2014 STATE OF THE MARKET REPORT FOR THE MISO ELECTRICITY MARKETS

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Guide to Acronyms

AMP	Automated Mitigation Procedures
ARC	Aggregators of Retail Customers
ARR	Auction Revenue Rights
ASM	Ancillary Services Markets
BCA	Broad Constrained Area
BTMG	Behind-The-Meter Generation
CC	Combined Cycle
CDD	Cooling Degree Days
CMC	Constraint Management Charge
CONE	Cost of New Entry
CROW	Control Room Operating Window
CSAPR	Cross-State Air Pollution Rule
CT	Combustion Turbine
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
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 *2014 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 Midwest that encompass a geographic area from Montana to Michigan. In late 2013, MISO integrated the MISO South sub region covering portions of Texas, Louisiana, Mississippi, and Arkansas.

MISO operates competitive markets for energy, ancillary services, capacity, and financial transmission rights (FTRs) to satisfy the electricity needs of its market participants. These markets coordinate the commitment and dispatch of generation to ensure that resources are meeting system demand reliably and at the lowest cost.

The MISO markets establish prices that reflect the marginal value of energy at each location on the network. These prices facilitate efficient actions by participants in the short term (e.g., to dispatch resources and to schedule imports and exports) and efficient decisions in the long term (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 2014

The year was characterized by two distinct periods. The first quarter exhibited extremely cold weather and tight natural gas market conditions caused by the "polar vortex." The rest of the year was characterized by mild weather and historically-low natural gas prices, leading to less extreme system conditions and less volatile market outcomes, especially in the summer months. As a result, the market outcomes varied considerably throughout the year.

- Natural gas prices at Chicago City Gate rose 165 percent in the first quarter. After mid-March, natural gas prices were only slightly higher than in 2013, resulting in an annual increase of 44 percent.
- Natural gas prices in the South region did not exhibit the same level of price volatility as prices in the Midwest region, and rose just 16 percent in 2014.
- Energy prices in the first quarter of 2014 averaged $53.02 per MWh, over 80 percent higher than in the first quarter of 2013. Energy prices in the last three quarters averaged $35.29 per MWh, just 6 percent higher than the same period in 2013.

The strong relationship between energy and ancillary services prices and natural gas costs indicated by these results is expected in a well-functioning, competitive market because natural gas-fired resources were the marginal source of supply in most intervals in 2014.

In addition to natural gas price fluctuations, other variations in supply and demand also affected energy prices in 2014. Although load rose by one percent on an annual average basis, load levels were significantly different in 2014 than 2013.

- The extreme weather in the first quarter led to high winter loads that contributed to increased shortages and the volatile energy prices. These increased shortages explain why the average energy price, adjusting for fuel prices, was up 13 percent.
- However, mild summer temperatures in 2014 led to lower load levels in the remainder of the year. The annual peak of 115 GW occurred in August, significantly below the forecasted peak of 127 GW.

MISO operating actions to during the extreme conditions in 2014 highlighted again the shortcomings of the pricing models and effects of uncoordinated interchange scheduling. Extreme conditions on January 7 highlighted in this report indicate a continued need to reform energy and ancillary services pricing to reflect operating actions taken during emergencies. MISO has filed pricing changes that we believe will help lessen the pricing inefficiencies that can occur when emergency actions are taken. Efficient shortage pricing during tight operating conditions is essential in MISO for providing economic signals to support investment and maintenance of resources, in part because MISO's capacity market is not designed to provide the signals needed to maintain resource adequacy.

In addition to its impacts on overall energy prices, the tight market conditions during the Polar Vortex in the first quarter caused substantial increases in transmission congestion and ancillary services prices:

- Day-ahead congestion revenue increased 71 percent from 2013 to 2014 to total $1.44 billion. Roughly two-thirds of this increase is attributable to MISO's integration of the South Region.

MISO's does not collect congestion revenue associated with all of the congestion on its network because of unscheduled loop flows across MISO's network and the transmission entitlements granted to PJM. The total value of real-time congestion rose 53 percent in 2014 to 2.43 billion. The MISO energy and ancillary service markets generally performed competitively in 2014. Conduct of suppliers was broadly consistent with expectations for a workably competitive market, as indicated by the following two empirical measures of competitiveness:

- A "price-cost mark-up" compares energy prices based on actual offers to a simulated energy price based on competitive offer prices. Our analysis revealed the price-cost mark-up was 1.0 percent in 2014, which indicates that the MISO markets were highly competitive.

- The output gap is a measure of potential economic withholding. It rose considerably from 2013 levels from 0.1 percent to 0.58 percent of load. Even at this higher level, however, it continues to be relatively low. Consequently, market power mitigation measures were applied infrequently.

We recommend two changes to the MISO market rules to address local market power concerns observed in recent years that were not effectively mitigated under the existing market power mitigation measures.

- The first change addresses market power associated with transitory congestion that can enable a supplier to raise prices sharply. These conditions do not persist long enough for MISO to define a narrow constrained area (NCA) and, therefore, substantial local market power can be exercised when these conditions persist.

- The second change addresses local market power associated with reliability commitments that can allow suppliers to extract excessive Revenue Sufficiency Guarantee (RSG) payments. For 2014, the existing mitigation framework mitigated less than 14 percent of the $130 million in payments for offers above reference levels, indicating that the current mitigation measures have not been fully effective. Accordingly, we recommended changes to the mitigation framework for RSG that MISO filed at FERC in 2015.

B. Long-Term Economic Signals and Resource Adequacy

Market prices should provide signals that govern participants' long-run decisions (including investment, retirement, and maintenance decisions). Whether these signals are adequate can be measured by the net revenues generators receive in excess of their production costs.

- Net revenues in 2014 rose modestly from last year in most locations, but continue to be substantially less than the necessary to revenues to make new investment profitable in any area (i.e., the annual cost of new entry or "CONE").
- Net revenues were highest for combustion turbines in Texas because of periods of severe congestion into the WOTAB area and the associated higher prices that occurred in 2014.

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 currently prevailing capacity surplus. As the capacity surplus falls due to retirements and load growth, the economic signals will continue to be inadequate because of the shortcomings of MISO's current capacity market. This resource adequacy concern is likely to arise as environmental regulations, increasing wind output, and low natural gas prices accelerate the retirements of many coal-fired resources in the near future. MISO's most recent surveys indicate expected coal plant retirements of eight GW by April 2016, which would cause MISO to be capacity-deficient. Hence, it is important for resource adequacy provisions to facilitate an efficient capacity market that will provide the necessary economic signals to maintain an adequate resource base.

In the near-term, our assessment indicates that the system's resources should be adequate for the summer of 2015 if the peak conditions are not substantially hotter than normal.

- MISO estimates a planning reserve margin of 18 percent, which exceeds the planning reserve requirement of 14.8 percent.
- Incorporating a realistic performance from MISO's demand response (DR) capability and hotter than normal summer conditions, the MISO planning margin is below nine percent.

This margin should be sufficient to satisfy MISO's operating reserves assuming a typical level of forced outages of five to eight percent.

MISO implemented its Planning Resource Auction (PRA) for the 2013/2014 planning year. The PRA is an improvement over the former voluntary capacity auction because of its zonal requirements for capacity. For 2014/2015:

- The auction cleared at $16.75 per MW-day, which is about seven percent of CONE.
- Zone 1 was export-constrained and cleared at $3.29 per MW-day (i.e., the amount cleared in that auction is equal to the sum of the zone's obligation plus the export limit);
- The constraining 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 RAC and contributed to MISO's relatively low auction clearing prices for 2013/2014 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. The minimum capacity requirements and deficiency price set forth in Module E of the Tariff[1] 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. Moreover, we demonstrate that improving the performance of the capacity market by implementing a sloped demand curve will provide benefits to the states and the vertically-integrated utilities in the MISO region.

- The sloped demand curve will not raise the expected costs for most regulated LSEs who build capacity to ensure they will not be deficient.
- The sloped demand curve reduces risk for the LSEs by stabilizing the costs of having varying levels of surplus.
- A smaller share of the total capacity costs are borne by retail customers. Because wholesale capacity market revenues play an important role in helping the LSE recover

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

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.

Hence, we continue to recommend MISO work with its stakeholders to develop a sloped demand curve that would recognize that incremental capacity above the minimum requirement has value (i.e., improves reliability). This change would allow capacity prices to rise efficiently as capacity margins fall to accurately signal the value of capacity to both new investors and to suppliers considering environmental retrofits.

Finally, we also recommend that retired or suspended units be given more flexibility to participate in the MISO PRA by better coordinating the PRA and Attachment Y provisions. Also, to allow these units to be efficiently used for the portions of the year when they are most economic, we recommend MISO consider transitioning to a seasonal capacity market. Finally, we make two recommendations to improve the modeling of MISO's local capacity requirements.

PJM Capacity Market Barriers. The capacity market also suffers from barriers to efficient capacity trading with PJM. These include limits on access to cross-border capacity and certain requirements that a unit in MISO be "pseudo-tied" to PJM. The pseudo-tying of significant quantities of resources to PJM raises serious concerns that this will undermine the efficiency of MISO's dispatch. We recommend that MISO limit additional pseudo-ties and work with PJM to develop alternative procedures to ensure the delivery of capacity from MISO.

C. Transmission Congestion

MISO manages flows over its network to avoid overloading transmission constraints by altering the dispatch of its resources. This establishes efficient, location-specific prices that represent the marginal costs of serving load at each location given the congestion. These congestion costs arise in both the day-ahead and real-time markets. Day-ahead congestion costs collected by MISO are paid to financial transmission rights (FTR), represent the economic property rights associated with the transmission system. FTRs are acquired in the FTR 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 2014, the FTRs were funded at 97 percent. MISO has implemented improvements to the FTR markets to reduce underfunding. However, we recommend MISO:

- Allocating 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
- Allocating 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. 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 their allocation of FTR revenues. The above recommendations provide the following benefits:

- Provide incentives for transmission operators to schedule outages more efficiently – to limit their duration and take outages in periods that are least likely to severe congestion.
- Improve participants' ability to use FTRs to hedge congestion and facilitate forward transactions.
- Raise FTR revenues for transmission customers as FTR prices rise, which should more than offset the allocation of underfunding costs. Additionally, FTRs that are held by transmission customers (converted ARRs), which constitute most of the FTRs, will receive higher day-ahead congestion revenues.

Finally, we report on significant dispatch and pricing inefficiencies in managing external constraints that are activated when Transmission Line Load Relief (TLR) procedures are invoked. For example, in the vast majority of intervals in which others call a TLR and MISO incurred substantial congestion costs to provide relief, the constraint was not binding (i.e., the relief had no value). These constraints created excess costs for MISO's customers. Therefore, we recommend changes to reduce these costs and improve efficiency.

D. Day-Ahead Market Performance

Convergence of day-ahead and real-time energy prices is important because the day-ahead market coordinates most resource commitments, and because it is the basis for almost all energy and congestion settlements with participants.

- There was a 5.4 percent day-ahead premium in the energy markets in 2014, which is higher than in recent years. This occurred mainly in the first quarter and was the result of the volatile market conditions during the Polar Vortex.
- Price convergence was poor in MISO South early in 2014, which was likely due to inexperience with the market and volatile local congestion that occurred early in 2014.

Virtual transactions provided essential liquidity and improved the convergence of day-ahead and real-time energy prices. Cleared virtual transactions increased 22 percent in 2014, which was likely due in part to the improvements in RSG cost allocation that were implemented in early 2014. These changes reduced the inefficient allocation of RSG costs to virtual transactions.

Price convergence was worst at congested locations in 2014, as in prior years. Price-insensitive transactions continued to frequently be placed to establish an energy-neutral (balanced) position (offsetting virtual supply and demand at different locations) to arbitrage congestion-related price differences. These balanced positions are valuable in improving the convergence of congestion patterns between the day-ahead and real-time markets. However, participants cannot currently submit price-sensitive virtuals to take a balanced position, which unnecessarily increases the risk these positions. Accordingly, we recommend MISO develop a virtual spread product that would allow participants to take balanced positions price sensitively, which should improve the convergence of congestion between the day-ahead and real-time market.

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, and 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.

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 rather than being responsive to five-minute signals. 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 increased 19 percent in 2014, consistent with a comparable increase in price volatility. These payments would be substantially reduced if MISO settled with participants on a five-minute basis. Additionally, flexible resources would have received more than $35 million in higher net revenues and inflexible resources would have received lower net revenues under a five-minute settlement. These changes in settlements would provide much better incentives to follow dispatch instructions and, in doing so, would generate production cost savings for the system and improve reliability. Hence, we continue to recommend that MISO implement five-minute settlements for generators and external transactions. These settlement changes will improve

In addition, we have proposed improved uninstructed deviation thresholds to provide better incentives for generators to be flexible and perform well in following MISO's dispatch signals. In addition to improving the operation of the system, this change would have lowered DAMAP payments by 17 percent or $14 million in 2014.

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

- Day-ahead RSG payments increased from $2.4 million to $11.5 million per month.
  - Most of these costs are attributable with the integration of MISO South -- 80 percent were associated with VLR commitments in the South.
  - Not all of these costs were properly identified as VLR costs and MISO is working to better identify these commitments.
- Real-time RSG payments rose eight percent to $10 million per month. Most of this increase was due to higher fuel price and tight conditions in the first quarter. MISO made $80 million in real-time RSG payments in February and March alone.

F. External Transaction Scheduling and External Congestion

As in prior years, MISO remained a substantial net importer of power in 2014, importing an average of 3.9 GW per hour in real time. 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. MISO is working with PJM on such a proposal.

Interface pricing is currently impacted by a flaw involving the pricing of congestion in the interface prices. This flaw has caused both neighboring RTOs settling with physical transactions for the same relief on market-to-market constraints, which generally results in the participants being overcompensated and leads to substantial balancing congestion and FTR underfunding.

- We estimate this pricing flaw resulted in net overpayments by PJM of $45 million 2014 and over $90 million since 2012.
- For MISO, our estimate of overpayments is more modest – $7 million in 2014 and $15 million over the last three years.

We have been working with PJM and MISO on this issue. There is now a consensus on the problem, but not yet on a solution. We continue to recommend that MISO's interface prices include only the costs associated with its own transmission constraints and exclude the effects of all external constraints. PJM has also proposed a solution, but our analysis of PJM's proposed solution indicates that it would result in substantial inefficiencies and dissavings.

G. Demand Response

Demand response is an important contributor to MISO's resource adequacy and provides a number of other benefits to the market. MISO continues 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 GW of DR resources, which includes 4 GW of behind-the-meter generation. However, most of MISO's capability to reduce load 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 been working with its utilities 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:

- Developing a means to allow LMRs to set energy prices, which will become increasingly important as generating resources retire and MISO relies more heavily on LMRs under emergency conditions; and
- Modifying the emergency procedures to utilize its DR capability more efficiently.

H. Recommendations

Although the markets performed competitively in 2014, we make 22 recommendations in this report intended to improve the performance of MISO's markets. Of these recommendations, 15 were recommended in prior reports. This is not unexpected as many of them require both Tariff and software changes that can require years to implement. MISO addressed four of our prior recommendations in 2014 and early 2015, 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.[2]

[2] MISO's focus areas are:

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(s)	Recommendations	High Benefit	Feasible in ST
Energy Pricing and Transmission Congestion				
2008-2	3,7	Develop provisions that allow non-dispatchable LMRs, BTMG and other emergency resources to set energy prices in the real-time market.		✓
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.		
External Transaction Scheduling and External Congestion				
2012-3	4	Remove external congestion from interface prices to eliminate excess payments and charges to physical transactions.	✓✓	✓
2005-2	1,4	Expand the JOA to optimize the interchange with PJM and SPP to improve the inter-RTO price convergence.	✓	
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				
2013-2	1	Improve allocation of VLR costs by identifying VLR commitments made by the DA market.		✓
2010-11	1	Include expected deployment costs when selecting units to provide spinning reserves.		✓
Improve Dispatch Efficiency and Real-Time Market Operations				
2011-7	1,3	Implement a ramp capability product to address unanticipated ramp demands.	✓	
2012-12	1	Improve thresholds for uninstructed deviations.	✓	✓
2011-10	1,2	Implement procedures to utilize provisions of the JOA that would improve day-ahead M2M coordination with PJM.		
2012-16	1,3	Re-order MISO's emergency procedures to utilize demand response efficiently.		✓
2014-4	1,2,3	Eliminate the SRPBC Hurdle Rate and collect any potential transmission costs that may be payable to SPP and other parties through a fixed charge.	✓	
Resource Adequacy				
2008-11	7	Remove inefficient barriers to capacity trading with adjacent areas.		
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.		
2014-7	7	Reduce capacity requirements for local resource zones when capacity has been exported to a neighboring market.		✓

I. Introduction

As the Independent Market Monitor (IMM) for MISO, Potomac Economics is responsible for evaluating the competitive performance, design, and operation of wholesale electricity markets operated by MISO. In this *2014 State of the Market Report*, we provide 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 and a market for Financial Transmission Rights (FTRs). The energy markets are designed to facilitate an efficient daily commitment of generation, to dispatch the lowest-cost resources to satisfy the system's demands without overloading the transmission network, and to provide transparent economic signals to guide short-run and long-run decisions by participants and regulators. The FTR market allows participants to hedge the risks of congestion associated with serving load or engaging in other transactions.[3]

In 2009, MISO began operating as a balancing authority and introduced markets for regulation and contingency reserves, known collectively as Ancillary Services Markets (ASM), and a monthly spot market for capacity. Ancillary Services Markets jointly optimize the allocation of resources between energy and ancillary services products. This joint optimization also allows energy and ancillary services prices to reflect the opportunity cost tradeoffs between products, as well as shortages of both products. The capacity market was modified in 2013 as MISO introduced an annual Planning Reserve Auction (PRA) that better identifies locational capacity needs throughout MISO. Though an improvement, the PRA continues to reflect a poor representation of the demand for capacity (or planning reserves), which undermines its ability to provide efficient economic signals. In late 2013, MISO integrated the MISO South subregion covering portions of Texas, Louisiana, Mississippi, and Arkansas.

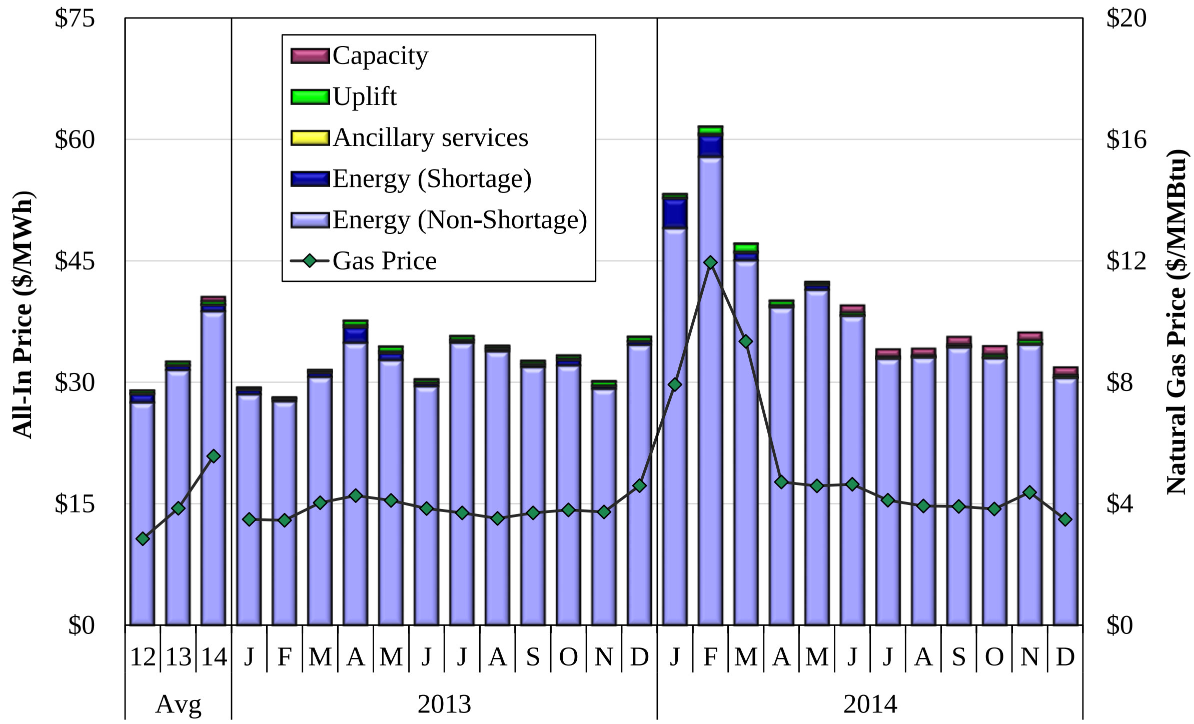
3 FTRs are financial instruments that entitle their holder to a payment equal to the congestion price difference between locations in the day-ahead energy market.

II. Prices and Load Trends

A. Market Prices in 2014

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 of electricity 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.[4] We separately show the portion of the all-in energy price that is associated with shortage pricing for one or more products.

Figure 1: All-In Price of Electricity
2013–2014



The all-in price in 2014 rose 25 percent from 2013 to average $40.60 per MWh. Most of this rise was attributable to extreme weather conditions that occurred in the first quarter that led to volatile natural gas prices, fuel availability issues, and high winter peak loads. During the "Polar Vortex" conditions that prevailed during the first quarter, natural gas prices often exceeded $10

4 Capacity costs prior to June 2013 are estimated by multiplying the VCA clearing price times the capacity requirements in each month. Thereafter, capacity costs equal the product of the PRA clearing price and capacity cleared.

per MMBtu and were 165 percent higher on average than during the first quarter of 2013. These conditions led to an increase in the all-in price of 84 percent for the first quarter, compared to only nine percent for the remainder of 2014. Conditions were relatively mild after mid-March as MISO experienced moderate summer temperatures.

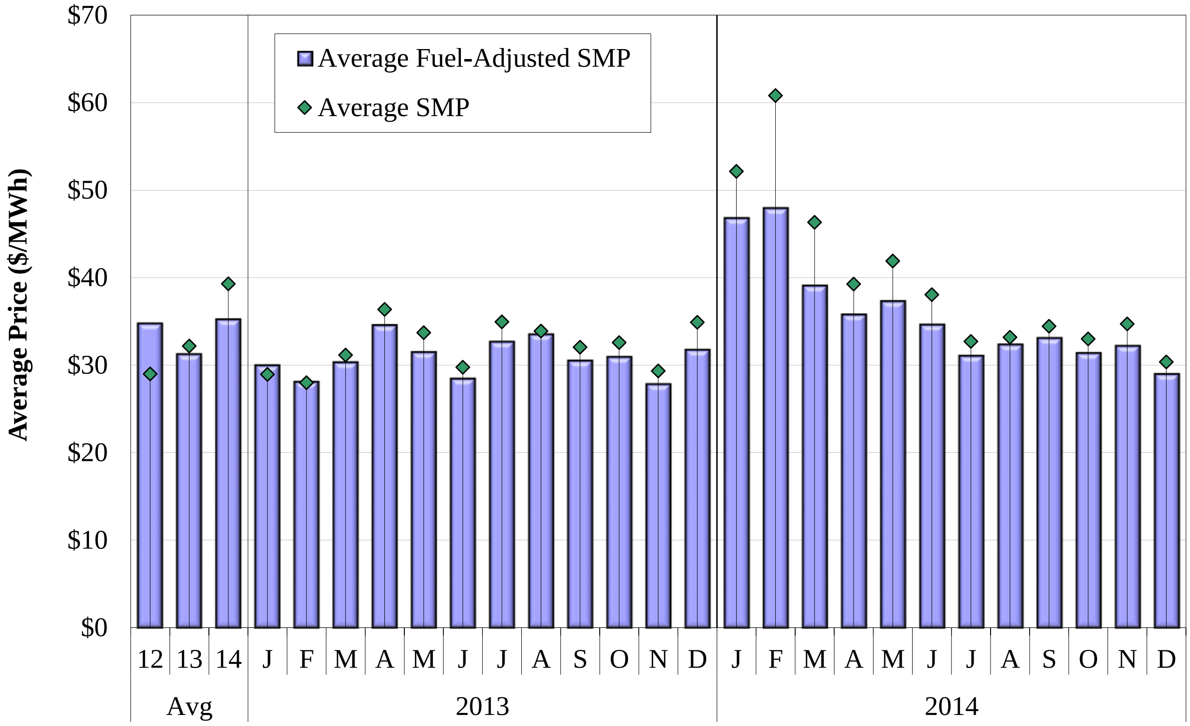
As in prior years, the energy component constituted nearly the entire all-in price, although slightly higher capacity prices for the 2014/2015 planning year added nearly $1 per MWh beginning in June and constituted approximately three percent of the all-in price during this period. The increase in the PRA clearing price reflects a narrowing capacity surplus, but capacity remains undervalued due to shortcomings to the PRA design. The most notable shortcoming is the lack of a sloped capacity demand curve. 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 retirements accelerate.

Uplift costs are costs incurred to meet system requirements that are not fully recovered in the day-ahead and real-time markets. They include Revenue Sufficiency Guarantee (RSG) payments and Price Volatility Make-Whole Payments (PVMWPs). Uplift costs rose with fuel prices to 40 cents per MWh, while ancillary services costs declined to just 12 cents. The decline occurred because ancillary services requirements were unchanged after the MISO South integration despite the far larger footprint and increase in capability (i.e., the same requirements are now being met with a substantially larger pool of resources).

The figure shows that energy price fluctuations continue to be strongly correlated with natural gas price movements. This correlation is expected in a well-functioning, competitive market because fuel costs represent the majority of most suppliers' marginal production costs. Since suppliers in a competitive market have an incentive to offer supply at marginal cost, changes in fuel prices should translate to comparable changes in offer prices.

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 SMP in 2014 rose 22 percent from 2013, while the fuel-adjusted SMP rose 13 percent. This indicates that non-fuel-cost factors contributed to nearly 60 percent of the rise in the SMP. The most notable non-fuel-cost factor was the extreme weather during the first quarter. These conditions increased load and decreased supply availability, which required more intensive use of high-cost resources than would occur under normal conditions.

Figure 2: Fuel-Adjusted System Marginal Price
2013–2014



B. Fuel Prices and Energy Production

The substantial changes in fuel prices and the integration of MISO South both resulted in changes in MISO's reliance on different types of generation. In particular, high natural gas prices in early 2014 tended to reduce MISO's output from natural gas-fired units, but integration of MISO South in December 2013 increased the share of MISO's capacity that is gas fired from 30 percent to 39 percent, and reduced share that is coal-fired from 57 percent to 46 percent. The

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

following table shows how these changes affected the share of energy produced by fuel-type as well as the generators that set the real-time energy prices in 2014.

Table 1: Capacity, Energy Output and Price-Setting by Fuel Type
2013–2014

	Installed Capacity (Summer)				Energy Output		Price Setting			
	Total (MW)		Share (%)		Share (%)		SMP (%)		LMP (%)	
	2013	2014	2013	2014	2013	2014	2013	2014	2013	2014
Nuclear	7,299	12,763	7%	9%	12%	16%	0%	0%	0%	0%
Coal	61,234	66,658	57%	46%	71%	58%	82%	75%	90%	90%
Natural Gas	32,415	55,852	30%	39%	8%	17%	17%	23%	30%	84%
Oil	2,391	3,125	2%	2%	0%	0%	0%	0%	2%	4%
Hydro	2,165	3,621	2%	3%	1%	1%	0%	0%	2%	2%
Wind	1,600	1,027	1%	1%	8%	6%	0%	1%	50%	48%
Other	610	564	1%	0%	0%	1%	0%	0%	2%	4%
Total	**107,714**	**143,610**								

The lowest-cost resources (coal and nuclear) produced most of the energy. Natural gas-fired units produced 17 percent of MISO's energy. This was more the double the share produced in 2013, but remains lower than the share of capacity that is gas-fired. The energy share was limited by the sharp rise in gas prices from $3.85 per MMBtu in 2013 to $5.53 in 2014.[6]

Although natural gas-fired units produce a modest share of the energy in MISO, they play an important role in setting energy prices. Natural gas-fired units set the system-wide price in 46 percent of all intervals from January to March and in 23 percent all intervals for the year, which tend to be the highest-load intervals. Congestion frequently causes natural gas-fired resources to be on the margin in a local area in the same interval that a lower-cost resource may be setting the system-wide price. Hence, natural gas set LMPs in local areas in 84 percent of all intervals, which underscores why natural gas prices continue to be an important driver of energy prices.

Despite the decline in its share of total generation to 58 percent in 2014, coal-fired resources set the SMP in 75 percent of all intervals in 2014. Western (Powder River Basin) mine-mouth coal prices rose $0.09 to $0.71 per MMBtu, but railway congestion often added considerable costs (as

6 This is the Chicago City Gate price, a representative pricing point for the Midwest region. At Henry Hub, representative for the South region, prices rose just 16 percent to $4.32 per MMBtu. We discuss the implications of this price separation in the Polar Vortex section II.D.

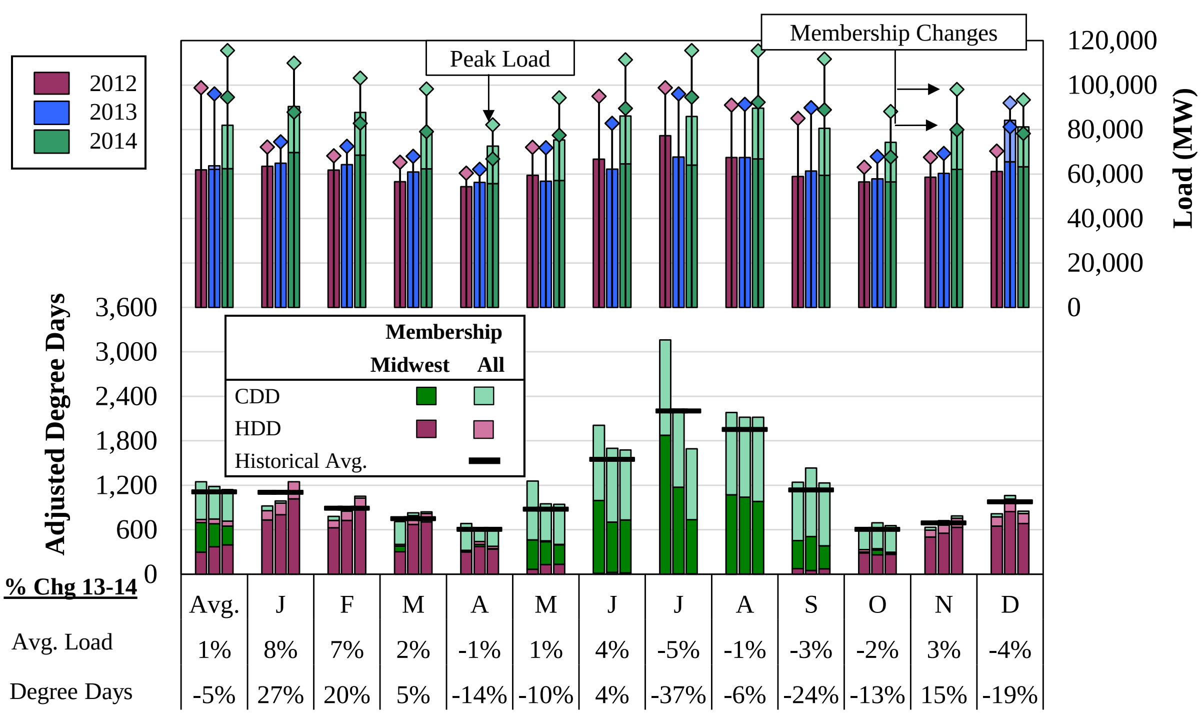
well as uncertainty) to this mine-mouth price. Eastern (Illinois Basin) mine-mouth prices rose four percent to $1.91 per MMBtu.

The capacity values in Table 1 are consistent with MISO's planning values, so they are derated from the nameplate capacity level by more than 13 GW. Since there is no wind in the South region, the output share from wind fell to six percent (although total output increased). Growth in wind capacity moderated due to expiring federal tax credits. Wind resources set LMPs in local areas in almost half of all intervals in 2014 as wind units were ramped down to manage congestion. The average price set by wind resources was $-11 per MWh, which tended to prevail in relatively limited areas.

C. Load and Weather Patterns

Long-term load trends are generally driven by economic and demographic changes in the region. However, short-term load patterns are determined by weather patterns. Figure 3 illustrates the influence of weather on load by showing the heating and cooling requirements together with the monthly average load levels over the past three years.

Figure 3: Heating and Cooling Degree Days
2012–2014



The top panel shows the monthly average load in the bars and the peak monthly load in the diamonds. The loads are shown for the Midwest region (for comparison to past years) and all of MISO (including MISO South). The bottom panel shows monthly Heating Degree Days (HDD) and Cooling Degree Days (CDD) summed across six representative locations in MISO.[7]

Total degree days in 2014 declined by five percent primarily because of mild summer conditions. In January to March, degree days were 15 percent above the historical average because of the sustained cold weather during the Polar Vortex. In contrast, the cooling degree days in July were more than one-quarter below the average (and roughly half of July of 2012). These factors largely offset and the average load in MISO increased by one percent in 2014 as economic activity continued to grow at a modest pace. MISO set its annual peak load of 114.9 GW on August 3, which was well below the expected "50/50" forecasted peak of 127.2 GW from its *2014 Summer Resource Assessment*. Hence, the mild summer conditions led to very few potential shortages or other tight operating conditions. However, the unusual winter conditions did contribute to volatile energy prices and shortages that are discussed in the next subsection.

D. Evaluation of First Quarter 2014 (Polar Vortex)

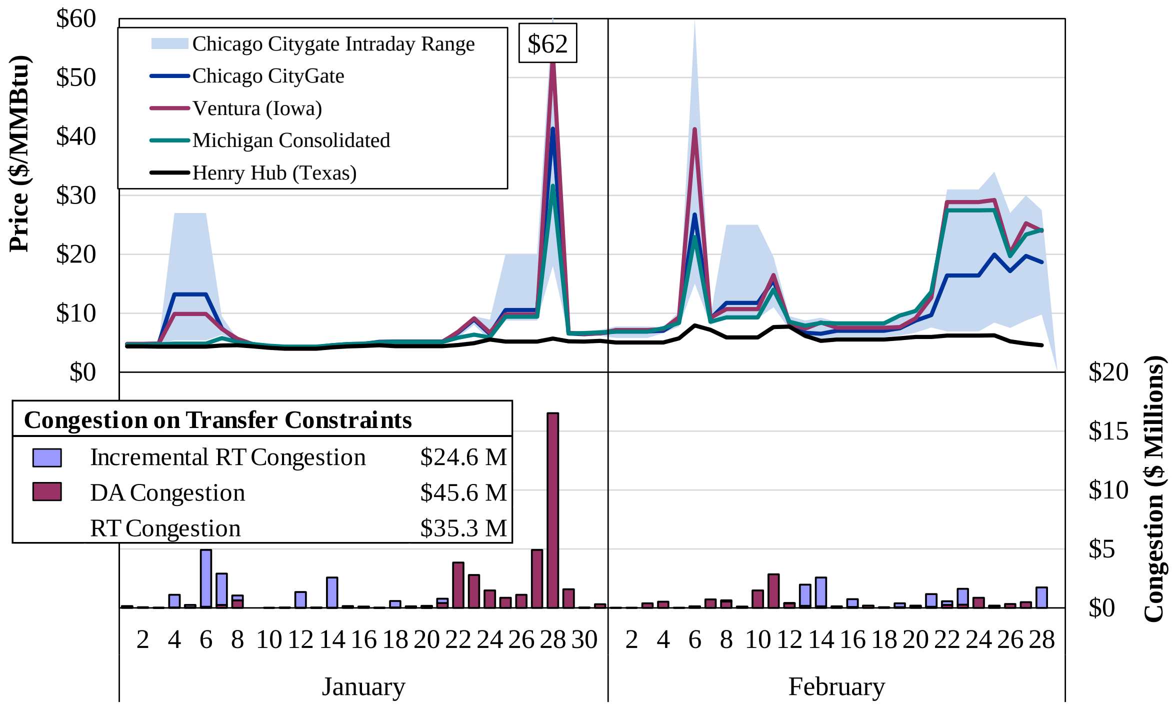
The Polar Vortex caused sharp increases in electricity demand and natural gas prices throughout the Eastern Interconnect, coupled with supply reductions due to natural gas curtailments. Together these changes resulted in shortages and sharply higher energy and operating reserve prices. Because the high gas prices were mostly confined to the Midwest region, MISO experienced substantial south-to-north of congestion driven by large fuel cost differences between the Midwest and South regions. The volatile gas prices in the Midwest also contributed to record levels of congestion and uplift in that region.

The next three figures more closely review market conditions and specific market events during the first quarter of 2014. The top panel in Figure 4 below shows daily natural gas prices at four locations in the MISO footprint in January and February. We separately show the intraday price range at Chicago Citygate, a representative price for many participants. This range is typically

7 HDDs and CDDs are defined using aggregate daily temperature observations relative to a base temperature (in this case, 65 degrees Fahrenheit). To account for the relative impact of HDDs and CDDs, HDDs are inflated by a factor of 6.07 to normalize their effects on load as estimated by regression analysis. The long-term average degree-days are based on data from 1971 to 2000.

small but can be large on peak winter days. The bottom panel shows congestion costs for four transfer constraints between the Midwest and South region. It shows total day-ahead congestion costs and "incremental real-time congestion" costs (measured as the product of real-time physical flow and the real-time shadow price) when it exceeds day-ahead congestion costs. This shows the extent to which the congestion is incurred in the day-ahead versus real-time market.

Figure 4: Daily Natural Gas Prices
January–February, 2014

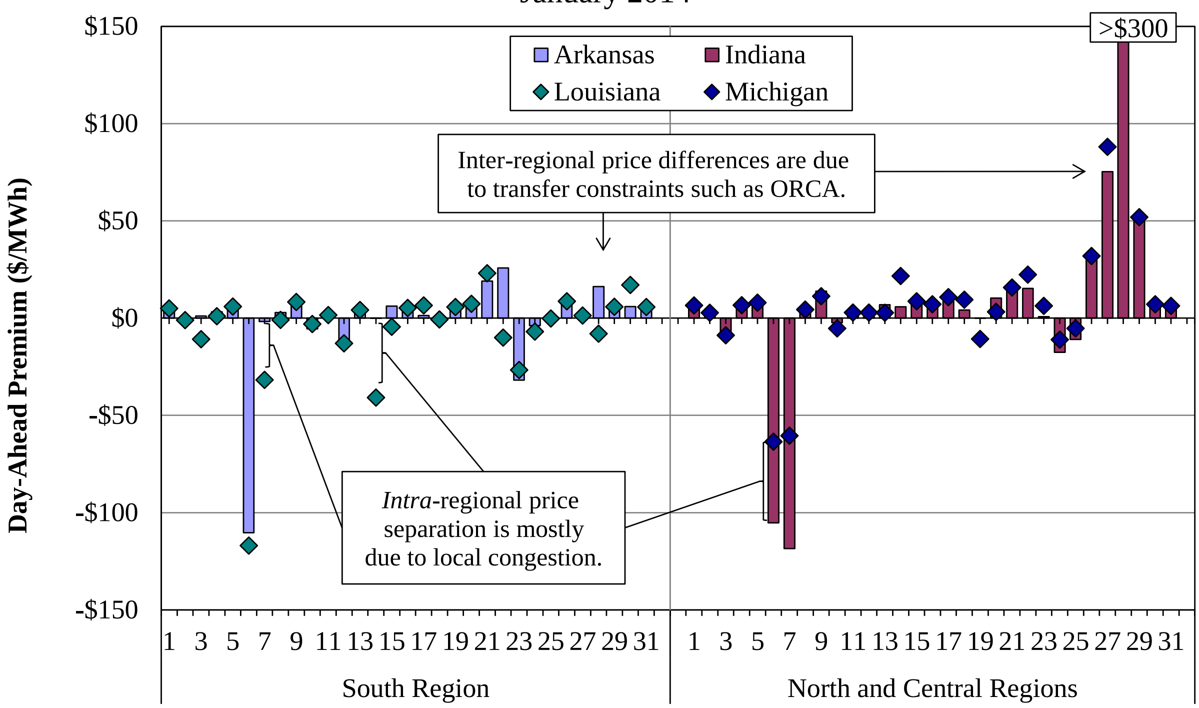


Natural gas prices in the Midwest region during the period shown in the figure averaged over $8 per MMBtu and occasionally exceeded $30. Some suppliers' natural gas costs were even higher because of off-take penalties. Marginal production costs of natural-gas-fired units in the Midwest Region were as much as 10 times higher than in the South Region on some days because of the regional gas price differences. These extreme cost differences contributed to net exports from the MISO South region and substantial associated congestion costs over the interregional transfer constraints. On several days, these constraints resulted in large price differences between the South and Midwest regions. On January 28 for example, prices were $200 to $300 per MWh higher in the Midwest than in the South for most of the day, which was almost entirely due to two severely binding constraints in TVA.

More broadly, the unusually high level of interregional and localized congestion caused by the natural gas price volatility during the Polar Vortex was often not accurately anticipated in the day-ahead market during this period. Figure 5 shows day-ahead/real-time price convergence during January. The bars in this figure show the average daily day-ahead premium at hubs close to the ORCA interface between the regions (Arkansas and Indiana). The diamonds show the premium at two hubs in constrained areas further away (Michigan and Louisiana). Hence, the bars show price convergence over the transfer constraints, while differences between a bar and a diamond are due to local congestion within the region.

Figure 5: Daily Price Convergence

January 2014



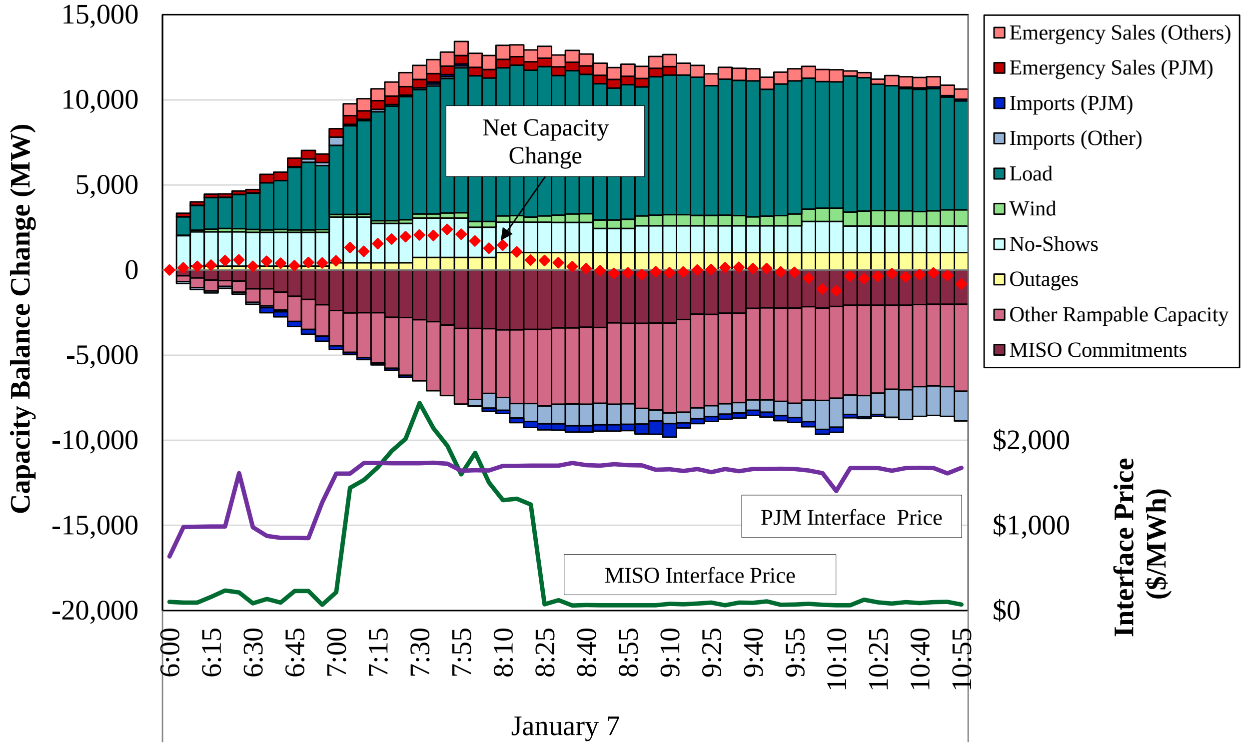
Inter-regional price separation was most significant in January. For example, when the entire Eastern Interconnect experienced some of its coldest temperatures of the winter on January 7, real-time prices were significantly under-anticipated by the day-ahead market. MISO set its all-time winter peak of 109.6 GW on the prior day. Price separation was also very significant in late January, when large fuel price differences between the two regions resulted in the most substantial congestion of the winter.

As mentioned above, January 7 was among the coldest and tightest days of the Polar Vortex period. MISO experienced shortages and real-time prices in excess of $2000 per MWh. In

Figure 6, we show the cumulative impact of the primary real-time supply-and-demand factors that affected the net capacity balance on the morning of January 7. These factors are: (1) net imports from PJM; (2) net imports from all other areas; (3) load, including any operator offset; (4) wind output; (5) capacity scheduled day-ahead that failed to start ("no-shows"); (6) large generator outages; (7) other rampable capacity; and (8) MISO unit commitments. We separately identify schedules to PJM and others that were approved due to emergency conditions.

In this analysis, factors that contribute to higher prices are shown as positive values (reductions in supply or increases in demand), while factors that reduce prices are shown as negative values. The net capacity change is shown by the red markers. All values are measured against their respective level at the start of the period shown.

Figure 6: Contributing Factors to Real-Time Prices
January 7, 06:00–11:00



On this morning, the scheduling of emergency energy to PJM contributed to MISO going into an operating reserve shortage that lasted for over an hour. MISO scheduled a cumulative 1,200 MW of emergency sales. The first 500 MW were appropriately scheduled, but the second 700 MW were scheduled at a time when 1.5 GW of MISO capacity was on forced outage or failed to start. At its deepest point, MISO was roughly 1,900 MW short of operating reserves and holding only 300 MW of reserves. MISO attempted to commit nearly all available resources and operated reliably through this event. However, the recognition of the shortage appeared to be late and the approval of the additional 700 MW in exports at 7:00 warrants review.

MISO's reliability mandate requires it to take emergency actions to maintain reliability and avoid shortages. When these actions are effective, market prices may not reflect the true costs of taking these actions and lower-cost options may be overlooked. The Extended Locational Marginal Pricing (ELMP), which began in March 2015, has improved MISO's real-time pricing by ensuring that online peaking resources set prices when they are marginal. Additionally, MISO has filed for Tariff changes that would utilize the ELMP model to allow emergency actions to set real-time prices. We also recommend that MISO evaluate its emergency actions to determine whether they are taken in the most efficient order. Currently, MISO cannot call demand response until it has exhausted almost all other emergency actions.

E. Long-Term Economic Signals

While price signals play an essential role in facilitating efficient commitment and dispatch of resources in the short term, they also provide long-term economic signals that govern investment (or retirement) of resources and transmission capability. This section reviews the long-term economic signals provided by the MISO markets. These economic signals can be evaluated by measuring the "net revenue" that a new generating unit would have earned from the market under prevailing prices. More precisely, net revenue is the revenue that a new generator would earn above its variable production costs if it ran when it was economic and did not run when it was uneconomic. A well-designed market should produce net revenue sufficient to finance new investment when available resources are insufficient to meet system needs. Figure 7 and Figure 8 show estimated net revenues for a hypothetical new combustion turbine (CT) and combined-cycle (CC) generator for the prior three years in various locations in the Midwest and South regions. For comparison, the figures also show the minimum annual net revenue that would be needed for these investments to be profitable (i.e., the "Cost of New Entry", or CONE).

Figure 7: Net Revenue Analysis
Midwest Region, 2012–2014

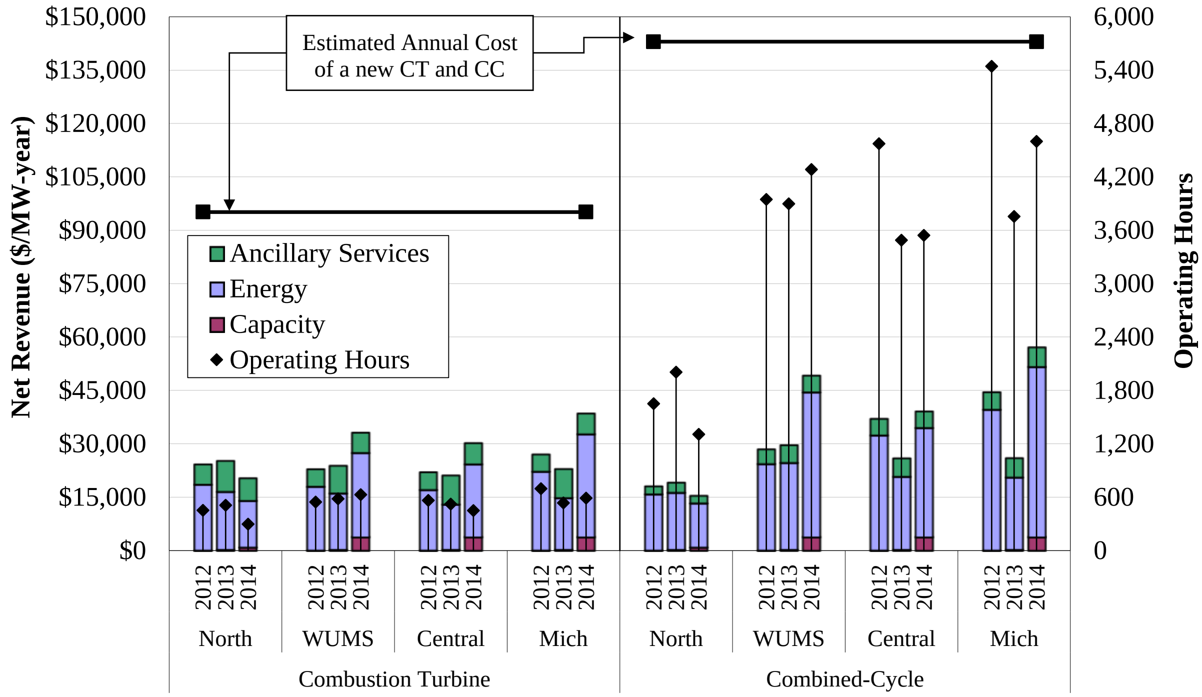
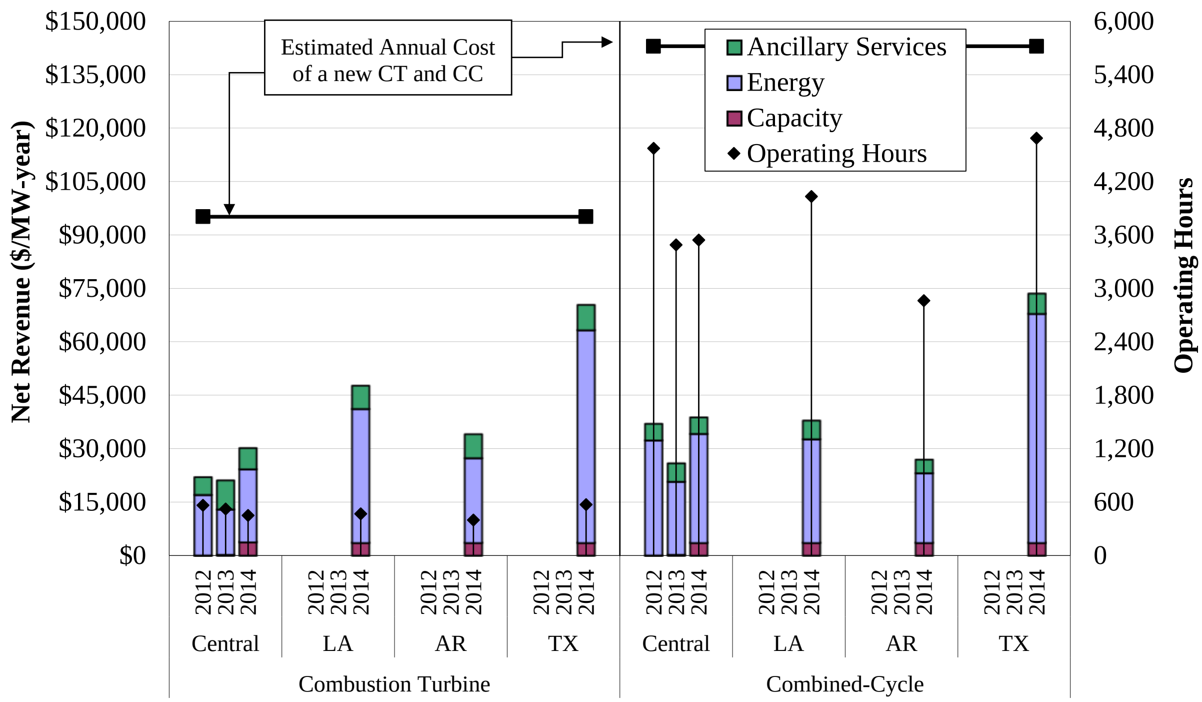


Figure 8: Net Revenue Analysis
South Region, 2012–2014



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 2014 because integration had not occurred.

Estimated net revenues in 2014 for both types of units rose modestly from last year in most locations, but continue to be substantially less than CONE in all regions. Net revenues were highest for combustion turbines in Texas because of periods of severe congestion into the WOTAB area that occurred in 2014. 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.

Despite recent improvements made to the Resource Adequacy Construct, capacity market design issues continue to undermine MISO's economic signals as MISO's capacity surplus dissipates. MISO may be short of capacity as soon as the 2016–2017 planning year, when increased retirements and capacity exports are projected to result in a capacity deficiency. The retirements are due to environmental regulations that will affect most of the coal-fired capacity in the Midwest region. Almost eight GW is expected to retire and an additional 1.4 GW is expected to convert to another fuel source. To address these inadequate price signals we recommend a number of improvements to both the energy market and the capacity market. The next section discusses the supply in MISO and evaluates the design and performance of the capacity market as it relates to ensuring the adequacy of MISO's resources.

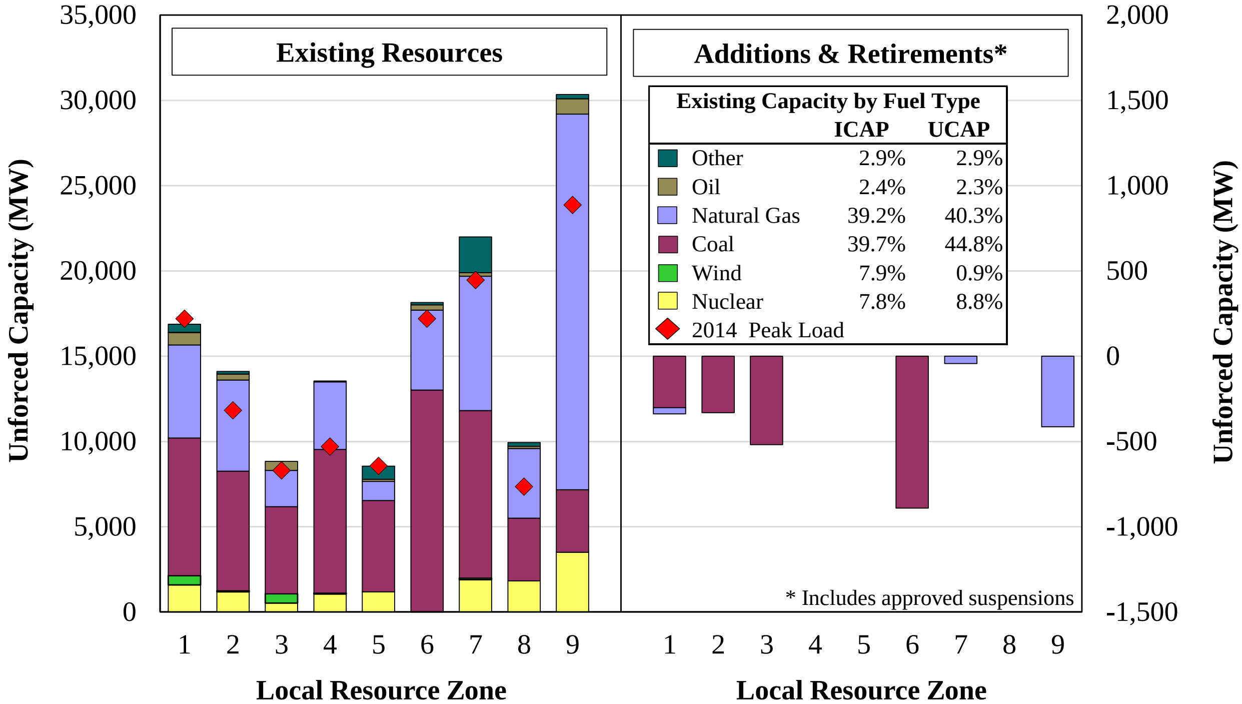
III. Resource Adequacy

This section evaluates the adequacy of the supply in MISO for the upcoming summer and over the long term. This evaluation includes an assessment of economic signals provided by MISO's markets that can play a critical role in facilitating the investment MISO needs to meet its resource adequacy needs.

A. Regional Generating Capacity

Figure 9 shows the summer 2015 capacity distribution of existing generating resources by Local Resource Zone. The left panel shows the distribution of Unforced Capacity (UCAP) by zone and fuel type, along with the 2014 peak load in each zone. The right panel displays the change in the generating capacity from last summer. The inset table breaks down total UCAP and Installed Capacity (ICAP) shares by fuel type.

Figure 9: Distribution of Generating Capacity
By Fuel Type and Zone, Summer 2015



UCAP values account for forced outages and intermittency and so are lower than ICAP values. Hence, wind capacity, although it makes up nearly eight percent of nameplate capacity, makes up less than one percent of UCAP.

Unforced capacity exceeded the 2014 peak load in all zones except Zone 1 (wind capacity is significant) and Zone 5. Because the average output from wind units in the West region is often greater than their UCAP credit, the western areas frequently produce substantial surplus energy that is dispatched to serve load in eastern areas. This pattern produces the west-to-east flows and congestion typically observed in the MISO markets. Wind growth moderated in 2014 due in part to the expiration of federal tax credits that were not renewed. Some wind units that may be eligible for tax credits may still be placed into service in the next couple of years, and lower construction costs and other incentives and mandates may result in new wind capacity being included in utility rate cases. Additional wind growth may also be supported in the coming years by the incremental completion of the Multi Value Project ("MVP") Portfolio, comprised of 17 transmission projects with regional benefits.

Roughly 2.5 GW of coal unit retirements are expected before summer 2015, but up to eight GW are expected by the summer of 2016 in response to environmental requirements. There are no new additions expected before summer. These trends and higher capacity exports to PJM are substantially reducing MISO's planning reserve margins as shown in the next subsection.

B. Planning Reserve Margins

This subsection assesses capacity levels in MISO and their adequacy for satisfying the forecasted peak loads for summer 2015. In its *2015 Summer Resource Assessment*, MISO presented baseline planning reserve margins alongside a number of valuable scenarios that show the sensitivity of the margins to changes in key assumptions. For example, MISO's *Assessment* includes a scenario that assumes hotter-than-normal peak conditions. This section includes our evaluation of MISO's planning reserve margins using the same capacity data. We have also worked with MISO to harmonize our assumptions so our Base Case planning reserve level is the same as MISO's.

However, we include some scenarios that 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 2015

		Alternative IMM Scenarios		
			High Temperature Cases	
	Base Case	Realistic DR	Full DR	Realistic DR
Load				
Base case	127,319	127,319	127,319	127,319
High Load Increase	-	-	6,280	6,280
Total Load (MW)	127,319	127,319	133,599	133,599
Generation				
Internal Generation	143,696	143,696	143,696	143,696
BTM Generation	4,413	4,413	4,413	4,413
Hi Temp Derates*	-	-	(4,900)	(4,900)
Adjustment due to Transfer Limit**	(3,834)	(3,834)	(3,834)	(3,834)
Total Generation (MW)	144,276	144,276	139,376	139,376
Imports and Demand Response				
Demand Response	5,938	4,750	5,938	4,750
Net Firm Imports	56	56	56	56
Margin (MW)	22,951	21,763	11,771	10,583
Margin (%)	**18.0%**	**17.1%**	**9.2%**	**8.3%**

Notes:
* Based on the available capacity on the three hottest days of 2012 and on August 1, 2006. Available capacity can vary substantially based on ambient air and water temperatures, and other factors.
** The MISO Base Case Reserve Margin assumes that 3,834 MW of capacity in MISO South cannot be accessed due to the 1000 MW Transfer Limit, which reduces the overall MISO Capacity Margin.

The first column in Table 2 show the MISO base case, which we believe reasonably reflects expected planning reserves. However, MISO's base case includes an assumption 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 instead are granted a 100 percent capacity credit. MISO has rarely deployed these resources, but its limited experience suggests a much 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 it 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 2013. 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 is 18 percent, which substantially exceeds the Planning Reserve Margin Requirement of 14.8 percent.[8] The high-temperature cases show much lower margins—as low as 8.3 percent when DR is also derated to a realistic level. This is significant because this margin must provide MISO's operating reserves (2,400 MW) and includes no forced outages, which generally range from five to eight percent. Hence, under these conditions, MISO would likely have to rely on non-firm imports and emergency actions to meet its system requirements.

Overall, these results indicate that the system's resources should be adequate for summer 2015 if the peak demand conditions are not substantially hotter than normal. However, planning reserve margins have been decreasing and will likely continue to fall as new environmental regulations are implemented. Therefore, it is important for the resource adequacy provisions to facilitate an efficient capacity market that will provide the necessary economic signals to maintain an adequate resource base. These issues are discussed in detail in the following three subsections.

8 The 2014 Planning Reserve Margin Requirement is for all of MISO. Due to the potential transfer limits from South to Midwest and Midwest to South, we have included the firm contract path limit of 1,000 MW in all scenarios. MISO has similarly included this in its Base Case.

C. Potential Impact of the New EPA Regulations

MISO continues to study and model the potential impacts of the environmental regulation on MISO markets. In previous years, we have discussed the challenges of major environmental initiatives by the U.S. Environmental Protection Agency (EPA) including 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 pressure older coal units into retirement or high-cost retro-fits to mitigate the emissions and other environmental effects.

The environmental regulations will continue to affect MISO planning and operations, especially with respect to coal-fired resources. The most recent EPA initiative, called the Clean Power Plan, will involve far-reaching impacts that likely exceed the individual impacts of any previous initiative. MISO has studied the combined impact of these first three EPA initiatives and project approximately eight GW of coal capacity to retire.[9] Additionally, MISO projects retirements associated with the Clean Power Plan of up to 14 GW.[10]

The EPA released the drafted Clean Power Plan in 2014 and the final rule is expected June 2015. The Plan directs states to file individual compliance plans by June 2017 at the latest. These plans are required to specify a range of emission mitigation efforts that could include higher generator efficiency; more frequent dispatch of lower-emitting units (like CCGTs); higher penetration of renewable resources; and energy demand reduction. The overall objective is to cut CO_2 emissions by 30 percent (from 2005 levels) by 2030. While the rules require individual state plans, they envision and encourage regional coordination. The states have flexibility to coordinate with other states to meet their individual goals. For example, they could pursue a cap-and-trade system encompassing multiple states.

The MISO's preliminary studies of the Clean Power Plan indicates that coal-fired resources would be impacted significantly. Coal-fired resources as a percentage of MISO energy output change from 56 percent in the "business as usual case" to between 33 percent and 40 percent, depending on the approach taken by the states. The ability to trade emission allowances allows

9 See "Long-Term Resource Adequacy Update," MISO Presentation to the MISO Board of Directors System Planning Committee, October 22, 2014.

10 See "GHG Regulation Impact Analysis – Initial Study Results," MISO Presentation to Stakeholders, September 17, 2014.

the region to exploit the most efficient sources of emissions reductions and minimize the costs of complying with the CPP. Nonetheless, we anticipate that the CPP will substantially affect the supply in MISO.

Together with the increased penetration of wind resources and sustained low gas prices, the EPA regulations will continue to put substantial economic pressure on less efficient coal resources to retire, which should reduce planning reserve margins in MISO. These retirements, together with the increase in capacity exports to PJM, are causing MISO to forecast a need for additional resources to satisfy MISO's planning needs in the 2016-2017 planning year. The shortcomings in MISO's current RAC, namely the modeling of the demand in the Planning Reserve Auction, will prevent it from performing the key role of providing efficient incentives to resolve this capacity deficiency and supporting reliable planning reserve margins over the long term. Hence, addressing these shortcomings continues to be a high-priority recommendation.

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 are currently 12 units classified as SSR that are eligible for up to $6.1 million in gross cost recovery per month. An additional 10 units are under consideration for SSR status by MISO. We will continue to work with MISO on reviewing and, as needed, clarifying these procedures in order to ensure that SSR decisions result in efficient outcomes. Additionally, as retirements accelerate, it is very important that the capacity market and the Attachment Y and SSR process are well aligned to allow the market to facilitate reasonable retirement decisions and capacity market outcomes. These issues are discussed in the following subsection.

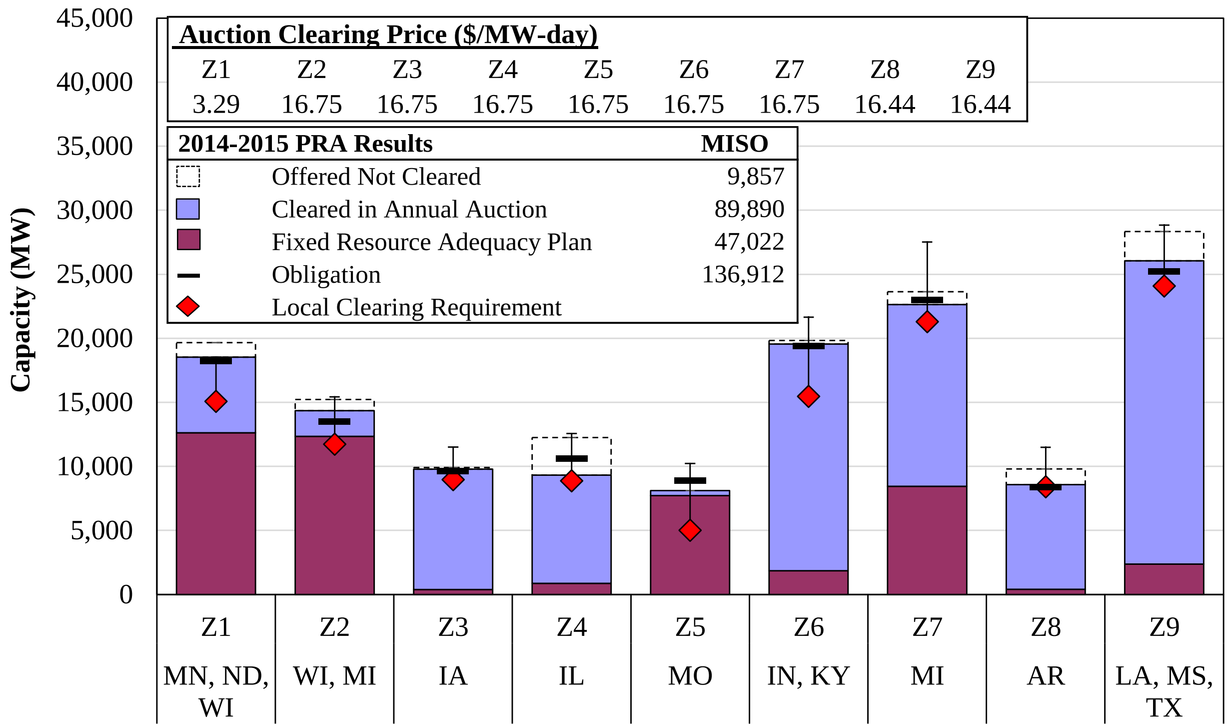
E. Capacity Market

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. 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 10 shows the combined outcome of the PRA auction held in April 2014 for the 2014-2015 Planning Year.

Figure 10: Planning Resource Auctions
2014–2015 Planning Year



The figure shows the obligation in each zone, along with the minimum and maximum amount of capacity that can be purchased in each zone. The obligation is set by the greater of the system-wide planning reserve requirement or the local clearing requirement. The minimum amount is the local clearing requirement which is equal to the local resource requirement minus the maximum level of capacity imports. The maximum amount is equal to the obligation plus the maximum level of capacity exports. The auction for the 2014–2015 planning year cleared at $16.75 per MW-day, which is about seven percent of CONE. Zone 1 was export-constrained and cleared at $3.29 per MW-day (i.e., the amount cleared in that auction is equal to the sum of the zone's obligation plus the export limit), while the constraining 1,000 MW transfer limit between the Midwest (Zones 1-7) and South (Zones 8 and 9) regions resulted in a slightly lower clearing price in MISO South.

2. Capacity Market Design

The performance of the capacity market under the PRA is undermined by four significant issues: (1) the current "vertical demand curve"; (2) barriers to capacity trading with PJM; (3) barriers to participation in the auction affecting units with suspension or retirement plans impacting the planning year; and (4) the local resource zones do not adequately reflect transmission limitations.

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.[11] 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 may become particularly acute as planning reserve margins decline toward the minimum requirement level with the likely retirement of significant amounts of coal-fired capacity in MISO as soon as the 2015–2016 planning year.

Load-serving entities and their ratepayers should benefit from a sloped demand curve. LSEs in the Midwest have generally planned and built resources to achieve a small surplus on average 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.

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 assume: (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)

11 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.

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 (around the 1.5 percent market 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. Under the three percent case, for example, the current market would produce almost no wholesale capacity revenue even though the LSE's surplus is improving reliability for the region. Under the sloped demand curve in this case, almost half of the costs of the new unit would be covered by the capacity market revenues.

Hence, although a sloped demand curve could increase costs to non-vertically integrated LSEs that must purchase large quantities of capacity through an RTO's market, the example above shows that this is not the case 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).

Capacity Deliverability

The second issue with MISO's current capacity market is the prevailing barriers to capacity trading between PJM and MISO. Capacity prices in both markets will only be efficient if participants can freely import and export capacity to arbitrage capacity price differences between markets to the extent that the physical transmission capability allows. Current barriers include a variety of PJM provisions that limit access to transmission, as well as the obligations imposed on external resources that sell capacity into PJM.

We described these barriers in detail in a number of prior filings to FERC, including comments filed in a recent technical conference FERC held to address capacity market issues in the Northeast, and two sets of comments filed in response to PJM's proposal to introduce Capacity Import Limits (CILs) that would further restrict the ability of external suppliers to export capacity to PJM. We believe the CILs could be a long-term solution to this issue if they are set at reasonable levels and if they replace (rather than supplement) the other barriers to efficient capacity trading. For example, PJM and MISO could eliminate unit specific deliverability testing and point-to-point firm transmission requirements, and treat all resources as fungible up to the CIL. This would be an efficient means of facilitating capacity deliverability, and would only require coordinated rules to enforce capacity requirements and ensure the delivery of firm energy when the importing RTO calls for its capacity.

One deliverability issue in particular that raises substantial economic and reliability concerns is PJM's promotion of pseudo-tying arrangements as a means to satisfy PJM's capacity obligations. A pseudo tie in this case would cause the external capacity resource to be dispatched by PJM. However, it is unnecessary and undesirable to have an external capacity resources pseudo tied because it will cause an array of flows over the transmission system of the RTO where the unit is located that will be impossible to manage efficiently. We know of no compelling reason to require pseudo tying over a regime that would ensure firm delivery of energy to the importing RTO. We continue to recommend that MISO work with PJM to make progress in these areas and address barriers to inter-RTO capacity transactions.

Coordination with Attachment Y Process

The third issue with MISO's current capacity market relates to the Attachment Y process for suspending or retiring resources. The current market includes inefficient barriers to participation in the PRA for units in suspension or those that have filed under Attachment Y to suspend or retire a resource. These barriers include:

- Suspended units are disqualified from the PRA; and
- Resources that have submitted Attachment Y filings for retirement with effective dates during the planning year lose their interconnection rights and cannot satisfy their capacity obligations after the effective date.

In both cases, the PRA should be a process that assists suppliers in making efficient decisions regarding its resource, including whether to bring it back from suspension or to retire or suspend the unit. In order to do this, MISO would need to modify the PRA rules to allow:

- Suspended units to participate in the PRA and to defer the required testing in the same manner that new resources or units with catastrophic outages can defer such testing.
- 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 suspension, or to b) retire or suspend the unit during the planning year if MISO determines it is not needed during the period when it would be unavailable. Without this flexibility, such units would have to arrange for substitute capacity for the balance of the planning year and would be out of compliance with the Tariff if they are unable to do so. 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, the remainder of the obligation will also terminate without a replacement requirement.

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 Issues

The fourth 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.

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. Resources cleared in the day-ahead receive commitment and scheduling instructions based day-ahead results and must perform these contractual obligations or be charged the real-time price for any products not supplied. Both the day-ahead and real-time markets continued to perform competitively in 2014.

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

- Because most generators in MISO are committed through the day-ahead market, good market performance is essential to efficient commitment of MISO's generation;[12]
- Most wholesale energy bought or sold through MISO's markets is settled in the day-ahead market; and
- Entitlements of firm transmission rights are determined by day-ahead market outcomes (i.e., payments to FTR holders are based on day-ahead congestion).

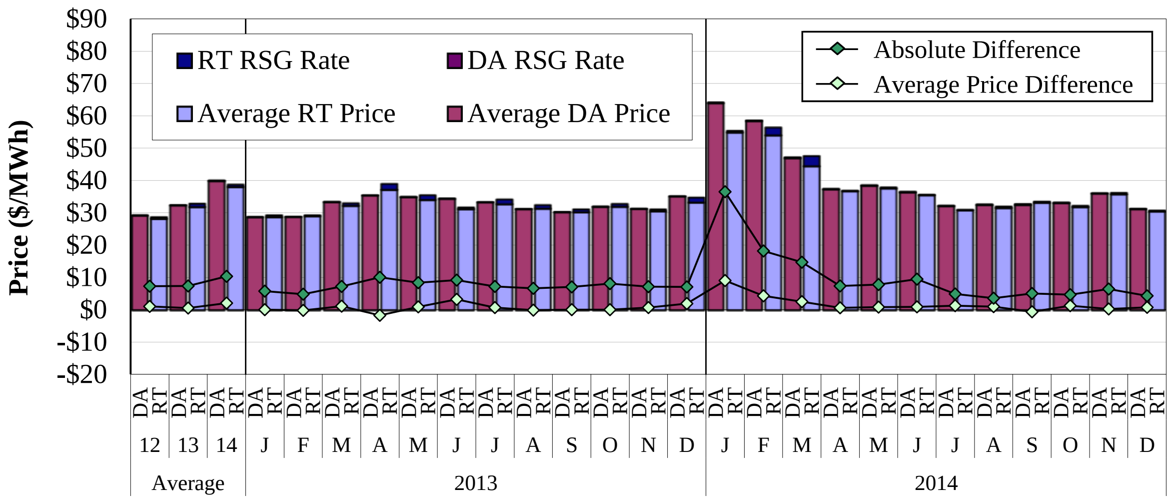
A. Price Convergence with the Real-Time Market

Day-ahead market performance is primarily evaluated by the degree to which its outcomes converge with those of the real-time market because the real-time market reflects actual physical supply and demand for electricity. Participants' day-ahead market bids and offers should reflect their expectations of market conditions for the following day. However, a number of factors, such as wind output volatility, forced generation or transmission outages, and load forecasting 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).

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

Figure 11 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. Because real-time RSG charges tend to be much larger than day-ahead RSG charges, the table shows the average price difference adjusted to account for the difference in RSG charges.

Figure 11: Day-Ahead and Real-Time Prices
2013–2014



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

Indiana Hub	1	-1	3	-2	-2	1	-9	-1	9	-2	-4	-3	-2	0	1	16	4	-1	2	2	3	4	2	-2	3	0	2
Michigan Hub	2	-1	7	-1	1	3	-10	-3	5	-5	-3	-4	-2	3	3	25	7	26	-1	2	-5	4	3	-2	3	0	2
Minnesota Hub	-4	-4	1	1	3	1	-11	2	0	-6	-8	-4	-6	-10	-6	16	-9	-5	-3	3	4	1	3	0	3	4	-5
WUMS Area	-2	-1	2	-1	3	1	-9	-3	4	-2	-6	0	-1	5	-1	19	-2	-1	-3	3	0	2	2	-5	1	3	1
Arkansas Hub			-4												1	-12	-16	-20	1	4	10	5	2	-4	-1	3	2
Louisiana Hub			-6												-1	-22	-14	-19	-12	11	1	4	3	-4	2	2	4
Texas Hub			-1												3	-6	-14	-13	-4	-6	31	3	5	2	1	2	5

Day-ahead premiums in 2014 averaged 5.4 percent, considerably more than in previous years. The volatile conditions during the Polar Vortex periods significantly impacted price convergence in the first quarter. Real-time price volatility related to interregional constraints, including the ORCA transfer constraints and TVA and SPP external constraints, produced very large day-ahead premiums in the Midwest region and real-time premiums in the South region. This was most severe on days with higher gas prices in the Midwest than in the South region. Significant congestion in the northern locations in February and March caused price convergence at the Minnesota Hub to deviate from this general pattern.

Convergence was poor at the Michigan Hub in February and early March. Convergence was exacerbated by under-anticipated real-time congestion into the area. Natural gas prices were far higher and more volatile in southeast Michigan due to operational flow orders, flow restrictions, and penalties on distribution pipelines. Commitments in both markets to manage the associated congestion required tens of millions of dollars in RSG payments, less than a third of which were allocated under the CMC rate.[13]

From late May to early June in the WOTAB load pocket, outage-related congestion caused poor convergence. As a result, there were considerable real-time premiums in May and day-ahead premiums in early June at the Texas Hub.

Market conditions were far less volatile after the spring. There was a modest day-ahead premium at most locations in most months. The 5.4 percent day-ahead premium was reduced to 3.4 percent when accounting for RSG costs allocated to real-time deviations from day-ahead purchases. Over the long term, we expect day-ahead load to pay a small premium (net of RSG costs) because scheduling load day ahead limits the price risk associated with higher real-time price volatility.

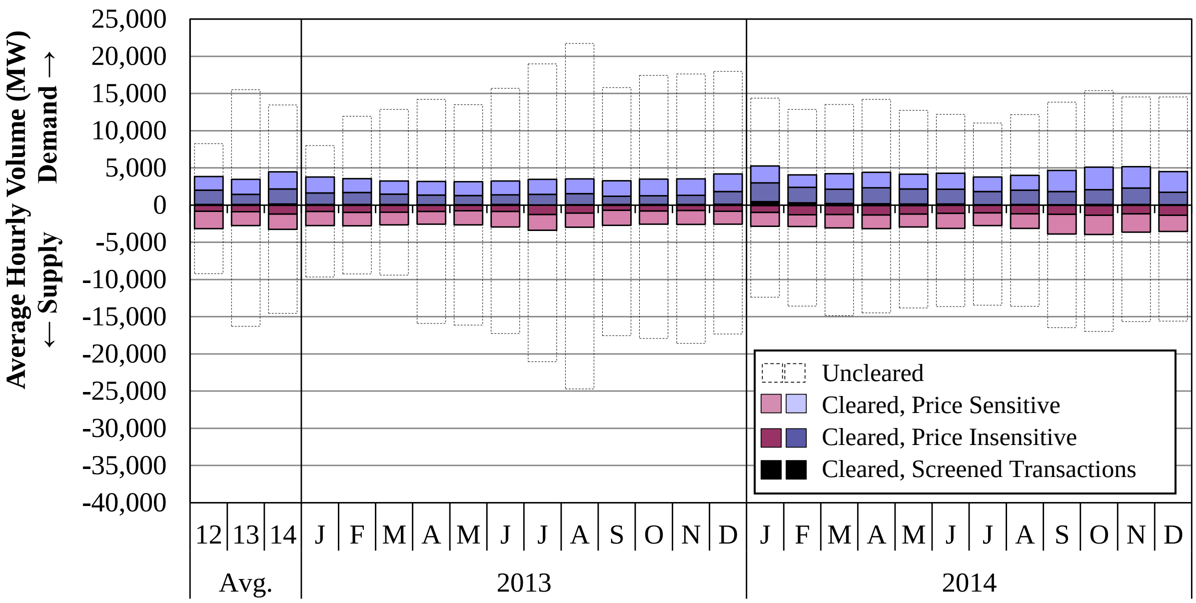
B. Virtual Transactions in the Day-Ahead Market

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 12 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 2013 and 2014. The virtual bids and offers that did not clear are shown as the transparent areas.

13 FERC-approved changes to the RSG allocation methodology in March 2014 would have allocated two-thirds of these costs under the CMC rate, which would have been a more efficient result.

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 they are offered at more than $20 above (demand willing to buy much higher than) and below (supply willing to sell much lower than) an "expected" real-time price.[14] 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 12: Virtual Load and Supply in the Day-Ahead Market
2013–2014



Percent Screened

	12	13	14	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Demand	2.2	2.2	3.6	2.8	2.2	2.4	1.8	2.2	2.7	1.0	1.5	2.3	2.4	2.3	2.5	8.9	7.9	5.3	4.3	3.4	3.5	1.8	2.0	1.2	2.0	1.9	1.2
Supply	1.4	1.2	1.6	1.1	2.0	1.5	1.2	1.4	1.2	0.4	0.5	1.2	1.4	1.8	1.3	2.1	2.7	2.7	1.9	2.0	1.6	0.9	0.2	0.7	1.6	1.4	1.1
Total	1.9	1.8	2.7	2.1	2.1	2.0	1.5	1.8	2.0	0.7	1.0	1.8	2.0	2.1	2.1	6.5	5.7	4.2	3.3	2.8	2.7	1.4	1.2	1.0	1.9	1.7	1.2

The figure shows that offered volumes declined by 14 percent from last year largely because one participant ceased submitting "backstop" bids, which are offered well above (in the case of demand) or below (supply) the expected price range. Backstop bids and offers clear less than

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

one percent of the time, but are substantially profitable when they clear. These transactions are beneficial because they mitigate particularly large day-ahead price movements.

Cleared transactions rose 22 percent to 7.7 GW per hour, which is consistent with the expansion of the MISO footprint after MISO South integration. Financial participants, which tend to offer more price-sensitively than physical participants, offered and cleared a much larger share of transactions than in prior years.

The share of Screened Transactions rose to 2.7 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 2014.

Price-insensitive transactions overall continued to constitute a substantial share of all virtual transactions. These transactions occur for two primary reasons:

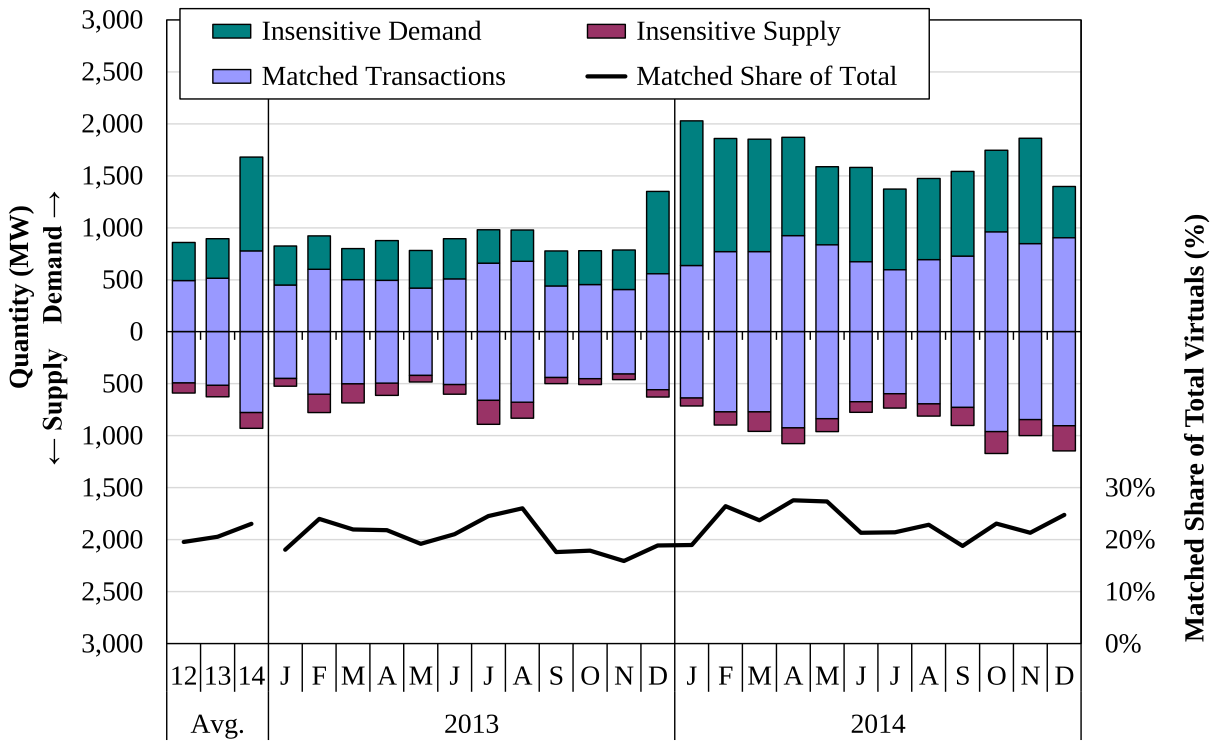
- To establish an energy-neutral position across a particular constraint to arbitrage congestion-related price differences between the day-ahead and real-time markets; and
- To balance the participant's portfolio so as to avoid RSG deviation charges assessed to net virtual supply.[15]

Figure 13 examines more closely these insensitive virtual transactions. "Matched" virtual transactions in the figure are a subset of these transactions whereby the participant clears both insensitive supply and insensitive demand that offset one another in a particular hour.

This figure shows that 60 percent of insensitive transactions and 23 percent of all virtual transactions were "matched" transactions. 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. Therefore, we are recommending that MISO continue to engage in stakeholder discussions to pursue a virtual spread product.

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.

Figure 13: Matched Virtual Transactions
2013–2014



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 rose from $1.01 per MWh in 2013 to $1.47 per MWh in 2014. Profits were highest during the Polar Vortex—55 percent of profits occurred in the first quarter of 2014. This is because there are greater arbitrage opportunities during periods with significant congestion. Profitability after March averaged $0.86 per MW, slightly lower than profitability during the same period in 2013.

Supply profitability averaged \$2.76 per MW, although 40 percent (\$0.71 per MW) was offset by real-time RSG costs allocated to net virtual supply under the DDC rate. Supply profitability never exceeded \$2 per MW after April. Demand profitability was lower at \$0.53 per MW, which reflects the moderate day-ahead premium observed in MISO and the fact that it is generally considered a "helping deviation" and, therefore, is not allocated real-time RSG costs. Low virtual profitability is consistent with an efficient day-ahead market, which is important because it coordinates the daily commitment of MISO's resources.

Transactions by financial-only participants in 2014 continued to be considerably more profitable (\$1.81 per MW) than those by generation owners and load-serving entities (\$-0.91 per MW), 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.

D. Fifteen-Minute Day-Ahead Scheduling

The day-ahead market currently clears on an hourly basis. As a result, all day-ahead schedule changes occur at the top of each hour. In hours when load is ramping rapidly, the hourly changes in day-ahead load (and scheduled supply to satisfy that load) are not well correlated with the changes in real-time load.

Many participants in the real-time market attempt to match their day-ahead schedules, which can cause severe ramp demands at the top of the hour and can contribute to transitory operating reserve shortages and inflated production costs during these periods. Ramp demands are caused by unit commitments, de-commitments, and changes to physical schedules that are all concentrated at the top of the hour. Solving the day-ahead market more frequently would result in more flexible commitments and schedules that could better align with actual ramp demands in real time. Computer hardware performance limitations previously prevented MISO from adopting such a granular day-ahead market. However, performance has improved significantly over time and should continue to improve in the future. Therefore, as MISO considers its longer-term market improvements and priorities, we recommend it evaluate the costs and benefits of modifying the day-ahead market to clear on a fifteen-minute basis.

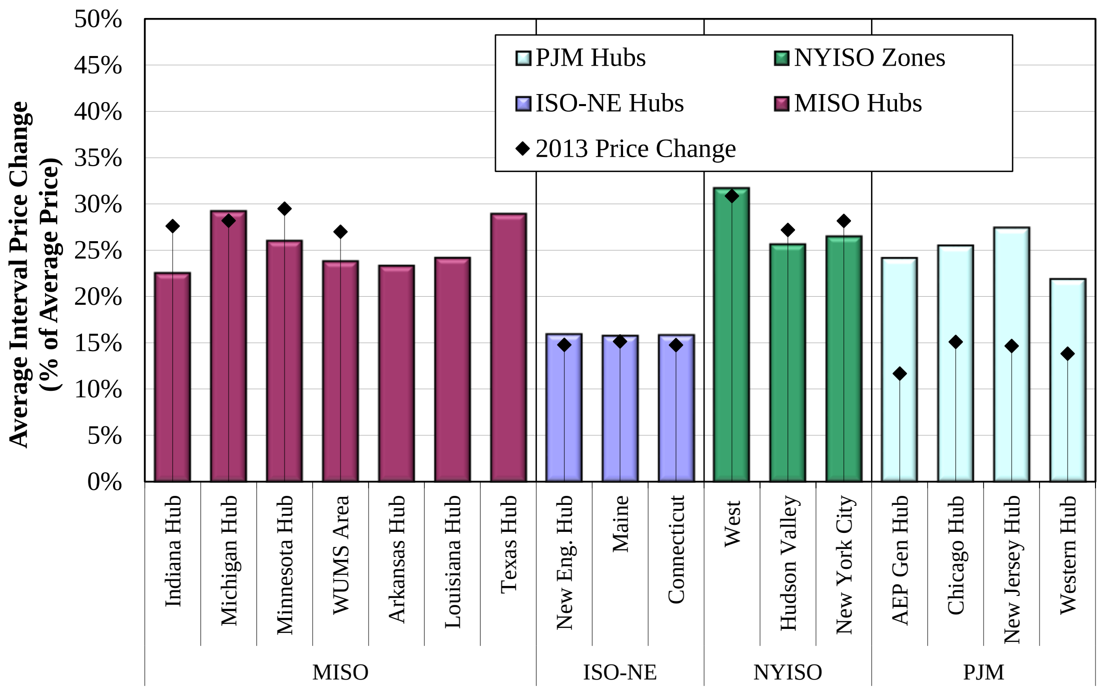
V. Real-Time Market

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

This section evaluates the 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. MISO's real-time market operates on a five-minute time horizon and therefore has access to limited dispatch flexibility when conditions change. 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, either upward or downward. Figure 14 compares fifteen-minute price volatility at representative points in MISO and in three neighboring RTOs.

Figure 14: Fifteen-Minute Real-Time Price Volatility
2014



Real-time price volatility in MISO as measured by the average of the absolute change in price between 5-minute intervals declined four percent from 2013 to $5.48/MWh per interval. Although prices were highly volatile in the first quarter ($10.64 per interval) due to the Polar Vortex, volatility was nearly 40 percent lower from April to December 2014 ($3.76) compared to the same period in 2013 ($6.03).

Despite the decline in 2014, MISO historically has had greater price volatility than its neighboring RTOs 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.

High 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 is currently developing a “Ramp Capability” product, set for implementation in 2016, that will 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. We believe this product will be beneficial and continue to recommend its adoption. We also support MISO’s decision to evaluate the incremental benefits of a Look-Ahead Dispatch tool after deployment of the ramp product.

B. Ancillary Services Markets

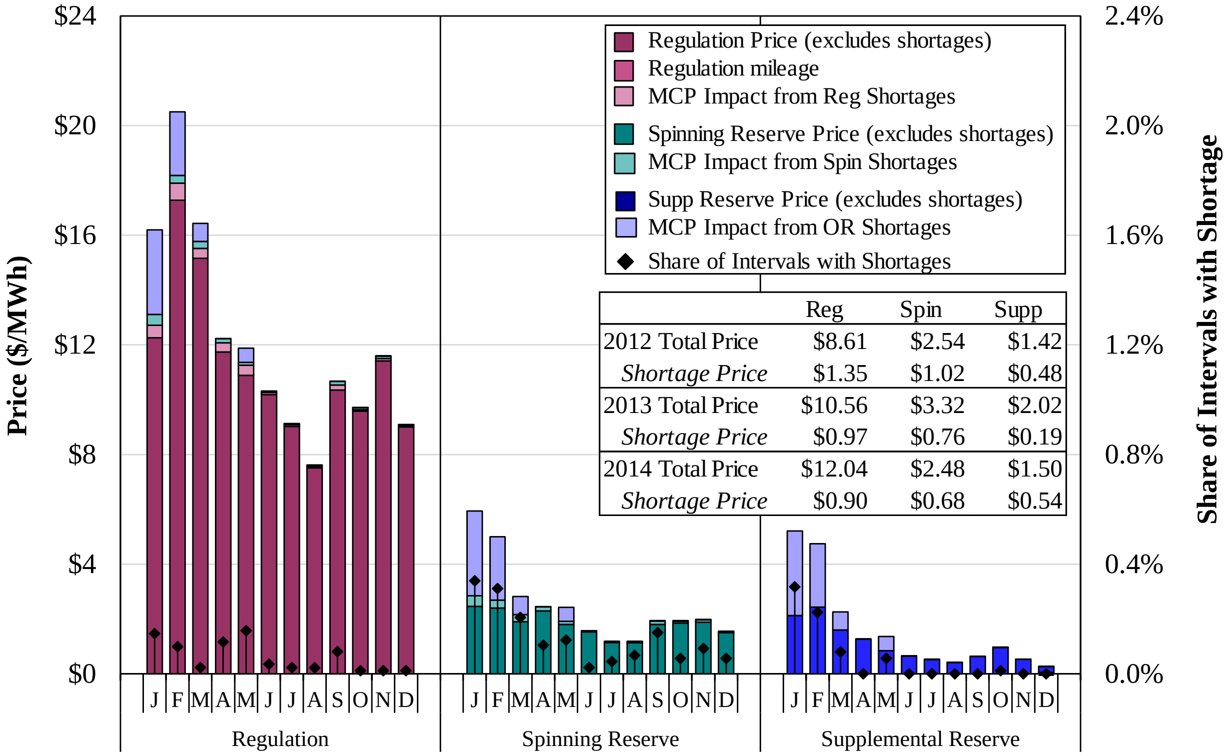
ASM continued to perform as expected with no significant issues in 2014. Since their inception in 2009, jointly-optimized ancillary services markets have produced significant benefits, leading to improved flexibility and lower costs of satisfying the system's reliability needs. These markets have also facilitated more efficient energy pricing that reflects the economic trade-off between reserves and energy, particularly during shortage conditions.

Figure 15 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 2014. 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.[16] 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.

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

[16] The demand curve penalty price for regulation, which is indexed to natural gas prices, averaged $204 per MWh in 2014 and was priced over $400 per MWh in February. 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 those in excess of 10 percent). MISO introduced a new Operating Reserve Demand Curve in May 2013 that prices the first four percent of an operating reserve shortage at $200 per MWh. More significant shortages are priced from $1,100 to $3,400 per MWh, depending on their severity.

Figure 15: ASM Prices and Shortage Frequency
2014



Monthly average clearing prices for regulating reserves rose 14 percent to $12.04 per MWh. The increase in regulation prices was primarily due to higher energy prices. Because of higher energy prices, providing regulation has a higher opportunity cost (i.e. the opportunity cost is generally equal to the difference between the generator's LMP and marginal cost).

Spinning reserve prices declined 25 percent to $2.48 per MWh due to more available supply after integration of MISO South and an unchanged clearing requirement. There were also fewer spinning reserve shortages, especially after February. This was offset by an increase in shortages for contingency reserves, however, which added an additional 35 cents to each reserve product's clearing price relative to 2013. These shortages were most significant in January and February, when sustained cold weather and fuel uncertainties created significant ramp demands on the system. Nevertheless, supplemental reserve prices also declined 25 percent in 2014 overall.

C. Settlement and Uplift Costs

Uplift costs are very important because they create costs that are difficult for customers to hedge and generally reveal areas where the markets 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 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 16 and Figure 17 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 shows RSG payments in both nominal and fuel-adjusted terms.[17] Figure 16 disaggregates day-ahead fuel-adjusted payments made for capacity and for VLR needs. Figure 17 disaggregates real-time time fuel-adjusted payments made for capacity, VLR, or for congestion management.

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

Figure 16: Day-Ahead RSG Payments
2013–2014

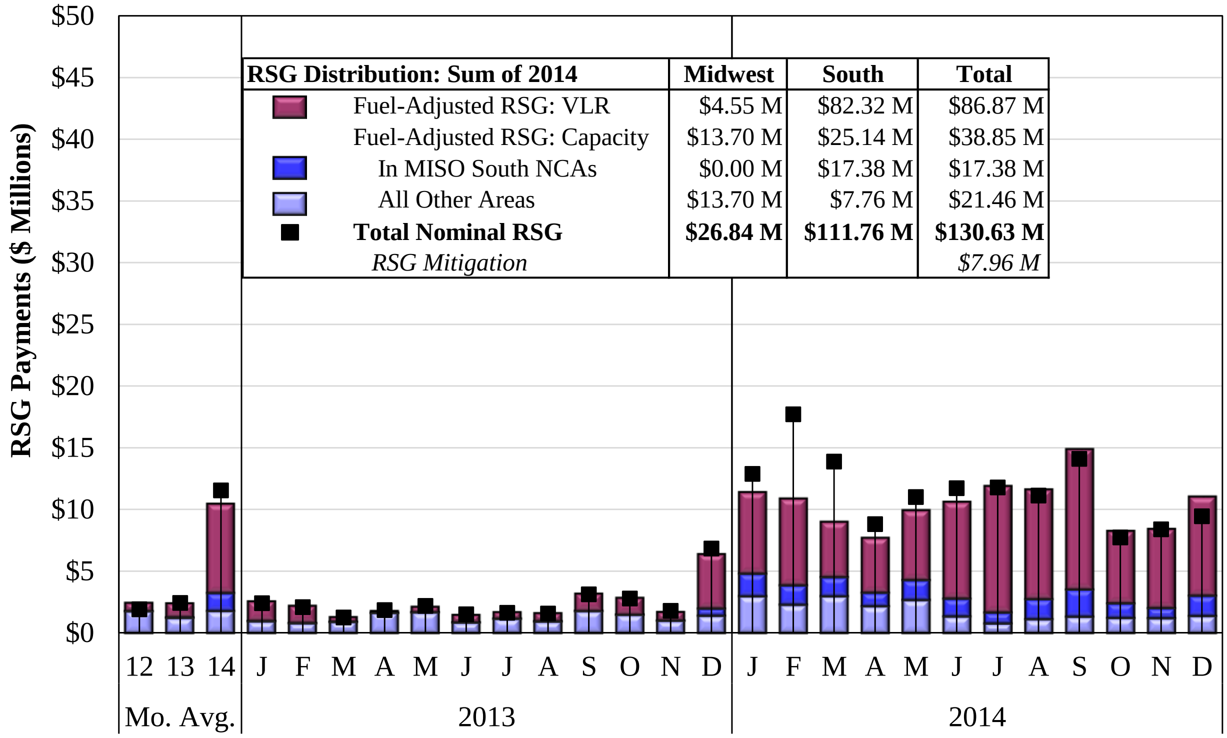
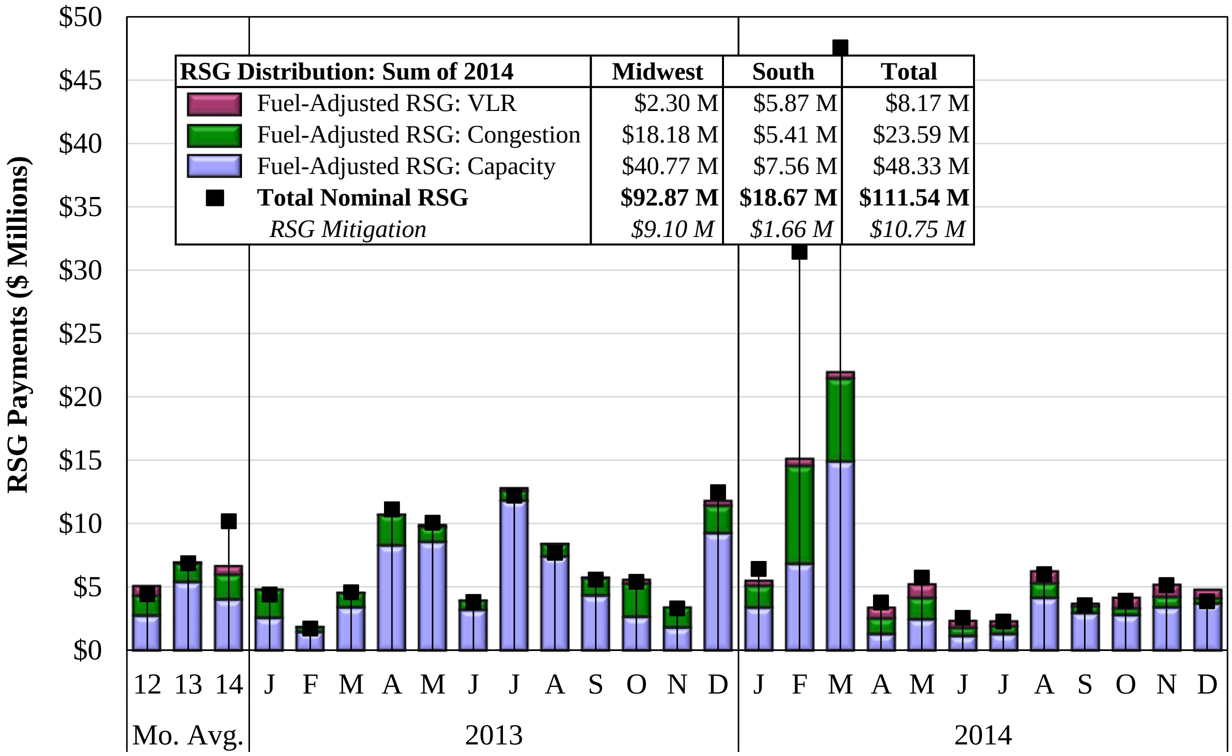


Figure 17: Real-Time RSG Payments
2013–2014



Day-ahead nominal RSG costs rose from $2.4 million to $11.5 million per month, mainly as a result of MISO South integration. Twelve percent of the increase from 2013 was due to the rise in fuel prices. Nominal payments were highest in February, when fuel prices were relatively high, but fuel-adjusted payments were highest in late summer. Over 65 percent of day-ahead RSG payments were to units in MISO identified as committed for VLR purposes. However, if all units that were ultimately committed to satisfy VLR requirements in MISO South were identified (including those committed by the day-ahead market software), the costs attributable to VLR requirements would exceed 80 percent of the day-ahead RSG costs. We have been recommending MISO improve its processes for identifying and allocating these VLR costs. MISO is pursuing approaches to address this recommendation.

Real-time RSG payments rose eight percent from 2013 to $10.2 million per month, most of which was attributable to fuel price increases. Adjusting for fuel prices, real-time RSG declined by four percent. The most expensive months by far were February and March, when MISO paid nearly $80 million because of unprecedented capacity needs during the Polar Vortex. This was compounded by significant congestion into Michigan in late February and early March. Payments after March were lower than in 2013 because load was fully scheduled in the day-ahead market and market conditions were generally mild.

More than $15 million of all RSG was mitigated in 2014. The mitigation applied to VLR commitments was very effective in addressing local market power in these areas. However, the mitigation measures applied to units committed for other reasons were not nearly as effective. Hence, we have recommended that MISO extend the VLR mitigation framework to apply to all resources committed for congestion management or other local needs. See our discussion on this proposed reform in Part 2 Section III.D. In March 2015, MISO filed for Tariff changes to implement this recommendation.

2. Real-Time RSG Cost Allocation

MISO classifies RSG cost 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 how participants cause each type of commitment.

This cost allocation process was the result of proposed changes MISO filed in 2013 that FERC largely approved in 2014. 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.

However, FERC rejected one key element of MISO's proposal because it found that MISO's evidentiary support was insufficient. This proposed change involves allocating real-time RSG costs to supply-increasing deviations that occur after the notification deadline (NDL). These deviations do not directly cause real-time RSG, but instead reduce real-time RSG by reducing the commitments made based on the LAC results (which runs after the NDL). Allocating RSG costs to supply-increasing deviations reduces the RSG rate charged to the deviations that actually do cause RSG. In doing so, this undermines the economic incentive that should deter the conduct that causes RSG.

In response to the FERC's invitation to provide additional empirical evidence, we conducted a study to determine the effect of supply-increasing deviations on real-time RSG costs. We found that supply-increasing deviations result in significant reductions in commitments and associated real-time RSG. This study has been provided to MISO and should support a MISO filing this summer to exempt supply-increasing deviations from real-time RSG cost allocation.

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 18 shows the monthly totals for the two components of PVMWP, along with measures of price volatility at the system level (SMP volatility) and at the locations where units are receiving the payments (LMP volatility).

Figure 18: Price Volatility Make-Whole Payments
2013–2014

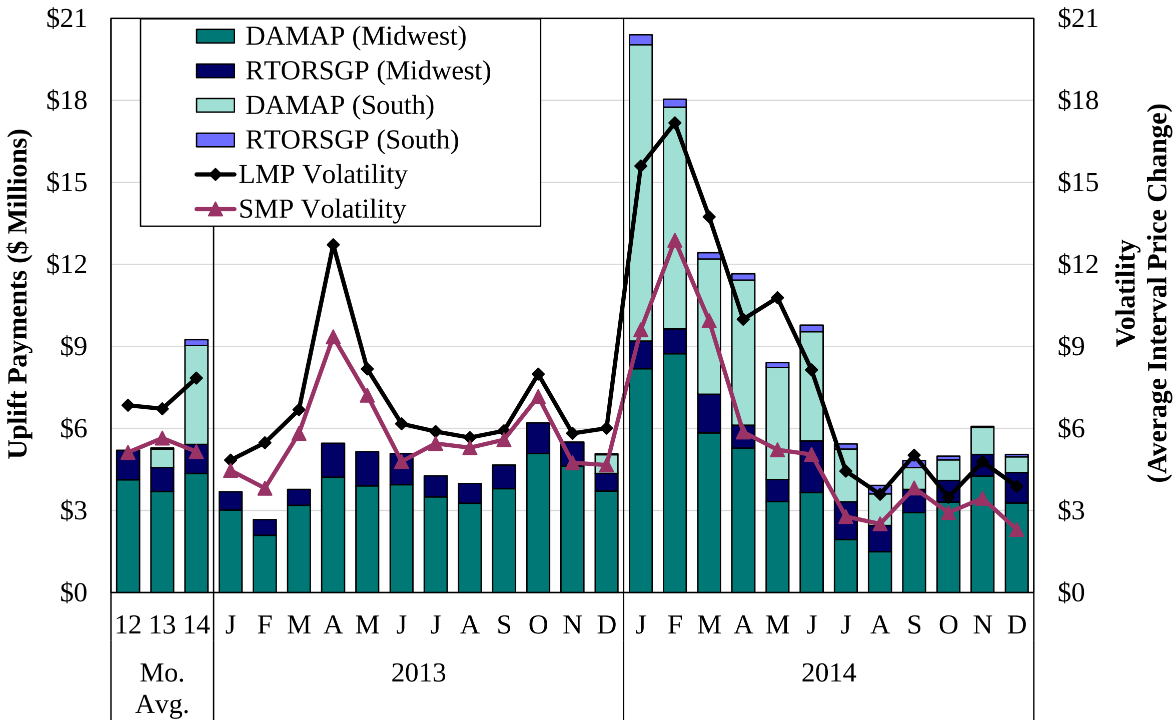


Figure 18 shows that the total PVMWP value averaged $9.2 million per month in 2014, and was strongly correlated with price volatility at the resources' location, as one would expect. In the Midwest region, the PVMWP value rose 19 percent, consistent with the 17 percent increase in price volatility at locations receiving payments. Payments were largest in the first quarter of 2014, as a result of the volatile market conditions during the Polar Vortex, and declined steadily thereafter. Most of these payments were made to flexible coal units during ramping hours.

DAMAPs constituted over 80 percent of the total PVMWP value. The largest payments in MISO South were to units that were not responding well to MISO's dispatch instructions, but remained eligible for payments because of MISO's high deficient energy tolerances.

Errors that we detected in MISO's State Estimator model contributed to apparent poor generator performance as it caused at least two of the MISO South units to receive inefficient dispatch instructions in the spring and early summer, which contributed to more than $2 million in DAMAP costs. In early July, this modeling error was resolved and the DAMAP paid to these resources declined dramatically.

4. Five-Minute Settlement

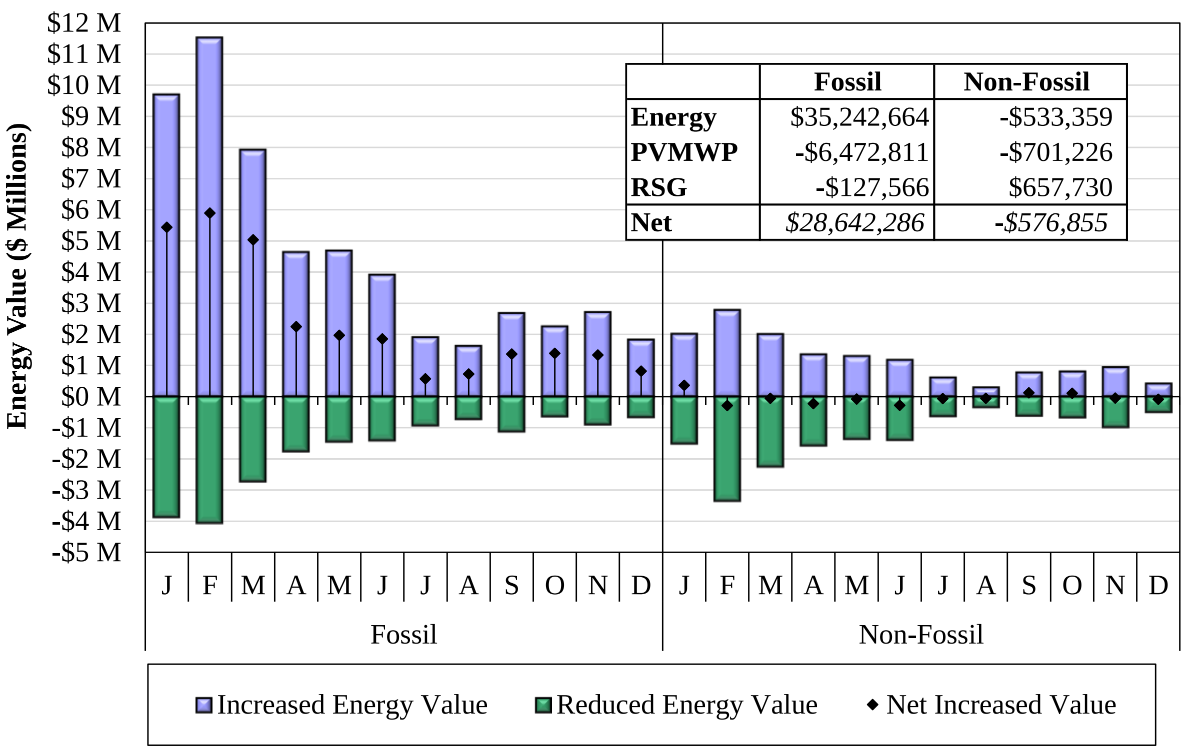
MISO produces new dispatch signals and prices every five minutes, but settles with generators and physical schedulers on an hourly basis using an average of the five-minute prices. This can create inconsistencies between the dispatch signals and the hourly prices that subsequently create incentives for 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 19 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-fueled resources tend to be more flexible and better able to respond to dispatch instructions than other resources (e.g., intermittent resources).

Figure 19: Net Energy Value of Five-Minute Settlements

2014



The figure shows that fossil fuel-fired resources in 2014 received settlements that were $35 million less than they would have received settling based on the five-minute prices and output. Most of these differences were accrued in the first half of the year, when shortages and congestion-related price spikes were far more frequent. Nearly 20 percent of this lost value, however, was paid to resources in the form of PVMWP.

Flexible steam units in particular earned $19 million less than what would have been paid under a five-minute settlement regime. Non-fossil resources were paid on net nearly the same in hourly energy revenues as their actual five-minute energy value, although overpayments to pumped storage facilities ($3.4 million) were offset by underpayments to wind units ($1.9 million). Physical schedules (not shown) were also undervalued by the hourly settlements by nearly $8 million.

The fact that fossil fuel-fired units would receive more revenue and non-fossil ones would likely receive less under a five-minute dispatch is consistent with the fact that flexible, controllable resources are generally more valuable to the system and, therefore, would benefit from a more granular settlement. In the absence of congestion, dispatchable wind resources are typically infra-marginal at full output, so normally they cannot ramp up in response to higher prices. Additionally, wind resource output is negatively correlated with load and often contributes to congestion at higher output levels, so hourly-integrated prices often overstate the economic value of wind generation.[18]

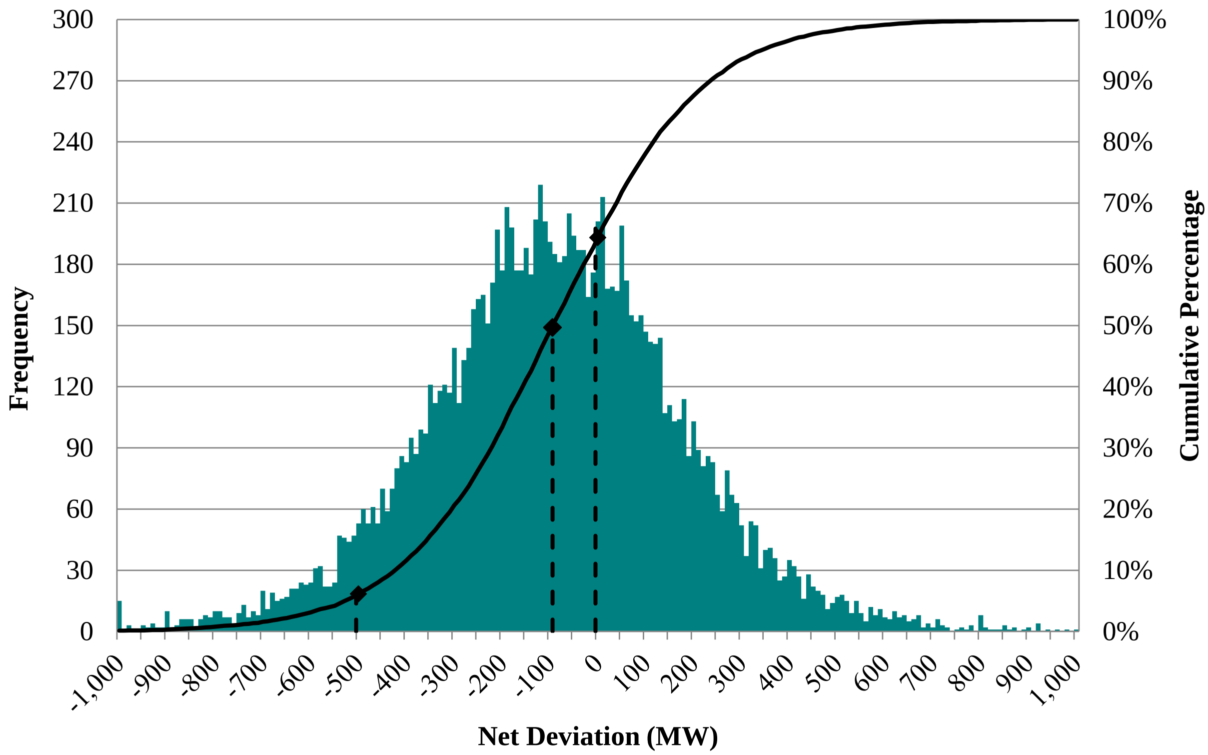
These results show there are substantial discrepancies between the actual value of energy on a five-minute basis and settlements currently made on an hourly basis. The PVMWPs alone are not sufficient to address these discrepancies. Our five-minute settlement recommendation will improve the incentives for generators to follow dispatch instructions, provide more flexibility, and provide incentives for participants to schedule imports and exports more efficiently. Hence, we continue to recommend MISO evaluate the feasibility of five-minute settlements.

18 RSG payments to non-fossil fuel-fired units (shown in the table) are largely caused by the reduction in energy payments to pumped storage units committed by MISO since they frequently do not cover their offered costs.

5. Generator Deviations

MISO sends energy base-point instructions to generators every five minutes identifying the expected output at the end of the next five-minute interval. It 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.[19] 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. MISO's criteria for identifying deviations are significantly more lenient than most other RTOs. Figure 20 shows the frequency of net deviations (without regard to tolerance bands) during peak summer hours 2014.

Figure 20: Frequency of Net Deviations
Peak Summer Hours, 2014



MISO was net deficient (generators collectively producing less than instructed) in nearly two-thirds of all peak summer intervals. The median deficiency was 95 MW (down from 151 MW last year) but still exceeded 500 MW in over six percent of the intervals (this share exceeded 17 percent during the top 10 load days). Significant net negative deviations can contribute to

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

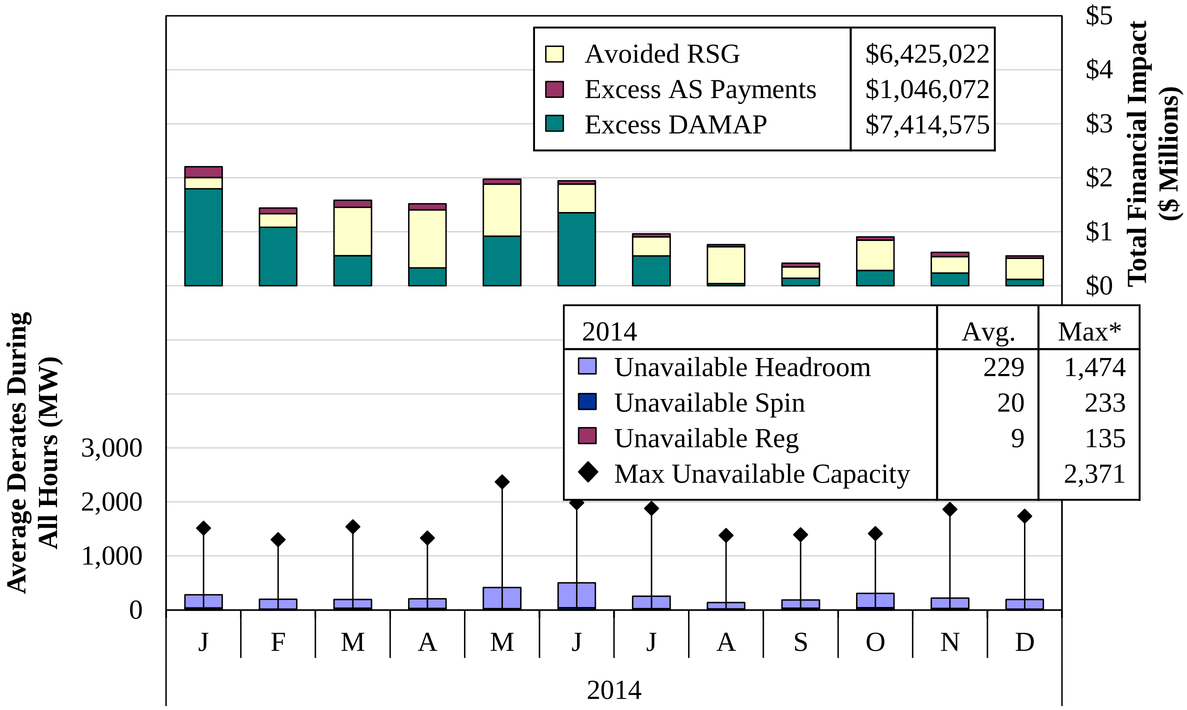
shortages because of limited availability of other resources to compensate for the negative deviations.

MISO currently deems a generator to be incurring an uninstructed deviation only when it is more than eight percent above or below its dispatch instruction for four consecutive intervals. This exempts the vast majority of deviation quantities from significant settlement penalties. This is the most tolerant criteria of any RTO, most of which employ a five-percent band with no consecutive interval criteria. The looseness of this band allows resources to effectively derate themselves by simply not moving over many consecutive intervals. So long as the dispatch instruction is not eight percent higher than its current output, a resource can simply ignore its dispatch instruction. Unfortunately, because it is still considered to be on dispatch, it can receive unjustified DAMAP payments and avoid RSG charges it would otherwise incur if it were to be derated.

In fact, we have developed screens to identify resources that are effectively derated, but are simply not responding to dispatch signals rather than derating their units by updating their offer parameters. We do this because it is a violation of the MISO Tariff for a supplier to not update its offer parameters. In recent years, we have found numerous examples when resources were operating well below their economic output levels (often reflected in their day-ahead schedules) and were not put off-control or derated in real-time. Subsequent investigations have found a number of cases when a generation owner knew a particular resource could not operate to its real-time limits but failed to provide updated offers to the market portal or notify MISO operators. When the quantities or economic impacts of this conduct are significant, we have referred these participants to FERC's Office of Enforcement.

Derates or other limitations that are not reported to MISO can: a) undermine reliability because it will not have accurate information on the supply available to satisfy the system's needs; and b) increase the system's costs by generating PVMWPs to the resource that is not responding and allow the supplier to avoid being allocated RSG costs it otherwise would incur if it updated its offer. MISO has been developing processes to facilitate frequent updates of offer parameters by participants. To show how significant these unreported (or "inferred") derates have been, the following figure shows the monthly inferred derate quantities (the bottom panel), separately showing resources scheduled for regulation, spinning reserves, or simply providing headroom (latent reserves) in the energy market. The top panel shows the financial impacts of this conduct in the form of unjustified DAMAP and ancillary service market payments, as well as RSG charges that the suppliers avoided by not updating their real-time offer parameters.

Figure 21: Unreported ("Inferred") Derates
Daily Peak Hours, 2014

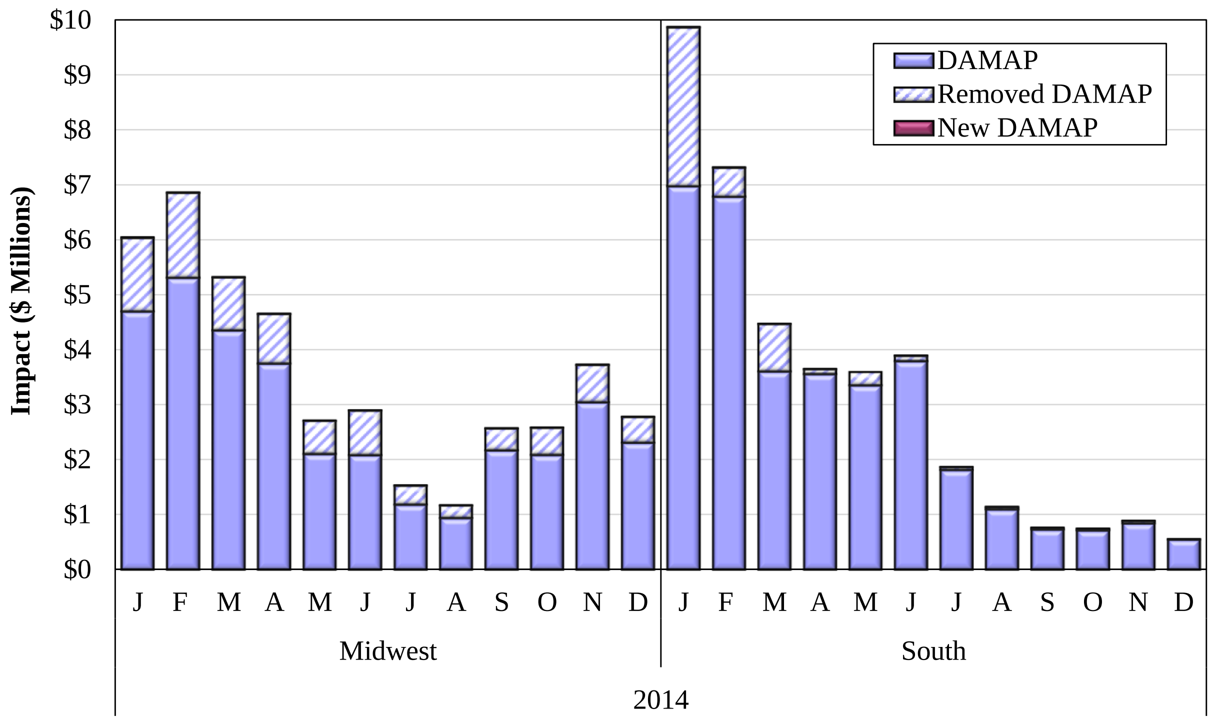


* Daily Average Maximum

The figure shows that participants received almost $15 million in economic benefits by not reporting derates, which included DAMAP payments, reserve payments, and avoided RSG charges. Unfortunately, these factors provide incentives for participants not to report derates or update their offers when they are no longer responding to dispatch signals. Further, the quantities of inferred derates were substantial. The quantities of inferred derates averaged 258 MW in 2014, far larger than the 128 MW averaged in 2013. Much of this increase is attributable to resources in the South region that exhibited poor generator performance in early 2014. The State Estimator error discussed earlier in this section contributed to the higher inferred derates in the first half of the year. Correction of this modeling issue and FERC's announcement of sanctions against inferred derates we had previously referred to FERC enforcement likely contributed to improved generator performance and reduced inferred derates during the second half of 2014.

In previous *State of the Market* reports, we recommended MISO modify the tolerance bands for uninstructed deviations (Deficient and Excessive Energy) by basing them on unit ramp rates, an approach that more effectively identifies units that are not following dispatch and provides an incentive to offer and provide faster response. Figure 22 illustrates the consequence of implementing the proposed tolerance bands on DAMAP paid in 2014. The solid blue bars together with the stacked hatched bars indicate the total amount of DAMAP paid in 2014. The hatched blue area alone is the amount of DAMAP that was paid but would not have been if IMM proposed criteria were in place. The maroon bars, which are minimal, indicate the DAMAP that would be paid under the new criteria but was not paid in 2014.

Figure 22: Impact of IMM-Proposed Eligibility Rules on DAMAP
2014



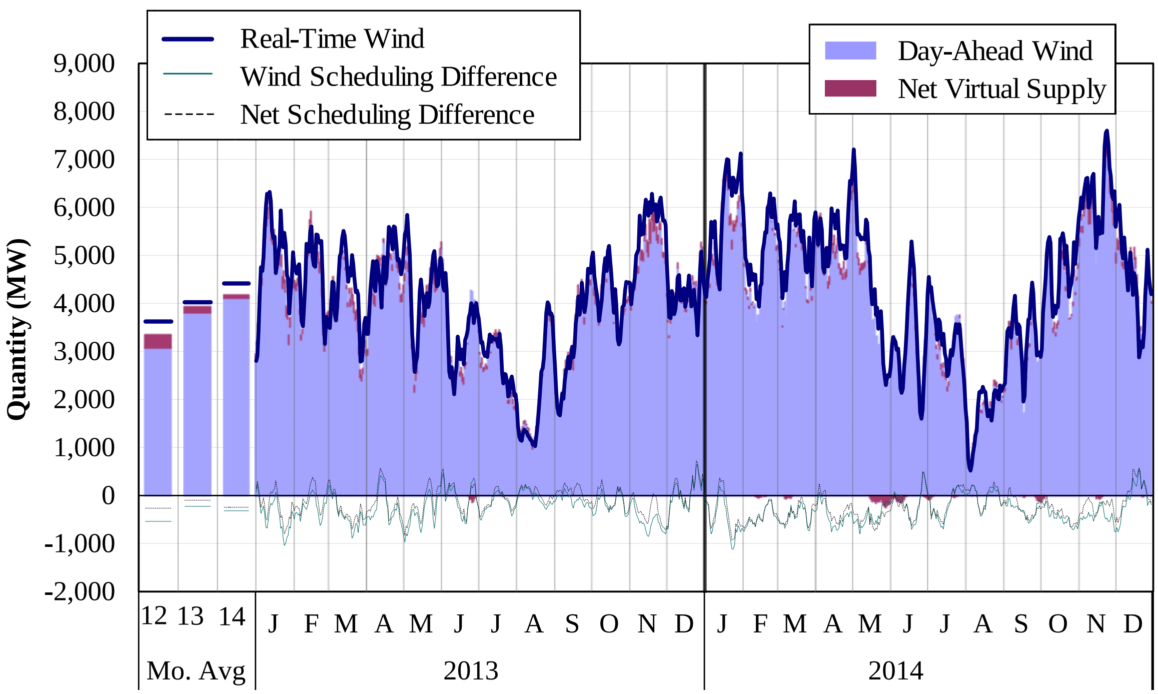
The IMM-proposed tolerance bands would have eliminated 17 percent, or $14 million, of DAMAP paid in 2014. Substantial additional savings will be achieved if MISO modifies its tolerance bands consistent with our recommendations.

D. Wind Generation

Installed wind capacity in MISO has grown steadily and now exceeds 14 GW. Although wind generation promises substantial environmental benefit, the output of these resources is intermittent and, as such, it presents particular operational, forecasting, and scheduling challenges. These challenges are amplified as wind's portion of total generation increases. Wind resources accounted for 7.6 percent of installed capacity and 6.1 percent of generation in 2014. These statistics are lower than in previous years because they are calculated relative to all installed resources, which expanded with the MISO South integration, and there is no wind capacity in the South region.

Figure 23 shows a daily seven-day moving average of day-ahead scheduled wind and real-time wind output since 2013.

Figure 23: Day-Ahead and Real-Time Wind Generation
2013–2014



Real-time wind generation in MISO increased 10 percent in 2014 to over 4.4 GW per hour. MISO set an all-time record of 11.1 GW of wind output in November 2014. This has since been exceeded in January 2015 at 11.9 GW. The figure also shows that wind output is substantially lower during summer months than during shoulder months, particularly during the highest load hours. This reduces its value from a reliability perspective. Under-scheduling of wind output in the day-ahead market can create price convergence issues and lead to uncertainty regarding the need to commit resources for reliability. Wind was more under-scheduled in the day-ahead in 2014 than it was in 2013. Furthermore, net virtual supply, which can mitigate the underscheduling, did not contribute as much to offset the deficit as it did in 2013. In all, net scheduling averaged 248 MW less than real-time output.

Managing wind output is significantly aided by the adoption of the Dispatchable Intermittent Resource (DIR) type, which was first introduced in June 2011.[20] 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. Economic curtailments in 2014 rose from 140 MW per interval last year to 201 MW and at times exceeded 1,000 MW. Manual wind curtailments averaged just three MW per interval. Wind output is being curtailed at approximately twice the rate compared to curtailments prior to DIR adoption in 2011. DIR resources can set prices — they did so in over half of all intervals — at an average of -$7 per MWh. These low prices set by wind units typical prevail in relatively small congested areas.

Finally, as total wind capacity continues to grow, the volatility of its output that must be managed by MISO also grows. Volatility of wind output, as measured by the absolute average interval change in output between intervals and excluding economic DIR curtailments, rose to 305 MW per hour and included some intervals where production dropped in excess of 2,000 MW. Significant reductions in output, when they are not forecasted, can lead to substantial price volatility and can require MISO to make real-time commitments to replace lost output. The DIR has been valuable in improving the control of wind resources and responding to changes in output. 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.

20 As of the December 2014 commercial model, 118 out of 183 wind units (approximately 80 percent of capacity) are modeled as DIR. Most other wind resources are exempt from the DIR requirement.

VI. Transmission Congestion and FTR Markets

MISO manages flows over its network to avoid overloading transmission constraints by altering the dispatch of its resources and establishes 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 transmission facilities. In LMP markets, this generation redispatch or "out-of-merit" cost is reflected in the congestion component of the locational prices.[21] The congestion component of the LMPs can vary substantially across the system, causing LMPs to be 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 2014

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.

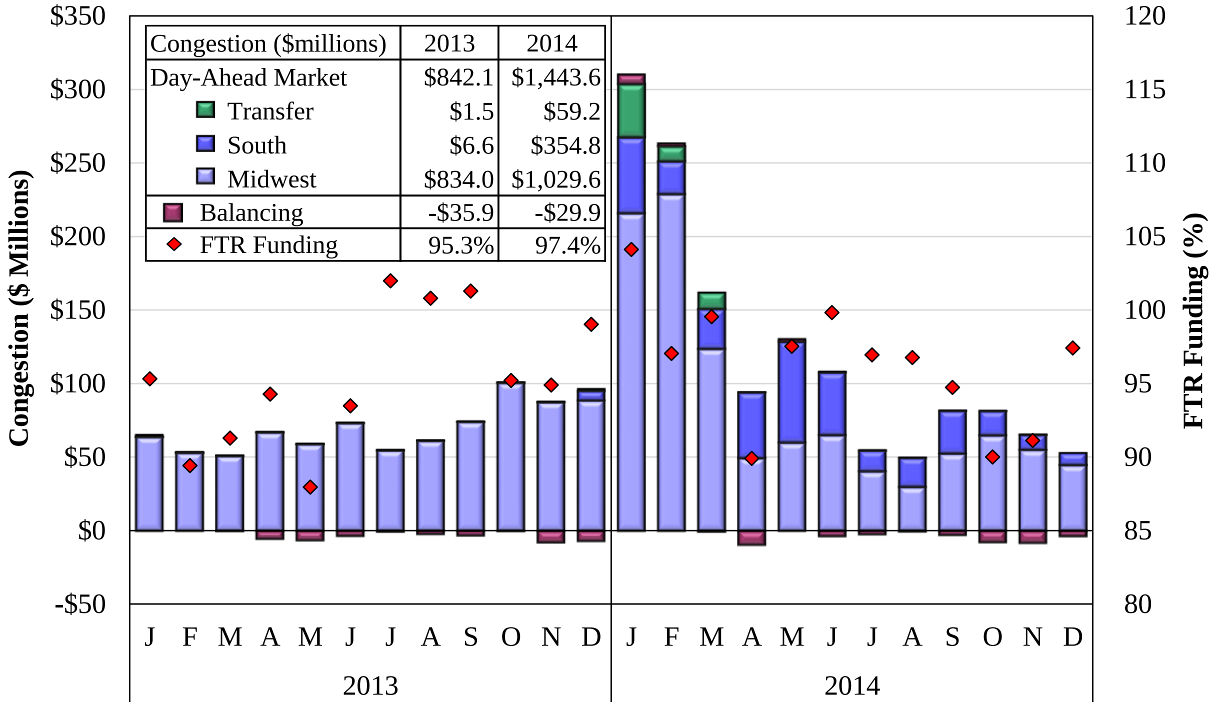
The resulting congestion revenue is paid to holders of FTRs. FTRs represent the economic property rights associated with the transmission system. A large share of the value of these rights is allocated to participants. The residual FTR capability is sold in the FTR markets with this revenue contributing to the recovery of the costs of the network. FTRs provide an instrument for market participants to use to hedge day-ahead congestion costs. If the FTRs issued by MISO are physically feasible (do not imply more flows over the network than the

[21] 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.

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 24 summarizes the day-ahead congestion by region, the balancing congestion incurred in real time, and the FTR funding levels in 2013 to 2014.

Figure 24: Day-Ahead and Balancing Congestion and Payments to FTRs
2013–2014



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

Day-Ahead Congestion Costs

Day-ahead congestion costs rose 71 percent to $1.44 billion in 2014. More than $400 million of the rise is attributable to the expanded footprint due to integration and corresponds to congestion on constraints in MISO South or congestion on the transfer constraints between the regions. However, congestion during the Polar Vortex in the Midwest was the highest since the markets began. The unusually cold weather and high gas prices increased the cost of redispatching generation to manage congestion. In addition, gas price differences between locations in the South and Midwest resulted in south-to-north power flows and transfer constraint congestion.

Day-ahead congestion after March was 32 percent lower than the same period in 2013 because conditions were mild and fuel prices were relatively low. Additionally, the modeling of the transfer constraints changed in April when MISO introduced the South Region Power Balance Constraint and a "hurdle rate" of roughly $10 per MWh. These changes allowed MISO to transfer more than 1000 MW without generating excessive congestion costs.

FTR Shortfalls

FTR obligations exceeded congestion revenues by $69 million, or a shortfall of just 2.6 percent and a substantial reduction from last year, when they were underfunded by 4.7 percent. Shortfalls occurred in all months except January, when obligations were overfunded by $18 million. Some of the shortfall reduction can be attributed to FTR surplus generated on the transfer constraints because the FTRs defined in 2014 did not encompass the full transfer capability (or were sometimes defined in the opposite direction of the binding transfer constraints). Hence, the surpluses generated by the transfer constraints offset other shortfalls, and contributed to the aggregate surplus in the first quarter of 2014.

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 Shortfalls

These costs generally 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. These costs must be uplifted to MISO's customers. RTOs should generally seek to minimize these costs by achieving maximum consistency between the day-ahead and real-time market models. Figure 25 shows that balancing congestion shortfalls in 2014 remained a small share (2 percent) of total congestion costs. In 2014, balancing congestion shortfalls totaled nearly $19 million (excluding JOA uplift of $10.8 million). MISO had positive balancing congestion revenue of $7.7 million during the first quarter, but balancing costs of $37.5 million during the last nine months of the year. These low levels of balancing congestion indicate that MISO is doing a good job of maintaining consistency between the day-ahead and real-time market models.

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. Congestion revenues collected through the MISO markets are substantially less than the value of real-time congestion on the system, which totaled $2.43 billion in 2014. This substantial difference is caused primarily by loop flows that do not pay MISO for use of its network and PJM's entitlements on the MISO system (PJM does not pay for its use up to its entitlement).

The value of congestion was 52 percent greater than in 2013. Roughly 30 percent of the increase can be attributed to the integration of MISO South. Real-time congestion increased most sharply in the East region (up 69 percent) and on market-to-market constraints (up 77 percent), particularly in the first quarter. Outages in Michigan during this period resulted in congestion that was extremely costly to manage given the high loads and volatile natural gas prices in the first quarter. After the first quarter, the real-time congestion declined significantly and was 34 percent lower from April to December than during the same period in 2013.

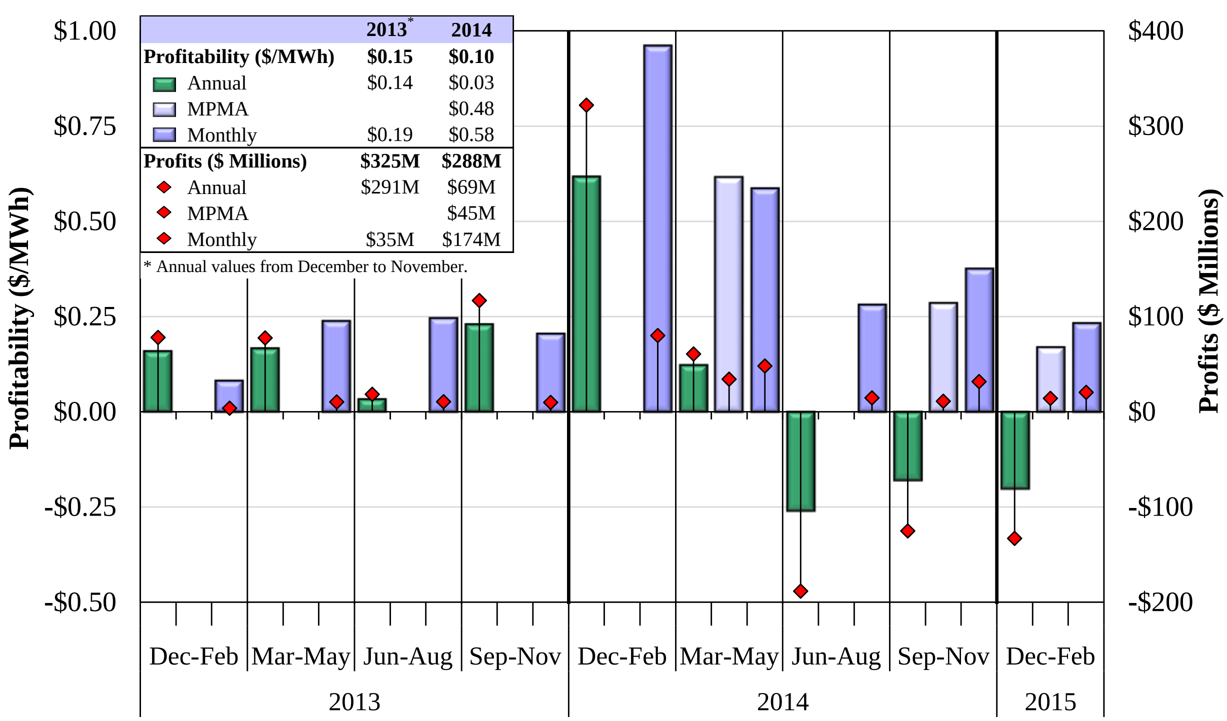
C. FTR Market Performance

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 = the FTR price minus the day-ahead congestion payments). 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 values established in the FTR markets. MISO currently runs the FTR market in three timeframes: annual (from June to May), monthly, and a recently implemented Multi-Period Monthly Auction (MPMA). The MPMA was launched in November 2013 and facilitates FTRs trading for future months or seasons in the planning year.

Figure 25 shows our evaluation of the profitability of these auctions by showing the seasonal profits for FTRs sold in each market. The values are calculated seasonally even though the FTRs are sold for durations of one year, one season, or one month.

Figure 25: FTR Profits and Profitability
2013–2014



The congestion in Winter 2013/2014, including the severe congestion in Michigan, was almost entirely unpriced in the FTR markets. This caused the FTR profitability to be unusually high during this period – i.e., FTR prices were low compared to the day-ahead FTR obligations. For example, day-ahead congestion at Michigan exceeded $20 per MWh at times, yet FTR prices did not exceed $1.50 per MWh. This factor explains the relatively high profitability (> $0.50 per MWh) shown for the first and second quarters of 2014. The first quarter, in particular, generated $400 million in FTR profits, the highest level we've ever recorded. More than $300 million of this profit was associated with Annual FTRs, a large portion of which were captured by transmission customers that converted their ARRs to FTRs. After this timeframe, FTR profits returned to more normal levels.

Figure 25 also shows that the FTRs issued through the annual FTR market were substantially unprofitable. The FTR congestion value was $446 million less than the annual auction valuation in the first three seasons of the 2014-2015 auction year (June 2014 through February 2015). These FTR losses are largely the result of market participants self-scheduling ARRs – effectively offering to buy the right at any cost (or refusing to sell at any price). 57 percent of the losses were associated with ARR self schedules by customers in MISO South, which may be attributable to their lack of experience with the MISO markets.

D. FTR Shortfall Allocation

Underfunding has persisted on the MISO system in recent years and occurs when MISO is obliged to pay FTR holders more than the congestion revenues it collects in the day-ahead market. As discussed above, this occurs when the FTRs issued by MISO imply power flows over the network that are greater than the flows that can be accommodated in the day-ahead market. 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 (e.g., MISO may collect half of the day-ahead congestion revenue it needs to fund its FTRs over a particular interface), 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 surpluses are allocated back to transmission customers. Hence, FTRs will never be funded at greater than 100 percent of the FTR obligation.

Underfunding FTRs is undesirable because it undermines the value of the FTR as a financial instrument by introducing unnecessary uncertainty regarding its value. This ultimately results in lower prices as participants discount their FTR bids to account for the uncertainty. The magnitude of this price effect will depend on how risk averse participants are in the FTR market.

It is likely in the long-run that FTR prices will fall by more than the FTR underfunding, which means that transmission customers are harmed by allocating the shortfalls to FTR holders. For ARRs that are converted to FTRs, 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 financially from this change on net. At the same time, fully funding the FTRs will make them more effective instruments for hedging congestion-related risk and facilitating forward contracting.

Finally, a direct allocation of the FTR shortfalls to transmission customers 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, there is 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 to model in the FTR markets because it could reduce their ARR allocation.[22] In this case, higher quantities of ARRs/FTRs over an interface may directly benefit the participant while the costs of overstating the capability is socialized and spread to all MISO participants. As MISO reconsiders its allocation of FTR shortfalls, it should consider directly

22 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.

allocating a portion of the FTR shortfalls to participants that cause the shortfalls 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 limit the duration and optimize the timing of planned transmission outages. It will also provide incentives for participants to take appropriate maintenance measures to avoid unexpected transmission outages.

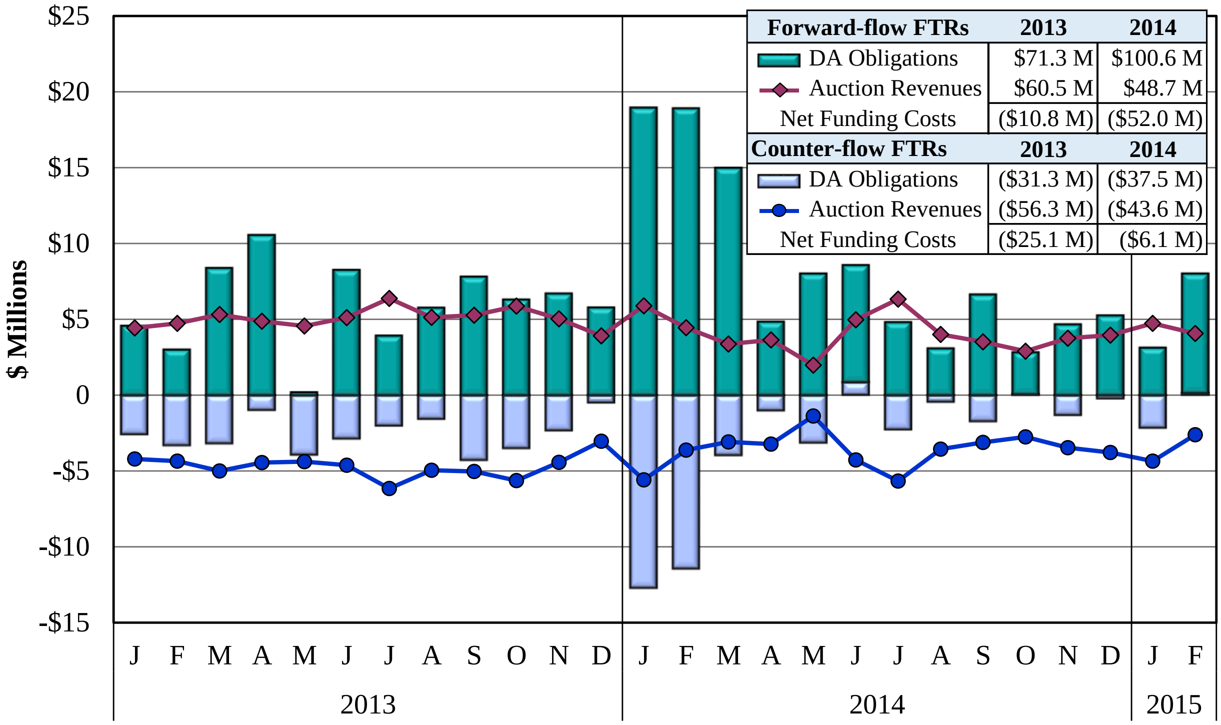
E. Monthly and MPMA Auctions

In the MPMA and Monthly FTR auctions, 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. For example, imagine MISO has issued 250 MW of FTRs over an interface that now can only accommodate 200 MW of flow. MISO can sell 50 MW of counter-flow FTRs so that MISO's net FTR obligation in the day-ahead market is only 200 MW.

MISO is restricted in its ability to do this because it is prohibited from clearing the MPMA or monthly FTR auctions with a negative residual. Hence, it can sell counter-flow FTRs to the extent that it has sold forward-flow FTRs in the same auction. This limits MISO's ability to resolve feasibility issues through the monthly and MPMA auctions. 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, the following figure compares the auction revenues from the monthly FTR auction to the day-ahead FTR obligations associated with the FTRs sold. It separately shows forward direction FTRs and counter-flow FTRs. The net funding costs are the difference between the auction revenues and the day-ahead obligations. A negative value indicates that MISO sold FTRs at a price less than their ultimate value.

Figure 26: FTR Profits and Profitability
2013–2014



This figure shows that in most months MISO sold forward-flow FTRs at less than their ultimate value or paid participants more to accept counter-flow FTRs than the value of these obligations. This was not the case for counter-flow FTRs during the Polar Vortex when congestion levels were much higher in the day-ahead market than the monthly FTR markets had anticipated. During January and February, for example, MISO paid less than $10 million to issue counter-flow FTRs but reduced its day-ahead FTR obligations by almost $24 million.

However, outside of the first quarter of 2014, MISO typical sold incremental FTRs for roughly half of their ultimate value on average over the period shown in the figure. The results were somewhat worse for counter-flow FTRs where MISO on average paid participants 174 percent more to accept counter-flow FTRs than they were ultimately worth. While the negative auction residual restriction artificially limits MISO’s ability to sell counter-flow FTRs, this limitation benefited MISO’s customers based on the pattern of prices for counter-flow FTRs shown in the figure, which were generally much higher than the value of the counter-flow FTRs sold.

Overall, these results indicate that the FTR markets are 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 those 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 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. Market-to-Market Coordination with PJM

MISO's market-to-market (M2M) process under the Joint Operating Agreement (JOA) with PJM efficiently manages constraints affected by both 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 higher shadow price 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.

Total congestion on MISO market-to-market constraints rose 67 percent to nearly $500 million. The largest congestion costs by far were in the first quarter of 2014 and were largely associated with the constraints in Michigan discussed above in this section. On PJM market-to-market constraints, congestion rose by a similar percentage but totaled only $22 million.[23] Figure 27 shows the market-to-market settlements for 2013 and 2014, which are based on each RTO's firm flow entitlements and market flows on the other's constraints.

23 As mentioned in the previous subsection, even though 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.

Figure 27: Market-to-Market Settlements
2012–2014

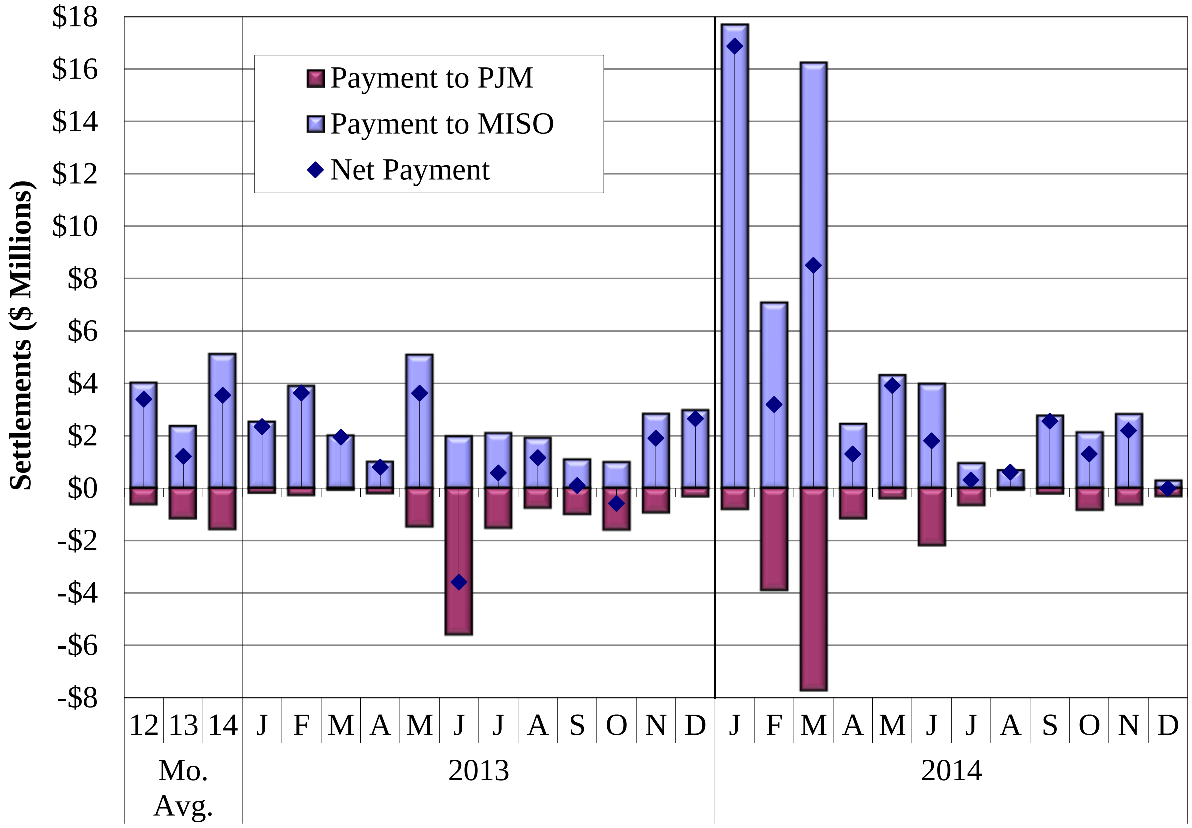


Figure 27 shows net payments flowed from PJM to MISO because PJM exceeded its FFE on MISO's system much more frequently than MISO did on PJM's system. Net payments, which totaled $43 million, were nearly three times greater than in 2013 and were greatest in January ($16 million). Payments from PJM to MISO exceeded $60 million, and were partially offset by $19 million in payments from MISO to PJM. 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.

This report also evaluates 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.

We recommended in our *2012 State of the Market Report* that the RTOs coordinate their FFEs in the day-ahead market, which should improve the efficiency of both RTOs' day-ahead markets. MISO has been working with PJM in evaluating this recommendation. The RTOs have committed to improved data exchange and implement other prerequisites for day-ahead FFE coordination, the initial phase of which is planned for the third quarter of 2015.

G. 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 its 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. The congestion value on external flowgates corresponded to a small share of total congestion in 2014, but had widespread price impacts. In fact, the transmission constraint that had the largest impact on generator LMPs in 2014 was an external constraint managed by SPP.

One reason this flowgate and other external non-market-to-market flowgates often have a large impact on the MISO market is that 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. Additionally, virtually all of MISO's flows over external constraints are deemed to be non-firm even though most of the flows are associated with the dispatch of network resources to serve MISO's load. Historically, the dispatch of network resources to serve load is deemed firm, which is still the case for the utilities around MISO, including Tennessee Valley Authority (TVA). The severe congestion on external constraints raises substantial economic concerns because in our evaluation of TLR events, we have generally found that the external constraints are not physical binding (i.e., the flow is well below its limit) during the periods when they are severely binding in MISO.

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 2014:

- Net imports in both the day-ahead and real-time markets rose to roughly 4 GW.
- MISO largest and most actively scheduled interface is the PJM interface and MISO remains a net importer from PJM.
  - Net real-time imports from PJM rose 72 percent to 695 GW.
  - However, MISO was a net exporter to PJM on some extreme high load days during the Polar Vortex in late January when prices in PJM were far higher than in MISO.
  - Some of the scheduling patterns between MISO and PJM were not efficient 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 46 percent, although nearly 60 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. In addition to the event in July 2013, discussed at length in the *2013 State of the Market Report*, there were other examples of uncoordinated transaction that led to shortages that impaired reliability and produced unnecessary price volatility during the winter 2013/2014. 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

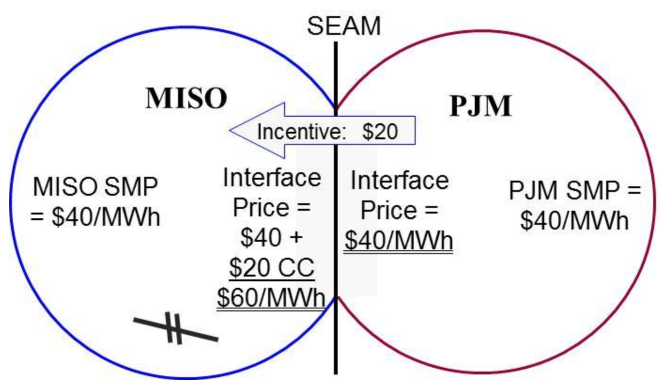
Each RTO posts its own interface price at which it will settle with physical schedulers wishing to sell and buy power from the neighboring RTO. Participants will schedule between the RTOs to take advantage of differentials between the two interface prices. Establishing efficient interface prices would 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 calculate the congestion effects for imports and exports by running a power flow model that includes a representation of both their network and portions of the Eastern Interconnect surrounding their network.

This approach to setting interface prices is efficient as long as the congestion components of the prices estimated by each RTO on their own system are reasonably accurate, which depends entirely on the interface definition. If they are accurate, the interface price will reflect the marginal benefit (or cost) of a transfer into or out of the system. In other words, the congestion component is the net congestion cost incurred (or relieved) on the RTO's own system by the transfer from or to its neighboring RTO. As power moves from one RTO area to the other, it will change the flow on the RTOs' transmission networks and can relieve congestion or aggravate congestion on multiple constrained transmission facilities. The sum of the net congestion effects from a transfer is the congestion component of the interface price. When calculated accurately, traders' responses to these prices will help the system converge to an efficient outcome and lower the total costs for both systems.

The following figure illustrates the purpose and application of interface prices by showing prices and settlements for a non-market-to-market constraint binding in MISO. Although it is not material to the example, for simplicity we assume each RTO's region-wide "system marginal price" (SMP) is equal to $40 per MWh.

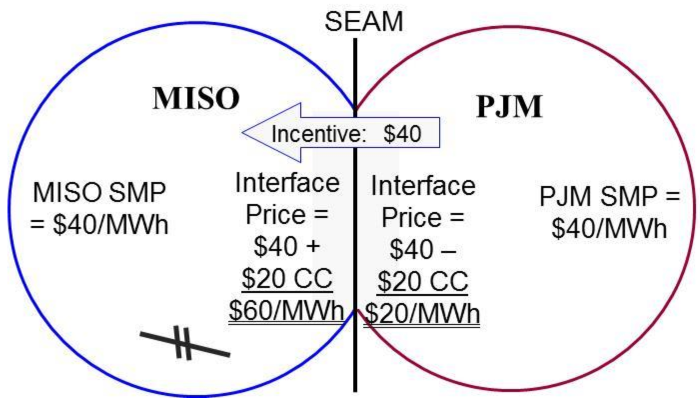
Figure 28: Interface Pricing for a Non-Market-to-Market Constraint



In this example, we assume that a binding constraint in MISO is relieved by an import into MISO from PJM. MISO estimates the value of the relief ($20 in this example) and the interface price will include a congestion component to create an efficient incentive for participants to schedule the transaction. PJM's interface price would not include a congestion component for this because it is a MISO constraint.

However, 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. This is illustrated in the Figure 29. Under market-to-market and the RTO's current interface pricing protocols, this constraint will appear in both RTOs' interface prices to reflect each of their estimates of the relief the transaction will provide.

Figure 29: Interface Pricing for a Market-to-Market Constraint



MISO's settlement is unchanged, but PJM's settlement now includes the $20 congestion component in its interface price, which is redundant. This doubles the incentive to $40 per MWh for participants to schedule the transaction ($60-$20). PJM makes a $20 payment to the participant by charging it only $20 per MWh to leave the PJM system (rather than the $40 per MWh it costs to generate the power being exported). PJM's $20 congestion payment will be uplifted to its customers because the impact of the transaction is not included in its market flow calculation. In other words, PJM (as the non-monitoring RTO or "NMRTO") would get no credit in the market-to-market settlement process for this real-time transaction or the payment it has made to motivate it to be scheduled.

One solution to this problem, which we believe resolves all of the efficiency and equity concerns associated with this pricing flaw, is for PJM to simply stop making the $20 payment in this example. This would ensure that the incentive to transact reflects the value of the relief to MISO who is managing the constraint and eliminates the need for settlement rules that would give PJM credit for making these types of payments. While there has been wide agreement that interface pricing should be coordinated in order to rectify this over-payment of congestion costs, the RTOs have not achieved a consensus on the preferred solution.

In our *2012 State of the Market Report*, we provided specific examples of the problem, which are reproduced in section VI.B.1 of Appendix to this report. These examples show definitively that the RTO's are engaged in duplicative congestion settlements on market-to-market constraints. 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 2014, of which $44.7 million was incurred by PJM. These amounts do not include overpayments made for other external 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 and continue to discuss potential solutions. We have taken the lead in using actual data to examine the benefits and unintended consequences of the two solutions advanced by MISO and PJM. These are the only two solutions that have been proposed – no other ones have been proposed by the stakeholders in either area. We discuss the two alternatives below.

1. MISO IMM Proposed Solution

Our proposed interface definition is based on sourcing imports and sinking exports at the non-monitoring RTO's load-weighted reference bus.[24] Effectively, this assumes an interface definition where the power would source from locations throughout the non-monitoring RTO's footprint. By calculating the congestion component assuming power is injected in the exporting RTO across a broad range of locations and is withdrawn in the importing region across a broad range of locations, the congestion effects will reflect how power actually flows between the

24 The load-weighted reference bus is used by the non-monitoring RTO to calculate the congestion effects for all of its own generation and load.

areas. In reality, the source of the power for an export will be every marginal unit in the exporting RTO's area, which are generally distributed throughout its footprint.

This approach is consistent with the way all RTOs measure locational congestion effects (for generation and load buses and interfaces) relative to a central common "reference bus." To calculate the congestion component of the interface price for a constraint, the RTO first calculates the marginal flow impact on the constraint (i.e., the "shift factor") of injecting a megawatt at the MISO reference bus and withdrawing it at specified locations (known as the "interface definition") in the adjacent area.

Figure 30: Interface Definition using Reference Buses

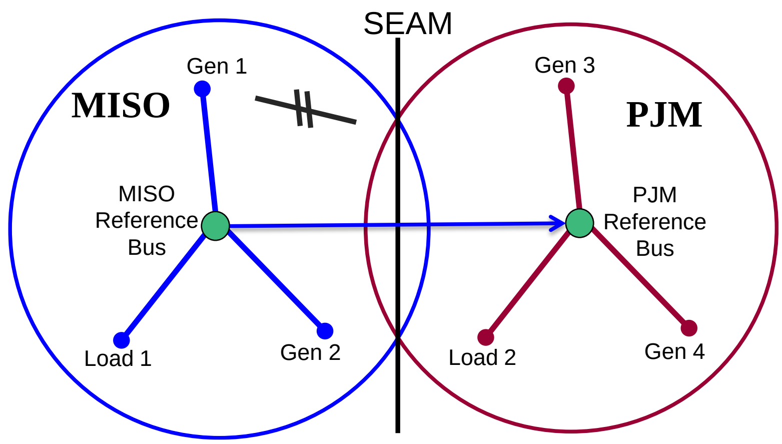


Figure 30 shows MISO using the PJM reference bus as its interface definition. This results in congestion effects that correspond to moving power from the reference bus in one area to the reference bus in the other area.

The congestion component is equal to the shift factor multiplied by the shadow price for the constraint. At any given time, the interchange transaction may affect multiple binding constraints, relieving some and aggravating others. The congestion component shows the net impact of all of these individual effects.

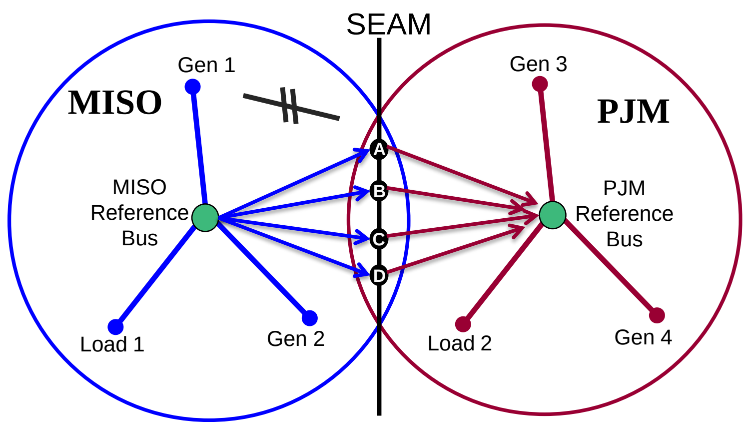
By establishing an interface price that includes the congestion effects of a transfer between MISO and PJM, the congestion benefits and costs will be fully priced and settled. This is essential because it provides efficient incentives for participants to schedule transactions between the two areas. Our proposed solution, which has been endorsed by MISO, would simply call for each RTO to estimate and price the full congestion effects for their own constraints, and remove the interface congestion effects associated with the other RTO's coordinated flowgates. This interface price would conform directly to the efficient interface pricing described above, i.e., it represents the marginal value to the system of an import or export and would eliminate the redundant settlement by the non-monitoring RTOs.

In addition, the MISO IMM proposal also is straightforward and would ensures efficient pricing. As we explain below, the PJM proposal also solves the double-settlement problem, but introduces other potentially serious problems.

2. The PJM Proposed Solution

As an alternative to the MISO IMM proposal, PJM proposes to define a common set of interface buses that would act as the assumed sources and sinks for estimating transfers. This would eliminate the "double-counting" of congestion in the settlements, but introduces other potentially severe problems. The PJM proposal is illustrated in Figure 31.

Figure 31: Interface Definition using Buses at the Seam



We agree that utilizing a common interface definition can eliminate the redundant congestion pricing because the ultimate source and sink are the same as in the MISO IMM proposal – the reference buses of the two RTOs. However, under this proposal, MISO would price the congestion effects *from* its Reference Bus to A, B, C, and D, while PJM prices the same effects from the seam *to* its Reference Bus. In reality, what happens under this proposal is the RTOs calculate shift factors that tend to be larger and offsetting so they sum to the same shift factor (i.e., flow effect on the constraint) as injecting at one reference bus and withdrawing at the other.

While this may have intuitive appeal, this solution will produce an efficient settlement *only* if both RTOs' markets produce the same shadow prices for the constraint. Remember that the congestion component for each RTO is equal to the shift factor times the shadow price. With the inflated shift factors this proposal produces, it is *very* important that both RTOs are using the same shadow price. We have evaluated this solution and found that this necessary condition often does not hold, particularly in the day-ahead market. Therefore, this solution would distort the incentive to schedule imports and exports when market-to-market constraints are binding.

It also introduces serious concerns for some of the constraints that are not coordinated as market-to-market constraints because only the monitoring RTO settles the congestion effects of transactions with the participant for these constraints. Assuming power sources/sinks at a small number of points at the seam sharply inflates the congestion payments for some constraints and reverses the sign of the congestion settlement for others. PJM has shown power flow analysis results that demonstrate these concerns on the PJM system as well.

Ultimately, the distorted and volatile congestion settlements that would occur under the PJM proposal would result in two significant problems:

- They would cause participants to schedule transactions inefficiently over the PJM-MISO interface; and
- They will create balancing congestion uplift for the RTOs' customers because the RTOs would make payments for flow relief that the transactions will not produce.

We do not believe these problems can be effectively addressed under the PJM proposal and no party has identified any legitimate concerns with our proposal. Therefore, we continue recommend that both PJM and MISO implement the approach we have developed.

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.

3. Interface Pricing and 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 costs it incurs, it is inequitable for MISO's customers to bear these costs. These costs totaled $7.4 million in 2014 and $3.9 million in 2013.

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 external congestion from its interface prices.

4. Ongoing Discussions and Initiatives

We have continued to discuss our concerns among stakeholders regarding seams issues. We participated in Commission proceedings involving coordination between MISO and PJM. This included filing multiple comments explaining our interface pricing concerns in detail and providing extensive empirical support for adopting the MISO IMM interface pricing proposal. We believe efficient transactions between MISO and its neighboring RTOs is a critical element of efficient wholesale electricity markets. We will continue to work with PJM and SPP in order to advance solutions to these issues. Because of the critical nature of these issues, we have and will continue to call on FERC to require the RTOs to agree on a solution or mandate a solution if the RTOs cannot agree.

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 2014. 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 (573), but the WUMS Area (2647) and the South region (3693) are highly concentrated. Generation ownership is most highly concentrated in the South region 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 affects 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) 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 (94 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 Midwest NCAs had pivotal suppliers on 90 percent of the constraints.

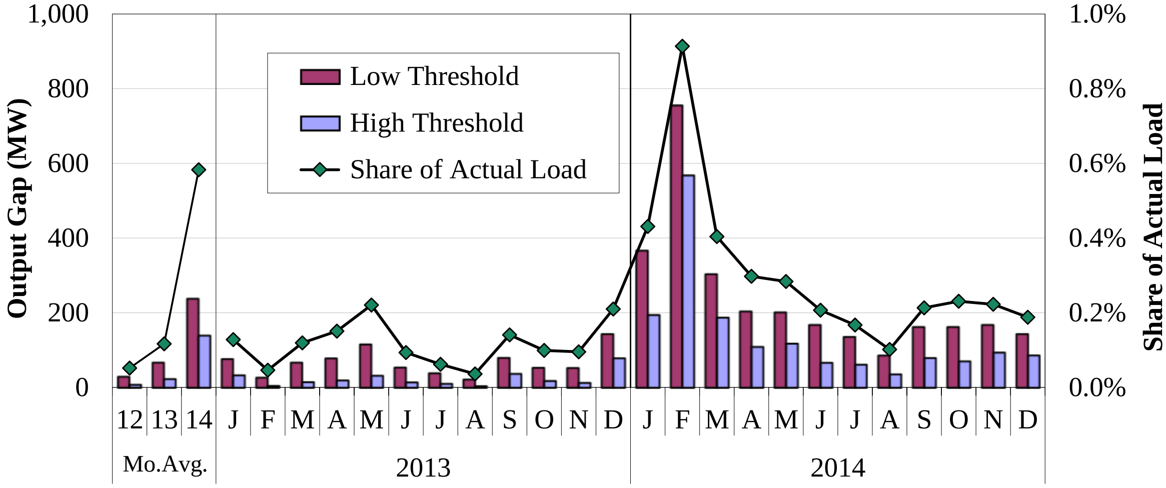
Overall, these results indicate that local market power persists with respect to both BCA and NCA constraints, and that market power mitigation measures remain critical.

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 just 1.0 percent in 2014, down from last year, which reflects that the 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 threshold for mitigation (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 output by submitting inflated energy offers, as well as units that were not committed because of inflated economic or physical offer parameters.

Figure 32: Economic Withholding – Output Gap Analysis
2013–2014



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 rose in 2014, but at 0.58 percent of load, they continued to be very low. The larger footprint contributed to the higher output gap levels because some of the units in MISO South submitted relatively high-cost offers for some products. Output gap levels were highest in February, partly because of intra-day fuel volatility. This volatility is difficult to immediately reflect in reference levels, so some of the changes in offer prices reflected in the output gap metric are actually competitive. 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 rose significantly in 2014. 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 2014, total RSG mitigation was greater than in prior years, largely because of the mitigation of one participant's conduct in early March that lowered payments by several million dollars.

The unprecedented natural gas price volatility during the first quarter of 2014 increased the possibility of inappropriate mitigation because of the difficulty of accurately adjusting reference levels. Nonetheless, most instances of mitigation were appropriate and effectively limited the exercise of market power. However, some mitigation results in early 2014 were successfully challenged (and references and mitigated quantities were restated to reflect accurate fuel price information). In late 2014, we improved our processes 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 2014/2015 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.

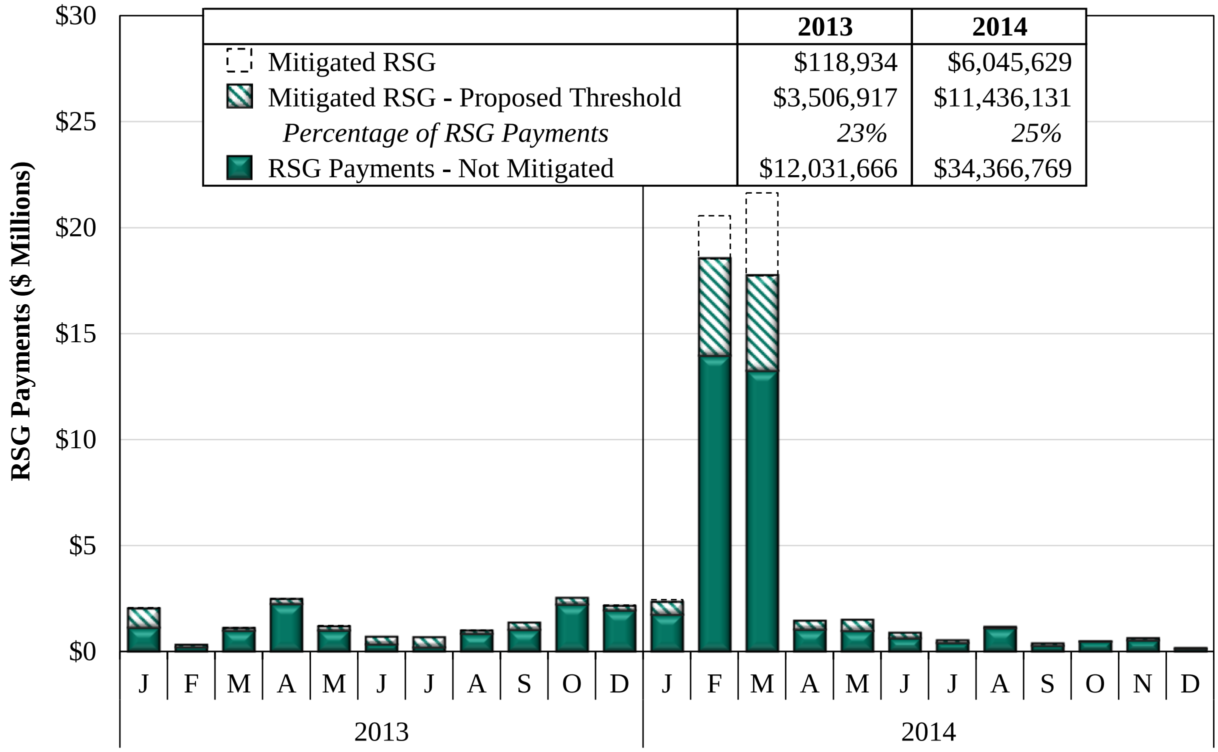
The MISO market has two approaches for testing and mitigating market power exercised to increase RSG payments. The original approach was developed before the start of the market for congestion-related commitments and the more recent approach was developed to mitigate payments for VLR commitments. We compare the two frameworks in this section. The key differences in these frameworks include:

- Congestion-related mitigation measures call for conduct tests to be performed on each offer parameter individually and include an impact test with a $50-per-MW threshold to determine when conduct identified through the conduct test should be mitigated.
- VLR mitigation measures utilize a conduct test based on the aggregate as-offered production cost of a resource (recognizing the joint effect of all of the offer parameters). The VLR production cost-based conduct test effectively serves as an impact test as well. When units committed for VLR require an RSG payment, every dollar of increased production costs will translate to an additional dollar of RSG.

Our evaluation of the VLR mitigation framework suggests that it is more effective at addressing market power exercised to increase RSG payments, in part because measuring the joint effect of all offer parameters is a superior approach for identifying anticompetitive conduct. We studied whether applying the VLR RSG mitigation framework to all RSG would be more effective than the current RSG mitigation rules. Because market power concerns associated with the VLR commitments are much greater, it is reasonable to employ a higher for other RSG mitigation. Therefore, we evaluated a conduct and impact threshold equal to the greater of $25 per MWh or 25 percent (rather than the 10 percent threshold applied to VLR commitments).

This threshold should balance the need for suppliers to modify their offers for changes in actual costs, while more effectively mitigating anticompetitive increases in RSG payments. The percentage provision allows for reasonable treatment of a wide array of units with differing costs. Figure 33 shows total real-time RSG payments in each month in 2013 and 2014, including the payments that were actually mitigated under the current framework and the additional mitigation that would have occurred under the proposed production-cost framework.

Figure 33: Real-Time RSG Payments by Mitigation Classification
2013–2014



The existing mitigation framework mitigated less than 14 percent of the $130 million in payments for offers above reference levels. This indicates that the current RSG mitigation rules applied to congestion-related commitments have not been fully effective in addressing inflated RSG costs, and that the conduct thresholds are too generous.

Under the proposed production-cost framework for RSG mitigation, an additional $11.4 million (25 percent) of RSG payments would have been mitigated in 2014. The importance of such a revision is most clearly demonstrated in the first quarter of the year, when inflated offer prices contributed to the sharp increase in RSG payments along with increases in gas prices. In this period, an additional $9.7 million would have been mitigated under the proposed framework. This analysis demonstrates both the improved effectiveness and the importance of improving the mitigation measures that are applied to congestion-related commitments. Hence, we recommended in last year's report that MISO reform the RSG mitigation rules so that RSG mitigation associated with congestion-related commitments is implemented in the same manner as the mitigation rules for VLR-related commitments. This reform will harmonize the RSG mitigation approach between the two types of commitments and will limit opportunities to exercise market power, as we showed above. We supported a recent MISO filing to implement this recommendation.

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. The NCA thresholds are required to be calculated based on a historical 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. To address this concern, we have recommended that MISO establish a dynamic NCA.

To identify when a dynamic NCA may have been beneficial, we have evaluated mitigation that would have been warranted at thresholds that are 50 percent of the BCA thresholds (effectively $50 per MWh). Since this threshold is higher than what we would propose for the dynamic NCA, these results will identify fewer mitigation instances than would be mitigated by the dynamic NCA. Nonetheless, we have identified a number of instances over the past two years when mitigation would have been warranted. Two examples presented in Section VII.F of the Analytic Appendix illustrate why this provision would be beneficial. Both of these cases lasted less than two months, but the conduct that would have been mitigated during these periods 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 entire timeframes affected by the outages.

These examples show that current Tariff provisions are at times insufficient to effectively address episodes of local market power. Therefore, we recommend MISO expand Module D mitigation provisions to allow for greater flexibility in defining NCAs and to modify formulas for the threshold calculations to address transitory episodes of congestion. We recommend that the threshold for the dynamic NCA be set at $25 per MWh (rather than the default BCA thresholds of $100 per MWh) and be triggered by the IMM when such mitigation would be warranted and the congestion is expected to continue 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 4 shows overall DR participation in MISO, NYISO and ISO-NE in the prior four years.

Table 4: Demand Response Capability in MISO and Neighboring RTOs
2009–2014

	2014	2013	2012	2011
MISO[1]	**10,356**	**9,798**	**7,196**	**7,376**
Behind-The-Meter Generation	4,072	3,411	2,969	3,001
Demand Resources	4,943	5,045	2,882	2,898
DRR Type I	372	372	372	472
DRR Type II	76	76	71	75
Emergency DR	894	894	902	930
NYISO[3]	**1,211**	**1,306**	**1,925**	**2,161**
ICAP - Special Case Resources	1,124	1,175	1,744	1,976
Of which: Targeted DR	*369*	*379*	*421*	*407*
Emergency DR	86	94	144	148
Of which: Targeted DR	*14*	*40*	*59*	*86*
DADRP	0	37	37	37
ISO-NE[4]	**2,487**	**2,101**	**2,769**	**2,755**
Real-Time DR Resources	796	793	1,193	1,227
Real-Time Emerg. Generation Resources	255	279	588	650
On-Peak Demand Resources	997	629	629	562
Seasonal Peak Demand Resources	439	400	359	316

1 Registered as of December 2014. All units are MW. Source: MISO webite, published at: www.misoenergy.org/WhatWe Do/StrategicInitiatives/Pages/DemandResponse.aspx. MISO has indicated that the total amount of DR may actually be as high as 11,329 at the end of 2014.

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 DR Working Group Presentation, Jan. 7, 2015.

The table shows that MISO had over 10 GW of registered demand-response capability available in 2014, which makes up a larger share of capacity than it does in neighboring RTOs. MISO's capability comes in varying degrees of responsiveness. Over 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 22 Demand Response Resources ("DRRs") were active in the MISO markets in 2014, they only cleared a small amount of energy and reserves in the MISO markets. All but one 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 done so 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.[25] 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.

25 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 its markets continued to perform competitively and efficiently in 2014, we recommend MISO make a number of changes. 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.

Fifteen 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 five of our past recommendations in 2014 or in early 2015. These 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.

2008-2[26]: Develop provisions that allow non-dispatchable LMRs, BTMG and other emergency resources to set energy prices in the real-time market.

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, addressing this recommendation will improve incentives to schedule imports and exports, to schedule load in the day-ahead market (and reduce RSG costs), and to invest in resources needed to maintain adequate supplies in MISO.

Status: MISO agrees with this recommendation. MISO implemented ELMP on March 1, 2015, which allows EDR to set prices. However, MISO operators call for the deployment of LMR and BTMG (which total nearly 8.5 GW) and take a variety of emergency actions before they call on EDR. Since LMRs, BTMG and other emergency actions will not set prices under the current ELMP model, real-time prices are likely not to reflect the value of these resources when MISO deploys them during emergencies. MISO has developed an emergency pricing proposal that would enable LMRs, BTMG, and other emergency resources to set price when called.

Next Steps: We have worked with MISO on the emergency pricing proposal. MISO made a filing with FERC on May 22, 2015 and requested an effective date of June 1, 2016. The solution MISO proposed would fully address this recommendation.

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

MISO clears the real-time market in five-minute intervals and schedules physical schedules on a fifteen-minute basis. However, it settles both physical schedules and 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.

26 To facilitate tracking, in this and future *State of the Market Reports* the numbering for a particular recommendation will be held constant across annual and quarterly reports. A recommendation of 2008-3 indicates the third recommendation listed in the *2008 State of the Market Report*. Beginning in the 2013 report all new recommendations will be listed sequentially as they appear in the Recommendations section as 2013-1, 2013-2, and so on.

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, and for participants to schedule imports and exports more efficiently.

Status: This recommendation was originally proposed in our *2012 State of the Market Report*. MISO has agreed this recommendation would have significant benefits and has had initial informal discussions with stakeholders. Implementing five-minute settlements for physical schedules was identified as a prerequisite for MISO fully complying with the scheduling requirements of Commission Order 764. Hence, MISO has moved forward on this aspect of the recommendation and filed with the Commission in 2014. Implementation is planned for the second quarter of 2015.

Next Steps: We believe MISO already has the metering and data necessary to support 5-minute settlements with generators, and implementing it will require only modest changes to MISO's existing settlement calculations. However, MISO has indicated it is continuing to evaluate this recommendation. We continue to recommend that MISO seek stakeholder input and allocate the resources to move forward on this recommendation.

2012-5: Introduce a virtual spread product.

Sixty percent of price-insensitive virtual bid and offer volumes (and 21 percent of all volumes) in 2014 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 prevent the participant from engaging in transactions that are 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 has evaluated the feasibility and costs and benefits of developing such a product. 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, as well as the practical implications of a virtual spread product on the day-ahead solution times.

Next Steps: MISO should complete its 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 whether to implement a 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 3rd quarter of 2015.

Next Steps: The IMM will work with MISO to 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.

Status: This is a new recommendation.

2014-2: Introduce a 30-Minute Local Reserve product to reflect VLR requirements.

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).

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 to eliminate excess payments and charges to physical transactions.

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. These TLR constraints raise more serious concerns than the external market-to-market constraints do because MISO typically prices TLR constraints at shadow costs that are many times higher than the value of the constraints in the neighboring area. Hence, the TLR congestion included in interface prices results in highly distorted incentives to schedule imports and exports. To fully address these concerns, we are recommending that MISO eliminate the portions of the congestion components of the interface prices associated with the external constraints.

Status: This recommendation was originally made in our *2012 State of the Market Report*, although it was previously raised in our *2011 State of the Market Report.* Over the past three years, we have been working with MISO, PJM, and stakeholders through the Joint and Common Market Stakeholder group to achieve a consensus on the nature and costs of the problem, and on a preferred solution. We have also raised this concern in proceedings before FERC in the context of the JOA and market-to-market coordination with SPP. In its order conditionally approving SPP's JOA with MISO, FERC has ordered SPP to file quarterly informational reports on the status of SPP and MISO's resolution of the problem. While a general consensus has been reached on the nature and the range of costs associated with the problem with both PJM and SPP, no consensus has yet been reached on the best solution.

MISO can address a sizable portion of this problem by modify its interface pricing and should encourage PJM and SPP to do the same. It is not essential that MISO and the other RTOs (PJM and SPP) modify their interface pricing at the same time. MISO has begun taking steps to implement our recommended solution, but has not committed to an implementation date.

Next Steps: MISO is completing its evaluation of the software costs of removing external congestion from its interface prices in its FTR market, day-ahead market, and real-time market. Consistency between these markets is important. MISO should also continue to work with PJM and SPP so that they do the same, and make any conforming changes necessary to the JOA to ensure that the market flow calculations do not include flows associated with imports and exports.

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

The RTOs continue to discuss allowing 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, or others that will allow the interface between the markets to be more fully utilized, would generate substantial benefits 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), which allows participants to submit intra-hour interchange transactions with a spread bid price. Based on a CTS design, 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).

Since 2014, MISO and PJM staff have conducted a number of joint workshops with stakeholders on this topic and PJM supports a coordinated transaction scheduling process with MISO.

Next Steps: MISO and PJM are completing a conceptual design and expect to make a FERC filing in mid-2015 with a proposed implementation in early 2017.

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 NERC documents and discussing alternatives with MISO.

Next Steps: Once we identify potential changes in the MISO procedures and in relevant joint operating agreements, MISO should move forward to implement these changes.

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. With one exception, all of these recommendations have now been adopted. The remaining recommendation in this area is discussed below.

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. Therefore, we recommend 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.

Status: This recommendation was originally made in 2014 based on a review of the first several months of operation after the integration of MISO South. MISO's first response was to review the Operating Guides to improve their compatibility with market operations. While the problem lessened slightly, it continues to be significant and the IMM has continued to monitor and comment on this issue. MISO is identifying both short run and long run options to address this recommendation. In the short-run, MISO plans to use a commitment model to simulate an economic commitment to determine which additional units must be committed to satisfy the VLR requirements. This will allow MISO to identify them as VLR units. In the long-run, it would be more efficient to model the constraint accurately in the day-ahead market and implement an analytic screen to identify when the VLR constraint caused the commitment of a generating unit.

Next Steps: MISO should complete the implementation of its short-term solution. Once implemented, we will work with MISO to identify feasible long-term solutions. In addition to identifying feasible technical solutions, MISO will need to determine whether Tariff changes are needed to implement the long-term solution.

2010-11: Improve expected deployment costs when selecting units to provide 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 complete the evaluation requested by stakeholders in the second half of 2015.

Next Steps: MISO should complete the requested evaluation and work with its customers to develop proposed Tariff changes.

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.

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

In the past, we have recommend a look-ahead dispatch process to address ramp demands that can be foreseen by MISO. Some of the most significant ramp demands MISO faces, however, are unforeseen. These include unforeseen ramp demands associated with unit outages, changes in wind, and changes in "non-conforming" load. To address these unforeseen ramp demands, MISO can procure ramp capability. This can be done by establishing ramp capability targets along with economic values for the ramp capability (e.g., a ramp capability demand curve). Even at a relatively low demand curve level, 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 would be valuable independent of a look-ahead dispatch process.

Status: MISO filed this proposal with the Commission in June 2014 and it was conditionally approved in October 2014. MISO subsequently made compliance filings and is awaiting final approval from the Commission.

Next Steps: MISO expects to implement this solution in the first quarter of 2016, pending approval from the Commission.

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 (which also requires the deviation occur in four consecutive intervals) is substantially more lenient than those of other RTOs.[27] Additionally, by establishing a threshold that is a fixed percentage of the dispatch instruction, the deviation tolerance band effectively becomes larger as a resource is ramped from its minimum output level to its maximum output level.

27 MISO's threshold also includes a minimum of six MW and a maximum of 30 MW.

To address these concerns, we recommend MISO adopt thresholds based on resources' ramp rates that are tighter than its current thresholds. This report includes a specific proposal in Section V.C.5. This will improve suppliers' incentives to follow MISO dispatch signals and, if used to determine eligibility for DAMAP and RTORSGP payments, will also help address the concerns we have raised regarding unreported unit derates.

Status: MISO agrees with this recommendation and is continuing to evaluate our proposal, which will ultimately be prioritized through the Market Roadmap process.

Next Steps: We are available to work with MISO 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.

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 responding RTO based on the responding RTO's day-ahead shadow price. This is a valuable provision because a constraint binding in the day-ahead market at the firm-flow entitlement can be costly and inefficient for constraints that are not expected to bind in real time or bind at levels that would enable an RTO to exceed its firm-flow entitlement in real time at a very low cost. Neither PJM nor MISO has ever requested additional firm-flow entitlement in the day-ahead market. Implementing this recommendation would likely improve the resource commitments in both RTOs.

Status: MISO has been working with PJM in evaluating this recommendation and has committed to stakeholders and FERC that it will meet intermediate deadlines to complete prerequisite projects including improved data exchange. In addition, MISO and PJM plan for an initial phase of firm flow entitlement exchange in the 3rd quarter of 2015. MISO and PJM presented initial results of a of detailed cost-benefit study for day-ahead coordination at the Joint and Common Market Meeting in May 2015 and received support for implementation from PJM and MISO stakeholders.

Next Steps: The RTOs should continue to work together to develop more detailed procedures and to finalize their plans for to move forward on implementation.

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.

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 sub regional 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 to limit transfers to 1,000 MW in an attempt to reduce exposure to SPP transmission charges. This is called the "Sub-Regional Power Balance Constraint" or "SRPBC". On July 16, 2014, MISO filed to implement a Hurdle Rate for the constraint of roughly $10 per MWh that would allow MISO to transfer more than 1,000 MW if the savings were larger than the hurdle rate.[28]

Although the Hurdle Rate was an improvement over the SRPBC, we remain concerned that inserting a variable cost of scheduling transfers above 1,000 MW inefficiently distorts MISO's commitment and dispatch because the SRPBC is not a physical constraint. The inefficient increase in congestion costs imposed on MISO customers are not offset by any countervailing

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

efficiency gains or cost savings in SPP because the market-to-market and TLR processes will be utilized by SPP when the transfers cause congestion in SPP. Additionally, the SRPBC can cause the dispatch model to compromise other internal constraints in order to satisfy the SRPBC, which has caused MISO to disable the SRPBC in the past. All of these costs are heightened by the fact that FERC has recently ordered a change in the Hurdle Rate methodology that would increase the rate by multiples of the current Hurdle Rate.[29]

As the parties move toward a resolution in the settlement process, we recommend 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: 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.

[29] Both MISO and Potomac Economics has filed for rehearing of this order.

2008-11: Remove inefficient barriers to capacity trading with adjacent areas.

A number of existing barriers limit capacity trading between MISO and PJM. These include access to transmission capability, deliverability requirements, and an unclear application of capacity obligations to external suppliers. These barriers substantially distort the capacity prices in both markets, thereby providing inaccurate economic signals to invest and retire resources. Eliminating these barriers will require the cooperation of both RTOs. In eliminating these barriers, we specifically recommend that the RTOs:

- Establish operating procedures to guarantee the delivery of firm energy associated with the quantity of external capacity resources;
- Establish reciprocal enforcement of capacity obligations in the exporting area (e.g., the day-ahead must-offer requirement); and
- Eliminate the use of pseudo-tying arrangements as a means to satisfy capacity obligations for external resources. Such arrangements can produce sizable economic inefficiencies and undermine reliability because they turn commitment and dispatch control for the unit over to the neighboring RTO that will not be modeling all of the transmission constraints and reliability requirements affected by the resource.

Status: MISO and PJM have performed a joint study of the capacity transfer capability between markets. Some progress has been made to eliminate some barriers to capacity transfers. However, very little progress has been made in addressing any of the three specific recommendations we describe above that would help facilitate a seamless capacity market across the region. We have recommended that FERC issue a mandate to assist the RTOs in making progress.

Next Steps: If no mandate is provided by FERC, MISO should continue to refine its proposals and discuss them with PJM in an attempt to achieve a consensus.

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.

<u>Status</u>: 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.

<u>Next Steps</u>: 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.

<u>2013-4</u>: 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. Furthermore, units that are currently suspended cannot 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 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 discussed the details of this IMM recommendation with customers in the fourth quarter of 2014. There was general support, minimal feedback, and plans were agreed to for filing Tariff language in time for the 2015/2016 PRA. However, MISO did not proceed to file the Tariff changes necessary to address this recommendation.

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.

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; and

- 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.

MISO has been discussing the potential benefits of transitioning to a seasonal capacity market structure. To capture the benefits described above, we recommend that MISO complete this evaluation and pursue implementation of seasonal capacity requirements.

Status: This is a new recommendation.

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: This is a new recommendation.

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. 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 require that the auction be cleared and prices be set as if these resources do not exist, which does not accurately reflect the true supply and demand conditions in the zone. This issue will become even more important next year as exports to PJM grow.

To address this concern, we recommend 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. In implementing this recommendation, it is necessary to rely on the neighboring market's performance requirements to have increased assurance that the units will be running when the MISO local zone needs the capacity.

Status: This is a new recommendation.

F. Recommendations Addressed by MISO

In addition to the progress made on a some of recommendations discussed above, MISO addressed several past recommendations by implementing changes to its market software, operating procedures, or Tariff provisions in 2014 and early 2015. These recommendations are discussed below.

2012-12a: Develop enhanced tools to identify units that are effectively derated or not following dispatch so that they may be placed off control.

This recommendation addressed cases where resources were well below their economic output levels because they were effectively derated or not responding to dispatch, but did not update their offer parameters to show that they were derated. Unreported derates impact reliability and can result in substantial unjustified make-whole payments and avoided RSG charges. Such units should be put off control by MISO. This requires a tool to alert MISO when this is happening.

In 2014, MISO enhanced its tools and procedures used to monitor the performance of units in real time. MISO's goals were to identify units that may be unresponsive to dispatch signals. However, MISO recognized that the procedures implemented in 2014 may not identify some units that are effectively derated by large amounts because they are unresponsive over multiple intervals.

Status and Resolution: We have seen substantial improvements (declines) in our metrics and screens designed to detect inferred (unreported) derates. We believe MISO's new tools and procedures and improved awareness on the part of stakeholders have contributed significantly to this improvement. MISO also has a related project to enable participants to update offers within the hour. This is scheduled for implementation in 2015. We will continue to monitor for unreported derates and refer suppliers to FERC as appropriate. We will also reassess any need for additional screening tools after MISO completes implementation of its tools to allow enhanced ability for participants to update offers in real-time.

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).

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

<u>Status and Resolution:</u> With the support of these results, MISO plans to file to address this recommendation in the near future.

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 have worked with MISO to present this change to its stakeholders and develop the necessary Tariff changes. MISO filed for these changes in the second quarter of 2015 and is awaiting a FERC Order. MISO has also developed the software changes necessary to implement these changes.

2012-17: Modify the market systems to recognize supplemental reserves being provided from quick-start units when they are in the process of starting.

When resources providing supplemental reserves are committed, the reserves are shifted to online resources. Unfortunately, MISO does not perceive that the committed resource is providing reserves or energy until the unit is synchronized and providing energy. Hence, all capacity from the resource will appear to be lost for five to 15 minutes. During this period, the quality of reserve capability is actually enhanced (not degraded) because the resource can provide energy and reserves more quickly to the system once it is online.

Status and Resolution: In 2014, MISO studied this recommendation and confirmed that the issue exists. The impacts related to this issue have declined because MISO has modified its operating practices to avoid committing resources that are providing offline supplemental reserves, and because the recently implemented ELMP pricing model allows such units to set prices prior to coming online. Therefore, this recommendation no longer warrants prioritization for response by MISO.

2011-14: Evaluate capacity credits provided to LMR to increase their accuracy.

In order for the capacity market to produce outcomes that are consistent with market fundamentals, it is important that the supply be accurately represented. LMR (excluding BTMG) receives full capacity credit under Module E even though these demand response resources are not tested to ensure their capability.[30] These resources have been shown in the past to have the ability to provide only a fraction of the total claimed capability. For example, MISO has

[30] The capacity credited to demand response LMR are adjusted to account for serving load without incurring transmission losses by grossing up the MW quantity by the appropriate LBA transmission loss percentage. It is also grossed up by the applicable PRM to equate to a load deduction.

reported that less than one-half of these resources were available during the winter shortages in early 2014. In addition, only roughly one-half of this demand response capability was responsive when they were deployed during shortage conditions in summer 2006.

Qualifying this capability at a level that accurately reflects its expected ability to reduce load can substantially affect the PRA results and economic signals provided by MISO's markets. Therefore, we recommended adopting testing procedures if possible, and/or derating these resources based on their actual performance or expected performance when called.

Status and Resolution: In recent years, progress has been made in assuring the demand response LMR capacity will fully deploy when needed.

- The Tariff requires annual accreditation by one of three allowable methods; documentation of capability through State programs, third party auditors, or past performance data which can be mock tests results.
- The Tariff has penalty provisions which can lead to demand response LMRs being disqualified to serve as capacity resources.
- MISO has continued to develop improved communication through the MISO Communication System (MCS) that requires market participants to report their LMR availability in real-time.
- MISO performs monthly drills to ensure that LBAs are prepared for deployment when called upon.

These changes reduce our concerns that MISO is granting excessive credit to LMRs in satisfying its capacity requirements. We intend to monitor the MCS data to ensure that LBAs and market participants are meeting their reporting requirements. Additionally, we intend to monitor the actual responses of the LMRs when MISO deploys them in the future. If we find that the data does not support an expectation of a full response, we will reinstate this recommendation.