2011 STATE OF THE MARKET REPORT FOR THE MISO ELECTRICITY MARKETS

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FOR MISO

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Guide to Acronyms

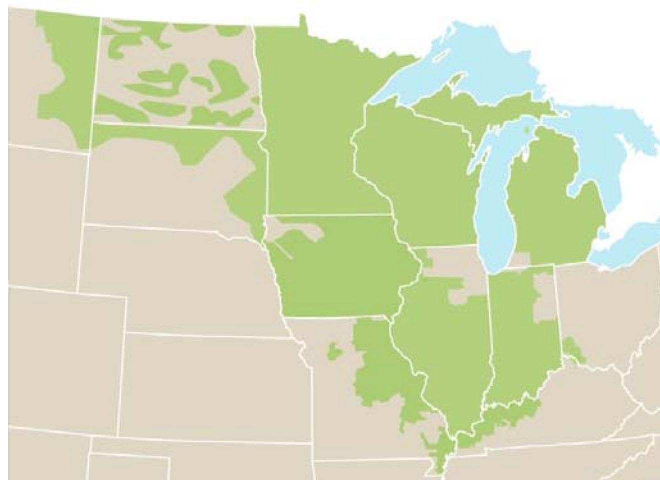
ARC	Aggregators of Retail Customers
ARR	Auction Revenue Rights
ASM	Ancillary Services Markets
BCA	Broad Constrained Area
BTMG	Behind-The-Meter Generation
CC	Combined Cycle
CDD	Cooling Degree Day
CMC	Constraint Management Charge
CONE	Cost of New Entry
CSAPR	Cross-State Air Pollution Rule
CT	Combustion 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
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.
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	Midwest Independent Transmission System Operator
MMBtu	Million British thermal units, a measure of energy content
MTLF	Mid-Term Load Forecast
MVL	Marginal Value Limit
MW	Megawatt
MWh	Megawatt-hour
NCA	Narrow Constrained Area
NERC	North American Electric Reliability Corporation
NSI	Net Scheduled Interchange
NYISO	New York Independent System Operator
PJM	PJM Interconnection, Inc.
PVMWP	Price Volatility Make Whole Payment
PY	Planning Year
RAC	Resource Adequacy Construct
RCF	Reciprocal Coordinated Flowgate
RDI	Residual Demand Index
RSG	Revenue Sufficiency Guarantee
RTO	Regional Transmission Organization
RTORSGP	Real-Time Offer Revenue Sufficiency Guarantee Payment
SMP	System Marginal Price
SSR	System Support Resource
STLF	Short-Term Load Forecast
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 MISO, our core functions include monitoring and reporting on the competitiveness and efficiency of MISO's wholesale electricity markets, transmission service, and balancing authority operations; identifying attempts to exercise market power and market flaws; and recommending improvements to market design and operations. This Executive Summary to the *2011 State of the Market Report* provides an overview of our assessment of the performance of the markets.

MISO operates competitive wholesale 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 the system's demands reliably and at the lowest cost.



The MISO markets also establish prices that reflect the marginal value of energy at each location on the network that facilitate efficient actions by participants in the short-term (i.e., resource dispatch and import/export scheduling), as well as efficient long-term decisions (i.e., investment, retirement, and maintenance).

A. Competitive Performance of the Market

The MISO energy and ancillary service markets generally performed competitively in 2011. Conduct of suppliers was broadly consistent with expectations for a workably competitive market. Our analysis revealed little evidence of potential attempts to exercise market power or engage in market manipulation. The output gap, a measure of economic withholding, declined over the course of the year and averaged less than 0.1 percent of actual load, which is extremely low. Consequently, market power mitigation measures were applied very infrequently.

B. Market Outcomes and Prices in 2011

Real-time energy prices in MISO averaged $33.61 per MWh, and ranged from $29 in the West region to $37 in the East. Prices were 1.9 percent lower than in 2010 due to (a) lower natural gas prices, which declined 8 percent and (b) lower loads, which declined 0.6 percent.[1] This correlation between energy and natural gas prices is expected in a workably competitive market where natural gas-fired resources are often the marginal supply.

Load averaged 64.6 GW in 2011 and set an all-time market peak at 103,985 GW on July 20th. During the peak-load week in late July the market performed well even with several days of loads above 100 GW, which were the result of record temperatures throughout the footprint. Although it did declare an Energy Emergency on July 21st, MISO did not rely on emergency procedures or involuntary load reductions to meet the system's needs at any time during the year. This is partly because MISO currently has a sizable capacity surplus, as is reflected in capacity prices. The Voluntary Capacity Auction (VCA) in 2011 continued to clear near zero, averaging only $0.50 per MW-month in 2011.

The value of real-time congestion totaled $1.24 billion, a 20 percent increase from 2010. The largest regional rise in congestion occurred in the Central region (up 44 percent), where market-to-market (M2M) constraints bound more frequently than in prior years. Congestion persisted in a west-to-east pattern, partly as a result of continued growth in wind output in the West. Wind output increased 30 percent to 3.0 GW. The introduction of the DIR type in June 2011 has made congestion there more manageable.

Finally, ancillary services prices broadly declined over the course of the year and averaged 6-10 percent lower than in 2010. This is attributable to the cumulative effects of lower energy prices, lower natural gas prices, fewer shortages (as load volatility has decreased), and lower demand curve penalty prices (for regulating reserves). MISO's ancillary services markets continue to operate with no significant issues. The regulating reserve market will change in response to FERC Order 755, requiring compensation for regulating resource's movement when deployed.

1 This value is adjusted for membership changes, including the departure of FirstEnergy in June.

C. Day-Ahead Market Performance

Convergence of energy prices between the day-ahead and real-time markets is important because day-ahead outcomes determine most resource commitments and are the basis for the payments to FTRs. Energy prices converged well on a monthly basis during 2011. However, the market was less effective in arbitraging locational differences in some of MISO's more congested areas. This report includes recommendations that should improve liquidity of the day-ahead market in these areas.

For the year, the day-ahead premium averaged 2 percent, down from 3 percent in 2010. The reduced day-ahead premium is in line with expectations as the real-time RSG rate declined from $2.04 per MWh in 2010 to $0.96 in 2011. Since this rate is applied to net purchases in the real-time market, this rate should be positively correlated with day-ahead purchases and with the resulting day-ahead price premium.

In addition, real-time price volatility declined in 2011 compared to 2010, which reduces the incentive to pay a day-ahead premium as a hedge against real-time price volatility. Scheduled virtual transactions increased by approximately 33 percent, which was primarily due to the change in the real-time RSG allocation in April 2011 that is discussed below. However, much of the increase was comprised of price-insensitive virtual transactions that are not as beneficial at promoting price convergence as those that are price sensitive. Some of the price-insensitive trading appeared motivated by price differences associated with different loss factors in the day-ahead and real-time markets. MISO took steps to improve the modeling of day-ahead loss factors in December, which resulted in a reduction in the associated virtual trading activity.

D. Real-Time Market Performance and Uplift

Substantial volatility in real-time energy markets is expected because the demands of the system can change rapidly and because supply flexibility is restricted by the physical limitations of the resources and the 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 operates a true five-minute real-time market, sending out new dispatch instructions and price signals every five minutes. As currently designed, the real-time market software is limited in its ability to "look ahead" and anticipate near-term needs.[2] As a result, the system is frequently "ramp-constrained" (i.e., generators are moving as quickly as they can up or down), which produces transitory price spikes. Because settlements are based on hourly average prices, the MISO market includes price-volatility make-whole payments (PVMWP) to ensure that suppliers have the incentive to be flexible and respond to MISO's dispatch instructions. PVMWP rose 23 percent in 2011 to $84 million as congestion-related price volatility increased at some locations and some generators provided additional flexibility. These payments supplement MISO's RSG payments that ensure resources cover their as-offered costs.

In 2011, real-time RSG payments declined 45 percent from 2010 because load was more fully scheduled day ahead during most months (reducing MISO's need to commit peaking resources after the day-ahead market to satisfy incremental load), and because lower natural gas prices reduced the production costs of most of the units receiving RSG payments. Commitment of resources for voltage support, however, continued to occur consistently throughout the year. In 2010, some of the offer prices of these resources were well above competitive levels and led to inflated RSG payments. In response to an IMM recommendation in the *2010 State of the Market Report*, MISO filed in December 2011 for tighter market power mitigation thresholds for such commitments.

In April 2011, MISO implemented a revised RSG cost allocation methodology. The new methodology includes:

- A charge for RSG costs related to managing congestion to participants with net real-time deviations from the day-ahead that load the constraint;
- A charge for RSG costs related to satisfying market-wide capacity needs to participants with net deviations that increase the need to commit peaking resources for capacity; and
- A charge to load for costs that are not caused by deviations.

Our analysis indicates that this allocation is not consistent with causes of the costs, which produces inefficient incentives by (a) discouraging conduct that does not cause the costs and (b) not discouraging conduct that does cause the costs. In particular, MISO allocates 90 percent of

2 A Look-Ahead Commitment (LAC) was implemented in the second quarter of 2012 that improves the system's ability to commit and decommit fast-starting resources economically.

the real-time RSG costs to market-wide deviations, even though such deviations are likely only causing approximately one-third of the costs. Market-wide deviations often bear a majority of real-time RSG costs in hours when the total net deviations are *negative* (i.e., when they are not likely causing any costs). In addition, a FERC-mandated error in the cost allocation formula is reversing the intended allocation of congestion-related costs to virtual load and virtual supply. These issues are addressed in the recommendations below.

E. Resource Adequacy and Demand Response

Overall, these results indicate that the system's resources should be adequate for summer 2012 if the peak conditions are not substantially hotter than normal. Under normal conditions, we estimate a capacity surplus of 17 percent (15 GW), which accounts for expected forced outage rates and assumes that MISO's full 8000 MW of DR is available and responds when called. This surplus is more than enough to satisfy MISO's 2400 MW reserve needs. In an unusually hot year, however, the combination of higher load, higher temperature-related deratings, and lower load diversity will reduce MISO's capacity margin to 5 percent (4.8 GW). At this level, MISO will be relying on a combination of additional imports or DR curtailments of 5.7 GW to avoid reserve shortages. Hence, it is critical that MISO DR capability perform well when called.

While the supply is adequate for the upcoming summer, the increased penetration of wind resources and new EPA regulations will put substantial downward pressure on capacity margins in MISO over the short-term to mid-term time horizons. MISO's analysis suggests that up to 12 GW of coal-fired capacity in MISO would be at risk of retirement due to the compliance costs of these regulations. Subsequent analysis by MISO indicates that higher levels of capacity could be at risk if the prevailing low natural gas prices continue for the long term. MISO surveys of market participants' compliance plans also indicate substantial amounts of potential retirements and long-term outages related to environmental retrofits.

The MISO RAC will play a pivotal role in assuring that the market supports reliable capacity margins over the long-term. Our review of the RAC, including changes that were filed in 2011 and await FERC approval, indicates that it will not provide efficient incentives to facilitate the investment necessary to maintain an adequate resource base. The two most critical flaws are (a) the representation of the demand for capacity in MISO's VCA and (b) the prevailing barriers to capacity trading between PJM and MISO. These issues have contributed to MISO's capacity market clearing at close to zero in every month of 2011. The minimum capacity requirements and deficiency price in Module E establish a "vertical demand curve", which implicitly values incremental capacity at zero. We 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 prices to rise efficiently as capacity margins fall to accurately signal the value of capacity, which will be important for both new investors and for suppliers considering environmental retrofits. It would also enable potential investors to project long-term capacity revenues and facilitate forward contracting. Finally, we find that the capacity credit for wind resources and a large share of the DR resources are likely overstated under Module E, which results in lower capacity prices in the VCA. We recommend MISO evaluate improvements that would allow the credits to better reflect the resources' expected contributions during peak conditions.

As discussed above, DR is an important contributor to MISO's resource adequacy and provides a number of other benefits to the market. MISO lost 1300 MW of DR capability during 2011, largely due to the departure of FirstEnergy in June 2011. However, the amount of DR participating in MISO DR programs, including Emergency Demand Response (EDR) increased from 400 MW in 2010 to 1500 MW. This is a significant change because it increases MISO's control and ability to set prices efficiently when these resources are deployed. MISO is also implementing the capability for Aggregators of Retail Customers (ARCs) to actively participate in the MISO markets, which should expand its DR capability. However, the RAC provides a key economic signal for DR, so the improvements described above to the RAC will facilitate the efficient development of new demand response resources.

F. Recommendations

Although the markets performed competitively in 2011, we recommend a number of improvements. Some of these recommendations were made in prior reports, which is not unexpected as many of them require both tariff and software changes that can require years to implement. However, MISO addressed seven past recommendations in 2011 and early 2012 that are discussed in Section X of this report. The following table shows our current recommendations, organized by the area of the market they address.

Recommendations
Energy Pricing and Transmission Congestion
1. Develop provisions that allow non-dispatchable DR (including interruptible load and BTMG) to set energy prices in the real-time market.
2. Discontinue the constraint relaxation algorithm for market-to-market constraints and set LMPs based on a transmission constraint's marginal value limit when the constraint is unmanageable.
3. Consider implementing a graduated marginal value limit (i.e., transmission demand curve) for transmission constraints.
RSG Cost Allocation
4. Improve the allocation of real-time RSG costs to make it more closely aligned with causes of the costs by making the following changes: a. Netting market-wide deviations to determine the share of the real-time RSG that should be allocated via the DDC rate. b. Use of GSFs to determine the costs that should be allocated via the CMC rate. c. CMC sign error affecting the RSG cost allocation to virtual transactions.
Market Operations
5. In the short-term, improve the use of the load offset parameter to proactively manage the system's ramp capability to address anticipated ramp demands.
6. In the longer-term, develop a look-ahead real-time dispatch capability to more efficiently manage the system's ramp capability to address anticipated ramp demands.
7. Implement a ramp capability product to address unanticipated ramp demands.
8. Eliminate the transmission constraint deadband.
9. Expand the JOA to optimize the interchange with PJM to improve price convergence with PJM.
10. Implement procedures to utilize provisions of the JOA that would improve day-ahead M2M coordination with PJM.
ASM Improvements
11. Improve the efficiency reserve selections by eliminating the guarantee payments to deployed spinning reserves.
Resource Adequacy
12. Remove inefficient barriers to capacity trading with adjacent areas.
13. Introduce a sloped demand curve in its RAC to replace the current vertical demand curve.
14. Evaluate capacity credits provided to wind resources and LMR.
15. Improve SSR designation and compensation provisions.

I. Introduction

As the Independent Market Monitor (IMM) for the Midwest Independent Transmission System Operator (MISO), Potomac Economics is responsible for evaluating the competitive performance, design, and operation of wholesale electricity markets operated by MISO. In this *2011 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 spot market for capacity. ASM jointly optimize the allocation of resources between energy and ancillary service products. The joint optimization also allows energy and ancillary service prices to reflect the opportunity cost tradeoffs between products, as well as shortages of both products. The Voluntary Capacity Auction (VCA), implemented in June 2009, allows participants to buy and sell capacity to satisfy residual capacity requirements under Module E of the MISO Tariff. The addition of each of these markets has improved the long-term economic signals in MISO.

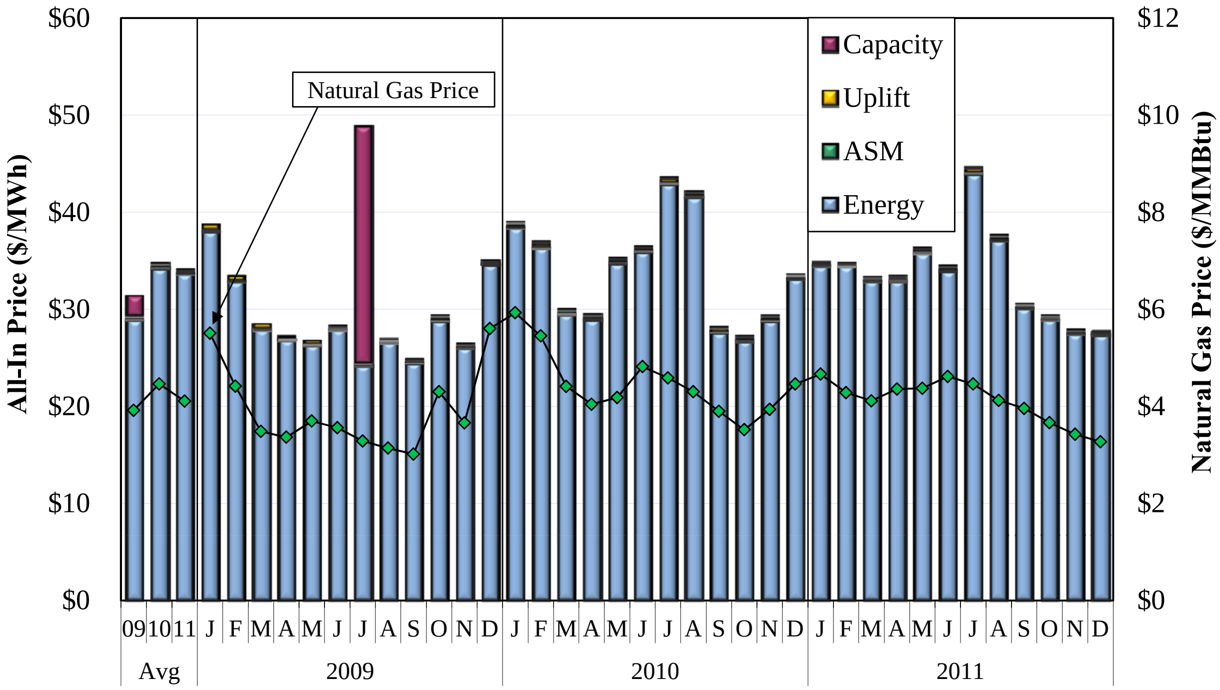
3 FTRs are financial instruments that entitle their holder to a payment equal to the congestion price difference between locations in the day-ahead energy market.

II. Prices and Load Trends

A. Market Prices in 2011

Figure 1 summarizes changes in energy prices and other market costs. It shows 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. Capacity costs are estimated by multiplying the VCA clearing price times the capacity requirements in each month.

Figure 1: All-In Price of Electricity
2009–2011

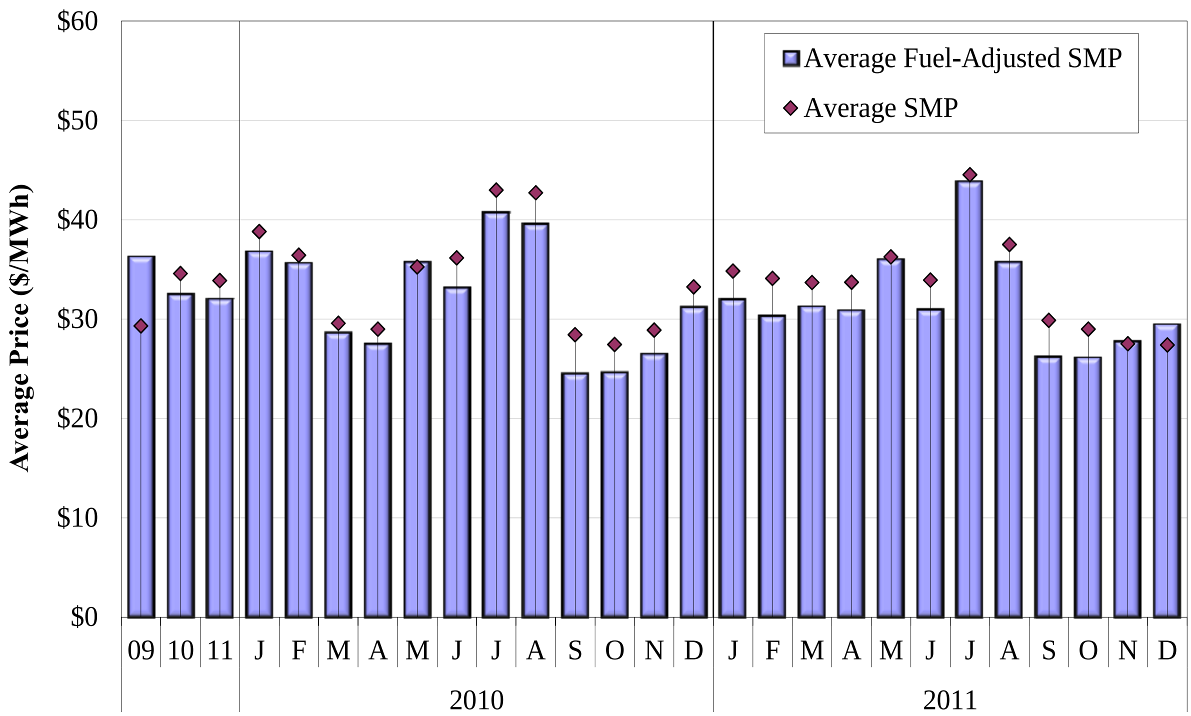


The all-in price in 2011 declined 2 percent to $34.11 per MWh. The decline is attributable to lower fuel prices and a slight reduction in average load, particularly in August. As in prior years, the energy component comprises the vast majority of the total all-in price, nearly 99 percent. Uplift costs, including RSG payments and PVMWP, decreased 8 cents to $0.31 per MWh. The contribution to the all-in price in 2011 by ancillary services costs was 15 cents, and capacity costs contributed less than one cent per MWh. These levels are virtually unchanged from 2010. Very low capacity prices are expected from the VCA when there is a prevailing capacity surplus in MISO. Recent member departures have not significantly affected the VCA results.

The figure also shows that energy price fluctuations are driven in large part by natural gas prices. This relationship exists 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 translate to changes in offer prices. The correlation between natural gas and energy prices is not stronger because natural gas-fired resources only set prices in 23 percent of the intervals; although, these periods tend to be the highest-load intervals. Coal-fired resources set the energy price in 93 percent of intervals, including virtually all off-peak intervals. Frequently congestion causes both natural gas and coal to be on the margin in the same interval in different areas. Although natural gas prices declined 8 percent from last year, coal prices rose by 6 to 10 percent and oil prices rose by 37 percent.

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 average three-year fuel price of the marginal fuel during the interval.[4]

Figure 2: Fuel-Adjusted System Marginal Price
2009–2011



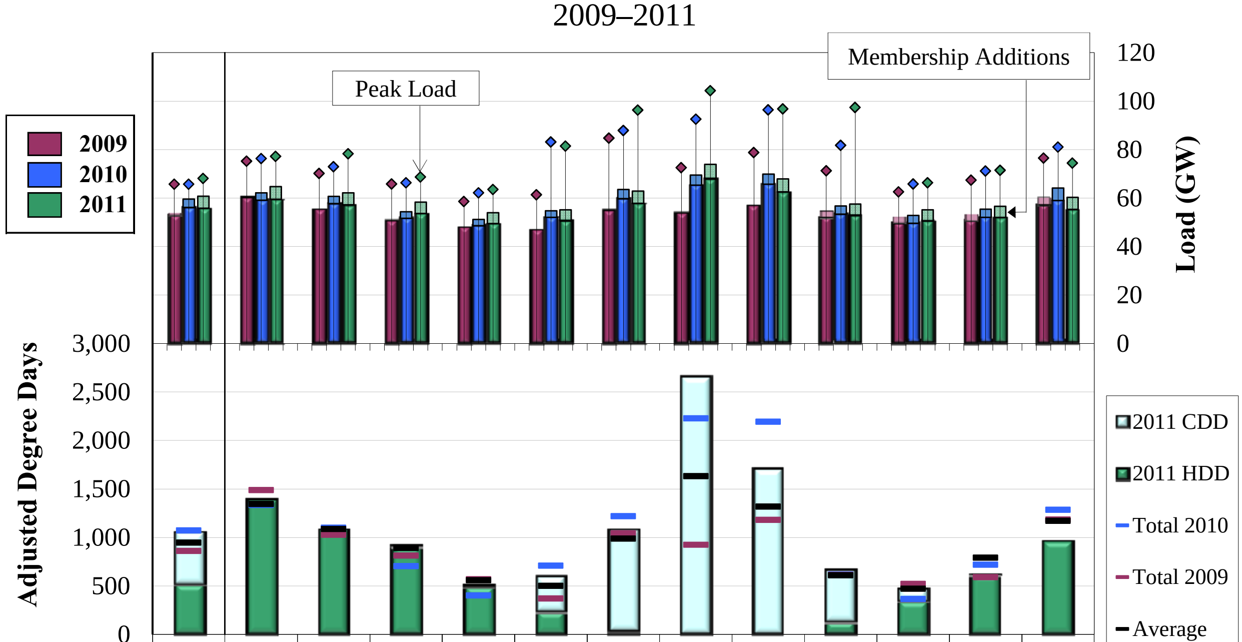
4 See Figure A4 in the Appendix for a detailed explanation of this metric.

Figure 2 shows that average fuel-adjusted energy prices in 2011 declined 1.4 percent, slightly less than the 2.0 percent drop in average SMP. This indicates that fuel prices were just one cause of the decline in energy prices since 2010. The balance—approximately two-thirds of the total change—is attributable to a 0.6 percent decline in average load, increased generation by intermittent resources, and a 1.5 GW increase in average net imports.

B. Load and 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 for 2009 to 2011. The top panel shows the monthly average load in the bars and the peak monthly load in the diamonds. The bottom panel shows monthly Heating Degree Days (HDD) and Cooling Degree Days (CDD) summed across four representative locations in MISO.[5]

Figure 3: Heating and Cooling Degree Days
2009–2011



10-11 % Chg	2011	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Avg. Load	-1%	1%	-1%	4%	2%	-3%	-3%	4%	-5%	-1%	2%	0%	-6%
Degree Days	-2%	4%	-2%	30%	25%	-16%	-12%	19%	-22%	7%	28%	-15%	-26%

5 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 (i.e., so one adjusted-HDD has the same impact on load as one CDD). The factor was estimated by regression analysis.

Total degree days declined by 2 percent from 2010, consistent with the modest reduction in average load of 0.6 percent.[6] Most months in 2011 exhibited weather patterns consistent with or slightly more extreme than historical averages. However, November and December were mild, with higher than normal temperatures. July was exceptionally warm across the region, resulting in a 7.5 percent rise in the annual peak load to 104 GW, 6 GW higher than the peak load forecast in MISO's *2011 Summer Resource Assessment*. The week of July 17–23 is examined in greater detail below. The impact on load of continued improvement in economic activity offset the slight decline in degree days. The Chicago Purchasing Manager's Index, a leading business barometer and a broad measure of economic activity in the region, has been expansionary since October 2009.

C. Peak Load Week, July 17 to 23

A heat wave that spanned all of MISO in late July contributed to record load levels for several days. As shown below, temperatures were significantly above the historical average across the MISO, although the heat wave subsided earlier in the West region.

Table 1: Temperatures in MISO during the Peak Summer Week

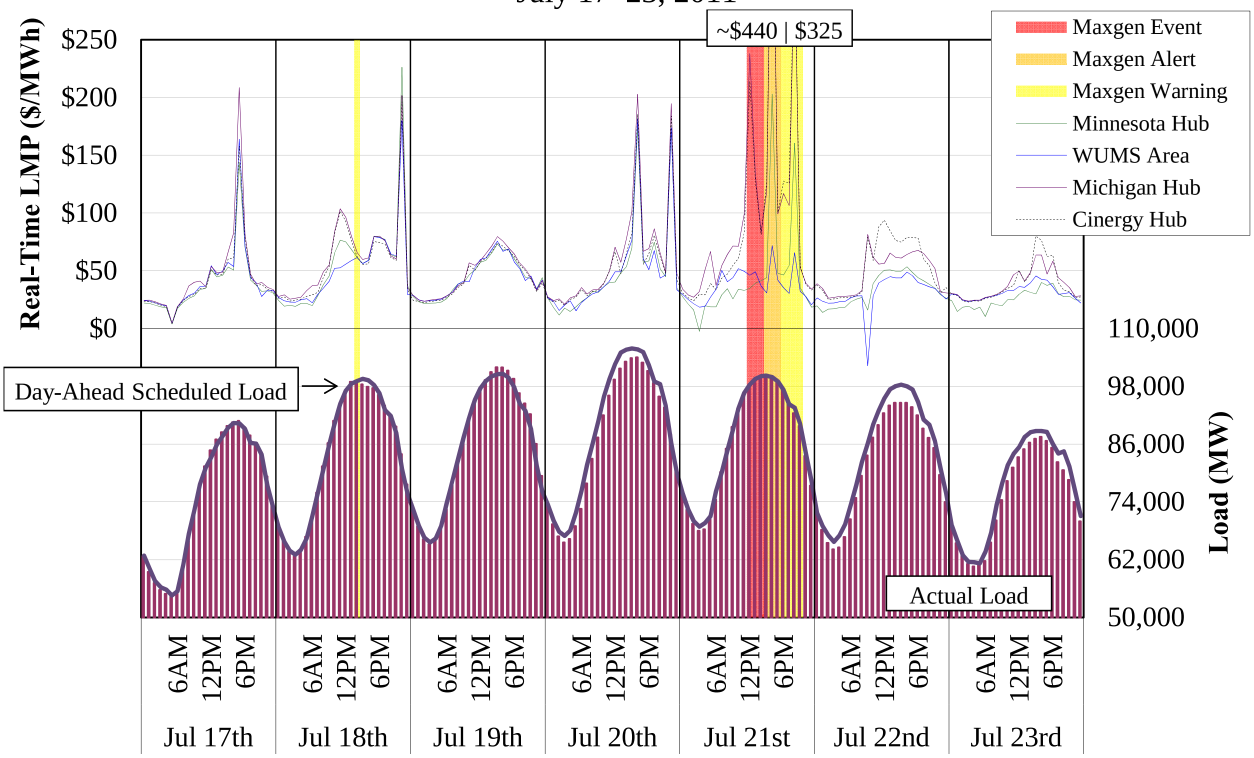
	Historical Average	July 17	July 18	July 19	July 20	July 21	July 22	July 23
Cincinnati	87	91	93	96	98	99	97	93
Detroit	84	93	96	90	96	100	95	91
Indianapolis	86	94	94	96	98	100	97	96
Milwaukee	82	95	95	85	98	94	86	86
Minneapolis	84	93	98	97	96	86	89	85
St. Louis	90	95	97	99	100	103	101	100

Figure 4 shows the day-ahead and real-time load in the lower panel and real-time prices in the upper panel. Shaded areas show various types of Maximum Generation Alerts and Events. MISO issued a Hot Weather Alert from July 17–23, Conservative Operations from July 18–22,

6 Unless otherwise stated, percentage changes in load reported in this report are adjusted for membership additions and departures, including FirstEnergy in June 2011. Aggregate load numbers are not adjusted.

and Maximum Generation Alerts on July 18 and 21. Although load peaked on July 20th, supply conditions were tighter on July 21st because wind output was 3 GW lower.

Figure 4: Load and Real Time Prices
July 17–23, 2011



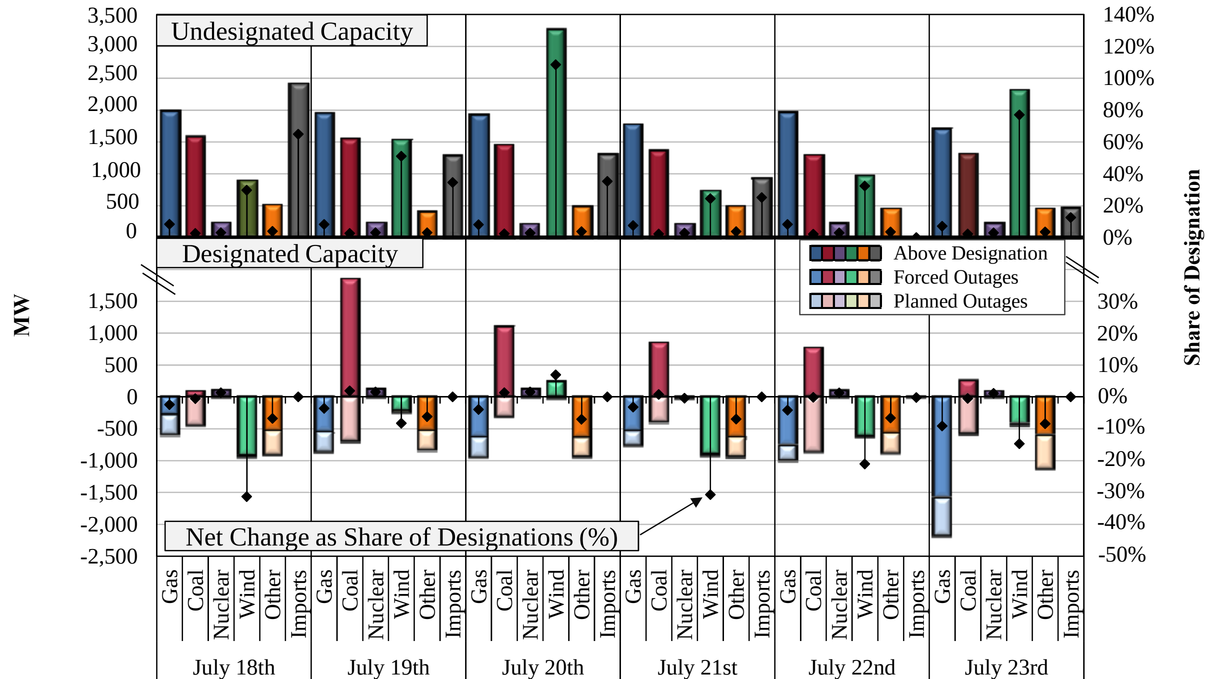
On July 20th, actual load peaked at 103,975 MW between 3 and 4 p.m., which was almost 2 GW lower than the net load scheduled day ahead for this hour. Controlling for membership, this peak exceeded the 2006 summer load peak by 1 GW and exceeded MISO's forecasted peak for the year by 6 GW. Real-time prices averaged $191 per MW in this hour and congestion was limited. Wind output of 4 to 5 GW helped prevent the need for a Maximum Generation warning or alert.

On July 21st, a Maximum Generation Event Step 1a was declared from noon to 3 pm, which triggered cuts of approximately 100 MW of non-firm exports to PJM. No voluntary load reductions or emergency commitments of generators occurred on this day. The Maximum Generation event was caused in part by the fact that wind output was roughly 3 GW lower than in the peak hours of July 20th. Congestion out of WUMS also reduced supply available to the rest of MISO and caused WUMS prices to remain low when prices in other areas rose sharply.

On July 22–23, lower loads and day-ahead load scheduling above 100 percent led to modest prices on July 22–23. Voluntary load curtailment (estimated at 500 to 900 MW) during the heat wave helped satisfy the system's needs but was not reflected in energy prices.

The next figure examines generation and import capability available during the daily peak hour in each day of the heat wave relative to the designated capacity under Module E. The top panel shows capacity that was not designated (so any available capacity is a net increase from designated levels), while the bottom panels shows changes from the designations due to forced and planned outages. Reductions in wind output are classified as forced outages in this figure.

Figure 5: Peak Hour Capability
July 17–23, 2011



Market-Wide Summary (all unit types) -- Percent Change from Module E Designations:						
Undesignated Cap.	6.8%	6.2%	7.7%	4.9%	4.3%	5.7%
Designated Capacity	-2.4%	-0.6%	-0.7%	-2.0%	-2.3%	-3.5%
Total Supply Δs	4.3%	5.6%	7.0%	2.9%	2.1%	2.2%

The figure shows that designated resources provided on average 2 percent less capacity than designated as a result of:

- Higher than anticipated forced outages;
- High-temperature derates of gas-fired capacity exceeded forecasts by 700 MW; and

- Variability of wind resources—on July 21, Module E wind resources were 31 percent below designated capacity.

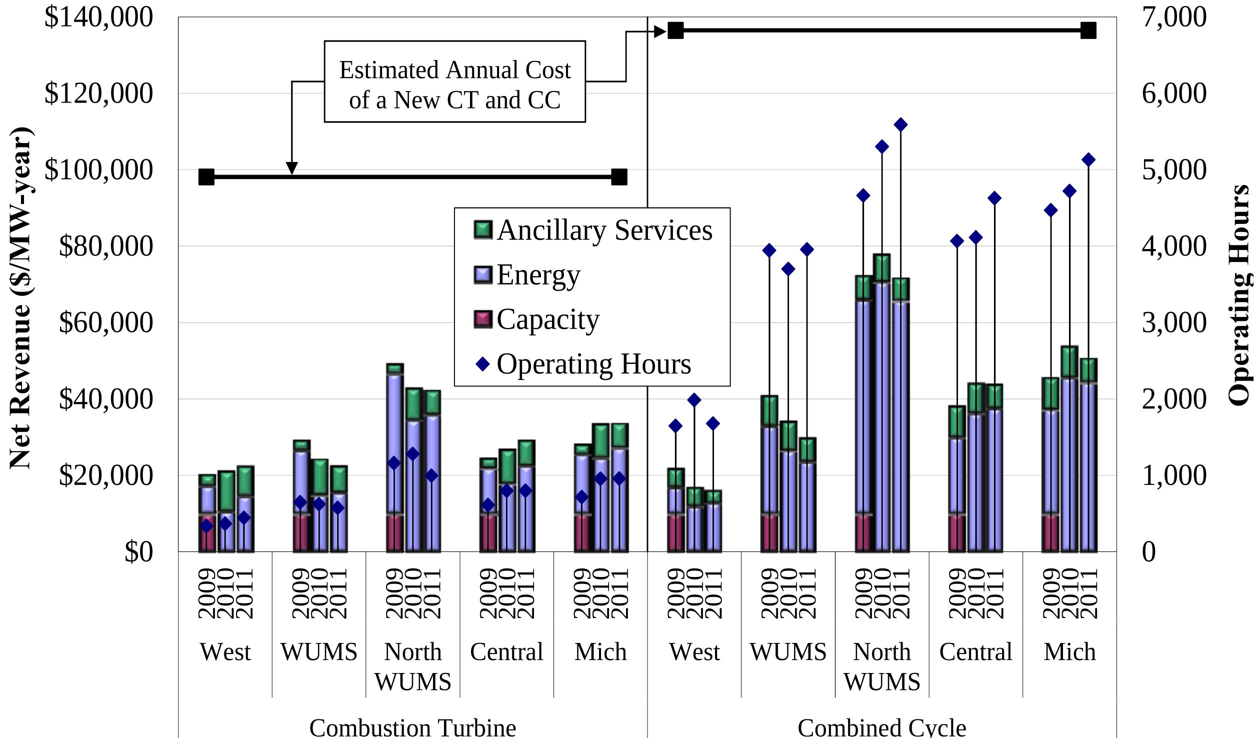
However, undesignated capacity and increased imports more than compensated for this shortfall. Hence, there were no load curtailments or emergency commitments during the week. Nonetheless, the under-performance of designated resources raises concerns. We address this concern by recommending that MISO modify the capacity credits for wind resources and certain types of demand response to increase their accuracy.

D. 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.

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 6 shows estimated net revenue for a hypothetical new Combustion Turbine (CT) and Combined-Cycle (CC) generator for the prior three years. For comparison, the figure also shows 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 6: Net Revenue Analysis
2009–2011



The net revenue in 2011 for both types of units was substantially less than CONE in all regions. This is consistent with expectations because the MISO region continues to exhibit a capacity surplus and did not experience significant shortages in 2011. Even in North WUMS, the most congested area in MISO during 2011, revenues for a CC and CT were only 53 and 43 percent of CONE, respectively. Although there is currently a capacity surplus, market design issues remain that will likely undermine the economic signals when the surplus dissipates and resources are needed. To address this issue, we recommend a number of improvements to MISO's RAC, and recommend that demand response resources set energy prices when they are on the margin under peak conditions.

The next section summarizes and evaluates the supply in MISO and in the capacity market intended to ensure the adequacy of MISO's resources.

III. Resource Adequacy

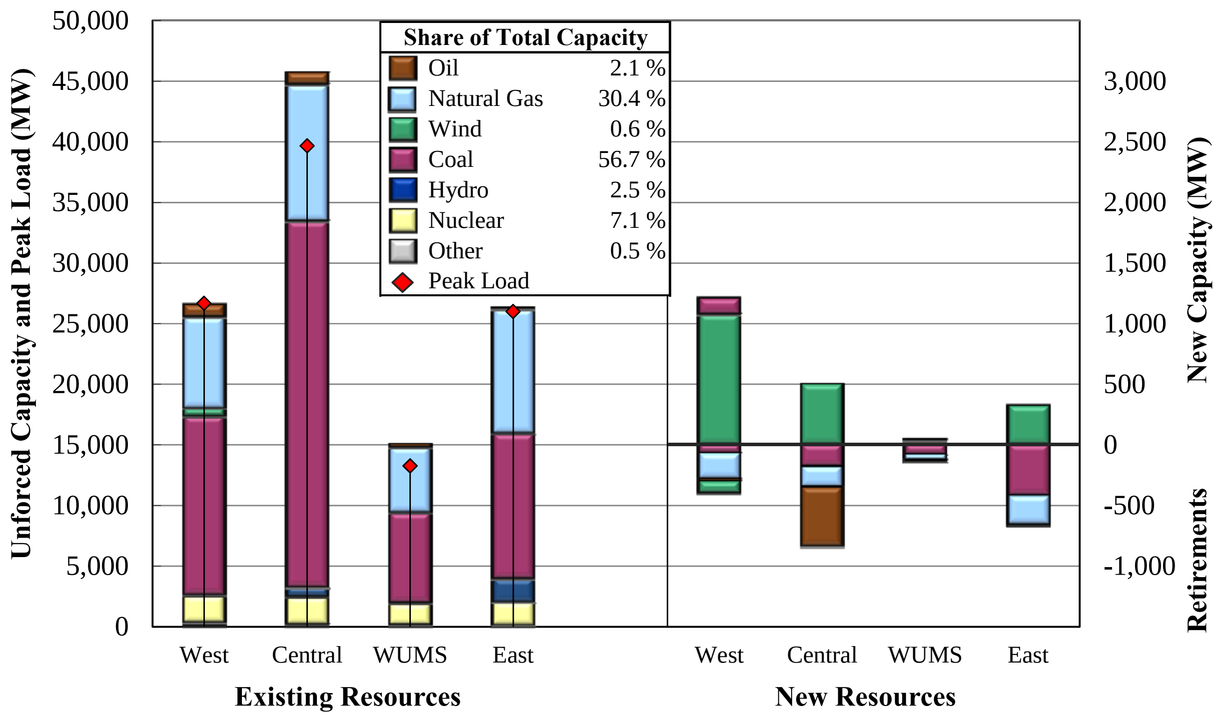
This section evaluates the supply in MISO, including:

- Summarizing the current resources and recent changes;
- Evaluating the adequacy of resources for meeting peak needs in 2012;
- Discussing future issues that may threaten supply; and
- Reviewing the outcomes and design of resource adequacy provisions.

A. Regional Generating Capacity

Figure 7 shows the capacity distribution of existing generating resources. The left panel shows the distribution of unforced capacity by region and fuel type, along with the annual peak load in each region. The right panel displays the change in the resources from 2010 to 2011 based on summer capacity ratings, which do not account for forced outages or intermittency.[7]

Figure 7: Distribution of Generating Capacity
By Fuel Type and Coordination Region, 2011



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7 Because we show unforced capacity in the left panel, wind resources are substantially derated. This is not true for the summer ratings shown for new resources in the right panel.

Regional capacity exceeded the 2011 peak load in each region, except the West region. However, the average wind output is much greater than the unforced capacity levels of wind resources, which cause the largest surpluses to exist in the western areas and the smallest surpluses to exist in the eastern areas. These differences promote the west-to-east flows and congestion patterns typically observed in the MISO markets. Despite increased wind generating capacity, MISO continues to depend heavily on coal-fired generation, which accounts for over 50 percent of MISO's generating resources. As discussed later in this section, MISO expects some capacity to retire in response to proposed changes to environmental rules.

The majority of capacity additions in 2011 were wind units in the West region, where wind profiles are most attractive. Although wind resources are relatively costly, they benefit from a variety of subsidies, including production tax credits, state renewable portfolio standards, and the expected benefits of the transmission investments planned to improve their deliverability (i.e., Multi-Value Projects). The loss of 14.3 GW of capacity in the East Region due to FirstEnergy's departure is not reflected in the figure.

B. Capacity Margins

This section assesses capacity levels in MISO and their adequacy for satisfying the forecasted peak loads for summer 2012. We estimate capacity margin values under various scenarios that are intended to indicate the expected physical surplus over the forecasted load. The data used in this section is consistent with the data used by MISO in its annual *Summer Resource Assessment*. However, the *capacity margins* we calculate are different from the *reserve margins* MISO has calculated and reported in past assessments.

The planning reserve margins are generally based on: (a) peak load forecasts under normal conditions;[8] (b) normal load diversity; (c) average forced outage rates; and (d) full response from DR resources (behind the meter generation, interruptible load, and directly controllable load management). These factors tend to cause the capacity levels to overstate the levels one would expect under warmer-than-normal summer peak conditions. For example, many resources must

8 Expected peak load in reserve margin forecasts are generally median "50/50" forecasts (i.e., there exists a 50 percent chance load will exceed this forecast, and a 50 percent chance it will fall short).

be derated in response to environmental restrictions or the effect of high ambient temperatures when warmer-than-normal summer conditions occur.[9] This factor, however, is offset by the fact that planning reserve margins do not include resources in the region that are not designated as capacity resources. We generally include undesignated capacity to evaluate what resources are likely to be physically available under peak conditions.

In its *2012 Summer Resource Assessment*, MISO presented baseline planning reserve margin calculations alongside a number of valuable scenarios that demonstrate the sensitivity to changes in the key assumptions that we evaluate in our capacity margin analysis. For example, MISO's Assessment includes scenarios that include undesignated capacity, as well as assumptions related to hotter than normal peak conditions that we describe below in our analysis. Because we use the same capacity data, our results are fully consistent with the MISO Summer Assessment.

Table 2 shows our estimated capacity margins for summer 2012 for a normal year (e.g., assumes a 50/50 load forecast, average load diversity, and an average rate of forced outages/deratings) and a "high-temperature" year (e.g., assumes a 90/10 load forecast, lower load diversity, and higher temperature-related deratings).[10] The latter case is consistent with conditions that prevailed in the peak demand period in 2006 and 2011. We also include multiple DR scenarios to show how varying response rates affect MISO's overall resource adequacy. These scenarios also provide insight regarding MISO's expected reliance on DR.

9 The summer ratings are generally based on ambient temperatures far below what can be expected during summer heat events that are associated with peak load. Drought conditions can lead to generator outlet cooling water restrictions (as occurred in 2006), resulting in significant deratings for impacted resources.

10 The capacity margin formula is: [(Capacity + Imports) – (Peak Load – DR)] ÷ (Peak Load – DR) – 1.

Table 2: Capacity, Load and Capacity Margins
Summer 2012

Region	Base Case Full DR	Base Case Half DR	Base Case No DR	High Temp and Low Diversity Full DR	High Temp and Low Diversity Half DR	High Temp and Low Diversity No DR
East						
Load	36,955	36,955	36,955	40,108	40,108	40,108
Capacity	37,933	37,933	37,933	36,969	36,969	36,969
Demand Response	2,152	1,076	-	2,152	1,076	-
Margin	*8.8%*	*5.8%*	*2.8%*	*-2.4%*	*-5.1%*	*-7.7%*
Central						
Load	31,608	31,608	25,833	34,305	34,305	34,305
Capacity	36,299	36,299	23,930	35,376	35,376	35,376
Demand Response	2,075	1,037	-	2,075	1,037	-
Margin	*26.6%*	*22.8%*	*0.7%*	*13.6%*	*10.3%*	*7.1%*
West						
Load	25,833	25,833	31,608	28,037	28,037	28,037
Capacity	23,930	23,930	36,299	23,321	23,321	23,321
Demand Response	3,825	1,913	-	3,825	1,913	-
Margin	*17.4%*	*8.6%*	*19.2%*	*4.8%*	*-2.7%*	*-9.4%*
MISO						
Load	94,395	94,395	94,395	102,450	102,450	102,450
Capacity	98,162	98,162	98,162	95,666	95,666	95,666
Demand Response	8,052	4,026	-	8,052	4,026	-
Margin Qty (MW)	***15,331***	***11,305***	***7,279***	***4,780***	***754***	***(3,272)***
Margin (%)	***17.1%***	***12.3%***	***7.7%***	***4.9%***	***0.8%***	***-3.2%***

The results in Table 3 show that the capacity surplus varies considerably depending on the load and demand response capability assumptions. The baseline capacity margin for MISO region is 17.1 percent based on the expected load, average load diversity, average forced outage rates, and full response from the DR resources. Regional capacity margins are 8.8 percent in the East region, 17.4 percent in the West and 26.6 percent in the Central, which helps explain why MISO generally exhibits west-to-east power flows. The capacity surplus in this case is more than enough to satisfy MISO’s 2400 MW reserve needs.

For the high-temperature case, the results show that MISO will likely be short of operating reserves during peak demand conditions. In this case, the combination of higher load, higher temperature-related deratings, and lower load diversity will reduce MISO’s capacity margin to 5 percent or 4.8 GW. Since this surplus includes more than 8 GW of load curtailments and MISO’s reserve requirements are 2.4 GW, this case implies that MISO will be relying on 5.7 GW from a combination of additional imports or DR curtailments to avoid reserve shortages. This is well over half of the DR capability in MISO. In the half-DR case, the capacity margin falls to 750 MW, substantially less than the 2.4 GW operating reserve requirement (i.e., indicating a substantial reserve shortage). Likewise, the high-temperature case indicates that the system will be substantially short of *energy* in the no DR scenario. Although these shortages would likely be mitigated by increased imports, these results underscore how important it is for the MISO DR capability to perform well when called.

Overall, these results indicate that the system's resources should be adequate for summer 2012 if the peak demand conditions are not substantially hotter than normal. However, capacity margins are 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 subsections.

C. Potential Impact of the New EPA Regulations

MISO continues to study and model the potential impacts of the Environmental Protection Agency's (EPA) Cross-State Air Pollution Rule (CSAPR) and Mercury and Air Toxics Standards (MATS) on the MISO market. MISO's analysis suggests that up to 12 GW of capacity in MISO would be at risk of retirement due to the compliance costs of these regulations. Subsequent analysis by MISO indicates that higher levels of capacity could be at risk if the prevailing low natural gas prices continue for the long term. MISO surveys of market participants' compliance plans also indicate substantial amounts of potential retirements and long-term outages related to environmental retrofits.

Together with the increased penetration of wind resources, it is clear that the new EPA regulations will put substantial downward pressure on capacity margins in MISO over the short-term to mid-term time horizons. The MISO RAC will play a pivotal role in assuring that the market supports reliable capacity margins over the long-term.

D. Attachment Y and SSR Status Designations

Attachment Y to the MISO Tariff requires suppliers to submit retirement plans to MISO six months in advance of its desired retirement date. Based on a reliability study, MISO may designate a resource as a System Support Resource (SSR). This designation had never been applied in MISO until early 2012. An SSR cannot retire until a reliability solution (e.g., a system upgrade) can be implemented or the reliability condition no longer exists. An SSR must be compensated during this period.

MISO's first SSR designations in 2012 have shed light on deficiencies in the Attachment Y process and the vagueness of the Tariff provisions governing SSR compensation. MISO has begun work with its stakeholders to address these issues. Perhaps the most important issue is that the "equitable compensation" called for in the Tariff should include only "going-forward" costs, which are the minimum costs the supplier must incur to remain in operation. In other words, going-forward costs should include only costs that can be avoided by retiring or "mothballing" the unit. Compensation above this level would create substantial rent-seeking incentives. Clarifying both the designation and compensation provisions is particularly urgent because of the large number of units that are likely to be affected by the EPA regulations. We will continue working with MISO on improving and clarifying these procedures in order to ensure that SSR provisions result in efficient outcomes.

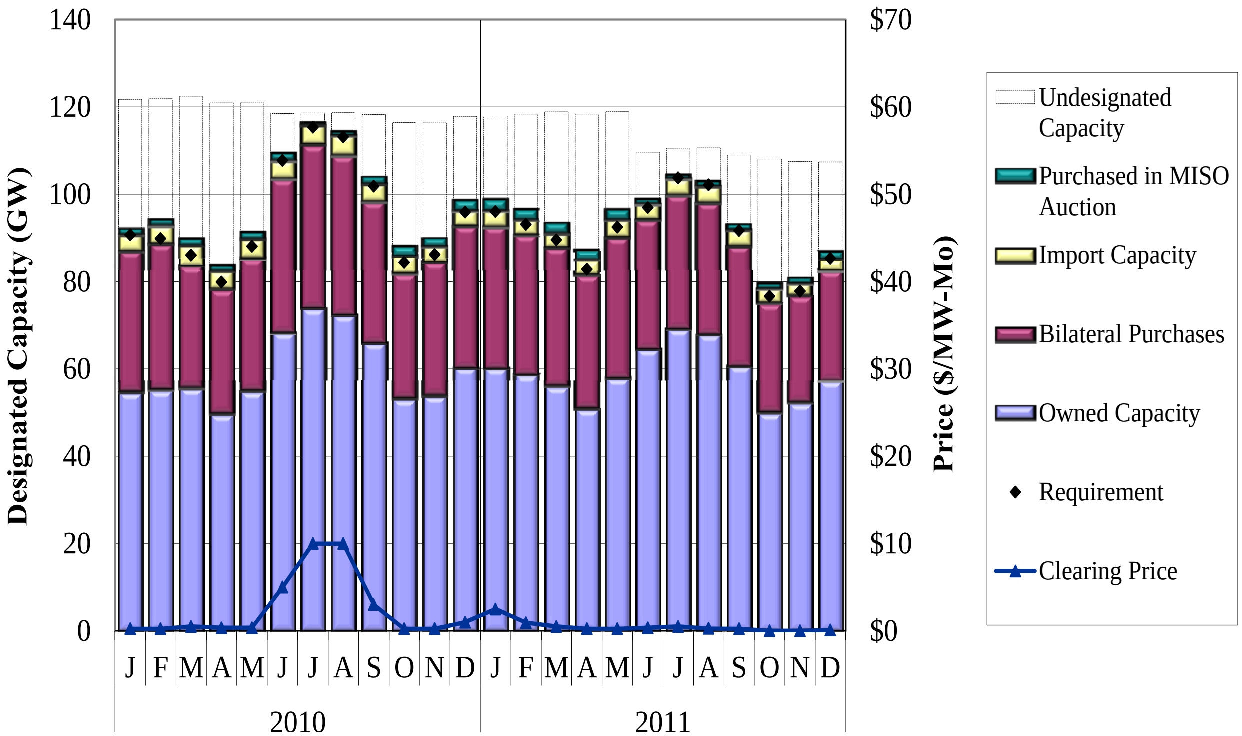
As discussed further in the next section, it is also important that the capacity market sends appropriate signals to minimize the need for Attachment Y submittals.

E. Capacity Market

Since June 2009, MISO has run a monthly VCA to allow LSEs to procure capacity to meet their Module E requirements. The VCA provides a revenue stream that, in addition to energy and ancillary service market revenues, should signal when new resources are needed. However, certain design flaws with the MISO's current RAC are substantially undermining its performance.

Figure 8 shows monthly VCA market results for 2010 and 2011. Cleared capacity in the VCA averaged only 1.7 GW, since most LSE obligations were satisfied through owned capacity or bilateral purchases. Low cleared quantities are consistent with the intention of the VCA as a balancing market. Although very little capacity clears through this market, it provides a transparent spot price for capacity that should be the primary driver of forward capacity prices (and, therefore, a critical component of the economic signal for investment).

Figure 8: Voluntary Capacity Auction
2010–2011



As previously mentioned, the drop in total capacity in June 2011 coincides with the departure of FirstEnergy from the MISO market. This departure has not materially impacted the surplus capacity in MISO.

MISO has filed proposed changes to its RAC, the most significant of which is the incorporation of a locational component to the Module E requirements and VCA clearing. This will allow the market to more accurately signal the supply and demand conditions in different locations. In addition, MISO has proposed mitigation measures to prevent artificial suppression of clearing prices due to uneconomic investment.

Notwithstanding the filed changes, the capacity market is still undermined by two significant issues: the inefficiency of a vertical demand curve and barriers to capacity trading with PJM. First, the current market is based on a single minimum capacity requirement for each LSE and a deficiency price for any LSE that is short. This effectively establishes a vertical demand curve for capacity. 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). Additionally, the vertical demand curve is inconsistent with the underlying value of capacity from a reliability perspective. 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 have provided comments to FERC and reiterate in this *State of the Market Report* recommendations that Module E 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—a market that is highly sensitive to withholding that can cause the VCA to clear 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 in MISO as the capacity margins decline with the likely retirement of significant amounts of coal-fired capacity because of the new EPA regulations.

The second issue in the MISO's current capacity market is the prevailing barriers to capacity trading between PJM and MISO. Capacity prices in both markets will only be efficiently determined 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 have described these barriers in detail in a recent filing to FERC.[12] We continue to recommend that MISO work with PJM to address these barriers, although PJM has not acknowledged that this is a problem.

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.

12 Motion for Request For Leave To Answer and Answer of the MISO Independent Market Monitor, Docket No. ER11-4081-000.

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 committed and scheduled in the day-ahead do receive start and stop instructions based on the day-ahead results.[13] Both markets continued to perform competitively in 2011.

The performance of the day-ahead market is important for at least three reasons:

- Since most generators in MISO are committed through the day-ahead market, good performance of that market is essential to efficient commitment of MISO's generation;
- 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). Figure 9 shows the monthly and annual price convergence at the Cinergy Hub in the upper panel and for other locations in the table below the figure. Because real-time RSG charges tend to be much larger than day-ahead RSG charges, the lower table adjusts the average price difference to account for the difference in RSG charges.

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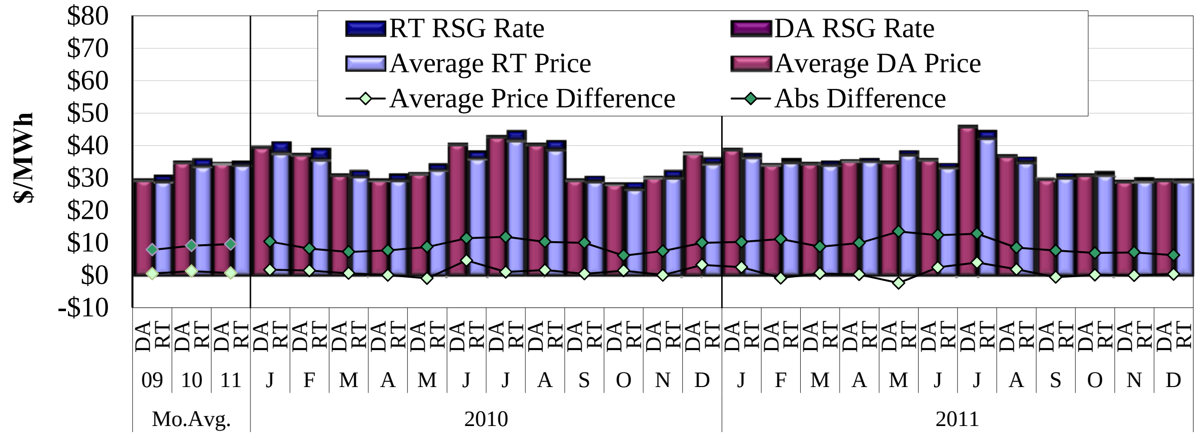
13 In between the day-ahead and real-time, MISO evaluates the day-ahead results relative to the forecasted capacity needs for the next day. Based on this Forward Reliability Assessment Commitment (FRAC) MISO may start additional capacity not-committed in the day-ahead.

Figure 9: Day-Ahead and Real-Time Prices
2009–2011



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

	09	10	11	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Cinergy Hub	2	4	2	4	4	2	0	-3	13	2	4	2	5	0	9	7	-2	2	1	-6	7	9	5	-2	0	0	1
Michigan Hub	2	4	2	8	3	2	3	2	10	5	2	2	-5	2	10	6	-5	3	7	-5	2	8	4	-3	2	-4	3
Minnesota Hub	4	2	-2	13	4	4	-2	-3	0	-5	3	5	7	-1	4	1	-6	-10	-16	5	-9	6	-1	-4	0	4	11
WUMS Area	8	7	3	13	9	9	1	-5	15	-2	10	21	11	4	2	3	-6	0	-4	5	6	8	-1	1	9	8	8

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

	09	10	11	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Cinergy Hub	-4	-2	-1	-4	-5	-3	-5	-8	7	-3	-2	-3	-1	-6	5	4	-4	-1	-1	-9	4	4	1	-5	-2	-2	0
Michigan Hub	-3	-2	-1	0	-5	-3	-2	-2	5	-1	-4	-3	-10	-4	6	3	-7	0	5	-7	0	4	1	-6	0	-6	2
Minnesota Hub	-3	-5	-5	4	-5	-2	-8	-8	-8	-13	-5	-2	0	-8	-1	-2	-8	-13	-18	1	-13	0	-5	-8	-3	1	10
WUMS Area	2	0	0	4	-1	3	-5	-9	7	-9	3	14	4	-3	-3	0	-8	-3	-6	2	3	2	-5	-2	7	5	7

In 2011, there was a MISO-wide day-ahead premium of 1.8 percent, which is consistent with the high level of net load scheduling in the day-ahead market. Net load scheduling in the daily peak hour averaged 100.5 percent and 100.1 percent in all hours during 2011. After accounting for the RSG cost allocations to load purchases, the MISO-wide premium fell to -0.7 percent. Over the long term, we expect small sustained day-ahead premiums because scheduling load day-ahead limits the risk associated with higher real-time price volatility.

The unadjusted premium of 1.8 percent is down from approximately 3 percent in 2010. The smaller day-ahead premium in 2011 is in line with lower real-time RSG cost allocations, which averaged $0.96 per MWh in 2011 compared with $2.04 per MWh in 2010. We discuss RSG cost allocations in greater detail in Section V.D.2.

Modest day-ahead energy premiums prevailed in all of the MISO regions, except at the Minnesota Hub in the West region. West region prices early in the year were affected by less real-time congestion than expected in the day-ahead market due to increasing real-time wind output and outages. The MISO markets generally are slightly less effective at arbitraging congestion-related price differences. However, the improved RSG cost allocation implemented in April of 2011 lowered the cost of establishing virtual positions over constrained interfaces, which improved participants' ability to arbitrage locational differences. This is most evident in WUMS where the day-ahead premium dropped from 7-8 percent in 2009 and 2010 to 3 percent in 2011.

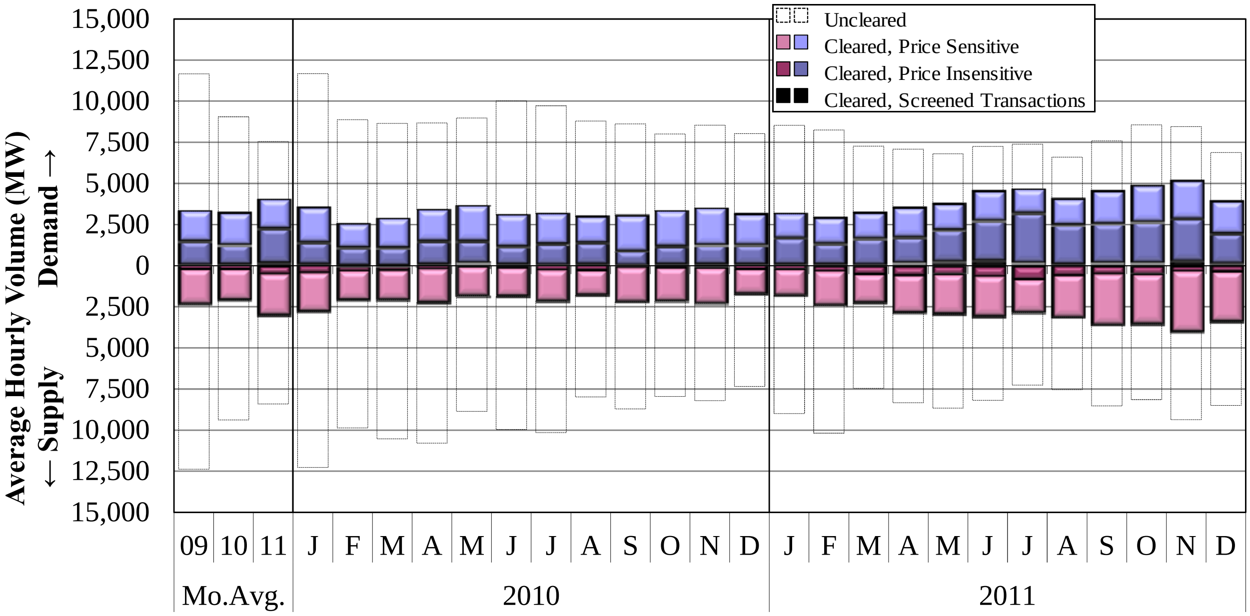
Our analysis also shows that average differences declined in the second half of the year as average prices and price volatility both decreased. Lower natural gas prices later in the year led to a reduction in the gas-coal spread, thereby reducing the slope of the generation supply curve. A flatter supply curve reduces price volatility and provides lower cost redispatch options for congestion management.

B. Virtual Transactions

Virtual transactions in day-ahead market are essential facilitators of price convergence that arbitrage price differences between the day-ahead and real-time markets. Figure 10 shows the average cleared and offered amounts of virtual supply and virtual demand in the day-ahead market. It shows components of daily virtual bids and offers and net virtual load (i.e., cleared virtual load less virtual supply) in the day-ahead market in 2010 and 2011. The virtual bids and offers that did not clear are shown as dashed areas at the end points of the solid bars.

The figure also distinguishes between bids and offers that are price-sensitive and price insensitive (i.e., those that are very likely to clear). Bids and offers are considered price-insensitive when they are offered at more than $30 above and below "expected" real-time prices. Price-insensitive bids and offers that contribute to a significant difference in congestion at a location between the day-ahead and real-time markets (labeled "Screened Transactions") are routinely investigated because they are generally not rational and lead to price divergence.

Figure 10: Virtual Load and Supply in the Day-Ahead Market
2009–2011



Percent Screened

Demand	1.8	2.6	4.6	3.4	1.1	0.4	2.6	4.7	2.8	2.4	3.8	1.5	2.3	2.9	2.8	2.5	3.0	2.4	5.4	7.5	6.7	4.1	2.4	4.3	6.2	5.7	3.8
Supply	0.9	0.9	2.5	1.4	0.8	0.7	1.1	1.1	0.9	0.9	0.7	0.9	0.8	0.8	1.1	1.0	2.3	2.5	3.7	3.3	3.3	2.7	1.3	2.2	4.0	1.7	1.4

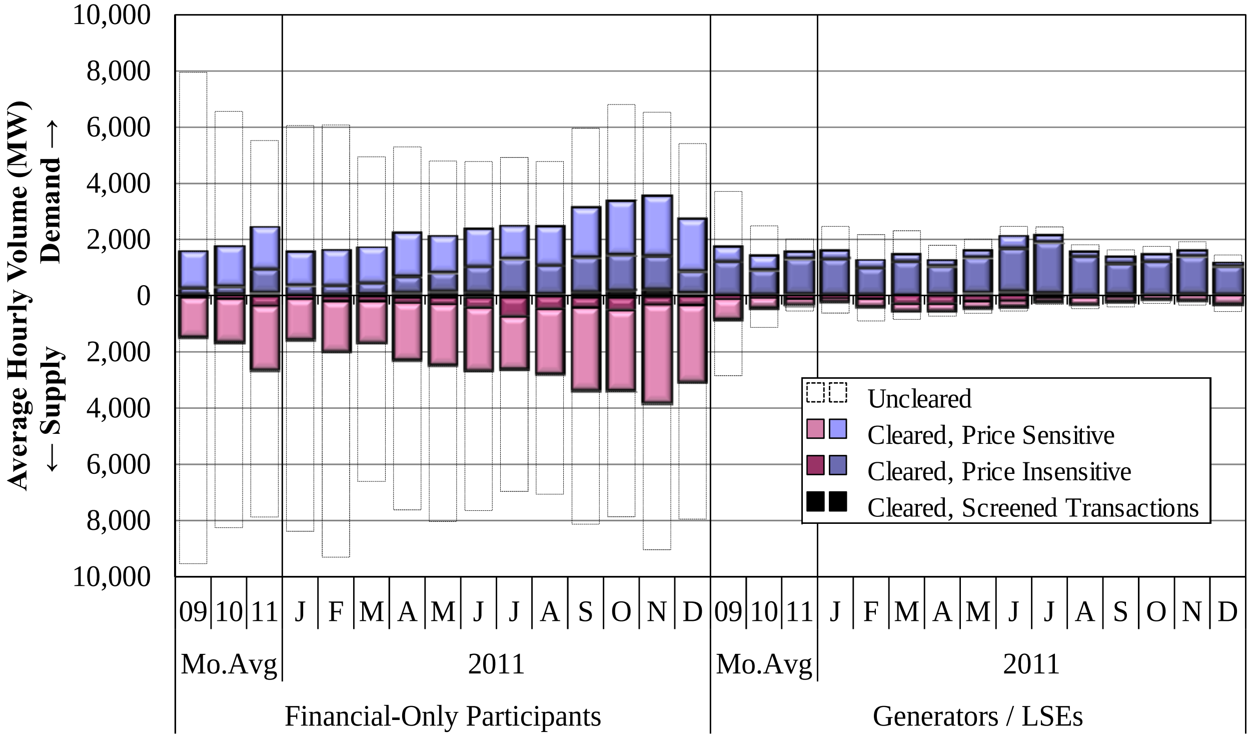
Virtual trading levels decreased substantially after 2008, when FERC ordered changes in the real-time RSG cost allocation that resulted in substantial charges to virtual supply transactions. Despite this loss in liquidity, price convergence has been good overall in MISO, but not as good in congested areas where the loss in liquidity has had the largest effects. Cleared virtual transactions increased in April 2011 when MISO implemented new RSG cost allocation measures. The change generally reduces the allocation of RSG costs to virtual supply, and eliminates any allocation when virtual supply is netted against a participant’s virtual load.

The figure shows that cleared volumes increased by 33 percent in 2011 from 2010. Much of this rise was associated with price-insensitive bids and offers. Approximately 30 percent of demand bids and 6 percent of supply offers were price-insensitive, compared to 14 and 2 percent, respectively, in 2010. The increase in price-insensitive offers was likely due to the change in RSG cost allocation. While some participants appeared to take positions across constrained paths to arbitrage differences in day-ahead and real-time congestion, a few participants employed price-insensitive transactions to exploit sustained locational price differences due to marginal loss factor divergence between the day-ahead and real-time markets. One participant who appeared to be arbitraging significant differences in marginal loss factors between the day-ahead and real-time markets ceased this activity after MISO modified its methodology to eliminate large transitory differences. Because the price-insensitive transaction levels increased, the percentage screened for further review also increased to roughly 3.6 percent of cleared transactions. After further investigation we concluded that none of these transactions were subject to mitigation in 2011.

Gross virtual profitability was modest at $0.58 per MWh on average, down from $0.75 per MWh in 2010 and $0.80 per MWh in 2009. Total virtual profits were $35.4 million. Virtual supply was considerably more profitable ($1.50 per MWh) than virtual demand ($-0.11 per MWh). This is expected because day-ahead prices were higher on average than real-time prices. However, the real-time RSG costs allocated to virtual supply averaged $0.96 per MWh, which lowered the net profitability of virtual supply transactions to $0.54 per MWh. The fact that virtual profitability has been falling generally indicates that the increased liquidity in the day-ahead market is improving its performance.

Figure 11 shows the virtual trading activity separately for financial-only participants and physical participants. The figure shows that financial participants provide most of the virtual liquidity in the day-ahead market overall. Much of the virtual trading by financial participants occurred at individual nodes, which allows them to arbitrage price differences related to congestion. Figure 11 also shows that most of the increase in volumes was also attributable to financial participants. These participants accounted for 73 percent of cleared volumes in 2011, up from 65 percent in 2010. Much of this increase, however, was price insensitive. These transactions provide less value to the day-ahead market than price-sensitive transactions because the latter are much more effective at facilitating price convergence. This report contains a number of recommendations for improvements to the allocation of real-time RSG costs that should improve the incentive to submit price-sensitive transactions and should increase the overall virtual transactions volumes.

Figure 11: Virtual Load and Supply in the Day-Ahead Market
2009–2011, by Market Participant



Physical participants generally offer much less price-sensitively than financial participants because physical participants are using such transactions to hedge against supply and demand uncertainty. While financial participant cleared volumes were evenly divided between supply and demand, nearly 90 percent of physical participant volumes were demand bids. Physical participants (notably LSEs) have consistently been willing to incur losses on virtual demand, likely to hedge against real-time price risk or supply availability. In June and July, demand profitability for physical participants averaged approximately $-4 per MWh.

Transactions by financial-only participants were considerably more profitable than those by generation owners and load-serving entities, 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.

V. Real-Time Market

A. Real-Time Price Volatility

Substantial volatility in real-time energy markets is expected because the demands of the system can change rapidly, and supply flexibility is restricted by the physical limitations of the resources and the transmission network. In contrast, the day-ahead market operates on a longer time horizon with more commitment options and liquidity provided by virtual transactions.

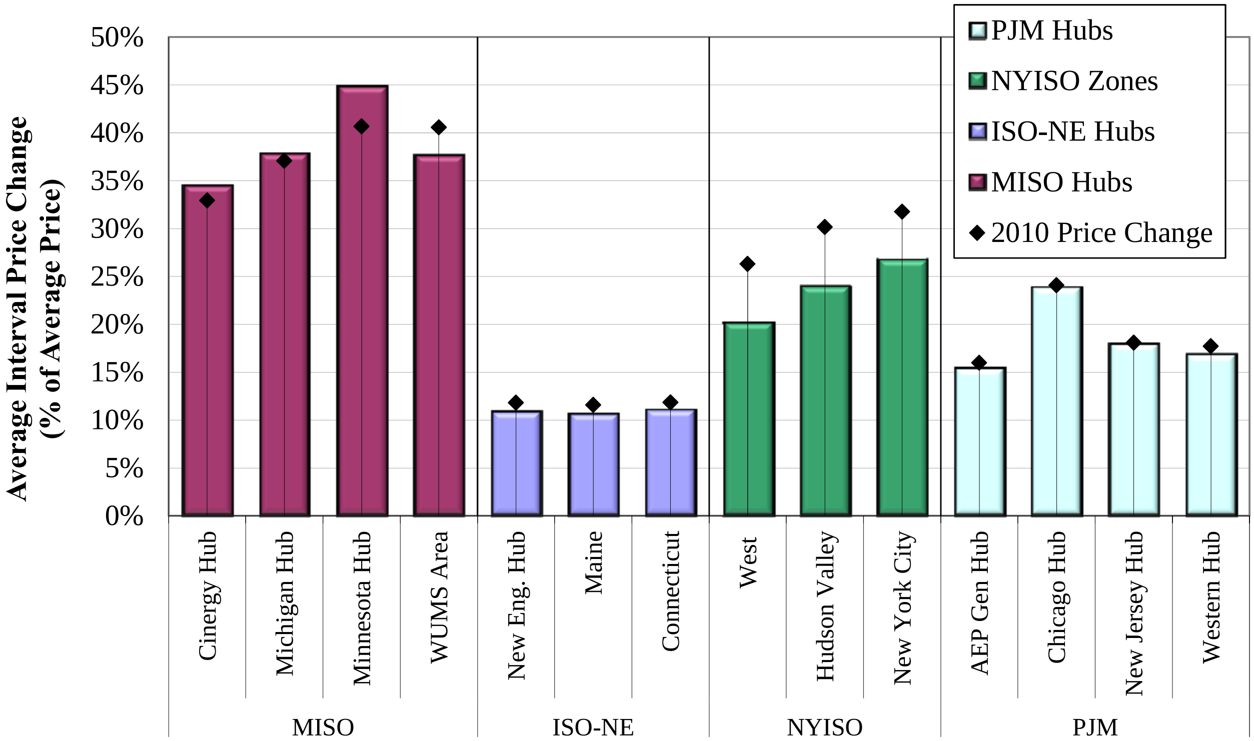
MISO's real-time market operates on a five-minute time horizon. Hence, when conditions change, the real-time market only has access to the dispatch flexibility that its units can provide in five minutes. Since the real-time market software is limited in its ability to "look ahead" and anticipate near-term needs, the system is frequently "ramp-constrained" (i.e., some generators are moving as quickly as they can up or down). This limitation results in transitory price spikes, either upward or downward. This section evaluates the volatility of the real-time energy prices.

Figure 12 compares fifteen-minute price volatility at representative points in MISO and in three neighboring RTOs. Overall, price volatility in MISO remains considerably higher than in neighboring RTOs, although it declined considerably in the last quarter of 2011. One reason volatility is higher in MISO is that it runs a true five-minute real-time market (producing a new real-time dispatch every five minutes). NYISO does so as well, but it has a look-ahead dispatch system that optimizes multiple intervals. Other RTOs dispatch every 10 to 15 minutes, which tends to provide more flexibility (which lowers volatility) but maintains less control of the system (by relying more on regulation to balance supply with demand between intervals).

The volatility in MISO 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.

Figure 12: Fifteen-Minute Real-Time Price Volatility
2011



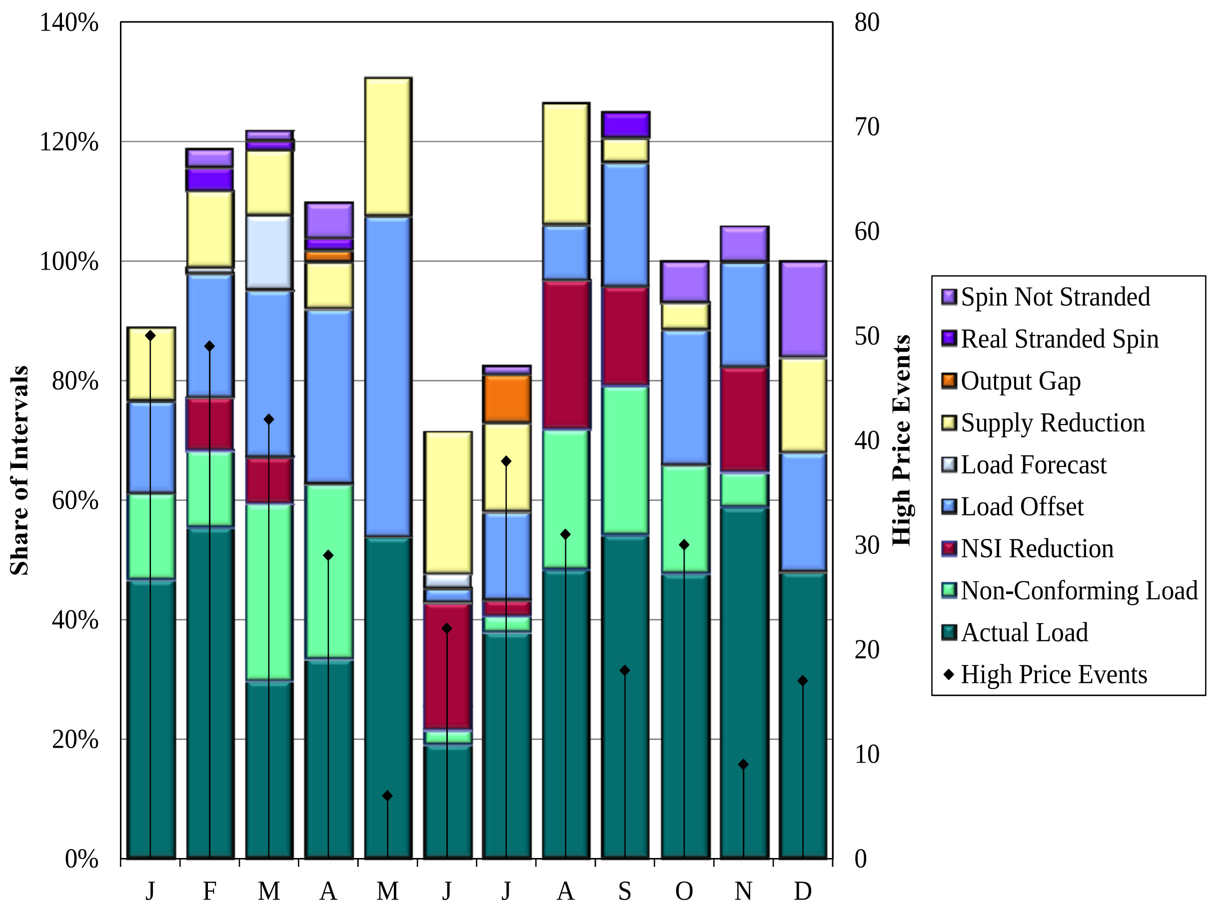
Ramp constraints tend to bind most frequently at the top of the hour, when NSI and generation changes are largest. Over the course of the day, they occur most frequently when load is ramping up or down near the peak hour of the day. In addition, transmission congestion at times results in higher price volatility in specific regions, particularly in the West region where fluctuations in wind output can contribute to excess generation conditions there. This report includes a number of recommendations to improve the management of system ramp capability and to reduce price volatility.

B. Evaluation of High Real-Time Energy Prices

In most cases, the price volatility shown in the prior section is a result of relatively high energy prices that are often transitory. This subsection evaluates the primary causes of high prices in MISO. Intervals priced at greater than $175 per MWh occurred 609 times in 2011, or 0.58 percent of all intervals. These instances were predominantly driven by changing generation demands that caused ramp constraints to bind as the market attempted to simultaneously meet energy and ancillary services requirements. The high-priced intervals were often accompanied by shortages of spinning reserves. However, the penalty price—the maximum cost MISO is willing to incur for regulating reserves and spinning reserves—was less than \$175 in 2011.[14] In other words, the system could have ramped to meet ancillary services demands in some cases, but the cost to do so would have exceeded the value of the ancillary services products. As a result, the system procured less than the requirement and the value of foregone ancillary services product was included in both the ancillary services and energy prices.

Figure 13 shows nine primary contributors to such events. When one of these factors produced a ramp demand greater than 300 MW leading into the shortage, we classify that factor as a contributor to the shortage. In many cases, more than one factor contributed to the same event (so the total can exceed 100 percent), while in some events none of the factors contributed.

Figure 13: Contributors to High-Priced Events
2011



14 The monthly regulating reserve penalty price in 2011 ranged from \$130 to \$175 per MWh and declined sharply in the second half of the year due to declining natural gas prices. The spinning reserve penalty price was unchanged from 2010 at \$98 per MWh.

This analysis shows that high-priced intervals are predominantly caused by changes in load or net interchange. The height of the bars in summer is lower, not because there are fewer events in the summer, but because the high-load periods can result in high prices that are not due to the factors identified in the figure.

Figure 13 shows that there are significant contributors to high prices over which MISO has an operational impact. For example the offset parameter, which allows the operators to increase or decrease the load served by the real-time market, contributed to 19 percent of the high-priced events. Although difficult to quantify, some of these offsets that increase the ramp demand of the system in the near term may be justifiable if they prevent a larger shortage later.

The "supply reduction" factor, which primarily includes units shutting down at the end of the day or various types of outages, contributed to 13 percent of the high prices. However, the output gap, a measure of potential withholding of economic resources, only contributed to 1 percent of the events. A fuller discussion of each of the factors is contained in Section 4 of the Appendix.

We have recommended improvements in several operational areas related to these factors. MISO has made significant progress on these recommendations over the past year, including implementing a new look-ahead commitment model to economically commit and decommit peaking resources as well as a new Short-Term Load Forecasting (STLF) model. This report contains three other recommendations to improve MISO's ability to manage the system's ramp demand and reduce price volatility:

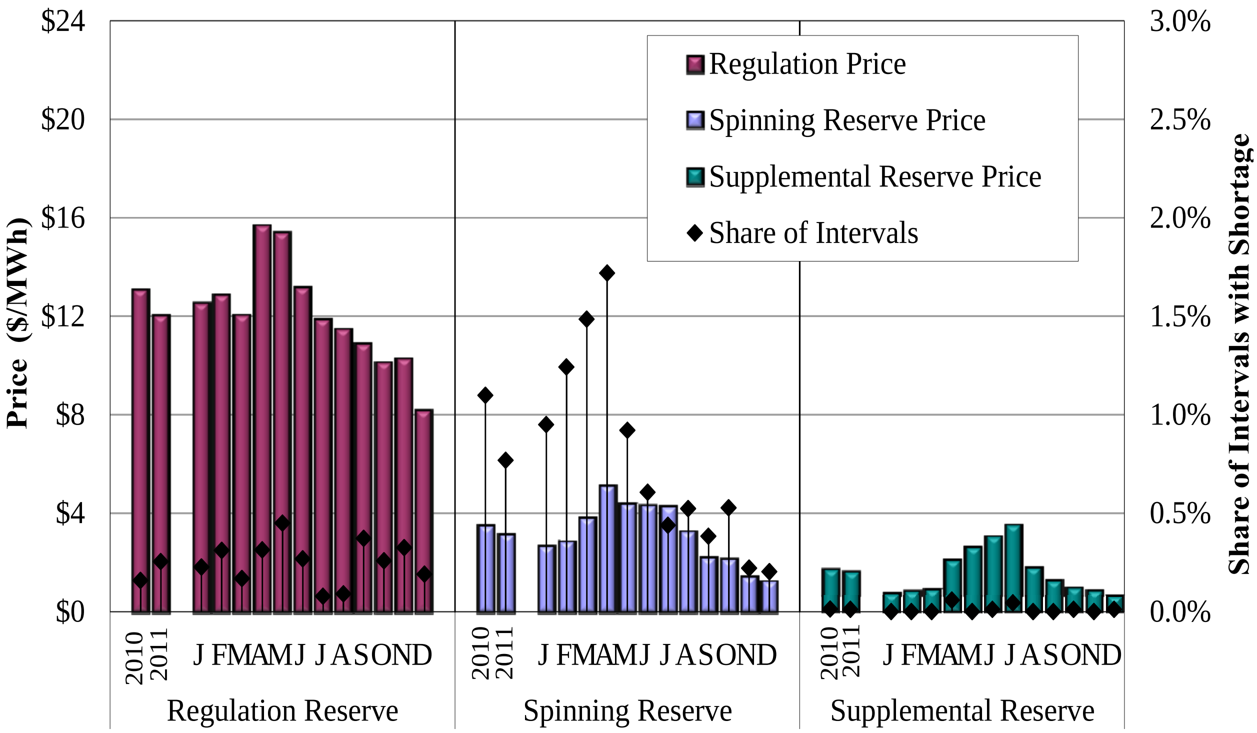
- In the short term, improve the use of the load offset parameter to proactively manage the system's ramp capability;
- In the longer term, develop a look-ahead real-time dispatch capability, which would include a multi-period dispatch optimization to move resources in anticipation of system demands over the next several intervals; and
- Implement a ramp-capability product.

The first two recommendations address ramp demands that can be foreseen by MISO. Some of the most significant ramp demands MISO faces, however, are unknown in advance. This includes unit outages and changes in non-conforming load. To address these unforeseen ramp demands, the third recommendation is for MISO to procure ramp capability. This can be done by establishing ramp capability targets along with economic values for the ramp capability (i.e., a ramp capability demand curve). MISO has been developing a promising concept for this type of product.

C. Ancillary Services Markets

ASM continued to perform as expected with no significant issues in 2011. Since their inception in 2009, jointly-optimized ancillary service 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 14 shows monthly average real-time prices for regulation, spinning reserves, and supplemental reserves. It also shows the share of intervals in shortage for each product.

Figure 14: ASM Prices and Shortage Frequency
2011



Monthly average marginal clearing prices for all products declined in the second half of 2011. For the year, prices averaged 6 to 10 percent below 2010 prices. These declines were due to the cumulative effects of fewer spinning reserve shortages and a reduction in opportunity costs of providing reserves. Shortages of spinning reserves decreased significantly after the departure in June 2011 of FirstEnergy, which had the most non-conforming load that can change abruptly and cause transitory shortages. Opportunity costs decreased in 2011 as energy prices fell and as lower natural gas prices led to a flatter supply curve.

Marginal clearing prices for regulation decreased 8 percent from 2010 to $12.03 per MWh. Prices peaked in April at near $16 per MWh but declined to $8 per MWh by December. Since regulating reserves can be used to supply lower-quality reserves, a reduction in high-priced spinning reserve shortage periods resulted in a corresponding decrease in regulation prices. A substantial reduction in the regulating reserve demand curve penalty price, which sets price during regulating reserve shortage periods, further contributed to this decline.

Spinning reserve prices averaged $3.14 per MWh, down 10 percent from 2010. The spin relaxation algorithm in 2011, although improved from prior years, periodically set prices during shortages well below the penalty price. This was eliminated in April 2012 when MISO implemented a demand curve for spinning reserves that ceased “relaxing” the spinning reserve requirement to set prices during shortage. Supplemental reserve prices also fell slightly in 2011, averaging $1.62 per MWh. Supplemental reserves were deployed just five times in 2011 and, with one exception on June 4, performed well.

D. Real-Time RSG Payments and Other Make-Whole Payments

MISO employs two primary forms of make-whole payments in real time to ensure resources cover their as-offered costs and, therefore, have incentives to be flexible:

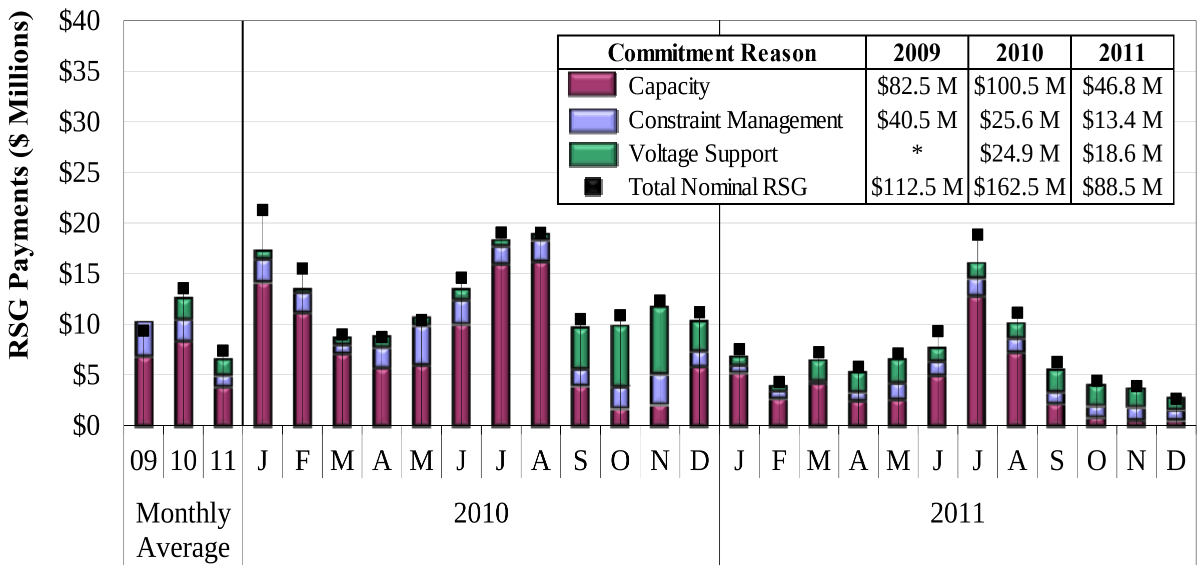
- RSG payments ensure that the total market revenue a generator receives when economically committed is at least equal to its as-offered costs over its commitment period.
- PVMWP assures that suppliers will not be financially harmed in the hourly settlement by following MISO’s five-minute dispatch signals.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

Resources committed after the day-ahead market receive “real-time” RSG payments when 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 they contribute to causing the costs, which is not occurring currently for reasons we discuss later in this subsection.

1. Real-Time RSG Costs

Figure 15 shows real-time RSG payments, which account for more than 85 percent of total RSG payments (the balance is paid day-ahead). Since fuel prices have considerable influence over suppliers' production costs, the figure shows RSG payments in both nominal and fuel-adjusted terms.[15] It also separately shows the fuel price-adjusted RSG payments associated with commitments made for capacity purposes, voltage support, and constraint management.[16] The table below the figure shows the share of RSG costs paid to peaking and non-peaking resources. Peaking resources are generally high-cost, inflexible resources relied upon in real time to meet system reliability needs, particularly in summer.

Figure 15: Real-Time RSG Payments
2010–2011



Share of Real-Time RSG Costs by Unit Type (%)

Peaking Units	71	54	59	57	54	59	58	64	50	70	71	45	25	26	47	60	53	54	51	45	67	75	67	47	51	43	38
Other Units	29	46	41	43	46	41	42	36	50	30	29	55	75	74	53	40	47	46	49	55	33	25	33	53	49	57	62

15 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.

16 Voltage support classification is unavailable prior to 2010. Commitments for voltage support in 2009 are instead classified as being for constraint management.

Real-time nominal RSG costs declined 45 percent from 2010. Capacity-related RSG costs declined the most—by a fuel-adjusted 53 percent—because load was more than fully scheduled in 2011 than in 2010 on average, which reduces the commitments that MISO must make for capacity in real time.

RSG paid to units committed for constraint management and voltage support declined by a fuel-adjusted 48 and 25 percent, respectively. Voltage-related RSG payments were made consistently throughout the year. These commitments raise market power concerns because a supplier facing little or no competition to resolve these types of local reliability requirements can extract substantial market-power rents under current mitigation measures. In the *2010 State of the Market Report* we recommended MISO seek authority for tighter conduct and impact mitigation thresholds applicable to such commitments. MISO filed these changes in late December 2011 and expects to implement this recommendation in late summer 2012 pending FERC approval.

2. Real-Time RSG Cost Allocation

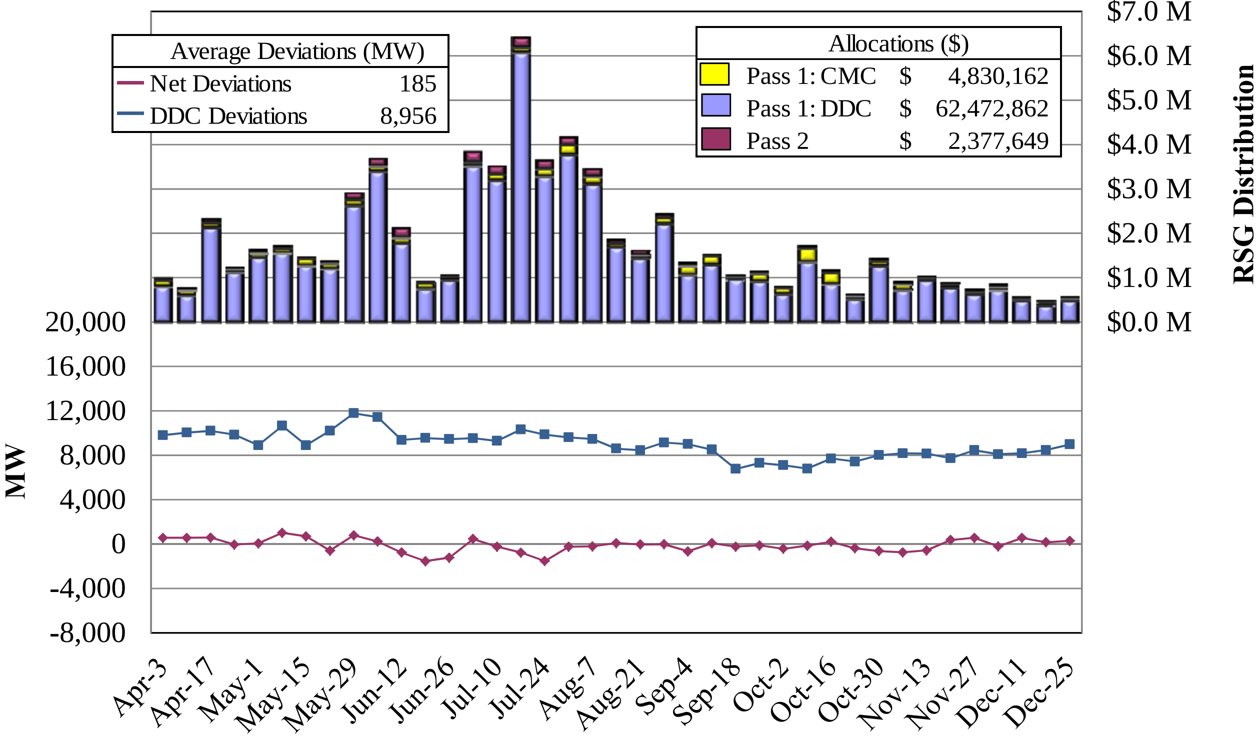
In April 2011, MISO implemented a revised RSG cost allocation methodology. The new methodology recognizes that resources paid RSG payments are committed to meet either capacity needs or to manage congestion. RSG costs are intended to be paid for by market participants based on their real-time net deviations from day-ahead schedules that:

- Contribute to congestion on specific constraints (collected via the Constraint Management Charge or CMC); or
- Contribute to a market-wide capacity need (e.g., under-scheduled load, virtual supply, etc.). This charge is known as the Day-Ahead Deviation and Headroom Charge (DDC).

The balance of the real-time RSG costs, if any, is collected from load on a load-ratio share basis (known as “Pass 2”). Figure 16 shows daily average allocations through the DDC rate, the CMC rate, and Pass 2 for each week from April to December in the upper panel. In the lower panel, the figure shows the average net deviations for each week and the total net harming deviations on which the real-time RSG costs are allocated through the DDC rate.[17]

17 The harming deviations exclude those that are netted against helping deviations at the participant level.

Figure 16: RSG Cost Allocation by Week
April–December 2011



RSG charges totaled nearly $70 million between April and December 2011, almost 90 percent of which was allocated to deviations under the DDC rate using the current allocation methodology (effective April 1, 2011). This is substantially inconsistent with the causes of real-time RSG costs: only one-third of the costs were incurred to satisfy the market-wide capacity needs of the system. The high level of costs allocated under the DDC rate occurred because:

- The allocation is not explicitly based on the total net deviations. The figure shows that the net deviations were often negative (i.e., reducing the need to commit resources for capacity) and averaged only 185 MW, while the allocation was based on harming deviations of almost 9,000 MW (after netting at the participant level).

- Costs associated with managing congestion are allocated under the DDC rate when the current methodology does not allocate those costs to the CMC rate. The primary issue is that a share of the costs allocated under the CMC rate cannot exceed the GSF of the committed resource on the constraint. This fails to recognize that the constraint in most cases causes all of the costs, regardless of the magnitude of the GSF.

- The majority of RSG costs are incurred to manage voltage and local reliability (VLR) constraints. These commitments protect load in local areas and are not usually affected by deviations and therefore should be primarily allocated to local load. MISO filed this proposal with FERC in December 2011 and is awaiting a FERC decision.[18]

The second factor is significant because it causes the CMC rate's share of total charges to be inappropriately low (7 percent). The CMC also contains a flaw affecting the allocation to virtual transactions.[19] In short, FERC ordered a change to the MISO Tariff provision pertaining to the CMC allocation to virtual transactions that inadvertently reversed the allocation. Under the current process, helping virtual transactions are subject to the CMC allocation while harming ones are not (they may even be netted against other harming deviations). Addressing this flaw is one of our recommendations, although the procedural options for doing so are unclear since FERC denied MISO's rehearing request regarding this error.

3. Price Volatility Make-Whole Payments

PVMWP address concerns that, under the current hourly-settlement process, resources that respond flexibly to volatile five-minute price signals can lose profits or incur losses. Hence, these payments provide suppliers the incentive to offer flexible physical parameters and follow dispatch instructions.

Figure 17 shows that the two components of PVMWP rose a cumulative 23 percent to $84 million in 2011. This increase is due to a modest increase in price volatility at recipients' locations and improved resource flexibility. There was a modest decline in overall price volatility (based on SMP) in the second half of 2011 that can be attributed partially to the departure in June of a significant amount of non-conforming load within FirstEnergy. However, price volatility at recipients' locations increased slightly in the second half of 2012.

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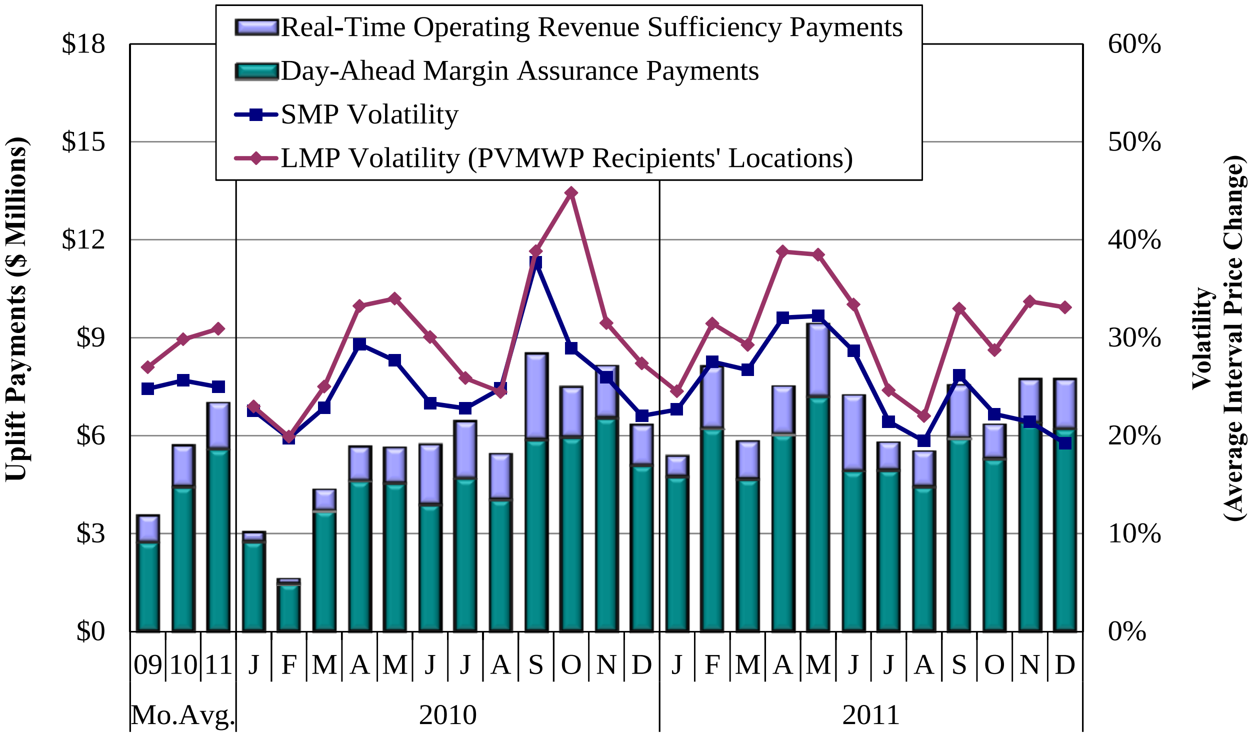
18 See Docket ER12-679-000. A companion filing requested additional mitigation authority, including tighter mitigation thresholds for voltage and reliability constraints. This MISO filing was supported by stakeholders and was responsive to a recommendation the IMM made in the 2010 State of the Market Report.

19 The currently effective Tariff language for adjusting deviations for allocating CMC to virtual transactions is found in 40.3.3.a.ii.4: "For deviations occurring prior to the Notification Deadline, the Real-Time Revenue Sufficiency Guarantee Constraint Management Charge shall be based on the following deviations adjusted for the applicable Commercial Pricing Node Constraint Contribution Factor: any Virtual Transaction resulting from a cleared Virtual Supply Offer or the negative of any Virtual Transaction resulting from a cleared Virtual Bid."

Figure 17: Price Volatility Make-Whole Payments
2010–2011



Although it did not account for a significant increase in the PVMWP costs, we identified a flaw in the DAMAP formula that provided inefficient incentives for participants to increase their payment by lowering a resource's day-ahead offer well below its marginal cost ($-1,000 per MWh in the extreme). MISO quickly addressed this issue by limiting the as-offered cost recovery to the higher of a resource's day-ahead and real-time energy offer.[20]

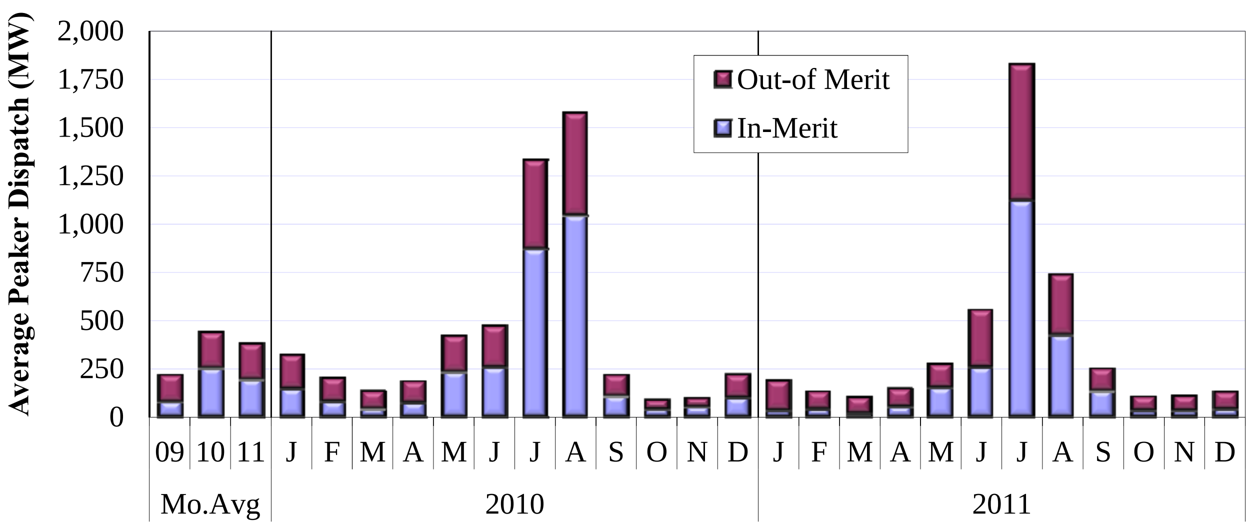
Throughout 2011 we continued to work with MISO to seek improvements in the eligibilty and settlement rules associated with RSG payments and PVMWP, and we made a number of specific recommendations. The resolution of most of the identified issues will require Tariff filings with FERC. Where appropriate, MISO will be discussing proposed changes with stakeholders. We support this process because it will reduce the vulnerability of the market to strategies designed to generate inappropriate make-whole payments.

20 MISO on May 13, 2011 made a Section 205 filing to modify the PVMWP calculation to address participant behavior to accrue undue DAMAP, which FERC approved on July 12.

4. Dispatch of Peaking Resources

The dispatch of peaking resources is an important component of the real-time market because peaking units are a primary source of RSG costs and a critical determinant of efficient price signals. The average hourly dispatch of peaking resources in 2011 declined 13 percent to 374 MW. The vast majority of such commitments occurred during peak summer days, when high loads occasionally resulted in the need to commit over 13 GW of peaking capacity. Commitments on such days are more often in-merit (i.e., the energy offer price is less than the prevailing LMP) than on other days because their incremental energy is needed to meet generation demand, and not needed solely to maintain headroom or provide ancillary services. In-merit commitments decreased in the second half of 2011 as day-ahead load scheduling increased.

Figure 18: Dispatch of Peaking Resources
2010–2011: All Hours



Out-of-Merit Quantity and Share

MW	137	182	182	173	120	88	106	185	212	461	530	106	46	44	116	152	87	81	91	119	295	706	310	113	69	75	88
%	64	42	48	54	60	68	59	44	45	35	34	49	54	47	54	82	68	82	64	44	53	39	42	46	68	70	69

However, nearly half of all peaking resources ran "out-of-merit" order. A peaking resource dispatched out-of-merit does not indicate that the unit was dispatched inappropriately. Rather, it simply indicates that the LMP was set by a lower-cost resource (peaking units operating at their economic minimum or maximum are ineligible to set price). When units are dispatched out-of-merit, RSG costs generally increase. In addition, peaking resources, because they can start relatively quickly, are often the only resources that can be committed in real time to serve load not scheduled day-ahead. Hence, if real-time prices are not set by the peaking resources when committed, real-time prices will be lower and will not reveal the natural incentive to schedule load fully in the day-ahead market (which would allow lower-cost resources to be committed in place of the peaking resources).

In addition, setting inefficiently low real-time prices can encourage participants to import and export power inefficiently. MISO's continuing efforts to implement a new "Extended LMP" pricing method should allow peaking resources to set prices more often when they are needed to satisfy the system's energy and ASM requirements. This should improve MISO's real-time energy pricing, reduce RSG payments, and improve the results of the day-ahead market.

E. Wind Generation

Wind generation in MISO has grown steadily since the start of the markets in 2005. Although wind generation promises substantial environmental benefit, the output of these resources is intermittent. As such, wind generation presents particular operational, forecasting, and scheduling challenges. These challenges are amplified as wind's portion of total generation increases—wind resources now account for 7.1 percent of installed capacity and 5.2 percent of generation. In 2011, MISO set new records for wind generation (8.0 GW) and volatility (2.1 GW decrease in one hour, on February 14).

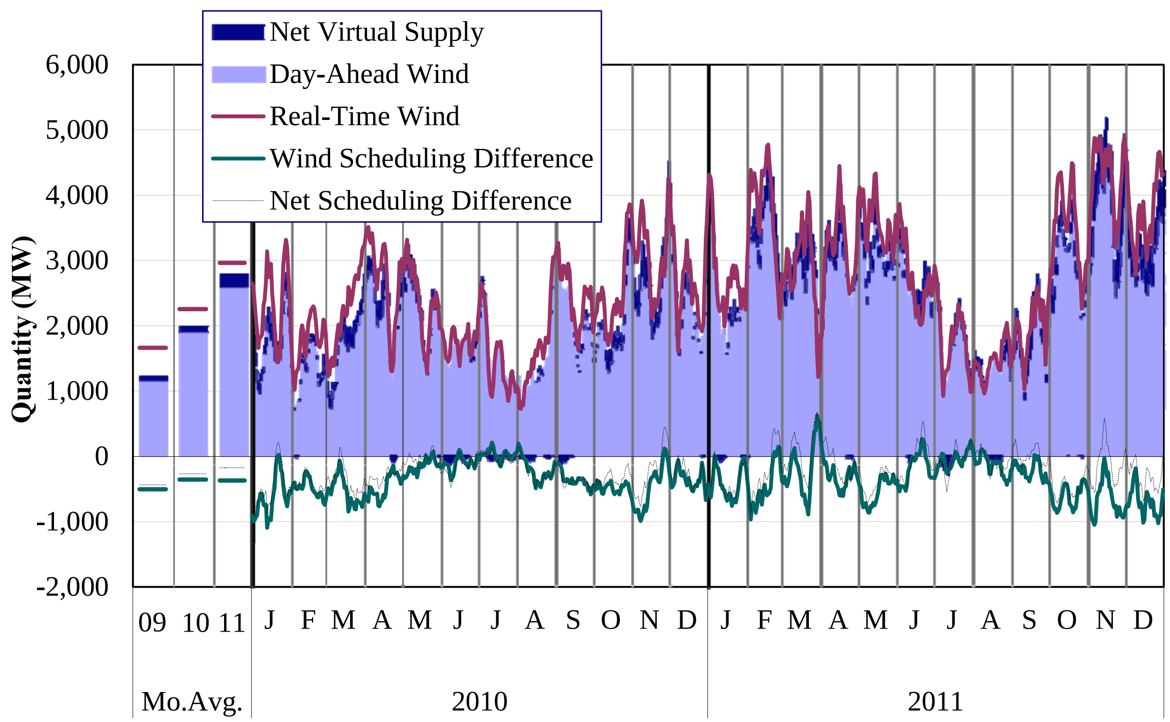
These challenges should be moderated by the continued adoption of the DIR resource type, which was introduced in June 2011. DIR participation by wind resources provides MISO much more timely control over its wind resources by allowing them to be dispatchable (i.e., to respond economically to dispatch instructions). The expansion of DIR has reduced the need for manual curtailments to manage congestion or over-generation conditions by 33 percent in 2011. By December 2011, over 3 GW of wind units were DIRs and much of the remaining wind resources are anticipated to convert by June 2013, which should greatly reduce manual curtailments.[21] In addition, recommendations for managing the system's ramp capability that are set forth in this

21 Units placed into service prior to April 1, 2005 are exempt from this requirement.

report should further improve MISO's ability to respond efficiently and reliably to fluctuations in wind output.

Figure 19 shows a seven-day moving average of real-time wind output, as well as wind output scheduled in the day-ahead market since 2010. Underscheduling 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. Virtual supply at wind locations is also shown in the figure because the response by virtual supply in the day-ahead market offsets the impact of underscheduling by wind resources.

Figure 19: Day-Ahead and Real-Time Wind Generation
2010–2011



Real-time wind generation in MISO in 2011 increased 30 percent to average nearly 3,000 MW. It remained underscheduled by an average of 365 MW, or 12 percent, although net virtual supply in 2011 made up more than half of this discrepancy. Since August 31, 2010 deviations from day-ahead (i.e., real-time reductions in wind generation compared to the day-ahead schedule) are no longer exempt from RSG charges, which may provide an incentive for participants to use conservative forecasts in the day-ahead.

The figure also shows that wind output is substantially lower during summer months than during shoulder months, which reduces its value from a reliability perspective. For this reason, wind resources receive capacity credits toward satisfying Module E requirements that are only a fraction of their installed capacity. The average capacity credit increased from 12.9 percent in Planning Year 2011–12 to 14.9 percent for Planning Year 2012–13. The capacity credit provided to wind resources in part reflects performance of wind resources during peak load hours averaged over multiple historical years. Even one unusually windy peak day can cause this measure and the resulting capacity credits to be overstated.

Wind output was unusually high on a small number of peak demand days, which has an outsized impact on the average wind output. For this reason, the resulting capacity credit level may be higher than one would expect on a representative peak demand day. The median of these output values would represent a more reasonable expectation of the likely wind output on a peak demand day. As discussed further in the Recommendations section of this report, we recommend that MISO be more conservative with Module E wind capacity credits by modifying its methodology to grant credits for no more than the lower of the mean or median output on peak demand days. This will help ensure that MISO's capacity market supports investment in the resources it needs to maintain reliability.

Finally, as total wind capacity continues to grow, the volatility of its output that must be managed by MISO also grows. Sixty-minute volatility in 2011 increased 18 percent to an average of 218 MW per hour. Although the DIR has been extremely valuable in improving the control of wind resources and responding to these changes in output, MISO is working to develop changes in procedures and evaluate market design changes that may be beneficial for managing the changes in wind output.

VI. Transmission Congestion and Financial Transmission Rights

MISO manages flows over its network to avoid overloading transmission constraints by altering the dispatch of its resources to establish efficient, location-specific prices that represent the marginal costs of serving load at each location. Transmission congestion arises when the lowest-cost resources cannot be fully dispatched because transmission capability is limited. As a result, LMPs can vary substantially across the system, reflecting the fact that higher-cost units must be dispatched in place of lower-cost units to serve incremental load while not overloading any transmission facilities. This causes LMPs to be higher in “constrained” locations.

LMPs also include a marginal loss component. Transmission losses occur whenever power flows across the transmission network. Generally, transmission losses increase as power is transferred over longer distance, at higher volumes, and over lower-voltage facilities.

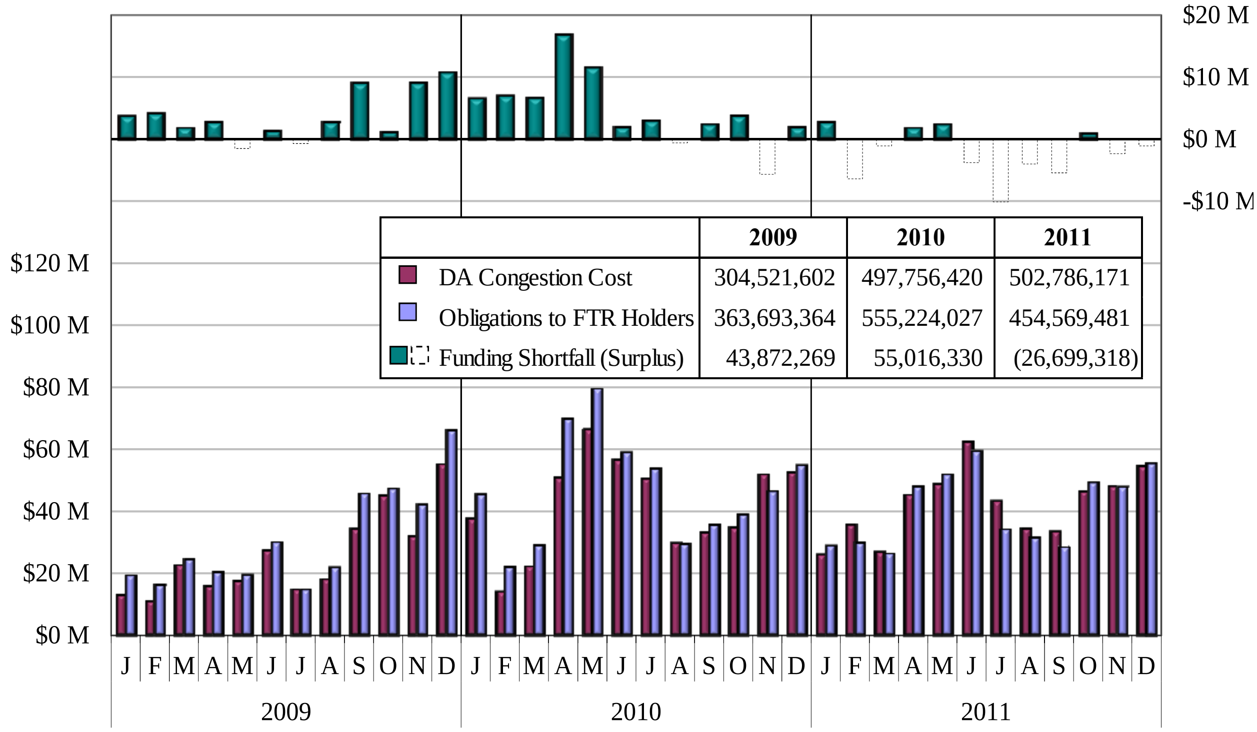
A. Day-Ahead Congestion Costs and FTRs

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 supplied and where it is scheduled to be consumed.

The resulting congestion revenue is paid to holders of FTRs, which represent the economic property rights associated with the transmission system. A large share of the value of these rights is allocated to participants. The residual FTR capability is sold in the FTR markets with this revenue contributing to the recovery of the costs of the network. FTRs provide an opportunity for market participants to hedge against day-ahead congestion. As such, congestion costs and FTR obligations should be roughly equal unless the transmission capability reflected in participants’ FTRs is more or less than the transmission capability used in the day-ahead market.

Figure 20 summarizes the day-ahead congestion, the obligations to FTR holders, and any differences that resulted in surpluses or shortfalls on a monthly basis from 2009 to 2011.

Figure 20: Day-Ahead Congestion and Payments to FTRs
2009–2011



Day-ahead congestion costs rose slightly from $498 million in 2010 to $503 million in 2011. For the first time, MISO's annual congestion revenue day-ahead exceeded its FTR obligations. The full funding of FTR obligations was due to several modeling and procedural improvements made by MISO in 2010. MISO continued to make procedural improvements in 2011, including better procedures for modeling planned and forced transmission outages, as well as a more complete modeling of lower-voltage branches of the network in the FTR market. As a result, funding levels since the start of the 2010–2011 FTR year in June 2010 have averaged 103 percent.

While most RTOs continue to have problems with underfunding FTRs, significant overfunding can also be of potential concern if the underlying assumptions in the FTR market become too conservative (i.e., MISO may not be selling all of its transmission capability). This holds particularly for M2M constraints, which were over-funded by nearly 25 percent in 2011.

Other forms of transmission rights exist in MISO that were established to account for grandfathered transmission agreements that existed when the markets were implemented. However, roughly 90 percent of the day-ahead congestion revenue was used to fund FTRs in 2011, with most of the balance used to fund the other grandfathered rights.[22] It is important that a high percentage of day-ahead congestion continue to be paid to FTRs because the other transmission rights do not provide the same efficient incentives as FTRs.

Real-time congestion costs in 2011 (not shown in the figure) were a small share of total congestion costs collected by MISO. These costs generally occur when the transmission capability available in the real-time market is less than was assumed. In 2011, real-time congestion costs were *negative* (i.e., a real-time surplus) for the first time, indicating that day-ahead transmission capability assumed to be available (i.e., the limits net of assumed of loop flows) was slightly less than the capability actually available in the real-time market. An additional source of the real-time surplus is PJM's M2M payments associated with PJM's real-time use of the system in excess of its Firm Flow Entitlement (FFE). PJM's payments are netted against MISO's positive real-time congestion costs.[23] We recommend in this report that MISO and PJM implement Joint Operating Agreement (JOA) provisions allowing sharing of FFE in the day-ahead. This would likely reduce PJM's real-time congestion payments and improve overall efficiency of the RTOs' commitment and dispatch.

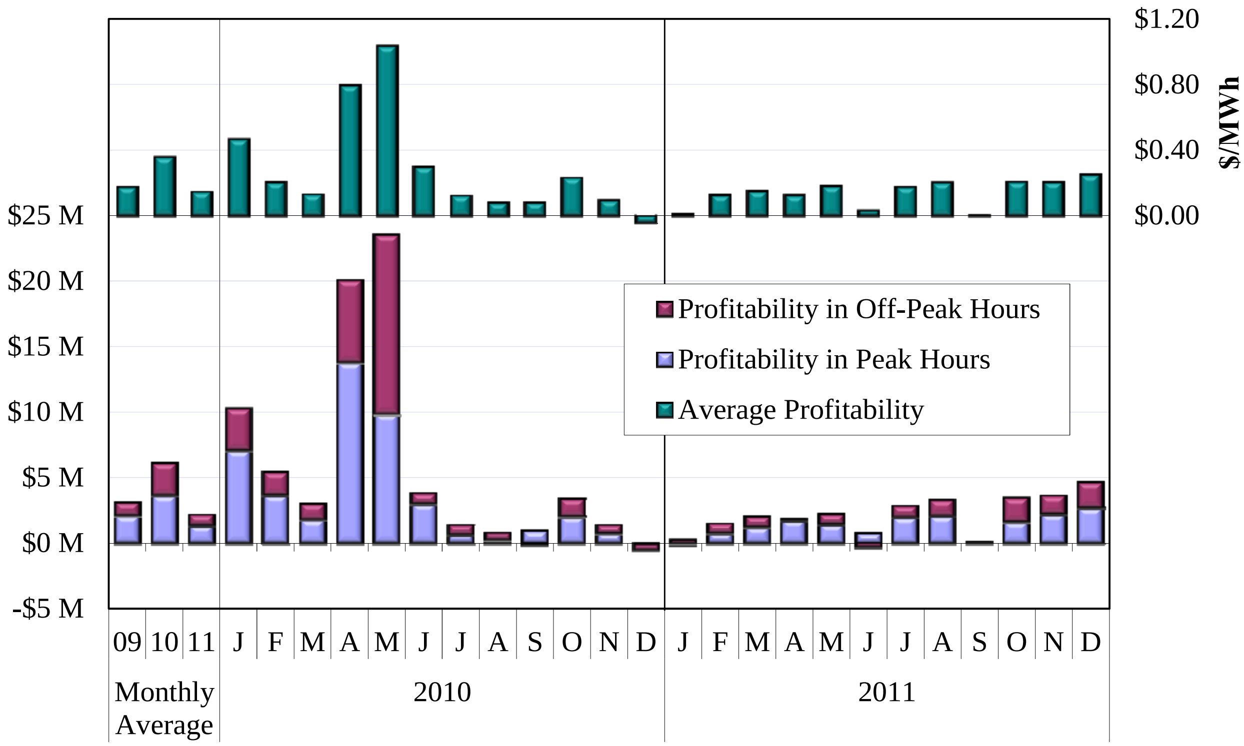
Congestion revenues collected through the MISO markets are substantially less than the value of real-time congestion on the system, which totaled $1.24 billion in 2011. This substantial difference is caused primarily by loop flows that do not pay MISO for use of its network and PJM's entitlements on the MISO system (PJM does not pay for its use up to its entitlement). Because MISO collects congestion revenues for only a portion of its transmission capability, it sells or allocates FTRs for only the capability it expects to utilize in the day-ahead market. Aligning the available transmission capability in the FTR and day-ahead markets ensures that

22 The three classes of "grandfathered" transmission rights that are paid rebates are RT carve-outs, DA carve-outs, and DA Option B rebates. Together these rebates totaled 8.5 percent of total payments, up from 5.3 percent last year. The remainder is paid to FTR holders.

23 In the day-ahead MISO limits its M2M flowgates to the physical limit less PJM's FFE and other forecasted loop flows.

FTR shortfalls and surpluses are limited, and also contributes to FTR prices converging with anticipated day-ahead congestion. This convergence is an indicator of the performance of the FTR market (i.e., low FTR profits (losses), which are the difference between the price of the FTR and the congestion paid to it). In Figure 21, we show the profitability of FTRs sold in the monthly market. In a well-functioning and liquid FTR market, profitability should be low.

Figure 21: Monthly FTR Profitability
2009–2011



In 2011, FTR profitability averaged $0.15 per MWh, a reduction from $0.36 in 2010. In 2011, monthly FTR prices generally responded to changes in congestion patterns in the following month. The principle exception was the peak-hour congestion out of the West region, which eased in the second half of 2011. Profitability of FTRs in spring 2010 was unusually high, which was due in part to significant outage-related congestion into Michigan that was not fully anticipated in the FTR auction.[24]

24 A detailed discussion on FTR auction results can be found in the Appendix.

B. Real-Time Congestion Value and Constraint Manageability

As discussed above, the congestion revenue collected through the MISO markets was less than half of the real-time congestion that actually occurred on the MISO network. This subsection discusses the value of real-time congestion on the MISO network in 2011.

Figure 22: Real-Time Congestion by Coordination Region
2009–2011

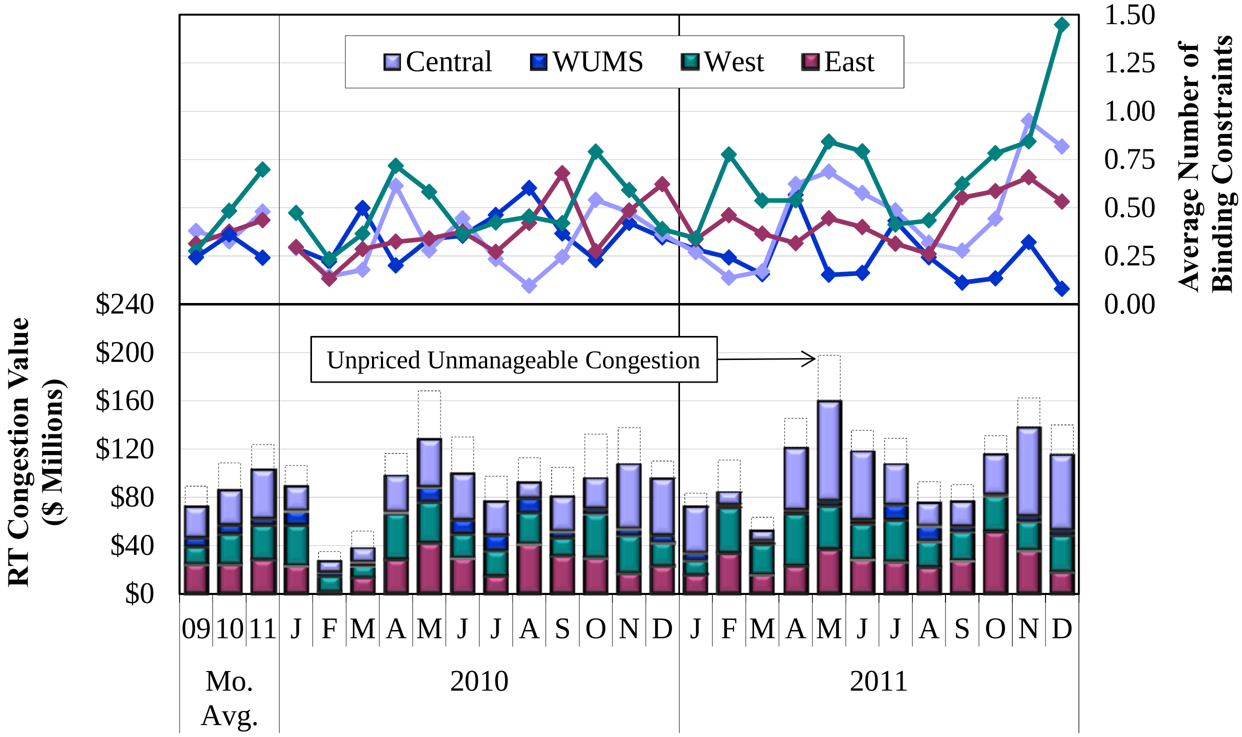


Figure 22 shows the value of real-time congestion by coordination region, along with the average number of binding constraints. The congestion value increased 20 percent in 2011 to $1.24 billion, two-thirds of which occurred on internal constraints. Much of the increase occurred on M2M constraints that bound more often than in previous years, particularly in the Central region. In addition, constraints in the West region bound more frequently than they did in 2010 because of an increase in wind generation, an increase in DIR participation (prior to DIR, the manual curtailments would not be reflected in binding constraints), and because MISO in 2011 controlled a greater number of low-voltage constraints.

The figure also shows that $245 million of congestion value was unpriced in 2011 due to a “constraint relaxation” algorithm that sets the congestion value of a constraint when it is in violation. Constraints are violated, or considered "unmanageable", when the real-time market is unable to redispatch its resources quickly enough (or lacks sufficient redispatch capability) to relieve the constraint.[25] The market utilizes Marginal Value Limits (MVLs) that cap the costs that the energy market will incur to reduce constraint flow to its limit. In order for the MISO markets to perform efficiently, the MVL must reflect the full reliability cost of violating the constraint (often $2,000 per MWh) and the LMPs must reflect this value when a constraint is violated. Instead, many unmanageable constraints in 2011 were priced well below their MVL—they were relaxed to zero in a quarter of the instances when a constraint was violated (so the LMPs would not reflect the unmanageable congestion). In early 2012, MISO disabled this algorithm for non-M2M constraints. We recommend MISO disable this algorithm on all constraints because it distorts the congestion signals provided by real-time prices, undermines the efficiency of the day-ahead prices and commitments, and adversely affects longer-term market decisions.

In addition to the pricing issues, we have also investigated the causes of the unmanageable congestion. The largest single factor that caused transitory constraint violations was unforeseen changes in network flows. However, we also identified an operating algorithm called the "transmission deadband" that contributed to a substantial share of the unmanageable congestion. The deadband is a constraint-specific amount (most commonly two percent) set by MISO operators that reduces the limit after a constraint initially binds. The original intent of the deadband was to limit the frequency with which constraints would bind and then immediately unbind—it was thought that this could result in LMP and generator dispatch volatility.

However, our investigation of unmanageable congestion in MISO revealed that 30 percent of the unmanageable congestion was the result of the transmission deadband that caused a constraint to appear to be violated (i.e., when the flow was less than the original transmission limit, but higher than the deadband-adjusted limit). We estimate that the deadband accounted for $140 million in unmanageable congestion and more than 19 percent of all congestion in MISO in 2011. We believe that the deadband is actually increasing volatility because the unmanageable congestion

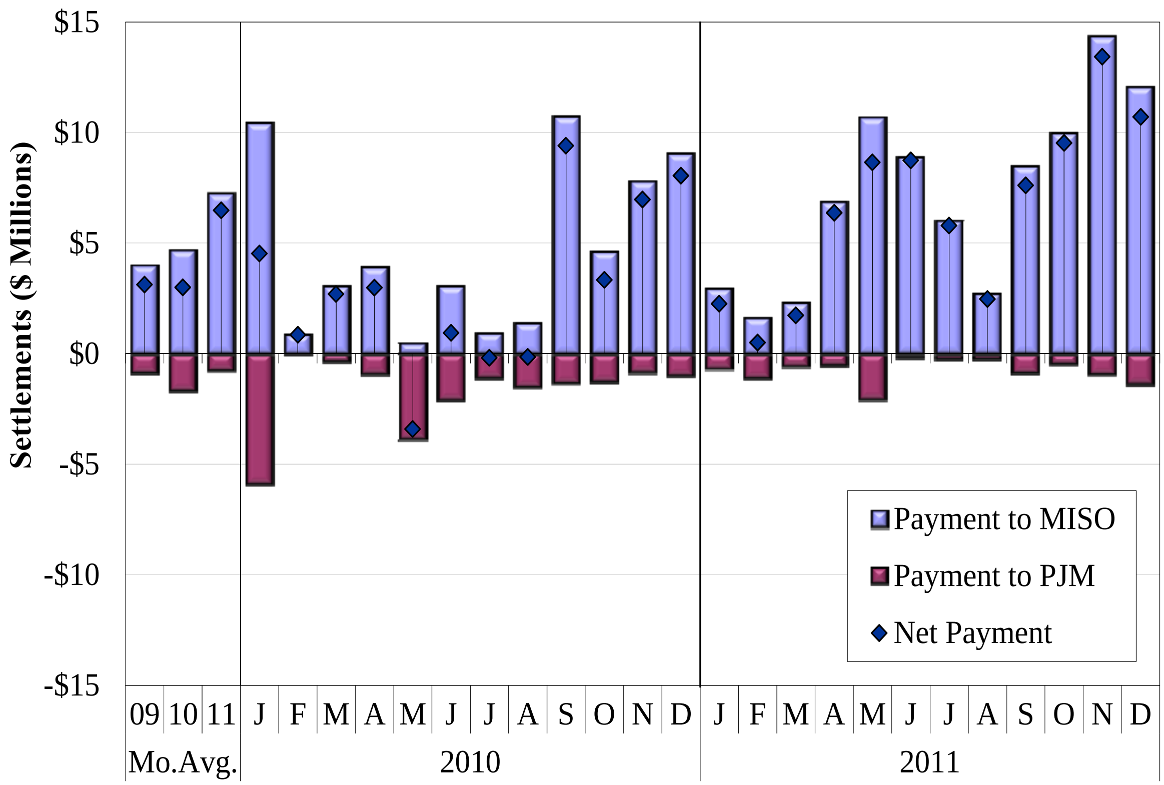
25 Because MISO frequently binds constraints at slightly less than their physical limit, for the purposes of the prior figure we define a constraint as violated when the flow is more than five percent above its limit.

it causes generally results in sharp LMP changes. It also inefficiently reduces the utilization of the transmission system by causing constraints to bind at levels less than their physical capability. Finally, a number of market improvements have been implemented that reduce the volatility the deadband was intended to address. These include incentives for generators to be flexible, such as the introduction of the price volatility make-whole payment and ASM co-optimization. We are unaware of any other RTO that currently employs a transmission deadband and recommend that MISO discontinue its use.

C. Market-to-Market and Coordination with PJM

MISO's M2M process under the JOA with PJM efficiently manages constraints affected by both RTOs. The process allows each RTO to more efficiently relieve congestion on its constraints with re-dispatch from the other RTO's resources if it is less costly for them to do so. Each RTO is compensated for excess flows from the other RTO when flow exceeds its FFE. Much of the M2M process is now automated and has improved pricing in both markets. Figure 23 shows M2M settlement results for 2010 and 2011.

Figure 23: Market-to-Market Settlements
2009–2011



The figure shows net payments flowed from PJM to MISO in each month in 2011 because PJM exceeded its FFE on MISO's system much more frequently than MISO did on PJM's system. Net payments by PJM to MISO more than doubled to $6.5 million per month, in part because of the increase in congestion on MISO's M2M constraints. Congestion on MISO M2M constraints increased 45 percent in 2011 to nearly $460 million, while on PJM M2M constraints it declined 33 percent to just $16 million.[26]

Shadow price convergence on MISO M2M constraints, an indicator of PJM's responsiveness to requests for relief, improved considerably from 2010 and is now comparable to convergence on PJM M2M constraints. Nonetheless, the RTOs should continue to work together to identify enhancements to the relief software, modeling parameters, or other procedures that may be limiting the provision of relief.

Finally, a review of JOA procedures in 2011 found that neither RTO had ever coordinated the permitted use of FFEs in their day-ahead markets. We recommend that MISO work with PJM to develop procedures to implement this provision to help reduce congestion management costs and improve overall efficiency.

26 Though the congestion value is relatively small on external flowgates, the shadow prices and price impacts can be relatively large.

VII. External Transactions

A. Overall Import and Export Patterns

As in prior years, MISO in 2011 remained a substantial net importer of power in both the day-ahead and real-time markets. Real-time net imports increased 49 percent to an average of 4.6 GW per hour. Imports rose on all major interfaces; the increase was largest on the PJM interface, where they increased over 50 percent, to 1.6 GW.

Relative prices in adjoining areas create incentives to schedule imports and exports that change the net interchange between the areas. Real-time price volatility and the scheduling timeframes can make it difficult to arbitrage interregional price differences effectively. This is exacerbated by the fact that MISO allows for fifteen-minute scheduling, but it settles on an hourly basis. 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.

This measure indicates external scheduling performance in 2011 was poor. The share of transactions with PJM that were scheduled in the profitable direction was 45 percent, up slightly from 43 percent last year. Many hours still exhibit large price differences that can be attributed to scheduling uncertainties.

MISO has worked to improve the scheduling of external transactions. In December, MISO improved procedures for physical scheduling (its Ramp Reservation System) to better align the approval process with system ramp capability to support NSI changes. In particular, MISO now has separate permissible hourly schedule changes for imports and exports and can allow more increases in net imports. However, to address the efficiency problem described above, we recommend that MISO expand the JOA with PJM to optimize the interchange and improve the interregional price convergence. The RTOs have discussed allowing participants to submit offers to transact within the hour if the spread in the RTOs' real-time prices is greater than the offer price. This type of 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 ones in the other area.

B. Wheeling Transactions and Loop Flows

The wheeling of transactions from IESO to PJM through MISO continued in 2011 and averaged 600 MW. These transactions create significant “loop flows” since roughly 50 percent of the power flows through NYISO. The IESO-to-PJM transactions remained substantially profitable in 2011 (averaging over $10 per MWh) in part because they do not pay for the congestion they cause in NYISO. A portion of these transactions, however, were then scheduled back from PJM into MISO and earned much higher profits than simply scheduling from IESO to MISO. This additional profitability is a function of PJM’s external interface pricing that pays transactions based on the perceived congestion they relieve in PJM. Since roughly half of the power associated with these transactions is deemed to enter PJM from NYISO, it can relieve constraints in eastern PJM. If these constraints are M2M constraints that are reflected in MISO real-time market as well, it is possible that both RTOs could be paying the transaction for relief of the same constraint under their interface pricing rules. The RTOs should evaluate whether this is an issue that can be addressed.

In 2012, initial operation of the Michigan–IESO PARs began with full operation expected to commence in June 2012. Full operation of the PARs should reduce the loop flows and improve the scheduling incentives, although the RTOs are still developing the changes in its interface pricing methodologies to reflect the new flow patterns expected with the PARs in operation.

VIII. Competitive Assessment and Market Power Mitigation

This section contains a competitive assessment of the MISO markets. Locational market power in wholesale markets can be substantial when transmission constraints or reliability requirements limit the effective competition to satisfy the system's needs in an area. This section includes a review of market power indicators, an evaluation of participant conduct, and a summary of the use of market power mitigation measures in 2011.

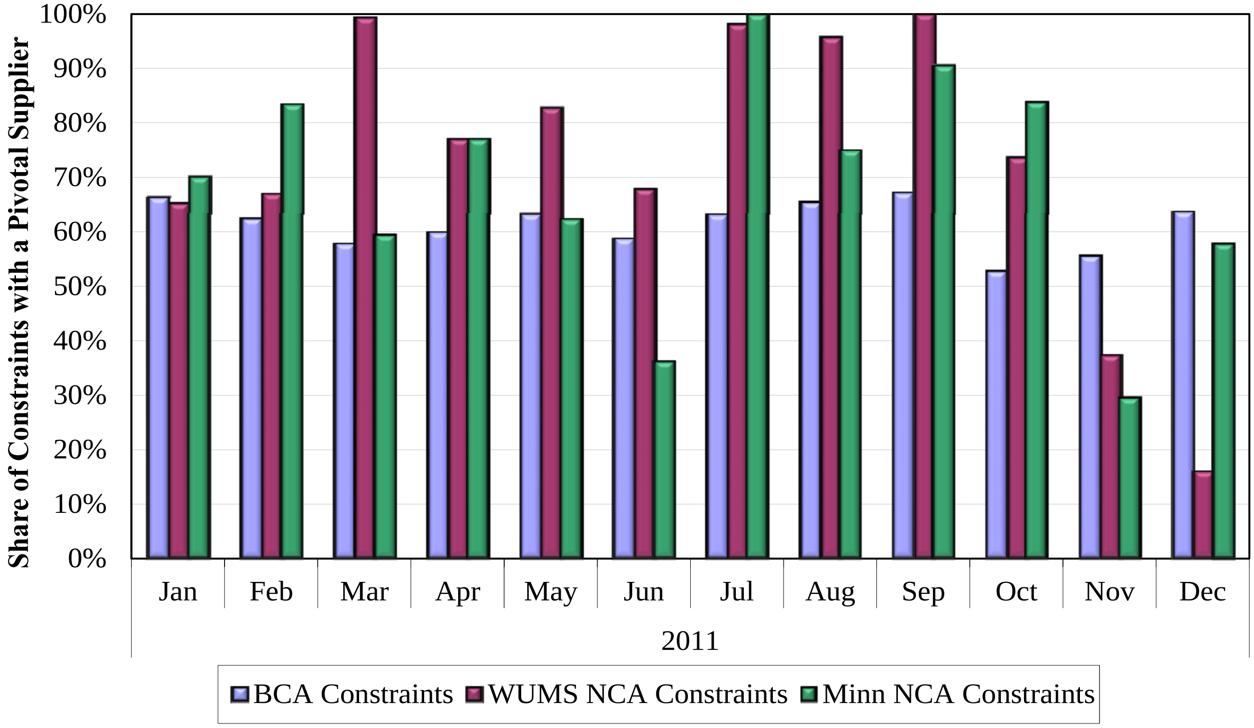
A. Structural Market Power Analyses

Our analysis shows that market concentration, as measured using the Herfindahl-Hirschman index (HHI), is low for the overall MISO area. However, it is considerably higher in the individual regions—it is nearly 2,500 in the East region (i.e., "highly concentrated"). The regional HHIs are higher than those in the comparable zones of other RTOs because vertically-integrated utilities in MISO that have not divested generation tend to have substantial market shares. However, since the metric does not recognize the physical characteristics of electricity or network constraints, the HHI is limited as an indicator of overall competitiveness.

A more reliable indicator of potential market power is whether a supplier is pivotal, which occurs 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 will become more necessary.

We also evaluate local market power by identifying pivotal suppliers for relieving transmission constraints. We focus the analysis on two types of constrained areas that are currently defined for purposes of market power mitigation: Narrow Constrained Areas (NCA) and Broad Constrained Areas (BCA). NCAs are chronically constrained areas that raise more severe potential local market power concerns (i.e., tighter market power mitigation measures are employed). Three NCAs are currently defined: Minnesota, WUMS, and North WUMS (a subarea of WUMS). BCAs include all other areas within MISO that are isolated by transient binding transmission constraints.

Figure 24: Constraint-Specific Pivotal Supplier Analysis
2011



The majority of active constraints in 2011—62 percent—had at least one supplier that was pivotal. Similarly, 55 and 64 percent of active NCA constraints into WUMS and Minnesota, respectively, had a pivotal supplier. Although roughly 60 percent of active BCA constraints had a pivotal supplier, in almost 90 percent of intervals one of these BCA constraints (with a pivotal supplier) was binding. This is a much higher share than the share of intervals for any one of the NCAs (which did not exceed 10 percent of the intervals) because the number of NCA constraints is far more limited than the number of BCA 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.

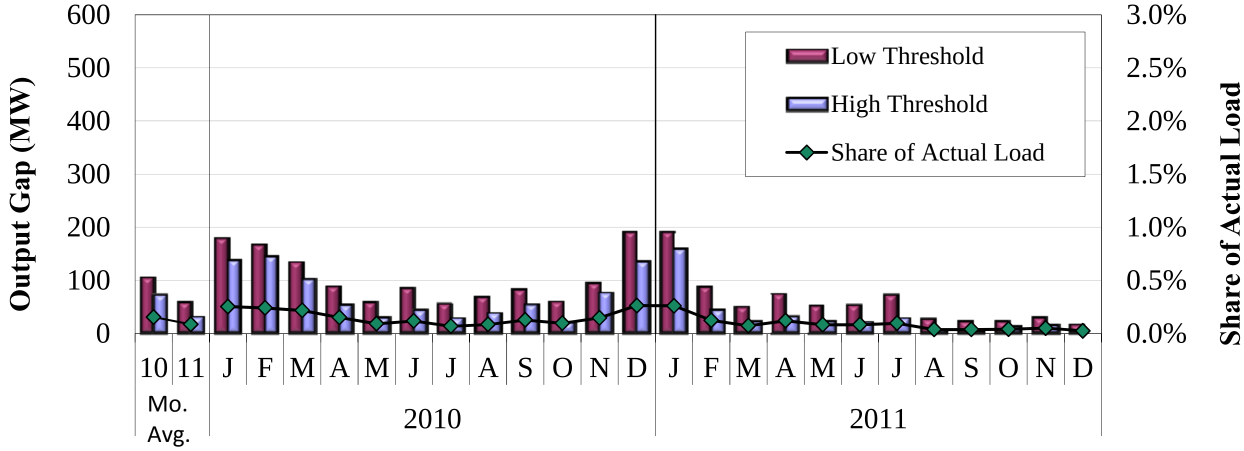
B. Evaluation of Competitive Conduct

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 SMP that assumes all suppliers had submitted offers at their estimated marginal cost.

We found an average system marginal price mark-up of just 1.3 percent, which reflects the competitiveness of MISO's energy markets.

Figure 25 shows our "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.

Figure 25: Economic Withholding – Output Gap Analysis
2010–2011



Low Threshold Results by Unit Status (MW)

	10	11	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Off-Line	43	24	74	110	75	28	12	31	16	19	18	5	33	95	143	44	21	14	9	11	23	0	1	11	12	0
On-Line	62	34	105	57	59	60	46	54	38	49	64	54	61	96	48	43	29	60	43	42	49	26	22	12	17	16

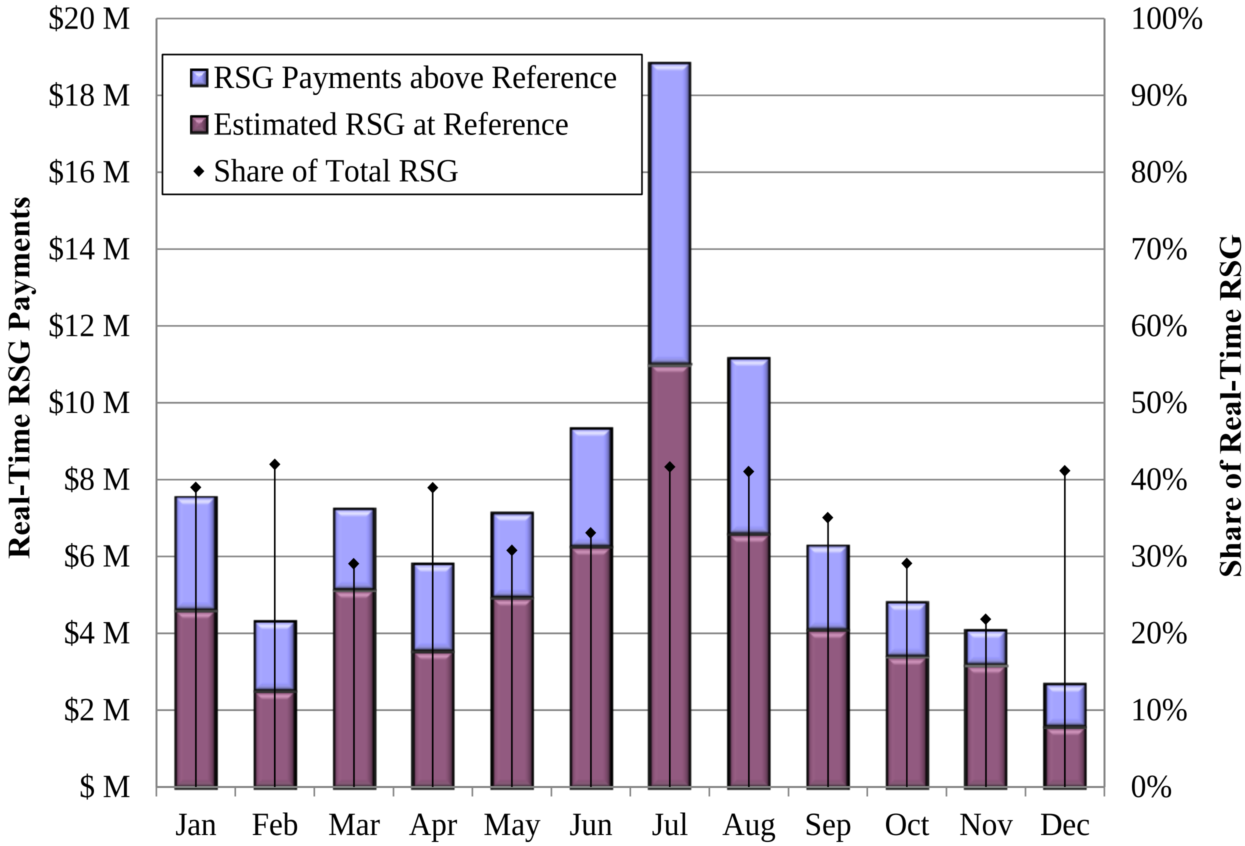
High Threshold Results by Unit Status (MW)

	10	11	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Off-Line	42	22	67	110	73	27	12	31	16	19	18	5	33	89	142	29	16	14	9	10	19	0	1	11	12	0
On-Line	30	8	71	35	29	26	17	12	12	19	36	15	43	46	17	14	5	17	13	10	9	6	4	1	3	1

Output gap levels continued to decline in 2011 and averaged just 58 MW per hour at low threshold and 30 MW per hour at high threshold. As a share of actual load, it averaged less than 0.1 percent, which is extremely low. The two metrics declined after January because NCA threshold levels, which are revised annually, were updated on February 1. These results and others in this report show, in aggregate, very little indication of significant economic or physical withholding in 2011. Nonetheless, we monitor these levels on an hourly basis and routinely investigate instances of potential withholding.

Local market power can also be associated with repeated resource commitments for local reliability needs (including voltage support). Certain commitments raised significant competitive concerns beginning in late 2010 and continued into 2011. Hence, we evaluate RSG payment conduct in Figure 26, separating payments by conduct: those receiving payment with offers at their reference value, and those receiving payments with offers above their reference value.

Figure 26: RSG Payments by Conduct
2011



The figure confirms that a substantial minority of RSG payments—$32 million in 2011—was associated with payments to participants offering above a unit's reference value. While some of these excess payments reflect legitimate costs, some are likely associated with offers that exceed the resources' marginal costs. Such suppliers are still being committed because they are often the only suppliers positioned to satisfy the local reliability issue. This issue is most acute in the case of local needs, such as voltage support in an area. Based on a recommendation in last year's

State of the Market Report, MISO filed tighter mitigation thresholds for such VLR commitments in December 2011, which are expected to be implemented in late summer 2012.

C. Summary of Market Power Mitigation

Finally, 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 depending on the frequency with which NCA constraints bind. The chronic nature of the NCAs and the lower mitigation thresholds generally lead to more frequent mitigation there than in BCAs, even though the system has many more BCAs. As in prior years, very little mitigation was imposed in the day-ahead market. This is expected because the day-ahead market is much less vulnerable to withholding because of the liquidity provided by virtual traders.

Real-time NCA and BCA energy market mitigation remained rare in 2011. BCA mitigation was unchanged from 2010 in terms of unit-hours mitigated (28 unit-hours) but slightly higher in terms of MWhs mitigated (1,488 MWh). NCA mitigation in 2011 was also relatively flat from 2010, totaling 9 unit-hours and 288 MWhs.

Despite infrequent mitigation in 2011, the pivotal supplier analyses discussed earlier in this section continue to indicate that local market power is a significant concern. If exercised, local market power could have substantial economic and reliability consequences within MISO. Hence, market power mitigation measures remain essential.

IX. Demand Response

Demand Response (DR) improves reliability in the short term, contributes to resource adequacy in the long term, 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 3 shows overall DR participation in MISO, NYISO and ISO-NE in the prior three years.

Table 3: DR Capability in MISO and Neighboring RTOs
2009–2011

		2011	2010	2009
Midwest ISO	**Total***	**7,376**	**8,663**	**12,550**
	Behind-The-Meter Generation	3,001	5,077	4,984
	Load Modifying Resource	2,898	3,184	4,860
	DRR Type I	472	46	2,353
	DRR Type II	75	0	111
	Emergency DR	930	357	242
	Of which: LMR	404	N/A	N/A
NYISO	**Total**	**2,173**	**2,362**	**2,384**
	ICAP - Special Case Resources	1,976	2,103	2,061
	Of which: Targeted DR	407	489	531
	Emergency DR	148	257	323
	Of which: Targeted DR	86	77	117
	DADRP	37	331	331
ISO-NE	**Total**	**2,755**	**2,719**	**2,292**
	Real-Time DR Resources	1,227	1,255	873
	Real-Time Emerg. Generation Resources	650	672	875
	On-Peak Demand Resources	562	533	N/A
	Seasonal Peak Demand Resources	316	259	N/A

* Registered as of December 2011.

The table shows that MISO had 7.4 GW of registered demand-response capability in 2011, comparable as a share of capacity to neighboring RTOs. The reduction in capability from 2010 to 2011 is largely due to the departure of FirstEnergy in June 2011. MISO's capability comes in varying degrees of responsiveness. Most of the MISO DR is interruptible load (i.e., "load-modifying resources" or LMR) developed under regulated utility programs or 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. Only 547 MW participates directly in MISO's energy markets as Demand Response Resources (DRR), Types I and II. However, this is a substantial increase from 2010, when a single resource participated. The majority of these resources provide only supplemental reserves.

MISO considers DR to be a priority and continues to actively expand its DR capability. One means to do so is for Aggregators of Retail Customers (ARCs) to actively participate in the MISO markets. FERC approved Tariff language in December 2011 that compensates an ARC-operated resource cleared for energy at the full LMP. The approved Tariff language would not remove a predetermined "Marginal Foregone Retail Rate", a proxy for the costs the retail customer providing the service would have incurred to consume, from the ARC payment. This will increase the incentive for DR resources to curtail beyond the marginal cost of serving the customer, which may cause DR resources to reduce their curtailment offer prices and increase the frequency of curtailments. ARCs providing other products such as capacity or ancillary services would be paid just the market price for those products.

MISO has significant potential for more fully-integrated DR capability. Its proposed programs and Tariff changes address many barriers to their participation. 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. One change that is particularly important is a modification to price-setting methodologies to let emergency actions and all forms of DR—including those not callable by MISO—contribute to setting efficient shortage prices in the markets. Failure to do so will undermine the efficiency of the market during peak periods and can serve as a material economic barrier to the development of new resources. MISO's proposed ELMP pricing methodology will improve the extent to which DR resources are integrated by allowing EDR to set energy prices. We recommend that MISO consider expanding this capability to LMR, including BTMG.

Finally, the integration of DR in the resource adequacy construct is very important because it can potentially have a sizable effect on the price signals provided by MISO's capacity market. LMR (including BTMG) currently can be deducted from an LSE's capacity requirement under Module E. This effectively provides a near 100 percent capacity credit to LMR, which are not tested to verify their capability. When they have been called in the past, MISO has received only a fraction of their total claimed capability. Therefore, we recommend adopting testing procedures if practicable, and derating these resources based on their actual performance when called.

X. Recommendations

Although its markets continued to perform competitively and efficiently in 2011, we recommend MISO make a number of changes. We have organized the recommendations by the aspects of the market that they affect:

- Energy Pricing and Transmission Congestion
- RSG Cost Allocation
- Market Operations
- Ancillary Services
- Resource Adequacy

A number of the recommendations described below were recommended in prior *State of the Market* reports. This is not unexpected because some of the recommendations can require substantial software changes, stakeholder review and discussions, regulatory filings or potential litigation regarding Tariff changes. Because these processes can be time-consuming and because software changes must be prioritized with other software projects, recommendations can take multiple years to complete. MISO addressed seven of our past recommendations in 2011 or in early 2012; 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. Real-Time Energy Pricing and Transmission Congestion

Efficient energy pricing in the real-time market is essential. Even though a very small share (1-2 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.

1. Develop provisions that allow non-dispatchable DR (including interruptible load and BTMG) 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 interruptible load, BTMG or other forms of DR. If these resources cannot set prices in the real-time market, MISO will be understating energy prices increasingly during peak demand conditions. Prices in these hours play an important role in sending efficient economic signals to maintain adequate supply resources and to develop additional demand-response capability. Therefore, allowing demand response to set real-time energy prices 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: The recommendation was originally proposed in 2008 and MISO agrees with it. MISO has worked to address this recommendation by allowing EDR to set prices through the ELMP initiative, which is scheduled to go into testing in early 2014. This will be a significant improvement, assuming FERC approves the ELMP proposal. However, MISO will generally call for the deployment of LMR and BTMG (which total nearly 6 GW) before it calls on EDR in an emergency. Since LMR and BTMG will not set prices under the ELMP proposal, real-time prices are likely not to reflect curtailment costs when MISO deploys DR.

Next Steps: While the progress in potentially allowing EDR resources to set prices as part of the ELMP initiative has been substantial, it is important to address LMR and BTMG that will be deployed first in an emergency. This may be accomplished by establishing a default curtailment cost for each class, or by compelling these resources to participate in the EDR program. The latter approach has the advantage of providing MISO more direct access to these classes of DR capability, and perhaps an improved capacity to verify their ability to curtail load when needed.

2. Discontinue the constraint relaxation algorithm for market-to market constraints and set LMPs based on a transmission constraint's marginal value limit when the constraint is unmanageable.

The constraint relaxation algorithm artificially reduces the real-time congestion that is reflected in MISO's LMPs when a constraint is violated (i.e., when the real-time market cannot reduce the flow to less than the limit in the interval). Pricing such congestion accurately is important because it will facilitate day-ahead market outcomes that cause generation to be committed efficiently to manage the congestion. It also provides the necessary economic signals to guide investment in new resources and transmission. In 2011, the constraint relaxation algorithm reduced apparent real-time congestion by one-third, or $620 million.

Status: This recommendation was originally proposed in 2005. MISO has expressed agreement with this proposal and on February 1, 2012 discontinued use of this algorithm for all non-M2M constraints. It continues to employ the methodology on M2M constraints because PJM has expressed disagreement with MISO discontinuing its use on these constraints.

Next Steps: Congestion on M2M constraints represents nearly 40 percent of all congestion on the MISO system. While the action taken by MISO in February represents substantial progress, it is essential to address M2M constraints because they are currently not being priced efficiently. We understand that MISO will continue its dialogue with PJM to determine whether there is hope of achieving a consensus on this change. If not, other avenues should be explored, since the use of this methodology is not specified or otherwise required under the JOA with PJM.

3. Consider implementing a graduated marginal value limit (i.e., transmission demand curve) for transmission constraints.

This report shows that transmission constraints are frequently violated in small quantities or for brief periods of time. This occurs because the power flows over MISO's constraints are affected by external factors that can cause them to change unexpectedly. To the extent this causes relatively small violations, it may not substantially affect reliability. If this is true, pricing small violations at the full MVL may not be efficient. This can be remedied by replacing the single MVL with a graduated demand curve.

Status: This is a new recommendation for 2011. However, MISO has been investigating the feasibility and cost of implementing transmission demand curves.

Next Steps: MISO should complete its evaluation of the costs of this recommendation. Because 71 percent of the congestion value that occurred on the MISO network in 2011 was on constraints that were in violation, the introduction of transmission demand curves could significantly lower congestion-related costs. If such curves reflect the reliability implications of violating the constraints by small amounts, it will lead to more efficient real-time pricing. It is important that the transmission demand curves reflect the system's reliability needs and that MISO operates the system consistent with the demand curves.

B. RSG Cost Allocation

Failure to allocate costs to those market participants that cause them will produce inefficient incentives by (a) discouraging conduct that does not cause the costs and (b) not discouraging conduct that does cause the costs. The current allocation rules for RSG costs, though substantially improved in April 2011, continue to produce an allocation of real-time RSG costs that is inconsistent with cost causation. In particular, MISO still allocates 90 percent of the real-time RSG costs to market-wide deviations, even though such deviations are likely only causing approximately one-third of the costs. Market-wide deviations often bear a majority of real-time RSG costs in hours when the total net deviations are *negative* (thus they cannot be contributing to MISO's need to commit resources for capacity). In addition, an error in the cost allocation formula is reversing the intended allocation of CMC costs to virtual load and virtual supply. This means virtuals that help reduce RSG costs are bearing the costs, while those that hurt are not. The recommendation in this area includes three specific changes to address these issues.

4. Improve the allocation of real-time RSG costs to make it more closely aligned with causes of the costs by making the following changes:

a) Netting market-wide deviations to determine the share of the real-time RSG costs that should be allocated via the DDC rate.

Netting helping and harming market-wide deviations is important because it allows one to determine the extent to which total deviations are contributing to the need for MISO to commit resources after the day-ahead market. The current rules allow for netting at the market participant level and administrative netting through Financial Schedules (allowing one participant's harming deviation to be offset by another participant's helping deviation). To date, no participants have used this mechanism.

Status: This is a new recommendation. However, the IMM discussed this change with MISO and with the RSG Task Force in February 2012.

Next Steps: We recommend that MISO work with stakeholders to develop a proposal to modify the Tariff to use net deviations on a market-wide basis when determining the share of the capacity-related real-time RSG costs that should be attributed to the net deviations. This change does not preclude continuing to charge the resulting DDC rate to market participants on a net basis for each participant.

b) Use of GSFs to determine the costs that should be allocated via the CMC rate.

The CMC formula currently under-allocates congestion-related RSG costs to the deviations that contribute to the need to incur these costs. The primary issue is that these RSG costs are multiplied by the GSF for the committed resource as one step in determining the share that will be allocated to congestion-related deviations. While it is true that this will indicate the share of the resource's output that will provide relief on the constraint, it fails to recognize that in most cases *all* of the commitment costs were incurred because of the constraint, regardless of the magnitude of the GSF. Our studies have shown the average GSF of units committed for congestion management is roughly 35 percent, but is often as low as 5 or 10 percent. Consequently, a CMC deviation that might be entirely responsible for causing a commitment and any associated RSG payments frequently bears only a small fraction (e.g., 5 percent) of the costs.

Additionally, most of the costs that are not borne by deviations affecting the constraint are then borne by market-wide deviations under the current Tariff. While there are times when constraint commitments would contribute to capacity needs (such as VLR commitments), we believe the share of costs appropriately allocated to the DDC should be limited to a share that reflects MISO's estimate of the typical capacity benefit of these commitments. In the case of VLR commitments, this share is approximately 10 percent.

Status: This is a new recommendation. However, the IMM has discussed this change with MISO and with the RSG Task Force in February 2012.

Next Steps: MISO should work with stakeholders to develop proposed changes to the Tariff.

c) CMC sign error affecting the RSG cost allocation to virtual transactions.

The third issue is the result of an Order by FERC that compelled MISO to misallocate CMC charges to virtual transactions.[27] The misallocation results in charges to virtual transactions that relieve the constraint and credits (against other deviations) virtual transactions that load the constraint. While the sign error was been identified by MISO in numerous filings and questioned by certain participants in a complaint, FERC denied rehearing on the issue and dismissed the complaint.

Status: MISO is considering procedural options for addressing this error and the IMM is considering filing a market design flaw referral with FERC.

Next Steps: MISO should determine the best procedural avenue for correcting the error.

C. 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

27 *See* Docket EL07-86-013.

and other inputs to the real-time market as necessary. Each of these actions can substantially affect the outcomes of the real-time market.

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 RTO's in the Eastern Interconnect. These ramp demands can be satisfied at a much lower cost if they are anticipated and 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.

5. In the short-term, improve the use of the load offset parameter to proactively manage the system's ramp capability.

Operators currently use the "offset" parameter to manage system ramp capability by incrementally increasing or decreasing load served by the real-time market. Suboptimal use of this parameter can reduce ramp capability and increase price volatility. Improving the accuracy of the offset will likely require improving the tool used to produce recommended offset levels and modifying the procedures to use these values.

Status: This recommendation was originally proposed in 2005 and MISO has worked to improve its use. MISO developed an initial offset tool in consultation with the IMM. However, it is not currently sufficient to allow operators to use the tool to set the offset proactively to manage the system's ramp capability. MISO also developed a metric that it uses to evaluate its use of the offset parameter on a daily basis. However, a metric that evaluates the production cost impacts of binding ramp constraints is needed.

Next Steps: MISO should pursue additional changes to the offset tool and the performance metric to provide the information that real-time operators need to use the offset parameter more proactively. We are developing a measure of the costs incurred to dispatch higher-cost resources when increased system ramp demands occur. This measure should provide a basis for a new performance metric and the modification to the offset tool. We plan to continue collaborating with MISO on these improvements.

6. **In the longer-term, develop a look-ahead real-time dispatch capability.**

This look-ahead capability would include a multi-period dispatch optimization feature to move resources in anticipation of system demands over the next several intervals. This capability would be a clear improvement over the use of the offset parameter because the look-ahead dispatch would proactively move resources in optimal locations in advance of their anticipated need, securing the necessary ramp capability at the lowest cost.

Status: This was originally proposed in 2005 along with a Look-Ahead Commitment (LAC) capability to better manage the economic commitment and decommitment of gas turbines. MISO has developed the look-ahead commitment model and it was implemented on April 1, 2012. The Look-Ahead Dispatch (LAD) capability is relatively resource-intensive and has not been scheduled for implementation. MISO is currently evaluating the LAD's costs and benefits relative to other software projects.

7. **Implement a ramp capability product.**

The prior two recommendations address ramp demands that can be foreseen by MISO. Some of the most significant ramp demands MISO faces, however, are unforeseen in advance. These include unit outages and changes in "non-conforming" load. To address these unforeseen ramp demands, MISO could 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.

Status: This is a new recommendation and MISO has already been developing this concept.

8. **Eliminate the transmission constraint deadband.**

Our evaluation of the unmanageable congestion in MISO revealed that 30 percent of the value of constraint violations occurred when the transmission deadband alone caused a constraint to appear to be violated (i.e., when the flow was less than the original transmission limit). We estimate that the deadband accounted for $140 million in unpriced congestion and 19 percent of all congestion value in MISO during 2011. While eliminating the deadband would not cause this congestion to fall to zero, it would be significantly less. The deadband was intended to reduce price and generator dispatch volatility by helping ensure that once constraints were binding, they continued to do so. However, we believe that the deadband is actually increasing volatility because it contributes to unmanageable congestion that often results in sharp LMP changes. It also inefficiently reduces the utilization of the transmission system by binding constraints at levels less than their physical capability. We are unaware of any other RTO that currently employs a transmission deadband.

Status: This is a new recommendation.

9. Expand the JOA to optimize the interchange with PJM to improve the price convergence with PJM.

The RTOs have discussed 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 ones in the other area.

Status: This recommendation was originally proposed in 2005 and MISO has been discussing options with PJM. MISO staff has engaged in discussions with PJM and developed a white paper describing the options for addressing this recommendation. PJM stakeholders to date have expressed limited interest or support for this initiative.

Next Steps: If PJM is willing, we recommend that MISO work with PJM to complete a detailed concept and work with stakeholders in both areas to garner support for the concept.

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 M2M constraints and to compensate the responding RTO based on the responding RTO's DA shadow price. This is a valuable provision because a constraint binding in the day-ahead market at the FFE 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 FFE in real-time at a very low cost. As highlighted in the JOA Baseline Review, neither PJM nor MISO has ever requested additional FFE in the day-ahead market.

Since the start of M2M coordination, PJM has consistently been over its FFE in the real-time on a large number of Reciprocal Coordinated Flowgates (RCFs) and consequently has paid MISO for use of additional FFE in real-time based on real-time shadow prices. Under the JOA, PJM's payments would likely be reduced if the additional FFE were to be requested in the day-ahead market when MISO would have more ability to efficiently commit (or decommit) resources to manage the additional flows on MISO RCFs. This would reduce MISO's real-time congestion costs and likely reduce PJM's M2M payments.

Status: This is a new recommendation.

Next Steps: While Section 4.1 of the JOA provides a basic procedure for implementing day-ahead coordination, we recommend that the RTOs work together to develop more detailed procedures. The RTOs should include data exchange related to day-ahead results in order to facilitate the ability to monitor and audit this process.

D. ASM Improvements

11. Eliminate guarantee payments to deployed spinning reserves.

Compensating spinning reserve suppliers for out-of-market deployment costs when they are called on to produce energy leads to an inefficient selection of spinning reserve resources because these expected deployment costs are not considered when resources are selected. Eliminating these payments, including RTORSGP and real-time RSG payments, for spinning reserve deployments will improve reserve market efficiency by causing expected deployment costs of operating reserves to be reflected in participants' offers. This in turn will allow MISO to schedule those resources with the lowest total costs, including deployment costs. It will also allow these costs to be efficiently reflected in spinning reserve prices

One additional recommendation involves changes to DAMAP and RTORSGP eligibility rules to address significant gaming concerns that have been discussed confidentially with MISO.

Status: This recommendation was originally made in the *2010 State of the Market Report* and MISO has been developing proposed changes to address it.

Next Steps: MISO should complete the stakeholder process to develop proposed Tariff changes.

E. Resource Adequacy Improvements

Reasonable resource adequacy provisions and a well-functioning capacity market will be increasingly important as capacity 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 provide the resources over the long-term that are necessary to maintain reliability.

12. Remove inefficient barriers to capacity trading with adjacent areas.

A number of existing barriers limit capacity trading between MISO and PJM, which 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.

Status: This recommendation was originally proposed in 2008. MISO has been developing proposals to address this recommendation, but PJM stakeholders have generally opposed changes in this area. In recent FERC filings we have sought a mandate to compel the RTOs to collaborate on a proposal to address this issue.

Next Steps: If no mandate is provided by FERC, MISO should continue to refine its proposals and discuss them with PJM. Additionally, MISO and the IMM should discuss other procedural options for acquiring a FERC mandate to address this issue.

13. Introduce a sloped demand curve in its RAC to replace the current vertical demand curve.

Establishing only a minimum requirement and deficiency charges results in an implicit vertical demand curve for capacity in MISO. 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 potentially 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.

Status: This recommendation was first proposed in the *2010 State of the Market Report* and MISO is considering its potential value in the context of the RAC.

Next Steps: MISO should develop a proposal that can be discussed with MISO stakeholders.

14. Evaluate capacity credits provided to wind resources and 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. We have identified three classes of capacity that are likely overstated in the capacity market. First, the basis for the capacity credit provided to wind resources is based on the performance of wind resources during peak load hours averaged over multiple historical years . Even one unusually windy peak day can result in an anomalously high average output levels. Since the capacity credit should be based on capability that can be reasonably expected during peak conditions, the current approach may overstate the capacity credit. This will, in turn, lower capacity prices and reduce the incentive to invest in other resources that are needed for reliability. A better basis for the capacity credit would be the lower of the median or the mean wind performance on peak days, which would exclude anomalously high output levels and more accurately account for resources that have performed poorly.

LMR (excluding BTMG) can currently be fully deducted from an LSE's capacity requirement under Module E. This effectively provides a 100 percent capacity credit to DR resources that are not tested to ensure their capability and have shown in past deployments to provide only a fraction of the total claimed capability. Therefore, we recommend adopting testing procedures if possible, and/or derating these resources based on their actual performance when called upon.

Status: This is a new recommendation.

15. Improve SSR designation and compensation provisions.

MISO has received a number of recent applications for SSR status from suppliers that intend to retire one or more resources. The number of such requests will likely increase as the new environmental regulations become effective, particularly given the issues described in this report that are leading to understated capacity prices. The current Tariff language related to SSR compensation is vague and does not specify the procedures MISO should follow when considering alternatives to satisfying the reliability needs. In addition, the Tariff does not specify what costs MISO should consider when determining equitable compensation.

It is critical that the designation and compensation provisions be well-defined to avoided creating incentives for suppliers to seek SSR status for resources that would not otherwise be retired or otherwise placed out of service. The IMM recommends the MISO include only going-forward costs in the "equitable compensation" for SSR resources. These costs should include all avoidable costs of remaining in service, and exclude any sunk or unavoidable costs.

Status: This is a new recommendation. We have been reviewing the MISO's approach for its first SSR status designation. MISO has been working with its stakeholders to develop improvements to the SSR provisions.

F. Recommendations Addressed in the Past Year

MISO in 2011 and early 2012 addressed a number of past recommendations by implementing changes to its market software or operating procedures, or by completing the design and regulatory work associated with new market elements. These recommendations are discussed below.

1. Develop real-time software and market provisions that allow gas turbines running at their economic minimum or maximum to set energy prices.

This was originally proposed in 2005 and required significant research. MISO has made substantial progress in working to respond to this recommendation through its ELMP initiative. ELMP was filed in December 2011 and is expected to be tested in a production environment in early 2014. ELMP will allow gas turbines and EDRs to set prices in the Real-Time Energy and Operating Reserve Markets. It will also allow commitment costs (start-up and no-load costs) to be reflected in the LMPs and MCPs.

This change will improve the efficiency of real-time prices, improve incentives to schedule load fully in the day-ahead market and reduce RSG costs. To set prices correctly, ELMP will distinguish between gas turbines and EDR that are economic or otherwise needed versus those that would be shut down if they were flexible.

2. Discontinue the constraint relaxation algorithm and set LMPs based on a transmission constraint's marginal value limit when the constraint is unmanageable.

This recommendation was originally proposed in 2005. MISO on February 1, 2012 discontinued use of this algorithm for all non-M2M constraints. As noted above, MISO continues to employ the methodology on M2M constraints.

For the non-M2M constraints, discontinuing this algorithm has helped to more accurately reflect the value of congestion in MISO's LMPs when a constraint is violated. Pricing such congestion accurately is important because it will facilitate day-ahead market outcomes that cause generation to be committed efficiently to manage congestion. It also provides important economic signals to guide investment in new resources and transmission.

3. Seek additional improvements to the STLF used by the real-time market to reduce system ramp capability consumed by changes in real-time load.

This recommendation was originally proposed in 2009. MISO implemented the ITRON-based STLF in March 2012 to improve the accuracy of its dispatch process. An improved STLF will allow the system to satisfy fluctuating demands while ramping generation up and down more smoothly, and should reduce price volatility and improve generator dispatch efficiency in the real-time market.

Experience with ITRON in production is somewhat limited. Based on testing and experience to date, ITRON has significantly improved the STLF in the 30-minute to two-hour timeframe and provides more flexibility to select different forecasting techniques based on different load conditions. After evaluating the ITRON performance, MISO will consider the extent to which additional efforts to improve STLF are needed.

4. Improve the performance of the spinning reserve market by:

- **a) Improving the consistency between the reliability requirement for spinning reserve and the market requirement; and**
- **b) Allowing the spinning reserve penalty price (or reserve demand curve) to set the price in the spinning reserve market (and be reflected in energy prices) during spinning reserve shortages by not relaxing the requirement.**

This recommendation was originally proposed in 2009. MISO implemented a number of interim solutions to significantly improve shortage pricing in 2010. On May 1, 2012 MISO implemented a spinning reserve demand curve. The spinning reserve demand curve will further improve the dispatch and pricing of the market during shortage conditions and the demand curve should reduce price volatility by sending graduated price signals as MISO approaches reserve shortages.

5. Implement tighter market power mitigation thresholds for resource commitments made for local reliability needs (including voltage support).

This recommendation was originally proposed in 2009. MISO filed for Voltage and Local Reliability (VLR) mitigation authority with FERC in December 2011. This authority is needed to address the market power associated with VLR constraints, which often can be resolved by only one supplier. MISO expects to implement this recommendation in late summer 2012 following at technical conference scheduled for mid-May 2012.

6. Align allocation of RSG costs associated with VLR resource commitments with cost-causation.

This recommendation was originally presented to the MISO RSG Task Force and the Market Subcommittee in 2011. MISO filed proposed changes in its cost-allocation provisions in December 2011. MISO expects to implement the new allocation of VLR-related RSG costs in late summer 2012 following a technical conference scheduled by FERC in mid-May 2012. The benefits of aligning allocation with cost causation include providing efficient incentives for market participants affected by the local voltage or reliability issues to make investments to address the issues. Importantly, compared to other allocation methodologies based on offer parameters, it is not subject to manipulation.

7. Develop improved "look-ahead" capabilities in the real-time that would improve the commitment of quick-starting gas turbines and the management of ramp capability on slow-ramping units.

This recommendation has two aspects:

- Using an economic model to commit and de-commit peaking units economically to minimize the system's overall production costs; and
- Implementing a multi-period dispatch optimization to move slower-ramping units in anticipation of system demands over the ensuing hour.

This recommendation was originally proposed in 2005. The first phase of the LAC using a production cost minimization objective function was implemented on April 1, 2012. During testing of the LAC Phase I, MISO found it improved the commitment of short-lead time resources, lowered production costs and increased headroom. In limited experience to date, the LAC Phase I implementation has performed as expected.