Summary of 2019 MISO State of the Market Report

Presented to:

MISO Board Markets Committee

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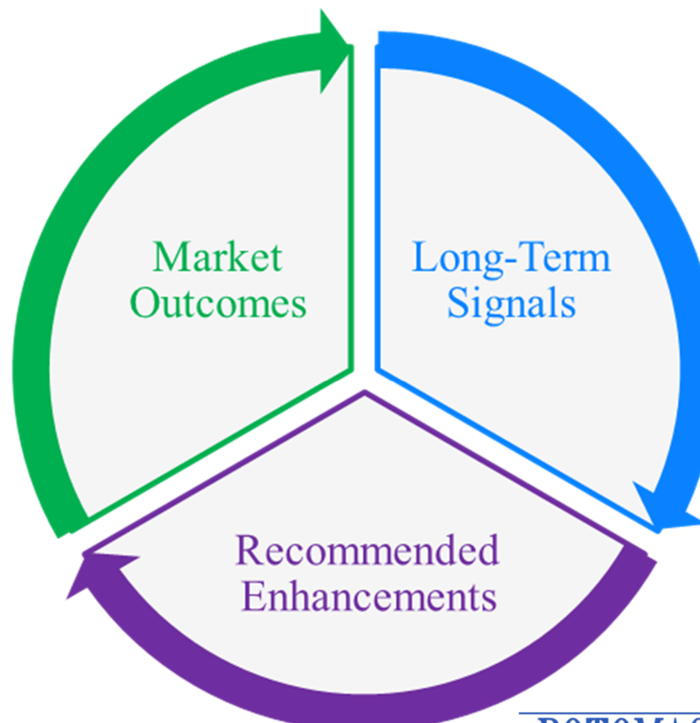
Introduction

- As the Independent Market Monitor (IMM) for MISO, we:
  - ✓ Evaluate the competitive performance and operation of the MISO markets; and
  - ✓ Identify and recommend changes to existing and proposed market rules and operating procedures.
- This presentation summarizes:
  - ✓ Market highlights from 2019;
  - ✓ The competitive performance and efficiency of the markets;
  - ✓ Long-term economic signals; and
  - ✓ Recommendations for improvements.



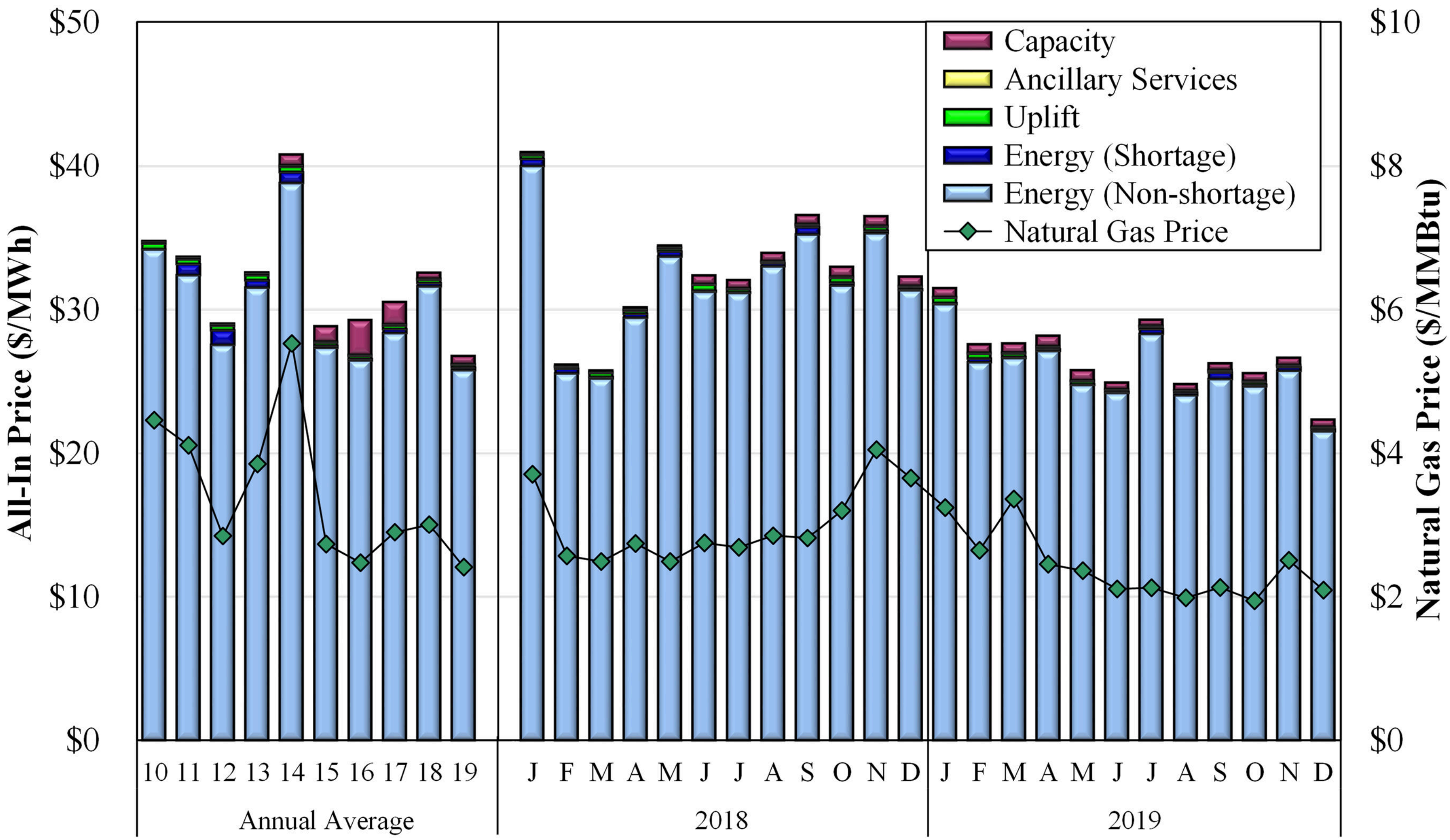
Competitive Performance and Areas of Focus

- The MISO markets performed competitively 2019.
  - ✓ The “price-cost mark-up” was effectively zero – indicating that offers were highly competitive.
  - ✓ The “output gap” measure of potential economic withholding remained low at under 0.1 percent of load, and market power mitigation was rare.
- However, we identify substantial opportunities to improve MISO’s market performance and lower costs, some of which will be critical as its generation portfolio continues to transition toward heavier reliance renewable resources.
- This presentation focuses on the following key areas:
  - ✓ Overall market outcomes in 2019;
  - ✓ Managing congestion on the transmission network;
  - ✓ Improving real-time pricing and the incentives it provides for good generator performance, availability and flexibility; and
  - ✓ Long-term economic signals governing resource adequacy.

Market Highlights: Load and Prices

- The all-in price fell 18 percent to average $26.75 per MWh.
  - ✓ Lower energy prices were driven by a 2 percent lower average load and a 20 percent reduction in natural gas prices.
  - ✓ The correlation of energy and natural gas prices is expected in a well-functioning, competitive market.
- After controlling for fuel prices, the adjusted SMP fell by 10 percent that can be attributed to two main factors:
  - ✓ *Generation Demand*: The combination of a two percent decrease in load and a 1.2 GW increase in net imports reduced total generation demand by 4 percent.
  - ✓ *Generation Mix*: Greater availability of nuclear resources and continued wind penetration combined to increase the output of low-cost non-fossil fuel generation sources by 8 percent.
- MISO's annual peak load of 121 GW occurred on July 19, consistent with the typical occurrence of annual system peak around the third week of July.
  - ✓ The average number of degree days fell by 8 percent overall in 2019, which was generally due to milder weather during the summer months.

All-In Price



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

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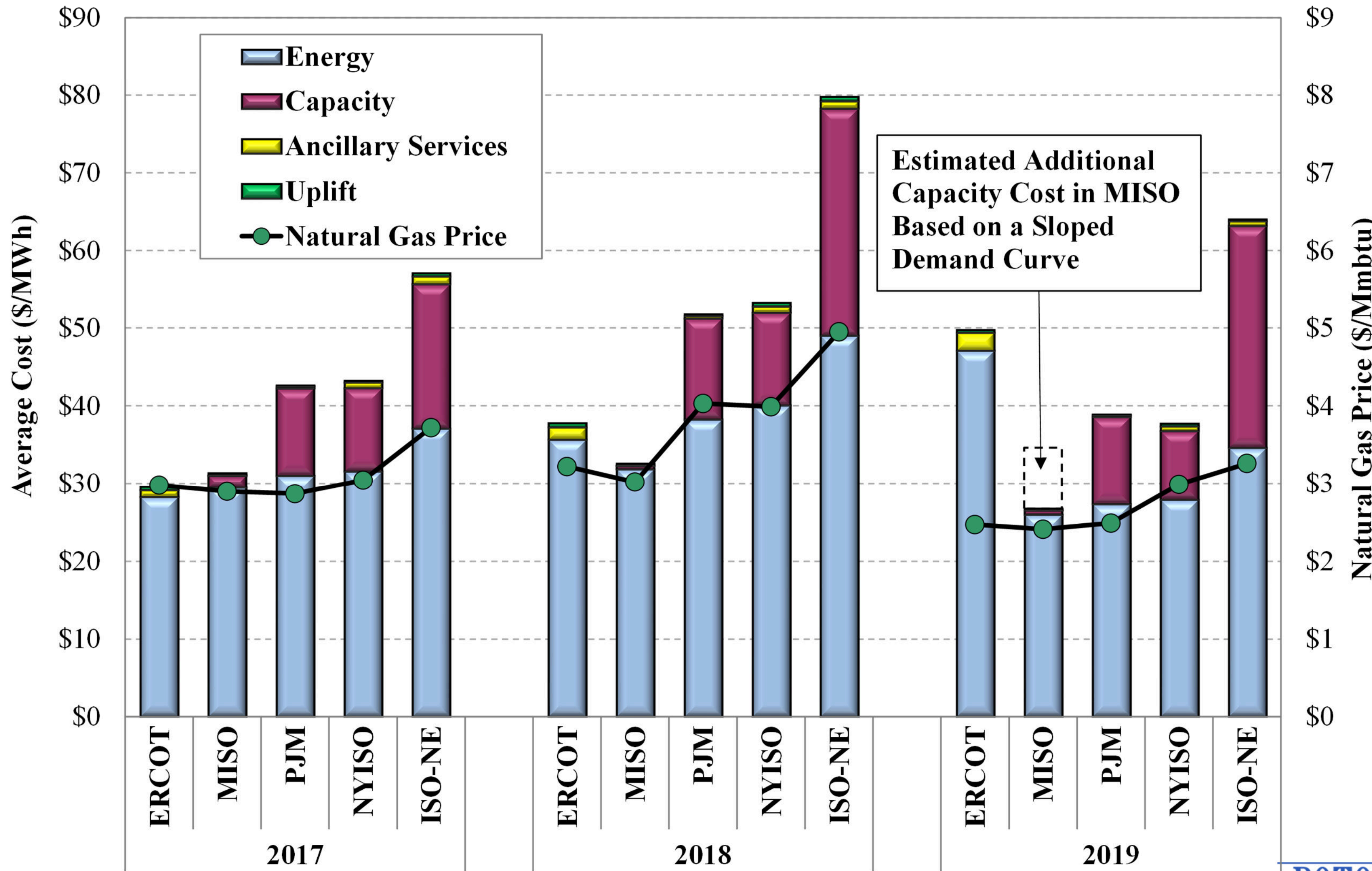
All-In Price Comparison



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Day-Ahead Market Performance

- Day-ahead market performance is key because it coordinates the commitment of MISO's resources and facilitates almost all settlements.
- MISO's day-ahead market performed well in 2019:
  - ✓ Day-ahead prices converged well with real-time prices, exhibiting a premium of less than one percent on average. This was due in part to active virtual trading that provides essential liquidity in the day-ahead market.
  - ✓ The report shows that virtual trading was efficiency enhancing on net.
- The table below shows that virtual trading is generally more active in MISO than in other RTOs and virtual profits are low as a result.
  - ✓ Virtual supply profits are higher because they are allocated the RSG they cause.

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

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Management of Transmission Congestion

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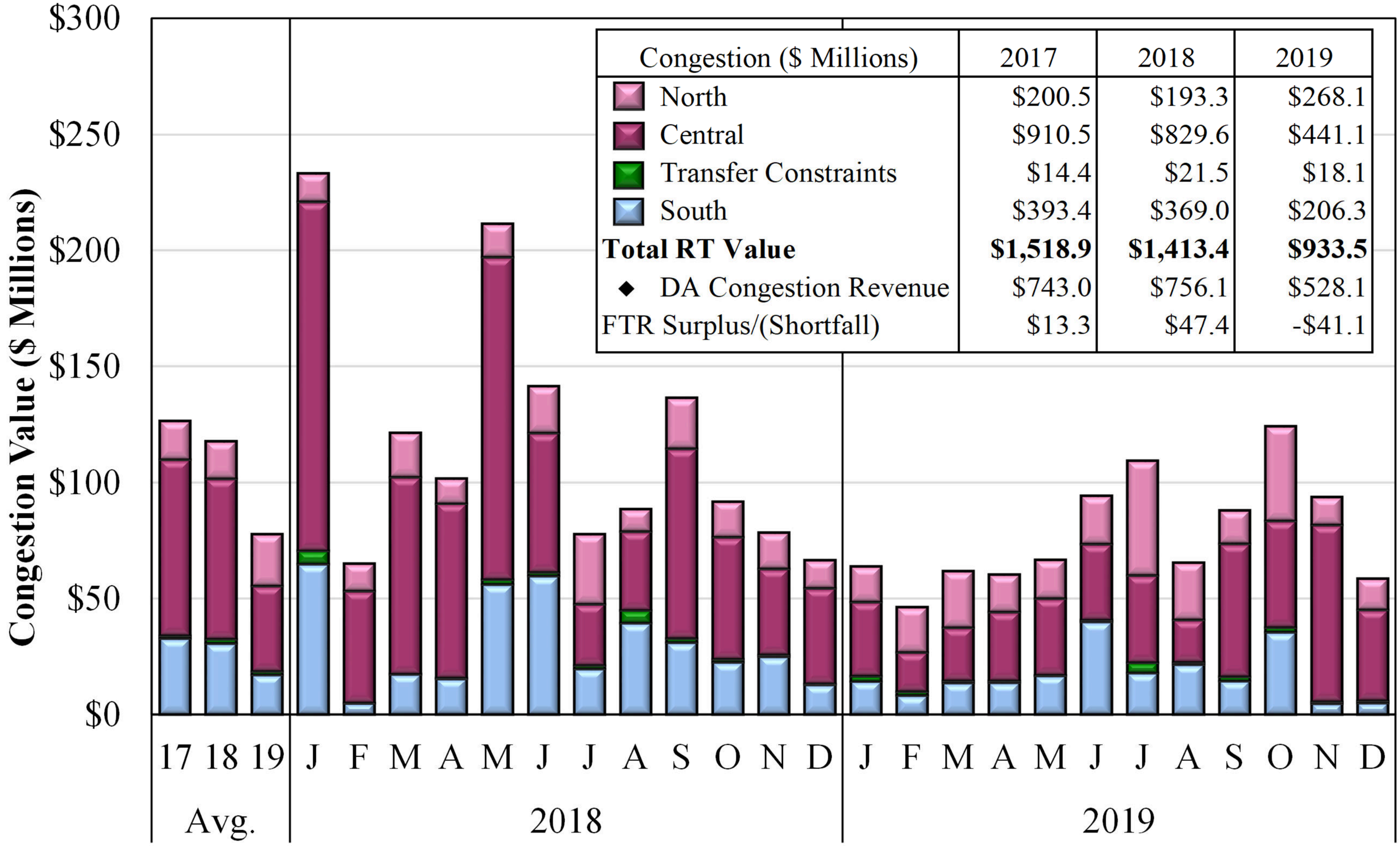
Real-Time Congestion

- Transmission congestion often causes prices to vary throughout MISO.
- Overall, the value of real-time congestion fell by 35 percent in 2019 to $933 million, which was due to:
  - ✓ Key transmission upgrades in MISO and in neighboring regions;
  - ✓ The addition of a 1,000 MW combined-cycle unit in a South load pocket; and
  - ✓ Falling natural gas prices have reduced the spread in costs between the generators that are re-dispatched to manage the flows over binding constraints.
- Nonetheless, several key issues continue to encumber congestion management and full utilization of the transmission network, including:
  1. Use of very conservative static ratings by most transmission operators;
  2. A parameter than prevents the real-time dispatch model from utilizing generators with modest effects on a constraint.
  3. Limitations of MISO’s authority to coordinate outages; and
  4. Issues in defining and coordinating market-to-market constraints.
- Resolving these issues would likely reduce congestion by 20 to 30 percent.

Real-Time Value of Congestion in MISO



Congestion ($ Millions)	2017	2018	2019
North	$200.5	$193.3	$268.1
Central	$910.5	$829.6	$441.1
Transfer Constraints	$14.4	$21.5	$18.1
South	$393.4	$369.0	$206.3
Total RT Value	**$1,518.9**	**$1,413.4**	**$933.5**
◆ DA Congestion Revenue	$743.0	$756.1	$528.1
FTR Surplus/(Shortfall)	$13.3	$47.4	-$41.1

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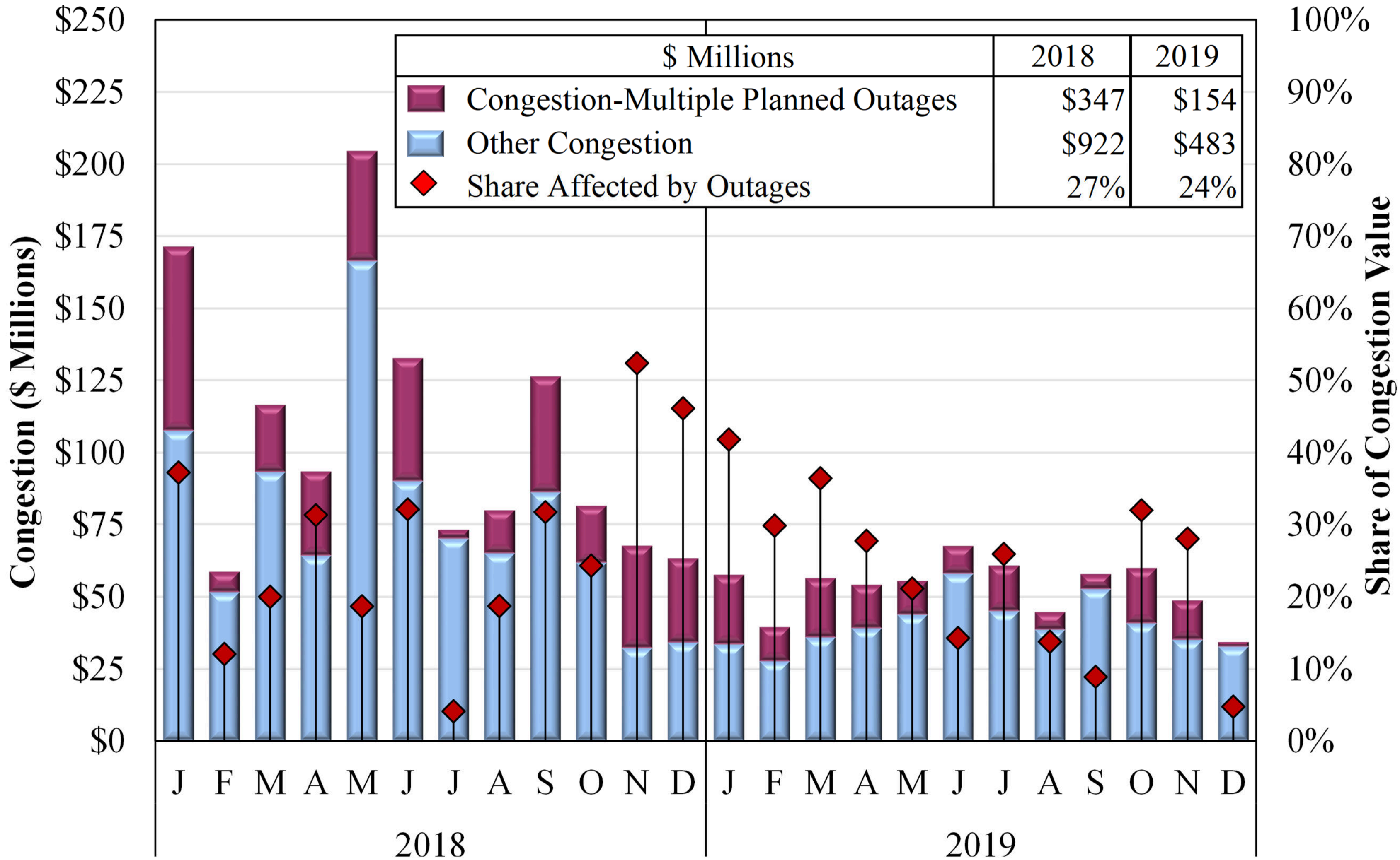
Transmission Congestion Issues

- *Improved Transmission Ratings*. Most TOs do not adjust their facility ratings to reflect ambient temperatures and wind speeds.
  - ✓ Broad adoption of ambient-adjusted ratings (AAR) could have reduced congestion costs by as much as $150 million over the past two years.
  - ✓ Additionally if all TOs provided Short-Term Emergency Ratings, we estimate a potential additional savings of $114 million in 2018 and 2019.
- *Outage Coordination*. Multiple, simultaneous generation outages affecting the same constraint contributed to over $150 million – almost one quarter - of MISO's real-time congestion.
- *Allow Relief from Low-Impact Generators*. MISO employs a 1.5% Generator Shift Factor ("GSF") cutoff to identify units to use to manage congestion.
  - ✓ For some constraints, this eliminates almost all the economic relief available to manage the constraint.
  - ✓ Our analysis shows $67 million of incremental economic relief would be available if the GSF cutoff were reduced to 0.5 percent – more than half of which is on just ten low-voltage and M2M constraints.

Congestion Management Concerns: Outage-Related Congestion



Benefits of Ambient-Adjusted and Short-Term Emergency Ratings

		Savings ($ Millions)			# of Facilites for 2/3 of Savings	Share of Congestion
		Ambient Adj. Ratings	Emergency Ratings	Total		
Total Estimated Benefits						
2018	Midwest	$77	$48	$125	19	12.7%
	South	$7	$18	$25	2	7.1%
	Total	**$85**	**$66**	**$150**	**21**	**11.2%**
2019	Midwest	$62	$36	$98	18	14.5%
	South	$4	$12	$16	3	8.0%
	Total	**$66**	**$48**	**$114**	**21**	**13.0%**

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Market-to-Market Congestion Issues

- In 2019, we continued to see improvements in the administration of testing and activation of M2M constraints.
  - ✓ Congestion costs associated with these issues fell 50 percent.
  - ✓ However, we have identified opportunities for improvements two areas.
- <u>Optimize the Relief Requests</u>: one or more of these three inefficient relief request outcomes occurred in 26 percent of coordinated intervals.
  - ✓ *Volatile relief requests*: Impacts about 22 percent of coordinated intervals.
  - ✓ *Undersized relief requests*: Results in price convergence and higher costs. SPP constraints accounted for about 90 percent of these intervals in the study period.
  - ✓ *Oscillation*: SPP-monitored constraints were more subject to oscillation than MISO constraints, accounting for 95 percent of all oscillation intervals.
- <u>M2M Testing Criteria</u>: used to determine whether a constraint should be defined as a M2M constraint.
  - ✓ Our report shows that the current tests have defined a number of M2M constraints for which coordination provides little to no benefit.
  - ✓ We recommend a revised test based on the availability of relief.

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Congestion Management Concerns: M2M Coordination and TVA Coordination

Market-to-Market Administration Issues

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

Market-to-Market Coordination 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	34	0.2%	1,053	3.3%	1,087	2.4%
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%**

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Real-Time Pricing and Incentives

Real-Time Pricing: Introduction and Issues

- Real-time pricing in wholesale electricity markets is crucial because it:
  - ✓ Facilitates efficient day-ahead scheduling and external transactions;
  - ✓ Motivates good generator performance, availability and flexibility;
  - ✓ Sends economic signals that govern long-term investment and retirement decisions.
- The key aspects of real-time pricing that we evaluate include the effectiveness and efficiency of:
  1. The Extended Locational Marginal Pricing (ELMP) model to allow peaking resources to set prices;
  2. The pricing of emergency actions; and
  3. The pricing of operating reserve shortages.

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Real-Time Pricing in MISO: ELMP

- Efficient real-time pricing requires that fast-start peaking resources and emergency actions to set prices.
  - ✓ We previously showed that the ELMP rules undermined its effectiveness.
  - ✓ In 2019, online ELMP increased prices by \$0.35 per MWh on average.
  - ✓ In November, MISO implemented changes that allow resources committed in the day-ahead market to set prices in real time.
  - ✓ We are recommending an additional change (to the ramp assumptions) that will increase its effects – up to almost \$1 on average in 2019.
- The effects of improving LMP are understated in 2019 because conditions were relatively mild and MISO did not utilize peaking resources as much normal.

Alternative ELMP Methods	Avg. Price Increase (\$/MWh)	% of Fast-Start Peaker Eligible	% of Intervals Affected
Current Including Day-Ahead Units	\$0.35	32.8%	11.1%
No Ramp Limitation	\$0.96	56.9%	21.2%

Real-Time Pricing in MISO: Shortage Pricing

- Shortage pricing provides critical economic signals to suppliers to be available and flexible, to perform well, and accommodate long-term changes:
  - ✓ Expansion of renewable resources,
  - ✓ Greater reliance on demand response, and
  - ✓ Lower capacity margins.
- The Operating Reserve Demand Curve (ORDC) should set prices when MISO is short of reserves or the cost of procuring reserves exceeds its value.
- Efficient shortage pricing requires that the ORDC equal the expected value of lost load = Probability of Losing Load * Value of Lost Load (VOLL)
- The current ORDC is not optimal, so we recommend that MISO:
  1. Develop an economic ORDC based on the probability of losing load at different reserve levels that captures all uncertainties and contingencies; and
  2. Use a VOLL reflecting all classes of customers, we estimate $23,000/MWh.
  3. Eliminate offline pricing that artificially sets prices as if there is no shortage.
- Efficient shortage pricing can reduce the reliance on revenue from the capacity market to maintain resource adequacy.

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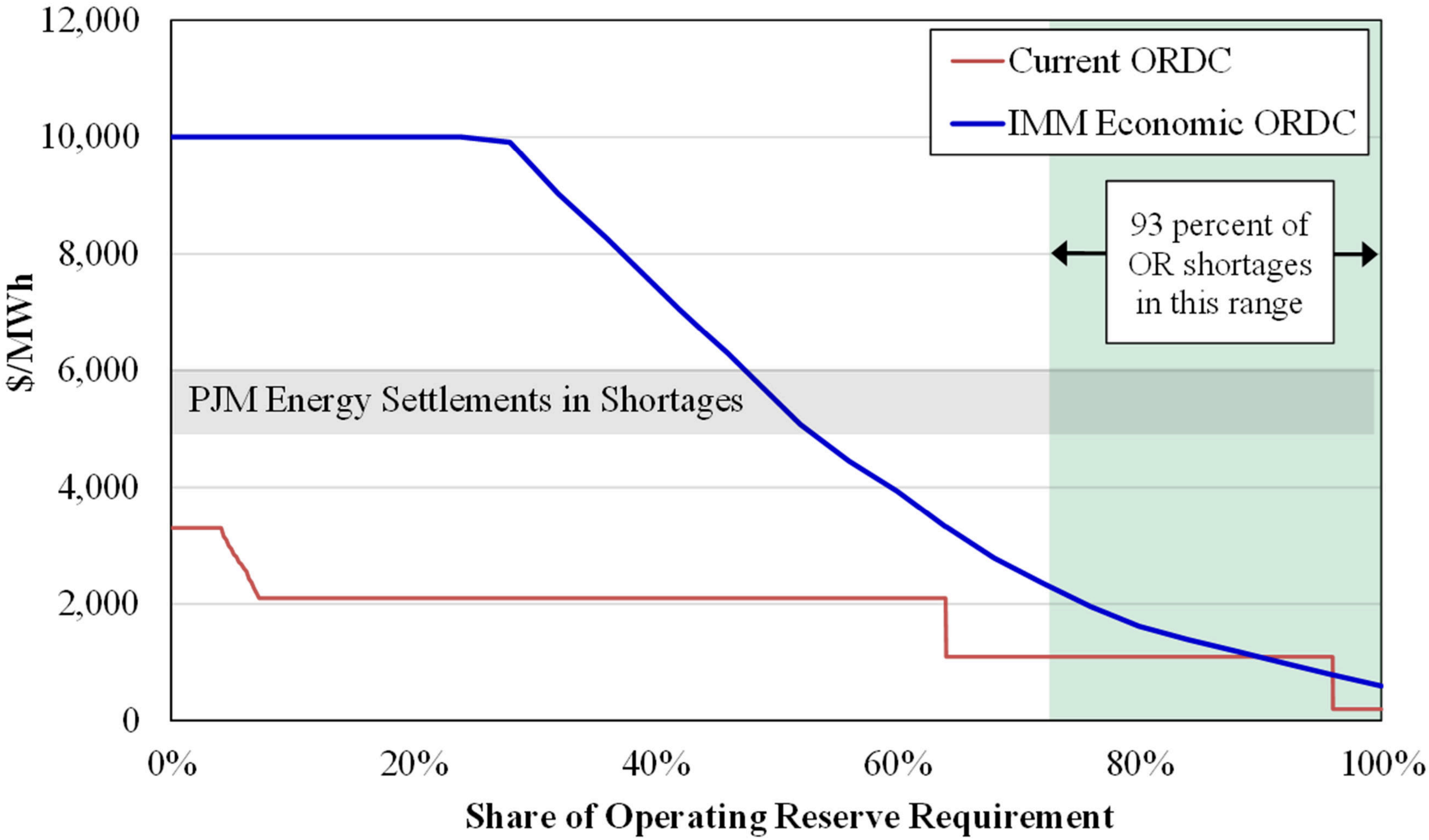
Operating Reserve Demand Curve IMM Recommendation



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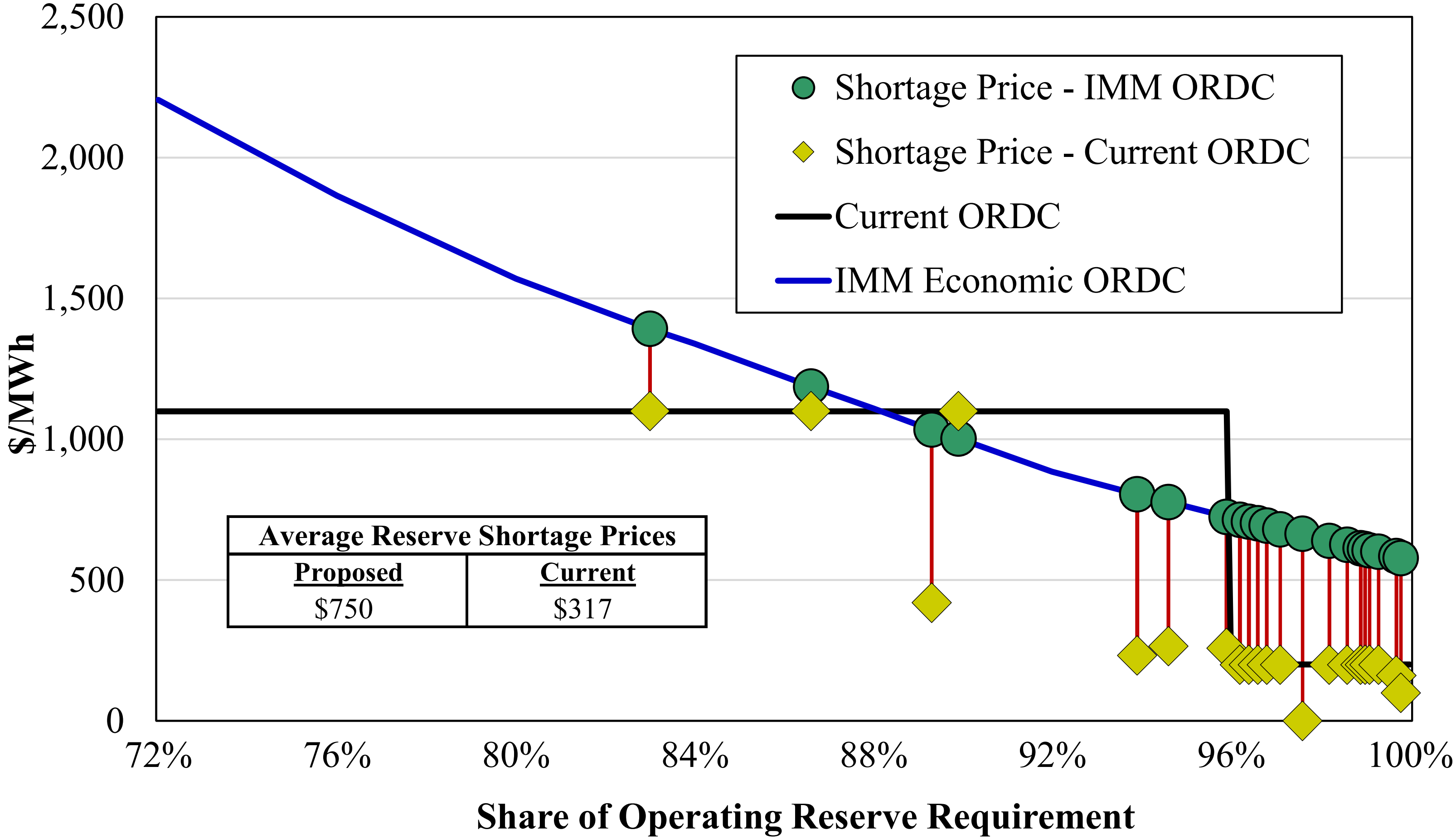
Shortage Pricing in 2019



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Real-Time Pricing in MISO: Efficient Emergency Offer Price Floor

- During emergency events, MISO can access supply that is unavailable during non-emergency conditions, some of which is not dispatchable.
  - ✓ Emergency Offer Floor Prices – calculated based on resource offers - apply to the 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.
- Our results indicate that the current emergency floor price calculations result in a high degree of variability because it depends on suppliers' offers.

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

Resource Adequacy in MISO

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MISO Capacity Margins

- In 2019, capacity levels were flat from 2018 to 2019 as:
  - ✓ Almost 3 GW of coal resources retired in the Midwest;
  - ✓ 2.5 GW of gas-fired resources entered, primarily in the South; and
  - ✓ 2 GW of wind entered, which translated to an UCAP increase of 600 MW.
- Our Base Case 2020 Summer Assessment indicates MISO's capacity margin should be sufficient at 20 percent, well above the 18 percent requirement.
  - ✓ A more realistic scenario – with average historical planned and unreported outages shows results in a summer capacity margin of 11 percent.
  - ✓ Including only two-hour lead time LMRs results in a margin of 8 percent.
  - ✓ Hotter than normal conditions results in capacity deficiencies.
- Fortunately, MISO enjoys substantial import capability from its neighbors in all directions.
  - ✓ This would be utilized to avoid shortages in all be the hottest conditions.

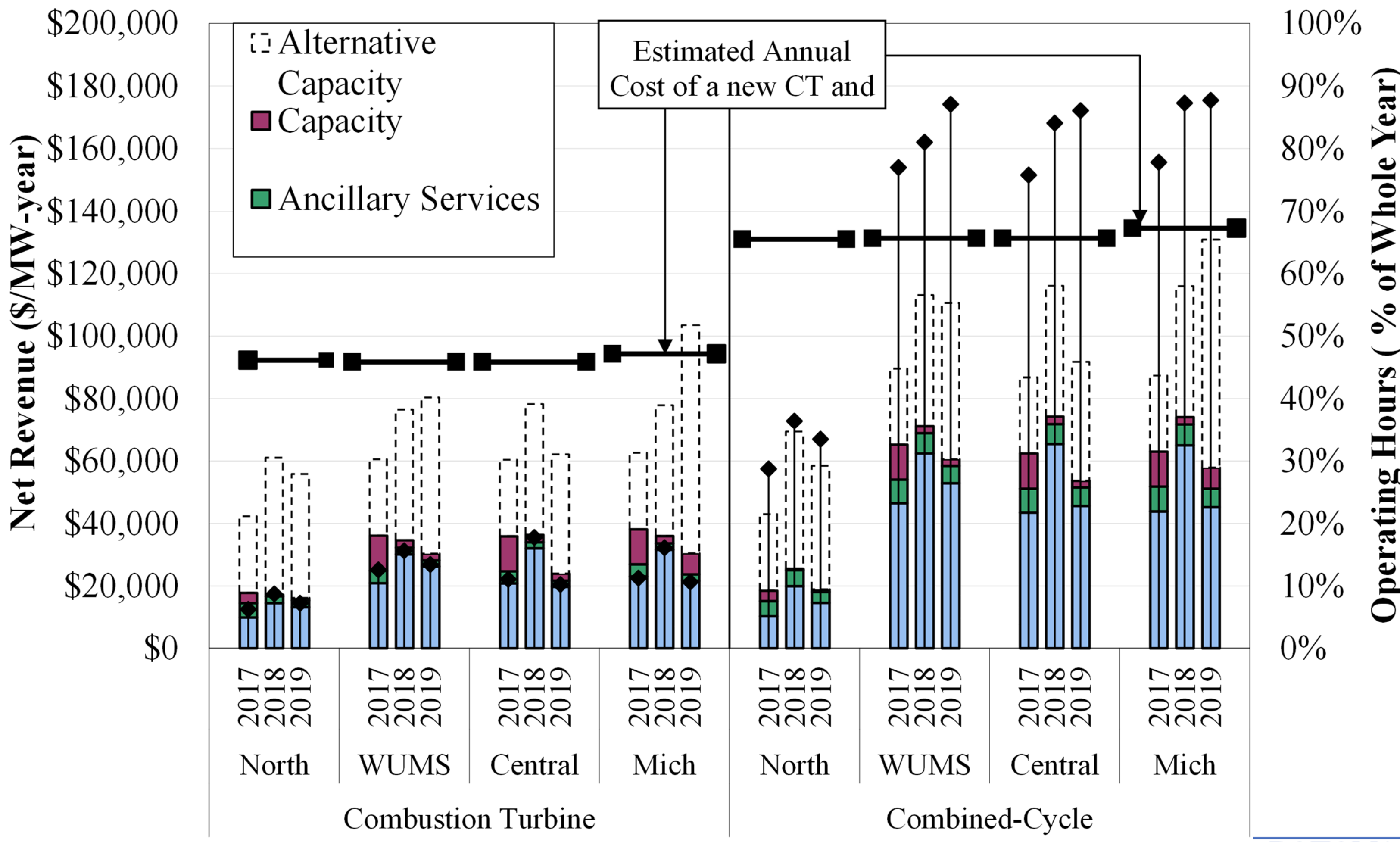
Summer Assessment

		Alternative IMM Scenarios*			
				High Temperature	
	Base Scenario	Realistic Scenario	Realistic <=2HR	Realistic Scenario	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 Export	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%**

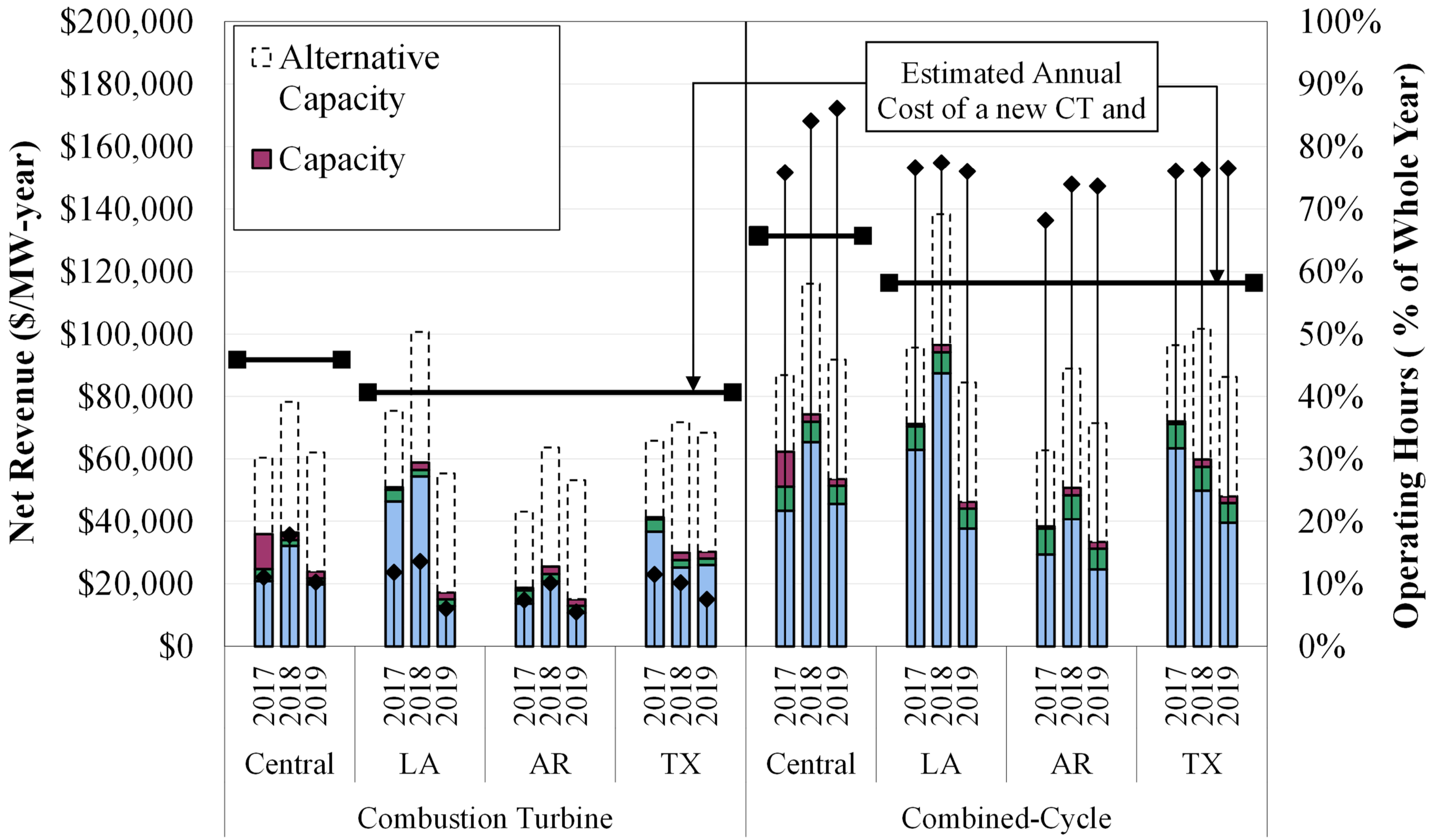
Long-Term Price Signals and the PRA

- The PRA has generally produced inefficiently low prices:
  - ✓ Outside of Zone 7 (MI), capacity prices generally represented less than *two* percent of the revenue needed to support investment in new peaking resources.
  - ✓ Zone 7 was an outlier, clearing at CONE in the most recent auction, partly because MISO implemented Tariff changes that prevent units on outage during the peak months from qualifying to sell capacity.
- "Net revenues" are the revenues a new unit would earn above its variable costs if it runs when it is economic. Well-designed markets should:
  - ✓ Provide net revenue sufficient to support new investment when existing resources are inadequate to meet the system's needs; and
  - ✓ Produce adequate net revenues to cover the costs of remaining in operation (Going-Forward Costs or "GFCs") for resources providing material reliability.
- The following figures show that MISO's markets are not providing net revenues sufficient invest in new resources in any location.
  - ✓ Addressing the principle design flaw in the PRA would cause revenues to approach the CONE for a new unit at current capacity levels.
  - ✓ Investment would be economic for resources with cost advantages.

Net Revenues: Midwest



Net Revenues: South



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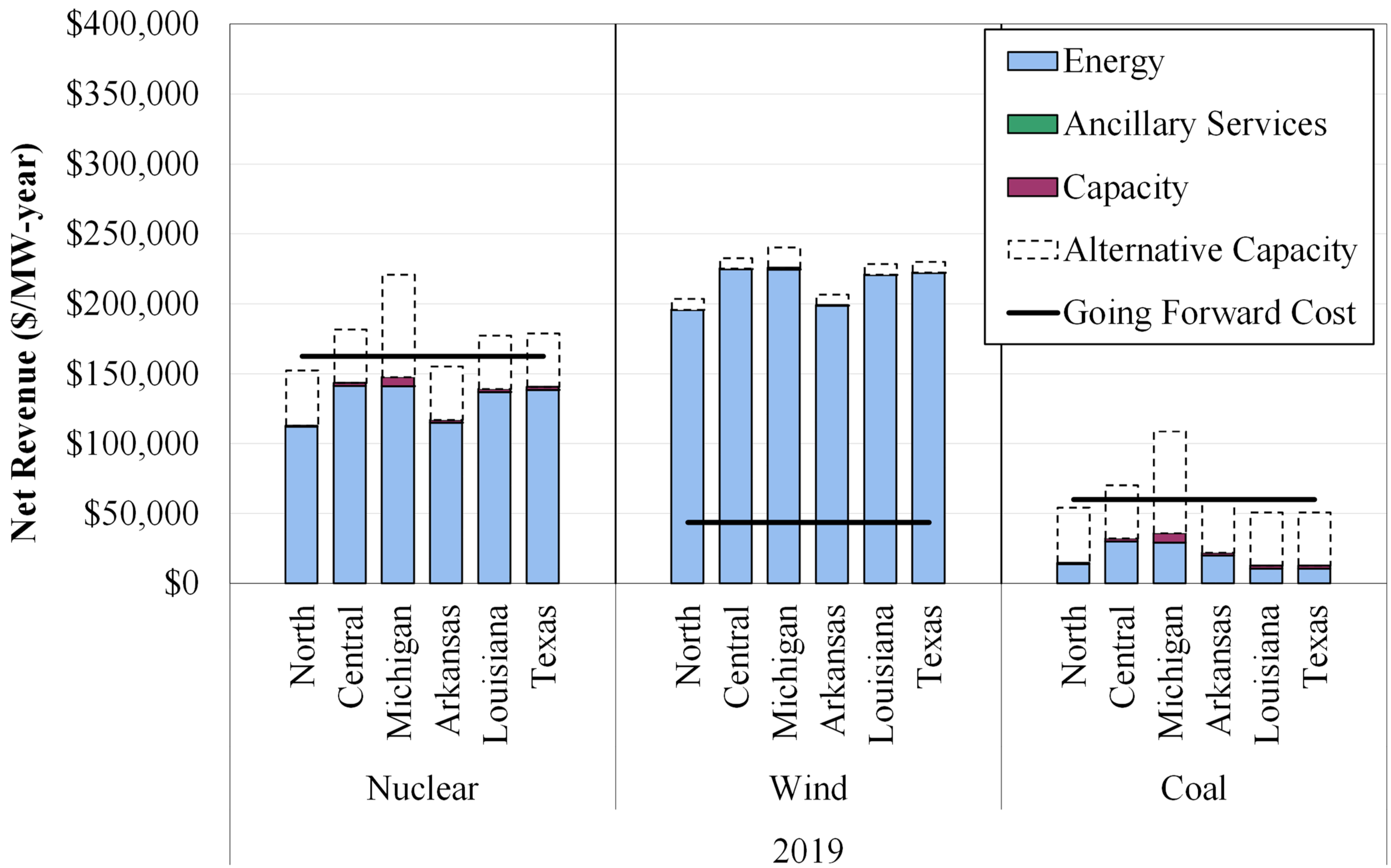
Capacity at Risk

- Understated capacity prices also affect the ability of existing resources to cover their going-forward costs of remaining in operation.
- We conducted an analysis to evaluate MISO’s capacity at risk for long-term suspension or retirement for coal, nuclear, and wind resources.
  - ✓ Wind resources are more than revenue adequate;
  - ✓ Typical coal and nuclear resources are exhibiting revenue shortfalls.
- Coal resources at risk
  - ✓ Roughly 18 GW of coal resources are not covering their GFCs under the prevailing auction clearing prices.
  - ✓ Only roughly 5 GW could retire before prices would likely rise sufficiently to sustain the others, but MISO would be close to capacity deficient.
  - ✓ Improving the design of the PRA would cause a large share of these resources to cover their GFCs.
- Improving shortage pricing in MISO would reduce need to rely on capacity revenues.

Capacity at Risk: Nuclear, Wind, and Coal



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Capacity Accreditation

- MISO’s historic accreditation methodology tends to provide excessive capacity credit to its resources.
  - ✓ Does not generally account for any type of outage other than a forced outage.
  - ✓ MISO made a change in March 2019 to address short-notice planned outages during emergencies, but this has almost no effect on accreditation levels.
- We recommend changes to base accreditation on availability during the tightest margin hours of the year.
  - ✓ Includes all outages and derates, including those that are not reported.
  - ✓ Availability is measured when the resource is needed most – when the supply margin (total supply minus total demand) is smallest (tightest 5% of hours).
  - ✓ These effects can be mitigated by better outage scheduling.

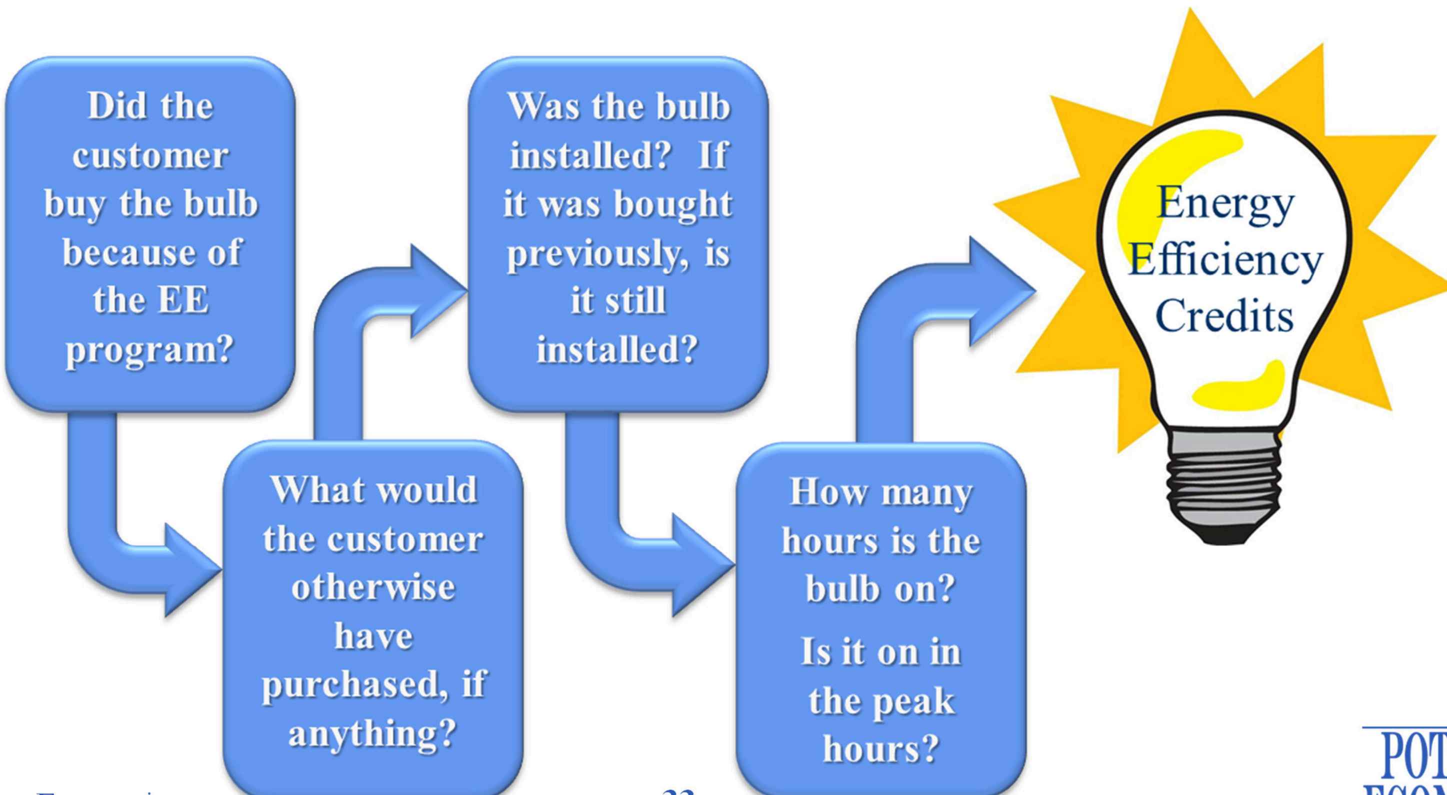
Resource Class	Capacity (MW)*	Current UCAP Derate (XEFORd)	IMM Proposal: Outages & Derates in Tightest Hours
Combined Cycle**	17,989	2.6	17.5
Coal	50,474	7.6	20.2
Combustion Turbine (Gas)	27,127	4.9	12.4
Nuclear	12,393	2.4	13.7
Steam Turbine (Gas)	12,787	6.4	19.7

Other Key Resource Adequacy Recommendations

- We have recommended a number of other changes that would improve the procurement of capacity in MISO:
  - ✓ Limit accreditation of emergency-only resources based on their likely availability during emergencies – resources with notification times longer than 2 hours are largely inaccessible in most emergencies.
  - ✓ Improve the modeling of transmission constraints in the PRA and recognize transmission constraints when zones are defined.
  - ✓ Consider transitioning to a seasonal capacity market, which will allow more flexibility to take seasonal outages and reflect resources' varying capabilities.
- We are also recommending that MISO disqualify energy efficiency (EE) from selling capacity because:
  - ✓ Capacity payments to EE are inefficient – these payments are redundant to the savings customers receive by installing EE.
  - ✓ Even were such payments justified, the EE quantities cannot be accurately calculated because they are based on a series of speculative assumptions.
  - ✓ EE has been growing rapidly and does not provide reliability that is comparable to other capacity resources.

Energy Efficiency in MISO

Planning Year	Enrolled Qty	Net Sales	Offer MW	Cleared/FRAP
2017/18	98	0	98	98
2018/19	173	0	173	173
2019/20	312	0	312	312
2020/21	650	0	650	650



Recommendations

List of Recommendations

SOM Number	Recommendations	High Benefit	Near Term
Energy Pricing and Transmission Congestion			
2019-1	Improve the relief request software for market-to-market coordination.	✓	
2019-2	Improve the testing criteria for defining market-to-market constraints.		
2019-3	Develop improved capabilities to receive and validate current and forecasted dynamic ratings from transmission facilities.	✓	✓
2018-1	Improve emergency pricing by establishing an efficient default floor and accurately accounting for emergency imports.	✓	
2018-2	Lower GSF cutoff for constraints with limited relief.		
2016-1	Improve shortage pricing by adopting an improved Operating Reserve Demand Curve reflecting the expected value of lost load.	✓	✓

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List of Recommendations

SOM Number	Recommendations	High Benefit	Near Term
Energy Pricing and Transmission Congestion			
2016-3	Enhance authority to coordinate transmission and generation planned outages.		
2015-1	Expand eligibility for online resources to set prices in ELMP and suspend pricing by offline resources.	✓	✓
2015-2	Expand utilization of temperature-adjusted and short-term emergency ratings for transmission facilities.	✓	
2012-5	Introduce a virtual spread product.		
2014-3	Improve external congestion related to TLRs by developing a JOAs with TVA and IESO.		
2012-3	Remove external congestion from interface prices.		

List of Recommendations

SOM Number	Recommendations	High Benefit	Near Term
Operating Reserves and Guarantee Payments			
2010-11	Incorporate expected deployment costs into the selection criteria when clearing reserve products.		
2018-3	Improve the RDT Agreement to procure reserves on the RDT and compensate the joint parties when the reserves are deployed.		
Dispatch Efficiency and Real-Time Market Operations			
2019-4	Clear CTS transactions every five minutes based on the most recent five-minute prices in the neighboring RTO area.	✓	
2018-4	Clarify the criteria and improve the logging for declaring emergencies and taking emergency actions.		✓
2017-2	Remove transmission charges from CTS transactions.	✓	✓
2017-4	Improve operator logging tools and processes related to operator decisions and actions.		
2017-5	Evaluate the feasibility of implementing a 15-minute day-ahead market under the Market System Enhancement.	✓	
2016-6	Improve the accuracy of the LAC recommendations.		✓

List of Recommendations

SOM Number	Recommendations	High Benefit	Near Term
Resource Adequacy			
2019-5	Remove eligibility for energy efficiency to sell capacity.		✓
2018-5	Improve capacity accreditation by accounting for unforced and unreported outages and derates during tight supply periods.	✓	
2018-6	Modify the supply and demand inputs for capacity by: a) accounting for behind-the-meter process load, b) improving planning assumptions, and c) validating suppliers' data.		✓
2017-6	Require the ICAP of Planning Resources be deliverable.		✓
2017-7	Establish PRA capacity credits for emergency resources that better reflect their expected availability and performance.		
2015-6	Improve the modeling of transmission constraints in the PRA.		
2014-5	Transition to seasonal capacity market procurements.		
2014-6	Define local resource zones based on transmission constraints and local reliability requirements.		
2010-14	Improve the modeling of demand in the PRA.	✓✓	