2015 STATE OF THE MARKET REPORT FOR THE MISO ELECTRICITY MARKETS

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FOR MISO

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Guide to Acronyms

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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, identifying market design flaws or inefficiencies, and recommending improvements to the market design and operating procedures. This Executive Summary to the *2015 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 encompass 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 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 resource available and to schedule imports and exports) and support long term decisions (e.g., resource investment, retirement, and maintenance).

The remainder of this Executive Summary provides an overview of market outcomes, a discussion of key market areas, and a list of recommended market enhancements.

A. Market Outcomes and Competitive Performance in 2015

The MISO energy and ancillary service markets generally performed competitively in 2015. The most notable factor affecting market outcomes in 2015 was the considerable decline in natural gas prices, which fell to levels that have not occurred since the commencement of the MISO markets in 2005. The 50 percent decrease in natural gas prices from 2014 and decline in other fuel prices led to reductions in most prices and market costs:

- The average market-wide real-time energy price fell 32 percent to an average roughly $27 per MWh.
- Day-ahead congestion costs fell nearly 50 percent and real-time congestion dropped 45 percent. The biggest declines were in the first quarter of 2015, compared to the Polar Vortex conditions that occurred in MISO during the same period in 2014.
- The generation mix in MISO shifted as gas-fired resources increased their share of total energy output from 17 percent in 2014 to 23 percent in 2015. Gas-fired were even more important in setting prices, setting the system marginal price in 76 percent of intervals and locational prices somewhere in MISO in 95 percent of intervals.
- Real-time price volatility fell in 2015 as increased utilization of gas-fired resources provided more flexibility and ramp capability to the system.
- Net interregional flows between the MISO South and MISO Midwest regions shifted substantially from the predominant North-to-South direction to flow from South-to-North as the utilization of gas-fired generation in MISO South increased.
- Revenue Sufficiency Guarantee Payments, most of which are paid to natural gas-fired peaking resources fell 42 and 48 percent in 2015 in MISO's day-ahead and real-time markets, respectively.

In addition to overall declines in fuel prices discussed above, other variations in supply and demand also affected energy prices in 2015.

- Load levels fell by two percent on an annual average basis, mostly due to milder weather conditions than in 2014.
- The annual peak of 120 GW of load was set in July, much lower than the forecasted peak of 127.3 GW for 2015.

The strong relationship between energy and ancillary services prices and natural gas prices discussed above is expected in a well-functioning, competitive market because natural gas-fired resources were the marginal source of supply in most intervals in 2015 and fuel costs constitute the vast majority of most resources' marginal costs.

Beyond this overall correlation, we evaluate the competitive performance of the MISO markets be assessing the conduct of its suppliers, which was broadly consistent with expectations for a workably competitive market. This is indicated by the following two empirical measures of competitiveness:

- A "price-cost mark-up" compares simulated energy prices based on actual offers to energy prices based on competitive offer prices. Our analysis revealed the price-cost mark-up was down from 1.0 percent in 2014 to effectively zero in 2015, which indicates that the MISO markets were highly competitive.
- The "output gap" is a measure of potential economic withholding. It fell from 0.58 percent of actual load on average to 0.11 percent of load, which is *de minimus*. Consequently, market power mitigation measures were applied infrequently.

MISO implemented several market design changes in 2015 that should improve the efficiency and competitiveness of the MISO markets.

- On March 1, MISO implemented Market-to-Market (M2M) coordination with SPP to more efficiently manage congestion on constraints that both RTOs affect.
- MISO also implemented the Extended Locational Marginal Pricing (ELMP) on March 1, which allows online inflexible peaking resources and demand response resources to set prices when they are economic. It also allows offline resources to set prices during transmission or energy shortage conditions.
- In June, FERC approved improvements we recommended to improve the effectiveness of the RSG mitigation by testing the aggregate effect of all of a resource's offer parameters on its RSG payments against a lower mitigation threshold.

B. Long-Term Economic Signals and Resource Adequacy

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 2015.

- Net revenues in 2015 declined compared to last year in all regions, and they continue to be substantially less than the necessary revenues necessary for new investment to be profitable in any area (i.e., the annual cost of new entry or "CONE").

- Net revenues were highest for combustion turbines in Texas and Louisiana because of periods of severe congestion into the WOTAB (in Texas) and Amite South (in Louisiana) load pockets and associated higher prices during these periods in 2015.

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.

Capacity market design issues described in this report have contributed to inadequate price signals, which will become an increasing concern as the capacity surplus falls due to retirements and units exporting capacity to neighboring RTOs. In 2015, approximately 1 GW of MISO's coal-fired resources retired, largely due to the combined effects of low gas prices and the costly retrofits required by environmental regulations. Hence, we continue to believe that it is important for the MISO markets to provide the necessary economic signals to maintain an adequate resource base.

Summer Capacity Margins. In the near-term, our assessment indicates that the system's resources should be adequate for the summer of 2016 if the peak conditions are not substantially hotter than normal.

- We estimate a planning reserve margin of 20.5 percent, which exceeds MISO's planning reserve requirement of 15.2 percent.
- However, under hotter than normal summer conditions and incorporating a realistic assumption regarding the performance from MISO's demand response (DR) capability, the planning margin will be below 12 percent. This margin should be sufficient to satisfy MISO's operating needs given the typical forced outage rate of five to eight percent.

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 nine local zones, and models a number of transmission constraints. The constraints include the transfer constraint between MISO South

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

and MISO Midwest, and import/export constraints for each of the local zones. The PRA results for 2015/2016:

- The auction cleared at $3.48 per MW-day in most zones, which is about 1.5 percent of CONE (close to zero).
- Zone 4 (Illinois) was import-constrained and cleared at $150 per MW-day, consistent with the prevailing prices in PJM where suppliers can and have exported capacity. Since it is rational for those with excess capacity to offer at prices that reflect their opportunity to export the capacity, we found that the market outcome in Zone 4 was competitive.
- The 1,000-MW transfer limit between MISO Midwest (Zones 1-7) and MISO South (Zones 8 and 9) resulted in a slightly lower clearing price in MISO South.

Two significant shortcomings continue to undermine the efficiency of the PRA and contributed to MISO's relatively low auction clearing prices for 2015/2016 and the low levels of net revenues available to new investors.

- Design of MISO's PRA; and
- Prevailing barriers to capacity trading between PJM and MISO.

PRA Design Issues. Several PRA design issues persist that continue to undermine the efficiency of the PRA and contributed to MISO's relatively low auction clearing prices for 2015/2016. The most notable shortcoming is that the minimum capacity requirements and deficiency price set forth in the Tariff 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 to the system and results in inefficient capacity market outcomes.

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. MISO has been working on a proposal to improve the capacity pricing in CRAs and we have been providing comments and advice. In this context, we have offered an alternative proposal that would establish prices for CRAs that reflect the marginal reliability value of MISO's unregulated resources. MISO's vertically-integrated load-serving entities and the regulated resources they own would not settle at these prices.

We have recommended a variety of improvements to the PRA that will also improve the outcomes in the CRA.

- We had recommended that FERC allow suspended units to participate in the PRA and MISO made a filing in December 2015 to address this recommendation.
- We continue to recommend that MISO allow units with Attachment Y retirement requests to participate in the PRA and have ability to postpone or cancel the retirement if they clear.
- In order to allow units to be most efficiently used for the portions of the year that they are economic, we recommend MISO consider transitioning to a seasonal capacity market.
- Finally, we recommend that MISO define local resource zones primarily based on transmission constraints and local reliability needs.

PJM Capacity Concerns. Because MISO's market does not establish efficient capacity prices, suppliers with uncommitted capacity have strong incentives to export their capacity to PJM. In addition to reducing MISO planning reserve margin, this is raising substantial operational concerns because PJM requires these units to be "pseudo-tied" to PJM. Because these units create substantial power flows over the MISO's network, this will undermine the efficiency of MISO's dispatch and its ability to manage congestion on its network cost effectively. The effects of these pseudo-tied units will have to be managed under the M2M coordination process with PJM. We identified roughly 300 new constraints (internal MISO constraints that bound in 2015) that will require M2M coordination as a result of units pseudo-tying into PJM.

We recommend that MISO implement firm capacity delivery procedures with PJM in lieu of pseudo-ties. This offers a balanced approach towards meeting the capacity obligations to PJM. 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.

C. 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 2015. Day-ahead congestion costs fell nearly 50 percent to $751 million in 2015. Much of the annual reduction in congestion in the year-over-year comparison occurred during the first quarter (the Polar Vortex occurred in the first quarter of 2014). Day-ahead congestion after March was 30 percent lower than the same period in 2014 because conditions were mild and fuel prices were relatively low. Falling natural gas prices reduced congestion costs because gas-fired units are generally the resources that are dispatched to manage the power flows over binding constraints. In addition, the difference in the marginal energy costs of coal and gas decined, further reducing redispatch costs incurred to manage congestion.

During 2015, MISO continued to pursue improvements that lowered the cost of congestion and improved dispatch efficiency.

- In October, MISO reached a settlement agreement with SPP and other parties to allow more transfers between MISO South and Midwest regions. It eliminates the $10 Hurdle Rate that restricted transfers higher than 1000 MW and contributed to significant dispatch inefficiencies. As of February 2016, MISO may now transfer 3,000 MW in the North to South direction and 2,500 MW in the South to North direction with no hurdle rate.

- MISO and the IMM worked with transmission operators to improve the utilization of the transmission system by obtaining more accurate transmission ratings. This includes expanded use of temperature-adjusted, emergency ratings, and use of dynamic voltage and stability ratings. We recommend that MISO continue this work, and work with neighboring regions where dynamic voltage and stability ratings may reduce TLRs.

- On March 1, MISO implemented market-to-market coordination with SPP, which included the WAPA Basin region after October. The implementation was a successful overall and has lowered the impact of SPP constraints on MISO’s dispatch and prices. However, early issues arose that will likely require resettlement and procedures are being developed to address these issues. These procedures involve transferring control of M2M constraints to the neighboring RTO if it has the most effective relief for the constraint.

FTR Funding. Day-ahead congestion costs collected by MISO that are paid to Financial Transmission Rights (FTR) 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. In 2015, the FTRs were funded at 99.8

percent, which is a substantial improvement over 2014. However, this aggregate funding level masks the fact that constraints in some areas are substantially over-funded while other areas are underfunded, which results in substantial cost-shifting. MISO has improveed the FTR markets to reduce underfunding, but transmission outages that are not known when FTRs are sold continue to generate underfunding. To address these concerns, we recommend that MISO:

- Allocate underfunding shortfalls that result from transmission outages to the transmission owner or, if not feasible, to transmission customers at locations on the system affected by the outage; and
- Allocate the balance of the shortfalls to transmission customers in proportion to the FTR revenues and Auction Revenue Rights they received.

Currently, shortfalls are allocated to the FTR holders, resulting in funding that is less than 100 percent. This diminishes the value of the FTRs as congestion hedges and lowers FTR prices, which ultimately causes MISO's transmission customers to bear these costs. This recommendation would improve the incentives for transmission operators to schedule outages more efficiently and limit their duration, and raise FTR revenues for transmission customers.

External Congestion. We report on significant dispatch and pricing inefficiencies in managing external constraints that are activated when Transmission Line Load Relief (TLR) procedures are invoked. With the initiation of M2M with SPP, this issue has been reduced. However, MISO may still incur substantial congestion costs to provide relief under TLR when the constraint is not binding (i.e., the relief had no value) or has much less value in the external region.

D. Day-Ahead Market Performance

The day-ahead market is critically important because it coordinates most resource commitments and because it 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 resource commitments needed to efficiently satisfy the system's real-time operational needs. In 2015:

- The day-ahead premium fell to 0.6 percent, which was considerably smaller than the 5.4 percent day-ahead premium in 2014.
- A number of congestion episodes caused by forced generator and transmission line outages occurred in MISO South that led to transitory periods of divergence in that area.

- Under-scheduling of wind in the day-ahead led to poor convergence at the Minnesota Hub in some periods, particularly in the fall when wind output was high. Fortunately, virtual supply at wind locations offset much of this underscheduling.

Virtual transactions provided essential liquidity and improved the convergence of day-ahead and real-time energy prices. Cleared virtual transactions increased 32 percent in 2015, resulting in lower overall profitability of virtual trades. This is consistent with virtual activity improving convergence between the day-ahead and real-time markets.

Price convergence was worst at congested locations in 2015, 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. 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 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.

E. 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 2015 as indicated above, falling 32 percent as fuel prices decreased.

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. PVMWP in MISO Midwest decreased 40 percent in 2015, consistent with a comparable decrease in price volatility.

PVMWPs would be substantially reduced and generators would have stronger incentives to be flexible and follow MISO's dispatch instructions if MISO settled with participants on a five-minute basis. For example, flexible resources would have received more than $15 million in higher net revenues under a five-minute settlement. By providing better incentives to follow dispatch instructions, MISO would realize production cost savings for the system and improve reliability. Hence, we have recommended that MISO implement five-minute settlements, which FERC endorsed in a Notice of Proposed Rulemakings (NOPR) issued in September 2015. FERC proposed requiring RTOs to settle with generators in the same time increments as its dispatch (i.e., 5-minute pricing for MISO).[2] MISO has filed supporting comments in response to this and is working towards implementation of consistent dispatch and settlement intervals.

Generator Performance. Our most substantial 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 2015 averaged 314 MW, and exceeded 730 MW in the worst 10 percent of the intervals in 2015. This raises 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 to 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 payments by more than $8 million in 2015.

Uplift 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 48 percent to $5.3 million per month.
- Day-ahead RSG payments decreased from $11.5 million to $6.7 million per month. 75 percent of these costs are associated with Voltage and Local Reliablity (VLR) commitments in MISO South.

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

Most of these reductions were due to lower fuel prices and lower real-time system congestion. However, the RSG associated with VLR 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).

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 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.[3] 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.

Currently ELMP rules permit only 2 percent of the online peaking resources to set prices. MISO has proposed a Phase 2 implementation of ELMP that would add an additional 12 percent and eliminate approximately $4.4 Million of the RSG paid to these resources. We are recommending that ELMP be extended to most of the remaining peaking resources. Our proposal would account for 90 percent of online peaking resources and eliminate a $20 million in RSG.

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 less than 10 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 prices during shortage conditions and recommend that MISO disable the offline pricing logic as quickly as possible.

3 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…."

F. External Transaction Scheduling and External Congestion

As in prior years, MISO remained a substantial net importer of power in 2015, importing an average of 2.8 GW per hour in real time. However, as a result of wheels from IESO to PJM through MISO and dynamically-scheduled exports to PJM from the South region, MISO was a net exporter to PJM in 2015. 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 to 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 it results in inefficient transactions that increase price volatility, reduce dispatch efficiency, increase uplift costs, and sometimes create operating reserve shortages. 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 price is greater than the offer price (i.e., Coordinated Transaction Scheduling or CTS). MISO worked with PJM to develop and file a CTS proposal. Although we support the CTS proposal, we requested that FERC Order PJM to eliminate all fees charged to CTS transactions.

Interface pricing is currently impacted by a flaw involving the pricing of congestion in the interface prices. This flaw is that both MISO and PJM settle with physical transactions for the same relief on market-to-market constraints. This generally results in the participants being overcompensated, leads to substantial balancing congestion and FTR underfunding, and facilitates inefficient imports and exports. We have been working with PJM and MISO on this issue and continue to recommend that MISO modify its interface prices to include only the costs associated with its own transmission constraints and exclude the effects of all external constraints. PJM has also proposed a less efficient solution that MISO has agreed to pursue. Unfortunately, our analysis indicates that the PJM solution will result in less efficient imports and exports and raise costs for customers in both regions.

G. 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 will continue to seek to expand its DR capability, including efforts to allow for Batch Load DR and Price Responsive Demand. Currently, MISO has more than 10.5 GW of DR resources, which includes 4 GW of behind-the-meter generation. However, most of MISO's DR capability is in the form of interruptible load developed under regulated utility programs (referred to as "load-modifying resources" or LMRs). MISO does not directly control LMRs and it 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.

H. Table of Recommendations

Although the markets performed competitively in 2015, we make 22 recommendations in this report intended to improve the performance of MISO's markets. Of these recommendations, 14 were recommended in prior reports. This is not unexpected as many of our recommendations require both Tariff and software changes that can require years to implement. MISO addressed nine of our prior recommendations in 2015 and early 2016, which are discussed in Section X.F.

The table below shows our current recommendations, organized by the market area they address. The table includes an "SOM number," which indicates the year in which it was first introduced and the recommendation number in that year, and separately indicates whether it would provide high benefits to the market and whether it can be achieved in the short-term.

We also note the "Focus Areas" from MISO's market vision and roadmap process, which are to:

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. Develop Resources Efficiently Consistent with Long-term Reliability and Policy Objectives.

SOM Number	Focus Area	Recommendations	High Benefit	Feasible in ST
Energy Pricing and Transmission Congestion				
2012-2	3,4	Implement a five-minute real-time settlement for generation.	✓	
2012-5	1,2	Introduce a virtual spread product.	?	
2012-9	1,3	Allow the definition of a "dynamic NCA" that is utilized when network conditions create substantial market power.		✓
2014-1	2	Modify the allocation of transmission shortfalls in order to fully fund MISO's FTRs.		✓
2014-2	1,3,7	Introduce a 30-Minute Local Reserve product to reflect the VLR requirements.	✓	
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	✓	
External Transaction Scheduling and External Congestion				
2012-3	4	Remove external congestion from interface prices to eliminate excess payments and charges to physical transactions.	✓	✓
2014-3	2	Improve external congestion related to TLRs by working to modify assumptions that would reduce MISO's relief obligations.		
Guarantee Payment Eligibility Rules and Cost Allocation				
2010-11	1	Include expected deployment costs when selecting units to provide spinning reserves.		
2015-3	1	Model the VLR Requirement in the Day-Ahead Market		

SOM Number	Focus Area	Recommendations	High Benefit	Feasible in ST
Improve Dispatch Efficiency and Real-Time Market Operations				
2012-12	1	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 and SE errors in real-time operations.		✓
Resource Adequacy and Planning				
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 and recognizing affiliates.		✓
2015-8	7	Improve the limit on the transfer constraint between MISO South and Midwest in the PRA.		✓

I. INTRODUCTION

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

MISO introduced competitive wholesale electricity markets on April 1, 2005. These markets include day-ahead and real-time energy markets that allow MISO to utilize the lowest-cost resources to satisfy the system's demands without overloading the transmission network. They also provide economic signals to govern short- and long-run decisions by participants. MISO administers Financial Transmission Rights (FTRs) that allow participants to hedge congestion costs associated with serving load and other transactions.[4]

In 2009, MISO introduced markets for regulation and contingency reserves, known as Ancillary Services Markets (ASM), and a capacity market. The ancillary services and energy markets are jointly optimized in order to allocate of resources efficiently. This also allows prices to fully reflect both shortages of and tradeoffs between the products. MISO modified its capacity market in 2013 by introducing an annual Planning Reserve Auction (PRA) that better identifies MISO's locational capacity needs. Though an improvement, the demand is poorly represented, which undermines the market's ability to facilitate efficient investment and retirement decisions.

In late 2013, MISO integrated the MISO South region in Texas, Louisiana, Mississippi, and Arkansas. Power transfers between MISO South and Midwest regions had been limited for most of 2014 through January 2016, when MISO implemented a settlement agreement allowing it to transfer much more power between regions and lower its dispatch costs. Other improvements in 2015 included MISO initiating market-to-market coordination with SPP and the Extended Locational Marginal Pricing (ELMP) to produce more efficient real-time prices.

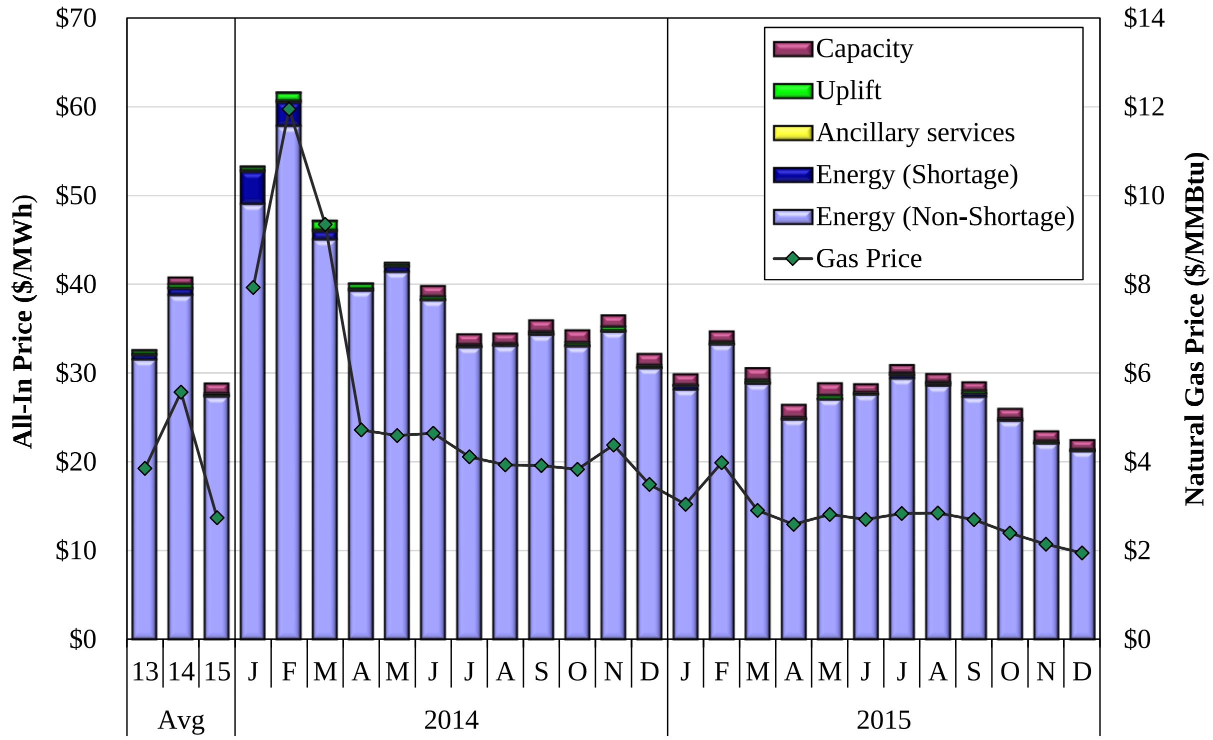
4 FTRs are financial instruments that entitle their holder to a payment equal to the congestion price difference between locations in the day-ahead energy market.

II. PRICES AND LOAD TRENDS

A. Market Prices in 2015

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 one or more reserve products.

Figure 1: All-In Price of Electricity
2014–2015



The all-in price in 2015 fell 29 percent from 2014 to average $28.91 per MWh. The large decrease was driven by much lower natural gas prices, declines in other fuel prices, and increased wind generation. MISO also experienced relatively mild weather and corresponding load levels through much of 2015. The average price of natural gas decreased more than 50 percent from 2014 to 2015 and the average mine-mouth coal price fell 17 percent from 2014.

As in prior years, the real-time energy component constituted nearly the entire all-in price, although slightly higher capacity prices added $1.08 per MWh, approximately four percent of the all-in price during this period. The PRA clearing price in the 2015/2016 delivery year was slightly lower than the prior year on average, despite the relatively high price in Zone 4 ($150 per MW-day). The other zones in MISO cleared at less than $3.50 per MW-day. Unlike other zones, Zone 4 is predominately comprised of unregulated suppliers that compete to service competitive retail loads. We concluded that the $150 per MW-day price in this zone was competitive given the other opportunities for these suppliers (i.e., to export capacity to PJM). In all other zones, capacity remained undervalued due to shortcomings in the PRA design discussed in this report. Improving the performance of the capacity market should play a pivotal role in ensuring that MISO will continue to have access to sufficient capacity in the future as coal, and even potentially nuclear, resource retirements accelerate.

Uplift payments are made to resources dispatched by MISO to meet system requirements when the resources do not fully recover their costs in the day-ahead or real-time markets. These payments include Revenue Sufficiency Guarantee (RSG) payments and Price Volatility Make-Whole Payments (PVMWPs). Lower fuel prices led to lower uplift payments in 2015, reducing their contribution to the all-in price to 22 cents per MWh. Ancillary services costs also declined to just 7 cents per MWh.

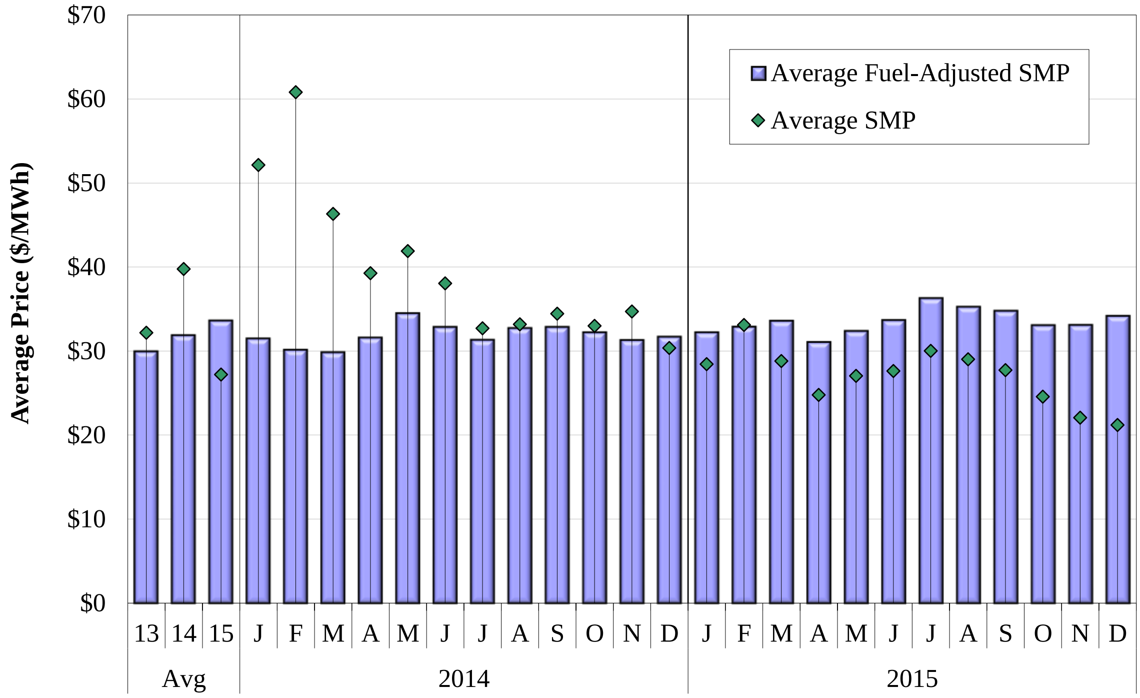
Figure 1 also shows that energy prices continue to be strongly correlated with gas price changes. This is expected in a well-functioning, competitive market because fuel costs are the majority of most suppliers' marginal costs. Since suppliers in competitive markets have an incentive to offer marginal cost, fuel price changes should result in comparable offer price changes.

To estimate 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] The average nominal SMP in 2015 dropped 32 percent from 2014, while the fuel-adjusted SMP rose five percent. This indicates

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

that while fuel price declines caused sharp price decreases, non-fuel factors offset these reductions to a modest extent in 2015.

Figure 2: Fuel-Adjusted System Marginal Price
2014–2015



The highest fuel-adjusted SMP occurred in July 2015 when loads were the highest (especially compared to the relatively cool July experienced in 2014). It was also high during certain periods in the fall and early spring because of relatively high outage rates. Some of the increases late in 2015 when gas prices were at their lowest may also reflect the difficulty of adjusting for such large changes in fuel prices.

B. Fuel Prices and Energy Production

The substantial changes in fuel prices during 2015 altered the generation mix in MISO. In particular, low natural gas prices throughout 2015 increased MISO's output from natural gas-fired units and decreased the generation from coal-fired resources. Given the typical difference in emission rates for these types of resources, we estimate that this shift in generation reduced MISO's CO2 emissions by more than 5 percent. The following table shows how these changes affected the share of energy produced by fuel-type and which generators that set the real-time energy prices in 2015.

Table 1: Capacity, Energy Output, and Price-Setting by Fuel Type
2014–2015

	Unforced Capacity				Energy Output		Price Setting			
	Total (MW)		Share (%)		Share (%)		SMP (%)		LMP (%)	
	2014	2015	2014	2015	2014	2015	2014	2015	2014	2015
Nuclear	12,763	12,432	9%	9%	16%	15%	0%	0%	0%	0%
Coal	66,658	59,181	46%	42%	58%	52%	40%	23%	85%	95%
Natural Gas	55,852	58,013	39%	42%	17%	23%	59%	76%	82%	94%
Oil	3,125	2,063	2%	1%	0%	0%	0%	0%	0%	0%
Hydro	3,621	3,603	3%	3%	1%	1%	0%	0%	2%	2%
Wind	1,027	2,412	1%	2%	6%	7%	0%	1%	45%	45%
Other	564	1,688	0%	1%	1%	1%	0%	0%	4%	4%
Total	**143,610**	**139,391**								

The lowest-cost resources (coal and nuclear) produced most of the energy. Natural gas-fired output increased from 17 percent in 2014 to 23 percent in 2015, but remains lower than its 42 percent share of capacity. This increase in gas-fired energy output was due to the rising utilization of gas-fired resources as natural gas prices decreased. Conversely, the utilization of coal resources continued to decline in 2015.

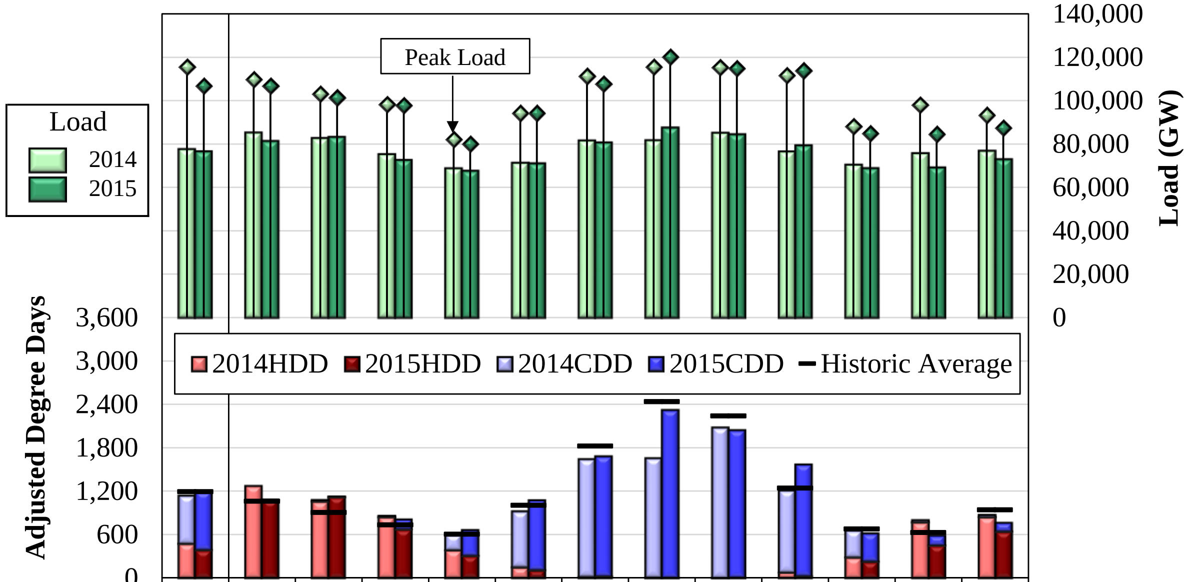
Although natural gas-fired units produce a modest share of the energy in MISO, they play an important role in setting energy prices. Gas-fired units set the system-wide price in 76 percent of all intervals for the year, up from 59 percent in 2014. Congestion frequently causes gas-fired units to be on the margin in local areas when a lower-cost unit may be setting the system-wide price. Hence, natural gas-fired resources set LMPs in local areas in 94 percent of all intervals, highlighting why it continues to be an important driver of energy prices. Conversely, coal-fired resources set the SMP in 23 percent of intervals, down from 40 percent in 2014. This reflects the much larger reductions in natural gas prices than coal prices 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 has the largest effect on wind resources that are shown as only 2 percent of MISO's planning resources. Although wind resources' share of both energy and unforced capacity are well below 10 percent, they set LMPs in local areas at an average price of $-1 per MWh in almost half 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 shows 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
2014–2015



<u>% Chg 14-15</u>	Avg	J	F	M	A	M	J	J	A	S	O	N	D
Avg. Load	-1%	-5%	1%	-4%	-2%	0%	-1%	7%	-1%	4%	-2%	-9%	-5%
Degree Days	5%	-15%	4%	-6%	10%	16%	2%	40%	-2%	30%	-6%	-26%	-12%

Although the degree days increased slightly in 2015, the average load in MISO decreased by one percent. MISO set its annual peak load of 120.0 GW on July 28, which was slightly higher than the peak load in 2014. Nonetheless, the peak load in 2015 was less than the forecasted peak of 127.3 GW from MISO's *2015 Summer Resource Assessment*, which was due to the milder than normal condition during the summer.

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.

Total degree days in 2015 increased 5 percent, largly because the summer in 2015 were closer to normal compared to the unusually mild summer in 2014. The Polar Vortex in the winter of 2014 led to greater heating degree days, while 2015 marked a return to less extreme winter weather.

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 the long-term economic signals provided by the MISO markets by measuring the "net revenue" a new generating unit would have earned in 2015. Net revenue is the revenue that 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 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 MISO 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, 2013–2015

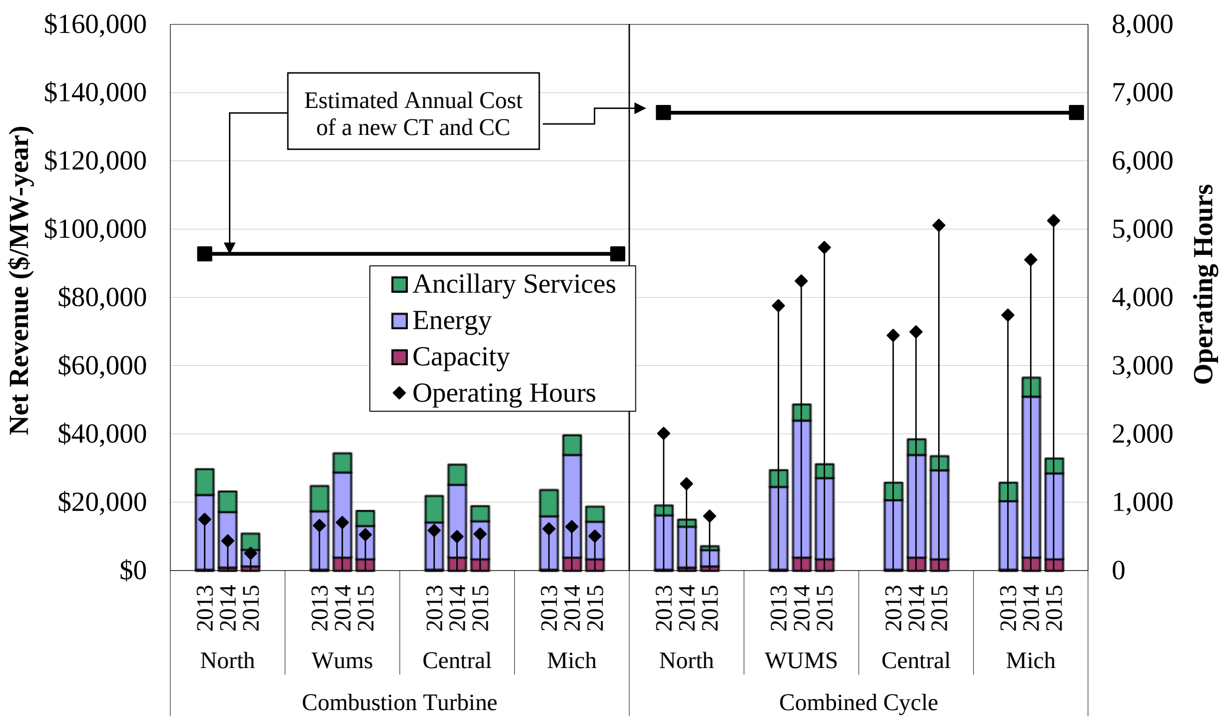
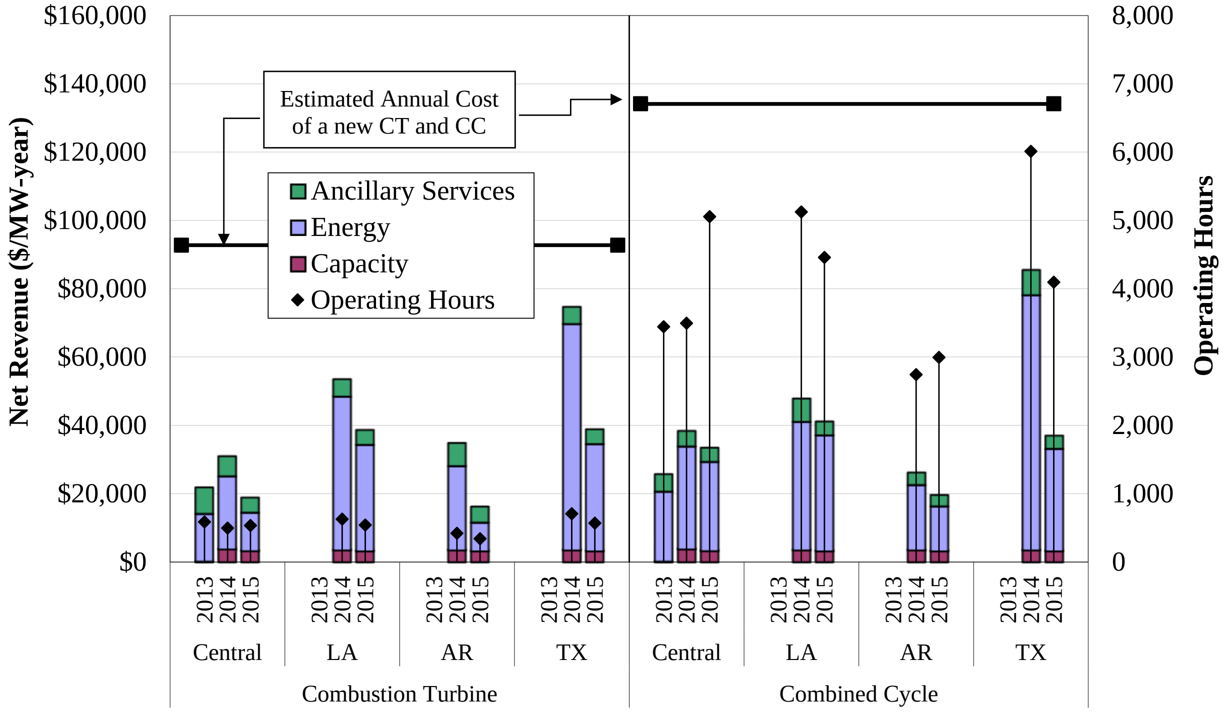


Figure 5: Net Revenue Analysis
South Region, 2013–2015



Note: "Central" refers to the Central region of MISO Midwest and is included for reference purposes. There is no data for MISO South locations prior to its integration into MISO in December 2013.

Estimated net revenues in 2015 for both types of units decreased from last year in all locations, primarily driven by sharply lower fuel prices and associated energy prices throughout MISO. As a result, net revenues continue to be substantially less than CONE in all regions. The relatively low levels of net revenues are consistent with expectations because of the capacity market design issues we describe in this report and the prevailing near-term capacity surplus.

Capacity market design issues continue to undermine MISO's economic signals as MISO's capacity surplus dissipates and as resources are faced with additional capital expenses needed to comply with existing or future environmental regulations. 3.8 GW retired or entered suspension in 2016 and an additional 2.5 GW are expected to retire in 2016. This values do not include the potential effects of EPAs clean power plan or the growing capacity exports to PJM. Given these developments, the economic signals provided by the MISO markets are becoming increasingly important. To improve these price signals, we recommend a number of changes to both the energy market and the capacity market. The next section discusses the supply in MISO in more detail and evaluates the design and performance of the capacity market.

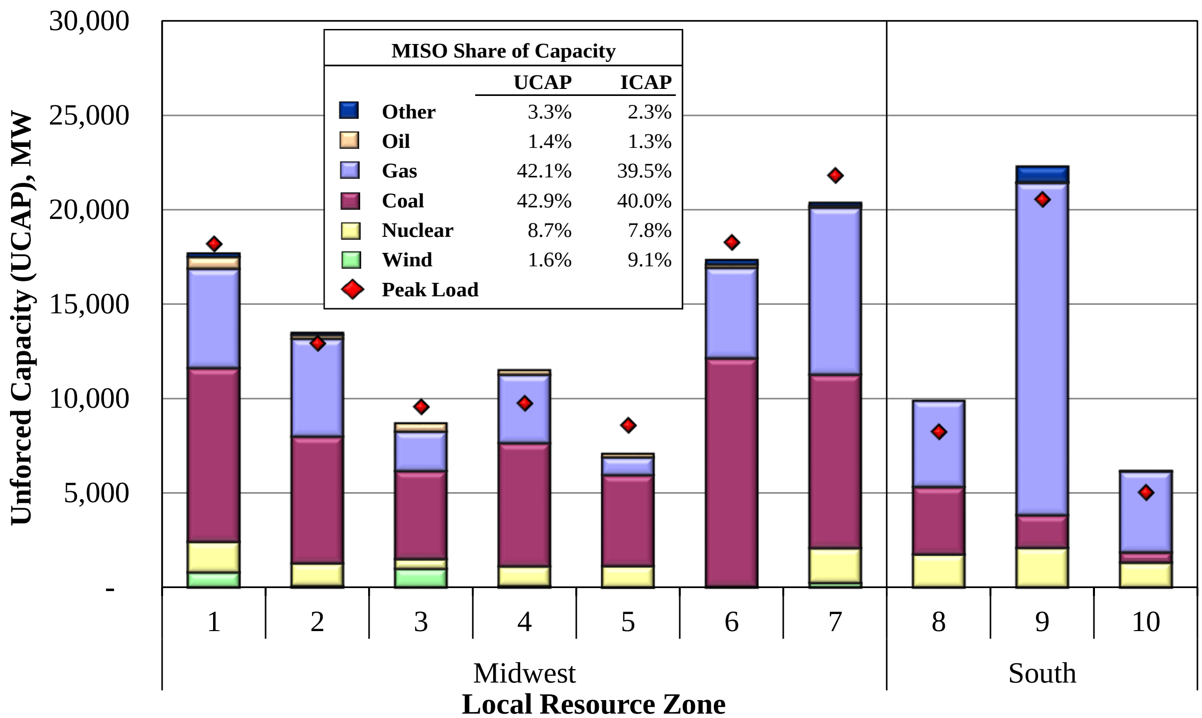
III. Resource Adequacy

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

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 2015 by zone and fuel type, along with the 2015 coincident peak load in each zone. UCAP was based on data for the MISO 2016 PRA. UCAP values account for forced outages and intermittency and so are lower than ICAP values, as shown in the inset table. Hence, although wind is more than nine percent of MISO's ICAP, it is less than two percent of MISO's UCAP.

Figure 6: Distribution of Existing Generating Capacity
By Fuel Type and Zone, December 2015



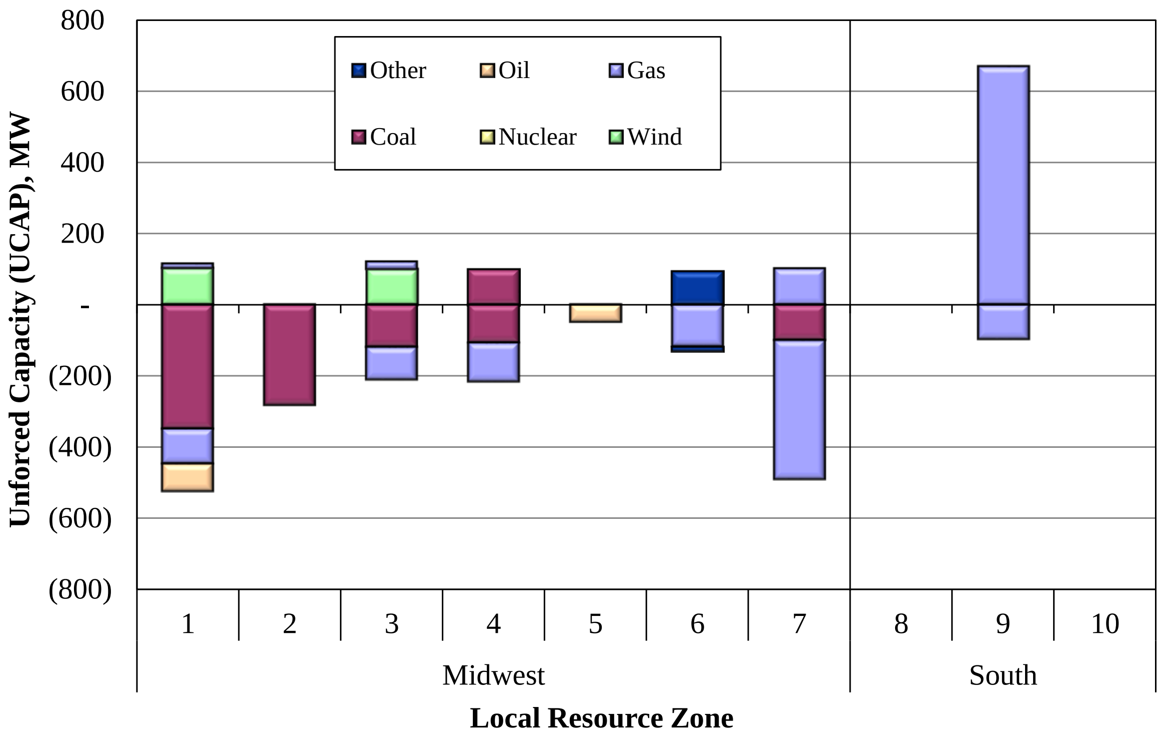
This figure shows that gas-fired resources now account for roughly the same share of MISO's capacity as coal-fired resources. In future years, we expect gas-fired capacity to surpass coal resources as coal resources retire and new gas resources enter. The figure also shows that the gas-fired capacity shares are largest in MISO South. As natural gas prices have fallen, interregional flows have increasingly shifted to be from MISO South to MISO Midwest.

Additionally, because the average output from wind units in the western zones (zones 1 and 3) is generally greater than their UCAP credit, the western areas produce substantial surplus energy when wind output is high and cause significant west-to-east flows and associated 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 2015.

Figure 7: Distribution of Additions and Retirements of Generating Capacity
By Fuel Type and Zone, 2015



Retirements. In 2015, 2 GW of resources retired, partly in response to environmental regulations issued by the U.S. Environmental Protection Agency (EPA). These regulations include the Cross-State Air Pollution Rule (CSAPR), the Mercury and Air Toxics Standards (MATS), and the Coal Ash Rule. Not surprisingly, these regulations tend to lead older coal units to retire to avoid high-cost retrofits that would otherwise be required to mitigate the emissions and other environmental effects. In addition to roughly 1 GW of coal retirements in 2015, 1.8 GW of coal-fired units were suspended and 1.5 GW is expected to retire in 2016 (as indicated in MISO's survey or announced by participants).[7] Further, additional retirements and suspensions have been announced in 2016 that can be attributed to the inefficient capacity pricing in MISO. Additionally, capacity exports to PJM are growing where capacity prices are more reflective of its reliability value. As a result, MISO may be short of capacity as soon as 2018.

Finally, EPA issued the Clean Power Plan (CPP) in August of 2015, which was stayed by the Supreme Court on February 9, 2016 pending judicial review. If it is implemented, it will result in far-reaching impacts that likely will exceed the individual impacts of any previous initiative. MISO's analysis of the CPP indicates that it may see 8 to 24 GW of additional retirements, although it is pending judicial review. In comments submitted to the EPA, MISO has argued that the CPP should consider reliability concerns and a reliability safety valve.[8]

New Additions. Most new capacity was natural gas-fired resources. Almost 800 MW entered in 2015, most of which was in MISO South. Growth of wind resources moderated in 2015 due in part to the uncertainty regarding the renewal of the federal tax credits. In December, Congress extended the investment and production tax credits of $23/MWh. As discussed further below in Section V.E., wind resources under construction by 2016 receive the full credit for the first 10 years of operation. The credit decreases 20 percent for units that begind construction each year from 2017 through 2019. Additional wind growth may also occur in the coming years as Multi Value Projects ("MVP") are completed, which include 17 transmission projects with regional benefits expected to significantly exceed the estimated $6.3 billion cost. Three of these projects are completed, six are underway and expected to be completed between 2016 to 2019, and the remaining eight are pending. No new generation additions are expected before summer.

C. Planning Reserve Margins

This subsection assesses capacity levels in MISO and their adequacy for satisfying the forecasted peak loads for summer 2016. In its *2016 Summer Resource Assessment*, MISO presented baseline planning reserve margins alongside a number of valuable scenarios that show the

7 MISO Quarterly EPA Survey Update, March 2016.

8 See January 21, 2016 Letter from John Bear, MISO President and CEO, to Honorable Gina McCarthy, EPA Administrator.

sensitivity of the margins to changes in key assumptions. We have worked with MISO to ensure that our Base Case planning reserve level is consistent with MISO's, with one notable exception. While MISO's transfer limit assumption is based off of the 2016/2017 PRA transfer limit assumed value of 876 MW, we assume a probabilistic derated transfer capability of 2,000 MW, which results in a higher starting planning reserve margin in our base case. This is discussed in more detail below. We include some scenarios that differ from MISO's to show how alternative assumptions regarding demand response (load-modifying resources or "LMRs") and unusually hot temperatures would affect MISO's planning reserve margins. Table 2 shows three scenarios that examine the effects of variations in these key assumptions.

Table 2: Capacity, Load, and Planning Reserve Margins
Summer 2016

		Alternative IMM Scenarios		
			High Temperature Cases	
	Base Case	**Realistic DR (1)**	**Full DR (2)**	**Realistic DR (3)**
Load				
Base Case	125,913	125,913	125,913	125,913
High Load Increase	-	-	6,318	6,318
Total Load (MW)	125,913	125,913	132,231	132,231
Generation				
Internal Generation	140,565	140,565	140,565	140,565
BTM Generation	3,462	3,462	3,462	3,462
Hi Temp Derates*	-	-	(4,900)	(4,900)
Adjustment due to Transfer Limit**	(1,203)	(1,203)	-	-
Total Generation (MW)	142,824	142,824	139,127	139,127
Imports and Demand Response				
Demand Response	6,413	5,130	6,413	5,130
Capacity Imports	2,540	2,540	2,540	2,540
Margin (MW)	25,863	24,581	15,849	14,566
Margin (%)	**20.5%**	**19.5%**	**12.6%**	**11.6%**

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 1,203 MW (50/50 scenario) of capacity in MISO South cannot be accessed due to the 2,000 MW Transfer Limit (applying probabilistic derates on the 2,500 MW Transfer Limit) so this reduces the overall MISO Capacity Margin.

The first column in Table 2 shows the base case, which assumes that MISO will receive full response from its Demand Response (DR) resources (interruptible load and controllable load management) when they are deployed. These resources are not subject to testing procedures on a comparable basis to other generating resources, but are still granted a 100 percent capacity credit.

MISO has rarely deployed these resources, but its limited experience suggests a lower response rate. Over time, MISO's certification requirements, data collection from LBAs on available demand response, and penalties for failing to respond have improved. Therefore, we anticipate a higher response rate now than the apparent 50 percent response rate MISO received in 2006 when demand response was called. The "Realistic DR" case in the table reflects the derating of the DR capacity by 20 percent but is otherwise identical to the base case.

The final two columns show the "Full DR" and "Realistic DR" scenarios under peak conditions that are hotter than normal. These columns represent a "90/10" case, which should only occur one year in ten. This is an important case because particularly hot weather can have a significant impact on both load and supply. High ambient temperatures can reduce the maximum output levels of many of MISO's generators, while outlet water temperature or other environmental restrictions cause certain resources to be derated. 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. In its *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 a more realistic assumption of derates that may occur under high-temperature conditions is needed.

The results in the table show that the capacity surplus varies considerably in these scenarios. The baseline capacity margin for the MISO Midwest region exceeds 20 percent, which substantially exceeds the Planning Reserve Margin Requirement of 15.2 percent.[9] The high-temperature cases show much lower margins—as low as 11.6 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 5 to 8 percent but may be much higher do to correlated factors for example during periods of extreme temperatures.

Overall, these results indicate that the system's resources should be adequate for summer 2016 if the peak demand conditions are not substantially hotter than normal. However, planning reserve

9 The 2016 Planning Reserve Margin Requirement is for all of MISO. Due to the potential transfer limits from MISO South to MISO Midwest, we have included the firm contract path limit of 2,000 MW in all scenarios, which is based on a probabilistic derating of the full 2,500 MW transfer capability. MISO has included a more stringent transfer constraint of 876MW in its Base Case.

margins have been decreasing and will likely continue to fall as new environmental regulations are implemented and suppliers continue to export capacity to PJM. A capacity shortfall could occur as early as 2018 based on the 2015 OMS survey adjusted for recently announced retirements and suspensions. Therefore, it remains important for the capacity market to provide the necessary economic signals to maintain an adequate resource base. These issues are discussed in detail in the following three subsections.

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. An SSR cannot retire or be suspended until a reliability solution, such as transmission upgrades, can be implemented or the reliability condition no longer exists. The SSR agreement provides for compensation to the market participant during this period of delayed retirement.

In 2013, SSR credits net of market revenues (the portion uplifted to nearby load zones) totaled over $6 million and were paid to six units. There is currently one unit classified as SSR that is eligible for nearly $0.5 million in gross cost recovery per month. Two additional units recently lost SSR status, one in December 2015 and the other in February 2015. 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.

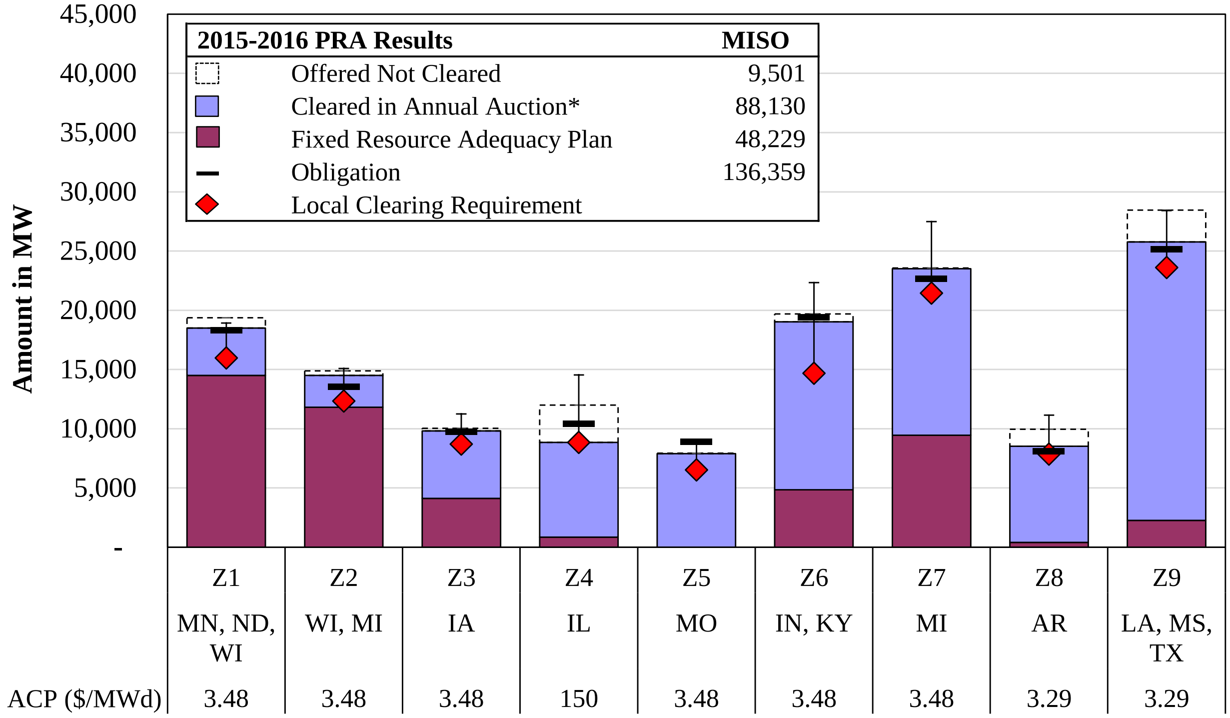
E. Capacity Market

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. The PRA was implemented in 2013 to better reflect regional capacity needs and to allow zonal capacity prices to separate when a zone’s minimum clearing requirement or export limit is binding. This provides a more accurate signal regarding the value of capacity in various locations.

1. Capacity Market Outcomes

Figure 8 shows the combined outcome of the PRA auction held in April 2015 for the 2015-2016 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.

Figure 8: Planning Resource Auctions
2015–2016 Planning Year



The auction for the 2015/2016 planning year cleared at $3.48 per MW-day in most zones, which is about 1.5 percent of CONE. Zone 4 was import-constrained and cleared at $150.00 per MW-day, while the 1,000 MW transfer limit between the Midwest (Zones 1-7) and South (Zones 8 and 9) regions was binding and resulted in a slightly lower clearing price in MISO South. Although the price was substantially higher in Zone 4, this price is consistent with the prevailing prices in PJM where suppliers have the opportunity to export capacity. Since it is rational for those with excess capacity to offer at a price that reflects their foregone opportunity to export the capacity, we found that the market outcome in Zone 4 was competitive. The auction was properly implemented and market power mitigation was properly applied.

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 make other changes to the market power mitigation rules in response to a December 2015 Order from FERC. Resources still have the right to request facility-specific reference levels, based on avoided costs;
- Adjusted the zonal import limits so that they are now account for capacity exports form the zone, which is in line with our recommendation made in the 2014 SOM; and
- Reduced the transfer constraint limit between the South and Midwest regions to 876 MW. This amount is well below a reasonable expectation of transfer capability under the Settlement Agreement with SPP and the Joint Parties.

The clearing prices in the 2016/2017 PRA where higher in most of the zones in the Midwest (except in Zone 4). Zones 2 through 7 cleared at $72 per MW-day, while Zone 1 remained export constrainted and cleared at $19.72. Zones 8, 9, and 10 in MISO South were constrained by the transfer constraint and cleared at $2.99 per MW-day. These results were substantially affected by the transfer limit of 876 MW that MISO employed in this action. Under the Settlement Agreement with SPP, MISO may use 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.

2. Capacity Market Design

The PRA continues to reflect a poor representation of the demand for capacity, which undermines its ability to provide efficient economic signals. The performance of the capacity market under the PRA is undermined by three significant issues: (1) the current “vertical demand curve”; (2) barriers to participation in the auction affecting units with retirement plans impacting the planning year; and (3) the local resource zones that do not adequately reflect transmission limitations. Additionally, we discuss MISO’s proposal to reform the market in competitive retail areas at the end of this subsection.

Sloped Demand Curve

The PRA effectively establishes a vertical demand curve because there is a single minimum capacity requirement for each LSE and a deficiency price for any LSE that is short. Because the marginal cost of selling capacity for most units is close to zero, 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. This is not true 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.[10] 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 true because a market with a vertical demand curve is highly sensitive to withholding because 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 since 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 with the retirement of significant amounts of capacity in 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 an LSE's requirement; and
- The costs of being deficient are large.

10 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.

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. Since this additional capacity provides reliability value to MISO, 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) an 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.

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:

1.) *The sloped demand curve does not raise the expected costs for most regulated LSEs*. In this example, if an LSE fluctuates between one and two percent surplus, its costs will be virtually the same under the sloped and vertical demand curves.

2.) *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 surplus levels between one and four percent vary by only 26 percent versus a 300 percent variance in cost under the vertical demand curve.

3.) *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 the market's surplus.

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 (unregulated suppliers, competitive retail providers, and capacity importers and exporters).

Coordination with Attachment Y Process

The second issue with MISO's current capacity market relates to 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 its resource, including whether to retire the unit. In order to do this, MISO would need to modify the PRA rules to allow:

- Units with Attachment Y 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, its 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 NCA areas 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. Its latest proposal would define two seasons, summer and winter. We have recommended that MISO define four seasons, which facilitate savings for participants. First, it would allow high-cost units to suspend during the shoulder months or not keep the unit staffed in these 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.

Capacity Market Changes in Competitive Retail Areas

As discussed above, MISO’s capacity market is not designed to provide efficient prices and incentives to govern investment and retirement decisions. This is a problem, particularly in competitive retail areas (CRAs) where unregulated suppliers rely on the market to retain needed resources. MISO has proposed a capacity market design for CRAs to address this.

We recommend the following principles for developing a capacity market design proposal for Competitive Retail Areas:

- The market design should produce prices that are consistent with the reliability value of the capacity procured.
- The capacity product and obligations should be comparable throughout all of MISO.
- The procurement in the competitive retail area should be tightly integrated and optimized with the procurements in other areas.

MISO's proposed capacity market reforms for competitive retail areas includes a) a sloped demand curve for the participating demand; b) 3-year forward auction procurement for the full resource requirements for the CRAs; and c) participation rules that allow competitive retail access LSEs to opt-out of participation in the new market.

We have evaluated this proposal and find that it will not produce efficient prices or effectively address the underlying market issues in the competitive retail areas. We are concerned in general that forward procurement: a) will not likely facilitate efficient new investment because new resources clear for only 1 year (less than 3 percent of the life of most resources), and b) can interfere with efficient retirement decisions because suppliers must determine whether old resources will continue to operate for an additional 4 years (3 years plus the planning year), which is not optimal for units facing physical or regulatory uncertainty. However, our larger concerns are with MISO's specific application of forward procurement that would bifurcate its capacity market -- procuring for the CRA three years forward and for all other requirements in the prompt auction. Bifurcating the market in this manner:

- Eliminates the ability to optimize procurements across the MISO footprint (in the CRA and outside the CRA); and
- Fails to price the broader reliability needs that resources in the CRAs contribute to satisfying.

There is no available remedy to address these concerns and we have other concerns regarding other aspects of the proposal. Therefore, we have proposed an alternative proposal 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 are continuing to discuss this alternative with MISO and its participants.

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.[11] Resources cleared in the day-ahead receive commitment and scheduling instructions based on day-ahead results and must perform these contractual obligations or be charged the real-time price for any products not supplied.[12] Both the day-ahead and real-time markets continued to perform competitively in 2015.

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;[13]
- 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, such as wind output volatility, forced generation or transmission outages, and load forecasting

11 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.

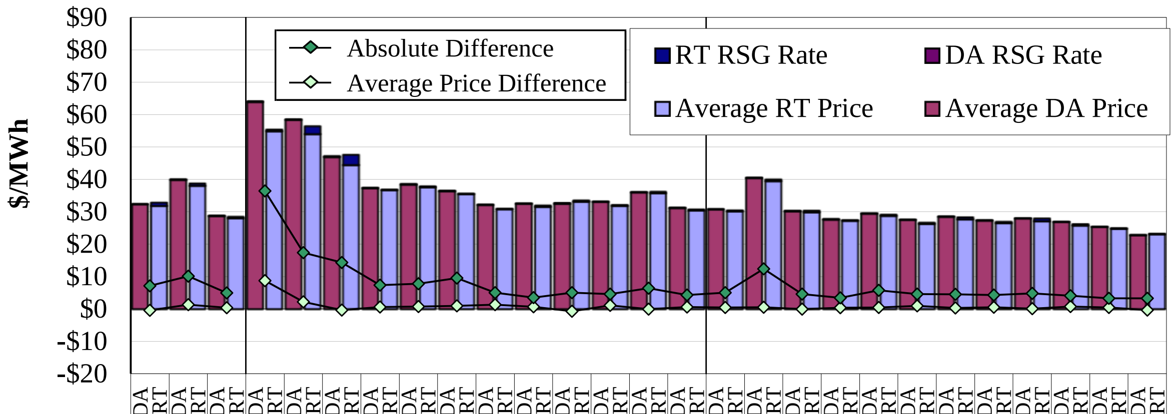
12 In addition, resources with day-ahead schedules that are derated in real-time or not following real-time instructions are subject to allocation of of the Day-Ahead Deviation Charge (DDC) or Constraint Management Charge (CMC). Virtual supply and physical transactions scheduled in the day-ahead are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

13 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.

errors, can cause real-time prices to be significantly higher or lower than anticipated in the day ahead. While these factors may limit convergence in a well-performing market on an hourly basis, prices should converge well over longer timeframes (monthly or annually).

Figure 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
2014–2015



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

	Average			2014												2015											
	13	14	15	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Indiana Hub	-1	3	1	16	4	-1	2	2	3	4	2	-2	3	0	2	1	1	0	1	2	3	1	2	0	3	2	-2
Michigan Hub	-1	7	1	25	7	26	-1	2	-5	4	3	-2	3	0	2	7	6	-1	2	0	0	0	0	-3	2	3	0
Minnesota Hub	-4	1	2	16	-9	-5	-3	3	4	1	3	0	3	4	-5	-1	0	-1	2	3	-1	3	0	-2	14	5	3
WUMS Area	-1	2	1	19	-2	-1	-3	3	0	2	2	-5	1	3	1	1	0	2	4	1	3	3	0	1	1	-1	0
Arkansas Hub		-3	1	-12	-16	-20	1	4	10	5	2	-4	-1	3	2	-3	3	-3	4	3	3	-3	0	0	0	6	4
Louisiana Hub		-6	-2	-22	-14	-19	-12	11	1	4	3	-4	2	2	4	0	2	-10	-2	0	-10	1	-5	0	0	-1	4
Texas Hub		-1	-4	-6	-14	-13	-4	-6	31	3	5	2	1	2	5	-1	1	-5	4	-10	4	0	-7	-2	-12	-15	3

Day-ahead premiums in 2015 averaged 0.6 percent. When adjusting for the DDC, which averaged $0.41 per MWh, the day-ahead premiums were very small and considerably smaller than the prior year. However, there were a number of congestion episodes that resulted in transitory periods of significant divergence:

- In March, congestion on two local constraints due to planned and forced generator outages was not anticipated in the day-ahead resulting in real-time premiums at the Louisiana and Texas Hubs.

- In May, forced outages resulting from severe weather and flooding in Texas caused significant price divergence at the Texas Hub.
- In June and August, forced generator and line outages caused real-time price spikes in Lousiana and the day-ahead market did not respond rapidly. Commitments in Texas for VLR caused congestion on lines into the load pocket, which was not sufficiently priced in the day-ahead market during August.
- In October, convergence was poor at the Minnesota Hub, driven by new wind records and underscheduling of wind in the day-ahead. This caused lower levels of congestion to prevail in the day-ahead market than in the real-time market.
- In the fall, convergence was poor in the South, particularly at the Texas and Louisiana Hubs, which was driven by unit forced outages and exacerbated by under-anticipated real-time congestion into the area.

The day-ahead market was 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 an interface . This would lower the risk of arbitraging the congestion-related differences between the two markets and ultimately cause the day-ahead market to more quickly converge with the congestion emerging in the real-time market.

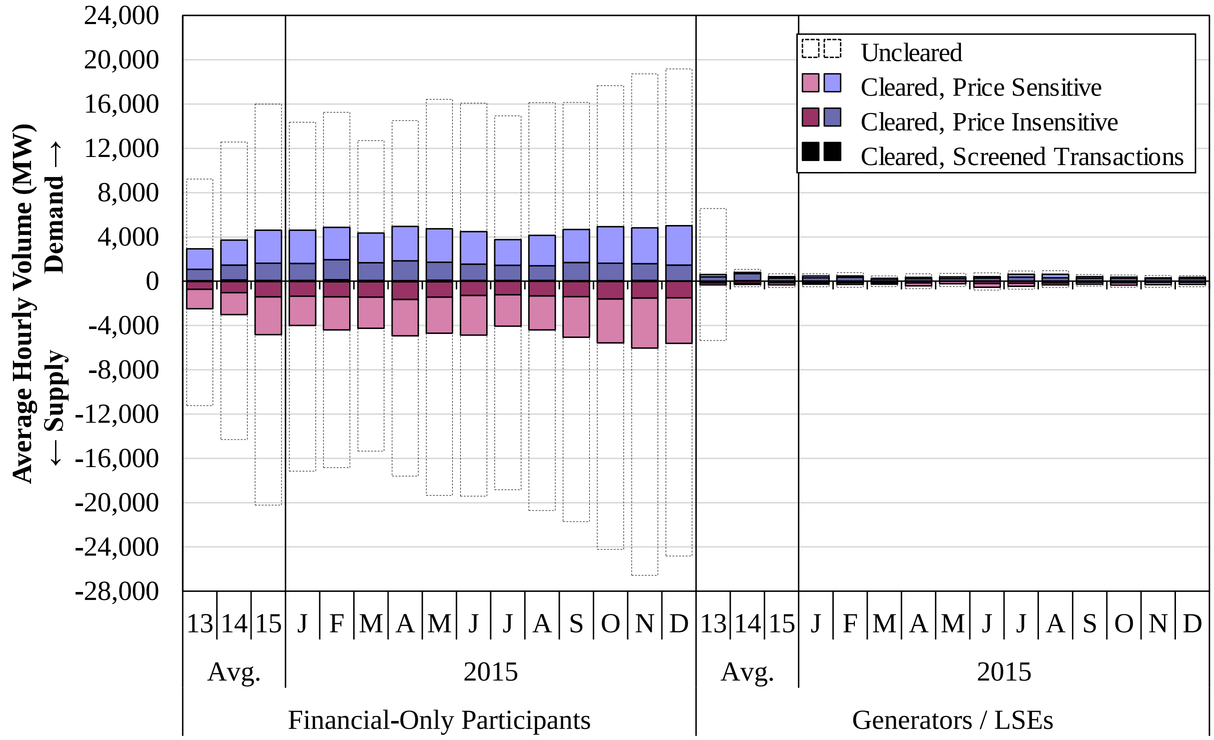
B. Virtual Transactions in the Day-Ahead Market

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 be performed in real time and, therefore, they are settled 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 shows components of daily virtual bids and offers in the day-ahead market in 2014 and 2015. The virtual bids and offers that did not clear are shown as the transparent areas.

The figure 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[14] or supply is offered at $20 below an expected real-time price. In such instances, the participants is 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: Virtual Load and Supply in the Day-Ahead Market
2014–2015



The figure shows that offered volumes increased by 32 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.

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

Cleared transactions rose 30 percent to 10.2 GW per hour. The largest cleared volumes of virtuals were at the hubs, particularly Indiana Hub with over 3.7 million MWh of cleared virtual transactions. Overall, there was a 40 percent increase in the amount of virtual supply and 22 percent increase in virtual demand that was offered into the market on an hourly basis in 2015. This was largely driven by the activity of financial traders. Financial participants, who tend to offer more price-sensitively than physical participants, offered and cleared a much larger share of transactions than in prior years. They offered in 41 percent more virtual supply and 27 percent more virtual demand. Most of the increases in financial participants' virtual supply offers were in MISO Midwest in the final quarter of 2015. This activity helped to moderate the effects of underscheduled wind in the day-ahead market.

The share of Screened Transactions, which are transactions that may constitute manipulation, fell to one percent. We did not find any material instances of virtual transactions contributing to a sustained price divergence, and no virtual bid restrictions were implemented in 2015.

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 across a particular constraint to arbitrage congestion-related price differences between the day-ahead and real-time markets; and
- To balance the participant's portfolio so as to avoid RSG deviation charges assessed to net virtual supply.[15]

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 increased by 37 percent in 2015. To the extent that matched transactions are attempting to arbitrage congestion-related price differences, we believe that a virtual spread product to allow participants to engage in these transactions price sensitively would be more efficient.

15 In April 2011, MISO revised its RSG cost allocation measures that generally will reduce the allocation to virtual supply, and eliminate any allocation when virtual supply is netted against a participant's virtual load. This change has increased participants' incentives to clear equal amounts of virtual supply and demand at different locations by submitting them price-insensitively.

Therefore, we are recommending that MISO continue to engage in stakeholder discussions to pursue 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). The transaction would be profitable if the difference in real-time congestion between the source and the sink is greater than the day-ahead difference. The transaction would lose money if the difference is less. 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 $1.47 per MWh in 2014 to $0.76 per MWh in 2015. Virtual supply profitability averaged $1.32 per MWh, although 31percent of these profits were offset by real-time RSG costs allocated to net virtual supply under the DDC rate. Supply profitability never exceeded $2 per MWh after January. Demand profitability was lower at $0.18 per MWh, which reflects the moderate day-ahead premium observed in MISO. Because virtual demand is generally considered a "helping deviation" it is not allocated real-time RSG costs. 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.

Virtuals that help converge the day-ahead and real-time prices contribute to the optimal commitment of generating resources. Longer-start units that are unable to be committed in real-time can get a commitment in the day-ahead in anticipation of real-time price increases when virtuals accurately send a higher day-ahead price signal than there would otherwise be absent the virtuals. The longer-start resources tend to be more efficient than quick-start resources that are called upon in real-time during sharp changes in load.

Finally, virtual transactions by financial-only participants in 2015 continued to be considerably more profitable ($0.79 per MWh) than those made by generation owners and load-serving entities ($0.34 per MWh), which is consistent with the conclusion that the arbitrage by financial participants has improved the convergence between day-ahead and real-time prices. Transactions that promote convergence are profitable (e.g., selling virtual supply at high day-ahead prices), while those that lead prices to diverge are unprofitable. In the next subsection, however, we evaluate the virtual transactions on a more detailed basis to determine the share of the virtual transactions that are contributing to improved day-ahead market outcomes.

D. Benefits of Virtual Trading in 2015

We conducted an empirical analysis of virtual trading in MISO in 2015 that evaluated virtuals' contribution to the efficiency of the market outcomes. We determined that 56 percent of all cleared virtual transactions in MISO were efficiency-enhancing, and 46 percent were not. We identified efficiency-enhancing virtuals as those that were profitable based on congestion that was modeled in the day-ahead and real-time market, 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 (9 percent of virtual transactions) that was 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 Table 4 shows the total MWhs of cleared virtual transactions that were efficiency-enhancing and not efficiency-enhancing by market participant type.

Table 4: Efficient and Inefficient Virtual Transactions by Type of Participant
2015

	Financial Participants		Physical Participants		Total	
Category	**Average Qty. (MW)**	***Share of Class***	**Average Qty. (MW)**	***Share of Class***	**Average Qty. (MW)**	***Share of Total***
Efficiency - Enhancing	5,329	*57%*	424	*56%*	5,752	*56%*
Not Efficiency-Enhancing	4,097	*43%*	333	*44%*	4,430	*44%*

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 $56 million in 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:

- 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 $56 million in 2015.

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 establish with a high degree of confidence that virtual trading was highly beneficial in 2015.

Some have argued that virtual transactions can sometimes profit, but not produce efficiency benefits. We agree and have identified these profits (they are not included in 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 $35.5 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.

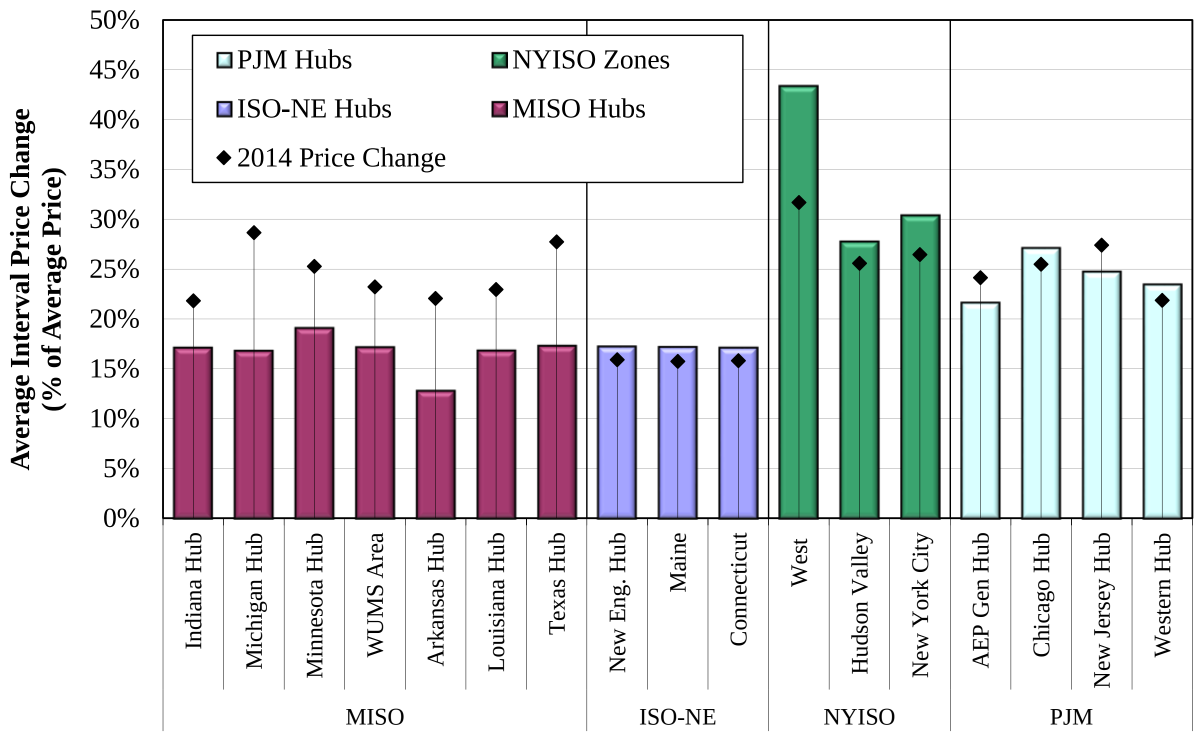
V. Real-Time Market

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 transmission network. In contrast, the day-ahead market operates on a longer time horizon with more commitment options and liquidity provided by virtual transactions. Since the real-time market is limited in its ability to anticipate near-term needs, the system is frequently "ramp-constrained" (i.e., some units are moving as quickly as they can). This results in transitory price spikes (upward or downward). 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
2015



Real-time price volatility in MISO as measured by the average of the absolute change in price between 5-minute intervals declined 56 percent in 2015 to $2.43 per MWh per interval. This decrease in volatility is in part due to the decline in natural gas prices, which reduces energy price levels overall, as well as the level of congestion in the market (which is a source of volatility). In 2014, much of the real-time price volatility was driven by the Polar Vortex, which occurred in the first quarter ($10.64 per interval). After the Polar Vortex in 2014, price volatility was lower from April to December 2014 ($3.76).

Figure 11 also shows that MISO historically has had greater price volatility than PJM and ISO-New England because MISO runs a true five-minute real-time market (producing a new real-time dispatch every five minutes). PJM and New England ISO dispatch their systems every 10 to 15 minutes, which tends to provide more flexibility and lower volatility. However, by producing new dispatch instructions less frequently, an RTO must rely more heavily on regulation to balance supply and demand between intervals. NYISO dispatches the system every five minutes like MISO, but it has a look-ahead dispatch system that optimizes multiple intervals. 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 has implemented a “Ramp Capability” product in the spring of 2016, which is anticipanted to result in the real-time market holding additional ramp capability when the projected benefits exceed its cost. This product should improve MISO’s ability to manage the system’s ramp demands.

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 having LMPs prices 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[16] and some demand response resources to set prices when:

- They are online and the resource is deemed economic by the ELMP model; or
- They are offline and deemed economic to set prices during transmission or energy shortage conditions.

The first of these reforms is intended to address a long-standing recommendation 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 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 (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.

There are a number of adverse market effects when economic units supplying incremental energy are not included in price setting:

- MISO will generally need to pay RSG payments to cover these units' as-offered costs;
- Real-time prices will be understated and will not provide efficient incentives to schedule energy in the day-ahead market when lower-cost resources could potentially be scheduled that would reduce or eliminate the need to rely on high-cost peaking resources in real time;

16 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…."

- The market will 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 resources.

Accordingly, the objective of the online pricing reforms in ELMP is to allow certain inflexible resources to set prices in the MISO 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 either not feasible or not economic to start are allowed to set energy prices, the resulting prices will be inefficiently low.

Since it was initiated in March 2015, ELMP has had a modest effect on MISO energy prices:

- ELMP lowered market-wide real-time prices by $0.03 per MWh on average in 2015.
  - The online pricing component of ELMP has raised real-time prices in 6.3 percent of intervals market-wide, resulting in an average increase of $0.08 per MWh.
  - The offline pricing component has affected prices in only 0.9 percent of intervals, but the effects are larger because this component mitigates shortage pricing. On average, it lowered real-time energy prices in 2015 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 -$1.90 to $1.20 per MWh on a monthly average basis at the most affected locations.
- ELMP had almost no effect in the day-ahead market as expected.

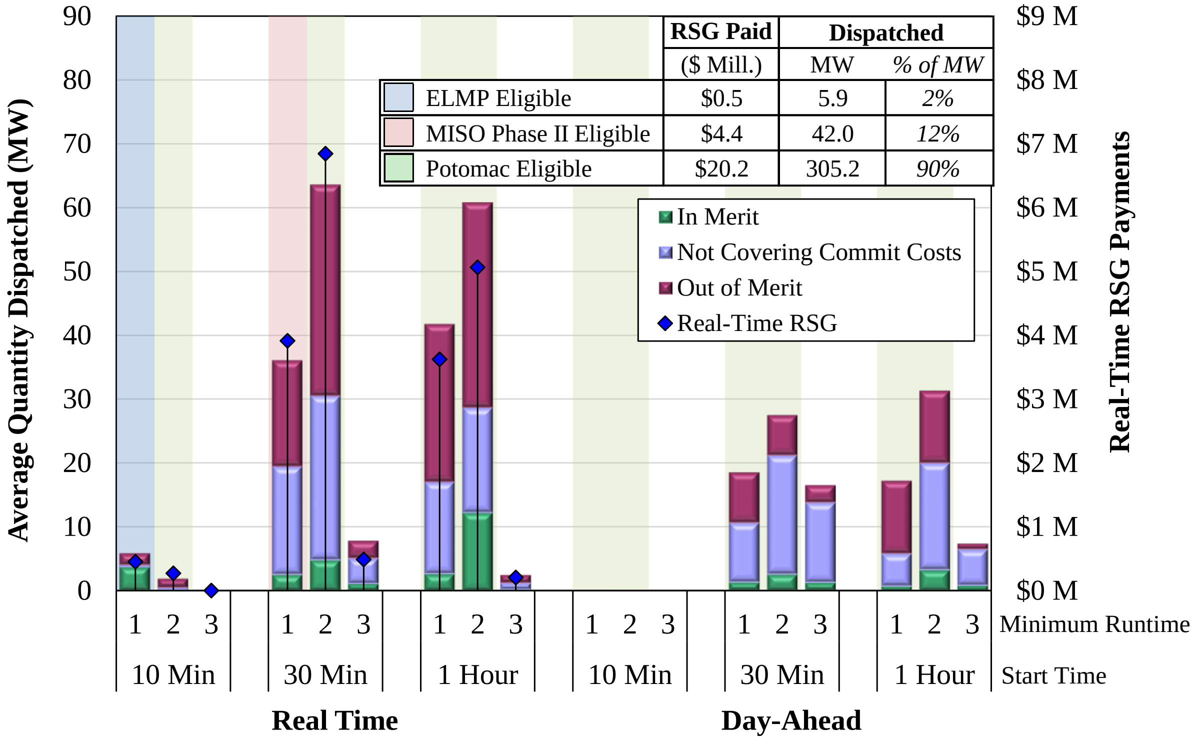
Our review of these results raises concerns that the online pricing results much smaller than is optimal, while the offline pricing results are larger than is optimal. The analyses below provide our evaluation of these two aspects of ELMP and the proposed changes that should be considered in Phase II.

Figure 12 shows all of the energy produced by online peaking resources, divided 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.

Currently, 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 1 hour or less, and c) are not scheduled in the day-ahead market. These units are shown to the far left of the figure (shaded in blue), which include only two percent of the peaking resources dispatched by MISO.

Figure 12: Eligibility for Online Peaking Resources in ELMP
March 2015 to December 2015



	RSG Paid ($ Mill.)	Dispatched MW	Dispatched % of MW
ELMP Eligible	$0.5	5.9	*2%*
MISO Phase II Eligible	$4.4	42.0	*12%*
Potomac Eligible	$20.2	305.2	*90%*

The additional units that MISO has previously proposed be eligible to set prices under Phase 2 of ELMP are shaded in light red, while the additional units the IMM is recommending be eligible to set prices in Phase 2 are shaded in light green. The IMM proposal would allow 90 percent of all of the peaking resources to set prices, which currently account for more than $20 million in RSG.

To allow ELMP to be effective in allowing online peaking resources to set prices in the real-time market, we propose that MISO expand the eligibility rules under Phase 2 of ELMP to include all peaking resources with start times of 1 hour or less and minimum run times of 2 hours or less, regardless of whether they are scheduled in the day-ahead market.

We have also evaluated the offline pricing in ELMP during transmission violations and operating reserves shortages. Under these conditions, the ELMP sets prices based on the hypothetical commitment of an offline unit that MISO could theoretically utilize to address the shortage. However, this is only efficient when the offline resource is: a) feasible (can be started quickly), and b) economic for addressing the shortage. When units are either not feasible or not economic to start are allowed to set energy prices, the resulting prices will be inefficiently low.

When committing 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 the operators did not believe the unit could be on in time to help resolve the shortage and/or 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 economic based on MISO's ex ante real-time prices. This analysis reveals that:

- For reserve shortages, the offline units that set prices are started about a quarter of the time and are economic about 30 percent of the time. Combining the two factors, we found that these units were only economic *and* started roughly **10 percent** of the time.
- For transmission violations, the offline units that set prices were economic 65 percent of the time. However, considering only units that started at least one time during the year for a transmission violation, the offline units were economic only 28 percent of the time. We also found that only 8 percent of the time when units set prices were they actually started by operators. Combining the factors, we found that roughly **4 percent** were economic *and* started.

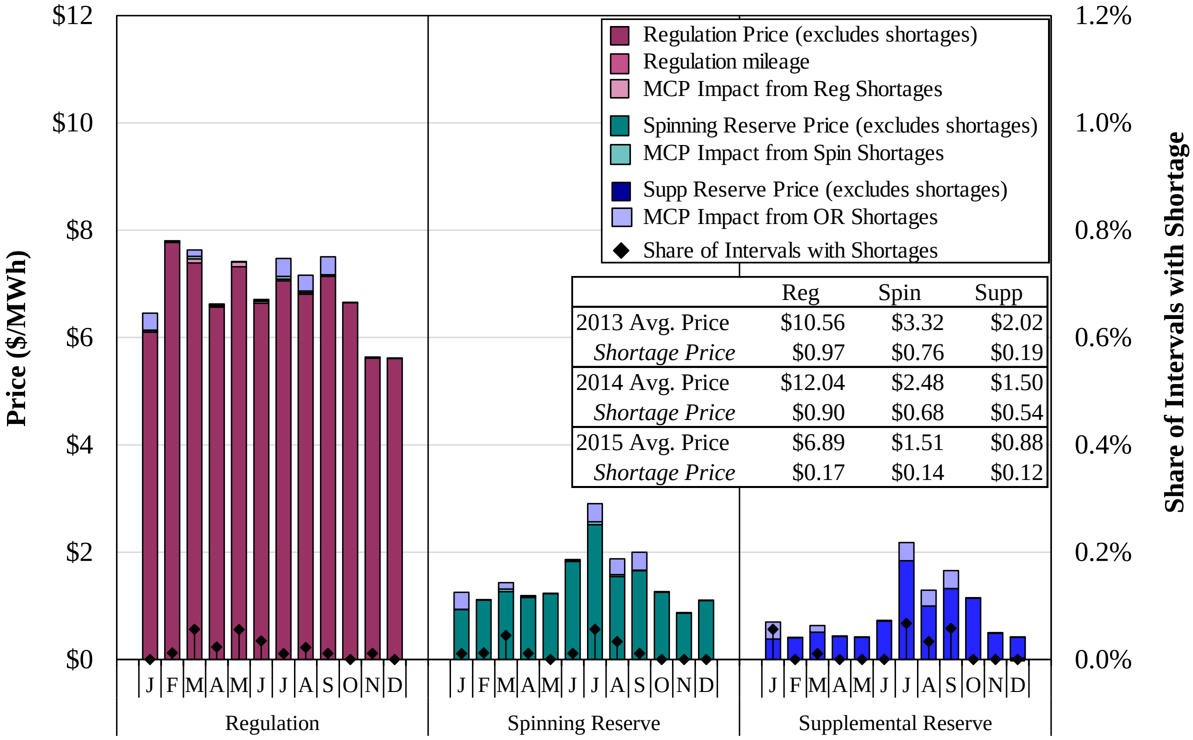
Based on these results, we conclude that ELMP's offline pricing component is not satisfying the economic principles outlined above and is leading prices to be less efficient during shortage conditions. Therefore, we recommend that MISO disable the offline pricing logic as quickly as possible.

C. Ancillary Services Markets

ASM continued to perform as expected with no significant issues in 2015. 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.

Figure 13 shows monthly average real-time prices for regulation, spinning reserves, and supplemental reserves, along with the contribution of shortage pricing to each product's clearing price in 2015. It also shows the share of intervals in shortage for each product. MISO uses demand curves to specify the value of all of its reserve products.[17] When the market is short of one or more of its ancillary service products, the demand curve for the product(s) 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: ASM Prices and Shortage Frequency
2015



	Reg	Spin	Supp
2013 Avg. Price	$10.56	$3.32	$2.02
Shortage Price	$0.97	$0.76	$0.19
2014 Avg. Price	$12.04	$2.48	$1.50
Shortage Price	$0.90	$0.68	$0.54
2015 Avg. Price	$6.89	$1.51	$0.88
Shortage Price	$0.17	$0.14	$0.12

The supplemental reserve prices in this figure show the price for MISO's market-wide operating reserve requirement, the only requirement that supplemental reserves can satisfy. A spinning reserve resource can satisfy both the operating reserve requirement and the spinning reserve

17 The demand curve penalty price for regulation, which is indexed to natural gas prices, averaged $105 per MWh in 2015. The spinning reserve penalty price was unchanged at $65 per MWh (for shortage quantities of less than 10 percent of the reserve requirement) and $98 per MWh (for quantities in excess of 10 percent). 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.

requirement, so the spinning reserve price will include a component associated with operating reserve shortages. In other words, shortages of operating reserves will be included in the price of higher-value products, including energy. Likewise, the regulation product includes components associated with spinning and operating reserve shortages.

Monthly average clearing prices for regulating reserves and spinning resources fell 43 and 39 percent, respectively. These decreases were primarily due to the fact that lower energy prices reduce the opportunity costs of providing these products. The opportunity cost is generally equal to the difference between the generator's LMP and marginal cost, and constitutes a large share of the overall price for both products. The price for supplemental reserves fell 41 percent from 2014, much of which was due to the decrease in the value of shortages to 42 cents. This reduction was also reflected in the lower average prices of each of the higher-quality reserves.

D. Settlement and Uplift Costs

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

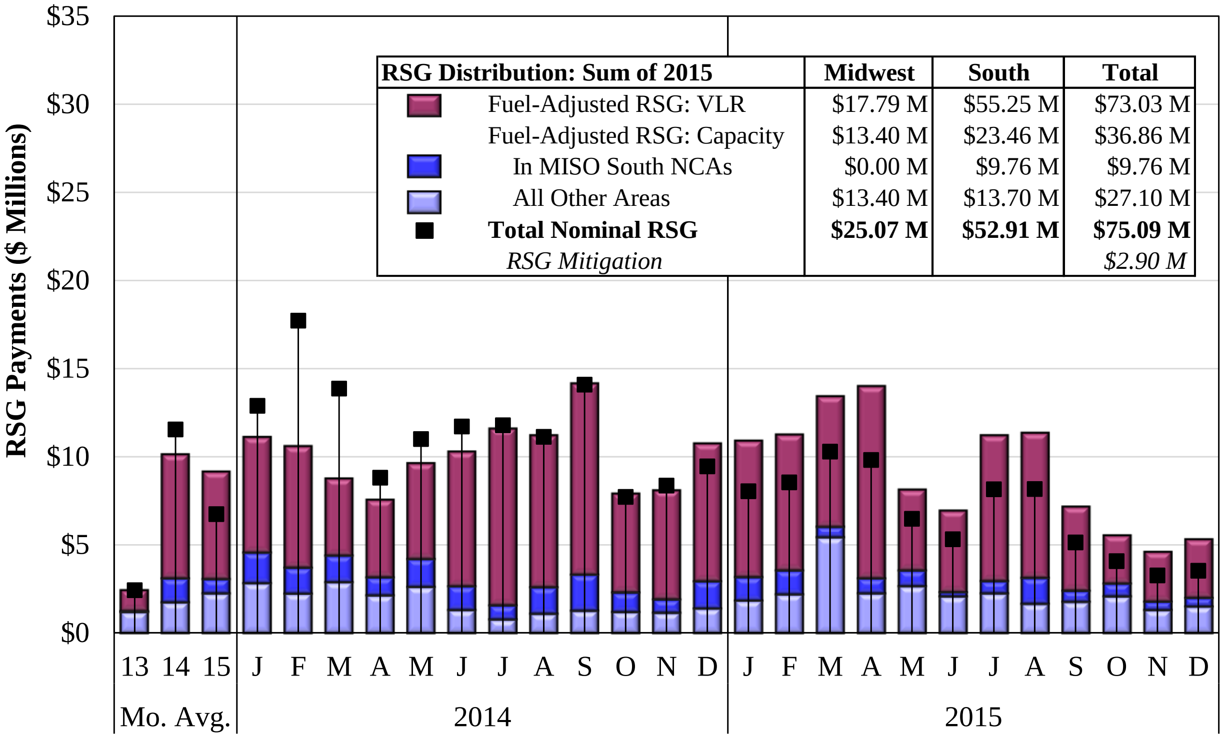
- Revenue Sufficiency Guarantee payments ensure that the total market revenue a generator receives when economically committed is at least equal to its as-offered costs over its commitment period.
- Price Volatility Make Whole Payments ensure that suppliers will not be financially harmed in the hourly settlement by following MISO's five-minute dispatch signals. The PVMWP consists of two payments: Day-Ahead Margin Assurance Payments (DAMAP) and Real-Time Offer Revenue Sufficiency Guarantee Payments (RTORSGP).

Resources committed by MISO for economic capacity or for congestion management after the day-ahead market receive a "real-time" RSG payment if their as-offered costs are not recovered through the LMP in the real-time market. The costs related to RSG payments are recovered via charges that are "uplifted" to market participants. It is most efficient to allocate RSG costs to market participants in proportion to how much they contribute to causing the costs.

1. Day-Ahead and Real-Time RSG Costs

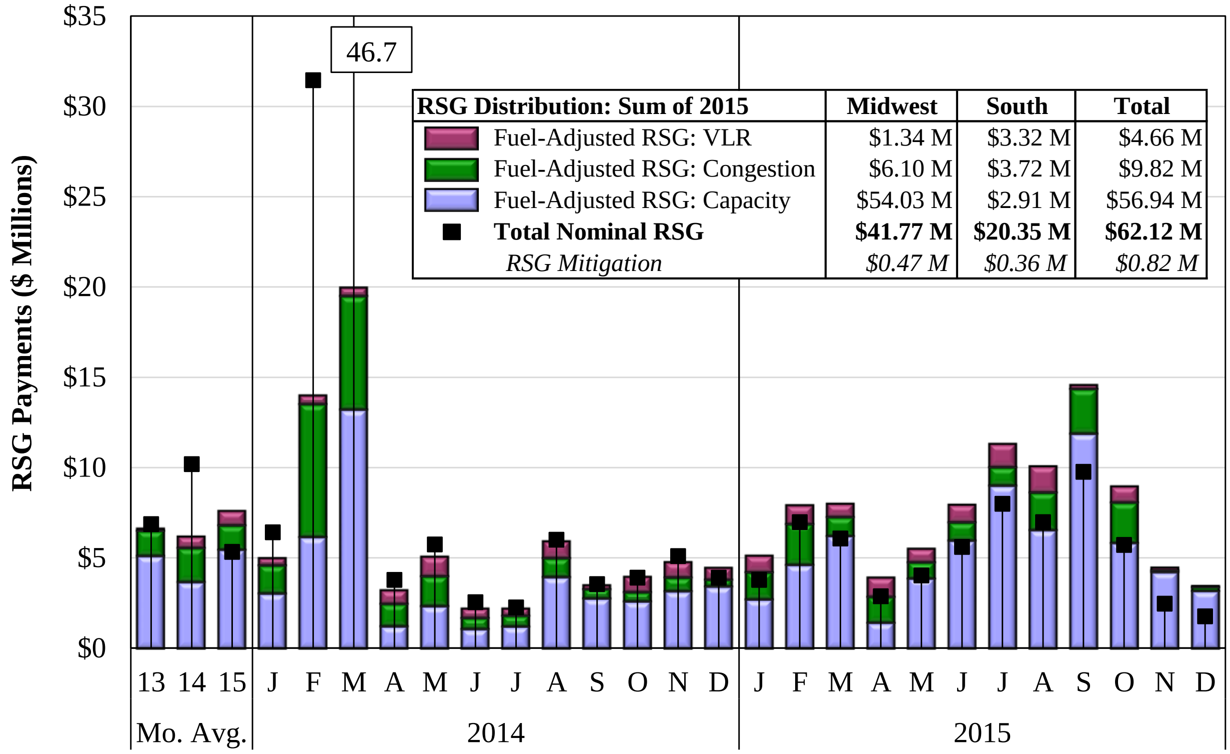
Figure 14 and Figure 15 show, respectively, monthly averages for day-ahead and real-time RSG payments over the last two years. RSG payments in the day-ahead market are now higher than in real time because most voltage and local reliability (VLR) commitments are made before or during the day-ahead market. Because fuel prices have considerable influence over suppliers' production costs, the figures show RSG payments in both nominal and fuel-adjusted terms.[18] Figure 14 disaggregates day-ahead fuel-adjusted payments made for capacity and for VLR needs. Figure 15 disaggregates real-time time fuel-adjusted payments made for capacity, VLR, or for congestion management.

Figure 14: Day-Ahead RSG Payments
2014–2015



18 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 15: Real-Time RSG Payments
2014–2015



Day-ahead nominal RSG costs decreased by 41.7 percent to $6.73 million per month in 2015, primarily because of lower fuel prices. The figure shows that when accounting for changes in fuel prices, the fuel-adjusted day-ahead RSG was down only slightly from 2014. Roughly 67 percent of day-ahead RSG payments were to units in MISO identified as committed for VLR needs. The slight reduction in fuel-adjusted RSG in 2015 was largely attributable to lower VLR costs and were caused by a number of process improvements and changes in the operating guides made by MISO in 2015. In addition, 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.

Real-time RSG payments fell 48 percent from 2014 primarily because of lower fuel price. Adjusting for changes in fuel prices, real-time RSG actually increased by 23 percent in 2015. This increase mainly occurred in July through October when lower day-ahead load scheduling resulted in increased use of peaking resources. Despite implementation of ELMP, most peaking resources utilized by MISO did not set energy prices so they required RSG payments to cover their as-offered costs. We are recommending that the eligibility of peaking resources to set energy prices in ELMP be expanded, which should lower real-time RSG.

Less than $1 million of real-time RSG was mitigated in 2015 under MISO's market power mitigation provisions. In July 2015, MISO implemented our recommended change to its mitigation measures that apply to RSG payments.

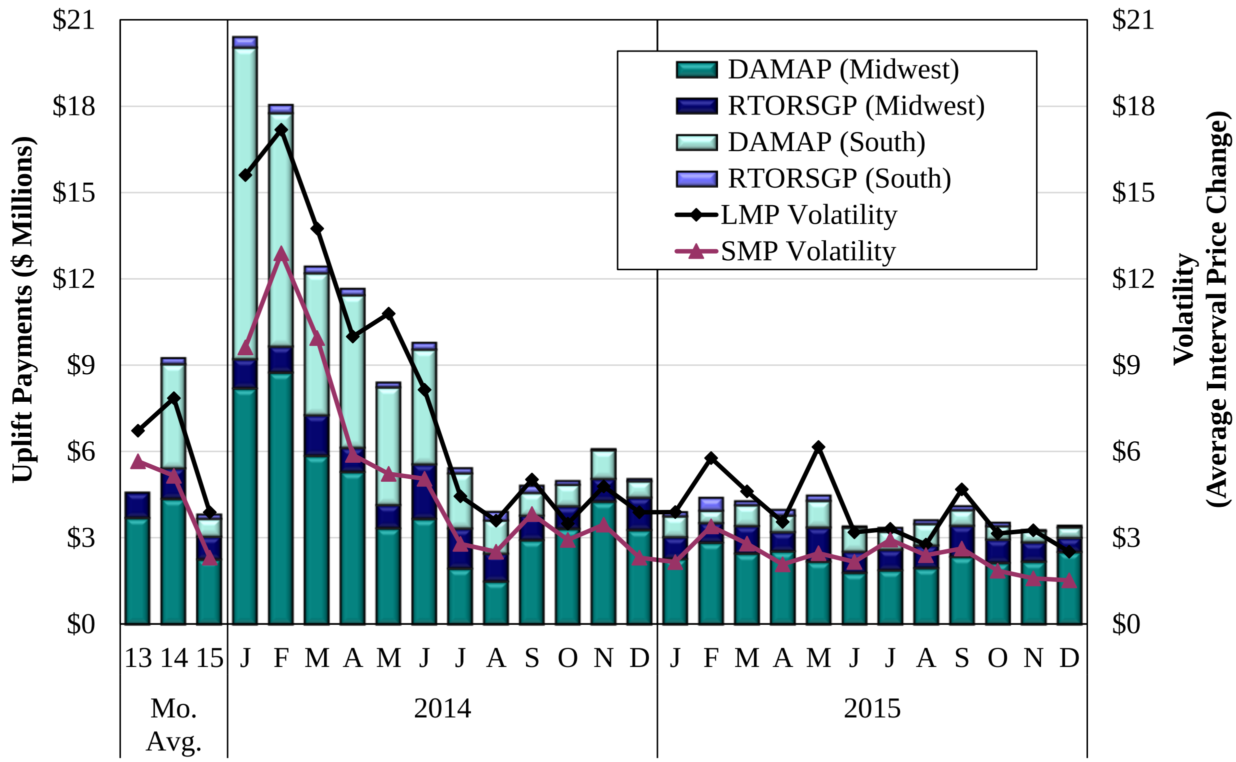
2. Real-Time RSG Cost Allocation

MISO classifies RSG costs to recognize that the costs arise from commitments to meet three main objectives: (1) system-wide capacity needs, (2) congestion management, or (3) voltage and local reliability needs. Once classified, these cost are allocated based on the extent to which participants cause each type of commitment. This cost allocation process was the result of proposed changes that FERC largely approved in 2014. A final key improvement (that FERC had previously rejected) was approved and implemented in 2015. The changes in allocation have contributed to improved performance of MISO's market, additional liquidity (particularly in the day-ahead market), and lower costs overall. MISO's cost allocation methodology is an industry best practice and a model for other RTOs.

3. Price Volatility Make-Whole Payments

PVMWPs address 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 to follow dispatch instructions. These payments come in two forms: Day-Ahead Margin Assurance Payments (DAMAP) and Real-Time Offer Revenue Sufficiency Guarantee Payments (RTORSGP). DAMAP are made when generators operate below their day-ahead schedule and below the level that is economic given the hourly settlement price and their offer prices. RTORSGP are made when a unit operates above the level that would be economic given the hourly energy price. Figure 16 shows the monthly totals for the two components of PVMWP, along with measures of price volatility at the system level (SMP volatility) and price volatility at the locations where units are receiving the payments (LMP volatility).

Figure 16: Price Volatility Make-Whole Payments
2014–2015



The figure shows that the PVMWP levels in 2015 were strongly correlated with price volatility at the recipients' locations. Total PVMWP values declined 59 percent as price volatility at the resources' locations fell 50 percent. Some of the reduction in payments was also due to better generator performance in responding to dispatch instructions, particularly in MISO South.

Nonetheless, roughly one quarter of the DAMAP continues to be paid to units dispatched 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. The recommendations to address generator deviations that are described earlier in this report should reduce the unjustified DAMAP payments.

We continued to work with MISO in 2015 to detect residuals in MISO's State Estimator model that contributed to apparent poor generator performance and resulted in substantial DAMAP payments. As a result, corrections have been made that have reduced DAMAP by millions from 2014 levels. We recommend MISO develop new tools to identify such state-estimator issues in the future so that they can be quickly addressed.

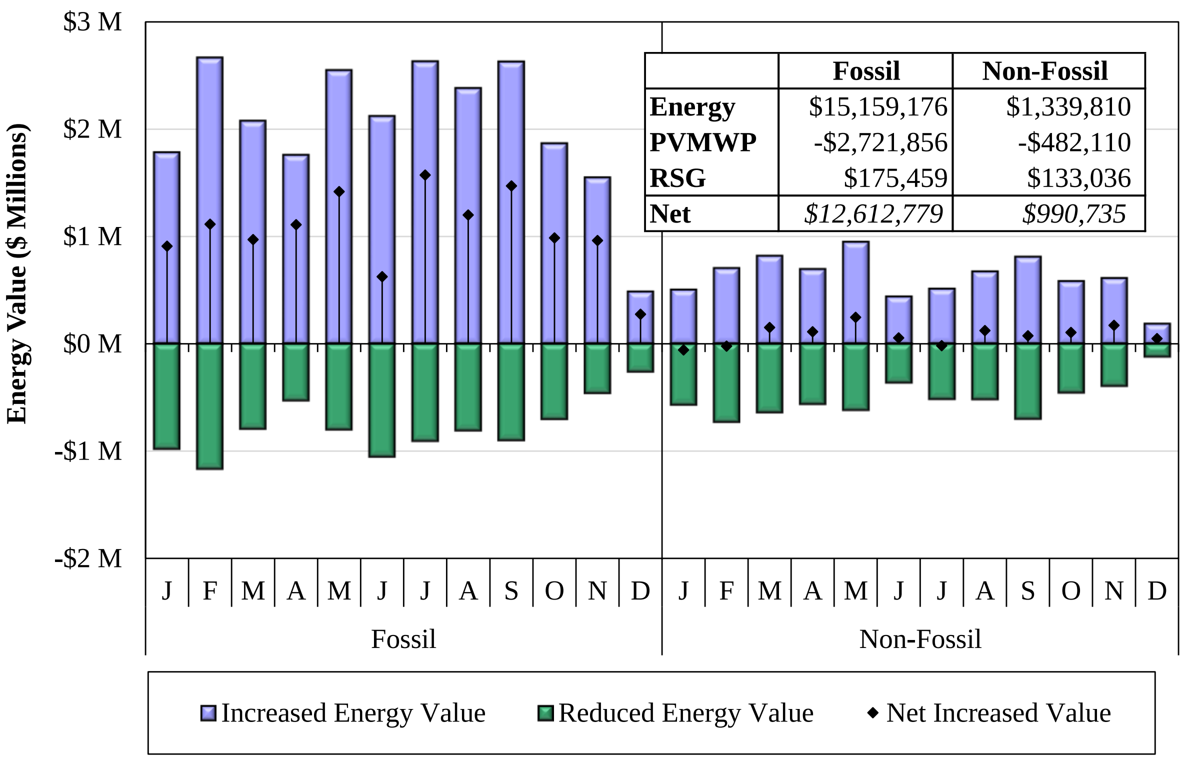
4. Five-Minute Settlement

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 simply 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.

Figure 17 shows how five-minute settlements would change the total payments to fossil fuel-fired and non-fossil fuel-fired resources (relative to the current hourly settlement). We show this distinction because fossil-fuel-fired resources tend to be more flexible and better able to respond to dispatch instructions than other resources (e.g., intermittent resources).

Figure 17: Net Energy Value of Five-Minute Settlements
2015



The figure shows that fossil fuel-fired resources in 2015 received settlements that were $15 million less than they would have received settling based on the five-minute prices and output. Only 20 percent of this lost value was paid to resources in the form of PVMWP. Flexible steam units in particular earned $10 million less than what would have been paid under a five-minute settlement regime. Non-fossil resources are not adversely impacted as much by the current hourly settlement because they tend to be less controllable than the fossil-fired resources, particularly wind resources. In other words, flexible, controllable resources are generally more valuable to the system and, therefore, would benefit from a more granular settlement.

These results show 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. For a number of years we have recommended that MISO implement five-minute settlements with generators to improve their incentives to follow dispatch instructions and provide more flexibility. FERC supported this recommendation in a Notice of Proposed Rulemakings (NOPR) issued in September 2015 which would require that RTOs settle with market participants in the same time increments as they use to dispatch the system (i.e., 5-minute settlements for MISO).[19]

5. Generator 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 an eight-percent tolerance band for four or more consecutive intervals within an hour.[20] The purpose of the tolerance band is to permit deviations that balances 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 that has 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

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

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

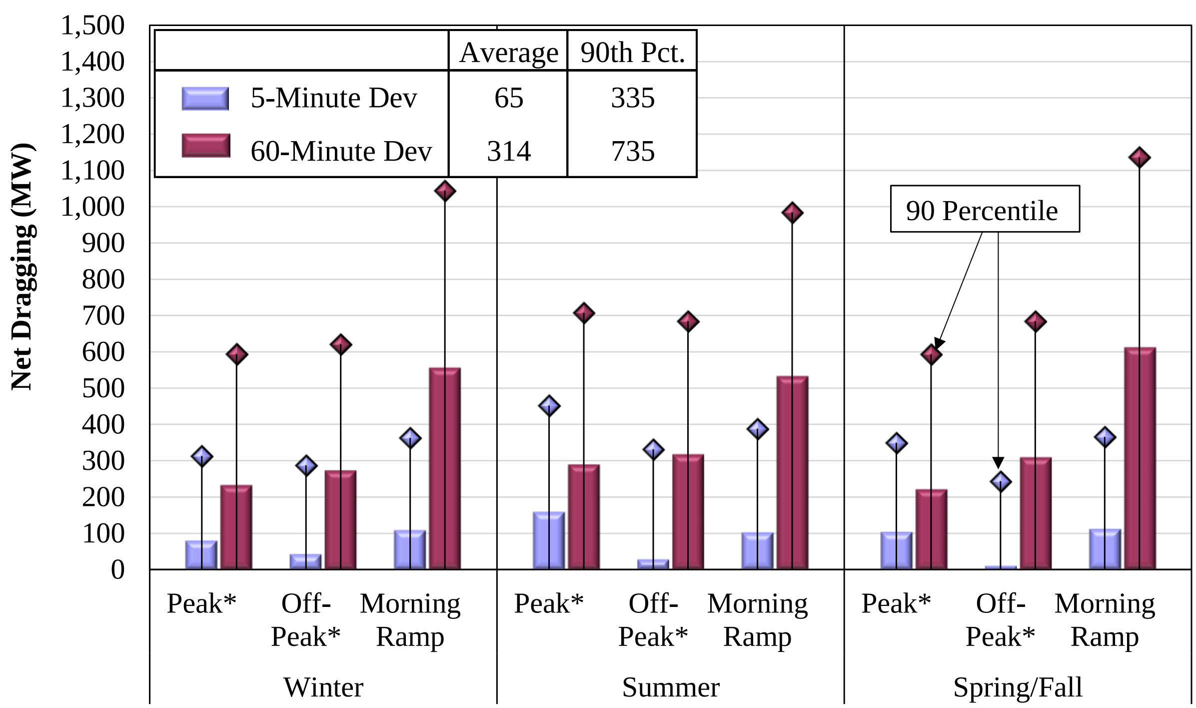
poorly (or not at all) to MISO's dispatch. Resources identified by the tool should be contacted by MISO operators and if placed off-control is warranted, which results in the dispatch echoing the current output level of the resource.

Figure 18 shows the size and frequency of two types of net deviations:

- 5-minute deviation is the difference between MISO's dispatch instructions and the generators' response 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 where the energy the generator would be producing had it followed MISO's dispatch instructions over the prior 60 minutes versus the energy it is actually producing. 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.

Figure 18: Average 5-Minute and 60-Minute Net Deviations
2015



* Excludes morning ramp hours.

This analysis shows that MISO's deviations 5-minute and 60-minute are sizable in all seasons and types of hours. While, the average 5-minute deviations are slightly higher in the morning ramp-up hours, the 60-minute deviations are much higher in these hours, averaging more than 500 MW. This is more than half of MISO's entire spinning reserves scheduled in most hours. The differences in the deviation levels is important because the MISO operators will generally only see the 5-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.

The figure also shows that in the worst 10 percent of peak hours, the 60-minute deviation exceeded 600 MW and exceeded 1000 MW during the morning ramp hours. This is roughly half MISO's entire contingency reserve requirement. 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 may, therefore, not be making commitments that are justified economically or by the reliability needs of the system.

Our other concern is that generators performing poorly receive a substantial amount unjustified DAMAP payments and avoid RSG charges because they are generally still considered to be on dispatch (they only lose eligibility for DAMAP when they are deviating or off control). We monitor for "inferred derates" where the lack of response be a generator over time causes it to effectively be derated, which averaged 248 MW per hour in 2015 and was more than 2500 MW in some hours.[21] Because participants are obligated to report derates under the tariff, we have referred the most significant inferred derates to FERC enforcement. Additionally, such conduct can qualify as physical withholding when there is not physical cause for the derating. We have identified such cases and MISO has imposed physical withholding sanctions.

While potential sanctions by FERC or MISO may deter the most serious cases of inferred derates, it does little to generally improve the poor generator performance that has produced the deviations shown above. Ultimately, 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.

21 See Figure A49 in the Analytical Appendix that shows the detailed inferred derate results.

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 allow a resource to be unresponsive for four consecutive intervals to allow for configuration changes or changes in mill operations.[22]

Having established this threshold, we recommend that MISO apply it in a number of ways to improve participants' performance incentives and MISO's operation of the system:

1. Apply the standard settlement rules pertaining to Excess and Deficient energy;
2. Remove eligibility for price volatility make-whole payments 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 a better tool for operators to use in real time to identify inferred derates and to 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. Additionally, some of these deviations and associated DAMAP are caused by errors in MISO's State Estimator model. We continue to recommend that MISO develop new tools to identify and address State-Estimator errors that are affecting the dispatch.

E. Wind Generation

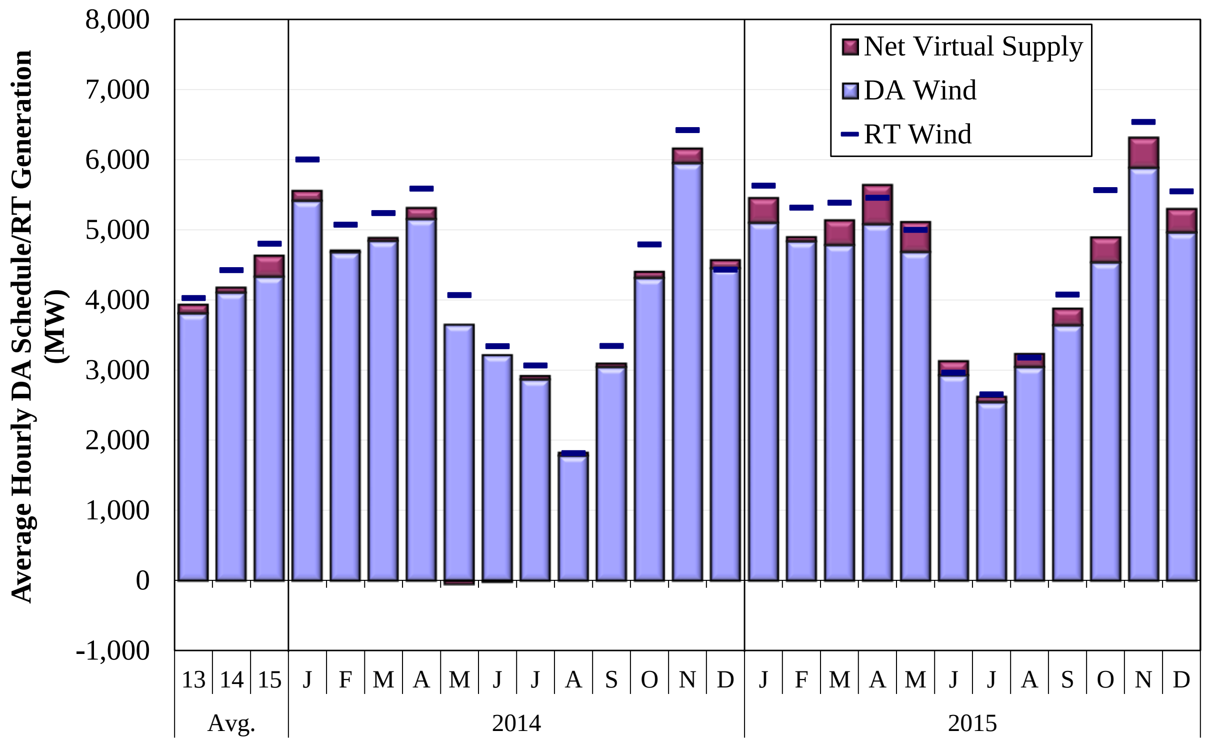
On December 18, 2015, Congress passed legislation extending the investment tax credits (ITCs) and production tax credits (PTCs) for wind projects. Wind projects that began construction in

22 Additional detail and a graphical illustration of the proposed threshold is provided in Section 6 of the Analytical Appendix.

2015 or 2016 will receive 30 percent ITCs or $23 per MWh in PTCs. Wind resources must choose either the PTC or the ITC. In MISO, where wind resources typically have higher capacity factors, most new wind resources choose the PTC. The PTCs for wind resources under construction by 2016 receive the full credit for the first 10 years of operation. The credit decreases 20 percent each year for units that begin construction from 2017 through 2019. These relatively large subsidies will likely foster the continued growth of wind in the short-term. Installed wind capacity in MISO has grown to more than 15 GW. Although wind generation promises substantial environmental benefit, the output of these resources is intermittent and presents operational challenges. These challenges are amplified as wind's portion of total generation increases. Wind resources accounted for 9.1 percent of installed capacity and 7 percent of generation in 2015.

Figure 19 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 and wind locations and the Minnesota hub, which is in close proximity to many of MISO's wind resources.

Figure 19: Day-Ahead and Real-Time Wind Generation
2014–2015



Real-time wind generation in MISO increased 8 percent in 2015 to nearly 4.8 GW per hour. MISO set several all time wind records in 2015, the last of which was set in November at 12.6 GW. These records have been exceeded in 2016, with new records set in January and February (13.1 GW). We expect this trend to continue as more wind resources are added to the system.

This figure shows that wind output is substantially lower during summer months than during shoulder months, which reduces its value from a reliability perspective. Additionally, wind suppliers generally schedule less output in the day-ahead market than their real-time output, which can be attributed to the nature of some of the suppliers' contracts and the financial risk related to being allocated RSG costs when real-time 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 442 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 volatility of its output that must be managed by MISO also grows. Sharp reductions in output can lead to substantial price volatility and require MISO to make real-time commitments to replace lost output.

Growing wind output in the western portions of MISO's system has also created 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 to manage over-generation conditions. In addition, recommendations for managing the system's ramp capability that are included in this report should further improve MISO's ability to respond efficiently and reliably to fluctuations in wind output.

VI. Transmission Congestion and FTR Markets

MISO's markets manage flows over its network to avoid overloading transmission constraints by altering the dispatch of its resources and establish 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 redispatch or "out-of-merit" cost is reflected in the congestion component of MISO's locational prices.[23] The congestion component of the LMPs can vary substantially across the system with LMPs higher in "congested" areas.

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. Congestion Costs and FTR Funding in 2015

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 LMPs at locations where energy is scheduled to be produced and consumed.

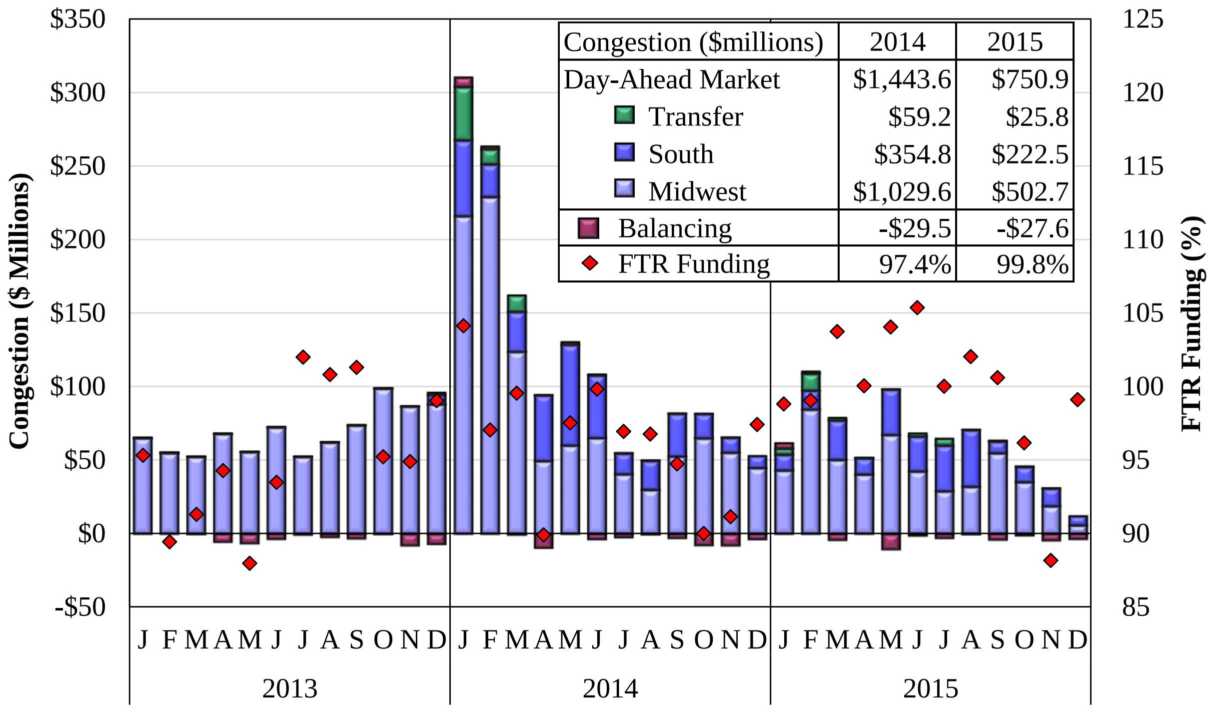
The resulting congestion revenue is paid to holders of FTRs. FTRs represent the economic property rights associated with the transmission system. A large share of the value of these rights is allocated to participants. The residual FTR capability is sold in the FTR markets with this revenue contributing 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

23 The congestion component of the LMP is one of three LMP components. The main component is the system energy price, which is the cost of the next MW of production available to the system. The congestion component is the second component. The third component is the marginal loss component. This reflects transmission losses that occur whenever power flows across the transmission network. Generally, transmission losses increase as power is transferred over longer distances, at higher volumes, and over lower-voltage facilities.

MISO are physically feasible (flows over the network do not exceed 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.

Figure 20 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 2013 to 2015. As discussed further below, large amounts of balancing congestion costs typically indicate real-time transmission outages, derates, or loop flow that was not anticipated in the day-ahead market.

Figure 20: Day-Ahead and Balancing Congestion and Payments to FTRs
2013–2015



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 nearly 50 percent to $751 million in 2015. Much of the annual reduction in congestion in the year-over-year comparison occurred during the first quarter (the Polar Vortex occurred in the first quarter of 2014). Day-ahead congestion after March was 30 percent lower than the same period in 2014 because conditions were mild and fuel prices were relatively low. Natural gas prices, in particular, were very low in 2015. This reduces congestion costs because natural gas-fired units are generally the resources that are dispatched to manage the power flows over binding constraints.

Of this, 33 percent corresponds to congestion on constraints in MISO South or congestion on the transfer constraints between the regions. 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.

FTR Shortfalls

FTR obligations exceeded congestion revenues by $3.4 million, a shortfall of less than one percent and a substantial reduction from last year when they were underfunded by 2.6 percent. While slight shortfalls occurred in a number of months, the only significant shortfall occurred in November at $16 million. Over half of this underfunding was caused by two transmission outages not modeled (or fully modeled) in the annual and monthly auctions.

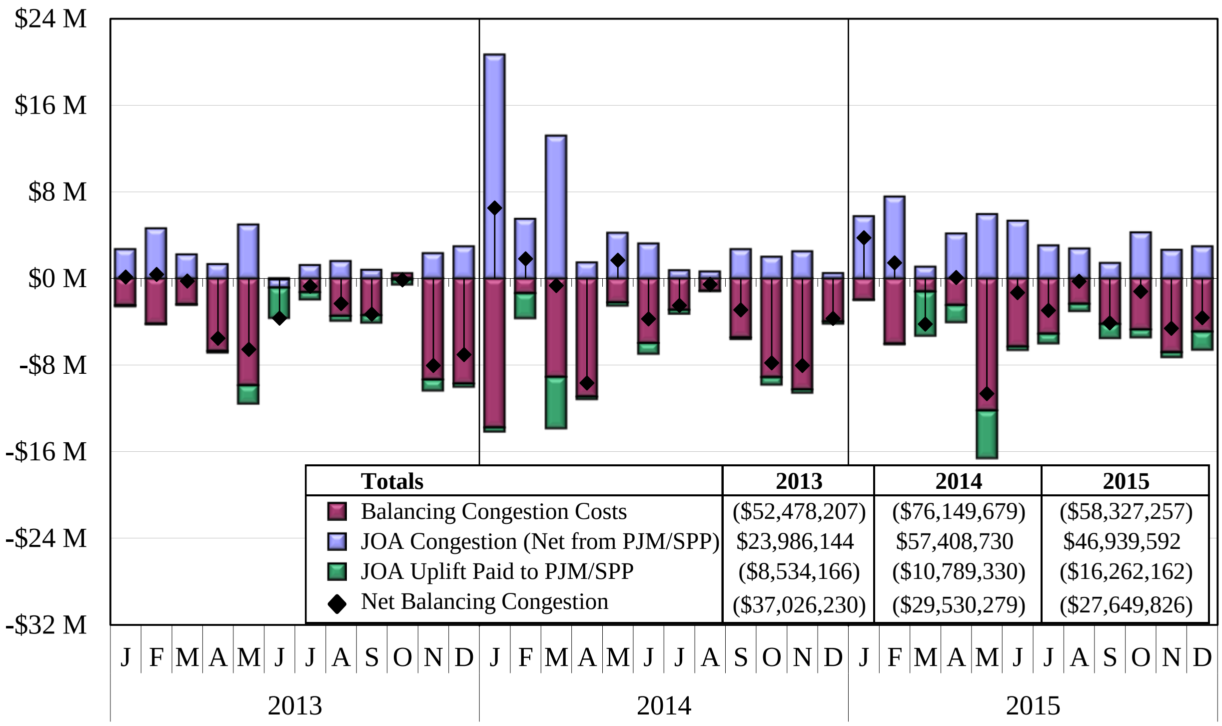
As was the case in November 2015, the most significant causes for underfunding continue to be planned and unplanned transmission outages—particularly forced and short-duration scheduled outages or derates that are not reflected in the FTR auctions. Underestimated loop flows also account for the some of the shortfalls because loop flows across the MISO system reduce the capability MISO can utilize in the day-ahead and real-time markets. The allocation of FTR shortfalls is discussed in Section VI.D.

Balancing Congestion

Balancing congestion shortfalls occur when the transmission capability available in the real-time market is less than what was scheduled by the day-ahead market. Balancing congestion shortfalls can result from forced transmission outages or derates in real time, or greater than anticipated loop flows. Likewise, balancing congestion surpluses occur when there is more transmission capability available in the real-time market than was scheduled in the day-ahead market. Net balancing congestion shortfalls must be uplifted to MISO's customers. These costs are collected from all real-time loads and exports (on a pro-rata basis) so it does not directly impact FTR funding. While real-time forced outages and derates cannot be eliminated, persistent high levels of negative balancing congestion costs may indicate day-ahead modeling issues. Accordingly, RTOs should generally seek to minimize these costs by achieving maximum consistency between the day-ahead and real-time market models.

Balancing congestion costs in 2015 remained a small share (3.6 percent) of total congestion costs. Figure 21 shows that balancing congestion shortfalls totaled nearly $11.5 million (excluding JOA uplift of $16.1 million) in 2015. JOA uplift payments are made to pay for market flows on coordinated market-to-market constraints. MISO had positive balancing congestion surplus of nearly $1 million during the first quarter, but balancing congestion shortfalls of $28.6 million during the last nine months of the year. These levels of balancing congestion costs are relatively low and indicate that MISO is doing a good job of maintaining consistency between the day-ahead and real-time market models.

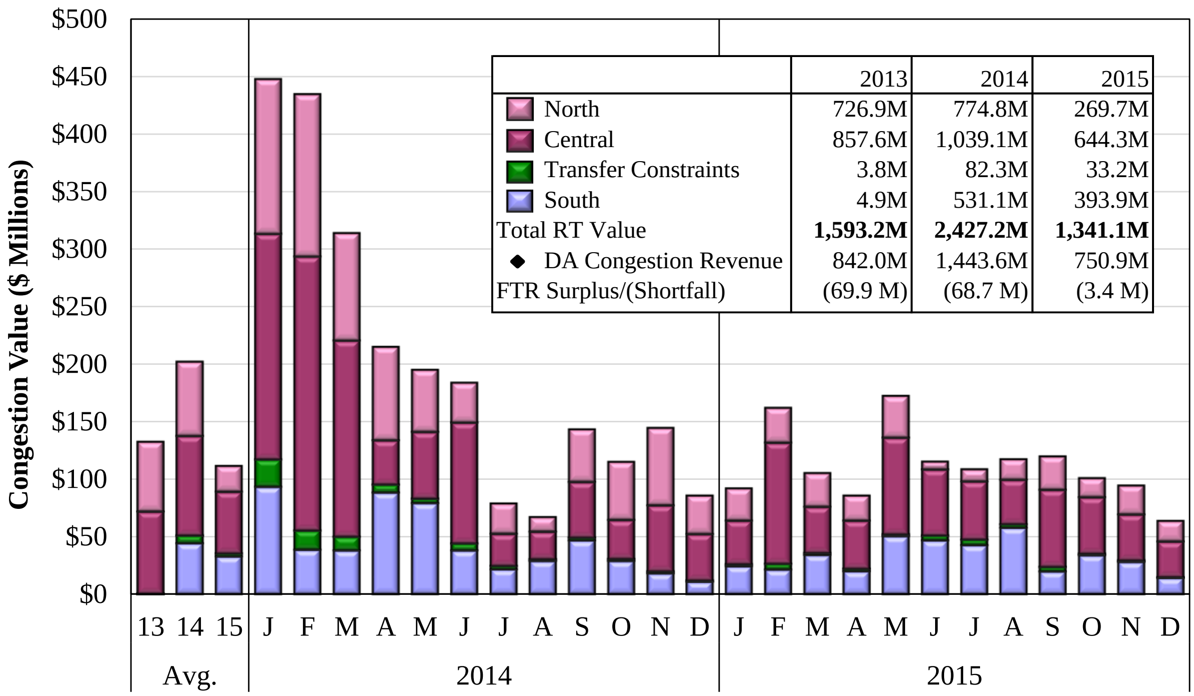
Figure 21: Balancing Congestion Costs
2013–2015



B. Real-Time Congestion Value

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 physically as MISO dispatches its system. As shown in Figure 22, real-time congestion revenues collected through the MISO markets are substantially less than the value of real-time congestion on the system, which totaled $1.3 billion in 2015. This substantial difference is caused primarily by loop flows that do not pay MISO for use of its network and 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.

Figure 22: Value of Real-Time Congestion and Payments to FTRs
2014–2015



	2013	2014	2015
North	726.9M	774.8M	269.7M
Central	857.6M	1,039.1M	644.3M
Transfer Constraints	3.8M	82.3M	33.2M
South	4.9M	531.1M	393.9M
Total RT Value	**1,593.2M**	**2,427.2M**	**1,341.1M**
◆ DA Congestion Revenue	842.0M	1,443.6M	750.9M
FTR Surplus/(Shortfall)	(69.9 M)	(68.7 M)	(3.4 M)

The value of real-time congestion in 2015 was 45 percent lower than in 2014 because lower natural gas prices reduced the cost of redispatching generation to manage congestion. While congestion declined during most of the year, the largest percentage declines were in the first quarter when the 2014 Polar Vortex produced unusually severe congestion.

C. FTR Market Performance

An FTR represents a forward purchase of day-ahead congestion costs. Because transmission customers have and are continuing to pay for the embedded costs of the transmission system, they are entitled to the economic property rights to the network. This is accomplished by allocating Auction Revenue Rights (ARRs) to transmission customers associated with their network load and resources. ARRs give customers the right to receive the FTR revenues MISO receives when it sells FTRs that correspond to their ARRs, 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. When this occurs, FTR profits are low (profits = 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 the FTR auction in two timeframes:

- 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, launched in November 2013, facilitates FTR trading for future periods in the planning year.

Figure 23 shows our evaluation of the profitability of these auctions by showing the seasonal profits for FTRs sold in each market. For comparison purposes, profitability of monthly rights purchased in the MPMA are aggregated seasonally in this figure.

Figure 23 shows that the FTRs issued through the annual FTR market were substantially unprofitable beginning in summer of 2014 and through the spring of 2015, and again in the winter of 2015/2016. In both periods, this occurred because less congestion occurred than was anticipated by the FTR market. The day-ahead congestion value was $133 million less than the annual auction valuation in the first three seasons of the 2015-2016 auction year (June 2015 through February 2016), most of which occurred in the winter. These FTR losses are largely 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 23: FTR Profits and Profitability
2014–2015

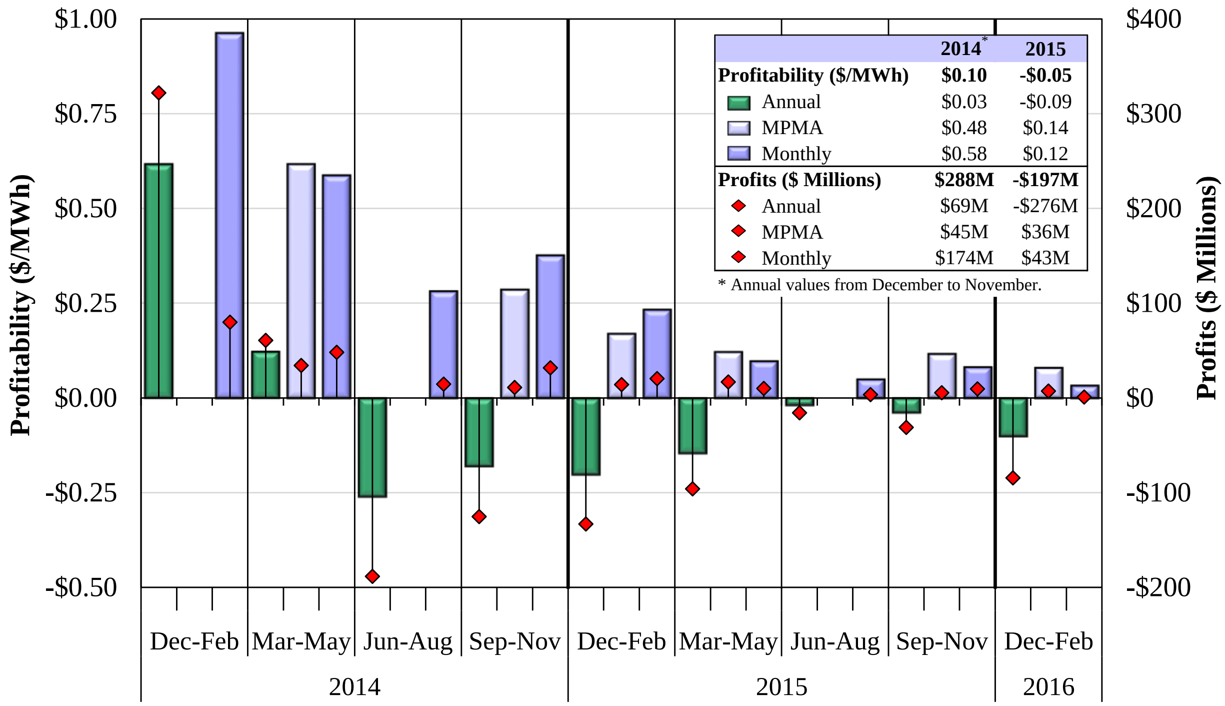


Figure 23 also shows that the FTRs purchased in the MPMA and prompt month have generally been slightly profitable. These market tend to produce prices that are generally more in line with anticipated congestion than the annual auction. Additionally, since they occur much closer to the operating timeframe, better information is available to forecast congestion.

D. FTR Shortfalls and Allocation

FTR shortfalls occurs when MISO is obliged to pay FTR holders more than the congestion revenues it collects in the day-ahead market. Although the level of funding increased from past years to 99.8 percent in 2015, FTR shortfalls were more prevalent in certain time periods and market areas. For example, the funding levels for local balancing areas ranged from 180 percent to 30 percent.[24] As discussed above, underfunding occurs when the FTRs awarded by MISO imply power flows over the network that are greater than the flows that can be accommodated in the day-ahead market.

24 See Figure A-73 in the Analytical Appendix.

Currently, the shortfalls are allocated to all FTR holders. As a result, although the shortfalls may all be generated by congestion in one area of the system, MISO will reduce the funding for all of its FTRs. The treatment of FTR surpluses is not symmetric with the treatment of FTR shortfalls. Shortfalls are allocated to FTR holders, but net annual surpluses are allocated back to transmission customers. Hence, FTRs will never be funded at greater than 100 percent of the FTR obligation. Socializing the shortfalls has a number of undesirable effects. In particular, it:

- Provides an incentive for transmission owners to under-report potential outages that could reduce their ARRs since the costs of the shortfalls are socialized.
- Inequitably shifts costs between various areas of the MISO system.
- Undermines the value of the FTR as a financial instrument by introducing unnecessary uncertainty regarding its value.
- Lowers FTR prices and revenues as participants discount their FTR bids to account for the uncertainty. If participants in the FTR market are risk averse, it is likely in the long-run that FTR prices will fall by more than the FTR underfunding amount.

Therefore, transmission customers are harmed by allocating the shortfalls to FTR holders. For ARRs that are converted to FTRs, transmission customers directly incur the shortfalls. However, for FTRs that are sold, transmission customers will receive less allocated transmission revenue because of the FTR price effects than they would if the shortfall were simply directly allocated to them (and FTRs were funded at 100 percent).

Therefore, we are recommending that MISO modify its FTR shortfall allocation to fully fund its FTR obligations by allocating the shortfalls directly to transmission customers. We believe customers will receive higher transmission revenues as the prices for the FTRs rise, which should more than offset the allocation of FTR shortfalls. Additionally, those FTRs that are held by transmission customers (converted ARRs) would be largely unaffected by this change. Hence, we believe transmission customers will benefit from this change. At the same time, fully funding the FTRs will make them more effective instruments for hedging congestion-related risk and facilitating forward contracting.

Finally, changing the allocation of the FTR shortfalls would allow MISO to improve the incentives that govern transmission operations. The largest single cause of shortfalls is planned and unplanned transmission outages that were not modeled in the FTR markets. At best, the current allocation provides little incentive to minimize the duration of these outages and schedule them during periods that cause the least congestion. At worst, some participants may have an incentive not to disclose outages to MISO for the FTR auction because it could reduce their ARR allocation.[25] In this case, higher quantities of ARRs/FTRs over an interface directly benefits the participant, while the costs of overstating the capability are socialized and spread to all MISO participants. MISO also should consider directly allocating FTR shortfalls caused by derating transmission facilities or scheduling outages in excess of those modeled in the FTR market. This direct allocation will provide efficient incentives for participants to disclose and optimize planned transmission outages, and take steps to avoid unexpected transmission outages.

E. Multi-Period Monthly 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 interface.[26]

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 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, it often cannot reduce the FTR obligations on the path by selling counter-flow FTRs. This is not always bad 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.

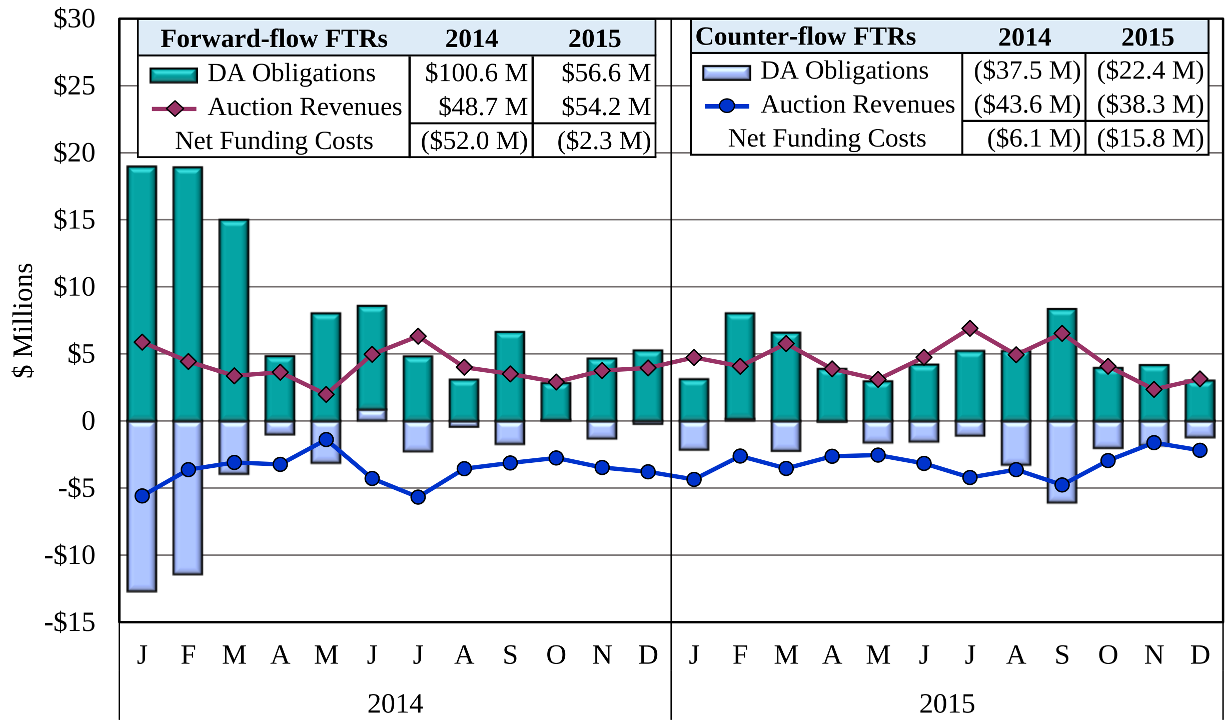
To evaluate MISO's sale of forward-flow and counter-flow FTRs, Figure 24 compares the auction revenues from the MPMA prompt month (the first full month after the date of the auction) to the day-ahead FTR obligations associated with the FTRs sold. It separately shows

25 This discussion recognizes that a large share of the transmission customers that receive the ARRs are vertically-integrated utilities that are also responsible for operating the transmission system.

26 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.

forward direction FTRs 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 24: Prompt-Month MPMA FTR Profitability
2014–2015



This figure shows that in most months of 2015 MISO sold forward-flow FTRs at close to their ultimate value, but MISO paid participants 70 percent more to accept counter-flow FTRs than the value of these obligations. While the negative auction residual restriction artificially limits MISO's ability to sell counter-flow FTRs, this limitation benefited MISO's customers in 2015 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.

If liquidity can be improved, we recommend 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.

F. Improving the Utilization of the Transmission System

During 2015, MISO and the IMM worked with transmission operators on processes and procedures to enable greater utilization of the transmission network. This can be accomplished by operating to higher transmission limits that 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. 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 both normal and emergency limits, but we have identified some transmission owners that provide only normal ratings.

To estimate the congestion savings of using temperature-adjusted ratings, we performed a study utilizing NERC/IEEE estimates of ambient temperature effects on transmission ratings. Using this data 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 as much as $165 million in production costs savings could be achieved by fully adopting temperature-adjusted, short-term emergency ratings throughout MISO.

MISO already initated discussions on the use of temperature-adjusted and short-term emergency ratings with its Transmission Owners. Additionally, we worked with MISO and one transmission owner in 2015 to implement a pilot program to make use of temperature-adjusted, short-term emergency ratings on a number of key facilities. This program is ongoing but preliminary results indicate clear benefits with no reliablity issues and this program will likely generate considerable cost savings on these constraints. We recommend MISO continue work with transmission owners to gather and use temperature-adjusted, short-term emergency ratings.

Finally, there are substantial potential savings with more wide-spread use of Voltage and Stability Analysis Tools (VSAT) in real time. In January 2015, the VSAT software was implemented and successfully used to reduce costs of managing stability constraints in the MISO North region. In 2014, the congestion on a key interface exceeded $31 million in real-time. After implementation of VSAT, this was reduced to less than $1 million. We support MISO's efforts to work with transmission providers in other MISO regions or neighboring regions that call TLRs that affect MISO to adopt such software.

G. Sub-Regional Power Balance Constraint and Hurdle Rate

Throughout 2015 MISO's generation dispatch and regional transfers between the MISO South and Midwest regions were limited by both the physical ORCA limit (3000 MW) and the Sub-Regional Power Balance Constraint (SRPBC), modeled with a 1000 MW limit and Hurdle Rate of $9.57/MW. The Hurdle Rate was implemented by MISO in 2014 to reflect the potential costs of disputed transmission charges from SPP, which prevents transfers above 1000 MW unless the dispatch savings are higher than $9.57 per MWh.

In January 2016, FERC approved a settlement agreement between MISO, SPP, and the Joint Parties to resolve disputed charges and to establish a fixed cost payment for usage above MISO's firm contract path rights of 1000 MW.[27] The Agreement went into effect February 1, 2016 and permits transfers up to 2,500 MW from South to North and 3,000 MW from North to South. The termination of the Hurdle Rate had resulted in significant increases in economic transfers and

27 See Docket ER14-1174.

associated production cost savings.[28] Because natural gas prices remain low, these changes have allowed MISO to benefit by more fully utilizing the large quantity of low-cost gas-fired resources in MISO South. The agreement satisfies our 2014-4 recommendation to eliminate the SRPBC Hurdle Rate and collect any potential transmission costs that may be payable to SPP and other parties through a fixed charge.

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

MISO's market-to-market process under the Joint Operating Agreement (JOA) with neighboring RTOs efficiently manages 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 redispatch. Under the market-to-market process, each RTO is allocated firm rights 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 redispatch responds by reducing flow to help manage the constraint.

Because the RTOs are allocated specific rights on the constraint for their dispatch (so-called Firm Flow Entitlements or "FFEs"), the responding RTO is essentially allocating some of its own Firm Flow Entitlement to the other RTO. The RTO that uses the other RTO's Firm Flow Entitlement will compensate the other for its use based on the congestion management costs that are saved through this coordination process. Much of the market-to-market process is now automated and has improved pricing in both markets.

MISO initiated market-to-market with SPP on March 1, 2015. The implementation was successful and has lowered the impact of SPP constraints on MISO's congestion costs and LMPs. However, in the first few months, there were significant issues with the coordination on two SPP flowgates. MISO and SPP continue to discuss these issues and some of the large payments made by MISO may be resettled. One key issue raised was the importance of developing a procedure for the MRTO to transfer control of a market-to-market constraint to the NMRTO under conditions where the NMRTO has most of the effective relief capability (and

28 See our Quarterly report for Winter 2015/2016.

likely the most market flows). PJM and MISO already have such a procedure, which has improved reliablity and reduced congestion costs substantially on the affected constraints. Hence, we recommend that MISO continue working with SPP to implement such a procedure.

Congestion on MISO market-to-market constraints fell 42 percent from $515 million in 2014 to $300 million in 2015, even with the addition of coordination with SPP. Congestion on external market-to-market constraints, those monitored by PJM and SPP, rose 25 percent, totaling $29 million.[29] Figure 25 shows the market-to-market settlements for 2014 and 2015, which are based on each RTO's firm flow entitlements and market flows on the other's constraints.

Figure 25: Market-to-Market Settlements
2014–2015

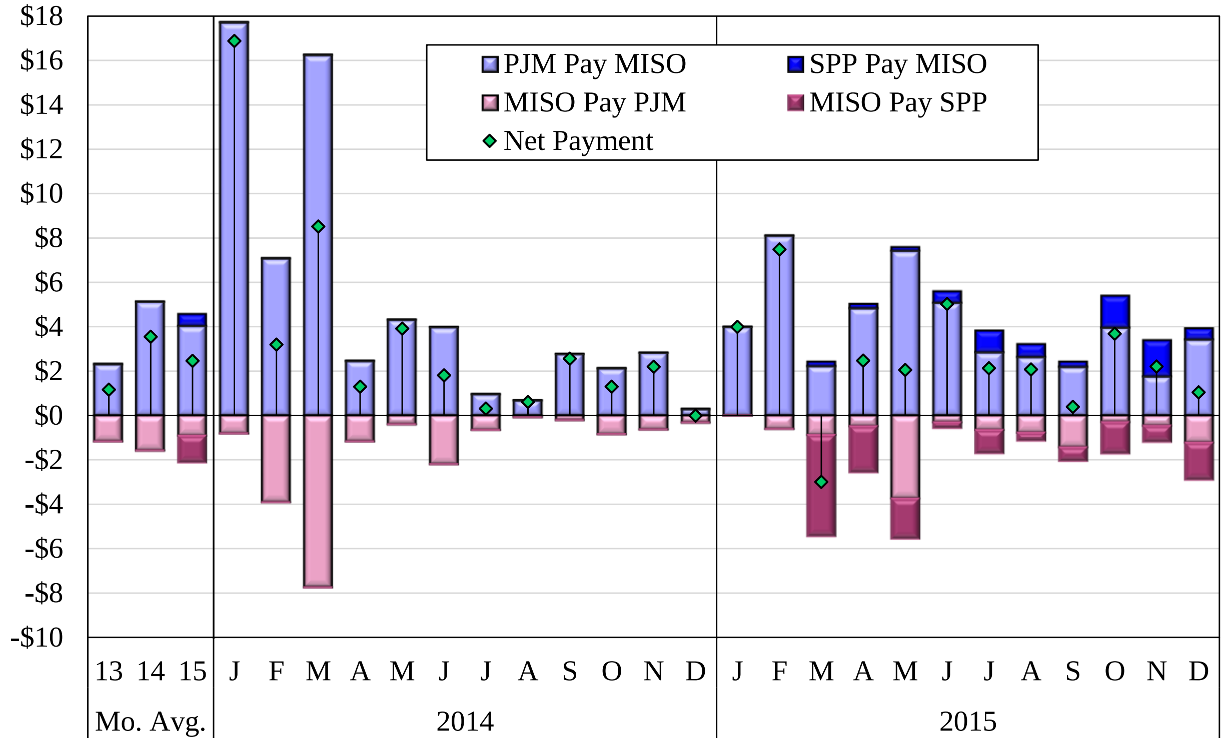


Figure 25 shows net payments flowed from PJM to MISO because PJM exceeded its FFE on MISO's system much more frequently than MISO did on PJM's system. Net payments from PJM totaled $38 million. These payments were 12 percent lower than in 2014, which was

29 As mentioned in the previous subsection, the congestion value is relatively small on external flowgates because it measures only the MISO market flow impacts and not the total flow on external constraints. Nonetheless, the price impact of external constraints can still be substantial.

largely due to the high payment levels during the Polar Vortex in 2014. One of the reasons the market-to-market settlements are skewed in favor of MISO is that PJM's interface pricing methodology is flawed. Because their interface definitions generally inflate estimated congestion relief provided by imports and exports, PJM schedules excessive quantities of market flows over MISO's constraints. These excessive market flows ultimately exceed PJM's firm flow entitlements and compel PJM to make large payments to MISO.

Alternatively, MISO's market-to-market settlements with SPP tend to be skewed in favor of SPP. In 2015, MISO's net payments to SPP were $8 million, of which $4.3 million occurred in the first month of coordination and is being disputed by MISO. As discussed above, this payment will likely be resettled.

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

Finally, MISO and PJM implemented our recommendation to coordinate FFE levels in the day-ahead market in late January 2016. We will be evaluating the effectiveness of this process in lowering the costs of managing the flows on these constraints. SPP has not agreed to implement a similar day-ahead coordination procedure.

I. Effects of Pseudo-Tying MISO Generators

In recent years, increasing quantities of MISO capacity have been exported to PJM. Regrettably, PJM has recently implemented rules to require external capacity to be pseudo-tied to PJM. We have raised 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

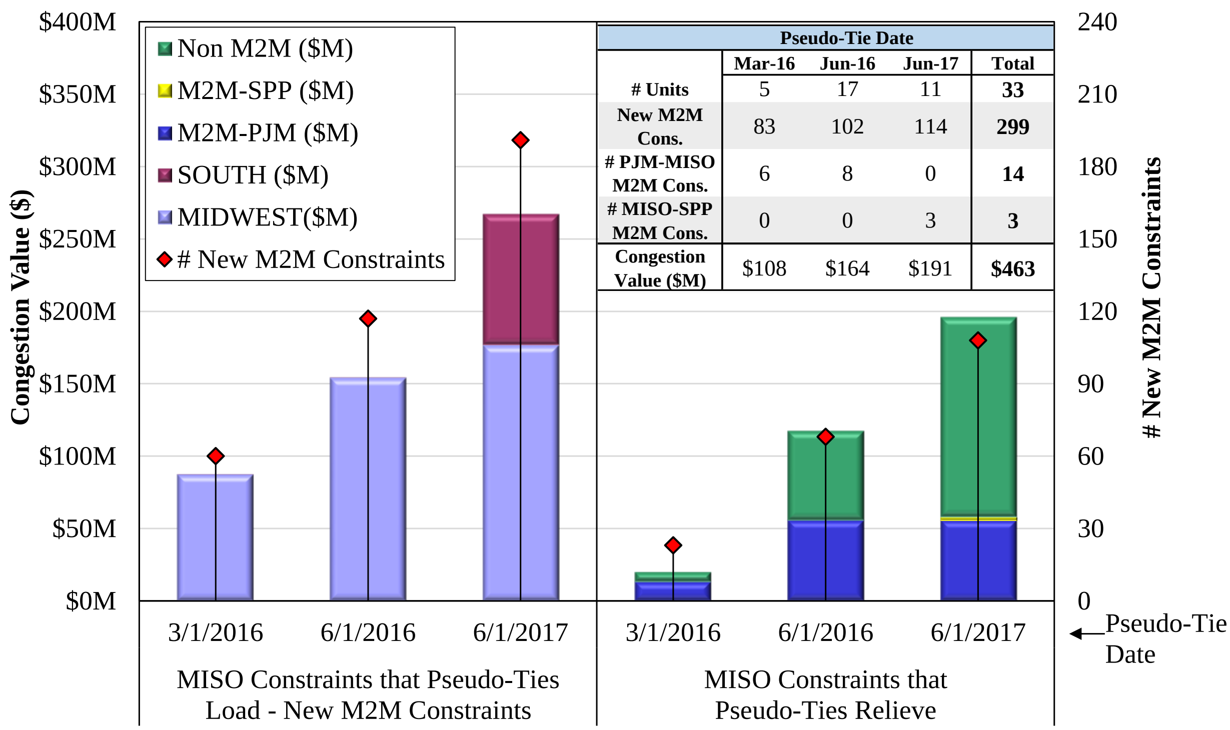
- Transfer control of generators that relieve other MISO constraints so that MISO will no longer have access to them to manage congestion on these constraints.

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. Unfortunately, this coordination is not as effective as dispatch control and many constraints will not be coordinated. To evaluate these issues, Figure 26 shows the effects of pseudo-tying the generators to PJM:

- The left panel shows the number (red diamond) and congestion value (bars) of MISO constraints in 2015 would have qualified as new market-to-market constraints. We show this separately for the three groups of resources that currently plan to pseudo-tie to PJM in March 2016, June 2016, and June 2017.

- The right panel shows the number of new market-to-market constraints that would be defined because of the relief the pseudo-ties provide on the constraints. It also shows the congestion value of these constaints (red bars) and others MISO constraints (blue bars are PJM M2M and green bars are SPP M2M) that are relieved by the pseudo-tied resources.

Figure 26: Effects of Pseudo-Tying MISO Resources to PJM
2015



	Pseudo-Tie Date			
	Mar-16	Jun-16	Jun-17	Total
# Units	5	17	11	**33**
New M2M Cons.	83	102	114	**299**
# PJM-MISO M2M Cons.	6	8	0	**14**
# MISO-SPP M2M Cons.	0	0	3	**3**
Congestion Value ($M)	$108	$164	$191	**$463**

Based on our analysis shown in Figure 26, almost 300 non-market-to-market constraints that bound in 2015 will now need to be defined as market-to-market constraints so they can be coordinated. This will occur because units located on MISO's transmission system will be under the dispatch control of PJM so the only way to adjust their output to manage the flows over these MISO constraints is to us the market-to-market process. This is a serious issue because the figure also shows that the value of the congestion on these constraints was approximately $400 million in 2015, roughly 30 percent of all MISO real-time congestion value.[30]

J. Congestion on Other External Constraints

Congestion in MISO can occur 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 excessive relief requests for these external 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 of the flows are associated with dispatching network resources to serve MISO's load.

As a result, these external 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.

For example, during one TLR event on February 20, 2015, TVA issued TLR on the Volunteer-Phipps Bend flowgate that caused extreme congestion and had widespread price effects throughout the MISO market for much of the day. Our analysis of this event revealed that rating TVA used was overly conservative and the flows were generally well below the constraint's limit. These issues were excercerbated by the fact that MISO's dispatch flows are generally treated as non-firm while TVA's comparable dispatch flows are firm (so MISO must bear almost the total cost of lowering the flow on the constraint). We have recommended changes to address these issues.

30 In addition, MISO would lose the direct control to economically commit/decommit these resources for congestion management.

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 2015:

- Hourly net imports in the day-ahead and real-time markets averaged 2.4 and 2.8 GW, respectively.
- MISO's largest and most actively scheduled interface is the PJM interface. As a result of wheels from IESO to PJM through MISO and dynamically-scheduled exports to PJM from MISO South, MISO was a net exporter to PJM in 2015.
  - Hourly average real-time exports to PJM were 503 MW.
  - Some of the scheduling patterns between MISO and PJM were inefficient because of flaws in the RTOs' interface prices, 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 an economic and reliability standpoint. 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 prevailing price differences. Additionally, the lack of RTO coordination of participants' schedules leads to substantial errors in the aggregate quantities of interregional transaction 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. The share of transactions with PJM that were scheduled in the profitable direction was only 53 percent, although nearly 58 percent of those settling at the real-time price were profitable. Many hours still exhibit large price differences that can be attributed to scheduling uncertainties. MISO and PJM plan to address these issues by introducing "Coordinated Transaction Scheduling" (CTS), which allows the RTOs to adjust transaction schedules each 15 minutes based on the price differences between the two markets.

We have previously estimated $59 million in annual efficiency benefits associated with optimizing the scheduling of the PJM interface with MISO. PJM recently implemented a comparable approach with the New York ISO.

B. Interface Pricing and External Transactions

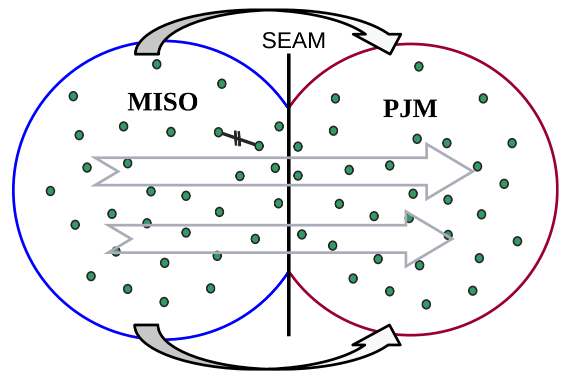
Each RTO posts its own interface price at which it will settle with physical schedulers wishing to sell and buy power from the neighboring RTO. Participants will schedule between the RTOs to arbitrage the differentials between the two interface prices. Interface pricing is essential because:

- It is the sole means to facilitate efficient power flows between RTOs.
- Poor interface pricing can lead to significant uplift costs and other inefficiency.
- They are an essential basis for "coordinated transaction scheduling" or "CTS" to maximize the utilization of the interface.

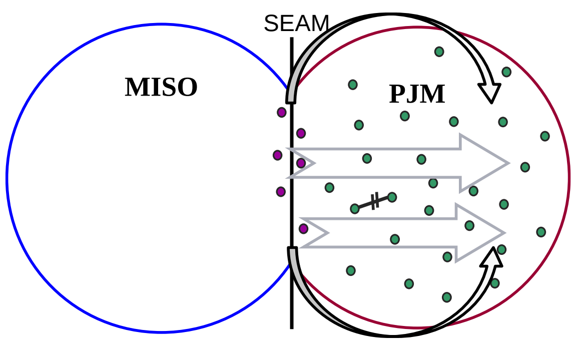
Establishing efficient interface prices would be simple in the absence of transmission congestion and losses – each RTO would simply post the interface price as the cost of the marginal resource on their system (the system marginal price, or "SMP"). Participants would respond by scheduling from the lower-cost system to the higher-cost system until the system marginal prices come into equilibrium (and generation costs equalized). However, congestion is pervasive on these systems and 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 generators, the source of the power is known so 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". Using this interface definition, the RTOs use transmission models to calculate the flow effects for imports and exports. These flow effects (i.e., the "shift factor") times the value of the binding transmission constraints is the congestion component that will be included in the interface price. If the interface definition is 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 below. This figure is consistent with MISO's current interface pricing, which calculates flows for exports to PJM based on the power sinking throughout PJM. This is accurate because PJM will ramp down all of its marginal generators when it imports power.



However, PJM assumptions are much different. It assume the power sources and sinks from the border with MISO as shown in the second figure. This 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.



Interface Pricing Flaw on M2M Constraints. We raised a separate concern in our *2012 State of the Market Report*, that MISO and PJM are including redundant congestion component in their interface prices for M2M constraints. When MISO and PJM independently calculate interface prices that include the cost of congestion on the same "coordinated" market-to-market flowgate, the total settlement will over-pay or over-charge the market participant for the congestion effects of the transaction.

We have also quantified some of the related inefficiencies and costs to both PJM and MISO related to this pricing flaw. We estimate that the two RTOs together incurred costs of $51.5 million in net overpayments on market-to-market constraints in 2015, of which $44.7 million was incurred by PJM. These amounts do not include overpayments made for other external constraints (only for the PJM and MISO M2M constraints).

In addition to the overpayments for transactions that are expected to help relieve the constraint, this issue causes transactions to be overcharged for congestion when they are expected to aggravate a constraint. Although this effect will not result in uplift, it serves as an economic barrier to efficient external transactions.

We continue to work with MISO and PJM, and their respective stakeholders through the JCM process to address the problem and have now largely achieved a consensus between the RTOs on the problem. We continue to discuss two potential solutions:

- The non-monitoring RTO could simply stop including its neighbor's M2M constraints in its interface prices. This would ensure that the incentive to transact reflects the value of the relief to MISO who is managing the constraint. This solution resolves all of the efficiency and equity concerns associated with this pricing flaw, and can be applied to all external constraints for all interfaces.
- PJM proposes that both RTOs adopt a common interface comprised of limited number of nodes close to the MISO-PJM seam. While this may have intuitive appeal, our analysis indicates that it would produce less efficient, more volatile interface prices,

Both approaches improve the interface price signals associated with M2M constraints, but the PJM solution substantially distorts MISO's pricing of its own internal constraints. Therefore, we have opposed the PJM solution because it will distort the incentive to schedule imports and exports. Nonetheless, the RTOs have announced to their participants that they intend to implement PJM's 10-point common interface, at least in the short-term. We believe this is a mistake and will be prepared to quantify the distortions.

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. Market-to-market constraints activated by PJM are one type of external constraint that MISO activates in its real-time market. MISO also activates constraints located in external areas when the system operator calls a TLR and redispatches 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 because this enables MISO to respond to TLR relief requests as efficiently as possible. While redispatching internal generation is required, MISO is not obligated to pay participants to schedule transactions that 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 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.
- Second, 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 decisions related to PJM M2M constraints.

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 2015. Our assessment is based on measuring and assessing market power in the MISO markets, which exists 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 than less concentrated markets. Market concentration is low for the overall MISO area (603), but relatively high in some local areas, such as the WUMS Area (2715) and the South region (3578). Generation ownership is most highly concentrated in MISO South where a single supplier operates nearly 60 percent of the generating capacity. However, the metric does not include the impacts of load obligations, which substantially affect suppliers' incentives to raise prices. It also doesn't 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 since electricity cannot be economically stored. Hence, when load increases, the excess capacity will fall and the resources of large suppliers may be required to meet load. We evaluate local market power by identifying pivotal suppliers for relieving transmission constraints into constrained areas, including the five Narrow Constrained Areas (NCAs) and the Broad Constrained Areas (BCAs) that are defined for purposes of market power mitigation. NCAs are chronically constrained areas that raise more severe potential local market power concerns (i.e., tighter market power mitigation measures are employed). Our results showed that a supplier was frequently pivotal in both types of constrained areas:

- In the periods during the year when a one or more BCAs became activated due to a transient binding constraint, the vast majority (89 percent) of the BCA constraints had at least one supplier that was pivotal.
- At least one BCA constraint with a pivotal supplier was binding in nearly all intervals.
- In the two MISO South NCAs, 99 percent of binding NCA constraints had a pivotal supplier.
- The MISO Midwest NCAs had pivotal suppliers on 93 percent of the constraints.

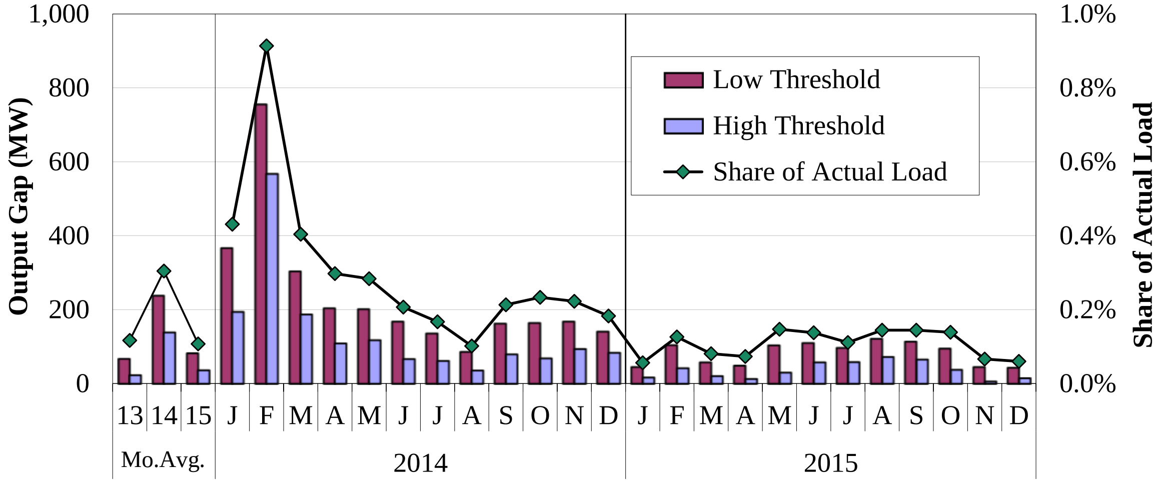
Overall, these results indicate that local market power persists with respect to both BCA and NCA constraints, and that market power mitigation measures remain critical.

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 -0.3 percent in 2015, varying monthly from a high of 1.7 percent to a low of -2.1 percent. The low average mark-up indicates that MISO's energy markets were very competitive.

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 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 27: Economic Withholding – Output Gap Analysis
2014–2015



Low Threshold Results by Unit Status (MW)

Offline	4	13	99	8	2	6	0	12	1	9	0	26	11	4	70	140	519	154	99	82	18	29	22	32	14	21	52
Online	26	55	140	69	25	62	79	104	53	30	22	55	42	50	74	228	236	150	105	120	150	107	65	131	149	147	92

High Threshold Results by Unit Status (MW)

Offline	3	10	82	7	1	4	0	10	1	6	0	23	7	2	59	106	451	130	83	71	13	21	15	20	9	19	50
Online	5	14	57	27	4	11	20	22	14	5	5	14	11	11	20	89	116	57	26	46	54	41	21	60	62	75	36

The figure shows that output gap levels fell in 2015 to 0.11 percent of load, 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.

C. Summary of Market Power Mitigation

Most market power mitigation in MISO’s energy market continues to occur 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 higher 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 and RSG mitigation in both MISO markets fell significantly in 2015. RSG payments occur when a resource is committed out of market to meet capacity requirements or to manage congestion. The RSG payments are based on the offer parameters of the resource. If the resource offers its unit at parameters that exceed its mitigation thresholds, it may inflate its RSG payments and be mitigated. Voltage and Local Reliability (VLR) commitments are one type of capacity commitment for which participants may be paid RSG. Most VLR commitments are in MISO South and are subject to tighter mitigation thresholds. In 2015, total RSG mitigation fell by 81 percent compared to 2014.

Instances of mitigation were appropriate and effectively limited the exercise of market power. Some RSG mitigation results in early 2014 were challenged and mitigation was restated to reflect accurate fuel price information. These cases occurred because natural gas prices can move sharply during natural gas shortage conditions and the mitigation under these rare conditions can be inaccurate because a lagged price index is necessary to determine generators' costs. To address this issue, we improved our processes in late 2014 to identify when real-time natural gas prices are rising sharply so that reference levels can be dynamically adjusted intraday. This process was effective during the winter of 2015/2016 in preventing inappropriate mitigation.

D. Evaluation of RSG Conduct and Mitigation Rules

Local market power is often associated with reliability needs that cause resources to be committed by MISO. This form of market power is exercised by changing a resource's offer parameters to increase the RSG payment received by the supplier. To evaluate how effective the mitigation measures have been in addressing this form of market power, we estimated the share of the RSG paid that corresponds to competitive offers. We determined that less than half of the RSG costs paid for VLR commitments is associated with competitive offer prices, while the balance is attributable to increases in one or more offer parameters above competitive levels.

In June, FERC approved a lower threshold for RSG mitigation in BCAs and NCAs, which will result in mitigation if a supplier's conduct increases production costs by more than the lower $25 per MWh or 25 percent (analogous to the 10 percent threshold used for VLR commitments).

Additionally, there is no longer a separate impact test. This lower threshold resulted in an initial increase in RSG mitigation in August through October, when transmission outages resulted in a number of transmission-related commitments. By Fall and early Winter, both transmission and VLR-related mitigation fell in part because of low natural gas prices. Lower natural gas prices result in reduced RSG and less frequent RSG mitgation as gas resources become more economic.

E. Dynamic NCAs

The current Tariff provisions (Section 63.4 of Module D) related to the designation of NCAs are focused only on sustained congestion affecting an area. 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 one or more pivotal suppliers, an NCA can generally not be defined because it would not be expected to bind for 500 hours in a 12-month period. In addition, even if an NCA is defined, the conduct and impact thresholds are based on historical congestion, so they would not reflect the congestion for up to 12 months.

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 quickly recognize that their units are needed to manage the constraints. In Section VII.F of the Analytical Appendix, we show two examples from prior years that illustrate this issue. Although both of these cases lasted less than two months, the conduct increased prices at affected locations by roughly $150 per MWh in the hours that would have been mitigated, and by $4 to $10 per MWh over the timeframes affected by the outages.

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 an NCA). This provision would help ensure that transitory network conditions do not allow the exercise of substantial local market power.

IX. Demand Response

Demand response improves operational reliability, contributes to resource adequacy, reduces price volatility and other market costs, and mitigates supplier market power. Therefore, it is important to provide efficient incentives for the development of DR and to integrate it into the MISO markets in a manner that promotes efficient pricing and other market outcomes. Table 5 shows overall DR participation in MISO, NYISO, and ISO-NE in the prior four years.

Table 5: Demand Response Capability in MISO and Neighboring RTOs
2012–2015

		2015	2014	2013	2012
MISO[1]		**10,563**	**10,356**	**9,798**	**7,196**
	Behind-The-Meter Generation	4,213	4,072	3,411	2,969
	Load Modifying Resource	5,121	4,943	5,045	2,882
	DRR Type I	330	372	372	372
	DRR Type II	116	76	76	71
	Emergency DR	782	894	894	902
NYISO[3]		**1,325**	**1,211**	**1,306**	**1,925**
	ICAP - Special Case Resources	1,251	1,124	1,175	1,744
	Of which: Targeted DR	385	369	379	421
	Emergency DR	75	86	94	144
	Of which: Targeted DR	14	14	40	59
	DADRP	0	0	37	37
ISO-NE[4]		**2,685**	**2,487**	**2,101**	**2,769**
	Real-Time DR Resources	692	796	793	1,193
	Real-Time Emerg. Generation Resources	300	255	279	588
	On-Peak Demand Resources	1,222	997	629	629
	Seasonal Peak Demand Resources	471	439	400	359

[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 2014. Retrieved January 15, 2015. 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, 2015. Source: ISO-NE Demand Response Working Group Pesentation, Jan. 7, 2015.

The table shows that MISO had over 10 GW of registered demand-response capability available in 2015, which makes up a larger share of capacity than it does in neighboring RTOs. MISO's capability comes in varying degrees of responsiveness. Nearly 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 29 Demand Response Resources ("DRRs") were active in the MISO markets in 2015, they only cleared a small amount of energy and reserves in the MISO markets. All but two of these 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, therefore, important to ensure that real-time markets produce efficient prices when DR resources are deployed (they have not been deployed since 2006).

One change that we have recommended in prior reports is a modification to the ELMP model to allow emergency actions and all forms of DR to contribute to setting efficient real-time prices. MISO recently filed changes to its pricing rules that would address this recommendation. MISO's proposed changes to the emergency procedures will improve market efficiency during peak periods and will improve incentives for development of new resources.

Finally, DR integration into the Resource Adequacy Construct can affect the price signals provided by MISO's capacity market. All demand response resources are treated comparable to generation resources in their ability to meet planning reserve margins in the PRA. However, LMRs are not subject to comparable testing and verification as generating resources.[31] Despite the capacity market design issues we describe in this report, accurately accounting for the true capability of LMRs could increase the clearing prices significantly in the PRA, making them more reflective of the actual supply and demand conditions in MISO. Hence, we have recommended in prior reports that MISO adopt testing procedures if practicable, and derating these resources based on their actual performance when called.

31 They are still required to verify their capability, but it is likely not as accurate as MISO's process for generation resources.

X. RECOMMENDATIONS

Although MISO's markets continued to perform competitively and efficiently in 2015 overall, we recommend a number of improvements in MISO's market design or operating procedures. These 22 recommendations are organized by the aspects of the market that they affect:

- Energy Pricing and Transmission Congestion;
- External Transaction Scheduling and External Congestion;
- RSG Cost Allocation and PVMWP Eligibility Rules;
- Dispatch Efficiency and Real-Time Market Operations; and
- Resource Adequacy.

Fourteen 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 nine of our past recommendations, which were implemented in 2015 or being implemented in early to mid 2016. Recommendations that are addressed are discussed at the end of this section. 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. The following three recommendations address this area.

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.

<u>Status</u>: This recommendation was originally proposed in our *2012 State of the Market Report*. In September 2015, FERC issued a NOPR in RM15-24 calling for consistency between settlement intervals and dispatch intervals. MISO has agreed this recommendation and filed supporting comments in response to the Commission's NOPR. MISO's NOPR comments propose a timeline dependent upon it first implementing a significant upgrade to the MISO Settlement System.

<u>Next Steps</u>: The software changes to implement this recommendation will be significant and require stakeholder involvement. MISO projects completion of its Settlement System upgrade in the first quarter of 2017, to be followed by the planned implementation of this recommendation in the 1st quarter of 2018. This timeline could change pending FERC's final rule and the corresponding compliance requirements.

2012-5: Introduce a virtual spread product.

73 percent of price-insensitive virtual bid and offer volumes (and 24 percent of all volumes) in 2015 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 that when they submit a price-insensitive transaction, it may ultimately be highly unprofitable for the participant and produce excess day-ahead congestion that can cause inefficient resource commitments.

Status: This recommendation was originally proposed in our *2012 State of the Market Report*. . MISO continues to discuss this recommendation with stakeholders and has held a number of workshops with stakeholders to explore the development of such a product. MISO continues to evaluate costs and benefits, and develop software improvements 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 and forecasted for implementation in the fourth 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.

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

The current Tariff provision (Section 63.4 of Module D) related to the designation of NCAs is focused only on chronic congestion that creates sustained local market power. However, transitory conditions (transmission or generation outages) can arise that create a severely-constrained area where the market is vulnerable to the exercise of substantial local market power. Although these areas would not satisfy the criteria to be defined as permanent NCAs, we have concluded that under these transitory conditions, the current Tariff provisions are insufficient to effectively address the resulting local market power. This recommendation 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: The IMM has continued to evaluate instances that warrant the definition of a dynamic NCA and developed a proposed trigger for defining a dynamic NCA. We anticipate MISO making a FERC filing in the third quarter of 2016 and implementation by early 2017, pending FERC's approval.

Next Steps: The IMM will work with MISO to create a filing plan, develop proposed Tariff revisions to address this recommendation and present the proposed revisions to MISO's stakeholders. Once filed and approved by the Commission, most of the changes in the software and processes would be implemented by the IMM and could be completed relatively quickly.

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, resulting 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.

This recommendation would ensure that all FTRs issued by MISO are funded at 100 percent by allocating the shortfall directly to transmission customers. Customers will receive higher FTR revenues as the prices for the FTRs rise, which should more than offset this allocation. Additionally, those FTRs that are held by transmission customers (converted ARRs), which constitute most of the FTRs, will receive higher day-ahead congestion revenues. Hence, the transmission customers should not be financially harmed.

We recommend that MISO explore two principles for allocating the shortfalls:

- Some or all of the shortfalls that are due to transmission outages should be allocated to the transmission owner or, if not feasible, to transmission customers in the portion of the system affected by the outage; and
- The balance of the shortfalls should be allocated to transmission customers in proportion to the FTR revenues and ARR values they received.

The first principle will provide incentives for transmission operators to schedule outages more efficiently – to limit their duration and take the outages in periods that are least likely to cause significant congestion costs. In addition to providing improved incentives for outage scheduling, funding FTRs at 100 percent will improve participants’ ability to use them to hedge congestion and facilitate wholesale energy transactions.

<u>Status:</u> MISO’s initial assessment was that this recommendation correctly raises the opportunity to improve economic incentives for scheduling outages. MISO concluded that additional options to improve the economic incentives for outage scheduling should be explored. MISO’s initial assessment also concluded that modifying the allocation of FTR shortfalls is not high priority at this time because funding levels are relatively high.

Next Steps: The IMM will be working with MISO to explore options for improving the economic incentives for outage scheduling, and to more fully evaluate the potential benefits of this recommendation to assist in prioritizing this in the market roadmap process.

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

MISO is incurring substantial RSG 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 due to the contingencies. In essence, MISO is committing resources to hold reserves on online resources.

We recommend that MISO create a local 30-minute reserve product in these areas so that these requirements can be priced and procured through MISO's markets (rather than through out-of-market commitments that result in uplift). This would be beneficial because it would provide market signals to build fast-starting units 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 produce, 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 is currently evaluating this recommendation and has classified it as a high priority in the Roadmap process and assigned a forecasted implementation time in the second quarter of 2019

Next Steps: MISO should complete an evaluation of the benefits of implementing a 30-minute reserve product more broadly beyond the areas subject to VLR requirements.

2015-1: Expand eligiblity 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 have a very small effect in allowing online peaking resources set prices when they are the marginal source of supply in MISO. This can be attributed to the eligibility rules that allow only 2 percent of the online peaking resources to potentially set prices. We recommend expanding the eligibility to include peaking resources with start times up to one hour and 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: Although this is a new recommendation, MISO has begun discussing these issues with its participants as it develops a plan for the Phase II implementation. For those changes in Phase II that do not require software modifications, MISO anticipates implementation in the first quarter of 2017. Changes that require software modifications will likely require more time.

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 shows potential savings of up to $165 million of reduced congestion costs 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 use of both temperature-adjusted and short-term emergency ratings. Additionally, we recommend that MISO work with its Transmission Owners to establish a consistent rating methodology to communicate an expectation that emergency ratings should be based on short-term temperature-adjusted ratings.

Status: This is a new recommendation.

B. External Transaction Scheduling and External Congestion

Efficient scheduling of imports, exports, and "wheel-through" transactions is very important because it affects not only the market prices and congestion in MISO, but throughout the Eastern Interconnect. We have seen a number of cases where poor scheduling of transactions between MISO and PJM has contributed to substantial shortages and price spikes in one area or the other. We have been evaluating the scheduling processes and the interface prices the RTOs post that incentivize participants to schedule transactions. This evaluation has indicated the need for improvements that are addressed by the recommendations below.

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.

<u>Status</u>: 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 four years, we have been working 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 indicated that it intends 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, and that the preferred short-term and long-term solution is for MISO to remove all external congestion from its interface prices.

<u>Next Steps</u>: We are encouraging MISO to complete any software change necessary to remove external congestion from its interface prices. These changes are necessary to remove other external constraints in other adjacent areas, regardless of whether MISO decides to move forward with this solution at the PJM interface. Ultimately, we believe that this is the best alternative for the PJM interface as well.

2014-3: Improve external congestion related to TLRs by working to modify assumptions that would reduce MISO's relief obligations.

The implementation of market-to-market coordination with SPP has significantly reduced the TLR inefficiencies. TLRs called by SPP had previously had the largest effects on MISO's prices. However, the integration of MISO South has increased the frequency of TLRs called by TVA. Hence, this recommendation remains an important improvement that can reduce price distortions caused by TLRs. We recommend MISO explore the option of designating its day-ahead scheduled flows as firm, which would substantially reduce its relief obligations because most TLRs affect non-firm schedules. This would also ensure that the entity calling the TLR would be redispatching its own resources to contribute to managing the constraint when MISO is required to provide relief.

Status: We have been reviewing the relevant documents and agreements, and discussing alternatives with MISO. The NERC documents allow for the change we propose, but MISO is bound by a Joint Operating Agreement that would not allow this change. MISO is evaluating the feasibility of securing agreements to revise these documents or agreements in order to address this recommendation.

Next Steps: We continue monitor for and evaluate the negative impacts on MISO's markets and customers caused by TLRs. MISO has also been discussing is issue internally and the next step would involve approaching some of the neighboring entities to propose this change.

C. Guarantee Payment Eligibility Rules and Cost Allocation

Failure to allocate RSG costs to those market participants that cause them will produce inefficient incentives by: (a) discouraging efficient conduct that does not cause the costs and (b) not discouraging conduct that does cause the costs. Therefore, the allocation of RSG costs is very important because it affects the performance of the market.

In 2013, MISO filed a series of proposed Tariff revisions consistent with our *2012 State of the Market Report* recommendations. The proposed revisions addressed problems with the allocation of real-time RSG costs that over-allocated costs to market-wide deviations and under-allocated costs to deviations that affected constraints. Additionally, we made recommended changes in the eligibility rules for PVMWP and RSG to address gaming strategies that can result in unjustified payments.

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

This recommendation could be implemented 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.

These solutions would accomplish a very similar objective. The first solution 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 solution would also include the expected deployment costs in the selection and pricing of spinning reserves, but it would be accomplished by MISO calculating the expected deployment costs.

Some participants have expressed a preference for the second solution, which would impose less deployment risk on the reserve suppliers by continuing the guarantee payment MISO makes today. We believe that both solutions would be effective at addressing the inefficient selection and pricing of spinning reserves that we observe today.

Status: This recommendation was originally made in the *2010 State of the Market Report* and MISO has presented this to its stakeholders. The stakeholders recommended that MISO evaluate potential alternatives to resolve the issue. MISO's current schedule is to update the evaluation of the benefits and identify potential alternatives in the second quarter of 2016, but this has been prioritized as "low" in the MISO Roadmap process.

Next Steps: MISO should complete the requested evaluation and work with its customers to determine priority based on the estimated beneifts and prospects of solution options. Upon decision to move forward, MISO should work with Market Participants to develop deisgn details, business rules and proposed Tariff changes.

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. While this may be necessary for units with long start times, this practice does not allow for an optimal commitment of resources through the day-ahead market. If MISO were to accurately model the VLR requirements in its Day-Ahead Market, it could reduce the total costs of satisfying all of its requirements by waiting to optimize its generator commitments through the day-ahead market with more accurate information on load, topology, and the status and costs of all other generators.

Therefore, we recommend that MISO modify its day-ahead market model to explicity model the VLR requirements and develop and process to allow units scheduled in the day-ahead market to be accurately identified as VLR units when they are scheduled to satisfy this requirement. In addition, we recommend MISO review and modify the tariff as needed.

Status: This is a new recommendation.

D. 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 include 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 three 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.[32] 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 V.D.5. 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 requires that units overall move 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 to allow the LAC model to make better recommendations.

Status: MISO generally agrees with this recommendation and has been evaluating this proposal. We work with MISO to estimate the impacts of revised thresholds to ensure that they will be effective and will not create any unintended outcomes. Implemenation of this recommendation is currently included in the Market Roadmap process and is planned for fourth quarter 2016.

Next Steps: MISO and the IMM are working to finalize and test the revised rules. Once this is completed, MISO will need to present the proposal to its stakeholders and file the revised thresholds at FERC.

32 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.

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 it has invoked a number of other 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: Limited progress has been made to date.

Next Steps: MISO should review the existing DR resources in MISO to estimate the costs of calling on them to curtail.

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 on MISO and its customers.

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). Recommendations 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 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 a poor response can be caused when residuals are large relative to the offered ramp rate of the resource.

Status: This is a new recommendation

E. Resource Adequacy

Reasonable resource adequacy provisions and a well-functioning capacity market are intended to provide economic signals, together with MISO's energy and ancillary services markets, to establish efficient incentives to govern investment and retirement decisions. These economic signals will be increasingly important as planning reserve margins in MISO fall due to the compliance costs of new environmental regulations and due to low prevailing energy prices, both of which will increase retirements of uneconomic units. MISO filed proposed changes to its Resource Adequacy Construct in 2011 that should improve price signals and reliability. However, there remain a number of critical issues that are undermining the economic signals provided by the MISO markets. The recommendations in this subsection are intended to address these issues to help ensure that the market will facilitate investment in the resources over the long term that are necessary to maintain reliability.

2010-14: Introduce a sloped demand curve in the RAC to replace the current vertical demand curve.

The use of only a minimum requirement and deficiency charges to represent capacity demand in MISO 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 new environmental regulations that will require substantial compliance costs.

A sloped demand curve would more accurately reflect the reliability value of capacity in excess of the minimum requirement. It also will 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.

Status: MISO is developing principles governing future market developments, including changes in its resource adequacy provisions and processes. The principles include the objective of facilitating efficient investment so they are consistent with this recommendation. However, there is currently no consensus among the participants and States regarding this objective.

Next Steps: MISO should continue to work with its stakeholders and Organization MISO States 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.

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. In addition, units that are currently suspended could not previously qualify to offer into the PRA. 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. Finally, capacity resources should have more flexibility to retire or shut down temporarily prior to the end of the planning year if their capacity is not needed. Flexibility will improve market efficiency by reducing inefficient barriers to participating in the PRA.

The Attachment Y notification requirements should also be expanded to include extended outages, either forced or planned, and the qualifications to be a planning resource should reflect reasonable expectations of the resource's availability during the peak seasons of the affected planning years.

Status: MISO did modify the use of the GVTC Deferral provisions of 69A.7.9, 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. The FERC conditionally accepted the revisions subject to condition on February 12, 2016.

MISO has not taken steps to improve the flexibility for Generation Units that are pending retirement to participate in the PRA because it does not agree with this element of the recommendation. Similarly, 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 change that address this 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 the case currently. 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: MISO has been moving the transition to a seasonal capacity market structure through the market participant process, but has proposed only two seasons. Two seasons eliminate the opportunity to achieve savings that could be achieved by scheduling efficient economic outages during the shoulder months and only reduces the other 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 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, both of the 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, transmission security, 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, transmission security, 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.

Beginning in June 2016, approximately 2 GW of capacity in MISO will begin pseudo-tying to PJM because it was sold in the PJM capacity market. In June 2017 another 2 GW of capacity in MISO will begin pseudo-tying to PJM. Under its Capacity Performance construct, PJM requires external resources to pseudo-tie to PJM beginning in 2017. 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 be reducing dispatch efficiency and reliability. Additionally, the reduced dispatch efficiency will impose substantial potential cost exposure on both RTOs as the number of M2M constraints will increase by hundreds.

We have developed proposed "Firm Capacity Deliver 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 capacity resources. In nearly all respects, these provisions can be designed to impose requirements on MISO's capacity resources that are comparable to PJM's internal capacity resources, without compromising dispatch efficiency or degrading local reliability. In fact, these provisions would increase PJM's access to the external capacity and make its delivery to PJM more reliable.

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

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.

This process can lead to sub-optimal procurements and prices. Hence, we recommend that MISO add transmission constraints as needed to address potential simultaneous feasibility issues and to reflect the differing impact of zonal resources on regional constraints. For example, MISO is in the process of adding external capacity zones. Some external zones are interconnected to both MISO South and MISO Midwest, which means that only some of the capacity procurements from those zones should be deemed to cross the transfer constraint. If MISO were to model a limited number of regional constraints, it could assign zonal shift factors for each of these constraints that would optimize the procurements and prices. Currently, the only regional constraint is the transfer constraint and all of the constraints effectively assume 100 percent of the net import or export flow over the designated constraints. Introducing zonal shift factors that can be less than 100 percent would substantially improve the PRA solutions.

For example, assume an external zone spans the transfer constraint such that 50 percent of the power flows into MISO South and 50 percent into MISO Midwest. Further, assume the transfer constraint binds in the PRA and sets prices of $50 per MW-day in the Midwest and $10 per MW-day in MISO South. The PRA should recognize that procuring an additional megawatt from the external zone is more costly than procuring it from the Midwest (because half of the MW will flow over the transfer constraint), but less costly than purchasing the additional megawatt from MISO South. Assuming a 50 percent zonal shift factor for this zone on the transfer constraint would result in a price in the external zone of $30 per MW-day. 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 arise in its simultaneous feasibility assessment.

Status: This is a new recommendation.

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

As capacity margins fall in MISO, the market will become more vulnerable to physical withholding. However, the MISO tariff currently has two shortcomings that potentially limit MISO's ability to mitigate clear exercises of market power in the PRA through physical withholding. First, the physical withholding thresholds are applied on a market participant basis, rather than a company basis. This would allow a large supplier to create multiple market participants to effectively circumvent the mitigation. Second, it is not clear the 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 and applying the physical withholding conduct threshold jointly to all market participants that are affiliates.

Status: This is a new recommendation.

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. MISO recently entered into a settlement agreement whereby MISO has the authority to schedule transfers up to 3000 MW from MISO Midwest to South and 2500 MW from MISO South to Midwest. However, MISO neighbors may declare an emergency and instruct MISO to temporarily reduce its interregional transfers to a lower level. This should be rare 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 874 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.[33] This approach is not reasonable because holders of firm transmission rights cannot prevent MISO from transferring power over the transfer interface between the regions. These participants simply

33 In a similar fashion, MISO established a 2794 MW transfer limit from MISO Midwest to MISO South, but it did not bind in the most recent PRA.

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 most recent PRA for planning year 2016/2017. 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: This is a new recommendation.

F. Recommendations Addressed by MISO

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 2014 and early 2015. These recommendations are discussed below.

2011-10: Implement procedures to utilize provisions of the JOA that would improve day-ahead market-to-market coordination with PJM.

Under the JOA, each RTO has the option to request additional FFE on market-to-market constraints and to compensate the other RTO based on the other RTO's day-ahead shadow price. This is valuable provision because a constraint binding in the day-ahead market at the firm-flow entitlement level can be costly and inefficient for constraints that are not expected to bind in real time (or bind at a very low cost). Hence, we recommended that MISO work with PJM to develop procedures that would allow the RTOs to to achieve these savings by implementing procedures to exchange Firm Flow Entitlements (FFE) prior to the day-ahead market.

Status and Resolution: This recommendation has been addressed by MISO. In late January, MISO and PJM implemented revised JOA provisions for exchanging FFE in the day-ahead market. We will be assessing results of the new day-ahead coordination procedures in future reports.

2008-2: Develop provisions that allow non-dispatchable LMRs, BTMG and other emergency resources to set energy prices in the real-time market.

This recommendation addressed concerns that as the capacity surplus falls in MISO, the peak needs of the system will increasingly be satisfied by LMRs, BTMG, or emergency operator actions. If these resources and actions cannot set prices in the real-time market, MISO will be understating the marginal value of energy during these periods. Prices in these hours play a crucial role in sending efficient long-term economic signals to maintain adequate supply resources and to develop additional demand-response capability. Therefore, we recommended that MISO develop provisions to allow these actions and resources to set energy prices in the real-time market.

<u>Status and Resolution</u>: MISO made a FERC filing to implement this recommendation in May 2015. The solution MISO proposed would fully address this recommendation. FERC approved these provisions and implementation of the new software is expected July 1, 2016.[34]

2013-2: Improve allocation of VLR costs by identifying VLR commitments made by the DA market.

To satisfy a number of local reliability requirements in the MISO South region, MISO utilizes both the Multi-day Forward Reliability Assessment (MFRAC) and the Day-Ahead Commitment process. MISO's MFRAC process generally commits resources with longer startup times when necessary to meet the local reliability requirements. For all other resources, MISO relies on the day-ahead market to commit the necessary resources in these load pockets by modeling the local commitment constraints in each of these areas. Unfortunately, there is no way currently to tell why a resource committed through the day-ahead market was committed, so none of them are flagged as VLR commitments. To the extent that the local commitment constraints are binding and cause the commitment of resources that receive day-ahead RSG, these costs should be allocated locally. In 2014, we recommended that MISO develop a means to identify VLR commitments that are made through the day-ahead market so the related RSG costs can be allocated consistent with the VLR methodology.

34 See FERC Docket No. ER16-1577-000.

Status and Resolution: In 2014 and continuing through 2015, MISO made a number of incremental improvements to the VLR commitment process that has both reduced the amount of VLR RSG, and improved the identification and allocations of the RSG. We continue to recommend a long-run improvement to model the VLR constraints explicitly in the day-ahead market (See Recommendation 2015-3). However, the improvements made by MISO to date adequately address this recommendation.

2011-7: Implement a ramp capability product to address unanticipated ramp demands.

We have recommended and supported MISO's development of a ramp capability product to allow it to efficiently address ramp demands. This product is in lieu of a look-ahead dispatch process to address ramp demands that can be foreseen by MISO, and would also address unforeseen ramp demands associated with unit outages, changes in wind, and changes in "non-conforming" load. This product allows the real-time market can likely make low-cost tradeoffs to maintain a higher level of ramp capability. Because it would address unanticipated ramp needs, procuring ramp capability is valuable independent of a look-ahead dispatch process.

Status and Resolution: MISO implemented the Ramp Product in May 2016.

2014-4: Eliminate the SRPBC Hurdle Rate and collect any potential transmission costs that may be payable to SPP and other parties through a fixed charge.

The Southwest Power Pool ("SPP") filed a complaint in 2014 claiming that MISO should pay for unscheduled flows that MISO's dispatch causes on the SPP transmission system when MISO's subregional transfers exceed 1,000 MW. The Commission set the matter for hearing in March 2014, but allowed the SPP transmission charges to go into effect, subject to refund. In response, MISO established a dispatch constraint, known as the "Sub-Regional Power Balance Constraint" or "SRPBC" with a Hurdle Rate of $10 per MWh, to limit transfers to 1,000 MW except in cases when the transfers above 1000 MW are worth more than $10 per MW.[35] This framework inefficiently distorted MISO's commitment and dispatch because the SRPBC was not a physical constraint. The inefficient increase in congestion costs imposed on MISO customers were not

35 The Hurdle Rate is essentially a transmission demand curve (based on the expected transmission charges).

offset by any countervailing efficiency gains or cost savings in SPP. In the settlement discussions we recommended that MISO:

- Eliminate the Hurdle Rate by increasing the SRPBC limit from 1,000 MW to the full transfers allowable under the Operations Reliability Coordination Agreement ("ORCA");
- Structure any potential transmission payments as fixed payments that would not vary based on the transfers in any particular hour; and
- Negotiate increased entitlements for MISO on SPP's constraints under the market-to-market process that correspond to the transmission costs MISO agrees to pay.

Status and Resolution: In February 2016, MISO eliminated the SRPBC. The settlement includes a fixed payment that is based on historical usage.

2014-7: Reduce capacity requirements for local resource zones when capacity has been exported to a neighboring market.

The capacity clearing prices in Zone 4 in the 2015/2016 planning resource auction cleared at higher prices than all other areas in MISO due to the binding local clearing requirement. The binding of the local clearing requirement in Zone 4 was impacted by roughly 1,200 MW exported from Zone 4 to PJM. Many of these resources will continue to be dispatched by MISO and can be utilized to satisfy local requirements and manage congestion into the area. Yet, the current Tariff provisions required that the auction be cleared and prices be set as if these resources did not exist, which does not accurately reflect the true supply and demand conditions in the zone.

To address this concern, we recommended that MISO file Tariff revisions to treat local capacity exports as creating counter flow over the interfaces into the zone. This would cause the capacity to be replaced by the lowest-cost capacity from any area in MISO, rather than requiring that additional capacity be procured from within the zone.

Status and Resolution: On December 31, 2015, the FERC required MISO to implement this redcommendation as part of addressing the complaints surrounding the results of the 2015/2016 PRA for Zone 4. MISO filed Tariff language changes that implement the recommendation on January 29, 2016 as required by the Order.

2005-2: Expand the JOA to optimize the interchange with PJM and SPP to improve the inter-RTO price convergence.

We recommended that the RTOs allow participants to submit offers to transact within the hour if the difference between MISO's and PJM's real-time prices is greater than the offer price. This change would allow the interface between the markets to be more fully utilized and generate substantial savings by allowing lower-cost resources in one area to displace higher-cost resources in the other area. Additionally, it will improve reliability in both areas and avoid the types of shortages MISO experienced in 2013 that were in large part caused by poor utilization of the interface with PJM.

Status: This recommendation was originally proposed by the IMM in 2005 and MISO has been discussing options with PJM. PJM and the NYISO have developed Coordinated Transaction Scheduling (CTS). CTS allows participants to submit intra-hour interchange transactions with a spread bid price that the RTOs can strike transactions on a 15-minute basis when the spread in prices is sufficiently large (i.e. greater than a strike price).

On December 15, 2015, MISO and PJM filed proposed tariff changes to implement CTS with a requested effective date of March 1, 2017. The IMM filed comments supporting the CTS proposal, except for the fact that PJM plans to charge uplift costs and other fees to CTS transactions. This will reduce the effectiveness and efficiencly of the CTS results and we have requested that FERC mandate the elimination of these charges by PJM. Following implementation of CTS with PJM, we will be monitoring the results. Based on these results and pending the resolution of interface pricing issues with SPP, we will recommend that MISO will work toward implementation of CTS with SPP.

2013-1: Allocate real-time RSG costs only to harming deviations (pre- and post-notification deadline (NDL)).

MISO distinguishes between deviations that occur prior to the NDL and those that occur after it. Prior to this proposed change, real-time RSG was allocated to:

- Participants in the pre-NDL period who had net deviations that decrease supply (harming deviations); and

- All deviations in the post-NDL period -- both helping deviations (those that increase supply) and harming deviations (those that decrease supply).

In 2015, the we completed a study of post-NDL deviations, which showed that supply-increasing deviations do not cause RSG. In fact, they generally lower RSG overall and should therefore not be allocated real-time RSG.

Status and Resolution: In October 2015 we supported MISO's filing to implement this recommendation and FERC approved this filing in January 2016 in ER16-213.

2013-3: Improve the market-power-mitigation measure applicable to RSG payments.

Periods of chronic congestion occurred over the past year that required the repeated commitment of certain resources. In these cases, certain suppliers are often pivotal and can generate large increases in RSG payments without being mitigated. Based on our evaluation of these patterns, we found that the current Tariff provisions related to mitigation of RSG commitments made to manage congestion have not been fully effective. This is due in part to the fact that the conduct test is applied to each offer parameter individually (rather than evaluating the joint effect of changes in all offer parameters) and the impact test threshold is too large. MISO's newer RSG mitigation framework applied to VLR commitments is more effective because it utilizes a conduct test based on the aggregate as-bid production cost of a resource (which captures the joint impact of all of the resource's bid parameters). We recommended applying this framework to all RSG payments (but with a larger threshold than is applied to VLR commitments).

Status and Resolution: We worked with MISO to develop the necessary Tariff changes. MISO filed for these changes in the second quarter of 2015 and implemented in the revised software on June 30, 2015.