2019 State of the Market Report for the MISO Electricity Market

Analytic Appendix

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Independent Market Monitor
for the Midcontinent ISO

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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, our conclusions from these analyses and how they relate to performance of the markets are discussed in the main 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 capacity market was replaced in June 2013 by the annual Planning Resource Auction (PRA).

Key changes or improvements implemented in 2019 included:

- In February, FERC approved tariff changes to increase MISO's market access to LMRs by allowing MISO to schedule LMRs in advance of an anticipated emergency and requiring LMRs to register availability consistent with their seasonal capability.
- In April, MISO implemented capacity accreditation changes that treat generator planned outages during emergencies that were not scheduled far in advance as forced outages, although these changes have had very small effects.
- In May, MISO implemented a number of key changes that have significantly improved generators' incentives to follow MISO's dispatch instructions and the operational performance of the system overall. These changes included:
  - Changes in the Uninstructed Deviation thresholds and rules;
  - Improvements in the Price Volatility Make-Whole Payment settlement formulas affecting units that are not performing well in following dispatch instructions;
  - Modifications to MISO's regulation commitment process to reduce the volume of regulation-based deratings, while expanding the units available to schedule to provide regulation.
- In October, MISO filed tariff changes that would prevent resources from qualifying to provide capacity if they are on outage during the peak summer months.
- In November, MISO modified the ELMP framework to allow the costs of fast-start resources scheduled in the day-ahead market to participate in setting real-time prices.
- In December, MISO lifted the energy offer cap from $1,000 per MWh to $2,000 per MWh as mandated by FERC.
- MISO also proposed a number of recommended improvements to the market power mitigation provisions in Module D in December that were approved by FERC and implemented in early 2020.

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.

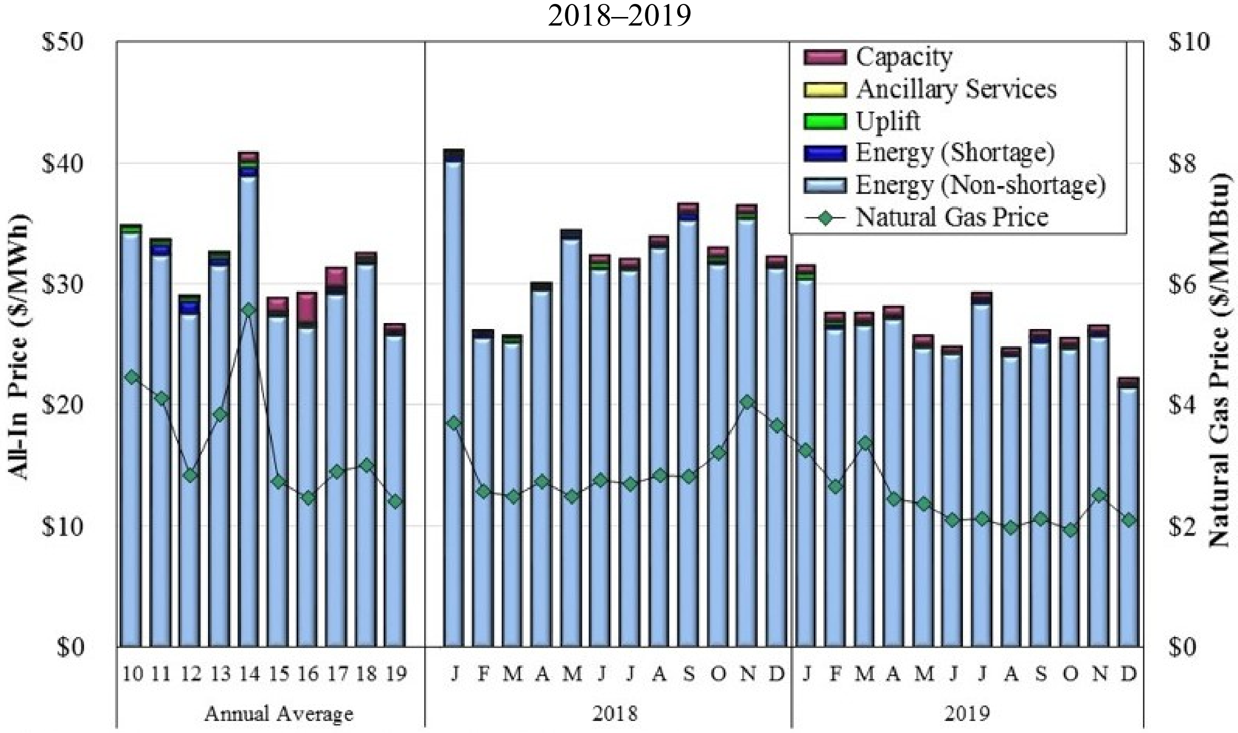
A. Market Prices in 2019

In a well-functioning, competitive market, suppliers have an incentive to offer at their marginal costs. Therefore, energy prices should correspond closely with resources' marginal production costs, which are primarily comprised of fuel costs for most resources. Although coal-fired resources historically have been marginal in a large share of hours, low natural gas prices in recent years have 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 2018 to 2019 along with the price of natural gas at the Chicago Citygate trading hub. The leftmost section shows the annual average prices for 2010 through 2019. The all-in price represents the cost of serving load in MISO's electricity market. It includes the load-weighted real-time energy cost, 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
2018–2019



*Energy prices are separated into Shortage and Non-shortage after 2010.

Figure A2: Cross Market All-In Price Comparison

To provide perspective on how the MISO markets compare to the other eastern RTOs, Figure A2 shows the all-in price for each market from 2017 through 2019. These markets have migrated to similar market designs, including locational energy markets, operating reserves and regulation markets, and capacity markets (with the exception of ERCOT). However, the details of the market rules can vary substantially.

Figure A2: Cross Market All-In Price Comparison
2017-2019

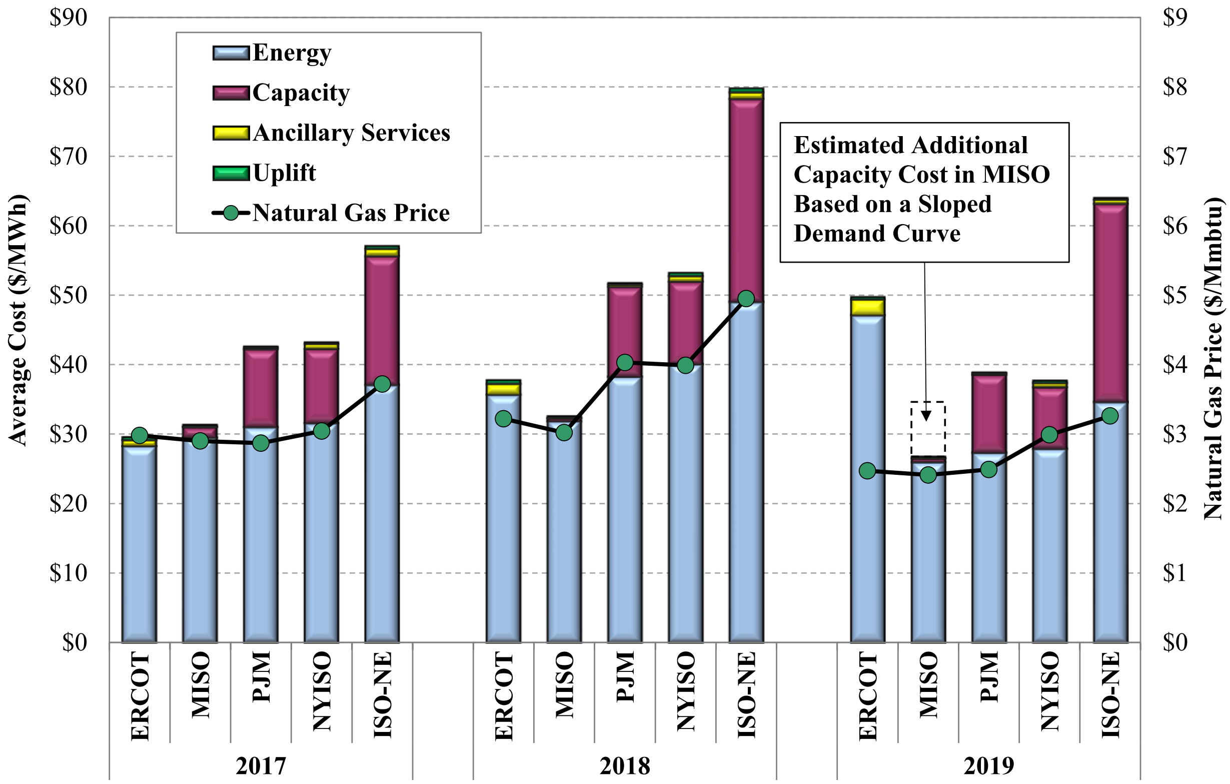


Figure A3: Real-Time Energy Price-Duration Curves

Figure A3 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 A3: Real-Time Energy Price-Duration Curve

2019

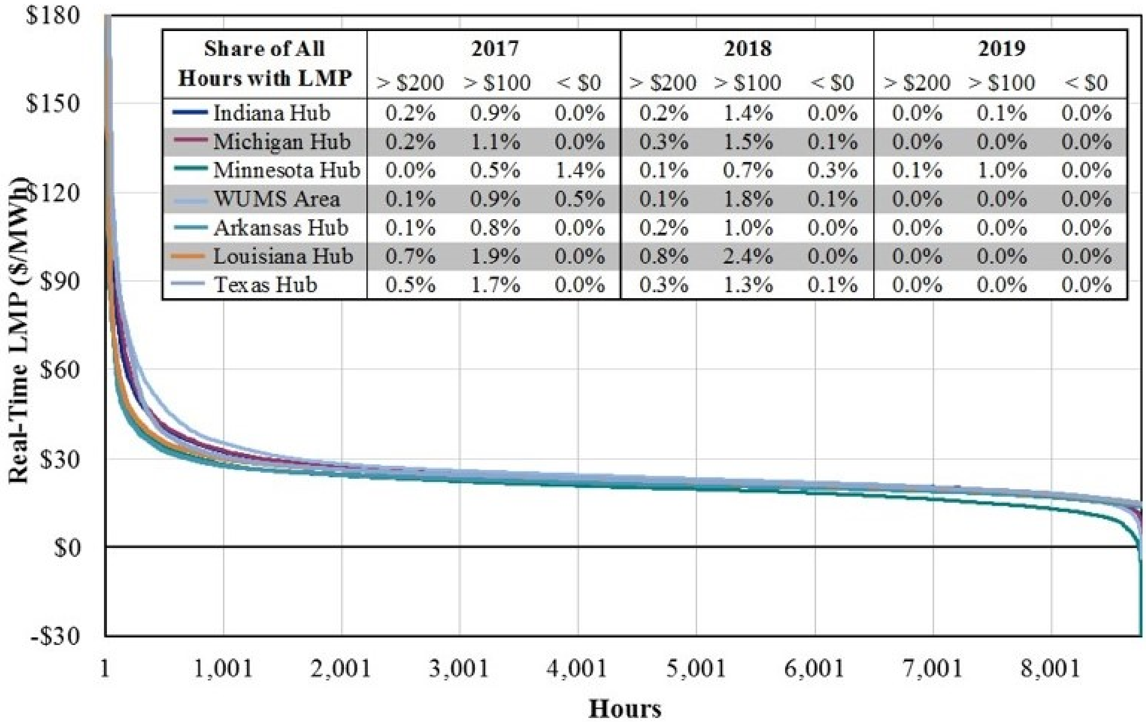


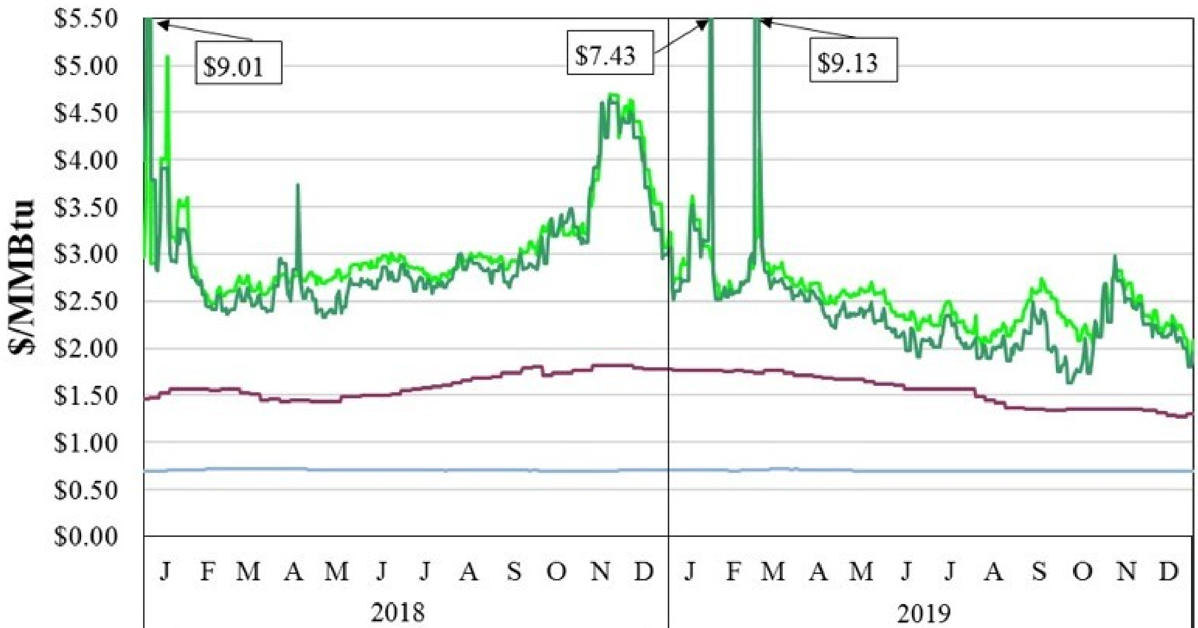
Figure A4: MISO Fuel Prices

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 natural gas-fired resources set energy prices in a large share of hours, electricity prices tend to be highly correlated with natural gas prices. Coal-fired units frequently set prices in off-peak hours.

Figure A4 shows the prices for natural gas, oil, and two types of coal in the MISO region since the beginning of 2018.[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 2017 for each type of fuel.

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.

Figure A4: MISO Fuel Prices
2018–2019



Annual Average	2017	2018	2019
Chicago NG	$2.90	$3.02	$2.41
Henry NG	$2.96	$3.12	$2.51

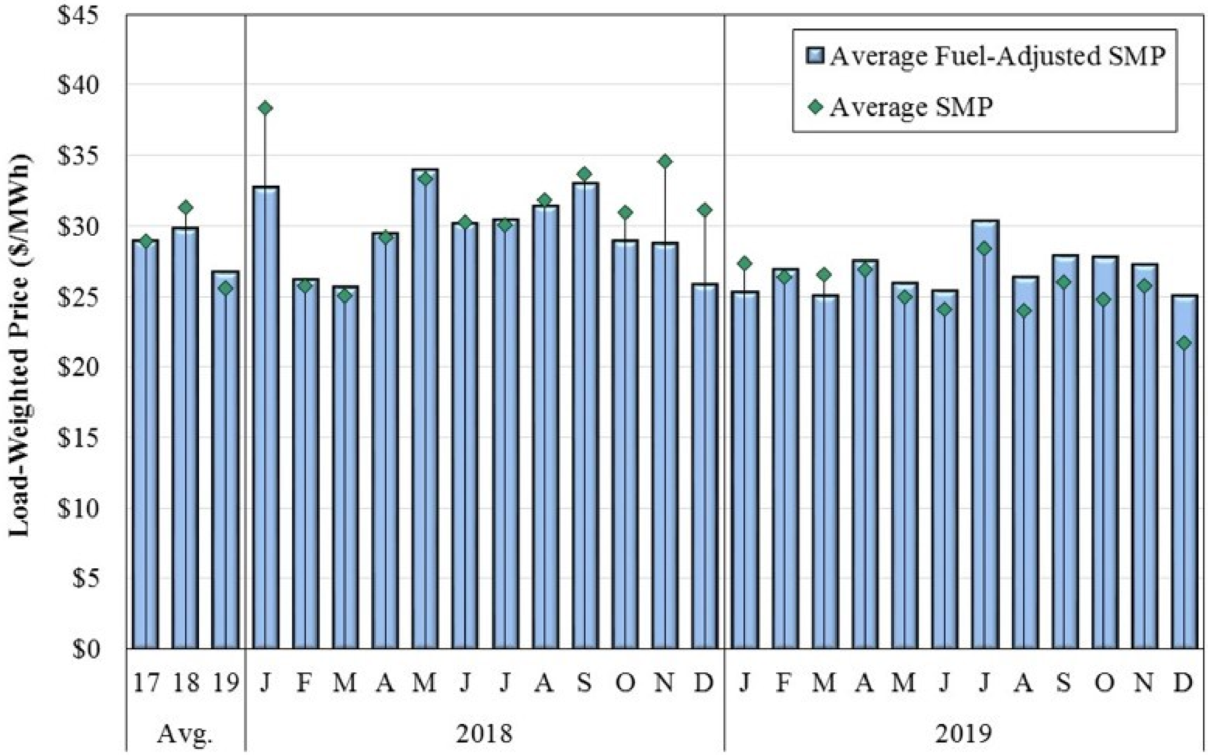
Annual Average	2017	2018	2019
IB Coal	$1.46	$1.61	$1.55
PRB Coal	$0.67	$0.71	$0.70

Figure A5: Fuel-Price-Adjusted System Marginal Price

Fluctuations in marginal fuel prices can obscure the underlying trends and performance of the electricity markets. In Figure A5, 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.

To calculate this metric, the SMP of each real-time interval was indexed to the average fuel price of the marginal fuel from 2017 through 2019. 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—the result of differences in regional generation mix—that would impact the economics of interchange with neighboring areas.

Figure A5: Fuel Price-Adjusted System Marginal Price
2018–2019



B. Fuel Prices and Energy Production

Figure A6: Price Setting by Unit Type

Figure A6 examines the frequency with which different types of generating resources set the real-time SMP in MISO. The top panel in the figure shows the average prices when each type of unit was on the margin, and the bottom panel shows the share of market intervals that each type of unit set the real-time price.

While baseload coal-fired units have historically set price in the majority of hours, that share has been declining over time. The year 2018 was the first year that coal resources set the marginal energy price less frequently than gas-fired resources. Nearly all 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 A6: Price-Setting by Unit Type
2018–2019

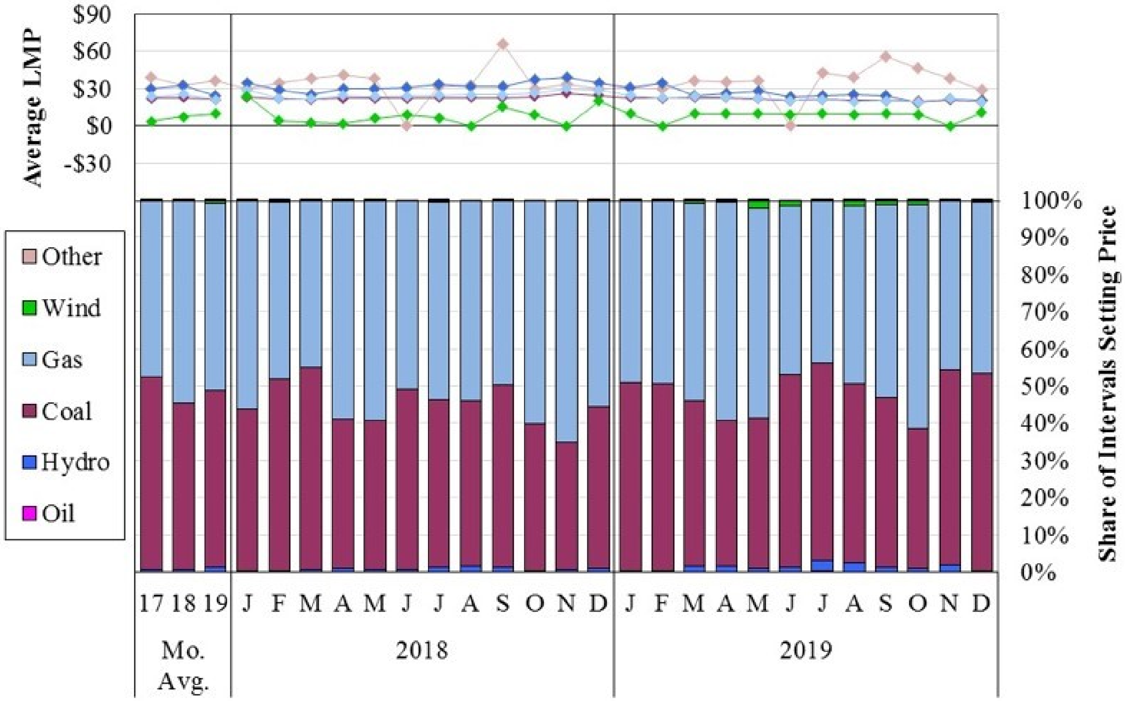


Table A1: Capacity, Energy Output, and Price-Setting by Fuel Type

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 2019 compared to 2018. The lowest marginal cost resources (coal and nuclear) produce most of the energy. Because natural gas-fired units are higher marginal-cost resources, they tend to produce a lower share of MISO's energy than their share of MISO's installed capacity. While wind resources comprise a small share of MISO's unforced capacity because of their intermittent nature, their contribution to energy output is much higher.

Table A1: Capacity, Energy Output, and Price-Setting by Fuel Type
2018–2019

	Unforced Capacity				Energy Output		Price Setting			
	Total (MW)		Share (%)		Share (%)		SMP (%)		LMP (%)	
	2018	2019	2018	2019	2018	2019	2018	2019	2018	2019
Nuclear	12,225	12,107	10%	9%	16%	17%	0%	0%	0%	0%
Coal	48,775	46,864	38%	37%	47%	39%	45%	47%	78%	81%
Natural Gas	55,240	56,673	43%	44%	27%	31%	54%	51%	87%	89%
Oil	1,691	1,568	1%	1%	0%	0%	0%	0%	0%	0%
Hydro	3,966	4,034	3%	3%	1%	2%	1%	1%	1%	2%
Wind	3,005	3,660	2%	3%	8%	9%	0%	1%	31%	38%
Other	2,678	2,703	2%	2%	2%	1%	0%	0%	2%	2%
Total	**127,580**	**127,608**								

C. Load and Weather Patterns

Figure A7: Load Duration Curves and 2019 Peak Load

Although market conditions can still be tight in the winter and shoulder seasons 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 A7 shows load levels for 2019 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 2017 through 2019 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 2019. The "Predicted Peak (50/50)" is the predicted peak load in 2019 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 A7: Load Duration Curves and 2019 Peak Load
2017–2019

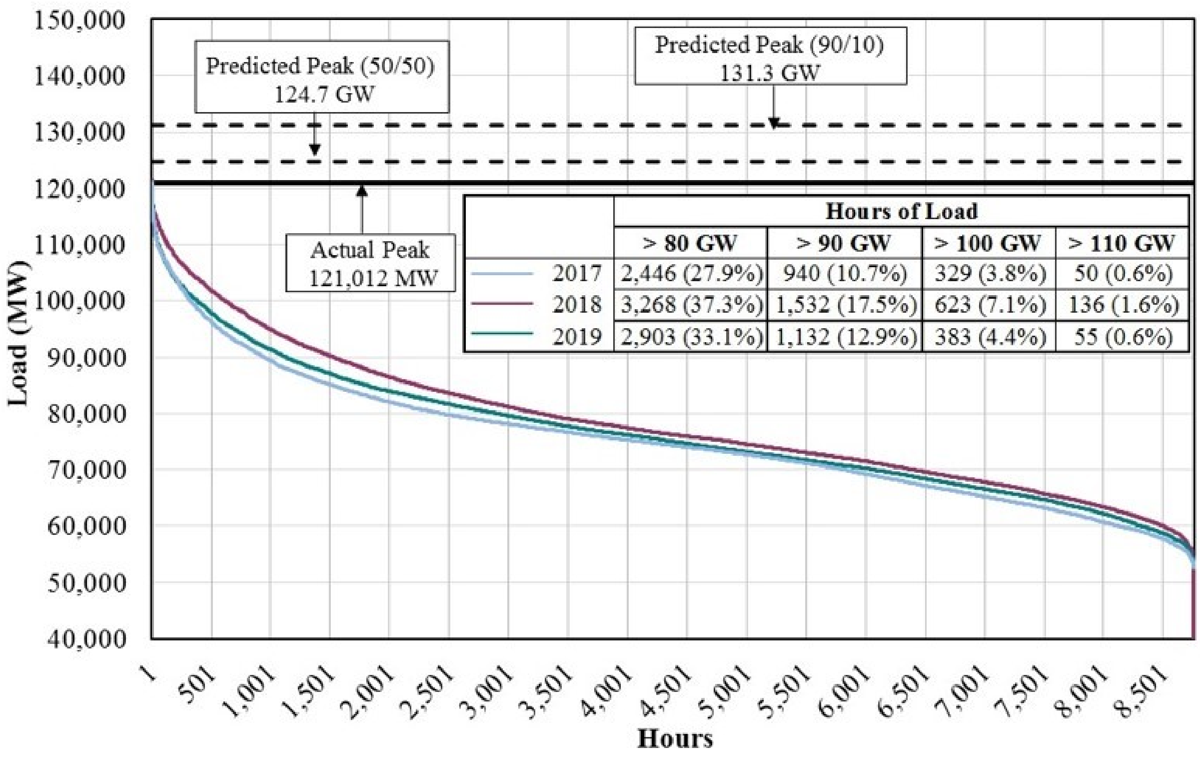
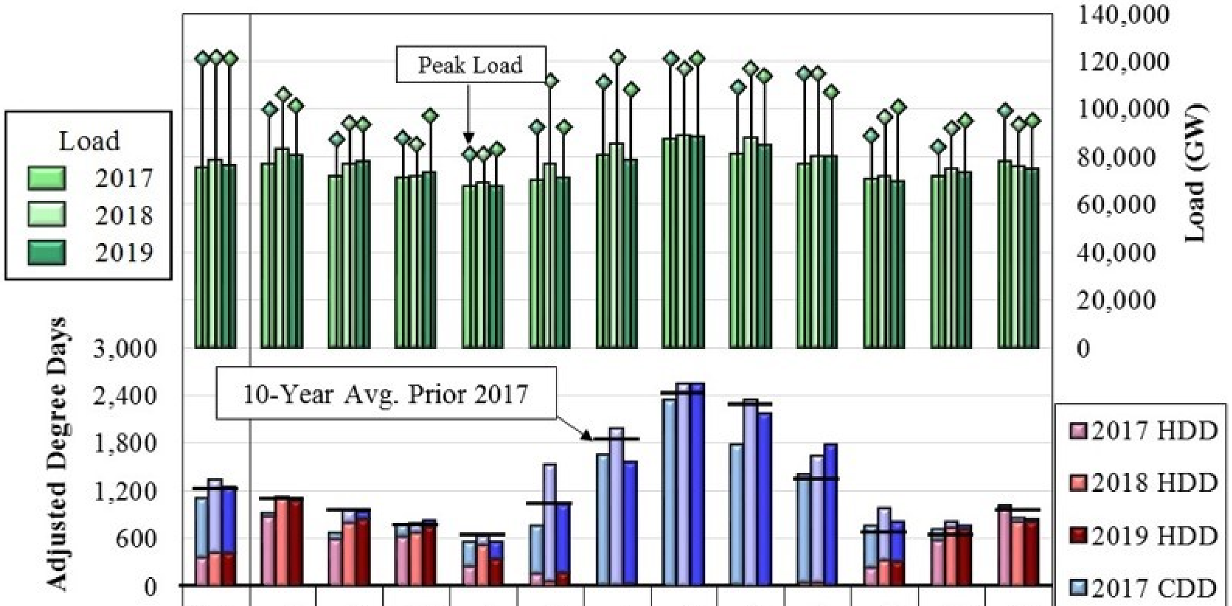


Figure A8: Heating and Cooling Degree-Days

MISO's load is temperature sensitive. Figure A8 illustrates the influence of weather on load by showing heating and cooling degree-days 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 over the 10 years prior to 2017 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 A8: Heating and Cooling Degree-Days
2017–2019



% Chg 18-19	Avg	J	F	M	A	M	J	J	A	S	O	N	D
Avg. Load	-2%	-3%	2%	2%	-3%	-7%	-8%	0%	-4%	0%	-3%	-2%	-2%
Degree Days	-8%	-3%	-1%	4%	-12%	-33%	-21%	0%	-7%	9%	-17%	-5%	-1%

D. Ancillary Services Markets

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 services products, the demand curve for that product will set the market-wide price for that product and be included in the price of higher valued reserves and energy. The three main ancillary services products are regulation, spinning reserves, and supplemental reserves. Total Operating Reserves are the sum of these three products. Spinning and supplemental reserves are both categories of contingency reserves.

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.

The demand curves for the various ancillary services products in 2019 were:

- Regulation: varies monthly according to the prior month's gas prices and averaged $132.49 per MWh in 2019.
- 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).[3]
- Total Operating Reserves:[4]
  - For cleared reserves less than four percent of the market-wide requirement, the Value of Lost Load ($3,500 per MWh) minus the monthly demand curve price for regulation.
  - For cleared reserves between four and twelve percent, the estimated probability of lost load based on a single large resource contingency.
  - For cleared reserves between twelve percent and the Most Severe Single Contingency (MSSC), the curve is flat at $2,100 per MWh and then steps down to $1,100 per MWh through 96 percent of the requirement. For cleared reserves more than 96 percent of the market-wide requirement: $200 per MWh.

The most important reserve constraint is the market-wide operating reserve requirement (contingency reserves plus regulation). This is because a shortage of total operating reserves has the greatest potential impact on reliability. Accordingly, the total operating reserve constraint 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 A9: Real-Time Ancillary Services Clearing Prices and Shortages

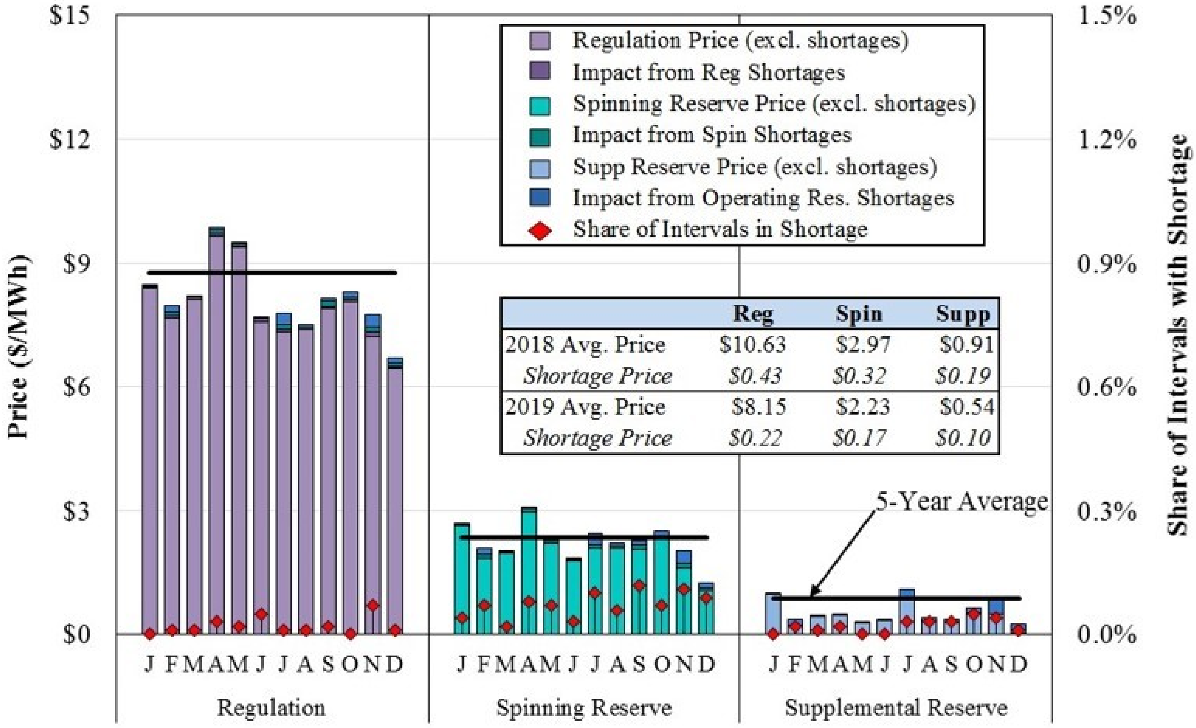
Figure A9 shows monthly average real-time clearing prices for the three ancillary service products in 2019: regulation, spinning reserves, and supplemental reserves.

Supplemental reserves are the lowest quality reserve because the technical requirements are less stringent than for regulation and spinning reserves. But because supplemental reserves will be short in conjunction with total reserves, a shortage of supplemental reserves is an operating reserve shortage and will result in the largest shortage-pricing component in each of the other reserve prices and in the energy price. Figure A9 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.

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

4 There is no separate demand curve for Supplemental Reserves. Prices for Supplemental Reserves during shortages are established by the Total Reserve demand curve (known as the operating reserve demand curve or ORDC).

Figure A9: Real-Time Ancillary Services Clearing Prices and Shortages
2019



	Reg	Spin	Supp
2018 Avg. Price	$10.63	$2.97	$0.91
Shortage Price	*$0.43*	*$0.32*	*$0.19*
2019 Avg. Price	$8.15	$2.23	$0.54
Shortage Price	*$0.22*	*$0.17*	*$0.10*

Note: Supplemental Reserve shortages in the figure reflect Operating Reserve shortages.

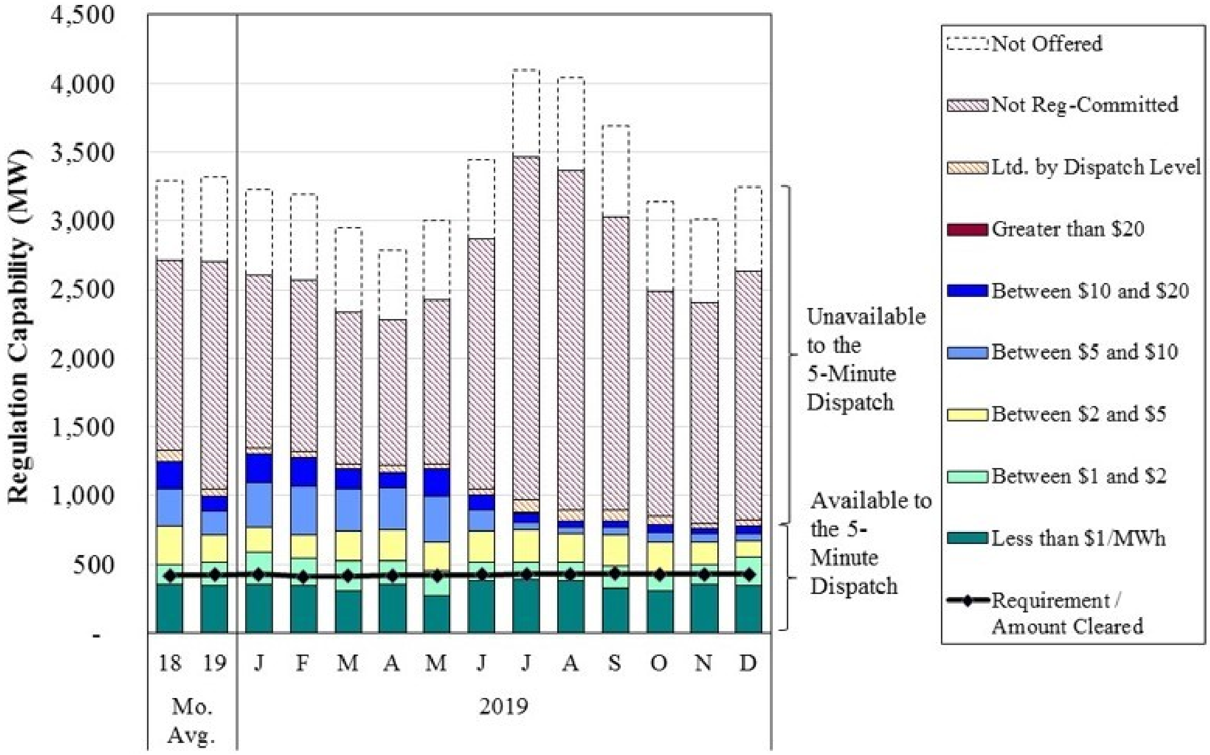
Additionally, higher-quality reserves can always be substituted for lower-quality reserves. Therefore, the price for spinning reserves will always be equal to or higher than supplemental reserves. Likewise, when a shortage occurs in a lower-quality reserve product, it appears in the price of all higher-quality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

Figure A10: Regulation Offers and Scheduling

ASM offer prices and quantities are the primary determinants of ASM outcomes. Figure A10 examines average regulation capability on MISO resources. Regulation capability 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 A10: Regulation Offers and Scheduling
2019



The figure above distinguishes between the regulation that is 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 A11: 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 Regulation always equal or exceed those for Spinning Reserves, which in turn always equal or exceed prices for Supplemental Reserves. As with Regulation, Spinning and Supplemental reserve prices can exceed the highest cleared offer as a result of opportunity costs or shortage pricing.

Figure A11 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 A11: Contingency Reserve Offers and Scheduling
2019

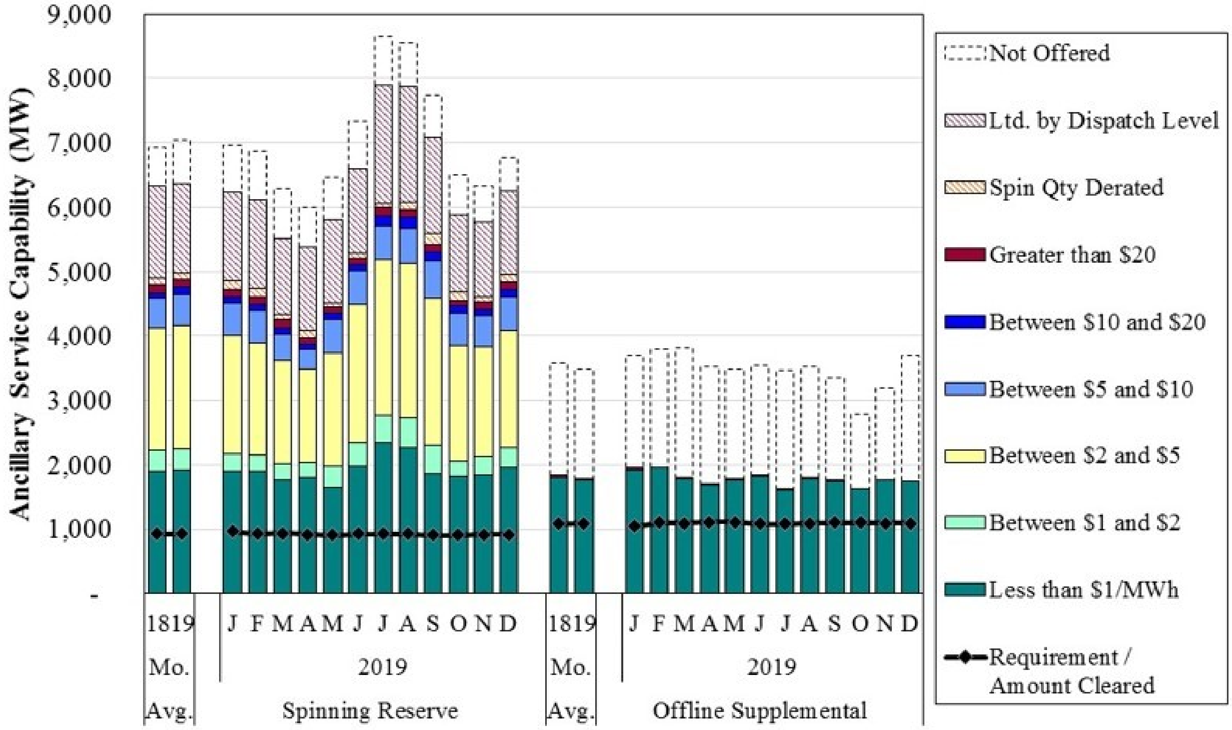


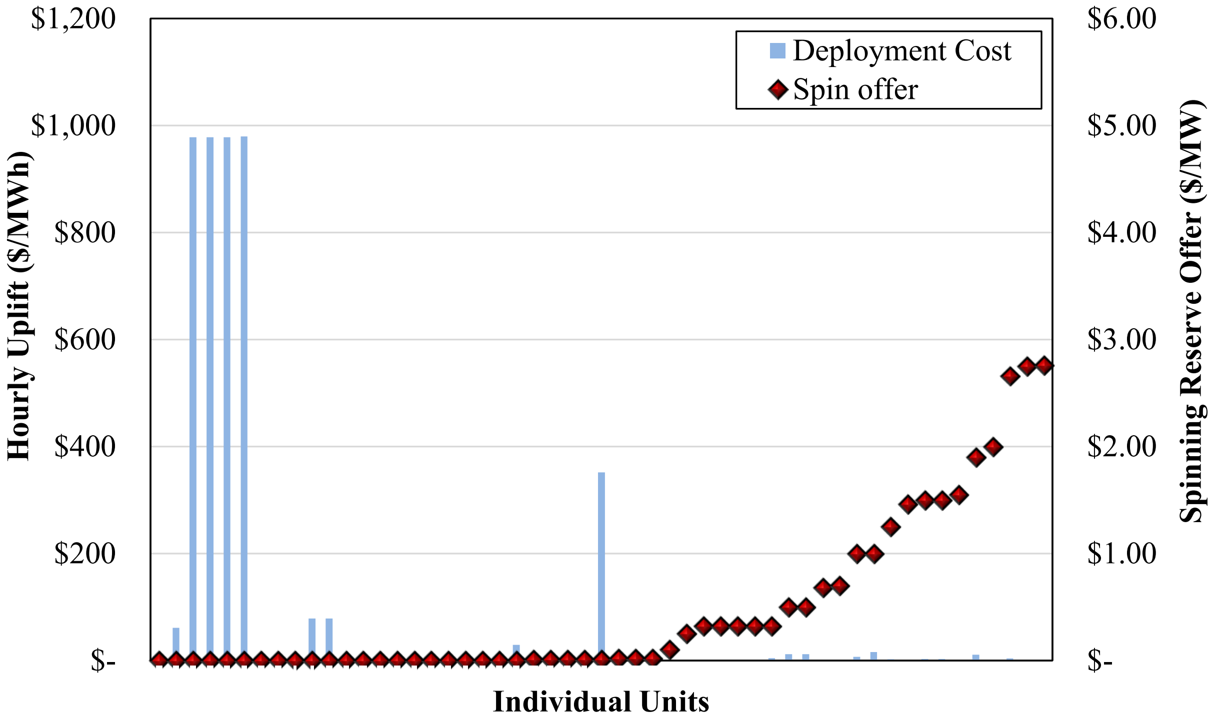
Figure A12: Deployment Costs and Spinning Reserve Clearing

When selecting and clearing resources to provide reserves, MISO does not consider the costs to produce energy during reserve deployment events. Resources are deployed for Spinning Reserves on a pro rata basis, and they are made whole to their energy offers. This results in scheduling inefficiencies because suppliers that receive make-whole payments have no incentive to incorporate expected deployment costs in their offers. In this year's report, we reintroduce a previous recommendation that MISO consider expected deployment costs when scheduling reserves because increased participation from demand-side resources has raised the market's exposure to deployment-related uplift costs. These resources generally have unusually high energy costs driven by opportunity costs of curtailed load, which should be considered when scheduling them to provide reserves.

We provide a case study using hourly spin offer data from December 17, 2019 and assume a 6:20 a.m. spin deployment to illustrate this issue. In our example, we calculated the incremental deployment costs by taking the difference between resources' offered energy costs prior to the deployment, based on their pre-deployment output level, and resources' offered costs associated with a full spin deployment, on a per MWh basis. We assumed that LMPs were constant. We divided one hour of incremental energy out-of-market costs by the spinning reserve schedule awarded for each resource in that interval.

In Figure A12, we illustrate the results of our analysis. On the left axis, we show unit hourly uplift on a $ per MWh basis, and on the right axis we plot the spinning reserve offers. The individual units are ordered on the horizonal axis in merit order, based on the spin availability offers. Self-scheduled resources are on the far left of the offer curve and are treated as though they submitted $0 availability offers. Resources whose offers were not selected for spin in this interval are not shown in the chart.

Figure A12: Deployment Costs and Spinning Reserve Clearing
December 17, 2019 at 6:20 a.m.



III. 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

Figure A13 and Figure A14: Day-Ahead Energy Hub Prices and SMP

Figure A13 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 associated day-ahead System Marginal Price (SMP). Figure A14 shows similar results for off-peak hours (10 p.m. to 6 a.m. on weekdays and all hours on weekends and holidays). Higher prices in one location relative to another indicate congestion and loss factor differences between those areas.

Figure A13: Day-Ahead Hub Prices and SMP
Peak Hours, 2018–2019

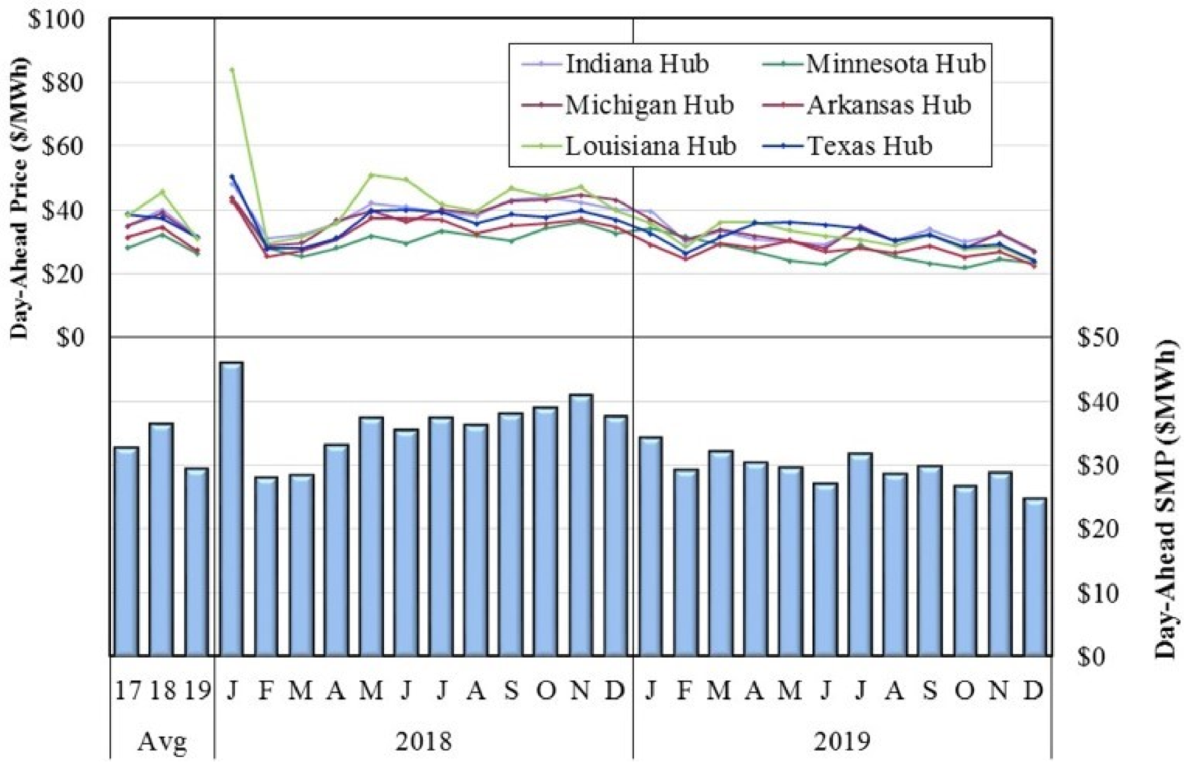
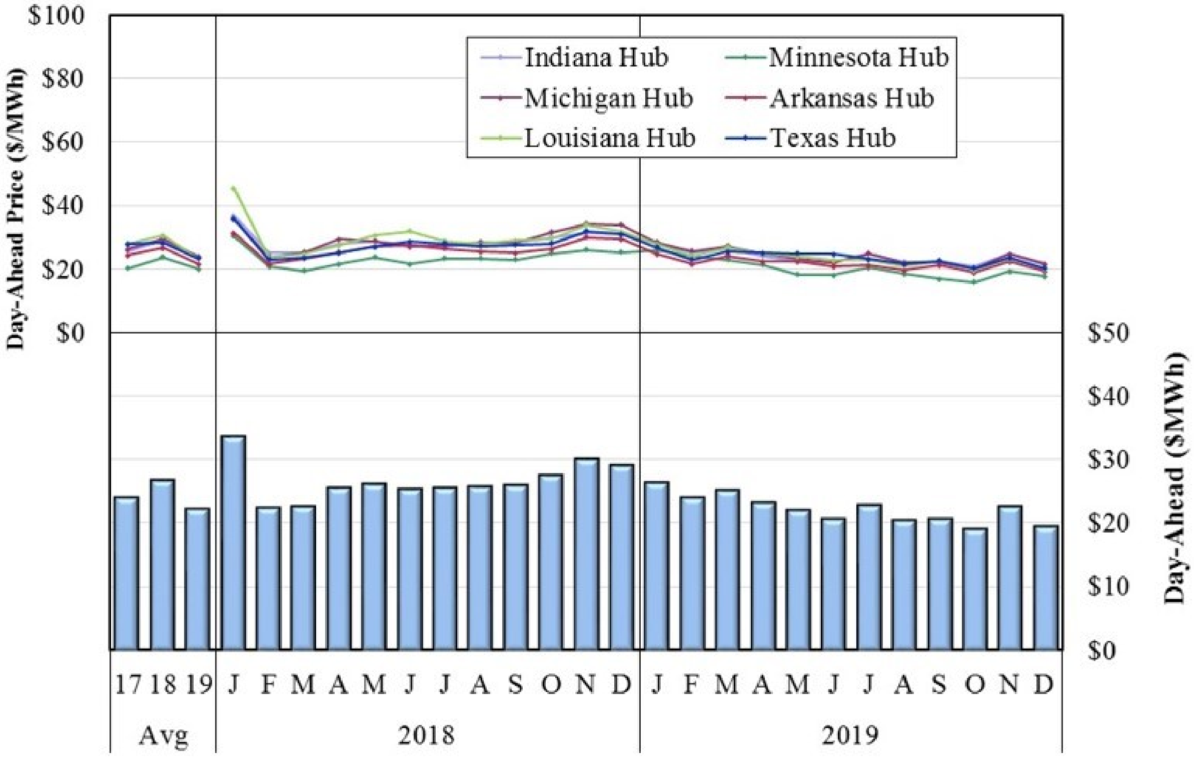


Figure A14: Day-Ahead Hub Prices and SMP
Off-Peak Hours, 2018–2019



B. Price Convergence with the Real-Time Market

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 the real-time physical dispatch is not being anticipated in the day-ahead market. This can result in:

- Generating resources not being efficiently committed because 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.

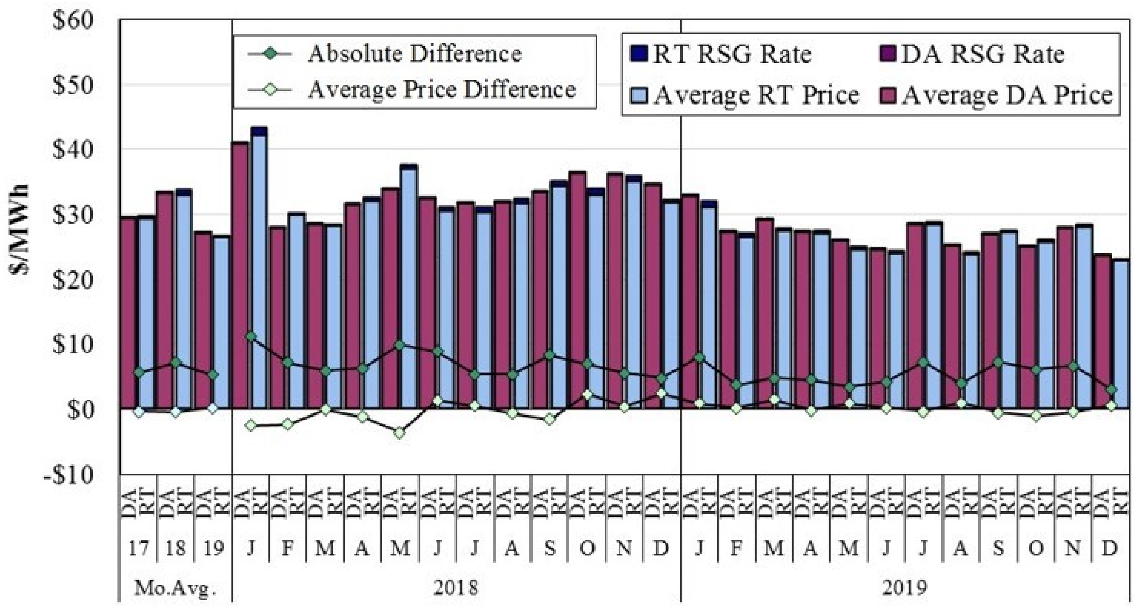
A modest day-ahead price premium reflects rational behavior because purchases in the day-ahead market are subject to less price volatility, which is valuable to risk-averse buyers. Additionally, purchases in the real-time market are subject to the allocation of real-time Revenue Sufficiency Guarantee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

Figure A15 to Figure A21: Day-Ahead and Real-Time Prices

The next seven figures summarize price convergence in the MISO markets by showing 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.[5] The table below the figures shows the average day-ahead and real-time price difference, including and excluding 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 A15: Day-Ahead and Real-Time Prices

2018–2019: Indiana Hub

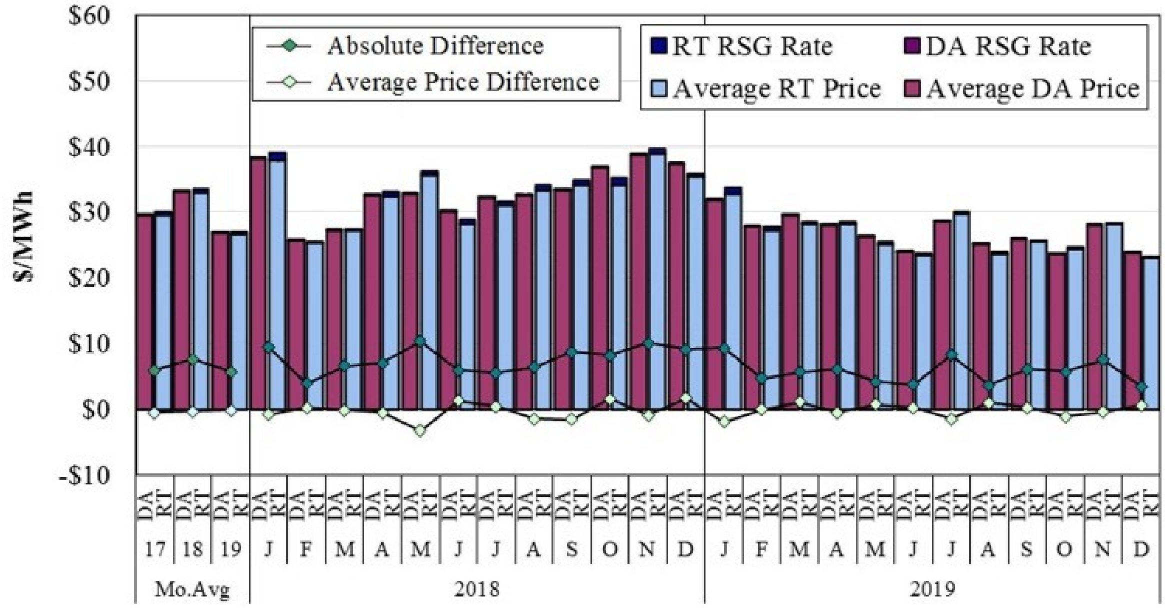


Average DA-RT Difference (% of Real-Time Price)

Excluding RSG	0	1	2	-4	-7	0	-2	-8	7	4	0	-3	10	3	9	6	3	6	0	5	2	0	5	-1	-3	-1	3
Including RSG	-1	-1	1	-6	-8	0	-4	-10	4	2	-2	-4	7	1	7	3	1	5	-1	4	1	-1	4	-2	-4	-2	3

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

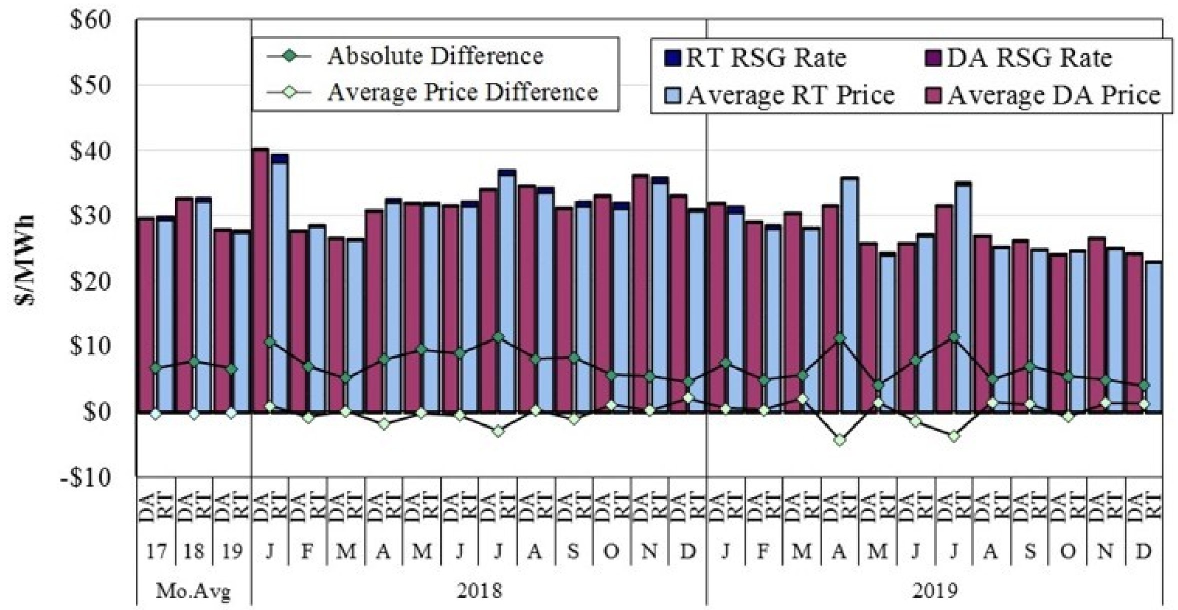
Figure A16: Day-Ahead and Real-Time Prices
2018–2019: Michigan Hub



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

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

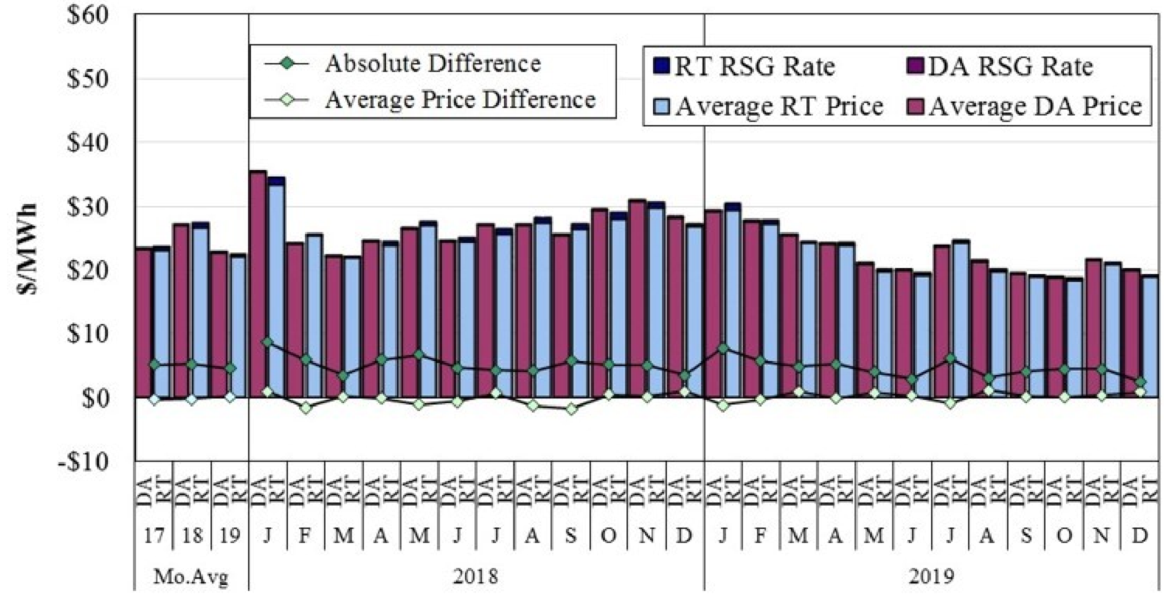
Figure A17: Day-Ahead and Real-Time Prices
2018–2019: WUMS Area



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

Excluding RSG	1	1	1	5	-3	1	-4	1	0	-6	3	-2	6	3	8	5	3	8	-12	7	-4	-10	7	5	-2	6	6
Including RSG	-1	-1	0	2	-3	0	-6	-1	-2	-8	1	-4	3	0	7	1	1	7	-12	6	-6	-11	6	4	-3	5	5

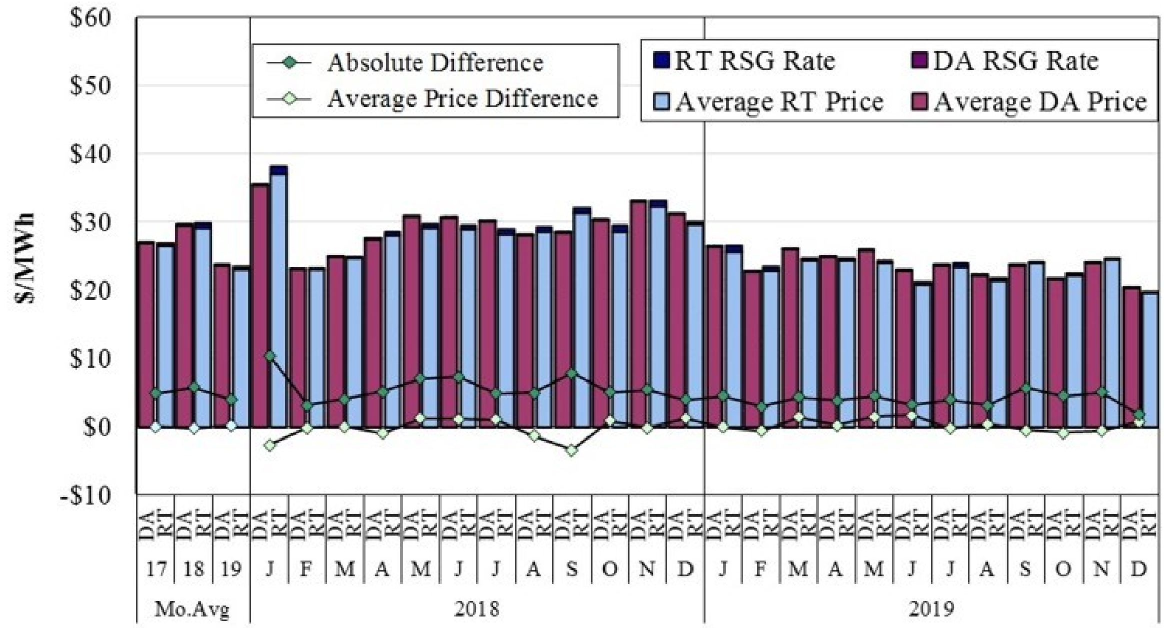
Figure A18: Day-Ahead and Real-Time Prices
2018–2019: Minnesota Hub



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

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

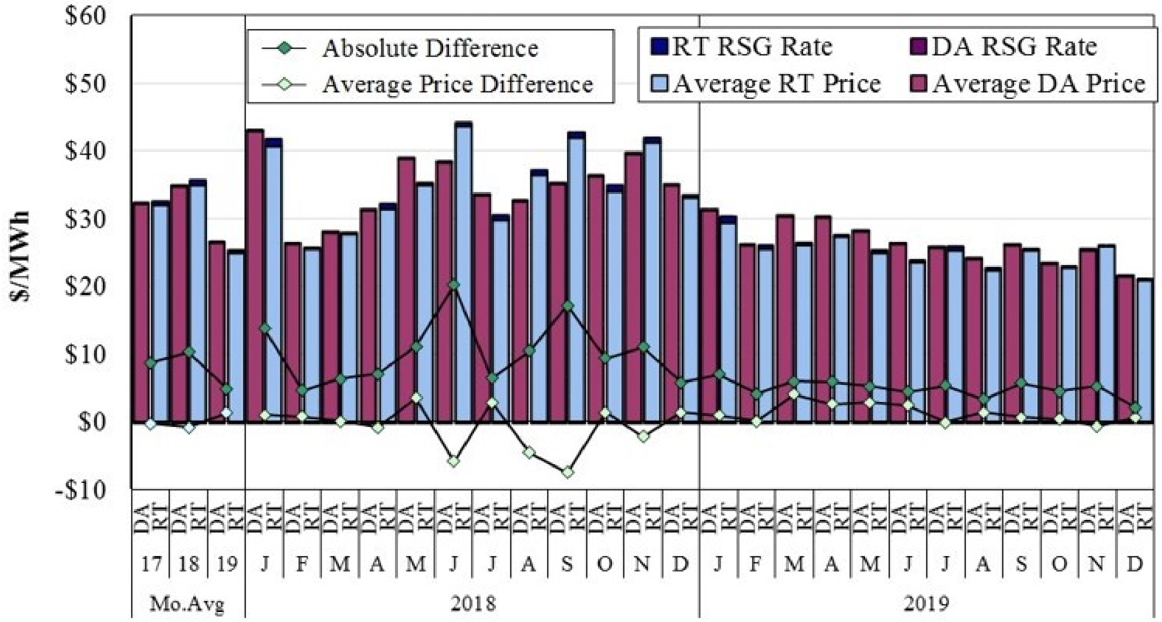
Figure A19: Day-Ahead and Real-Time Prices
2018–2019: Arkansas Hub



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

Excluding RSG	2	1	3	-5	0	0	-2	6	6	6	-2	-9	6	2	5	3	0	7	2	8	9	1	3	-1	-3	-2	4
Including RSG	0	-1	1	-7	-1	0	-4	4	4	3	-4	-11	3	-1	4	0	-3	5	1	6	8	-1	2	-2	-4	-3	4

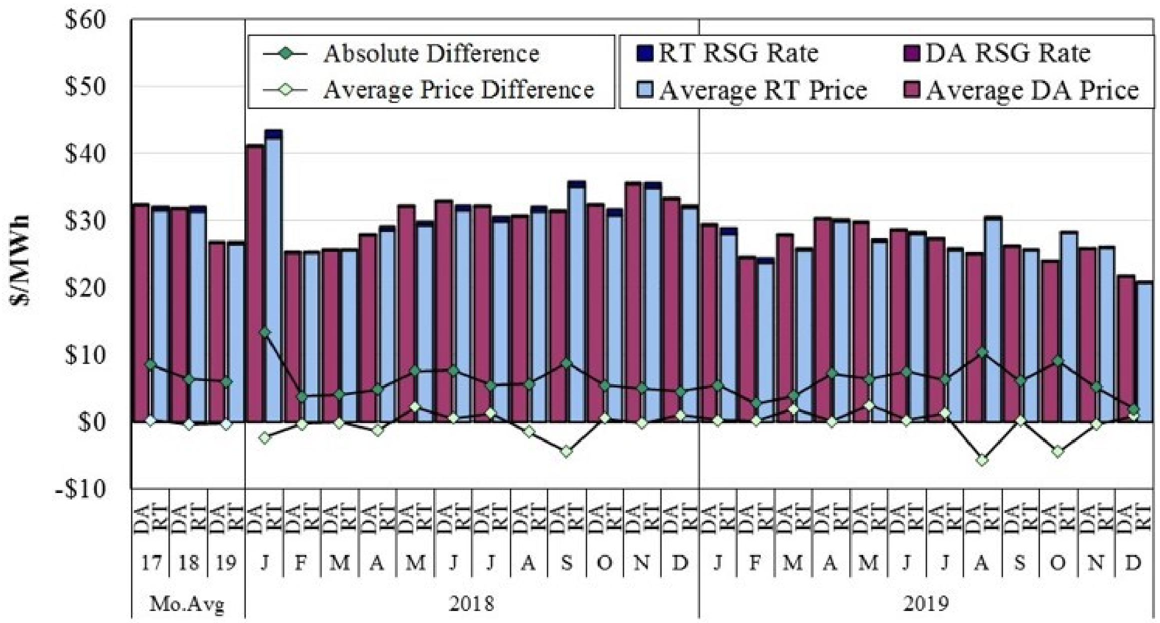
Figure A20: Day-Ahead and Real-Time Prices
2018–2019: Louisiana Hub



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

Excluding RSG	0	-1	6	5	3	1	-1	11	-12	12	-11	-16	7	-4	5	6	2	16	10	13	12	1	8	3	2	-2	3
Including RSG	-1	-2	5	3	3	0	-3	10	-13	9	-12	-18	4	-5	4	3	0	15	9	11	10	0	6	2	1	-3	2

Figure A21: Day-Ahead and Real-Time Prices
2018–2019: Texas Hub



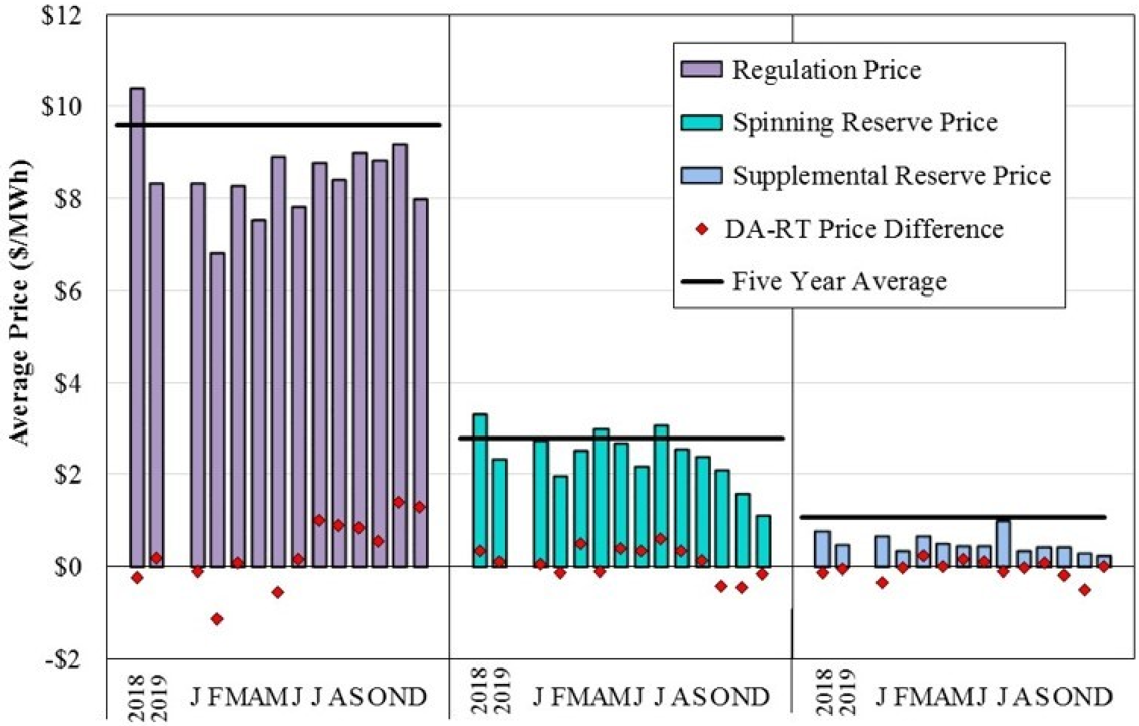
Average DA-RT Difference (% of Real-Time Price)

Excluding RSG	2	1	0	-3	0	0	-3	9	4	7	-2	-11	5	2	4	4	3	9	1	11	2	7	-17	2	-15	0	5
Including RSG	1	-1	-1	-5	-1	0	-5	8	2	4	-5	-12	2	-1	3	1	1	7	0	9	1	5	-18	1	-16	-1	4

Figure A22: Day-Ahead Ancillary Services Prices and Price Convergence

The figures above show the convergence of MISO's energy market prices. 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 A22 shows monthly average day-ahead clearing prices in 2019 for each ancillary services product, along with day-ahead and real-time price differences.

Figure A22: Day-Ahead Ancillary Services Prices and Price Convergence
2019



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 day-ahead load is defined as day-ahead cleared physical load, plus cleared virtual load minus cleared virtual supply, plus NSI. The differences between net day-ahead load and real-time load is important because they can undermine the efficiency of the generator commitments patterns and raise RSG costs.

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 after the day-ahead market to satisfy the system's real-time demand. Despite improvements from expansion of ELMP, peaking resources often do not set real-time prices, even if those resources are effectively marginal (see Section IV.B). This can contribute to suboptimal real-time pricing and can result in inefficient outcomes 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.

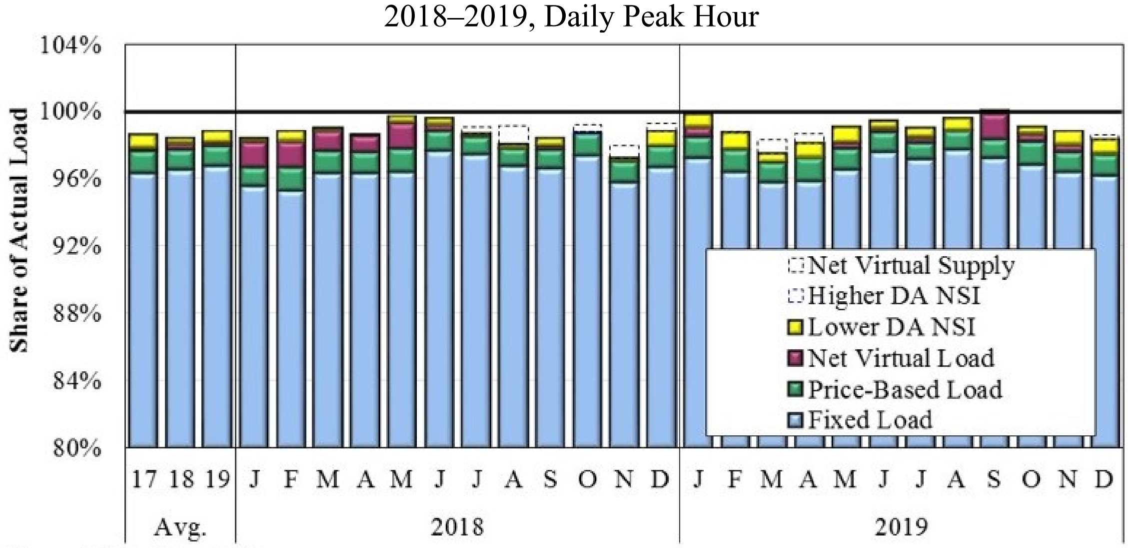
Additionally, significant supply increases after the day-ahead market can lower real-time prices and create an incentive for participants to schedule net load at less than 100 percent. The most common sources of increased supply in real time are:

- 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 A23 to Figure A25: Day-Ahead Scheduled Versus Actual Loads

To show net day-ahead load-scheduling patterns, Figure A23 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 A24 and Figure A25.

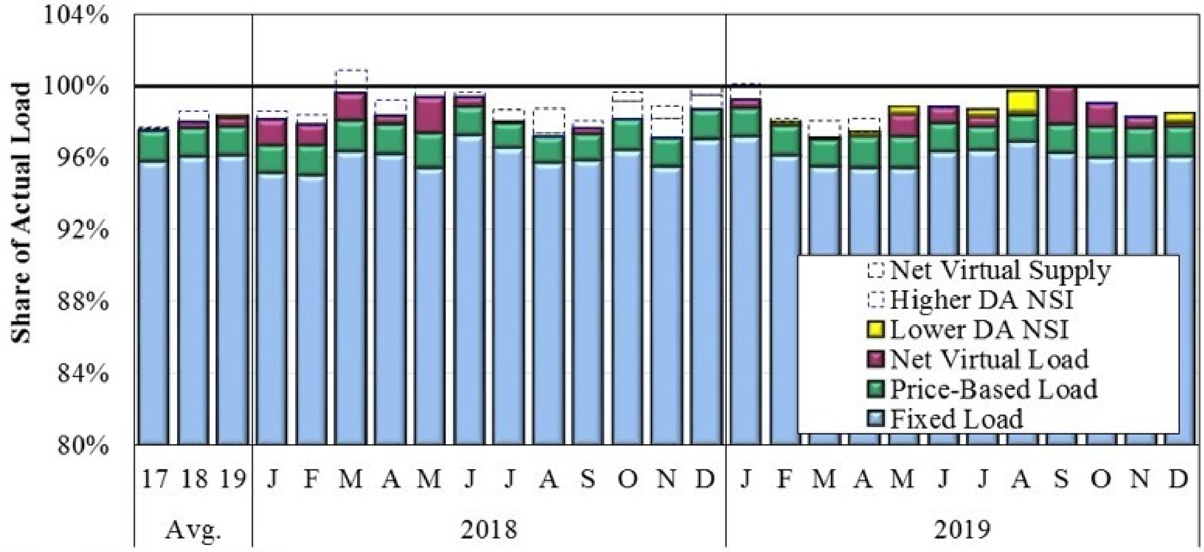
Figure A23: Day-Ahead Scheduled Versus Actual Loads
2018–2019, Daily Peak Hour



Share of Actual Load (%)

All Hours	99.2	99.0	99.1	98.7	98.6	99.3	98.6	100.0	99.7	99.4	99.3	98.9	99.1	97.5	98.8	99.7	98.8	98.1	98.5	99.0	99.6	99.9	100.1	100.0	98.9	98.5	98.2
Peak Hours	98.6	98.4	98.8	98.3	98.8	99.0	98.6	99.7	99.5	98.6	98.0	98.3	98.7	97.2	98.8	99.8	98.7	97.5	98.1	99.1	99.4	99.0	99.5	100.0	99.1	98.8	98.3

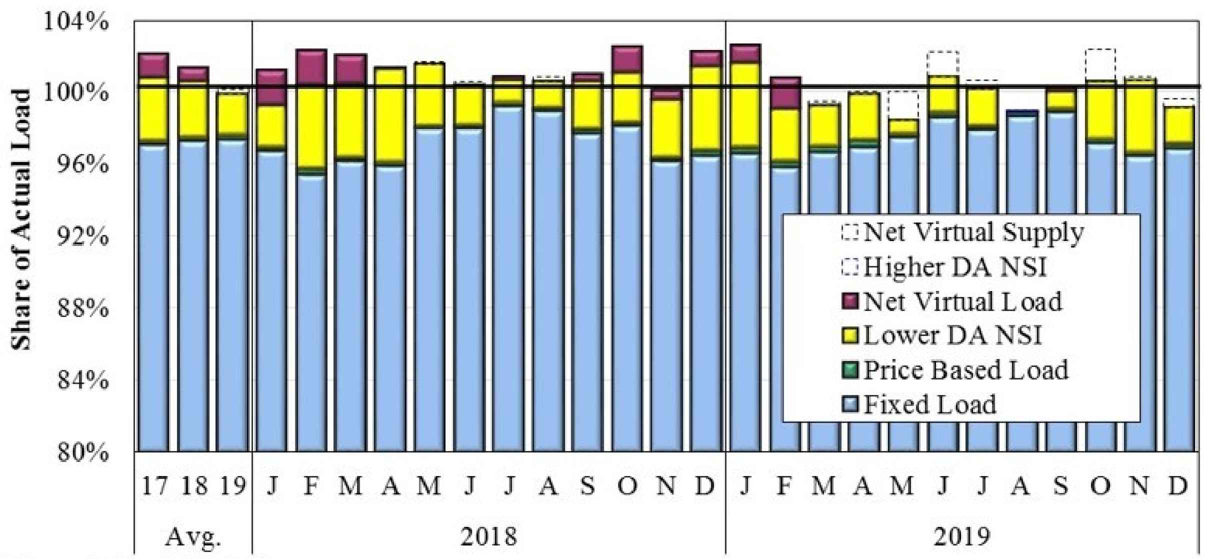
Figure A24: MISO Midwest Day-Ahead Scheduled Versus Actual Loads
2018–2019, Daily Peak Hour



Share of Actual Load (%)

	17	18	19	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
All Hours	98.0	98.2	98.7	97.9	97.7	98.7	98.4	98.9	99.0	98.5	98.5	97.8	98.0	96.7	97.9	98.9	98.4	97.9	97.8	98.6	98.8	99.7	100.3	99.9	98.5	97.7	98.2
Peak Hours	97.5	97.9	98.3	98.1	97.8	99.5	98.3	99.4	99.3	97.9	97.1	97.6	98.1	97.1	98.7	99.2	97.9	97.1	97.4	98.8	98.8	98.6	99.7	99.9	99.0	98.2	98.5

Figure A25: MISO South Day-Ahead Scheduled Versus Actual Loads
2018–2019, Daily Peak Hour



Share of Actual Load (%)

	17	18	19	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
All Hours	102.5	101.6	100.5	101.3	101.3	101.7	101.7	103.1	101.6	101.9	101.5	101.9	102.1	99.9	101.4	102.2	100.1	99.0	100.5	100.1	101.8	100.3	99.5	100.1	99.9	100.7	98.2
Peak Hours	102.1	101.3	99.9	101.2	102.3	102.0	101.3	101.5	100.4	100.9	100.6	101.0	102.5	100.1	102.2	102.6	100.8	99.3	99.9	98.5	100.9	100.2	98.9	100.2	100.6	100.7	99.1

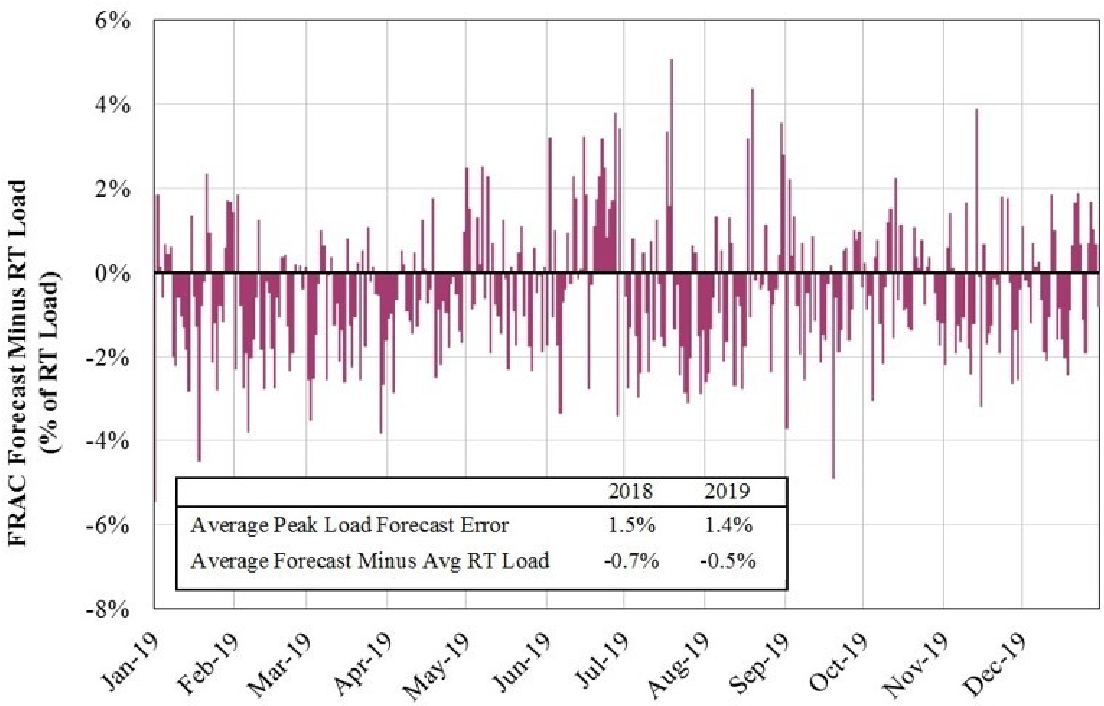
D. Load Forecasting

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 A26: Daily MTLF Error in Peak Hour

Figure A26 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 2019.

Figure A26: Daily MTLF Error in Peak Hour
2019



E. Hourly Day-Ahead Scheduling

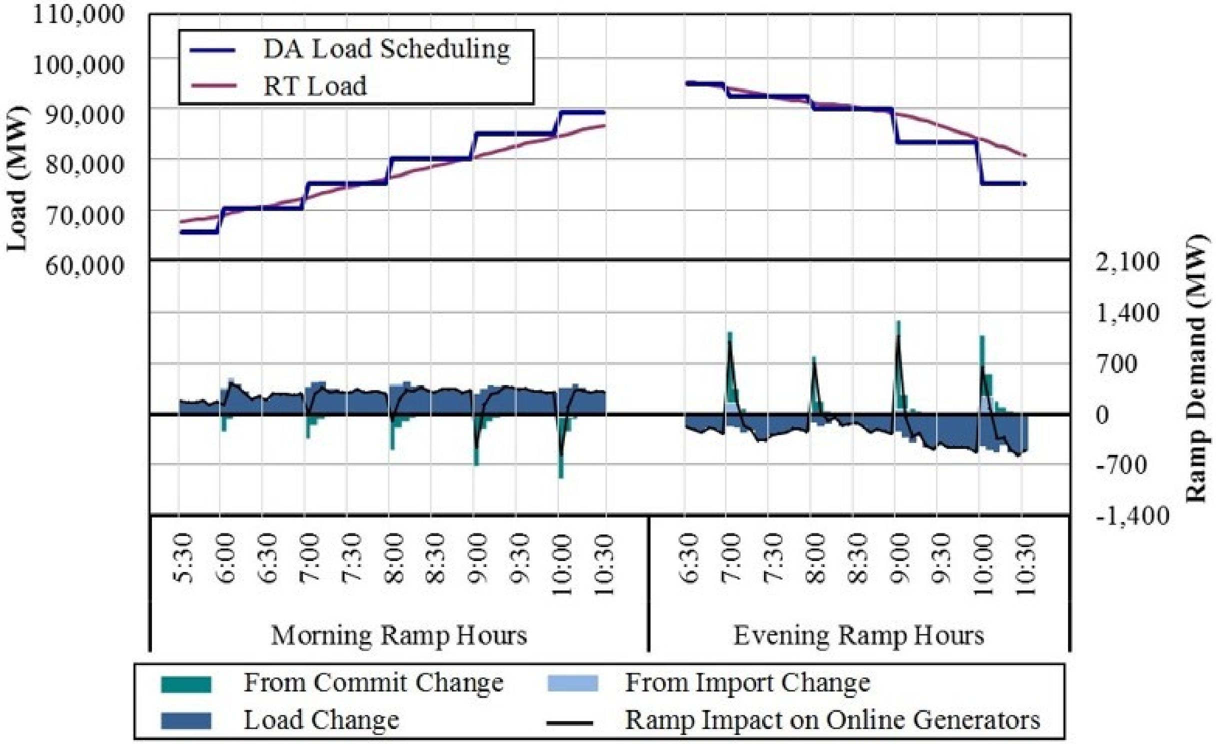
The day-ahead energy and ancillary services markets clear on an hourly basis. As a result, all day-ahead scheduled ramp demands coming into the real-time market, including unit commitments, de-commitments, and changes to physical schedules are concentrated at the top of each hour.

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. MISO should consider implementing a shorter scheduling interval in the day-ahead market.

Figure A27: Ramp Demand Impact of Hourly Day-Ahead Market

Figure A27 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 A27: Ramp Demand Impact of Hourly Day-Ahead Market
Summer 2019



F. Virtual Transactions in the Day-Ahead Market

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 real-time prices. Virtual trading is profitable when the trader buys low and sells high: for virtual demand bids this is when the real-time energy price is higher than the day-ahead price, while for virtual supply offers this is when the day-ahead energy price is higher than the real-time price.

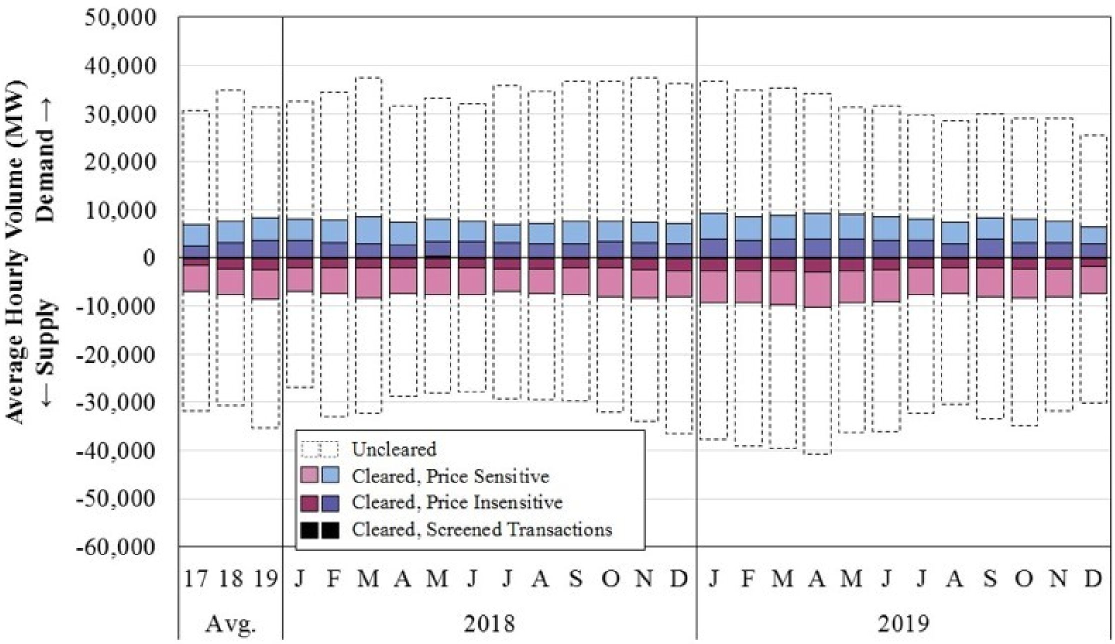
Accordingly, if virtual traders expect day-ahead prices to be higher than real-time prices, they sell virtual supply forward and buy it back financially in the real-time market. If they forecast higher real-time prices, they buy virtual load. This trading is one of the primary means to arbitrage prices 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.[6]

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 using a virtual position would cause prices to diverge from real-time prices. This divergence would cause the virtual position to be unprofitable. We monitor for such behavior and utilize mitigation authority to restrict virtual activity when appropriate.

Figure A28 and Figure A29: Day-Ahead Virtual Transaction Volumes

Figure A28 shows the average offered and cleared amounts of virtual supply and virtual demand in the day-ahead market from 2018 to 2019. Figure A29 separates the 2019 volumes by region. 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).

Figure A28: Day-Ahead Virtual Transaction Volumes
2018–2019

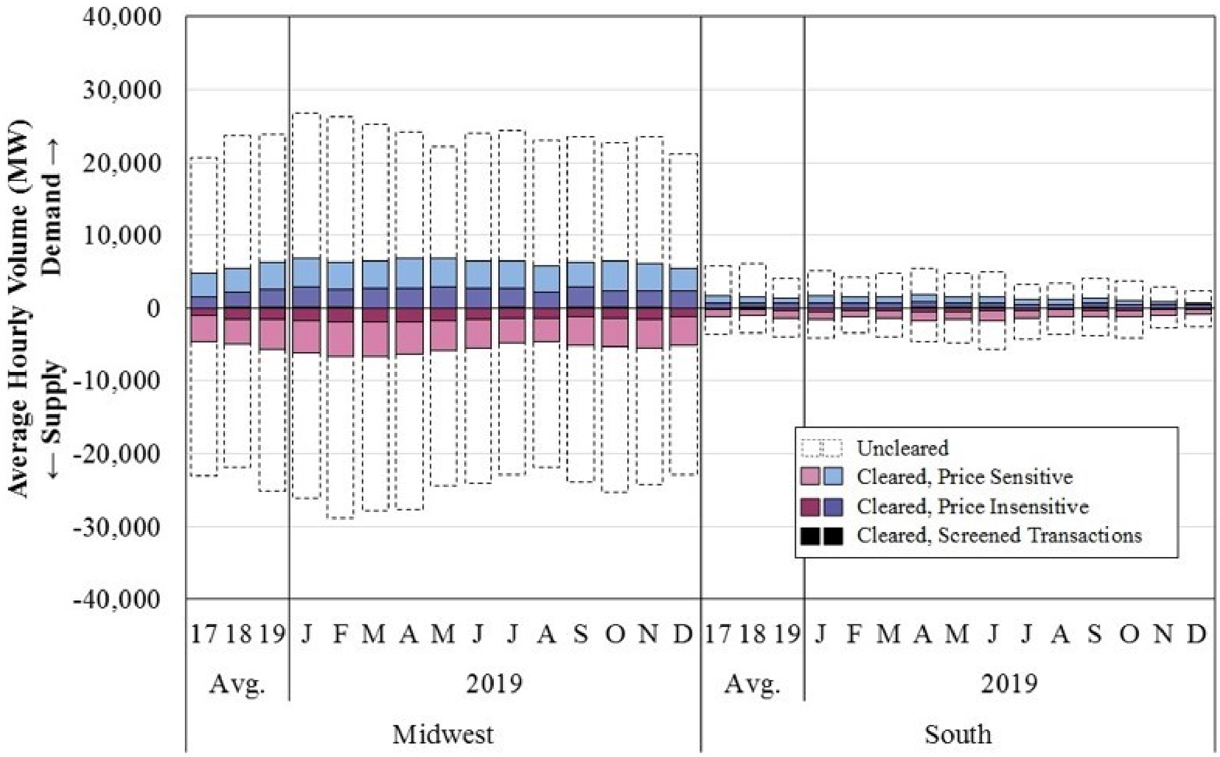


6 Chaves, Jose Pablo and Yannick Perez. 2010. Virtual Bidding: A Mechanism to Mitigate Market Power in Electricity Markets: Some Evidence from New York Market, Working Paper.

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).

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

Figure A29: Day-Ahead Virtual Transaction Volumes by Region
2019



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 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 A30 to Figure A33: 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 A30 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 A31 and Figure A32 show the same values by region, and Figure A33 shows these values by type of location.

Figure A30: Virtual Transaction Volumes by Participant Type
2019

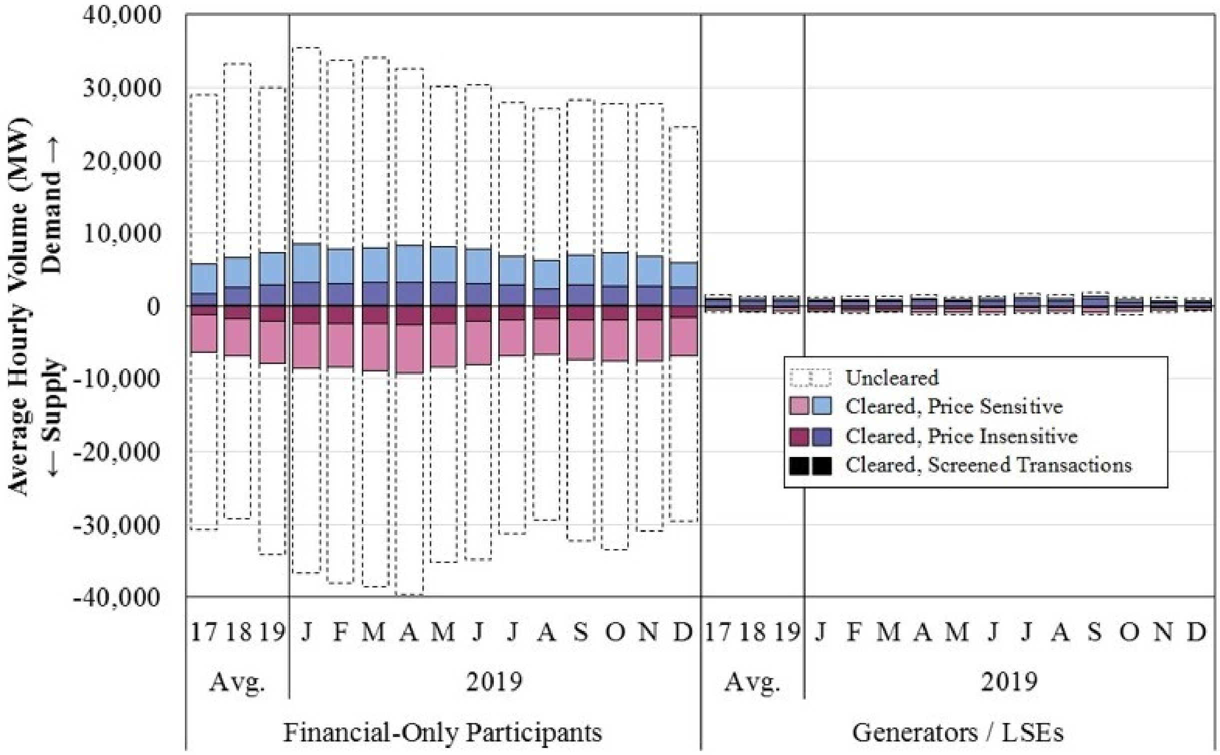


Figure A31: Virtual Transaction Volumes by Participant Type
MISO Midwest, 2019

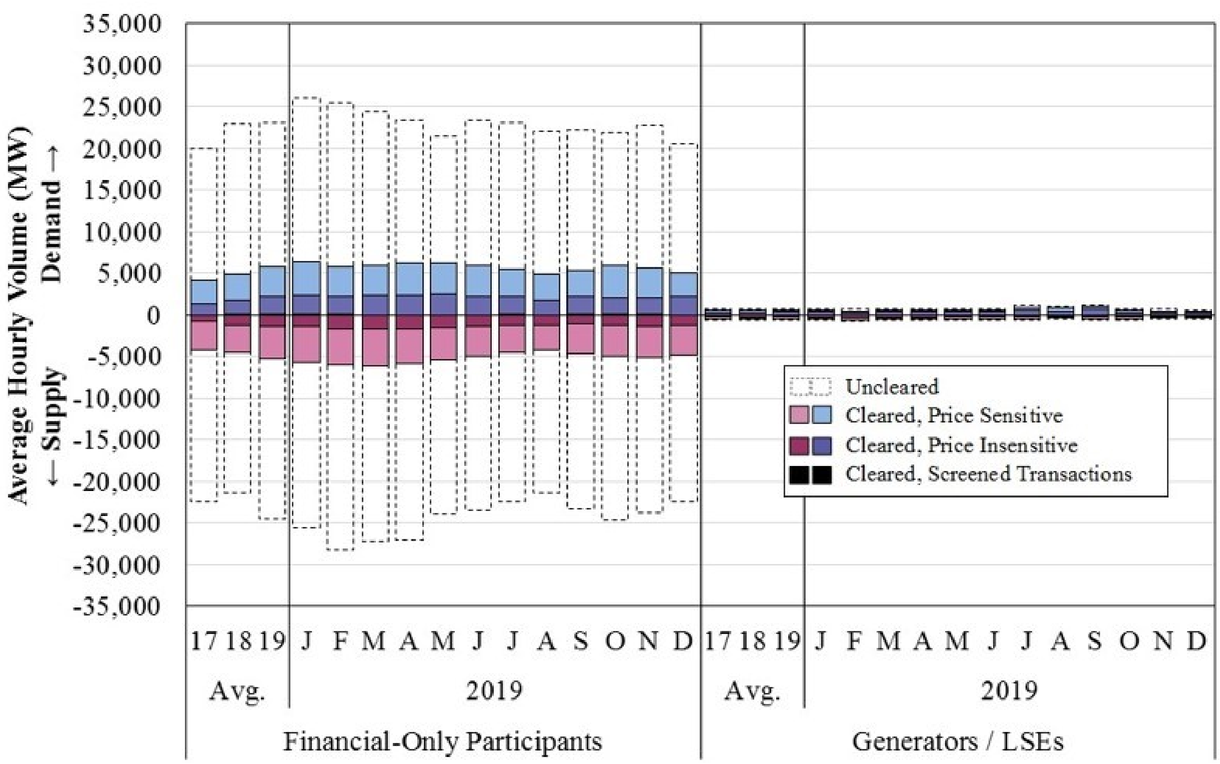


Figure A32: Virtual Transaction Volumes by Participant Type
MISO South, 2019

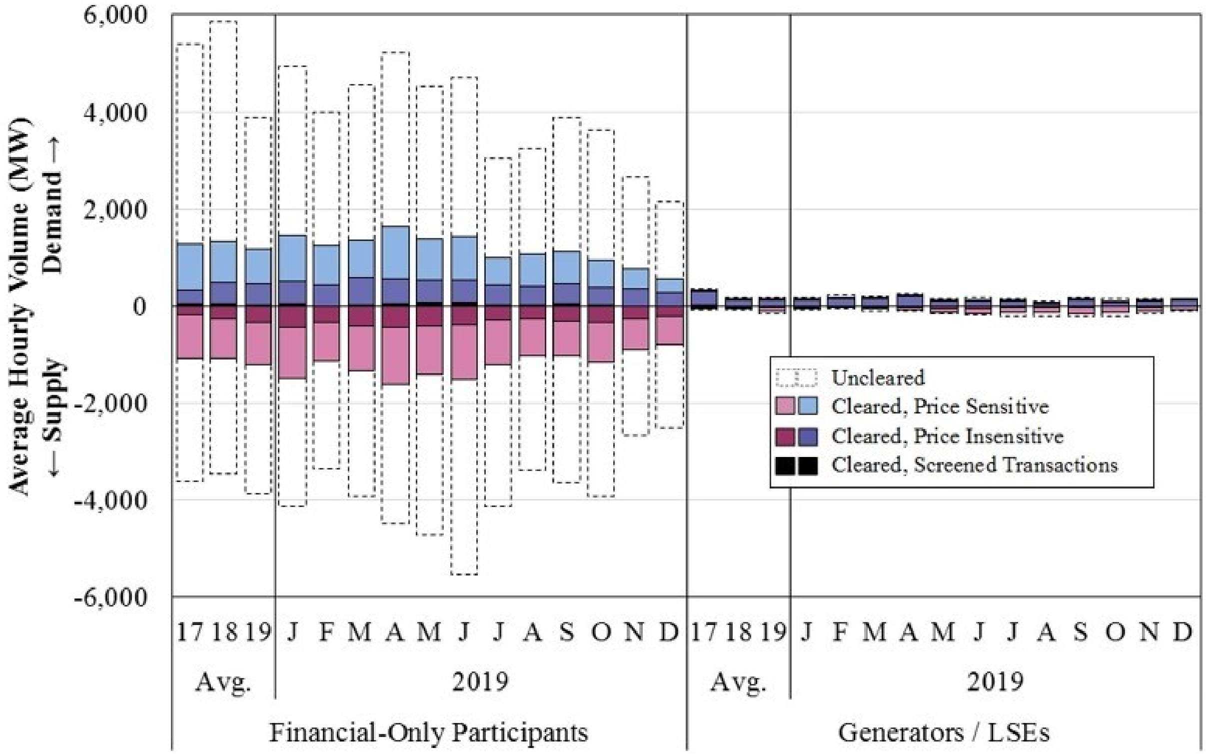


Figure A33: Virtual Transaction Volumes by Participant Type and Location
2017–2019

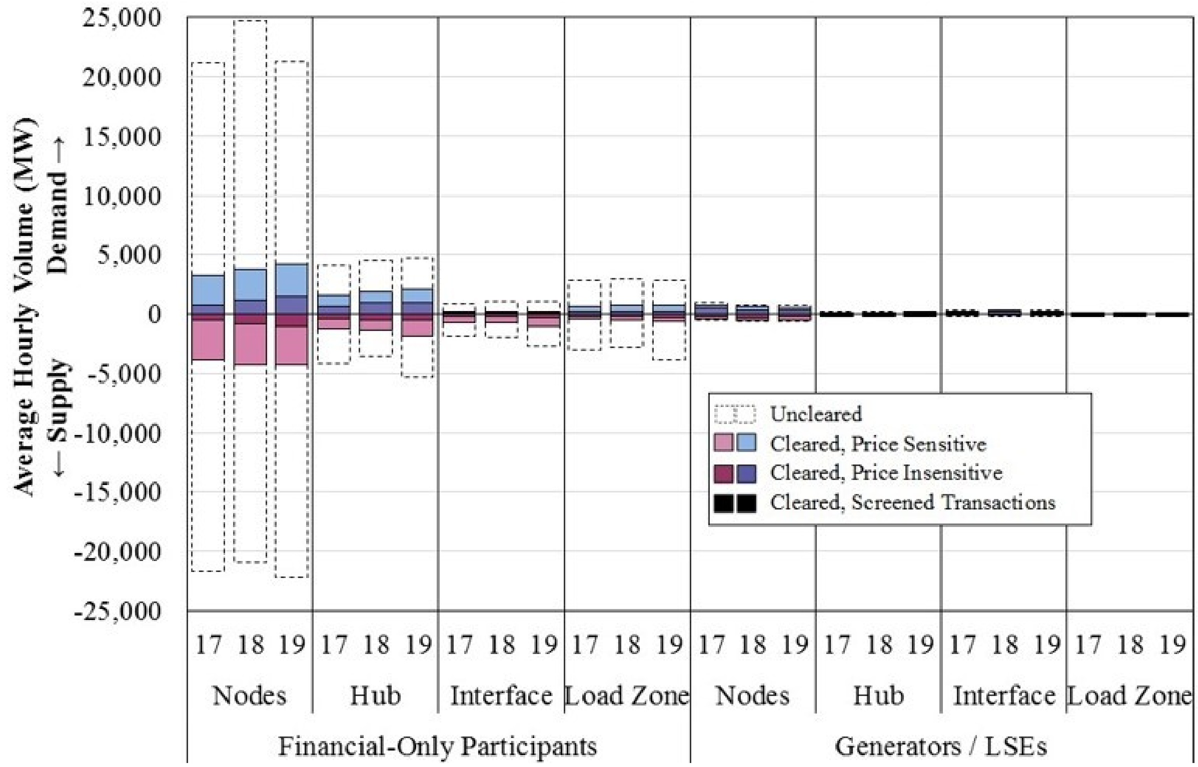


Figure A33 above disaggregates transaction volumes further by type of participant and four types of locations: hub locations, load zones, generator nodes, and interfaces. Hubs, interfaces, and load zones are aggregations of many electrical nodes and, therefore, are less prone to congestion-related price spikes than generator locations.

Figure A34: Matched Price-Insensitive Virtual Transactions

Figure A34 shows monthly average cleared virtual transactions that are considered price insensitive. As discussed above, price-insensitive bids and offers are priced to make them very likely to clear. 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 relative to 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 A34: Matched Price-Insensitive Virtual Transactions
2018–2019

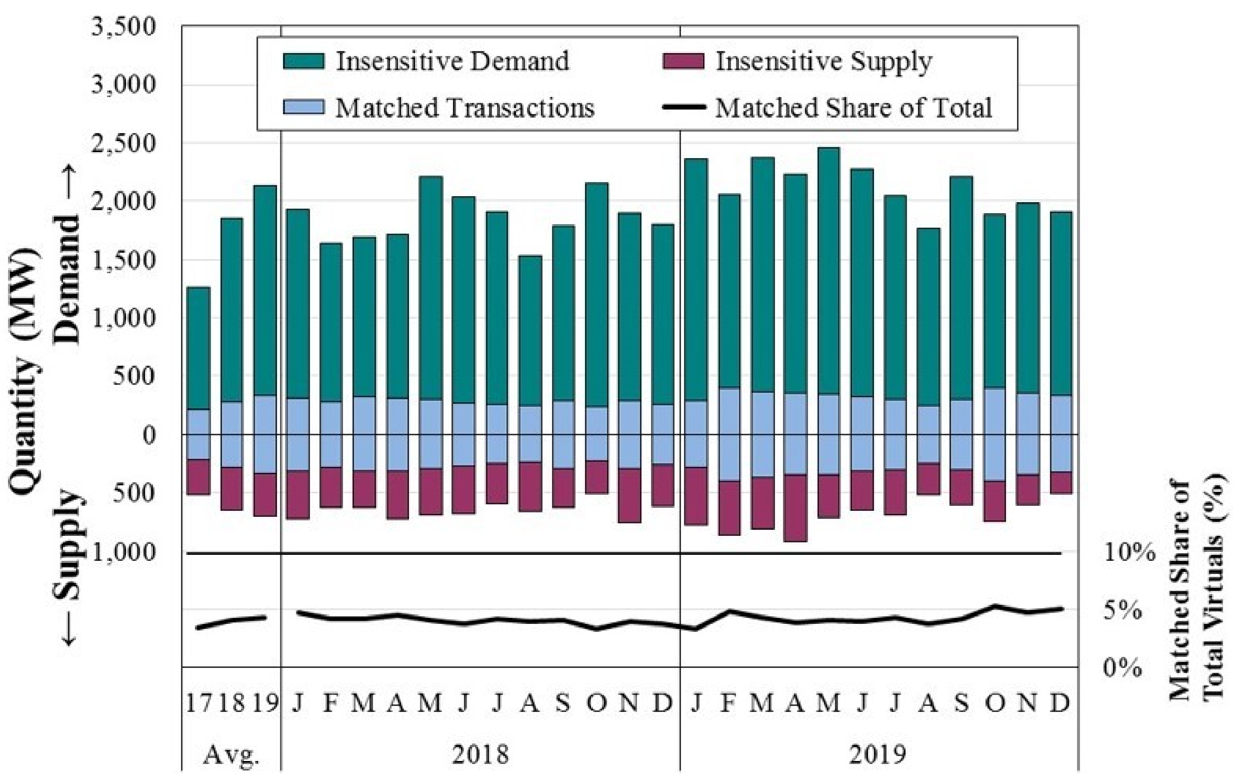
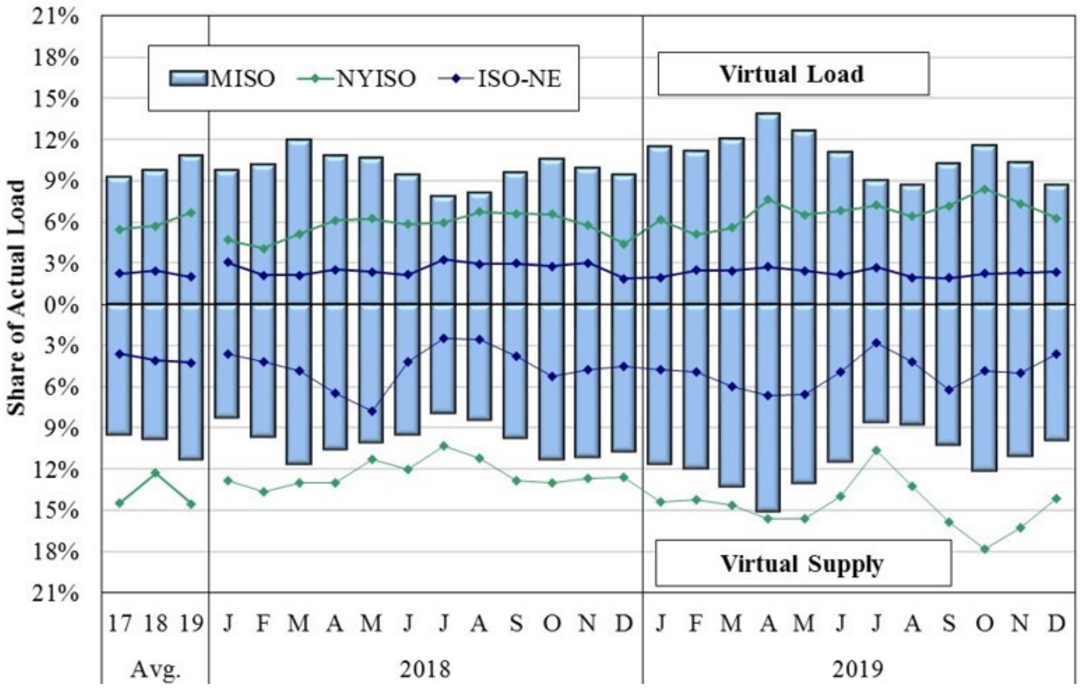


Figure A35: Comparison of Virtual Transaction Levels

To compare trends in MISO to other RTOs, Figure A35 shows cleared virtual supply and demand in MISO, ISO-NE, and NYISO as a share of actual load.

Figure A35: Comparison of Virtual Transaction Levels
2018–2019



G. Virtual 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.

Table A2: Comparison of Virtual Trading Volumes and Profitability

To provide perspective on the virtual trading in MISO, Table A2 compares virtual trading in MISO to trading in NYISO and ISO New England.

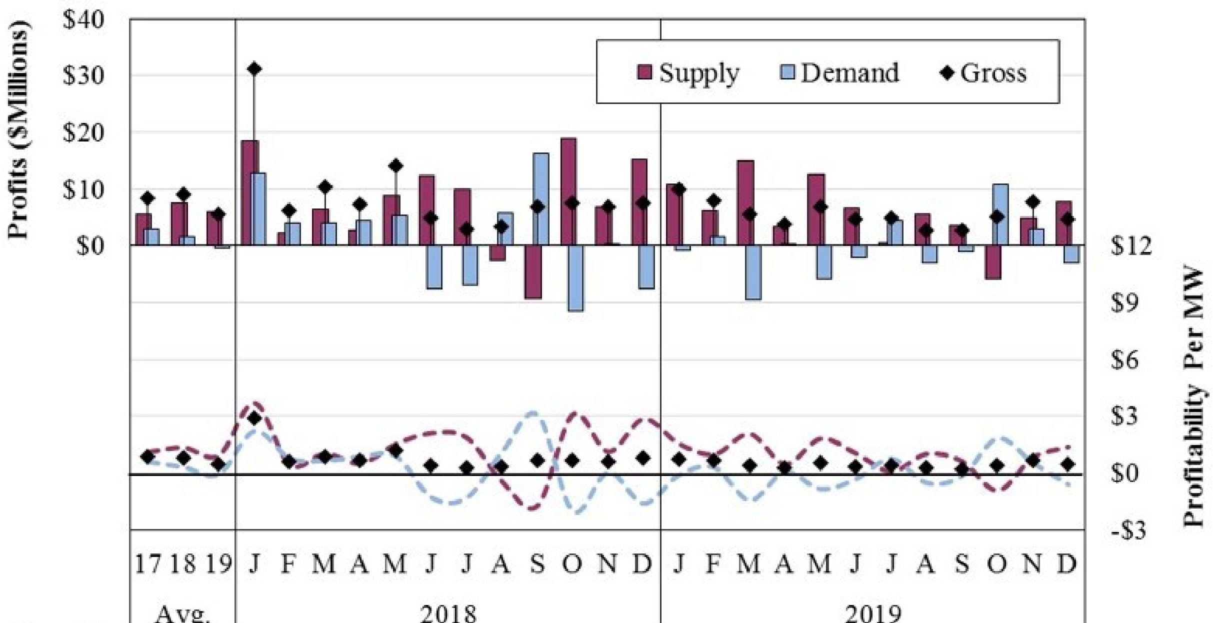
Table A2: Comparison of Virtual Trading Volumes and Profitability
2019

Market	Virtual Load		Virtual Supply	
	MW as a % of Load	Avg Profit	MW as a % of Load	Avg Profit
MISO	10.8%	-$0.07	11.3%	$0.94
NYISO	6.7%	$0.17	14.5%	$0.43
ISO-NE	2.3%	-$1.20	4.9%	$1.26

Figure A36 to Figure A37: Virtual Profitability

Figure A36 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 A37 shows the same results disaggregated by type of market participant: entities owning generation or serving load and financial-only participants.

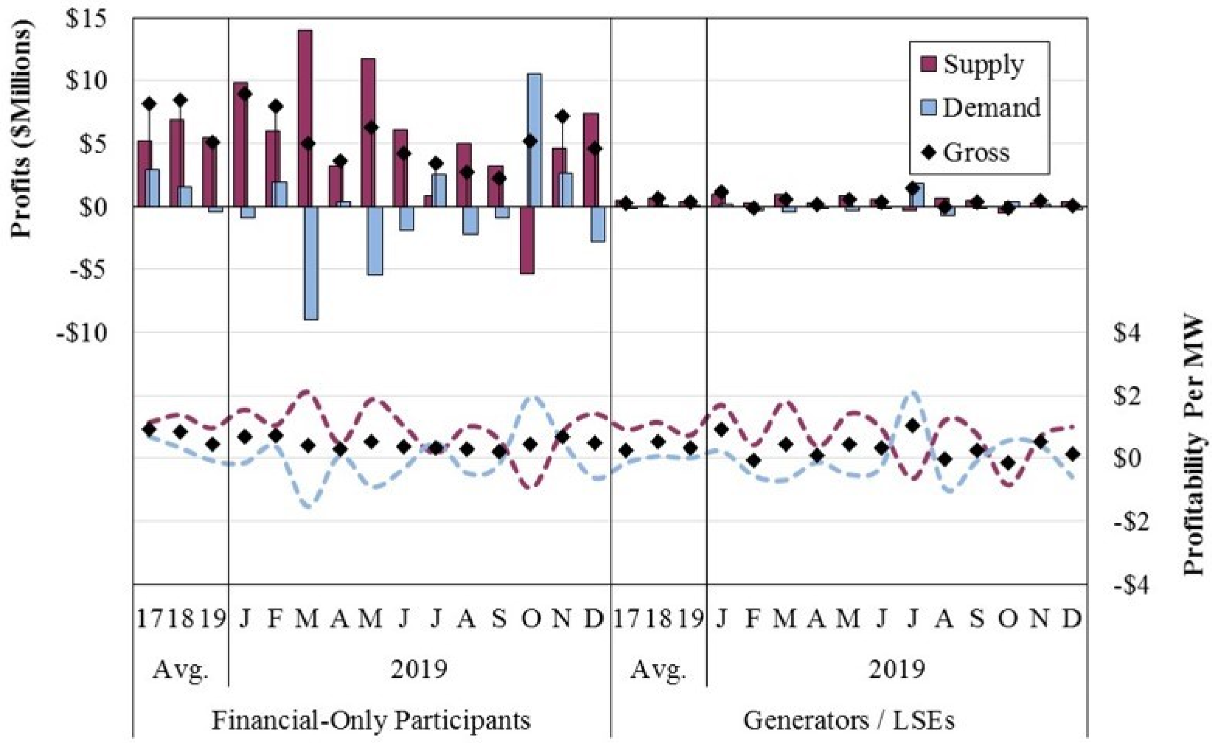
Figure A36: Virtual Profitability
2018–2019



Percent Screened

	17	18	19	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Supply	0.3	0.4	0.2	1.0	0.2	0.3	0.3	0.5	0.5	0.4	0.1	0.3	0.4	0.4	0.3	0.2	0.1	0.3	0.3	0.2	0.2	0.3	0.2	0.4	0.3	0.3	0.1
Demand	1.3	1.6	1.0	2.3	0.6	1.1	1.1	3.0	2.6	2.3	0.8	1.3	1.9	1.1	0.7	1.7	0.6	0.8	0.9	1.0	1.4	1.1	0.5	1.6	1.1	0.9	0.7
Total	0.8	1.0	0.6	1.7	0.4	0.7	0.7	1.8	1.5	1.4	0.5	0.8	1.2	0.7	0.5	1.0	0.4	0.5	0.6	0.6	0.8	0.7	0.3	1.0	0.7	0.6	0.4

Figure A37: Virtual Profitability by Participant Type
2019



H. Benefits of Virtual Trading in 2019

We conducted an empirical analysis of virtual trading in MISO in 2019 that evaluated virtual transactions' 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 quantities (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 virtual transactions contributed to better market efficiency in MISO by providing incrementally better commitments in the day-ahead market and leading to better convergence.

To conduct our analysis, we first identified constraints that were modeled consistently in the day-ahead and real-time markets and those that were not. We categorized efficiency-enhancing virtual transactions as those that were profitable based on congestion that was modeled in the day-ahead and real-time markets, as well as the marginal energy component (system-wide energy price). We did not include transactions that were profitable because of un-modeled constraints or day-ahead and real-time marginal loss factor divergence. Profits from 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.

We designed tests based on an observed transaction at time *t* and an associated lagged value (*t-24* for observations in hours 0-11 and *t-48* for observations in hours 12-24). These lagged values correspond to the real-time prices a participant would have observed by the time the participant submitted bids or offers for the next day in the day-ahead market. We used three tests to identify unprofitable efficiency-enhancing virtual transactions:

- 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 trade 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.

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.

Table A3 to Table A5: Efficient and Inefficient Virtual Transactions in 2019

The following three tables summarize the virtual transaction quantities, profits, and losses in the efficiency-enhancing and non-efficiency-enhancing categories in 2019. Table A3 shows all participants combined, Table A4 shows financial participants, and Table A5 shows physical participants.

Table A3: Efficient and Inefficient Virtual Transactions in 2019

	All Participants			
	MWh	Convergent Profits	Rent-Seeking Loss	Rent-Seeking Congestion
Efficiency Enhancing (Profitable)	73,781,722	$522.7M	$.6M	-$8.9M
Efficiency Enhancing (Unprofitable)	11,310,674	-$42.1M	$3.8M	$3.7M
Total Efficiency	***85,092,395***	***$480.5M***	***$4.4M***	***-$5.2M***
Not Efficiency Enhancing (Profitable)	4,826,223	-$19.8M	$6.2M	$31.4M
Not Efficiency Enhancing (Unprofitable)	58,335,271	-$428.1M	$4.9M	-$8.1M
Total Inefficiency	***63,161,493***	***-$447.9M***	***$11.1M***	***$23.3M***
Total	**148,253,889**	**$32.6M**	**$15.5M**	**$18.1M**

Table A4: Efficient and Inefficient Virtual Transactions in 2019 – Financial Participants

	Financial Participants			
	MWh	Convergent Profits	Rent-Seeking Loss	Rent-Seeking Congestion
Efficiency Enhancing (Profitable)	66,782,554	$481.1M	$.4M	$8.3M
Efficiency Enhancing (Unprofitable)	10,149,592	-$39.0M	$3.4M	$3.5M
Total Efficiency	***76,932,146***	***$442.1M***	***$3.8M***	***$4.9M***
Not Efficiency Enhancing (Profitable)	4,247,529	-$18.9M	$5.6M	$30.1M
Not Efficiency Enhancing (Unprofitable)	52,491,005	-$393.4M	$4.4M	$7.6M
Total Inefficiency	***56,738,534***	***-$412.2M***	***$10.0M***	***$22.5M***
Total	**133,670,680**	**$29.9M**	**$13.8M**	**$17.6M**

Table A5: Efficient and Inefficient Virtual Transactions in 2019 – Physical Participants

	Physical Participants			
	MWh	Convergent Profits	Rent-Seeking Loss	Rent-Seeking Congestion
Efficiency Enhancing (Profitable)	6,999,168	$41.6M	$.2M	-$.6M
Efficiency Enhancing (Unprofitable)	1,161,082	-$3.2M	$.4M	$.2M
Total Efficiency	***8,160,250***	***$38.4M***	***$.6M***	***-$.3M***
Not Efficiency Enhancing (Profitable)	578,694	-$.9M	$.5M	$1.3M
Not Efficiency Enhancing (Unprofitable)	5,844,266	-$34.8M	$.5M	-$.5M
Total Inefficiency	***6,422,959***	***-$35.7M***	***$1.0M***	***$.8M***
Total	**14,583,209**	**$2.8M**	**$1.6M**	**$.5M**

The profits and losses shown in the tables above are useful because they account for the fact that some transactions are relatively more efficient or relatively more inefficient than others. Each table also shows rents earned by virtual transactions, which are profits that do not produce efficiency benefits. The rents reflect profits associated with un-modeled day-ahead constraints and differences in the loss components between the two markets. These rents do not generally 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 beneficial to market efficiency in 2019.

IV. Real-Time Market Performance

In this section, we evaluate real-time market outcomes, including prices, loads, and uplift payments. We also assess the dispatch of peaking resources and the ongoing integration of wind generation. Wind generation has continued to grow and set new output records in 2020, the last of which was April 9, 2020 at 18.1 GW.

The real-time market performs the vital role of dispatching resources to minimize the total production cost of satisfying 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 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

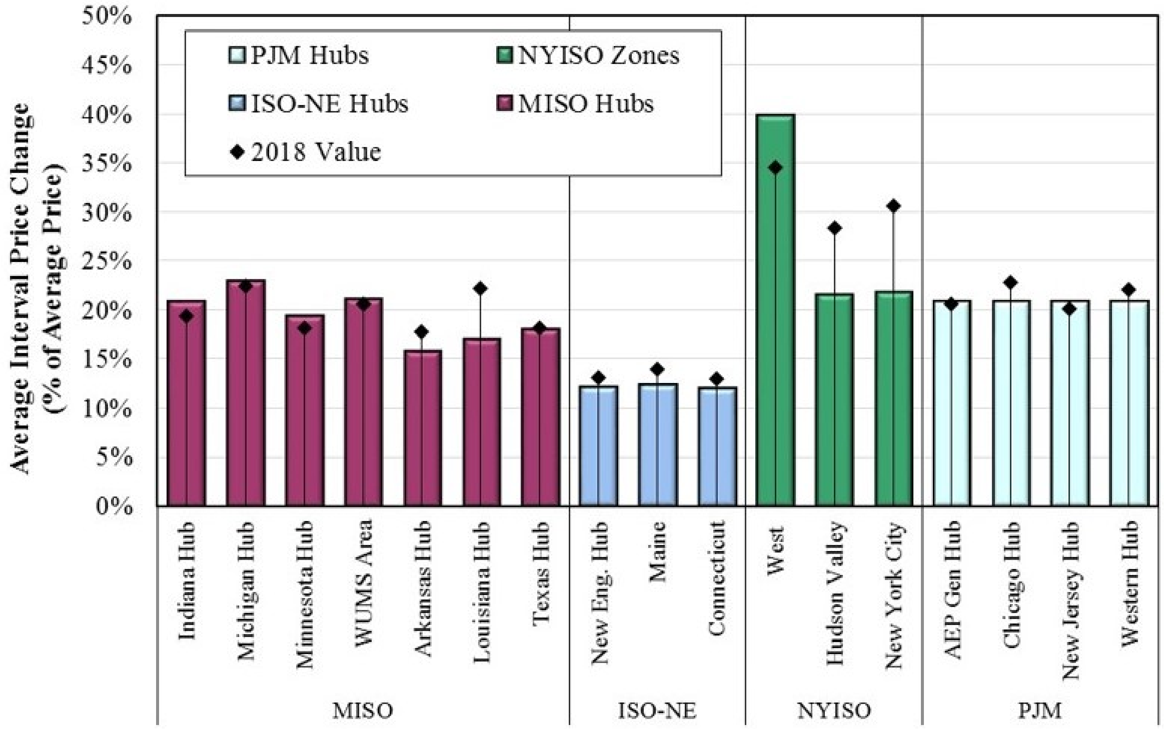
Substantial volatility in real-time markets is expected because the demands of the system can change rapidly, and supply flexibility is restricted by generators' physical limitations. This subsection evaluates and discusses the volatility of real-time prices. Sharp price changes frequently occur when 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 A38: Fifteen-Minute Real-Time Price Volatility

Figure A38 provides a comparative analysis of price volatility by showing the average percentage change in real-time prices between 15-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 A38: Fifteen-Minute Real-Time Price Volatility
MISO and Other RTO Markets, 2019



B. Evaluation of ELMP 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. In May 2017, MISO implemented ELMP Phase 2. In November 2019, MISO further expanded ELMP to incorporate Fast-Start Resources committed in the day-ahead market to participate in real-time price setting. 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 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 resources include online "Fast-Start Resources" (currently including units that can start within 60 minutes) and demand response resources.
- It allows offline Fast-Start Resources to be eligible to set prices during transmission violations or energy shortage conditions.

The first element of ELMP addresses 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 energy demand. 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 several 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; and
- 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.

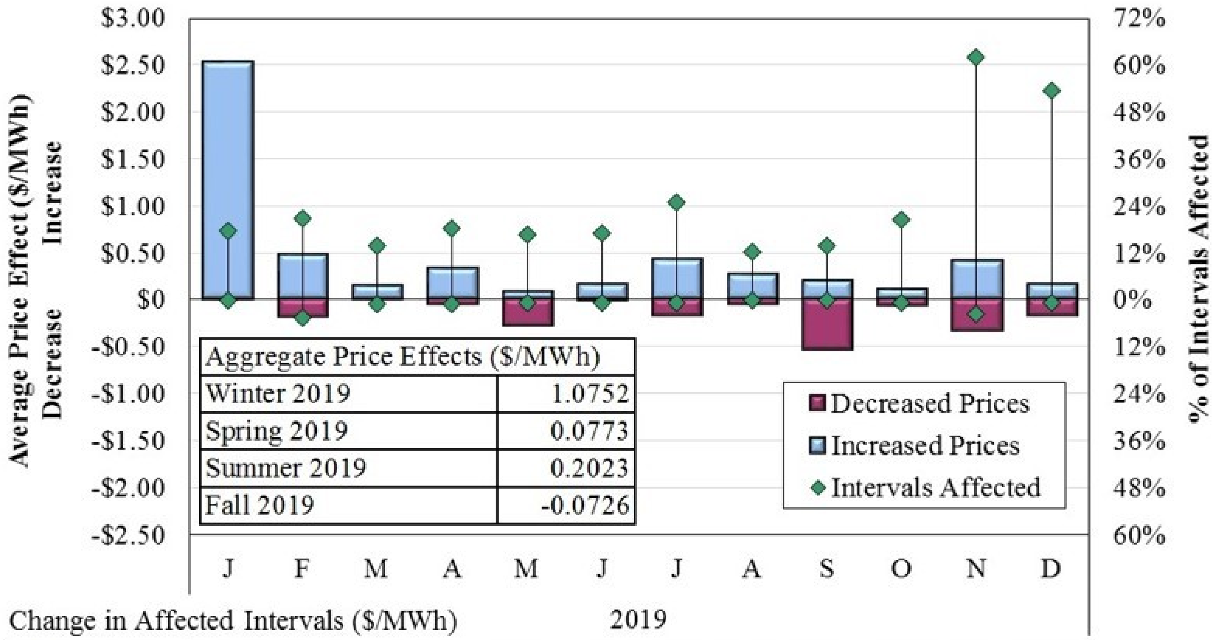
The second element of ELMP allows offline Fast-Start Resources to set prices under shortage conditions. Shortages include transmission violations and operating reserves shortages. It is efficient for offline resources to set the price only when a) they are feasible (can be started quickly), and b) they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

Figure A39 to Figure A41: ELMP Price Effects

Figure A39 to Figure A41 summarize the effects of ELMP by showing the average upward effects via the online pricing, average downward effects via the offline pricing, and 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 affected locations (i.e., congestion-related effects). Additionally, to show the size of the ELMP price adjustments, the tables below each of the first two figures show the size of the adjustments in those intervals that the ELMP model affected the price.

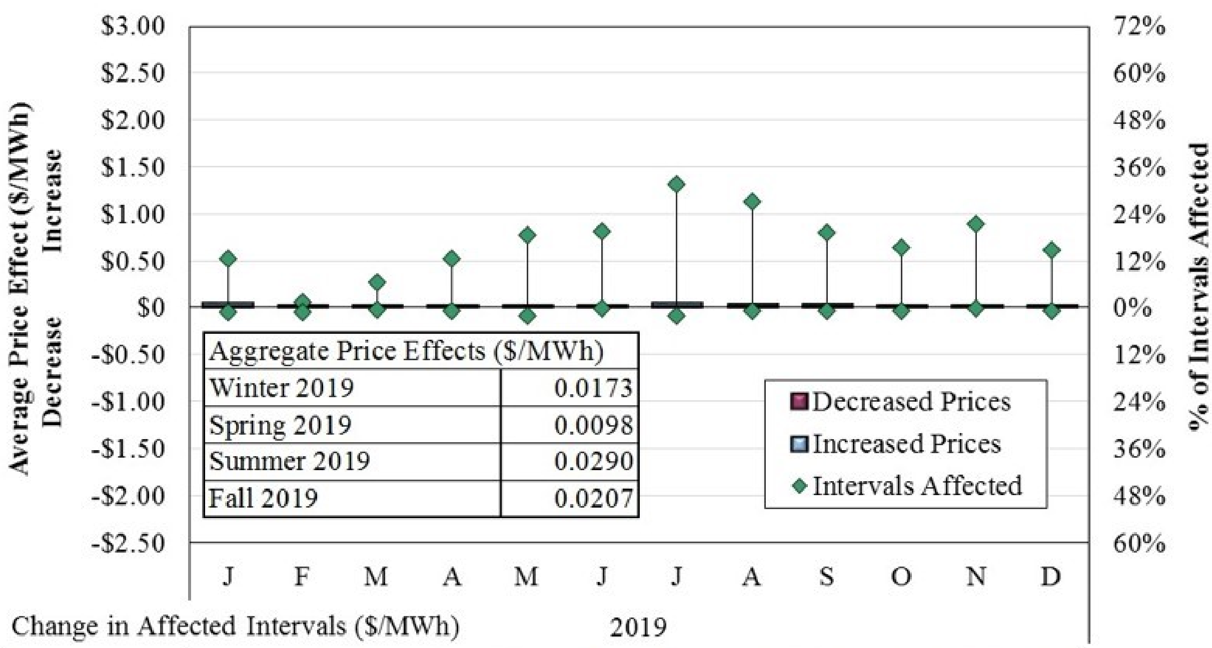
Figure A39: Average Market-Wide Price Effects of ELMP
Real-Time Market, 2019



Change in Affected Intervals ($/MWh)

	J	F	M	A	M	J	J	A	S	O	N	D
SMP Increase	14.43	2.33	1.06	1.82	0.55	1.01	1.71	2.20	1.43	0.54	0.68	0.30
SMP Decrease	-1.6	-4.4	-1.2	-5.4	-39.5	-3.4	-26.3	-19.1	-198.7	-8.6	-9.0	-20.3

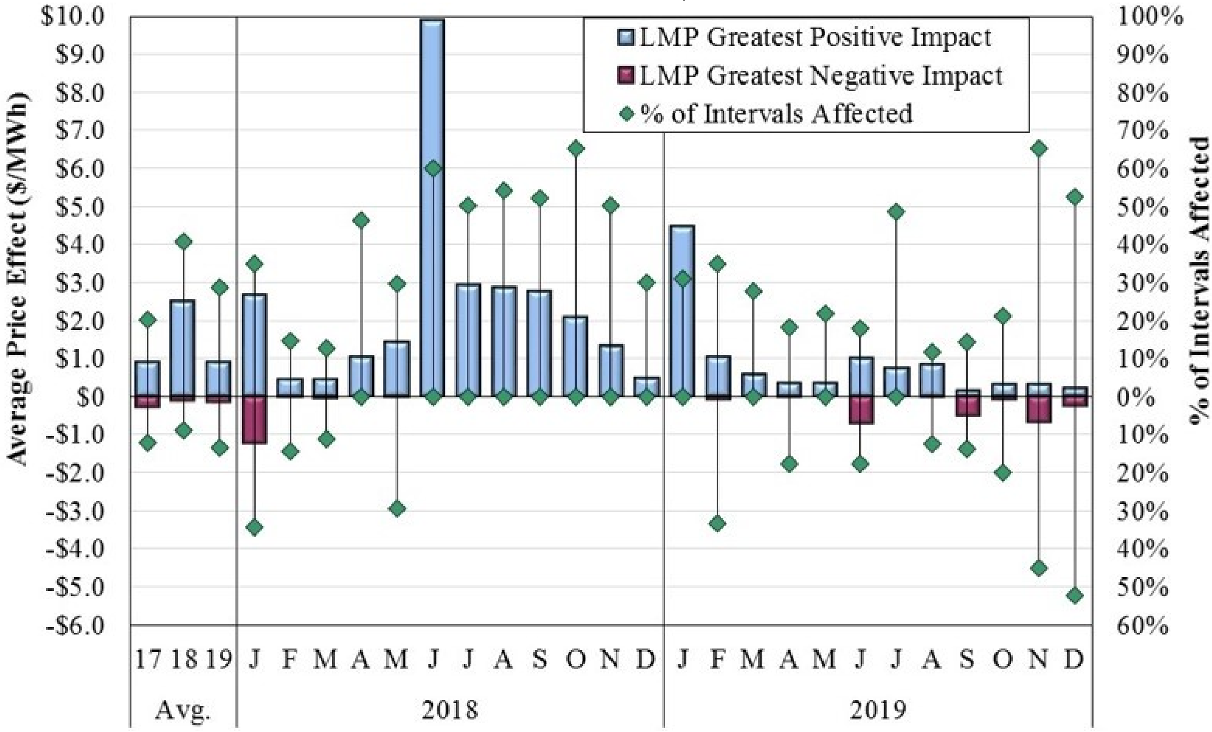
Figure A40: Average Market-Wide Price Effects of ELMP
Day-Ahead Market, 2019



Change in Affected Intervals ($/MWh)

	J	F	M	A	M	J	J	A	S	O	N	D
SMP Increase	0.33	0.15	0.12	0.08	0.07	0.07	0.15	0.10	0.17	0.08	0.09	0.07
SMP Decrease	-0.03	-0.07	-0.08	-0.01	-0.03	-0.03	-0.02	-0.04	-0.01	-0.02	-0.01	-0.09

Figure A41: Price Effects of ELMP at Most Affected Locations
Real-Time Market, 2019



The primary focus of our recommendation to expand ELMP to date has been selecting which resources should be eligible to set prices in the ELMP model. However, it is equally important to address *how* resources participate in ELMP. The first three phases of ELMP do not allow resources to set prices when the dispatch model seeks to ramp them down at their maximum ramp rate, even if the resources continue to provide marginal energy to the grid. This ramp test substantially reduces the number of resources that qualify as marginal, price-setting resources. In both the ISO-NE and NYISO variants of ELMP, a resource may be considered marginal and set prices unless it is dispatched to zero. This is a significant advantage over MISO's ELMP approach, which we evaluate below in Figure A42.

Figure A42: Energy Price Effects of ELMP Expansion

The following figure shows the estimated hourly SMP effects of various ELMP assumptions in 2019. In each real-time market interval, we modeled energy demand clearing with three sets of assumptions. The first scenario replicated ELMP Phase II that existed up until November 1, 2019 is shown by the dashed maroon line. The second scenario depicted in the green dashed line shows the effects of expanding the eligible fast-start resources to include resources scheduled in the day-ahead market, which was implemented by MISO on November 1, 2019. The last scenario shown by the blue line approximated ELMP outcomes assuming unlimited ramp down capability, which the IMM has recommended that MISO consider implementing. These lines show the average price differences between prices in the ELMP scenarios and the ex-ante prices.

The inset table identifies the average SMP effect for each of the scenarios and the proportion of market intervals when the eligible resources were needed to meet generation demand.

Figure A42: Energy Price Effects of ELMP Expansion
2019

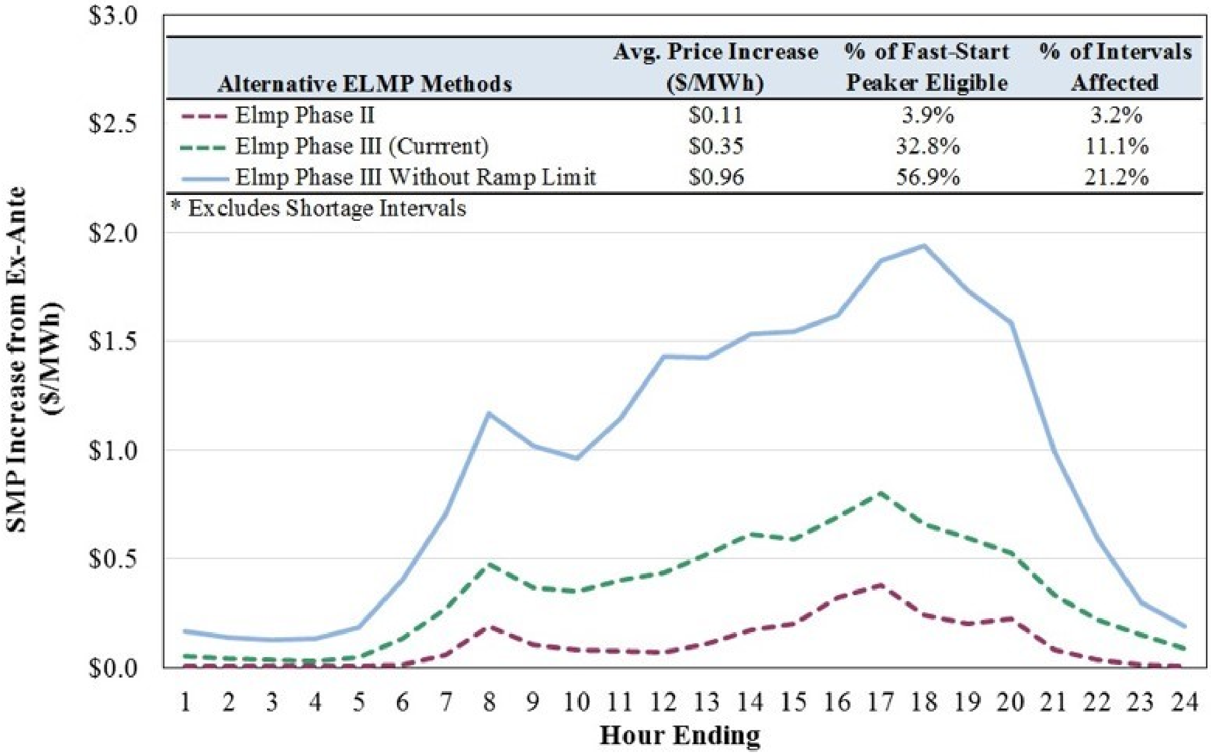


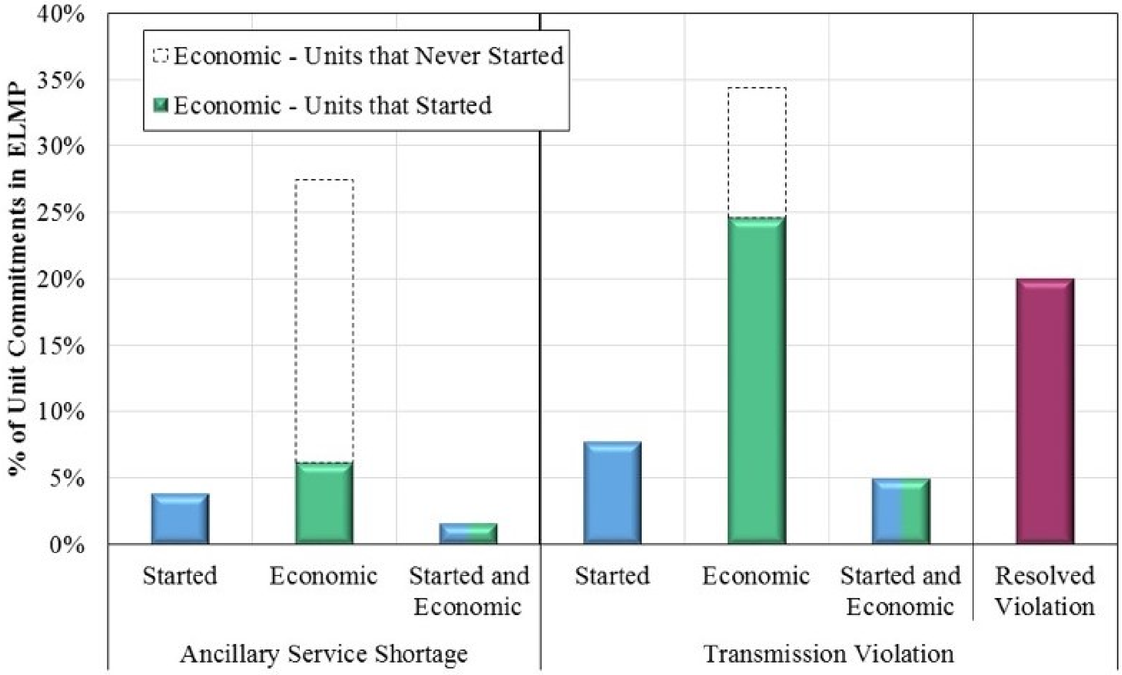
Figure A43: Evaluation of Offline Units Setting Prices

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

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 reserve 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 online in time to 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 A43 summarizes whether the offline units that set prices in 2019 were a) economic, b) started by MISO, and c) both started *and* economic. The maroon bar on the right in the figure indicates whether the resources actually resolved a transmission violation. The figure shows operating reserve shortages in the left panel and transmission violations in the right panel.

Figure A43: Evaluation of Offline Units Setting Prices
2019



To determine whether the units were economic (green bar), we compared the real-time market revenues the unit would have 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 identified the units that started (blue bar) by whether the UDS recognized the units as online in the three intervals following the recommended commitment intervals. If 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 actually resolved 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. Emergency Pricing in ELMP

Table A6: Extreme Values of Emergency Offer Floor Prices

During emergency events, MISO can access supply outside of the market that is unavailable during non-emergency conditions, some of which is not dispatchable. In order to prevent the emergency supply from depressing prices, MISO's emergency pricing construct applies Emergency Offer Floor Prices to these emergency MWs in the ELMP pricing engine to allow them to set prices.

An efficient Emergency Offer Floor Price should satisfy the following criteria:

- The value should reflect the cost of reliability requirements or constraints that would not be satisfied without the emergency MWs;

- The value should be stable and knowable in advance; and
- The value should not be subject to manipulation by any single entity.

Proxy offers are currently formed as the maximum of the resource's offer and either the Emergency Tier I or Tier II Offer Floor Price. The Tier I floor, equal to the highest available economic offer of any resource in the emergency area, applies to emergency resources available under EEA Level 1 events. The Tier II floor applies to EEA Level 2 emergency resources and is calculated as the highest available economic or emergency offer in the area. Because these offer floors are set by a suppliers' offer, the floors can vary widely.

MISO declared two regional emergencies in 2019, and on another occasion failed to declare a regional emergency despite meeting the operational criteria for doing so. In each of these emergency events, Emergency Offer Floor Prices were established. In most of these cases, we believe the floor prices substantially understated the true value of emergency power. However, the risk remains that a single entity could raise a single resource's offer and sharply inflate the proxy Emergency Offer Floor Price.

We conducted an analysis to determine the extent of the volatility of calculated emergency offer floor prices in 2019, based on resource offers. This analysis shows that emergency floor prices that would have prevailed if MISO were to have declared an emergency in the South or Midwest regions. In Table A6, we show the minimum and maximum values that were calculated by region, as well as the largest inter-hour change.

Table A6: Extreme Values of Emergency Offer Floor Prices
2019

Region	Extreme Values		Largest Inter-hour Change
	Minimum	Maximum	
MIDWEST	$122	$1,288	$783
SOUTH	$79	$338	$234

D. Spinning Reserve Shortages

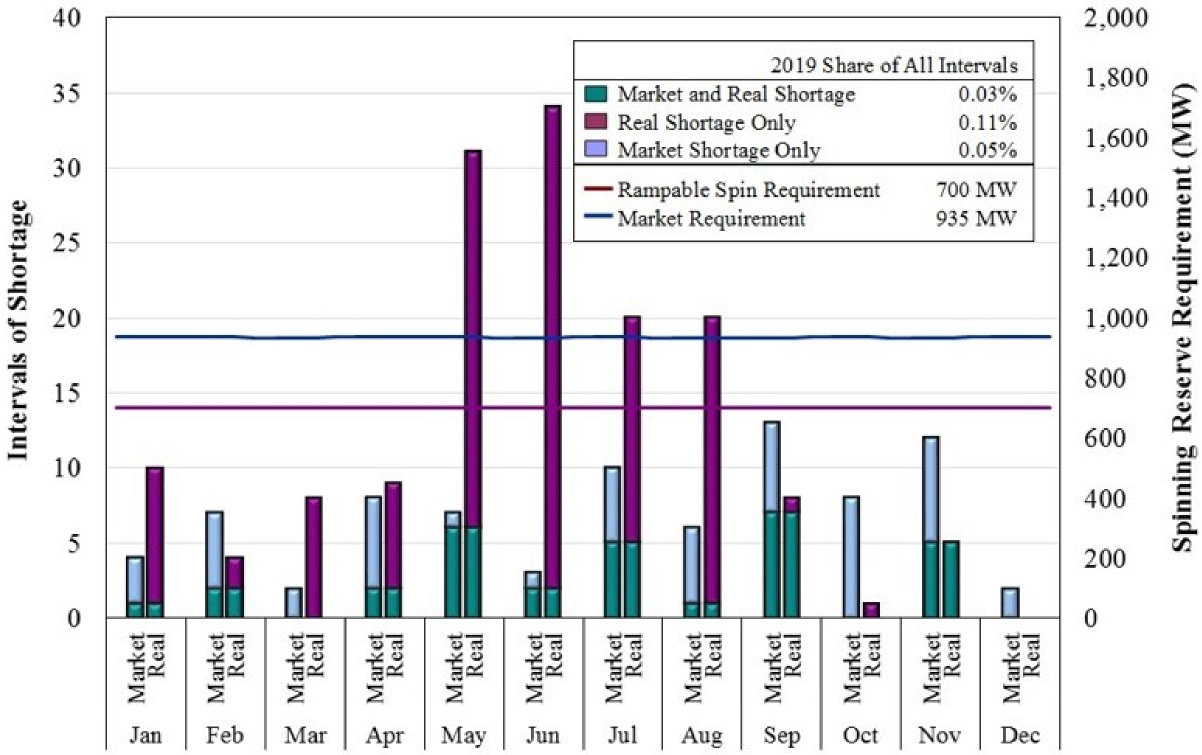
Figure A44: Market Spin Shortage Intervals vs. Rampable Spin Shortage Intervals

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 more than 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.[7] To minimize such outcomes, MISO should set the market requirement to make market results as consistent with real conditions as possible.

Figure A44 shows all intervals in 2019 with a real (physical) shortage, a market shortage, or both, as well as the physical and market requirements.

Figure A44: Market Spin Shortage Intervals vs. Rampable Spin Shortage Intervals
2019



E. Supplemental Reserve Deployments

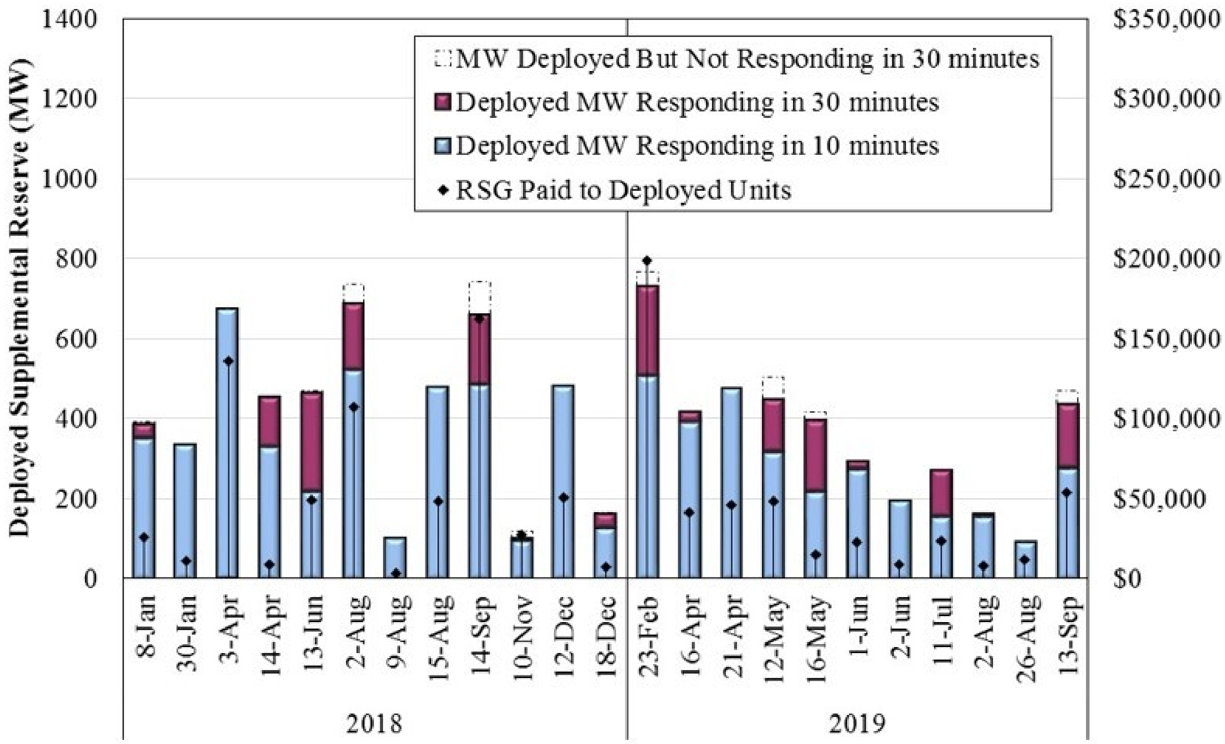
Figure A45: Supplemental Reserve Deployments

Supplemental reserves are deployed during Disturbance Control Standard (DCS) and Area Reserve Sharing (ARS) events. Figure A45 shows offline supplemental reserve response during the 11 deployments in 2019 and 11 in 2018, 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 respond when deployed.

The figure includes the RSG payments to deployed offline reserves. Because their commitment costs are not considered when scheduling supplemental reserves, high uplift payments could indicate a need to consider expected deployment costs when scheduling reserves.

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

Figure A45: Supplemental Reserve Deployments
2018–2019



F. Shortage Pricing in MISO

Efficient shortage prices play a key role in establishing economic signals to guide investment and retirement decisions in the long-term, facilitating optimal interchange and generator commitments in the short-run, and efficiently compensating flexible resources. Compensating flexible resources efficiently will be increasingly important as the penetration of renewable resources increases. The output of most renewable resources is intermittent and increases supply uncertainty, which will likely increase the frequency of reserve shortages.

Virtually all shortages in (co-optimized) energy and ancillary markets are of reserve products (i.e., RTOs will hold less reserves than required rather than not serving the energy demand). MISO also experiences capacity shortages. When an RTO is short of reserves, the value of the foregone reserves should set the reserve market clearing price and be embedded in all higher-value products, including energy. This value is established in the reserve demand curve for each reserve product, so efficient shortage pricing requires properly valued reserve demand curves.

The most highly valued reserve demand curve in MISO is the total Operating Reserve Demand Curve (ORDC). Shortages of total operating reserves are the most severe reserve shortages and the most likely to impact pricing during capacity emergencies. An efficient ORDC should: a) reflect the marginal reliability value of reserves at each shortage level; b) consider all supply contingencies, including multiple simultaneous contingencies; and c) have no artificial discontinuities that can lead to excessively volatile outcomes. The marginal reliability value of reserves at any shortage level is equal to the expected value of lost load. This is equal to the following product at each reserve level:

Net value of lost load (VOLL) * the probability of losing load.

MISO's current ORDC does not reflect the value of reserves because:

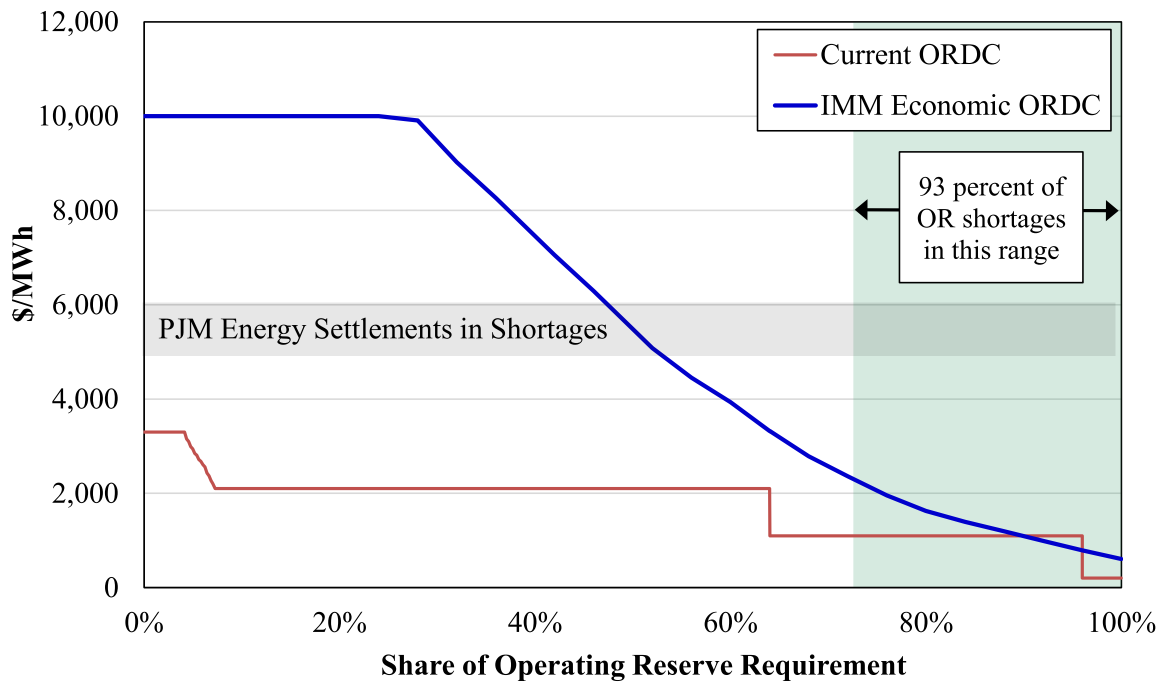
- The slope of the ORDC is not based on the probability of losing load;
- Only a small portion of the curve is based on the probability of losing load – over 90 percent of the current ORDC is set by administrative overrides of $200 per MWh, $1,100 per MWh, and $2,100 per MWh; and
- MISO's current VOLL of $3,500 per MWh is significantly understated.

This subsection shows and discusses an improved, more accurate ORDC and compares it to MISO's current ORDC. It then shows the series of analyses that underly the proposed ORDC, beginning with a more reasonable VOLL and then providing the basis for an improved simulation of the probability of losing load.

Figure A46: Current and Proposed Operating Reserve Demand Curve

Figure A46 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 $2,100 per MWh then $1,100 per MWh. Small shortages of less than four percent are priced at the lowest step of $200 per MWh. As shortage levels increase on the $1,100 per MWh step of the current ORDC, the prices remain fixed and do not accurately reflect the fact that the probability of losing load is increasing.

Figure A46: Current and Proposed Operating Reserve Demand Curve



The IMM's economic ORDC reflects the marginal value of lost load based on an assumed VOLL of $23,000 per MWh and a probability of losing load that the IMM estimated using a Monte Carlo simulation.[8] The inputs to this simulation are described below.

Table A7: Summary of Direct Survey Outage Costs Studies

VOLL is a widely understood concept that represents the lost value to consumers when electricity service is interrupted. It can be thought of as the value of reliable service and it is usually measured by estimating interruption or outage costs. Outage costs are typically estimated through survey methods, although many studies have been conducted using only macroeconomic analysis. Although macroeconomic analysis has the advantage of relying on widely available data, it also tends to be much less accurate. The survey studies have the distinct advantage of creating data using actual customer experiences regarding outages. Survey methods underpin the major benchmark studies of outage costs in US jurisdictions including key meta studies that have established versatile outage cost estimators.

The most widely referenced meta studies have been conducted by Sullivan, et al. of the Berkeley National Laboratory. An initial study was conducted in 2009 (2009 Berkeley Study) and later updated in 2015 (2015 Berkeley Study). A precursor to the Berkeley studies (Lawton and Sullivan 2001) was used as the basis for the 2005 MISO VOLL study. The estimated coefficients of the econometric model from Lawton and Sullivan were used to establish a range of outage cost values in MISO using 2005 MISO-specific data. Some significant survey-based outage cost studies have also been conducted in other countries.

Table A7 summarizes the results of these survey-based studies. The results in the table are organized in two sections based on the different service classes within the studies. The first set of studies listed in the table divide the classes between Residential, Large Commercial/Industrial, and Small Commercial/Industrial. The second set of studies divide the classes between Residential, Commercial, and Industrial.

The table shows that the average outage costs range from $5,800 per MWh for residential customers to up to $87,000 per MWh for small commercial and industrial customers. Given MISO's current VOLL assumption of $3,500 per MWh, these results indicate the need to revisit and update the VOLL assumption to a more reasonable level.

We believe the most reasonable means to do this is to use the Berkeley model with updated data for MISO. The Berkeley model relies on previous survey-based outage studies that form a meta data set used as a basis for an econometric model.

8 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.

Table A7: Summary of Direct Survey Outage Costs Studies

	System Wide	Residential	Large C/I	Small C/I	Source
US Southwest		$ -	$ 10,280	$ 41,497	Berkely - LEI ERCOT
US (2009)		$ 125	$ 9,653	$ 19,933	Berkely - LEI ERCOT
US (2015)		$ 3,791	$ 25,041	$ 338,862	Berkely (2015)
US-MISO		$ 2,033	$ 34,328	$ 49,510	SAIC - LEI ERCOT
NZ 2018 (lower)		$ 2,430	$ 4,741	$ 25,337	NZ Power/PWC
NZ 2018 (upper)		$ 5,011	$ 24,083	$ 49,180	NZ Power/PWC
			Commercial	Industrial	
New Zealand (2012)	$ 48,353	$ 13,288	$ 91,023	$ 36,174	NZEA - LEI ERCOT
Australia Victoria	$ 52,066	$ 4,853	$ 33,535	$ 12,252	LEI ERCOT
Autralia	$ 53,554			$ -	LEI ERCOT
Ireland (2010)	$ 11,175	$ 21,062	$ 12,035	$ 3,869	LEI ERCOT
Ireland (2007)	$ 19,057				LEI ERCOT
Average	$ 36,841	$ 5,844			
Average (Large C/I and Small C/I)			$ 18,021	**$ 87,386**	
Average (Commercial Industrial)			**$ 45,531**	$ 13,074	
Average Non-Residential			$ 43,228		
Average Commercial/Small C/I, excl.Berkely 2015, NZ 2012)			$ 41,255		

Note : All values in 2020 $/MWh

The econometric model in the Berkeley studies estimates the effects on outage costs from key parameters specific to individual customer classes. In particular, the estimated coefficients of the econometric model can be applied to estimate outage costs for specific regions, time periods, and customer classes. We used 2018 MISO data and assumed a one-hour outage, and found:

- *Residential customers.* The outage costs range from $3,600 per MWh to $3,900 per MWh, depending on customer income.
- *Large non-residential customers.* The outage costs ranged from $32,000 per MWh for a non-manufacturing customer to $73,000 per MWh for a manufacturing customer.
- *Small commercial/industrial customers.* Outage costs range from $84,000 per MWh for non-manufacturing customers to $184,000 per MWh for manufacturing customers.

The small commercial/industrial estimates are outside the range of values found by all other studies. Accordingly, to identify a reasonable VOLL for MISO, we use the average of the residential and large commercial/industrial valued from the Berkley Model. We weighted the outage cost estimate for the two groups in accordance with annual MWh of consumption in MISO in 2018. This weighted average yielded a MISO-wide outage cost of $23,000 per MWh. We propose that MISO use this as the VOLL in the ORDC.

Figure A47: 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 alternative Participation Factor (PF) for each generation technology type is similar to the NERC-defined Weighted Service Factor. 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. 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.

As shown in Figure A47, these two methodologies result in modest differences in participation factors. Because all nuclear resources are larger than 100 MW, the current methodology has a 100 percent participation factor. Our alternative, 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 A47: Participation of Resources in Loss of Load Probability

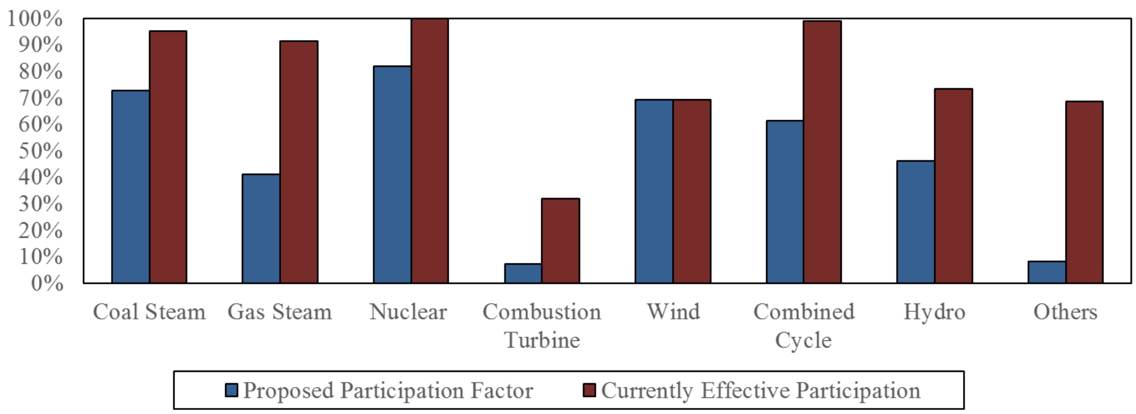
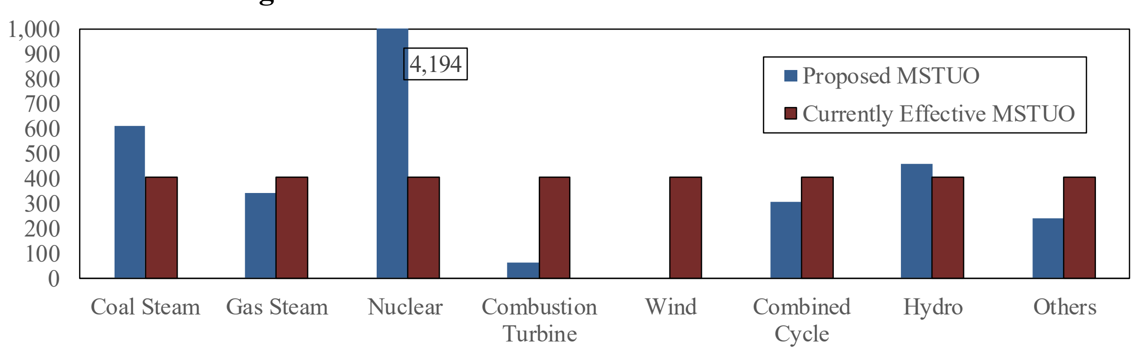


Figure A48: ORDC-Estimated Unit Failure Risk

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 A48: 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 zero and one. If the assigned random number was less than $1-e^{(-PF * ORP / MSTUO)}$, 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.

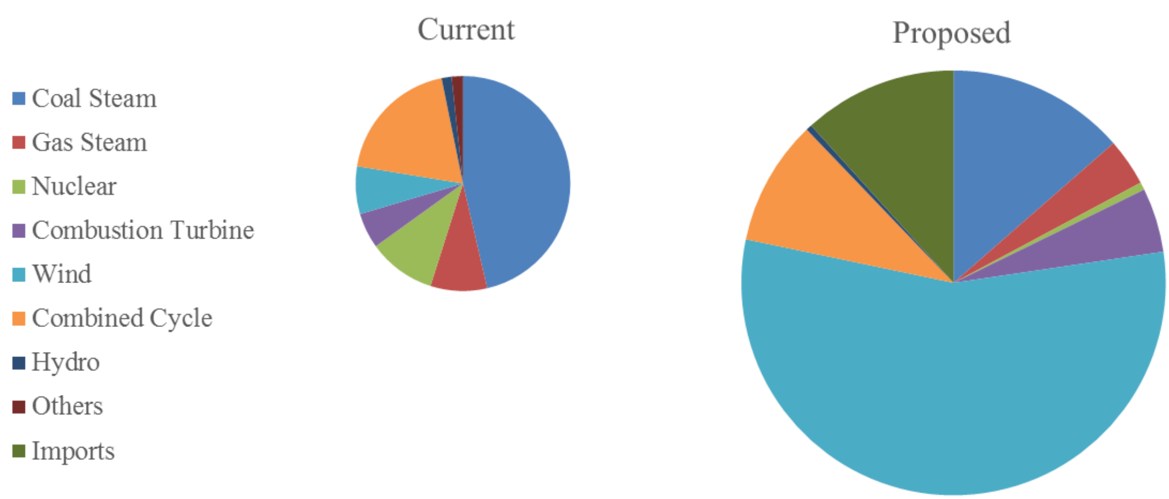
Intermittent resources and net imports were simulated as supply-side forecast risks using similar methodologies. First, a distribution of actual aggregate forecast errors was calculated from the historical period. The errors equaled the difference between actual capability in hour t and the forecasted capability schedule two hours prior to t. Next, a distinct random number between zero and one 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 zero and the inverse of the normal cumulative distribution with mean and standard deviations calculated from the group forecast error distribution.

Figure A49: 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 a 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 A49 shows the average risk associated with each resource type according to the current and proposed methodologies. The relative size of the pie charts indicates the average level of risk estimated by each methodology, while the slices of the pie indicate each resource type's contribution within the methodology.

Figure A49: 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. Uplift Costs: RSG Payments

RSG payments compensate generators committed by MISO when market revenues are insufficient to cover the generators' production costs.[9] Generally, MISO makes most of these 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 market. Because 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 (a) meet capacity needs that can arise during peak load or sharp ramping periods, (b) meet real-time load that was under-scheduled in the day-ahead market, or (c) secure a transmission constraint, a local reliability need, or to maintain voltage in a location.

MISO makes many voltage and local reliability (VLR) commitments, predominantly in the day-ahead market. Most VLR commitments occur in the South region to manage load pocket requirements. In order to satisfy these requirements and accommodate the startup times of the required resources, MISO makes reliability commitments in advance of or in the day-ahead markets. A significant portion of the day-ahead RSG is associated with these VLR resources.

Peaking resources are the most likely to receive RSG payments because they are the highest-cost class of resources and, even when setting the price, they receive minimal LMP margins to cover their startup and no-load costs. Additionally, peaking resources frequently do not set the energy price because they are operating at their economic minimum, so the price is set by a lower-cost unit. This increases the likelihood that an RSG payment may be required.

Figure A50 and Figure A51: RSG Payments

Figure A50 shows the total day-ahead RSG payments and distinguishes between payments made for VLR and 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 A51 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.

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

Figure A50: Total Day-Ahead RSG Payments
Fuel-Cost Adjusted, 2018–2019

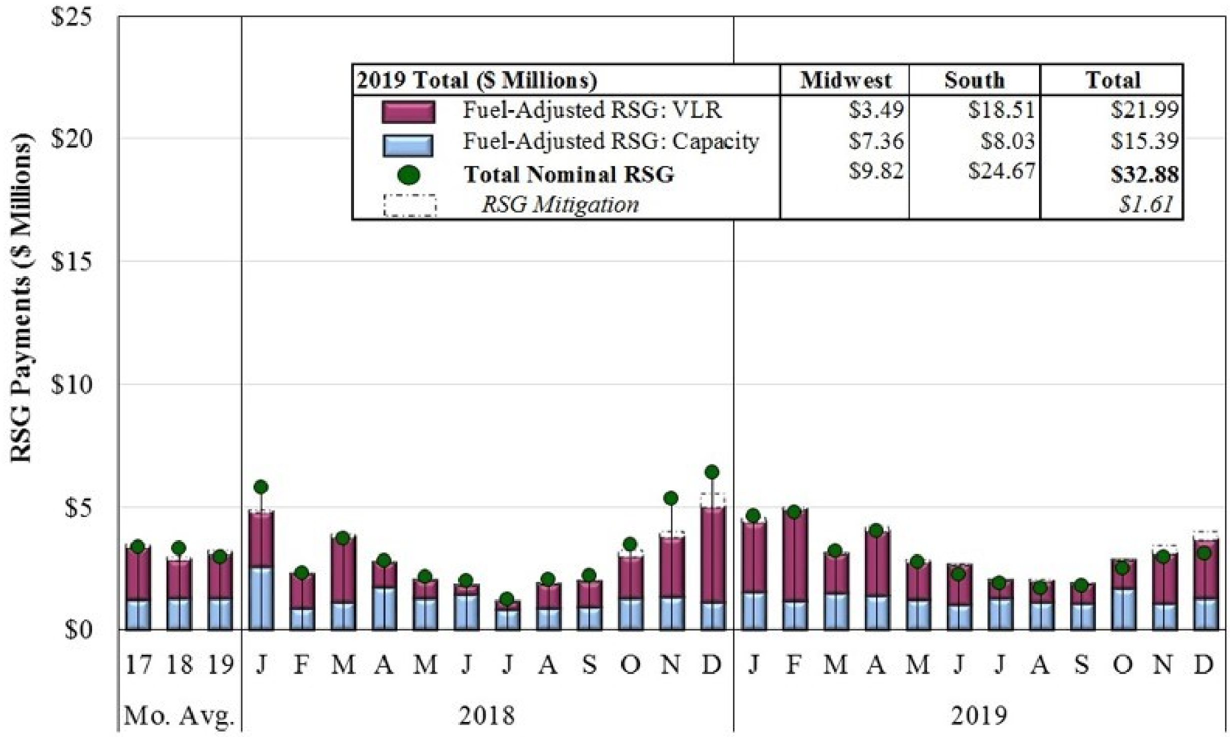


Figure A51: Total Real-Time RSG Payments
Fuel-Cost Adjusted, 2018–2019

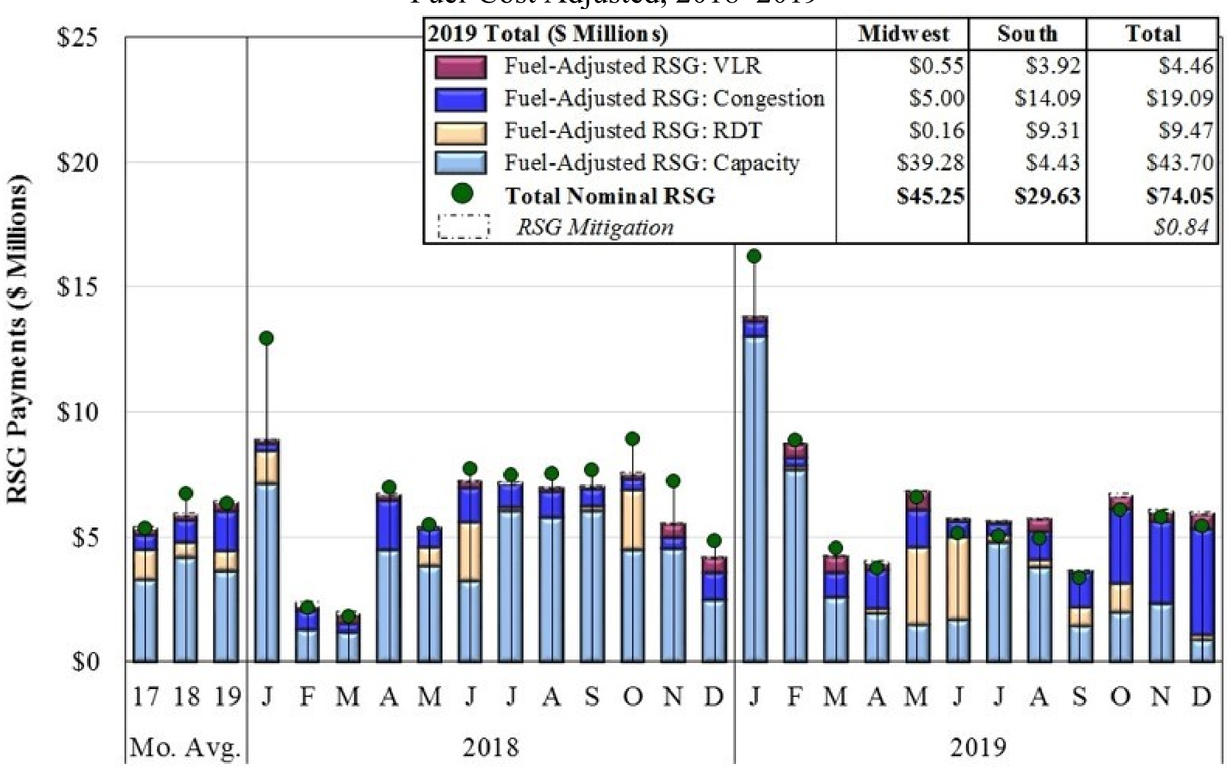


Figure A52: RSG for Units Committed for RDT

MISO has made a substantial number of resource commitments in the Midwest or South to satisfy regional capacity needs when the Regional Directional Transfer 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. We evaluated the magnitude of these costs to determine the benefit of a regional reserve product, which FERC approved in January 2020. Implementation of the regional "Short-Term Reserve" product is scheduled for December 2021.

Figure A52 below shows the total RSG that MISO has incurred for these commitments since January 2018 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 A52: RSG for Units Committed for RDT
2018–2019

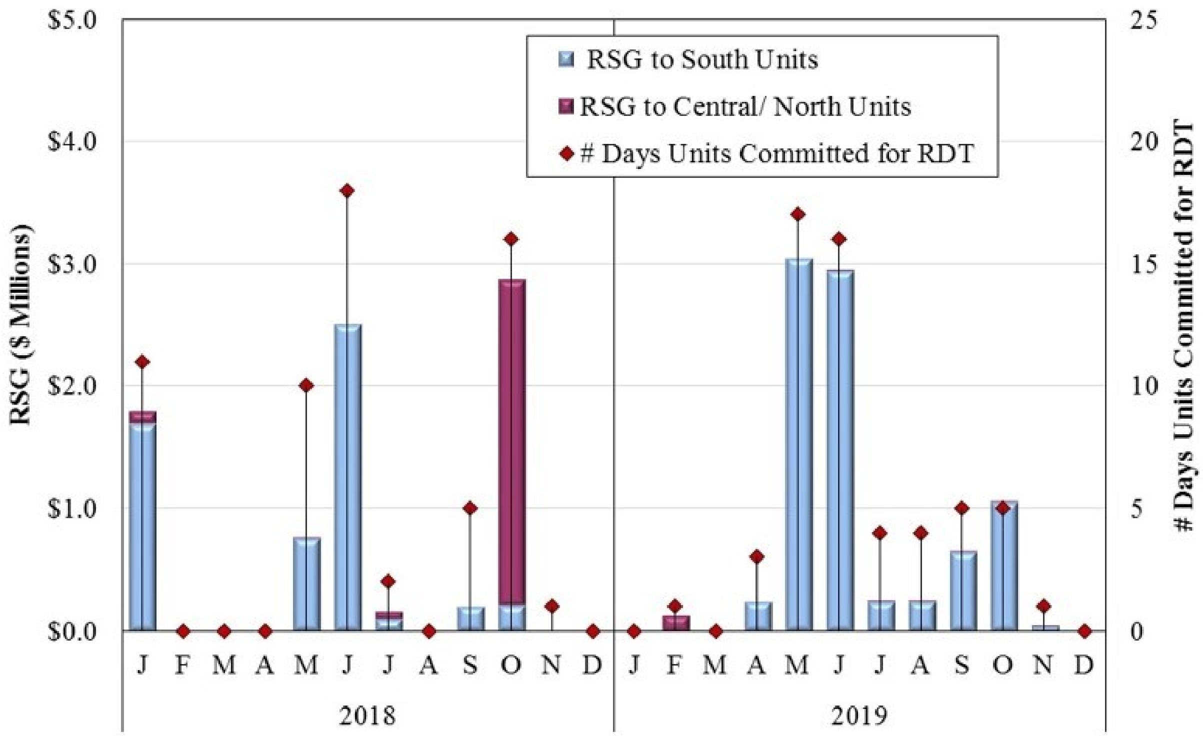
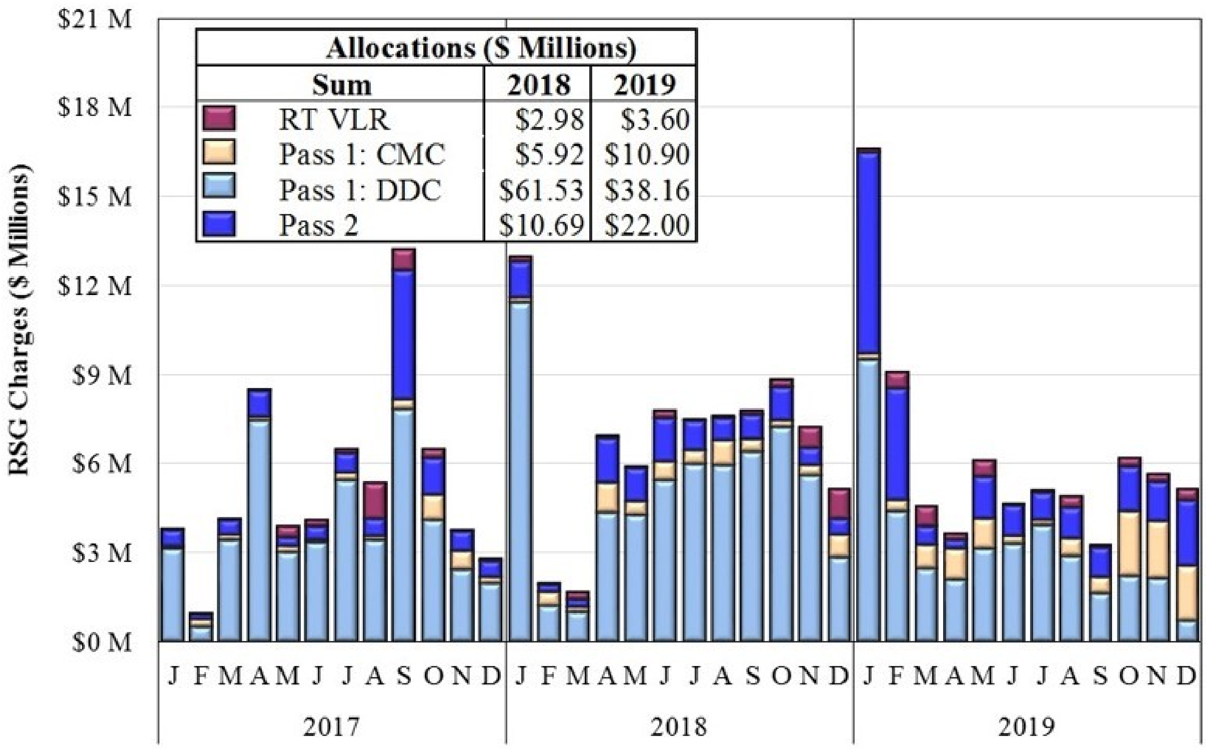


Figure A53: Allocation of RSG Charges

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").[10]

Figure A53 summarizes how real-time RSG costs were allocated among the DDC, CMC, and Pass 2 charges in each month from 2017 to 2019. 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.

Figure A53: Allocation of RSG Charges
By Month, 2017–2019



10 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.

H. Uplift Costs: 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 following MISO's dispatch signals are not financially harmed, removing a potential disincentive to providing more operational flexibility.

The PVMWP consists of two separate payments: Day-Ahead Margin Assurance 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 it 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 either payment.

Figure A54: Price Volatility Make-Whole Payments

Figure A54 shows monthly average PVMWPs for each of the past three years on the left, while the monthly PVMWPs over the past two years are shown on the right. The figure separately shows price volatility based on: (1) the System Marginal Price and (2) the LMP at generator locations receiving PVMWP. It is expected that payments should correlate with price volatility because 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 A54: Price Volatility Make-Whole Payments
2018–2019

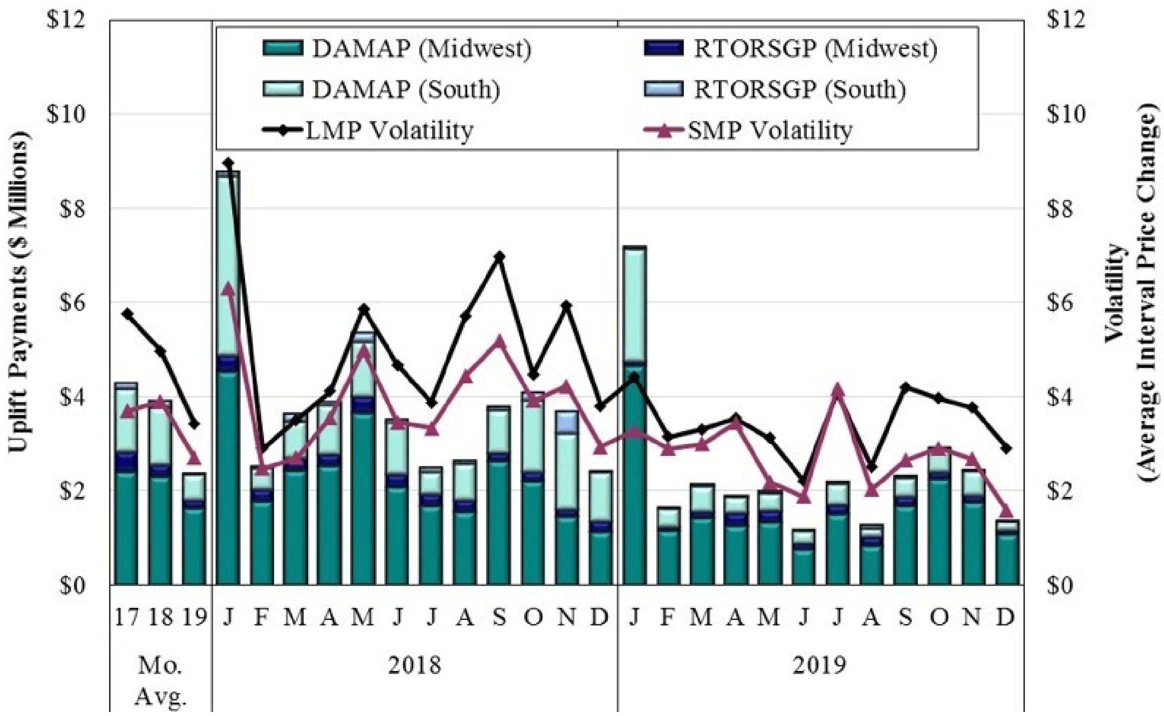


Table A8: Causes of DAMAP

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 day-ahead schedule when economic, which erodes their margins earned in the day-ahead market.

This payment was intended to provide incentives for generators to be flexible and to be held harmless if MISO directs them to dispatch down in response to 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. Previously, generators would not lose eligibility for DAMAP when they perform poorly, and we addressed this in our recommendations. In May 2019, MISO implemented changes to the Uninstructed Deviation thresholds and PVMWP formulations that have resulted in lower unjustified DAMAP payments.

Table A8 shows the causes of DAMAP in 2019 compared to 2018. The table shows the total DAMAP, the shares of DAMAP that are paid to units following MISO's dispatch signals, and the shares paid to units that are not performing well in following dispatch signals. Most categories have fallen significantly because of the May 2019 rule changes.

Table A8: Causes of DAMAP

Item Description	2018		2019	
	DAMAP ($ Millions)	% Share	DAMAP ($ Millions)	% Share
Following Instruction	$31.1	74%	$21.8	87%
SE Issue	$1.1	3%	$0.0	0%
Inferred Derate	$0.1	0%	$0.0	0%
Dragging - Failing New Threshold	$2.8	7%	$0.3	1%
Wind Unjustified	$1.3	3%	$0.0	0%
Dragging - Not Failing New Threshold	$5.4	13%	$2.9	12%
Total	**$41.9**	**100%**	**$25.1**	**100%**

Note: Excluded Hour Beginning 0 in the Analysis

I. 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.

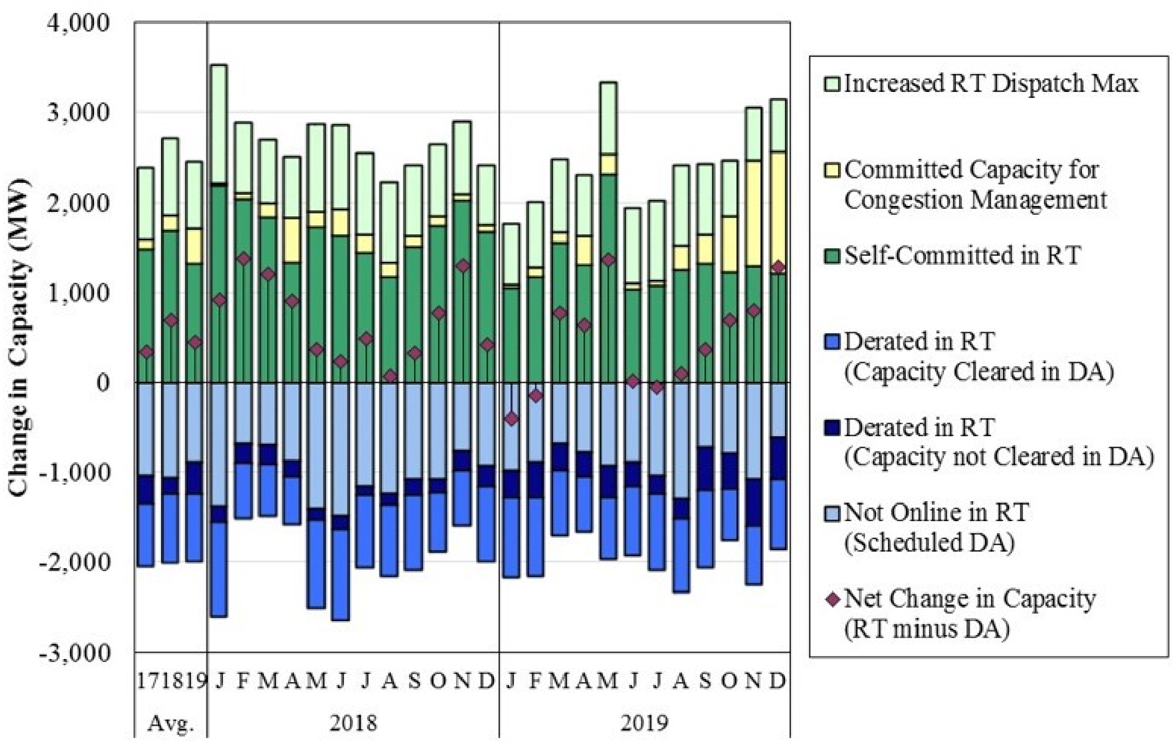
Figure A55: Changes in Supply from Day Ahead to Real Time

Figure A55 summarizes changes in supply availability from day-ahead to real-time markets. 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 in the day-ahead market sometimes decide not to start their units in real time but instead 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 in the day-ahead market that is not online in real time; capacity derated in real time (separated by resources cleared and not scheduled in the day-ahead market) and increased available capacity (increases from day-ahead capacity); and units committed for congestion management.

The figure separately indicates the net change in capacity between the day-ahead and real-time markets. A net shortfall indicates that MISO would need to commit additional capacity, while a surplus would allow MISO to 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 A55: Changes in Supply from Day Ahead to Real Time
2018–2019



J. 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.

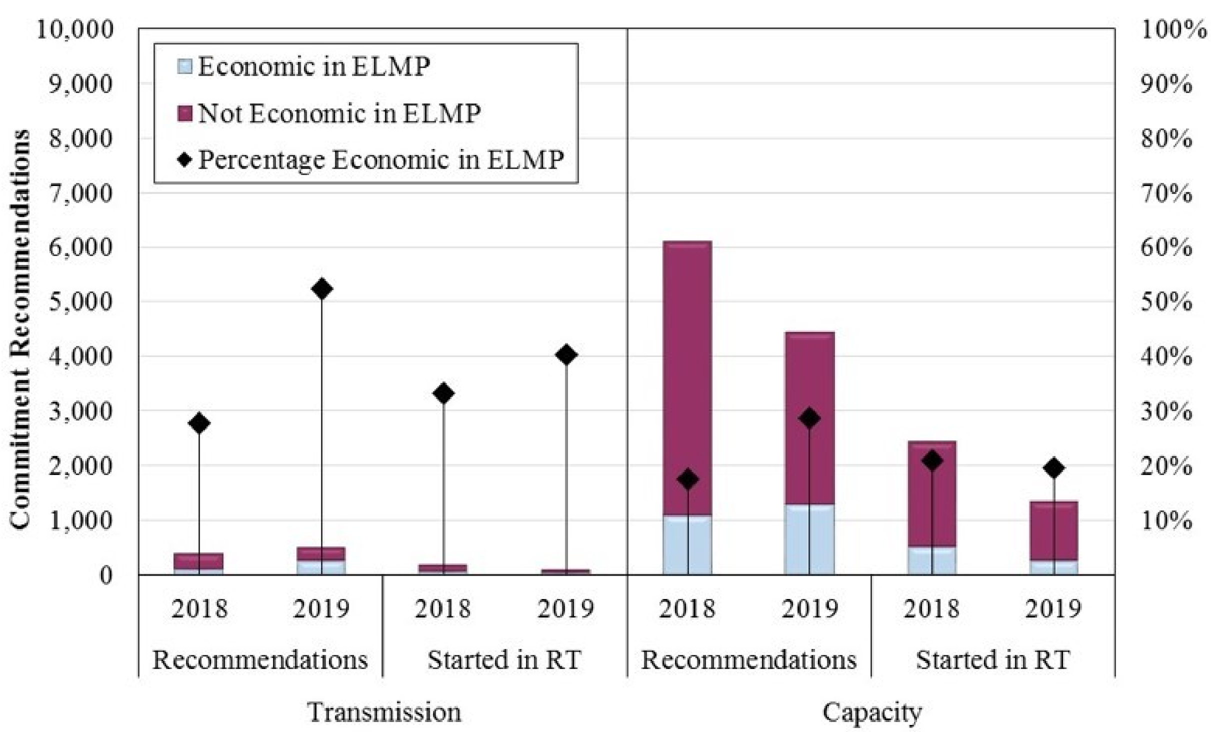
Figure A56: Economic Evaluation of LAC Commitments

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, using ELMP prices, 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 that it be started and the end of the unit's minimum runtime.

Figure A56 below shows the results of our analysis. The left panel represents LAC commitment recommendations for transmission constraints, and the right panel represents all other LAC commitment recommendations. In each panel, the stacked bars on the left show all the distinct recommendations that LAC made throughout 2018 and 2019, indicating the recommendations that were economic and not economic based on the real-time ex-post energy prices. The right stacked bars show 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 A56: Economic Evaluation of LAC Commitments
2019

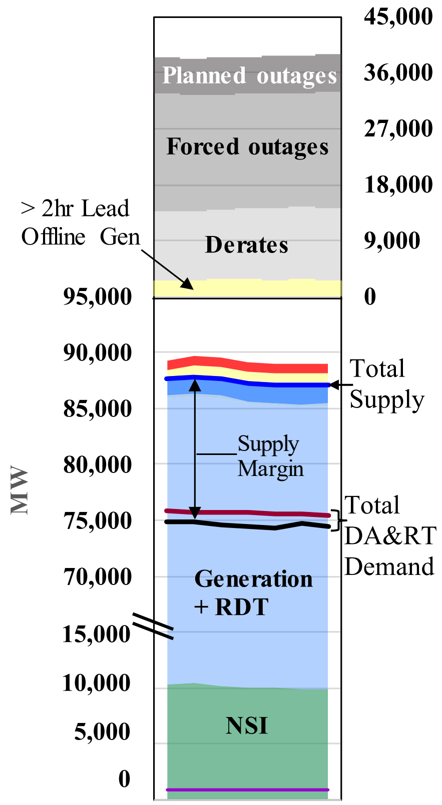


K. Review of Emergency Events

Over the past few years, MISO has experienced a significant increase in the frequency and severity of generation emergencies. Much of this increase is attributable to a narrowing reserve margin and impacts of the market's evolving generation mix. Investments in gas-fired resources, renewable resources, and load-modifying resources have replaced much of the energy lost because of retirements of coal and nuclear baseload resources. Increased intermittent output and its associated fluctuations, along with increased reliance on LMRs that can only be deployed during emergencies, has resulted in more frequent emergency events. These events are important to evaluate because they reveal how well the market performs under stress, and this helps inform improvements in both market design and operations.

Figure A57 through Figure A59: Emergency Conditions in MISO in 2019

MISO declared two regional emergencies in 2019 and chose not to declare an emergency on another occasion despite meeting the criteria for one. MISO scheduled LMRs four times between January and May,[11] and two of the LMR deployments were scheduled in advance of declaring an emergency to access resources limited by long notification times.[12] MISO did not take more extensive emergency actions, such as scheduling emergency imports.



We illustrate the 2019 emergency events with standard figures that compare the resource supply and the forecast and actual demand during those events. We utilize figures that show each component of the supply and demand so they can be analyzed. The illustration to the left shows each element included in the figures.

The total available supply is shown in the figure with a royal blue line and it is comprised of NSI (green area), online generation plus RDT capability into the area plus offline resources that can start in less than 30 minutes (light blue area), online emergency generator ranges utilized (dark blue area), and emergency transactions (if any, they are shown in orange). The purple line at the bottom represents deployed LMR capacity, when relevant. Cancelled LMRs are represented by a dotted purple line.

This total available supply can be compared to the total demand. Total demand is equal to the actual real-time load plus a regional reserve requirement based on the largest generator contingency. The figure includes this total demand (black line), the day-ahead forecast of total demand (maroon line), and the two-hour demand forecast when relevant (not shown). The supply margin

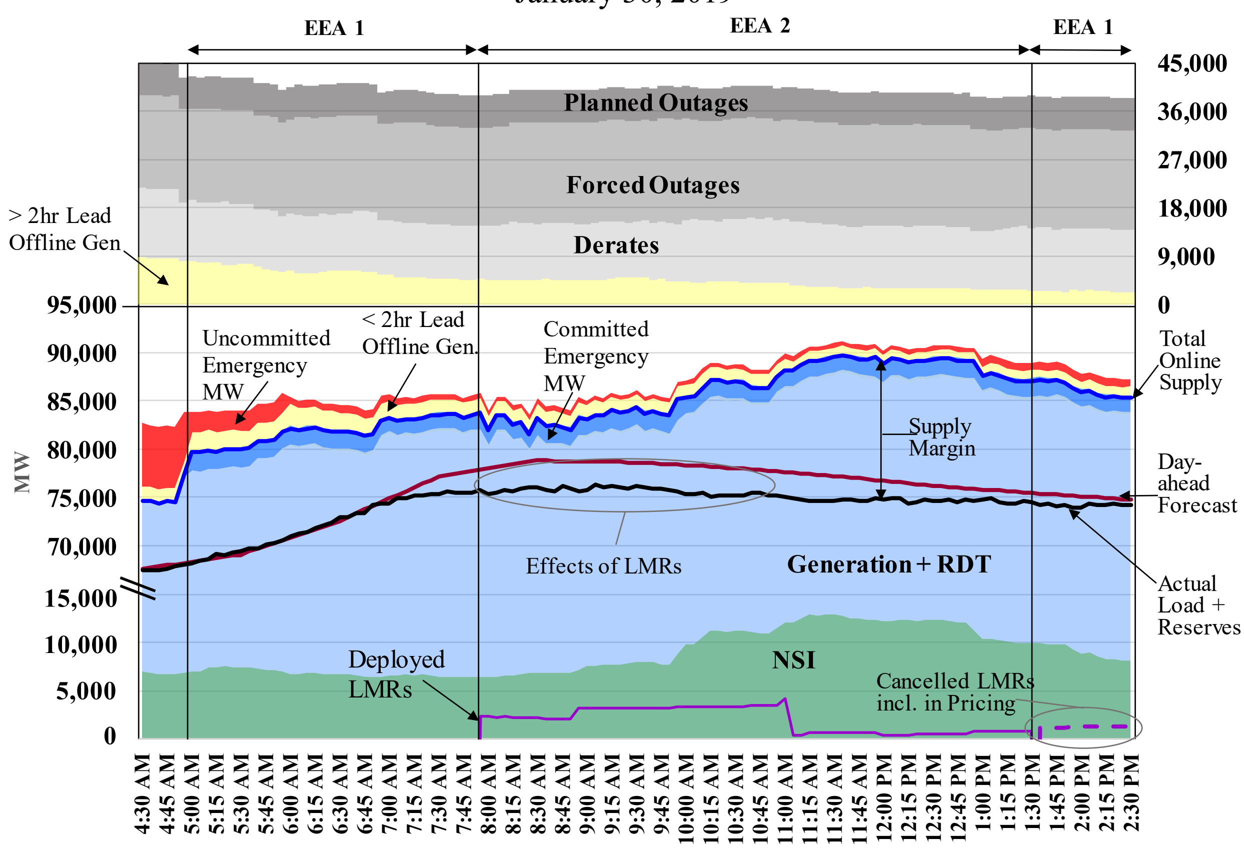
11 Three of the four LMR schedules were related to the same event.

12 Tariff changes that were accepted by FERC early in the year allow MISO to schedule LMRs in advance of anticipated emergencies in order to access the LMRs with long notification times.

can be determined at any point in time as the difference between total demand (the black line) and the total available supply (the royal blue line). MISO experiences a capacity deficiency when the black line crosses above the royal blue line, which will result in MISO exceeding the RDT scheduling limit when the largest contingency occurs in the North or South.[13]

The figure also shows supply components that are *not* available to the real-time market (above the royal blue line). This supply includes offline generators with modest start times (< 2 hours and > 30 minutes), shown by the yellow area, and offline emergency generation (Available Maximum Emergency-AME) shown by the red area. The top panel of the figure shows other unavailable generation, including offline generation with long lead times (> 2 hours) shown in yellow, as well as planned outages, forced outages, and derates (shown in shades of gray). Figure A57 through Figure A59 show two emergency events that occurred in MISO in 2019, and one day when an emergency event should have been called.

Figure A57: Emergency Conditions in MISO Midwest
January 30, 2019



13 Under the RDT agreement, MISO is required to schedule transfers within limits (nominally 3,000 MW from North to South and 2,500 MW from the South to the North) within 30 minutes following a contingency.

Figure A58: Maximum Generation Emergency in MISO South
May 16, 2019

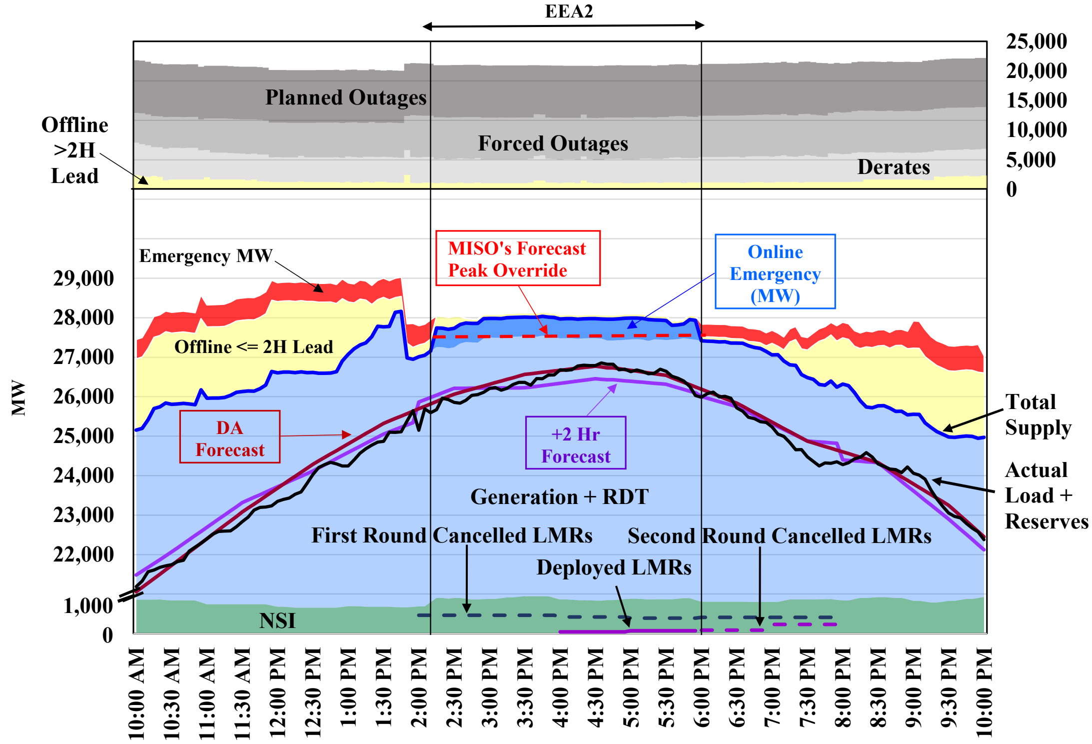
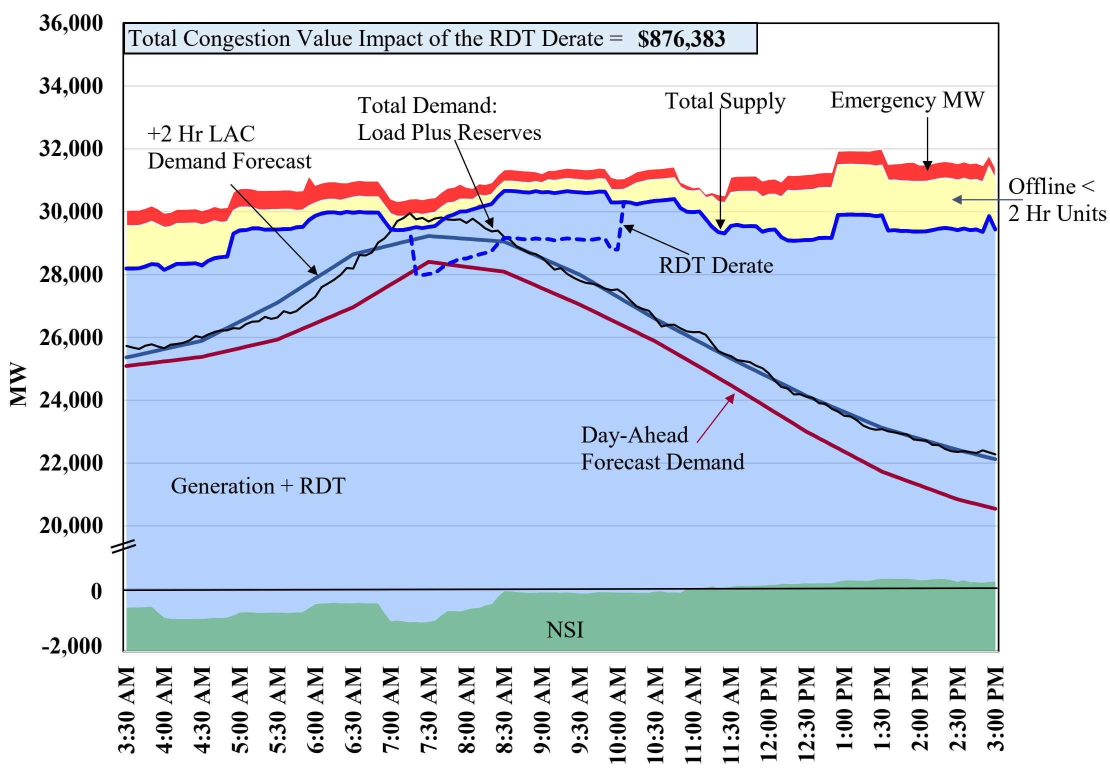


Figure A59: Conditions in MISO South
November 13, 2019



Prior to 2017, LMRs had not been called upon in MISO since 2007, but they have an increasingly important role in planning for and operating during emergency events. LMRs were deployed in MISO South on April 4, 2017, a second time on January 17, 2018, and a third time on September 15, 2018. A more recent event occurred in MISO South on May 16, 2019, as well as an emergency event in MISO Central and North on January 30, 2019. We discuss the events in detail in Section IV.G of the Report.

Table A9: Availability of Emergency-Only Resources

We conducted an analysis of these main LMR events. We analyzed the amount of time that emergency resources had to prepare for the events, based on the timing of the declarations of the events. Based on MISO's declarations for these emergency events, we identify which emergency resources that cleared in the 2020-2021 capacity auction would have been available to be scheduled based on the resources' notification and startup or shutdown times.

We divided the associated MW into tranches, based on the offered notification times on the emergency days (for AME resources) or registered notification times (for LMRs). In the case of the cleared LMRs, we included the notification times for a peak hour on a peak day (Monday through Friday) since some resources have notification times that vary. For AME resources, we included the average capacity offered with the various notification times at the time of the declarations during the actual emergency events

Table A9: Availability of Emergency-Only Resources During Emergency Events
2020/2021 Planning Resource Auction Results

Event	Lead Time to Event	Available Capacity (MW)		
		LMR-DR**	LMR-BTMG**	AME***
April 4, 2017	Less than 15 Minutes	356.8	980.3	695.0
January 17, 2018	1.5 - 2 Hours	4,403.6	3,047.0	1,648.8
September 15, 2018	Less than 15 Minutes	356.8	980.3	143.0
January 30, 2019	1 - 1.5 Hours	1,624.6	1,547.9	521.0
May 16, 2019				
Advance Schedule *	12 + Hours	7,557.4	4,444.9	N/A
Second Emergency	Less than 15 Minutes	356.8	980.3	80.0
May 17, 2019 *	12 + Hours	7,557.4	4,444.9	N/A
Total Cleared Capacity		**7,557.4**	**4,444.9**	**N/A**

* Pre-Scheduled LMRs were cancelled in advance of event, no response required. Pre-scheduling of LMRs in advance of emergency declarations began after February 19, 2019 (Docket No. ER19-650-000).
** LMR Capacity determined from PRA 2020/21 results and registered lead times.
*** AME is actual energy available as Emergency Resources within lead time on date of event.

L. Generator Dispatch Performance

MISO sends dispatch instructions to generators every five minutes that specify the expected output at the end of the next five-minute interval. Historically, MISO would 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] However, in May 2019 MISO altered the Uninstructed Deviation (UD) threshold from being based on output to being a function of the offered ramp rate. MISO's criteria for identifying deviations, both the percentage bands and the consecutive interval test, had been significantly more relaxed than most other RTOs'.

Having a relatively relaxed tolerance band allowed 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 could effectively derate a unit by simply not moving over many consecutive intervals. We discuss these "inferred derates" later in this subsection.

As long as the dispatch instruction is not outside of the allowable tolerance, 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:

- Five-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 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 A60 and Figure A61: Frequency of Net Five-Minute Deviations

Figure A60 shows a histogram of MISO-wide net five-minute deviations from 6 am to 10 pm, which includes MISO's high-ramp and peak hours in the summer and winter seasons. Figure A61 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 and 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 zero 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.v.).

Figure A60: Frequency of Net Deviations
Ramp and Peak Hours, 2019

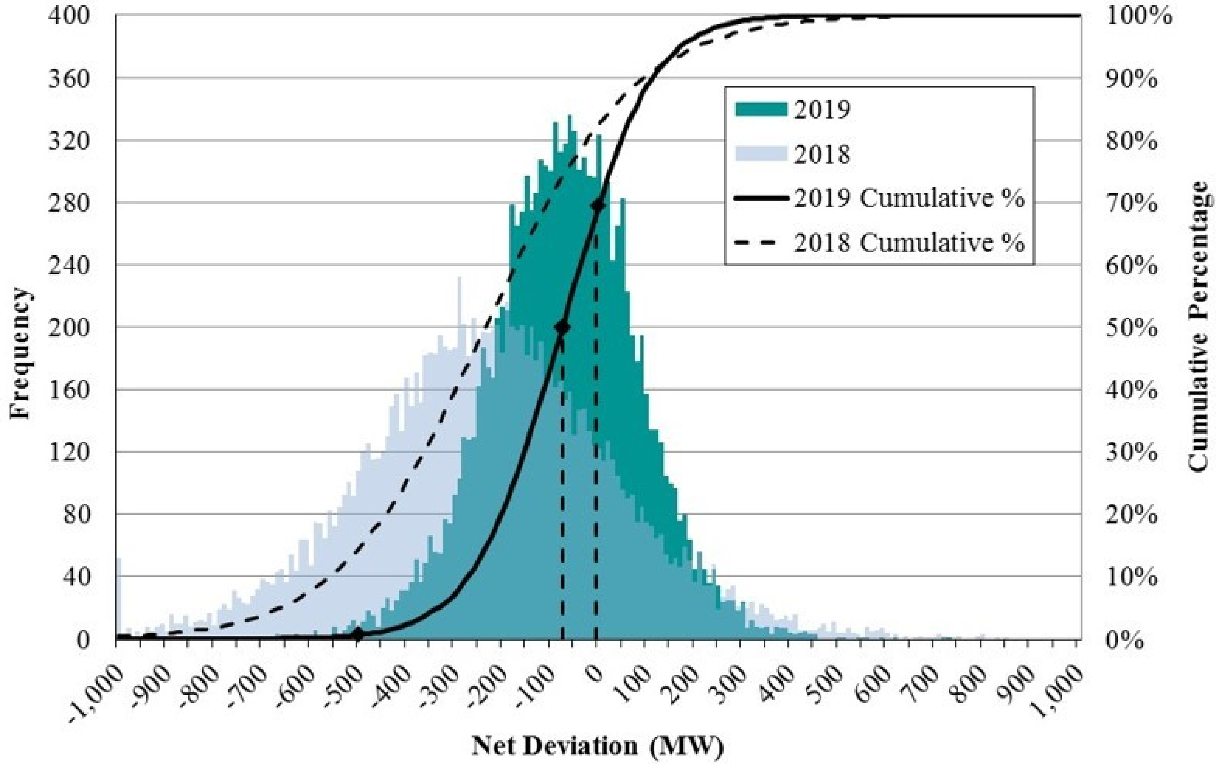


Figure A61: Frequency of Net Deviations
Ramp-Up Hours, 2019

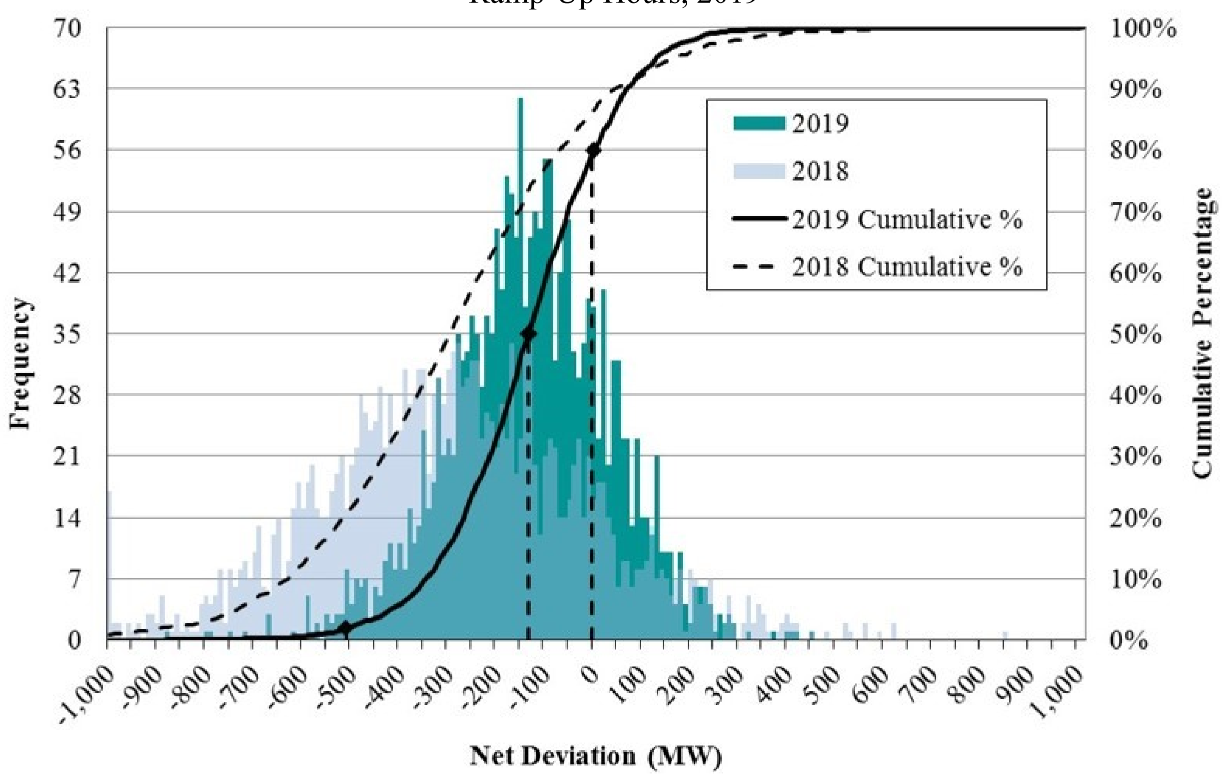


Figure A62: Five-Minute and 60-Minute Deviations

Figure A62 shows the size and frequency of the 5-minute and 60-minute net deviations. The figure shows these results by hour, highlighting the difference between the worst performing resources and the average deviations.

Figure A62: Five-Minute and 60-Minute Deviations
2019

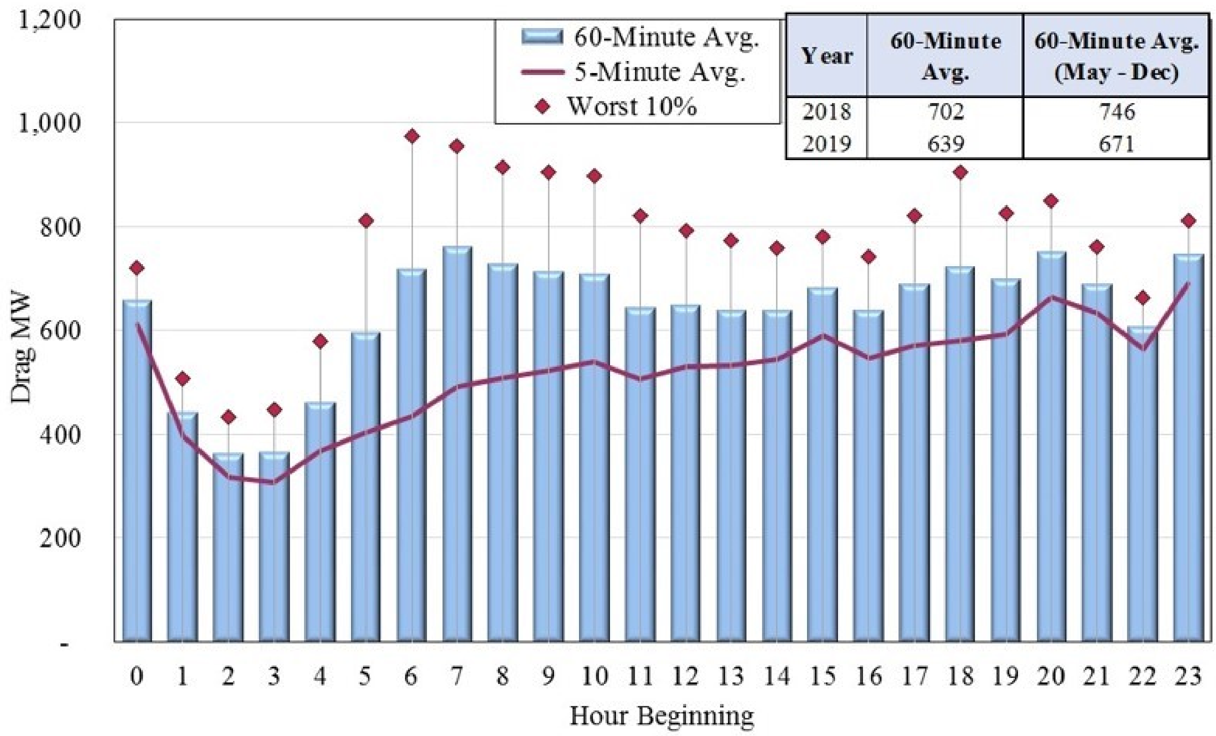


Figure A63 to Figure A65: 60-Minute Deviation by Fuel and Hour

In the next three figures, we estimated the sources of 60-minute net deviations by fuel type and their impact. The horizontal axis is hour beginning (HB) of the day. The vertical stacked bars are the average 60-minute deviations for each HB, where red, blue, and green are the deviations from coal, gas, and wind units, respectively. The three charts represent all year, winter only, and the summer season only. Over 80 percent of the 60-minute deviations in the system are attributed to coal units as compared to gas or wind.

Figure A63: 60-Minute Deviation by Fuel and Hour
2019

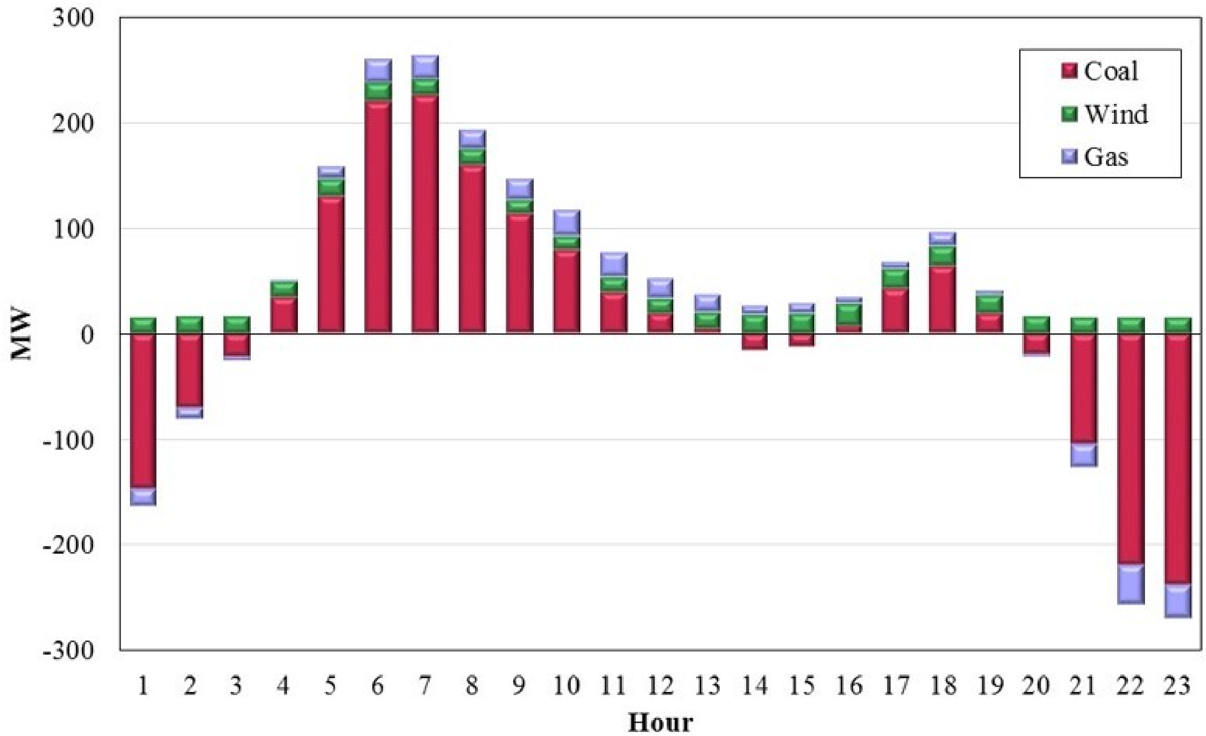


Figure A64: 60-Minute Deviation by Fuel and Hour
Summer 2019

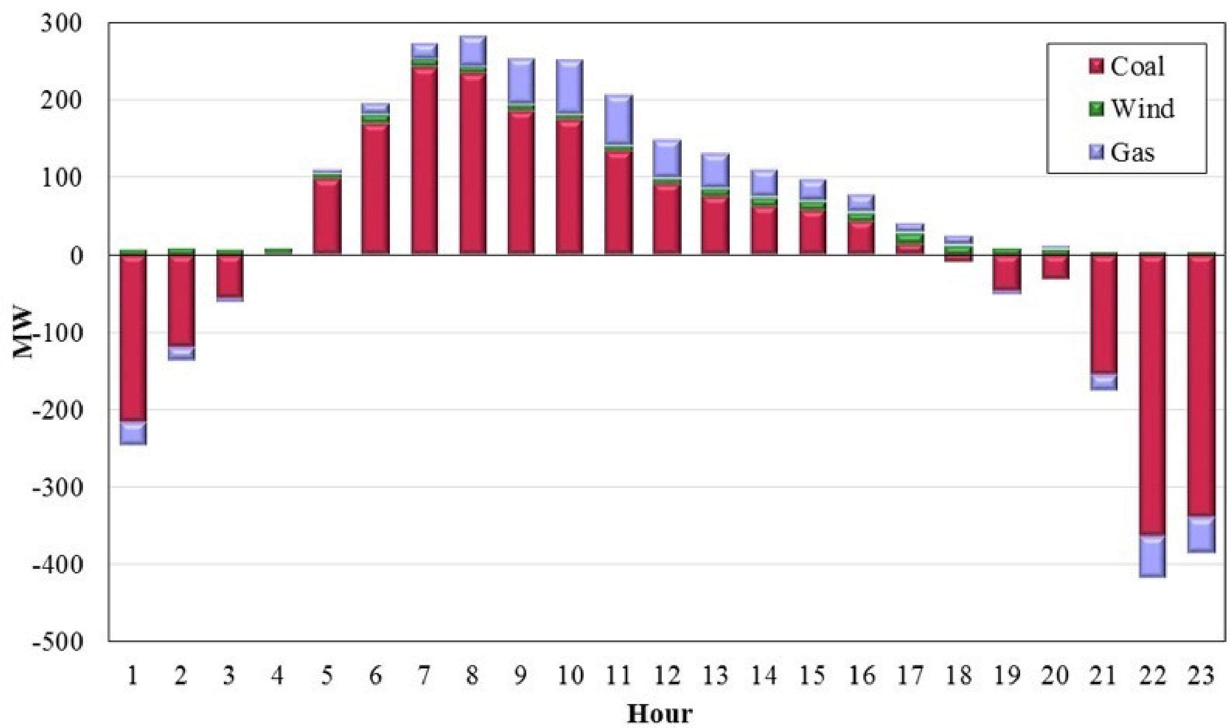


Figure A65: 60-Minute Deviation by Fuel and Hour
Winter 2019

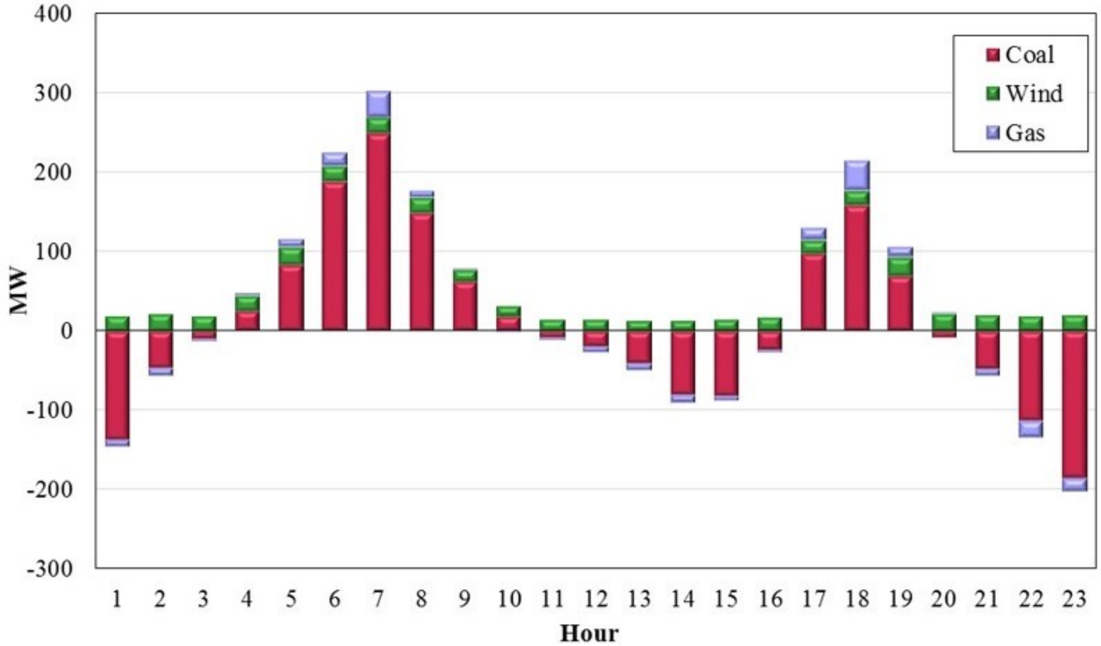


Figure A66: 60-Minute Deviations by Type of Conduct

To better show the effects of the deviations, we measured dragging by hour of the day in Figure A66, as well as the dragging that prevailed in the worst 10 percent of hours. The annual averages over all hours are shown for both dragging and overproduction in the inset table.

Figure A66: Hourly 60-Minute Deviations by Type of Conduct
2019

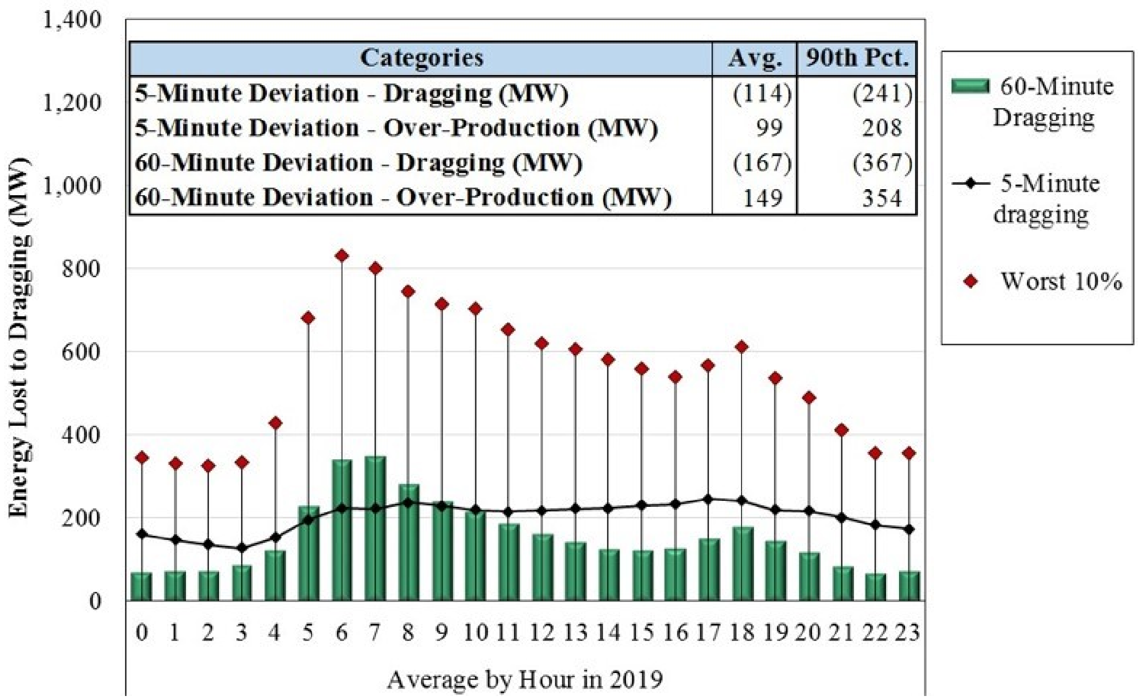
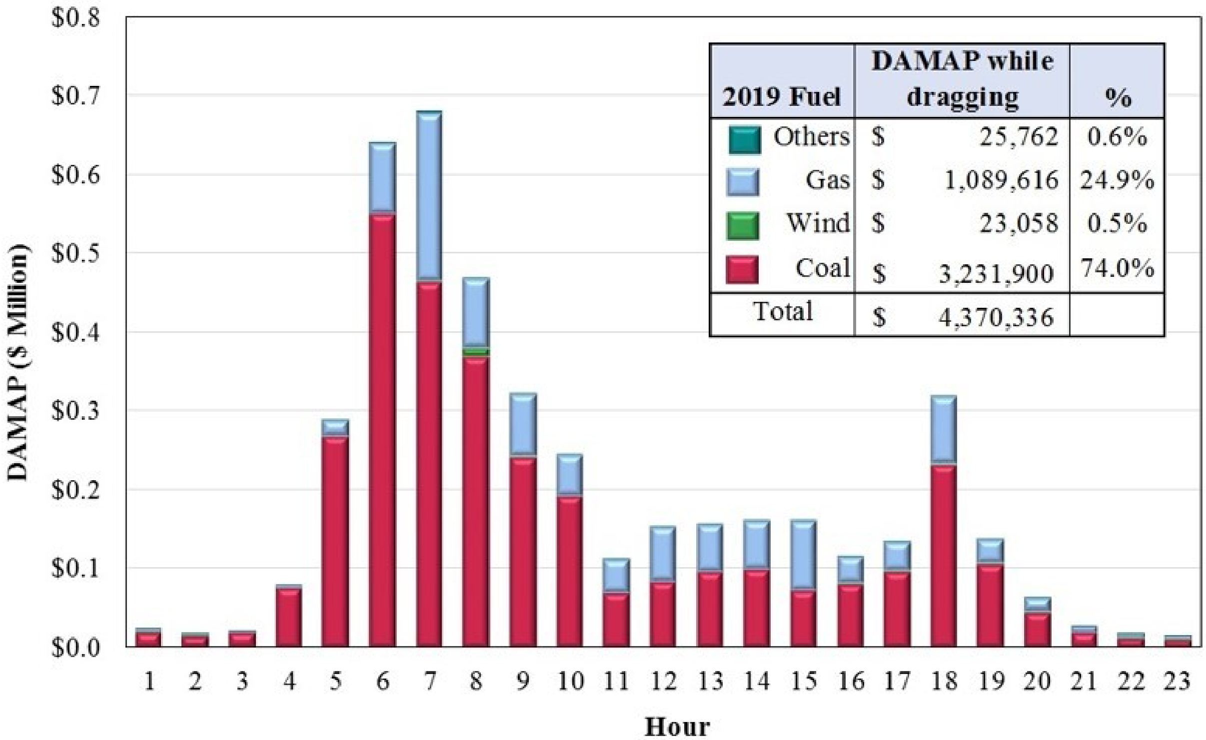


Figure A67: DAMAP to Dragging Units by Fuel Type

The next figure is intended to show the DAMAP caused by 60-minute deviations. The horizontal axis shows the hours beginning (HB) throughout the day. The vertical stacked bars are DAMAP in dollars to units with 60-minute deviations from their dispatch instructions. Different colors represent fuel types, where maroon represents coal units, blue is for gas units, and wind units are shown in green.

Figure A67: DAMAP to Dragging Units by Fuel Type
2019



2019 Fuel	DAMAP while dragging	%
Others	$ 25,762	0.6%
Gas	$ 1,089,616	24.9%
Wind	$ 23,058	0.5%
Coal	$ 3,231,900	74.0%
Total	$ 4,370,336	

M. Dispatch Operations: Offset Parameter

The offset parameter is a quantity chosen by the MISO real-time operators to adjust the load to be served by the UDS. A positive offset value is added to the short-term load forecast to increase the generation dispatched, while a negative offset decreases the load and the corresponding dispatched generation. Offset values may be needed for many reasons. For example, operators may use positive offsets when:

- Generator outages occur that are not yet recognized by UDS to increase generation to compensate for the loss in generation;
- Generators are dragging (producing less than MISO's dispatch instruction);
- Wind output is over-forecasted; or
- Operators believe the short-term load forecast is under-forecasted;

Likewise, operators may use negative offsets when:

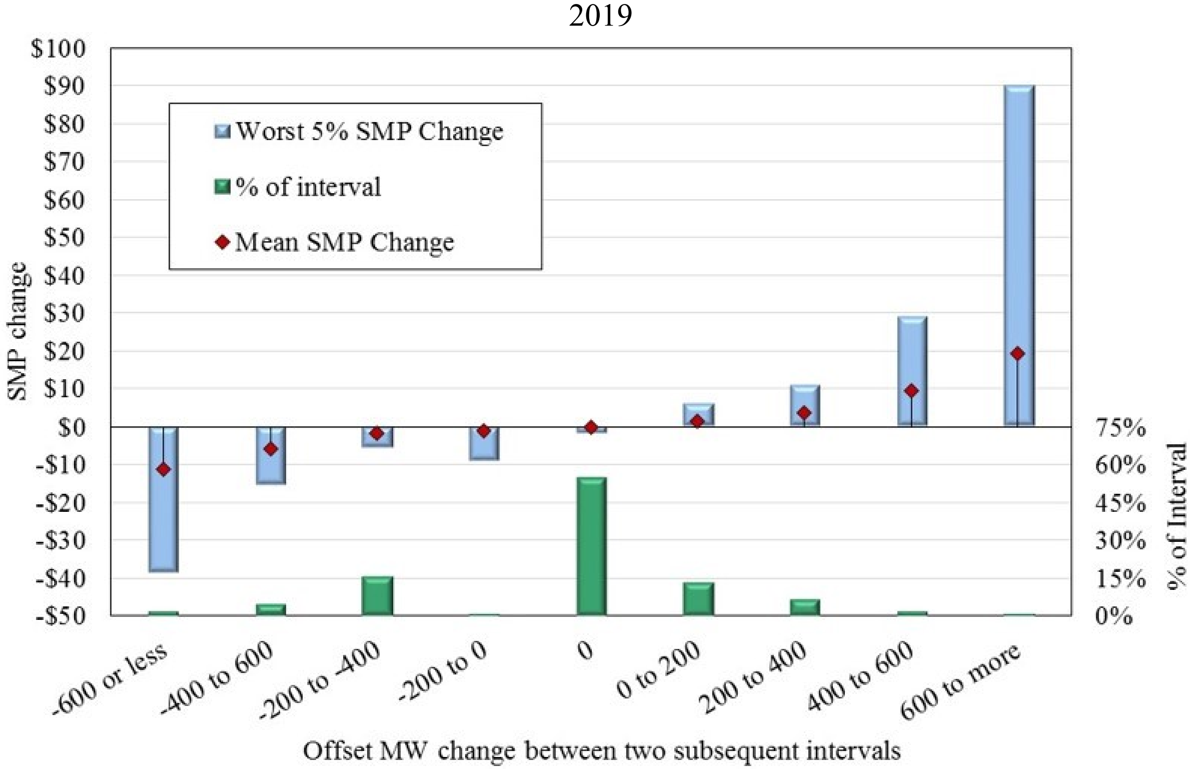
- Generators that are coming online that are not yet recognized by UDS and may require negative offsets to decrease generation (units are not recognized until they are synchronized);
- Generators are overproducing (producing more than MISO's dispatch instruction);
- Wind output is under-forecasted; or
- Operators believe the short-term load forecast is over-forecasted;

Each UDS interval is initialized with a base case and five alternative cases that have different offset values. After the solutions are available, the MISO operators choose the case that they think best represents the market conditions (accounting for factors listed above and others). When large changes in the offset are made from one interval to the next, it can substantially affect the MISO-wide energy prices (i.e., the System Marginal Price or SMP). We evaluated how changes in the offset value affected the SMP.

Figure A68: Impact of Offset Changes on SMP

Figure A68 summarizes our results of this analysis. The horizonal axis shows nine tranches of intervals grouped by the change in offset from the prior interval. The primary vertical axis represents the change in SMP associated with the change in offset for the respective tranches. The droplines are the mean change associated with the change in offset and the blue vertical bars are the worst five-percent change in MISO's SMP associated with the change in offset.

Figure A68: Impact of Offset Changes on SMP
2019



N. Dispatch of Peaking Resources

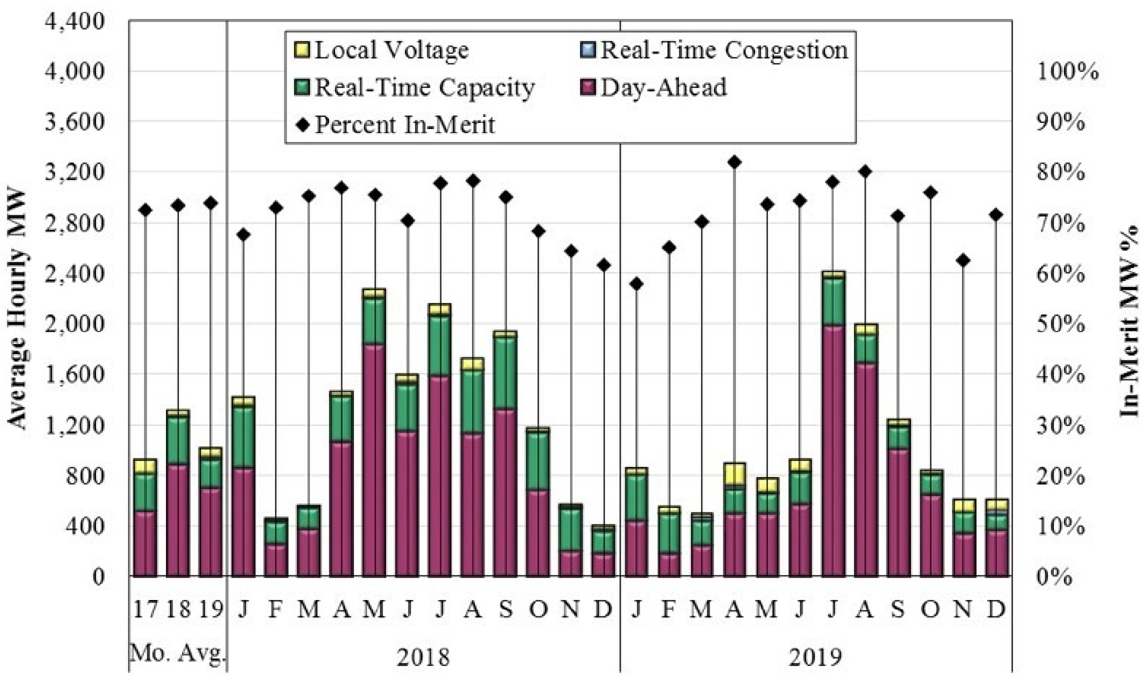
Peak demand is often satisfied by generator commitments in the real-time market. Typically, peaking resources account for a large share of real-time commitments because they are available on short notice and have attractive commitment-cost profiles (i.e., low startup costs and short startup and minimum-run times). These qualities make peaking resources optimal candidates for satisfying the incremental capacity needs of the system. However, 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 A69: Dispatch of Peaking Resources

Figure A69 shows average hourly dispatch levels of peaking units in 2019 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 A69: Dispatch of Peaking Resources
By Commitment Reason, 2018–2019



O. Wind Generation

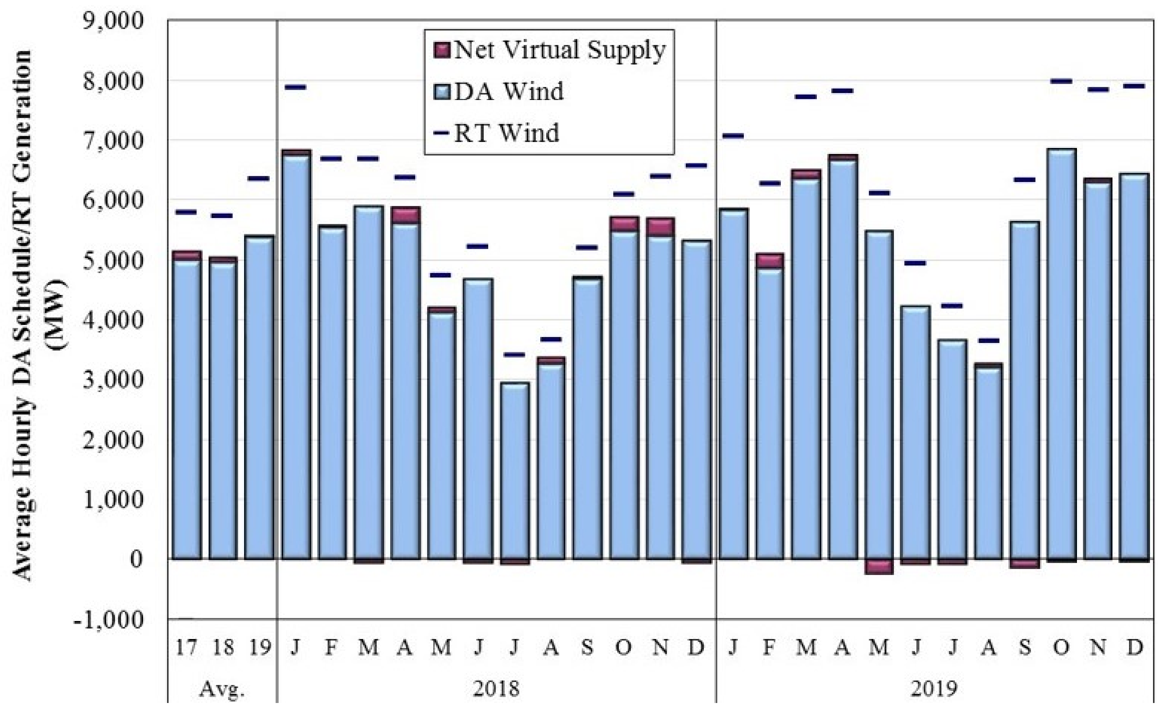
Wind generation in MISO has grown steadily since the start of the markets in 2005. Although wind generation promises substantial environmental benefit, the output of these resources is intermittent and, as such, presents unique operational and scheduling challenges.

About 91percent of MISO's wind units are Dispatchable Intermittent Resources (DIR). DIRs are physically capable of responding to dispatch instructions and can, therefore, set the real-time energy price. DIRs can submit offers in the day-ahead market, are eligible for all uplift payments, and are subject to all typical operating requirements. For both DIR and non-DIR wind units, MISO utilizes short and long-term forecasts to make assumptions about wind output. The prevalence of DIRs allows MISO to rarely utilize manual curtailments to ensure reliability. Wind resources are also qualified to sell capacity under Module E of the Tariff based on their contribution to satisfying MISO's planning requirements.[15]

Figure A70: Day-Ahead Scheduling Versus Real-Time Wind Generation

Figure A70 shows the hourly average wind scheduled in the day-ahead market and real-time markets by month. Under-scheduling of output in the day-ahead market can create price convergence issues and lead to uncertainty regarding the need to commit resources for reliability. Virtual supply at wind locations is also shown in the figure because the response by virtual supply in the day-ahead market can offset the effects of under-scheduling by the wind resources.

Figure A70: Day-Ahead Scheduling Versus Real-Time Wind Generation
2018–2019



15 Capacity credits for wind resources are determined by evaluating a unit's performance during the peak hour of each of the prior seven years' eight highest-load days (56 hours). For the 2019-2020 Planning Year, the system-wide capacity credit for wind is 15.7 percent, while individual credits range from 0.5 to 27.2 percent.

Figure A71: Generation Wind Over-Forecasting Levels

In 2016, we 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 congestion. Dispatch deviations arise because an over-forecasted resource will produce less than the dispatch instruction. Figure A71 shows 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 axis in 2018 and 2019.

Figure A71: Generation Wind Over-Forecasting Levels
2018–2019

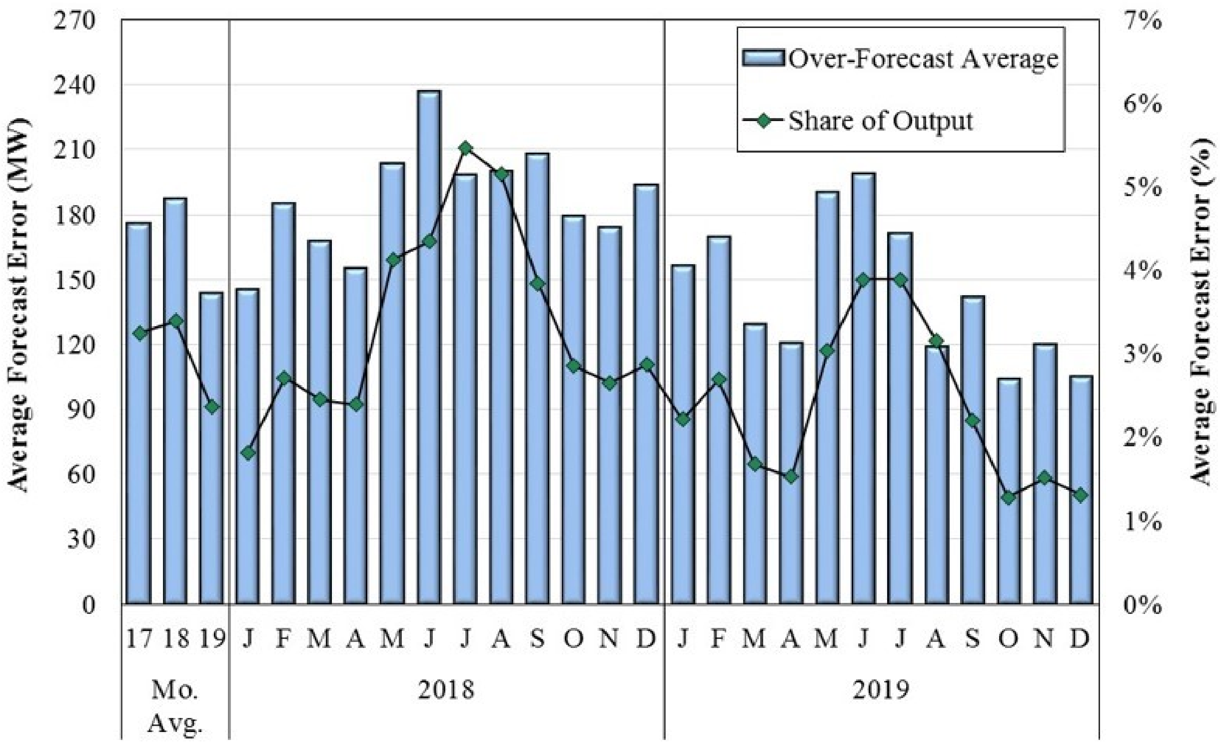


Figure A72: Seasonal Wind Generation Capacity Factors by Load Hour Percentile

Wind capacity factors that are measured as actual output as a percentage of nameplate capacity vary substantially year-to-year, as well as by region, hour, season, and temperature. Figure A72 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 A72: Seasonal Wind Generation Capacity Factors by Load-Hour Percentile
2019

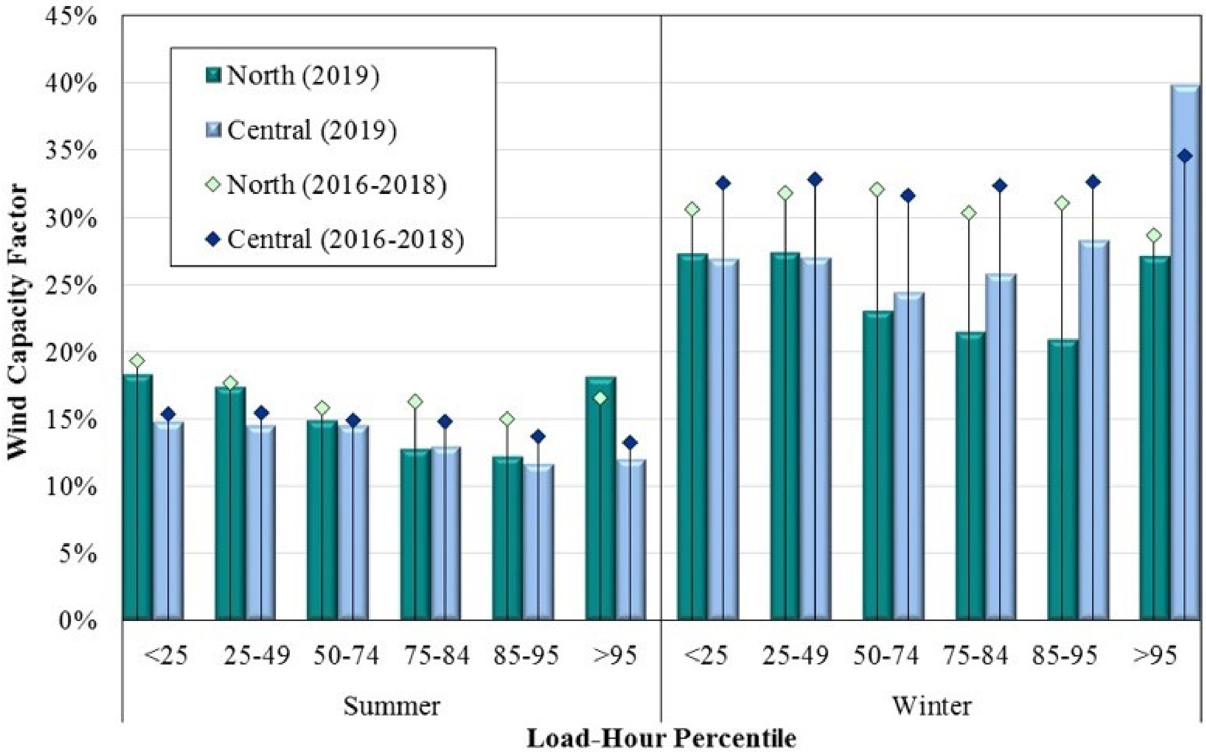
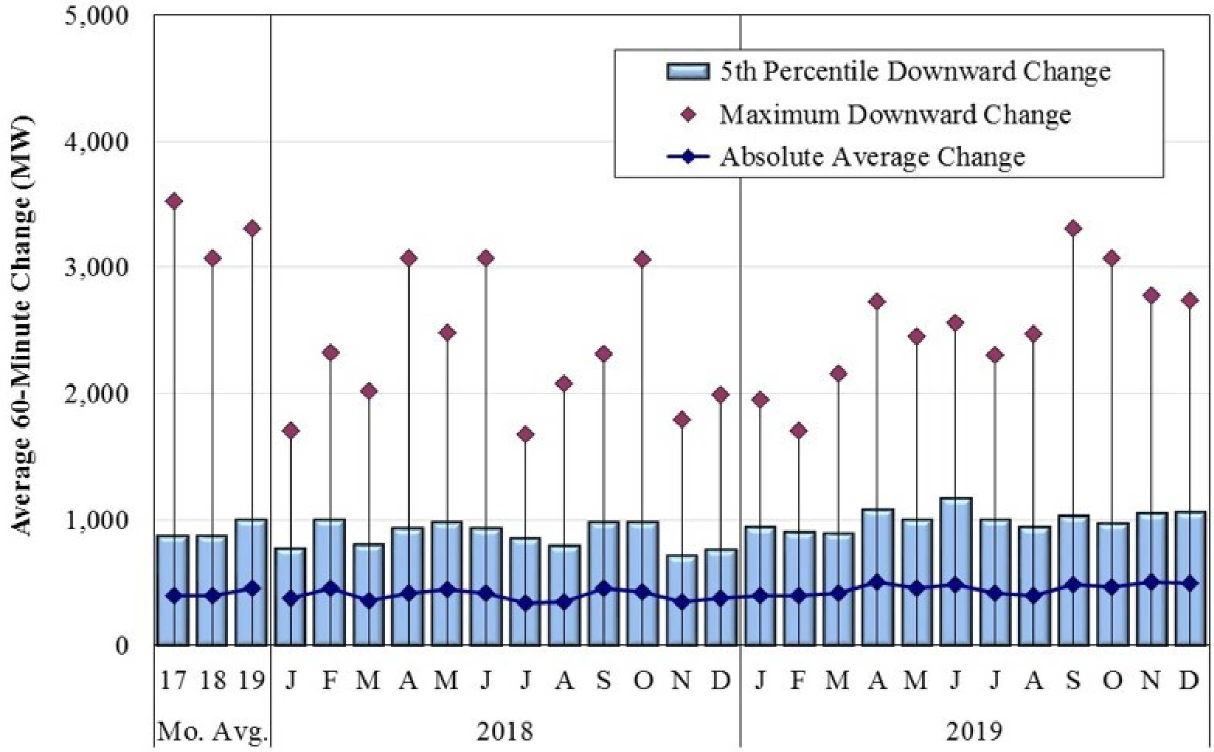


Figure A73: Wind Generation Volatility

Wind output can be highly variable and must be managed through curtailment, the re-dispatch of other resources, or commitment of peaking resources. Figure A73 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;
- The maximum hourly decrease in each month in the drop lines; and
- Changes in wind output that are due to MISO economic curtailments are excluded from this analysis.

Figure A73: Wind Generation Volatility
2018–2019



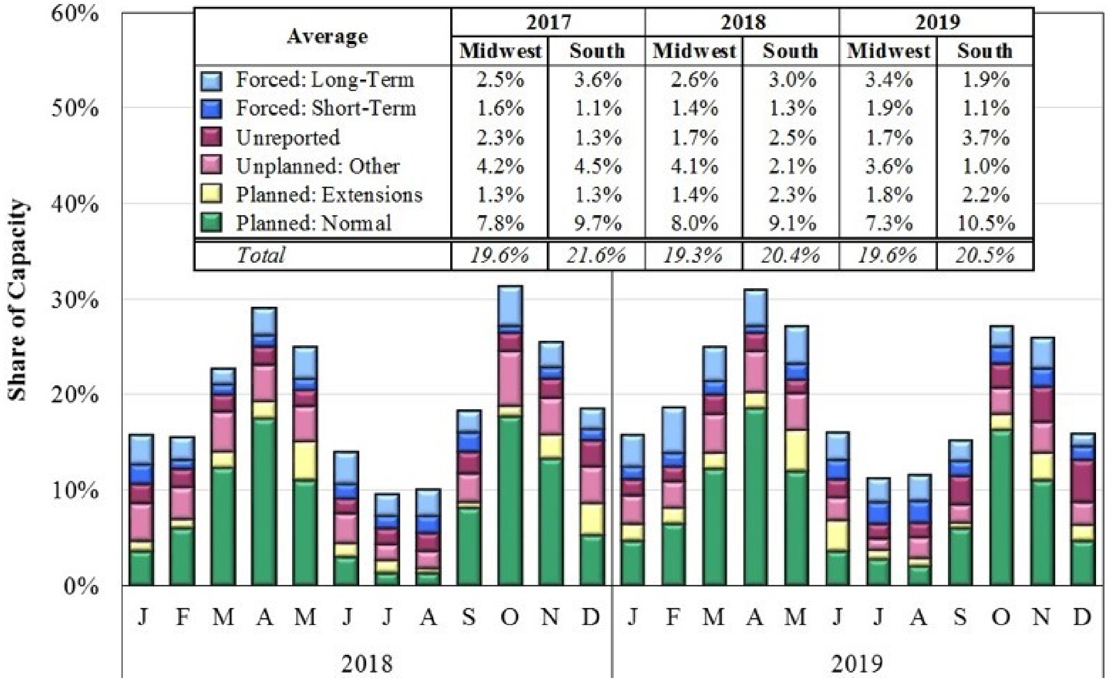
P. Outage Scheduling

Figure A74: Generator Outage Rates

Figure A74 shows the monthly average planned and unplanned generator outage rates for the two most recent years (and annual averages for the last three years). Only full outages are included, so partial outages or deratings are not shown. The figure also distinguishes between short-term unplanned outages (lasting fewer than seven days) and long-term unplanned outages (seven days or longer). Additionally, the figure distinguishes between normal planned outages and short-notice planned outages that are scheduled within seven days of the actual start of the outage. Planned outages are often scheduled in low-load periods when economics are favorable for participants to perform maintenance, although short-notice planned outages and short-term unplanned outages are frequently the result of emergent operating problems.

Short-notice and short-term outages are 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 VIII.G.

Figure A74: Generator Outage Rates
2017–2019

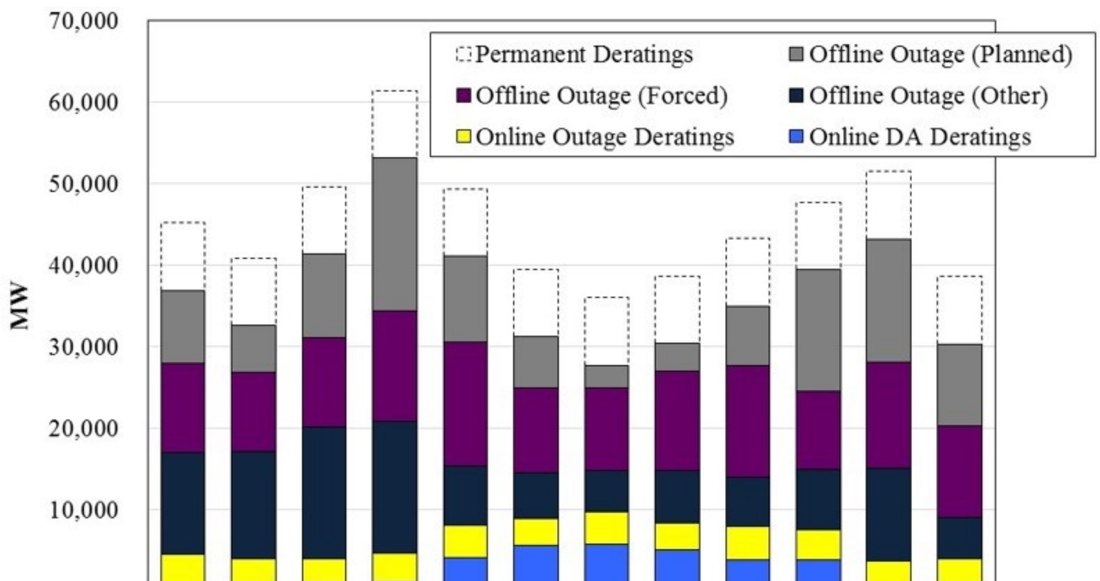


Average	2017		2018		2019	
	Midwest	South	Midwest	South	Midwest	South
Forced: Long-Term	2.5%	3.6%	2.6%	3.0%	3.4%	1.9%
Forced: Short-Term	1.6%	1.1%	1.4%	1.3%	1.9%	1.1%
Unreported	2.3%	1.3%	1.7%	2.5%	1.7%	3.7%
Unplanned: Other	4.2%	4.5%	4.1%	2.1%	3.6%	1.0%
Planned: Extensions	1.3%	1.3%	1.4%	2.3%	1.8%	2.2%
Planned: Normal	7.8%	9.7%	8.0%	9.1%	7.3%	10.5%
Total	*19.6%*	*21.6%*	*19.3%*	*20.4%*	*19.6%*	*20.5%*

Figure A75: Capacity Unavailable During Peak Load Hours in 2019

Figure A75 shows unavailable capacity during the peak hour of each month. Suppliers should maximize unit availability in summer peak periods when demand is highest, but temperature and environmental restrictions can cause deratings to be highest during these periods.

Figure A75: Capacity Unavailable During Peak Load Hours in 2019



18	9	8	7	15	16	15	15	16	15	8	8	Peak Hour
Jan 30	Feb 08	Mar 05	Apr 01	May 31	Jun 27	Jul 19	Aug 05	Sep 11	Oct 01	Nov 13	Dec 19	Peak Date
101,104	93,576	97,410	82,946	92,659	107,927	121,114	113,779	107,067	100,929	95,080	95,114	Peak Load

V. Transmission Congestion and FTR Markets

Managing transmission congestion is among MISO's most important roles. MISO monitors thousands of potential network constraints throughout its system. MISO manages flows over its network by altering the dispatch of its resources to avoid overloading these transmission constraints. 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, which is different from 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. For at least two reasons, 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 serving 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 and their real-time flows up to their entitlement levels do not settle with MISO.

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, the participant 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 not fully anticipated in day-ahead prices, MISO will collect less congestion revenue in the day-ahead market than the real-time value of congestion on its system.

Figure A76: Value of Real-Time Congestion by Coordination Region

Figure A76 shows the total monthly value of real-time congestion by MISO's Reliability Coordination regions in 2018 and 2019. The bars on the left panel of the chart show the average monthly value of the past three years.

Figure A76: Value of Real-Time Congestion by Coordination Region
2018–2019

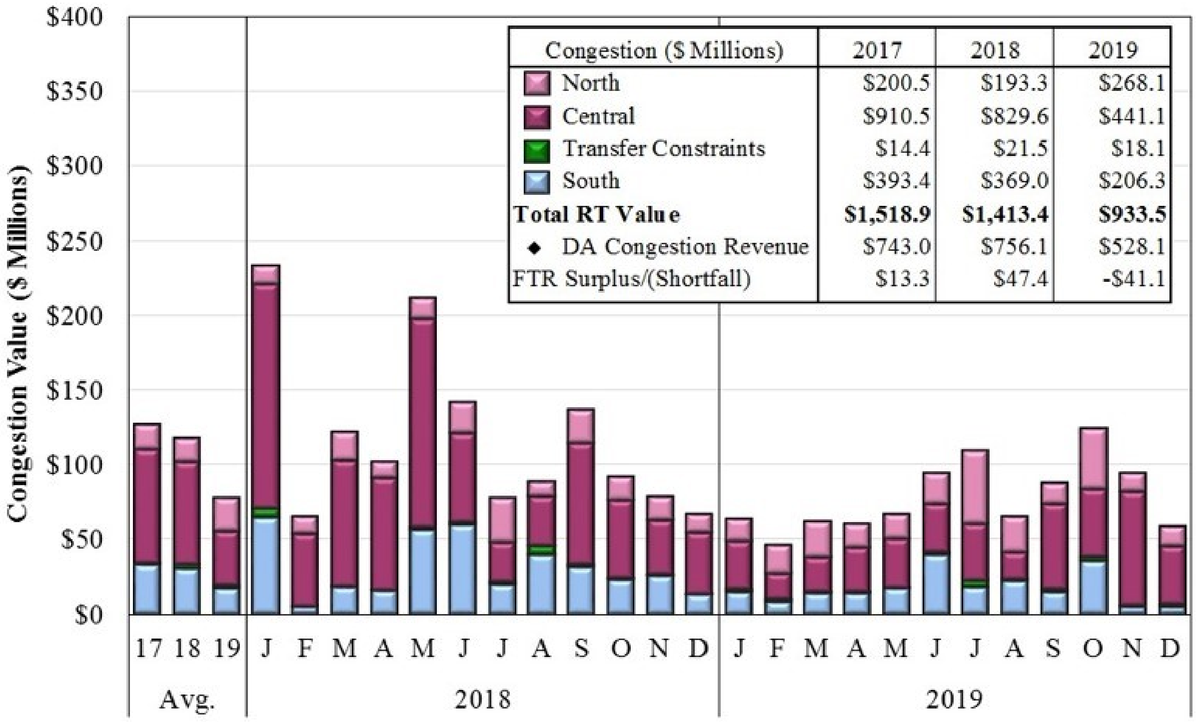


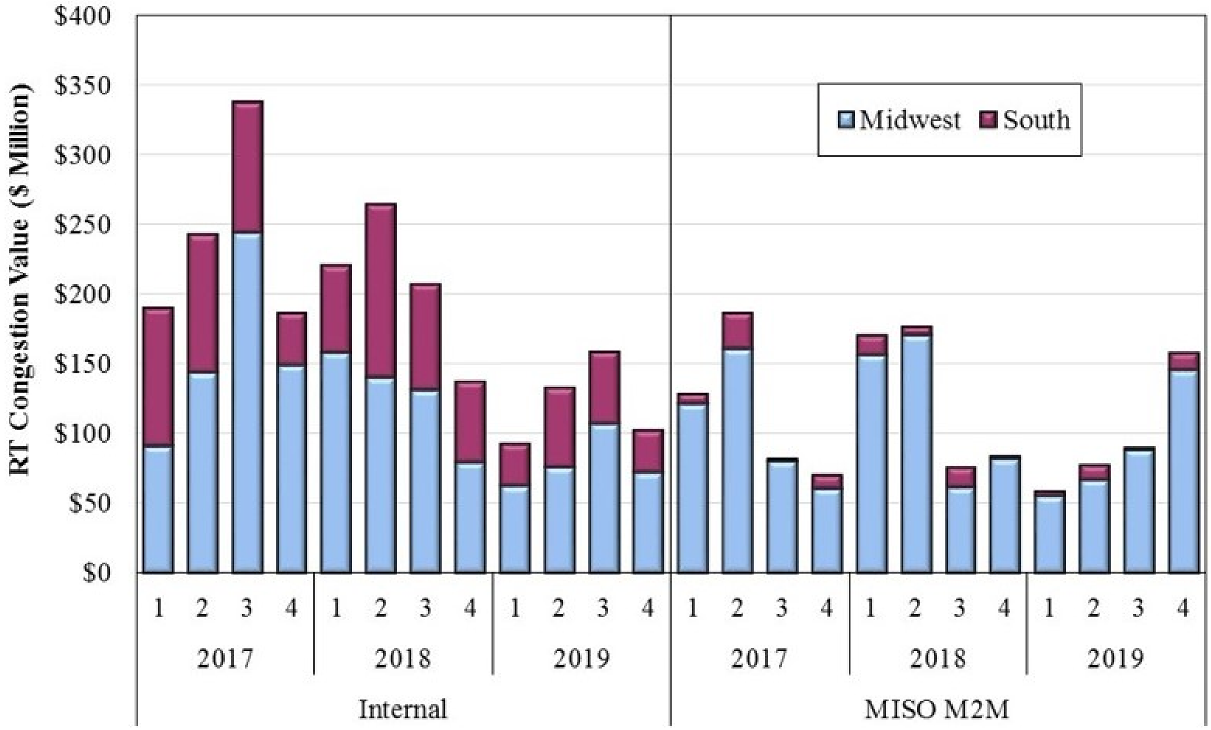
Figure A77: Value of Real-Time Congestion by Type of Constraint

To better identify the drivers of the real-time congestion value, Figure A77 disaggregates the results by the MISO subregion and by the two types of constraints:

- Internal Constraints: Constraints internal to MISO where MISO is the Reliability Coordinator that are not coordinated with PJM or SPP.
- MISO market-to-market (M2M) Constraints: MISO constraints coordinated with SPP and PJM through the M2M process.

The flow on PJM and SPP M2M constraints is limited to the MISO market flow, and this flow is used in our measure of congestion value. Market flow is defined as MISO's flow on the constraints in MISO's dispatch model and does not represent the total flow on these constraints. The internal constraints represented in the MISO dispatch model include the total flow.

Figure A77: Value of Real-Time Congestion by Type of Constraint
By Quarter, 2017–2019



B. Day-Ahead Congestion and FTR Funding

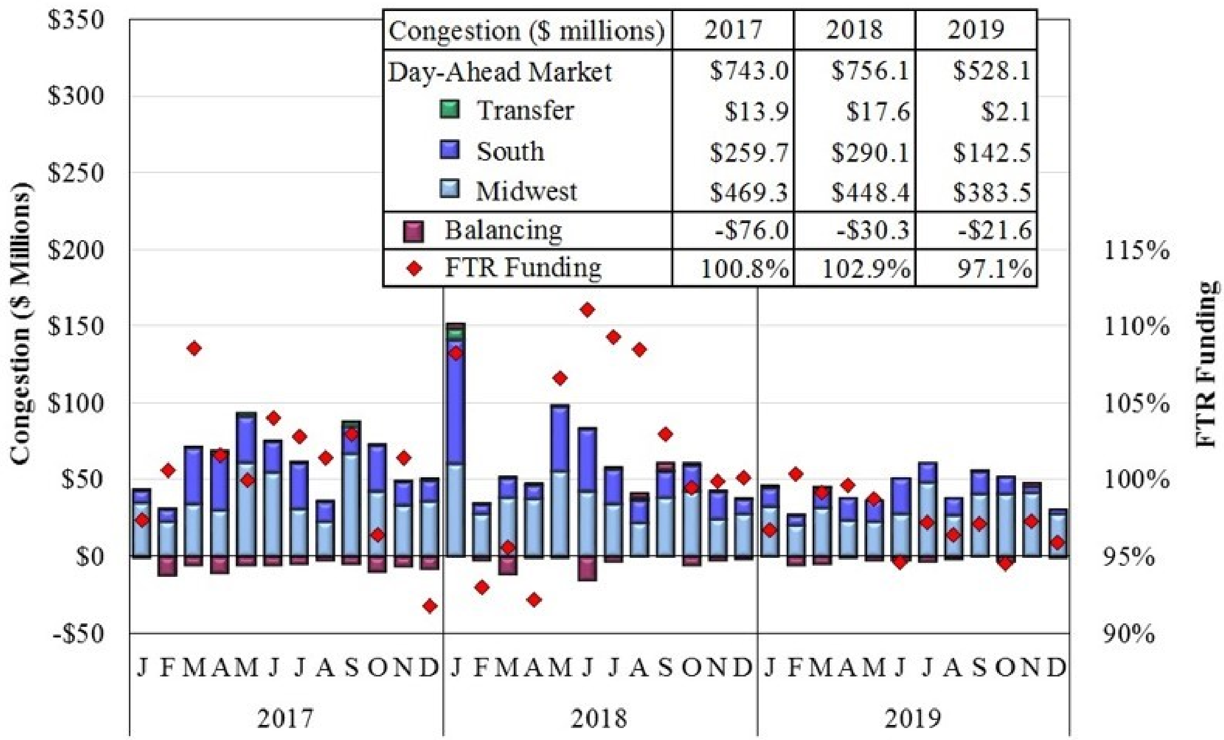
MISO's day-ahead energy market is designed to send accurate and transparent locational price signals that reflect congestion and losses on the network. MISO collects congestion revenue in the day-ahead market based on the differences in the LMPs at locations where energy is scheduled to be produced and 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 revenues 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 has not been allocated is sold in the FTR markets, with the resulting market revenues contributing to the recovery of the costs of the network. FTRs provide an instrument for market participants to hedge 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 FTR holders 100 percent of the FTR entitlement.

Figure A78: Day-Ahead and Balancing Congestion and Payments to FTRs

Figure A78 shows the total day-ahead congestion revenues for constraints in MISO Midwest, MISO South, and the transfer constraints between MISO Midwest and MISO South for the last three years. It also shows balancing congestion revenue (net congestion collections in real time), as well as the funding level of the FTRs.

Figure A78: Day-Ahead and Balancing Congestion and Payments to FTRs
2017–2019



An FTR is 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 system and, therefore, are entitled to the system's economic property rights. This allocation of property rights is accomplished by allocating Auction Revenue Rights (ARRs) to transmission customers associated with their historical usage of the network given their network load and generating resources. ARRs are a MW value defined between two locations on the network, and they give customers the right to receive the FTR revenues that MISO collects when it sells FTRs that correspond to the ARRs. Customers can also convert their ARRs into FTRs directly.

MISO is obligated to pay FTR holders the FTR quantity times the per-unit congestion cost between the source and sink of the FTR.[16] Congestion revenues collected in MISO's day-ahead market fund the FTR obligations. Surpluses and shortfalls are limited when participants hold FTR portfolios consistent with the capability of the network. When MISO sells FTRs that reflect different network capability than is available in the day-ahead market, shortfalls or surpluses can occur. Reasons for differences between FTR capability and day-ahead capability include:

- Loop flows caused by generators and loads outside the MISO region;[17] and

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

17 "Loop Flows" cannot be directly calculated and, in this context, would be measured as real-time flows less the calculated real-time market flows from PJM, SPP, and the MISO commercial flows (which include 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.

- 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.

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 an FTR revenue shortfall. This is because only part of the network is being used by MISO participants who pay congestion charges.

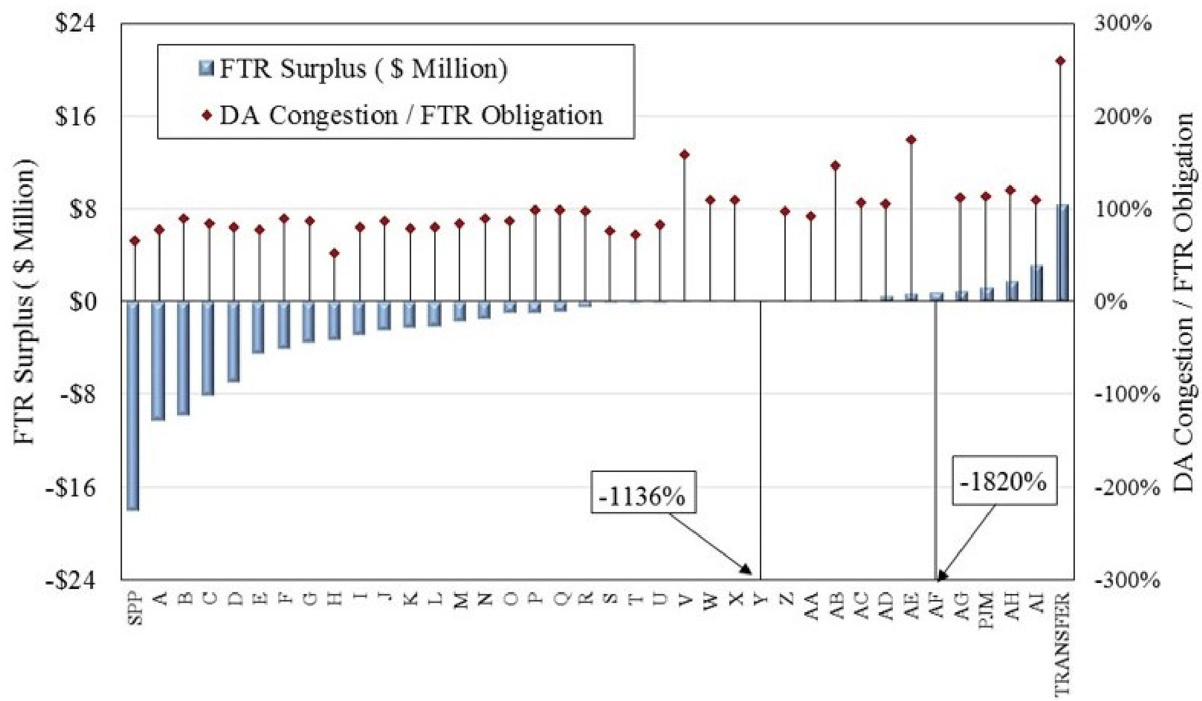
During each month, MISO will fund FTRs by applying surplus revenues from overfunded hours *pro rata* to shortfalls in other hours. Monthly congestion revenue surpluses accumulate until the end of the year, when they are prorated to reduce any remaining FTR shortfalls. MISO has continued to work to improve the FTR and ARR allocation processes.

Figure A79: FTR Funding by Type of Constraint and Control Area

At an aggregate level, MISO's FTRs experienced a shortfall in 2019. 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 Local Balancing Authority (LBA) can illuminate any potential cost-shifting that may be occurring among participants.

Figure A79 shows the monthly FTR surpluses and shortfalls (in both dollars and percentage terms) by LBA for 2019. The LBAs are masked with sequential letters. The constraints in each LBA include all internal and MISO-coordinated M2M constraints. External M2M constraints are summarized by the coordinating RTO. The RDT constraint and external constraints that impact transfers between the MISO South and MISO Midwest are shown as "Transfer" constraints. Other external TLR constraints are categorized as Non-MISO.

Figure A79: FTR Funding by Type of Constraint and Control Area
2019



C. Balancing Congestion Revenues

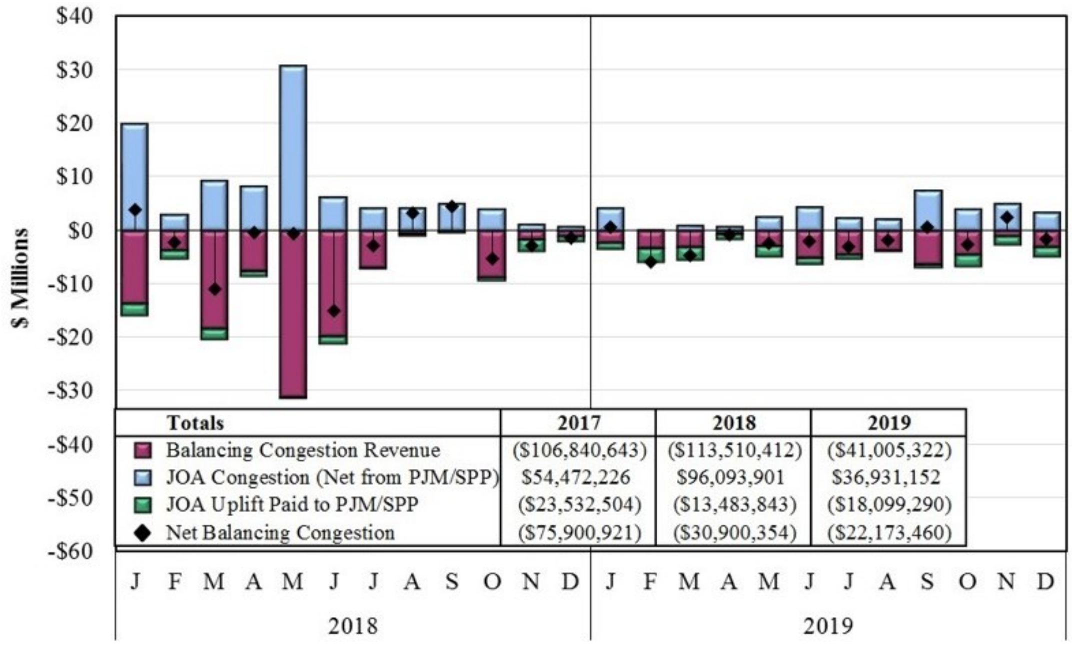
Balancing congestion revenues are congestion collections in the real-time market based on deviations from day-ahead congestion outcomes. The magnitude of balancing revenues should be small if the day-ahead market accurately forecasts the real-time network capabilities. However, balancing congestion revenue shortfalls can be large and result in substantial costs to customers if the day-ahead model is not fully consistent with the real-time network topology.

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 negative balancing congestion costs. Failure to model the constraint can allow participants to schedule more day-ahead flows over the constraint than are possible in real time. The costs to "buy back" the day-ahead flows, or balancing congestion costs, must be collected through an uplift charge to MISO's customers.

Figure A80: Balancing Congestion Costs

To understand balancing congestion revenues, Figure A80 shows these amounts disaggregated into (1) the real-time congestion revenues (costs) collected by having to increase (or reducing) 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). 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 A80: Balancing Congestion Costs
2017–2019



D. Key Congestion Management Issues

Given that MISO generally experiences between $1 and $1.5 billion in real-time congestion each year, reform that can improve the efficiency of its congestion management can deliver sizable savings. Some of these opportunities are discussed later in the discussion of M2M coordination. This subsection identifies two key opportunities to improve the management of congestion more broadly.

Modifying GSF Cutoffs for Congestion Management

A generation shift factor (GSF) indicates how changes in net injections at a given node will impact flows on the constraint. The GSF cutoff is a GSF level below which MISO's dispatch software assumes a generator or load's effect on a constraint is zero. MISO employs a GSF cutoff of 1.5 percent to reduce the complexity and solution time of its market optimization models, preventing electrically distant generators from being re-dispatched to manage congestion. The flows created by these generators and loads are unpriced and treated as loop flow for purposes of market settlements.

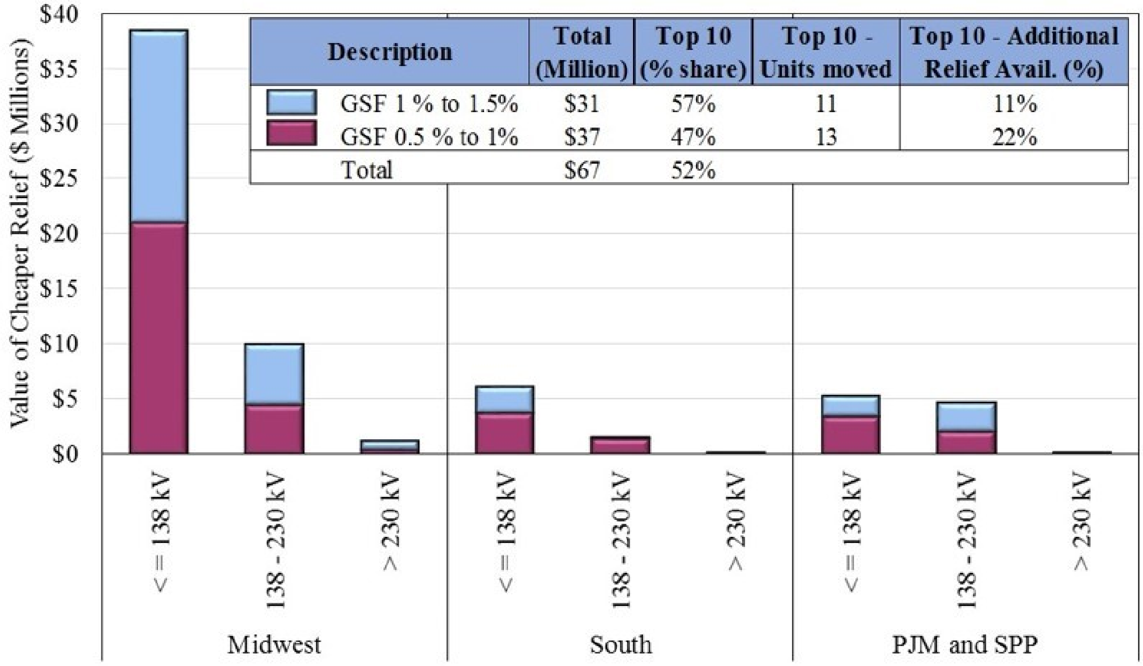
While we believe that the use of the 1.5 percent GSF cutoff is generally reasonable, it forecloses valuable congestion relief on some constraints and can adversely affect reliability. Additionally, the RTOs engage in M2M settlements based on all market flows (down to a zero GSF level). Hence, the GSF cutoff can prevent MISO from efficiently reducing its market flows and raise the resulting M2M settlement costs. Finally, the FTR markets do not employ a GSF cutoff and this inconsistency can lead to FTR surpluses and shortfalls.

Figure A81 and Figure A82: Value of Additional Available Relief

To evaluate the effects of employing a lower GSF cutoff, we recalculated GSFs down to 0.5 percent for all market days in 2019. Active real-time transmission constraints were mapped to the day-ahead GSFs (although we removed from our analysis binding periods when significant differences existed between the day-ahead and real-time constraints). This information was used to calculate the additional economic relief available from online dispatchable units and offline fast start resources with GSFs between 0.5 and 1.5 percent. We summarize our results by voltage class and region in Figure A81 below.

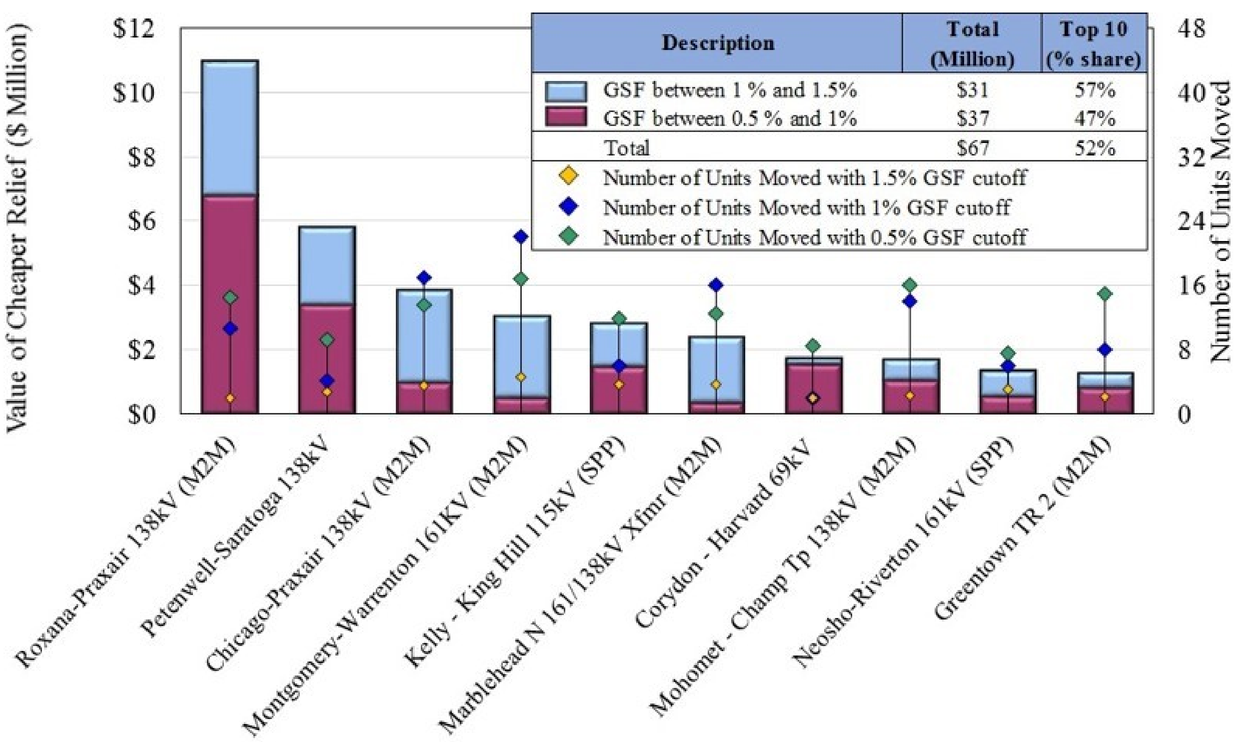
We calculate the value of the additional relief by multiplying the shadow price by the relief capability on the constraint that is available at a cost less than the shadow price of the constraint. In the table insert, we indicate the incremental value of relief gained by reducing the cutoff from 1.5 percent to 1 percent and separately the additional relief by further lowering the GSF cutoff to 0.5 percent. The three columns on the right indicate the percentage of additional relief that pertains to the top 10 constraints that would be affected by this change, how many additional units would move on average for those constraints, and the average percentage of total additional relief available. In Figure A82, we illustrate the top 10 constraints that would be most affected by this recommended change.

Figure A81: Value of Additional Available Relief
2019



Description	Total (Million)	Top 10 (% share)	Top 10 - Units moved	Top 10 - Additional Relief Avail. (%)
GSF 1 % to 1.5%	$31	57%	11	11%
GSF 0.5 % to 1%	$37	47%	13	22%
Total	$67	52%		

Figure A82: Value of Additional Available Relief
2019, Top 10 Constraints



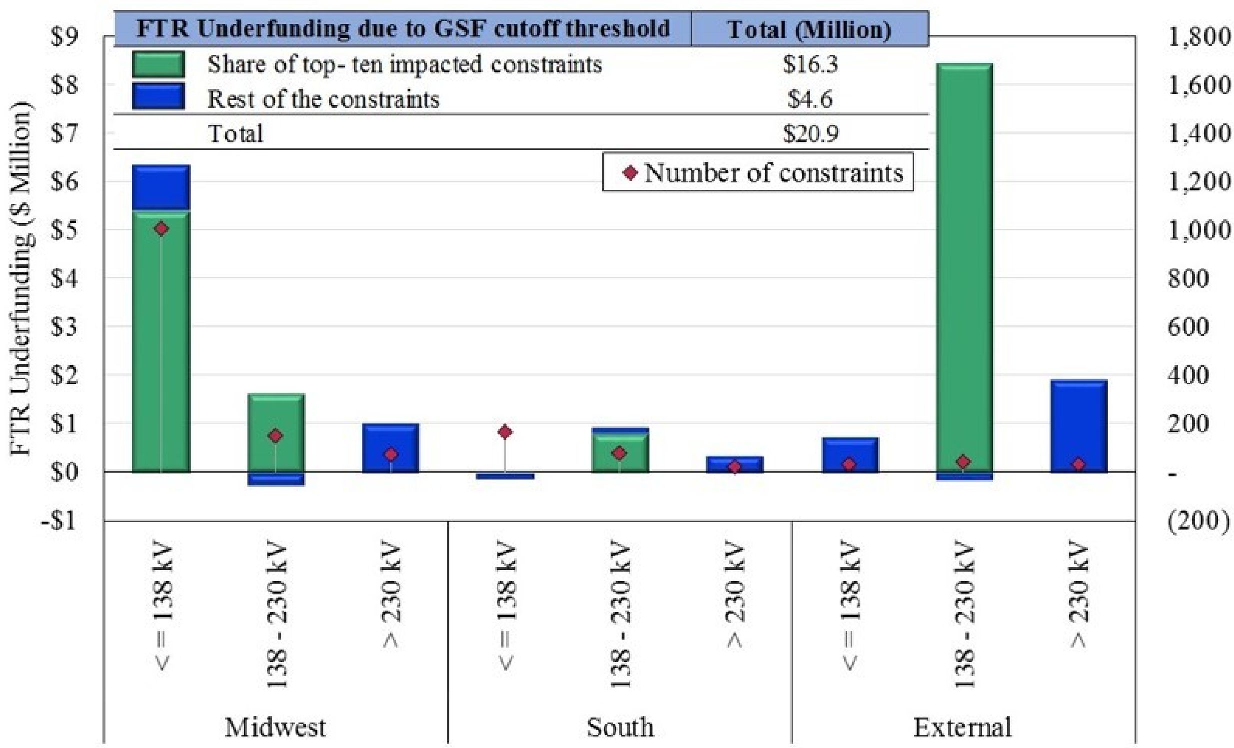
Description	Total (Million)	Top 10 (% share)
GSF between 1 % and 1.5%	$31	57%
GSF between 0.5 % and 1%	$37	47%
Total	$67	52%
Number of Units Moved with 1.5% GSF cutoff		
Number of Units Moved with 1% GSF cutoff		
Number of Units Moved with 0.5% GSF cutoff		

Figure A83: FTR Underfunding Due to GSF Cutoff Threshold

In Figure A83 below, we calculate the FTR underfunding value that was due to the 1.5 percent GSF cutoff threshold in the day-ahead market by multiplying the congestion component of the constraints at the affected nodes (nodes with GSF values between 0.5 and 1.5 percent) by the corresponding FTR volumes that were sold in the FTR auction. No GSF cutoff is employed for FTRs in the FTR auctions, so the FTR volumes tend to be higher than the revenues collected in the day-ahead market.

We show the FTR underfunding by region and constraint voltage class category. The green column represents the top 10 most impacted constraints, whereas the blue column represents all other constraints. In the table insert, we indicate the FTR underfunding that pertains to the top 10 constraints that would be affected by this change in comparison to the rest of the constraints.

Figure A83: FTR Underfunding Due to GSF Cutoff Threshold
2019



Effects of Outage Coordination on Transmission Congestion

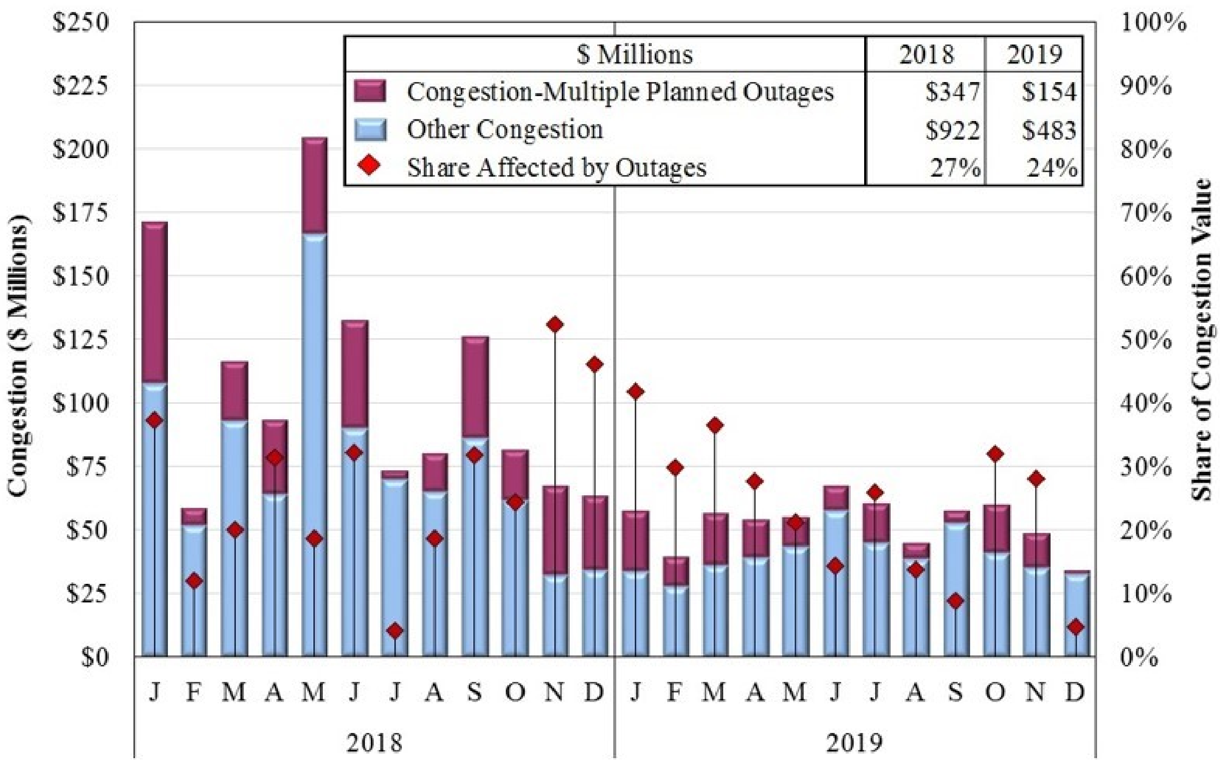
Generators take planned outages to conduct periodic maintenance, to evaluate or diagnose operating issues, and to upgrade or repair various systems. Similarly, transmission operators conduct periodic planned maintenance on transmission facilities, which generally reduces the transmission capability of the system. MISO evaluates only the reliability effects of the planned outages, including conducting contingency and stability studies on planned outages.

Participants tend to consolidate planned outages in the spring and fall shoulder-load months, assuming opportunity costs are lower by 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 schedule 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 A84: Congestion Affected by Multiple Planned Generation Outages

Figure A84 provides a high-level evaluation of how uncoordinated planned outages may affect congestion. It shows the real-time congestion value incurred from January 2018 through December 2019. We identify the portion of the congestion on constraints substantially impacted by two or more planned generation 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 concurrent planned generation outages. The diamonds indicate the percentage share of congestion that was due to concurrent planned generation outages.

Figure A84: Congestion Affected by Multiple Planned Generation Outages
2018–2019



E. Transmission Ratings and Constraint Limits

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 assumptions used for rating the facilities, additional power flows can be accommodated.[18] Therefore, if transmission owners develop and submit Ambient Adjusted Ratings (AARs) for temperature, they would allow MISO to operate to higher transmission limits and achieve substantial production costs savings. Most transmission owners do not currently provide AARs.

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.[19] However, we have identified some transmission owners that provide only normal ratings for most facilities.

In 2015, MISO began a pilot program to employ temperature-adjusted, short-term emergency ratings on several key facilities operated by Entergy. Over time, the program has expanded to include additional Entergy facilities and has yielded clear benefits without causing reliability issues. Further expansion of the program to other transmission operators would generate considerable congestion management savings throughout MISO.

Estimated Benefits of Using AARs and STEs

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

Figure A85: Potential Value of Additional Transmission Capability

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 Continuous Current for different classes of transmission elements (e.g., Forced Air-Cooled Transformers and Transmission Lines). We used the most conservative class of permissible ratings increases under the Standard for the type of element (Line or Transformer). We then used the ambient temperatures prevailing in the transmission area to estimate the temperature-

18 In some areas where wind speed is a more important ambient factor than temperature, permissible ratings could be significantly impacted by the measured wind speed. We have not estimated benefits of improved ratings due to wind speed measurements or other factors that if measured could allow for a dynamic increase in ratings.

19 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 reliably accommodated for two to four hours). Because most constraints are contingency 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.

adjusted rating. We calculated the value of increasing the transmission limits by multiplying the increase in the temperature-adjusted limit by the real-time shadow price of the constraint.

To estimate the benefits of providing emergency ratings, we identified transmission elements whose normal and emergency ratings were identical. For these elements, we assumed that the short-term emergency rating would increase by 10 percent. This is a reasonable assumption given that the average emergency ratings, when provided by a transmission owner, are 9 to 17 percent higher for each facility type and voltage class combination.

Figure A85 shows the estimated benefits of increasing the incremental transmission capability that could be made available by consistently utilizing temperature-adjusted emergency ratings. The results are shown by month and region for the last two years.

Figure A85: Potential Value of Additional Transmission Capability
2018–2019

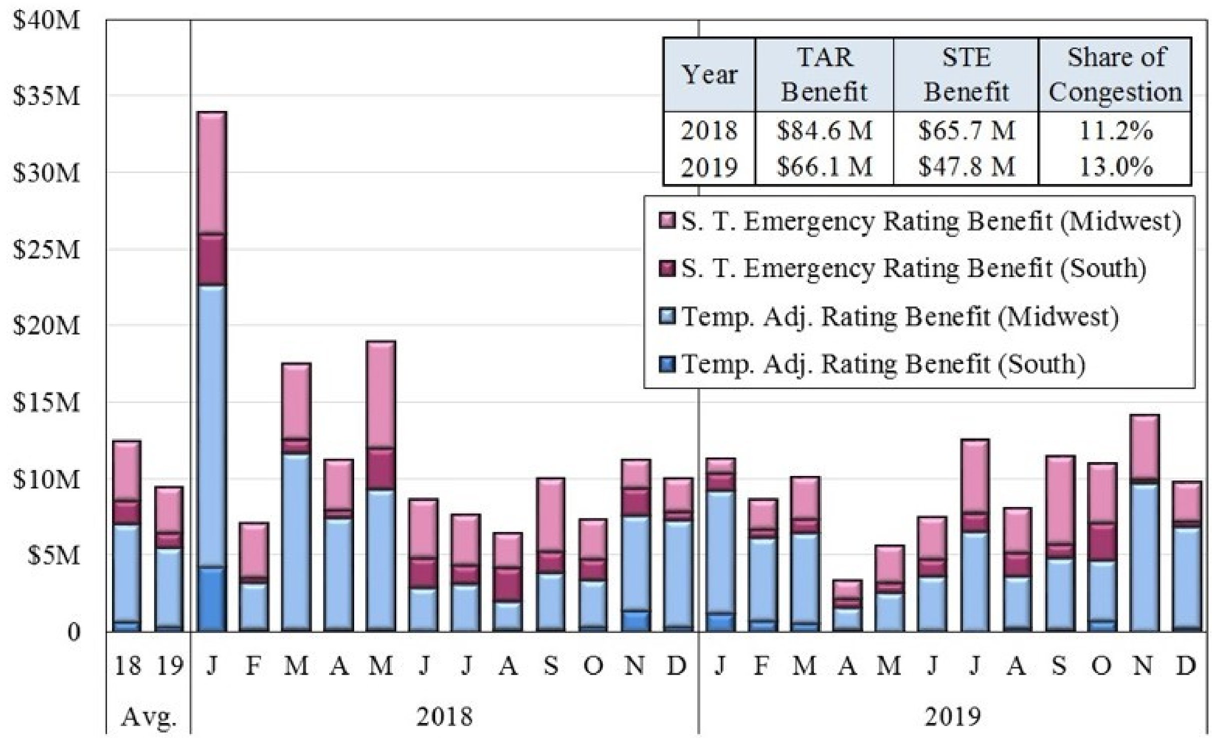
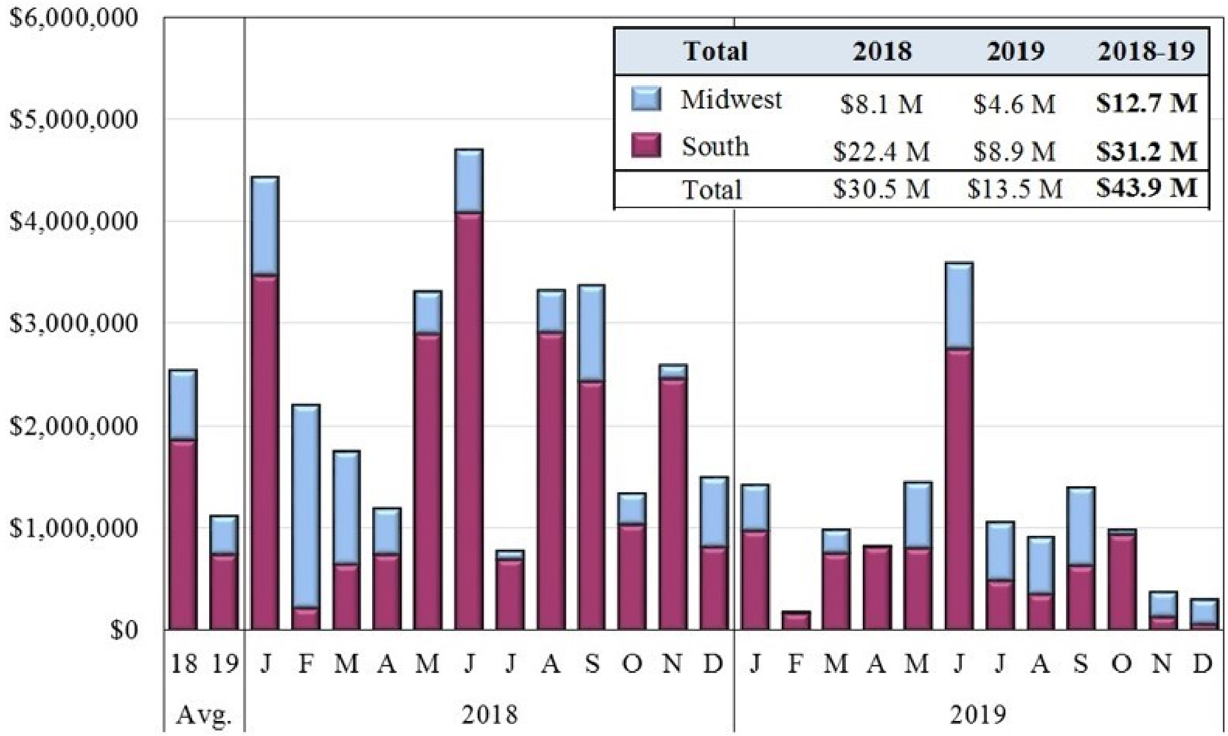


Figure A86: Estimated Actual Savings of AARs

Only two transmission owners currently utilize dynamic or temperature-adjusted ratings on a significant number of transmission facilities. We have estimated the savings that are currently being achieved by these transmission owners because they temperature-adjust a substantial number of their transmission facilities. Neither transmission owner adjusts their ratings on an hourly basis to maximize the benefits, but the benefits are still substantial. Figure A86 summarizes our estimates of the congestion savings by region that have actually been realized from these two transmission owners' use of temperature-adjusted ratings. The congestion savings are calculated as the product of the prevailing shadow price and the difference between the constraint limit (including the temperature adjustment) and the seasonal emergency rating. This methodology is a conservative estimate of savings, given that the shadow price would increase if the market were controlling to a lower, non-adjusted rating.

Figure A86: Estimated Actual Savings of AARs
2018–2019

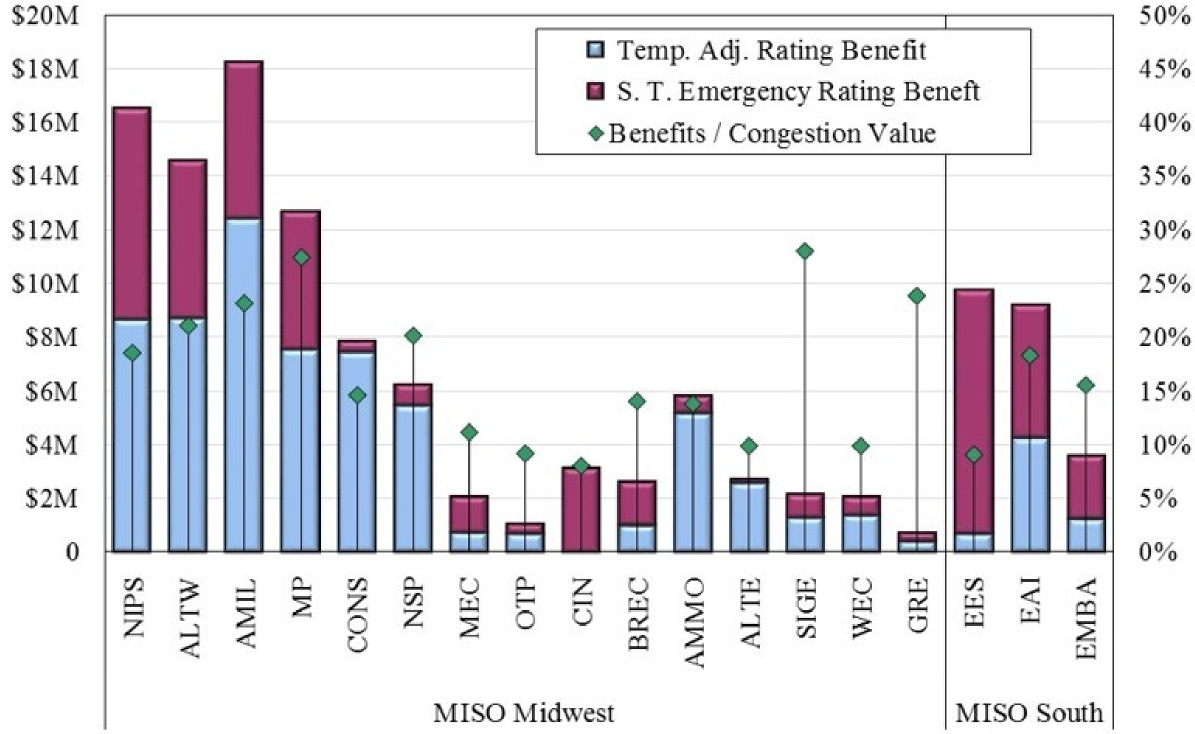


The adoption of temperature-adjusted ratings on the most congested facilities can achieve a large share of the potential benefits. For example, by selectively targeting 9 of its most congested transmission elements for the Entergy pilot program, Entergy was able to recover more than 50 percent of the potential benefits of applying temperature-adjusted limits across its entire network.

Figure A87: Area-Specific Savings Potential of Ratings Enhancement

Figure A87 organizes the potential savings by transmission area for the 24 most congested areas in MISO. The bars indicate the relative ambient temperature-adjusted and short-term emergency savings potential in each area. The drop lines show the number of transmission elements that would need to be temperature-adjusted in order to realize two-thirds of the potential benefits in each area.

Figure A87: Area-Specific Savings Potential of Ratings Enhancement
2018–2019



Recommended Improvements to Achieve the AAR Benefits

The estimated AAR benefits assume that each of the adjustable constraints were adjusted and the STE ratings were used for each constraint. In reality it takes some time to prepare MISO's systems to receive the dynamic adjustments in the ratings and for the TO to gather the information to calculate the adjustments. Currently, MISO can accept new constraints to be adjusted when it updates its transmission model once per quarter. Unfortunately, a sizable portion of the benefits are lost by not being able to activate a constraint more quickly when it begins to bind or when an outage causes a new constraint to bind. Additionally, MISO does not currently have a process to calculate AARs for use in its day-ahead market.

Therefore, we recommend that MISO improve the flexibility of its systems and process to enable more dynamic and accurate dynamic ratings. Improvements are recommended in three areas:

- *System flexibility*: Allow more rapid addition of facilities for which TOs can provide AARs or dynamic line ratings (reflecting factors other than temperature), including those identified in the outage coordination process.
- *Forecasted ratings*: New systems are needed to accept or calculate forecasted ratings for use in the day-ahead market, reliability assessments, and FTR markets.
- *Improving Validation and Transparency*: MISO should more actively validate transmission ratings, which will require new processes and the collection of key data (e.g., limiting elements, post-contingent actions, and times associated with the STEs).

Table A10: Available AAR Benefits from Enhanced System Flexibility

Table A10 below shows the total estimated benefits from AARs over the past two years and the share of the benefits that could be achieved under different scenarios, including:

- MISO's current practice of updating its network model quarterly and assuming TOs take at least one week to gather the information to begin submitting AARs after the constraint begins binding significantly;
- Shortening the model updates to once every two weeks, still assuming TOs require one week to begin submitting AARs; and
- Implementing AARs for new constraints instantaneously with no lag on the part of MISO or the TO.

We recognize that it may not be possible or cost-effective to adjust all constraints, so we assume that MISO and its TOs will only activate constraints to be adjusted when they have been binding significantly or are projected to bind. Therefore, we screened the monitoring element of a constraint if it failed any of the following congestion thresholds:

1. Congestion Value in the last two years to last four months > $1,000,000; or
2. Congestion Value in the last four months to last two months > $250,000; or
3. Congestion Value in the last month > $125,000; or
4. Congestion Value in the last week > $65,000.

Based on the following three factors, we calculate the AAR benefits that could be captured in the current process:

1. Date when the monitoring element failed the congestion threshold.
2. Time granularity of the MISO model update such that AARs could be used on a monitoring element – Quarterly, Bi-weekly, or continuous.
3. Time needed for the TO to begin providing the AARs instead of a static rating after the monitoring element failed the congestion threshold – one week and no lag.

The congestion thresholds are backward-looking, but AAR benefits are forward-looking. Once a monitoring element fails the congestion thresholds, we can capture the AAR benefits from the next model update after incorporating the time-lag associated with convincing a TO to submit an AAR for their transmission element.

Table A10: Available AAR Benefits from Enhanced System Flexibility

Additional Benefits from System Flexibility	AAR Benefits ($ Millions)	Incremental AAR Benefits ($ Millions)	% of Total Benefits
Total AAR Benefits (2018–2019)	**$151**		
Current System - Quarterly Updates	$66		44%
Bi-Weekly Model Update - 1 Week Lag	$104	$37	69%
Continuous Updates with No Lag	$142	$39	95%

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

The separate JOAs between MISO and PJM and SPP establish M2M processes for coordinating congestion management of designated transmission constraints on each of the RTOs' systems. The objectives of these processes are to pursue reliable congestion management, efficient generation re-dispatch on these constraints, and consistent prices between the markets.

The monitoring RTO (MRTO) is the RTO responsible for the security and monitoring of the physical flow on the flowgate. When a M2M constraint is activated, the MRTO provides its shadow price to the counterparty market along with the requested relief (i.e., the desired reduction in flow). The shadow price measures the MRTO'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 (NMRTO) 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 marginal cost up to the MRTO's shadow price. From a settlement perspective, each market is allocated Firm Flow Entitlement (FFE) on each of the M2M constraints. Settlements between the RTOs are based on their flows over the constraint relative to their FFEs.

Figure A88 and Figure A89: PJM and SPP Market-to-Market Events

Figure A88 and Figure A89 show the total number of M2M constraint-hours coordinated with PJM and SPP, respectively. The top panel shows flowgates coordinated by PJM/SPP, while the bottom panel shows MISO flowgates. The darker-shaded bars show the number of peak hours when M2M flowgates were active. The lighter shade shows the total for off-peak hours.

Figure A88: Market-to-Market Events: MISO and PJM
2018–2019

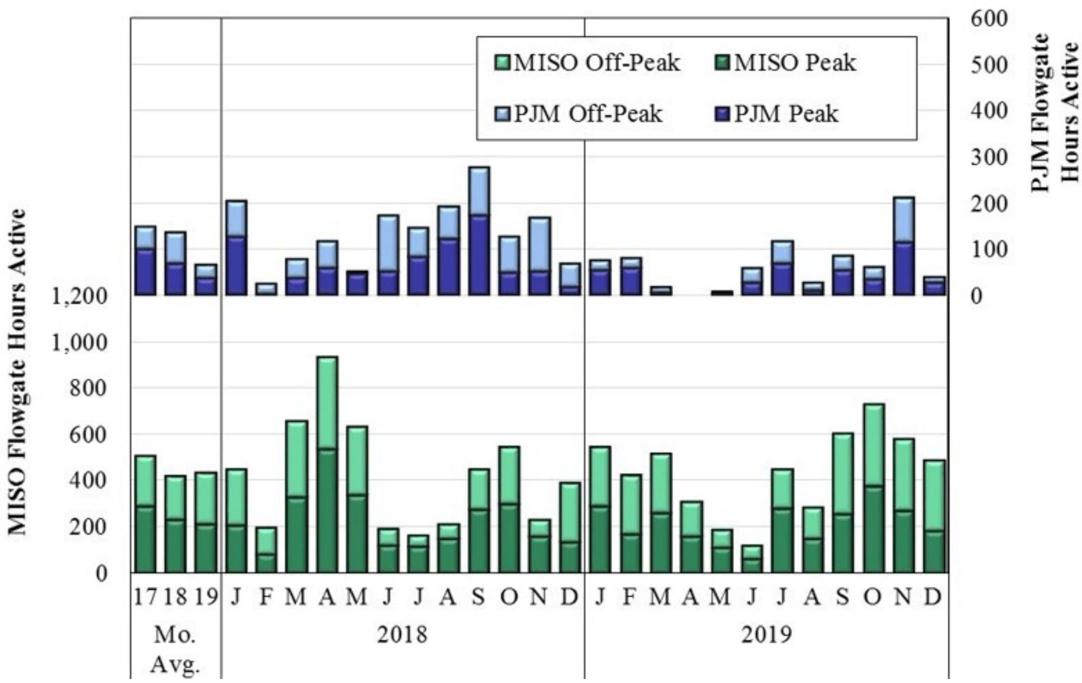


Figure A89: Market-to-Market Events: MISO and SPP
2018–2019

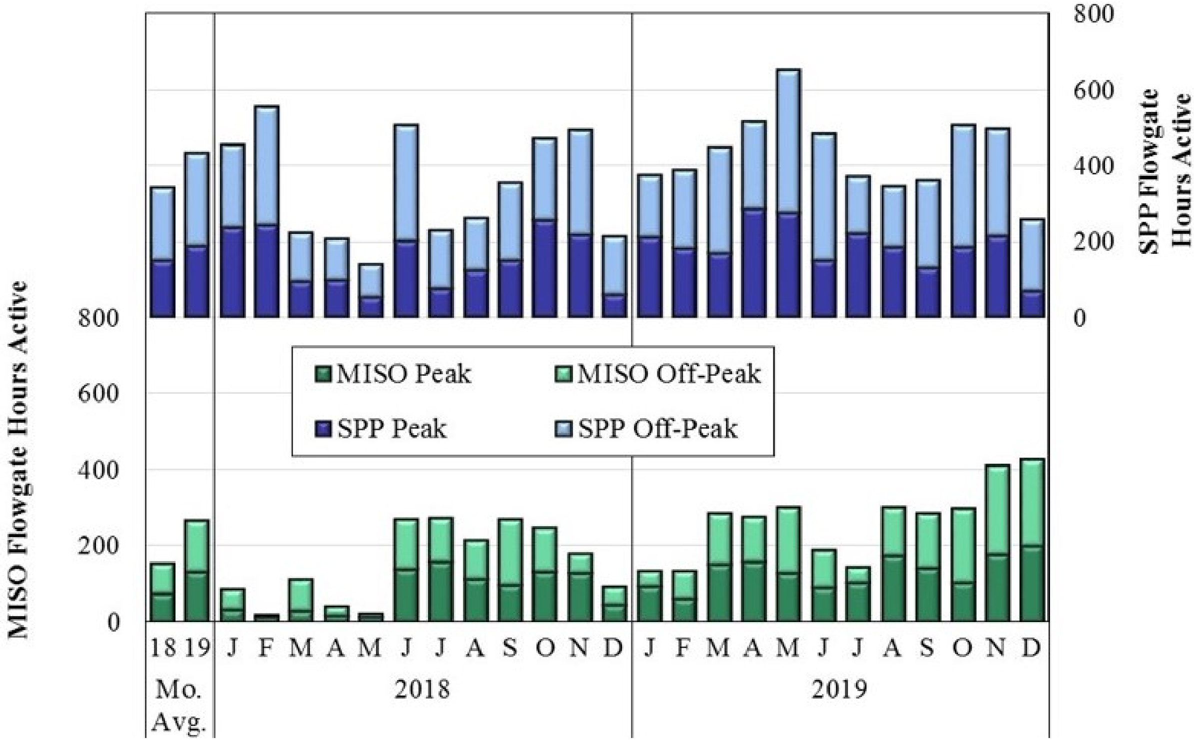
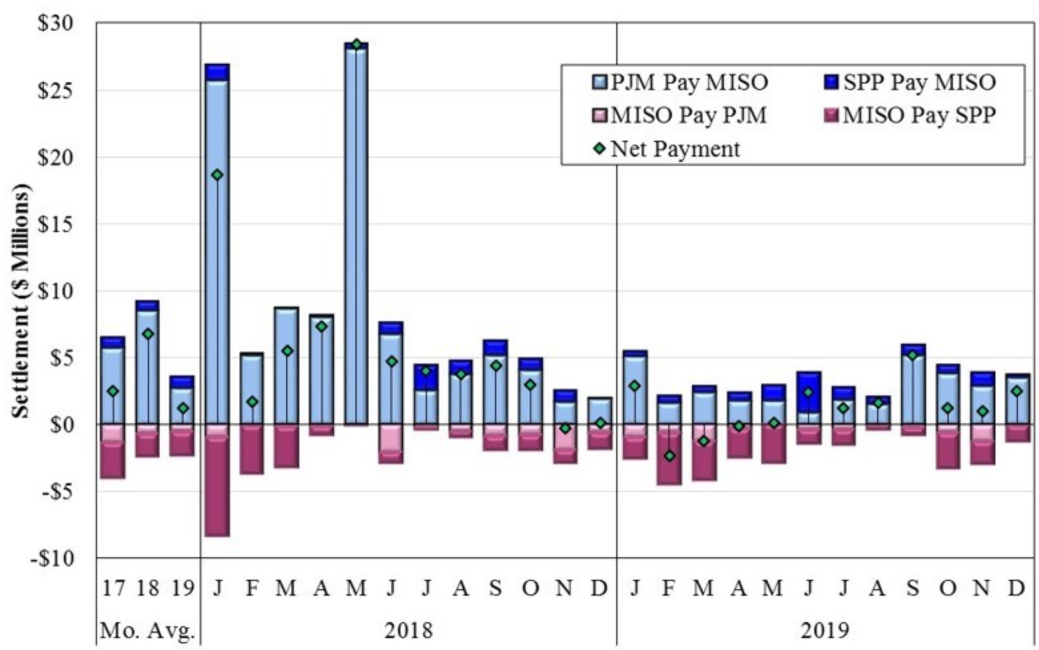


Figure A90: Market-to-Market Settlements

Figure A90 summarizes MISO's financial settlement of M2M coordination with SPP and PJM.

Figure A90: Market-to-Market Settlements
2018–2019



These settlements are based on the NMRTO's actual market flow compared to its FFE. If the NMRTO'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 NMRTO's flow exceeds its FFE, then it owes the cost of the MRTO'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.

Table A11: Real-Time Congestion on Constraints Affected by Market-to-Market Issues

We evaluate the effectiveness of the M2M process by tracking the convergence of the shadow prices of M2M constraints in each market. When the process is working well, the NMRTO will continue to provide additional relief until the marginal cost of its relief (its shadow price) is equal to the marginal cost of the MRTO's relief. Our analysis shows that for the most frequently binding M2M constraints, the M2M process generally contributes to shadow price convergence over time and substantially lowers the MRTO's shadow price after the M2M process is initiated.

Convergence is much less reliable in the day-ahead market, but MISO and PJM implemented our recommendation to coordinate FFE levels in the day-ahead market in late January 2016. The RTOs have not actively utilized this process, so it has not had substantial effects. However, we will continue to evaluate the effectiveness of this process in improving day-ahead market outcomes. SPP has not agreed to implement a similar day-ahead coordination procedure.

While the M2M process improves efficiency overall, there are three issues that can reduce the efficiency and effectiveness of coordination:

- Failure to test constraints that would likely qualify to be M2M constraints;
- Delays in testing constraints after they start binding to determine whether they should be classified as M2M; and
- Delays in activating M2M constraints when they are binding.

These issues can result in a failure to coordinate M2M congestion, causing inefficient dispatch and inappropriately high congestion costs. Serious equity concerns can also arise if the external area exceeds its flow entitlement on the constraint without compensating the MRTO. Hence, we identify constraints that were not coordinated because of these issues. These screens identified 33 non-M2M constraints that should have been coordinated as M2M with either PJM or SPP. We then quantified the congestion on these constraints, which is shown in Table A11.

Our screening accounts for the time required to identify, test, and activate a M2M:

- *Never Classified as M2M.* Most of these constraints were not classified because testing was not requested by MISO. To account for transitory constraints that would not warrant testing, we exclude constraints that only bound on one day during the year.
- *Delay in Testing*. We removed the first two days a constraint bound in real time to account for the expected time it takes to perform the tests.
- *Delay in Activation*. We did not remove any days if the constraint had been previously identified as M2M.

Table A11: Real-Time Congestion on Constraints Affected by Market-to-Market Issues
2017–2019

Item Description	PJM ($ Millions)			SPP ($ Millions)			Total ($ Millions)		
	2017	2018	2019	2017	2018	2019	2017	2018	2019
Never classified as M2M	$85	$5	$1	$109	$15	$14	$194	$21	$15
M2M Testing Delay	$19	$22	$8	$11	$8	$10	$31	$29	$17
M2M Activation Delay	$6	$11	$1	$12	$7	$1	$18	$18	$2
Total	$110	$38	$10	$133	$30	$25	$243	$68	$34

Figure A91 and Figure A92: 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 five frequently active M2M constraints coordinated by PJM and MISO, respectively. The analysis shows the extent to which the RTOs' shadow prices on these 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 MRTO that was logged prior to the first response from the NMRTO; and
2. Post-activation shadow prices for both the MRTO and NMRTO, 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 NMRTO provides relief by limiting flows in its real-time dispatch.

Figure A91: PJM Market-to-Market Constraints with MISO
2019

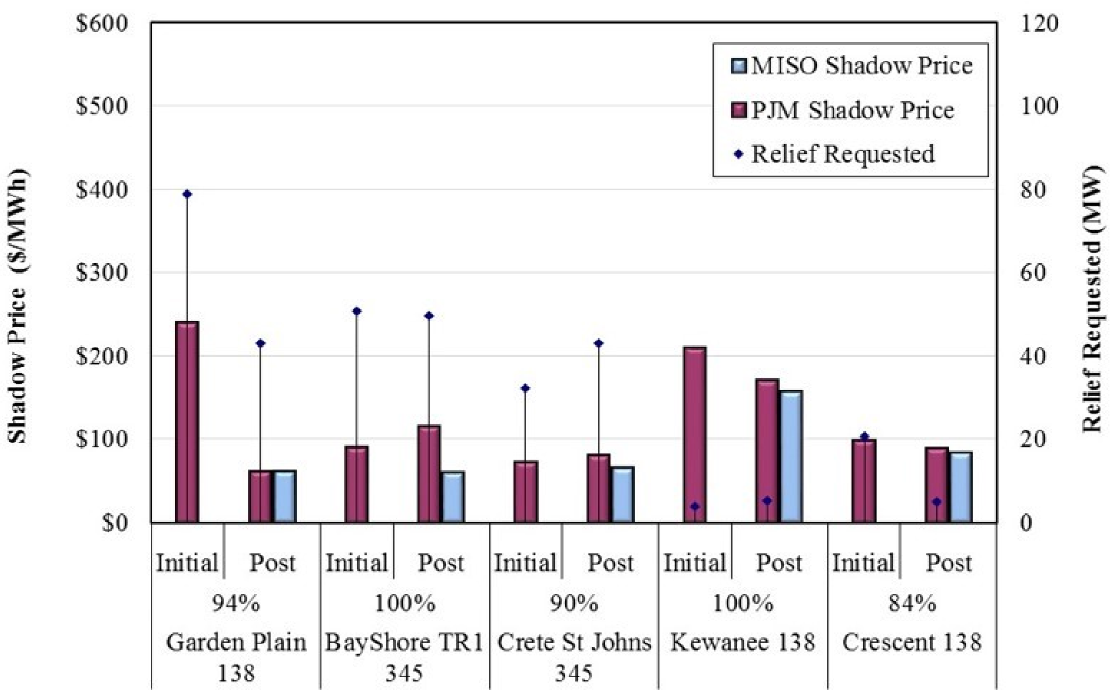


Figure A92: MISO Market-to-Market Constraints with PJM
2019

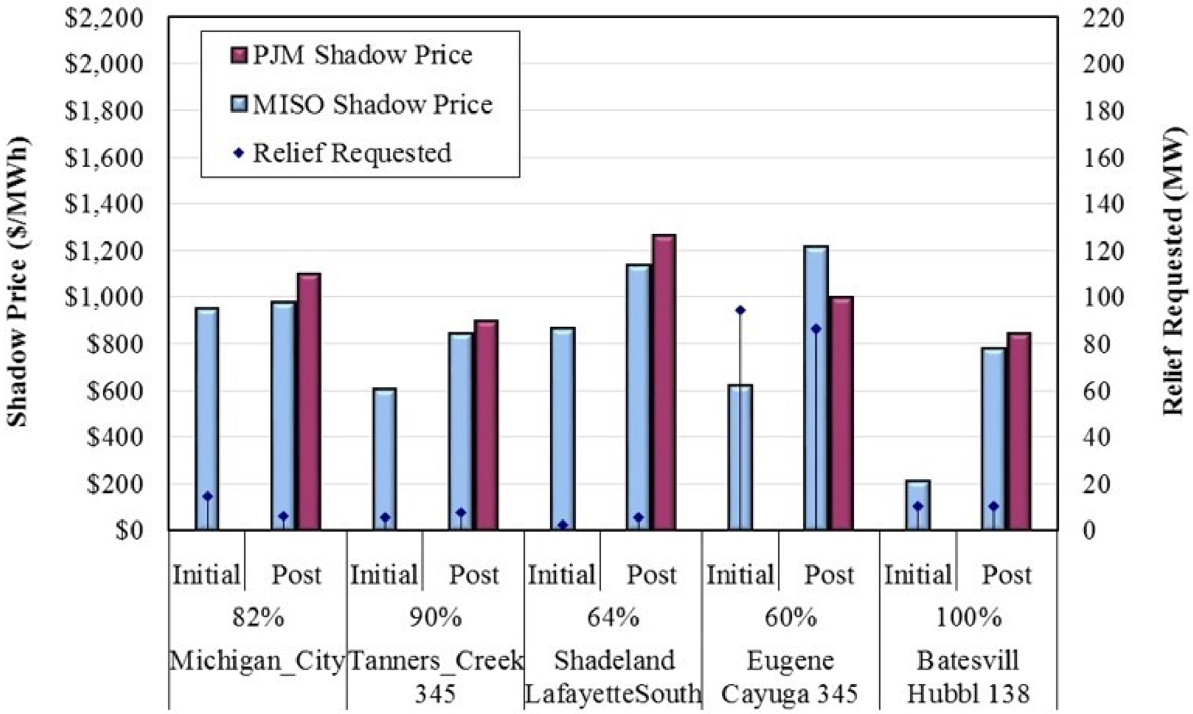


Figure A93 and Figure A94: Market-to-Market Outcomes with SPP

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 the neighboring RTO has the most effective relief for the constraint. In late June 2017, MISO and SPP executed a Memorandum of Understanding (MOU), and the RTOs reached agreement on the most important aspects of coordination under the JOA. The MOU should help the RTOs avoid future issues like those that occurred in 2015.

The next two figures examine five frequently coordinated M2M constraints between 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 show the same results for the constraints coordinated with SPP as the prior two figures showed for the constraints coordinated with PJM.

Figure A93: SPP Market-to-Market Constraints with MISO
2019

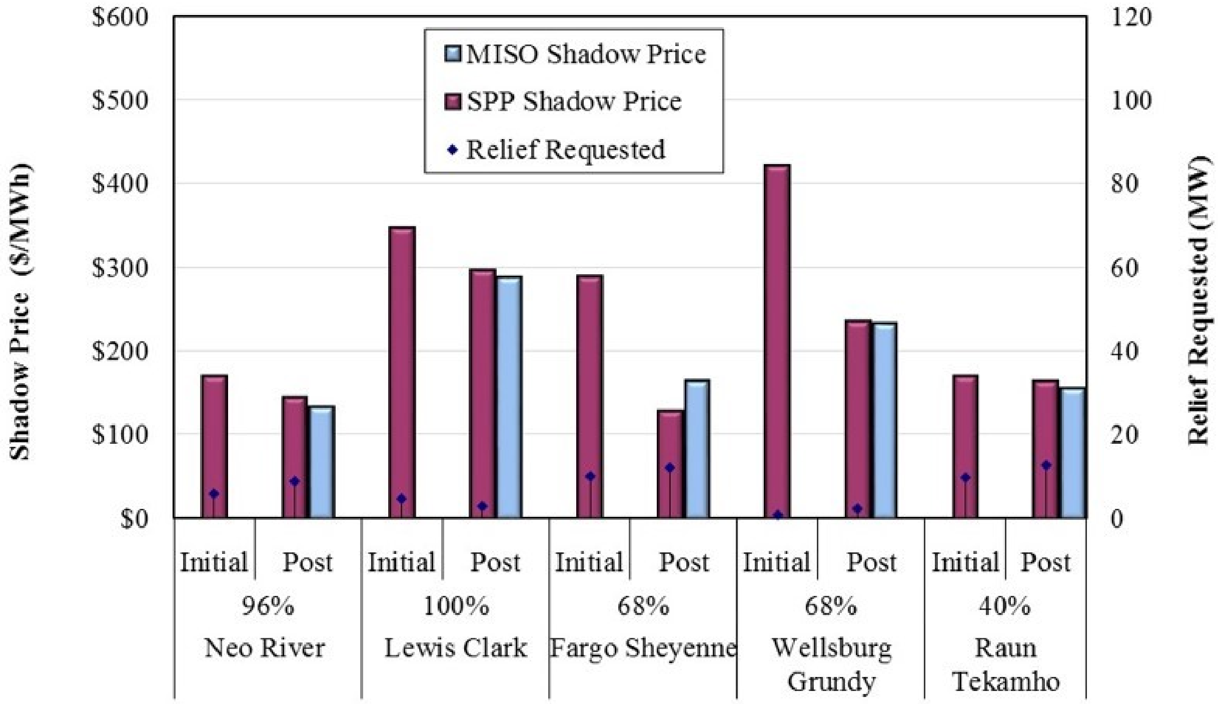


Figure A94: MISO Market-to-Market Constraints with SPP
2019

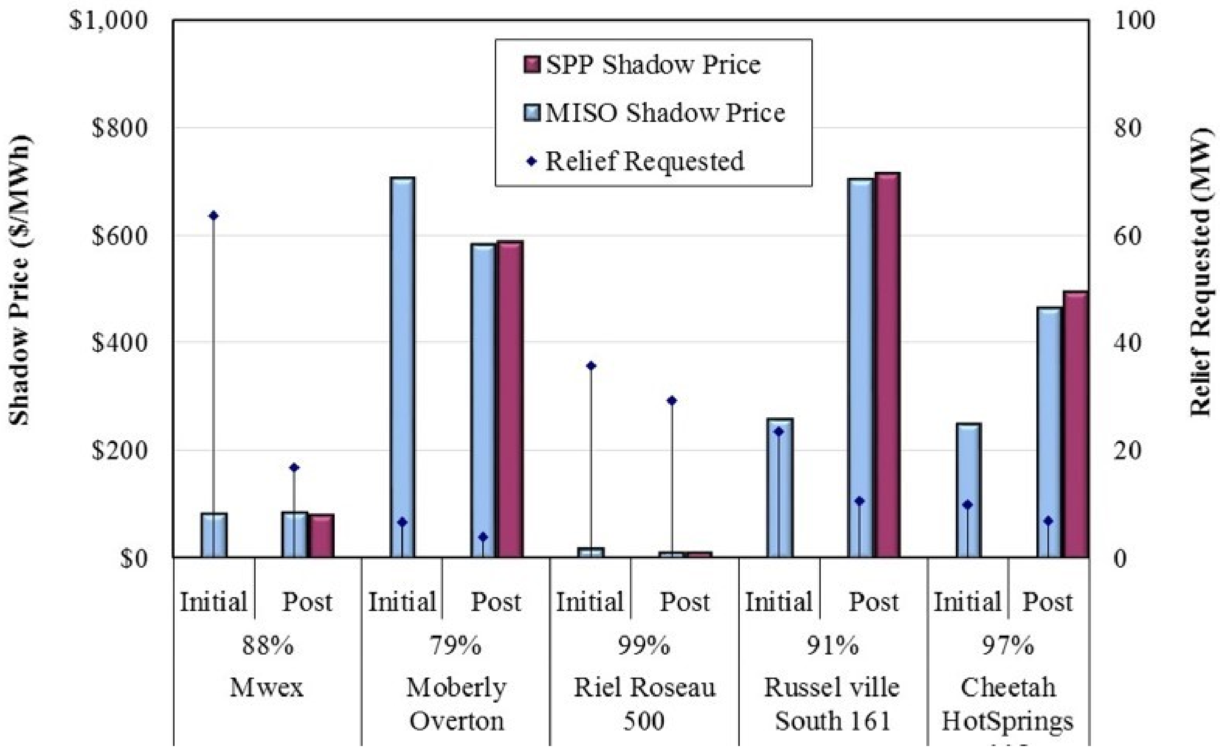
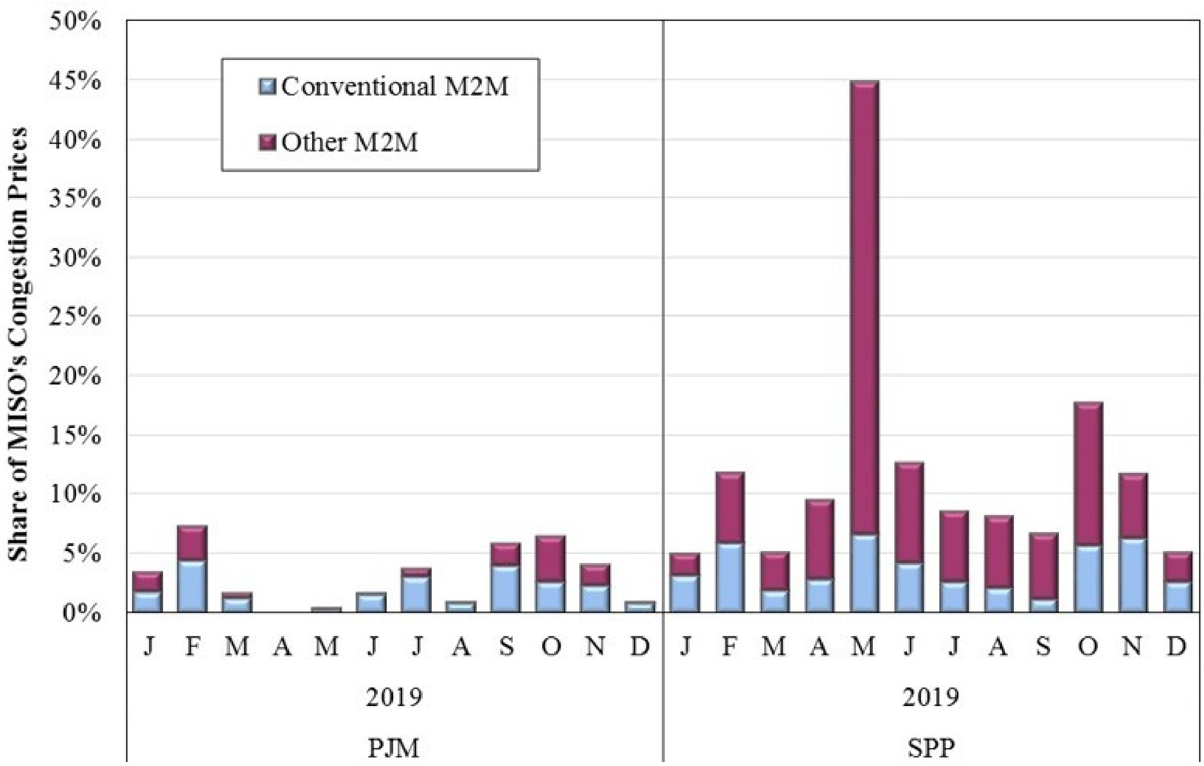


Figure A95: Congestion Costs on PJM and SPP Flowgates

Because MISO market flows comprise a small share of their physical capability, external M2M constraints account for a small share of congestion value in MISO's market. However, these external constraints do have significant impacts on locational pricing and market revenues for MISO generators. Figure A95 details the contribution to congestion pricing 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 and SPP constraints coordinated through the M2M process.

The pricing effects in the figure are sub-divided into conventional and non-conventional M2M procedures (i.e., using overrides, safe operating modes, TLRs, or other processes to manage the congestion). Although often justified, these non-conventional means 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 A95: Congestion Costs on PJM and SPP Flowgates
2019



Market-to-Market Relief Software

When a M2M constraint binds, the coordination is initiated by the MRTO that is responsible for managing the constraint. The MRTO coordinates management of the constraint with the NMRTO by sending its marginal cost of providing relief on the constraint (i.e., the "shadow price") and a the quantity of relief it would like the NMRTO to provide (at a cost not to exceed the shadow price).

Hence, a key component of successful M2M coordination is optimizing the amount of relief that the MRTO requests from the NMRTO. If the request is too low, then the NMRTO will not provide all its economic relief, resulting in higher congestion costs and potentially higher settlement costs for the NMRTO. If the request is too high, it can result in congestion oscillation that can raise costs.

Table A12: Frequency of Substantial Relief Request Issues

Table A12 screens each of the intervals in which M2M coordination with SPP is active and categorizes the intervals when the relief request methodology produces requests that are unreasonably low, causing oscillation, or are excessively volatile. We identify relief requests as "undersized" if the MRTO's shadow price exceeds the NMRTO's shadow price by more than $100 over multiple intervals. Oscillation periods meet one of two conditions: a) a constraint unbinding after being violated in the prior ten minutes or b) the shadow price fluctuating from greater than $100 to $0 to greater than $100 over three consecutive intervals. Volatile relief request periods show a 5-minute request change that exceeds the greater of 10 MW and 3 percent of the transmission limit. This analysis excludes constraint intervals when coordination was switched to the NMRTO.[20]

Table A12: Frequency of Substantial Relief Request Issues

	MISO Flowgates		SPP Flowgates		All Flowgates	
	Intervals	Share	Intervals	Share	Intervals	Share
Total Coordinated Intervals	**13,857**	**100%**	**32,201**	**100%**	**46,058**	**100%**
Undersized Relief Request	149	1.1%	1,315	4.1%	1,464	3.2%
Oscillation	75	0.5%	1,590	4.9%	1,665	3.6%
Volatile Relief Request	2,529	18.3%	7,523	23.4%	10,052	21.8%
Intervals Exceeding Limit	**317**	**2.3%**	**6,133**	**19.0%**	**6,450**	**14.0%**

Market-to-Market Test Criteria Software

Identifying the constraints to coordinate is important to ensure both efficient and reliable coordination, to establish equitable settlements, and to improve the price signals in the NMRTO market. Currently, a constraint will be identified as a M2M constraint when the NMRTO has:

- a generator with a shift factor greater than 5 percent; or
- Market flows over the MRTO's constraint of greater than 25 percent of the total flows (SPP JOA) or 35 percent of the total flows (PJM JOA).

These two tests are not optimal in identifying constraints that would benefit from coordination because they do not consider the economic relief the NMRTO will likely have available. The single generator test is particularly questionable because it ignores the size and economics of the unit – this test does not ensure that the NMRTO has any economic relief.

20 In May 2020, we conducted a Seams Study on Market-to-Market Coordination with SPP for OMS-RSC. The study period was June 2018 through May 2019. The full study is available here: https://www.potomaceconomics.com/wp-content/uploads/2020/06/Seams-Study_MISO-IMM_M2M-Evaluation_Final.pdf

Figure A96: Share of the Relief from the MRTO

To illustrate this issue, Figure A96 evaluates the effectiveness of the coordination process by showing the share of economic relief from SPP and MISO for their respective M2M constraints binding from June 2018 through May 2019. This figure shows the portion of the total relief on the x-axis and the available economic relief on the y-axis that is held by the MRTO.[21] The size of the bubbles indicates the amount of congestion associated with each constraint, and the colors separately identify MISO and SPP constraints. Perfect convergence would cause the data points to lie on the dashed 45-degree line. However, even if the observations fall on this line, convergence may still be poor during some events or periods. When both percentages are very high, the expected value of coordinating the congestion management of the constraint is limited because the NMRTO has a very small share of the relief capability.

Figure A96: Share of the Relief from the MRTO

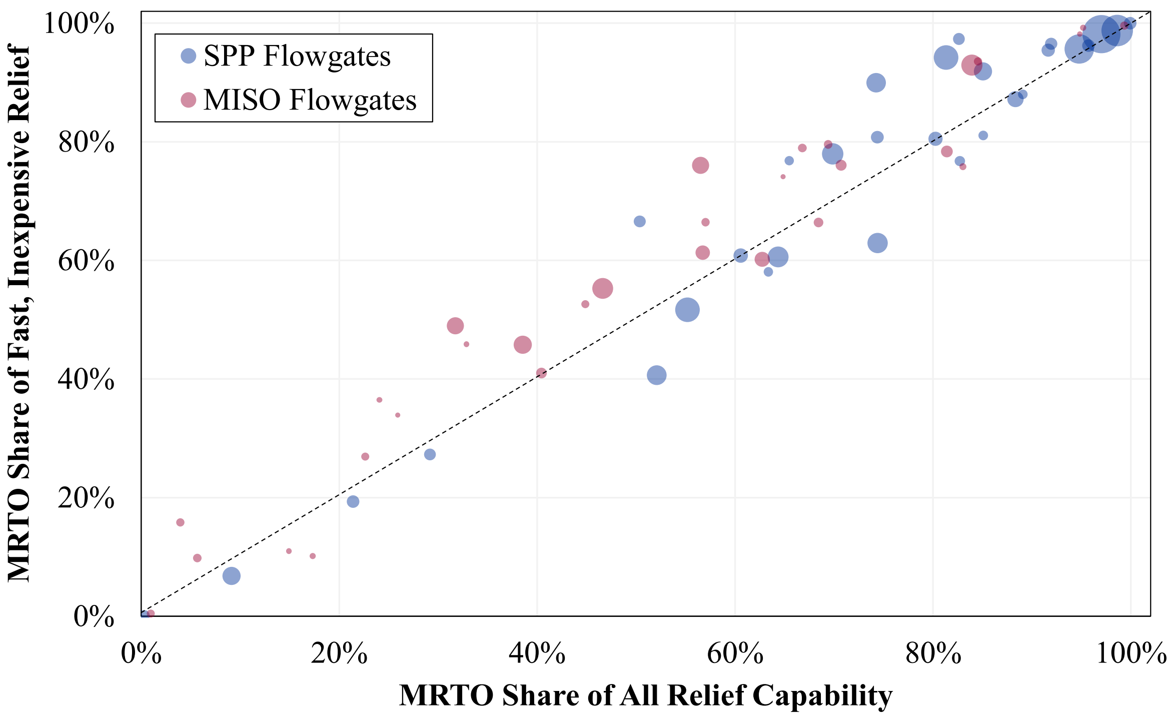
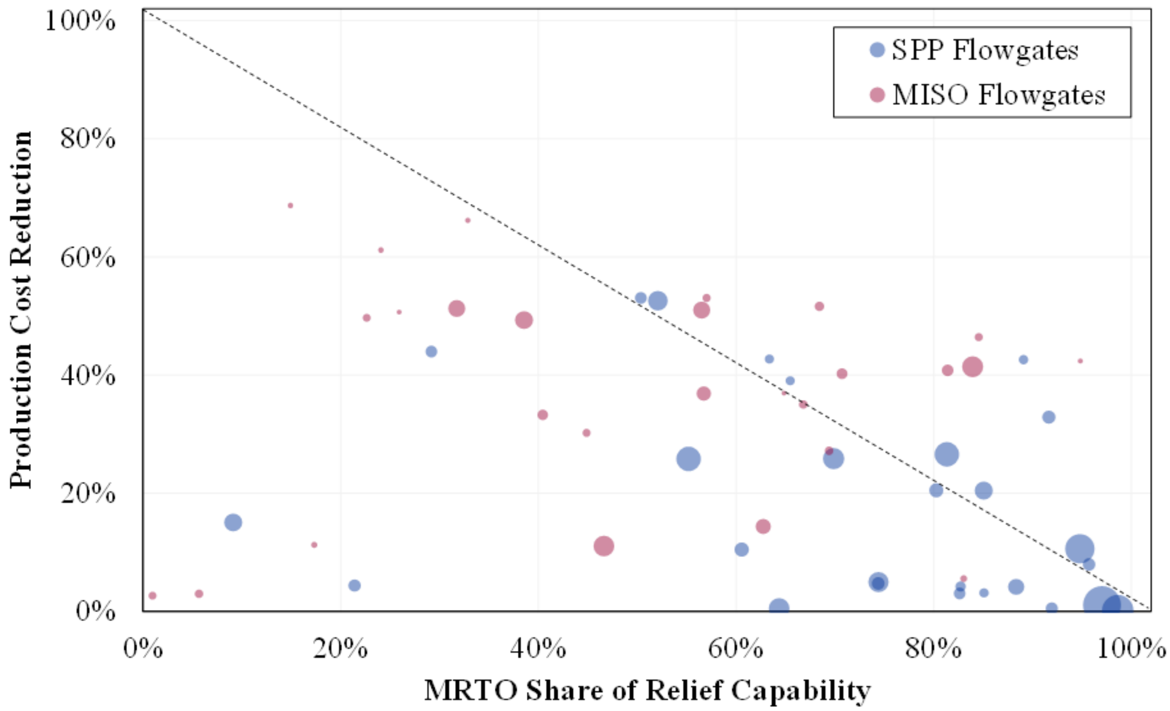


Figure A97: Production Cost Savings and Relief Distribution

To evaluate the value of these constraints being coordinated, Figure A97 shows the relationship between the MRTO's relief capability (as it rises to 100%, the NMRTO relief falls to 0%) and the production cost savings of coordinating the constraint. As before, the size of the bubbles indicates the amount of congestion associated with each constraint, and the colors separately identify MISO and SPP constraints.

21 Economic relief is categorized as any redispatch relief that could be provided within five-minutes time with a shadow price less than or equal to $200.

Figure A97: Production Cost Savings and Relief Distribution



G. Congestion on Other External Constraints

This subsection provides an analysis of congestion that occurs on external constraints located in adjacent systems that are not coordinated through the M2M processes. MISO incurs congestion on external constraints when a neighboring system calls a TLR for a constraint. 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. To provide the requested relief, MISO calculates its market flows before the TLR is called and sets a limit equal to the market flows less the requested relief. This process will be efficient only if the cost of providing the relief is less costly than the other system's cost to manage the flow on the constraint. Unfortunately, this has historically not been true. One concern is that the relief obligations are based on its forward flows, not MISO's net flows that may be lower than the forward flows because of counterflow on the constraint. Because the relief obligation is outsized, it is often very costly to provide the relief, and MISO's marginal cost of providing the relief is included in its LMPs.

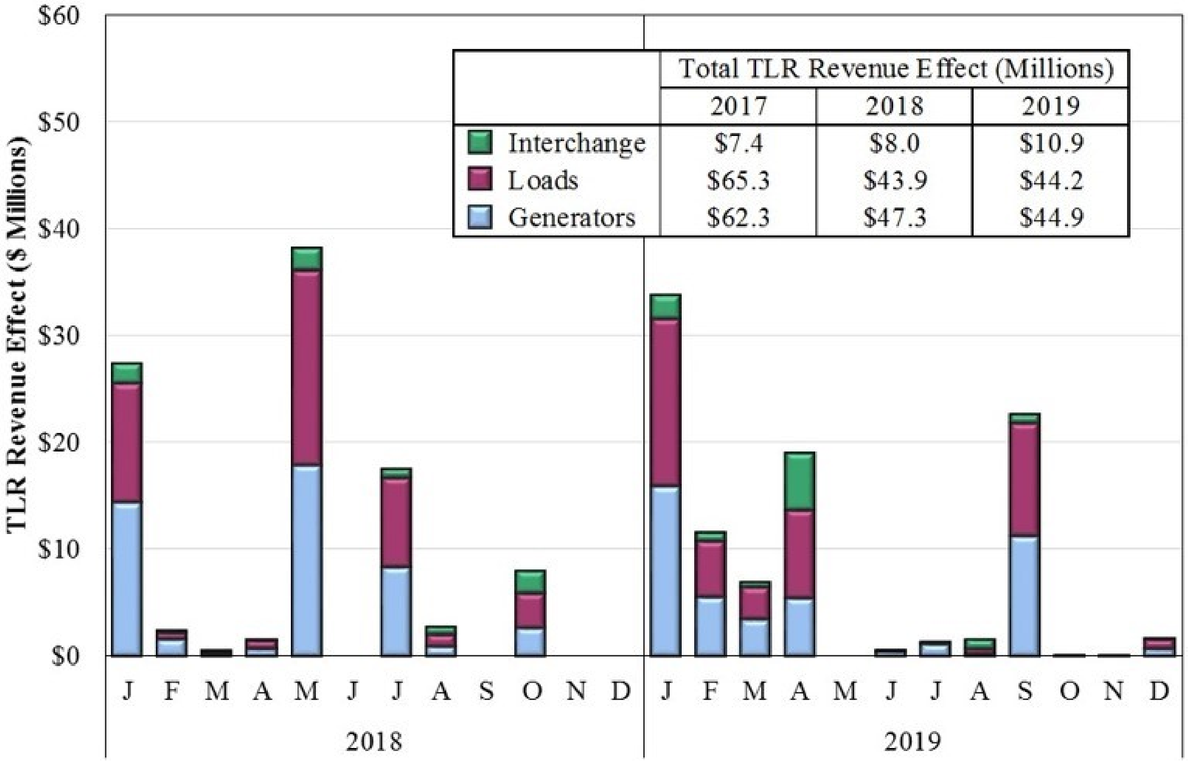
Figure A98: Real-Time Valuation Effect of TLR Constraints

Because external constraints can cause substantial changes in LMPs in MISO, we estimate these effects by calculating the increase in real-time payments by loads and the reduction in payments to generators caused by the external constraints.[22] Figure A98 shows increases and decreases in hourly revenues that result from binding TLR constraints. The reported congestion value for

22 External constraints also affect interface prices settlements, an issue that is further evaluated in Section VII.B.

these constraints is low because MISO's market flow on external flowgates is generally low or negative. Therefore, the reported congestion value masks the larger impact that these constraints have on MISO's dispatch and pricing.

Figure A98: Real-Time Valuation Effect of TLR Constraints
2018–2019



	Total TLR Revenue Effect (Millions)		
	2017	2018	2019
Interchange	$7.4	$8.0	$10.9
Loads	$65.3	$43.9	$44.2
Generators	$62.3	$47.3	$44.9

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)[23] to manage congestion caused in part by schedules and the dispatch activity of external entities.

Before energy markets were introduced in 2005, nearly all congestion management for MISO transmission facilities was accomplished through the TLR process. TLR is an Eastern Interconnection-wide process that allows Reliability Coordinators to obtain relief from external entities 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.

23 To implement TLR procedures on defined flowgates, Reliability Coordinators depend upon the IDC. The IDC provides Reliability Coordinators 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 Reliability Coordinators in the TLR process.

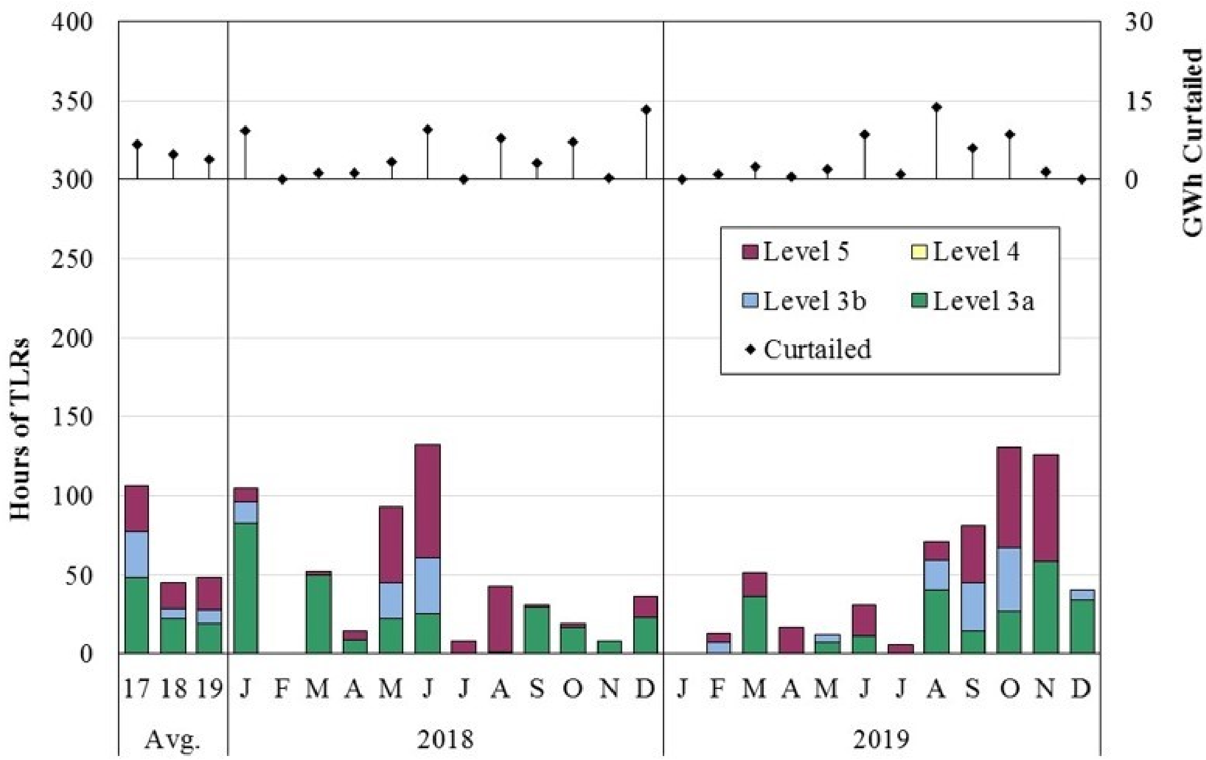
External entities not dispatched by MISO also contribute to total flows on MISO flowgates. If external transactions contribute more than five percent of the total flow on a MISO binding facility, MISO can invoke a TLR to ensure that these transactions are curtailed to reduce the flow over the constrained 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 A99 and Figure A100: Periodic TLR Activity

Figure A99 shows monthly TLR activity on MISO flowgates in 2018 and 2019. 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 A99: Periodic TLR Activity
2018–2019



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

- Level 3—Non-firm curtailments;[24]

24 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.

- Level 4—Commitment or re-dispatch of specific resources or other operating procedures to manage specific constraints; and
- Level 5—Curtailment of firm transactions.[25]

Figure A100 shows the total number of TLR hours aggregated by the Reliability Coordinator declaring the TLR.

Figure A100: TLR Activity by Reliability Coordinator
2018–2019

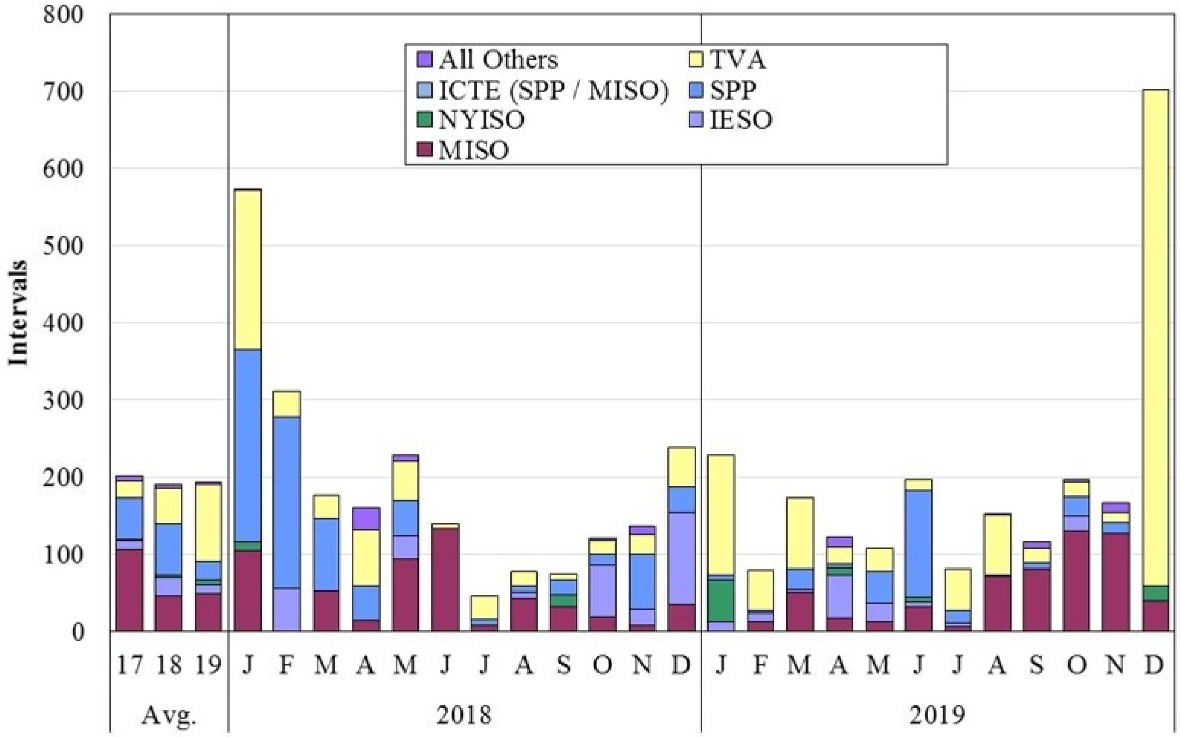


Table A13: Economic Congestion Relief from TVA Generators

Table A13 illustrates the potential savings that could be achieved by utilizing TVA generation to provide lower cost relief on constraints binding in MISO. Our analysis focuses on economic relief on two types of constraints:

- MISO internal constraints; and
- TVA constraints 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 shows the potential savings available through economic coordination.

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

Table A13: Economic Congestion Relief from TVA Generators
2019

Status	Total Congestion Value ($ Millions)	Re-dispatch Savings ($ Millions)
MISO Constraints	$131.0	$6.6
TVA (TLR) Constraints binding in MISO	$3.8	$1.3
Total	**$134.8**	**$7.9**

H. Congestion Manageability

MISO monitors the flows on all 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).[26]

While this is intended to reduce the flow on the constraint, some constraints can be difficult to manage if the available relief from 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 critical to system reliability (e.g., those that could lead to cascading outages) are operated more conservatively.

Figure A101: Constraint Manageability

The next set of figures depicts the manageability of internal and MISO-managed M2M constraints. Figure A101 shows how frequently-binding constraints were manageable and unmanageable in each month from 2018 to 2019.

26 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.

Figure A101: Constraint Manageability
2018–2019

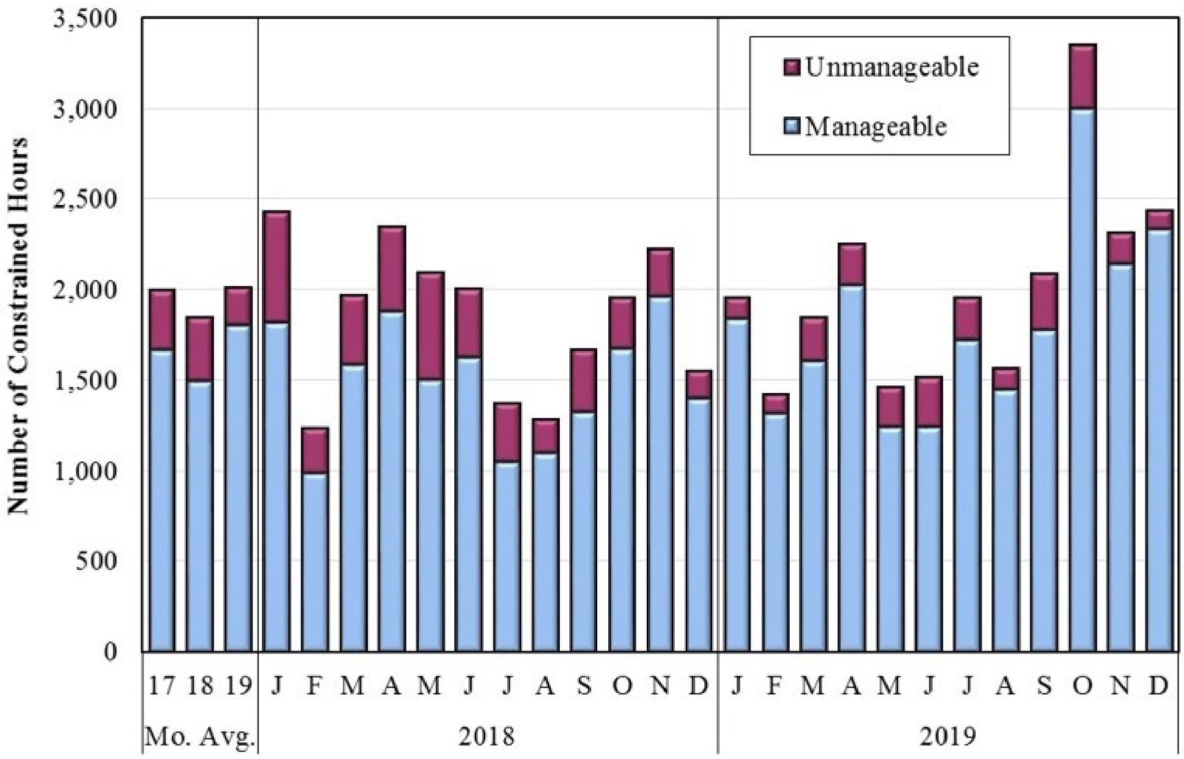


Figure A102: Real-Time Congestion Value by Voltage Level

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 Transmission Constraint Demand Curves (TCDCs) that cap the marginal cost (shadow price) that the energy market will incur to reduce constraint flows to their limits. Efficient market performance requires the TCDC to reflect the reliability cost of violating the constraint.

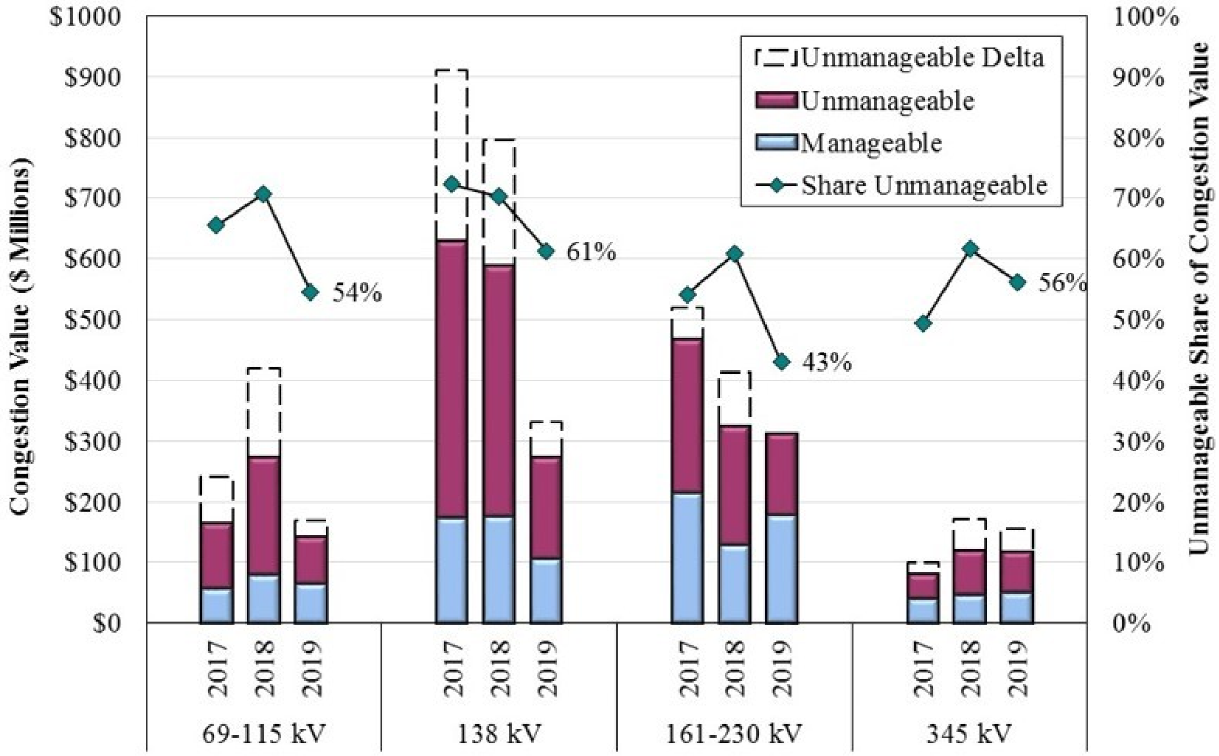
When the constraint is violated (i.e., unmanageable), the most efficient shadow price is the TCDC of the violated constraint. This produces an efficient result because the LMPs will reflect MISO's expressed value of the constraint. Prior to February 2012, an algorithm was used to "relax" the limit of 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 the value of unmanageable constraints. Its sole function was to produce a shadow price for unmanageable constraints that was lower than the TCDC. 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 A102 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 A102 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 TCDC) and the relaxed shadow price used to calculate prices.[27]

Figure A102: Real-Time Congestion Value by Voltage Level
2017–2019



I. FTR Market Performance

Because an 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: an annual auction for the June to May planning year and the MPMA for the current and future months. The MPMA was launched in November 2013 and facilitates FTR trading for future months or seasons remaining

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

in the planning year. 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.

Figure A103: FTR Profits and Profitability

Figure A103 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 and seasons remaining in the planning year.

Figure A103: FTR Profits and Profitability
2018–2019

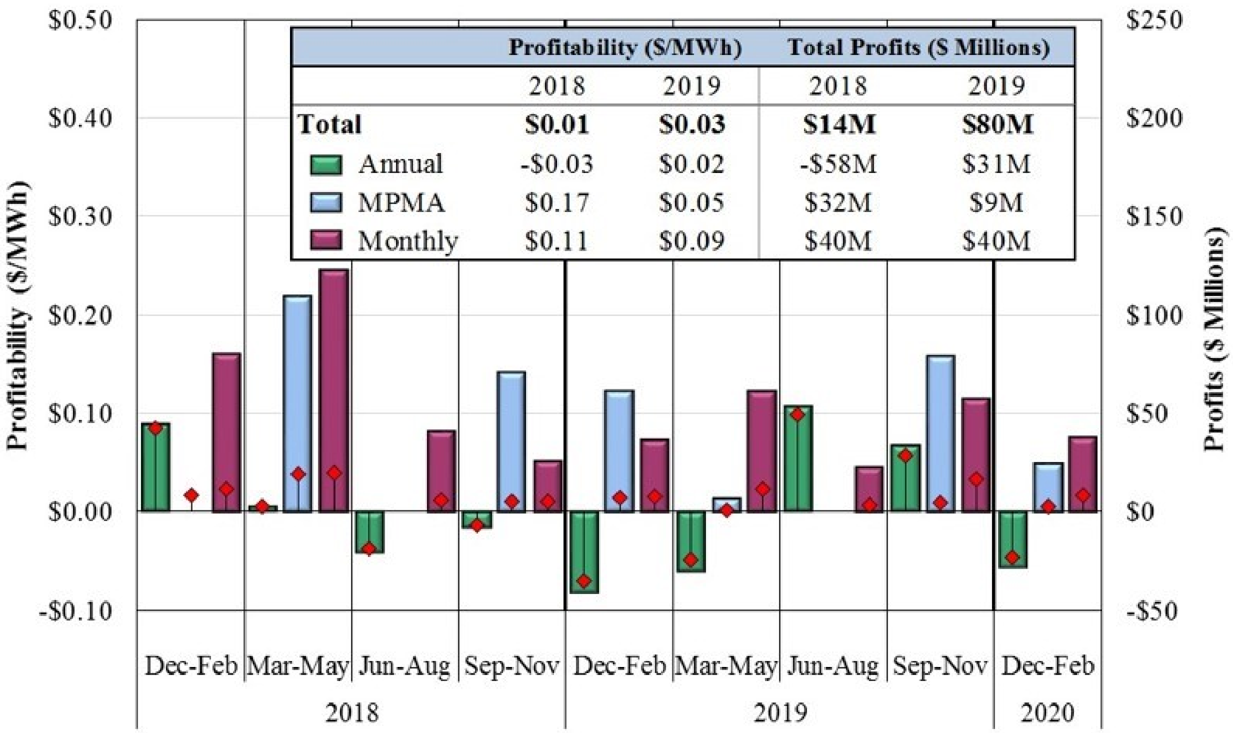


Figure A104 to Figure A106: FTR Profitability

The next three figures show the profitability of FTRs purchased in the annual, seasonal, and monthly FTR auctions in more detail for 2017 to 2019. 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 both FTRs sold and 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 A104: FTR Profitability
2017–2019: Annual Auction

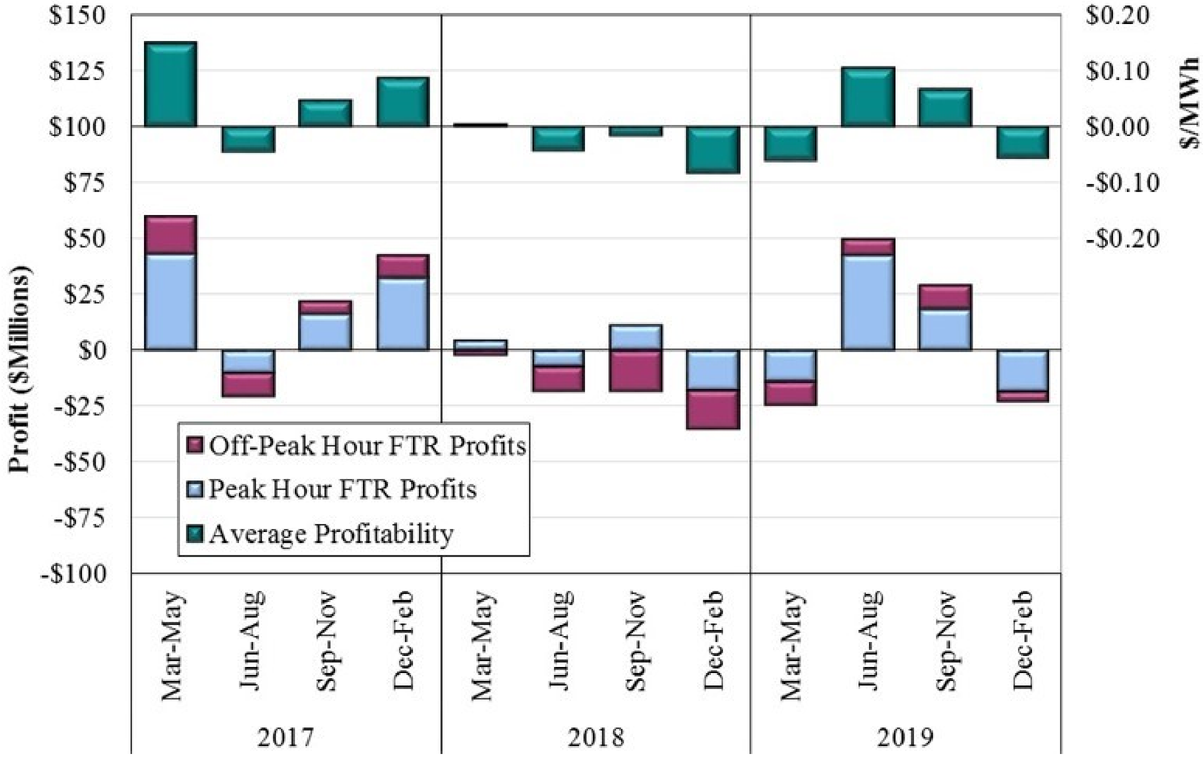


Figure A105: FTR Profitability
2018–2019: Monthly Auction

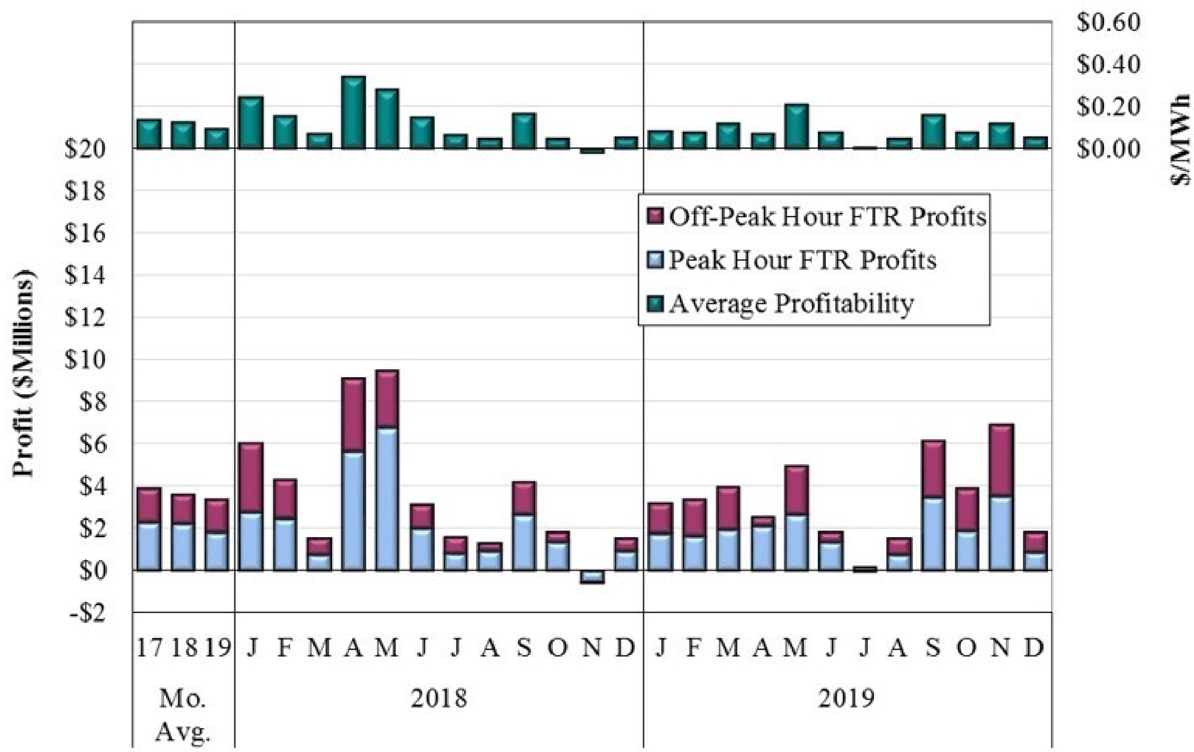


Figure A106: FTR Profitability
2017–2019 Seasonal Auction MPMA

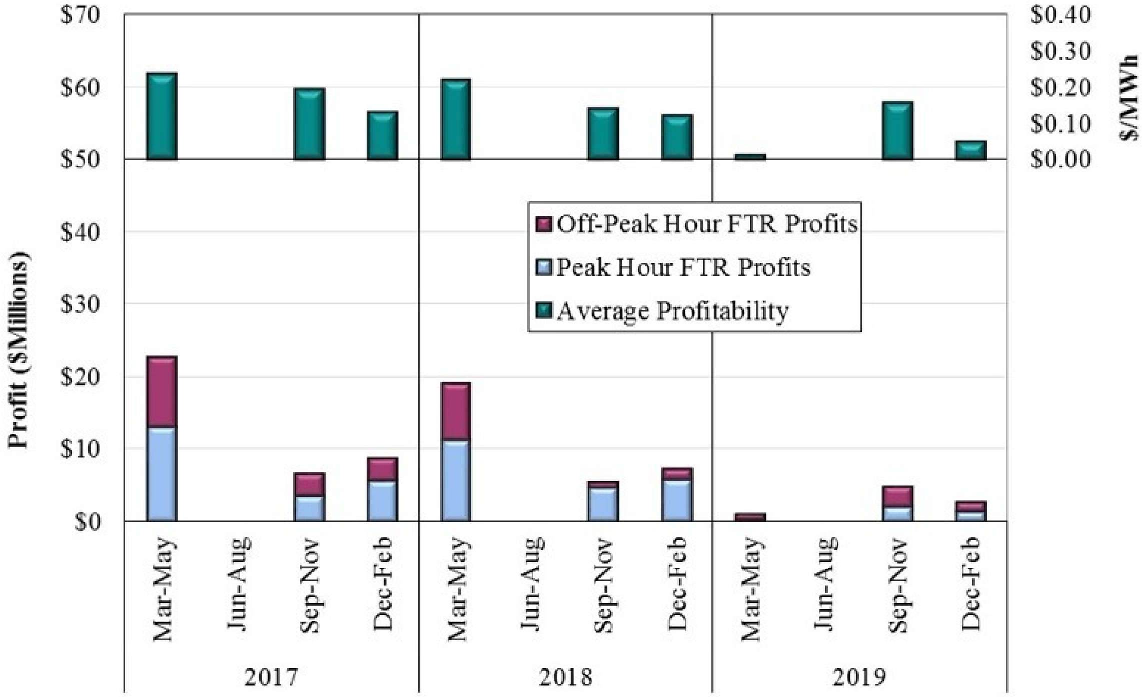


Figure A107 to Figure A120: Comparison of FTR Auction Prices and Congestion Values

The next 14 figures compare monthly FTR auction revenues to the day-ahead FTR obligations at four locations in the Midwest and three locations in the South in peak and off-peak hours.

Figure A107: Comparison of FTR Auction Prices and Congestion Value
Indiana Hub, 2018–2019: Off-Peak Hours

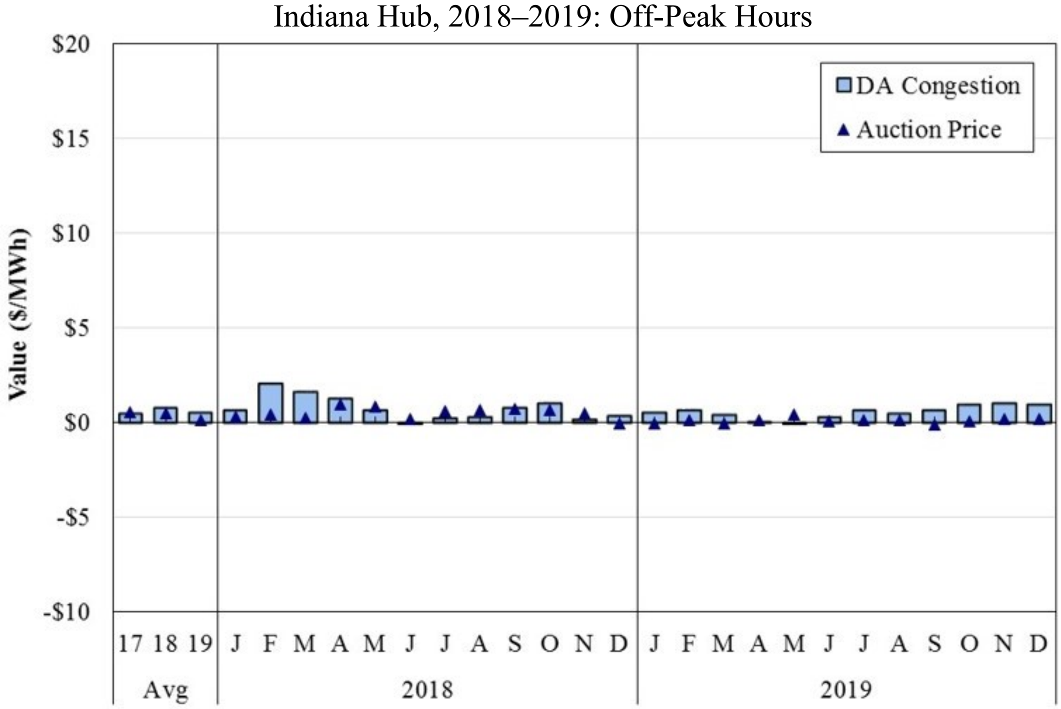


Figure A108: Comparison of FTR Auction Prices and Congestion Value
Indiana Hub, 2018–2019: Peak Hours

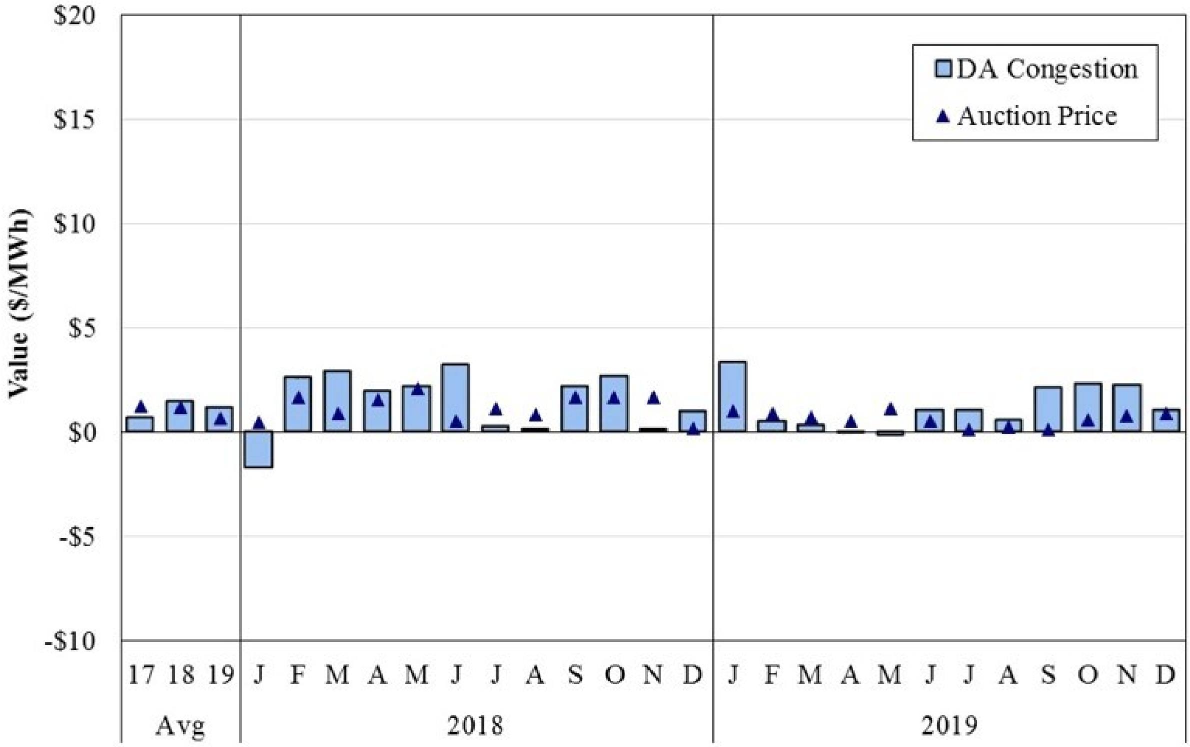


Figure A109: Comparison of FTR Auction Prices and Congestion Value
Michigan Hub, 2018–2019: Off-Peak Hours

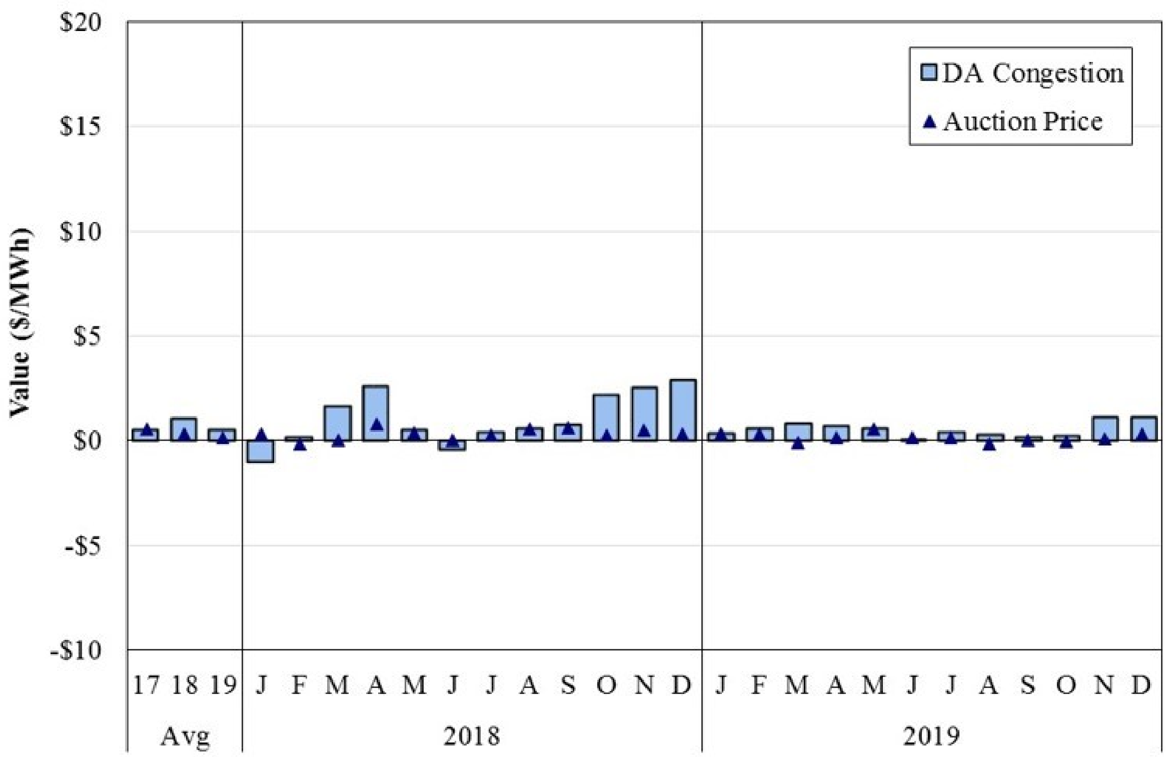


Figure A110: Comparison of FTR Auction Prices and Congestion Value
Michigan Hub, 2018–2019: Peak Hours

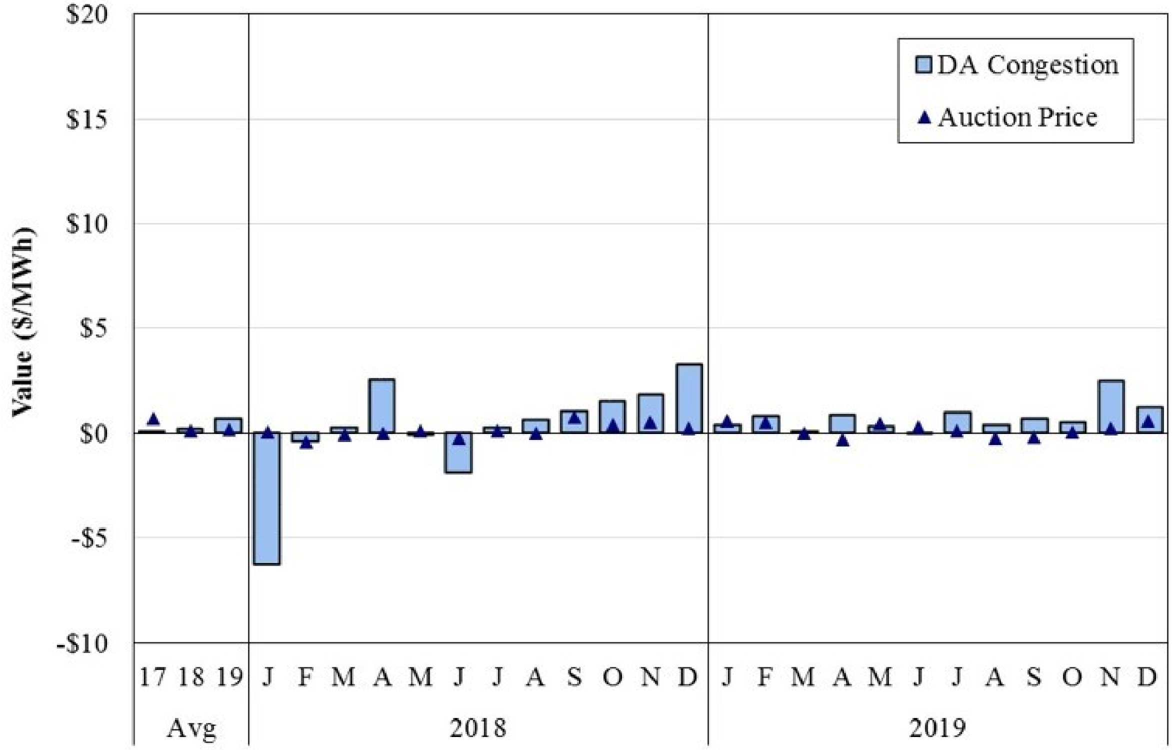


Figure A111: Comparison of FTR Auction Prices and Congestion Value
WUMS Area, 2018–2019: Off-Peak Hours

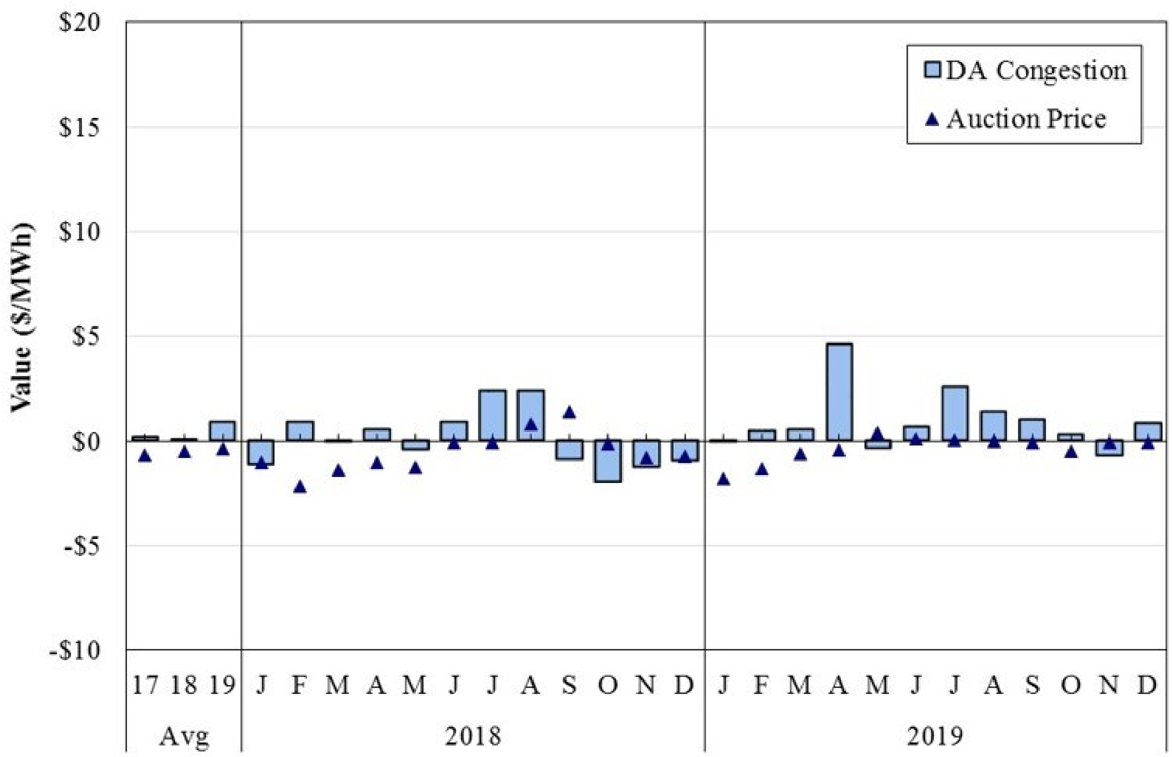


Figure A112: Comparison of FTR Auction Prices and Congestion Value
WUMS Area, 2018–2019: Peak Hours

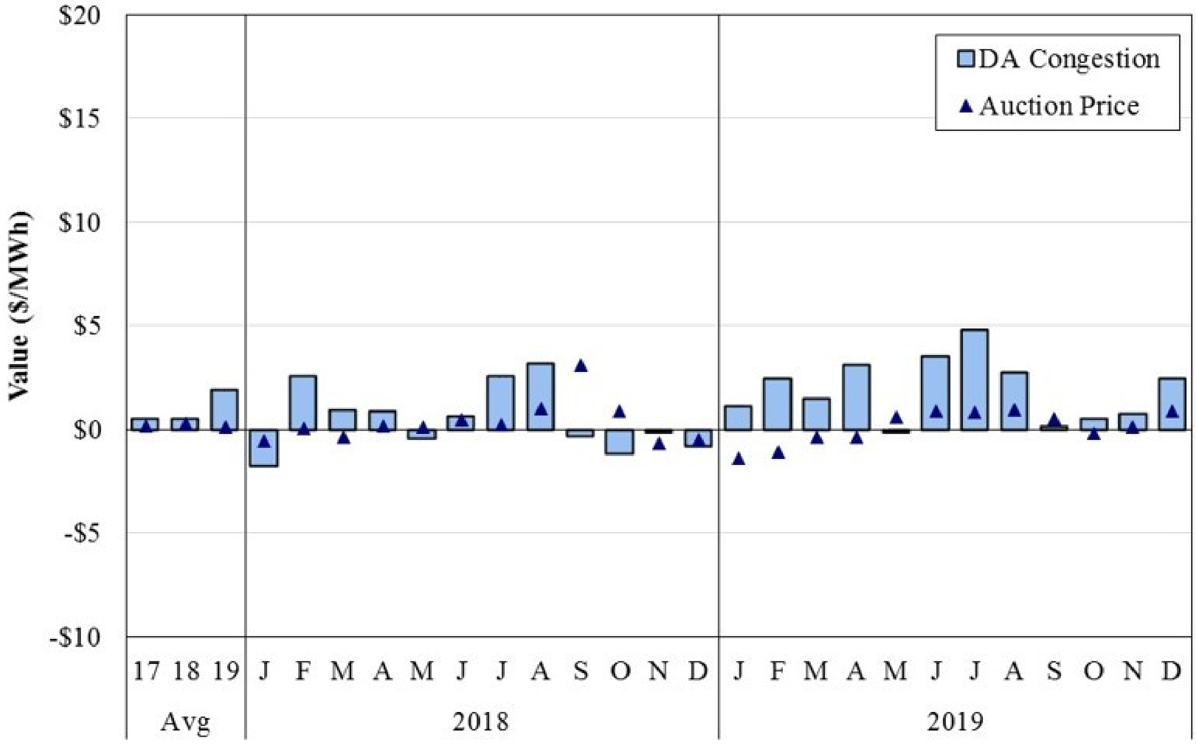


Figure A113: Comparison of FTR Auction Prices and Congestion Value
Minnesota Hub, 2018–2019: Off-Peak Hours

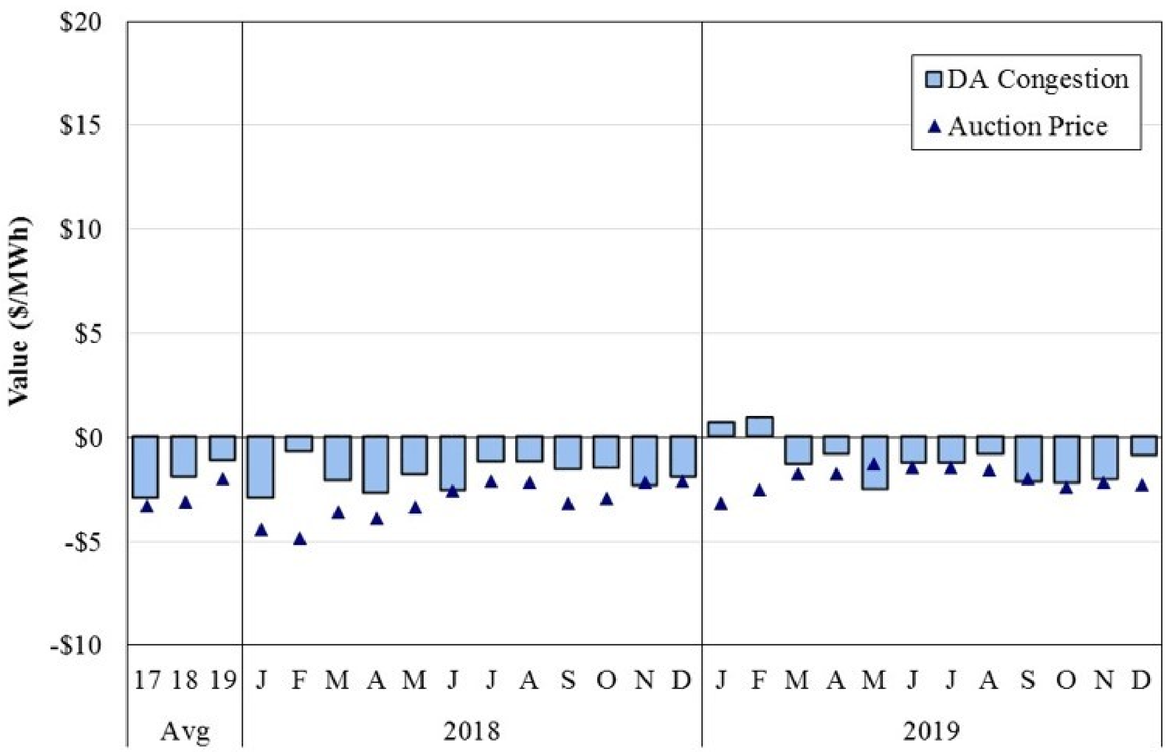


Figure A114: Comparison of FTR Auction Prices and Congestion Value
Minnesota Hub, 2018–2019: Peak Hours

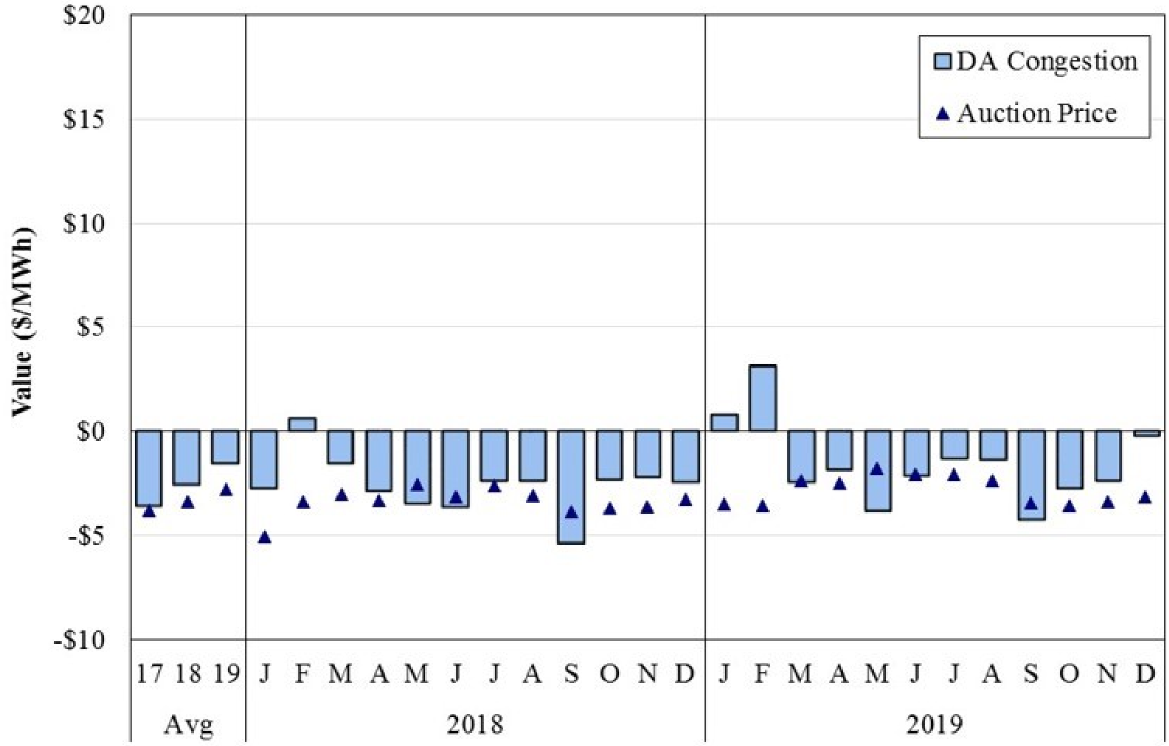


Figure A115: Comparison of FTR Auction Prices and Congestion Value
Arkansas Hub, 2018–2019: Off-Peak Hours

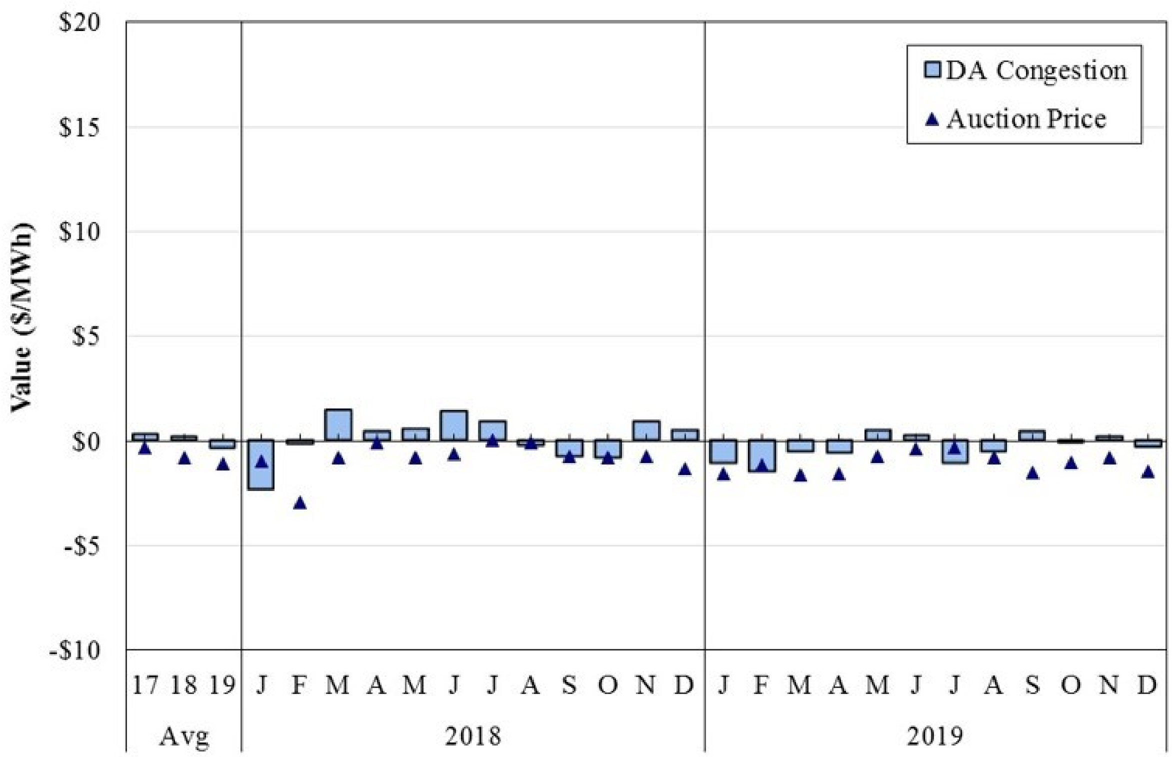


Figure A116: Comparison of FTR Auction Prices and Congestion Value
Arkansas Hub, 2018–2019: Peak Hours

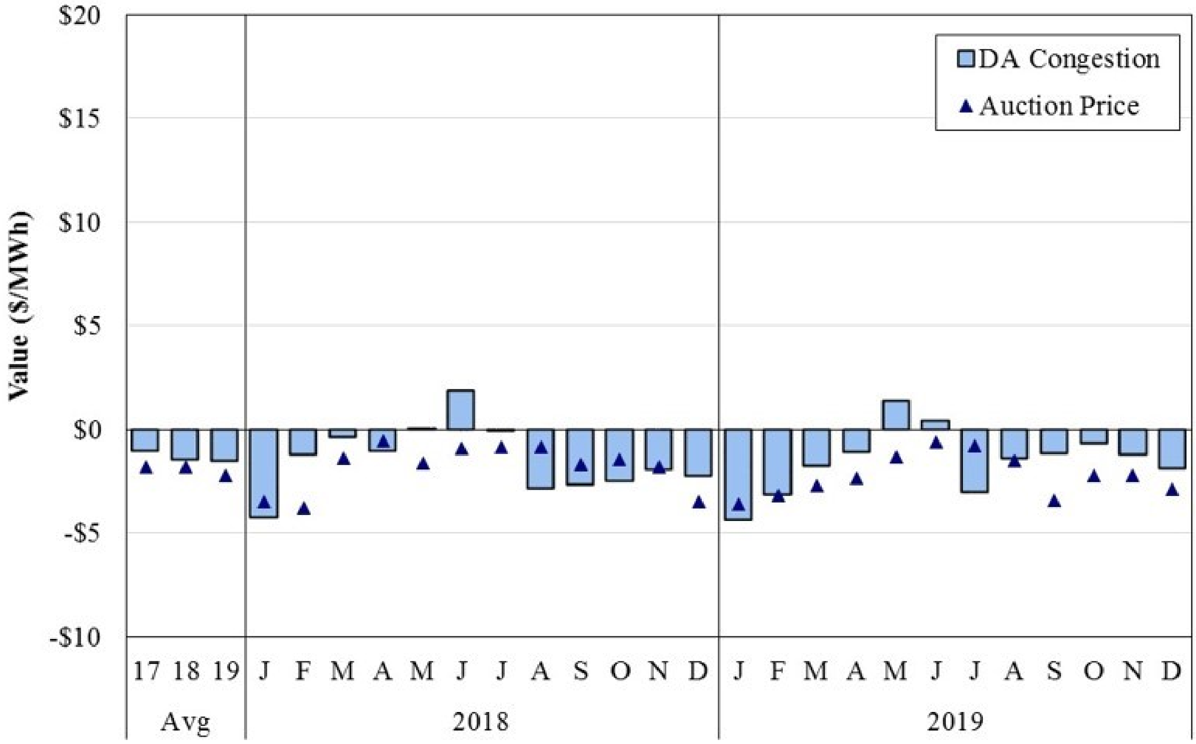


Figure A117: Comparison of FTR Auction Prices and Congestion Value
Louisiana Hub, 2018–2019: Off-Peak Hours

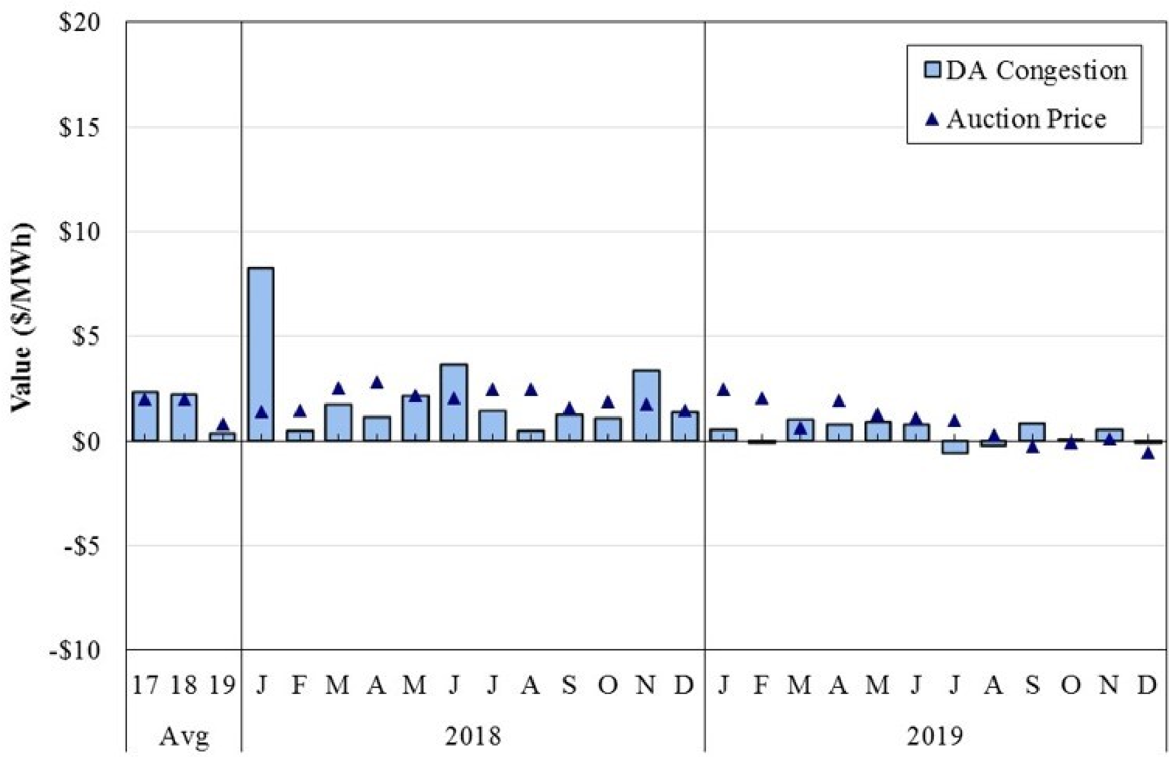


Figure A118: Comparison of FTR Auction Prices and Congestion Value
Louisiana Hub, 2018–2019: Peak Hours

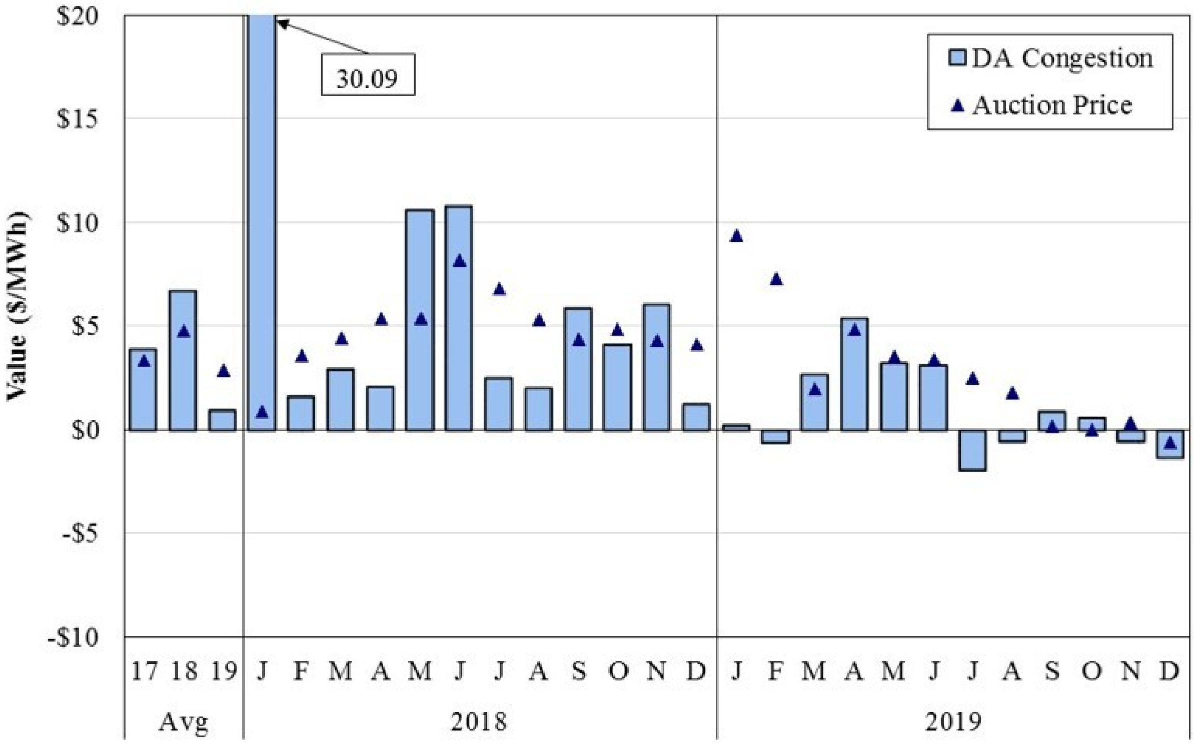


Figure A119: Comparison of FTR Auction Prices and Congestion Value
Texas Hub, 2018–2019: Off-Peak Hours

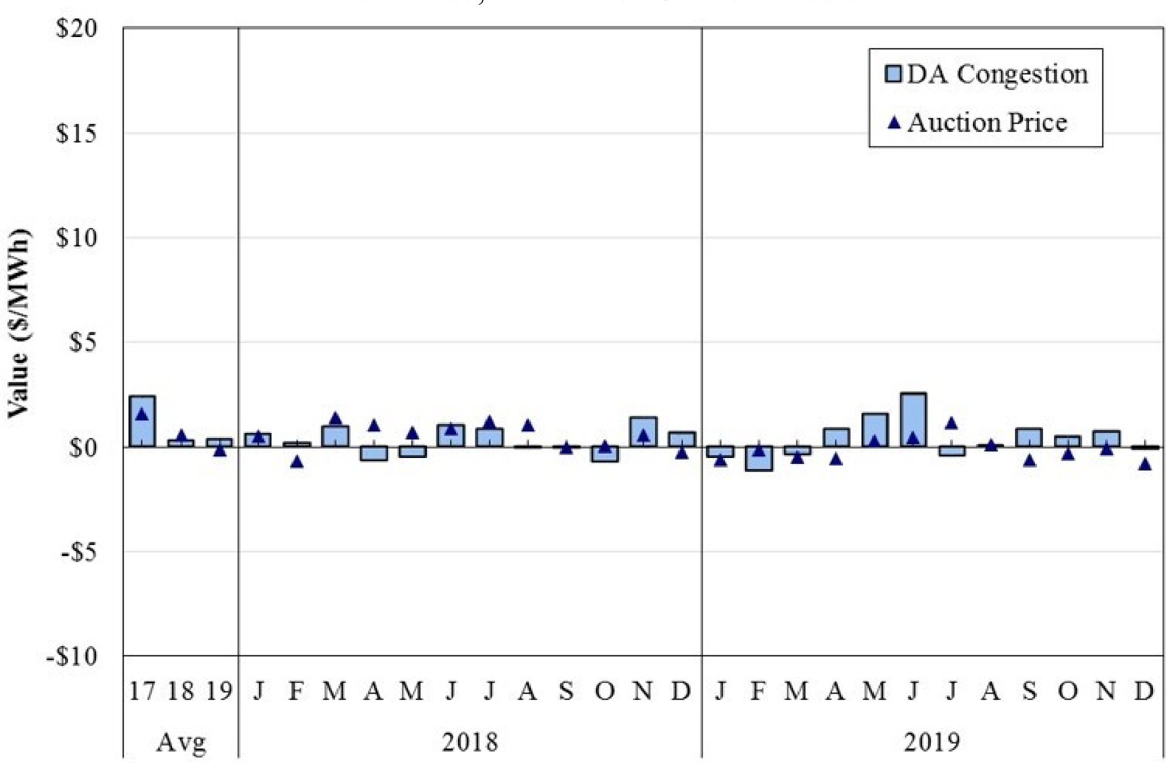
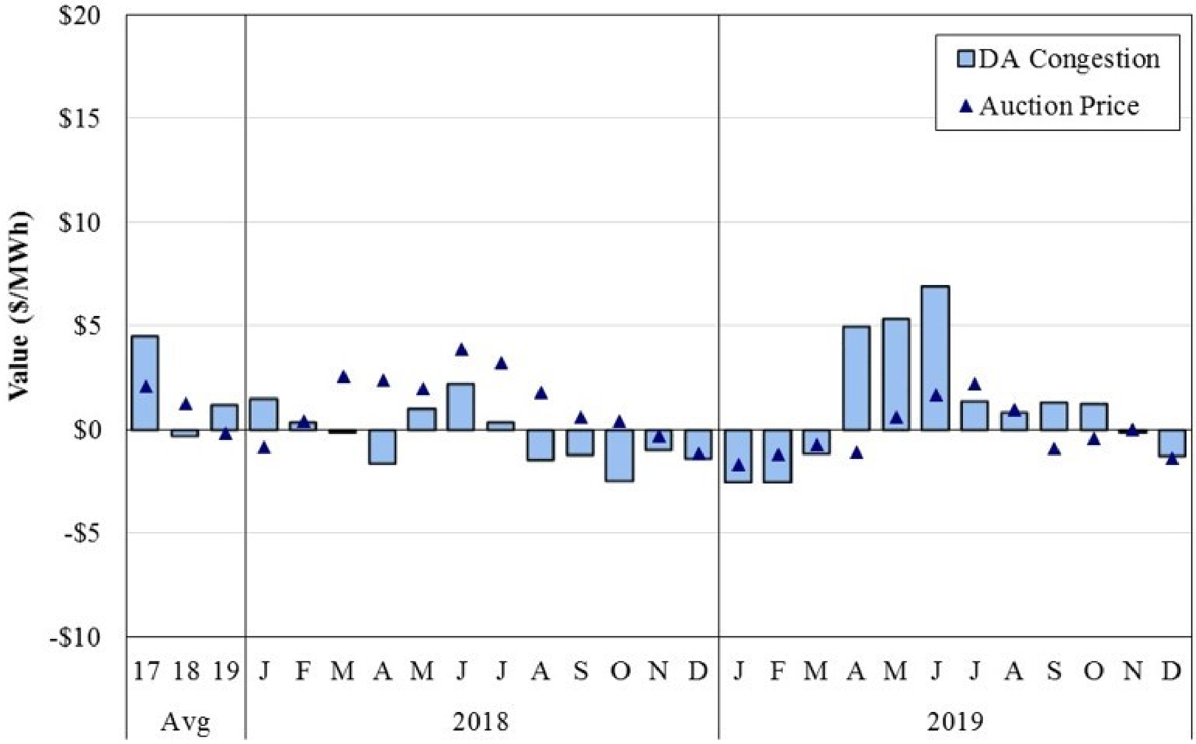


Figure A120: Comparison of FTR Auction Prices and Congestion Value
Texas Hub, 2018–2019: Peak Hours



J. 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.

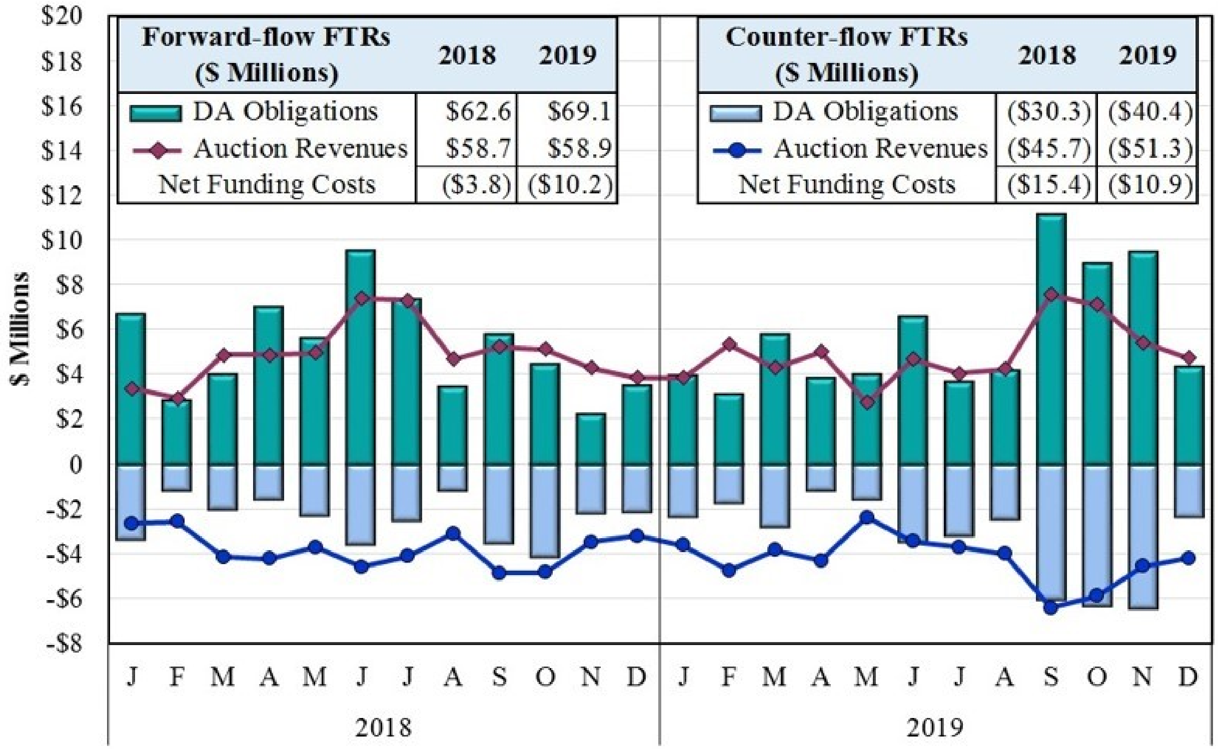
MISO is restricted in its ability to do this because it is prohibited from clearing the MPMA or monthly FTR auctions with a negative financial residual. Hence, it can sell counter-flow FTRs to the extent that it has sold forward-flow FTRs in the same auction. This limits MISO's ability to resolve feasibility issues through the MPMA FTR 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 A121: Prompt-Month MPMA FTR Profitability

To evaluate MISO's sale of forward-flow and counter-flow FTRs, Figure A121 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 value.

Figure A121: Prompt-Month MPMA FTR Profitability
2018–2019



VI. Resource Adequacy

This section examines the supply and demand conditions in the MISO markets. We summarize load and generation within MISO. In 2019, there were 137 market participants that either owned generation resources (totaling 177 GW of nameplate capacity) or served load in the MISO market.[28] 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 GW of resources, which we exclude from our analysis unless noted. The largest non-market coordinating member is Manitoba Hydro. It does not submit bids or offers but may schedule imports and exports.[29]

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 evaluate separately 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. Regional Generating Capacity

Figure A122: Distribution of Existing Generating Capacity

Figure A122 shows the December 2019 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.

28 As of January 2020, MISO membership totaled 472 Certified Market Participants including power marketers, state regulatory authorities, and other stakeholder groups.

29 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 A122: Distribution of Existing Generating Capacity
By Fuel Type and Zone, December 2019

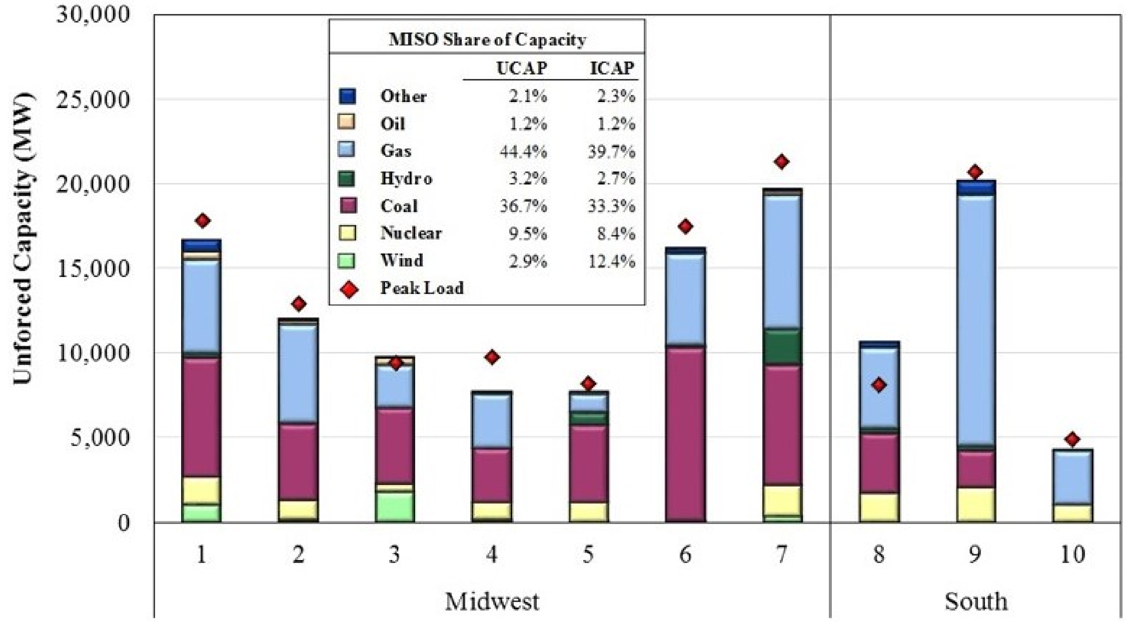
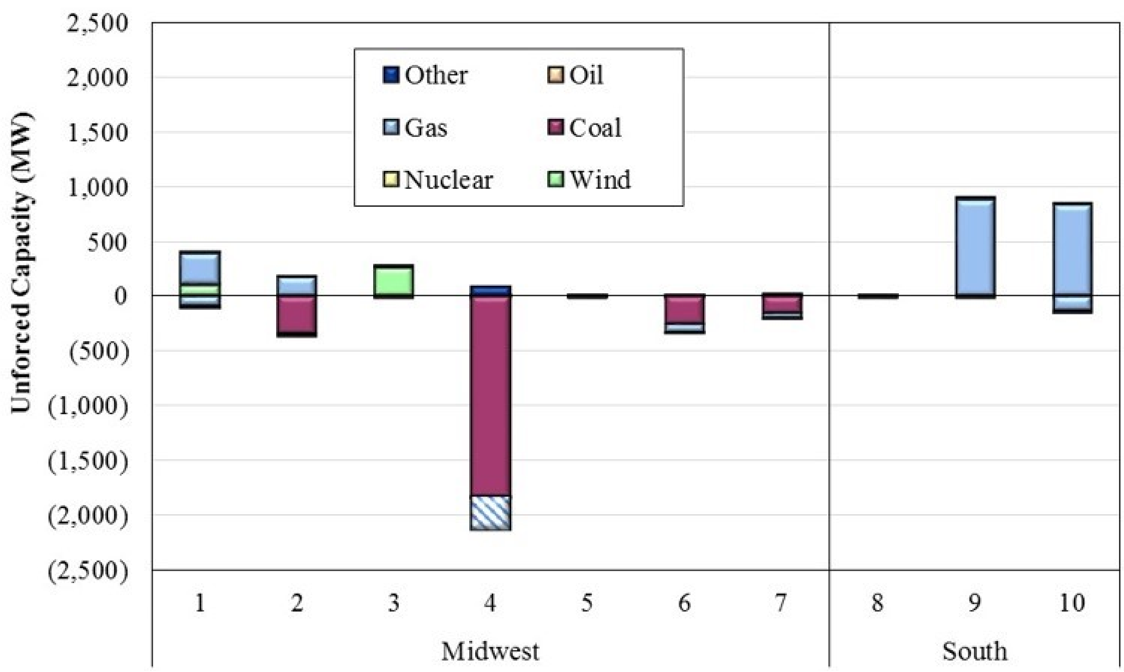


Figure A123: Additions and Retirements of Generating Capacity

Figure A123 shows the change in the UCAP values during 2019 in each zone caused by resource retirements, additions, and interconnection changes. The hatched area represents capacity that entered long-term suspension in 2019 and is not expected to return to the market.

Figure A123: Additions and Retirements of Generating Capacity
2019, By Fuel Type and Zone



B. Planning Reserve Margins and Summer Readiness

Table A14: Capacity, Load, and Reserve Margins

This subsection summarizes capacity levels in MISO and their adequacy for satisfying the forecasted peak loads for summer 2019. We have worked closely with MISO to ensure that our Base Case planning reserve level is consistent with MISO's assumptions in its *2020 Summer Resource Assessment,* including a 1,900 MW transfer limit assumption[30] between MISO South and MISO Midwest. We provide four additional scenarios that we describe in detail below and that we believe more realistically represent MISO's summer peak reliability margin.

MISO's reliability assessment is designed to ensure that an adequate supply margin exists across the forecasted summer peak to maintain the NERC reliability standard that the risk of loss of load does not exceed one day in ten years. The Planning Reserve Margin Requirement (PRMR) is determined through the Loss of Load Expectation (LOLE) study that currently assumes that no planned outages are scheduled across the summer peak, and that all LMRs and emergency-only resources can be fully utilized in the event of a declared emergency.

Historically a significant amount of capacity has been on planned outage during the summer peak months, and these outages were generally not scheduled well in advance. Additionally, a significant amount of capacity is generally unavailable to MISO's real-time market because of unreported outages and derates that are only evident through resource offers into MISO's DART system. Emergency-only resources may participate as capacity resources with registered lead times less than or equal to 12 hours, yet most emergencies have been declared within two hours. Emergency-only resources with longer lead times are less useful when MISO enters emergency conditions, particularly when those resources are demand-side management and represent load that must continue to be served until it is able to curtail.

The reserve margins in the table are generally based on: (a) peak-load forecasts under normal conditions;[31] (b) normal load diversity; (c) average forced outage rates; (d) an expected level of wind generation based on wind accreditation; and (e) full response from both imports and Demand Response (DR) resources that cleared the PRA (behind the meter generation, interruptible load, and direct controllable load management).

Table A14 below shows our base case and four alternative scenarios that examine the impact on MISO's planning reserve margins from short-notice planned outages, variations in emergency-only resources' lead times, and unusually hot temperatures. In this summer assessment, we include a conservative measure of historical non-capacity imports during the summer peak in order to calculate an expected margin around the summer peak.

30 We do not think this is an accurate assumption based on real-time operations, but we include this assumption to align our Base Case with MISO's Base Case.

31 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).

The columns in Table A14 include a number of cases:

- Column 1: Base case that assumes a 1,900 MW transfer limit between the South and Midwest, that MISO will be able to access all demand response resources in a given emergency situation, and that the summer planned outages will be limited to those scheduled and approved by April 1, 2020.
- Column 2: Assumes that the transfer capability between MISO South and Midwest will be 2,300 MW, consistent with MISO operations, and that planned and unreported outages and derates will be consistent with the average of the previous two years' summer peak months during on-peak hours. This scenario also assumes that MISO will only be able to access 75 percent of demand response resources in a given emergency situation, consistent with historical observations.
- Column 3: Modifies column 2 by removing emergency-only resources that cannot respond within two hours because Maximum Generation Emergency events are often precipitated by unforeseen outages and other contingencies. MISO is often not able to declare this type of event more than two hours in advance of the most critical conditions and has historically detected and declared emergencies between 10 minutes and 4 hours in advance of the emergency situation.
- Columns 4 and 5: The same as columns 2 and 3 with an additional assumption that hotter than normal summer peak conditions prevail that correspond to a "90/10" case (i.e., 90 percent chance load is lower and ten percent chance load is higher, which means it should only occur one year in ten).

The high-temperature cases are important because hot weather can significantly affect both load and supply. High ambient temperatures can reduce the maximum output limits of many MISO generators, while outlet water temperature or other environmental restrictions cause certain resources to be derated.[32] In its *2020 Summer Assessment*, MISO shows a high-load scenario that includes an estimate of high-temperature derates. While we believe this scenario is a realistic forecast of potential high-load conditions, we continue to believe that it likely understates the derates that may occur under high-temperature conditions.

32 These high-temperature derates are highly variable, so we assume high-temperature conditions from the MISO high-temperature scenario in its 2020 Summer Assessment.

Table A14: Capacity, Load, and Reserve Margins
Summer 2020

	Base Scenario	Alternative IMM Scenarios*: Realistic Scenario	Realistic <=2HR	High Temperature: Realistic Scenario	High Temperature: Realistic <=2HR
Load					
Base Case	124,866	124,866	124,866	124,866	124,866
Energy Efficiency Programs	(650)	(650)	(650)	(650)	(650)
High Load Increase	-	-	-	7,032	7,032
Total Load (MW)	124,216	124,216	124,216	131,898	131,898
Generation					
Internal Generation Excluding Exports	134,773	134,773	134,668	134,773	134,668
BTM Generation	4,445	4,445	3,047	4,445	3,047
Unforced Outages and Derates**	(167)	(10,899)	(10,899)	(18,499)	(18,499)
Adjustment due to Transfer Limit	(1,749)	-	-	-	-
Total Generation (MW)	137,302	128,320	126,816	120,720	119,216
Imports and Demand Response* **					
Demand Response	7,557	5,668	3,303	5,668	3,303
Capacity Imports	3,833	3,833	3,833	3,833	3,833
Margin (MW)	24,476	13,604	9,735	(1,678)	(5,546)
Margin (%)	**19.7%**	**11.0%**	**7.8%**	**-1.3%**	**-4.2%**
Effects of Non-Firm Imports					
Summer Peak Net Imports	1,609	1,609	1,609	1,609	1,609
Expected Margin (MW)	26,085	15,214	11,345	(68)	(3,937)
Expected Margin (%)	**21.0%**	**12.2%**	**9.1%**	**-0.1%**	**-3.0%**

* Assumes 75% response from DR.

** Base scenario shows approved planned outages for summer 2020. Alternative realistic cases use historical average unforced unit unavailability during July and August peak hours. High temperature incremental outages based upon MISO's 2020 Summer Assessment.

*** Cleared amounts for the 2020/2021 planning year.

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.

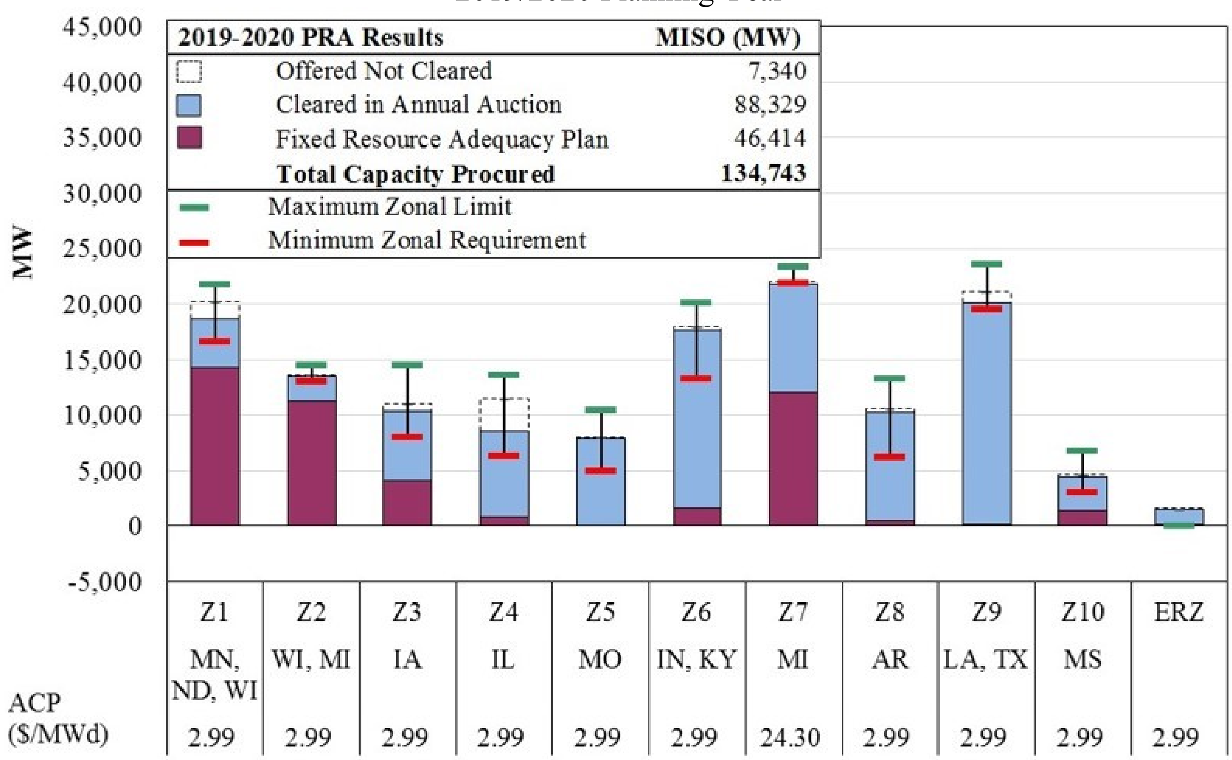
Figure A124: Planning Resource Auction

Figure A124 shows the zonal results of the 2019/2020 annual PRA, held in the spring of 2019 and covering June 2019 to May 2020. The figure shows the minimum and maximum amount of capacity that can be purchased in the red and green lines. The stacked bars show the total amount of capacity offered. The stacked bars include capacity offered but not cleared (ghost bars), capacity cleared (blue bars), or self-supplied (maroon) in each zone. Zonal obligations are set by the greater of the system-wide planning reserve requirement or the local clearing requirement. The minimum amount is the local clearing requirement, which is equal to the local reliability requirement minus the maximum level of capacity imports. The maximum amount is equal to the obligation plus the maximum level of capacity exports.

Zone 7 was constrained on the local clearing requirement and cleared the 2019/2020 auction at $24.30 per MW-day, while the clearing price in all other zones was $2.99 per MW-day. The $2.99 per MW-day clearing price is extremely low and provides suppliers with less than two percent of the revenues needed to cover the cost of entry for a new peaking resource.

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 A124: Planning Resource Auction
2019/2020 Planning Year



D. Qualifications and Accreditation of Supply in the PRA

We have become increasingly concerned that MISO's PRA rules allow resources that cannot satisfy MISO's reliability needs to provide capacity, including: a) Load Modifying Resources (LMRs) with long notification times that are called to satisfy MISO's capacity requirements in the operating horizon, and b) resources that are not fully deliverable. Additionally, MISO does not procure capacity for all of MISO's firm load. Resolving these concerns would result in price signals that better reflect the value of capacity in MISO.

Table A15: Alternative Capacity Auction Clearing Prices

We evaluated the impact that these changes would have had on the clearing prices in 2020/2021 by re-solving the Planning Resource Auction. Starting with the base clearing scenario that represents the actual PRA results, we analyzed scenarios to show the effects of improving the qualification of capacity resources and demand for capacity. In the first scenario, we identified LMRs that require notification beyond 6 hours in order to be deployed and then removed the UCAP associated with these resources from the offer stack.

In our second scenario, we determined the amount of ICAP on ERIS resources that may not be deliverable because some resources do not hold firm transmission up to their full ICAP levels. We converted this ICAP into UCAP and removed this difference from the capacity auction supply stack to re-clear the auction. Although this change removes a significant amount of capacity, we expect that were MISO to adopt our recommendation, resources would procure more firm transmission in order to qualify a larger amount of capacity in the auction.

In our third scenario, we applied the planning reserve margin (PRM) to the firm process and electric load behind the meter and netted the load plus PRM from the UCAP of the associated cogeneration facility. MISO's current practice is to net the load from the ICAP value, which effectively does not procure the capacity needed to reliably serve the firm process loads.

The individual scenarios were then combined to show the impact of implementing all the recommendations together. In addition to evaluating the base case scenarios against the current capacity auction construct that relies on a vertical demand curve, we also conducted a series of similar sensitivities assuming a sloped demand curve.

The results of these scenarios are shown in Table A15 below.[33] The first column labels the scenario, and the second column indicates the quantity of UCAP affected (on the supply side or demand side) by the sensitivity. The middle three columns show the resulting clearing prices of the sensitivities by region excluding Zone 7, which cleared at CONE in all scenarios. We show the resulting prices in these areas using the current vertical demand curve, while the three columns to the right indicate our results using a sloped demand curve.

33 The Unconstrained North is Zones 1 through 6. The Unconstrained South is Zones 8 and 10. The external zones have clearing prices that fall between the Unconstrained North and South.

Table A15: Alternative Capacity Auction Clearing Prices
2020/2021 Planning Resource Auction

Alternative Capacity Auction Scenarios	Affected UCAP	Vertical Demand Curve Prices*			Sloped Demand Curve Prices**		
		Unconstrained South	Zone 9 (LA, TX)	Unconstrained North	Unconstrained South	Zone 9 (LA, TX)	Unconstrained North
Base Scenario		$4.75	$6.88	$5.00	$148.23	$155.10	$148.23
- LMR > 6 hr Notification Time	1,226.6	$12.12	$12.12	$12.12	$168.51	$168.51	$168.51
- Undeliverable ICAP	2,933.2	$14.99	$20.02	$25.38	$200.86	$200.86	$200.86
+ Procurement for BTM Firm Load	270.2	$4.75	$23.64	$5.00	$152.89	$171.94	$152.89
Combination of Alternative Scenarios	4,384.3	$27.20	$27.20	$108.00	$213.61	$213.61	$234.23

* Zone 7 (MI) fell short of its Local Clearing Requirement and cleared at CONE ($257.73). This result applies to all other vertical demand scenarios.
** Zone 7 clears at $270.41 (5% above CONE) in all sloped demand scenarios.

E. Long-Term Economic Signals

In this subsection, we summarize the long-term 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 generator would earn above its variable production costs if it were to operate only when revenues from energy and ancillary services exceeded its costs. Well-designed markets 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 9,905 Btu per kWh.[34] The net revenue analysis includes assumptions for variable Operations and Maintenance (O&M) costs, fuel costs, and expected forced outage rates.

Figure A125 and Figure A126: Net Revenue Analysis

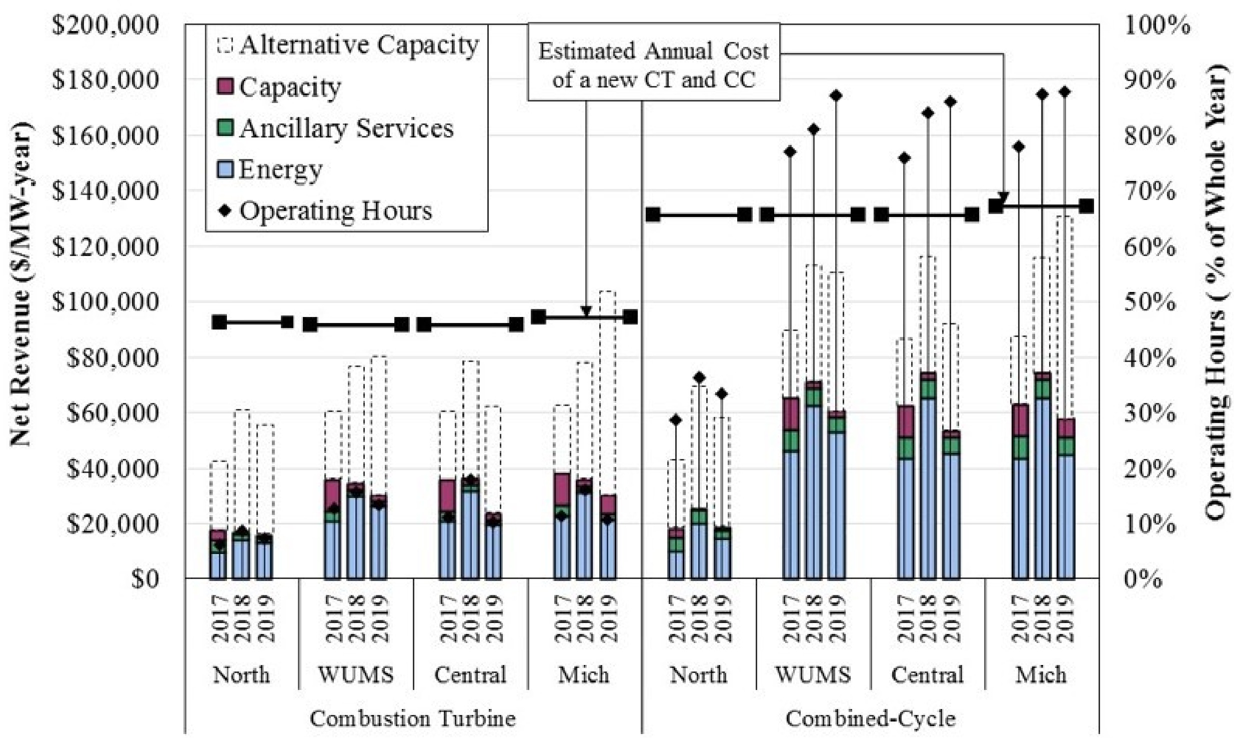
The next two figures compare the net revenue plus the capacity market revenue that would have been received by new CC and CT units in different MISO regions compared to the revenue that would be required to support new investment in these units. To determine whether net revenue levels would support investment 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 is shown in the figure as horizontal black segments and is based on data from the U.S. Energy Information Administration (EIA) and

34 These assumptions are used in the 2020 EIA Annual Energy Outlook. See: https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf

various financing, tax, inflation, and capital cost assumptions. The CONE for a CT is estimated to be $91.73 per kW-year in Central, $81.25 per kW-year in the South, $92.30 per kW-year in the West and $94.34 per kW-year in the East.[35] For a CC, the CONE is about $131.32 per kW-year in Central, $116.35 per kW-year in the South, $130.96 per kW-year in the West and $134.45 per kW-year in the East. Cost changes for the CC resulted in a solid increase in most regions since last year.

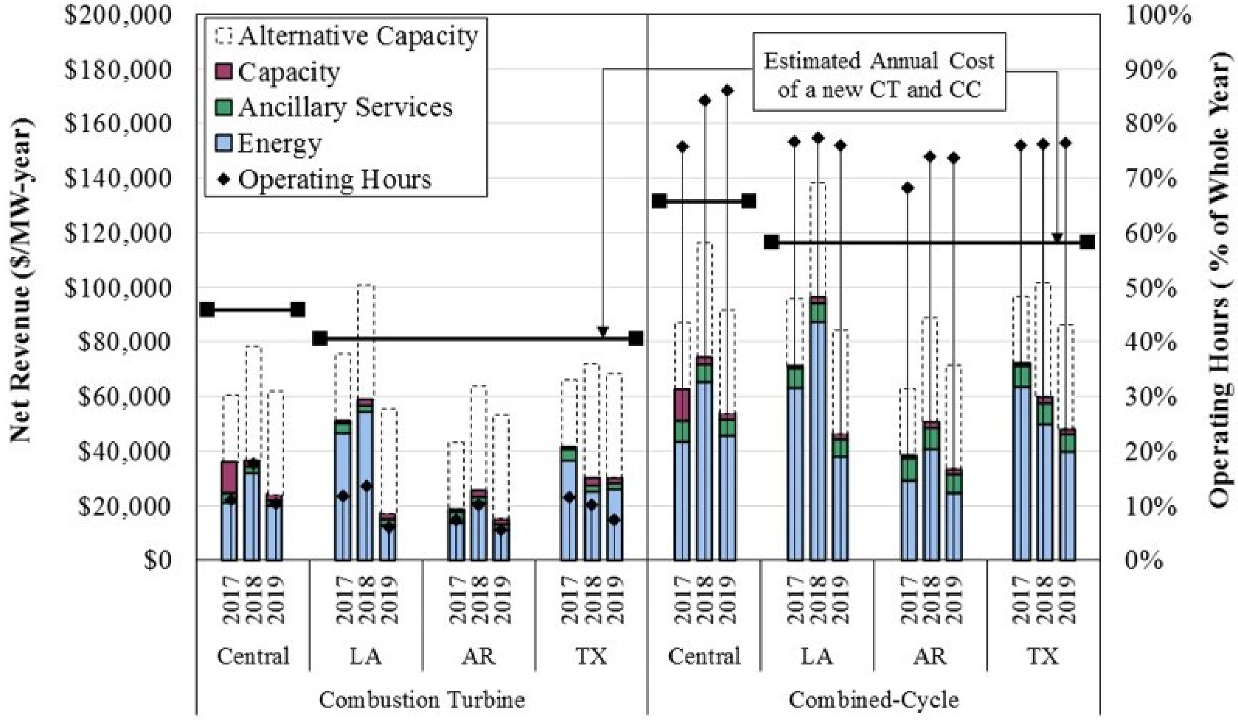
Combined-cycle generators run more frequently and earn more energy rents than simple-cycle CTs because CC units have substantially lower production costs per MWh. Therefore, the estimated energy net revenues for CC generators tend to be substantially higher than they are for CT generators. Conversely, 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. We added a transparent bar to illustrate the net revenues that CTs and CCs would have realized if MISO improved its modeling of demand efficiently in its capacity auction. The diamonds 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 A125: Net Revenue Analysis
Midwest Region, 2017–2019



35 The CONE values for CTs in Narrow Constrained Areas are published each year by the IMM along with other assumptions used to update NCA mitigation thresholds.

Figure A126: Net Revenue Analysis
South Region, 2017–2019



F. Existing Capacity at Risk Analysis

Since its inception, MISO has enjoyed a surplus of capacity beyond the minimum reliability requirement. When resources are unable to recover their fixed costs in the long run, they risk having to suspend operations or retire completely. Moreover, some resources may continue operating but reduce maintenance expenditures, leading them to have more frequent forced outages and deratings. MISO's capacity surplus has dwindled in recent years, as older, baseload units with higher fixed costs have entered long-term suspension or retired. This trend has largely been due to falling natural gas prices and the poor design of MISO's capacity market that results in understated capacity prices. Most of the new capacity entering MISO is either gas-fired generators or renewable resources.

Figure A127: Capacity at Risk by Technology Type

In this year's report, we conduct an analysis to evaluate capacity at risk for long-term suspension or retirement for three types of technology in MISO: nuclear, wind, and coal. Our analysis compares the annual resource net revenues to the technology-specific Going Forward Costs (GFCs) defined in Module E of MISO's Tariff. For coal unit net revenue, we included the median unit's two-year historical net revenues within the relevant resource adequacy zone. For nuclear, we assume a 2,156 MW unit with VOM costs of $10 per MWh and that the resource runs year-round. Finally, for wind we assume a 200 MW unit with $0 marginal costs and a 30 percent capacity factor. This analysis is illustrated on Figure A127 below. The blue bars indicate the revenues that the resources received through the energy markets, and the maroon bars represent capacity market revenues on a dollar per MW-year basis. The ghost bars represent capacity revenues that the resources would have received were the PRA to employ a sloped demand curve. Alternative wind capacity values are much smaller than coal and nuclear because of the much smaller UCAP value that wind receives for its ICAP compared to conventional resources.

Figure A127: Capacity at Risk by Technology Type
2019

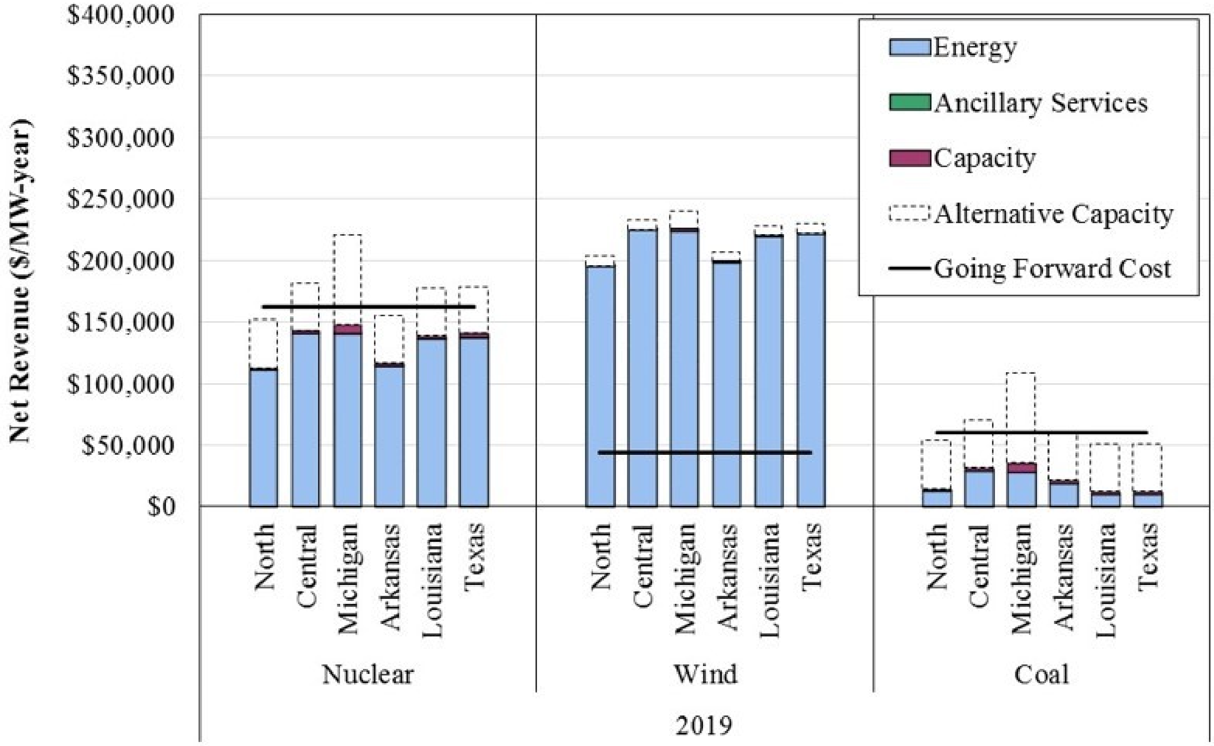


Figure A128: Coal-Fired Resource Net Revenues Under Alternative Demand Curves

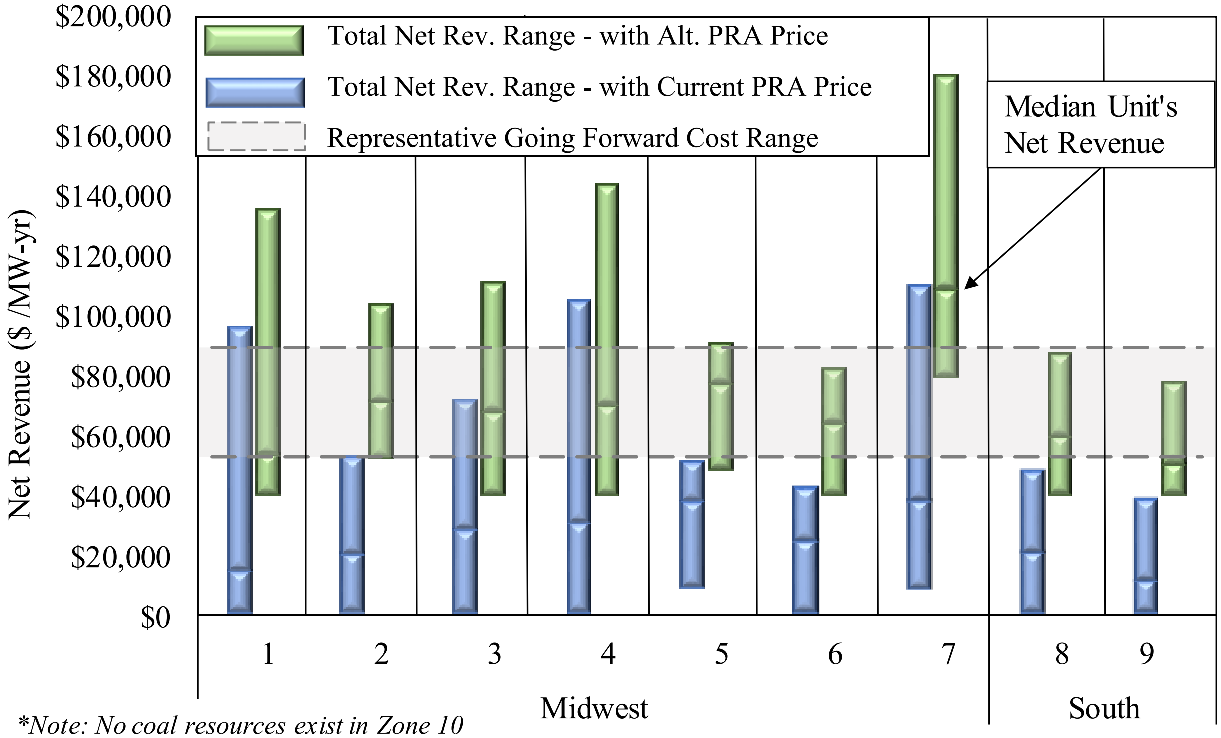
While evaluating the capacity at risk for suspension and retirement is useful to identify classes of resources that most likely cannot recover GFCs based on revenue streams, an additional examination of the actual set of resources that are at the highest risk is warranted. Figure A128 shows plot the range of net revenues for existing coal resources by local reliability zone in MISO in dollars per MW-year using two-year net revenues and capacity auction clearing prices from MISO's 2019/2020 PRA in the blue bars. The bottom of the column indicates the minimum net revenue received by any coal-fired resource in the capacity zone, the top of the column is the maximum amount, and the median annual net revenues are represented by the middle bar.

Our net revenue numbers include revenues from the energy and ancillary markets,[36] any associated uplift that was received, and capacity auction revenues. In order to get a capacity-weighted distribution, we created a 1 MW tranche for each resource with its associated annual net revenue. We also show the net revenue range that would prevail if MISO were to employ a

36 We put a $0 floor in energy and ancillary market net revenues.

sloped demand curve in the capacity auction in the green bars. The grey shaded range represents a reasonable range of GFCs for coal resources, based on resource information used to calculate Facility-Specific Reference Levels (FSRL) in MISO's annual capacity auction.

Figure A128: Coal-Fired Resource Net Revenues Under Alternative Demand Curves
2019



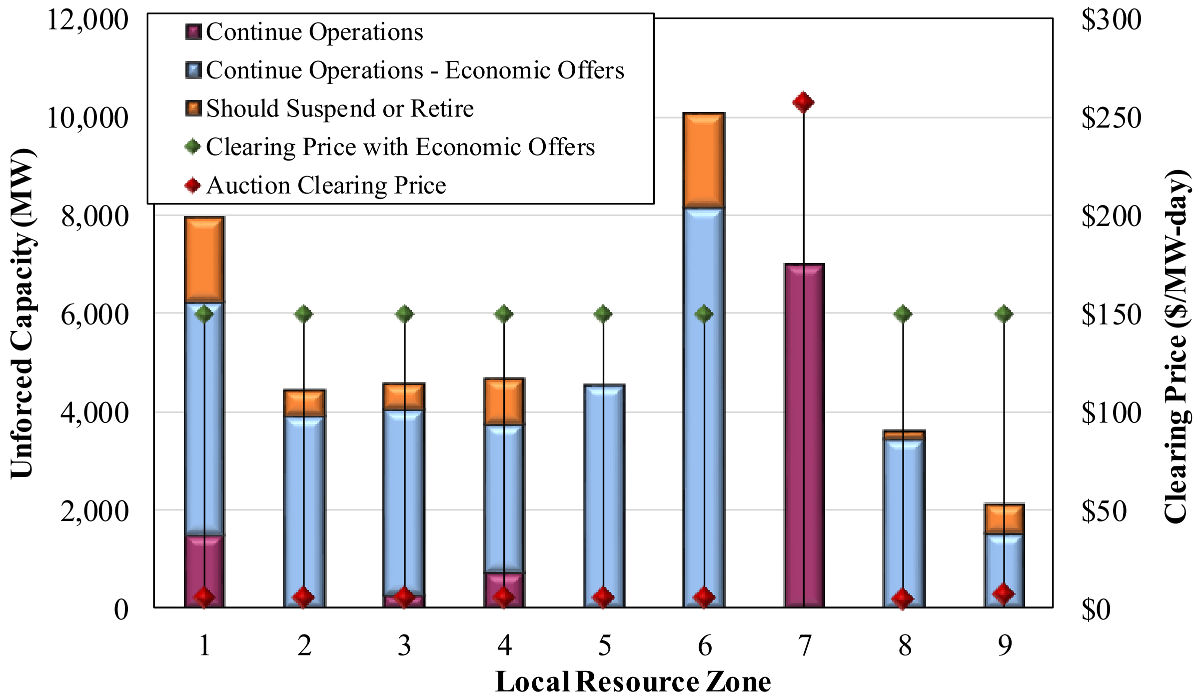
**Note: No coal resources exist in Zone 10*

Figure A129: Evaluation of Economic Coal Resource Retirements

The prior analysis shows that many coal units may be uneconomic to continue to operate. Were uneconomic coal to retire, the remaining coal resources would be more economic to continue operating. We conducted an analysis to determine what an optimal amount of coal retirements would be under the current capacity construct (vertical demand curve) were coal resources to offer into the capacity auction to reflect the capacity revenues that would be needed to cover their GFCs. In Figure A129 below, we show the alternative zonal clearing amount and corresponding prices, as well as the amount of coal capacity that would retire, were all coal resources to offer their resources rationally by zone. In this analysis, we re-solved the 2020/2021 capacity auction by substituting offers for existing coal resources based on the difference between the resources' net revenues and the Tariff-based Technology-Specific Avoidable Costs.

The diamonds in the figure are alternative capacity clearing prices in the 2020/2021 capacity auction, plotted against the right axis, that would result were all coal resources to offer into the capacity auction economically. The maroon bars indicate the amount of capacity that currently receives adequate compensation to continue operations, based on 2020/2021 auction clearing prices. The blue bars represent the additional amount of capacity that would be economic were all coal resources to offer rationally, and the orange bars represent the capacity that would remain uneconomic despite higher clearing prices.

Figure A129: Evaluation of Economic Coal Resource Retirements
2020



G. Capacity Market Design

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, based on the Cost of New Entry (CONE) that MISO updates annually. These requirements result in a vertical demand curve, which implies that demand is insensitive to the price and any additional available capacity beyond the minimum resource requirement is effectively worthless to MISO. 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 the capacity market using 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 like MISO's 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) the amount of expected net revenues from energy and ancillary services markets to cover the GFCs).

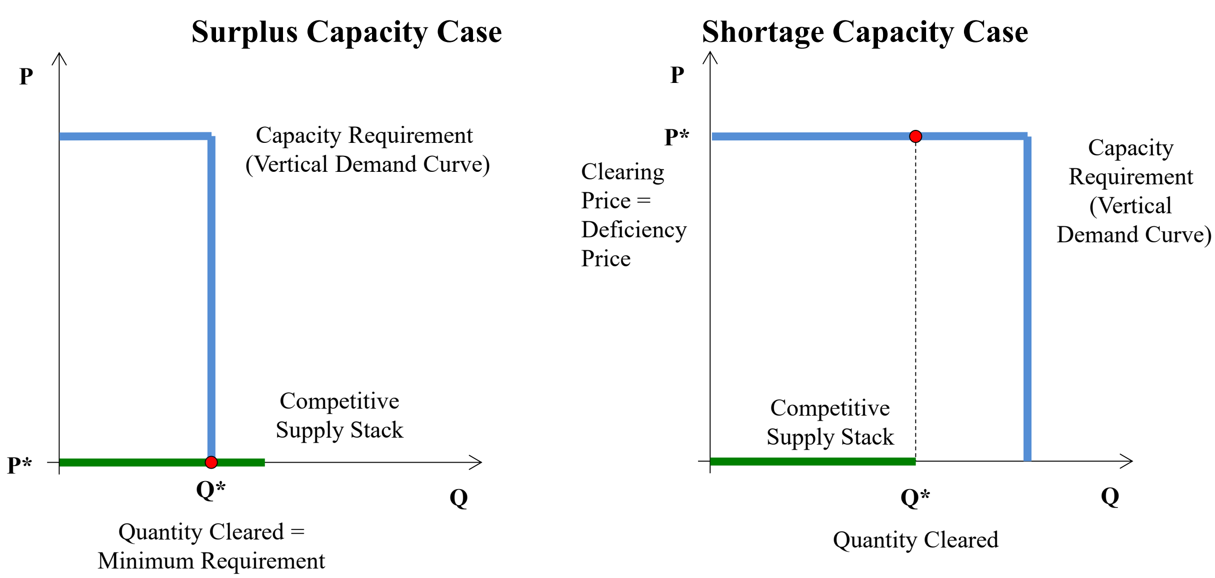
Two primary principles govern capacity supply offers:

- *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 capacity offer of zero.

Figure A130: Surplus and Shortage Capacity Cases with Vertical Demand Curve

Because GFCs are generally covered by energy revenues and capacity obligations are not costly to satisfy, most suppliers are willing to be 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, as shown in Figure A130 below.

Figure A130: Surplus and Shortage Capacity Cases with Vertical Demand Curve



This figure shows that:

- If the market is not in a shortage, the price will clear at a price close to zero, which characterizes the 2019/2020 auction results in MISO. Almost all zones in MISO cleared at

$2.99 per MW-day, except for Zone 7, implying that additional existing capacity outside of Michigan has very little value to MISO.

- If the market is in shortage, as indicated in the figure on the right, then the supply and demand curves do not cross, and the price will clear at the deficiency price.

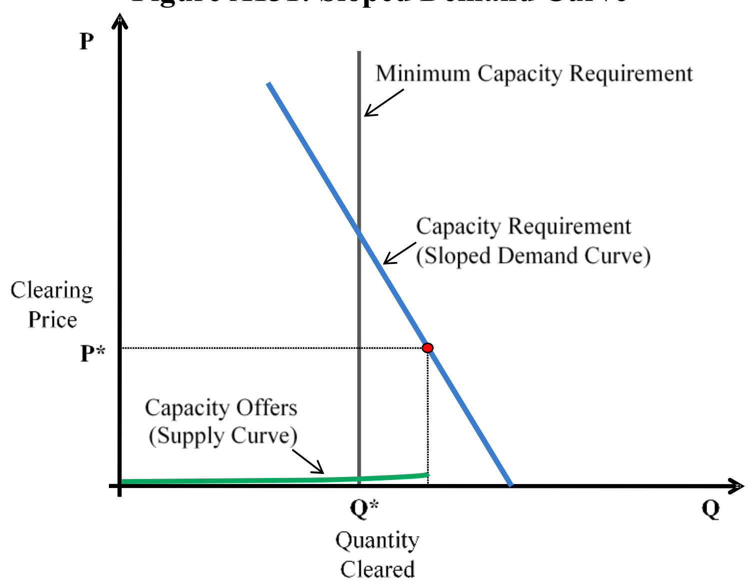
This pricing dynamic and the associated market outcomes raise at least three significant issues regarding the long-term performance of the current capacity market:

- 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, which can hinder long-term contracting and investment by making it extremely difficult for potential investors to forecast the capacity market revenues. This difficulty 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 small changes in supply creates a strong incentive for suppliers to withhold capacity to raise prices. Withholding in such a market is nearly costless because the foregone capacity sales would otherwise be priced at close to zero. Hence, market power is a greater potential concern, even if the market is not concentrated.

Figure A131: 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.

Figure A131: 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), some of the most important parameters have been 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 for why an infinite slope is efficient or reasonable.

Short-Term Effects of PRA Reform

Figure A132: Supply and Demand in 2020/2021 PRA

To demonstrate the significance of the flawed vertical demand curve, we estimated the clearing price in MISO that would have prevailed in the 2020/2021 PRA if MISO employed sloped demand curves in the PRA, as shown in Figure A132. The blue dashed line in Figure A132 represents the vertical demand curve actually used in the 2020/2021 PRA, and the solid green line indicates the maximum amount of capacity in MISO that was not stranded behind auction constraints. We constructed the supply curve using all capacity that was offered into the MISO auction either with an associated price or through self-supplied resources from Fixed Resource Adequacy Plans.

The sloped demand curve we use in this simulation is similar to the curve used by MISO witnesses in the analysis of MISO's "competitive retail solution" in FERC Docket Number ER17-284. The top of the curve is at 1.05 x CONE and 98.8% of the planning reserve margin requirement (PRMR). The sloped demand curve and the vertical demand curve intersect at CONE. In other words, the sloped demand curve price is equal to CONE at the PRMR quantity.

For our simulation, we assumed a linear demand curve where the zero-crossing point (the point where additional capacity is assumed to have no value) determines the slope of the demand curve. Any sloped capacity demand curve must be parameterized through analysis and discussion with market participants. The capacity demand curve for the New York Control Area (i.e., all of New York) crosses zero at 112% of the minimum capacity requirement. The capacity demand curve for the PJM crosses zero at 107.5% of the minimum capacity requirement. For our simulation, we used the average of these two values and assumed a zero-crossing point of

109.75% of the MISO-wide PRMR. Changing this slope will change the precise clearing price we estimate, but not the overall conclusion that assuming a vertical demand curve produces prices that do not reflect the marginal reliability value of capacity resources in MISO.

Figure A132: Supply and Demand in 2020/2021 PRA

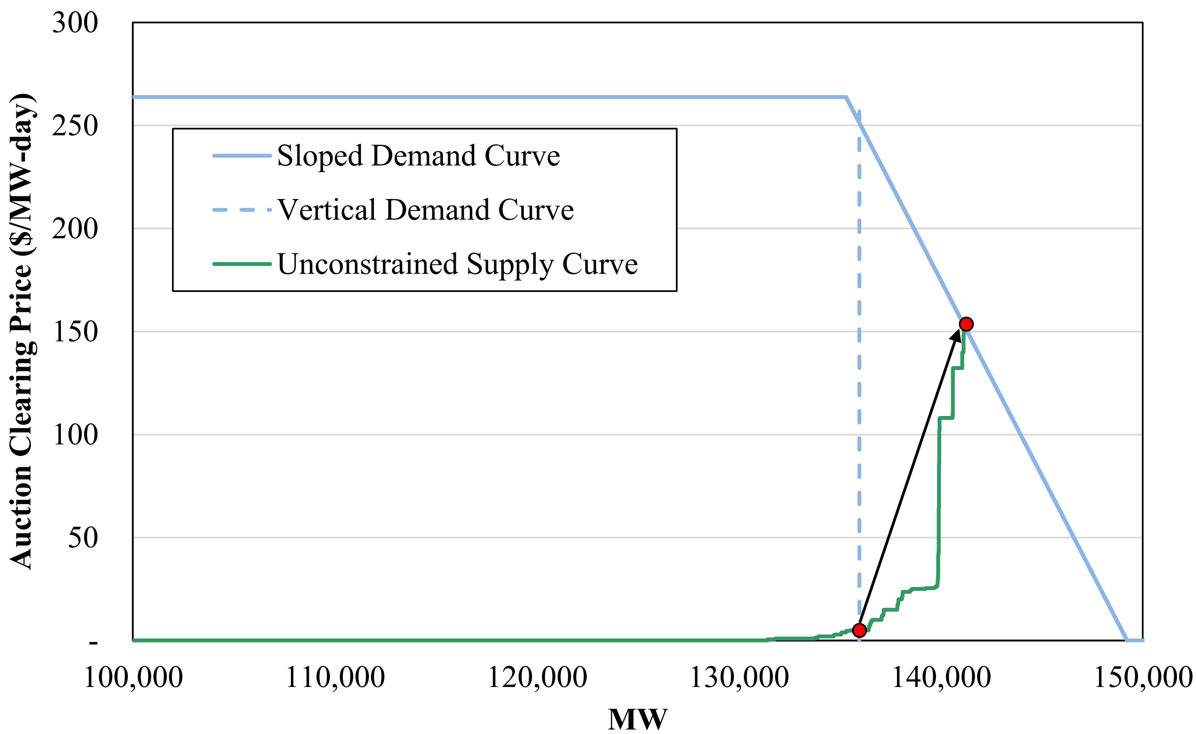


Table A16: Effects of Sloped Demand Curve by Type of Participant

Based on the simulation described in the prior section, we estimated how improving the design of the PRA would have affected various types of market participants in the 2020/2021 PRA. We calculated the simulated settlements for each participant based on their net sales. The change in settlement is calculated by changing price and quantity for each participant. For the buyer-side settlement, costs increase because of a higher capacity price and an increase in their capacity requirement of approximately five percent because of the market clearing at a surplus level of approximately five percent. For the seller-side settlement, revenues increase because of higher sales prices and, for those with economic excess, higher sales volume. Economic excess is the uncleared volumes under the vertical demand curve that are economic relative to other uncleared offers to meet the additional demand under the sloped demand curve. We then aggregated the participant-level results into three categories: competitive suppliers, competitive retail LSEs, and vertically-integrated utilities.

These effects are important because the economic price signals from the wholesale market guide key decisions by unregulated participants in MISO, including competitive suppliers and competitive retail LSEs. These effects are shown in Table A16 below. For each type of participant, the values are aggregated for participants whose net revenues would increase and for those whose net revenues would decrease (or costs that would increase).

Table A16: Effects of Sloped Demand Curve by Type of Participant
2020/2021 PRA

Type of Participant	Net Revenue Increases	Net Revenue Decreases	Total
Vertically Integrated	$677.0M	-$653.0M	$24.0M
Merchant Generators	$622.5M		$622.5M
Retail Choice Load		-$646.5M	-$646.5M

Reforming the Accreditation of Capacity in MISO

Generating resources are currently qualified and accredited to sell capacity based on their forced outages, which are considered in the EFORd calculation and are the basis of their UCAP levels. Under MISO's existing capacity accreditation construct, resources' UCAP values are determined by discounting their total installed capacity based on forced outages that participants self-report to GADS between September 1st and August 31st for the previous 3 years.[37] We have identified a number of issues with MISO's current accreditation methodology, which include incomplete GADS reporting by market participants, inaccurate Generation Verification Testing (GVTC) data submitted into GADS, and improper weighting of forced outage hours in the accreditation penalty by resource classification. The net result is that the assumed reliability value of resources that participate in MISO's capacity auction is inconsistent with their true value.

In March 2019, FERC approved a MISO Tariff change[38] that penalizes short-notice non-forced outages that occur during a declared Maximum Generation Emergency as forced outages (and derates) for the purpose of calculating a resource's forced outage rate for the next applicable Planning Year. Specifically, resources would be penalized based on a number of planned outage hours equal to the greater of: (1) the period during which the resource's outage overlaps with the Maximum Generation Emergency or (2) 24 hours. Planned outages scheduled 120 days in advance receive a Safe Harbor.

Table A17: Alternative Capacity Accreditation Derates by Resource Class

We evaluated the impact of an alternative accreditation methodology on resources with an obligation to offer UCAP in the 2020/2021 Planning Year by using GADs and CROW data from September 1, 2016 through August 31, 2019. Specifically, we are recommending that MISO calculate a resource's UCAP derate amount based on its average outages and derates occurring during the five percent of hours with the smallest day-ahead supply margins (total supply – total demand).

To determine the subset of tight hours, we divided the September 1, 2016 through August 31, 2019 accreditation period into three years (each spanning from September to August of the subsequent year) and selected the five percent of hours with the smallest margin in the day-ahead

37 One exception to this exists for Load-Modifying Resources that receive additional capacity credit associated with the PRMR value and transmission losses. A second exception to this is for wind resource whose accreditation is based on their history of delivered energy rather than forced outages or derates.

38 Docket No. ER19-915-000.

market.[39] We also added in all hours of declared emergencies during the accreditation period (if not already included in the tightest margin hours). This subset of hours goes into the denominator of our alternative forced outage rate calculation. In the numerator of the UCAP derate ratio, we determined the total availability of generator resources during the same subset of hours. Availability is based on the resources' offered economic maximum or emergency maximum (in the real-time market) when resources were on control or offline, or the actual output of the resource while running off control. We subtract the resource's availability from its installed capacity (ICAP) to determine the derate quantity. We summed the outage hours for each resource (using fractional equivalent hours for derates).

In Table A17 below, we show the amount of capacity in each major resource category along with the median value of the current UCAP derate (the XEFORd rate) and the UCAP derate under the IMM proposed methodology.

Table A17: Alternative Capacity Accreditation Derates by Resource Class

Resource Class	Capacity (MW)*	Current UCAP Derate (XEFORd)	IMM Proposal: Outages & Derates in Tightest Hours
Combined Cycle**	17,989	2.6	17.5
Coal	50,474	7.6	20.2
Combustion Turbine (Gas)	27,127	4.9	12.4
Nuclear	12,393	2.4	13.7
Steam Turbine (Gas)	12,787	6.4	19.7

* Includes units with an obligation to offer UCAP in the 2020/21 PRA. Excludes a small number of units that have an XEFORd of 0 and newer units that were not in operation prior to 9/1/2019.

** A few additional units are excluded from this resource class due to anomalous outage patterns.

39 Day-ahead margin is the hourly FRAC load forecast subtracted from the sum of max available MWs from online resources and those from offline resources with less than 24 hour offered notification/startup time. We also considered the top 5% real-time margin hours, but it produced very similar results.

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 submitted 20 minutes before the transaction period starts. 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 the system. On October 3, 2017, MISO implemented Coordinated Transaction Scheduling (CTS) with PJM that allows market participants to schedule transactions based on the forecasted price spread between markets. This section reviews the magnitude of the interchange and the efficiency of the scheduling process.

A. Overall Import and Export Patterns

Figure A133 to Figure A136: 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. 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. The third and fourth figures show the data by interface.

Figure A133: Average Hourly Day-Ahead Net Imports
2019

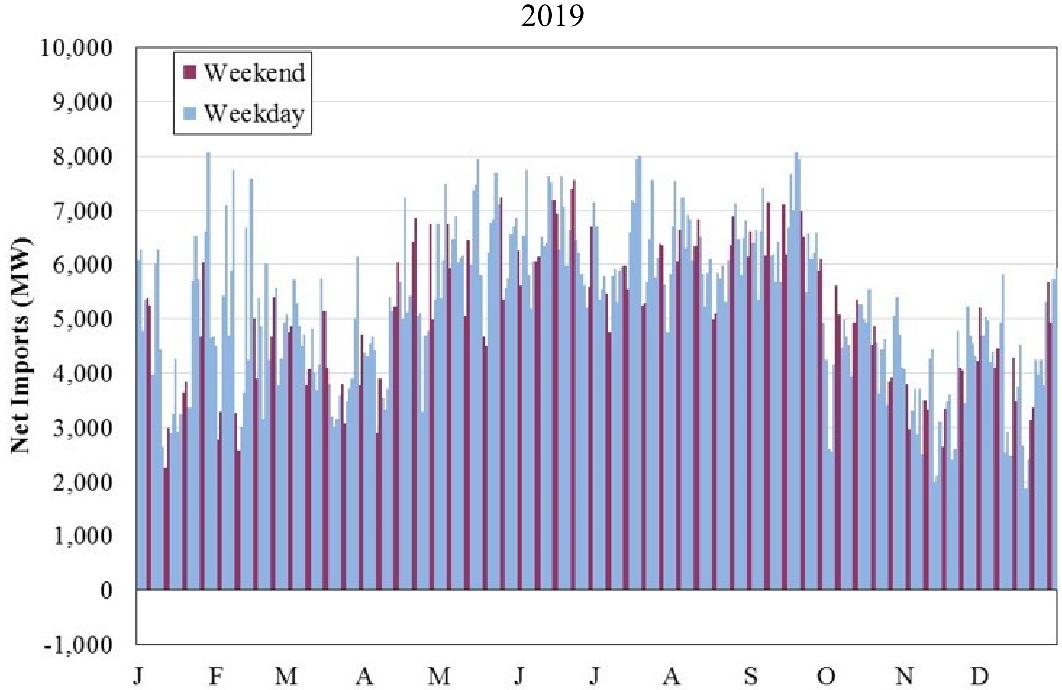


Figure A134: Average Hourly Real-Time Net Imports
2019

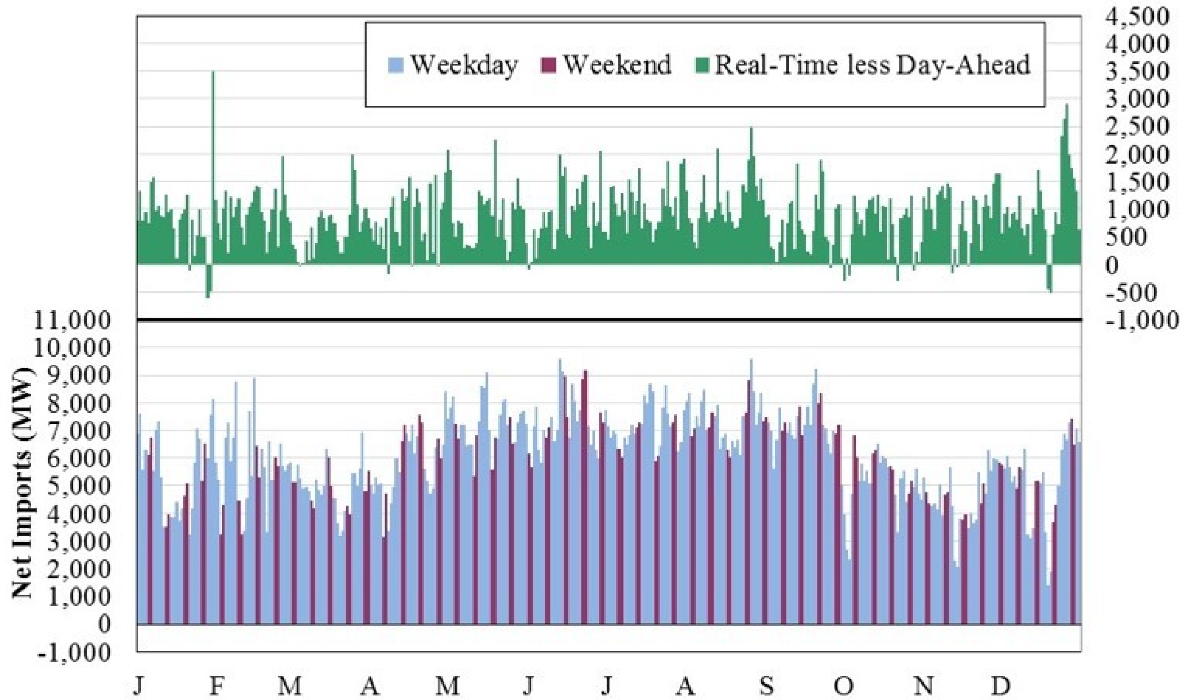


Figure A135: Average Hourly Day-Ahead Net Imports
2019, by Interface

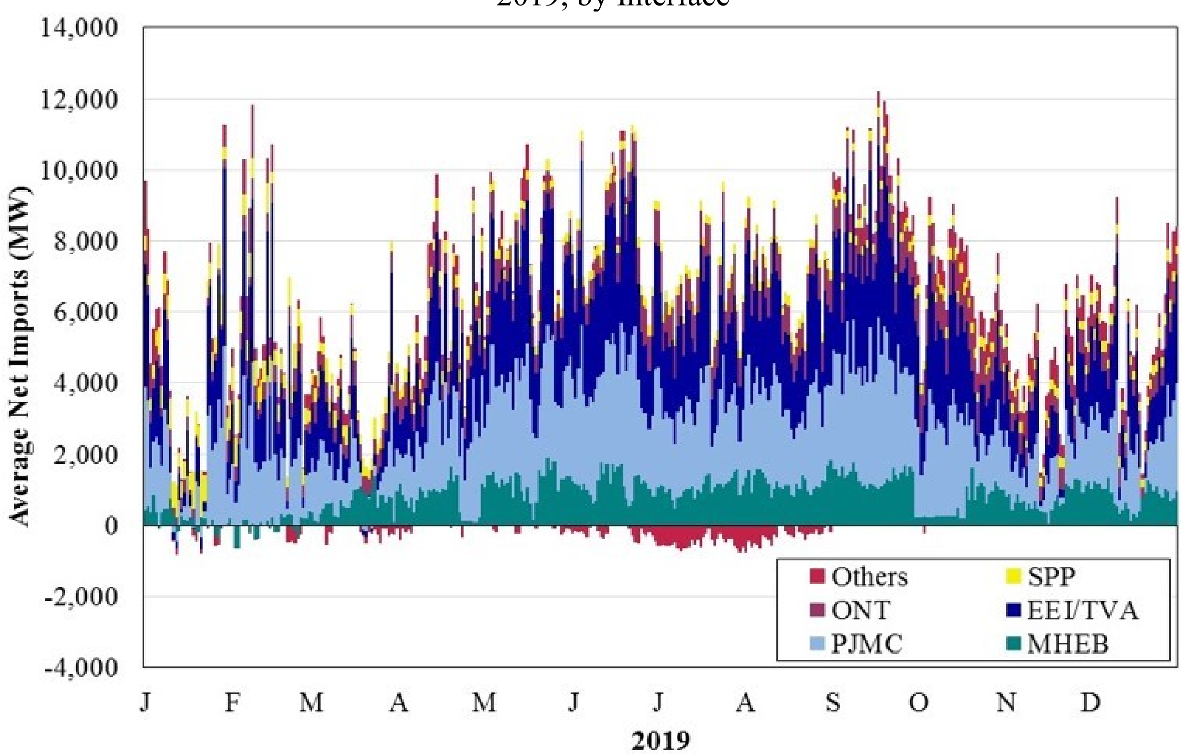


Figure A136: Average Hourly Real-Time Net Imports
2019, by Interface

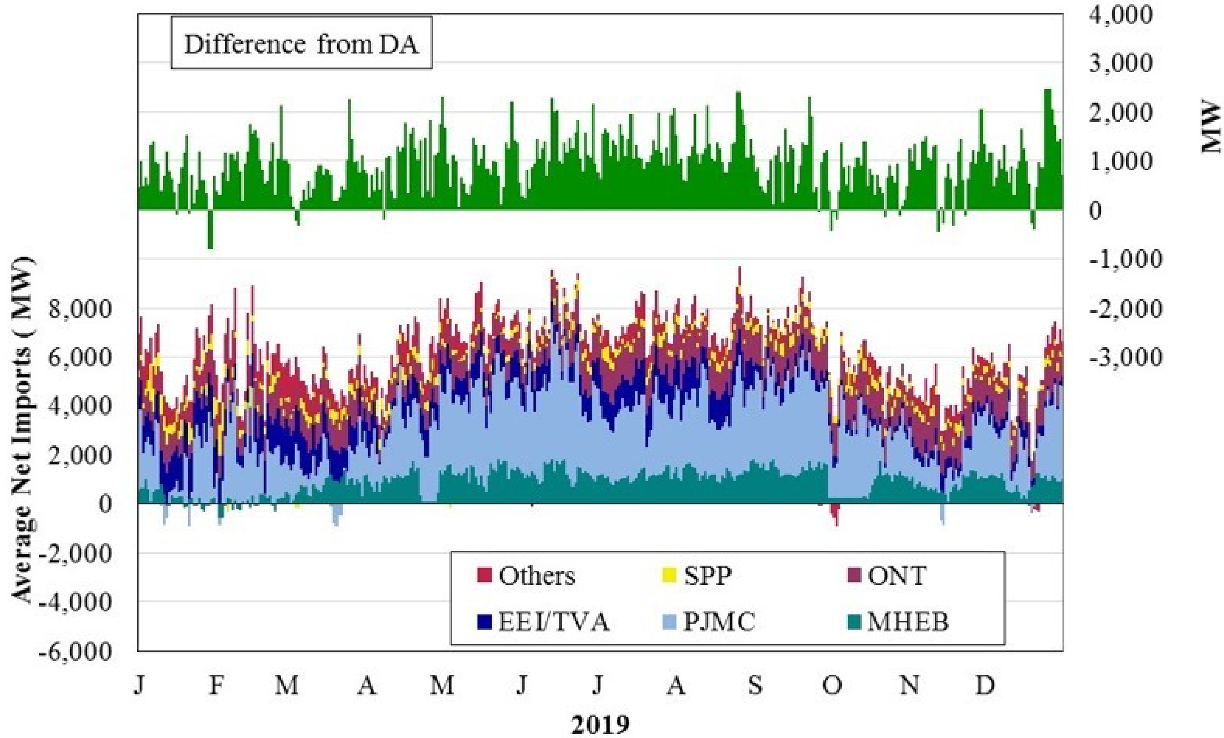


Figure A137 and Figure A138: Average Hourly Real-Time Net Imports by Interface

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 5 GW per hour. Relative prices in adjoining areas govern net interchange. Therefore, price movements cause participants' incentives to import or export to change over time.

Accordingly, Figure A137 shows the average quantity of net imports scheduled across the MISO-PJM interface in each hour of the day in 2018 and 2019, along with the standard deviation of such imports.[40] Figure A138 shows the same results for the two Canadian interfaces (Manitoba Hydro, at left, and Ontario).

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

Figure A137: Average Hourly Real-Time Net Imports from PJM
2018–2019

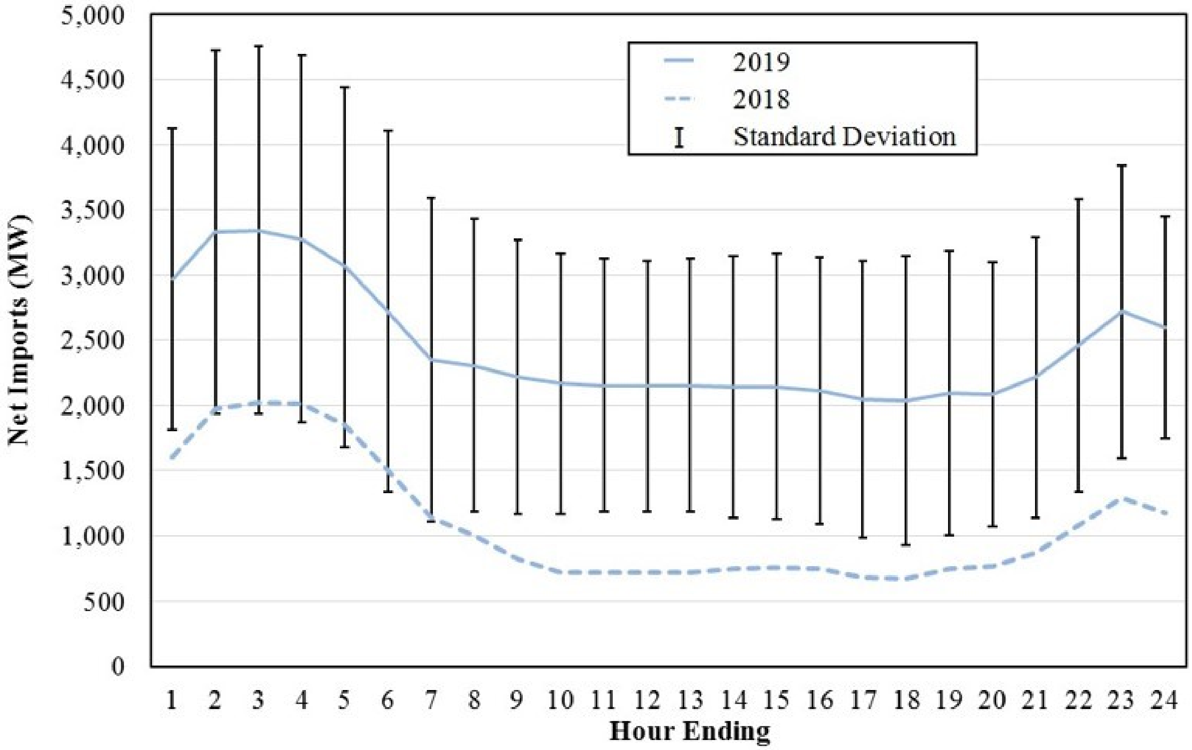
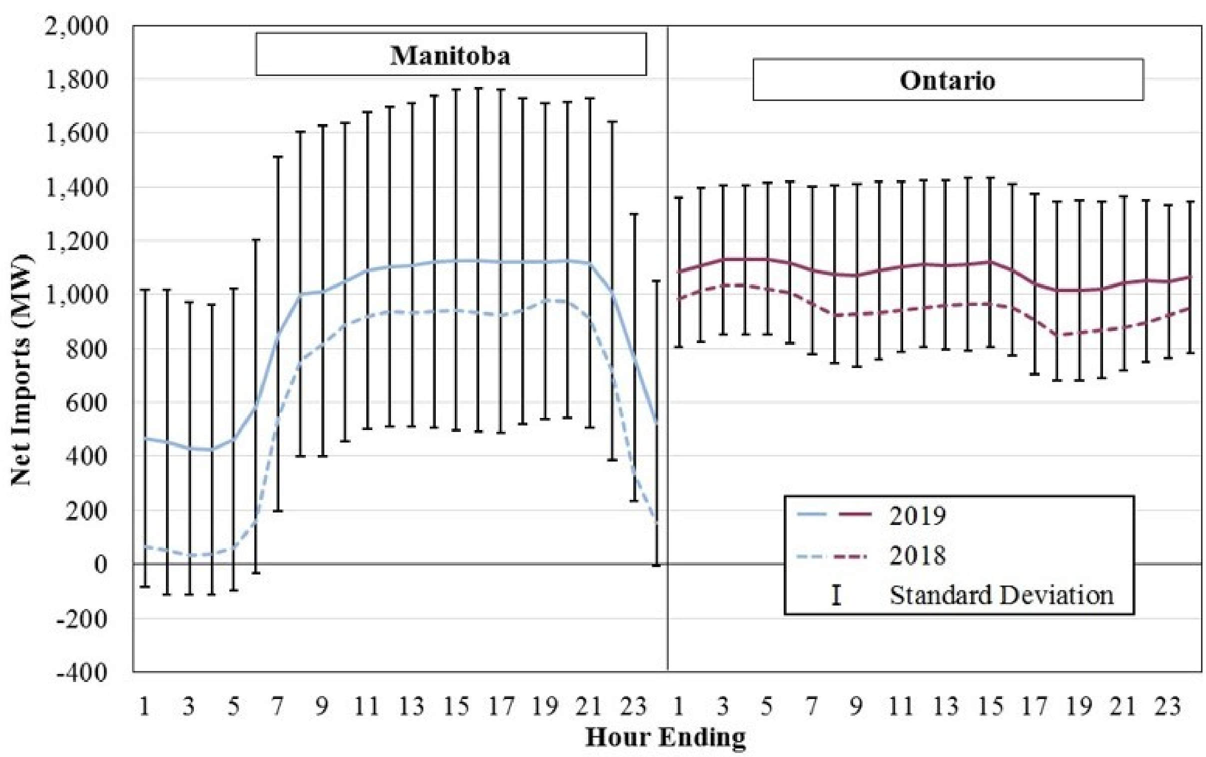


Figure A138: Average Hourly Real-Time Net Imports from Canada
2018–2019



B. Coordinated Transaction Scheduling

On October 3, 2017, MISO and PJM implemented Coordinated Transaction Scheduling (CTS). CTS allows market participants to submit offers to schedule imports or exports between the RTOs within the hour if the forecasted spread between the MISO and PJM real-time interface prices is greater than the offer price. Participants' offers, which can be multi-part offers with separate prices for increasing quantities, must be submitted 75 minutes before the specific interval. Offers then clear if they are greater than the spread in forecasted interface prices 30 minutes prior to the interval. CTS transactions are settled based on real-time interface prices.

Figure A139: CTS vs. Traditional NSI Scheduling

Since its inception in October 2017, there has been very little participation in CTS. We have previously shown that high transmission and energy charges have deterred traders from using CTS in lieu of traditional transaction scheduling. To determine the impact that the transaction fees have on CTS, we conducted an analysis comparing:

- a scheduling strategy using CTS offers, to:
- a strategy using short-lead time transactions scheduled 30 minutes ahead (i.e., the traditional means of scheduling transactions).

Excluding the charges applied to CTS transactions, the CTS transactions should be more profitable if the mechanism operates effectively because participants are able to submit an offer price. In contrast, the traditional scheduling mechanism requires participants to submit transactions that are not price-sensitive and are based on their expectations of the price spreads that will exist when the transactions are flowing.

We used 2018 and 2019 for our analysis but excluded a time period with a forecasting bias that MISO had to correct (June 12, 2018 through March 15, 2019). The results of our analysis are shown in Figure A139 below.

In this analysis, we compare 1 MW CTS transactions offered at various target spreads, from $0 to $20 in increments of $5, to 1 MW short-lead scheduled transactions initiated when the actual real-time interface price spread 30-minutes prior to the transaction exceeded the applicable target spread. Our analysis applies to both imports and exports. All offered CTS exports incur reservation charges of $0.75 per MWh and an additional $1.75 per MWh if they clear. Offered CTS imports incur reservation charges of $0.28 per MWh and an additional $0.55 per MWh if they clear. Cleared short-lead transactions incur the total costs listed above, based on direction. The CTS transactions tend to incur much higher costs because they incur a reservation charge for every MW bid/offered even though a very small share clear.

In Figure A139, the solid bars represent gross profits ($ per MWh) from each strategy, and the diamonds represent net $ per MWh revenues (including reservation and other market charges).

Figure A139: CTS vs. Traditional NSI Scheduling
2018–2019

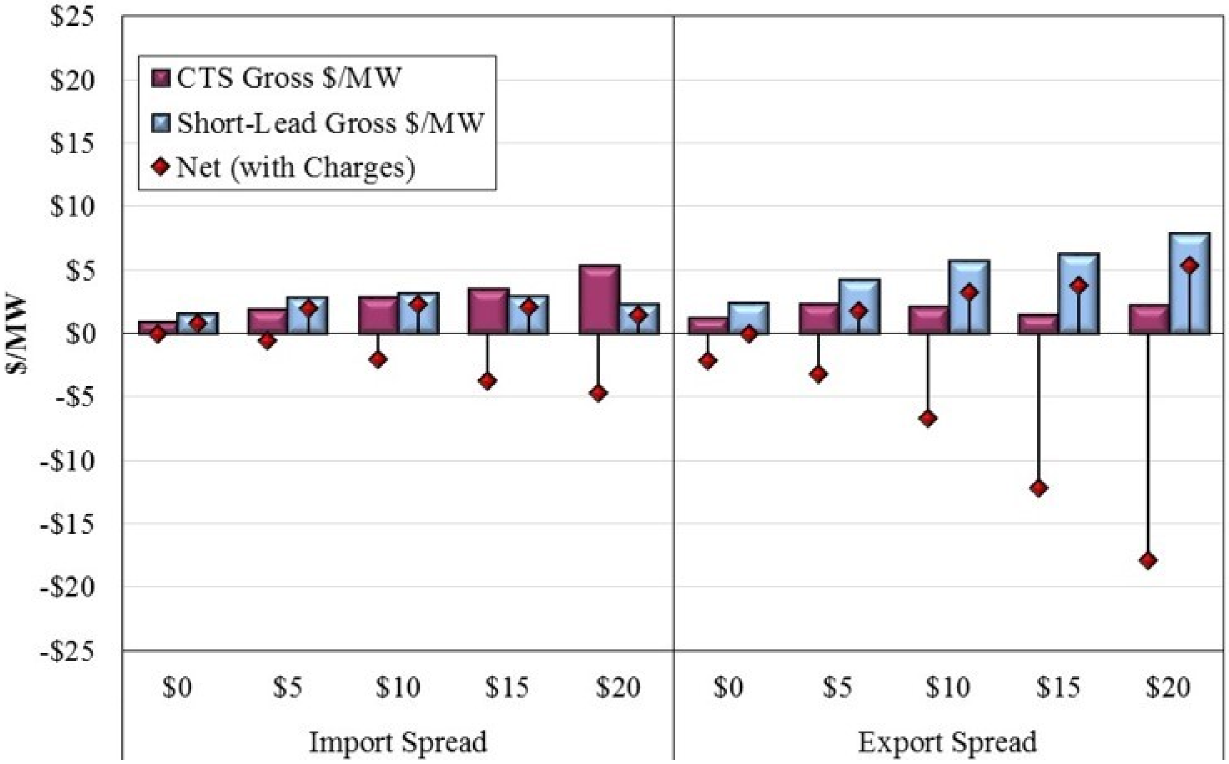
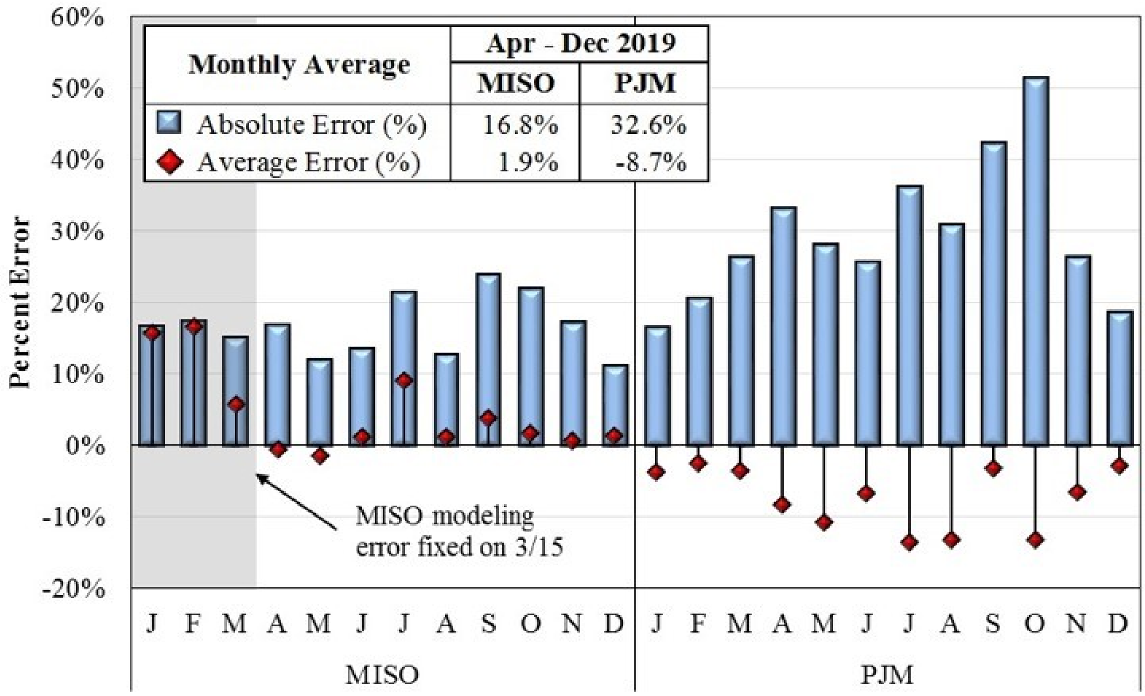


Figure A140: MISO and PJM CTS Forecast Errors

The adoption of CTS has been limited because of persistent forecasting errors in both MISO and PJM. We measured the difference between the actual LMP and the forecasted price used for CTS. In Figure A140, we show the differences by month as a share of average LMPs, in both average and absolute average terms.

The red diamonds represent the monthly average of the differences between the real-time LMPs at the respective RTOs' interface (five-minute prices averaged to 15-minute intervals) and the 15-minute forecasted interface prices used for CTS, expressed as the percentage difference relative to average real-time LMPs. Positive error means that the forecasted prices, on average, were lower than real-time LMPs, while negative error means the forecasted prices were higher. The blue bars show this error calculation in absolute terms. The annual errors in the table are an average of all the respective monthly values, excluding January through March when there was a known bias in the MISO forecast.

Figure A140: MISO and PJM CTS Forecast Errors
2019



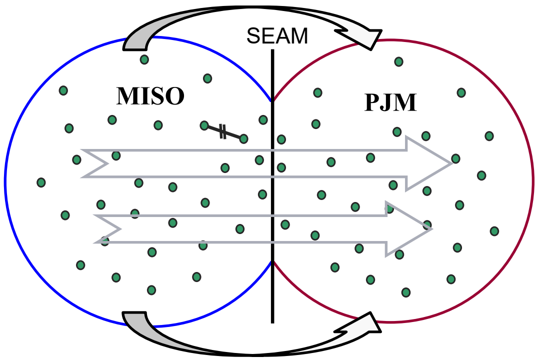
C. Interface Pricing and External Transactions

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 flows between the RTOs to arbitrage differences 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.

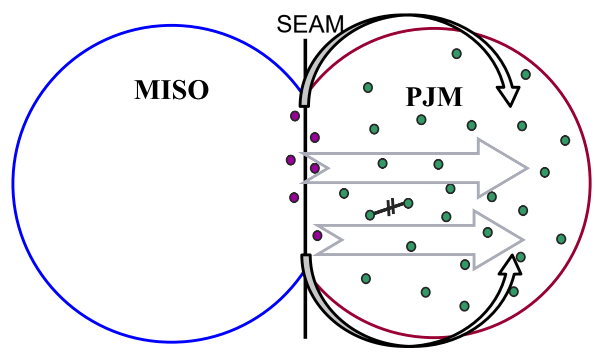
Establishing efficient interface prices would be simple in the absence of transmission congestion and losses – each RTO would simply post the interface price as the cost of the marginal resource on their system (the system marginal price, or "SMP"). Participants would respond by scheduling from the lower-cost system to the higher-cost system until the SMPs equalize. However, congestion is pervasive on these systems, so the fundamental issue with interface pricing is estimating the congestion costs and benefits from imports and exports.

Like the LMP 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 the actual source or sink of the power, the interface price will provide an efficient transaction scheduling incentive and lower the costs for both systems.



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 below on the left. This figure 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.

Because both RTO's price congestion on M2M constraints, some congestion had been redundantly priced by MISO and PJM. To address this concern, PJM and MISO agreed to implement a "common interface" that assumes the power sources and sinks from the border with MISO, as shown in the second figure on the right below. This common interface" consists of 10 generator locations near the PJM seam with five points in MISO's market and five in PJM. This approach tends to exaggerate the flow effects of imports and exports on constraints 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 are concerned that the common interface definition sets inefficient interface prices. Our interface pricing studies show that in aggregate, the common interface has led to larger average errors and volatility at the interface. These results indicate that this approach was a mistake. Fortunately, MISO only uses this type of interface definition at the PJM interface, whereas PJM uses this approach on all of its interfaces.

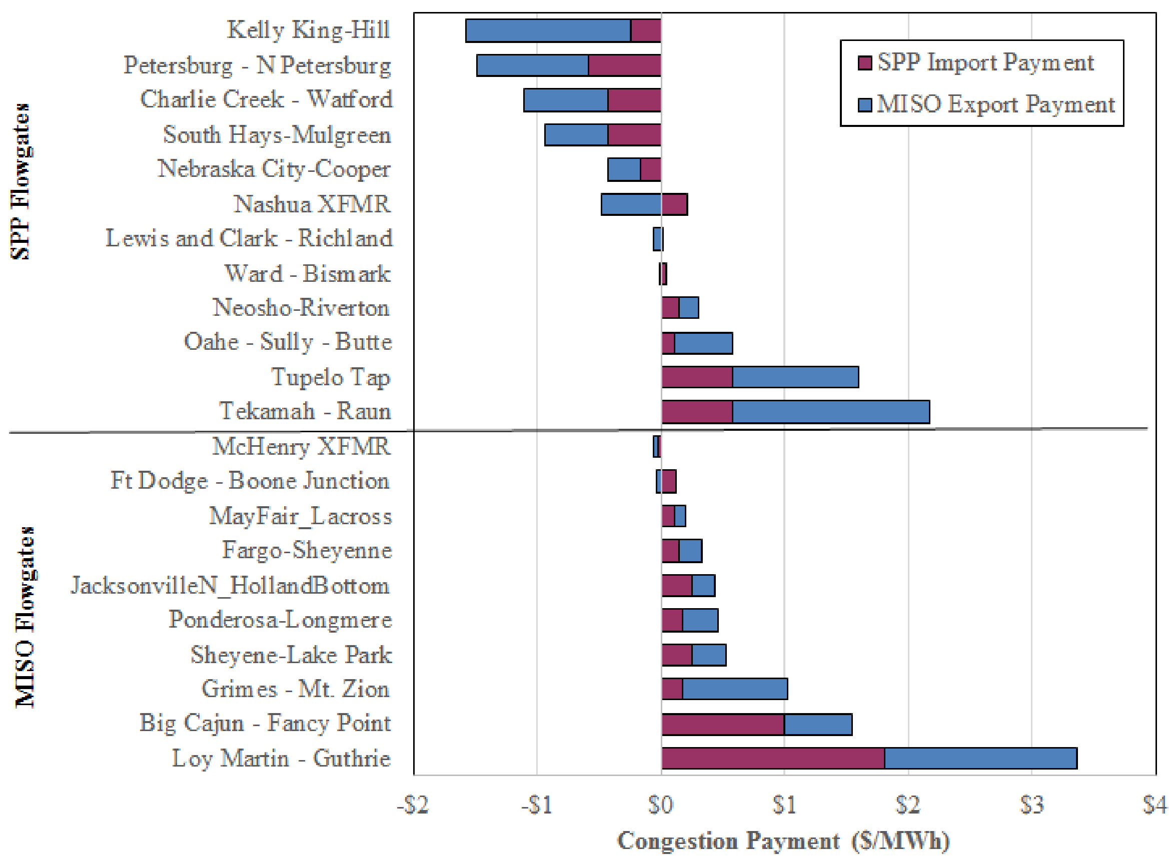
We have recently studied interface pricing at the MISO-SPP interface in collaboration with the SPP MMU. We have verified that redundant congestion pricing is still occurring based on their overlapping interface definitions. Given our findings regarding the common interface approach adopted with PJM, this approach should not be considered at the SPP interface. Selected analyses of the MISO-SPP interface are described below.

Figure A141: Real-Time Congestion Pricing at the SPP-MISO Interface

Both MISO and SPP both employ reasonable interface definitions to estimate how imports from and exports to the other area will affect their transmission constraints. An unintended consequence of this is how congestion is priced on M2M constraints because they are activated and modeled in both RTOs' real-time markets. This causes SPP and MISO to "double pay" transactions for the congestion effects on M2M constraints.

To show how this occurs, we have calculated the average interface pricing component associated with selected individual M2M constraints. These coordinated constraints had congestion values exceeding $1 million between June 2018 and May 2019. Figure A141 shows the congestion component calculated by both SPP and MISO for each constraint, separately showing MISO constraints and SPP constraints. The congestion payments are displayed as the settlement of an export transaction from MISO to SPP. A negative value indicates that the participant would be charged the corresponding amount; whereas, a positive value indicates that the participant would be paid for congestion relief.

Figure A141: Real-Time Congestion Pricing at the SPP-MISO Interface



Even though their interface definitions differ, this figure shows that both RTOs estimate very similar effects on each of the jointly managed constraints. Unfortunately, this results in congestion payments and charges that are roughly double the efficient level. The payments made by the MRTO alone are efficient because they reflect the marginal cost of managing the constraint.

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.[41] 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 this inequity, these congestion payments motivate participants to schedule transactions inefficiently for at least 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 IESO calls a TLR, it will establish an interface price (or congestion settlement) for a transaction over its interface with MISO that includes the effect of the transaction on its own constraint. MISO's additional payment is redundant 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 compensates schedulers for inefficient added relief at the expense of MISO customers.

Finally, MISO's shadow cost for external TLR constraints is frequently and significantly overstated compared to the monitoring system operator's true marginal cost of managing the congestion on the constraint. As shown above in Section V.G, this causes the congestion component of the interface prices associated with TLR constraints to be highly distortionary and provides inefficient scheduling incentives.

D. Price Convergence Between MISO and Adjacent Markets

Like other markets, MISO relies on participants to increase or decrease net imports to cause prices to converge with adjacent markets. Given future price uncertainty when transactions are scheduled, perfect convergence is not expected. Transactions can start and stop at 15-minute intervals during an hour and must be scheduled 20 minutes in advance of the operating period.

Figure A142 and Figure A143: 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. Figure A142 shows these results for the MISO-PJM interface, and Figure A143 shows the results for the MISO-IESO interface.

41 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.

Figure A142: Real-Time Prices and Interface Schedules
PJM and MISO, 2019

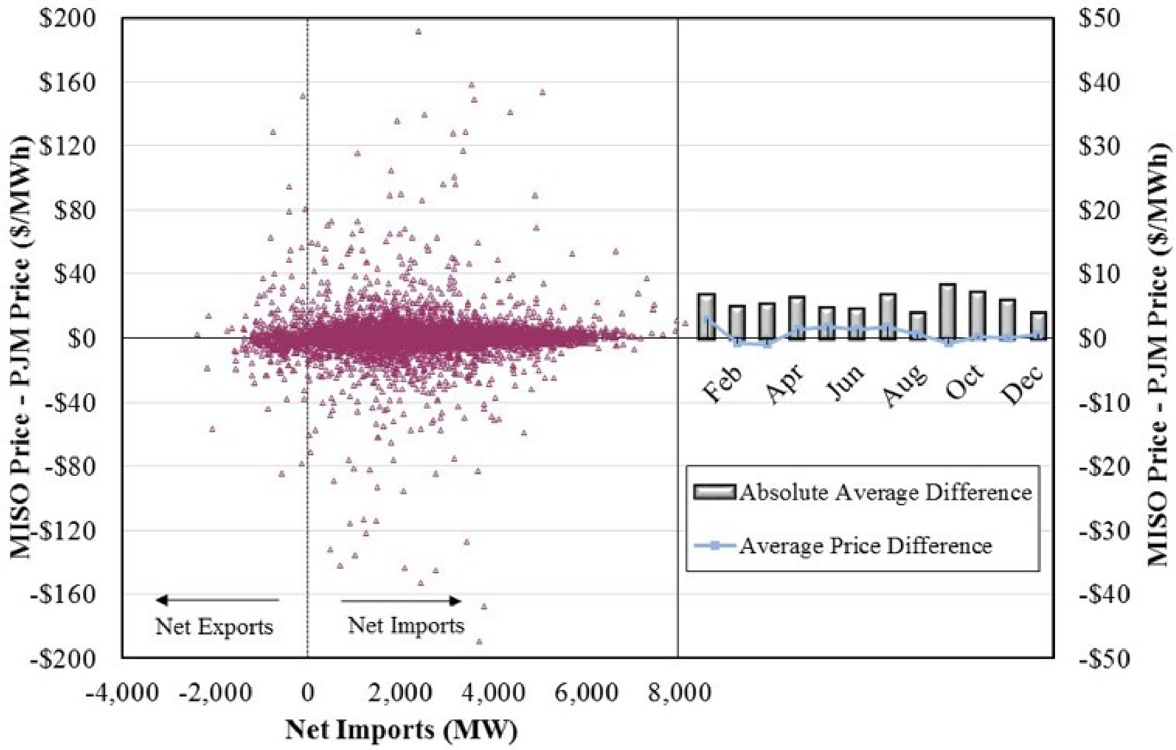
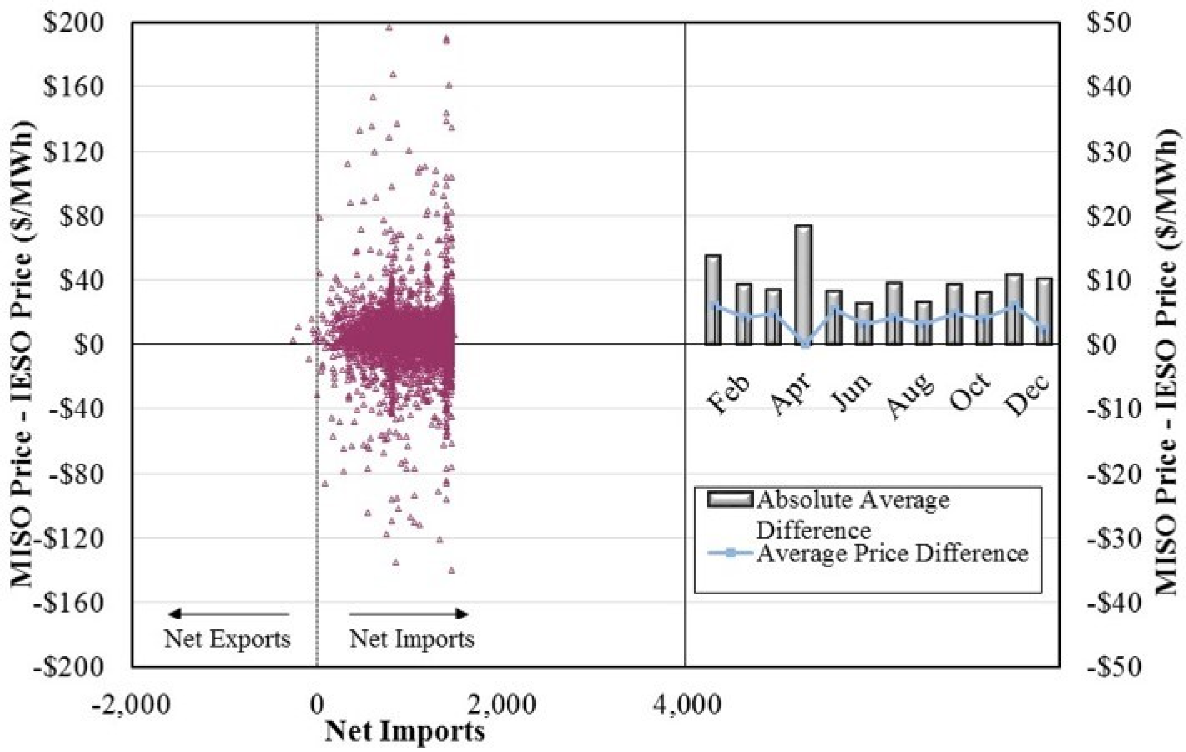


Figure A143: Real-Time Prices and Interface Schedules
IESO and MISO, 2019



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 susceptible to the exercise of market power.

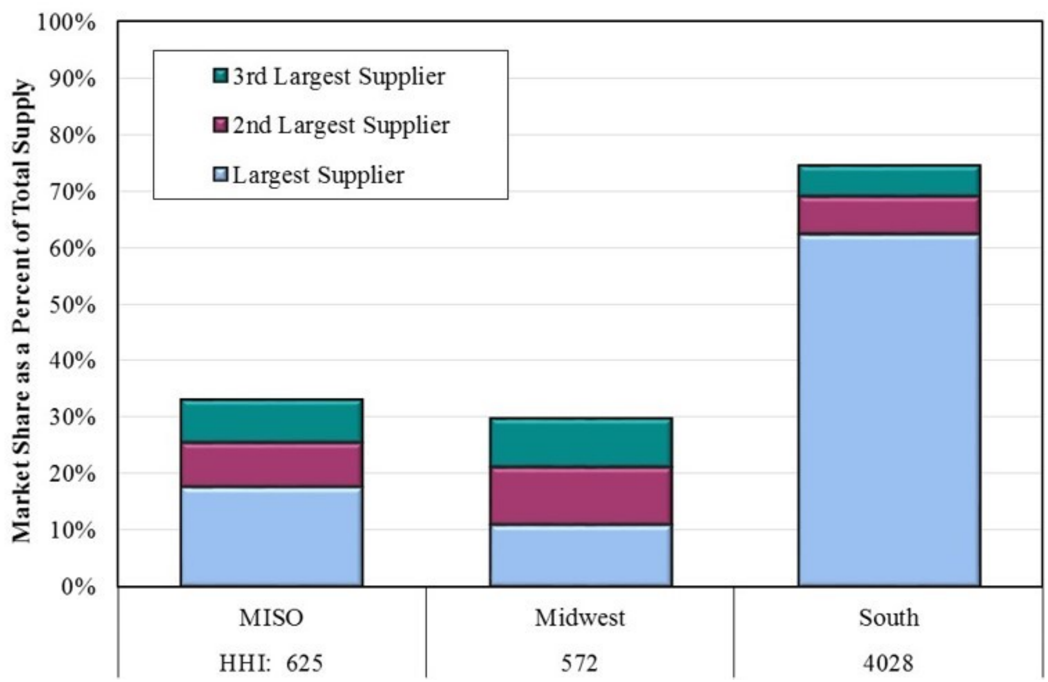
A. Structural Market Power Indicators

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 A144: Market Shares and Market Concentration by Region

The first analysis shows the market concentration using the Herfindahl-Hirschman Index (HHI). The HHI is calculated by summing the square of each participant's market share in percentage terms. Antitrust agencies characterize markets with an HHI less than 1000 as unconcentrated and those with an HHI in excess of 1800 as highly concentrated. Figure A144 shows generating capacity-based market shares and HHIs for MISO and its subregions.

Figure A144: Market Shares and Market Concentration by Region
2019



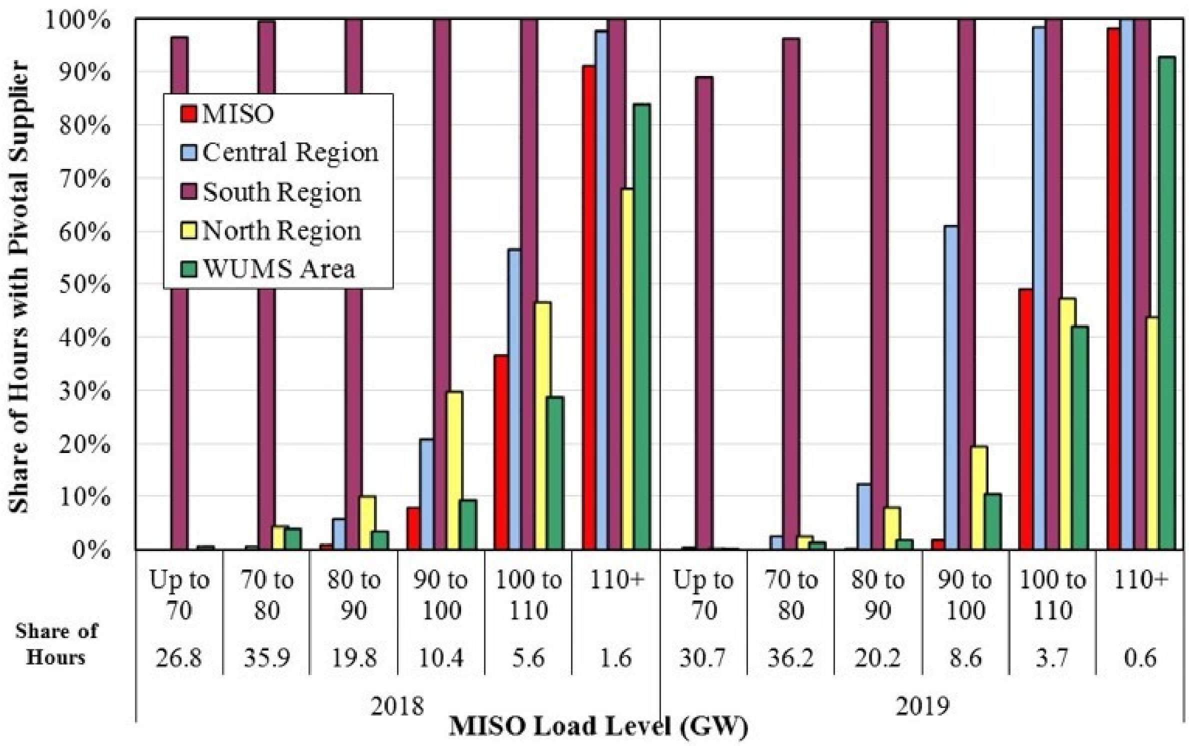
Market shares and the HHI are only general indicators of market concentration and not a definitive measure of market power. The most significant shortcoming of market shares and HHIs for identification of market power in electricity markets is that they generally do not account for demand or network constraints. In wholesale electricity markets, these factors have a profound effect on competitiveness. Because market shares and HHI do not recognize the physical characteristics of electricity that can cause a supplier to have market power under various conditions, these measure alone do 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 A145: Pivotal Supplier Frequency by Region and Load Level

A better measure of potential market power is the pivotal supplier metric. This metric considers both the supply, demand, and import capability into the market. A supplier is pivotal when some of its resources are needed to satisfy the demand (i.e., it is a monopolist over some portion of the load).

Figure A145 summarizes the results of this analysis, showing the percentage of total hours with a pivotal supplier by region and load level. Prices are most sensitive to withholding under high-load conditions, which makes it more likely that a supplier could profitably exercise market power in those hours. The percentages shown below the horizontal axis indicate the share of hours that comprise each load-level share.

Figure A145: Pivotal Supplier Frequency by Region and Load Level
2018–2019



While the regional 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, indicates 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 load 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 or a substantial share 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), including *Dynamic* Narrow Constrained Areas. 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 MISO Midwest (the Minnesota NCA, the WUMS NCA, and the North WUMS NCA) and two in MISO South (WOTAB and Amite South NCAs).[42]

Market power associated with BCA constraints can also be significant. When a non-NCA transmission constraint binds, a BCA is defined that includes all resources that significantly affect the power flows on the constraint. BCA constraints are not chronic like NCA constraints. However, they can raise competitive concerns. Because of 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 A146 to Figure A149: Pivotal Suppliers on Transmission Constraints

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 A146 to Figure A149 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 A148 and Figure A149 show the percentage of the intervals with active constraints in each month by region with at least one pivotal supplier. For the purposes of this analysis, the WUMS and North WUMS NCAs in the Midwest region are combined.

42 Based on the results of the NCA threshold calculation specified in Tariff Section 64.1.2.d, the conduct-impact thresholds that applied to the NCAs for most of 2019 ranged from $27.56 per MWh in North WUMS to $100.00 per MWh in Amite South. The WUMS, WOTAB, and Minnesota thresholds were $30.55, $59.19, and $55.55 per MWh, respectively.

Figure A146: Percentage of Intervals with at Least One Pivotal Supplier
Midwest Region, 2019

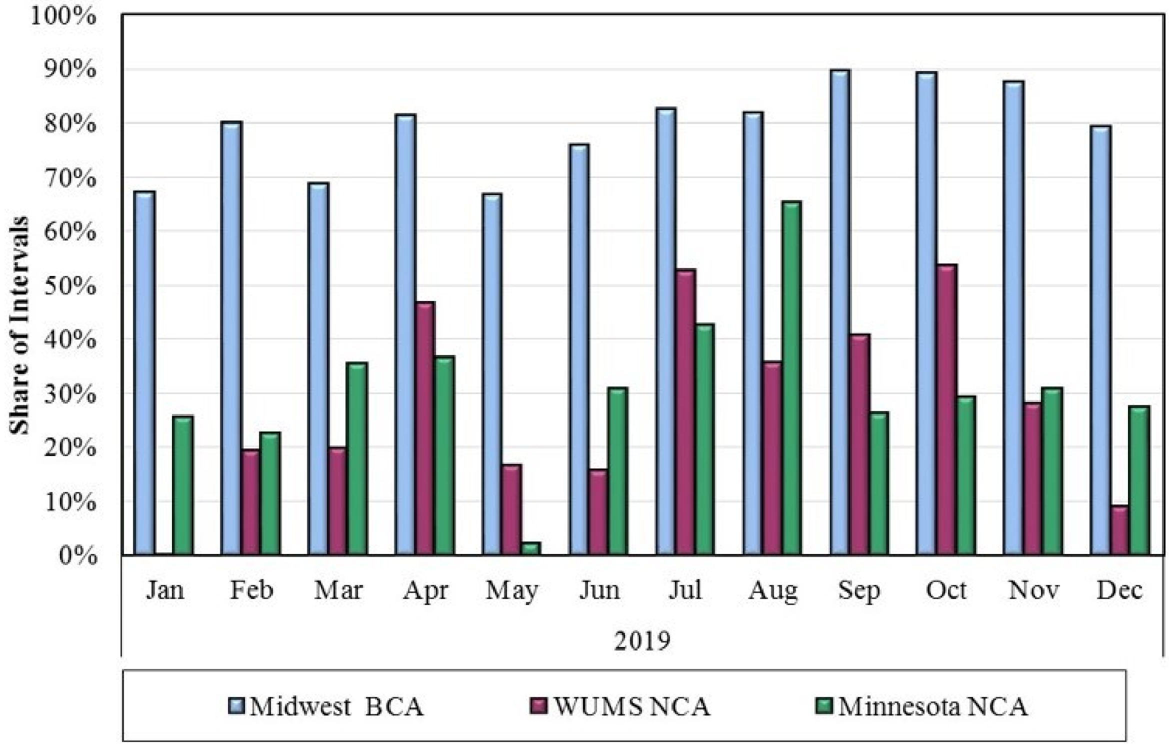


Figure A147: Percentage of Intervals with at Least One Pivotal Supplier
MISO South, 2019

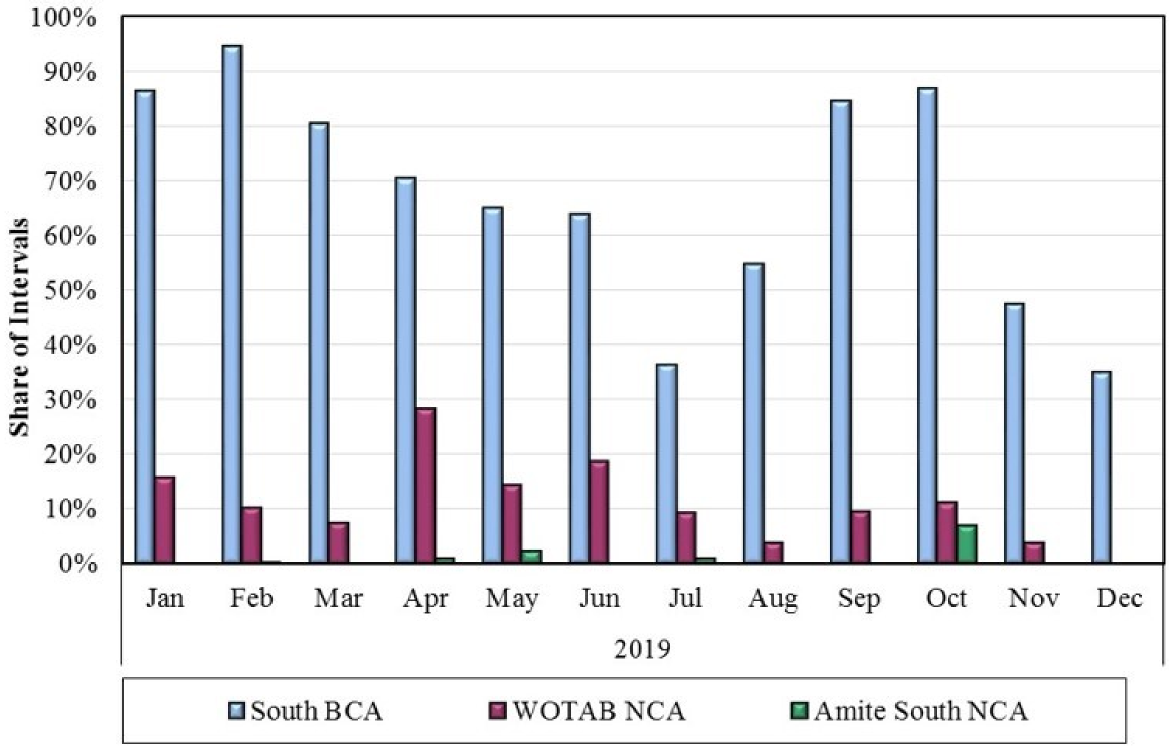


Figure A148: Percentage of Active Constraints with a Pivotal Supplier
Midwest Region, 2019

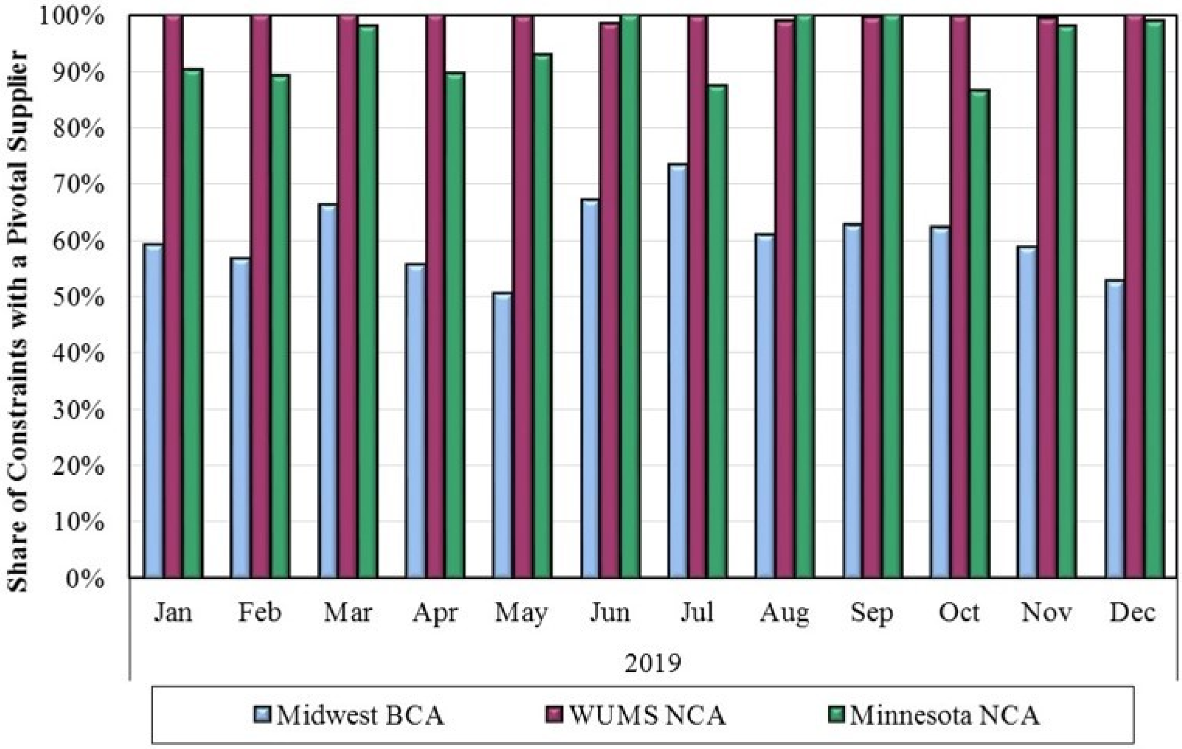
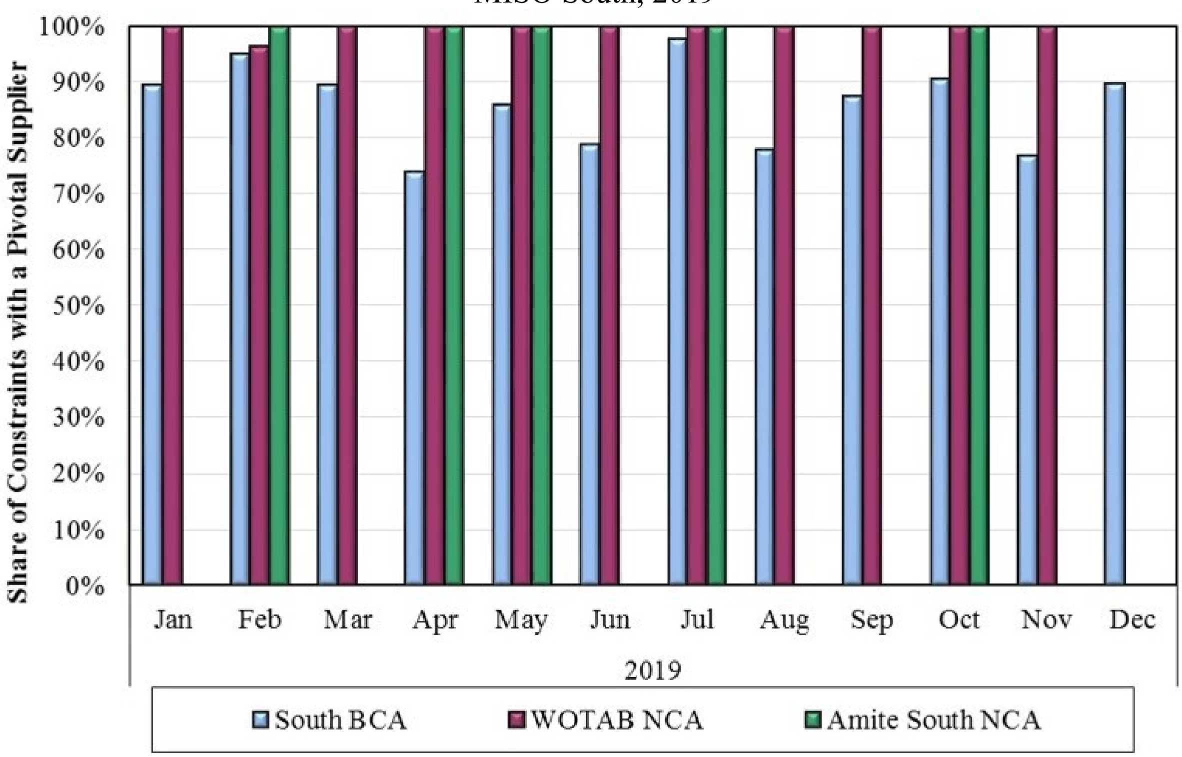


Figure A149: Percentage of Active Constraints with a Pivotal Supplier
MISO South, 2019



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 its resource at a price substantially above a competitive offer (i.e., above its marginal cost) 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 costs. 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. Nonetheless, we found an average system marginal price-cost mark-up of *approximately zero* (–0.1 percent) in 2019, varying monthly from a high of 5.4 percent to a low of -3.7 percent. The negligible average mark-up indicates that MISO markets were highly competitive. Mark-ups of less than three percent lie within the bounds of highly competitive expectations.

We found an average system marginal price-cost mark-up of –0.1 percent in 2019, varying monthly from a high of 5.4 percent to a low of -3.7 percent. The negligible average mark-up indicates that MISO's energy markets produced very competitive results.

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.[43] 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 market power mitigation. The second prerequisite is the "impact test," which requires that the identified conduct significantly affect market prices or guarantee payments.

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 the unit's 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.

43 See Module D, Section 62.a, which 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."

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 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 A150: Economic Withholding – Output Gap Analysis

Figure A150 shows monthly average output gap levels for the real-time market in 2018 and 2019. The output gap shown in the figure and summarized in the table includes two types of units:

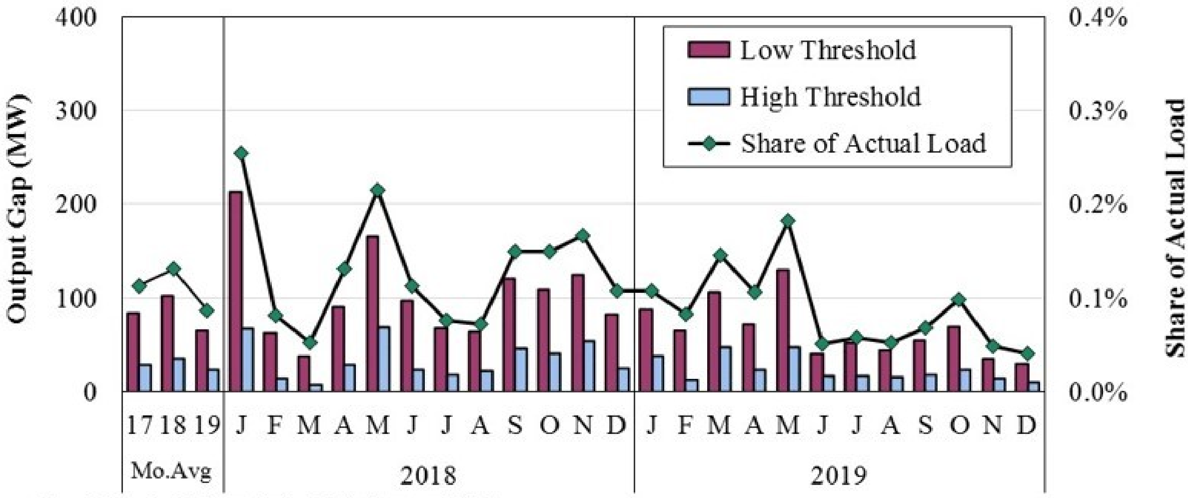
(1) online and quick-start units available in real time, and

(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 beginning on June 1, 2019 were $30.55 per MWh for resources located in the WUMS NCA, $27.56 for those in the North WUMS NCA, $55.55 for those in the Minnesota NCA, and $59.19 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 A150: Economic Withholding – Output Gap Analysis
2018–2019



Low Threshold Results by Unit Status (MW)

	17	18	19	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Offline	6	12	13	30	0	0	3	41	12	4	9	17	17	6	3	30	2	31	12	15	8	9	9	10	15	10	5
Online	78	90	52	182	63	37	88	124	84	64	54	102	90	118	78	56	63	75	60	114	33	42	36	45	54	25	25

High Threshold Results by Unit Status (MW)

	17	18	19	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Offline	6	10	11	20	0	0	2	35	9	3	9	16	16	5	3	24	2	28	8	10	7	9	8	8	11	10	5
Online	23	24	12	46	14	7	26	33	15	15	13	30	24	48	21	13	11	19	15	36	9	8	7	10	12	4	4

Figure A151 to Figure A154: Real-Time Average Output Gap and Load

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 A151: Real-Time Average Output Gap and Load
Central Region, 2019

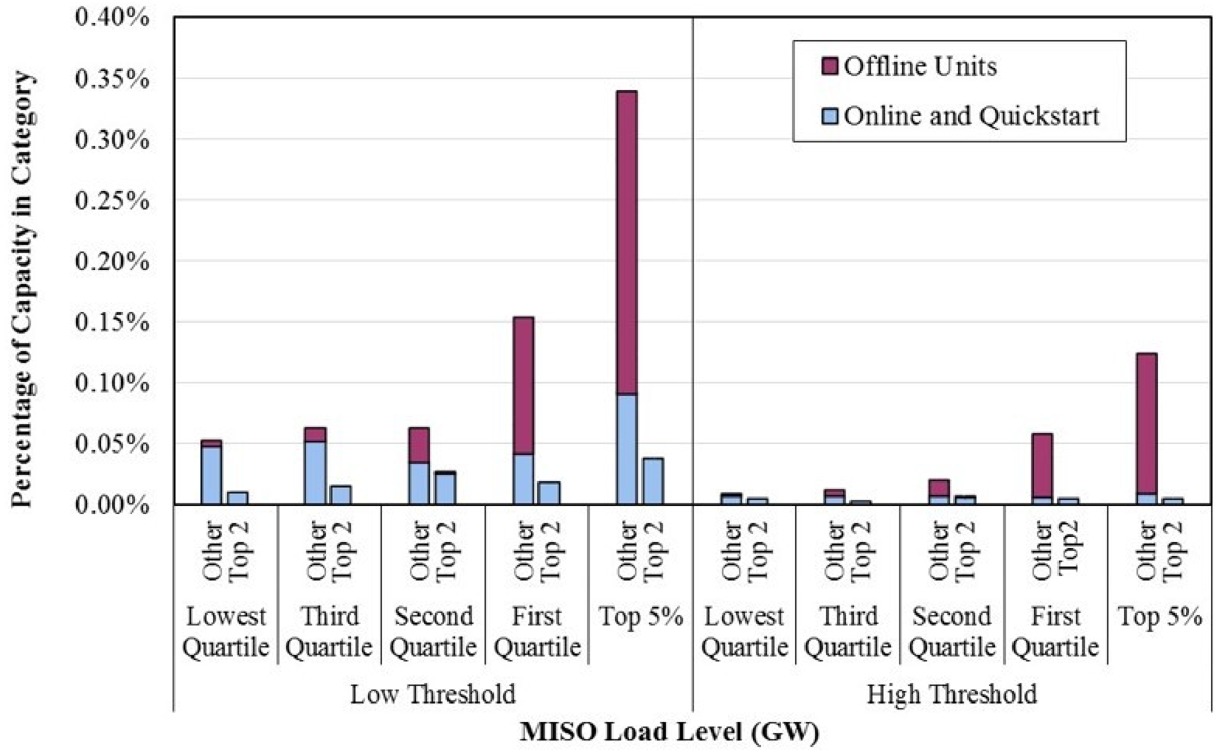


Figure A152: Real-Time Average Output Gap and Load
MISO South, 2019

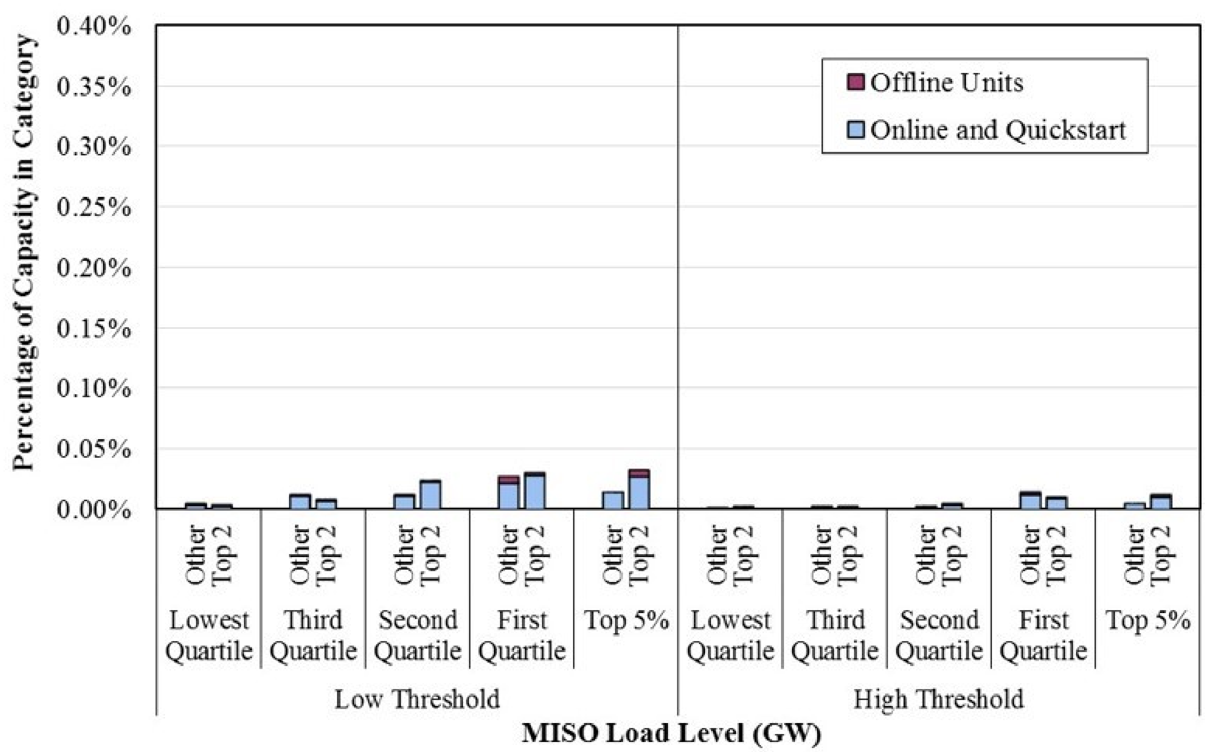


Figure A153: Real-Time Average Output Gap and Load
North Region, 2019

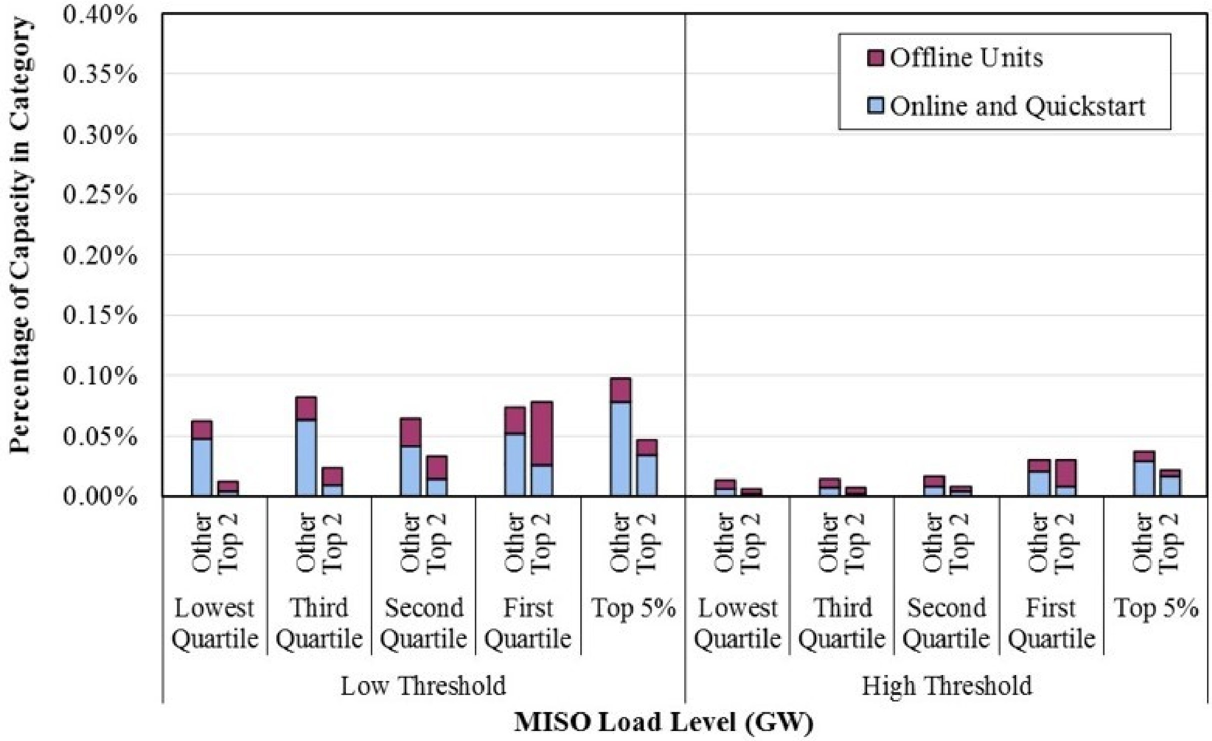
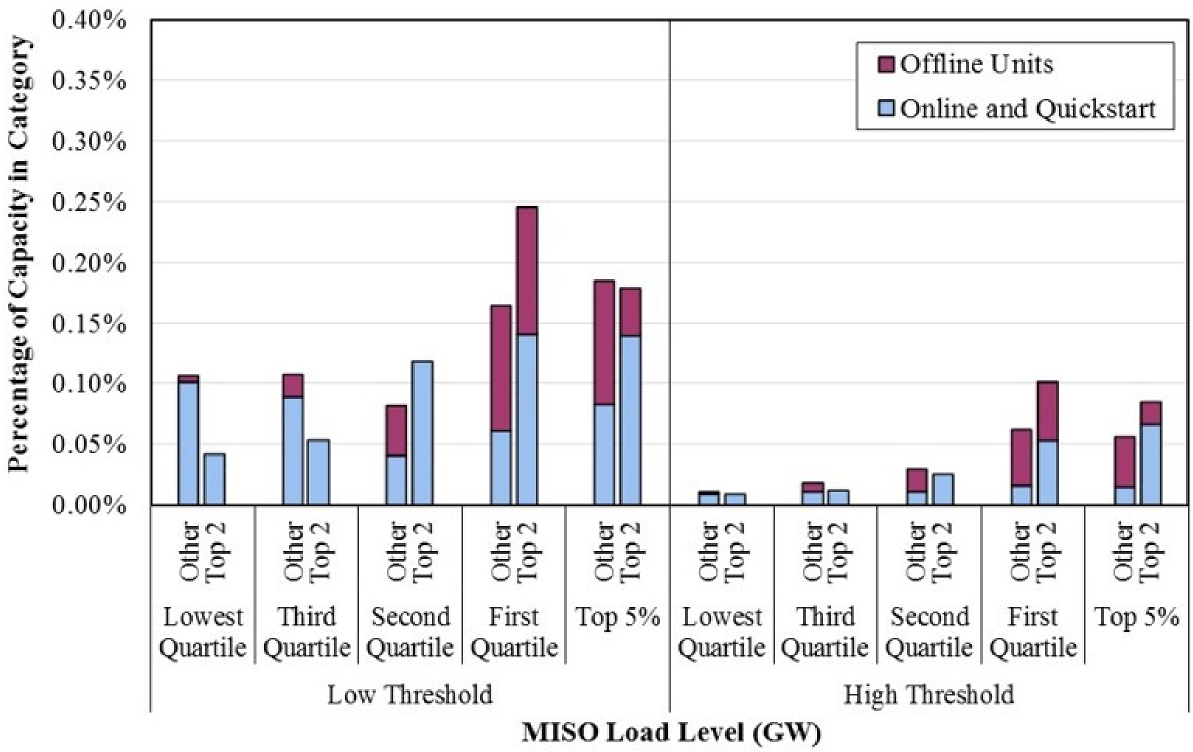


Figure A154: Real-Time Average Output Gap and Load
WUMS Area, 2019



D. Market Power Mitigation

In this next subsection, we examine the frequency with which market power mitigation measures were imposed in MISO markets in 2019. 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 A155: Day-Ahead and Real-Time Energy Offer Mitigation by Month

Figure A155 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, both of which provide liquidity. This makes the day-ahead market much less vulnerable to withholding and market power.

Figure A155: Day-Ahead and Real-Time Energy Offer Mitigation by Month

2019

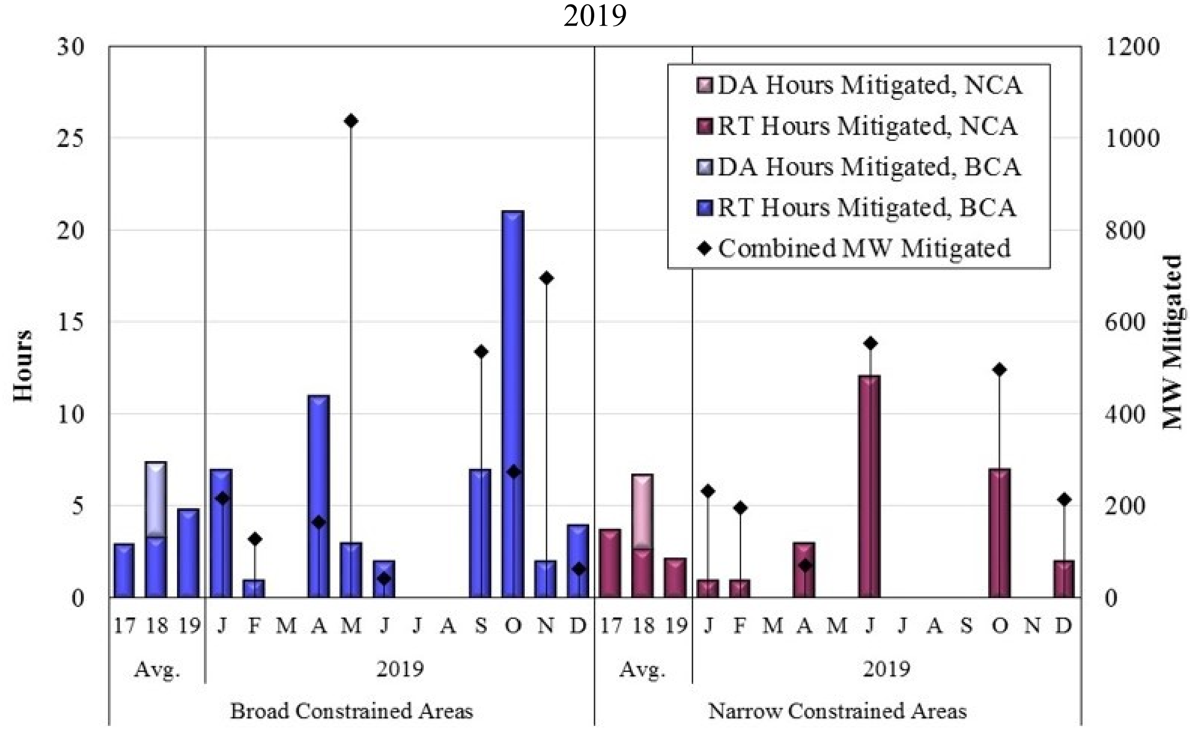
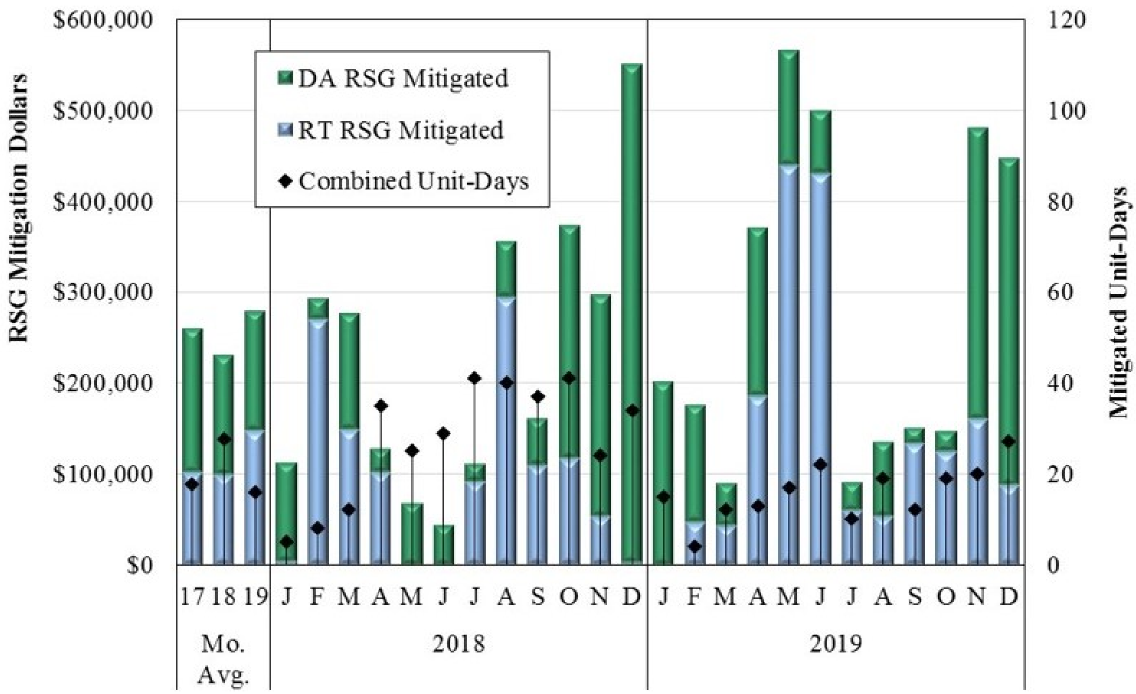


Figure A156: Day-Ahead and Real-Time RSG Mitigation by Month

Participants can exercise market power by raising their offers when their units 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: (1) the unit is committed for a constraint or a local reliability issue; (2) the unit's offer exceeds the conduct threshold of: the greater of $25 or a 25 percent increase in production costs. Figure A156 shows the frequency and amount by which RSG payments were mitigated in 2018 and 2019 and average amounts for the last three years.

Figure A156: Day-Ahead and Real-Time RSG Mitigation by Month
2018–2019



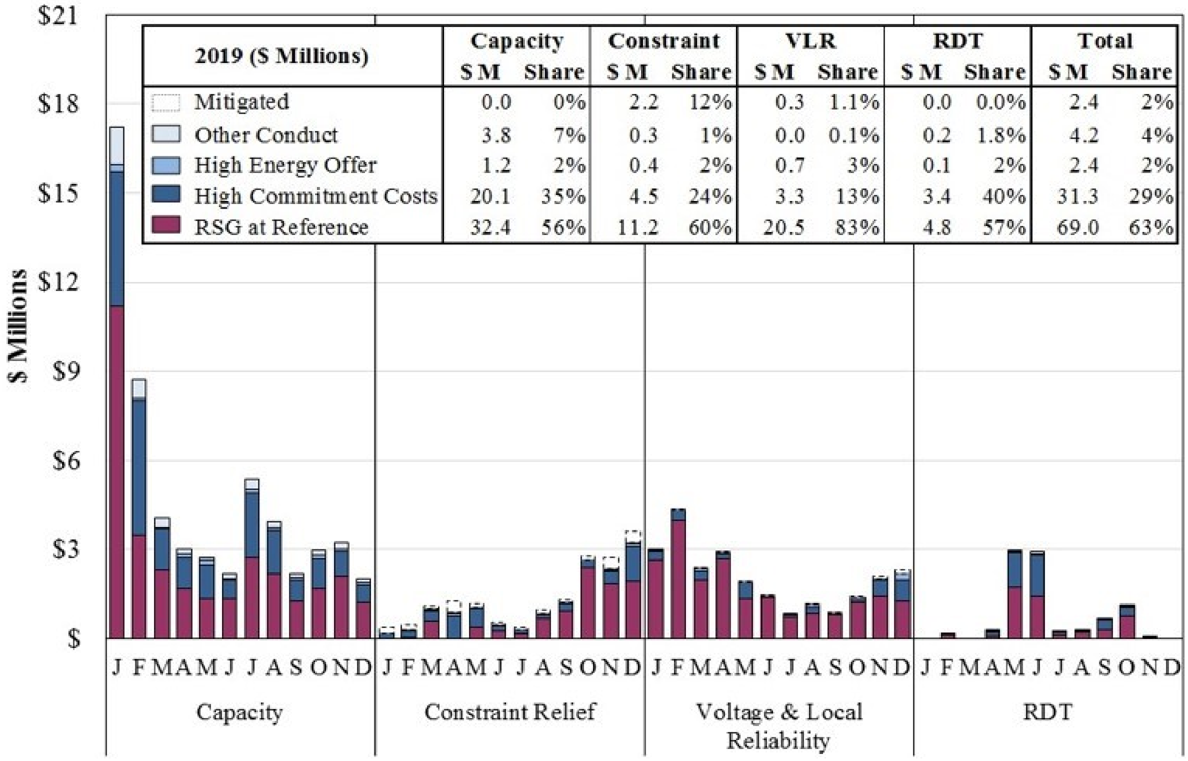
E. Evaluation of RSG Conduct and Mitigation Rules

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

Figure A157 to Figure A159: Real-Time RSG Payments by Conduct

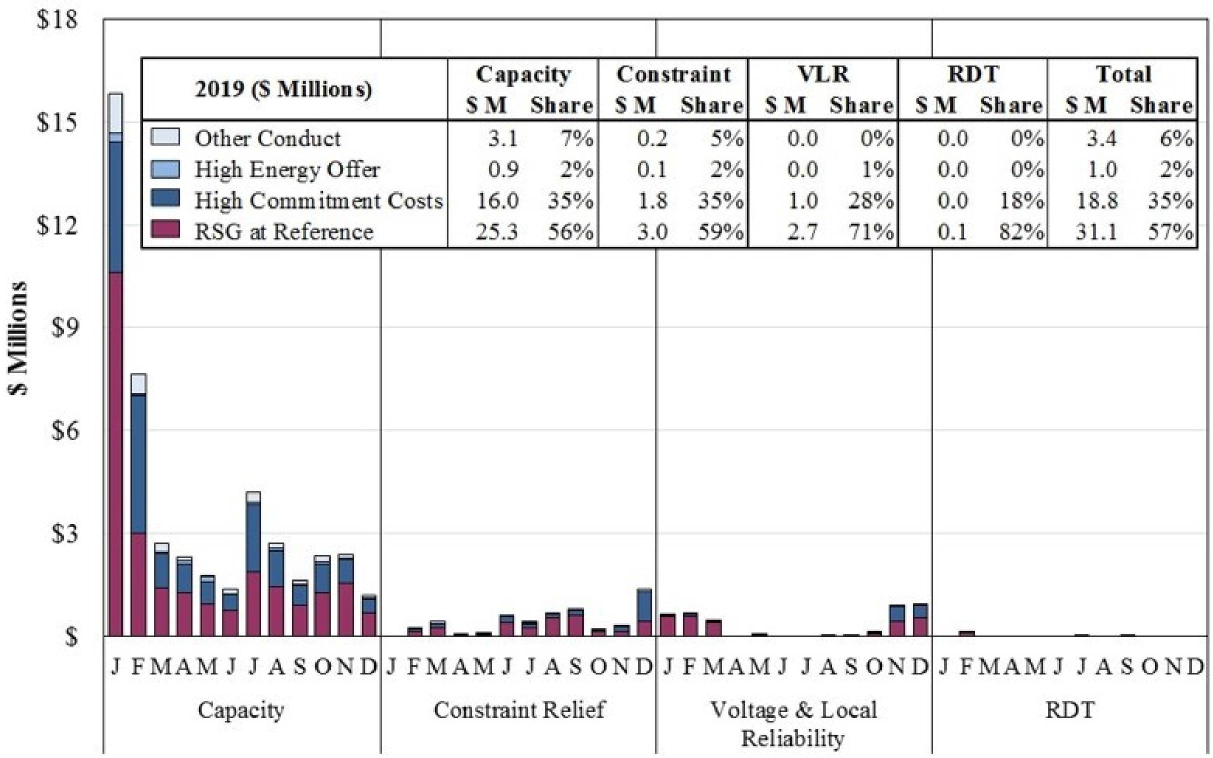
We evaluate conduct associated with RSG payments in the following figures, separating the payments associated with resources' reference levels and the payments associated with the portions of resources' bid parameters (e.g., economic and physical parameters) that exceed their reference levels. The results are shown separately for units committed for capacity, regional capacity needs (i.e., the RDT), for VLR requirements, and for congestion management. The category "Mitigated" includes both day-ahead and real-time amounts. Figure A157 shows all of MISO, while Figures A158 and A159 distinguish between the Midwest and South, respectively.

Figure A157: Real-Time RSG Payments by Conduct
By Commitment Reason, 2019



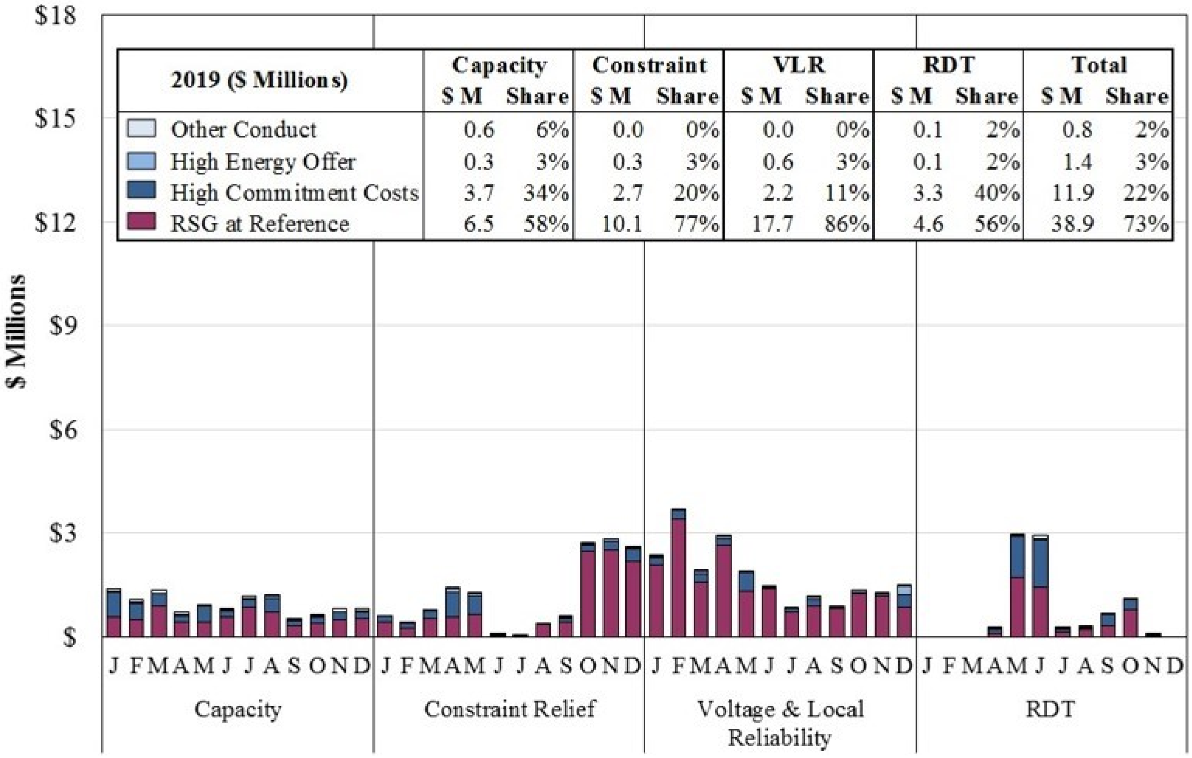
2019 ($ Millions)	Capacity $ M	Capacity Share	Constraint $ M	Constraint Share	VLR $ M	VLR Share	RDT $ M	RDT Share	Total $ M	Total Share
Mitigated	0.0	0%	2.2	12%	0.3	1.1%	0.0	0.0%	2.4	2%
Other Conduct	3.8	7%	0.3	1%	0.0	0.1%	0.2	1.8%	4.2	4%
High Energy Offer	1.2	2%	0.4	2%	0.7	3%	0.1	2%	2.4	2%
High Commitment Costs	20.1	35%	4.5	24%	3.3	13%	3.4	40%	31.3	29%
RSG at Reference	32.4	56%	11.2	60%	20.5	83%	4.8	57%	69.0	63%

Figure A158: Real-Time RSG Payments by Conduct
Midwest Region, by Commitment Reason, 2019



2019 ($ Millions)	Capacity $ M	Capacity Share	Constraint $ M	Constraint Share	VLR $ M	VLR Share	RDT $ M	RDT Share	Total $ M	Total Share
Other Conduct	3.1	7%	0.2	5%	0.0	0%	0.0	0%	3.4	6%
High Energy Offer	0.9	2%	0.1	2%	0.0	1%	0.0	0%	1.0	2%
High Commitment Costs	16.0	35%	1.8	35%	1.0	28%	0.0	18%	18.8	35%
RSG at Reference	25.3	56%	3.0	59%	2.7	71%	0.1	82%	31.1	57%

Figure A159: Real-Time RSG Payments by Conduct
MISO South, by Commitment Reason, 2019



2019 ($ Millions)	Capacity		Constraint		VLR		RDT		Total	
	$ M	Share	$ M	Share	$ M	Share	$ M	Share	$ M	Share
Other Conduct	0.6	6%	0.0	0%	0.0	0%	0.1	2%	0.8	2%
High Energy Offer	0.3	3%	0.3	3%	0.6	3%	0.1	2%	1.4	3%
High Commitment Costs	3.7	34%	2.7	20%	2.2	11%	3.3	40%	11.9	22%
RSG at Reference	6.5	58%	10.1	77%	17.7	86%	4.6	56%	38.9	73%

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 cost 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 commitments patterned after the VLR mitigation framework and eliminated the impact test. In August 2018, FERC approved MISO's mitigation authority for resources committed for the RDT in MISO South that employs the same mitigation measures as for resources committed for transmission congestion.[44] These changes have improved the effectiveness of the RSG mitigation measures.

44 Docket No. ER18-1464-003.

F. 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 A160 to Figure A162: Ancillary Services Market Offers

Figure A160 to Figure A162 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 A160 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 A160: Ancillary Services Market Offers
2018–2019

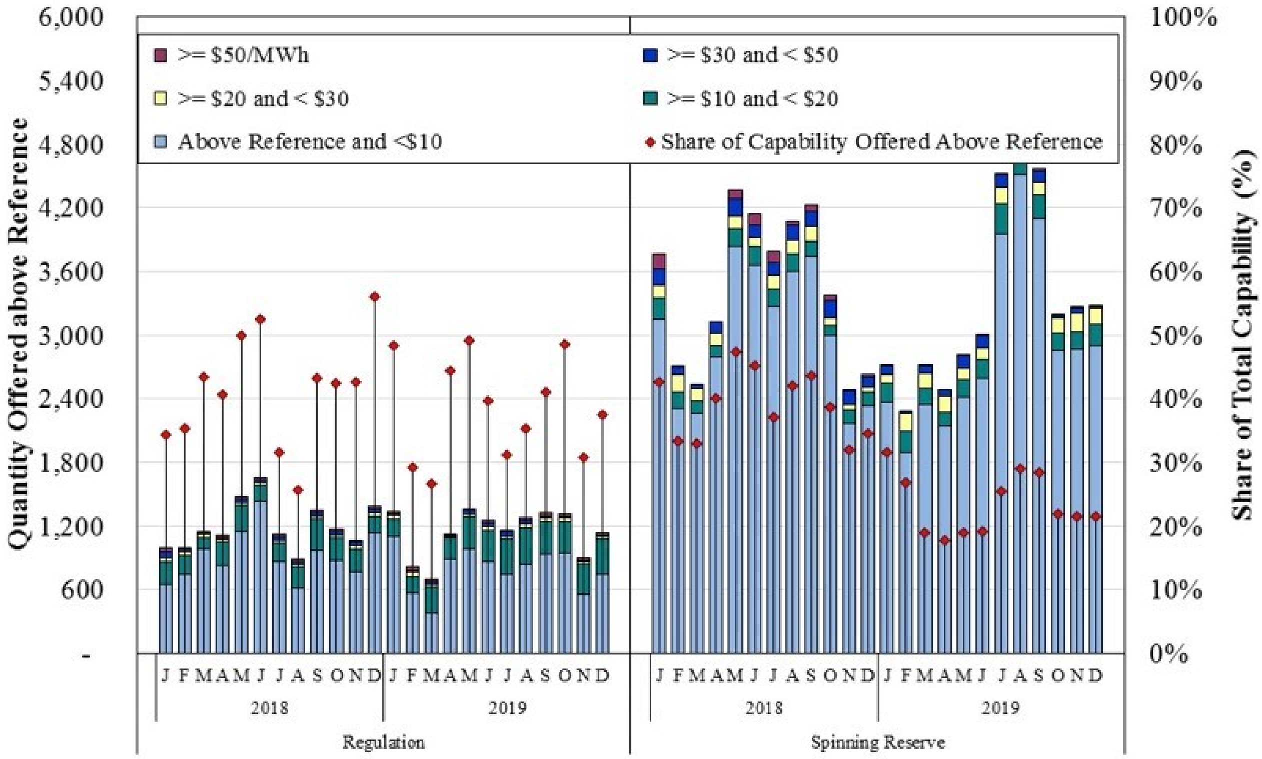


Figure A161: Ancillary Services Market Offers
Midwest Region, 2018–2019

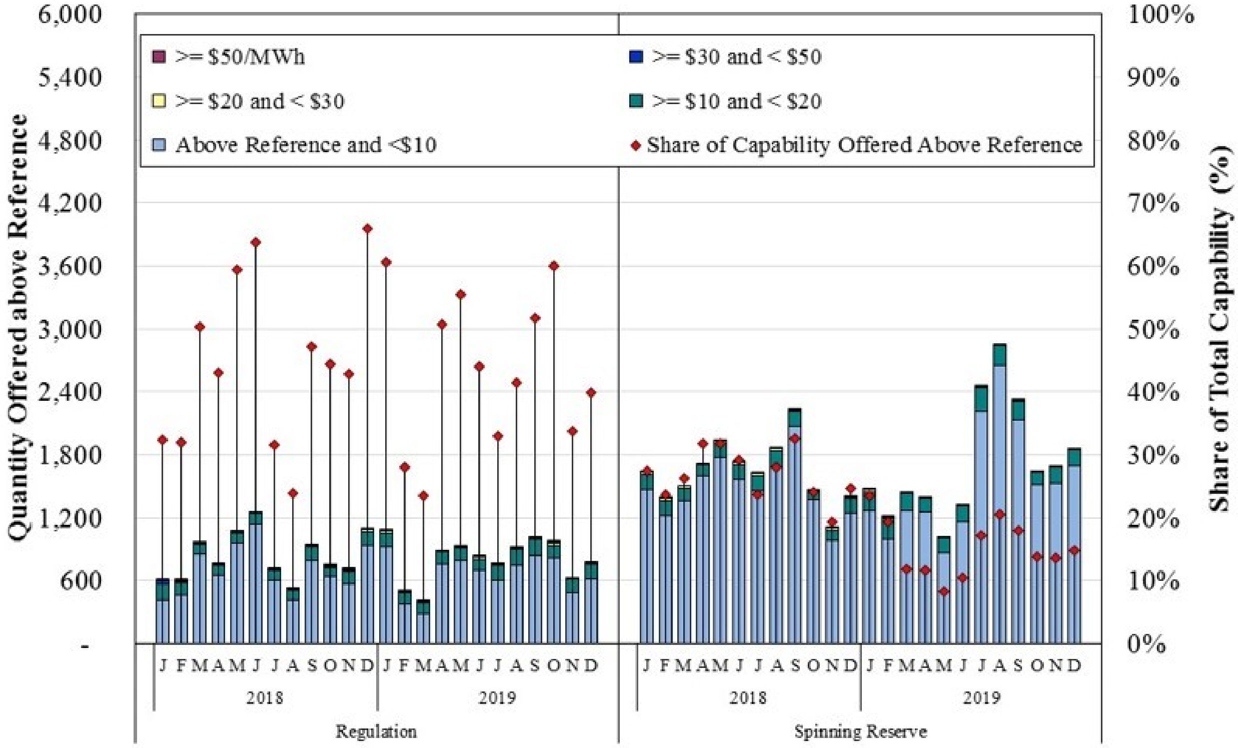
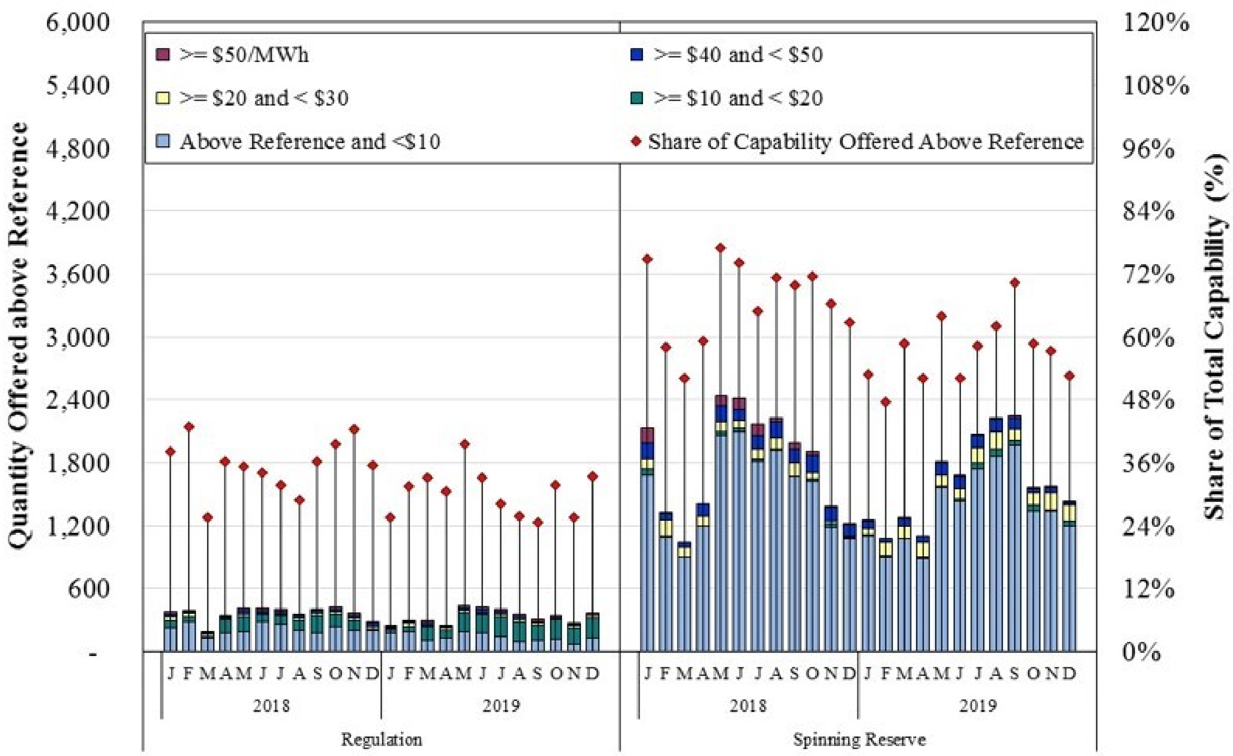


Figure A162: Ancillary Services Market Offers
MISO South, 2018–2019



G. 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 prevailing market price is unavailable to produce some or all of its output as a result of offering restricted physical parameters or declaring other conditions. For instance, this form of withholding may be accomplished by a supplier unjustifiably claiming an outage or derating its resource (lowering the economic maximum parameter). 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 A163 to Figure A166: Real-Time Deratings and Forced Outages

The following four figures show, by region, the average share of capacity unavailable to the market in 2019 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 a unit that would be economic during the outage 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 A163: Real-Time Deratings and Forced Outages
Central Region, 2019

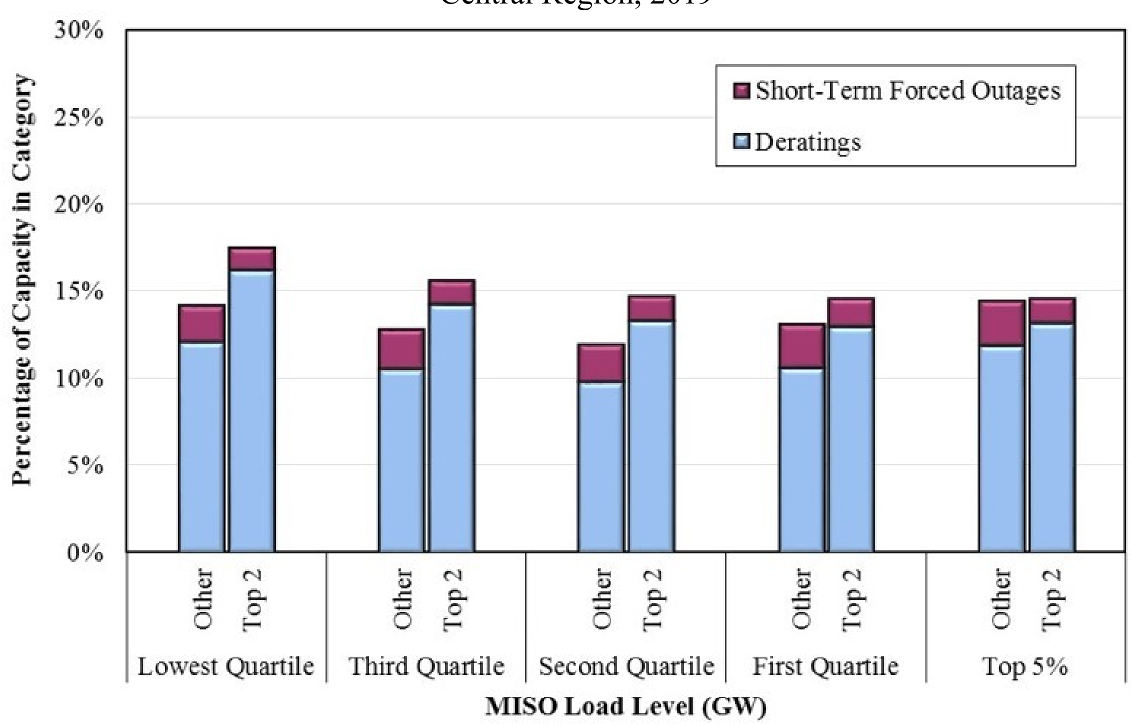


Figure A164: Real-Time Deratings and Forced Outages
MISO South, 2019

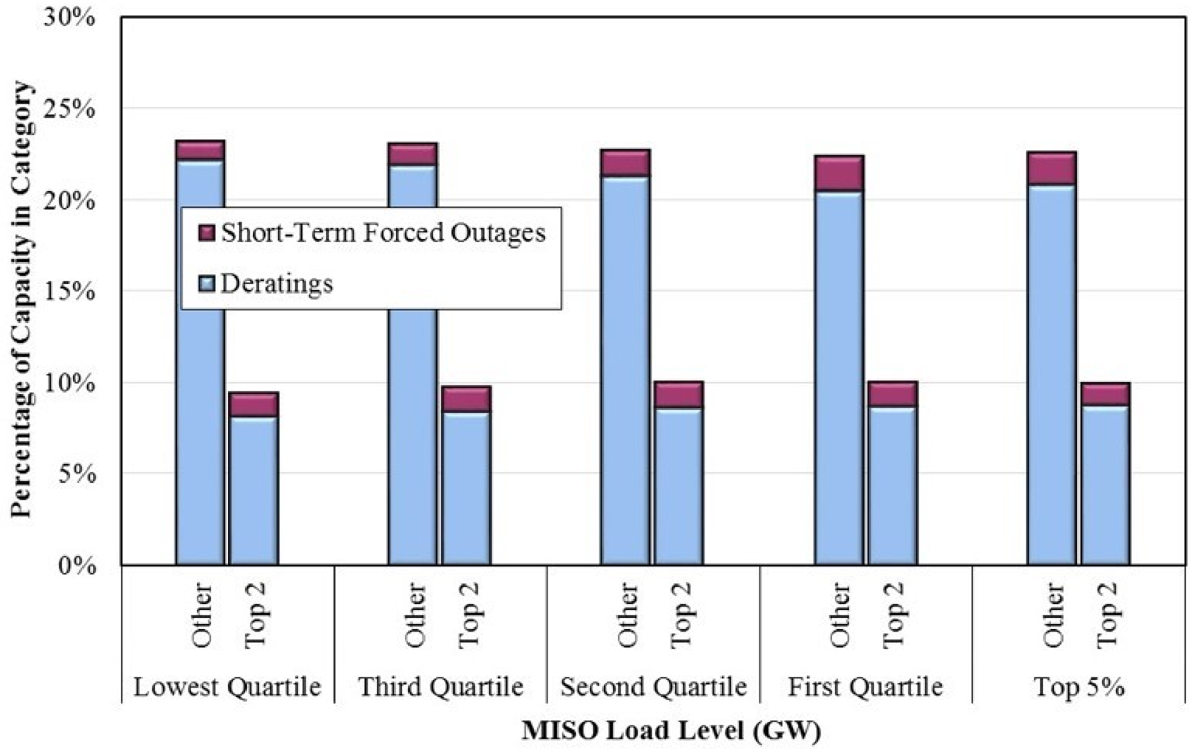


Figure A165: Real-Time Deratings and Forced Outages
North Region, 2019

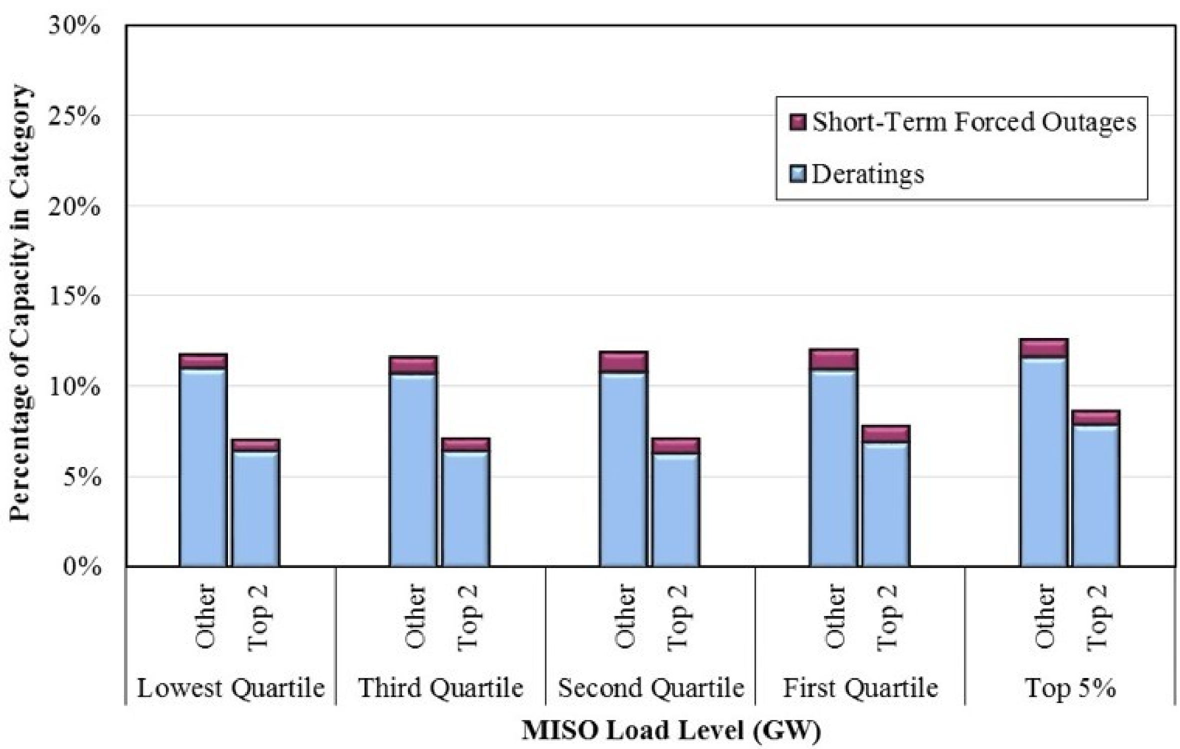
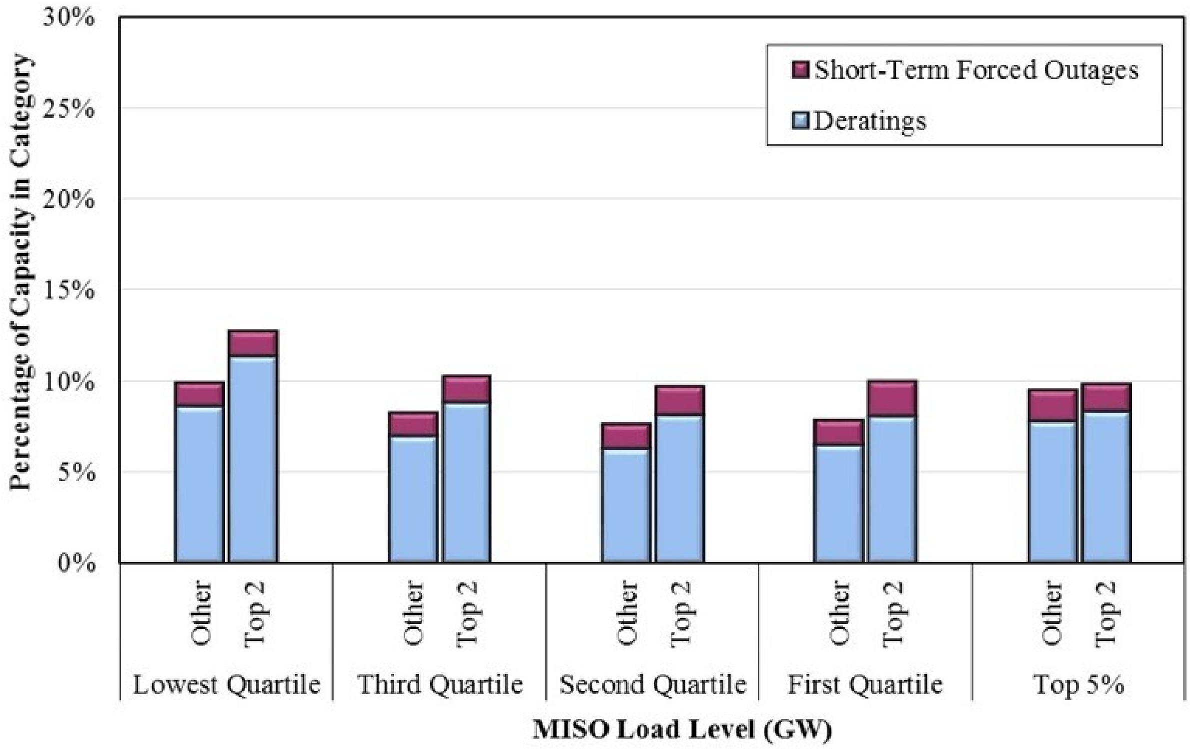


Figure A166: Real-Time Deratings and Forced Outages
WUMS 2019



IX. Demand Response Programs

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;
- Reductions in price volatility and other market costs; and
- Mitigation of 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 value of facilitating DR through wholesale market mechanisms and transparent economic signals.

A. Demand Response Participation in MISO

DR resources can broadly be categorized as either:

- Emergency DR, which responds to capacity shortages; or
- Economic DR, which responds to high energy market prices.

Emergency DR. MISO can call for emergency demand response resources to be activated in advance of a forecasted system emergency, thereby supporting system reliability. By definition, however, emergency DR is not price-responsive and does not yet participate directly in the MISO markets. The DR that falls in this category include:[45]

1. Load-Modifying Resources (LMRs) that are obliged to curtail in emergencies and satisfy planning reserve margin requirements (PRMR).
    - LMR-BTMG: These behind-the-meter generation assets do not have direct interconnection to MISO.
    - LMR-DR: This primarily includes legacy interruptible demand administered under regulated utility programs.
2. Emergency Demand Response Resources (EDRs) that are called in emergencies but are not obliged to offer and do not satisfy MISO's PRMR.

LMRs can also register as Emergency Demand Response resources (EDRs), which participate differently than LMRs. EDRs submit offers 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

45 Some DR may participate in more than one category, depending on the resource capability and responsibilities the resource is willing to accept.

at the greater of the prevailing real-time LMP or the offer costs (including shut down costs) for the amount of verifiable demand reduction provided. EDR resources are eligible to set the price.

Economic DR. These 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, interchange, and system 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.

MISO's economic DR is limited to two types of Demand Response Resources (DRRs) that economically respond to prices in the energy and ancillary services markets:

- DRR Type 1: These resources can supply a fixed, pre-specified quantity of energy or contingency reserves through physical load interruption. These resources 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 ELMP, MISO included DRR Type I resources as part of the definition of Fast-Start Resources that may set prices if they meet the eligibility requirements.
- DRR Type 2: These resources can supply varying levels of energy or operating reserves on a five-minute basis. Therefore, they are treated comparable to generating resources and can set prices. These resources are "dynamic pricing" resources, which is the most efficient form of DR because prices formed under this approach provide customers with price signals throughout the day. Significant barriers to broadly implementing dynamic pricing.

DRRs are eligible to participate in all of the MISO markets, including satisfying LSEs' resource adequacy requirements under Module E of the Tariff. However, DRR Type I units cannot provide regulating reserves given their operating limitations.

Table A18: DR Capability in MISO and Neighboring RTOs

Table A18 shows total DR capabilities of MISO and neighboring RTOs. Because of differences in their requirements and responsiveness, individual classes of DR capability are not comparable. For resources outside of MISO, the following types of demand response exist:

- *Special Case Resources*: A demand response program that helps to maintain reliability by calling on electricity users to reduce consumption during times of shortage conditions
- *On-Peak Resources*: These resources offer on their reduced electricity consumption during June-August non-holiday weekdays from 1 p.m. – 5 p.m. and on December-January non-holiday weekdays from 5 p.m. – 7 p.m.

- *Seasonal-Peak Resources*: These resources offer on their reduced electricity consumption during the months of January, June, July, August and December in the times of highest load consumption.

Table A18: DR Capability in MISO and Neighboring RTOs
2017–2019

		2017	2018	2019
MISO[1]		**11,495**	**12,931**	**13,611**
	LMR-BTMG	3,822	4,496	4,480
	LMR-DR	6,112	7,137	7,684
	DRR Type I	620	621	811
	DRR Type II	0	3	13
	Emergency DR	941	674	624
NYISO[2]		**1,237**	**1,314**	**1,288**
	Special Case Resources - Capacity	1,221	1,309	1,282
	Emergency DR	16	5	6
	Day-Ahead DRP	0	0	0
ISO-NE[3]		**2,655**	**2,988**	**3,309**
	RT DR Resources/DR Assets	683	262	321
	On-Peak Demand Resources	1,418	2,214	2,440
	Seasonal Peak Demand Resources	554	512	548

[1] Registered as of December 2019. All units are MW.
[2] Registered as of July 2019. Source: Annual Report on Demand Side Management Programs of the New York Independent System Operator, Inc., Docket ER01-3001.
[3] Seasonal audited capabilty as of December 1, 2019. Source: ISO-NE Demand Response Working Group Presentation.