2010 STATE OF THE MARKET REPORT
FOR THE MISO ELECTRICITY MARKETS

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Guide to Acronyms

ARC	Aggregators of Retail Customers
ARR	Auction Revenue Rights
ARS	Automatic Reserve Sharing
ASM	Ancillary Services Markets
BCA	Broad Constrained Area
BREC	Big Rivers Electric Cooperative
BRM	Broader Regional Markets Initiative
BTMG	Behind-The-Meter Generation
CC	Combined Cycle
CDD	Cooling Degree Day
ComEd	Commonwealth Edison Company
CONE	Cost of New Entry
CT	Combustion Turbine
DAMAP	Day-Ahead Margin Assurance Payment
DIR	Dispatchable Intermittent Resource
DLC	Direct Load Control
DPC	Dairyland Power Cooperative
DR	Demand Response
DRR	Demand Response Resource
EDR	Emergency Demand Response
EEA	Emergency Energy Alert
ELMP	Extended LMP
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

(continued)

LAC	Look-Ahead Commitment
LAD	Look-Ahead Dispatch
LMP	Locational Marginal Price
LSE	Load-Serving Entity
M2M	Market-to-Market
MCP	Marginal Clearing Price
MFRR	Marginal Foregone Retail Rate
MHEB	Manitoba Hydro Electricity Board
MidAmerican	MidAmerican Energy Holdings, Inc.
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
O&M	Operations and Maintenance
PJM	PJM Interconnection, Inc.
PVMWP	Price Volatility Make Whole Payment
PY	Planning Year
RDI	Residual Demand Index
RSG	Revenue Sufficiency Guarantee
RTO	Regional Transmission Organization
RTORSGP	Real-Time Offer Revenue Sufficiency Guarantee Payment
SMP	System Marginal Price
STLF	Short-Term Load Forecast
TLR	Transmission Line Loading Relief
VCA	Voluntary Capacity Auction
WUMS	Wisconsin-Upper Michigan System

I. Executive Summary

As the Independent Market Monitor ("IMM") for the Midwest Independent Transmission System Operator ("MISO"), Potomac Economics is responsible for evaluating competitive performance, design, and operation of wholesale electricity markets operated by MISO. In this *2010 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 that produce prices that vary across the region to reflect the marginal cost of supply, transmission congestion and losses. These 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. MISO also operates a market for Financial Transmission Rights ("FTRs") that allows participants to hedge congestion risk associated with serving load or engaging in other transactions.[1]

In 2009, MISO began operating as a balancing authority and introduced markets for regulation and contingency reserve, known collectively as Ancillary Services Markets ("ASM"), and a spot market for capacity. ASM jointly optimize the allocation of resources between energy and ancillary services, and allow prices to reflect shortages more efficiently. The Voluntary Capacity Auction ("VCA") allows Load-Serving Entities ("LSEs") to meet residual capacity requirements under Module E of the MISO Tariff. Together these additions improve the efficiency of MISO's long-term economic signals.

1 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.

A. Summary of Findings

Overall, we found that markets operated by MISO performed competitively in 2010. Although certain suppliers in MISO have local market power, our analysis suggests very few competitive concerns that suppliers withheld resources to raise prices. We also find that the markets generally resulted in efficient utilization of the region's resources to satisfy the demand for electricity. However, this report does raise some specific concerns related to pricing in and operation of the MISO markets that are addressed by 14 recommendations listed at the end of this executive summary.

Because the market continued to perform competitively in 2010, market power mitigation measures were employed infrequently to address withholding that would have increased energy prices or uplift costs.[2] We do, however, identify one market power issue associated with resources that are committed to satisfy local reliability requirements or to support the voltage of the system at a location. In these cases, which can result in repeated commitments for an extended period of time, the supplier frequently faces no competition. The current market power mitigation measures are insufficient for these commitments due to the extent of the market power and the chronic nature of these issues. We estimate that suppliers with resources committed to satisfy these requirements increased their Revenue Sufficiency Guarantee ("RSG") payments by $16 million by raising their offer prices. Hence, we recommend a new mitigation measure that would more effectively address these types of commitments.

In a competitive market, suppliers face strong incentives to offer their supply at prices close to their short-run marginal costs of production, the vast majority of which are fuel costs. We again found a strong correspondence between real-time energy prices and fuel prices in 2010, which demonstrates the competitiveness of the MISO markets. Real-time energy prices averaged $34 per MWh, up 18 percent from 2009 due primarily to a rise in fuel prices. Natural gas prices rose 14 percent to $4.46 per MMBtu, while western coal prices rose 42 percent.[3]

2 In addition, virtual trading mitigation was employed once in 2010 to limit the trading of one participant.

3 Oil prices rose 31 percent, but oil-fired units were rarely on the margin in 2010.

Although most of the price increase is attributable to higher fuel prices, higher load also contributed to the increase. The contribution of factors other than fuel prices is indicated by the fact that real-time energy prices, adjusted for changes in fuel prices, rose 3 percent in 2010. Average load in 2010 increased more than 6 percent (after adjusting for new member additions) due to improved economic conditions in 2010 and above-average summer temperatures. Load peaked at 109 GW in 2010, an increase of 13 percent from 2009.

In addition, the value of real-time transmission congestion increased 18 percent to $1.08 billion partly because of the increase in fuel prices, which raise the redispatch costs incurred to manage congestion. The largest increase in congestion was in the West Region because wind output continued to grow rapidly. The "constraint relaxation" algorithm that MISO uses when flows over a transmission constraint exceed its limit, however, artificially reduced real-time congestion. We estimate that this algorithm reduced real-time congestion by 25 percent (more than $300 million) in 2010, which substantially affected the day-ahead market outcomes and FTR values. We have recommended that MISO discontinue use of this algorithm since 2005 and continue to believe this is a critical flaw that should be addressed.

Real-time uplift costs, including RSG and Price Volatility Make-Whole Payments ("PVMWP"), increased 46 percent to $230 million. Less than one-third of this increase was due to higher fuel prices and increased peaking unit commitments to meet summer loads. Slightly more than one-third of the increase was associated with commitments made to manage local voltage and raised the competitive concerns noted above. Finally, the balance of the increase ($26 million) was attributable to higher PVMWP in 2010, partly caused by increased price volatility at specific generator locations. As a result of our investigation of these PVMWP, we identified some issues with the PVMWP formulas that we recommend revising.

Despite higher loads and energy prices, overall incentives for new investment in 2010 remained weak due to the surplus capacity in the region. Our report, as well as MISO's *2011 Summer Assessment*, continues to project substantial surplus capacity. Including all demand response capability, we estimate a planning reserve margin in the range of 28 percent to 37 percent depending on the summer capability of the resources that are assumed. These margins substantially exceed MISO's planning reserve requirements that have recently increased from 15 percent to 17 percent.

In long-run equilibrium, markets should provide net revenues that provide efficient incentives for investment and retirement. Although the introduction of ASM and the VCA in 2009 improved their structure and completeness, we find that in 2010 the MISO markets provided insufficient net revenue to cover annualized cost of new investment for a generic combined-cycle unit or gas turbine. This result is consistent with expectations for a well-functioning market because the prevailing capacity surplus should not lead to outcomes that produce incentives to build new resources.

Although existing resources are expected to be more than adequate to satisfy the system's demands and reliability requirements in 2011, MISO continues to develop and promote various changes to its market design and operating procedures to allow additional resources – particularly intermittent resources, Demand Response ("DR") resources, and interruptible load – to integrate more fully into its existing markets. MISO is anticipating continued growth in wind generating capacity, to more than 10 GW in total. Although wind provides substantial environmental benefits, its intermittent nature limits its contribution to reliability and resource adequacy in the long-run. To address operational and market issues with intermittent resources, MISO filed tariff changes that would allow wind resources to become dispatchable and to set price as Dispatchable Intermittent Resources ("DIRs") beginning in June 2011. MISO is currently anticipating that 1.2 GW of wind capacity will participate as DIRs initially.

Given the importance of external transactions and the extensive network interactions in the Midwest, our report evaluates the interchange and coordination with neighboring areas. MISO continues to rely on imports from adjacent areas. Real-time imports increased 8 percent to an average of 3.2 GW per hour, predominantly across interfaces with PJM Interconnection ("PJM") and Manitoba Hydro Electric Board ("MHEB"). Overall prices at the border between the markets are as well arbitraged in most hours as one can expect under current market rules. Substantial efficiency benefits can be achieved, however, by improving the net interchange between markets, particularly with PJM.

MISO has been discussing an initiative to improve interchange with PJM, which is the most valuable of the improvements proposed by the Broader Regional Markets Initiative ("BRMI"), developed by the Regional Transmission Organizations ("RTOs") around Lake Erie. Other BRMI proposals address transaction scheduling around Lake Erie that generates significant unscheduled power flows (i.e., "loop flows"). Taken together, we estimate annual production cost savings of $300 million for MISO, New York Independent System Operator ("NYISO"), Independent Electricity System Operator of Ontario ("IESO"), and PJM.

In the remainder of this Executive Summary, we provide a more detailed discussion of market outcomes and issues in 2010, along with 14 recommendations to improve the efficiency and competitiveness of the MISO markets. These recommendations address energy pricing, congestion management, real-time operations, external transaction scheduling, the M2M process with PJM, and capacity market rules. Many of these have been recommended in prior *State of the Market* reports and are being pursued by MISO.

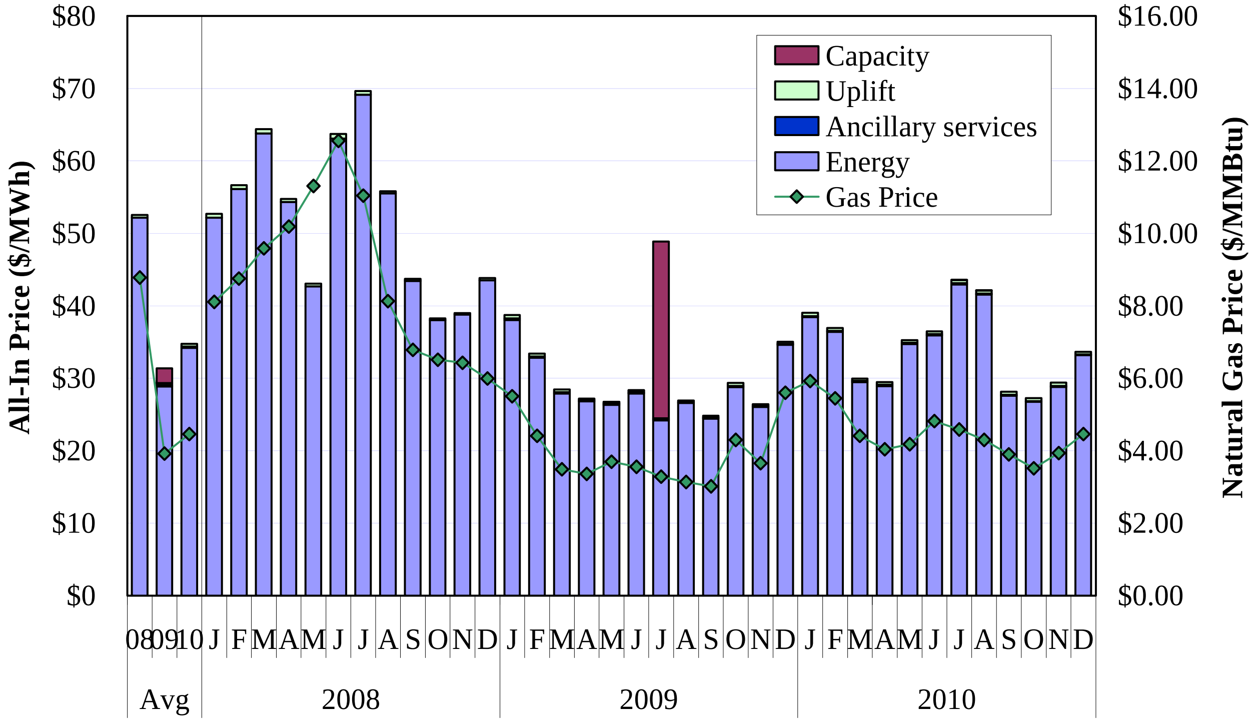
B. Short-Term Prices and Long-Term Economic Signals

Figure E-1 summarizes changes in 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 from the real-time markets. The all-in price of electricity is equal to the load-weighted, average real-time energy price plus capacity cost, ancillary services cost, and average real-time uplift cost per MW of real-time load.[4]

The all-in price in 2010 was up 11 percent from 2009 to nearly $35 per MWh. More than 98 percent of the total all-in price remained associated with energy costs. Ancillary services costs were unchanged from 2009 at $0.15 per MWh, while uplift costs increased by one-third to $0.39 per MWh. The capacity component of the all-in price averaged just $0.01 per MWh in 2010, a function of very low capacity prices that are the result of the prevailing surplus capacity levels and the design of the VCA in MISO.

4 Uplift costs are primarily comprised of real-time RSG and PVMWP.

Figure E-1: All-In Price of Electricity
2008-2010

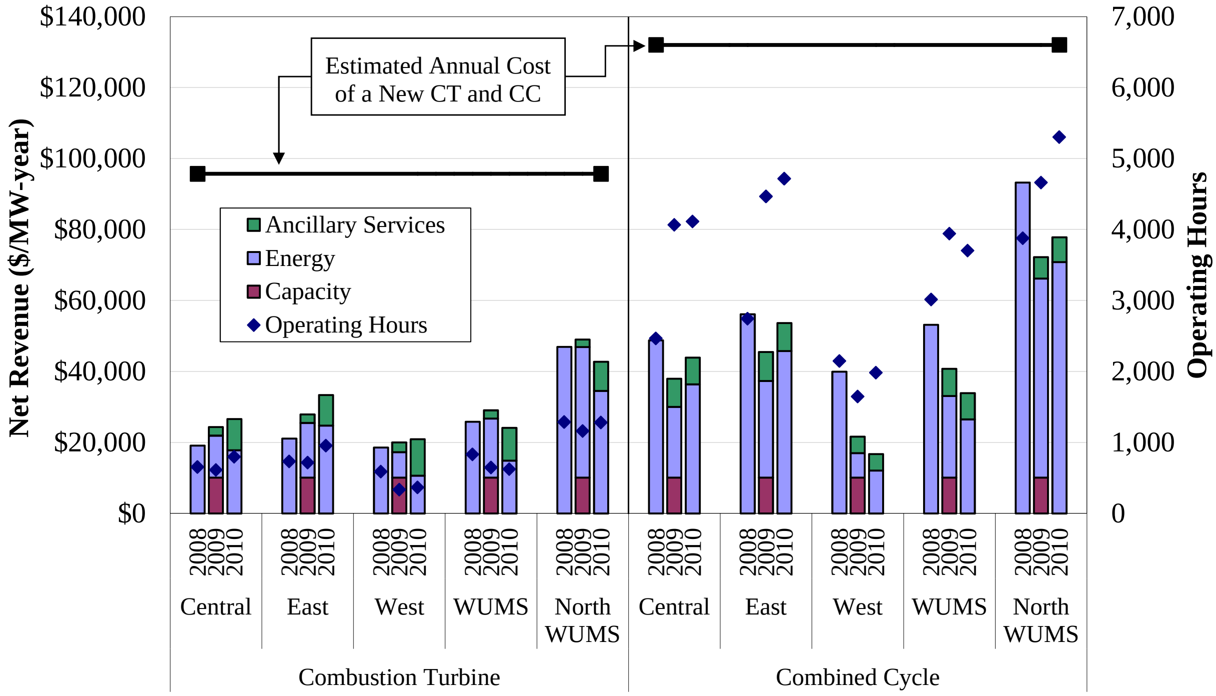


The figure shows that energy price fluctuations are driven in large part by fuel prices as expected. This relationship exists because fuel costs represent the majority of most suppliers' marginal production costs. Since suppliers in a competitive market have an incentive to offer supply at marginal cost, changes in fuel prices translate to changes in offer prices when the market performs competitively. Natural gas prices rose 14 percent, while western coal and oil prices rose 42 and 31 percent, respectively. Energy prices were notably higher during the summer months as unusually warm temperatures led to substantially higher load in 2010.

To estimate price effects of factors other than the rise in fuel prices, we calculate a fuel price-adjusted System Marginal Price ("SMP") that is based on the marginal fuel in each 5-minute interval. Average fuel-adjusted energy prices rose only 3 percent, demonstrating that fuel prices were primary drivers in the year-over-year rise in energy prices. The remaining increase in energy prices that was not associated with fuel prices is attributable primarily to higher load in 2010. After adjustments for new members, load rose by more than 6 percent. This growth was driven by improved economic conditions in 2010 and above-average summer temperatures.

One of the most important assessments of the MISO markets is our evaluation of wholesale price signals that govern investment in both new resources and transmission capability. These price 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 runs when it is economic and does not run when it is not economic. A well-designed market should produce net revenue sufficient to finance new investment when available resources are insufficient to meet system needs. Figure E-2 shows estimated net revenues for a hypothetical new Combustion Turbine ("CT") and Combined-Cycle ("CC") generator for 2008 through 2010. 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 E-2: Net Revenue Analysis
2008-2010



The net revenue analysis indicates that net revenues for both a new CC and CT unit were substantially less than the annual CONE for both technology types in 2010, even in the highest-priced regions. The results of the net revenue analysis are consistent with expectations because the MISO region continues to exhibit a sizable capacity surplus and did not experience significant shortages in 2010. Recent and anticipated future changes should assure that long-term economic signals provide efficient incentives to invest in new resources when the surplus dissipates and resources are needed.

Long-term market signals improved with the introduction of jointly-optimized ASM in early 2009. When resources are insufficient to satisfy reserve requirements, operating reserve demand curves set reserve and energy prices that reflect shortages. MISO is also working on changes to allow peaking resources and demand-response resources to set prices, which would further promote efficient shortage pricing and increase net revenues.

Finally, the introduction in 2009 of the VCA, a monthly spot market for capacity, was also intended to improve long-term market signals. The VCA provides an additional means for loads to satisfy their Module E Tariff capacity requirements. In 2010, clearing prices remained near zero, reflecting the region's capacity surplus and the fact that the capacity market recognizes no value for any capacity in excess of the minimum planning reserve (i.e., it operates with a vertical demand curve). MISO is currently working with participants and the Organization of MISO States to improve to the capacity construct and the IMM is providing comments. Additionally, we recommend that MISO begin considering implementation of a sloped demand curve to reflect the reliability value of capacity in excess of the minimum requirement and to produce more efficient capacity prices.

C. Day-Ahead and Real-Time 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 at any point in time. The day-ahead market operates one day in advance of the real-time market. It is largely financial, setting financially-binding, one-day forward contracts for energy and ancillary services. The vast majority of transactions in MISO are facilitated through the day-ahead market. This report finds that both the day-ahead and the real-time markets performed competitively in 2010, and this section provides a more detailed discussion of the evaluation of these markets.

1. Day-Ahead Market

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).

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. During 2010, price convergence in MISO continued to show a day-ahead premium of roughly 3 percent. This premium can be attributed to higher volatility, greater risk, and approximately $2 per MWh in RSG costs allocated to real-time purchases (i.e., negative deviations). The day-ahead premiums are generally larger in MISO than in other RTOs because of the higher RSG allocations to real-time purchases.

By arbitraging price differences between the day-ahead and real-time markets, active virtual supply and demand participation in the day-ahead market contributes to price convergence between the two markets. Virtual trading levels have decreased substantially since late 2008 when FERC ordered changes in the real-time RSG 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. Liquidity in the day-ahead market should improve in 2011 when MISO implements the new RSG allocation, which will reduce the costs allocated to virtual supply and other real-time deviations.

2. Real-Time Market

Real-time energy prices averaged $34 per MWh in 2010, up 18 percent from 2009. Real-time prices are generally more volatile than day-ahead prices. Introduction of ASM in 2009 improved supply flexibility, thereby allowing the real-time market to satisfy system demands with less price volatility. Nevertheless, volatility in MISO remains substantially higher than in neighboring RTOs because it runs a true five-minute real-time market that produces a new dispatch and prices every five minutes.[5] Since the real-time market software is limited in its ability to look ahead, the system is frequently "ramp-constrained" (i.e., generators are moving as quickly as they can up or down). This limitation results in transitory price spikes, both up or down.

This report shows that ramp constraints tend to bind and cause price volatility 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") over one or more of MISO's external interfaces 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 on the system.

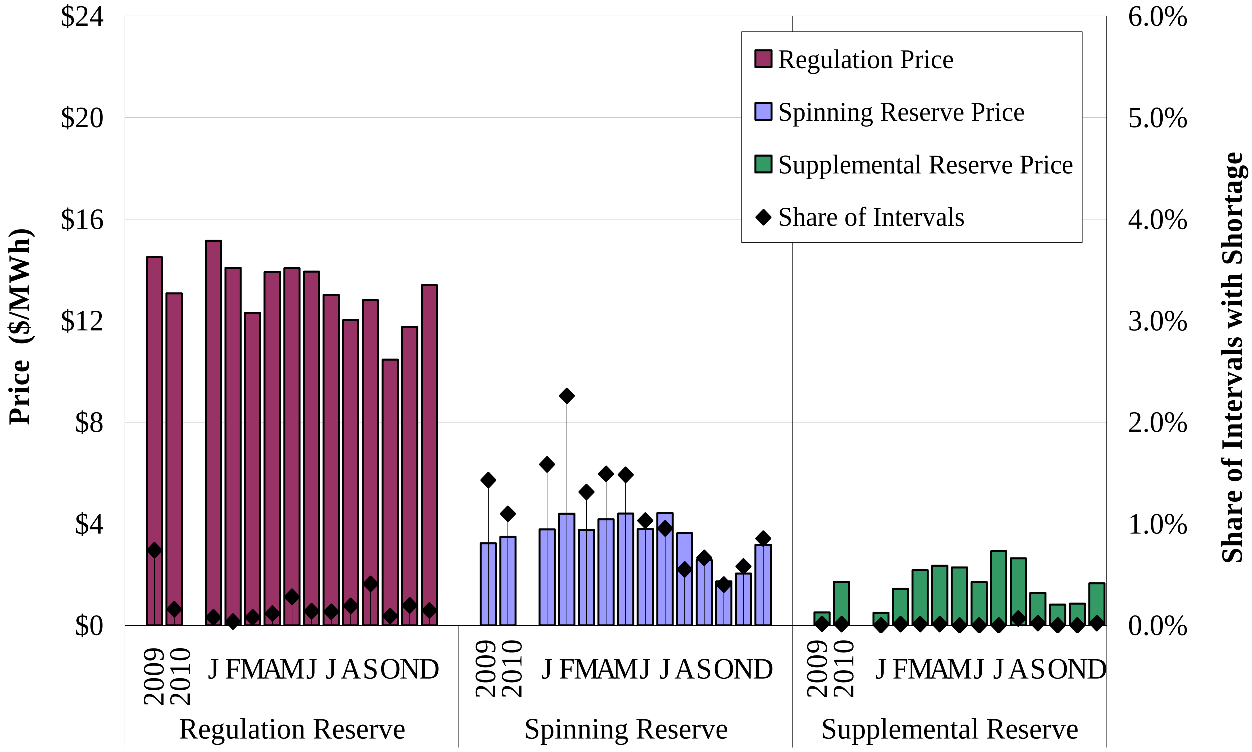
This report includes a number of recommendations to improve the management of system ramp capability and to reduce price volatility.

3. Ancillary Services Markets

ASM continued to perform as expected with no significant issues in 2010. ASM prices have been consistent with expectations and with ASM results in similar RTO markets. Ancillary service markets have produced significant benefits, leading to improved flexibility and less price volatility. These markets have also facilitated more efficient energy pricing that reflects the economic trade-off between reserves and energy, particularly during shortage conditions. Figure E-3 shows monthly average prices for regulation, spinning reserves, and supplemental reserves. It also shows the share of intervals in shortage for each product.

5 A number of other RTOs produce a new dispatch roughly every 15 minutes with a 15-minute time horizon.

Figure E-3: ASM Prices and Shortage Frequency
2010



Monthly average regulation prices generally declined throughout 2010, decreasing nearly 10 percent on an annual basis from 2009. These reductions were due to fewer shortages, a reduction in the reserve demand curve, and slightly lower requirements. Prices were relatively stable, ranging from a maximum of $15 per MWh in January to a low of $10 in October.

Spinning reserve prices averaged less than $4 per MWh, up 8 percent from 2009. Although shortages declined, prices increased modestly in part from improved shortage pricing (reduced relaxation during shortage conditions). However, the spin relaxation algorithm continues to sometimes set prices during shortages well below its true value. Hence, we recommend eliminating the relaxation algorithm and implementing a spinning reserve demand curve.

Supplemental reserve prices rose in 2010 because of a substantial decline in offer volume. This decrease was largely caused by market participant concerns over their ability to meet deployment obligations. MISO is working with market participants to clarify the MISO Tariff's must-offer requirements and deployment obligations.

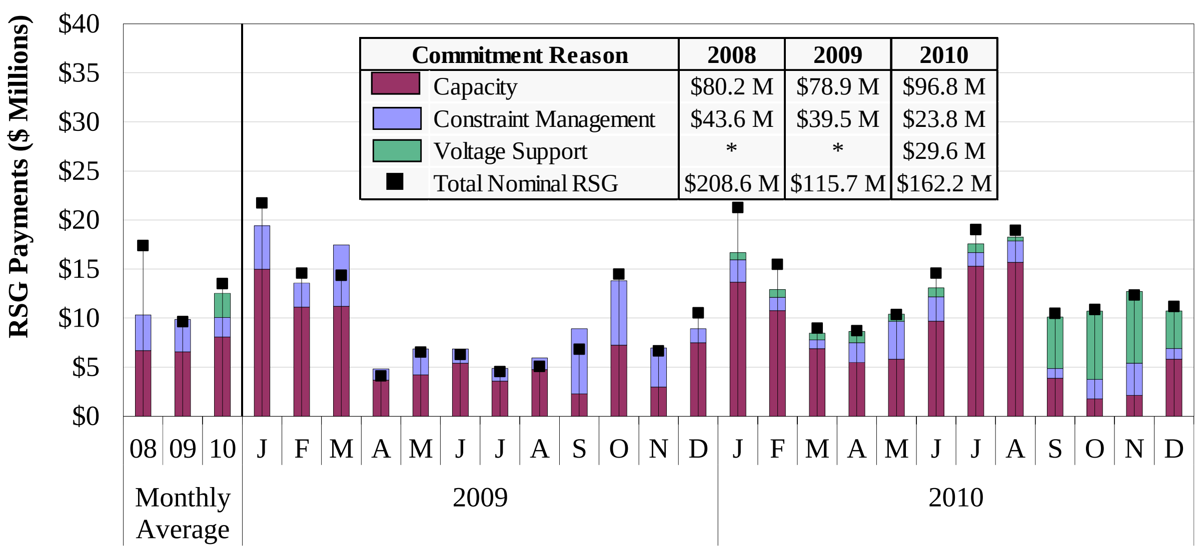
4. RSG and Other Make-Whole Payments

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

- RSG payments ensure that the total market revenue a generator receives when its offer is accepted is at least equal to its as-offered costs.
- PVMWP provides assurances to suppliers that they will not be financially harmed by responding to MISO's prices and following its dispatch signals. PVMWP consists of two payments: Day-Ahead Margin Assurance Payments ("DAMAP") and Real-Time Offer Revenue Sufficiency Guarantee Payments ("RTORSGP").

MISO commits resources after the day-ahead market that receive "real-time" RSG payments when their as-offered costs are not recovered through the Locational Marginal Price ("LMP") in the real-time market. Figure E-4 shows real-time RSG payments, which account for more than 85 percent of all RSG payments.

Figure E-4: Real-Time RSG Payments
2009-2010



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

Peaking Units	62	63	52	57	66	50	48	67	69	48	60	67	79	69	68	56	53	57	56	62	49	69	71	42	22	24	45
Other Units	38	37	48	43	34	50	52	33	31	52	40	33	21	31	32	44	47	43	44	38	51	31	29	58	78	76	55

* Voltage-related commitment information unavailable prior to 2010.

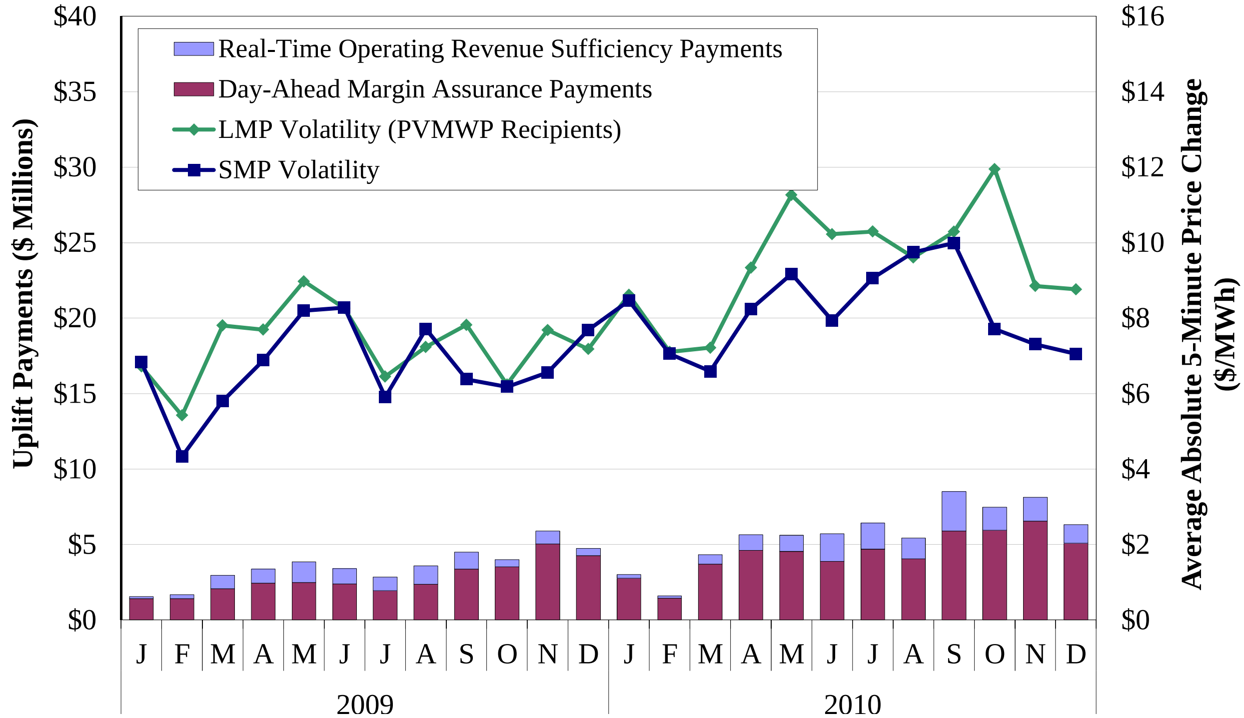
Since fuel prices have considerable influence over suppliers' production costs, the figure shows RSG payments in both nominal and fuel-adjusted terms. It also separately shows the fuel price-adjusted RSG payments associated with commitments made for capacity purposes, voltage support, or constraint management. 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.

Real-time nominal RSG costs grew to approximately $162 million in 2010 as a result of increased commitments to manage congestion, higher loads, and higher fuel prices (which increase commitment costs). The 48 percent share paid to non-peaking resources in 2010 was considerably higher than in prior years. This increase was due primarily to more than $25 million in payments made from September to December to select units that were committed routinely to resolve a local voltage issue in WUMS. The majority of this cost was associated with increased offer prices (i.e., offers above the resources' competitive reference levels). Nonetheless, the offer prices did not increase sufficiently to warrant mitigation under current market power mitigation measures.

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. Although current mitigation rules are generally effective in addressing market power associated with transmission congestion and most commitments made by MISO for reliability, we no longer believe they are adequate for these types of local needs. Therefore, we recommend the mitigation measures be expanded to apply tighter conduct and impact mitigation thresholds under these conditions.

PVMWP (comprised of DAMAP and RTORSGP, collectively) address concerns that, under the current hourly settlement process, resources that respond flexibly to volatile five-minute price signals can see lost profits or uneconomic operation. Hence, they provide suppliers the incentive to offer flexible physical parameters to MISO. Figure E-5 shows the two components of PVMWP which, in aggregate, rose 60 percent to $68 million in 2010, due largely to higher overall price volatility. While investigating these payments, however, we found that some increases are attributable to shortcomings in the DAMAP and RTORSGP formulas.

Figure E-5: Price Volatility Make-Whole Payments
2009-2010



5. 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 dispatch of peaking resources doubled in 2010 to an average of 452 MW per hour. Two-thirds of these commitments occurred during peak summer months when high loads occasionally resulted in days with an average of more than 5,000 MW of peaking resources dispatched per hour. On these days, the majority of peaking resources ran in-merit (i.e., when the energy offer price was less than the prevailing LMP).

However, approximately 40 percent of all peaking resources that were dispatched in 2010 ran "out-of-merit" order. A peaking resource dispatched out-of-merit does not indicate it was dispatched inappropriately; it simply indicates that the LMP was set by a lower-cost resource. Large shares of peaking resources dispatched out-of-merit indicate the resources may not be setting energy prices, which generally results in higher RSG costs.

Peaking resources are generally the only resources that can be committed in real time to serve the load not scheduled day-ahead. Hence, if real-time prices are not set by the peaking resources, real-time prices will be lower and create a disincentive to purchase energy in the day-ahead market. While a higher percentage of peaking resources were in-merit in 2010 than in prior years, we recommend that MISO continue to work on a pricing method to allow inflexible units and DR resources to set prices.

D. Generating Capacity and Reserve Margins

MISO added two additional members in 2010 and increased its total market capacity to 144 GW. The expected departure of First Energy in June 2011, along with further additions and retirements, is expected to reduce total nameplate capacity to 134 GW for summer 2011. This produces a planning reserve margin of 43 to 56 percent depending on the level of demand-side management assumed. These margins, however, do not include typical deratings (i.e., reductions in generator capabilities), which can be substantial during periods of hot weather.

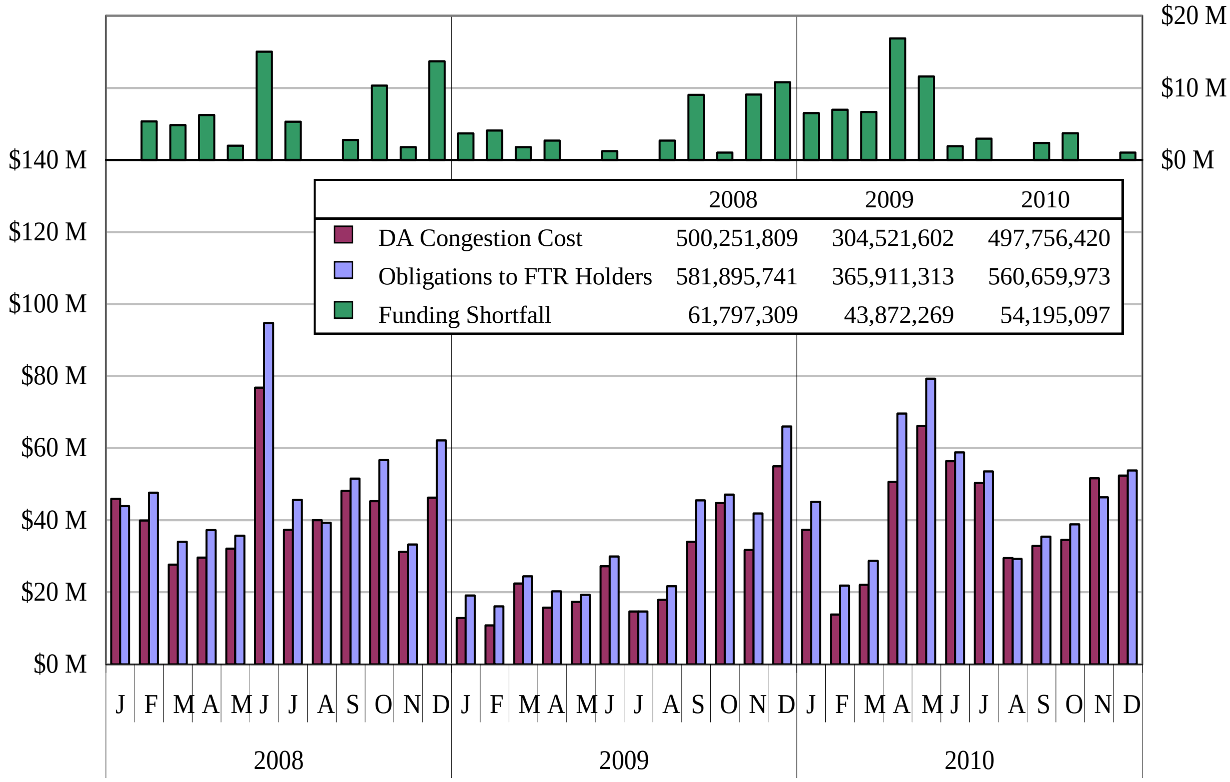
When we account for deratings that are apt to occur during high temperature events associated with peak conditions, we project a system-wide planning reserve margin of 17 to 28 percent for summer 2011. This is slightly higher than summer 2010 because it includes 3.4 GW of anticipated capacity additions. In the East Region, however, it is significantly lower (ranging from only 3.7 to 14 percent) due partly to the departure of First Energy.

MISO anticipates additions of 1,700 MW of wind generation (predominantly in the West Region), as well as 1,700 MW of fossil-fuel units in the Central Region. Nearly 1.1 GW of retirements are expected, the majority of which are coal units in the East Region. The continued growth of wind resources in the western portion of the footprint provides substantial environmental benefits, although it also creates operational and market challenges that the MISO has worked to address. The DIR type being implemented in June 2011 will address many of these challenges by allowing wind units to respond to dispatch instructions and set prices.

E. Transmission Congestion and Financial Transmission Rights

One significant benefit of the MISO energy market is accurate and transparent locational price signals that reflect congestion on the network. Figure E-6 shows total congestion costs in the day-ahead market and the payments to FTR holders that they fund.

Figure E-6: Day-Ahead and Payments to FTRs
2008-2010



Day-ahead congestion in 2010 rose 54 percent to nearly $500 million. This growth is attributable to higher loads and increased transmission outages, particularly in the East Region. The congestion collected in the day-ahead market is considerably less than the actual value of real-time congestion on the system ($1.08 billion). This result was expected and was a function of loop flows, PJM entitlements, and poor price convergence at some congested locations.

The figure shows that day-ahead congestion revenue continued to be less than FTR obligations – 11 percent less in 2010. Shortfalls are undesirable because they introduce uncertainty regarding the value of the FTRs and ultimately reduce the revenues from the FTR market. However, the figure shows that funding improved in 2010 from 2009 and 2008, when 17 and 14 percent of

FTR obligations were unfunded, respectively. Significant improvements in the monthly FTR modeling beginning in April and the seasonal auction for June resulted in dramatic improvements in FTR funding levels. These improvements included:

- Improved constraint forecasting and identification procedures;
- More complete modeling of lower-voltage branches of the network; and
- Improved modeling and accuracy of limits on radial constraints (although significant underfunding continues on these constraints).

A well-modeled day-ahead market should minimize the real-time residual congestion costs. These costs are incurred when less transmission capability is available in real time than in the day-ahead market from lower transmission limits or increased loop flows. In 2010, the day-ahead market captured nearly all of the congestion costs. The reduction in residual, real-time congestion indicates that MISO's day-ahead modeling has improved.

Finally, the value of real-time congestion on MISO's transmission system rose 18 percent in 2010 to $1.08 billion. More than 20 percent of this congestion occurred on constraints that are in violation (i.e., flow exceeds the limit) because the real-time market is unable to redispatch its resources quickly enough (or simply lacks sufficient redispatch capability) to satisfy the constraint. In these cases, MISO utilizes a "constraint relaxation" algorithm to set the congestion value of the constraint that will be reflected in LMPs.

Since 2005, we have recommended that MISO discontinue the use of this algorithm because it artificially suppresses congestion pricing. In 2010, 27 percent of the violated constraints were priced at zero due to this algorithm. In total, we estimate that it reduced real-time congestion by $313 million in 2010, a reduction of roughly 25 percent. This substantially affects not only the real-time energy market, but also the day-ahead and FTR markets. The secondary effects of this problem on congestion in the day-ahead market can result in inefficient changes in resource commitments that increase supplemental resource commitments and associated RSG costs. Additionally, FTR prices and revenues can be understated, which affects the recovery of transmission costs and incentives for new transmission investment. Therefore, we continue to believe that the relaxation algorithm is a significant flaw in the MISO markets and that it is essential to discontinue its use on all MISO transmission constraints.

F. Market-to-Market and Coordination with PJM

This report includes an evaluation of the M2M process under the Joint Operating Agreement ("JOA") with PJM that is instrumental in efficiently managing constraints affected by both RTOs. Overall, M2M coordination has resulted in more efficient management of congestion and more efficient LMPs in RTO energy markets. M2M constraint hours and payments both increased considerably in 2010. Congestion on MISO-coordinated constraints rose 23 percent, while congestion on PJM constraints rose 16 percent. Net payments to MISO remained approximately $3 million per month since PJM generally used more than its M2M entitlements on MISO's system and MISO used less than its entitlements on PJM's system.

In addition, shadow price convergence on MISO M2M constraints improved modestly in 2010 but remained substantially worse than convergence on PJM M2M constraints. Hence, we continue to recommend that the RTOs work together to identify enhancements to the relief software, modeling parameters, or other procedures that may be limiting PJM's provision of relief.

G. Financial Transmission Right Pricing

FTRs are important in an LMP-based energy market. They provide an opportunity for market participants to hedge against day-ahead congestion since day-ahead congestion over the path that defines an FTR is rebated to the holder. We analyzed the performance of the FTR market by evaluating how well FTR prices reflect the value of their entitlements based on day-ahead congestion. Differences between FTR prices and payments are referred to as FTR profits if the value is positive and FTR losses if the value is negative.

In a well-functioning, liquid FTR market, these profits should be relatively low because the market-clearing price for the FTR should reflect a rational expectation of the instrument's congestion value. By this measure, MISO's FTR market functioned well, with the profit for FTRs purchased in the seasonal market averaging just $0.09 per MWh and the profit for FTRs purchased in the monthly market averaging just $0.19 per MWh. Although profits were higher in April and May due to unexpected congestion, convergence was generally very good.

H. External Transactions

MISO continued to rely heavily on imports from adjacent areas in 2010. After accounting for the impact of wheeling transactions scheduled through MISO to PJM, MISO was a net importer over all its major interfaces with adjacent regions. Real-time net imports increased 8 percent to an average of 3.2 GW per hour. Relative to 2009, imports decreased by 800 MW in January to May and increased by 700 MW in June to December primarily because of changes in interchange with PJM.

Prices at the border between the markets are reasonably well-arbitraged in most hours, given current market rules. However, many hours exhibit large price differences that can be attributed to scheduling uncertainties as transactions are scheduled at least 30 minutes in advance with little information regarding schedules of other participants or changes in supply and demand in each market. This weakness indicates that substantial efficiency benefits can be achieved by improving the net interchange between markets, particularly with PJM. MISO has been discussing an initiative with PJM to improve the net interchange, which is the most valuable of the initiatives being pursued by the RTOs around Lake Erie. Other initiatives address transaction scheduling around Lake Erie that generates significant unscheduled power flows (i.e., “loop flows”). Taken together, we estimate annual production cost savings of $300 million for MISO, NYISO, IESO, and PJM.

I. Competitive Assessment and Market Power Mitigation

This report contains a competitive assessment of the MISO markets that includes a review of market power indicators, an evaluation of participants’ conduct, and a summary of the imposition of mitigation measures in 2010. Our analysis shows that market concentration measured using the Herfindahl-Hirschman index (“HHI”) is low for the overall MISO area, although it is considerably higher in the individual regions.

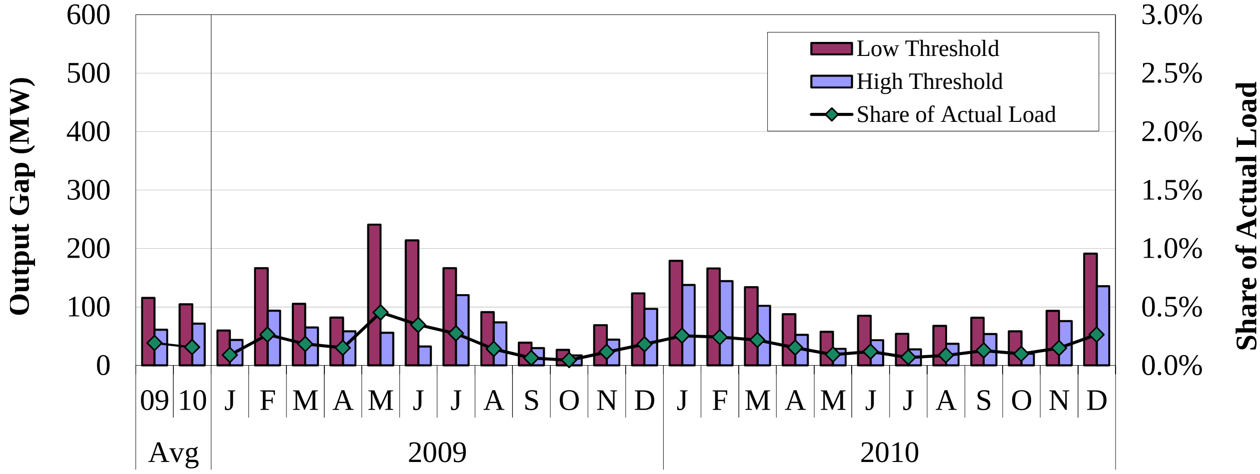
A more reliable indicator of potential market power is whether a supplier is pivotal, which occurs when its resources are necessary to satisfy load or to manage a constraint. In the examination of pivotal suppliers, we focus particular attention on two types of constrained areas that are defined for 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: one each in Minnesota, WUMS, and North WUMS (a subarea of WUMS). BCAs include all other areas within MISO that are isolated by transient binding transmission constraints.

The majority of active constraints in 2010 had at least one supplier that was pivotal. Seventy-six and 60 percent of active NCA constraints into WUMS and Minnesota, respectively, had a pivotal supplier. Likewise, one or more suppliers were pivotal on 56 percent of active BCA constraints. These results indicate that local market power persists with respect to both BCA and NCA constraints, and that market power mitigation measures remain critical.

Despite these indicators of recurring structural market power, our analyses of individual participant conduct show little evidence of attempts to physically or economically withhold resources to exercise market power. We calculated a price-cost mark-up that compares the system marginal price based on actual offers to a simulated system market price assuming 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 indicates the competitiveness of MISO’s energy markets.

Figure E-7 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” (one-half of the mitigation threshold).

Figure E-7: Economic Withholding – Output Gap Analysis
2009-2010



Low Threshold Results by Unit Status (MW)

Off-Line	68	43	28	97	43	35	190	177	78	15	13	17	59	61	74	110	75	28	12	31	16	19	18	5	33	95
On-Line	48	62	32	70	63	48	51	36	89	76	26	10	10	62	105	57	59	60	46	54	39	49	64	54	61	96

High Threshold Results by Unit Status (MW)

Off-Line	22	42	25	52	9	21	8	7	46	1	5	13	41	37	67	110	73	27	12	31	16	19	18	5	33	89
On-Line	39	30	18	42	57	38	48	25	75	73	25	4	3	60	71	35	29	26	17	12	12	19	36	15	43	46

Output gap levels were modestly lower in 2010 than in 2009, averaging 72 MW at the high threshold and 105 MW at the low threshold. As a share of actual load, low threshold output gap levels ranged from 0.07 percent in July to 0.26 percent in December. Quantities were higher in the winter months as a function of relatively high energy prices and fuel price volatility. These results and others in this report show little indication of significant economic or physical withholding in 2010. Nonetheless, we monitor these levels on an hourly basis and routinely investigate instances of potential withholding.

Finally, 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 measures for economic withholding caps a unit's offer price when it exceeds the conduct threshold and the offer raises clearing prices or RSG substantially. Because conduct has generally been competitive, market power mitigation has been imposed infrequently.

Nonetheless, market power associated with repeated resource commitments for local reliability needs (including voltage support) raised significant competitive concerns in 2010. Hence, we recommend a modification in the market power mitigation measures to address these concerns.

J. Demand Response

Demand participation in the market 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. Accordingly, development of DR in MISO is a priority.

When all forms of DR (both passive and active) are included, MISO has nearly 9,000 MW of demand-response capability. As a share of peak load (nearly 8 percent) this is comparable to neighboring RTOs. Much of this capability, however, is interruptible load developed under regulated utility programs and callable by MISO. More than 5,000 MW consists of behind-the-meter generation. Neither interruptible load nor Behind-the-Meter Generation is dispatchable and, therefore, very little DR participates directly in MISO's energy markets. Only 46 MW of non-dispatchable "Type I" demand-response resources participated in 2010 while no "Type II" resources participated.

To comply with the FERC's Order 719 and 719-A requiring a platform for expanded demand-response participation, MISO established a stakeholder process to identify and address specific barriers related to market rules, settlement provisions, and operating requirements. It filed tariff revisions with the FERC on October 2, 2009 to allow Aggregators of Retail Customers ("ARC") to participate in MISO market. The FERC has not yet approved final Tariff language permitting ARC participation.

MISO proposed to pay ARC resources the prevailing LMP minus a predetermined marginal foregone retail rate when load is curtailed. The approach is efficient because it provides the same incentives to retail customers that they would have under a dynamic retail pricing regime. It is not consistent, however, with FERC's Order 745 regarding compensation for DR resources and MISO will likely have to re-file its Tariff in this regard.

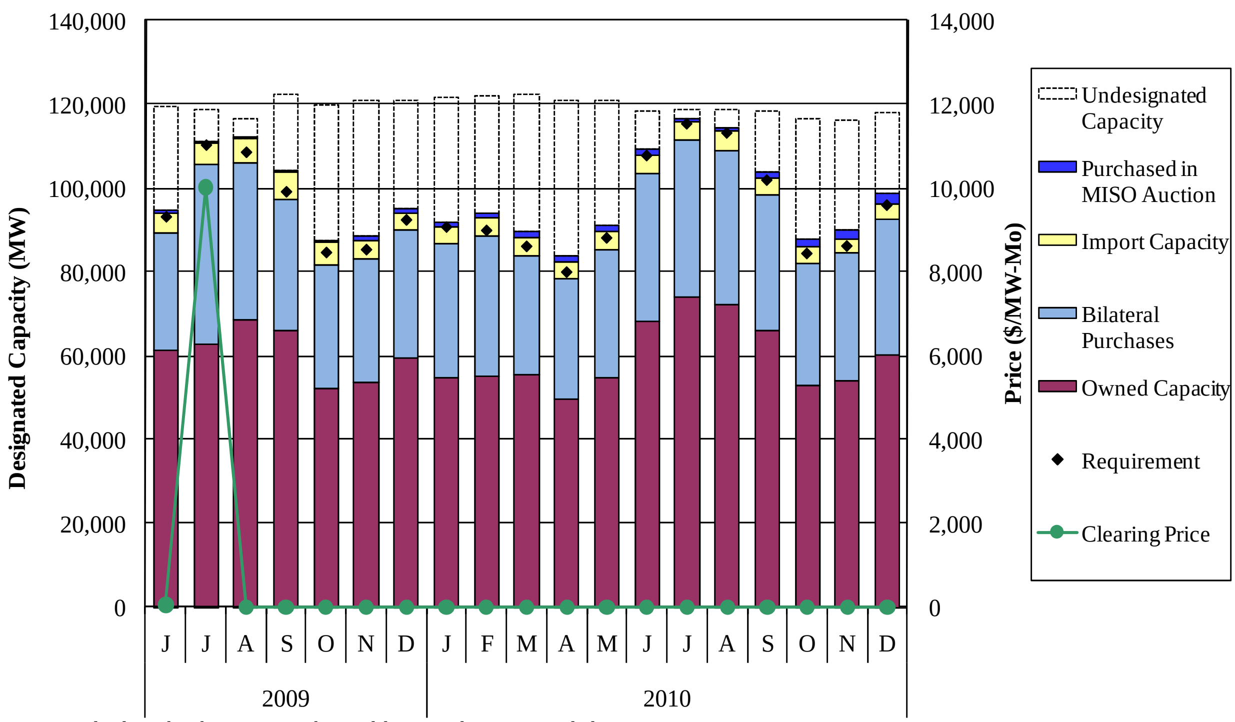
Finally, MISO is also considering pricing changes that would be necessary to allow load interruptions and other emergency actions to set prices in energy and reserve markets. We strongly support this work because it should improve pricing during peak conditions when demand response resources are called.

K. Capacity Market

Since June 2009, MISO has run a monthly VCA to allow LSEs to procure capacity to meet their Module E capacity requirements. This market can play an important role in providing the long-term price signals essential when new resources are needed.

Figure E-8 shows monthly VCA market results since inception. Quantities of capacity cleared in the VCA rose by nearly 1,000 MW in 2010 but remain a very small percentage (2.6 percent) of total designated capacity. This level is consistent with the purpose of the VCA as a balancing market since most LSEs' needs are satisfied through owned capacity or bilateral purchases.

Figure E-8: Voluntary Capacity Auction Results
2009–2010



Note: Total column height represents the total designated capacity, including imports.

The figure shows that the total capacity available in 2010 significantly exceeded requirements – from a minimum of 3 percent for July to a maximum of 51 percent for April. This fluctuation occurs because the monthly requirement is based on forecasted peak energy demand for the month. The VCA clearing prices have been close to zero in most months, which is consistent with the substantial capacity surplus prevailing in MISO and the vertical demand curve implicit in the VCA.

MISO is currently working with participants and the Organization of MISO States to develop improvements to the capacity construct and the IMM is providing comments. Although it is not currently under consideration, we recommend that MISO evaluate the use of a sloped demand curve in its resource adequacy construct in the future. A sloped demand curve would more accurately reflect the reliability value of capacity in excess of the minimum requirement and produce more efficient capacity prices.

Finally, we have concerns regarding the ability of participants to import and export capacity, particularly with PJM. Capacity markets serve an important role in providing long-term economic signals to govern investment in RTO markets. However, capacity prices 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. Therefore, we recommend that MISO identify and remove barriers to trading capacity between regions. This effort must include working actively with PJM to ensure that undue barriers do not prevent MISO suppliers from selling in its capacity market.

L. Summary of Recommendations

Although its markets continued to perform competitively and efficiently in 2010, we recommend MISO make the following improvements:

Energy Pricing

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

   This change would 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, the market must distinguish between gas turbines that are needed versus those that would be shut down if they were flexible and dispatched optimally.

   Status: Originally proposed in 2005 and MISO agrees with the recommendation. MISO has made substantial progress in working to respond to this recommendation through its Extended LMP ("ELMP") initiative. This recommendation has required significant research and development.

2. **Develop provisions that allow non-dispatchable DR (or interruptible load) to set energy prices in the real-time market when they are called upon in a shortage.**

   Like the first recommendation, this would improve price signals in the highest-demand hours. 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.

   Status: Originally proposed in 2008 and MISO agrees with the recommendation. MISO is working to address this recommendation through the ELMP initiative.

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

   This algorithm artificially reduced real-time congestion on MISO's system by 25 percent or more than $300 million in 2010. It adversely affects day-ahead market outcomes and associated resource commitments, raises RSG costs, and depresses the value of FTRs. Hence, we recommend it be discontinued on all MISO constraints, including M2M constraints.

Status: Originally proposed in 2005 and MISO has expressed agreement with this recommendation in the past. Implementation for this recommendation is not difficult or resource intensive. MISO is considering whether it believes operating procedures or other changes should be made prior to implementation.

Real-Time Market Performance and Operations

4. 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.

Better management of ramp needs and commitment of gas turbines would reduce out-of-merit quantities, reduce RSG payments, and improve energy pricing. We have recommended this previously and MISO has initiated a project to develop such capabilities.

Status: Originally proposed in 2005 and MISO agrees with the recommendation. MISO has developed an initial look-ahead commitment model that is being tested. However, the initial model us currently set-up in a manner that does not respond to the recommendation because the objective function does not minimize production costs. MISO plans to make this change later. The look-ahead dispatch capability is relatively resource intensive and has not been scheduled for implementation.

5. Prior to development of the look-ahead capability, improve the use of the load offset parameter.

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: Originally proposed in 2005 and MISO agrees with the recommendation. An initial offset tool has been developed, but is not actively used to set the offset proactively to manage the system's ramp capability. Additional changes to the tool are needed.

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

Suppliers face little or no competition when they are needed to resolve local reliability requirements and can extract substantial market power rents under the current mitigation measures. This recommendation addresses these competitive concerns, which are not adequately addressed under the current mitigation measures.

Status: This is a new recommendation and MISO is investigating it.

7. To achieve better price convergence with PJM, we recommend the RTOs consider expanding the JOA to optimize the interchange between the two areas.

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.

Status: Originally proposed in 2005 and MISO agrees with the recommendation. MISO staff has developed a white paper describing options for addressing this recommendation and has initiated discussions with PJM.

8. Continue working with PJM to improve the M2M process by:

a) More closely monitoring the information being exchanged with PJM to quickly identify cases where the process is not operating correctly;

b) Discontinuing the constraint relaxation algorithm on M2M constraints that cannot be resolved by the monitoring RTO;

c) Working together to identify any other modeling parameters, provisions, or procedures that may be limiting PJM's relief; and

d) Clarifying the JOA to avoid future disagreements.

The M2M process plays a vital role in coordinating congestion management between the two areas. These changes should increase the effectiveness and efficiency of this process.

Status: Originally proposed in 2005 and MISO agrees with the recommendation. MISO has been working with PJM through the settlement process and outside of this process to make improvements to the JOA.

9. Seek additional improvements to the Short-Term Load Forecast ("STLF") used by the real-time market to reduce system ramp capability consumed by changes in real-time load.

MISO relies on a short-term load forecast of demand in its dispatch process. Real-time system operation can be enhanced by improving the accuracy of its STLF, including receiving more timely and accurate information on non-conforming load. Together with Recommendation 5, improving the STLF will allow systems to satisfy fluctuating demands while ramping generation up and down more smoothly. This should reduce price volatility and improve generator dispatch efficiency in the real-time market.

Status: Originally proposed in 2009 and MISO agrees with the recommendation. MISO is implementing an ITRON STLF implementation to improve its forecasting. However, it has not begun work to improve information regarding non-conforming load.

10. Discontinue modeling of radial constraints in the day-ahead market.

Since these constraints cannot bind in the real-time market, this change will improve the convergence of congestion values between the day-ahead and real-time market and improve FTR funding for FTRs affected by these constraints.

Status: Originally proposed in 2009 and MISO disagrees with the recommendation. MISO disagrees with this recommendation, but is continuing to discuss this recommendation with the IMM.

<u>ASM Improvements</u>

11. Eliminate Real Time Offer Revenue Sufficiency Payments to deployed operating reserves.

Compensating operating-reserve suppliers for out-of-market deployment costs when they are called on to produce energy was not the original purpose of these payments and leads to an inefficient selection of operating-reserve providers. Eliminating this payment for reserve deployments will improve reserve market efficiency by causing expected deployment costs of operating reserves to be included in participants' offers. Their inclusion, in turn, will allow MISO market to schedule the resources with the lowest total costs, including deployment costs.

Two additional recommendations involve changes in DAMAP and RTORSGP eligibility rules to address significant gaming concerns and have been sent confidentially to MISO.

Status: This is a new recommendation and MISO is investigating it.

12. 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.

Although the spinning reserve market has generally performed well in 2010, these changes will further improve the dispatch and pricing of the market during shortage conditions.

Status: Originally proposed in 2009 and MISO agrees with the recommendation. MISO has made improvements to decrease the relaxation, but has not discontinued its use. We will continue to work with MISO to address this recommendation.

Capacity Market Improvements

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

MISO should modify deliverability requirements for external resources to establish a maximum amount of capacity imports by interface that can be utilized to satisfy an LSE's capacity requirements under Module E. This information should allow participants to arbitrage capacity price differences between the markets more effectively to the extent physical transmission capability allows. Ultimately, this will cause both markets to send more efficient long-term price signals and improve the stability of the RTOs by reducing incentives for participants to alter RTO membership.

Status: Originally proposed in 2008 and MISO agrees with the recommendation. MISO has developed a proposal to address this recommendation and is awaiting feedback from PJM.

14. Evaluate the use of a sloped demand curve in its resource adequacy construct in the future.

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 is a new recommendation and MISO is investigating it.

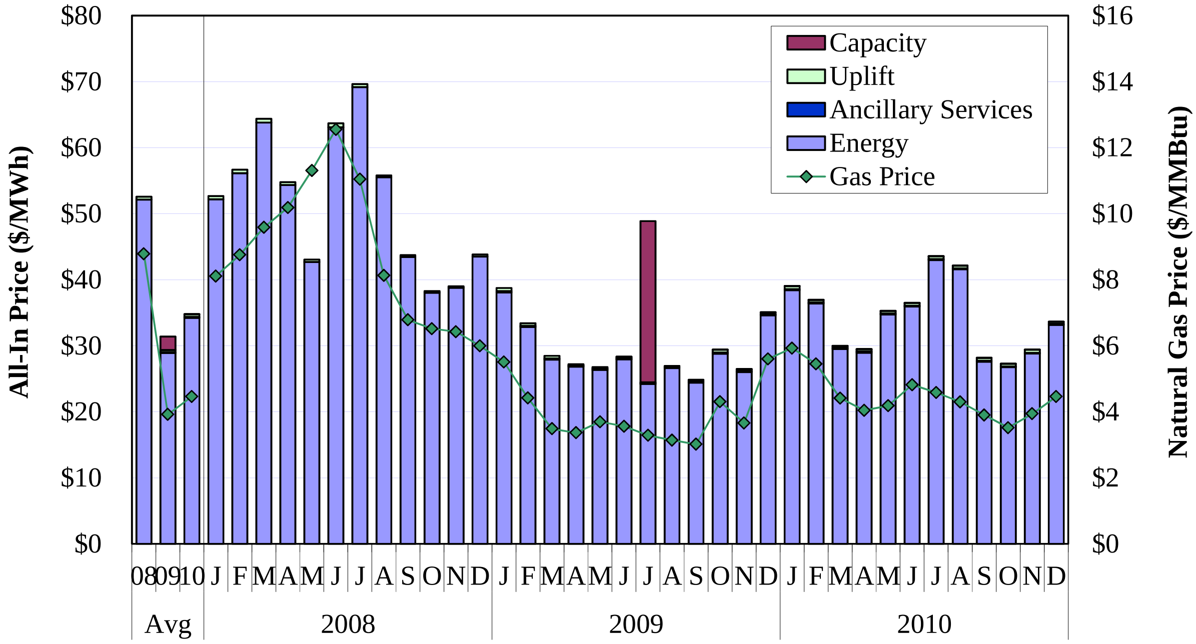
I. Prices and Revenues

MISO has operated competitive wholesale electricity markets since April 2005. These include day-ahead and real-time markets for energy, and regulating and contingency reserves (known as ASM). MISO also operates a market for FTRs and a monthly voluntary capacity auction that began in June 2009. In this section, we evaluate prices and revenues associated with the day-ahead and real-time energy markets.

A. Prices

Our first analysis is an overview of electricity and fuel prices for the MISO markets. Figure 1 shows the "all-in" price of electricity from 2008 to 2010 and the price of natural gas.[6] The all-in price represents the costs of serving load in MISO's real-time markets. It includes the load-weighted real-time energy price, real-time ASM costs, uplift costs, and monthly capacity costs per MWh of real-time load.[7]

Figure 1: All-In Price of Electricity
2008–2010



6 Unless indicated otherwise, the natural gas price is the Chicago Citygate spot price as published by Platts.

7 Costs for ASM are shown since January 2009. Costs for capacity are shown since June 2009.

The all-in price averaged $34.76 per MWh in 2010, up 11 percent from 2009. Real-time energy prices, the dominant component of the all-in price, increased by 18 percent. This increase was primarily due to higher load and fuel prices. Natural gas prices rose 14 percent, while western coal and oil prices rose 42 and 31 percent, respectively.

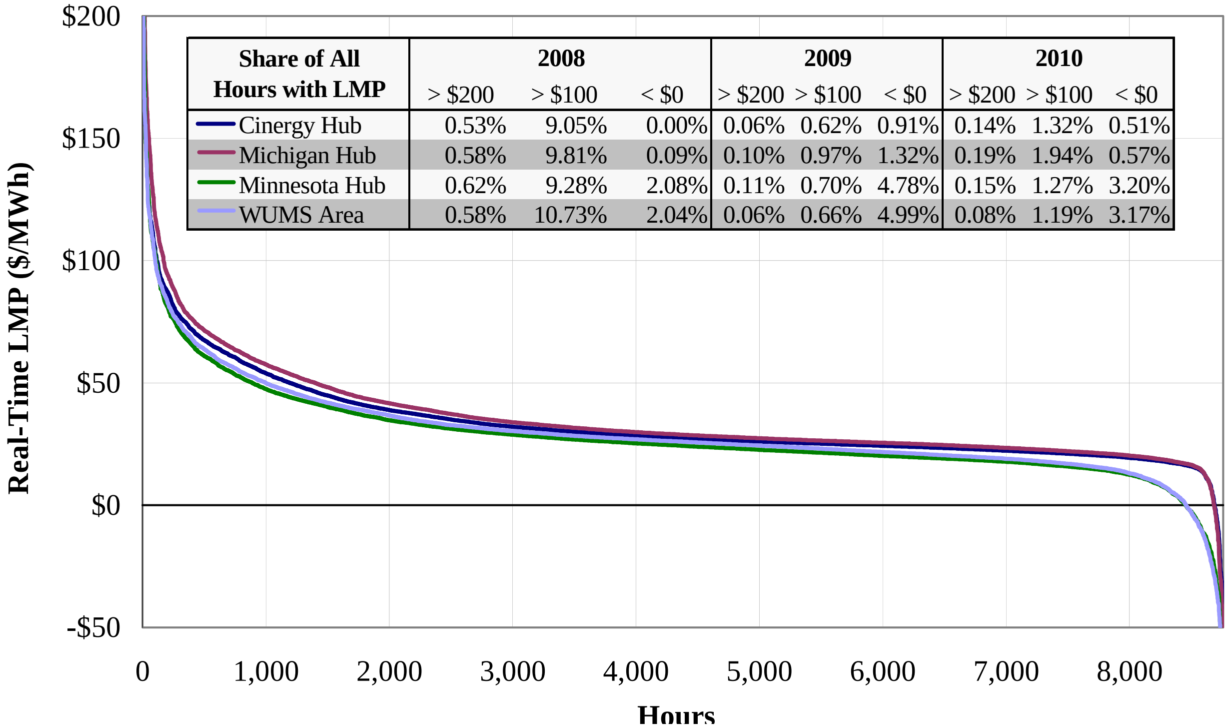
Prices were correlated positively with natural gas prices, even though natural gas was on the margin in fewer than one-quarter of all hours. Suppliers in a well-functioning, competitive market have the incentive to offer energy at their marginal cost. Since fuel costs represent the majority of their variable production costs (i.e., marginal costs), generators' energy offers tend to rise in step with fuel costs in a competitive market. Therefore, the positive correlation between fuel prices and electricity prices indicates that the markets performed competitively in 2010.

Uplift costs, comprised primarily of RSG and PVMWP to generating resources, increased 46 percent in 2010 to $230 million. This equates to $0.39 per MWh of actual load, or roughly 1 percent of the all-in price. Capacity and ASM costs contributed marginally to the all-in price, consistent with infrequent energy shortages and low capacity prices in MISO during 2010.

Figure 2 shows the range of real-time hourly prices for four representative locations in MISO in the form of a price-duration curve. A price-duration curve shows the number of hours (on the horizontal axis) when the LMP is greater than or equal to a particular price level (on the vertical axis). For example, the curve for the Cinergy Hub indicates that in approximately 1,100 hours during 2010 the Cinergy Hub price exceeded $50 per MWh. The table in the figure summarizes the percentage of hours with pricing greater than $200, greater than $100, and less than $0 in the prior three years.

The figure shows that price duration curves at each location shifted upward modestly from 2009 because of higher loads and fuel prices. Higher fuel prices in particular tend to raise prices over a wide array of hours.

Figure 2: Real-Time Energy Price-Duration Curve
2010: All Hours



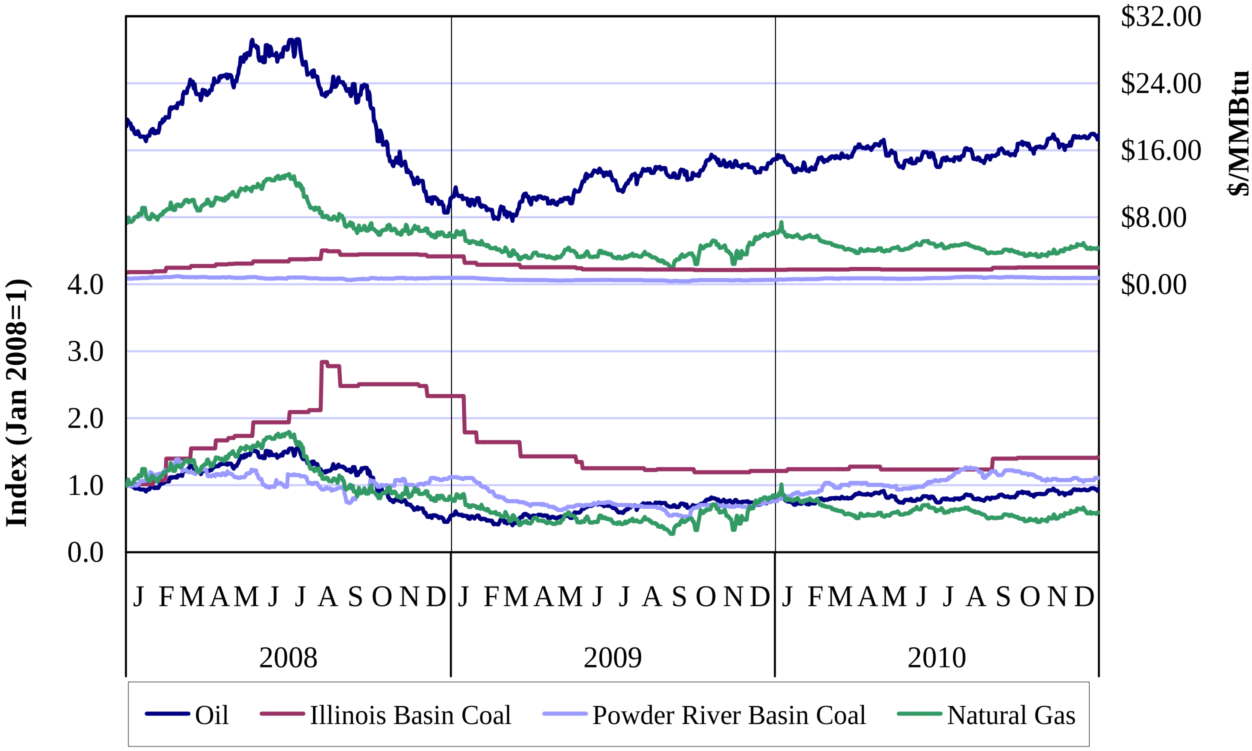
Share of All Hours with LMP	2008 > $200	2008 > $100	2008 < $0	2009 > $200	2009 > $100	2009 < $0	2010 > $200	2010 > $100	2010 < $0
Cinergy Hub	0.53%	9.05%	0.00%	0.06%	0.62%	0.91%	0.14%	1.32%	0.51%
Michigan Hub	0.58%	9.81%	0.09%	0.10%	0.97%	1.32%	0.19%	1.94%	0.57%
Minnesota Hub	0.62%	9.28%	2.08%	0.11%	0.70%	4.78%	0.15%	1.27%	3.20%
WUMS Area	0.58%	10.73%	2.04%	0.06%	0.66%	4.99%	0.08%	1.19%	3.17%

The differences between these curves in this figure are due to congestion and losses that cause energy prices to vary by location. As in prior years, prices were generally closely aligned during most hours of the year, with Michigan Hub prices consistently highest in the footprint. The substantial divergence between western and eastern hubs during low-priced hours (those above 8,000 on the curve) indicates a pattern of west-to-east congestion. Prices were below zero in approximately 3 percent of hours at the Minnesota Hub and in the Wisconsin-Upper Michigan System ("WUMS") Area, down from 5 percent in 2009. Minimum Generation Alerts and Minimum Generation Events were less prevalent in 2010 than in 2009, although they still contributed to occasional system-wide negative pricing.

The share of hours with prices exceeding $200 and $100 per MWh increased at all locations. Nonetheless, less than 2 percent of all hours exceeded $100 per MWh, compared to 10 percent of hours in 2008, when natural gas prices were almost twice as high. Energy prices during peak hours send critical economic signals that govern investment and retirement decisions. In particular, high prices during shortage conditions are necessary to support investment in the region. However, surplus capacity conditions in 2010 led to very few periods of such shortages. Long-run price signals are further explored in the net revenue analysis later in this section.

As noted previously, fuel prices are the largest component of most generators' marginal costs and are, therefore, a primary determinant of the overall price of energy. Most fuel price inputs rose from 2009 as economic conditions improved. Figure 3 shows the prices for natural gas, oil, and coal in the MISO region from 2008 to 2010. The top panel shows nominal prices in dollars per million British thermal units ("MMBtu"), while the bottom panel shows fuel price movements in relative terms with each fuel indexed to January 2008.

Figure 3: MISO Fuel Prices
2008–2010

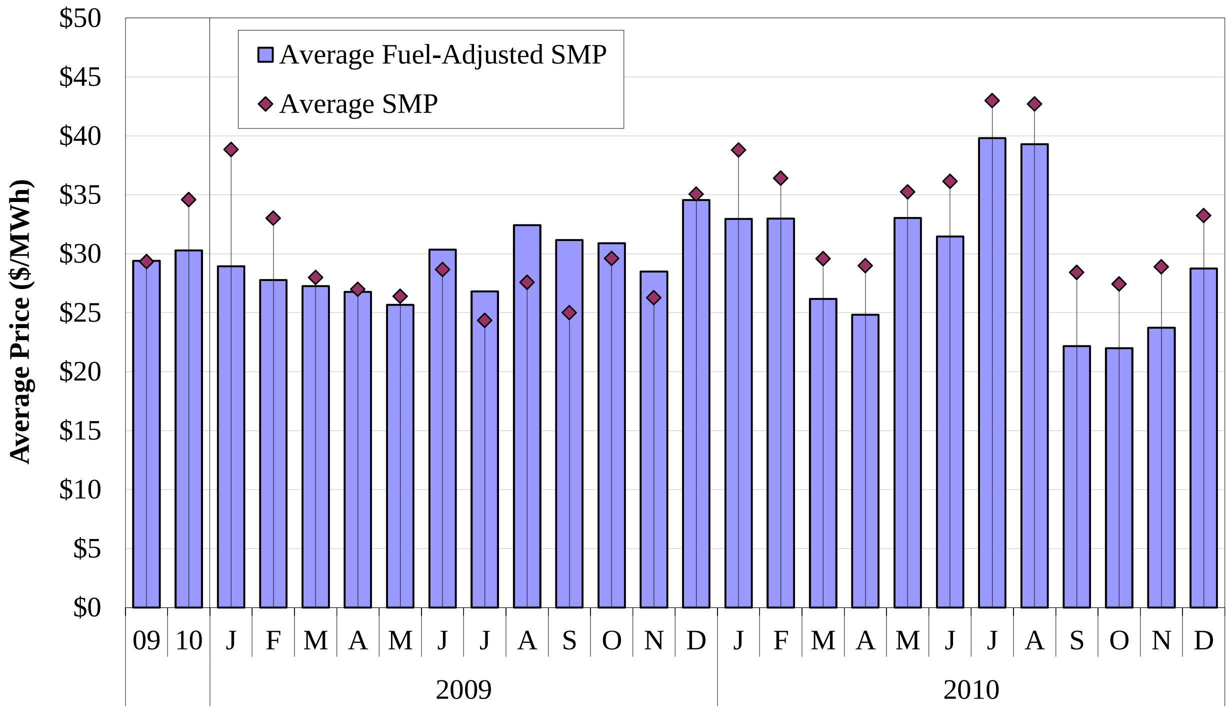


Natural gas prices averaged $4.46 per MMBtu in 2010, up 14 percent from 2009. Prices peaked in January at over $6 before falling to under $5 for the remainder of the year. Despite the increase, prices remained modest by historical comparisons. Oil prices averaged $15.63 per MMBtu, continuing a gradual increase that began in early 2009. Prices ended December near $18. Oil use is typically insignificant (as it was in 2010) but can become more so during peak winter load conditions if gas supplies are interrupted, as they were in February 2007.

Coal prices are generally more stable than spot natural gas and oil prices. Powder River Basin prices rose from $0.53 per MMBtu in January to $0.88 in August and averaged $0.73. Although 42 percent more expensive than in 2009, Powder River Basin coal remained by far the cheapest fossil fuel used for generation. Illinois Basin coal prices fell slightly to $1.84 per MMBtu and, aside from a 13 percent rise in September, were largely flat.

The impact of fluctuations in marginal fuel prices can obscure the underlying performance of the electricity markets. Hence, we calculate a fuel price-adjusted SMP shown in Figure 4 below. This measure highlights variations in electricity prices that are due to factors other than fluctuations in fuel prices, such as changes in load or congestion costs. To calculate this metric, each real-time interval's SMP was indexed to the average two-year fuel price of the marginal fuel during the interval. The price-setting fuel for each interval was assumed to be the fuel that was most frequently on the margin during that particular interval (more than one fuel can be on the margin in a single interval). This metric does not account for changes in commitment or dispatch that may occur under different levels of fuel prices.

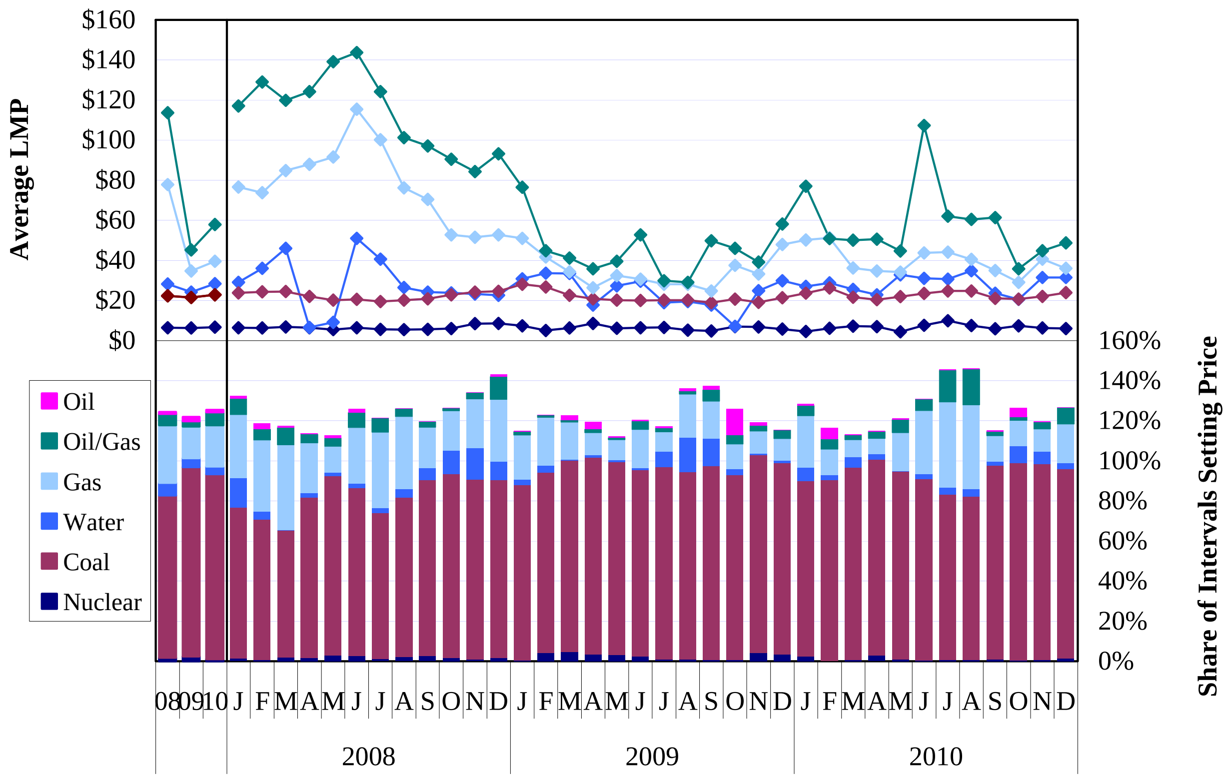
Figure 4: Fuel-Price Adjusted System Marginal Price
2009–2010



Since fuel prices in 2010 generally rose 10 to 40 percent from 2009 levels, fuel-adjusted prices were lower than the nominal SMP in each month. For the year, average fuel-adjusted energy prices rose 3 percent on an overall increase in economic activity and warmer than average summer temperatures. When compared to the 18 percent rise in the nominal SMP, this result indicates that fuel price changes accounted for most of the year-over-year change in electricity prices. However, the methodology does not capture several likely impacts of changing fuel prices, such as changes in generator commitment patterns or relative inter-regional price differences that would affect imports and exports.

Figure 5 examines the frequency with which different types of generating resources set price in MISO. When a constraint is binding, more than one type of unit may be setting prices (one in the constrained area and one in the unconstrained area). Therefore, the total for all the fuel types will exceed 100 percent. The figure shows the average prices that prevailed in 2008 to 2010 when each type of unit is on the margin (in the top panel) and how often each type of unit set the real-time clearing price (in the bottom panel).

Figure 5: Price Setting by Unit Type
2008–2010



Coal units set prices in 92 percent of all intervals in 2010, including virtually all off-peak intervals. This level is comparable to 2009 results, but is an increase from 2008 when coal was on the margin in 81 percent of hours. The continued high frequency of coal setting prices is due to the relatively low coal prices – Illinois Basin coal prices declined slightly in 2010, and Powder River Basin coal remained by far the lowest-cost fossil fuel on a per-MMBtu basis. In addition, sustained growth in wind output shifted the energy supply curve (lowering overall supply costs). This shift displaced higher-cost generation, including combined-cycle and less efficient coal-fired generation. As a result, coal-fired units were more frequently on the margin.

Natural gas and oil resources typically set prices during the highest-load hours. Hence, these fuel prices have a greater impact on load-weighted average prices than the percentages suggest. Natural gas-fired, oil-fired, and dual-fired resources set prices in 23 percent of intervals in 2010, but almost 35 percent of all real-time energy costs were incurred when these resources were on the margin. In 2009, these resources were on the margin in 17 percent of intervals.

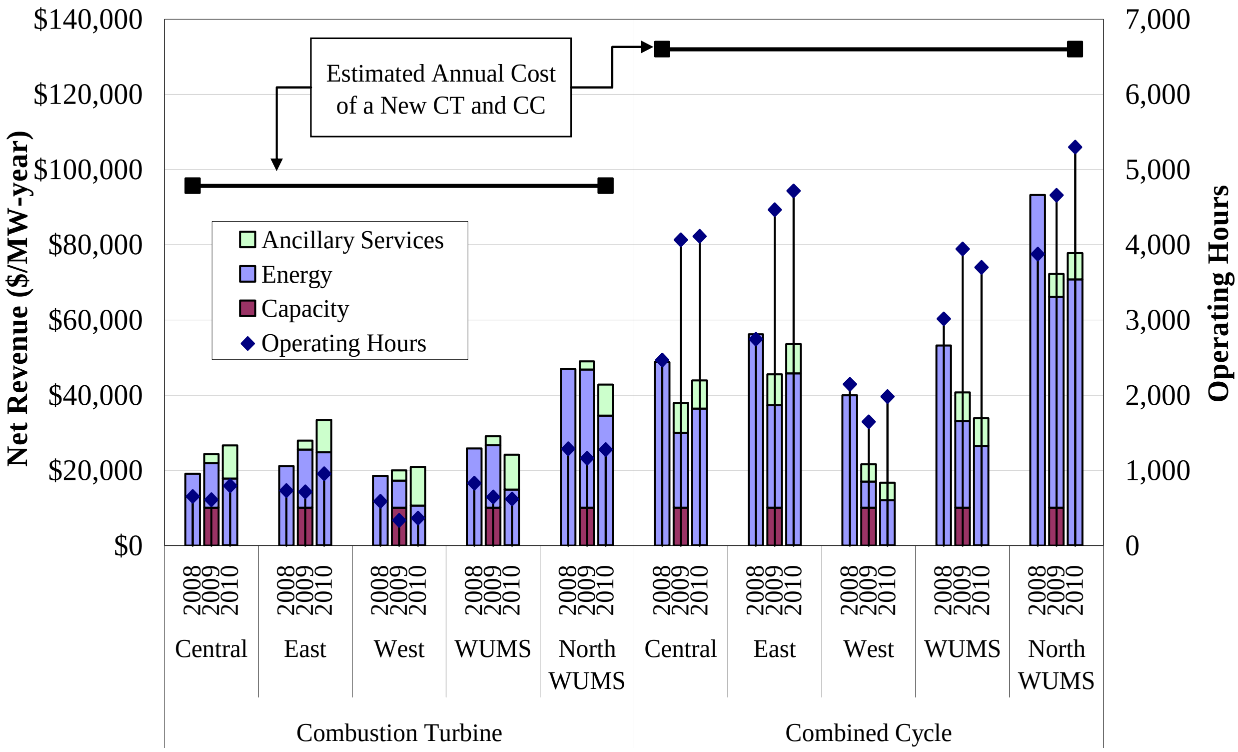
B. Net Revenue Analysis

In this subsection, we evaluate the long-run economic signals produced by MISO's energy, ASM, and capacity markets. Our evaluation uses the "net revenue" metric, which measures the revenue that a new generator would earn above its variable production costs if it were to operate only when revenues from energy and ancillary services exceeded its costs. A well-designed market should allow a new entrant to earn a level of net revenue that is sufficient to finance new investment when new resources are needed. However, even if the system is in long-run equilibrium, random factors in each year (e.g., weather conditions, generator availability, and fuel prices) will cause the net revenue to be higher or lower than the equilibrium value.

Our analysis examines the economics of two types of new units: a natural gas CC unit with an assumed heat rate of 7,000 Btu per kilowatt-hour ("kWh") and a natural gas CT unit with an assumed heat rate of 10,500 Btu per kWh. We also incorporate standardized assumptions for calculating net revenues put forth by the FERC and the Energy Information Administration that account for variable Operations and Maintenance ("O&M") costs, fuel costs, and expected forced outage rates. The introduction in 2009 of ASM and capacity markets have provided some additional revenues, but not enough to currently support new investment in either resource type.

Figure 6 shows net revenue provided by the MISO markets from 2008 to 2010. To determine whether these net revenue levels would support investment in new resources, the figure also shows the estimated annualized cost of a new unit (which equals the annual net revenue a new unit would need to earn in MISO wholesale markets to make the investment economic). The estimated costs of new entry for each type of unit were largely unchanged from 2009 to 2010: $96 per kW-year for a CT and $132 per kW-year for a CC generator (these entry costs are shown in the figure as horizontal black segments). Because CC generators have substantially lower production costs per MWh than simple-cycle CT generators, they run more frequently (at a 17 percent capacity factor on average in 2010, compared to 3.5 percent for CTs). Hence, the estimated net revenues for CC generators from energy and ASM are substantially higher. Capacity revenues, however, are constant across unit types and regions. Since CTs provide far less energy, capacity revenues typically have a larger impact on a CT's net revenues than on a CC unit's net revenues.

Figure 6: Net Revenue and Operating Hours
2008–2010



Net revenues for a new CT in 2010 ranged from $21,000 to $43,000 per MW-year in the regions shown, while net revenues for a new CC ranged from $16,000 to $77,000 per MW-year. This variation in net revenues across the footprint is expected and has not changed significantly from prior years. For example, net revenues are substantially higher in the East Region than in the West Region due to prevailing congestion patterns. A large majority of revenues come from energy, with ancillary services revenues contributing approximately one-quarter of total revenues. Capacity prices, which averaged just $34 per MW-year in 2010, have contributed very little to net revenues.[8]

The figure also compares net revenues to annualized costs for new capacity at all locations. Net revenues continued to be substantially lower than the costs of new capacity throughout the MISO market. These results are consistent with expectations because the MISO footprint continues to exhibit a sizable capacity surplus and did not experience significant periods of shortage in 2010.

MISO is working on pricing changes to allow peaking units and interruptible load to set prices. This effort has the potential to further improve efficient shortage prices and to increase net revenues. As excess capacity in the region declines, it will be important that MISO's markets send efficient long-term signals. To that end, we continue to recommend several additional improvements to pricing mechanisms in this report.

8 The lone exception was in July 2009, the month after the VCA was introduced, when the clearing price was unusually high. VCA results are discussed in greater detail in Section II.

II. Load and Resources

In this section, we provide an overview of the supply and demand conditions in the MISO markets. We summarize load and generation within the MISO region and evaluate the resource balance in light of available transmission capability on the MISO network.

We confine our analysis to participants in MISO's markets.[9] Currently, more than 90 entities own generation resources in the MISO market. This group includes large investor-owned utilities, municipal and cooperative utilities, and independent power producers.

Our analysis divides MISO into four geographic areas:

- East – includes MISO areas that had been located in the North American Electric Reliability Corporation's ("NERC") ECAR region;
- West – includes MISO areas that had been located in the NERC MAPP region;
- Central – includes MISO areas that had been located in the NERC MAIN region but excludes MAIN utilities located in the WUMS Area; and
- WUMS – MISO control areas located in the WUMS Area. It is part of the East reliability region.

The East, West and Central regions are coordination regions that MISO uses to operate the system. We examine the WUMS Area separately due to differences in transmission topology and historical congestion patterns. These four regions should not be viewed as distinct geographic markets, particularly with respect to market concentration. In reality, binding transmission constraints govern the extent of the geographic markets from a competitive perspective. A detailed analysis of market power is provided in Section VI.

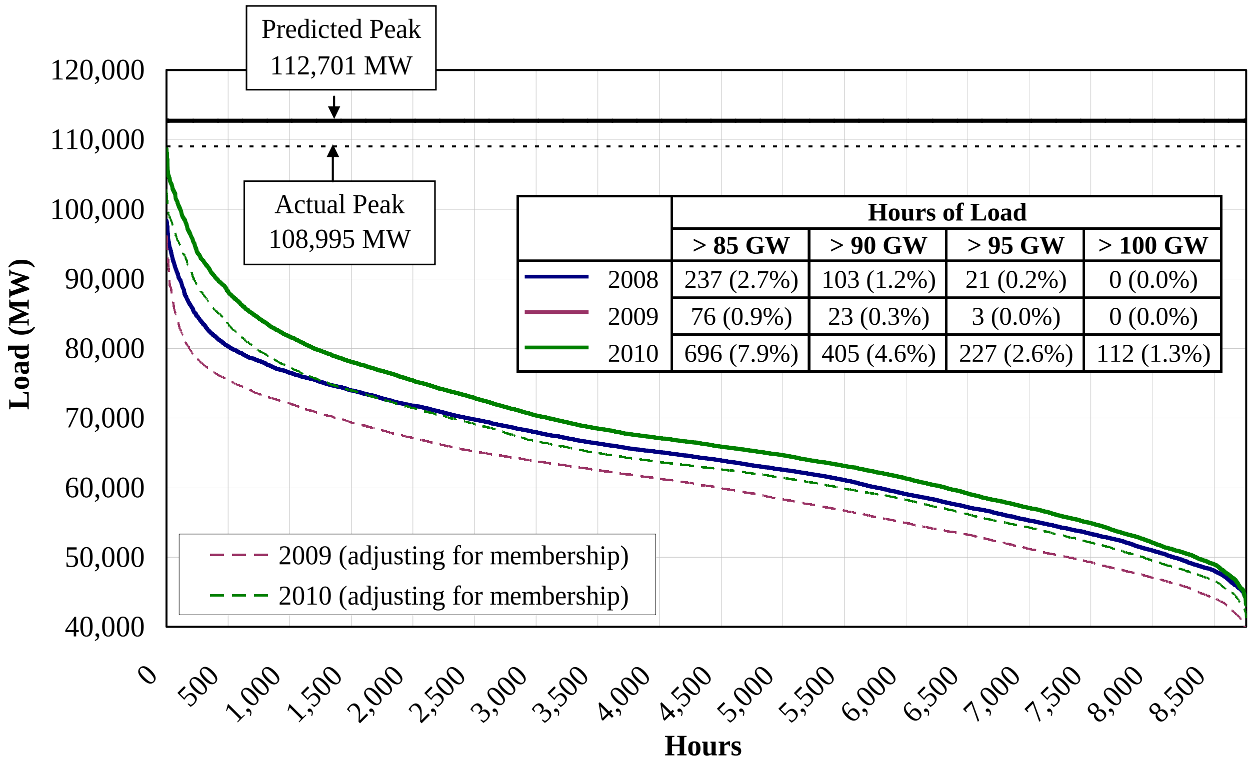
A. Load Patterns

Our first analysis in this section summarizes 2010 load patterns throughout MISO. MISO is generally a summer-peaking region, although northern portions of the West Region are winter-peaking. Figure 7 shows actual load levels for the past three years in the form of hourly load

9 MISO services as the reliability coordinator for a region that is broader than its market area.

duration curves, which show the number of hours (on the horizontal axis) in which load is greater than an indicated level (on the vertical axis). The figure also shows the curves for 2009 and 2010 adjusted for changes in membership[10] and, in the table, the number and percentage of hours when load exceeded certain high-load thresholds.

Figure 7: Load Duration Curves
2008–2010



	Hours of Load			
	> 85 GW	**> 90 GW**	**> 95 GW**	**> 100 GW**
2008	237 (2.7%)	103 (1.2%)	21 (0.2%)	0 (0.0%)
2009	76 (0.9%)	23 (0.3%)	3 (0.0%)	0 (0.0%)
2010	696 (7.9%)	405 (4.6%)	227 (2.6%)	112 (1.3%)

The figure indicates a clear upward shift in the 2010 load duration curve from 2009 levels. Average load increased 10 percent to 67.4 GW and, for the first time since 2007, peaked above 100 GW in 112 hours. These increases are primarily attributable to unusually warm temperatures across the Midwest during the summer as well as an increase in economic activity from 2009. On a membership-adjusted basis, average load increased 6.2 percent compared to 2009, but decreased 0.8 percent compared to 2008. However, load during the top 1,000 hours of

10 Big Rivers Electric Corporation, Dairyland Power Cooperative, MidAmerican Electric Company, and Muscatine Power and Water joined MISO after January 2009; therefore, the data from these control areas has been removed throughout the report when quoting metrics after adjustment for membership.

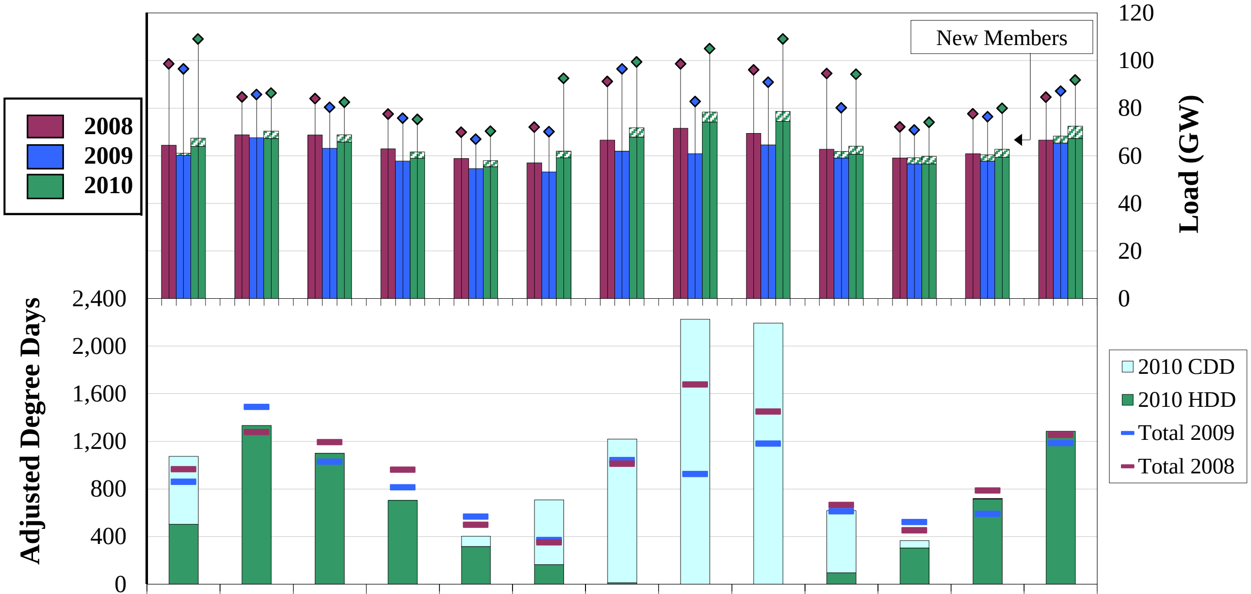
2010 was considerably higher than in 2008 due to relatively hot summer conditions. Nevertheless, the instantaneous peak load of 109 GW was 3.3 percent below the predicted peak demand of 112.7 GW in MISO's *Summer Assessment*.

The figure also shows that nearly 20 percent of the peak energy demand occurs in the top 5 percent of hours, which is a typical pattern of energy demand. Because electricity cannot economically be stored in large quantities, this load pattern indicates that a large share of MISO's resources is needed primarily to meet the system's peak energy or operating reserve demands. The pattern underscores the importance of efficient pricing during peak load hours as well as in the capacity market to ensure that the system continues to maintain adequate resources.

A large portion of MISO's load is temperature-sensitive. Figure 8 illustrates the influence of weather on load by showing the heating and cooling requirements together with the monthly average load levels for 2008 to 2010.

Figure 8: Heating and Cooling Degree Days

Weekly Average of Four Cities in MISO, 2008–2010



09-10 % Chg	2010	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Avg. Load	6.2%	-0.5%	4.2%	2.2%	1.5%	11.3%	9.6%	21.9%	15.4%	2.7%	0.0%	2.8%	3.0%
Degree Days	24.7%	-10.4%	6.9%	-13.2%	-29.4%	91.2%	16.9%	141.1%	85.8%	0.8%	-29.9%	22.2%	8.6%

The top panel shows the monthly average loads in the bars and the peak monthly load in the diamonds. Adjusted for membership changes, annual peak and average loads rose 6.9 and 6.2 percent, respectively. The bottom panel shows monthly Heating Degree Days ("HDD") and Cooling Degree Days ("CDD") summed across four representative locations in MISO.[11]

Total degree days increased by 25 percent year-over-year, the vast majority of which occurred in the summer months. Cooling degree days in July increased 141 percent – due to well above-normal temperatures particularly in the East and Central Regions. This pattern is in stark contrast to summer 2009 when the coolest July on record for most of the footprint contributed to a 15 percent drop in average load. In all, the load in the summer months increased by 11 to 22 percent from 2009. Most other months were relatively normal, with only April and September experiencing substantial declines in degree days. Increased economic activity also contributed to higher loads. The Chicago Purchasing Manager's Index, a leading business barometer and a broad measure of economic activity in the region, was expansionary in each month of 2010.

B. Generation Capacity

This section of the report summarizes the generation MISO has available to serve its energy and ancillary services needs. The figures in this section includes only capacity owned by entities that are participants in the MISO markets and excludes capacity owned by MISO reliability-only members (e.g. Manitoba Hydro, Western Area Power Administration). MISO serves as the Reliability Coordinator for these entities, but reliability-only members do not submit bids or offers in MISO wholesale markets. Including resources of reliability-only members, the total nameplate generating capacity for MISO was nearly 160 GW in 2010.

Generating resources in MISO's market footprint totaled 144.4 GW at the end of 2010, an increase of 5.3 percent from 2009. Figure 9 shows the distribution of this capacity by coordination region.

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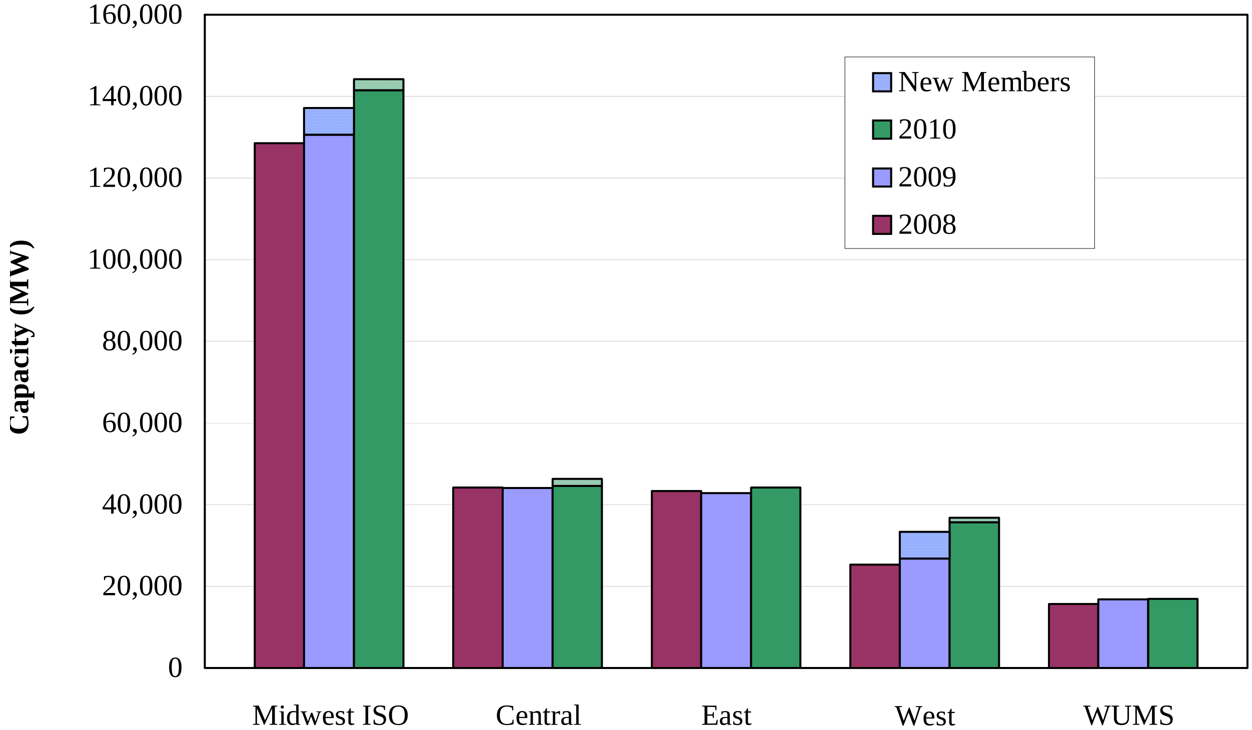
11 HDDs and CDDs are defined using aggregate daily temperature observations relative to a base temperature (in this case, 65 degrees Fahrenheit). For example, a mean temperature of 25 degrees Fahrenheit in a particular week in Minneapolis results in (65-25) * 7 days = 280 HDDs. To account for the relative impact of HDDs and CDDs, HDDs are inflated by a factor of 6.07 to normalize the effects on load (i.e., so that one adjusted-HDD has the same impact on load as one CDD). This factor was estimated using a regression analysis.

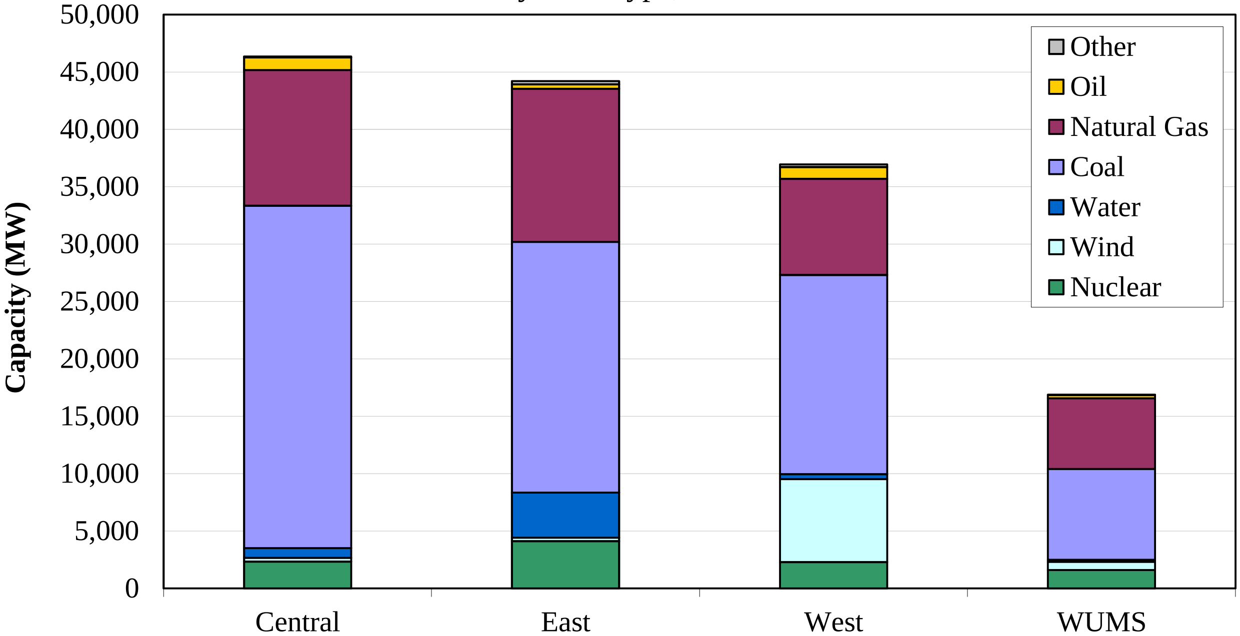
Figure 9: Generation Capacity in MW by Coordination Region
2008–2010



Consistent with the distribution of load in MISO, over two-thirds of generating resources are located in the East and Central Regions. Because WUMS is a frequently congested area, we show it separately from the rest of MISO's East region. In 2010, the additions of Dairyland Power Cooperative ("DPC") in June and Big Rivers Electric Cooperative ("BREC") in December shifted nearly 3 GW of reliability-only capacity into the market. Since these new members are shown separately, the rest of the changes represent newly-built additions or retirements (MidAmerican joined in 2009). The majority of new capacity in 2010 consisted of wind resources in the West Region (1.5 GW) and a mixture of fossil-fueled resources in the East region.

In addition to the location of generation, the geographic distribution of fuel used by those generators is important because it determines marginal costs and ultimately contributes significantly to the price patterns in MISO region. Our next analysis shows the generating capacity by fuel type in the four primary regions of MISO.

Figure 10: Distribution of Generation Capacity by Coordination Region
By Fuel Type, 2010



MISO continues to rely on coal-fired generating resources for over half of its installed capacity (53 percent). Because coal units are generally baseloaded, they generate an even larger share (75 percent) of the total energy produced. The second-largest fuel type is natural gas, which accounts for almost 28 percent of the generating resources in MISO. These resources are more expensive than most of the other resources in the region and are, therefore, dispatched at a lower capacity factor. Gas-fired units produce less than 6 percent of the energy in the region, but frequently set the energy price in peak hours. Nuclear units are baseloaded like most coal units. Although they account for just 7 percent of total capacity, nuclear units produce 14 percent of generation. This is because they are among the lowest-cost resources and, therefore, run at very high capacity factors. Wind resources have increased steadily since the start of the markets and now account for 6 percent of market capacity and 3.5 percent of total energy output.

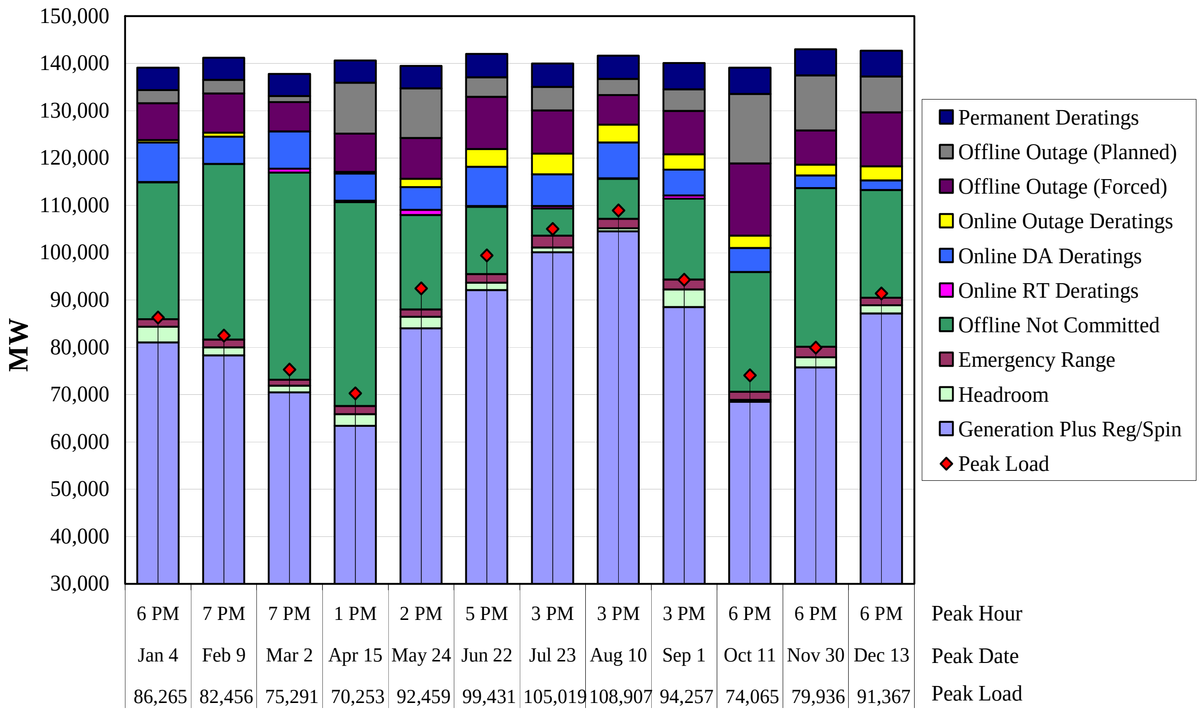
While the mix of generating capacity is fairly homogeneous across MISO footprint, certain regions have conditions that favor investment in particular generator types. Coal-fired resources constitute nearly two-thirds of the resource mix in the Central Region due to its access to low-cost fuel. Meanwhile, the West Region contains the vast majority of the wind capacity (84 percent) due to comparatively attractive wind profiles in the area. Nearly 20 percent of the West

Region's generation capacity is wind. Such a high concentration of wind generating capacity can present operating and reliability challenges that are discussed in Section IV of the report.

C. Generator Availability and Outages

In this section, we examine the availability of generation capacity, particularly in peak-load hours when resource availability is most important. Figure 11 shows the status of generation capacity during the peak-load hour of each month in 2010.

Figure 11: Availability of Capacity during Monthly Peak-Load Hour
2010

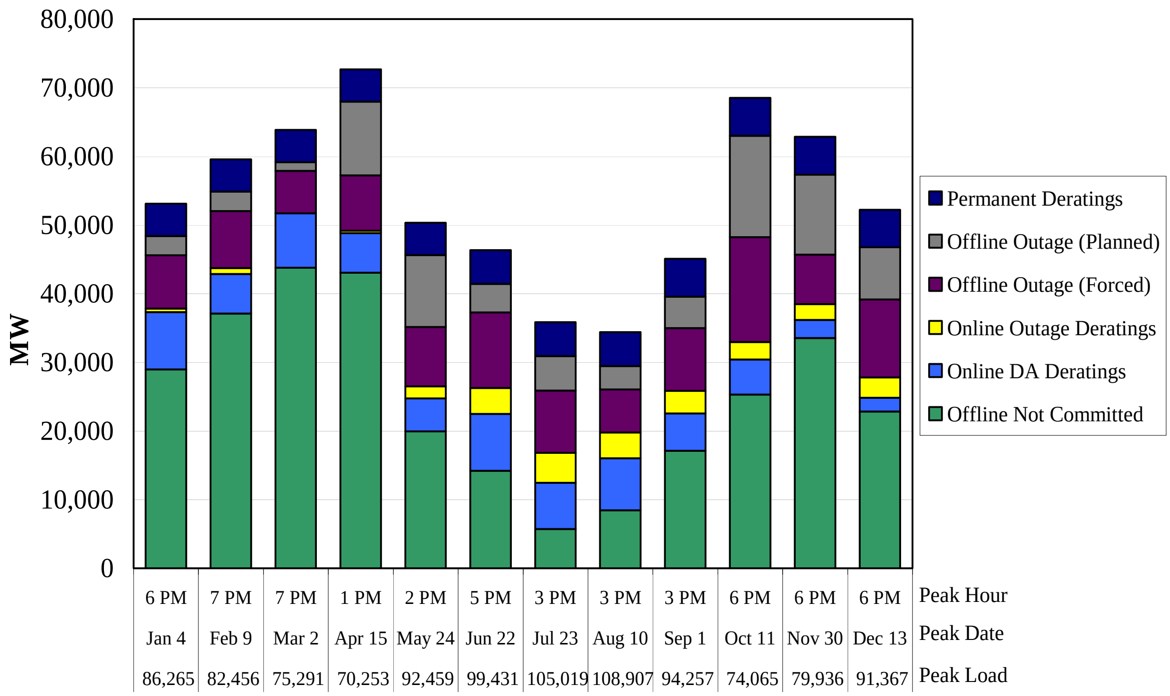


The peak hourly load in each month is shown as a red diamond. Most of the load is served by MISO resources, whose output is the bottom (blue) segment of each bar. The next two segments are "headroom" (capacity available on online units above the dispatch point), and the emergency output range. These three segments are the total online capacity available to MISO. The other segments are the remaining capacity that cannot be dispatched for the identified reasons.

Peak load was generally higher than the emergency maximum of all online generation, but well below total available capacity. This pattern indicates that MISO continues to use net imports to satisfy its peak energy demands instead of committing offline resources. The annual peak load occurred at 3 p.m. on August 10 at nearly 109 GW.[12] Even during this peak hour, over 8 GW of available generation was not committed, which is indicative of the sizable capacity surplus in MISO region. As a result MISO was not forced to call for load interruptions or demand-response curtailments during summer peak periods. Excess headroom, which can indicate over-commitment during peak hours and potentially suppress peak pricing, was less of a concern in 2010, except in September at nearly 3.7 GW. Available headroom and its impact on prices and volatility are evaluated further in Section IV.C of the report.

Finally, this figure also shows changes in total generation capacity. The additions of DPC in June and BREC in December brought a cumulative 3 GW of capacity into the market. Other monthly differences in total capacity are due to the variability of intermittent generation in each peak hour. Unavailable intermittent capacity between a wind resource's permanently derated level and actual output is not shown on the chart. To better depict the unavailable capacity in the peak hours, Figure 12 shows only deratings, outages, and other offline capacity.

Figure 12: Capacity Unavailable during Peak Hours
2010



12 Peak-load hours occurred in mid-afternoon during summer and in the evening during winter, which is consistent with MISO's shifting seasonal load pattern.

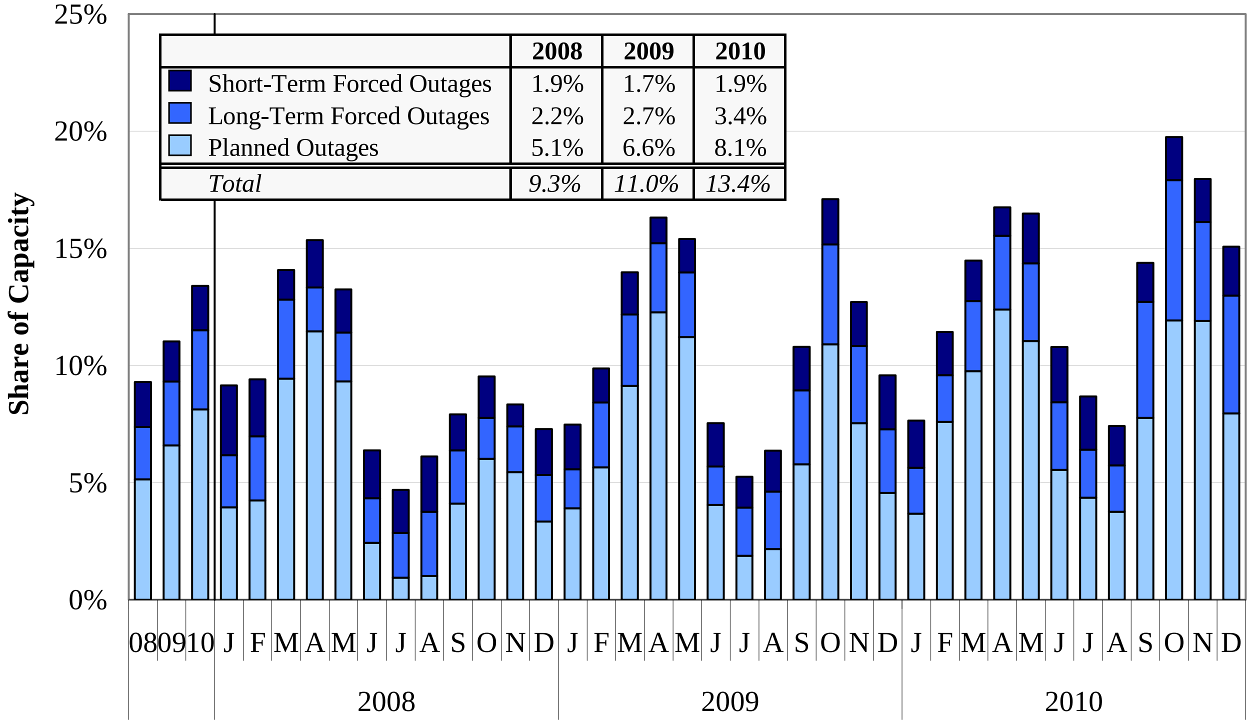
Large quantities of generation remained uncommitted in the peak hour of most months. Even during the peak-load hours in July and August, the available uncommitted generation capacity was approximately 6 and 8 GW, respectively. It averaged 25 GW in monthly peak hours, down from more than 30 GW in 2009 because of the increase in peak load levels. Deratings in the day-ahead market (shown in bright blue) were slightly higher during summer months due to high ambient temperatures that reduce the capability of some types of generators.

Typically, maintenance planning will maximize resource availability in summer peak periods (planned outages are lowest in the summer). Consequently, the larger subset of units in-service should increase the total non-outage deratings during these periods. Furthermore, 5.5 GW of capacity is permanently derated (relative to nameplate capacity ratings) and unavailable for dispatch in any hour, which is largely attributable to two factors. First, many units cannot produce their nameplate output under normal operation, particularly the large quantity of older baseload units in the region. Second, wind resources often have ratings in excess of available transmission capability. Figure 13 illustrates monthly planned and forced generator outage rates in 2008 to 2010. The figures include only full outages; it does not include the partial outages or deratings shown in the prior figure. The figure also distinguishes between short-term forced outages (lasting fewer than seven days) and long-term forced outages (seven days or longer).

Including the three categories of outages, the annual combined outage rate increased in 2010 to 13.4 percent collectively. This rate is up from 11 percent in 2009 and 9.3 percent in 2008. Module E changes in late summer 2009 provided incentives for participants to report outages more accurately, and may, therefore, have contributed to increases in the reported outage during the past two years.

Planned outages also increased to an average of 8.1 percent from the relatively high level of 6.6 percent that prevailed in 2009, when load and energy prices were relatively low. These increases in planned outages occurred in both shoulder months and the peak summer months, and warrant a closer evaluation if this trend continues.

Figure 13: Generator Outage Rates
2008–2010



Short-term outages, which are more likely than other outages to reflect physical withholding, rose slightly to 1.9 percent of capacity. Meanwhile, long-term forced outage rates rose to 3.4 percent in 2010. The largest total outage levels occurred in the spring (16 percent) and fall (17 percent) because planned outages, which comprised the majority of these outages, are generally scheduled during low-load seasons. We examine outages and deratings from a competitive perspective in Section VI.

D. Resource Margins and Generation Adequacy

This section assesses capacity levels in MISO and their adequacy to cover the forecasted peak loads for summer 2011. For purposes of evaluating resource adequacy, estimated reserve margins will be optimistic if all potential deratings are not fully reflected. In particular, many resources during peak-load events must be derated in response to environmental restrictions or due to the effect of high ambient temperatures. Summer ratings, for example, are often 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. Drought and heat events often occur concurrent with peak-load events. Available capacity levels during high temperature conditions in summer can, therefore, be significantly lower than those typically assumed in planning studies and result in lower actual reserve margins.

Table 1 shows our analysis of MISO's capacity levels and margins for summer 2011 given the forecasted peak load and the announced capacity additions and retirements. We calculate the reserve margin as follows:

Reserve margin = [(Capacity + Firm Imports) ÷ Internal Demand or Load] - 1.

The table includes separate reserve margin calculations based on internal demand and internal load. Internal load is the non-coincident (by region) and coincident (for the entire footprint) peak-load forecast done by MISO. We define internal demand as internal load less the sum of behind-the-meter generation, interruptible load and other demand-side management programs. Hence, the margins based on internal demand include the effects of demand response capability, while those based on internal load do not.

Table 1: Capacity, Load and Reserve Margins for each MISO Region
2010–2011 Planning Year

Region	Load	Firm Net Imports	Nameplate		Available Capacity[1]		High Temp. Capacity[2]	
			Capacity	Reserve Margin	Capacity	Reserve Margin	Capacity	Reserve Margin[4]
East								
Internal Load	24,503	285	29,632	22.1%	26,659	10.0%	25,133	3.7%
Internal Demand[3]	22,232	285	29,632	34.6%	26,659	21.2%	25,133	14.3%
Central								
Internal Load	39,407	1,879	49,773	31.1%	46,587	23.0%	43,218	14.4%
Internal Demand	37,675	1,879	49,773	37.1%	46,587	28.6%	43,218	19.7%
West								
Internal Load	25,968	2,410	37,967	55.5%	28,599	19.4%	26,255	10.4%
Internal Demand	22,976	2,410	37,967	75.7%	28,599	35.0%	26,255	24.8%
WUMS								
Internal Load	12,848	320	17,478	38.5%	15,867	26.0%	15,005	19.3%
Internal Demand	11,710	320	17,478	52.0%	15,867	38.2%	15,005	30.9%
MISO								
Internal Load	98,053	5,549	134,850	43.2%	117,712	25.7%	109,610	17.4%
Internal Demand	89,919	5,549	134,850	56.1%	117,712	37.1%	109,610	28.1%

1 Midwest ISO Summer-Rated Capacity from its 2011 Summer Assessment, including undesignated capacity and wind at 8% capacity credit.
2 High Temperature capacity is based upon tempearture derates that occurred in the Day-Ahead market of August 1, 2006.
3 Net Internal Demand estimate excludes all DSM (interruptible load, DCLM, and behind the meter generation).
4 Our planning reserve margins differ from the Midwest ISO's because: a) we include temperature-related deratings (reduces our margins), b) we include all physical capacity, not only those designated as capacity (increases our margins), c) we calculate our margins based on internal load and internal demand while the Midwest ISO's is generally based on internal demand, d) we exclude estimated forced outage rates (increases our margins).

Reserve margins are highly sensitive to the assumed maximum-capacity levels and whether interruptible demand is included. Since the nameplate capacity level is substantially higher than is generally available during peak conditions for most generating units, the reserve margins associated with nameplate capacity are generally overstated.

Available capacity levels, which are based on the summer capacity ratings recognized by MISO in its own planning studies, provide more accurate reserve margins. Based on this measure of capacity and recognizing the projected capacity changes for 2010, the reserve margin for MISO region is 26 percent based on internal load and 37 percent based on internal demand. These reserve margins vary within MISO subregions from 10 percent to 26 percent based on internal load and from almost 21 percent to more than 38 percent based on internal demand. Although MISO uses this measure of capacity to calculate their reserve margins, they report reserve margins significantly less than this level. The primary reason for this is that MISO includes only capacity designated under Module E to satisfy an LSE’s capacity needs (i.e., undesignated capacity is not included). We include this capacity because excluding it masks the true capacity surplus in the region and, in reality, it provides both energy and reserves in the MISO markets.

However, our reserve margins based on available capacity are still overstated because they do not include account for the additional deratings to temperature-sensitive capacity that occurs under peak-demand conditions. When we account for these additional deratings, the projected reserve margin in summer 2011 for the MISO region falls to 17 percent based on internal load and 28 percent based on internal demand. At the regional level, the reserve margin varies from 3.7 percent to nearly 20 percent based on internal load and from 14 percent to 31 percent based on internal demand. Since 10 percent or more of the capacity can be unavailable due to forced outages or set aside for operating reserves, real-time conditions may be tight on some peak days. Hence, interruptible load may need to be curtailed under extreme conditions or if forced outages are higher than average at under peak demand conditions.[13]

13 MISO’s planning margins are slightly lower than the ones we estimate in Table 1. While MISO does not remove high-temperature deratings as we do, it excludes capacity that is not needed to satisfy LSEs’ capacity obligations. Our estimate includes all physical capacity.

These results indicate that the system's resources are more than adequate for summer 2011; however, new resources will be needed over the longer term. Although the additions of ASM and the VCA have improved long-term economic signals, the results of the net revenue analysis presented earlier in this report indicate that they do not currently support new entry. This raises no immediate concern because these results are consistent with the substantial surplus that currently exists in MISO. It is not surprising, therefore, that little capacity aside from subsidized wind generation has been added to the system in the last few years. The adoption of several recommended pricing changes should help ensure alignment of economic signals and reliability needs once the need for new investment is forecasted.

Table 2 shows the new capacity in MISO's *2011 Summer Assessment* that has been added since the *2010 Summer Assessment*.[14]

Table 2: Planned Capacity Additions
Quantities in MW, 2010–2011 Planning Year

Region	Coal	Gas	Waste	Water	Wind	Total
Central	880	795	0	0	150	1,825
East	0	0	2	0	10	12
West	0	0	0	9	1,381	1,390
WUMS	0	0	0	0	162	162
Total	**880**	**795**	**2**	**9**	**1,703**	**3,390**

Nearly 3.4 GW of additions are expected by summer 2011. Although the additional capacity is substantial, half is wind generation, which contributes less to reliability than conventional supply or DR resources due to its intermittent nature. Wind investments are often driven by factors other than the price signals from MISO's markets, such as state renewable portfolio standards or federal subsidies. These investments can cause significant congestion and other operational issues that may require new investments in transmission capability and improvements in operating procedures. The introduction of the DIR type beginning in June 2011 should alleviate some of these concerns.

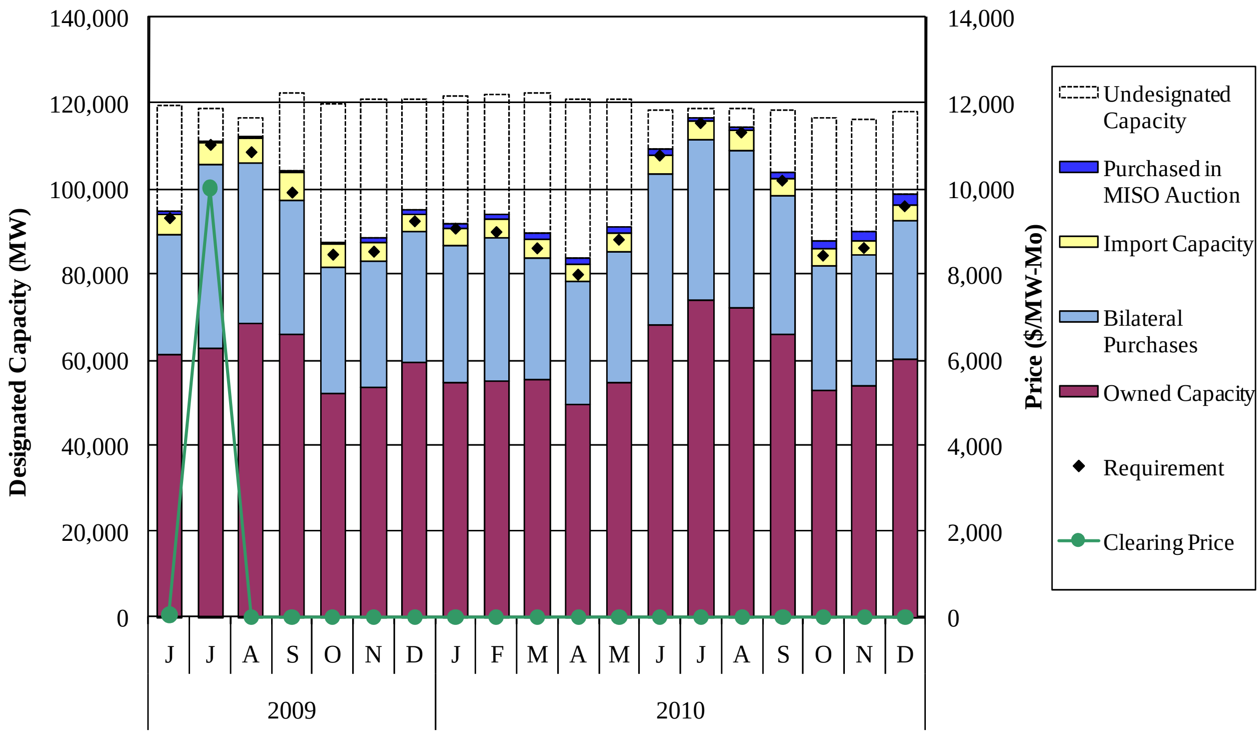
14 Some of these additions occurred in fall 2010, after the completion of the *2010 Summer Assessment*.

Much of the remaining new capacity is fossil-fueled resources located in the Central Region. These additions should improve MISO's ability to manage congestion in this area. MISO is also anticipating 1.1 GW of retirements. Over 70 percent of these retirements are coal units, predominantly in the East Region. This figure excludes the anticipated exit of First Energy in June 2011, which will remove 13.6 GW of capacity from MISO region. The First Energy departure has resulted in lower reserve margins in the East Region.

E. Voluntary Capacity Auction

MISO in June 2009 began operating a voluntary monthly capacity auction to allow LSEs to procure capacity to meet their Tariff Module E capacity requirement. Figure 14 shows the monthly results of the VCA since its inception.

Figure 14: Voluntary Capacity Market Results
June 2009 to December 2010



Note: Total column height represents the total designated capacity, including imports.

The average capacity cleared in the monthly VCA rose by 1,000 MW in 2010, but remained a small percentage (2.6 percent) of total designated capacity. This level of activity is consistent with the intent of the VCA as a balancing market, with most LSEs' capacity needs satisfied through owned capacity (61 percent on average in 2010) or bilateral purchases (33 percent).

Figure 14 also shows that capacity designations have always met or exceeded requirements, ranging from 1 percent in summer months to nearly 5 percent in shoulder months. The total capacity available generally exceeded the requirements by a wide margin, although it narrowed in summer months; it ranged from a minimum of 3 percent for July to a maximum of 51 percent for April. These surpluses should decline as load grows and supply contracts through retirements, declining imports, or increasing exports. The VCA clearing prices have been close to zero in most months, which is consistent with the substantial prevailing capacity surplus and the vertical demand curve implicit in the VCA.[15]

MISO is currently working with participants and the Organization of MISO States to develop improvements to the capacity construct and the IMM is providing comments. Although it is not currently under consideration, we recommend that MISO evaluate the use of a sloped demand curve in its resource adequacy construct in the future. A sloped demand curve would more accurately reflect the reliability value of capacity in excess of the minimum requirement and produce more efficient capacity prices.

Finally, we have concerns regarding the ability of participants to import and export capacity, particularly with PJM. Capacity markets serve an important role in providing long-term economic signals to govern investment in RTO markets. However, capacity prices 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. Therefore, we recommend that MISO identify and remove barriers to trading capacity between regions. This effort must include working actively with PJM to ensure that undue barriers do not prevent MISO suppliers from selling in its capacity market.

15 In July 2009, peak demand and large quantities of capacity that were not offered (or offered at very high prices) resulted in a clearing price of approximately $10,000 per MW-month. We investigated this conduct and concluded that these results were attributable to inexperience with this new market and uncertainty regarding a retail load auction occurring in the same timeframe. Such conditions have not reappeared.

III. Day-Ahead Market Performance

In this section, we evaluate the performance of the day-ahead. The evaluation is focused on four main areas: (1) energy prices relative to load and other operating conditions; (2) convergence of prices between the day-ahead and real-time energy markets; (3) performance of ancillary services markets; and (4) day-ahead load scheduling and virtual trading. Each of these areas is addressed separately in the subsections below. Based on our assessments in these subsections, we conclude that MISO's day-ahead market performed well overall in 2010.

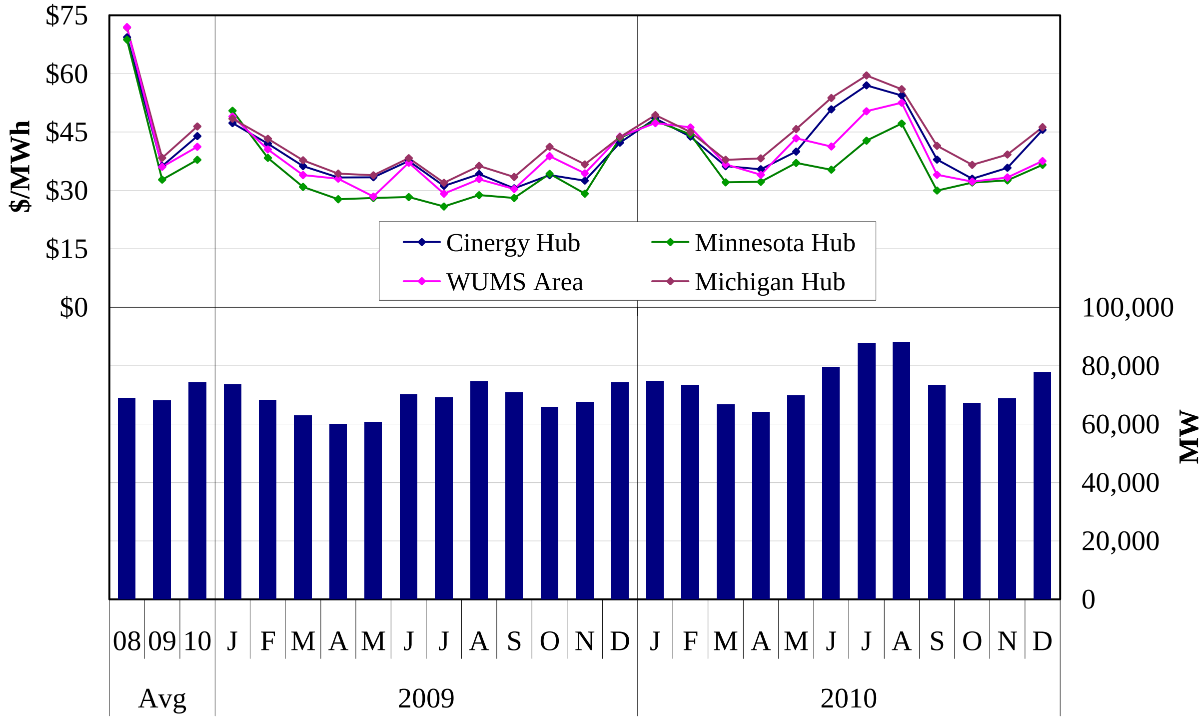
The performance of the day-ahead market is very important. In the day-ahead market, participants make financially binding forward purchases and sales of power for delivery in real time. These transactions are made for a variety of reasons, including satisfying the participant's own supply, managing risk by hedging the participant's exposure to the real-time market, or arbitraging with the real-time markets. For example, load serving entities can insure against volatility in the real-time market by purchasing in the day-ahead market. In fact, most power procured through MISO's markets is financially settled in the day-ahead market. In addition, FTRs are settled based on day-ahead market results. Finally, the day-ahead market plays a critical role in coordinating generator commitments. For all of these reasons, the performance of the day-ahead market is essential.

A. Day-Ahead Energy Prices and Load

During 2010, MISO's day-ahead energy market averaged a system-wide price per MWh of $35.45 per MWh on a load-weighted, average basis. This represents an increase of almost 20 percent that was due to higher fuel prices and load levels. In this subsection, we review day-ahead peak and off-peak energy prices and scheduled load in each region.

Figure 15 shows daily average day-ahead prices during peak hours (6 a.m. to 10 p.m. on weekdays) at four representative hub locations in MISO and the corresponding scheduled load (which includes net cleared virtual demand). Differences in prices among the hubs show the prevailing congestion patterns throughout the year. High prices in one location relative to another location indicate congestion from a low-priced to a high-priced area.

Figure 15: Day-Ahead Hub Prices and Load
2010: Peak Hours



System-wide day-ahead prices were stable throughout the year and tracked changes in fuel prices and load conditions well. The load-weighted, average day-ahead price in peak hours rose 19 percent in 2010 to $42.69 per MWh. This increase was due to increased fuel prices and load. Average prices during peak hours were highest during a sustained heat wave in summer and in January when natural gas prices were highest.

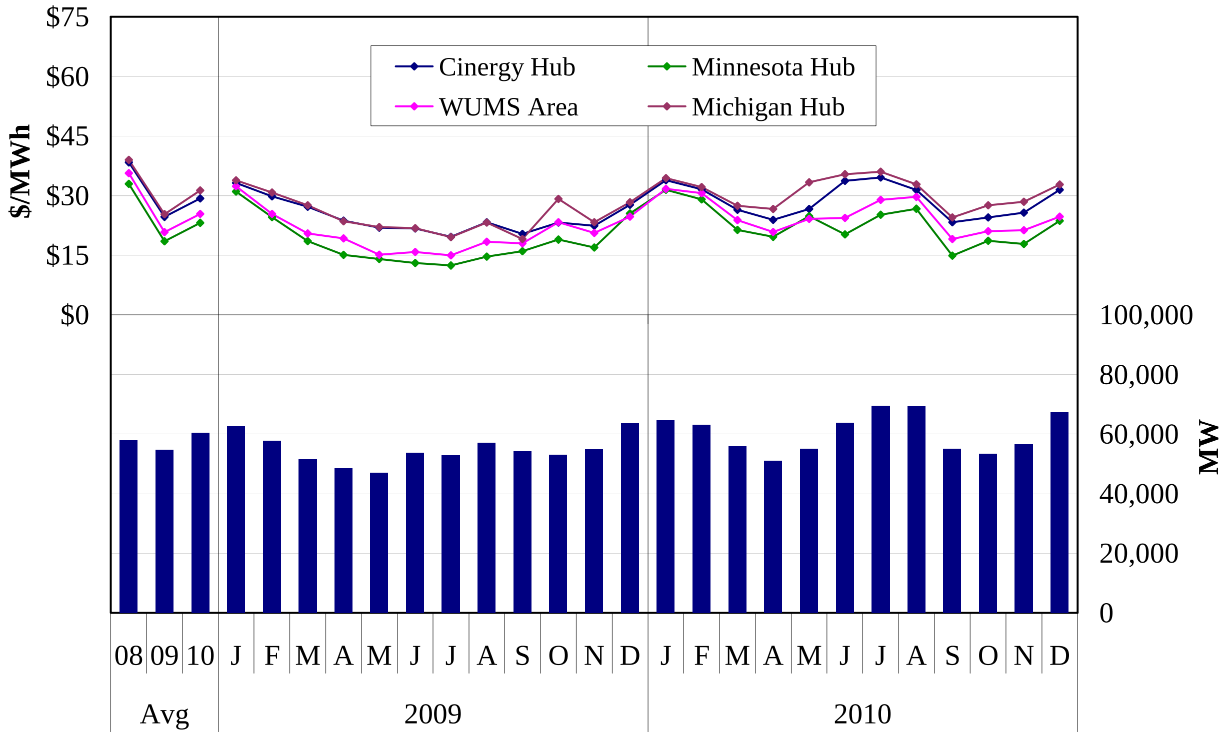
During 2010, persistent west-to-east congestion across MISO again caused the lowest average prices in Minnesota ($38/MWh) and the highest prices in Michigan ($46/MWh). Congestion was most apparent in June and July, when high loads in the East Region and transmission outages contributed to a nearly $20 price difference between Minnesota and Michigan Hubs. Despite day-ahead scheduled loads often approaching 100 GW, peak prices in June to August averaged just over $50 per MWh reflecting the moderate prevailing fuel prices.

Figure 16 shows similar results for off-peak hours (10 p.m. to 6 a.m. on weekdays and all hours on weekends). Day-ahead off-peak prices averaged $27.65 per MWh in 2010, a 21 percent increase from 2009. Prices in 2010 remained 28 percent lower than in 2008. The rise in prices relative to 2009 was due in part to higher average day-ahead scheduled loads (which increased

5.6 percent, adjusted for membership), and in part to higher coal prices (coal-fired generation was almost always on the margin during off-peak hours). Off-peak prices did not rise as much as peak prices because the load effects and fuel price effects were smaller.

As in prior years, the price spread between the eastern and western areas in MISO was more consistent during off-peak hours. Prices averaged over $31 per MWh at Michigan Hub and $29 at Cinergy Hub, while WUMS Area and Minnesota Hub prices averaged $26 and $23, respectively. This price separation is partly attributable to increased day-ahead scheduled wind generation, which increased 46 percent from 2009 and contributed to recurring congestion out of the West Region. High loads in the winter-peaking West Region reduced the average difference between Minnesota and Michigan Hub prices in January and February to $3 per MWh compared to $9 per MWh for the rest of the year.

Figure 16: Day-Ahead Hub Prices and Load
2010: Off-Peak Hours



B. Day-Ahead and Real-Time Price Convergence

This subsection evaluates the convergence of prices in the day-ahead and real-time energy markets. Good convergence between day-ahead and real-time prices is a sign of a well-functioning day-ahead market. 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).

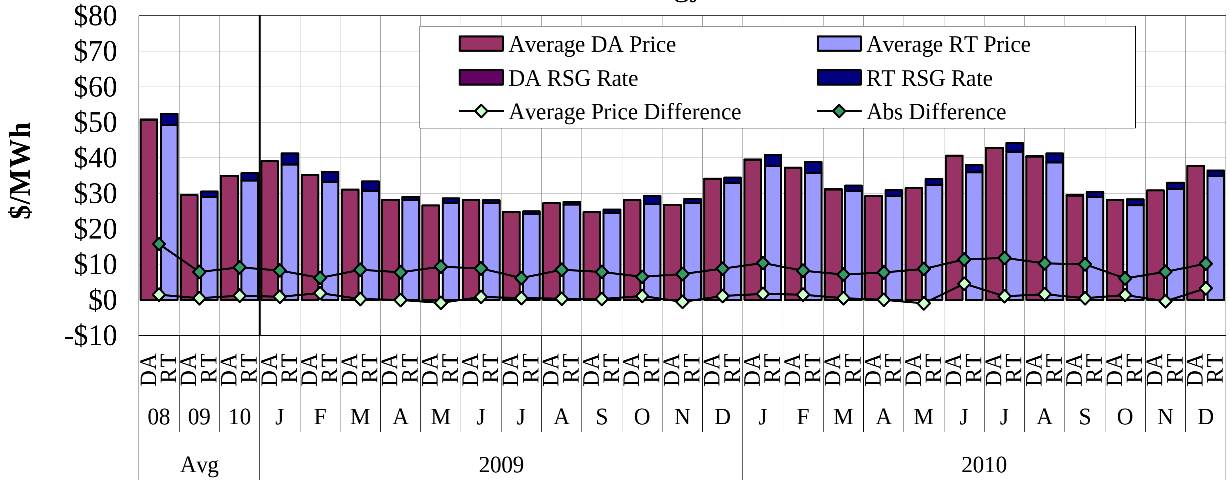
Participants' day-ahead market bids and offers should reflect their expectations of market conditions the following day, but a variety of factors can cause real-time prices to be significantly higher or lower than anticipated in the day-ahead. While a well-performing market may not result in prices converging on an hourly basis, it should lead prices to converge well on a monthly or annual basis.

A modest day-ahead price premium is rational because purchases in the day-ahead market are subject to less price volatility (which is valuable to risk-averse buyers). Additionally, purchases in the real-time market are subject to allocation of real-time RSG costs (which are much larger than day-ahead RSG costs). The RSG allocation methodology in 2010 imposed disproportionately large costs on virtual supply transactions.[16] This factor contributed to considerable declines in virtual activity since 2008 and to larger price differences by reducing the effectiveness of the arbitrage by participants. RSG costs and allocations are discussed in greater detail in Section IV.D of the report.

Figure 17 shows monthly average prices in the day-ahead and real-time markets at the Cinergy Hub, along with the average RSG cost per MWh. Cinergy Hub remains the most liquid forward trading point in the region.

16 Beginning in April 2011, a new RSG allocation methodology was implemented that includes an allocation of RSG costs to deviations that cause congestion.

Figure 17: Day-Ahead and Real-Time Prices
2009–2010: Cinergy Hub



Average DA-RT Price Difference (% of Real-Time Price)																											
Cinergy Hub	3	2	3	2	6	1	0	-3	3	2	1	1	4	-2	3	4	4	2	0	-3	13	2	4	2	5	-1	9
Michigan Hub	3	2	4	4	5	4	0	-4	-1	0	4	3	7	-1	2	8	3	2	3	2	10	5	2	2	-5	-2	10
Minnesota Hub	3	4	2	7	8	12	3	1	11	-3	6	-5	1	4	-1	13	4	4	-2	-3	0	-5	3	5	7	-3	4
WUMS Area	3	8	7	8	12	12	6	4	13	2	8	5	8	16	5	13	9	8	1	-5	15	-2	10	21	11	4	2
Average Absolute DA-RT Price Difference (% of Real-Time Price)																											
Cinergy Hub	32	27	27	22	19	28	28	34	33	25	32	32	24	27	27	28	23	23	26	27	32	28	27	35	23	25	29
Michigan Hub	33	32	31	22	19	29	33	34	34	27	37	47	39	34	27	30	24	24	32	39	33	31	27	40	37	26	31
Minnesota Hub	38	39	35	29	28	43	46	51	51	34	42	41	34	35	36	36	28	28	30	37	35	29	31	47	39	43	32
WUMS Area	37	39	33	25	31	38	39	55	55	33	37	39	37	41	37	35	26	28	28	35	41	30	33	50	31	32	31

The table below the figure shows two measures of price convergence for four locations:

- The average day-ahead and real-time price difference, which measures overall price convergence; and
- The average of the hourly absolute value of the day-ahead and real-time price difference. This show the typical difference whether positive or negative. This measure indicates how volatile price differences are and shows how consistent day-ahead and real-time prices were on an hourly basis.

The Cinergy Hub experienced modest day-ahead premiums in most months of 2010. After accounting for differences in RSG allocations, which averaged $2.04 per MWh for real-time purchases versus $0.04 for day-ahead purchases, price convergence was very good. Regionally price differences were largest in WUMS, where the day-ahead premium averaged 7 percent and exceeded 20 percent in September. Real-time congestion on M2M constraints out of WUMS contributed to lower prices in real time there, particularly in late summer. The 2010 day-ahead premiums at the Michigan and Minnesota Hubs averaged 4 and 2 percent, respectively.

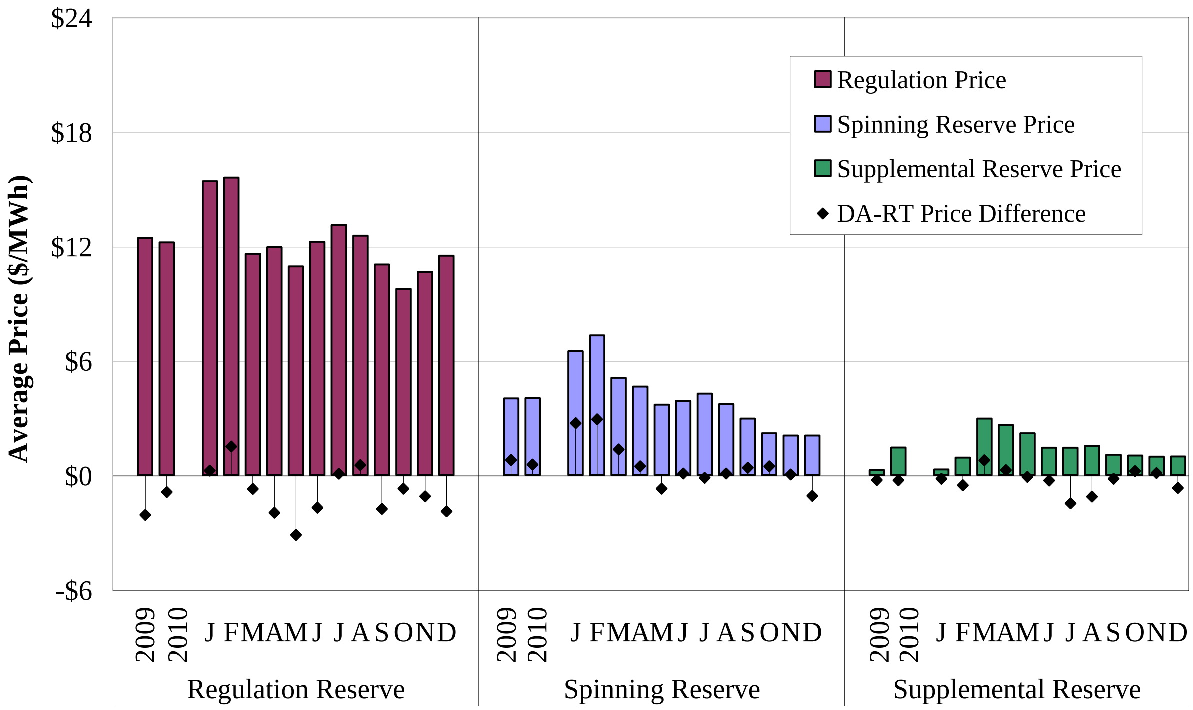
The absolute value of the hourly price differences at the Minnesota and WUMS Hubs in 2010 continued to be higher than in other areas. The delta is attributable to higher price volatility there, caused partly by negative real-time price spikes during off-peak hours. This was at times exacerbated by the underscheduling of wind output in the day-ahead market. Underscheduling increased manual curtailments of wind output in real time because of congestion and resulted in lower real-time prices in the West. In a well-functioning market, this price separation would be arbitraged by virtual supply; however, the decline in virtual trading discussed above limited the response of the market to arbitrage these large price differences.

C. Day-Ahead Ancillary Services Markets

Ancillary service markets are comprised of day-ahead and real-time markets for regulating reserves, operating reserves, and supplemental reserves that are jointly optimized with the energy markets. They were introduced in January 2009 and continued to operate with no significant issues in 2010. ASM prices have been consistent with expectations and are comparable to results in similar RTO markets. Figure 18 shows monthly average day-ahead clearing prices for MISO’s ancillary services products for 2010, along with day-ahead to real-time price differences.

Figure 18: Day-Ahead Ancillary Services Prices and Price Convergence

2010



Compared to 2009, ASM prices for regulating and spinning reserves were nearly unchanged in 2010, averaging $12 and $4 per MWh, respectively. Regulating reserve clearing prices were higher in real time in most months that was due to:

- Increased real-time energy price volatility, which increases the opportunity costs of generators providing regulation; and
- Reduced regulation availability due to MISO's real-time regulation commitment process, which selects only a subset of regulation-eligible units.

Day-ahead spinning reserve clearing prices decreased over 2010, in part because of headroom commitment changes to the day-ahead Resource Scheduling and Commitment process in June. Those changes increased day-ahead spinning reserve capability.

Supplemental reserve prices rose substantially in 2010, averaging $1.72 per MWh for the year. They increased in February because concerns were raised by the Commission and others regarding suppliers' performance during deployments in 2009 and their ability to satisfy deployment obligations. Some suppliers reduced their offer quantities significantly in response to these concerns. In addition, higher load levels reduced the amount of offline quick-start capacity available to schedule as contingency reserves. Finally, occasional shortages of supplemental reserves, occurring mostly during Automatic Reserve Sharing ("ARS") events in summer, resulted in slightly higher real-time prices in some months. Together, these factors resulted in the significant price increases in 2010. MISO is working with stakeholders to clarify supplemental reserve deployment response obligations. It has recently filed tariff provisions to test the deployment of supplemental reserves and to cap the offer quantities at the demonstrated response during actual events or tests. Increased certainty regarding deployment obligations should allow suppliers to increase their offer quantities and lower supplemental reserve prices.

D. Day-Ahead Load Scheduling and Virtual Trading

Our next analysis addresses load scheduling and virtual trading in the day-ahead market. These aspects of the market play an important role in overall market efficiency by promoting optimal commitments and improved price convergence between day-ahead and real-time markets. Day-ahead load includes price-sensitive load, fixed load, and virtual load. Price-sensitive load is scheduled (i.e., cleared) if the day-ahead price is equal to or less than the load bid. A fixed-load schedule does not include a bid price, indicating a desire to be scheduled regardless of the day-ahead price. Physical load is the sum of the fixed load and the cleared price-sensitive load.

Virtual trading in the day-ahead market consists of purchases or sales of energy that are not associated with physical load or resources. Similar to price-sensitive load, virtual load is cleared if the day-ahead price is equal to or less than the virtual load bid. We are generally interested in comparing the net scheduled load in the day-ahead market to the actual real-time load. Net scheduled load is defined as physical load plus cleared virtual load, minus cleared virtual supply. The relationship of the net scheduled load to the actual load affects commitment patterns and RSG costs because units are committed and scheduled in the day-ahead to satisfy the net load.

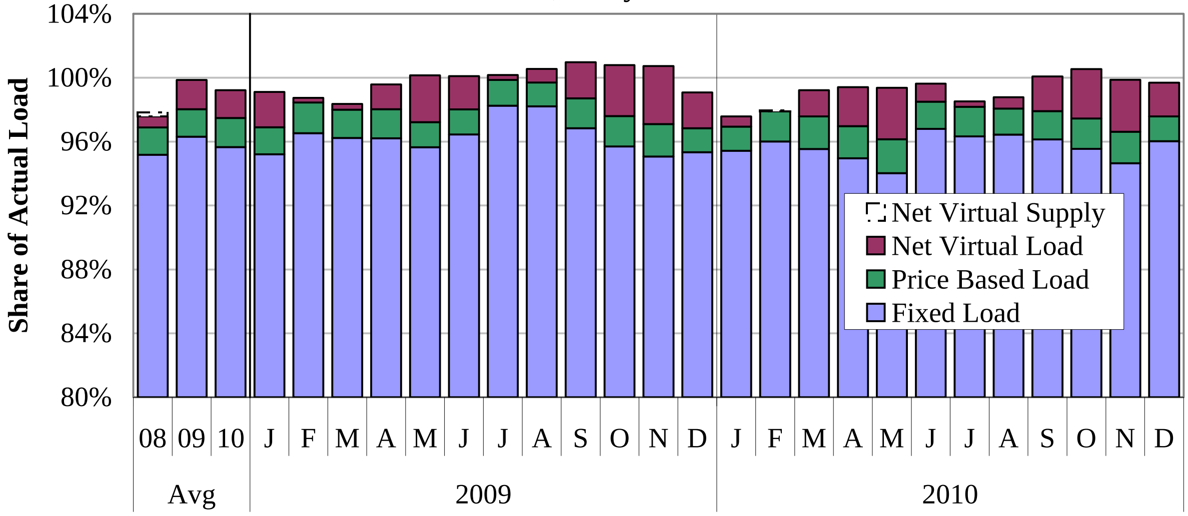
When day-ahead net load is significantly less than real-time load, particularly in the peak-load hour of the day, MISO frequently commits peaking resources to satisfy incremental load increases. As shown later in this section, peaking resources often do not set real-time prices, even if those resources are effectively marginal. This can contribute to suboptimal real-time pricing and can result in inefficiencies because lower-cost units that could have been committed through the day-ahead market can be displaced by peaking units committed in real time. Because these peaking units frequently due not set real-time prices, the economic feedback to schedule more fully in the day-ahead market will be masked.

Additionally, when participants or MISO commit significant quantities of generation after the close of the day-ahead market, this additional supply can lower real-time prices and create an incentive for participants to schedule net load at less than 100 percent. The most common sources of additional supply increases in real time are:

- Supplemental commitments made by MISO for reliability after the day-ahead market;
- Self-commitments made by market participants after the day-ahead market; and
- Wind output under-scheduled in the day-ahead market.

To show net load-scheduling patterns in the day-ahead market, Figure 19 compares the monthly peak-hour day-ahead scheduled load to actual load. The figure shows the daily peak hours when underscheduling is mostly likely to require MISO to commit additional generation. The table below the figure also shows the average scheduling levels in all hours.

Figure 19: Day-Ahead Scheduled versus Actual Loads
2009–2010, Daily Peak Hour



Share of Actual Load(%)

	08	09	10	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
All Hour	99.2	99.9	99.3	100.1	99.4	98.7	99.2	99.4	99.9	100.3	100.7	100.4	100.1	100.2	100.6	98.2	98.9	99.3	99.2	99.4	99.9	99.2	99.4	99.4	99.8	99.4	100.0
Peak Hour	97.6	99.9	99.2	99.1	98.7	98.4	99.6	100.2	100.1	100.2	100.5	101.0	100.8	100.7	99.1	97.6	97.9	99.2	99.4	99.4	99.6	98.5	98.8	100.1	100.5	99.9	99.7

Net load scheduled in the day-ahead market as a percentage of real-time load during all hours declined slightly to 99.3 percent on average for 2010. Similarly, scheduling in the peak hour of each day (i.e., the hour most likely to require MISO to commit additional generation) decreased to 99.2 percent. Nevertheless, these scheduling levels are very close to full scheduling and do not raise material concerns.

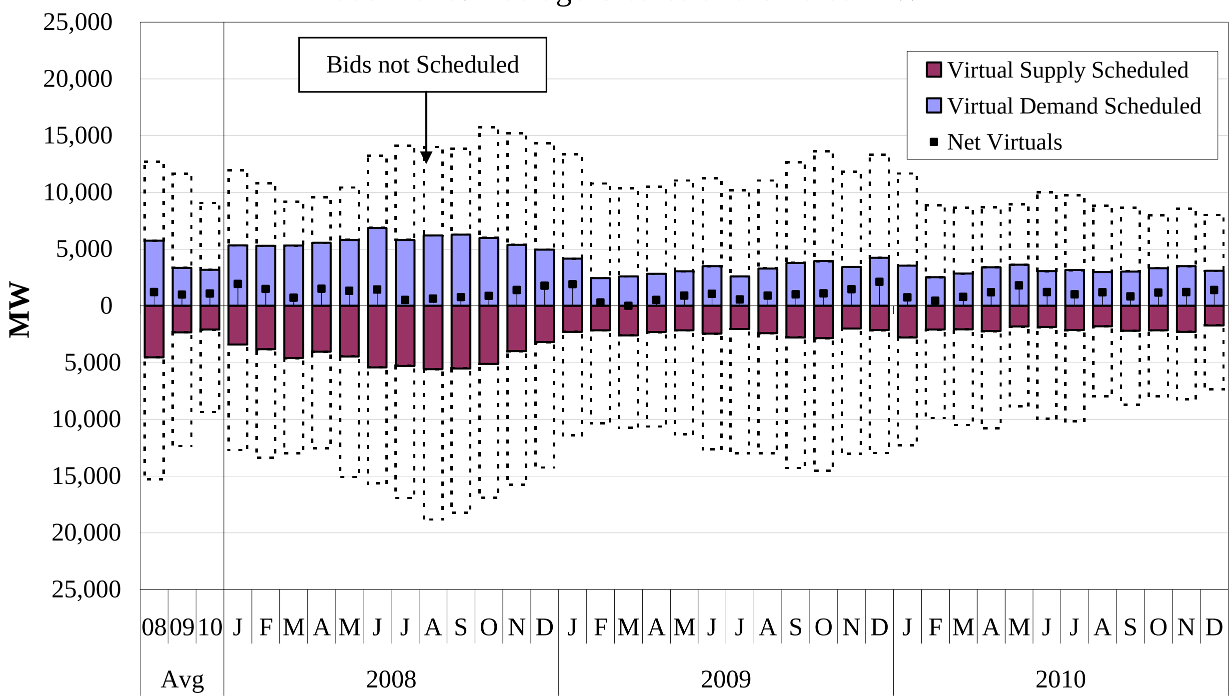
As in prior years the vast majority of this load (96 percent) was fixed. The balance was comprised of price-sensitive load or net virtual load. As noted above, nearly full-load scheduling has reduced MISO's reliance on peaking resources in the real-time market and has lowered real-time RSG costs, although load increases in 2010 increased real-time commitments overall.

The next figure assesses virtual trading activity. Virtual trading provides essential liquidity to the day-ahead market because it constitutes a large share of the price-sensitivity at the margin that is needed to establish efficient day-ahead prices. Virtual transactions scheduled in the day-ahead market are settled in the real-time market. Virtual demand bids are profitable when the real-time energy price is higher than the day-ahead price, while virtual supply offers are profitable when the day-ahead energy price is higher than the real-time price. For example, if the market clears 1 MW of power for $50 in the day-ahead market, sellers must then purchase or produce 1 MW in real time to cover the trade.

Accordingly, if virtual traders expect real-time prices to be lower than day-ahead prices, they would sell virtual supply in the day-ahead market and buy (settle financially) the power back based on real-time market prices. Likewise, if virtual traders expect real-time prices to exceed day-ahead prices, they would buy virtual load in the day-ahead market and sell (settle financially) the power back based on real-time prices. This trading is one of the primary means of arbitraging prices in the two markets, causing day-ahead prices to converge with real-time prices. Price convergence resulting from this arbitrage increases day-ahead market efficiency.

Figure 20 shows virtual supply and demand volumes in the day-ahead market. The figure 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 from 2008 to 2010. The virtual bids and offers that did not clear are shown as dashed areas at the end points of the solid bars. These virtual bids and offers were rendered non-economic by prevailing day-ahead market prices.

Figure 20: Virtual Load and Supply in the Day-Ahead Market
2008–2010: Average Cleared and Offered MW



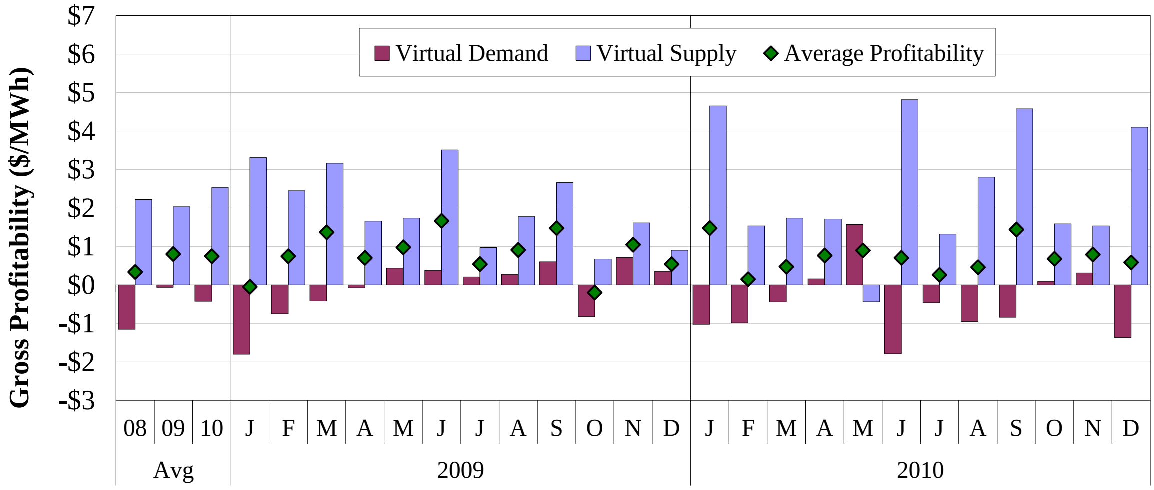
Offered and cleared virtual volumes have declined precipitously since 2008. Virtual supply offer volumes have declined 39 percent since 2008, while total virtual bids and offers decreased by 23 percent from 2009 to 2010. Likewise, cleared virtual demand and supply volumes declined almost 10 percent 2010, and are down 45 and 54 percent since 2008, respectively. Much of this decline in activity is attributable to a series of Orders by the FERC requiring allocation of RSG costs in part to cleared virtual supply transactions. The average rate applied to virtual supply volumes was $2.04 per MWh in 2010 and was relatively volatile.

The prevailing RSG allocation rate in 2010 (the “Interim Rate”) allocated nearly all real-time RSG costs to deviations between the day-ahead and real-time markets, such as real-time physical load changes, virtual supply volumes, and import schedule changes. RSG charges are, however, also caused by peaking resources not setting prices, congestion, reliability needs, and outages. Hence, the Interim Rate over-allocates costs to deviations relative to the portion of the RSG costs they actually cause, including virtual supply transactions, which bore 21 percent ($34 million) of all real-time RSG costs under this rate in 2010. A revised RSG methodology addressing many of these concerns was implemented in April 2011.

Reduced virtual trading activity raises potential concerns about day-ahead market performance because active virtual trading in that market promotes price convergence with the real-time market. Good price convergence, in turn, facilitates an efficient commitment of generating resources. Active virtual supply also protects the day-ahead market against market manipulation and market power abuses. To date, very few virtual transactions have raised potential concerns, and virtual trading restrictions (i.e., mitigation) have been applied only once, in early 2010. MISO made subsequent modeling changes that reduce the likelihood of similar virtual strategies being attempted or being profitable.

Figure 21 shows monthly average gross profitability of virtual purchases and sales, as well as the volume of virtual supply and demand that cleared the market. Gross profitability is the difference between the price at which virtual traders bought and sold positions in the day-ahead market and the price at which these positions were covered (i.e., settled) in the real-time market. Gross profitability excludes RSG cost allocations.

Figure 21: Profitability of Day-Ahead Virtual Trading
2008–2010



Share of Cleared Virtuals with Extreme Profitability (%)

Profit> $50/MWh	2.8	1.2	2.3	0.7	1.2	1.7	0.9	2.0	1.6	0.7	1.4	1.5	0.8	0.7	1.4	2.4	1.0	1.3	2.1	3.6	2.4	2.3	1.7	2.7	2.7	2.5	2.5
Profit< -$50/MWh	3.7	1.6	1.1	0.9	1.0	1.6	1.7	1.6	1.7	0.8	1.6	1.6	1.7	2.5	2.2	1.2	0.8	0.6	1.0	1.5	0.9	1.3	1.0	1.4	1.0	1.3	1.1

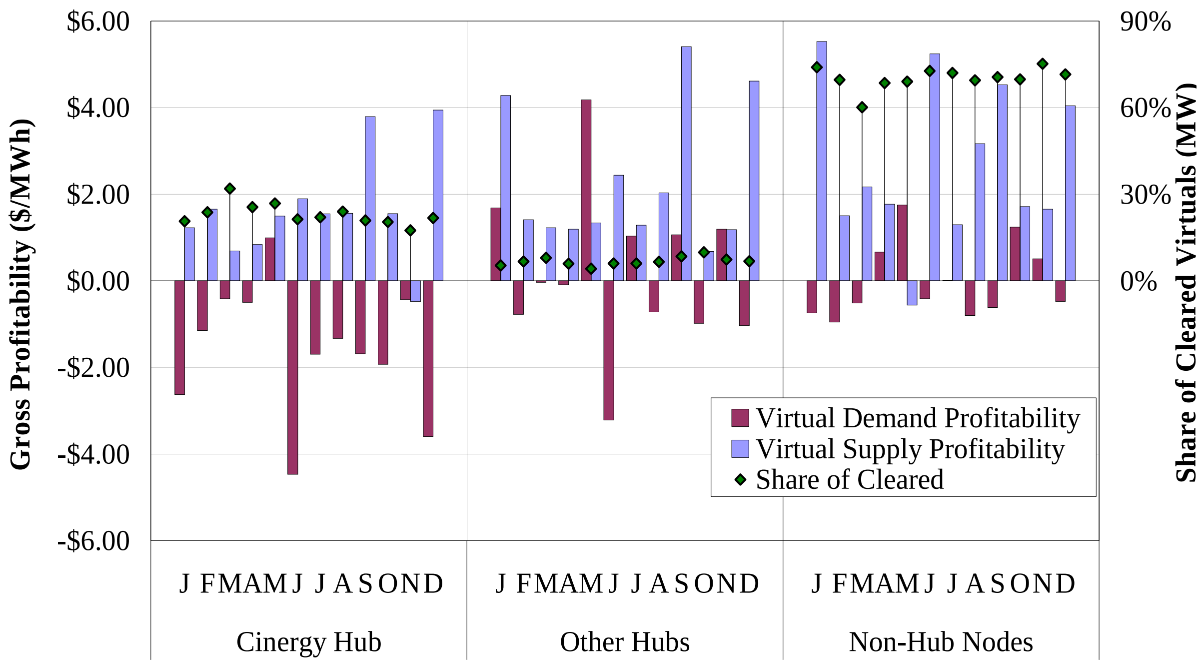
Profitability of all cleared virtual transactions decreased slightly to $0.75 per MWh and is largely unchanged from prior years. Low profitability is expected in a market that is well-arbitraged. Virtual supply has been considerably more profitable than virtual demand ($2.53 per MWh versus -$0.43 per MWh) because of the prevailing day-ahead price premium. After subtracting weighted-average RSG cost allocations of $1.87 per MWh, however, virtual supply transactions netted an average profit of only $0.66 per MWh.

The table below the figure shows the percentage of virtual transactions clearing with abnormally large profits or losses. Large sustained profits from virtual trading may indicate day-ahead modeling inconsistencies, while large losses may indicate an attempt to manipulate day-ahead prices. In 2010 the portion of transactions generating losses greater than $50 per MWh fell to nearly 1 percent and never exceeded 1.5 percent in any month in 2010. Attempts to create artificial congestion or other price movements in the day-ahead market can cause prices to diverge from real-time prices and be unprofitable.

For example, a participant may submit a high-priced (and, therefore, likely to clear) virtual bid at a constrained location that causes artificial day-ahead market congestion. The participant can buy in the day-ahead market at the high (i.e., congested) price and sell the energy back at a lower (i.e., uncongested) price in the real-time market. Although it is foreseeable that the virtual transaction would be unprofitable, the participant could earn net profits if the payments to its FTRs (or payments through some other physical or financial position) increase as a result of the higher day-ahead congestion. We continually monitor for indications of such attempts and have mitigation authority to address them. Virtual losses that warrant further investigation have been rare and only one pattern of trades warranted mitigation in 2010.

To examine how profitability of virtual transactions varies by type of location, Figure 22 shows the monthly average profitability of virtual purchases and sales at the Cinergy Hub, other hubs, and other nodes. Cinergy Hub was the single most liquid trading point in MISO, with 23 percent of all virtual trading volume, down from nearly 30 percent in 2009. Most other virtual trading activity occurred at non-hub locations. The virtual trading volume is shown by the diamonds in the figure that are plotted against the right-side axis.

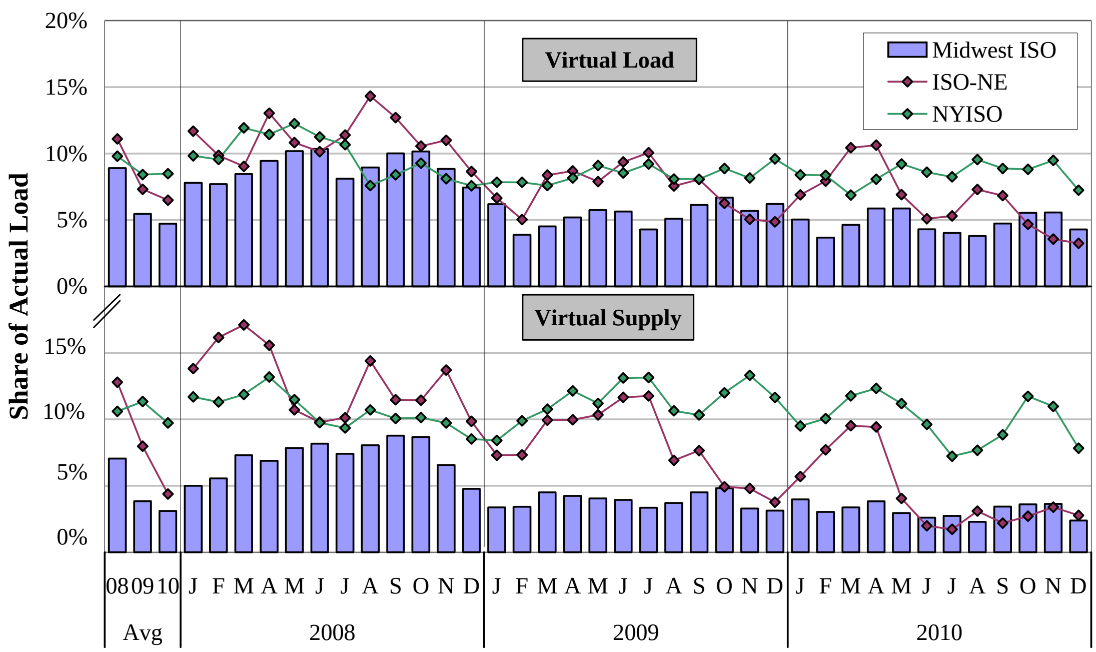
Figure 22: Virtual Profitability by Location
2010



The average gross profit per MWh of cleared virtual supply offers was $2.53 in 2010. Virtual supply was generally more profitable at the nodal level ($2.67 per MWh) because nodal locations are generally less liquid and more prone to congestion-related price spikes than hub locations since hubs are an aggregation of many nodes. Over 85 percent (or nearly $40 million) of virtual supply profits were at nodal locations. However, the allocation of RSG costs offset the majority of these profits. Conversely, the average gross loss per MWh of cleared virtual demand was $0.43 in 2010. Virtual demand was consistently unprofitable at the Cinergy Hub and slightly profitable at other locations. Approximately one-third of all cleared virtual load bids in 2010 were at the Cinergy Hub, where virtual load lost an average of $1.57 per MWh, accounting for nearly all of the losses. Many of the bids at Cinergy may be physical hedges by LSEs to protect against real-time price volatility. Such hedges tend to be modestly unprofitable, but may be rational if LSEs are risk averse.

To compare trends in MISO to those in other RTO markets, Figure 23 shows monthly average virtual supply and demand transactions for MISO, ISO New England ("ISO-NE"), and New York ISO ("NYISO") as a percent of actual load. Virtual load and supply volumes declined in all those markets beginning in the fourth quarter of 2008 primarily due to tight credit conditions. Virtual volumes in NYISO declined slightly in 2010, but remained at nearly 10 percent as a share of actual load. Volumes in ISO-NE fell in mid-2010 because of modeling changes deployed in May as well as increased uplift charges.

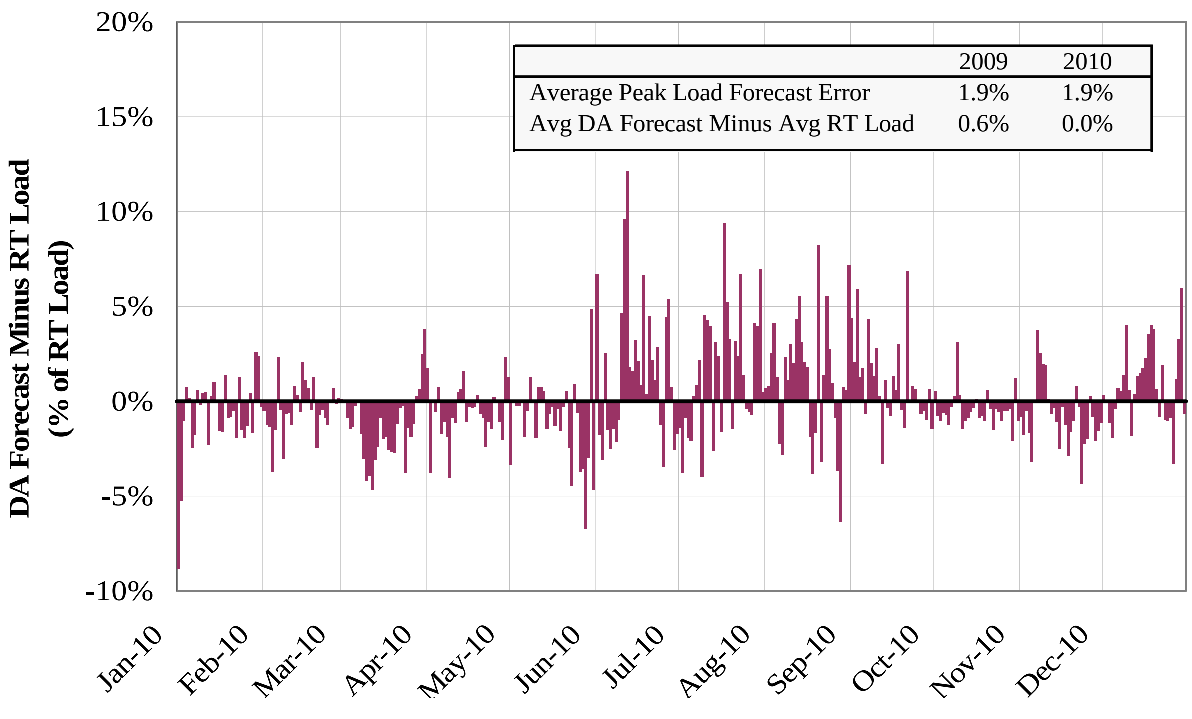
Figure 23: Virtual Transaction Volumes
2008–2010



As a share of actual load, virtual volumes in MISO declined by nearly 25 percent from 2009 levels. Volumes averaged less than 4 percent of actual load, lower than either NYISO or ISO-NE. The pattern of declining virtual trading levels was partly due to the high RSG cost allocation applied to deviations (including virtual supply) beginning in November 2008. This rate averaged $2.04 per MWh in 2010 but varied considerably. The standard deviation was $2.39. This allocation affects virtual load as well since some participants combine virtual supply and load transactions to arbitrage congestion levels across an interface.

Our next analysis examines MISO's day-ahead forecasted load. Figure 24 shows the percentage difference between the Mid-Term Load Fforecast ("MTLF") used in the day-ahead model and real-time actual load for the peak hour of each day in 2010. Load forecasting is a key element of an efficient forward commitment process. Accuracy of the MTLF is particularly important for the reliability assessment commitment process performed after the day-ahead market closes, but before the real-time operating day begins. Inaccurate forecasts can cause MISO to commit more or fewer resources than necessary resources to meet demand, both of which can be costly. Participants in the day-ahead market may also rely on MISO's forecast to inform their decisions.

Figure 24: Daily Day-Ahead Forecast Error in Peak Hour
2010



	2009	2010
Average Peak Load Forecast Error	1.9%	1.9%
Avg DA Forecast Minus Avg RT Load	0.6%	0.0%

On average, the day-ahead forecast of peak load is equal to the actual real-time load. Although such comparability indicates that forecasting was very accurate overall, it can mask substantial day-to-day variability in load-forecasting accuracy. The average peak-load forecast error (i.e., the magnitude of the error, regardless of direction) was 1.9 percent in 2010, unchanged from 2009 and comparable to the performance of other RTOs. Consistent with the prior two years, the figure shows load tended to be over-forecasted in summer and under-forecasted in shoulder months. This pattern is partially due to load forecast errors by participants. In addition, summer storms contribute to increased volatility in real-time load associated with rapid temperature changes. This volatility in real-time load leads to larger forecasting errors.

IV. Real-Time Market Performance

In this section, we evaluate real-time market outcomes, including prices and uplift payments. We also assess the dispatch of peaking resources in real time and the integration of wind generation. We conclude this section with a number of suggested improvements intended to enhance the efficiency and competitive performance of the markets.

The real-time market performs the vital role of dispatching resources every five minutes to minimize the costs of satisfying the system's energy and operating reserve needs, given the physical limitations of the individual resources and the transmission network. Every 5 minutes, the real-time market utilizes the latest information regarding generation, load, transmission flows and other system conditions to produce new dispatch instructions for each resource and prices for each node on the system.

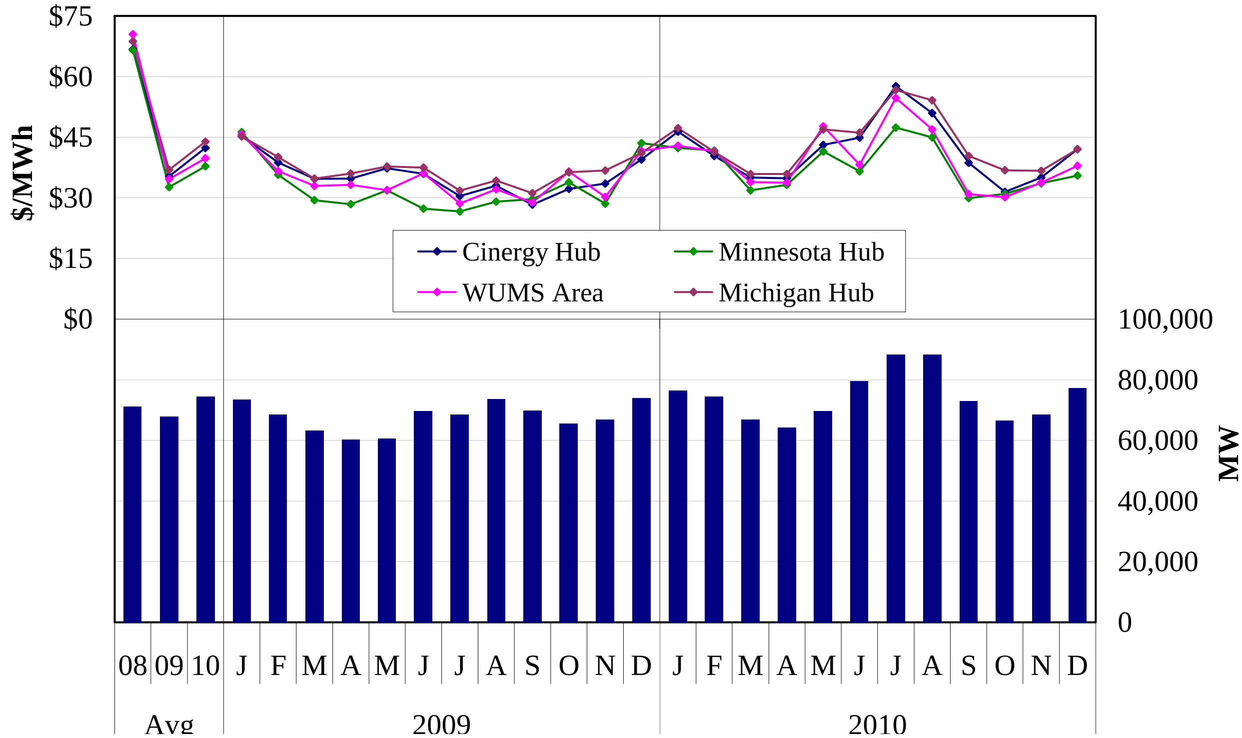
While some RTO markets operate every 15 minutes, the 5-minute interval permits more rapid and accurate response to changing conditions. In general, the 5-minute dispatch reduces the need for regulating reserves and permits greater utilization of resources. As discussed further below, however, 5-minute real-time market intervals can lead to more volatile prices.

Real-time market outcomes are also critical because they indirectly affect day-ahead market outcomes. Energy purchased in the day-ahead market (and other forward markets) is priced based on expectations of future prices in the real-time markets. Higher real-time prices, therefore, can lead to higher day-ahead and other forward market prices. Because forward purchasing is a primary risk-management tool for participants, increased volatility in the real-time market can also lead to higher forward prices by raising risk premiums in the day-ahead market.

A. Real-Time Prices and Load

We begin this subsection with an overview of real-time energy prices and average load during peak hours in Figure 25 below.

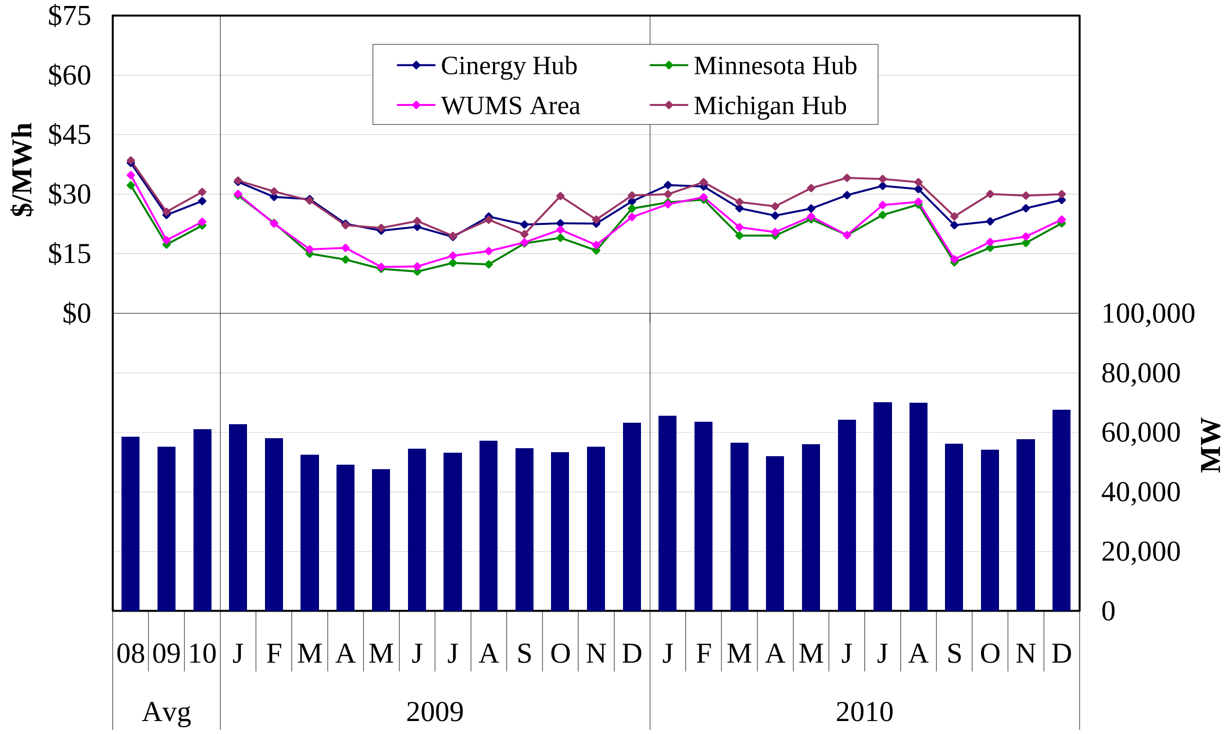
Figure 25: Real-Time Hub Prices and Load
2010: Peak Hours



The figure shows a positive correlation between peak load and peak prices. The load-weighted, real-time energy price during peak hours in 2010 was $41.43 per MWh, up 19 percent from 2009, but down 38 percent lower from 2008. As described in Section I, increases in fuel prices and summer loads were responsible for the price increase in 2010. Surplus conditions in MISO, however, limited the frequency of high-priced events. Only one Maximum Generation Alert and no Maximum Generation Events occurred in 2010.

The price differences between the hubs in the figure are caused by transmission congestion. As in the day-ahead market, west-to-east congestion prevailed throughout the year and peaked during the summer. Prices in the East Region averaged $44 per MWh, while prices in the West Region averaged only $38. This west-to-east trend is less apparent during peak hours than during off-peak hours, when higher levels of wind output and lower load contribute to excess generation conditions in the West Region. Figure 26 shows pricing and load during off-peak hours.

Figure 26: Real-Time Hub Prices and Load
2010: Off-Peak Hours



Off-peak energy prices averaged $26.49 per MWh in 2010, 36 percent lower than the average for peak hours because most of the off-peak prices are set by relatively inexpensive coal-fired resources. Like the peak prices, off-peak prices rose 19 percent from those in 2009 because of higher fuel prices and load. With only one Minimum Generation Event, system-wide negative pricing was rare in 2010.

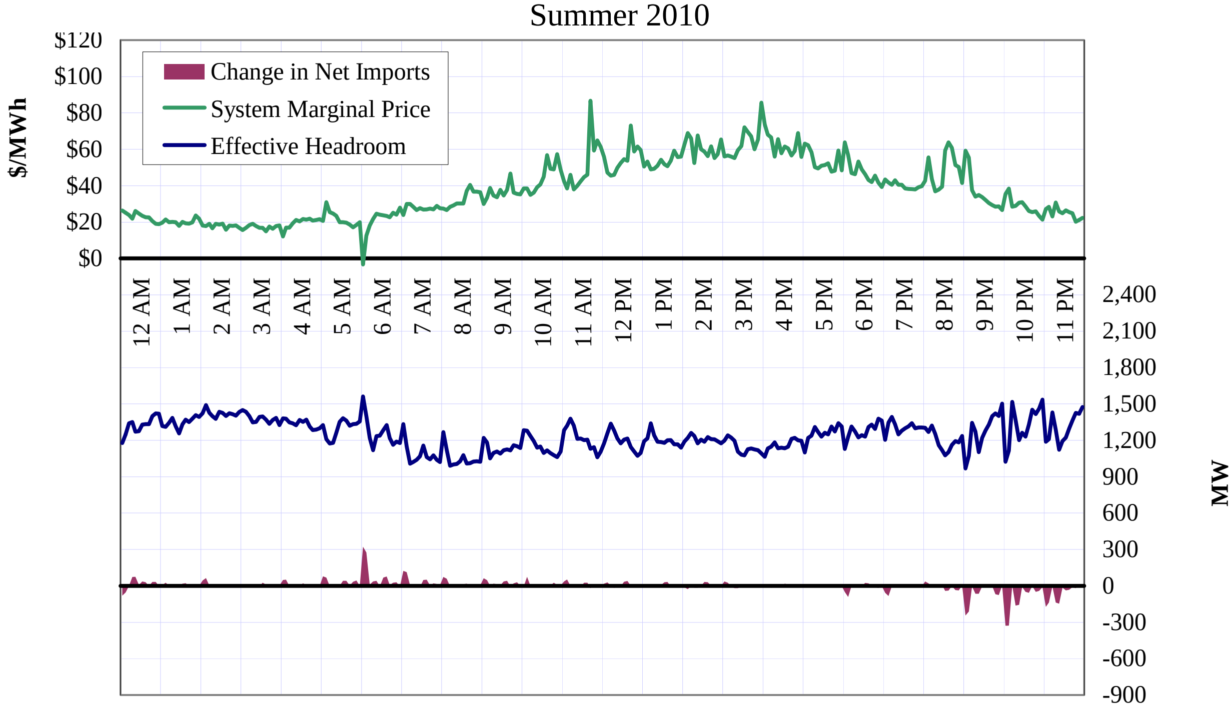
West-to-east congestion persisted throughout the year and resulted in lower off-peak prices in the western half of the footprint. Prices averaged just $22 and $23 per MWh at Minnesota Hub and WUMS Area, respectively – compared to $31 per MWh at Michigan Hub and $28 per MWh at Cinergy Hub. Congestion from the West Region resulted in more than 260 off-peak hours with negative prices at the Minnesota Hub and WUMS in 2010. Meanwhile, transmission and generator outages affecting the southwestern Michigan interface contributed to the East region having the highest off-peak energy prices in the footprint.

1. Real-Time Price Volatility

Substantial volatility in real-time wholesale electricity markets is expected because the demands of the system can change rapidly, and physical flexibility of the supply is restricted by the physical limitations of the resources and the transmission network. However, an RTO's real-time software and operating actions can significantly affect real-time price volatility. This section evaluates and discusses the volatility of real-time prices.

Figure 27 shows the interval-level, average real-time prices by time of day. Five-minute price volatility decreased substantially with the introduction of jointly-optimized energy and ancillary services markets in 2009, but it remains relatively high. The figure also shows two key drivers of price volatility: changes in NSI and the effective headroom on the system. Effective headroom is the amount of generation that can be utilized in the next five minutes, given ramp limitations.

Figure 27: Real-Time Prices and Headroom by Time of Day
Summer 2010

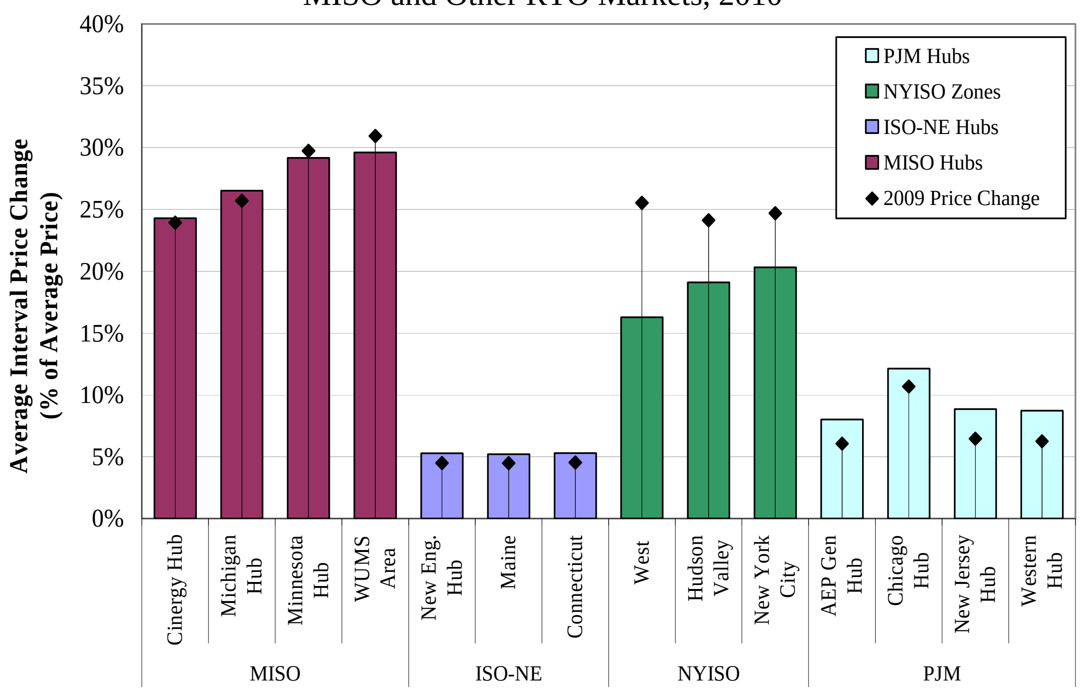


As in prior years, prices in 2010 fluctuated most when load was ramping up or down near the peak-load hour of the day (in the late afternoon during the summer). Sharp price movements frequently occur when the system is ramp-constrained, which occurs when the system's generation is increasing or decreasing to accommodate fluctuations in NSI, load, or other needs.

The dispatch model generally consumes headroom on lowest-cost (baseload) units first until these units are moving upward as fast as possible. Once these units are ramp-constrained, the market must turn to higher-cost resources that set higher prices. If all units are ramp-constrained, the market will generally exhibit a transitory shortage in one or more classes of operating reserves. These relatively high prices will fall once sufficient time has passed allowing the lowest cost units to reach their economic output levels. This price volatility can be lessened by improving the system's management of its ramp capability, which is the focus of two of the recommendations in this report.

These ramp constraints are exacerbated by generator inflexibility arising from decreases in offered ramp capability or dispatch range. The fluctuations in real-time prices, shown in the top panel, are directly related to changes in effective headroom, which often changes significantly at the top of the hour when NSI changes and the commitment and de-commitment of units are occurring. Generation de-commitment effects are largest late in the day when generators are shutting down. Figure 28 provides a comparative analysis of price volatility by showing the average percentage change in real-time prices between five-minute intervals for several locations in MISO and other RTO markets.

Figure 28: Five-Minute, Real-Time Price Volatility
MISO and Other RTO Markets, 2010



Within MISO, the figure shows that the Cinergy Hub exhibited the least volatility interval-to-interval because it was the least affected by congestion. WUMS is historically the most congested location and, in turn, exhibited the most price volatility. Overall, volatility is largely unchanged from 2009.

The figure also shows that MISO and the NYISO have the most price volatility, while ISO-NE has the least. These differences can be explained by software and operational characteristics of the various markets. MISO and NYISO are true five-minute markets with a five-minute dispatch horizon. Ramp constraints are more prevalent in these markets as a result of the shorter time to move generation. However, NYISO's real-time dispatch is a multi-period optimization that looks ahead one hour, so it can anticipate ramp needs and begin moving generation to accommodate them. We recommend a similar approach for MISO.

Despite producing five-minute prices using ex-post pricing models, PJM and ISO-NE generally produce a real-time dispatch every 10 to 15 minutes. As a result, these systems are less likely to be ramp-constrained because they have 15 minutes of ramp capability to serve system demands. Since the systems are redispatched less frequently, they are apt to satisfy shorter-term changes in load and supply more heavily with regulation. This is likely to be less efficient than more frequent dispatch cycles.

Finally, the actual load served by the real-time market can fluctuate substantially from interval to interval, which can consume a significant portion of the system's ramp capability. In some cases, these fluctuations are real and often caused by changes in "non-conforming" load. Non-conforming load is generally associated with industrial facilities that can change their consumption sharply and without advance notice.

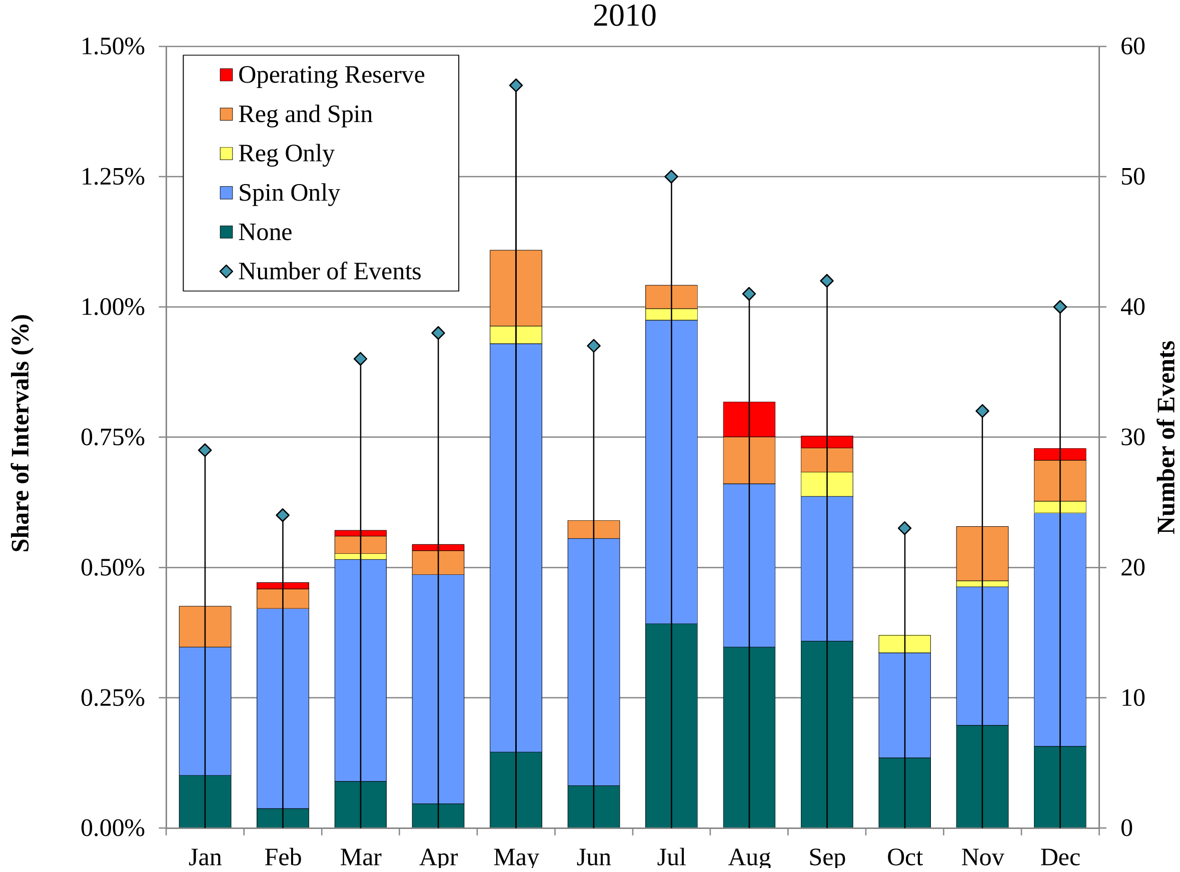
In other cases, the fluctuations are due to errors in the STLF. To reduce this source of price volatility, we recommend that MISO seek additional improvements to the STLF the real-time market uses to reduce system ramp consumed by changes in real-time load.

2. Evaluation of High Real-Time Energy Prices

In 2010, we analyzed primary causes of relatively high prices in MISO. For this study, we evaluated high-priced event that are defined as an uninterrupted period of one or more five-minute intervals characterized by an SMP greater than $175 per MWh. There were 449 such events in 2010, lasting on average 1.6 intervals. The longest event lasted eight intervals (less than one hour).

The second class of events consisted of high prices at a specific location caused by congestion. We identified these events by an LMP greater than $175 per MWh and a congestion component greater than or equal to $50 per MWh. These events were localized and occurred much more frequently. In 2010, 6,744 such events occurred, lasting 8.76 intervals on average. The longest constraint-specific locational price spike lasted 16 hours. The results of our high, system-wide price study are shown in Figure 29.

Figure 29: High-Priced SMP Events
2010

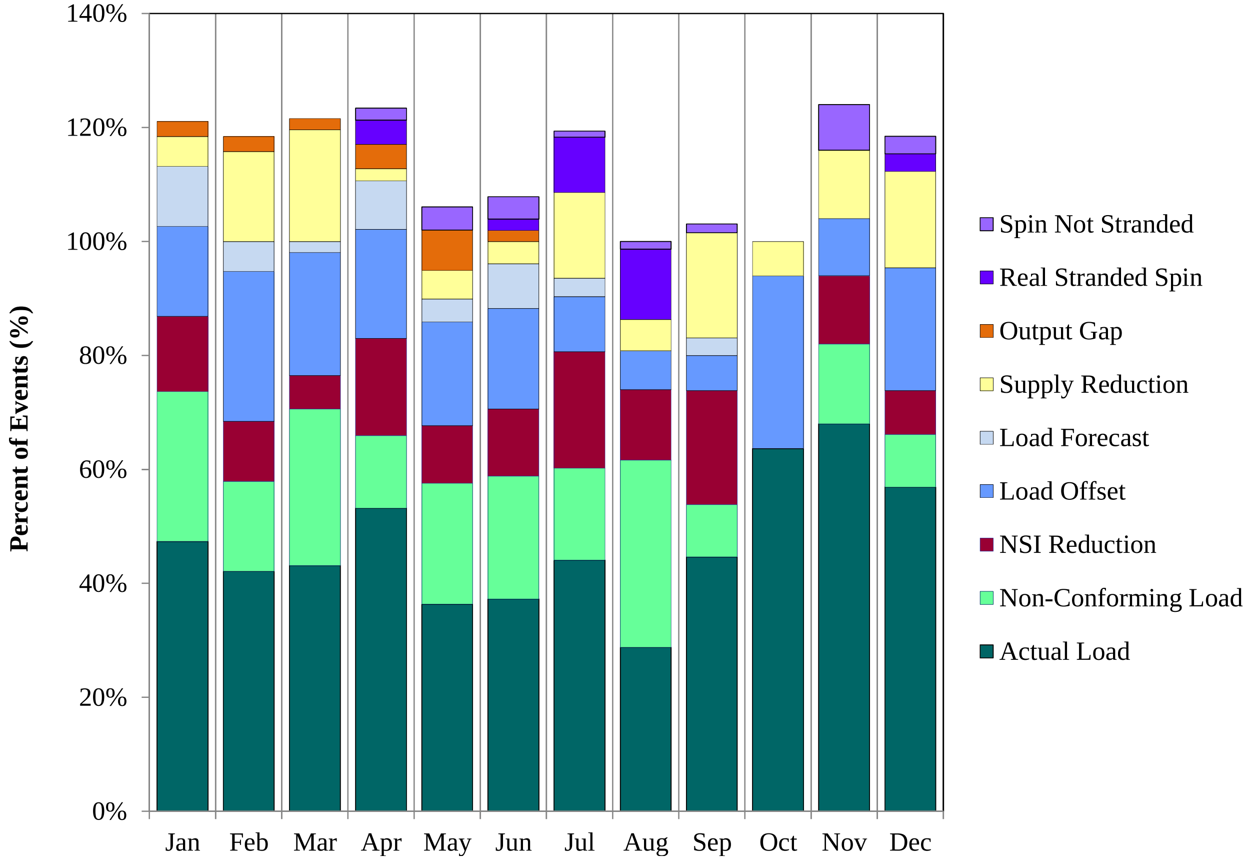


The figure indicates the number of system-wide pricing events by month, along with the types of ancillary services shortages that occurred during the events. High-priced events occurred in each month, but ranged from 23 in October to 57 in May. Since price spikes often lasted for only a single interval, the share of total high-priced intervals was less than 1 percent during most months. The number of events increased modestly during high-load summer months.

In three-quarters of high-priced intervals, the market was short one or more ancillary services product. Since the value of forgone ancillary services is included in both the ancillary service and energy prices, it is not surprising that most high prices were associated with shortages of contingency reserves or regulation. High summer loads caused nearly half of the high-priced events that did not result in a shortage. In general, the system goes into shortage in the lowest value reserve first, making trade-offs that maintain higher-value reserves. Hence, the system generally goes short of spinning reserve first (as was the case in 60 percent of 2010's high-priced intervals), then regulating reserve (12 percent), and then operating reserves (2 percent).

Figure 30 shows primary causes of high SMPs during 2010. In each high-priced event, the system is limited in its ability to ramp the necessary supply to satisfy both energy and ASM requirements. In some cases, the system could have ramped to meet system demands, but the cost to do so would have exceeded the value of one or more of the reserve products. As a result, the system procured less than the entire requirement. There are numerous factors that demand ramp from the system and thus contribute to the shortage and associated high price. Of these factors, we evaluate nine of the most significant. When one of these factors produced a ramp demand leading into the shortage greater than 300 MW, we classify that factor as a contributor to the shortage. Since more than one factor could contribute materially to the same shortage, the total exceeds 100 percent.

Figure 30: Causes of High-Priced SMP Events
2010



The most prevalent causes of high-priced events were sharp shifts in load and interchange, which accounted for over 70 percent of the high-priced intervals. Actual load contributed to 45 percent of events, while non-conforming load (a subset of actual load) contributed to an additional 18 percent. Sudden reductions in NSI occurred during 13 percent of high-priced intervals. The ramp demands originating from changes in NSI declined from prior years because MISO adjusted its criteria and procedures for evaluating and approving physical schedules.

Real-time operation of the system by MISO can also contribute to high-priced events. During 2010, the most significant operational factor was the "offset", a value used by operators to adjust the system-wide load served by the real-time market. Operator offsets contributed to a ramp shortage in 16 percent of high-priced intervals. 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 second operational factor relates to the STLF used to determine real-time market load. In 3 percent of intervals, real-time market load increased much faster than actual load, suggesting a poor forecast. Improvements made by MISO nearly eliminated the STLF as a contributor to high-priced events after July 2010.

The behavior of suppliers in MISO can also contribute to high-priced events. Supply reductions, such as outages, deratings, or decommitments, can cause the system to ramp in order to replace the lost supply. This was a contributing factor in approximately 11 percent of high-priced intervals. Potential economic withholding, as identified by the "output gap" metric, contributed only in the first half of the year, and was significant in less than 2 percent of the high-priced intervals.

Finally, spinning reserves can become "stranded" behind transmission constraints. MISO manually designates a unit to be stranded when it is expected to be behind a significant binding constraint, which causes the unit to lose its ability to provide reserve. This constraint normally has little impact on prices because the reserves can be shifted to other units at little cost. Our analysis, however, indicated that stranded spinning reserves caused a spinning reserve shortage in 3 percent of the high-priced intervals. In an additional 2 percent of intervals, spinning reserve units designated as stranded by MISO were not physically affecting any binding constraint; therefore, this reserve capability should have been available to resolve the spinning reserve shortage. MISO is evaluating enhanced tools to improve identifying and designating stranded reserve.

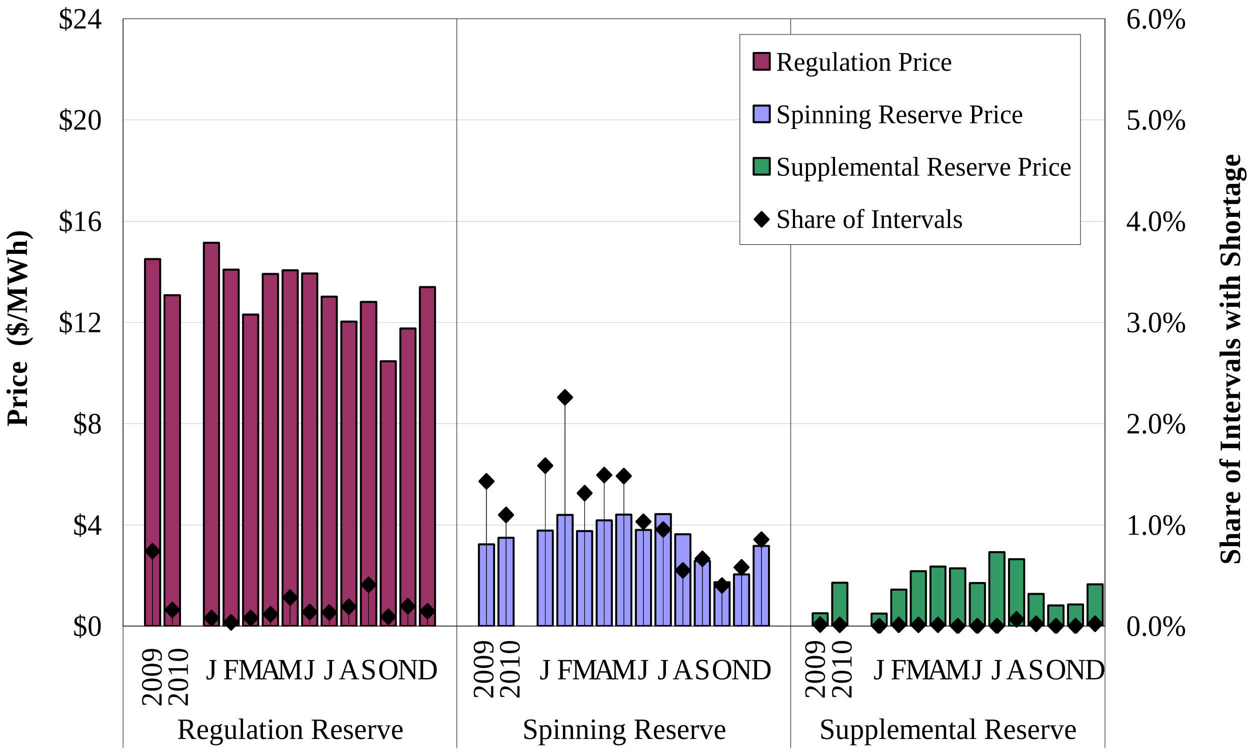
B. Ancillary Service Markets

1. ASM Prices in 2010

Figure 31 shows monthly average, real-time clearing prices for MISO's ancillary services products in 2010 and an annual comparison to 2009. Regulating and spinning reserve prices generally declined during 2010. Year-over-year regulating reserve prices decreased 9 percent to $13 per MWh due to a 79 percent decline in regulation shortages; a slight decline in the average requirement; and a decrease in the regulating reserve demand curve penalty price used to set price during shortages. Prices generally declined over the course of the year, peaking in January at over $15 per MWh and falling to as little as $10.47 in October. Zonal regulation premiums were small throughout the footprint, with the highest premiums in Zone 5 (Michigan).

Spinning reserve prices rose 8 percent in 2010 from 2009, to average $3.49 per MWh. Shortages declined during 2010, occurring in less than 1 percent of intervals after June. The price effects of the decline in shortages was offset by more consistent pricing (i.e., reduced relaxation) when shortages occurred and by higher opportunity costs of providing reserves associated with higher energy prices.

Figure 31: Real-Time Ancillary Service Prices and Shortages
2009-2010



Supplemental reserve prices rose from $0.51 per MWh in 2009 to $1.72 in 2010. Supplemental reserve prices rose in February due to a decline in the supplemental reserves offers. The reduction in offers occurred when concerns were raised by the Commission and others regarding suppliers' performance during deployments in 2009 and their ability to satisfy deployment obligations. Some suppliers reduced their offer quantities significantly in response to these concerns. In addition, higher load levels reduced the amount of offline quick-start capacity available to schedule as contingency reserves. Finally, occasional shortages of supplemental reserves, occurring mostly during ARS events in summer, resulted in slightly higher real-time prices in some months. Together, these factors resulted in significant real-time price increases in 2010.

MISO is working with stakeholders to clarify supplemental reserve deployment response obligations. It has recently filed tariff provisions to test the deployment of supplemental reserves and to cap the offer quantities at the demonstrated response during actual events or tests. Increased certainty regarding deployment obligations should allow suppliers to increase their offer quantities and lower supplemental reserve prices.

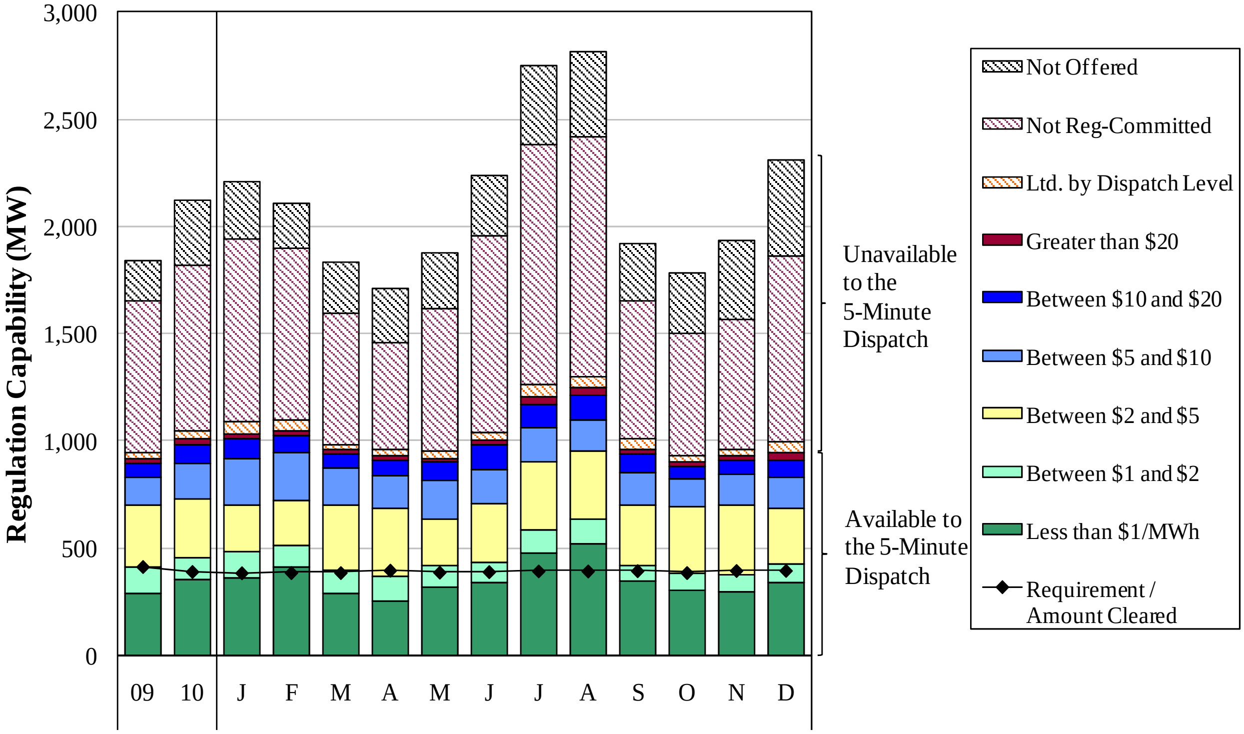
Total operating reserve shortages remained very infrequent, occurring just 13 times in 2010. Total operating reserve is the most valuable reserve class because a shortage of total operating reserve has the biggest potential impact on reliability. Therefore, starting at $1,100 per MWh, total operating reserve has the highest-priced reserve demand curve. To the extent that increasing load and unit retirements reduce the capacity surplus in MISO, more frequent operating reserves shortages can play a key role in providing long-term economic signals to invest in new resources.

2. ASM Offers

To understand the outcomes for the ASM products, we evaluate the real-time offer prices and quantities. We summarize these quantities and offer prices in this subsection, beginning with the regulation market.

Average regulation capability rose 16 percent in 2010 to 2,125 MW. However, it remained less than other operating reserves because: a) it can only be provided by regulation-capable resources, and b) it is limited to five minutes of bi-directional ramp capability. Spinning reserve can be provided by a wider range of resources and is based on ten minutes of ramp capability. In Figure 32, the solid segments of bars show capability available to be scheduled, while the hatched segments represent capability that cannot be scheduled.

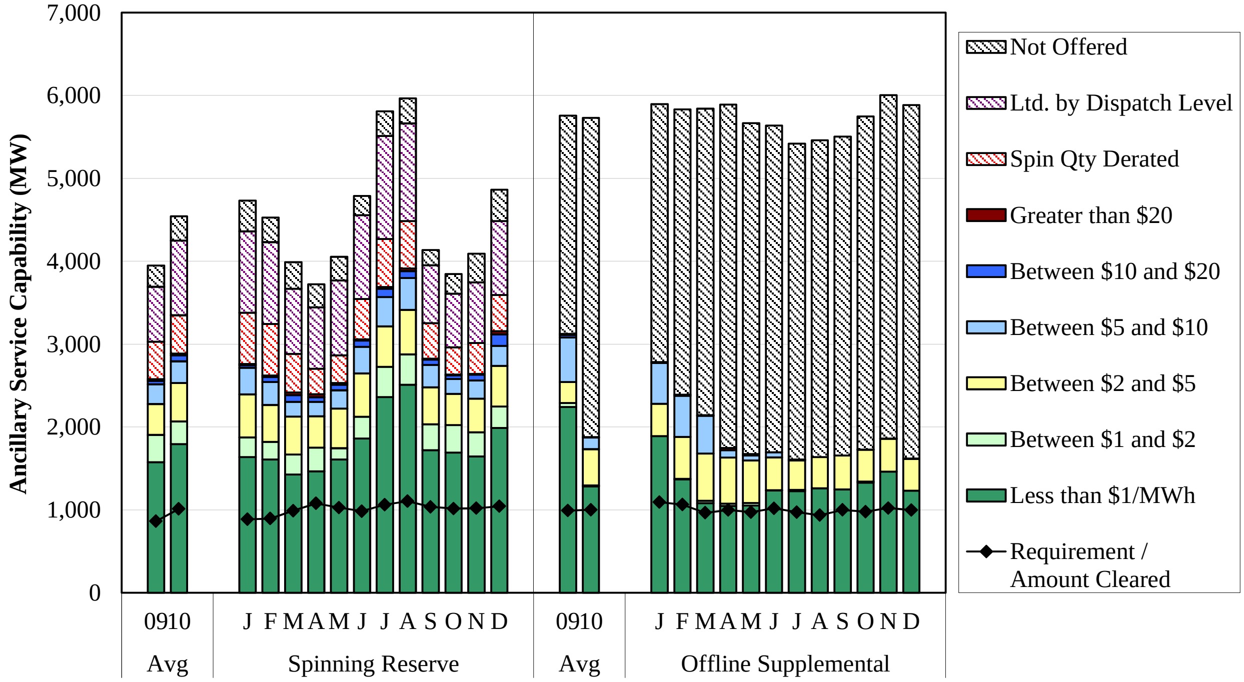
Figure 32: Regulation Offers and Commitments
2010



The figure shows that three-quarters of the unavailable regulation is due to resources not being "committed" for regulation. Commitment is the process by which MISO selects available units with regulation offers that can be included in a five-minute, real-time co-optimization for scheduling of regulation (and of other reserve products) and energy. Seasonal increases in committed regulating reserve resulted in lower cost offers (the darker green bars) becoming marginal: the marginal offer price in July and August was less than $1 per MWh. The average marginal clearing price for regulation was $13 per MWh in 2010, but sufficient capability was typically available to meet the requirement (the black line) with offers less than $2. This availability is caused by a clearing price that includes opportunity costs when resources must be dispatched up or down from their economic level to provide bi-directional regulation capability.

Figure 33 shows offer prices and quantities of qualified spinning and offline supplemental reserve available in the real-time market. The figure shows that the share of each ancillary service product that cleared the market averaged between 15 and 25 percent of the qualified capability in each month. This finding indicates that these markets are competitive because individual suppliers are unlikely to be pivotal when substantial excess capability is in the market.

Figure 33: Spinning and Supplemental Reserve Offers and Commitments
2009-2010



As with regulation, clearing prices for spinning reserve were higher than offer prices as a result of opportunity costs and ramp shortages. Clearing prices averaged $3.49 per MWh, but sufficient capability was typically available to meet the requirement with offers less than $1. The co-optimization of energy and ancillary service products, however, results in prices that often reflect opportunity costs or shortage costs. Almost half of the spinning reserves that could not be scheduled was the result of units that are operating near their dispatch maximum, thereby limiting their spinning reserve capability.

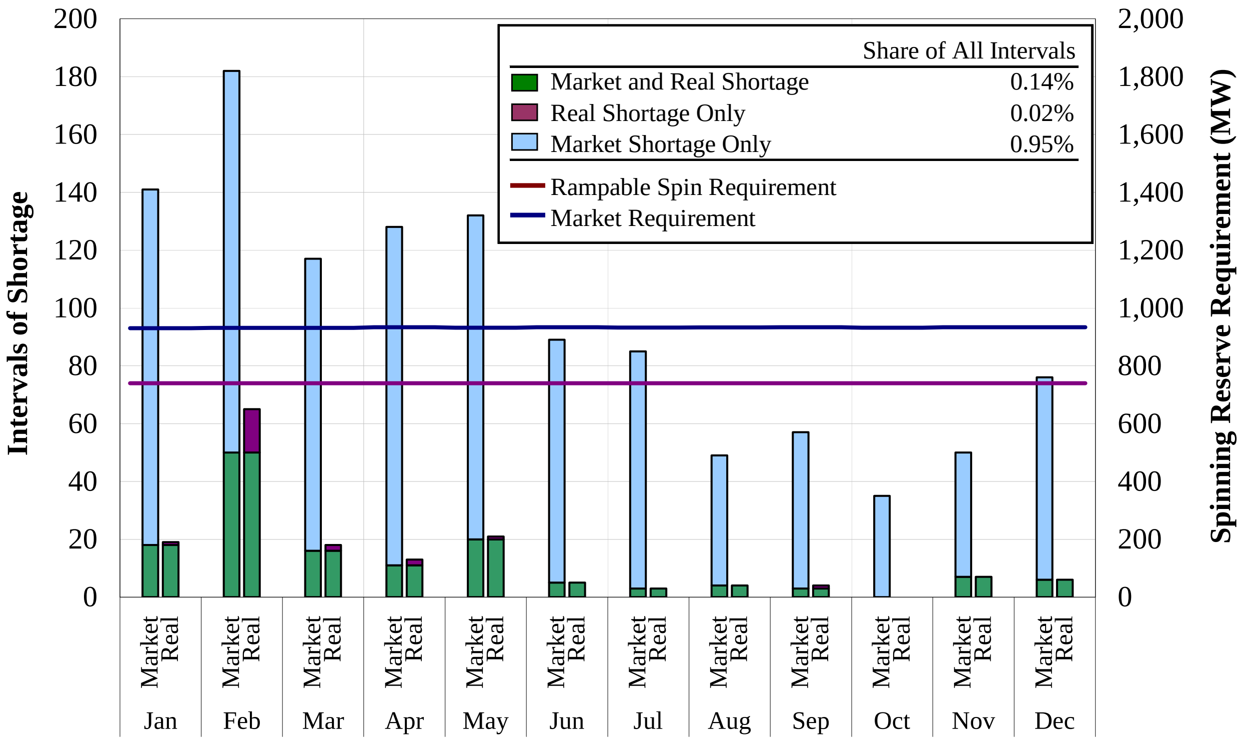
The figure also shows that over two-thirds of supplemental reserve capacity was not offered in 2010. Offers exceeded 4,000 MW per hour in March 2009, but fell by more than 50 percent due to participant concerns about meeting performance requirements during reserve deployments. MISO is establishing deployment reliability guidelines that should instruct participants on whether they should offer capability from a particular resource. Suppliers with resources that exceed the minimum level of expected deployment reliability may be deemed to be withholding if their failure to offer their resources results in a price spike for operating reserves and energy. MISO also recently filed tariff provisions to test the deployment response of supplemental reserves and cap offer quantities at the achieved response during actual or test events.

3. Evaluation of Spinning Reserve and Regulation Shortages

MISO operates with a minimum required amount of spinning reserve that can be deployed immediately for contingency response to a contingency. However, units scheduled for spinning reserves may temporarily be unable to provide the full quantity in 10 minutes if the real-time energy market is instructing them to ramp up. To account for this discrepancy, MISO maintains a market requirement that exceeds its real requirement for “rampable” spinning reserve by approximately 200 MW. As a result, market shortages can occur when MISO is not physically short, and vice versa. To minimize such outcomes, MISO should set the market requirement to make market results as consistent with real conditions as possible.

Figure 34: Market Spin Shortage Intervals vs. Rampable Spin Shortage Intervals

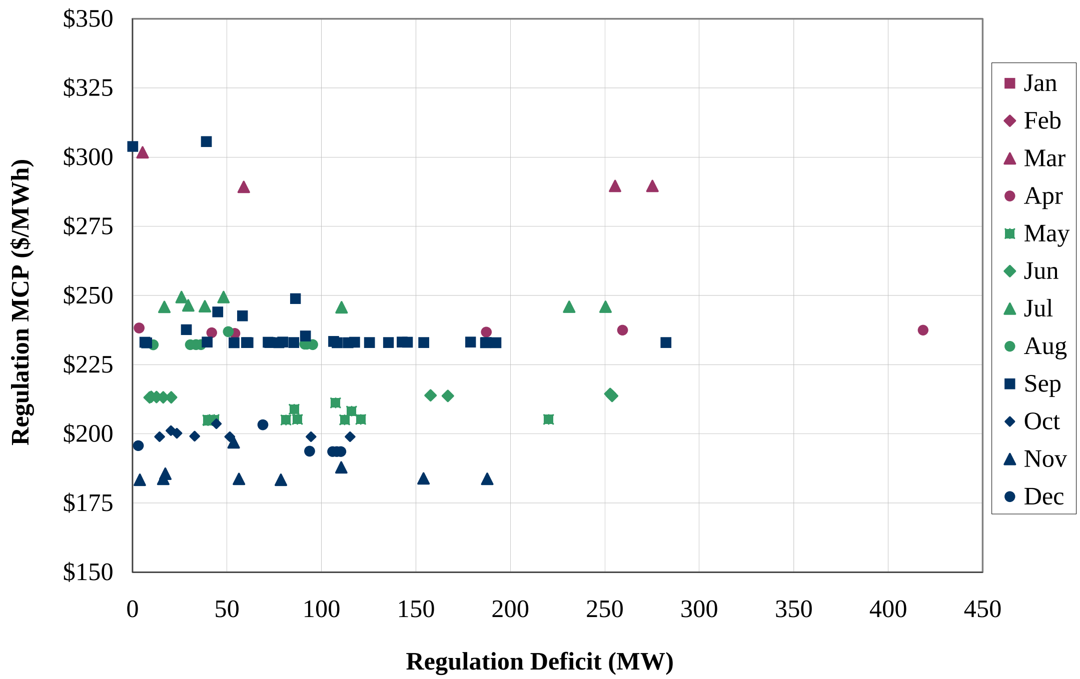
2010



To evaluate how well MISO has satisfied this general objective, Figure 34 shows all intervals with either a real or a market shortage in 2010. Real shortages occurred in 0.16 percent of intervals, a 50 percent decrease from 2009. However, market shortages occurred in more than 1 percent of all intervals, indicating most of market shortages were not real shortages. These results indicate that consistency between market and real shortages could be improved, which would, in turn, improve the market's economic signals. Hence, we recommend that MISO improve the consistency between the two requirements by setting the market requirement dynamically or, alternatively, by reducing the difference between the two requirements.

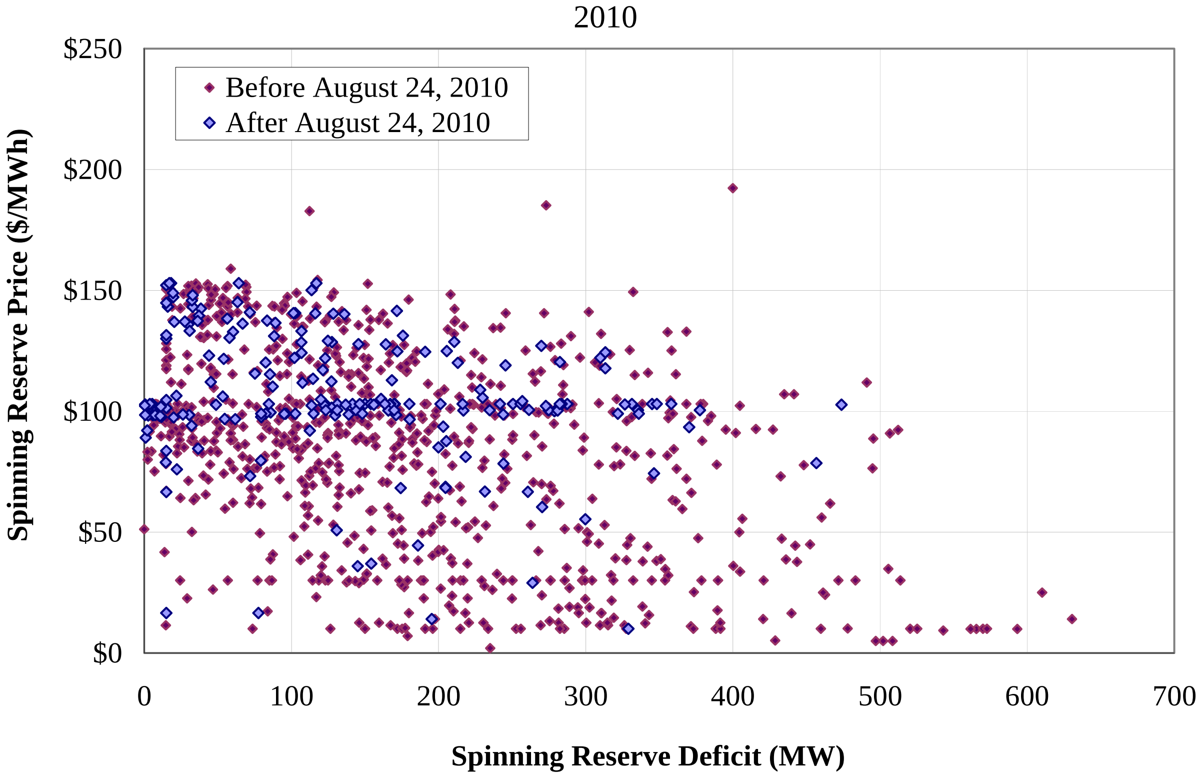
In assessing regulation pricing during shortages, we found actual regulation shortages occurred in just 166 intervals in 2010 (i.e., in less than 0.2 percent of all intervals). The 166 intervals of shortages represent almost an 80 percent decline from 778 in 2009. This decrease was due to the increased in flexibility from removal of dispatch bands in March 2010; high regulation commitment levels; and fewer hours with very low loads in 2010 (when few regulation-capable units were online). In general, shortage amounts were small, averaging under 100 MW. Figure 35 shows the regulation price during shortage intervals for 111 intervals when the market was not concurrently short of spinning reserve. Each month is indicated by a separate marker.

Figure 35: Regulation Deficits and Prices
2010



The regulation price during shortage intervals is equal to the regulation penalty price, which averaged $226 per MWh, plus the spinning reserve price. The regulation penalty price is calculated monthly by MISO per a Tariff formula intended to reflect the commitment cost of a peaking resource. The calculated regulation penalty price fell consistently throughout 2010. The figure shows that regulation shortage prices were consistent with the monthly penalty price regardless of deficit size. Such consistency is appropriate and reflects the fact that MISO does not relax the requirement during shortages. Figure 36 plots similar price-quantity results for each spinning reserve shortage in 2010.

Figure 36: Spinning Reserve Deficits versus Spinning Reserve Prices



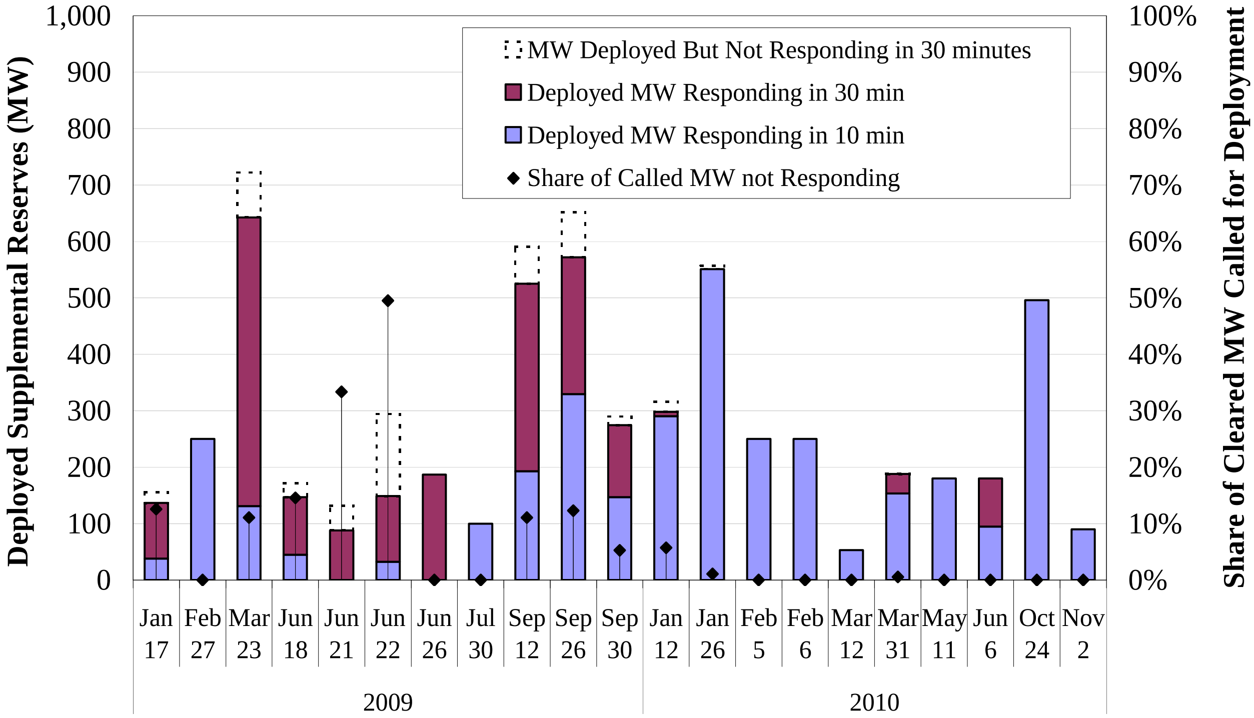
Shortages generally occur when the demands on the system cause the real-time market to have insufficient ability to ramp up online resources to satisfy its energy and spinning reserve requirements. In these cases, spinning reserve prices should theoretically reflect the reliability cost of being short of the required reserve. In 2010, this value was administratively set at $98 per MWh. Beginning in February 2010, MISO implemented an additional penalty constraint priced at $50 per MWh that required at least 90 percent of the spinning reserve to be met by generating resources (as opposed to DR). These constraints prevent the real-time market from taking actions more costly than $148 per MWh plus the prevailing operating reserve clearing price to maintain its spinning reserve. Although maximum efficiency is achieved when prices are set at the penalty price (i.e., the cost for a system-wide spinning reserve shortage), this does not always occur because MISO "relaxes" its spinning reserve requirement when it is short. In August 2010, a modeling change was implemented to reduce the relaxation in order to improve pricing during spinning reserve shortages.

In 2010, spinning reserve shortages occurred 1,141 times (1.1 percent of all intervals), down from more than 1,500 in 2009. Almost 70 percent of shortages occurred during peak hours, when system ramp needs were greatest. Figure 36 shows the shortage quantity and price for the 1,068 shortages in 2010 when the regulating reserve and total operating reserve were not in shortage. Shortage prices after the August modeling change are clustered much more consistently around the $98 and $148 per MWh price points, indicating that the relaxation algorithm did not impact price as much as it had previously. Prices prior to the change were widely dispersed, and many of the largest deficits were priced the lowest. The largest of these shortages (630 MW) was priced at just $14 per MWh. In all, 205 of these spinning reserve shortages were priced at less than $50, suggesting that the relaxation methodology had been distorting spinning reserve shortage prices. MISO is in the process of developing a true demand curve for spinning reserve which should further improve shortage pricing.

4. Supplemental Reserve Deployments

Supplemental reserves are deployed during Disturbance Control Standard and ARS events. In line with prior years, 10 such deployments occurred in 2010. Figure 37 shows the response of the supplemental reserves deployed, separately indicating those that were successfully deployed within 10 minutes (as required by MISO) and within 30 minutes (as required by NERC). In response to poor 2009 performance and a recommendation of the IMM, MISO implemented improved measurement and verification procedures in 2010.

Figure 37: Non-Responsive Supplemental Reserve Deployments
2009-2010

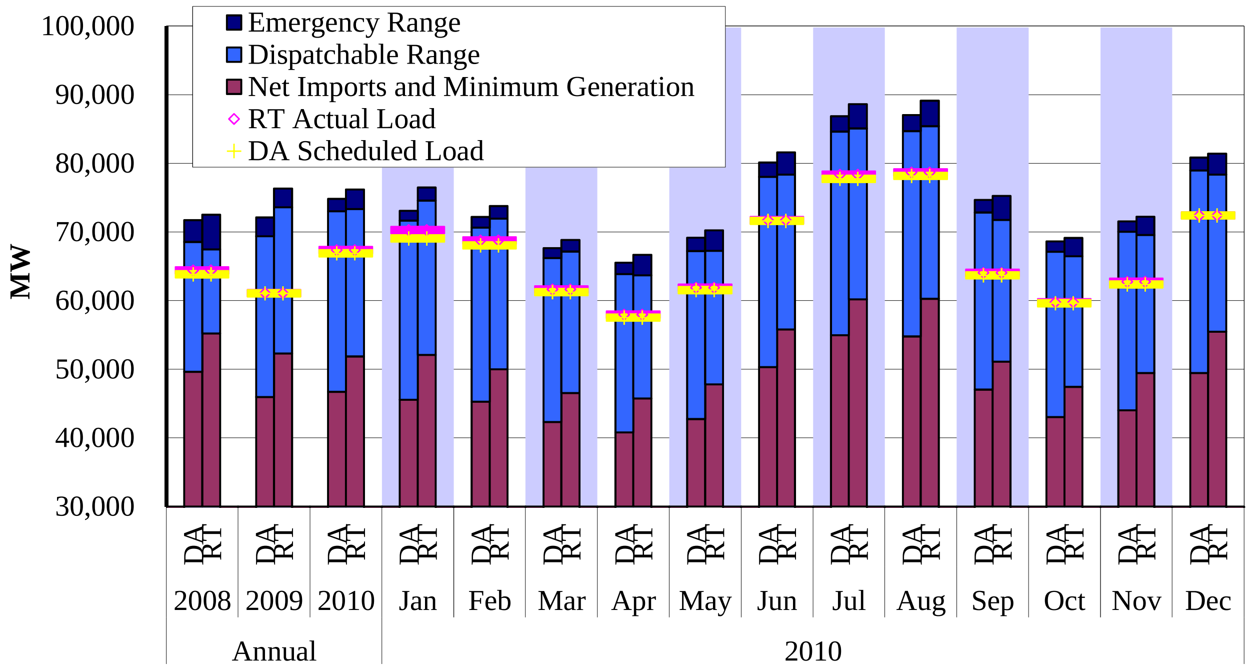


Supplemental reserve deployment response improved markedly in 2010. On average, 94 percent of the reserves were successfully deployed within 10 minutes, up from just 36 percent in 2009. In all, 99 percent of deployed reserves (i.e., all but 25 MW) were successfully deployed within the 30-minute NERC requirement. In contrast, only 87 percent had been successfully deployed in 2009. The improvement is encouraging because the lack of response can impact reliability and raise concerns that some suppliers may be selling reserves that they are incapable of deploying. Since offered quantities decreased substantially in 2010, these results may indicate that only comparatively more capable resources are still being offered.

C. Availability of Generation in Real Time

The availability of generation in the real-time market is important because it enables MISO to redispatch the system to manage transmission constraints, while satisfying all energy and operating reserves requirements. In general, the day-ahead market coordinates the commitment of most generation that is dispatched in real time. Figure 38 details the average monthly generation scheduled in the day-ahead and real-time markets.

Figure 38: Day-Ahead and Real-Time Generation
2010: All Hours

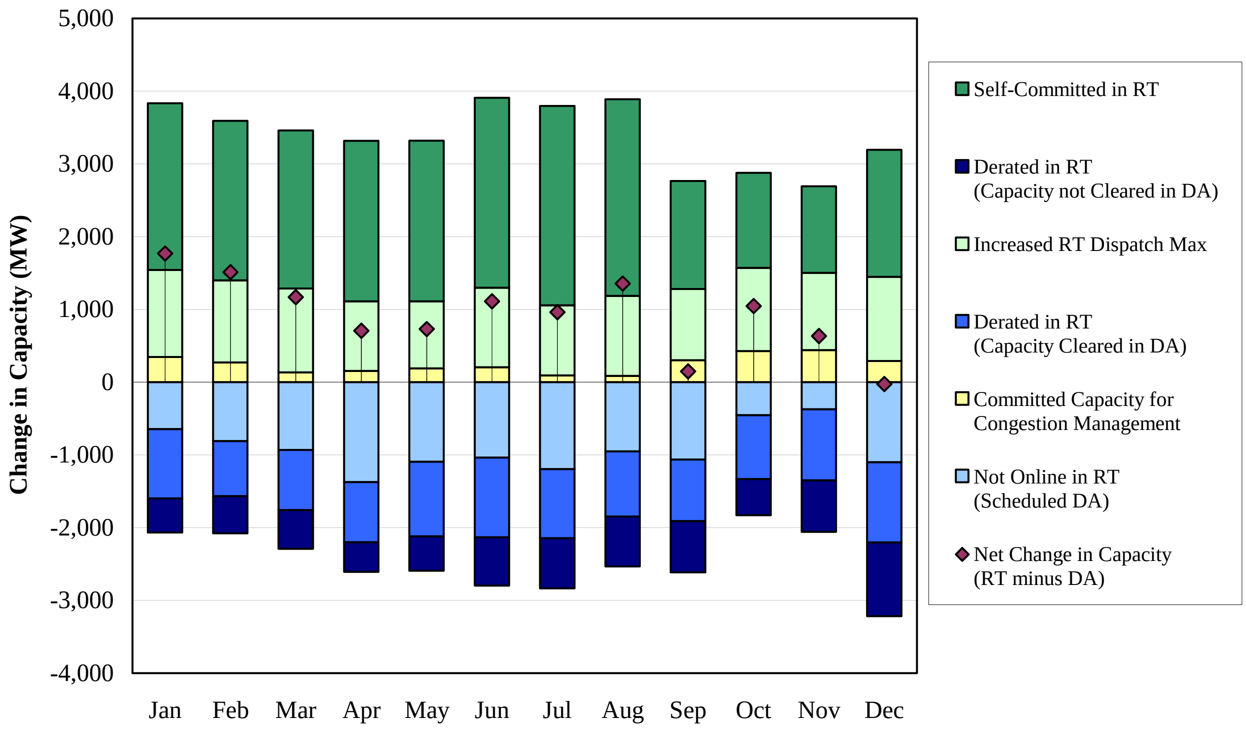


Generation capability is consistently greater in the real-time than in the day-ahead market. This situation occurs because participants self-schedule some resources after the ISO completes commitments generation in the day-ahead market. On a market-wide basis, MISO commits generation after the day-ahead market when: (1) load is higher than expected; (2) load is under-scheduled in the day-ahead market; or (3) net virtual supply scheduled in the day-ahead market must be replaced in real time. In addition, MISO often commits additional generation to manage congestion or satisfy local system reliability needs.

On a monthly basis, the generation committed in real time declined in 2010 as a result of the day-ahead headroom commitment logic implemented on April 21. During the first three months of 2010, the average increase in real-time supply (excluding the emergency range above a generator’s economic maximum) was 2 GW per hour. From May to December, only 300 MW of additional supply was committed in the real-time market. The figure also shows that the average dispatchable range (i.e., the range between each online unit’s economic maximum and minimum) decreased from day ahead to real time. This reduction was partly due to wind generation, which is considered self-scheduled output in real time, but can offer dispatchable range in the day-ahead market. Wind generation accounted for an hourly difference of 1.5 GW in dispatch range between the day ahead and real time.

Figure 39 shows our further evaluation of changes in supply availability after the day-ahead market. These changes are important because they can compel MISO to commit additional capacity in real time. On average 2.5 GW, or 4 percent, of capacity scheduled in the day-ahead market was unavailable in real time during 2010. This level of availability is comparable to prior years and is attributable partly to forced outages, decommitments, or deratings after the day-ahead market. In addition, suppliers scheduled day ahead sometimes decided not to start their units in real time, but instead to buy back energy at the real-time price. The capability lost in real time was more than offset on average in each month by almost 1 GW of capacity increases from suppliers increasing their dispatch maximum in real time, as well as 2 GW of self-scheduled resources.

Figure 39: Changes in Supply, Day-Ahead to Real-Time
2010

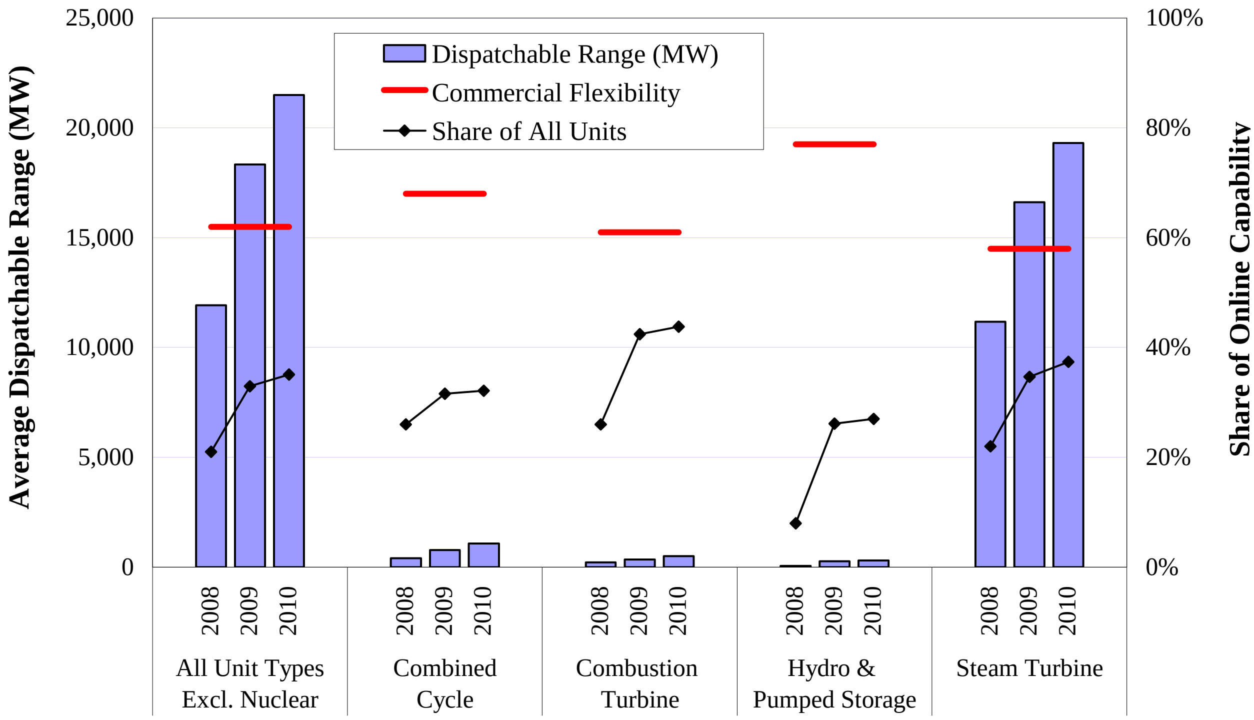


The difference in an online unit's economic maximum and minimum dispatch (i.e., its dispatchable range) is important because it provides the flexibility needed to follow load and to manage congestion. An analysis of the 2008 to 2010 period shows dispatch flexibility increased substantially across all unit types in 2009 and the increased flexibility continued in 2010. ASM contributed to the increased flexibility because:

- The quantity of ASM products a supplier can sell is based on a unit's dispatch range and ramp rates;
- The PVMWP ensures generators are not harmed by responding flexibly to MISO dispatch instructions when prices are volatile; and
- The output ranges previously held out of the real-time market to provide ancillary service are now available to the real-time market and co-optimized with energy.

The figure also shows "commercial flexibility", which reflects the maximum dispatchable range that could be offered physically according to data provided to MISO. The results show that the vast majority of MISO's flexibility was provided by steam units. Flexibility remains lower than the full physical flexibility that many generators could provide. The effects of losses in flexibility on MISO's ability to manage congestion are evaluated later in the report.

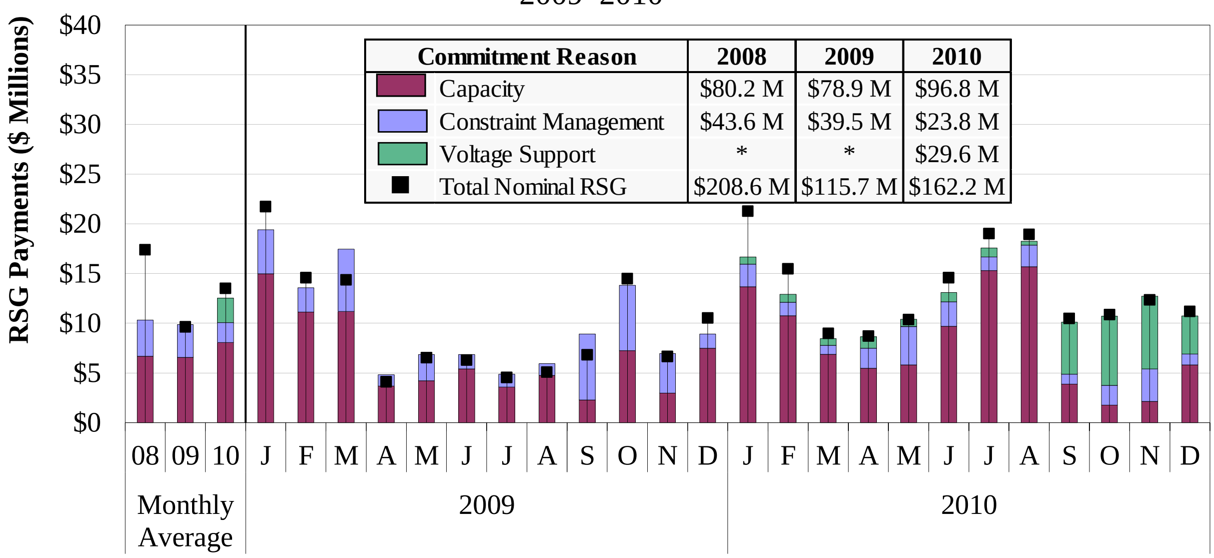
Figure 40: Real-Time Dispatchable Range
2008–2010



D. Revenue Sufficiency Guarantee Payments

This subsection reviews RSG payments that are made to generators committed by MISO when market revenue in the applicable MISO market is insufficient to cover generators' as-offered production costs. Resources that are not committed in the day-ahead market but must run to maintain reliability are the most likely recipients of RSG payments. These are called "real-time" RSG payments because such units receive their LMP (and ASM) revenues from the real-time market. Because the day-ahead market is financial, units that are uneconomic are generally not selected so it generates minimal RSG costs. Peaking resources are the most likely to warrant an RSG payment because they are generally the highest-cost resources and, even when setting price, receive minimal LMP margin to cover their startup and no-load costs. Additionally, peaking resources frequently do not set the energy price (i.e., the price is set by a lower-cost unit), which increases the likelihood that an RSG payment may be required. Figure 41 and Figure 42 show RSG payments in the real-time and day-ahead markets, respectively.

Figure 41: Total Real-Time RSG Payment Distribution
2009–2010



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

Peaking Units	62	63	52	57	66	50	48	67	69	48	60	67	79	69	68	56	53	57	56	62	49	69	71	42	22	24	45
Other Units	38	37	48	43	34	50	52	33	31	52	40	33	21	31	32	44	47	43	44	38	51	31	29	58	78	76	55

Results in Figure 41 are divided between RSG payments to peaking and non-peaking units. We also distinguish between payments made to commit resources for overall capacity needs versus to manage congestion or to satisfy a local reliability requirement. To exclude effects from fuel price changes, these figures adjust the RSG costs for changes in fuel prices (based on 2010 year-end fuel prices).

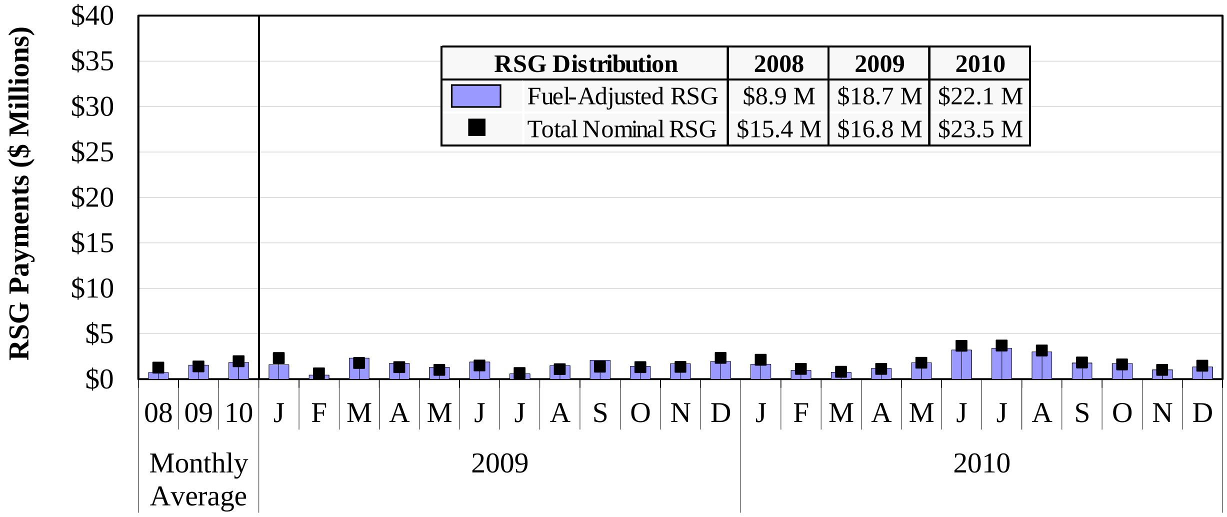
The figure shows that real-time nominal RSG costs in 2010 rose 40 percent to $162 million. Over 85 percent of RSG costs were generated in the real-time market, over half of which was paid to peaking resources even though they had generated only 1 percent of total energy in 2009. This is expected because the commitments needed for reliability occur after the day-ahead market when peaking resources are the primary available resources. Higher fuel prices accounted for much of the rise in real-time RSG costs – fuel-adjusted RSG costs rose only 27 percent. The remaining increase was largely due to substantially higher commitment costs during the high-load summer months, as well as to increased costs associated with non-peaking resources committed for local reliability.

Nearly half of real-time RSG payments in 2010 were made to non-peaking units, up from approximately one-third in 2008 and 2009. This increase was primarily due to substantial payments (totaling $29.6 million) to non-peaking resources committed from September to December to provide localized voltage support to the system. These payments are evaluated further in Section VI of the report. As in 2009, two-thirds of fuel-adjusted, real-time RSG payments were made to units committed for capacity purposes. Less than full load scheduling early in the year and high summer loads resulted in considerable capacity commitments after close of the day-ahead market.

Figure 42 summarizes the RSG costs generated in the day-ahead market. This figure shows that nominal day-ahead RSG costs increased by 40 percent to $23.5 million. The increase is attributable to greater commitments from day-ahead headroom commitment software deployed in April. However, day-ahead RSG costs continue to be a small percentage of total uplift costs in the market.

Figure 42: Total Day-Ahead RSG Payment Distribution

2009–2010



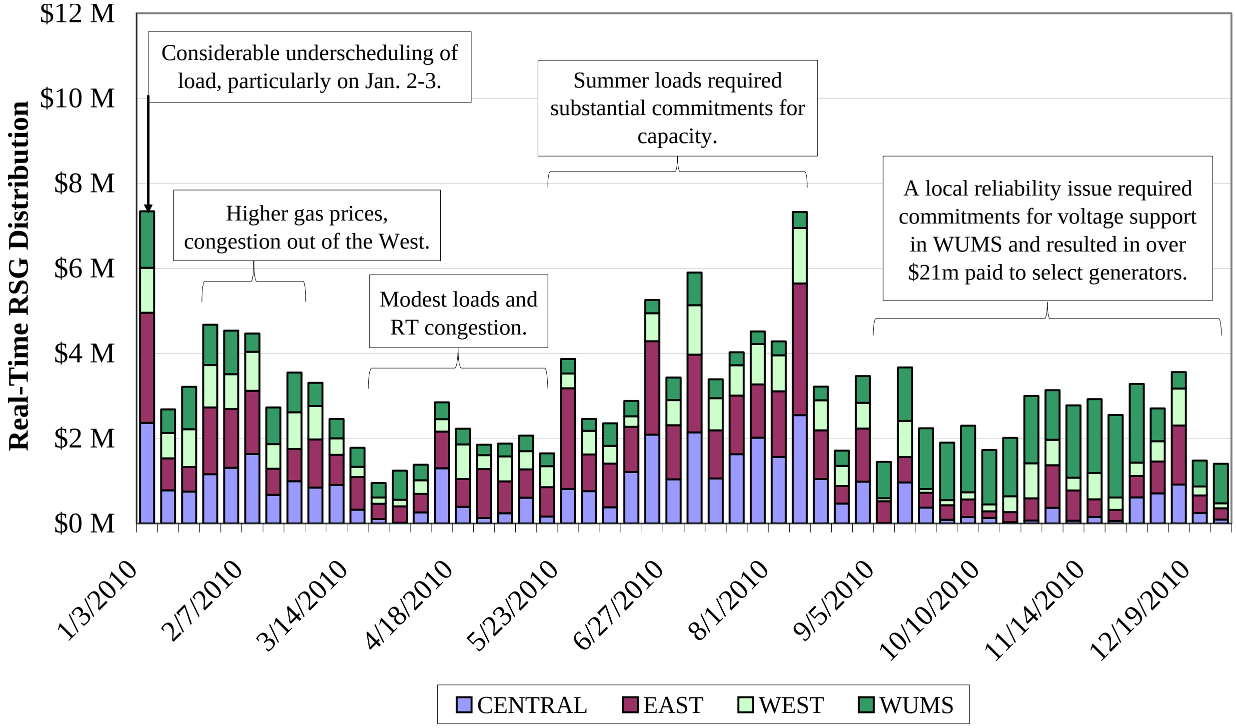
Share of Day-Ahead RSG Costs by Unit Type

Peaking Units	13	6	14	3	2	1	1	16	14	4	11	8	5	4	3	4	0	2	3	14	11	26	35	10	3	3	9
Other Units	87	94	86	97	98	99	99	84	86	96	89	92	95	96	97	96	100	98	97	86	89	74	65	90	97	97	91

To better illustrate trends in RSG costs, Figure 43 analyzes real-time RSG distribution data by week and region. Overall, real-time RSG payments were consistent with load patterns. Higher fuel prices and periodic under-scheduling contributed to elevated RSG payments early in 2010. In addition, congestion on constraints out of the West Region also required real-time commitments. In summer, high actual loads combined with modest day-ahead under-scheduling compelled additional commitments in real time, predominantly in the East and Central Regions.

Regionally, RSG payments were nearly unchanged in the East Region but increased elsewhere. Payments rose fastest (by 78 percent) in the West Region. As a result, just 57 percent of payments were in the East or Central Regions, down from 71 percent a year ago. Nevertheless, more RSG payments were made to resources in the East Region than in any other region in 2010, due in part to continued transmission upgrades and other unplanned outages. Payments in WUMS rose precipitously in September and were associated with commitments to provide voltage support. This voltage issue required commitment of non-peaking units and resulted in over $25 million in payments. Market power issues related to these types of commitments are evaluated in greater detail in Section VI.

Figure 43: Weekly RSG Payment Distribution by Region
2010

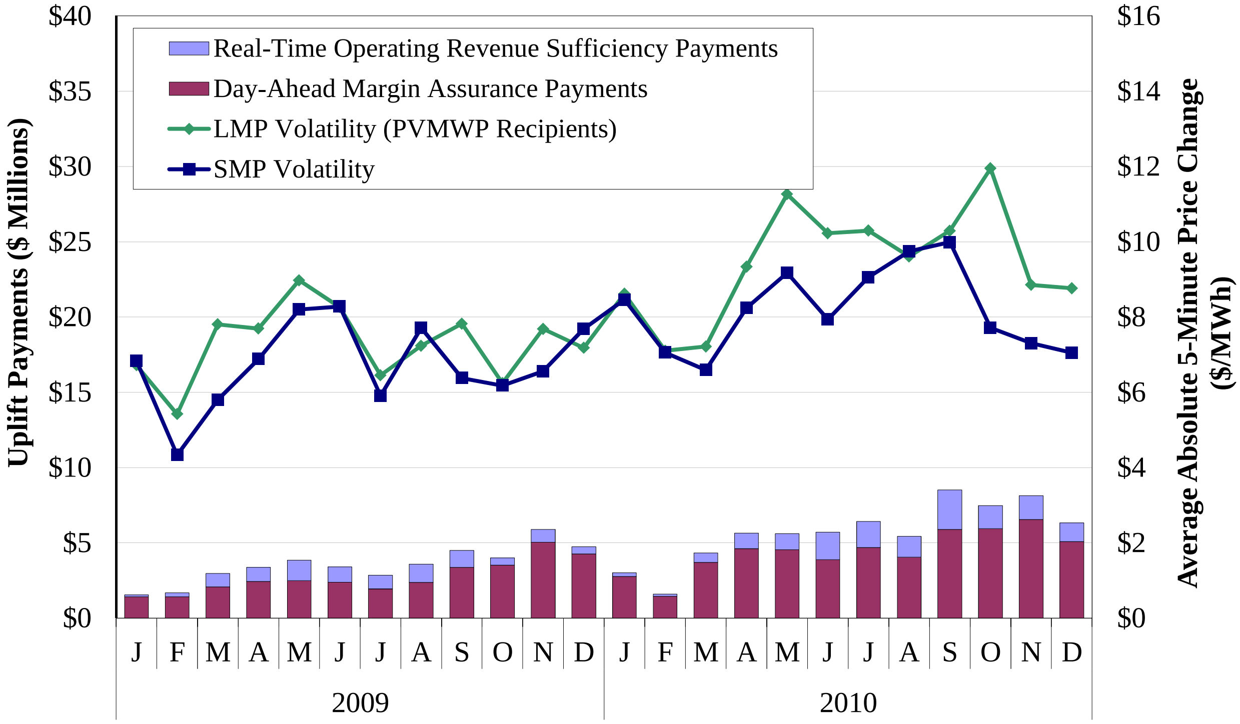


E. Price Volatility Make-Whole Payments

MISO introduced the PVMWP in 2008 to ensure adequate cost recovery from the real-time market for resources offering dispatch flexibility. The payment ensures that suppliers responding to MISO's prices and following its dispatch signals in real time are not harmed by doing so. The payment should, therefore, eliminate a generator's incentive to be inflexible. The PVMWP consists of two separate payments: DAMAP and RTORSGP.

The DAMAP is paid to a resource dispatched to a level below its day-ahead schedule in a manner that erodes its day-ahead margin because the hourly real-time price is less than its as-offered costs. Conversely, the RTORSGP is made to a qualified resource that is unable to recover its incremental energy costs when dispatched to a level above its day-ahead schedule. Opportunity costs for avoided revenues are not included in the payment. These payments rose a combined 60 percent in 2010, as shown in Figure 44. DAMAP totaled $53.2 million, while RTORSGP totaled over $15 million. The lines on the figure show price volatility based on: the system marginal price and one based on the LMPs at generator locations receiving PVMWPs.

Figure 44: Price Volatility Make-Whole Payment
2009-2010



The figure shows that payments are correlated with price volatility, which largely explains why the payments have increased. When volatility increases, the payments to flexible suppliers following dispatch will tend to increase. In addition, LMP volatility is higher at recipients' locations as expected, since they are generally asked to move more than other suppliers due to the larger price fluctuations. These increases also highlight the importance of making improvements in the operation of the system that will tend to reduce price volatility. This report recommends two such improvements.

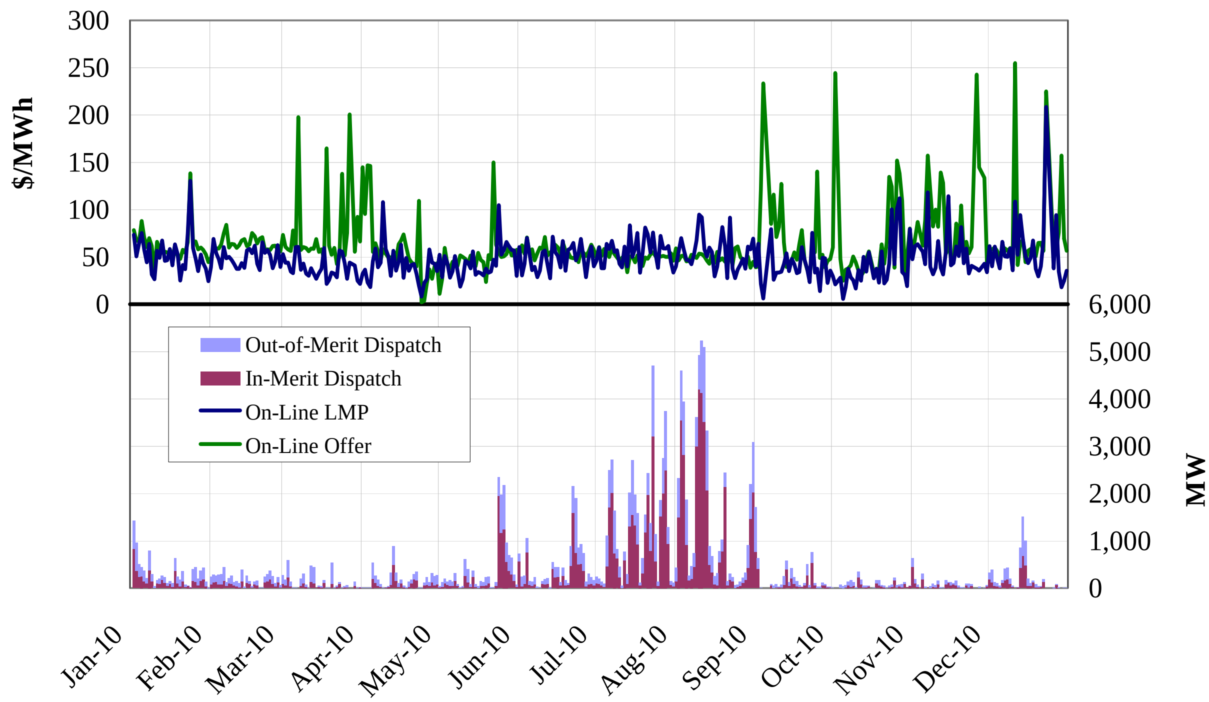
After investigating the PVMWP increases and the rules governing payments, we recommended changes to provide better incentives and reduce opportunities for gaming. These recommended changes included eliminating RTORSGP to deployed operating reserves. This change would improve efficiency by causing expected deployment costs to be included in participant offers, thereby minimizing total costs (including deployment costs). In 2010, the largest recipient of RTORSGP was a DR resource that began selling spinning reserve midyear and was paid nearly $1 million when deployed to cover energy curtailment costing $500 per MWh.

We separately identified in a Tariff flaw that gives participants an undue opportunity to game DAMAP. Specifically, participants can trigger a DAMAP by making a low day-ahead offer understating production costs, and then making a correspondingly higher real-time offer, compelling MISO to reduce its real-time output. MISO has filed with the FERC to address this issue by deducting from the DAMAP the higher of the day-ahead or real-time production costs (rather than just the day-ahead costs). This change can prevent suppliers from improperly extracting DAMAP based on real-time output reductions that are solely from their own actions, while continuing to provide proper incentives for flexible offers in real time. In addition, we have identified an additional gaming issue that MISO is currently evaluating.

F. Dispatch of Peaking Resources

Real-time demand is often satisfied by supplemental generator commitments, typically in the form of quick-start peaking resources, because their commitment is low in costs but high in flexibility. Dispatch of peaking resources is important because it is a significant determinant of RSG costs and affects energy prices. Figure 45 shows average daily dispatch levels of peaking units in 2010 and evaluates the consistency of peaking unit dispatch and market outcomes.

Figure 45: Average Daily Peaking Unit Dispatch and Prices
2010: All Hours



In 2010, an average of 465 MW was dispatched per hour, an increase of 105 percent from 2009 when the hourly dispatch averaged 227 MW. The principal reason for this year-over-year growth was higher summer loads due to relatively hot temperatures in 2010. Nearly two-thirds of all peaking unit commitments occurred during the high-load summer months, when more generation capacity was needed to meet the system's needs. In May to September, an average of 1,200 MW was dispatched. Two other factors contributed to increased dispatch of peaking resources. First, less than full load scheduling, particularly in July and August, increased the need for real-time commitments. Second, an increase in real-time transmission congestion resulted in more commitments for localized congestion management.

The figure also provides an evaluation of the consistency between peaking resource dispatch and market outcome. The top panel compares average LMP at the peaking resources' locations (referred to as "Online LMP" in the chart) to average offer price of the dispatched peaking resources (referred to as "Online Offer"). In the bottom panel, we show shares of peaking resource output that are in-merit order (when the resource LMP is greater than offer price) and out-of-merit order (when the resource LMP is less than offer price).

Most peaking resources were dispatched in-merit order in 2010, which is unusual. Approximately 40 percent were out-of-merit in 2010, compared to 67 percent in 2009. The higher in-merit share in 2010 was due to the large share of peaking resource dispatch that occurred during high-load periods in the summer when peaking resources were more likely to set price. Under the majority of conditions, however, peaking resources are typically dispatched out-of-merit because they cannot set prices when they run at their economic minimum or maximum (gas turbines often have a very narrow operating range).

When peaking or demand-response resources are the most economic option for meeting market demand but do not set price, real-time prices can generally be inefficiently low. This condition affects incentives to schedule load in the day-ahead market and ultimately determines the commitment of resources in the day-ahead market. A suboptimal commitment coming from the day-ahead market tends to raise real-time production costs. Inefficiently low real-time prices when peaking resources are dispatched also distorts incentives of participants to import and export power efficiently. We have recommended changes to improve real-time pricing by allowing peaking resources and demand resources to set prices. MISO has done substantial work to develop a feasible approach in this area with its Enhanced LMP initiative.

G. Wind Generation

Wind generation and capacity have grown rapidly in MISO market since its inception. Wind resources now account for 6 percent of installed capacity (approximately 9.2 GW) and 3.5 percent of generation, producing up to 6,700 MWh. This growth trend is expected to continue with the prevalence of abundant wind capability in western areas of the footprint, favorable existing federal and state mandates, and various subsidies and tax incentives. In addition, future federal carbon and energy policies are apt to encourage further wind generation. Although wind generation promises substantial environmental benefit, these resources are intermittent. As such, wind generation presents particular operational, forecasting, and scheduling challenges that most conventional resources do not. Intermittent resources are by definition prone to changes in output that can result in system reliability and congestion management problems. These challenges are amplified as wind's portion of total generation increases.

In the day-ahead market, intermittent resources can submit offers (accompanied by generation forecasts) and can be designated as capacity resources under Module E of the Tariff at an 8 percent capacity factor.[17] In real time, however, they cannot schedule offers, be committed, follow setpoint instructions, or be dispatched by the real-time market. As a result, the market generally does not coordinate the production of intermittent resources. Instead, MISO relies on rule-based methods in the commitment and scheduling algorithms to relax lower priority requirements and utilizes manual dispatch when necessary to ensure reliability.

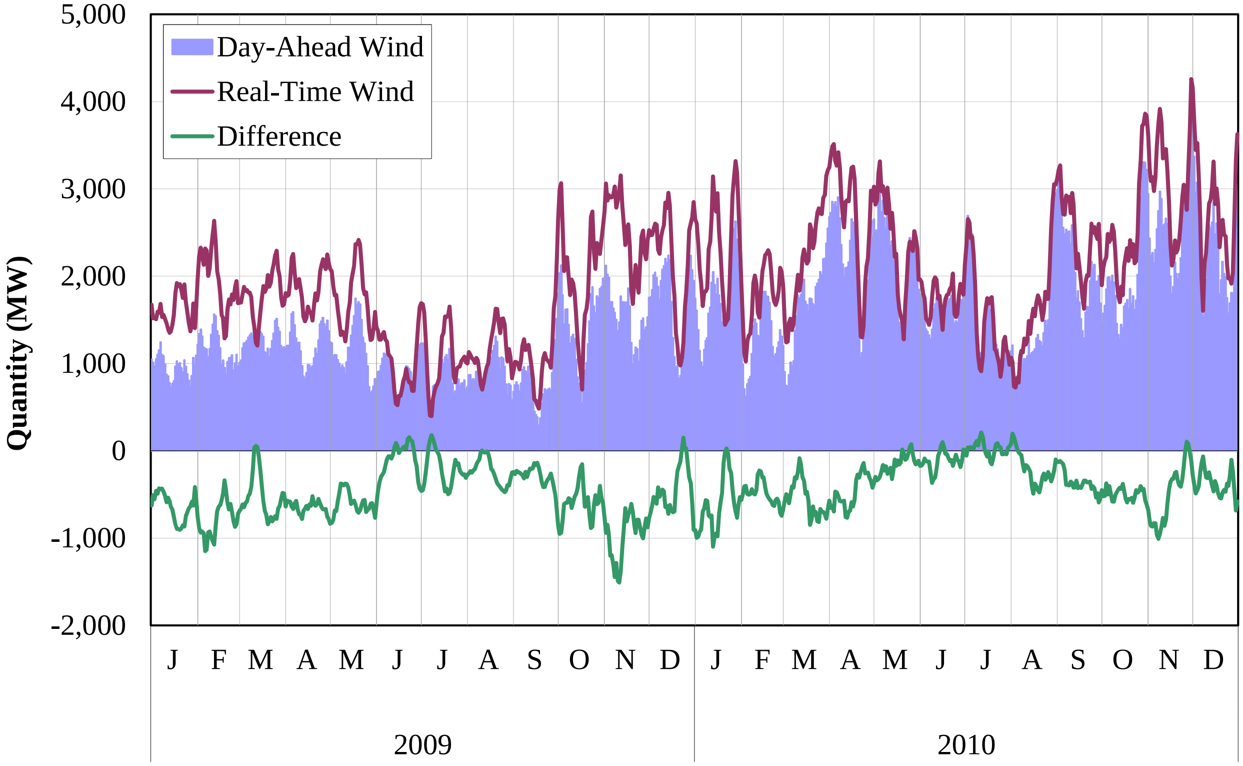
The DIR type, to be introduced in June 2011, will allow wind units to become dispatchable (from zero to a forecasted maximum) and to set price. This process has potential to improve pricing and congestion management in MISO, most notably in the West Region, and to reduce RSG amounts for managing such congestion.

17 This capacity factor was reduced from 20 percent from PY2009. For PY2011, this will be set on a unit basis and will average 12.9 percent (for wind resources designated as Module E resources).

Efficient RSG cost allocation is essential to effective integration of wind generation, but allocations must remain incentive-compatible with energy markets and must be assessed on a cost-causation basis. As such, intermittent resources should no longer be exempt from resource deviations under the new indicative RSG rate. Initially 1,200 MW of wind resources are anticipated to participate as DIR, with most wind resources required to participate as DIR resources by June 2013 (units placed in service prior to April 1, 2005 are exempt).

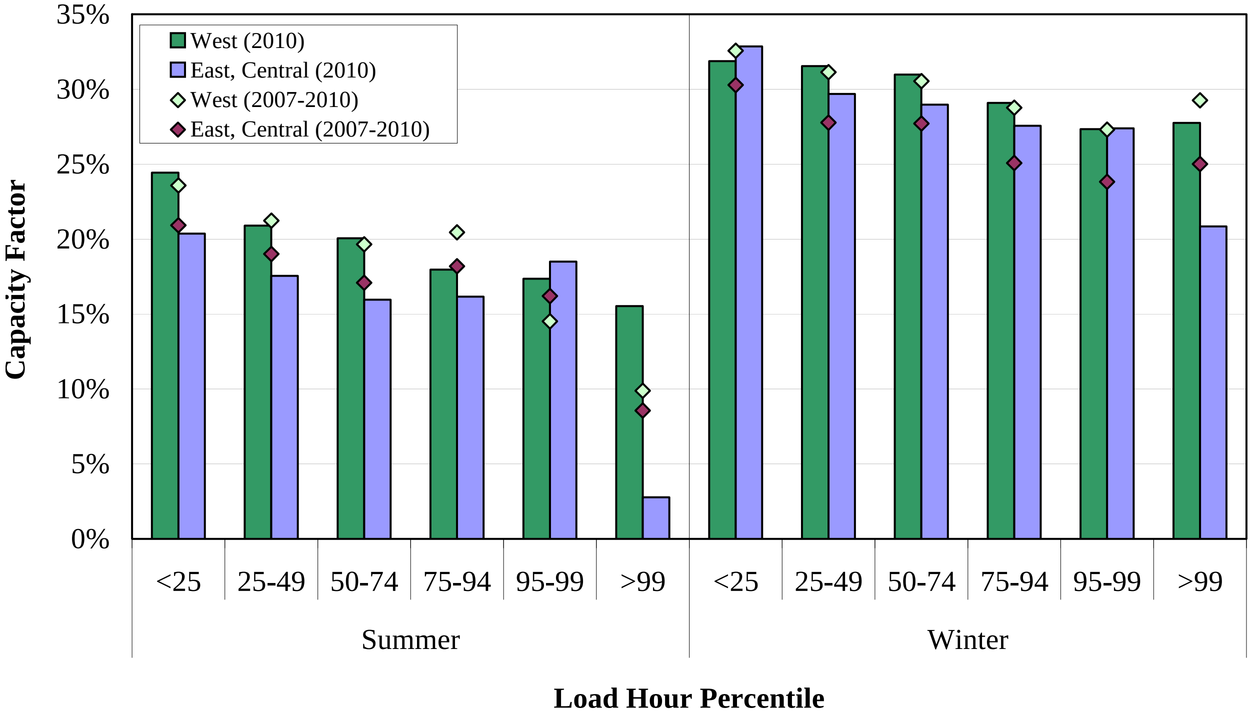
Figure 46 shows a seven-day moving average of wind generation scheduled in the day-ahead and real-time markets in 2009 and 2010. The figure shows the continued rapid growth of wind generation (by 35 percent in 2010) and the seasonality of wind – output is generally higher during shoulder months. Day-ahead scheduling of wind generation improved slightly in 2010, although wind remains modestly underscheduled. Underscheduling in the day-ahead market can create price convergence issues in western areas and lead to uncertainty regarding the need to commit resources for reliability.

Figure 46: Day-Ahead Scheduling versus Real-Time Wind Generation
Seven-Day Moving Average: 2009–2010



Wind capacity factors, measured as actual output as a percentage of capacity, vary substantially across the footprint year-to-year and by region, hour, season, and temperature. They have been generally higher in the western part of the footprint where the resource potential is greater. Wind capacity factors have also generally been higher during off-peak hours, in winter and spring, and when temperatures are generally mild. Figure 47 shows average hourly wind capacity factors by load-hour percentile. This breakdown shows how capacity factors have changed with various load levels. The x-axis in the figure shows tranches of data by load level. For example, the '<25' bars show the capacity factor during the 25 percent of 2010 hours when load was lowest. The figure is also organized by season and region.

Figure 47: Wind Generation Capacity Factors by Load Hour Percentile
2010



The figure shows that wind output (as reflected by capacity factor) is generally negatively correlated with load, particularly in the summer. Capacity factors are lowest when output is most valuable. The spread between western and eastern capacity factors is larger in winter than in summer, but the difference narrows at higher load levels. As a result of these differences, MISO allocated capacity credits for Planning Year ("PY") 2011 on a per-unit basis, rather than doing so evenly system-wide. The capacity credits involved range from 0 to 31 percent and average 12.9 percent. This should more accurately reflect of a unit's actual peak performance.

Since wind units cannot currently respond to economic dispatch instructions through the real-time energy market, units must at times be curtailed manually by MISO's operators to manage congestion or to address a local reliability issue. Wind suppliers may also curtail themselves in response to low prices, although these curtailments appear to MISO as a sudden reduction in wind output. The manual curtailment of wind units is often an inefficient means to relieve congestion because the process does not allow prices to reflect accurately the marginal costs incurred to manage the congestion. The June 2011 implementation of DIR is expected to address this issue for the 1,200-MW subset of units that initially participate, and should reduce the manual curtailments for those that are not participating.

Figure 48: Wind Curtailments by MISO
2008–2010

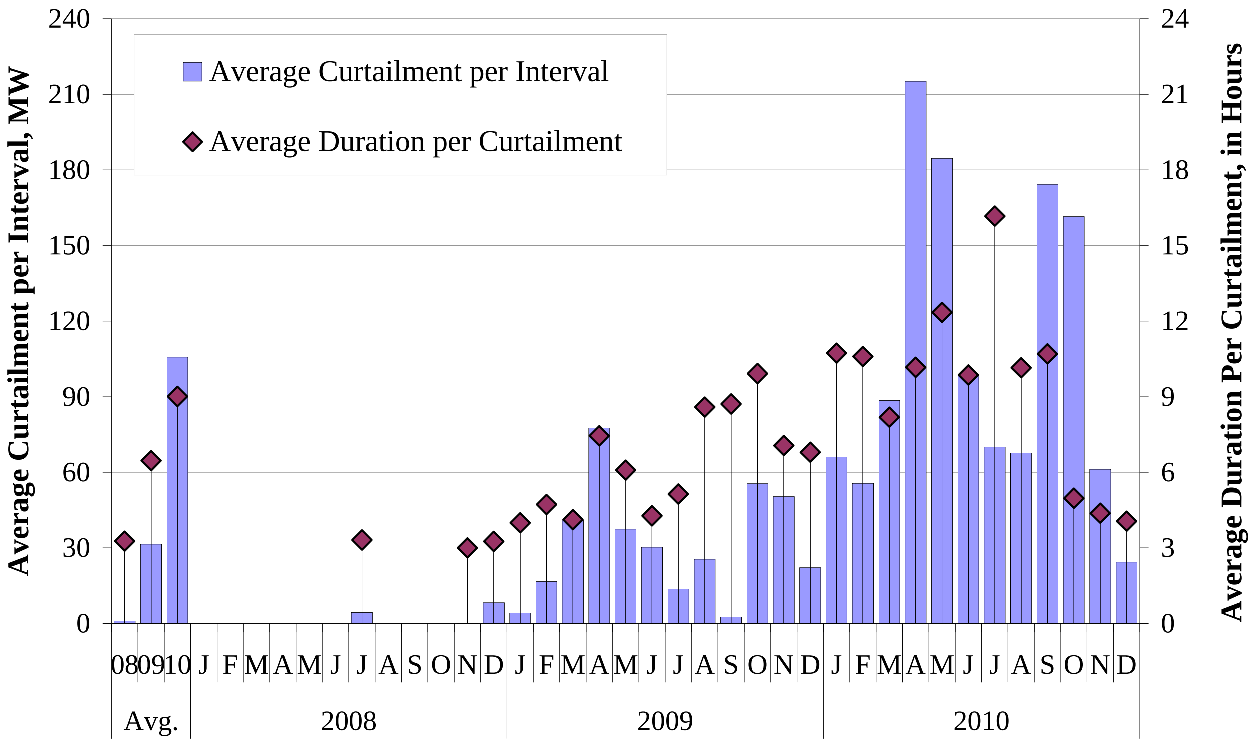


Figure 48 shows MISO-initiated wind curtailments more than tripled in 2010. Curtailments occurred in nearly two-thirds of all intervals, up from 30 percent in 2009. On average, over 100 MW of wind was curtailed per interval in 2010, compared to approximately 30 MW in 2009. As much as 870 MW was curtailed in one interval. Curtailments are greater during shoulder months, when wind generation and penetration levels (wind as a share of online generation) are highest. The figure additionally shows that average curtailment length also grew considerably, to approximately nine hours. MISO improved its wind forecasting in July and its curtailment tools and procedures in late September. As a result, average curtailment times fell to approximately five hours in October to December.

Figure 49: Wind Volatility
Average 60-Minute Change: 2009–2010

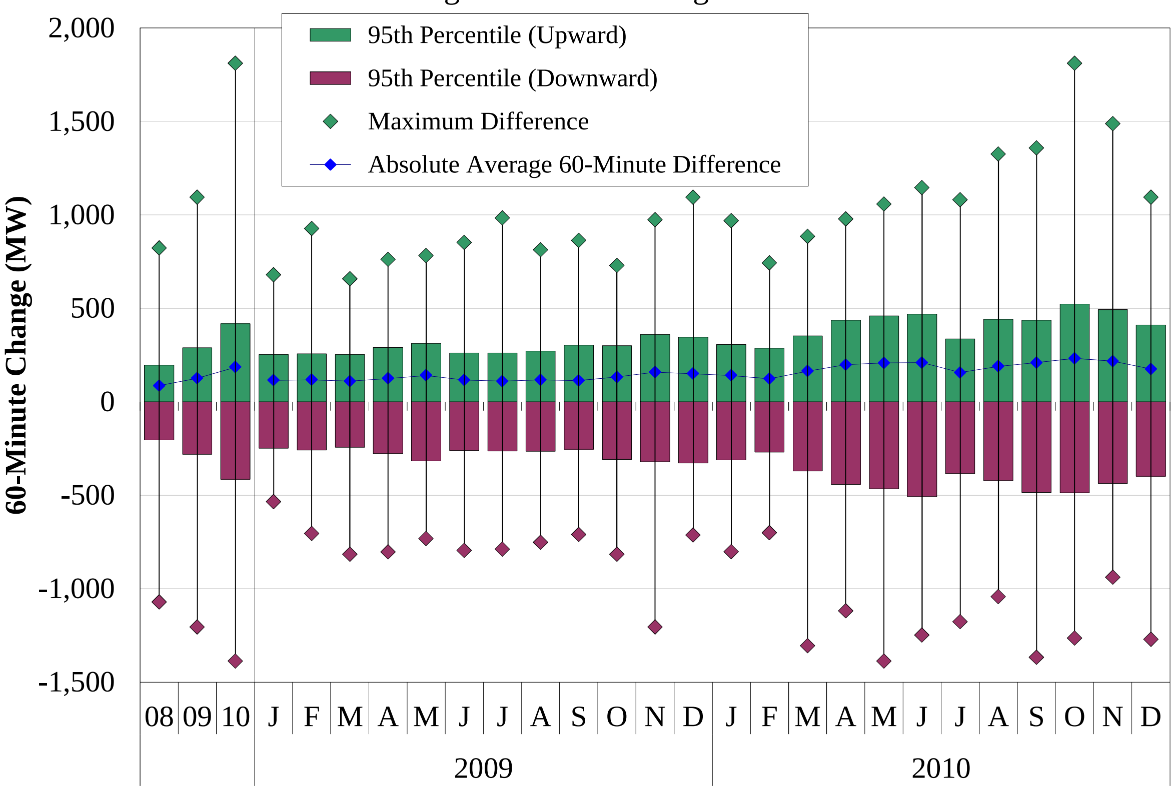


Figure 49 shows the average absolute value of the 60-minute change in wind generation by month in 2009 and 2010. The average absolute change was 186 MW in 2010, up 47 percent from 2009. As a result of this variability, wind output must generally be "firmed" by other resources through redispatch or by the commitment of peaking resources. The figure also shows the largest changes in output managed by MISO; these are indicated by the directional 95th percentile drop lines. The magnitude of these changes grew consistently over the past three years along with the total wind capacity, and averaged more than 400 MW in both directions in

2010. Maximum hourly changes in 2010 were roughly 1,800 MW upward (on October 20) and 1,400 MW downward (on May 25).[18] In addition, volatility was higher during spring and fall when loads were lower. If, as expected, wind capacity continues to grow, MISO must continue to work to accommodate such fluctuations efficiently and reliably.

H. Market Conclusions and Recommendations

Overall, MISO's real-time markets performed efficiently in 2010. However, real-time market performance was affected by:

- Reduced dispatch flexibility offered by many generators, which can make congestion more difficult to manage. This difficulty has improved substantially under ASM.
- Absence of a real-time model to optimize commitment and de-commitment of peaking resources.
- Prices that do not always reflect costs of peaking or demand resources when they are marginal energy sources.
- Shortcomings in current processes to manage system ramp capability needed to accommodate movements in non-conforming load, NSI, wind, and other factors that lead to increased price volatility.
- Current state of the integration of wind resources into the MISO markets.

These issues are addressed by the following recommendations:

1. Develop a Look-Ahead Commitment ("LAC") and Dispatch ("LAD") capability to facilitate better commitment of peaking resources and management of ramp capability.

MISO's peaking resource commitment process can be improved by using an economic model to commit and de-commit peaking units. Such look-ahead capability should include a multi-period dispatch to optimize output of slower-ramping units to meet system demand over the next hour. Better management of ramp needs and commitment of gas turbines would reduce out-of-merit

18 This record was since eclipsed on February 14, 2011, when wind output declined by nearly 2,100 MW in one 60-minute span.

quantities, reduce RSG payments and improve energy pricing. MISO's LAC and LAD projects should develop these capabilities.

2. Prior to the development of the LAC, MISO should improve the use of its load offset parameter.

Currently, this parameter is used to manage ramp capability by incrementally increasing or decreasing the load served by the real-time market. The recommendation likely requires improving the tool used to produce recommended offset levels and modifying its procedures to use these values.

3. Develop real-time software and market provisions to allow gas turbines running at their Economic Minimum or Economic Maximum to set energy prices.

This change would improve efficiency of real-time prices, better incentives to schedule load fully in the day-ahead market, and reduce RSG costs. MISO has the ELMP project underway to develop a feasible approach.

4. Develop provisions to permit DR resources to set energy prices in the real-time market when they are called upon in a shortage.

These provisions would improve price signals during the highest-demand hours, which are important for ensuring that the markets send efficient economic signals to develop and maintain adequate supply resources and develop additional DR capability. It may be possible to address this recommendation in conjunction with the pricing recommendation for gas turbines.

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

MISO should explore potential improvements to information it receives on non-conforming load.

V. Transmission Congestion and Financial Transmission Rights

A primary function of MISO's energy markets is to serve load and meet reserve obligations with the lowest-cost resources possible given the limitations of the transmission network. The locational market structure in MISO has been designed to ensure that transmission capability is used efficiently and that energy prices reflect the marginal value of energy at each location. Congestion costs arise when transmission line flow limits prevent lower-cost generation on the unconstrained side of a transmission interface from replacing higher-cost generation on the constrained side of the interface. This results in higher LMPs in the constrained area. An efficient system typically has some congestion because transmission investment to alleviate congestion should only occur when the cost of such investment is less than the benefit of eliminating it.

When congestion arises, the price difference across an interface represents the marginal value of transmission capability between the two areas. When the power transferred across the interface reaches its limit, congestion costs are approximately equal the difference in LMP prices across the interface multiplied by the transfer amount. MISO collects these congestion costs in the settlement process through the congestion component of the LMP. Net load in the constrained area settles at the constrained area price and the net generation in the unconstrained area settles at the unconstrained price. As a result, load pays more than generators receive. The excess is the cost of congestion. Locational prices that reflect congestion provide economic signals important to managing, transmission network congestion in both the short run and long run. In the short run, the signals allow generation to be efficiently committed and dispatched to manage the network flows. In the long run, they govern investment and retirement decisions.

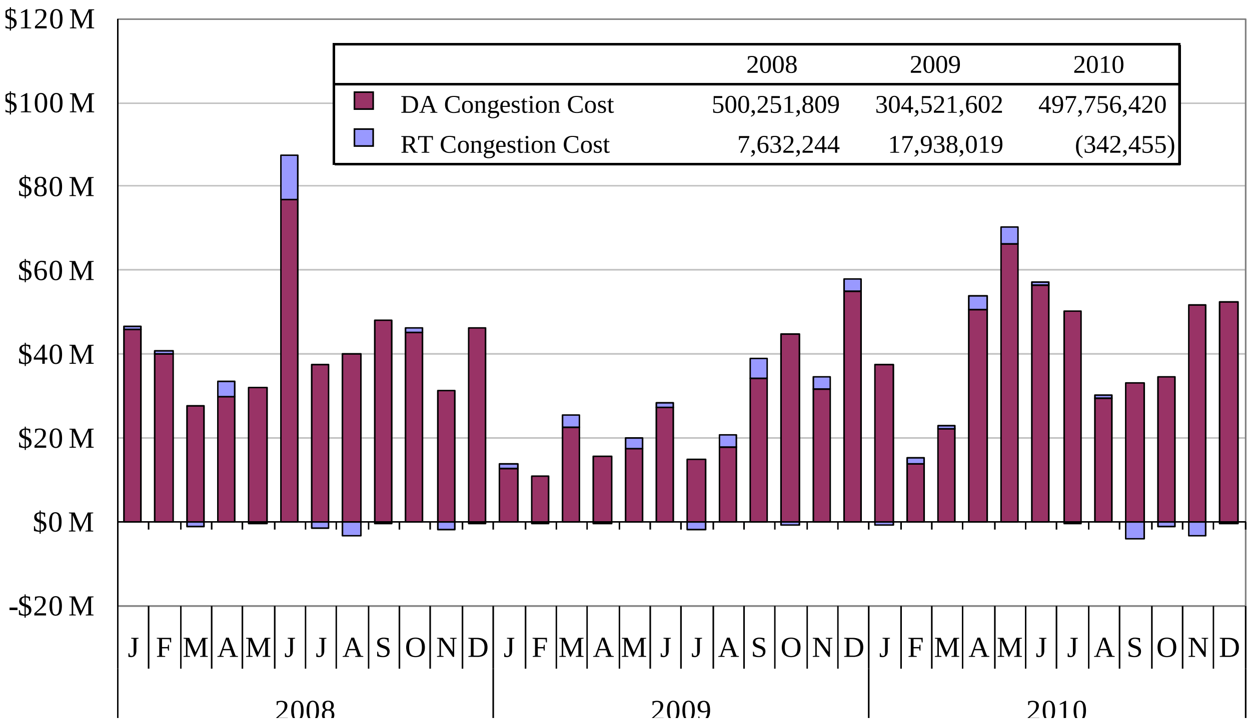
In this section of the report, we evaluate congestion costs, FTR market results, and MISO's management of congestion during 2010. We begin this section by presenting an overall summary of congestion costs incurred in the day-ahead and real-time markets.

A. Day-Ahead and Real-Time Congestion Costs

Most congestion costs are collected through the day-ahead market because the day-ahead schedules generally utilize the vast majority of the systems transmission capability. Real-time balancing congestion settles based on real-time market results and, like all other settlements in the real-time market, relates only to deviations from day-ahead schedules. In other words, congestion costs collected in the real-time market occur only when transmission limits decrease from the day-ahead market model, or when “loop flow” increases from levels assumed in the day-ahead market. Both conditions reduce transmission capability available to the real-time market and cause MISO to incur real-time congestion costs recovered through uplift charges.

For example, if a transmission interface is fully scheduled in the day-ahead market and is congested, MISO will collect no additional congestion costs in the real-time market. Congestion cost may increase or decrease (i.e., price differences may be larger or smaller in real time than they were on a day-ahead basis), but no additional net real-time settlement occurs unless actual interface flow changes from the amount scheduled day ahead. If, however, the limit were to fall (i.e., the interface were derated) or loop flow were to increase over the congested interface, MISO would incur real-time congestion costs to achieve required reduction in real-time interface flows. Figure 50 shows total congestion costs incurred by month in the day-ahead and real-time markets from 2008 to 2010.

Figure 50: Total Congestion Costs
2008–2010



Day-ahead congestion costs in 2010 increased 63 percent to $498 million, which is near 2008 levels. Congestion costs were highest in the second quarter due to transmission outages in the East Region, generation outages throughout the footprint and high loads from unseasonably warm temperatures during the last week of May and into June.

Real-time congestion costs were minimal, which is expected when modeling of the transmission system is consistent between the day-ahead and real-time markets. A negative real-time congestion cost total implies that network modeling was consistent between the day-ahead and real-time markets in 2010. Costs averaged $80 million per year between 2006 and 2007 (not shown) before declining to $7 million in 2008 and $17 million in 2009. In 2010, these costs fell to -$342,000. Negative balancing congestion costs were primarily the result of net payments from PJM to MISO for M2M coordination, which totaled $36 million in 2010. As in 2009, real-time congestion costs in 2010 did not exceed $5 million in any month.

B. Day-Ahead Congestion and FTR Obligations

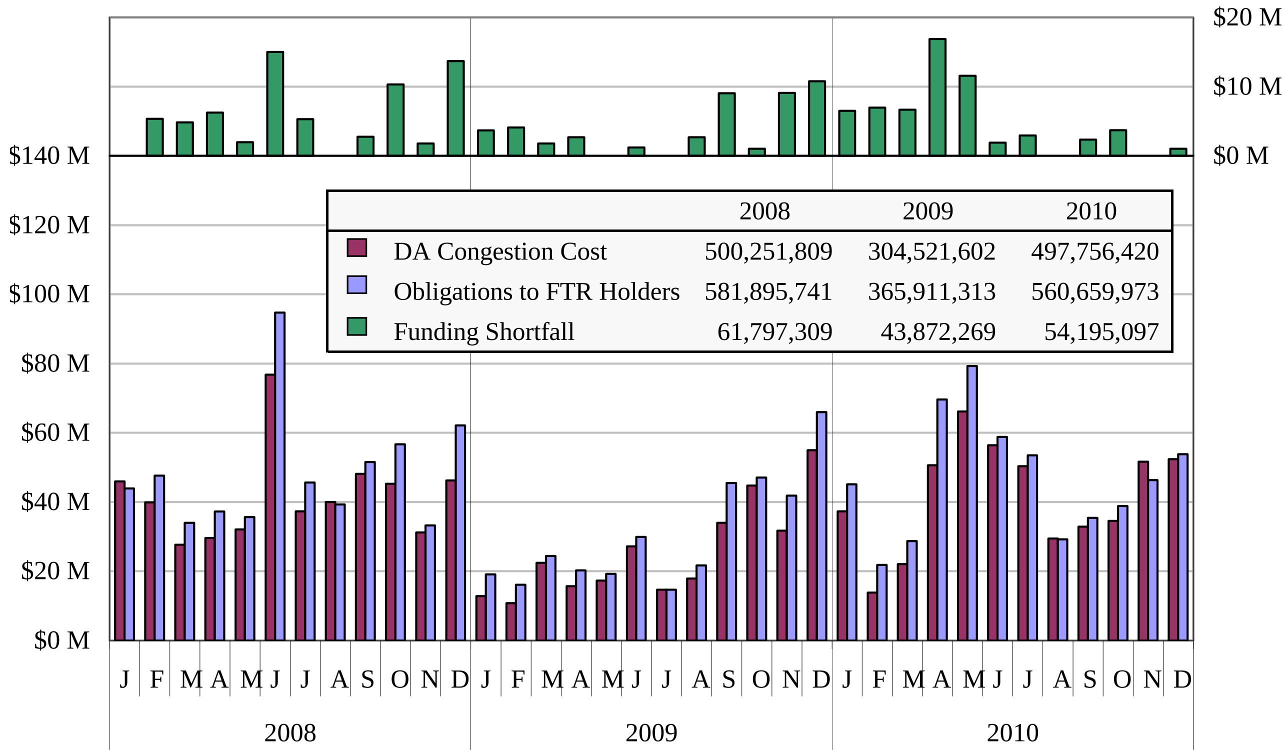
The economic value of transmission capacity is reflected in FTRs. FTR holders are entitled to congestion costs collected between the source and sink locations for a particular FTR. Hence, FTRs allow participants to manage price risk from congestion. FTRs are distributed through an annual allocation process as well as through seasonal and monthly auctions. In June 2008, the MISO introduced Auction Revenue Rights ("ARRs") to the FTR market. This approach allocates auction revenue from an FTR to the ARR holder rather than to the FTR itself. If customers prefer to hold an FTR, they can still purchase one and be in the same position as they would have been had FTR been allocated directly to them.

MISO is obligated to pay FTR holders the value of day-ahead congestion over the path that defines each FTR. In particular, the FTR payment obligation is the FTR quantity times the per-unit congestion cost between the source and sink of the FTR.[19] Congestion revenues collected in MISO's day-ahead market pay FTR obligations. Surpluses and shortfalls are expected to be limited when participants hold FTR portfolios that match power flows over the transmission

19 An FTR obligation can be in the "wrong" direction (counter flow) and can require a payment from the FTR holder.

system. When FTRs exceed the transmission system's physical capability or loop flow from activity outside MISO uses its transmission capability, MISO may collect less day-ahead congestion revenue than it owes to FTR holders.[20] During each month, MISO attempts to fund FTRs by applying surplus revenues from overfunded hours *pro rata* to shortfalls in other hours. Monthly congestion revenue surpluses accumulate until year end, when they are prorated to reduce remaining FTR shortfalls. Figure 51 compares monthly total day-ahead congestion revenues to monthly total FTR obligations.

Figure 51: Day-Ahead Congestion Revenue and Payments to FTR Holders
2008–2010: All Hours



	2008	2009	2010
DA Congestion Cost	500,251,809	304,521,602	497,756,420
Obligations to FTR Holders	581,895,741	365,911,313	560,659,973
Funding Shortfall	61,797,309	43,872,269	54,195,097

During 2010, day-ahead congestion collections were 11 percent less than FTR obligations. Because of improved modeling procedures, the shortfall was less than it had been in prior years (between 12 and 17 percent in 2007 to 2009). Shortfalls are undesirable because they introduce uncertainty and can distort FTR values.

20 The day-ahead model includes assumptions on loop flows that are anticipated to occur in real time.

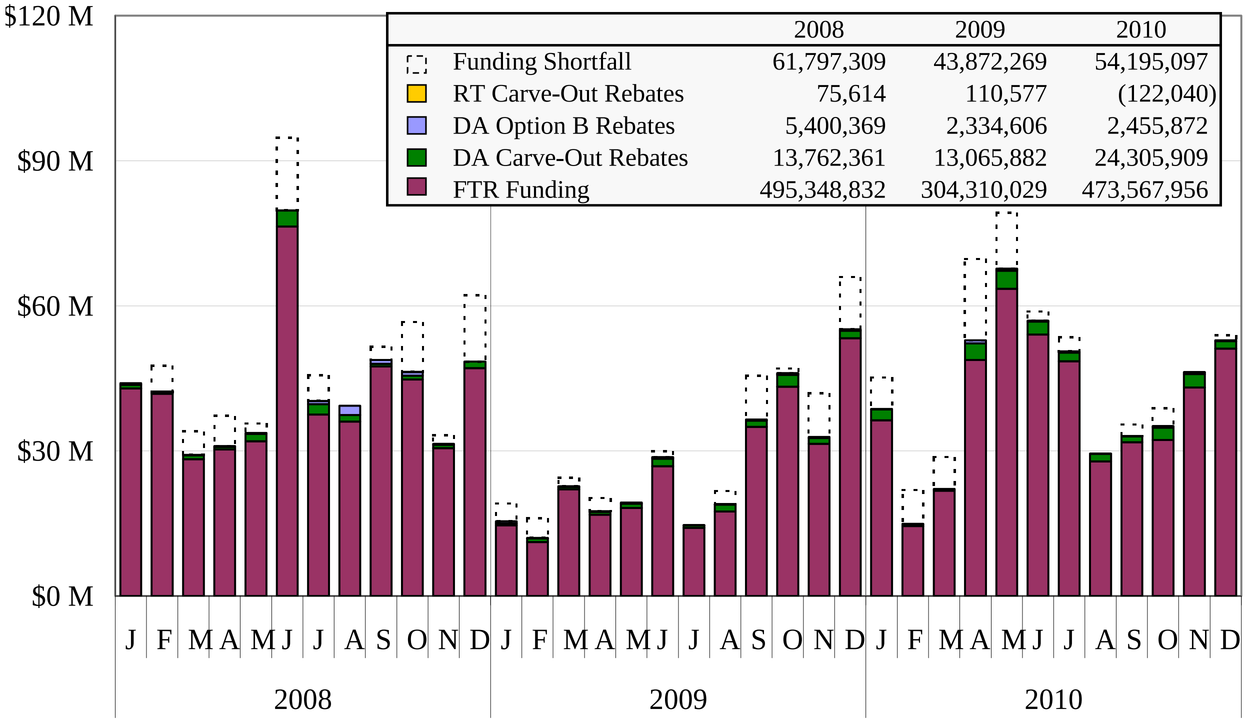
When MISO sells FTRs that correspond to different transmission capability than is ultimately available in the day-ahead market, shortfalls (i.e. it sold too many FTRs) or surpluses (too few FTRs) occur. Reasons for differences between FTR and day-ahead modeling that contribute to surpluses and shortfalls are similar to differences discussed previously between the day-ahead and real-time markets. Transmission outages or other factors cause system capability in the day-ahead modeling to differ from capability assumed when FTRs were allocated or sold. In addition, generators and loads outside the MISO region can cause loop flows that use more or less transmission capability than is assumed in the FTR market model. Unanticipated loop flows are a problem because MISO collects no congestion revenue from transactions that cause it. If MISO allocates FTRs for the full capability on these interfaces, the loop flow can create an FTR revenue shortfall.

MISO has continued to work on FTR and ARR allocation processes and associated modeling to reduce shortfalls. MISO implemented its latest improvements to FTR modeling in April 2010. The seasonal auction for June 2010 resulted in dramatic improvements in FTR funding levels. Improvements included better constraint forecasting and identification procedures; more complete modeling of the lower-voltage network; and improved modeling of radial constraint limits. Underfunding on radial constraints is discussed in greater detail later in this section. From June to December, hourly and monthly FTR allocations funded 96 percent of obligations.

MISO “grandfathered” agreements for certain other types of transmission rights to protect entities with pre-existing transmission arrangements. Holders of these rights receive rebates that refund any congestion charges incurred on a specified path in the day-ahead or real-time markets. The rights include an alternative type of FTR with use-it-or-lose-it characteristics (i.e., “Option B” FTRs) and congestion “Carve-Outs.”

Figure 52 shows monthly payments and obligations to conventional FTRs, as well as Option B and Carve-Out FTR holders in 2008 to 2010. The figure shows that throughout the period approximately 95 percent of payments went to holders of conventional FTRs. Only 5 percent of payments were made to Option B and Carve-Out FTR holders. Modest payments for these other rights are a good outcome because they do not provide the same efficient incentives as conventional FTRs. Although payments to day-ahead holders of Carve-Out FTRs nearly doubled from $13 million in 2009 to $24 million in 2010, the higher amount still represents less than 5 percent of all payments. A large portion of this amount was due to increased congestion in the West Region and in WUMS that augmented the value of selected carve-outs.

Figure 52: Payments to FTR Holders
2008–2010: All Hours



As a percentage of obligations, payments to the holders of alternative rights increased to 4.8 percent, up from 3.3 and 4.2 percent in 2008 and 2009, respectively. The FTR funding rate improved in 2010, although the shortfall increased by more than $10 million in nominal terms. Although MISO has steadily improved the accuracy of its FTR process, we recommend further improvements later in this section that should increase the FTR funding rate.

One source of FTR shortfalls is the use of fictitious "radial constraints" in the day-ahead market. MISO imposes radial constraints from the transmission network to individual generator buses to limit day-ahead modeled flow to the generator buses and to prevent excessive virtual load from clearing at these locations. These radial constraints are modeled in the day-ahead because virtual load bids cleared at these locations can result in infeasible day-ahead model solutions. This problem arises because the market software reflects low-voltage facilities at the unit site (i.e., where the step-up transformer that brings the power onto the higher-voltage network is modeled). Of course, such radial constraints are unnecessary in the real-time market because such infeasibilities cannot exist (i.e., power never flows out to a generator location since there is no physical load there). Radial constraints ensure that the day-ahead market will solve, but they can cause congestion that would never exist in a real-time market. Prior to May 2010, these constraints were not generally reflected in the FTR market. As a result, more FTRs could sink at generator locations than radial constraints could support in the day-ahead model. This situation led to FTR shortfalls and potential manipulation opportunities.

Figure 53: FTR Underfunding and Day-Ahead Congestion
Radial Constraints, 2009–2010

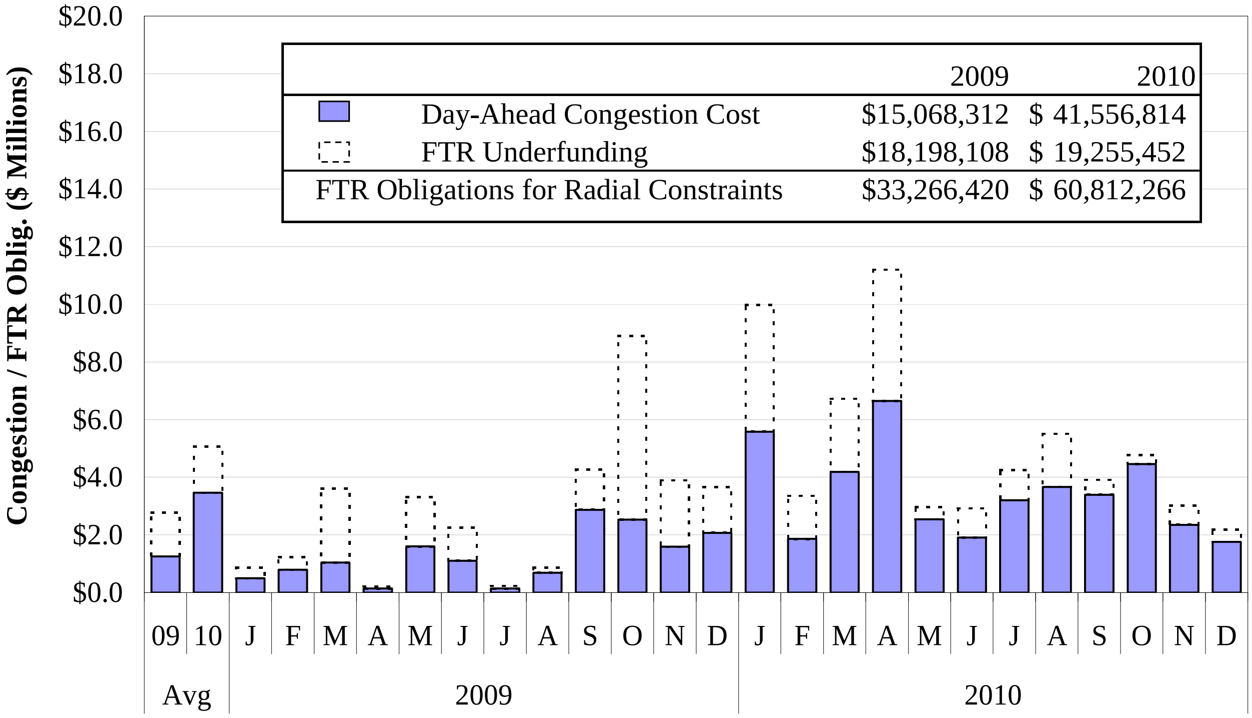
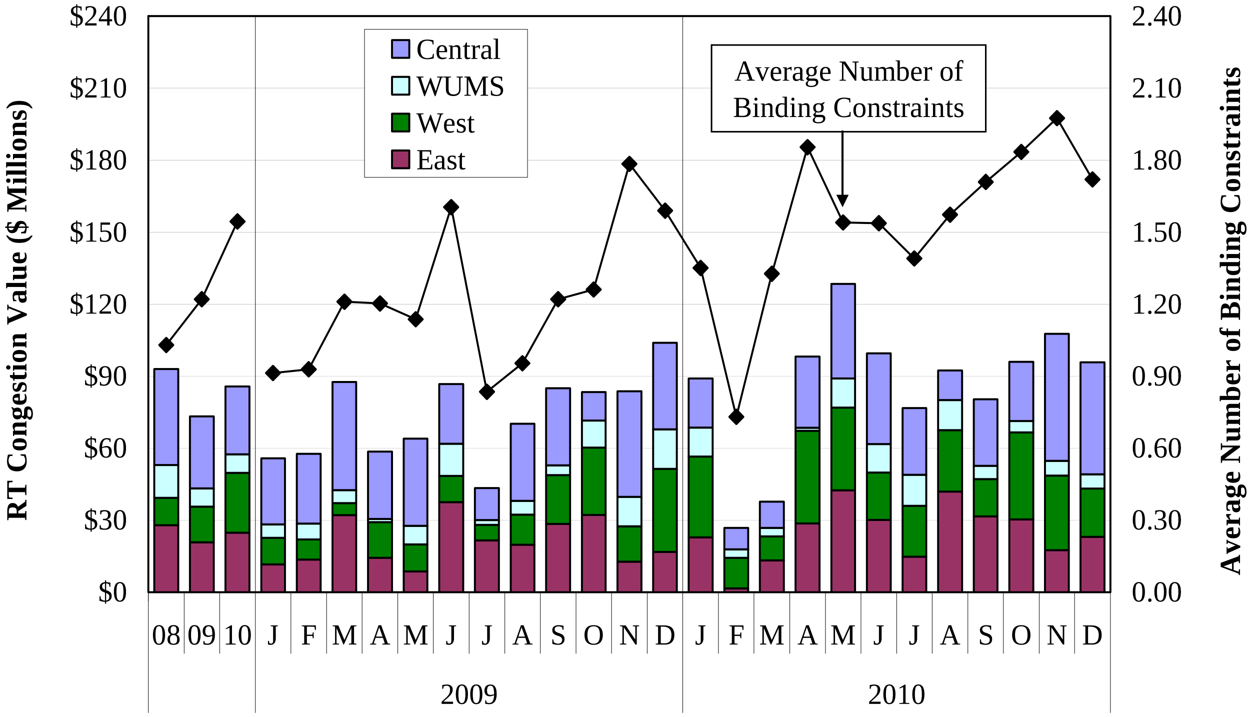


Figure 53 above shows day-ahead congestion and estimated hourly FTR shortfalls for radial constraints. Radial constraints generated more than 8 percent of total day-ahead congestion (up from 1 percent in 2009) but contributed to more than one-third of FTR shortfalls. Two-thirds of this underfunding occurred between January and April 2010 before MISO had improved modeling of these constraints in FTR auctions. However, FTR underfunding remained significant on these constraints for the rest of 2010. We continue to recommend that MISO remove these step-up transformer facilities and associated radial constraints from the day-ahead and FTR markets, since this congestion cannot materialize in the real-time market.

C. Value of Congestion in the Real-Time Market

In this subsection, we study congestion patterns in the real-time market. We focus here on the *value* of real-time congestion, rather than the day-ahead and real-time balancing congestion costs collected by MISO. This difference is important because MISO does not collect congestion costs for all actual flows over its system (e.g., loop flows incur no congestion costs).[21] For the purposes of the analyses in this subsection, we calculate an implied value for real-time congestion. This value equals the marginal cost of a constraint (i.e., the shadow price) times the flow over the constraint in a given dispatch interval. Figure 54 shows the value of real-time congestion by region and the average number of binding constraints in 2009 and 2010.

Figure 54: Value of Real-Time Congestion by Coordination Region
2009–2010



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21 In our discussion, congestion refers to the cost of a particular constraint. The term "congestion costs" specifically refers to the component of LMP that is collected by MISO.

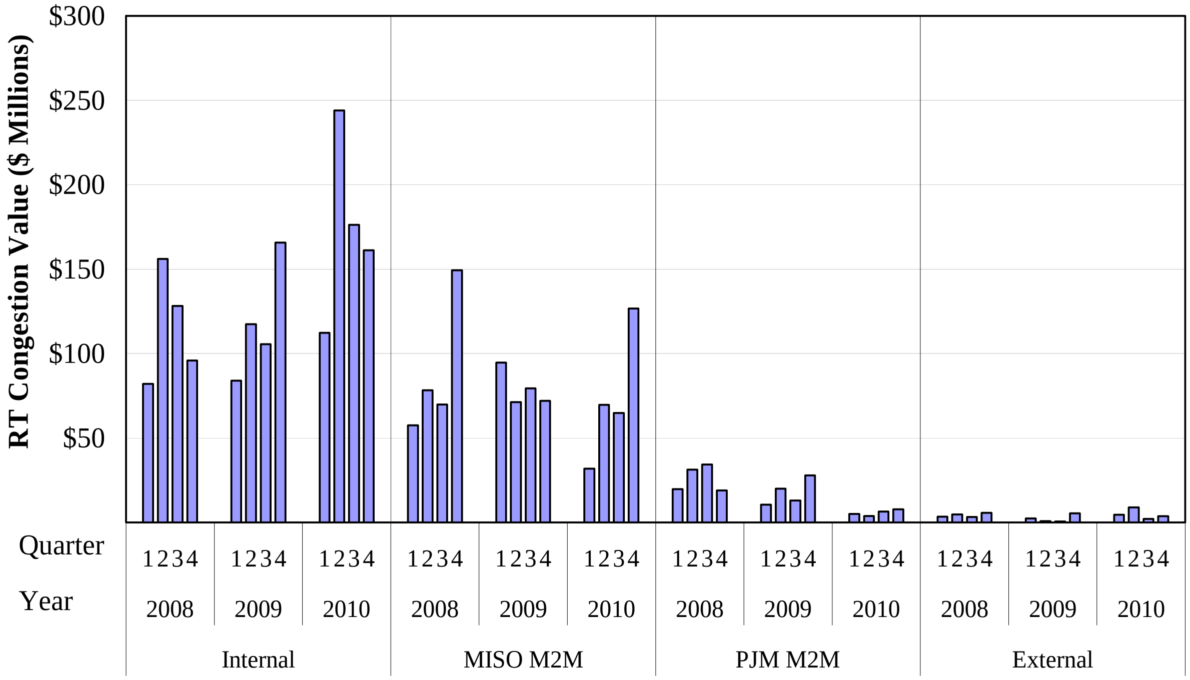
Real-time congestion increased 18 percent to $1.03 billion in 2010. This value continues to exceed day-ahead and real-time congestion costs collected by MISO because loop flows use some transmission network capability without reimbursing MISO, and because the JOA entitles PJM to use MISO transmission on M2M flowgates (i.e., Firm Flow Entitlements, or "FFE").

Congestion occurred on transmission interfaces throughout the footprint in 2010. It increased most rapidly in the West Region, rising by $120 million (67 percent) to $299 million. That region's share of total congestion also increased to 30 percent, up from 20 percent in 2009. In addition, nearly half of all binding constraints were in the West Region, many of which were lower-voltage lines associated in part with intermittent, non-dispatchable wind generation. As a result, the average number of binding constraints per interval in 2010 increased from 1.21 to 1.54. In the East Region congestion increased 20 percent to $298 million, while Central Region congestion decreased 6 percent to $340 million. Congestion in WUMS was nearly unchanged in 2010 from 2009. As discussed further below, congestion out of WUMS on the interface with PJM (included in the East Region totals) increased substantially in 2010.

To better identify the sources of congestion, Figure 55 shows the value of real-time congestion by type of constraint. This quantity is computed in the same way as the value of congestion in the previous analysis. We define four constraint types:

- Those internal to MISO and not coordinated with PJM. Since they are not M2M constraints, we refer to them as "internal constraints";
- MISO constraints that are coordinated with PJM. These are labeled "MISO M2M" constraints;
- PJM constraints coordinated with MISO. These are labeled "PJM M2M constraints; and
- Constraints located on other systems that MISO must help relieve by redispatching generation when Transmission Line Loading Relief ("TLR") procedures are invoked by a neighboring system (referred to as "external constraints." in this report).

Figure 55: Value of Real-Time Congestion by Type of Constraint
2008–2010



Nearly 96 percent of total real-time congestion value in 2010 occurred on MISO-managed constraints (i.e., internal and MISO M2M constraints). Of this, approximately 30 percent occurred on M2M constraints. Although few constraints are coordinated under the M2M process, 10 of the top 14 highest-valued constraints were MISO M2M constraints. Each of these 10 high-value constraints is located in the eastern half of MISO region, most of which are substantially affected by generation in the Commonwealth Edison ("ComEd") area. PJM M2M constraints and external constraints (often triggered by TLRs) continue to be quite a small share of total congestion, respectively totaling $23 and $19 million.

Many MISO-managed, M2M constraints were triggered by local outages. For example, all congestion on the two highest-valued constraints occurred in relatively brief periods that were due partly to outages. For example, $39 million occurred over a few weeks in the fourth quarter in the Central Region, while $32 million occurred over just a two-day period in August in the East Region. M2M congestion out of WUMS and into Michigan persisted all year, occurring partly because MISO assumed control of a frequently-binding tie line between WUMS and

Commonwealth Edison. A number of transmission projects are underway these areas that should alleviate some of the congestion on this interface.

D. Transmission Line Load Relief Events

MISO continues to rely on TLR procedures and the NERC Interchange Distribution Calculator to support certain aspects of congestion management. Before energy markets were introduced, virtually all congestion management for MISO transmission facilities was accomplished through the TLR process. TLR is an Eastern Interconnection-wide process that allows reliability coordinators to mitigate potential or actual operating security limit violations while respecting transmission service reservation priorities. When a constraint is binding, the real-time dispatch model manages its market flows over the constrained transmission facility by economically redispatching generation. External entities not dispatched by MISO can also contribute to total flows over constrained internal transmission facilities. If total external flows account for more than 5 percent of flow on a facility, MISO can invoke a TLR to ensure that external parties contribute to reducing the flow over the constrained facility.

As detailed in prior reports, the TLR process is a much less efficient and less controllable means to manage congestion than optimized generation dispatch through LMP markets. TLR provides less timely and certain control of power flows over the system. We also found in the past that the TLR process resulted in three times more curtailments on average than would be required by economic redispatch. These factors make the curtailment of scheduled transactions through the TLR process a less reliable option for constraint management than LMP markets. Figure 56 shows TLR activity on MISO flowgates on a monthly basis for 2009 and 2010.

The top panel of the figure shows quantities of scheduled energy curtailed by TLR events. The bottom panel of the figure provides hourly TLR activity by the various TLR levels. NERC's active response TLR levels include:

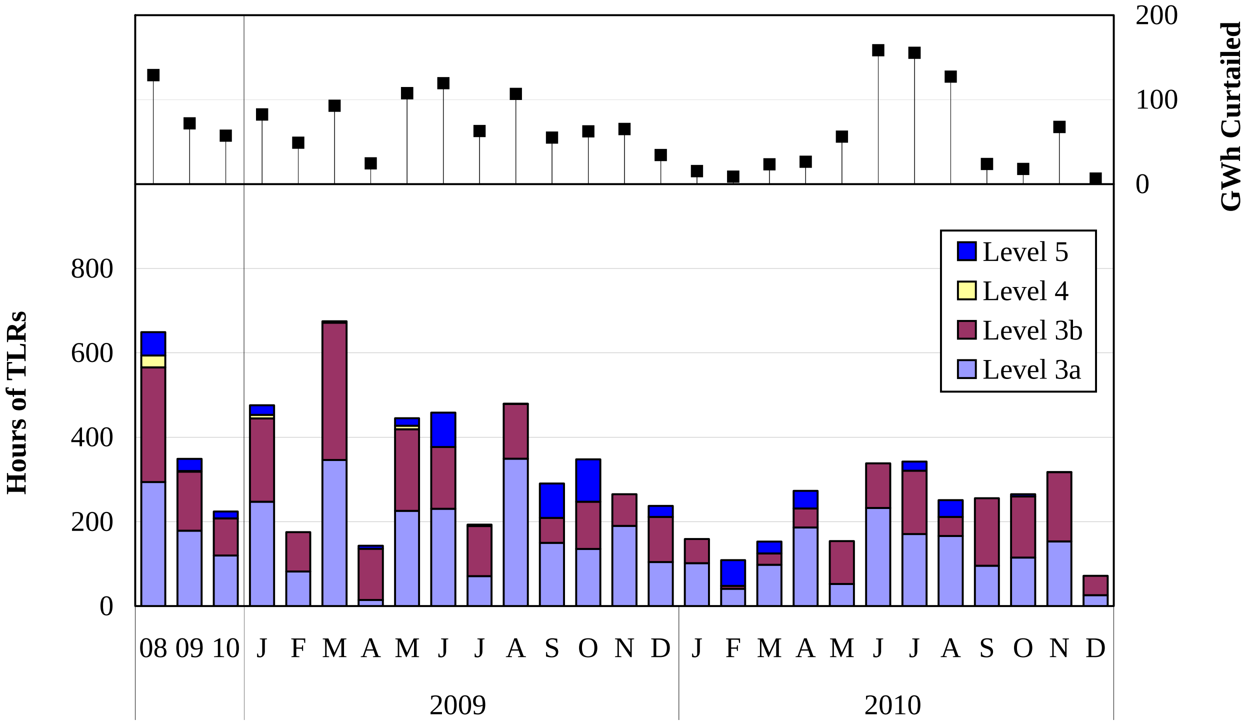
- Level 3: non-firm curtailments;[22]

22 Level 3 (3a for next hour and 3b for current hour) allows reallocation of transmission service by curtailing interchange transactions to allow interchange transactions using higher priority transmission service.

- Level 4: commitment or redispatch of specific resources or other operating procedures to manage specific constraints; and

- Level 5: curtailment of firm transactions.[23]

Figure 56: Periodic TLR Activity
2008–2010



TLR flowgate-hours in 2010 decreased 20 percent from 2009 levels, while curtailed amounts declined 36 percent. Nearly 60 percent of total curtailed GWh occurred on a series of M2M constraints out of WUMS, mostly during the May-to-August period. The more severe Level 4 TLRs have been virtually eliminated since 2007 and Level 5 TLRs have been greatly reduced, totaling just 38 GWh in 2010. Although significant quantities of TLRs are still invoked to ensure that transactions external to MISO are curtailed when contributing to congestion, MISO relies primarily on optimized generation dispatch for managing congestion.

23 NERC's TLR procedures include four additional levels: Level 1 (notification), Level 2 (holding transfers), Level 6 (emergency procedures) and Level 0 (TLR concluded).

E. Congestion Manageability

Congestion management is among MISO's most important roles. It monitors thousands of potential network constraints in real time throughout MISO using its real-time market model to maintain flow on each activated constraint at or below the operating limit while minimizing overall production cost. As flow over a constraint nears (or is expected to near) the limit in real time, the constraint is activated in the market model.

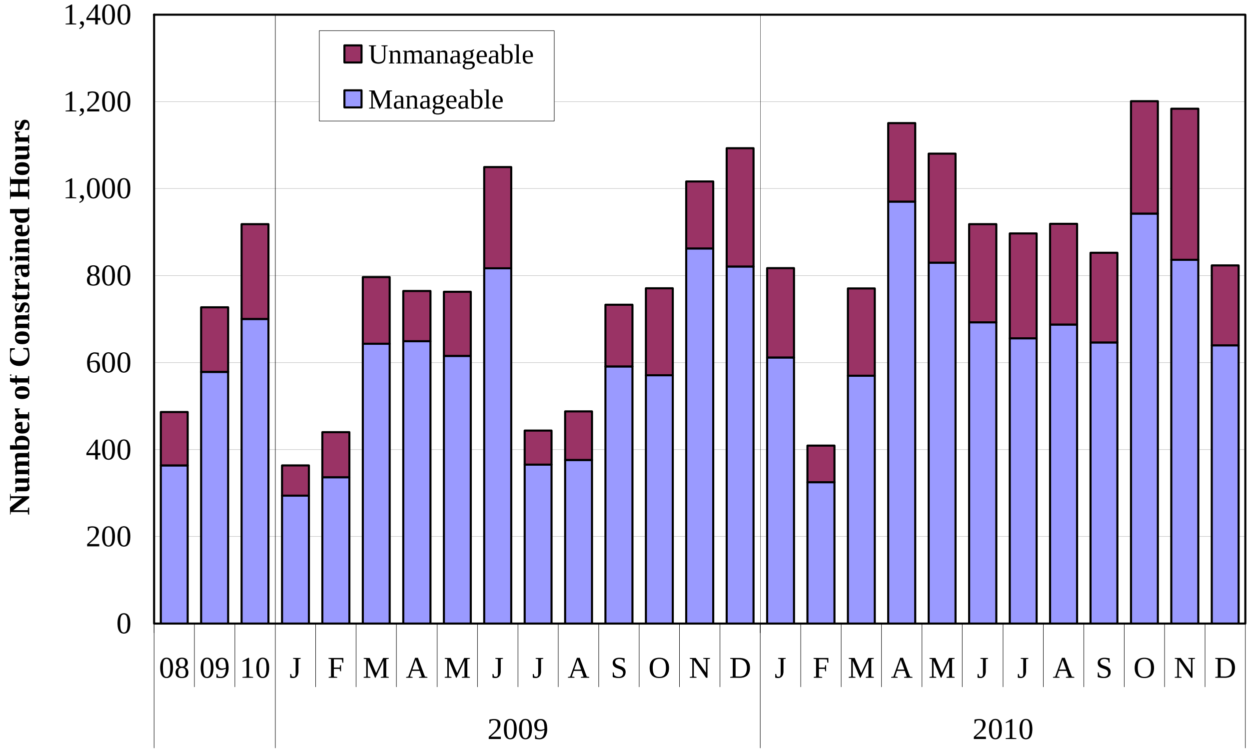
MISO's real-time, LMP-based energy market dispatches generation subject to transmission constraints on the network. This process uses the relief available by redispatching its resources, especially those with high Generation Shift Factors ("GSFs") that have relatively large impacts on constraints. Sometimes constraints are difficult to manage if available relief capability of generators affecting a constraint is limited. The available redispatch capability is reduced when:

- Generators that are most effective at relieving the constraint are not online;
- Generator flexibility is reduced (i.e., generators set operating parameters, such as dispatch range or ramp rate, lower than actual physical capabilities); or
- Generators are already at their limits (e.g. operating at the maximum point of their dispatch range, the "EcoMax").

When available relief capability is insufficient to reduce the flow below the transmission limit in the next five-minute interval, we refer to the transmission constraint as "unmanageable." Importantly, the presence of an unmanageable constraint does not mean the system is not reliable. MISO's performance criteria for most constraints require control to be restored to the limit within 20 minutes. If control is not restored within 30 minutes, a reporting criterion to stakeholders is triggered. Constraints that are more critical are operated more conservatively. When a constraint is unmanageable in MISO market, an algorithm is used to "relax" the limit of the constraint to calculate a shadow price and the associated LMPs. This "relaxation algorithm" is evaluated later in this section of the report.

Figure 57 and Figure 58 show the manageability of MISO's constraints (i.e., does not include PJM M2M or external constraints) by month and voltage level, respectively. The first figure shows how frequently constraints were unmanageable in each month of 2009 and 2010.

Figure 57: Unmanageable Constraints
2009–2010

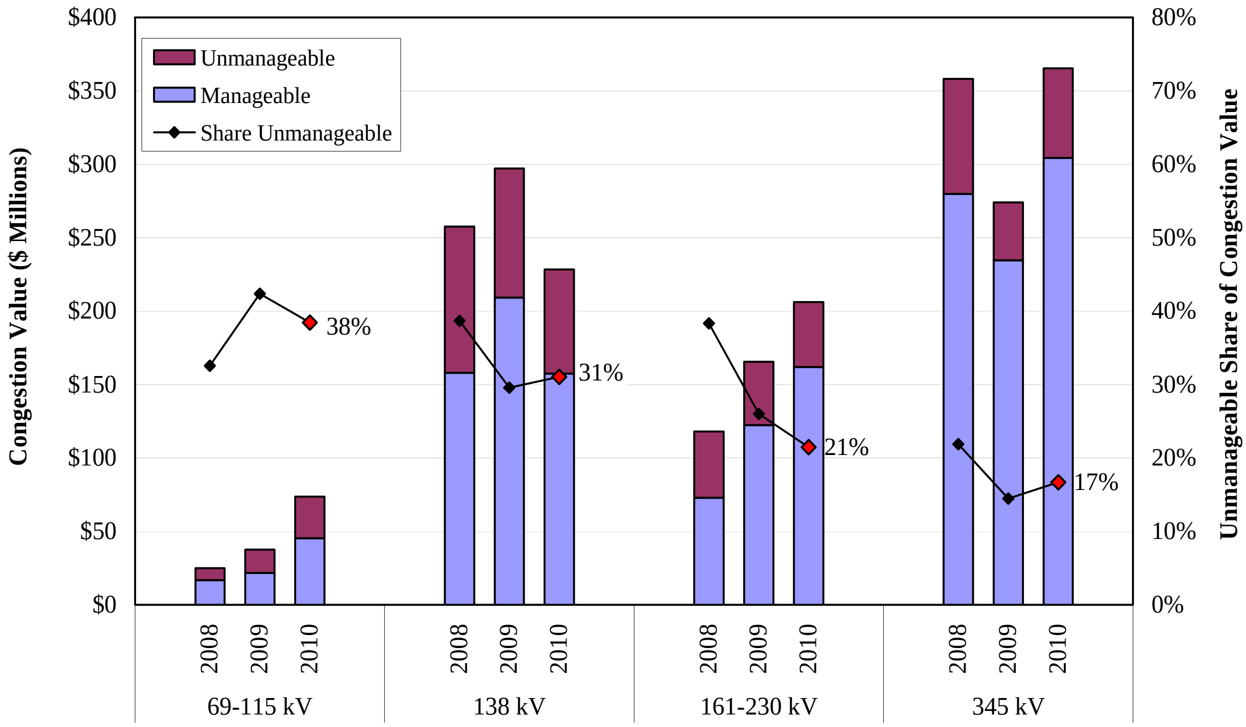


Total constrained hours increased 26 percent to an average of 919 hours per month in 2010. The share of unmanageable constraint hours increased slightly from 20 percent in 2009 to 23 percent in 2010, primarily due to an increase in the frequency of low-voltage constraints that tend to be less manageable.

The second figure examines manageability of constraints from 2008 to 2010 by voltage level. Given the physical properties of electricity, more power flows over higher-voltage lines. This characteristic causes resources and loads over a wider geographic area to affect higher-voltage constraints. Conversely, low-voltage constraints typically must be managed with a smaller set of more localized resources. As a result, these facilities are often more difficult to manage.

From 2009 to 2010, congestion increased by at least 25 percent on all constraint-voltage classes except 138 kV. The largest voltage-class increase was 96 percent on low-voltage constraints (i.e., those rated 69 to 115 kV). Manageability in this voltage class improved slightly to 62 percent in 2010, but these constraints remain considerably more difficult to control than higher-voltage constraints. Approximately 82 percent of the congestion on constraints rated 161 kV or greater was manageable in 2010. The levels of unmanageability in 2010 suggest that MISO is continuing to accept responsibility for low-voltage facilities that it lacks the resources to manage effectively. We continue to encourage MISO establish criteria for determining when it should secure these low-voltage facilities and when they are more appropriately secured by local balancing authorities.

Figure 58: Value of Real-Time Congestion by Path
2008–2010

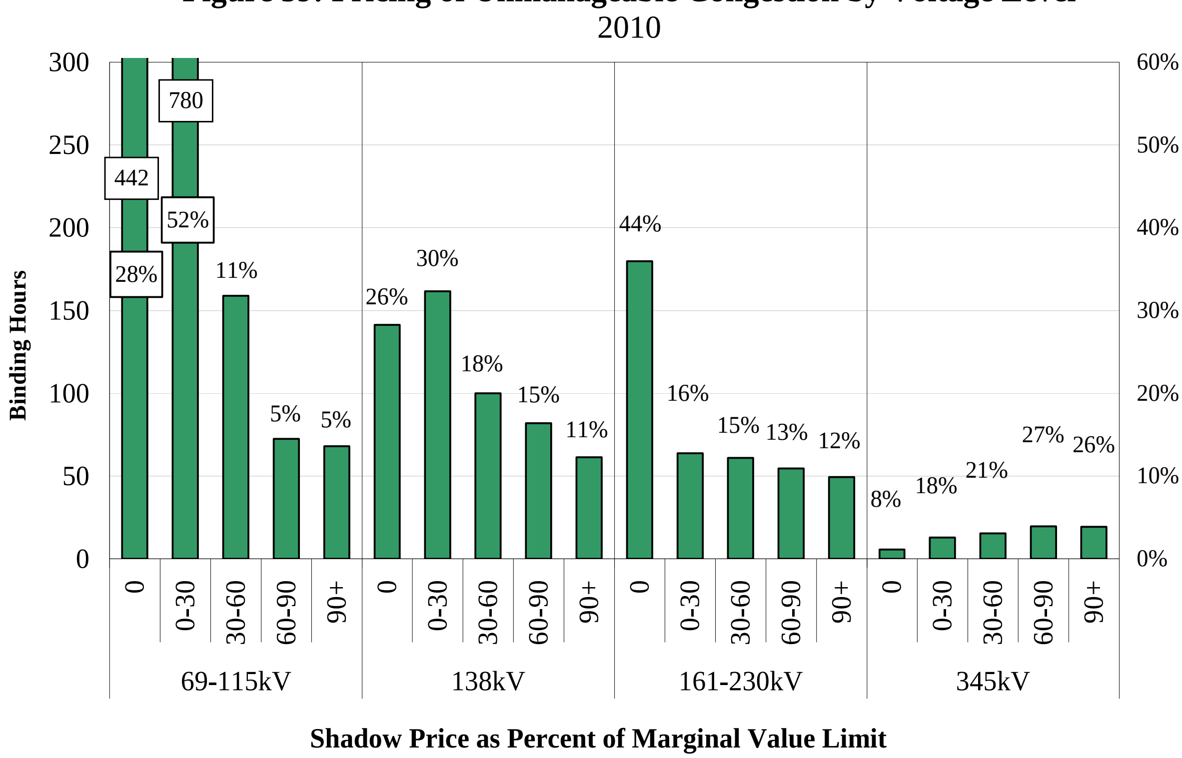


Given the frequency with which constraints are unmanageable, it is very important that the congestion be priced efficiently and reflected in MISO's LMPs. Before evaluate MISO's pricing, it is important to understand how the real-time market treats transmission constraints. The real-time market model utilizes "Marginal Value Limits" ("MVL") that caps the marginal cost (i.e., the shadow price) that the energy market will incur to reduce the constraint flow to the limit. In order for the MISO markets to perform efficiently, the MVL must reflect the reliability cost of violating the constraint.

When the constraint is violated (i.e., unmanageable), the most efficient LMP would be one that fully reflects the MVL of the violated constraint. This is efficient because it aligns the real-time LMPs with MISO's operation of the system. However, the constraint relaxation algorithm described above is designed to produce LMPs that are inconsistent with value of unmanageable constraints. Its sole purpose is to produce a shadow price for unmanageable constraints that is lower than the MVL, although there is no economic theory that would support setting LMPs on the basis of these relaxed shadow prices.

The efficiency costs of this constraint relaxation algorithm are related to the divergence between the relaxed shadow prices and the MVLs. Figure 59 evaluates the pricing of unmanageable constraints by showing the relationship between shadow price and MVL. In this figure, the unmanageable constraint hours are divided into tranches by the ratio of the shadow price to the MVL of the constraint. This ratio determines the extent to which the shadow price fully reflects the cost of the violated constraint. When the shadow price is close to 100 percent of the MVL, LMPs will accurately reflect congestion on the unmanageable constraint. When the ratio is significantly less than 100 percent, congestion reflected in the LMPs is inefficiently muted.

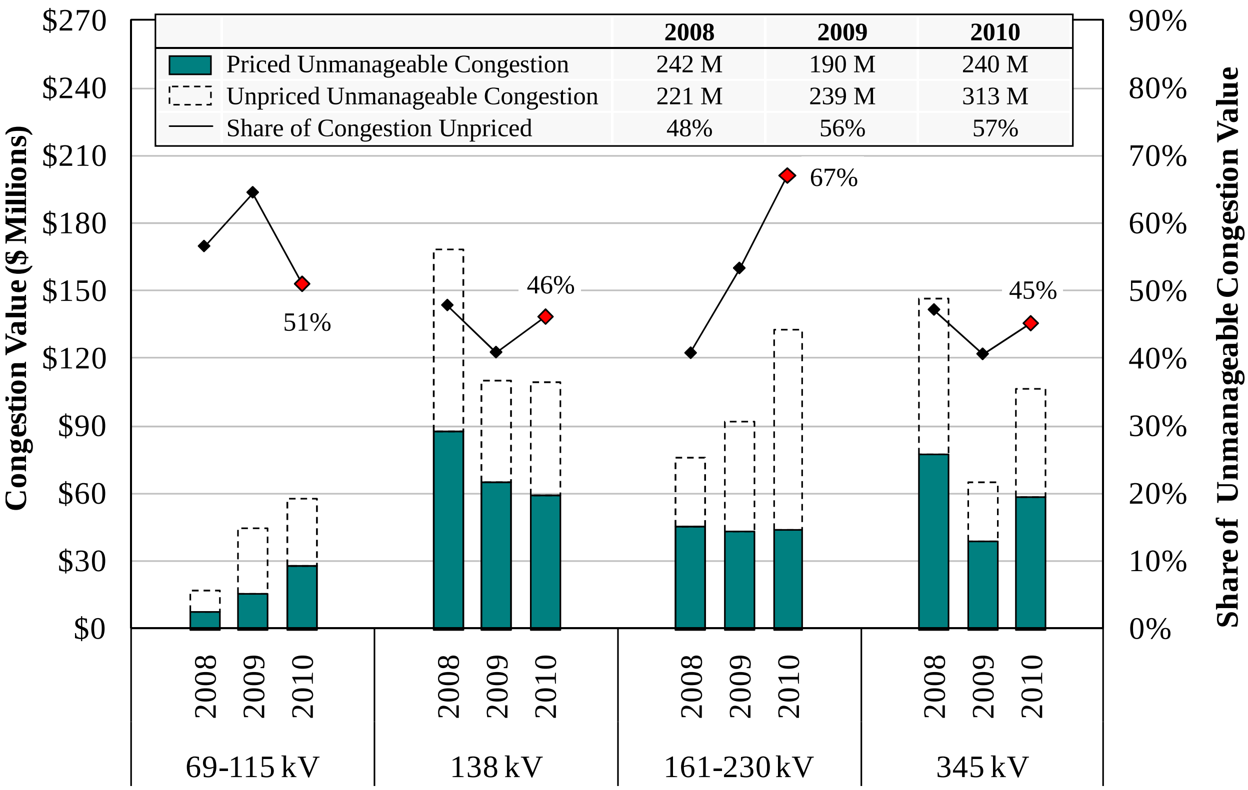
Figure 59: Pricing of Unmanageable Congestion by Voltage Level



The vast majority of shadow prices in binding hours do not approach full MVL. Nearly 60 percent of unmanageable congestion occurs on low-voltage constraints, and over three-quarters of these hours have shadow prices less than 30 percent of their MVL. Higher-voltage constraints are also substantially underpriced: over half of unmanageable constraints rated 138 kV or higher are priced at less than 30 percent of their MVL. The most worrisome conclusion from this analysis is that 27 percent of all unmanageable constraints are priced at zero, which means that the market does not reflect these violated constraints at all in LMPs. In summary, these results show that the relaxation algorithm often produces inefficiently low shadow prices that distort the associated LMPs. We believe this is a significant flaw in MISO markets.

To estimate the economic impact of this flaw, Figure 60 shows the value of real-time congestion associated with violated constraints, separately showing the portion of congestion that was priced and reflected in market outcomes and the portion artificially eliminated by the relaxation algorithm (nearly 60 percent).

Figure 60: Effect of the Constraint Relaxation Algorithm on Real-Time Congestion
2008-2010



This figure shows that the relaxation algorithm artificially suppressed the value of congestion in the real time by $313 million in 2010, up from $239 million in 2009. It also shows that congestion was substantially underpriced for constraints in all voltage classes. This reduction in the value of real-time congestion has inefficient indirect effects that go far beyond the real-time market. Because the multi-settlement system provides strong incentives for participants to arbitrage the day-ahead and real-time prices, a pricing flaw in the real-time market should be reflected in the day-ahead market outcomes as well. The most important implication of this is that the day-ahead schedules will not efficiently anticipate the congestion, which means that the generating resources committed through the day-ahead will not efficiently provide for relief of the unmanageable congestion. For example, if an unmanageable constraint into a load-pocket is not priced fully in the real-time, the day-ahead price and load scheduled in the load-pocket will be correspondingly lower. This can cause higher-cost units to not be scheduled day-ahead and, thus, be unavailable in real time to manage the constraint.

Another indirect effect of the constraint relaxation algorithm is that the FTRs defined over these constraints will not be priced at their full value. This occurs because the FTR entitlements are based on day-ahead market results that will not fully price the unmanageable congestion. Hence, less revenue will be collected in the FTR market, which affects other charges needed to recover the costs of the transmission system and reduces incentives to build new transmission facilities.

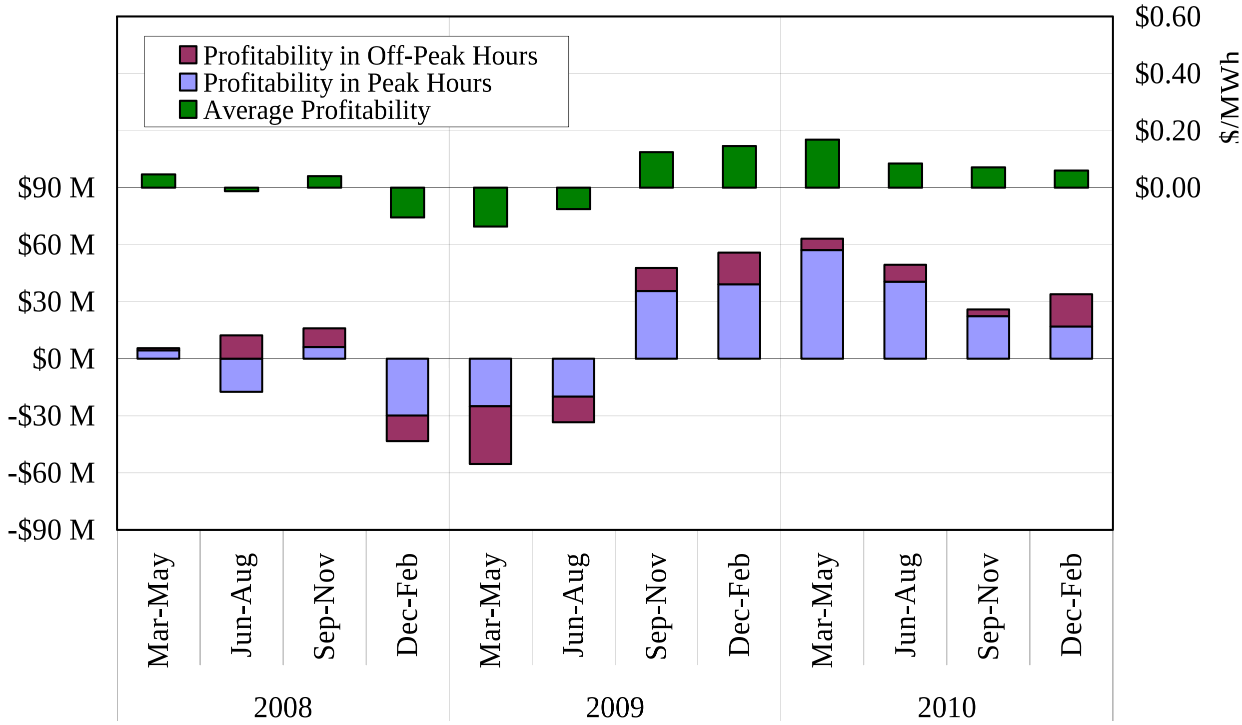
Based on all of these inefficient effects of the constraint relaxation algorithm, we continue to believe that it a significant flaw in the MISO markets. Hence, we continue to recommend that MISO discontinue its use on all MISO transmission constraints.

F. FTR Auction Prices and Congestion

The MISO administers a market for FTRs that allows participants to hedge the congestion costs in the market. This subsection evaluates the performance of the FTR market. MISO auctions the majority of transmission rights through seasonal and monthly auctions. A small percentage of rights are allocated directly to holders of Option B and Carve-Out FTRs. Before June 2008, most FTRs were allocated annually based on physical usage of the system. Since then, most transmission rights have been auctioned (or self-scheduled via ARRs) seasonally.

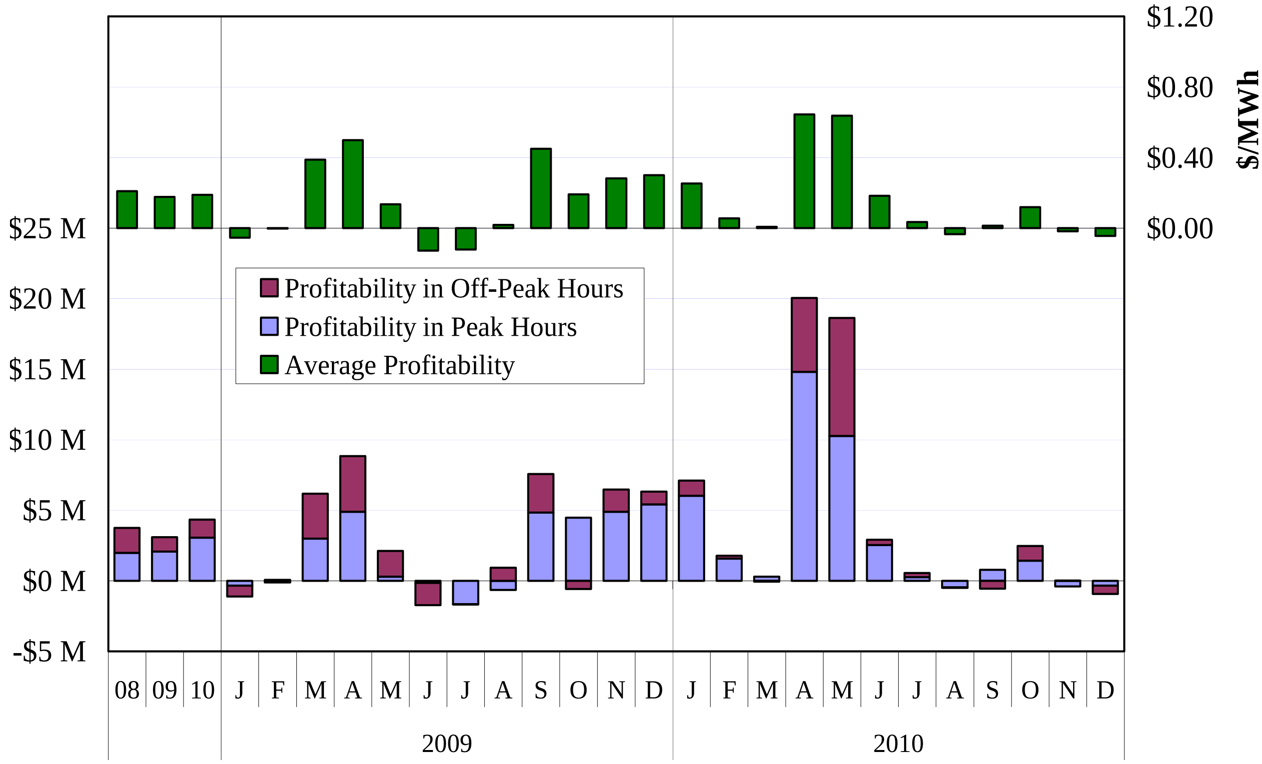
A well-functioning market should produce FTR prices that reflect a reasonable expectation of day-ahead congestion. Therefore, a key indicator of FTR market liquidity is profitability of FTR purchases. FTR profits are the difference between the costs to purchase the FTR and the payout its holder receives based on congestion in the day-ahead market. In a liquid FTR market, profits should be low because the market-clearing price for the FTR should reflect the expected value of congestion payments to the FTR holder. During 2010, seasonal FTRs were always profitable albeit at a low level. The profitability of monthly FTRs, however, fluctuated and ended the year unprofitable. Figure 61 shows the profitability of FTRs purchased in the seasonal FTR auction.

Figure 61: FTR Profitability
Seasonal Purchases, 2008–2010



FTRs sold in the seasonal FTR auction were consistently profitable in 2010, earning a modest $0.09 per MWh on average. Profits during peak periods, which averaged $120 million, were over six times greater than off-peak profits. Figure 62 shows that profits for monthly FTRs were low and sometimes negative. They averaged $0.19 per MWh in 2010 and ranged from $0.64 per MWh in April and May to a loss of $0.04 in December. As with the seasonal auction, monthly peak profits ($36.7 million) were much larger than off-peak profits ($15.4 million). These results indicate that liquidity and FTR market performance has been good, generally causing FTR prices to accurately reflect their value.

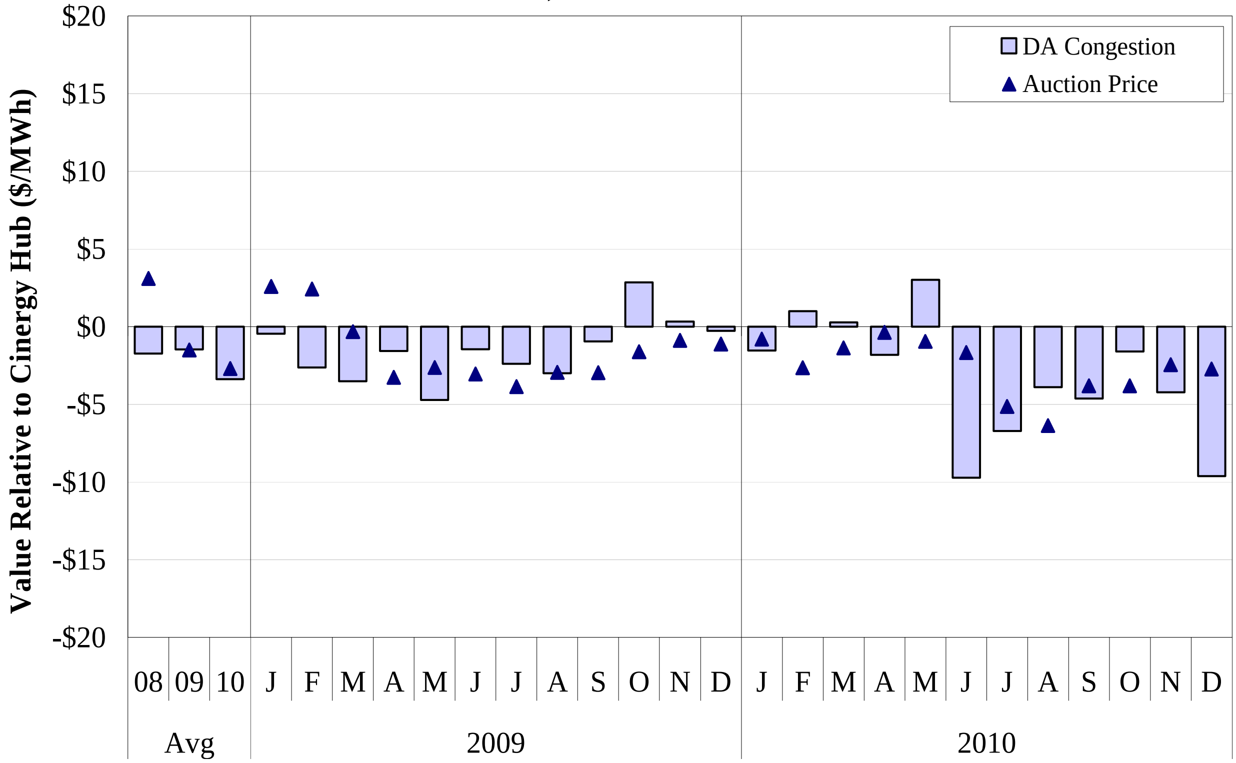
Figure 62: FTR Profitability
Monthly Purchases, 2008–2010



Our next analysis further examines the performance of the FTR markets by comparing monthly FTR auction prices to day-ahead congestion payable to FTR holders at representative locations in MISO. These differences should generally be small in a well-functioning market.

We analyze values for the WUMS Area, the Minnesota Hub, and the Michigan Hub in both peak and off-peak hours. All values in the figures are computed relative to Cinergy Hub, which is the most actively-traded location in MISO. Figure 63 shows the monthly and annual differences for FTRs sourced in WUMS, indicating that for most months in 2010 WUMS was *export* constrained overall. This is a significant change from years prior to 2008. The direction of congestion in the WUMS region has reversed since 2008 because of: a) transmission upgrades into the area, and b) increased west-to-east power flows associated with increased wind output that has grown rapidly in recent years.

Figure 63: Comparison of FTR Auction Prices and Congestion Value
WUMS Area, 2009–2010: Peak Hours



Peak-hour congestion out of WUMS increased in June 2010 due to higher loads in the East, unit additions in WUMS, and congestion on certain M2M flowgates. Congestion averaged $0.19 per MWh in January to May and -$5.76 thereafter. In all, convergence between auction prices and congestion values was only fair in 2010 because volatility in monthly congestion patterns increased. The average absolute value of the monthly spread (the difference regardless which is higher) during the year was $2.93 per MWh, an increase of $0.60 from 2009. Auction prices the following month generally adjusted to changes in congestion patterns. When adjusting for a one-month lag in convergence, the average spread falls to $1.53 per MWh.

Figure 64 shows the same analysis for off-peak hours. Off-peak hours in WUMS continued to exhibit negative (export) congestion as well, caused in part by high levels of wind generation in the West Region. Congestion averaged -$4.04 per MWh in 2010 during these hours, slightly less than the -$4.26 found in 2009. In general, convergence is better during off-peak than peak hours because volatility tends to be lower. The average monthly off-peak spread between auction prices and congestion in 2010 was $1.84 per MWh, up from $1.51 in 2009.

Figure 64: Comparison of FTR Auction Prices and Congestion Value
WUMS Area, 2009–2010: Off-Peak Hours

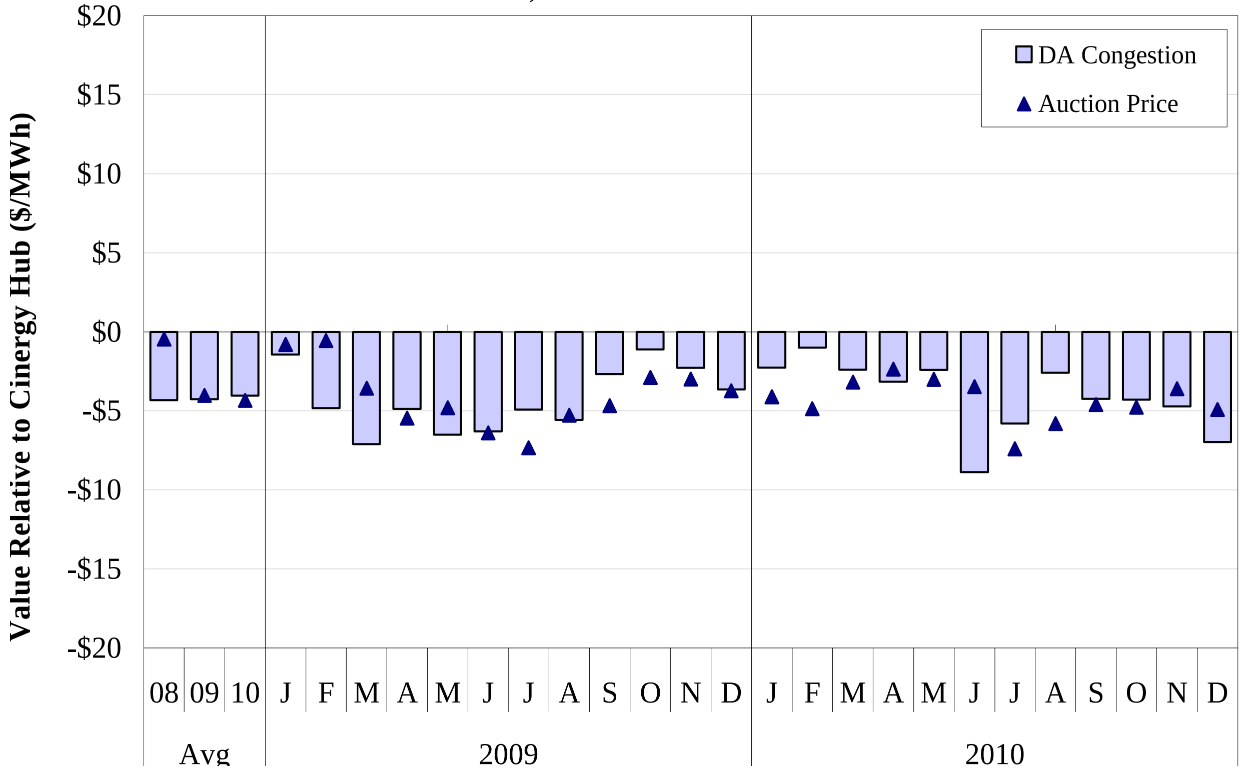


Figure 65 and Figure 66 show the same analysis for the Minnesota Hub in peak and off-peak hours, respectively. As in WUMS, convergence between congestion values and FTR prices at the Minnesota Hub decreased modestly in 2010. Peak congestion values relative to the Cinergy Hub were negative for most months, a reflection of persistent west-to-east congestion. The trend was strongest after May when day-ahead congestion averaged -$5.65. Prior to May, it averaged only -$0.83 per MWh. The average monthly peak-hour spreads in 2010 was $2.47 per MWh, up 10 percent from 2009.

Off-peak congestion in 2010 was again more uniform than peak congestion and never switched directions, a pattern that can add difficulty in accurate FTR valuation. The average monthly off-peak spreads was $2.21 per MWh in 2010, up from $1.79 in 2009. Peak and off-peak spreads in 2010 were similar to those in 2009 but substantially lower than those in earlier years. Like other locations, the analysis reveals a one-month lag in convergence, which is not unexpected since FTRs are sold before the month when the congestion occurs. Adjusting for this lag in FTR prices improves convergence at Minnesota Hub by one-third.

Figure 65: Comparison of FTR Auction Prices and Congestion Value
Minnesota Hub, 2008–2010: Peak Hours

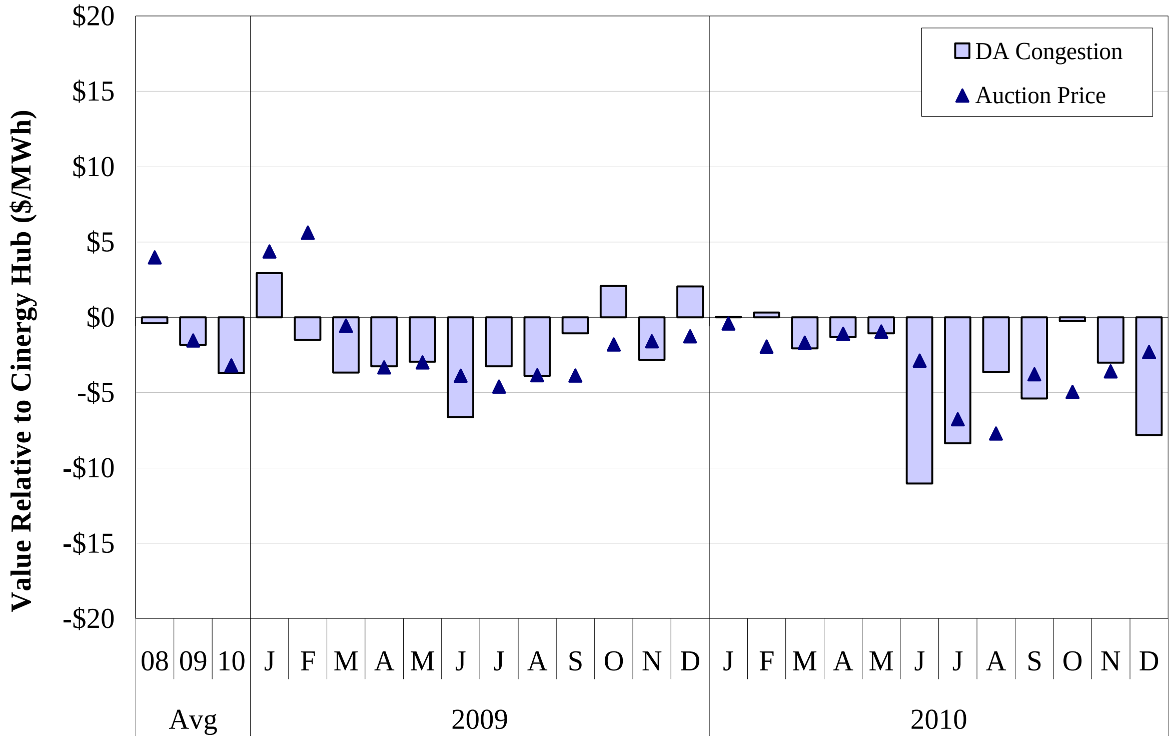


Figure 66: Comparison of FTR Auction Prices and Congestion Value
Minnesota Hub, 2008–2010: Off-Peak Hours

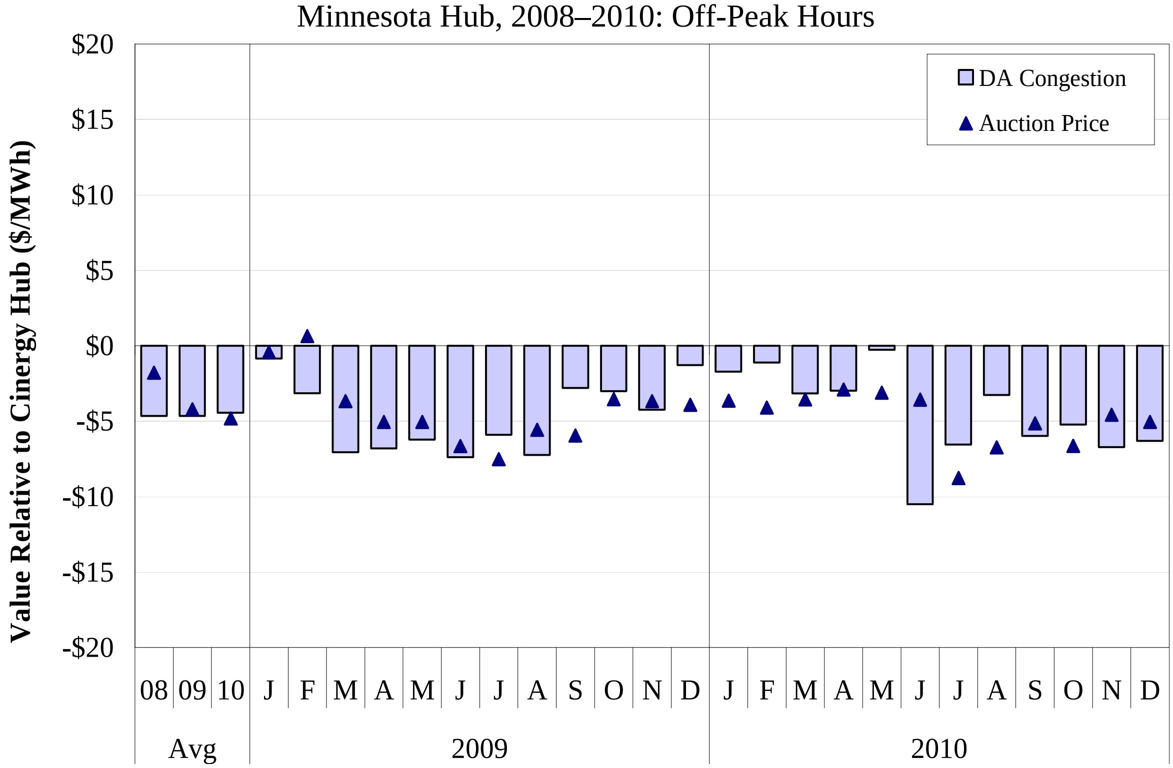
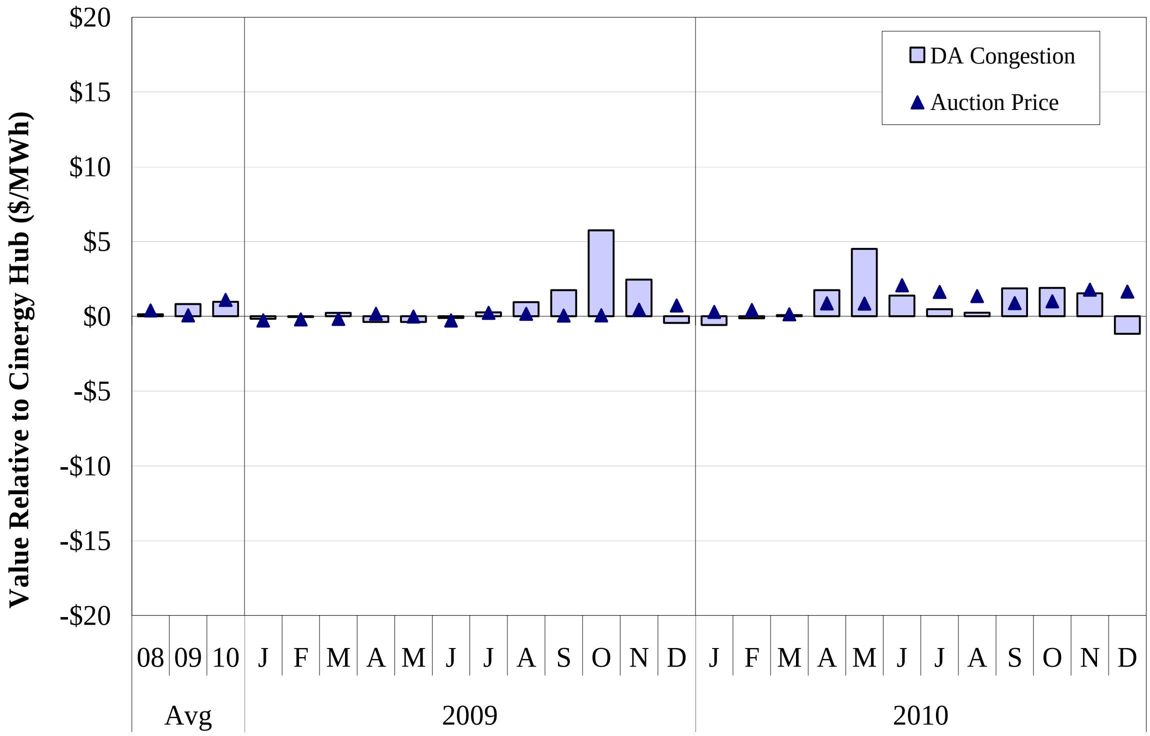


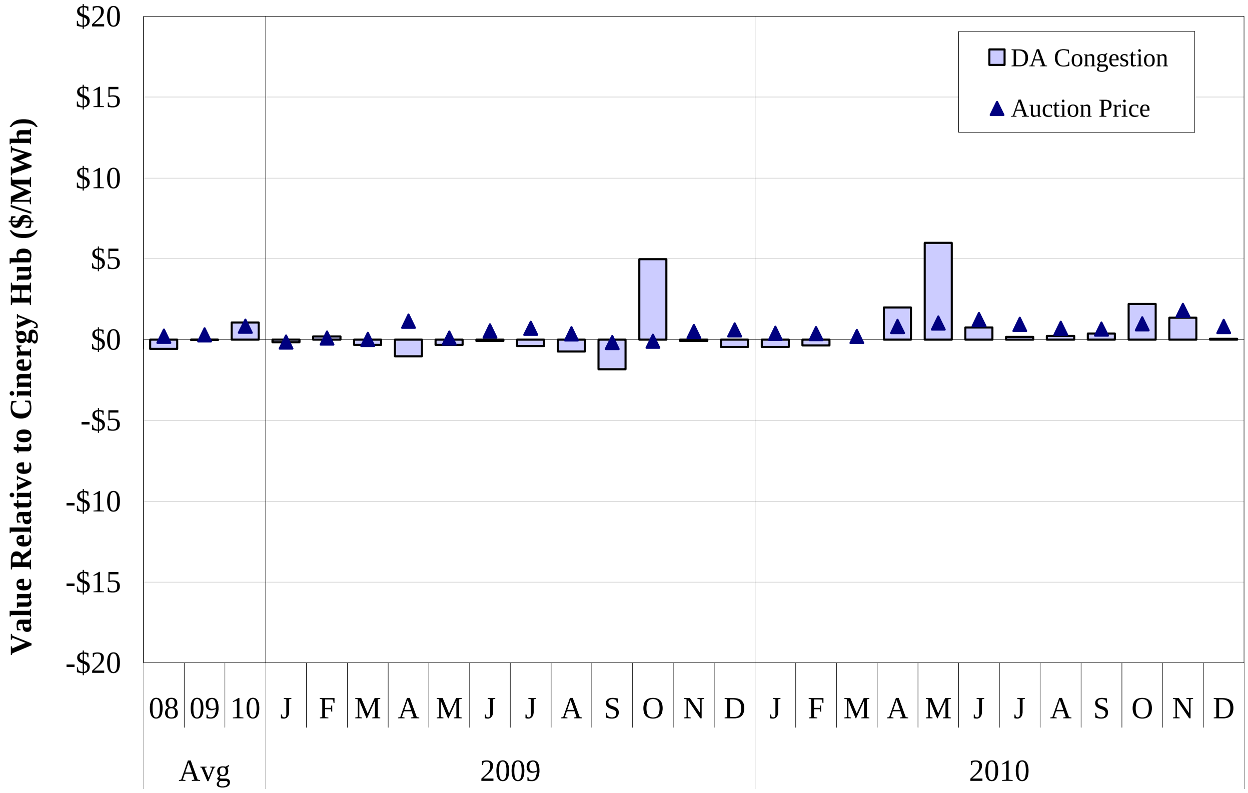
Figure 67 and Figure 68 show the value of congestion and FTR prices from the Cinergy Hub to the Michigan Hub. Both measures are considerably lower than at either Minnesota or WUMS. However, congestion into Michigan persisted for nearly all of 2010. This congestion reflected import constraints on the southwestern Michigan interface that were exacerbated by transmission outages in the second and fourth quarters of the year. The average monthly spread between congestion values and FTR prices in 2010 was $1.16 per MWh, comparable to the $1.09 per MWh value in 2009.

Figure 67: Comparison of FTR Auction Prices and Congestion Value
Michigan Hub, 2008–2010: Peak Hours



Convergence between the Michigan and Cinergy Hubs is affected more by generator and transmission outages than by hourly load or wind patterns. As a result, unlike at the WUMS or Minnesota Hubs, peak and off-peak convergence is very similar. Overall, these results for the Michigan Hub indicate reasonably good convergence. Full convergence is often impaired by loop flows around Lake Erie. Coordinated operation of five phase angle regulators, of which two are controlled by MISO, should improve flows around Lake Erie. Although significant regulatory issues to their full implementation remain, they are all currently expected to be in service before the end of 2011.

Figure 68: Comparison of FTR Auction Prices and Congestion Value
Michigan Hub, 2008–2010: Off-Peak Hours

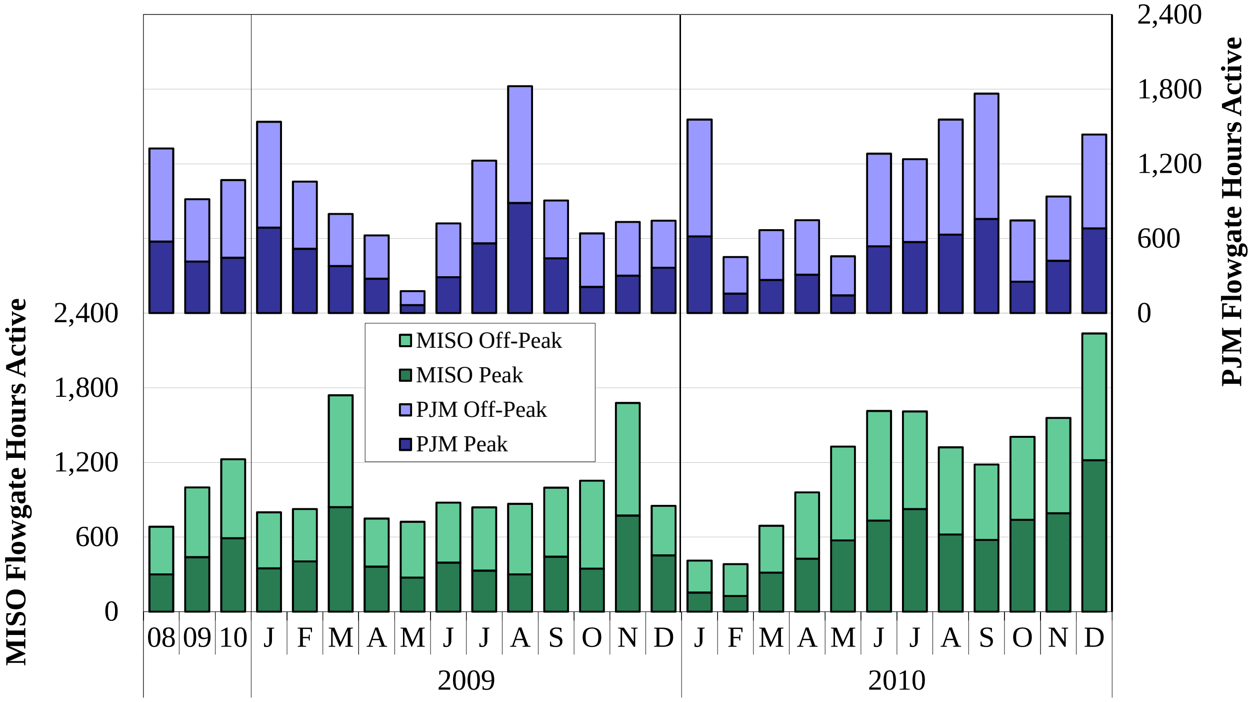


G. Market-to-Market Coordination with PJM

The JOA between MISO and PJM establishes a M2M process for coordinating relief of transmission constraints at designated flowgates. The process is essential to ensure that generation is efficiently dispatched to manage these constraints and that prices in both markets are consistent.

Under the terms of the JOA, when a M2M constraint is activated, the monitoring RTO is responsible for coordinating reliability for the constraint and provides its shadow price and the quantity of relief requested (i.e., the desired reduction in flow) from the other market. This shadow price measures the marginal cost of the monitoring RTO for relieving the constraint. When the reciprocating RTO receives the shadow price and requested relief, it incorporates both values into its real-time market to provide as much of the requested relief as possible at a cost up to the monitoring RTO's shadow price. From a settlement perspective, each market is entitled to its FFE on each of the M2M constraints. Settlements are made between the RTOs based on their actual flows over the constraint relative to their entitlements. Figure 69 shows the total number of 2009 and 2010 M2M constraint-hours (i.e., instances when a M2M constraint was active and binding). The top panel represents coordinated flowgates located in PJM and the bottom panel represents flowgates located in MISO. The darker shade in the stacked bars represents the total number of peak hours in the month when coordinated flowgates were active. The lighter shade represents the total for off-peak hours.

Figure 69: Market-to-Market Events
2009–2010

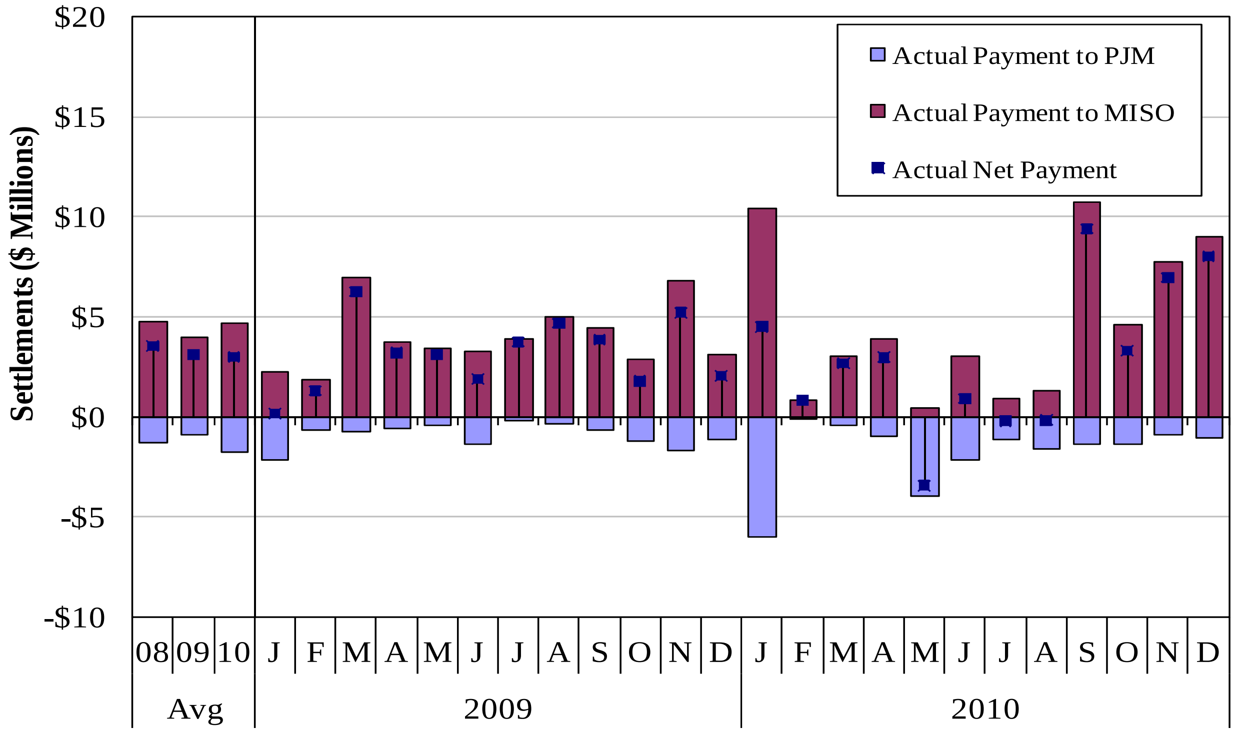


M2M activity increased considerably in 2010: binding hours on MISO and PJM-coordinated flowgates increased by 23 percent and 16 percent, respectively. MISO flowgate activity increased the most during peak hours (up 35 percent) and rose steadily over the year. In January 2010, a key constraint from WUMS (in MISO) to ComEd (in PJM) switched from PJM to MISO coordination. This constraint, which bound more frequently in 2010 as a result of new baseload generation in WUMS, contributed to more constraint hours in MISO. M2M congestion on

MISO constraints were lowest in January and February, consistent with the very low congestion totals observed on internal constraints. Activity on PJM M2M constraints was highest in summer, when demands on the system and west-to-east flows were the greatest.

Figure 70 summarizes the financial settlement of M2M coordination. The M2M settlement is based on the reciprocating RTO's actual market flows compared to its FFE. If the reciprocating RTO's market flow is below its FFE, then it is paid for any unused entitlement at its internal cost of providing that relief. Alternatively, if the reciprocating RTO's flow exceeds its FFE, then it owes the cost of the monitoring RTO's congestion for each MW of flow in excess of its FFE. In the figure, positive values represent payments made to MISO on coordinated flowgates and negative values represent payments to PJM on coordinated flowgates. The drop line shows net payment to (or from) MISO in each month.

Figure 70: Market-to-Market Settlements
2009–2010



During 2010 each RTO received, on average, approximately $1 million per month more than they did in 2009; overall, net payments continue to be made by PJM to MISO. Net payments were largely unchanged at $3 million per month to MISO although PJM received a considerable net payment in May. These results suggest that MISO generally uses less transmission capability than its FFE on M2M constraints, due in part to relative relief provided by each RTO when M2M constraints are activated. This pattern was particularly clear in the September to December period, when net payments totaled almost $28 million.

Since the M2M process plays such an important role in pricing and congestion management in both areas, we continue to evaluate its effectiveness and to recommend improvements. Successful M2M coordination should lead to two outcomes. First, the shadow prices of the two RTOs should converge after activation of a coordinated constraint. Second, the shadow prices should decrease from the initial value as the two RTOs collaborate to manage the constraint. The following analyses evaluate whether these outcomes have been realized.

Figure 71 and Figure 72 examine the five most frequently activated M2M constraints on the PJM and MISO systems. The analysis is intended to show the extent to which shadow prices on coordinated constraints converge between the two RTOs. We calculated average shadow prices and the amount of relief requested during M2M events, including:

- An initial shadow price representing the average shadow price of the monitoring RTO that was logged prior to the first response from the reciprocating RTO; and
- Post-activation shadow prices for both the monitoring and reciprocating RTOs. The post shadow price is the average price in each RTO after the requested relief associated with the M2M process is provided.

Values below the x axis (i.e., horizontal axis) report the share of active constraint hours when the constraint was coordinated (i.e., relief was provided by the reciprocating RTO). Cases in which the reciprocating RTO did not respond and relief capability was unavailable are excluded from these calculations.

Figure 71: PJM Market-to-Market Constraints
Relief Requested and Shadow Prices, 2010

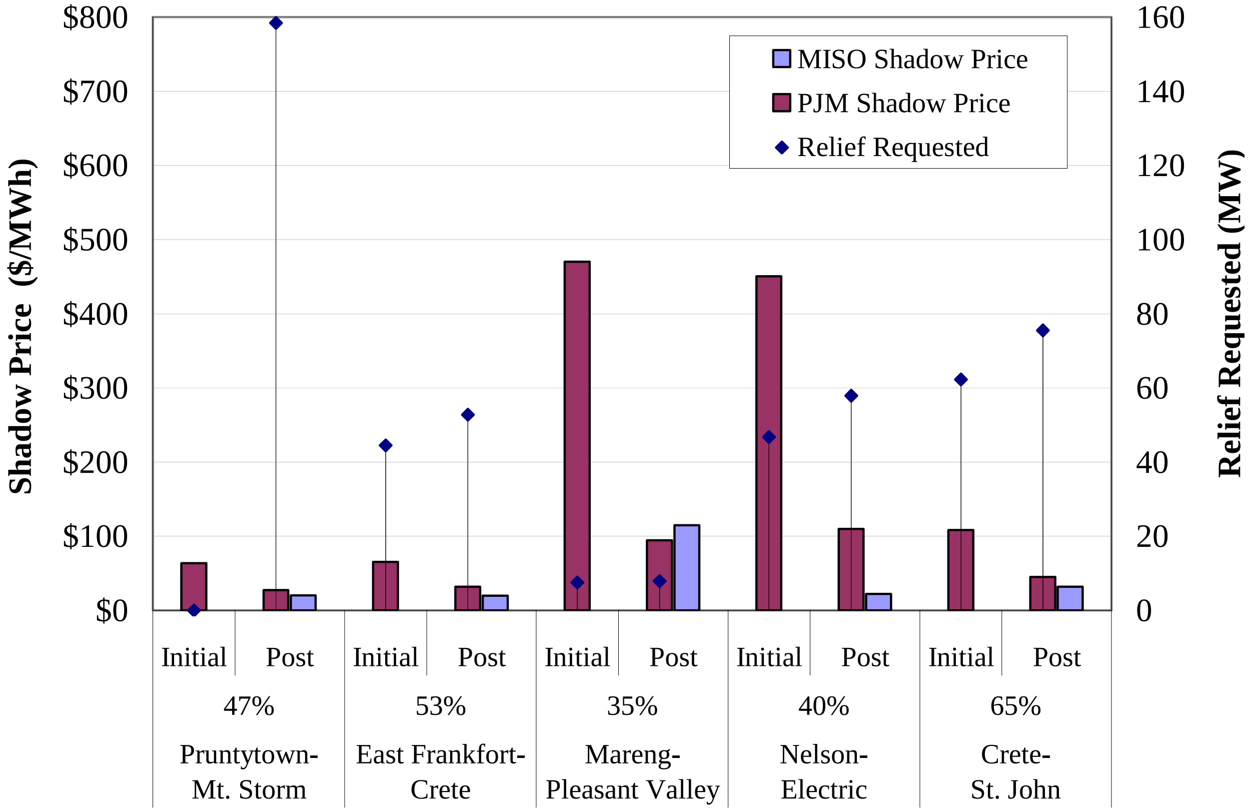
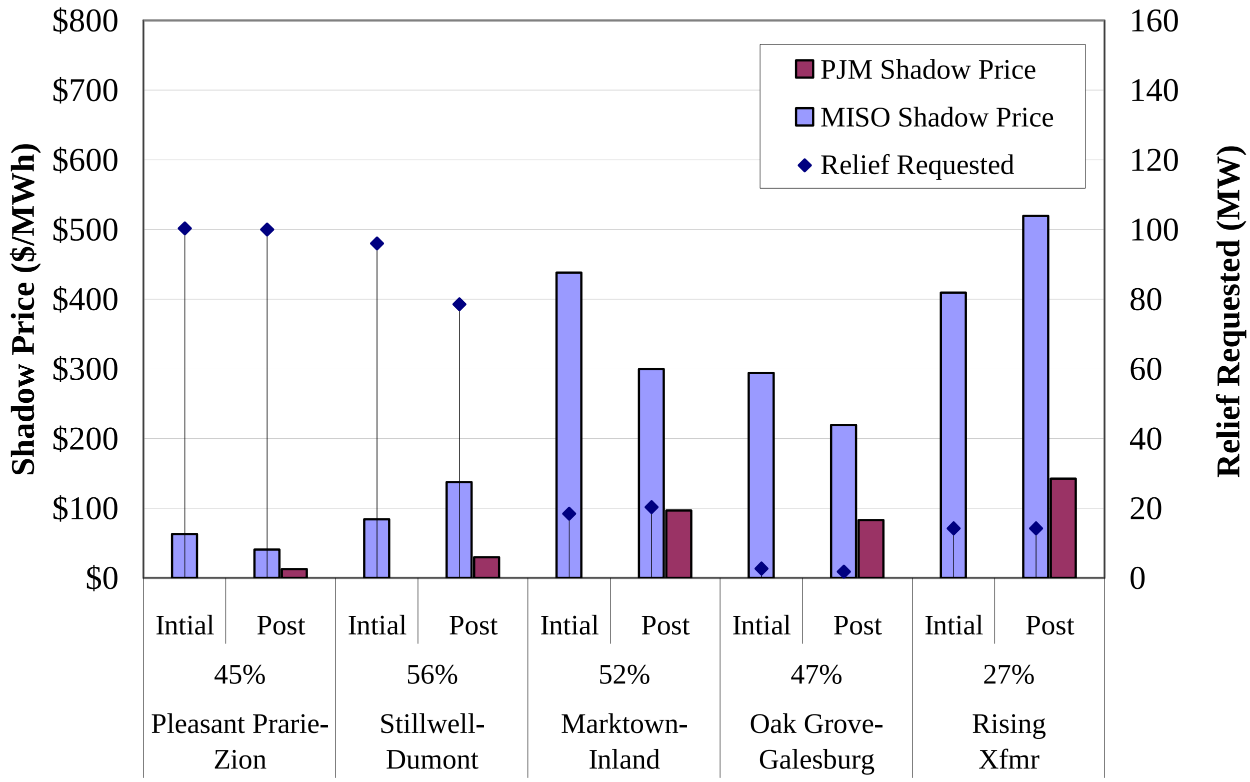


Figure 71 shows PJM shadow prices decreased significantly after constraint activation and converged with MISO shadow prices over the duration of the event, suggesting that the M2M process achieved its objective. The relief requested varies considerably by constraint as well as over the course of the coordinated hours for each constraint. The process to determine appropriate relief request is based on prevailing market conditions and is almost fully automated; however, the RTOs have each recognized that the software has not always provided accurate or reasonable relief values. For this reason, improvements to the software and related procedures continue. A revised version of the software was implemented in late 2010, but manual relief requests continued to be used on certain flowgates. In spite of suboptimal relief requests, MISO's response to PJM relief requests contributed to reduced PJM shadow prices, and thereby constraint management costs, when the RTOs were coordinating. In most cases, post-activation shadow price convergence was very good.

Figure 72 shows the same analysis for the most active M2M constraints coordinated by MISO. The most common flowgates for M2M coordination are those that limit west-to-east flows, including Pleasant Prairie-Zion (in WUMS), Stillwell-Dumont (in the East Region) and Oak Grove-Galesburg (in the Central Region). PJM has made changes that have allowed it to provide substantially more relief than in prior years when MISO activates a M2M constraint.

Figure 72: MISO Market-to-Market Constraints

Relief Requested and Shadow Prices, 2010



As was the case for PJM, shadow prices associated with MISO constraints tend to decrease and move toward convergence over the duration of an event. Still, our comparison of MISO results to those for PJM shows a smaller reduction in shadow prices and less price convergence. However, both parameters improved in 2010 as compared to 2009.

Additional cost-effective relief may be available from PJM. The improvement to the relief software may improve these results, although we recommend that the RTOs work together to identify any other modeling parameters, provisions, or procedures that may be limiting PJM's relief.

MISO and PJM responded to a number of past IMM recommendations in 2010 that should further improve performance of the M2M process in 2011. In particular, the Broader Regional Markets Initiative should produce interconnection-wide cost savings in 2011 and provide better coordination of the interchange with PJM. Nevertheless, we continue to recommend the following additional changes:

- MISO should institute a process to monitor more closely the information exchanged with PJM to quickly identify when the process is not operating correctly.
- MISO should discontinue the constraint relaxation algorithm, even on M2M constraints that cannot be resolved by the monitoring RTO.
- The RTOs should work together to identify any other modeling parameters, provisions, or procedures that may be limiting PJM's relief.
- The RTOs should clarify the JOA in the following specific areas to avoid future disagreements:
    1. Use of marginal value limits;
    2. Pre-positioning on coordinated constraints;
    3. Use of proxy flowgates;
    4. Obligation to activate a coordinated constraint;
    5. Obligation to test new constraints; and
    6. Flowgate definitions and the thresholds used to identify new coordinated constraints.

Additionally, we continue to recommend that the RTOs expand their M2M process to optimize interchange between markets.

VI. Competitive Assessment

This section assesses the competitive structure and performance of MISO's markets in 2010. The competitive assessment evaluates multiple measures of market power and, more importantly, whether market power has been exercised. Such assessments are particularly important for LMP markets because they can provide opportunities to exercise local market power in congested areas.

A. Market Structure

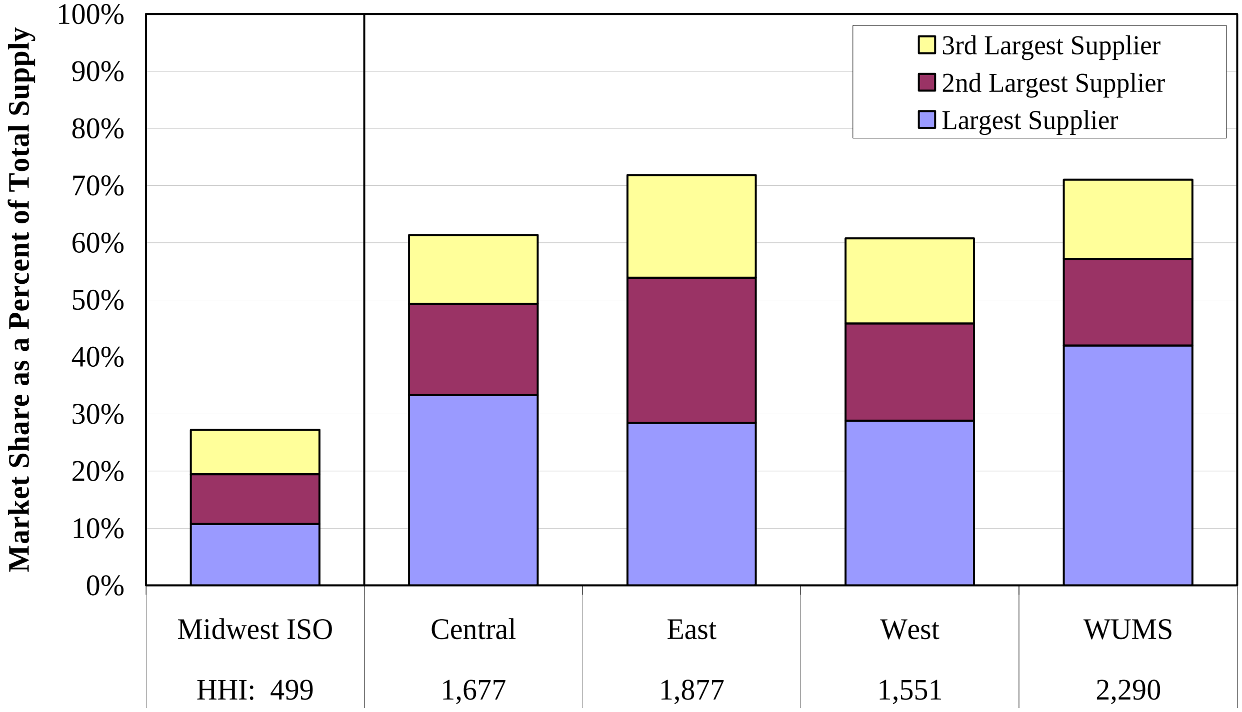
This first subsection provides three structural analyses of the market. The first market power indicator is the generation ownership concentration of both MISO as a whole and the various regions within it. The latter two analyses address the frequency with which suppliers in MISO are "pivotal", i.e., needed to serve load reliably or to resolve transmission congestion. In general, the two pivotal supplier analyses provide much more reliable indications of potential market power in electricity markets than the market concentration analysis does.

1. Structural Market Concentration

The first analysis evaluates the market's concentration using the Herfindahl-Hirschman Index. The HHI is a standard measure of market concentration calculated by summing the square of each participant's market share. Antitrust agencies generally characterize markets with HHIs greater than 1,800 as "highly concentrated", while markets with HHIs less than 1,000 are not considered to be concentrated. The HHI is only a general indicator of market concentration and not a definitive measure of market power. The HHI's most significant shortcomings for identification of market power in electricity markets are that it does not account for demand, network constraints, or load obligations. In wholesale electricity markets, these factors have a profound effect on competitiveness. Figure 73 shows generating capacity-based market shares and HHI calculations for MISO as a whole and within each region.

The market concentration of the entire MISO footprint is low at 499, indicative of a competitive market. The largest three suppliers combined have a total market share of less than 30 percent. This metric indicates that generation ownership in MISO as a whole is not concentrated; however, each of the four regions is substantially more concentrated than MISO as a whole.

Figure 73: Market Shares and Market Concentration by Region
2010



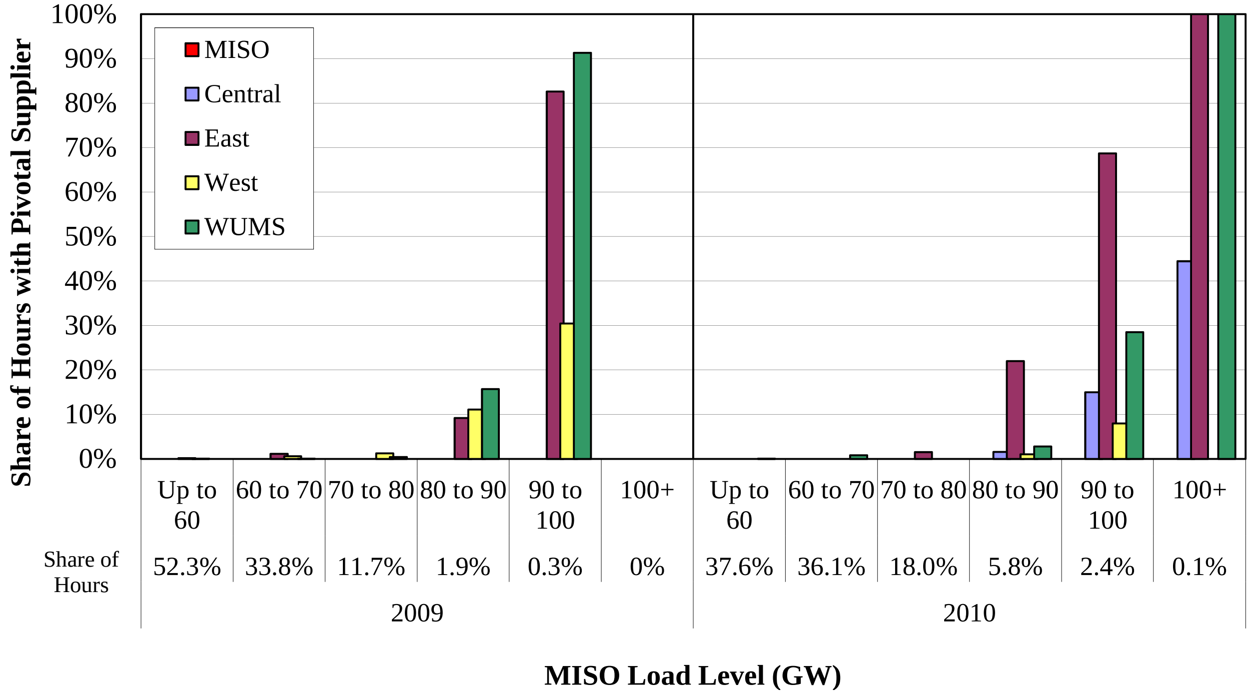
Although HHI values fell in all regions in 2010 due to investment and membership additions, the East Region and WUMS area remain highly concentrated: the top three suppliers control more than 70 percent of the supply in both of these regions. Continued investment by small suppliers in the West has resulted in the lowest regional market concentration in MISO. 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. Divestitures of generation in other RTO zones generally reduce market concentration because the assets are typically sold to a number of smaller entities.

2. Residual Demand Index

The HHI market concentration metric is commonly used to evaluate of market power. However, the HHI does not allow one to draw reliable inferences regarding the competitiveness of electricity markets because it does not recognize physical characteristics of electricity that can cause a supplier to have market power.

The next two analyses more accurately reveal potential competitive concerns in MISO energy markets. The first metric is the Residual Demand Index ("RDI"), which measures the part of the load in an area that can be satisfied without the resources of its largest supplier. The RDI is calculated based on the internal capacity and all import capability into the area, not just the imports actually scheduled. In general, the RDI decreases as load increases. An RDI greater than 1 means that the load can be satisfied without the largest supplier's resources. An RDI less than 1 indicates that a supplier is "pivotal" and a monopolist over some of the load. Figure 74 summarizes the results, showing the percentage of total hours with a pivotal supplier by region and load level. The percentages shown below the x-axis indicate the percent of hours falling into each load-level tranche.

Figure 74: Pivotal Supplier Frequency by Load Level[24]
2009–2010



Pivotal supplier frequency rose sharply with load in both 2009 and 2010. This is typical in electricity markets since electricity cannot be economically stored, so when load increases the excess capacity will fall and the resources of the largest suppliers will become more necessary.

24 In 2009 load never exceeded 100 GW. The 2010 load values are adjusted for membership changes in order to allow more direct comparisons to 2009.

Prices are most sensitive to withholding under high-load conditions which makes it more likely that a supplier could profitably exercise market power. This relationship explains why market power concerns are greatest when load is highest. The load increase in 2010 is the primary reason for the year-over-year increase in pivotal supplier frequency. Although the pivotal supplier frequency remains high under peak-load conditions, the market power mitigation measures have effectively addressed most competitive concerns.

The share of hours with a pivotal supplier increased in all regions in 2010 except the West Region, where the addition of MidAmerican in September 2009 and influx of new wind capacity throughout 2009 and 2010 has altered the competitive landscape. The regions with the most frequent pivotal suppliers were the East Region (3.3 percent of hours) and WUMS (1.3 percent). In the East Region, 70 percent of hours with adjusted load exceeding 90 GW had a pivotal supplier. Pivotal suppliers were less of a concern in the West and Central Regions, and no supplier was pivotal during any hour in MISO as a whole during 2010.

3. Constraint-Specific Pivotal Supplier Analysis

While the RDI pivotal supplier analysis is useful for generally evaluating a market's competitiveness, accurately identifying local market power requires a still more detailed analysis focused on specific transmission constraints that can isolate locations on the transmission grid. Such analyses measure potential local market power concerns more precisely than either HHI or RDI by specifying when a supplier is pivotal relative to a particular transmission constraint.

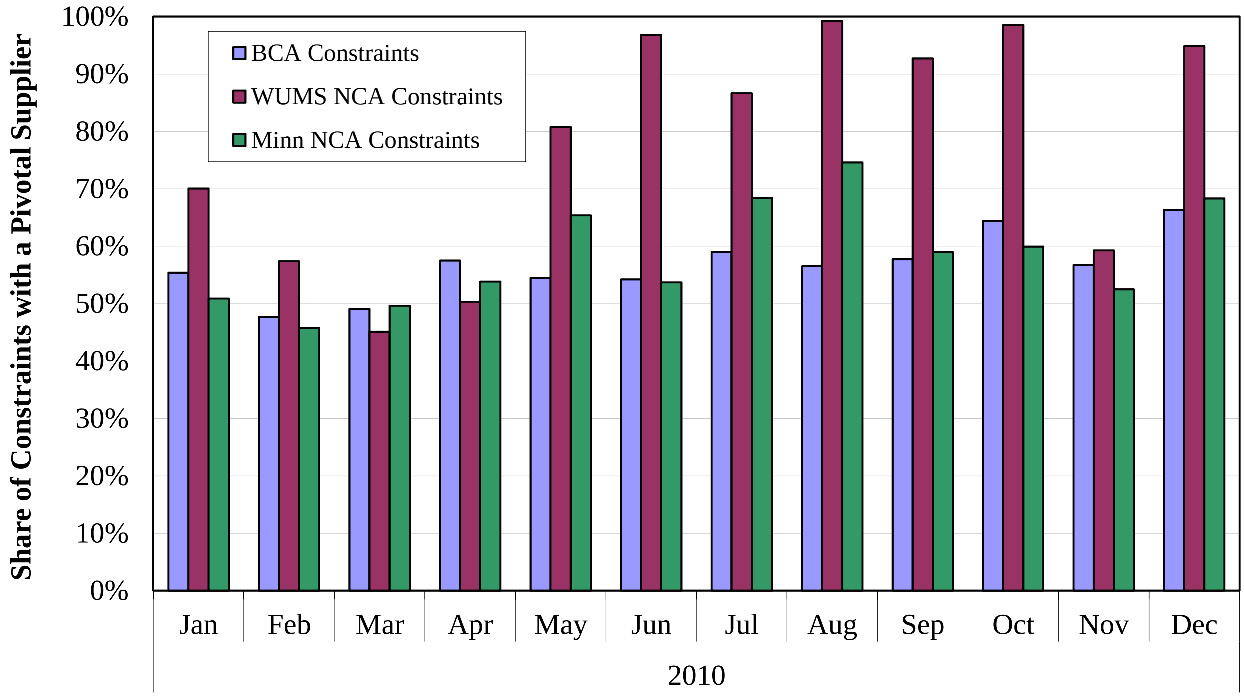
A supplier is pivotal for a constraint when it has the resources to overload that constraint to an extent that all other suppliers combined cannot relieve the constraint. This is frequently the case for lower-voltage constraints because the resources that most affect the flow over the constraint are those that are near the constraint. If the same supplier owns all of these resources, this supplier is likely pivotal to maintaining reliability. In 2010, 10 percent of the $1.03 billion in congestion was on low-voltage constraints.

Two types of constrained areas are defined for purposes of market power mitigation: BCAs and NCAs. The definition of BCAs and NCAs is based on the electrical properties of the transmission network that can lead to local market power. NCAs are chronically constrained areas where one or more suppliers are frequently pivotal. Hence, they can be defined in advance and are subject to tighter market power mitigation. The three NCAs currently defined in the MISO markets are the Minnesota NCA,[25] the WUMS NCA, and the north WUMS NCA.

Market power associated with other constraints (i.e., BCA constraints) can still be significant. If such constraints are not chronic, however, they raise limited competitive concerns. Due to the vast number of potential constraints and the fact that the topology of the transmission network can change significantly when outages occur, it is neither feasible nor desirable to define all possible BCAs in advance. Therefore, BCAs are defined dynamically when non-NCA transmission constraints bind. A BCA includes all generating units with significant impact on power flows over the constraint. Figure 75 shows shares of active NCA and BCA constraints with at least one pivotal supplier in 2010.

Figure 75: Percentage of Active Constraints with a Pivotal Supplier

2010

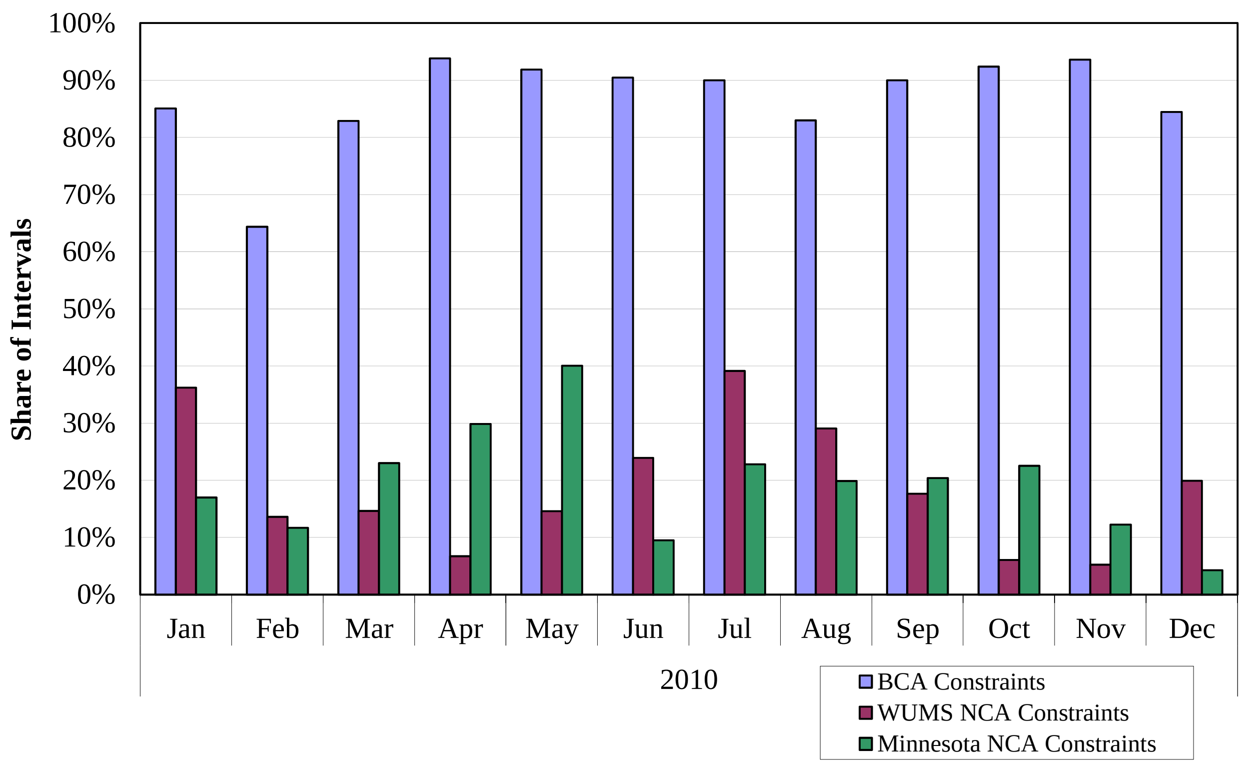


25 Minnesota NCA is defined by constraints limiting imports into southeast Minnesota and part of northern Iowa.

During 2010, active constraints in BCAs and the defined NCAs had a pivotal supplier in the majority of hours during most months. Among active constraints in 2010, 76 percent of those into the WUMS NCA had a pivotal supplier (up from 69 percent in 2009); 60 percent of those into the Minnesota NCA had a pivotal supplier (down from 75 percent); and 56 percent of all BCA constraints had a pivotal supplier (down from 64 percent). Consistent with the findings of the RDI measure, the share of binding constraints with pivotal suppliers tends to be higher during the higher-load summer months in NCAs. Nearly all constraints into WUMS exhibited a pivotal supplier from June to October. These results indicate that local market power conditions are not limited to just NCA constraints, and that market power mitigation measures remain essential.

This need is further punctuated by Figure 76, which shows the percentage of all market intervals when at least one supplier was pivotal for such a constraint. Unlike the previous analysis, this one shows how frequently BCA and NCA constraints are active. Therefore, it measures how frequently local market power may be a problem within MISO.

Figure 76: Percent of Intervals with at Least One Pivotal Supplier
2010



The figure shows an active BCA constraint with at least one pivotal supplier in 87 percent of the hours during 2010, up from 79 percent in 2009. This increase was impacted by the MISO assuming responsibility for more lower-voltage constraints, which resulted in a higher number of binding constraints. Only once did this frequency fall below 80 percent (64 percent in February). The share of intervals with a pivotal supplier in each NCA was largely unchanged at approximately 20 percent in both areas. The number of constraints defining each NCA is substantially smaller, so the share of all intervals with a pivotal supplier is expect to be smaller.

B. Participant Conduct

The structural analyses in the prior sections indicate the likely presence of local market power associated with transmission constraints in the MISO market area. In this section, we analyze participant conduct to determine whether it was consistent with competitive behavior or whether it was consistent with attempts to exercise market power. We begin this section by estimating a price-cost markup. Then we test for two types of conduct consistent with the exercise of market power: economic withholding and physical withholding. Economic withholding occurs when a participant offers resources substantially above competitive levels in an effort to raise market clearing prices or RSG payments. Physical withholding occurs when a unit that would be economic at the market price is unavailable to produce some or all of its output. Such withholding is usually accomplished by claiming an outage or by derating a resource but may also be accomplished through other physical offer parameters.

1. Price-Cost Markup Analysis

The price-cost markup analysis estimates the "markup" of real-time market prices over suppliers' competitive costs. It compares the simulated SMP under two separate sets of assumptions: (1) suppliers offer at prices equal to their reference levels; and (2) suppliers' actual offers. We then calculate a yearly load-weighted average of the estimated system marginal price under each scenario. The difference in estimated SMPs is the markup. This analysis does not account for physical restrictions on units and transmission constraints, or potential changes in the commitment of resources, both of which would require re-running market software.

This metric is useful in evaluating the competitive performance of the market. A competitive market should produce a small markup because suppliers should have incentives to offer at their marginal cost. Our estimated average annual markup was approximately 1.3 percent in 2010, compared to the 1.2 percent and 2.0 percent estimated in 2009 and 2008, respectively. Many factors can cause reference levels to vary slightly from suppliers' true marginal costs, so we would not expect to see a markup exactly equal to zero. Markups of 1-2 percent are not material and indicate that markets have performed competitively during this period.

2. Economic Withholding

An analysis of economic withholding requires a comparison of actual offers to competitive offers. Suppliers lacking market power maximize profits by offering resources at marginal cost, i.e., a generator's competitive offer price. A generator's marginal cost is the incremental cost of producing additional output. Marginal cost includes inter-temporal opportunity costs, risk associated with unit outages, fuel, additional O&M, and other costs attributable to the incremental output. For most fossil-fuel resources, marginal costs are closely approximated by variable production costs (primarily fuel and variable O&M costs). At high output levels or after running for long periods without routine maintenance, however, outage risks and expected increases in O&M can create substantial additional incremental costs. Generating resources with energy limitations, such as hydroelectric units or fossil-fuel units with output restrictions due to environmental considerations, forego revenues in future periods to produce in the current period. These units incur inter-temporal opportunity costs of production that can ultimately cause their marginal cost to exceed variable production cost.

Establishing a competitive benchmark, or "reference level", for units' marginal cost is a key component of analyses to identify economic withholding. This benchmark is necessary to determine the quantity of output that is potentially economically withheld. MISO's market power mitigation measures include a variety of methods to calculate a resource's reference levels. We use these reference levels for the analyses below. The mitigation measures also include a threshold that defines the premium above the reference levels a supplier may offer before potentially warranting mitigation. This threshold is used in the market power mitigation "conduct test".

To identify potential economic withholding, we calculate an "output gap" metric, based on a resource's startup, no-load, and incremental energy offer parameters. The output gap is the difference between the economic output level of a unit at the prevailing clearing price and the amount actually produced by the unit. In essence, the output gap quantifies the generation that a supplier may be withholding from the market by submitting offers above competitive levels. Therefore, the output gap for any unit would generally equal:

$Q_i^{econ} - Q_i^{prod}$ when greater than zero, where:

Q_i^{econ} = Economic level of output for unit i; and

Q_i^{prod} = Actual production of unit i.

To estimate Q_i^{econ}, the economic level of output for a particular unit, it is necessary to look at all parts of the unit's three-part reference level: start-up cost reference, no-load cost reference, and incremental energy cost reference. These costs jointly determine whether a unit would have been economic at the clearing price for at least the unit's minimum run time.

We employ a three-stage process to determine the economic output level for a unit in a particular hour. First, we examine whether the unit would have been economic for commitment on that day if it had offered its true marginal costs. In other words, we examine whether the unit would have recovered its actual startup, no-load, and incremental costs running at the dispatch point dictated by the prevailing LMP (constrained by its Economic Minimum and Economic Maximum) for its minimum run time. Second, if a unit was economic for commitment, we then identify the set of contiguous hours when it was economic to dispatch.

Finally, we determine the economic level of incremental output in hours when the unit was economic to run. When the unit was not economic to commit or dispatch, the economic level of output was considered to be zero. To reflect the timeframe when such commitment decisions are made in practice, this assessment was based on day-ahead market outcomes for non-quick-start units and on real-time market outcomes for quick-start units.

Because our benchmarks for units' marginal costs are inherently imperfect, we add a threshold to the resources' reference level to determine Q_i^{econ}. This ensures that we will identify only significant departures from competitive conduct. The thresholds are based on those defined in the Tariff for BCAs and NCAs and are described in more detail below.

Q_i^{prod} is the actual observed production of the unit. The difference between Q_i^{econ} and Q_i^{prod} represents how much the unit fell short of its economic production level. However, some units are dispatched at levels lower than their three-part offers would indicate due to transmission constraints, reserve considerations, or other changes in market conditions between the unit commitment and real-time. Therefore, we adjust Q_i^{prod} upward to reflect three-part offers that would have made a unit economic to run, even though the unit may not have been fully dispatched. Hence the output gap formula used for this report is:

$Q_i^{econ} - \max(Q_i^{prod}, Q_i^{offer})$ when greater than zero, where:

Q_i^{offer} = offer output level of i.

By using the greater of actual production or the output level offered at the clearing price, units that are subject to ramp limitations are excluded from the output gap.

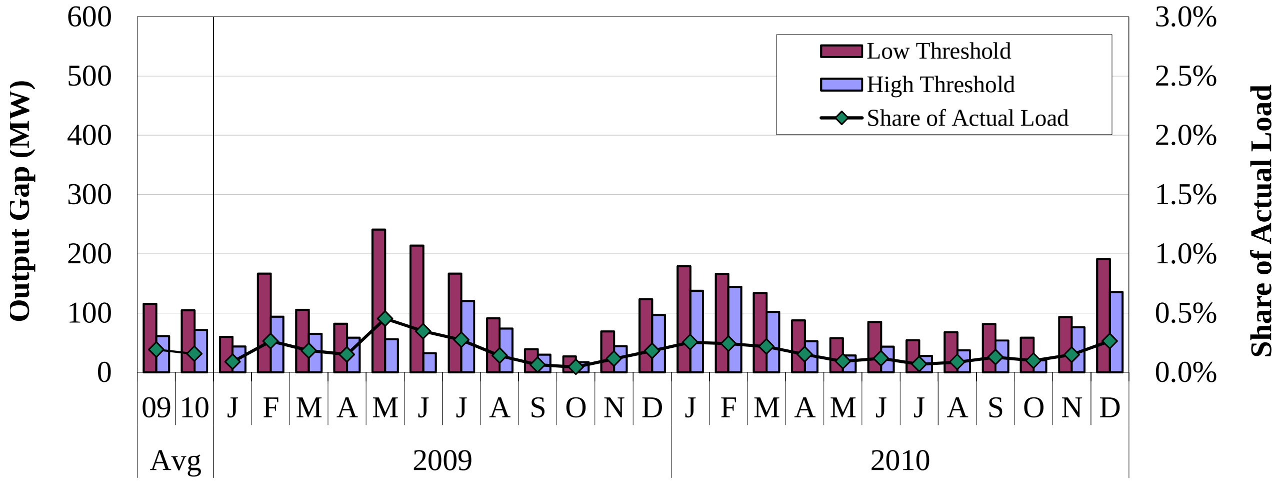
Figure 77 shows monthly average output-gap levels for the real-time market in 2009 and 2010. The output gap shown in the figure and summarized in the table includes two types of units: (1) online and quick-start units available in real time; and (2) offline units that would have been economic to commit. The data is arranged to show the output gap using the mitigation threshold in each area (i.e., “high threshold”), and one-half of the mitigation threshold (i.e., “low threshold”). Resources located in NCAs are tested at the NCA conduct thresholds and resources outside NCAs are tested at BCA conduct thresholds.

The high threshold for resources in BCA is the lower of $100 per MWh above the reference or 300 percent of the reference. The thresholds effective during most of 2010 were $56.33 per MWh for resources located in the WUMS NCA, $28.39 per MWh for resources in the North WUMS NCA, and $77.66 per MWh for resources in the Minnesota NCA.[26] The low threshold is set to 50 percent of the applicable high threshold for a given resource. For example, for a

26 Thresholds for January 1 to February 28, 2010 were $22.11 per MWh for the WUMS and North WUMS NCAs, and $42.97 per MWh for the Minnesota NCA.

resource in WUMS, the low threshold would be $28.17 per MWh (50 percent of $56.33). For a resource's unscheduled output to be included in the output gap, its offered commitment cost per MWh or incremental energy offer must exceed the given resource's reference plus the applicable threshold. The lower threshold would indicate potential economic withholding of output that is offered at a price significantly above its reference yet within the mitigation threshold.

Figure 77: Monthly Average Output Gap: Real-Time Market
2009–2010



Low Threshold Results by Unit Status (MW)

	Avg 09	Avg 10	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	68	43	28	97	43	35	190	177	78	15	13	17	59	61	74	110	75	28	12	31	16	19	18	5	33	95
On-Line	48	62	32	70	63	48	51	36	89	76	26	10	10	62	105	57	59	60	46	54	39	49	64	54	61	96

High Threshold Results by Unit Status (MW)

	Avg 09	Avg 10	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	22	42	25	52	9	21	8	7	46	1	5	13	41	37	67	110	73	27	12	31	16	19	18	5	33	89
On-Line	39	30	18	42	57	38	48	25	75	73	25	4	3	60	71	35	29	26	17	12	12	19	36	15	43	46

Figure 78 shows that, on average, output gap levels at the high threshold were modestly higher in 2010 than in 2009 and they were slightly lower at the low threshold. In 2010 offline and online output gap levels combined to average 72 MW at high thresholds and 105 MW at low thresholds. Levels were highest in the winter months as a result of relatively high energy prices and fuel price volatility. As a share of actual load, output gap at low threshold remains considerably below 0.5 percent, and ranged from 0.07 percent in July to 0.26 percent in December. These levels are extremely low and raise very few competitive concerns. However, we monitor these levels continually and have investigated many specific output gap issues. In nearly all cases, output gap can be explained by specific operating conditions and other competitive factors.

Despite low output gap levels, further examination of the issue can be useful. Any measure of potential withholding inevitably includes some quantities that can be justified; therefore, we generally evaluate not only the absolute level of the output gap but also how it varies with factors that can cause a supplier to have market power. This process lets us test if a participant's conduct is consistent with attempts to exercise temporal market power.

The most important factors in this type of analysis are participant size and load level. Larger suppliers generally are more likely to be pivotal and tend to have greater incentive to increase prices than relatively smaller suppliers. Load level is important because the sensitivity of the price to withholding usually increases with load, particularly at the highest levels. This pattern is due in part to the fact that rivals' least expensive resources will be more fully-utilized serving load under these conditions, leaving only the highest-cost resources to respond to withholding.

The effect of load on potential market power was evident earlier in this section in the pivotal supplier analyses. Figure 78 to Figure 81 show output gap in each region by load level, separately showing the two largest suppliers in the region versus all other suppliers. The figures also show the average output gap at the mitigation thresholds and at one-half of the mitigation thresholds (the high and low thresholds discussed previously).

Figure 78: Real-Time Market Output Gap
Central Region, 2010

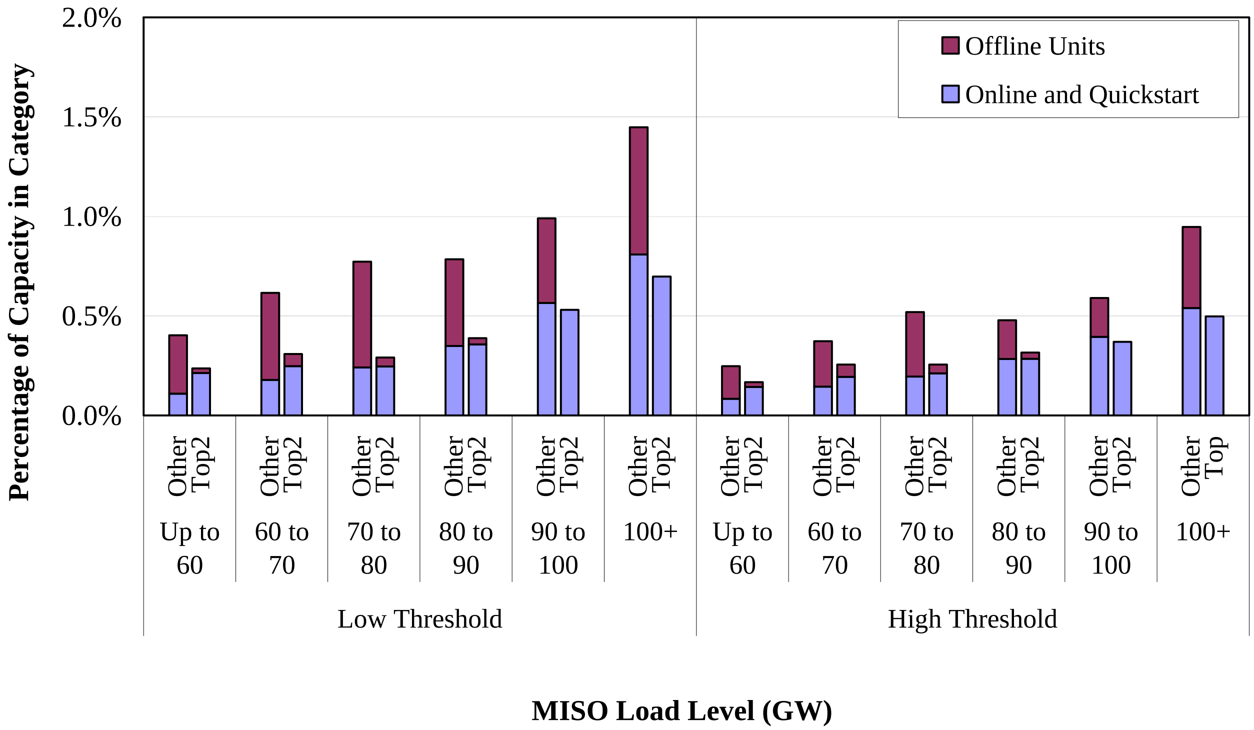


Figure 79: Real-Time Market Output Gap
East Region, 2010

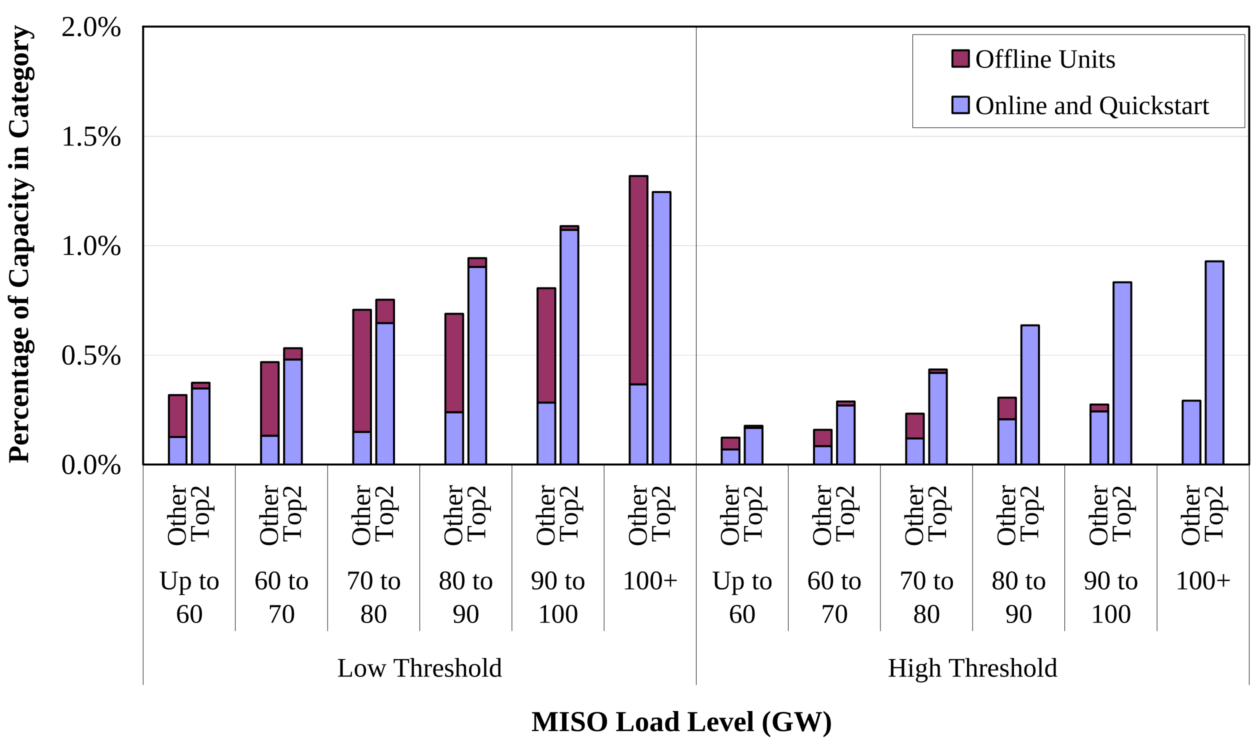


Figure 80: Real-Time Market Output Gap
West Region, 2010

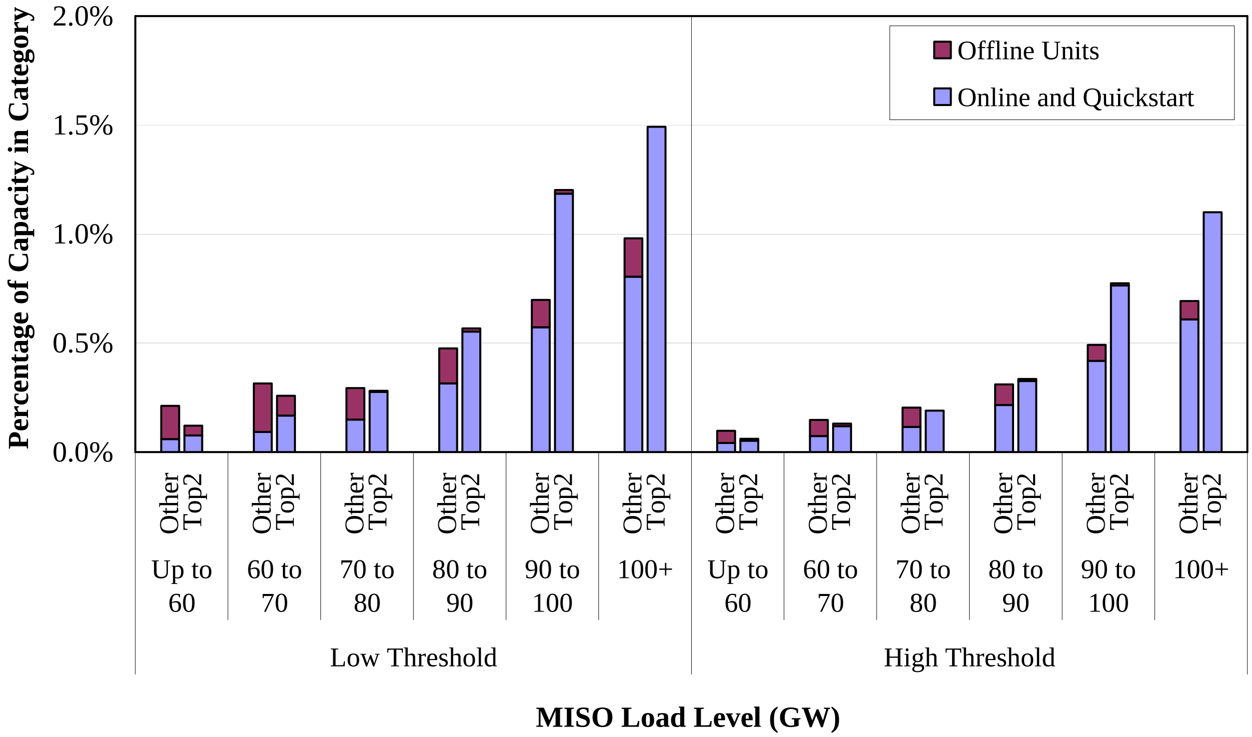
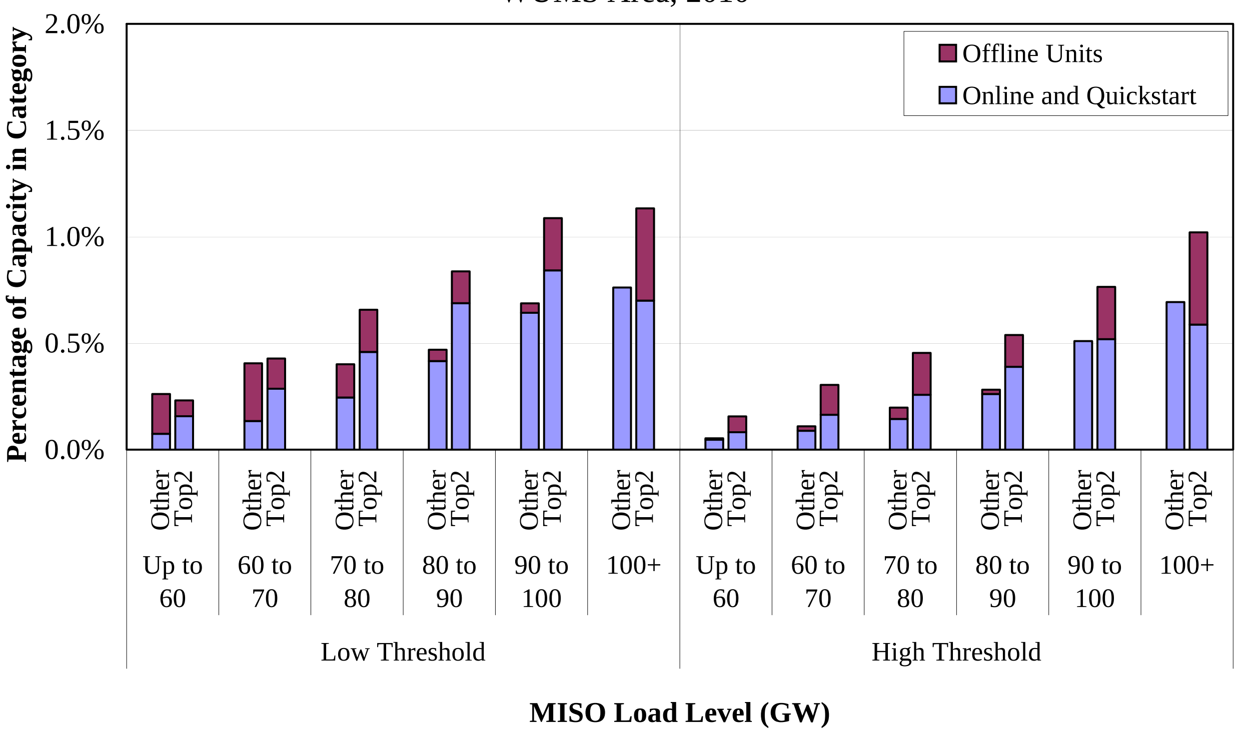


Figure 81: Real-Time Market Output Gap
WUMS Area, 2010



The results confirm that participants' conduct in 2010 did not raise material competitive concerns. The output gap as a percentage of actual load at both threshold levels is less than 1 percent at most load levels and locations. Higher load levels in 2010 resulted in modest increases in output gap at the highest load levels (over 100 GW), but the output gap never exceeded 1.5 percent in any region. In general, output gap increases with load because the high prices that occur at high-load levels cause a much greater share of resources to be economic. However, because this could also signal a rise in anticompetitive conduct, we investigate increases in output gap levels at higher-load levels on an ongoing basis. These investigations did not raise material competitive concerns in 2010.

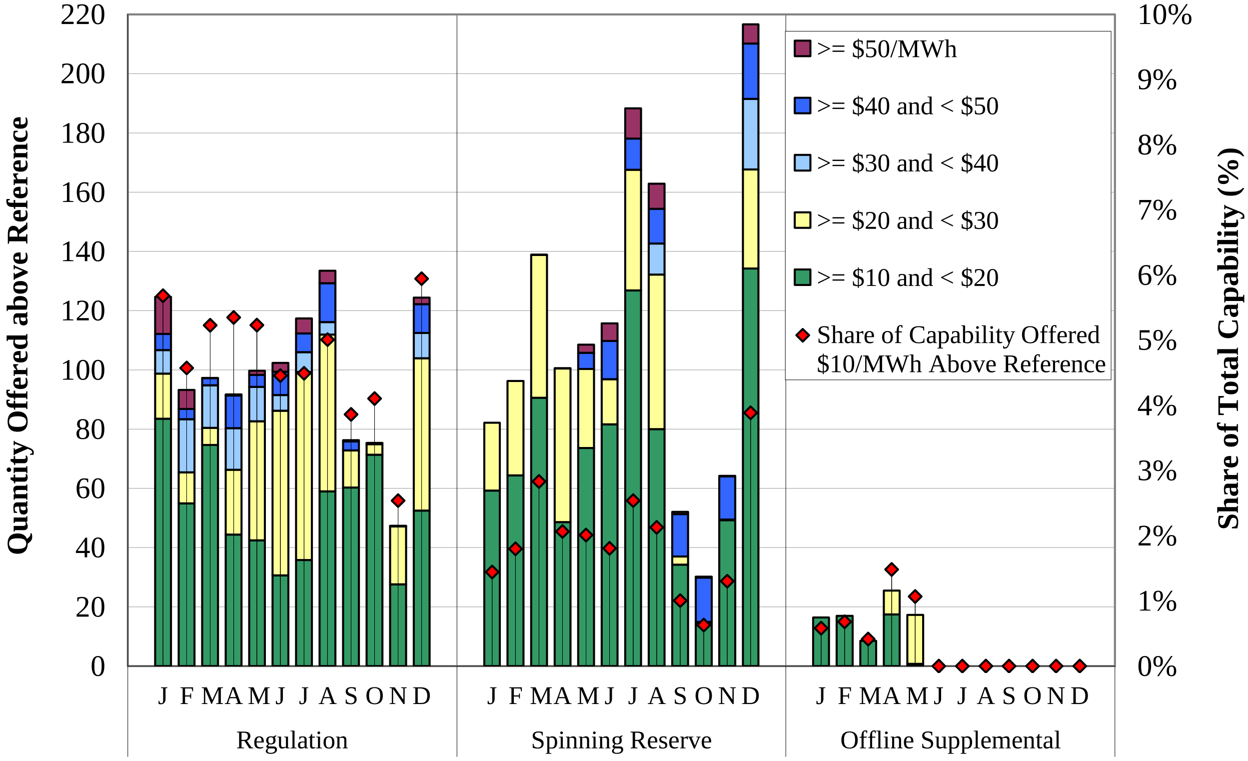
In the West and WUMS regions, output gap levels were modestly higher for the top two suppliers in each region compared to other suppliers. In the other regions, the output gap was close to or lower than the output gap of the other suppliers.

These results, coupled with our ongoing monitoring of hourly results, indicate that economic withholding has not been a significant concern in 2010. The competitive offer patterns that prevailed in 2010 are indicative of the structural characteristics of the market that encourage suppliers to bid at marginal cost. Despite higher loads, surplus generation conditions minimized the incentive to economically withhold supply, even during high-load conditions. Additionally, many of the largest suppliers in MISO are large LSEs with little economic incentive to withhold resources.

We also evaluated the Ancillary Services Markets and found that they generally performed competitively in 2010. Figure 82 shows monthly average quantities of regulation and operating reserves offered at prices ranging from $10 to $50 per MWh above each unit's reference level.[27] As in the energy market, a reference level for ancillary services is an estimate of the competitive offer level for the service (i.e., the unit's marginal cost of supplying the service).

27 These thresholds are below the BCA mitigation threshold, which is the lesser of 300 percent or $50 per MWh (for offer prices greater than $5 per MWh).

Figure 82: Ancillary Service Offers
2010



Offers for ancillary services available through MISO-managed markets were generally competitive in 2010. On average, 99 MW of regulation capability (or 4.7 percent of the online regulation capability) was offered at more than $10 per MW above its reference level. This level is largely unchanged from 2009, when 4.8 percent of online capacity was offered above reference. The share offered at more than $20 per MWh above reference increased to 45 MW on average, up from 19 MW in 2009. Similar to regulation, 113 MW of spinning reserve capability (or 2.0 percent of the total capability) exceeded the reference level at the $10 per MWh threshold, up slightly from 105 MW in 2009. Offers exceeding reference levels were lowest between September and November, when less than 50 MW on average failed.

Offer prices in 2010 for supplemental reserves, and in turn conduct failures (offers that exceed reference levels by defined thresholds), remained low. Supplemental reserve offer conduct failures did not occur after May, which coincides with the reduction in overall offer volumes (see Figure 33). There were six ASM mitigation events in 2010, all of which involved the mitigation of regulation offers. Given the relatively small share of the total capability represented by these offers and the fact that some resources naturally have higher perceived costs or risks associated with selling ancillary services, we conclude that ASM offers in 2010 were competitive and contributed to good overall performance.

3. Physical Withholding

Prior analyses assessed offer patterns to identify potential economic withholding. By contrast, physical withholding occurs if a unit that would be economic at the market price is unavailable to produce some or all of its output as a function of a non-economic parameter or condition. For instance, this form of withholding may be accomplished by a supplier unjustifiably claiming an outage or derating of the resource. Although we analyze broad patterns in outages and deratings for this report, we also monitor for potential physical withholding on a day-to-day basis and audit outages and deratings with a substantial effect on market outcomes.

Figure 83 to Figure 86 show average share of capacity unavailable to the market in 2010 because of forced outages and deratings in one of the four regions of MISO. As with the output gap analysis, this conduct may be justifiable or may represent physical withholding. Therefore, we evaluate the conduct relative to load levels and participant size to detect patterns consistent with withholding. Attempts to withhold would likely occur more often at high-load levels when prices are most sensitive to withholding. We also focus particularly on short-term outages (lasting fewer than seven days) and partial deratings because long-term forced outages are less likely to be profitable withholding strategies. Taking a long-term, forced outage of an economic unit would cause the supplier to forego profits on the unit during hours when the supplier does not have market power.

Figure 83: Real-Time Deratings and Forced Outages
Central Region, 2010

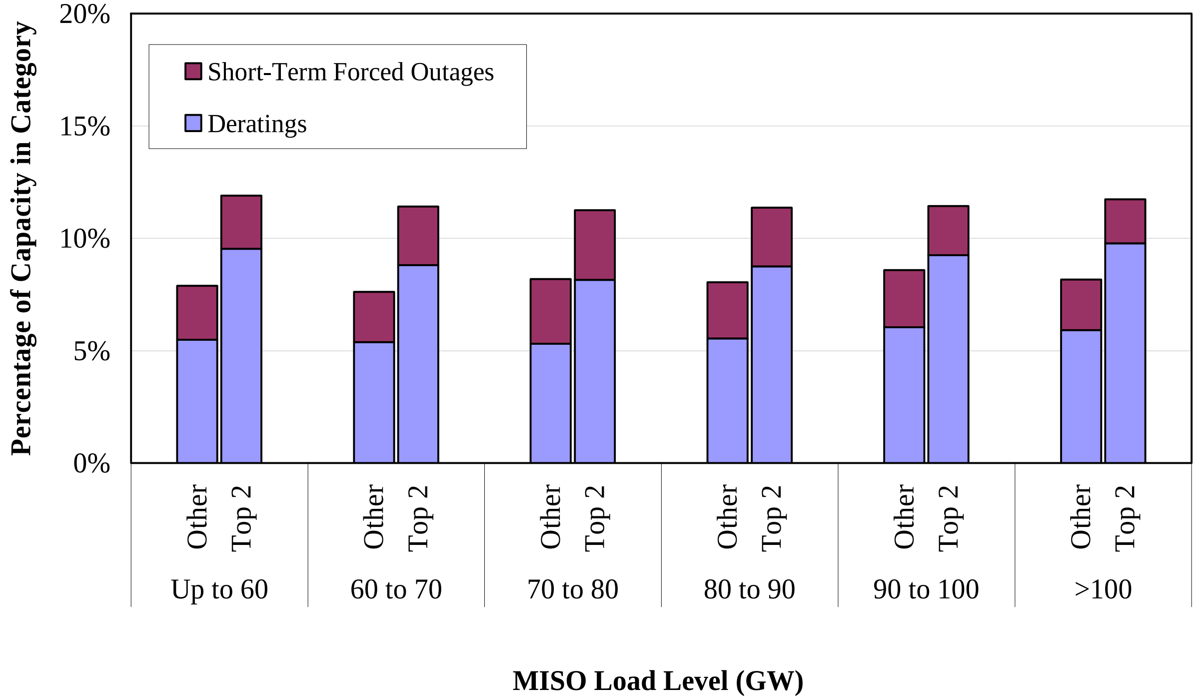


Figure 84: Real-Time Deratings and Forced Outages
East Region, 2010

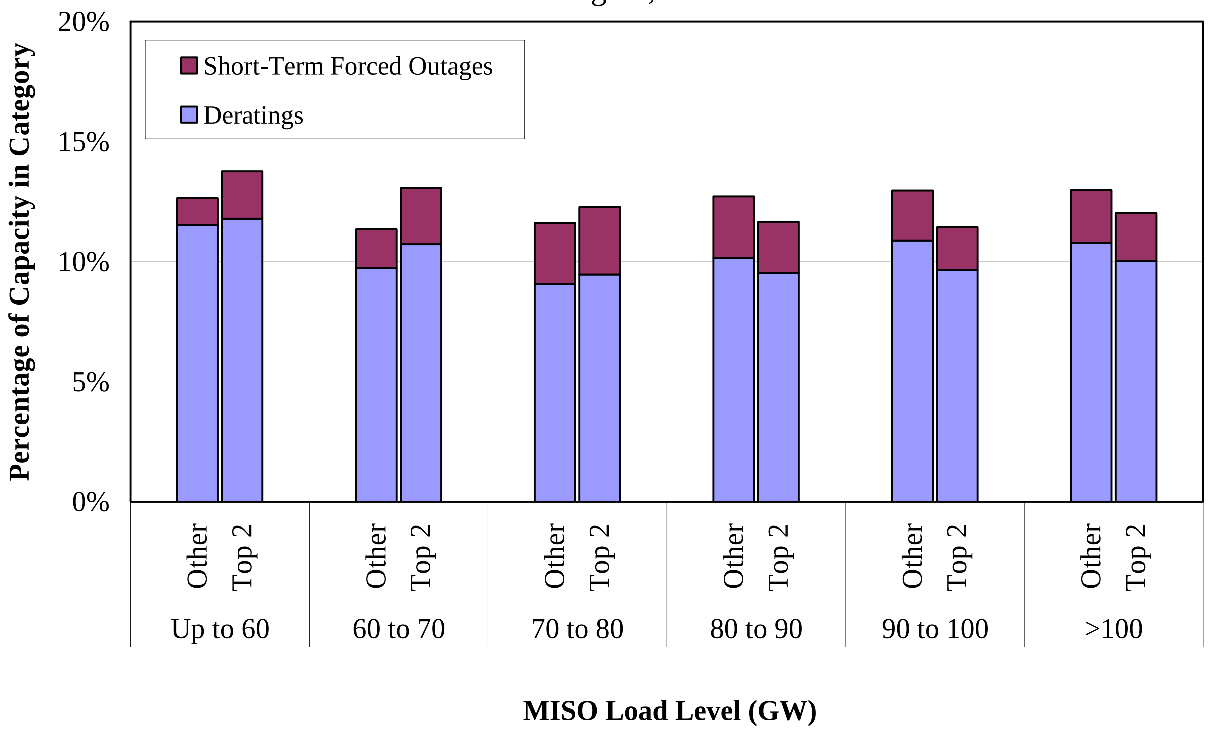


Figure 85: Real-Time Deratings and Forced Outages
West Region, 2010

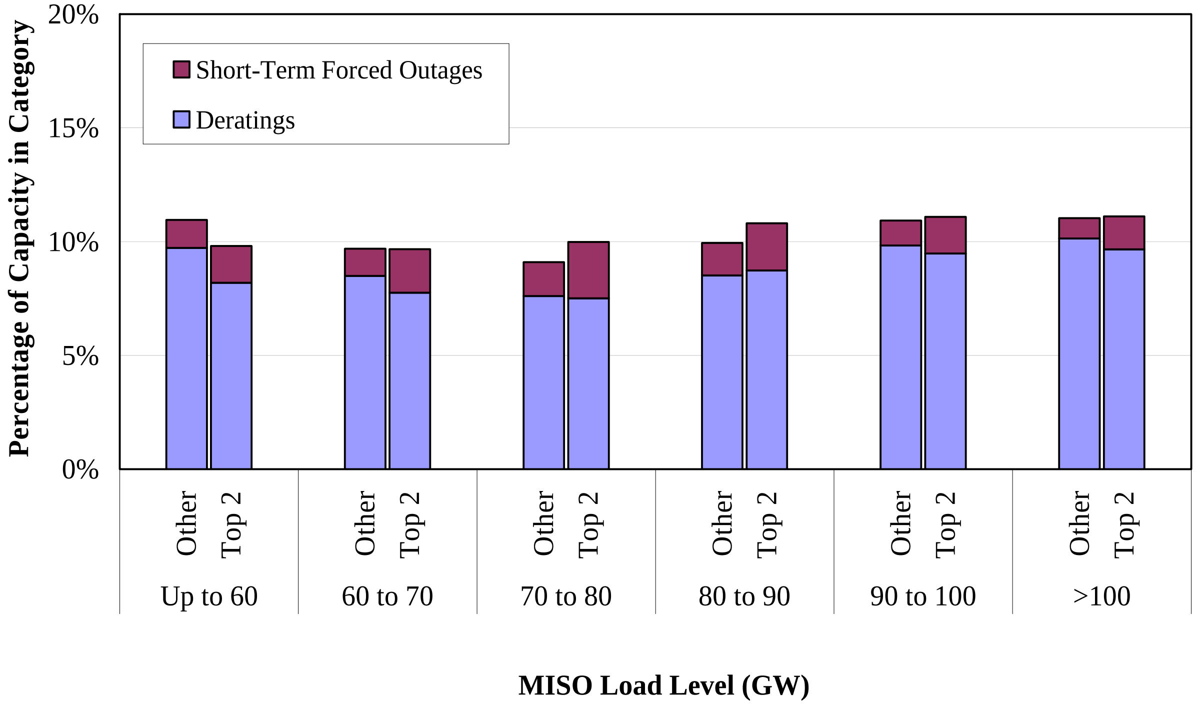
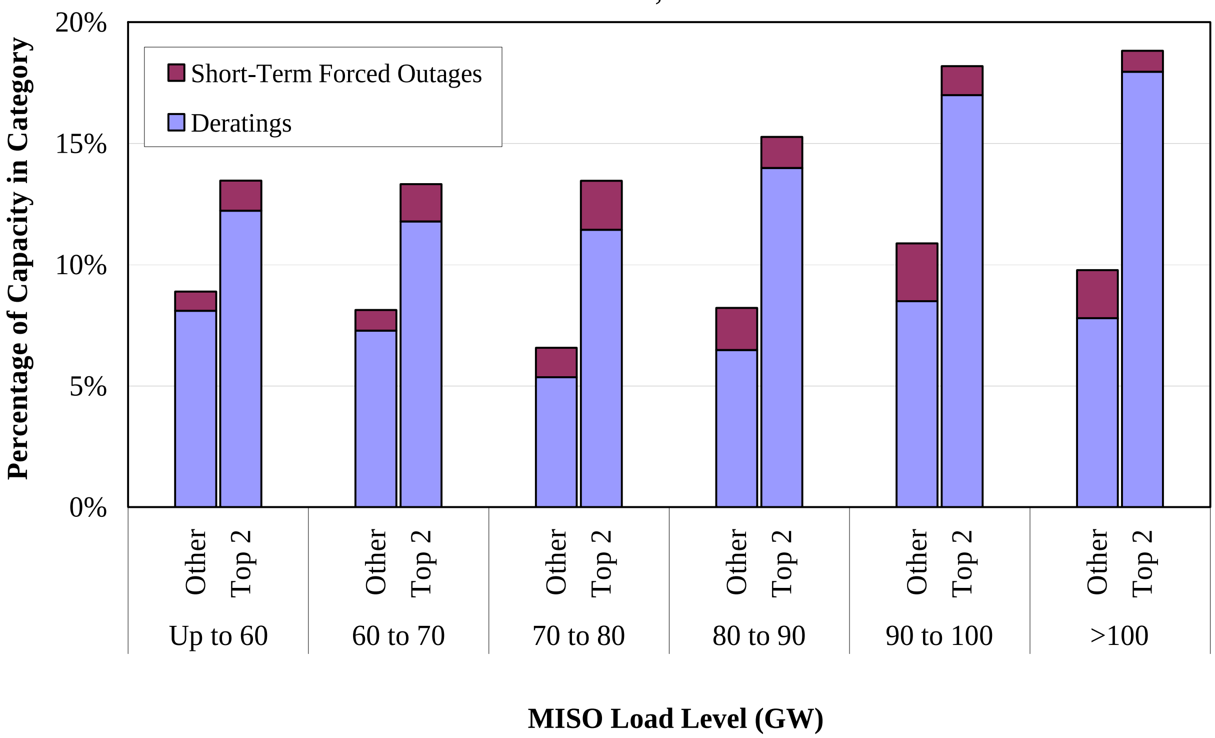


Figure 86: Real-Time Deratings and Forced Outages
WUMS Area, 2010



The results presented in the figures do not raise substantial competitive concerns. Outages and deratings increased slightly from 2009 levels, but remained fairly low. Much of the increase is in the form of deratings, in part because of higher ambient temperatures during the warmer-than-normal summer months. In the East and West Regions, deratings and outages are comparable across all load levels, and generally ranged from 8 to 12 percent for both the largest suppliers and all other suppliers. In the Central Region and WUMS area, the largest suppliers exhibited outages and deratings that were materially higher than those by other suppliers. The spike in WUMS can be attributed to high-temperature deratings of a number of combined cycle resources and did not contribute to an increased congestion pattern in the region. Short-term forced outages remain a small share of the overall unavailable capacity. They were highest in the Central Region, but even there only comprised on average one-quarter of unavailable capacity.

We continue to investigate any outages or deratings that create substantial congestion or other price effects. Our audits and investigations have not uncovered any significant attempts to physically withhold generation in 2010.

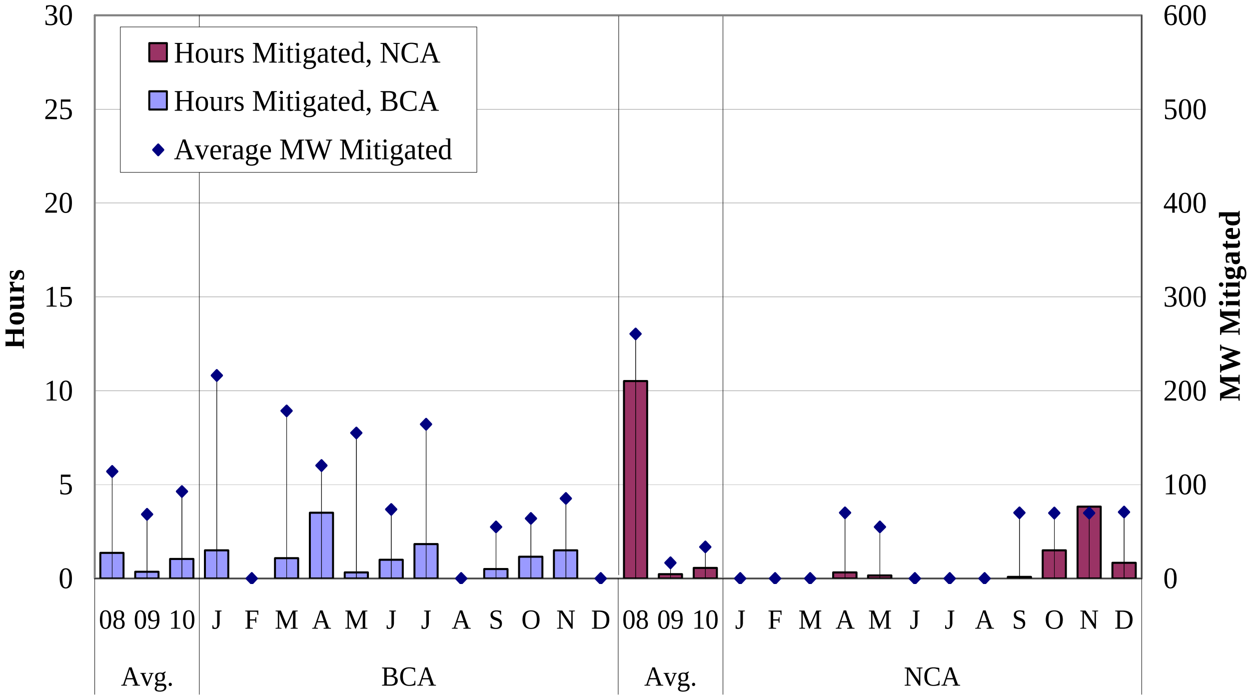
C. Market Power Mitigation

In this final subsection, we examine the frequency with which market power mitigation measures were imposed in MISO markets in 2010. Mitigation caps a unit's offer price when a set of specified criteria are met, as outlined in Module D of MISO's Tariff. The mitigation measures are intended to preclude abuses of locational market power while minimizing interference with the market when the market is workably competitive. MISO only imposes mitigation measures when suppliers' conduct exceeds well-defined conduct thresholds *and* when the effect of that conduct on market outcomes exceeds well-defined market impact thresholds. By applying these conduct and impact tests, the mitigation measures are designed to allow prices to rise efficiently to reflect legitimate supply shortages, while effectively mitigating inflated prices associated with artificial shortages that result from physical or economic withholding in transmission-constrained areas. MISO has almost completely automated this process.

Market participants are subject to potential mitigation specifically when transmission constraints that are binding can result in substantial locational market power. When a transmission constraint is binding, one or more suppliers may be in a position to exercise market power if competitive alternatives are not available. 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. Figure 87 shows the frequency and quantity of mitigation in the real-time energy market by month. 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.

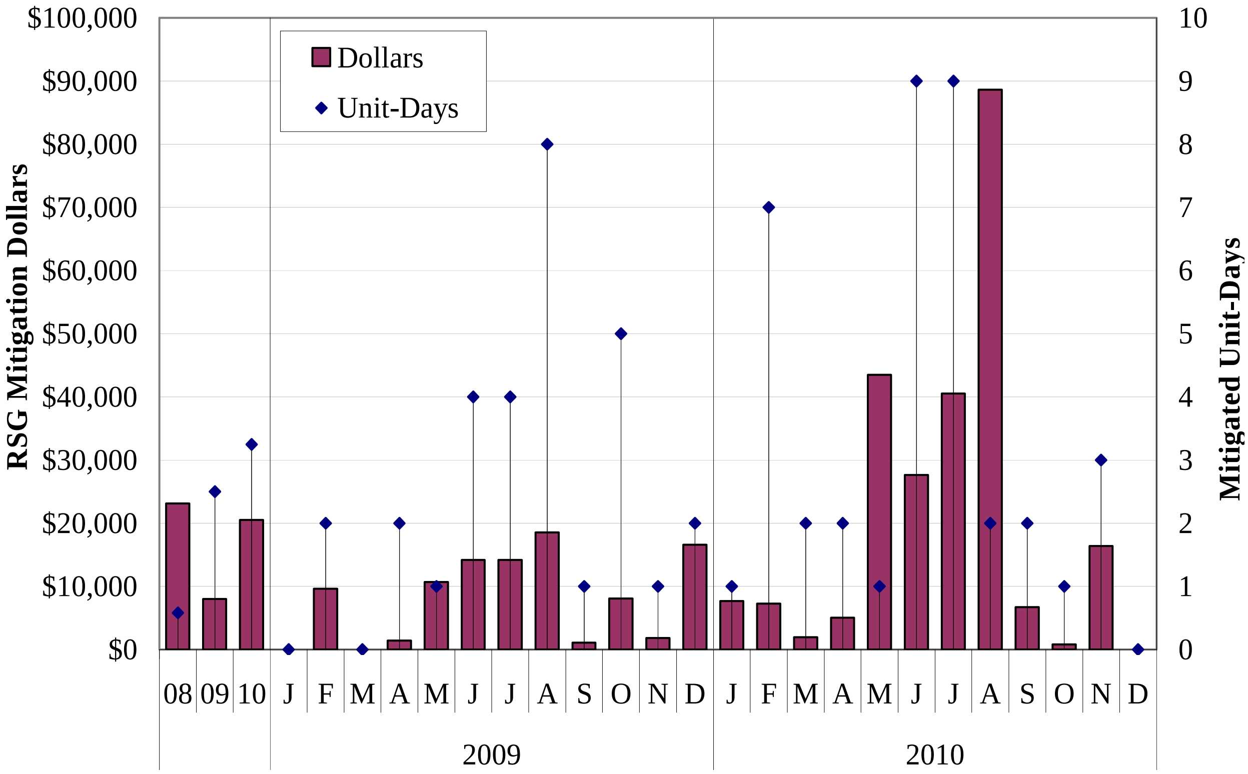
Figure 87: Real-Time Energy Mitigation by Month
2010



Real-time NCA and BCA energy mitigation remained rare in 2010 but rose from 2009 lows. Mitigated BCA unit-hours increased to over 12 hours, while mitigated NCA unit-hours increased to nearly 7 hours. The increase is, in part, due to higher levels of congestion. Average mitigation quantities, however, decreased to just 60 MW per unit-hour of NCA mitigation and 89 MW per unit-hour of BCA mitigation. It averaged nearly 200 MW in 2009. Despite infrequent mitigation in 2010, 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.

Participants can also exercise market power by raising their offers when their resources must be committed to resolve a constraint or to satisfy a local reliability requirement. This can compel MISO to make substantially higher RSG payments. MISO designed mitigation measures to address this conduct. These mitigation measures are triggered when the following three criteria are met: (1) the unit must be committed for a constraint or a local reliability issue; (2) the unit's offer must exceed the conduct threshold; and (3) the effect of the inflated offer must exceed the RSG impact threshold (i.e., raise the unit's RSG payment by $50 per MWh). Figure 88 shows the frequency and amount by which RSG payments were mitigated in 2009 and 2010.

Figure 88: Real-Time RSG Payment Mitigation by Month
2009–2010



RSG mitigation occurred for 39 unit-days in 2010, up from 30 in 2009 and just 7 in 2008. The total dollar amount mitigated similarly increased to $246,000. This growth largely reflects higher fuel prices and load. The higher fuel prices raise suppliers' as-bid production costs and the higher load, particularly during the summer, generally increases the need to commit resources for reliability that require RSG. Despite the year-over-year increase, RSG mitigation remains infrequent; however, this does not indicate a lack of locational market power. Without the mitigation measures, the MISO market would be exposed to substantial market power.

VII. Demand-Response Programs

Demand response involves actions taken to reduce consumption from normal levels when the value of consumption is less than the marginal cost to supply the electricity. DR allows for participation in the energy markets by end users and contributes to:

- Reliability in the short term;
- Least-cost resource adequacy in the long term;
- Reduced price volatility and other market costs; and
- Reduced supplier market power.

Additionally, price-responsive demand has the potential to enhance wholesale market efficiency. Even modest consumption reductions by end-users during high-price periods can significantly reduce the costs of committing and dispatching generation to satisfy system needs. These benefits underscore the need to facilitate DR through wholesale market mechanisms and transparent economic signals.

DR resources can broadly be categorized as either Emergency DR ("EDR"), which respond to capacity shortages, or "economic DR," which respond to high energy market prices. MISO can call for EDR resources to be activated in advance of a forecasted system emergency, thereby supporting system reliability. By definition, however, EDR is not price-responsive and does not participate directly in the MISO markets. Economic DR resources respond to energy market prices not only during emergencies, but at any time when energy prices exceed the marginal value of the consumer's electricity consumption.

The real-time market is significantly more volatile than the day-ahead market because of its physical restrictions and contingencies. Given the high value of most electricity consumption, DR resources tend to be more valuable in real time during abrupt periods of shortage when prices spike. In the day-ahead market, prices are less volatile and supply alternatives are much more available. Consequently, DR resources are generally less valuable in the day-ahead market. On a longer-term basis, however, consumers can shift consumption patterns in response to day-ahead prices (from peak to off-peak periods, thereby flattening the load curve). These actions improve the overall efficiency and reliability of the system.

A. DR Resources in MISO

MISO's demand response capability declined in 2010 to approximately 8,700 MW. The vast majority of this capability is legacy "reliability" DR programs locally administered by LSEs, either through load interruption (i.e., known as Load-Modifying Resources, or "LMR") or through Behind-The-Meter Generation ("BTMG"). These resources are beyond the control of MISO and effectively reduce the overall load that the system had to meet. The share of DR that can respond actively to MISO through dispatch instructions is nearly zero. Such resources are classified as Demand Response Resources ("DRR") and were eligible to participate in all the MISO markets in 2010, including satisfying LSEs' resource adequacy requirements under Module E of the Tariff.

1. Types of DRR

MISO characterizes DRR that participate in the MISO markets as Type I or Type II resources. Type I resources are capable of supplying a fixed, pre-specified quantity of energy or contingency reserve through physical load interruption. Conversely, Type II resources are capable of supplying varying levels energy or operating reserves on a five-minute basis, such as through controllable load or behind-the-meter generation.

Because Type I resources are inflexible – they provide either no response or their "Target Demand Reduction Amount" – they cannot set prices in the MISO markets. In this respect, MISO treats Type I resources in a similar fashion as generation resources that are block-loaded for a specific quantity of energy or operating reserves. As noted previously in the context of the ELMP Initiative, MISO is pursuing an initiative to develop an appropriate pricing methodology to allow Type I and other "fixed-block" offers to establish market prices. In 2010, 15 units were active in the commercial model, but only three actually participated in the energy market, clearing on average less than 1 MW per interval. For the 2011 planning year, 10 units have registered to provide 46 MW of capacity, down from 2,353 MW in 2009 (see Table 3). This decrease occurred because pumped storage resources that had been the largest provider of DRR Type I stopped participating as DRR in September 2009. .

Most other Type I capacity comes from interruptible-load programs aimed at large industrial customers. Enrollment typically requires minimum amounts of reduction in load and a minimum level of peak demand. In an interruptible load program, customers agree to reduce consumption by (or to) a predetermined level in exchange for a small, per-kWh reduction in their fixed rate. MISO does not directly control this load; therefore, although penalties exist for noncompliance, such programs are ultimately voluntary. Direct Load Control ("DLC") programs are targeted toward residential and small Commercial and Industrial ("C&I") customers and often targets certain equipment. In the event of a contingency, the LSE manually reduces the load of this equipment (e.g., air-conditioners or water heaters) to a predetermined level.

Type II resources can set prices because they are capable of supplying energy or operating reserves in response to a five-minute instruction. They are, therefore, treated comparably to generation resources. These price-based resources are referred to as "dynamic pricing" resources. Dynamic pricing is the most efficient form of DR because rates formed under this approach provide customers with accurate price signals that vary throughout the day to reflect the higher cost of providing electricity during peak demand. These customers can alter their usage efficiently in response to the prices. Significant barriers to implementing dynamic pricing include the minimum required load of the participating customer, extensive infrastructure outlays and potential retail rate reform. Four Type II resources were active in the commercial model in 2010, although only one unit actually participated in the energy market, clearing 11 MW per interval in 2010. No Type II resources are registered for the 2011 planning year.

LSEs are also eligible to offer DRR capability into ASM. Type II resources can currently offer all ancillary services products, whereas Type I units are prohibited from providing regulating reserve. Physical requirements required of regulating reserve-eligible units (namely, the ability to respond to small changes in instructions within four seconds) are too demanding for Type I resources. Type I units were also prohibited from providing spinning reserve until February 2, 2010. In 2010, all DRR units combined provided an average of 10 MW of regulating reserve, 98 MW of spinning reserve, and 50 MW of supplemental reserve.

Module E of MISO's Tariff allows DR resources, with the exception of those that qualify only for EDR, to count toward fulfillment of an LSE's capacity requirements. DR resources can also be included in MISO's long-term planning process as comparable to generation. DRR units are treated like generation resources in the VCA, while LMR must meet additional Tariff-specified criteria prior to their participation. The ability for all DR resources to provide capacity under Module E goes a long way toward addressing economic barriers to DR and ensuring comparable treatment with MISO's generation.

The EDR initiative began in May 2008 and allows MISO to directly curtail load in specified emergency conditions if DRR dispatched under ASM and LSE-administered DR programs are unable to meet demand. EDR is supplementary to existing DR initiatives and requires the declaration of a NERC Energy Emergency Alert ("EEA") 2 or EEA 3 event. Resources that do not qualify as DRR or DRR units that are not offered into energy or operating reserves markets are still eligible to reduce load and be compensated as EDRs. For the current planning year, 32 resources providing 357 MW of capacity were registered as EDR.

EDR offers are submitted on a day-ahead basis, rather than on a monthly basis, which allows for more accurate availability of such resources. During emergency conditions, MISO selects offers on a merit basis based on the provided curtailment prices up to a $3,500-per-MWh cap. EDR participants who reduce demand in response to dispatch instructions are compensated at the greater of the prevailing real-time LMP or the offer costs (including shut down costs) for the amount of verifiable demand reduction provided. EDR resources are not yet eligible to set price because of their inflexibility, but we have recommended that MISO investigate changes that would allow them to set price when they are needed.

2. Aggregators of Retail Customers

The FERC in August 2008 issued Orders 719 and 719-A directing RTOs to improve DR participation in wholesale electricity markets. More specifically, these orders require comparable treatment for DR and existing generation resources. In response, MISO has established a stakeholder process to identify and address specific barriers related to market rules, settlement provisions, and operating requirements. The largest such barrier is the limitation of direct market participation to resources with loads of more than 1 MW. By pooling small resources, ARCs can serve as an intermediary between MISO and retail customers who can reduce consumption.[28] This measure has been successfully implemented in neighboring RTOs (see Table 3).

MISO filed Tariff revisions on October 2, 2009 to allow ARCs to participate in all the MISO markets. Under the terms of the proposed revised Tariff, an ARC-operated resource cleared for energy would be paid the LMP minus a predetermined Marginal Foregone Retail Rate ("MFRR"). The MFRR is intended as a proxy for costs the retail customer providing DRR would have incurred to consume. This is an economically efficient payment, because reducing load provides the retail customer savings for foregoing consumption. This payment to the ARC would be assessed to the LSE and result in a net payment to the retail customer equal to the LMP. ARCs providing other products such as capacity or ancillary services would be paid just MCP for that product.

The FERC has not yet approved these Tariff revisions; however they are inconsistent with its March 15, 2011 "Final Rule on Demand Response Compensation".[29] This ruling requires DR resources be compensated at LMP when the DR dispatch is cost-effective, as determined by a new "net benefits test". The MISO is required to file with the FERC a net benefits analysis and further Tariff revisions by summer 2011.

3. Inter-ISO Comparison of DR Programs

Table 3 shows that MISO's cumulative DR capabilities compare favorably to those of neighboring RTOs. MISO's total DR resources exceed 8,600 MW, far more than the capability of neighboring RTOs, and allow for direct participation of DR resources in all the MISO markets. These resources total 7.9 percent of peak 2010 load, which is comparable to other RTOs, but is a 31 percent decrease from 2009. Much of this decline was in the form of MISO-

28 An ARC is by definition a market participant sponsoring a DRR resource provided by a customer whom it does not serve at retail. An ARC can also be an LSE sponsoring a DRR that is the retail customer of another LSE.

29 Demand Response Compensation in Organized Wholesale Energy Markets, Order No. 745, 76 Fed. Reg.16,658 (Mar. 24, 2011), 134 FERC ¶ 61,187 (2011).

controlled resources that participated only marginally in 2010 energy markets. Other RTOs are, however, substantially ahead of MISO in implementing economic DR.

Table 3: Comparison of DR Programs across RTOs.
2009–2010

		2010	Pct. of 2010 Peak	2009	Y/Y Change
MIDWEST ISO	**TOTAL**	**8,663**	**7.9%**	**12,550**	**-31%**
	Behind-The-Meter Generation	5,077		4,984	2%
	Load Modifying Resources	3,184		4,860	-34%
	DRR Type-I	46		2,353	-98%
	DRR Type-II	0		111	-100%
	Emergency DR	357		242	47%
NYISO	**TOTAL**	**2,362**	**7.1%**	**2,384**	**-1%**
(as of Aug 31, 2010)	ICAP - Special Case Resources	2,103		2,061	2%
	Of which: Targeted DR	*489*		*531*	-8%
	Emergency DR	257		323	-20%
	Of which: Targeted DR	*77*		*117*	-34%
	DADRP	331		331	0%
ISO-NE	**TOTAL**	**2,719**	**10.0%**	**2,292**	**19%**
	Real-Time DR Resources	1,255		873	44%
	Real-Time Emerg. Generation Resources	672		875	-23%
	On-Peak Demand Resources	533		N/A	
	Seasonal Peak Demand Resources	259		N/A	

Note: Quantities in MW.

B. Improving DR Integration in the MISO Market

MISO has initiated significant efforts to reduce barriers to integrating DR resources into existing markets. As quantities of DR grow, they are expected to be deployed more frequently to satisfy peak loads and to respond to system contingencies. Therefore, it will be increasingly important to ensure that real-time markets produce efficient prices and other market outcomes when DR resources are deployed.

Prior *State of the Market* reports have demonstrated that when MISO has called for load curtailments under emergency conditions, prices have generally been understated and have not efficiently reflected the shortages (or the value of foregone consumption). The most notable event occurred on August 1-2, 2006 when extremely high temperatures throughout the MISO footprint resulted in record electricity demand. Emergency procedures were invoked by MISO that resulted in voluntary load reductions of nearly 3,000 MW. Prices during peak hours on August 1, 2006, however, ranged from $50 to $150 per MWh and were less than $100 in the highest demand hour. These prices did not reflect conditions that triggered load curtailments.

When DR resources do not set prices, as in the example above, a key component of the economic signals needed to support generation, transmission, and demand-side management investment is missing. Hence, it should be a high priority of MISO to permit all such resources to set energy and ancillary service prices at efficient levels when DR is implemented. Such an effort can improve market economic signals by accurately reflecting the value of provided energy. Integrating such a capability into the market will be challenging. In a 2009 compliance filing with the FERC, MISO stated that "current systems are not adequate to permit this because such resources are not able to move incrementally in response to small changes in conditions."[30]

A similar issue prevents peaking resources from setting price when they are the marginal resource, but are dispatched at their economic minimum or maximum. MISO, through its ELMP initiative, has been developing pricing to reflect marginal offer cost for peaking resources. The work is encouraging and has the potential to allow DR resources to set energy prices as well. Hence, we recommend MISO consider including this design feature in the ELMP or other methods of permitting DR resources to set price in the real-time energy market when they are the marginal resources, notwithstanding their general lack of flexibility.

C. Conclusions

With more than 8,600 MW of existing potential DR capability, MISO has significant potential for more fully integrated DR. MISO's existing and proposed programs address many barriers to DR, although much work remains to be done.

One change that is particularly important is a modification to price-setting methodologies to let emergency actions and all forms of DR contribute to setting efficient shortage prices in energy

30 Midwest Independent Transmission System Operator (2009). "EDR Quarterly Report Filing," filed before the Commission, October 21, 2009. Docket No. ER08-404-000.

and AS markets. Failure to set efficient shortage prices when DR resources or other emergency actions clear the market under shortage or near-shortage conditions can serve as a material economic barrier to the development of new DR resources.

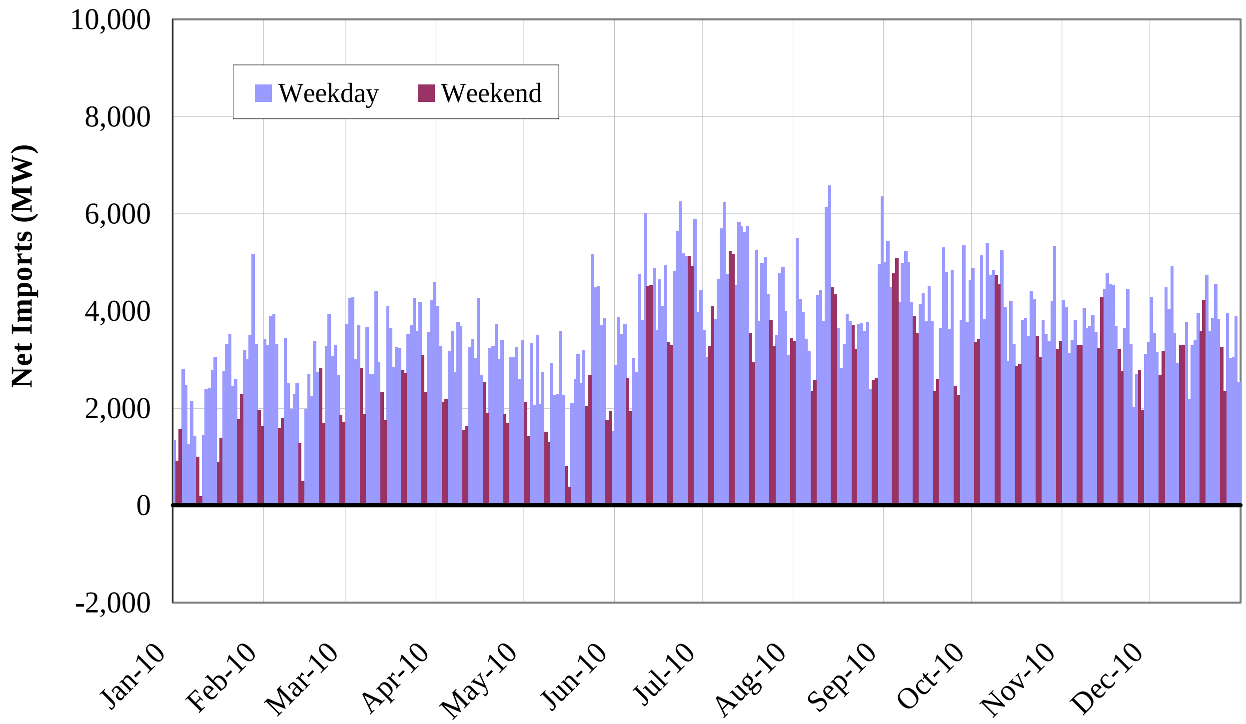
VIII. External Transactions

MISO remains a net importer of power during all hours and seasons, and relies heavily on imports to satisfy the demands of the market. In this section, we summarize the magnitude of external transactions and the efficiency of the transaction scheduling process.

A. Import and Export Quantities

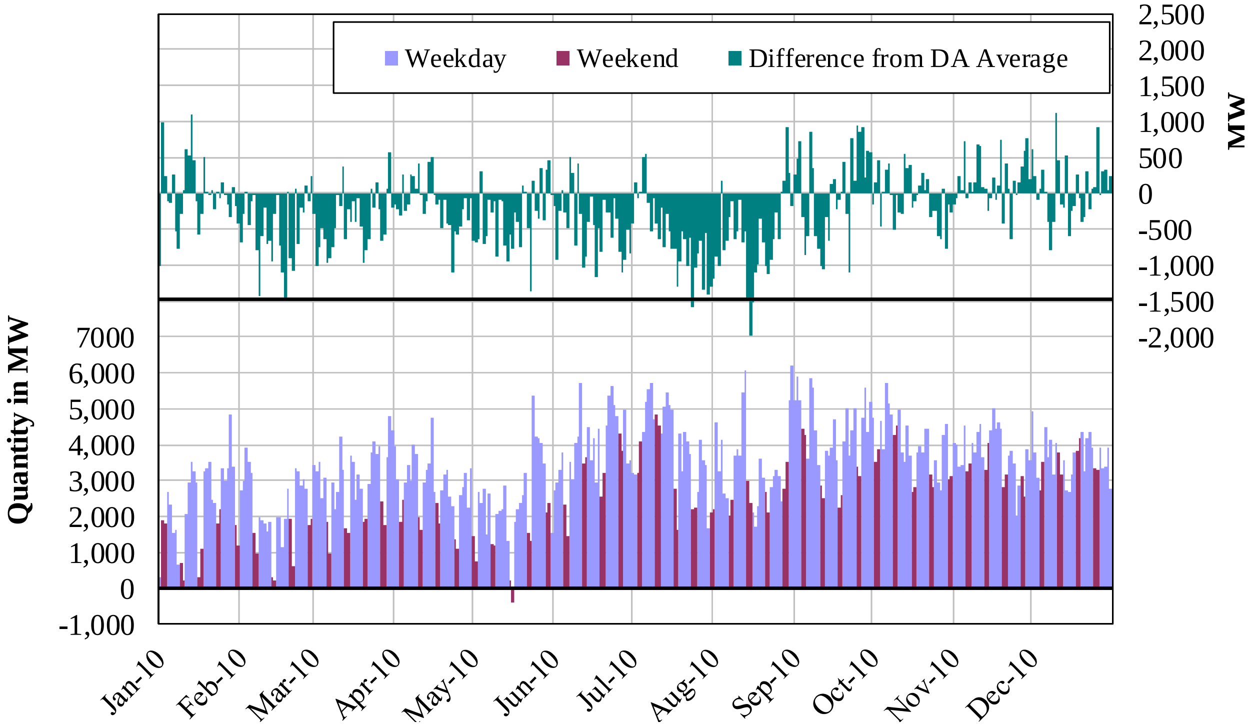
Figure 89 shows the daily average of hourly net imports scheduled in the day-ahead market. Net imports in 2010 averaged nearly 3.5 GW per hour, down less than 2 percent from 2009. As in prior years, weekday imports were nearly 1 GW higher than weekend imports. During January to May, net imports averaged nearly 800 MW less than in the same period in 2009, while net imports in June to December were nearly 700 MW greater. Net imports from Manitoba increased by over 1,000 MW between May and July, and contributed to west-to-east congestion in MISO.

Figure 89: Average Hourly Day-Ahead Imports
All Hours, 2010



Net imports in the real-time market can vary substantially from the levels scheduled in the day-ahead market. Figure 90 shows the average hourly net imports scheduled in the real-time market each day over all interfaces, and the deviation of real-time imports from day-ahead imports. Real-time net imports increased 8 percent in 2010 to an average of 3.2 GW. Net imports from PJM in particular increased to nearly 1 GW. Imports from PJM, Manitoba and Ontario comprised the majority of all net imports.

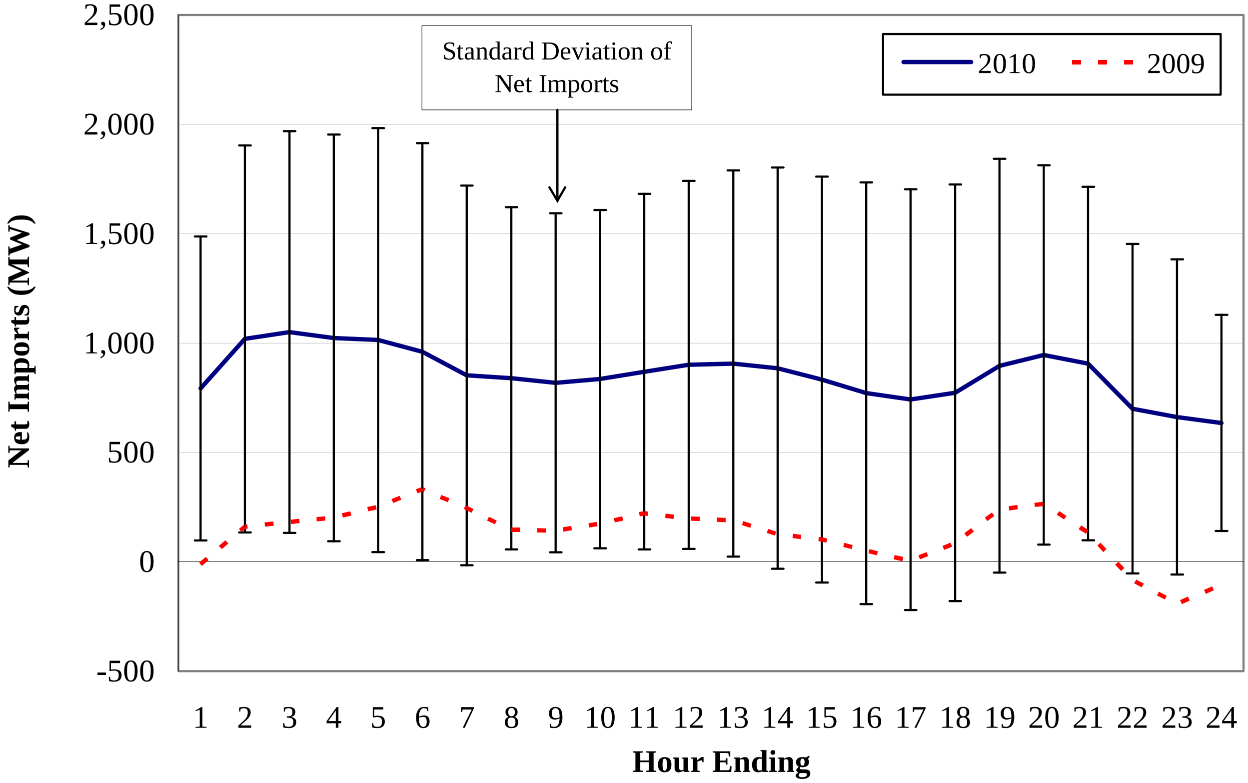
Figure 90: Average Hourly Real-Time Imports
All Hours, 2010



In 2010, real-time net imports generally decreased from those scheduled in the day-ahead market. On 30 days during the year, average net imports decreased by more than 1,000 MW, which can create reliability issues that MISO must manage. Large changes in net imports can cause MISO to commit additional generation and to rely more on peaking resources. Changes between day ahead and real time were greatest in summer. Differences in net imports over the PJM and Manitoba interfaces, which together averaged nearly -400 MW in summer, dissipated in September. As in prior years, overall reductions in real-time imports were larger on the western interfaces, particularly the interface with the Western Area Power Administration.

The interface between MISO and PJM, both of which operate LMP markets over wide geographic areas, is the most significant interface for MISO. Accordingly, Figure 91 shows the average net imports scheduled for MISO-PJM interface in each hour of the day.

Figure 91: Hourly Average Real-Time Net Imports from PJM
2010

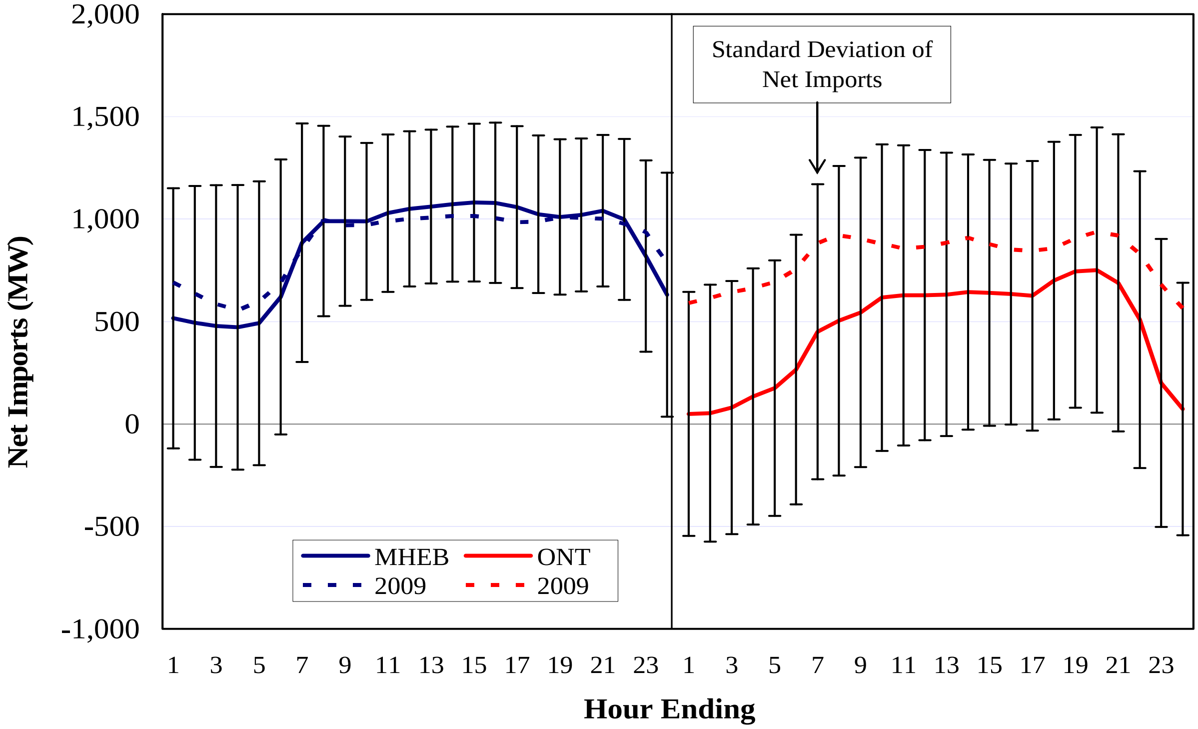


As noted previously, MISO is a net importer of power during each hour on average. Imports in 2010 increased consistently across all hours from 2009. Net imports from PJM are generally not correlated with load because wheeled transactions from Ontario tend to increase with load and lower the net imports at the PJM interface. The figure also shows the standard deviation of the net imports, indicating that imports regularly vary by as much as 2,000 MW. The variation occurs because similarity in resource mix in PJM and MISO causes price in the two areas to move within similar ranges. Since relative prices in the two areas govern net interchange, price movements can cause incentives to import or export to oscillate.

Figure 92 shows hourly real-time net imports across the Canadian interfaces. MISO exchanges power with Canada through interfaces with MHEB (left panel) and the IESO (right panel).

MISO is a net importer across both interfaces, although a large share of the net imports from Ontario results from transactions to PJM wheeling through MISO.

Figure 92: Hourly Average Real-Time Imports from Canada
2009–2010



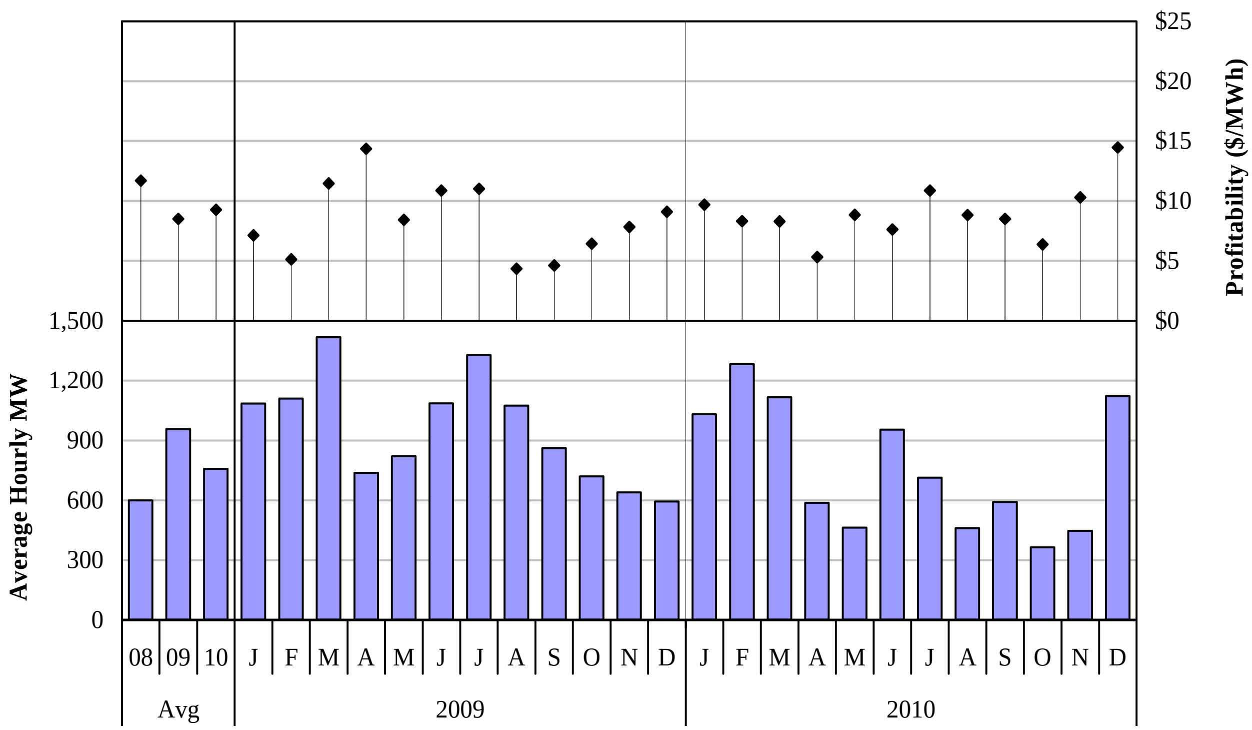
Net import volumes across both interfaces track load and increase substantially during peak hours. Hourly net imports from MHEB were largely unchanged from 2009 levels, and averaged approximately 500 MW during off-peak hours and 1,000 MW during peak hours. The variation in schedules, as indicated by the one-standard deviation error bars, is considerably wider during off-peak hours. Hourly net imports from Ontario in 2010 decreased in all hours by an average of 350 MW but remained mostly positive. The flow direction changed periodically, particularly during off-peak hours. Excluding wheeled transactions to PJM, MISO was a net exporter to Ontario, averaging 263 MW per hour.

B. Lake Erie Loop Flow

Issues surrounding "contract path" transaction scheduling by the four RTOs around Lake Erie persisted into 2010. Adverse effects of this scheduling were primarily related to congestion it caused in the NYISO market. The underlying problem in each case was that settlements occur based on the scheduled path (i.e., the "contract path"), but actual power flows also occur on other paths (flows resulting from the schedule that are not part of the contract path are generally referred to as "loop flows"). The scheduled path of a transaction does not alter physical power flows between generation and load. Physical flows that differ from scheduled flows are loop flows that must be accounted for by RTO operators. Inconsistencies between the physical flows that result from a transaction and the scheduled path of the transaction can distort participants' incentives and can lead to inefficient scheduling.

NYISO banned circuitous schedules in July 2008. Schedules from the IESO to PJM (across MISO) increased thereafter. Figure 93 shows the monthly quantity and profitability of these transactions in 2009 and 2010. Although volumes decreased by 21 percent in 2010, these transactions remain persistently profitable: average profits were nearly $10 per MWh in 2010. Profitability is calculated based on prices in PJM and IESO minus MISO's wheeling charge (i.e., on this basis, profitability excludes costs allocated by IESO, which would reduce it). These transactions may not always be efficient, even though they are generally profitable.

Figure 93: Actual Flows Around Lake Erie
IESO to PJM Schedules, 2009–2010



If these transactions had to pay for the congestion they caused in New York, many would be unprofitable. This raises efficiency concerns.

Five PARs, of which two are operated by MISO, are in the process of being placed in operation that could help improve consistency between scheduled and actual flows. However, implementation has been significantly delayed by the lack of necessary agreements among relevant transmission owners and operators, as well as regulatory delays. Operation is now expected to begin in late 2011.

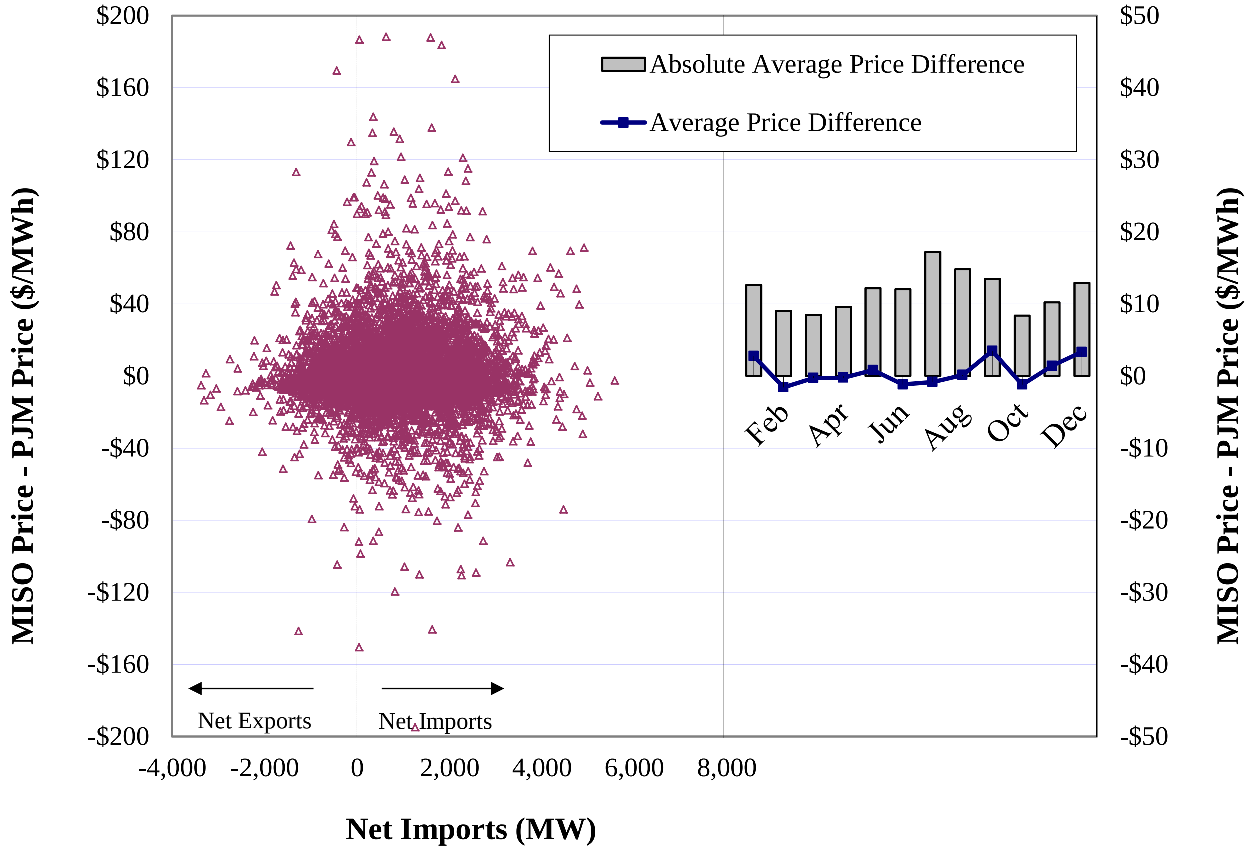
The BRMI developed with IESO, NYISO, and PJM should further improve utilization of the Lake Erie interfaces. We estimated in a separate study cumulative annual production cost savings of $297 million for these initiatives and continue to strongly support their full adoption. Much of this savings is from improved coordination of the interchange between PJM and MISO, which is discussed later in this section.

C. Price Convergence between MISO and Adjacent Markets

Like other markets, MISO relies on participants to increase or decrease net imports to cause prices between MISO and adjacent markets to converge. Given uncertainty regarding price differences from transactions being scheduled in advance, perfect convergence should not be expected.

Our analysis of these sechedules is presented in a series of figures, each with two panels. The left panel is a scatter plot of real-time price differences and net imports during unconstrained hours. Good market performance would be characterized by net imports into MISO when its prices are higher than those in neighboring markets. The right side of each figure shows monthly averages for hourly real-time price differences between adjacent regions and the monthly average magnitude of the hourly price differences (average absolute differences). In an efficient market, prices should converge when the interfaces between regions are not congested.

Figure 94: Real-Time Prices and Interface Schedules
PJM and MISO, 2010

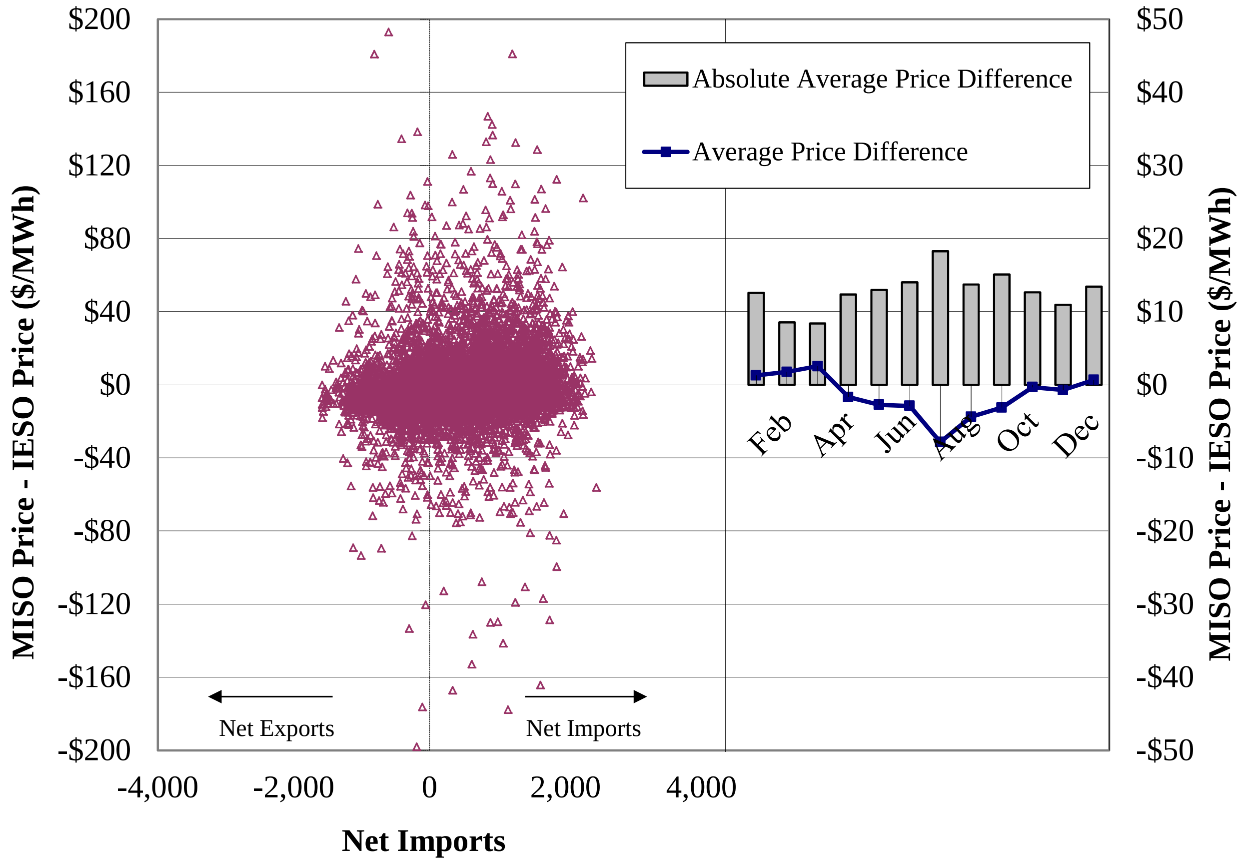


MISO and PJM prices varied by just a few dollars in either direction for most of 2010. The absolute average price difference was roughly $12 per MWh in 2010, up from $10 in 2009, and was modestly higher during summer months as indicated in the right panel. Net power flows were scheduled from PJM to MISO in 80 percent of hours in 2010, as shown in the left panel. Import and export quantities remain widely scattered relative to the price differences. In over 56 percent of hours (identified in the figure by all hourly values in the top-left and bottom-right quadrants), power was scheduled in the wrong direction; that is, from the higher-priced market to the lower-priced market.

To achieve better price convergence between the two markets, we continue to recommend the RTOs optimize the net interchange between the two areas, or allow participants to submit intra-hour offers to transact that would be scheduled based on forecasted price differences. Fifteen-minute scheduling would improve efficiency and accuracy of real-time conditions by shortening the scheduling process. Alternatively, the RTOs could determine the optimal physical interchange in a coordinated intra-hour scheduling process by evaluating hourly market participant bids that correspond to the spread of real-time prices between the RTOs. This change would likely achieve the vast majority of any potential economic savings (i.e., lower overall production costs across the RTOs) from jointly dispatching the generation in the two regions. MISO has begun investigating how to implement this recommendation and discussing it with PJM.

Similar to the previous analysis of the PJM interface, Figure 95 shows the analysis of real-time prices and schedules between MISO and IESO.

Figure 95: Real-Time Prices and Interface Schedules
IESO and MISO, 2010



The pattern in the left panel of the figure confirms that MISO was a net importer of power from IESO in 2010. Net imports averaged 458 MW, up from -100 MW in 2009. This result is unexpected because the IESO price premium averaged $1.45 per MWh, as indicated in the right panel. IESO prices were considerably higher than those in MISO during the second and third quarters: premiums there averaged $3.77 per MWh over the period and peaked near $8 in July. Absolute average price differences averaged $12.74 per MWh, down 6.1 percent from $13.57 in 2009 and down 39 percent from $21 in 2008.

This dispersion of prices and schedules in the figure shows that transactions were relatively unresponsive to price differences. Similar to MISO-PJM interface, power in 2010 was scheduled from the higher-priced market to the lower-priced market in a majority of hours. Interpreting these results is complicated by the lack of a nodal market in the IESO. Therefore IESO prices may not fully reflect the true value of power imported from MISO. Internal constraints in the IESO can cause such imports to be more or less desirable than the price would indicate. Given the current market design in the IESO, limited options are available for improving external transaction efficiency over this interface.

D. Resource Adequacy and External Transactions

The MISO relies on a high level of net imports to meet its energy needs. Therefore, it is reasonable to expect that it will rely on comparable levels of external capacity to meet its resource adequacy needs under Module E. Our review of the Module E requirements, however, indicates potential problems with participants' ability to import capacity from external areas and to export them, particularly to PJM. Capacity prices can only be efficiently determined if participants are able to freely import and export capacity to arbitrage capacity price differences between markets to the extent that the physical transmission capability allows. Therefore, it is critical to identify and eliminate barriers that inefficiently hinder such transactions.

With regard to imports, the current requirement that a deliverability study be performed in advance of participation by an external entity is an onerous, time-intensive requirement that creates an effective barrier to entry. Hence, we recommend MISO modify its deliverability requirement for external resources to establish a maximum amount by interface that can be utilized to satisfy LSEs' capacity requirements under Module E.

With regard to exports to PJM, relatively little capacity has been able to be exported to PJM, despite current price differences. This may be due to a number of factors, including deliverability requirements, transmission reservation provisions, operational requirements, or other market obligations. We believe it is important for MISO and PJM to work together to identify barriers to capacity transactions and to develop solutions to eliminate those barriers. Ultimately, cooperation can enable both markets to send more efficient long-term price signals and can improve the stability of the RTOs by reducing incentives for participants to alter RTO membership.