2016 State of the Market Report for the MISO Electricity Market

Analytic Appendix

Prepared By:

POTOMAC ECONOMICS

Independent Market Monitor for the Midcontinent ISO

June 2017

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

I. INTRODUCTION

This Analytical Appendix provides an extended analysis of the topics raised in the main body of the Report. We present the methods and motivation for each of the analyses. However, the discussion of our conclusions regarding the performance of various components of the market is contained in the body of the Report. In addition, the body of the Report includes a discussion of our recommendations to improve the design and competitiveness of the market.

MISO has operated competitive wholesale electricity markets for energy and financial transmission rights (FTRs) since April 2005. MISO added regulating and contingency reserve products (jointly known as ancillary services) in January 2009 and added a capacity market in June 2009. The prior capacity market was replaced by the annual Planning Resource Auction (PRA) in June 2013.

Several notable market changes occurred in 2016 that affected the performance of the MISO markets. Key changes or improvements implemented in 2016 included:

- On February 1, 2016 the ORCA agreement was amended and became the Regional Dispatch Transfer (RDT), allowing 3,000 MW of flow in the North-to-South direction and 2,500 MW of flow in the South-to-North direction.
- On March 1, five resources in the MISO footprint pseudo-tied into PJM, followed by seven additional resources on June 1.
- On May 1, MISO implemented the ramp product, which contributed to reduced price volatility and slightly lower prices in the real-time market.
- On July 1, emergency pricing was implemented to ensure that additional supply or demand reductions acquired through emergency actions are priced at appropriate shortage levels.
- In September, the Real-Time Offer Enhancement (RTOE) capability was introduced to allow resources to update offers intra-hour to reflect short-term operating limitations.
- MISO's day-ahead market moved up a half an hour in November in order to better align the gas and electricity markets.
- In December, MISO made changes to their real-time model processing time to allow model inputs to more accurately reflect system conditions at the time of the model run.

II. Prices and Load Trends

In this section, we provide our analyses of the prices and outcomes in MISO's 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 generators' marginal production costs, which are primarily comprised of fuel costs for most generators. Although coal-fired resources historically have been marginal in a large share of hours, sharp reductions in natural gas prices over the past two years has caused gas-fired units to be marginal in most peak hours. Additionally, congestion frequently causes gas-fired units to set prices in local areas.

Figure A1: All-In Price of Electricity

Figure A1 shows the monthly "all-in" price of electricity from 2015 to 2016 along with the price of natural gas at the Chicago Citygate. The leftmost section shows the annual average prices for 2014 through 2016. 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 services costs, uplift costs, and capacity costs (PRA clearing price multiplied by the capacity requirement) per MWh of real-time load. We separately show the portion of the all-in energy price that is associated with shortage pricing for one or more products.

Figure A1: All-In Price of Electricity
2015–2016

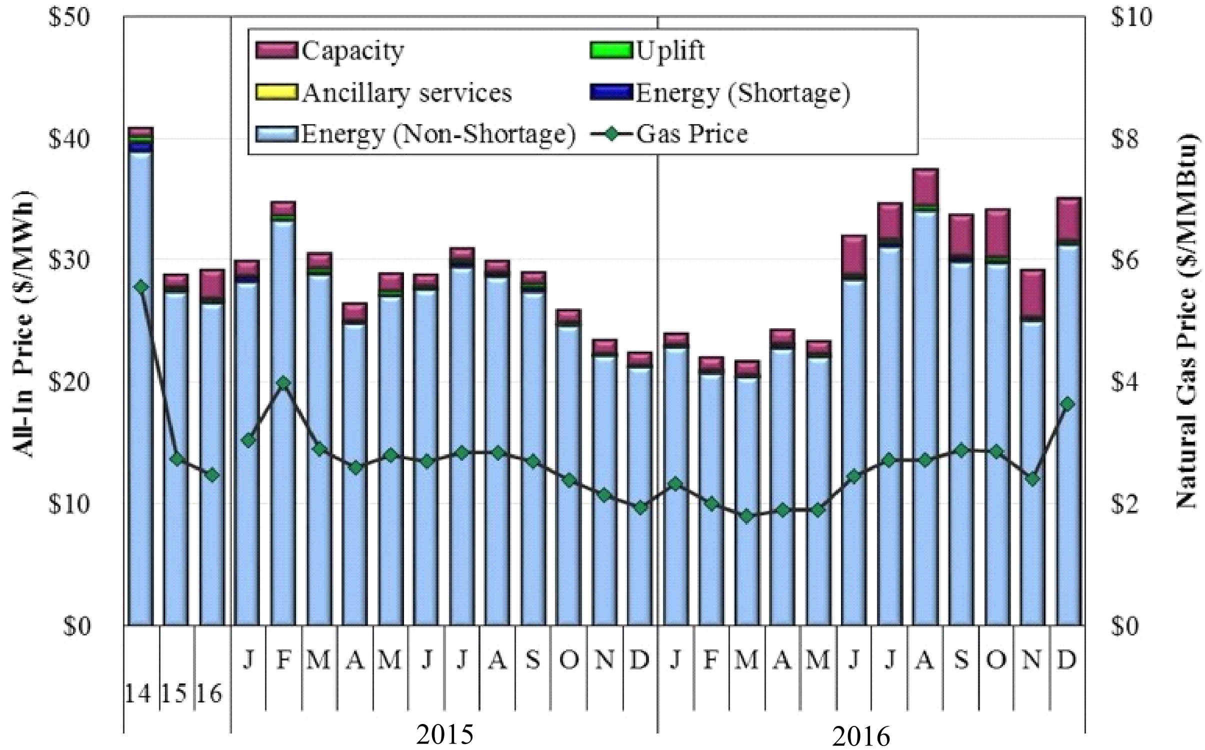


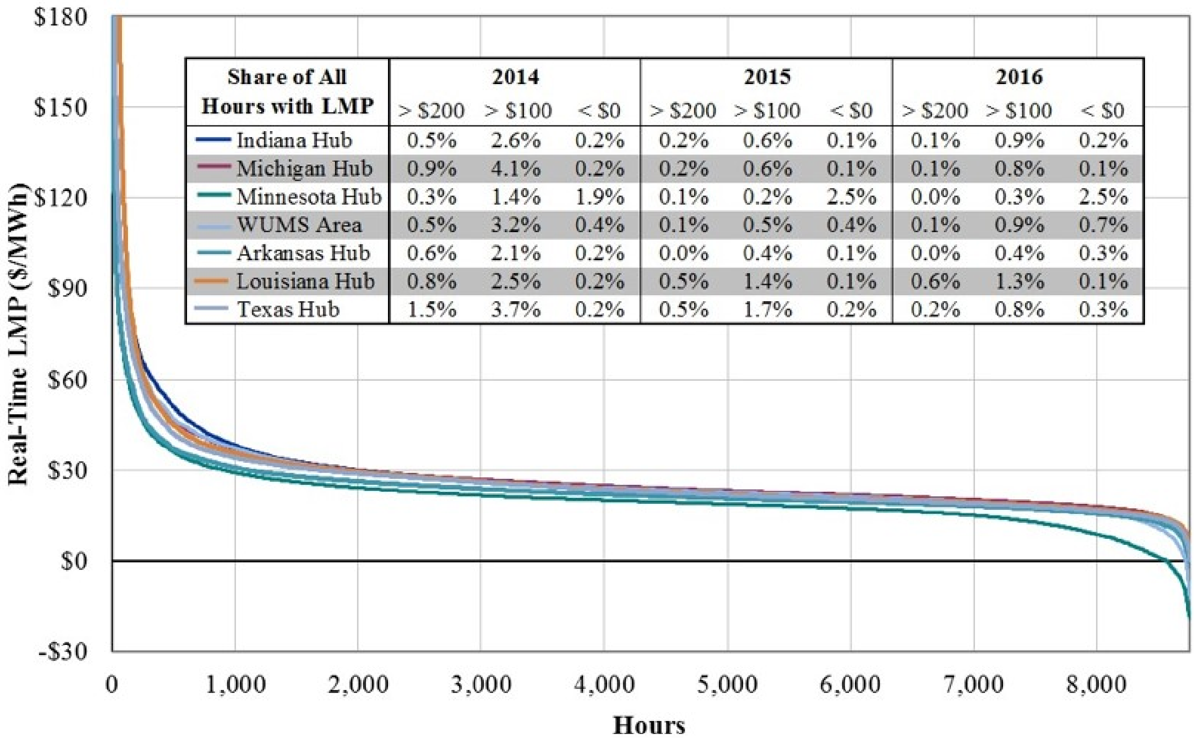
Figure A2: Real-Time Energy Price-Duration Curves

Figure A2 shows the real-time hourly prices at seven 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 percentage of hours with prices greater than $200, greater than $100, and less than $0 per MWh in the three most recent 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.

Broad changes in prices are generally driven by changes in underlying fuel prices that affect many hours. In contrast, changes in prices at the high end of the duration curve are usually attributable to differences in weather-related peak loads that impact the frequency of shortage conditions.

Figure A2: Real-Time Energy Price-Duration Curve
2016



Share of All Hours with LMP	2014 > $200	2014 > $100	2014 < $0	2015 > $200	2015 > $100	2015 < $0	2016 > $200	2016 > $100	2016 < $0
Indiana Hub	0.5%	2.6%	0.2%	0.2%	0.6%	0.1%	0.1%	0.9%	0.2%
Michigan Hub	0.9%	4.1%	0.2%	0.2%	0.6%	0.1%	0.1%	0.8%	0.1%
Minnesota Hub	0.3%	1.4%	1.9%	0.1%	0.2%	2.5%	0.0%	0.3%	2.5%
WUMS Area	0.5%	3.2%	0.4%	0.1%	0.5%	0.4%	0.1%	0.9%	0.7%
Arkansas Hub	0.6%	2.1%	0.2%	0.0%	0.4%	0.1%	0.0%	0.4%	0.3%
Louisiana Hub	0.8%	2.5%	0.2%	0.5%	1.4%	0.1%	0.6%	1.3%	0.1%
Texas Hub	1.5%	3.7%	0.2%	0.5%	1.7%	0.2%	0.2%	0.8%	0.3%

Figure A3: MISO Fuel Prices

As we have noted, fuel prices are a primary determinant of overall electricity prices because they constitute most of the generators' marginal costs. Hence, because the MISO market has performed very competitively, electricity prices tend to be highly correlated with natural gas prices since natural gas-fired resources set energy prices in a large share of hours. Coal-fired units frequently set prices in off-peak hours.

Figure A3 shows the prices for natural gas, oil, and two types of coal in the MISO region since the beginning of 2015.[1] The figure shows nominal prices in dollars per million British thermal units (MMBtu). The table below the figure shows the annual average nominal prices since 2014 for each type of fuel.

Figure A3: MISO Fuel Prices
2015–2016

Annual Average	2014	2015	2016
Oil	$20.18	$11.68	$9.69
Natural Gas	$5.53	$2.73	$2.47

Annual Average	2014	2015	2016
IB Coal	$1.91	$1.59	$1.31
PRB Coal	$0.71	$0.59	$0.58

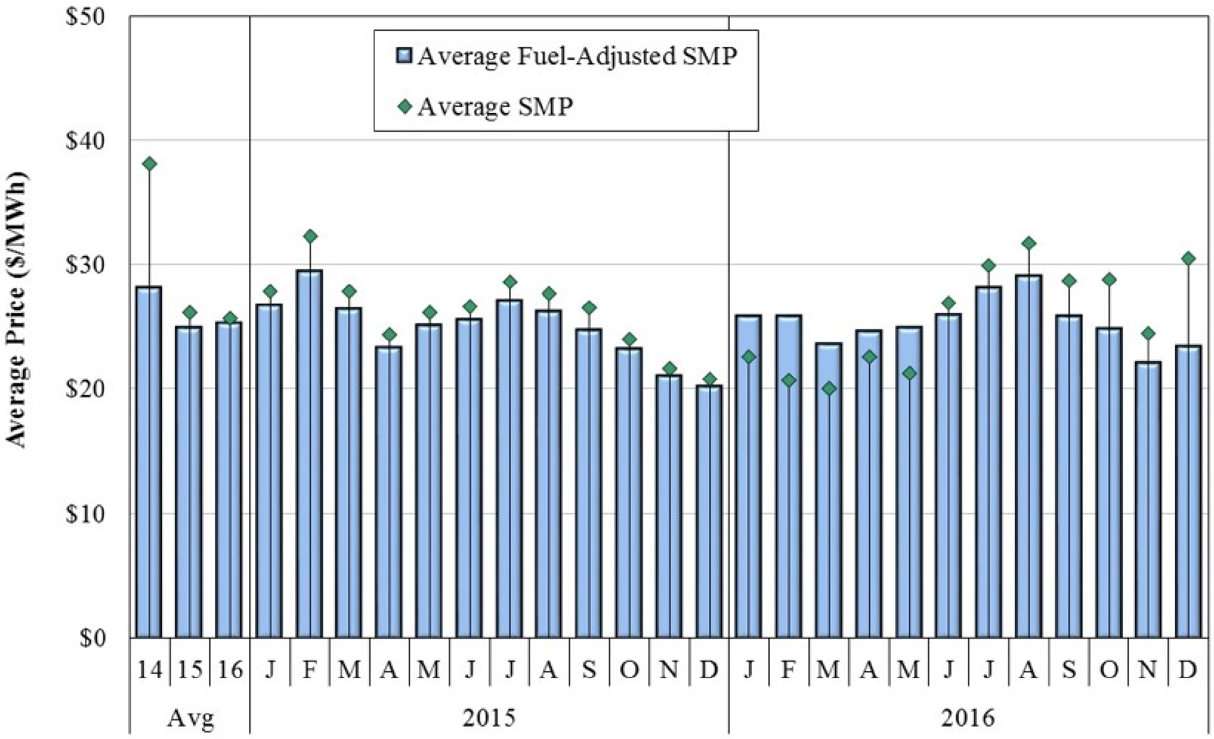
Figure A4: Fuel-Price Adjusted System Marginal Price

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 system marginal price (SMP). The SMP indicates the system-wide marginal cost of energy (excluding congestion and losses); the fuel adjustment isolates variations in 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 from period to period as a result of unit additions or retirements and from interval to interval because of unit outages or deratings, congestion management needs, or output by intermittent resources.

1 Although output from oil-fired generation is typically minimal, it can become significant if natural gas supplies are interrupted during peak winter load conditions. The majority of MISO coal-fired generators have historically received supplies from the Powder River Basin or other Western supply areas.

To calculate this metric, each real-time interval's SMP was indexed to the average three-year fuel price of the marginal fuel during the interval. Downward adjustments were the greatest when fuel prices were the highest and vice versa. Multiple fuels may be marginal so we calculate each interval's SMP adjustment on a quantity-weighted basis. 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 with neighboring areas.

Figure A4: Fuel Price-Adjusted System Marginal Price
2015–2016



B. Price Setting by Fuel Type

Figure A5: Price Setting by Unit Type

Figure A5 examines the frequency that different types of generating resources set the system energy price in MISO. The figure shows the average prices that prevailed when each type of unit was on the margin in the top panel and the share of market intervals that each type of unit set the real-time price in the bottom panel.

Historically, baseload coal-fired units set prices in the majority of hours. After the integration of MISO South and the reduction in natural gas prices over the past two years, gas-fired units set MISO's energy prices in most peak hours and in constrained areas. Most wind resources can be economically curtailed when contributing to transmission congestion. Because their incremental costs are mostly a function of lost production tax credits, wind units often set negative prices in export-constrained areas when they must be ramped down to manage congestion.

Figure A5: Price-Setting by Unit Type
2015–2016

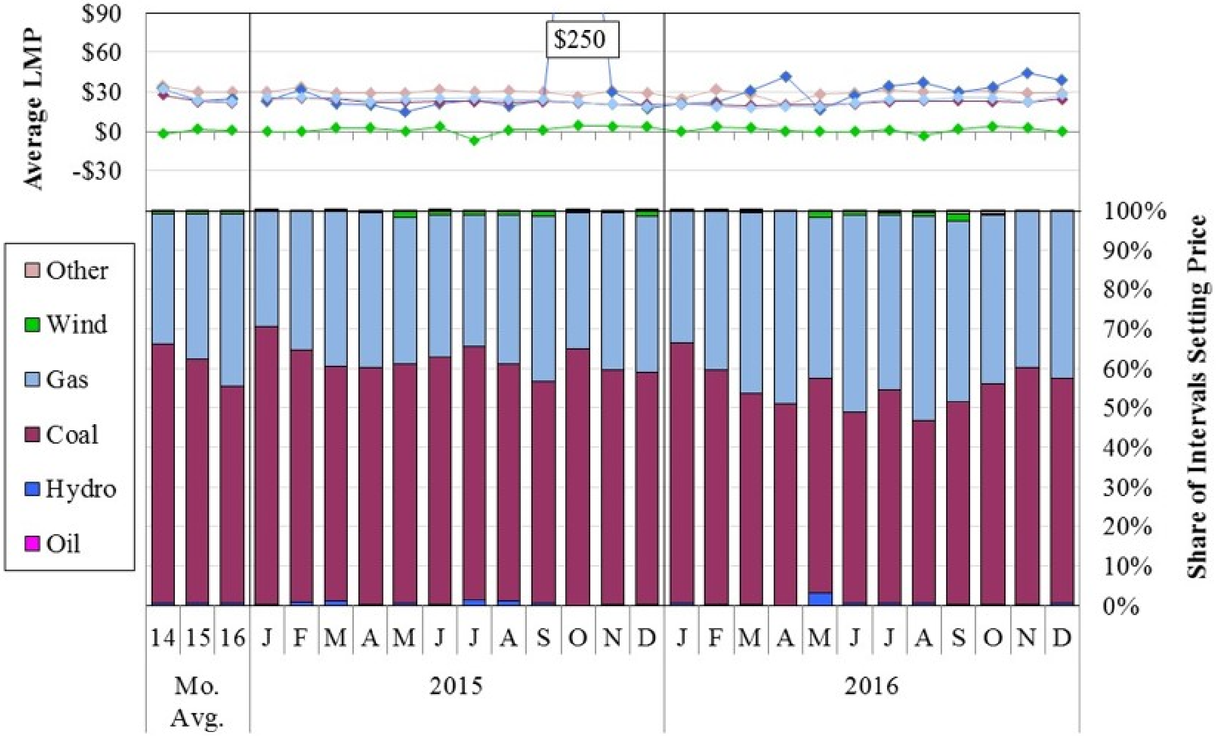


Table A1: Capacity, Energy Output and Price-Setting by Fuel Type

Table A1 summarizes how changes in fuel prices have affected the share of energy produced by fuel-type, as well as the generators that set the real-time energy prices in 2016 compared to 2015. The lowest-cost marginal cost resources (coal and nuclear) tend to produce most of the energy. Since they are higher marginal cost resources, natural gas-fired units tend to produce a lower share of MISO's energy than their share of MISO's installed capacity, although their capacity factor and energy production have risen over time as natural gas prices have declined.

Table A1: Capacity, Energy Output and Price-Setting by Fuel Type
2015–2016

	Unforced Capacity				Energy Output		Price Setting			
	Total (MW)		Share (%)		Share (%)		SMP (%)		LMP (%)	
	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
Nuclear	12,432	12,432	9%	9%	16%	16%	0%	0%	0%	0%
Coal	59,181	53,471	42%	41%	50%	46%	62%	55%	95%	85%
Natural Gas	58,013	55,367	42%	42%	24%	27%	37%	44%	94%	85%
Oil	2,063	1,832	1%	1%	0%	0%	0%	0%	0%	0%
Hydro	3,603	3,478	3%	3%	1%	1%	1%	1%	2%	2%
Wind	2,412	2,796	2%	2%	7%	8%	1%	1%	45%	32%
Other	1,688	2,076	1%	2%	1%	2%	0%	0%	4%	3%
Total	**139,391**	**131,452**								

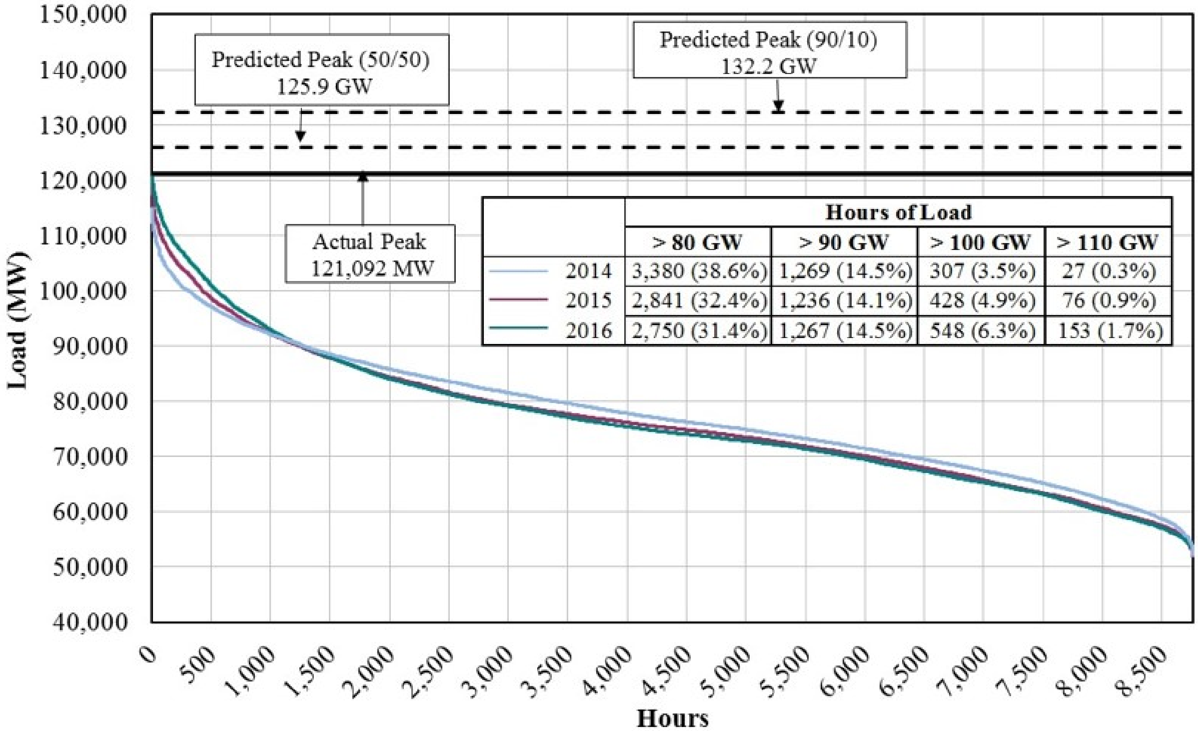
C. Load Patterns

Figure A6: Load Duration Curves and Peak Load

Although market conditions can still be tight in the winter periods because of generation and transmission outages and fuel supply issues, MISO continues to be a summer-peaking market. To show the hourly variation in load, Figure A6 shows load levels for 2016 and prior years in the form of hourly load duration curves. The load duration curves show the number of hours on the horizontal axis in which load is greater than or equal to the level indicated on the vertical axis. We show curves for 2014 through 2016 separately.

These curves reveal the changes in load that are due to economic activity and weather conditions, among other things. The inset table indicates the number and percentage of hours when load exceeded 80, 90, 100, and 110 GW of load. The figure shows the actual and predicated peak load for 2016. The "Predicted Peak (50/50)" is the predicted peak load in 2016 where MISO expected the load could be higher or lower than this level with equal probability. The "Predicted Peak (90/10)" is the predicted peak load where actual peak will be at or below this level with 90 percent probability (i.e., there is only a 10 percent probability of load peaking above this level).

Figure A6: Load Duration Curves and 2016 Peak Load
2014–2016



	Hours of Load			
	> 80 GW	> 90 GW	> 100 GW	> 110 GW
2014	3,380 (38.6%)	1,269 (14.5%)	307 (3.5%)	27 (0.3%)
2015	2,841 (32.4%)	1,236 (14.1%)	428 (4.9%)	76 (0.9%)
2016	2,750 (31.4%)	1,267 (14.5%)	548 (6.3%)	153 (1.7%)

Figure A7: Heating and Cooling Degree-Days

MISO's load is temperature sensitive. Figure A7 illustrates the influence of weather on load by showing heating and cooling degree-days that are a proxy for weather-driven demand for energy. These are shown along with 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. The bottom panel shows monthly Heating Degree-Days (HDD) and Cooling Degree-Days (CDD) averaged across four representative cities in MISO Midwest and two cities in MISO South.[2] The table at the bottom shows the year-over-year changes in average load and degree-days.

Figure A7: Heating and Cooling Degree-Days
2014–2016

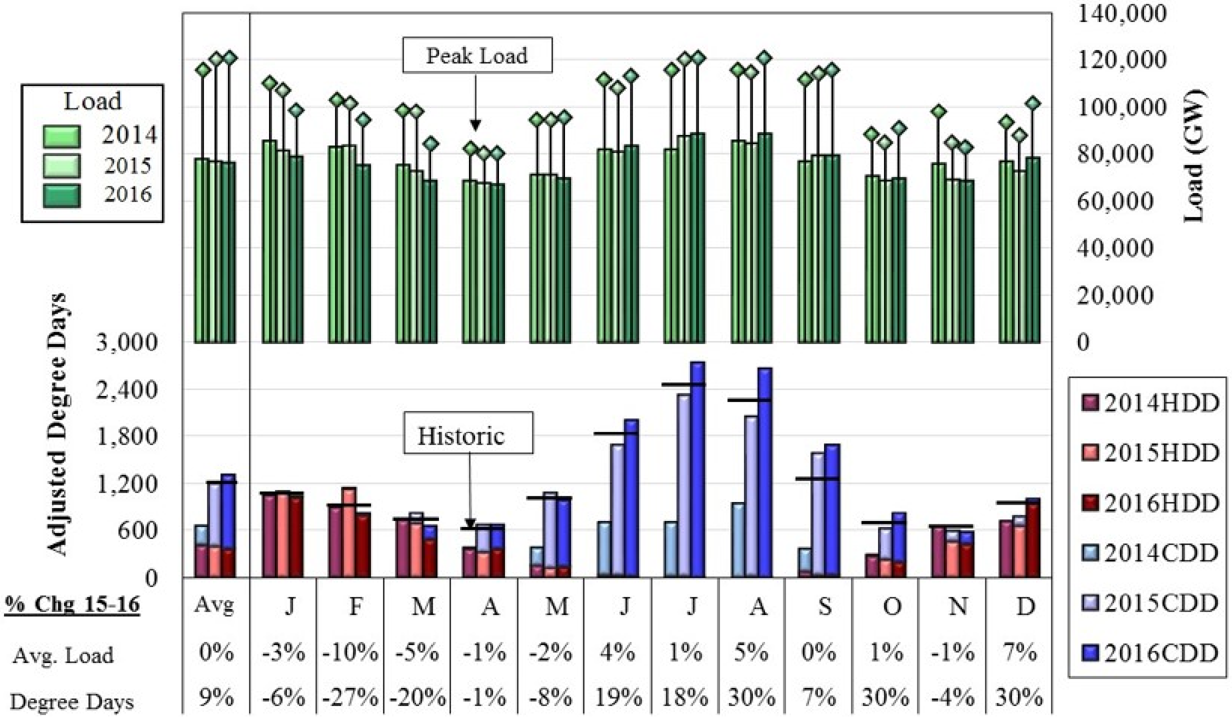


Table A2: Temperature, Loads and Market Outcomes

MISO experienced hot weather events on several days during the summer months in 2016. In June, high loads and outages in MISO South resulted in substantial congestion into the South over the RDT constraint and into Louisiana. MISO declared Hot and Severe Weather Alerts and Conservative Operations, and local transmission owners declared emergency conditions on several days. On June 17, MISO issued a Maximum Generation Alert in the South. In July, interregional flows reversed, flowing South-to-North as MISO declared Severe and Hot Weather Alerts throughout the Midwest. Table A2 and Figure A8 summarize the loads, actions taken by MISO, and the market outcomes on seven of the highest-load days in July and Augest of 2016.

2 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.

On July 21, MISO declared a Maximum Generation Event (Step 1) and remained in Conservative Operations through the evening of July 22. During this event:

- Forecasted load climbed to nearly 125 GW.
- Actual peak load was roughly 4 GW lower because storms in Wisconsin, Michigan, and Indiana reduced loads in those areas and market participants voluntarily curtailed loads by nearly 1,600 MW, according to data submitted by LBAs.
- MISO committed 195 peaking resources, but because MISO's load was lower than expected, prices were low and real-time RSG exceeded $1.6 million.
- Emergency Pricing rules introduced on July 1 called for MISO to apply a proxy offer floor price to all emergency MWs, but they did not set the prices on July 21. The storms and voluntary load reductions reduced load, so the emergency capacity was not deemed necessary by ELMP. However, this event revealed some software issues that MISO has since addressed.

The turbines committed by MISO also did not set prices because very few were eligible under MISO's ELMP provisions. We conducted a simulation that showed that expanding ELMP's eligibility rules would have raised prices in the peak hours by 38 percent on July 21 and lowered MISO's real-time RSG by 14 percent.

MISO also experienced several hot periods in August and declared local Conservative Operations for severe flooding conditions in Amite South and the DSG load pockets. On August 29, MISO issued a Maximum Generation Alert for the Midwest Region. MISO paid nearly $2 million in RSG on that day, as real-time load exceeded the day-ahead scheduled load by 1 GW.

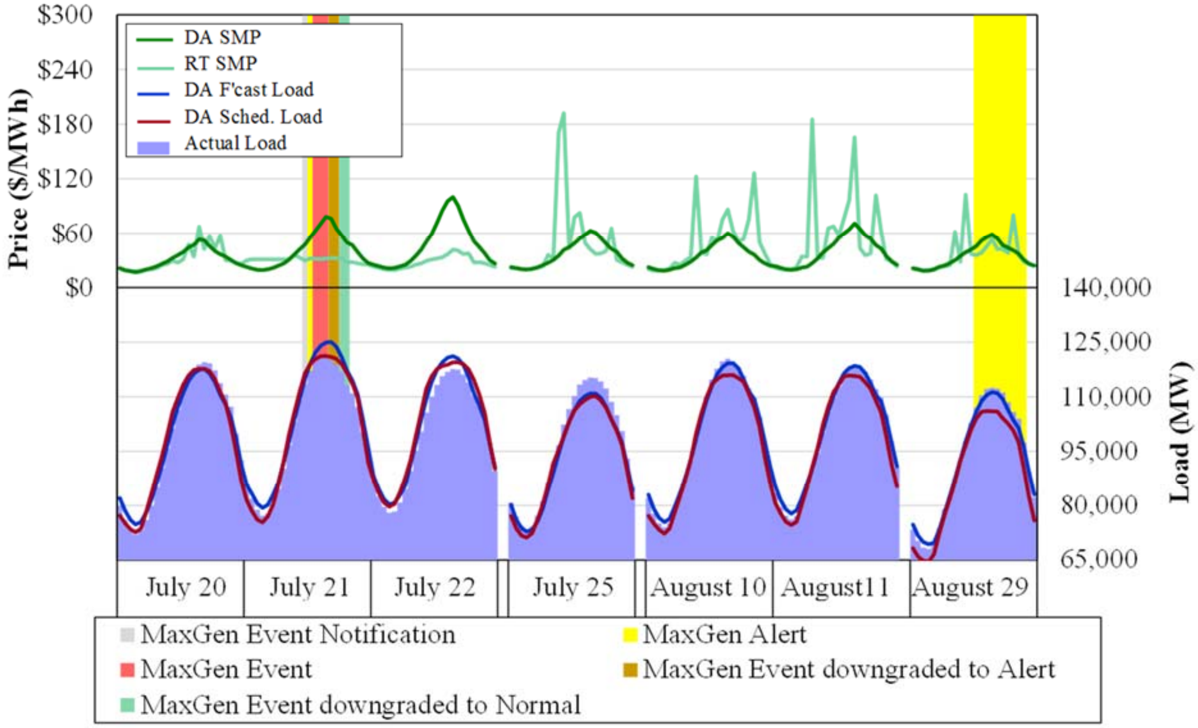
Table A2: Temperature, Loads and Market Outcomes

High Load Days in Summer 2016

	Hist.	July				August		
	Avg.	20	21	22	25	10	11	29
Detroit	81	86	91	93	91	95	91	82
Indianapolis	84	87	90	90	90	86	93	90
Milwaukee	79	93	93	90	89	88	94	83
Minneapolis	82	93	95	97	87	91	84	86
Little Rock	93	98	99	98	94	95	95	95
New Orleans	90	98	99	91	93	93	97	95
Number of CTs Committed		71	195	80	172	136	198	157
RT RSG ($K)		122	1,676	123	967	561	1,096	$1,942
DA Peak Forecasted Load (GW)		118	125	121	111	119	118	111
RT Peak Scheduled Load (GW)		120	121	118	115	121	118	112
Max RT SMP (Hourly)		$68	$36	$42	$192	$127	$185	$103
Max DA SMP (Hourly)		$53	$78	$100	$63	$60	$71	$59

Max Gen Event Max Gen Alert

Figure A8: Day-Ahead and Real-Time Load Scheduling and Prices
High Load Days in Summer 2016



D. 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 revenues 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 revenues 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 (CC) unit with an assumed heat rate of 6,600 Btu per kWh and a natural gas combustion turbine (CT) unit with an assumed heat rate of 9,920 Btu per kWh.[3] The net revenue analysis includes assumptions for variable Operations and Maintenance (O&M) costs, fuel costs, and expected forced outage rates.

3 These assumptions are used in the 2017 EIA Annual Energy Outlook.

Figure A9 and Figure A10: Net Revenue and Operating Hours

The next two figures compare the market revenue that would have been received by new CC and CT units in different MISO regions compared to the revenue that would be required to support new investment in these units. To determine whether net revenue levels would support investment in new resources, we first estimate the annualized cost of a new unit. The figures show the estimated annualized cost, which is the annual net revenue a new unit would need to earn in MISO wholesale markets to make the investment economic. The estimated Cost of New Entry (CONE) for each type of unit are shown in the figure as horizontal black segments and is based on data from the U.S. Energy Information Administration (EIA) and various financing, tax, inflation, and capital cost assumptions. The CONE value for the CT is published each year by the IMM along with the assumptions.

Combined-cycle generators run more frequently and earn more energy rents than simple-cycle CTs because CC units have substantially lower production costs per MWh. Therefore the estimated energy net revenues for CC generators tend to be substantially higher than they are for CT generators. Conversely, capacity and ancillary services revenues typically account for a comparatively larger share of a CT's net revenues. Capacity requirements and import and export limits enforced in the Planning Resource Auction (PRA) vary by zone, so capacity revenues vary depending on the clearing price in each zone. The estimated net revenues earned by these two types of resources in different MISO regions are shown as stacked bars in the figure. The drop lines show the estimated run hours of each unit type during the year. We reproduce the Central Region results on the MISO South figure for comparison purposes.

Figure A9: Net Revenue and Operating Hours
Midwest Region, 2014–2016

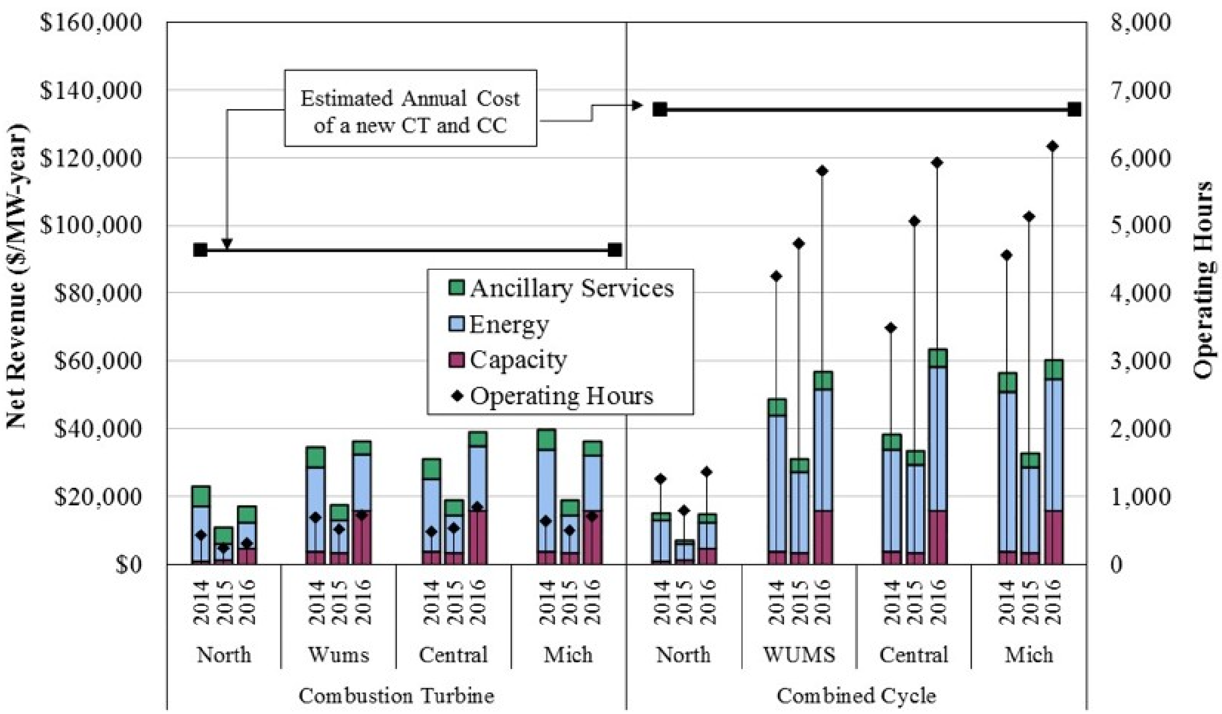
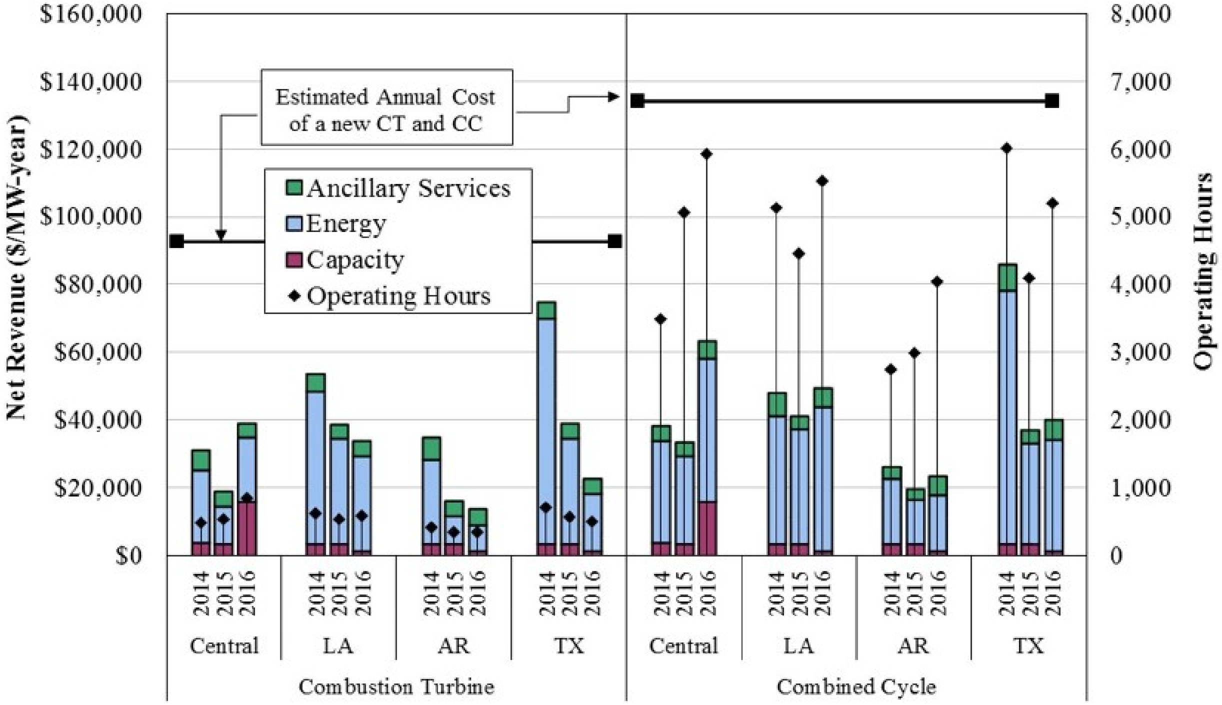


Figure A10: Net Revenue and Operating Hours
South Region, 2014–2016



III. Resource Adequacy

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 2016 there were 128 market participants that either owned generation resources (totaling 175 GW of nameplate capacity) or served load in the MISO market.[4] This group includes large investor-owned utilities, municipal and cooperative utilities, and independent power producers.

MISO serves as the reliability coordinator for an additional 15.7 GW of capacity. The largest coordinating member is Manitoba Hydro. It does not submit bids or offers into the markets, but may schedule imports and exports.[5] We exclude Manitoba Hydro from our analysis unless noted.

MISO reorganized its reliability coordination function in 2014 into three regions: North, Central (together known as Midwest), and South. These regions are defined as follows:

- North (formerly West)—Includes MISO control areas that had been located in the North American Electric Reliability Corporation's (NERC) MAPP region (all or parts of Iowa, Minnesota, Montana, North Dakota, and South Dakota);
- Central (formerly East and Central)—Includes MISO control areas that had been located in NERC's ECAR and MAIN regions (all or parts of Illinois, Indiana, Iowa, Kentucky and Michigan, Missouri, and Wisconsin); and
- South—Includes MISO control areas that joined in December 2013 (all or parts of Arkansas, Louisiana, Mississippi, and Texas).

In many of our analyses, we separately review the existing NCAs, currently WUMS, North WUMS, Minnesota (including portions of IOWA), WOTAB, and Amite South because the binding transmission constraints that define these areas require a closer examination. (A detailed analysis of market power is provided in Section VIII of this Appendix.)

A. Generating Capacity and Availability

Figure A11: Distribution of Existing Generating Capacity

Figure A11 shows the December 2016 distribution of existing generating resources by Local Resource Zone. The figure shows the distribution of Unforced Capacity (UCAP) by zone and fuel type, along with the annual peak load in each zone. UCAP values for wind are lower than Installed Capacity (ICAP) values because they account for forced outages and intermittency. The inset table in the figure breaks down the total UCAP and ICAP 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.

4 As of February 2017, MISO membership totaled 437 Certified Market Participants including power marketers, state regulatory authorities, and other stakeholder groups.

5 Manitoba does submit a limited amount of offers under the External Asynchronous Resources (EAR) procedure, which permits dynamic interchange with such resources through the five-minute dispatch.

Figure A11: Distribution of Existing Generating Capacity
By Fuel Type and Zone, December 2016

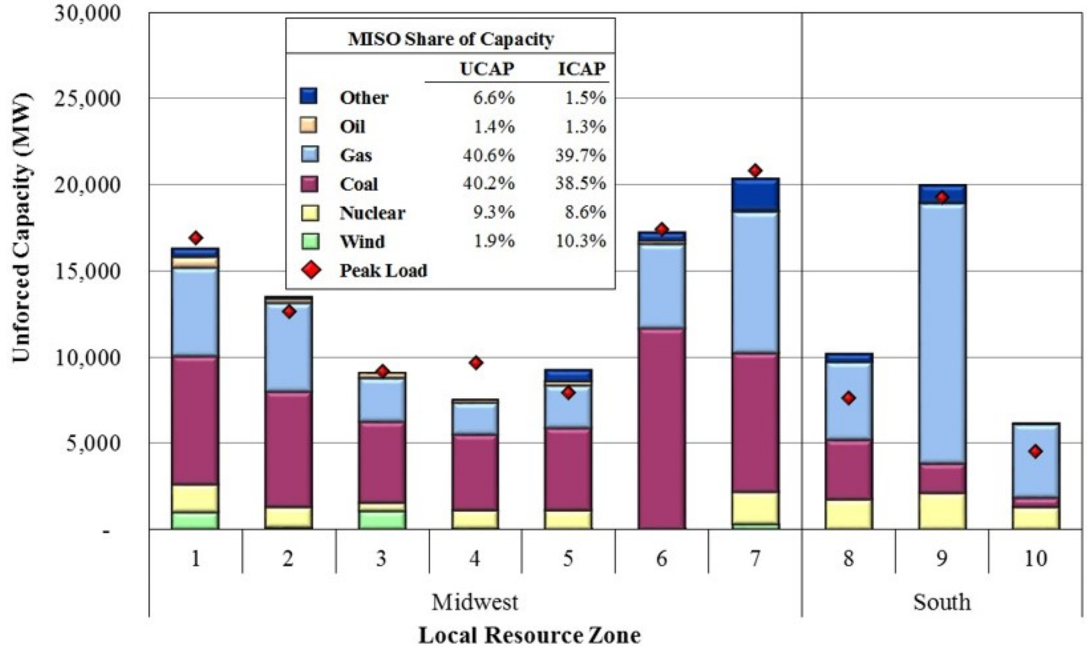


Figure A12: Resource Additions and Retirements

Figure A12 shows the change in the UCAP values during 2016 in each zone caused by resource retirements, additions, and interconnection changes. For the same reason as described above, the UCAP values shown for wind resources are much lower than nameplate or ICAP values.

Figure A12: Resource Additions and Retirements
By Fuel Type and Zone, 2016

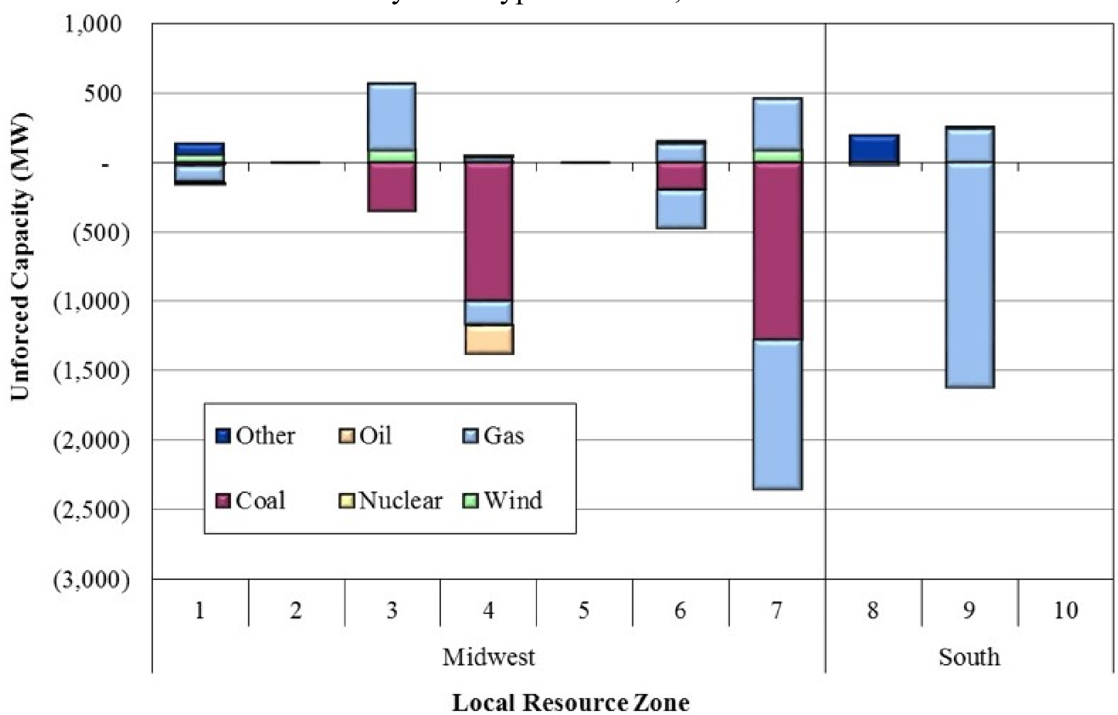


Figure A13: Availability of Capacity During Peak Load Hour

Figure A13 shows the status of generating capacity during the peak load hour of each month. The load in each of these peak hours 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 of resources. These four segments represent the total capacity available to MISO. The other segments are the remaining capacity that cannot be dispatched for the indicated reasons. These categories of deratings and outages are generally shown separately for online and offline units.

The figure 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 base-load units in the region. Additionally, wind resources often have ratings in excess of available transmission capability.

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 A13: Availability of Capacity During Peak Load Hour
2016

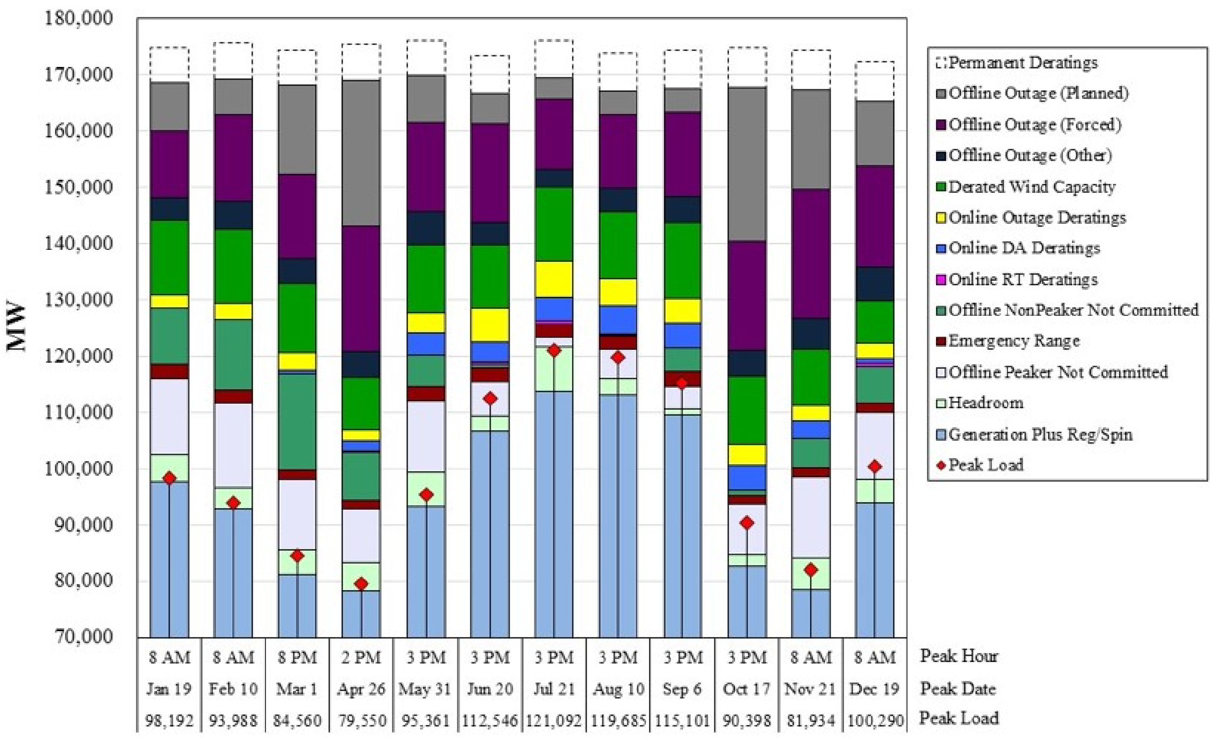


Figure A14: Capacity Unavailable During Peak Load Hours

Figure A14 is very similar to Figure A13 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 the greatest during these periods.

Figure A14: Capacity Unavailable During Peak Load Hours

2016

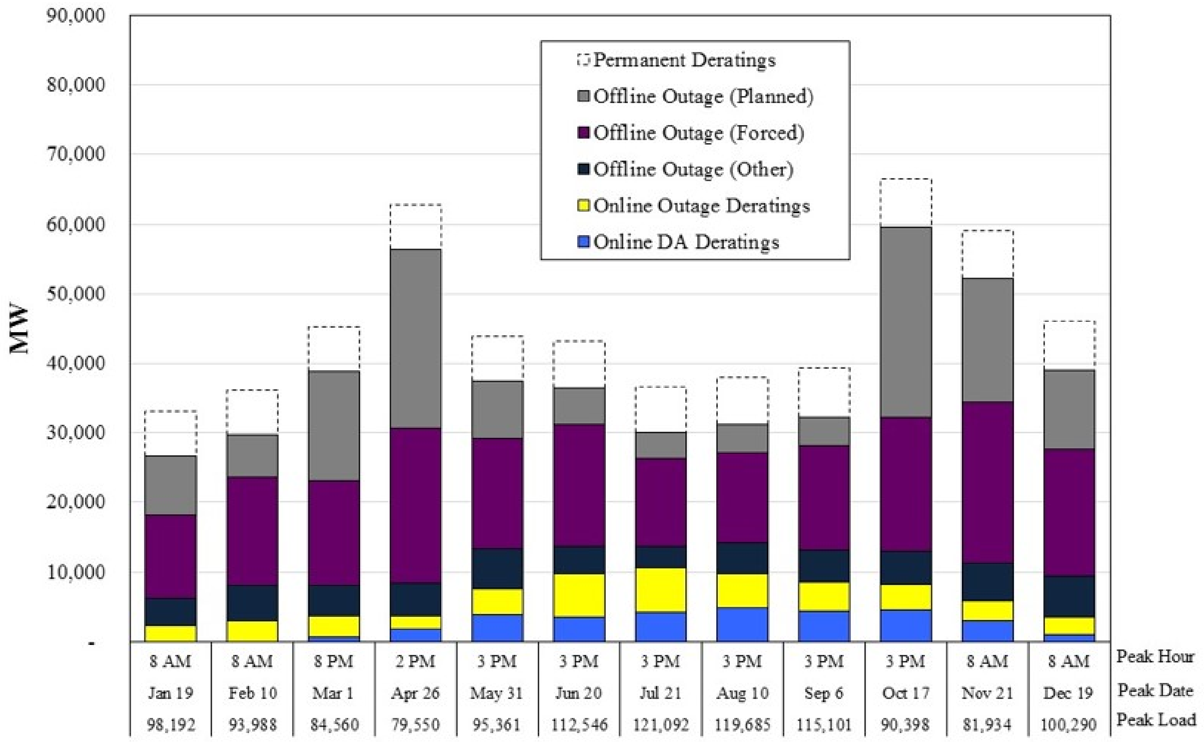
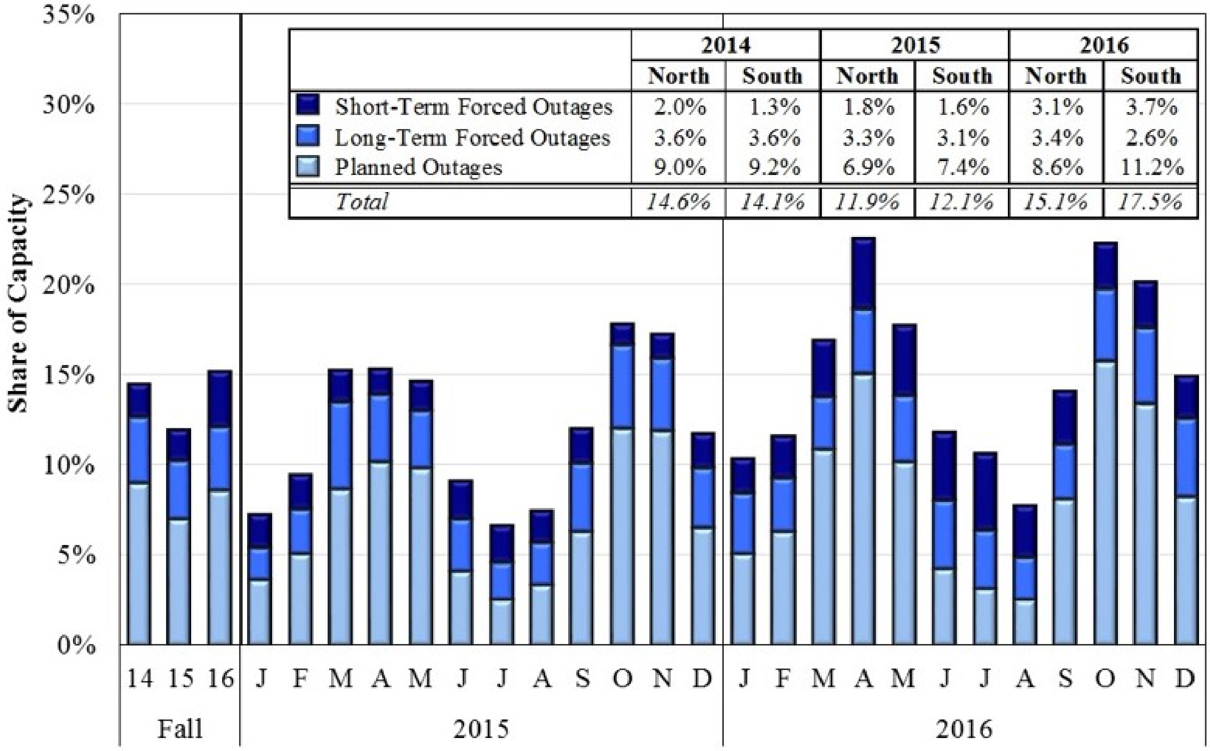


Figure A15: Generator Outage Rates

Figure A15 shows monthly average planned and forced generator outage rates for the two most recent years (and annual averages for the last 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. 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.H.

Figure A15: Generator Outage Rates
2014–2016



B. Planning Reserve Margins and Resource Adequacy

Table A3: Capacity, Load, and Reserve Margins

This subsection evaluates the supply in MISO, including the adequacy of resources for meeting peak needs in the summer of 2017. We estimate planning reserve margin values under various scenarios that are intended to indicate the expected physical surplus over the forecasted load. In its 2017 *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.

The planning reserve margin quantity is the sum of all quantities of capacity, including demand response and firm imports, minus the expected load and exports. The planning reserve margin in percentage terms is then calculated by dividing the margin by load (net of demand response). Our results are shown in Table A3.

The reserve margins in the table are generally based on: (a) peak-load forecasts under normal conditions;[6] (b) normal load diversity; (c) average forced outage rates; (d) an expected level of wind generation and imports; and (e) full response from Demand Response (DR) resources (behind the meter generation, interruptible load, and direct controllable load management). We

6 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).

have worked with MISO to ensure that our Base Case planning reserve level is consistent with MISO's, with one notable exception. While MISO's transfer limit assumption is based on the 2017/2018 Planning Resource Auction (PRA) transfer limit assumed value of 1,500 MW, we assume a probabilistic derated transfer capability of 2,000 MW, which results in a slightly higher starting planning reserve margin in our base case.

These assumptions tend to cause the base case reserve margin to overstate the surplus that one would expect under warmer-than-normal summer peak conditions or if demand response (load-modifying resources or "LMRs") do not perform fully when deployed. Therefore, we include some scenarios that differ from MISO's to show how alternative assumptions regarding DR deployments and unusually hot temperatures would affect MISO's planning reserve margins.

Table A3: Capacity, Load, and Reserve Margins
Summer 2017

		Alternative IMM Scenarios		
			High Temperature Cases	
	Base Case	Realistic DR	Full DR	Realistic DR
Load				
Base Case	125,020	125,020	125,020	125,020
High Load Increase	-	-	7,211	7,211
Total Load (MW)	125,020	125,020	132,231	132,231
Generation				
Internal Generation	140,850	140,850	140,850	140,850
BTM Generation	4,009	4,009	4,009	4,009
Hi Temp Derates*	-	-	(4,900)	(4,900)
Adjustment due to Transfer Limit**	(2,157)	(2,157)	-	-
Total Generation (MW)	142,701	142,701	139,958	139,958
Imports and Demand Response				
Demand Response***	6,112	4,890	6,112	4,890
Capacity Imports****	3,483	3,483	3,483	3,483
Capacity Exports	(3,636)	(3,636)	(3,636)	(3,636)
Margin (MW)	23,640	22,417	13,686	12,464
Margin (%)	**18.9%**	**17.9%**	**10.9%**	**10.0%**

Notes:
* Based on an analysis of quantities offered into the day-ahead market on the three hottest days of 2012 and on August 1, 2006. Quantities can vary substantially based on ambient water temperatures, drought conditions, and other factors.
**The MISO Base Case Reserve Margin assumes that 2,157 MW (50/50 scenario) of capacity in MISO South cannot be accessed due to the 2,000 MW Transfer Limit (applying probabalistic derates on the 2,500 MW Transfer Limit) so this reduces the overall MISO Capacity Margin.
***Demand Response reflects cleared Demand Response for 2017/2018 planning year.
****Capacity imports reflects cleared imports from 2017/2018 planning year.
This table excludes the total pseudo tied capacity amount of 5,241.7MW out of MISO in 2017/2018 planning year.

The second and fouth columns in the table show "Realistic DR" cases that assume an 80 percent response rate from DR to account for both availability and performance uncertainties. A good response rate is expected because MISO has improved its Tariff requirements on DR, which now includes penalty provisions for non-performance and requires an annual demonstration of demand reduction capability for each planning year. However, some DR resources can require up to 12 hours of advanced notice to respond and most DR is not under the direct control of MISO. Additionally, there is a lack of recent historical response data during emergency conditions. When DR was deployed in 2006, the response rate was roughly 50 percent.

We also attempt to account for generator derates under higher temperatures than normal in scenarios (2) and (3). MISO's high-temperature scenario assumes an annual equivalent forced outage rate-demand (EFORd) and monthly net dependable capacities, which doesn't fully capture the negative correlation between loads and power plant capability under conditions when ambient temperatures are much higher than normal. In addition to the ambient temperature effects, power plants cooled by river water can experience deratings when water temperatures are too high. Since many of MISO's generators use common bodies of water for cooling, derates that are due to high inlet/outlet temperatures may be correlated. 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.

C. Capacity Market Results

In June 2009, MISO began operating the monthly Voluntary Capacity Auction (VCA) to allow load-serving entities (LSEs) to procure capacity to meet their Tariff Module E capacity requirements. The VCA was intended to provide a balancing market for LSEs, with most capacity needs being satisfied through owned capacity or bilateral purchases. The PRA replaced the VCA in June 2013 and incorporates zonal transfer limits to better identify regional capacity needs throughout MISO. Zonal capacity import and export limits, if they bind, cause price divergence among the zonal clearing prices.

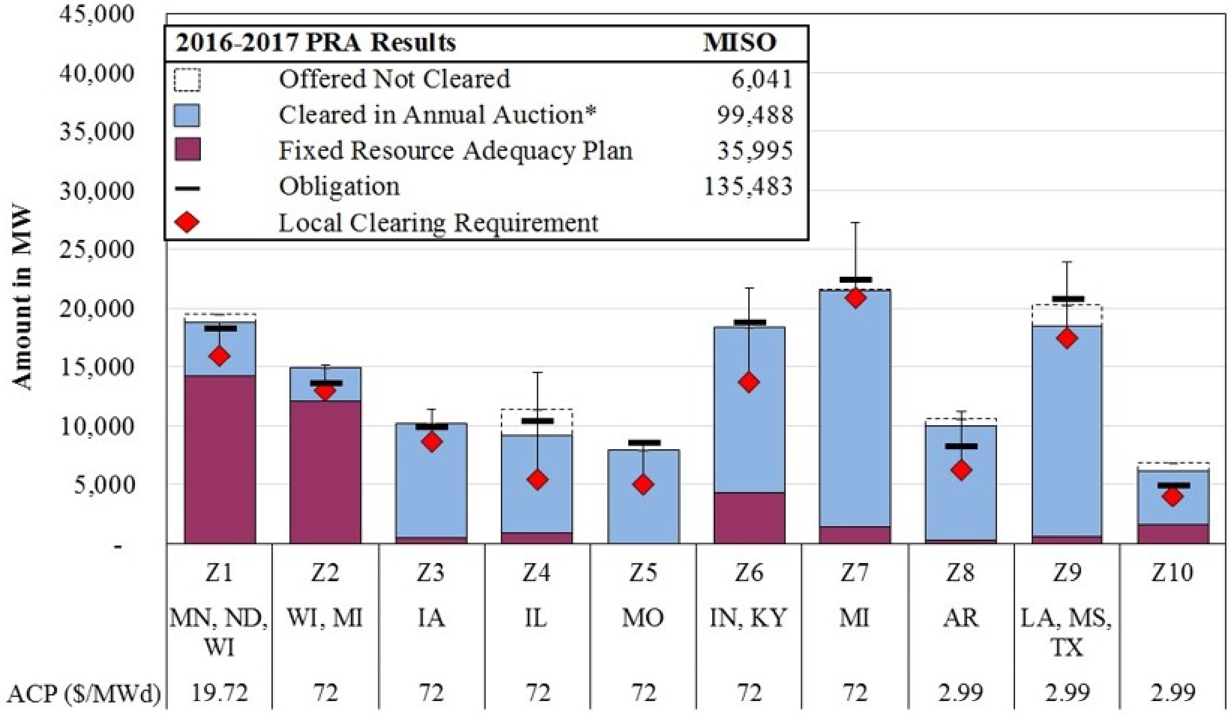
Figure A16: Planning Resource Auction

Figure A16 shows the zonal results of the 2016/2017 annual PRA, held in spring 2016 and covering June 2016 to May 2017. The black dash marks the capacity obligation, which is the total amount required to be procured by LSEs in each zone. Differences between this amount and the cleared amount are constrained by each zone's capacity import and export limits. The local clearing requirement (LCR), which is the minimum amount that must be procured within a zone, is indicated by the red diamond. When the LCR binds so that only the LCR quantity is procured in a zone, the price in the zone will rise. In the 2016/2017 auction:

- Zone 1 was export-constrained and bound at $19.72 per MW-day, a much lower price than other zones in the Midwest subregion.
- MISO Midwest, excluding Zone 1, cleared at $72 per MW-day.
- The 2016/2017 auction only allowed 876 MW to be transferred between MISO South and MISO Midwest. This constraint bound in the auction, causing Zones 8, 9 and 10 to clear at a significantly lower price of $2.99 per MW-day.

Participants can elect to cover all or part of their obligation via a "Fixed Resource Adequacy Plan" (FRAP), which exempts resources from participating in the auction. FRAPs are counted against local clearing requirements, but they cannot set the clearing prices.

Figure A16: Planning Resource Auction
2016–2017



D. Capacity Market Design: Modeling Demand Curve Efficiently

The PRA consists of a single-price auction to determine the clearing prices and quantities of capacity procured in MISO and in each of the ten zones. The demand in this market is implicitly defined by the minimum resource requirement and a deficiency price that is based on the Cost of New Entry (CONE), which MISO updates annually. These requirements result in a vertical demand curve, which means that demand is insensitive to the price and MISO is willing to buy the same amount of capacity at any price. 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. In particular, we discuss the benefits of this change for the integrated utilities in the MISO area. We begin below by discussing the attributes of supply and demand in a capacity market.

Attributes of Demand in a Capacity Market

The demand for any good is determined by the value that 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 system reliability and lower real-time energy and ancillary services costs for consumers, although these effects diminish as the surplus increases. The contribution of surplus capacity to reliability 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 consumers is the source of a number of the concerns described in this section.

Attributes of Supply in a Capacity Market

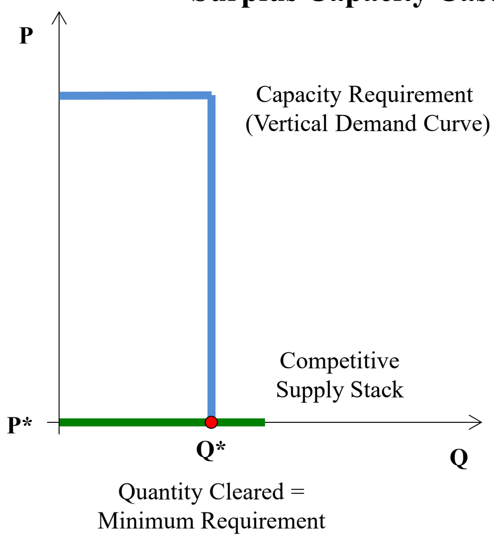
In workably competitive capacity markets, the competitive offer for existing capacity (i.e., the marginal cost of selling capacity) is generally close to zero, ignoring export opportunities. A supplier's offer represents the lowest price it would be willing to accept to sell capacity. This is determined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

- *Capacity Obligations*. Suppliers that sell capacity in MISO are not required to accept costly obligations that could substantially increase the suppliers' costs of selling capacity.
- Effects of GFCs. For most resources, the net revenues available from RTOs' energy and ancillary services markets are sufficient to keep the resources in operation. Therefore, no additional revenue is needed from the capacity market, which would cause the supplier to submit a non-zero capacity offer.

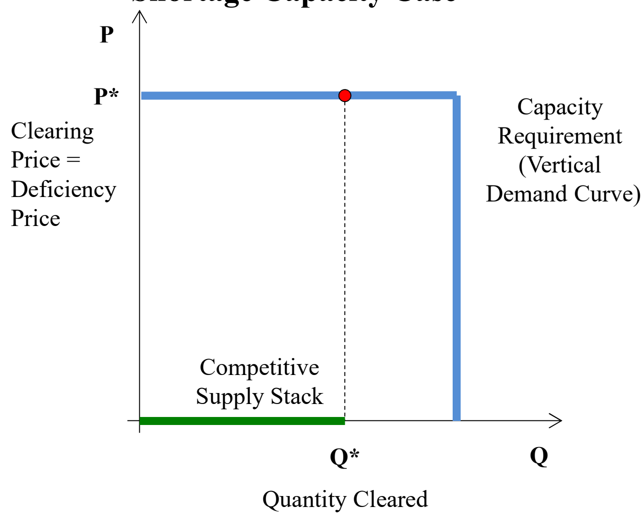
Because GFCs are generally covered by energy revenues and capacity obligations are not costly to satisfy, most suppliers are willing price-takers in the capacity market, accepting any non-zero price for capacity. When the low-priced supply offers clear against a vertical demand curve, only two outcomes are possible.

- If the market is not in a shortage, the price will clear close to zero, which characterizes the most recent auction results in MISO. In the 2017/2018 PRA, all zones in MISO cleared at close to zero, indicating that additional capacity has no value to MISO.
- If the market is in shortage, as indicated in the figure on the right, when the supply and demand curves do not cross the price will clear at the deficiency price.

Surplus Capacity Case



Shortage Capacity Case



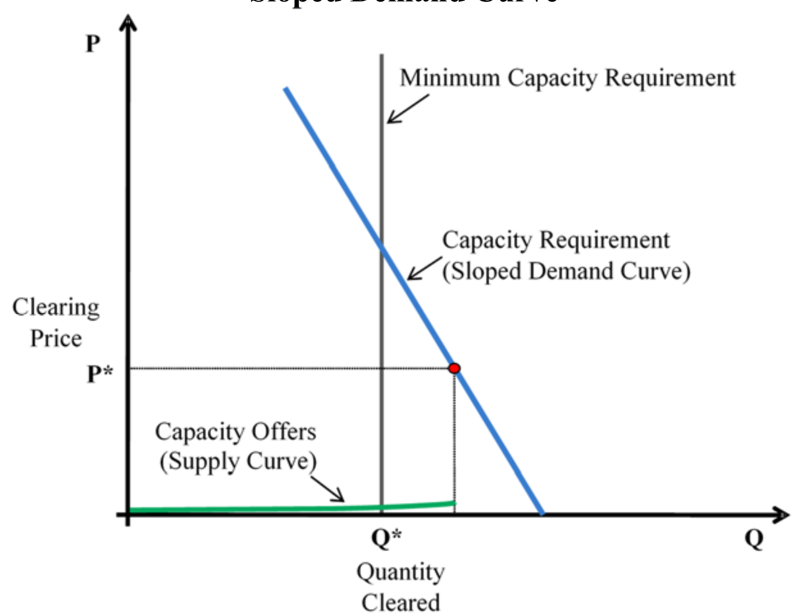
This pricing dynamic and the associated market outcomes raise at least three significant issues regarding the long-term performance of the current capacity market:

- Because 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.
- This market will result in substantial volatility and uncertainty. 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 with any certainty that the market will be short in the future and produce capacity revenues substantially greater than zero. This would undermine the effectiveness of the capacity market in maintaining adequate resources, even when short-term prices rise.
- 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 a greater potential concern, even in a market that is not concentrated.

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. The figure below illustrates the sloped demand curve and the difference in how prices would be determined.

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 reflects the marginal value of capacity because the sloped portion is based on the reliability benefit of exceeding planning reserves. 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 decreasing the price effects of withholding. This incentive to withhold falls as the market approaches the minimum capacity requirement level. While it would not likely completely mitigate potential market power, a sloped demand curve would significantly improve suppliers' incentives.

If a sloped demand curve is introduced, 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), FERC 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.

Effects of a Sloped Demand Curve on Vertically-Integrated LSEs

LSEs and their ratepayers should benefit from a sloped demand curve. LSEs in MISO have generally planned and built resources to achieve a small surplus on average over the minimum requirement because:

- Investment in new resources is "lumpy," occurring in increments larger than necessary to match the gradual growth in an LSE's requirement; and
- The costs of being deficient are large.

Under a vertical demand curve, the cost of the surplus must entirely be borne by the LSEs' retail customers because LSEs will generally receive very little capacity revenue to offset the costs that they incurred to build the resources. Since this additional capacity provides reliability value to MISO, the fact that LSEs receive no capacity revenues is inefficient. Adopting a sloped demand curve would benefit most regulated LSEs as we explain below.

Table A4: Costs for a Regulated LSEs under Alternative Capacity Demand Curves

Table A4 shows how hypothetical LSEs are affected by a sloped demand curve when they hold varying levels of surplus capacity beyond the minimum capacity requirement. The scenarios assume: (1) an LSE with 5,000 MW of minimum required capacity; (2) net CONE of $65,000 per MW-year and demand curve slope of -0.01 (matching the slope of the NYISO curve); and (3) a market-wide surplus of 1.5 percent, which translates to an auction clearing price of $4.74 per KW-month ($54.85 per KW-year).

For each of the scenarios, we show the amount that the LSE would pay to or receive from the capacity market along with the carrying cost of the resources the LSE built to produce the surplus. Finally, in a vertical demand curve regime where the LSE will not expect to receive material capacity revenues for its surplus capacity, all of the carrying cost of the surplus must be paid by the LSE's retail customers. The final column shows the portion of the carrying cost borne by the LSE's retail customers under a sloped demand curve.

Table A4: Costs for a Regulated LSE under Alternative Capacity Demand Curves

LSE Surplus	Market Surplus	Capacity Market Revenues ($Million)	Carrying Cost of Surplus ($Million)	Carrying Cost Borne by Retail Load	Surplus Cost: Sloped Demand Curve	Surplus Cost: Vertical Demand Curve
1.0%	1.5%	$-1.43	$3.25	100%	$4.68	$3.25
2.0%	1.5%	$1.41	$6.50	78%	$5.09	$6.50
3.0%	1.5%	$4.25	$9.75	56%	$5.50	$9.75
4.0%	1.5%	$7.10	$13.00	45%	$5.90	$13.00

These results illustrate three important dynamics, namely that the sloped demand curve:

- *Does not raise the expected costs for most regulated LSEs*. In this example, if an LSE fluctuates between 1 and 2 percent surplus (around the 1.5 percent market surplus), its costs will be virtually the same under the sloped and vertical demand curves.
- *Reduces risk for the LSE* by stabilizing the costs of having differing amounts of surplus. The table shows that the total costs incurred by the LSE at surplus levels between 1 and 4 percent vary by only 26 percent versus a 300 percent variance in cost under the vertical demand curve.
- *Reduces the share of costs borne by retail customers*. Because wholesale capacity market revenues play an important role in helping the LSE recover the costs of new resources, the LSE's retail customers will bear a smaller share of these costs when the LSE's surplus exceeds the market's surplus. Under the 3 percent case, for example, the current market would produce almost no capacity revenue even though the LSE's surplus is improving reliability for the region. Under the sloped demand curve in this case, almost half of the costs of the new unit would be covered by the capacity market revenues.

Hence, although a sloped demand curve could increase costs to non-vertically integrated LSE's that must purchase large quantities of capacity through an RTO's market, the example above shows that this is not the case for the vertically-integrated LSE's that dominate the MISO footprint. In fact, it will likely reduce the costs and long-term risks facing MISO's LSEs in satisfying their planning reserve requirements. In addition, this will provide efficient market signals to other types of market participants, such as unregulated suppliers, competitive retail providers, and capacity importers and exporters.

As discussed in more detail in the SOM Report, understated capacity prices are a particular problem in Competitive Retail Areas (CRAs) where unregulated suppliers rely on the market to retain resources MISO needs to ensure reliability.

IV. Day-Ahead Market Performance

In the day-ahead market, market participants make financially-binding forward purchases and sales of electric energy for delivery in real time. Day-ahead transactions allow LSEs to procure energy for their own demand, thereby managing risk by hedging their exposure to real-time price volatility. Participants also buy and sell energy in the day-ahead market to arbitrage price differences between the day-ahead and real-time markets.

Day-ahead outcomes are important because the bulk of MISO's generating capacity available in real time is actually committed through the day-ahead market, and almost all of the power procured through MISO's markets is financially settled in the day-ahead market. 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 A17 and Figure A18: Day-Ahead Energy Prices and Load

Figure A17 shows average day-ahead prices during peak hours (6 a.m. to 10 p.m. on non-holiday weekdays) at six representative hub locations in MISO and the corresponding scheduled load (which includes net cleared virtual demand). Differences between the hub prices generally reflects transmission congestion on the MISO system.

Figure A17: Day-Ahead Hub Prices and Load
Peak Hours, 2015–2016

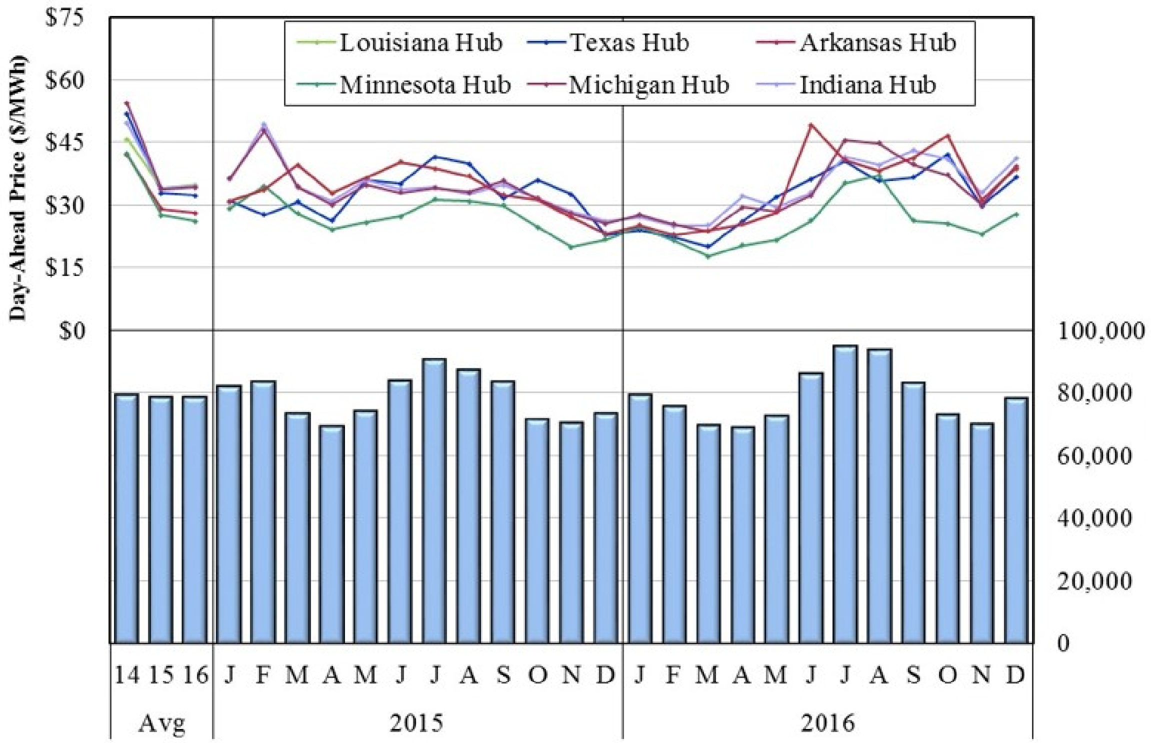
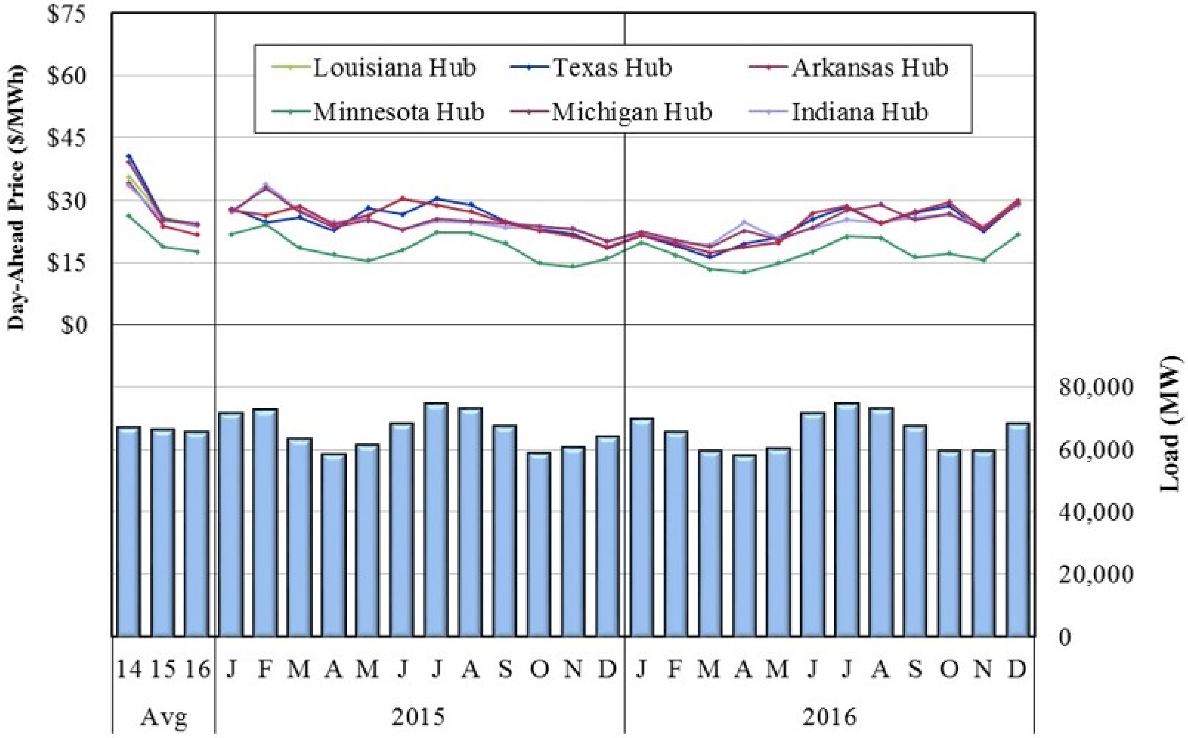


Figure A18 shows similar results for off-peak hours (10 p.m. to 6 a.m. on weekdays and all hours on weekends and holidays). Differences in prices among the hubs show the prevailing congestion and loss patterns. High prices in one location relative to another location indicate congestion and loss factor differences from a low-priced area to a high-priced area.

Figure A18: Day-Ahead Hub Prices and Load
Off-Peak Hours, 2015–2016



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 vital for overall market efficiency.

If the day-ahead prices fail to converge with the real-time prices, then anticipated conditions are not being realized in the physical dispatch in real time. This can result in:

- Generating resources not being efficiently committed since most are committed through the day-ahead market;
- Consumers and generators being substantially affected because most settlements occur through the day-ahead market; and
- Payments to FTR holders not reflecting the true transmission congestion on the network, which will ultimately distort future FTR prices and revenues.

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

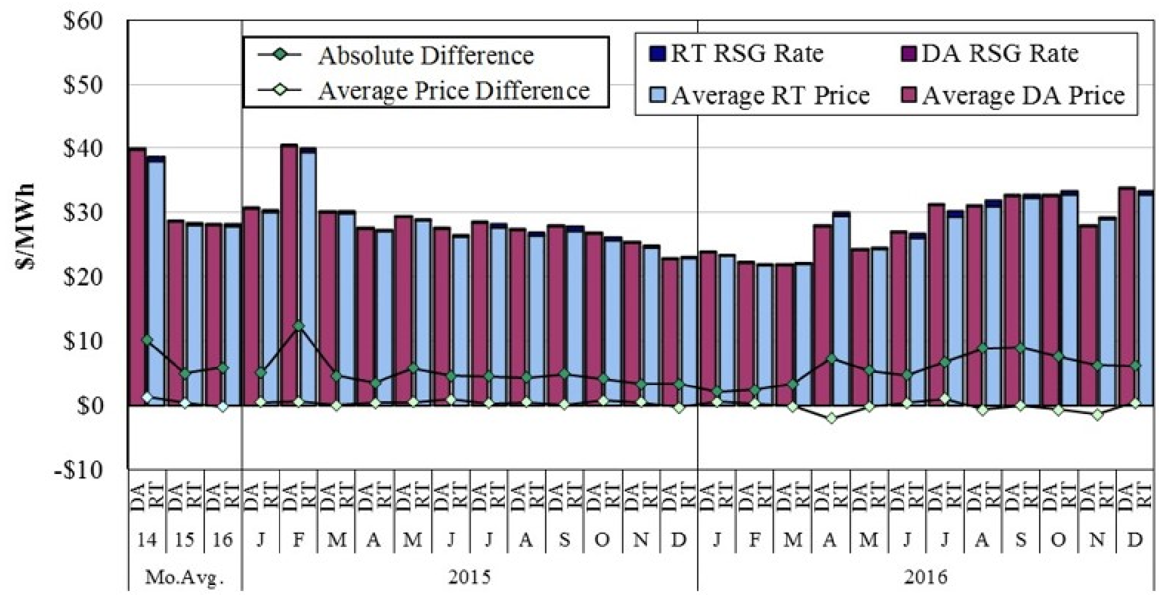
A modest day-ahead price premium reflects rational behavior because purchases in the day-ahead market are subject to less price volatility that is valuable to risk-averse buyers. Additionally, purchases in the real-time market are subject to allocation of real-time Revenue Sufficiency Guarantee (RSG) costs that are typically much larger than day-ahead RSG charges. Most day-ahead purchases can avoid these RSG costs.

Figure A19 to Figure A25: Day-Ahead and Real-Time Prices

The next seven figures show monthly average prices in the day-ahead and real-time markets at representative locations in MISO, along with the average RSG costs allocated per MWh.[7] 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 RSG charges. Real-time RSG is assessed to deviations from the day-ahead schedules that are settled through the real-time market, including net virtual supply. Real-time RSG charges are generally much higher than day-ahead charges and, therefore, should lead to modest day-ahead price premiums.

Figure A19: Day-Ahead and Real-Time Prices

2015–2016: Indiana Hub

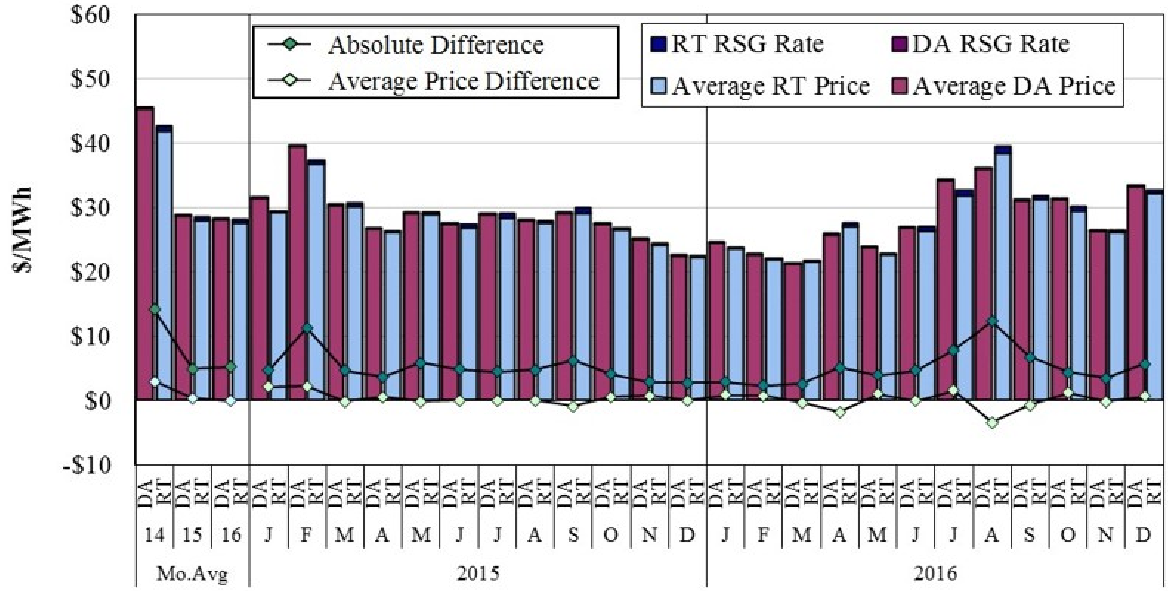


Average DA-RT Difference (% of Real-Time Price)

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

7 The rate is the Day-Ahead Deviation Charge (DDC) Rate, which excludes the location-specific Congestion Management Charge (CMC) Rate and Pass 2 RSG.

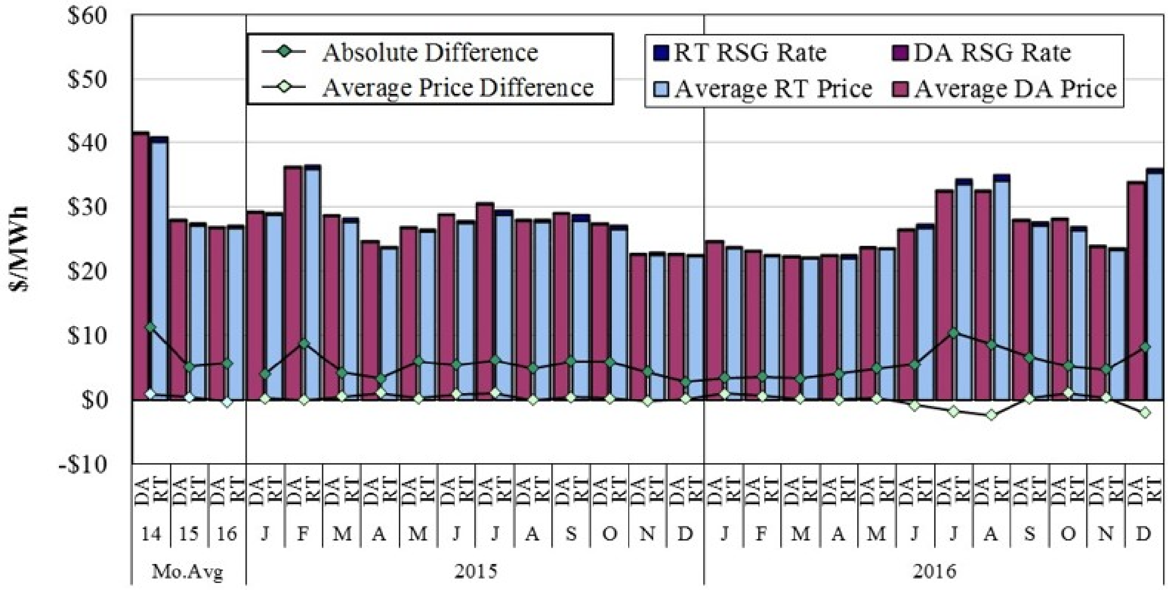
Figure A20: Day-Ahead and Real-Time Prices
2015–2016: Michigan Hub



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

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

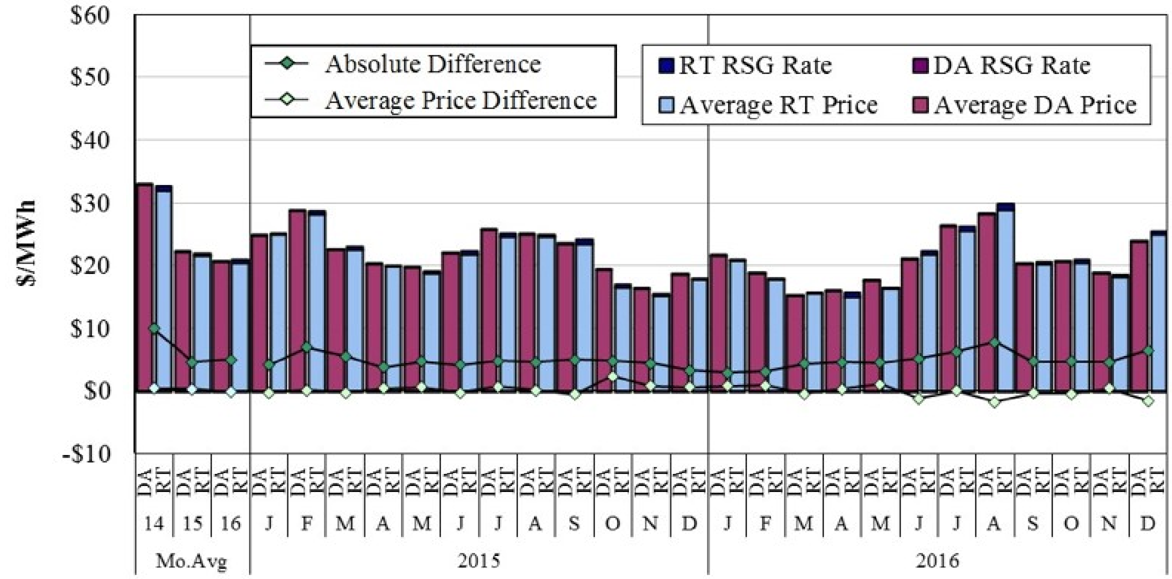
Figure A21: Day-Ahead and Real-Time Prices
2015–2016: WUMS Area



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

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

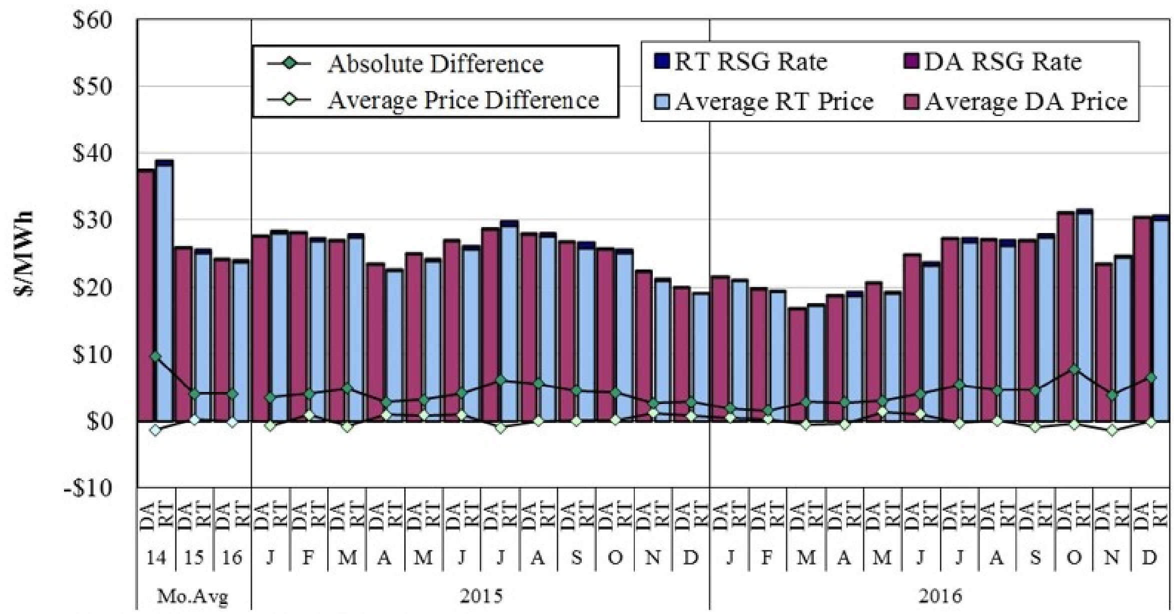
Figure A22: Day-Ahead and Real-Time Prices
2015–2016: Minnesota Hub



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

Excluding RSG	3	3	1	-1	2	0	2	4	0	5	2	1	16	7	4	4	5	-2	6	7	-3	3	-3	1	1	3	-4
Including RSG	1	2	-1	-1	0	-1	2	3	-1	3	0	-2	14	5	3	4	5	-3	2	6	-5	0	-6	-2	-2	2	-6

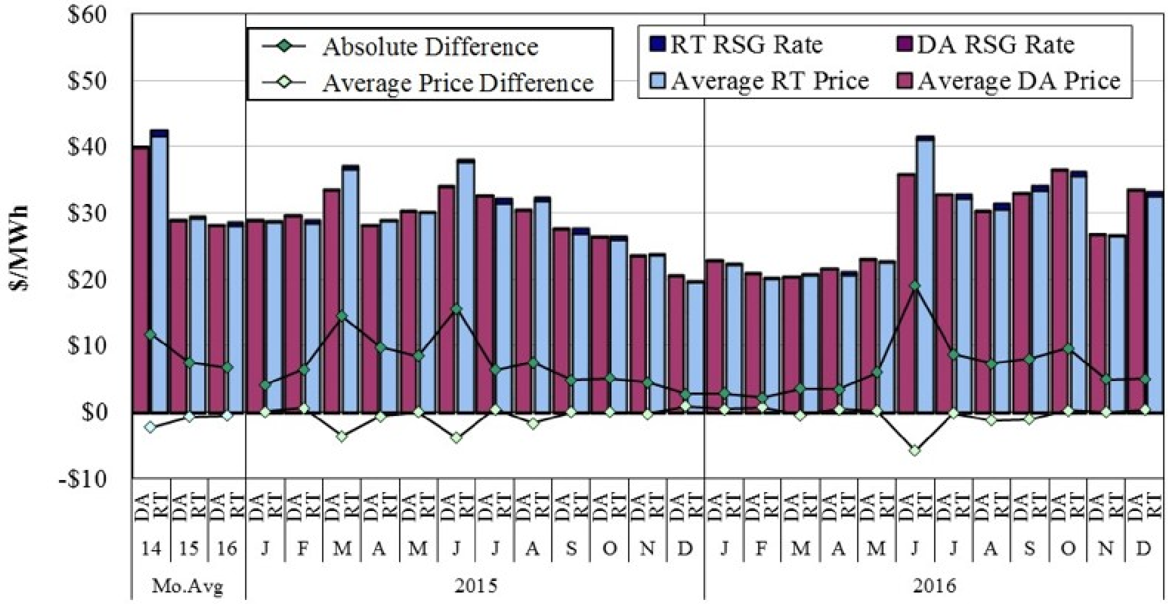
Figure A23: Day-Ahead and Real-Time Prices
2015–2016: Arkansas Hub



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

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

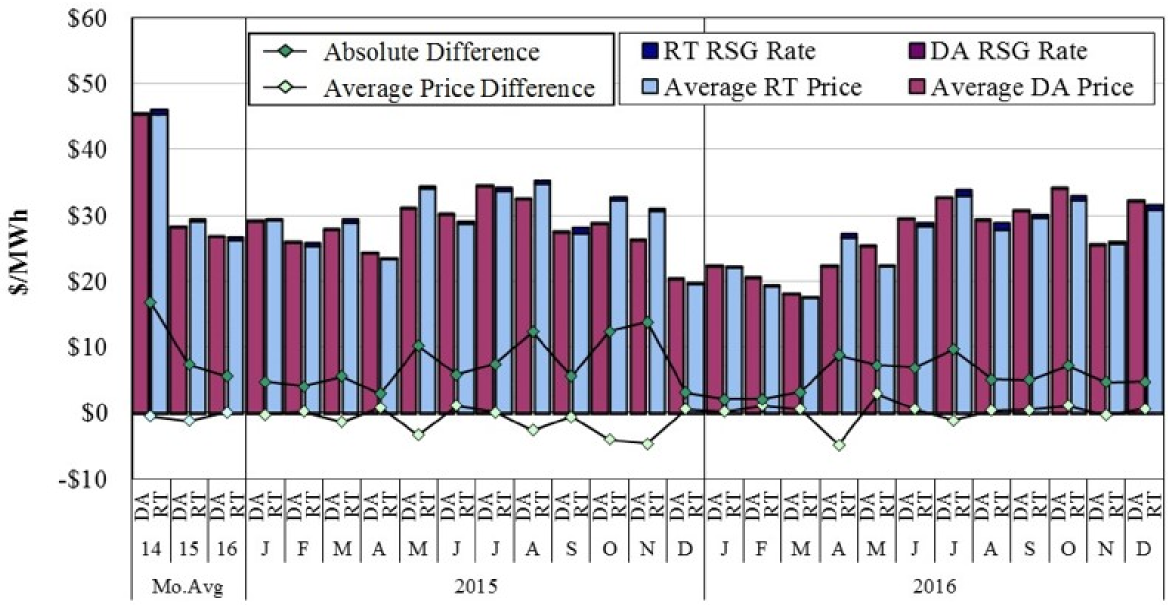
Figure A24: Day-Ahead and Real-Time Prices
2015–2016: Louisiana Hub



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

Excluding RSG	-4	-1	0	1	3	-9	-2	1	-10	3	-4	3	1	0	5	2	4	-2	5	2	-13	2	-1	-2	2	1	3
Including RSG	-6	-2	-2	0	2	-10	-2	0	-10	1	-5	0	0	-1	4	2	3	-2	2	1	-14	-1	-4	-3	1	0	1

Figure A25: Day-Ahead and Real-Time Prices
2015–2016: Texas Hub



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

Excluding RSG	0	-3	2	-1	2	-4	3	-9	5	2	-7	0	-11	-15	3	1	6	4	-16	14	4	-1	5	3	5	0	4
Including RSG	-1	-4	1	-1	1	-5	4	-10	4	0	-7	-2	-12	-15	3	1	6	3	-18	13	2	-3	1	2	3	-1	2

Figure A26: Day-Ahead Ancillary Services Prices and Price Convergence

The figures above show the convergence of MISO's energy markets. Price convergence is also important for MISO's ancillary services markets, which are jointly optimized with the energy markets. These markets have operated without significant issues since their introduction in January 2009. Figure A26 shows monthly average day-ahead clearing prices in 2016 for each ancillary services product, along with day-ahead to real-time price differences.

Figure A26: Day-Ahead Ancillary Services Prices and Price Convergence
2016

C. Day-Ahead Load Scheduling

Load scheduling, Net Scheduled Interchange (NSI), 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, plus NSI. The differences between net scheduled load and real-time load affect commitment patterns and RSG costs because units are committed and scheduled in the day-ahead 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 system's needs. Peaking resources often do not set real-time prices, even if those resources are effectively marginal (see Section N). 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 (even though they are more expensive than other resources), the economic feedback and incentive to schedule more fully in the day-ahead market will be diluted.

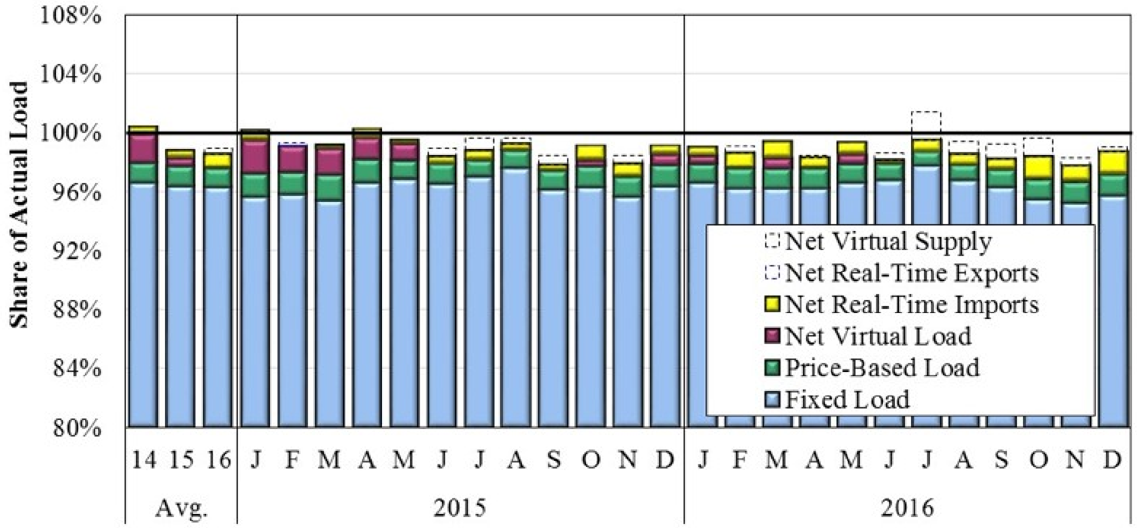
Additionally, significant supply increases after the day-ahead market can lower real-time prices and create an incentive for participants to schedule net load at less than 100 percent. The most common sources of increased supply in real time are:

- 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 A27 to Figure A29: Day-Ahead Scheduled Versus Actual Loads

To show net load-scheduling patterns in the day-ahead market, Figure A27 compares the monthly average day-ahead scheduled load to average real-time load. The figure shows only the daily peak hours, when under-scheduling is most likely to require MISO to commit additional units. The table below the figure shows the average scheduling levels in all hours and for the peak hour. We show peak hour scheduling separately by region in Figure A28 and Figure A29.

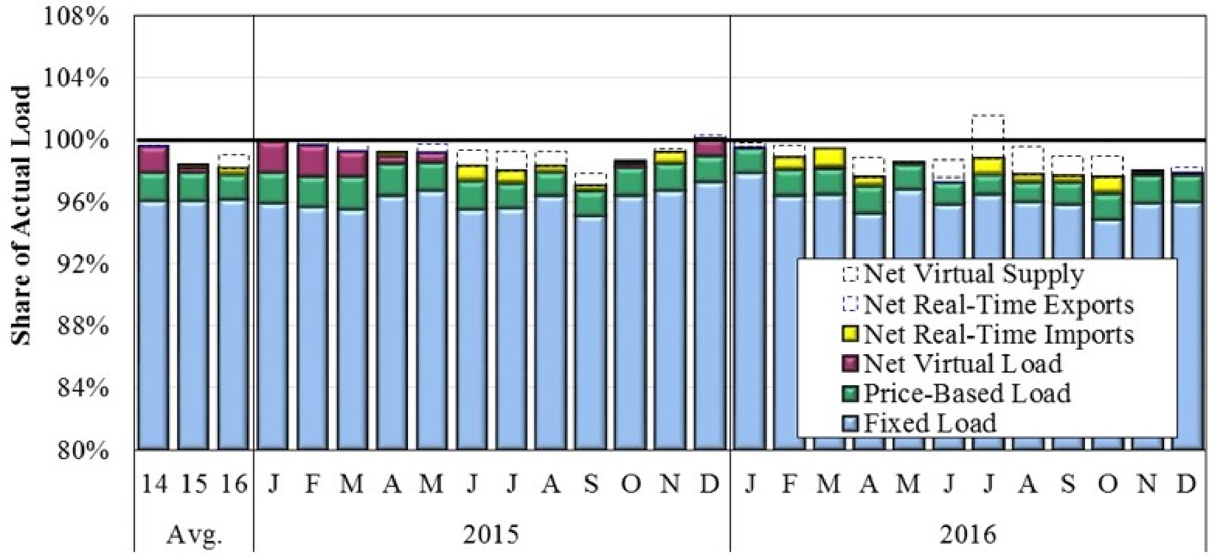
Figure A27: Day-Ahead Scheduled Versus Actual Loads
2015–2016, Daily Peak Hour



Share of Actual Load (%)

	Avg. 14	Avg. 15	Avg. 16	2015 J	F	M	A	M	J	J	A	S	O	N	D	2016 J	F	M	A	M	J	J	A	S	O	N	D
All Hours	100.6	99.0	98.7	99.9	98.9	98.6	99.3	99.4	98.5	99.4	99.6	98.5	98.2	97.9	98.4	99.0	98.2	98.3	98.7	99.6	98.6	100.1	99.4	98.3	98.5	97.8	98.9
Peak Hours	100.3	98.8	98.5	100.1	99.0	99.1	100.2	99.4	98.4	98.8	99.3	97.8	99.1	97.9	99.1	99.0	98.6	99.4	98.2	99.3	98.1	99.4	98.5	98.2	98.4	97.7	98.7

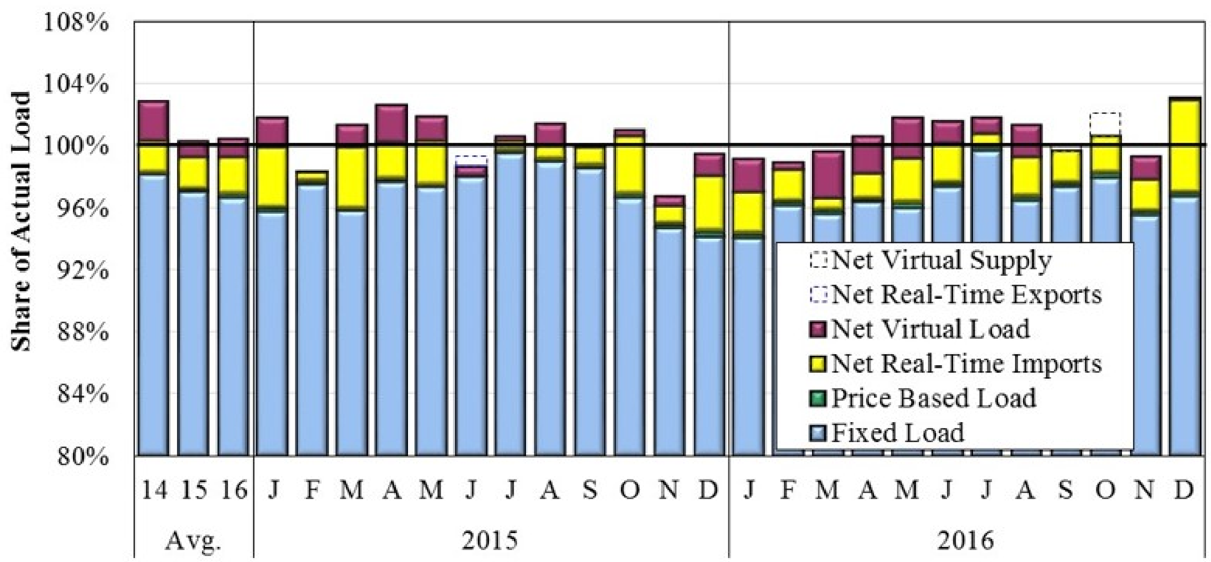
Figure A28: Midwest Region Day-Ahead Scheduled Versus Actual Loads
2015–2016, Daily Peak Hour



Share of Actual Load (%)

	Avg. 14	Avg. 15	Avg. 16	2015 J	F	M	A	M	J	J	A	S	O	N	D	2016 J	F	M	A	M	J	J	A	S	O	N	D
All Hours	99.7	98.5	98.1	99.2	99.0	97.8	98.6	98.5	98.1	98.7	98.8	97.8	97.7	97.8	97.9	98.7	97.8	98.2	98.1	98.9	97.7	99.4	98.9	97.5	97.5	97.0	97.5
Peak Hours	99.6	98.3	98.1	99.9	99.7	99.2	99.1	99.1	98.3	97.9	98.2	97.0	98.6	99.2	100.0	99.4	98.8	99.4	97.5	98.6	97.2	98.8	97.7	97.6	97.6	98.0	97.8

Figure A29: South Region Day-Ahead Scheduled Versus Actual Loads
2015–2016, Daily Peak Hour



Share of Actual Load (%)

	Avg. 14	Avg. 15	Avg. 16	2015 J	F	M	A	M	J	J	A	S	O	N	D	2016 J	F	M	A	M	J	J	A	S	O	N	D
All Hours	103.3	100.6	100.7	101.8	98.6	101.4	101.6	102.0	99.5	101.3	101.8	100.3	99.9	98.3	100.0	100.2	99.3	99.0	100.7	101.6	101.4	102.3	101.0	100.7	101.5	100.3	103.3
Peak Hours	102.9	100.3	100.5	101.8	98.3	101.3	102.6	101.8	98.7	100.6	101.4	99.9	101.0	96.8	99.5	99.1	98.9	99.7	100.6	101.8	101.5	101.8	101.3	99.6	100.6	99.3	103.1

D. Hourly Day-Ahead Scheduling

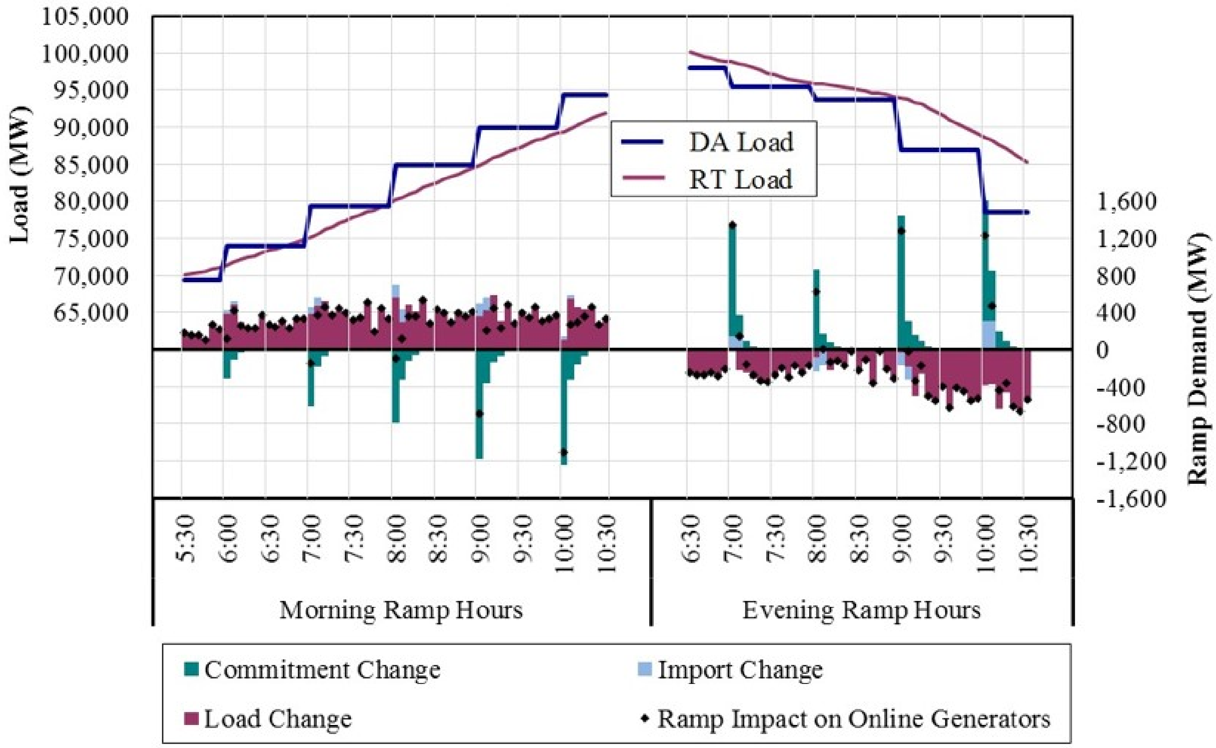
The day-ahead energy and ancillary services market currently solves on an hourly basis. As a result, all day-ahead scheduled ramp demands coming into the real-time market, including unit commitments, de-commitments, and changes to physical schedules are concentrated at the top of the hour.

MISO has several options to manage the impact of top-of-the-hour changes in real time, including staggering unit commitments (which can result in increased RSG payments) or proactively using load offsets in order to reduce ramp impacts. Nonetheless, the real-time ramp demands created by the current hourly resolution of the day-ahead market can be substantial and can produce significant real-time price volatility. When it has the ability to do so, MISO should consider implementing a shorter time interval in the day-ahead market.

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

Figure A30 below shows the implied generation ramp demand attributable to day-ahead commitments and physical schedules compared to real-time load changes. When the sum of these changes is negative, online generators are forced to ramp up in real time to balance the market. When the sum of these factors is positive, generators are forced to ramp down in real time. The greatest ramp demand periods occur at the top of the hour because of day-ahead commitment changes and changes in NSI.

Figure A30: Ramp Demand Impact of Hourly Day-Ahead Market
Summer 2016



E. Virtual Trading Activity

Virtual trading provides essential liquidity to the day-ahead market because it constitutes a large share of the price sensitivity at the margin that is needed to establish efficient day-ahead prices. Virtual transactions scheduled in the day-ahead market are settled against prices established 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.

Accordingly, if virtual traders expect day-ahead prices to be higher than real-time prices, they would sell virtual supply and buy the power back financially in the real-time market. If they forecast higher real-time prices, they would buy virtual load. This trading is one of the primary means to arbitrage prices between the two markets. Numerous empirical studies have shown that this arbitrage converges day-ahead and real-time prices and, in doing so, improves market efficiency and mitigates market power.[8]

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 the virtual transaction to be unprofitable.

For example, a participant may submit a high-priced (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 energy 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 it has financial positions (including FTRs) that would benefit. We monitor for such behavior and utilize mitigation authority to restrict virtual activity when appropriate.

Figure A31 and Figure A32: Day-Ahead Virtual Transaction Volumes

Figure A31 shows the average offered and cleared amounts of virtual supply and virtual demand in the day-ahead market from 2015 to 2016. Figure A32 separates these volumes by region in 2016. 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 offered above the clearing price and demand bid below the clearing price).

---

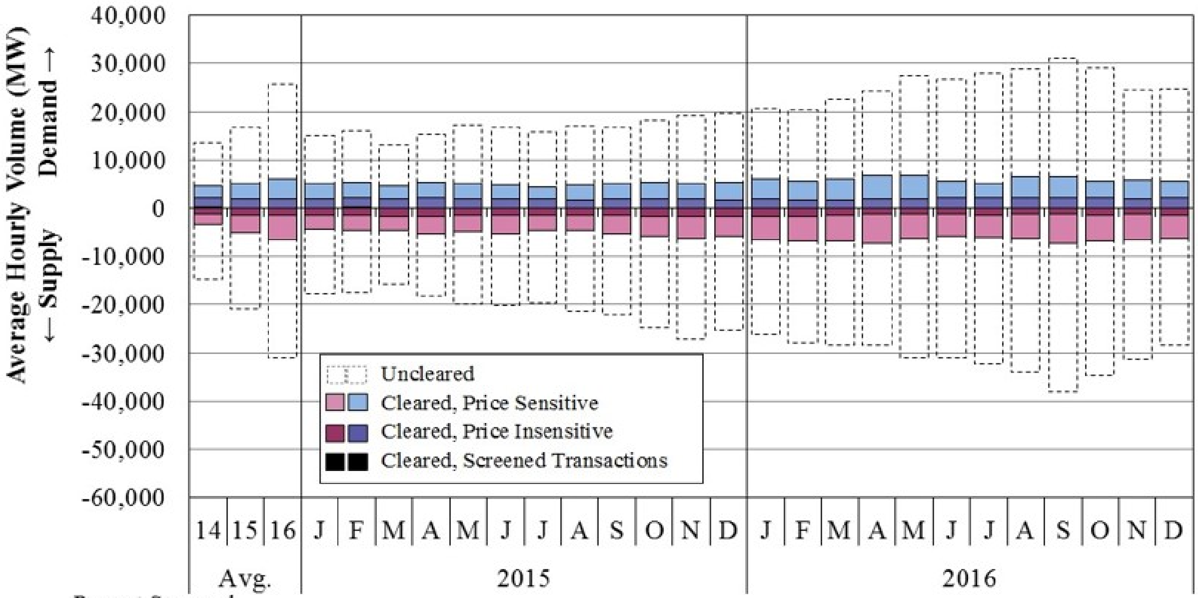
8 Chaves, Jose Pablo and Yannick Perez. 2010. Virtual Bidding: A Mechanism to Mitigate Market Power in Electricity Markets: Some Evidence from New York Market, Working Paper.

Hadsell, Lester, and Hany A. Shawky. 2007. One-Day Forward Premiums and the Impact of Virtual Bidding on the New York Wholesale Electricity Market Using Hourly Data, Journal of Futures Markets 27(11):1107-1125.

Jha, Akshaya, and Frank Wolak. 2014. Testing for Market Efficiency with Transactions Costs: An Application to Convergence Bidding in Wholesale Electricity Markets. Working paper, March 2015.

Mercadal, Ignacia. 2015. Dynamic Competition and Arbitrage in Electricity Markets: The Role of Financial Players. Working Paper, University of Chicago, October 2015.

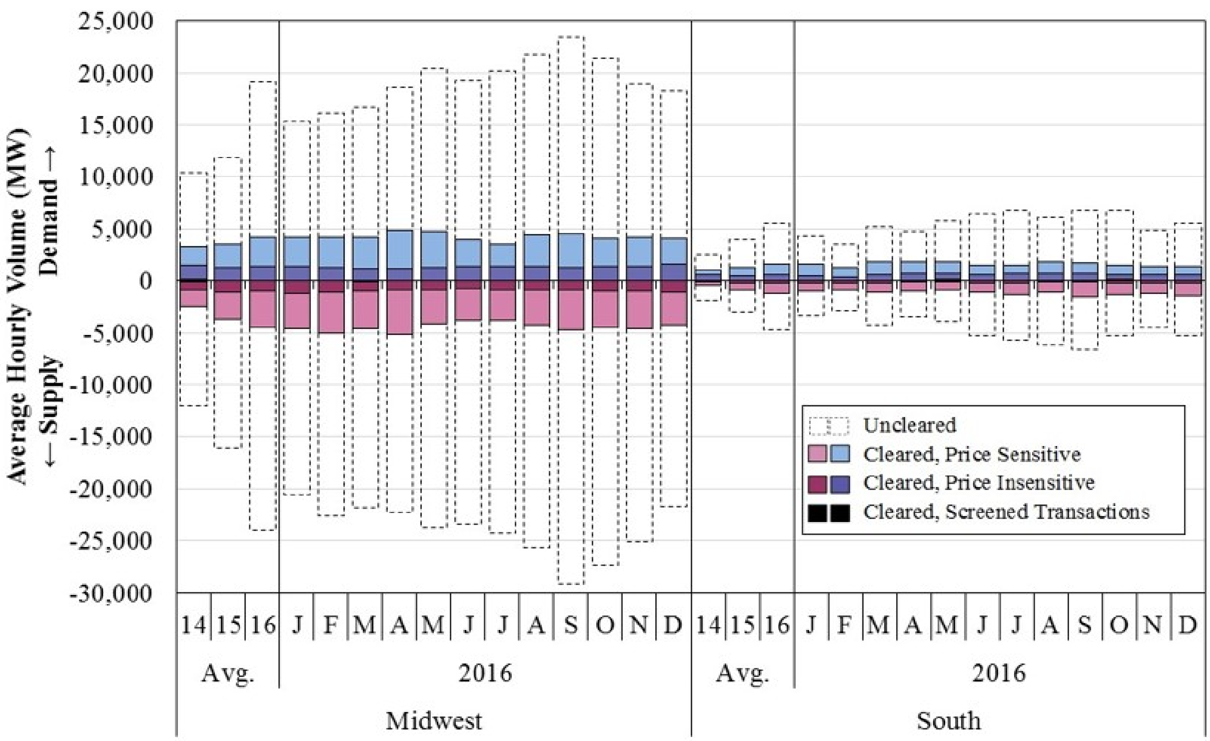
Figure A31: Day-Ahead Virtual Transaction Volumes
2015–2016



Percent Screened

	14	15	16	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Demand	3.5	1.5	1.2	1.6	3.0	1.7	1.0	1.7	1.6	1.6	1.7	1.1	1.1	1.4	0.6	0.8	1.0	1.0	1.2	1.6	1.5	1.2	1.3	1.2	2.1	0.4	1.1
Supply	1.4	0.6	0.4	0.6	1.0	1.0	0.9	1.0	0.4	0.4	0.2	0.5	0.5	0.4	0.2	0.4	0.5	0.8	0.4	0.3	0.2	0.3	0.3	0.3	0.6	0.4	0.6
Total	2.6	1.0	0.8	1.1	2.1	1.4	1.0	1.4	0.9	1.0	1.0	0.8	0.8	0.8	0.4	0.6	0.7	0.9	0.8	1.0	0.8	0.7	0.8	0.7	1.2	0.4	0.8

Figure A32: Day-Ahead Virtual Transaction Volumes by Region
2016



The figures above separately distinguish 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 these figures, bids and offers submitted at more than $20 above or below an expected real-time price as calculated by the IMM are considered price insensitive. A subset of these transactions contributed materially to an unexpected difference in the congestion between the day-ahead and real-time markets and warranted further investigation. These volumes are labeled ‘Screened Transactions’ in the figures.

Figure A33 to Figure A36: Virtual Transaction Volumes by Participant Type

The next figures show day-ahead virtual transactions by participant type. This is important because participants engage in virtual trading for different purposes. Physical participants are more likely to engage in virtual trading to hedge or manage the risks associated with their physical positions. Financial participants are more likely to engage in speculative trading intended to arbitrage differences between day-ahead and real-time markets. The latter class of trading is the conduct that improves the performance of the markets. Figure A33 shows the same results but additionally distinguishes between physical participants that own generation or serve load (including their subsidiaries and affiliates) and financial-only participants. Figure A34 and Figure A35 show the same values by region, and Figure A36 shows these values by type of location.

Figure A33: Virtual Transaction Volumes by Participant Type
2016

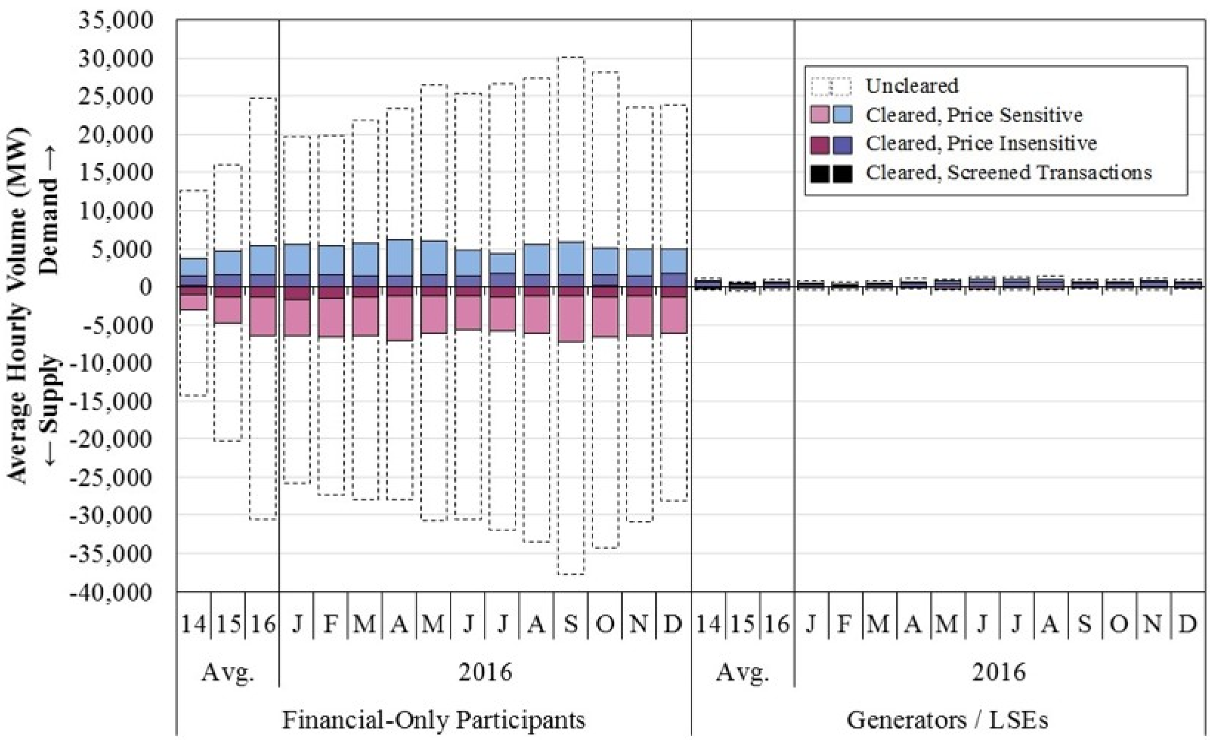


Figure A34: Virtual Transaction Volumes by Participant Type
Midwest Region, 2016

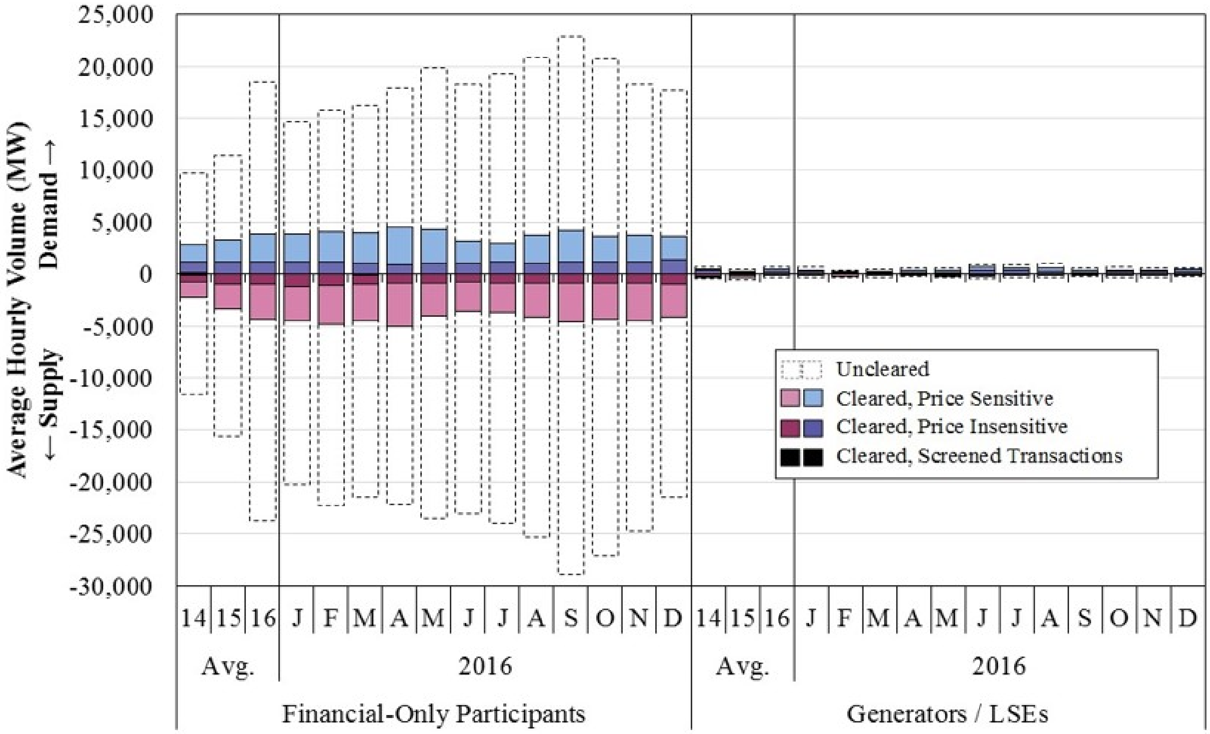


Figure A35: Virtual Transaction Volumes by Participant Type
South Region, 2016

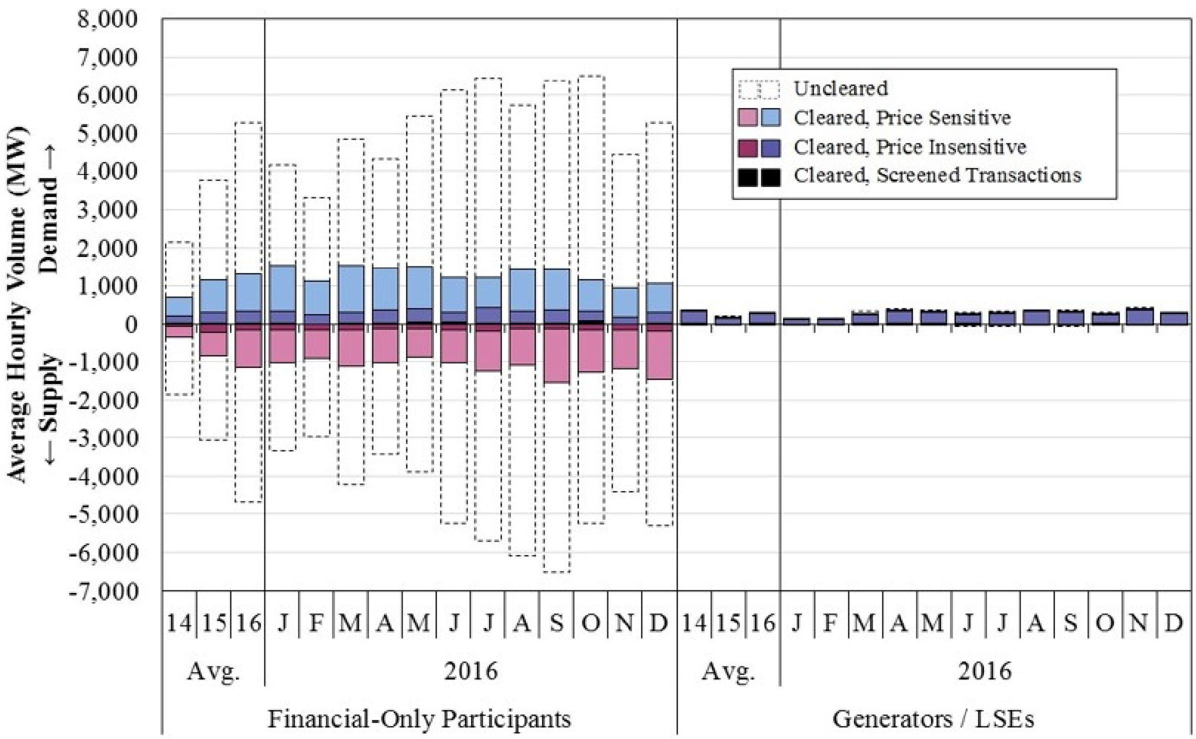


Figure A36: Virtual Transaction Volumes by Participant Type and Location
2014–2016

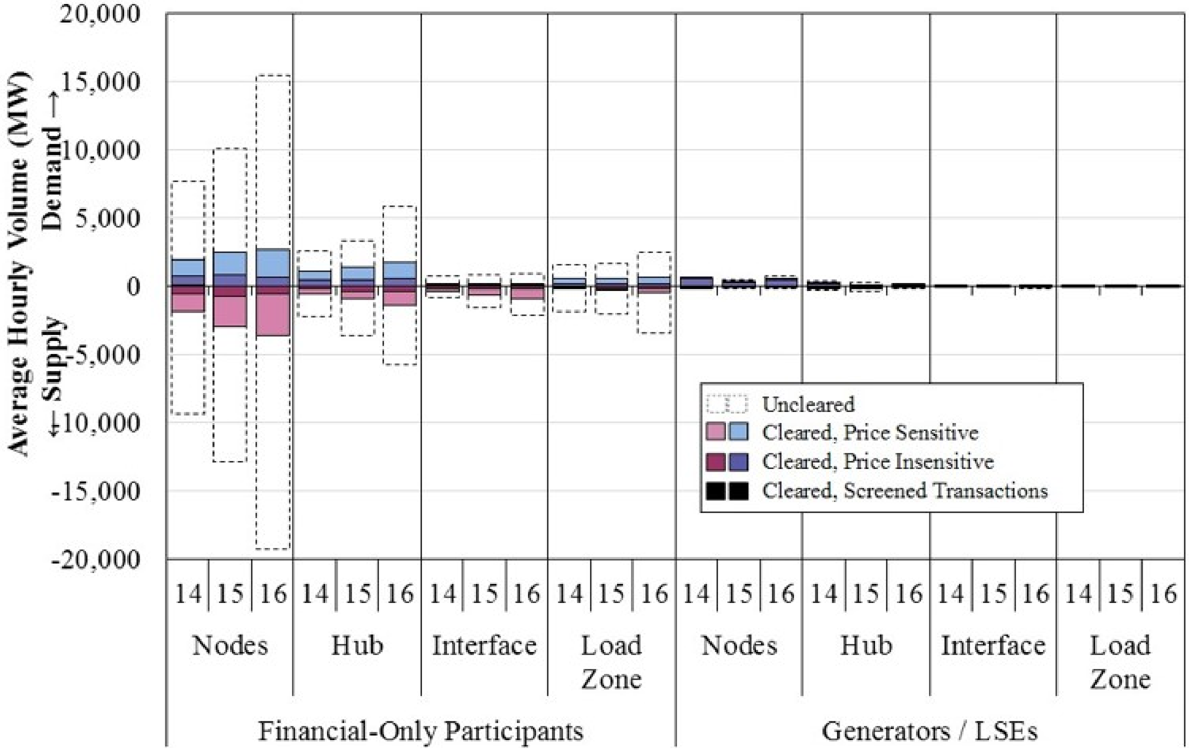


Figure A36, above, disaggregates transaction volumes further by type of participant and four types of locations: hub locations, load zones, generator nodes, and interfaces. Hubs, interfaces, and load zones are aggregations of many electrical nodes and, therefore, are less prone to congestion-related price spikes than generator locations.

Figure A37: Matched Price-Insensitive Virtual Transactions

Figure A37 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. The figure also shows the subset of transactions that are "matched," which occur when the participant clears both insensitive supply and insensitive demand in a particular hour.

Price-insensitive transactions are most often placed for two reasons:

- A participant seeks an energy-neutral position across a particular constraint. This allows the participant to arbitrage differences in congestion and losses between locations.
- A participant seeks to balance their portfolio. RSG or Day-Ahead Headroom and Deviation Charges (DDC) to virtual participants are assessed to net virtual supply, so participants can avoid such charges by clearing equal amounts of supply and demand. Such "matched" transactions rose substantially after RSG revisions in April 2011.

Figure A37: Matched Price-Insensitive Virtual Transactions

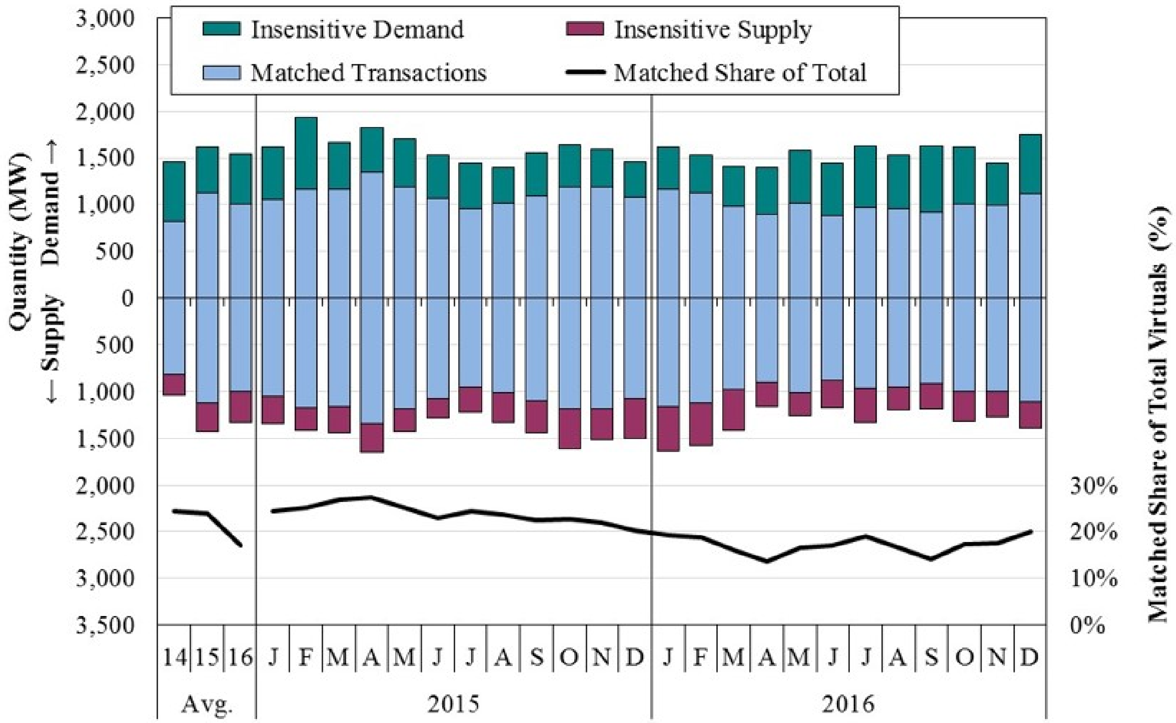
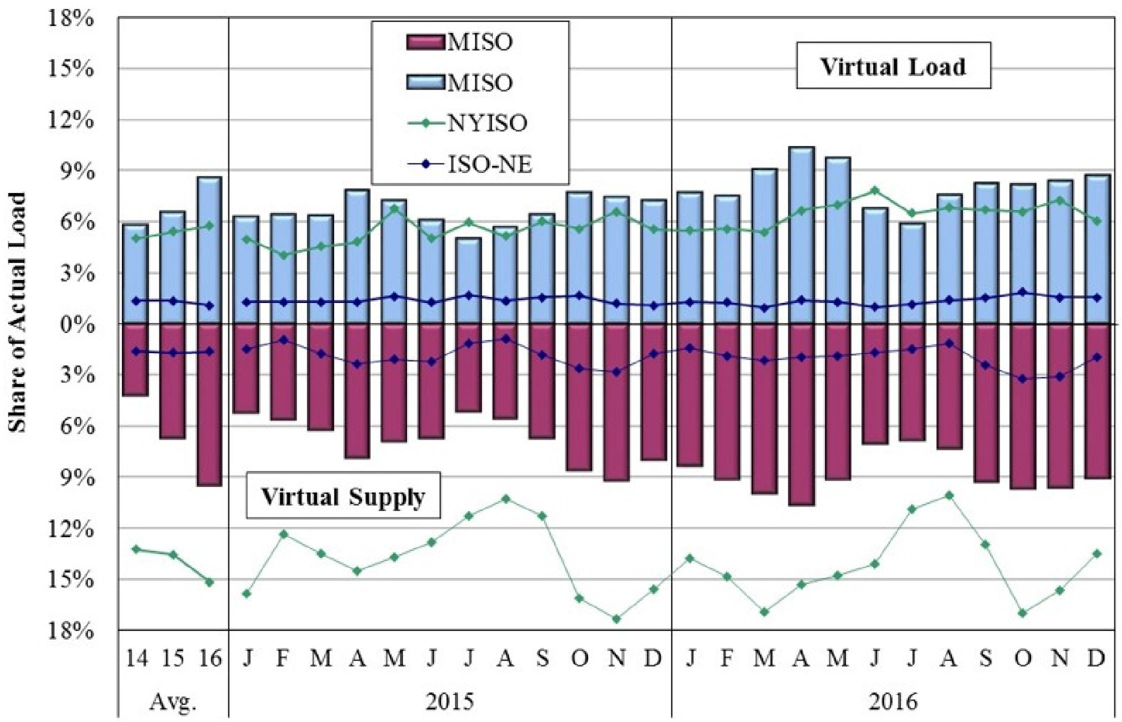


Figure A38: Comparison of Virtual Transaction Levels

To compare trends in MISO to other RTOs, Figure A38 shows cleared virtual supply and demand in MISO, ISO-NE, and NYISO as a share of actual load.

Figure A38: Comparison of Virtual Transaction Levels



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 A39 to Figure A40: Virtual Profitability

Figure A39 shows monthly total profits and average gross profitability of cleared virtual positions. 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 A40 shows the same results disaggregated by type of market participant: entities owning generation or serving load and financial-only participants.

Figure A39: Virtual Profitability
2015–2016

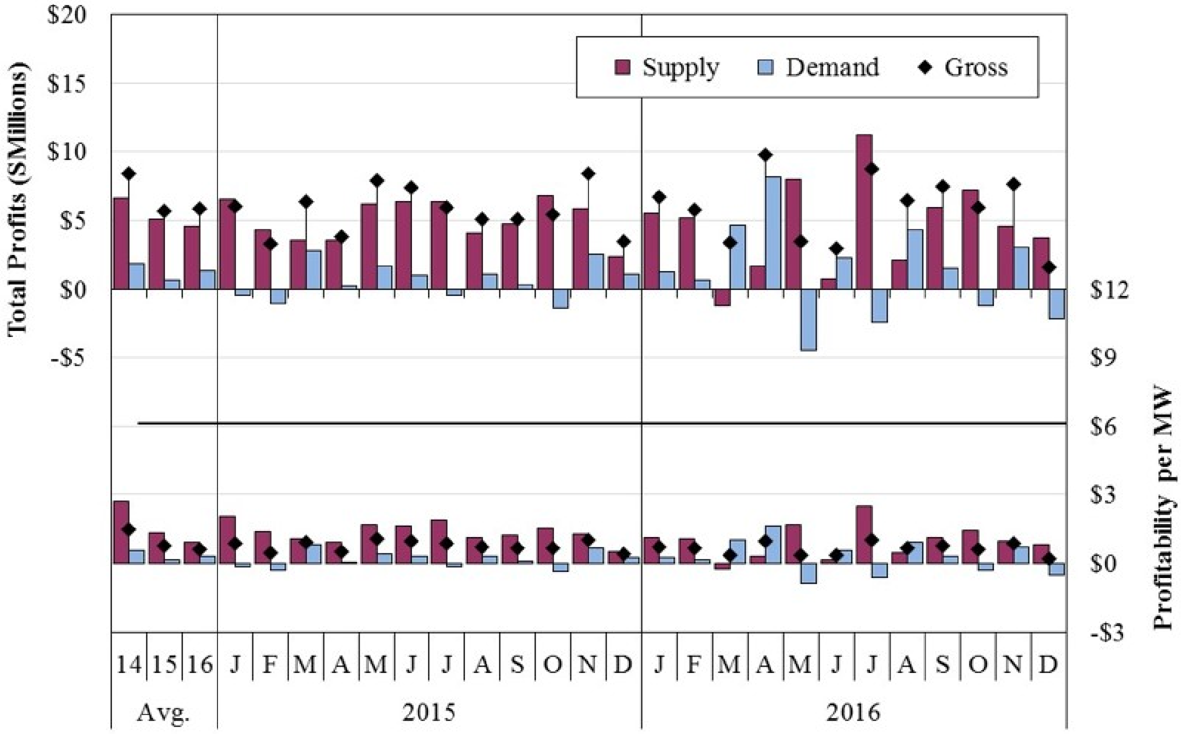
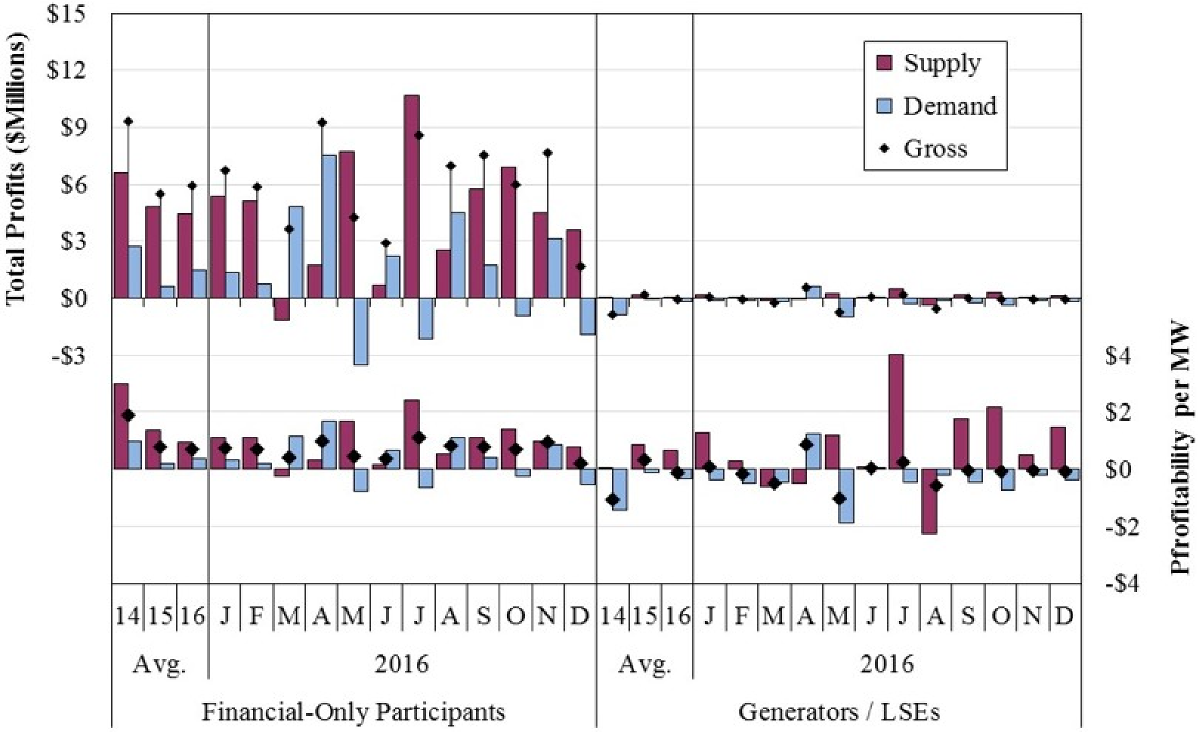


Figure A40: Virtual Profitability by Participant Type
2016



G. Benefits of Virtual Trading in 2016

We conducted an empirical analysis of virtual trading in MISO in 2016 that evaluated virtuals' contribution to the efficiency of market outcomes. Our analysis categorized virtual transactions into those that led to greater market efficiency as evidenced by their profitability on consistently modeled constraints, those that did not improve efficiency as evidenced by their unprofitability, and those transactions that, while profitable, did not produce efficiency benefits. We examined our results both in terms of quantites (MWh) and net profits.

The virtual transactions in each category provide an indication of what percentage of virtual activity contributed to market efficiency. Net profits, calculated as the difference between the profits and the losses on consistently modeled constraints, indicate whether on the margin virtuals contributed to better market efficiency in MISO by providing incrementally better commitments in the day-ahead and leading to better convergence.

To conduct our analysis, we first identified constraints that were modeled consistently in the day-ahead and real-time and those that were not. We categorized efficiency-enhancing virtuals as those that were profitable based on congestion that was modeled in the day-ahead and real-time market, and the marginal energy component (system-wide energy price). We did not include transactions that were profitable because of un-modeled constraints or the marginal loss factors, because profits on these factors do not lead to more efficient day-ahead market outcomes. We also identified virtual transactions that were unprofitable but efficiency-enhancing, because they led to improved price convergence. This happens when virtual transactions respond to a real-time price trend, but overshoot so they are ultimately unprofitable at the margin. Virtual transactions that did not improve efficiency were those that were unprofitable based on the energy and congestion on modeled constraints and did not contribute to price convergence.

We designed three tests in order to accurately identify unprofitable efficiency-enhancing virtual transactions. The tests were based on time *t* and a lagged time (*t-24* for hours 0-11 and *t-48* for hours 12-24 of the time *t* day). These lags correspond to the real-time prices a participant would observe by the time it must submit bids or offers for the following day-ahead market.

- Convergence Test: Whether the absolute value of the difference between the day-ahead and real-time LMPs at time *t* was less than the absolute value of the differences between the day-ahead and real-time LMPs in the lagged time period.
- Day-Ahead Price Movement Test: Whether the movement in the day-ahead price improved convergence – whether the absolute value of the difference between the day-ahead and real-time LMP at time *t* was smaller than the absolute value of the difference between the lagged day-ahead price and the current real-time price.
- Virtual Directional Test: To determine whether the virtual helped move the day-ahead price in the right direction, we test whether the virtual bid or offer would have been profitable based on the lagged difference between the day-ahead and real-time price.

Table A5 and Table A6: Virtual Evaluation Summaries

Table A5 summarizes the virtual transaction quantities that fall in the efficiency-enhancing and non-efficiency-enhancing categories, divided by the type of entity submitting the transactions.

Table A5: Efficient and Inefficient Virtual Transactions in 2016

	Financial Participants		Physical Participants		Total	
	Average Hourly MWh	Share of Class	Average Hourly MWh	Share of Class	Average Hourly MWh	Share of Total
Efficiency - Enhancing Virtuals	6,790	*58%*	400	*47%*	7,190	*57%*
Non - Efficiency - Enhancing Virtuals	4,956	*42%*	456	*53%*	5,412	*43%*

Table A6 below shows the total profits and losses associated with efficiency-enhancing and non-efficiency-enhancing virtuals in MISO in 2016 by market participant type. The profits and losses account for the fact that some transactions are more efficient or inefficient than others.

Table A6: Analysis of Virtual Profits and Losses of Virtual Transactions in 2016

	Financial Participants		Physical Participants		Total
	Total Profits (Losses) $	Share of Class	Total Profits (Losses) $	Share of Class	Total Profits (Losses) $
Efficiency - Enhancing Virtuals	418,670,660	*96%*	17,879,821	*4%*	436,550,481
Non - Efficiency - Enhancing Virtuals	(350,725,453)	*94%*	(21,291,917)	*6%*	(372,017,370)
Rent	31,123,674	*90%*	3,637,049	*10%*	34,760,723

Table A6 also shows rents earned by virtual transactions, which are profits that do not produce efficiency benefits. The rents include profits associated with un-modeled day-ahead constraints and differences in the loss components between the two markets. These rents do not indicate a concern with virtual trading, but rather opportunities for MISO to improve the consistency of its modeling between the day-ahead and real-time markets.

Importantly, the total benefits are much larger than the marginal net benefits shown above because: a) profits of efficient virtual transactions become smaller as prices converge; and b) losses of inefficient virtual transactions get larger as prices diverge. To accurately calculate this total benefit would require one to re-run all of the day-ahead and real-time market cases for the entire year. Nonetheless, our analysis allows us to establish with a high degree of confidence that virtual trading was highly beneficial in 2016.

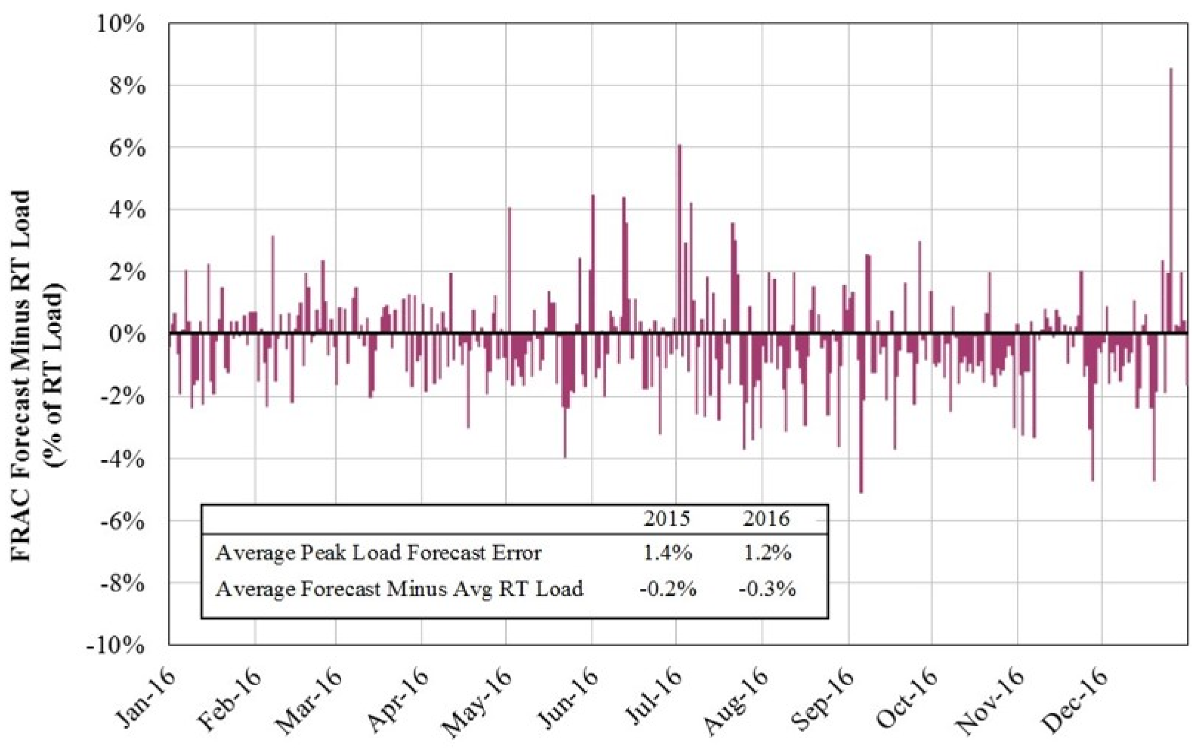
H. Load Forecasting

Load forecasting is a key element of an efficient forward commitment process. Accuracy of the Mid-Term Load Forecast (MTLF) is particularly important because it is an input to the Forward Reliability Assessment Commitment (FRAC) process performed after the day-ahead market closes and before the real-time operating day begins. Inaccurate forecasts can cause MISO to commit more or fewer resources than necessary to meet demand, both of which can be costly.

Figure A41: Daily MTLF Error in Peak Hour

Figure A41 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 2016.

Figure A41: Daily MTLF Error in Peak Hour in 2016



V. 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. Wind generation has continued to grow, and MISO set a number of new records in 2016.

The real-time market performs the vital role of dispatching resources to minimize the total production 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 services 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 partly a 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

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. This subsection evaluates and discusses the volatility of real-time prices. Sharp price changes frequently occur when the market is ramp-constrained (when a large share of the resources are moving as quickly as possible), which occurs when the system is moving to accommodate large changes in load, NSI, or generation startup or shutdown. This is exacerbated by generator inflexibility arising from lower offered ramp limits or reduced dispatch ranges.

Figure A42: Fifteen-Minute Real-Time Price Volatility

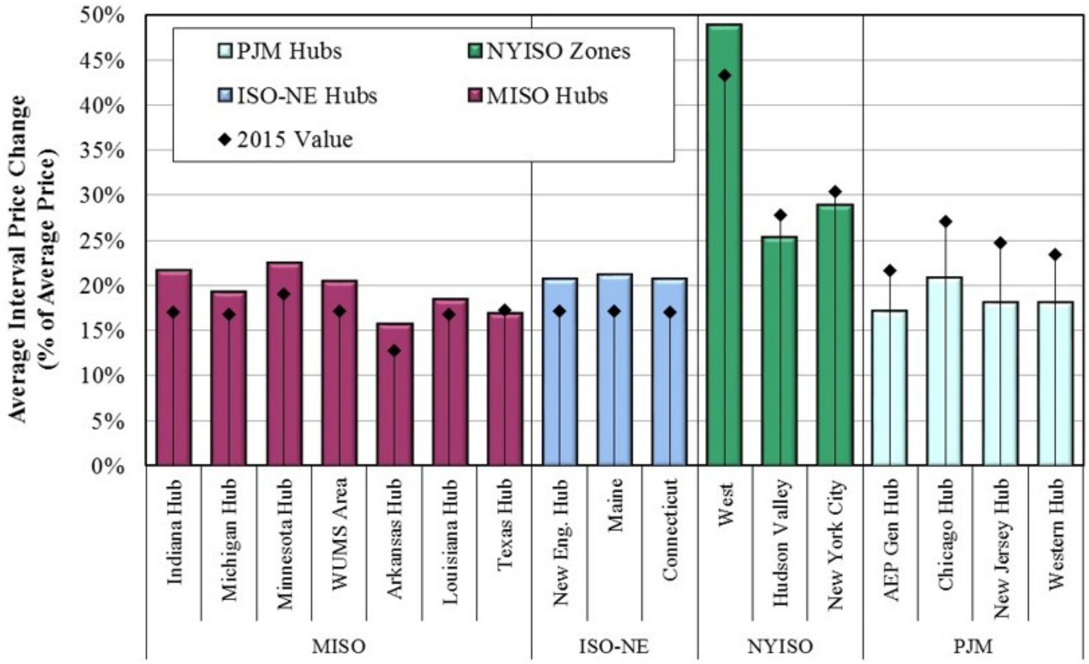
Figure A42 provides a comparative analysis of price volatility by showing the average percentage change in real-time prices between fifteen-minute intervals for several locations in MISO and other RTO markets. Each of these markets has a distinct set of operating characteristics that factor into price 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 more than 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. Because the systems are re-dispatched 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.

Figure A42: Fifteen-Minute Real-Time Price Volatility
MISO and Other RTO Markets, 2016



B. Evaluation of ELMP Price Effects

MISO introduced pricing reforms for its day-ahead and real-time energy markets through the implementation of the Extended Locational Marginal Pricing algorithm (ELMP) on March 1, 2015. ELMP is intended to improve price formation in the day-ahead and real-time energy and ancillary services markets by having LMPs better reflect the true marginal costs of supplying the system at each location. ELMP is a reform of the previous price-setting engine that affects prices, but does not affect the dispatch. ELMP reforms pricing in two main ways:

- It allows online, inflexible resources to set the LMP if the inflexible unit is economic. These are online "Fast-Start Resources"[9] and demand response resources.

9 Fast-Start Resource is defined in the Tariff term as a Generation Resource or DR Resource respond within 10 minutes of being notified and that has a minimum run time of one hour or less.

- It allows offline Fast-Start Resources to be eligible to set prices during transmission violations or energy shortage conditions.

The first of these reforms is intended to address a long-standing recommendation to remedy issues that we first identified shortly after the start of the MISO energy markets in 2005. The pricing algorithm in UDS does not always reflect the true marginal cost of the system because inflexible high-cost resources are frequently not recognized as marginal, even though they are needed to satisfy the system's needs. The most prevalent class of such units is online natural gas-fired turbines that often have a narrow dispatch range. Because it is frequently not economic to turn them off (they are the lowest cost means to satisfy the energy needs of the system), it is appropriate for the energy prices to reflect the running cost of these units.

There are a number of adverse market effects when economic units supplying incremental energy are not included in price setting:

- MISO will generally need to pay RSG to cover these units' full as-offered costs;
- Real-time prices will be understated and will not provide efficient incentives to schedule energy in the day-ahead market, when lower-cost resources could be scheduled that would reduce or eliminate the need to rely on high-cost peaking resources in real time;
- The market will not provide efficient incentives for participants to schedule exports or imports, which can prevent lower-cost energy from being imported to displace the higher-cost peaking resources.

Accordingly, the objective of the online pricing reforms in ELMP is to allow certain inflexible resources to set prices in the MISO energy markets.

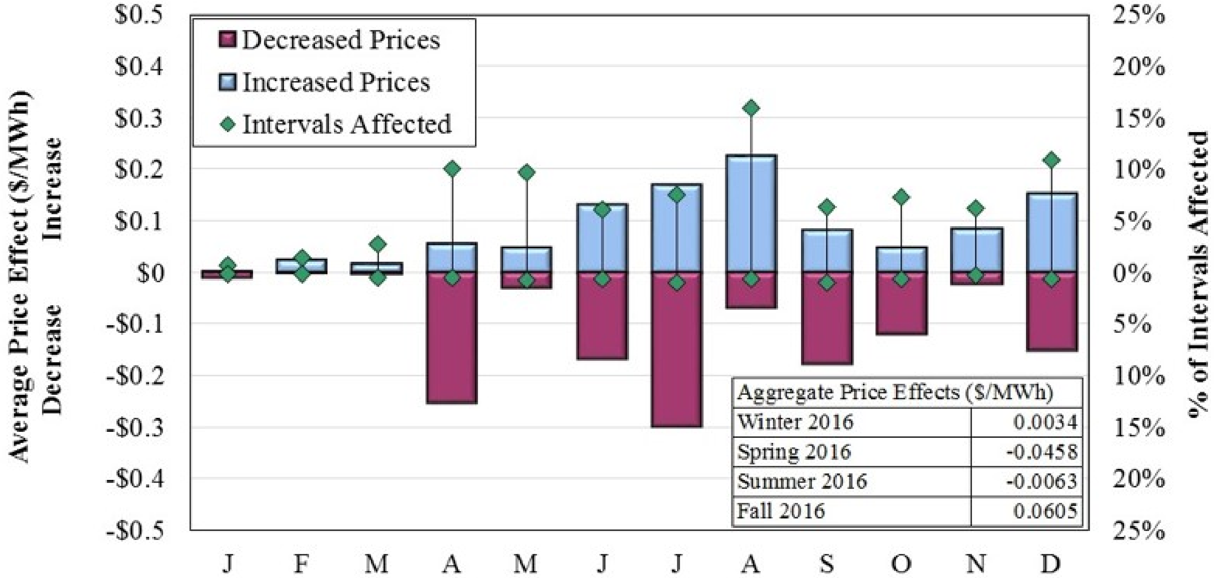
The second reform allows offline Fast-Start Resources to set prices under shortage conditions. Shortages include transmission violations and operating reserves shortages. It is efficient for offline resources to set the price only when a) they are feasible (can be started quickly), and b) they are economic for addressing the shortage. However, when units that are either not feasible or not economic to start are allowed to set energy prices, the resulting prices will be inefficiently low. We review and discuss both of these reforms in this section.

Figure A43 to Figure A45: ELMP Price Effects

Figure A43 to Figure A45 summarize the effects of ELMP by showing the average upward effects via the online pricing, average downward effects via the offline pricing, along with the frequency that the ELMP model altered the prices upward and downward.

These metrics are shown for the system marginal price (i.e., the market-wide energy price) in the real-time market and day-ahead market, as well as for the LMP at the most effected locations (i.e., congestion-related effects). Additionally, to show the size of the ELMP price adjustments, the table below the first two figures shows the size of the adjustments in those intervals that the ELMP model affected the price.

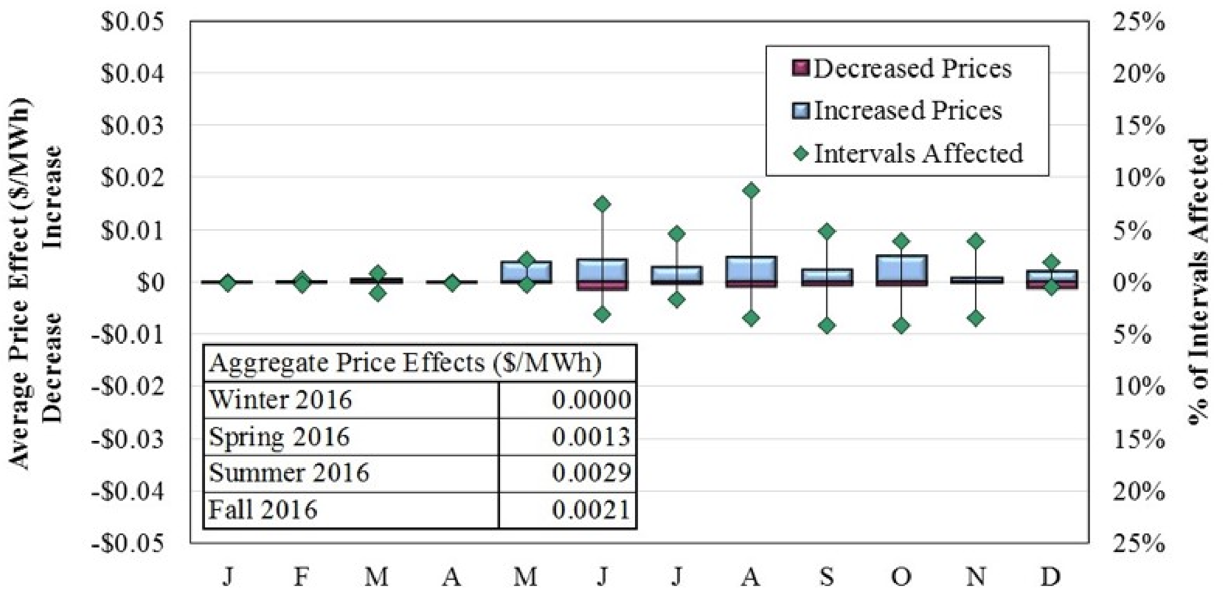
Figure A43: Average Market-Wide Price Effects of ELMP
Real-Time Market, 2016



Change in Affected Intervals ($/MWh) 2016

SMP Increase	1.50	0.51	1.92	0.70	0.56	0.51	2.17	2.26	1.41	1.30	0.68	1.38	1.41
SMP Decrease	-7.24	-7.92	-2.25	-1.15	-53.12	-4.04	-26.42	-29.66	-10.46	-18.64	-18.95	-7.54	-23.90

Figure A44: Average Market-Wide Price Effects of ELMP
Day-Ahead Market, 2016



Change in Affected Intervals ($/MWh) 2016

SMP Increase	0.00	0.02	0.08	0.00	0.18	0.06	0.06	0.05	0.05	0.13	0.02	0.12
SMP Decrease	-0.01	-0.02	-0.02	-0.18	-0.08	-0.05	-0.04	-0.03	-0.02	-0.02	-0.01	-0.22

Figure A45: Price Effects of ELMP at Most Affected Locations
Real-Time Market, 2016

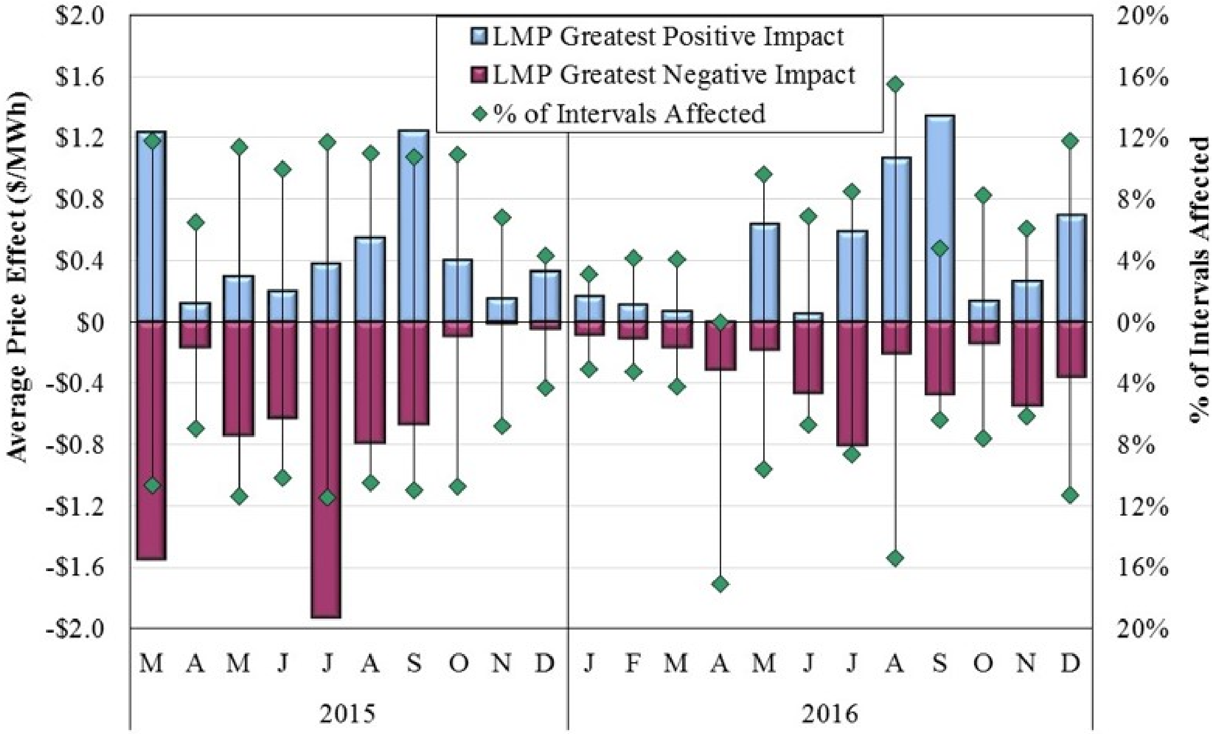


Figure A46: Eligibility of Online Peaking Resource in ELMP

Allowing inflexible online resources to set energy prices increases the effectiveness and efficiency of the markets. The figures above show that the upward price effects of ELMP have been relatively small. We attribute these small effects largely to the ELMP eligibility rules. In this section, we show the portions of MISO's online peaking resources that have been eligible to set prices under the Phase I and II ELMP rules and the portions that remain ineligible.

Figure A46 shows all of the energy produced by online peaking resources, divided by:

- Whether they were scheduled during or after the day-ahead market;
- Their start-up time; and
- Their minimum run-time.

We show this combination because only units not scheduled day-ahead that can start in 10 minutes or less and have a minimum runtime of one hour or less were eligible to set real-time prices in the ELMP pricing model in 2016. These units are shown to the left of the figure shaded in blue. The additional units that became eligible in May 2017 to set real-time prices under Phase II of ELMP are shaded in pink, while the units the IMM proposes be eligible to set prices are shaded in green. The IMM proposal would allow most of the remaining peaking resources that receive RSG payments to be eligible to set prices in ELMP. Hence, we propose that MISO evaluate expanding the eligibility rules beyond Phase II of ELMP to include these additional classes of peaking resources.

Figure A46: Eligibility of Online Peaking Resources in ELMP
2016

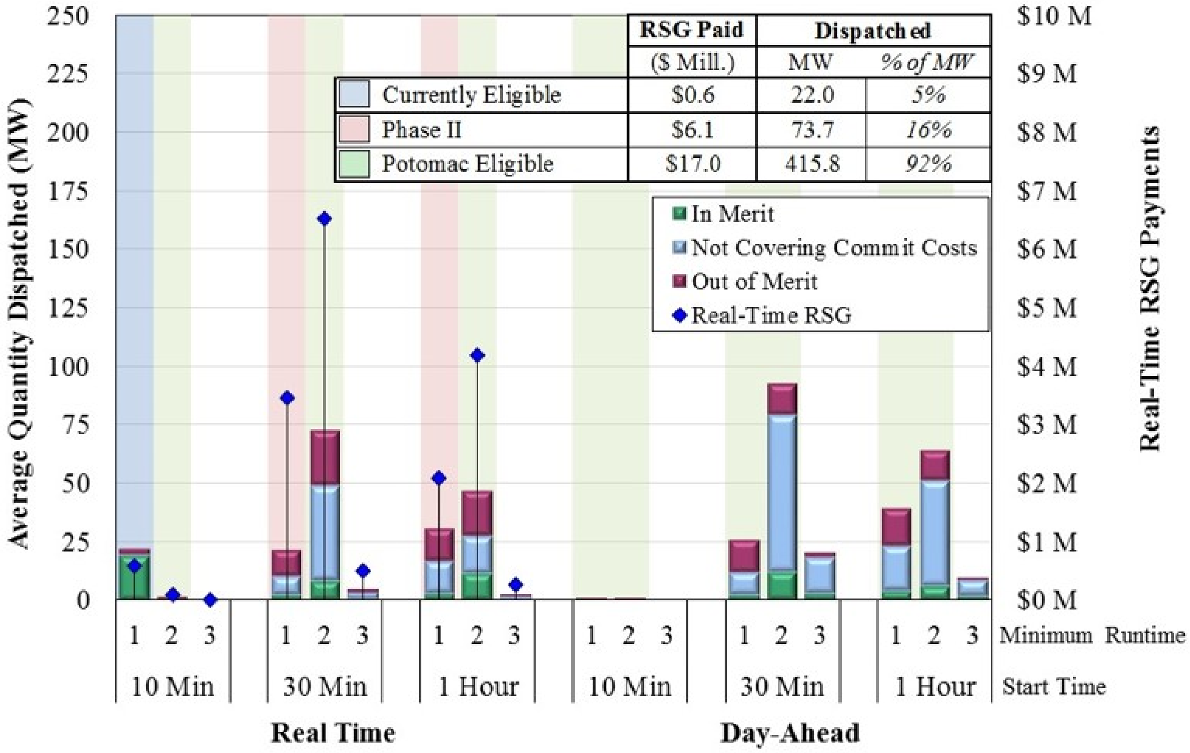


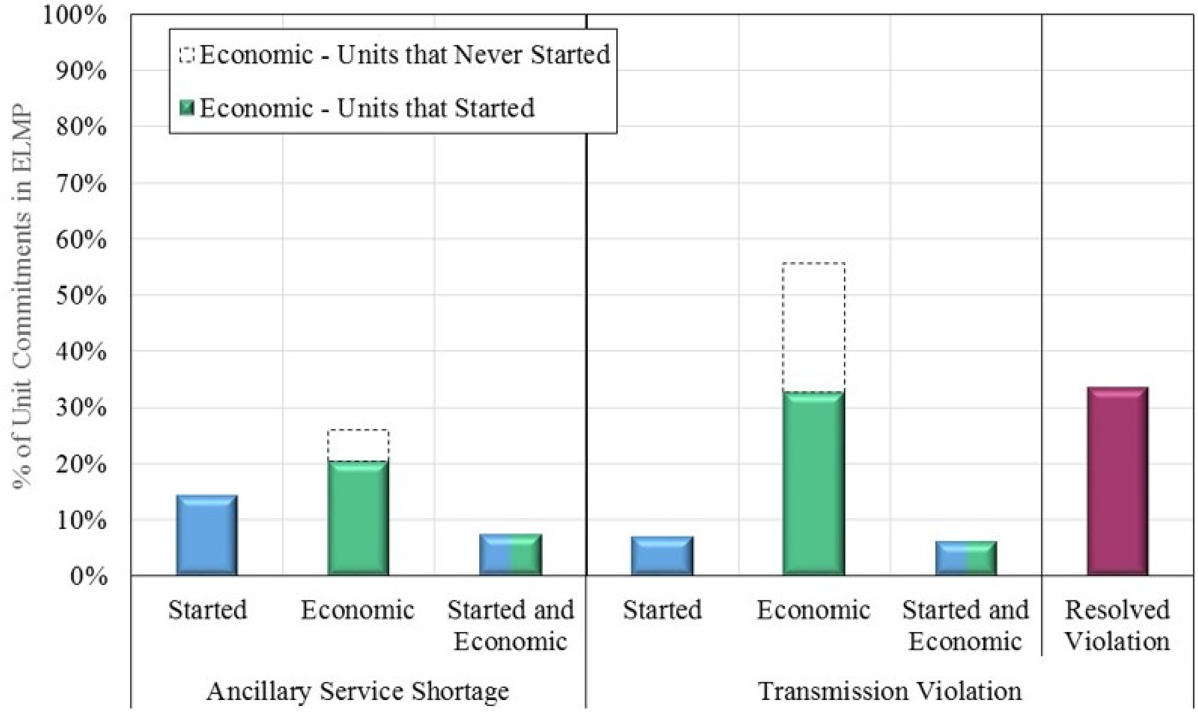
Figure A47: Evaluation of Offline Units Setting Prices in ELMP

ELMP also includes provisions for allowing offline Fast-Start Resources to set price under shortage conditions. Shortages include transmission violations and operating reserves shortages. Prior to the implementation of ELMP, offline units could not set prices because UDS only optimizes the schedules from online resources. Offline units or units in start-up mode are invisible to the UDS.

When an operating reserve shortage or a transmission violation occurs, the ELMP software may set prices based on the hypothetical commitment of an offline unit that MISO could utilize to address the shortage. This is only efficient when the offline resource is: a) feasible (can be started quickly enough to help), and b) economic for addressing the shortage. When units that are either not feasible or not economic to start set prices, the prices will be inefficiently low.

When committing an offline unit is feasible and is the economic action to take during a transmission violation or operating reserves shortage, we expect that the unit will be started by MISO. When resources are not started, we infer that the operators did not believe the unit could be on in time help resolve the shortage and/or that the operator did not expect that the unit would be economic to operate for the remainder of its minimum runtime. Therefore, Figure A47 summarizes whether the offline units that set prices in 2016 were a) economic, b) started by MISO, and c) both started *and* economic. The figure also indicates whether the resources actually resolved a transmission violation in the maroon bar on the right. The figure shows operating reserve shortages in the left panel and transmission violations in the right panel.

Figure A47: Evaluation of Offline Units Setting Prices in 2016



To determine whether the units were economic (green bar), we compared the real-time market revenues the unit would received to their total dispatch costs. The total costs included start-up and no load costs for the units' minimum runtime, starting with the interval after the interval that they were committed. We determined that the units started (blue bar) by whether the UDS recognized the units as online in the three intervals following the recommended commitment intervals. If both of the conditions for economic commitments and MISO starts were met, we determined that the units were both started and economic (blue and green bar).

We also determined whether the offline units setting prices in the ELMP cases for transmission violations were actually resolving the violations (maroon bar). This is important because if an offline unit does not resolve the violation, it may alter the system-wide energy price inefficiently without significantly changing the congestion pricing associated with the violated constraint.

C. Real-Time Ancillary Service Prices and Shortages

Scheduling of energy and operating reserves, which include regulating reserves and contingency reserves, is jointly optimized in MISO's real-time market software. As a result, opportunity cost trade-offs result in higher energy prices and reserve prices. Energy and ancillary services markets (ASM) prices are additionally affected by reserve shortages. When the market is short of one or more ancillary service products, the demand curve for that product will set the market-wide price for that product and be included in the price of higher value reserves and energy. The demand curves for the various ancillary services products in 2016 were:

- Regulation: varies monthly according to the prior month's gas prices. It averaged $8.26 per MWh in 2016.

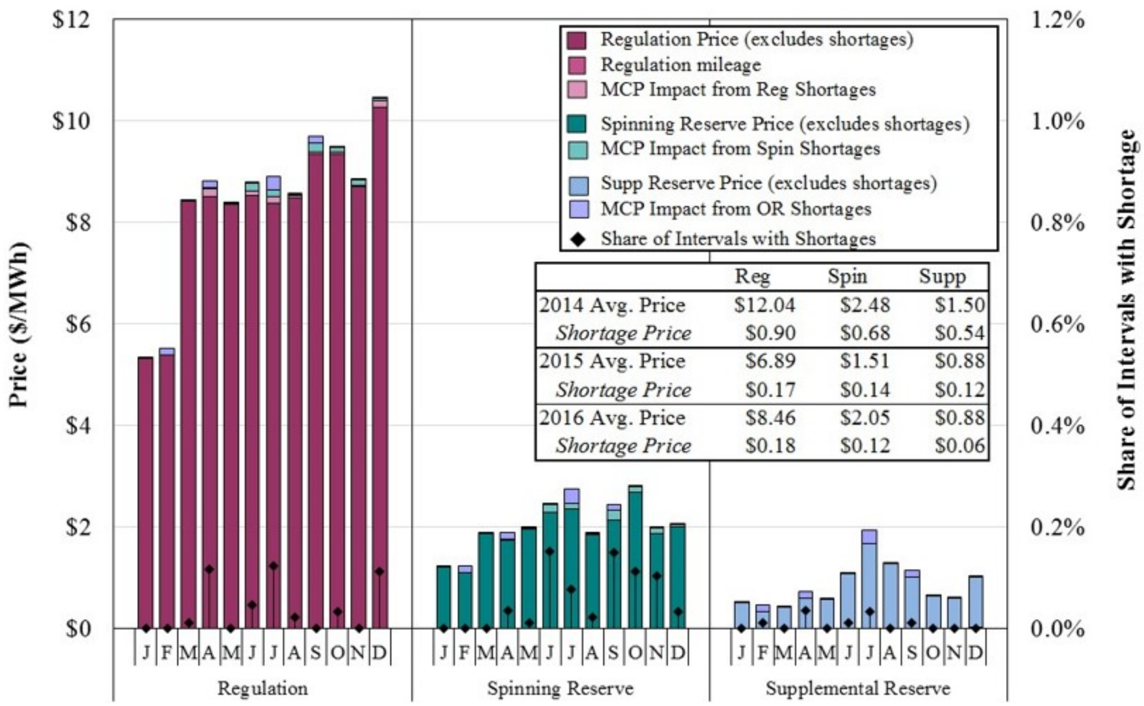
- Spinning Reserves: $65 per MWh (for shortages between zero and 10 percent of the market-wide requirement) and $98 per MWh (for shortages greater than 10 percent).[10]
- Total Operating Reserves:
  - For cleared reserves less than four percent of the market-wide requirement: Value of Lost Load ($3,500) minus the monthly demand curve price for regulation.
  - For cleared reserves between four and 96 percent of the market-wide requirement: priced between $1,100 (the combined offer caps for energy and contingency reserves) and the above, depending on the estimated probability of loss of load.
  - For cleared reserves more than 96 percent of the market-wide requirement: $200.

Total operating reserves (including contingency reserves plus regulation) is the most important reserve requirement because a shortage of total operating reserves has the greatest potential impact on reliability. Accordingly, total operating reserves has the highest-priced reserve demand curve. To the extent that increasing load and unit retirements reduce the capacity surplus in MISO, more frequent operating reserve shortages will play a key role in providing long-term economic signals to invest in new resources.

Figure A48: Real-Time Ancillary Services Clearing Prices and Shortages

Figure A48 shows monthly average real-time clearing prices for ASM products in 2016. The price for supplemental reserves, which are provided from offline fast-start units, is MISO's contingency reserve price because this is the only product that it can sell.

Figure A48: Real-Time Ancillary Services Clearing Prices and Shortages
2016



10 There is an additional $50 per MWh penalty called the "MinGenToRegSpinPenalty."

Contingency reserves are the lowest quality reserve, but because the contingency reserve demand curve is the highest priced, contingency reserve shortages will typically be the largest shortage-pricing component in each of the operating reserve prices and in the energy price. The figure above shows the frequency with which the system was short of each class of reserves, as well as the impact of each product's shortage pricing.

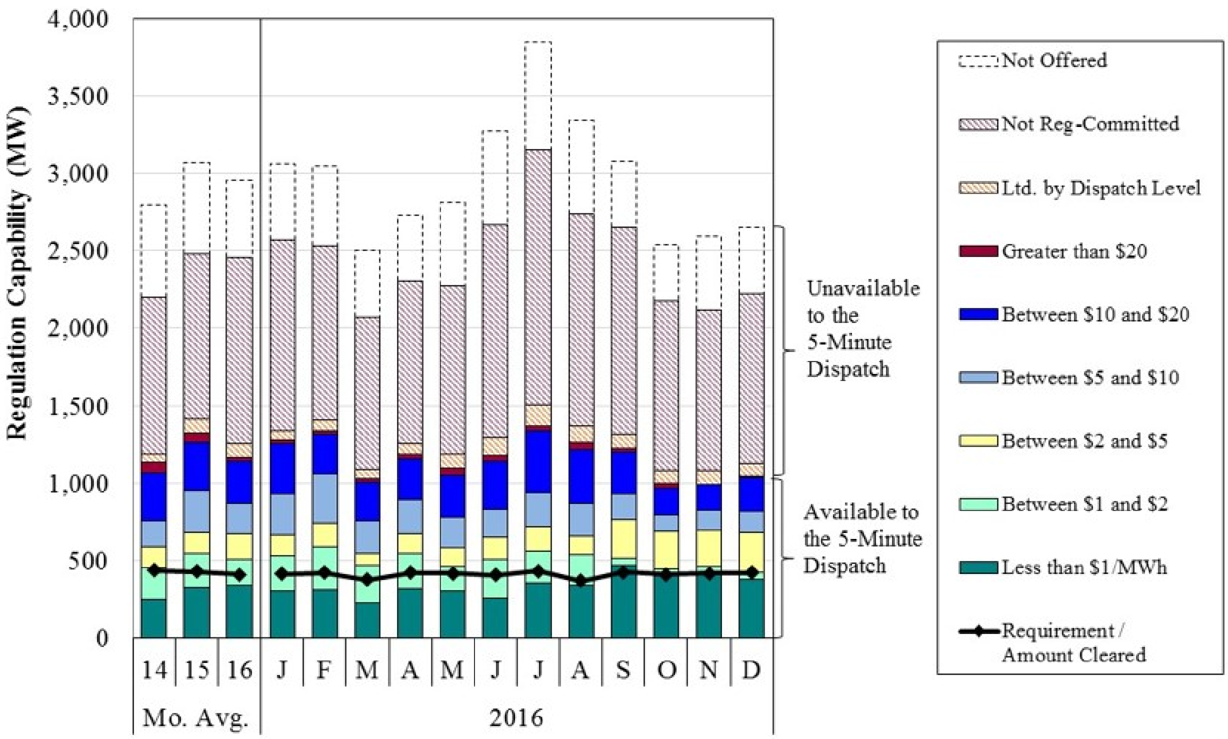
Additionally, higher quality reserves can always be substituted for lower quality reserves. Therefore, the price for spinning reserves will always be equal to or higher than supplemental reserves (i.e., contingency reserves). Likewise, when a shortage occurs in a lower quality reserve product (e.g., contingency reserves), it appears in the price of all higher quality reserves.

Figure A49: Regulation Offers and Scheduling

ASM offer prices and quantities are the primary determinants of ASM outcomes. Figure A49 examines average regulation capability, which is less than spinning reserve capability 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 can be considerably higher than the highest cleared regulation offer prices 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.

Figure A49: Regulation Offers and Scheduling
2016



The figure above 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. The figure separately shows the quantities unavailable because they are not offered by participants, not committed by MISO, or limited by dispatch level (i.e., constrained by a unit's operating limits).

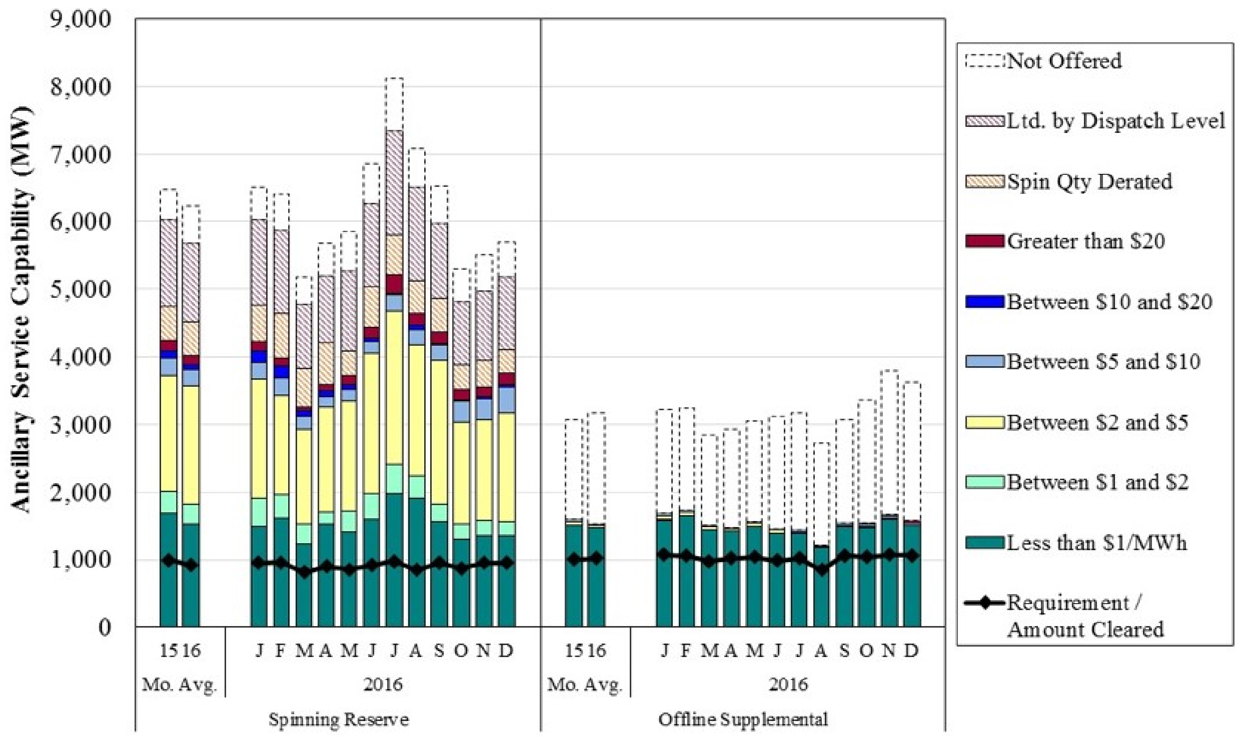
Figure A50: Contingency Reserve Offers and Scheduling

MISO has two classes of contingency reserves: spinning reserves and supplemental reserves. Spinning reserves can only be provided by online resources for up to 10 minutes of ramp capability (limited by available headroom above their output level). Supplemental reserves are provided by offline units that can respond within 10 minutes, including their startup and notification times. The contingency reserve requirement is satisfied by the sum of the spinning reserves and supplemental reserves.

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 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 shortage pricing.

Figure A50 shows the quantity of spinning and supplemental reserve offers by offer price. Of the capability not available for dispatch, the figure distinguishes between quantities not offered, derated, and limited by dispatch level.

Figure A50: Contingency Reserve Offers and Scheduling
2016



D. Spinning Reserve Shortages

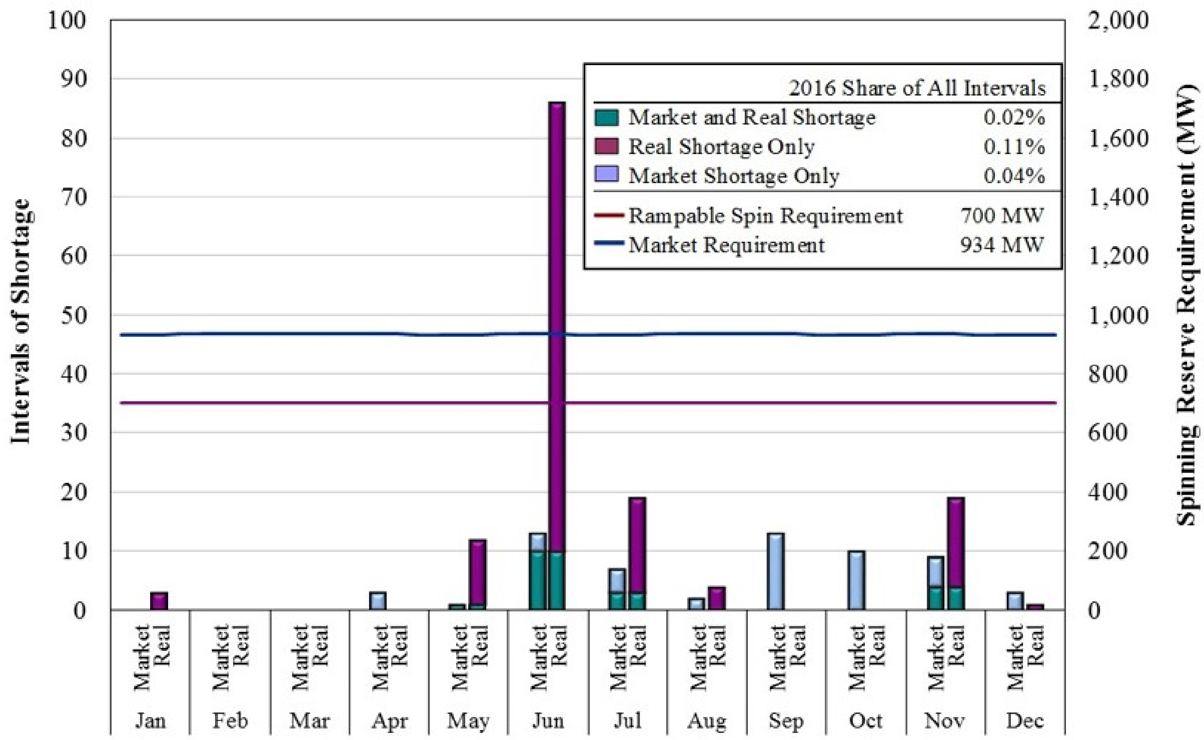
Figure A51: Market Spin Shortage Intervals vs. Rampable Spin Shortage Intervals

MISO operates with a minimum required amount of spinning reserves 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 10 minutes if MISO is ramping them up to provide energy. To account for concerns that ramp-sharing between ASM products could lead to real ramp shortages, 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 of spinning reserves.[11] To minimize such outcomes, MISO should set the market requirement to make market results as consistent with real conditions as possible.

Figure A51 shows all intervals in 2016 with a real (physical) shortage, a market shortage, or both, as well as the physical and market requirements.

Figure A51: Market Spin Shortage Intervals vs. Rampable Spin Shortage Intervals
2016



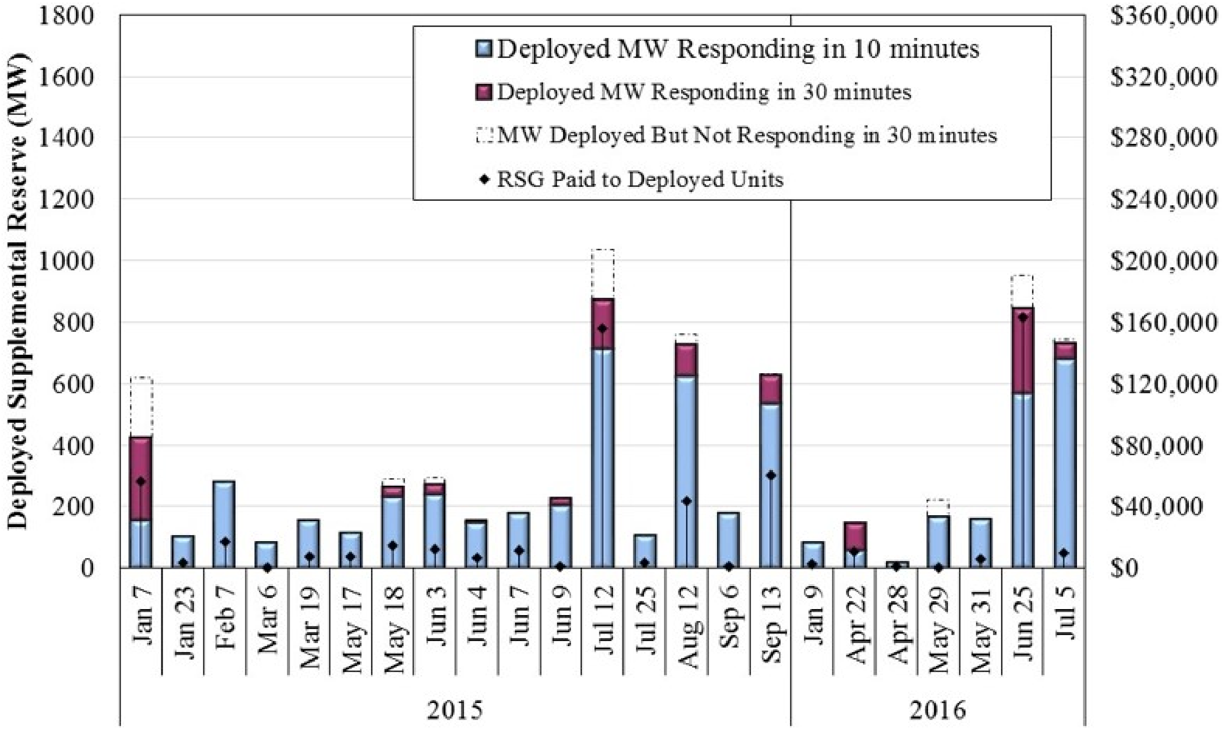
11 It is also possible for the system to be physically short temporarily, when units are ramping to provide energy, but not indicate a market shortage because ramp capability is shared between the markets.

E. Supplemental Reserve Deployments

Figure A52: Supplemental Reserve Deployments

Supplemental reserves are deployed during Disturbance Control Standard (DCS) and Area Reserve Sharing (ARS) events. Figure A52 shows offline supplemental reserve response during the seven deployments in 2016, separately indicating those that were successfully deployed within 10 minutes (as required by MISO) and within 30 minutes (as required by the North American Electric Reliability Corporation or "NERC"). The summary is valuable because it indicates how reliably MISO's offline reserves start when MISO needs them.

Figure A52: Supplemental Reserve Deployments
2015-2016



F. Operating Reserve Demand Curve

Since operating reserves price the reliability costs of shortages in MISO, efficient market design requires a properly-valued Operating Reserve Demand Curve (ORDC). Efficient shortage prices can send signals for new investment, facilitate optimal interchange between markets and commitment in times of shortage, and balance the value of holding reserves subject to the cost of violating transmission constraints. An efficient ORDC should abide by four principles:

- Reflect the marginal reliability value of reserves at each shortage level;
- Consider all significant types of supply-side contingencies;
- Evaluate risks of simultaneous contingencies; and
- Have no discontinuities that lead to volatile outcomes.

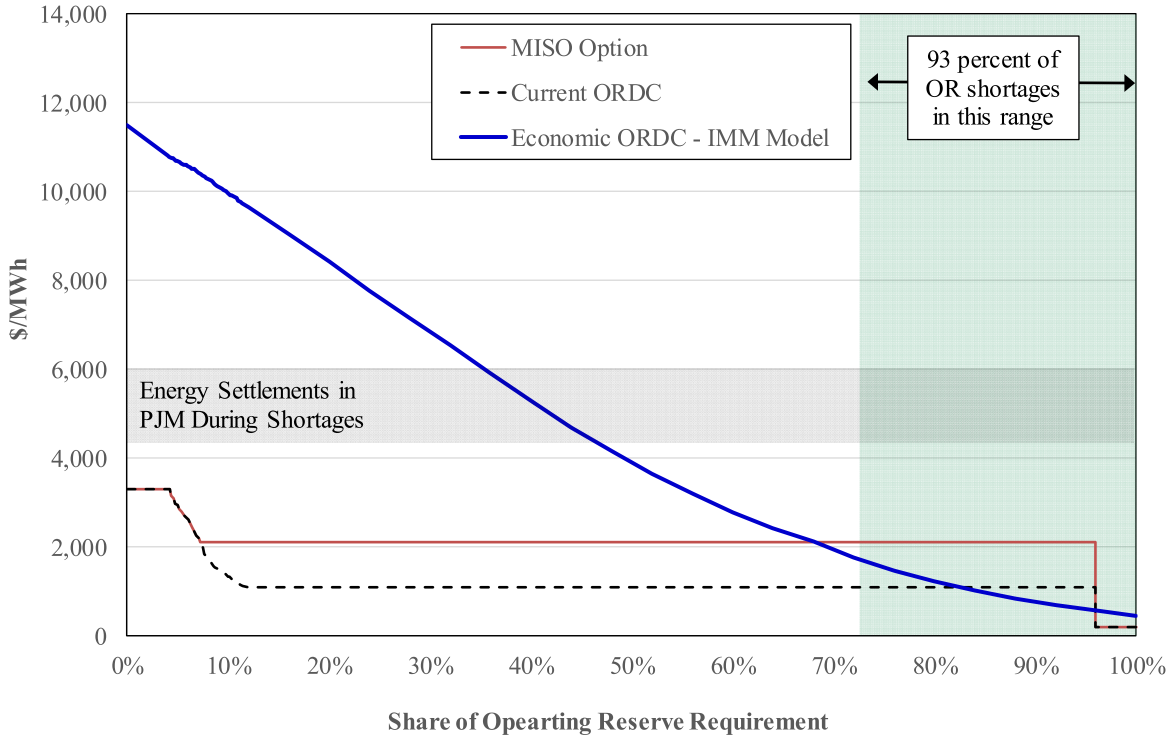
The marginal reliability value of reserves at any shortage level is equal to the expected value of the load that may not be served, which is equal to the product of the net value of lost load ("VOLL") and the probability of losing load at that reserve level. MISO's current ORDC includes these factors, but it is flawed for reasons we discuss more fully in the report:

- MISO's current $3,500 VOLL is understated; and
- The slope of the ORDC is not based on the probability of losing load as described above.

Figure A53: Current and Proposed Operating Demand Curves

Figure A53 below shows the current ORDC and a curve that illustrates the IMM's economic ORDC. The shape of the current curve is initially downward-sloping, but it then flattens out for an extended range at $1,100. Small shortages of less than 4 percent are priced at the lowest step of $200. As shortage levels increase on the $1,100 step of the current ORDC, the prices remain fixed and do not accurately reflect the fact that the probability of losing load is increasing. The "MISO Option" is the new curve proposed by MISO to comply with Order 831, which raised the the offer cap from $1000 to $2000 per MWh.

Figure A53: Current and Proposed Operating Demand Curves



The IMM's economic ORDC reflects the marginal value of lost load based on an assumed VOLL of $12,000 and a probability of losing load that the IMM estimated using a Monte Carlo simulation[12]. This simulation incorporates the risk of generator forced outages along with other supply-side risks, such as intermittent resource forecast error and changes in net imports. The

12 The simulation will estimate the conditional probabilities across 10,000 iterations. This simulation will be updated once per year using historical data from the prior calendar year where applicable.

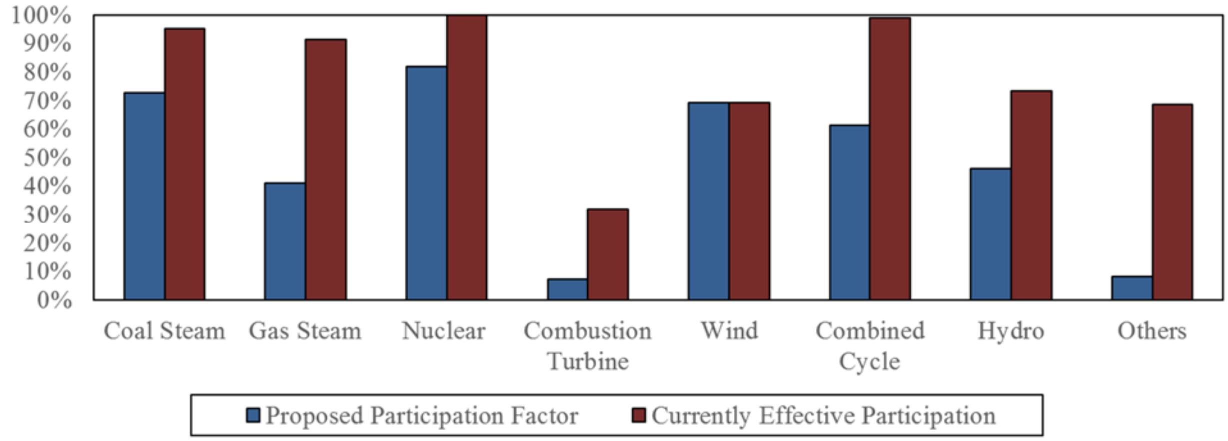
approach utilizes market participation factors and technology-specific forced outage risks to more accurately reflect the contribution to reliability provided by different types of conventional generating resources. The IMM's recommended simulation approach enables the evaluation of multiple, concurrent risks. These risks are consistent with the actual reliability issues and challenges faced by MISO Operations. The increasing impact of intermittent generation on the MISO market is also better reflected by this model. Our methodology accounts for the fact that these resources impact reliability more through their intermittent nature than forced outages of conventional resources. The report discusses the differences between these two curves and the benefits of the economic ORDC. Below we review some of the key inputs to the calculation of the current ORDC and the economic ORDC

Figure A54: Participation of Resources in Loss of Load Probability

The current ORDC includes all resources greater than 100 MW in the loss of load estimation. This equal treatment ignores the reality that some resources and technology types operate more often and have a greater contribution to system reliability. Our proposed Participation Factor (PF) for each generation technology type is similar to the NERC-defined Weighted Service Factor[13]. It equals the sum of the online capacity of that type divided by the sum of the installed capacity of that type across all hours of the historical period.

As shown in the figure below, these two methodologies result in modest differences. Since all nuclear resources are larger than 100 MW, the current methodology has a 100 percent participation factor. The IMM approach has a lower participation factor that reflects outages during the study period. The most significant differences impact combustion turbines, gas steam units and combined-cycle resources. These intermediate load technologies have higher shares of large resources than the share of capacity committed. Since an uncommitted, offline resource is not at risk of taking a forced outage, this is the appropriate means to measure participation.

Figure A54: Participation of Resources in Loss of Load Probability

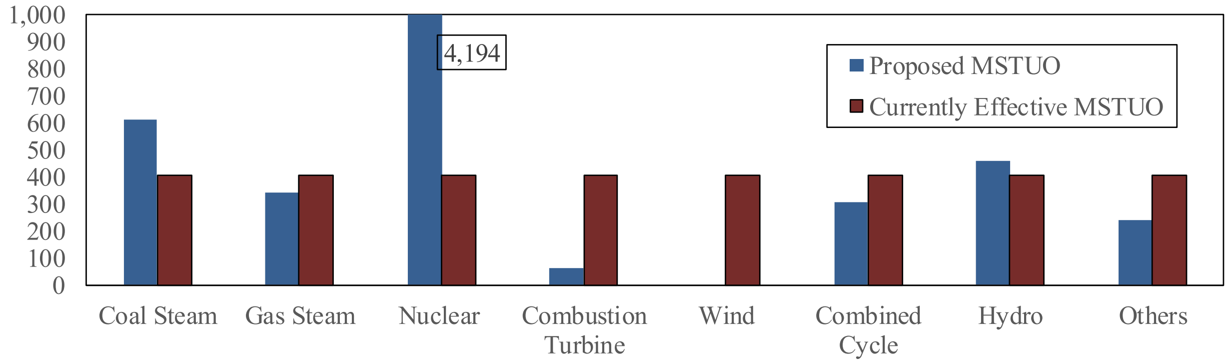


13 This metric is different from a traditional capacity factor, which measures energy output as a share of generation capability. The PF assumes resources are contributing their full capacity to satisfying energy, ancillary services, headroom, and ramp capability needs.

Figure A55: ORDC-Estimated Unit Failure Risk

NERC GADS failure rates, measured by the Mean Service Time to Unplanned Outage (MSTUO), vary significantly among technology types. This is a key input to the ORDC because it determines how likely it is that contingencies will occur that cause a loss of load. The technology-specific values, shown in blue, range from 30 hours per unplanned outage for combustion turbines to over 4,000 hours for nuclear units. Under MISO's current ORDC, all generators are assumed to have an equivalent rate of forced outage. As shown in the figure below as the maroon bar, this assumption is inconsistent with resources' actual failure rates.

Figure A55: ORDC – Estimated Unit Failure Risk



Based on these proposed parameters, we estimated the generator forced outages as follows. For each simulation iteration, each non-wind generator was assigned a random number between 0 and 1. If the assigned random number was less than $1\text{-}e^{(-PF * ORP / MSTUO)}$, the generator was simulated to be forced out of service. We assumed a two-hour outage recovery period (ORP), which is the number of hours MISO needs to fully respond to supply-side contingencies in the RAC process.

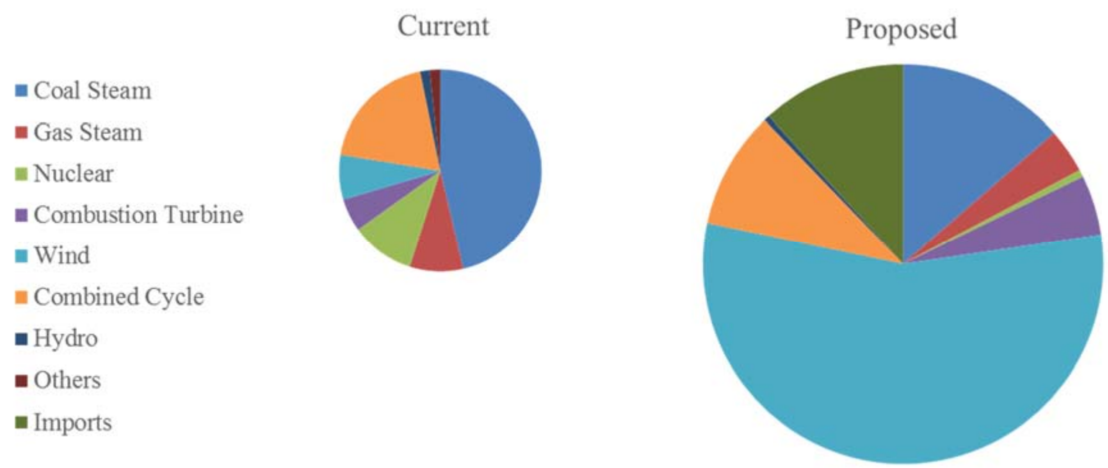
Intermittent resources and net imports were simulated as supply-side forecast risks using similar methodologies. First, a distribution of actual aggregate forecast errors was calculated from the historical period. The errors equaled the difference between actual capability in hour t and the forecasted capability schedule two hours prior to t. Next, a distinct random number between 0 and 1 was assigned to each supply group for each iteration. This number served as the distribution probability. The simulated forced outage equivalent was the maximum of 0 and the inverse of the normal cumulative distribution with mean and standard deviations calculated from the group forecast error distribution.

Figure A56: Distribution of Outage Risks by Technology Type

After calculating aggregate forced outage, intermittent resource forecast and NSI scheduling risks, these values were summed by iteration of the Monte Carlo simulation. Conditional probabilities at a given reserve level were calculated as the number of iterations with forced outages greater than or equal to that reserve level divided by the total number of iterations. These probabilities accurately reflected the risk to real-time operations of losing load at any reserve shortage level.

Figure A56 shows the average risk associated with each resource type according to the current and proposed methodologies. The relative size of the pie charts indicates that average level of risk estimated by each methodology; whereas, the slices of the pie indicate each resource type's contribution within the methodology.

Figure A56: Distribution of Outage Risks by Technology Type



These results show a four-fold increase in total outage risk under the IMM-proposed methodology, in part because our methodology accounts for the risk of multiple simultaneous outages. While the risk increased for most technologies, there are other notable differences. Wind resources accounted for more than 50 percent of the total outage risk in the proposed model. The volatility of wind coupled with significant forecasting error has created unique challenges. As wind and solar penetration increases over time, this formulation will better capture the loss of load risks. The greatest decline shown in the figure is the contribution of nuclear resources. These resources fail infrequently, so their risk to real-time reliability is greatly reduced under the proposed methodology.

G. 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.

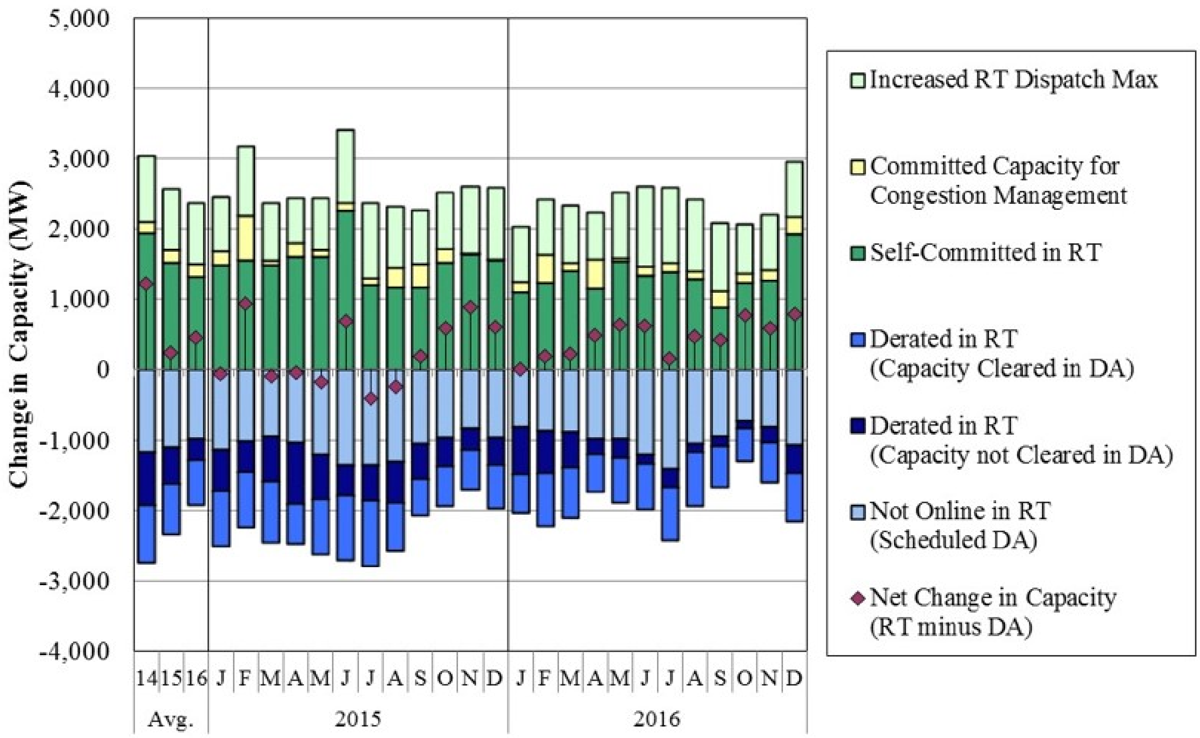
Figure A57: Changes in Supply from Day Ahead to Real Time

Figure A57 summarizes changes in supply availability from day-ahead to real time. Differences between day-ahead and real-time availability are to be expected and are generally attributable to real-time forced outages or derates and real-time commitments and de-commitments by MISO. In addition, suppliers who are 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 market may self-commit their generation resources in real time.

The figure shows six types of changes: generating capacity self-committed or de-committed in real time, capacity scheduled day-ahead that is not online in real time; capacity derated in real time (separated by resources cleared and not scheduled day-ahead) and increased available capacity (increases from day-ahead); 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 de-commit or shorten real-time MISO commitment periods. The amount actually committed for capacity in real time is not included in the figure.

Figure A57: Changes in Supply from Day Ahead to Real Time
2015–2016



H. Look Ahead Commitment Performance Evaluation

MISO's Look Ahead Commitment (LAC) model minimizes the total production cost of committing sufficient resources to meet the short-term load forecast. This is the primary tool that MISO uses to make economic commitments of peaking resources in real time. To evaluate the performance of the LAC (whether the commitments that LAC recommended were in fact economic), we compared the LAC recommendations to the Unit Dispatch System (UDS) results. We also assess the extent to which MISO operators follow the LAC recommendations.

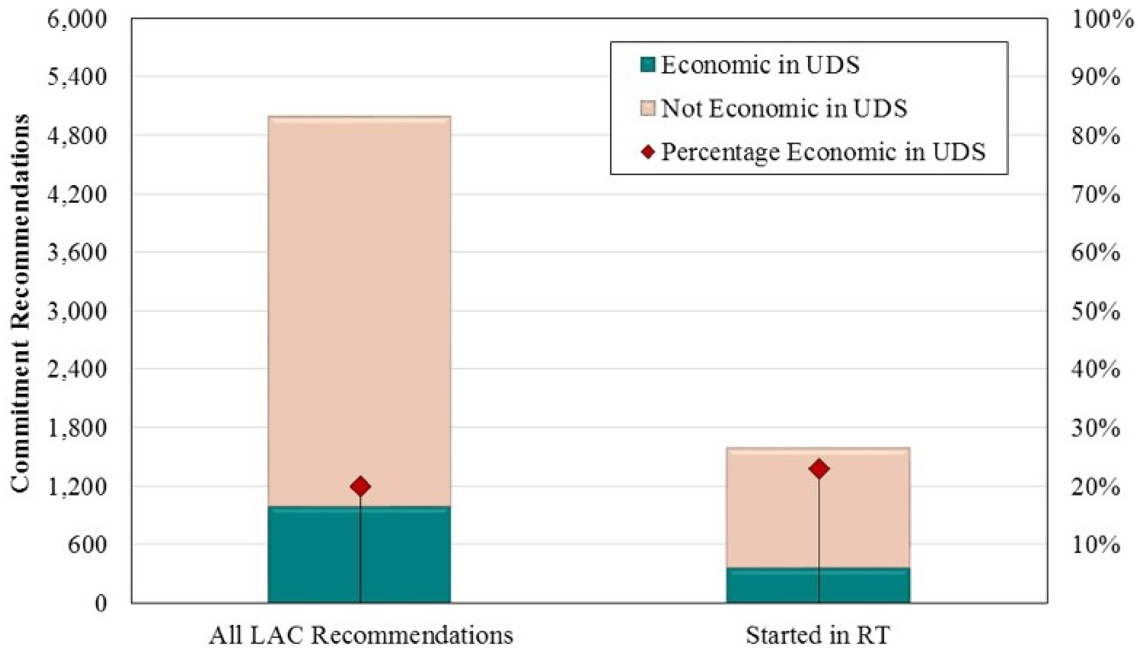
Figure A58: Economic Evaluation of LAC Commitments

For our analysis, we labeled resources that were online in a LAC solution that were not previously committed as "recommendations". We only consider recommendations that would have to be acted on before a new LAC case runs (based on the unit's startup time) because we expect operators to wait to commit resources when possible. We ignore repeated recommendations within the unit's minimum runtime to avoid excessively weighting repeated LAC recommendations that operators oppose.

We determined whether the recommendations would have been economic by comparing the estimated real-time revenues over the minimum runtime of the unit to the total production cost of the unit (including start cost, no load costs, and incremental energy costs). We determined that a unit was "started in real time" if it came online between the time LAC recommended it start and the end of the unit's minimum runtime.

Figure A58 below shows the results of our analysis. The left stacked bar includes all the distinct recommendations that LAC made throughout 2016, indicating the recommendations that were and were economic and not economic based on the real-time energy prices. The right stacked bar shows the portion of the recommended resources that were actually started, distinguishing between those that were and were not economic. The diamond in each bar indicates the share of those recommendations that were economic.

Figure A58: Economic Evaluation of LAC Commitments
2016



I. Generator Performance

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.[14] 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 produce far less than their economic output level by responding poorly to MISO's dispatch signals over many intervals (i.e., by "dragging" over an hour or more). Additionally, suppliers can effectively derate a unit by simply not moving over many consecutive intervals. We discuss these "inferred derates", later in this subsection.

For example, 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 Day-Ahead Margin Assurance Payments (DAMAP) and avoid RSG charges it would otherwise incur if it were to be derated. These criteria exempt the majority of deviation quantities from significant settlement penalties.

In this section, we calculate two types of deviations to evaluate generator performance:

- 5-minute deviation is the difference between MISO's dispatch instructions and the generators' responses in each interval.
- 60-minute deviation is the effect over 60 minutes of generators not following MISO's dispatch instructions.

We calculate the net 60-minute deviation by calculating the difference between where the energy the generators would have been producing had they followed MISO's dispatch instructions over the prior 60 minutes versus the energy they were actually producing.

Figure A59 and Figure A60: Frequency of Net 5-Minute Deviations

Figure A59 shows a histogram of MISO-wide net 5-minute deviations from 6 am to 10 pm, which includes MISO's high-ramp and peak hours in the summer and winter seasons. Figure A60 shows the same results for the ramp-up hours. These hours are particularly important because MISO's need for generators to follow their dispatch signals is largest in these hours. When the demands on the system are increasing rapidly, if resources do not respond, MISO will not be able to satisfy its energy and operating reserve requirements.

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.

14 The tolerance band can be no less than 6 MW and no greater than 30 MW (Tariff section 40.3.4.a.i.).

Figure A59: Frequency of Net Deviations
Ramp and Peak Hours, 2016

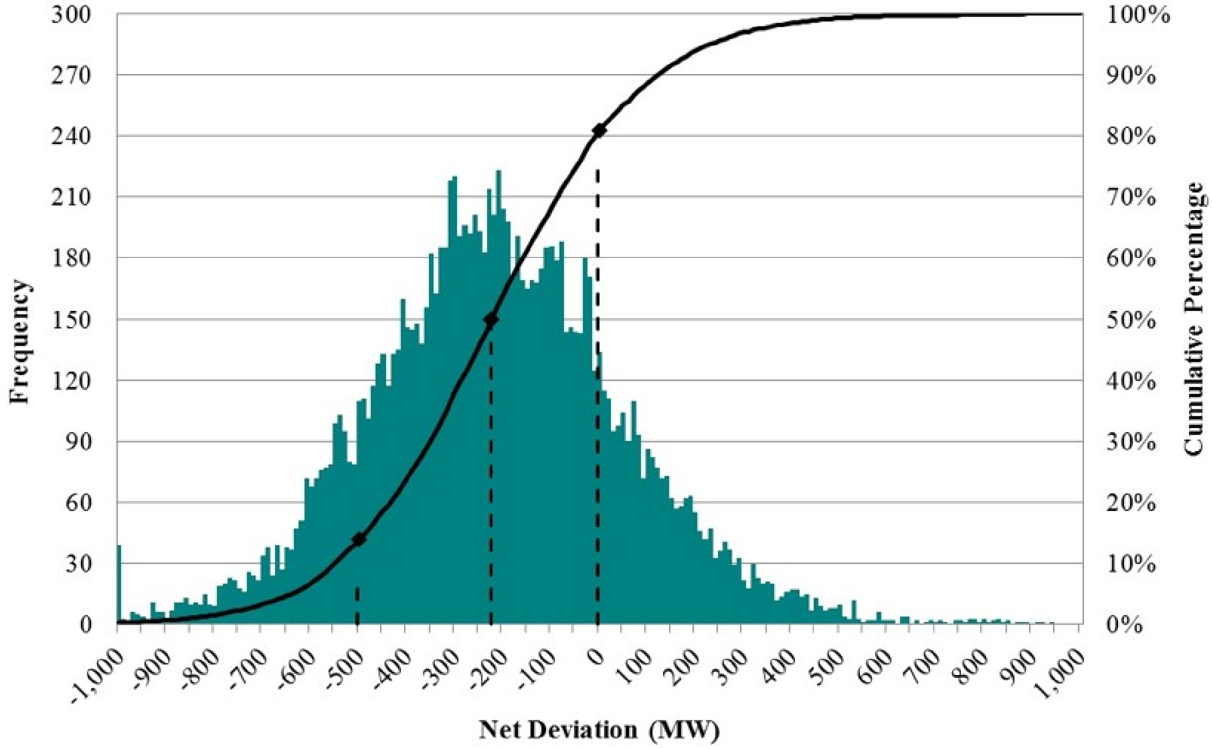


Figure A60: Frequency of Net Deviations
Ramp-Up Hours, 2016

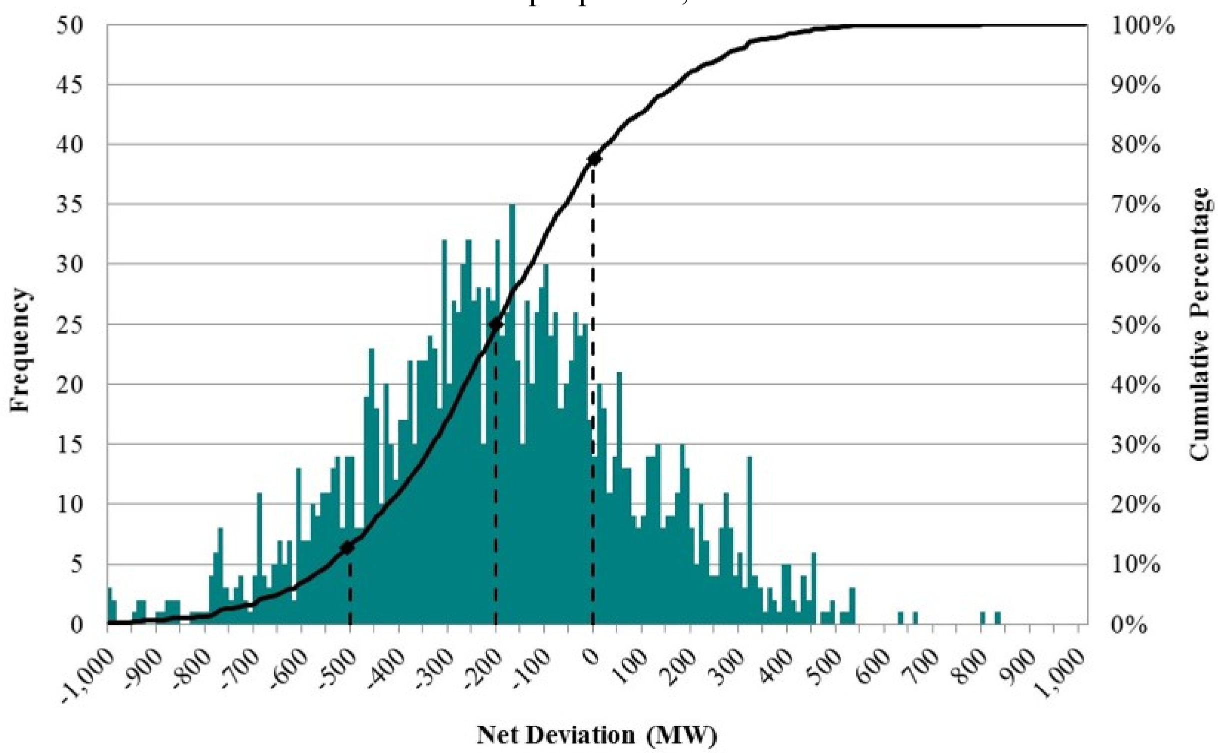


Figure A61: 5-Minute and 60-Minute Deviations by Season

Figure A61 shows the size and frequency of the 5-minute and 60-minute net deviations. The figure shows these results by season and type of hour, including the typically steep ramping hours of the day, adjusted for seasonality, when the impact of deviations was most severe on both pricing and reliability.

Figure A61: 5-Minute and 60-Minute Deviations by Season
2016

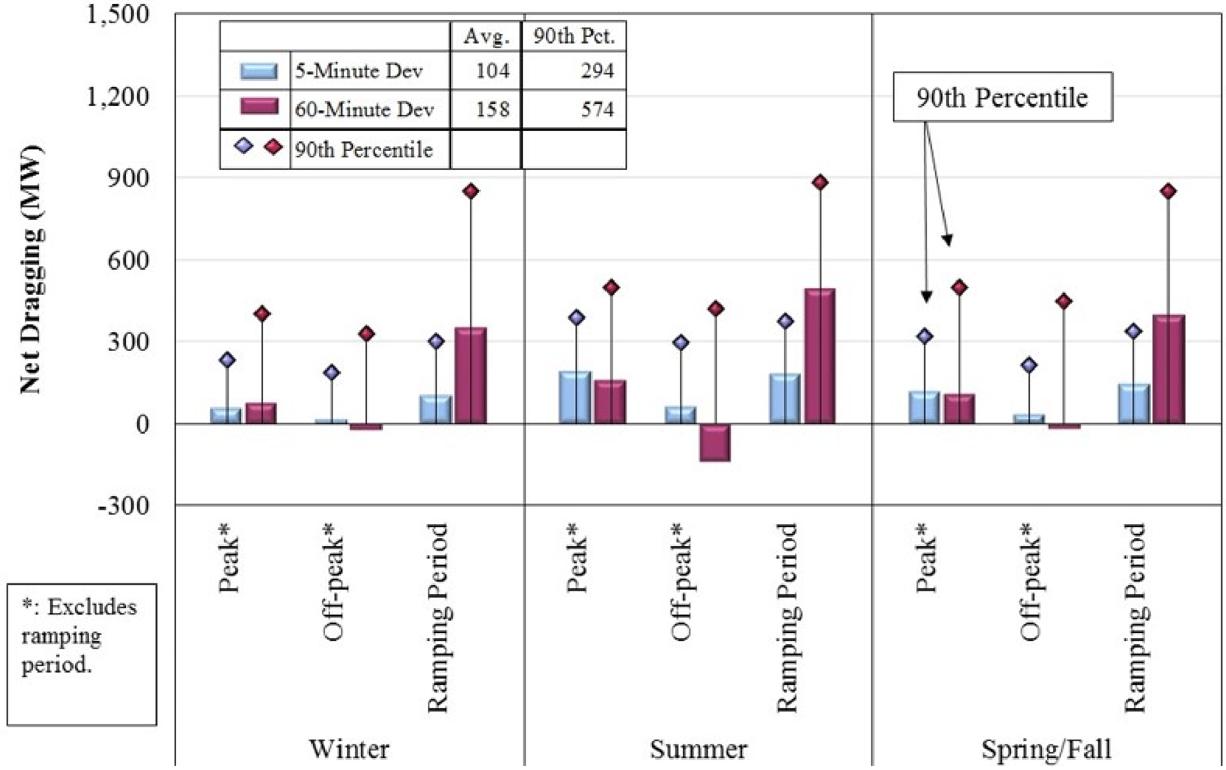


Figure A62: 60-Minute Deviations by Type of Conduct

To better understand the components of the 60-minute deviations, we have estimated how much of the deviations was potentially caused by inaccuracies in the State Estimator (SE) model versus various classes of poor generator performance. The SE model can cause deviations when it under-estimates a unit's output level. The real-time market uses the SE output to determine how much a generator can move up in the next interval. Therefore, if the SE output is lower than the unit's actual output, this scenario can limit the unit's instructions to ramp up and prevent it from achieving an economic output level.

The categories of poor generator performance shown in this figure include:

- Deviations that would not fail under the IMM's proposed threshold.
- Deviations that would qualify as an uninstructed deviation under the IMM's proposed threshold for "deficient energy" described later in this section; and

- Inferred Derates: Resources effectively derated, because the resource stops moving up at a level well below its economic dispatch level. In some cases, these are units that are violating the tariff by failing to report a derate condition. We have referred some of these suppliers to FERC enforcement;[15]

Figure A62 show the average of each of the quantities by hour of the day in 2016, as well as the amount of hourly dragging in total that prevailed in the worst 10 percent of the hours.

Figure A62: Hourly Dragging by Type of Conduct
2016

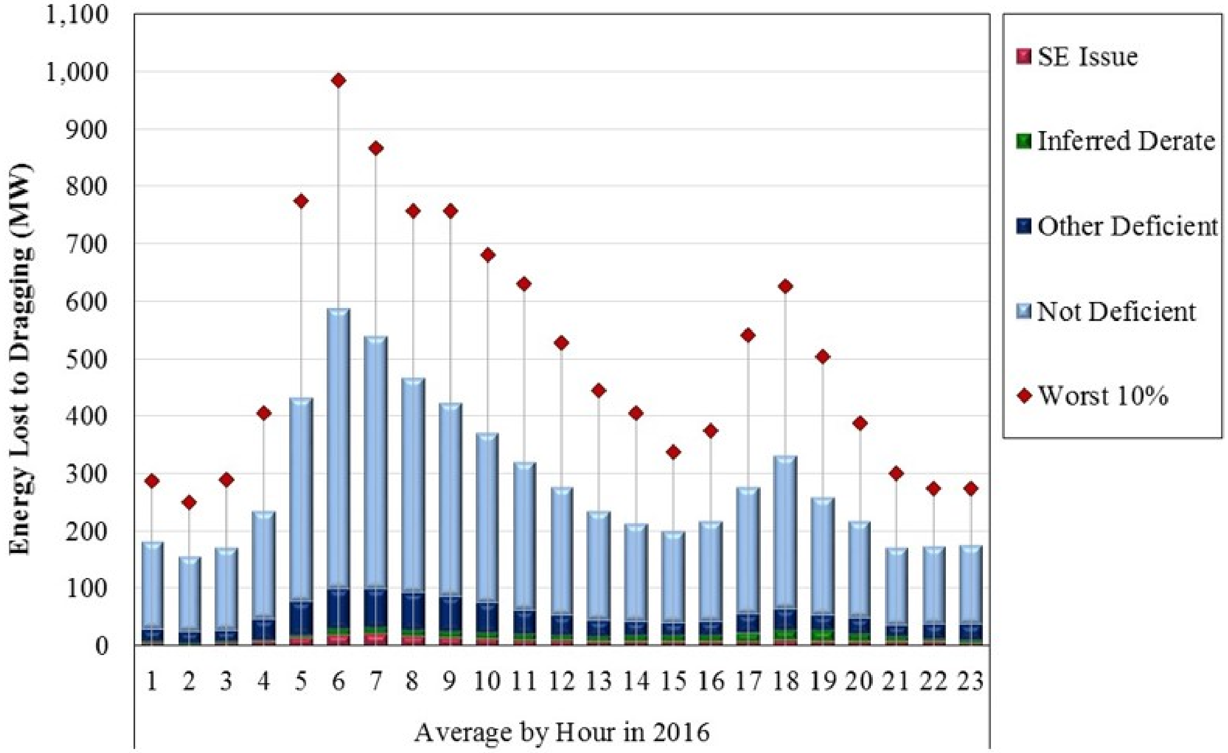


Figure A63: Proposed Change in Uninstructed Deviation Thresholds

We continue to recommend a specific approach to tighten the tolerance bands for uninstructed deviations (Deficient and Excessive Energy) that would be more effective at identifying units that are not following dispatch. This approach is based on units' ramp rates. The specific threshold calculation we propose equals one-half of the resource's five-minute ramp capability plus a value that corresponds to the basepoint change for the direction in which the unit is moving (i.e., basepoint change included for deficient energy when the unit is moving up and for excessive energy when the unit is moving down).

15 See EMT Section 39.2.5(c). As MISO notes in the relevant BPM: 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.

This specification provides increased tolerance only in the ramping direction, so units that are dragging slightly or responding with a lag will not violate the threshold. Additionally, since the current thresholds require that a unit fail in four consecutive intervals, the IMM proposed threshold would similarly require that a resource be unresponsive for four consecutive intervals before it would be considered to be deviating or not following dispatch. This approach has a number of advantages compared to the current output-based thresholds, to include:

- The threshold will be the same regardless of the output level (ability to follow dispatch does not change as the output level increases);
- It will more readily identify units that are not responding to dispatch signals (resources that do not move or move in opposition to the dispatch instruction will be identified);
- Making thresholds proportional to offered ramp rate will eliminate the current incentive to provide an understated ramp rate; and
- Output-based thresholds enable a resource to avoid being flagged for not following dispatch if it offers low ramp rates.

Figure A63 illustrates how these thresholds would be calculated and applied in three cases. Each of the cases assumes a unit that has been operating at 350 MW, has a two MW-per-minute ramp rate, and is receiving dispatch instructions to increase output at its ramp rate. In the first case, the unit is not moving. In the second and third cases, the unit is ramping up at 50 percent and 100 percent of the unit's ramp rate. The lighter areas are the existing thresholds, while the darker areas are our proposed thresholds. A unit is producing excessive or deficient energy when the diamond marker, indicating the unit's output level, falls outside a particular tolerance band for four consecutive intervals.

Figure A63: Proposed Generator Deviation Methodologies

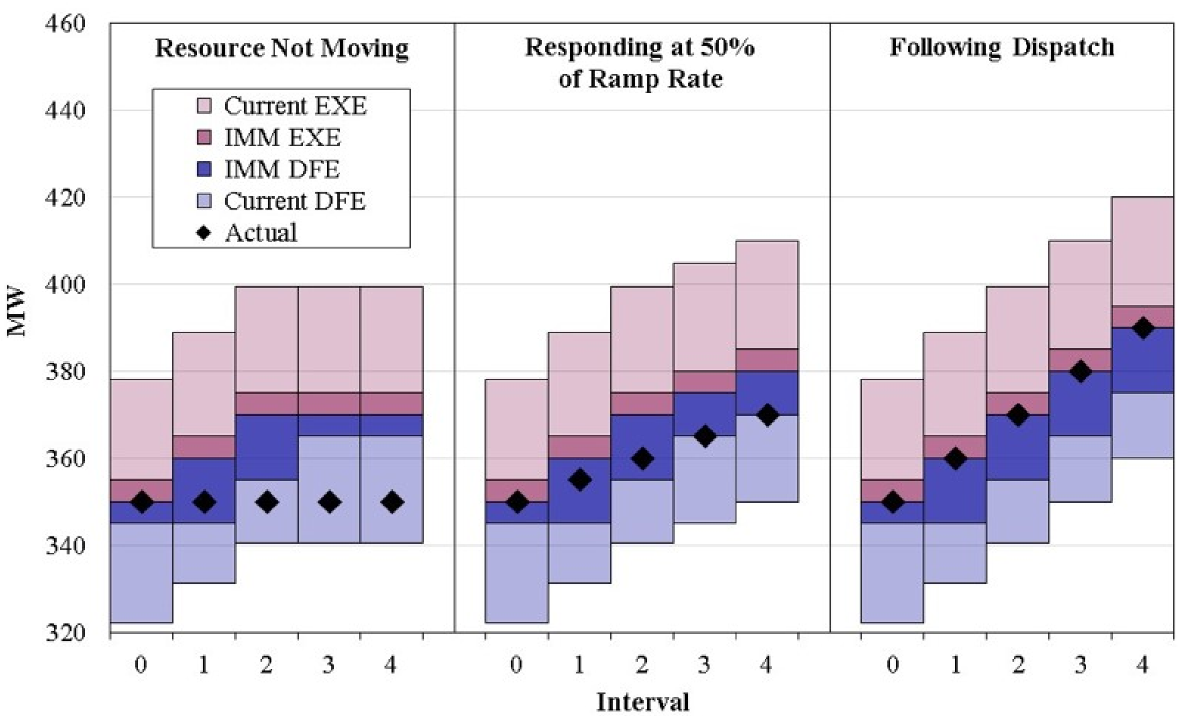
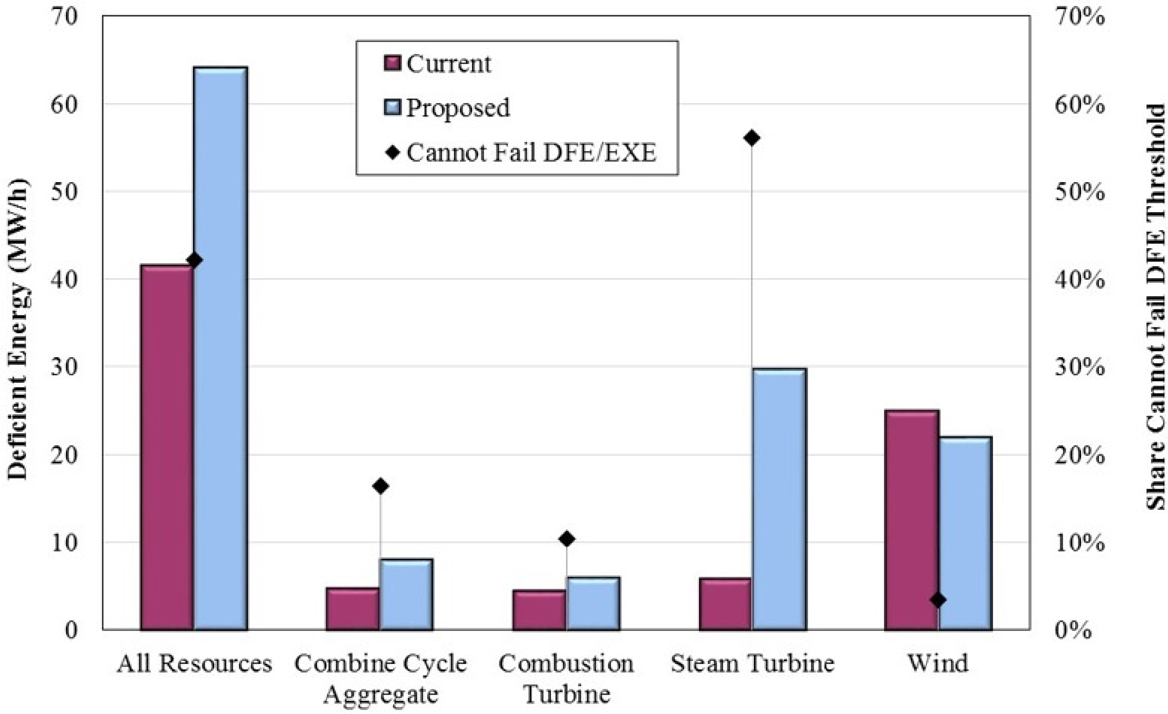


Figure A64: Impacts of IMM-Proposed Uninstructed Deviation Thresholds

Figure A64 illustrates the consequence of implementing the proposed tolerance bands to identify the deficient energy from different types of units. The maroon bars show the results of the current threshold, while the blue bars show the results under the IMM threshold. The proposed ramp-based threshold will more effectively identify units that are dragging for most types of units, which is why it results in higher levels of deficient energy. However, this threshold will reduce deviations identified from wind resources because they tend to have fast ramp rates. This means that most wind resources will be subject to a higher threshold under the IMM proposal. This figure also shows the share of each kind of technology that can ignore MISO's dispatch signal entirely without failing under MISO's current deviation threshold.

Figure A64: Impacts of IMM-Proposed Deviation Thresholds
2016



J. Revenue Sufficiency Guarantee Payments

RSG payments compensate generators committed by MISO when market revenues are insufficient to cover the generators' production costs.[16] Generally, MISO makes most out-of-merit commitments in real time to satisfy the reliability needs of the system and to account for changes occurring after the day-ahead. 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 (a) capacity needs that can arise during peak load or sharp ramping periods, (b) real-time load that was under-scheduled day-ahead, or (c) to secure a transmission constraint, a local reliability need, or to maintain the system's voltage in a location.

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

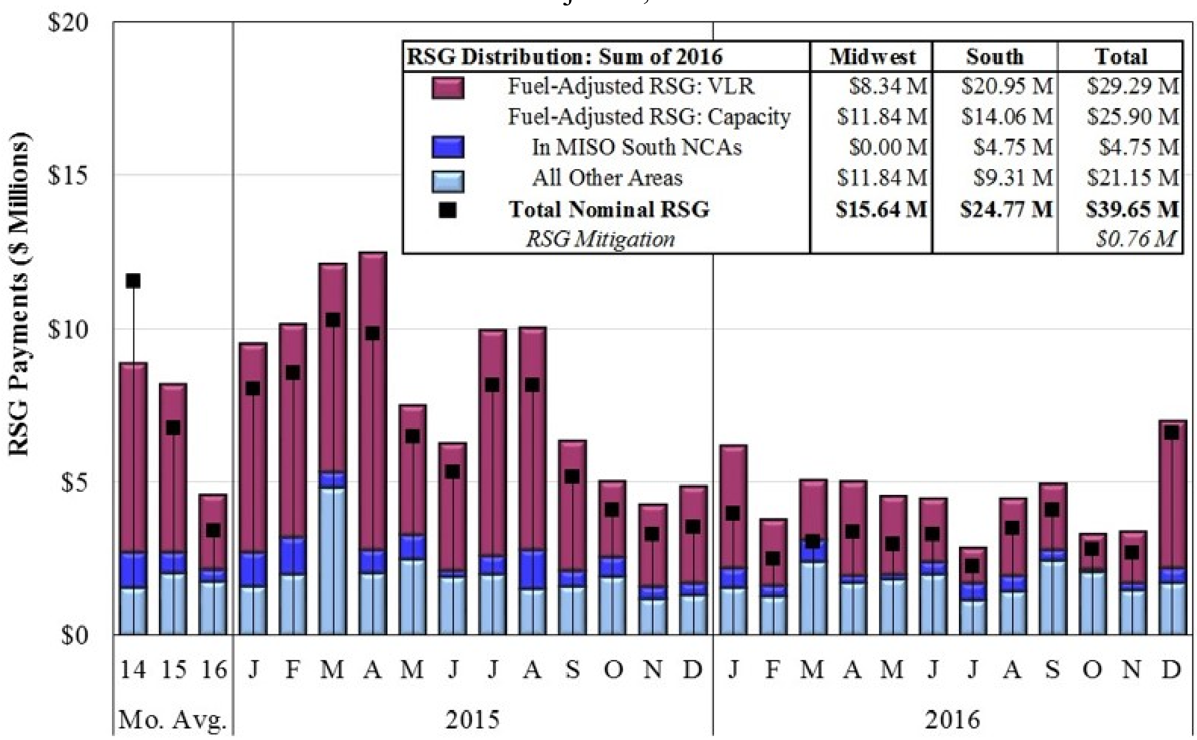
Beginning in the fall of 2012, MISO began making many voltage and local reliability (VLR) commitments, predominantly in the day-ahead market. VLR commitments increased after the South region integration in 2013 because of the implementation of new operating procedures in MISO South load pockets. In order to satisfy the requirements of these operating guides and constrained by the startup times of the required resources, MISO makes the associated reliability commitments in advance of or in the day-ahead markets. Consequently, day-ahead RSG payments are now larger than real-time payments in most months.

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, so 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 A65 and Figure A66: RSG Payment Distribution

Figure A65 shows total day-ahead RSG payments and distinguishes between payments made for VLR and for capacity needs. In addition, capacity payments made to units in MISO South NCAs are separately identified because these units are typically committed for VLR and are frequently subject to the tighter VLR mitigation criteria. The results are adjusted for changes in fuel prices, although nominal payments are indicated separately. Figure A66 shows total real-time RSG payments and distinguishes among payments made to resources committed for overall capacity needs, to manage congestion, or for voltage support.[17]

Figure A65: Total Day-Ahead RSG Payments
Fuel-Cost Adjusted, 2015–2016



RSG Distribution: Sum of 2016	Midwest	South	Total
Fuel-Adjusted RSG: VLR	$8.34 M	$20.95 M	$29.29 M
Fuel-Adjusted RSG: Capacity	$11.84 M	$14.06 M	$25.90 M
In MISO South NCAs	$0.00 M	$4.75 M	$4.75 M
All Other Areas	$11.84 M	$9.31 M	$21.15 M
Total Nominal RSG	**$15.64 M**	**$24.77 M**	**$39.65 M**
RSG Mitigation			*$0.76 M*

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

Figure A66: Total Real-Time RSG Payments
Fuel-Cost Adjusted, 2015–2016

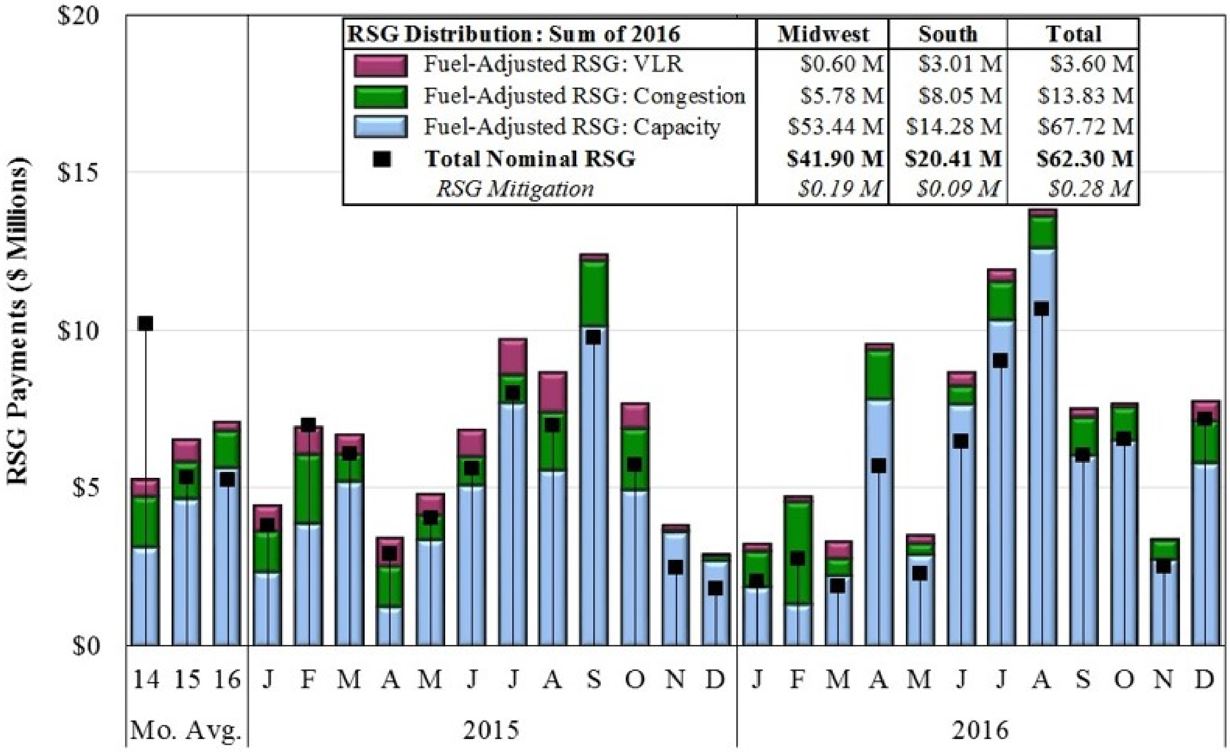


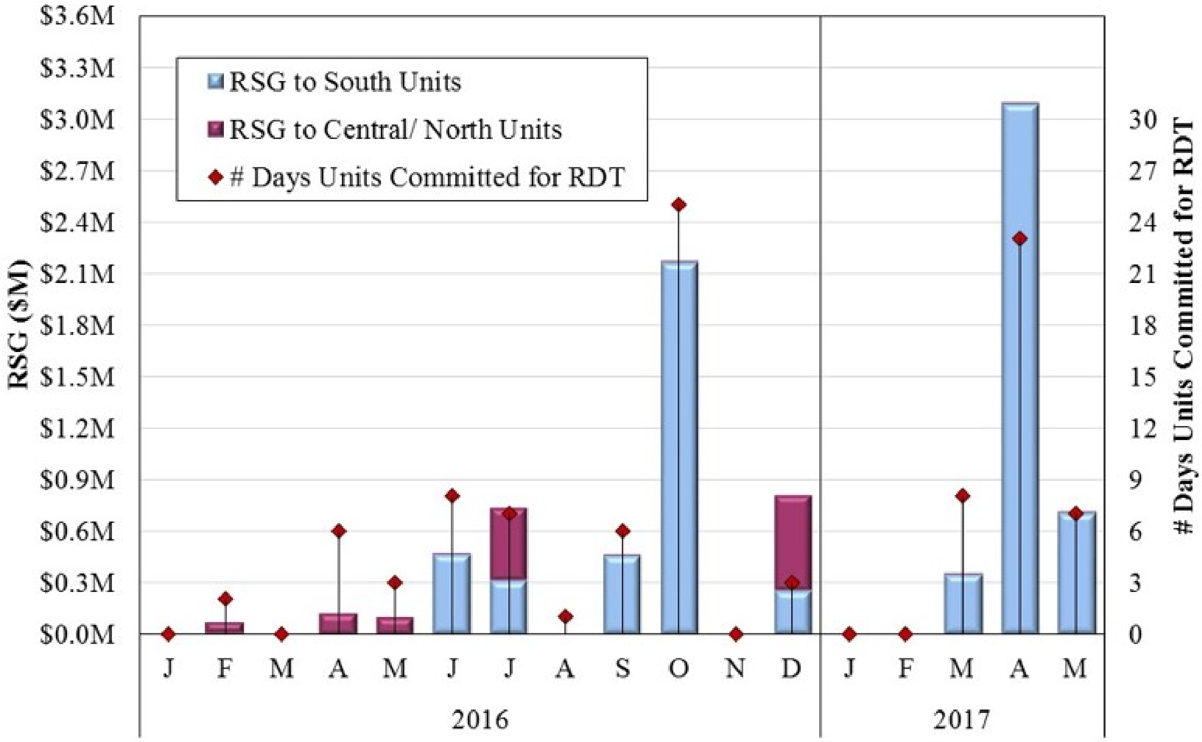
Figure A67: RSG for units committed for RDT

We have identified a substantial number of resource commitments and associated RSG paid in MISO Midwest or MISO South to satisfy regional capacity needs when the Regional Dispatch Transfer (RDT) constraint is binding or potentially binding. These commitments are not generally needed to manage the dispatch flows over the RDT, but they ensure that sufficient capacity is available in the importing region.

These commitments are made outside of the market because MISO's markets do not include regional capacity requirements. In more recent months, particularly during periods of high generator outages in MISO South, MISO has incurred significant RSG for these types of commitments, and the costs of the commitments are allocated across the entire MISO footprint under the DDC rate.

Figure A67 below shows the total RSG that MISO has incurred for these commitments since June 2016 and in which region (Midwest or South) the commitments were located. The maroon segment of the bars shows RSG payments to resources in the Midwest, and the blue bar segments indicate the resources that were committed in the South region.

Figure A67: RSG for units committed for RDT
2016



K. 30-Minute Reserve Product

Over the past three years, MISO paid $120.3 million in Revenue Sufficiency Guarantee (RSG) payments to resources in the two MISO South Voltage and Local Reliability (VLR) load pockets of Amite South and WOTAB. These out-of-merit resources were committed to satisfy reliability objectives that exceed standard N-1 reliability requirements. Essentially, these resources are needed to provide intermediate-term reserves because limited quick-start reserves are available to recover from a first contingency in a timely fashion in those regions.

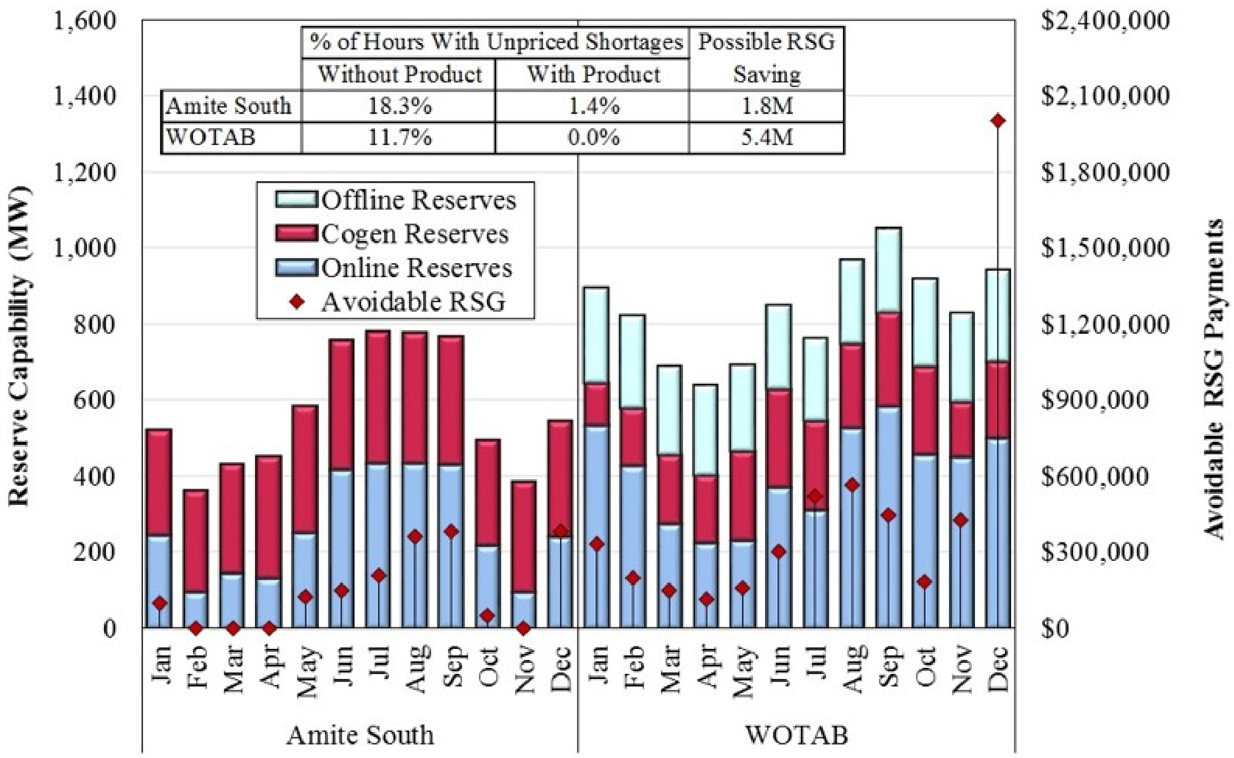
The adoption of an explicit 30-minute reserve product would address these VLR needs at lower costs than the current practice of committing resources to be online for VLR. It would also provide incentives to spur investment in fast-start peaking resources in the impacted areas by allowing real-time prices to reflect these reliability needs. In addition to receiving significant amounts of uplift, these commitments tend to suppress prices elsewhere in the footprint, cause inefficient congestion on the inter-regional transfer constraint, and increase the cost of managing local emissions restrictions.

Figure A68: 30-Minute Reserve Capability in South Load Pockets

Figure A68 below evaluates the 30-minute reserve capability that is currently available to respond to a system contingency and the associated RSG savings from using those reserves to meet reliability objectives. We identified three main types of potential 30-minute reserve providers: co-generation facilities (red bars), combustion turbines that can start within 30 minutes (light blue bars), and longer-start resources that must be online to participate (blue bars). The figure shows the available reserves by load pocket. The left axis indicates the available capability in MW, and the right axis indicates the potential RSG that could have been avoided by procuring this through a reserve product, rather than committing generation to meet the same requirement with un-dispatched ranges (i.e., headroom) on online resources. The RSG savings is the sum of the RSG paid to the units de-committed in our simulation.

While generally price takers, some co-generation facilities could potentially be incentivized to participate in a 30-minute reserve market. In exchange for infrequent deployment (requiring host load curtailment), these resources would receive a consistent stream of revenue in the form of 30-minute reserve availability payments and a reduction in VLR cost allocation. The combustion turbines that we included in our analysis were limited to a 30-minute startup time because the reserve product payments would presumably offset the cost of staffing the facilities and eliminate longer notification times. Online resource reserve capability excludes 30-minute capable units when they are online but deemed unnecessary. Although this additional capability would not eliminate the need for VLR commitments, it would significantly reduce the amount of VLR uplift.

Figure A68: 30-Minute Reserve Capability
South Load Pockets (2016)



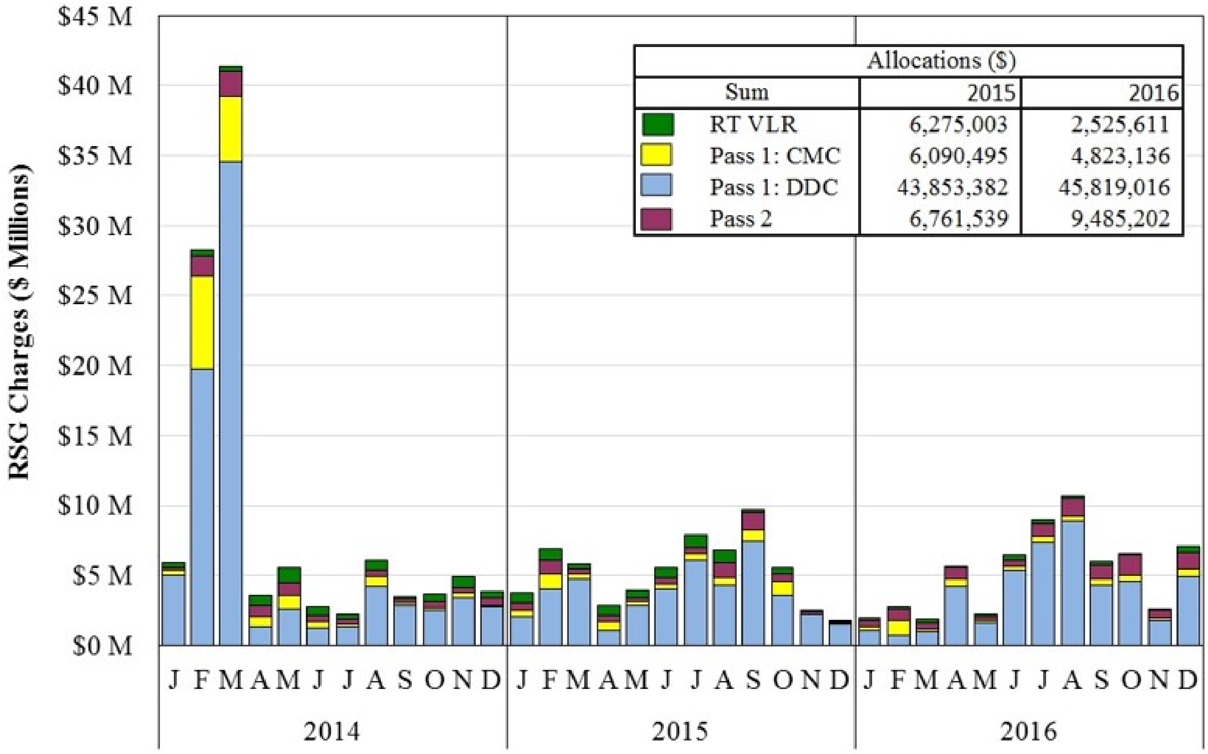
	% of Hours With Unpriced Shortages		Possible RSG
	Without Product	With Product	Saving
Amite South	18.3%	1.4%	1.8M
WOTAB	11.7%	0.0%	5.4M

Figure A69: Allocation of RSG Charges

The RSG process was substantively revised in April 2011 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, or deviations that increase flow on the identified constraint, are allocated a share of the RSG costs under the Constraint Management Charge (CMC) rate. Any residual RSG cost is then allocated market-wide on a load-ratio share basis ("Pass 2").[18]

Figure A69 summarizes how real-time RSG costs were allocated among the DDC, CMC, and Pass 2 charges in each month from 2014 to 2016. Until March 2014, the CMC allocations were inappropriately limited based on the GSF of the committed unit, which caused a significant portion of constraint-related RSG costs to be allocated under the DDC charge. This is more closely examined in the next figure.

Figure A69: Allocation of RSG Charges
By Month, 2014–2016



L. 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.

18 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.

The PVMWP consists of two separate payments: DAMAP and Real-Time Operating Revenue Sufficiency Guarantee Payment (RTORSGP). DAMAP is paid when a resource's day-ahead margin is reduced as a result of being 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 that are due to binding transmission constraints or ramp constraints. Conversely, the RTORSGP is made to a qualified resource that is unable to recover incremental energy costs when dispatched above its economic level in real time. Opportunity costs for potential revenues are not included in the payment.

Figure A70: Price Volatility Make-Whole Payments

Figure A70 shows monthly average PVMWPs for each of the past three years in the far left panel. The monthly PVMWPs over the past two years are shown in the two right panels. The figure separately shows two measures of price volatility based on (1) the System Marginal Price (SMP) and (2) the LMP at generator locations receiving PVMWP. It is expected that payments should correlate with price volatility, since volatility leads to greater obligations to flexible suppliers. LMP volatility is expected to be higher than SMP volatility because LMPs include the effect of transmission congestion.

Figure A70: Price Volatility Make-Whole Payments
2015–2016

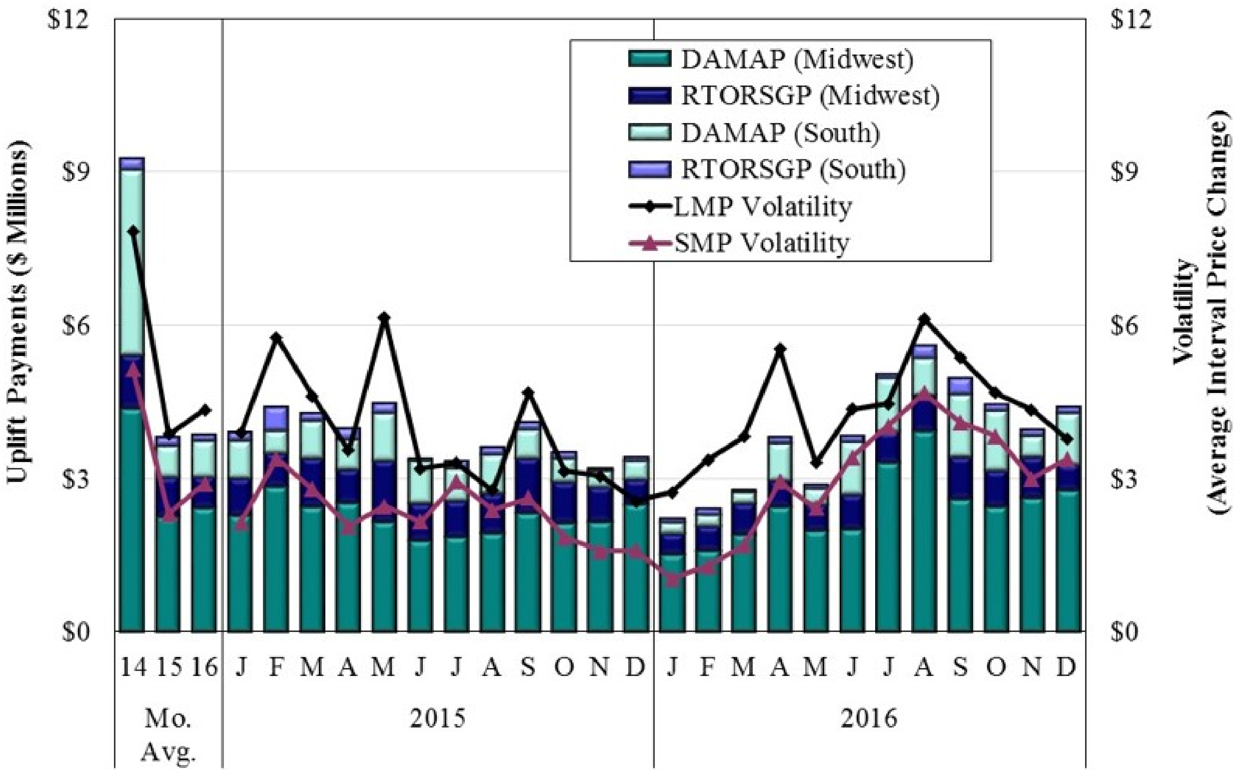


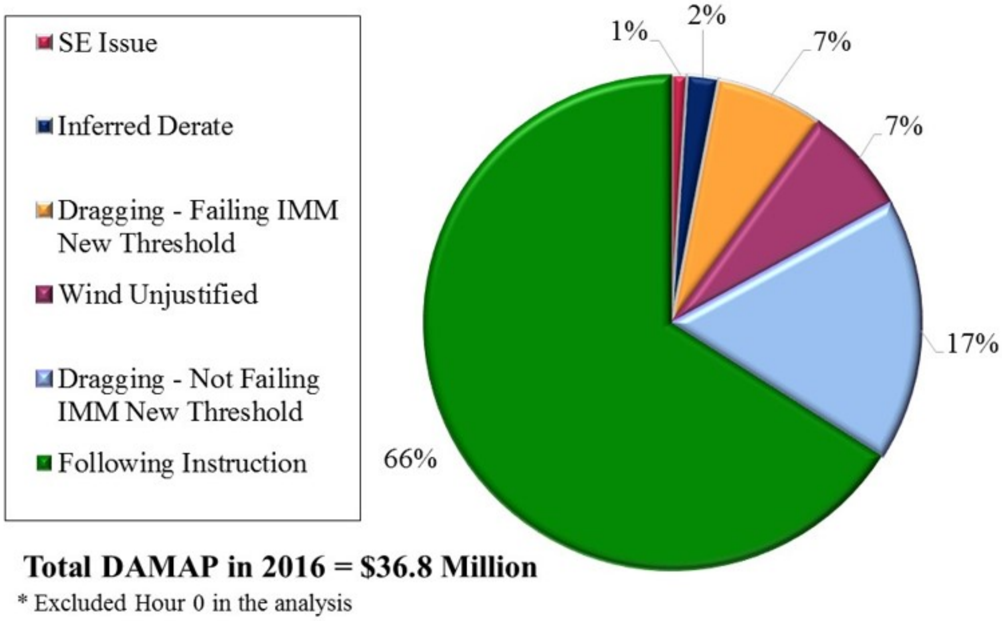
Figure A71: Causes of DAMAP

In addition to the reliability consequences of resources failing to follow MISO's dispatch signals, prolonged dragging can result in substantial DAMAP. DAMAP costs arise when generators are dispatched below their economic output level and it causes their margins earned in the day-ahead market to fall.

This payment was intended to provide incentives for generators to be flexible and to be held harmless if MISO directs them to dispatch down temporarily in response to volatile real-time prices. DAMAP was not intended to hold generators harmless when they produce less output than would be economic because they are performing poorly. Nonetheless, generators generally do not lose eligibility for DAMAP when they perform poorly, a situation we address in our recommendations.

Figure A71 shows the total DAMAP in 2016, the shares of DAMAP that are paid to units following MISO's dispatch signals, as well as those there are not performing well in following dispatch signals. These are categorized in the same manner as the prior figure.

Figure A71: Causes of DAMAP
2016



M. 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 generation on an hourly basis.[19] The five-minute real-time market produces prices that more accurately reflect system conditions and aids 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

19 In response to Order 764, MISO implemented 15-minute settlement for physical transactions in June 2015.

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 base point 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 is intended to induce generators to provide dispatch flexibility and to respond to five-minute dispatch signals. While the PVMWP removes 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 A72: 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 in 2016. 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 overvalued.

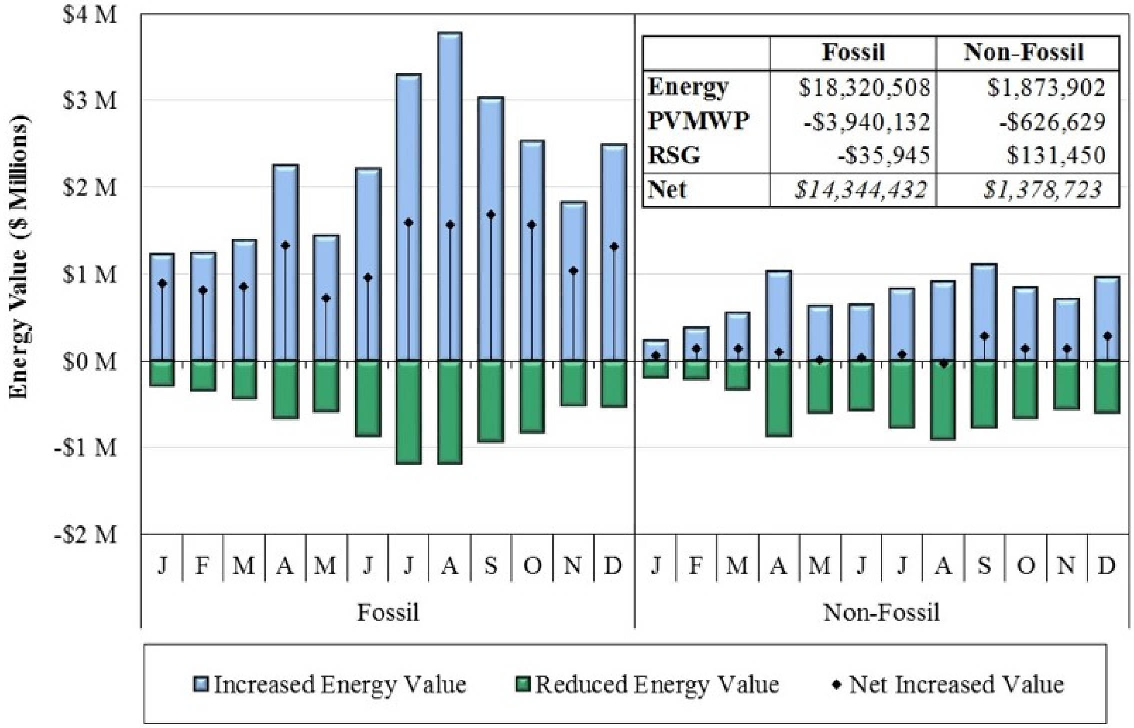
The figure shows the differences in energy value in the five-minute versus hourly settlement for fossil-fueled and non-fossil resources. Fossil-fueled resources tend to provide more flexibility and, therefore, tend to produce more in intervals with higher five-minute prices. Some non-fossil fuel types, 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 output; 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.

FERC issued a Notice of Proposed Rulemaking (NOPR) in RM15-24 calling for consistency between settlement intervals and dispatch intervals. MISO has agreed with our related recommendation to implement five-minute settlements and filed supporting comments in response to the Commission's NOPR. FERC issued Order 825 requiring five-minute settlements and MISO plans to complete its implementation in March 2018.[20]

[20] "Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators," FERC RM15-24-000, NOPR issued September 17, 2015.

Figure A72: Net Energy Value of Five-Minute Settlement
2016



	Fossil	Non-Fossil
Energy	$18,320,508	$1,873,902
PVMWP	-$3,940,132	-$626,629
RSG	-$35,945	$131,450
Net	*$14,344,432*	*$1,378,723*

N. 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.

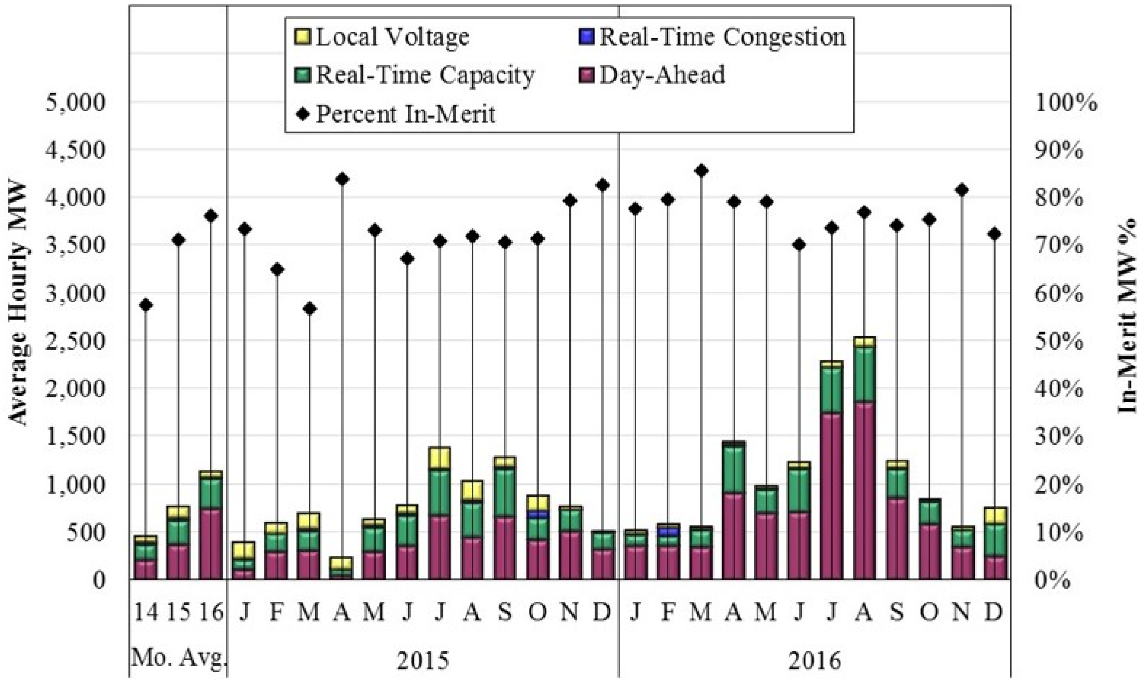
While low commitment costs make peaking resources attractive for meeting capacity needs, they generally have high incremental energy costs and frequently do not set the energy price because they are often dispatched at their economic minimum level (causing them to run "out-of-merit" order with an offer price higher than their LMP). When a peaking unit does not set the energy price or runs out-of-merit, it will be revenue-inadequate for covering its startup and minimum generation costs. This revenue inadequacy results in real-time RSG payments.

MISO's aggregate load peaks in the summer so 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 A73: Dispatch of Peaking Resources

Figure A73 shows average hourly dispatch levels of peaking units in 2016 and evaluates the consistency of peaking unit dispatch and market outcomes. The figure is disaggregated by the unit's commitment reason and separately indicates the share of the peaking resource output that is in-merit order (i.e., the LMP exceeds its offer price).

Figure A73: Dispatch of Peaking Resources
By Commitment Reason, 2015–2016



O. 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 proportion of total generation increases.

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 nearly zero output to a forecasted maximum) and can, therefore, set the real-time energy price. DIRs are treated comparably to other dispatchable generation. They are eligible for all uplift payments and are subject to all requisite operating requirements. Nearly 87 percent of MISO's wind capacity is currently capable of responding to dispatch instructions.

DIRs can submit offers in the day-ahead market. For both DIR and non-DIR, MISO utilizes short and long-term forecasts to make assumptions about wind output. With the expanded DIR capability, MISO now rarely needs to utilize manual curtailments to ensure reliability. Wind resoures are also qualified to sell capacity under Module E of the Tariff based on their contribution to satisfying MISO's planning requirements.[21]

Figure A74: Day-Ahead Scheduling Versus Real-Time Wind Generation

Figure A74 shows the hourly average wind scheduled in the day-ahead market and dispatched in the real-time market by month since 2015. 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.

Figure A74: Day-Ahead Scheduling Versus Real-Time Wind Generation
2015–2016

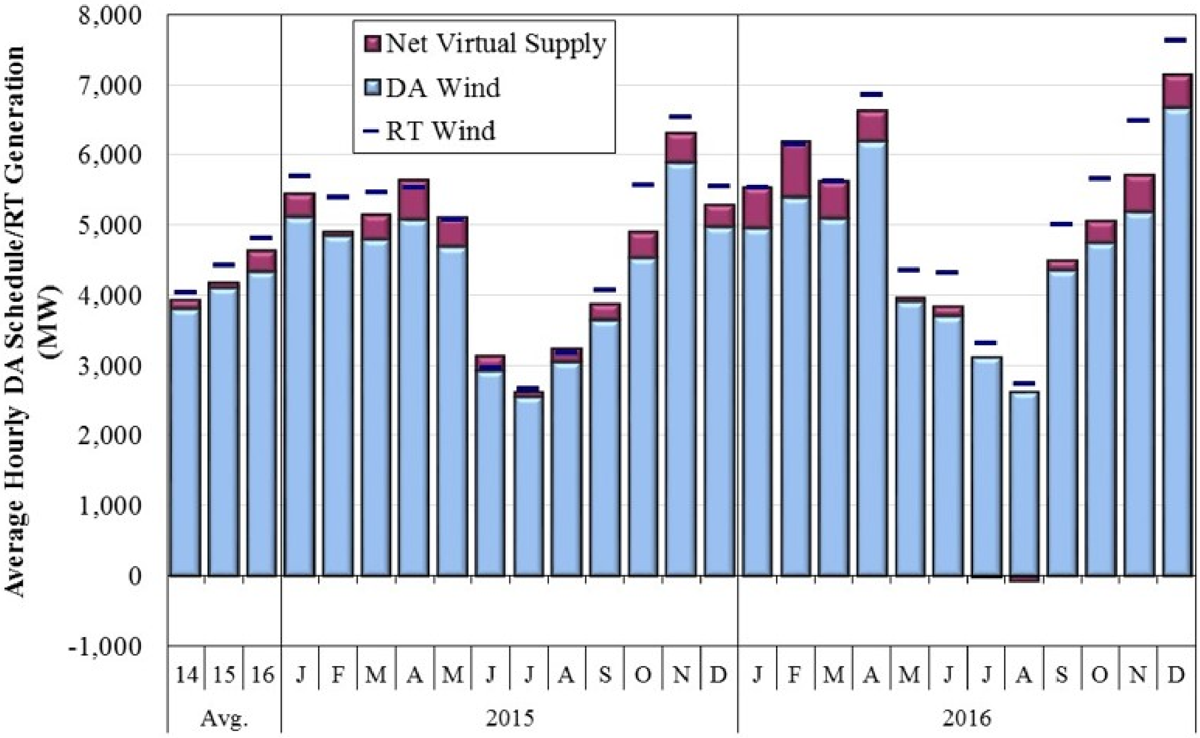


Figure A75: Generation Wind Over-Forecasting Levels

Over the past year, we have identified significant concerns with certain wind resources that frequently and substantially over-forecast their wind output. The wind forecasts are important because MISO uses them to establish wind resources' economic maximums in the real-time energy market. Because wind resources typically offer at lower prices than any other resources, their forecasted output also typically matches their MISO dispatch instructions, absent

21 Module E capacity credits for wind resources are determined 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. For the upcoming 2017-2017 Planning Year, the system-wide capacity credit for wind is 15.6 percent, unchanged from last year. Excluding resources that received no credit, individual credits range from 0.9 to 26.2 percent.

congestion. Since an over-forecasted resource will produce less than the dispatch instruction, this results in dispatch deviations. Figure A1shows the monthly average dispatch deviations from the wind resources in the bars, as well as the average forecast error plotted as a line against the right y-axis in 2015 and 2016.

Figure A75: Generation Wind Over-Forecasting Levels
2015-2016

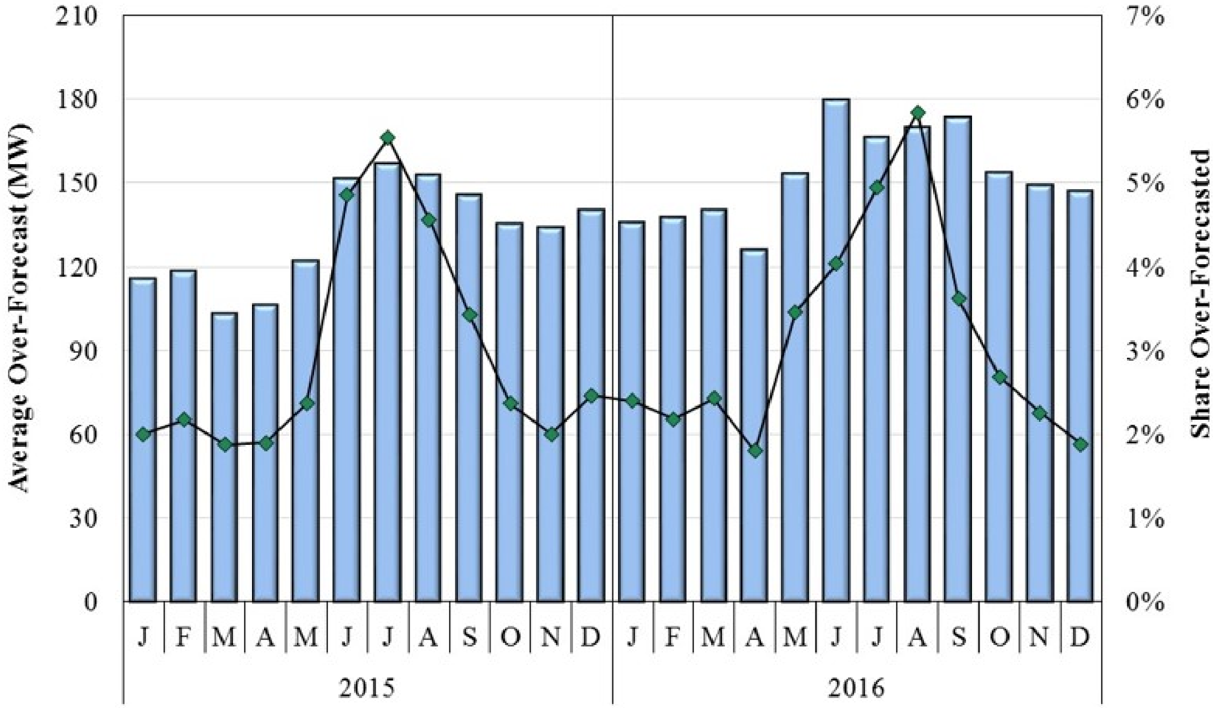


Figure A76: Wind DAMAP Compensation

We determined that one of the factors that led to the over-forecasting concerns is that MISO's current settlement rules provide strong incentives for DIR resources to over-forecast their output in real time. These incentives result from two main factors: DAMAP and uninstructed deviation settlements. The DAMAP compensation is evaluated below

Currently, a flaw in the MISO DAMAP settlements formula allows existing DIR wind resources to receive DAMAP when they are dispatched at their economic maximums, which is unintended. The intent of the tariff is to only make DAMAP payments when units are dispatched below their economic maximums. However, the tariff was written in a manner that did not recognize that the economic maximums can change every five minutes as they can for DIR wind units (it changes hourly for all other units) because it was written before the advent of DIR resources.

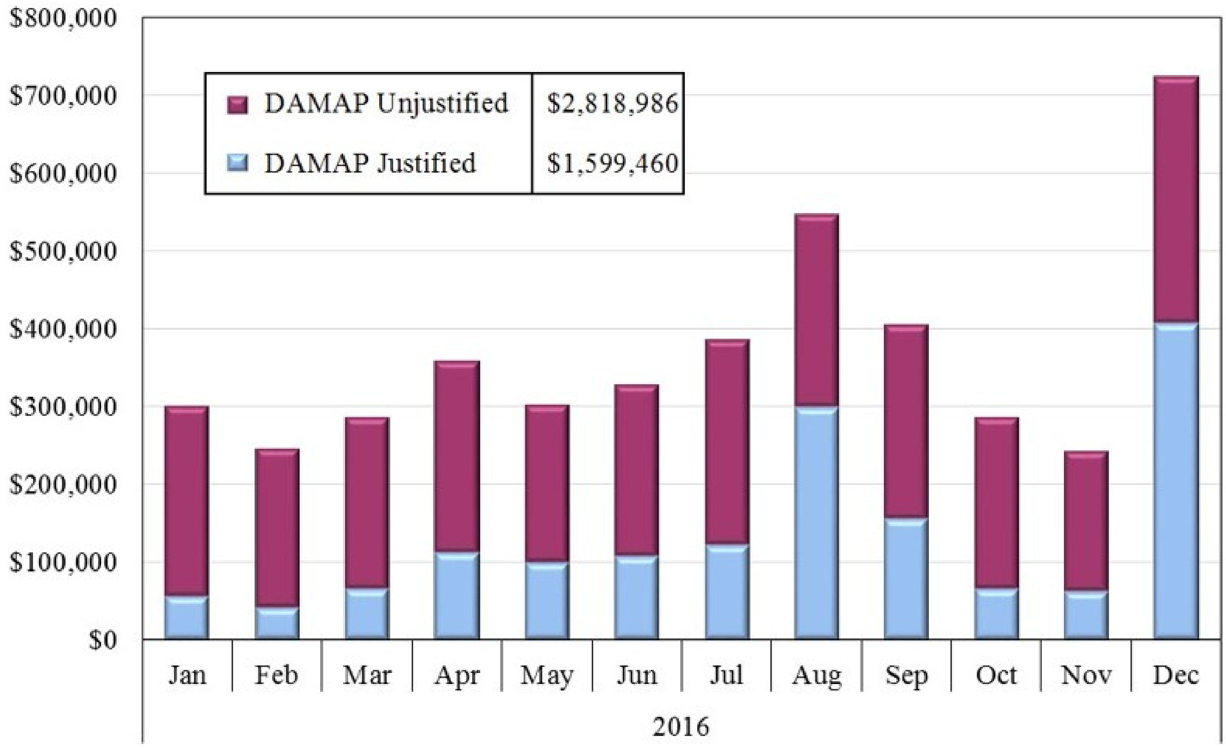
To show the extent to which wind resources received DAMAP as a result of the tariff flaw in 2016, we classified DAMAP paid to wind units as:

- Justified: Payments to resources that were economically curtailed and dispatched by MISO below their forecast maximum. As a result of integrated-hourly settlements and ELMP ex-post pricing, MISO re-dispatch can erode day-ahead margins.

- Unjustified: Payments that are the direct result of the tariff flaw. In these cases, the wind resources were dispatched at their economic maximum and could not have produced the output on which they recovered DAMAP payments.

Figure A76 shows DAMAP in these two categories by month during 2016. We estimate that $2.82 million (or 64 percent), of DAMAP to wind units was unjustified.

Figure A76: Wind DAMAP Compensation
2016



Some of the unjustified DAMAP is likely the unintentional result of wind suppliers seeking to avoid large excessive energy penalties described below. However, these DAMAP payments can substantially increase the total revenues of a wind resource so the tariff flaw described above may be motivating some of the suppliers to over-forecast their output in order to receive these unjustified payments.

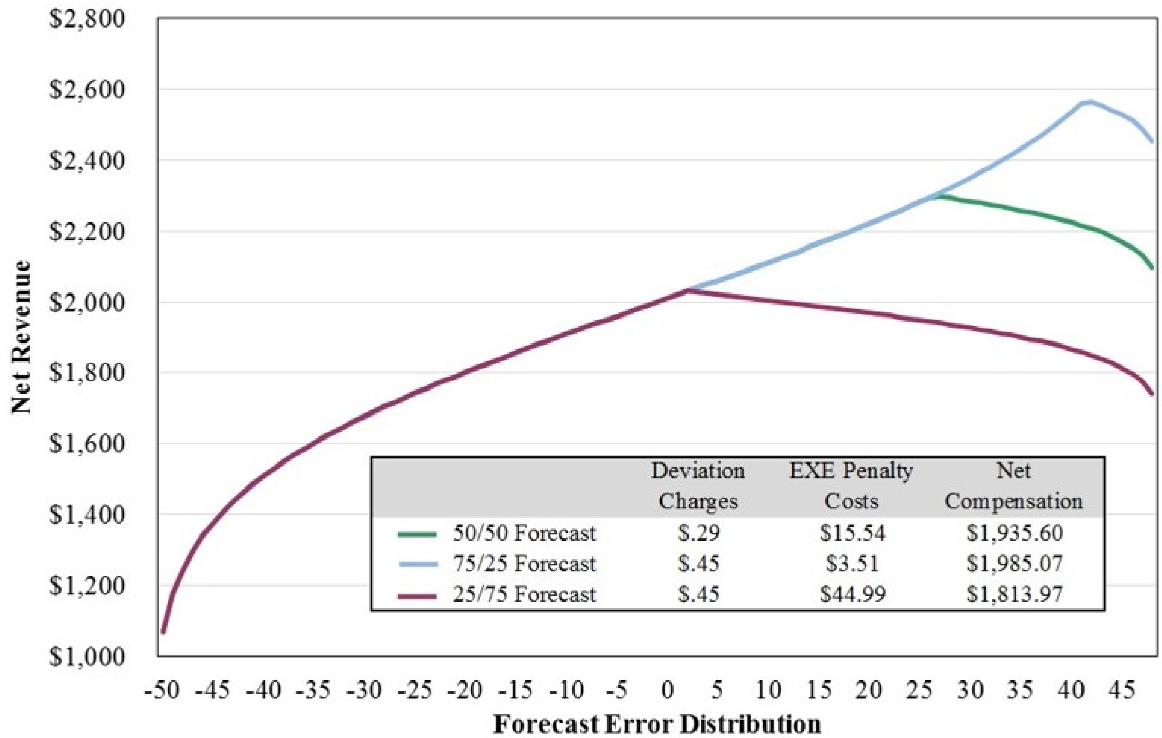
Figure A77: Expected Settlement Value of Forecast Alternatives

The second potential cause of the persistent over-forecasting by wind resources is that they face asymmetric costs for uninstructed deviations associated with forecast errors. One reason for this is that generators are paid the lower of their offer price or zero for excessive energy. Because of Production Tax Credits, wind resources generally submit substantially negative incremental energy offers, so the penalty for excessive energy is much larger than for other resource types (the penalty is the difference between the LMP and their offer price).

Conversely, wind units are only deficient when the resources' actual generating capabilities are less than their forecasts, a situation that does not cause them to forego any profit margin.[22] These factors combine to yield a relatively strong incentive to over-forecast wind resources' output. This is evaluated in the figure below, which shows the settlements for a wind resource under three wind forecast alternatives: a 25/75 low forecast (75 percent chance output will exceed the forecast), a 50/50 forecast (even likelihood high or low), and a 75/25 high forecast (75 percent chance output will fall short of forecast). These scenarios depict a theoretical resource with a known wind speed forecast and standard deviation of forecast errors.

The net revenues shown in the figure as lines include LMP payments less excessive energy penalties and deviation charges, primarily in the form of Day-Ahead Headroom and Deviation Charges, at the differing levels of forecast errors shown on the x-axis. An assumed price elasticity was included to reflect the expected reduction in LMP revenues from higher forecasts.

Figure A77: Expected Settlement Value of Forecast Alternatives
2016



These results are equivalent when the wind speed and output is lower than forecasted (i.e., negative forecast error). However, the net revenues differ substantially when the wind speed and output is higher than forecasted because, if they produce significantly more than their forecasted economic maximum, they are exposed to substantial excessive energy penalty costs. Hence, the most profitable forecast of the three is the 75/25 over-forecast scenario. In this scenario, the risk of excessive energy charges outweighs the cost of more deviation charges and lower LMPs. The market rules should incent unbiased forecasting.

22 In fact, wind resources will generally receive a DAMAP settlement that will provide this profit margin on the energy they are unable to produce.

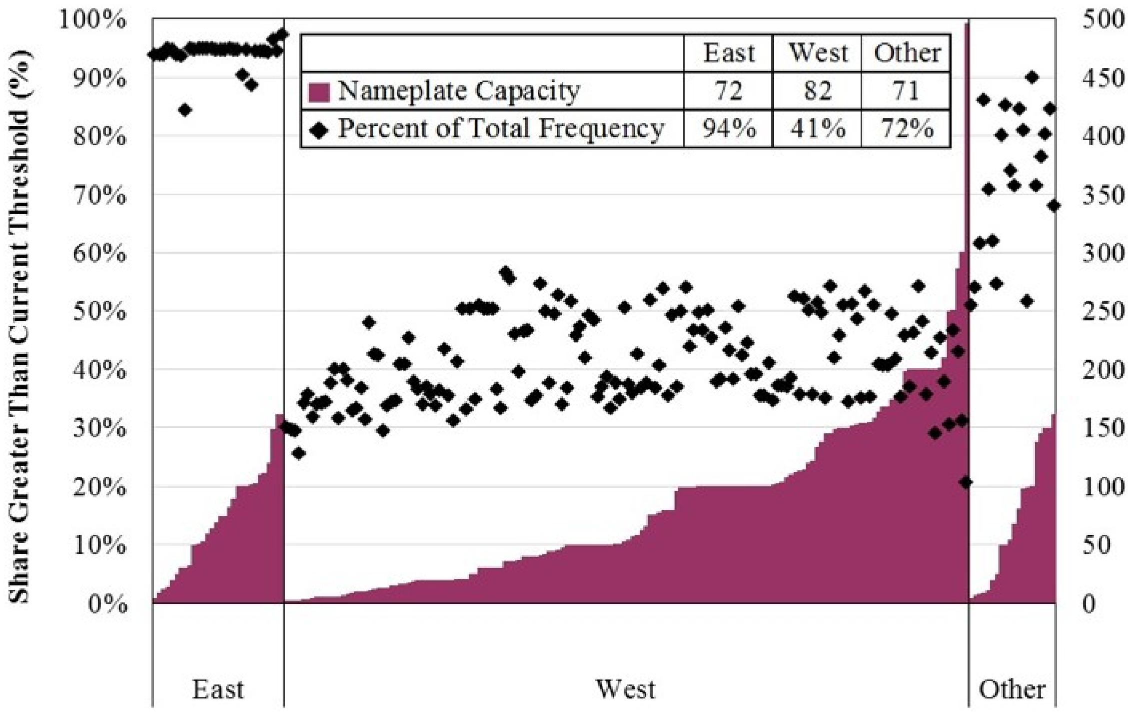
Figure A78: Hours when Proposed Wind EXE Threshold Exceeds Current Threshold

We have recommended that MISO should also consider other approaches to promote unbiased wind resource forecasts, including adopting Excessive Energy (EXE) thresholds for wind resources that recognize the potential for congestion to arise if wind resources over-produce.[23] In addition to receiving basepoint instructions from MISO, wind resources could receive not-too-exceed limits that would allow wind resources to exceed their dispatch instructions up to a reliable maximum level. This solution would maximize the economic value of these low-cost resources while mitigating reliability concerns associated with wind output volatility.

We conducted an analysis to determine how frequently wind generation thresholds would exceed the current thresholds under this type of approach. We define the proposed EXE threshold equal to the headroom on constraints affected by the wind resources – the difference in the defined flow limit and the actual flow on the constraint – divided by the aggregate GSF of all wind units loading that constraint. This approach allows the threshold to vary with the headroom on the constraint, tightening the threshold in congested periods and relaxing the threshold in uncongested periods.

In Figure A78, we compared the proposed threshold to the existing EXE threshold (the greater of six MW or eight percent of the unit's output) to determine when the proposed threshold was greater or equal than the current threshold. When the proposed threshold is higher, wind units could increase their output without incurring penalties or having a negative impact on reliability. Figure A78 shows wind unit size in the bars and how frequently the proposed threshold is greater or equal to the current threshold in the diamonds by resource and region.

Figure A78: Hours in 2016 when Proposed EXE Threshold Exceeds Current Threshold



23 ISO New England employs a similar approach.

The results vary considerably by region. Resources in the Other and East legacy regions would benefit the most from transmission-dependent EXE thresholds. In these regions, the proposed threshold is greater or equal to the current threshold 72 and 94 percent of the time, respectively. Units in the West legacy region benefit less, with expanded thresholds occurring approximately 41 percent of the time on average because of the higher wind output and more persistent congestion in this region.

Figure A79: Seasonal Wind Generation Capacity Factors by Load Hour Percentile

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

Figure A79 shows average hourly wind capacity factors by load-hour percentile, shown separately by season and for two MISO Coordination regions (North and Central). This breakdown shows how capacity factors 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 A79: Seasonal Wind Generation Capacity Factors by Load-Hour Percentile
2016

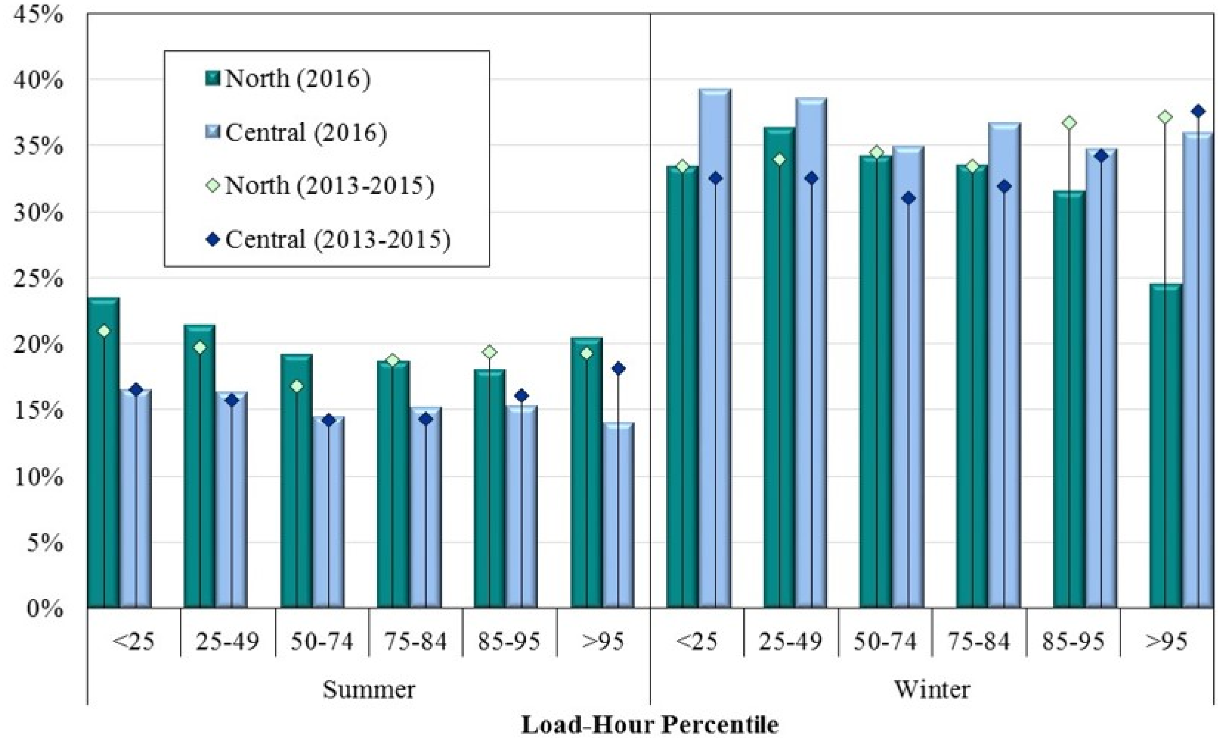
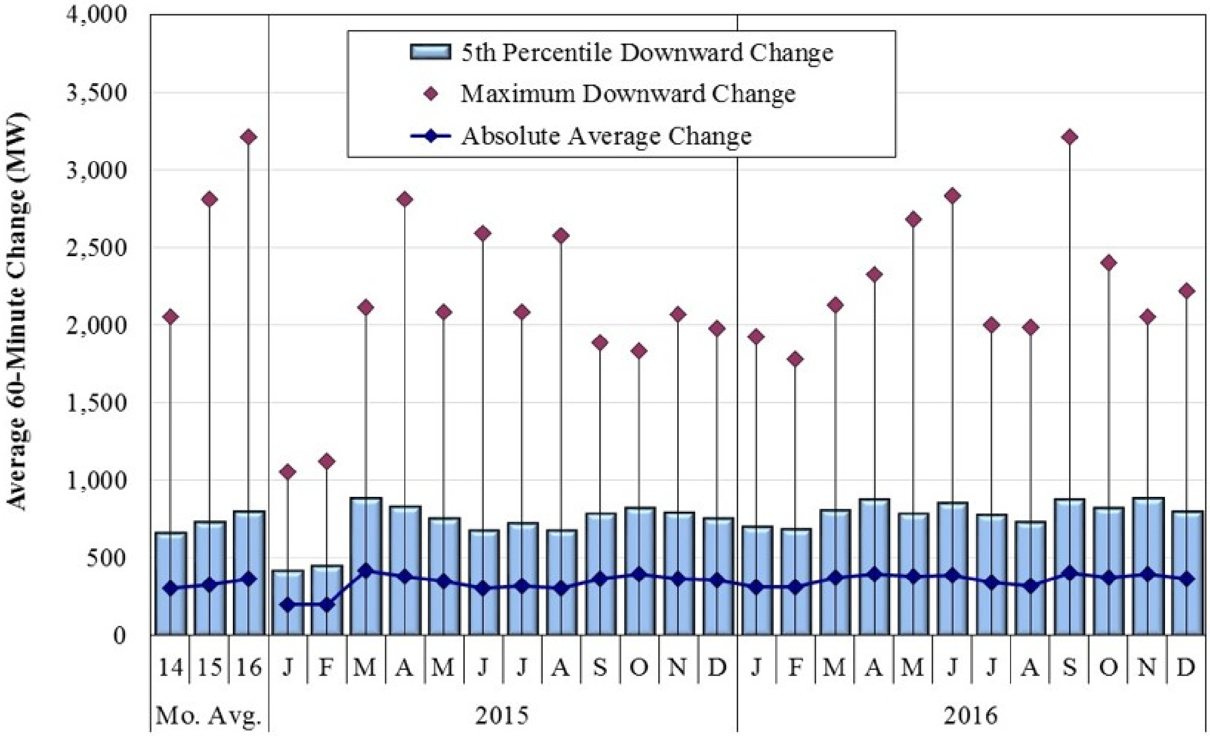


Figure A80: Wind Generation Volatility

Wind output can be highly variable and must be managed through curtailment, the re-dispatch of other resources, or commitment of peaking resources. Figure A80 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 purple bars; and
- The maximum hourly decrease in each month in the drop lines.
- Changes in wind output that are due to MISO economic curtailments are excluded from this analysis.

Figure A80: Wind Generation Volatility
2015–2016



VI. TRANSMISSION CONGESTION AND FTR MARKETS

Congestion management is among MISO's most important roles. MISO monitors thousands of potential network constraints throughout its system. MISO manages flows over its network to avoid overloading these transmission constraints by altering the dispatch of its resources. This establishes efficient, location-specific prices that represent the marginal costs of serving load at each location.

Transmission congestion arises when the lowest-cost resources cannot be fully dispatched because of limited transmission capability. The result is that higher-cost units must be dispatched in place of lower-cost units to avoid overloading transmission facilities. In LMP markets, this generation re-dispatch, or "out-of-merit," cost is reflected in the congestion component of the locational prices. The congestion component of the LMPs can vary substantially across the system, causing higher LMPs in "congested" areas.

These congestion-related price signals are valuable not only because they induce generation resources to produce at levels that efficiently manage network congestion, but also because they provide longer-term economic signals that facilitate efficient investment and maintenance of generation and transmission facilities.

A. Real-Time Value of Congestion

This section reviews the value of real-time congestion, rather than congestion revenues collected by MISO. The value of congestion is defined as the marginal value, or shadow price, of the constraint times the power flow over the constraint. If a 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. There are two primary reasons why MISO does not collect the full value of the congestion on its system.

First, the congestion value is based on the total flow over the constraint, and MISO settles with only part of the flows on its constraints. Generators and loads outside of MISO contribute to flows over MISO's system (known as "loop flows") that do not pay MISO for their congestion value. Additionally, neighboring PJM and SPP have entitlements to flow power over MISO's system.

Second, most flows are settled through the day-ahead market. Once a participant has paid for flows over a constraint in the day-ahead market, it does not have to pay again in the real-time market that only settles on deviations from the day-ahead market. Therefore, when congestion is not foreseen and therefore not fully anticipated in day-ahead prices, MISO will collect less congestion revenue than the real-time value of congestion on its system.

Figure A81: Value of Real-Time Congestion by Coordination Region

Figure A81 shows the total monthly value of real-time congestion by MISO's Reliability Coordination regions in 2015 and 2016. The bars on the left panel of the chart show the average monthly value against the left axis in each of the past three years.

Figure A81: Value of Real-Time Congestion by Coordination Region
2015–2016

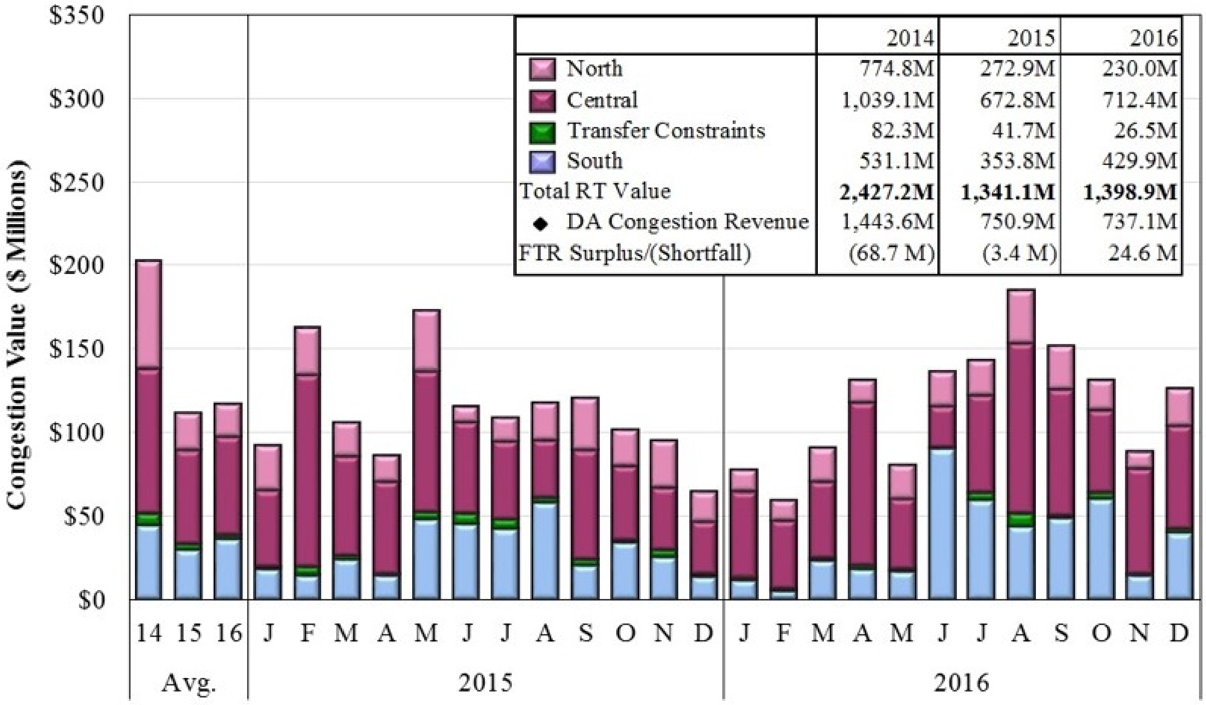


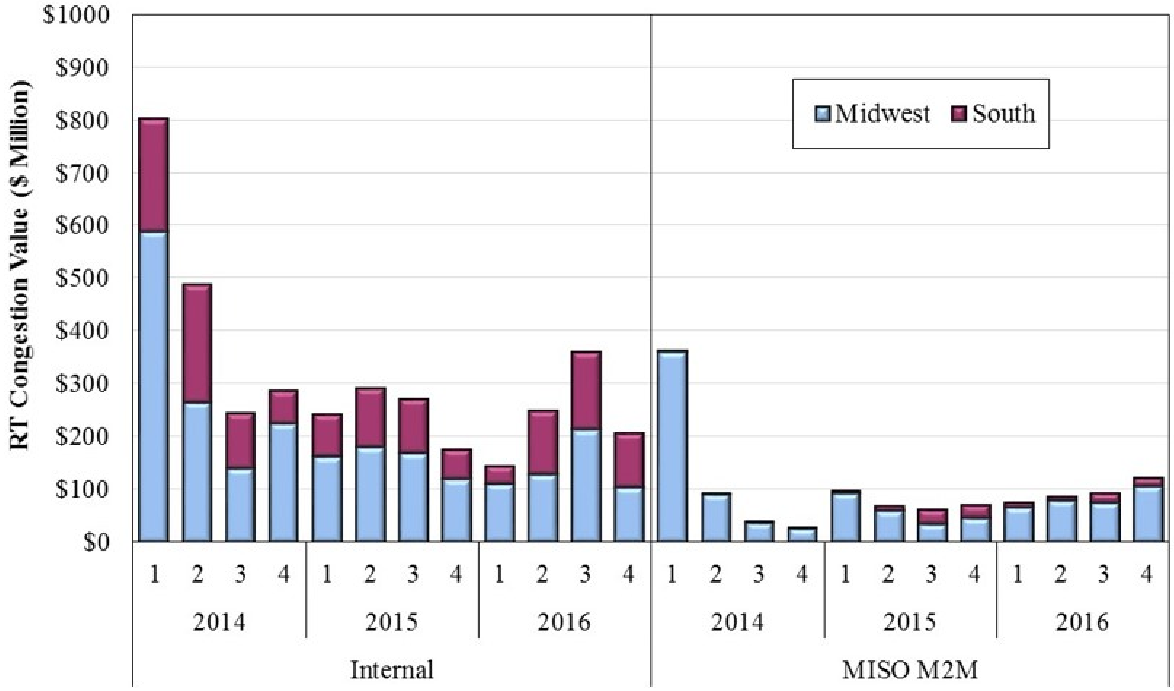
Figure A82: Value of Real-Time Congestion by Type of Constraint

To better identify the drivers of the real-time congestion value, Figure A82 disaggregates the results by the type of constraint and by the MISO subregion. We define four constraint types:

- Internal Constraints: Those constraints internal to MISO where MISO is the Reliability Coordinator that are not coordinated with PJM or SPP.
- MISO market-to-market (M2M) Constraints: M2M constraints that are coordinated by MISO. Many of these are substantially impacted by generation in the Commonwealth Edison (ComEd) area of PJM, and beginning in March 2015, these include constraints coordinated with SPP.
- PJM and SPP M2M Constraints: M2M constraints coordinated with MISO and monitored by either PJM or SPP.
- External Constraints: Constraints located on other systems that MISO must help relieve by re-dispatching generation. These include PJM and SPP constraints that are not M2M constraints and those coordinated by other Transmission Operators such as TVA and Southern Company.

The flow on PJM and SPP M2M constraints and on external constraints represented in the MISO dispatch is limited to the MISO market flow. The internal and MISO M2M constraints represented in the MISO dispatch include the total flow. The estimated value of congestion on external constraints (but not their impact on LMP congestion components) understates the effects that the external constraints have on MISO dispatch pricing.

Figure A82: Value of Real-Time Congestion by Type of Constraint
By Quarter, 2014–2016



B. Day-Ahead Congestion Costs and FTR Funding

MISO's day-ahead energy market is designed to send accurate and transparent locational price signals that reflect congestion and losses on the network. MISO collects congestion revenue in the day-ahead market based on the differences in the LMPs at locations where energy is scheduled to be produced and consumed.

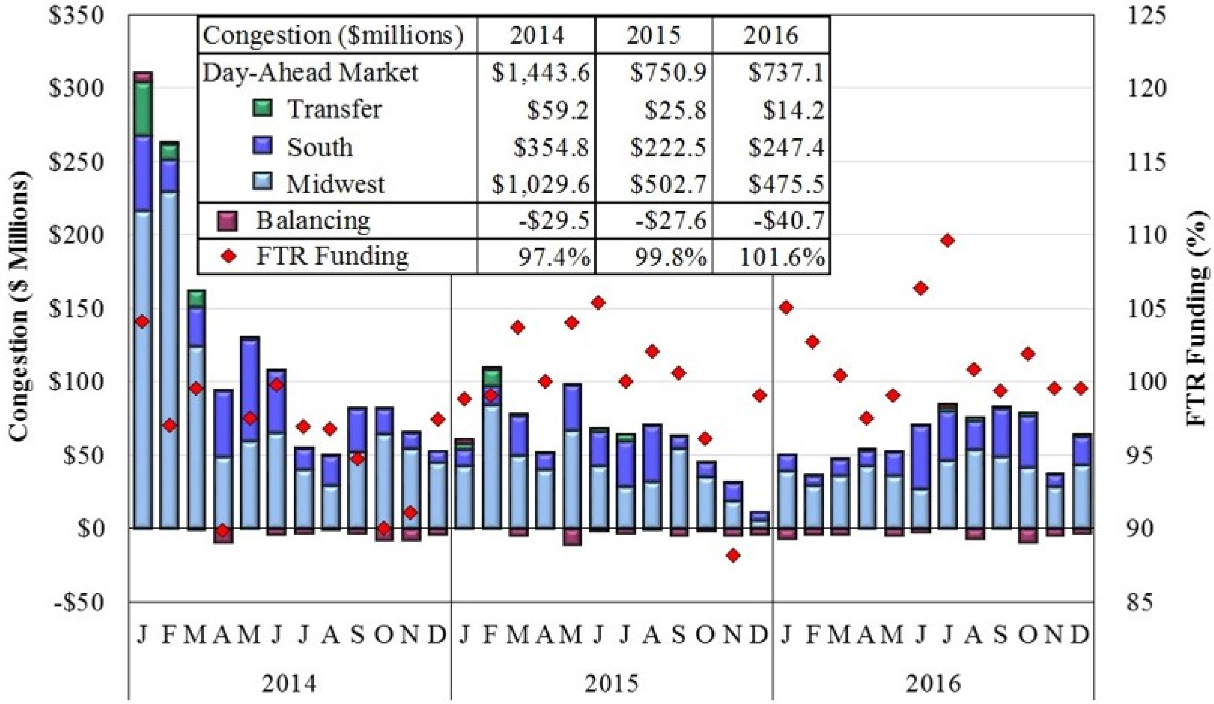
The resulting congestion revenue is paid to holders of Financial Transmission Rights (FTRs). FTRs represent the economic property rights of the transmission system, entitling the holder to the day-ahead congestion between two points on the network. A large share of the value of these rights is allocated to MISO market participants. The residual FTR capability that hasn't been allocated is sold in the FTR markets, with the market revenues contributing to the recovery of the costs of the network.

FTRs provide an instrument for market participants to hedge the expected day-ahead congestion costs. If the FTRs issued by MISO are physically feasible, meaning that they do not imply more flows over the network than the limits in the day-ahead market, then MISO will always collect enough congestion revenue through its day-ahead market to "fully fund" the FTRs – to pay them 100 percent of the FTR entitlement.

Figure A83: Day-Ahead and Balancing Congestion and Payments to FTRs

Figure A83 shows total day-ahead congestion revenues for constraints in the Midwest subregion, South subregion, and the transfer constraints between the Midwest and South regions for the last three years. It also shows the balancing congestion costs (these are costs because they are actually negative revenues), as well as the funding level of the FTRs.

Figure A83: Day-Ahead and Balancing Congestion and Payments to FTRs
2014–2016



C. FTR Auction Revenues and Obligations

An FTR represents a forward purchase of day-ahead congestion costs that allows participants to manage day-ahead congestion risk. Transmission customers pay for the embedded costs of the transmission system and, therefore, are entitled to the economic property rights to the network. This allocation of property rights is accomplished by allocating Auction Revenue Rights (ARRs) to transmission customers associated with their network load and generating resources. ARRs give customers the right to receive the FTR revenues that MISO collects when it sells FTRs that correspond to their ARRs, or to convert their ARRs into FTRs directly in order to receive day-ahead congestion revenues.

FTRs can be bought and sold in the seasonal and monthly auctions. Residual transmission capacity not sold in the seasonal auction is sold in the monthly auctions. Additionally, MISO facilitates bilateral FTR trades in the monthly FTR auctions. Beginning in the fall of 2013, MISO began operating the Multi-Period Monthly Auction (MPMA), which permits Market Participants to purchase (or sell) FTRs for the next month and several future months in the current planning year.

MISO is obligated to pay FTR holders the FTR quantity times the per-unit congestion cost between the source and sink of the FTR.[24] 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 are consistent with the capability of the network. When MISO sells FTRs that reflect a different transmission capability than what is ultimately available in the day-ahead market, shortfalls or surpluses can occur. Reasons for differences between FTR capability and day-ahead capability include:

- Transmission outages or other factors that cause system capability modeled in the day-ahead market to differ from capability assumed when FTRs were allocated or sold; or
- Generators and loads outside the MISO region that contribute to loop flows that use more or less transmission capability than what is assumed in the FTR market model.[25]

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 flows can create a FTR revenue shortfall.

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 the end of the year, when they are prorated to reduce any remaining FTR shortfalls.

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 A84: FTR Funding by LBA

At an aggregate level, MISO's FTRs were fully funded in 2016. However, it is important to examine funding at a more detailed level to understand where inconsistencies may exist between the FTR market and the day-ahead market. Examining funding by LBA can illuminate any potential cost-shifting that may be occurring between participants.

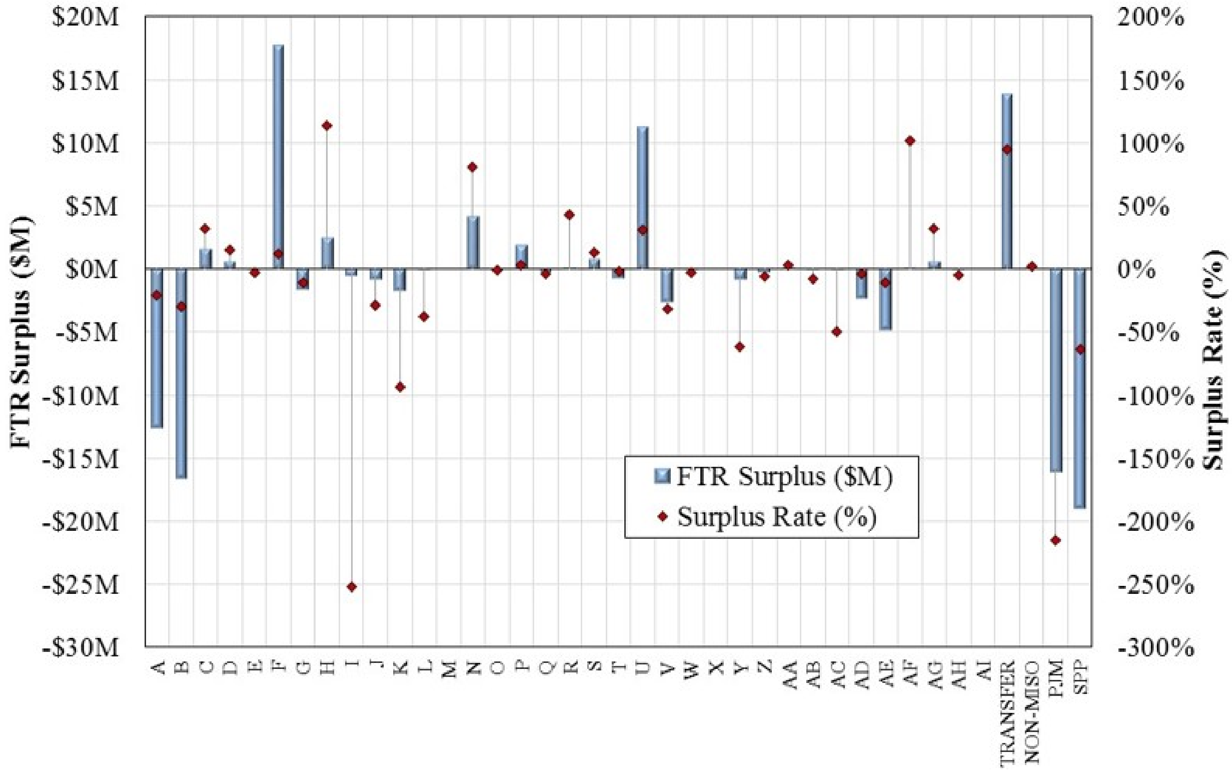
Figure A84 shows the monthly FTR surpluses and shortfalls (in both dollars and percentage terms) by LBA for 2016. The LBAs are masked with sequential letters. The constraints in each LBA include all internal constraints. External TLR constraints are shown as Non-MISO constraints, while external M2M constraints are shown based on whether they are located in PJM and SPP. . The Regional Dispatch Transfer (RDT) and external constraints that impact transfers between the South and Midwest regions are shown as "Transfer" constraints.

---

24 An FTR obligation can be in the counter-flow direction and can require a payment from the FTR holder.

25 "Loop Flows" cannot be directly calculated and, in this context, would be measured real-time flows less the calculated real-time market flows from PJM, SPP, and the MISO commercial flows (which include the MISO market flows and the impacts of physical transactions). For example, when Southern Company generation serves its own load, some of this would flow over the MISO transmission system and this would be "loop flow." The day-ahead model includes assumptions on loop flows that are anticipated to occur in real time.

Figure A84: FTR Funding by Type of Constraint and Control Area
2016



D. Multi-Period Monthly FTR Auction Revenues and Obligations

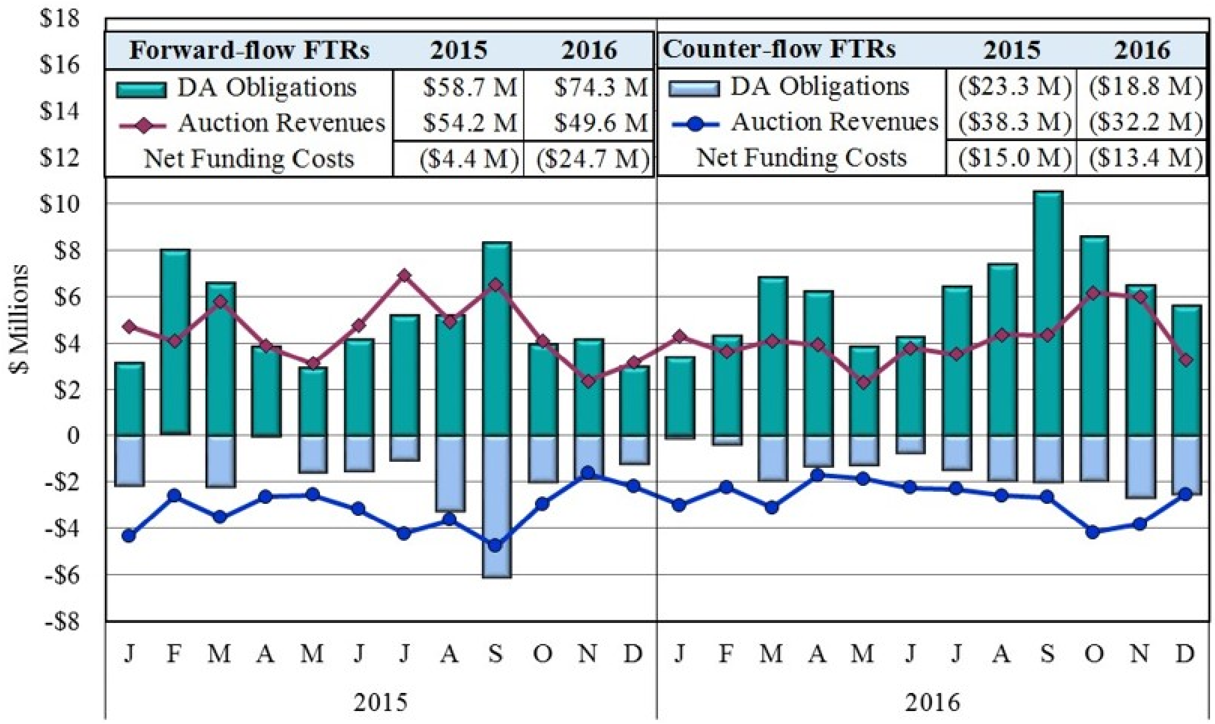
In the MPMA FTR auctions, MISO generally makes additional transmission capability available for sale and sometimes buys back capability on oversold transmission paths. MISO buys back capability by selling "counter-flow" FTRs, which are negatively priced FTRs on oversold paths. In essence, MISO is paying a participant to accept an FTR obligation in the opposite direction to cancel out excess FTRs on that transmission path. For example, if MISO issues 250 MW of FTRs over a path that now can only accommodate 200 MW of flow. MISO can sell 50 MW of counter-flow FTRs so that MISO's net FTR obligation in the day-ahead market is only 200 MW.

MISO is restricted in its ability to do this because it is prohibited from clearing the MPMA or monthly FTR auctions with a negative financial residual. Hence, it can sell counter-flow FTRs to the extent that it has sold forward-flow FTRs in the same auction. This limits MISO's ability to resolve feasibility issues through the MPMA auctions. In other words, when MISO knows a path is oversold, as in the example above, it often cannot reduce the FTR obligations on the path by selling counter-flow FTRs. This is not always bad because it may be costlier to sell counter-flow FTRs than it is to simply incur the FTR shortfall in the day-ahead market.

Figure A85: Monthly FTR Auction Revenues and Obligations

To evaluate MISO's sale of forward-flow and counter-flow FTRs, Figure A85 compares the auction revenues from the monthly FTR auction to the day-ahead FTR obligations associated with the FTRs sold. The figure separately shows forward-direction FTRs and counter-flow FTRs. The net funding costs are the difference between the auction revenues and the day-ahead obligations. A negative value indicates that MISO sold FTRs at a price less than their ultimate value.

Figure A85: Monthly FTR Auction Revenues and Obligations
2015–2016



E. Balancing Congestion Costs

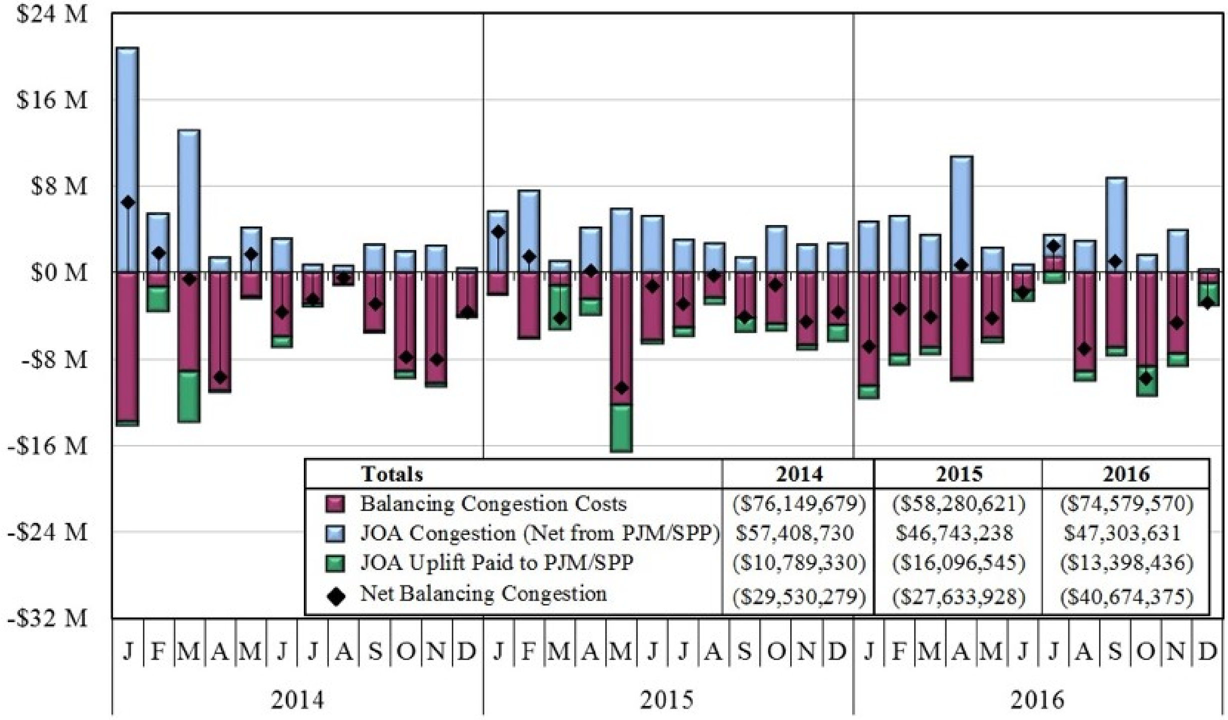
Balancing congestion costs are congestion costs collected in the real-time market based on deviations from day-ahead congestion outcomes. They should be small if the day-ahead market accurately forecasts the real-time network capabilities. However, balancing congestion can be large and result in substantial costs to MISO's customers if the day-ahead model is not fully consistent with the real-time topology of the system.

For example, if MISO does not model a particular constraint in the day-ahead market and it binds in real time, MISO can accumulate a substantial amount of balancing congestion. This occurs because the failure to model the constraint can allow participants to schedule more flows over the constraint in the day-ahead market than can be accommodated in real time. The costs incurred by MISO to "buy back" the day-ahead flows are negative balancing congestion revenues, or balancing congestion costs, that must be collected through an uplift charge to MISO's customers.

Figure A86: Balancing Congestion Costs

To understand balancing congestion costs, Figure A86 shows these costs disaggregated into (1) the real-time congestion costs incurred to reduce (or increase) the MISO flows over binding transmission constraints and (2) the M2M payments made by (or to) PJM and SPP under the Joint Operating Agreements (JOAs). For example, when PJM exceeds its flow entitlement on a MISO-managed constraint, MISO will re-dispatch to reduce its flow and generate a cost (shown as negative in the figure), while PJM's payment to MISO for this excess flow is shown as a positive revenue to MISO. We have also included JOA uplift in the real-time balancing congestion costs. JOA uplift results from MISO exceeding its Firm Flow Entitlement (FFE) on PJM M2M constraints and having to buy that excess back from PJM at PJM's shadow price. Like other net balancing congestion costs, JOA uplift costs are part of revenue neutrality uplift costs collected from load and exports.

Figure A86: Balancing Congestion Costs
2014–2016



F. Improving the Utilization of the Transmission System

Substantial savings could be achieved through widespread use of temperature-adjusted transmission ratings for all types of transmission constraints. For most transmission constraints, the ability to flow power through the facility is related to the heat caused by the power flow. When ambient temperatures are cooler than the typical assumption used for rating the facilities, additional power flows can be accommodated. Therefore, if transmission owners develop and submit temperature-adjusted transmission ratings, they would allow MISO to operate to higher transmission limits and achieve production costs savings. Most transmission owners do not provide temperature-adjusted ratings.

For contingency constraints, ratings should correspond to the short-term emergency rating level (i.e., the flow level that the monitored facility could reliably accommodate in the short-term if the contingency occurs). Most transmission owners provide MISO with both normal and emergency limits as called for under the Transmission Owner's Agreement.[26] However, we have identified some transmission owners that provide only normal ratings. Some of these transmission owners may have legitimate concerns regarding the actions MISO will be able to take after a contingency occurs to reduce the flows over the facility. In such cases, it would be useful for MISO to develop the ability to evaluate in real time its ability to respond after a contingency occurs and/or to develop operating guides that would assure such a response.

We worked with MISO and one transmission owner in 2015 to implement a pilot program to make use of temperature-adjusted, short-term emergency ratings on a number of key facilities. Preliminary results indicated that there were clear benefits with no reliability issues. The program is ongoing and includes additional lines outside of the scope of the original pilot program. Given the benefits, we have recommended expanding this program to other regions.

Finally, there are substantial potential savings with more wide-spread use of Voltage and Stability Analysis Tools (VSAT) in real time. In January 2015, the VSAT software was implemented and successfully used to reduce the costs of managing stability constraints in the Midwest region. In 2014, the congestion on a key interface exceeded $31 million in real time. After implementation of VSAT, this was reduced to less than $1 million. In 2016, MISO continued promote the use of VSAT in neighboring regions to enable reliable use of higher limits based on more accurate and timely reliability analyses. This would lower the costs of external constraints on MISO and its customers.

Figure A87: Potential Value of Additional Transmission Capability

The analysis in this section examines the potential value that may be available by more fully utilizing the transmission network. This can be accomplished by operating to higher transmission limits that would result from consistent use of improved ratings for MISO's transmission facilities, including temperature-adjusted emergency ratings.

Figure A87 shows our estimate of the congestion value of the incremental transmission capability that could potentially be made available by consistently utilizing temperature-adjusted emergency ratings. The results are shown by month and MISO Reliability Coordination Region for the last two years.

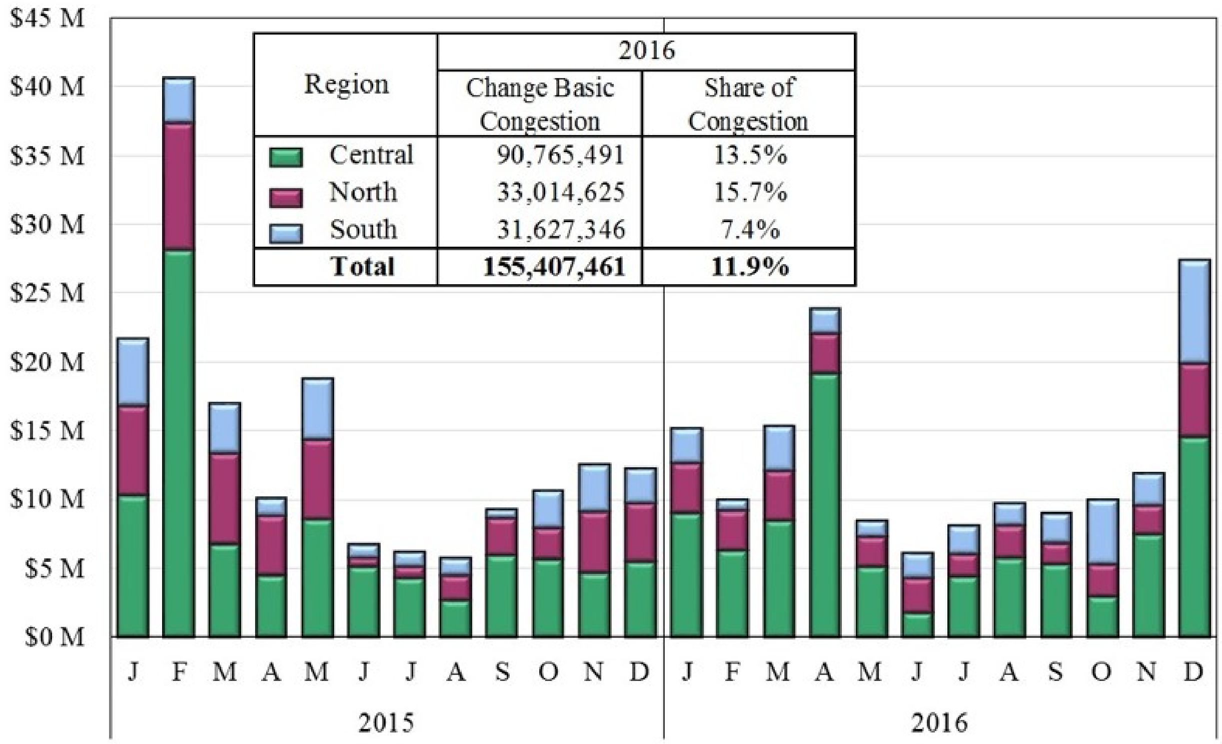
To estimate the congestion savings of using temperature-adjusted ratings, we performed a study using NERC/IEEE estimates of ambient temperature effects on transmission ratings. Using the formulae and data from IEEE Standards (IEEE Std C37.30.1™-2011), we derived ratios of allowable continuous facility current (flow) at prevailing ambient temperatures to the Rated

26 The Transmission Owners Agreement calls for transmission owners to submit normal transmission ratings on base (non-contingency) constraints and emergency ratings on contingency constraints ("temporary" flow levels that can be reliability accommodated for 2-4 hours). Because most constraints are contingent constraints (i.e., the limit is less than the rating to prepare for additional flows that will occur if the contingency happens), it is generally safe to use the emergency ratings.

Continuous Current for different class of transmission elements (e.g., Forced Air-Cooled Transformers, Self-Cooled Transformers, Overhead Conductors).

We used the most conservative class of ratings that were the lowest permissible ratings increase under the Standard for the type of element (Line or Transformer). We then used the highest ambient temperatures prevailing at the nearest temperature measurement location for each market date in 2016 to calculate an adjusted limit consistent with the temperature-adjusted ratings. The value of increasing the transmission limits was then calculated by multiplying the increase in the temperature-adjusted limit by the real-time shadow price of the constraint.

Figure A87: Potential Value of Additional Transmission Capability
2016



G. Transmission Line Loading Relief Events

With the exception of M2M coordination between MISO and PJM, MISO and SPP, and NYISO and PJM, Reliability Coordinators in the Eastern Interconnect continue to rely on TLR procedures and the North American Electric Reliability (NERC) Interchange Distribution Calculator (IDC)[27] to manage congestion on their systems that is caused in part by schedules and the dispatch activity of external entities.

27 To implement TLR procedures on defined flowgates, Reliability Coordinators (RCs) depend upon the IDC. The IDC provides RCs with the amount of relief available from curtailment of physical transactions. In addition, MISO, PJM, and SPP provide their market flow impacts on flowgates to the IDC for use by RCs in TLR.

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-M2M 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 re-dispatch its resources to reduce MISO's market flows over the constrained transmission facility by the amount requested.

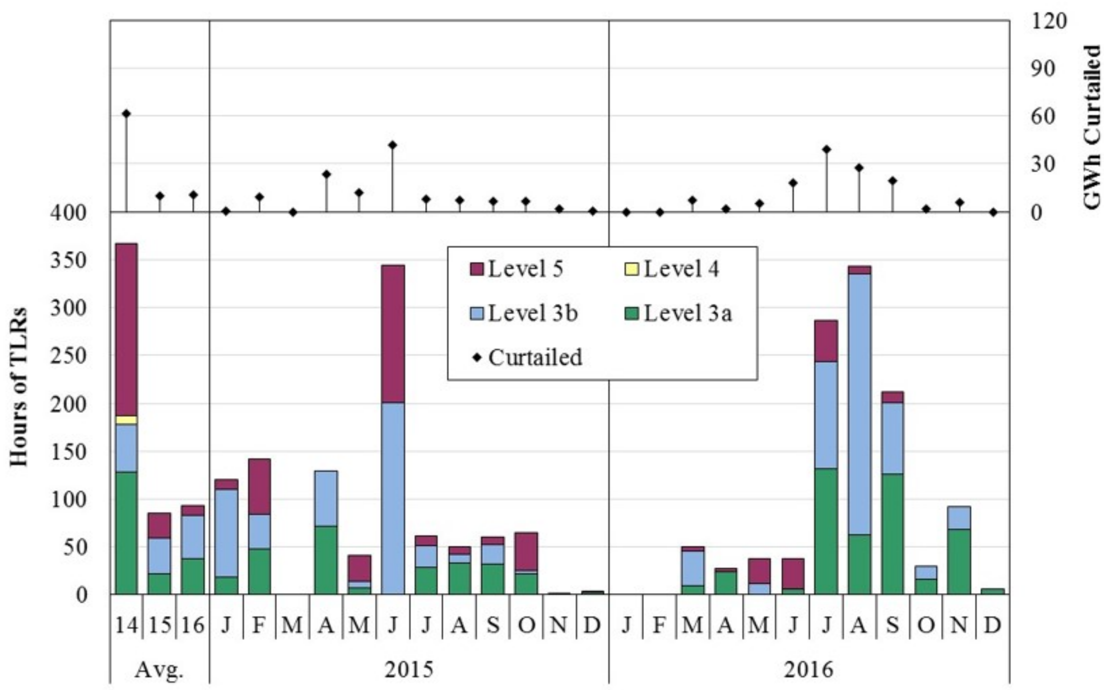
External entities not dispatched by MISO also contribute to total flows on MISO flowgates. If external transactions contribute more than five percent of their total flow on a MISO binding facility, MISO can invoke a TLR to ensure that these transactions are curtailed to reduce the flow over the constrained 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 re-dispatch.

Figure A88 and Figure A89: Periodic TLR Activity

Figure A88 shows monthly TLR activity on MISO flowgates in 2015 and 2016. 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 the total number of hours of TLR activity called by MISO, grouped by TLR level.

Figure A88: Periodic TLR Activity
2015–2016



These NERC TLR levels shown in both figures are defined as follows:

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

Figure A89 shows the total number of TLR hours aggregated by the Reliability Coordinator declaring the TLR.

Figure A89: TLR Activity by Reliability Coordinator
2015–2016

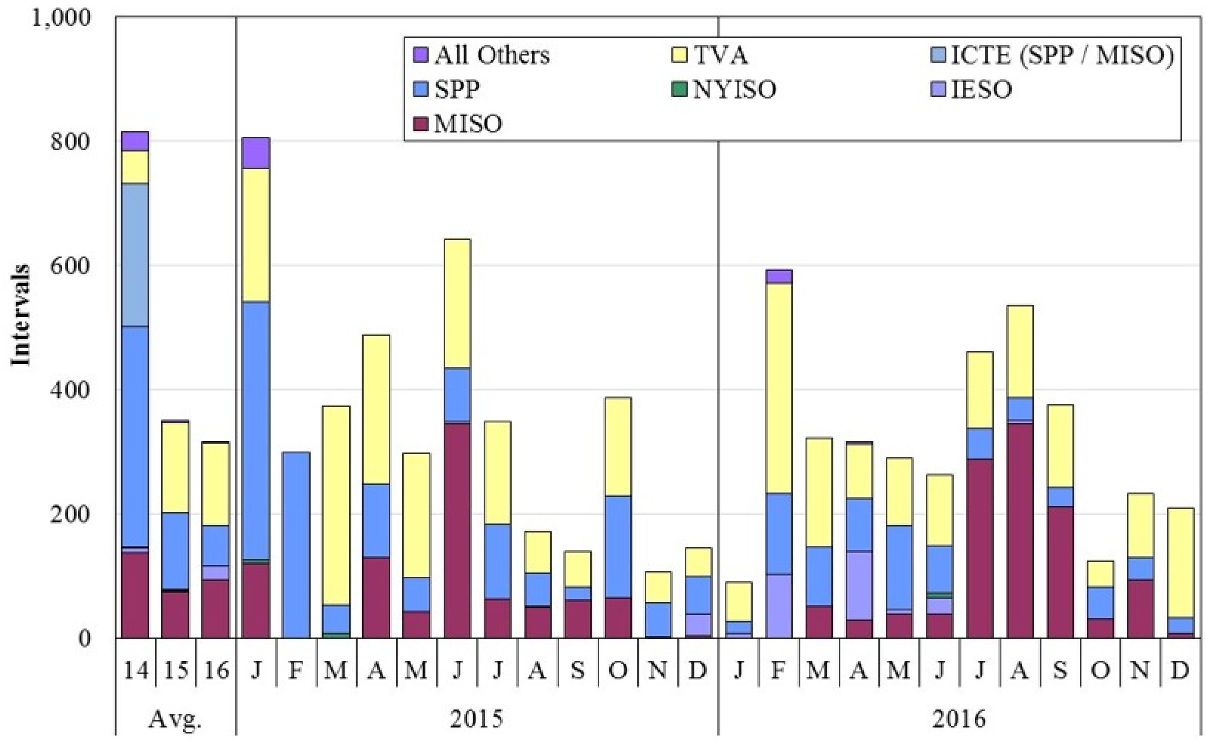


Figure A7: Heating and Cooling Degree-Days

Table A7 illustrates the potential savings that could be achieved by utilizing TVA generation to provide lower cost relief on contraints binding in MISO. Our analysis focus on economic relief on two types of constraints:

- MISO internal constraints; and

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

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

- TVA constriants that are binding in MISO's real-time market because TVA has called a TLR.

The purpose of this analysis is to quantify the potential value of a joint operating agreement to coordinate economic congestion management with TVA. The left column indicates the value of real-time congestion in cases where economic relief is available from TVA, while the right column indicates the potential savings that could have been realized through economic coordination.

Table A7: Economic Congestion Relief from TVA Generators
2016

Types of Constraints	Total Congestion Value ($ Millions)	Re-dispatch Savings ($ Millions)
MISO Constraints	$169.6 M	$16.9 M
TVA (TLR) Constraints binding in MISO	$21.1 M	$4.9 M
Total	$190.7 M	$21.8 M

H. Congestion Manageability

MISO monitors the flows on all of the transmission facilities throughout its network. It uses 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 the dispatch of generators with high Generation Shift Factors (GSFs).[30]

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 re-dispatch capability is reduced when:

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

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 because MISO's performance criteria allow for 20 minutes to restore control on most constraints. If control is not restored within 30 minutes, a reporting criterion to stakeholders is triggered. Constraints most

30 GSFs are the share of flow from a generator that will flow over a particular constraint. A negative shift factor means the flow is providing relief (or "counter-flow") in the direction the constraint is defined, and a positive shift factor means flow is in the direction of the constraint.

critical to system reliability (e.g., those that could lead to cascading outages) are operated more conservatively.

Figure A90: Congestion Manageability

The next set of figures depicts the manageability of internal and MISO-managed M2M constraints. Figure A90 shows how frequently binding constraints were manageable and unmanageable in each month from 2015 to 2016.

Figure A90: Constraint Manageability
2015–2016

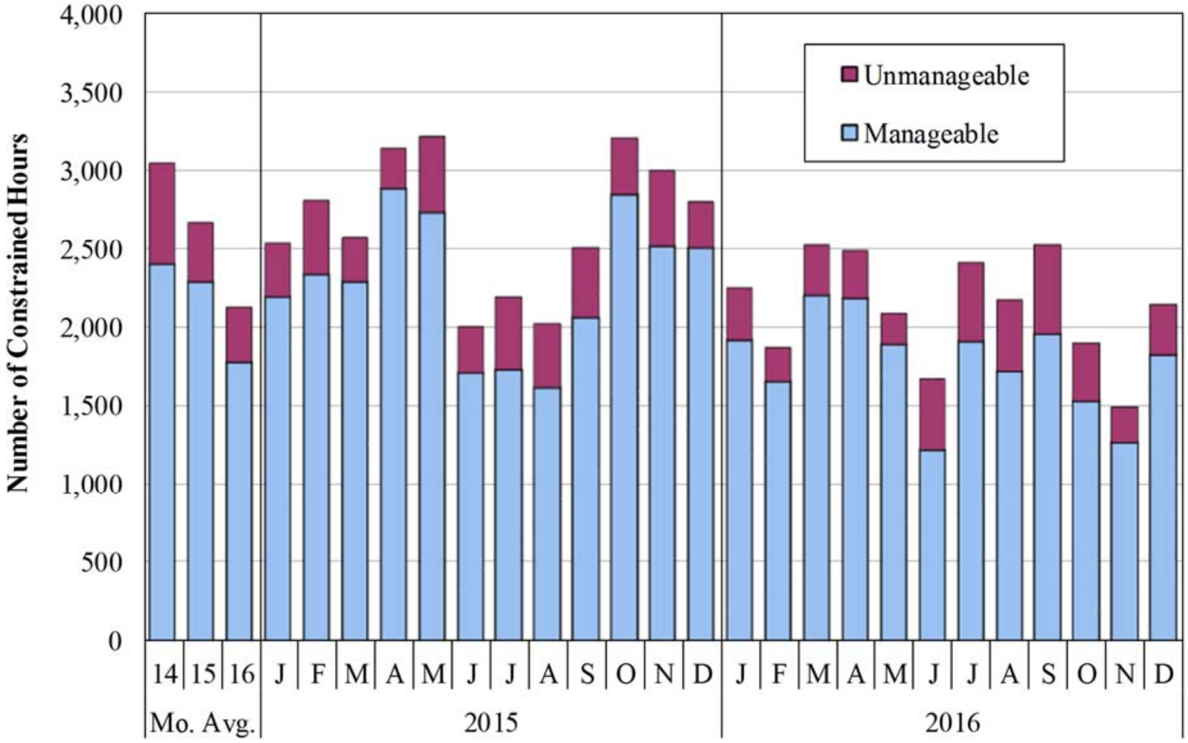


Figure A91: Real-Time Congestion Value by Voltage Level

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 (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 is 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, an algorithm was used to "relax" the limit of the constraint to calculate a shadow price and the associated LMPs when a constraint's flow exceeded its limit. 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 was 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-M2M constraints, it remains in place for all M2M constraints.

Figure A91 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 A91 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 A91: Real-Time Congestion Value by Voltage Level
2014–2016

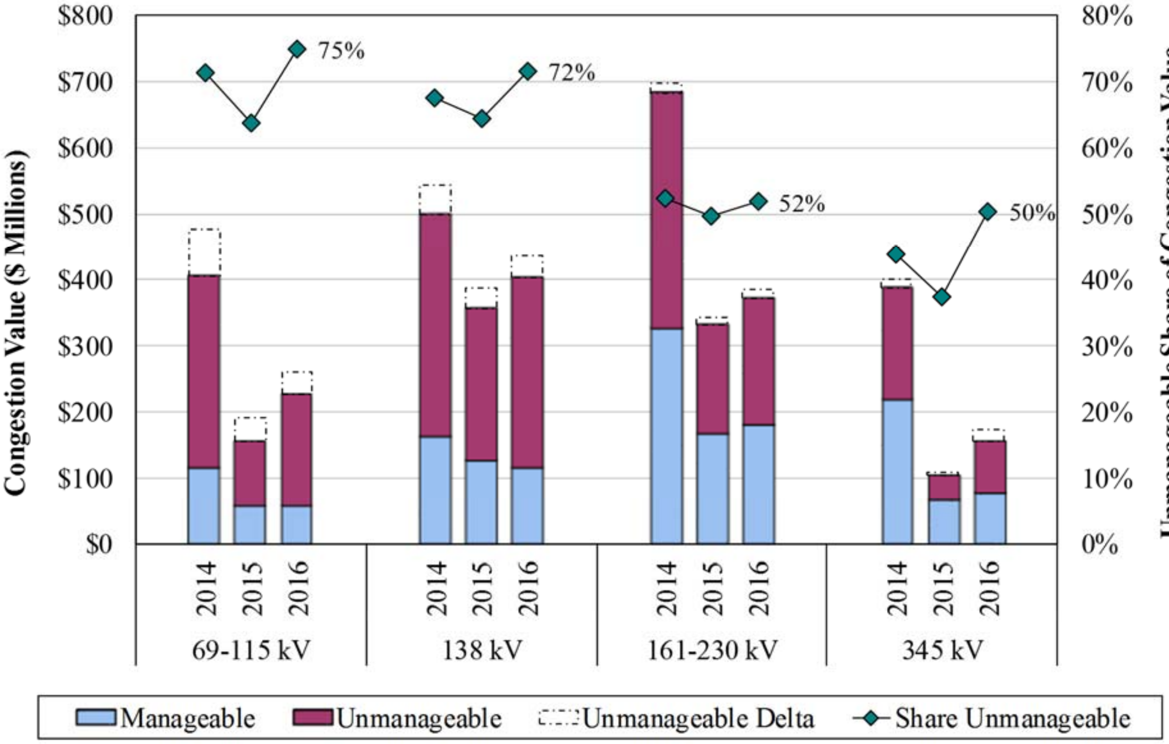


Figure A92: Congestion Affected by Multiple Planned Generation Outages

Generators take planned outages to conduct periodic maintenance, to evaluate or diagnose operating issues, and to upgrade or repair various system. Similarly, transmission operators conduct periodic planned maintenance on transmission facilities, which generally reduces the

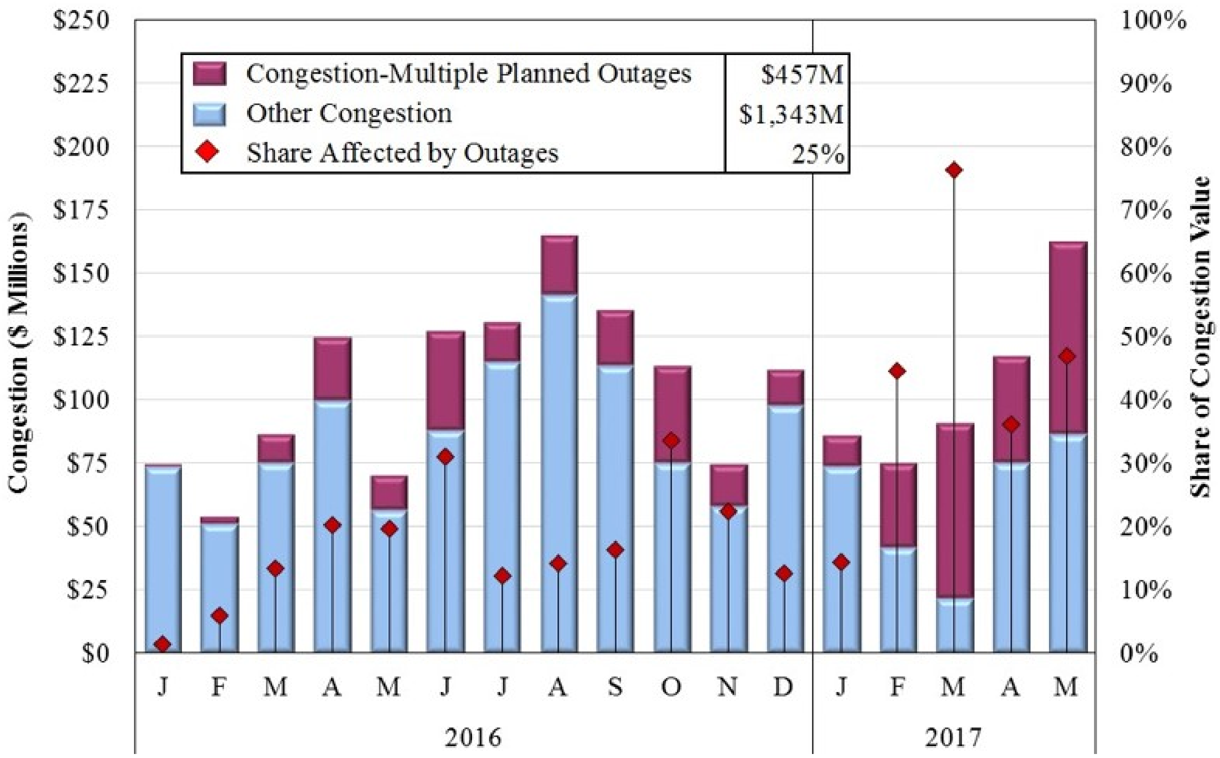
31 This figure excludes some less common voltages, such as 120 and 500 kV, and about four percent of total congestion value due to constraints that could not be classified according to voltage class.

transmission capability of the system. MISO evaluates the reliability effects of the planned outages, including conducting contingency and stability studies on planned outages.

Participants tend to consolidate planned outages in shoulder months, assuming opportunity costs are lower of taking outages when load is mild and prices are relatively low. However, this is not always true. Different participants may schedule multiple generation outages in a constrained area or transmission outages into the area at the same time without knowing what others are doing. Absent a reliability concern, MISO does not have the tariff authority to deny or postpone a planned outage, even when it will likely have substantial economic effects.

Figure A92 provides a high-level evaluation of how uncoordinated planned outages may affect congestion. It shows the real-time congestion value incurred from January 2016 through May 2017. We identify the portion of the congestion on constraints substantially impacted by two or more planned outages that affected at least 10 percent of the constraints' flows. The maroon bars represent the congestion attributable to multiple planned generation outages, and the blue bars indicate the total congestion not attributable to planned generation outages. The diamonds indicate the percentage share of congestion was due to concurrent planned generation outages.

Figure A92: Congestion Affected by Multiple Planned Generation Outages
2016-2017



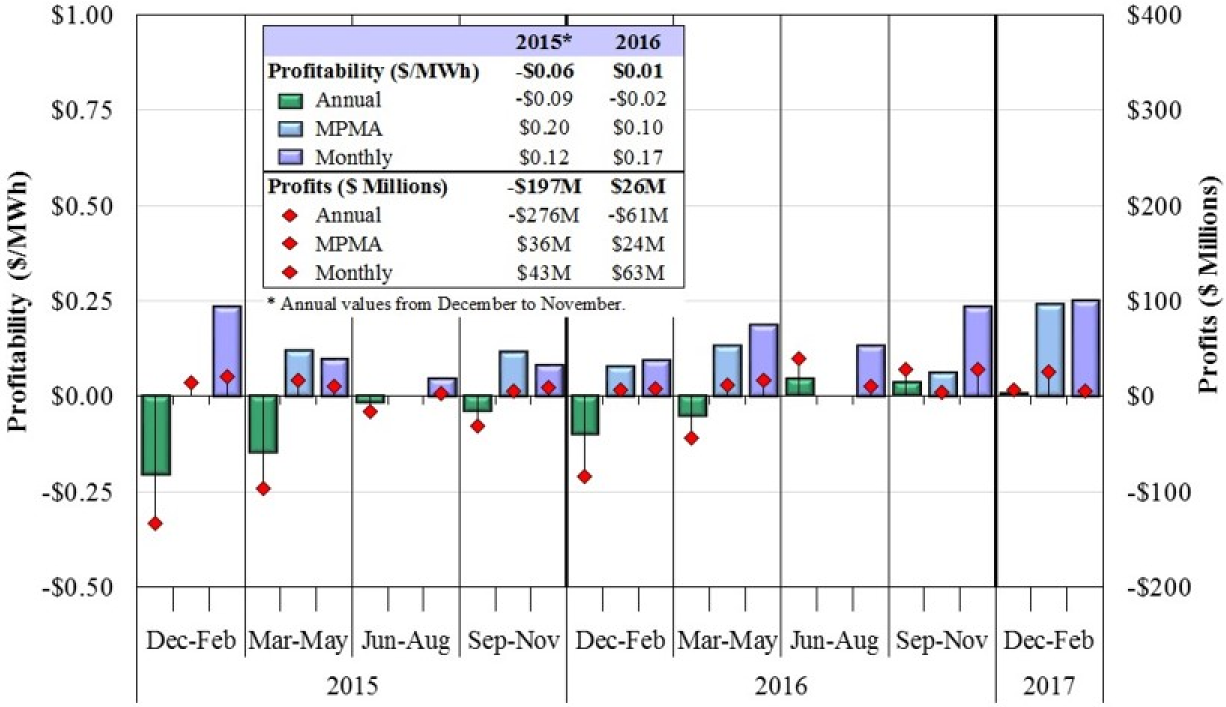
I. FTR Market Performance

Because a FTR represents a forward purchase of day-ahead congestion costs, FTR markets perform well when they establish FTR prices that accurately reflect the expected value of day-ahead congestion. When this occurs, FTR profits are low because the profits equal the FTR price minus the day-ahead congestion payments. It is important to recognize, however, that even if the FTR prices represent a reasonable expectation of congestion, a variety of factors may cause actual congestion to be much higher or much lower than the values established in the FTR markets. MISO currently runs the FTR market in two timeframes: annual for the June to May planning year and the current and future months via the MPMA. The MPMA was launched in November 2013 and facilitates FTR trading for future months or seasons remaining in the planning year.

Figure A93: FTR Profits and Profitability

Figure A93 shows our evaluation of the profitability of these auctions by presenting the seasonal profits for FTRs sold in each market. The values are calculated seasonally even though the FTRs are sold for durations of one year, one season, or one month. The monthly values shown in this figure are the prompt month in the MPMA, while the MPMA values are for future months.

Figure A93: FTR Profits and Profitability
2015–2016



	2015*	2016
Profitability ($/MWh)	-$0.06	$0.01
Annual	-$0.09	-$0.02
MPMA	$0.20	$0.10
Monthly	$0.12	$0.17
Profits ($ Millions)	-$197M	$26M
Annual	-$276M	-$61M
MPMA	$36M	$24M
Monthly	$43M	$63M

Figure A94 to Figure A96: FTR Profitability

The next three figures show the profitability of FTRs purchased in the annual, seasonal, and monthly FTR auctions in more detail for 2014 to 2016. The bottom panels show the total profits and losses, while the top panel shows the profits and losses per MWh.

The results in the figure include FTRs sold as well as purchased. FTRs sold are netted against FTRs purchased. For example, if an FTR purchased during 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 A94: FTR Profitability
2014–2016: Annual Auction

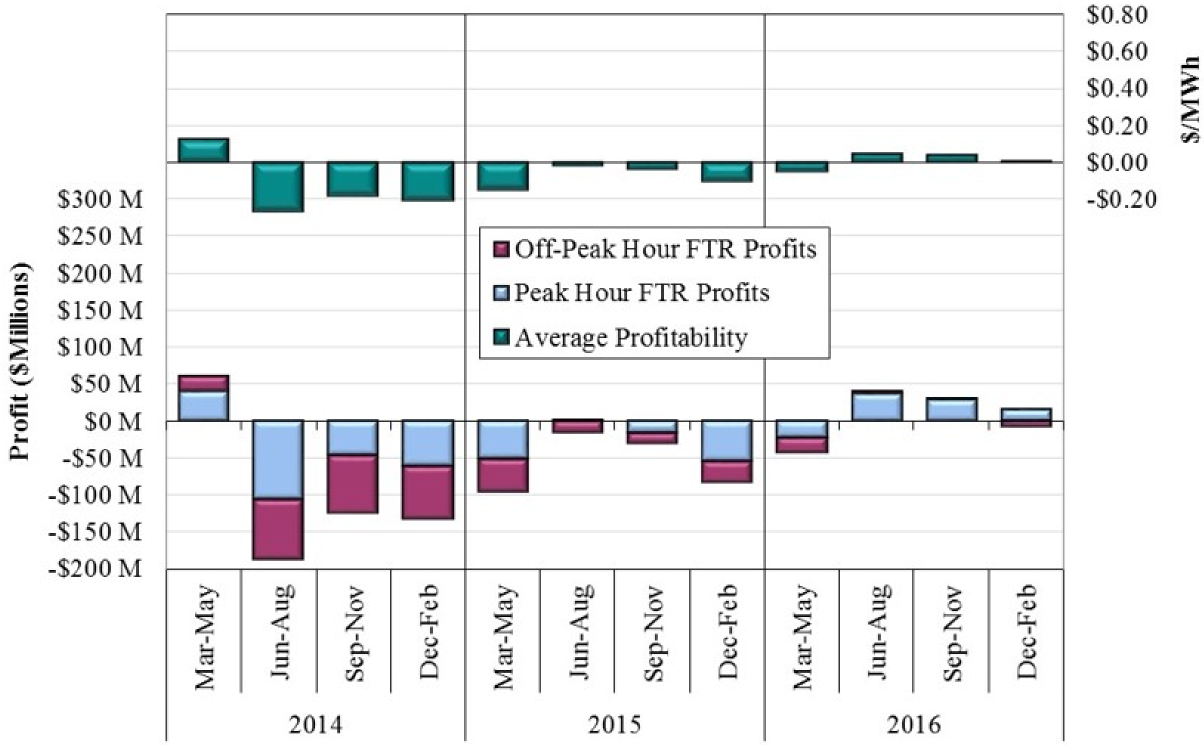


Figure A95: FTR Profitability
2015–2016: Monthly Auction

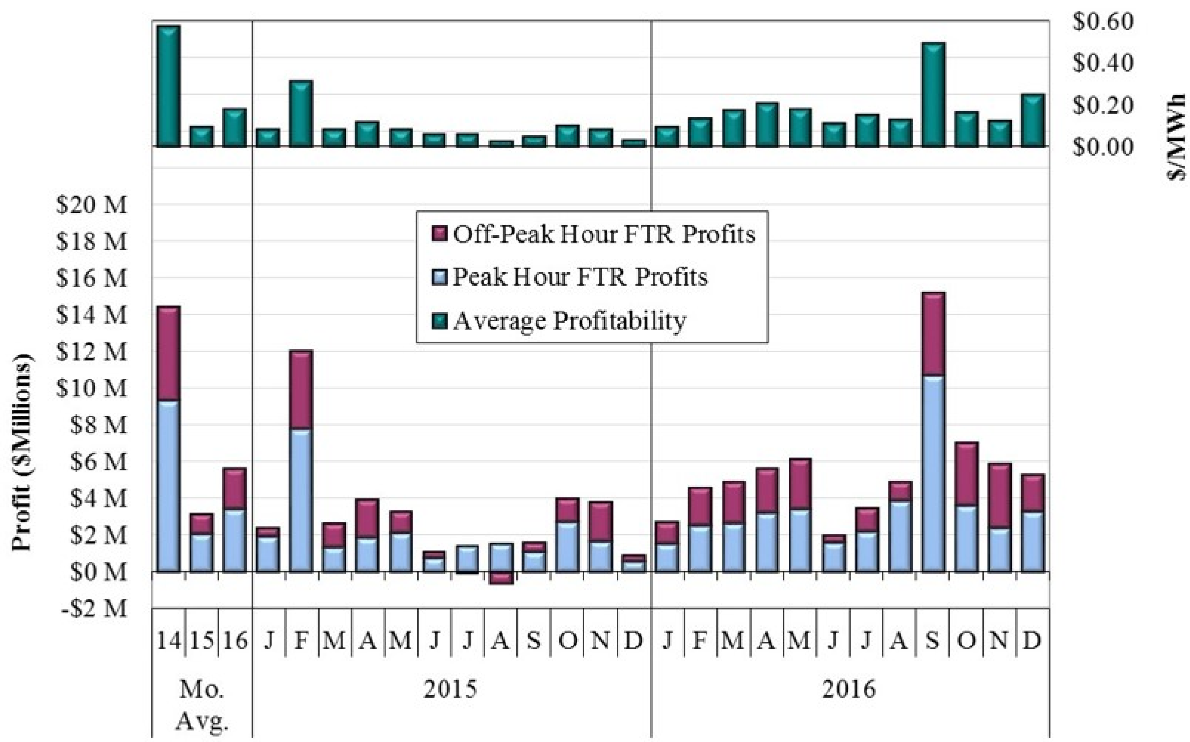


Figure A96: FTR Profitability
2014–2016 Seasonal Auction MPMA

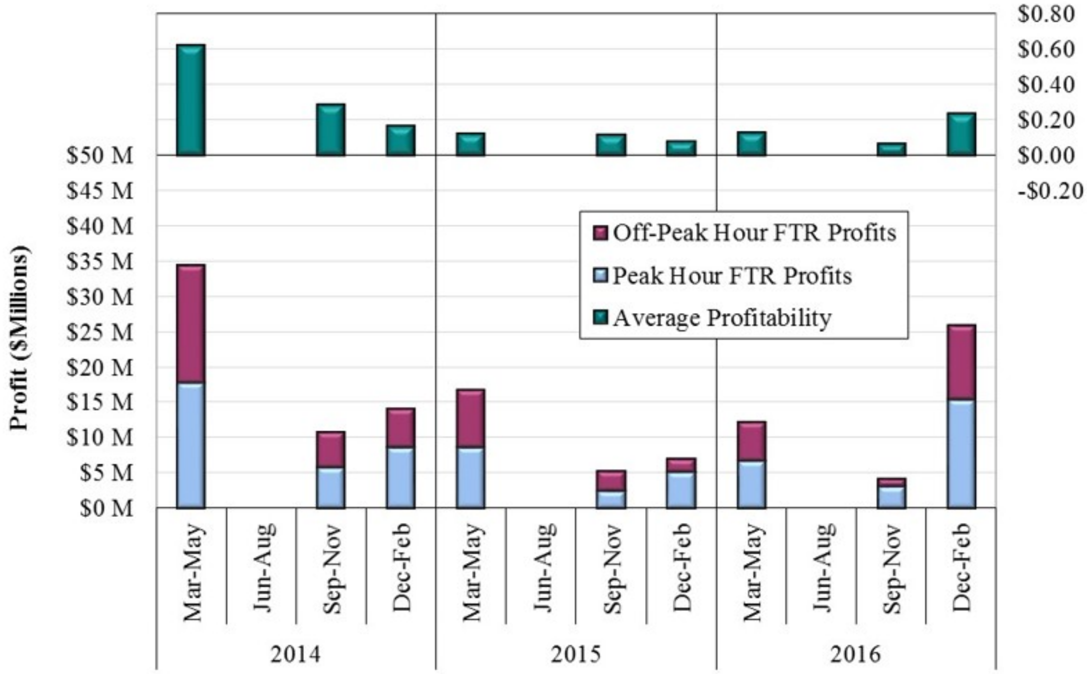


Figure A97 to Figure A110: Coparison of FTR Auction Prices and Congestion Value

The next 14 figures compare monthly FTR auction revenues to the day-ahead FTR obligations at representative locations in MISO. We show values for four ares in the Midwest Region and three areas in the South Region, separately showing peak and off-peak hours.

Figure A97: Comparison of FTR Auction Prices and Congestion Value
Indiana Hub, 2015–2016: Off-Peak Hours

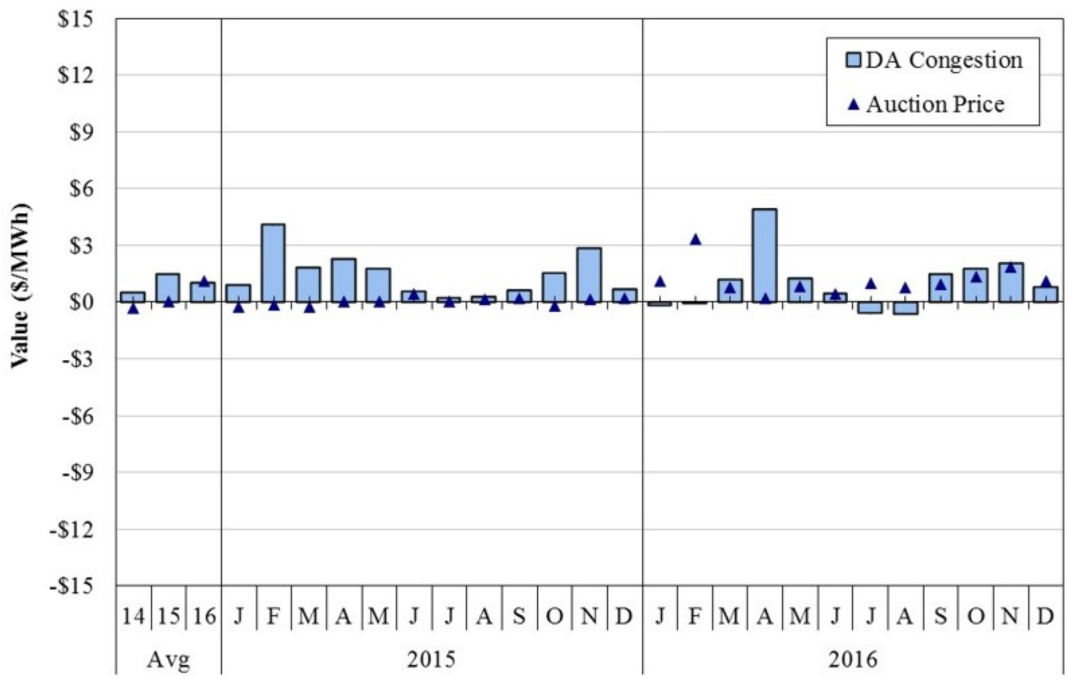


Figure A98: Comparison of FTR Auction Prices and Congestion Value
Indiana Hub, 2015–2016: Peak Hours

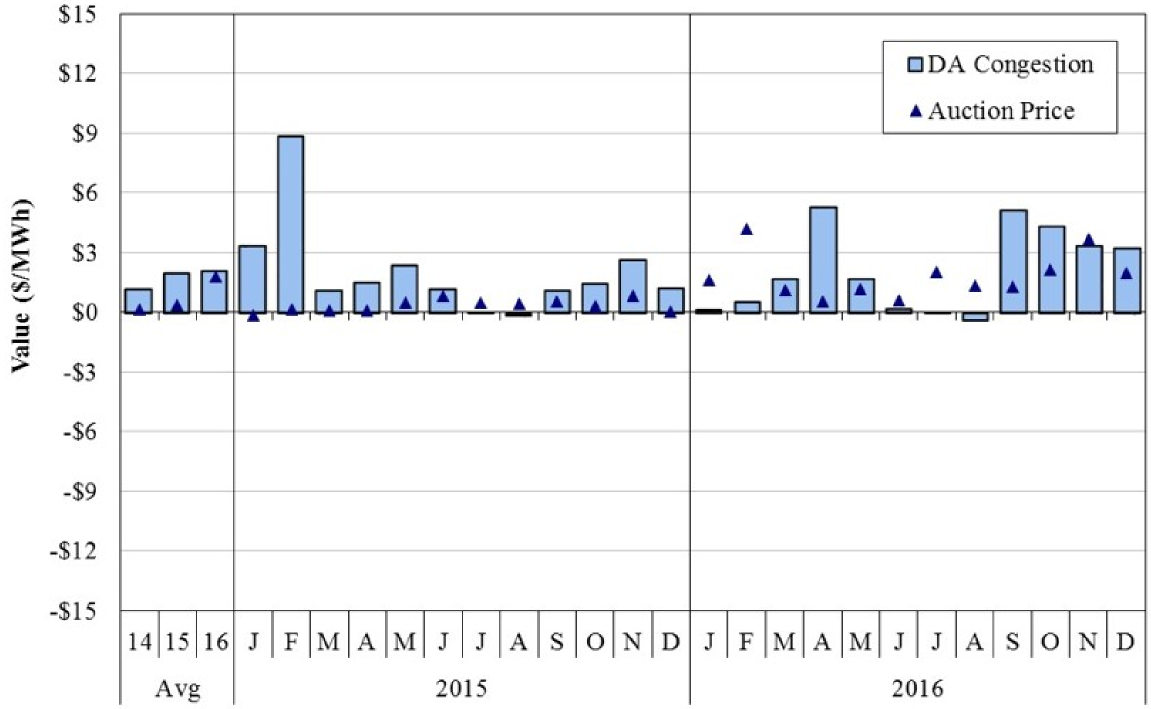


Figure A99: Comparison of FTR Auction Prices and Congestion Value
Michigan Hub, 2015–2016: Off-Peak Hours

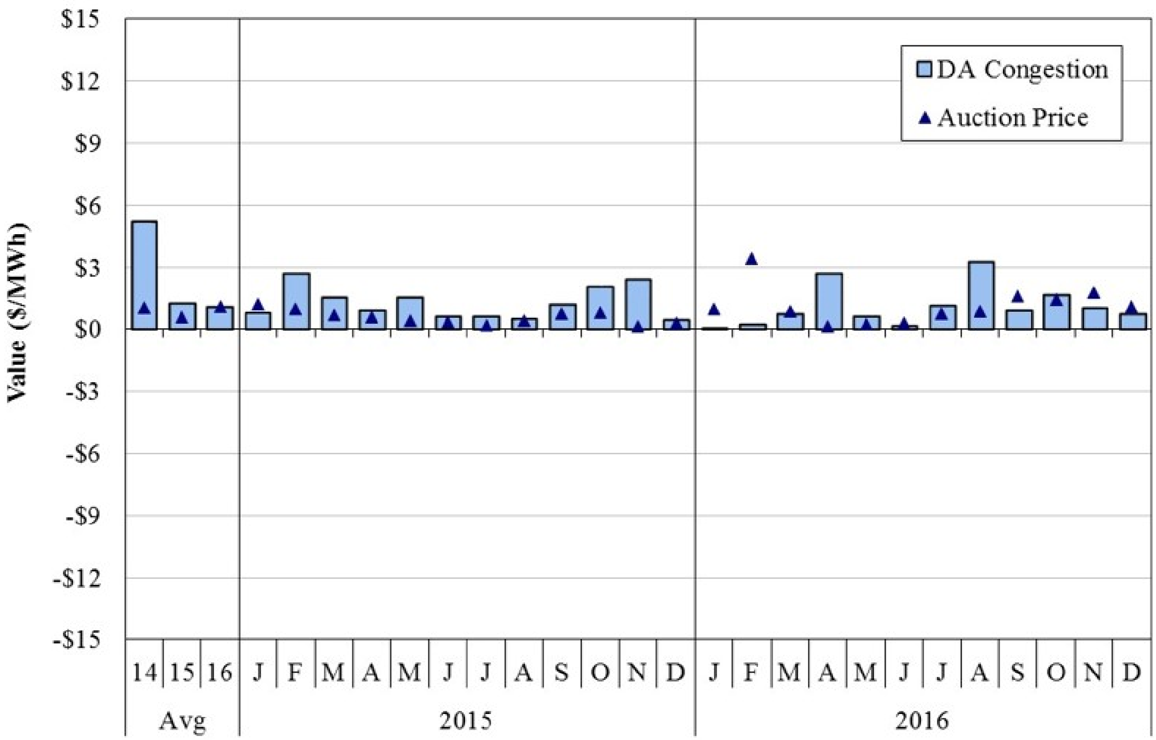


Figure A100: Comparison of FTR Auction Prices and Congestion Value
Michigan Hub, 2015–2016: Peak Hours

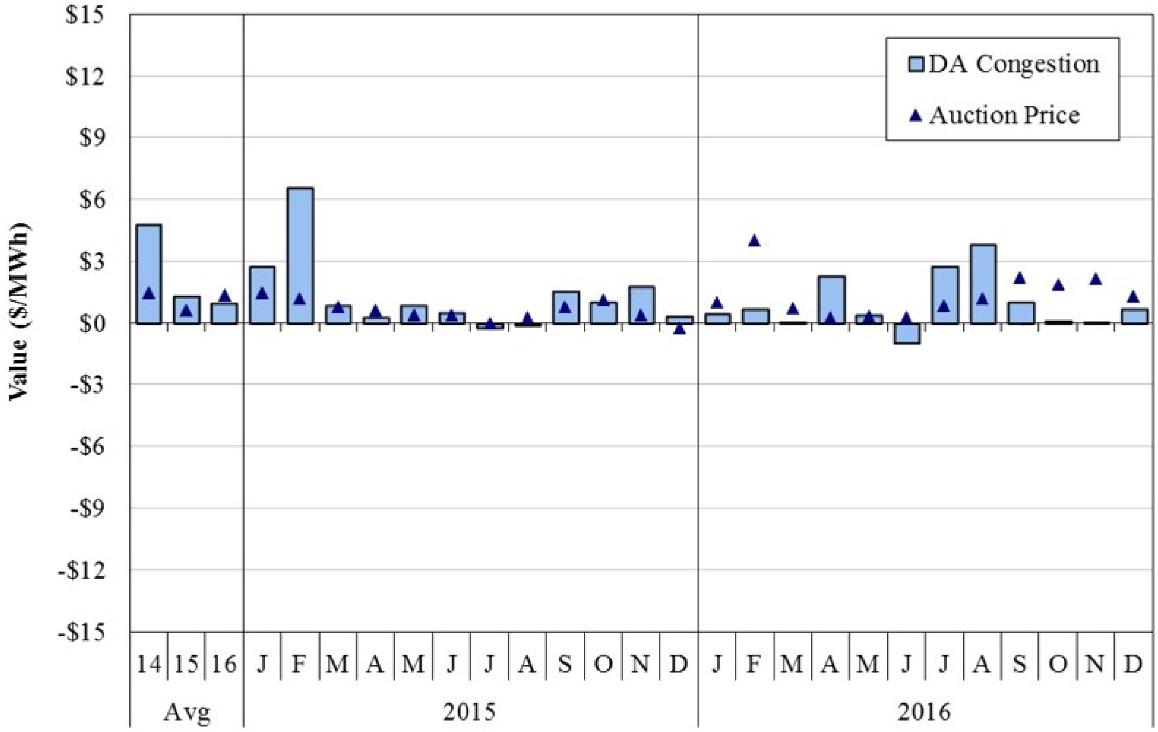


Figure A101: Comparison of FTR Auction Prices and Congestion Value
WUMS Area, 2015–2016: Off-Peak Hours

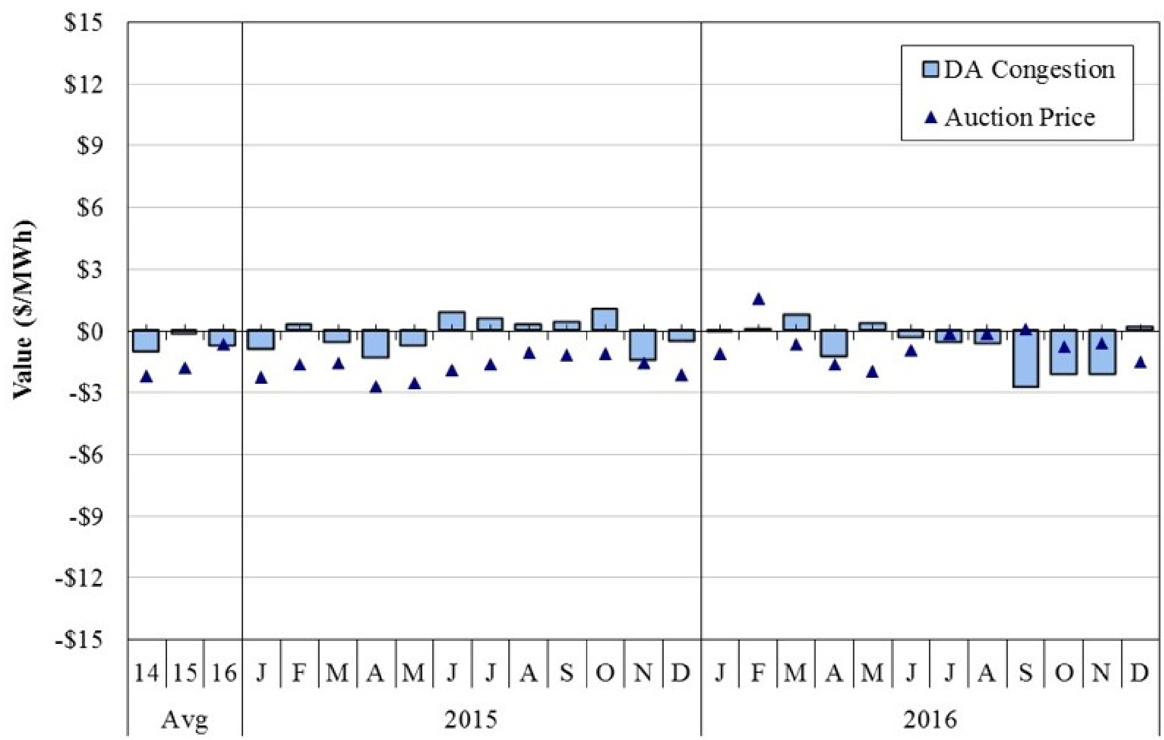


Figure A102: Comparison of FTR Auction Prices and Congestion Value
WUMS Area, 2015–2016: Peak Hours

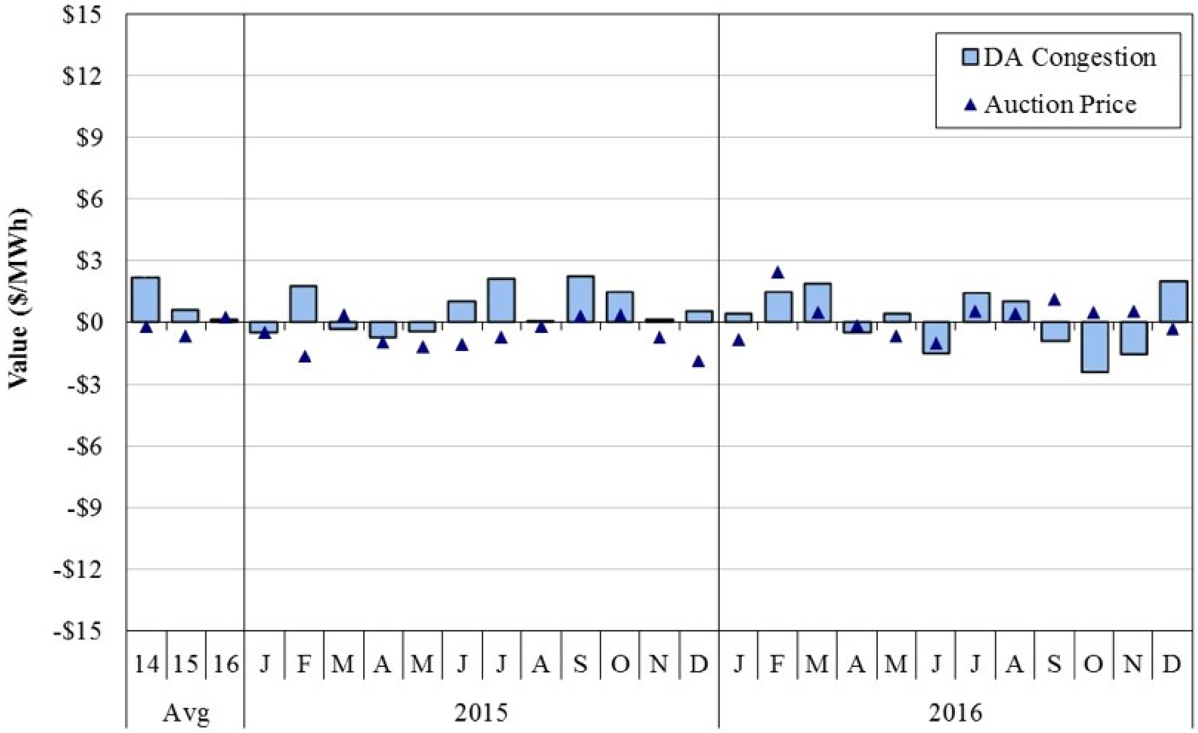


Figure A103: Comparison of FTR Auction Prices and Congestion Value
Minnesota Hub, 2015–2016: Off-Peak Hours

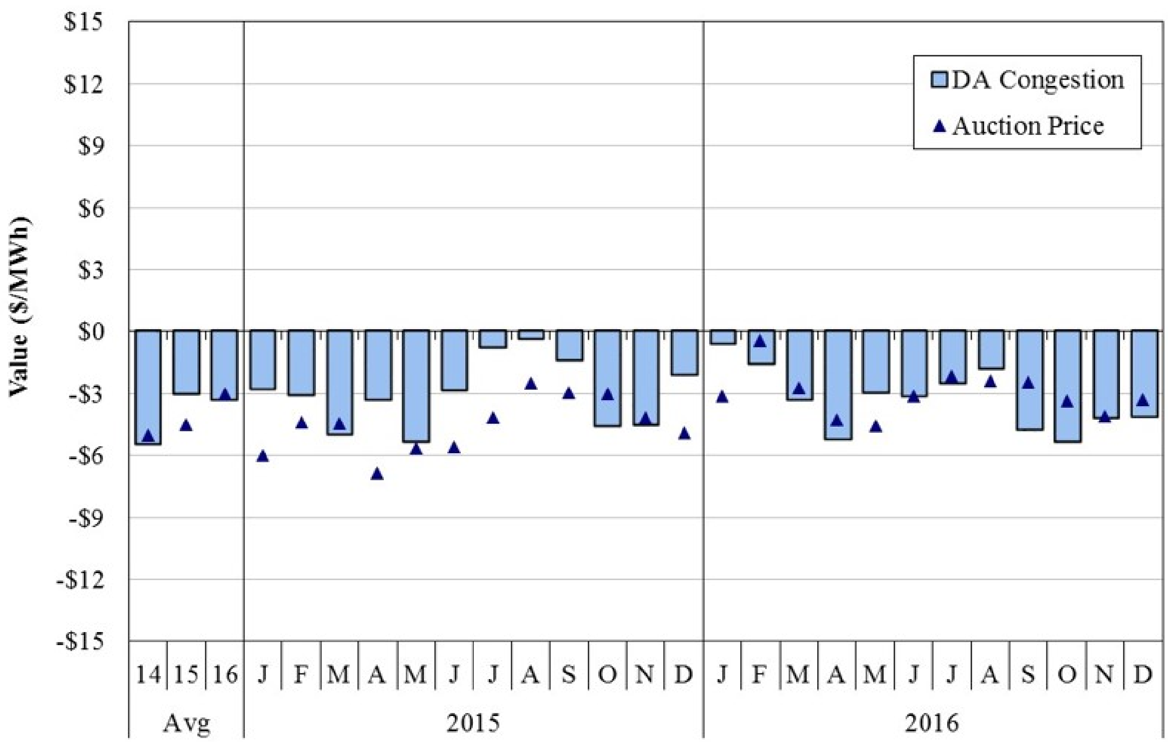


Figure A104: Comparison of FTR Auction Prices and Congestion Value
Minnesota Hub, 2015–2016: Peak Hours

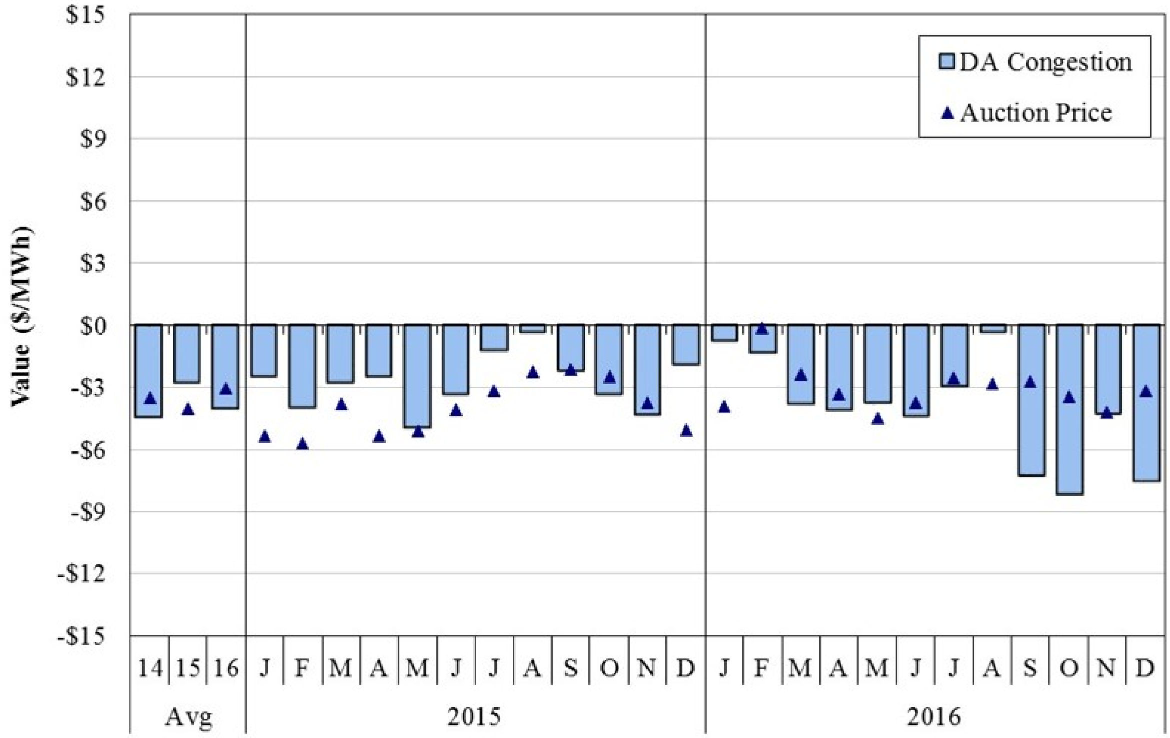


Figure A105: Comparison of FTR Auction Prices and Congestion Value
Arkansas Hub, 2015–2016: Off-Peak Hours

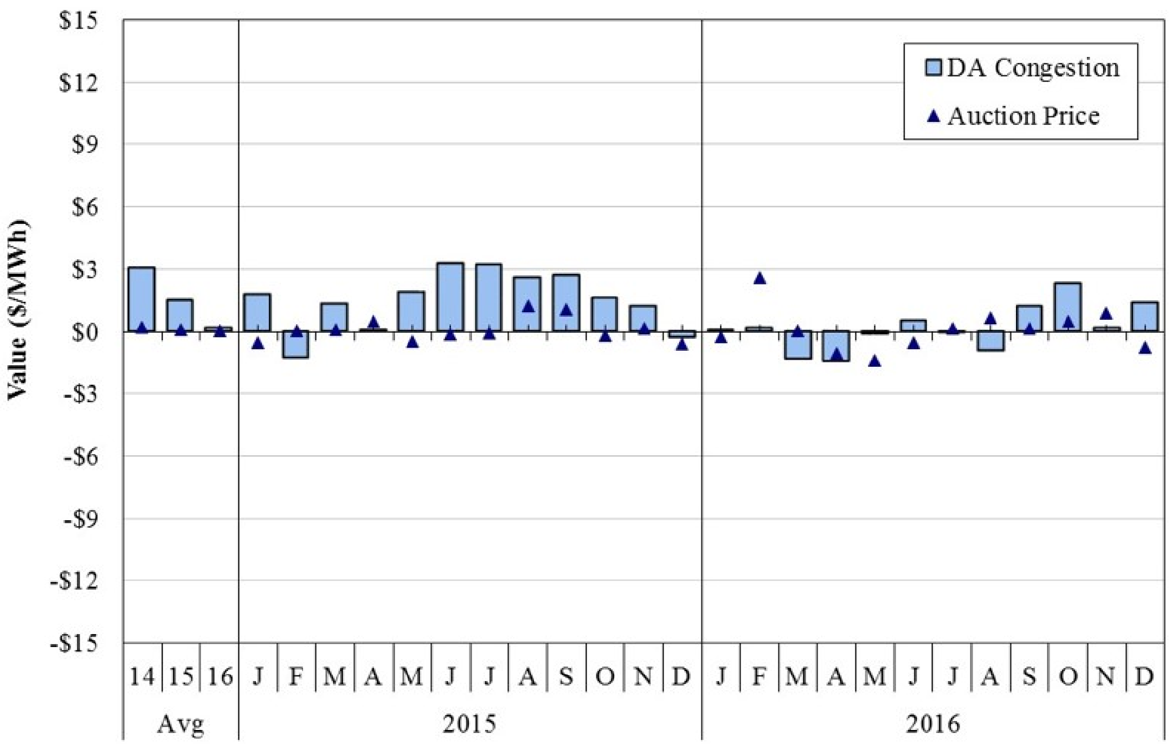


Figure A106: Comparison of FTR Auction Prices and Congestion Value
Arkansas Hub, 2015–2016: Peak Hours

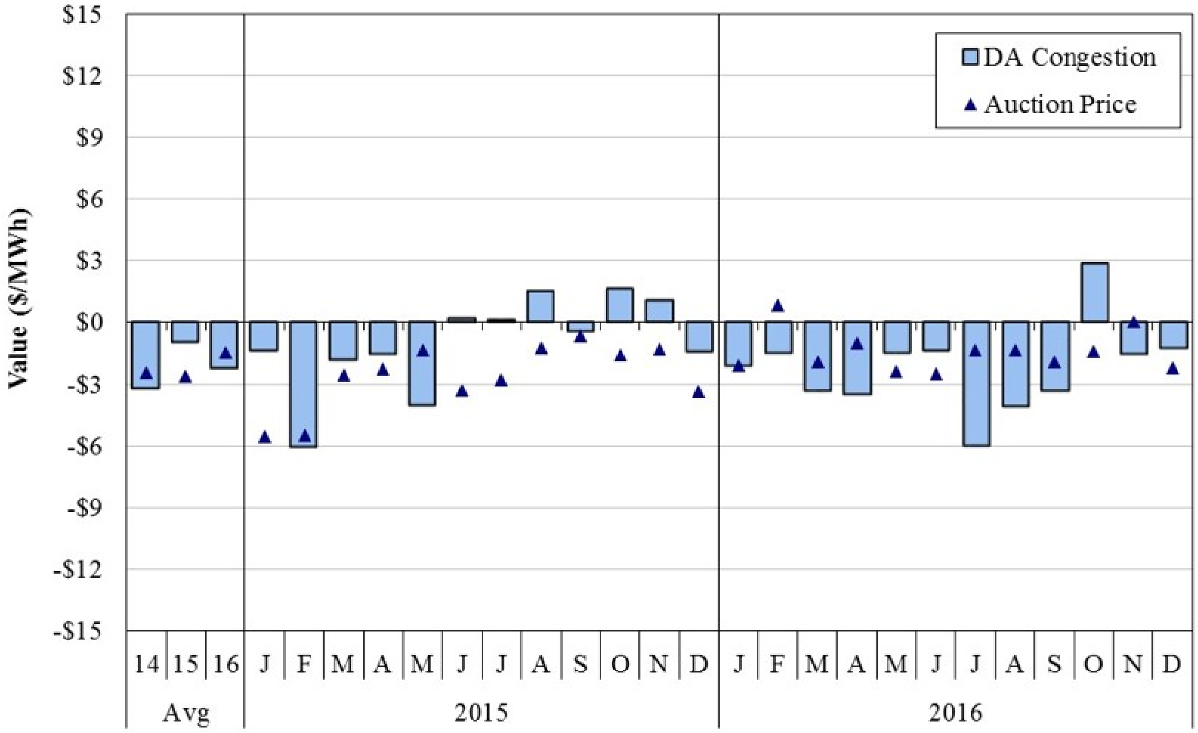


Figure A107: Comparison of FTR Auction Prices and Congestion Value
Louisiana Hub, 2015–2016: Off-Peak Hours

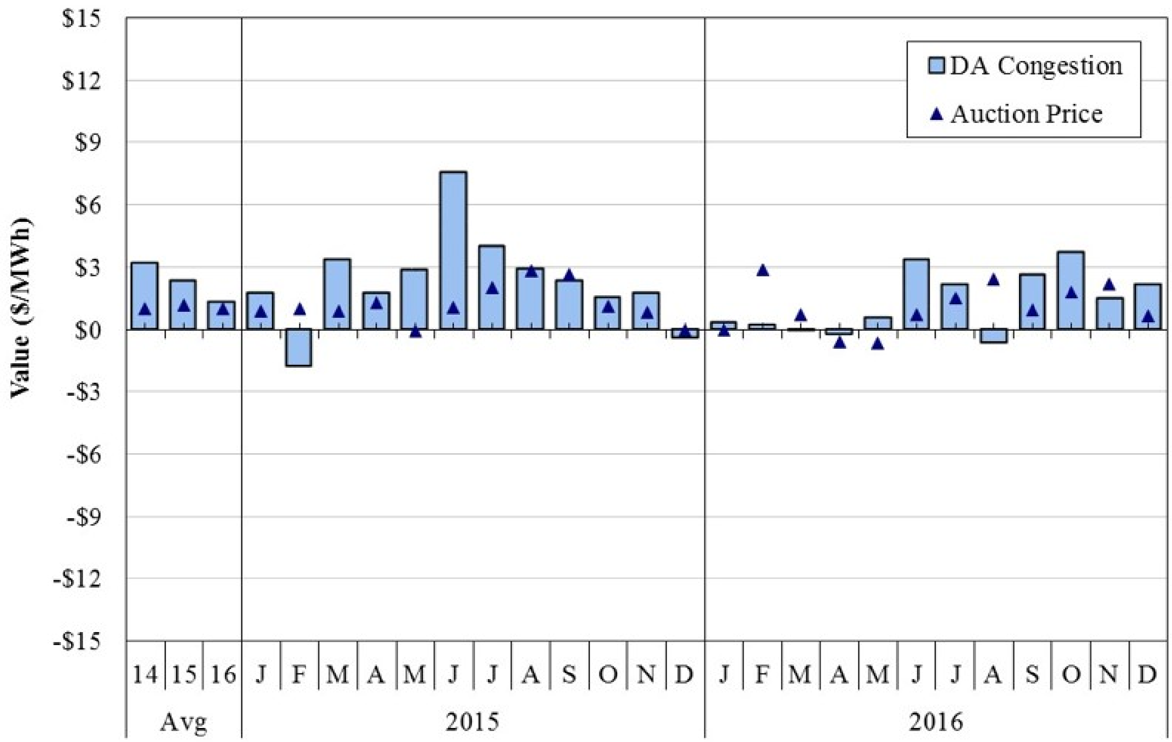


Figure A108: Comparison of FTR Auction Prices and Congestion Value
Louisiana Hub, 2015–2016: Peak Hours

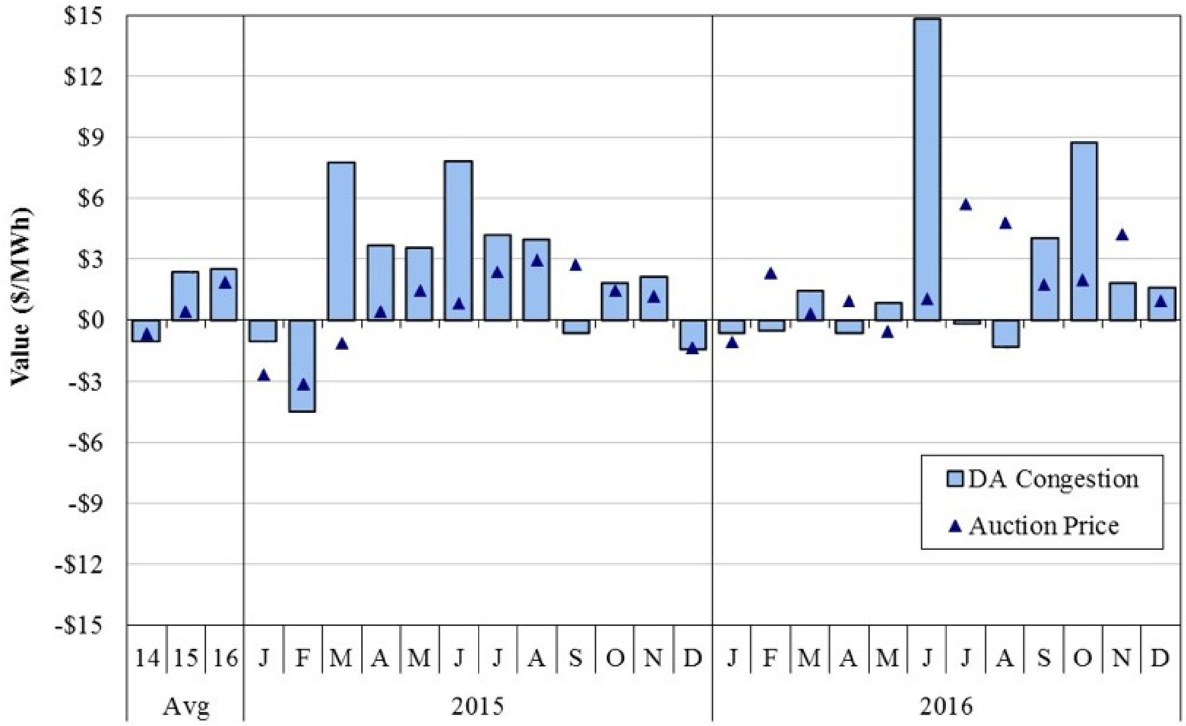


Figure A109: Comparison of FTR Auction Prices and Congestion Value
Texas Hub, 2015–2016: Off-Peak Hours

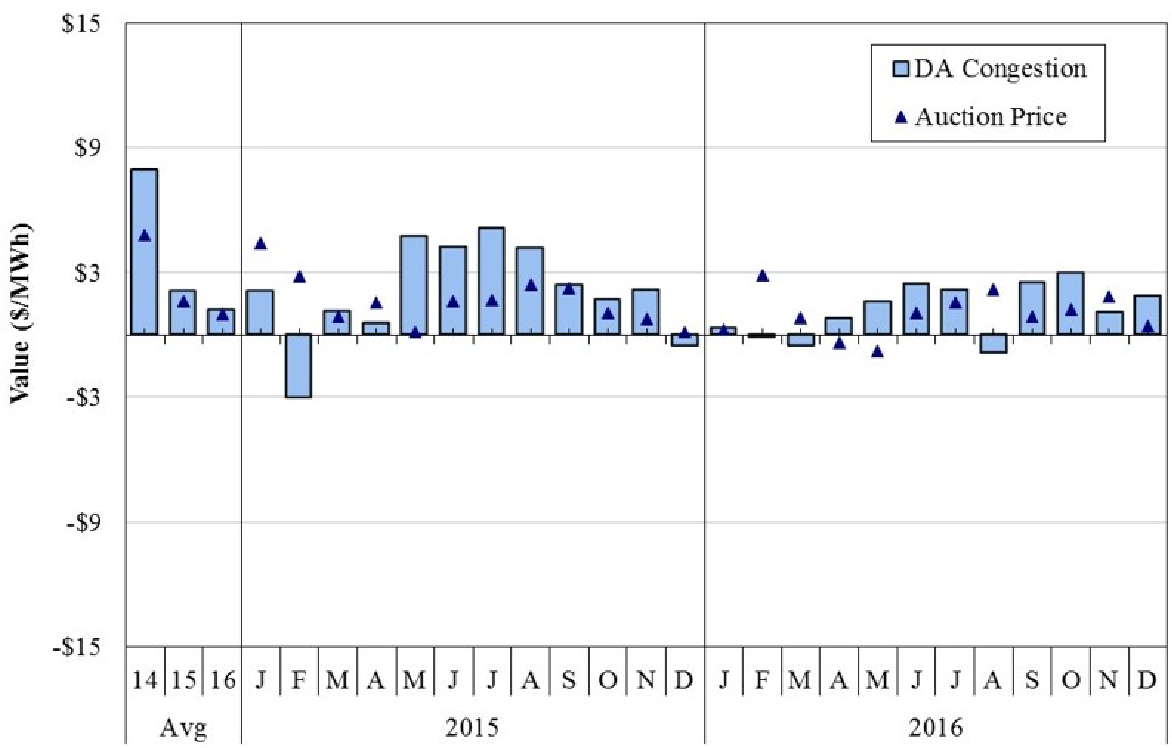
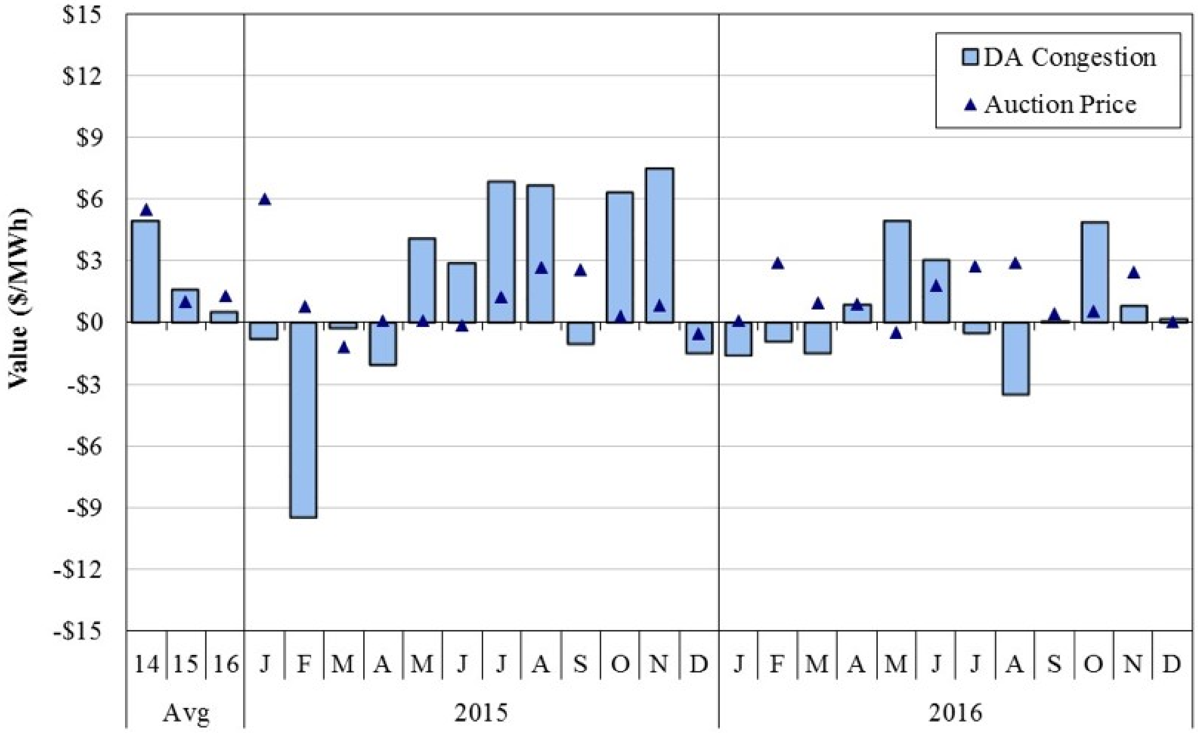


Figure A110: Comparison of FTR Auction Prices and Congestion Value
Texas Hub, 2015–2016: Peak Hours



J. Market-to-Market Coordination with PJM and SPP

The JOA between MISO and PJM establishes a M2M process for coordinating congestion management of designated transmission constraints on each of the RTO's systems. The objective of this process is to pursue efficient generation dispatch on these constraints and consistent prices between the markets.

When a M2M constraint is activated, the monitoring RTO provides its shadow price and the requested relief (i.e., the desired reduction in flow) from the other market. This shadow price measures the monitoring RTO's marginal cost for relieving the constraint. The relief requested varies considerably by constraint and over the coordinated hours for each constraint. The relief request is based on market conditions and is generally automated (although it can be manually selected by Reliability Coordinators). When the non-monitoring RTO receives the shadow price and requested relief quantity, it uses both values in its real-time market to provide as much of the requested relief as it can at a cost up to the monitoring RTO's shadow price. From a settlement perspective, each market is allocated FFE on each of the M2M constraints. Settlements between the RTOs based on their flows over the constraint relative to their FFEs.

Figure A111 and Figure A112: PJM and SPP Market-to-Market Events

Figure A111 and Figure A112 shows the total number of M2M constraint-hours coordinated between MISO and both PJM and SPP, respectively. 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 A111: Market-to-Market Events (MISO and PJM)
2015–2016

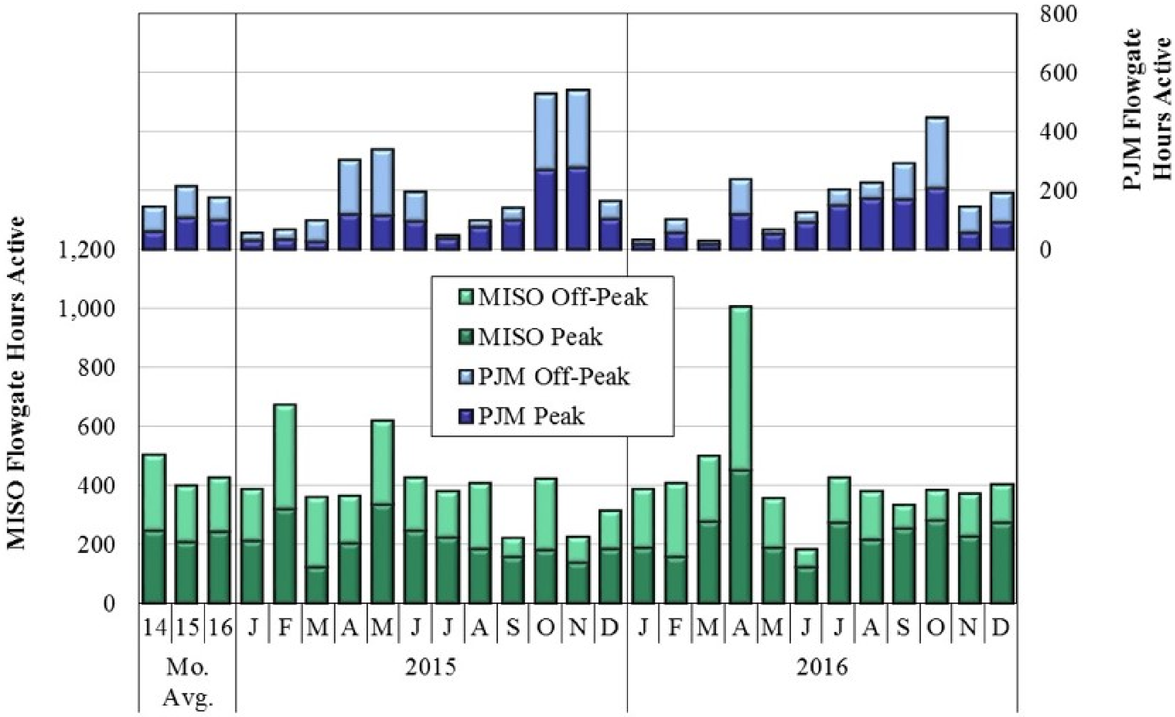


Figure A112: Market-to-Market Events (MISO and SPP)
2015–2016

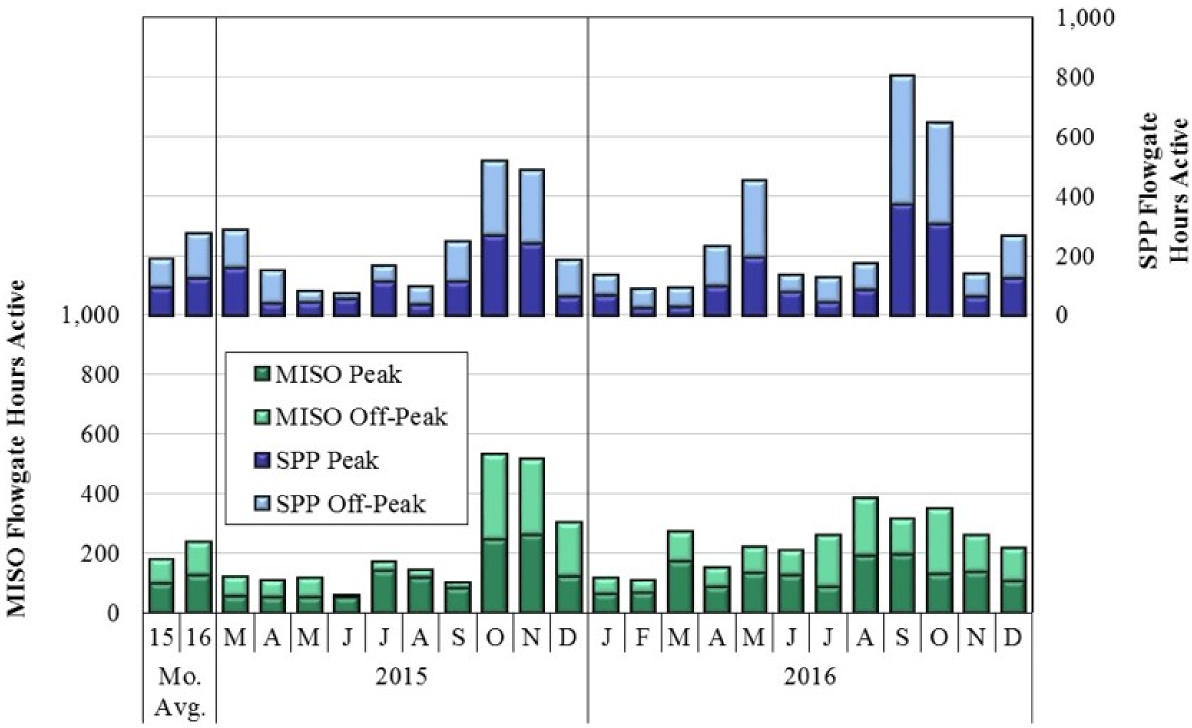


Figure A113: Market-to-Market Settlements

Figure A113 summarizes the financial settlement of M2M coordination with SPP and PJM. Settlement is based on the non-monitoring RTO's actual market flow compared to its FFE. If the non-monitoring 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 non-monitoring 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 from MISO to PJM and SPP on coordinated flowgates. The diamond marker shows net payments to or from MISO in each month.

Figure A113: Market-to-Market Settlements
2015–2016

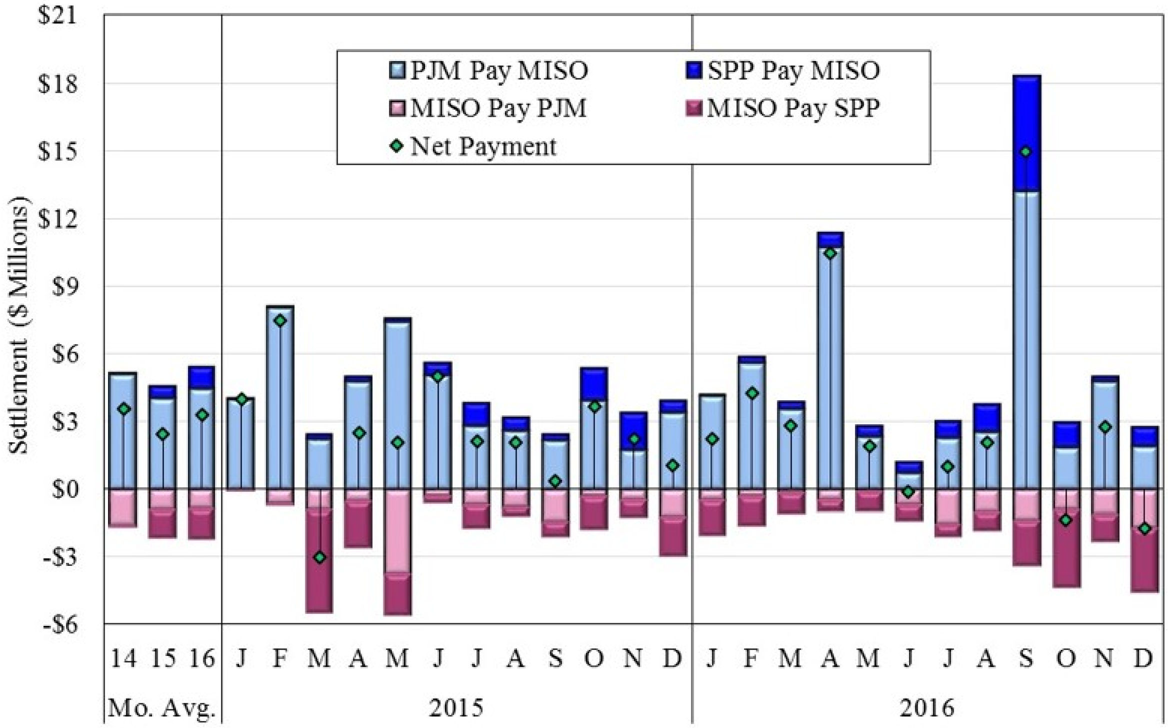


Figure A114 and Figure A115: Market-to-Market Outcomes with PJM

Successful M2M coordination should lead to two outcomes: a) the RTOs' shadow prices should converge after activation of a coordinated constraint; and b) the shadow prices should decrease from the initial value as the two RTOs jointly manage the constraint. The next two figures show the five most frequent M2M constraints by PJM and MISO, respectively. The analysis shows the extent to which the RTOs' shadow prices on coordinated constraints converge. We calculate the average shadow prices and relief requested during M2M events, including:

1. 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
2. Post-activation shadow prices for both the monitoring and reciprocating RTOs, which are the average prices in each RTO after the requested relief was provided.

The share of active constraint periods that were coordinated is shown below the x-axis. When coordinating, the reciprocating RTO provides relief by limiting flows in its real-time dispatch.

Figure A114: PJM Market-to-Market Constraints in 2016

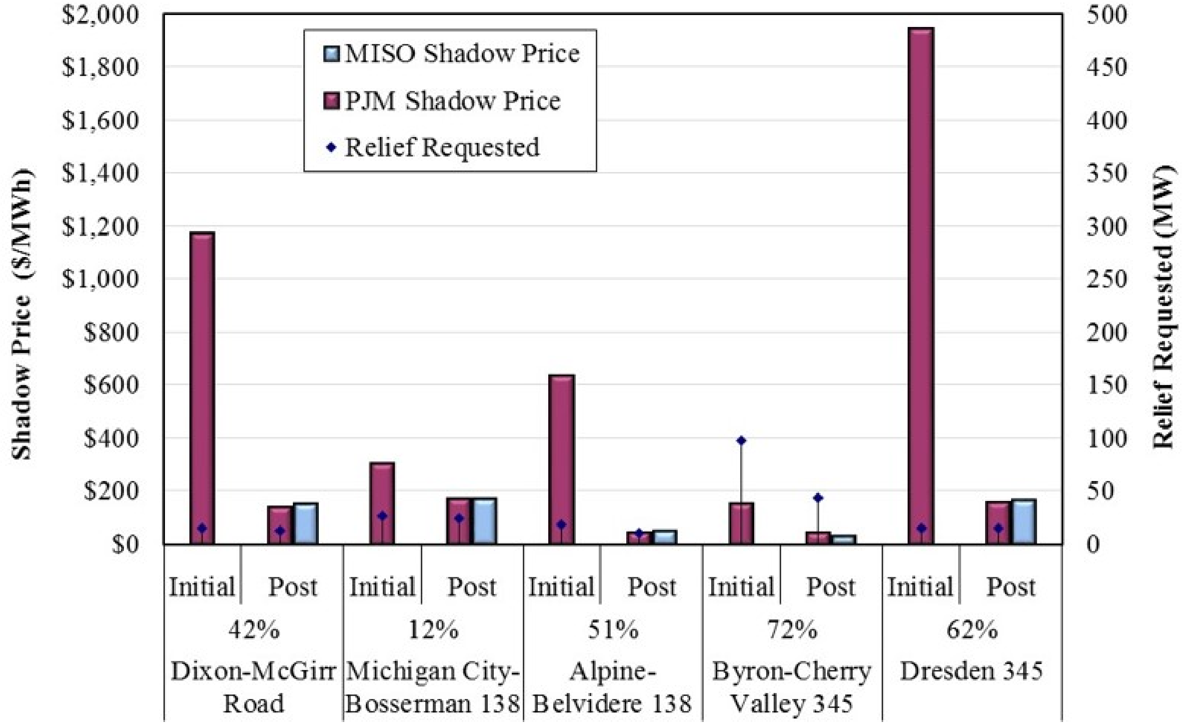


Figure A115: MISO Market-to-Market Constraints with PJM

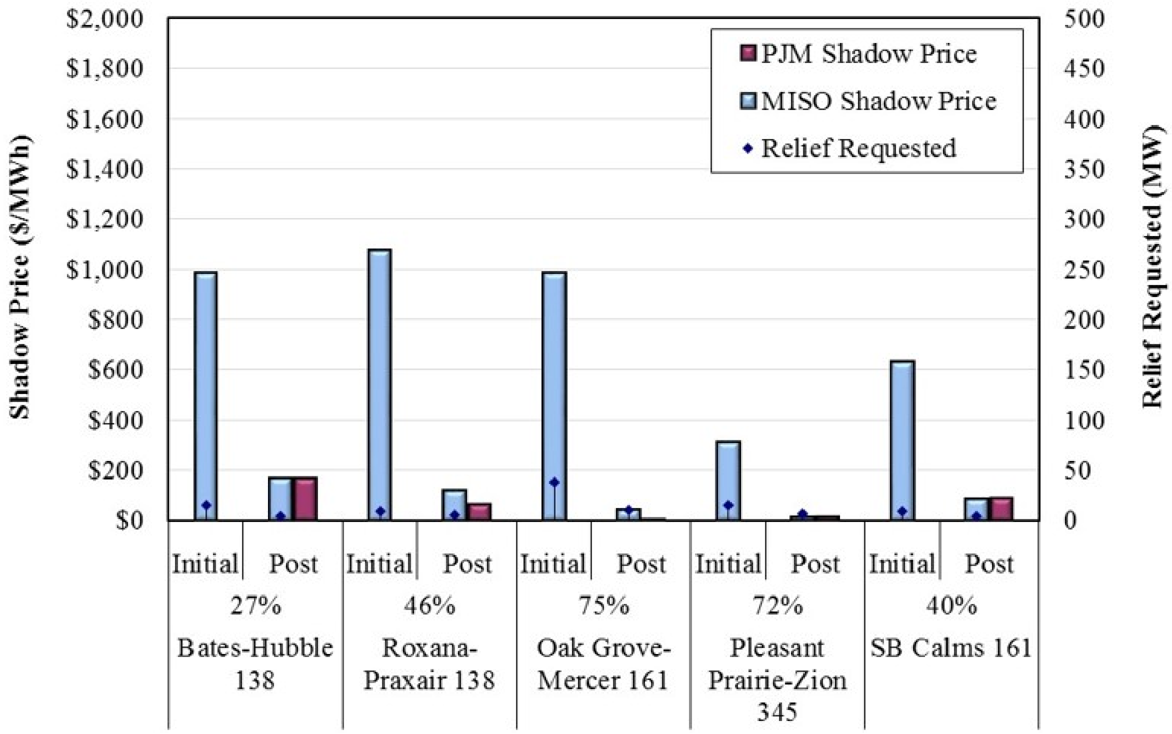


Figure A116 and Figure A117: Market-to-Market Outcomes with SPP

On March 1, 2015, MISO implemented M2M coordination with SPP and began coordinating with SPP in the WAPA Basin region after October 2015. Early issues arose and MISO is working with SPP to develop procedures to address these issues. These procedures involve transferring control of M2M constraints to the neighboring RTO if it has the most effective relief for the constraint. In late June MISO and SPP executed a Memorandum of Understanding (MOU). The RTOs reached agreement on the most important aspects of coordination under the JOA. The MOU should help the RTOs avoid future issues similar to those that occurred in 2015.

The next two figures examine the five most frequently coordinated M2M constraints by SPP and MISO, respectively. As with the prior two figures, the analysis is intended to show the extent to which shadow prices on coordinated constraints converge between the two RTOs. The figures shows the same results for the constraints coordinated with SPP as the prior two figures showed for the constraints coordinated with PJM.

Figure A116: SPP Market-to-Market Constraints
2016

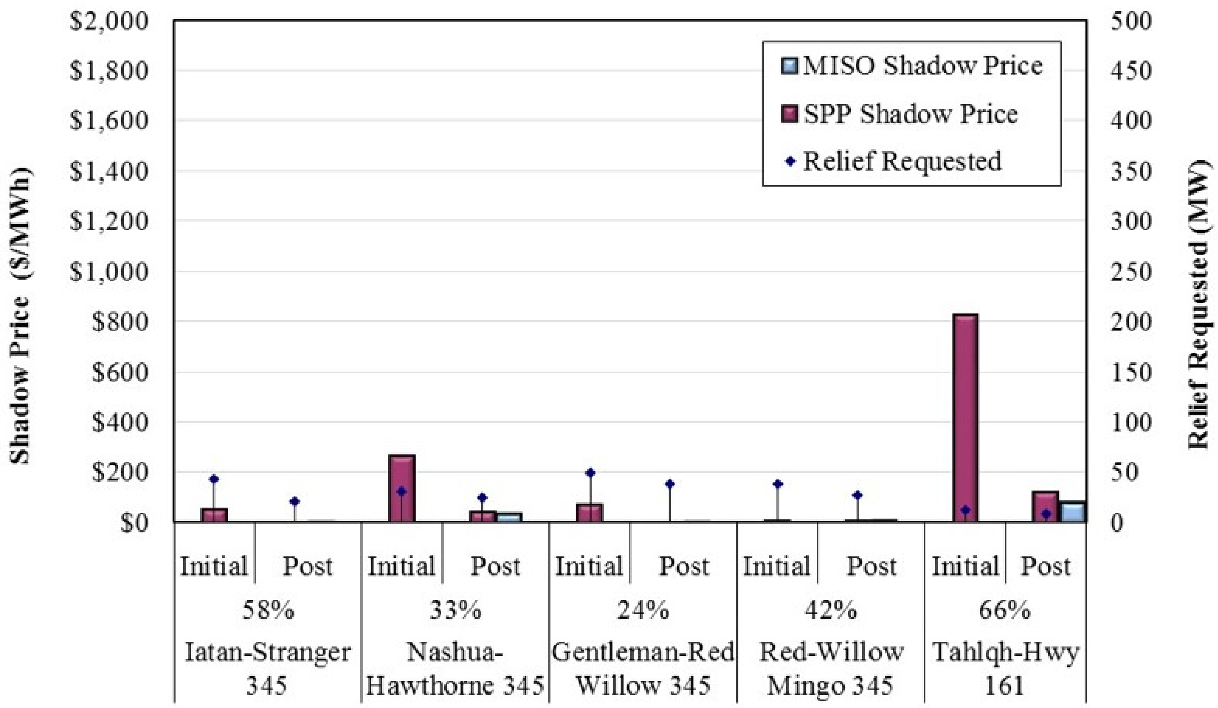


Figure A117: MISO Market-to-Market Constraints with SPP
2016

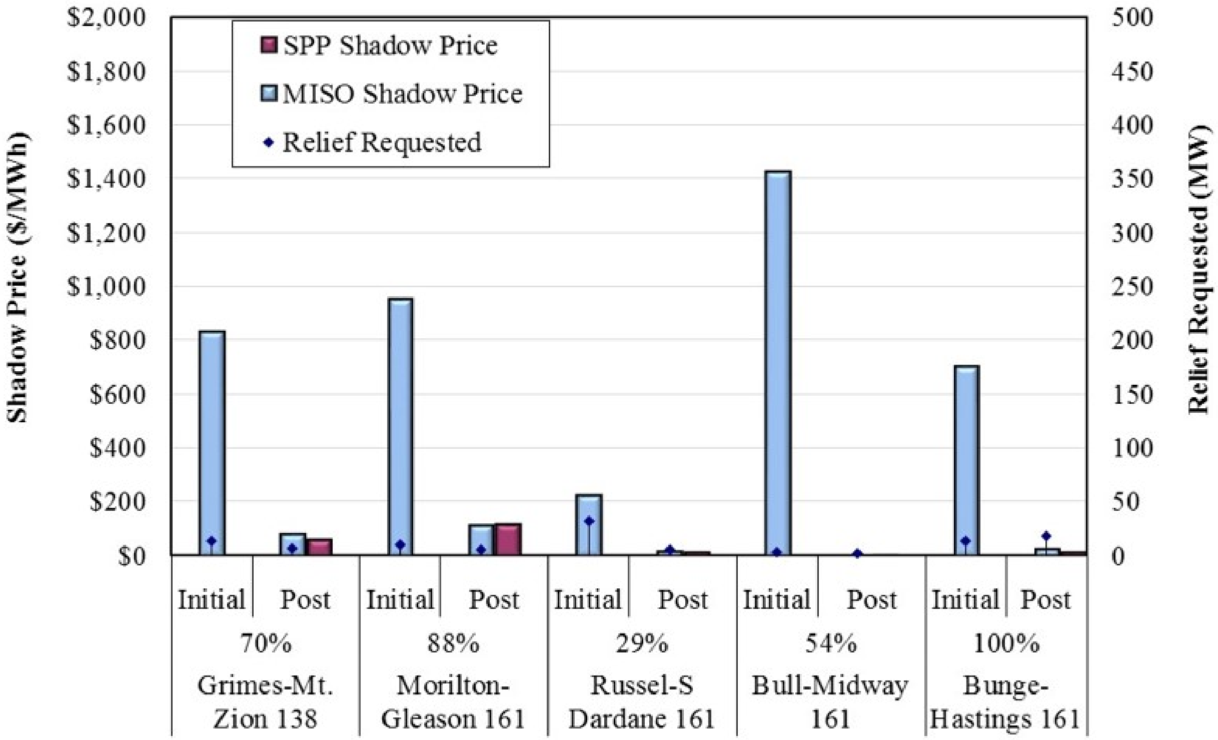


Figure A118: Congestion Costs on PJM and SPP Flowgates

Figure A118 shows the congestion prices in MISO markets associated with SPP and PJM transmission constraints. The figure shows the total share of the locational congestion prices in MISO's LMPs that are attributable to PJM's and SPP's constraints.

These results are divided between the prices that results from normal M2M coordination and prices associated with non-conventional M2M procedures (i.e., using overrides, safe operating modes, TLRs, or other processes to manage the congestion). Although sometimes justified, these alternatives are generally less efficient and lead to higher congestion costs so it is valuable to understand the extent to which they are being utilized.

Figure A118: Congestion Costs on PJM and SPP Flowgates
2015–2016

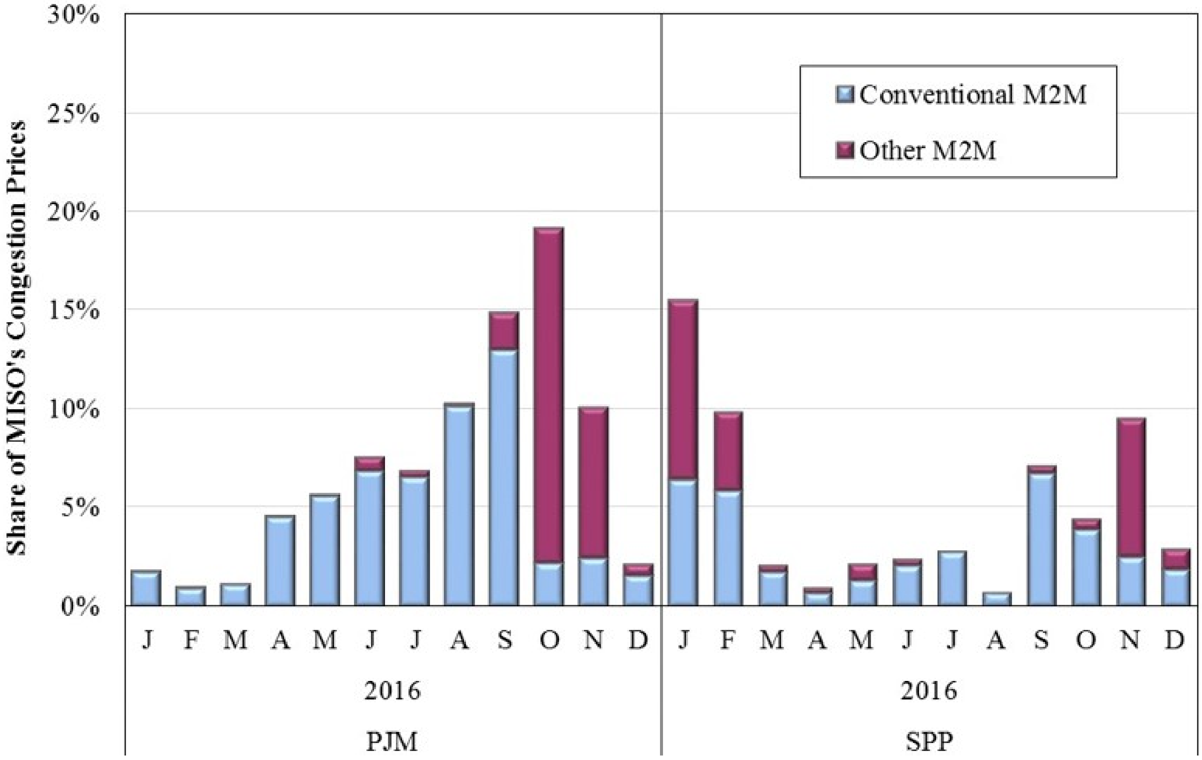


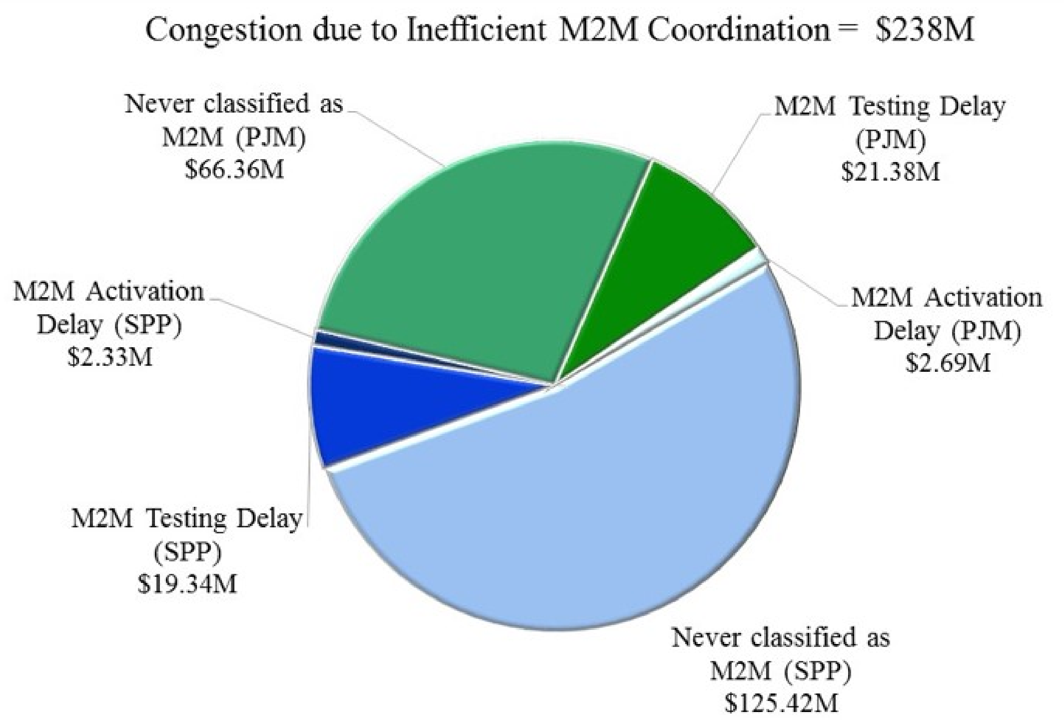
Figure A119: Congestion Due to Inefficient M2M Coordination

While the market-to-market process improves efficiency overall, we evaluated three issues that can reduce the efficiency and effectiveness of coordination:

- Failure to test all constraints that might qualify to be new market-to-market constraints;
- Delays in testing constraints after they start binding to determine whether they should be classified as market-to-market; and
- Delays in activating market-to-market constraints for coordination after they have been classified as market-to-market.

Each of these issues is significant because when a market-to-market constraint is not identified or activated, the savings of enlisting the non-monitoring RTO to provide economic relief on the constraint disappear. It also raises serious equity concerns because the non-monitoring RTO may vastly exceed its firm flow entitlements on the constraint with no compensation to the monitoring RTO. We developed a series of screens to identify constraints that should have been coordinated but were not because of the issues listed above. These screens identified 263 non-market-to-market constraints that should have been coordinated as market-to-market with either PJM or SPP. We then quantified the congestion on these constraints, which is shown in Figure A119.

Figure A119: Congestion Due to Inefficient M2M Coordination
2016



K. Effects of Pseudo-Tying MISO Generators

In recent years, increasing quantities of MISO capacity have been exported to PJM. PJM has recently implemented rules that require external capacity to be pseudo-tied to PJM. Beginning in 2015 and continuing into 2017, we have been raising serious concerns about this trend because allowing PJM to dispatch large numbers MISO generators will:

- Cause forward flows over a large number of MISO transmission facilities that are difficult to manage; and
- Transfer control of generators that relieve other MISO constraints so that MISO will no longer have access to them to manage congestion on these constraints.

The first issue can be partially addressed to the extent that these constraints will be defined as market-to-market constraints and, therefore, coordinated with PJM. However, this coordination is not as effective as dispatch control and many constraints will not be coordinated.

Figure A120: Effects of Pseudo-Tying MISO Resources to PJM

Figure A120 shows our evaluation of the effects of pseudo-tying the generators to PJM. This shows the value of real-time congestion on constraints that qualified as new market-to-market constraints only because of the resources that are pseudo-tied to PJM. The purpose of this analysis was to determine whether the pseudo ties are leading to less efficient congestion management and higher resulting congestion costs. The left side of the figure shows the monthly congestion on these constraints for the year that preceded the initiation of the first tranche of pseudo-ties on March 1, 2016. The second tranche of pseudo-ties began on June 1, 2016. The pink shading to the right shows the real-time congestion value on the same constraints in those months that these pseudo-ties were in place. The inset indicates the average congestion on the constraints per month prior to the pseudo-ties, and the average congestion on the same constraint

Figure A120: Effects of Pseudo-Tying MISO Resources to PJM
2016

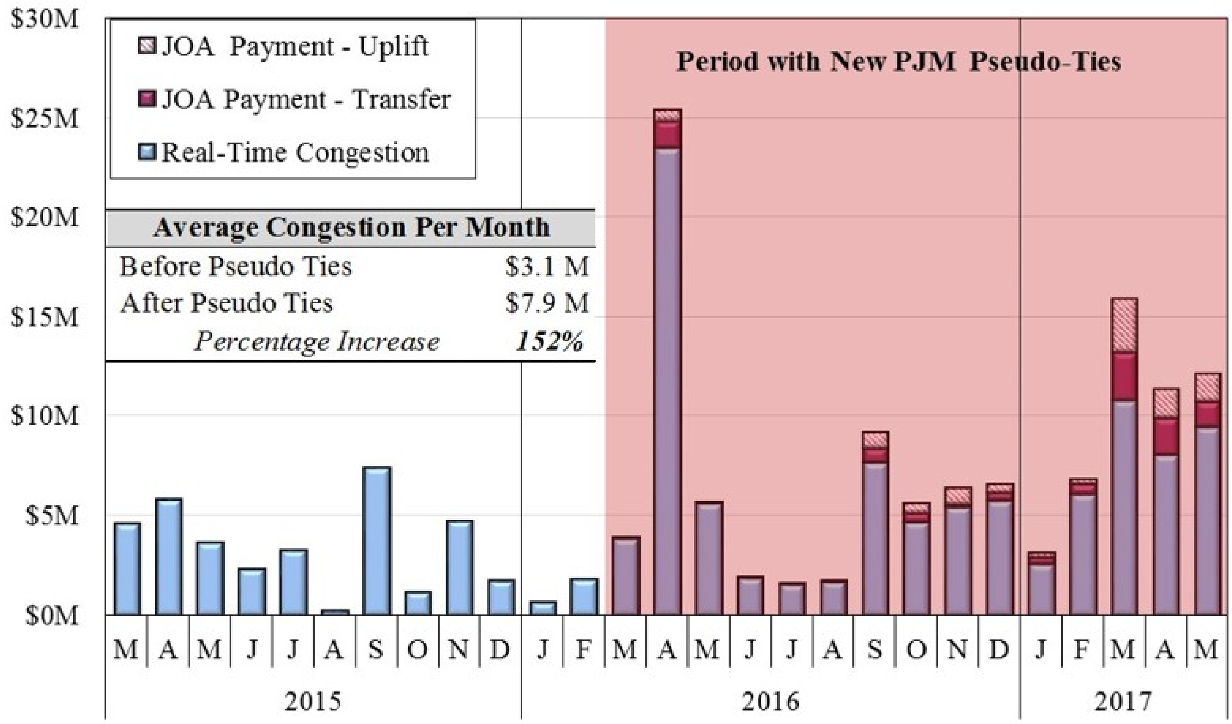


Figure A121: Potential Pseudo-Tie Impacts on MISO Constraints

We conducted an analysis to determine how many constraints have been or will need to be defined as M2M constraints solely because resources in MISO have been pseudo-tied to PJM. Pseudo-tied units located on MISO's transmission system are now under the dispatch control of PJM, so the flows they cause on MISO's constraints have become PJM's market flows. The market-to-market process is necessary to manage these flows. Unfortunately, the market-to-market coordination is not nearly as effective as full dispatch control, and many of the constraints remain non-market-to-market constraints.

In Figure A121, we identified a number of new M2M constraints that resulted from the March 2016 and June 2016 pseudo ties, as well as those that would have resulted were all of the capacity exported from MISO South into PJM in June 2017 pseudo-tied.[32] The left panel of the figure shows the constraints that the pseudo-tied units load (positive GSFs) that now qualify to be M2M constraints. The right panel shows the constraints that they unload (negative GSFs).

[32] Capacity exports in MISO South, while currently not required to pseudo-tie unless they are Capacity Performance resources, will ultimately have to pseudo-tie into PJM for the delivery year 2020/2021. This will cause many more constraints to be managed through the M2M process.

The drop line in each panel shows the number of new MISO constraints in each class that currently qualify or would qualify as market-to-market constraints, while the bars show the value of the real-time congestion on the constraints. Finally, the data is divided to show the effects of each of the groups of resources by the time period in which their capacity exports begin.

Figure A121: Potential Pseudo-Tie Impacts on MISO Constraints

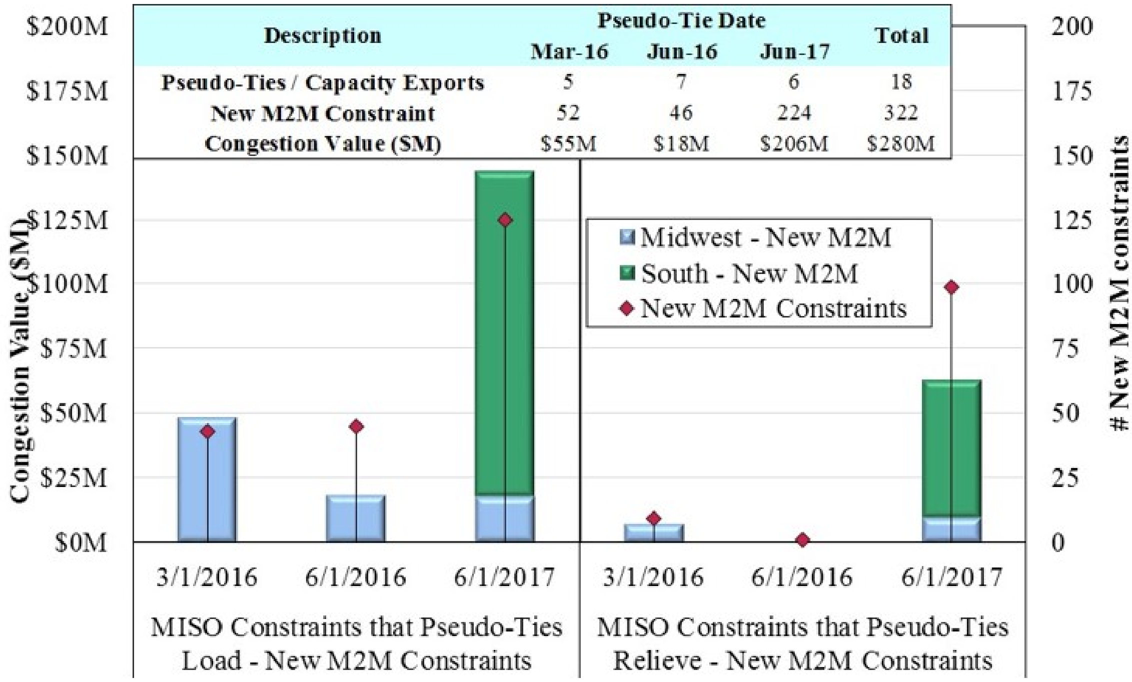


Figure A122: Inefficient Dispatch of MISO's Pseudo-Tied Units

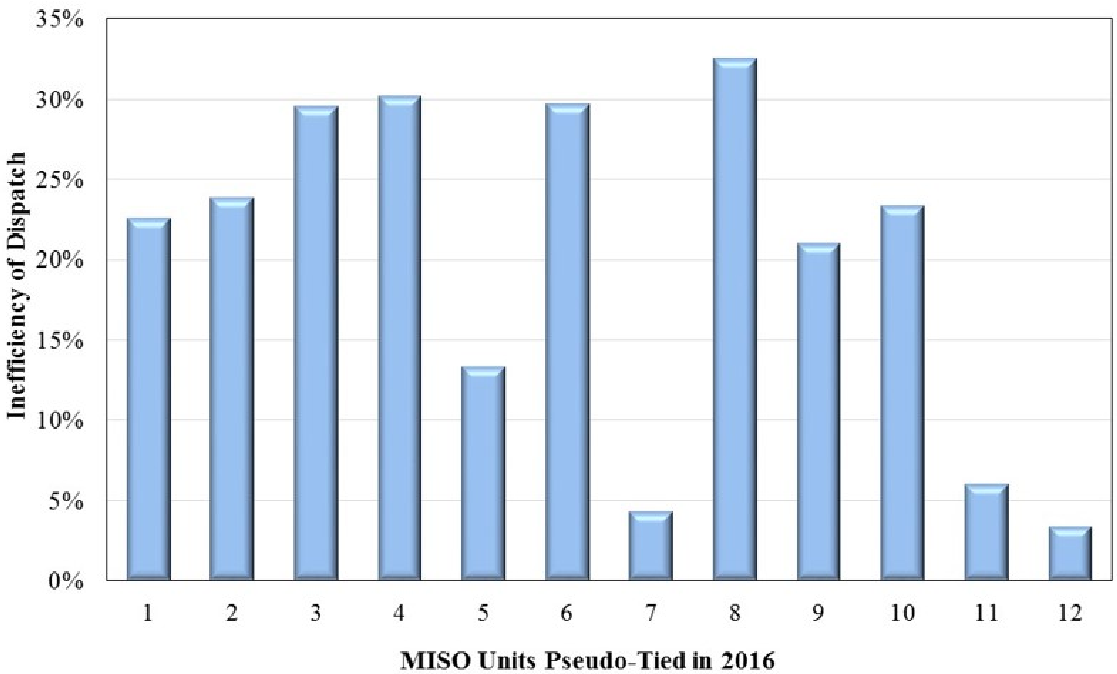
We have identified substantial dispatch inefficiencies and operational concerns associated with the proliferation of pseudo-ties. Many of these inefficiencies and operational issues are impossible to quantify. We performed an analysis of the dispatch inefficiencies associated with the 12 resources that were pseudo-tied by PJM in 2016. We measured the value of the dispatch inefficiencies by calculating the economic value of the output deviation.

The optimal dispatch by MISO is based on our estimate of its production costs and ramp rate limitations. It is important to include ramp rates in the analysis because resources cannot instantaneously move to the most economic dispatch level. The optimal dispatch in MISO is based on MISO LMPs because MISO's dispatch and prices fully capture all of the congestion and transmission losses based on MISO's more complete and accurate model of the system where the unit is located. The output deviation will be positive when the unit produces less output than optimal in MISO and negative when it produces more output than optimal in MISO.

We calculated a net inefficiency as the value of the output deviation to MISO, based on MISO's LMPs, minus the change in production costs to the unit of producing the optimal output. The net inefficiency is equal to: (output deviation * LMP_{MISO}) – (production cost of output deviation). This value is generally positive, and it represents forgone production costs savings when the unit is under-producing and inefficient production costs when the unit is over producing. The inefficiencies are particularly large when congestion is affected by the pseudo-tied units. Therefore, we calculated the net inefficiency as a percentage for each online unit in hours when congestion was greater than $5 per MWh at the units' locations by dividing the value of the net inefficiency by the total energy production costs of the units. The results of this analysis are shown in Figure A122 for each of the 12 currently pseudo-tied units.

Figure A122 shows that these units were dispatched inefficiently when they were online and affecting constraints on MISO's transmission system. Eight of the 12 units exhibited average inefficiencies greater than 20 percent. In other words, these units generally ran at levels that were much higher or much lower than optimal during congested periods. Figure A122 does not include periods when the units were clearly economic based on MISO's LMPs but were not committed by PJM. This was a frequent occurrence for one set of pseudo-tied resources.

Figure A122: Inefficient Dispatch of MISO's Pseudo-Tied Units
2016



These inefficiencies are very likely understated in our analysis because they do not include two other types of inefficiencies:

- Cases where the units would not have been economically committed by MISO (i.e., they were uneconomically committed through the PJM markets); or
- MISO committing and dispatching other (non-pseudo-tied) units inefficiently because it does not know how the pseudo-tied units will be dispatched.

During the periods that we analyzed, the weighted-average inefficiency exceeded 26 percent for the twelve pseudo-tied units. PJM incurs some of the costs implications of these problems because inefficient congestion management will often increase congestion costs on MISO's market-to-market constraints for which PJM bears cost responsibility.

L. Congestion on External Constraints

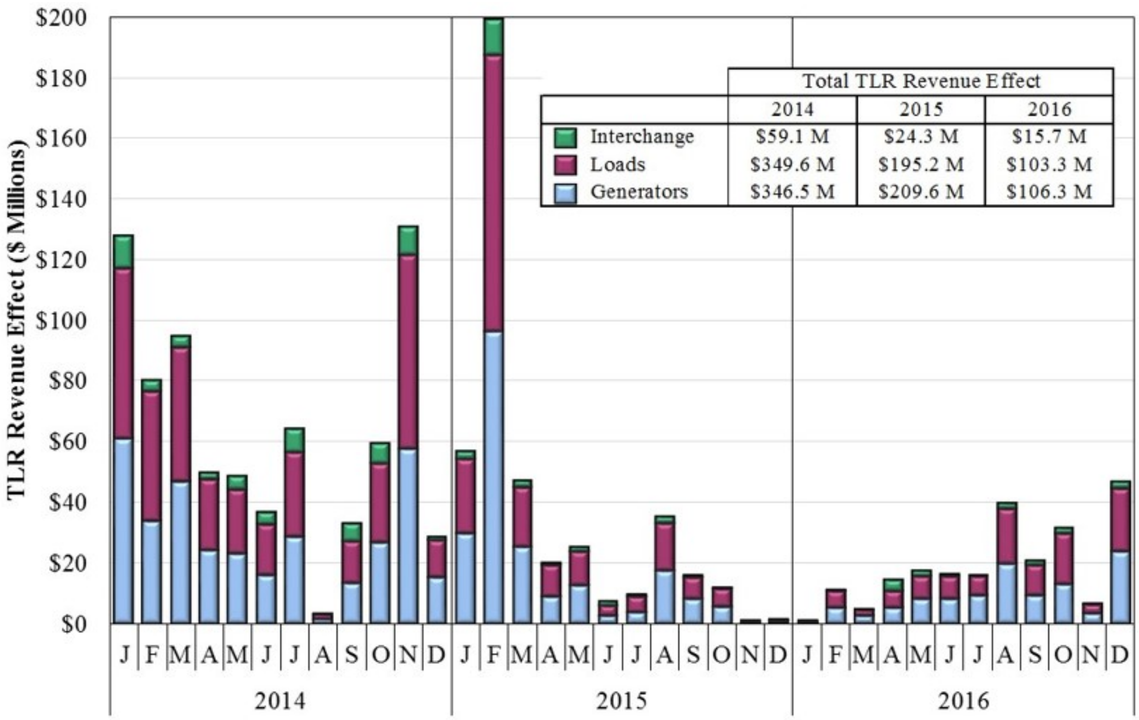
This subsection provides an analysis of congestion that occurs on external constraints located in adjacent systems. MISO incurs congestion on external constraints when a neighboring system calls a TLR for a constraint or initiates M2M coordination. When this occurs, MISO activates the constraint as it would an internal constraint, seeking to reduce its flow over the constraint by the amount of the required relief. This process will be efficient only if the cost of the relief provided by MISO is less costly than the adjacent system's cost to manage the flow on the constraint. Unfortunately, this has historically not been true. One contributing factor is that MISO receives relief obligations based on its forward flows, not the net flows it is actually causing. Because the relief obligation is outsized, it is often very costly for MISO to provide the relief requested, and MISO's marginal cost of providing the relief is included in its LMPs.

Figure A123: Real-Time Valuation Effect of TLR Constraints

Because external constraints can cause substantial changes in LMPs within MISO, we estimate the effects of these changes by calculating the total increase in real-time payments by loads and the reduction in payments to generators caused by the external constraints. External constraints also affect interface prices and the payments made to participants scheduling imports and exports, an issue that is further evaluated in Section VII.B.

Figure A123 shows increases and decreases in hourly revenues that result from TLR constraints binding in MISO. The reported congestion value for these constraints is low because MISO's market flow on external flowgates is generally low or negative. It therefore masks the larger impact that these constraints have on MISO's dispatch and pricing.

Figure A123: Real-Time Valuation Effect of TLR Constraints
2014–2016



VII. External Transactions

MISO is a net importer of power during nearly all hours and seasons. Given this reliance on imports, the processes to schedule and price interchange transactions can have a substantial effect on the performance and reliability of MISO's markets.

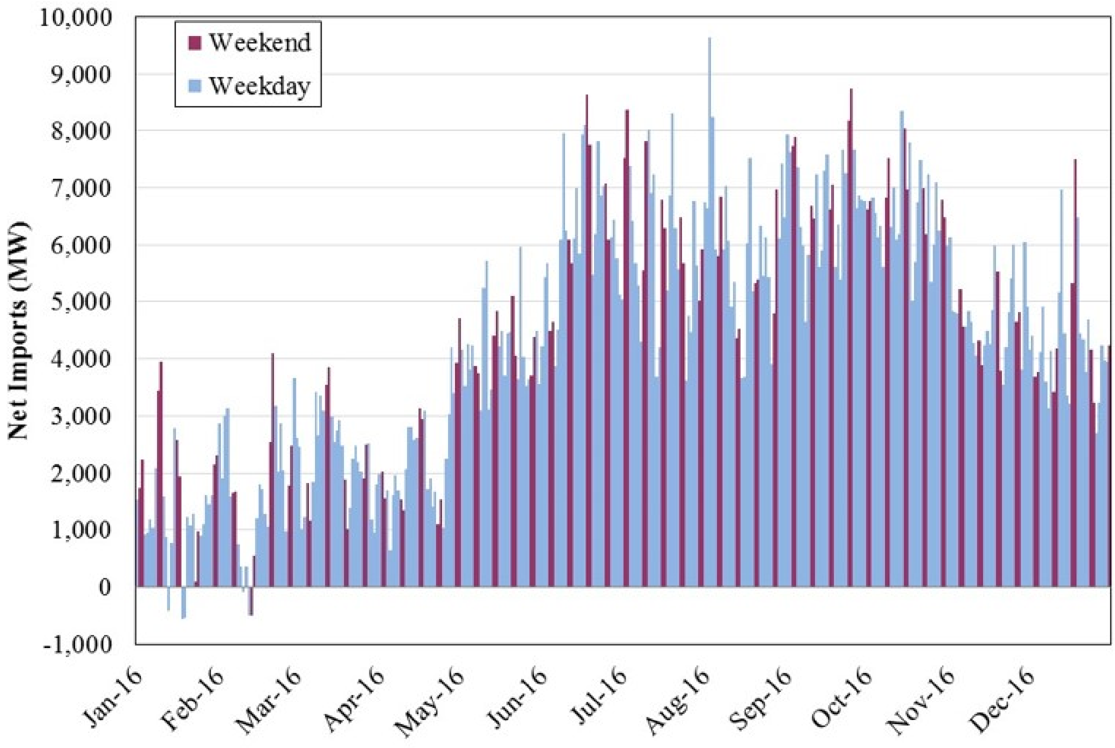
Imports and exports can be scheduled on a 15-minute basis, although the schedules are fixed 20 minutes before the transactions occur. The scheduling notification period was reduced from 30 minutes to 20 minutes on October 15, 2013, to satisfy the requirements of FERC's Order 764. Participants must reserve 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 submit a price-sensitive offer for external transactions in the real-time market. 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 A124 to Figure A127: Average Hourly Imports

The following four figures 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.

Figure A124: Average Hourly Day-Ahead Net Imports
All Interfaces, 2016



The second figure shows real-time net imports and changes from day-ahead net import levels. When net imports decline in real time, MISO may be compelled to commit peaking resources to satisfy the system's needs. The third and fourth figures show this information by interface.

Figure A125: Average Hourly Real-Time Net Imports in 2016

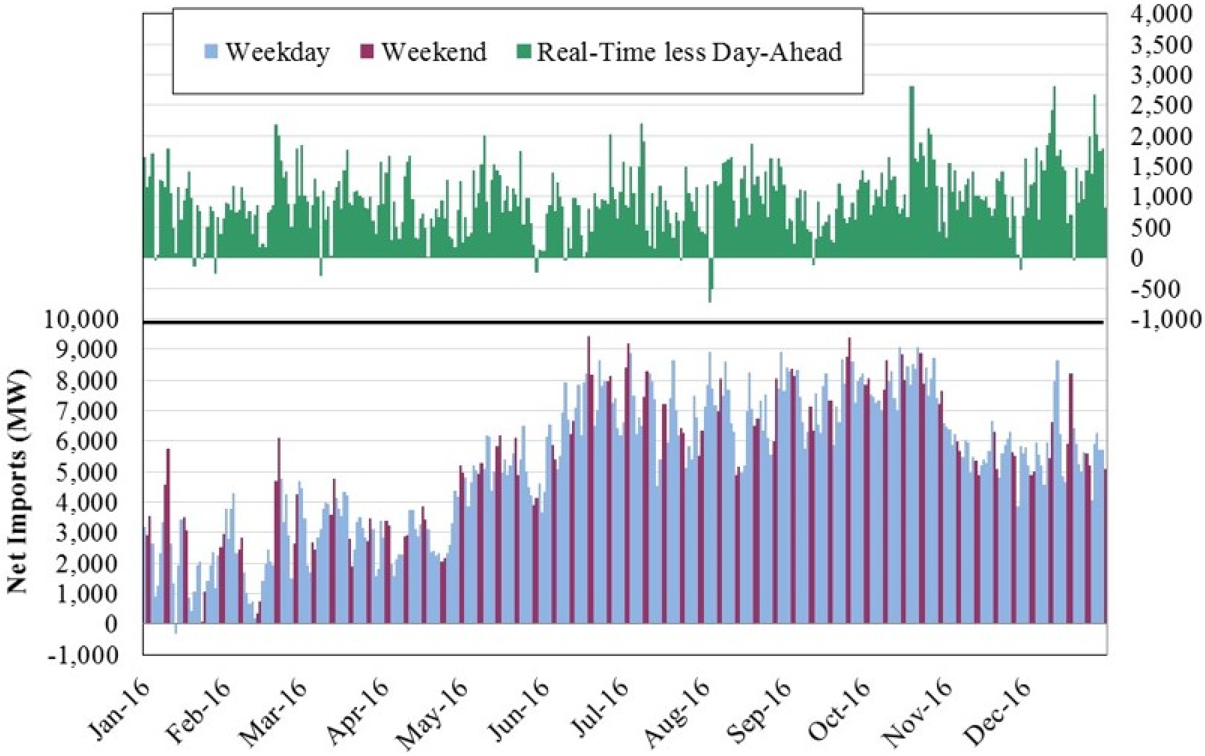


Figure A126: Average Hourly Day-Ahead Net Imports in 2016

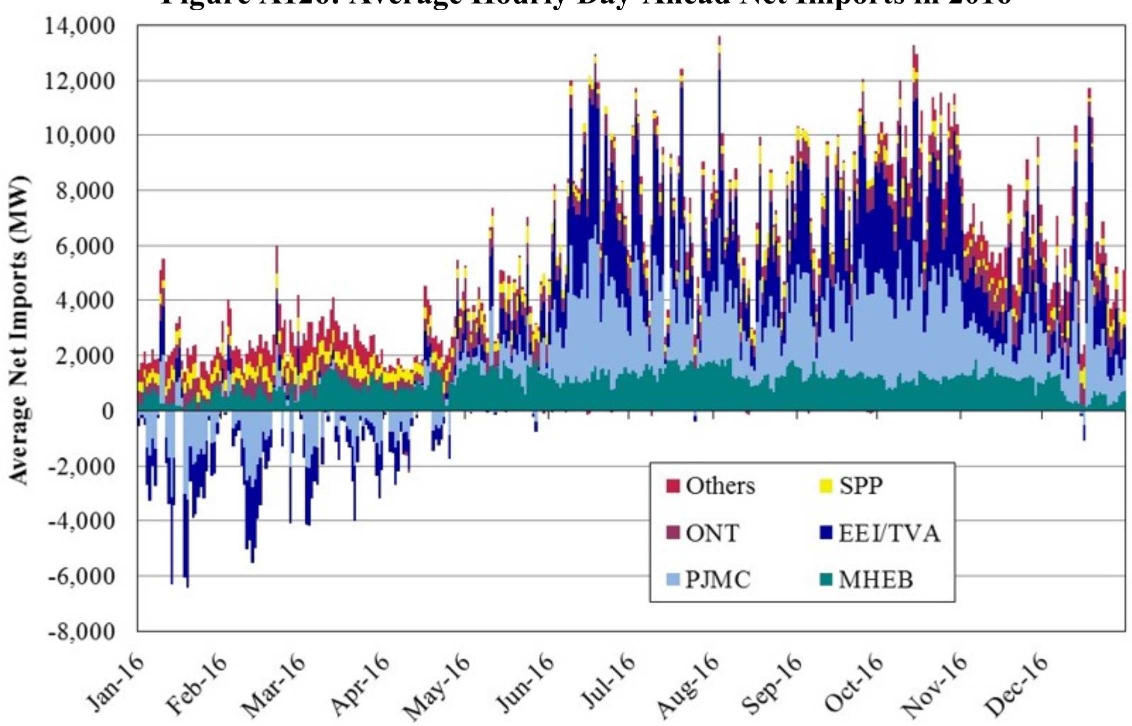


Figure A127: Average Hourly Real-Time Net Imports
2016, by Interface

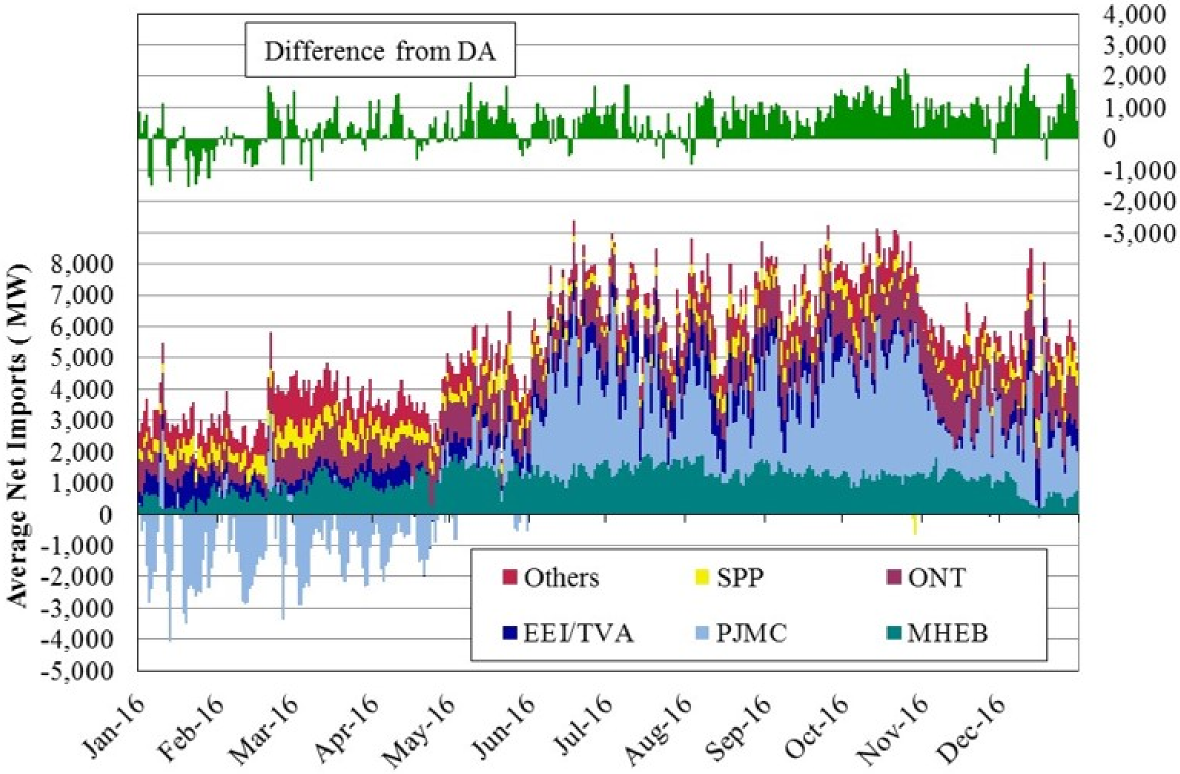


Figure A128 and Figure A129: Average Hourly Real-Time Net Imports by Interface

The next two figures examine net real-time imports for the PJM and Manitoba/Ontario interfaces. The interface between MISO and PJM, both of which operate LMP markets over wide geographic areas, is one of the most significant interfaces for MISO, because the interface can support interchange in excess of five GW per hour. Relative prices in adjoining areas govern net interchange. Therefore, price movements cause incentives to import or export to change over time.

Accordingly, Figure A128 shows the average quantity of net imports scheduled across the MISO-PJM interface in each hour of the day in 2015 and 2016, along with the standard deviation of such imports.[33] The subsequent figure shows the same results for the two Canadian interfaces (Manitoba Hydro, at left, and Ontario).

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

Figure A128: Average Hourly Real-Time Net Imports from PJM
2015–2016

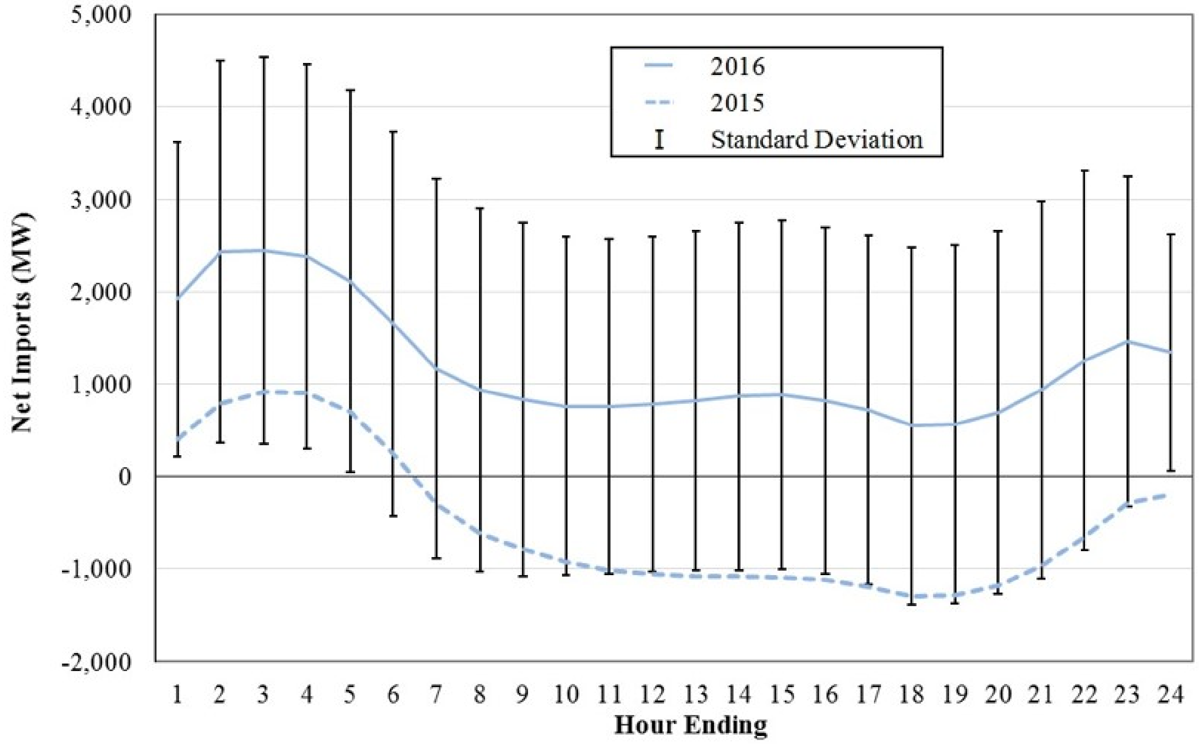
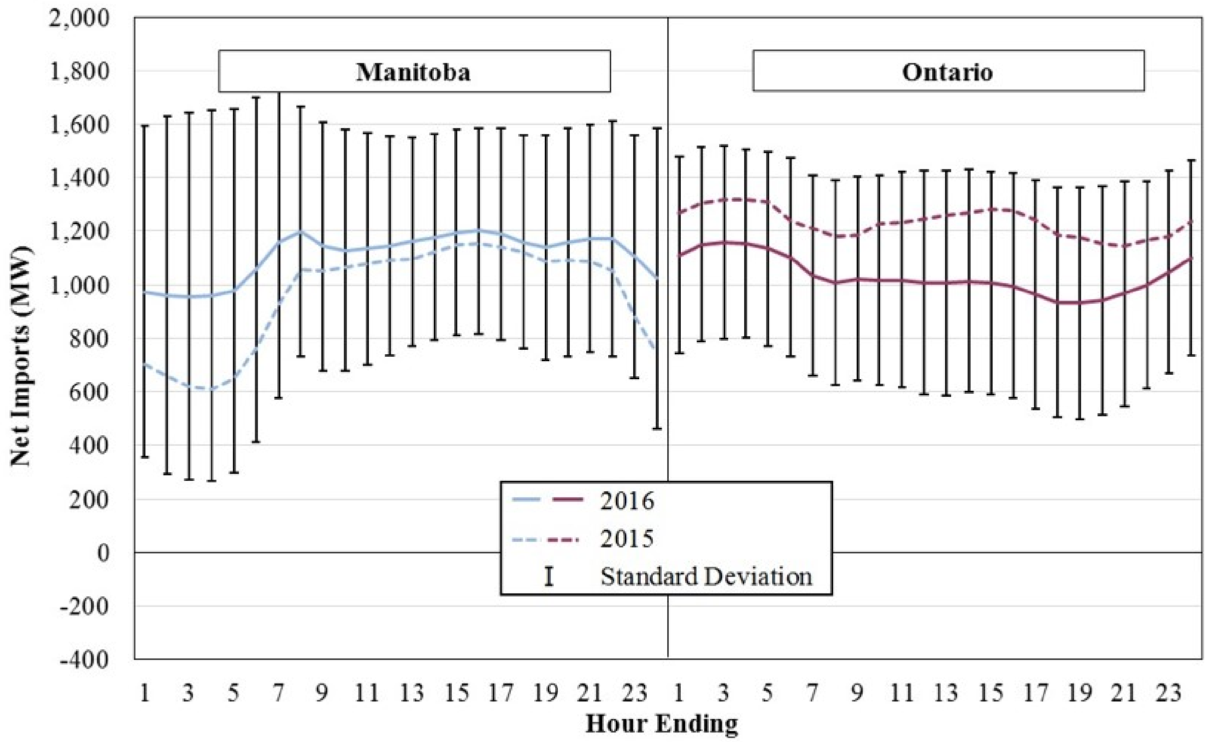


Figure A129: Average Hourly Real-Time Net Imports from Canada
2015–2016



B. Interface Pricing and External Transactions

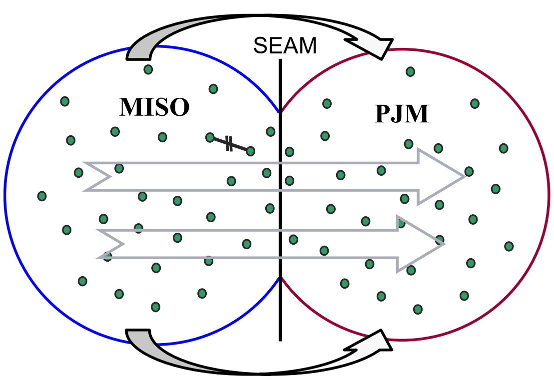
Each RTO posts its own interface price at which it will settle with physical schedulers wishing to sell and buy power from the neighboring RTO. Participants will schedule between the RTOs to arbitrage the differentials between the two interface prices. Interface pricing is essential because:

- It is the sole means to facilitate efficient power flows between RTOs;
- Poor interface pricing can lead to significant uplift costs and other inefficiencies; and
- It is an essential basis for CTS to maximize the utilization of the interface.

Establishing efficient interface prices would be simple in the absence of transmission congestion and losses – each RTO would simply post the interface price as the cost of the marginal resource on their system (the system marginal price, or "SMP"). Participants would respond by scheduling from the lower-cost system to the higher-cost system until the SMPs come into equilibrium (and generation costs are equalized). However, congestion is pervasive, so the fundamental interface pricing challenge is estimating the congestion costs and benefits from cross-border transfers (imports and exports).

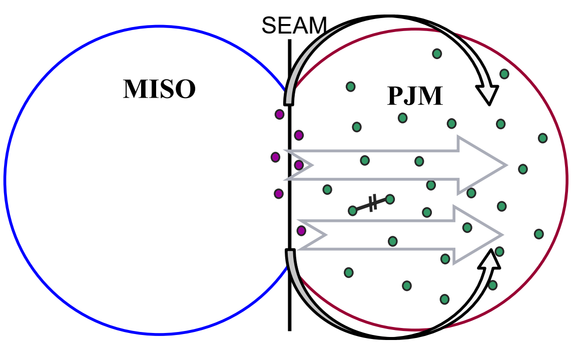
Like the locational marginal price at all generation and load locations, the interface price includes: a) the SMP, b) a marginal loss component, and c) a congestion component. For generator locations, the source of the power is known and, therefore, congestion effects can be accurately calculated. In contrast, the source of an import (or sink for an export) is not known, so it must be assumed in order to calculate the congestion effects. This is known as the "interface definition." If the interface definition reflects where the power is actually coming from (import) or going to (export), the interface price will provide an efficient incentive to transact and traders' responses to these prices will lower the total costs for both systems.

Interface Pricing with PJM



In reality, when power moves from one area to the other, generators ramp up throughout one area and ramp down throughout the other area (marginal units), as shown in the figure to the left. This is consistent with MISO's interface pricing before June 2017, which calculated flows for exports to PJM based on the power sinking throughout PJM. This is accurate because PJM will ramp down all of its marginal generators when it imports power.

However, PJM assumptions are much different. It assumes the power sources and sinks from the border with MISO as shown in the figure to the right. This approach tends to exaggerate the flow effects of imports and exports on any constraint near the seam, because it underestimates the amount of power that will loop outside of the RTOs.



We have identified the location of MISO's marginal generators and confirmed that they are distributed throughout MISO, so we remain concerned that PJM's interface definitions on all of its interfaces tend to set inefficient interface prices. We believe that the inaccuracy of PJM's congestion components plays a major role in causing MISO to be a net importer from PJM (1.2 GW on average).

Interface Pricing and External TLR Constraints

M2M constraints activated by PJM or SPP are one type of external constraint that MISO activates in its real-time market. MISO also activates constraints located in external areas when the external system operator calls a TLR. It is appropriate for external constraints to be reflected in MISO's real-time dispatch and internal LMPs. This enables MISO to respond to TLR relief requests as efficiently as possible. While re-dispatching internal generation is required to respond to TLRs, MISO is not obligated to pay participants to schedule transactions that relieve constraints in external areas. In fact, the effects of real-time physical schedules are excluded from MISO's market flow, so MISO gets no credit for any relief that these external transactions provide.[34] Because MISO receives no credit for this relief and no reimbursements for the costs it incurs, it is inequitable for MISO's customers to bear these costs. Most of these costs are paid in the form of balancing congestion that is uplifted to MISO load.

In addition to the inequity of these congestion payments, they motivate participants to schedule transactions inefficiently for three reasons. First, these beneficial transactions are already being fully compensated by the area where the constraint is located in most cases. For example, when a SPP constraint binds and SPP calls a TLR, it will establish an interface price for MISO that includes the marginal effect of the transaction on its own constraint. MISO's additional payment is duplicative and inefficient.

Second, the TLR process assigns market flow obligations and curtails physical schedules to enable the owner to manage a given flowgate. Any reduction in flow above these amounts results in a decrease in the monitoring area's need to reduce its own flows and can lead to unbinding of the transmission constraint in the monitoring area. MISO's current interface pricing encourages and compensates additional relief from physical schedulers that benefits the flowgate owner.

Finally, MISO's shadow cost for external TLR constraints is frequently significantly overstated compared to the monitoring system operator's true marginal cost of managing the congestion on the constraint. As shown in Section VI, this causes the congestion component of the interface prices associated with TLR constraints to be highly distortionary and provide inefficient scheduling incentives. One should expect that is will result in inefficient schedules and higher costs for MISO customers.

34 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.

C. Price Convergence Between MISO and Adjacent Markets

Like other markets, MISO relies on participants to increase or decrease net imports to cause prices between MISO and adjacent markets to converge. Given uncertainty regarding price differences from transactions being scheduled in advance, perfect convergence should not be expected. Transactions can start and stop at 15-minute intervals during an hour, but are settled on an hourly basis. This discrepancy between the hourly settlement and the scheduling timeframe can create incentives for participants to schedule transactions that are uneconomic when they are flowing but are nonetheless profitable under hourly settlement. To comply with FERC's Order 764, MISO reduced its scheduling deadline to 20 minutes in advance of the operating period.

Figure A130 and Figure A131: Real-Time Prices and Interface Schedules

Our analysis of these schedules is presented in two figures, each with two panels. The left panel displays 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 as 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 A130: Real-Time Prices and Interface Schedules
PJM and MISO, 2016

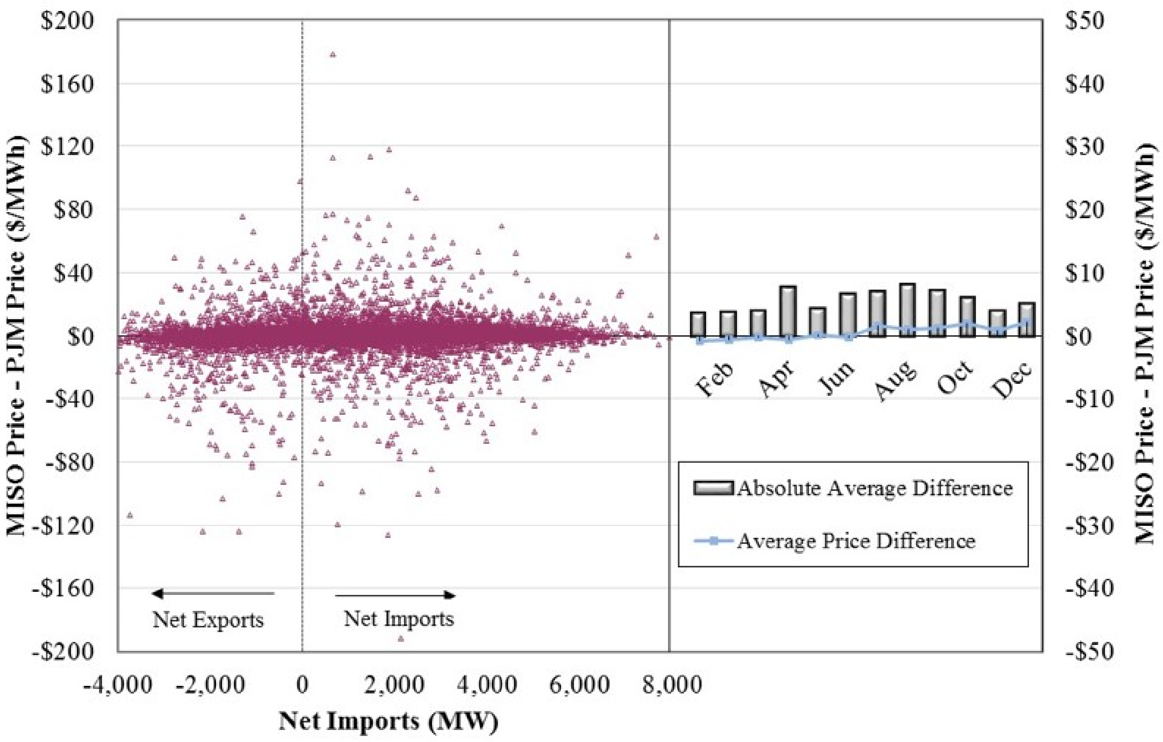
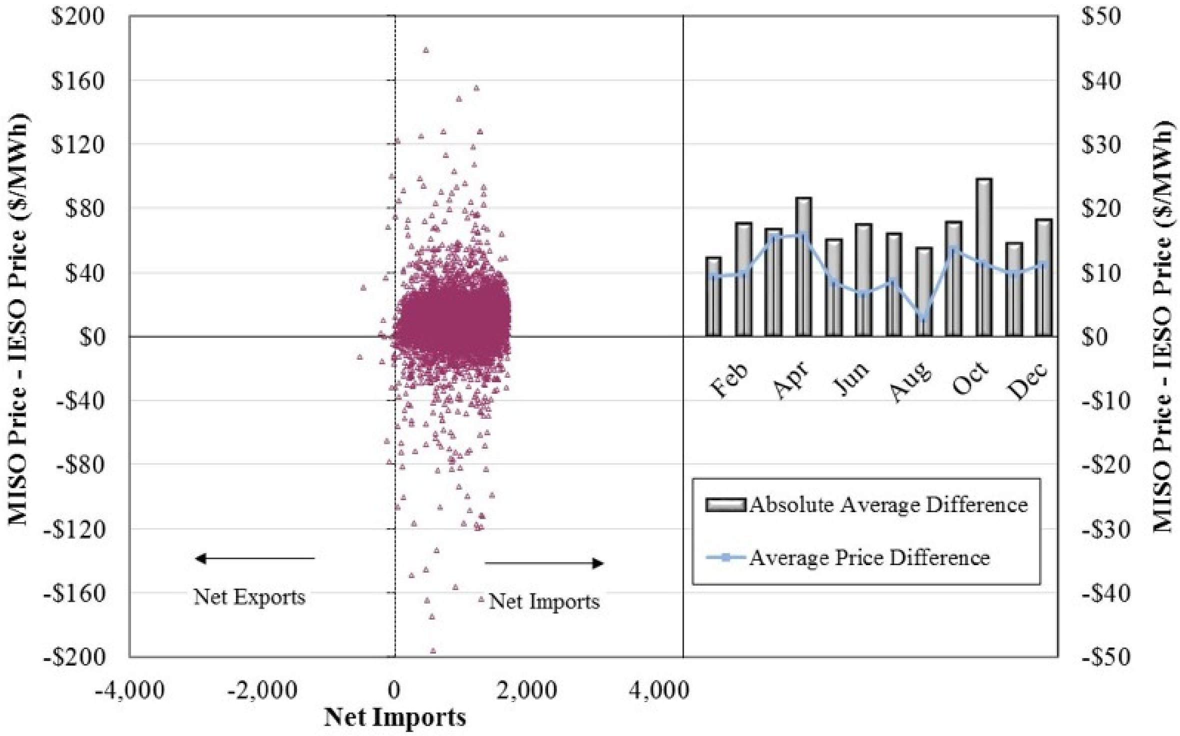


Figure A131: Real-Time Prices and Interface Schedules
IESO and MISO, 2016



VIII. Competitive Assessment

This section evaluates the competitive structure and performance of MISO's markets using various 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 while the market as a whole may normally be highly competitive, local market power associated with chronic or transitory transmission constraints can make these markets highly susceptible to the exercise of market power.

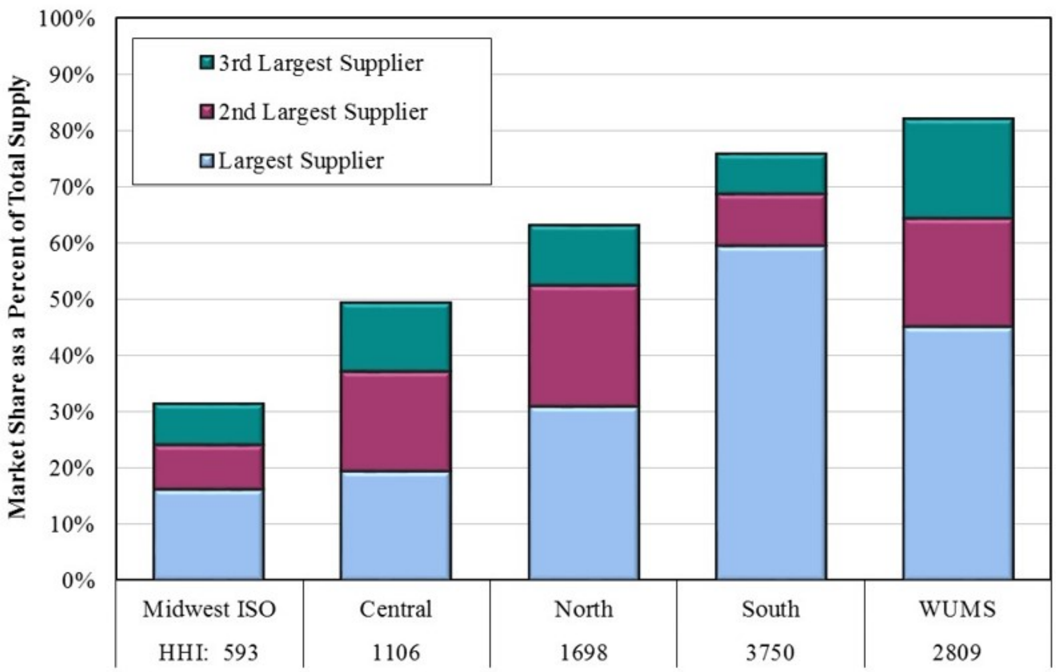
A. Market Structure

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

Figure A132: 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. Figure A132 shows generating capacity-based market shares and HHIs for MISO and its subregions.

Figure A132: Market Shares and Market Concentration by Region
2016



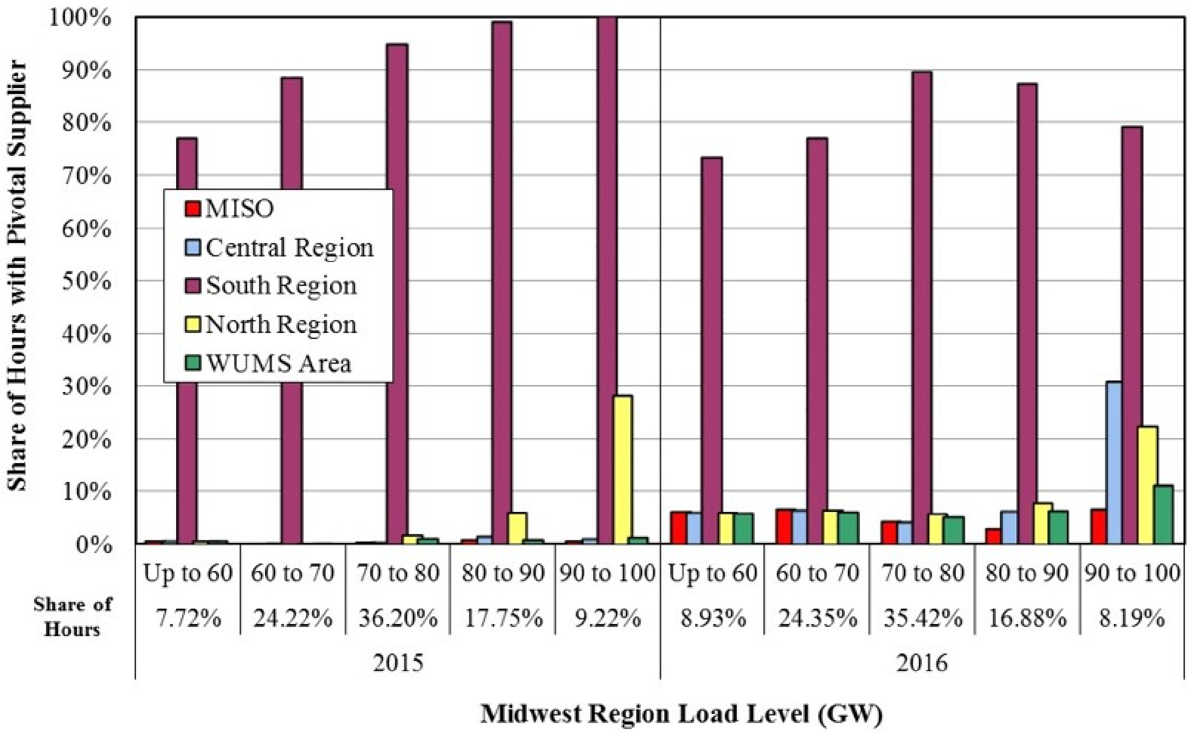
The HHI is only a general indicator of market concentration and not a definitive measure of market power. The HHI's most significant shortcoming for identification of market power in electricity markets is that it generally does not account for demand or network constraints. In wholesale electricity markets, these factors have a profound effect on competitiveness. Because the HHI does not recognize the physical characteristics of electricity that can cause a supplier to have market power under various conditions, 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 A133: Pivotal Supplier Frequency by Region and Load Level

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

Figure A133 summarizes the results of this analysis, showing the percentage of total hours with a pivotal supplier (e.g., RDI less than one) 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 A133: Pivotal Supplier Frequency by Region and Load Level
2015–2016



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 can.

A supplier is pivotal on a constraint when it has the resources to overload the constraint to such an extent that all other suppliers combined are unable to 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. As a result, such a supplier can potentially manipulate congestion and control prices.

Two types of constrained areas are defined for purposes of market power mitigation: Broad Constrained Areas (BCAs) and Narrow Constrained Areas (NCAs). The definitions of BCAs and NCAs are 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. There are three NCAs in the Midwest Region (the Minnesota NCA, the WUMS NCA, and the North WUMS NCA[35]) and two in the South Region (WOTAB and Amite South NCAs).

Market power associated with BCA constraints can also be significant. A BCA is defined when non-NCA transmission constraints bind and includes all generating units with significant impact on power flows over the constraint. BCA constraints are not chronic like NCA constraints are; however, they can raise competitive concerns. Due to the vast number of potential constraints and the fact that the topology of the transmission network can change significantly when outages occur, it is neither feasible nor desirable to define all possible BCAs in advance.

Figure A134 to Figure A137: Pivotal Suppliers

The next four figures evaluate potential local market power by showing the frequency with which suppliers are pivotal on individual NCA and BCA constraints. Figure A134 to Figure A137 show, by region, the percentage of all market intervals by month during which at least one supplier was pivotal for each type of constraint. Figure A136 and Figure A137 show, by region, the percentage of the intervals with active constraints in each month with at least one pivotal supplier. For the purposes of this analysis, the WUMS and North WUMS NCAs in Midwest region are combined.

35 Based on the results of the NCA threshold calculation specified in Tariff Section 64.1.2.d, the thresholds that applied to the NCAs for most of 2016 ranged from $22.31 per MWh in North WUMS to $100.00 per MWh in Amite South. The WUMS, WOTAB, and Minnesota thresholds were $25.73, $31.86, and $43.83 per MWh, respectively.

Figure A134: Percent of Intervals with at Least One Pivotal Supplier
Midwest Region, 2016

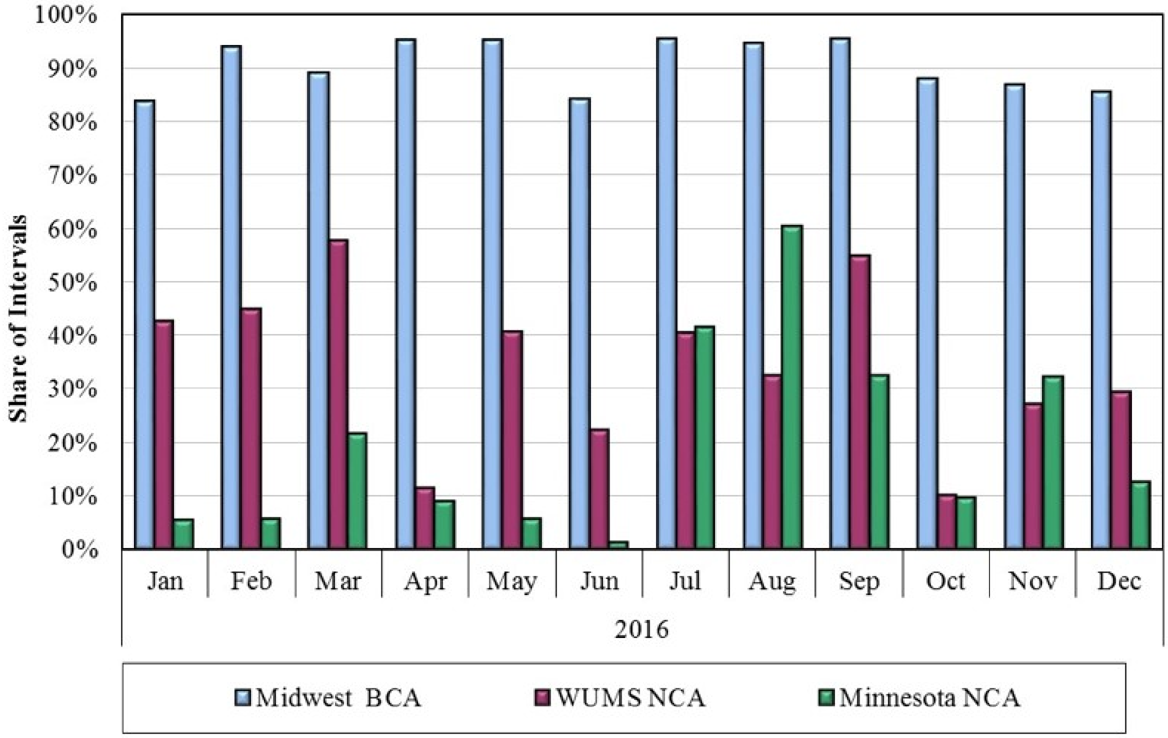


Figure A135: Percent of Intervals with at Least One Pivotal Supplier
South Region, 2016

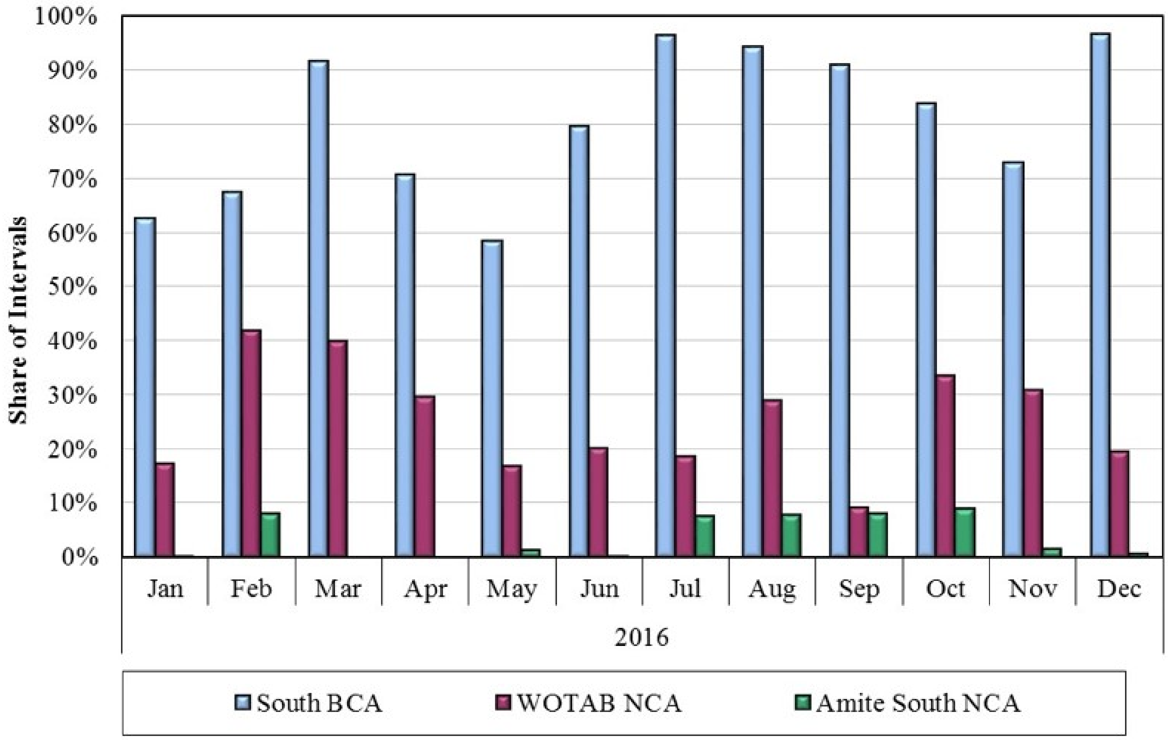


Figure A136: Percentage of Active Constraints with a Pivotal Supplier
Midwest Region, 2016

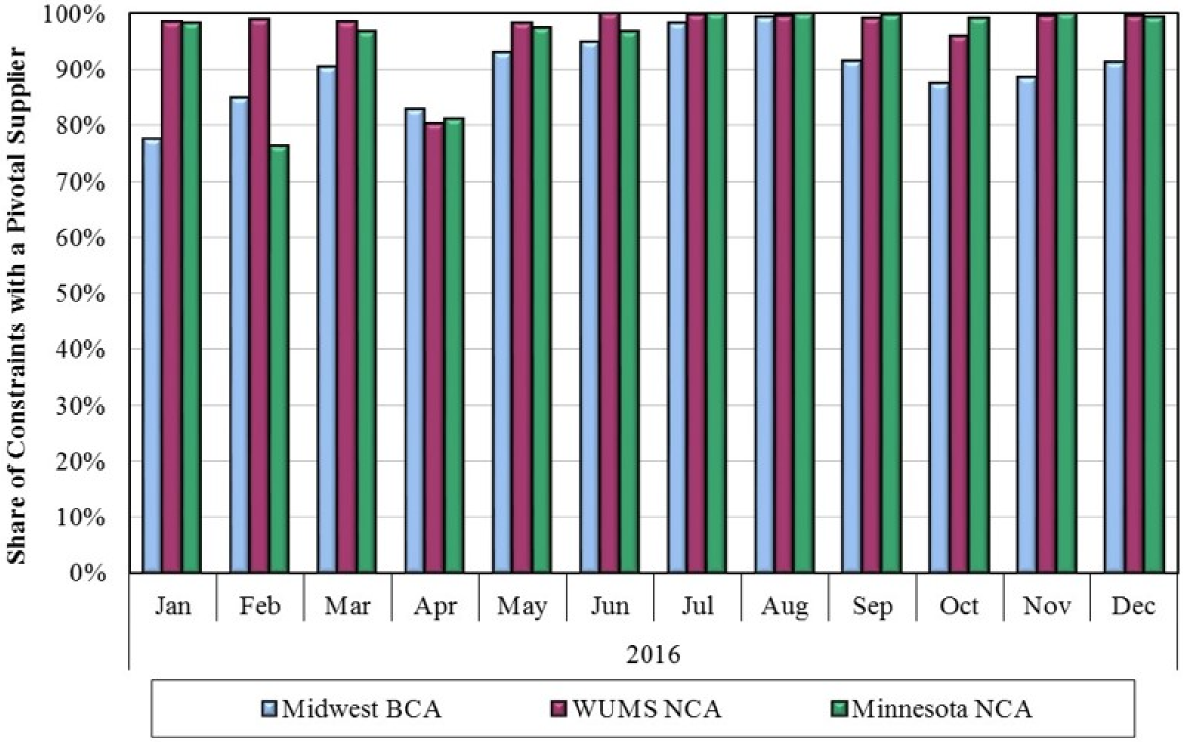
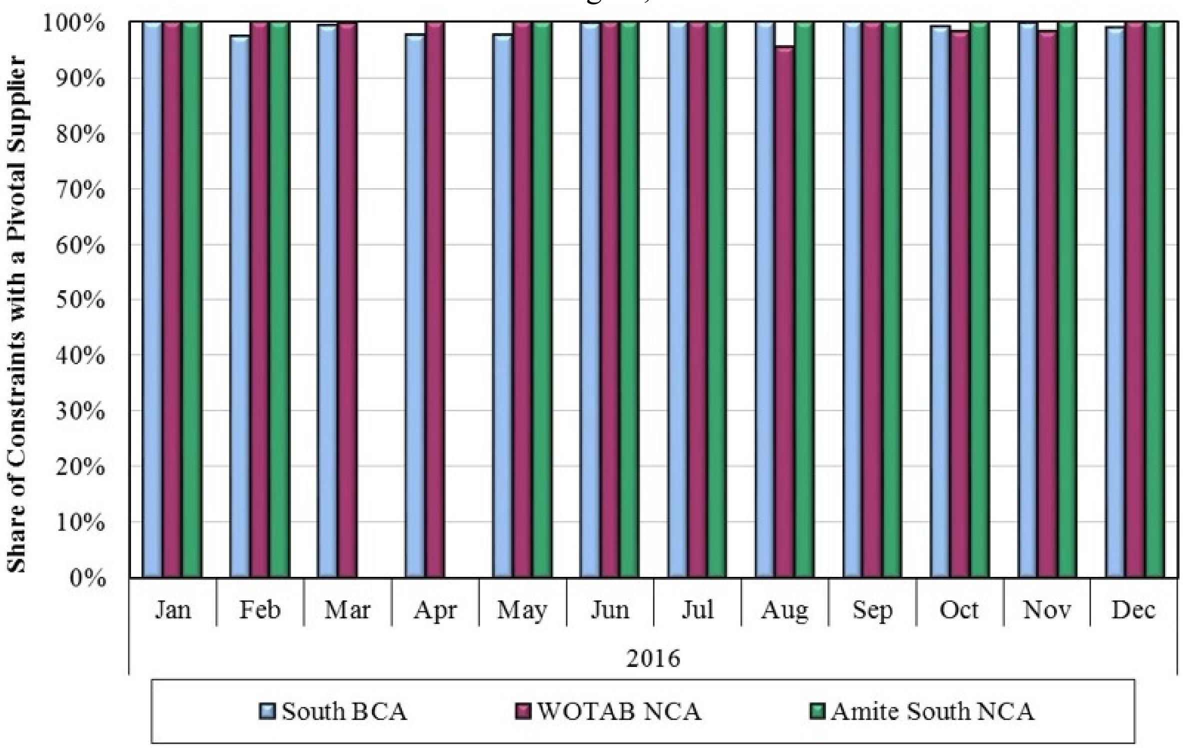


Figure A137: Percentage of Active Constraints with a Pivotal Supplier
South Region, 2016



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 indications of 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, which are the resources' marginal costs, 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.

The price-cost mark-up 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 under competitive conditions could lead to resources not clearing the market, which would result in lost revenue contributions 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. However, the average price-cost mark-up for 2016 was approximately zero, which indicates that MISO markets were highly competitive. Mark-ups of less than three percent lie within the bounds of highly competitive expectations.

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 costs. A generator's marginal cost is its incremental cost of producing additional output. Marginal cost may include inter-temporal opportunity costs, risk associated with unit outages, fuel, variable operations and maintenance (O&M), and other costs attributable to the incremental output. For most fossil fuel-fired resources, marginal costs are closely approximated by variable production costs that primarily consist of 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-fired units with output restrictions because of environmental considerations, may forego revenues in future periods to produce in the current period. These units can incur inter-temporal opportunity costs of production that can ultimately cause their marginal cost to exceed variable production cost.

Establishing a competitive benchmark for each offer parameter, 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 and in the application of mitigation. The comparison of offers to competitive benchmarks - reference prices plus the applicable threshold specified in the Tariff - is the "conduct test," which is the first prerequisite for imposing the market power mitigation. The second prerequisite is the "impact test," which requires that the identified conduct significantly affect market prices or guarantee payments.[36]

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, based on the unit's reference levels, 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 our estimate of its 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

36 Module D, Section 62.a states:

"These market power Mitigation Measures are intended to provide the means for the Transmission Provider to mitigate the market effects of any conduct that would substantially distort competitive outcomes in the Markets and Services administered by the Transmission Provider, while avoiding unnecessary interference with competitive price signals."

typically 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.

Our benchmarks for units' marginal costs are imperfect, particularly during periods with volatile fuel prices. Hence, 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. This would indicate 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 that is due to ramp limitations is excluded from the output gap.

Figure A138: Economic Withholding -- Output Gap Analysis

Figure A138 shows monthly average output gap levels for the real-time market in 2015 and 2016. The output gap shown in the figure and summarized in the table includes two types of units:

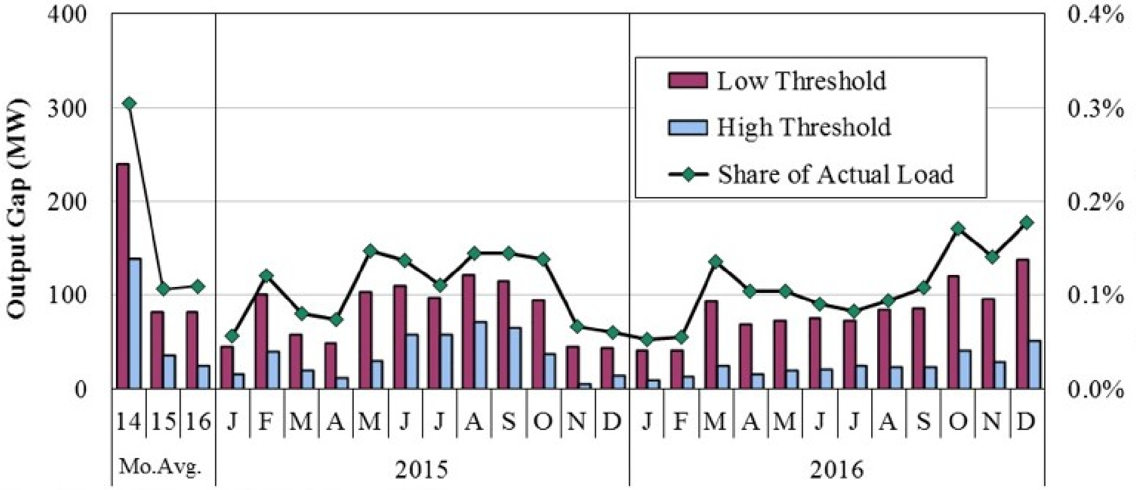
(1) online and quick-start units available in real time, and

(2) offline units that would have been economic to commit.

The data are arranged to show the output gap using the mitigation threshold in each area ("high threshold") and one-half of the mitigation threshold ("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 that were effective during most of 2016 were $25.73 per MWh for resources located in the WUMS NCA, $22.31 for those in the North WUMS NCA, $43.83 for those in the Minnesota NCA, and $31.86 and $100.00 for the WOTAB and Amite South NCAs, respectively. The low threshold is set to 50 percent of the applicable high threshold for a given resource. For example, for a resource in Amite South, the low threshold would be $50.00 per MWh, or 50 percent of $100.00. 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 A138: Economic Withholding -- Output Gap Analysis
2015–2016



Low Threshold Results by Unit Status (MW)

Offline	98	27	11	12	31	5	4	15	43	54	66	57	32	0	10	6	11	0	1	0	1	15	13	13	30	21	25
Online	140	55	71	34	70	53	46	90	68	43	56	57	63	45	34	36	31	94	69	73	74	58	72	73	89	75	113

High Threshold Results by Unit Status (MW)

Offline	82	23	10	11	17	5	3	11	34	49	58	50	25	0	7	5	10	0	1	0	1	15	11	11	26	21	24
Online	57	14	15	6	24	16	10	19	24	9	14	16	14	6	8	6	5	25	16	20	20	11	14	14	16	8	29

Figure A139 to Figure A142: Real-Time Average 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), and they show the two largest suppliers in the region versus all other suppliers separately. The figures also show the average output gap at the high and low mitigation thresholds defined above.

Figure A139: Real-Time Average Output Gap
Central Region, 2016

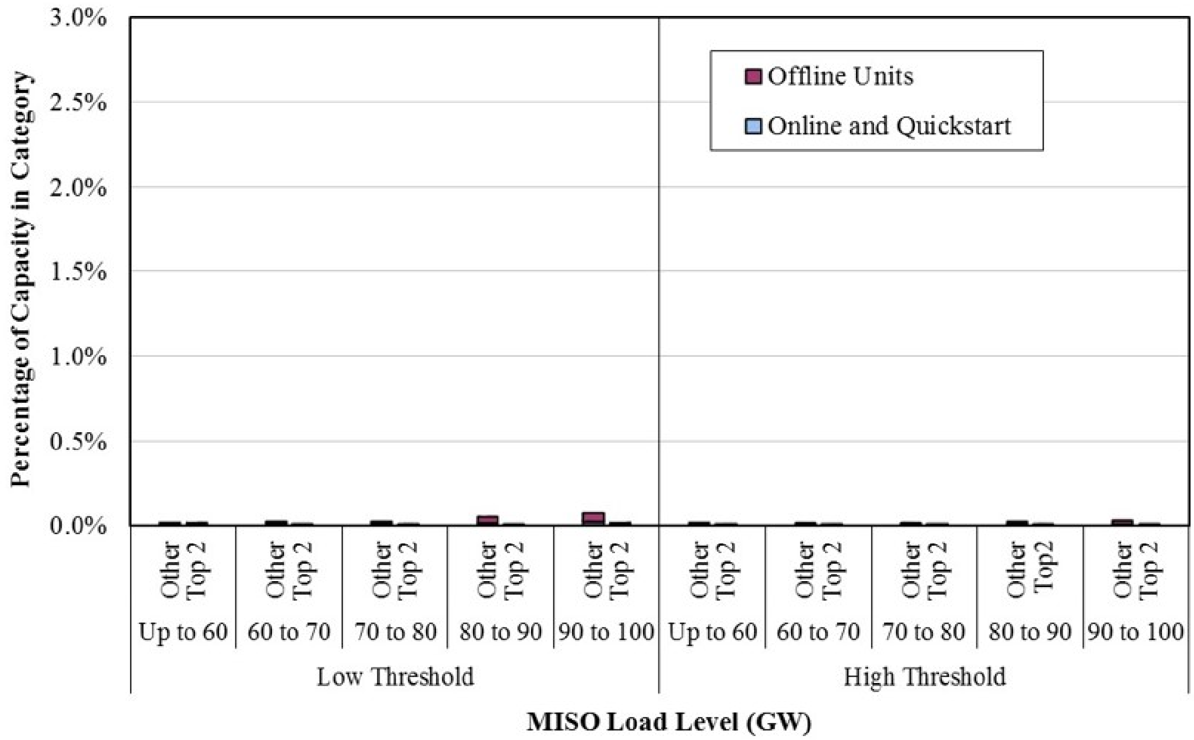


Figure A140: Real-Time Average Output Gap
South Region, 2016

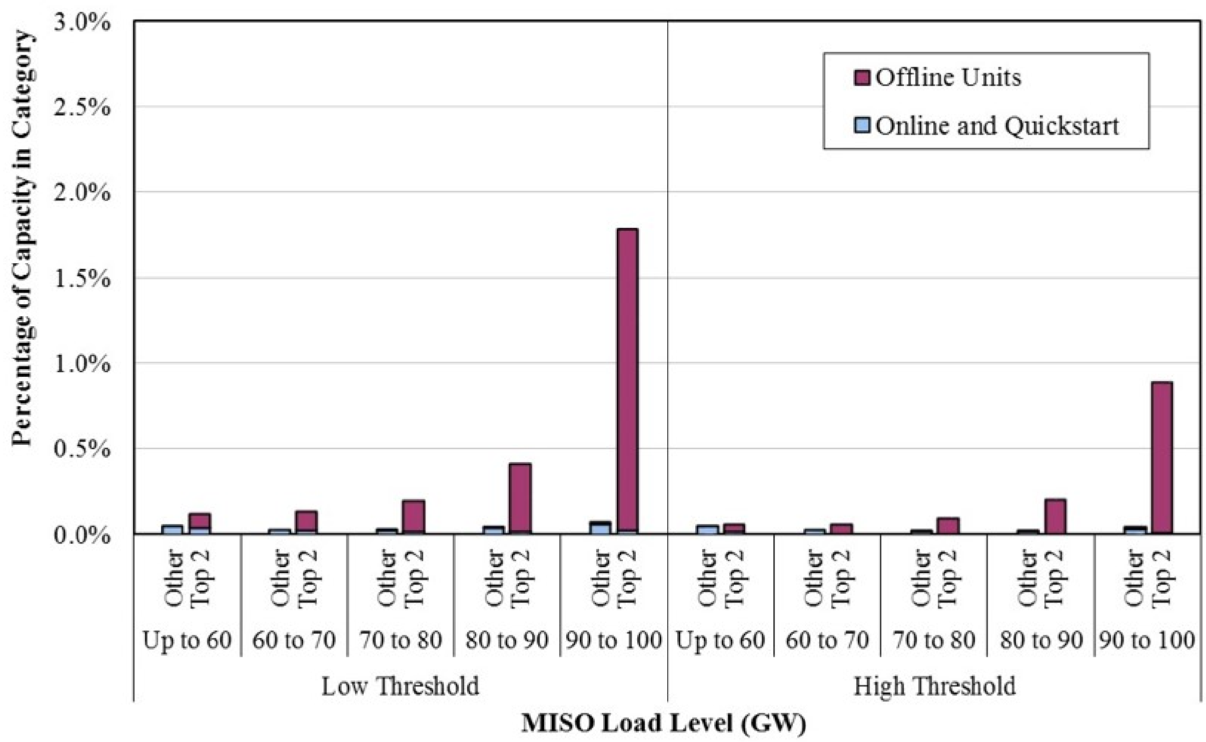


Figure A141: Real-Time Average Output Gap
North Region, 2016

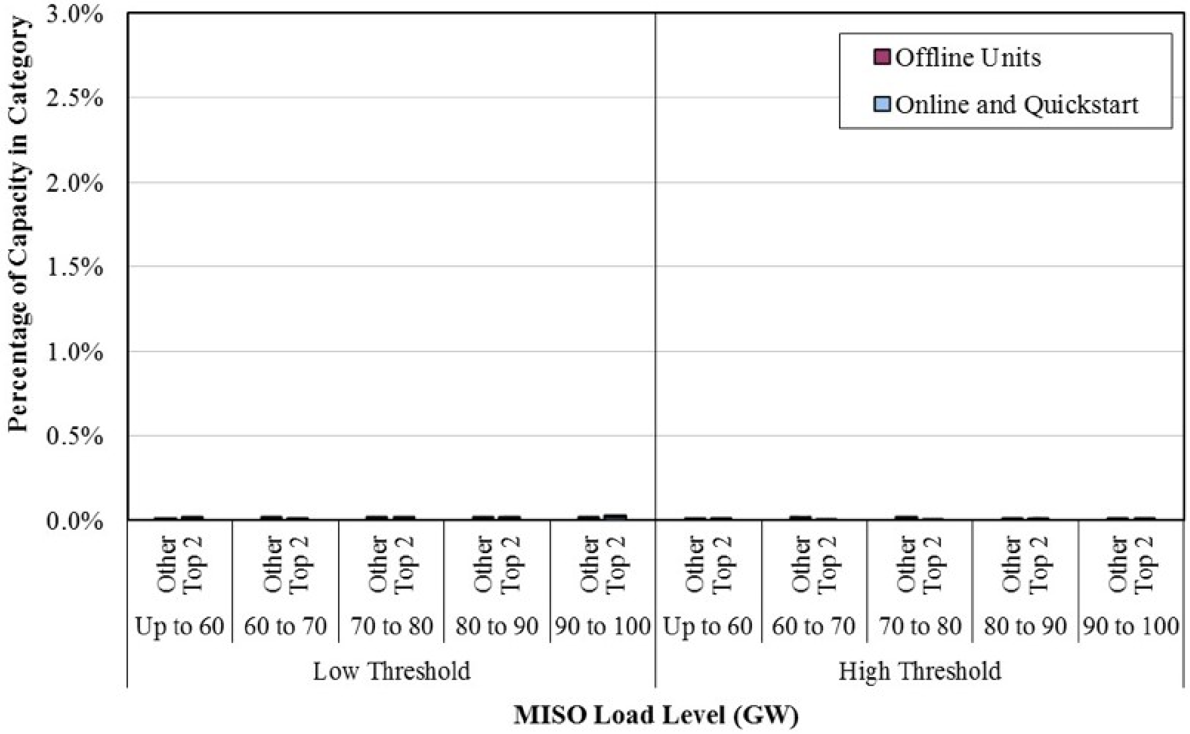
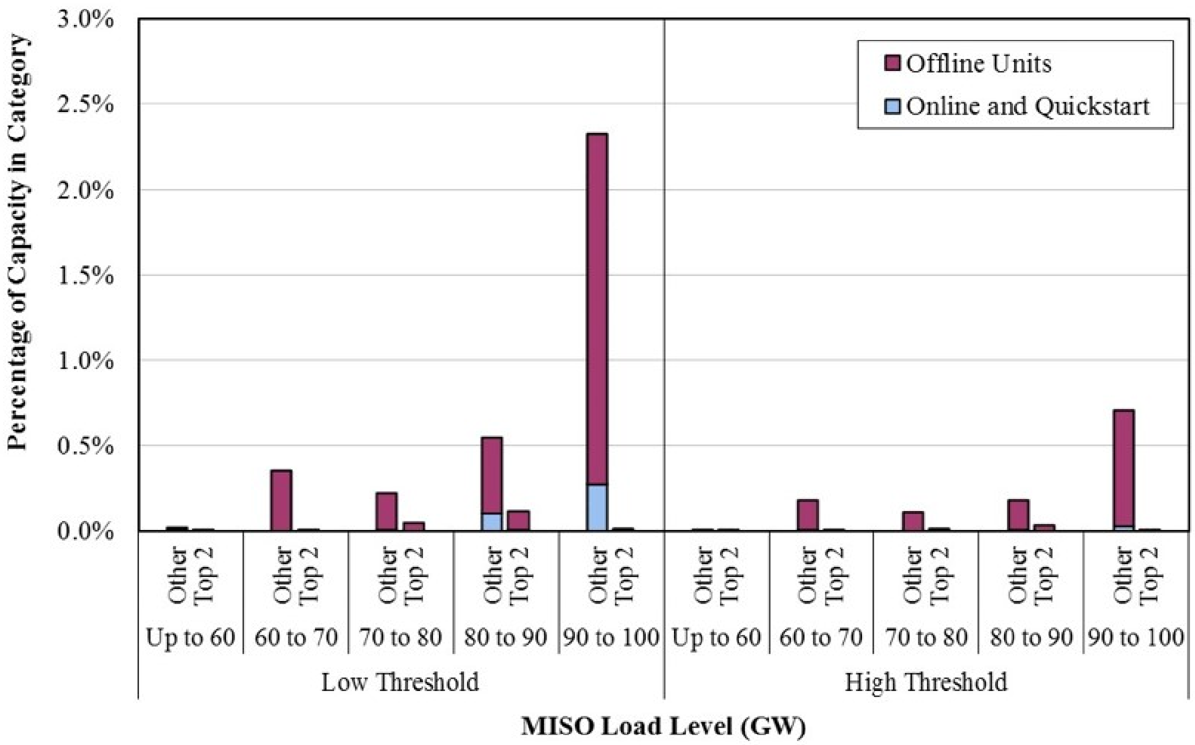


Figure A142: Real-Time Average Output Gap
WUMS Area, 2016



D. Market Power Mitigation

In this next subsection, we examine the frequency with which market power mitigation measures were imposed in MISO markets in 2016. 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 when transmission constraints bind that can result in local market power. The mitigation thresholds differ depending on the two types of constrained areas: BCAs and NCAs. Market power concerns are greater in NCAs, because the congestion is chronic and a supplier is typically pivotal when the congestion occurs. As a result, the conduct and impact thresholds for NCAs, which are a function of the frequency of the congestion, are generally lower than for BCAs.

Figure A143: Day-Ahead and Real-Time Energy Mitigation by Month

Figure A143 shows the frequency and quantity of mitigation in the day-ahead and real-time energy markets by month. Mitigation generally occurs more frequently in the real-time market because the day-ahead market has virtual participants and many more commitment and dispatch options available to provide liquidity. This makes the day-ahead market much less vulnerable to withholding and market power.

Figure A143: Day-Ahead and Real-Time Energy Mitigation by Month
2016

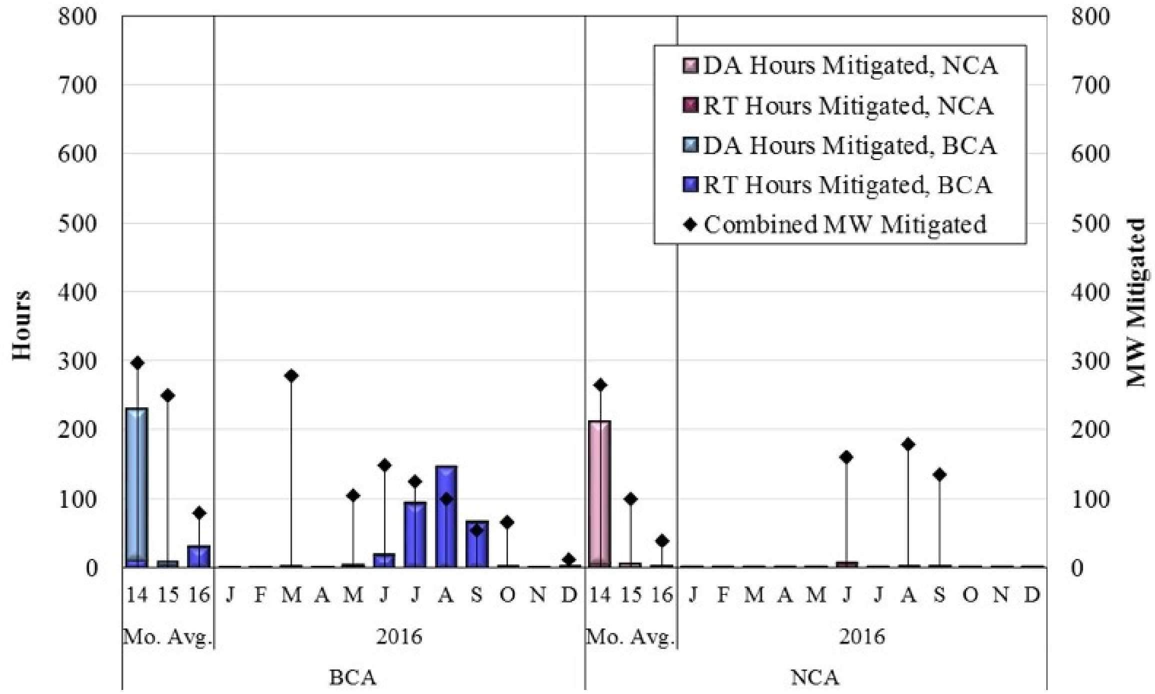
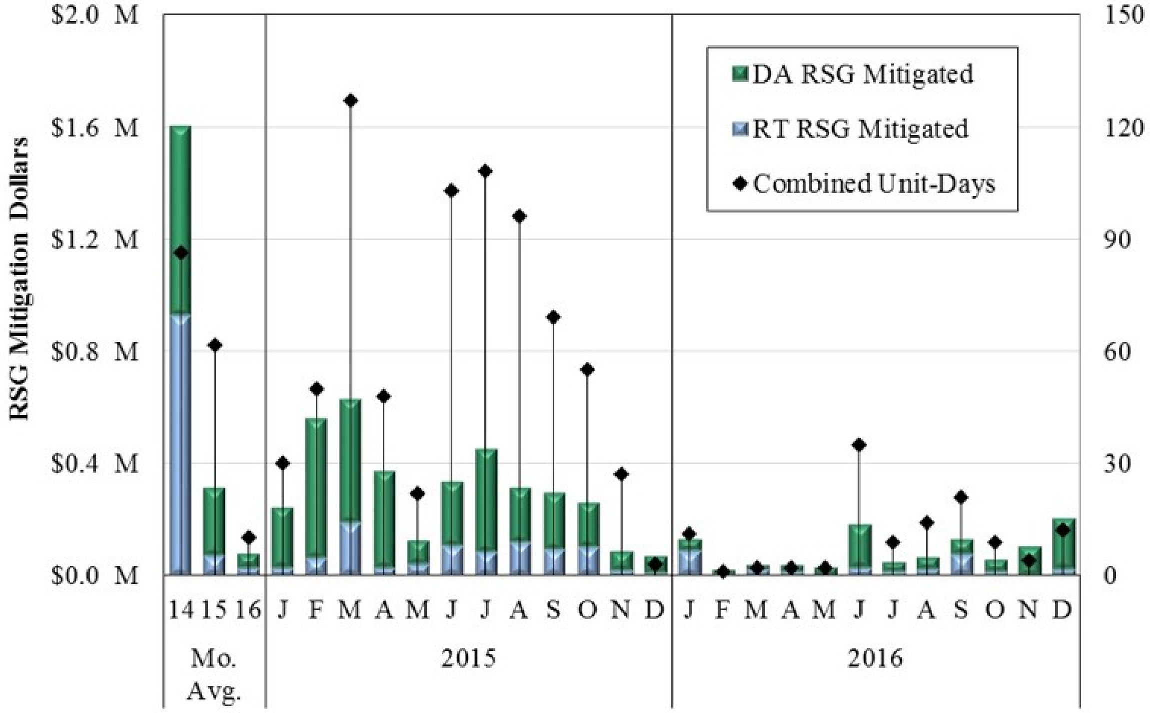


Figure A144: Day-Ahead and Real-Time RSG Mitigation by Month

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's mitigation measures address this conduct and are triggered when the following three criteria are met: (1) the unit must be committed for a constraint or a local reliability issue; (2) its offer must exceed the conduct threshold; and (3) the effect of the inflated offer must exceed the RSG impact threshold, which in June 2015 fell from $50 per MWh for BCA and NCAs to the greater of $25 or a 25% increase in production costs with a zero impact threshold. Figure A144 shows the frequency and amount by which RSG payments were mitigated by month in 2015 and 2016 and average monthly values for the last three years.

Figure A144: Day-Ahead and Real-Time RSG Mitigation by Month
2015–2016



E. Evaluation of RSG Conduct and Mitigation Rules

We routinely evaluate the effectiveness of the mitigation measures in addressing potential market power exercised to affect energy prices, ancillary service prices, or RSG payments. In this subsection we evaluate RSG-associated conduct.

Figure A145 to Figure A147: Real-Time RSG Payments by Conduct

We evaluate conduct associated with RSG payments in the following figure, separating the payments associated with resources' reference levels and the payments associated with the portions of resources' bid parameters (e.g., economic and physical parameters) that exceed their reference levels. The results are shown separately for units committed for capacity and for congestion management. We also distinguish between the Midwest and South Regions. For Figure A145, the category "Mitigated" includes both day-ahead and real-time amounts.

Figure A145: Real-Time RSG Payments by Conduct
By Commitment Reason, 2016

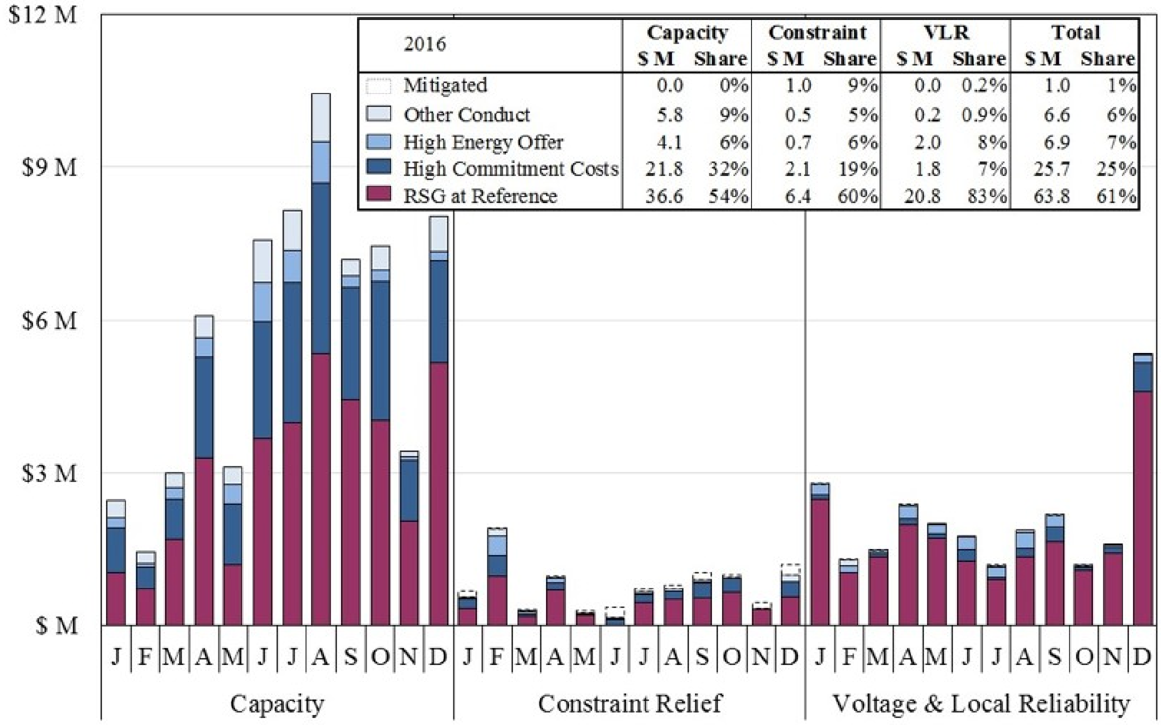


Figure A146: Real-Time RSG Payments by Conduct
Midwest Region, by Commitment Reason, 2016

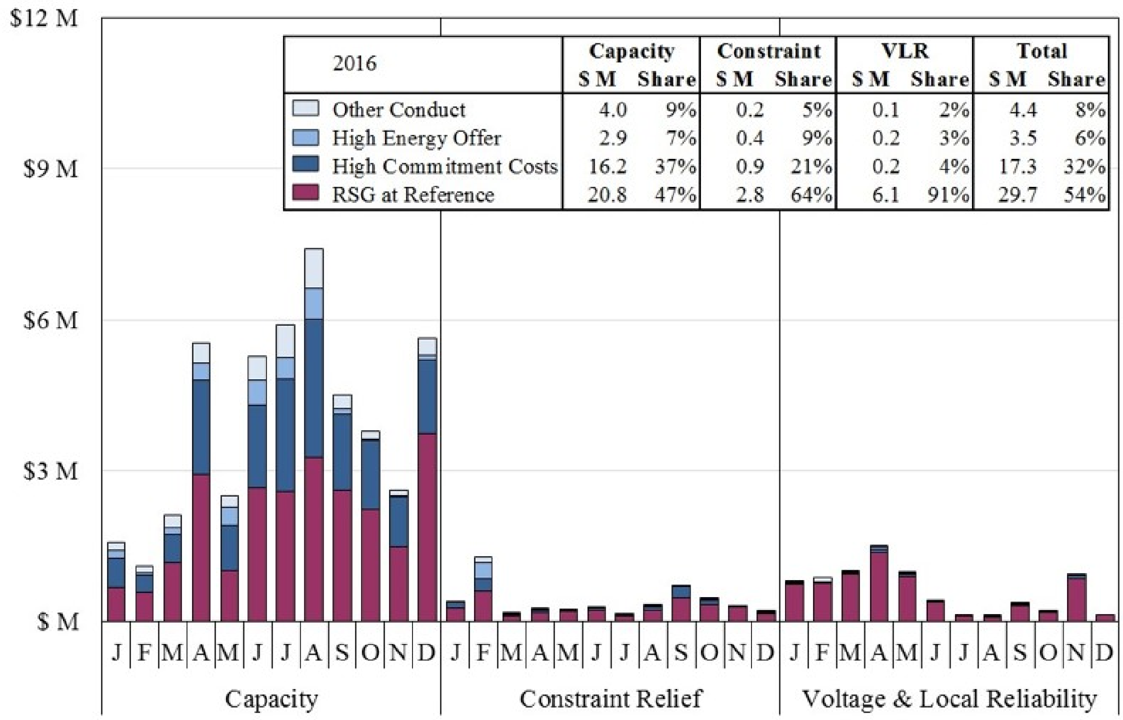
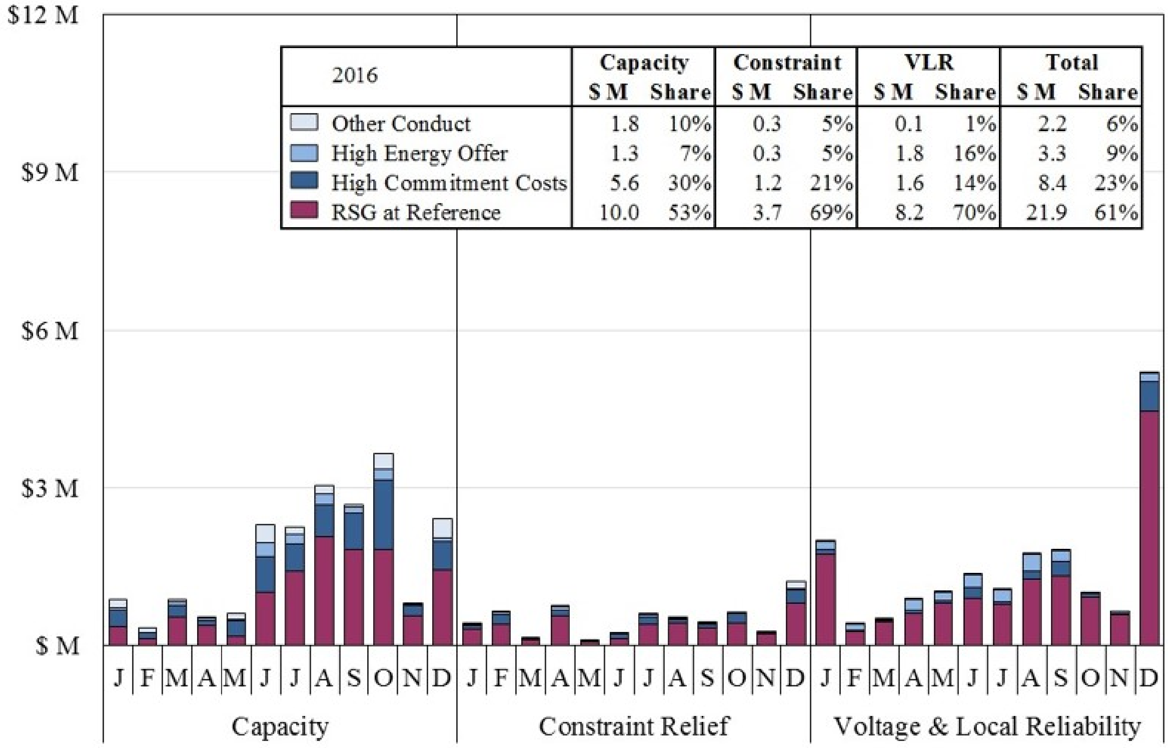


Figure A147: Real-Time RSG Payments by Conduct
South Region, by Commitment Reason, 2016



2016	Capacity $ M	Capacity Share	Constraint $ M	Constraint Share	VLR $ M	VLR Share	Total $ M	Total Share
Other Conduct	1.8	10%	0.3	5%	0.1	1%	2.2	6%
High Energy Offer	1.3	7%	0.3	5%	1.8	16%	3.3	9%
High Commitment Costs	5.6	30%	1.2	21%	1.6	14%	8.4	23%
RSG at Reference	10.0	53%	3.7	69%	8.2	70%	21.9	61%

Prior to June 2015, the RSG mitigation measures included conduct tests that were performed on each bid parameter individually and employed a $50 per MW impact threshold. In contrast, the voltage and local reliability (VLR) mitigation utilizes a conduct test based on the aggregate as-offered production cost of a resource. This method recognizes the joint impact of all of the resources' offer parameters. When units committed for VLR require an RSG payment, every dollar of increased production costs will translate to an additional dollar of RSG, so the conduct test also serves as an impact test. In late June 2015, FERC approved a $25 or 25 percent conduct test for constraint relief commitments that was patterned after the VLR mitigation framework and eliminated the impact test. This approach has improved the effectiveness of the RSG mitigation framework.

F. Dynamic NCAs

The market power mitigation measures are effective, in part, because MISO has the authority to designate NCAs. NCAs are chronically-constrained areas where tighter conduct and impact thresholds are applied to address the heightened local market power concerns. 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 severe transitory congestion area, an NCA is often not defined because it is not expected to be congested for for 500 hours per year. These transitory conditions often arise because of transmission outages or generation outages. Once the congestion pattern begins, suppliers may recognize that their units are needed to manage the constraints and exercise market power under the relatively generous BCA thresholds.

To address this concern, we have recommended that MISO expand Module D of its tariff to allow it to establish "dynamic" NCAs when transitory conditions arise that lead to sustained congestion. We recommend that the threshold for the dynamic NCA be set at $25 per MWh and be triggered by the IMM when mitigation would be warranted under this threshold and congestion is expected in at least 15 percent of hours (more than double the rate that would be required to permanently define a NCA). This provision will help ensure that transitory network conditions do not allow the exercise of substantial local market power.

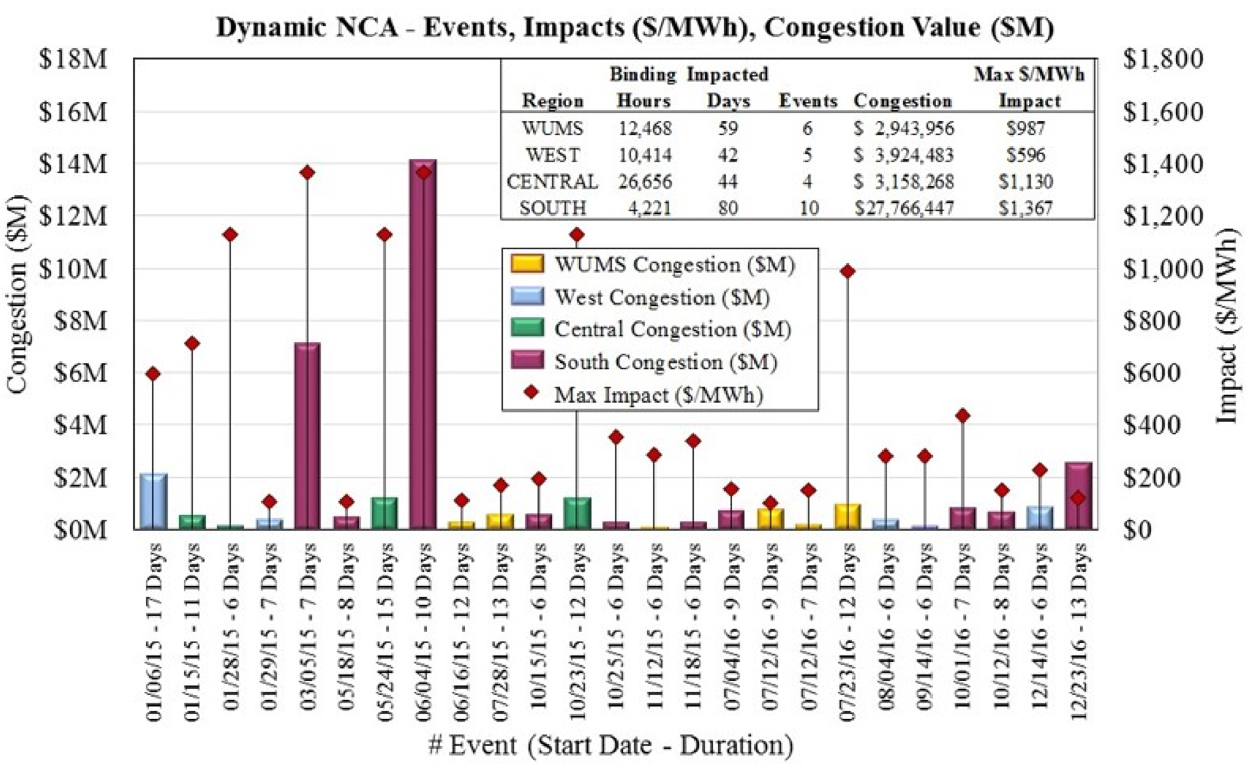
Figure A148: Dynamic NCA Evaluation of Events

To assess the need for this enhancement, we performed an evaluation to determine how frequently dynamic NCAs would have been defined and when mitigation would have been warranted in 2015 and 2016. The results of this evaluation are shown in Figure A148 below, which shows the results from applying our two proposed criteria over the past two years:

- Conduct and impact is identified at $25 per MWh thresholds in a constrained area; and
- The constraint defining the area is binding in at least 15 percent of the intervals over 5 days.

The left axis in Figure A148 shows the value of real-time congestion (the sum of the shadow price times the flow) during each event meeting the Dynamic NCA criteria. The right axis shows the maximum impact of the market power mitigation during the Dynamic NCA event. The events themselves are color coded to show the region in which they occurred.

Figure A148: Dynamic NCA Evaluation of Events
Impacts and Congestion, 2015 - 2016



G. Participant Conduct – Ancillary Services Offers

In this section, we review the conduct of market participants in the ancillary services markets by summarizing the offer prices and quantities for spinning reserves and regulation.

Figure A149 to Figure A151: Ancillary Services Market Offers

Figure A149 to Figure A151 evaluate the competitiveness of ancillary services offers. These figures show monthly average quantities of regulation and spinning 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. Figure A149 shows the offers for all of MISO, while the two figures that follow separately show the offers in the MISO South and MISO Midwest regions.

As in the energy market, ancillary services reference levels are resource-specific estimates of the competitive offer level for the service, which are the marginal costs of supplying the services. We exclude supplemental (contingency reserves) from this figure because this product is almost never offered at more than $10 per MWh above reference levels.

Figure A149: Ancillary Services Market Offers
2015–2016

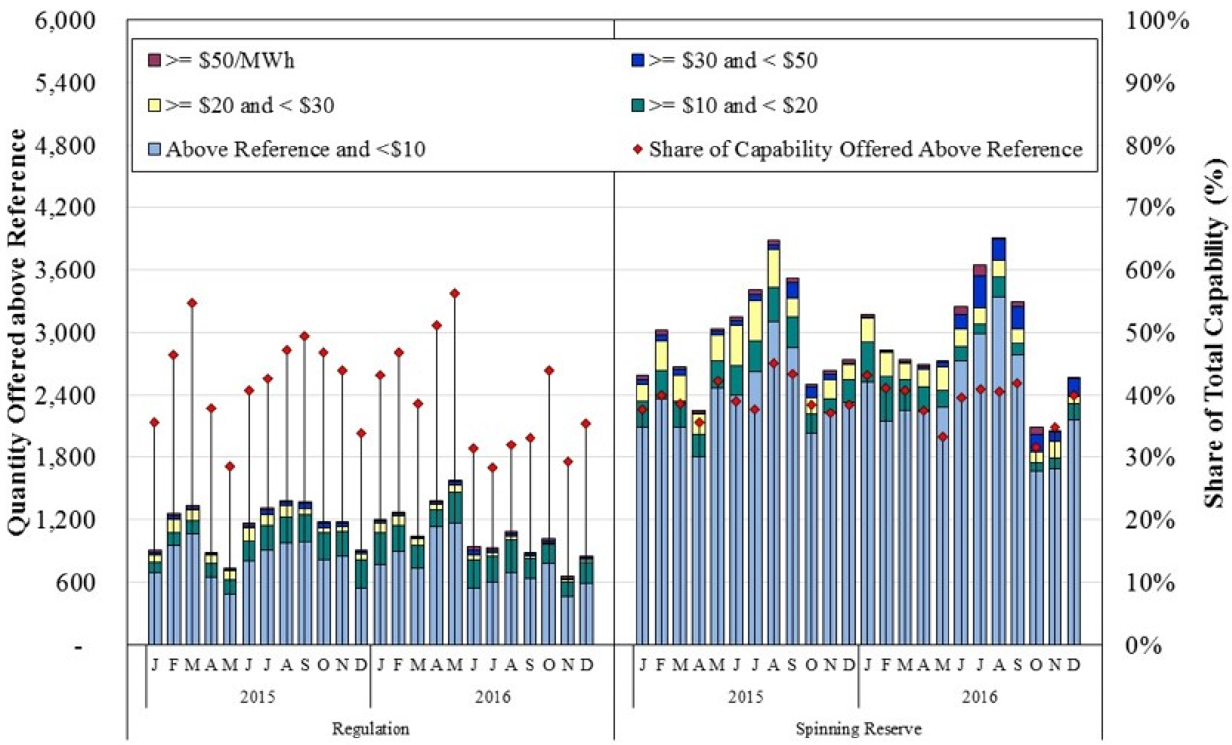


Figure A150: Ancillary Services Market Offers
Midwest Region, 2015–2016

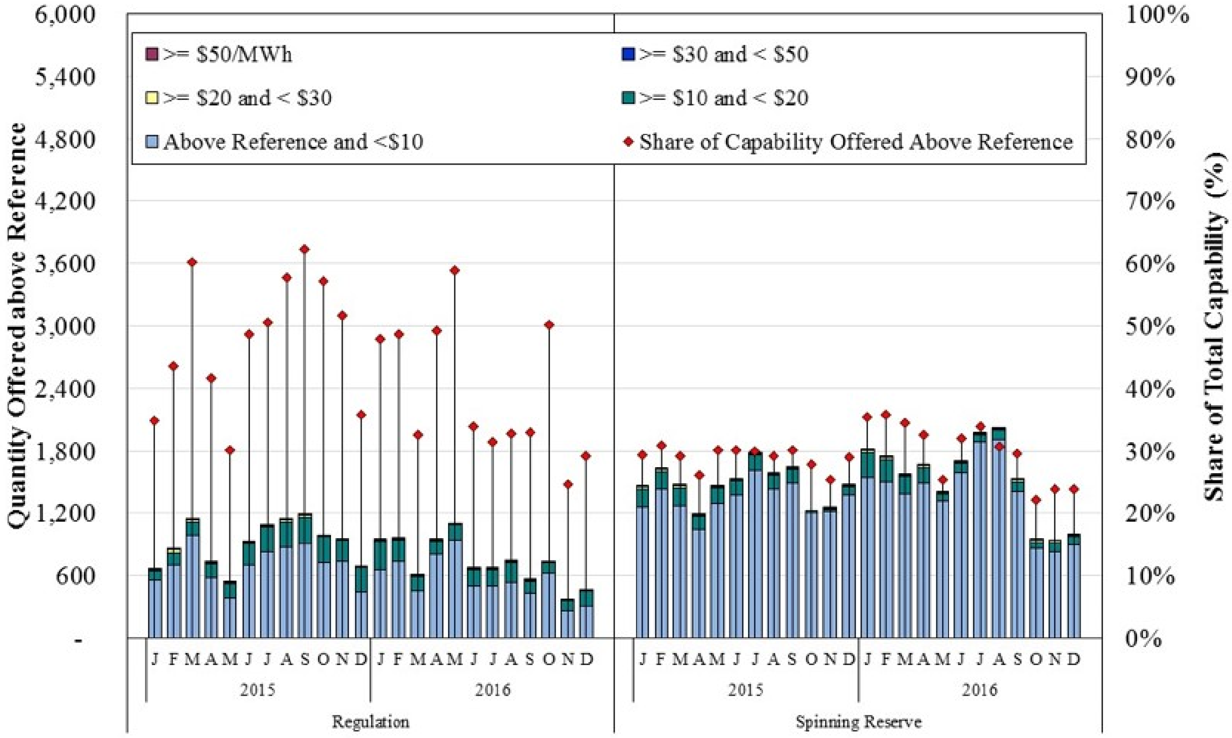
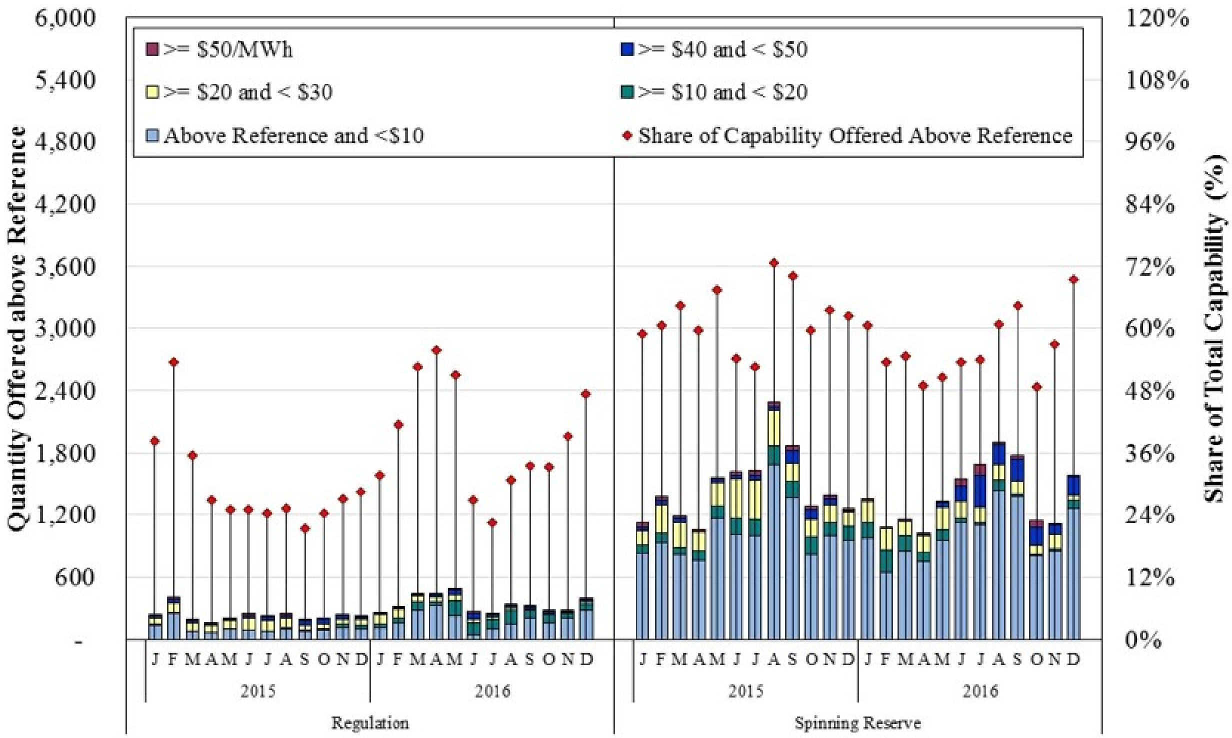


Figure A151: Ancillary Services Market Offers
South Region, 2015–2016



H. Participant Conduct – Physical Withholding

The previous subsections 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 result of offering non-economic parameters or declaring other conditions. For instance, this form of withholding may be accomplished by a supplier unjustifiably claiming an outage or derating their resource. Although we analyze broad patterns of 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 A152 to Figure A155: Real-Time Deratings and Forced Outages

The following four figures show, by region, the average share of capacity unavailable to the market in 2016 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 and short-term deratings that last fewer than seven days, 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 potential 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 A152: Real-Time Deratings and Forced Outages
Central Region, 2016

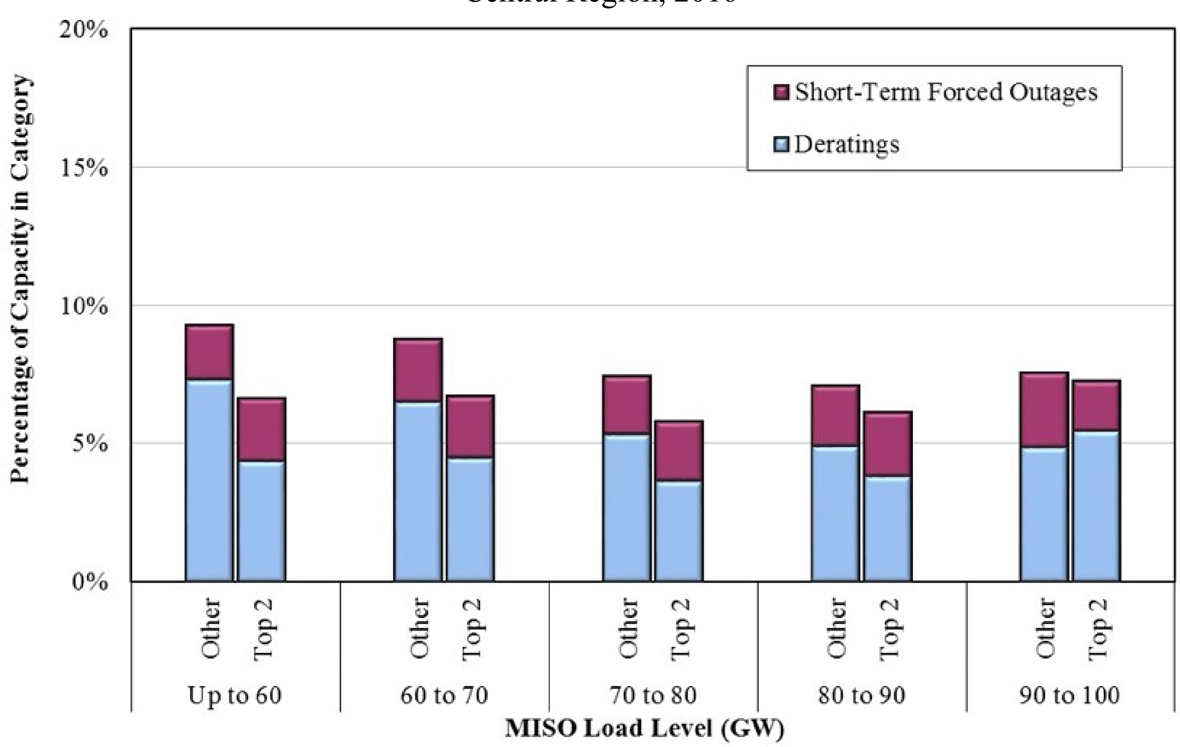


Figure A153: Real-Time Deratings and Forced Outages
South Region, 2016

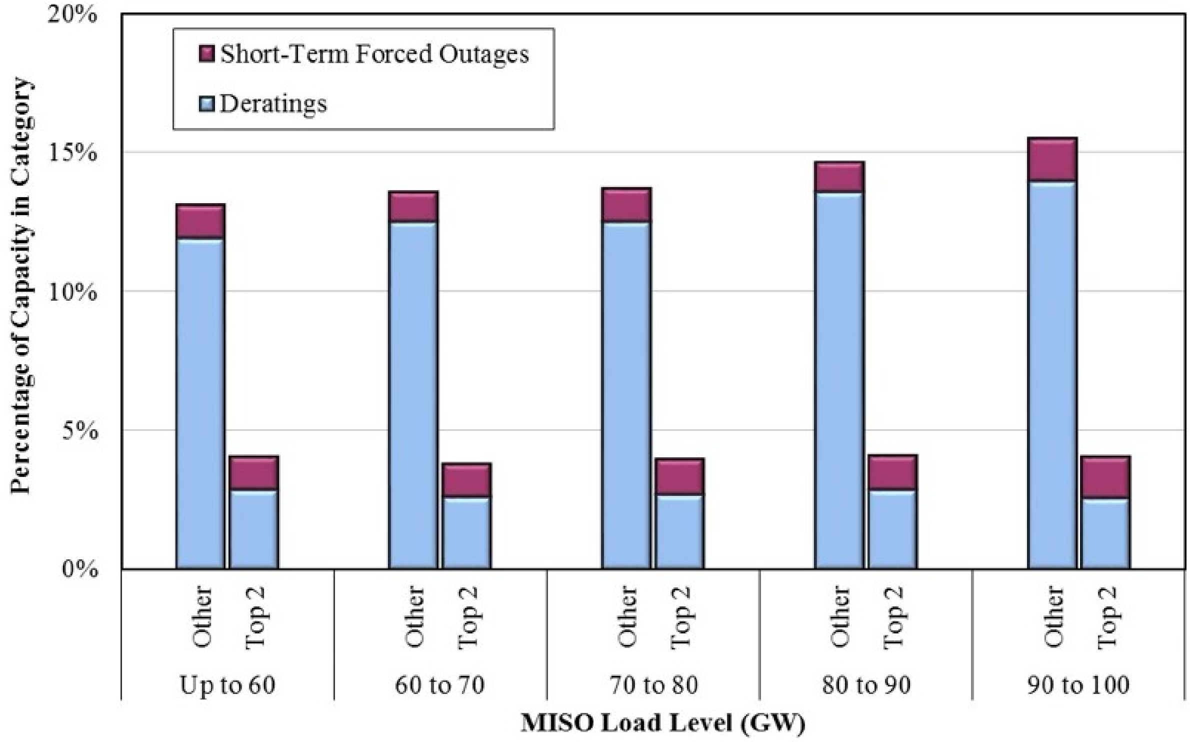


Figure A154: Real-Time Deratings and Forced Outages
North Region, 2016

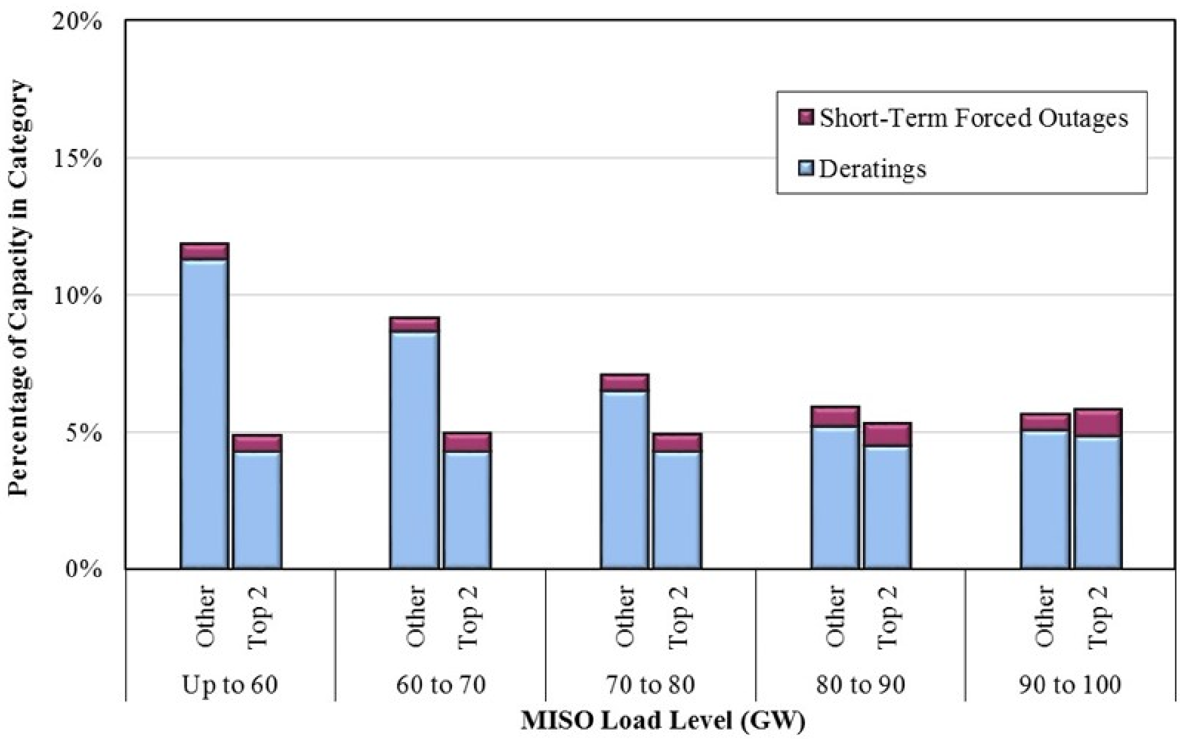
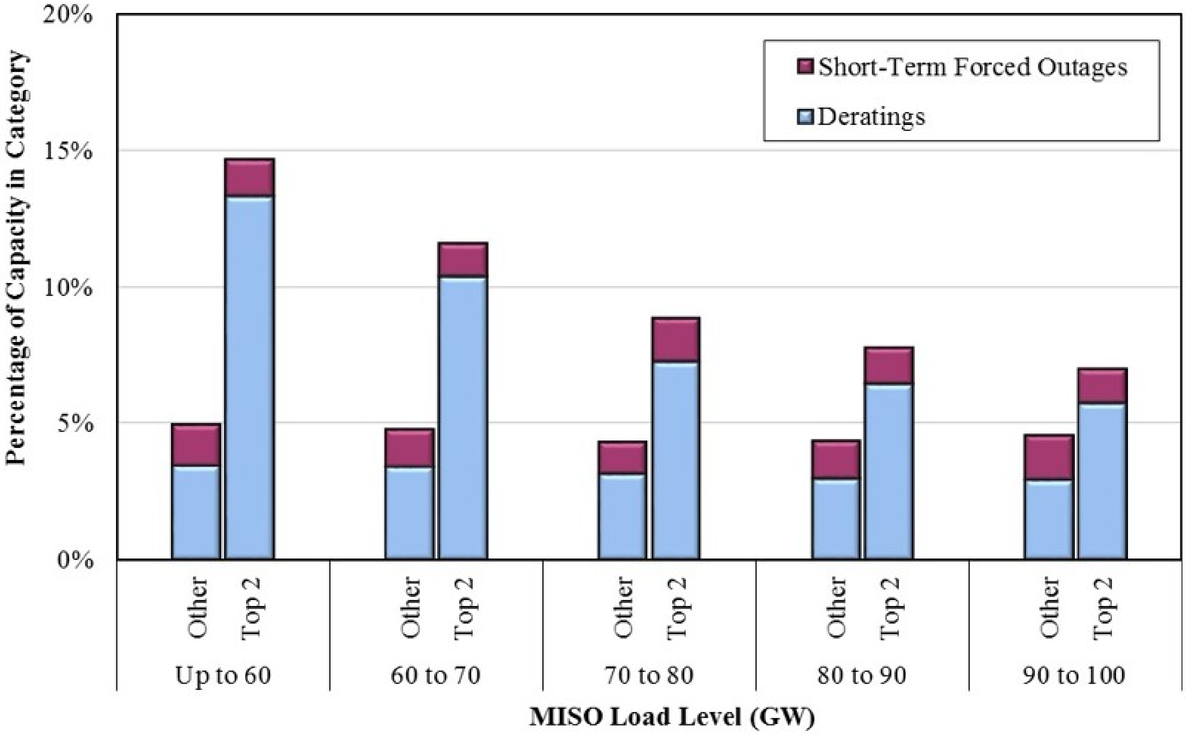


Figure A155: Real-Time Deratings and Forced Outages
WUMS Area, 2016



IX. 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 greatly reduce the costs of committing and dispatching generation. 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.[37] 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, such as 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, such as from peak to off-peak periods, thereby flattening the load curve.

A. DR Resources in MISO

MISO's DR capability rose in 2016 to more than 10.7 GW. The majority of the DR takes the form of legacy DR programs administered by load-serving entities (LSEs), either through load interruptions (Load-Modifying Resources, or LMR) or through behind-the-meter-generation

37 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 (BTMG).

(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 this year, including satisfying LSEs' resource adequacy requirements under Module E of the Tariff.

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 21 Type I resources available to the markets in 2016, and 14 of them cleared an average of 11 MW of energy.

Type I resources. 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. They 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 resources are "dynamic pricing" resources. Dynamic pricing is the most efficient form of DR because rates formed under this approach provide customers with accurate price signals throughout the day. These customers can then alter their usage in response the prices. Significant barriers to implementing dynamic pricing include the minimum required load of the participating customer, infrastructure outlays, and potential retail rate reform. Only one Type II resource was active in 2016, and that resource left MISO's market in Spring 2016.

LSEs are also eligible to offer DRR capability into the ASM markets. 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 2016, DRR Type I resources provided 55 MW per hour of contingency reserves, a small increase from 2015.

Other Forms of DR in MISO. Most other DR capacity comes from interruptible load programs for 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 targeting residential and small commercial and industrial customers. In the event of a contingency, the LSE manually reduces the load of this equipment to a predetermined level.

EDRs allow MISO to directly curtail load in specified emergency conditions if DRR is dispatched in the ancillary services market and LSE-administered DR programs are unable to meet demand under non-emergency conditions. EDR is supplementary to existing DR initiatives and requires the declaration of a NERC Energy Emergency Alert level 2 or 3 event. Resources that do not qualify as DRR are still eligible to reduce load and be compensated as EDRs. EDR offers are 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 LMP cap. EDR participants who curtail their demand 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 can set price as of the March 1, 2015, go-live of ELMP.

Finally, 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 PRA, while LMR must meet additional Tariff-specified criteria prior to their participation.

Table A8: DR Capability in MISO and Neighboring RTOs

Table A8 shows total DR capabilities of MISO and neighboring RTOs. Due to differences in their requirements and responsiveness, individual classes of DR capability are not comparable.

Table A8: DR Capability in MISO and Neighboring RTOs
2014-2016

		2016	**2015**	**2014**
MISO[1]		**10,721**	**10,563**	**10,356**
	Behind-The-Meter Generation	4,089	4,213	4,072
	Load Modifying Resource	4,616	5,121	4,943
	DRR Type I	525	330	372
	DRR Type II	75	116	76
	Emergency DR	1,416	782	894
NYISO[3]		**1,653**	**1,325**	**1,211**
	ICAP - Special Case Resources	1,192	1,251	1,124
	Of which: Targeted DR	372	385	369
	Emergency DR	75	75	86
	Of which: Targeted DR	14	14	14
	DADRP	0	0	0
ISO-NE[4]		**2,600**	**2,685**	**2,487**
	Real-Time DR Resources	702	692	796
	Real-Time Emerg. Generation Resources	2	300	255
	On-Peak Demand Resources	1,386	1,222	997
	Seasonal Peak Demand Resources	510	471	439

[1] Registered as of December 2015. All units are MW. Source: MISO website, published at: www.misoenergy.org/WhatWeDo/StrategicInitiatives/Pages/DemandResponse.aspx.

[2] Roughly 2/3 of the EDR are also LMRs.

[3] Registered as of July 2016. Retrieved May 2, 2017. Source: Annual Report on Demand Side Management Programs of the New York Independent System Operator, Inc., Docket ER01-3001.

[4] Registered as of Jan. 1, 2017. Source: ISO-NE Demand Response Working Group Pesentation.