2012 STATE OF THE MARKET REPORT FOR THE MISO ELECTRICITY MARKETS

ANALYTICAL APPENDIX

POTOMAC ECONOMICS

JUNE 2013

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I. Prices and Revenues

MISO has operated competitive wholesale electricity markets for energy and FTRs since April 2005. MISO 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.

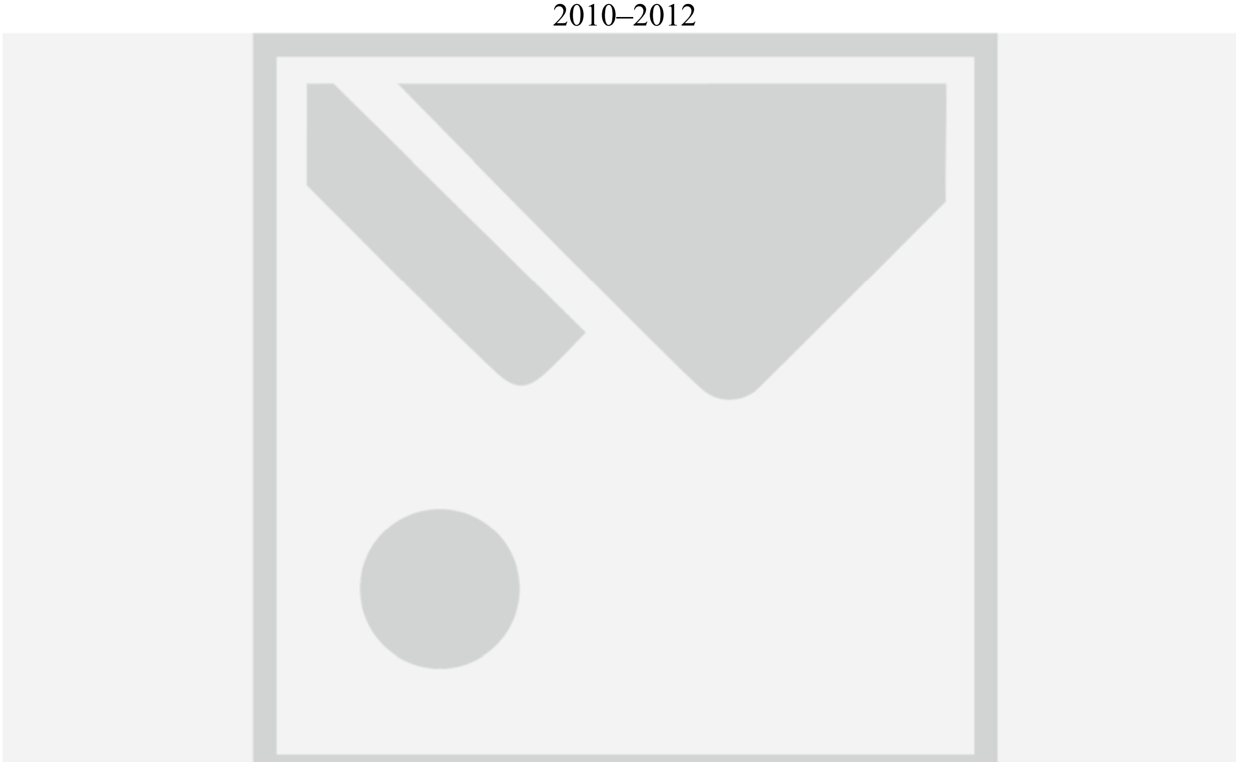
A. Prices

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 constitutes 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 load-weighted average energy prices.

Figure A1: All-In Price of Electricity

Figure A1 shows the "all-in" price of electricity from 2010 to 2012 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 clearing price times the capacity requirement) per MWh of real-time load.

Figure A1: All-In Price of Electricity
2010–2012



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 which cause energy prices to vary by location.

The table inset in the figure provides the portion of hours with prices greater than $200 and $100, and less than $0 per MWh in the prior three years. The highest prices often occur during peak load periods when shortage conditions are most common. Prices in these hours are an important component of the economic signals that govern investment and retirement decisions.

Figure A2: Real-Time Energy Price-Duration Curve
2012

Figure A3: MISO Fuel Prices

As noted previously, fuel prices are a primary determinant of overall electricity prices since they constitute most of generators' marginal costs. Figure A3 shows the prices for natural gas, oil, and two types of coal in the MISO region since 2011.[2] The top panel shows nominal prices in dollars per MMBtu along with a table showing annual average nominal prices since 2010. The bottom panel shows fuel price changes in relative terms, with each fuel indexed to January 2011.

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
2011–2012

Figure A4: Fuel-Price Adjusted System Marginal Price

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 or derates, 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 most common marginal fuel type during an interval (more than one fuel can be on the margin in a particular interval). 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
2011–2012

<u>Key Observations: Prices</u>

i. Real-time energy prices fell 13.9 percent in 2012 from 2011.

- Natural gas prices declined 31 percent and coal prices fell as well.
- Load was relatively flat from 2011 to 2012, but hot weather during the summer contributed to a number of shortages that partially offset the effects of lower fuel prices on average real-time prices.

ii. Real-time energy prices in MISO averaged $28.56 per MWh, and regionally ranged from $26 in the West region to $30 in the East.

iii. The average all-in price declined by 14 percent in 2012, virtually the same as the decline in real-time energy prices since energy prices again constituted 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 $0.23 per MWh and remained less than 1 percent of the all-in price.
- Despite a considerable rise in operating reserve shortages that were all priced at over $1,100 per MWh, the contribution to the all-in price in 2012 of ancillary services costs declined 2 cents to just $0.13.

- The reduction in natural gas prices flattened the energy supply curve, reducing the opportunity cost of foregone energy embedded in ancillary service clearing prices.

iv. Capacity costs contributed just one cent per MWh to the all-in price because of the current capacity market design shortcomings and prevailing capacity surplus in MISO.

v. Adjusting for changes in fuel prices, the SMP rose nearly four percent.

- This indicates that non-fuel factors contributed to higher prices and partially offset the substantial reduction in fuel prices.
- The largest factor was the increase in shortage events during the high-temperature conditions in July.

B. Price Setting and Capacity Factors

Figure A5: Price Setting by Unit Type

Figure A5 examines the frequency with which different types of generating resources set price in MISO. Since more than one type of unit can be marginal in an interval, the total for all fuel types exceeds 100 percent. When a transmission constraint is binding, different fuels may be marginal in the constrained and unconstrained areas. The figure shows the average prices that prevailed when each type of unit was 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 majority of its baseload capacity—is coal-fired, these units tend to set price in most hours. 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
2011–2012

Figure A6: Capacity Factors by Unit Type

Figure A6 shows average monthly capacity factors—the share of total hours that the average unit was generating—for three types of common generators: coal steam, gas-fired combined-cycle, and gas-fired combustion turbine. Coal steam units provide much of the baseload generation in MISO, while combined-cycle units generally provide mid-load capacity. Combustion turbine resources provide much of the system's peaking capacity.

Fluctuations in fuel prices and load will impact the relative competitiveness of each type of resource—in a competitive market, the higher the capacity factor of a unit, the more competitive it is. We show each year separately, since yearly changes for each month are predominantly due to changes in fuel prices. Monthly fluctuations over the course of a given year, meanwhile, predominantly reflect changes in load.

Figure A6: Capacity Factors by Unit Type
2012

Key Observations: Price Setting and Capacity Factors

i. The decline in natural gas prices increased the share of intervals that natural gas was a marginal fuel from 28 percent in 2011 to 46 percent in 2012.

   – Although it sets price in less than one-half of the intervals, natural gas is an important driver of energy prices because these intervals tend to be the highest-priced periods.

ii. Coal remained the most prevalent price-setting fuel in MISO. It was at least one of the marginal fuels (in at least some locations) in 92 percent of all intervals and generated two-thirds of all of the energy in 2012.

iii. Expansion of the participation of wind resourses as DIR continued in 2012, which allows them to economically curtail and set the real-time energy price.

   – Wind resources set prices in 33 percent of intervals (usually in very small areas affected by congestion) at an average price of $-16 per MWh.

   – Wind resources often bid negative incremental energy offers because of the federal production tax credit available to wind resources. This can reduce the implied marginal cost of such units to as low as $-34 per MWh.

iv. Because of low natural gas prices, natural gas resources were substantially more competitive with coal resources in 2012 than in prior years, particularly in the first half of the year.

- Natural gas-fired combustion turbine and combined-cycle units operated at capacity factors during the first half of 2012 that were more than double their capacity factors from 2010 or 2011.

- Conversely, the capacity factors of coal steam units were more than 10 percentage points lower on average in the first half of 2012 compared to 2011.

C. Net Revenue Analysis

In this subsection, we summarize the long-run economic signals produced by MISO's energy, ancillary services, 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 or changes in 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 combined-cycle unit with an assumed heat rate of 6,930 Btu per kWh and a natural gas CT unit with an assumed heat rate of 9,750 Btu per kWh consistent with inputs to the EIA Annual Energy Outlook. We also incorporate standardized assumptions for calculating net revenue put forth by the Commission. The net revenue analysis includes assumptions for variable Operations and Maintenance (O&M) costs, fuel costs, and expected forced outage rates from these and other sources.

Figure A7: Net Revenue and Operating Hours

To determine whether net revenue levels would support investment in new resources, Figure A7 also shows the estimated annualized cost of a new unit. The estimated annualized cost is 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.

Combined-cycle generators run more frequently (and earn more energy rents) than simple-cycle combustion turbine generators because combined-cycles have substantially lower production costs per MWh. Hence, the estimated energy net revenues for combined-cycle generators are substantially higher than they are for combustion turbines. Conversely, capacity and ancillary services revenues typically account for a comparatively large share of a combustion turbine's net revenues. Capacity prices were uniform across the MISO footprint in 2012, but may not be in future. Zonal requirements under the new capacity construct can result in regional capacity prices higher than the market-wide clearing price. No zonal constraint bound in the 2013-2014 Planning Year auction.

Figure A7: Net Revenue and Operating Hours
2010–2012

Key Observations: Net Revenues

i. Net revenues in 2012 for both combined-cycles and combustion turbines were substantially less than the cost of new entry in all regions. This is consistent with expectations because the MISO region continues to exhibit a capacity surplus and did not experience significant shortages this year.

  – Net revenues for a combustion turbine in North WUMS rose 45 percent but remained less than two-thirds of the cost of new entry.

  – Results are otherwise nearly unchanged from last year 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 only limited periods of shortage pricing in MISO. When such periods increase in frequency, they can provide economic signals that additional capacity is necessary.

  – Future pricing changes will allow peaking and demand response resources to more reliably and efficiently set prices.

iii. The revised Resource Adequacy Construct (RAC), which takes effect with the 2013-14 Planning Year beginning on June 1, adds zonal locational requirements to the capacity market that will allow prices to better reflects regional capacity needs.

- The revised RAC auction ran for the first time in April. None of the zones were binding and the market cleared at just $31.94 per MW-month, indicating that the RAC has not substantially changed the pricing patterns from the VCA.

- Despite tighter market-power mitigation measures under the new construct, we did not find significant attempts at physical or economic withholding.

iv. Additional changes are needed to the RAC to ensure that it will provide efficient incentives to invest in new resources when the surplus dissipates and resources are needed.

- Resources may be needed sooner than previously anticipated due to forthcoming environmental regulations affecting MISO's coal resources.

- We continue to recommend several changes to MISO's RAC to improve price signals, including:

  - ✓ 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 86 market participants own generation resources (totaling 129.3 GW of capacity) or serve load in the MISO market.[3] 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 and Entergy, which provide an additional 62 GW of capacity. These entities do not submit physical bids or offers into MISO's markets, but may schedule energy into or out of the market.[4] 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.

3 As of March 2013, MISO membership totals 140 entities when including power marketers, brokers, state regulatory authorities and other stakeholders. There are 362 separate Certified Market Participants.

4 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 five-minute dispatch of a limited portion of the MISO-MH interchange.

A. Load Patterns

Figure A8: Load Duration Curves

MISO is a summer-peaking market overall. To show the hourly variation in load, Figure A8 shows load levels for 2012 in the form of an hourly load duration curve. The curve shows the number of hours (on the horizontal axis) in which load is greater or equal to the level indicated on the vertical axis. We separately show curves for 2010, 2011, and 2012 adjusted to the membership that existed in all three years, so changes in load due to other factors (e.g., weather and economic activity) can be more easily discerned. The inset table indicates the number and percentage of hours when load exceeded 80, 85, 90 and 95 GW of load for the membership-adjusted curves.

Figure A8: Load Duration Curves
2010–2012

Figure A9: Heating and Cooling Degree-Days

MISO's load is temperature-sensitive. Figure A9 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.[5] The bottom panel shows monthly Heating Degree-Days (HDD) and Cooling Degree-Days (CDD) averaged across four representative locations in MISO.[6] The table at bottom shows the year-over-year changes in average load and degree-days.

Figure A9: Heating and Cooling Degree-Days
2010–2012

Key Observations: Load Patterns

i. After adjusting for changes in membership, there was a slight overall downward shift in the load duration curve for 2012 compared to 2011.

 – The summer loads in 2012 were higher, however, which caused the average load in the top 1,000 hours to be 2.1 percent higher.

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

6 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.

ii. Total degree days in 2012 declined by one percent overall, but degree days in June and July were 39 and six percent higher than in 2011, respectively.

- For every state in the MISO footprint, 2012 was one of the three warmest years on record (118 years of observations). June and July recorded cooling degree-days 51 and 72 percent above the historical average, respectively.

- Yearly peak loads were set on July 6 at 96.7 GW, on July 17 at 97.7 GW, and on July 23 at 98.5 GW (an all-time market peak).

- The peak load on July 23 was more than 4 GW higher than the "50/50" forecasted peak, but four GW *below* the "90/10" forecasted peak.

  - ✓ Other days exhibited a higher demand for generation (net of wind output). For example, MISO declared a Maximum Generation Event on July 17 that resulted in voluntary load curtailments, even though the peak load was lower than on July 23.

  - ✓ MISO's performance on these peak days is evaluated in the next subsection.

iii. There was only a slight increase in economic activity from 2011 as measured by the Chicago Purchasing Manager's Index, a broad metric of economic activity in the region.

iv. Over 20 GW of generating capacity was needed to meet the energy and operating reserve demands during the highest five percent of load hours, which is a typical pattern for energy demand.

- This generating capacity is needed to satisfy the system's peak energy or operating reserve demands because electricity cannot economically be stored in large quantities.

- This pattern also 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. Evaluation of Peak Summer Days

MISO experienced several weeks of record triple-digit temperatures at most of its load centers beginning in late June. Two subsequent, shorter heat waves later in July similarly challenged MISO's system. This next subsection evaluates the performance of the markets during the year's highest-load days.

Figure A10: Peak Load Days - Temperatures

Figure A10 shows the high temperature at six cities in the footprint on notable days in June and July, along with the historical average. The colored bars indicate MISO's Maximum Generation declarations, including Alerts (in yellow), Warnings (in orange), and Events (in red). MISO additionally declared Conservative Operations and Hot Weather Alerts on each day.

Figure A10: Peak Load Days - Temperatures
June and July, 2012

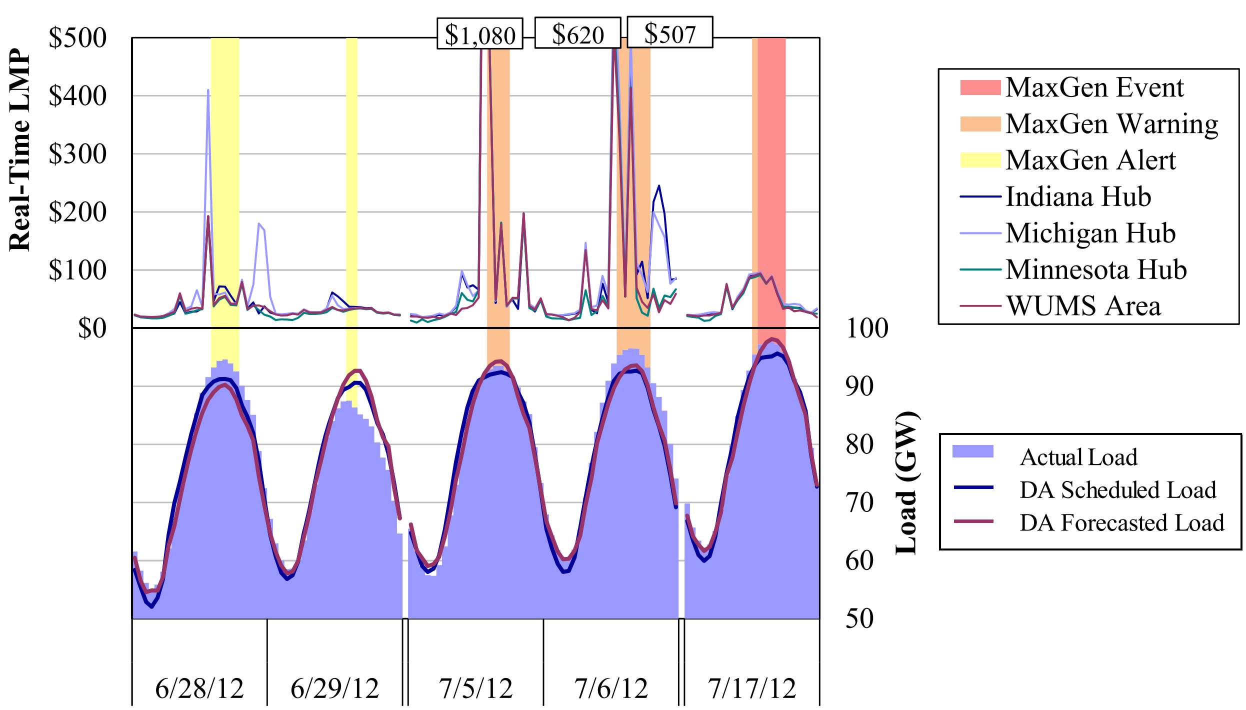
	Hist. Avg.	June 27	28	29	30	July 1	2	3	4	5	6	7	8	15	16	17	x 23	24	25
Cincinnati	85	89	102	100	102	98	95	95	99	99	102	104	100	89	97	97	95	86	95
Detroit	82	89	98	93	93	93	91	84	100	88	99	96	86	93	91	100	97	86	86
Indianapolis	85	91	104	103	97	95	98	98	102	103	105	105	96	95	98	101	102	97	103
Milwaukee	80	93	96	86	92	84	87	97	102	103	94	86	81	88	98	100	99	86	96
St. Louis	89	99	108	106	105	102	100	101	105	105	106	107	98	96	98	103	106	107	108
Minneapolis	79	91	87	89	89	93	98	93	98	91	99	84	87	90	98	94	96	82	92

x MISO set an all-time peak load of 98,556 MW.

Figure A11: Peak Load Days – DA Load Scheduling and RT Prices

The top portion of Figure A11 shows a summary of real-time hub prices during six of the most notable days of summer. The bottom portion of the figure shows major contributors to real-time prices: the day-ahead forecasted load (maroon line), day-ahead scheduled load (blue line), and real-time load (light blue bars). An over-scheduling of load in the day-ahead can depress real-time prices, while under-scheduling can require MISO to make substantial (and often expensive) real-time commitments.

Figure A11: DA Load Scheduling and RT Energy Prices
Select Summer Days, 2012



In addition to extremely high demand for electricity, there are many other factors not shown in this figure that determine real-time prices. They include unplanned generator and transmission outages and derates; operator actions, such as unit commitments or load offsets; changes in real-time wind generation and net interchange; and changes in other supply, such as additional ramping capability or self-commitments.

Figure A12 to Figure A15: Contributing Factors to Real-Time Prices, Select Days

In the next set of charts, we show the cumulative impact of seven primary real-time supply and demand factors that affected the net capacity balance on four afternoon days in July. These seven factors are: (1) net imports from PJM; (2) net imports from all other areas; (3) load, including any operator offset; (4) wind; (5) significant generator outages; (6) other rampable capacity[7]; and (7) MISO unit commitments.

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

Figure A12: Contributing Factors to Real-Time Prices
July 5, 12:40–16:50

7 "Other Rampable Capacity" is additional capacity that can be dispatched within five minutes that is made available on online units because they are ramping up.

Figure A13: Contributing Factors to Real-Time Prices
July 6, 12:00–16:00

Figure A14: Contributing Factors to Real-Time Prices
July 17, 11:30–18:00

Figure A15: Contributing Factors to Real-Time Prices
July 23, 14:40–18:00

Key Observations: Evaluation of Peak Days

i. Reliability was maintained on each day during the peak period, and the markets accurately signaled the shortages that occurred.

 – Although LSEs voluntarily curtailed load on many days, MISO did not call for demand response to maintain reliability.

ii. However, markets were not well coordinated with operating procedures to satisfy the needs of the system as efficiently as possible.

iii. MISO's reliability mandate and associated operating procedures generally require it to take actions to maintain reliability and avoid shortages.

 – When these actions are effective, market prices may not reflect the true costs of meeting these needs and lower-cost options may be overlooked.

 – The ELMP project will improve MISO's pricing during these conditions, particularly if it can be extended to price demand response and other MISO reliability actions.

 – MISO's operating procedures warrant review to determine whether reliability actions are taken in the most efficient order. For example, MISO cannot call for most demand response unit it has exhausted almost all other emergency actions.

iv. On most days, changes in net imports from PJM were one of the primary causes of the shortages and associated price volatility.

- Imports and exports must be scheduled at least 30 minutes in advance and are not coordinated.
- Hence, adjustments in net interchange may over- or under-estimate the quantity needed to achieve efficient interchange.
- Additionally, excessive reactions by participants scheduling over the PJM interface immediately after periods of shortage caused MISO's prices to be very low and raised RSG costs.

v. Since the current Joint and Common Market (JCM) initiative to align the business rules will not address the underlying causes of these scheduling inefficiencies, we recommend the RTOs make the interchange optimization initiative a high priority.

C. Generating Capacity and Availability

Figure A16: Distribution of Generating Capacity by Coordination Region

Figure A16 shows the summer 2013 distribution of existing generating resources by Local Resource Zone. The left panel shows the distribution of Unforced Capacity (UCAP) by zone and fuel type, along with the annual peak load in each zone. The right panel displays the change in the UCAP values from last summer. UCAP values are lower than Installed Capacity (ICAP) values because they account for forced outages and intermittency. Hence, wind capacity does not feature prominently in this figure, even though it makes up 9.3 percent of ICAP.

The inset table in the figure breaks down the total UCAP by fuel type. The mix of fuel types is important because it determines how changes in fuel prices, environmental regulations, and other external factors may affect the market.

Figure A16: Distribution of Generating Capacity
By Fuel Type, Summer 2013

Figure A17: Availability of Capacity during Monthly Peak Load Hour

Figure A17 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 A17: Availability of Capacity, During Peak Load Hour
2012

Figure A18: Capacity Unavailable During Peak Load Hours

Figure A18 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 of greater resource utilization and environmental restrictions, non-outage deratings are expected to be greatest during these periods.

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

Figure A18: Capacity Unavailable During Peak Load Hours
2012

Figure A19: Generator Outage Rates

Figure A19 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 in low-load periods when economics are favorable for participants to perform maintenance. Conversely, short-term outages are frequently the result of an operating problem.

Short-term outages are also important to review because they are more likely to reflect attempts by participants to physically withhold supply from the market since it is less costly to withhold resources for short periods when conditions are tight than to take a long-term outage. We evaluate market power concerns related to potential physical withholding in Section VII.F.

Figure A19: Generator Outage Rates
2010–2012

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

i. Coal-fired generating resources account for 49 percent of MISO's installed (nameplate) capacity, and 55 percent of its unforced capacity (adjusted for forced outages and intermittency).

   – Coal and nuclear resources generally provide baseload generation and in 2012 produced 67 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.

ii. Relatively low gas prices in 2012 caused natural gas resources to be more cost-competitive with coal resources and resulted in dispatch changes.

   – Gas-fired energy output increased by 75 percent in 2012.

   – Conversely, coal-steam output declined by six percent in 2012 compared to 2011.

iii. MISO's unforced capacity exceeds the forecasted 2013 peak load in all seven zones.

- However, because the average output from wind units in western portions of the footprint (e.g., Zones 1 and 3) is usually greater than their UCAP levels, western areas frequently produce substantial surplus energy that is dispatched to serve load in eastern areas.
  - ✓ This pattern produces the west-to-east flows and congestion patterns typically observed in the MISO markets.
  - ✓ The high concentration of wind generating capacity can present operating and reliability challenges, which are discussed in Section IV.I. of the Appendix.

iv. MISO expects fewer than 400 MW of coal retirements by summer 2013 (although some units are considered inoperable). The most significant retirement was of a nuclear unit in Wisconsin that occurred in May 2013.

v. The EPA's CSAPR and MATS rules, if implemented as proposed, are forecasted to contribute to retirement of up to 12 GW of coal resources over the next several years. This has significant implications for the MISO markets given the dominance of coal-fired generating capacity in MISO.

- The CSAPR ruling has been temporarily delayed, which should reduce the amount of coal retirement decisions in the near term.
- MATS retirements, which are most significant, are not expected to emerge materially until 2014.

vi. Cumulative outages increased to an average of 12.7 percent in 2012.

- The long-term forced outage of a single large coal unit accounted for two-thirds of the increase in 2012 from 2011.
- Planned outages declined, likely due to a postponement of various environmental regulations that contributed to higher planned outage rates in fall 2011.
- Outages were lowest during the summer when capacity needs were greatest because planned outages generally take place in other seasons. As expected, short-term forced outages peaked during this time as a result of greater resource utilization and high ambient temperatures.

D. Planning Reserve Margins and Resource Adequacy

This subsection evaluates the supply in MISO, including the adequacy of resources for meeting peak needs in 2013.

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

In Table A1 we estimate planning reserve margin values under various scenarios that are intended to indicate the expected physical surplus over the forecasted load. In its *2013 Summer Resource Assessment*, MISO presented baseline planning reserve margin calculations alongside a number of valuable scenarios that demonstrate the sensitivity to changes in the key assumptions that we evaluate in our planning reserve margin analysis. Because we use the same capacity data, our results are consistent with the MISO Summer Assessment, although we evaluate some scenarios with different assumptions.

The planning reserve margin quantity is the sum of all quantities of capacity, including demand response and imports, minus the expected load. The planning reserve margin in percentage terms is then calculated by dividing the margin by load (net of demand response).

The reserve margins in the table are generally based on: a) peak-load forecasts under normal conditions;[8] b) normal load diversity; c) average forced outage rates; d) an expected level of wind generation and imports; and e) full response from DR resources (behind the meter generation, interruptible load, and direct controllable load management). These assumptions tend to cause the reserve margin to overstate the surplus that one would expect under warmer-than-normal summer peak conditions.

The IMM scenarios in the table account for three major differences between MISO and the IMM's planning reserve margins. The first difference is that non-firm expected imports are rarely included in planning reserve margins, and we exclude them from all IMM scenarios. Since it is possible that neighboring regions will also be peaking and external supplies are short, an RTO capacity market designed to satisfy its planning reserve requirements will generally only accept supply firm imports. The impact of only this exclusion is shown in the first scenario.

The second difference is that DR and wind generally do not provide the same level of reliable supply as conventional resources. To account for this, we show a "Full DR" case and a more conservative "Realistic Wind and DR" case. Under a less generous methodology, the capacity value of MISO's wind resources would fall by more than 1,300 MW. Likewise, most DR is not under the direct control of MISO, and when it was called in 2006 MISO received a peak response of 2,600 MW, far lower than the more than 6 GW of claimed capability. Hence, we assume a DR response rate of 50 percent in the second and fourth scenarios.

The final difference is that MISO's margin does not account for generator derates under peak conditions with higher temperatures than normal. Power plants are frequently cooled by river

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

water, and experience efficiency losses when water temperatures are too high. There is significant uncertainty regarding the size of these derates, so our number in the last two columns of the table is an average of what was observed on extreme peak days in 2006 and 2012 (two years with weather substantially hotter than normal). However, significant supply derates can be a bigger contributing factor to tight reserve margins than an increase in load.

Table A1: Capacity, Load, and Reserve Margins by Region
Summer 2013

<u>Key Observations: Resource Adequacy</u>

i. Unit-level wind capacity credits for Planning Year 2013 ranged from zero to 30.4 percent.

ii. Wind output is strongly negatively correlated with load, which means that wind is often the lowest during peak periods when it is needed most. This presents challenges for developing an appropriate capacity credit for wind resources.

iii. The expected reliability value of wind units is less than assumed by MISO using its ELCC method to develop wind units' capacity credits, which is based on the mean wind output on peak days.

   – Using the median wind output, the average credit declines from 13.3 percent to 11.5 percent.

   – Both the mean and median of wind output essentially results in a 50/50 probability that the wind output will be equal to or higher than the capacity credit level.

- ✓ This is far less than the confidence in the performance of conventional generating resources. The ratings for conventional resources are adjusted downward to account for forced outage rates that typically range from 5 to 10 percent.
- ✓ To increase the confidence that the capacity credited to wind resources will available during peak conditions, MISO should adopt a methodology based on the lowest quartile of wind output during peak conditions. Applied on a unit basis, this would reduce the credit to just 2.7 percent, or to 5.5 percent if applied on a market-wide basis.

iv. The baseline capacity margin for MISO region is 28.1 percent, which greatly exceeds the Planning Reserve Margin Requirement of 14.2 percent.[9]

- – The relatively high level of non-firm imports, wind, and DR resources makes up nearly half of this margin, however.
- – This underscores the importance of accurately assessing the realistic capacity contributions and pricing of each of these sources of capacity.

v. The four IMM scenarios show much lower planning reserve margins.

- – Excluding non-firm imports and applying more realistic assumptions for wind and DR yields a planning reserve margin of 18.7 percent.
- – High temperature leads to both higher load levels and higher generation deratings.
  - ✓ This case yields a planning margin as low as 6.9 percent, which would not be sufficient to both satisfy MISO's operating reserve requirements (2,400 MW) and account for resources that are on forced outage, which generally range from five to eight percent.
  - ✓ Under these conditions, MISO would only avoid firm curtailments by utilizing non-firm imports or getting higher than expected response from its wind resources or its demand response.

vi. Overall, these results indicate that the system's resources should be adequate for summer 2013 if the peak summer conditions are not substantially hotter than normal. However, capacity margins will likely decrease in the future, and may accelerate as new environmental regulations are implemented.

- – Therefore, it is important for the Resource Adequacy Construct to provide efficient economic signals to facilitate the investment needed to maintain an adequate resource base. This report includes a number of recommendations designed to achieve this objective.

9 The 2013 Planning Reserve Margin Requirement is 2.5 percentage points lower than last year's requirement, and is mainly due to a modeling adjustment that allows MISO to access more external resources from neighboring entities.

E. Capacity Market Results

In June 2009, MISO began operating a monthly voluntary 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 A20: Voluntary Capacity Auction Results

Figure A20 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 A20: Voluntary Capacity Auction
2011–2012

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

i. The VCA has consistently cleared at very low prices as a result of the prevailing capacity surplus in MISO.

   – Auction prices peaked in July 2012 at $50 per MW-month. However, this peak monthly rate equates to less than 1 percent of the cost of new entry.

   – This low prevailing price is the result of the current capacity surplus in MISO and the market design shortcomings discussed in this Report.

ii. The 13.2 GW decrease in total capacity in June 2011 marks the departure of FirstEnergy from the MISO market. The decline of 2.2 GW in January 2012 is associated with the departure of Duke Ohio. These changes have not materially impacted resource adequacy.

iii. Cleared capacity in the VCA averaged only 1.1 GW, or 1.3 percent of designated capacity, 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. Therefore, it is a critical component of the economic signal for investment.

iv. The VCA requirement was based on a participant-forecasted monthly peak load.

- Monthly capacity designations in 2012 exceeded the requirement by an average of 2.7 percent.
- Total resources, meanwhile, exceeded the requirement by an average of 31 percent, and by 7.6 percent in July because of the current capacity surplus.

v. In June 2013 MISO introduced a revised Resource Adequacy Construct that includes zonal capacity requirements to reflect the deliverability limitations of the system. It also includes mitigation measures to potential exercises of market power.

- This auction cleared at $1.05 per MW-month, consistent with the very low VCA prices.
- While the RAC changes will improve the economic signals produced by the MISO markets, further improvements are necessary for the market to perform efficiently.

vi. 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.

F. Capacity Credits for Wind Resources

MISO's 2013 *Wind Capacity Report* (formerly part of the Loss of Load Expectation Study) identified a system-wide capacity credit of 13.3 percent for the upcoming Planning Year. The study evaluates each unit's performance during prior year peak conditions to forecast unit-specific capacity factors for the upcoming Planning Year. The study uses the eight highest daily peak hours of each of the past eight years, for a sample size of 64. These capacity factors are then adjusted downward to account for the resulting load reduction of a system without the availability of these resources. This is known as the Effective Load Carrying Capacity (ELCC).

Figure A21 shows data for the 169 wind units in MISO and their capacity credit (pre- and post-ELCC adjustment). The stacked bars show capacity credits using two more conservative methods: one uses the median output of the 64 peaks and one using the lowest quartile. The inset table shows the system-wide average for each estimate.

Figure A21: Wind Capacity Credits
2010–2012

<u>Key Observations: Wind Capacity Credits</u>

i. This figure shows that the capacity credits substantially exceed the true capacity value of the wind resources.

   – As much as possible, wind UCAP credit should be estimated in a manner that produces a comparable level of expected availability to other types of generating resources.

   – This is not the case under MISO's methodology, which produces wind credits that will likely not be achieved in most peak load hours. Because its methodology is based on the mean wind output, one unusually windy peak day can cause this measure and the resulting capacity credits to be overstated.

- Using the median output level by unit in peak load hours would lower the average PY 2013–14 capacity credit to 11.5 percent. Even using the median, however, overstates the credit because one should expect the wind output to be less than this level in half of the peak load hours.

  - ✓ Therefore, this report shows the effects of assuming the lowest quartile of output during peak hours on the unit-by-unit basis.

  - ✓ This methodology would produce an average capacity credit for the wind resources of 2.7 percent for PY 2013–14. We recommend that MISO consider this as an alternative for granting UCAP credits for wind resources in future.

G. Capacity Market Design: Sloped Demand Curve

The VCA consisted of a single-price auction to determine the clearing price and quantities of capacity. The demand in this market is implicitly defined by the minimum resource requirement and a deficiency price. These requirements result in a vertical demand curve (i.e., demand that is insensitive to the price, buying the same amount of capacity at any price). This did not change under the Planning Resource Auction process. In this section, we describe the implications of the vertical demand curve for market performance and the benefits of improving the representation of demand in this market through the use of a sloped demand curve. We begin below by discussing the attributes of supply and demand in a capacity market.

1. Attributes of Demand in a Capacity Market

The demand for any good is determined by the value the buyer derives from the good. For capacity, the value is derived from the reliability provided by the capacity to electricity consumers. The implication of a vertical demand curve is that the last MW of capacity needed to satisfy the minimum requirement has a value equal to the deficiency price, while the first MW of surplus has no value. In reality, each unit of surplus capacity above the minimum requirement will increase reliability and lower real-time energy and ancillary services costs for consumers (although these effects diminish as the surplus increases). This value can only be captured by a sloped demand curve. The fact that a vertical demand curve does not reflect the underlying value of capacity to consumer's electricity is the source of a number of the concerns described later in this section.

2. Attributes of Supply in a Capacity Market

In workably competitive capacity markets, the competitive offer for capacity (i.e., the marginal cost of selling capacity) is generally close to zero.[10] A supplier's offer represents the lowest price it would be willing to accept to sell capacity. This is determined by two factors: (1) whether there are costs the supplier will incur to satisfy the capacity obligations for the resource (the "going-forward costs", or "GFC"), and (2) whether a minimum amount of revenue is

10 This ignores potential opportunity costs of exporting capacity to a neighboring market.

necessary from the capacity market in order to remain in operation (i.e., the expected net revenues from energy and ancillary services markets do not cover GFC).

For most resources, the net revenues available from RTOs' energy and ancillary services markets are sufficient to keep a resource in operation. Hence, no additional revenue is needed from the capacity market (which would cause the supplier to submit a non-zero capacity offer). With regard to the first factor, suppliers that sell capacity in MISO are not required to accept costly obligations (that would substantially increase the marginal costs of selling capacity).

Hence, most suppliers are willing price-takers in the capacity market, accepting any non-zero price for capacity. One factor that could cause internal capacity suppliers to offer non-zero prices is the opportunity to export capacity. If such opportunities exist, suppliers should rationally include this opportunity cost in their capacity offer price. Currently, such opportunities are limited. Experience in the VCA has confirmed that most suppliers are essentially price-takers, submitting offers at prices very close to zero.

3. Implications of the Vertical Demand Curve for Performance of the Capacity Market

When the low-priced supply offers clear against a vertical demand curve, only two outcomes are possible. If the market is not in a shortage, the price will clear close to zero – this is illustrated in Figure 1 below and has characterized the recent VCA results in MISO. If the market is in shortage (so the supply and demand curves do not cross), the price will clear at the deficiency price, as shown in Figure 2.

Figure 1: Surplus Capacity Case

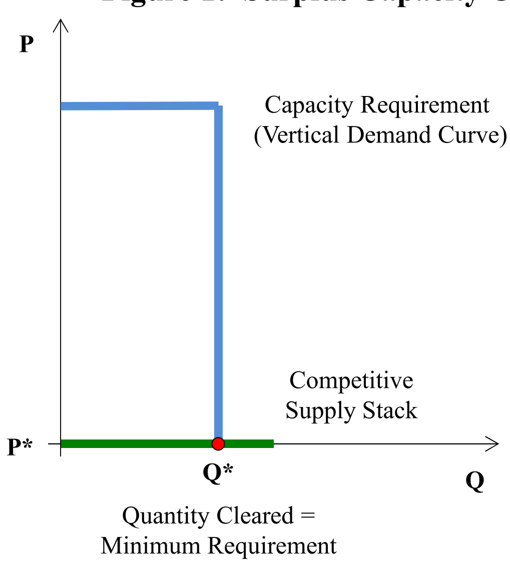
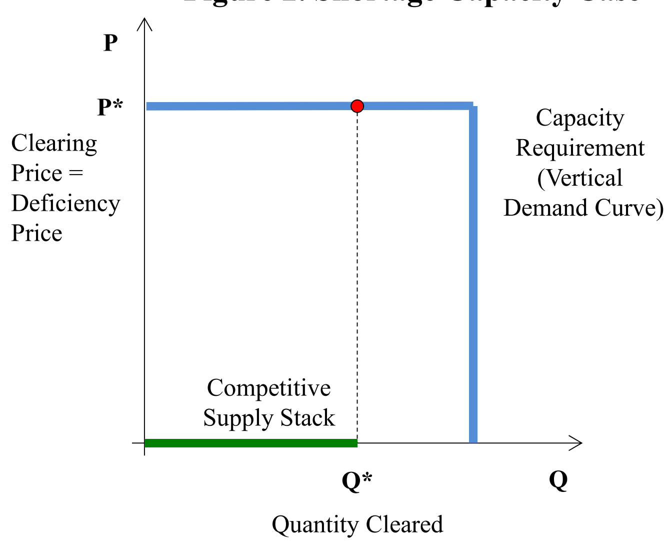


Figure 2. Shortage Capacity Case



This pricing dynamic and the associated market outcomes raise significant issues regarding the long-term performance of the proposed RAC. First, this market will result in significant volatility and uncertainty for market participants. This can hinder long-term contracting and investment by making it extremely difficult for potential investors to forecast the capacity market revenues. In fact, it may be difficult for an investor to forecast that the market will be short in the future with enough certainty that its forecasted capacity revenues will be substantially greater than zero. This would undermine the effectiveness of the capacity market in maintaining adequate resources.

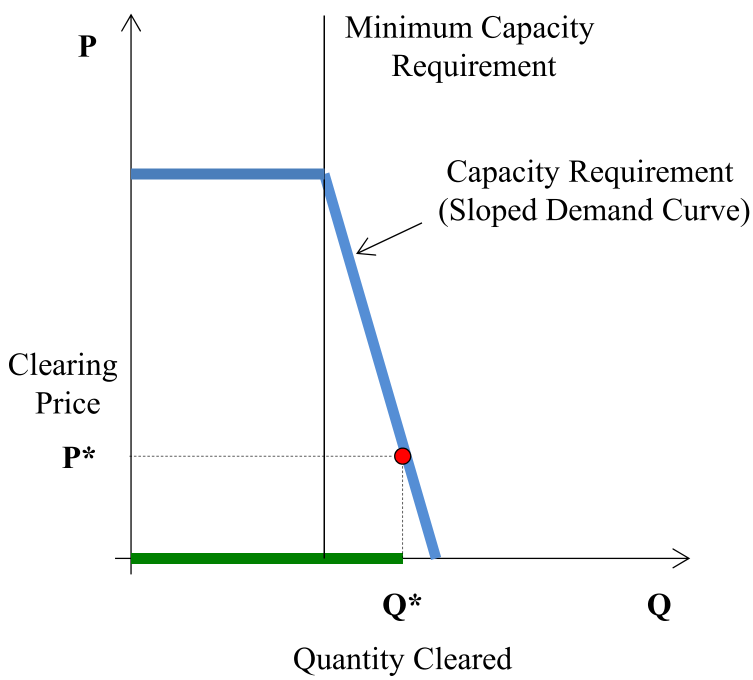
Second, since prices produced by such a construct do not accurately reflect the true marginal value of capacity, the market will not provide efficient long-term economic signals to govern investment and retirement decisions.

Third, a market that is highly sensitive to such small changes in supply around the minimum requirement level creates a strong incentive for suppliers to withhold resources to raise prices. Withholding in such a market is nearly costless since the foregone capacity sales would otherwise be priced at close to zero. Therefore, market power is of greater potential concern, even in a market that is not concentrated. These concerns grow when local capacity zones are introduced where the ownership of supply is generally more concentrated.

4. Benefits of a Sloped Demand Curve

A sloped demand curve addresses each of the shortcomings described above. Importantly, it recognizes that the initial increments of capacity in excess of the minimum requirement are valuable from both a reliability and economic perspective. Figure 3 illustrates the sloped demand curve and the difference in how prices would be determined.

Figure 3: Sloped Demand Curve



When a surplus exists, the price would be determined by the marginal value of additional capacity as represented by the sloped demand curve, rather than by a supply offer. This provides a more efficient price signal from the capacity market. In addition, the figure illustrates how a sloped demand curve would serve to stabilize market outcomes and reduce the risks facing suppliers in wholesale electricity markets. Because the volatility and its associated risk is inefficient, stabilizing capacity prices in a manner that reflects the prevailing marginal value of capacity would improve the incentives of suppliers that rely upon these market signals to make investment and retirement decisions.

A sloped demand curve will also significantly reduce suppliers' incentives to withhold capacity from the market by increasing the opportunity costs of withholding (foregone capacity revenues) and decrease the price effects of withholding. This incentive to withhold falls as the market approaches the minimum capacity requirement level. While it would not likely be completely effective in mitigating potential market power, it would significantly improve suppliers' incentives. Likewise, the sloped demand curve reduces the incentives for buyers or policymakers to support uneconomic investment in new capacity to lower capacity prices.

If a sloped demand curve is introduced, the MISO will need to work with its stakeholders to develop the various parameters that define the demand curve. We recognize that this process is likely to be difficult and contentious. However, in simply approving a minimum requirement and a deficiency price (i.e., a vertical demand curve), the Commission should recognize that some of the most important parameters are being established implicitly with no analysis or discussion. In particular, such an approach establishes a demand curve with an infinite slope, but with no analysis or support in the record for why an infinite slope is efficient or reasonable.

Key Observations: Capacity Market Design

ii. Based on both the theoretical and practical concerns with the current vertical demand curve, we 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 longer-term price signals and incentives to govern investment and retirement decisions; and
- Reduce the incentive to exercise market power in the capacity market by withholding resources.

iii. The need for a sloped demand curve may become particularly acute in MISO as the reserve margins continue to decline with the likely future retirement of significant amounts of coal-fired capacity.

- These retirements are likely because of a number of factors, including low natural gas prices, increased wind penetration, and the compliance costs associated with new EPA regulations.
- These retirements are expected to outpace net dependable capacity growth from wind units and new installed gas-fired capacity.

III. Day-Ahead Market Performance

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 A22 and Figure A23: Day-Ahead Energy Prices and Load

Figure A22 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 A23 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 A22: Day-Ahead Hub Prices and Load
Peak hours, 2011–2012

Figure A23: Day-Ahead Hub Prices and Load
Off-peak hours, 2011–2012

<u>Key Observations: Day-Ahead Energy Prices and Load</u>

i. Prices continue to be moderately correlated with load, exhibiting the highest prices in the summer months and, to a lesser extent, in winter months. However, as discussed in Section I.B, fuel prices generally play a larger role in determining energy prices.

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

- Despite greater wind generation in 2012, congestion occasionally occurred *into* Minnesota, particularly in April and in December.
  - ✓ This reversal in congestion generally occurs when network deratings or outages reduce net imports over the Manitoba interface or cause other significant change in network flows.
  - ✓ This resulted in narrower price differences among the four hubs than in prior years.
- Prices at Indiana and Michigan Hub separated most from the other hubs in July, when very high loads produced significant west-to-east power flows.

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. Convergence between day-ahead and real-time prices is a sign of a well-functioning day-ahead market, which is vitally important.

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 generators may be substantially affected because 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. However, 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 A24 to Figure A27: 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.[11] The table below the figures shows the average day-ahead and real-time price difference, which measures overall price convergence. We show it separately for prices including net real-time RSG charges, which are much higher than day-ahead charges and therefore should contribute to modest day-ahead premiums.

11 The rate is the Day-Ahead Deviation Charge Rate, which excludes the location-specific Congestion Management Charge Rate and Pass 2 RSG.

Figure A24: Day-Ahead and Real Time Price
2011–2012: Cinergy Hub

Figure A25: Day-Ahead and Real Time Price
2011–2012: Michigan Hub

Figure A26: Day-Ahead and Real Time Price
2011–2012: WUMS Area

Figure A27: Day-Ahead and Real Time Price
2011–2012: Minnesota Hub

MISO's ancillary service markets consist of day-ahead and real-time markets for regulating reserves, spinning 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. In mid-December, MISO added a regulation mileage compensation to its ancillary services markets, per FERC Order 755.

Figure A28: Day-Ahead Ancillary Services Prices and Price Convergence

Figure A28 shows monthly average day-ahead clearing prices in 2012 for each ancillary service product, along with day-ahead to real-time price differences.

Figure A28: Day-Ahead Ancillary Services Prices and Price Convergence
2012

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

i. In 2012, there was a day-ahead premium of 3.6 percent at the Indiana Hub, 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. This is up from 2.0 percent in 2011.

ii. After accounting for $0.58 per MWh in average RSG cost allocations to day-ahead deviations, the adjusted day-ahead premium was 1.7 percent at Indiana Hub and was close to zero at the Minnesota Hub and WUMS Area.

  – Real-time RSG costs in 2012 fell over 40 percent from 2011, when the average allocation rate of $0.96 per MWh.

iii. As in 2011, modest day-ahead premiums prevailed in all of the MISO regions except at the Minnesota Hub in the West region, where occasional congestion into the region occurred because of:

- A day-ahead modeling issue and the outage of the 500-kV line from Manitoba, (resulting in the West being import-constrained) in late spring; and
- Transmission outages and derates, many of which are associated with LIDAR surveys. These outages and derates were largest in November and December.

iv. Over the long term, we expect small day-ahead premiums because scheduling load day-ahead reduces risk associated with higher real-time price volatility and because of higher RSG cost allocations to real-time deviations.

v. Absolute average price differences declined at all four hubs and were lowest at the Minnesota Hub and WUMS Area.

- This was most apparent in the first half of the year, when natural gas prices were lowest.
- Lower natural gas prices result in smaller differences between coal and natural gas generation offers which lowers congestion by lowering redispatch costs. This in turn reduces price volatility.

vi. Wind generation remained considerably under-scheduled day-ahead in 2012. However, virtual supply offset much of this discrepancy.

vii. Day-ahead market clearing prices for regulation and spinning reserves declined by over 20 percent from 2011.

- As discussed in the real-time market section below, ancillary services prices in the day-ahead (and real-time) often clear based on the opportunity costs of providing them rather than energy. Hence, ancillary service prices track energy prices, falling in 2012 overall and peaking in July.

viii. Day-ahead contingency reserve prices converged reasonably well with real-time prices, except in July when there were 25 intervals exhibiting real-time operating reserve shortages.

- In general, the day-ahead market did not anticipate these shortages, resulting in an average real-time premium for all products (since higher-quality reserves can be substituted for lower-quality reserves).

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 net day-ahead 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 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 increased supply 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;
- Under-scheduled wind output in the day-ahead market; and
- Real-time net imports above day-ahead schedules.

Figure A29: Day-Ahead Scheduled Versus Actual Loads

To show net load-scheduling patterns in the day-ahead market, Figure A29 compares the monthly day-ahead scheduled load to actual load in 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 shows the average scheduling levels in all hours and for the peak hour.

Figure A29: Day-Ahead Scheduled Versus Actual Loads
2010–2012, Daily Peak Hour

Key Observations: Load Scheduling

i. During the peak hour, when MISO commitments are most often required, load in MISO remained fully scheduled at 100.7 percent, a slight increase from 2011.

   – Full load scheduling allows the day-ahead commitments to align with commitment needed in real time, which generally reduces RSG payments.

ii. Over all hours, load was slightly under-scheduled at 99.4 percent. This was most apparent during off-peak hours when load was considerably under-scheduled at times.

   – Under-scheduling of load in off-peak hours often does not result in additional real-time commitments since headroom is usually large in off-peak hours.

D. Fifteen-Minute Day-Ahead Scheduling

The day-ahead energy and ancillary services market currently solves on an hourly basis. As a result, all day-ahead scheduled ramp demands coming into the real-time market, including unit commitments, de-commitments, and changes to physical schedules are concentrated at the top of the hour.

MISO currently has several options to manage the top-of-the-hour changes, including: staggering unit commitments (this can result in increased revenue sufficiency guarantees), proactively using load offsets to reduce ramp impacts. Nonetheless, the ramp demands can be substantial and can produce significant price volatility.

Figure A30 below shows the implied generation ramp demand attributable to day-ahead commitments and physical scheduling compared to real-time load changes. When the sum of these changes is negative, online generators are forced to ramp up to balance the market. When the sum is positive, generators are forced to ramp down.

Figure A30: Ramp Demand Impact of Hourly Day-Ahead Market
Summer 2012

Key Observations: Fifteen-Minute Scheduling

i. Absent actions taken by MISO operators, online generators would be forced to ramp down at the top of morning ramp-up hours, and vice versa during evening hours to accommodate losses of physical schedules and unit de-commitments.

   – Since MISO is generally a net importer, commitment and physical schedule changes are usually in the same direction (i.e., reduce generation demand in the morning ramp hours and increase generation demand in the evening ramp hours).

   – The average implied ramp demand during the first two intervals in an hour is -455 MW in morning ramp hours and over 650 MW in evening ramp hours.

ii. Running the day-ahead market based on fifteen-minute intervals would result in more flexible commitments and schedules that could better align scheduled ramp with actual ramp demand in real time.

- Since IT limitations that had once prevented a more granular day-ahead market have fallen over time, MISO should evaluate the costs and benefits of revising its day-ahead market to schedule energy and ancillary services on a 15-minute basis.

E. 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 to arbitrage prices between 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 would 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. In this case, the participant would 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 A31: Virtual Transaction Volumes

Figure A31 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 2010 to 2012. 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 $20 above or below an expected real-time price, respectively, are considered price-insensitive. A subset of these volumes, which we identify to have contributed materially to an unexpected difference in the congestion at the location between the day-ahead and real-time markets, warrant closer investigation. These volumes are labeled ‘Screened Transactions’ in the figure.

Figure A31: Virtual Transaction Volumes
2011–2012

Figure A32: Virtual Transaction Volumes by Participant Type

Figure A32 shows the same results but additionally distinguishes between physical participants (those that own generation or serve load, including their subsidiaries and affiliates), and financial-only participants.

Figure A32: Virtual Transaction Volumes by Participant Type
2012

Figure A33: Virtual Transaction Volumes by Participant Type and Location

Figure A33 disaggregates transaction volumes further by type of participant and type of location: Cinergy and Indiana Hubs, 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 are. Indiana Hub remained the single most liquid trading point in MISO during 2012.

Figure A33: Virtual Transaction Volumes by Participant Type and Location
2010–2012

Figure A34: Matched Virtual Transactions

Figure A34 shows monthly average cleared virtual transactions that are considered price-insensitive. As discussed above, price-insensitive bids and offers are priced to make them very likely to clear. "Matched" virtual transactions are subsets of these transactions where the participant clears both insensitive supply and insensitive demand in a particular hour. Such transactions are most often placed for two reasons:

- A participant seeking an energy-neutral position across a particular constraint.
- A participant seeking to balance their portfolio. RSG deviation charges to virtual participants are assessed to net virtual supply, so participants can avoid such charges by clearing equal amounts of supply and demand. Hence, "matched" transactions rose substantially after the April 2011 revisions.

Figure A34: Matched Virtual Transactions
2010-2012

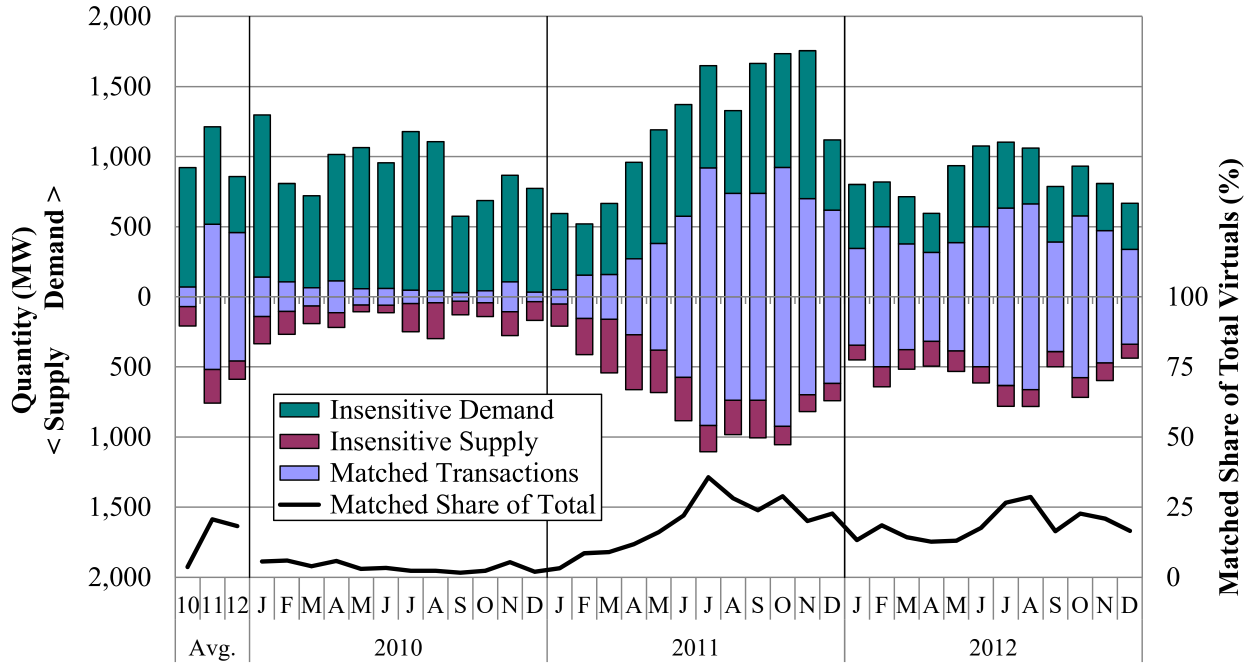


Figure A35: Virtual Transaction Volumes, MISO and Neighboring RTOs

To compare trends in MISO to other RTOs, Figure A35 shows virtual supply and demand in MISO, ISO New England (ISO-NE), and New York ISO (NYISO) as a percent of actual load.

Figure A35: Comparison of Virtual Transaction Volumes
2010–2012

Key Observations: Virtual Transaction Volumes

i. Offered total virtual volumes (demand and supply) rose 14 percent from 2011, while cleared volumes rose 3 percent.

   – The increase in offered demand by physical participants in the second half of 2012 was due to one participant offering at very low prices that rarely cleared.

ii. The price-sensitivity of volumes improved modestly in 2012. Just fewer than 60 percent of cleared volumes were price-sensitive, up from 50 percent in 2011.

   – Nearly two-thirds of insensitive volumes, and 18 percent of all virtual volumes, were "matched" transactions.

      ✓ These transactions are most likely to benefit from a spread bid product.

   – The substantial rise in matched transactions from 2010 (when just four percent of all volumes were matched) is mostly due to RSG allocation revisions.

      ✓ In determining a participant's deviations that will be the basis for allocating it RSG costs, MISO now nets the participants virtual load and virtual supply. This has increased the incentive for participants to balance their portfolio.

iii. To the extent that matched transactions are attempting to arbitrage congestion-related price differences, a virtual spread product to allow participants to engage in these transactions price sensitively would be more efficient and would likely improve the price convergence between the two markets at locations affected by congestion. PJM and ERCOT both have similar products.

- Participants using such a spread product would specify the maximum congestion difference between two points they are willing to pay (up to which they are willing to schedule a transaction)

- The transaction would be profitable if the difference in real-time congestion between the source and the sink is greater than the day-ahead difference, and would lose money if it is less.

- The product would settle only on the difference in the congestion component of the LMP, so there is no energy risk. In addition, since it would only clear as a spread, there is no execution risk comparable to the risk participants face today of only one side of the "matched" transactions clearing.

iv. Fewer than two percent of cleared volumes were "screened" as contributing to a material divergence in prices, which up slightly from 2011.

- No virtual bid restrictions were imposed in 2012.

v. MISO recently filed Tariff changes to reverse the CMC rate sign error, which caused congestion-related RSG costs to be misallocated to virtual transactions. This is addressed more fully in Section IV.

vi. In 2012, financial-only participants continued to provide most of the virtual liquidity in the day-ahead market and offered much more price-sensitively than physical participants.

- Approximately 31 percent of financial-only participant volumes were price-insensitive (down from 39 percent in 2011), compared to nearly 72 percent of physical participant volumes (down from 82 percent in 2011).

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

- The vast majority of physical participants' volumes were demand bids placed at hub locations.

F. 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 A36: Virtual Profitability

Figure A36 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 A36: Virtual Profitability
2011–2012

Figure A37: Virtual Profitability by Participant Type

Figure A37 shows the same results disaggregated by type of market participant: entities owning generation or serving load, and financial-only participants.

Figure A37: Virtual Profitability by Participant Type
2012

Key Observations: Virtual Profitability

i. Gross virtual profitability declined $0.06 per MW from 2011 to an average of $0.52 per MW in 2012.

- This is in line with prior years and consistent with expectations—it has averaged between $0.32 and $0.80 since 2006.
- Total virtual profits declined comparably from $35.4 million in 2011 to $32.6 million in 2012.

ii. As expected, virtual supply was considerably more profitable ($1.31 per MW), than virtual demand ($-0.15).

- These outcomes are consistent with the prevailing day-ahead premium.
- The real-time RSG costs allocated under the DDC rate averaged $0.58 per MW, which lowered the net profitability of virtual supply transactions.
- Low virtual profitability is consistent with a competition and liquid in the day-ahead market, which allows it to efficiently schedule MISO's generating resources.

iii. Transactions by financial-only participants in 2012 were considerably more profitable (at $0.89 per MW) than those by physical participants ($-0.36).

- As noted above, physical participants (notably LSEs) have consistently incurred losses on virtual demand, likely to hedge against real-time price risk or supply availability.

- This pattern of losses was most acute during peak hours on high-load days in summer. In July, demand profitability for these participants averaged nearly $-2.00 per MW.

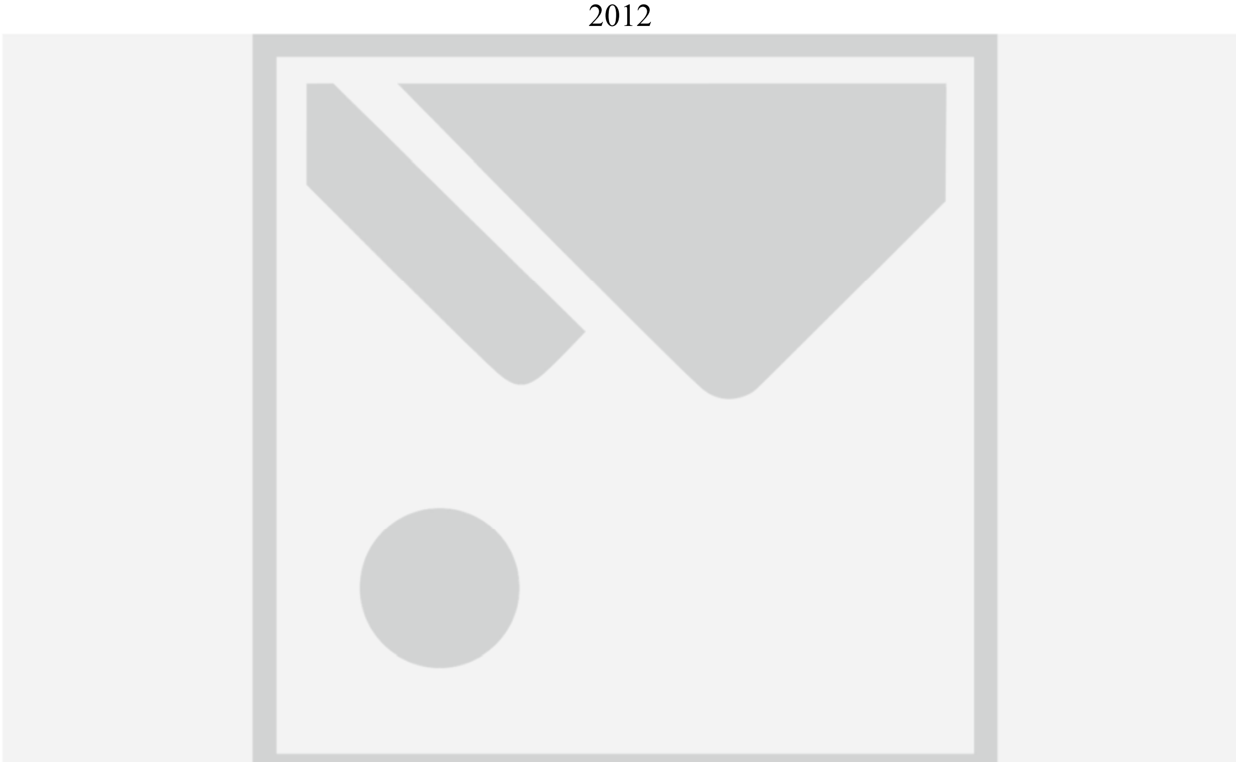
G. Load Forecasting

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 Forward Reliability Assessment Commitment (FRAC) process, which is 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.

Figure A38: Daily MTLF Error in Peak Hour

Figure A38 shows the percentage difference between the MTLF used in the FRAC process and real-time actual load for the peak hour of each day in 2012.

Figure A38: Daily MTLF Error in Peak Hour
2012



Key Observations: Load Forecasting

i. In 2012, MISO generally forecasted peak-hour loads accurately. Several observed patterns continued from previous years:

- The average forecast error was considerably greater in absolute terms in summer months because of the higher uncertainty associated with weather-related loads.
  - ✓ The timing of weather fronts that can substantially increase or decrease temperatures contributes to the load forecast errors.
- Load was under-forecasted on each of the seven highest-load days of the year, by 3.2 percent, on average.
- Load was modestly under-forecasted in other seasons, particularly in fall.
- Roughly half of this impact is attributable to misalignment of the forecasted and actual peak hour, which biases these results toward under-forecasting.

ii. Overall, we find that MISO's load forecasting was consistent with the performance of other RTOs and did not generally raise significant concerns.

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 ongoing 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 A39 and Figure A40: 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 subsection 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, Net Scheduled Interchange (NSI), or generation startup or shutdown. This is exacerbated by generator inflexibility arising from lower offered ramp limits or dispatch range.

Figure A39 and Figure A40 show the interval-level, average real-time prices by time of day in summer and winter 2012, respectively. Five-minute price volatility in MISO decreased substantially with the introduction of jointly-optimized energy and ancillary services markets in 2009, but it remains high relative to other RTOs in the Eastern Interconnect. The figure also shows two key drivers of price volatility: changes in NSI and the effective headroom on the system. Effective headroom is the amount of additional generation available in the next five minutes, given individual resource ramp limitations.

Figure A39: Real-Time Prices and Headroom by Time of Day
2012: Summer

Figure A40: Real-Time Prices and Headroom by Time of Day
2012: Winter

Figure A41: Five-Minute, Real-Time Price Volatility

Figure A41 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 more 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 A41: Five-Minute, Real-Time Price Volatility
MISO and Other RTO Markets, 2012

Figure A42: Factors that Contribute to High Energy Prices

The next analysis evaluates the factors that contributed to relatively high system marginal prices in MISO. These high prices were generally the result of binding ramp constraints on many resources that occurred when the system requirements changed rapidly. For this analysis, we evaluated high-priced events, defined as uninterrupted periods of one or more five-minute intervals with an SMP greater than $175 per MWh. There were 208 such events in 2012, lasting on average 1.7 intervals. The longest event lasted nine intervals, or 45 minutes. In nearly three-quarters of the events, the market was short one or more ancillary services products. 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 reserves or regulation.

Figure A42 shows primary causes of high SMPs during 2012. In each high-priced event, the system was 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 (as listed in the legend in the figure). When one of these factors produced a ramp demand greater than 300 MW leading into the shortage, we classify that factor as a contributor to the shortage. More than one factor could contribute materially to the same shortage; in a few shortages, none of the nine contributed.

Figure A42: Contributors to High-Priced Events
2012

Key Observations: Real-Time Price Volatility and High Priced Events

i. The fluctuations in real-time prices are directly related to ramp demands at the top of the hour when NSI changes and unit commitments and decommitments occur. Generation decommitment effects are largest in the evening when generators are shutting down.

ii. Price volatility declined approximately 25 percent from 2011 to an average of $5.19 per interval, or 19 percent of the average price.

- This is partly due to a reduction in natural gas prices, which allows more flexible natural gas units to be competitive with baseload generation.
- Price volatility remained highest at the Minnesota Hub (at 23 percent) because of fluctuations in wind output and lower average prices.
- Approximately one-half of the wind output was DIR in 2012 and was able to respond to dispatch instructions, which improved wind output manageability and lowered price volatility.

iii. Overall, price volatility in MISO remains considerably higher than in neighboring RTOs.

- 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).

iv. 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.

v. In most cases, price volatility is a result of relatively high energy prices that are often transitory. Intervals priced at greater than $175 per MWh occurred 361 times in 2012, or 0.34 percent of all intervals, down from 609 intervals last year.

- The majority of high-priced intervals were 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.

vi. 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 (over 50 percent of ramp-constrained intervals) or net interchange (11 percent of intervals).
  - ✓ Although reductions in net imports were significant in only 38 intervals, they were a key cause of some of the severe shortages that occurred in early July.
  - ✓ This is discussed in greater detail in Section II.B.
- The offset parameter, which allows the operators to increase or decrease the load served by the real-time market, contributed to 22 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 seven percent of high-priced intervals.
- Potential economic withholding, as identified by the "output gap" metric, was significant in only two intervals, both in July.

vii. The introduction of the Look-Ahead Commitment (LAC) tool in 2012 improved the efficiency of commitments made during the operating day.

- The vast majority of real-time peaking unit commitments are now made based on the suggestions made by the LAC tool.
- We have recommended further improvements to the real-time commitment process, including a Look-Ahead Dispatch (LAD, a multi-period dispatch optimization) and a ramp capability product to improve system flexibility.

B. ASM Prices and Offers

Scheduling of energy and operating reserves, which include 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 important 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 may play a key role in providing long-term economic signals to invest in new resources.

Figure A43: Real-Time Ancillary Service Prices and Shortages

Figure A43 shows monthly average real-time clearing prices for ASM products in 2012. It also shows the frequency with which the system was short of each class of reserves. We show separately the impact of each product's shortage pricing.

Figure A43: Real-Time Ancillary Services Clearing Prices and Shortages
2012

Figure A44: Regulation Offers and Scheduling

ASM offer prices and quantities are primary determinants of ASM outcomes. Figure A44 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 highest cleared offers because the prices 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. Hence, 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 A44: Regulation Offers and Scheduling
2012

Figure A45: 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, provided by offline units that can respond within 10 minutes (including startup and notification times). As noted above, 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 prices paid to 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 A45 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 A45: Contingency Reserve Offers and Scheduling
2012

<u>Key Observations: ASM Prices and Offers</u>

i. Monthly average market clearing prices for all ancillary services products declined from 2011 averages because of lower gas prices (which reduced the opportunity cost of providing reserves) and fewer spinning reserve shortages.

- Market clearing prices for regulation declined 26 percent from 2011 to $8.88 per MWh.
  - ✓ Prices peaked in July at $13.46 per MWh, but more than one-third of this average price was associated with contingency reserve shortages that occurred in July.
- Contingency reserve shortages rose nearly four-fold and contributed nearly $0.50 to each reserve product's market clearing price.

ii. Per FERC Order 755, MISO introduced a two-part compensation scheme for regulation in December that paid participants separately for regulation capacity and for "mileage" service (actual up and down movement).

- Many participants' regulation offer prices rose considerably after this change due to a lack of familiarity with the two-part offers. This had only a limited impact on clearing prices.

iii. Spinning reserve prices averaged $2.74 per MWh, a 13 percent decline from 2011.

iv. Supplemental reserve prices declined 4 cents to average $1.58 per MWh. Such reserves were deployed just three times in 2012 (see Figure A49).

v. Although the average clearing price for regulation was nearly $9 per MWh, sufficient capability was generally available to meet the requirement with offers less than $1.

- Similar conditions prevailed for spinning and supplemental reserves, where the average clearing price was considerably higher than the marginal unit's offer price.
- As discussed previously these differences reflect opportunity costs of not providing energy and, to a lesser extent, the impact of shortage pricing.

C. ASM Shortages

Figure A46: 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. 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.[12] To minimize such outcomes, MISO should set the market requirement to make market results as consistent with real conditions as possible. Figure A46 shows all intervals in 2012 with a real (physical) shortage, a market shortage, or both, as well as the physical and market requirement.

12 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 A46: Market Spin Shortage Intervals vs. Rampable Spin Shortage Intervals
2012

Figure A47: Regulation Deficits and Clearing Prices

The next two figures examine shortage pricing of regulating and spinning reserves, respectively. Figure A47 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.

Figure A47: Regulation Deficits vs. Clearing Prices
2012

Figure A48: Spinning Reserve Deficits and Clearing Prices

Figure A48 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. Modeled constraints prevent the real-time market from taking actions more costly than a predetermined amount (set at $98 per MWh in 2012) plus the prevailing operating reserve clearing price to maintain its spinning reserve.[13] MISO introduced a lower penalty price (set at $65 per MWh) for shortages less than 10 percent of the reserve requirement in 2012.

13 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 A48: Spinning Reserve Deficits vs. Clearing Prices
2012

Figure A49: Non-Responsive Supplemental Reserve Deployments

Supplemental reserves are deployed during Disturbance Control Standard and ARS events. Figure A49 shows offline supplemental reserve response during the eight deployments in 2011 and 2012, separately indicating those that were successfully deployed within 10 minutes (as required by MISO) and within 30 minutes (as required by NERC).

Figure A49: Supplemental Reserve Deployments
2011–2012

Key Observations: Ancillary Services Markets

i. Inconsistencies between market and real (capacity or ramp-limited) spinning reserve shortages persisted in 2012. For over 90 percent of market shortages, there was no accompanying real shortage.

   – This indicates that the market requirement was set slightly too higher and that some of the shortages occurred because the costs to procure the reserves exceeded the price the market model was willing to pay.

   – There were five intervals of real shortage that were not reflected in the market price.

ii. Shortage pricing for all reserve products now relies on demand curves that reflect the increasing cost of a shortage, which rises proportionate to the size of the shortage.

   – Regulation shortage pricing occurred reliably at the monthly regulating reserve demand curve penalty price (which averaged $113.20 per MWh in 2012). This sends efficient economic signals to the market.

   – The initial point on the contingency reserve demand curve is $1,100 per MWh (the sum of the price caps for energy and contingency reserve offers) and goes up to the predetermined Value Of Lost Load (VOLL, set at $3,500 per MWh) minus the penalty price for regulation. This is a reasonable demand curve for contingency reserves.

iii. MISO adopted a two-step demand curve for spinning reserves on May 1, 2012. Shortage quantities of less than 10 percent of the reserve requirement were thereafter priced at $65 per MWh, while those exceeding 10 percent were priced at $98 per MWh.

- Shortage prices in 2012 were mostly clustered around these two price points, indicating that MISO reliably priced their reserves at the predetermined penalty price, and that the requirement was not often relaxed significantly.
- The four shortage intervals priced below $65 per MWh all occurred prior to this modeling change.

iv. There were only three supplemental reserve deployments in 2012. Unit responses improved considerably from prior years, with nearly all deployed quantities delivered within 10 minutes.

v. When quick-start units carrying offline supplemental reserves are committed for energy, MISO does not account for either energy or reserves until it is fully synchronized, which can take 5 to 15 minutes.

- This accounting discrepancy affected 2.3 percent of market intervals in 2012 by an average of 107 MW, caused two operating reserve shortages, and contributed materially to an additional seven OR price spikes of at least $100 per MWh.
- MISO should pursue changes to the accounting of its reserves that would recognize the reserves being provided during the period when a quick-start unit is starting.

D. Generation Availability and Flexibility in Real Time

The flexibility of generation available to the real-time market provides MISO the ability to manage transmission congestion and satisfy energy and operating reserve obligations. 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 A50: Changes in Supply, Day-Ahead Market to Real-Time Market

Figure A50 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 and 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 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 between the day-ahead and real-time markets. A net shortfall indicates that MISO would need to commit additional capacity, while a surplus would allow MISO to decommit or shorten real-time MISO commitment periods. The amount actually committed for capacity in real time is not included in the figure.

Figure A50: Changes in Supply, Day-Ahead Market to Real-Time Market
2011–2012

Figure A51: 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 dispatchable 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 A51 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.E.

Figure A51: Real-Time Dispatchable Range
2010–2012

Key Observations: Availability of Generation in Real Time

i. On average, 1.9 GW (3.1 percent) of capacity scheduled in the day-ahead market was unavailable in real time, a modest decline from the 3.2 percent recorded last year.

 – Participants that decide not to start their units in real time due to unfavorable economics remain financially responsible for their day-ahead scheduled output.

ii. This lost capability was offset by 585 MW of capacity increases from suppliers increasing their dispatch maximum in real time and 1,228 MW of self-scheduled or MISO-committed resources.

 – Changes in commits by suppliers in real time can add or subtract significant amounts of available real-time capacity as suppliers self-commit (units not committed in the day-ahead market), or decommit (units committed in the day-ahead market) based on their forecast of real-time prices.

 – Most of MISO's dispatch flexibility continues to be provided by steam units. However, steam units provide similar flexibility as most other types of resources (i.e., dispatch ranges from 30 to 45 percent of their economic maximums).

- The average flexibility offered by MISO generators remains approximately 60 percent of what they are physically capable of providing.

- The slight increase in dispatch flexibility is due to the increase in DIR participation by wind resources.

  - ✓ While DIR flexibility helps to manage congestion, its benefits for ramp management are limited to periods with sharp decreases in load or low absolute load levels such as Minimum Generation Events.

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.[14] Resources committed after the day-ahead market receive most of the RSG payments in MISO because this is the timeframe in which MISO must make most out-of-merit 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 payments. MISO commits resources in real time for many reasons; including to meet (1) capacity needs that can arise during peak load or sharp ramping periods, (2) real-time load under-scheduled day-ahead, or (3) a local reliability need to manage congestion or maintain the system's voltage in a location. Beginning in the fall of 2012, MISO began making many voltage and local reliability commitments in the day-ahead market. Nonetheless, the majority of RSG costs associated with reliability commitments remain in real time.

Peaking resources are the most likely to receive RSG payments because they are the highest-cost class of resources and, even when setting price, receive minimal LMP margins 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 A52 to Figure A54: RSG Payment Distribution

Figure A52 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 A53 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.[15]

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

15 We examine market power issues related to commitments for voltage support in Section VII.

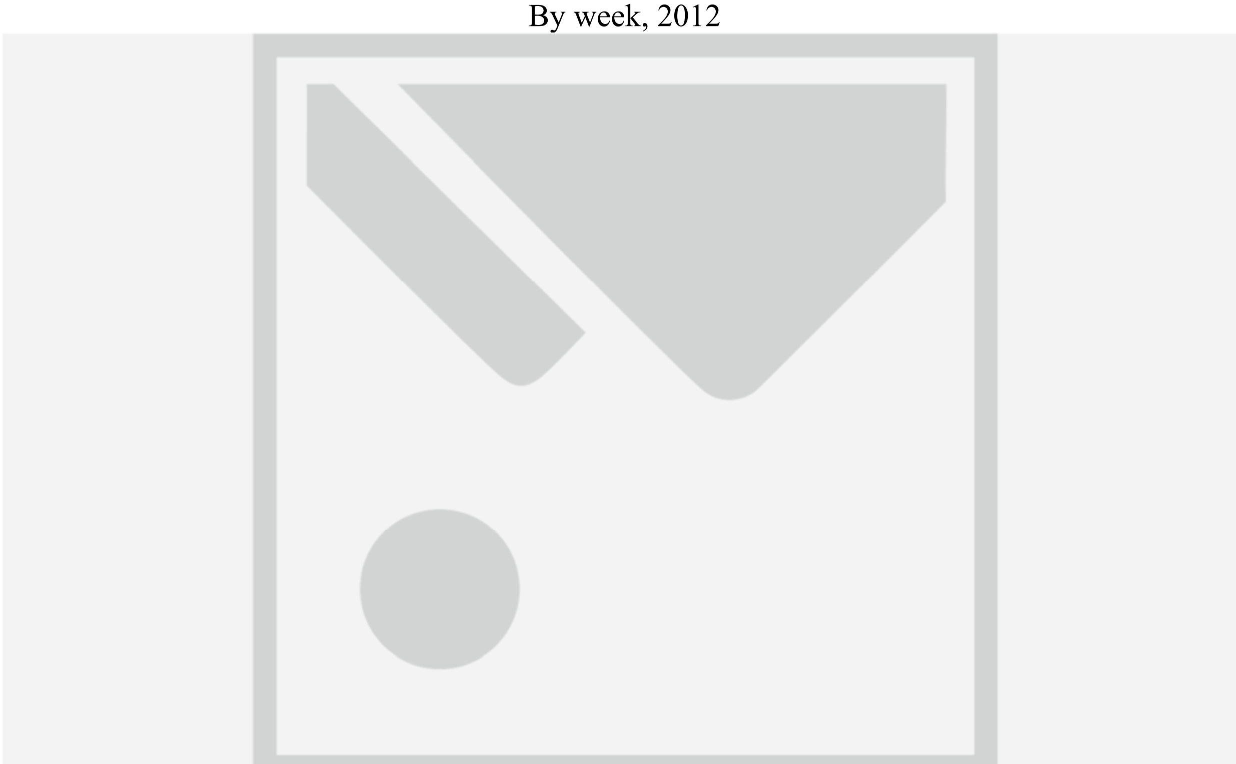
Figure A52: Total Day-Ahead RSG Payments
Fuel Adjusted, 2011–2012

Figure A53: Total Real-Time RSG Payments
Fuel Adjusted, 2011–2012

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 congestion management (or other local need) or a capacity need. When committing a resource for congestion management, MISO operators identify the particular constraint that is being relieved. Supply and demand deviations from the day-ahead market that contribute to the need for the commitment (deviations that increase flow on the identified constraint) are allocated a share of the RSG costs under the CMC rate. Any constraint-related RSG costs not allocated under the CMC rate are currently allocated to net participant deviations (negative net deviations pre-notification deadline (NDL) and all deviations post-NDL) under the DDC rate. Any residual RSG cost is then allocated market-wide on a load-ratio share basis ("Pass 2").[16]

Figure A54 summarizes, in the top panel, how real-time RSG costs were allocated among the DDC, CMC, and Pass 2 charges in each week of 2012. The bottom panel shows daily average total net deviations from the day-ahead, for each week in 2012, as well as the total deviations that are paying the DDC charge. Since the CMC allocations are inappropriately limited based on the GSF of the committed unit, a significant portion of RSG costs that should be allocated to CMC deviations are passed on to the DDC charge. We have recommended that MISO eliminate the GSF factor from the CMC allocation formula.

Figure A54: Allocation of RSG Charges
By week, 2012



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

Figure A55: Allocation of Constraint-Related RSG Costs

Figure A55 examines more closely 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 three blue blocks is allocated to market-wide deviations under the DDC rate. The lightest blue 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. As discussed previously, the second block occurs because MISO allocates only the portion of the costs based on the GSF of the committed unit that corresponds to its actual relief (counterflows) over the constraint, and not the full cost. The darkest blue block is allocated under the DDC rate for reasons we cannot identify, but may be due to errors in logging or the definition of the constraint.

Figure A55: Allocation of Constraint-Related RSG Costs
2011–2012

Key Observations: RSG Payments

i. Real-time RSG payments declined 41 percent from 2011 to 2012.

– This reduction was mostly due to substantially lower fuel prices. Hence, payments adjusted for changes in fuel prices were more than 13 percent greater than their nominal equivalent.

ii. Commitments for voltage support, which used to be made in real time, were mostly shifted to the day-ahead market beginning in September. Accordingly, day-ahead RSG payments declined just eight percent from last year.

- These commitments can raise market power concerns because a supplier facing little or no competition to resolve voltage and local reliability (VLR) issues has the ability to extract substantial market-power rents.
- In mid-2012, MISO instituted tighter mitigation measures for such local reliability situations and modified the allocation of RSG costs related to VLR commitments so that nearby LBAs pay the vast majority.

iii. Payments for real-time capacity commitments declined by more than one-half to a fuel-adjusted $27.1 million.

- Capacity needs were modest except in July, when record loads required significant real-time commitments on many days.
- Load was significantly under-scheduled on very few days in 2012, which limited the capacity commitment needs of MISO in real time.

iv. Payments for commitments made to resolve congestion, however, rose by 24 percent to a fuel-adjusted $17.9 million.

v. Our analysis indicates that the current allocation of real-time RSG costs remains somewhat inconsistent with principles of cost-causation.

- 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.
  - ✓ This inappropriately reduced CMC charges and correspondingly increased DDC charges by almost $8 million in 2012.
- As a result, the net deviations affecting the identified constraints bore approximately half of these RSG costs and the balance was borne by the market-wide deviations.
- Consequently, the vast majority of RSG costs again were charged under the DDC rate. Only in October, when there were significant transmission outages in the Central region, did CMC-allocated costs exceed 20 percent of the total.

vi. The lack of market-wide netting and other rules related to the calculation of deviations to allocate RSG costs also contributed to the over-allocation of costs to deviations.

- Net deviations averaged -121 MW and were negative in 47 percent of hours.
- Negative net deviations, if calculated in a manner consistent with cost causation, should reduce the need for MISO to commit resources for capacity, and therefore would not contribute to any real-time RSG costs.

vii. Finally, the CMC formula in 2012 continued to reflect a flaw affecting the allocation to virtual transactions. In 2011, the Commission ordered a change to the MISO Tariff provision pertaining to the CMC allocation to virtual transactions that inadvertently reversed the allocation.

- MISO filed several Tariff changes in late February 2013 that have been approved by the Commission to correct this and improve the efficacy of the RSG rules.

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 A56: Price Volatility Make-Whole Payment

Figure A56 shows total monthly PVMWP statistics 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 will be relied upon for redispatch more so than other suppliers due to larger price fluctuations and because the SMP volatility does not include volatility related to transmission congestion.

Figure A56: Price Volatility Make-Whole Payments
2011–2012

Figure A57 disaggregates the two make-whole payments into three categories: (1) *Net Energy Cost Recovery*, the amount of each payment due to price differences between the day-ahead market and real time; (2) *Margin Recovery*, the additional amount needed to ensure the supplier's day-ahead margin is not reduced because it responded to the real-time dispatch instructions; and (3) *Infeasible/Unavoidable Margin*, the difference in market payments between what is achievable day-ahead (assuming 60 minutes of ramping capability) and in real time (assuming five minutes of ramping), when units are ramping up or down as quickly as possible in real time.

Figure A57: Price Volatility Make-Whole Payment Distribution
2012

Key Observations: Price Volatility Make-Whole Payments

i. Total PVMWP declined 25 percent to $63.2 million in 2012, consistent with the decline in SMP volatility.

- Payments were greatest in July, when SMP volatility was highest due to a substantial number of ancillary services shortages, including 25 intervals of operating reserve shortages.

- LMP-based volatility was greatest in October due to significant transmission outages in the Central region, but this required payments to a relatively small set of units.

- In late January, MISO implemented a new contingency analysis tool which provided more timely and accurate information for the dispatch model. This enhancement also contributed to the decline in price volatility.

ii. DAMAP, which declined 25 percent in 2012 to $50.0 million, was paid predominantly to flexible coal units during ramping hours. RTORSGP declined 22 percent to $13 million.

- The majority of these payments were for net energy cost recovery, with approximately one-third going to margin recovery (above cost).

– Payments for infeasible and unavoidable energy, which is inherent to the discrepancy between the scheduling timeframe for the day-ahead and real-time markets, were a very small portion of total PVMWP.

iii. In 2012 the IMM made a referral to FERC regarding a resource which was inappropriately paid DAMAP for energy that was scheduled in the day-ahead but was unavailable in real time.

– The resource remained eligible in real time in part because it did not update its real-time offers to reflect its derated capacity.

✓ In addition, MISO eligibility rules did not identify that the resource was "dragging" and unable to follow its base points.

– IMM screening of operational and market data identified significant quantities of unit derates that went unreported by MPs to MISO, which resulted in significant quantities of inappropriate DAMAP payments and avoided RSG allocations.

– The unreported derated capability would have been erroneously considered by MISO's reliability assessment evaluations as available.

✓ A portion of this was also inappropriately paid for providing reserves that could not have been provided if called upon.

– In response, we recommend several changes to the DAMAP eligibility rules and MISO operating procedures.

G. Five Minute Settlement

While MISO clears the real-time market in five-minute intervals and schedules physical transactions on a 15-minute basis, it settles both physical transactions and generation on an hourly basis. The five-minute real-time market produces prices that more accurately reflect system conditions and aides in more rapid response to system ramp and congestion management needs than longer intervals used in some other markets. Hourly settlement, however, creates financial incentives that are often in opposition to the five-minute dispatch signals for generators. When an hourly settlement value is anticipated to be higher than a resource's incremental cost, the resource has the incentive to dispatch up regardless of MISO's basepoint instruction, provided it stays within MISO's deviation tolerances.

MISO has attempted to address the discrepancy between the five- minute dispatch and the hourly settlement incentives with the PVMWP. The PVMWP are intended to induce generators to provide dispatch flexibility and to respond to five-minute dispatch signals. While the PVMWP remove some of the disincentives a generator would have to follow five-minute dispatch signals under the hourly settlement, settling on a five-minute basis for generation would provide a much stronger incentive for generators to follow five-minute dispatch. It would also remove incentives for generators to self-commit in hours following price spikes to profit from hourly settlements and it would be compatible with other MISO initiatives (e.g., a ramp product). The five-minute settlement of physical schedules would remove similar harmful incentives for physical schedules.

Figure A58: Net Energy Value of Five-Minute Settlement

The next figure examines the over- and under-counting of energy value associated with the hourly settlement of the five-minute dispatch. The hourly settlement is based on a simple average of the five-minute LMPs and is not weighted by the output of the resource. A resource tends to be undervalued when its output is positively correlated with LMP and vice versa. For example, a resource that produces more output in intervals when five-minute prices are lower than the hourly price would be over-valued.

The figure shows the differences in energy value in the five-minute versus hourly settlement for fossil-fueled and non-fossil resources. Fossil-fueled resources tend to provide more controllable and therefore tend to produce more in intervals with five-minute prices are higher. Some non-fossil fuel types such as nuclear provide little dispatch flexibility so the average output across a given hour is consistent and seldom results in any discernible difference in valuation. Wind resources, on the other hand, can only respond to price by curtailing in the downward direction. (Normally they cannot ramp up in response to price increases because they typically operate at their maximum.) Additionally, wind resource output is negatively correlated with load and often contributes to congestion at higher output levels, so hourly-integrated prices often overstate the economic value of its generation.

Figure A58: Net Energy Value of Five-Minute Settlement
2012

Figure A59: Net Energy Value of Physical Schedules Settlement

The figure below shows a similar analysis for physical scheduling. As noted above, these transactions may be scheduled to start and stop every fifteen minutes (thirty minutes in advance) but similar to generation, are settled based on an average hourly interface prices. Consequently, like generation, these schedules may be paid more or less than their value depending upon whether the five-minute interval prices during the 15 scheduled interval are more or less than the hourly average price.

This chart shows overvalued transactions as positive values and undervalued transactions as negative values. In contrast to generation, which was in aggregate consistently undervalued, physical schedules are consistently overvalued. The stacked bar shows the total for the top six market participants in terms of settlement values, and the drop line shows the net relative five-minute to hourly valuation for all participants.

Figure A59: Net Energy Value of Physical Schedules Settlement
2012

Key Observations: Five-Minute Settlement

i. In 2012, fossil-fueled resources produced nearly $29 million more in actual energy value than was reflected in their real-time energy revenues.

- The increased energy value was highest in July when load and commitment of dispatchable generation was highest.
- In other months, the increased energy value for fossil-fueled resources was fairly uniform. Some of the increased energy value (about $3 million or 10 percent) not paid to these resources in the form of energy revenue was paid as PVMWP.
- Combustion turbines were underpaid by about $0.47 per MWh on average, while combined-cycle units were underpaid by about $0.25 per MWh.

ii. For the same period, non-fossil fueled resources were paid $5.8 million more in energy revenue with hourly settlement than their actual five-minute energy value.

- These resources were also paid an additional $0.9 million in PVMWP.
- The contribution of RSG to non-fossil units results from excess energy payments to pumped storage resources under the hourly-integrated settlement.

- ✓ A reduction in energy payments would be offset by an increase in RSG payments since these units are often committed economically by MISO.

– Wind resources were overpaid by $0.20 per MWh.

iii. In 2012, physical schedules in aggregate were overvalued under the current hourly settlement by over $4 million, down from $6.8 million in 2011.

– Physical schedules were overvalued consistently for the last two years with the exception of two months (March 2011 and June 2012), when they were slightly undervalued.

– Top market participant schedules were overvalued in every month for the past two years.

iv. To improve the incentives of suppliers and physical schedulers, we are recommending that MISO consider moving to a five-minute settlement.

H. 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 their 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, it will be revenue-inadequate because it receives no energy rents to cover its startup and minimum generation costs. This revenue inadequacy results in real-time RSG payments.

Since MISO's aggregate load 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 such resources. In addition, several other factors can contribute to commitments of peaking resources, including day-ahead net scheduled load that is less than actual load, transmission congestion, wind forecasting errors, or changes in real-time NSI.

Figure A60: Average Daily Peaking Unit Dispatch and Prices

Figure A60 shows average daily dispatch levels of peaking units in 2012 and evaluates the consistency of peaking unit dispatch and market outcomes. The figure is disaggregated by the unit's commitment reason. It separately indicates the share of the peaking resource's output that is in-merit order (when the peaking resource's LMP is less than its offer price) and the balance is out-of-merit order).

Figure A60: Dispatch of Peaking Resources
By Commitment Reason, 2011–2012

<u>Key Observations: Dispatch of Peaking Resources</u>

i. The average hourly dispatch quantities of peaking resources rose 61 percent from 2011 to 667 MW.

   – The vast majority of such dispatch occurred during peak summer days, when high loads resulted in the need to commit over 5 GW per hour of peaking capacity.

ii. This dispatch increase was confined primarily to those peaking resources committed day-ahead, which more than doubled to 539 MW on average.

   – Low natural gas prices, particularly early in 2012, resulted in many peaking units being increasingly economic to commit in the day-ahead market. Hence, the share of in-merit dispatch of peak resources was highest in the spring.

iii. Forty percent of all peaking resources ran out-of-merit order, indicating that they frequently do not set energy prices when they are needed.

   – Low fuel prices and high summer load decreased the share of resources running out-of-merit order in 2012, but this share still indicates a significant market issue.

   – 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.

I. 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 and, as such, 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).[17] 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 these resources. Instead, MISO utilizes short and long-term forecasts to make assumptions about wind output, and utilizes curtailments 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. As of March 2013, the majority of wind units in MISO are DIRs, although some resources modeled as DIRs are "off control" and not yet able to respond to dispatch instructions.[18]

Figure A61: Day-Ahead Scheduling Versus Real-Time Wind Generation

Figure A61 shows a seven-day moving average of wind scheduled in the day-ahead market and dispatched in the real-time market since 2011. Under-scheduling 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 under-scheduling by the wind resources.

17 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 zero 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 five percent to 32.5 percent.

18 Wind resources placed in service prior to April 2005 are exempt from the April 1, 2013 deadline to participate as Dirs.

Figure A61: Day-Ahead Scheduling Versus Real-Time Wind Generation
2011–2012

Figure A62: Wind Generation Capacity Factors by Load Hour Percentile

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

Figure A62 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 horizontal 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 A62: Seasonal Wind Generation Capacity Factors by Load Hour Percentile
2012

Figure A63: Wind Curtailments by MISO

Since much of the wind capacity is located in the West region and its output impacts lower voltage transmission constraints, the growth in wind output over time has resulted in increased congestion out of western areas. Before the phased introduction of DIR beginning in June 2011, MISO operators manually curtailed wind resource output regularly to manage congestion and address local reliability issues. Manual curtailments are an inefficient means to relieve congestion because the process does not allow prices to reflect the marginal costs incurred to manage the congestion. This inefficiency is eliminated when DIR units are economically curtailed.

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 A63 shows the average wind curtailments since 2010. The figure distinguishes between MISO-issued manual and economic (DIR) curtailments. Manual curtailments of units that have since become DIR (as of March 2013) are indicated by the lighter color.

Figure A63: Wind Curtailments
2011–2012

Figure A64: Wind Volatility

Wind output can be highly variable and must be managed through the redispatch of other resources, curtailment of wind resources, or commitment of peaking resources. Figure A64 summarizes the volatility of wind output on a monthly basis over the past two years by showing:

- The average absolute value of the 60-minute change in wind generation in the blue line;
- The largest five percent of hourly decreases in wind output in the blue bars; and
- The maximum hourly decrease in each month in the drop lines.

Changes in wind output due to MISO economic curtailments are excluded from this analysis.

Figure A64: Wind Generation Volatility
2011–2012

<u>Key Observations: Wind Generation</u>

i. Real-time wind generation in MISO in 2012 increased 22 percent to average 3,618 MW, which accounted for 7 percent of total generation.

- Wind resources now account for 9 percent of installed capacity (over 12 GW), a 23 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.
- In a change from prior years, federal production tax credits of $22 per MWh are available to all wind projects that begin construction in 2013, not just those placed into service.
- Credits are available for ten years after the placed-in-service date and require measured and verifiable wind output. This provides an incentive to wind resources to produce energy as low as $-34 per MWh.[19]

19 Since the PTC is an after-tax credit, its pre-tax equivalent (assuming a tax rate of 35 percent) is: $22 / (1 – tax rate) = $34.

ii. Wind remained under-scheduled in the day-ahead by an average of 581 MW, or 15 percent, although net virtual supply in 2011 made up approximately half of this discrepancy.

- Since August 31, 2010 deviations from the 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 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.
- The average capacity credit was 14.7 percent in Planning Year 2012-13. It is set at 13.3 percent for the 2013-14 year, with individual credits for 169 units ranging from zero to 30.4 percent.
- We believe this methodology results in overstated capacity credits for wind and continue to recommend a more conservative approach.

v. The continued adoption of DIR has greatly improved MISO's ability to manage wind output and price it efficiently.

- Over one-half of all wind resources at the end of 2012 were dispatchable and could respond to economic signals. Wind resources set price in approximately one-third of all intervals, and did so at an average as-offered cost of $-15 per MWh.
- This added flexibility has greatly reduced the amount of manual wind curtailments made by MISO. In 2012, manual wind curtailments averaged 30 MW per interval, over 60 percent less than in 2011 and over 70 percent less than in 2010.
- Economic curtailment of DIR wind units averaged 65 MW per interval, more than twice as great as manual curtailments. This should increase as more wind resources enter MISO in western areas and contribute to congestion.

– Sixty-minute wind volatility (excluding economic DIR curtailments) in 2012 increased 17 percent to an average hour-to-hour change of 279 MW, and peaked at over 2,100 MW on September 24.

✓ MISO is working to develop changes in procedures and evaluate market design changes that may be beneficial for managing the changes in wind output.

J. Inferred Derates

MISO's current set of tools used to monitor the performance of units in real time are not designed to identify units that may be chronically not responding to dispatch signals over multiple intervals. The current system focuses on single interval results and is designed to support control area criteria, such as ACE. Consequently, a unit that may be effectively derated by large amounts and unable to follow dispatch may not be identified by MISO's current tools and procedures. Resources are required to update their real-time offer parameters and report derates under MISO's Tariff.[20] However, we found numerous examples in 2012 where resources were operating well below their economic output levels (often reflected in their DA schedules). In these cases, the resources were effectively derated in real time, but were not put off-control or derated in real time.

This can undermine reliability by causing operators to believe they have more available capacity than they actually do. It can cause less effective dispatch and congestion management since the derated units would not provide the energy or congestion relief the dispatch is seeking. It directly impacts the resource's eligibility to receive DAMAP payments and allow the resource to avoiding RSG charges. Finally, in some cases the derated capacity was actually selected to provide spinning reserves, which results in MISO meeting its requirements with capacity that cannot respond if needed in an emergency.

The following figure summarizes our review of instances when units were effectively derated in real time and did not update their economic maximums in their offers. The bottom panel shows the average hourly quantity of unreported derates for all on-peak hours. Derates are shown separately for capacity that was unavailable but was scheduled for regulation, spinning reserves, or credited for providing headroom (latent reserves) in MISO's reliability analysis. The diamond drop-line shows the maximum hourly quantity in the month. The top panel shows the cumulative DAMAP and ASM clearing payments that were made in each month that should not

20 As MISO notes in the relevant BPM, under Generator Derate Procedure Instructions:

> Under the EMT Section 39.2.5(c), the values in Generation Offers shall reflect the actual known physical capabilities and characteristics of the Generating Resource [or Dynamic Dispatchable Resource (DRR)] on which the Offer is based. As defined in the EMT, the Economic Minimum and Economic Maximum is the minimum and maximum achievable MW level at which a Generation Resource may be dispatched by the UDS in real-time under normal system conditions for an Hour on a particular Operating Day.
>
> Any derate, either planned or unplanned, to a Generation Resource's Ramp Rate that causes the unit to be unable to achieve its Offered Economic Minimum/Maximum limit for the Offer Hour will require the GOP to also update the Generation Resource's Hourly Economic Minimum/Maximum to the achievable limits that the derate causes on the Generation Resource's physical capability. Unit derates should not be managed solely with an adjustment to the ramp rate offer.

have been, and RSG charges that were avoided because the resource did not report the derate to MISO.

Figure A65: Unreported ("Inferred") Derates
2012

<u>Key Observations: Inferred Derates</u>

i. In 2012, resources that were operating below their day-ahead schedules due to unreported "inferred" derates:

   – Were paid over $2 million in DAMAP;

   – Avoided over $1 million in RSG; and

   – Were paid nearly $0.7 million for scheduled ancillary services that they likely could not have provided if deployed.

ii. The average hourly quantities of unreported derates averaged almost 300 MW, which is almost half of the total amount of rampable spinning reserves MISO operators seek to maintain.

   – In many hours, these inferred derate quantities were much larger than 300 MW, peaking at almost 2,000 MW at one point in July.

iii. We make a number of recommendations in this report to address this issue, including:

- MISO improving its screening and reporting of these types of derates, as well as its operating procedures for designating a resource off-control or derated; and

- Tightening the tolerances for uninstructed generator deviations, which would make it more difficult for resources to fail to follow MISO's dispatch instructions without: a) incurring deviation penalties, b) being placed off dispatch, b) losing eligibility for DAMAP payments, and c) charged RSG costs. This is discussed more fully in the next subsection.

K. Generator Deviations

MISO sends dispatch instructions to generators every five minutes that specify the expected output at the end of the next five-minute interval. It assesses penalties to generators if deviations from these instructions remain outside an eight-percent tolerance band for four or more consecutive intervals within an hour.[21] The purpose of the tolerance band is to permit a level of deviations that balances the physical limitations of generators with MISO's need for units to accurately follow dispatch instructions. MISO's criteria for identifying deviations, both the percentage bands and the consecutive interval test, are significantly more relaxed than most other RTOs including NYISO, CAISO, and PJM.

Having a relatively relaxed tolerance band allows resources to effectively derate themselves by simply not moving over many consecutive intervals, which is discussed in the previous subsection. As long as the dispatch instruction is not eight percent higher than its current output, a resource can simply ignore its dispatch instruction. Because it is still considered to be on dispatch, it can receive unjustified DAMAP payments and avoid RSG charges it would otherwise incur if it were to be derated.

Figure A66 and Figure A67: Generator Deviations

Figure A66 and Figure A67 show interval average gross deviations (both excessive and deficient) and net deviations by hour and by interval. This figures show the deviations using MISO's current deviation tolerance rules, as well as under two alternative tolerances:

- Using a five-percent tolerance band instead of an eight-percent band; and

- Using a five-percent tolerance band and removing MISO's four consecutive interval requirement.

21 The tolerance band can furthermore be no less than six MW and no greater than 30 MW (Tariff section 40.3.4.a.i.). This minimum and maximum were unchanged for this analysis.

Figure A66: Average Deviations by Hour
2012

Figure A67: Average Deviations by Interval
2012

Figure A68 and Figure A69: Frequency of Net Generator Deviations

Figure A68 shows a histogram of MISO-wide interval deviations during peak hours in summer months without applying any deviation tolerance rules. Figure A69 shows the same results for peak hours on only the 10 highest-load days. In each figure, the curve indicates the share of deviations (on the right vertical axis) that are less than the deviation amount (on the horizontal axis). The markers on this curve indicate three points: the percentage of intervals with net positive deviations less than -500 MW, less than 0 MW, and the median deviation.

Figure A68: Frequency of Net Deviations
Peak Summer Hours, 2012

Figure A69: Frequency of Net Deviations
Top 10 Summer Hours, 2012

Key Observations: Generator Deviations

i. The average gross negative deviation (before applying any tolerance tests) in 2012 was 478 MW, while gross positive deviations averaged 453 MW.

– Gross deviations were greatest during ramping hours and in Hour Beginning 0 (when units get new day-ahead schedules), and lowest during the middle of the afternoon.

✓ This is expected because units are moving most often in these hours to accommodate changes in demand or generation commitments.

– By interval, gross deviations were greatest at the top of the hour. However, MISO considers a small share of these to be excessive because of its four consecutive interval per hour rule.

✓ A unit that is deviating beyond the eight percent threshold for only the six consecutive intervals that span across the hour (i.e., intervals 45, 50, 55, 0, 5 and 10) is not considered to be producing excessive energy.

✓ The presence of this rule reduced gross deviations in 2012 by 36 percent and the deviations in the first interval of each hour by 53 percent.

ii. While net deviations are modest on the whole, they are greater when loads are highest.

- MISO was net deficient in over 75 percent of peak summer intervals, and by more than 140 MW in half of those intervals.

- In nearly seven percent of peak summer intervals, MISO was net deficient by more than 500 MW. On the top 10 load days, this percentage exceeded 15 percent.

- Significant net negative deviations can contribute to shortage situations, particularly when supply conditions are tight.

iii. This suggests that MISO should consider adopting tighter thresholds for excessive and deficient energy quantities to improve suppliers' adherence to dispatch instructions.

- Lowering the threshold to five percent would have increased the deviations subject to potential penalties by 13 percent in 2012, while eliminating the four-consecutive interval rule for excessive energy would have increased them by a further 85 percent.

- It may be appropriate to retain some form of multiple interval criteria to determine when to place a unit off-control or to determine RSG or PVMWP eligibility.

V. Transmission Congestion and Financial Transmission Rights

MISO's energy markets serve load and meet reserve obligations with the lowest-cost resources, 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.[22] An efficient system typically has some congestion because transmission investment to alleviate congestion should only occur when the production cost savings from eliminating the congestion exceed the cost of investment.

When congestion arises, the price difference between two locations represents the marginal value of transmission capability between them. When the power transferred across the interface or constraint[23] between the locations reaches its limit, the cost of the resulting congestion is equal to the marginal value of relieving the constraint (the cost of controlling one 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 location (where generation cannot be imported to replace higher-cost generation), the congestion component will be positive and increase the LMP; conversely, in locations where additional generation contributes to *increased* flow on constraints, the congestion component will decrease the LMP.[24]

In a congested location, load will generally exceed generation. Therefore, when the net load in the constrained location settles at the higher constrained location price and the net generation in the unconstrained location 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 for 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.

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22 Transmission losses will still cause prices across the footprint to vary even absent any congestion.

23 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.

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

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

Real-time balancing congestion costs are settled 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. Among other reasons, congestion costs in the real-time market can 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) deviate from levels forecasted in the day-ahead market.

For example, suppose a transmission interface (or constraint) is fully scheduled in the day-ahead market. If in real time the limit is decreased (e.g., the interface is derated) or loop flows 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.[25]

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.[26] 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 Joint Operating Agreement 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 significantly less than the total value of real-time congestion on the MISO network.

Figure A70: Total Congestion Costs

Figure A70 shows total congestion costs incurred by month in the day-ahead and real-time markets since 2010.

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

26 The marginal value (or shadow price) is the amount of production cost that would be saved if the limit of the constraint could be increased by 1 MW.

Figure A70: Total Congestion Costs
2010–2012

Figure A71: Real-Time Congestion Costs

To better understand real-time congestion costs, Figure A71 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 flow entitlement on a MISO-managed 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 A71: Real-Time Congestion Costs
2010–2012

Key Observations: Congestion Costs

i. Day-ahead congestion costs rose 55 percent from $503 million in 2011 to $777 million in 2012.

  – This increase is in part due to increased congestion on mid-to-low voltage lines that were more completely modeled in 2012 because of continued enhancements MISO has made to the day-ahead processes.

ii. Congestion revenues collected through the MISO markets are substantially less than the value of real-time congestion on the system, which totaled $1.30 billion (see Subsection C below).

  – This difference is caused primarily by loop flows and PJM entitlements that do not pay MISO for use of its network.

iii. Real-time congestion costs in 2012 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 the day-ahead market.

  – Most of this was accrued by PJM's use of MISO's transmission service in excess of its Firm Flow Entitlement.

– Balancing congestion costs of $20.3 million indicate that the real-time transmission capability slightly exceeded the amount made available to the day-ahead market.

B. FTR Obligations and Funding

In the MISO market, the economic value of transmission capacity is reflected in Financial Transmission Rights ("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.[27] 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.[28] 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, if it sells too few). Reasons for differences between FTR capability and day-ahead capability are similar to those discussed previously between the day-ahead and real-time markets, including:

- 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; and

- 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.

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

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

Transactions that cause unanticipated loop flows are a problem because MISO collects no congestion revenue from them. If MISO allocates FTRs for the full capability of its system, loop flow can create an FTR revenue shortfall.

MISO has continued to work to improve the FTR and ARR allocation processes. Recent changes include new tools and procedures for the FTR modeling process, more conservative assumptions on transmission derates in the auction model, updated constraint forecasting and identification procedures, and more complete modeling of the lower-voltage network.

Figure A72: Day-Ahead Congestion Revenue and Payments to FTR Holders

Figure A72 compares monthly day-ahead congestion revenues to FTR obligations for 2010 to 2012. The top panel shows the FTR funding shortfall or surplus in each month. Significant shortfalls are undesirable because they introduce uncertainty and can distort FTR values. Significant funding surpluses are similarly unwelcome because they indicate that the capability of the transmission system was not fully available in the FTR market.

Figure A72: Day-Ahead Congestion Revenue and Payments to FTR Holders
2010–2012

Figure A73: Day-Ahead Congestion Revenue and Payments to FTR Holders

Figure A73 compares monthly total day-ahead congestion revenues to monthly total FTR obligations in 2012 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 A73: Day-Ahead Congestion Revenue and Payments to FTR Holders
2012

Figure A74: 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 provided by conventional FTRs.

Figure A74 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 A74: Payments to FTR Holders
2010–2012

Key Observations: FTR Obligations

i. In 2012, MISO recorded a $33 million FTR shortfall, which means FTRs were underfunded by 3.4 percent.

   – In 2011, FTRs were more than fully funded primarily because FTR surpluses on market-to-market constraints offset shortfalls on internal constraints.

      ✓ These surpluses disappeared in June, the start of the 2012–2013 FTR year.

ii. Significant drivers of underfunding on internal constraints included:

   – Underestimation of loop flow leading to overselling of FTRs.

   – Planned and unplanned transmission outages and derates that did not get modeled in the FTR auction.

      ✓ Most notable were a series of unplanned outages and derates associated with LIDAR (“Light Detection and Radar”) surveys.

   – FTRs that are sourced and sinked at the same station without limit or cost in the auction.

- ✓ Such FTRs, known as "Same-Bus" or "Zero-Cost" FTRs, can lead to underfunding when there is a congestion component difference in the day-ahead. This occurs most commonly when one of the locations is identified as a contingency in the day-ahead and real-time markets.
- ✓ In 2012, the value of such FTRs was over $7 million, most of which accrued on one constraint in the fourth quarter. This amount was almost entirely unfunded.
- ✓ MISO has filed a permanent Tariff change that does not award FTR bids with same-station pairings. This change became effective in March 2013.

iii. The vast majority of day-ahead congestion (89 percent) continues to be paid out via FTRs, rather than via other transmission rights, which is good because FTRs provide the most efficient incentives.

- – This share is down slightly from 91 percent in 2011 and 95 percent in 2010.
- – The majority of non-FTR rights exist in the West region, so payments in recent years to these holders have risen along with congestion.

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 A75: Value of Real-Time Congestion by Coordination Region

Figure A75 shows the total monthly value of real-time congestion by region and the average number of binding constraints per interval in 2011 and 2012. The bars on the left show the average monthly value in each of the past three years.

Figure A75: Value of Real-Time Congestion by Coordination Region
2011–2012

Figure A76: Value of Real-Time Congestion by Type of Constraint

To better identify the nature of constraints and the congestion value, Figure A76 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 and MISO market-to-market constraints include the total flow. The estimated value of congestion on external constraints (but not their impact on LMP congestion components) is therefore reduced.

Figure A76: Value of Real-Time Congestion by Type of Constraint
By Quarter, 2010–2012

Key Observations: Congestion Value

i. Real-time congestion value increased 5 percent from 2011 to $1.30 billion

   – Congestion rose the most on internal constraints (by 30 percent), which accounted for 73 percent of all congestion value.

   – Congestion was greatest in summer months, as expected, when hot weather contributed to higher flows over the network.

ii. Congestion rose in the West region by 48 percent because of:

   – A long-term forced outage of a large generating facility.

   – Transmission derates and outages associated with upgrades and LIDAR surveys, particularly in the fourth quarter;

   – Increased wind generation in the West. DIR participation has increased, which allows wind resources to set the LMP and makes congestion more manageable; and

   – MISO continuing to control a greater number of low-voltage constraints, most of which are situated in the West region.

iii. Congestion declined in other regions by seven to 25 percent, although transmission outages in the fourth quarter significantly contributed to congestion in the Central region.

iv. Congestion was much more fully priced in 2012 because MISO ended its practice of “constraint relaxation” on non-M2M constraints in February.

- This is a substantial improvement because constraint relaxation 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.

v. Although the congestion value on external flowgates is relatively small (less than two percent of the total), 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, even small relief obligations (based on forward-only 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 and between NYISO and PJM, 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 economic generation dispatch through LMP markets, the TLR process is an inefficient and rudimentary means to manage congestion. TLR provides less timely and less 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 A77 and Figure A78: Periodic TLR Activity

Figure A77 shows monthly TLR activity on MISO flowgates in 2011 and 2012. 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. These NERC TLR levels are:

- Level 3—Non-firm curtailments;[29]
- Level 4—Commitment or redispatch of specific resources or other operating procedures to manage specific constraints; and
- Level 5—Curtailment of firm transactions.[30]

Figure A78 shows TLR hours disaggregated by the Reliability Coordinator declaring the TLR.

Figure A77: Periodic TLR Activity
2011–2012

29 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.

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

Figure A78: TLR Activity by Reliability Coordinator
2011–2012

<u>Key Observations: TLR Events</u>

i. Compared to 2011, MISO's TLR quantities declined 9 percent to 147 hours per month, while TLR quantities declined 9 percent to 19 GWh per month.

- The hours of Level 5 TLRs increased significantly in July and August. However, these TLRs frequently did not result in any curtailed flows.

- MISO assumed Reliability Coordinator (RC) responsibilities for Entergy as of December 2012. As a result, TLR activity picked up in December and has continued into 2013.

    ✓ The benefits of Entergy integration will not be fully realized due to inefficient constraint management until market-to-market coordination with SPP is achieved.

ii. TLR activity by non-MISO RCs declined significantly in 2012.

- The most notable change resulted from the PARs placed into service to control Lake Erie loop flows, which limited the need for NYISO and IESO to call TLRs during the second half of 2012 (see Section VI.B).

E. Congestion Management

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.

Figure A79: Constraint Manageability

The next set of figures show manageability of internal and MISO-managed market-to-market constraints. Figure A79 shows how frequently binding constraints were manageable and unmanageable in each month from 2011 to 2012.

Figure A79: Constraint Manageability
2011–2012

Figure A80: Value of Real-Time Congestion by Voltage Level

Given the frequency that constraints are unmanageable, it is critical that unmanageable congestion be 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 flows to their limits. 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 the LMPs will reflect MISO's expressed value of the constraint. Prior to February 2012, when a constraint's flow exceeded its limit an algorithm was used to "relax" the limit of the constraint to calculate a shadow price and the associated LMPs. This constraint relaxation algorithm often produced LMPs that were inconsistent with value of unmanageable constraints. Its sole function was 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. Although this practice was discontinued for internal non-market-to-market constraints, it remains in place for all market-to-market constraints.

Figure A80 examines manageability of constraints by voltage level. Given the physical properties of electricity, more power flows over higher-voltage facilities. This characteristic causes resources and loads over a wide 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 A80 separately shows the value of real-time congestion on constraints that are not in violation (i.e., “manageable”), the congestion that is priced when constraints are in violation (i.e., “unmanageable”), and the congestion that is not priced when constraints are in violation. The unpriced congestion is based on the difference between the full reliability value of the constraint (i.e., the MVL) and the relaxed shadow price used to calculate prices.[31]

Figure A80: Real-Time Congestion Value by Voltage Level
2010–2012

Figure A81: Results of Transmission Deadband Deactivation

MISO uses an operating algorithm called the “transmission deadband” in its constraint management procedures. The deadband is a constraint-specific amount (most commonly two percent) by which the limit of a constraint is automatically reduced after it initially binds. The original intent was to limit oscillation, or the frequency with which constraints would bind and then immediately unbind. By reducing oscillation, it was thought that the deadband would reduce LMP and generator dispatch volatility. In our 2011, we presented analyses indicating that the deadband was likely increasing volatility, rather than decreasing it. We recommended that MISO deactivate the deadband.

31 This figure excludes some less common voltages, such as 120 and 500 kV, and about four percent of total congestion value due to constraints that could not be classified according to voltage class.

In December 2012, MISO began conducting a field test by disabling the deadband on a subset of frequently binding constraints to determine if its removal was beneficial and whether it posed any reliability concerns. MISO had practical concerns related to dispatch volatility and theorized that some of the IMM's perceived benefits would be negated by MISO needing to control constraints at a lower percentage of their physical limit.

Figure A81 shows a summary of our findings for the four most frequently binding test constraints. The results were compiled for the three months prior to the field test when the deadband was active (the "On" period) and the first three months after the deadband's deactivation (the "Off" period). The shadow price volatility is measured as the average absolute change in the shadow price from the first binding interval to the next binding interval.

Figure A81: Results of Transmission Deadband Deactivation
2011–2012

<u>Key Observations: Congestion Management</u>

i. The manageability of congestion improved slightly from 81.6 percent manageable in 2011 to 83.4 percent in 2012.

   – It improved at all voltage levels, although it remains most unmanageable on lower-voltage constraints.

ii. The amount of "unpriced" congestion declined 82 percent to $43.3 million.

   – Nearly $17 million, or 39 percent of this total, was accrued in January before the constraint relaxation algorithm was disabled on non-M2M constraints.

- Constraint relaxation remains in effect on market-to-market constraints, but those constitute a very small portion of the total congestion value. An average of $2.4 million per month in congestion value remained unpriced after February 1.

- We continue to believe that MISO should disable this algorithm on market-to-market constraints because it distorts the congestion prices in MISO, although its effects are much smaller than they had been in the past.

iii. We continue to recommend that MISO return functional control over low-voltage constraints to transmission owners when TOs can better manage those facilities.

iv. Deadband deactivation on the constraints shown in the figure resulted in substantial declines in shadow price volatility and increases in flowgate utilization.

- This is consistent with IMM expectations, and we recommend MISO extend the deactivation to all constraints as soon as possible.

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 an FTR and the payout its holder receives from congestion in the day-ahead market. In a liquid FTR market, profits should be close to zero because the market-clearing price for the FTR should reflect the expected value of congestion payments to the FTR holder.

Figure A82 and Figure A83: 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 A82 and Figure A83 include FTRs sold as well as purchased. FTRs sold are netted against FTRs purchased. For example, if an FTR purchased in round one of the annual auction is sold in round two, the purchase and sale of the FTR in round two would net to zero.

Figure A82: FTR Profitability
2010–2012: Seasonal Auction

Figure A83: FTR Profitability
2011–2012: Monthly Auction

Figure A84 to Figure A89: 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 the Indiana Hub, which replaced the Cinergy Hub as the most actively-traded location in MISO in 2012. Results are shown separately for peak and off-peak hours.

Figure A84: Comparison of FTR Auction Prices and Congestion Value
WUMS Area, 2011–2012: Peak Hours

Figure A85: Comparison of FTR Auction Prices and Congestion Value
WUMS Area, 2011–2012: Off-Peak Hours

Figure A86: Comparison of FTR Auction Prices and Congestion Value
Minnesota Hub, 2011–2012: Peak Hours

Figure A87: Comparison of FTR Auction Prices and Congestion Value
Minnesota Hub, 2011–2012: Off-Peak Hours

Figure A88: Comparison of FTR Auction Prices and Congestion Value
Michigan Hub, 2011–2012: Peak Hours

Figure A89: Comparison of FTR Auction Prices and Congestion Value
Michigan Hub, 2011–2012: Off-Peak Hours

Key Observations: FTR Auction Prices

i. FTR profitability increased from $0.05 per MWh in 2010 to $0.20 in 2012.

- Profits were greatest in summer due to tighter peak load conditions (and associated congestion) than what was anticipated in the FTR auction.

- Two-thirds of FTRs cleared in the seasonal auction. The remaining incremental capability was sold, at comparable profitability (approximately $0.20 per MWh), in the monthly auction.

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

- Outage-driven congestion into Minnesota, notably in late spring and in December, was poorly anticipated in the FTR auction.

G. Market-to-Market Coordination with PJM

The Joint Operating Agreement 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, ensures efficient generation dispatch on these constraints, and ensures 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 automated, although at times it can yield 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 A90: Market-to-Market Events

Figure A90 shows the total number market-to-market constraint-hours (i.e., instances when a constraint was active and binding) in 2011 and 2012. 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 A90: Market-to-Market Events
2011–2012

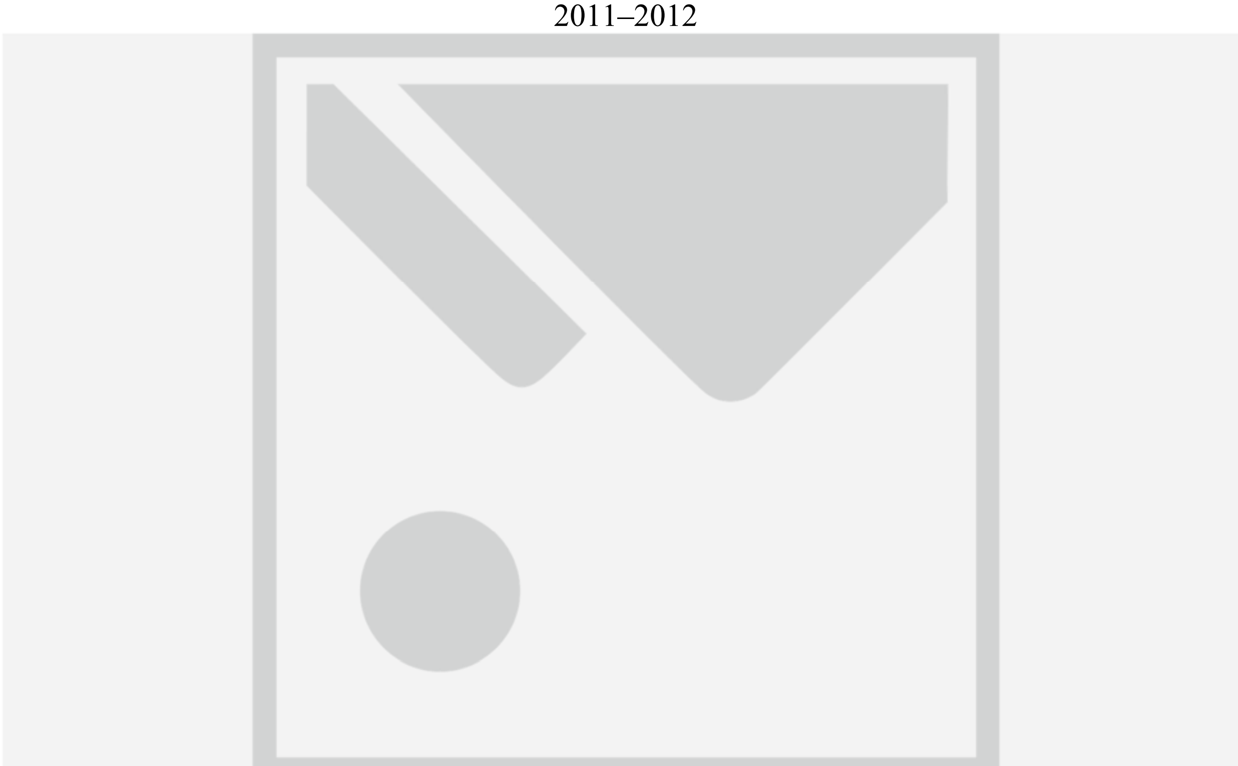


Figure A91: Market-to-Market Settlements

Figure A91 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 A91: Market-to-Market Settlements
2011–2012

Figure A92 and Figure A93: 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.

The share of active constraint periods that were coordinated is shown below the horizontal axis. When coordinating, the reciprocating RTO can provide relief by limiting market flow in its real-time dispatch.

Figure A92: PJM Market-to-Market Constraints
2012

Figure A93: MISO Market-to-Market Constraints
2012

Key Observations: Market-to-Market Coordination

i. The value of congestion on MISO M2M constraints declined nearly 30 percent from 2011 to $325 million, while congestion on PJM M2M constraints declined 53 percent to just $7.5 million.

ii. Net payments flowed from PJM to MISO in most months of 2012 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 declined 42 percent to $3.8 million per month. A number of factors contributed to this including:
  - ✓ In November, MISO resettled (repaid PJM) approximately $7 million based on a disputed interpretation of the JOA. The IMM referred the matter to FERC as a Tariff violation and a number of participants have filed a complaint to challenge MISO's interpretation and the associated resettlement.
  - ✓ Beginning in October and extending into 2013, a PJM accounting error led to an overstatement of FFEs used in settlement. This resulted in approximately $2 million in underpayments to MISO in 2012 and $4.3 million overall (including 2013). An adjustment will be made in 2013.

- In November, over $2 million in payments to PJM resulting from transmission derates on a flowgate in the Central region.

iii. We support efforts by both RTOs to incorporate the coordinated use of FFEs into the day-ahead market, which should improve the efficiency of both RTOs' markets.

iv. Shadow price convergence on MISO M2M constraints (an indicator of PJM's responsiveness to requests for relief) was good in 2012 and 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.

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 convey any price sensitivity associated with their external transactions.

This section of the appendix reviews the magnitude of these transactions and the efficiency (or inefficiencies) of the scheduling process.

A. Import and Export Quantities

Figure A94 to Figure A97: 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, 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 be compelled to commit additional generation (often peaking resources) to satisfy the system's needs. The third and fourth figures show similar information by interface.

Figure A94: Average Hourly Day-Ahead Net Imports
2012

Figure A95: Average Hourly Real-Time Net Imports
2012

Figure A96: Average Hourly Day-Ahead Net Imports
2012, by Interface

Figure A97: Average Hourly Real-Time Net Imports
2012, by Interface

Figure A98 and Figure A99: 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 A98 shows the average quantity of net imports scheduled across the MISO-PJM interface in each hour of the day in 2011 and 2012, along with the standard deviation of such imports.[32] The subsequent figure shows the same results for the two Canadian interfaces (Manitoba Hydro, at left, and Ontario).

Figure A98: Average Hourly Real-Time Net Imports, from PJM
2012

32 Wheeled transactions, predominantly from Ontario to PJM, are included in the figures.

Figure A99: Average Hourly Real-Time Net Imports, from Canada
2012

Key Observations: Import and Export Quantities

i. As in prior years, MISO in 2012 remained a substantial net importer of power in both the day-ahead and real-time markets.

  – Real-time net imports decreased 12 percent to an average of 4.2 GW per hour.

  – The decrease occurred entirely on the larger PJM and Manitoba interfaces, where real-time net imports declined by 15 to 20 percent.

  – Imports from Manitoba are highest in summer, when water levels are highest.

ii. Real-time imports averaged approximately 300 MW greater than day-ahead imports, and did so in three quarters of all days.

  – 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.

  – As previously discussed, large changes in imports from PJM during peak load conditions in July contributed to price volatility and AS shortages, and demonstrated the need for optimized interchange.

B. Transaction Scheduling Around Lake Erie and Loop Flow

"Contract path" transaction scheduling between the four RTOs around Lake Erie has created significant issues. 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. MISO made several improvements on this front in 2012, including the introduction in April of coordinated interface operations via Phase Angle Regulators (PARs). PARs allow the RTOs to better manage loop flow, and improved interface pricing in October.

Figure A100: Transaction Schedules from Ontario to PJM

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 A100 shows the average hourly quantity and profitability of these transactions in each month in 2011 and 2012. Profitability is calculated based on prices in PJM and IESO minus MISO's wheeling charge.[33] Although generally profitable, these transactions may not always be efficient because:

- They do not pay for any congestion they cause in NYISO, which raises efficiency concerns; and
- They will be over-compensated by MISO and PJM when a market-to-market constraint is binding in both markets because the interface prices in both markets will reflect the full value of the relief provided by the transaction (see the next subsection for a discussion of this flaw).

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.

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

Figure A100: IESO to PJM Schedules
2011–2012

Key Observations: Transaction Scheduling Around Lake Erie

i. The wheeling of transactions from IESO to PJM through MISO continued in 2012 and averaged over 600 MW per hour, a slight rise from 2011.

– These transactions create significant "loop flows" since approximately half of the physical power flows through NYISO.

– The IESO-to-PJM transactions remained substantially profitable in 2012 (averaging over $10 per MWh), in part because they do not pay for the congestion they cause in NYISO and because they will compensated twice by PJM and MISO when they are deemed to be relieving a market-to-market constraint.

ii. 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, which pays transactions based on the perceived congestion they relieve in PJM.

– Since roughly one-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 the MISO real-time market as well, each RTO is separately paying the transaction for relief of the same constraint under their current interface pricing rules. (This market flaw is discussed in the next subsection.)

iii. Full operation of the Michigan-IESO PARs began in mid-July, and has reduced loop flows.

- This contributed to a 50 percent reduction in the instances when loop flow on the interface are greater than 200 MW (the Control Band). PAR tap settings are not adjusted for flows below this amount.
- It has also reduced congestion and the frequency of TLR schedule curtailments, thereby improving overall scheduling incentives.

iv. In October 2012, MISO began settling Ontario transactions at a new pricing node that represents the average of the four circuits terminating on the IESO side of the interface.

- The profitability of Ontario transactions in October to December was only slightly higher than if they had been settled at the previous pricing node.

C. Overpayment and Overcharging of Congestion in Interface Pricing

The interface prices posted for both MISO and PJM include the marginal effects of external transactions scheduled over the given interface on all binding constraints. For example, when MISO calculates its interface price for PJM (used to settle all imports from and exports to PJM), it models how the injections in one area and withdrawals in the other area are likely to affect all binding constraints in MISO. Therefore, transactions that would *aggravate* a constraint will incur a congestion charge (i.e., by being paid less for an import or charged more for an export), while those that *relieve* the constraint will receive a congestion payment (i.e., by being paid more for an import or charged less for an export).

As described above, the congestion components of the interface prices will reflect the effects of external transactions on *all* binding constraints in MISO, including internal constraints, external constraints, and market-to-market constraints. In general, this is efficient to the extent that the interface prices accurately reflect the congestion effects of the transactions because it will motivate participants to schedule transactions efficiently. However, we believe that MISO's interface prices inappropriately account for congestion on external constraints and market-to-market constraints.

It is appropriate for external constraints to be reflected in MISO's LMPs because the MISO dispatch will then limit the market flows in the most economical way.[34] This enables MISO to respond to relief requests under the PJM JOA for market-to-market constraints and TLR obligations for other external constraints.

However, MISO is not obligated to pay participants to schedule transactions that relieve constraints in external areas. In fact, the effects of real-time physical schedules are excluded

34 Market flows are the flows that MISO generation and load cause on external constraints and are the basis for MISO's obligations to alter its dispatch under the market-to-market agreements and under TLRs.

from MISO's market flow so they would not be credited as relief being provided by MISO.[35] In most cases, these beneficial transactions are already being fully compensated by the area where the constraint is located. For example, when PJM market-to-market constraints bind and are activated in the MISO market, both RTOs pay (or charge) the transaction for the estimated effect of the transaction on the constraint. Since the constraint is active in both markets, both RTOs follow the process described above for setting the interface prices.

To establish whether this double settlement exists, we identified hours when no constraints were binding in PJM or MISO except a single common market-to-market constraint. The following two examples are such cases. By focusing on the prices in these cases, it is relatively straightforward to evaluate this issue because the congestion component of the interface prices in both PJM and MISO will solely reflect the estimated effects related to the single binding market-to-market constraint.

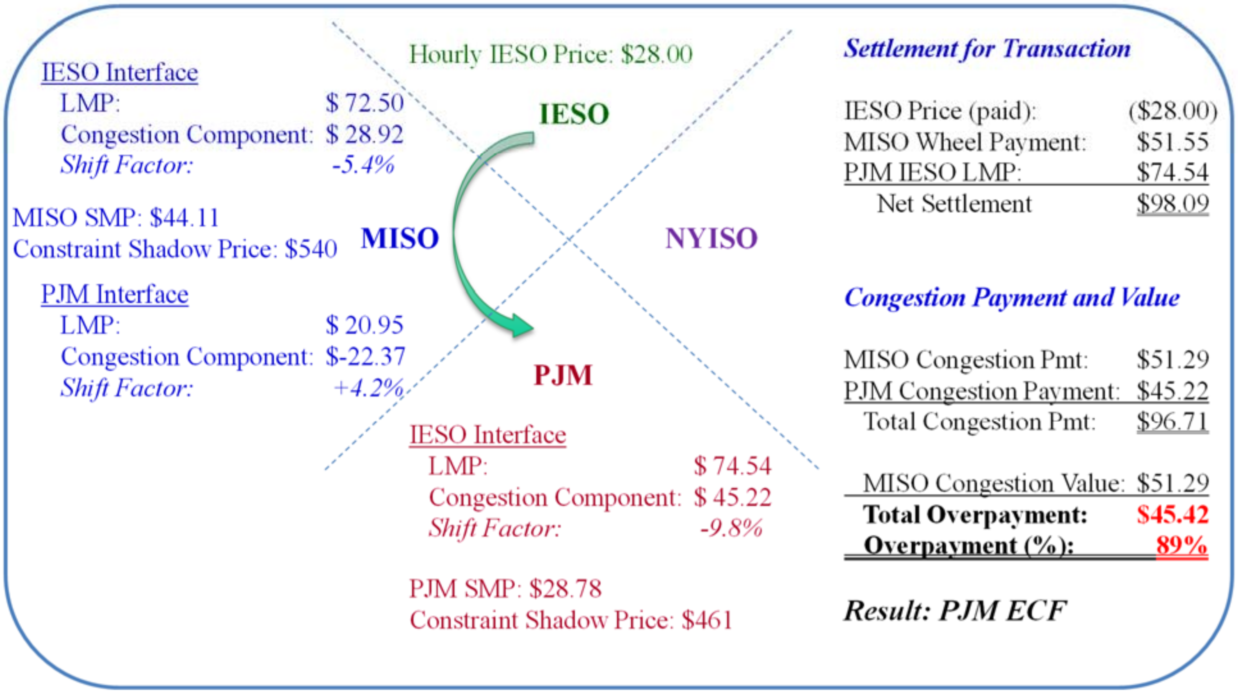
In the first example below, we show an hour where the only binding constraint was a MISO market-to-market constraint. The example then shows the settlements that would result for a transaction scheduled from IESO to PJM (wheeled through MISO). This transaction would help relieve the MISO constraint so it would receive congestion payments from MISO and PJM.

In the second example, we show an hour where the only binding constraint was a PJM market-to-market constraint. The example then shows the settlements that would result for a transaction scheduled from PJM to MISO. This transaction would help relieve the PJM constraint so it would receive congestion payments from MISO and PJM.

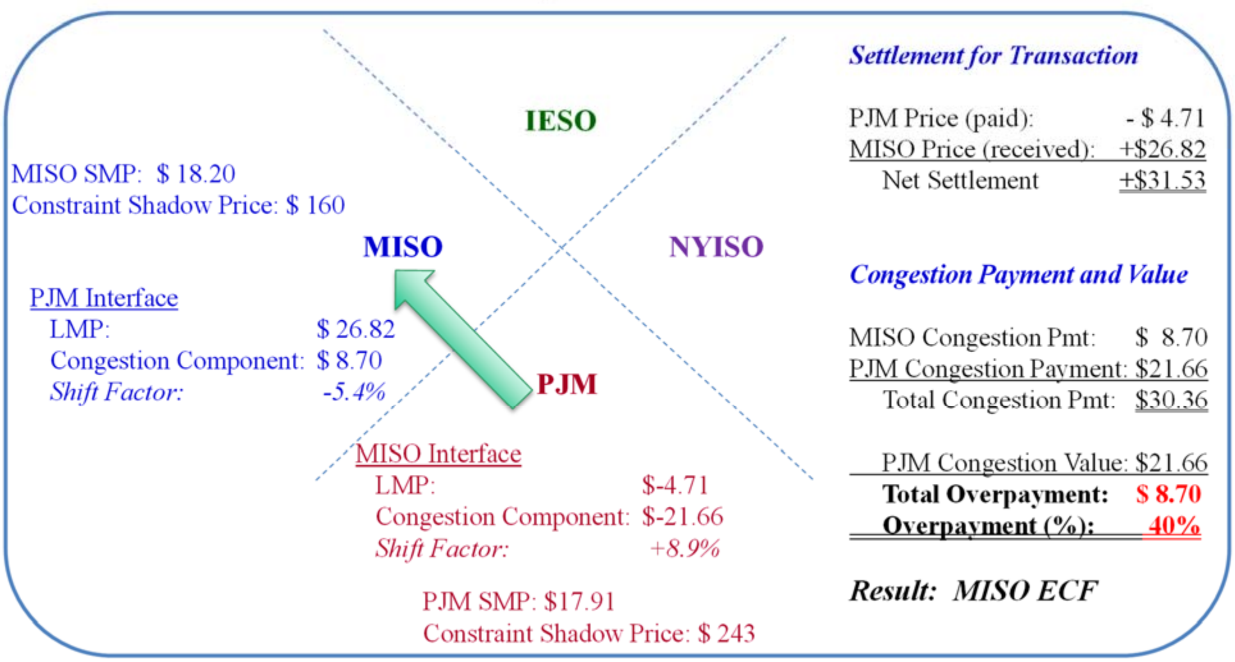
To better understand the prices and settlements, we show each interface LMP along with the congestion component of the LMP and the Generation Shift Factor (GSF). The GSF indicates the marginal constraint-flow impact of transactions over that interface. The congestion component of the interface price should equal the GSF times the shadow price of the constraint. The LMP also includes a marginal loss component that is not shown.

35 Likewise, transactions scheduled in MISO's day-ahead market and curtailed via TLR on an external flowgate are compensated by MISO as if they are relieving the constraint even though this effect is excluded from MISO's market flow calculation.

Example #1: MISO as Monitoring RTO for a Wheel from IESO-PJM Wheel
M2M Constraint: Monroe–Wayne flo Monroe - Brownstown
Date: 8/7/2012 in Hour-Ending 11pm



Example #2: MISO as Non-Monitoring RTO for an Import from PJM
M2M Constraint: Crete-St. John's Tap flo Dumont – Wilton Center
Date: 4/14/2012 in Hour-Ending 3am



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

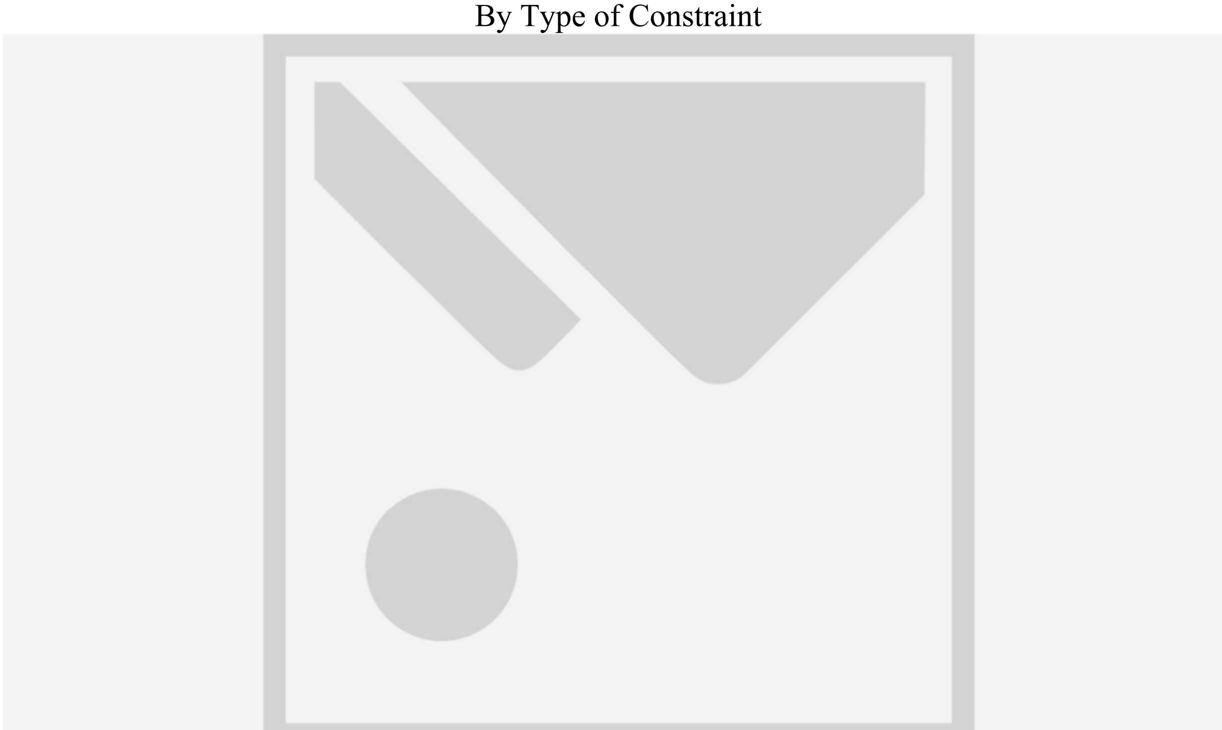
The following figure summarizes the overpayments and overcharges that we estimate occurred in 2012 by type of constraint. Positive values are over-payments and negative values are transactions that were over-charged. The data separately shows amounts from the day-ahead and real-time market.

Figure A101: Over-Compensation and Over-Charging of External Transactions *Over-Compensation of External Transactions*

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

The following figure summarizes the overpayments and overcharges that we estimate occurred in 2012 by type of constraint. Positive values are over-payments and negative values are transactions that were over-charged. The data separately shows amounts from the day-ahead and real-time market.

Figure A101: Over-Compensation and Over-Charging of External Transactions
By Type of Constraint



Key Observations: Overpayment and Overcharging of Congestion in Interface Pricing

ii. The first example shows that MISO would pay the full value of the relief provided.

- MISO would pay the transaction $51.55 per MWh to the scheduling entity for this wheeling transaction, including $51.29 per MWh for congestion relief -- this congestion payment to the scheduling entity fully reflects MISO's estimated benefits of this transaction in relieving the constraint.

- However, the example shows that PJM also makes a congestion payment of $45.22 per MWh (which is why the IESO interface price is so much higher than the PJM system marginal price).

- The participant is paid $98.09 per MWh overall to schedule this transaction, of which $96.71 are congestion payments from MISO and PJM. This payment exceeds the true value of the relief by $45.42 per MWh, or 89 percent (almost double).

iii. PJM's payment in Example #1 would generate ECF or FTR under-funding.

- Because the impact of this transaction is not a component of its market flow, PJM gets no credit in the market-to-market settlement process for this real-time transaction.

- If this is a real-time transaction, the $45.22 congestion payment will be collected from its customers as an uplift charge.[36]

iv. In Example #2, ECF or FTR under-funding is generated by MISO's payment.

- If this transaction is scheduled in real time, MISO's payment would result in negative ECF.

v. We estimate that there were over $40 million in over-payments in 2012, of which $33 million were made by PJM.

- These amounts do not include overpayments made by PJM for other external constraints.

- We expect that these amounts to be higher as fuel costs rise.

vi. The figure also shows transactions that were over-charged. This understates the scope of this problem because there may be a large number of efficient transactions that are not scheduled because of the over-charge, which would not be shown in the figure.

36 Since PJM's generation levels can affect its market flows on the constraint, the transaction could have a secondary effect on its market-to-market settlements (positive or negative) that are not quantified.

vii. The figure shows that MISO's overpayments to external transactions extended beyond PJM.

- For example, when SPP invokes TLRs to solicit relief from MISO, MISO activates the constraint and its interface prices will adjust to account for the effects of the external transactions on the constraint.

- Although the interface prices will motivate participants to schedule transactions to relieve these constraints, MISO receives no reimbursement or other credit for this relief since it does not reduce MISO's obligation.

- Instead, the congestion payments made through the SPP interface price must be collected from its customers as uplift (accounting for $10.5 million in negative ECF accruals during the 2011-2012 time period).

viii. We recommend modifying interface pricing to produce more efficient signals to facilitate physical scheduling. One approach to satisfy this objective would be to eliminate the congestion components associated with external constraints for its interfaces.

D. MISO Redispatch in Response to TLRs for External Constraints

Another source of inefficient congestion management is the relief obligations and Marginal Value Limits MISO uses when responding to TLR requests. MISO reports its market flow to the IDC in the net, forward-only, and reverse-only directions. When an external (non-M2M) flowgate binds and MISO gets a relief obligation, the obligation is based solely on its forward-direction market flows, even if on net its market flows are greatly relieving the flowgate already. MISO will bind this flowgate at its internal default MVL of $2,000, which is often many times higher than the monitoring RTO's MVL. For example, SPP's default MVL on binding flowgates is $500 per MW. By allowing MISO's dispatch to incur inefficient congestion management, MISO increases the congestion costs its customers must bear in LMPs, as well as potentially increasing its negative ECF and FTR underfunding.

Figure A102: Average MISO and SPP Shadow Prices

An example of this is shown in Figure A102. The figure shows monthly average shadow prices on a representative SPP constraint that bound frequently in the past two years.

Figure A102: Average MISO and SPP Shadow Prices
Select SPP Constraint, 2011–2012

Key Observations: MISO Redispatch in Response to TLRs for External Constraints

i. For the last two years when MISO market flows have contributed to a binding external constraint, MISO's shadow price has frequently been much higher than the shadow prices in the neighboring area to manage its constraint.

   – The figure shows that MISO's shadow price was often three to four times higher than SPP's shadow price.

   – Often, the constraint was not even binding in SPP when MISO was incurring substantial redispatch costs (as indicated by MISO's shadow cost).

   – This is highly inefficient, generating wasteful costs in MISO and distorting the short and long-term economic signals produced by the MISO markets.

ii. We recommend MISO cap its MVL on external constraints at a level that reflects the marginal costs incurred by the monitoring RTO's to manage the constraint.

   – We also recommend that MISO's relief obligations under the TLR process be based on its net effect on the external constraint, which would greatly reduce the inefficiencies of this process.

E. 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 are settled on an hourly basis. This discrepancy between the hourly settlement and the 15-minute schedules can create incentives for participants to schedule transactions that are uneconomic for 15 minutes when the transaction would appear to be profitable under hourly settlement.

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 A103 and Figure A104: Real-Time Prices and Interface Schedules

Our analysis of these schedules is presented in two 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 A103: Real-Time Prices and Interface Schedules
PJM and MISO, 2012

Figure A104: Real-Time Prices and Interface Schedules
IESO and MISO, 2012

Key Observations: Price Convergence

i. The dispersion of prices and schedules on the interfaces shows 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 net imports (values in the top-right panel). This often does not occur because:

  - ✓ Real-time market schedules must be submitted no less than 30 minutes in advance of real-time market clearing.
  - ✓ Since real-time prices are relatively volatile, there is substantial uncertainty regarding the direction and optimal magnitude for schedules between RTOs;
  - ✓ The lack of coordination between the many market participants that schedule transactions between the RTOs; and

- The lack of a nodal market in IESO also contributes to the difficulty in scheduling transactions efficiently.

ii. The share of hours in which transactions with IESO were scheduled in the profitable direction improved from 48 percent in 2011 to 68 percent.

iii. The share of hours in which PJM transactions were scheduled in the profitable direction rose to 51 percent in 2012, up from 45 and 43 percent in the prior two years.

- In addition, many hours still exhibited large price differences that can be attributed to scheduling uncertainties, which indicates that substantial savings could be achieved by improving the scheduling processes.

- In the JCM, PJM and MISO are agreeing to an alignment of scheduling rules and timelines that may modestly improve performance in 2013.

  - ✓ However, alignment of scheduling rules will not address the observed inefficiency inherent with uncoordinated interchange.
  - ✓ Hence, we recommend that MISO expand the JOA with PJM to optimize the interchange and improve the interregional price convergence.

iv. 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 five- 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 payments that may arise when the external interface becomes constrained.

- While PJM staff have worked with MISO on this concept, to date PJM stakeholders have not prioritized these improvements highly enough for the ISO's to move forward.

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 very profitable to exercise.

A. Market Structure

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

The second and third analyses address the frequency with which suppliers in MISO are "pivotal" and are 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 A105: 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 (in percentage terms). Antitrust agencies generally characterize markets with an HHI greater than 1,800 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 shortcoming for identification of market power in electricity markets is that it generally does not account for demand or network constraints. In wholesale electricity markets, these factors have a profound effect on competitiveness.

Figure A105 shows generating capacity-based market shares and HHI calculations for MISO as a whole and within each region.

Figure A105: Market Shares and Market Concentration by Region
2012

Because the HHI does not recognize the physical characteristics of electricity that can cause a supplier to have market power, 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 A106: 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 A106 summarizes the results of this analysis, 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 horizontal axis indicate the share of hours that comprise each load-level tranche.

Figure A106: Pivotal Supplier Frequency by Region and Load Level
2011–2012

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, by specifying when a supplier is pivotal relative to a particular transmission constraint, measure local market power more precisely than either the HHI or RDI.

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 for managing the congestion on the constraint.

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,[37] the WUMS NCA[38], and the North WUMS NCA.

37 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. 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 A107 and Figure A108: 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 A107 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 A108 shows, of the intervals with active constraints in each month, the percentage with at least one pivotal supplier.

Figure A107: Percent of Intervals with at Least One Pivotal Supplier
2012

38 Beginning in early 2013, the thresholds that apply to WUMS NCA were set equal to BCA thresholds.

Figure A108: Percentage of Active Constraints with a Pivotal Supplier
2012

Key Observations: Market Structure

i. The market-wide HHI was flat at almost 550 in 2012.

– 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.[39]

– Regional HHIs and the market shares of each of the top three suppliers were also little changed from 2011.

ii. 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.

– We previously raised competitive concerns regarding commitments made to support the voltage of the system in specific local areas.[40] MISO filed proposed changes to

39 Generation divestiture in other RTOs generally reduce market concentration because the assets are typically sold to multiple entities.

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

market power mitigation measures to address this concern in December 2011, which are pending with the Commission.

iii. The majority of active constraints in 2012—57 percent—had at least one supplier that was pivotal.

- The results were comparable for various types of constraints, including BCA constraints (57 percent) and NCA constraints into Minnesota (58 percent) and WUMS NCA constraints (63 percent).
- At least one BCA constraint with a pivotal supplier was binding in over 95 percent of intervals, up from 90 percent last year.
- This share is considerably larger than it is for NCAs because the number of constraints in each NCA is much smaller.
- Since BCA constraints are more broadly defined, there are often multiple binding BCA constraints per interval.

iv. 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 the next three subsections, 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 at prices 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.

One metric to evaluate the competitive performance of the market is the price-cost mark-up, which estimates the "mark-up" of real-time market prices over suppliers' competitive costs. It compares a 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 SMP under each scenario. The percentage difference in 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. (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 one to two 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 exercise market power by physically or economically withholding resources.

ii. The average SMP mark-up was just 0.6 percent in 2012, down from 1.3 percent in 2011.

iii. These results indicate that the MISO energy markets performed competitively in 2012.

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 their marginal cost. 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, variable 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 identifying 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 (additionally, impact must be considered). 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 economic minimum and maximum) for its minimum run time. Second, if a unit was economic for commitment, we then identify the set of contiguous hours when it was economic to dispatch.

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

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

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

$Q_i^{econ} - \max(Q_i^{prod}, Q_i^{offer})$ when greater than zero, where:
Q_i^{offer} = offer output level of i.

By using the greater of actual production or the output level offered at the clearing price, infeasible energy due to ramp limitations is excluded from the output gap.

Figure A109: Real-Time Monthly Average Output Gap

Figure A109 shows monthly average output gap levels for the real-time market in 2011 and 2012. 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. Within NCAs the high thresholds effective during most of 2012 were $95.52 per MWh for resources located in the WUMS NCA, $26.44 for those in the North WUMS NCA, and $64.10 for those 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 Minnesota NCA, the low threshold would be $32.05 per MWh (50 percent of $64.10). 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 A109: Real-Time Average Output Gap
2011–2012

Figure A110 to Figure A113: 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 A110: Real-Time Average Output Gap
Central Region, 2012

Figure A111: Real-Time Average Output Gap
East Region, 2012

Figure A112: Real-Time Average Output Gap
West Region, 2012

Figure A113: Real-Time Average Output Gap
WUMS Area, 2012

Key Observations: Economic Withholding

i. Output gap levels continued to be very low in 2012 and averaged just 30 MW per hour at the low threshold and eight MW per hour at high threshold.

  – As a share of actual load, output gap again averaged less than 0.1 percent, which is extremely low.

ii. Most of the slight decline in output gap from 2011 is due to changes in the NCA threshold levels.

  – In most regions, 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.

  – The lone exception was in the West. However, the output gap in the West accounted for just 1.4 percent of actual load in the 72 hours when load exceeded 90 GW.

  – 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 A114: Ancillary Services Offers

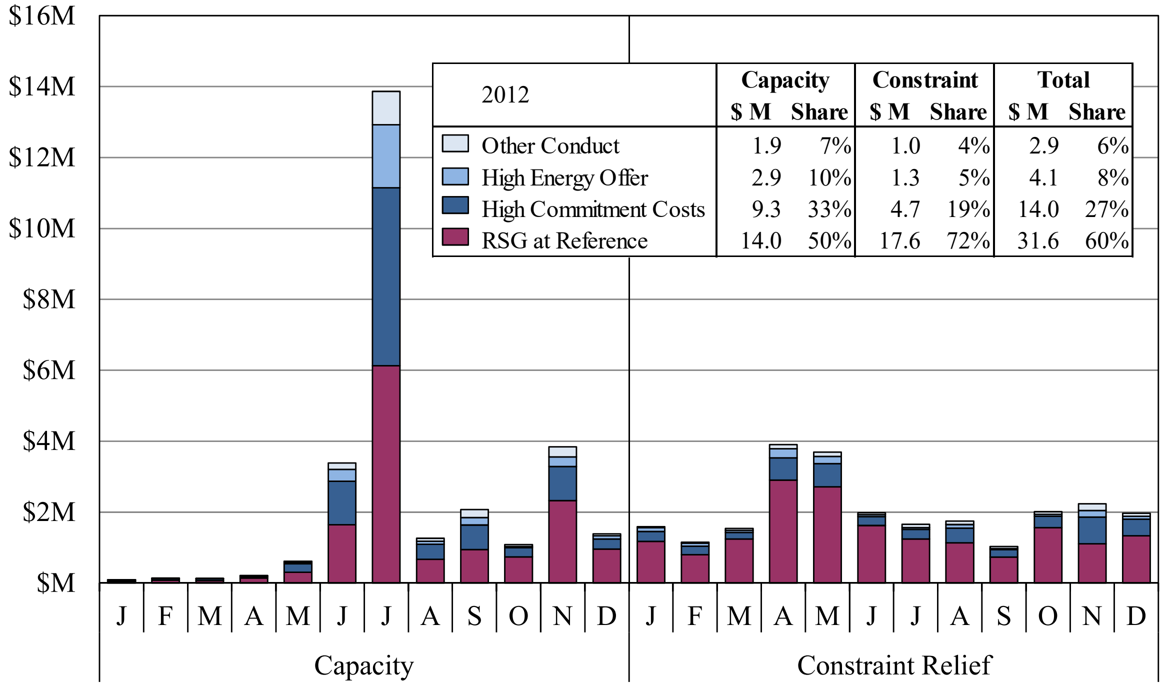
Figure A114 evaluates the competitiveness of ancillary service offers. It shows monthly average quantities of regulation and contingency reserve offered at prices ranging from $10 to $50 per MWh above reference levels, as well as the share of total capability that those quantities represent. As in the 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 A114: Ancillary Services Offers
2012

Figure A115: RSG Payments by Conduct

Local market power can also be associated with repeated resource commitments for reliability needs. We evaluate conduct associated with RSG payments in Figure A115, separating the payments associated with resources' reference levels, and the payments associated with the portions of resources' bid parameters (e.g., energy or commitment costs) that exceed their reference levels. The results are shown separately for units committed for capacity and for congestion management. Significant RSG payments were made to units committed for voltage support in 2011, which resulted in the IMM filing for tighter mitigation thresholds—production costs 10 percent above reference—implemented starting in September 2012. Most such commitments are now made by the day-ahead market.

Figure A115: RSG Payments by Conduct
By Commitment Reason, 2012



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

i. Just over three percent of all regulating reserves was offered at more than $10 per MWh above reference, and only one percent was offered at more than $20 above reference.

- In late December, the introduction of the regulation mileage offer and compensation scheme resulted in some participants mistakenly offering regulation at prices up to $100 above reference for a short time.

  ✓ This explains the regulation conduct spike in December, but these high offers did not materially impact clearing prices.

ii. A similar amount of spinning reserves was offered at more than $10 per MWh above reference.

- These quantities (and particularly those offered at $20 or more above reference) rose during the high-load summer months because more resources were online and available for scheduling of spinning reserves and regulation.

iii. No supplemental reserves were offered at more than $10 per MWh above reference.

- Infrequent offline deployments (only three events in 2012) limit the risk associated with offering offline reserve, which lead to the low observed offer prices.

iv. One-half of capacity-related RSG payments and 60 percent of congestion-related RSG payments were made to units for costs associated with the units' reference levels.

- Since units committed for capacity are more often committed in-merit, payments above reference for these units were lower (as a share of the total) than for units earning constraint-related RSG payments.
- One-quarter of all RSG costs in 2012 (and one-third of those for capacity) were for commitment costs above reference.

v. RSG payments above reference levels totaled $21.0 million, 44 percent lower than in 2011.

- Much of the decline was associated with new mitigation measures for voltage and local reliability commitments.
  - ✓ Although these commitments continued into 2012, the resources were offered at close to their reference values.
  - ✓ Tighter mitigation thresholds for VLR commitments have reduced the ability of suppliers to exercise market power in such areas (see Section VII.G).
- These results and others in this report show little indication of significant economic withholding in 2012. Nonetheless, we monitor these metrics on an hourly basis and routinely investigate instances of potential withholding.

E. Dynamic NCAs

The current Tariff provisions related to the designation of NCAs are focused only on sustained congestion. An NCA is an area defined by one or more constraints that are expected to bind for at least 500 hours in a 12-month period.

Consequently, when conditions arise that create a severely-constrained area with one or more pivotal suppliers, an NCA can only be declared if the constraint is expected to bind for 500 hours in a 12-month period. In addition, even if an NCA is defined, the conduct and impact thresholds are based on historical congestion so they would not reflect the congestion for up to 12 months.

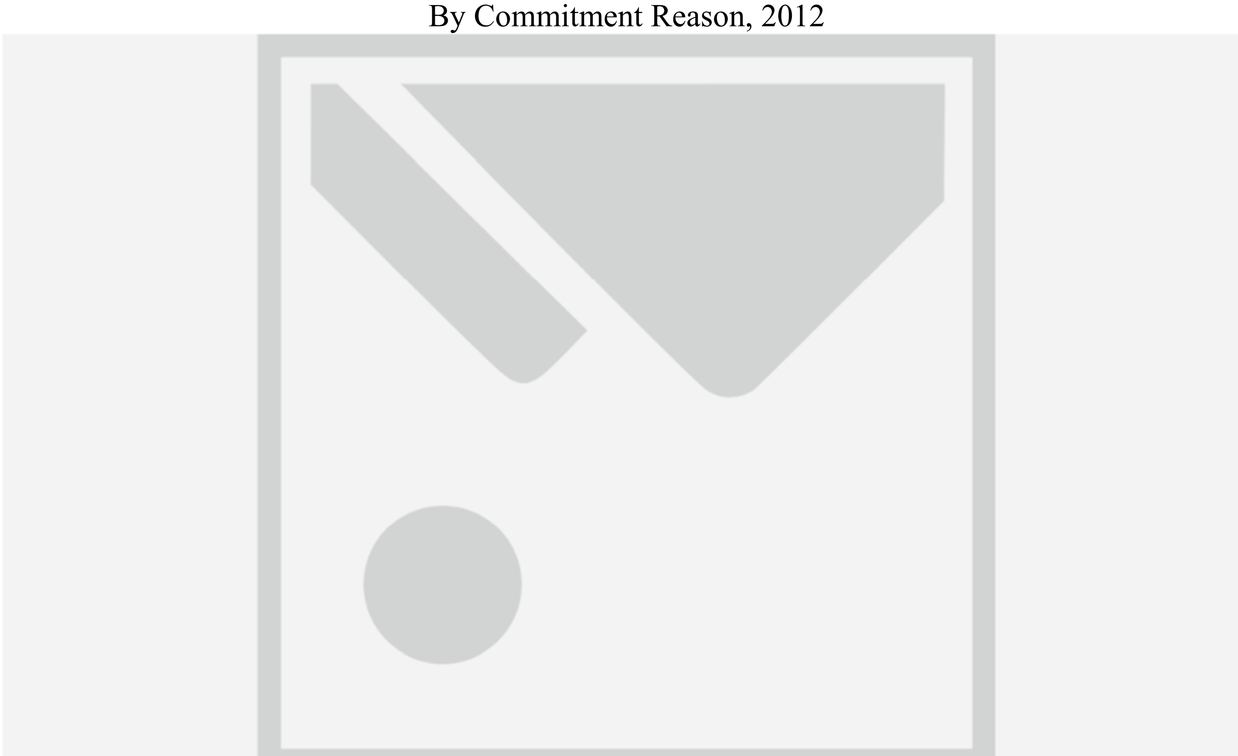
Figure A116 and Figure A117: RSG Conduct in Select Constrained Areas

In our next analysis, we show how the current Tariff provisions related to NCA designations are insufficient to identify market power that can arise in transitory episodes. Figure A116 and Figure A117 show the same analysis as in the previous subsection for a set of units in two constrained areas within MISO in 2012. The figures also show the number of binding hours for the constraints that define each area. The dashed horizontal line shows the monthly constraint-hour rate (approximately 42 hours) that is equivalent to an NCA's annual minimum of 500 hours.

In the first example, the congestion in the area was anticipated based on transmission studies and expected outages, but the binding hours did not exceed 500 hours for the year. In the second example, the congestion was not anticipated and exceeded 500 hours, but was transient and is not likely to occur again.

Figure A116: RSG Payments by Conduct, Area 1
By Commitment Reason, 2012

Figure A117: RSG Payments by Conduct, Area 2
By Commitment Reason, 2012



<u>Key Observations: Dynamic NCAs</u>

i. In the first example, a pivotal supplier exercised market power throughout the year, often raising commitment and dispatch costs up to the BCA conduct thresholds.

ii. In the second example, a pivotal supplier with a resource committed almost exclusively for the relief of the constraints in the area generally offered competitively throughout the period.

- Although it collected $7.5 million in RSG payments, it could have raised offers and earned an additional $2 million in payments under the BCA thresholds.

iii. These results indicate that current Tariff provisions are at times insufficient to effectively address market power associated with transitory episodes of local market power.

- Therefore, we recommend MISO expand Module D mitigation provisions to allow for greater flexibility in defining NCAs and to modify formulas for the threshold calculations to address transitory episodes of congestion.

F. 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 non-economic parameters or conditions. 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 that have substantial effects on market outcomes.

Figure A118 to Figure A121: Real-Time Deratings and Forced Outages

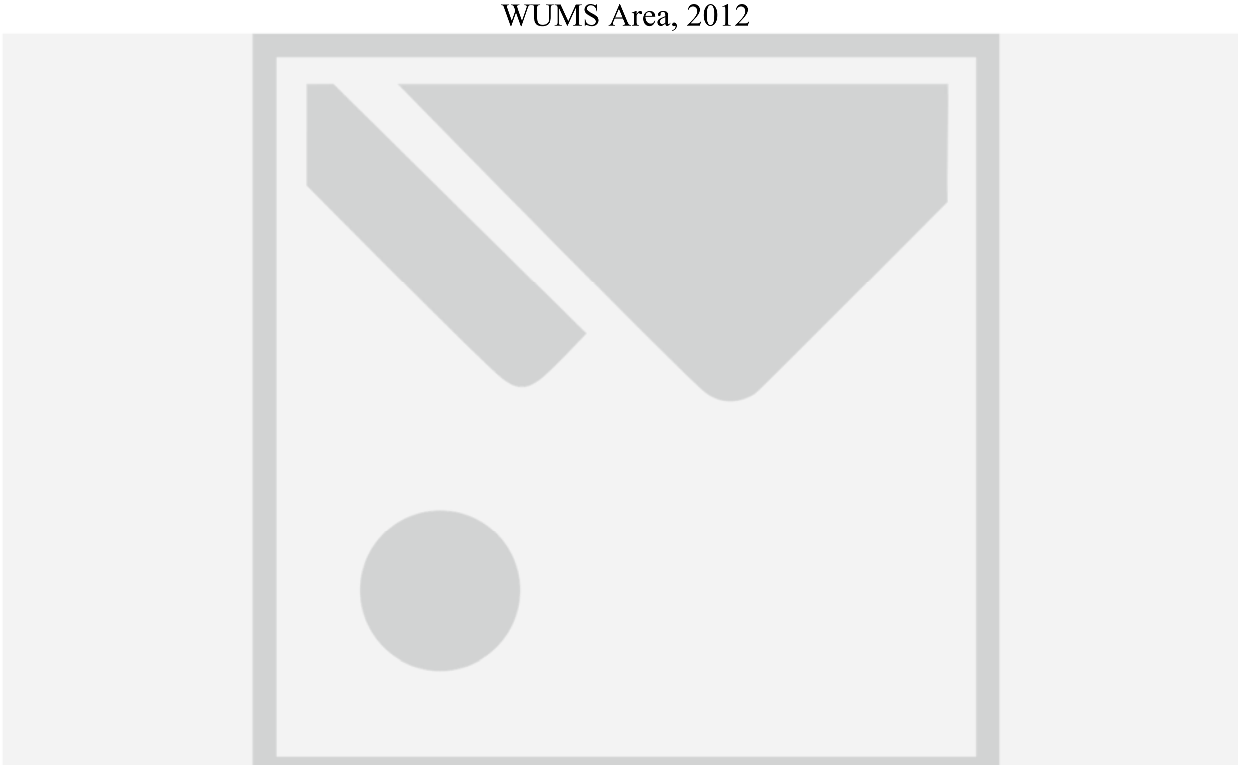
The following four figures show, by region, the average share of capacity unavailable to the market in 2012 because of forced outages and deratings. As with the output gap analysis, this conduct may be justifiable or may represent the exercise of market power. Therefore, we evaluate the conduct relative 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 likely cause the supplier to forego greater profits on the unit during hours when the supplier does not have market power than it could earn in the hours in which it is exercising market power.

Figure A118: Real-Time Deratings and Forced Outages
Central Region, 2012

Figure A119: Real-Time Deratings and Forced Outages
East Region, 2012

Figure A120: Real-Time Deratings and Forced Outages
West Region, 2012

Figure A121: Real-Time Deratings and Forced Outages
WUMS Area, 2012



Key Observations: Physical Withholding

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

   – In most regions deratings increased slightly at higher load levels. This is expected because high ambient temperatures during unusually warm periods in summer can cause the ratings of thermal units to decrease.

      ✓ Forced outages did not increase materially 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. The deratings and outages of the largest suppliers in almost every region were generally lower than for other smaller suppliers.

   – We review these deratings and outages for those that could have potentially contributed to substantial congestion and associated price increases.

   – We did not find substantial attempts to raise price by physically withholding resources in 2012.

G. Market Power Mitigation

In this final subsection, we examine the frequency with which market power mitigation measures were imposed in MISO markets. When the set of Tariff-specified criteria are met, a mitigated unit's offer price is capped at its reference level, which is a benchmark designed to reflect a competitive offer. 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 binding transmission constraints 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 with which NCA constraints bind, are lower than for BCAs.

Figure A122: Real-Time Energy Mitigation by Month

Figure A122 shows the frequency and quantity of mitigation in the real-time energy market by month. We focus on the real-time market 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.[41]

Figure A122: Real-Time Energy Mitigation by Month
2012

Figure A123: 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 A123 shows the frequency and amount by which RSG payments were mitigated in 2011 and 2012.

41 There were several mitigation measures under VLR authority in the day-ahead market in 2012, but they are rarely invoked.

Figure A123: Real-Time RSG Mitigation by Month
2011–2012

Key Observations: Market Power Mitigation

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

- A total of 39 BCA unit-hours and 17 NCA unit-hours were mitigated in 2012, up from 22 and 9 unit-hours, respectively, last year.

- Mitigation totaled 1,958 MWh in BCAs and 546 MWh in NCAs.

ii. Mitigation of units for RSG payments declined by 36 percent to less than $400,000. In unit-day terms it declined by 53 percent.

- Seven unit-days were mitigated under the new VLR mitigation measures beginning in September. In addition, four units were mitigated under the VLR measures in the day-ahead market.

iii. Despite infrequent mitigation this year, the pivotal supplier analyses discussed earlier in this section continues 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.

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 reductions in consumption 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.[42] 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.

42 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.

A. DR Resources in MISO

MISO's demand response capability declined slightly in 2012 to approximately 7,200 MW. The majority of this takes the form of legacy DR programs administered by LSEs, either through load interruptions (Load-Modifying Resources, or LMR) or through behind-the-meter-generation (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 (DRRs) and were eligible to participate in all of the MISO markets in 2012, including satisfying LSEs' resource adequacy requirements under Module E of the Tariff.

1. Types of DRR

MISO characterizes DRRs 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 of energy or operating reserves on a five-minute basis. MISO had 19 Type I resources and one Type II resource available to the markets in 2012.

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 developing a pricing methodology to allow Type I and other "fixed-block" offers to establish market prices.

Type II resources can set prices because they are capable of supplying energy or operating reserves in response to five-minute instructions, 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 2012.

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 reserves. Physical requirements for 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 2012, DRR units provided an average of eight MW of regulating reserve (one unit), 116 MW of spinning reserve (three units) and 45 MW of supplemental reserve (13 units).

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. 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 in the ancillary services market 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 2013–2014 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 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
2009–2012

3. Aggregators of Retail Customers

In August 2008, the Commission 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 one MW. By pooling small resources, Aggregators of Retail Customers (ARCs) can serve as an intermediary between MISO and retail customers who can reduce consumption.[43] 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, which the Commission approved on December 15, 2011.[44]

43 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.

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

<u>Key Observations: Demand Response</u>

i. MISO had 7.2 GW of registered DR capability in 2012, comparable to the share of capacity of neighboring RTOs.

ii. 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 433 MW participated directly in MISO's energy markets as DRR Types I or II in 2012, down from 547 MW last year. All but three provided only supplemental reserves.

iii. 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.

- MISO continues to explore integrating Batch-Load Demand Response (BLDR) resources and Price-Responsive Demand (PRD) into the energy and ancillary services markets.
- One additional change that is particularly important is a modification to price-setting methodologies to allow DR resources to set real-time energy prices when they are needed.
  - ✓ 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.

iv. Since June 12, 2012 and as required by FERC Order 745, ARC resources are compensated for their energy at the full LMP.

- 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.

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

– LMR (excluding BTMG) can be used to meet an LSE's requirement under Module E. There are 343 such resources totaling nearly 5.4 GW that are a part of the upcoming Planning Year.

- ✓ Unlike some other neighboring RTOs, MISO does not test these resources to verify their capability, so they are granted a 100 percent capacity credit.
- ✓ When they have been called in the past, MISO has received only a fraction of their total claimed capability. In 2006, MISO received a peak response of 2,651 MW, far less than the more than 6,000 MW of total claimed capability at that time.
- ✓ Therefore, we recommend adopting testing procedures if practicable, and derating these resources based on their actual performance when called.