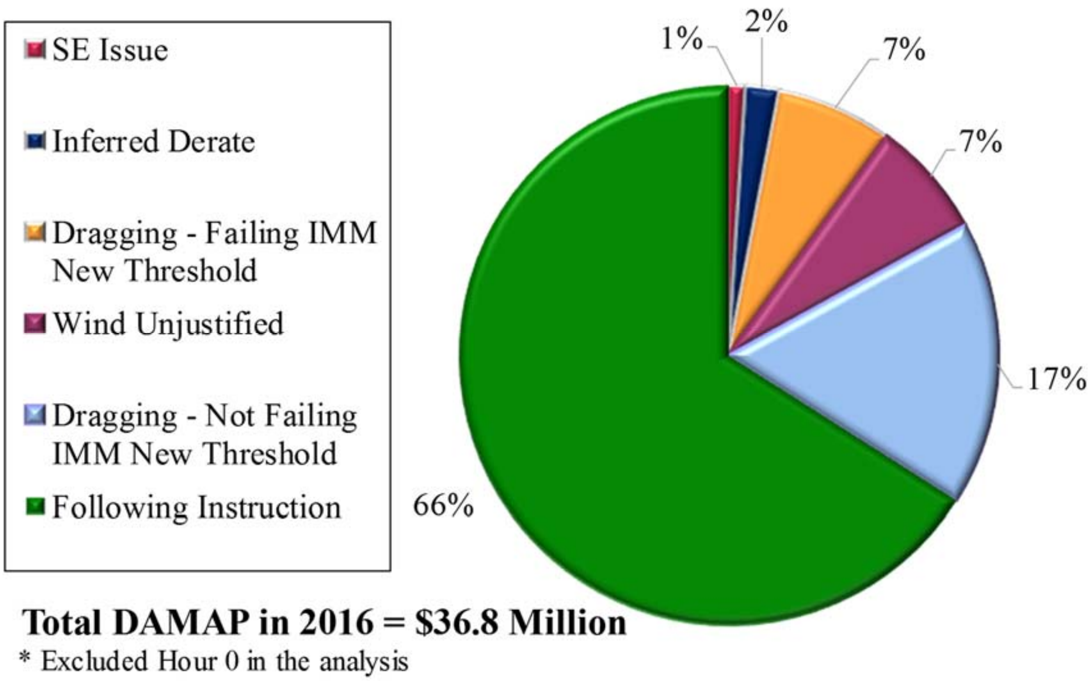


The figure shows that the PVMWP levels in 2016 were generally correlated with price volatility at the recipients' locations. Total PVMWP values rose 1.6 percent over the prior year as price volatility at the resources' locations increased by two percent. DAMAP accounted for all of the increase, as RTORSGP fell slightly from 2015 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, Figure 19 shows the total DAMAP paid in 2016, broken out into the follosing categories:

- 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 not following dispatch instructions and effectively derated as a result;
- Resources appearing to deviate due to State Estimator model errors; and
- Wind resources that were receiving unjustified DAMAP because of forecast errors.

Figure 19: Causes of DAMAP
2016



Almost three million dollars of the DAMAP were unjustified payments to wind resources that over-forecasted their output. These resources should not be eligible for DAMAP payments, but they remain eligible because of an error in the MISO tariff.[20]

Figure 19 also shows that more than one quarter 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 generators to avoid the economic consequences of poor performance. Further, we've identified a number of gaming strategies participants can employ to acquire unjustified payments. To address these issues, we are recommending that MISO reform the calculation of the DAMAP and RTORSGP to substantially reduce or eliminate the payments that are due to poor dispatch performance. Additionally, our other recommendations in this report that address generator deviations should 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 to be inflexible. To address these inconsistencies, MISO introduced the PVMWPs described above.

The PVMWPs have been effective at eliciting additional flexibility from MISO's resources. However, it is 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. Our analysis for 2016 indicates that:

- Fossil-fuel-fired resources in 2016 received settlements that were $18 million less than they would have received were they to have settled based on five-minute prices and output.
- Less than a quarter of this lost value was paid to resources in the form of PVMWP.
- Less controllable resources, such as wind resources, are not as adversely impacted by the current hourly settlement because they generally cannot respond to the 5-minute price signals.

These results indicate that there are substantial discrepancies between the actual value of energy on a five-minute basis and settlements currently made on an hourly basis. The PVMWPs alone are not sufficient to address these discrepancies. Therefore, we have been recommending for years that MISO implement 5-minute settlements with generators, which will improve their incentives to be flexible and follow dispatch instructions. FERC supported this recommendation

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

in a Rule issued in 2016, which require that RTOs settle with market participants in the same time increments as they use to dispatch the system (i.e., five-minute settlements for MISO).[21] MISO has scheduled an implementation date of March 2018.

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.[22] 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. However, MISO's criteria for identifying deviations are significantly more lenient than most other RTOs and contribute to poor performance by some suppliers with both economic and reliability implications. In addition to this settlement threshold, MISO's real-time operators employ a tool to identify resources that are responding poorly (or not at all) to MISO's dispatch. Resources identified by the tool should be contacted by MISO operators and, if warranted, placed off-control, which would result in the dispatch echoing the current output level of the resource.

Figure 20 shows the size and frequency of two types of net deviations:

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

The methodology for calculating the net 60-minute deviation is described in more detail in Section V of the Analytical Appendix, but it is essentially the difference between energy the generator is 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 and type of hour, including the typically steep ramping hours of 6, 7, and 8 a.m when the impact of deviations are most severe on both pricing and reliability.

This analysis shows that MISO's five-minute and 60-minute deviations are sizable in all seasons and types of hours. While the average five-minute deviations are slightly higher in the morning ramp-up hours than during other periods, the 60-minute deviations are much higher in these hours, averaging more than 400 MW. This continues to raises substantial concerns, averaging almost 20 percent of MISO's reserve requirements.

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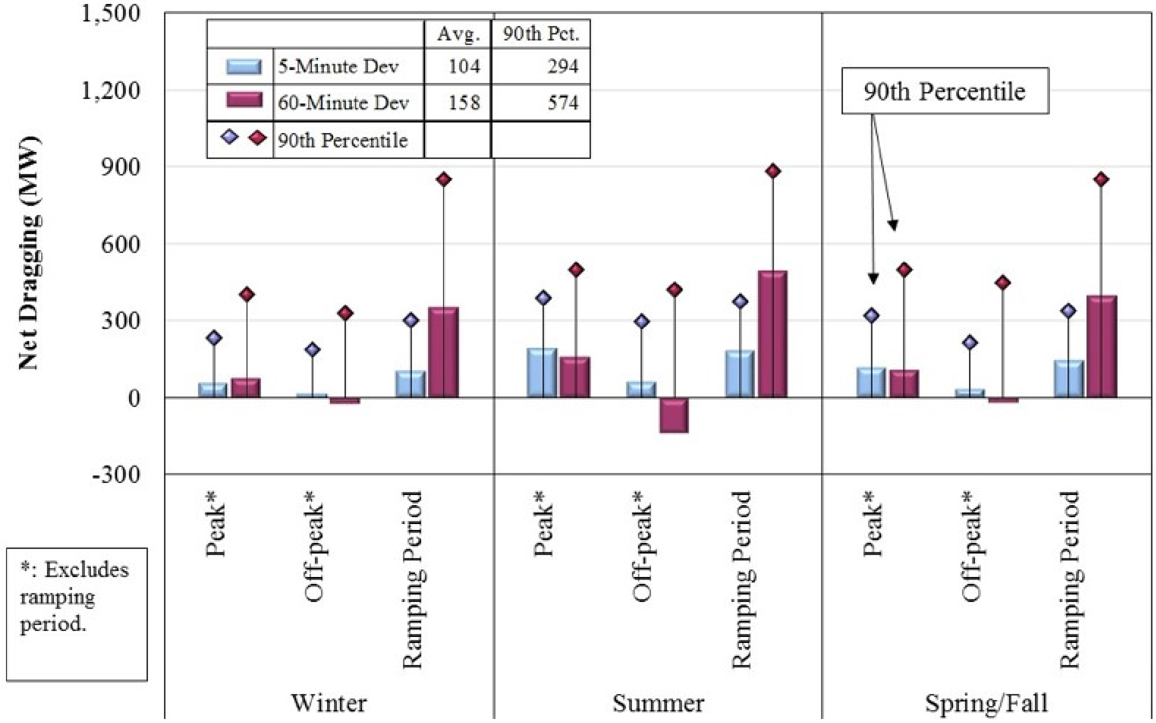
21 "Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators," FERC RM15-24-000, NOPR issued September 17, 2015.

22 See Tariff Section 40.3.4.a.i. The tolerance band can be no less than 6 MW and no greater than 30 MW.

Figure 20: Average Five-Minute and Sixty-Minute Net Deviations
2016



The differences in the deviation metrics shown in this figure are important because the MISO operators will generally only see the five-minute deviations, and they do not have a tool to show the effective loss of capacity that accrues over time from generators that are performing poorly. Further, almost 50 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 justified economically or needed for reliability.

In 2016, MISO addressed State Estimator (SE) issues for some resources late in the year that caused some of the deviations. We have worked closely with MISO to identify SE issues as they arose, and we continue to recommend that MISO develop new tools to identify and address SE errors that are affecting the dispatch.

Finally, we monitor for "inferred derates," where the lack of response from a generator over time causes the generator to effectively be derated, which averaged 158 MW per hour in 2016 and was more than 1150 MW in some hours.[23] 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

23 See Figure A49 in the Analytical Appendix for the detailed inferred derate results.

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.

First, MISO should 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. In Section V of the Analytical Appendix, we discuss our proposed threshold, which is based on units' ramp rates and provides for more tolerance only in the ramping direction, so units that are moderately dragging or responding with a lag will not violate the threshold. Like the current thresholds, our proposed threshold would permit a resource to be unresponsive for four consecutive intervals to allow for configuration changes or changes in mill operations.[24]

Having established this threshold, we recommend that MISO apply it in a number of ways:

1. Apply the standard settlement rules pertaining to Deficient and Excessive Energy;
2. Remove eligibility for PVMWP for that hour;
3. Remove eligibility for the unit to provide ancillary services or the ramp product for that hour and the following hour; and
4. Remove the unit's headroom (available capacity) from the LAC model;

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.

Second, we recommend that MISO develop better tools and procedures for operators to use in real time to identify inferred derates and place such resources off control. This will allow its real-time market to dispatch energy from other resources that will respond to the dispatch signal.

F. 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.

24 Additional detail and a graphical illustration of the proposed threshold is provided in Section VI of the Analytical Appendix.

As described earlier, MISO is also committing resources to satisfy capacity requirements in the Midwest and South subregions of MISO to ensure that it can withstand the largest congingency in the subregion without exceeding the RDT limit. 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.

For the subregions, defining such a product would likely alter the resource commitments in the day-ahead market to satisfy these needs at overall lower costs. It will also provide prices for these requirements, to include allowing the markets to price shortages when regional resources are insufficient to satisfy the full reserve requirement.

In the VLR areas, this would would provide market signals to build fast-starting units or other resources that can satisfy the VLR needs at a much lower cost (because they can satisfy the requirements while offline). Although this would not eliminate the need for VLR commitments, it would significantly reduce the amount of uplift within the MISO South load pockets of Amite South and WOTAB.

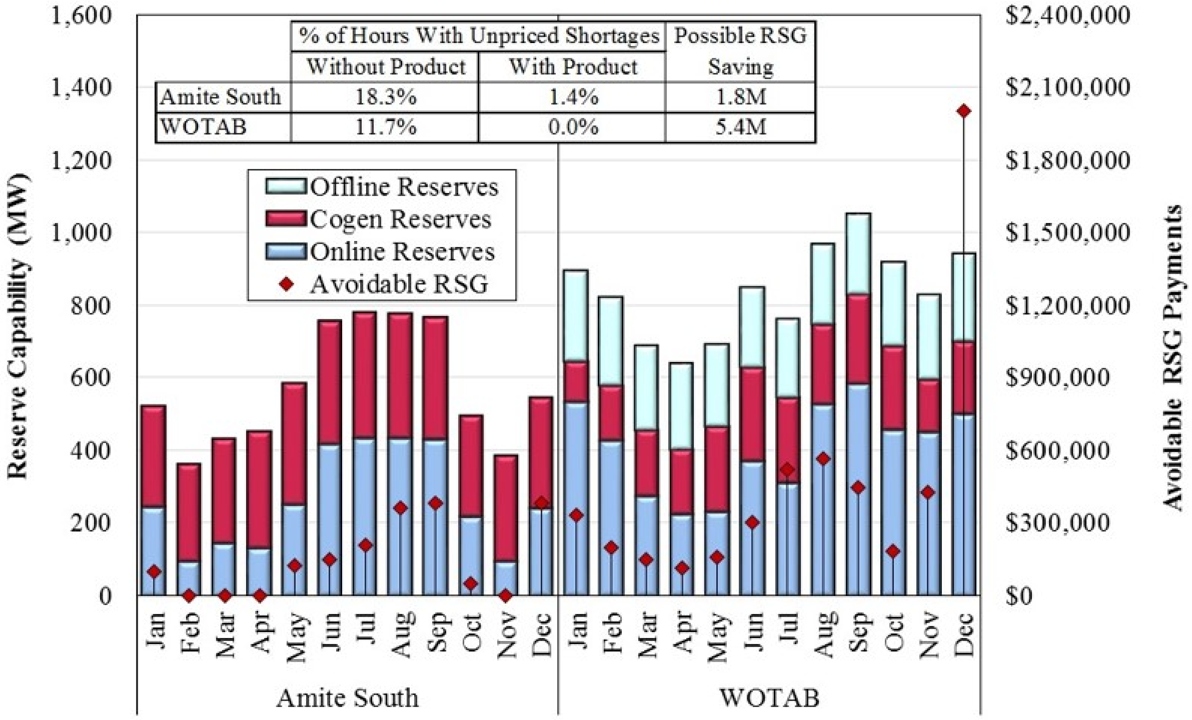
Additionally, defining such a product for the VLR areas may allow other resources that currently exist withing the load pockets to satisfy the VLR requirements. Figure 21 below quantifies all of the 30-minute reserve capability that is currently available to respond to a system contingency and the associated RSG savings from using those reserves to meet reliability objectives. We identified three main types of potential 30-minute reserve providers:

- Co-generation facilities (red bars),
- Combustion turbines that can start within 30 minutes (light blue bars), and
- Longer-start resources that must be online to participate (blue bars).

The figure shows the available reserves by load pocket. The left axis indicates the available capability in MW, and the right axis indicates the potential RSG that could have been avoided by procuring this through a reserve product, rather than committing generation to meet the same requirement with undispatched ranges (i.e., headroom) on online resources. The RSG savings is the sum of the RSG paid to the units de-committed in our simulation.

This analysis indicates that in 2016, MISO could have realized more than $7 million in RSG savings had a 30-minute reserve product been in place in the MISO South load pockets, and all of the resources we identified were capable of supplying it. While the two new categories of resources that we identified currently exist in the load pocket areas that could satisfy 30-minute reserve requirements, the resources do not have a means to sell this type of reserve product.

Figure 21: 30-Minute Reserve Capability Potential Savings
South Load Pockets, 2016



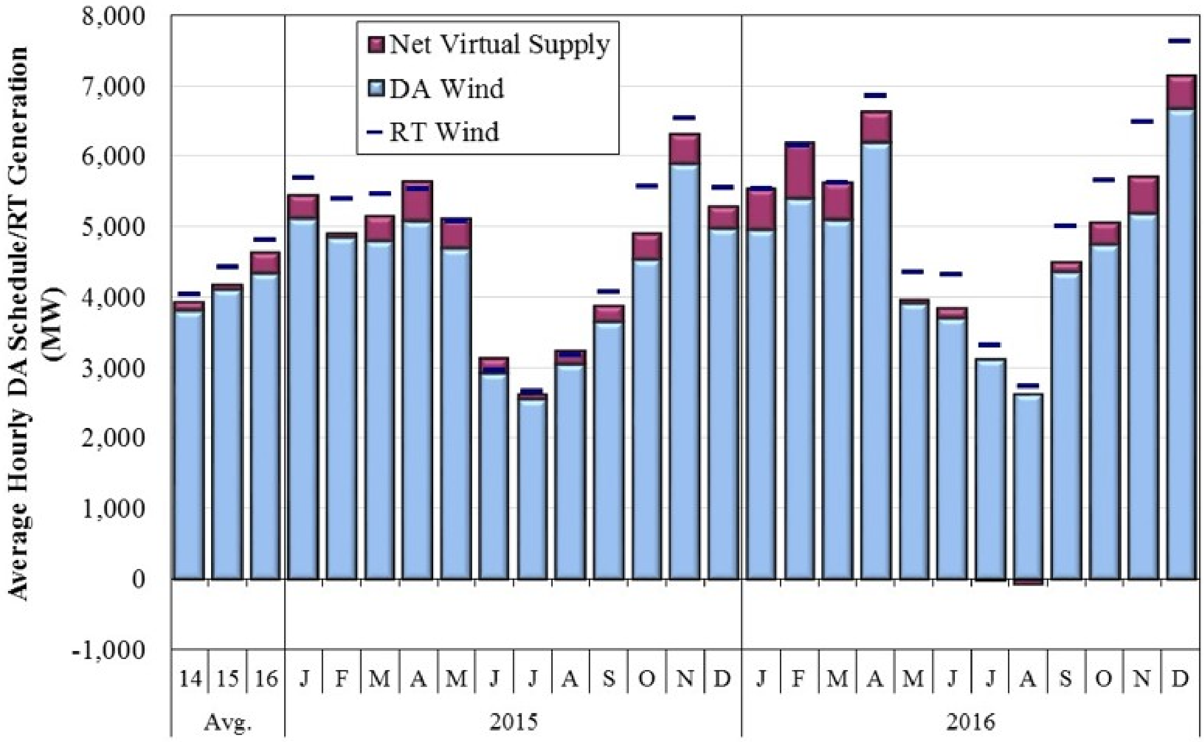
G. Wind Generation

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 for wind units in MISO, most new wind suppliers choose the PTC. Wind resources that were under construction by 2016 receive the full credit for 10 years, while the credit decreases 20 percent each year for units that begin construction from 2017 through 2019. These subsidies have resulted in an addition of 1.4 GW of wind capacity in 2016 and will continue to foster the growth of wind in the short-term. Installed wind capacity has grown to more than 16 GW. 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. Wind accounted for 10 percent of generation in 2016.

Day-Ahead and Real-Time Wind Generation

Figure *22* 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.

Figure 22: Day-Ahead and Real-Time Wind Generation
2015–2016



Real-time wind generation in MISO increased 9 percent in 2016 to 4.8 GW per hour. MISO set several all-time wind records in 2016, the last of which was set in December at 13.7 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 22 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 472 MW per hour. The figure shows that virtual supply played a key role in arbitraging the scheduling inconsistency caused by the wind suppliers by offsetting almost two-thirds of the underscheduled wind.

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. However, MISO's introduction of the Dispatchable Intermittent Resource (DIR) type in June 2011 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). The expansion of DIR has almost entirely eliminated manual curtailments as a means to manage congestion caused by wind output or over-generation conditions.

Wind Forecasting

Over the past year, we have identified significant concerns with certain wind resources that frequently and substantially over-forecast their wind output. 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. Since an over-forecasted resource will produce less than the dispatch instruction, this will result in dispatch deviations. Figure 23 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 2015 and 2016.

Figure 23: Generation Wind Over-Forecasting Levels
2015–2016

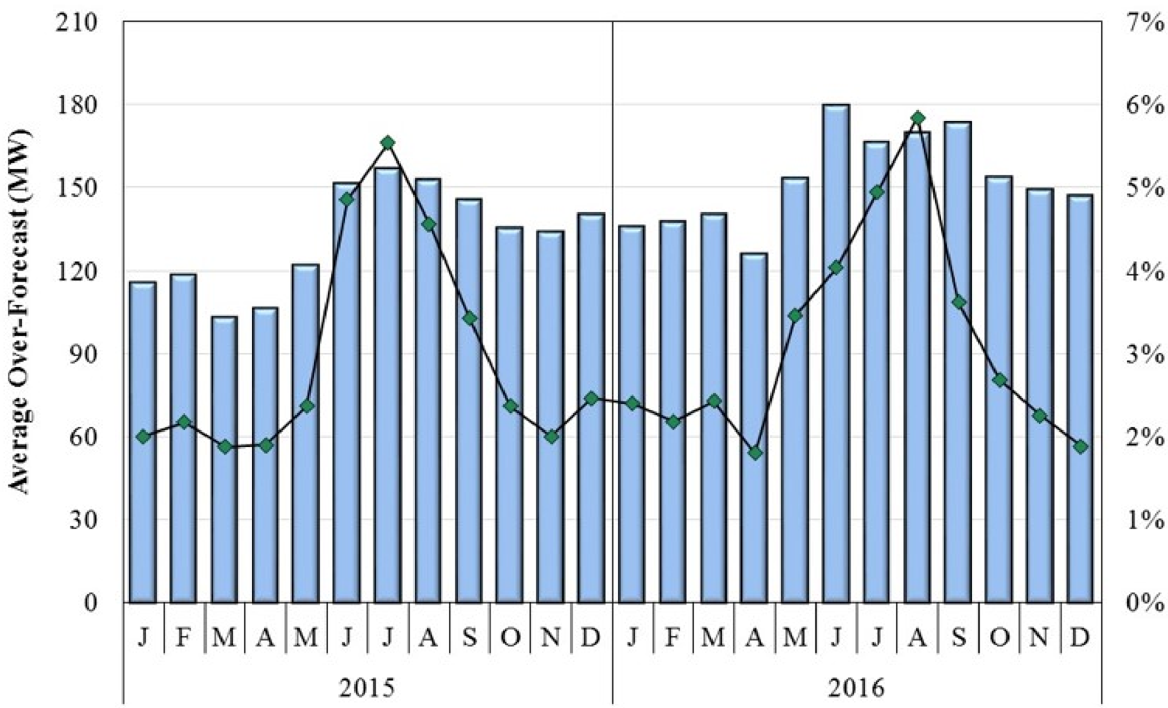


Figure 23 shows that wind resources in aggregate consistently over-forecast their output capability. The over-forecasting rate is much higher in the summer months even though the wind output tends to be lower in these months. We believe these patterns are consistent with incentives provided by the MISO market rules. We identified two primary factors that contribute to wind over-forecasting: DAMAP and uninstructed deviation settlements.

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 (it changes hourly for all other units), because it was written before the advent of DIR resources.

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. Due to 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.[25]

Aligning the excessive and deficient energy penalties (by reducing the explicit excessive energy penalty or increasing the costs of deficient energy) would help to balance the incentives and promote less-biased forecasts. 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.[26] MISO could provide wind resources a "not-too-exceed" limit that would allow wind resources to exceed its 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 forecast, 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.

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

26 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 the lowest-cost resources cannot be fully dispatched because transmission capability is limited – so higher-cost units must be dispatched in place of lower-cost units to avoid overloading a transmission facility. This generation re-dispatch or "out-of-merit" cost is reflected in the congestion component of MISO's locational prices.[27] The congestion component of the LMPs can vary substantially across the system, increasing LMPs in "congested" areas where increased generation would relieve the constraints. Conversely, congestion components lower 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 economic signals that facilitate efficient investment and maintenance of generation and transmission facilities.

A. Real-Time Value of Congestion in 2016

We separately calculate the value of real-time congestion by multiplying the flow over each constraint times the economic value of the constraint (i.e., the "shadow price"). This is a valuable metric, because it indicates the congestion that is actually occurring as MISO dispatches its system. Figure 24 shows the monthly real-time congestion values in 2015 and 2016.

The value of real-time congestion increased by four percent from last year to $1.4 billion. Natural gas prices decreased in 2016, which tends to reduce congestion costs because natural gas-fired units are generally dispatched to manage the power flows over binding constraints. Additionally, congestion was much lower in early 2016 because of mild winter weather. However, these factors were more than offset by:

- High congestion levels during the summer months. Real-time congestion rose 35 percent from last summer (to $464 million), which was due to high loads and key generation and transmission outages, particularly in the South.
- High network flows from wind resources in MISO and PJM contributed to the congestion in the Spring and Fall.
- Planned transmission outages (including outages for construction of Multi-Value Projects).

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

Figure 24: Value of Real-Time Congestion and Payments to FTRs
2015–2016

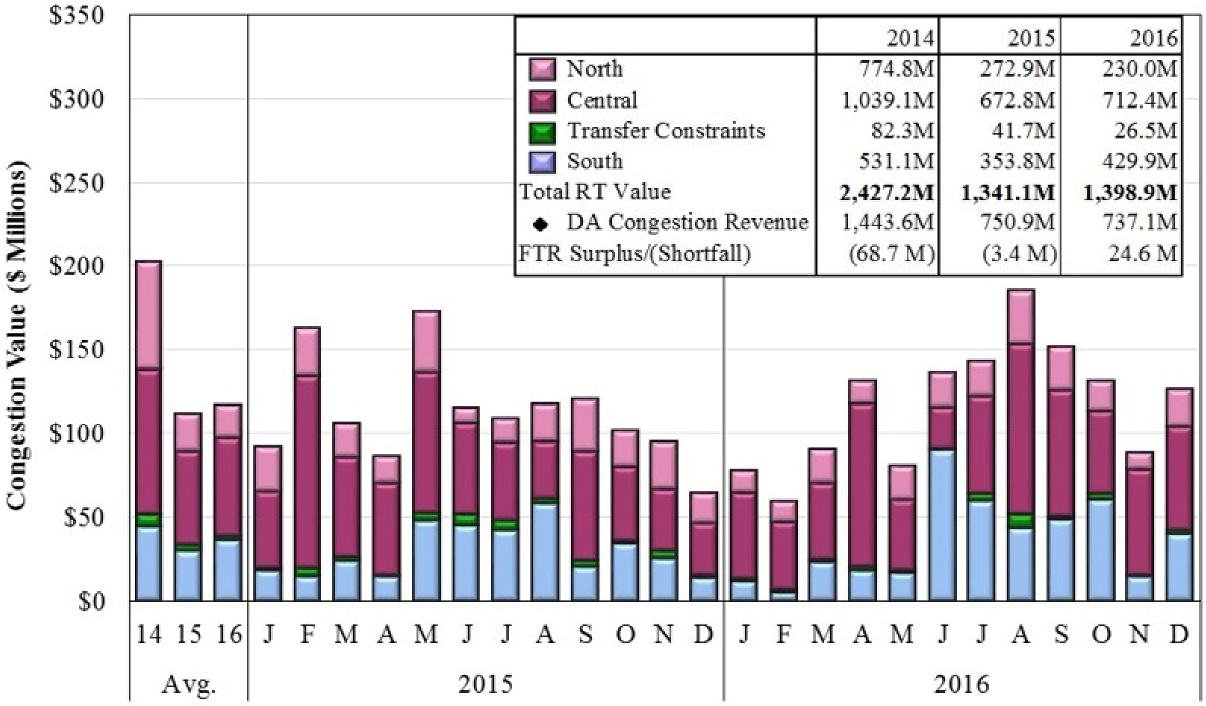


Figure 24 also shows that congestion on the transfer constraints fell significantly in 2016.[28] This was partly due to the settlement agreement with SPP and the Joint Parties approved in January 2016. This agreement allowed MISO to replace the Sub-Regional Power Balance Constraint (SRPBC), modeled with a 1,000 MW limit and Hurdle Rate of $9.57/MW (that reflected the potential transmission charges from SPP), with the RDT to constraint that allows directional transfers ranging from 2500 to 3000 MW. This has allowed MISO to capture substantial dispatch savings.[29] Congestion on the transfer constraints also fell because MISO also worked with TVA to improve TLR procedures and the day-ahead modeling of these constraints.

Although transmission congestion was only slightly higher in 2016, our evaluation of this congestion revealed issues that contributed to this increase. These issues are discussed later in this section, but include:

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

28 "Transfer" constraints are those whose flows are predominately or entirely affected by transfers between the MISO North and South sub-regions. This includes the current RDT constraint (and prior SRPBC), as well as certain external constraints that are activated in MISO when a TLR is called (generally by TVA).

29 See our Quarterly reports for Winter 2015/2016 through Spring 2017.

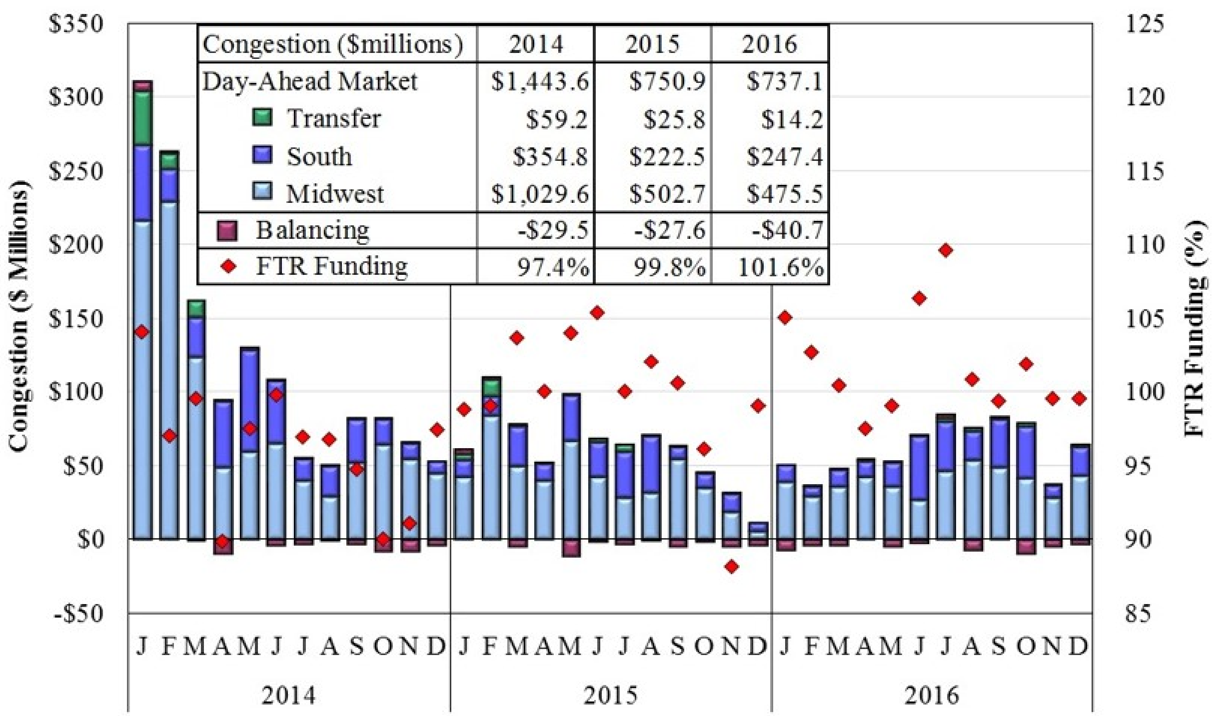
B. Day-Ahead Congestion Costs and FTR Funding in 2016

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 scheduled to be produced and consumed.

The resulting congestion revenue is paid to holders of FTRs, which represent the economic property rights associated with 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 (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 – to pay them 100 percent of the FTR entitlements.

Figure 25 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 2014 to 2016.

Figure 25: Day-Ahead and Balancing Congestion and Payments to FTRs
2014–2016



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 fell two percent to $737.1 million in 2016. Much of the reduction in congestion occurred during February when day-ahead congestion was 60 percent lower than the prior year. The decline in 2016 was caused by lower gas prices, mild weather conditions early in the year, and reduced congestion on transfer constraints.

The congestion costs collected through the MISO markets are much less than the value of real-time congestion on the system, which totaled $1.4 billion in 2016. 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 JOA counterparties, including PJM, SPP, and TVA. For example, PJM does not pay for its power flows on MISO's market-to-market constraints up to PJM's entitlements.

Congestion on constraints in MISO South and the transfer constraints between the Midwest and South regions accounted for 35 percent of all day-ahead congestion. The MISO South and Midwest regions have diverse load patterns and mixes of generation. Differences in weather, load, generation and transmission availability, and regional gas prices affect the transmission congestion patterns within each region and between the regions over the transfer constraints.

In the Fall of 2016, generation outages in MISO South led to several operational challenges and increases in day-ahead congestion, as nearly 40 percent of the total generating capacity was on outage in October. Three-quarters of these outages were planned. An additional 3.4 GW of capacity was derated. The high level of outages in the South also led to flows primarily North-to-South after late September, a reversal in the typical pattern.

FTR Shortfalls

Congestion revenues exceeded FTR obligations by $24.6 million – a surplus of 1.6 percent – a slight increase in funding from 2015 when FTRs were underfunded by 0.2 percent. Nearly half of the surplus ($12 million) occurred in July, while several other months experienced slight 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.

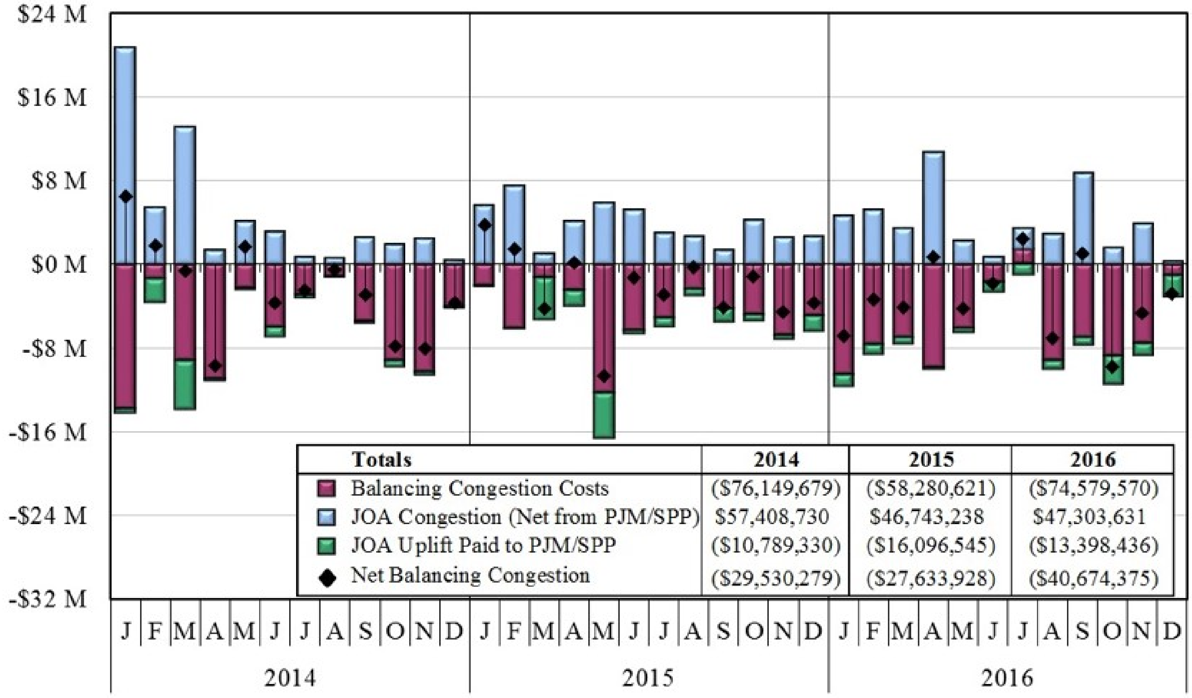
The most significant causes for underfunding continue to be planned and unplanned transmission outages—particularly forced and short-duration scheduled outages or derates that are not reflected in the FTR auctions. Underestimated loop flows also account for the some of the shortfalls, because loop flows across the MISO system reduce the capability MISO can utilize in the day-ahead and real-time markets. In 2016, 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 reduce flows scheduled in the day-ahead market are negative balancing congestion. 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 was 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) so they do not directly impact FTR funding. 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 generally seek to minimize these shortfalls by achieving maximum consistency between the day-ahead and real-time market models. Figure 26 shows the monthly congestion costs incurred by MISO monthly over the past three years.

Figure 26: Balancing Congestion Costs
2014–2016



Balancing congestion costs increased 47 percent in 2016. Figure 26 shows that balancing congestion shortfalls totaled nearly $41 million (excluding Joint Operating Agreement, or JOA, uplift of $13.4 million) in 2016. JOA uplift payments are made to pay for market flows on coordinated market-to-market constraints. MISO had balancing congestion shortfalls in all but two months of the year. These levels of balancing congestion costs indicate that consistency between the day-ahead and real-time market models could be improved.

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 system. 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 then 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 at the same time without knowing what others are doing. Absent a reliability concern, MISO does have the tariff authority to deny or postpone a planned outage, even when it will likely have substantial economic effects. Figure 27 provides a high-level evaluation of how uncoordinated planned outages can affect congestion. It shows the real-time congestion value incurred from January 2016 through May 2017. We identify the portion of the congestion on constraints substantially affected by two or more planned outages (affecting at least 10 percent of the constraints' flows).

Figure 27: Congestion Affected by Multiple Planned Generation Outages
January 2016 to May 2017

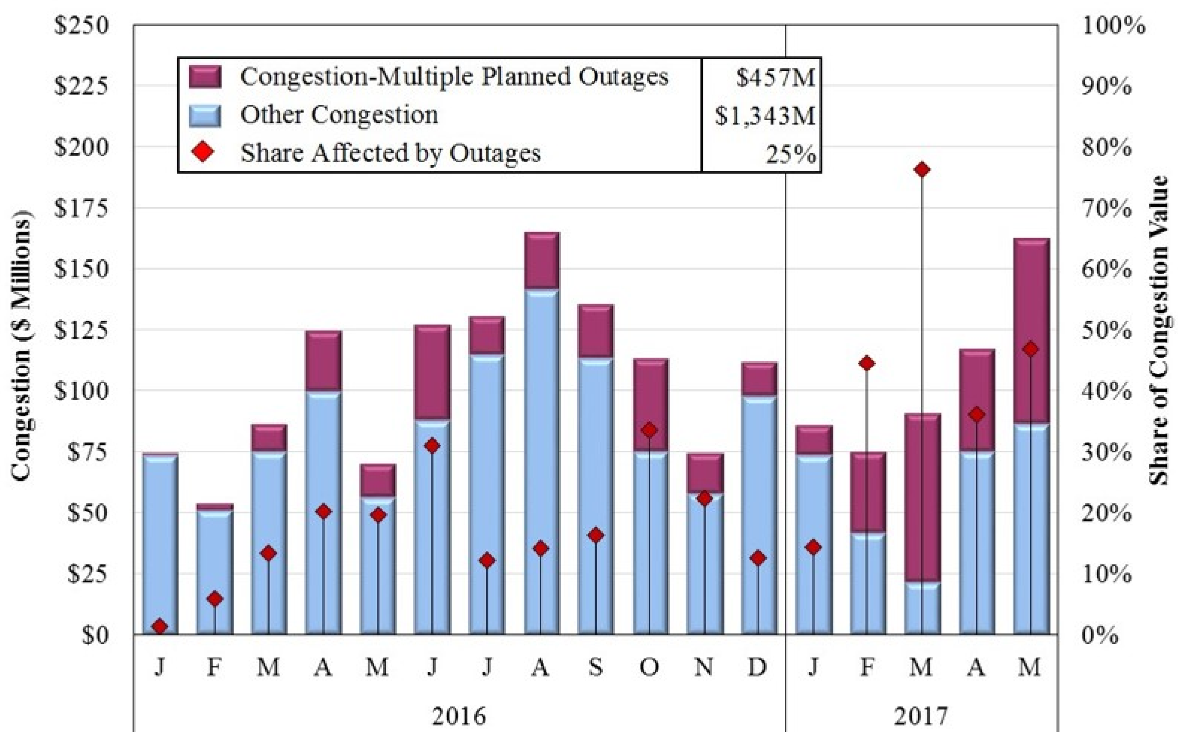


Figure 27 shows that 25 percent of the total real-time congestion – $457 million – was attributable to multiple planned generation outages. In the majority of the months that we analyzed, planned outages led to more than ten percent of the total congestion, and grew to more than 70 percent of all congestion in March 2017. These totals 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 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 Financial Transmission Right (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 much lower than FTR auction values. MISO currently runs:

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

FTR Market Profitability

Figure 28 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.

Figure 28 shows that FTRs issued through the annual FTR auction were substantially unprofitable in the first two quarters of 2016 because there was less congestion during the first two quarters than anticipated by the FTR market. However, they were profitable during the summer and fall quarters. The day-ahead congestion value was $175 million less than the annual auction valuation during the 2015-16 auction year (June 2015-May 2016). These FTR losses are 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).

Figure 28: FTR Profits and Profitability
2015–2016

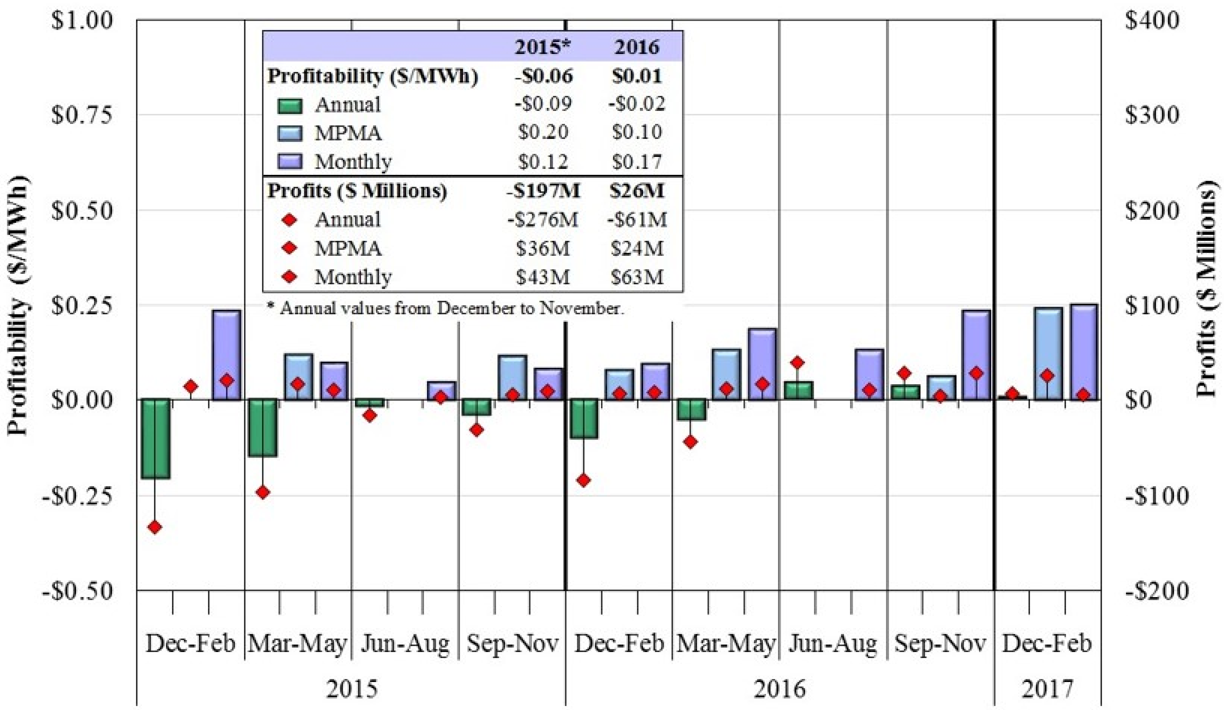


Figure 28 also shows that the FTRs purchased in the MPMA and prompt month have generally been profitable. These markets tend to produce prices that are more in line with anticipated congestion than the annual auction. Additionally, because the MPMA and prompt month occur much closer to the operating timeframe, better information is available to forecast congestion.

Multi-Period Monthly FTR Auction

In the MPMA FTR auction, MISO generally makes additional transmission capability available for sale and sometimes buys back capability on oversold transmission paths. MISO buys back capability by selling "counter-flow" FTRs, which are negatively priced FTRs on oversold paths. In essence, MISO is paying a participant to accept an FTR obligation in the opposite direction to cancel out excess FTRs on an constraint.[30]

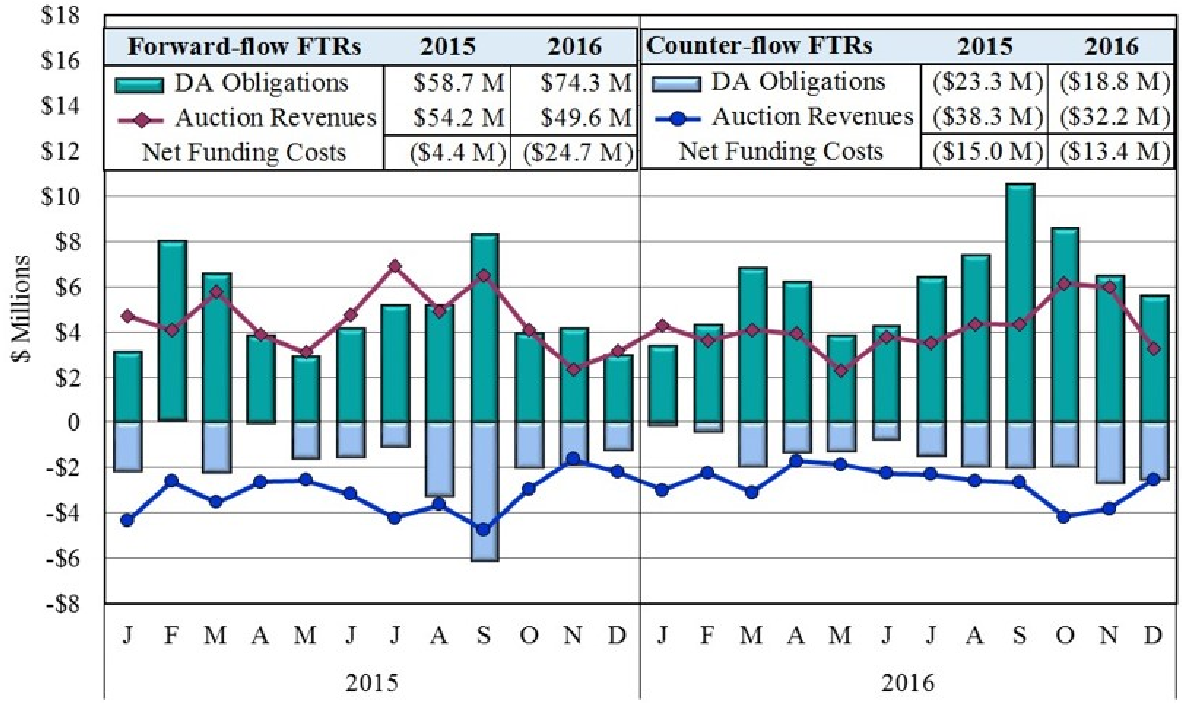
MISO is restricted in its ability to do this because it is prohibited from clearing the MPMA with a negative residual (e.g., MISO can fund the purchase of counter-flow FTRs only with net

30 For example, imagine MISO has issued 250 MW of FTRs over an interface that now can accommodate only 200 MW of flow. MISO could sell 50 MW of counter-flow FTRs so that MISO's net FTR obligation in the day-ahead market would be only 200 MW.

revenues from same auction). This limits MISO's ability to resolve feasibility issues through the MPMA. In other words, when MISO knows a path is oversold, as in the example above, 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 29 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. It separately shows forward direction 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 29: Prompt-Month MPMA FTR Profitability
2015–2016



This figure shows that MISO sold forward-flow FTRs at nearly $25 million less than their ultimate value in 2016, and net funding costs significantly increased. Similarly, MISO paid participants 71 percent more to accept counter-flow FTRs than the value of these obligations in 2016. While the negative auction residual restriction artificially limits MISO's ability to sell counter-flow FTRs, this limitation benefited MISO's customers in 2016 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. If liquidity cannot be improved, it may be beneficial for MISO to examine its auction processes to determine whether to limit the sale for 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 2016, MISO and the IMM continued to work with MISO and 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 wide-spread use of temperature-adjusted transmission ratings for all types of transmission constraints.[31] 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 $155 million in production costs savings could be achieved by fully adopting temperature-adjusted, short-term emergency ratings throughout MISO.

31 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.

In 2015, MISO implemented a pilot program to make use of temperature-adjusted, short-term emergency ratings on a number of key facilities, and this has matured into an ongoing program. In 2016, MISO expanded the number of facilities included in the program. The program has had clear benefits with no reliability issues, and expansion of the program will likely generate consirable savings on constraints throughout MISO. We recommend that MISO continue to 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. MISO is evaluating 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 RTO's 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 marginal value of the difference between the non-monitoring RTO's FFE and its market flow. Conversely, if the non-monitoring RTO's market flow exceeds its FFE, it will pay the monitoring RTO for the excess flow.

While MISO and PJM implemented market-to-market coordination years ago, MISO initiated market-to-market with SPP on March 1, 2015. In the first few months in 2015 there were significant issues with the coordination on two SPP flowgates. MISO and SPP continue to work to resolve differences between their respective interpretations of the JOA.

Summary of Market to Market Settlements

Congestion on MISO market-to-market constraints rose 26 percent from $300 million in 2015 to $377 million in 2016. Some of this increase 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. Congestion results on market-to-market constraints included:

- Congestion on external market-to-market constraints (those monitored by PJM and SPP) rose 23 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 $44 million, an increase of 17 percent from 2015.
  - The increase was due to resources pseudo-tying into PJM and corresponding definition of new market-to-market constraints, and PJM's flawed interface pricing methodology that generally inflates congestion payments to imports and exports.
- MISO's market-to-market settlements with SPP in 2016 resulted in net payments of $4.9 million from MISO to SPP.

Evaluation of the Market-to-Market Coordination

We evaluate the effectiveness of the market-to-market process by tracking the convergence of the shadow prices of market-to-market constraints in each market. When it 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 prevailing 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, the savings of enlisting the non-monitoring RTO to provide economic relief on the constraint disappear. It also raises serious equity concerns because 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 263 non-market-to-market constraints that should have been coordinated as market-to-market with either PJM or SPP. We then quantified the congestion on these constraints, which is shown in Table 6.

Table 6: Congestion on Constraints Affected by Market-to-Market Issues in 2016
$ Millions

Category of Issue	PJM	SPP	Total
Never classified as M2M	$66.4	$125.4	$191.8
M2M Testing Delay	$21.4	$19.3	$40.7
M2M Activation Delay	$2.7	$2.3	$5.0
Total	**$90.4**	**$147.1**	**$237.5**

These results indicate that the process for testing and activating market-to-market constraints can be improved significantly with both PJM and SPP. More than 80 percent of the congestion affected by these issues resulted from failures to designate constraints as market-to-market constraints that appeared to qualify under the JOA criteria. This indicates that the RTOs should improve the automation of their testing process to ensure that constraints are appropriately tested and activated to eliminate these issues.

Finally, one key insight that has emerged from our evaluation of some of the most costly market-to-market constraints is that sometimes it is efficient for the non-monitoring RTO to take monitoring responsibility for a constraint. This occurs when the non-monitoring RTO has the vast majority of the effective relief capability (and likely the most market flows). Hence, we recommend that MISO continue working with SPP and PJM to implement a procedure for the monitoring RTO to transfer the monitoring responsibility for a market-to-market constraint to the non-monitoring RTO when appropriate.

F. Effects of Pseudo-Tying MISO Generators

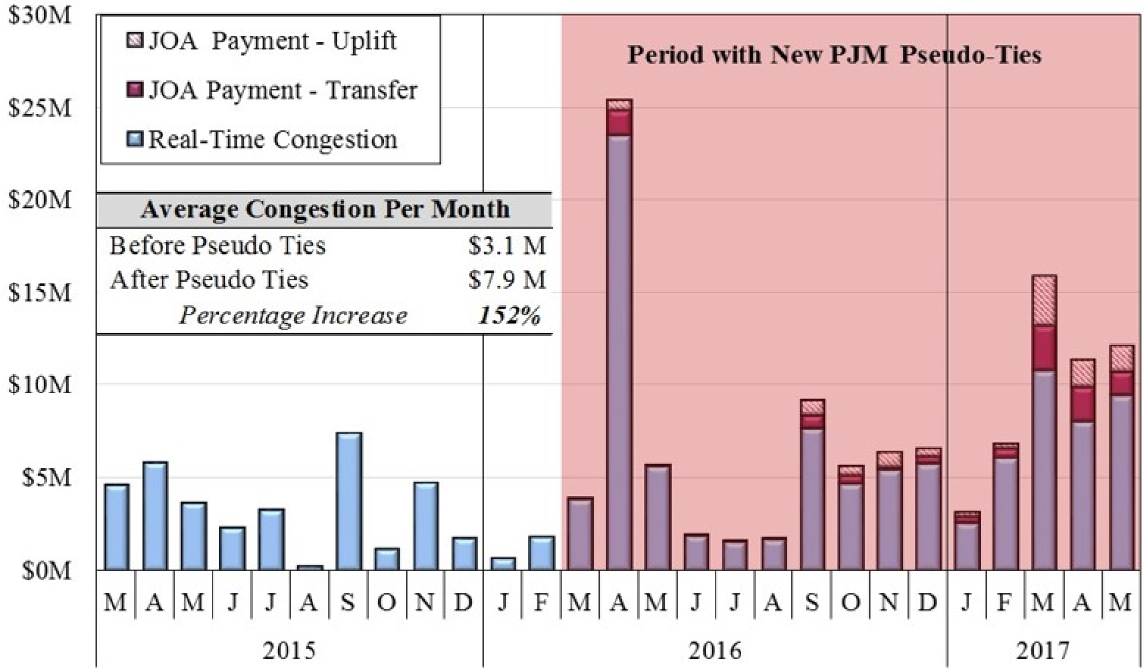
In recent years, increasing quantities of MISO capacity have been exported to PJM. PJM has recently implemented rules that require external capacity to be pseudo-tied to PJM. Beginning in 2015 and continuing into 2017, we have been raising serious concerns about this trend because allowing PJM to take 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. Figure 30 shows our evaluation of the effects of pseudo-tying the generators to PJM. This shows the value of real-time congestion on constraints that qualified as new market-to-market constraints only because of the resources that are pseudo-tied to PJM. The shading shows the period when MISO units were pseudo-tied 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.

Figure 30 shows that the real-time congestion values per month on the constraints affected by the pseudo-tied resources increased by 152 percent. 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 transmission system. 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.[32]

Figure 30: Effects of Pseudo-Tying MISO Resources to PJM
2016



We further evaluated these concerns 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 2016, this evaluation showed:

- Eight of the twelve units exhibited average inefficiencies greater than **20 percent** when online (i.e., running at much higher or lower levels than optimal in congested periods).
- When we include 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 **26 percent** for all the pseudo-tied units.

We continue to be very concerned about the increasing quantities of MISO generators that are pseudo-tying to PJM. We continue to recommend that MISO and PJM develop procedures for

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

firm capacity delivery as a more efficient and reliable alternative to pseudo-tying resources to PJM. To facilitate this solution, we have filed a Section 206 complaint against PJM's tariff to eliminate its current requirement that all external resources be pseudo-tied to PJM.[33]

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 Transmission Line-Loading Relief (TLRs), 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 affecting MISO are often not physically binding during the periods when they are severely binding in MISO. To remedy these issues, we have recommended that MISO pursue a JOA with TVA that would allow TVA and MISO to coordinate the relief requested on each other's transmission system more efficiently than is occurring under the current TLR process. To quantify the potential value of such a JOA to MISO, Table 7 shows instances where TVA had lower-cost relief available than MISO on MISO's constraints (first row), and TVA's constraints (second row). The columns show the congestion value on these constraints and the potential savings from coordination.

Table 7: Economic Relief from TVA Generators
2016

Types of Constraints	Total Congestion Value ($ Millions)	Re-dispatch Savings ($ Millions)
MISO Constraints	$169.6 M	$16.9 M
TVA (TLR) Constraints binding in MISO	$21.1 M	$4.9 M
Total	$190.7 M	$21.8 M

This analysis shows it would extremely valuable to coordinate congestion management with TVA, which would lower the costs of managing congestion on both systems, make MISO's relief obligations to TVA more equitable, and reduce price distortions caused by TVA's TLRs.

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

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 2016:

- Hourly net imports in the day-ahead and real-time markets averaged 2.4 and 5.3 GW, respectively.
- MISO's largest and most actively-scheduled interface is the PJM interface. MISO was a net importer from PJM in 2016.
  - Hourly average real-time imports from PJM were 1,175 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. Two-thirds of the transactions with PJM were scheduled in the profitable direction, while 63 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 large savings. MISO and PJM plan to address these issues by introducing "Coordinated Transaction Scheduling" (CTS) in late 2017, which allows the RTOs to adjust transaction schedules every 15 minutes based on forecasted price differences between the two markets. In late 2014, PJM implemented a comparable approach with the New York ISO (NYISO). Early in 2016, we filed comments on the MISO and PJM CTS proposal.[34]

[34] Motion To Intervene Out Of Time and Comments Of Potomac Economics, Ltd., filed in Docket No. ER16-533, Jan. 22, 2016.

While we supported the CTS filing, we requested that FERC mandate a change based on analysis of the market results from the CTS provisions implemented between NYISO and both PJM and ISO-NE. Our analysis showed that the CTS is much more liquid between NYISO and ISO-NE than between NYISO and PJM. We attributed this partly to the charges associated with the CTS transactions. We therefore recommended that FERC Order PJM to eliminate all CTS charges.

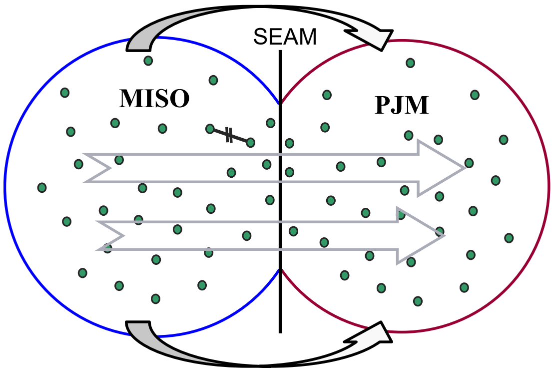
B. Interface Pricing and External Transactions

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 the differentials 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).

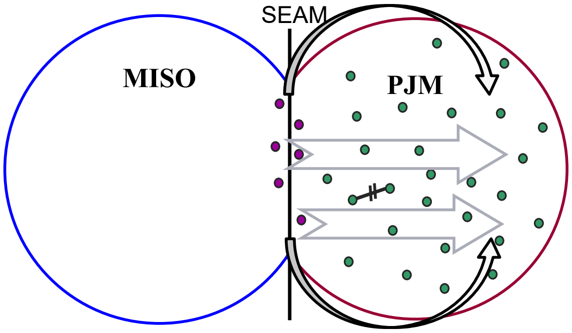
Like the locational marginal price at all generation and load locations, the interface price includes: a) the SMP, b) a marginal loss component, and c) a congestion component. For generator locations, the source of the power is known and, therefore, congestion effects can be accurately calculated. In 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 identied 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 (1.2 GW on average). For example, we previously showed that in 2015:

- MISO's system marginal price was 29 percent ($7.56/MWh) lower than PJM's on average, 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 of export 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.

Finally, we raised a concern in our *2012 State of the Market Report* that MISO and PJM were including redundant congestion components in their interface prices for M2M constraints (because these constraints are active in both markets simultaneously). This redundant settlement tends to overpay transactions that are expected to help relieve a constraint and overcharges transactions that are expected to aggravate a constraint. We recommended that the RTOs eliminate this redundancy by simply allowing the monitoring RTO alone to price the congestion for its constraints at the interface (i.e., MISO fully price MISO's constraints at the interface). Instead, the RTOs implemented PJM's proposal that RTOs adopt a common interface comprised of a limited number of nodes close to the MISO-PJM seam in the second quarter of 2017. This was a bad choice, as our analysis indicated that this would produce less efficient and more volatile interface prices. We will monitor the results of these changes to document these inefficiencies and work with the RTOs to develop better solutions over the long term. Similar discussions have begun with SPP, because MISO implemented a market-to-market process with SPP in March of 2015. However, SPP has not yet taken a position on any particular interface pricing proposal.

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 2016. Market power in electricity markets exist when a participant has the ability and incentive to raise prices. Market power can be indicated by a variety of empirical measures, and 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 a statistic calculated as the sum of the squared market shares of each supplier. More concentrated markets will have a higher HHI index. Market concentration is low for the overall MISO area (595), but relatively high in some local areas, such as the WUMS Area (2805) and the South region (3749). 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. It 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 Narrow Constrained Areas (NCAs) and the two 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 and 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-three 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 nearly all intervals.
- In the two MISO South NCAs, 99 percent of active constraints had a pivotal supplier.
- The MISO Midwest NCAs had pivotal suppliers on 98 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.

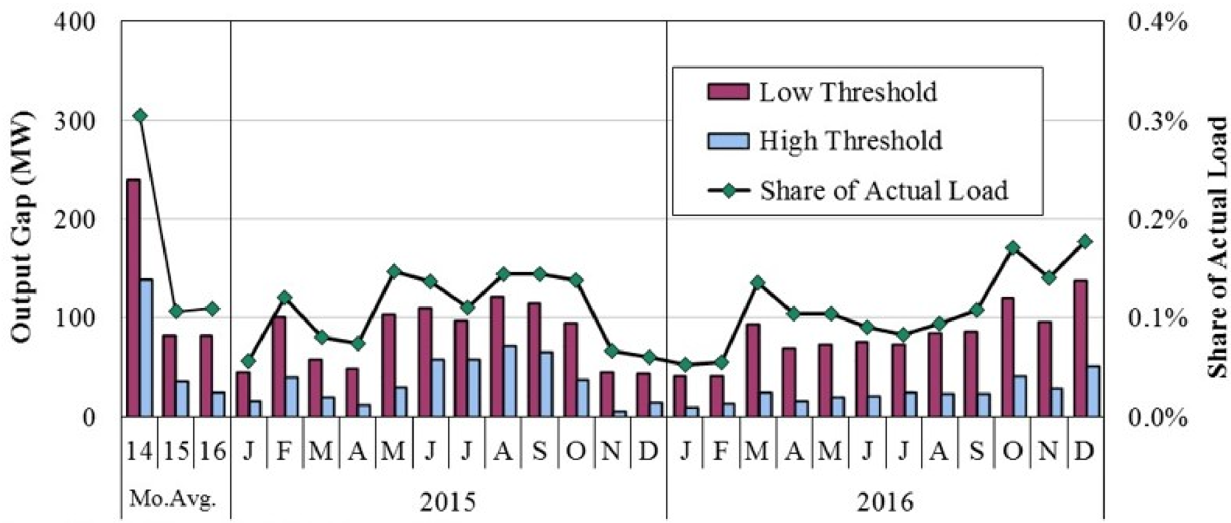
B. Evaluation of Competitive Conduct

Despite these indicators of structural market power, our analyses of individual participant conduct show little evidence of attempts to physically or economically withhold resources to exercise market power. This is confirmed in aggregate metrics of market competitiveness. We calculated a price-cost mark-up that compares the system marginal price, based on actual offers, to a simulated system marginal price that assumes all suppliers had submitted offers at their estimated marginal cost. We found an average system marginal price mark-up of 0.5 percent in 2016, varying monthly from a high of 3.4 percent to a low of -1.7 percent. The low average mark-up indicates that MISO's energy markets produced 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 31: Economic Withholding – Output Gap Analysis

2015–2016



Low Threshold Results by Unit Status (MW)

Offline	98	27	11	12	31	5	4	15	43	54	66	57	32	0	10	6	11	0	1	0	1	15	13	13	30	21	25
Online	140	55	71	34	70	53	46	90	68	43	56	57	63	45	34	36	31	94	69	73	74	58	72	73	89	75	113

High Threshold Results by Unit Status (MW)

Offline	82	23	10	11	17	5	3	11	34	49	58	50	25	0	7	5	10	0	1	0	1	15	11	11	26	21	24
Online	57	14	15	6	24	16	10	19	24	9	14	16	14	6	8	6	5	25	16	20	20	11	14	14	16	8	29

The figure shows that the average monthly output gap level was 0.11 percent of load in 2016, which is effectively *de minimus*. Although these results raise no overall competitive concerns, we monitor these levels on an hourly basis and routinely investigate instances of potential withholding.

We also evaluate the overall competitiveness of the MISO markets by calculating a a "price-cost mark-up." This metric compares simulated energy prices based on actual offers to energy prices based on competitive offer prices. The unit-specific reference levels calculated for each unit is the competitive benchmark we use in this analysis. Our analysis revealed the price-cost mark-up was effectively zero in 2016, which indicates that the MISO markets were highly competitive.

C. Summary of Market Power Mitigation

The instances of market power mitigation in 2016 were appropriate, and effectively limited the exercise of market power. Imposition of mitigation in the energy market and on RSG payments both fell substantially in 2016, 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, but increased in the real-time market in 2016. Mitigation was imposed in less than 4 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 its unit with inflated economic or physical parameters, it may inflate its RSG payments and be mitigated.

Commitments to satisfy system-wide capacity needs are not subject to mitigation because competition is generally robust to satisfy these needs.

In 2016, total RSG mitigation dollars fell by 76 percent as mitigation of RSG paid to resources committed for VLR needs decreased substantially, mainly because VLR commitments became less frequent and less costly. 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. Mitigation of RSG payments incurred to manage congestion remained low in 2016.

D. Evaluation of RSG Conduct and Mitigation Rules – 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.

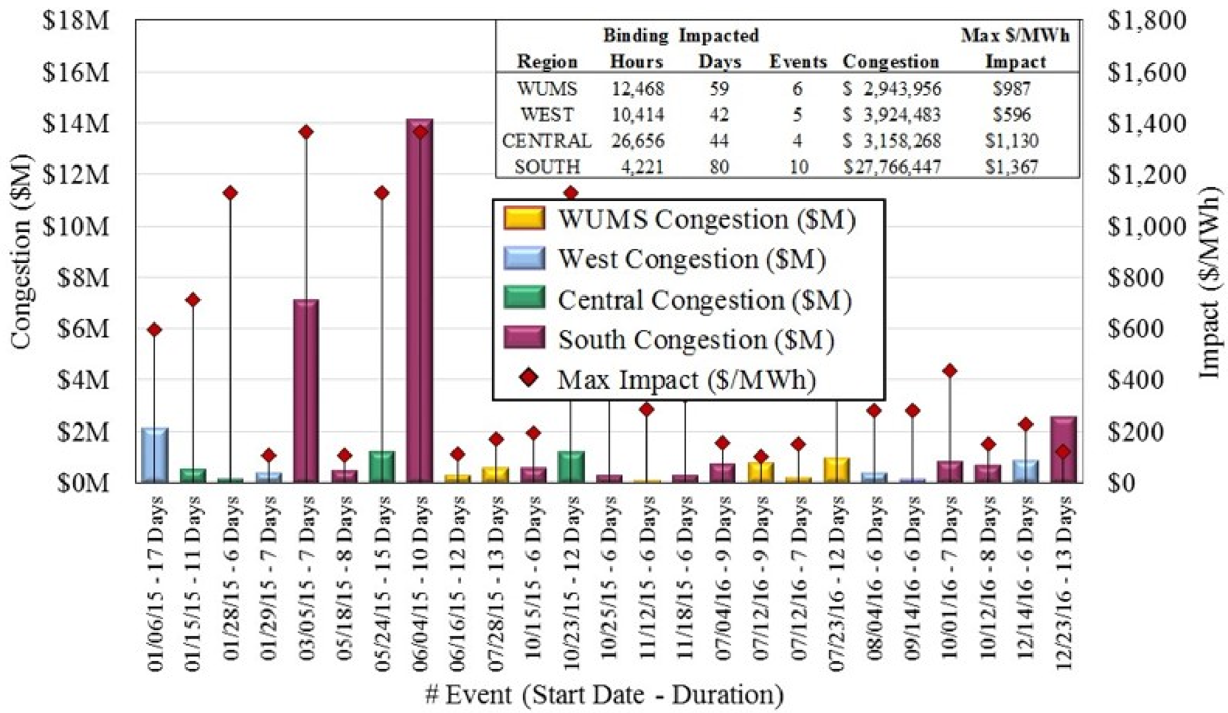
To address this concern, we have recommended that MISO expand Module D of its tariff to allow it to establish "dynamic" NCAs when transitory conditions arise that lead to sustained congestion. We recommend that the threshold for the dynamic NCA be set at $25 per MWh and be triggered by the IMM when mitigation 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 a NCA). This provision will help ensure that transitory network conditions do not allow the exercise of substantial local market power.

To assess the need for this enhancement, we performed an evaluation to determine how frequently dynamic NCAs would have been defined and when mitigation would have been warranted in 2015 and 2016. The results of this evaluation are shown in Figure 32 below, which shows the results from applying our two proposed criteria over the past two years:

- Conduct and impact is identified at $25 per MWh thresholds in a load pocket; and
- The load pocket is binding in at least 15 percent of the intervals over 5 days.

The left axis in figure Figure 32 shows the value of real-time congestion during each Dynamic NCA event (the sum of the shadow price times the flow). The right axis shows the maximum impact of the market power mitigation during the Dynamic NCA event. The events themselves are color coded to show the region in which they occurred.

Figure 32: Dynamic NCA Evaluation of Events
Impacts and Congestion, 2015–2016



Our results show that applying our proposed criteria in 2015 and 2016 would have resulted in:

- The declaration of 25 Dynamic NCAs with an average duration of nine days.
- The maximum price impacts during these events would have ranged from $105 per MWh to $1400 per MWh.
- The average price impacts over each entire event throughout the relevant constrained area ranged from $6.50 per MWh to $424 per MWh.

While Dynamic NCAs would have been declared in all of MISO's regions, the most frequent occurrences and largest impacts of Dynamic NCAs would have been in MISO South. This is not surprising because MISO South has experienced severe congestion resulting from transmission and generation outages.

IX. DEMAND RESPONSE

Demand response (DR) 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. Table 8 shows overall DR participation in MISO, NYISO, and ISO-NE in the prior three years.

Table 8: Demand Response Capability in MISO and Neighboring RTOs
2014–2016

		2016	2015	2014
MISO[1]		**10,721**	**10,563**	**10,356**
	Behind-The-Meter Generation	4,089	4,213	4,072
	Load Modifying Resource	4,616	5,121	4,943
	DRR Type I	525	330	372
	DRR Type II	75	116	76
	Emergency DR	1,416	782	894
NYISO[3]		**1,653**	**1,325**	**1,211**
	ICAP - Special Case Resources	1,192	1,251	1,124
	Of which: Targeted DR	372	385	369
	Emergency DR	75	75	86
	Of which: Targeted DR	14	14	14
	DADRP	0	0	0
ISO-NE[4]		**2,600**	**2,685**	**2,487**
	Real-Time DR Resources	702	692	796
	Real-Time Emerg. Generation Resources	2	300	255
	On-Peak Demand Resources	1,386	1,222	997
	Seasonal Peak Demand Resources	510	471	439

[1] Registered as of December 2015. All units are MW. Source: MISO website, published at: www.misoenergy.org/WhatWeDo/StrategicInitiatives/Pages/DemandResponse.aspx.

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

[3] Registered as of July 2016. 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 Jan. 1, 2017. Source: ISO-NE Demand Response Working Group Pesentation.

The table shows that MISO had nearly 11 GW of demand-response capability available in 2016, which is a larger share than in neighboring RTOs. MISO's capability exhibits varying degrees of responsiveness. More than 90 percent of the MISO DR is in the form of interruptible load (i.e., "Load-Modifying Resources," or LMR) developed under regulated utility programs and Behind-

The-Meter Generation (BTMG). MISO does not directly control either of these classes of DR, which cannot set the energy price, even under emergency conditions.

Although 21 Demand Response Resources ("DRRs") were active in the MISO markets in 2016, 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). MISO considers DR a priority and continues to actively expand its DR capability. 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. Prior to an April 2017 deployment in MISO South, they had not been deployed since 2006.

X. Recommendations

Although MISO's markets continued to perform competitively and efficiently in 2016 overall, we recommend a number of improvements in MISO's market design and operating procedures. These twenty-five recommendations are organized by the aspects of the market that they affect:

- Energy Pricing and Transmission Congestion: 7 total, 3 new.
- Operating Reserves and Guarantee Payments: 3 total, 2 new.
- Dispatch Efficiency and Real-Time Market Operations: 6 total, 3 new.
- Resource Adequacy: 9 total, 1 new.

Sixteen of the recommendations described below were recommended in prior State of the Market Reports. This is expected 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 three of our past recommendations, which were implemented in 2016 or are being implemented in early to mid-2017. We discuss recommendations that are addressed at the end of this section. Included in this section are also three 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.

A. Energy Pricing and Transmission Congestion

Efficient energy pricing in the real-time market is essential. Even though a very small share (one to two percent) of the energy produced and consumed in MISO is settled through the real-time market, the spot prices produced by the real-time market 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.

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

Our analysis indicates that the Phase 1 implementation of ELMP is having a very small effect 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 until recently allowed only five percent of the online peaking resources to potentially set prices. In May 2017, the set of eligible resources was expanded, which would have allowed 16 percent of online peaking resources to set prices. We recommend expanding the eligibility to include peaking resources with minimum runtimes up to two hours.

Additionally, there is no theoretical basis for distinguishing between peaking resources based on whether they were scheduled in the day-ahead market. Therefore, we recommend that peaking resources scheduled in the day-ahead market be eligible to set prices in the real-time energy market.

Finally, we find that ELMP's offline pricing has generally resulted in inefficient price reductions 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 find they are are adversely affecting MISO's real-time prices and recommend that MISO suspend the offline pricing.

Status: MISO has implemented the Phase II changes to expand ELMP eligibility for online resources to those that could be accommodated without software changes, including expanding ELMP eligibility to online resources that can be started within 60 minutes (previously limited to 10 minutes). This filing was accepted by FERC in April 2017 and implemented on May 1, 2017. We believe the pool of ELMP-eligible resources should be expanded even further, extending the minimum run time threshold and including day-ahead committed resources, but these changes require software modification. MISO and the IMM plan to evaluate the benefits of greater expansion after evaluation of the Phase II implementation.

Next Steps: We encourage MISO to develop an estimate of the resources necessary to expand the eligibility further. The IMM is evaluating the performance of the Phase II changes and will provide feedback to MISO and the participants on the priority of further expansion.

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 market shows that few transmission owners are utilizing MISO's capability to receive temperature-adjusted ratings. Most transmission owners provide seasonal ratings only, and we find 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 $165 million in 2015 and $155 million in 2016 if transmission owners provide 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 rating. Our analysis also shows substantial potential savings in congestion costs that 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 (or other factors such as ambient wind speed) 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.

<u>Status:</u> In 2016, MISO implemented a pilot program with one transmission operator that has been highly successful at reducing congestion costs and it has been expanded. However, MISO has not developed a comprehensive review program to identify opportunities to improve ratings across its entire system nor developed a day-ahead program to use predictive ratings. MISO has not yet aligned this recommendation with a Roadmap project called "Application of Dynamic and Predictive Ratings." However, this project proposed by MISO stakeholders is consistent with this recommendation. MISO is reviewing this Roadmap initiative but has provided no update or status other than to indicate that this is a low priority.

<u>Next Steps</u>: MISO should begin working with other Transmission Operators to expand its pilot program to other areas. To facilitate this expansion, we recommend that MISO develop procedures to evaluate MISO's ability to manage post-contingent flows when it utilizes emergency ratings. Additionally, we recommend that MISO develop procedures to develop predictive temperature-dependent ratings in its day-ahead market.

2012-5: Introduce a virtual spread product.

Seventy percent of price-insensitive virtual bid and offer volumes (and 17 percent of all volumes) in 2016 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., schedule 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.

<u>Status</u>: 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 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 low priority and forecasted for further evaluation in the third quarter 2019.

Next Steps: MISO should complete an evaluation of both the benefits of a spread product, as well as the economic costs and other impacts on day-ahead market operations of introducing this product. This will allow MISO and its stakeholders to determine the priority for the virtual spread product.

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

The implementation of market-to-market coordination with SPP has significantly reduced the TLR inefficiencies. TLRs called by SPP previously had the largest effects on MISO's prices. However, the integration of MISO South has increased the frequency of TLRs called by TVA. Subtantial benefits for MISO could be achieved by developing a JOA that would allow MISO's day-ahead scheduled flows to be considered firm for purposes of relief calculations, and perhaps even allow the TLR process to be replaced with an economic coordination process that would allow MISO and TVA to procure economic relief from each other.

Status: In the past few years, MISO has met with TVA a number of times to resolve specific transmission coordination and TLR issues, however MISO has not resolved this issue.

Next Steps: We continue to monitor for and evaluate the negative impacts on MISO's markets and customers caused by TLRs. The next step for this recommendation is to work with TVA to explore the development of a JOA that would mitigate the adverse effects of the TLRs.

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 Operating Reserve Demand Curve (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 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.

Status: This is a new recommendation

2016-2: Improve procedures for M2M Activation and Coordination including 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 these processes are not highly automated and involve considerable level of discretion and interaction between multiple business areas within and across RTOs. We identified some delays in establishing new M2M constraints or activating existing M2M constraints that reduce the effectiveness of M2M coordination. Additionally, some constraints were not established as M2M constraints although they appear to qualify under the M2M tests.

Our analysis indicates $238 million of congestion costs could have been more effectively managed if M2M coordination testing and activation procedures were more complete and timely. Further, a significant portion of this congestion, our analysis finds, could be provided by more efficient redispatch options. We therefore recommend that MISO improve the automation of its procedures for the testing and activation of M2M constraints, improve the logging of testing results, and develop criteria with its JOA partners to transfer control of M2M constraints when it would be beneficial to do so.

Status: This is a new recommendation.

2016-3: Enhanced Transmission and Generation Planned Outage Approval Authority

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. From January 2016 to May 2017, multiple simultaneous generation outages contributed to almost $457 million in real-time congestion costs – 25 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 costs in evaluating and approving transmission outages. It can deny or move outages if doing so will result in "significantly reduced congestion costs."[35] The ISO New England program has been found to have been very effective at reducing congestion costs.[36]

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: This is a new recommendation.

B. 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 them. 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.

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 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-

35 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.

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

market commitments that result in uplift). This would be beneficial because it would provide market signals to build fast-starting 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 it is 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. It allows 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, *Develop Additional Short Term Capacity Reserve 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 December 2021.

Next Steps: Given the benefits of this recommendation, MISO should increase the priority of this recommendation and accelerate its implementation. We also recommend that MISO consider implementing a 30-minute reserve product more broadly beyond the VLR areas.

2016-4: Establish regional reserve requirements and cost allocation.

We have identified a substantial number of resource commitments and associated RSG payments made in MISO Midwest or MISO South to satisfy regional capacity needs when the RDT is binding or potentially binding. These commitments are not generally needed to manage the dispatch flows over the RDT, but they ensure that sufficient capacity is available in the importing region. These commitments are made outside of the market because MISO's markets do not include regional capacity requirements. We believe 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: This is a new recommendation

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 resource have incentives to be flexible and are not harmed financially from following MISO's dispatch instructions. Under the current 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 enable manipulative strategies involving coordinating offer prices and deliberate poor performance. We have referred such conduct to the Commission's Office of Enforcement.

The only current means to address these concerns under the current rules are through eligibility criteria that cause a supplier to become ineligible 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: This is a new recommendation

C. Improve 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.

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.[37] In fact, many resources can ignore MISO's dispatch instructions altogether and not be deemed to be deviating under this criteria. Additionally, 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.

To address these concerns, we recommend MISO adopt thresholds based on resources' ramp rates that effectively differentiate poor performance from acceptable performance. We recommend a specific proposal in Section I of the Appendix and depict this in Figure A64. We have also provided MISO with a specification, and it has been presented in more detail at MISO Stakeholder meetings, including the Market Subcommittee. This proposal allows for a multi-interval delay in responding to changes in dispatch to recognize the unique challenges some units in MISO face, but it requires that units overall move at a rate no less than 50 percent of their offered ramp rate.

Resources that are deemed to be deviating under this criteria should incur uninstructed deviation penalties and costs and lose eligibility for PVMWP, ancillary services, and the ramp product. This will improve suppliers' incentives to follow MISO's dispatch signals and will, in turn, improve reliability and lower overall system costs. Additionally, it would be advisable to remove the ramp and headroom on such units from the LAC in order to allow the LAC model to make better recommendations.

<u>Status</u>: 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 included in the Market Roadmap process as Conceptual Design through the end of 2017. MISO is expected to present an analysis of this recommendation to stakeholders in the Fall of 2017.

<u>Next Steps</u>: MISO and the IMM are working to finalize and test the revised rules. Once this is completed and the implications of revised rules are estimated, MISO will need to present the results to its stakeholders and file the revised thresholds at FERC.

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, BTMG, or other forms of demand response. However, these resources cannot be called by MISO before MISO has invoked a number of other

37 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.

emergency actions that are costly and adversely impact the market. This recommendation would allow MISO to utilize these resources in a more efficient manner.

Status: This recommendation has been in the evaluation phase for the past four years and a further update is planned for mid-2017. Limited progress has been made to date and we are not aware of a substantive evaluation that has been performed to date.

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

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 RGDs. 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"). As we show in this report, these accumulated effects have sizable economic and potential reliability effects.

Therefore, we recommend that MISO improve its tools and procedures for addressing poor generator performance by developing a screen consistent with the uninstructed deviation screen (comparing actual response rate to offered ramp) over a sustained period (significant number of intervals). Recommendation 2012-12 proposes that units failing the uninstructed deviation threshold should not be able to sell ancillary services or the ramp product, or receive PVMWPs. Units performing even more poorly should be placed off-control by the operators.

In addition, we recommend 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. Based on our investigations over the past two years, the IMM has found that poor responses can be caused when residuals are large relative to the offered ramp rates of resources.

Status: MISO is still evaluating the recommendation to improve the tools to identify inferred derates. In the interim, the IMM will provide real-time indications of inferred derates that are identified by the IMM screens for MISO operators to evaluate. MISO did implement some changes to the UDS inputs and timing that should help reduce dragging caused by the latency of State-Estimator inputs. MISO is also in the process of developing tools to identify State-Estimator errors that are impacting economic dispatch to enable escalation and resolution by EMS engineers, which should be deployed in second quarter of 2017.

Next Steps: MISO will develop and implement the procedures and processes to use the real-time indicators provided by IMM processes. The procedures will include logging the response and outcome of the MISO actions. The IMM will review the logging and make further recommendations as appropriate.

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 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 and MISO is in the process of resolving this issue. However, inaccurate wind output assumptions and 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: This is a new recommendation

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

DIR 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: This is a new recommendation

2016-8: Validation of 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 Generation 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, 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: This is a new recommendation.

D. 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 due to 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.

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 that have emerged as natural gas prices have fallen.

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 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 is a particular problem in Competitive Retail Areas (CRAs) where competitive suppliers rely on the market to retain resources MISO needs 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.

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 establish efficient prices for competitive suppliers and competitive load.

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: 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 introduced a proposal that eliminates the distinction between suspensions and retirements, which among other changes, increases the flexibility of units with pending retirements to participate in the PRA. MISO acknowledges the difficulties of SSR units being Planning Resources, but has not yet introduced measures to address this into the stakeholder process.

Next Steps: MISO should continue to work through the stakeholder process to prepare Tariff changes that address this recommendation.

2016-9: Qualification of Planning 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. Currently, resources on extended forced outages that start after performing their GVTC 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. To address this issue, we recommend that MISO require such resources to be suspended and not qualified to sell capacity if they will not be operable during the peak season.

Status: This is a new recommendation.

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.

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 primarily 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 in these areas and the limited transmission capability into the areas because the current zones are much larger. 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 historic 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.

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 historic 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 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: In 2016, MISO's Pseudo-Tie Issues Task Team evaluated this recommendation and supported it with minor modifications. MISO has engaged PJM in a series of discussions and proposed a variant of Capacity Delivery Procedures to the MISO-PJM Joint and Common Market, but PJM has since indicated they cannot support it.

However, recognizing the problems caused by the pseudo-ties, both PJM and MISO have filed proposed tariff changes that will restrict their approval in the future, which will also unreasonably restrict capacity trading. 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.

Next Steps: The next steps on this recommendation will likely depend on FERC's Order on the RTOs' Section 205 filings and our Section 206 complaint. MISO, in response to PJM's 205 filing, has requested that FERC Order a Technical Conference to include a broad range of issues, including potential alternatives to meeting PJM's objectives.

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.

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, it should endeavor to do so in a manner that will facilitate modeling additional constraints in the future.

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 recommend 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 previously also included applying physical withholding mitigation jointly on affiliated market participants rather than on each participant independently. This change was filed by MISO and approved by FERC in early 2017.

Next Steps: Given that most other RTOs have addressed this form of potential market power abuse, MISO should justify why this is not a risk in the MISO market.

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 the South that can be relied upon to address contingencies in the 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 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.[38] This approach is not reasonable because holders of firm transmission rights cannot prevent MISO from

38 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.

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. This recommendation does not extend to Regional Pseudo-Tie Flow, as defined in the Settlement Agreement, which will pass through the regional transfer constraint.

Status: In MISO's compliance filing associated with the CMTC complaint, MISO codified 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.

Next Steps: The next steps will depend on FERC's order on MISO's compliance filing.

E. Prior Recommendations Not Included in the 2016 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 2015 and early 2016. These recommendations are discussed below, along with unresolved recommendations that are not included in this year's report.

Recommendations Addressed by MISO

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 cause generators to have the incentive 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 requires 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 early May 2017. MISO projects completion of its Settlement System upgrade in the third quarter of 2017, 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.

MISO is preparing a tariff filing to address this recommendation. It is intended to improve the effectiveness of the mitigation measures at addressing market power caused by transitory conditions (transmission or generation outages) that create severely-constrained areas. The tariff revisions would expand Module D mitigation provisions to allow temporary "dynamic" NCAs to be defined while the conditions persist and would employ a fixed conduct and impact threshold of $25 per MWh.

Status and Resolution: The IMM will support MISO's tariff filing and implementation of the dynamic NCA. We anticipate MISO making a FERC filing in the 2nd quarter of 2017 and implementation in the third quarter 2017, pending FERC's approval.

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. 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.

Status: 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).

Unresolved Recommendations Not Included in 2016 Report

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 generally duplicates the congestion pricing by the external system operator. For example, PJM already includes the congestion effects of external transactions in its interface pricing, so when MISO includes these same effects in its interface prices, the resulting congestion settlements are redundant and inefficient. The excessive settlement of congestion in the interface prices produces the following adverse results:

- The excess payments can result in higher negative excess congestion funds, market-to-market costs, or FTR underfunding.

- The excess payments can motivate participants to schedule inefficient transactions, while the excess charges can discourage efficient transactions.

The excess payments are not limited to market-to-market constraints in PJM. They also occur on constraints in other areas for which MISO activates constraints when the other system operator calls a TLR. To fully address these concerns, we continue to recommend that MISO eliminate the portions of the congestion components of the interface prices associated with the external constraints.

Status: This recommendation was originally made in our *2012 State of the Market Report*, although it was previously raised in our *2011 State of the Market Report.* Over the past five years, we worked with MISO, PJM, and stakeholders through the Joint and Common Market Stakeholder group to achieve a consensus on the problem and potential solution. While a long-term solution is limited by the scope of PJM's current transmission model, the RTOs have been evaluating short-term alternatives. MISO has made the decision to adopt PJM's proposed solution to both use a common interface definition. Unfortunately, our analysis to date has shown that this will provide less efficient, more volatile scheduling incentives than the preferred short-term and long-term solution, which is for MISO to remove all external congestion from its interface prices. We will monitor and evaluate the efficiency of the interface prices following the June 2017 implemention of the common interface. We also continue to encourage MISO to complete any software changes necessary to remove external congestion from its interface prices, as these changes are necessary to remove other external constraints in other adjacent areas.

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 owner 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. MISO concluded that additional options to improve the economic incentives for outage scheduling should be explored. However, MISO’s initial assessment also concluded that modifying the allocation of FTR shortfalls is not a high priority at this time because funding levels are relatively high. The MISO Roadmap status indicates that no action is planned and there is no specific date for a status update. Given MISO’s assessment and the fact that FTR funding levels have been high, we are suspending this recommendation and will reconsider it in the future.