2011 STATE OF THE MARKET REPORT FOR THE MISO ELECTRICITY MARKETS

ANALYTICAL APPENDIX

POTOMAC ECONOMICS

JUNE 2012

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I. Prices and Revenues

MISO has operated competitive wholesale electricity markets for energy and FTRs since April 2005. The market added regulating and contingency reserve products (jointly known as ancillary services) in January 2009, and a voluntary capacity auction began in June 2009. In this section, we summarize prices and revenues associated with the day-ahead and real-time energy markets.

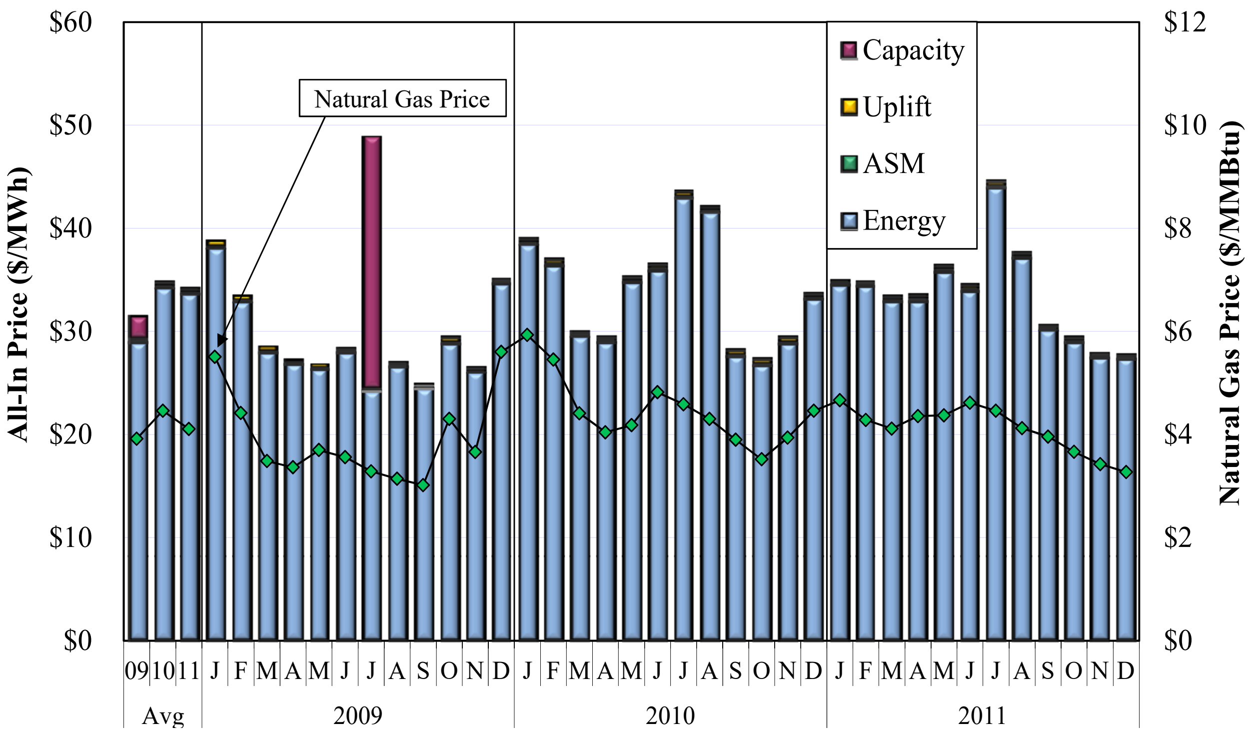
A. Prices

In a well-functioning, competitive market suppliers have an incentive to offer at their marginal costs. Therefore, energy prices should be positively correlated with the marginal costs of generation. For most suppliers, fuel comprises the majority of these costs. In MISO, coal-fired resources are marginal most often, but natural gas-fired resources tend to set prices at higher load levels and so have an outsized impact on average energy prices.

Figure A1: All-In Price of Electricity

Figure A1 shows the "all-in" price of electricity from 2009 to 2011 and the price of natural gas.[1] The all-in price represents the cost of serving load in MISO's real-time market. It includes the load-weighted real-time energy price, as well as real-time ancillary service costs, uplift costs, and capacity costs (VCA price times capacity requirement) per MWh of real-time load.

Figure A1: All-In Price of Electricity
2011: Peak Hours



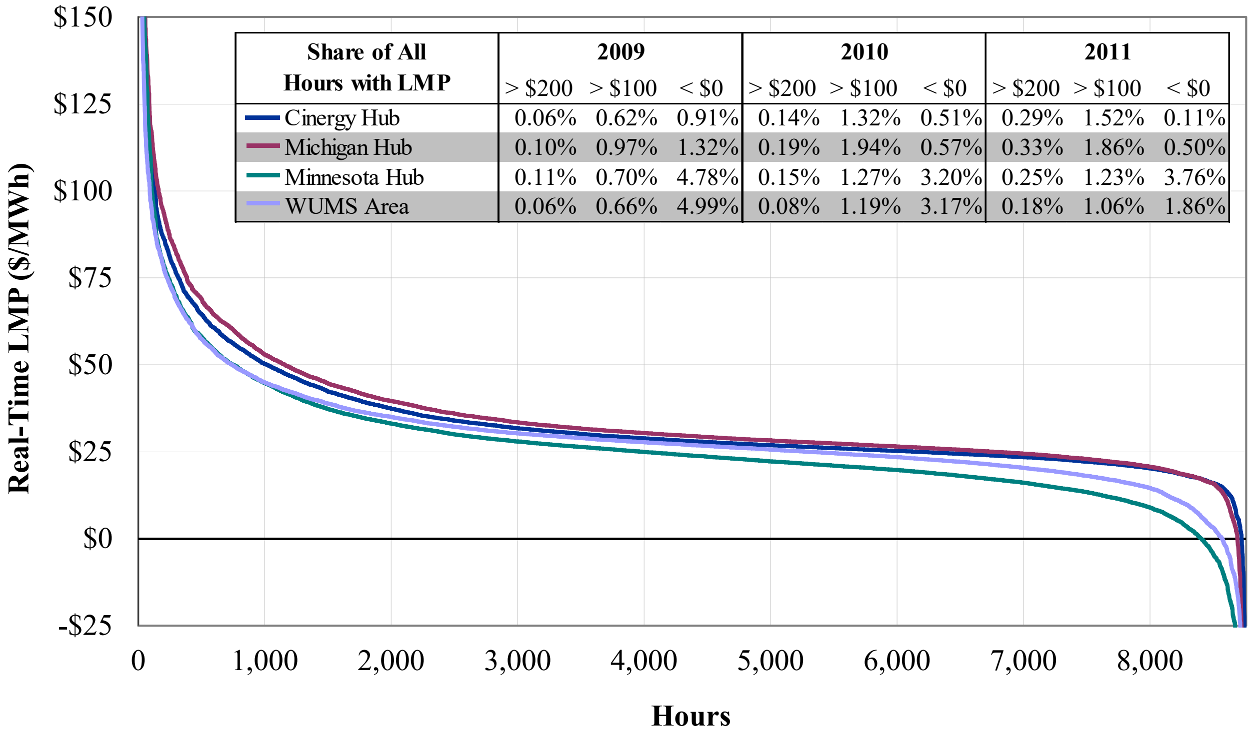
1 Specifically, the Chicago City Gate spot price for natural gas, as published by Platts.

Figure A2: Real-Time Energy Price-Duration Curves

Figure A2 shows the real-time hourly prices at 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). The differences between the curves in this figure are due to congestion and losses that cause energy prices to vary by location.

The table in the figure provides the percentage of hours with prices greater than $200, greater than $100, and less than $0 per MWh in the prior three years. The highest prices often occur during peak hours or shortage conditions and are an important component of the economic signals that govern investment and retirement decisions.

Figure A2: Real-Time Energy Price-Duration Curve
2011



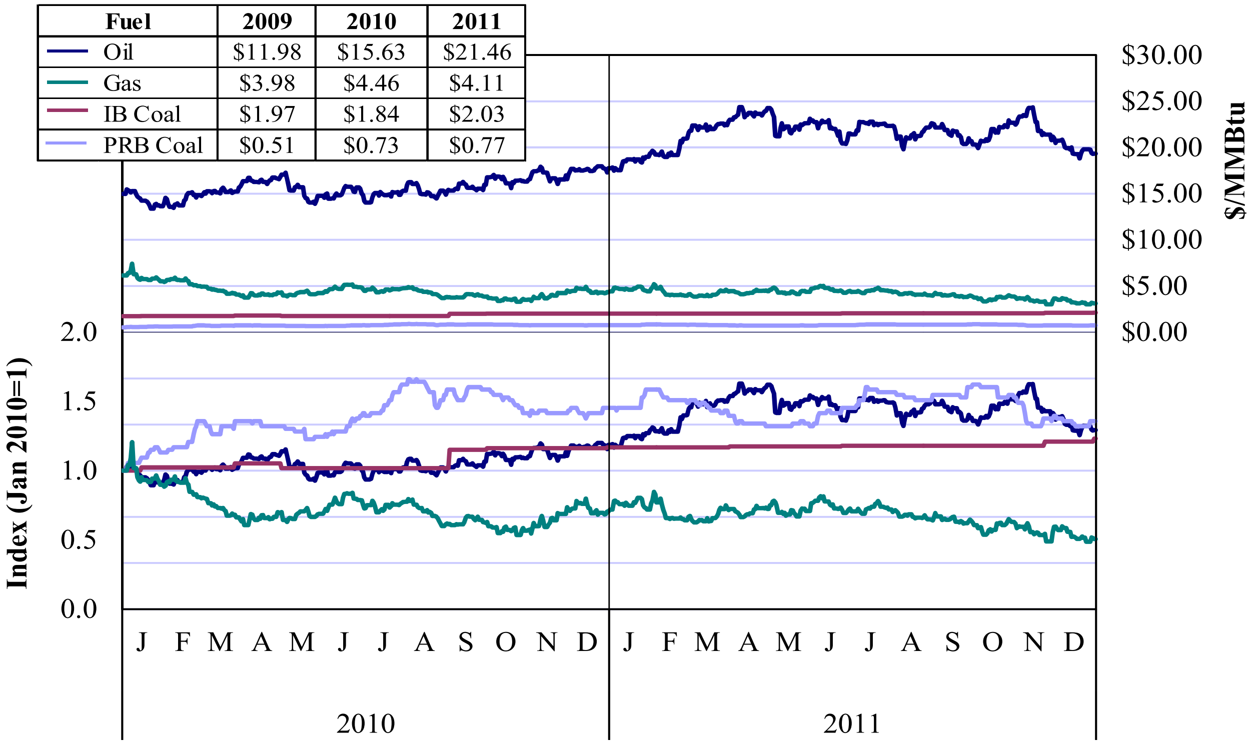
Share of All Hours with LMP	2009			2010			2011		
	> $200	> $100	< $0	> $200	> $100	< $0	> $200	> $100	< $0
Cinergy Hub	0.06%	0.62%	0.91%	0.14%	1.32%	0.51%	0.29%	1.52%	0.11%
Michigan Hub	0.10%	0.97%	1.32%	0.19%	1.94%	0.57%	0.33%	1.86%	0.50%
Minnesota Hub	0.11%	0.70%	4.78%	0.15%	1.27%	3.20%	0.25%	1.23%	3.76%
WUMS Area	0.06%	0.66%	4.99%	0.08%	1.19%	3.17%	0.18%	1.06%	1.86%

Figure A3: MISO Fuel Prices

As noted previously, fuel prices are a primary determinant of overall electricity prices since they comprise most of generators' marginal costs. Figure A3 shows the prices for natural gas, oil, and two types of coal in the MISO region since 2010.[2] The top panel shows nominal prices in dollars per MMBtu, while the bottom panel shows fuel price movements in relative terms, with each fuel indexed to January 2010.

2 Although output from oil-fired generation is typically minimal, it can become significant if gas supplies are interrupted during peak winter load conditions.

Figure A3: MISO Fuel Prices
2010–2011



Fuel	2009	2010	2011
Oil	$11.98	$15.63	$21.46
Gas	$3.98	$4.46	$4.11
IB Coal	$1.97	$1.84	$2.03
PRB Coal	$0.51	$0.73	$0.77

Figure A4: Fuel-Price Adjusted System Marginal Price

The impact of fluctuations in marginal fuel prices can obscure the underlying trends and performance of the electricity markets. Hence, in Figure A4 we calculate a fuel price-adjusted SMP. This measure isolates variations in real-time electricity prices that are due to factors other than fluctuations in fuel prices, such as changes in load, net imports or available generation. The available generation can change as a result of unit additions or retirements, unit outages, congestion management needs or output by intermittent resources.

To calculate this metric, each real-time interval's SMP is indexed to the average three-year fuel price of the marginal fuel during the interval. Hence, downward adjustment is greatest when fuel prices were highest and vice versa. The price-setting distinction was attributed to the fuel type that accounted for the plurality of units on the margin during an interval (more than one fuel can be on the margin in a particular interval). However, this methodology does not account for some impacts of fuel price variability, such as changes in generator commitment and dispatch patterns or relative inter-regional price differences (resulting from differences in regional generation mix) that would impact the economics of interchange.

Figure A4: Fuel-Price Adjusted System Marginal Price
2010–2011

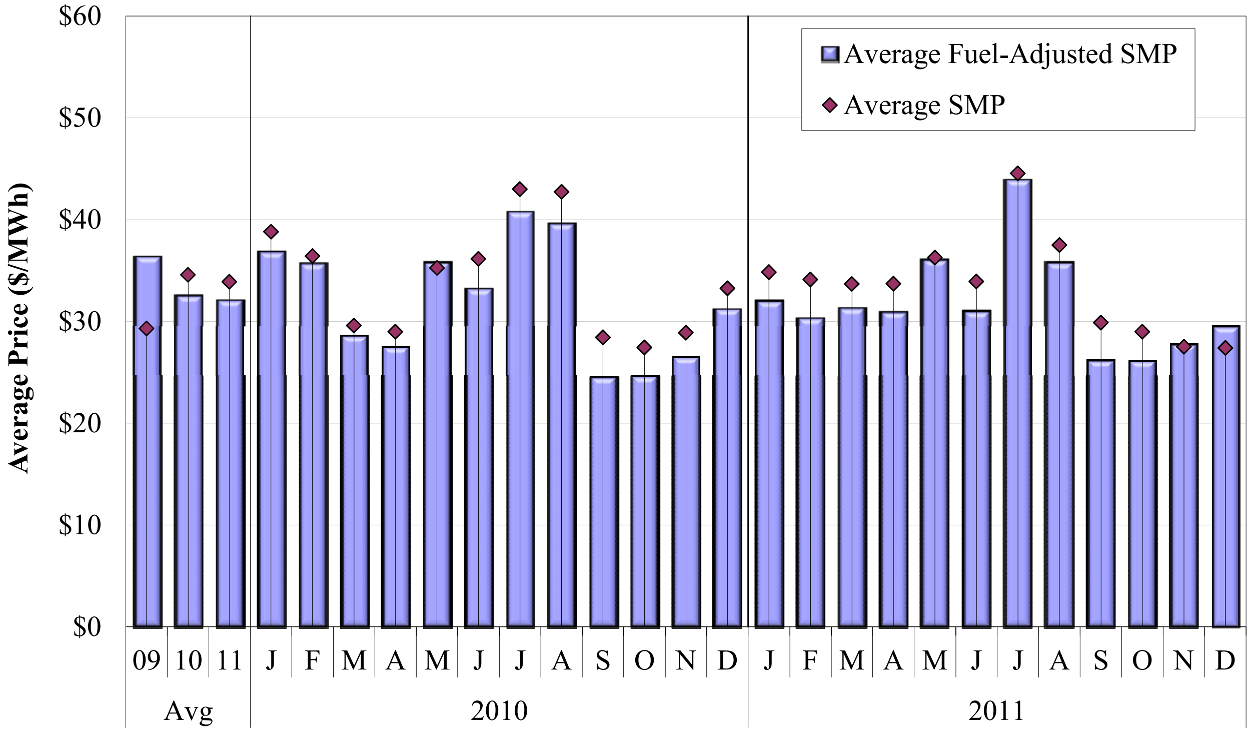
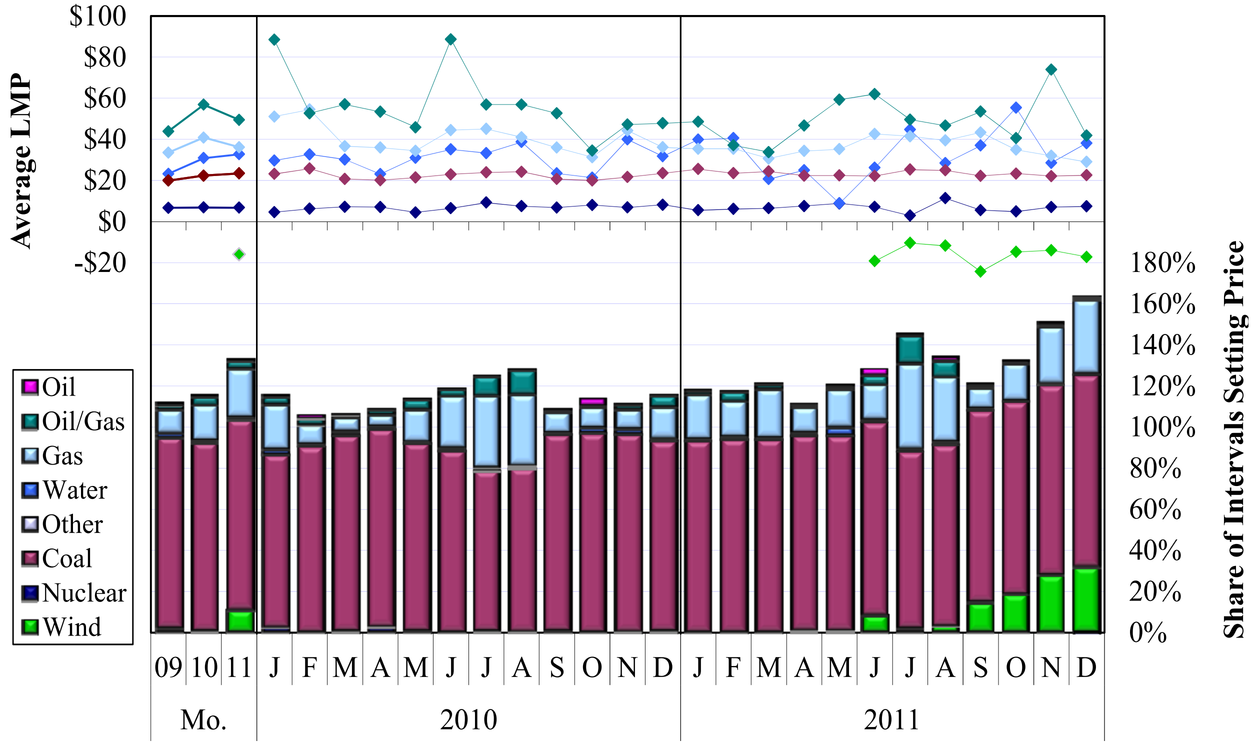


Figure A5: Price Setting by Unit Type

Figure A5 examines the frequency with which different types of generating resources set price in MISO. More than one type of unit may be marginal in an interval, particularly when a transmission constraint is binding (different fuels may be marginal in the constrained and unconstrained areas). Therefore, the total for all the fuel types exceeds 100 percent. The figure shows the average prices that prevailed when each type of unit is on the margin (in the top panel) and how often each type of unit set the real-time price (in the bottom panel).

Since approximately half of MISO's generation mix—and the large majority of its baseload capacity—is coal-fired, coal units tend to set price in a large majority of intervals. Natural gas and oil resources typically only set prices during the highest-load and ramp-up hours. Hence, these fuel prices have a greater impact on load-weighted average prices than the percentages suggest.

Figure A5: Price-Setting by Unit Type
2010–2011



Key Observations: Prices

i. Real-time energy prices in MISO averaged $33.61 per MWh, and ranged from $29 in the West region to $37 in the East. Energy prices were 1.9 percent lower than in 2010 due to:

a) lower natural gas prices, which declined 8 percent, and

b) lower average load, which declined 0.6 percent, as well as the lower summer loads in August when the weather was mild.[3]

ii. The average all-in price fell 2 percent for the same reasons that caused energy prices to fall as energy prices continued to constitute 99 percent of the all-in price.

– The total contribution to the all-in price from uplift costs, including RSG payments and PVMWP, decreased 8 cents to $0.31 per MWh and remained less than 1 percent of the all-in price.

– The contribution to the all-in price in 2011 by ancillary services costs was 15 cents, and capacity costs contributed less than one cent per MWh. These levels are virtually unchanged from 2010. Very low capacity prices are expected under the current market design when there is a prevailing capacity surplus in MISO.

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

- The all-in price figure also shows that energy price fluctuations are driven in large part by natural gas prices.

iii. Natural gas prices fell 8 percent in 2011.

- Natural gas-fired resources were on the margin more frequently in 2011 because of an increase in binding constraints and reductions in natural gas prices, particularly in the second half of the year.
- The correlation between natural gas and energy prices is not stronger because natural gas-fired resources only set prices in 23 percent of the intervals; although, these periods tend to be the highest load intervals.

iv. Coal prices increased by 6 to 10 percent in 2011 and it continues to be the most prevalent price-setting fuel in MISO.

- Coal-fired resources set the energy price in 93 percent of intervals, including virtually all of the off-peak intervals. Frequently congestion causes both natural gas and coal to be on the margin in the same interval in different areas.

v. The average fuel-adjusted energy prices in 2011 declined 1.4 percent, slightly less than the 2.0 percent drop in average SMP. This indicates that fuel prices were just one cause of the decline in energy prices since 2010.

- Approximately two-thirds of the total change in energy prices is attributable to a 0.6 percent decline in average load, increased generation by intermittent resources, and a 1.5 GW increase in average net imports.

vi. The introduction of DIR in June 2011 has allowed these wind resources to set price, on average near $-20 per MWh. These units' marginal costs are often below zero because of production tax credits.

B. Net Revenue Analysis

In this subsection, we summarize 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 provide sufficient net revenue to finance new investment when additional capacity is needed. However, even if the system is in long-run equilibrium, random factors in each year (e.g., weather conditions, generator availability, transmission topology changes, outages 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 Federal Energy Regulatory Commission (FERC or

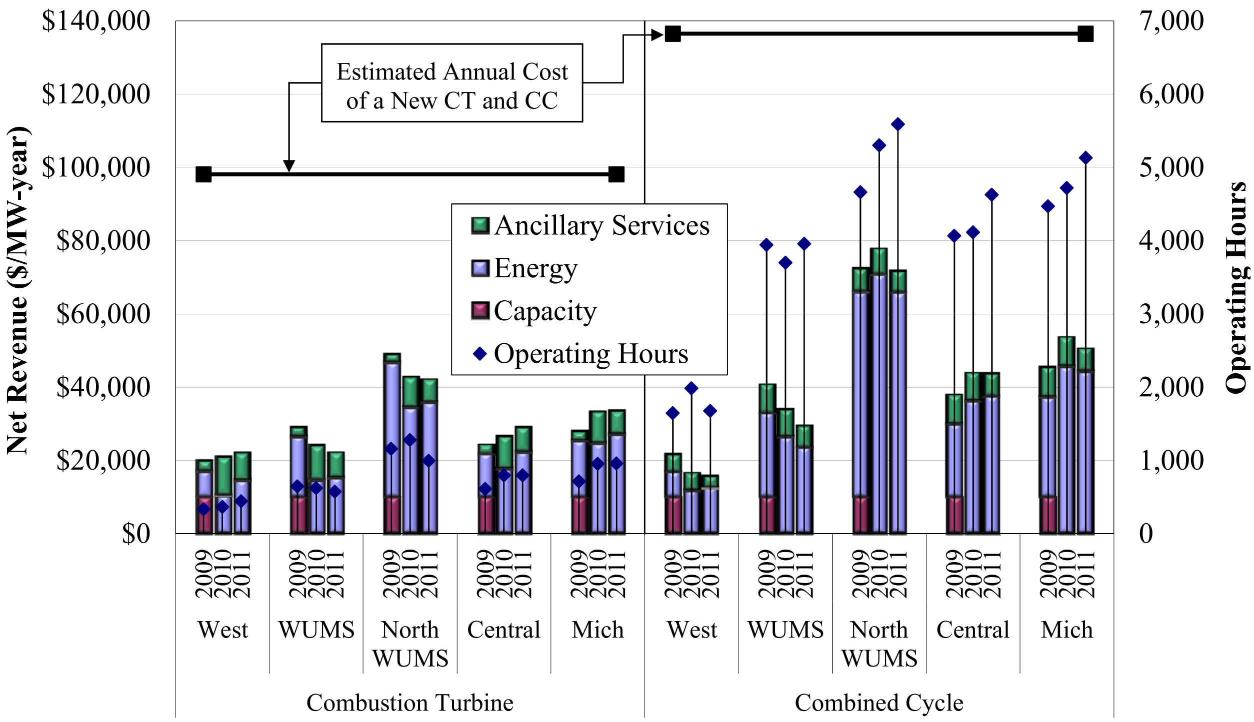
Commission) to account for variable Operations and Maintenance (O&M) costs, fuel costs, and expected forced outage rates.

Figure A6: Net Revenue and Operating Hours

To determine whether these net revenue levels would support investment in new resources, the Figure A6 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 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. Hence, the estimated energy net revenues for CC generators are substantially higher than for CTs. Currently capacity prices are the same across the regions, although MISO has filed to establish locational requirements that will likely result in locational price differences. Since CTs provide far less energy, capacity and ancillary service revenues typically have a larger impact on a CT's net revenues than on a CC's net revenues.

Figure A6: Net Revenue and Operating Hours
2010–2011



Key Observations: Net Revenues

i. The net revenue in 2011 for both types of units was substantially less than CONE in all regions. This is consistent with expectations because the MISO region continues to exhibit a capacity surplus and did not experience significant shortages in 2011.

- Even in North WUMS, the most congested area in MISO during 2011, revenues for a CC and CT were only 53 and 43 percent of CONE, respectively.
- Results are virtually unchanged from 2010 and are consistent with expectations for the MISO market because the prevailing capacity surplus in MISO should not lead to outcomes that produce incentives to build new resources

ii. In addition, there were limited periods of shortage pricing in MISO. Such periods, if they occur frequently, can provide signals to participants that additional capacity is necessary.

iii. Recent and anticipated future changes should improve the long-term economic signals Anticipated changes in 2012 include:

- A revised Resource Adequacy Construct, which adds a locational mechanism to capacity market prices to better reflect regional capacity shortages; and
- Improvements to real-time energy pricing to allow to peaking resources and demand response resources to set prices more predictably.

iv. However, additional changes are needed to the RAC to assure that it will provide efficient incentives to invest in new resources when the surplus dissipates and resources are needed.

- Resources may be needed more rapidly than previously anticipated due to forthcoming environmental regulations affecting MISO's coal resources.
- The recommendations pertaining to MISO's RAC address the prevailing issues that undermine the ability of the RAC to produce efficient price signals. These recommendations include:
  - ✓ The adoption of a sloped demand curve in the capacity auction to set more efficient capacity prices based on the quantity of surplus capacity in the market; and
  - ✓ Working with PJM to eliminate barriers to capacity trading between regions.

II. Load and Resources

This section examines 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.

In this section, we distinguish between market participants and reliability-only participants. Currently 83 market participants own generation resources (totaling 132 GW of capacity) or serve load in the MISO market.[4] This group includes large investor-owned utilities, municipal and cooperative utilities, and independent power producers. MISO also serves as the reliability coordinator for reliability-only members, such as Manitoba Hydro, which provide an additional 12.2 GW of capacity, but these entities do not submit bids or offers into MISO's markets.[5] Reliability-only (or coordinating) members are excluded from our analysis unless otherwise noted.

Our analysis divides MISO into four geographic areas:

- East – Includes MISO control areas that had been located in the North American Electric Reliability Corporation's (NERC) ECAR region;
- West – Includes MISO control areas that had been located in the NERC MAPP region;
- Central – Includes MISO control areas that had been located in the NERC MAIN region, but excludes MAIN utilities located in the Wisconsin-Upper Michigan System (WUMS) Area; and
- WUMS – MISO control areas located in the Wisconsin-Upper Michigan System Area.

The East, West and Central regions were coordination regions that MISO used to operate the system in 2010. In 2011, MISO consolidated the East and Central regions for purposes of reliability coordination. We examine the WUMS area, originally part of the East reliability region, separately due to differences in 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 VII of this Appendix.

4 MISO membership totals 134 entities when including power marketers,brokers, state regulatory authorities and other stakeholders.

5 Manitoba does submit offers for a limited amount of energy under a special procedure known as External Asynchronous Resources or EAR which permits dynamic interchange with such resources. This EAR essentially allows 5-minute dispatch of a limited portion of the MISO-MH interchange.

A. Load Patterns

Figure A7: Load Duration Curves

MISO as a whole is a summer-peaking market, although northern portions of the West region are winter-peaking. Figure A7 shows load levels for the prior three years in the form of hourly load duration curves. These curves show the number of hours (on the horizontal axis) in which load is greater or equal to an indicated level (on the vertical axis). We separately show curves 2010 and 2011 adjusted to the membership that existed in 2009 so changes in load due to other factors (e.g. weather and economic activity) can be more easily discerned. The table indicates the number and percentage of hours when load exceeded 80, 85, 90 and 95 GW of load.

Figure A7: Load Duration Curves
2009–2011

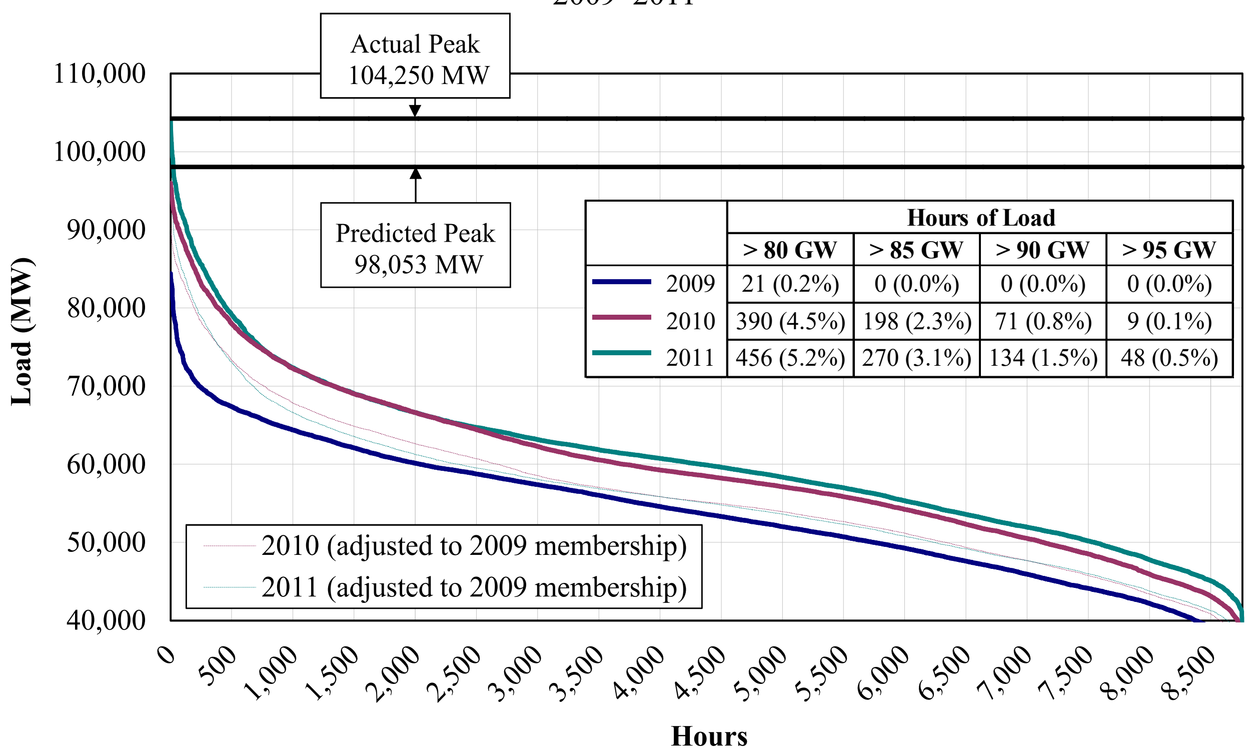


Figure A8: Heating and Cooling Degree-Days

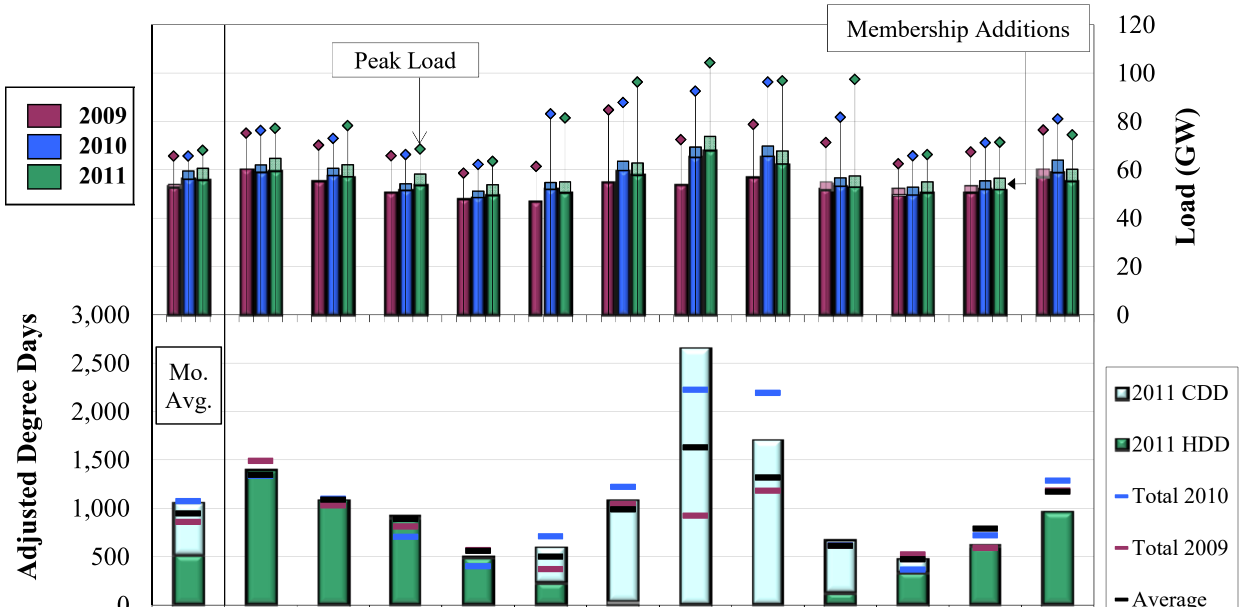
MISO's load is temperature-sensitive. Figure A8 illustrates the influence of weather on load by showing heating and cooling degree-days (a proxy for weather-driven demand for energy) alongside the monthly average load levels for the prior three years.

The top panel shows the monthly average loads in the bars and the peak monthly load in the diamonds. We separately indicate changes in peak and average load that are the result of new members.[6] The bottom panel shows monthly Heating Degree-Days (HDD) and Cooling Degree-

6 For comparability, we remove FirstEnergy from the load in this figure.

Days (CDD) averaged across four representative locations in MISO.[7] The table at bottom shows the year-over-year changes in average load and degree-days.

Figure A8: Heating and Cooling Degree-Days
2009–2011



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

Key Observations: Load Patterns

i. After adjusting for changes in membership, there was a slight downward shift in the load duration curve for 2011 compared to 2010, which was primarily due to milder weather (significantly lower degree days) in June, August, November and December.

ii. However, load has increased significantly from 2009 as both economic activity and degree-days were substantially higher in 2010 and 2011.

iii. Peak load was higher in the highest-load hours in 2011 than in 2010 due to relatively hot temperatures in late July.

– The actual peak of 104.0 GW on July 20 was nearly 6 GW higher than the peak load of 98.1 GW predicted in MISO's Summer Resource Assessment.

7 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.

- This did not create a significant issue this year because of the prevailing levels of surplus capacity in MISO and unusually high wind output on the peak day.

iv. Total degree days declined by 2 percent from 2010, consistent with the modest reduction in average load of 0.6 percent.

- Most months in 2011 exhibited weather patterns consistent with or slightly more extreme than historical averages.
- However, November and December were mild with higher than normal temperatures.
- July was exceptionally warm across the region, resulting in a 7.5 percent rise in the annual peak load.

v. A considerable portion of MISO's generation is required to meet the demands during the highest five 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 resources are needed primarily to meet only the system's peak energy or operating reserve demands.
- This pattern underscores the importance of efficient energy pricing during peak load hours and capacity pricing to ensure that the system continues to maintain adequate resources.

B. Generating Capacity and Availability

Figure A9: Distribution of Generating Capacity by Coordination Region

Figure A9 shows the capacity distribution of existing generating resources. The left panel shows the distribution of unforced capacity by region and fuel type, along with the annual peak load in each region. The right panel displays the change in the resources from 2010 to 2011 based on summer capacity ratings, which do not account for forced outages or intermittency.[8] The mix of fuel types is important because it determines how differential changes in fuel prices, environmental regulations, and other external factors will likely affect the market. The geographic distribution is important because it determines the intra-market power flows.

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

Figure A9: Distribution of Generating Capacity
By Fuel Type, 2011

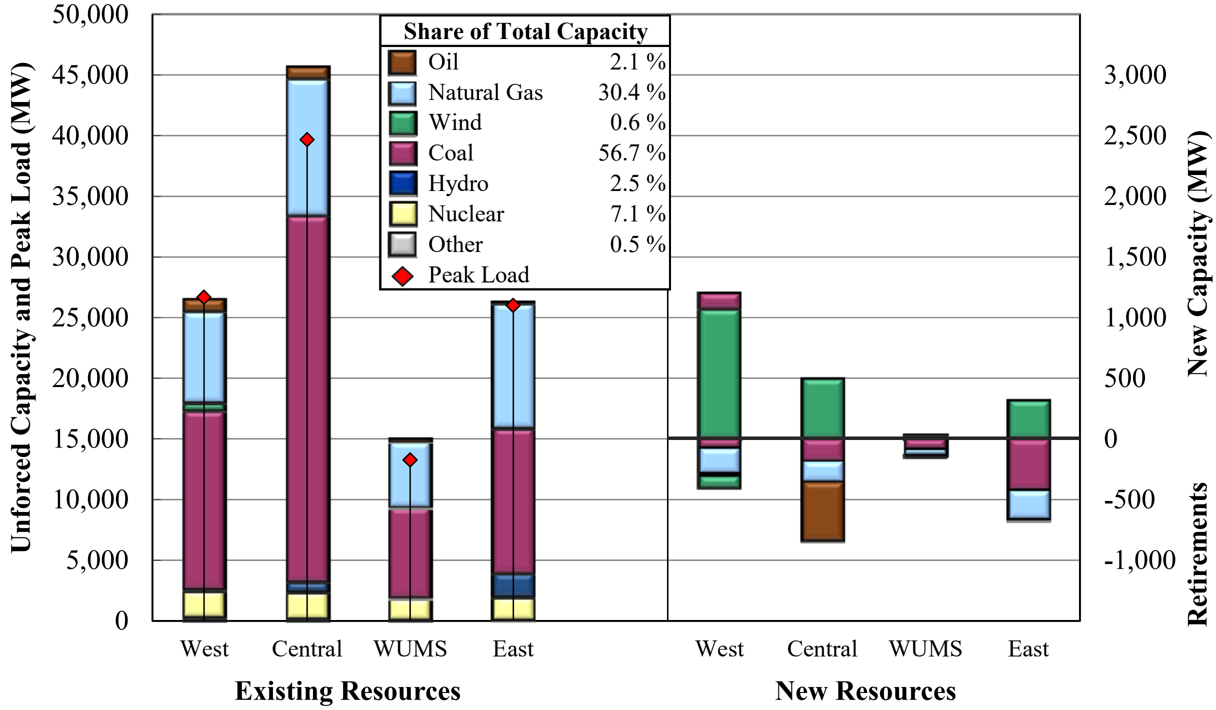
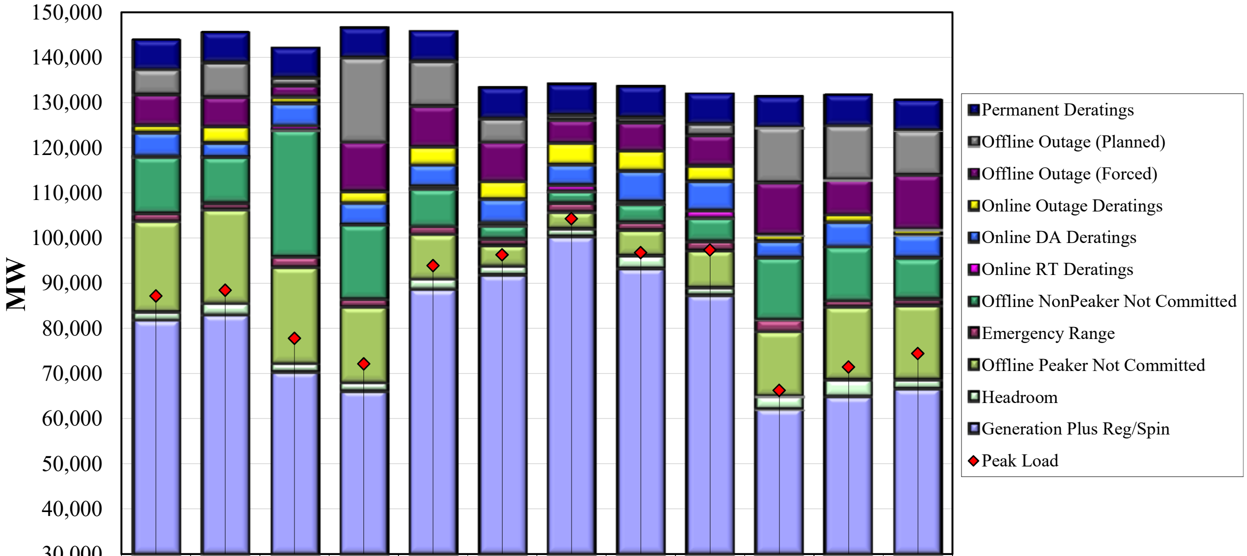


Figure A10: Availability of Capacity during Monthly Peak-Load Hour

Figure A10 shows the status of generating capacity during the peak load hour of each month. 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 three segments are "headroom" (capacity available on online units above the dispatch point), offline quick-start generating capacity, and the emergency output range. These four segments represent the total capacity available to MISO. The other segments are the remaining capacity that cannot be dispatched for the identified reasons.

The height of the bars is equal to total generating capacity. It reflects additions and retirements of generators, as well as market participant entry and exit. 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.

Figure A10: Availability of Capacity, During Peak Load Hour
2011



6 PM	8 AM	7 PM	10 AM	2 PM	4 PM	4 PM	4 PM	4 PM	2 PM	6 PM	7 PM	Peak Hour
Jan 21	Feb 10	Mar 10	Apr 19	May 31	Jun 7	Jul 20	Aug 1	Sep 1	Oct 7	Nov 29	Dec 6	Peak Date
87,132	88,396	77,753	72,089	93,844	96,279	104,250	96,758	97,347	66,239	71,381	74,411	Peak Load

Figure A11: Capacity Unavailable During Peak Load Hours

Figure A11 is very similar to the prior figure except that it shows only the offline or otherwise unavailable capacity during the peak hour of each month. Maintenance planning should maximize resource availability in summer peak periods, when the demands of the system (and prices) are highest. As a consequence, the larger subset of units in service should increase the total non-outage deratings during these periods.

The figure also shows the quantity of permanent deratings (relative to nameplate capacity), which, due to operating limitations, is unavailable in any hour. Many units cannot produce their nameplate output under normal operation, particularly older baseload units in the region. Wind resources additionally often have ratings in excess of available transmission capability.

Figure A11: Capacity Unavailable During Peak Load Hours
2011

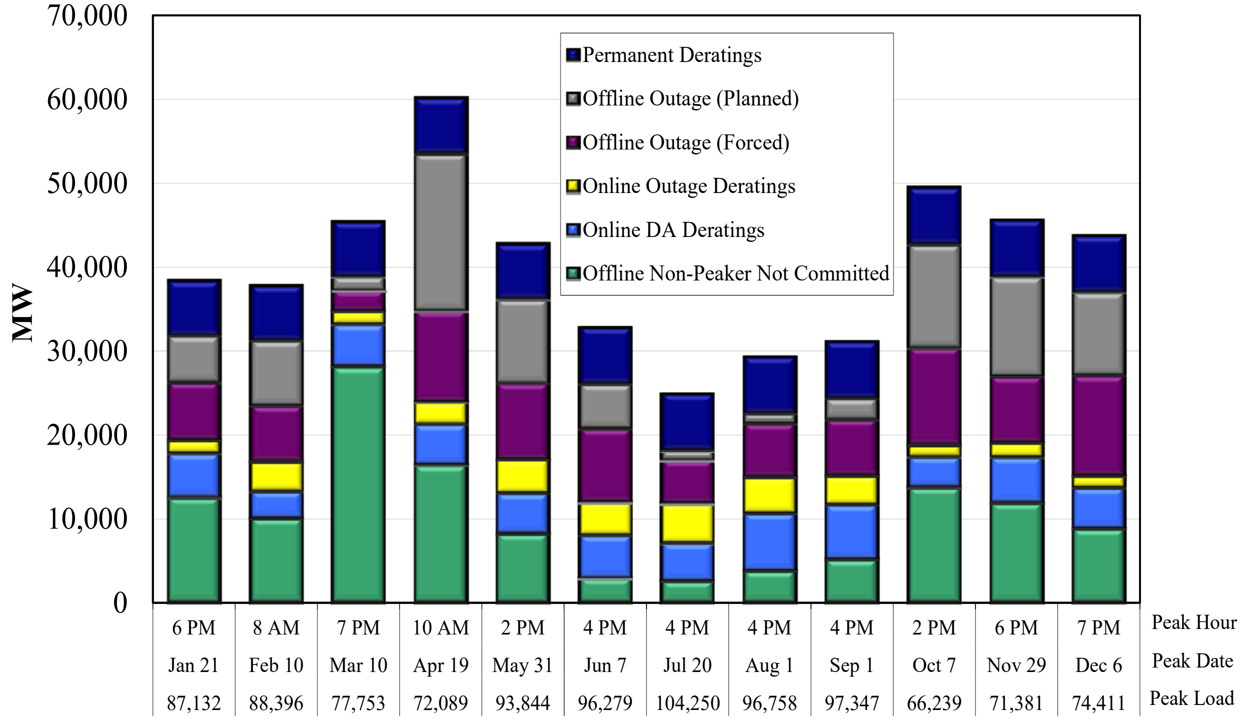
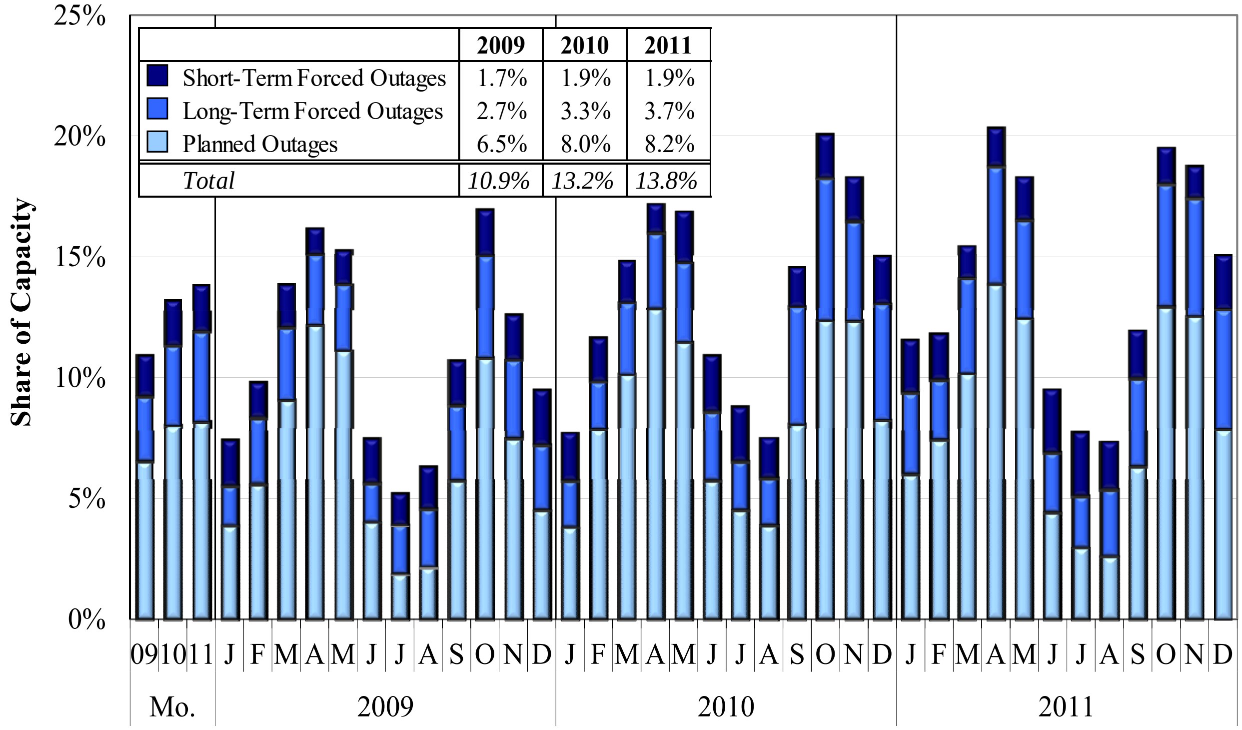


Figure A12: Generator Outage Rates

Figure A12 shows monthly average planned and forced generator outage rates for the prior three years. Only full outages are included; partial outages or deratings are not shown. The figure also distinguishes between short-term forced outages (lasting fewer than seven days) and long-term forced outages (seven days or longer). Planned outages are often scheduled for low-load periods when economics are favorable for participants to perform maintenance. Conversely short-term outages are usually the result of unit malfunction, but they may reflect attempts by participants to physically withhold energy from the market. We evaluate market power concerns related to potential physical withholding in Section VII.E.

Figure A12: Generator Outage Rates
2009–2011



<u>Key Observations: Generating Capacity and Availability</u>

i. Coal-fired generating resources account for more than 50 percent of MISO's installed capacity.

– Coal and nuclear resources are generally baseloaded and produce 74 and 13 percent of the energy in MISO, respectively.

– Natural gas units are generally more expensive, but provide MISO with the necessary flexibility to manage loads. However, natural gas resources are becoming competitive with coal resources as natural gas prices have fallen sharply.

ii. MISO generally has excess generating capability in western regions and excess load in eastern regions, which has resulted in predictable west-to-east network flows historically.

iii. MISO's generation is regionally diverse, although most wind is concentrated in the West region, where wind profiles are comparatively more attractive. Such a high concentration of wind generating capacity can present operating and reliability challenges. These are discussed in Section IV.H.

iv. The EPA CSAPR and MATS rules, if implemented as proposed, are forecasted to contribute to retirements of a significant number of coal resources. This has significant implications for the MISO markets given the dominance of coal-fired generating capacity in MISO.

v. Cumulative outages increased to an average of 13.8 percent in 2011. The rise was confined to long-term forced and planned outages.

– Relatively low energy prices and impending new environmental regulations contributed to higher planned outage rates in fall 2011.

vi. Outages were lowest during the summer when capacity needs were greatest because planned outages generally take place in other seasons. However, short-term forced outages peaked during this time as a result of more units being online.

C. Resource Margins and Generation Adequacy

This section evaluates the supply in MISO, including:

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

In the next table we estimate capacity margin values under various scenarios that are intended to indicate the expected physical surplus over the forecasted load. The data used to prepare this table is consistent with the data used by MISO in its annual *Summer Resource Assessment*. However, the *capacity* margins we calculate are different from the *reserve* margins MISO has calculated and reported in past assessments.

These reserve margins are generally based on: a) peak load forecasts under normal conditions;[9] b) normal load diversity; c) average forced outage rates; and d) full response from DR resources (behind the meter generation, interruptible load, and direct controllable load management). These factors tend to cause the reserve margin to overstate the surplus that one would expect under warmer-than-normal summer peak conditions. For example, many resources must be derated in response to environmental restrictions or the effect of high ambient temperatures when warmer-than-normal summer conditions occur.[10] In contrast, reserve margins do not include resources in the region that are not designated as capacity resources, which would tend to understate the expected surplus under peak conditions.

In its *2012 Summer Resource Assessment*, MISO presented baseline reserve margin calculations alongside a number of valuable scenarios that demonstrate the sensitivity to changes in some key assumptions, such as:

- Including undesignated capacity;

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

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

- Assuming higher than normal peak load (i.e., a 90/10 load forecast);
- Assuming lower load diversity; and
- Assuming increased forced outage rates (a probable outcome of extreme temperatures).

The results of these scenarios are consistent with the scenarios presented below in our capacity margin analysis. Table A1 shows our estimated capacity margins for summer 2012 for a normal year (which assumes a 50/50 load forecast and average load diversity) and a "high-temperature" year (which assumes a 90/10 load forecast, lower load diversity and higher deratings).[11] The latter case is consistent with conditions that prevailed in 2006 and 2011. We include multiple DR scenarios to show how varying response affects MISO's overall resource adequacy. These scenarios also provide insight regarding MISO's expected reliance on DR.

Table A1: Capacity, Load and Reserve Margins by Region
Summer 2012

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

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

Key Observations: Resource Adequacy

i. Regional capacity exceeded the 2011 peak load by at least 15 percent in each region.

ii. Despite increased wind generating capacity, MISO continues to depend heavily on coal-fired generation, which accounts for more than 50 percent of MISO's resources.

- As discussed later in this section, MISO expects a substantial amount of capacity to retire in response to proposed changes to environmental rules.

iii. The majority of capacity additions in 2011 were wind units in the West region, where wind profiles are most attractive. Although wind resources are relatively costly, they benefit from a variety of subsidies, including federal production and investment tax credits, state renewable portfolio standards and the transmission investments planned to improve their deliverability (i.e., Multi-Value Projects).

iv. Capacity surplus varies considerably depending on the load and demand response capability assumptions.

- The baseline capacity margin for MISO region is 17.1 percent based on the expected load, average load diversity, average forced outage rates and full response from the DR resources.
- Regional capacity margins are 8.8 percent in the East region, 17.4 percent in the West and 26.6 percent in the Central, which helps explain why MISO generally exhibits west-to-east power flows.
- The capacity surplus in this case is more than enough to satisfy MISO's 2,400 MW reserve needs, even if DR does not respond at close to 100 percent when called.[12]

v. For the high-temperature case, the results show that MISO will likely be short of operating reserves during peak demand conditions.

- In this case, the combination of higher load, higher temperature-related deratings, and lower load diversity will reduce MISO's capacity margin to 5 percent or 4.8 GW.
- Since this surplus includes more than 8 GW of load curtailments and MISO's reserve requirements are 2.4 GW, this case implies that MISO will be relying on a combination of additional imports or DR curtailments of 5.7 GW to avoid reserve shortages. This is well over half of the DR capability in MISO.

12 MISO's operating reserve requirements total 2,400 MW, so capacity margin quantities shown in the table that are below 2,400 MW indicate reserve shortage conditions or increased reliance on imports. Even with full response by MISO's DR, the high-temperature margin is less than 2,400 MW.

- In the half-DR case, the capacity margin falls to 750 MW, substantially less than the 2.4 GW operating reserve requirement (i.e., indicating a substantial reserve shortage).

- Likewise, the high-temperature case indicates that the system will be substantially short of energy in the no-DR scenario. Although these shortages would likely be mitigated by increased imports, these results underscore how important it is for the MISO DR capability to perform well when called upon.

vi. Overall, these results indicate that the system's resources should be adequate for summer 2012 if the peak demand conditions are not substantially hotter than normal. However, capacity margins are decreasing and will likely continue to fall as new environmental regulations are implemented.

- Therefore, it is important for the resource adequacy provisions to facilitate an efficient capacity market that will provide the necessary economic signals to maintain an adequate resource base. These issues are discussed in this Report and a number of the recommendations are designed to improve these signals.

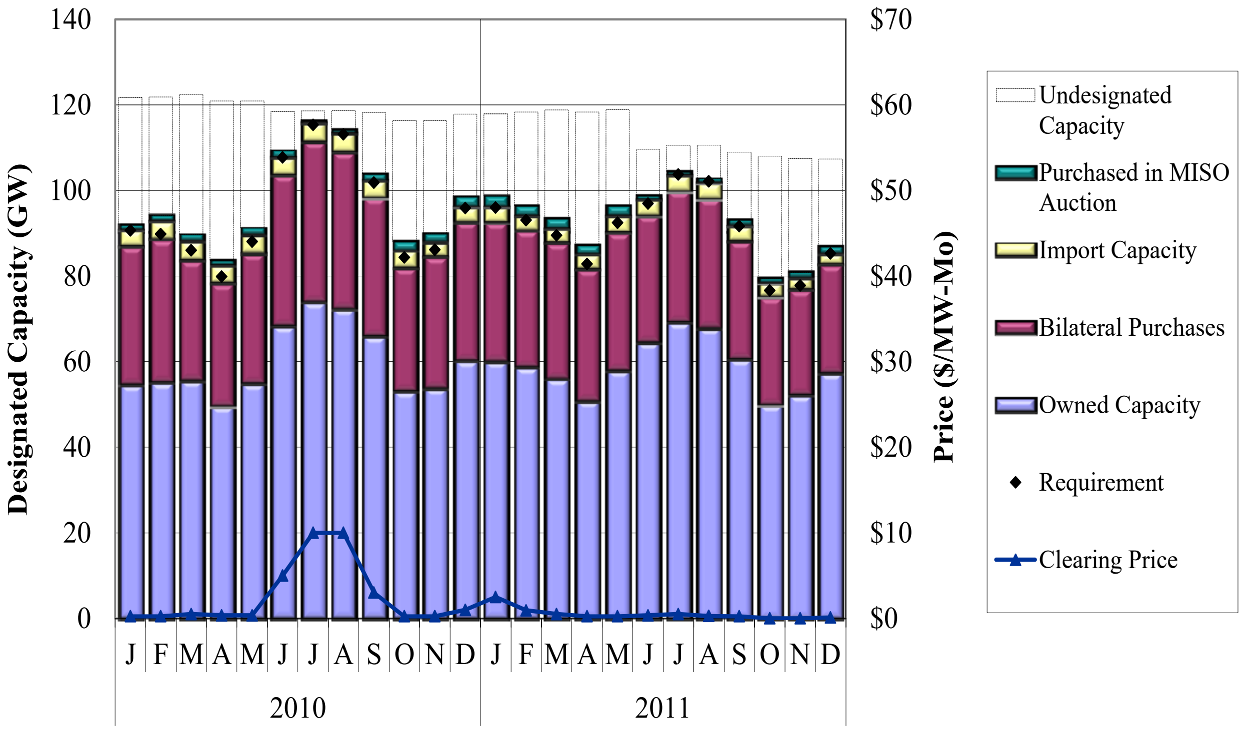
D. Capacity Market

In June 2009, MISO began operating a voluntary monthly capacity auction to allow LSEs to procure capacity to meet their Tariff Module E capacity requirements. The VCA is intended to provide a balancing market for LSEs, with most capacity needs being satisfied through owned capacity or bilateral purchases.

Figure A13: Voluntary Capacity Auction Results

Figure A13 shows the monthly results of the VCA for the prior two years. The capacity requirement, based on a "1-day-in-10-years" loss of load expectation, is determined monthly to account for seasonal fluctuations in demand. The column height represents the total designated capacity, including capacity provided by firm imports from external resources.

Figure A13: Voluntary Capacity Auction
2010–2011



<u>Key Observations: Capacity Market</u>

i. The VCA has consistently cleared at near-zero prices as a result of the prevailing capacity surplus in MISO.

   – The decrease in total capacity in June 2011 marks the departure of FirstEnergy from the MISO market. This change has not materially impacted resource adequacy.

ii. Cleared capacity in the VCA averaged only 1.7 GW, with most LSE obligations satisfied through owned capacity or bilateral purchases.

   – Low cleared quantities are consistent with the intention of the VCA as a balancing market. Although very little capacity clears through this market, it provides a transparent spot price for capacity that should be the primary driver of forward capacity prices (and, therefore, a critical component of the economic signal for investment).

iii. MISO has worked with its customers and filed proposed revisions to its Resource Adequacy Construct (RAC) to add locational components (to reflect the locational reliability needs of the system), introduce mitigation measures to prevent artificial suppression of prices through uneconomic entry, and improve other aspects of the market. These changes will improve the economic signals produced by the MISO markets, but further improvements are necessary and recommended in this *State of the Market Report*.

- We have filed comments with the Commission and continue to recommend that MISO modify the RAC to incorporate a sloped demand curve that would:
  - ✓ Allow capacity prices to efficiently reflect the marginal reliability value of additional capacity;
  - ✓ Produce more stable and predictable pricing, which would increase the capacity market's effectiveness in providing incentives to govern investment and retirement decisions; and
  - ✓ Reduce the incentive to exercise market power in the capacity market by withholding resources.
- The need for a sloped demand curve may become particularly acute in MISO as the reserve margins continue to decline with the likely retirement of significant amounts of coal-fired capacity because of the new EPA regulations.

iv. We also continue to recommend MISO work actively with PJM to ensure that undue barriers to cross-border capacity market trading do not prevent MISO suppliers from participating in PJM's currently higher-valued capacity market and vice versa.

- These barriers include: restricted access to firm transmission into PJM, the ability of long-term firm transmission holders to withhold firm transmission from capacity suppliers seeking to use it to support capacity transfers, and uncertainty regarding obligations on external suppliers that sell capacity into the PJM RPM market.
- We made a filing in ER11-4081-000 requesting that the Commission require PJM to work with MISO to address these barriers.

III. Day-Ahead Market Performance

In this section, we summarize the performance of the day-ahead market. The section is focused on four main areas: (1) convergence of prices between the day-ahead and real-time energy markets; (2) performance of ancillary services markets; (3) day-ahead load scheduling; and (4) virtual trading. Each of these areas is addressed separately in the subsections below.

In the day-ahead market, participants make financially binding forward purchases and sales of power for delivery in real time. Day-ahead transactions allow participants to procure energy for their own demand, managing risk by hedging the participant's exposure to real-time price variability, 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.

Day-ahead outcomes are important because the bulk of MISO's generating capacity is committed through the day-ahead market, and much of the power procured through MISO's market is financially settled day-ahead. In addition, obligations to FTR holders are settled based on congestion outcomes in the day-ahead market.

A. Day-Ahead Energy Prices and Load

Figure A14-Figure A15: Day-Ahead Energy Prices and Load

Figure A14 shows average day-ahead prices during peak hours (6 a.m. to 10 p.m. on weekdays, excluding holidays) at four representative hub locations in MISO and the corresponding scheduled load (which includes net cleared virtual demand. Figure A15 shows similar results for off-peak hours (10 p.m. to 6 a.m. on weekdays and all hours on weekends). Differences in prices among the hubs show the prevailing congestion and loss patterns throughout the year. High prices in one location relative to another location indicate congestion and loss factor differences from a low-priced area to a high-priced area.

Figure A14: Day-Ahead Hub Prices and Load
Peak hours, 2010–2011

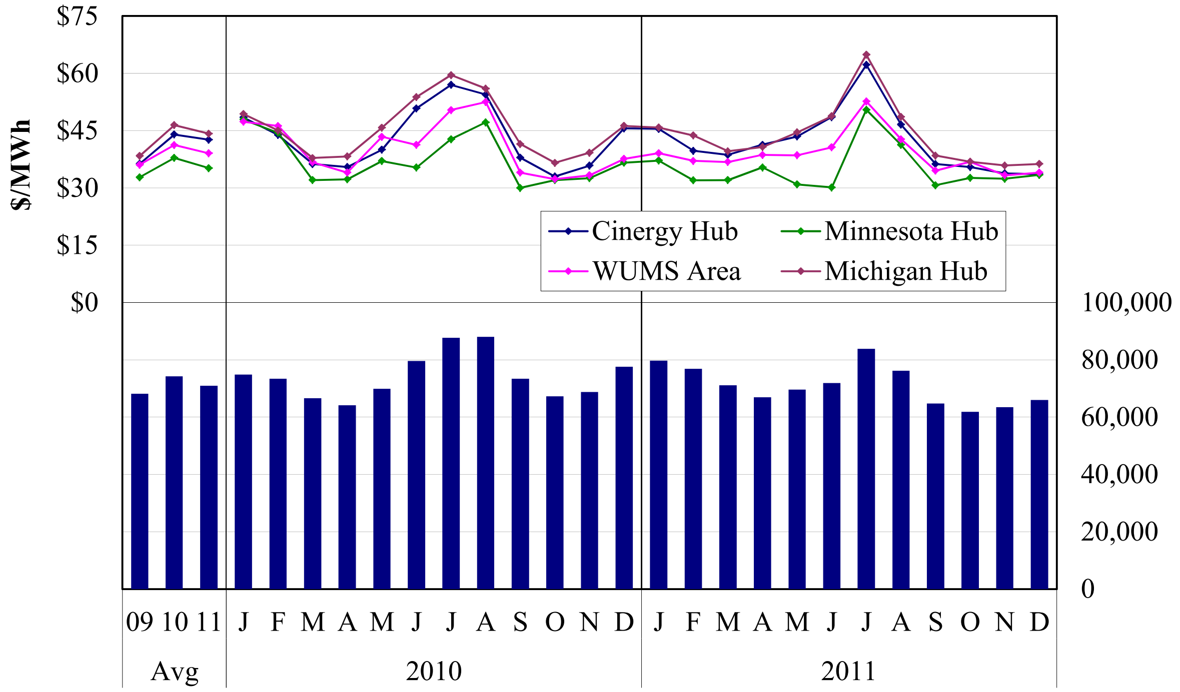
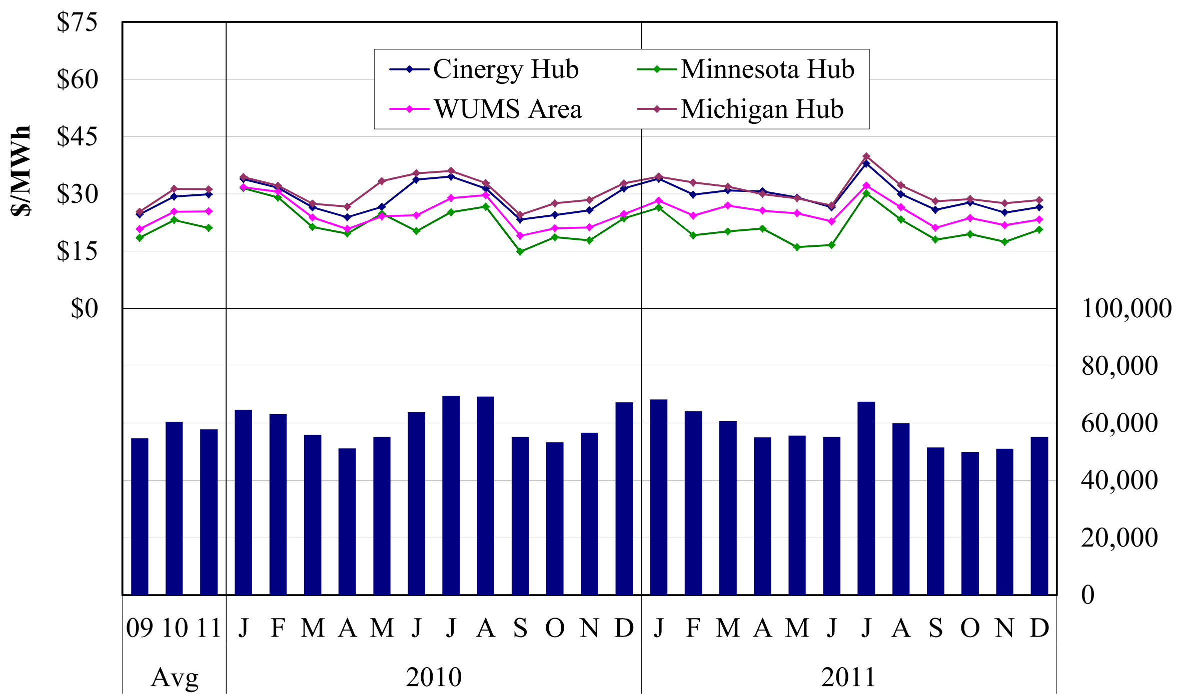


Figure A15: Day-Ahead Hub Prices and Load
Off-peak hours, 2010–2011



Key Observations: Day-Ahead Energy Prices and Load

i. Prices continue to be moderately correlated with load, exhibiting the highest prices in the summer months and, to a lesser extent, in January and February. However, fuel prices and other factors also play an important role in determining day-ahead prices.

ii. As in prior years, prices in both peak and off-peak hours show a prevailing price increase from West to East that is due to congestion and transmission losses.

- Prices in the West declined the most in 2011 compared to 2010, consistent with increased penetration of wind generation, especially during off-peak hours when wind generation tends to be higher.

- Prices in Michigan were again the highest-priced of the four locations, though only slightly above the Cinergy Hub.

B. Day-Ahead and Real-Time Price Convergence

This subsection evaluates the convergence of prices in the day-ahead and real-time energy and ancillary services markets. Good convergence between day-ahead and real-time prices is a sign of a well-functioning day-ahead market, which is vitally important for the reasons discussed at the beginning of this section. If the day-ahead prices fail to converge with the real-time prices:

- Generating resources will not be efficiently committed since most are committed through the day-ahead market;

- Consumers and/or generators may be substantially affected since most settlements occur through the day-ahead market; and

- Payments to FTR holders will not reflect the true transmission congestion on the network since they are determined by day-ahead market outcomes, which will ultimately affect FTR prices and revenues.

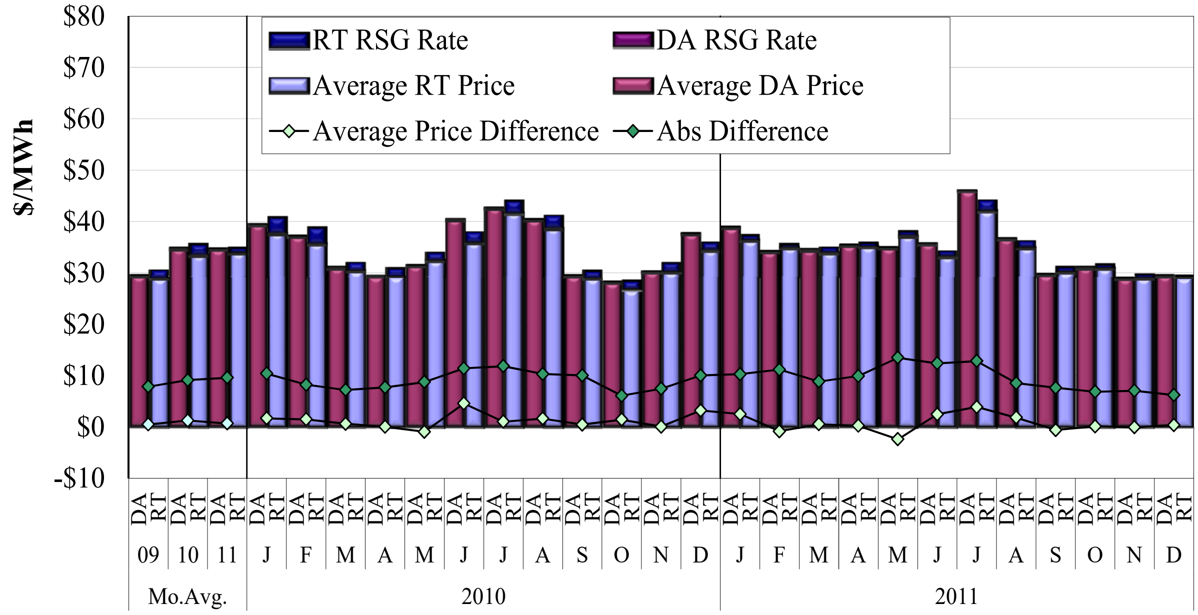
Participants' day-ahead market bids and offers should reflect their expectations of market conditions the following day, but a variety of factors can cause real-time prices to be significantly higher or lower than anticipated in the day-ahead. While a well-performing market may not result in prices converging 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 typically are much larger than day-ahead RSG costs).

Figure A16-19: Day-Ahead and Real-Time Prices

The next four figures show monthly average prices in the day-ahead and real-time markets at four representative locations in MISO, along with the average RSG cost per MWh.[13] The table below the figures shows the average day-ahead and real-time price difference, which measures overall price convergence. We show it separately including RSG charges levied to real-time deviations, which are generally higher in real-time and can contribute to modest day-ahead premiums.

Figure A16: Day-Ahead and Real Time Price
2009–2011: Cinergy Hub

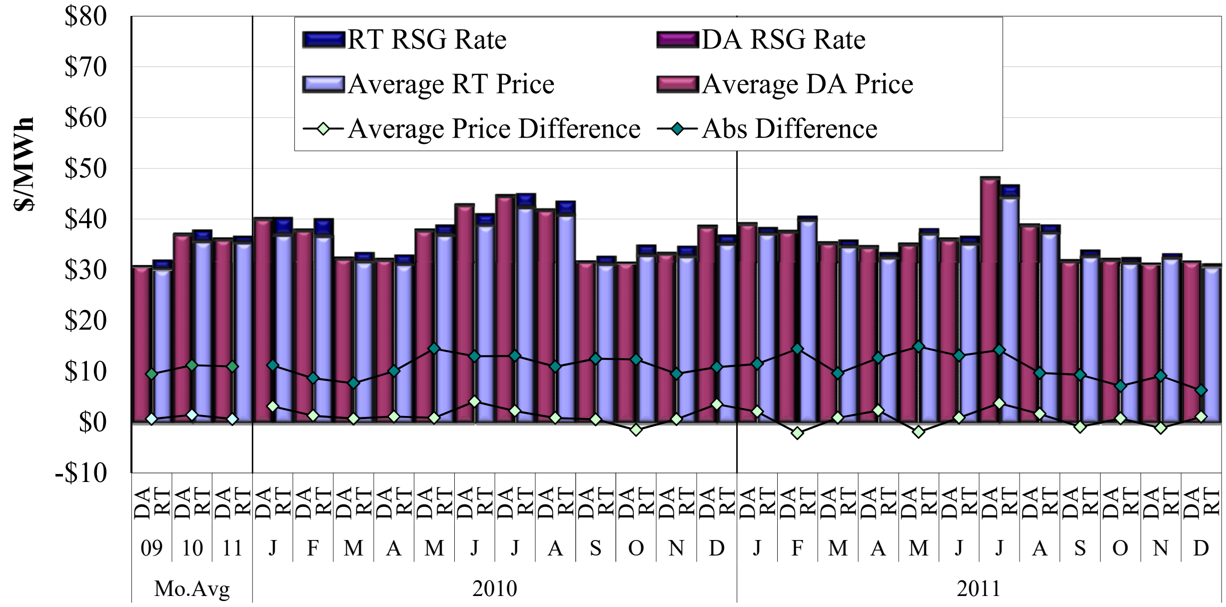


Average DA-RT Difference (% of Real-Time Price)

Excluding RSG	2	4	2	4	4	2	0	-3	13	2	4	2	5	0	9	7	-2	2	1	-6	7	9	5	-2	0	0	1
Including RSG	-4	-2	-1	-4	-5	-3	-5	-8	7	-3	-2	-3	-1	-6	5	4	-4	-1	-1	-9	4	4	1	-5	-2	-2	0

13 The rate only includes the Day-Ahead Deviation Charge Rate assessed evenly to Asset Owners, and excludes the location-specific Congestion Management Charge Rate.

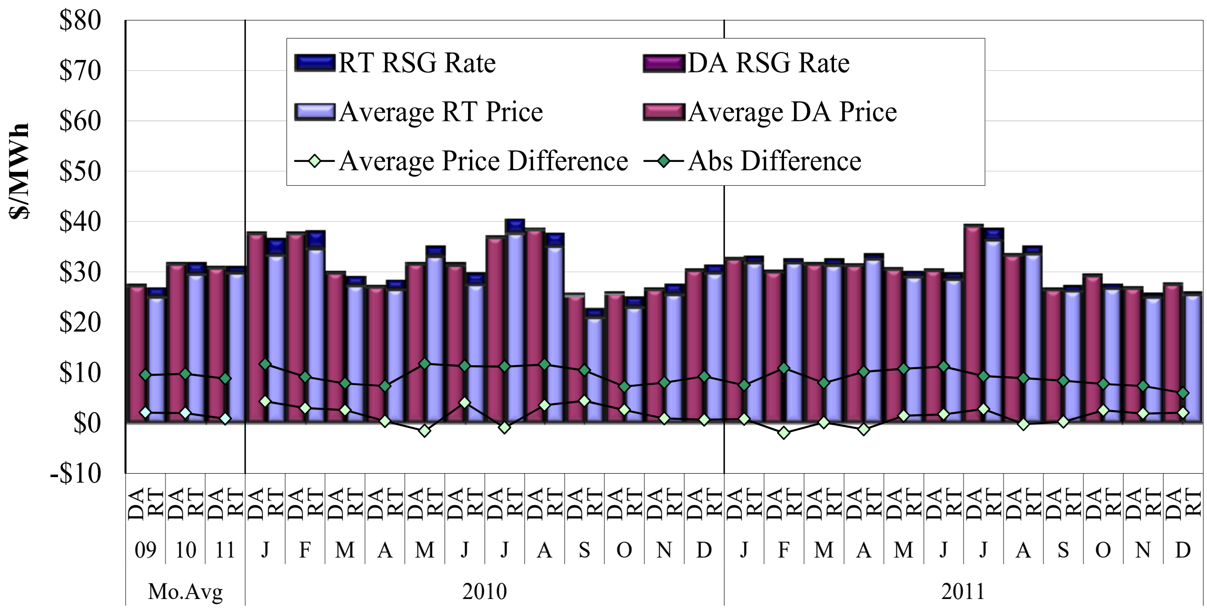
Figure A17: Day-Ahead and Real Time Price
2009–2011: Michigan Hub



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

Excluding RSG	2	4	2	8	3	2	3	2	10	5	2	2	-5	2	10	6	-5	3	7	-5	2	8	4	-3	2	-4	3
Including RSG	-3	-2	-1	0	-5	-3	-2	-2	5	-1	-4	-3	-10	-4	6	3	-7	0	5	-7	0	4	1	-6	0	-6	2

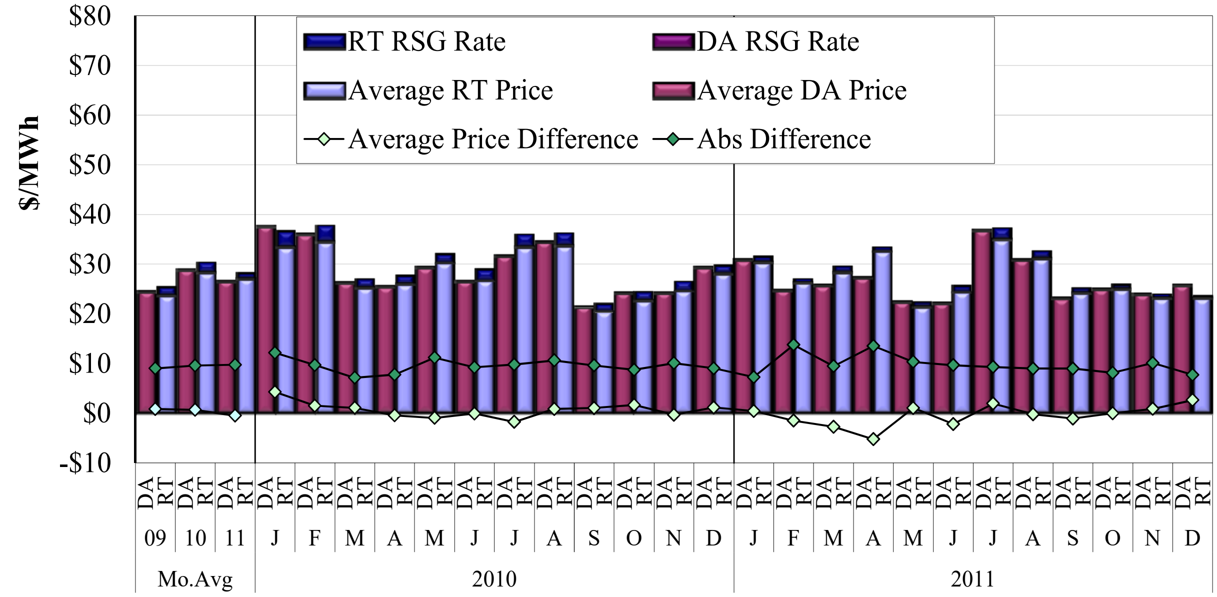
Figure A18: Day-Ahead and Real Time Price
2009–2011: WUMS Area



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

Excluding RSG	8	7	3	13	9	9	1	-5	15	-2	10	21	11	4	2	3	-6	0	-4	5	6	8	-1	1	9	8	8
Including RSG	2	0	0	4	-1	3	-5	-9	7	-9	3	14	4	-3	-3	0	-8	-3	-6	2	3	2	-5	-2	7	5	7

Figure A19: Day-Ahead and Real Time Price
2009–2011: Minnesota Hub



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

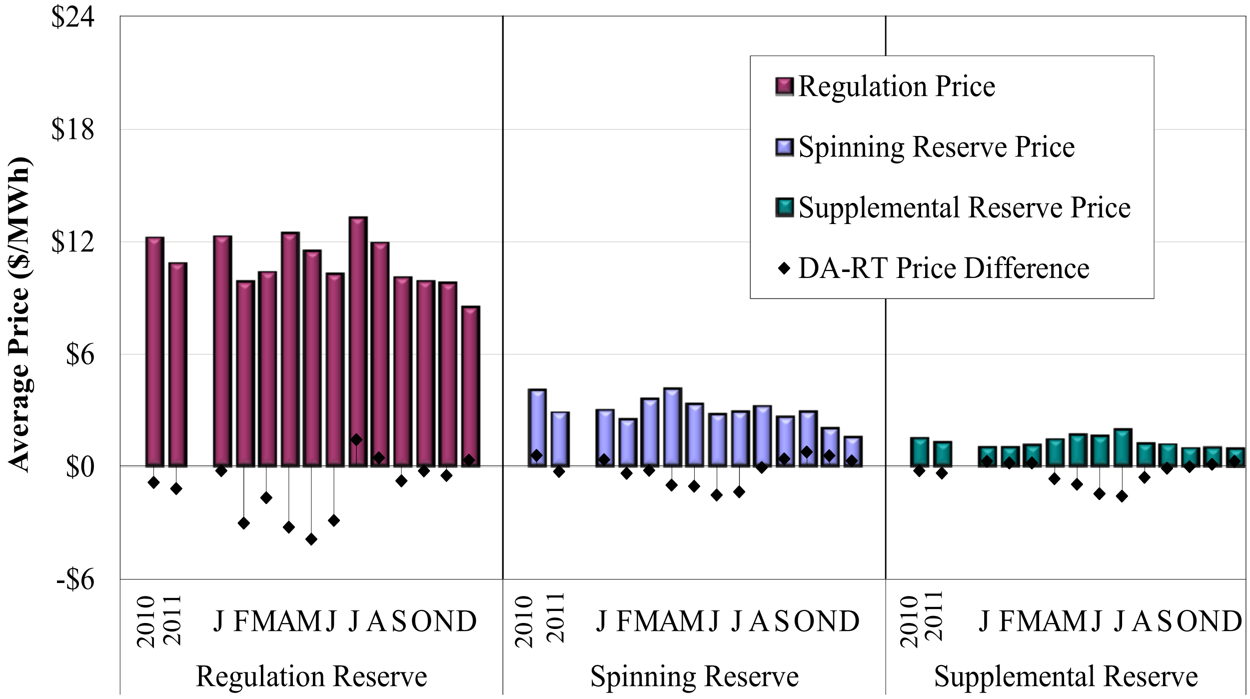
Excluding RSG	4	2	-2	13	4	4	-2	-3	0	-5	3	5	7	-1	4	1	-6	-10	-16	5	-9	6	-1	-4	0	4	11
Including RSG	-3	-5	-5	4	-5	-2	-8	-8	-8	-13	-5	-2	0	-8	-1	-2	-8	-13	-18	1	-13	0	-5	-8	-3	1	10

MISO's ancillary service markets consist of day-ahead and real-time markets for regulating reserves, operating reserves, and supplemental reserves that are jointly optimized with the energy markets. These markets have operated without significant issue since their introduction in January 2009.

Figure A20: Day-Ahead Ancillary Services Prices and Price Convergence

Figure A20 shows monthly average day-ahead clearing prices in 2011 for each ancillary service products, along with day-ahead to real-time price differences.

Figure A20: Day-Ahead Ancillary Services Prices and Price Convergence
2011



Key Observations: Day-Ahead and Real-Time Price Convergence

i. In 2011, there was a MISO-wide day-ahead premium of 1.8 percent, which is expected given the real-time RSG allocated to net real-time purchases and the lower volatility of prices in the day-ahead market.

- After accounting for the RSG cost allocations to load purchases, the MISO-wide premium fell to -0.7 percent.

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

- Over the long term, we expect small day-ahead premiums because scheduling load day-ahead limits the risk associated with higher real-time price volatility.

ii. Modest premiums prevailed in all of the MISO regions, except at Minnesota Hub in the West region. West region prices early in the year were affected by less real-time congestion than expected day-ahead due to increasing real-time wind output and outages.

iii. The MISO markets generally are slightly less effective at arbitraging congestion-related price differences. However, the improved RSG cost allocation implemented in April of 2011 lowered the cost of establishing virtual positions over constrained interfaces, which improved participants' ability to arbitrage locational differences.

 – This is most evident in WUMS where the day-ahead premium dropped from 7-8 percent in 2009 and 2010 to 3 percent in 2011.

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

v. Day-ahead ancillary services prices declined gradually over the course of the year and were slightly lower than those in 2010.

 – As in real-time, the majority of ancillary service prices are based on the opportunity costs of providing them in the co-optimization with energy.

 – Day-Ahead ancillary service prices fell in the second half of the year in step with energy price and real-time ancillary service price declines.

 – Day-ahead ancillary service prices converged reasonably well with real-time prices except in months with higher real-time shortages. In general, the day-ahead market does not anticipate these shortages well, resulting in an average real-time premium.

C. Day-Ahead Load Scheduling

Load scheduling and virtual trading in the day-ahead 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 is the sum of physical load and virtual load. Physical load includes cleared price-sensitive load and fixed 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. 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. Net scheduled load is defined as physical load plus cleared virtual load, minus cleared virtual supply. The relationship of net scheduled load to the real-time or actual load affects commitment patterns and RSG costs because units are committed and scheduled in the day-ahead only to satisfy the net day-ahead load.

When day-ahead net load is significantly less than real-time load, particularly in the peak-load hour of the day, MISO will frequently need to commit peaking resources in the real-time to satisfy the difference. Peaking resources often do not set real-time prices, even if those resources are effectively marginal (see Section IV.G). This can contribute to suboptimal real-time pricing and can result in inefficiencies when lower-cost generation scheduled in the day-ahead market is displaced by peaking units committed in real time. Because these peaking units frequently do not set real-time prices, the economic feedback and incentive to schedule more fully in the day-ahead market will be diluted.

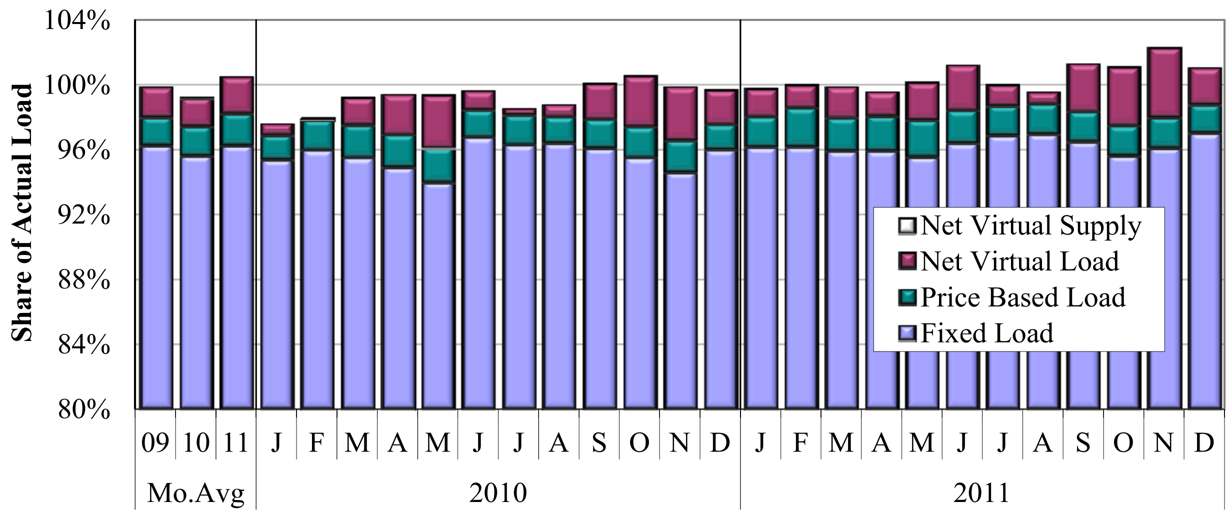
Additionally, significant supply increases after the day-ahead market can lower real-time prices and create an incentive for participants to schedule net load at less than 100 percent. The most common sources of additional supply increases in real time are:

- Supplemental commitments made by MISO for reliability after the day-ahead market;
- Self-commitments made by market participants after the day-ahead market;
- Wind output under-scheduled in the day-ahead market; and
- Real-time net imports above day-ahead schedules.

Figure A21: Day-Ahead Scheduled versus Actual Loads

To show net load-scheduling patterns in the day-ahead market, Figure A21 compares the monthly day-ahead scheduled load to actual load in the real-time. The figure shows only the daily peak hours, when under-scheduling is most likely to require MISO to commit additional generation. The table below the figure also shows the average scheduling levels in all hours.

Figure A21: Day-Ahead Scheduled versus Actual Loads
2009 – 2011, Daily Peak Hour



Share of Actual Load(%)

All Hour	99.9	99.3	100.1	98.2	98.9	99.3	99.2	99.4	99.9	99.2	99.4	99.4	99.8	99.4	100.0	100.3	99.8	99.6	99.3	99.4	100.8	100.9	100.2	100.4	100.4	100.5	99.6
Peak Hour	99.9	99.2	100.5	97.6	97.9	99.2	99.4	99.4	99.6	98.5	98.8	100.1	100.5	99.9	99.7	99.8	100.0	99.9	99.6	100.1	101.2	100.0	99.5	101.3	101.1	102.3	101.1

Key Observations: Load Scheduling

vi. Scheduled load averaged 100.1 percent of actual load over all hours of 2011. This is a slight increase from 2010, when load was slightly underscheduled (99.3 percent).

vii. During the peak hour, when MISO commitments are most often required, load was more than fully scheduled at 100.5 percent.

- This held particularly for the second half of 2011, when scheduling exceeded 101 percent for four consecutive months. As a result, RSG payments for capacity were relatively low.

D. Virtual Transaction Volumes

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 supply for $50 in the day-ahead market, sellers must then purchase (or produce) 1 MW in real time to cover the trade. They will incur a loss if their real-time cost (the LMP at the transaction location) exceeds $50, and a profit if it is less than $50.

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 (i.e. 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 the power back based on real-time prices. This trading is one of the primary means of arbitraging prices in the two markets and causes day-ahead prices to converge with real-time prices. Price convergence resulting from this arbitrage increases efficiency and mitigates market power in the day-ahead market.

Large sustained profits from virtual trading may indicate day-ahead modeling inconsistencies, while large losses may indicate an attempt to manipulate day-ahead prices. 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.

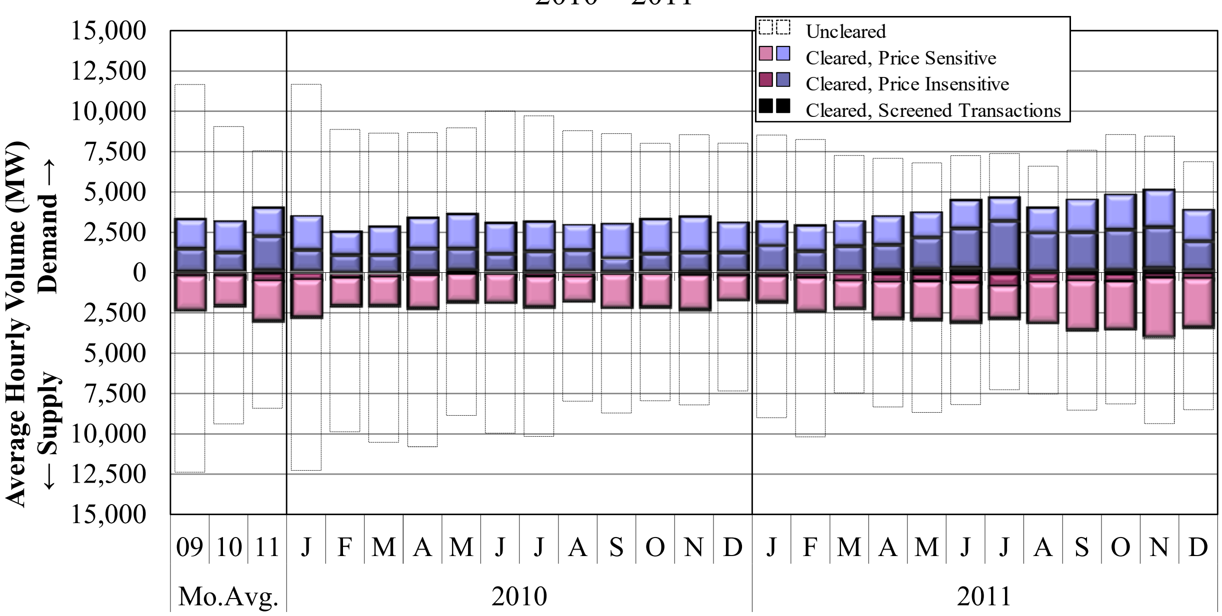
For example, a participant may submit a high-priced (and, therefore, likely to clear) virtual demand bid at an otherwise unconstrained location that causes artificial day-ahead market congestion. The participant can buy in the day-ahead market at the high (i.e., congested) price and sell the energy back 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 behavior and utilize mitigation authority to restrict virtual activity when appropriate.

Figure A22: Virtual Transaction Volumes

Figure A22 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 2009 to 2011. The virtual bids and offers that did not clear are shown as dashed areas at the end points (top and bottom) of the solid bars. These are virtual bids and offers that were not economic based on the prevailing day-ahead market prices (supply offers priced at more than clearing price and demand bids priced below the clearing price).

The figure separately distinguishes between price-sensitive and price-insensitive bids. Price-insensitive bids are those that are very likely to clear (supply offers priced well below the expected real-time price and demand bids priced well above the expected real-time price). For purposes of this figure, bids and offers submitted at more than $30 above or below an expected real-time price, respectively, are considered price-insensitive. A subset of these volumes, those that also contribute to a material difference in the congestion at the location between the day-ahead and real-time markets warrant further investigation. These volumes are labeled 'Screened Transactions' in the figure.

Figure A22: Virtual Transaction Volumes
2010 – 2011



Percent Screened

	09	10	11	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Demand	1.8	2.6	4.6	3.4	1.1	0.4	2.6	4.7	2.8	2.4	3.8	1.5	2.3	2.9	2.8	2.5	3.0	2.4	5.4	7.5	6.7	4.1	2.4	4.3	6.2	5.7	3.8
Supply	0.9	0.9	2.5	1.4	0.8	0.7	1.1	1.1	0.9	0.9	0.7	0.9	0.8	0.8	1.1	1.0	2.3	2.5	3.7	3.3	3.3	2.7	1.3	2.2	4.0	1.7	1.4

Figure A23: Virtual Transaction Volumes by Participant Type

Figure A23 shows the same results but distinguishes between physical participants (i.e., those that own generation or serve load) and financial-only participants.

Figure A23: Virtual Transaction Volumes by Participant Type
2011

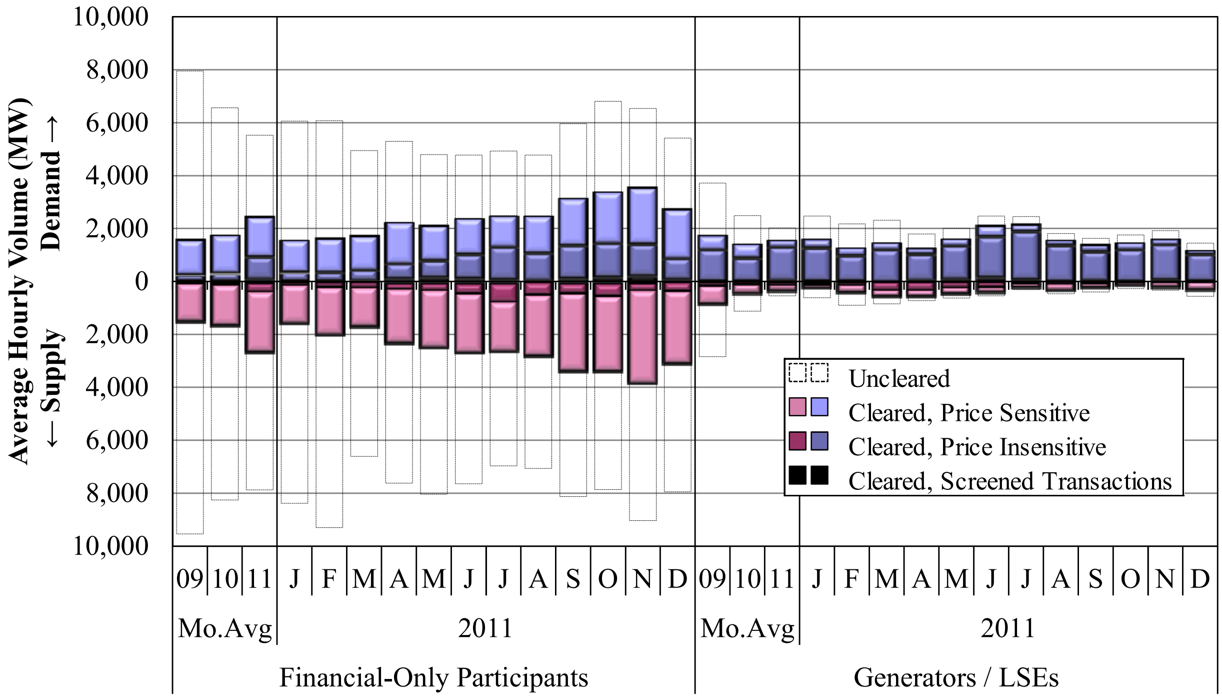


Figure A24: Virtual Transaction Volumes by Participant Type and Location

Figure A24 disaggregates transaction volumes further by type of participant and type of location: Cinergy Hub, other hubs and zones, and nodal locations. Hubs, interfaces and load zones are aggregations of many nodes and are therefore less prone to congestion-related price spikes than nodal locations. Cinergy Hub was the single most liquid trading point in MISO during 2011.

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Figure A24: Virtual Transaction Volumes by Participant Type and Location
2009 – 2011

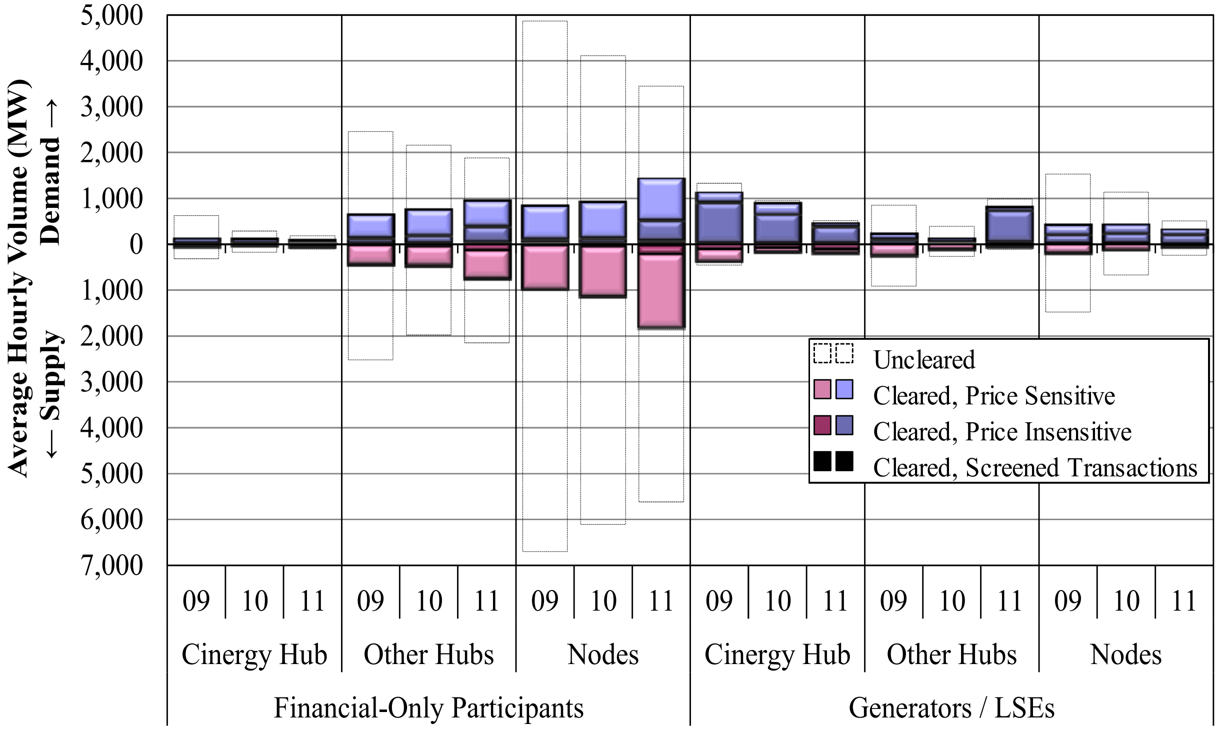
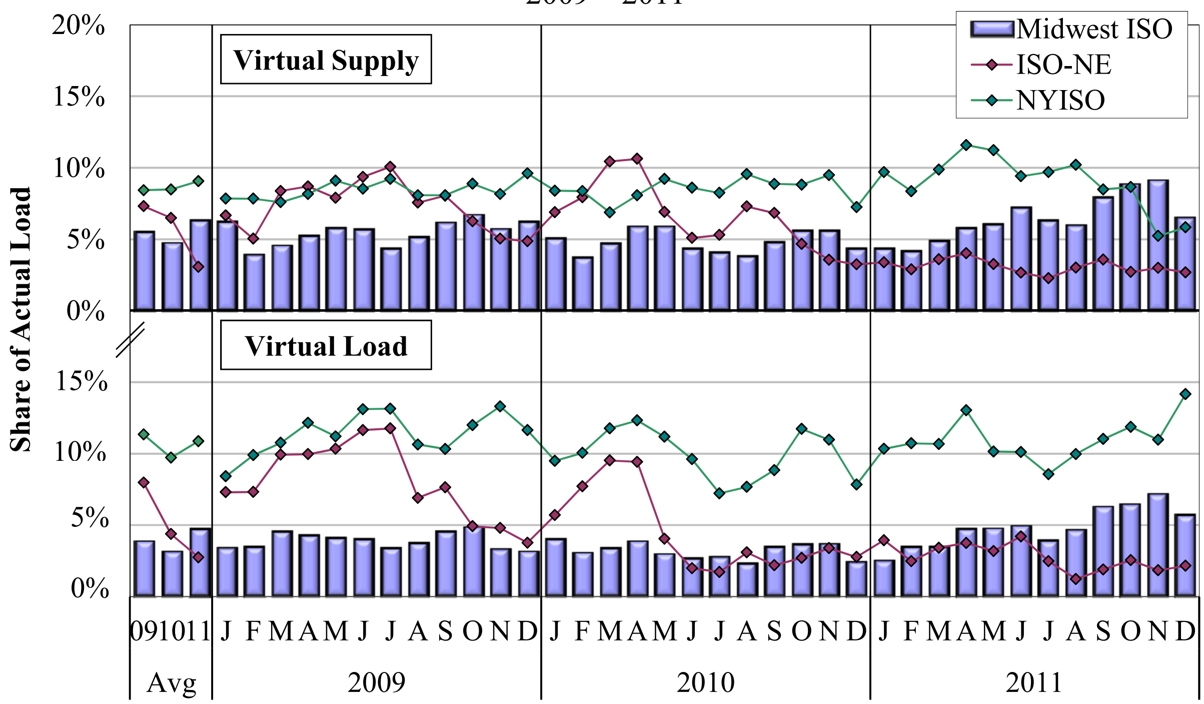


Figure A25: Virtual Transaction Volumes, MISO and Neighboring RTOs

To compare trends in MISO to other RTOs, Figure A25 shows virtual supply and demand in MISO, ISO New England (ISO-NE), and New York ISO (NYISO) as a percent of actual load.

Figure A25: Comparison of Virtual Transaction Volumes
2009 – 2011



Key Observations: Virtual Transaction Volumes

i. Virtual trading levels decreased substantially after 2008, when FERC ordered changes in the real-time RSG cost allocation that resulted in substantial charges to virtual supply transactions.

ii. Cleared volumes increased by 33 percent in 2011 from 2010. Much of this rise was associated with price-insensitive bids and offers.

iii. Approximately 30 percent of demand bids and 6 percent of supply offers were price-insensitive, compared to 14 and 2 percent, respectively, in 2010.

- The increase in price-insensitive offers was likely due to the change in RSG cost allocation in April 2011, which eliminated allocations to virtual supply when the participant has an offsetting virtual load or other "helping" deviation.

- Price insensitive transactions provide less value to the day-ahead market than price-sensitive transactions because the latter are much more effective at facilitating price convergence.

- Some participants use price-insensitive transctions to take positions across constrained paths to arbitrage differences in day-ahead and real-time congestion.

- A few participants employed price-insensitive transactions to exploit sustained locational price differences due to marginal loss factor divergence between the day-ahead and real-time markets. This provides no efficiency benefits.

  - ✓ One participant who appeared to be arbitraging significant differences in marginal loss factors between the day-ahead and real-time markets ceased this activity after MISO modified its methodology to eliminate large transitory differences in December.

- Because the price-insensitive transaction levels increased, the percentage screened for further review also increased to roughly 3.6 percent of cleared transactions. After further investigation, we concluded that none of these transactions warranted mitigation in 2011.

iv. Financial participants provide most of the virtual liquidity in the day-ahead market overall.

- Much of the virtual trading by financial participants occurred at individual nodes, which allows them to arbitrage price differences related to congestion.

- Most of the increase in volumes in 2011 was also attributable to financial participants. These participants accounted for 73 percent of cleared volumes in 2011, up from 65 percent in 2010.

- While financial participants' volumes were evenly divided between supply and demand, nearly 90 percent of physical participants' volumes were demand bids.

- The physical participants cleared demand volumes provide a hedge against load uncertainty or supply availability.

v. In 2011, we are recommending a number of improvements to the allocation of real-time RSG costs that should improve the incentive to submit price-sensitive transactions and should increase the overall virtual transactions volumes.

E. Virtual Transaction Profitability

The next set of charts examines the profitability of virtual transactions in MISO. In a well-arbitraged market, profitability is expected to be low. However, in a market with a prevailing day-ahead premium, virtual supply should generally be more profitable than virtual demand.

Figure A26: Virtual Profitability

Figure A26 shows monthly average gross profitability of virtual purchases and sales. 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 financially) in the real-time market. Gross profitability excludes RSG cost allocations, which vary according to the market-wide DDC rate and the hourly net deviation volume of a given participant.

Figure A26: Virtual Profitability
2010 – 2011

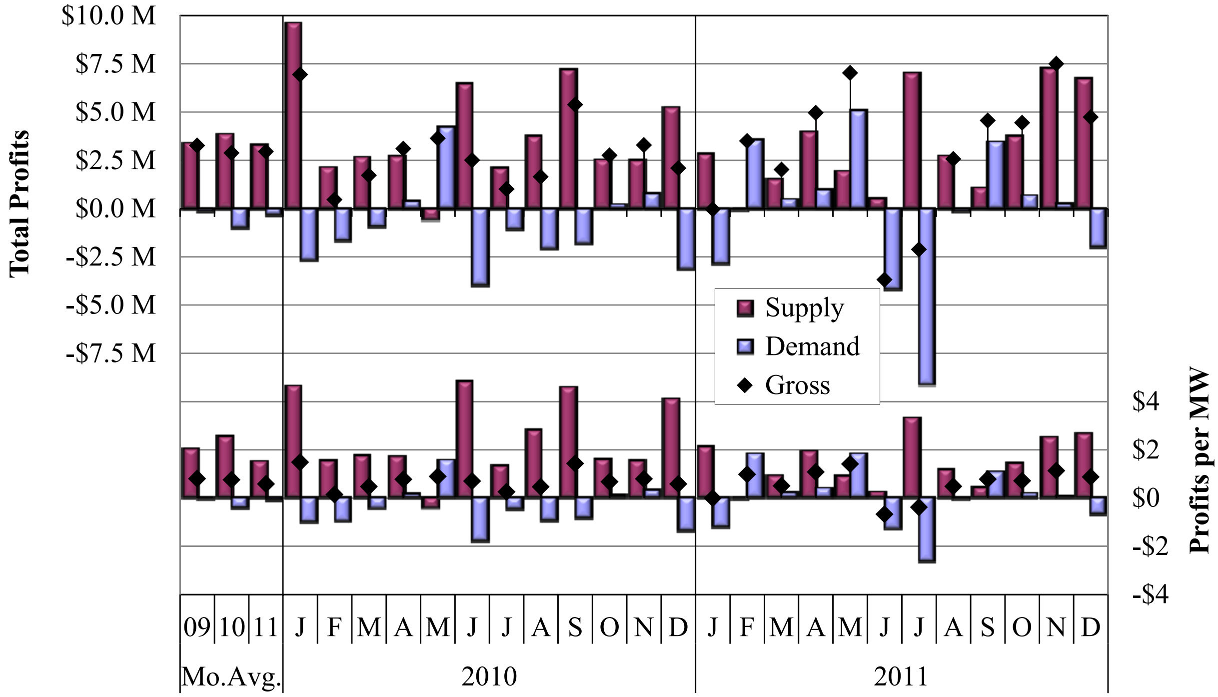
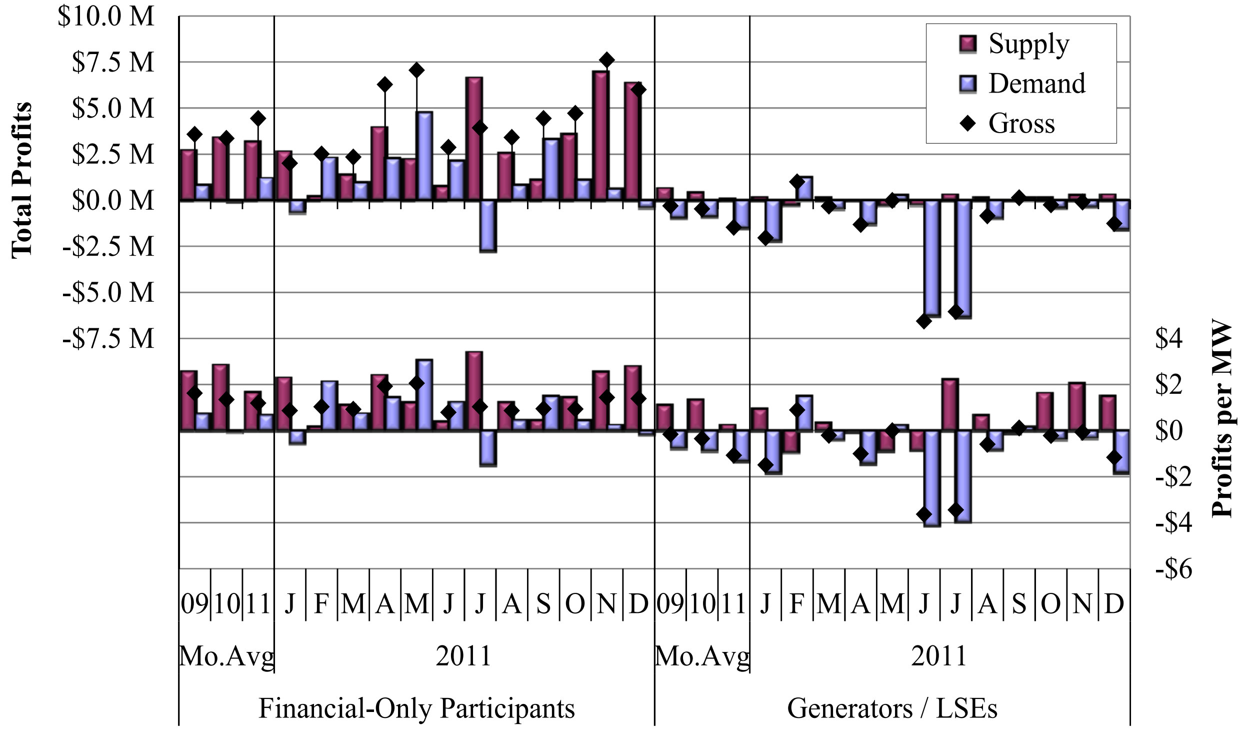


Figure A27: Virtual Profitability by Participant Type

Figure A27 shows the same results disaggregated by type of market participant: entities owning generation or serving load, and financial-only participants.

Figure A27: Virtual Profitability by Participant Type
2011



<u>Key Observations: Virtual Profitability</u>

i. Gross virtual profitability was modest at $0.58 per MWh on average, down from $0.75 per MWh in 2010 and $0.80 per MWh in 2009. Total virtual profits were $35.4 million.

ii. Virtual supply was considerably more profitable ($1.50 per MWh) than virtual demand ($-0.11 per MWh).

   – This is expected because day-ahead prices were higher on average than real-time prices.

   – However, the real-time RSG costs allocated to virtual supply averaged $0.96 per MWh (i.e., the DDC rate), which lowered the net profitability of virtual supply transactions to $0.54 per MWh.

   – The fact that virtual profitability has been falling generally indicates that the increased liquidity in the day-ahead market is improving its performance.

iii. Transactions by financial-only participants were considerably more profitable than those by generators or load-serving entities. In particular, virtual supply was the most profitable for financial-only participants ($1.66 per MW).

   – Physical participants (notably LSEs) have consistently been willing to incur losses on virtual demand, likely to hedge against real-time price risk or supply availability.

This pattern is most acute during peak hours on high-load days in summer. In June and July, demand profitability for physical participants averaged approximately $-4 per MWh.

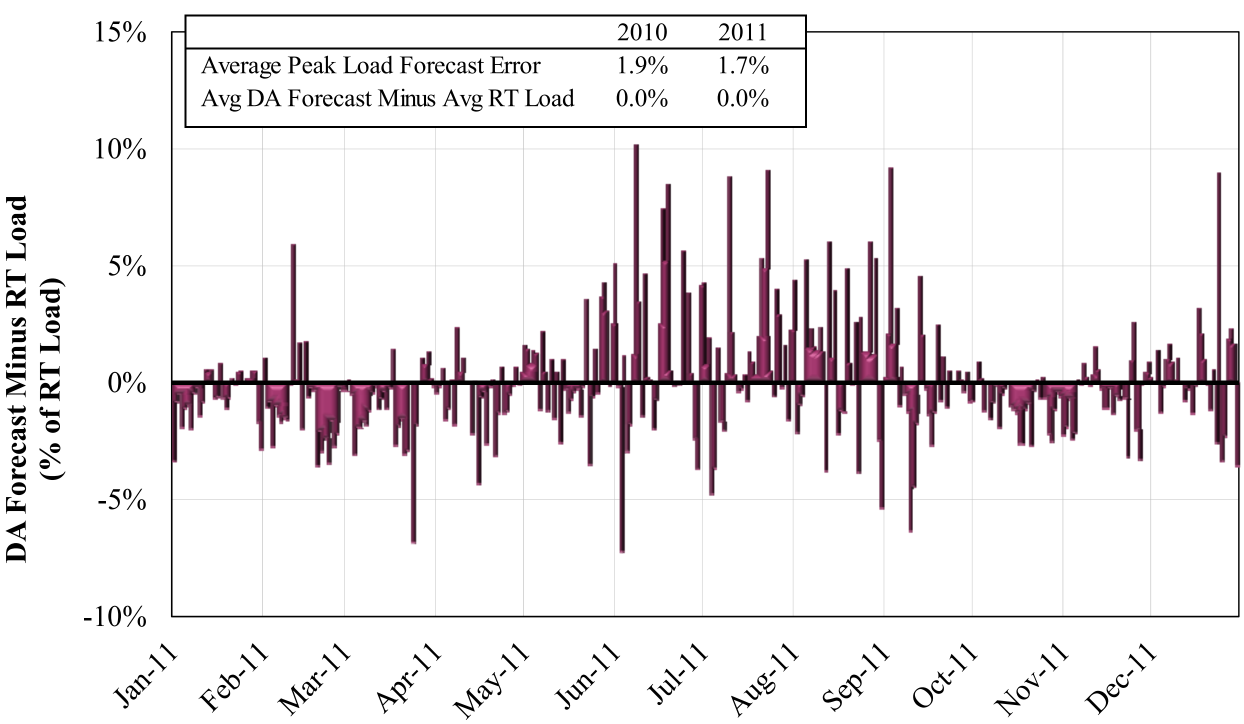
F. Load Forecasting

Load forecasting is a key element of an efficient forward commitment process. Accuracy of the Mid-Term Load Forecast (MTLF) is particularly important for the reliability assessment commitment process performed after the day-ahead market closes and before the real-time operating day begins. Inaccurate forecasts can cause MISO to commit more or fewer resources than necessary 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 A28: Daily Day-Ahead Forecast Error in Peak Hour

Figure A28 shows the percentage difference between the MTLF used in the day-ahead model and real-time actual load for the peak hour of each day in 2011.

Figure A28: Daily Day-Ahead Forecast Error in Peak Hour
2011



Key Observations: Load Forecasting

i. MISO in 2011 generally forecasted peak-hour loads accurately. Several patterns continued from previous years:

- Load was persistently over-forecasted during summer months, and at times substantially so. Thunderstorms, whose scope and timing are difficult to predict day-ahead, can reduce peak-hour loads considerably from what was expected.
- Load was modestly under-forecasted in spring and fall.

IV. Real-Time Market Performance

In this section, we evaluate real-time market outcomes, including prices, loads and uplift payments. We also assess the dispatch of peaking resources in real time and the continued integration of wind generation.

The real-time market performs the vital role of dispatching resources to minimize the cost of satisfying its energy and operating reserve needs, while observing generator and transmission network limitations. Every five 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 nodal location on the system.

While some RTOs clear their real-time energy and ancillary service markets every 15 minutes, MISO's five-minute interval permits more rapid and accurate response to changing conditions, such as changing wind output or load. Shortening the dispatch interval reduces regulating reserve requirements and permits greater resource utilization. These benefits sometimes come at the cost of increased price volatility, which we evaluate in this section.

Although most generator commitments are made through the day-ahead market, real-time market results are a critical determinant of efficient day-ahead market outcomes. Energy purchased in the day-ahead market (and other forward markets) is priced based on expectations of the real-time market prices. 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 Price Volatility

Figure A29-30: Real-Time Prices and Headroom by Time of Day

Substantial volatility in real-time wholesale electricity markets is expected because the demands of the system can change rapidly, and supply flexibility is restricted by generators' physical limitations. However, an RTO's real-time software and operating actions can help manage real-time price volatility. This section evaluates and discusses the volatility of real-time prices. Sharp price movements frequently occur when the market is ramp-constrained (when a large share of the resources are moving as quickly as possible), which occurs when the system is moving to accommodate large changes in load, NSI, or generation starting or stopping. This is exacerbated by generator inflexibility arising from lower offered ramp limits or dispatch range.

Figure A29 and Figure A30 show the interval-level, average real-time prices by time of day in summer and winter 2011, respectively. Five-minute price volatility decreased substantially with the introduction of jointly-optimized energy and ancillary services markets in 2009, but it remains high in MISO relative to other RTOs in the Eastern Interconnect. The figure also shows two key drivers of price volatility: changes in Net Scheduled Interchange (NSI) and the effective headroom on the system. Effective headroom is the amount of additional generation available in the next five minutes, given individual resource ramp limitations.

Figure A29: Real-Time Prices and Headroom by Time of Day
2011: Summer

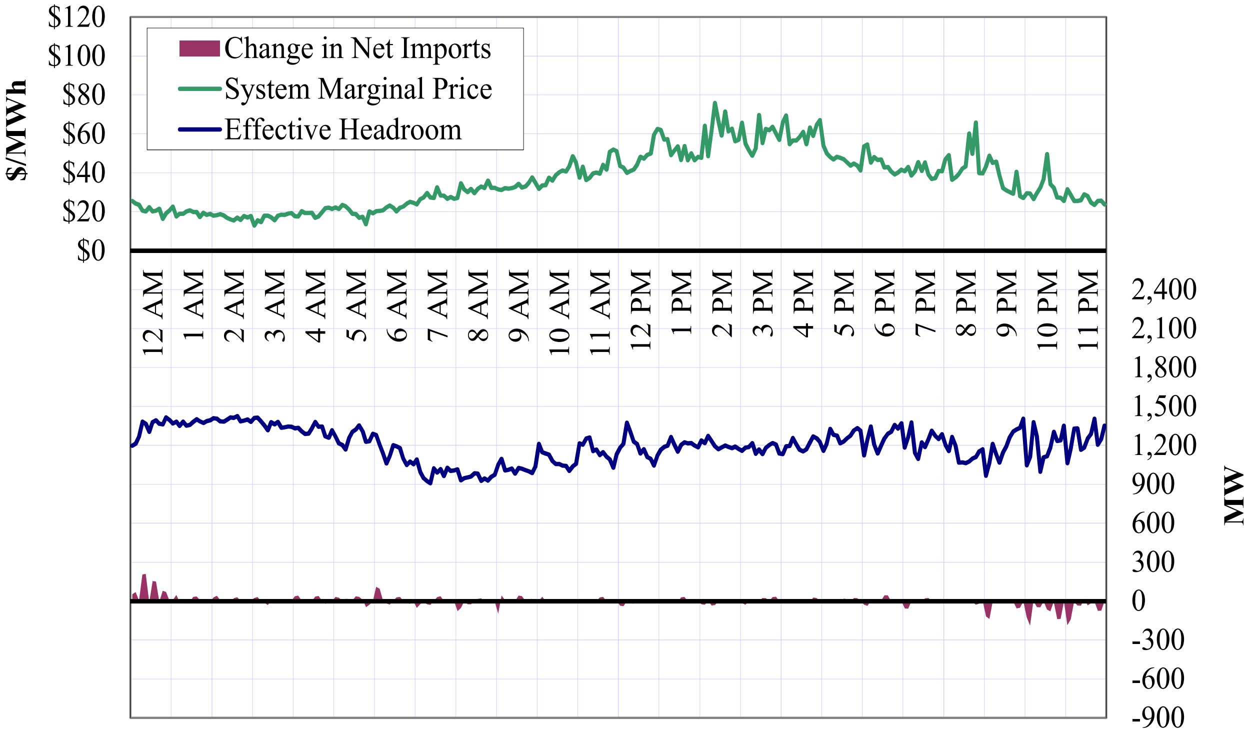


Figure A30: Real-Time Prices and Headroom by Time of Day
2011: Winter

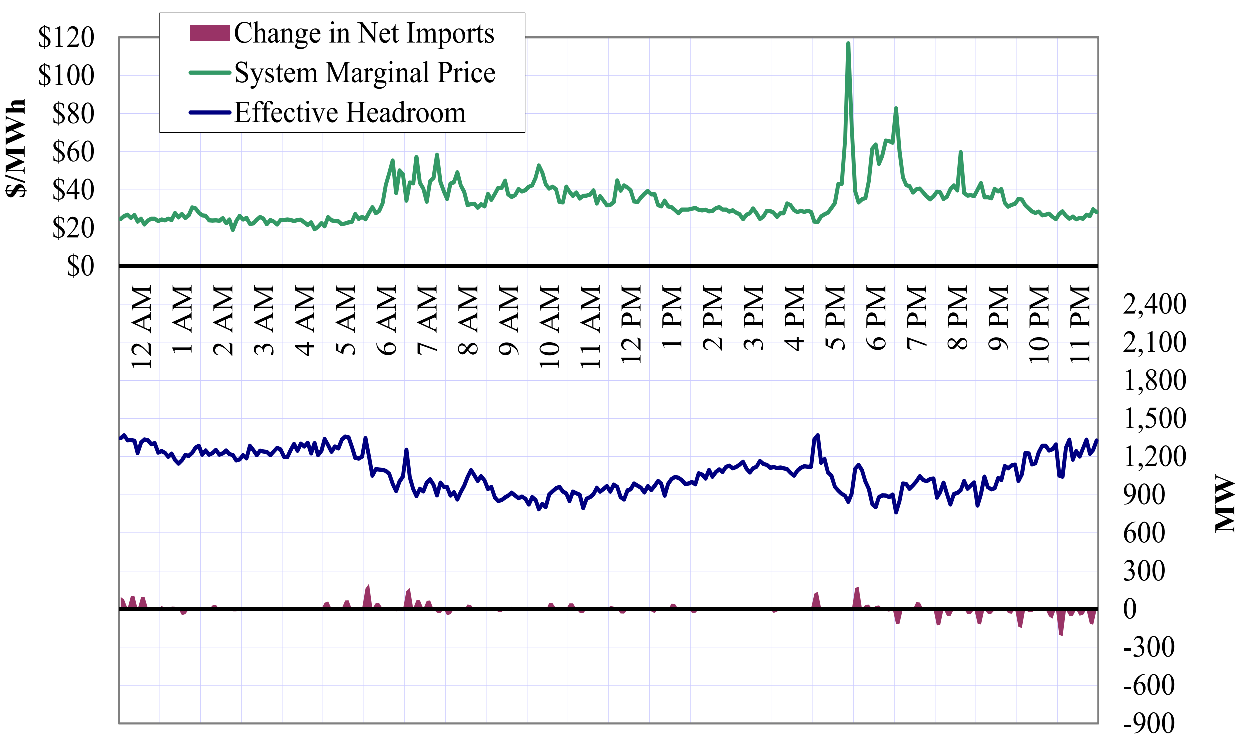


Figure A31: Five-Minute, Real-Time Price Volatility

Figure A31 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. Each of these markets has a distinct set of operating characteristics that factor into price volatility.

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 better anticipate ramp needs and begin moving generation to accommodate them. We are recommending MISO adopt a similar approach.

Although they produce 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—energy prices in these markets do not reflect prevailing conditions as accurately as five-minute markets do.

Figure A31: Five-Minute, Real-Time Price Volatility
MISO and Other RTO Markets, 2011

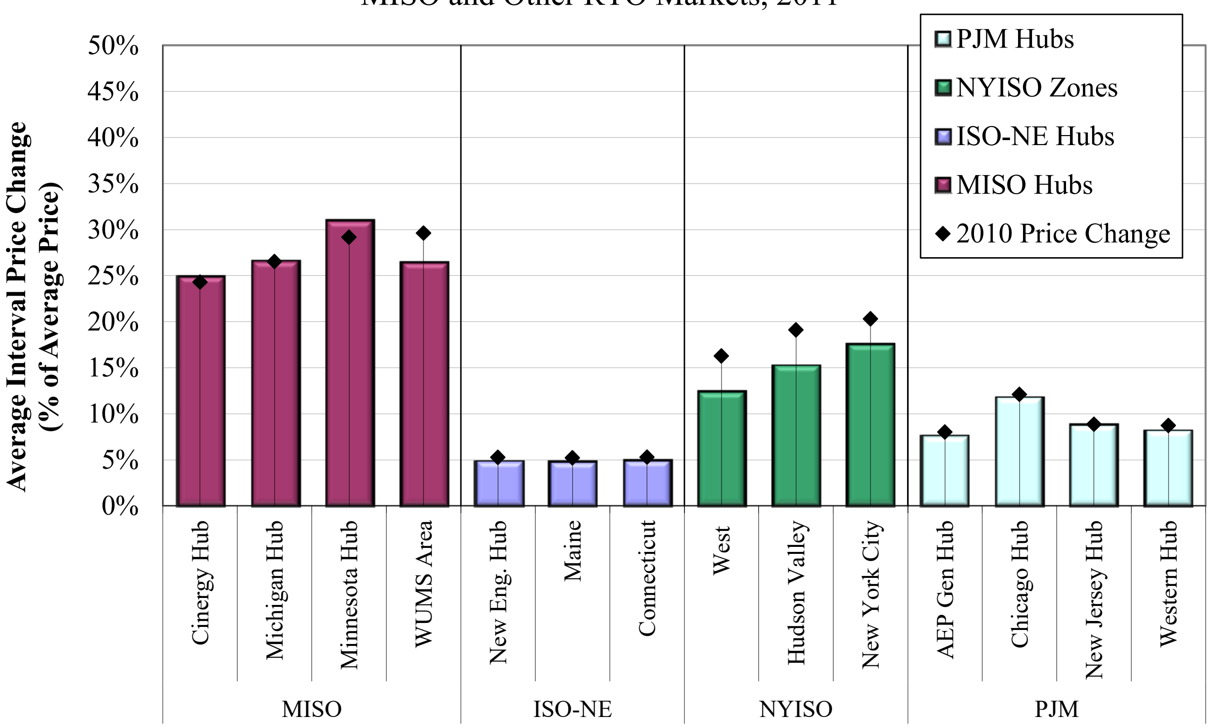
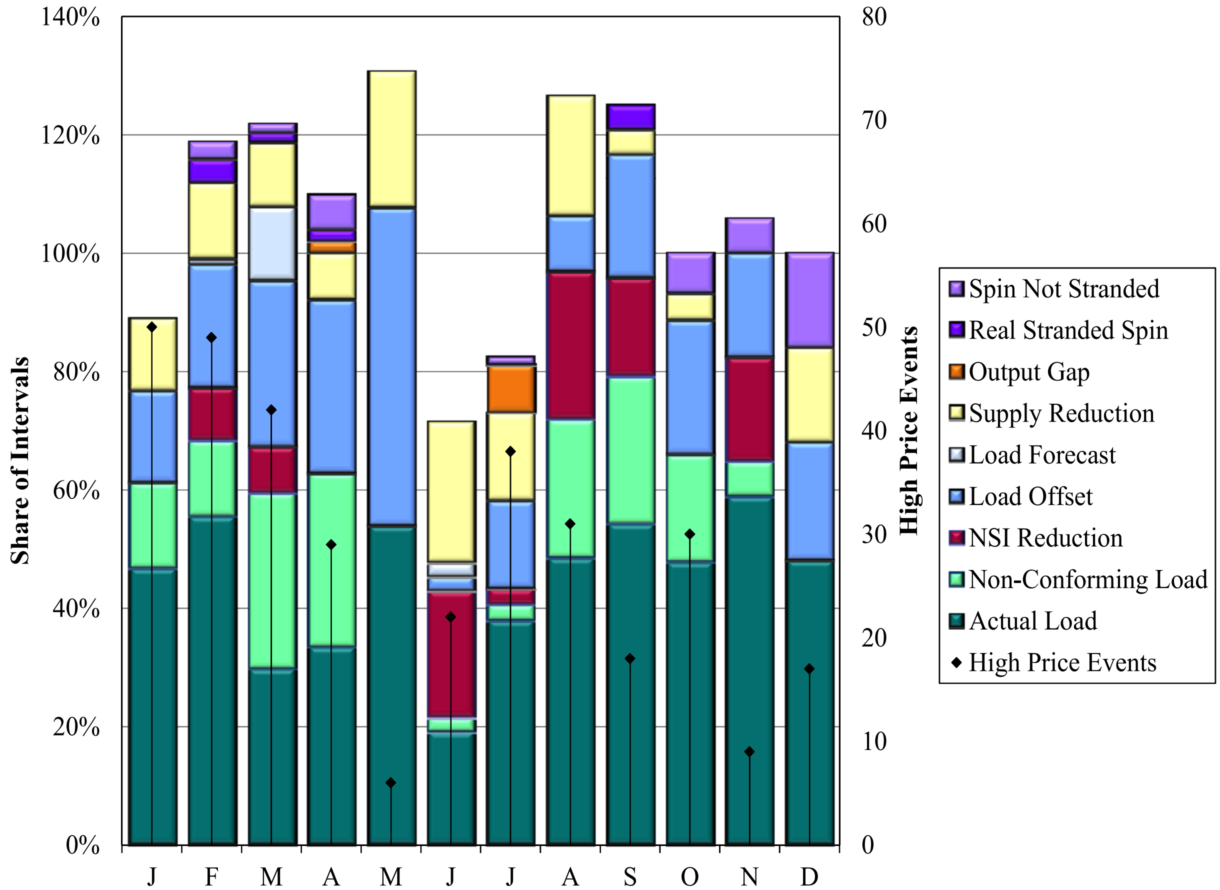


Figure A32: Factors that Contribute to High Energy Prices

The next analysis evaluates the factors that contribute to relatively high system marginal prices in MISO. These high prices are generally the result of binding ramp constraints on many resources that occur when the system requirements change rapidly. For this analysis, 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 341 such events in 2011, lasting on average 1.8 intervals. The longest event lasted 7 intervals, or 35 minutes. In nearly three-quarters of the events, the market was short one or more ancillary services product. Since the value of foregone 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.

Figure A32 shows primary causes of high SMPs during 2011. 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 increase the ramp demands on 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. More than one factor could contribute materially to the same shortage; in a few shortages, none of the nine contributed.

Figure A32: Contributors to High-Priced Events
2011



<u>Key Observations: Real-Time Price Volatility and High Priced Events</u>

i. The fluctuations in real-time prices are directly related to changes in effective headroom, which often changes significantly at the top of the hour when NSI changes and unit commitments and de-commitments occur. Generation de-commitment effects are largest late in the day when generators are shutting down.

ii. Overall, price volatility in MISO remains considerably higher than in neighboring RTOs, although it declined considerably in the last quarter of 2011.

- One reason volatility is higher in MISO is that it runs a true five-minute real-time market (producing a new real-time dispatch every five minutes).

- NYISO does so as well, but it has a look-ahead dispatch system that optimizes multiple intervals. Other RTOs dispatch every 10 to 15 minutes, which tends to provide more flexibility (which lowers volatility), but maintains less control of the system (by relying more on regulation to balance supply with demand between intervals).

– Volatility in MISO decreased in mid-2011 after the departure of FirstEnergy. FirstEnergy had the largest quantity of non-conforming load, such as industrial arc furnaces, which place substantial ramp demands on the system when it comes on and off. Such loads contributed materially to 8 percent of high-priced intervals in 2011.

iii. Ramp constraints tend to bind most frequently at the top of the hour, when NSI and generation changes are largest.

– Over the course of the day, prices fluctuated most when load was ramping up or down near the peak load hour of the day (mid-afternoon in summer, and in early evening in winter). Compared to prior years, NSI was less volatile and changes had less impact on prices in both the summer and winter.

✓ MISO has made changes in physical scheduling rules and the management of ramp that has helped reduce price volatility in the last several years.

– In addition, transmission congestion at times results in higher price volatility in specific regions, particularly in the West region where fluctuations in wind output can contribute to excess generation conditions there. Lower volatility should accompany increased penetration of DIR among wind resources.

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

iv. In most cases, the price volatility is a result of relatively high energy prices that are often transitory. Intervals priced at greater than \$175 per MWh occurred 609 times in 2011, or 0.58 percent of all intervals.

– The high-priced intervals were often accompanied by shortages of spinning reserves. However, the penalty price—the maximum cost MISO is willing to incur for regulating reserves and spinning reserves—was less than \$175 in 2011.

v. Relatively high prices were predominantly driven by changing system ramp demands (i.e., for generation to move up quickly) that caused ramp constraints to bind as the market attempted to simultaneously meet energy and ancillary services requirements.

– Large ramp demands were most often caused by changes in load or net interchange.

✓ Shifts in load (actual or non-conforming) contributed to 55 percent of high-priced events in 2011. Load forecast errors contributed to only 2 percent of these events.

✓ Sudden reductions in NSI occurred during 15 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.

- The offset parameter, which allows the operators to increase or decrease the load served by the real-time market, contributed to 19 percent of the high-priced events.

  ✓ Although difficult to quantify, some of these offsets that increase the ramp demand of the system in the near term may be justifiable if they prevent a larger shortage later.

- 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 13 percent of high-priced intervals.

- Potential economic withholding, as identified by the "output gap" metric, was significant in just over 1 percent of the high-priced intervals, and only in the first half of the year.

vi. We recommended three recommendations to improve MISO's ability to manage the system's ramp demand and reduce price volatility:

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

- In the longer term, develop a look-ahead real-time dispatch capability, which would include a multi-period dispatch optimization to move resources in anticipation of system demands over the next several intervals; and

- Implement a ramp capability product, which is described in the report.

B. ASM Prices and Offers

Scheduling of energy and operating reserves, which include ten-minute regulating reserves and contingency reserves, is jointly optimized in MISO's real-time market software. As such, opportunity cost trade-offs result in higher energy prices and reserve prices. ASM prices are additionally affected by reserve shortages. Total operating reserves is the most valuable reserve class because a shortage of total operating reserves has the biggest potential impact on reliability. Therefore, total operating reserves has the highest-priced reserve demand curve, which starts at $1,100 per MWh. To the extent that increasing load and unit retirements reduce the capacity surplus in MISO, more frequent operating reserve shortages can play a key role in providing long-term economic signals to invest in new resources.

Figure A33: Real-Time Ancillary Service Prices and Shortages

Figure A33 shows monthly average real-time clearing prices for ASM products in 2011. It also shows the frequency with which the system was short of each class of reserves.

Figure A33: Real-Time Ancillary Services Clearing Prices and Shortages
2011

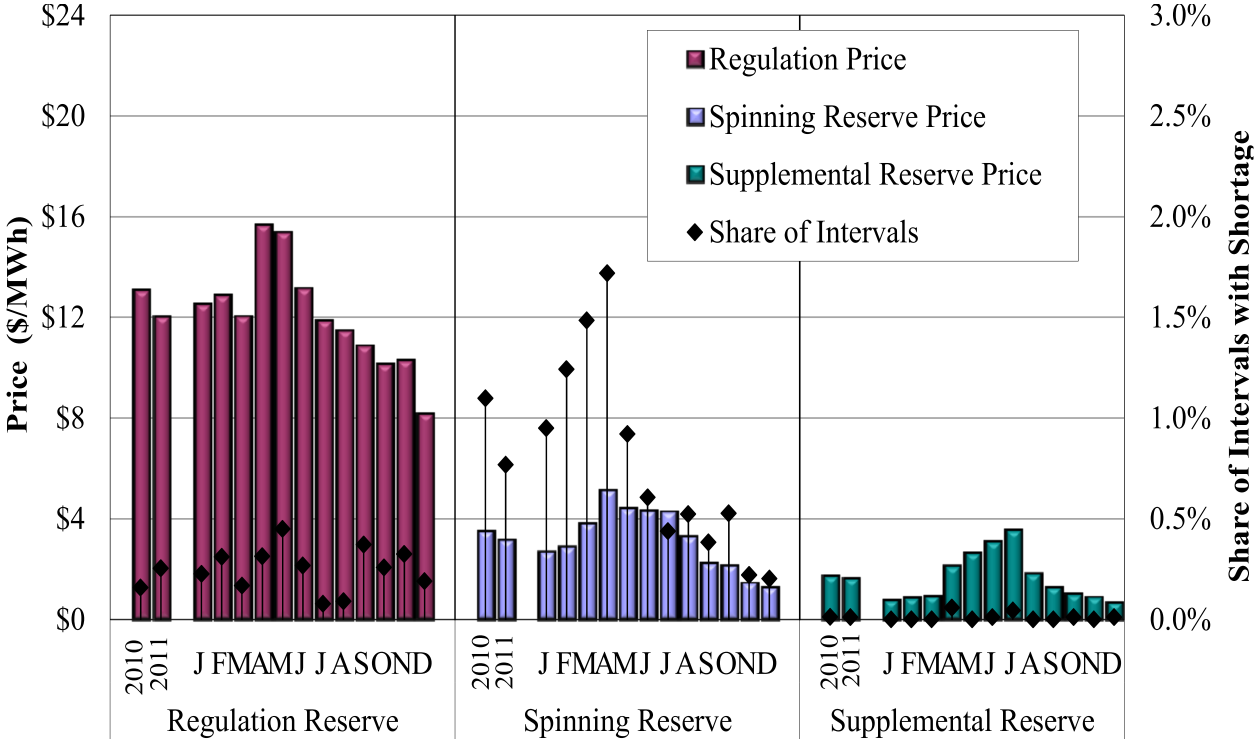


Figure A34: Regulation Offers and Scheduling

ASM offer prices and quantities are primary determinants of ASM outcomes. Figure A34 examines average regulation capability, which is the smallest of the three products because (a) it can only be provided by regulation-capable resources and (b) it is limited to five minutes of bi-directional ramp capability. Clearing prices for regulating reserves are considerably higher than the corresponding lowest-cost offers because they reflect opportunity costs incurred when resources must be dispatched up or down from their economic level to provide bi-directional regulation capability. In addition, as the highest quality ancillary service, regulation can substitute for either spinning or supplemental reserves, so any shortage in those products will be reflected in the regulating reserve price as well.

The figure distinguishes between quantities of regulation that are available to the five-minute dispatch (in the solid bars) and quantities that are unavailable (in the hashed bars). Of the unavailable quantities, the figure shows separately those that are not offered by participants, not committed by MISO, and limited by dispatch level (i.e., constrained by a unit's operating limits).

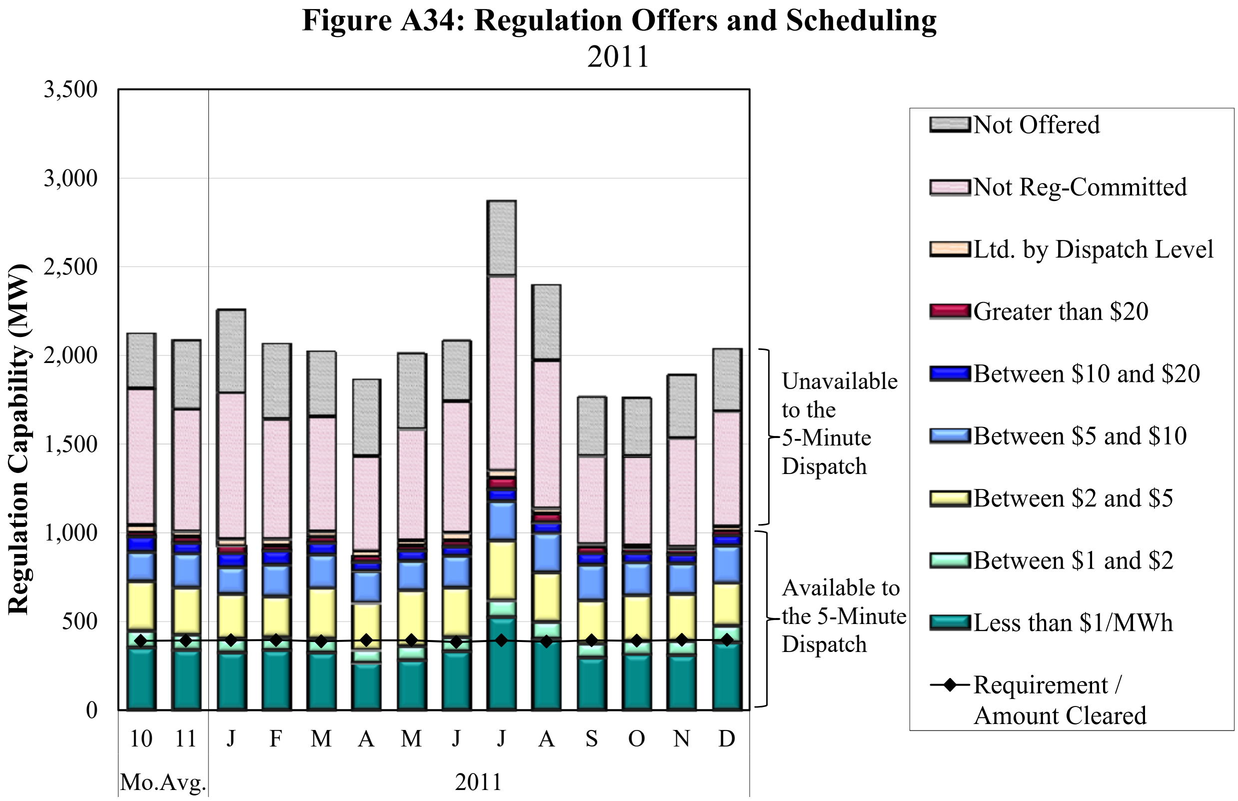
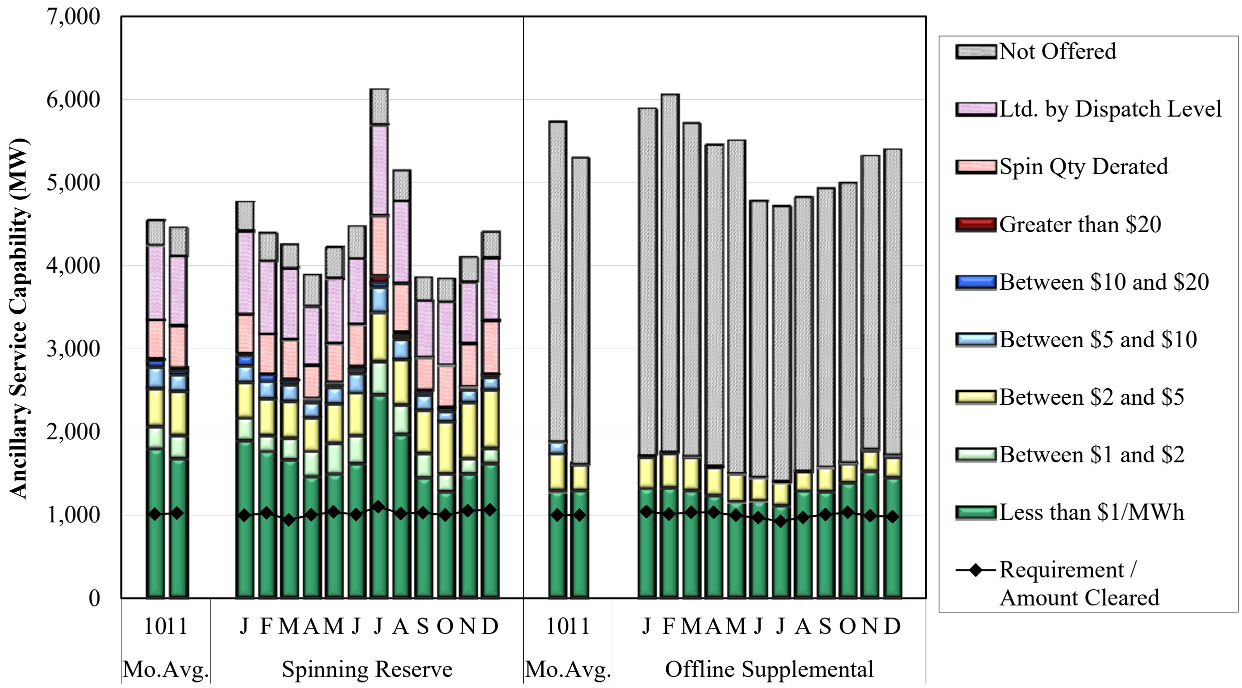


Figure A35: Contingency Reserve Offers and Scheduling

MISO has two classes of contingency reserves: spinning reserves and supplemental reserves. Spinning reserves can be provided by online resources based on ten minutes of their ramp capability. The contingency reserve requirement is satisfied by the sum of the spinning reserves and supplemental reserves, which are offline units that can respond within 10 minutes (including startup and notification times). As noted above for regulating reserves higher-valued reserves can be used to fulfill the requirements of lower-quality reserves. Therefore, prices for regulating reserves always equal or exceed those for spinning reserves which in turn will always equal or exceed the contingency reserve price paid supplemental reserves. As with regulation, spinning and contingency reserve prices can exceed the highest cleared offer as a result of opportunity costs or shortages.

Figure A35 shows the spinning and supplemental reserve offers by offer price. Of the capability not available to the dispatch, the figure distinguishes between quantities not offered, derated, and limited by dispatch level.

Figure A35: Contingency Reserve Offers and Scheduling
2011



Key Observations: ASM Prices and Offers

i. Monthly average marginal clearing prices for all products declined in the second half of 2011. For the year, prices averaged 6 to 10 percent below 2010 prices.

– These declines were due to the cumulative effects of fewer spinning reserve shortages and a reduction in opportunity costs of providing reserves.

– Shortages are therefore mostly due to ramp demands on the system that compel the real-time market to dispatch reserves temporarily in order to satisfy energy demands. Shortages are evaluated in the next section.

✓ Shortages of spinning reserves decreased significantly after the departure in June 2011 of FirstEnergy. FirstEnergy had the most non-conforming load of any area in MISO, which can change abruptly and cause transitory shortages.

– Opportunity costs decreased in 2011 as energy prices fell and as lower natural gas prices led to a flatter supply curve.

ii. Marginal clearing prices for regulation decreased 8 percent from 2010 to $12.03 per MWh. Prices peaked in April at near $16 per MWh but declined to $8 per MWh by December.

- Since regulating reserves can be used to supply lower-quality reserves, a reduction in high-priced spinning reserve shortage periods resulted in a corresponding decrease in regulation prices.

- A substantial reduction in the regulating reserve demand curve penalty price, which sets price during regulating reserve shortage periods, further contributed to this decline.

iii. Spinning reserve prices averaged $3.14 per MWh, down 10 percent from 2010.

- The spin relaxation algorithm in 2011, although improved from prior years, periodically set prices during shortages well below the penalty price.

- This was eliminated in April 2012 when MISO implemented a demand curve for spinning reserves that ceased "relaxing" the spinning reserve requirement to set prices during shortage.

iv. Supplemental reserve prices also fell slightly in 2011, averaging $1.62 per MWh. Supplemental reserves were deployed just five times in 2011 and, with one exception on June 4, performed well.

v. Although the average clearing price for regulation was $12 per MWh, sufficient capability was generally available to meet the requirement with offers less than $2.

- Similar conditions prevailed for spinning and supplemental reserves, where the average clearing price was considerably higher than the marginal unit's offer price (less than $1).

- These difference reflects opportunity costs of not providing energy and to a lesser extent the impact of shortage pricing, which we address in the next section.

C. ASM Shortages

Figure A36: Market Spin Shortage Intervals vs. Rampable Spin Shortage Intervals

MISO operates with a minimum required amount of spinning reserve that can be deployed immediately for contingency response. Most often, market shortages generally occur because the costs that would be incurred to maintain the spinning reserves exceed the spinning reserve penalty factor (i.e., the implicit value of spinning reserves in the real-time market).

Units scheduled for spinning reserves may temporarily be unable to provide the full quantity in ten minutes if the real-time energy market is instructing them to ramp up to provide energy. To account for ramp-sharing concerns, MISO maintains a market scheduling requirement that exceeds its real "rampable" spinning requirement by approximately 200 MW. As a result, market shortages can occur when MISO does not schedule enough resources in the real-time market to satisfy the market requirement, but is not physically short.[14] To minimize such outcomes, MISO should set the market requirement to make market results as consistent with real conditions as possible. Figure A36 shows all intervals with a real shortage, a market shortage, or both in 2011. The figure also shows that physical and market requirements in 2011.

Figure A36: Market Spin Shortage Intervals vs. Rampable Spin Shortage Intervals
2011

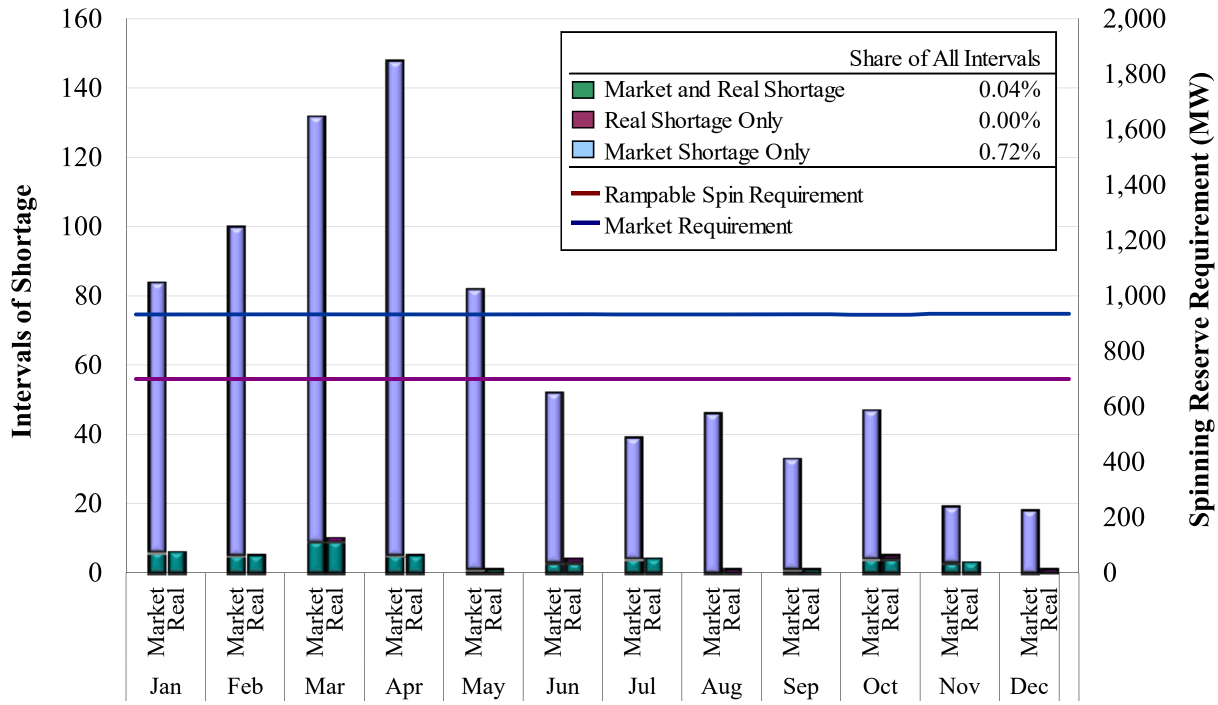


Figure A37: Regulation Deficits and Clearing Prices

The next two figures examine shortage pricing of regulating and spinning reserves, respectively. Figure A37 shows the regulation price during shortage intervals when the market was not concurrently short of spinning reserves (when spinning reserves are in shortage the shortage prices will be reflected in the regulating reserve price). The deficit (the amount of the scheduling requirement MISO was unable to meet) is shown on the x-axis, and the clearing price for the product is shown on the y-axis. Each month has a distinct marker. The regulation price during shortage intervals is equal to the regulation penalty price plus the spinning reserve price. The regulation penalty price changes monthly and is calculated using a formula intended to reflect the commitment cost of a peaking resource.

14 It is also possible for the system to be physically short temporarily when units are ramping to provide energy, but not indicate a market shortage because ramp capability is shared between the markets.

Figure A37: Regulation Deficits vs. Clearing Prices
2011

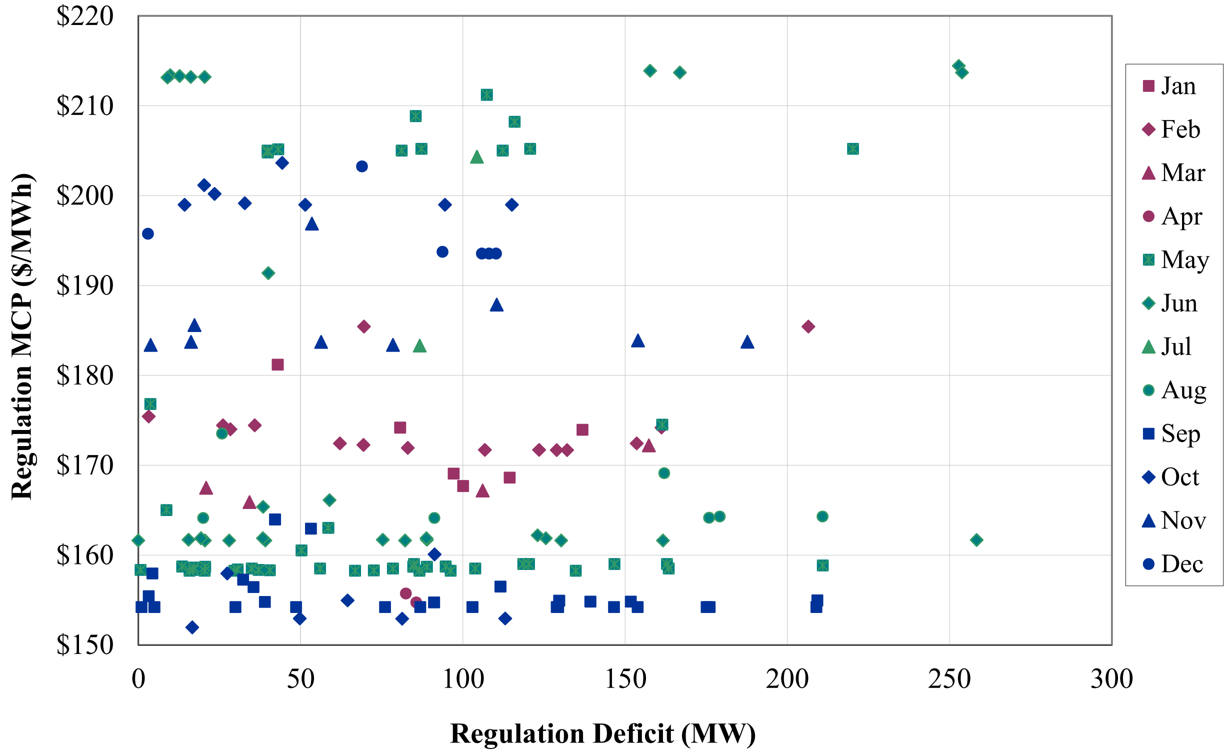


Figure A38: Spinning Reserve Deficits and Clearing Prices

Figure A38 shows similar results for all intervals with spinning reserve shortages. These shortages occur when the demands on the system prevent the real-time market from simultaneously satisfying 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. UDS model constraints prevent the real-time market from taking actions more costly than a predetermined amount (set at $98 per MWh in 2011) plus the prevailing operating reserve clearing price to maintain its spinning reserve.[15]

15 Specifically, the reliability cost of being short of spinning reserves is set administratively at $98 per MWh. An additional constraint requiring that 90 percent of the spinning reserve requirement be met by generating resources is set at $50 per MWh.

Figure A38: Spinning Reserve Deficits vs. Clearing Prices
2011

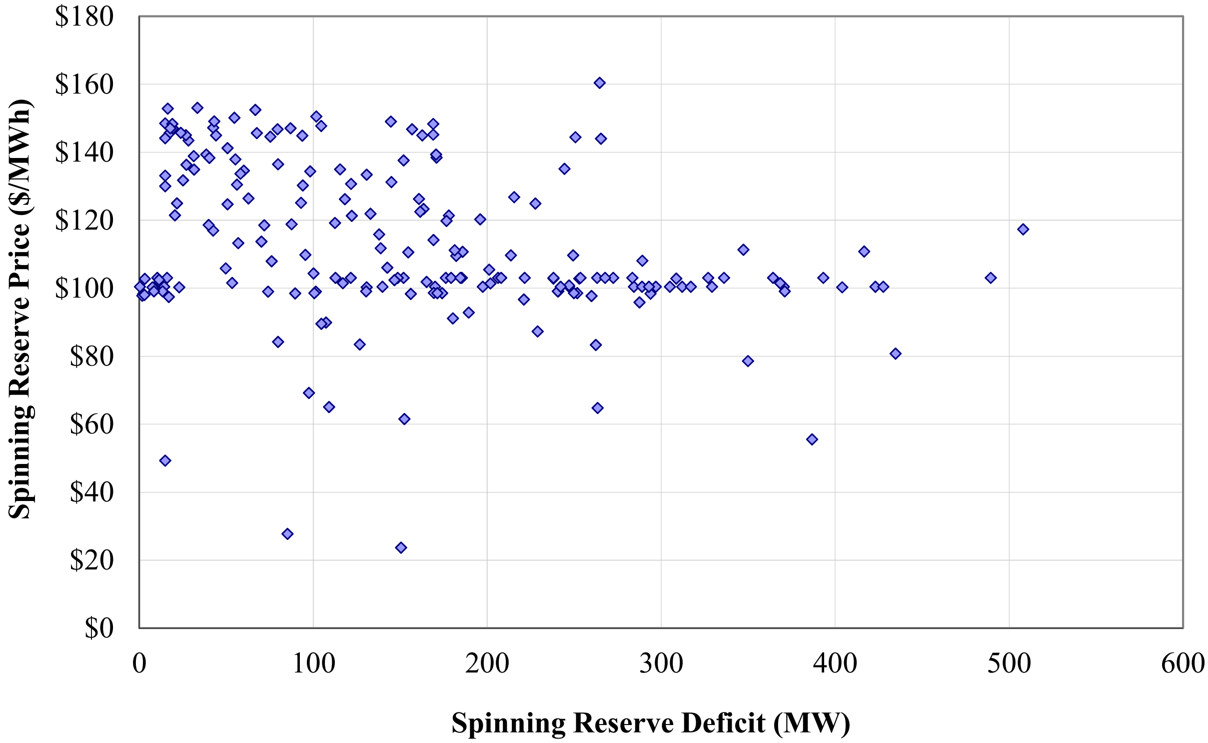
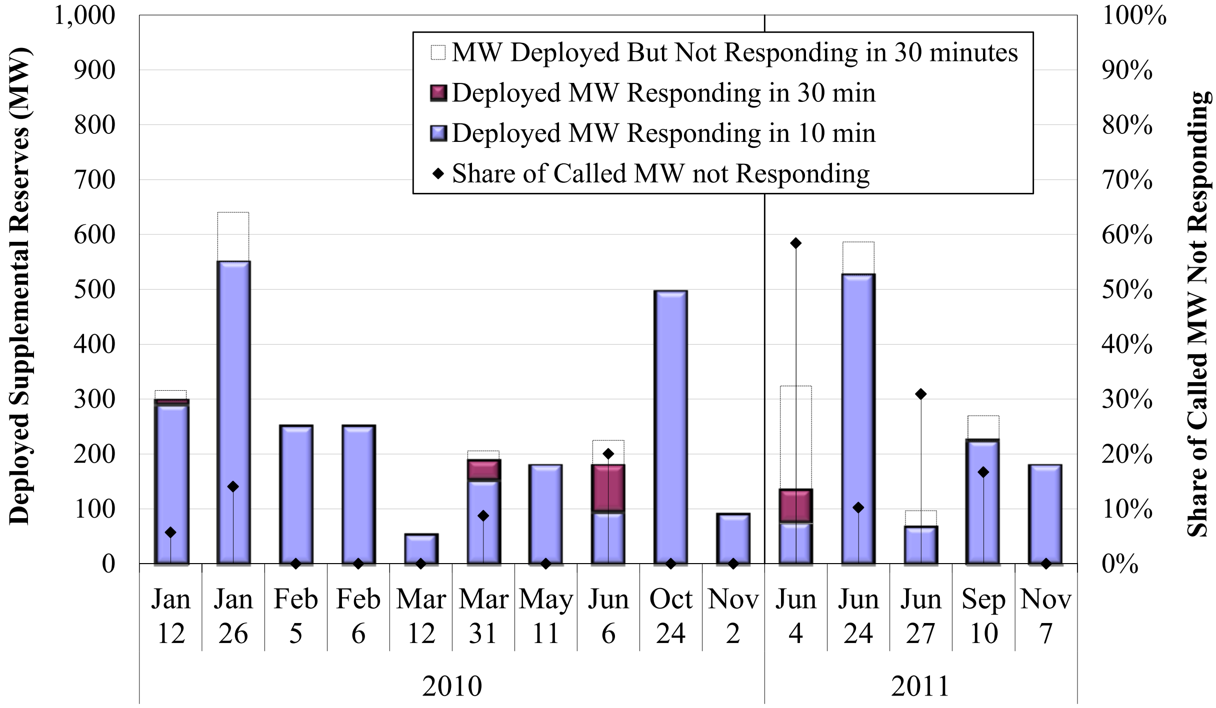


Figure A39: Non-Responsive Supplemental Reserve Deployments

Supplemental reserves are deployed during Disturbance Control Standard and ARS events. Figure A39 shows offline supplemental reserve response, separately indicating those that were successfully deployed within 10 minutes (as required by MISO) and within 30 minutes (as required by NERC). Due to poor deployment performance in 2009 and a recommendation from the IMM, MISO implemented improved measurement and verification procedures for offline supplemental reserves in 2010.

Figure A39: Supplemental Reserve Deployments
2011



<u>Key Observations: Ancillary Services Markets</u>

i. Inconsistencies between market and real shortages persisted in 2011. In most instances of a market shortage, there was no accompanying real shortage. There were very few instances when there was a real shortage that was not reflected in the market price.

ii. Regulation shortage pricing occurred reliably at the regulating reserve demand curve penalty price (which averaged $156 per MWh in 2011), which sends efficient economic signals to the market.

iii. Although efficient shortage pricing signals are 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 in the spinning reserve market because MISO "relaxes" its spinning reserve requirement when it is short.

– A modeling change was implemented in 2010 to reduce this relaxation. As expected, spinning reserve shortage prices are clustered more tightly around the $98 and $148 per MWh penalty price points, which indicate that the modeling change has reduced the relaxation considerably.

– MISO's adoption of a two-step demand curve for spinning reserves in mid-2012, should further improve shortage pricing because it recognizes that the cost of the shortage increases as its size increases. Additionally, MISO plans to discontinue its relaxation of the spinning reserve price when it implements the demand curve.

iv. Five offline supplemental reserve deployments occurred in 2011 compared to 10 such deployments occurred in 2010. With the exception of one event, the response by deployed supplemental reserves within expected levels.

D. Generation Availability and Flexibility in Real Time

MISO derives its ability to manage transmission congestion and satisfy energy and operating reserve obligations from the flexibility of generation available to the real-time market. In general, the day-ahead market coordinates the commitment of most generation that is online and available for real-time dispatch. The dispatch flexibility of online resources in real-time allows the market to adjust supply on a five-minute basis to accommodate NSI and load changes and manage transmission constraints.

Figure A40: Changes in Supply, Day-Ahead to Real-Time

Figure A40 summarizes changes in supply availability from day-ahead to real time. Differences between day-ahead and real-time availability are expected and are attributable to real-time forced outages or derates, real-time commitments and decommitments by MISO. In addition, suppliers scheduled day-ahead sometimes decide not to start their units in real time, but instead to buy back energy at the real-time price. Alternatively, suppliers not committed in the day-ahead may self-commit in real-time.

The figure shows six types of changes: generation self-committed or decommitted in real time, capacity scheduled day-ahead that is not online in the real-time; derated capacity (cleared and not cleared in day-ahead) and its inverse, increased available capacity; and units committed for congestion management. The figure separately indicates the net change in capacity. A net shortfall can compel MISO to commit additional capacity in real time.

Figure A40: Changes in Supply, Day-Ahead to Real-Time
2011

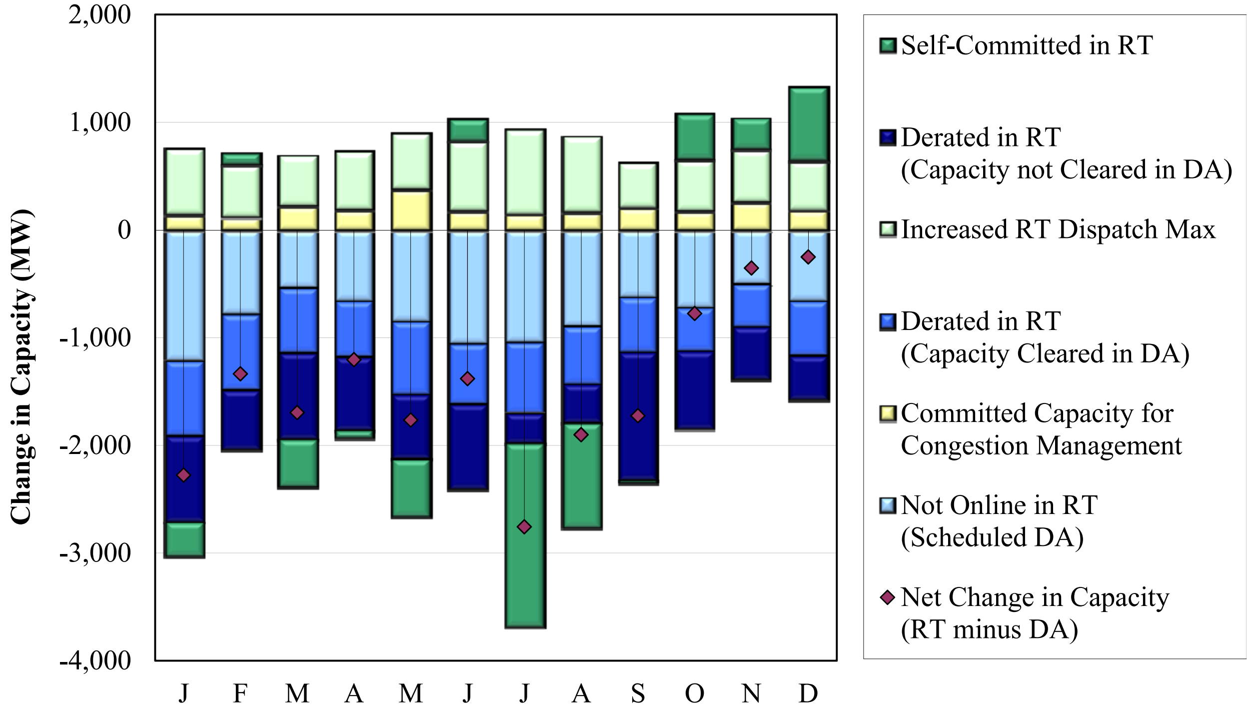


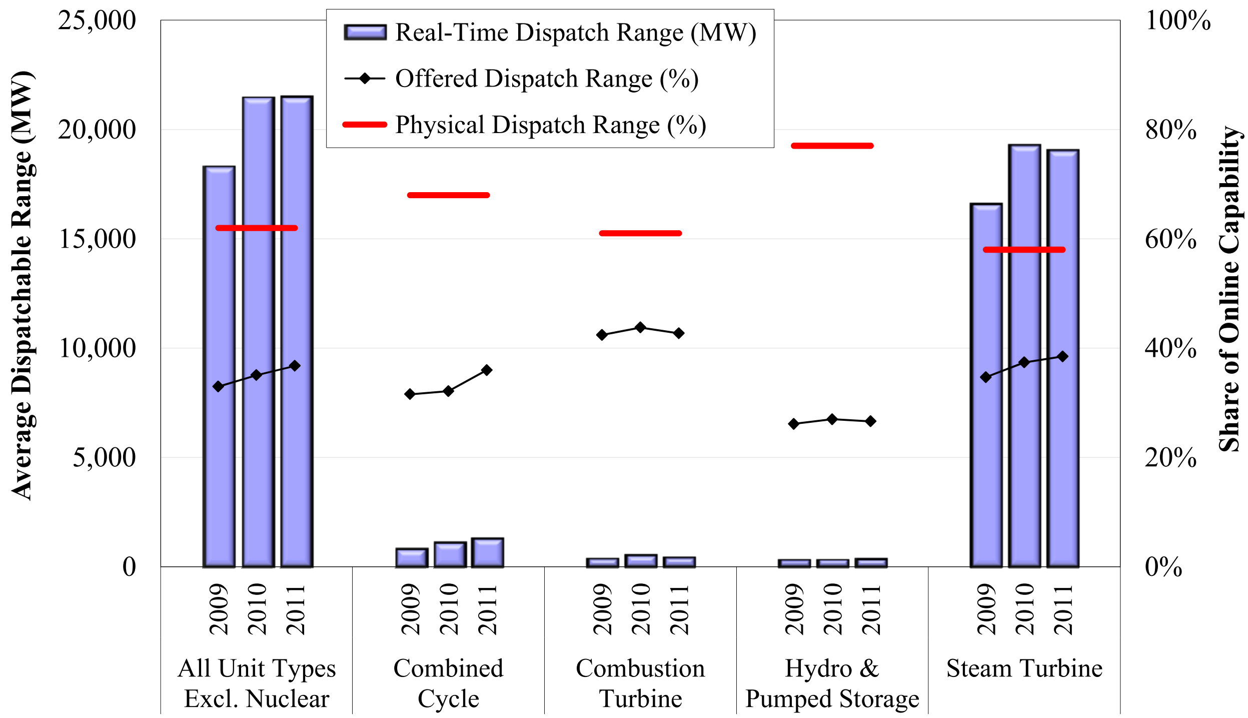
Figure A41: Real-Time Dispatchable Range

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. Flexibility improved with the introduction of ASM in 2009 because:

- The quantity of ASM products a supplier can sell is based on a unit's dispatch range and ramp rates;
- The PVMWPs ensure generators are not harmed by price volatility when following dispatch instructions; and
- The output ranges previously held out of the energy-only market to provide ancillary services are co-optimized with energy under ASM.

Figure A41 shows the yearly average dispatchable range of MISO units by unit type (combined cycle, combustion turbine, steam turbine, and hydro units). The figure separately indicates the "commercial flexibility," which is the maximum dispatchable range that could be offered physically (according to data provided to MISO). The impact of generator inflexibility on MISO's ability to manage congestion is evaluated in Section V.

Figure A41: Real-Time Dispatchable Range
2009–2011



Key Observations: Availability of Generation in Real Time

i. On average, 2.3 GW (3.4 percent) of capacity scheduled in the day-ahead market was unavailable in real time. This lost capability was in each month only partially offset by 550 MW of capacity increases from suppliers increasing their dispatch maximum in real time and 341 MW of self-scheduled or committed resources.

– Suppliers scheduled day ahead that decide not to start their units in real-time have to buy back energy at the real-time price.

ii. Most of MISO's flexibility continues to be provided by steam units. However, the steam units provide similar flexibility as most other types of resources (i.e., dispatch ranges from 35 to 40 percent of their Economic Maximum.

– There was a continued improvement in the amount of real-time flexibility offered in 2011 from prior years.

E. Revenue Sufficiency Guarantee Payments

Revenue Sufficiency Guarantee (RSG) payments compensate generators committed by MISO when market revenues are insufficient to cover the generators' production costs.[16] Resources committed after the day-ahead market receive most of the RSG payments in MISO because this

16 Specifically, the lower of a unit's as-committed or as-dispatched offered costs.

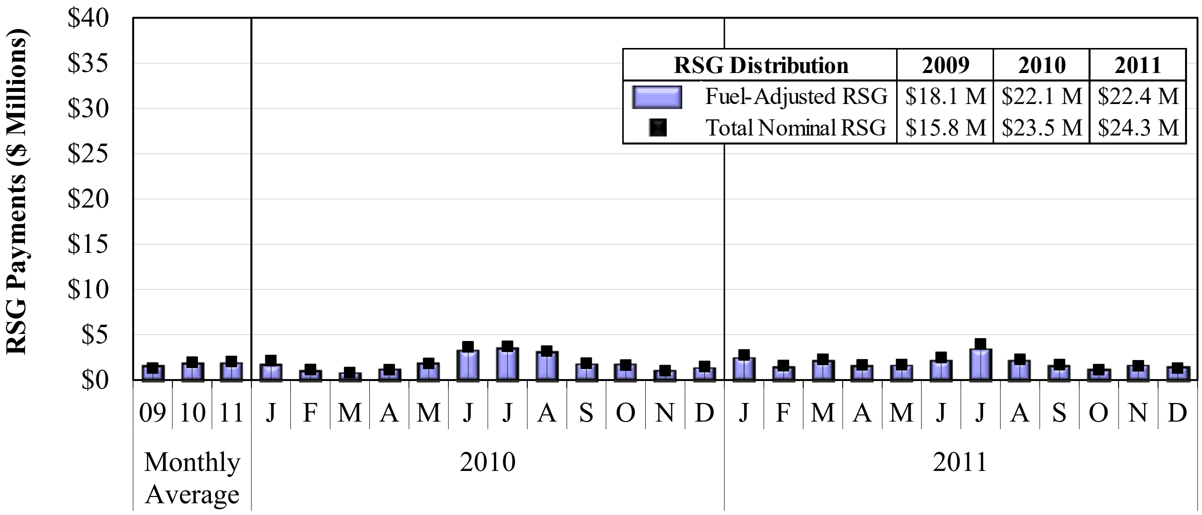
is the timeframe in which MISO must make commitments to satisfy the reliability needs of the system. Since these commitments receive market revenues from the real-time market, their production costs in excess of these revenues are recovered under "real-time" RSG. MISO commits resources in real time for many reasons, including to satisfy capacity needs that can arise during peak load for sharp ramping periods, or those that arise when net purchases in the day-ahead market are less than the real-time load, or to satisfy a local reliability need to manage congestion or maintain the system's voltage in a location.

Peaking resources are the most likely to be paid RSG because they are generally the highest-cost online 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) because they are operating at their economic minimum. This increases the likelihood that an RSG payment may be required.

Figure A42-44: RSG Payment Distribution

Figure A42 shows total day-ahead RSG payments. The results are adjusted for changes in fuel prices, although nominal payments are indicated separately. The table below the figures indicates the share of payments made to peaking and non-peaking units. Figure A43 shows total real-time RSG payments and distinguishes among payments made to resources committed for overall capacity needs, to manage congestion or for voltage support.[17]

Figure A42: Total Day-Ahead RSG Payments
2010–2011

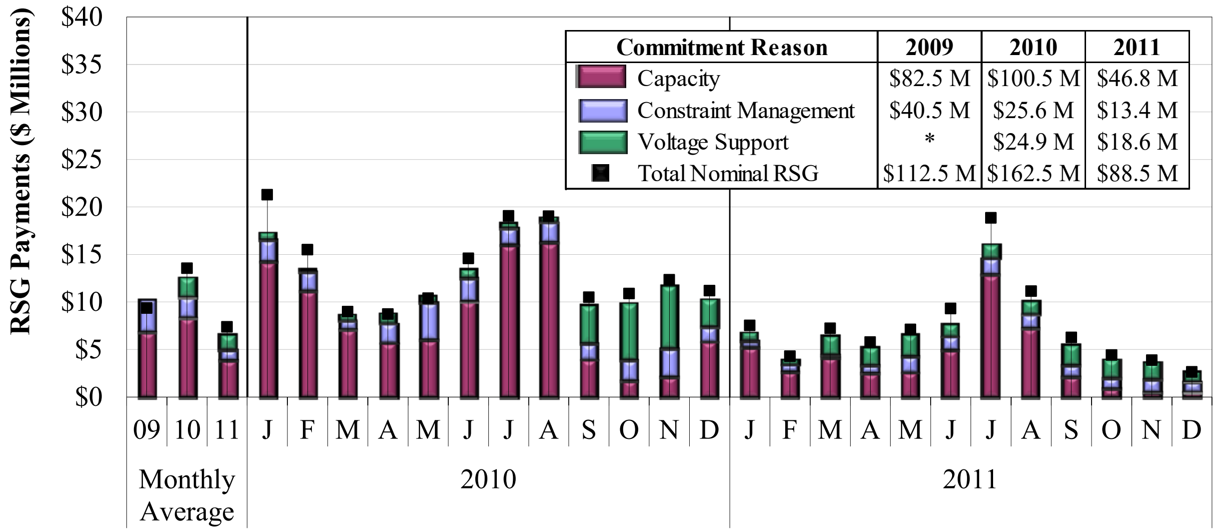


Share of Day-Ahead RSG Costs by Unit Type (%)

Peaking Units	7	14	13	4	0	2	3	15	11	27	36	11	3	3	9	1	0	2	2	6	20	40	15	20	9	6	5
Other Units	93	86	87	96	100	98	97	85	89	73	64	89	97	97	91	99	100	98	98	94	80	60	85	80	91	94	95

17 We examine market power issues related to commitments for voltage support in Section X.

Figure A43: Total Real-Time RSG Payments
2010–2011



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

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

The RSG process was substantively revised in April 2011 in an attempt to better reflect cost causation. Under the revised allocation methodology, RSG-eligible commitments are classified as satisfying either: a) a congestion management or other local need, or b) a capacity need. The RSG costs associated with these commitments are then allocated to market-wide deviations ("Day-ahead Deviation Charge" or DDC), deviations that affect constraints ("Congestion Management Charge" or CMC), and real-time load ("Pass 2").

Figure A44 summarizes how real-time RSG is allocated between the DDC, CMC, and Pass 2 charges. The top panel shows the monthly real-time RSG cost that was allocated to these three categories. The bottom panel shows daily average total net deviations from the day-ahead (all helping and harming deviations are netted in each hour), as well as the total deviations that are paying the DDC charge. The latter is generally larger than the former because helping and harming deviations under the current allocation are generally only netted if they are incurred by the same participant.

Figure A44: Allocation of RSG Charges
By week, April–December 2011

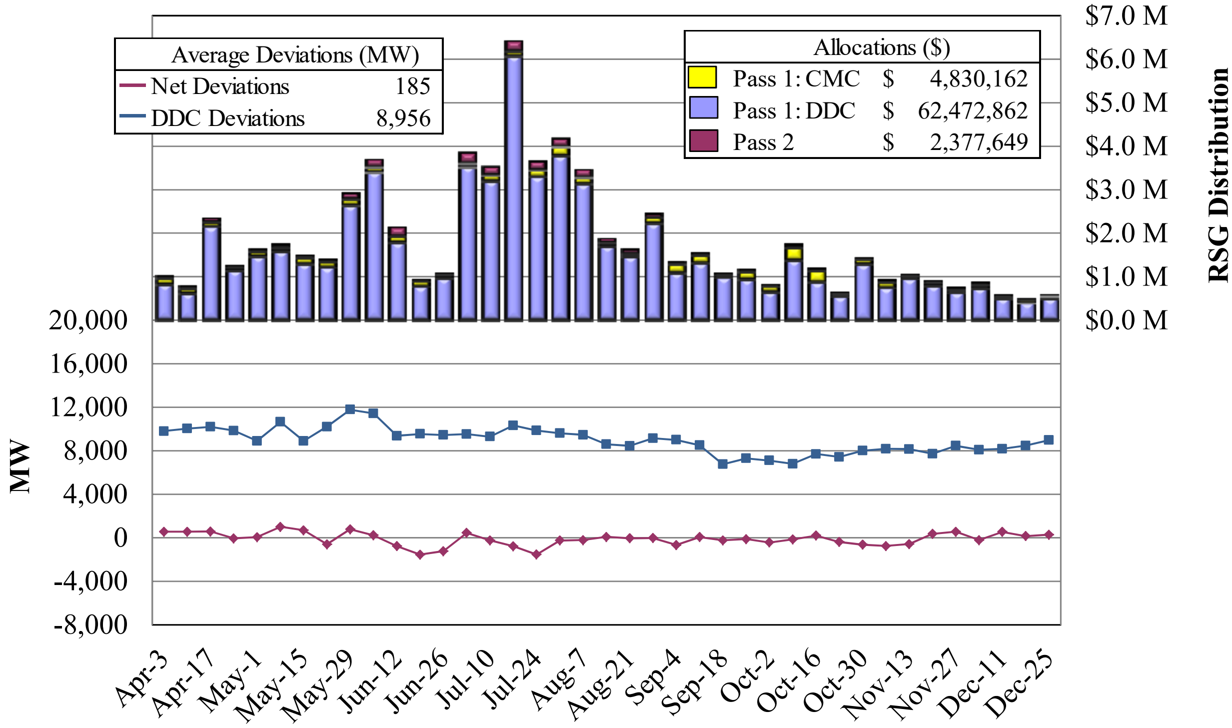


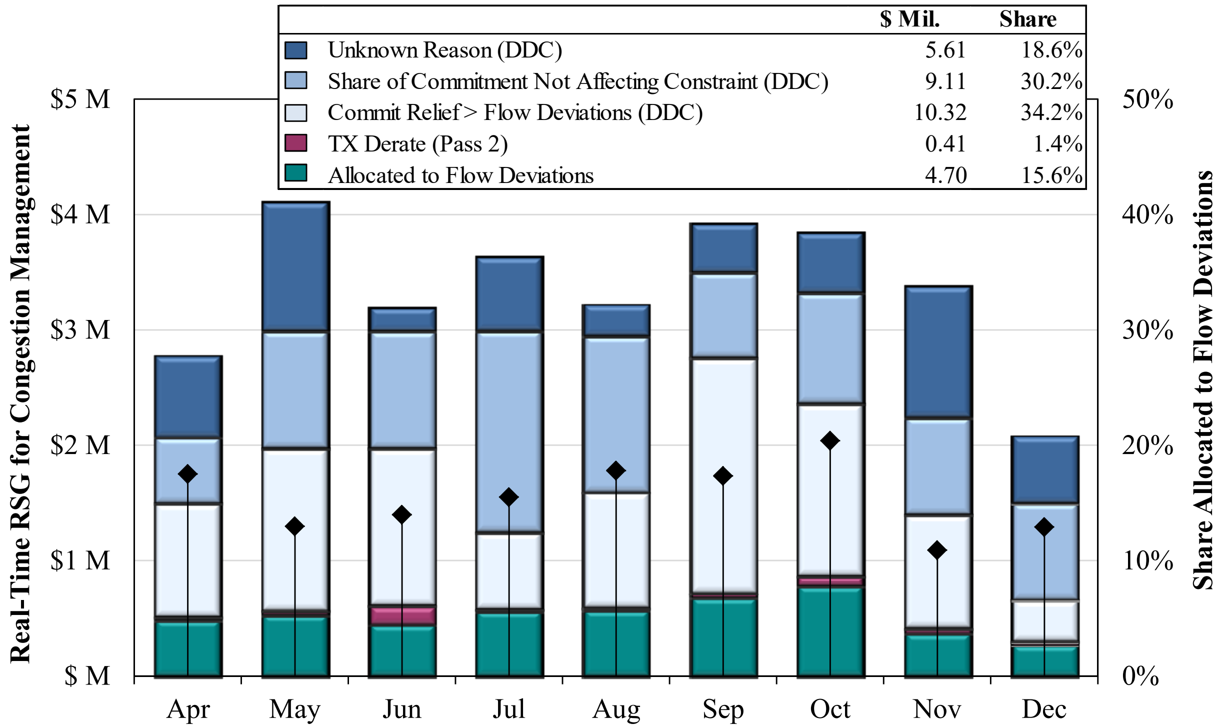
Figure A45: Allocation of Constraint-Related RSG Costs

When committing a resource for constraint management, MISO operators identify the particular constraint relieved. Deviations during the commitment period that increase flow on the identified constraint are allocated a share of the RSG costs under the CMC. The residual RSG costs after allocation to net constraint-flow deviations are recovered under the DDC and Pass 2 RSG charges.

Figure A45 shows how RSG costs associated with commitments to manage constraints and other local issues are allocated. The green portion of the bar is the portion allocated to those that create a flow deviation on the constraint for which the resource is committed. The maroon block corresponds to costs incurred because of a transmission derate and is allocated to load through Pass 2. Each of the blue blocks is allocated to market-wide deviations through the DDC rate. The first block occurs when the committed capacity exceeds the deviation flow (i.e., more committed relief is procured than the contribution of the harming deviations to the constraint flows. The second block occurs because MISO only allocates only the portion of costs of the committed unit that corresponds to its actual potential relief (counterflows) over the constraint. This last block is allocated to DDC for reasons we cannot identify, but may be due to errors in logging or the definition of the constraint.

Any constraint-related RSG costs not allocated to the CMC are then allocated to market-wide deviations (negative deviations only) through the DDC. Any remaining RSG cost is then allocated market-wide on a load-ratio share basis (Pass 2).[18]

Figure A45: Allocation of Constraint-Related RSG Costs
2011



<u>Key Observations: RSG Payments</u>

i. RSG payments declined 45 percent from 2010 to 2011.

– This reduction was partly due to lower fuel prices and partly due to the fact that net day-ahead load exceeded real-time load during the daily peak hour in 2011, which reduced the need for MISO to commit RSG-eligible resources in real time for market-wide capacity needs.

– Payments were highest in summer when capacity needs were greatest, peaking during the week of July 17, when loads at times exceeded 100 GW.

– Day-Ahead RSG payments remains relatively low, but have increased slightly (on a fuel-adjusted basis) since 2009 because various modeling changes resulted in more day-ahead commitments. These changes procured more headroom on resources scheduled in the day-ahead market.

18 A portion of constraint-related RSG may be allocated to Pass 2 if they are associated with real-time transmission derates or loop-flow.

ii. Real-time RSG payments account for more than 85 percent of total RSG payments (the balance is paid day-ahead).

- Real-time nominal RSG costs declined 38 percent from 2010.
- Capacity-related RSG costs declined the most—by a fuel-adjusted 53 percent—because load was more than fully scheduled in 2011 than in 2010 on average, which reduces the commitments that MISO must make for capacity in real time.

iii. Commitments for constraint management and for voltage support also declined by a fuel-adjusted 48 and 25 percent, respectively.

- Voltage-related RSG payments were made consistently throughout the year.
- These commitments raise market power concerns because a supplier facing little or no competition to resolve these types of local reliability requirements can extract substantial market-power rents under current mitigation measures.
- In the 2010 *State of the Market Report* we recommended MISO seek authority for tighter conduct and impact mitigation thresholds applicable to such commitments. MISO filed these in late December 2011 and expects to implement these changes in late summer 2012 subject to final FERC approval.

iv. Our analysis indicates that the current allocation of real-time RSG implemented in April 2011 is not allocating these costs consistent with the causes of the costs.

- RSG charges totaled nearly $70 million between April and December 2011, almost 90 percent of which was allocated to deviations under the DDC rate using the current allocation methodology (effective April 1, 2011).
  - ✓ However, only one-third of the real-time RSG is incurred for capacity needs, and this portion of the RSG is not always caused by deviations from the day-ahead market.
  - ✓ Net deviations were often negative (i.e., reducing the need to commit resources for capacity) and averaged only 185 MW. Therefore, there are many hours when deviations did not contribute to any real-time RSG.
- Costs associated with managing congestion are allocated under the DDC rate when the current methodology does not allocate those costs to the CMC rate.
  - ✓ The share of the costs allocated under the CMC rate cannot exceed the GSF of the resource committed for the constraint. This component of the allocation fails to recognize that the constraint in most cases causes all of the costs, regardless of the magnitude of the GSF.

  - ✓ As a result, the net deviations affecting the identified constraints bore only 16 percent of these RSG costs and the balance was borne by the market-wide deviations.

- Finally, the CMC also contains a flaw affecting the allocation to virtual transactions. In short, FERC ordered a change to the MISO Tariff provision pertaining to the CMC allocation to virtual transactions that inadvertently reversed the allocation.

- This report includes recommendations to modify the allocation rules to address these issues and improve its alignment with cost causation.

F. Price Volatility Make-Whole Payments

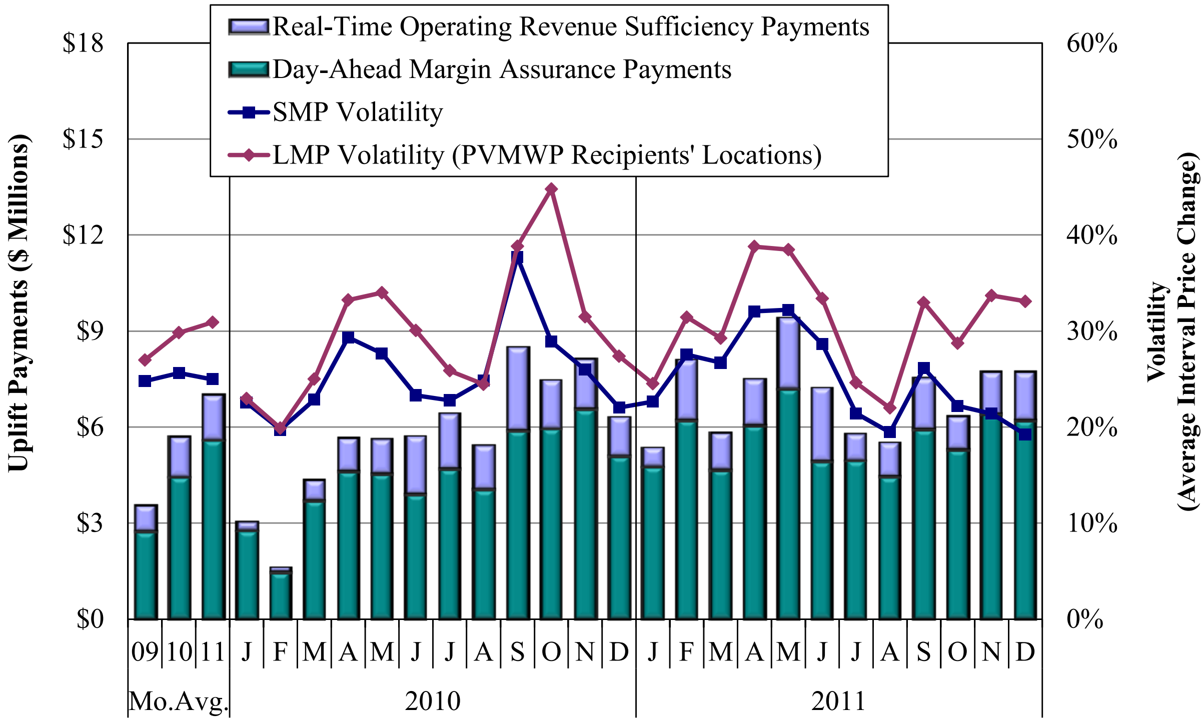
MISO introduced the Price Volatility Make-Whole Payment (PVMWP) in 2008 to ensure adequate cost recovery from the real-time market for those resources offering dispatch flexibility. The payment ensures that suppliers responding to MISO's prices and following its dispatch signals in real time are not financially harmed by doing so thereby removing a potential disincentive to providing more operational flexibility.

The PVMWP consists of two separate payments: Day-Ahead Margin Assurance Payment (DAMAP) and Real-Time Operating Revenue Sufficiency Guarantee Payment (RTORSGP). The DAMAP is paid when a resource whose day-ahead margin is reduced because it is dispatched in real-time to a level below its day-ahead schedule and has to buy its day-ahead scheduled output back at real-time prices. Often, this payment is the result of short-term price spikes in the real-time market due to binding transmission constraints or ramp constraints. 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.

Figure A46: Price Volatility Make-Whole Payment

Figure A46 shows total monthly PVMWP for the prior three years. The figure separately shows two measures of price volatility based on (i) the System Marginal Price (SMP) and (ii) the LMP at generator locations receiving PVMWP. Payments should correlate with price volatility, since volatility leads to greater obligations to flexible suppliers. Volatility at recipients' locations is expected to be higher because they are generally redispatched more than other suppliers are due to larger price fluctuations and because the SMP volatility does not include volatility related to transmission congestion.

Figure A46: Price Volatility Make-Whole Payments
2010–2011



Key Observations: Price Volatility Make-Whole Payments

i. The two components of PVMWP rose a cumulative 23 percent to $84 million in 2011.

- DAMAP and RTORSGP increased 26 and 13 percent, respectively, in 2011.
- The increase is due to a modest increase in price volatility at recipients' locations and improved resource flexibility.
- There was decline in overall price volatility (based on SMP) in the second half of 2011 that can be attributed partially to the departure in June of a significant amount of non-conforming load within FirstEnergy.

ii. Most of these payments went to flexible coal units in the East and Central regions that are affected by transmission constraints.

- In the spring of 2011, we identified a flaw in the DAMAP settlement formula that created a gaming opportunity. MISO filed to modify the formula and FERC approved the change, effective to May 17, 2011.
- Throughout 2011, we continued to work with MISO to seek improvements in the eligibility and settlement rules associated with RSG payments and PVMWP, which has included a number of specific recommendations.

G. Dispatch of Peaking Resources

Peak demand is often satisfied by generator commitments in the real-time market. Typically, peaking resources account for a large share of real-time commitments because they are available on short notice and have attractive commitment-cost profiles (i.e., low startup costs and short startup and minimum-run times). These qualities make peaking resources optimal candidates for satisfying the incremental capacity needs of the system.

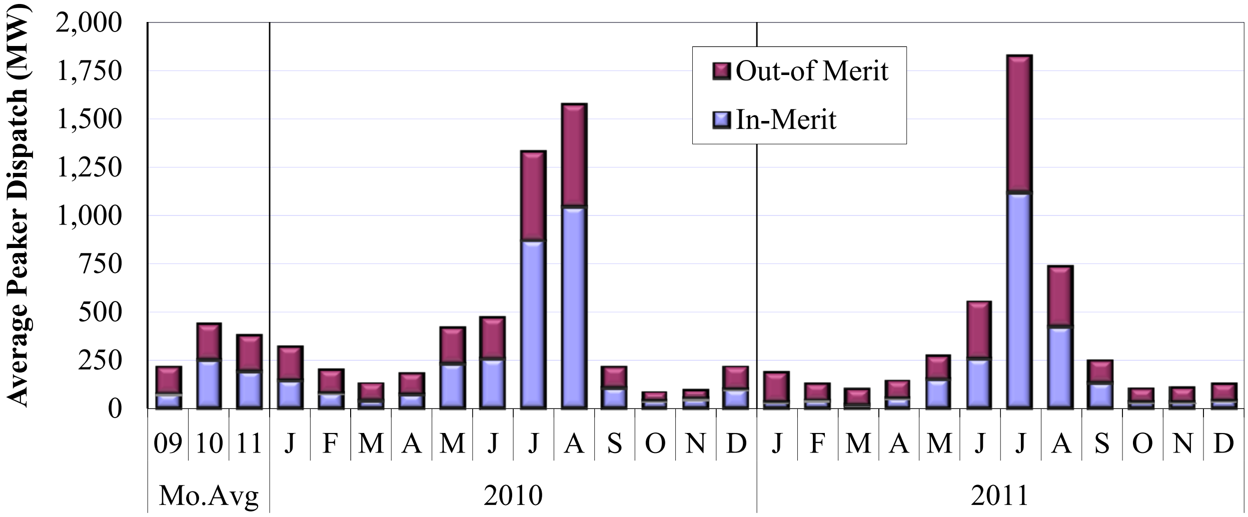
While low commitment costs make peaking resources attractive for meeting capacity needs, they have high incremental energy costs and frequently do not set the energy price because they are often dispatched at the economic minimum level (causing them to run "out-of-merit" order with an offer price higher than their LMP). When a peaking unit sets the energy price or runs out-of-merit, they will be revenue-inadequate because they receive no energy rents to cover its startup and minimum generation costs. This revenue inadequacy results in real-time RSG payments.

Since MISO's load in aggregate peaks in the summer, the dispatch of peaking resources has the greatest impact during the summer months when system demands can at times require substantial commitments of peaking resources. In addition, several other factors can contribute to peaking resource commitments, such as day-ahead net scheduled load that is less than actual load, transmission congestion, wind forecasting errors, or changes in real-time NSI.

Figure A47: Average Daily Peaking Unit Dispatch and Prices

Figure A47 shows average daily dispatch levels of peaking units in 2011 and evaluates the consistency of peaking unit dispatch and market outcomes. The figure indicates the share of peaking resource output that are respectively in-merit order (when the resource LMP is greater than its offer price) and out-of-merit order (when the resource LMP is less than its offer price).

Figure A47: Dispatch of Peaking Resources
2010–2011



Out-of-Merit Quantity and Share

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

Key Observations: Dispatch of Peaking Resources

i. The average hourly dispatch of peaking resources in 2011 declined 13 percent to 374 MW.

- The vast majority of such commitments occurred during peak summer days, when high loads occasionally resulted in the need to commit over 13 GW of peaking capacity.
- Commitments on such days are more often in-merit (i.e., the energy offer price is less than the prevailing LMP) than on other days because their incremental energy is needed to meet generation demand, and not needed solely to maintain headroom or provide ancillary services.
- As day-ahead load scheduling has increased, the use of peaking resources has decreased, particularly late in 2011 and into early 2012.

ii. Nearly half of all peaking resources ran "out-of-merit" order, indicating that the frequently do not set energy prices when they are needed.

- MISO's continuing efforts to implement a new "Extended LMP" pricing method should allow peaking resources to set prices more often when they are needed to satisfy the system's energy and ASM requirements. This will improve MISO's real-time and day-ahead energy pricing, and reduce RSG payments.

H. Wind Generation

Wind generation in MISO has grown steadily since the start of the markets in 2005. Although wind generation promises substantial environmental benefit, the output of these resources is intermittent. As such, wind generation presents particular operational, forecasting, and scheduling challenges. These challenges are amplified as wind's portion of total generation increases.

Intermittent resources can submit offers in the day-ahead market (accompanied by generation forecasts) and can be designated as capacity resources under Module E of the Tariff (adjusted for capacity factors).[19] In real time, however, most wind resources are limited in their ability to be dispatched by the real-time market. As a result, the real-time market software does not control the production of a large share of the intermittent resources. Instead, MISO relies heavily on short and long-term forecasts, and utilizes manual curtailment when necessary to ensure reliability.

MISO introduced the Dispatchable Intermittent Resource (DIR) type in June 2011. DIRs are wind resources that are physically capable of responding to dispatch instructions (from zero to a forecasted maximum) and can therefore set the real-time energy price. DIRs are treated comparable to other dispatchable generation, and therefore are eligible for all uplift payments and are subject to all requisite operating requirements. By June 2013, most wind units in MISO will be DIRs.[20]

Figure A48: Day-Ahead Scheduling versus Real-Time Wind Generation

Figure A48 shows a seven-day moving average of wind scheduled in the day-ahead market and generated in the real-time market since 2010. Underscheduling of output 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. Virtual supply at wind locations is also shown in the figure because the response by virtual supply in the day-ahead market offsets the effects of underscheduling by the wind resources.

19 Module E capacity credits for wind resources are determined by MISO's annual Loss of Load Expectation Study. It is established on a unit basis by evaluating a resource's performance during the peak hour of each of the prior seven years' eight highest peak load days, for a sample size of 56 peaks. In Planning Year 2011 credits averaged 12.9 percent, and individually they ranged from 0 to 31 percent. For Planning Year 2012, the average is 14.7 percent. Excluding six resources that received no credit, individual credits range from less than 5 percent to 32.5 percent.

20 Those resources placed in service prior to April 2005 are exempt from DIR requirements.

Figure A48: Day-Ahead Scheduling vs. Real-Time Wind Generation
2010–2011

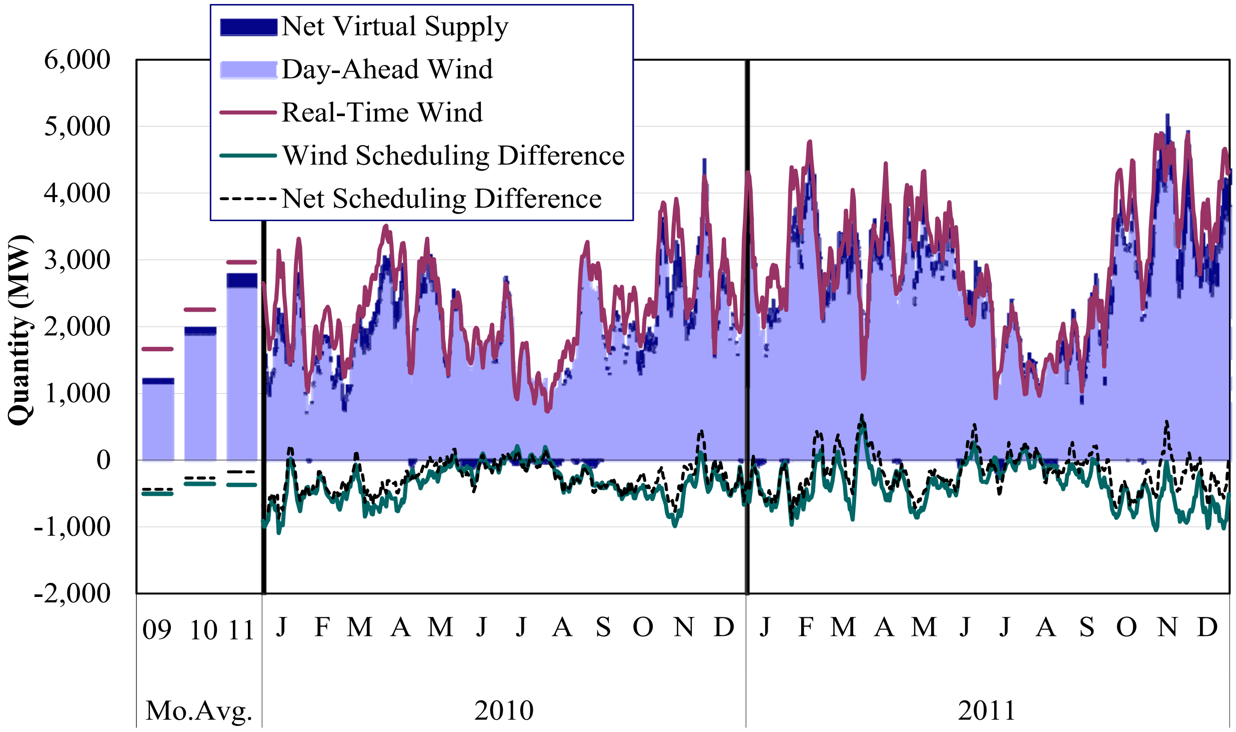


Figure A49: Wind Generation Capacity Factors by Load Hour Percentile

Wind capacity factors (measured as actual output as a percentage of nameplate capacity) vary substantially across the footprint year-to-year and by region, hour, season, and temperature.

Figure A49 shows average hourly wind capacity factors by load-hour percentile, shown separately by season and region. The figure also shows the four-year average. This breakdown shows how capacity factors have changed with overall load. 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 hours when load was lowest.

Figure A49: Wind Generation Capacity Factors by Load Hour Percentile
2011

Figure A50: Wind Curtailments by MISO

Since much of the wind capacity is located in the West region and affects lower voltage transmission constraints, the growth in wind output over time has resulted in increased congestion out of western areas. Most wind units cannot yet respond to economic dispatch instructions from MISO through the real-time energy market. Hence, MISO operators continue to manually curtail wind resource output to manage congestion and address local reliability issues. The manual curtailment of wind units is an inefficient means to relieve congestion because the process does not allow prices to reflect the marginal costs incurred to manage the congestion. In addition to MISO-issued curtailments, wind-resource owners at times choose to curtail their output in response to very low prices. Owner-instructed curtailments are not coordinated with or tracked by MISO, and appear to the market operator as a sudden reduction in wind output. These actions, which contribute to wind generation volatility (discussed later in this section), should decline as DIR integration expands.

Figure A50 shows the average wind curtailments since 2009. The figure distinguishes between MISO-issued manual and economic (DIR) curtailments, which began in June 2011. Manual curtailments of units that have since become DIR (as of June 2012) are indicated by the hashed pattern.

Figure A50: Manual Wind Curtailments
2009–2011

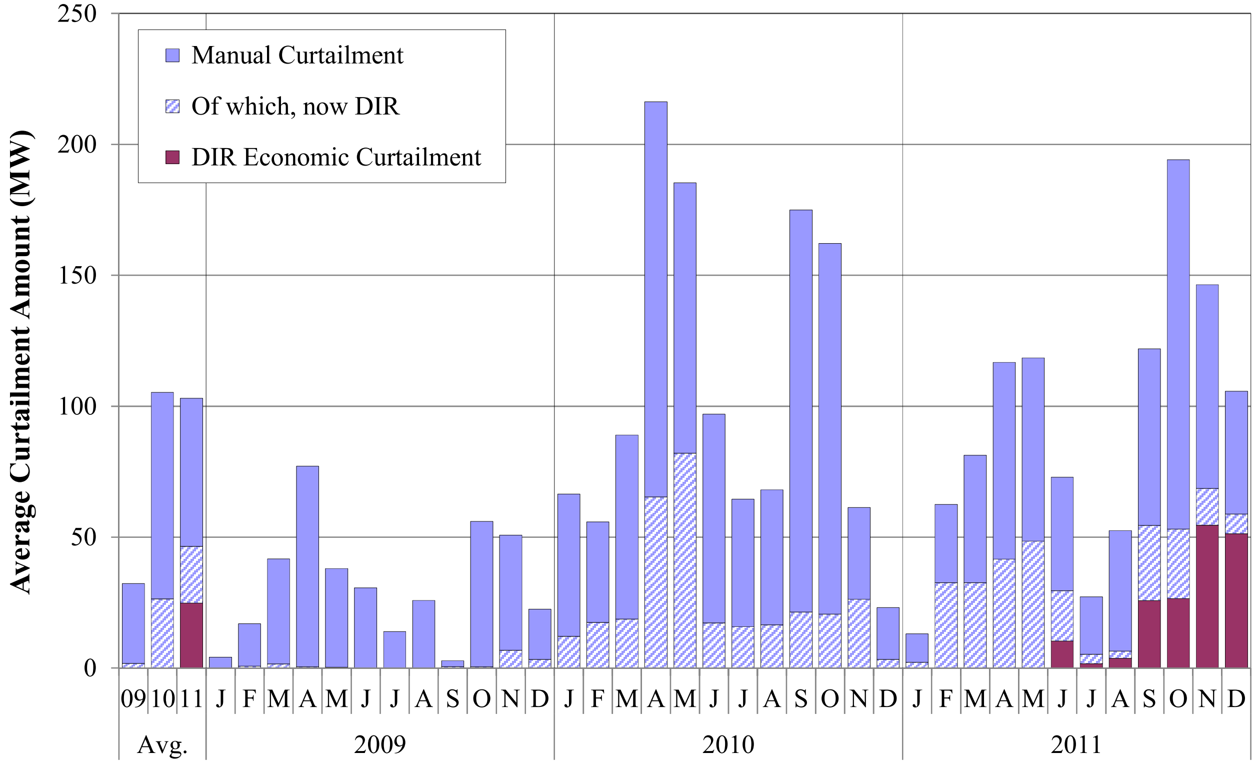
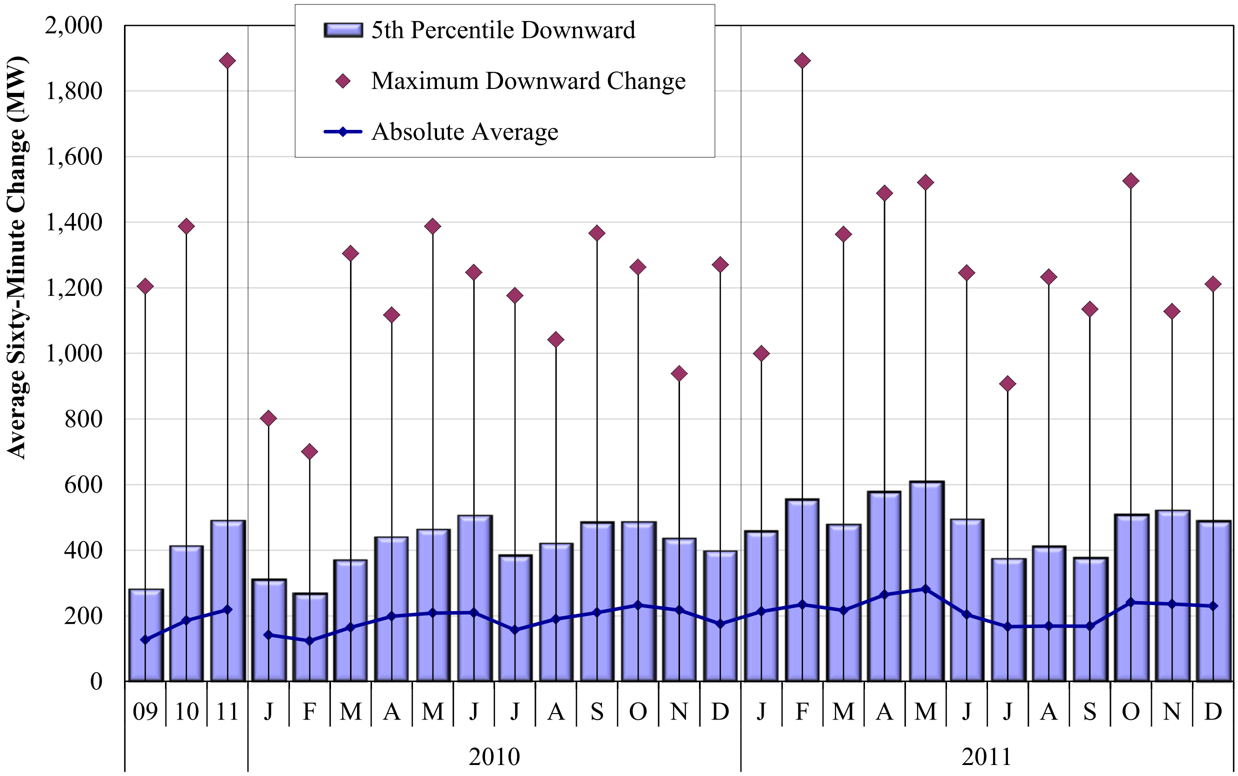


Figure A51: Wind Volatility

Because wind output is dependent on the changing velocity of the wind resource, wind output can be highly volatile. As a result, volatility in wind output must be managed through redispatch of other resources, curtailment of wind resources, or the commitment of peaking resources. Figure A51 summarizes the volatility of wind output on a monthly basis over the past two years by showing:

- The average absolute value of the sixty-minute change in wind generation in the blue line;
- The largest 5 percent of hourly decreases in wind output in the blue bars;
- The maximum hourly decrease in each month in the drop lines.

Figure A51: Wind Volatility
2010-2011



Key Observations: Wind Generation

i. Real-time wind generation in MISO in 2011 increased 30 percent to average nearly 3,000 MW, which was 5.0 percent of total genertion in 2011.

– Wind resources now account for 7.0 percent of installed capacity (approximately 10.6 GW), which is a 15 percent increase from 2010.

– This growth trend is expected to continue because of the wind capability in western areas of MISO, state mandates, and various subsidies and tax incentives.

– Uncertainty regarding the extension of federal production tax credits, which are set to expire at end-2012, may affect the number of units entering in the second half of 2012.

ii. Wind remained underscheduled in the day-ahead by an average of 365 MW, or 12 percent, although net virtual supply in 2011 made up more than half of this discrepancy.

– Since August 31, 2010 deviations from day-ahead (i.e., real-time reductions in wind generation compared to the day-ahead schedule) are no longer exempt from RSG charges, which may provide an incentive for participants to use conservative forecasts in the day-ahead.

iii. Wind capacity factors were highest in the West region where the resource potential is greatest.

iv. Wind output is substantially lower during summer months than during shoulder months, which reduces its value from a reliability perspective.

- The capacity factor of wind resources continues to be inversely correlated with load, as expected because wind tends to be strongest in shoulder seasons and at night.
- For this reason, wind resources receive capacity credits toward satisfying Module E requirements that are only a fraction of their installed capacity.
  - ✓ The average capacity credit increased from 12.9 percent in Planning Year 2011–12 to 14.9 percent for Planning Year 2012–13.
  - ✓ The capacity credit value is determined separately for each wind unit and is based on its output during prior peak demand days over the past several years.
  - ✓ We believe this methodology results in overstated capacity credits for wind and have recommended it be re-evaluated.

v. Sixty-minute volatility in 2011 increased 18 percent to an average of 218 MW per hour, and peaked at roughly 1,900 MW.

- Although the DIR has been extremely valuable in improving the control of wind resources and responding to these changes in output, MISO is working to develop changes in procedures and evaluate market design changes that may be beneficial for managing the changes in wind output.

vi. Despite the rise in output, manual curtailments of wind units to manage congestion or over-generation conditions decreased 26 percent in 2011.

- Much of this is attributable to the increased penetration of DIR, whose economic curtailments reduced the need for manual ones.
- Manual curtailments should be greatly reduced once the majority of wind resources convert to DIR type by June 2013.

V. Transmission Congestion and Financial Transmission Rights

MISO's energy markets serve load and meet reserve obligations with the lowest-cost resources possible, subject to the limitations of the transmission network. The locational market structure in MISO is 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 diverging LMPs that reflect the value of transmission.[21] 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 or constraint[22] reaches its limit, the cost of the resulting congestion is equal to the marginal value of the constraint (the cost of controlling 1 MW of flow on the constraint) multiplied by the total flow over the constraint. MISO collects these congestion costs in the settlement process through the congestion component of the LMP. In a constrained area, the congestion component will be positive and increase the LMP; conversely, in areas where additional generation contributes to *increased* flow on constraints, the congestion component will decrease the LMP.[23]

In a congested area, load will generally exceed generation. Therefore, when the net load in the constrained area settles at the higher constrained area price and the net generation in the unconstrained area settles at the lower unconstrained price, MISO will receive more revenue from the load than it pays to the generators. The difference is the cost of congestion or "congestion revenues". 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, these signals allow generation to be efficiently committed and dispatched to manage network flows; in the long run, they facilitate investment and retirement decisions that can significantly affect network congestion.

This section of the Appendix evaluates congestion costs, FTR market results and congestion management.

A. Total Day-Ahead and Real-Time Congestion Costs

Most congestion revenues are collected through the settlement of the day-ahead market because day-ahead schedules utilize the vast majority of the system's transmission capability. As described above, these are collected because the prices at load locations affected by congestion

21 Owing to losses, prices across the footprint will generally vary even absent any transmission congestion.

22 Throughout this report the terms "interface" and "constraint" are used interchangeably and refer to transmission constraints in the market clearing software that limit transfers of power from generation to load based on the network configuration and status. These constraints (and transmission losses) account for all the locational price differences.

23 This signifies that power injected at that location is less valuable because it aggravates the constraint.

will generally be higher than the prices at generator locations (because some of the generation is outside the constrained area and transmitted into the area over the constraint).

Real-time balancing congestion settles based on real-time market results and, like all other settlements in the real-time market, is only based on deviations from the day-ahead market. Most congestion costs in the real-time market occur when transmission limits change from the day-ahead market model, or when "loop flows" (flows across the MISO network created by generation and load on other systems) deviates from levels assumed in the day-ahead market.

For example, assume a transmission interface is fully scheduled in the day-ahead market and is congested. If the limit were to fall (e.g., the interface is derated) or loop flow were to increase over the congested interface, MISO would incur real-time congestion costs to redispatch generation to achieve the required reduction in real-time interface flows. Absent these changes, no balancing congestion costs would be incurred.[24]

We distinguish between congestion *costs* or *revenues* collected by MISO (via the congestion component of the LMP) and the *value* of real-time congestion of a particular constraint. This is the MW amount of flow on a constraint multiplied by the marginal value, or shadow price, of relieving one MW of flow.[25] The 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). In addition, the JOA between PJM and MISO entitles PJM to use a certain portion (its "Firm Flow Entitlement", or FFE) of transmission capability on market-to-market flowgates. Congestion costs collected by MISO are approximately one half of the total value of real-time congestion on the MISO network.

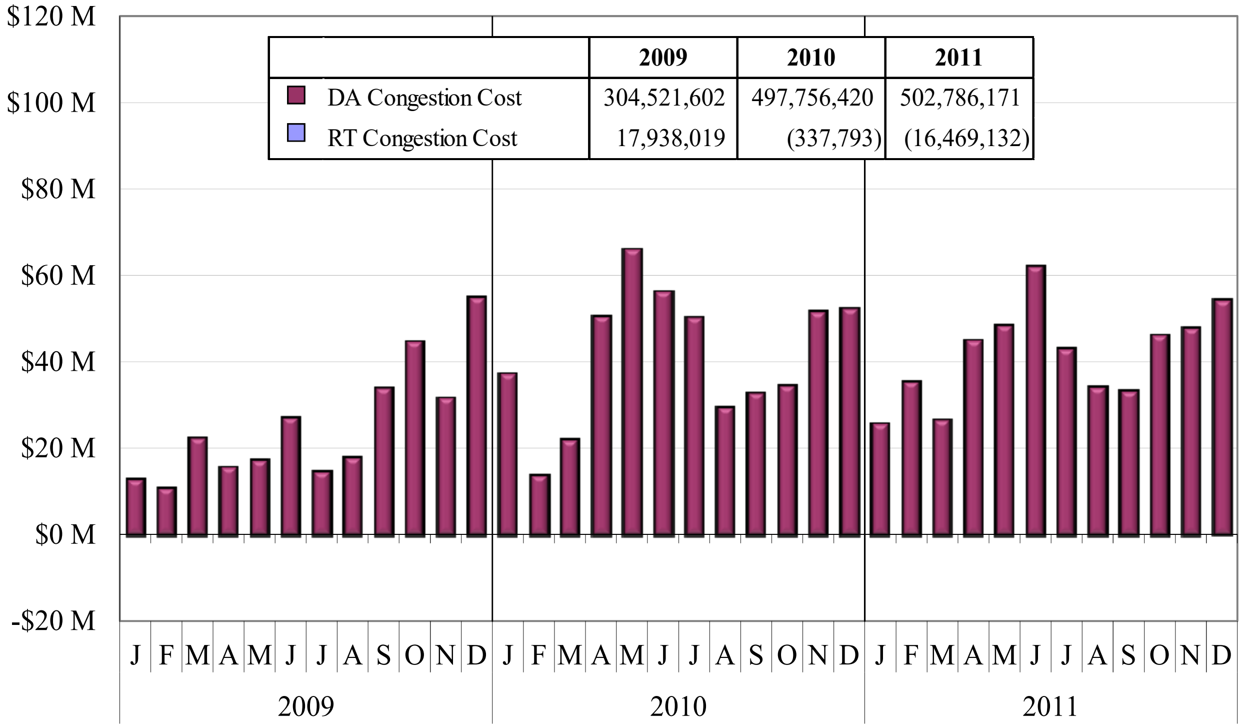
Figure A52: Total Congestion Costs

Figure A52 shows total congestion costs incurred by month in the day-ahead and real-time markets since 2009.

24 In MISO, these costs are incurred as negative Excess Congestion Funds, or "ECF".

25 The marginal value or shadow price is the amount of production cost savings if the limit of the constraint could be increased by 1 MW.

Figure A52: Total Congestion Costs
2009–2011



	2009	2010	2011
DA Congestion Cost	304,521,602	497,756,420	502,786,171
RT Congestion Cost	17,938,019	(337,793)	(16,469,132)

Figure A53: Real-Time Congestion Costs

To better understand the real-time congestion costs, Figure A53 shows these costs disaggregated into the real-time congestion costs incurred to reduce (or increase) the MISO flows over certain transmission constraints and the market-to-market payments made by (to) PJM under the JOA. For example, when PJM exceeds its entitlement on a constraint MISO will redispatch to reduce its flow and generate a cost (shown as positive in the figure), while PJM's payment to MISO for this excess flow is shown as a negative cost (i.e., revenue to MISO).

Figure A53: Real-Time Congestion Costs
2009–2011

Key Observations: Congestion Costs and FTR Obligations

i. Day-ahead congestion costs rose slightly from $498 million in 2010 to $503 million in 2011.

ii. Real-time congestion costs in 2011 were a small share of total congestion costs collected by MISO, which is good because these costs generally occur when the transmission capability available in the real-time market is less than was assumed.

- In 2011, real-time congestion costs were negative (i.e., a real-time surplus) for the first time, indicating that day-ahead transmission capability assumed to be available (i.e., the limits net of assumed of loop flows) was slightly less than the capability actually available in the real-time market.

- An additional source of the real-time surplus is PJM's M2M payments associated with PJM's real-time use of the system in excess of its Firm Flow Entitlement (FFE). PJM's payments are netted against MISO's positive real-time congestion costs.

iii. Congestion revenues collected through the MISO markets are substantially less than the value of real-time congestion on the system, which totaled $1.24 billion in 2011.

- This difference is caused primarily by loop flows that do not pay MISO for use of its network and PJM's entitlements on the MISO system (PJM does not pay for its use up to its entitlement).

iv. Finally, $245 million of congestion value was unpriced in 2011 due to a "constraint relaxation" algorithm that is discussed later in this section.

B. FTR Obligations and Funding

In the MISO market, the economic value of transmission capacity is reflected in FTRs. FTR holders are entitled to congestion costs collected in the day-ahead market between the source and sink locations that define a particular FTR. Hence, FTRs allow participants to manage day-ahead price risk from congestion. FTRs are distributed through an annual allocation process as well as through seasonal and monthly auctions.

Prior to June 2008, most FTRs were allocated based on the physical usage of the system. Since then, most transmission rights have been auctioned seasonally while the rights to the associated auction revenue are allocated via Auction Revenue Rights (ARRs). Holders of ARRs may receive the auction revenue or self-schedule the ARRs to receive the underlying FTRs. MISO sells the rights to residual transmission capacity that is not sold in the seasonal auction in monthly auctions. This also affords participants an opportunity to trade monthly obligations for seasonal rights.

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.[26] Congestion revenues collected in MISO's day-ahead market fund FTR obligations. Surpluses and shortfalls are expected to be limited when participants hold FTR portfolios that match power flows over the transmission 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.[27] During each month, MISO will 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 any remaining FTR shortfalls.

When MISO sells FTRs that reflect different transmission capability than what is ultimately available in the day-ahead market, shortfalls occur if it sells too many FTRs or surpluses occur if it sells too few FTRs. Reasons for differences between FTR capability and day-ahead capability 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 modeled in the day-ahead market to differ from capability assumed when FTRs were allocated or sold.

- Generators and loads outside the MISO region can contribute to loop flows that use more or less transmission capability than what is assumed in the FTR market model. Unanticipated loop flows are a problem because MISO collects no congestion revenue

26 An FTR obligation can be in the "wrong" direction (counter flow) and can require a payment from the FTR holder.
27 The day-ahead model includes assumptions on loop flows that are anticipated to occur in real time.

from transactions that cause it. If MISO allocates FTRs for the full capability of its system, the loop flow can create an FTR revenue shortfall.

MISO has continued to work on FTR and ARR allocation processes. In early 2010, it implemented new tools and procedures to the FTR modeling process, as well as more conservative assumptions on transmission derates in the auction model, to better approximate day-ahead and real-time conditions. These changes have reduced underfunding. Additional process changes and improvements in 2011 include better constraint forecasting and identification procedures; more complete modeling of the lower-voltage network; and improved modeling of radial-constraint limits.

Figure A54: Day-Ahead Congestion Revenue and Payments to FTR Holders

Figure A54 compares monthly day-ahead congestion revenues to FTR obligations for 2009 to 2011. The top panel shows the FTR funding shortfall or surplus in each month. Shortfalls are undesirable because they introduce uncertainty and can distort FTR values. Funding surpluses are similarly unwelcome because they indicate that the capability of the transmission system was not fully available in the FTR market.

Figure A54: Day-Ahead Congestion Revenue and Payments to FTR Holders
2009–2011

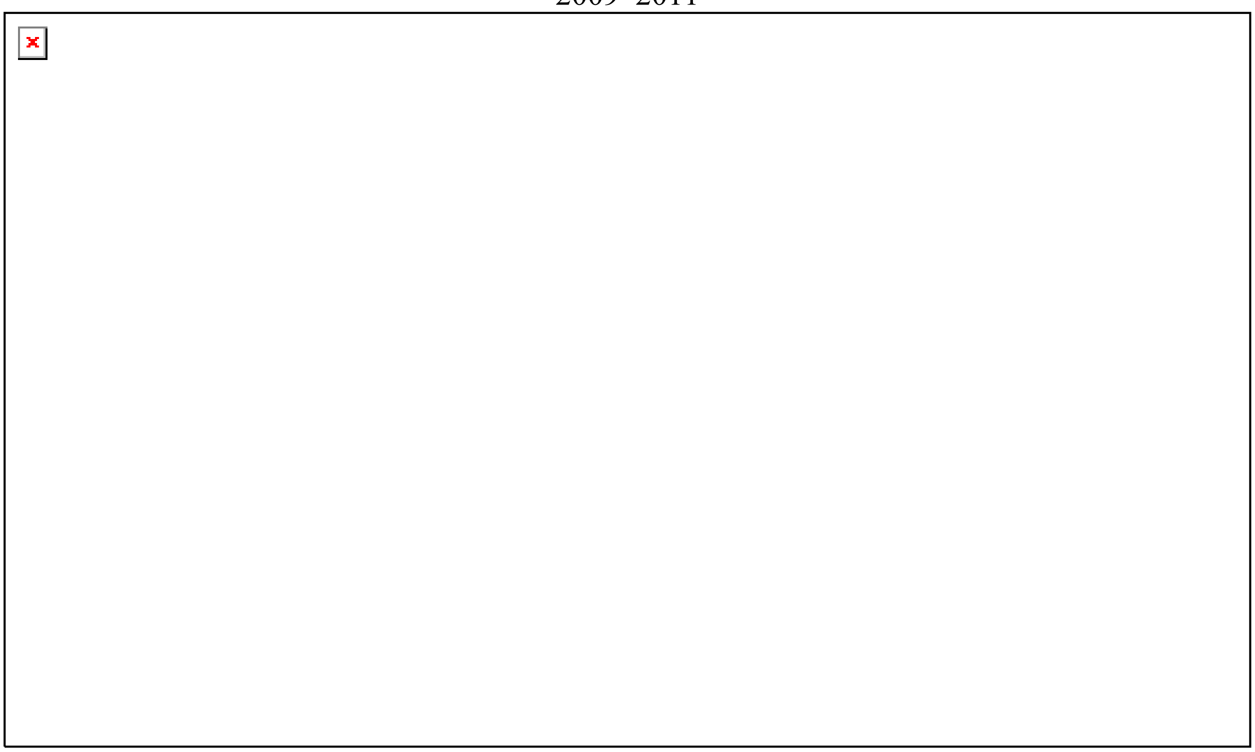


Figure A55: Day-Ahead Congestion Revenue and Payments to FTR Holders

Figure A55 compares monthly total day-ahead congestion revenues to monthly total FTR obligations in 2011 by type of constraint (e.g., internal, market-to-market, or external). Like the prior figure, the top panel shows the FTR funding shortfall or surplus in each month.

Figure A55: Day-Ahead Congestion Revenue and Payments to FTR Holders
2011

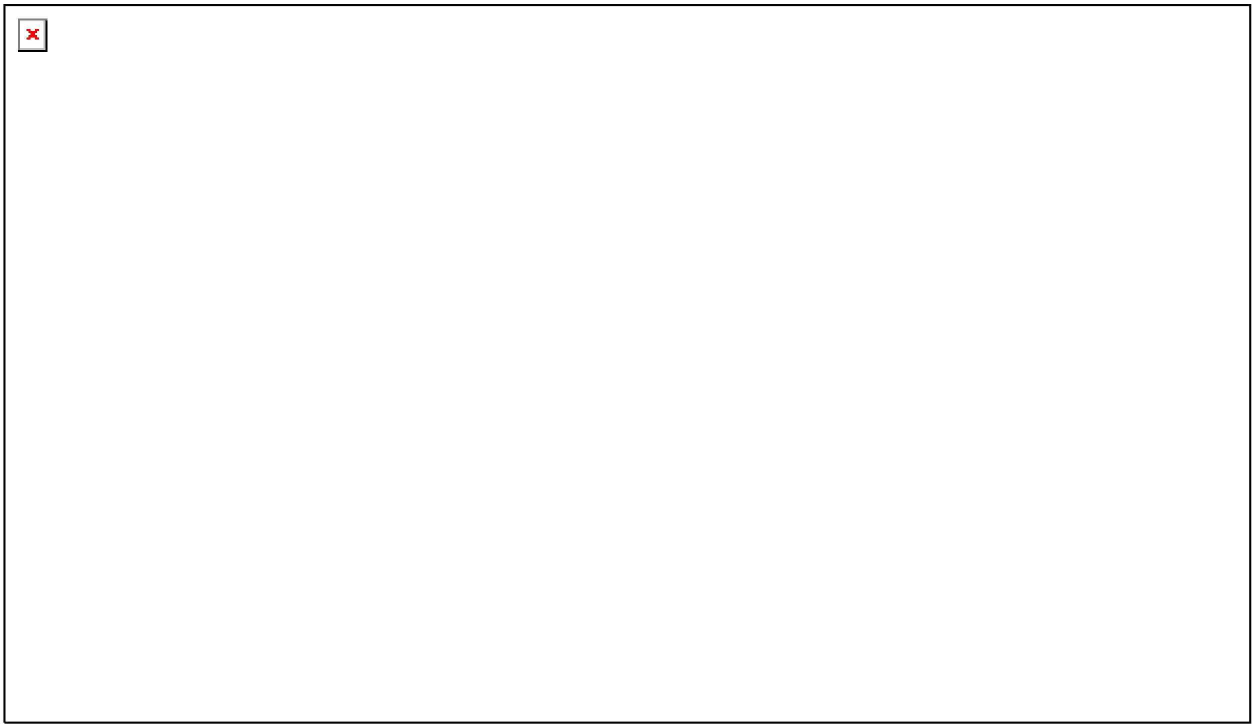


Figure A56: Payments to FTR Holders

In order to protect entities with transmission arrangements that predate the market, MISO established Grandfathered Agreements (GFAs). 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 (known as “Option B”) and rebates to “Carve-Out” GFAs. These only comprise a small portion of total transmission rights and do not provide the same incentives as conventional FTRs do.

Figure A56 shows monthly payments and FTR obligations, along with Option B and day-ahead and real-time Carve-Out rebates. The figure also shows the funding shortfall in each month.

Figure A56: Payments to FTR Holders
2010–2011

Key Observations: Congestion Costs and FTR Obligations

i. For the first time, MISO's annual congestion revenue day-ahead exceeded its FTR obligations so FTRs were fully funded.

- The improvement in FTR funding was modeling and procedural improvements made by MISO in 2010, as will as further improvements in 2011.
- The change in funding is largest in June 2010 and June 2011 due to the changes in annual auction results that started in those months.
- The improvements in 2011 included better procedures for modeling planned and forced transmission outages, as well as a more complete modeling of lower-voltage branches of the network in the FTR market.

ii. Significant overfunding can be of potential concern if the underlying assumptions in the FTR market become too conservative.

i. M2M constraints were over-funded by nearly 25 percent in 2011, suggesting that MISO may not be selling all of the transmission capability of these constraints.

v. Other forms of transmission rights exist in MISO that were established to account for grandfathered transmission agreements that existed when the markets were implemented.

- Roughly 90 percent of the day-ahead congestion revenue was used to fund FTRs in 2011, with most of the balance used to fund the other grandfathered rights.

- It is important that a high percentage of day-ahead congestion continue to be paid to FTRs because the other transmission rights do not provide the same efficient incentives as FTRs.

C. Value of Congestion in the Real-Time Market

This section reviews the value of real-time congestion, rather than collected congestion costs. As discussed previously, the value of congestion is defined as the marginal value (e.g., shadow price) of the constraint times the power flow over the constraint. If the constraint is not binding, the shadow price and congestion value will be zero. This indicates that the constraint is not affecting the economic dispatch or increasing production costs.

Figure A57: Value of Real-Time Congestion by Coordination Region

Figure A57 shows the total monthly value of real-time congestion by region and the average number of binding constraints per interval in 2010 and 2011. The bars on the left of the show the average monthly value in each year from 2009 to 2011.

Figure A57: Value of Real-Time Congestion by Coordination Region
2010–2011

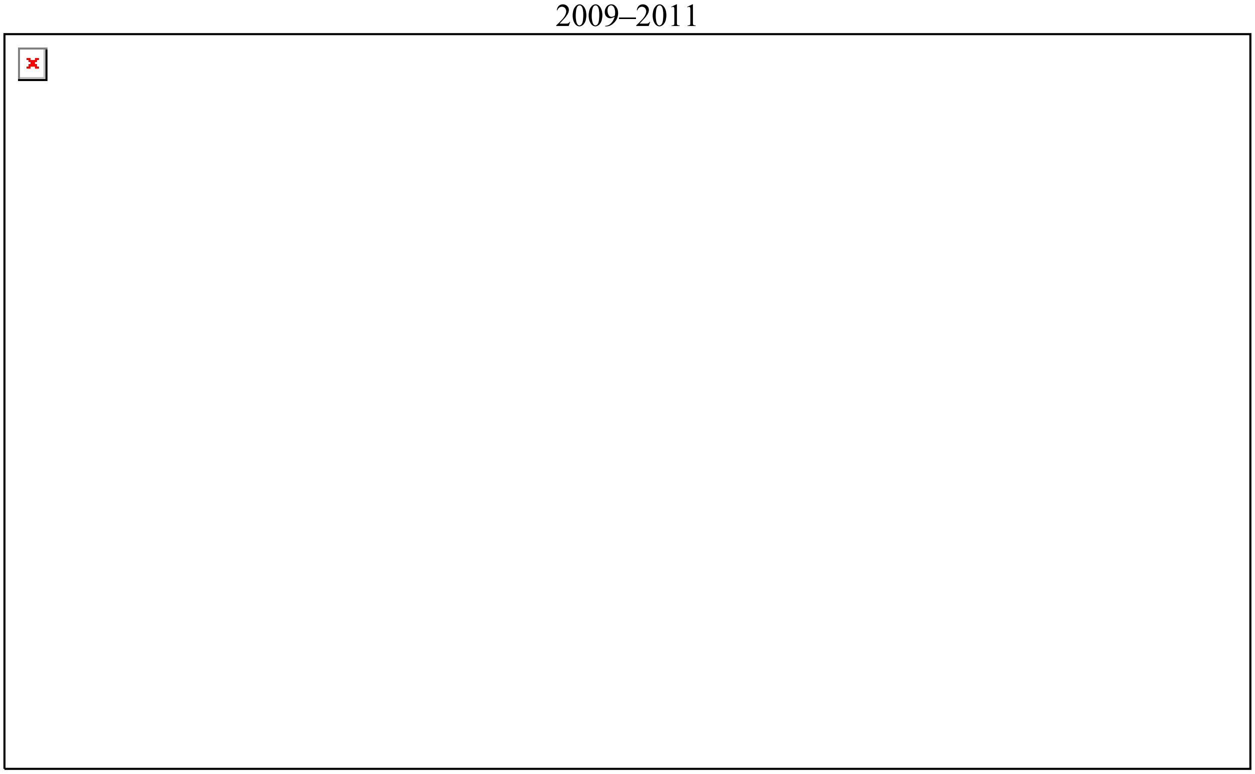
Figure A58: Value of Real-Time Congestion by Type of Constraint

To better identify the nature of constraints and the congestion value, Figure A58 disaggregates the results by type of constraint. We define four constraint types:

- Internal Constraints. Those constraints internal to MISO (where MISO is the reliability coordinator) and not coordinated with PJM.
- MISO M2M Constraints. MISO-coordinated market-to-market constraints. Many of these are substantially impacted by generation in the Commonwealth Edison (ComEd) area of PJM.
- PJM M2M Constraints. PJM-coordinated market-to-market constraints.
- External Constraints. 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. These include PJM constraints that are not market-to-market constraints.

The flow on PJM M2M constraints and on external constraints represented in the MISO dispatch is only the MISO market flow, whereas internal or MISO market-to-market constraints includes the total flow. Including only the market flow therefore reduces the estimated value of congestion on these constraints.

Figure A58: Value of Real-Time Congestion by Type of Constraint
2009–2011



Key Observations: Congestion Value

i. Congestion value increased 20 percent in 2011 to $1.24 billion, two-thirds of which occurred on internal constraints.

 - Much of the increase occurred on M2M constraints that bound more often than in previous years, particularly in the Central region (congestion rose 44 percent).

 - In addition, constraints in the West region bound more frequently than they did in 2010 because of an increase in wind generation, and increase in DIR participation (prior to DIR, the manual curtailments would not be reflected in binding constraints), and because MISO in 2011 controlled a greater number of low-voltage constraints.

 - Wind output increased 30 percent to 3.0 GW. The introduction of the DIR type in June 2011 has made congestion there more manageable.

ii. April and May had the highest quantities of congestion. Unusually cold weather and outages led to high congestion into Minnesota in April, while unusually hot weather at the end of May led to substantial congestion and very tight conditions in eastern areas.

iii. Although the congestion value on external flowgates is relatively small, their shadow prices and price impacts can be significant. MISO continues to receive obligations on external flowgates when their total market flow is in the reverse (opposite to the prevailing flow) direction.

 - MISO is working with NERC and other RTOs to address this issue. In such cases small relief obligations (based on forward direction flows rather than net flows) can cause significant price and market settlement impacts.

D. Transmission Line Load Relief Events

With the exception of market-to-market coordination between MISO and PJM, MISO and other reliability coordinators in the Eastern Interconnect continue to rely on TLR procedures and the NERC Interchange Distribution Calculator (IDC) to manage congestion that is caused in part by schedules and the dispatch activity of external entities.

Before energy markets were introduced in 2005, nearly 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 obtain relief from entities in other areas that have scheduled transactions that load the constraint. When an external (non-PJM market-to-market) constraint is binding and a TLR is called, MISO receives a relief obligation from the IDC. MISO responds by activating the external constraint so that the real-time dispatch model will redispatch its resources to reduce MISO's market flows over the constrained transmission facility by the amount requested. On MISO flowgates, external entities not dispatched by MISO can also contribute to total flows. If external transactions contribute more than five percent of their total flow on a MISO binding facility, MISO can invoke a TLR to ensure that these transactions are curtailed to reduce the flow over the constrained facility.

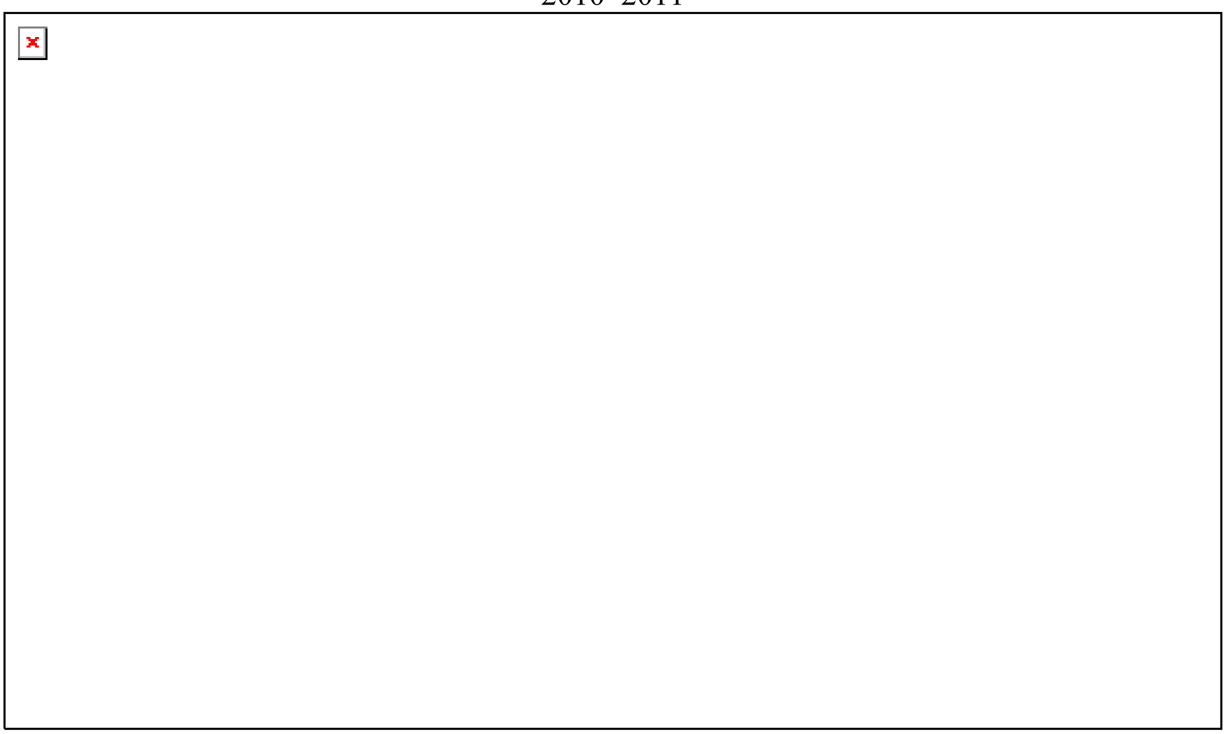
When compared to the economic generation dispatch through LMP markets, the TLR process is an inefficient and rudimentary means to manage congestion. TLR provides less timely and certain control of power flows over the system. We have found in prior studies that the TLR process resulted in approximately three times more curtailments on average than would be required by economic redispatch.

Figure A59: Periodic TLR Activity

Figure A59 shows monthly TLR activity on MISO flowgates in 2010 and 2011. The top panel of the figure shows quantities of scheduled energy curtailed by MISO in response to TLR events called by other RTOs. The bottom panel of the figure provides hourly TLR activity called by MISO, shown by the various TLR levels. NERC's TLR levels include:

- Level 3 – Non-firm curtailments;[28]
- Level 4 – Commitment or redispatch of specific resources or other operating procedures to manage specific constraints; and
- Level 5 – Curtailment of firm transactions.[29]

Figure A59: Periodic TLR Activity
2010–2011



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

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

Key Observations: TLR Events

i. MISO's TLR activity continued to decline in 2011. The number of curtailed hours and flows both decreased considerably from prior years.

ii. In April and again in October, MISO's difficulties managing the Manitoba interface required over 400 hours of TLR activity.

E. Congestion Manageability

Congestion management is among MISO's most important roles. It monitors thousands of potential network constraints throughout MISO using its real-time market model to maintain flow on each activated constraint at or below the operating limit while minimizing total 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. This causes MISO's energy market to economically alter the dispatch of generation that affects the transmission constraint, especially those with high Generation Shift Factors (GSFs). While this is intended to reduce the flow on the constraint, some constraints can be difficult to manage if the available relief from the generating resources 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, or "EcoMax").

When available relief capability is insufficient to control the flow over the transmission line in the next five-minute interval, we refer to the transmission constraint as "unmanageable". The presence of an unmanageable constraint does not mean the system is unreliable, since MISO's performance criteria allow for twenty minutes to restore control on most constraints. If control is not restored within thirty minutes, a reporting criterion to stakeholders is triggered. Constraints most critical to system reliability (e.g., constraints that could lead to cascading outages) are operated more conservatively. When a constraint's flow exceeded its limit in 2011, an algorithm was used to "relax" the limit of the constraint to calculate a shadow price and the associated LMPs. This relaxation algorithm was discontinued in February 2012 on internal constraints that are not jointly managed with PJM.

Figure A60: Constraint Manageability

The next set of figures show manageability of internal and MISO-managed market-to-market constraints. Figure A60 shows how frequently binding constraints were manageable and unmanageable in each month from 2010 to 2011.

Figure A60: Constraint Manageability
2010–2011

Figure A61-62: Value of Real-Time Congestion by Voltage Level

Given the frequency with which constraints are unmanageable, it is critical that unmanageable congestion is priced efficiently and reflected in MISO's LMPs. The real-time market model utilizes Marginal Value Limits (MVLs) that cap the marginal cost (i.e., the shadow price) that the energy market will incur to reduce constraint flow to its limit. In order for the MISO markets to perform efficiently, the MVL must reflect the full reliability cost of violating the constraint.

When the constraint is violated (i.e., unmanageable), the most efficient shadow price would be the MVL of the violated constraint. This produces an efficient result because it impacts the affected LMPs according to MISO's perceived value of constraint reliability. However, the constraint relaxation algorithm described earlier in this subsection often produces 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. No economic rationale supports setting prices on the basis of relaxed shadow prices.

Figure A61 and Figure A62 examine manageability 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.

Figure A61 separately shows the value of real-time congestion on constraints that are not in violation, the congestion that is priced when constraints are in violation, and the congestion that is not priced when constraints are in violation. The unpriced congestion is based on the difference between the value of the constraint (i.e., the MVL) and the relaxed shadow price used to calculate prices.

Figure A61: Value of Real-Time Congestion by Type of Constraint
2011

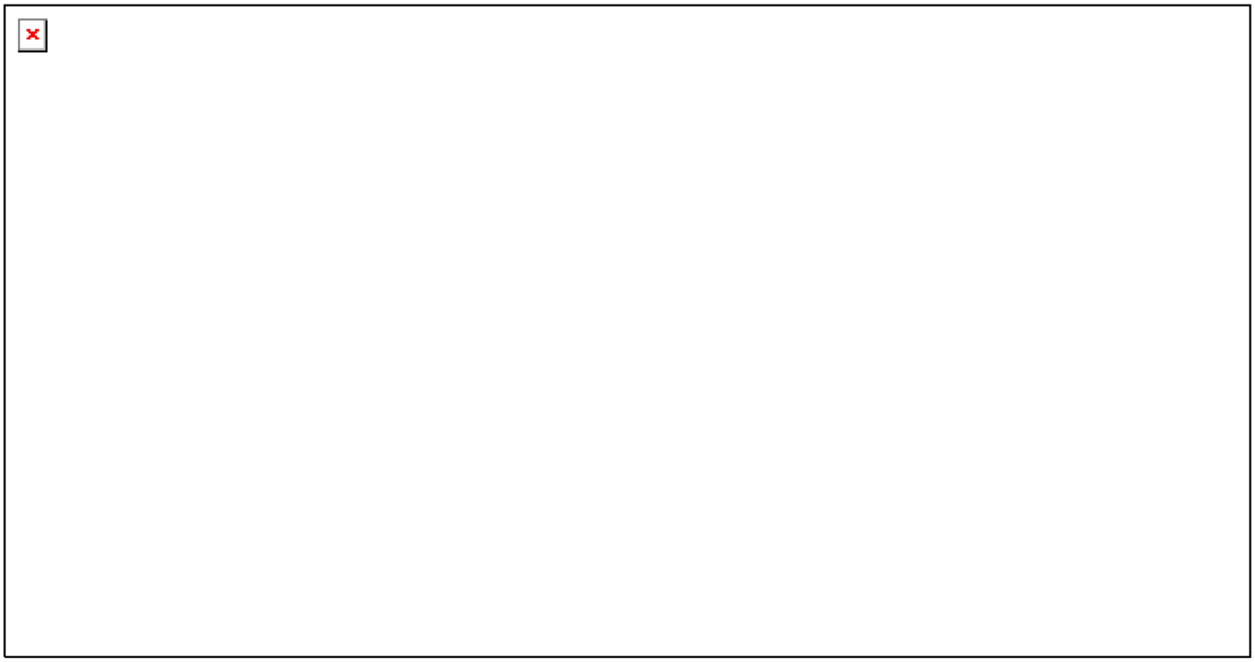


Figure A62: Pricing of Unmanageable Congestion by Voltage Level

The efficiency cost of constraint relaxation is determined by the difference between the relaxed shadow price and the MVL. Figure A62 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. Ultimately, this adversely affects the commitment and scheduling the day-ahead market and the longer-term incentives to invest in constrained areas.

Figure A62: Value of Real-Time Congestion by Type of Constraint
2011

Because the multi-settlement system provides financial incentives for participants to arbitrage the day-ahead and real-time prices, a pricing flaw in the real-time market can lead to inefficient day-ahead market outcomes as well. With regard to constraint relaxation, the implication is that the day-ahead market will not efficiently value congestion on constraints frequently relaxed in the real-time market. Therefore, the generating resources committed through the day-ahead will not provide adequate relief capability to manage the real-time constraint. 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 committed in the day-ahead and therefore not available in the 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 revenues 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.

In addition to constraint relaxation, we also identified an operating algorithm called the "transmission deadband" that contributed to a substantial share of the unmanageable congestion. The deadband is a constraint-specific amount (most commonly two percent) set by MISO operators that reduces the limit after a constraint initially binds. For example, if a constraint is activated and binds at its 200 MW physical limit, MISO's real-time dispatch software will reduce the limit to 196 MW in the subsequent market interval. The UDS dispatch model does not know that the limit is going to change in the following interval, so it does nothing to prepare to manage the constraint at the lower limit. While the constraint continues to bind, the limit will remain at deadband-adjusted (e.g. 196 MW) level. Once the constraint unbinds for one market interval, the deadband adjustment is removed and the limit returns to its initial value.

The original intent of the deadband was to limit the frequency with which constraints would bind and then immediately unbind—it was thought that this could result in LMP and generator dispatch volatility. This section evaluates whether the deadband is contributing significantly to unmanageable congestion.

Figure A63: Constraint Violations Resulting from Deadband Limit Adjustments

Figure A63 shows the frequency with which constraints during binding periods were violated in 2011. These constraint violations are differentiated between periods when the constraint flow was above or below the "original" limit, which is the effective limit controlled to in the first binding period. Since the deadband reduces the flow after the first binding period and thereafter, there are no violations below-the-original-limit in the first interval.

Figure A63: Contraint Limit Violations
2011

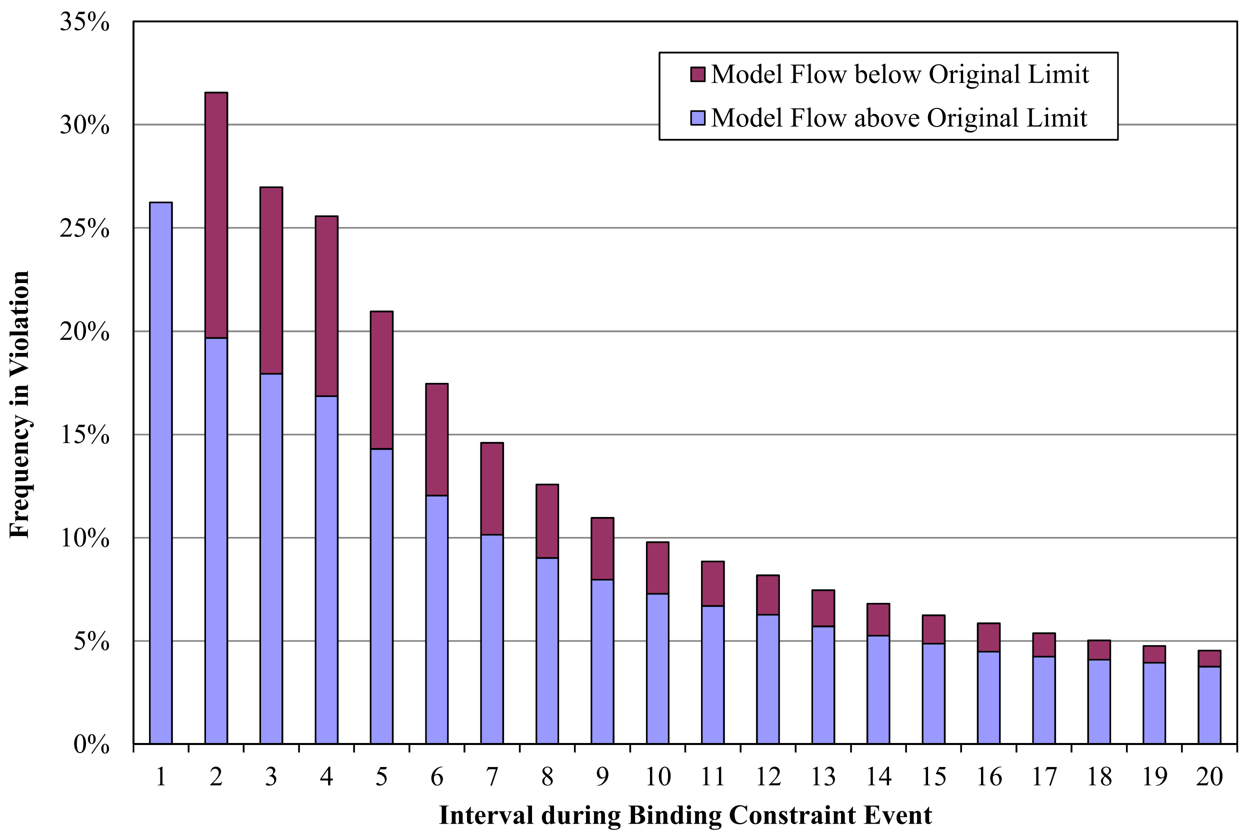
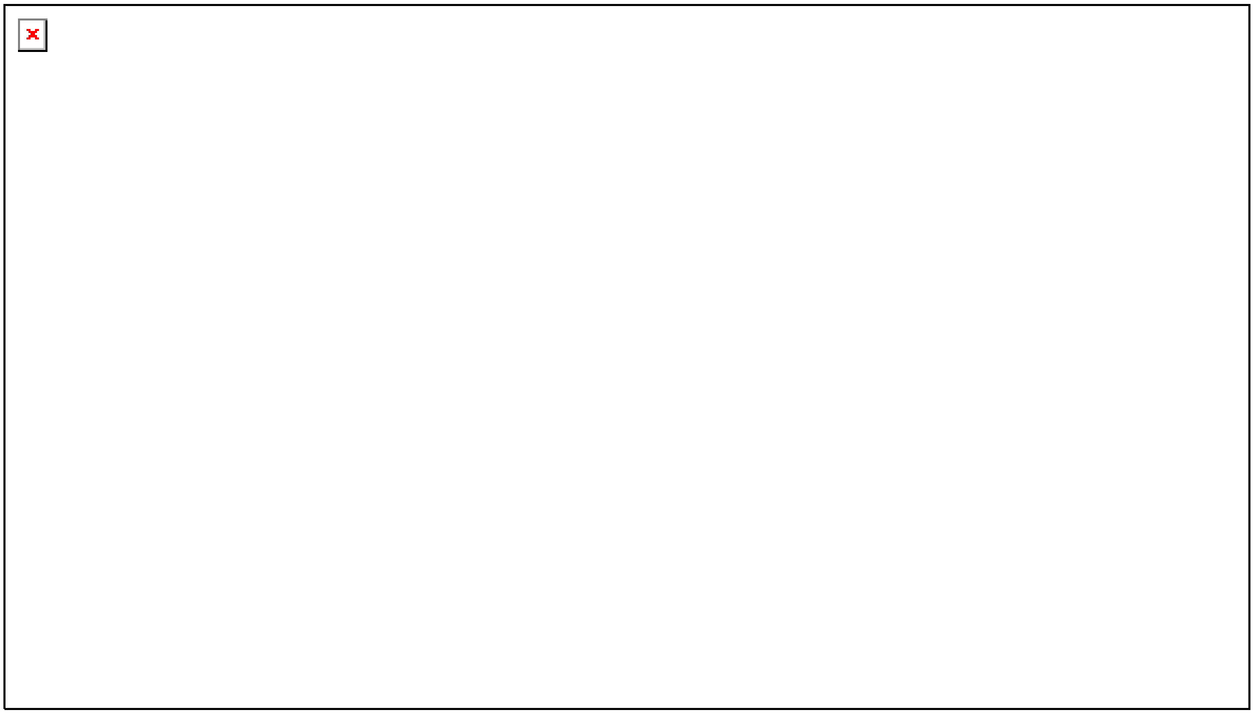


Figure A64: Deadband Impact on Unmanageable Congestion by Voltage Class

The next figure evaluates the congestion impact of deadband limit adjustments. The blue-shaded bars indicate the congestion value on unmanageable constraints that would have been accrued if constraint relaxation were turned off in these historical periods. Since constraint relaxation was deactivated for non-market-to-market constraints on February 1, 2012, this value provides a forecast of the congestion impact of the deadband going forward.

Figure A64: Congestion on Unmanageable Constraints
2009–2011



In addition to the cost calculated in the prior figure, there are additional congestion costs of the deadband that result from higher shadow prices on manageable constraints. These costs result from the increased redispatch necessary to control to lower deadband-adjusted limits. IMM case studies estimate that this shadow price impact, which is partially offset by higher flows but-for the deadband, doubles congestion costs when the deadband adjustment is put into effect in the interval after initial constraint binding.

Figure A65: Constraint Shadow Price Volatility – April 2012 Case Studies

Figure A65 and Figure A66 show the results of a series of over 300 case studies performed during the week of April 22, 2012. In these studies, we re-executed the real-time market dispatch software after disabling the deadband for constraints entering the second interval of a binding period to assess pricing and dispatch impacts. These "test" case results were then compared to "base" case outcomes to determine shadow price and specific generator dispatch differences.

Figure A65: Constraint Shadow Price Volatility
April 2012 Case Studies

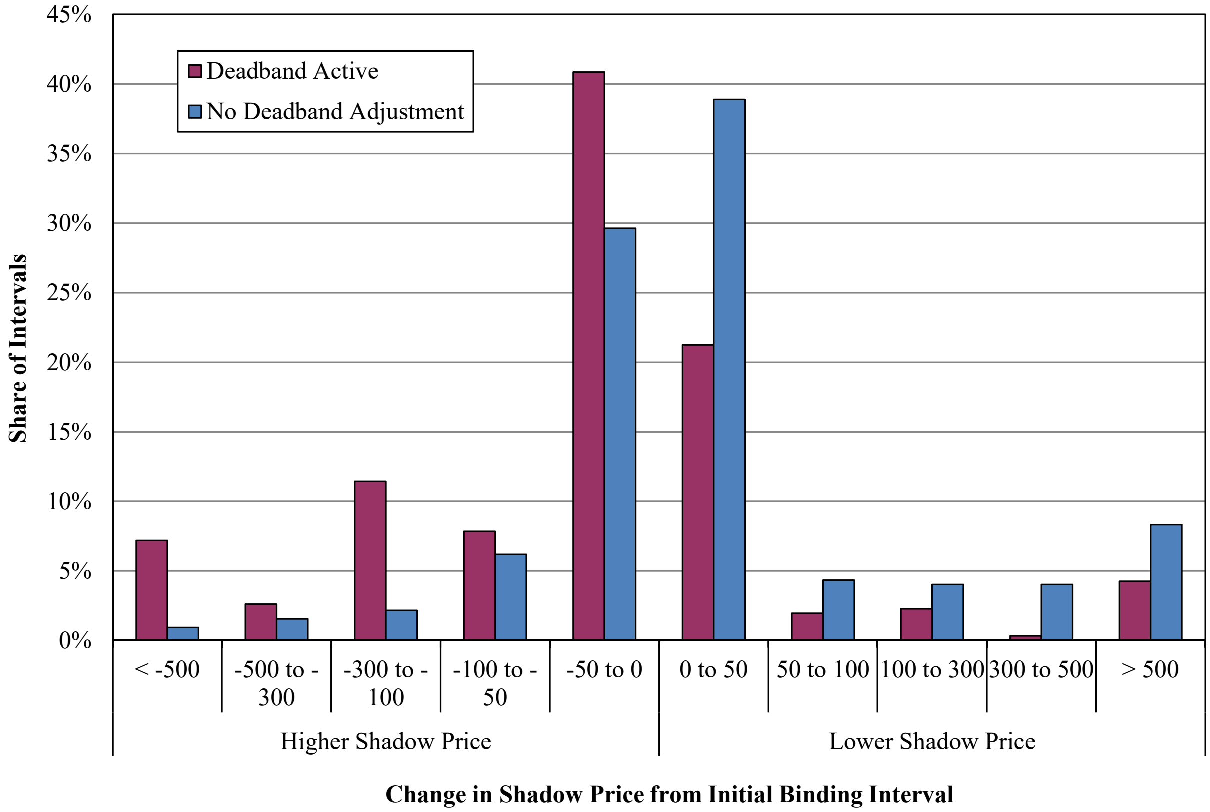
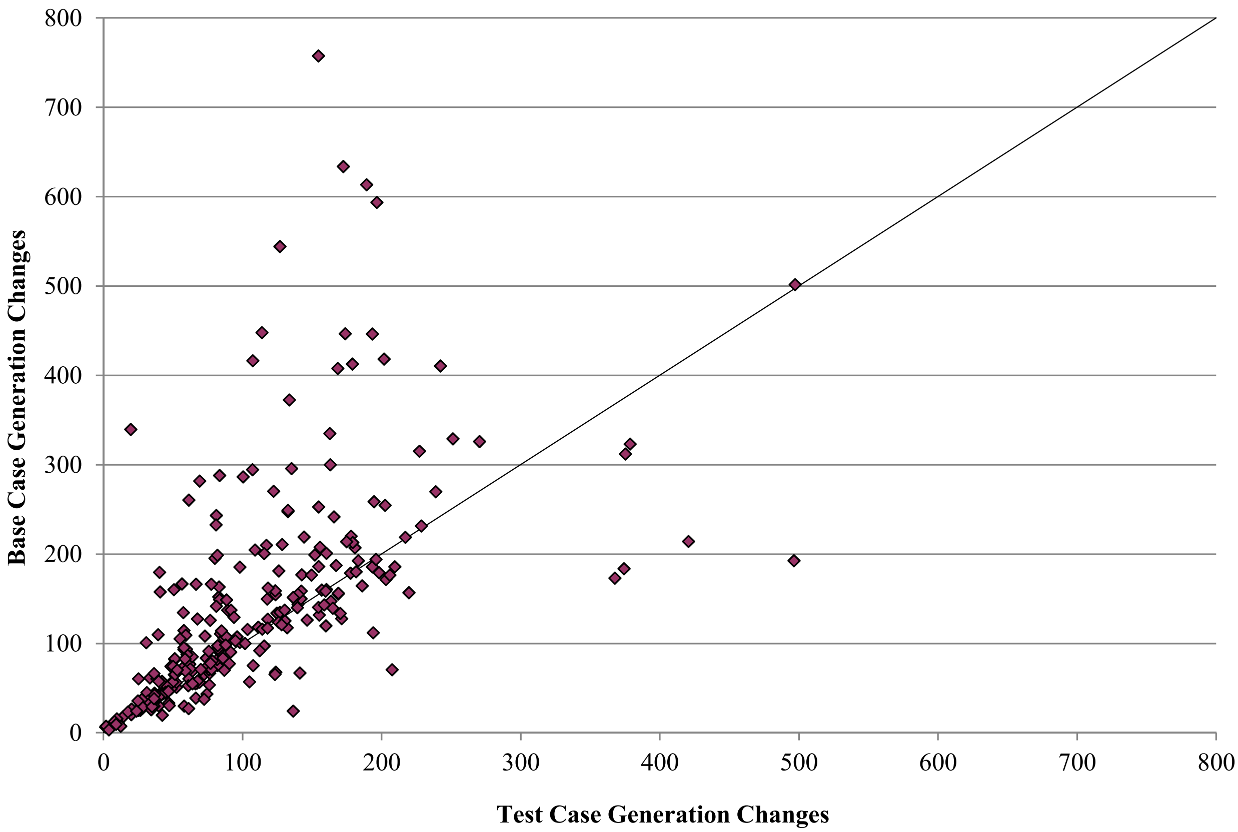


Figure A66: Generator Dispatch Volatility – April 2012 Case Studies

The next figure presents the market-wide changes in generator dispatch found in the case study. We summed the absolute dispatch point differences from the initial period dispatch for all generators that had different output levels in the base and test cases. We eliminated any dispatch changes that were identical in the base and test cases and, therefore, unrelated to the deadband issue.

Data points in the upper-left section of the chart indicate more dispatch volatility in the base case; whereas, points in the lower-right half indicate more volatility in the test (deadband-deactivated) case.

Figure A66: Generation Dispatch Volatility
April 2012 Case Studies



Key Observations: Congestion Manageability

i. Roughly $245 million of congestion value was unpriced in 2011 due to a "constraint relaxation" algorithm that sets the congestion value of a constraint when it is in violation.

– In order for the MISO markets to perform efficiently, the LMPs must reflect the full value of a constraint when it is violated.

– Instead, many unmanageable constraints in 2011 were priced well below their true value—they were relaxed to zero in a quarter of the instances when a constraint was violated (so the LMPs would not reflect the unmanageable congestion).

– In early 2012, MISO disabled this algorithm for non-M2M constraints.

ii. We recommend MISO disable this algorithm on all constraints because it distorts the congestion signals provided by real-time prices, undermines the efficiency of the day-ahead prices and commitments, and adversely affects longer-term market decisions.

iii. The most difficult constraints to manage are the lowest voltage constraints.

- We recommend MISO continue to work with transmission owners to return functional control of low voltage constraints which are better managed by the TO.

iv. Approximately 30 percent of the unmanageable congestion was the result of the transmission deadband that caused a constraint to appear to be violated (i.e., when the flow was less than the original transmission limit, but higher than the deadband-adjusted limit).

- The deadband accounted for $140 million in unmanageable congestion and more than 19 percent of all congestion in MISO in 2011.
- The deadband is actually increasing volatility because the unmanageable congestion it causes generally results in sharp LMP changes.
- It inefficiently reduces the utilization of the transmission system by causing constraints to bind at levels less than their physical capability.
- We are unaware of any other RTO that currently employs a transmission deadband and recommend that MISO discontinue its use.

v. The transmission constraint deadband was responsible for 30 percent of all violated constraints in 2011. In these cases, the constraint flow could have been controlled at the original (pre-deadband) limit.

- With no relaxation of the constraints, we estimate that the deadband alone accounted for $130 million in real-time congestion value.
- Most, but not all, of this congestion would be eliminated if the deadband were discontinued.

vi. The case study results found that in 70 percent of intervals, the deadband base case shadow price was greater than the shadow price during the first binding.

- Without the deadband, the shadow price increased in only 40 percent of intervals.

vii. In two-thirds of our case study intervals, generation dispatch changes were greater when the deadband limit adjustment was in effect.

F. FTR Auction Prices and Congestion

A well-functioning FTR 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.

Figure A67 and Figure A68: FTR Profitability

The next two figures show the profitability of FTRs purchased in the seasonal and monthly FTR auctions, respectively. The bottom panels show the total profits and losses, while the top panel shows the profits and losses per MWh.

The results in Figure A67 and Figure A68 include FTRs sold as well as purchased. FTRs sold are netted against FTRs purchased. For example, if an FTR purchased in round 1 of the annual auction is sold in round 2, the purchase and sale of the FTR in round 2 would net to zero.

Figure A67: FTR Profitability
2009–2011: Seasonal Auction

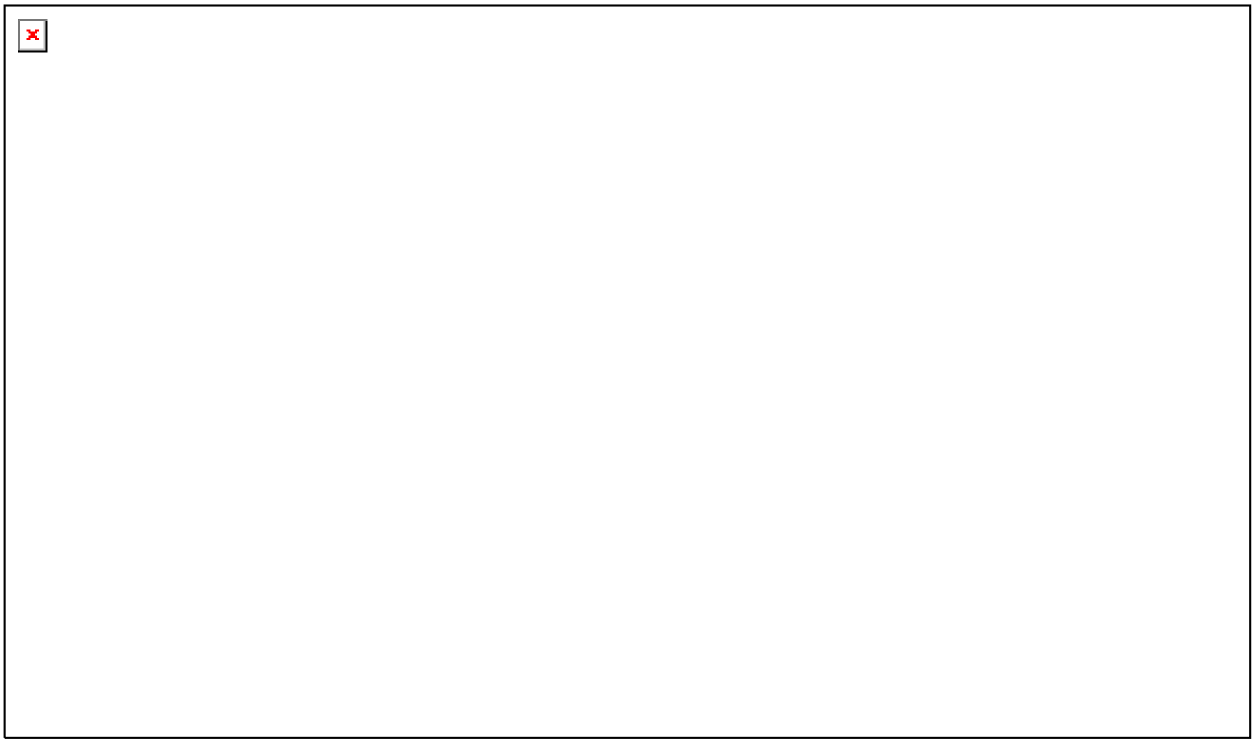


Figure A68: FTR Profitability
2010–2011: Monthly Auction

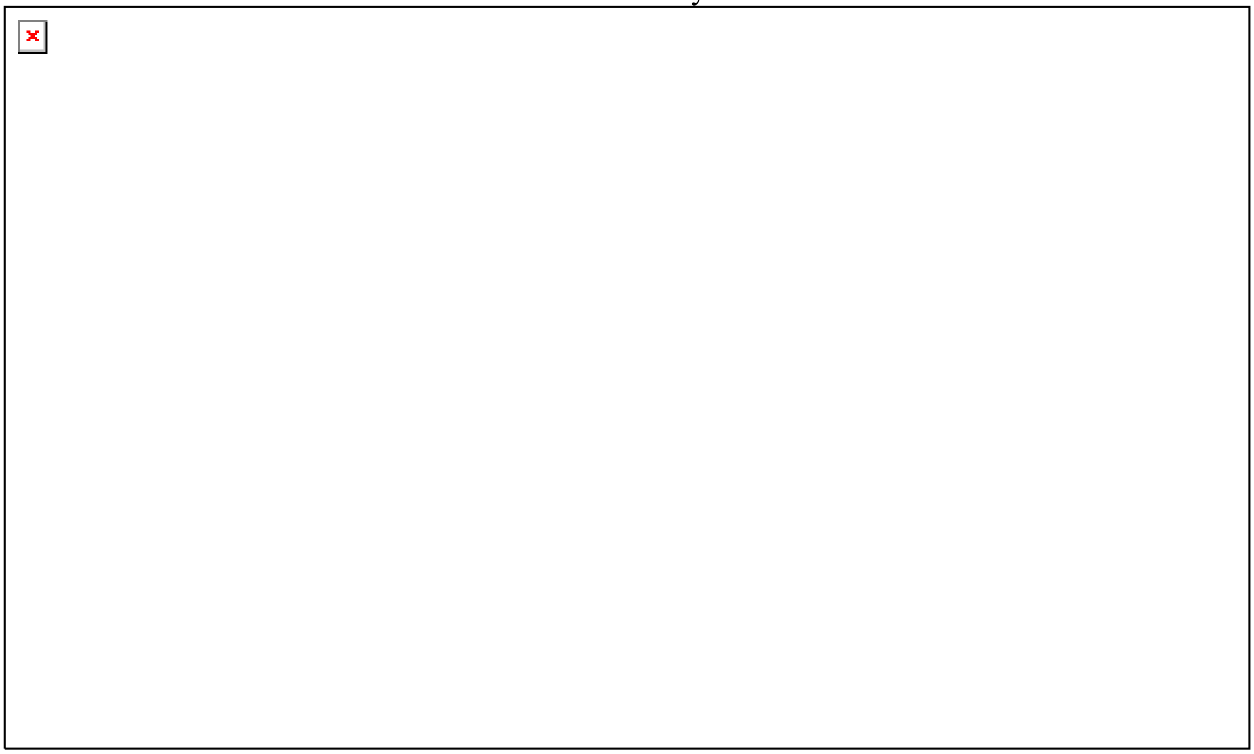


Figure A69 to Figure A74: Comparison of FTR Auction Prices and Congestion Value

The next six figures examine 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 between prices and congestion values should generally be small in a well-functioning market. However, one would expect them to generally reflect a one-month lag because of the auction timing.

We analyze values for the WUMS Area, the Minnesota Hub, and the Michigan Hub relative to Cinergy Hub, which was the most actively-traded location in MISO in 2011. Results are shown separately for peak and off-peak hours.

Figure A69: Comparison of FTR Auction Prices and Congestion Value
WUMS Area, 2010–2011: Peak Hours

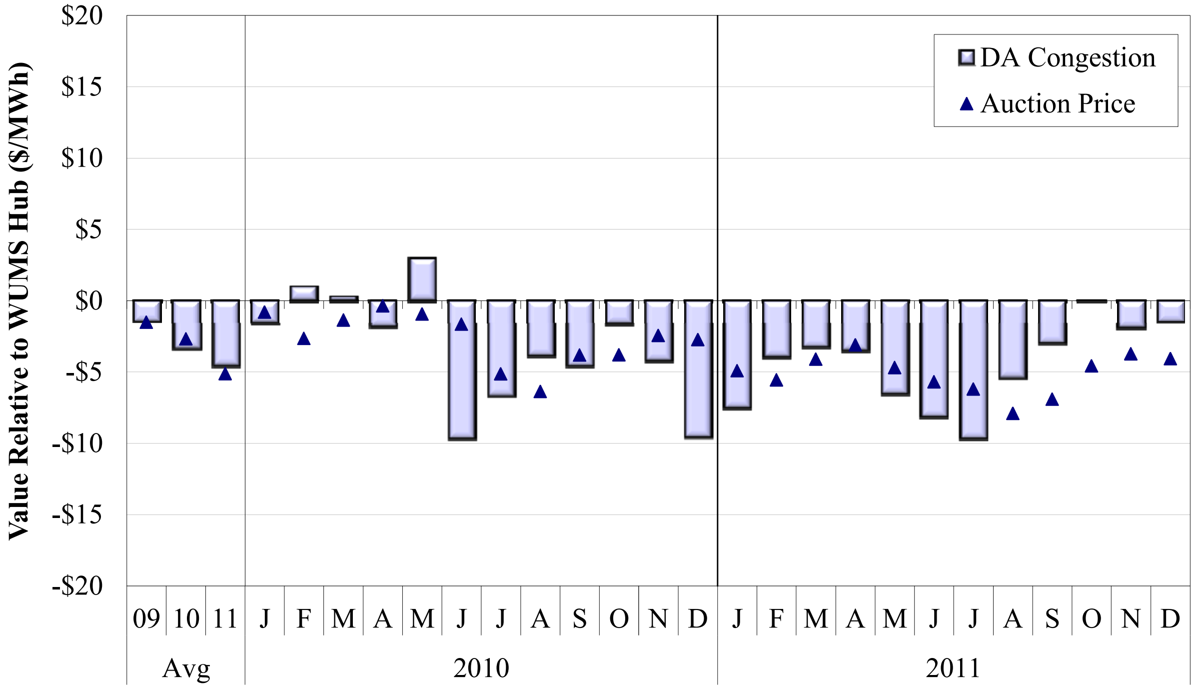


Figure A70: Comparison of FTR Auction Prices and Congestion Value
WUMS Area, 2010–2011: Off-Peak Hours

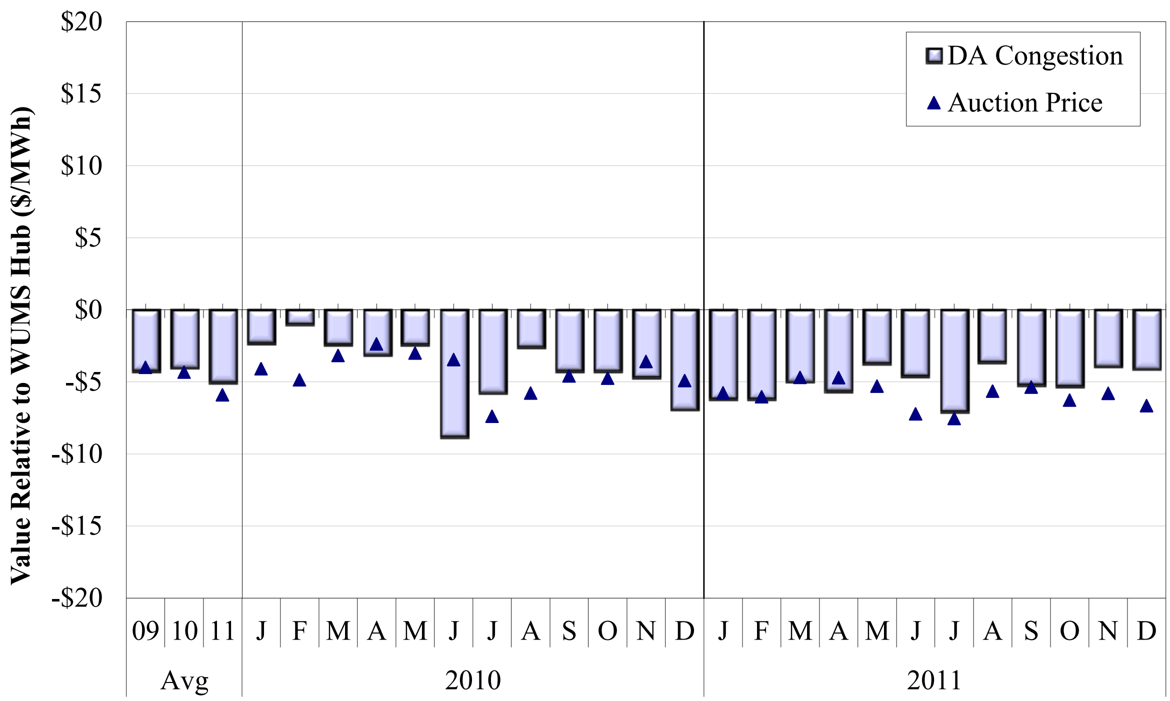


Figure A71: Comparison of FTR Auction Prices and Congestion Value
Minnesota Hub, 2010–2011: Peak Hours

Figure A72: Comparison of FTR Auction Prices and Congestion Value
Minnesota Hub, 2010–2011: Off-Peak Hours

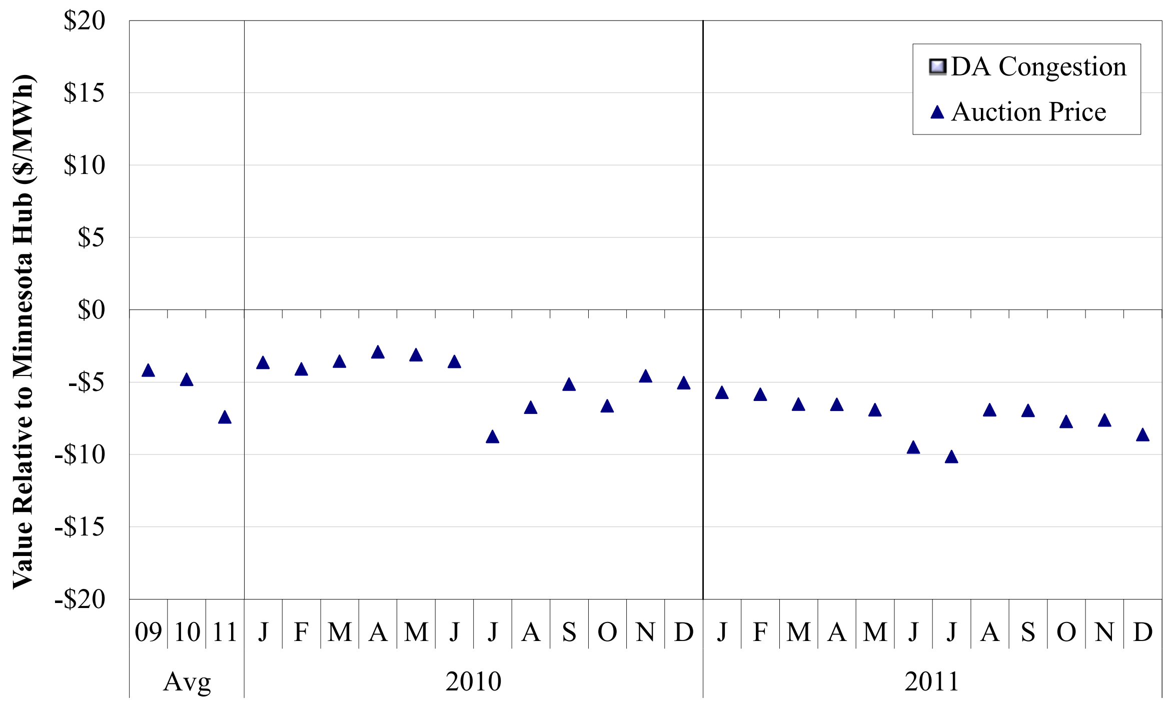


Figure A73: Comparison of FTR Auction Prices and Congestion Value
Michigan Hub, 2010–2011: Peak Hours

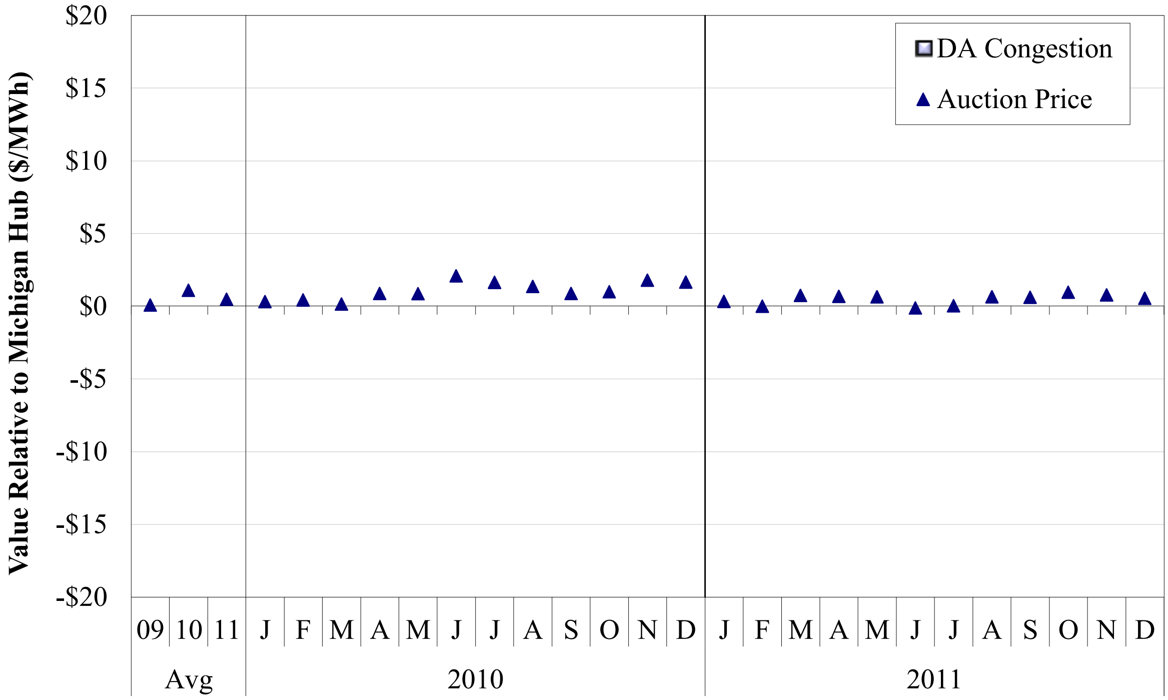
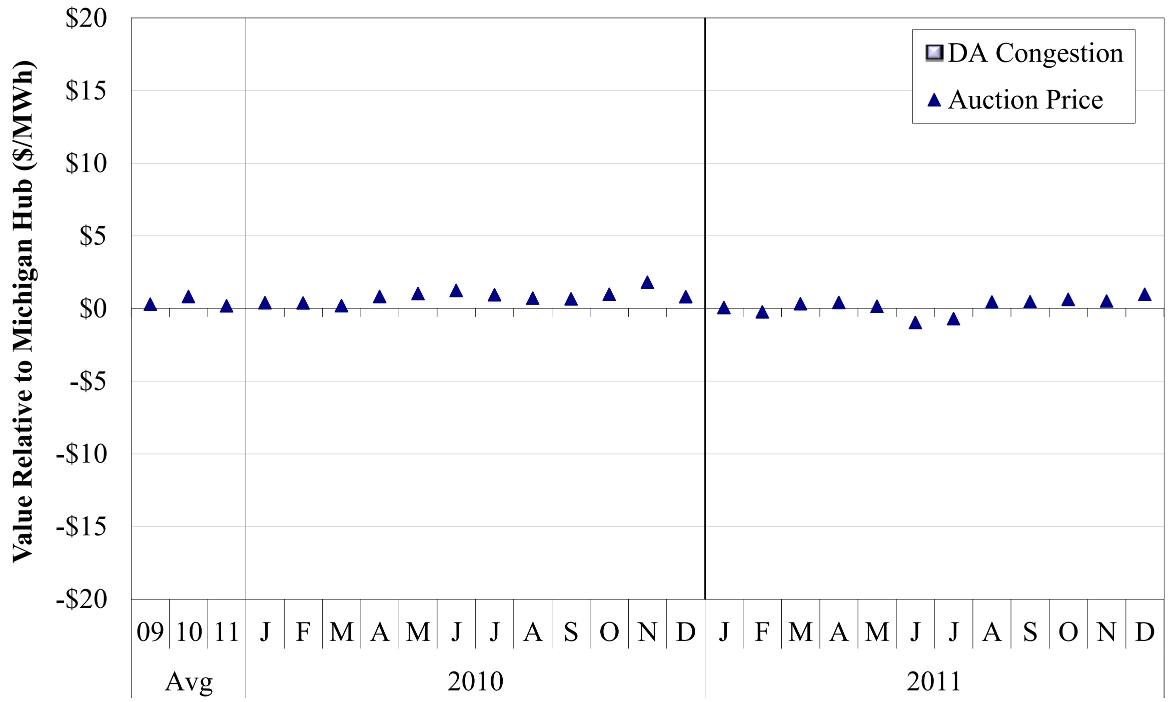


Figure A74: Comparison of FTR Auction Prices and Congestion Value
Michigan Hub, 2010–2011: Off-Peak Hours



Key Observations: FTR Auction Prices

i. In 2011, FTR profitability were very low – FTR profits averaged $0.15 per MWh, down from $0.36 in 2010.

ii. Monthly FTR prices generally responded to changes in congestion patterns quickly, usually in the following month.

- The principle exception was the peak-hour congestion out of the West region, which eased in the second half of 2011.

iii. Profitability of FTRs in spring 2010 was unusually high, which was due in part to significant outage-related congestion into Michigan that was not fully anticipated in the FTR auction.

G. Market-to-Market Coordination with PJM

The JOA between MISO and PJM establishes a market-to-market process for coordinating congestion management of designated transmission constraints on each of the RTO's systems. The process provides congestion management relief on coordinated flowgates in a least-cost manner and ensures efficient generation dispatch on these constraints and that prices are consistent between the markets.

Under the terms of the JOA when a market-to-market 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. 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, although it can yield at times inaccurate relief values. As such, gradual improvements continue to be made by both RTOs.

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 market-to-market constraints. Settlements are made between the RTOs based on their actual flows over the constraint relative to their entitlements.

Figure A75: Market-to-Market Events

Figure A75 shows the total number market-to-market constraint-hours (i.e., instances when a constraint was active and binding) in 2010 and 2011. 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 A75: Market-to-Market Events
2010–2011

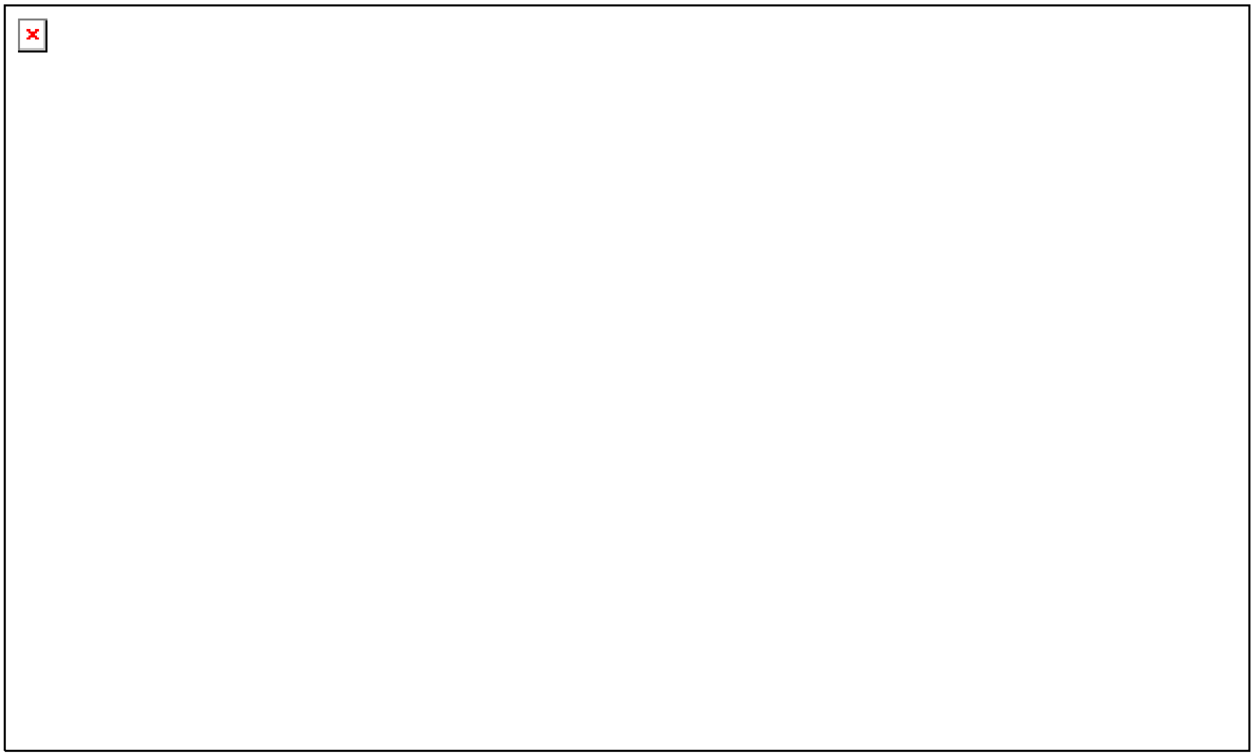


Figure A76: Market-to-Market Settlements

Figure A76 summarizes the financial settlement of market-to-market coordination. 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 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 excess flow.

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 A76: Market-to-Market Settlements
2010–2011

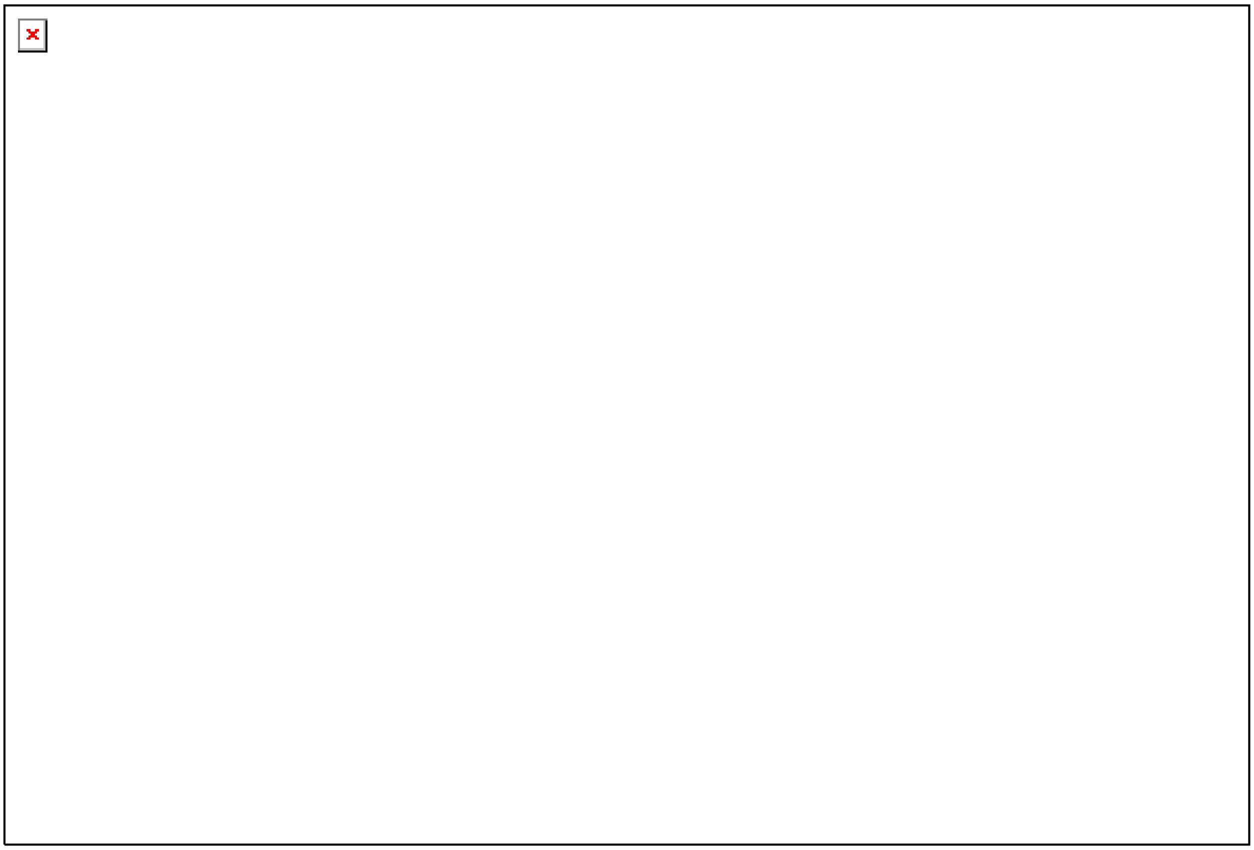


Figure A77 and Figure A78: Market-to-Market Outcomes

Successful market-to-market coordination should lead to two outcomes. First, the RTOs' shadow prices should converge after activation of a coordinated constraint. Second, the shadow prices should decrease from the initial value as the two RTOs jointly manage the constraint.

The next two figures examine the five most frequently coordinated market-to-market constraints by PJM and MISO, respectively. 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 market-to-market 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, which are the average prices in each RTO after the requested relief associated with the market-to-market process was provided.

Values below the x-axis indicate 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 A77: PJM Market-to-Market Constraints
Relief Requested and Shadow Prices, 2011

Figure A78: MISO Market-to-Market Constraints
Relief Requested and Shadow Prices, 2011

<u>Key Observations: Market-to-Market Coordination</u>

i. Net payments flowed from PJM to MISO in each month in 2011 because PJM exceeded its FFE on MISO's system much more frequently than MISO did on PJM's system.

 – Net payments by PJM to MISO more than doubled to $6.5 million per month, in part because of the increase in congestion on MISO's M2M constraints.

 – Congestion on MISO M2M constraints increased 45 percent in 2011 to nearly $460 million, while congestion on PJM M2M constraints declined 33 percent to just $16 million.

ii. Shadow price convergence on MISO M2M constraints, an indicator of PJM's responsiveness to requests for relief, improved considerably from 2010 and is now comparable to convergence on PJM M2M constraints.

 – Nonetheless, the RTOs should continue to work together to identify enhancements to the relief software, modeling parameters, or other procedures that may be limiting the provision of relief.

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

iv. MISO's market-to-market constraints were binding more frequently in the second half of 2011, partly because a new class of constraint became eligible for market-to-market coordination as a result of the PJM-MISO settlement agreement and tariff modifications.

 – The new constraints become eligible based on the total market flows of the non-monitoring RTO, even if no single generating location has greater than 5 percent impact.

VI. External Transactions

MISO relies on imports to satisfy the energy and capacity demands of the market, and is typically a net importer of power during all hours and seasons. Given its reliance on imports, the processes to schedule imports and exports and MISO's pricing of these transactions can have a substantial effect on the performance and reliability of MISO's markets.

Imports and exports are scheduled on a 15-minute basis, although the schedules are fixed 30 minutes before the transaction occurs. Participants must reserve ramp capability in order to schedule a transaction and MISO will refuse transactions that place too large a ramp demand on its system. Currently, participants cannot express any price-sensitivity associated with their external transactions.

This section of the appendix reviews the magnitude of these transactions and the efficiency of the scheduling process.

A. Import and Export Quantities

Figure A79-Figure A82: Average Hourly Imports

The first four figures in this section show the daily average of hourly net imports (i.e. imports net of exports) scheduled in the day-ahead and real-time markets in total and by interface.

The first figure shows the total net imports in the day-ahead market MISO-wide, distinguishing between weekdays (when demands are greater) and weekends. The second figure shows real-time net-imports and changes from day-ahead net import levels. When net imports decline substantially in real-time, MISO may sometimes be compelled to commit additional generation (usually peaking resources) to satisfy the system's needs. The third and fourth figures show similar information by interface.

Figure A79: Average Hourly Day-Ahead Net Imports
2011

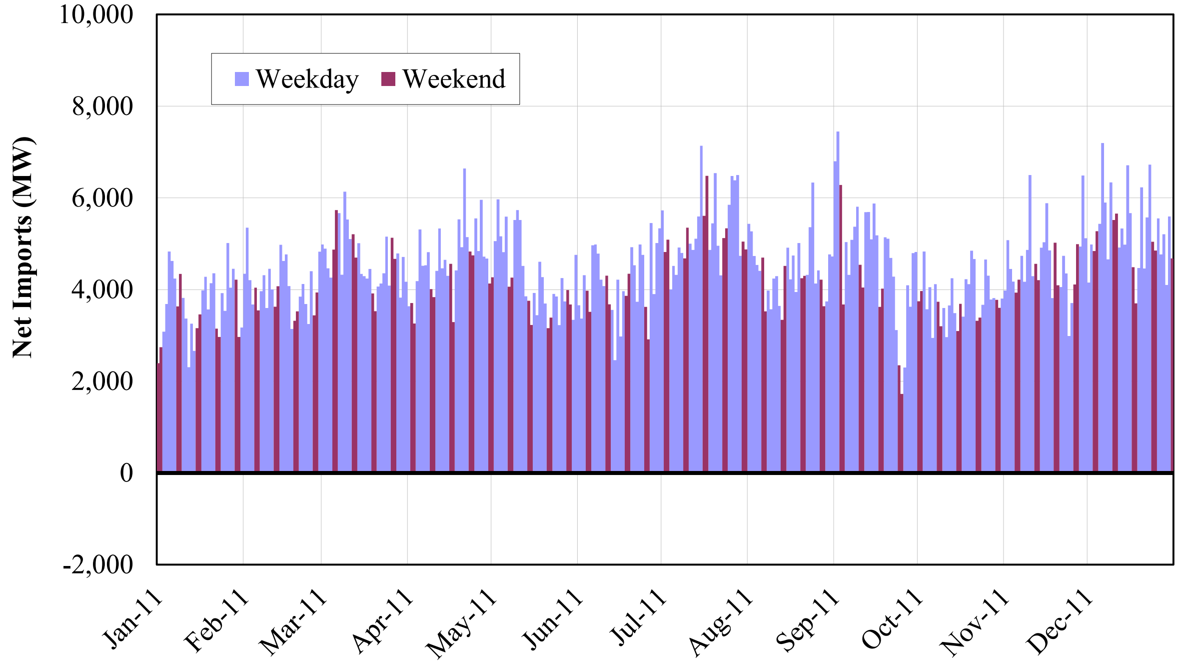


Figure A80: Average Hourly Real-Time Net Imports
2011

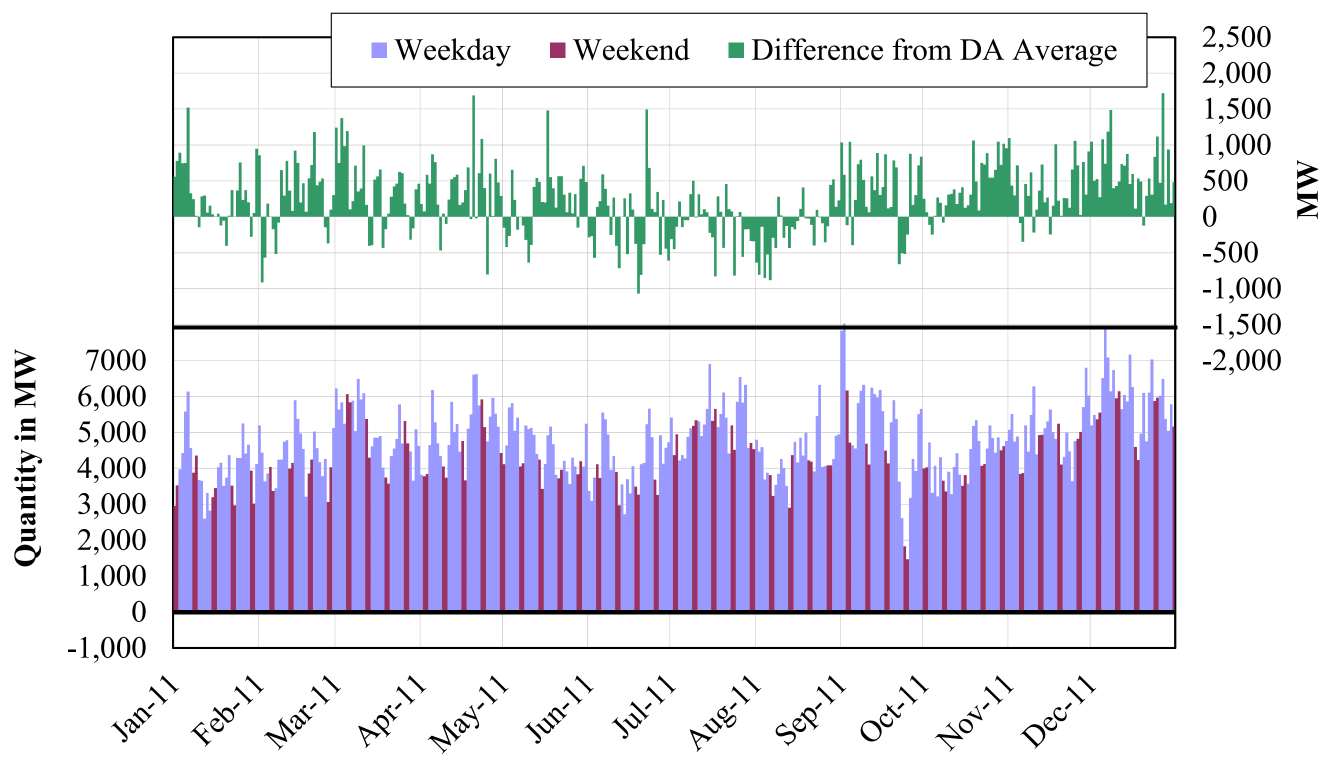


Figure A81: Average Hourly Day-Ahead Net Imports
2011, by Interface

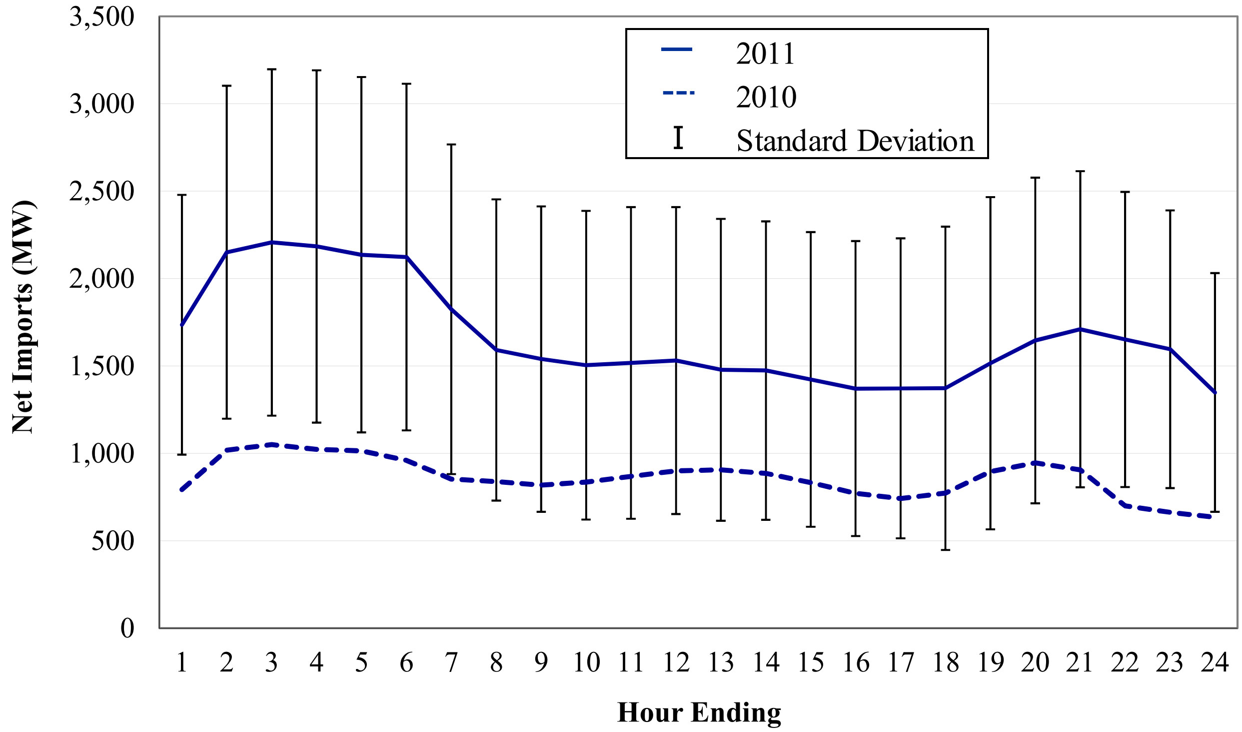
Figure A82: Average Hourly Real-Time Net Imports
2011, by Interface

Figure A83 and Figure A84: Hourly Average Real-Time Net Imports by Interface

The next two figures examine real-time imports by interface. The interface between MISO and PJM, both of which operate LMP markets over wide geographic areas, is the most significant interface for MISO. Since relative prices in adjoining areas govern net interchange, price movements can cause incentives to import or export to change over time.

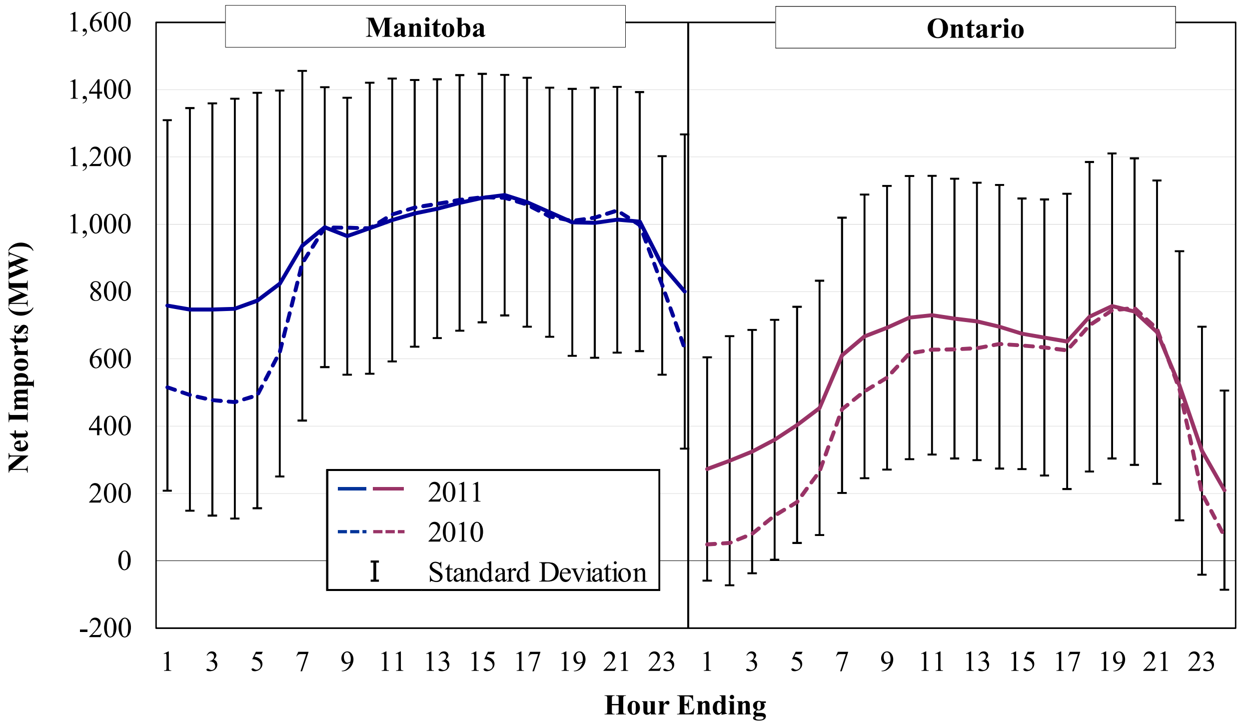
Accordingly, Figure A83 shows the average net imports scheduled across the MISO-PJM interface in each hour of the day in 2010 and 2011, along with the standard deviation of such imports.[30] The subsequent figure shows the same results for the two Canadian interfaces (Manitoba Hydro, at left, and Ontario).

Figure A83: Average Hourly Real-Time Net Imports, PJM
2011



30 Wheeled transactions (mostly from Ontario to PJM) are included in the figures.

Figure A84: Average Hourly Real-Time Net Imports, Canada
2011



Key Observations: Import and Export Quantities

i. As in prior years, MISO in 2011 remained a substantial net importer of power in both the day-ahead and real-time markets.

– Real-time net imports increased 49 percent to an average of 4.6 GW per hour.

– Imports rose on all major interfaces; the increase was largest on the PJM interface, where net imports increased over 50 percent to 1.6 GW.

ii. The consistent net imports in the energy market are consistent with the results of the capacity market. An average of 3.4 GW of imported capacity cleared in the VCA in 2011.

iii. Real-time imports averaged 77 MW greater than day-ahead imports, although this varied considerably by hour and season.

– Net imports were overscheduled day-ahead in summer (by 192 MW per hour on average), but underscheduled in all other months (169 MW).

– Large changes in net imports in real-time can contribute to price volatility. Declines in imports in particular can result in reliability issues that MISO must manage by committing additional generation, including peaking resources.

B. Transaction Scheduling Around Lake Erie and Loop Flow

"Contract path" transaction scheduling between the four RTOs around Lake Erie has created significant issue. The underlying problem is generally that settlements occur based on the scheduled contract path, but actual power flows occur on other paths. 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. The eventual introduction of five Phase Angle Regulators—of which two will be operated by MISO—and other interchange coordination improvements should reduce discrepancies between scheduled and actual flows.

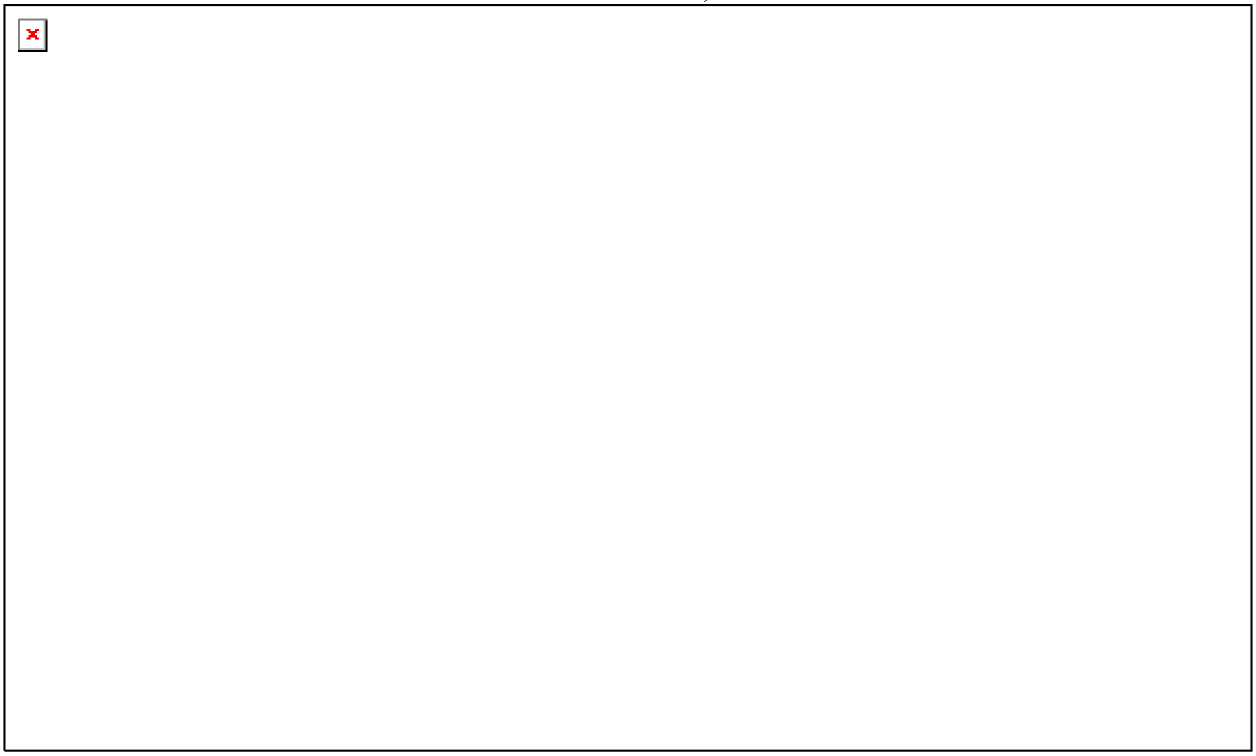
Figure A85: Actual Flows Around Lake Erie

NYISO banned circuitous schedules in July 2008 (including transactions from New York to PJM through MISO), and schedules from IESO to PJM (across MISO) increased thereafter. Figure A85 shows the monthly quantity and profitability of these transactions in the last two years. Profitability is calculated based on prices in PJM and IESO minus MISO's wheeling charge.[31] Although generally profitable, these transactions may not always be efficient since they do not pay for any congestion they cause in NYISO, which raises efficiency concerns.

The figure also shows the portions of the transactions that are then scheduled back into the MISO by the same participant. Effectively, these sets of transactions are scheduled from Ontario to MISO, but are first scheduled through PJM for reasons that we discuss below in the observations.

31 The profits shown excludes costs allocated by IESO including in some cases substantial congestion charges paid to export from IESO, which would reduce the profits.

Figure A85: Actual Flows Around Lake Erie
IESO to PJM Schedules, 2010–2011



Key Observations: Transaction Scheduling Around Lake Erie

i. The wheeling of transactions from IESO to PJM through MISO continued in 2011 and averaged 600 MW.

- These transactions create significant "loop flows" since roughly 50 percent of the power flows through NYISO.

- The IESO-to-PJM transactions remained substantially profitable in 2011 (averaging over $10 per MWh) in part because they do not pay for the congestion they cause in NYISO.

- A portion of these transactions, however, were then scheduled back from PJM into MISO and earned much higher profits than simply scheduling from IESO to MISO. This additional profitability is a function of PJM's external interface pricing that pays transactions based on the perceived congestion they relieve in PJM.
  - ✓ Since roughly half of the power associated with these transactions is priced as if it flows into PJM from NYISO, it receives congestion payments for relieving constraints in eastern PJM.
  - ✓ If these constraints are M2M constraints that are reflected in MISO real-time market as well, it is possible that both RTOs could be paying the transaction for relief of the same constraint under their interface pricing rules.
  - ✓ The RTOs should evaluate whether this is an issue that can be addressed.

ii. In 2012, initial operation of the Michigan–IESO PARs began; full operation is expected to commence in June 2012.

– Full operation of the PARs should reduce the loop flows and improve the scheduling incentives, although the RTOs are still developing the changes in its interface pricing methodologies to reflect the new flow patterns expected with the PARs in operation.

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.

With the exception of the interface with PJM, transactions are scheduled hourly. On the interface with PJM, transactions can be scheduled on as little as a 15 minute basis, but settled on an hourly basis. This temporal discrepancy had created some poor incentives to schedule uneconomically when the apparent hourly settlement was profitable even when the 15 minute period was not, and vice versa.

MISO and PJM modified their scheduling rules in 2009 to address problems caused by allowing participants to schedule 15-minute transactions at the end of the hour after they have seen prices at the beginning of the hour that would be included in the hourly settlement. MISO prohibited changes to schedules within the hour while PJM limited the duration of schedules to no less than 45 minutes.

Figure A86 and Figure A87: Real-Time Prices and Interface Schedules

Our analysis of these schedules 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 all 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. The first figure shows these results for the MISO-PJM interface; the second figure shows the same for the IESO-MISO interface.

Figure A86: Real-Time Prices and Interface Schedules
PJM and MISO, 2011

Figure A87: Real-Time Prices and Interface Schedules
IESO and MISO, 2011

<u>Key Observations: Price Convergence</u>

i. The dispersion of prices and schedules in the figures show that transactions remain relatively unresponsive to price differences. Ideally, net exports should only occur if prices in the neighboring RTO are greater than those in MISO (values in the bottom-left panel). The inverse holds for imports (values in the top-right panel). This often does not occur because of:

- Timing discrepancies—schedules must be submitted no less than 30 minutes in advance of real-time. Since real-time prices are relatively volatile, there is substantial uncertainty regarding the direction and optimal magnitude for inter-RTO schedules;
- The lack of coordination between the many market participants the schedule transactions between the RTOs; and
- In the case of IESO, the lack of a nodal market.

ii. The share of transactions with PJM that were scheduled in the profitable direction was 45 percent, up slightly from 43 percent last year.

- This is very inefficient as it indicates that power is flowing *from* the high-priced market *to* the lower priced market in more than half the intervals.
- In addition, many hours still exhibit large price differences that can be attributed to scheduling uncertainties.
- To address the efficiency we recommend that MISO expand the JOA with PJM to optimize the interchange and improve the interregional price convergence.

iii. To achieve better price convergence between the two markets, we continue to recommend the RTOs coordinate the net interchange between the two areas.

- In response to this recommendation, MISO has been working to develop a proposal to adjust the physical interchange with PJM in a coordinated intra-hour scheduling process.
- One proposal is to allow for Dispatchable Interchange Transactions (DIT), which will indicate a market participant's minimum price differential needed to engage in an intra-hour interchange transaction.
- The scheduling of such transactions can be optimized and adjusted on a 5- to 15-minute basis.
- We support this concept and believe it will enhance efficiency and price convergence between the RTOs. We commented in MISO stakeholder processes that DIT:
  - ✓ Should not be subject to uplift charges; and

- ✓ RTOs should retain the congestion that may arise when the external interface becomes constrained.

– While PJM staff have worked with MISO on this concept, to date PJM stakeholders have only supported action on improving physical scheduling rules.

iv. In December 2011, MISO improved procedures for physical scheduling (its Ramp Reservation System) to better align the approval process with system ramp capability to support NSI changes.

VII. Competitive Assessment

This section evaluates the competitive structure and performance of MISO's markets using multiple measures to identify the presence of market power and, more importantly, to assess whether market power has been exercised. Such assessments are particularly important for LMP markets because local market power associated with transmission constraints in these markets can be more profitable to exercise.

A. Market Structure

This first subsection provides three structural analyses of the markets. The first market power indicator is the concentration of generation ownership in MISO as a whole and in each of the regions within it.

The latter two analyses address the frequency with which suppliers in MISO are "pivotal" and needed to serve load reliably or to resolve transmission congestion. In general, the two pivotal supplier analyses provide more accurate indications of market power in electricity markets than does the market concentration analysis.

Figure A88: Market Shares and Market Concentration by Region

The first analysis evaluates the market concentration using the Herfindahl-Hirschman Index (HHI). The HHI is a standard measure of market concentration calculated by summing the square of each participant's market share (expressed as percentage). Antitrust agencies generally characterize markets with an HHI greater than 1,500 to be moderately concentrated, while those with an HHI in excess of 2,500 are considered to be highly 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 or network constraints. In wholesale electricity markets, these factors have a profound effect on competitiveness.

Figure A88 shows generating capacity-based market shares and HHI calculations for MISO as a whole and within each region.

Figure A88: Market Shares and Market Concentration by Region
2011

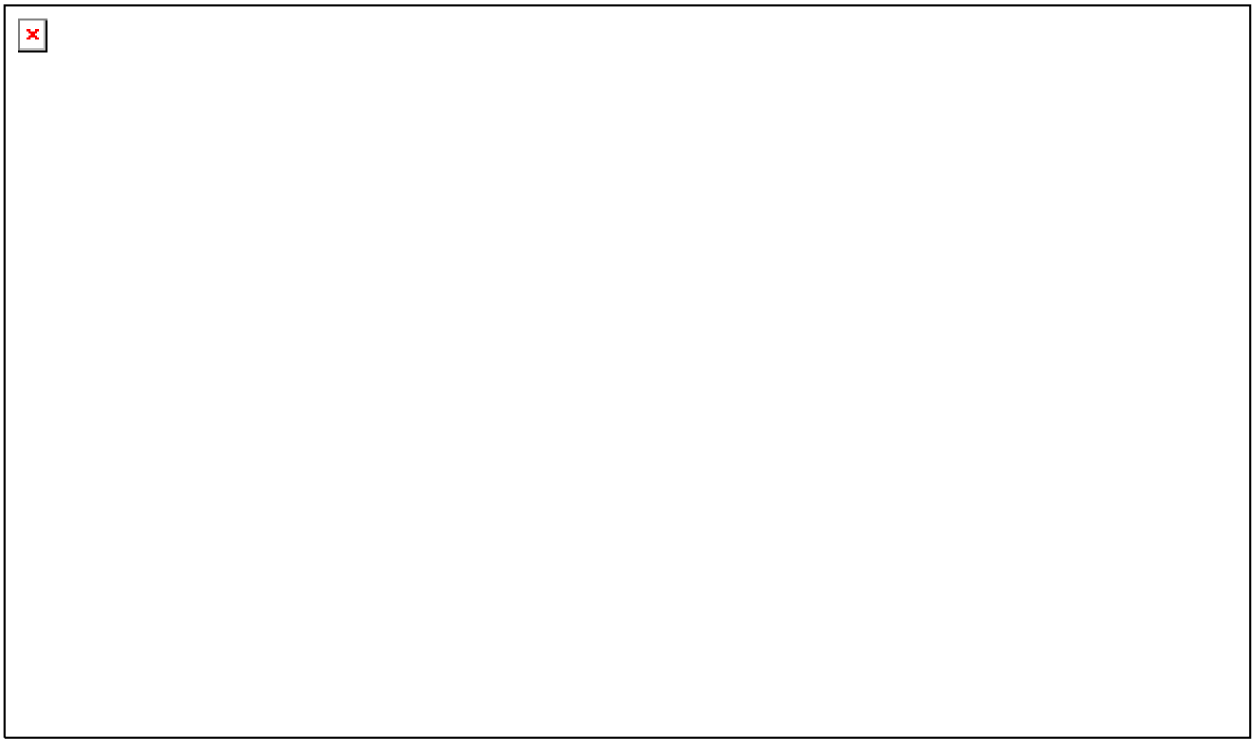
One drawback of the HHI is that it does not recognize physical characteristics of electricity that can cause a supplier to have market power. As such, the HHI alone does not allow for conclusive inferences regarding the overall competitiveness of electricity markets. The next two analyses more accurately reveal potential competitive concerns in the MISO markets.

Figure A89: Pivotal Supplier Frequency by Load Level

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 one means that the load can be satisfied without the largest supplier's resources. An RDI less than one indicates that a supplier is pivotal and a monopolist over some portion of the load.

Figure A89 summarizes these results, showing the percentage of total hours with a pivotal supplier by region and load level. (Prices are most sensitive to withholding under high-load conditions, which makes it more likely that a supplier could profitably exercise market power in those hours.) The percentages shown below the x-axis indicate the percent of hours that comprise each load-level tranche.

Figure A89: Pivotal Supplier Frequency by Region and Load Level
2010–2011



While the pivotal supplier analysis is useful for evaluating a market's competitiveness, the best approach for 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 local market power more precisely than either HHI or RDI by specifying when a supplier is pivotal relative to a particular transmission constraint.

A supplier is pivotal on a constraint when it has the resources to overload the 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 nearest to the constraint. If the same supplier owns all of these resources, that supplier is likely pivotal to maintaining reliability.

Two types of constrained areas are defined for purposes of market power mitigation: Broad Constrained Areas (BCAs) and Narrow Constrained Areas (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. As such, they can be defined in advance and are subject to tighter market power mitigation thresholds than BCAs. The three NCAs currently defined in the MISO markets are the Minnesota NCA,[32] the WUMS NCA, and the North WUMS NCA.

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

Market power associated with BCA constraints can also be significant. A BCA is defined dynamically when non-NCA transmission constraints bind, and includes all generating units with significant impact on power flows over the constraint. BCA constraints are not generally as chronic as NCA constraints are; however, they can raise 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.

Figure A90 and Figure A91: Frequency of Pivotal Suppliers

The next two figures evaluate potential local market power by showing the frequency with which suppliers are pivotal on individual NCA and BCA constraints. Figure A90 shows the percentage of all market intervals by month during which at least one supplier was pivotal for each type of constraint. For the purposes of this analysis, the WUMS and North WUMS NCAs are combined. Figure A91 shows, of the intervals with active constraints in each month, the percentage with at least one pivotal supplier.

Figure A90: Percent of Intervals with at Least One Pivotal Supplier
2011

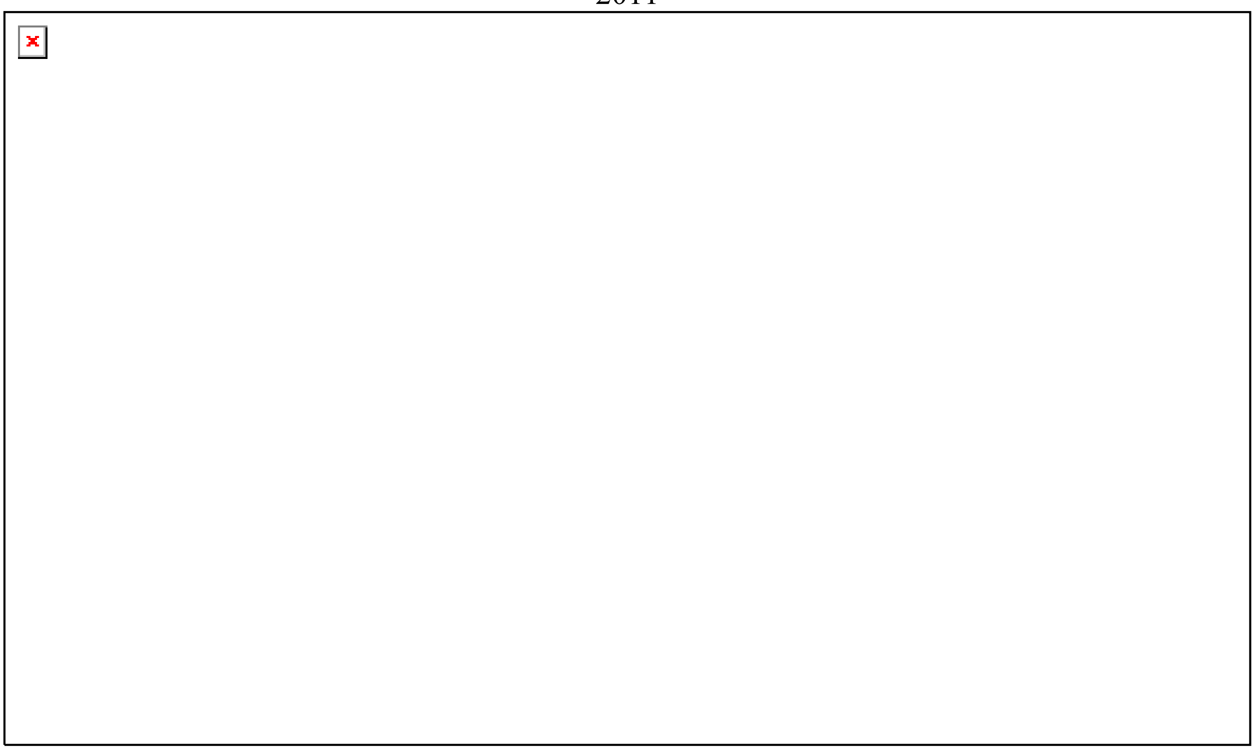
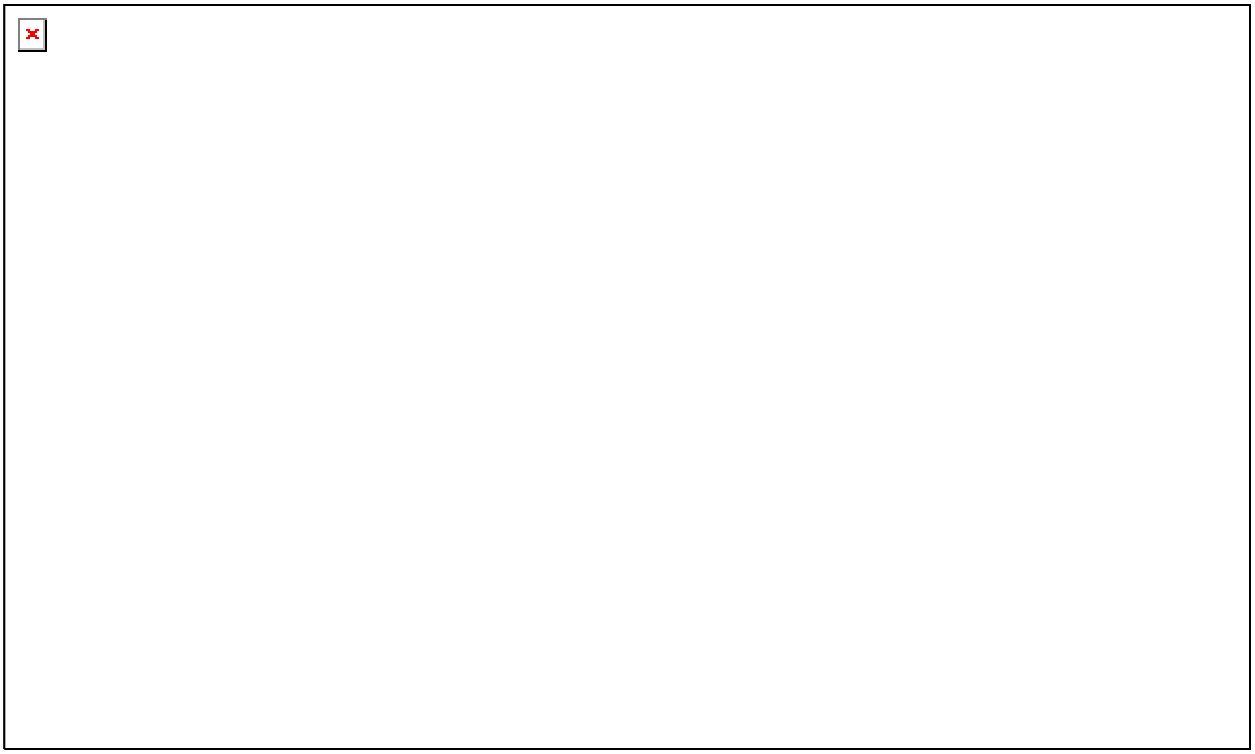


Figure A91: Percentage of Active Constraints with a Pivotal Supplier
2011



Key Observations: Market Structure

i. The market-wide HHI increased only slightly from 499 to 534.

– The market share of the top three suppliers did not change substantially in any region.

– 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.[33]

ii. The departure of FirstEnergy from the East region resulted in a substantial increase in the HHI there, from 1,877 last year to 2,476 this year.

iii. Pivotal supplier frequency rose sharply with load. 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.

– Market power mitigation measures effectively address most competitive concerns.

33 Generation divestiture in other RTOs generally reduce market concentration because the assets are typically sold to a number of entities.

- We previously raised competitive concerns regarding commitments made to support the voltage of the system in specific local areas.[34] MISO filed proposed changes to market power mitigation measures to address this concern in December 2011, which are pending with FERC.

iv. The majority of active constraints in 2011—61 percent—had at least one supplier that was pivotal.

- Similarly, 55 and 64 percent of active NCA constraints into WUMS and Minnesota, respectively, had a pivotal supplier.
- Roughly 60 percent of binding BCA constraints had a pivotal supplier.
- One of these BCA constraints (with a pivotal supplier) was binding in approximately 90 percent of intervals.
  - ✓ This is a much higher share than the share of intervals for any one of the NCAs (which did not exceed 10 percent of the intervals) because the number of NCA constraints is far more limited than the number of BCA constraints.
  - ✓ Since they are more broadly defined, there are often multiple binding BCA constraints per interval (on average 1.63).
- Overall, these results indicate that local market power persists with respect to both BCA and NCA constraints, and that market power mitigation measures remain critical.

B. Participant Conduct – Price-Cost Mark-Up

The structural analyses in the prior subsection indicate the likely presence of local market power associated with transmission constraints in the MISO market area. In this subsection, we analyze participant conduct to determine whether it was consistent with competitive behavior or whether there were attempts to exercise market power. 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 increase RSG payments. Physical withholding occurs when an economic unit is unavailable to produce some or all of its output. Such withholding is generally achieved by claiming an outage or derating a resource, although other physical parameters can be manipulated to achieve a similar outcome.

We begin this section by estimating a price-cost mark-up. The price-cost mark-up analysis estimates the "mark-up" 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

34 Suppliers with resources in these areas often face no competition for satisfying this reliability need.

estimated SMPs is the mark-up. 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 mark-up because suppliers should have incentives to offer at their marginal cost. In a competitive market, offering above marginal costs would be expected to result in lost revenue contribution to cover fixed costs. Many factors can cause reference levels to vary slightly from suppliers' true marginal costs, so we would not expect to see a mark-up exactly equal to zero. Mark-ups of 1-2 percent lie within the bounds of competitive expectations.

Key Observations: Price-Cost Mark-Up

i. Despite indicators of structural market power, our analyses of individual participant conduct show little evidence of attempts to physically or economically withhold resources to exercise market power.

ii. The average system marginal price mark-up was just 1.3 percent in 2011, which reflects the competitiveness of MISO's energy markets.

  - Many factors can cause reference levels to vary slightly from suppliers' true marginal costs, so we would not expect to see a mark-up exactly equal to zero.

  - The results in 2011 continue to support the conclusion that the MISO markets are performing competitively overall.

C. Participant Conduct – Potential 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 its 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).

However, marginal costs can exceed variable production costs. For instance, operating at high output levels or for long periods without routine maintenance can cause a unit to face an increased risk of outage and O&M costs. Additionally, 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 each unit is a key component of analyses to identify economic withholding. 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 are only potentially warranted when a supplier's offer prices exceed its reference levels by more than a threshold specified in the Tariff. 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 a 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 EcoMin and EcoMax) 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, infeasible energy due to ramp limitations is excluded from the output gap.

Figure A92: Monthly Average Output Gap: Real-Time Market

Figure A92 shows monthly average output gap levels for the real-time market in 2010 and 2011. 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 comparatively tighter NCA conduct thresholds and resources outside NCAs are tested at BCA conduct thresholds.

The high threshold for resources in BCAs is the lower of $100 per MWh above the reference or 300 percent of the reference. The thresholds effective during most of 2011 were roughly $99 per MWh for resources located in the WUMS NCA, $24.37 in the North WUMS NCA, and $100 per MWh for resources in the Minnesota NCA. The low threshold is set to 50 percent of the applicable high threshold for a given resource.

For example, for a resource in WUMS, the low threshold would be $49.50 per MWh (50 percent of $99). 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 A92: Real-Time Monthly Average Output Gap

2010–2011

Figure A93 to Figure A96: Real-Time Market Output Gap

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 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. The next four figures show output gap in each region by load level and by unit type (online and offline), 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 (high threshold) and at one-half of the mitigation thresholds (low threshold).

Figure A93: Real-Time Monthly Average Output Gap
Central Region, 2011

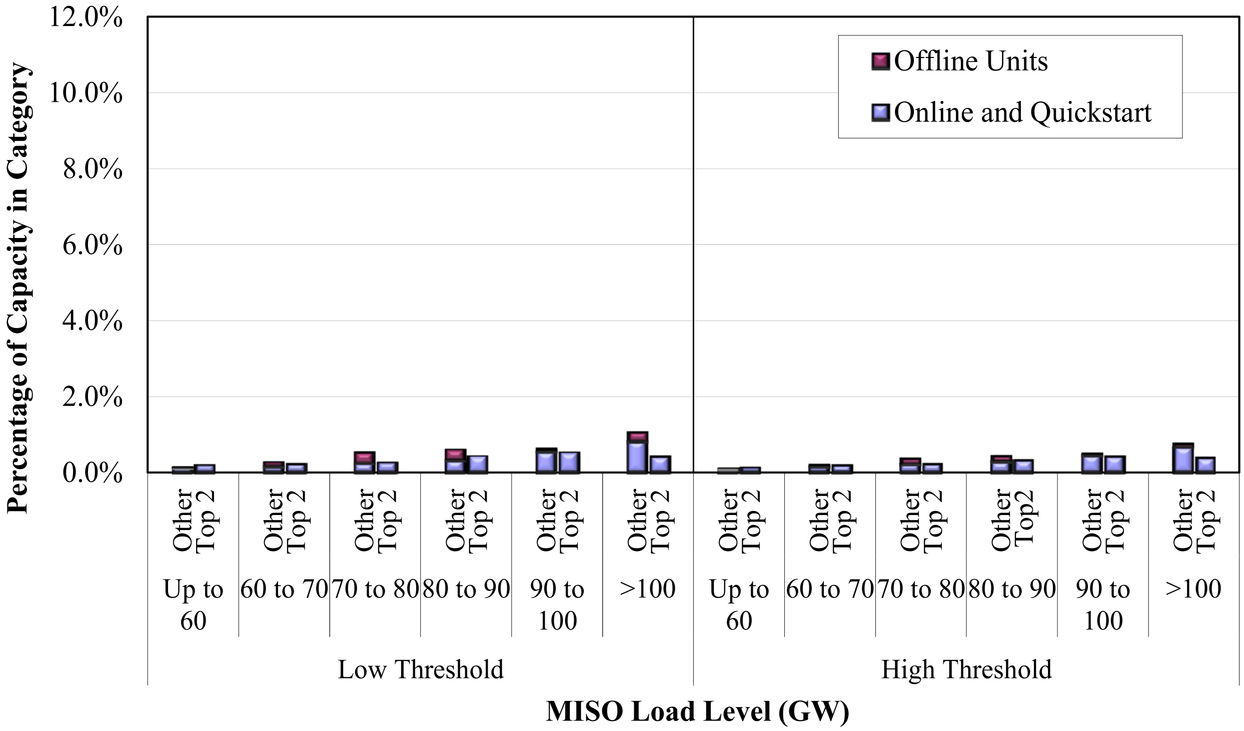


Figure A94: Real-Time Monthly Average Output Gap
East Region, 2011

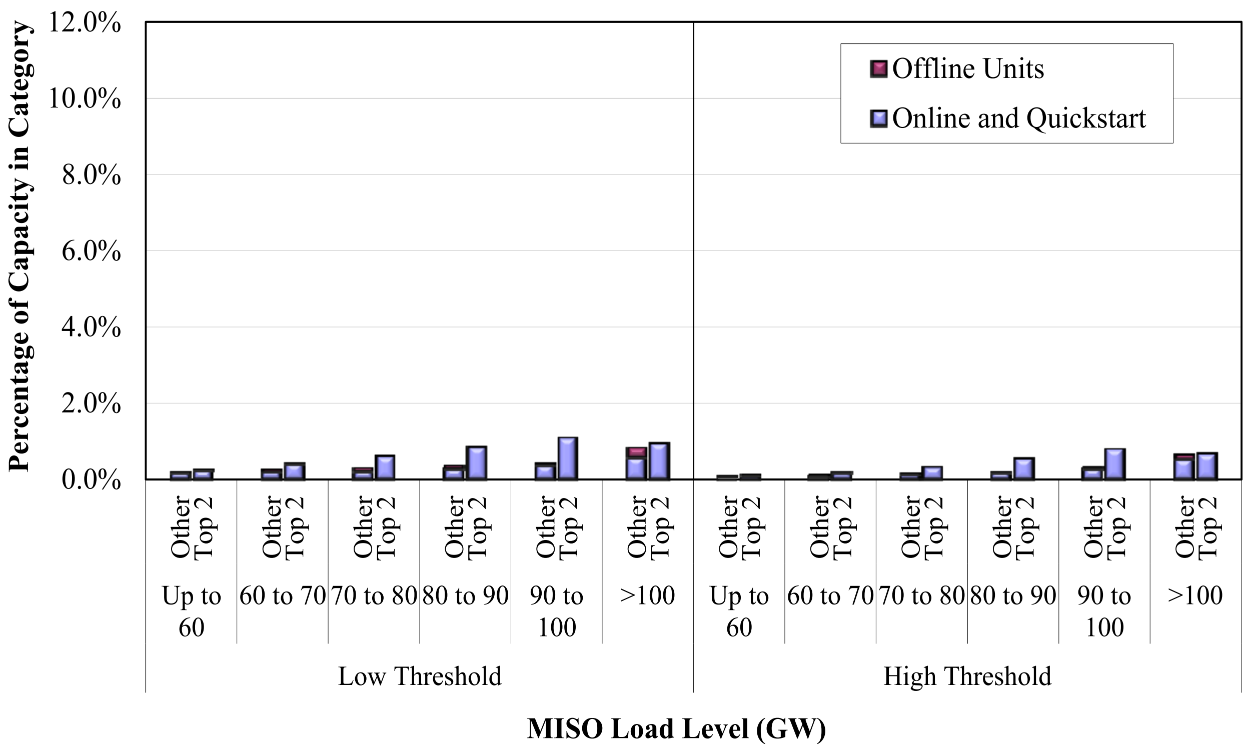


Figure A95: Real-Time Monthly Average Output Gap
West Region, 2011

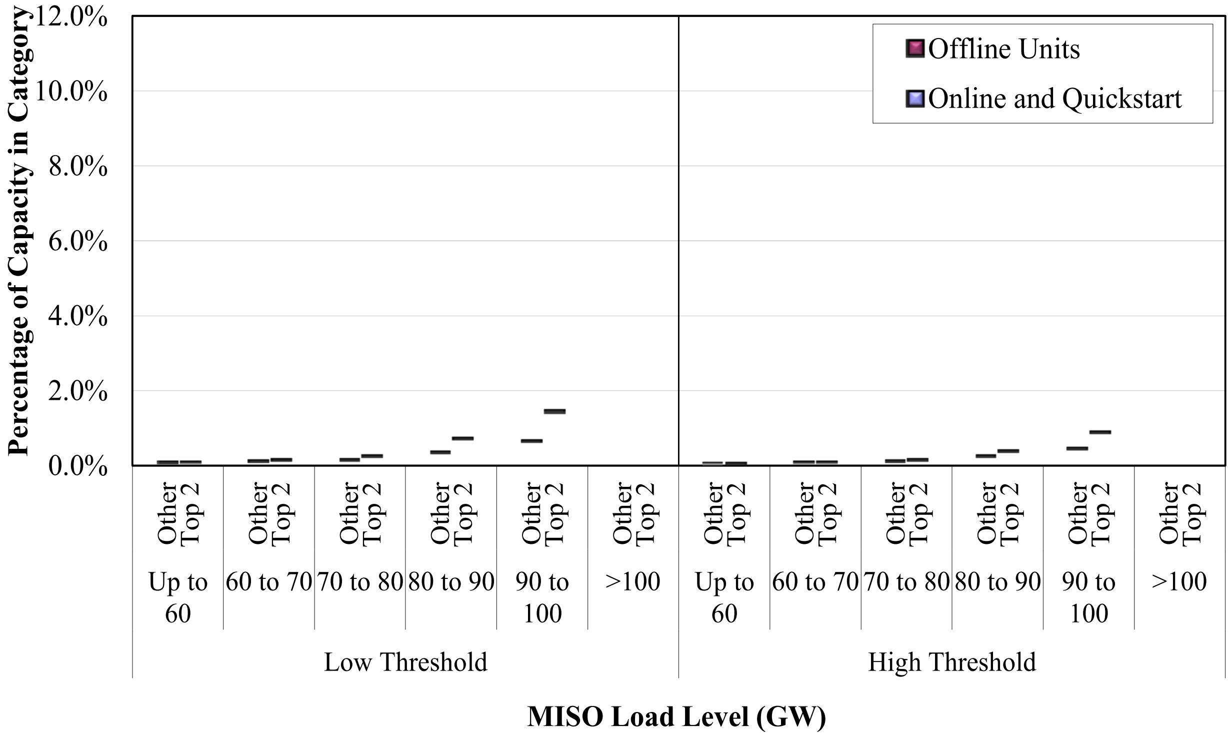
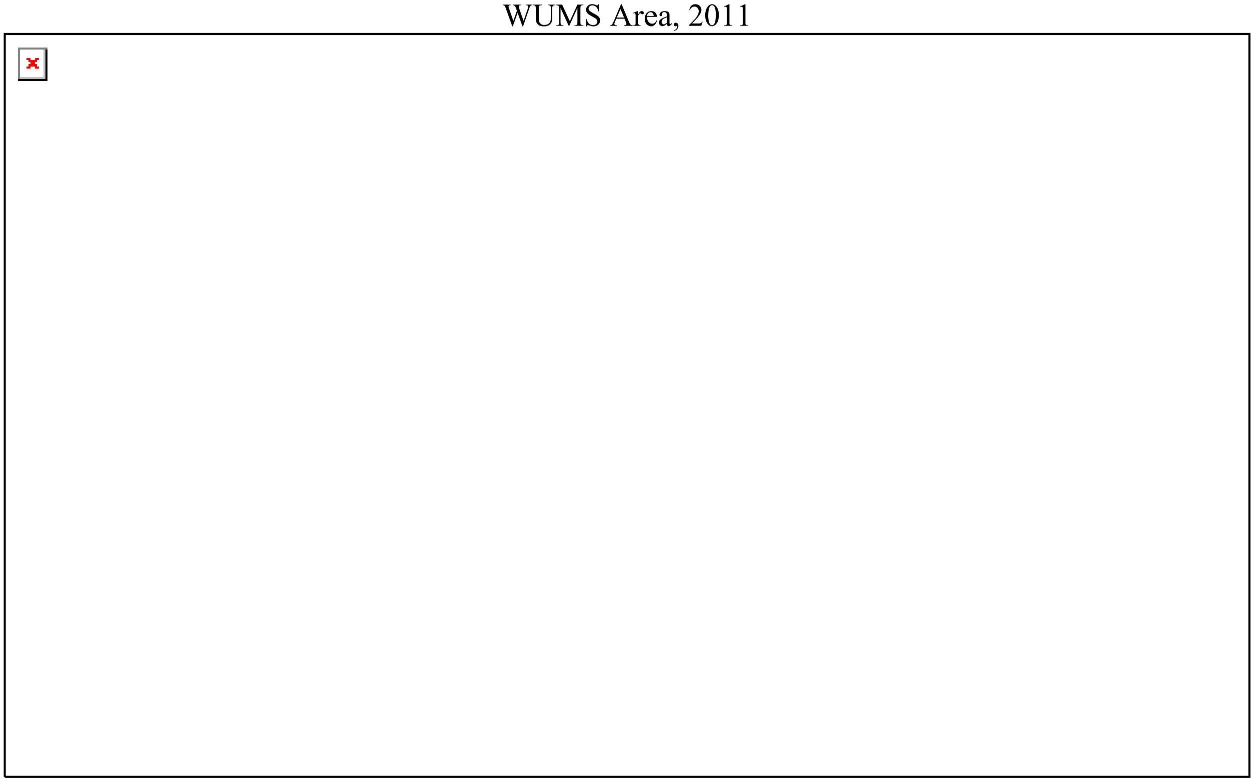


Figure A96: Real-Time Monthly Average Output Gap
WUMS Area, 2011



Key Observations: Economic Withholding

i. Output gap levels continued to decline in 2011 and averaged just 58 MW per hour at low threshold and 30 MW per hour at high threshold.

- As a share of actual load, it averaged less than 0.1 percent, which is extremely low.
- The two metrics declined after January because NCA threshold levels, which are revised annually, were updated on February 1.
- Additionally, the conduct of the largest supplier in each region was not substantially different than the conduct of other smaller suppliers that are less likely to have market power.
- Output gap generally increased slightly with load because the high prices that occur at high-load levels result in a much greater share of a resource to be economic.

D. Participant Conduct – Ancillary Services Offers and RSG Effects

Figure A97: Ancillary Services Offers

Figure A97 evaluates the competitiveness of ancillary service offers. It shows monthly average quantities of regulation and contingency reserve offered at prices ranging from $10 to $50 per MWh above reference levels. As in the energy market, ancillary service reference levels are resource-specific estimates of the competitive offer level for the service (i.e., the marginal cost of supplying the service).

Figure A97: Ancillary Services Offers
2011

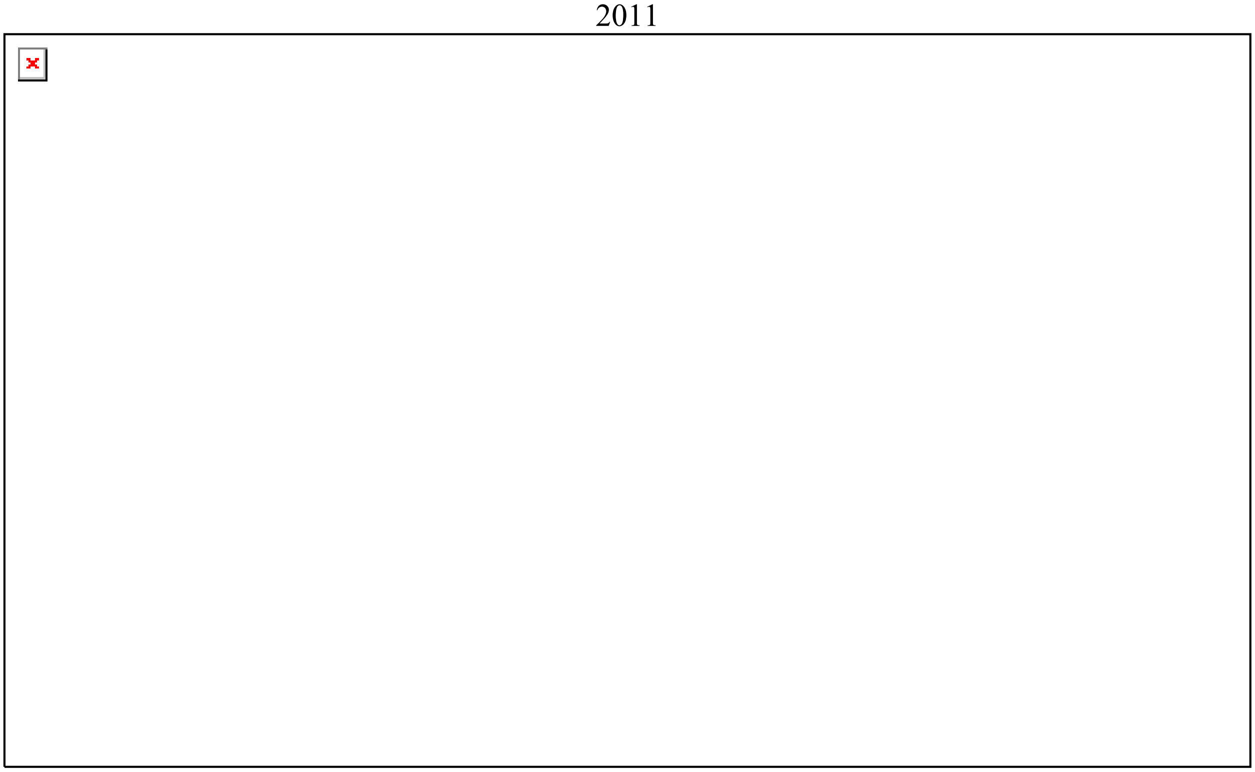
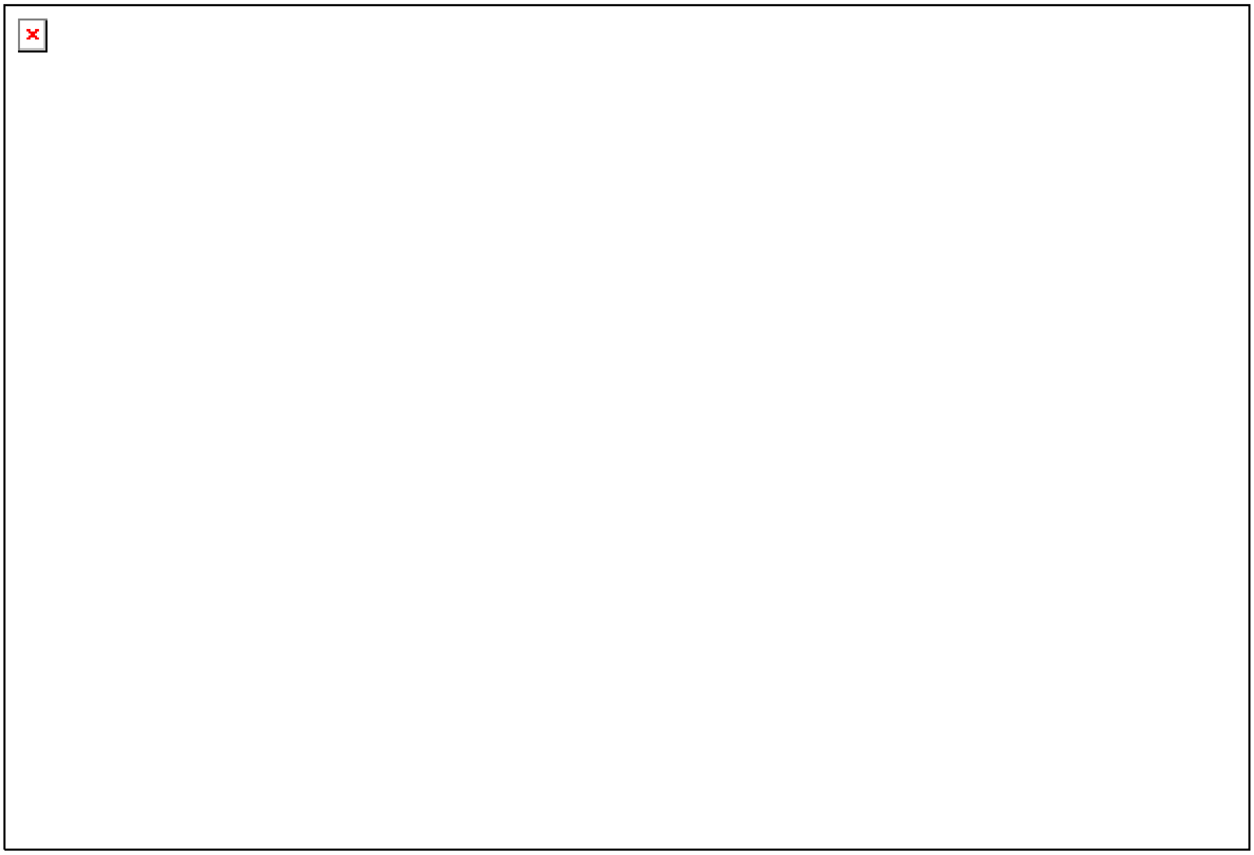


Figure A98: RSG Payments by Conduct

Local market power can also be associated with repeated resource commitments for local reliability needs (including voltage support). Certain commitments raised significant competitive concerns beginning in late 2010 and continued into 2011. Hence, we evaluate RSG payment conduct in Figure A98, separating payments that correspond to resources' reference levels, and payments associated with the portions of resources' offers that exceed their reference levels.

Figure A98: RSG Payments by Conduct
2011



<u>Key Observations: ASM Offers and RSG Effects</u>

i. ASM offers became more competitive over the course of 2011. By year's end, less than 2 percent of all ancillary services offers were at more than $10 per MWh above reference, and those above $20 per MWh all but disappeared in the fourth quarter.

- Almost no supplemental reserve was offered substantially above reference because prevailing prices for this service are so low.
- The spike in July for spinning reserves is due to opportunity costs of not providing energy during high-priced, high-load hours late in the month.

ii. These results and others in this report show very little indication of significant economic withholding in 2011. Nonetheless, we monitor these levels on an hourly basis and routinely investigate instances of potential withholding.

iii. A substantial minority of RSG payments—less than $37 million in 2011—was associated with payments to participants offering above a resource's reference level.

- While some of these excess payments reflect legitimate costs, some are likely associated with offers that exceed the resources' marginal cost.
- Such suppliers are still being committed because they are often the only suppliers positioned to satisfy the local reliability issue.
- This issue is most acute in the case of local needs, such as voltage support in an area. Based on a recommendation in last year's *State of the Market Report*, MISO filed tighter mitigation thresholds for such VLR commitments in December 2011, which are expected to be implemented in late summer 2012 subject to FERC approval.

E. Participant Conduct – Physical Withholding

The previous subsection analyzed offer patterns to identify potential economic withholding. By contrast, physical withholding occurs when 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 A99 to Figure A102: Real-Time Deratings and Forced Outages

Figure A99 to Figure A102 show by region the average share of capacity unavailable to the market in 2011 because of forced outages and deratings. 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 A99: Real-Time Deratings and Forced Outages
Central Region, 2011

Figure A100: Real-Time Deratings and Forced Outages
East Region, 2011

Figure A101: Real-Time Deratings and Forced Outages
West Region, 2011

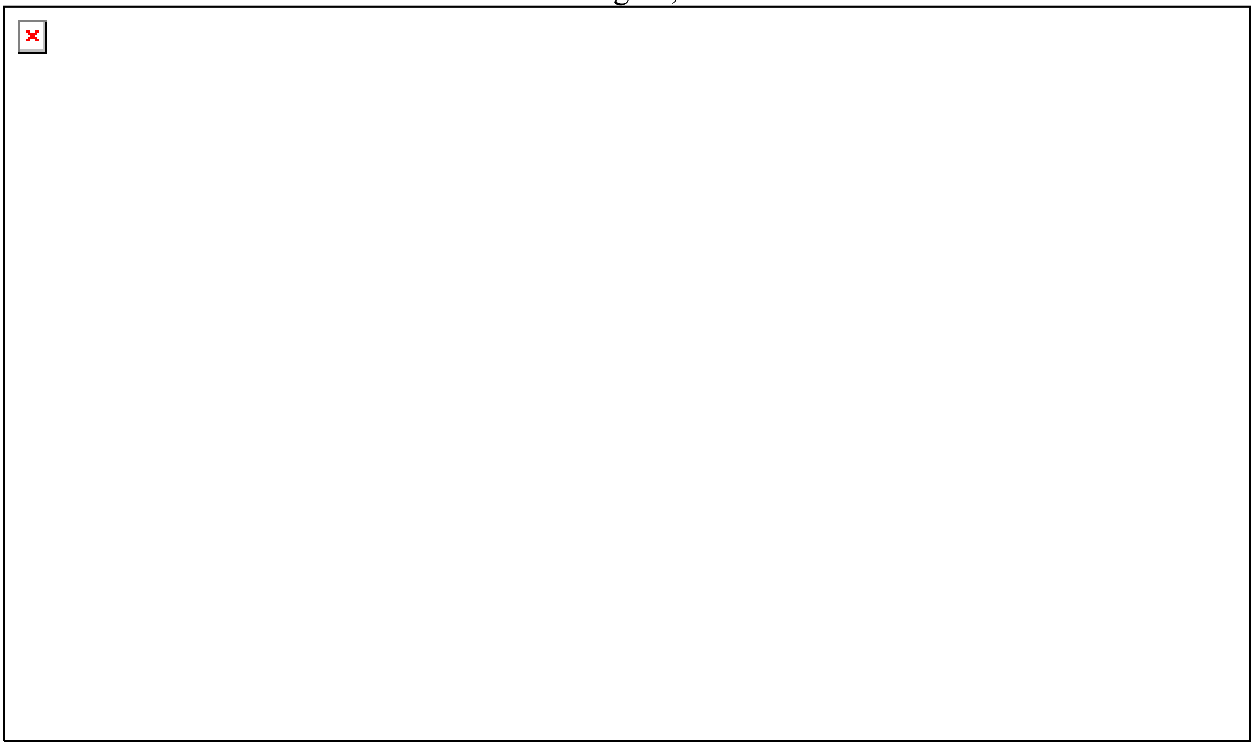
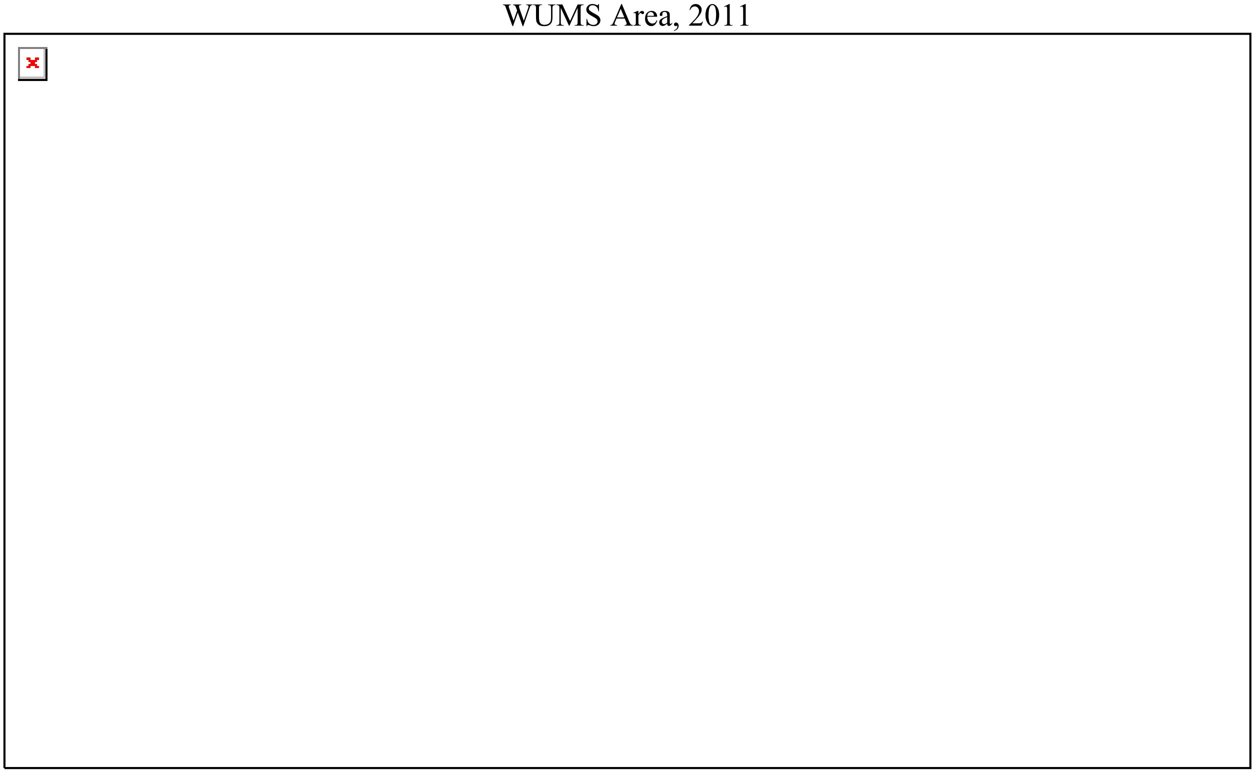


Figure A102: Real-Time Deratings and Forced Outages
WUMS Area, 2011



Key Observations: Physical Withholding

i. Deratings were generally in line with previous years, and do not raise substantial competitive concerns.

- In most regions, deratings increased at higher load levels. This is generally due to high ambient temperatures during unusually warm periods in summer that cause the maximum ratings of certain thermal units to decrease.
- Forced outages did not increase during peak periods and remain a small share of overall unavailable capacity.
- The forced outage rates of the largest suppliers in each region were comparable to the rates for other suppliers and none were unusually high during peak conditions.

ii. In the East region, deratings for the top two suppliers was substantially greater than those of other suppliers at all load levels.

- This is attributable to one particular unit but did not raise significant concerns.
- There were no indications of significant physical withholding in 2011. Nonetheless, we monitor these levels on an hourly basis and routinely investigate instances of potential withholding.

F. Market Power Mitigation

In this final subsection, we examine the frequency with which market power mitigation measures were imposed in MISO markets. When a set of Tariff-specified criteria are met, a mitigated unit's offer price is capped at its "reference level", or competitive benchmark. 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.

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.

Market power concerns are greater in NCAs because the congestion affecting these areas is chronic and a supplier is typically pivotal when the congestion occurs. As a result, conduct and impact thresholds for NCAs, which are calculated annually as a function of the frequency that NCA constraints bind, are lower than for BCAs.

Figure A103: Real-Time Energy Mitigation by Month

Figure A103 shows the frequency and quantity of mitigation in the real-time energy market by month. We focus on the real-time because little mitigation occurs day-ahead since the liquidity provided by virtual participants and the multitude of commitment options makes the day-ahead market much less vulnerable to withholding.

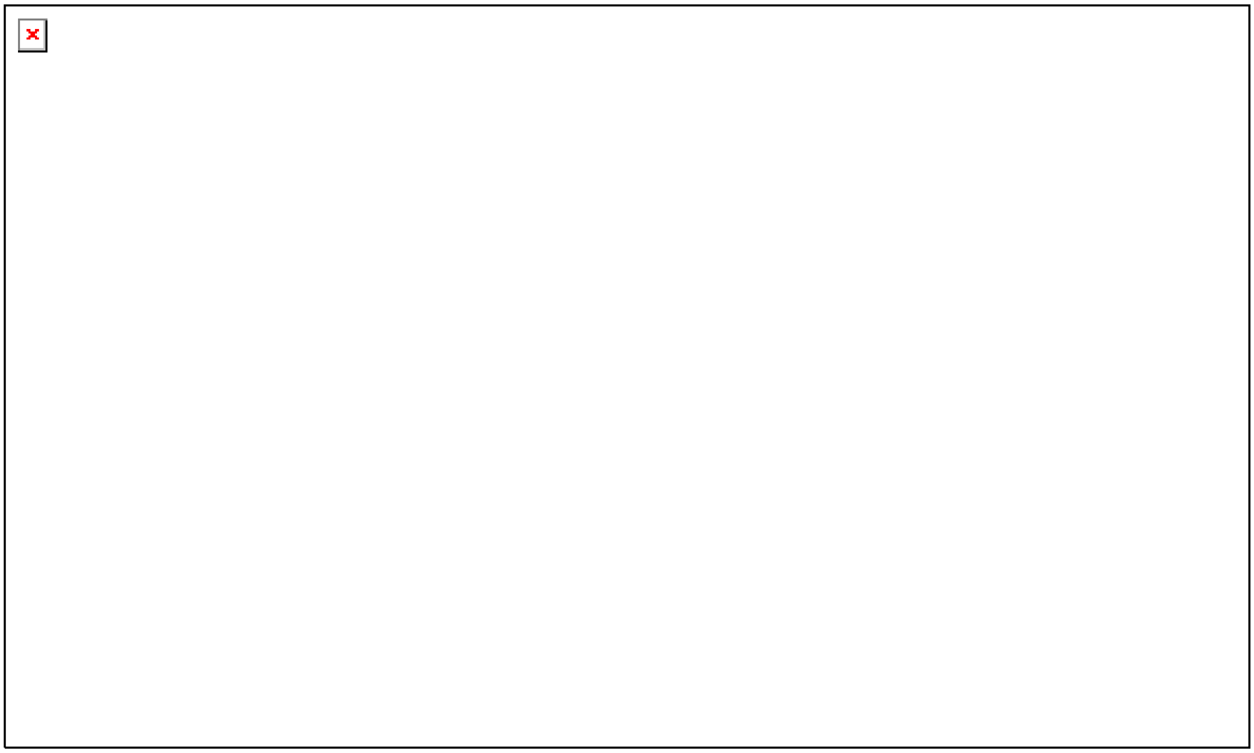
Figure A103: Real-Time Energy Mitigation by Month
2011

Figure A104: Real-Time RSG Payment Mitigation by Month

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 A104 shows the frequency and amount by which RSG payments were mitigated in 2010 and 2011.

Figure A104: Real-Time RSG Mitigation by Month
2010–2011



Key Observations: Market Power Mitigation

i. Real-time NCA and BCA energy mitigation remained infrequent in 2011.

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

ii. Mitigation of RSG payments more than doubled (to a total of $618,000).

- The rise in RSG mitigation is not a significant concern because the overall mitigation levels remain low.
- Much of the increase occurred during the high-load summer months, when RSG-eligible commitments were high.

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

As discussed above, MISO has filed for tighter mitigation measures to be applied to commitments for local voltage or local reliability needs, which is pending FERC's review.

VIII. Demand Response Programs

Demand Response (DR) involves actions taken to reduce consumption 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-priced 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 responds to capacity shortages, or "economic DR", which responds 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.[35] By definition, however, EDR is not price-responsive and does not yet 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 physical limitations that affect its ability to respond to changes in load and interchange, as well as contingencies (e.g., generator or transmission outages). 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 rise sharply.

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 2011 to approximately 7,300 MW. Much of the decrease was due to the departure in June of FirstEnergy, whose footprint contained a substantial amount of Behind-The-Meter-Generation (BTMG). The majority of this remaining capability is legacy DR programs administered by LSEs, either through load interruptions (Load-Modifying

35 A large share of the demand response capability in MISO cannot be called directly by MISO because it exists under legacy utility arrangements in the form of interruptible load or behind-the-meter generation.

Resources, or LMR) or through BTMG. These resources are beyond the control of MISO, but can reduce the overall demand of the system. The share of DR that can respond actively through MISO dispatch instructions comprises a small minority of MISO's DR capability. Such resources are classified as Demand Response Resources (DRR) and were eligible to participate in all the MISO markets in 2011, 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.

Type I resources are inflexible in that they provide either no response or their "Target Demand Reduction Amount". Therefore, they cannot set energy prices in the MISO markets, although they can set the price for ancillary services. 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 June, MISO added 7 new Type I resources, and now has 21 such resources active in its commercial model. However, only 11 of these resources actually participated in the energy market in 2011, clearing a cumulative 0.4 MW of energy per interval (they predominantly provided supplemental reserves).

Type II resources can set prices because they are capable of supplying energy or operating reserves in response to a five-minute instruction, and 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 conditions. These customers can then alter their usage efficiently in response to such prices. Significant barriers to implementing dynamic pricing include the minimum required load of the participating customer, extensive infrastructure outlays and potential retail rate reform. Only one 75-MW Type II resource was active in MISO in 2011, clearing approximately 11 MW of energy per interval.

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 most Type I resources. In 2011, all DRR units combined provided an average of 8.9 MW of regulating reserve, 111 MW of spinning reserve and 48 MW of supplemental reserve.

2. Other Forms of DR in MISO

Most other DR 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, such programs are ultimately voluntary, although penalties exist for noncompliance. 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.

Module E of MISO's Tariff allows DR resources 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 comparably to generation resources in the VCA, while LMR must meet additional Tariff-specified criteria prior to their participation. The ability for all qualified 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. During such an event, resources that do not qualify as DRR, or DRR units that are not offered into the markets, are still eligible to reduce load and be compensated as EDRs. For the upcoming 2012–2013 Planning Year, 30 resources providing 894 MW of capacity are registered as EDR.

EDR offers (curtailment prices and quantities, along with other parameters such as shutdown costs) are now submitted on a day-ahead basis. During emergency conditions, MISO selects offers on in economic merit-order based on the offered curtailment prices up to a $3,500-per-MWh cap. EDR participants who reduce their 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 MISO has proposed changes as part of its ELMP initiative that would allow them to do so when they are needed.

Table A2: DR Capability in MISO and Neighboring RTOs

Table A2 shows total DR capabilities of MISO and neighboring RTOs. Due to differences in their requirements and responsiveness, individual classes of DR capability are not readily comparable.

Table A2: DR Capability in MISO and Neighboring RTOs
2009–2011

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

* Registered as of December 2011.

3. Aggregators of Retail Customers

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, Aggregators of Retail Customers (ARCs) can serve as an intermediary between MISO and retail customers who can reduce consumption.[36] This measure has been successfully implemented in neighboring RTOs. MISO filed Tariff revisions on October 2, 2009 to allow ARCs to participate in all the MISO markets, to which FERC responded on December 15, 2011.[37]

36 An ARC is defined as 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.

37 MISO made additional compliance filings on March 14, 2012 to further comply with Orders 719 and 745.

Key Observations: Demand Response

i. MISO had 7.4 GW of registered demand-response capability in 2011, comparable as a share of capacity to neighboring RTOs.

ii. The reduction in capability from 2010 (8.7 GW) to 2011 (7.4 GW) is largely due to the departure of FirstEnergy in June 2011.

iii. MISO's capability comes in varying degrees of responsiveness. Most of the MISO DR is interruptible load (i.e., LMR) developed under regulated utility programs or behind-the-meter generation (BTMG).

- MISO does not directly control either of these classes of DR which cannot set the energy price, even under emergency conditions.
- Only 547 MW participates directly in MISO's energy markets as DRR Types I or II. A substantial increase from 2010, when a single resource participated.
- The majority of these resources provide only supplemental reserves.

iv. MISO considers DR to be a priority and continues to actively expand its DR capability. One means to do so is for ARCs to actively participate in the MISO markets.

- FERC approved Tariff language in December 2011 that compensates an ARC-operated resource cleared for energy at the full LMP, as required by FERC Order 745.

v. Paying the full LMP when DR resources curtail load raises efficiency concerns because:

- It will increase their incentive to curtail at prices less than the value of the electricity to the customer, which should inefficiently increase the frequency of curtailments; and
- It will create incentives to develop small-scale BTMG that is generally much more expensive, less flexible (not dispatchable by MISO), and more environmentally harmful than new conventional generation

vi. One change that is particularly important is a modification to price-setting methodologies to allow DR resources set real-time energy prices when they are needed.

- This will improve MISO's shortage pricing and improve economic signals to develop new resources.
- When DR resources are deployed and do not set prices, it undermines the efficiency of the market during peak periods and can serve as a material economic barrier to net imports in the short-run and the development of new resources in the long-run.

- MISO's proposed ELMP pricing methodology will improve the extent to which DR resources are integrated by allowing EDR to set energy prices. We recommend that MISO expand this capability to LMR, including BTMG.

vii. Finally, the integration of DR in the resource adequacy construct is very important because it can have a sizable effect on the price signals provided by MISO's capacity market.

- LMR (excluding BTMG) currently can be deducted from an LSE's capacity requirement under Module E.
- This effectively provides nearly a 100 percent capacity credit to DR, which are not tested to verify their capability.
- When they have been called in the past, MISO has received only a fraction of their total claimed capability.
- Therefore, we recommend adopting testing procedures if practicable, and derating these resources based on their actual performance when called.