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Francone Letter 9.5.25



Department of Energy

Washington, DC 20585

September 5, 2025

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RE: August 6, 2025 Submission

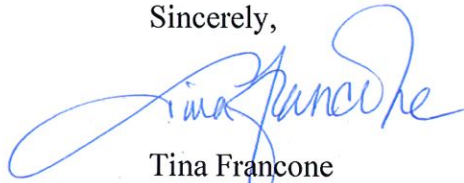
To Whom It May Concern:

Thank you for your August 6, 2025 submission on behalf of the Attorneys General of Maryland, Washington, Illinois, Michigan, Minnesota, Arizona, Colorado, Connecticut, and New York (collectively, the State AGs). The submission was titled “Motion to Intervene and Protective Request for Rehearing by the Attorneys General of Maryland, Washington, Illinois, Michigan, Minnesota, Arizona, Colorado, Connecticut, and New York” (Submission). It was not filed in any active docket.

On July 7, 2025, the U.S. Department of Energy (DOE) issued the Report on Strengthening U.S. Grid Reliability and Security (Resource Adequacy Report or RAR), fulfilling Section 3(b) of Executive Order 14262. The RAR presents a unified, transparent methodology for assessing the reliability of the bulk power system and identifying regions at elevated risk of resource inadequacy under projected load growth and plant retirement scenarios. DOE developed this approach in coordination with NERC and leading industry experts to provide a consistent, data-driven framework for informing federal reliability interventions, particularly as the grid faces surging demand from AI-driven data centers, reindustrialization, and electrification.

In the Submission, the State AGs seek rehearing of the RAR under section 313 of the Federal Power Act (FPA).¹ An application for rehearing under section 313 of the FPA² may be filed only by a “person, electric utility, State, municipality, or State commission” that is “aggrieved” by “an order issued by [DOE].”³ If these prerequisites are not met, there is no basis for rehearing. Here, we note that the RAR is simply a report that details the current condition of the United States electrical grid. It contains no directives, nor does it impose legal duties upon any party, including the State AGs. As such, it cannot be considered an “order” by which the State AGs are “aggrieved” within the meaning of section 313 of the FPA, as would be required to request rehearing. Accordingly, DOE will take no action on the Submission.

Sincerely,



Tina Francone
Director of the Grid Deployment Office, Acting

¹ Submission at 1.

² 16 U.S.C. § 8251(a).

³ *Id.*

Attachment U

MISO, 2023 Attributes Roadmap631174

Attributes Roadmap

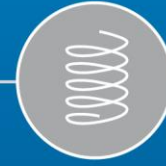
A RELIABILITY IMPERATIVE REPORT



SYSTEM
ADEQUACY



FLEXIBILITY



SYSTEM
STABILITY

DECEMBER 2023

Highlights

- The evolving energy landscape requires MISO and the industry to understand the increasing complexity of the transitioning system and proactively adapt to increasing risk and changing system conditions
- MISO's 2023 analysis highlights the need for market reforms and new requirements to ensure the sufficiency of three priority attributes where near-term risk is most acute: system adequacy, flexibility, and system stability
- The *Attribute Roadmap* recommends advancing a combination of current and new proposals as well as providing ongoing attributes visibility through regular reporting



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Version Number	Purpose / Change	Date
1.0	Initial posting.	December 2023
1.1	Updated with hyperlinks between the <i>Technical Appendix</i> and the <i>Attributes Roadmap</i> and correction of minor typos per stakeholder feedback.	June 2024



Executive Summary

INTRODUCTION

The *Attributes Roadmap* presents insights and solutions following an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly transforming energy landscape. The generation resource mix is diversifying; the surety of the fuel supply is declining; extreme weather is increasing in intensity and duration; and industrial load growth and electrification trends are poised to disrupt traditional load patterns. These factors create complex challenges for MISO and stakeholders and a shared imperative to urgently act to avoid a looming shortage of necessary system reliability attributes and ensure electricity is delivered every hour of every day to the 45 million people in the MISO region.

No single resource provides every needed system attribute. The needs of the system have always been met by a fleet of diverse resources operated in a manner that most efficiently meets the system needs. Preparing for the energy transition requires an improved understanding of the reliability attributes of the bulk electric system and the advancement of urgent market reforms and requirements to meet the changing system needs.

In 2023, MISO designed and completed a foundational analysis of the system reliability attributes. The analysis focused on three priority attributes where risk to the MISO system is most acute: **system adequacy, flexibility, system stability**, and their near-term risk factors (Figure 1). MISO developed recommended approaches and solutions based on input from various expert sources, including MISO's internal subject matter experts and past analyses, MISO stakeholders, external industry research, and leading industry experts.

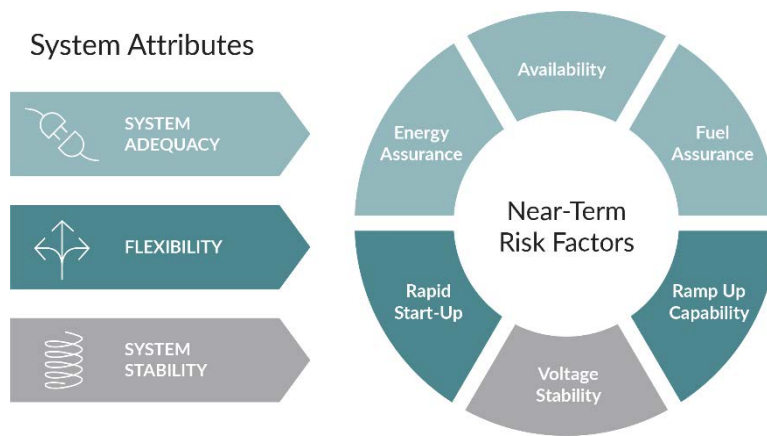


Figure 1: Three priority system reliability attributes and their near-term risk factor focus areas

INSIGHTS AND SOLUTIONS

To meet the rapidly evolving needs of the bulk electric system, urgent action is needed to advance a targeted portfolio of market reforms and system requirements, and to provide ongoing attributes visibility through regular reporting. In summary:

SYSTEM ADEQUACY refers to the ability to meet electric load requirements during periods of high risk. MISO focused on the near-term risk factors of availability, energy assurance, and fuel assurance.

- Approach: Best addressed in the planning horizon and served through capacity requirements, capacity accreditation (valuation), and market solutions within the seasonal resource adequacy construct where a diverse range of generation resources can contribute to meeting demand and



reserve requirements. Additionally, evolved coordination is needed between MISO's resource adequacy assessments and MISO state and member planning processes.

- Recommendations: MISO recommends a continued focus on one market clearing product (capacity), and further modernizing the resource adequacy construct to address emerging attribute-related risk factors through improved risk modeling, capacity accreditation, and capacity market qualification requirements. Additionally, MISO recommends providing visibility into future regional system adequacy needs and capabilities through improved forecasting and reporting.

FLEXIBILITY is the extent to which a power system can adjust electric production or consumption in response to changing system conditions. MISO focused on the near-term risk factors of rapid start-up and ramp-up capability.

- Approach: Best addressed in the operating timeframe and served through market solutions where resources can compete to meet the increasingly variable and uncertain real-time operational needs of the system.
- Recommendation: MISO recommends advancing two strategic objectives to address this attribute: (1) focus market signals on emerging flexibility needs through expanded and new ancillary service products, and (2) expand the fleet of qualifying resources able to provide flexibility by enhancing market systems and reforming resource participation models to enable emerging technologies to fully participate.

SYSTEM STABILITY is the ability to remain in a state of operating equilibrium under normal operating conditions and to also recover from disturbances. MISO focused on the nearest-term risk factor of voltage stability.

- Approach: Best addressed initially through requirements and technology standards and a multistep approach to require capabilities from resources to support grid stability.
- Recommendation: MISO recommends requirements for inverter-based resource controls as part of the resource interconnection process and incentives for critical reliability capabilities as needed.

The *Attributes Roadmap* includes current and new proposals to ensure the sufficiency of the priority system reliability attributes with approximate project relationship and timing (Figure 2). The report discusses each of these recommendations in detail as well as the analysis and research that supports the recommendations.

NEXT STEPS

The attributes insights and solutions will further inform the region's Reliability Imperative priorities. MISO's next step will be to integrate the recommendations into its processes with stakeholder engagement throughout. In addition, MISO will continue to monitor the efficacy of planned and implemented solutions, study additional system attributes, and consider solutions beyond this recommendation.

Timely collaboration is needed between MISO, its stakeholders, and the broader industry to continue this mission-critical work and ensure the region is prepared to reliably navigate the energy transition.

Find the latest project status on MISO's Dashboard for "[Identification of Sufficient Reliability Attributes RASC – 2022-1](#)." Ongoing system attributes work will be coordinated through the MISO Stakeholder [Resource Adequacy Subcommittee](#).

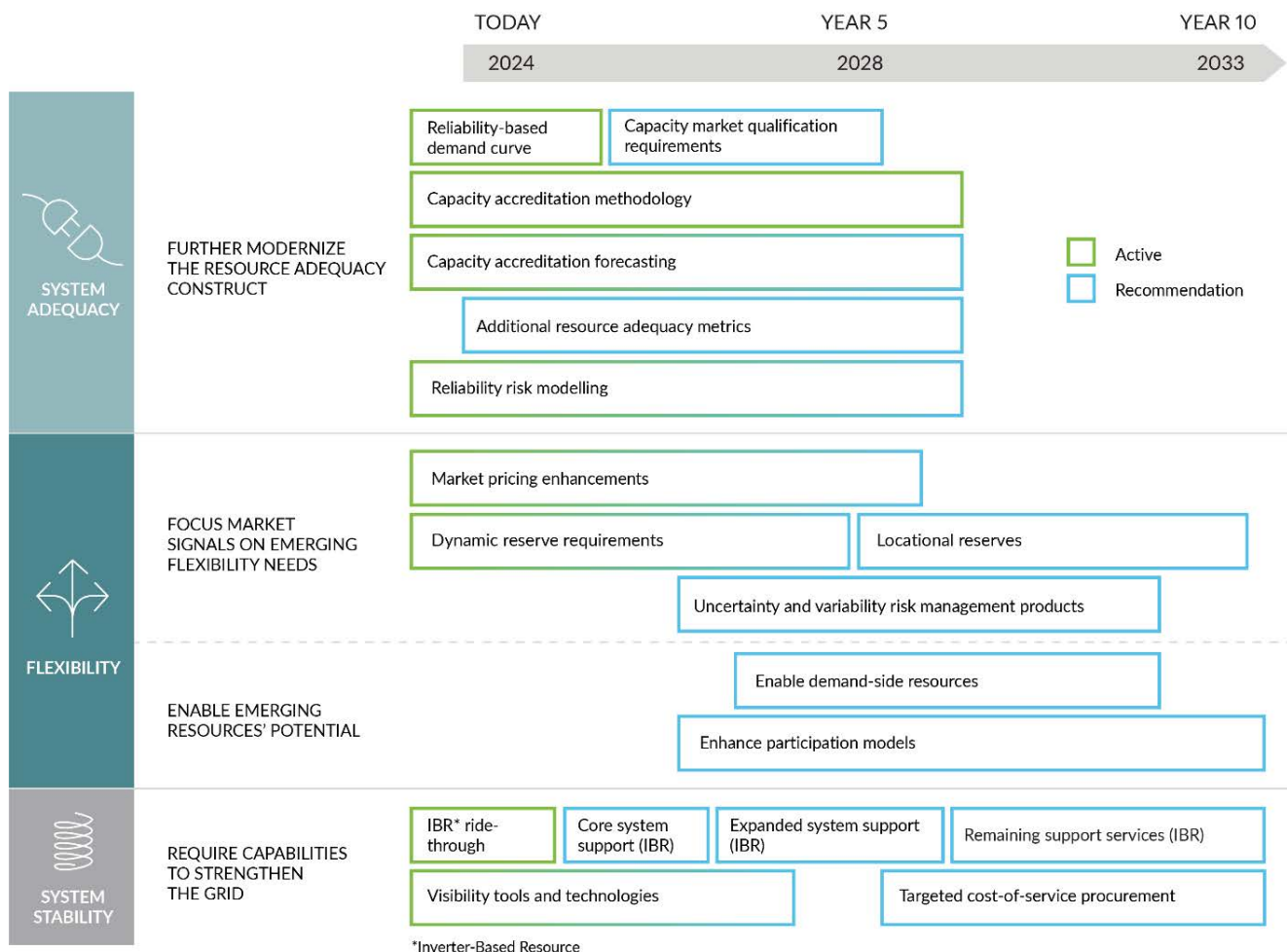


Figure 2: Hypothesis for attributes solution roadmap with approximate timing for projects currently underway (active) and proposed future projects (recommendation). The *Attributes Roadmap* discusses each recommendation in detail as well as the analysis and supporting research.



Project Introduction and Approach

System reliability attributes are characteristics of the bulk electric system. A wide range of attributes is needed to ensure reliability and support the region’s affordability and sustainability objectives. Importantly, no single generating resource provides every needed system attribute.¹ The foundational needs of the system have always been met by a fleet of diverse resources operated in a manner that most efficiently meets system needs.

As the system transforms, strategic assessments by MISO and other industry experts conclude that system reliability attributes will need to be increasingly studied, measured, incentivized, and required for the bulk electric system to maintain its expected levels of reliability.

MAJOR DRIVERS OF CHANGE INTRODUCE NEW AND SHIFTING SYSTEM RISK

Major industry trends are simultaneously changing the conditions of the system, for example:

- New generation and load resources coming online often do not have the same characteristics as the resources they are replacing, introducing the potential risk that the needs of the system will not be met by the transitioning fleet.
- Increased impacts from severe weather creates major challenges in managing transmission congestion, high rates of correlated forced outages, and extended periods of high demand.
- Demand for electricity is increasing to meet new needs (e.g., the information economy, efforts to rebuild domestic supply changes, and electrification) and disrupting traditional load patterns.

See [MISO’s Response to the Reliability Imperative](#) for a more detailed analysis of trends and drivers of change in the MISO region.

PAST STUDIES INFORM PRIORITIZATION AND APPROACH

The attributes project was informed by previous MISO studies assessing the region’s changing risk profile and exploring the reliability impact of the major drivers. This work includes:

[Markets of the Future:](#) Illustrated how and when MISO’s existing market structures will need to evolve to accommodate the profound changes that are occurring in the energy sector. The needs were presented in four broad categories: (1) Uncertainty and Variability; (2) Resource Models and Capabilities; (3) Location; and (4) Coordination. This report helped establish the foundation for the attributes work.



[MISO Futures:](#) Utilized a range of economic, policy, and technological inputs to develop three future scenarios that “bookend” what the region’s resource mix might look like in 20 years. The attributes team used the recently refreshed Future 2A forecasted resource portfolios to perform the forward looking five-year and 10-year analysis.



¹ EPRI, [Energy Supply Reference Card](#), 2023 Version.



Renewable Integration Impact Assessment (RIIA): Assessed the impacts of integrating increasingly higher levels of renewables into the MISO system. This assessment steered the attributes project in many ways, including the key finding that voltage stability and inverter-based converter stability are among the first system stability related challenges the MISO system will likely face.



Regional Resource Assessment (RRA): Recurring study based on the plans and goals that MISO members have publicly announced for their generation resources. This year's attributes analysis built upon the flexibility assessments of net load variability and uncertainty changes originally presented within the RRA.



The February (2021) Arctic Event: Discussed lessons learned from Winter Storm Uri, which affected the MISO region and other parts of the country in February 2021. MISO and its members took emergency actions during the event to prevent more widespread grid failures. The attributes work used Uri as a case study.



EXPLORATION OF THE SOLUTIONS LANDSCAPE

MISO began the process of developing possible solutions to the major questions regarding system adequacy, flexibility, and system stability by soliciting input from expert sources (Figure 3). From these queries, MISO filtered more than 100 possible solutions to the problems proposed.

Many solution options came from MISO's internal experts and past reports. Stakeholder discussions offered ideas, including recommendations for MISO's Independent Market Monitor (IMM). The team reviewed relevant industry research and literature, including work led by the Energy System Integration Group, NERC's Energy Reliability Assessment Task Force, and the Electric Power Research Institute (EPRI). Additionally, MISO reviewed the actions and published analysis of other grid operators, including PJM and ERCOT, the Australian Energy Market Operator, and UK's National Grid Electricity System Operator.

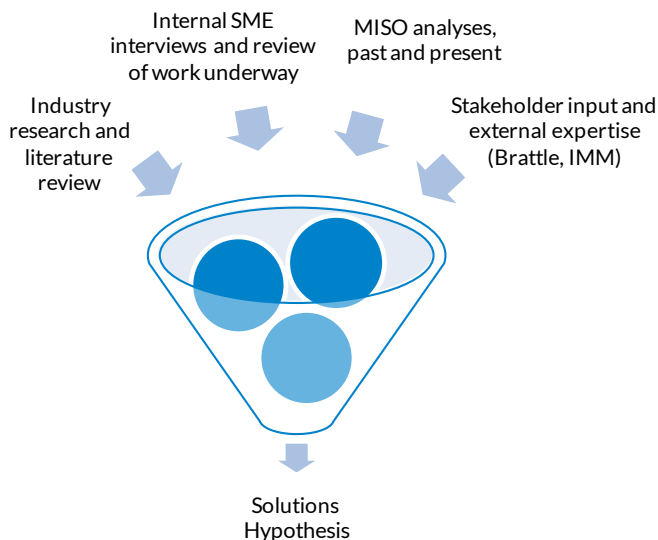


Figure 3: Sources of solutions considered

Solutions exploration and focus was done in consultation with The Brattle Group. MISO engaged Brattle on strategy and risk approaches, evaluation of the solutions for impact and efficiency, and industry expertise on solution implementation outcomes in other regions. Brattle presented its recommendation to the Resource Adequacy Subcommittee (RASC) in October 2023.²

² Brattle, "[MISO Reliability Attributes Solution Space](#)," presented to MISO's Resource Adequacy Subcommittee (RASC), October 4, 2023.



CRITERIA FOR EVALUATING CANDIDATE SOLUTIONS

Solutions were narrowed based on the following evaluation criteria:

TECHNICAL CRITERIA

- ✓ Helps **attract/retain** sufficient resources to provide the target reliability attribute
- ✓ **Operationally utilizes** the resource to provide the attribute

ECONOMIC CRITERIA

- ✓ Promotes **economically efficient investment**
- ✓ Promotes **economic efficient operations and performance**

PROCESS CRITERIA

- ✓ Provides **transparency** and predictability, without excessive complexity
- ✓ Has acceptable **implementation cost and time**

OTHER CONSIDERATIONS

- ✓ **Resource neutrality**
- ✓ Informs **long-term planning** for states and members
- ✓ **Adaptability** to change in policies and market conditions
- ✓ **Compatibility** with existing processes, markets, and policies

MISO applied the quantitative criteria against the initial list of solutions. With the shorter list of solution candidates, quantitative analysis was completed wherever practical to test the working hypotheses.

FOUNDATIONAL ANALYSIS AND SOLUTIONS

This report is divided into three sections, one for each priority attribute: system adequacy, flexibility, and system stability. Each section begins with a definition of the attribute and problem statement, followed by a high-level recap of the foundational analysis and key insights, as presented in the [September 2023](#) and [October 2023](#) attributes workshops. Following that is a directional recommendation of how to approach possible solutions, including what MISO recommends *not* to do. Lastly, each section contains details of the proposed roadmap of solutions, including related work underway at MISO.

MISO conducted foundational analysis for each priority system attribute to guide the solution selection and prioritization. The analysis relied on existing and vetted datasets, methods, and software, which were augmented to meet the specific needs of the study. Generally, the analysis compared a representation of today's system (e.g., planning year 22-23) to forecasted out-year system conditions derived from MISO's Future 2A expansion.³

³ Futures portfolio are based on Scenario 2A in MISO, [MISO Futures Report Series 1A](#), November 2023.



System Adequacy

NERC defines adequacy as the “ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.”⁴ MISO’s attributes team further framed the system adequacy attribute as the ability of a resource portfolio to meet capacity and energy demand for a wide range of system conditions, with the expectation that unserved demand does not exceed a predetermined criteria.

MISO focused the 2023 system adequacy analysis on the risk factors expected to be most acute in the near term: availability, energy assurance, and fuel assurance (Figure 4). Availability is the consistent and predictable ability to call on capacity at the time of need. Energy assurance is the ability of the system to adequately manage and deliver energy supply on a 24 hour, seven days a week basis, especially in the presence of variable-energy or energy-limited resources. Fuel assurance is the ability for resources to access primary or backup fuel for electric power production at the time of need. These aspects of system adequacy are interrelated. For instance, extreme weather can drive widespread performance issues across all three risk factors.

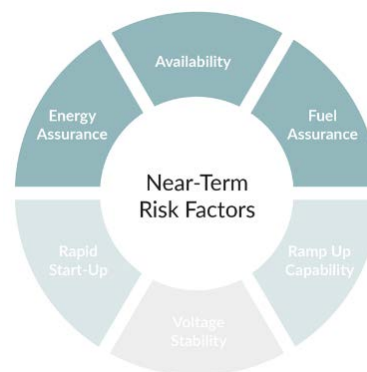


Figure 4: System Adequacy near-term risk factor focus areas

RECENT AND PROPOSED RESOURCE ADEQUACY REFORMS ADDRESS THE FUNDAMENTALS

The modernization of MISO’s resource adequacy construct is well-underway with recent and proposed changes to incorporate current industry best practices and address shifting risk. MISO’s recently implemented seasonal Planning Resource Auction (PRA) better acknowledges seasonal risks and resource capabilities throughout the year. The current accreditation methodology, approved by the Federal Energy Regulatory Commission (FERC) in 2022, also aligns the accreditation of thermal resources with their availability in the recent highest risk periods.

The proposed next step for resource adequacy reform is to credit all resources using a combination of the Direct Loss of Load (DLOL) method⁵ at the class level and the previously defined Resource Adequacy hours⁶ at the unit level. Load modifying resources (LMR) and other emergency resources are currently excluded from the proposed accreditation changes (DLOL method), due to their status as emergency only. MISO is working on a parallel initiative for these resources.

When MISO implements these proposed reforms, the fundamental components will be in place to address the energy transition. MISO recommends improvements to the underlying model to fully capture attribute risk.

⁴ NERC, [Glossary of Terms Used in NERC Reliability Standards, March 2023](#).

⁵ DLOL is an accreditation methodology that examines the contribution of a resource to the system during times of risk, represented by loss of load hours. MISO, [Resource Accreditation White Paper](#), November 2023.

⁶ FERC. Docket No. [ER22-495-002](#), February 16, 2023.



SYSTEM ADEQUACY REQUIRES EXTENDING LOSS OF LOAD EXPECTATION MODELING

Today, MISO's Loss of Load Expectation (LOLE)⁷ modeling incorporates an optimized planned outage schedule and randomly drawn forced outages based on historical unit-level outage data. Additionally, an extreme cold weather outage adder is modeled, which approximates weather-dependent outages using zone-specific, fixed outage profiles based on historical outage data during extreme cold temperatures. As the system's fleet continues to evolve, it is necessary to better understand and quantify the impact on the system risk from weather-related drivers, such as outages related to fuel unavailability, mechanical failure, and a breakdown of gas/electric coordination. To increase visibility into the weather-dependent risk drivers, it is important to explore the impact of fuel and non-fuel related outages on the LOLE framework. It is also key to acknowledge the regional implications of transfer limits between different geographical locations as the resource mix becomes more diverse.

The primary objective of the 2023 system adequacy attribute work was to develop a method for measuring emerging risk factors (availability, energy, and fuel assurance) and quantify their impact on system-wide accreditation and requirements. Two study cases were defined: (1) business-as-usual, and (2) enhanced risk assessment. The enhanced risk assessment case was designed to assess the impact of risk factors related to the delivery of energy during more constrained conditions (transfer limited). The enhanced risk assessment also extended the approach followed in the business-as-usual case for capturing weather-dependent outages, by modeling these as a function of the installed capacity. The two study cases were analyzed using three evolving resource portfolios: today, 2027, and 2032.⁸

The impacts of these risk factors were quantified by the resulting changes in accreditation and requirements between the two cases and across portfolios. The outcome of this assessment, which helped inform the solutions hypothesis, offers three key insights.

Resource Adequacy Terms:

- “*Loss of load Expectation*” (LOLE): Expected or average number of days during a given time period for which the available generation capacity is insufficient to serve demand
- “*Loss of load Hours*” (LOLH): Expected or average number of hours during a given time period where system demand will exceed the generating capacity
- “*Expected Unserved Energy*” (EUE): Amount of demand (measured in MWh) that the system will not meet during a given time period, averaged across a wide range of system conditions
- “*Conditional Value at Risk*” (CVaR): Expected unserved energy over the X% worst system conditions

⁷ IEEE reference for a comprehensive description of [LOLE resource adequacy terms](#).

⁸ Futures portfolio are based on Scenario 2A in MISO, [MISO Futures Report Series 1A](#), November 2023.



INSIGHT: Accreditation aligns with the risk distribution, regardless of the underlying sources of risk modeled, and tracks the contribution of individual resources

The proposed accreditation method (DLOL) aligns availability and need in the planning horizon at the class level. As the generation fleet evolves, the timing, volume, duration, and frequency of loss of load events are expected to change (Figure 5).⁹

The bulk of the risk moves away from the summer gross peak load and distributes across other seasons (Figures 5 and 6). In 2027, the risk is expected to balance between the summer and fall seasons. In 2032, the risk concentrates in the winter, driven by electrification and weather-dependent capacity.

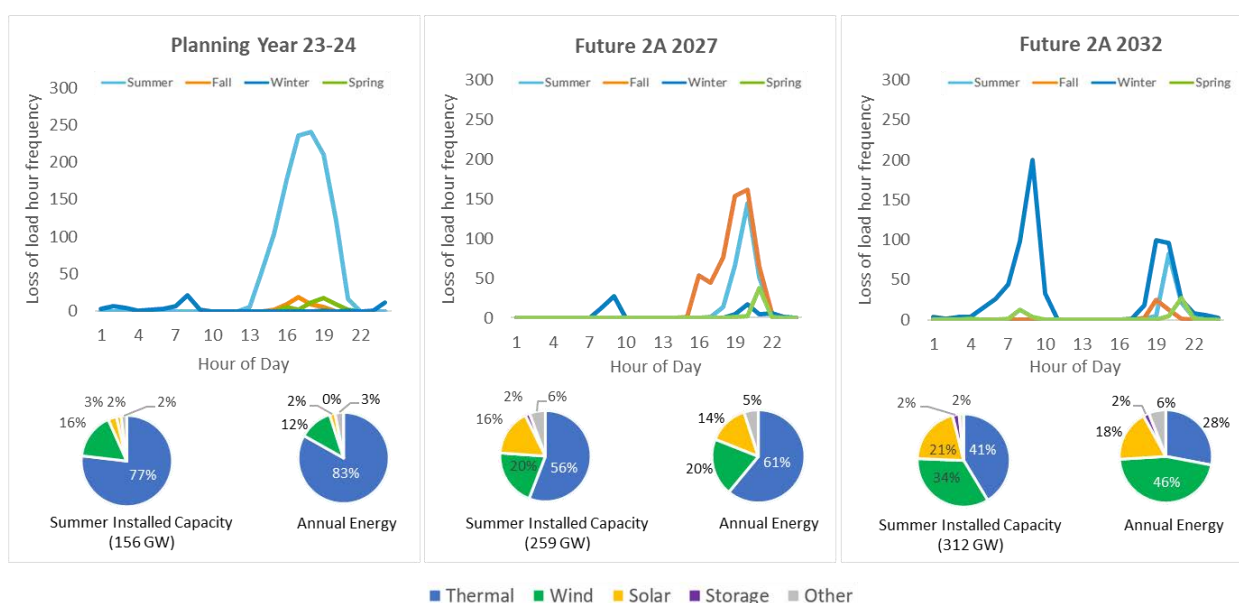


Figure 5: Evolution of risk distribution in future portfolios

These shifts in risk over time impact the accreditation of resources and system requirements, as both rely on the underlying LOLE model. Figure 6 illustrates the changes in summer accreditation and risk distribution from the business-as-usual LOLE simulations. The reduction in wind and solar accreditation in later years is driven by the shift in risk towards twilight hours. The slight increase in storage accreditation is due to the shorter duration and smaller magnitude events in the 2032 portfolio.

⁹ A summary of all metrics is included in section A.4.1 of the [Technical Appendix](#).

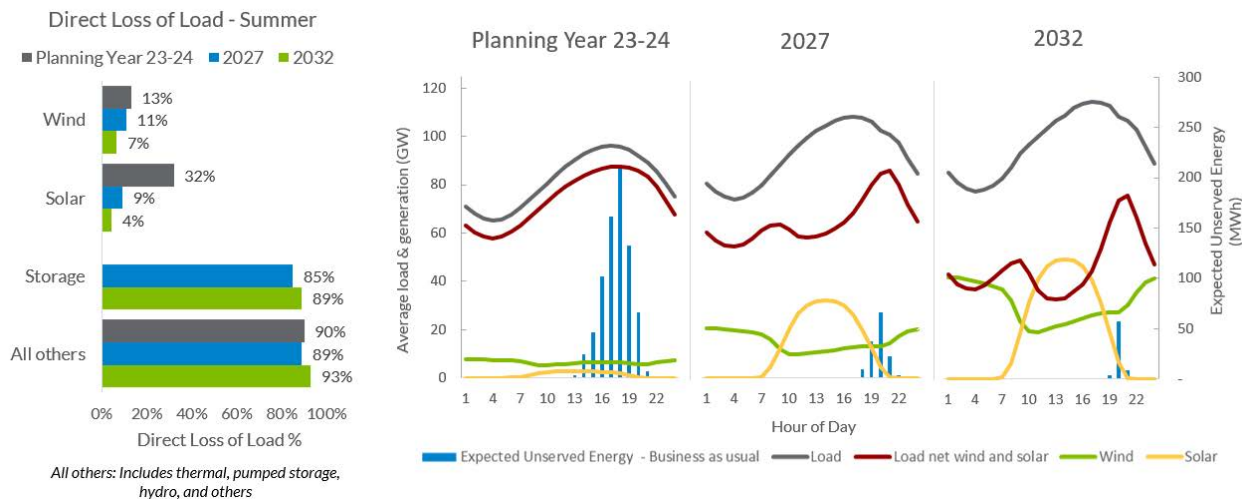


Figure 6: On the left, estimated summer season, class-level DLOL accreditation values for the three portfolios (today, 2027, and 2032) by fuel type. On the right, summer diurnal plots from the LOLE simulations showing average load, net load, and renewable generation for each hour.

Figure 7 shows the forward-looking accreditation results for the winter season. The changes in wind and solar accreditation are small, as the risk distribution in the winter season is concentrated in nighttime hours. The 2032 portfolio shows events that are longer in duration, more severe, and with a higher frequency (multiple events per day). This results in a lower accreditation for energy-limited storage resources¹⁰, as their ability to mitigate risk is proportional to their state of charge at the beginning of the event and total energy available.

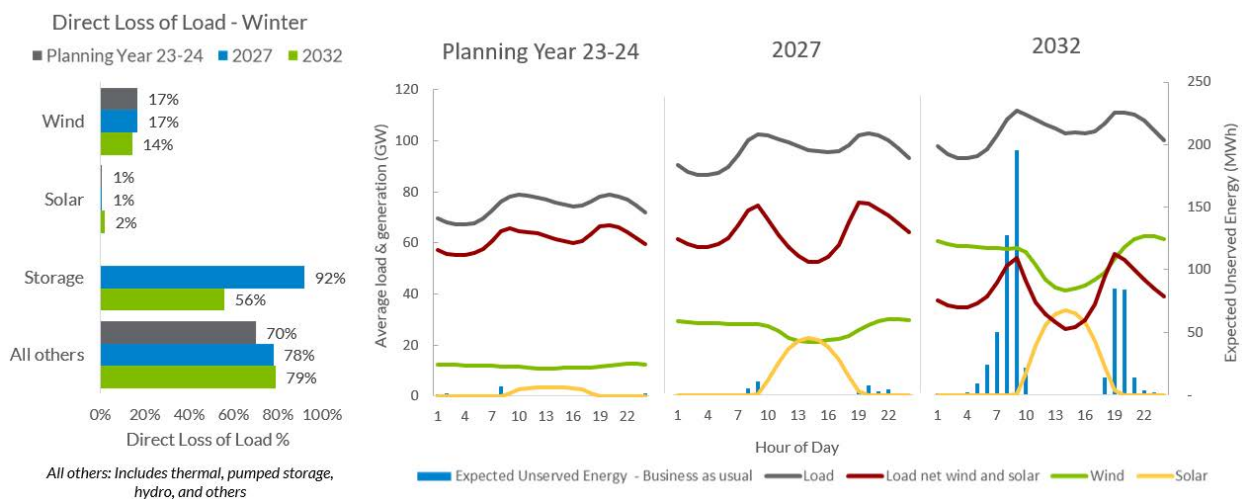


Figure 7: On the left, estimated winter season, class-level DLOL accreditation values for the three portfolios (today, 2027, and 2032) by fuel type. On the right, winter diurnal plots from the LOLE simulations showing average load, net load, and renewable generation for each hour.

¹⁰ Modeled as 4-hour resources in this analysis.



Capturing these interactions and changes in risk patterns are key to the development of a robust accreditation methodology that will serve existing and future portfolios, and the analysis demonstrated that robustness. The full set of forward-looking accreditation results are included in section A.4.1 of the [Technical Appendix](#).

INSIGHT: The acknowledgment of weather-dependent outages and deliverability captures additional risk factors that are projected to appear in future portfolios

The incorporation of weather-dependent outages increased winter LOLE. The incremental winter risk in 2027 and 2032 are primarily driven by weather-dependent correlated outages. Although both portfolios included the same planned retirements, the addition of “flex” units¹¹ resulted in additional correlated outages in 2027 and 2032. The concentration of long-duration events in extreme weather conditions, such as winter storm Uri in 2021, highlighted wind capacity impacts.

The incorporation of the regional directional transfer (RDT) limits between MISO North/Central and South in the enhanced risk assessment case increased LOLE across all seasons compared to the business-as-usual case (Figure 8). Risk increased the most in spring and winter in 2027 when the RDT constraint was added, while in 2032 risk increased the most in winter. These increases in LOLE show that the inclusion of transmission constraints into the model captures underrepresented transfer limitations between the two MISO regions. The modeling of non-firm external transactions was kept unchanged in the business-as-usual and enhanced risk assessment cases.¹²

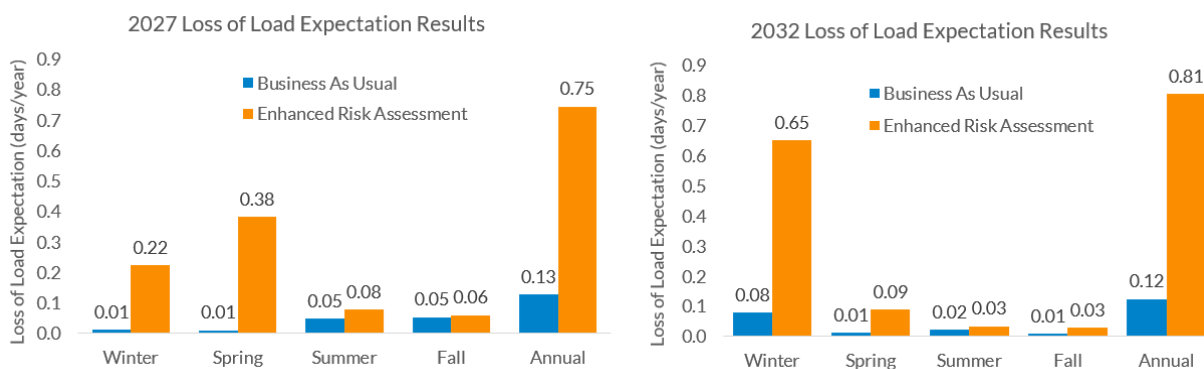


Figure 8: Seasonal LOLE results for the business-as-usual and enhanced risk assessment cases when both at the same adjustment.

The inclusion of the RDT constraint also had an impact on wind and storage accreditation values; the difference in DL0L between the business-as-usual and enhanced risk assessment cases for two resource classes (wind and battery storage) are shown in Figure 9. These accreditation changes can be attributed to transfer limit constraints when the RDT limit is enabled. It also highlights the difference in resource mixes

¹¹ MISO, [MISO Futures Report, Series 1A](#), November 2023.

¹² Modeling of non-firm external transaction was based on historical net-scheduled interchange between MISO and external regions, followed resource adequacy base business practices. More details are available in section A.2 of the [Technical Appendix](#).



between the North/Central and South in the model. Wind DLOL increased in the enhanced risk assessment cases because most of the wind capacity is in the North/Central region. However, most of the loss of load events were concentrated in the South region during periods of high wind availability in the North/Central, driving a higher MISO-wide wind accreditation. Similarly, storage DLOL decreased in the enhanced risk assessment cases because most of its capacity is in the North/Central region and was charging during loss of load events in the South region. Accreditation for the remaining resource classes did not change substantially between cases, with deltas under 3%. These values are shown in section A.4.2 of the [Technical Appendix](#).

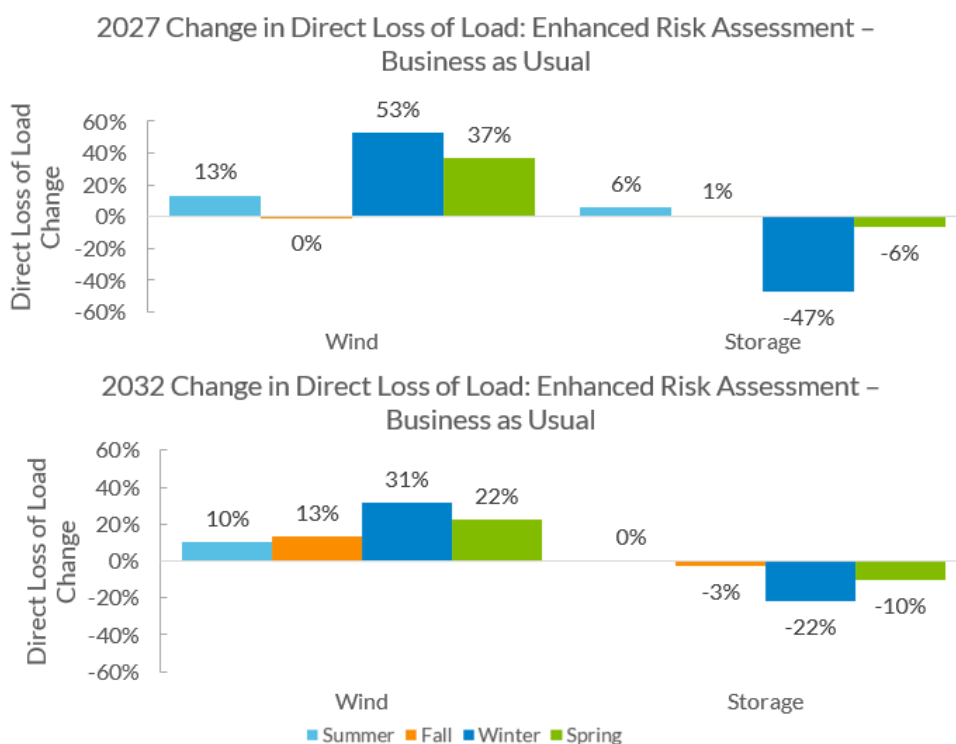


Figure 9: DLOL deltas between the enhanced risk assessment and business-as-usual cases for wind and battery storage resource classes when both cases are adjusted to seasonal LOLE targets.

MISO-wide planning reserve margin requirement (PRMR) increases when the RDT constraint is added to the model for both 2027 and 2032 (Figure 10). This change in the PRMR is due to the difference in fixed load adjustment to meet the 0.1 days/year LOLE target between the enhanced risk assessment and business-as-usual cases. The largest increase in the requirement for both years is in the winter season.

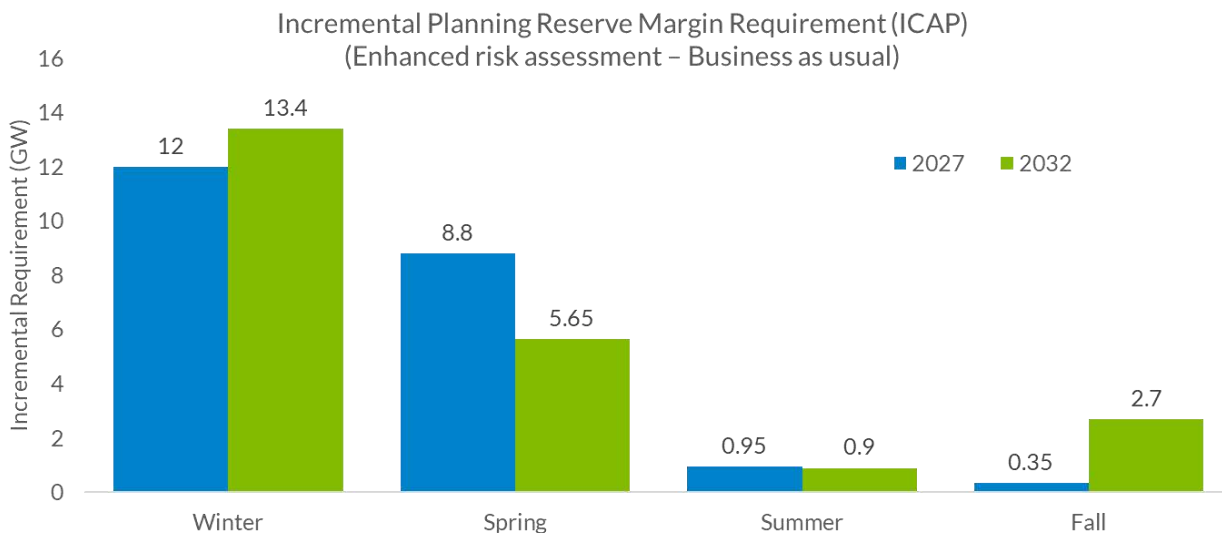


Figure 10: Incremental planning reserve margin requirement (PRMR) by season

INSIGHT: Initial system adequacy-focused flexibility analysis points to potential issues in 2032, additionally analysis is required to understand the implications

Season	PY22-23 Delta EUE (MWh)	2032 Delta EUE (MWh)
Winter	0	1794
Spring	0	6320
Summer	0	304
Fall	0	463

Table 1: EUE difference between business-as-usual and Adequacy-Flexibility analysis

The differences in expected unserved energy (e.g., delta EUE) between the business-as-usual and Adequacy-Flexibility analysis for the planning year 22-23 model and 2032 models are within the 300-6,320 MWh range (Table 1). For both models, the Flexibility analysis' Loss of Load Hours (LOLH) and LOLE matched exactly to the business-as-usual results of the corresponding model. The total EUE of all seasons matched exactly in the planning year 22-23 model, suggesting that flexibility is sufficient in the current portfolio.

In the 2032 model, MISO observed significant deviation in the results. Spring exhibits especially high EUE under the Flexibility constraints, followed by winter, fall, and summer. Figure 11 shows hours with high

To complete the flexibility analysis within the resource adequacy construct (adequacy-focused flexibility), additional operational data was added to the loss-of-load model, including maximum and minimum unit generation levels, up and down ramp limits, heat rates, and fuel costs. The most challenging week per season (in terms of highest expected unserved energy (EUE), net load, and net load ramping¹³) was selected for the planning year 22-23 and 2032 business-as-usual models.

The differences in expected unserved energy (e.g.,

¹³ Net load ramping is defined as the difference in net load between time periods t+1 and t.



netload driven by both Flexibility and business-as-usual EUE events in all seasons, while the Flexibility events show high variability in the netload ramping compared to the business-as-usual events. High rates of maintenance of thermal and flexible units in the spring had a major impact on the system's capability to mitigate the increased ramping up and down. This analysis did not include wind and solar generation curtailment, which could reduce ramping needs in the system.

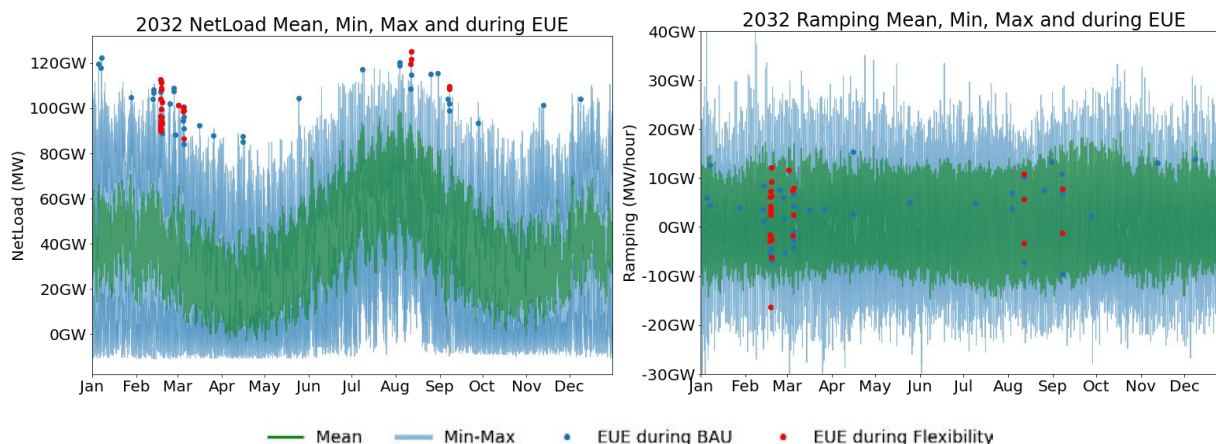


Figure 11: 2032 average, minimum, and maximum netload (left) and netload ramping (right). Blue and red dots signify netload and ramping at the event sample in business-as-usual and Flexibility

While this area of flexibility analysis within the resource adequacy construct presented some interesting results, further work is necessary to evaluate whether its inclusion in the system adequacy modeling is necessary. The proposed solutions in the operational adequacy space (see “Flexibility” section), coupled with the feedback loop between planning and operations, may be sufficient to ensure that flexibility issues are appropriately accounted for.

Find a detailed explanation of the full system adequacy analysis and results in sections A.3.3 and A.4.3 of the [Technical Appendix](#).

SYSTEM ADEQUACY RISK IS BEST ADDRESSED THROUGH CAPACITY REQUIREMENTS, ACCREDITATION AND FORWARD MARKETS

MISO recommends a continued focus on one market clearing product – capacity – because complex interactions between different resource types make it impractical to discretely quantify a specific amount of availability, energy duration, fuel requirement or related adequacy attributes. MISO’s analysis finds that the existing combination of capacity and reserve requirements, accreditation, and forward markets provide a sufficient framework to ensure system adequacy. Emerging attribute-related risk factors should be addressed by continually assessing and acknowledging operational risks through constraints in MISO’s risk models, the results of which will be reflected in accreditation and reserve requirements.

Additionally, MISO should focus on incentivizing good fuel assurance practices in three ways. (1) MISO will continue to apply and refine the “RA Hours” methodology to reward resources with sufficient fuel to maintain availability during times of risk with higher accreditation values. (2) MISO will create additional incentives through accreditation for resources with higher levels of fuel assurance (dual fuel, etc.) by exploring the creation of a firm fuel class, or similar, with qualification and ongoing operating performance



requirements. (3) MISO will continue the practice of multi-day commitments as needed through the Reliability Assessment and Commitment process and rely on the IMM to recognize extenuating circumstances in the cost of securing fuel.

WHAT NOT TO DO NOW

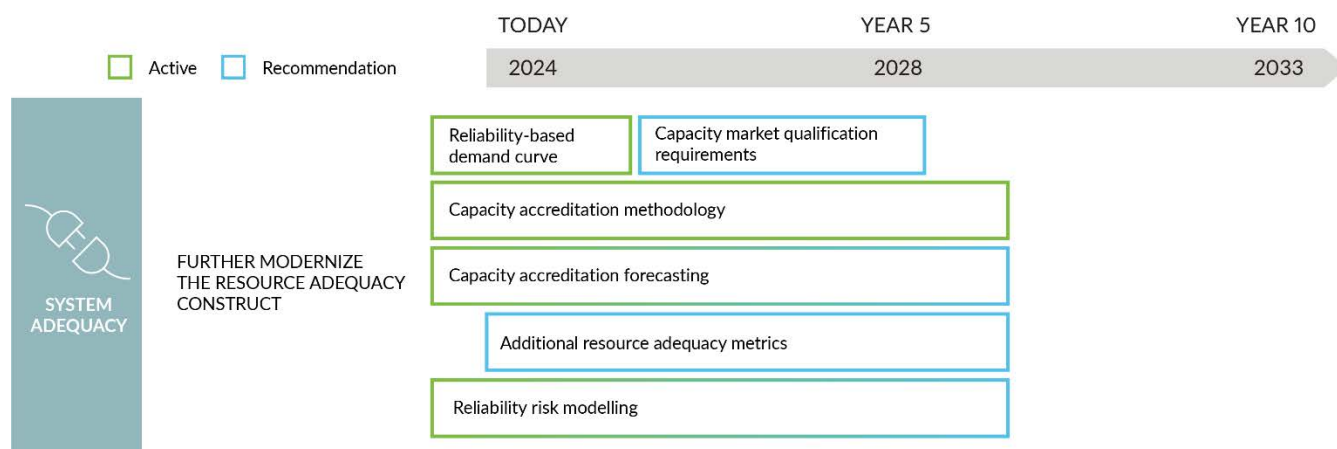
The *Attributes Roadmap* does not recommend new discrete capacity products (e.g., ramp capacity, energy reserves, or winter fuel programs). Capacity products outside the current construct may suppress energy and capacity prices. Additional products will increase complexity, requiring careful operational design, high implementation cost, and long implementation time with highly uncertain benefits.

MISO has also determined that there is currently no need to create an accelerated path for resource interconnection to account for attributes. Adequacy risks are regional in nature and more fully accounted for within the proposed resource adequacy enhancements. MISO continues to be focused on reaching the target queue timelines for all resources, which align with development timelines such that an accelerated path is not expected to result in earlier in-service dates.

There is no current need to account for the system adequacy attribute in the retirement (Attachment Y) programs because, again, adequacy risks are regional and better addressed through resource adequacy enhancements. Unless a policy need arises, Attachment Y is designed to be a stop-gap measure and is an insufficient mechanism to retain resources long-term or send long-term investment signals.

Lastly, MISO does not recommend taking broad action to secure forward gas supplies either through a multi-day market or forward fuel procurement. MISO will continue to commit gas and other resources beyond the day ahead market for limited reliability reasons and will explore improvements to that process and associated tools.

ROADMAP: FURTHER MODERNIZE THE RESOURCE ADEQUACY CONSTRUCT





SYSTEM ADEQUACY: Further Modernize the Resource Adequacy Construct

Implement the **reliability-based demand curve (RBDC)** to signal the value of incremental capacity

Clarify **capacity market qualification requirements** to ensure that resources are available when needed

- Clarification of obligations for market participation (e.g., minimum availability criteria, minimum winterization criteria, DIR participation, non-emergency status, etc.) to account for characteristics that cannot be properly modeled

Enhance **capacity accreditation methodology** to value the availability of all resources when needed most

- Transition to the proposed methodology to consistently accredit all resources for their availability during periods of highest potential and realized system risk
- Create and maintain resource accreditation classes to acknowledge differing risk profiles from similar resource types
- Explore an update to the allocation of PRMR requirements to better align with times of risk
- Enhance load modifying resource (LMR) accreditation to better align with availability when needed

Forecast seasonal capacity accreditation values annually for future years to understand how future system trends affect resource class accreditation and requirements for the benefit of market participants

Explore and report **additional resource adequacy metrics** to improve the quantification of risk and resource contribution

- Include more granular resource adequacy metrics in the annual report, including EUE, LOLH, conditional value at risk (CVaR)
- Explore the characteristics of daily LOLE considering EUE and other reliability metrics as the driving metric in the PRM to understand the trade-off between them
- *Conditional:* Implement alternative resource adequacy metrics if the exploration reveals a more robust metric than daily LOLE

Improve **reliability risk modeling** to best characterize existing and emerging system risks

- Incorporate correlated weather impacts in the LOLE model to account for outages such as those caused by reduced variable energy production or large-scale fuel shortages that are not currently modeled
- Incorporate transmission modeling in the LOLE model to account for increasing regional energy transfer requirements that result from the changing fleet and update downstream processes (e.g., accreditation, requirements) to utilize the enhanced geographical resolution
- Improve modeling of storage, energy-limited resources, and demand-based resources to properly capture their operational constraints and their additional contributions to the system (e.g., energy balancing, ancillary services)
- Explore implications of climate change for both supply and demand to improve load forecasting as well as address uncertainties and high-stress grid conditions
- Establish a feedback loop to analyze operational risk to identify diverging trends and continuously realign the risk model

Table 2: Hypothesis solutions roadmap to proactively address system adequacy attribute risk by further modernizing the resource adequacy construct.



SOLUTION: Implement the reliability-based demand curve to signal the value of incremental capacity

MISO's reliability-based demand curve approach¹⁴ seeks to provide more stable price signals for markets participants and regulators to provide the necessary capacity supply, while avoiding excessive infrastructure development. In September 2023, MISO filed tariff changes to FERC that include the following key elements:

- System-wide and sub-regional demand curves
- Incorporation of net cost of new entry and the marginal reliability impact resulting from MISO's loss of load modeling, that together determine the value of capacity
- A reliability-based demand curve opt-out provision for states that choose to not participate in the PRA

Should FERC approve the proposed changes, MISO aims for implementation in the 2025 PRA for Planning Year 2025-2026.

SOLUTION: Clarify capacity market qualification requirements to ensure that resources are available when needed

Characterizing system needs and risks through LOLE modeling is one of the pillars of MISO's resource adequacy construct, but modeling adjustments may not always be sufficient to fully capture systems risks for any number of reasons (e.g., lack of necessary data, software, or computational limitations, etc.). In limited circumstances, MISO recommends establishing new requirements or obligations for capacity market participation, such as minimum availability criteria, minimum winterization criteria, dispatchable intermittent resource (DIR) participation, and non-emergency status. MISO will work with stakeholders to develop these requirements when these attributes cannot be properly ensured through the accreditation construct, LOLE modeling, and capacity market.

SOLUTION: Enhance the capacity accreditation methodology to value the availability of all resources when needed most – and forecast seasonal accreditation values annually for future years to understand how future system trends affect resource class accreditation and requirements for the benefit of market participants

Resource accreditation should reflect the availability of resources when they are most needed. Significant growth of variable, energy-limited resources in the MISO footprint, along with changing weather impacts and operational practices, are shifting risk profiles in highly dynamic ways with implications to resource adequacy and planning. MISO is currently proposing to align capacity accreditation with system risk to estimate the capacity contribution of MISO resources.¹⁵ This approach measures resource accreditation during periods of both highest potential and realized system risks consistently across all resource types. MISO's plan includes a three-year transition for the implementation.

¹⁴ MISO, [Reliability Based Demand Curves Conceptual Design White Paper](#), September 2023.

¹⁵ MISO, [Resource Accreditation White Paper](#), November 2023.



As part of the proposed approach, resources are grouped into classes. In the future, MISO should create and maintain resource accreditation classes to acknowledge differing and evolving risk profiles from similar resource types. For instance, there may be a need for increased granularity to acknowledge diverging availability from resources sited in different areas of the MISO footprint or with different levels of fuel assurance. Resource classes should evolve to better track sources of system risks and better represent how to reflect resources characteristics contributions to system adequacy.

Like the proposed capacity accreditation reform, MISO should explore an update to the allocation of PRMR obligations to better align with times of risk. Transitioning the allocation process from seasonal gross peak to risk-based values would create incentives for LSEs to shift load toward those times of the year that are most effective at reducing the potential for unserved energy.

The current capacity accreditation proposal will be applied to all system resources, except for emergency-only resources such as Load Modifying Resources (LMRs). MISO is currently designing improvements to LMR accreditation.¹⁶ The reforms will determine appropriate capacity credits for LMRs that more closely align with their availability and account for specific characteristics (such as notification time), improve LOLE modeling assumptions to align with operations, and align assumptions of resource adequacy processes to facilitate efficient use of LMRs' potential.

Forward-looking accreditation values are an important input in making long-term investment decisions. MISO recommends providing regular forecasted seasonal capacity accreditation values and PRMR estimates to stakeholders, published within existing recurring reports (e.g., Regional Resource Assessment). Ongoing review of these forecasts will allow MISO and market participants to identify and prepare for emerging trends in advance of the capacity market binding period.

SOLUTION: Explore and report additional resource adequacy metrics to improve the quantification of risk and resource contribution

Most MISO resource adequacy processes rely on a single metric - daily LOLE - measuring either expected loss of load in days/year or days/period.¹⁷ As the system risks evolves, so will the nature of risks. Relying on a single metric does not convey the full picture of reliability.¹⁸ Outages with different characteristics such as outage time or magnitude may be considered equally under the 1-outage day in 10-year metric.

While MISO recommends the Planning Resource Margin (PRM) continue to be determined using a single reliability metric, MISO should regularly publish more granular resource adequacy metrics to inform planning decisions and enable members to determine their own needs. These additional metrics may include expected unserved energy (EUE), loss of load hours (LOLH), or conditional value at risk (CVaR). MISO should create a roadmap focused on the need to reform the resource adequacy criterion considering the range of more granular resource adequacy metrics.

¹⁶ MISO, [Resource Adequacy Subcommittee \(RASC\) stakeholder process](#).

¹⁷ G. Stephen, *et al*, "[Clarifying the Interpretation and Use of the LOLE Resource Adequacy Metric](#)", 2022 17th International Conference on Probabilistic Methods Applied to Power Systems (PMAPS), June 2022.

¹⁸ Energy Systems Integration Group, [Redefining Resource Adequacy for Modern Power Systems](#), 2021.



After the exploration of additional reliability metrics is complete, MISO should also explore the implications of replacing daily LOLE as the driving metric in the LOLE Study and PRM process. The implications of using other metrics should be understood, including their interdependencies and robustness as the system evolves. Should this exploration reveal one or more metrics that are more robust than daily LOLE, MISO should implement alternative reliability metrics to drive PRMR and accreditation processes.

SOLUTION: Improve reliability risk modeling to best characterize existing and emerging system risks

Current risk modeling performs a Loss of Load Expectation (LOLE) analysis to calculate the Planning Reserve Margin (PRM) requirement to ensure that MISO resources can reliably meet demand. As the fleet transitions, a broader set of conditions must be considered to maintain reliability. MISO recommends several LOLE model improvements to ensure that existing and emerging system risks are more accurately accounted for:

- Incorporate correlated weather impacts to the system. Resource outages caused by reduced variable energy production or large-scale fuel shortages are two examples of risks not currently modeled by MISO.
- Incorporating transmission modeling to recognize that the changing fleet will be enabled by increasing regional energy transfer. The risks related to events limiting transmission should be included in future models.
- Improvements to the representation of emerging technologies¹⁹ and emergency resources to properly capture their operational constraints and additional contributions to the system (such as energy balancing or ancillary services).

As the model improves, results of downstream processes (such as accreditation or requirement setting) will be impacted. Some of these recommendations may have significant implications in those processes. For example, incorporating transmission constraints in the LOLE model will provide additional insight on the locational nature of risk, which could be used to enhance zonal requirements.

Additionally, MISO is currently working to improve its load forecasting system by developing probabilistic forecasting capabilities, including expanding the available load forecasting models and weather scenario data available to the forecasting team. This additional information will allow load forecasts to better capture weather risk associated with climate change. MISO is working to evolve planning assumptions and tools that can address uncertainties and high-stress grid conditions through scenario-based planning that considers a broad range of plausible long-term futures as well as real-world system conditions, including challenging and extreme events.

Finally, MISO recommends establishing a feedback loop to continuously realign the risk model with operational risks. Work is underway to improve operations planning study models for greater consistency with Energy Management System (EMS) models.

¹⁹ Some emerging technologies present new challenges in resource adequacy modeling because their ability to contribute of the system depend on factors beyond whether the units is available or is experiencing an outage. For example, battery storage generation depends on its state of charge and load modifying resource may have limitation on the frequency and duration on their activation.



PLANNING HORIZON ANALYSIS NEXT STEPS

The work of modeling enhancements and understanding their impact on reliability and accreditation will be ongoing. Future investigations into planning horizon attribute risks and solutions could target questions such as:

- How can the LOLE modeling process be enhanced by including additional risk factors in the planned maintenance scheduling?
- What level of transmission granularity is needed to acknowledge local risk factors?
- How should storage operations be captured in LOLE models?



Flexibility

Flexibility is the extent to which a power system can modify electricity production or consumption in response to changing system conditions, expected (*variability*) or unforeseen (*uncertainty*). Flexibility is crucial to operating the energy system where the supply and demand of energy needs to be balanced over different timescales. From an operating timeframe point of view the real-time balance is most crucial. MISO has a primary responsibility towards reliability and ensuring operations and markets can respond to changes in net load ramps over extended timeframes. MISO's energy and ancillary services market should enable adequate system attributes so that Operations is able respond in time and balance the system needs.

MISO's focus for the 2023 flexibility analysis was on the potential shortage of rapid start-up and ramp-up capabilities in future years (Figure 12). Rapid start-up is the ability to quickly start-up offline generation. Ramp-up is the ability to follow load and resource imbalance to track intra- and inter-hour load fluctuations within a scheduled period.

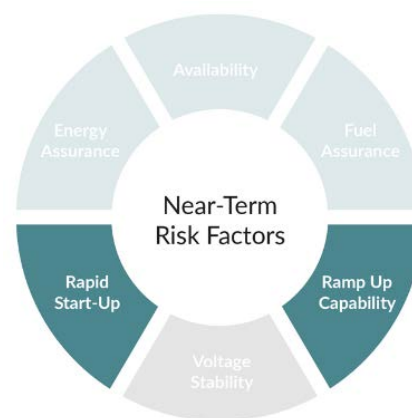


Figure 12: Flexibility near-term risk factor focus areas

MULTIPLE COINCIDENT SOURCES OF INCREASED VARIABILITY AND UNCERTAINTY DRIVE THE NEED FOR GREATER SYSTEM FLEXIBILITY

Historically, outages, load, and net scheduled interchange (NSI)²⁰ were the largest contributors of uncertainty and variability in managing the operating margin for the MISO region. MISO has historically depended on imports from neighbors who have had excess capacity. As the resource portfolio across the eastern interconnect evolves to include increasing amounts of variable resources, the complexity of managing operating margins will increase significantly and depending on import availability will become riskier.

Factors contributing to the increasing operational complexity, either due to greater variability or greater uncertainty include (1) increasing frequency and magnitude of system ramps, largely driven by the growth in renewable resources; (2) increased volatility in load forecasts due to changing weather and demand patterns; (3) more volatile generator outages, particularly related to aging of thermal units, extreme weather events, and fuel supply challenges; and (4) greater uncertainty of available energy at low margin hours, particularly in winter/spring evenings, as the fleet becomes more weather-dependent. These sources of increased variability and uncertainty drive the need for greater system flexibility in the future.

²⁰ Net Scheduled Interchange (NSI) is the net of MWs import and export schedules.



FOUNDATIONAL ANALYSIS

MISO's energy and ancillary services markets will play an important role in incentivizing competition for providing flexibility and other services that support energy delivery and reliability. MISO utilizes a two-settlement system comprising of a day-ahead market and a real-time market in which all products are simultaneously co-optimized. MISO needs to evaluate the ability of its market products to procure sufficient system attributes to maintain reliability without compromising efficiency under the evolving resource mix. This year's attributes analysis developed a simplified model of MISO's markets comprising the day-ahead unit commitment and real-time economic dispatch, which includes MISO's energy and ancillary services market products and rules.

The analysis centered around the simulation of stressed days to measure the potential unserved energy. For the current fleet, MISO chose historical extreme event days from different seasons for simulation. While for the future fleet, MISO selected potential stressed days in the future for comparison. In all simulations, MISO excluded operator reliability and emergency actions in order to provide a more meaningful comparison. Further, intraday commitments were excluded to keep the focus on the market constructs and not on MISO's unit commitment processes. A key limitation of these simulations was the exclusion of transmission constraints other than the RDT, but MISO hopes to address it in future analysis.²¹

The market simulations were carried out using a MISO-enhanced version of the Electrical Grid Research and Engineering Tool (MISO EGRET) that has implemented the main MISO energy and ancillary service market products and commitment rules.²² This tool was hosted in MISO Research and Development team's Advanced Simulation Environment, which provided the computational environment for running these simulations. This tool has previously been validated through extensive testing against MISO's production market system. For this year's analysis, data for the simulation was taken from day-ahead and look-ahead commitment (LAC) production cases for the two-stage market simulation. A new two-stage simulation framework appropriate for the attributes study was developed as part of this effort. The following key insights have informed the solutions hypothesis:

INSIGHT: Given the fleet transition the increase in net load variability and uncertainty will require new/enhanced market products and dynamic requirements that can achieve the greater flexibility needs on the operational timeframe.

A snapshot of one winter (January) and one summer month (August) across 2022, 2027, and 2032 indicates that the Future 2A fleet results in distinct new patterns for diurnal net load²³ profiles in both seasons (Figure 13).

²¹ The key assumptions used in this analysis are described in section A3.2 of the [Technical Appendix](#).

²² MISO-EGRET tool is described in the MISO, [Technical Appendix: RRA Assumptions and Methodology](#), from MISO, 2022 *Regional Resource Assessment*, November 2022.

²³ Net load is defined as gross load net of wind and solar generation.

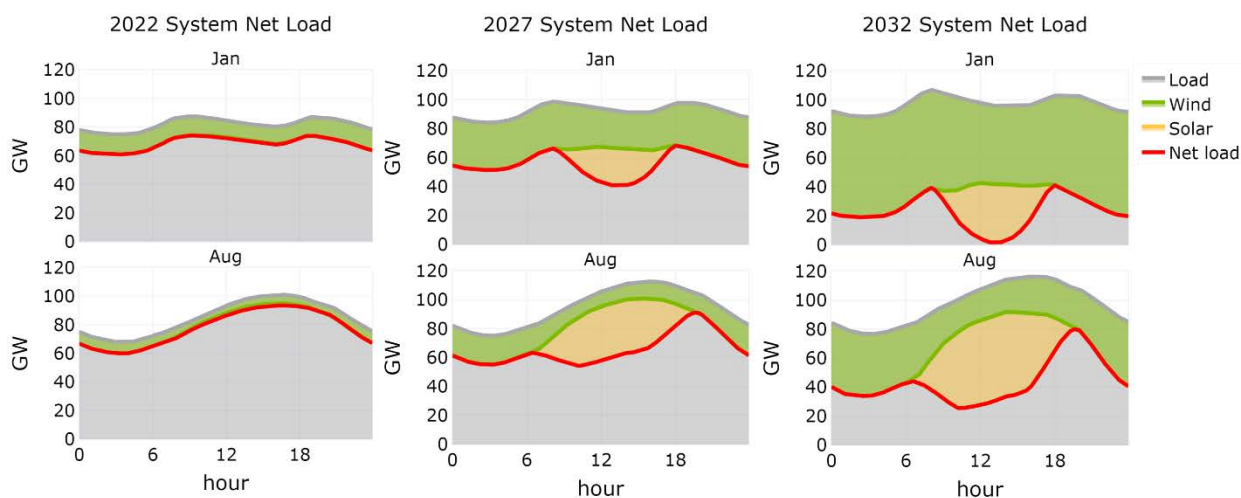


Figure 13: Monthly averages of diurnal net load components for January and August

With the generation fleet changes, the MISO winter diurnal net load pattern will begin to morph into the familiar “duck curve” shape,²⁴ with net load dropping around mid-day due to the increased presence of solar generation. In the evening as solar production decreases and electricity consumption increases, there is a significant increase in net load ramp-up. By 2032, the growth in wind and solar production in January results in even lower average net load around midday. In the summer months, the MISO system has historically seen a single daily net load peak in the late afternoon hours. By 2032, due to solar production, the daily net load peak is shifted to later in the day, into the post-sunset hours. Further the net load ramp needs in the evenings are projected to be high.

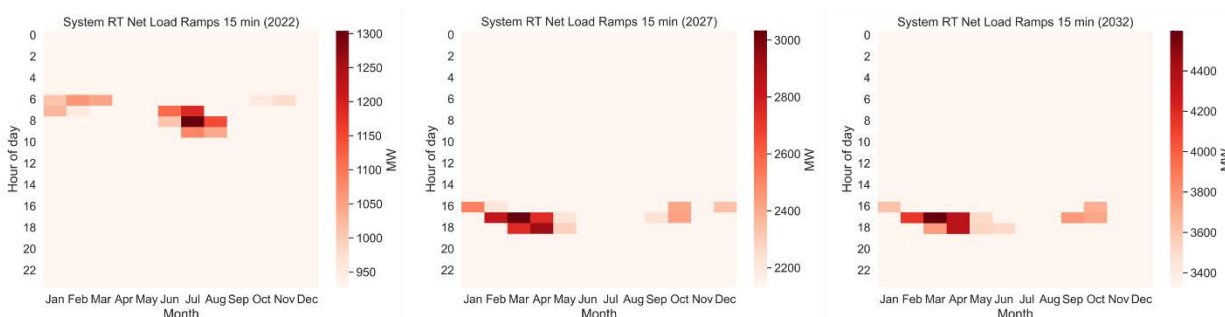


Figure 14: Highest 10 percentile of short duration net load up-ramps

Another way to visualize the ramping patterns is to look at the highest 10 percentile of short duration up-ramps (Figure 14). The quantitative change is significant. The maximum 15-minute up-ramp needs will be more than double by 2027 and 3.5 times by 2032 compared to 2022 levels.

²⁴ NREL, [Overgeneration from Solar Energy in California: A Field Guide to the Duck Chart](#), November 2015.



INSIGHT: The projected increase in risky days and lack of guarantees for availability of emergency and external resources increase the need to rely on demand side resources

The results from the Attributes market simulations of the historical events differ from the actual observations due to the assumptions described above. In reality, MISO Operations, acting in coordination with its neighbors, took many actions to manage the events successfully. The historical extreme event simulations show MISO's reliance on emergency resources as well as external resources, both of which are not guaranteed to be available in the energy market. For the historical summer event (Figure 15) in the base case the day-ahead commitment was inadequate to meet the real-time load due to a forecast error resulting in unserved energy. Additional scenarios were performed with different combinations of challenging conditions, such as the absence of LMRs or limited imports from neighbors (below the original maximum of approximately 13 GW systemwide net import amount). These cases increase unserved energy, with the worst result happening for the case with no imports into MISO and no LMR deployments (i.e., a "No LMR, No NSI" scenario). These scenarios highlight the importance of operator actions in maintaining reliability.

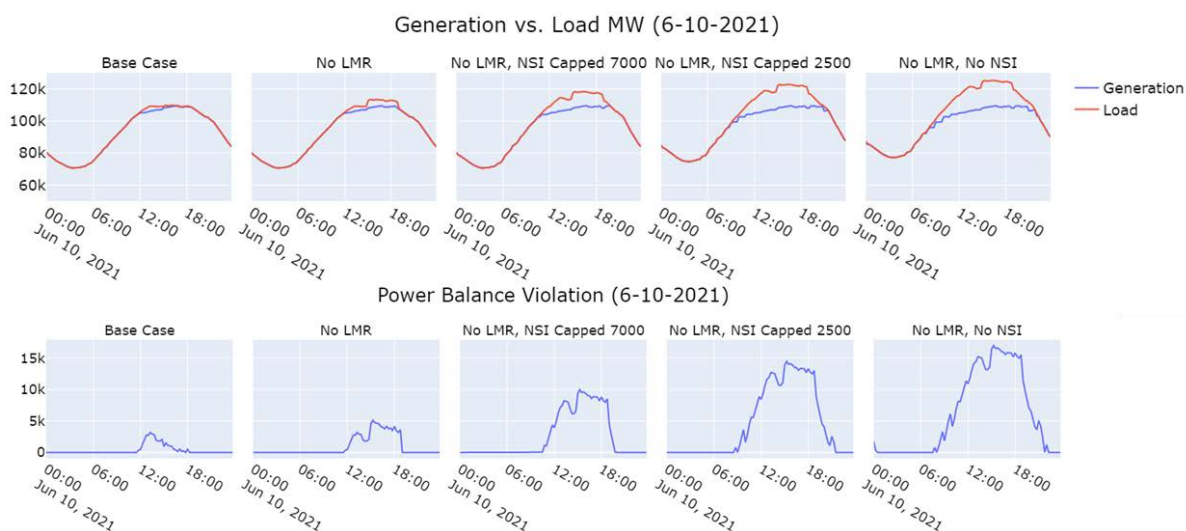


Figure 15: Simulation results for the summer event under different LMR and NSI scenarios

Over the past several years MISO has experienced several stressed days where it used emergency procedures as well as been dependent on imports from its Eastern Interconnect neighbors to manage challenging system conditions. Based on the results of this analysis these high-risk days are projected to grow in number and get more spread out across the year as the potential stressed days begin to show up in the shoulder seasons (Figure 16).

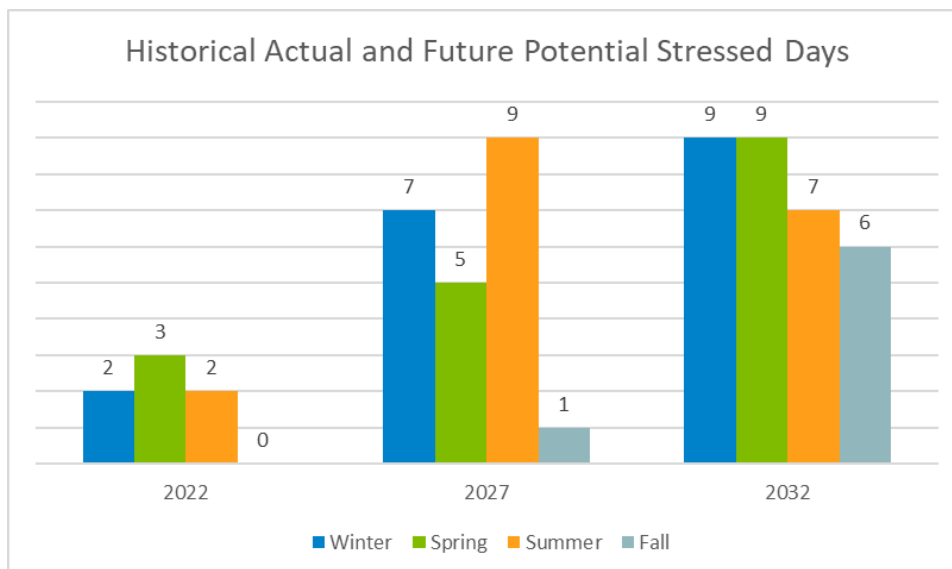


Figure 16: Historical events and future potential stressed days by season

With extreme weather, a greater number of high-risk days and the potential for climate change impacts, there are concerns for system reliability.

INSIGHT: The projected increase in duration and severity of events coupled with the retirement of conventional resources highlights the need for enabling the potential of emerging resources

The duration and severity of unserved energy events in a system with large penetration of renewables could increase since a large, sustained drop in renewable output could become the largest concern to manage in the operating timeframe. Figure 17 shows simulation results from various scenarios for a potential stressed day in Winter 2027. Figure 17a shows a small amount of unserved energy for the Base Case, because the Day-ahead commitment is inadequate to meet the Real-time load. Three individual stress scenarios are considered: a 50% drop in wind production throughout the day, a removal of external imports (MISO rather ends up exporting power), and a high-impact single gas pipeline outage. This last contingency, given Future 2A projected retirements, occurs in the MISO North/Central region and amounts to 6 GW. The wind-reduction scenario has the largest increase in unserved energy amongst the three cases. Finally, the worst-case event was simulated, where all 3 stress conditions occur on the same day.

Figure 17b illustrates how the use of quick-start units can address flexibility challenges. The worst-case event is used as the starting point and then quick start units are added until the unserved energy is mitigated. Quick start units are added beginning with the fastest group based on their lead-time of up to 20 min (i.e., 'quick 20 min'), and in later instances more units are added with increasing lead times of up to 60 min, 120 min etc. The mitigation occurs with units of lead-time of up to five hours.

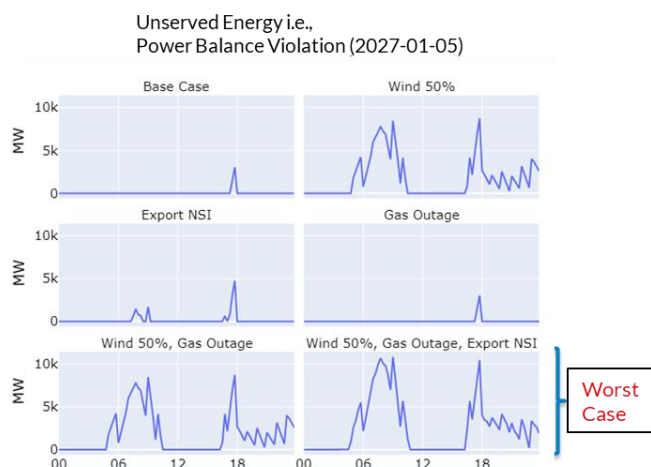


Figure 17a: Simulation results for base case and stressed scenarios for the winter 2027 event

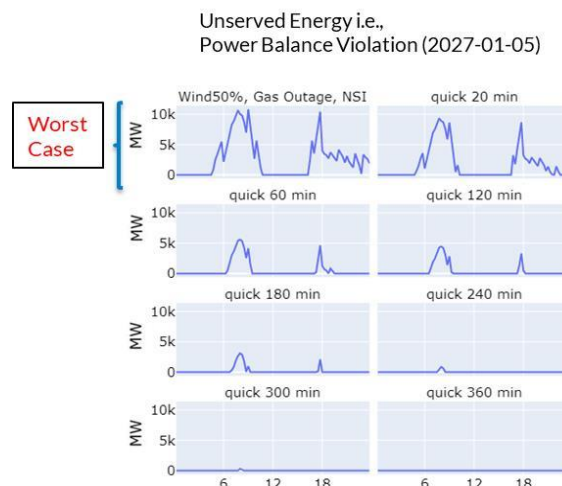


Figure 17b: Simulation results for worst stress case and mitigation using quick start units for the winter 2027 event

The Future 2A fleet assumes a new generator type known as the “flex” unit, which for this analysis is assumed to have the characteristics of fast combustion turbines. Thus, the overall quick start capacity in the 2027 and 2032 generation fleets is larger than in the current fleet.

Find a detailed explanation of the full flexibility analysis and results in section B of the [Technical Appendix](#).

FLEXIBILITY ATTRIBUTE RISK IS BEST ADDRESSED THROUGH MARKETS IN THE OPERATING TIMEFRAME

MISO recommends focusing the mitigation of flexibility risk on the operating horizon, specifically the real-time and day-ahead energy and ancillary services markets where key market design elements exist and are tested.

A focus on expanding current and new market products is needed to optimize flexible attributes and ensure availability and deliverability in real time on three fronts. MISO should (1) refine the quantities and formulation of ramping products (e.g., ramp, short-term reserves) based on operational experience and forward-looking studies, (2) explore implementing dynamic reserve requirements based on system risk, and more granular locational definitions to enhance deliverability of reserves, and (3) explore a new product for uncertainty management to reduce the need for “out-of-market” unit commitments for managing the day-ahead to real-time uncertainty.

Additionally, MISO should identify and address potential barriers preventing all resources from providing market services, allowing more resources to provide needed flexibility to the system. It should also create the capability to include flexible loads (e.g., controllable or price sensitive load) to provide market services.



WHAT NOT TO DO NOW

MISO projects, based on internal modeling efforts, that there will be sufficient resources to meet flexibility needs and therefore the development of discrete, flexibility requirements or derates in the capacity market is unnecessary at this time. Interactions between flexibility and capacity add excessive complexity to resource adequacy and may suppress capacity prices. Also, new capacity products do not directly increase utilization of that new flexibility characteristic in the operating horizon.

Additionally, the Forward Reliability Assessment Commitment remains MISO's preferred method to inform market participants of upcoming needs. Efficacy is expected under future conditions making a multi-day market product unnecessary. Market participants are responsible for continuing to signal their needs to MISO.

Lastly, MISO does not currently recommend consideration of flexibility attributes within MISO's resource interconnection or exit programs (Attachment Y) as flexibility risks are regional and will be fully accounted for within the expanded and new ancillary services products proposed in the roadmap below.

ROADMAP: FOCUS MARKET SIGNALS ON EMERGING FLEXIBILITY NEEDS



FLEXIBILITY: Focus market signals on emerging flexibility needs

Implement **market pricing enhancements** to send price signals that reflect the value of resource availability

- Update the value of lost load, which sets the price cap in the energy market, to send better price signals during emergency and scarcity conditions
- Change the operating reserve demand curve to improve the price incentive for flexibility
- Update the transmission constraint demand curves for improving congestion management

Implement **dynamic reserve requirements** to have better alignment between system conditions and risk

- Establish daily reserve requirements
- Dynamic requirements for reserves (regulation, contingency)
- Dynamic requirements for ramp capability product

Implement **locational reserves** to improve deliverability of reserves

- Evaluate dynamic reserve zones to better align zonal definitions and system conditions
- *Conditional:* Explore nodal reserves as an option to address the issue of reserve deliverability



Develop **new products for uncertainty and variability risk management** on the multi-hour time horizon to maximize the flexibility capabilities of existing resources

- Revisit participation model for flexible resources (potentially separate qualification for up and down ramp; additionally propose up and down regulation)
- Explore a new product for uncertainty management to manage flexibility needs and reduce out-of-market manual commitments
- Explore additional products to manage intra-hour netload variability (e.g., 30-, 60-min)

Table 3: Hypothesis solutions roadmap to proactively address flexibility attribute risk by focusing market signals on emerging flexibility needs.

SOLUTION: Implement market pricing enhancements to send price signals that reflect the value of resource availability

MISO's Resource Availability and Need (RAN) program identified concerns that market prices during historical emergencies and shortages have not reflected the scarce conditions. MISO's IMM has made multiple recommendations to improve MISO's emergency and scarcity pricing mechanisms. Efficient and transparent prices encourage Market Participants to make efficient operational decisions that can support and inform investment decisions. MISO is evaluating scarcity pricing during shortage events and near-term, mid-term, and long-term enhancements to various scarcity pricing mechanisms. In MISO's markets the locational marginal prices (LMP) are capped at the value of lost load, which is currently \$3,500/MWh. This value should be updated to ensure that valid prices are not truncated during reserve/transmission violations. MISO should evaluate updates to the operating reserve demand curve, to ensure that price signals are consistent with price formation principles. Along with updates to the value of lost load and operating reserve demand curve, the transmission constraint demand curve should be updated to ensure that MISO is able to manage congestion properly through price incentives during operating reserve shortages. The enhancements should send better price signals and manage growing uncertainty, incent flexibility, improve transparency, and address issues identified during recent emergency events. MISO is exploring additional enhancements to further improve price formation during emergency and scarcity conditions on a longer time horizon.

SOLUTION: Implement dynamic requirements to have better alignment between system conditions and risk

MISO co-optimizes energy and reserves leading to significant benefits for the footprint, including reduced costs and improved flexibility. Reserves are procured to provide backup capacity if necessary to deal with uncertainties and contingencies in the system that may impact reliability. With a transitioning resource portfolio, MISO is facing increasing variability and uncertainty in the availability of resources and system demand. MISO currently uses static reserve requirements. However, with higher levels of intermittent renewable resources MISO recognizes the need to move to dynamic reserve requirements so that reliability needs are better aligned with efficient market outcomes. As a first step, MISO looks to establish daily reserve requirements based on the forecasted risk level for the upcoming operating day. Future exploration should include intra-day dynamic reserve requirements derived from probabilistic net risk prediction as well as dynamic ramp product requirements to better manage ramp and uncertainties. In the future, with more wind and solar in the system, large drops in renewable production within 10 minutes could surpass the



single largest unit standard currently in use. This should require updating the contingency reserve requirements.

SOLUTION: Implement locational reserves to improve deliverability of reserves

Another key challenge associated with the increased uncertainty and variability is that of reserve deliverability, where the reserves may not be deliverable in real-time due to congestion. Historically to reliably deliver reserves, MISO utilized reserve zones in order to procure reserves in a dispersed manner. These reserve zones can be updated on a quarterly basis in conjunction with the network model updates. Currently MISO is using the reserve procurement approach on select constraints. MISO needs to implement improved locational granularity in its reserve products in order to ensure reserve deliverability. MISO should evaluate the possibility of dynamic reserve zones as a first step towards addressing this concern. Updating the reserve zones on a more frequent basis should improve market efficiency and system reliability, since there would be better alignment between zonal definitions and system conditions.

Conditionally, if additional reserve deliverability enhancements are required after the implementation of dynamic requirements, MISO should explore the procurement of reserves on a nodal basis in order to account for intra-zonal transmission congestion. The nodal reserve model could reduce the need for expensive out-of-market reserve disqualifications currently being utilized to manage the challenge of reserve deliverability.

SOLUTION: Develop new products for uncertainty and variability risk management on the multi-hour time horizon to maximize the flexibility capabilities of existing resources

Currently in MISO's market resources must be able to provide both upward and downward ramp to participate in the ramp capability product. This places limitations on some types of resources from participating in the ancillary services market. MISO should separate the qualification requirements for upward and downward ramp capability, which would allow more flexibility for different resource types to participate in the market. Further MISO should separate regulation into a regulation up product and a regulation down product to allow resources that are currently prevented from providing regulation due to congestion to provide regulation down. These solutions can expand the pool of resources which provide ancillary services.

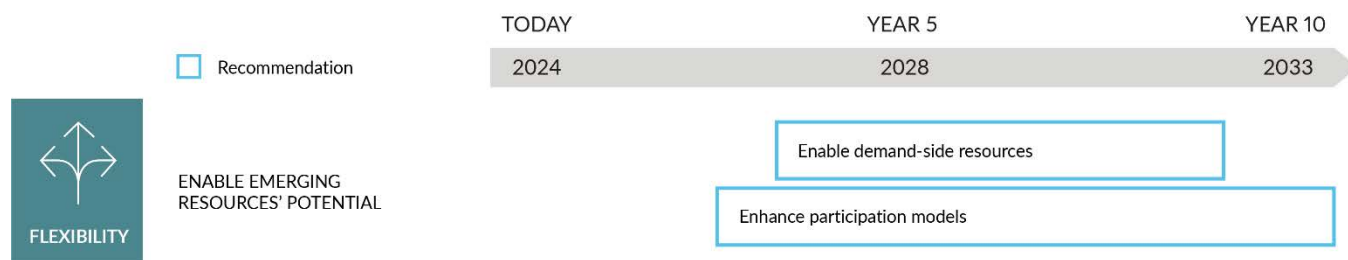
When there is a high degree of uncertainty operators may commit units "out of market" as insurance for the possibility of unexpected high net load. This uncertainty is expected to increase as the MISO fleet transitions to higher penetration of renewables. MISO should evaluate the development of a new uncertainty management product for managing these uncertainties. An uncertainty management product would allow "in market" procurement of units to meet uncertainty that would be committed when needed or released when not. This product could be provided by online and offline resources that are available to respond within certain response time (e.g., four hours lead-time). There may be a need for reserving long-lead units many hours in advance otherwise MISO might not have enough quick start resources to respond in time and avoid an unserved energy event. MISO should investigate how this product would work in conjunction with the current short-term reserve product.

Maintaining real-time power balance requires ramp flexibility from online units which has become more challenging as the proportion of intermittent renewable generation has increased. In 2016, MISO implemented a 10-minute ramp capability product to manage both variations (expected changes) and



uncertainties (unexpected changes) in the net load. The ramp capability product was designed to mitigate ramp shortages which were a common cause of price spikes. The current ramp capability product might not be able to manage extreme cases of ramping needs such as larger intra-hour ramps which are projected to occur as the penetration of renewables increases.²⁵ Hence MISO should consider additional products for longer ramp durations to manage the increasing intra-hour variability.

ROADMAP: ENABLE EMERGING RESOURCES' POTENTIAL



FLEXIBILITY: Enable emerging resources' potential	
Enable demand-side resources to enhance responsive load participation in energy markets	<ul style="list-style-type: none"> • Enable responsive load participation in energy markets • Enable visibility and controllability of Distributed Energy Resources (DER) in market operations
Evaluate options for enhancing participation models to allow all resources to provide market services to maximize capabilities	<ul style="list-style-type: none"> • Model multiple configuration resources in day-ahead market to increase flexibility and reduce commitment costs • Further optimize energy storage and co-located resources to leverage flexibility • Ensure commitment flexibility and management of days when net load approaches low values

Table 4: Hypothesis solutions roadmap to proactively address flexibility attribute risk by enabling emerging resources' potential.

SOLUTION: Enable demand-side resources to enhance responsive load participation in energy markets

Within MISO's footprint, demand resources that are used towards meeting the Planning Reserve Margin Requirement (PRMR) as part of the Planning Resource Auction (PRA) are known as Load Modifying Resources (LMR). LMRs include behind-the-meter generation and demand resources. In addition, MISO has a demand resource type known as Demand Response Resources that can provide service to the energy and ancillary services market. As of 2022, the majority of the approximately 12 GW of demand resources in MISO are classified as LMRs and only a small amount is classified as DRRs.

²⁵ MISO, [MISO's Renewable Integration Impacts Assessment \(RIIA\) study](#). Summary Report. February 2021.



One of the primary drivers of tightening operating margins is the accelerated retirement of thermal resources, which has increased the frequency of emergency declarations, with MISO relying more often on LMRs during these emergency events. In the past several years MISO has made changes to improve the availability and flexibility of LMRs for reliability such as reducing the maximum notification time requirement for LMR capacity accreditation from 12 hours to six hours. Maximum notification requirements should be further reduced to ensure maximum flexibility during emergency events.

MISO should increase its understanding of LMR capabilities and visibility into their granular locations to support more efficient and reliable commitment and dispatch. Part of the strategy may include leveraging emerging LMRs in the energy and ancillary services market. Moreover, there is a need for a detailed analysis of demand response participation across all MISO markets, which will inform a comprehensive strategy for better enabling load participation in MISO markets. Flexible price-responsive demand can provide many benefits, including mitigation of large net-load ramps, better management of contingency events, and enhanced market efficiency.

As the generation fleet transitions and new technologies enter the market MISO will need to evolve its operational and planning processes. Significant changes are expected in the coming decade on the demand side and supply side. One such coming transition focuses on distributed energy resources (DER). FERC Order 2222 requires DERs be allowed to participate in all aspects of Regional Transmission Organization (RTO) markets. This poses a number of challenges for MISO's operations, especially relating to visibility and controllability. MISO needs to consider the impacts of DERs on load forecasting. Further, MISO needs to implement distributed energy aggregated resources into the market engine, asset registration and settlements. Additionally, there is a need to identify and mitigate obstacles to customer readiness for DERs.

In total, MISO should find ways to increase participation of load resources in the MISO market and increase the flexibility they would contribute through MISO's various market products.

SOLUTION: Evaluate options for enhancing participation models to allow all resources to provide market services to maximize capabilities

With the advent of emerging resources, MISO should explore enhancing participation models to maximize the utilization of capabilities from these resources, along with those already present in the system. The harmonization of existing and upcoming capabilities throughout the energy transition will ensure smooth operations. The following are some examples that would contribute to this solution.

The multi-configuration resource model can enable significant flexibility from combined-cycle gas turbines (CCGT) across the MISO footprint. CCGTs with their ability for fast-ramping and quick response times could be a critical resource to addressing the variability needs. As the penetration of renewables increases the multi-configuration resource initiative can more fully exploit the capabilities of such resources to support the increasing flexibility needs of the system.

Large deployment of storage resources will present additional challenges in operations because, unlike traditional assets, their capabilities at any moment in time depends on their past actions. Charging and discharging decisions influence their state of charge at any moment, which influences the amount of energy they can generate or their ability to contribute to ancillary services. MISO should work to identify and mitigate any participation barriers for energy storage resources and co-located resources in MISO's markets that could help enable the additional optimization of such resources.



Finally, as the variable renewable penetration increases, the net load that needs to be covered by the remaining resources changes. Particularly, the minimum values of net load become lower, requiring a surge in the number of cycles for other resources between full generation and minimum generation levels. MISO should investigate minimum generation logic to ensure adequate commitment flexibility.

OPERATING HORIZON ANALYSIS NEXT STEPS

In addition to enhancements to its market products and requirements MISO should continue to focus on improvements to forecasting, visibility and commitment processes to ensure that MISO's operations are able to effectively manage challenging system conditions. One enhancement should include refinements to unit commitment tools so operators will increase their uptake of the Look Ahead Commitment (LAC) engine's recommendations.

Future investigations into operating horizon attribute risks and solutions could target questions such as:

- How should MISO design the new uncertainty management product given its sequencing with the short-term reserve?
- Should MISO implement a new intra-hour ramp product? This would be in addition to the existing 10-minute ramp capability product.
- How should MISO modify participation models which enable load modifying resources (LMR) in energy markets?
- How should MISO modify emergency pricing to avoid price suppression during events?



System Stability

System stability is the attribute of a power system that enables it to remain in a state of operating equilibrium under normal operating conditions and to regain an acceptable state of equilibrium after being subjected to a disturbance. MISO's focus for this year's analysis was on the voltage stability family of issues (Figure 18). Figure 19 shows a power system stability taxonomy often used in technical papers and how voltage stability relates to other system stability components.²⁶

Voltage stability refers to the ability of a power system to maintain steady voltages close to nominal value at all buses in the system after being subjected to a disturbance (e.g., loss of a transmission line) and is dependent on the ability of the combined generation and transmission system to provide the power required by the loads.^{27 28} Voltage stability is often thought of as load-driven rather than resource-driven, though resource characteristics effect voltage stability outcomes.

Find the detailed definition and explanation of MISO's current state voltage stability considerations, including transfer scenarios in reliability planning and contingencies in real time operations, in section C of the [Technical Appendix](#).

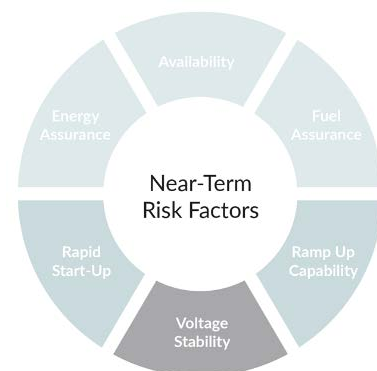


Figure 18: System stability near-term risk factor focus area

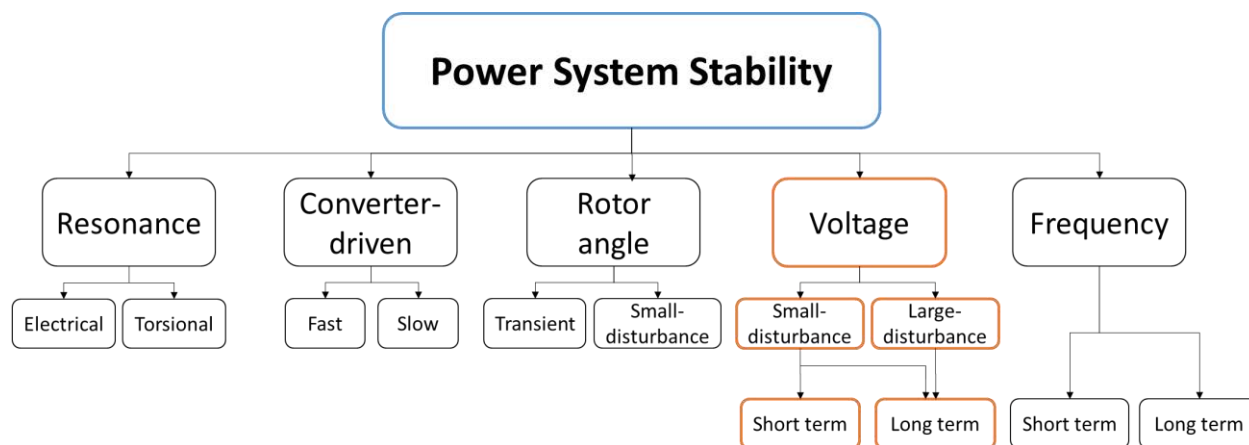


Figure 19: Taxonomy of power system stability considerations

²⁶ N. Hatziargyriou et al., "[Definition and Classification of Power System Stability – Revisited & Extended](#)," in *IEEE Transactions on Power Systems*, vol. 36, no. 4, pp. 3271-3281, July 2021.

²⁷ P. Kundur et al., "[Definition and classification of power system stability](#)," *IEEE Trans. Power Syst.*, vol. 19, no. 3, pp. 1387-1401, May 2004.

²⁸ T. Van Cutsem and C. Vournas, [Voltage Stability of Electric Power Systems](#). Norwell, MA: Kluwer, 1998.



VOLTAGE STABILITY-RELATED CHALLENGES ARE EXPECTED WITHIN FIVE YEARS

Several factors cause voltage instability, such as insufficient reactive power support, excessive loading, loss of transmission lines or generators, or inadequate voltage regulation. Emerging instability challenges are strongly correlated with today's energy transition trends, potentially leading to weak grid conditions under which instability issues materialize with greater frequency. Trends affecting voltage stability include:

- Synchronous machine retirements (e.g., coal-fired generators) reducing system strength and availability of reactive power
- Grid-following inverter-based resource (IBR) additions (e.g., solar generators) with software defined controls driving operating characteristics that are different from synchronous machines
- Generation siting that is further from load
- Changing dispatch patterns affecting synchronous machine fleet availability
- IBR model quality (verification and validation)

MISO's Renewable Integration Impact Assessment (RIIA) study indicated that voltage stability and inverter-based converter stability are among the first stability-related challenges the MISO system will likely face.²⁹ These challenges are projected to arise when renewable resources serve between 30% to 40% of MISO system annual energy. According to MISO's Future 2A resource expansion modeling, the 30% energy threshold may be reached around the year 2027.³⁰ Among the stability-related challenges studied in RIIA, not only are voltage stability challenges expected to emerge early in the energy transition, but the anticipated mitigation capital cost is expected to be the highest.

A lack of adequate voltage stability could result in loss of load in an area or protective system tripping of transmission lines or system components, potentially leading to cascading outages. Voltage collapse, one potential result from voltage instability, has been identified as a contributing factor in large scale blackouts across the globe, including Scandinavia (2003), the northeastern U.S. (2003), Athens, Greece (2004), and Brazil (2009). During the northeastern U.S. event in 2003, voltage instability resulted after multiple line tripping contingencies caused voltage fluctuations and reactive power deficiencies, causing generators and transformers to trip or malfunction.

ADVANCING VOLTAGE STABILITY ANALYSIS INCLUDED A NEW FOCUS ON EMERGING TOOLS AND GRID-FORMING INVERTER EFFICACY

This year's voltage stability analysis focused on (1) characterizing system strength using the short circuit ratio (SCR) approach, and (2) characterizing resources and stability limits using the dynamic impedance approach. The analysis characterized locations and potential severity of weak grid issues which often indicate potential stability challenges. Screening approaches, including those contemplated in this analysis, are used to identify areas and conditions that require deeper analysis. The two approaches are intended to bring visibility to a changing system and offer tools to account for resources' unique stability contributions in subsequent analysis.

²⁹ MISO, [MISO's Renewable Integration Impacts Assessment \(RIIA\) study](#). Summary Report. February 2021.

³⁰ MISO, "[Future 2A Expansion and Preliminary Siting](#)". Presented at LRTP Workshop, March 10, 2023.



The SCR approach is known to have limitations in areas of high inverter-based resource penetration as the metric is most appropriate when considering an IBR plant connected to a strong grid without the control interactions from other nearby inverters. While variations of the SCR metric account for interactions, modern inverter control topologies are beginning to decouple the IBR's fault contribution from system strength contributions, concepts that are tightly coupled in grids where synchronous machines are dominant.

The dynamic impedance method is relatively new, and MISO is working with industry partners to advance the understanding of its use and limitations. Using the approach to characterize grid-following IBR presented challenges, especially for large disturbances which resulted in severe voltage depressions. Using the approach for grid-forming IBR yielded promising results where both the large signal and small signal screening outcomes appear to be accurate. MISO is still investigating the method's efficacy for different applications based on other industry research evaluating similar approaches.^{31, 32, 33}

Grid-forming versus grid-following nomenclature:

- “Grid-following” (GFL) controls require a voltage source to maintain operation
- “Grid-forming” (GFM) controls create a voltage source and can operate in standalone mode

While these oversimplified terms are useful to communicate inverter capabilities broadly, control capability classification is more of a spectrum. For example, very fast grid-following controls provide some of the same support capabilities as grid-forming but are not capable of standalone operations.

INSIGHT: Localized pockets of stability challenges may materialize if emerging risks are not made visible and mitigated through controls and asset deployments

MISO's system strength screening analysis and results showed the highly localized and dynamic nature of potential voltage stability challenges, highlighting the need for improved visibility and proactive mitigation. System strength was shown to be affected by both long-term factors, such as a changing resource mix and transmission build, and short-term factors, like resource dispatch patterns across seasons. Using short circuit ratio (SCR) as an indicator of system strength, MISO completed a comparison analysis between future year and seasonal scenarios.

To consider the longer-term drivers, MISO compared the short circuit ratio (SCR) metric between a modeled 2025 summer peak and a modeled 2033 summer peak. Figure 20 shows the decrease (in red) or increase (in green) of the SCR metric, an indicator of system strength, between the two models and highlights the localized nature of system strength change.

³¹ Gu Y., Green T., “[Power System Stability with a High Penetration of Inverter-Based Resource](#),” in *Proceedings of the IEEE*, vol. 111, no. 7, pp. 832-853, July 2023, page 14, first paragraph.

³² J. Sun, “[Impedance-Based Stability Criterion for Grid-Connected Inverters](#),” in *IEEE Transactions on Power Electronics*, vol. 26, no. 11, pp. 3075-3078, Nov. 2011, page 1, last paragraph.

³³ S. Shah, et al., “[Impedance Methods for Analyzing the Stability Impacts of Inverter-Based Resources](#),” in *IEEE Electrification Magazine*, vol. 9, no. 1, pp. 53-65, March 2021, Section on “Large-Signal Impedance Analysis”.

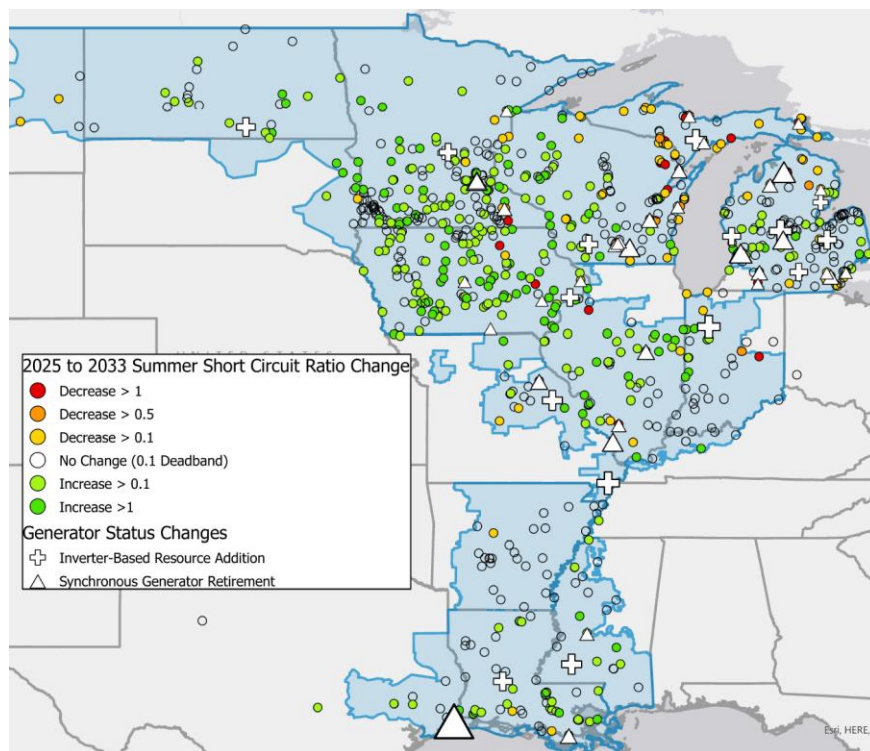


Figure 20: Change in short circuit ratio (SCR) between MTEP23 2025 summer peak and MTEP23 2033 summer peak cases³⁴

While this view shows the change in SCR as the resource portfolio evolves, the actual magnitude of SCR is crucial for using the metric as a screening tool. Additional details are contained in section C.3.2 of the [Technical Appendix](#) showing SCR magnitudes for the MISO Transmission Expansion Plan (MTEP) 2025, 2028, and 2033 cases. The [Technical Appendix](#) also contains sensitivities isolating the transmission and resource drivers over the planning horizon.

Shorter-term impacts on system strength are shown by comparing the 2025 summer model to the spring light load models (Figure 21), highlighting how voltage stability risks can change between seasons based on dispatch patterns. Different dispatch points warrant closer consideration, with a need to align planning models with actual operational conditions to better identify dispatch-related stability risks.

³⁴ Differences in resources between the MTEP23 2025 and MTEP23 2033 models could be attributed to resource additions, suspensions, outages, and retirements. For simplicity, these are labelled in Figure 20 as either an “Inverter-Based Resource Addition” or “Synchronous Generator Resource Retirement” to call out the locations of resource status changes driving SCR trends. However, the MTEP23 models used in this analysis are the same as those used in MISO’s MTEP processes, following applicable procedures in BPM-020.

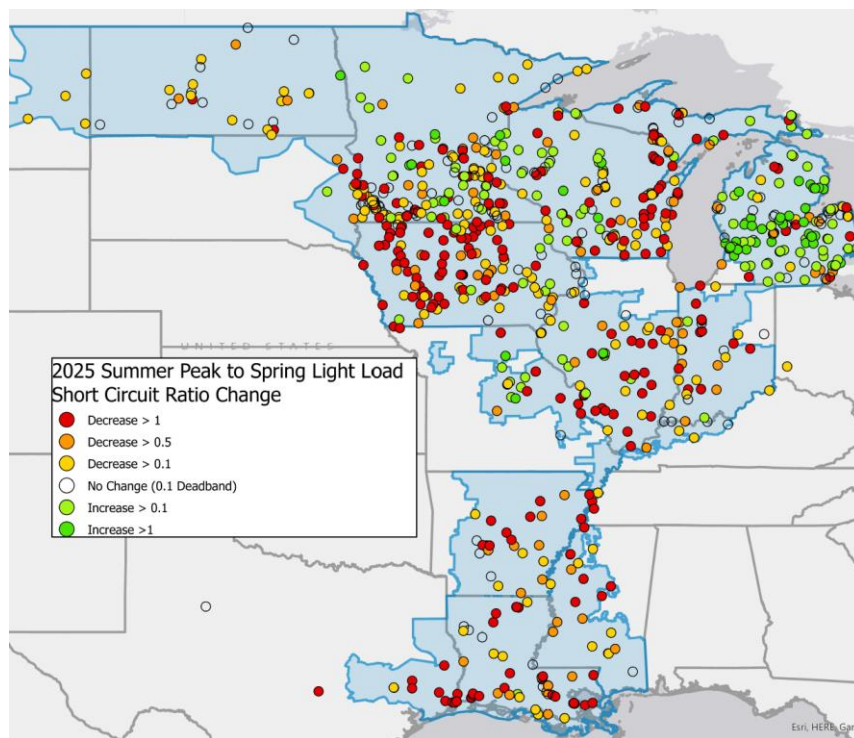


Figure 21: Change in short circuit ratio (SCR) between MTEP23 2025 summer peak and spring light load

INSIGHT: To gain greater visibility into potential voltage stability risks as the fleet transition accelerates, new scalable screening and analytics methods need to be developed

Given the localized and dynamic nature of voltage stability challenges, coupled with the granularity often required to model IBR control responses, screening accuracy at-scale becomes a significant challenge, especially for a system the size of the MISO footprint.

To illustrate this challenge, Figure 22 shows several methods for power system reliability analysis. The horizontal axis represents the study granularity or level of detail, and the vertical axis represents the level of effort, both human and computational, needed to support each tool. Increased granularity requires increased effort.

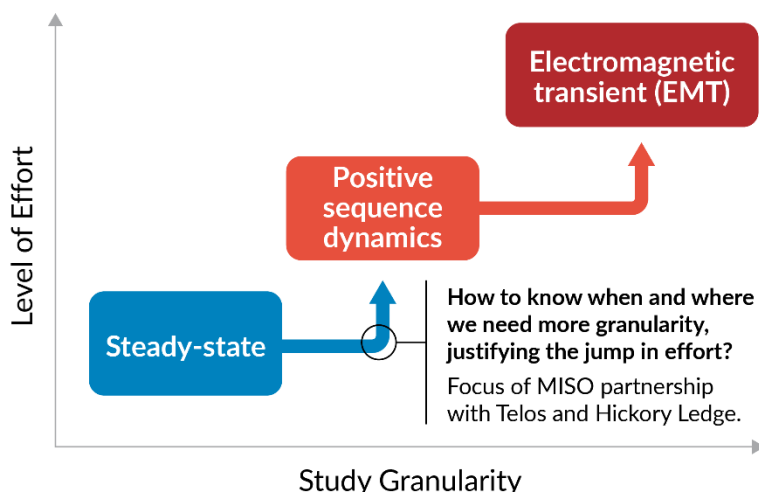


Figure 22: Illustration of effort-granularity tradeoff of common power system analysis tools

Steady state analysis is the simplest tool and can typically be performed for normal and contingency conditions at every bus location. However, steady state analysis does not provide the granularity or detail needed to understand potential dynamic voltage stability issues. A new tool is needed with practical consideration of the cost of the increased level of effort. Given the increased effort, it is typically not practical to perform more complex dynamic analysis at as many locations and under as many contingencies as the steady state analysis.

Any new approach must be scalable and accurately characterize different technology contributions to stability limits, especially given the wide range of responses from IBR's software-defined controls. In particular, the industry has recognized fundamental differences in so-called "grid-following" and "grid-forming" IBR controls.³⁵ Building on this understanding, MISO worked with energy consulting companies Telos Energy and HickoryLedge LLC to develop a repeatable analytical method to characterize these differences.³⁶ The results indicated that there are meaningful differences in the voltage support capabilities of different control types.

Figure 23 demonstrates results from the resource characterization approach using detailed electromagnetic transient (EMT) simulation on several commercially available grid-forming and grid-following inverters. The curves shown are composites from several different equipment models of that technology type and convey a typical response. Over the frequency range of interest, grid-forming controls appear to provide significant grid strengthening support capabilities, which can reduce voltage stability risks. The approach shows promise as an additional tool to characterize resources for the purpose of the simplified stability screening discussed in the next insight. Find additional details on resource characterization in section C.3.3 of the [Technical Appendix](#).

³⁵ B. Kroposki et al., "Achieving a 100% Renewable Grid: Operating Electric Power Systems with Extremely High Levels of Variable Renewable Energy," in *IEEE Power and Energy Magazine*, vol. 15, no. 2, pp. 61-73, March-April 2017.

³⁶ M. Richwine et al., "Power System Stability Analysis & Planning Using Impedance-Based Methods," in 22nd Wind & Solar Integration Workshop, September 2023, in *proceeding*.

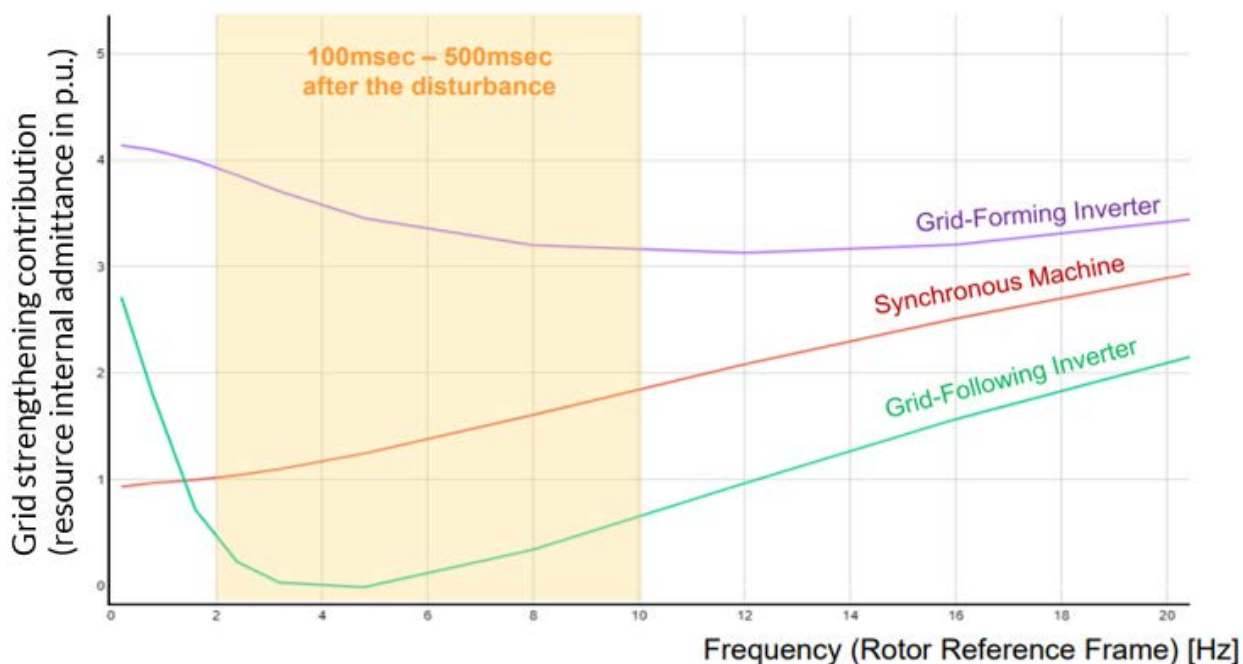


Figure 23: Resource characterization results from a series of detailed electromagnetic transient (EMT) simulations using detailed models. *Image source: Telos Energy*

INSIGHT: MISO-funded research aligns with broader industry findings showing the promise of “grid-forming” controls to support voltage stability in resource portfolios with higher levels of inverter-based resources

Recognizing potential shortcoming of existing system strength metrics and approaches, MISO worked with Telos and HickoryLedge to develop and demonstrate 1) next-generation analytical screening approaches, and 2) indicative results comparing grid-forming and grid-following inverter controls. The resulting dynamic impedance approach builds on resource characterization described in the previous insight, feeding this information into existing MISO tools to assess dynamic voltage stability limits of different resource mixes. Figure 24 provides an overview of the resource characterization and dynamic impedance screening processes.

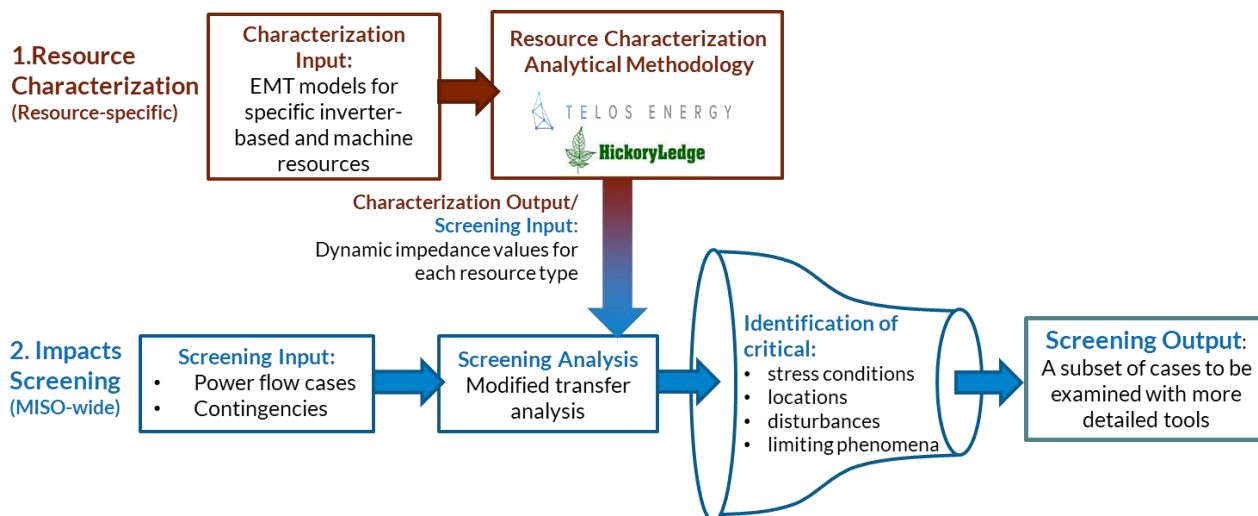


Figure 24: Overview of resource characterization and dynamic impedance screening process, described in greater detail in the [Technical Appendix](#).

The dynamic impedance screening approach was used on the scaled-up MISO system to assess the effect of resource mixes dominated by high amounts of grid-following or grid-forming inverters on dynamic voltage stability limits.³⁷ A high IBR case with high levels of grid-forming controls was shown to increase the dynamic voltage stability limit by approximately 10% when compared to a similar case that had high levels of grid-following controls. The result demonstrates a stark contrast in system strength support capabilities between grid-forming and grid-following controls and indicate grid-forming controls will be an important part of the solution to counteract risks associated with declining system strength driven by traditional resource retirements.

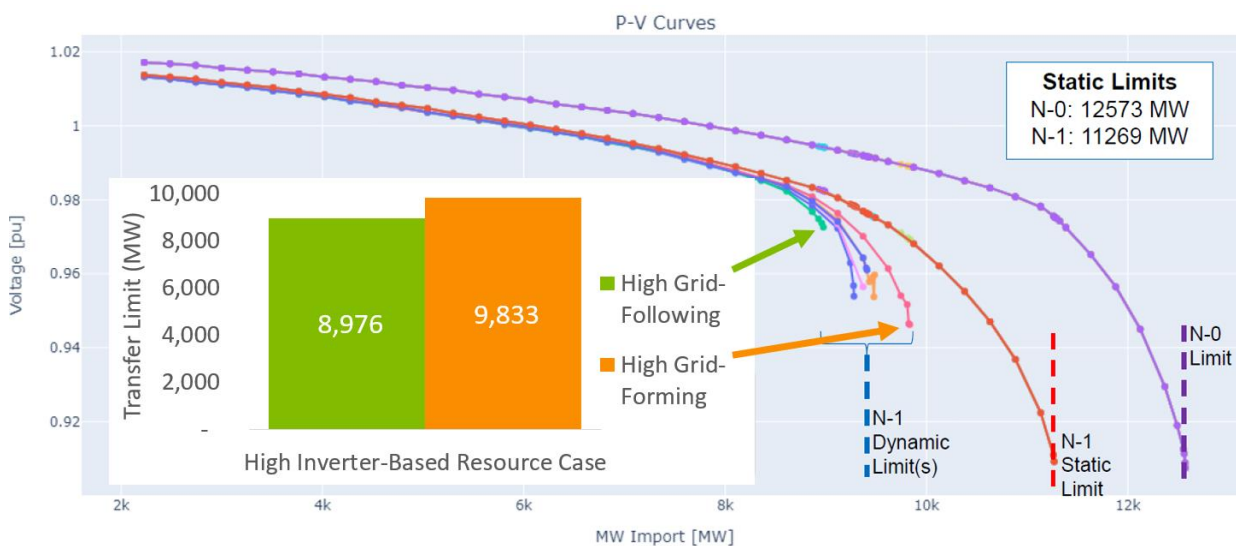


Figure 25: Dynamic impedance screening results comparing four select cases, varying IBR levels and grid-forming to grid-following proportions.

³⁷ Section C.3.3 in the [Technical Appendix](#) describes important caveats that place this demonstration assessing voltage stability limits in the realm of research and demonstration rather than conforming to typical reliability planning practices (e.g., TPL-001 contingencies).



Find a detailed explanation of the full voltage stability analysis and results in section C of the [Technical Appendix](#).

SYSTEM STABILITY ATTRIBUTE RISK IS BEST ADDRESSED THROUGH PLANNING, REGULATORY SOLUTIONS, TECHNOLOGY STANDARDS, AND LOCALIZED COST-OF-SERVICE PROCUREMENTS, WHEN APPLICABLE

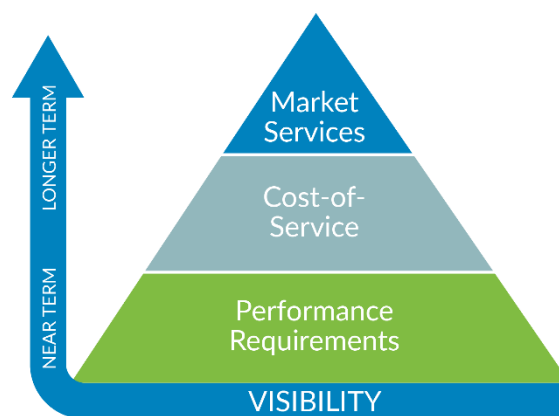
Stability challenges, including voltage stability, are best addressed in the planning timeframe by regulatory solutions because reactive deficiencies and solutions are highly localized. Obvious, low-cost solutions may be coordinated by technology standards and controls. Functionally, the types of solutions pursued should fit together in a way that drives efficiency and effectiveness, potentially forming a hierarchy (Figure 26).

Visibility: The development of new tools to provide clear visibility into localized voltage stability concerns is a prerequisite to forming any type of solution. Relatively few techniques exist for assessing large disturbance dynamic stability, and grid-following technologies appear to have a wide range of responses to more severe disturbances. Visibility examples include SCR screening, dynamic impedance screening, and critical clearing time screening.

Performance requirements: Build in voltage stability support through interconnection requirements applicable to all new resources, effectively minimizing the solution space required by other mitigations. Performance requirements should target control (i.e., software) capabilities without major cost implications. Examples include voltage ride-through, reactive current injection, and reactive power capability range.

Cost of service: Target specific needed capabilities that are outside of the standard set required for all resources. Cost of service solutions could include advanced functionalities that require additional conversion capacity or on-site energy storage.

Market services: Procure and dispatch services not met by a cost-of-service model. For instance, incentivizing the availability and delivery of stability services that an asset might otherwise withhold or not dispatch. While market services may ultimately be required in the long term, market solutions will be considered only after first exploring other options due to the localized nature of voltage stability issues.



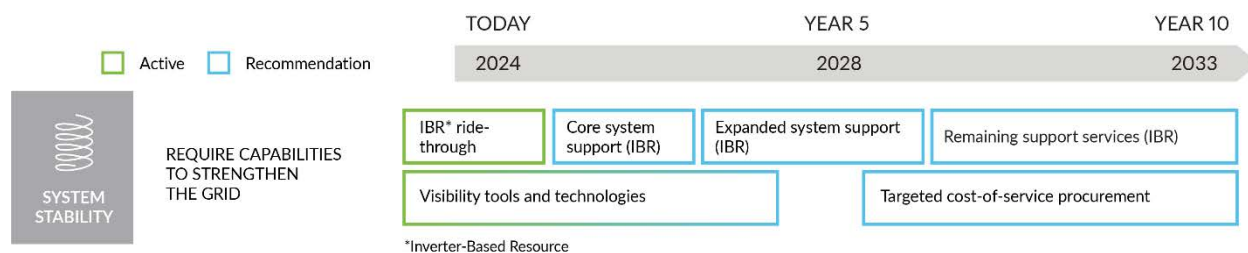
WHAT NOT TO DO NOW

Initial voltage stability issues are ineffectively addressed through market products given the local nature of the problem and solution and the subset of participants needed to engage with the issue. It has long been recognized that there cannot be a well-functioning market for reactive power like there can be for real



power; few jurisdictions have markets for reactive power services³⁸, other than incorporating voltage-based flow limits as MISO already does, and MISO is not aware of a large organized market with reactive power market products. MISO may revisit this solution in the future as these newer types of markets are demonstrated and refined on smaller island systems.

ROADMAP: REQUIRE CAPABILITIES TO STRENGTHEN THE GRID



³⁸ MISO's literature review found that Ireland's EirGrid has market services for reactive power. Further, the United Kingdom's National Grid Electric System Operator appears positioned to procure dynamic reactive power services. MISO did not view either of these island systems as directly comparable to the MISO context.



VOLTAGE STABILITY: Require capabilities to strengthen the grid
<p>Require ride-through capabilities for interconnection of inverter-based resources (IBR) to address unexpected tripping</p> <ul style="list-style-type: none"> • Adopt IBR performance from standard IEEE 2800 to keep resources online during a wider range of voltage and frequency disturbances • Address general IBR requirements (e.g., measurement accuracy, applicable voltages) to prepare for the adoption of future capabilities and performance requirements
<p>Require core system support capabilities for interconnection of IBRs to support system stability more actively</p> <ul style="list-style-type: none"> • Adopt high-level grid-forming performance requirements for energy storage systems, initially targeting “system strength” responses, with very fast resource reactive current controls • Expand adoption of IEEE 2800 to include voltage and frequency responses to support grid stability more actively under both normal and disturbance conditions. • Increase focus on assessing IBR plant conformance with sector partners
<p>Require expanded system support with more active IBR controls to support a system with high levels of IBR</p> <ul style="list-style-type: none"> • Adopt additional IBR performance requirements in IEEE 2800 which include very fast controls • Expand adoption of grid-forming performance requirements to include “synchronizing power” and “very fast frequency” (i.e., inertia-like responses) • Evaluate existing tool granularity and efficacy in assessing very fast IBR performance
<p>Require remaining support services to enable an IBR-dominant system</p> <ul style="list-style-type: none"> • Incorporate grid-forming black start capabilities so that IBR resources can qualify and contribute to re-energizing the system after major disturbances • Consider power electronic upsizing (i.e., inverter) to support system needs related to reactive fault current injection, black start, and system protection
<p>Evaluate targeted cost-of-service procurements to incentivize other technologies and the “energy buffer” required for more advanced grid-forming IBR performance</p> <ul style="list-style-type: none"> • Evaluate need for additional stability procurement requiring other technologies (e.g., static synchronous compensators, synchronous condensers, etc.) or upsized IBR hardware (e.g., inertia-like response, increased fault current) based on the impact of prior changes • Consider solution coverage over the broader range of stability issues – often categorized as voltage, frequency, angular, and converter-related – when evaluating cost of service solutions
<p>Advance visibility tools and technologies to make visible of shifting risks and support further solution evaluation</p> <ul style="list-style-type: none"> • Advance stability screening tools to better account for different types of IBR control responses • Continually refine grid-forming and grid-following model parameterization to match evolving performance requirements • Ensure appropriate model quality review procedures and tools are in place • Evaluate the need for limited electromagnetic transient (EMT) capabilities to evaluate grid-forming performance in the near-term and potentially expand to targeted system studies long-term • Consider additional needs for event recording technologies (e.g., digital fault recorders) to investigate events and validate models • Explore sensing and monitoring capabilities (e.g., phasor measurement units) for improved visibility of operational stability conditions

Table 5: Hypothesis solutions roadmap to proactively address voltage stability attribute risk by requiring capabilities to strengthen the grid.



MISO recommends IBR performance requirement adoption in four phases, each targeting specific ways in which grid-following and grid-forming IBR plants positively contribute to voltage stability. The phased design considers both reliability needs and industry readiness to install conforming plant equipment (Figure 27).

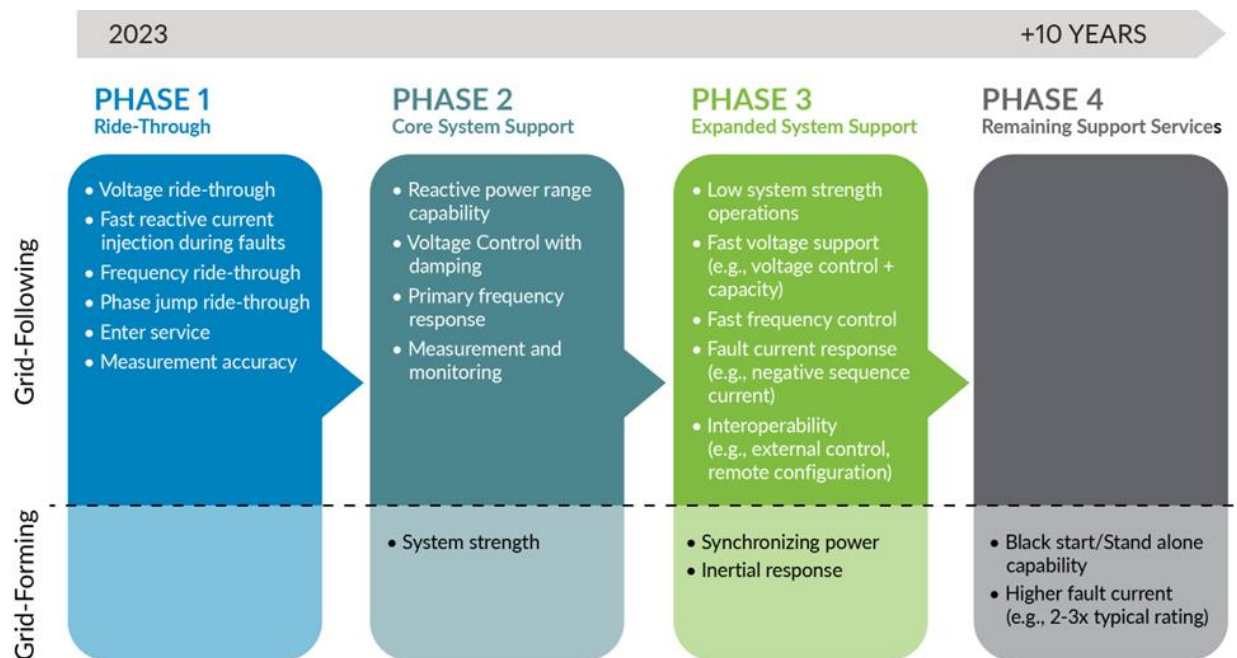


Figure 27: Summary of MISO’s phased recommendation on grid-following and grid-forming capabilities and performance requirements

SOLUTION: Require ride-through capabilities for interconnection of inverter-based resources to address unexpected tripping

In January 2023, MISO embarked on a path to improve IBR performance requirements using a reliability risk-based approach to evaluate potential gaps in MISO’s current Tariff. MISO shared the results of the risk assessment in March 2023 and finalized proposed tariff language in November 2023 to address the highest priority performance requirements and capabilities.³⁹ This proposal is Phase 1 of the recommended phased approach.

Performance requirements were prioritized based on whether they could address IBR tripping causes listed in eight recent NERC Disturbance Reports.⁴⁰ A supplemental source used for prioritization was the Federal Energy Regulatory Committee (FERC)’s IBR Notice of Proposed Rulemaking (NOPR) that led to Order 901, which in part directed NERC to develop standards to address the most significant IBR performance issues.⁴¹

The risk-based assessment found that the highest priority requirements were related to voltage support and dynamic responses. Priorities included frequency and voltage ride-through capabilities which require

³⁹ MISO, [MISO proposed GIA redlines to incorporate IBR Performance Requirements](#), Planning Advisory Meeting Materials, November 15, 2023.

⁴⁰ NERC, [Event Reports](#), accessed November 2023.

⁴¹ FERC, [Docket No. RM22-12-000](#); Order No 901. Issued October 19, 2023.



IBRs to stay connected during a range of disturbances, expanding on existing MISO ride-through requirements. Other priorities marked new capabilities, such as rate-of-change-of frequency ride-through and transient over-voltage ride-through, not contemplated in existing MISO requirements. Beyond ride-through, other capabilities identified as high priority for maintaining reliability include current injection during voltage ride-through and enter service criteria.

SOLUTION: Require core system support capabilities for interconnection of inverter-based resources to more actively support system stability

For Phase 2, MISO recommends developing grid-forming performance requirements for Battery Energy Storage Systems (BESS), targeting finalization of the performance capabilities by early 2025 with implementation timing determined with input from stakeholders. The grid-forming BESS requirements in Phase 2 aim to address strength support (i.e., fast reactive power support for voltage changes).

A NERC whitepaper released in September 2023 recommends that all newly interconnecting BESS should have grid-forming controls.⁴² NERC also states that grid-forming requirements, testing procedures, policies, and/or incentives should be developed now for BESS and co-located resources with BESS. NERC suggests grid-forming BESS technology offers a low-cost opportunity to improve stability. MISO agrees with these recommendations and suggests phasing in grid-forming requirements through MISO's stakeholder processes.

Regarding grid-following performance, MISO recommends expanding adoption of the IEEE 2800-2022⁴³ standard to include additional voltage and frequency capabilities and performance specifications to support grid stability more actively during normal operations (steady state) and disturbances (dynamic). These requirements could include reactive power range capabilities and voltage control with damping performance to support small signal voltage stability (e.g., sub-synchronous oscillations). In addition, MISO may recommend other performance not directly related to voltage stability, such as primary frequency response. Given the more active nature of some of these responses, additional supporting analysis is likely required, and MISO may consider recommending IEEE 2800 clauses related to measurement and monitoring to support performance monitoring and model validation.

Emerging grid-forming practices around the globe – *International grid operators overseeing resource transitions to high penetrations of IBRs have begun encouraging or requiring grid-forming capabilities from new resource interconnections. The Australian Energy Market Operator¹ and National Grid Electricity System Operator (NGESO)¹ have published voluntary grid-forming specifications, which are seen as a first step to contributing to stability support. Finland's Fingrid has released mandatory grid-forming specification that apply to only battery energy storage system (BESS) projects interconnecting in weak grid areas.¹ These early specifications focus on what some call "core" grid-forming capabilities, which are well-known capabilities that require no or minimal material modification to inverters compared to current grid-following practices.*

⁴² NERC. "[White Paper: Grid Forming Functional Specifications for BPS-Connected Battery Energy Storage Systems](#)", September 2023.

⁴³ IEEE, "[IEEE Standard for Interconnection and Interoperability of Inverter-Based Resources \(IBRs\) Interconnecting with Associated Transmission Electric Power Systems](#)", April 2022.



As IBR performance requirements continue to mature in the U.S., MISO recommends increased focus on assessing IBR plant conformance together with sector partners (interconnection customers, transmission owners, generator owners) and aided by international practices. MISO anticipates the future publication of draft standard IEEE P2800.2⁴⁴ will aid in defining conformance assessment best practices. Until then, MISO recommends working with the stakeholder community to define stopgap measures to ensure efficacy of performance requirements in place.

SOLUTION: Require expanded inverter-based resource performance to support a system with high levels of IBR

In Phase 3, the expanded system support performance requirement recommendations include adoption of remaining IEEE 2800 capabilities and performance; extending grid-following inverter requirements beyond current standards; and introducing additional grid-forming performance requirements for battery storage (BESS). These requirements start to extend stability support performance beyond strictly targeting voltage stability, which MISO recommends as additional attribute risk factors come into focus (e.g., declining system inertia).

Assuming no revision of IEEE 2800, additional performance capabilities recommended for adoption include fast frequency response, fault current response (e.g., negative sequence current), and expanded interoperability features (e.g., remote configuration). These expanded system support requirements come with more decision points and the potential for expanded analysis needs when compared to the earlier groupings of performance requirements. For instance, while IEEE 2800 offers different approaches for fast frequency response⁴⁵, industry research is still evaluating the use cases and effectiveness of these different options.⁴⁶ Considering additional grid-following capabilities, MISO will also consider recommendations that are not currently contemplated in IEEE 2800, such as defining a minimum level of system strength at which grid-following controls must be capable of stable operations.

Building upon grid-forming BESS recommendations established, MISO will expand performance requirements for this technology in Phase 3 to include expanded stability support features such as synchronizing power and very fast frequency response (i.e., inertia-like response). MISO anticipates additional detailed analysis will be required before enabling very fast frequency control to prevent unintended control interactions.

Lastly, MISO will assess industry readiness to expand grid-forming requirements to other IBR such as wind and solar resources without a storage component. MISO understands original equipment manufacturers are developing grid-forming capabilities for wind and solar plant equipment but have not publicly committed to timeframes when equipment may be available. MISO will continue to monitor industry control developments.⁴⁷

⁴⁴ IEEE. (Draft) [Recommended Practice for Test and Verification Procedures for Inverter-Based Resources \(IBRs\) Interconnecting with Bulk Power Systems](#).

⁴⁵ IEEE 2800-2022 includes discussion on fast frequency response (FFR) proportional to frequency deviation, FFR proportional to the rate of change of frequency (df/dt), fixed magnitude FFR with frequency trigger (step response), fixed magnitude FFR with df/dt trigger.

⁴⁶ NREL, [Different Types of Fast Frequency Response from Inverter Based Resources](#), October 2023.

⁴⁷ MISO participates in the universal interoperability for grid-forming inverters (UNIFI) consortium and NERC's inverter-based resource performance subcommittee (IRPS), among other industry venues. UNIFI, [Specification for Grid-forming Inverter-Based Resources, Version 1, December 2022](#). NERC, [Inverter-Based Resource Performance Subcommittee \(IRPS\)](#).



SOLUTION: Require remaining support services to enable an inverter-based-resource-dominant system

Preparing for a system with very high levels of load served by IBR, MISO's Phase 4 recommends incentivizing capabilities for remaining services that are primarily supplied by synchronous machines today. This largely translates to targeting black start and fault current needs which carry additional costs requiring incentivization.

MISO recommends defining grid-forming black start capabilities and performance requirements so that IBRs can qualify and contribute to re-energizing the system after major disturbances. Stakeholders and MISO may need to investigate potential barriers to IBR qualification as black start resources and consider options to allow resources with needed capabilities to participate.

Further, MISO recommends exploring inverter upsizing requirements needed for system support services related to reactive fault current injection, black start, and system protection (i.e., fault detection). Upsizing equipment drives increased capital costs, and potential operating and maintenance expenses, which would likely require incentives. Potential incentives are discussed further in the conditional solution section that follows.

SOLUTION: Evaluate targeted cost-of-service procurements to incentivize other technologies and the “energy buffer” required for more advanced grid-forming inverter-based resource performance

MISO anticipates that low-cost performance requirements, largely implementable through software-defined control changes, will provide only partial coverage of steady state and dynamic voltage stability needs. Additional assets are likely needed to address steady state reactive power and voltage damping requirements as well as fast active and reactive current responses.

A range of technologies are available to address voltage stability needs, including capacitor banks, static var compensators, static synchronous compensators (STATCOM), enhanced STATCOMs (i.e., on-board storage), high-voltage direct current (HVDC) terminals, and synchronous condensers. Each technology has unique technical and economic considerations. MISO recommends assessing applicable technology characteristics to gauge the potential role of each technology to mitigate stability risks and determine which assumptions to use in planning studies, should the technology be proposed as a potential mitigation measure. MISO may consider additional analysis to demonstrate potential roles for each technology. Such analysis should be coordinated with additional stability considerations (e.g., frequency, angular, converter-related). This was out of scope for this year's attributes effort.

Another cost-of-service mechanism may be required for IBR performance requirements that materially impact the capital or operating and maintenance costs for IBR plants. MISO suggests these additional costs are likely to materialize to address (1) IBR converter upsizing, and (2) “energy buffers.”

Converter upsizing allows for higher instantaneous current injection which could be needed to support higher levels of steady state reactive power, reactive fault current injection, black start capabilities, and system protection needs (i.e., fault detection). The level of converter upsizing to support voltage stability would be based on site-specific assessments of system needs. Future long-range assessments could consider evaluating indicative magnitudes and potential locations of converter upsizing opportunities.



Energy buffers ensure active power can be supplied when needed, which can come in the form of storage or operating a plant below the maximum available power. Energy buffer requirements may require additional equipment, such as batteries or super capacitors, or missed opportunity costs for selling energy or providing ancillary services. Examples of services that may require an energy buffer could include synchronizing power and frequency responses.

SOLUTION: Advance visibility tools and technologies to improve transparency of shifting risks and support further solution evaluation

Building upon the 2023 work, MISO and stakeholders should consider options to advance stability screening tools to better account for different types of IBR control responses. MISO recommends continued development and evaluation of the dynamic impedance screening approach. In addition, other approaches beyond SCR (e.g., critical clearing time metrics adapted for IBR) should be considered. The objective is to have scalable approaches to accurately assess the various stability challenges that could emerge in a high IBR resource portfolio.

Future approaches should continue to refine selection of analysis tools (e.g., positive sequence dynamics versus electromagnetic transient) and IBR model parameterization to match evolving performance requirements and impact assessment needs. Recent NERC event reports have indicated that there are reliability risks associated with inaccurate models and insufficient tool granularity.⁴⁸ MISO recommends engaging stakeholders to ensure appropriate model quality review procedures and tools are in place within the generator interconnection process.

MISO also recommends investigating the need for limited EMT simulation capabilities to evaluate grid-forming functional performance in the near term and potentially expanding to targeted system studies in the future. EMT capabilities are also needed for resource characterization within the dynamic impedance screening approach. NERC and industry have recognized the need for model quality verification procedures, especially when using EMT models. MISO recommends working with stakeholders to explore the need for standardized model quality review procedures, both for positive sequence dynamics models and EMT models, to the extent each type of model is required.

Lastly, MISO recommends investigating the need for operational sensing and monitoring technologies to improve visibility in the operating horizon and for use in post-event investigations. As an example, MISO recommends working with stakeholders to consider additional needs for event recording technologies (e.g., digital fault recorders) to investigate events and validate models. Further, MISO and stakeholders should explore sensing and monitoring capabilities (e.g., phasor measurement units) for improved visibility of operational stability conditions across a wide area.

SYSTEM STABILITY ANALYSIS NEXT STEPS

Future investigations into voltage stability risks and solutions could target questions such as:

- What proportion of new IBR should be grid-forming, and at what locations, to support reliability and reduce overall system costs?

⁴⁸ NERC, [2022 Odessa Disturbance](#), December 2022.



- What mix of other technologies (BESS, enhanced STATCOM, synchronous condensers, etc.) best supplements advanced IBR controls for stability support?
- How much energy buffer is needed for certain grid-forming capabilities (e.g., synchronizing power)?
- How much converter upsizing is needed to meet stability or system protection needs?
- How do different types of loads (e.g., high vs low inertia loads) effect the performance of grid-forming, grid-following, and different combinations of these controls?

Acknowledgments

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The latest status of MISO’s attributes-related work can be found on MISO’s Dashboard for “[Identification of Sufficient Reliability Attributes RASC - 2022-1](#).” Ongoing stakeholder discussions will be coordinated through the MISO Stakeholder [Resource Adequacy Subcommittee](#).



Acronyms

<i>AEMO: Australian Energy Market Operator</i>	<i>LMR: Load Modifying Resource</i>
<i>BESS: Battery Energy Storage System</i>	<i>LOLE: Loss of Load Expectation</i>
<i>CCGT: combined-cycle gas turbine⁵¹</i>	<i>LOLH: Loss of Load Hours</i>
<i>CVaR: Conditional Value at Risk</i>	<i>MISO: Midcontinent Independent System Operator</i>
<i>DER: Distributed Energy Resource</i>	<i>MTEP: MISO Transmission Expansion Plan</i>
<i>DLOL: Direct Loss of Load</i>	<i>NERC: North American Reliability Corporation</i>
<i>EGRET: Electric Grid Research & Engineering Tool</i>	<i>NOPR: Notice of Proposed Rulemaking</i>
<i>EMS: Energy Management System</i>	<i>NSI: Net Scheduled Interchange</i>
<i>EMT: Electromagnetic Transient</i>	<i>PRA: Planning Resource Auction</i>
<i>EPRI: Electric Power Research Institute</i>	<i>PRM: Planning Reserve Margin</i>
<i>EUE: Expected Unserved Energy</i>	<i>PRMR: Planning Reserve Margin Requirement</i>
<i>FERC: Federal Energy Regulatory Commission</i>	<i>RAN: Resource Availability and Need</i>
<i>GFL: Grid Following</i>	<i>RBDC: Reliability-based demand curve</i>
<i>GFM: Grid Forming</i>	<i>RDT: Regional Directional Transfer</i>
<i>HVDC: High Voltage Direct Current</i>	<i>RIIA: Renewable Integration Impact Assessment</i>
<i>IBR: Inverter-Based Resource</i>	<i>RRA: Regional Resource Assessment</i>
<i>IEEE: Institute of Electrical and Electronics Engineers</i>	<i>RTO: Regional Transmission Organization</i>
<i>IMM: Independent Market Monitor</i>	<i>SCR: Short Circuit Ratio</i>
<i>LAC: Look-Ahead Commitment</i>	<i>STATCOM: Static Var Compensators, Static Synchronous Compensators</i>

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Attachment V

MISO's Response to the Reliability Imperative, MISO
(Updated Feb. 2024)



MISO'S RESPONSE TO THE RELIABILITY IMPERATIVE

- UPDATED FEBRUARY 2024 -

Living Document

This is a “living” report that is updated periodically as conditions evolve, and as MISO, stakeholders and states continue to assess and respond to the Reliability Imperative.



misoenergy.org



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A Message from John Bear, CEO



We have to face some hard realities.

There are immediate and serious challenges to the reliability of our region's electric grid, and the entire industry – utilities, states and MISO – must work together and move faster to address them.

MISO and its utility and state partners have been deeply engaged on these challenges for years, and we have made important progress. But the region's generating fleet is changing even faster and more profoundly than we anticipated, so we all must act with more urgency and resolve.

Many utilities and states are decarbonizing their resource fleets. Carbon emissions in MISO have declined more than 30% since 2005 due to utilities and states retiring conventional power plants and building renewables such as wind and solar. Far greater emissions reductions – possibly exceeding 90% – could be achieved in coming years under the ambitious plans and goals that utilities and states are pursuing.

Studies conducted by MISO and other entities indicate it is possible to reliably operate an electric system that has far fewer conventional power plants and far more zero-carbon resources than we have today. However, **the transition that is underway to get to a decarbonized end state is posing material, adverse challenges to electric reliability.**

A key risk is that many existing “dispatchable” resources that can be turned on and off and adjusted as needed are being replaced with weather-dependent resources such as wind and solar that have materially different characteristics and capabilities. While wind and solar produce needed clean energy, they lack certain **key reliability attributes** that are needed to keep the grid reliable every hour of the year. Although several emerging technologies may someday change that calculus, they are not yet proven at grid scale. Meanwhile, efforts to build new dispatchable resources face headwinds from **government regulations and policies**, as well as **prevailing investment criteria for financing new energy projects**. Until new technologies become viable, we will continue to need dispatchable resources for reliability purposes.

But fleet change is not the only challenge we face. **Extreme weather events** have become more frequent and severe. **Supply chain and permitting issues** beyond MISO's control are delaying many new reliability-critical generation projects that are otherwise fully approved. **Large single-site load additions**, such as energy-intensive production facilities or data centers, may not be reliably served with existing or planned resources. **Incremental load growth** due to electric vehicles and other aspects of electrification is exerting new pressure on the grid. And **neighboring grid systems are becoming more interdependent** and reliant on each other, highlighting the need for more interregional planning such as the Joint Targeted Interconnection Queue study that MISO conducted with Southwest Power Pool.

This report documents how MISO is addressing these risks through the **Reliability Imperative** – the critical and shared responsibility that MISO, our members and states have to address the urgent and complex challenges to electric reliability in our region. MISO first published a Reliability Imperative report in 2020, and this is the fourth time we've updated it to reflect the changing landscape.

None of the work we must do is easy, but it is necessary. The region's 45 million people are counting on MISO and its utility and state partners to get it right. Thank you for your interest in these important issues.



Executive Summary

THE CHALLENGE: A “HYPER-COMPLEX RISK ENVIRONMENT”

There are urgent and complex challenges to electric system reliability in the MISO region and elsewhere. This is not just MISO’s view; it is a well-documented conclusion throughout the electric industry. The North American Electric Reliability Corporation, a key reliability entity throughout the U.S., Canada and part of Mexico, has described these challenges as a [“hyper-complex risk environment.”](#) These challenges include:

Fleet change: The new weather-dependent resources that are being built, such as wind and solar, do not provide the same critical reliability attributes as the conventional dispatchable coal and natural gas resources that are being retired. While emerging technologies such as long-duration battery storage, small modular reactors and hydrogen systems may someday offer solutions to this issue, they are not yet viable at grid scale.



Regulations, policies and investment criteria: Many dispatchable resources that provide critical reliability attributes are retiring prematurely due to environmental regulations and clean-energy policies. This regulatory environment, along with prevailing investment criteria for financing new energy projects, increases the challenges to build new dispatchable generation — even if it is critically needed for reliability purposes.



Fuel assurance: Gas resources can face challenging economics to procure fuel because they share the pipeline system with residential and commercial heating and manufacturing uses. Coal plants typically keep large stockpiles of fuel onsite, but coal supplies have tightened due to changing economics, import/export dynamics, supply chain issues and other factors. Aging resources can also be more prone to outages. While renewable resources such as wind turbines do not use “fuel” per se, they are sometimes unavailable due to adverse weather conditions.



Extreme weather events: While extreme weather has always been commonplace in the MISO region, severe weather events that impact electric reliability have been increasing. The [Electric Power Research Institute found](#) that hurricanes are increasing in intensity and duration, heat events are increasing in frequency and intensity and cold events are increasing in frequency. Examples include Winter Storm Elliott in 2022, Winter Storm Uri in 2021, Hurricane Ida in 2021, and Hurricanes Laura, Delta and Zeta in 2020.



Load additions: Some parts of the MISO region are enjoying a resurgence in manufacturing and/or other types of economic growth, with companies planning and building new factories, data centers and other energy-intensive facilities. While such development is welcome from an economic perspective, it can also pose significant reliability risks if the load additions it spurs cannot be reliably served with existing or planned resources.



Incremental load growth: While electricity demand has been flat for many years, it is expected to increase due to the electrification of other sectors of the economy. Electric vehicles are growing in popularity, and the residential and commercial sectors are increasingly using electricity for heating and cooling. These trends will accelerate more due to the electrification tax credits in the 2022 Inflation Reduction Act.





Supply chain and permitting issues: Many projects that have been fully approved through MISO’s Generator Interconnection Queue process are not going into service on schedule due to supply chain issues and permitting delays that are beyond MISO’s control. As of late 2023, about 25 gigawatts (GW) of approved resources are signaling delays that average 650 days to commercial operation.



RELIABILITY IMPERATIVE OVERVIEW

The **Reliability Imperative** is the term MISO uses to describe the shared responsibility that MISO, its members and states have to address the urgent and complex challenges to electric system reliability in the MISO region. MISO’s *response* to the Reliability Imperative consists of numerous interconnected and sequenced initiatives that are organized into four primary pillars, as shown here:

RELIABILITY IMPERATIVE PILLAR	KEY INITIATIVES <i>(partial list)</i>
<p>MARKET REDEFINITION Enhance and optimize MISO’s markets to ensure continued reliability and efficiency while enabling the changing resource mix, responding to more frequent extreme weather events, and preparing for increasing electrification</p>	<ul style="list-style-type: none"> • Ensure resources are accurately accredited • Identify critical system reliability attributes • Ensure accurate pricing of energy & reserves
<p>OPERATIONS OF THE FUTURE Focus on the skills, processes and technologies needed to ensure MISO can effectively manage the grid of the future under increased complexity</p>	<ul style="list-style-type: none"> • Manage uncertainty associated with increasing reliance on variable wind and solar generation • Prepare control room operators to rapidly assess and respond to changing system conditions • Use artificial intelligence & machine learning to enhance situational awareness & communications • Evaluate interdependency of neighboring systems
<p>TRANSMISSION EVOLUTION Assess the region’s future transmission needs and associated cost allocation holistically, including transmission to support utility and state plans for existing and future generation resources</p>	<ul style="list-style-type: none"> • Develop “Futures” planning scenarios using ranges of economic, policy, and regulatory inputs • Develop distinct “tranches” (portfolios) of Long Range Transmission Plan (LRTP) projects • Enhance joint transmission planning with seams partners • Improve processes for new generator interconnections and retirements
<p>SYSTEM ENHANCEMENTS Create flexible, upgradeable and secure systems that integrate advanced technologies to process increasingly complex information and evolve with the industry</p>	<ul style="list-style-type: none"> • Modernize critical tools such as the Day-Ahead and Real-Time Market Clearing Engines • Fortify cybersecurity and proactively address the rapidly evolving cyber threat landscape • Develop cutting-edge data and analytics strategies



RECENT KEY ACCOMPLISHMENTS

MISO and its stakeholders have made great progress under the Reliability Imperative in recent years. Some of our key accomplishments to date include:

Seasonal Resource Adequacy Construct: In August 2022, the Federal Energy Regulatory Commission (FERC) approved MISO's proposal to shift from its summer-focused resource adequacy construct to a new four-season construct that better reflects the risks the region now faces in winter and shoulder seasons due to fleet change, more frequent and severe extreme weather, electrification and other factors. This new construct seeks to ensure that resources will be available when they are needed most by aligning resource accreditation with availability during the highest risk periods in each season.

LRTP Tranche 1: The first of four planned portfolios of Long Range Transmission Planning (LRTP) projects was [approved by the MISO Board of Directors](#) in July 2022. This tranche of 18 projects represents a total investment of \$10.3 billion – the largest portfolio of transmission projects ever approved by a U.S. Regional Transmission Organization. These projects will integrate new generation resources built in MISO's North and Central subregions, supporting the reliable and affordable transition of the fleet and further hardening the grid against extreme weather events.

Reliability-Based Demand Curve: MISO's Planning Resource Auction (PRA) was not originally designed to set higher capacity clearing prices as the magnitude of a shortfall increases. This lack of a "warning signal" can mask an imminent shortfall – as occurred with the 2022 PRA. Accurate capacity pricing is also crucial to make effective investment and retirement decisions. MISO worked with its stakeholders to design a Reliability-Based Demand Curve that will improve price signals in the PRA. Full implementation is planned for the 2025 PRA, subject to FERC proceedings.

Futures Refresh: The MISO Futures utilize a range of economic, policy and technological inputs to develop three scenarios that "bookend" what the region's resource mix might look like in 20 years. In 2023, MISO updated its Futures to lay the groundwork for LRTP Tranche 2 and to better reflect evolving decarbonization plans of MISO members and states. The refreshed Futures also model how the financial incentives for clean energy in the 2022 Inflation Reduction Act could further accelerate fleet change. The refreshed Futures are indicated with an "A" (e.g., Future 2 was updated and renamed Future 2A).

System Enhancements: The Market System Enhancement (MSE) program made significant progress in 2023. In March, the Energy Management System upgrade was moved into service. This provides a more stable platform with improved visualization while enhancing functionality and user experience. MISO also took delivery of the Reliability Assessment Commitment for the Real-Time Market Clearing Engine, which will improve application security and reduce solution time. MISO also completed Model Manager Phase 2, which connects internal applications to improve model data propagation. MSE will continue to deliver more new products, including Day-Ahead and Real-Time Market Clearing Engine items.

MISO PRIORITIES GOING FORWARD

While far from a complete list, some of MISO's key priorities for 2024 include:

Attributes: In 2023, following an in-depth look at the challenges of reliably operating an electric system in a rapidly transforming landscape, MISO published an [Attributes Roadmap](#) of recommended solutions to address the potential scarcity of three priority attributes that appear to pose the most acute risks: system adequacy,



flexibility and system stability. The recommendations include further modernizing the resource adequacy construct, focusing market signals on emerging flexibility needs, and requirements for new capabilities from inverter-based resources. Next, MISO will prioritize attribute solution integration, including handoffs to MISO business units and stakeholder groups and the scoping of ongoing analysis.

Accreditation: MISO must ensure resource accreditation values reflect what we can expect to receive during high-risk periods. For non-thermal resources, MISO’s recommended approach blends a probabilistic methodology with availability during tight conditions, leveraging principles from the thermal accreditation reform implemented in 2022. MISO has proposed a three-year transition to the new methodology that will be applied to all non-emergency resources following the transition period. A FERC filing is planned for 2024.

LRTP Tranche 2: Work to develop the Tranche 2 portfolio of LRTP projects is progressing, with approval by MISO’s Board of Directors anticipated in 2024. Planning is complex, but MISO will continue to balance the need to plan quickly with the need to develop a robust, lowest-cost portfolio. Tranche 2 is based on the refreshed Future 2A, which reflects all decarbonization plans of MISO members and states. As with Tranche 1, MISO anticipates Tranche 2 will deliver sufficient benefits to qualify under the Multi-Value Project cost allocation mechanism, with costs allocated only to the subregion where benefits are realized.

CALL TO ACTION: WE MUST WORK TOGETHER AND MOVE FASTER

In light of the urgent and complex risks to electric reliability in the MISO region, utilities, states and MISO must all act with more urgency and more coordination to avoid a looming mismatch between the pace of adding new resources and the retirement of older resources in the MISO region. This means we must:

- Refine generation resource plans across MISO by accelerating the addition of reliability attributes and moderating retirements to avoid undue reliability risk
- Maintain transition resources as reliability “insurance” until promising new technologies become viable at grid scale
- Identify areas of risk in which electricity providers, states and MISO must coordinate

CONTINUED STAKEHOLDER INPUT IS CRUCIAL

Many of the ideas and proposals in this report reflect a great deal of technical input from MISO stakeholders. MISO appreciates stakeholder feedback on the Reliability Imperative, and we look forward to continuing the dialogue. This document is a “living” report that MISO regularly updates.



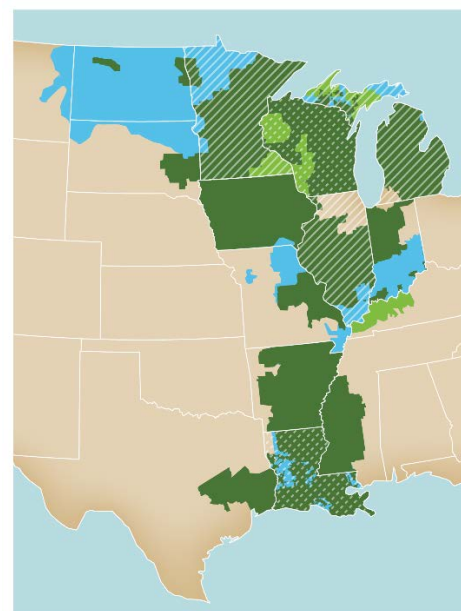
Challenges Driving the Reliability Imperative

COMPLEX POLICY LANDSCAPE

As the map indicates, many utilities and states in the MISO region have adopted policies and goals to decarbonize their resource fleets. Currently, about 75% of the region's total load is served by utilities that have ambitious decarbonization and/or renewable energy goals.

Without question, utilities and states are making remarkable progress toward their goals. Carbon emissions in MISO have already declined more than 30% since 2005, and far greater reductions are expected going forward.

Currently, wind and solar generation account for about 20% of the region's total energy. Under MISO modeling scenario Future 2A, which reflects all the clean-energy goals that utilities and states have publicly announced, wind and solar are projected to serve 80% of the region's annual load by 2042. Fleet change of that magnitude would foster a 96% reduction in carbon emissions compared to 2005 levels – which would be an extraordinary accomplishment for a region that was predominately reliant on fossil fuels not that long ago.



But at the same time, complex challenges to electric system reliability have been steadily materializing throughout the U.S. in recent years, including in MISO. These challenges are driven by a combination of economic, technological and policy-related factors along with extreme weather events. Here is a look at some of these challenges and the drivers associated with them:

TIGHTENING SUPPLY

Over the last 10-plus years, surplus reserve margins in MISO have been exhausted through load growth and unit retirements. Since 2022, MISO has been operating near the level of minimum reserve margin requirements. While MISO has implemented several reforms to help avert near-term risk, more work is urgently needed to mitigate reliability concerns in the coming years. In fact, the region only averted a capacity shortfall in 2023 because some planned generation retirements were postponed and some additional capacity was made available to MISO.

However, MISO cannot count on such actions being repeated going forward. Indeed, the North American Electric Reliability Corporation (NERC) [projects](#) the MISO region will experience a 4.7 GW shortfall beginning in 2028 if currently expected generator retirements actually occur. Notably, NERC says that shortfall will occur *even if* the 12-plus GW of new resources that are expected to come online by then actually materialize. This is because the new resources that are being built have significantly lower accreditation values than the older resources that are retiring, as is discussed in more detail below.



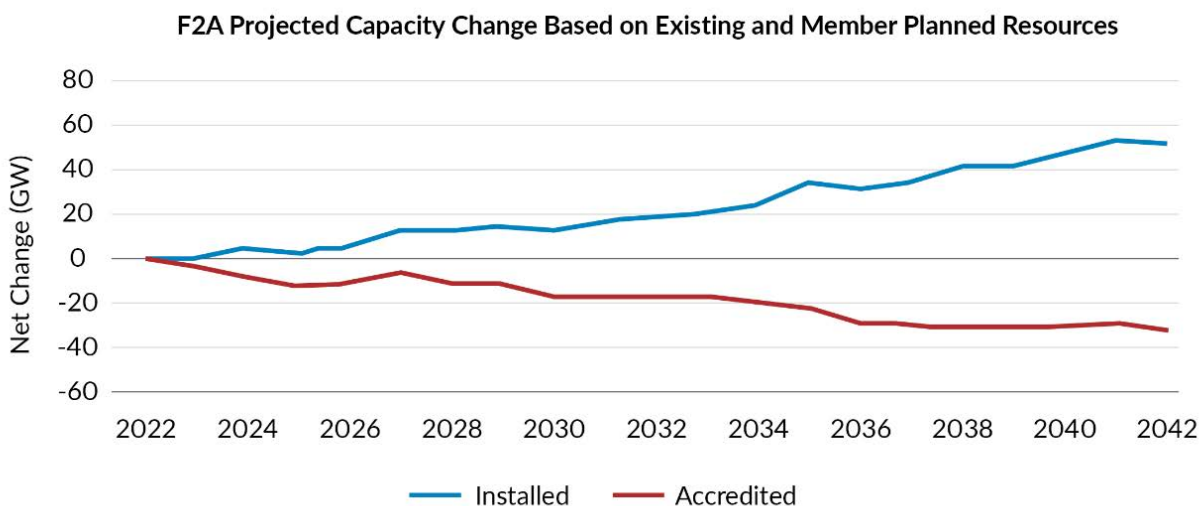
An annual planning tool called the **OMS-MISO Survey** tells a similar story. The survey compiles information about new resources utilities and states plan to build and older assets they intend to retire in the coming years. [The 2023 survey](#) shows the region’s level of “committed” resources declining going forward, with a potential shortfall of 2.1 GW occurring as soon as 2025 and growing larger over time. MISO administers the survey in partnership with the [Organization of MISO States \(OMS\)](#), which represents the region’s state regulatory agencies.

Other drivers of the region’s tightening supply picture include:

- U.S. Environmental Protection Agency (EPA) regulations that prompt existing coal and gas resources to retire sooner than they otherwise would.
- Wall Street investment criteria that make it more challenging to build new dispatchable generation, even if it is critically needed for reliability purposes.
- The approximately \$370 billion in financial incentives for clean-energy resources in the federal Inflation Reduction Act.

DECLINING ACCREDITED CAPACITY

Fleet change is creating a gap between the region’s levels of installed and accredited generation capacity. **Installed capacity** is the maximum amount of energy that resources could theoretically produce if they ran at their highest output levels all the time and never shut down for planned or unplanned reasons. **Accredited capacity**, by contrast, reflects how much energy resources are realistically expected to produce during times when they are needed the most by accounting for their performance, which includes limiting factors such as their forced outage rates during adverse weather conditions.



The chart above is from [MISO Future 2A](#), which reflects the publicly announced decarbonization plans of MISO-member utilities and states. As the chart shows, the region’s level of *installed* capacity – the blue line – is forecast to increase by nearly 60 GW from 2022 to 2042 due to the many new resources –



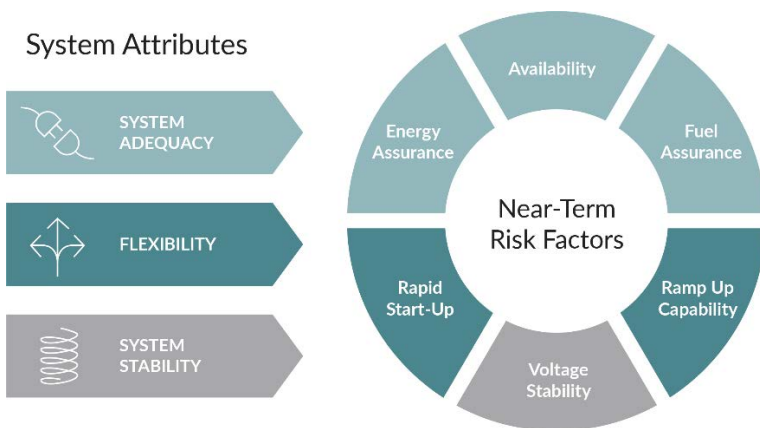
primarily wind and solar – that utilities and states plan to build in that 20-year time period.¹ But because those new wind and solar resources have significantly lower accreditation values² than the conventional resources that utilities and states plan to retire in the same 20-year period, the region’s level of *accredited* capacity – the red line – is forecast to decline by a net 32 GW by 2042.

MISO modeling indicates that a reduction of that magnitude could result in load interruptions of three to four hours in length for 13-26 days per year when energy output from wind and solar resources is reduced or unavailable. Such interruptions would most likely occur after sunset on hot summer days with low wind output and on cold winter days before sunrise and after sunset.

NEED FOR SYSTEM RELIABILITY ATTRIBUTES

Reliably navigating the energy transition requires more than just having sufficient generating capacity; it also requires urgent action to avoid a looming shortage of broader **system reliability attributes**. In 2023, MISO completed a foundational analysis of attributes, with a focus on three priority attributes where risk for the MISO system is most acute:

- **System adequacy** is the ability to meet electric load requirements during periods of high risk. MISO focused on the near-term risk factors of availability, energy assurance and fuel assurance.
- **Flexibility** is the extent to which a power system can adjust electric production or consumption in response to changing system conditions. MISO focused on the near-term risk factors of rapid start-up and ramp-up capability.
- **System stability** is the ability to remain in a state of operating equilibrium under normal operating conditions and to recover from disturbances. MISO focused on the nearest-term risk factor of voltage stability.



No single type of resource provides every needed system attribute; the needs of the system have always been met by a fleet of diverse resources. However, in many instances, the new weather-dependent resources that are being built today do not have the same characteristics as the dispatchable resources they are replacing. While studies show it is possible to reliably operate the system with substantially lower levels of dispatchable resources, the transformational changes require MISO and its members to study, measure, incentivize and implement changes to ensure that new resources provide adequate levels of the needed system attributes.

¹ It is not a typical industry practice for utilities and states to publicly announce their resource plans a full 20 years in advance, which is the time horizon that MISO used for the MISO Futures. Thus, this forecast should be viewed as a “snapshot in time” that will change going forward as utilities and states solidify their resource plans.

² In the Future 2A model, retiring conventional resources are accredited at 95% or more of their nameplate capacity, while wind is accredited at 16.6% and solar declines over time to 20%. Accreditation values will vary depending on the methodologies and assumptions that were used to create them.



In December 2023, MISO published an [Attributes Roadmap report](#) that recommends urgent action to advance a portfolio of market reforms and system requirements and to provide ongoing attributes visibility through regular reporting.

EMERGING TECHNOLOGIES SHOW PROMISE BUT ARE NOT YET VIABLE AT GRID SCALE

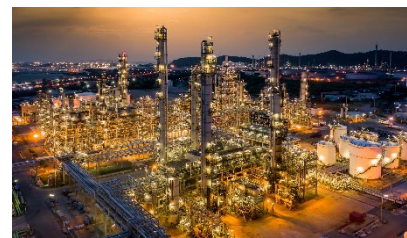
A number of emerging technologies are being developed that could potentially mitigate the challenges described above. They include long-duration battery storage, carbon capture, small modular nuclear reactors and “green” hydrogen produced from renewables, among others.

However, while these technologies show promise for the future, they are not yet commercially viable to be deployed at scale. MISO is actively engaged in tracking the progress of these technologies and is preparing to incorporate them into the system if/when the opportunity arises.

MISO does expect the commercial viability timelines of these technologies to be accelerated by the \$370 billion in financial incentives for clean energy in the 2022 Inflation Reduction Act. In recognition of that, MISO modeled those incentives in the refreshed MISO Futures. More information on emerging technologies is available in MISO’s [2022 Regional Resource Assessment](#).

LOAD ADDITIONS ARE SURGING

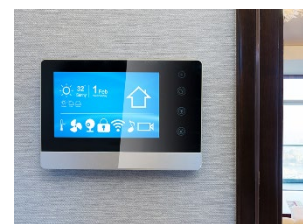
Some parts of the MISO region are enjoying a resurgence in manufacturing and/or other economic growth, with companies planning and building new factories, data centers and other energy-intensive facilities. For example, in the MISO South subregion that spans most of Arkansas, Louisiana, Mississippi and a small part of Texas, there are discussions and plans to build a variety of new manufacturing plants for steel, hydrogen, liquified natural gas and other heavy industry that could add more than 1,000 megawatts (MW) of new load. The tax credits for clean-energy manufacturing in the Inflation Reduction Act are helping to drive some of these additions.



While such development is welcome from an economic perspective, it can also pose significant grid reliability risks if the large load additions it spurs cannot be reliably served with existing or planned resources.

LOAD GROWTH DUE TO INCREMENTAL ELECTRIFICATION

While year-over-year demand for electricity in MISO has been fairly flat for many years, it is expected to increase going forward due to the electrification trends in other sectors of the economy. Electric vehicles are growing in popularity, and the residential and commercial building sectors are increasingly using electricity for heating and cooling purposes — with a desire to source this new electric load from renewables. These trends will likely accelerate even more due to the substantial financial incentives in the Inflation Reduction Act for electric vehicles, rooftop solar systems and electric appliances.





The impacts of these trends could be significant. In MISO’s 2021 [Electrification Insights report](#), MISO found that electrification could transform the region’s grid from a summer-peaking to a winter-peaking system and that uncontrolled vehicle charging and daily heating and cooling load could result in two daily power peaks in nearly all months of the year.

DELAYS TO APPROVED GENERATION PROJECTS

In addition to reliability being challenged by declining accredited capacity, electrification and load additions, another concern is that a large number of fully approved and much-needed new generation projects are being delayed by supply chain issues, regulatory issues, and other external factors beyond MISO’s control.

As of late 2023, about 25 GW of fully approved generation projects in MISO’s Generator Interconnection Queue had missed their in-service deadlines by an average of 650 days, with developers citing supply chain and permitting issues as the two biggest reasons for the delays. An additional 25 GW of fully approved queue projects had not yet missed their in-service deadlines as of late 2023, but MISO expects many of them will also be delayed by external factors.

As the region’s capacity picture continues to tighten, the possibility that upward of 50 GW of fully approved new generation projects could be delayed by external factors beyond MISO’s control is deeply concerning.

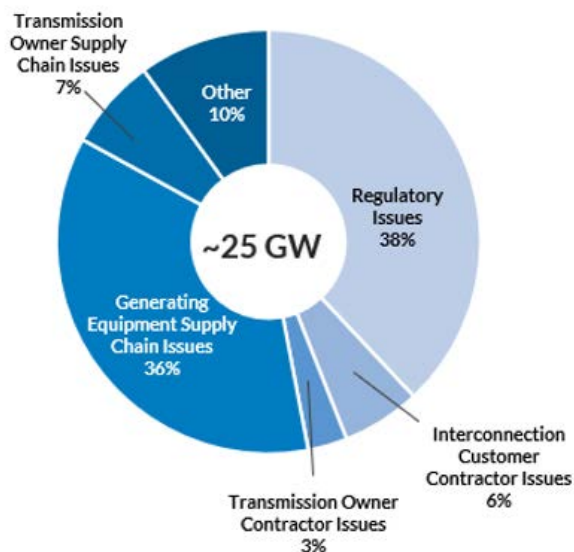
FUEL ASSURANCE RISKS

The transition to a low- to no-carbon electric grid also poses risks in the realm of fuel assurance. These risks impact conventional coal and gas resources that provide reliability attributes such as system adequacy, flexibility and system stability that may be becoming scarce due to fleet change.

Coal resources have historically been considered fuel-assure because large stockpiles of fuel can be stored on-site. However, coal supplies have tightened in recent years due to a confluence of factors, including contraction of the mining and transportation sectors and supply chain issues. These factors increase the risk that coal plants will be unable to perform due to a lack of fuel availability. Coal resources can also be affected by extreme winter weather freezing onsite coal piles and/or impacting coal-handling equipment.

Gas-fired resources are also subject to fuel-assurance risks because they rely on pipelines to deliver gas to them. However, because the pipeline system was largely built for home-heating and manufacturing purposes, gas power plants sometimes face very challenging economic conditions to procure the fuel they need to operate. In the MISO region, this has historically occurred during extreme winter weather events that drive up home-heating needs for gas. Many gas generators in MISO do not have “firm” fuel-delivery

25 GW of fully approved & much-needed generation projects are delayed by supply chain and other issues



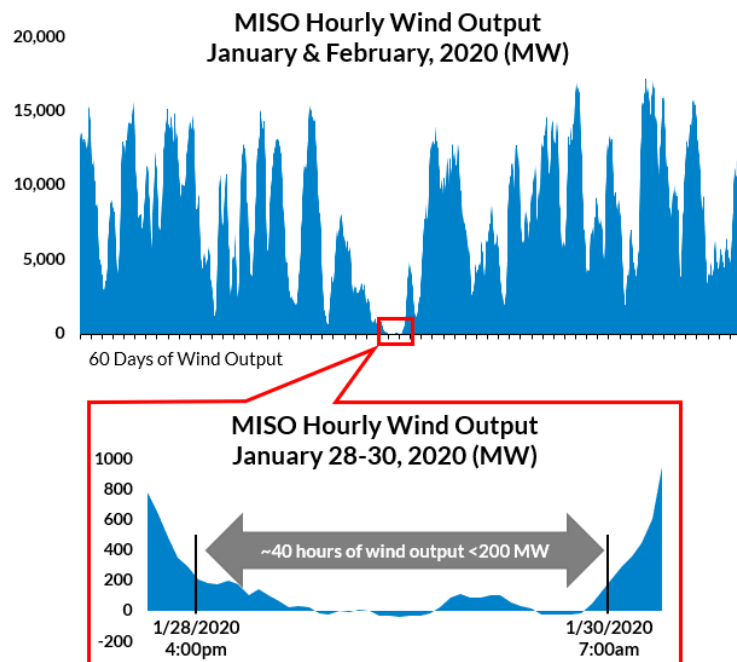


contracts, opting instead for less costly “interruptible” pipeline service or a blend thereof. Only about 27% of the gas generation that responded to MISO’s [2023-2024 Generator Winterization Survey](#) indicated it had firm transport contracts in place for all of their supplies during the 2023-2024 winter season. Additionally, gas power plants, gas pipelines and coal generators can be forced out of service by icing and other effects of severe winter weather — as has occurred in the MISO region and elsewhere with increasing frequency.

WIND DROUGHTS

Wind resources can experience “fuel” availability challenges in the form of highly variable wind speeds. Consequently, the energy output of wind can fluctuate significantly on a day-to-day and even an hour-by-hour basis — including multi-day periods when output drops far below average.

For example, over 60 consecutive days in January-February 2020, hourly wind output in MISO averaged more than 8,000 MW. However, as the chart shows, for 40 consecutive hours in the middle of that 60-day block, average hourly wind output dropped to less than 47 MW, and only once exceeded 200 MW in any single hour.



An even longer and broader “wind drought” occurred during Winter Storm Uri in 2021 when the MISO, Southwest Power Pool, Electric Reliability Council of Texas and PJM regions all experienced 12 consecutive days of low wind output.

Wind turbines can also be unavailable in extremely cold weather. While turbines equipped with special “cold weather packages” are designed to operate in temperatures as low as minus 22 F, they generally cut off if temperatures dip below that point. Still, it is important to keep in mind that all types of generators struggle in extreme cold, not just wind turbines.

EPA REGULATIONS COULD ACCELERATE RETIREMENTS OF DISPATCHABLE RESOURCES

While MISO is fuel- and technology-neutral, MISO does have a responsibility to inform state and federal regulations that could jeopardize electric reliability. In the view of MISO, several other grid operators, and numerous utilities and states, the U.S. Environmental Protection Agency (EPA) has issued a number of regulations that could threaten reliability in the MISO region and beyond.

In May 2023, for example, EPA proposed a rule to regulate carbon emissions from all existing coal plants, certain existing gas plants and all new gas plants. As proposed, the rule would require existing coal and gas resources to either retire by certain dates or else retrofit with costly, emerging technologies such as carbon-capture and storage (CCS) or co-firing with low-carbon hydrogen.



MISO and many other industry entities believe that while CCS and hydrogen co-firing technologies show promise, they are not yet viable at grid scale — and there are no assurances they will become available on EPA’s optimistic timeline. If EPA’s proposed rule drives coal and gas resources to retire before enough replacement capacity is built with the critical attributes the system needs, grid reliability will be compromised. The proposed rule may also have a chilling effect on attracting the capital investment needed to build new dispatchable resources.

RISKS IN NON-SUMMER SEASONS

In the past, resource adequacy planning in MISO focused on procuring sufficient resources to meet demand in the peak hour of the year, which normally occurs on a hot and humid summer day when air conditioning load is very high. If utilities had enough resources to reliably meet that one peak hour in the summer, the assumption was they could operate reliably for the other 8,759 hours of the year.

That assumption no longer holds true. Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region’s historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.

This changing risk profile is why MISO shifted from its annual summer-focused resource adequacy construct to a new framework that establishes resource adequacy requirements on a seasonal basis for four distinct seasons: summer (June-August); fall (September-November); winter (December-February); and spring (March-May). This new seasonal construct also seeks to ensure that resources will be available when they are needed most by aligning resource accreditation with availability during the highest risk periods in each season.





Pillar 1: Market Redefinition

MISO established the energy and ancillary service markets w nearly two decades ago when the composition of, and the risks to, the energy industry were very different from today. MISO's [Markets of the Future report](#) indicates that the region's foundational market constructs will continue to be effective going forward, but only with significant revisions. Further informed by the attributes analysis completed in 2023, MISO is enhancing and optimizing its market constructs and products to ensure they continue to deliver reliability and value in the face of fleet change, extreme weather events, electrification and load additions. This work occurs under four themes within the Market Redefinition pillar of the Reliability Imperative, as discussed below.

UNCERTAINTY AND VARIABILITY

In the planning horizon, MISO is addressing the changing risk profile and enhancing market signals for new resource investments. MISO's original resource adequacy construct was designed for a conventional fleet of resources where reliability risk was concentrated during the typical summer peak period. This is no longer the case. Factors such as aging conventional resources, more frequent and severe weather events and increased reliance on weather-dependent renewables have altered the region's historic risk profile, creating new risks in non-summer months and at differing times of the day. As the generation mix further diversifies, the accreditation process of evaluating each generator's contribution to the system is a critical reliability and planning mechanism.

In 2022, FERC approved MISO's proposal to shift from the annual, summer-based resource adequacy construct to a new construct with four seasons. The new seasonal construct also aligns the accreditation of thermal resources with availability in the highest-risk periods. These changes, implemented in the 2023-2024 Planning Resource Auction (PRA), are already delivering positive market outcomes, such as more proactive outage coordination among stakeholders and incentivizing improved unit performance.

MISO completed an evaluation of potential paths for non-thermal accreditation reforms 2022. This resulted in a proposed accreditation reform that leverages the principles from the thermal accreditation reform implemented in 2022, aligning the accreditation methodology for all resource types (except for emergency-only resources). MISO has proposed a transition period to begin applying the new accreditation methodology in the 2028-2029 planning year. The design work is expected to be finished with a filing with FERC in 2024.

The PRA was not designed to set higher capacity clearing prices as the magnitude of a shortfall increases. This lack of a "warning signal" can instill a false sense of calm among PRA participants, masking an imminent shortfall – as occurred with the 2022 PRA. MISO is working with its stakeholders to enhance pricing within the capacity construct by designing a Reliability-Based Demand Curve (RBDC) to better reflect MISO's market guiding principles, reliability risk and help avoid uneconomic retirements. Full implementation is planned for the 2025-2026 PRA, subject to FERC proceedings.



While the RBDC improves price signals in the planning horizon, MISO is also working on pricing reforms in the operating horizon. These focus on **scarcity pricing** when demand and reserve requirements exceed available supply in real time, often happening during extreme events when MISO enters emergency procedures to manage challenging conditions.

MISO's reforms to scarcity pricing will help incentivize appropriate market behavior, manage congestion throughout events and value reserve shortages appropriately, ultimately providing greater transparency and minimizing manual market intervention. MISO's focus areas for 2024 are updating the value of lost load, demand curves and forced-off assets that become physically disconnected from the grid due to weather-related transmission events. MISO has been presenting ideas at the [Market Subcommittee](#) stakeholder group. These enhancements will begin in 2024, with complete implementation expected by 2025.

Lastly, informed by the analysis of critical reliability attributes and in light of the changing reliability risk profiles in the region, MISO will work with stakeholders in 2024 to reevaluate the traditional risk metrics used in the industry for resource adequacy assessments and improve the underlying risk models.

RESOURCE MODELS AND CAPABILITIES

To avoid a looming shortage of necessary voltage stability attributes, as detailed in the [Attributes Roadmap](#), MISO will advance a multistep technology standard to require capabilities from inverter-based resources to support grid stability at interconnection. In January 2023, MISO embarked on a path to improve inverter-based resource performance requirements using a reliability risk-based approach to evaluate potential gaps in MISO's current tariff. MISO finalized the proposed Tariff language in November to address the highest priority performance requirements and capabilities. This proposal is Phase 1 of the recommended four-phase approach, and this cross-matrix "resource models and capabilities" project will continue in the Interconnection Process Working Group (IPWG).

Another area of focus is MISO's work toward compliance with **FERC Order 2222**, which facilitates the participation of distributed energy resources (DERs) in wholesale electricity markets. DERs are small-scale resources such as rooftop solar panels, electric battery storage systems or electric vehicles and their charging equipment. In isolation, these resources would not have much impact on the grid, but when they are aggregated into a larger block, they can be impactful. MISO is developing a plan to comply with this order through broad collaboration with stakeholders, members, regulators, distributors and DER aggregators.

IDENTIFYING LOCATIONAL NEEDS

Another critical focus associated with increased uncertainty and variability is challenging reserve deliverability due to congestion. Historically, MISO utilized reserve zones to procure and reliably deliver reserves. MISO is working to implement improved locational granularity in its reserve products to ensure deliverability. Updating the reserve zones more frequently should enhance market efficiency and system reliability since there would be better alignment between zonal definitions and system conditions.

In addition to the local deliverability of resources, MISO will explore approaches to better hedge congestion through MISO's Auction Revenue Rights (ARR) mechanism and the Financial Transmission



Rights market. Evaluation has identified gaps and is exploring potential areas of improvement, including updating approaches for allocating ARRs, more granular periods, and ways to incentivize outages that better align with day-ahead energy models.

ENHANCING COORDINATION

As operational uncertainty and complexity increase, MISO continues to improve coordination across stakeholders and external entities, including neighboring grid operators. The collaborative **OMS-MISO Survey** provides a prompt view of resource adequacy over the five-year horizon, characterizing relative levels of resource certainty. MISO's **Regional Resource Assessment (RRA)** provides a collective 20-year view of the evolution of members' resource plans. It aims to provide insights that help members, states and MISO prepare for the energy transition. MISO's [Attributes Roadmap](#) specifically identifies the need for evolved coordination between MISO's resource adequacy assessments and MISO state and member planning process to ensure attribute sufficiency. MISO is committed to continued analysis, transparency and collaboration in the Resource Adequacy stakeholder forum.

One example is how transmission owners and MISO are working together on **ambient-adjusted ratings (AARs)** and **seasonal ratings** on transmission lines in the region, per the requirements of FERC Order 881. While using more accurate line ratings does not diminish the need to build new transmission, having the most accurate line rating information can help ensure that the region's transmission system is fully utilized and delivers its maximum value. MISO has engaged in extensive discussions with its transmission owners and consulted with other interested stakeholders to develop a compliance approach that meets the requirements of FERC Order 881 and is consistent with MISO's Tariff.

“Our market products and the signals they send need to evolve and reflect the new realities and trends that we are experiencing. Input and support from our stakeholders will be key in the effective and timely implementation of these changes.”

Todd Ramey, MISO Senior Vice President, Markets and Digital Strategy



Pillar 2: Operations of the Future

MISO's control room operations are also challenged by fleet change, extreme weather and other risk drivers. In addition to implementing lessons learned from past events such as Winter Storm Elliott, forward-looking work is underway to ensure MISO has the capabilities, processes and technology to anticipate and respond to operational opportunities and challenges. This work, termed Operations of the Future, focuses on five buckets of work: (1) operations preparedness, (2) operations planning, (3) uncertainty and variability, (4) situational awareness and critical communications and (5) operational continuity.

OPERATIONS PREPAREDNESS

Tomorrow's control room will be very different from today. Operations preparedness is critical to managing the rapidly changing system conditions, increased volumes of data and enhanced technologies and tools that operators face. To ensure that control room personnel are ready to manage reliability effectively and efficiently in this new and continually evolving environment, MISO is developing improved operations simulation tools and enhancing operator training. In the future, operator and member training and drills will leverage a robust simulator that mirrors production and can quickly incorporate and maintain real-time event scenario simulations with broad, controlled access capabilities.

“In the past, predicting load and generation was relatively straight-forward. In the future, the operating environment will be much more variable, and we need the people, processes and technology to deal with that variability.”

Jennifer Curran, MISO Senior Vice President, Planning & Operations
and Chief Compliance Officer

OPERATIONS PLANNING

Operations planning helps MISO to remain a step ahead of the shifting energy landscape. System operators need to quickly access insights into the future and processes that enable the continued reliable and efficient operation of the bulk electric system. In the future, it will be necessary to leverage information in new ways. The ability to quickly model and analyze realistic planning scenarios will enable operators to develop and modify operating day plans from start to execution. Operators will be better prepared to manage increased uncertainty in resource availability with operational planning processes that are centralized and streamlined and outages that are proactively scheduled leveraging predictive economic impact analysis and power system studies.



UNCERTAINTY AND VARIABILITY

The increase in variable generation such as wind and solar has introduced greater uncertainty. Today, operators leverage a variety of market products and other analytics-based tools to manage uncertainty. To help manage increasing complexity, MISO is using machine-learning to predict net uncertainty for the upcoming operating day, using probabilistic forecasts and advanced analytics. With this more complete view, operators can create daily risk assessments that – when coupled with new dynamic reserve requirements – incentivize efficient unit-commitment decisions.

In the future, operators will need to manage the grid reliably and efficiently through tight margins, high-ramping periods, and increased variability by optimizing a risk management framework that accurately provides a risk profile based on net uncertainty impacts and by leveraging predictive economic impact analysis and power system studies.

SITUATIONAL AWARENESS AND CRITICAL COMMUNICATIONS

Situational awareness and critical communications will become even more important as operating risks become less predictable and more difficult to manage in day-to-day operations. New control room technologies and capabilities, improved real-time data capabilities and more complex operating conditions, driven by new load and generation patterns, will require MISO and its members to communicate even more quickly and efficiently.

Today, MISO operations rely heavily on the expertise of its operators. While operators have access to significant amounts of data related to weather, load and more, they must manually synthesize that data into useable information. Although this has worked well historically, solutions must envision a future with more complex information and operators who may not possess the same historical knowledge.

In the future, operators will need an integrated toolset that leverages artificial intelligence and machine learning, combined with additional data and analytics. Improvements in how MISO sees and navigates will give operators important information automatically. Systems will provide situational awareness insights for operators based on their function in the control room. Operators will analyze information and create new displays in real time to quickly assess the impacts of operational situations. Dynamic views of the state of the system will ensure operators can maintain the appropriate level of situational awareness while also reducing operator burden and automating key communication requirements, especially during critical events.

Additionally, enhancements to communications protocols, such as system declarations, will ensure that control rooms have the information they need when they need it. Automated messaging triggered by specific process and procedure actions will reinforce compliance with NERC standards.

OPERATIONAL CONTINUITY

Operational continuity capabilities need to evolve to align with the changing technologies, resource portfolio and threat landscape. Improved tools and updated processes are vital to ensuring that MISO can reliably operate the grid, mitigate risks, and, if necessary, recover quickly in the event of disruptions to toolsets or control centers.



Pillar 3: Transmission Evolution

The ongoing shift in the resource fleet and the substantial projected increase in load pose significant challenges to the design of the transmission system in the MISO region. MISO's Transmission Evolution work addresses these challenges in concert with other elements of the Reliability Imperative framework.

Under Transmission Evolution, MISO holistically assesses the region's future transmission needs while considering the allocation of transmission costs. This work creates an integrated transmission plan that reliably enables member goals while minimizing the total cost of the fleet transition, inclusive of transmission and generation. It also improves the transfer capability of the transmission system — meaning its ability to effectively and efficiently move energy from where it is generated to where it is needed.

LONG RANGE AND INTERREGIONAL TRANSMISSION PLANNING

Regional Long Range Transmission Planning (LRTP) and interregional planning are important parts of the Transmission Evolution pillar. The LRTP effort is developing four tranches of new backbone transmission to support MISO member plans for the changing fleet. In July 2022, the MISO Board of Directors [approved](#) LRTP Tranche 1. The 18-project portfolio of least-regret solutions is focused on MISO's Midwest subregion, representing \$10.3 billion in investment. The projects in Tranche 1 will provide a wide range of value, including congestion and fuel savings, avoided capital costs of local resources, avoided transmission investments, resource adequacy savings, avoided risk of load shedding and decarbonization.

“We see very little risk of over-building the transmission system; the real risk is in a scenario where we have underbuilt the system. Similarly, across markets and operations, our job is to be prepared.”

Clair Moeller, MISO President

This transmission investment hinges on appropriate allocation of the associated costs. MISO's Tariff stipulates a roughly commensurate “beneficiaries pay” requirement that must be met while balancing the divergent needs of MISO's three subregions. Because Tranches 1 and 2 primarily benefit the Midwest subregion, costs will only be allocated there. As Tranches 3 and 4 progress, other approaches may be considered based on stakeholder discussion. Work on Tranche 2 is progressing, with an anticipated approval by MISO's Board of Directors in 2024.

Futures refresh

MISO's future scenarios, or [Futures](#), set the foundation for LRTP. The Futures help MISO hedge uncertainty by “bookending” a range of potential economic, policy and technological possibilities based on factors such as load growth, electrification, carbon policy, generator retirements, renewable energy levels, natural gas prices and generation capital cost over a 20-year period.



Member and state plans often do not provide resource information for the full 20-year study period covered by LRTP. Although MISO does not have authority over generation planning or resource procurement, this lack of information creates a gap in the resources needed to serve load and meet member goals. MISO fills the gap through resource expansion analysis, which seeks to find the optimal resource fleet that minimizes overall system cost while meeting reliability and policy requirements. The resulting resource expansion plans are used with their respective Future to identify transmission issues and solutions.

To lay the groundwork for Tranche 2 and to better understand potential future needs based on the most recent plans, legislation, policies and other factors, MISO [refreshed](#) its three Futures in 2023. While the defining characteristics of each Future remained the same (e.g., load forecast and retirement assumptions), updates were made to data and information that inform the potential resource mix. Among other factors, this includes state and member plans, capital costs, operating and fuel costs and defined resource additions and retirements. MISO also modeled the impacts of the clean energy tax credits in the federal Inflation Reduction Act because those incentives are expected to accelerate the transition to a decarbonized grid.

Future 2A, the focus of Tranche 2, indicates that fleet change will increase in velocity due to stronger renewable energy mandates, carbon reduction goals and other policies. Future 2A projects a 90% reduction in carbon emissions by 2042 and forecasts that wind and solar will provide 30% of the region's energy a full 10 years earlier than the previous Series 1 Futures that were used for Tranche 1.

Planning for an uncertain future

When planning for larger, regional solutions that address needs 20 years into the future, there is inherent uncertainty, which is why LRTP is designed to identify “least-regrets” transmission solutions. Appropriately managing this uncertainty is a key function of planning. In developing Future 2A, MISO leveraged the consensus on policy goals among MISO members and states about how quickly change would occur. Additionally, MISO's comprehensive processes and robustness testing demonstrate the benefits and needs of transmission solutions that achieve member goals and minimize costs, including several iterations of analyses for Future 2A and other scenarios.

Other visibility tools

As the system becomes more interdependent and interconnected, MISO provides information to members about the outcomes and impacts of their individual plans when studied in the aggregate. Anticipating and communicating changing risks and future systems needs within the planning horizon is critical to ensure continued reliability.

As described earlier in this report, the **OMS-MISO Survey** compiles information about new resources that utilities and states plan to build and older assets they intend to retire in the coming years. While this tool looks several years ahead, certainty is lower in later years when many significant risks will need to be addressed.

Because utility and state plans can be less specific and certain, cover a shorter timeframe and are not always publicly available, MISO conducts the **Regional Resource Assessment (RRA)** to capture more information and details. The RRA aggregates utility and state plans and goals – both public and private –



over a 20-year planning horizon to shed light on regional fleet evolution trends and timing. The information is then used to model potential reliability needs and gaps that may arise and may be leveraged to inform and advance analysis of resource attributes. In the future, new tools will provide stakeholders with ongoing access to RRA information for greater visibility into the impact of these future system changes.

Interregional initiatives

MISO continually works with its neighboring grid operators, Southwest Power Pool (SPP) and PJM, to address issues on the seams. Joint, coordinated, system plan studies are regularly conducted to assess reliability, economic and/or public policy issues. The studies can be more targeted in scope with a shorter study cycle or can be more complex, requiring a longer study period.



The Joint Targeted Interconnection Queue (JTIQ) initiative with SPP is an example of a recent complex study initiative. This unprecedented, coordinated effort identified a portfolio of proposed transmission projects that align with both MISO's and SPP's interconnection processes. These projects will create additional transmission capability to enable generator interconnections in both regions.

In October 2023, the U.S. Department of Energy (DOE) [announced](#) it would award \$464.5 million in federal funding under the Grid Resilience and Innovation Partnerships (GRIP) program to the JTIQ portfolio. This historic opportunity significantly reduces the estimated investment for new transmission lines that will benefit seven states. A FERC filing to obtain approval of cost allocation for the JTIQ portfolio will be submitted in early 2024, and MISO Board approval will be sought thereafter. The process SPP and MISO followed to coordinate the study proved to be effective and significantly more efficient than typical Affected System Studies. Based on its success, the process will be included in the 2024 filing to enable improved coordination in the future.

PLANNING TRANSFORMATION

MISO's planning tools and processes must also evolve as the transitioning resource mix increases the complexity of transmission planning. In response, Planning Transformation, another component of the Transmission Evolution pillar, will develop aligned, adaptable and flexible processes and tools over the next five to 10 years to recognize and address emerging transmission threats and risks identified in markets and operations.

The new [MISO Transmission Expansion Plan \(MTEP\) Portal](#) is a major step in this transformation. The system launched in October 2023 and helps MISO staff and transmission owners manage project data more efficiently and effectively, and it will save hundreds of work hours each year. It also provides stakeholders better support for submitting, updating, tracking and managing MTEP projects and enables more transparency.

Other measures – such as the Generator Interconnection Portal and technology evaluation of resource siting – are already implemented, underway or planned for the future. These include evolving technology



for the resource transition, adapting planning criteria to enhance system resiliency and robustness, and integrating model data.

RESOURCE UTILIZATION

The Resource Utilization initiative focuses on improving resource utilization planning to include a dynamic generator retirement process, more rapid generator interconnections and resource reliability attributes that are addressed throughout the resource lifecycle.

To improve the generator retirement process, asset owners are now required to provide one-year advance notice of resource retirements, an increase from the prior 26 weeks. Quarterly retirement studies have also been instituted to better forecast the engineering workload needed to conduct analyses, and other changes are being implemented that help align retirements with MTEP processes and improve visibility of retirements to stakeholders.

MISO is also working to ensure its processes do not impede generator interconnections. Although MISO's queue processes have been effective in cycles with typical volumes, they are not sufficient for managing recent request volumes that are growing exponentially compared to historical norms. This significantly increases the time it takes MISO to complete studies, which drives more project withdrawals, provides less certainty of early study results, and, ultimately, complicates late-stage studies. These issues are compounded by many speculative projects, despite years of reforms on "first ready, first served" principles.

Improvements to customer-facing and backend operational queue processes over the past several years have enabled more efficient application processing. However, additional changes are needed to manage the dramatic growth in applications, further expedite the interconnection process and maximize transparency and certainty to customers.

As a result, MISO paused accepting interconnection applications for the 2023 cycle, with plans to resume in March 2024 after receiving FERC approval on multiple process improvements to ensure better interconnection requests are submitted. The 2024 cycle is anticipated to begin in the fall of 2024, as it has in previous years.

Tariff changes approved by FERC in January 2024 increase financial commitments and withdrawal penalties and require interconnection customers to provide greater site control for projects. FERC did deny a MISO proposal to cap the size of queue study cycles to ensure they do not exceed a certain percentage of MISO load. However, FERC provided guidance on how MISO could implement a cap in the future, as well as other improvements that will enable the dispatch of existing resources with new interconnection requests. MISO believes these changes will decrease applications and result in higher-quality, more viable projects entering the queue. A reduction in project withdrawals may ultimately reduce network upgrades between studies and provide greater planning certainty for customers and MISO.

In July 2023, FERC issued Order 2023 to ensure that generator interconnection customers can interconnect to the transmission system in a reliable, efficient, transparent, timely and nondiscriminatory manner. The order is mostly consistent with the queue changes MISO has already implemented and

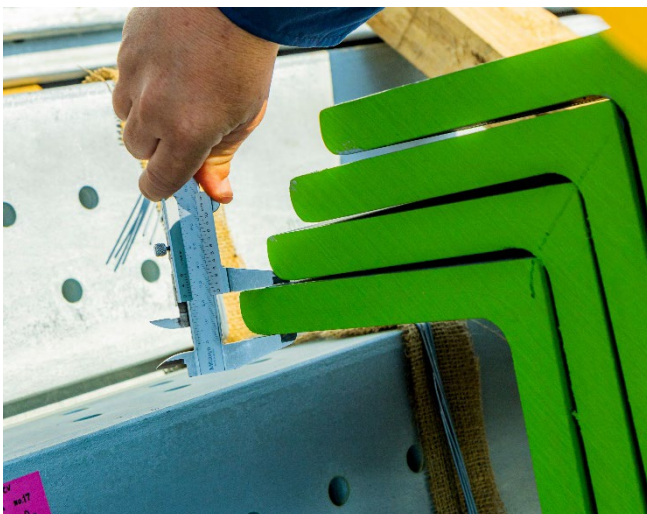


intends to implement going forward. MISO is reviewing the order to assess potential changes and compliance needs.

Lastly, as described in the Resource Models And Capabilities section of this report, MISO is advancing a multistep technology standard to require capabilities from inverter-based resources to support grid stability through the Interconnection Process Working Group. This cross-matrix work is further described in MISO's [Attributes Roadmap report](#) as a solution to mitigate the potential shortage of system stability attributes.

Delays outside of MISO's control

Despite improvements MISO has made to its Generator Interconnection Queue, many fully approved projects are not going into service on schedule due to supply chain issues and permitting delays that are beyond MISO's control. As of late 2023, about 25 gigawatts (GW) of resources that were fully approved through MISO's queue process had missed their in-service deadlines by an average of 650 days, with developers citing supply chain and permitting issues as the two biggest reasons for the delays. An additional 25 GW of fully approved queue projects had not yet missed their in-service deadlines as of late 2023, but MISO expects many of them will also be delayed by external factors.





Pillar 4: System Enhancements

Continual system enhancements and modeling refinements are the bedrock of MISO's response to the Reliability Imperative. The ongoing complexities of the electric industry landscape necessitate paramount upgrades to facilitate reliability-driven market improvements. The Market System Enhancement (MSE) program stands out as a visionary endeavor, focusing on upgrading, building and launching new systems with improved performance, security and architectural modularity. This strategic emphasis enhances MISO's capability to respond swiftly and efficiently and deliver new market products that align with the evolving industry landscape.

MISO places strategic importance on enabling a mature hybrid cloud capability to future-proof the technological infrastructure and foster a resilient and adaptable organizational framework. Simultaneously, the commitment to fostering a flexible work environment amplifies MISO's readiness for ongoing technological changes. This dynamic approach, centered on securely harnessing hybrid cloud technology, optimizes the work environment, positioning MISO for future advancements. The integration of these strategies underlines MISO's forward-looking approach and establishes its leadership in embracing advanced technologies for safeguarding operations.

MARKET SYSTEM ENHANCEMENT (MSE) PROGRAM

The MSE program, initiated in 2017, is a transformative force in reshaping MISO's market platform. Its focus on creating a more flexible, upgradeable and secure system underscores its pivotal role in accommodating the region's evolving portfolio and technology changes. The achievements in 2023 highlight the program's commitment to continuous improvement. The upgrade of the Energy Management System, completion of Phase 2 Core Development, and advancements in the Day-Ahead Market Clearing Engine and Real-Time Market Clearing Engine showcase MSE's impact on improving functionality, user experience, business continuity and security posture. This program is not merely a technological upgrade; it is a strategic initiative that positions MISO to meet the demands of the future electric grid.

“For MISO to continue to deliver on our mission, we must prioritize our plan to address the right strategic drivers that will enable us to accommodate the region’s evolving portfolio and technology changes. The work we do in System Enhancements supports the transformational efforts across the Reliability Imperative and will increase value to our stakeholders.”

Todd Ramey, Senior Vice President, Markets and Digital Strategy



WORK ANYWHERE

MISO's strategic move toward future-proofing its technological infrastructure involves enabling and maturing hybrid cloud capabilities. This initiative goes beyond technology; it embraces the transformative strategy of realizing a flexible work environment that transcends conventional boundaries. The delicate balance between the freedom to work remotely and stringent adherence to security and compliance requirements signifies a definitive change in how MISO approaches work. This shift sets the stage for a more agile and responsive workforce, enhancing productivity and embracing the evolving nature of work. Simultaneously, adopting a well-managed hybrid cloud platform forms the backbone of MISO's technological evolution, allowing seamless operations between on-premises data centers and the public cloud. This combination fortifies organizational resilience and propels MISO into a future where adaptability is the key to sustainable success.

SECURITY OF THE FUTURE

MISO's commitment to seamlessly integrating cutting-edge technologies is underpinned by a dedication to security, reliability and efficiency. This includes initiatives designed to fortify MISO's approach to cybersecurity. Refining identity and access management practices, adopting a proactive zero-trust approach and transforming asset management data quality and timeliness demonstrate MISO's proactive stance against the evolving cyber threat landscape. The commitment extends beyond external threats to assessing security best practices for the internal environment. The ongoing thorough review to evaluate and implement the latest security protocols, conduct regular audits and stay abreast of emerging threats exemplifies MISO's dedication to securing tomorrow.

DATA AND ANALYTICS

MISO's data strategy is a comprehensive framework that goes beyond a simple upgrade — it is a visionary approach to enhancing MISO's data capabilities. The three key priorities — fostering an enterprise culture, delivering a holistic process framework and providing a curated environment — fortify MISO's position as a leader in the energy sector. This strategy modernizes tools, platforms, technologies and processes and empowers teams to model, simulate, analyze and visualize data for informed decision-making. Through a focused and well-defined program, MISO is set to realize a data platform that not only meets the needs of today but is agile enough to adapt to the evolving landscape of data requirements.



MISO Roadmap

As illustrated below, the **MISO Roadmap** outlines MISO’s priorities to help its members to reliably achieve their plans and goals. The MISO Roadmap resides on MISO’s [public website](#).

--- MISO Roadmap ---

MARKET REDEFINITION INITIATIVES	2024				2025			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Uncertainty & Variability								
Resource Adequacy - Risk Model, Mitigation and Accreditation								
Market Price Alignment During Scarcity								
Resource Models & Capabilities								
Ensure Sufficient Attributes								
Implement Distributed Energy Aggregated Resources (DEAR)								
Demand Response Participation								
Identifying Locational Needs								
Effective Congestion Hedging								
Deliverability of More Flexible, Quick Ramping Market Products								
Enhance Coordination								
Transmission Capability								
Information to Aid Market Decisions								
Bulk Seams Efficiency								
OPERATIONS OF THE FUTURE INITIATIVES	2024				2025			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Operations Preparedness								
Enable Robust Simulation Environment								
Operations Planning								
More Frequent Model Changes								
Align Operational Planning Processes								
Uncertainty & Variability								
Quantify Net Uncertainty								
Situational Awareness & Critical Communication								
Increase Operator Situational Awareness & Visualization								
Maximize Operator Decision-Making Consistency and Efficiency								
Modernize Control Room Critical Communications								
Operational Continuity								
TRANSMISSION EVOLUTION INITIATIVES	2024				2025			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Long Range & Interregional Transmission Planning								
LRTP Tranche 1: Midwest Least Regrets								
LRTP Tranche 2: Midwest Continued Progression								
LRTP Tranche 3: South Region								
LRTP Tranche 4: Midwest/South Interconnection								
Enhance Joint Transmission Planning with Seams Partners								
Explore New Sustainable Cost Allocation Mechanisms to Fit Future Transmission Needs								
Planning Transformation								
Evolve Planning Tools for Resource Transition								
Enhance System Resiliency and Robustness								
Integrate Planning Model Data (Model Manager Phase 3)								
Resource Utilization								
Streamline Resource Interconnection by Implementing Queue Reforms and Order 2023								
Enhance Visibility into Expected Commercial Operation Dates of New Generation Resources								
SYSTEM ENHANCEMENTS INITIATIVES	2024				2025			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Market System Enhancements								
Next Generation Market System								
Work Anywhere								
Flexible Work Environment								
Hybrid Cloud Capability								
Business Continuity								
Security of the Future								
Identify, Protect Against, and Detect Advanced Threats								
Improve Identity and Access Management Practices								
Data & Analytics								
Curated Environment Enabling Intuitive Data Exploration and Utilization								
Process Framework to Advance Analytical Capabilities and Trusted Decision-Making								
Enterprise Culture Where Robust Data Standards are Embedded and Embraced								



MISO's Role

This report is written from MISO's perspective. However, the responsibility for ensuring grid reliability and resource adequacy in the MISO region is not MISO's alone. It is shared among Load Serving Entities (LSEs), states and MISO, each of which have designated roles to play.

LSEs are utilities, electric cooperatives and other types of entities that are responsible for providing power to end-use customers. In most (though not all) of the MISO region, LSEs have designated service territories and are regulated by state agencies. LSEs have exclusive authority to plan and build new generation resources and to make decisions about retiring existing resources, with oversight from state agencies as applicable by jurisdiction.

MISO performs certain transmission planning functions but does not plan or build new generation or decide which existing resources should retire. MISO exercises functional control of its members' generation and transmission assets with the consent of its members and per the provisions of its Tariff, which is subject to approval by FERC. By operating these assets as efficiently as possible on a region-wide basis, MISO generates substantial cost savings and other reliability benefits that would not otherwise be realized.

MISO also establishes and administers resource adequacy requirements for LSEs and states, as applicable by jurisdiction. These include:

- A **Planning Reserve Margin (PRM)** that sets the level of contractually obligated resources that MISO can call into service when normally scheduled resources go offline for planned or unplanned reasons or when demand surges due to extreme weather conditions or other factors. The PRM is set through MISO's stakeholder process.
- A **Planning Resource Auction (PRA)** that LSEs can use to procure needed resources or sell surplus resources. LSEs can "opt out" of the PRA by using their own resources or negotiating bilateral contracts with other entities.
- **Resource accreditation metrics** that determine how much "credit" various types of resources receive toward meeting resource adequacy requirements based on factors such as their unplanned outage rates.
- **Locational procedures** that determine how much capacity is needed in certain parts of the MISO region for reliability purposes and how much can be imported from and exported to other locations, among other things.

MISO engages with a broad range of stakeholders to share ideas and discuss potential solutions to the challenges facing the region. The Reliability Imperative work also involves a robust, collaborative dialogue across the many forums within the stakeholder process. The collaboration that takes place in these forums has provided valuable policy and technical-related feedback, and MISO is committed to continuing that engagement.



MISO INITIATIVES ARE INTERCONNECTED AND SEQUENCED

MISO's strategic priorities are connected and build upon each other. Success in one area depends on progress in another, so efforts must be coordinated and sequenced. For example, achieving reliable and economically efficient grid operations requires new tools and processes to be developed under the Operations of the Future workstream and market enhancements to be developed under the Market Redefinition workstream.

Given the urgent and complex challenges that are facing the region, it is crucial for MISO members, states and MISO to work together to execute on the reforms that are needed.

The MISO Value Proposition

MISO creates substantial cost savings and other benefits by managing the grid system on a regional basis that spans all or parts of 15 states and one Canadian province. Before MISO was created, the system was managed by 39 separate Local Balancing Authorities (LBAs), which made the grid much more fragmented and far less economically efficient than it is today.

The benefits that MISO created in calendar year 2022 range from \$3.3 billion to \$4.5 billion, according to the [Value Proposition study](#) that MISO performs every year. That represents a benefit-to-cost ratio of about 12:1 when compared to the fees that utilities pay to be members of MISO. MISO creates benefits in a variety of ways, including through efficient dispatch and reduced need for assets. Since the Value Proposition study was launched in 2007, the cumulative benefits that MISO has created exceed \$40 billion. And notably, that figure does not reflect all the benefits MISO creates due to the conservative approach that MISO uses to conduct the study.

While continuing to use this conservative approach, MISO anticipates that it will create even more benefits going forward by helping its members and states to achieve their decarbonization goals in a reliable manner. In June 2022, MISO looked at those anticipated future benefits in a supplemental report called the [Forward View of the Value Proposition](#). That report estimates the value that MISO will create going forward in two ways that are not specifically reflected in the "standard" Value Proposition study: (1) the value of sharing carbon-free energy from areas with higher levels of renewables to regions with lower levels, and (2) the value of sharing flexibility attributes that are required to integrate those new renewables while maintaining reliability.

MISO found that by including these two additional value streams, MISO's total benefit-to-cost ratio would increase from approximately 12:1 today to approximately 26:1 by 2040. This illustrates that while there are indeed many challenges associated with fleet change, there are also tremendous economic benefits that utilities and states can realize by pursuing their decarbonization goals as members of MISO.



Informing the Reliability Imperative

MISO's response to the Reliability Imperative has been informed by years of conversations with stakeholders. MISO has also undertaken numerous studies to assess the region's changing risk profile and to explore how reliability is being affected by various drivers. This work includes:

Attributes Roadmap: This study looks at three key electric system attributes where near-term risk is most acute: (1) System Adequacy, (2) Flexibility and (3) System Stability. The Attributes Roadmap recommends advancing a combination of current and new proposals as well as providing ongoing attributes visibility through regular reporting.



Renewable Integration Impact Assessment (RIIA): This study assesses the impacts of integrating increasingly higher levels of renewables into the MISO system. RIIA indicates that planning and operating the grid will become significantly more complex when greater than 30% of load is served by wind and solar. However, RIIA also indicates that renewable penetrations of greater than 50% could be reliably achieved if utilities, states, and MISO coordinate closely on needed actions.



Regional Resource Assessment (RRA): The RRA is a recurring study based on the plans and goals MISO members have publicly announced for their generation resources. The RRA aggregates these plans and goals to develop an indicative view of how the region's resource mix might evolve to meet utilities' stated objectives. The RRA aims to help utilities and states identify new and shifting risks years before they materialize, creating a window to develop cost-effective solutions.



MISO Futures: The MISO Futures utilize a range of economic, policy and technological inputs to develop three future scenarios that "bookend" what the region's resource mix might look like in 20 years. The Futures inform the development of transmission plans and help MISO prioritize work under the Reliability Imperative. Series 1 was published in 2021. In 2023, MISO updated the report to Series 1A to reflect evolving member/state plans and the clean energy incentives in the Inflation Reduction Act, among other things.

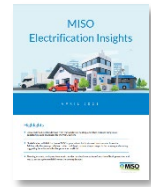


Markets of the Future: This report illustrates how and when MISO's market structures will need to evolve in order to accommodate the transformation of the energy sector. The needs are presented in four broad categories: (1) Uncertainty and Variability, (2) Resource Models and Capabilities, (3) Location and (4) Coordination. This report helped establish the foundation for the work MISO is currently doing to identify critical system attributes.



The February (2021) Arctic Event: This report discusses lessons learned from Winter Storm Uri, which affected the MISO region and other parts of the country in February 2021. MISO and its members took emergency actions during the event to prevent more widespread grid failures. Uri illustrated how extreme weather can exacerbate the challenges of fleet change. Preparing for extreme weather is a major part of MISO's response to the Reliability Imperative.





Electrification Insights: This report explores the challenges and opportunities the grid could face from the growth of electric vehicles and the increasing electrification of other sectors of the economy, such as homes and businesses. The report indicates electrification could transform the MISO grid from a summer-peaking to a winter-peaking system, and that vehicle charging and daily heating and cooling load could result in two daily power peaks nearly all year.

From this groundwork, we know there are many challenges ahead. But we also believe we can respond to the Reliability Imperative in a manner that enables our members to achieve their resource plans and policy objectives. We are determined to do the hard work required to ensure our members benefit from MISO membership.

Acronyms Used in This Report

DER: Distributed Energy Resource

FERC: Federal Energy Regulatory Commission

GW: Gigawatt

JTIQ: Joint Targeted Interconnection Queue

LBA: Load Balancing Authority

LSE: Load Serving Entity

LRTP: Long Range Transmission Planning

MSC: Market Subcommittee

MISO: Midcontinent Independent System Operator

MSE: Market System Enhancement

MTEP: MISO Transmission Expansion Plan

MW: Megawatt

NERC: North American Electric Reliability Corporation

OMS: Organization of MISO States

PAC: Planning Advisory Committee

PRA: Planning Resource Auction

PRM: Planning Reserve Margin

RBDC: Reliability-Based Demand Curve

RIIA: Renewable Integration Impact Assessment

RRA: Regional Resource Assessment

SPP: Southwest Power Pool

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Attachment W

**2025 OMS-MISO Survey Results, OMS and MISO
(Updated June 6, 2025)**



2025 OMS-MISO Survey Results

Furthering our joint commitment to regional resource adequacy, OMS and MISO are pleased to announce the results of the 2025 OMS-MISO Survey

June 6, 2025

Updated 6/6/2025: Slide 21

The 2025 OMS-MISO Survey reinforces near-term risks and highlights key uncertainties impacting resource adequacy

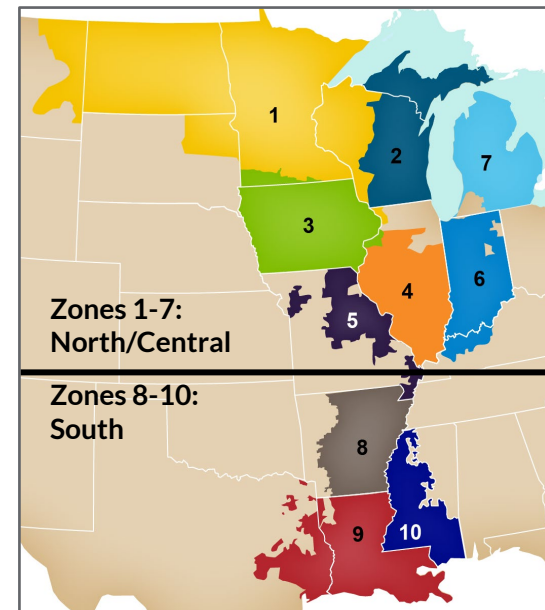
- Projections result in a potential surplus ranging from 1.4 GW to 6.1 GW for summer 2026. At least 3.1 GW* of additional capacity beyond the committed capacity will be needed to meet the projected planning reserve margin forecast.
- Queue and market reforms, improved resource deployment timelines and other initiatives will help maintain resource adequacy through 2031.
 - Replacement and surplus queue projects will mitigate the impact of retirements by using existing interconnection service, supplying ~25% of new capacity additions.
- As solar penetration grows, reliability risks are spreading into winter from summer.
- Load growth, driven by economic development, is outpacing previous forecasts with a 2.2% compound annual growth rate over five years.
- Resource accreditation reforms (e.g., Direct Loss of Load in PY 2028/29) are expected to provide a clearer view of resource adequacy, system-level outlooks remain consistent with current methods.

All references to capacity in this presentation indicate seasonal accredited capacity (SAC), unless noted otherwise.

The OMS-MISO Survey provides a resource adequacy view over a five-year horizon based on currently available information

The survey* results indicate the degree to which expected capacity resources satisfy planning reserve margin requirements with either a surplus or a deficit

- 91% of existing generation participated in the 2025 OMS-MISO Survey, representing 97.4% of MISO load.
- Various projected capacity scenarios and large spot-load additions highlight the increasing uncertainty and evolving risk.
- Load Serving Entities (LSEs) are expected to have adequate resources to meet load reserve requirements in each zone.
- MISO zonal views are not included this year as the annual capacity import limit and capacity export limit study will provide value updates and be reported in the Loss of Load Expectation report in November.



Additional factors can impact projected deficits or surpluses that are observed in the survey



Downside Risks





- Winter reliability risk intensifies due to low solar accreditation during the season
- Rapid industrial and commercial growth adds pressure on resource adequacy
- Continued backlog and uncertainty in generation queue (296 GW) complicates timely resource additions
 - 54 GW of signed Generation Interconnection Agreements (GIAs) not yet online (71% of which are wind and solar)
- Accelerated pace of resource retirements is driven by regulatory pressures, economic pressures and aging infrastructure
- Persistent supply-chain disruptions, labor constraints and permitting challenges delay new resource deployments



Upside Possibilities

- Market reforms, including Reliability-Based Demand Curve and accreditation updates, provide clearer and stronger investment signals
- Enhanced forecasting methods recognizing replacement/surplus units improve accuracy and confidence
- Queue reforms reduce speculative projects and streamline resource integration processes
- Retirement deferrals offer a potential short-term reliability buffer against seasonal projected capacity shortfalls
- Easing of supply, labor, or permitting constraints could speed deployments

Summer Seasonal Accreditation Values

Resource Category	2025 Survey	2024 Survey
 Potentially Unavailable Resources	<ul style="list-style-type: none"> No Changes 	<ul style="list-style-type: none"> Indicated as “Low Certainty” in survey results by market participants Includes potential retirements or suspensions Assumes resources will not be used to meet PRMR
 Potential New Capacity – New Point of Interconnection	<ul style="list-style-type: none"> Historical Projection: Results in 3.5 GW/yr <ul style="list-style-type: none"> <i>Driven by 2022-2024 actuals</i> Emerging Projection: Results in 6.2 GW/yr average <ul style="list-style-type: none"> <i>Informed by member responses to OMS-MISO Survey request, these members represent 97% of the load in the footprint</i> <i>Fuel mix of new resources indicated by OMS-MISO Survey member responses</i> 	<ul style="list-style-type: none"> Using 3-Year Historical Average: Capacity addition (2.3 GW/yr) based on the average new capacity built in Planning Years 2020-2022 Using Alternative Projection: Informed by timing estimates from interconnection customers with signed Generator Interconnection Agreement projects* (6.1 GW/yr) Assumes resources will be used to meet PRMR
 Replacement/ Surplus Project Impact Potential New Capacity – Existing Point of Interconnection	<ul style="list-style-type: none"> Replacement Impact Highlighted: Results in additional “new resources” to offset the impacts of retirements Historical Replacement : Valued at 1.2 GW/yr <ul style="list-style-type: none"> <i>50% replacement & surplus queue adoption</i> Emerging Replacement: Valued at 2.4 GW/yr <ul style="list-style-type: none"> <i>100% replacement & surplus queue adoption</i> <i>The replacement queue is not directly part of MISO’s queue cycle methodology, and until recently the adoption rate of future replacement resources was unknown</i> 	<ul style="list-style-type: none"> Not included
 Committed Capacity	<ul style="list-style-type: none"> No Changes 	<ul style="list-style-type: none"> Existing generation resources External resources with firm contracts to MISO load Assumes resources will be used to meet PRMR

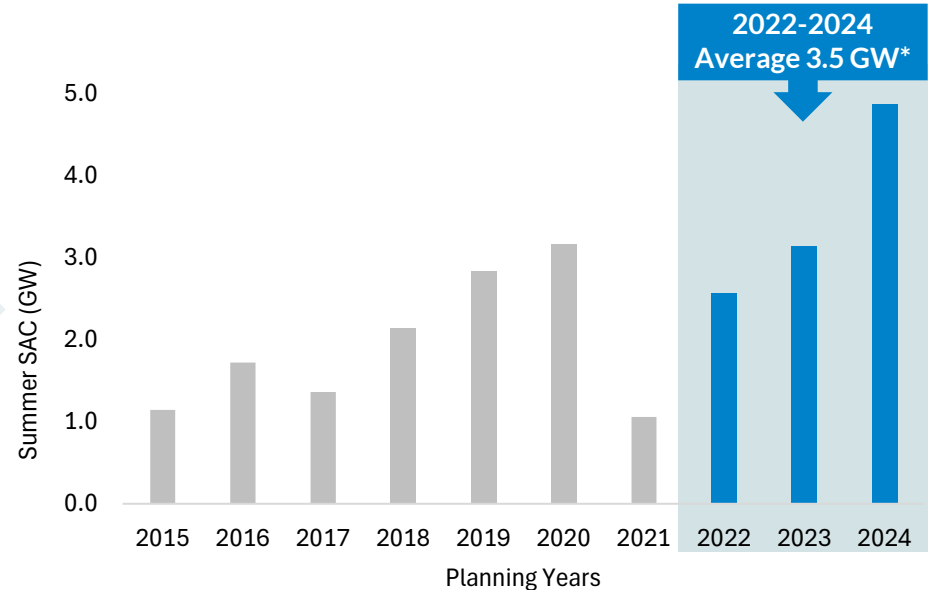
Trends and market pressures related to new capacity additions suggest that refinements are needed to better reflect uncertainty

Previously, MISO used probability-adjusted estimates for projects in various queue phases. Due to the significantly larger queue and constraints on projects with signed Generation Interconnection Agreements (GIAs), this approach no longer applies. As in 2024, the 2025 survey employs two estimates:

- 1. Three-Year Historical Average:** based on the historical rate of additions per planning year*
- 2. Emerging Projection:** based on member submittals to the OMS-MISO Survey

These projections are combined with the MISO Surplus and Replacement Queues to create bookend capacity forecasts for the MISO footprint.

The scale and pace of new resource additions have varied over time

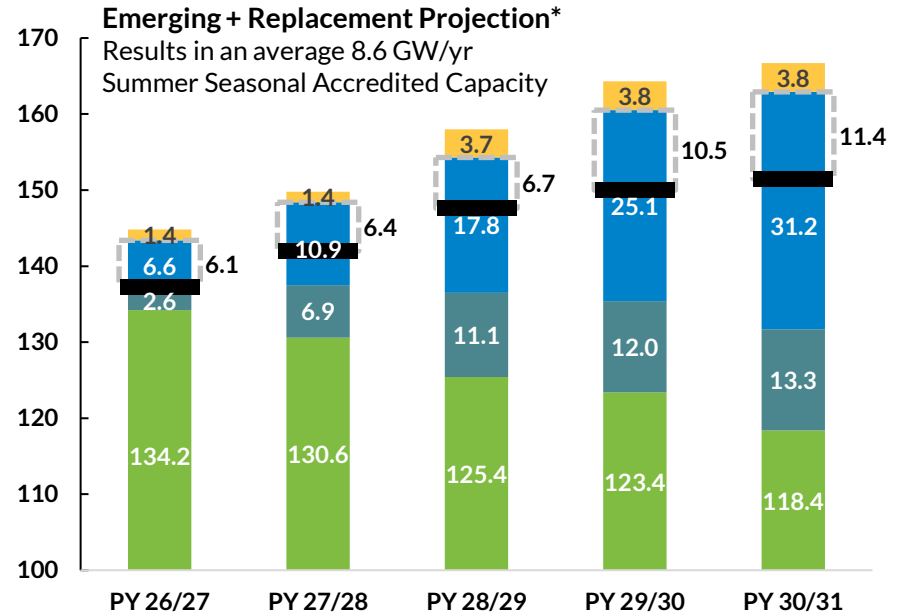
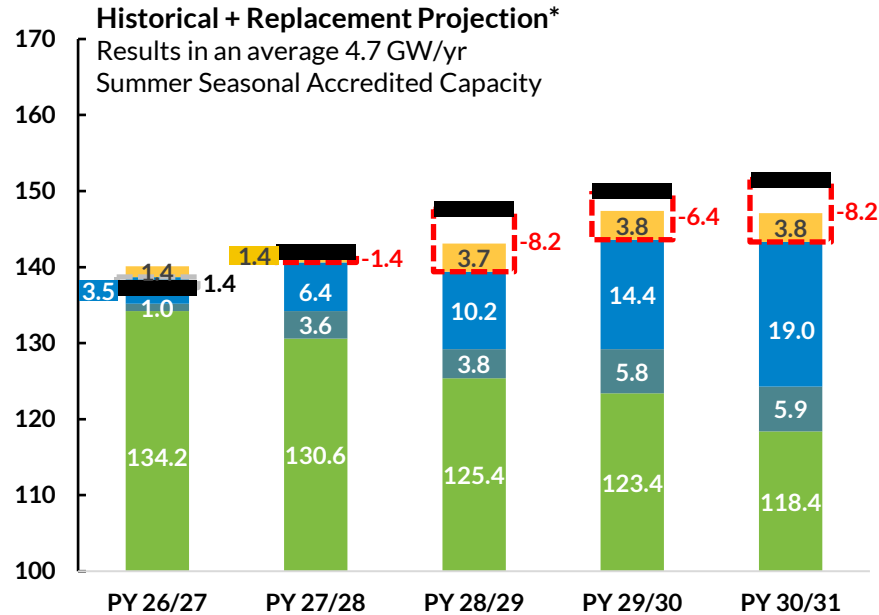


Queue applications: Nameplate 296 GW Queue & 54 GW Signed GIAs not yet online (as of 5/14/25)

Historical + Replacement & Emerging + Replacement Projections vs PRMR

~4.7 GW & 8.6 GW Status Quo Summer SAC Installation Rate

MISO Resource Adequacy Projections – Summer



- Projected PRMR with LSE forecast
- Potentially Unavailable Resources
- Potential New Capacity
- Value of Replacement/Surplus Projects
- Committed Capacity





*Using methods for potential New Capacity described on Slide 5

PRMR: Planning Reserve Margin Requirement

- Red border values indicate the additional potential deficit against the Projected PRMR
- Gray border values indicate the potential surplus against the Projected PRMR

- Capacity accreditation values and Planning Reserve Margin projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart

Winter Seasonal Accreditation Values

Resource Category	2025 Survey	2024 Survey
 Potentially Unavailable Resources	<ul style="list-style-type: none"> No Changes 	<ul style="list-style-type: none"> Indicated as “Low Certainty” in survey results by market participants Includes potential retirements or suspensions Assumes resources will not be used to meet PRMR
 Potential New Capacity – New Point of Interconnection	<ul style="list-style-type: none"> Historical Projection: Results in 1.4 GW/yr <ul style="list-style-type: none"> <i>Driven by 2022-2024 actuals</i> Emerging Projection: Results in 4.1 GW/yr average <ul style="list-style-type: none"> <i>Informed by member responses to OMS-MISO Survey request, these members represent 97% of the load in the footprint</i> <i>Fuel mix of new resources indicated by OMS-MISO Survey member responses</i> 	<ul style="list-style-type: none"> Not included
 Replacement/ Surplus Project Impact Potential New Capacity – Existing Point of Interconnection	<ul style="list-style-type: none"> Replacement Impact Highlighted: Results in additional “new resources” to offset the impacts of retirements Historical Replacement : Valued at 1.0 GW/yr <ul style="list-style-type: none"> <i>50% replacement & surplus queue adoption</i> Emerging Replacement : Valued at 2.1 GW/yr <ul style="list-style-type: none"> <i>100% replacement & surplus queue adoption</i> <i>The replacement queue is not directly part of MISO’s queue cycle methodology, and until recently the adoption rate of future replacement resources was unknown</i> 	<ul style="list-style-type: none"> Not included
 Committed Capacity	<ul style="list-style-type: none"> No Changes 	<ul style="list-style-type: none"> Existing generation resources External resources with firm contracts to MISO load Assumes resources will be used to meet PRMR

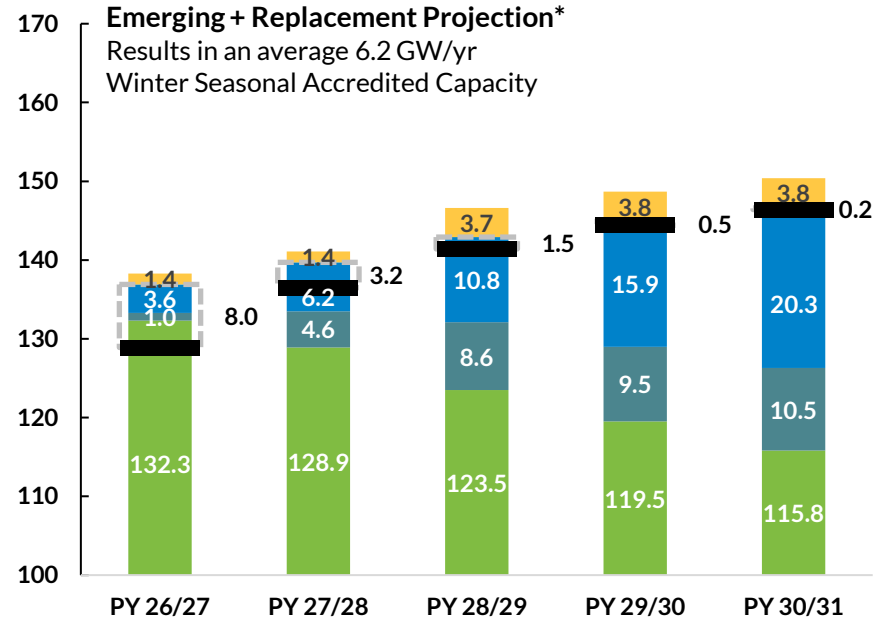
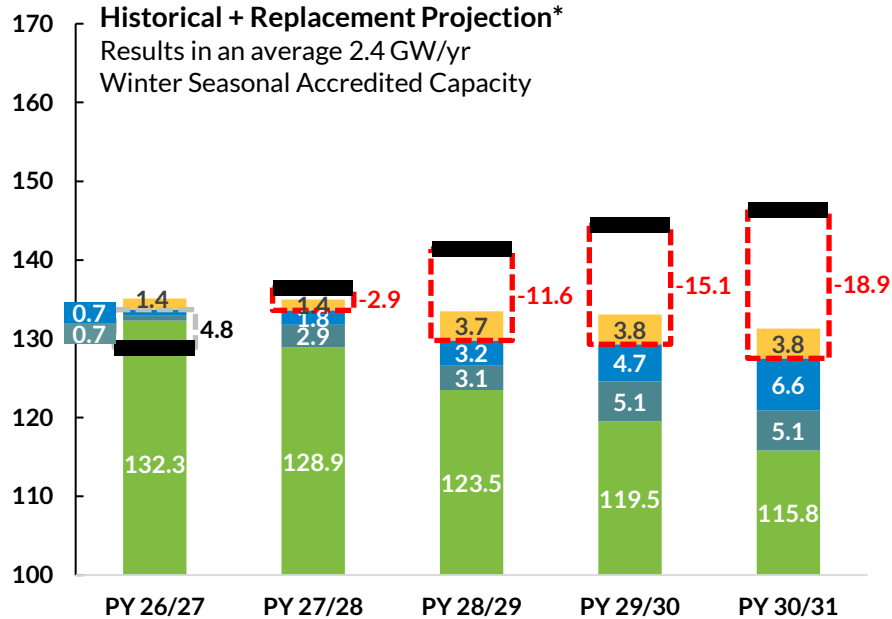
PRMR: Planning Reserve Margin Requirement

Committed Capacity: Resources committed to serving MISO’s load

Potentially Unavailable Resources: May be available to serve MISO’s load but may not have firm commitments

Historical + Replacement & Emerging + Replacement Projections vs PRMR ~2.4 GW & 6.2 GW Status Quo Winter SAC Installation Rate

MISO Resource Adequacy Projections – Winter



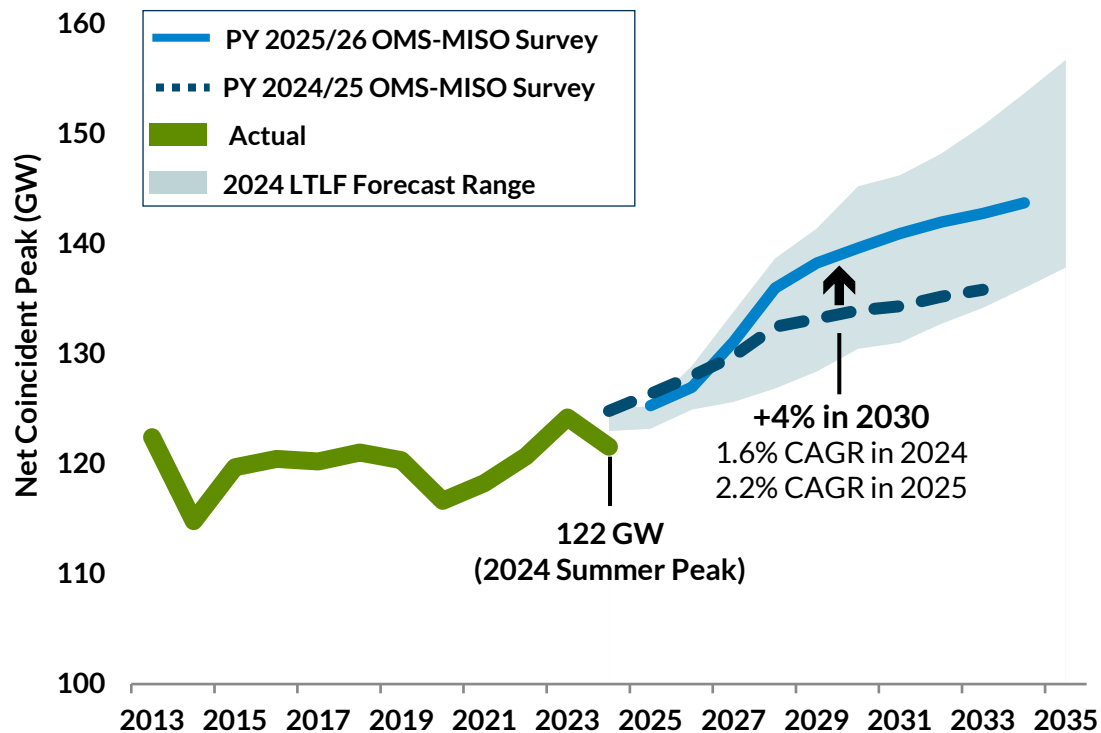
- Projected PRMR with LSE forecast
- Potentially Unavailable Resources
- Potential New Capacity
- Value of Replacement/Surplus Projects
- Committed Capacity

*Using methods for potential New Capacity described on Slide 8
PRMR: Planning Reserve Margin Requirement

- Red border values indicate the additional potential deficit against the Projected PRMR
- Gray border values indicate the potential surplus against the Projected PRMR

- Capacity accreditation values and Planning Reserve Margin projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart

OMS-MISO Survey responses show increasing load forecasts year-over-year and are close to the high end of MISO Long-Term Load Forecast



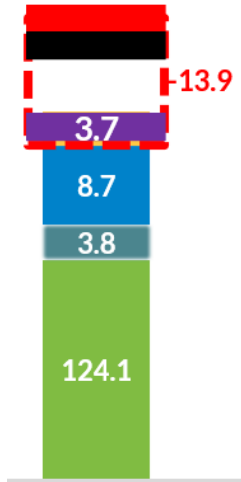
- Load growth through 2035 will exacerbate capacity shortfall and operational risks
- Many new loads will require additional firm, controllable resources

Anticipated Impact in MISO's region 2024-44 Growth TWh Low-High*



- High
- Data Centers (149-241)
- Electric Vehicles (54-91)
- Industry Development & Offshoring (21-105)
- Hydrogen (25-95)
- Low
- Building Electrification (36-43)

NEW: The 2025 OMS-MISO Survey includes sensitivities considering a range of new, large spot-load additions



PY 28/29

*Illustrative example:
PY 2026/27 using three-
year historical average*

PRMR based on Long-Term Load Forecast “High Trajectory”

- Models higher load-growth scenario per Long Term Load Forecast¹
- Red dashed border values = deficit; gray dashed border values = surplus

PRMR based on LSE submitted load forecast

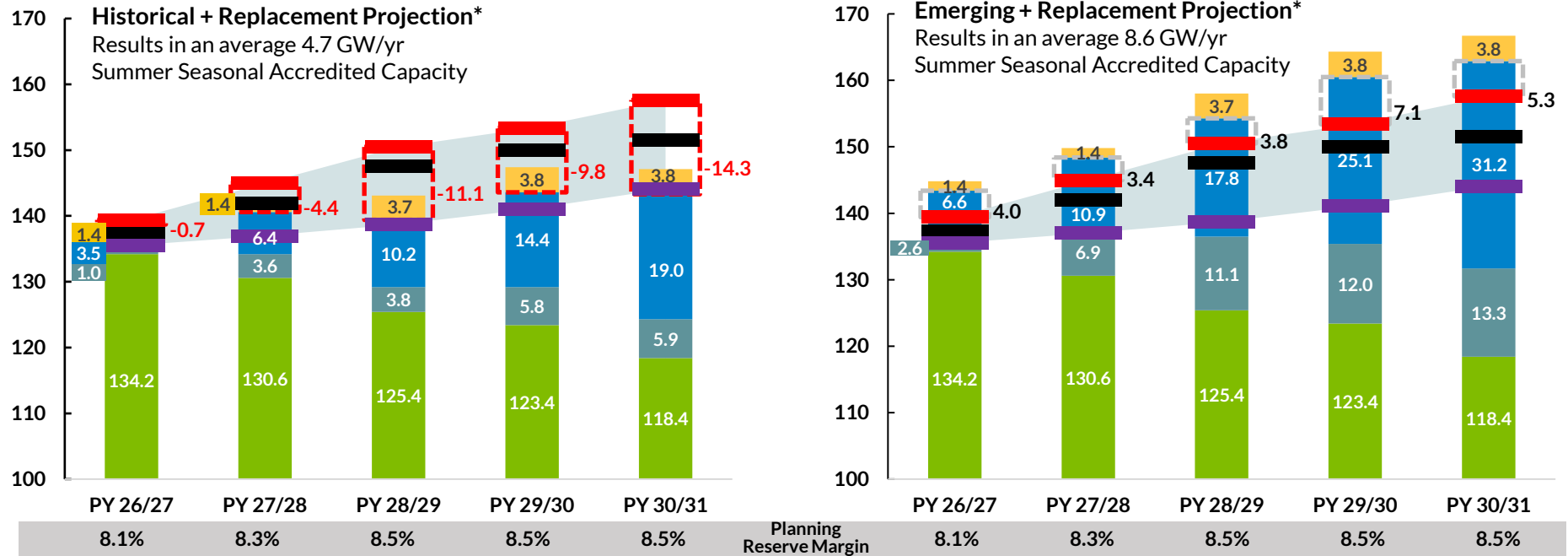
- LSE-submitted Non-Coincident Peak Forecast (NCPF) converted to Coincident Peak Forecast (CPF) using MISO-posted coincidence factors
- Transmission losses added
- PRMR calculated using out year PRM% from PY 2025/26 LOLE Study

PRMR based on Long-Term Load Forecast “Current Trajectory”

- Models lower load-growth scenario per Long-Term Load Forecast¹

Capacity deficits continue to grow in the near and long term under a large spot-load additions scenario

MISO Resource Adequacy Projections – Summer



- Projected PRMR for 'High Trajectory' scenario
- Projected PRMR for 'Current Trajectory' scenario
- Projected PRMR with LSE forecast
- Potentially Unavailable Resources
- Potential New Capacity
- Value of Replacement/Surplus Projects
- Committed Capacity
- Shaded area indicates spread between projected PRMR for "Current Trajectory" and "High Trajectory" scenario from Long-term Load Forecast
- Red border values indicate the additional potential deficit with "High Trajectory" scenario case
- Gray border values indicate the potential surplus with "High Trajectory" scenario case
- Capacity accreditation values and Planning Reserve Margin projections based on current practices
- *Using Potential New Capacity as described on Slide 5.
- PRMR: Planning Reserve Margin Requirement

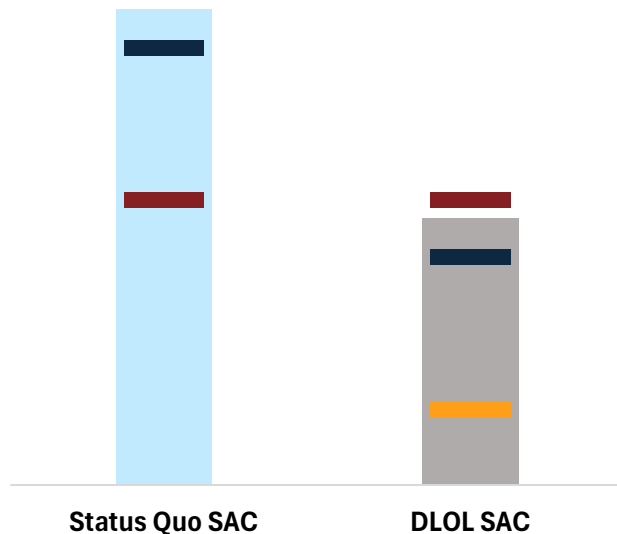
MISO's existing accreditation methods can overstate a resource's capacity value during the highest risk periods, especially as the region's risk profile changes, leading to understated risk

- Increased reliance on wind, solar and storage, projected large-load additions and electrification, and frequent large-scale weather events are decoupling periods of risk from periods of high demand.
- These drivers are upending traditional methods for establishing reliability requirements and resource accreditation.
- MISO's resource accreditation methodology* (Direct Loss of Load) will value a resource's marginal contribution to reliability during the highest risk periods.

MISO's accreditation reforms, targeted for implementation in PY 2028/29, will better measure a resource's contribution to reliability.

High Level Description of Status Quo vs Direct Loss of Load

Comparing Accreditation for Status Quo & DLOL SAC



Peak Load Forecast

- Submitted annually by members

Critical Hours Load Forecast

- Illustrative only, not collected

Planning Reserve Margin Requirement (PRMR) at

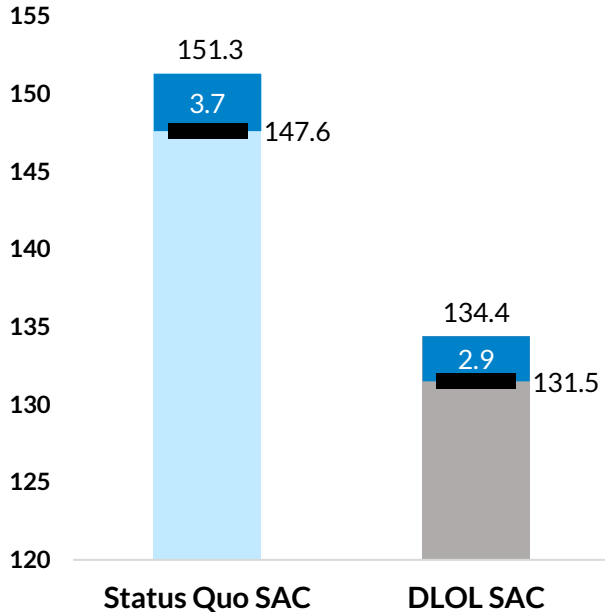
- Status Quo: Peak Load
- DLOL: critical hours

Light Blue: Status Quo SAC value of Resources during MISO peak to meet PRMR

Grey: DLOL SAC value of Resources during critical hours to meet PRMR

Status Quo vs Direct Loss of Load Accreditation for summer 2028

Comparing Accreditation from Status Quo & DLOL Seasonal Accredited Capacity Summer 2028 (GW)



- In principle, surplus/deficit moving from status quo to DLOL SAC should remain unchanged
- Modeled load and resource mix that is misaligned from OMS-MISO Survey results will cause deviations in surplus/deficit
- PY 2028/29 was most comparable in load and resource mix, which is why DLOL view is only shown for one year

- Planning Reserve Margin Requirement (PRMR)
- Surplus (Nearly equivalent between Status Quo & DLOL)
- Status Quo SAC value of Resources during MISO peak to meet PRMR
- DLOL SAC value of Resources during critical hours to meet PRMR

MISO has acted on many Reliability Imperative initiatives to address resource adequacy challenges, but there's more to be done

Ongoing Challenges

- Accelerating demand for electricity
- Rapid pace of generation retirements continue
- Loss of accredited capacity and reliability attributes
- Intermittent nature of new resource additions
- Delays of new resource additions
- More frequent extreme weather

Completed Initiatives

- ✓ Implemented Reliability-Based Demand Curve in 2025 PRA
- ✓ Generation interconnection queue cap
- ✓ Improved generator interconnection queue process (*New application portal June 2025*)
- ✓ Approved over \$30 billion in new transmission lines

Initiatives In Progress

- ❑ Implement interim Expedited Resource Addition Study (ERAS) process (2025)
- ❑ Implement Direct Loss of Load (DLOL)-based accreditation (PY 2028/29)
- ❑ Enhance resource adequacy risk modeling
- ❑ Reduce queue cycle times through automation
- ❑ Demand Response and Emergency Resource reforms
- ❑ Enhance allocation of resource adequacy requirements

The 2025 OMS-MISO Survey emphasizes that decisions made today by utilities, regulators, MISO and its members will critically shape future resource adequacy

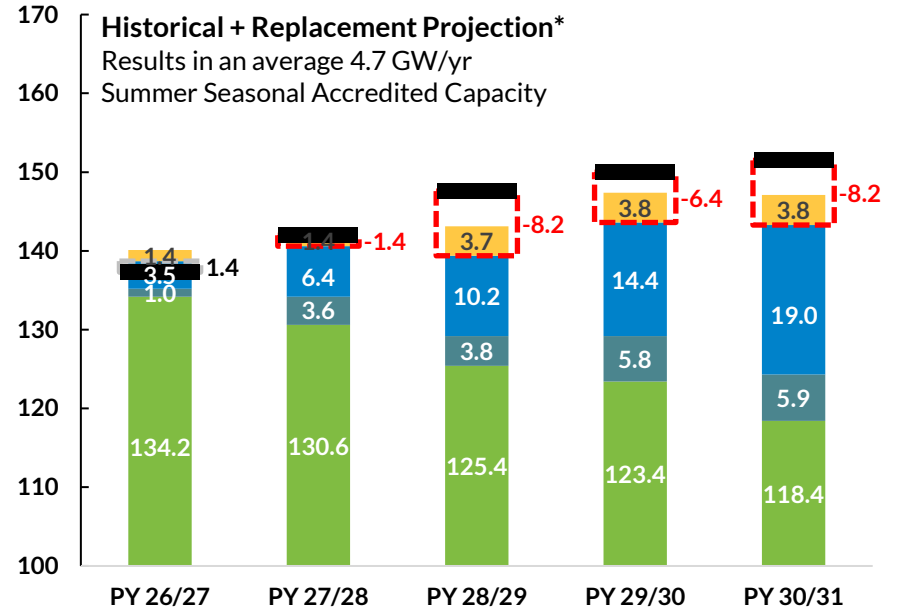
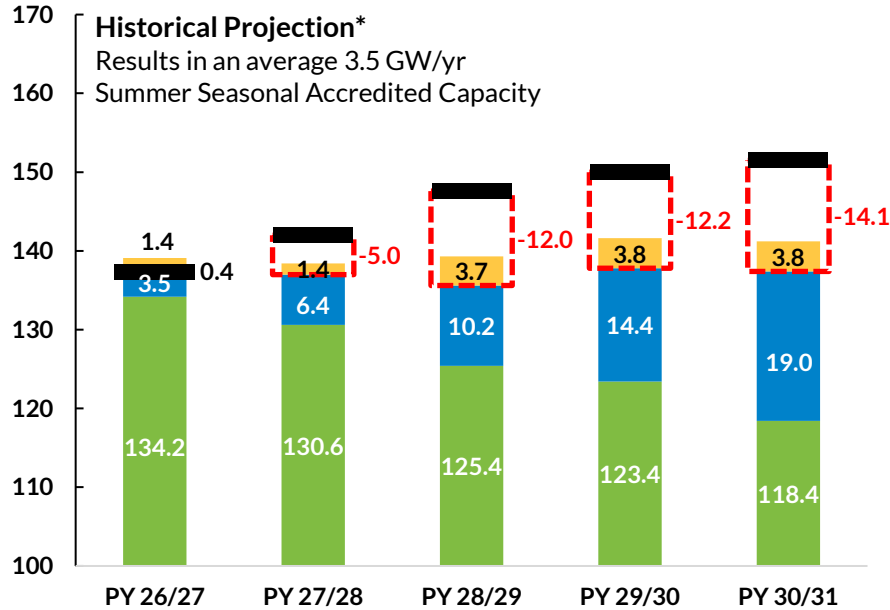
- This year's survey highlights significant uncertainty in projected resource adequacy, underscoring the urgent need for accelerated resource additions, strategic retirement planning, and proactive management of increasing load growth.
- Ongoing collaboration between OMS and MISO remains essential to address intensifying reliability risks, particularly as seasonal challenges, especially in winter, grow increasingly complex.
- Continued and immediate actions are required to streamline the addition of new capacity, align resources effectively with new load demands.
- MISO's ongoing resource adequacy reforms remain critical and responsive, directly addressing evolving reliability challenges.

Appendix

Historical & Historical + Replacement Projections vs PRMR

~3.5 GW & 4.7 GW Status Quo Summer SAC Installation Rate

MISO Resource Adequacy Projection – Summer



- Projected PRMR with LSE forecast
- Potentially Unavailable Resources
- Potential New Capacity
- Value of Replacement/Surplus Projects
- Committed Capacity

*Using methods for potential New Capacity described on Slide 5
PRMR: Planning Reserve Margin Requirement

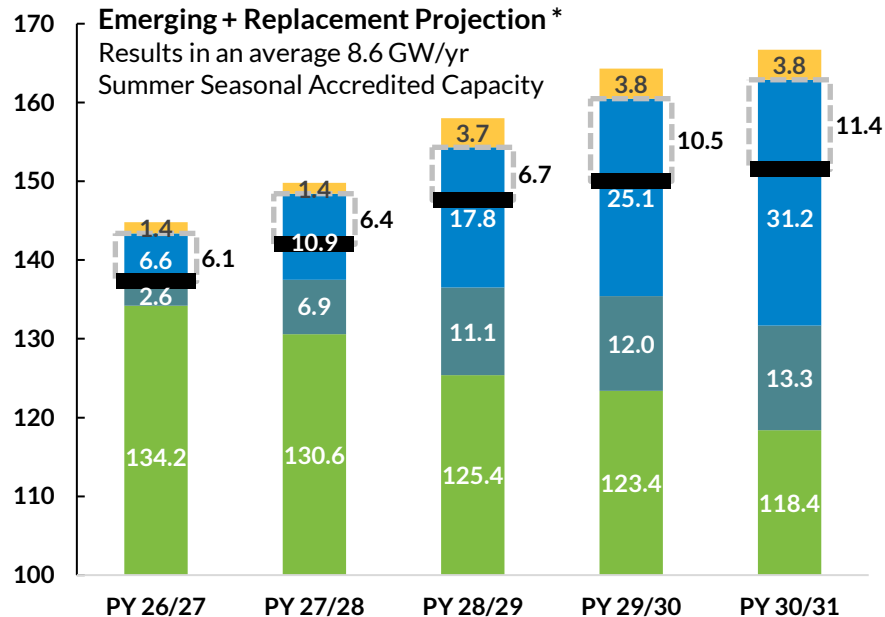
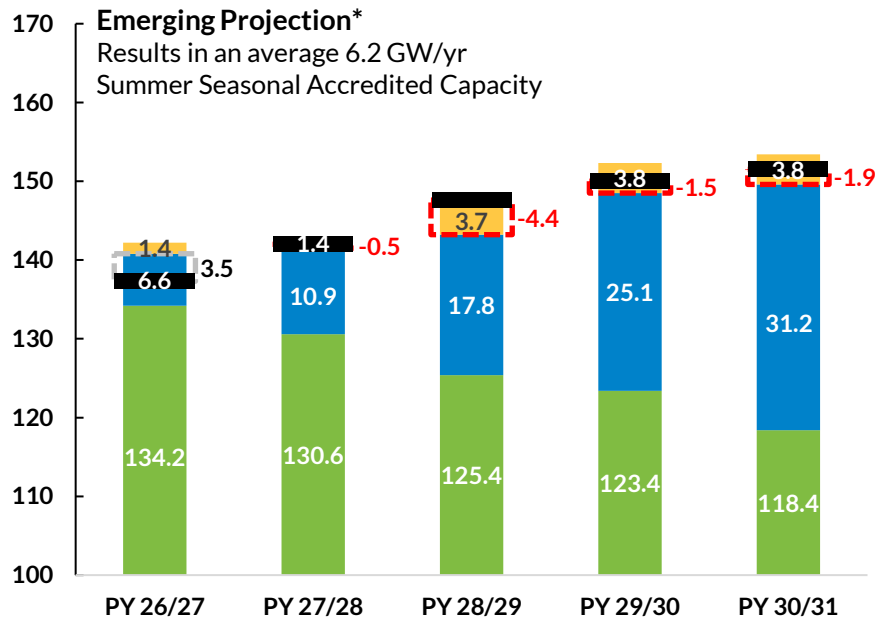
- Red border values indicate the additional potential deficit against the Projected PRMR
- Gray border values indicate the potential surplus against the Projected PRMR

- Capacity accreditation values and Planning Reserve Margin projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart

Emerging & Emerging + Replacement Projections vs PRMR

~6.2 GW & 8.6 GW Status Quo Summer SAC Installation Rate

MISO Resource Adequacy Projection – Summer



- Projected PRMR with LSE forecast
- Potentially Unavailable Resources
- Potential New Capacity
- Value of Replacement/Surplus Projects
- Committed Capacity

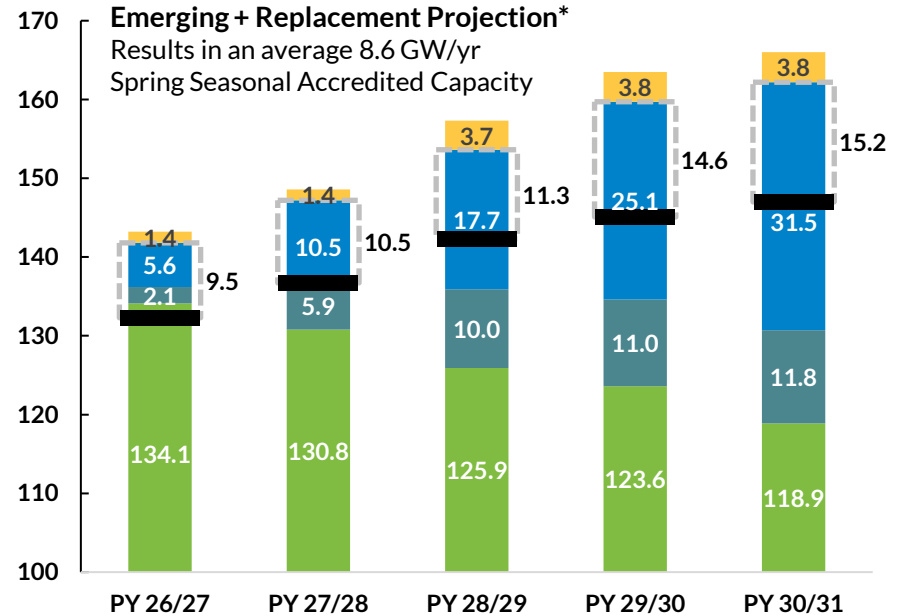
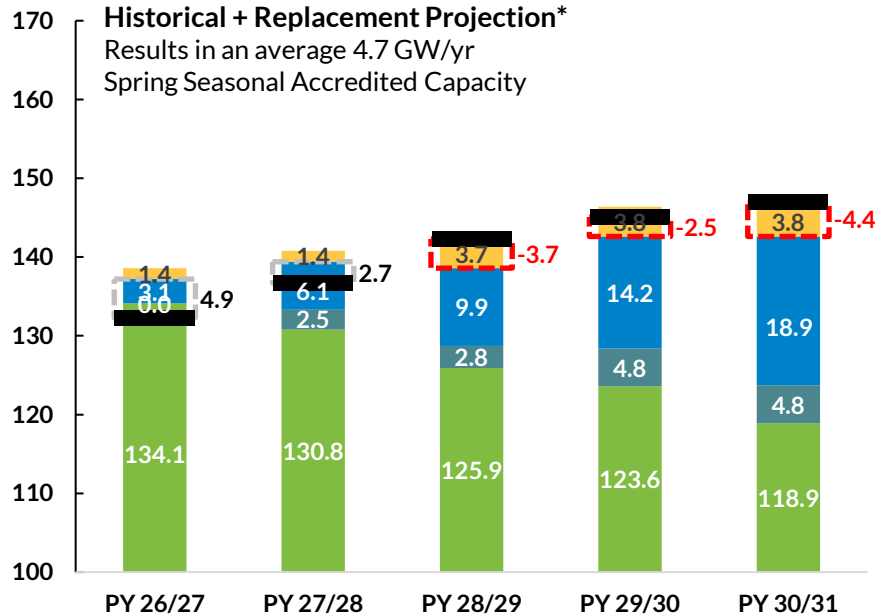
*Using methods for potential New Capacity described on Slide 5
PRMR: Planning Reserve Margin Requirement

- Red border values indicate the additional potential deficit against the Projected PRMR
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- Capacity accreditation values and Planning Reserve Margin projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart

Historical + Replacement & Emerging + Replacement Projections vs PRMR ~4.7 GW & 8.6 GW Status Quo Fall SAC Installation Rate

MISO Resource Adequacy Projection – Fall



- Projected PRMR with LSE forecast
- Potentially Unavailable Resources
- Potential New Capacity
- Value of Replacement/Surplus Projects
- Committed Capacity

*Using methods in line with potential New Capacity described on Slide 5

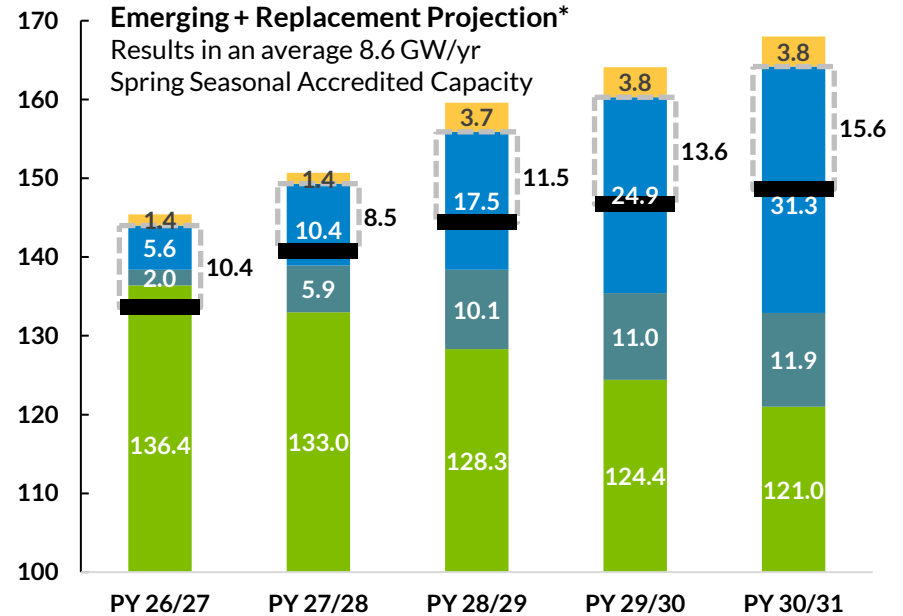
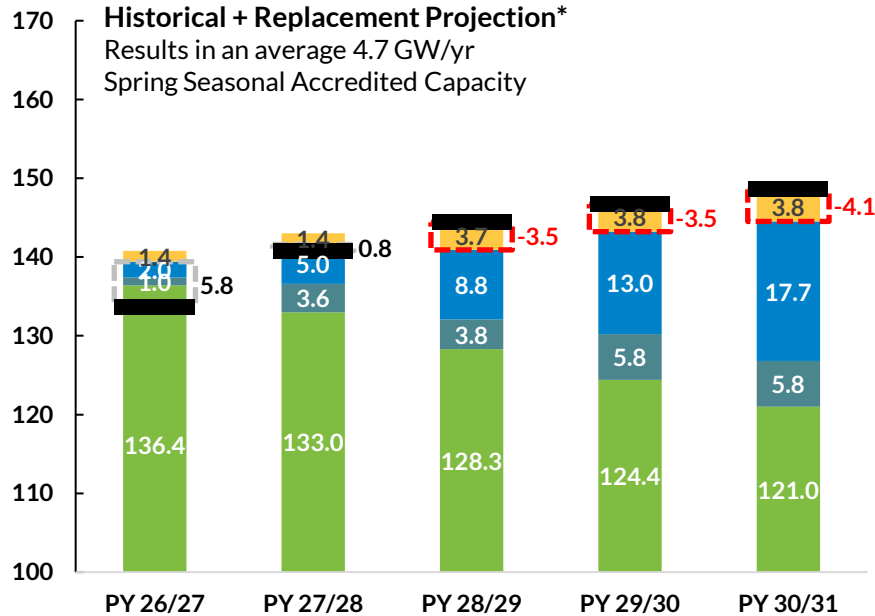
PRMR: Planning Reserve Margin Requirement

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- Capacity accreditation values and Planning Reserve Margin projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart

Historical + Replacement & Emerging + Replacement Projections vs PRMR ~4.7 GW & 8.6 GW Status Quo Spring SAC Installation Rate

MISO Resource Adequacy Projection – Spring



- Projected PRMR with LSE forecast
- Potentially Unavailable Resources
- Potential New Capacity
- Value of Replacement/Surplus Projects
- Committed Capacity

*Using methods in line with potential New Capacity described on Slide 5

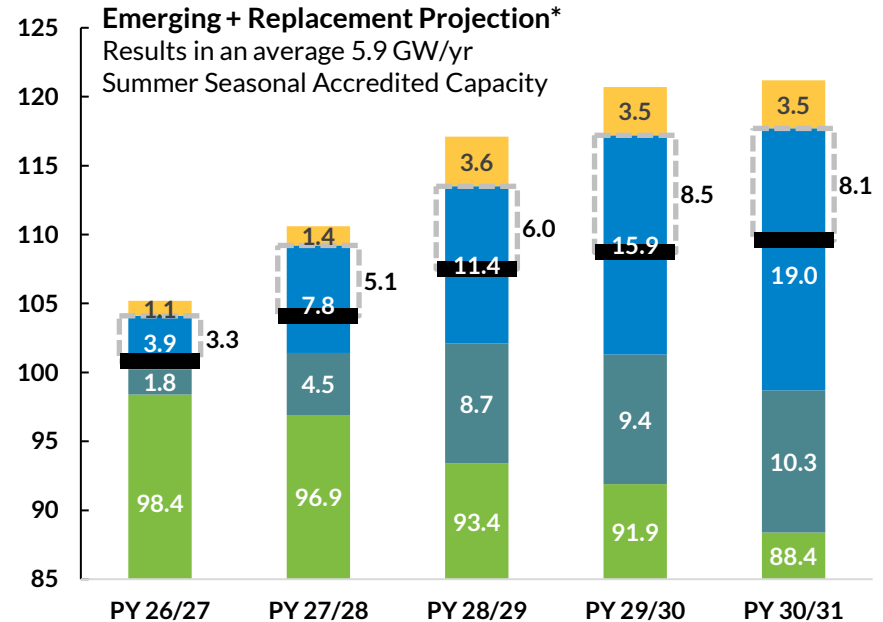
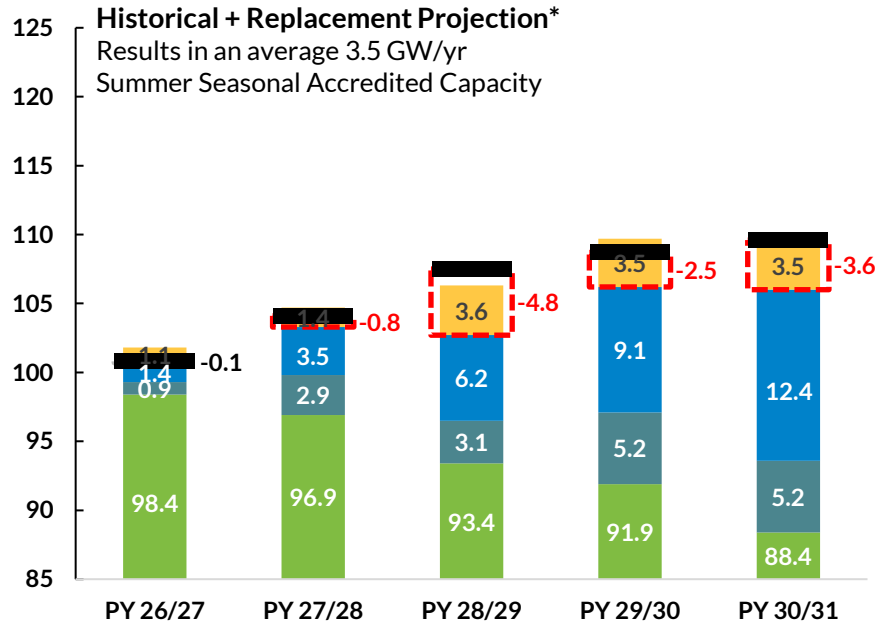
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- Capacity accreditation values and Planning Reserve Margin projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart

Historical + Replacement & Emerging + Replacement Projections vs PRMR ~4.7 GW & 8.6 GW Status Quo Summer SAC Installation Rate

MISO Resource Adequacy Projections – Summer MISO North/Central



- Projected PRMR with LSE forecast
- Potentially Unavailable Resources
- Potential New Capacity
- Value of Replacement/Surplus Projects
- Committed Capacity

*Using methods for potential New Capacity described on Slide 5
PRMR: Planning Reserve Margin Requirement

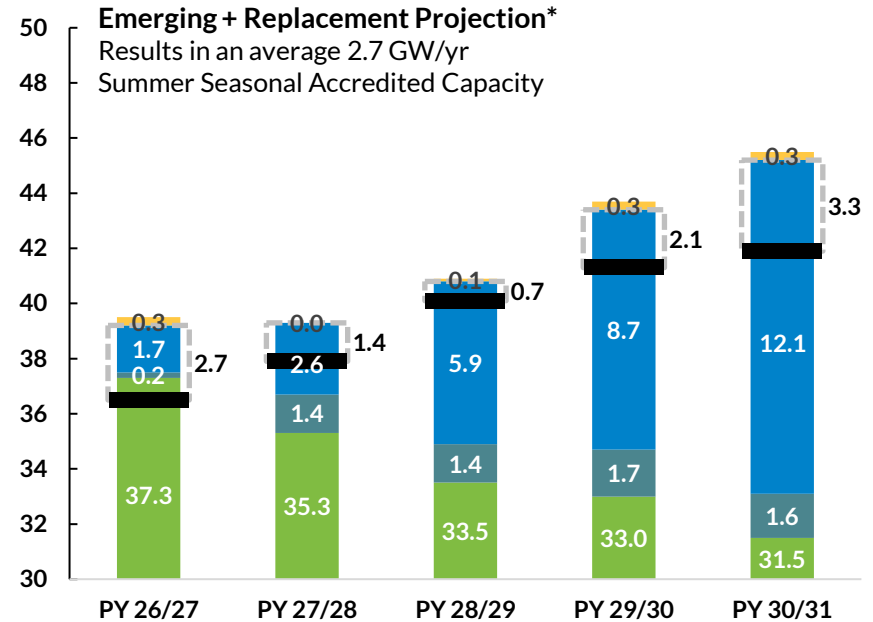
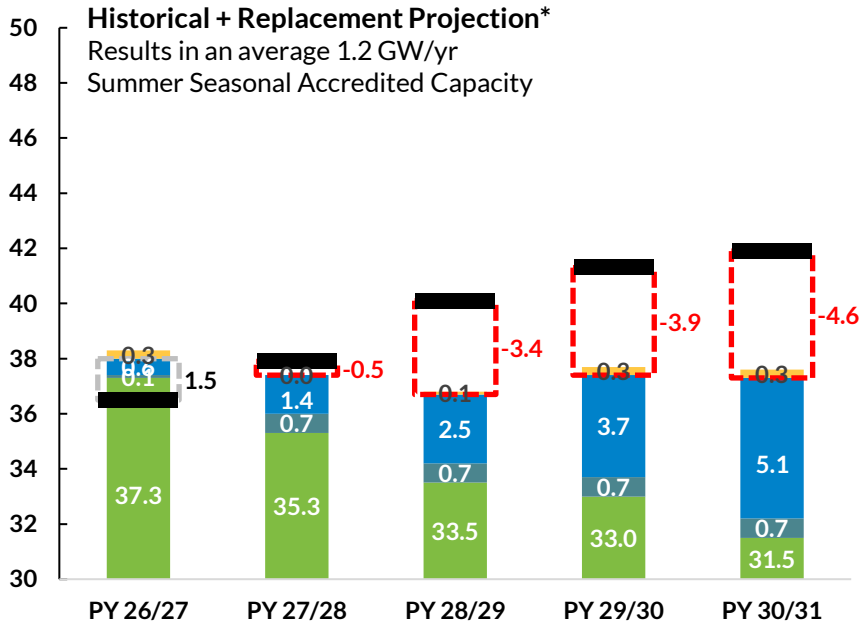
- Red border values indicate the additional potential deficit against the Projected PRMR
- Gray border values indicate the potential surplus against the Projected PRMR

- Capacity accreditation values and Planning Reserve Margin projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart

Historical + Replacement & Emerging + Replacement Projections vs PRMR

~4.7 GW & 8.6 GW Status Quo Summer SAC Installation Rate

MISO Resource Adequacy Projections – Summer MISO South



- Projected PRMR with LSE forecast
- Potentially Unavailable Resources
- Potential New Capacity
- Value of Replacement/Surplus Projects
- Committed Capacity

*Using methods for potential New Capacity described on Slide 5

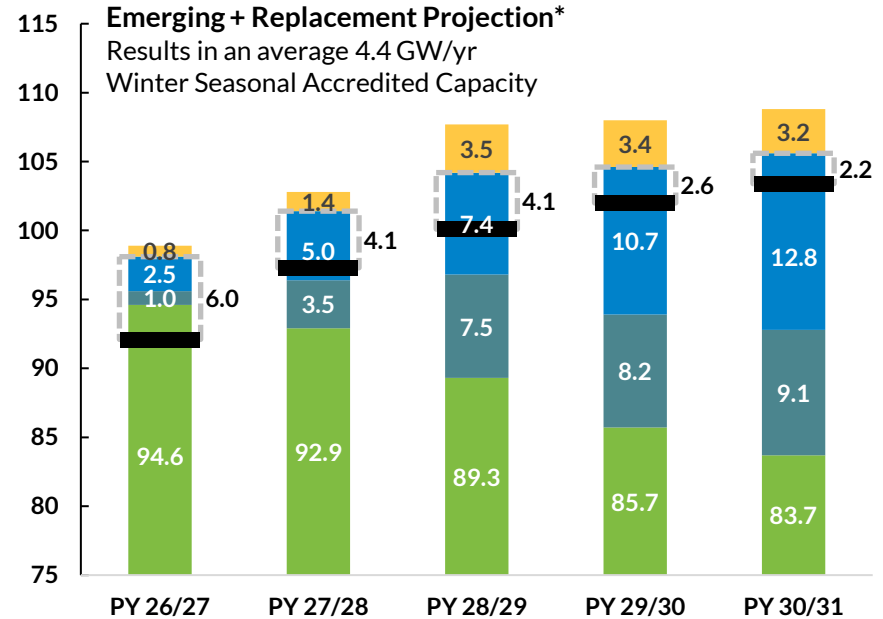
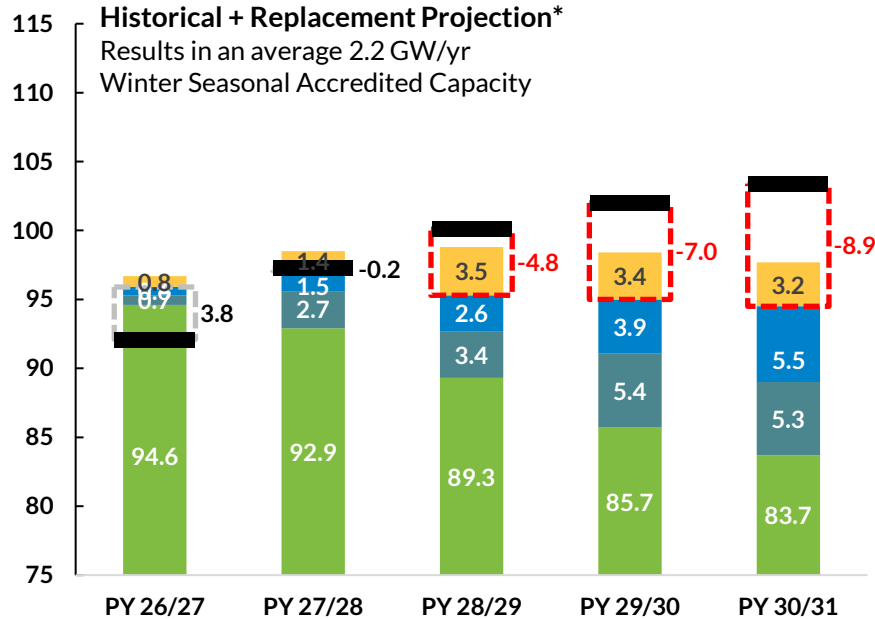
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- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart

Historical + Replacement & Emerging + Replacement Projections vs PRMR ~2.4 GW & 6.2 GW Status Quo Winter SAC Installation Rate

MISO Resource Adequacy Projections – Winter MISO North/Central



- Projected PRMR with LSE forecast
- Potentially Unavailable Resources
- Potential New Capacity
- Value of Replacement/Surplus Projects
- Committed Capacity

*Using methods for potential New Capacity described on Slide 8

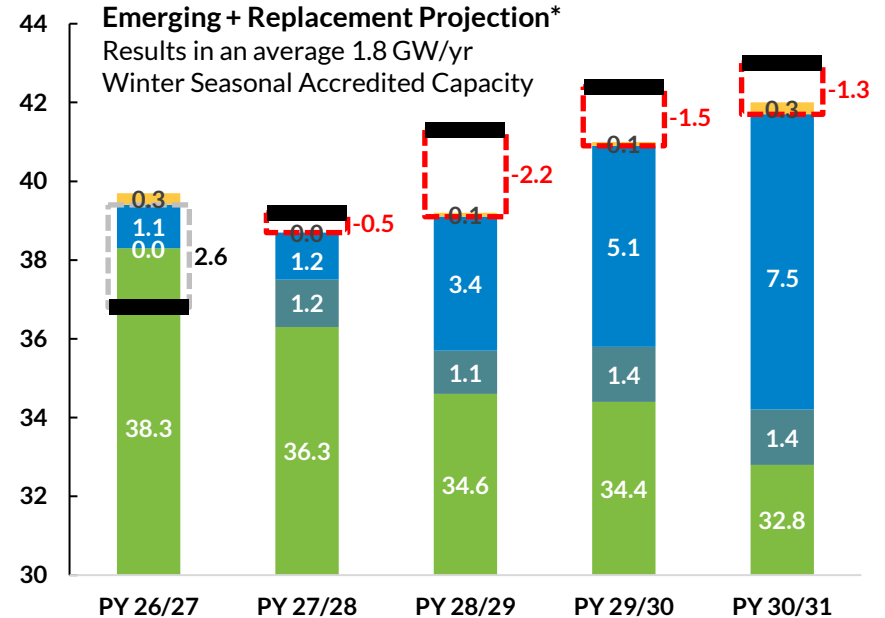
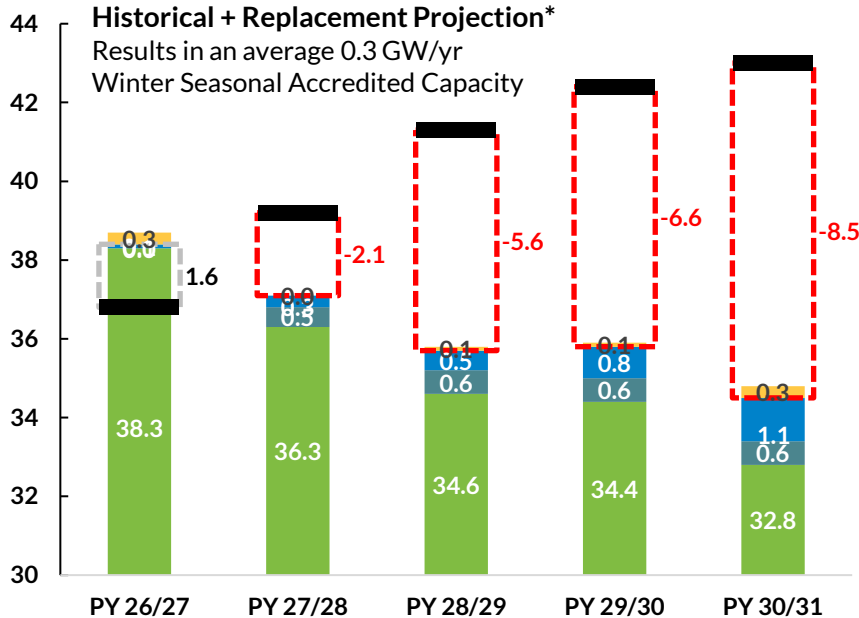
PRMR: Planning Reserve Margin Requirement

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- Capacity accreditation values and Planning Reserve Margin projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart

Historical + Replacement & Emerging + Replacement Projections vs PRMR ~2.4 GW & 6.2 GW Status Quo Winter SAC Installation Rate

MISO Resource Adequacy Projections – Winter MISO South



- Projected PRMR with LSE forecast
- Potentially Unavailable Resources
- Potential New Capacity
- Value of Replacement/Surplus Projects
- Committed Capacity

*Using methods for potential New Capacity described on Slide 8
PRMR: Planning Reserve Margin Requirement

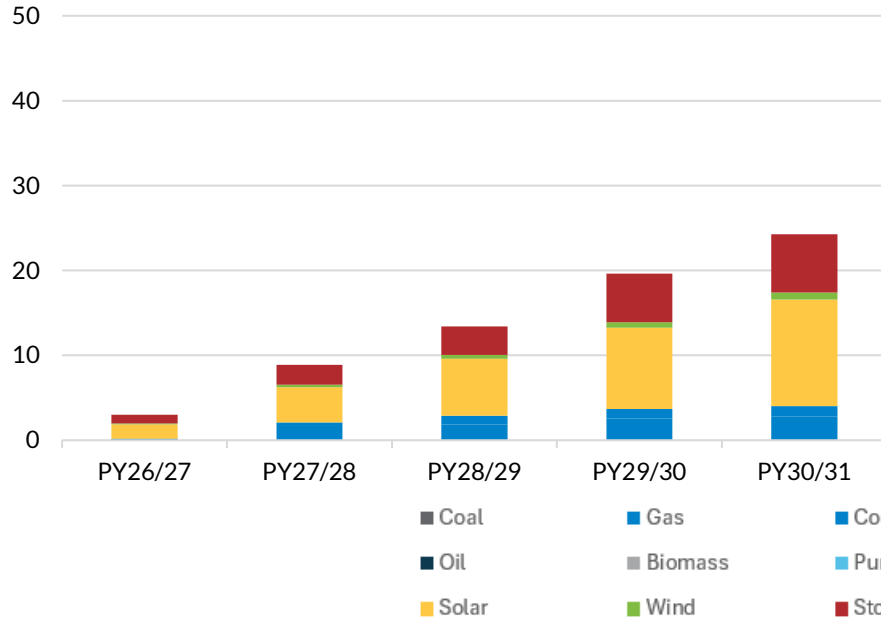
- Red border values indicate the additional potential deficit against the Projected PRMR
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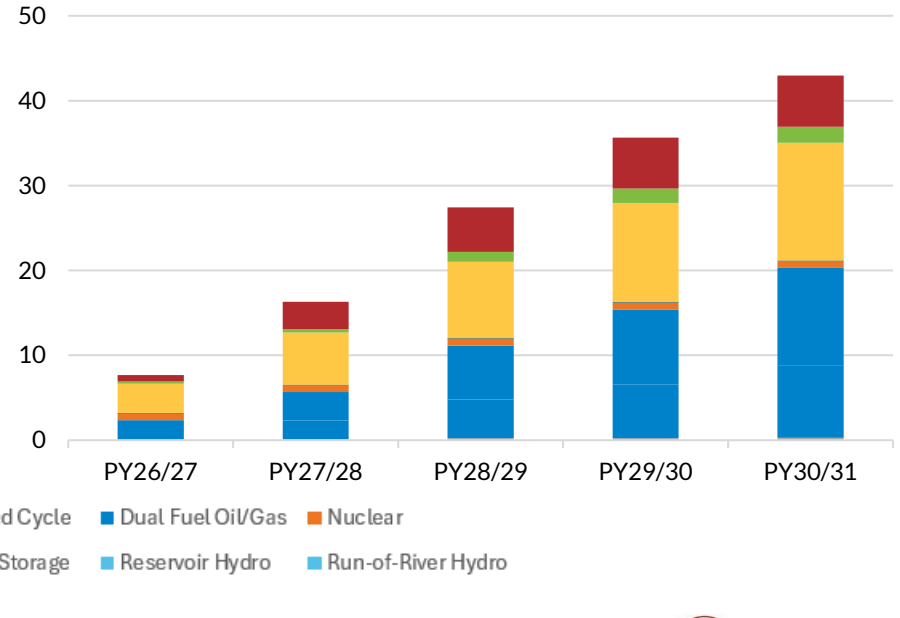
OMS-MISO Survey projections of new resource accreditation value -Status Quo SAC calculations

Projections of New Resource Fuel Mix – Summer

Historical + Replacement Projection New Resource Capacity (GW Summer SAC)



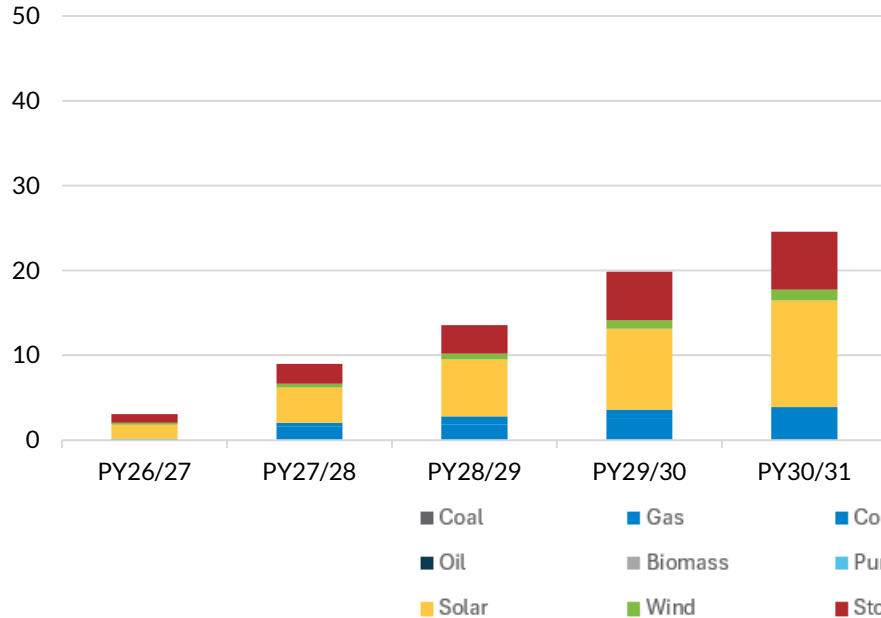
Emerging + Replacement Projection New Resource Capacity (GW Summer SAC)



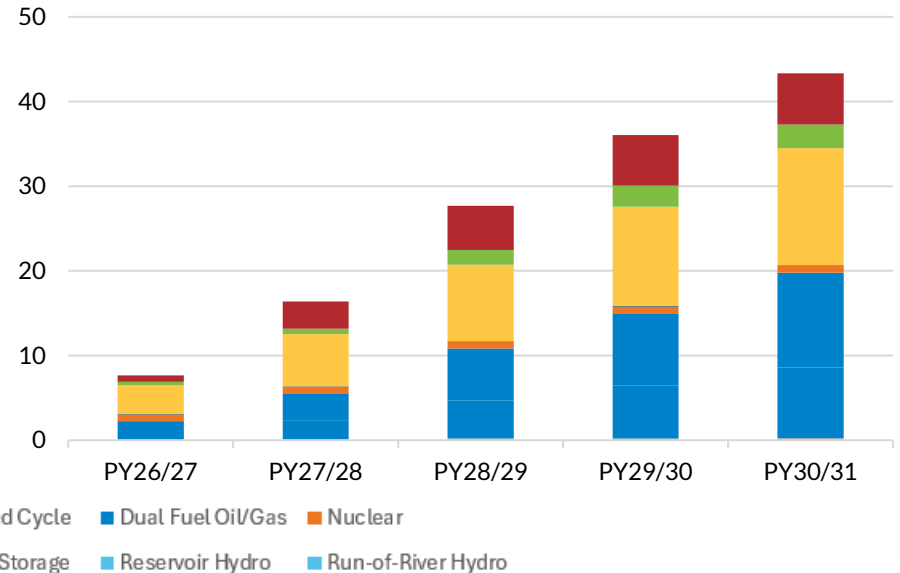
OMS-MISO Survey projections of new resource accreditation value -Status Quo SAC calculations

Projections of New Resource Fuel Mix – Fall

Historical + Replacement Projection*
New Resource Capacity (GW Fall SAC)



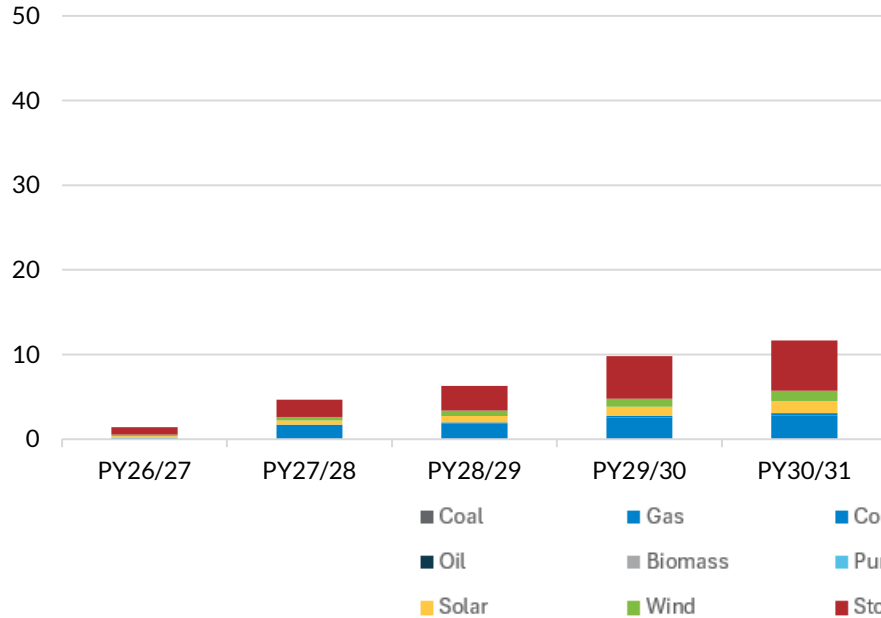
Emerging + Replacement Projection
New Resource Capacity (GW Fall SAC)



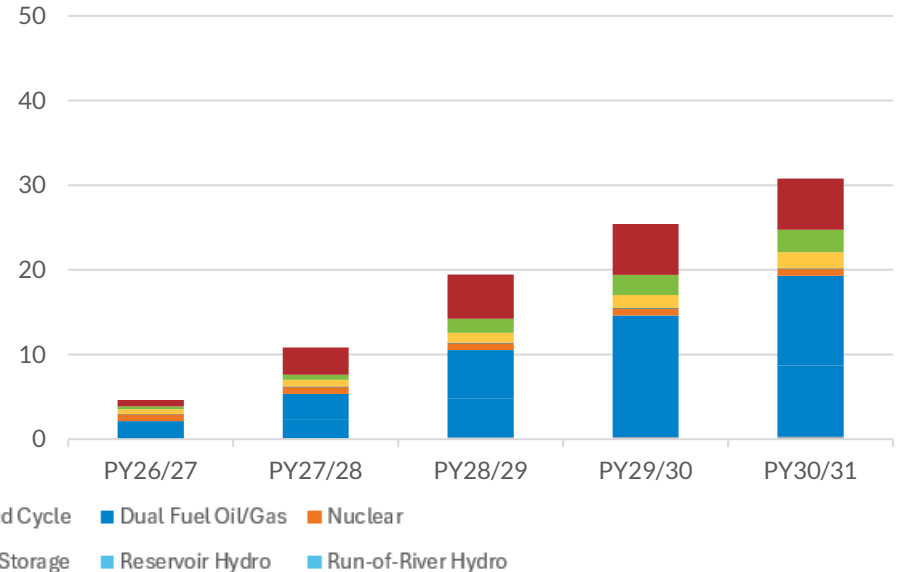
OMS-MISO Survey projections of new resource accreditation value -Status Quo SAC calculations

Projections of New Resource Fuel Mix – Winter

Historical + Replacement Projection New Resource Capacity (GW Winter SAC)



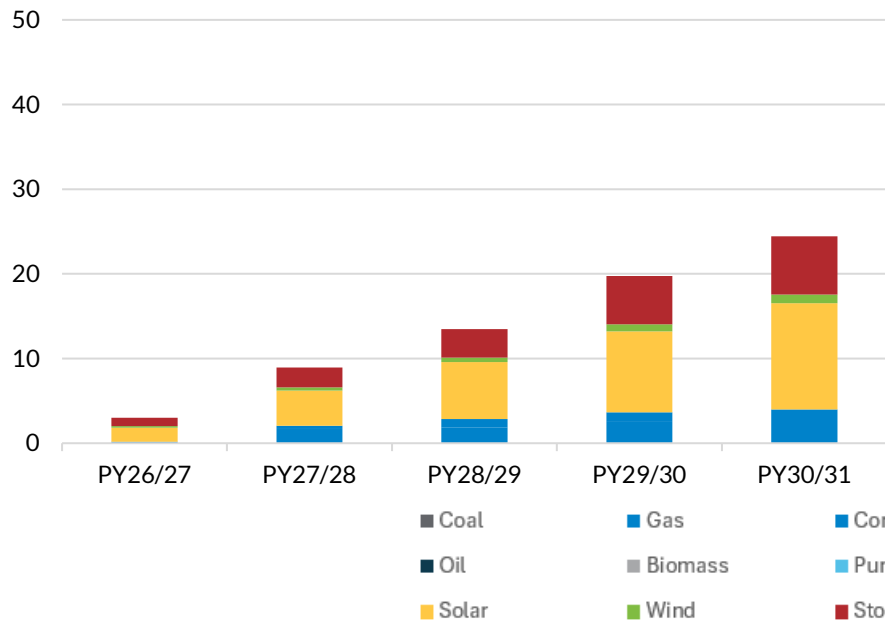
Emerging + Replacement Projection New Resource Capacity (GW Winter SAC)



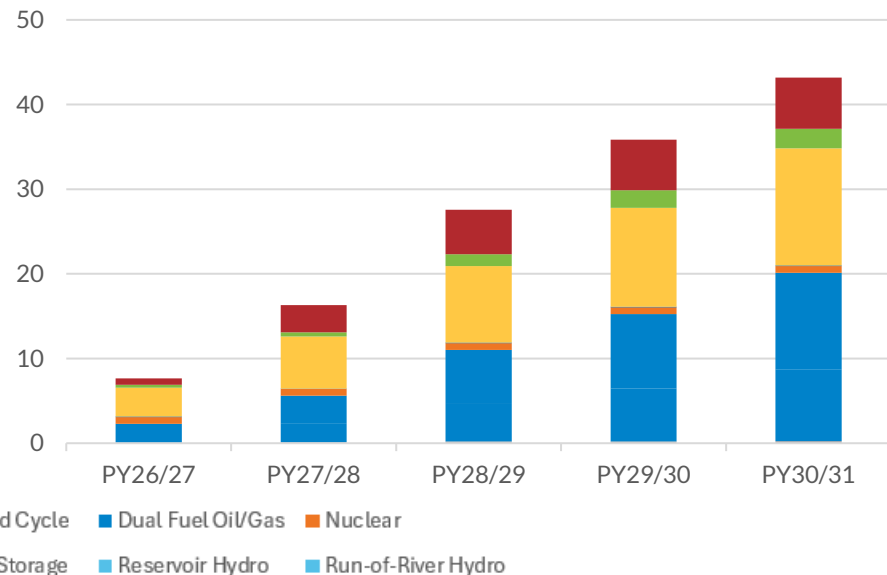
OMS-MISO Survey projections of new resource accreditation value -Status Quo SAC calculations

Projections of New Resource Fuel Mix – Spring

Historical + Replacement Projection New Resource Capacity (GW Spring SAC)



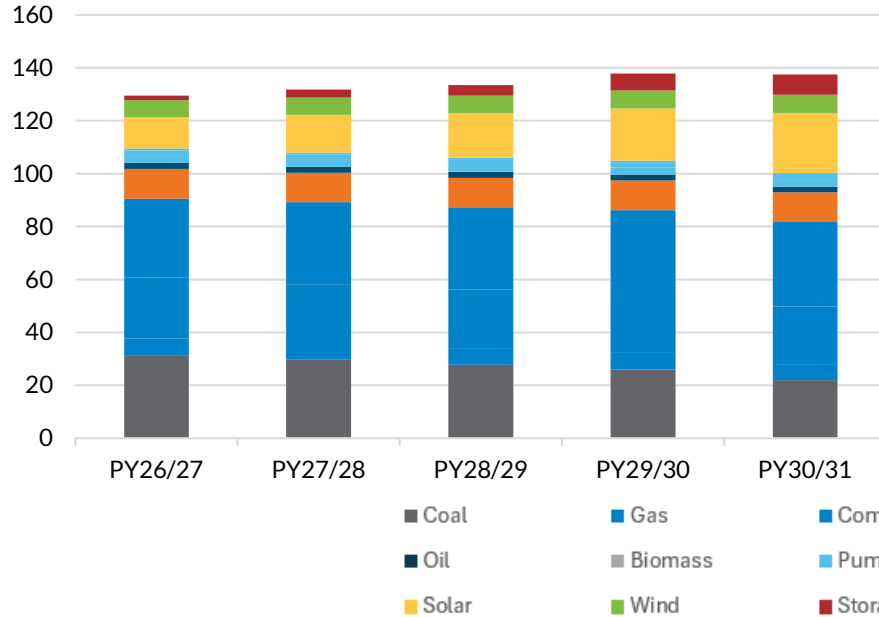
Emerging + Replacement Projection New Resource Capacity (GW Spring SAC)



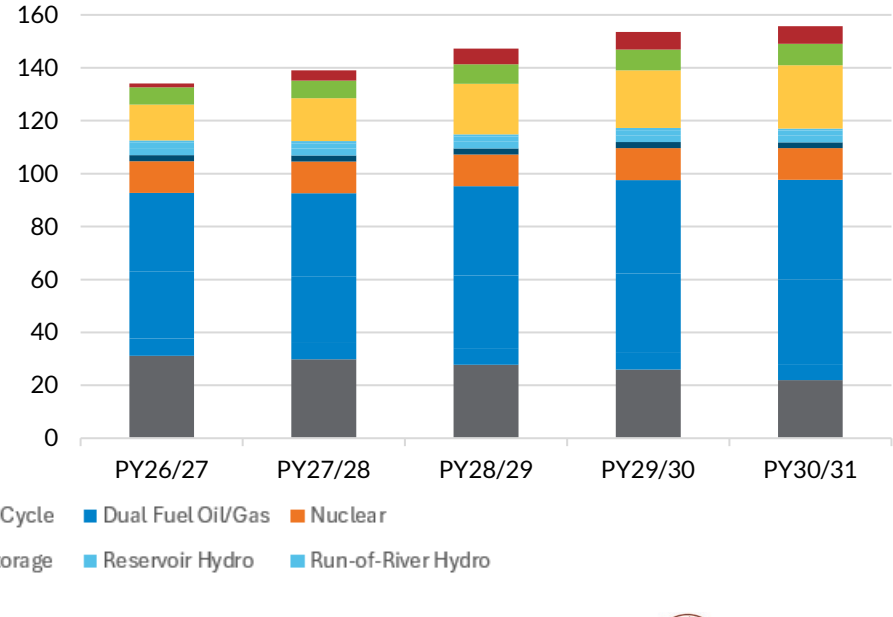
OMS-MISO Survey projections of fleet total resource accreditation value -Status Quo SAC calculations

Combined Projections of Fuel Mix – Summer

Historical + Replacement Projection Total Capacity (GW Summer SAC)



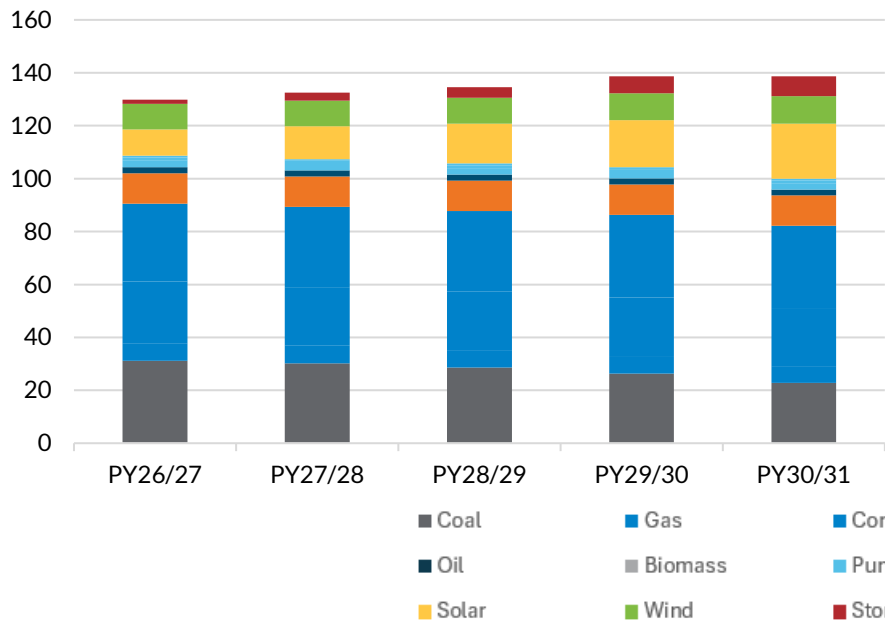
Emerging + Replacement Projection Total Capacity (GW Summer SAC)



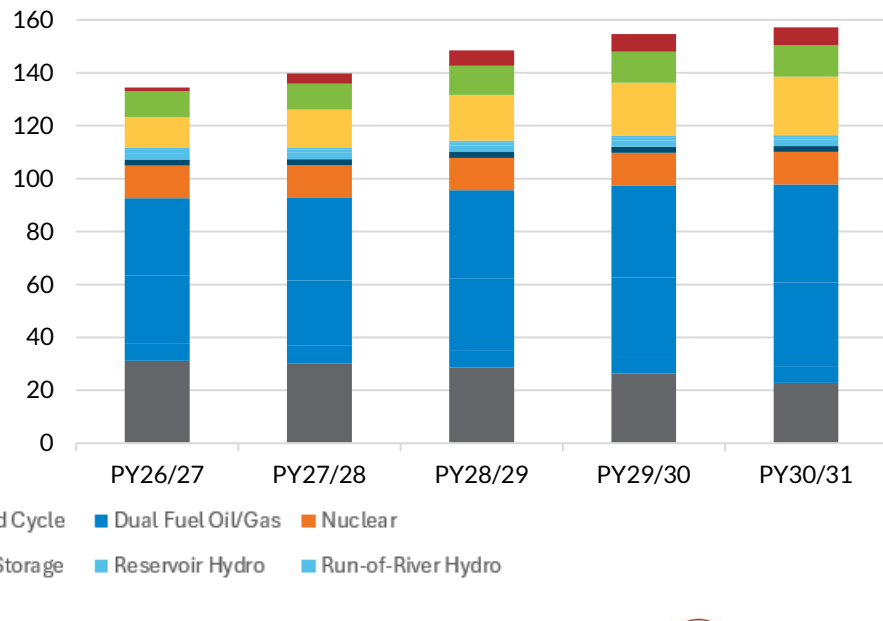
OMS-MISO Survey projections of fleet total resource accreditation value -Status Quo SAC calculations

Combined Projections of Fuel Mix – Fall

Historical + Replacement Projection Total Capacity (GW Fall SAC)



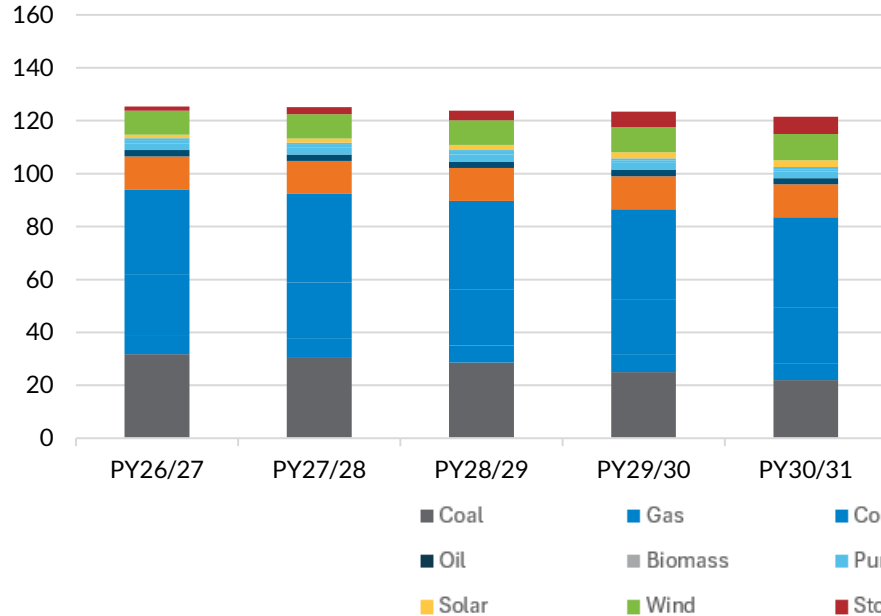
Emerging + Replacement Projection Total Capacity (GW Fall SAC)



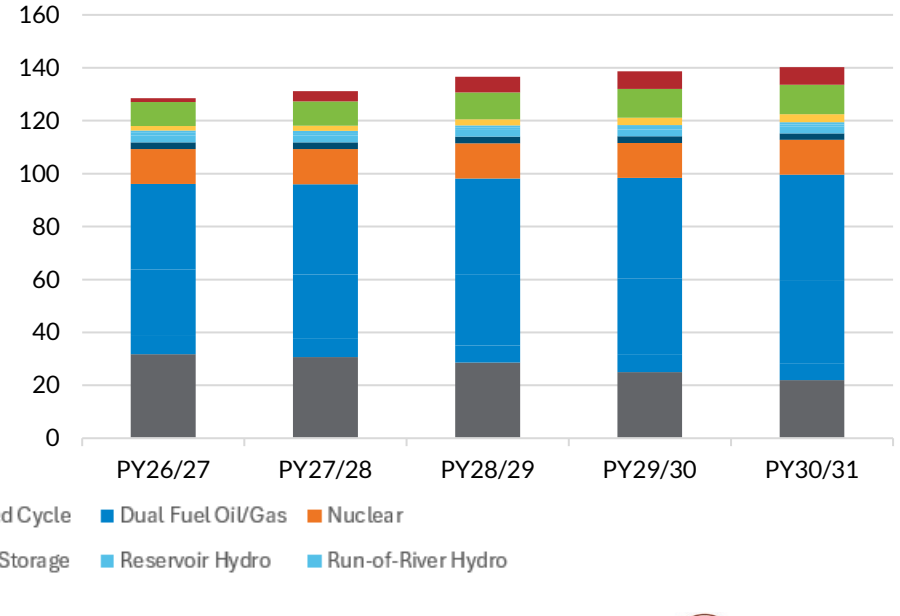
OMS-MISO Survey projections of fleet total resource accreditation value -Status Quo SAC calculations

Combined Projections of Fuel Mix – Winter

Historical + Replacement Projection Total Capacity (GW Winter SAC)



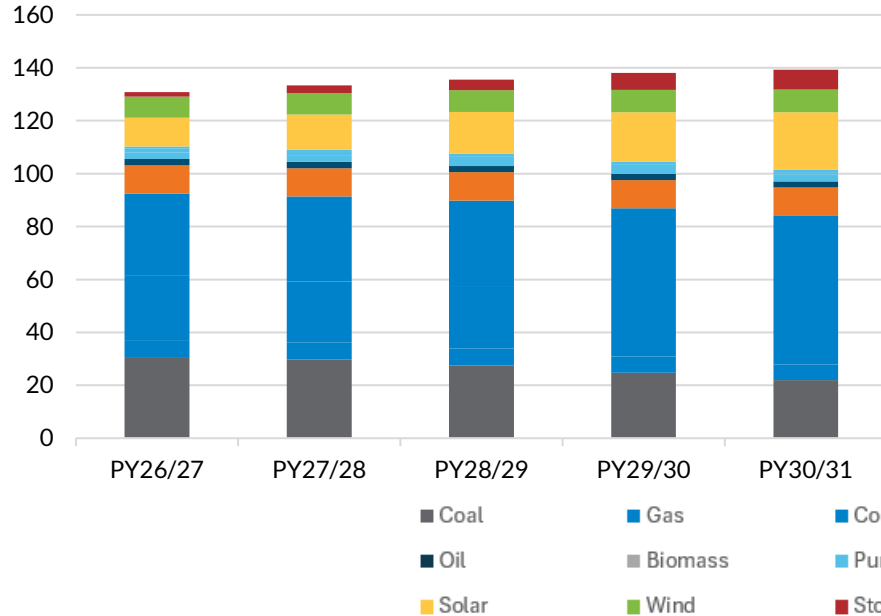
Emerging + Replacement Projection Total Capacity (GW Winter SAC)



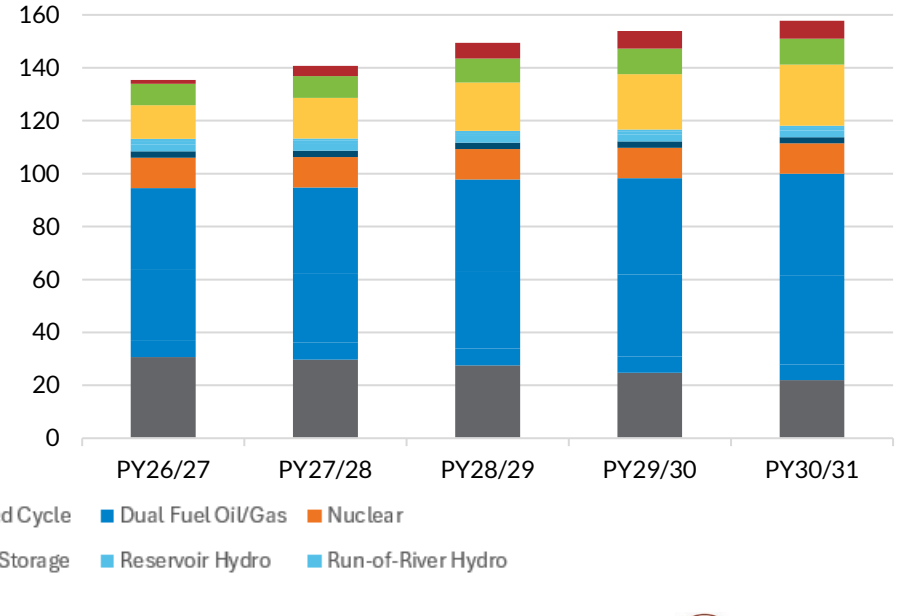
OMS-MISO Survey projections of fleet total resource accreditation value -Status Quo SAC calculations

Combined Projections of Fuel Mix – Spring

Historical + Replacement Projection Total Capacity (GW Spring SAC)



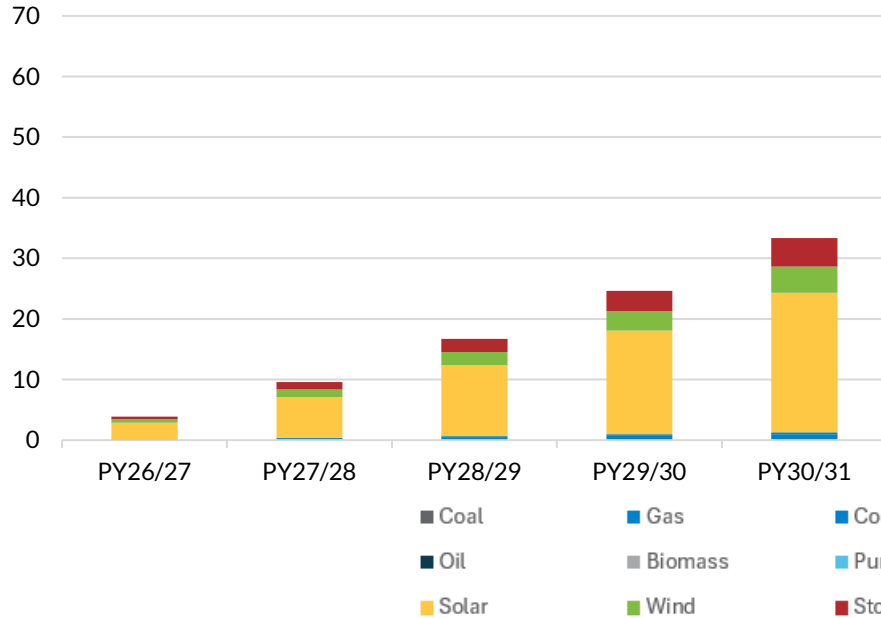
Emerging + Replacement Projection Total Capacity (GW Spring SAC)



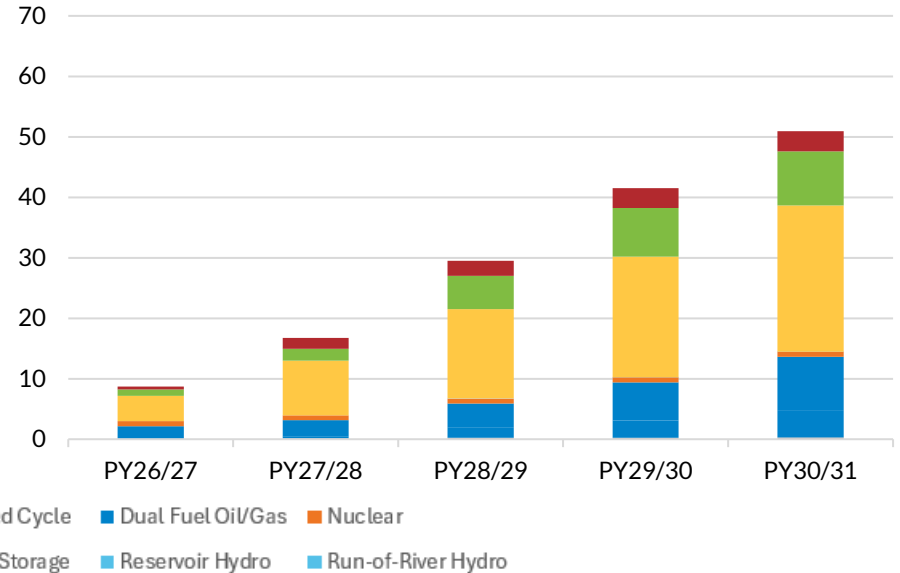
OMS-MISO Survey projections of new resource deliverable nameplate

Combined Projections of Fuel Mix, New Resource Nameplate Only (ICAP)

Historical Projection New Resource Nameplate (GW)



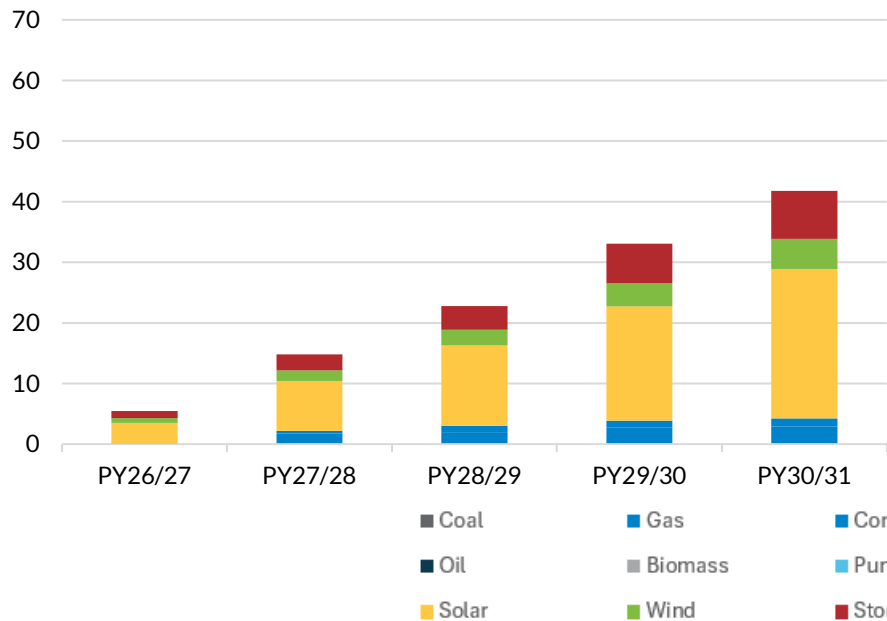
Emerging Projection New Resource Nameplate (GW)



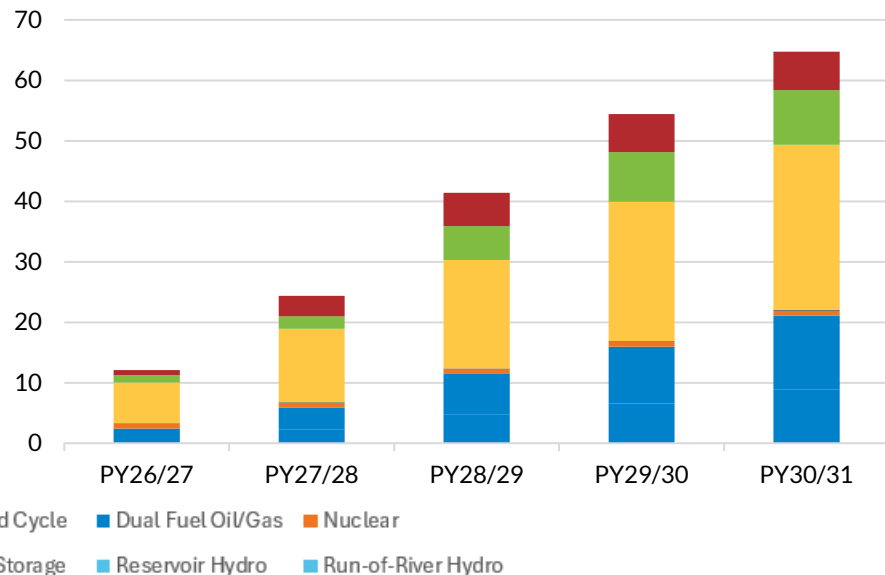
OMS-MISO Survey projections of new resource deliverable nameplate

Combined Projections of Fuel Mix, New Resource Nameplate Only (ICAP)

Historical + Replacement Projection New Resource Nameplate (GW)



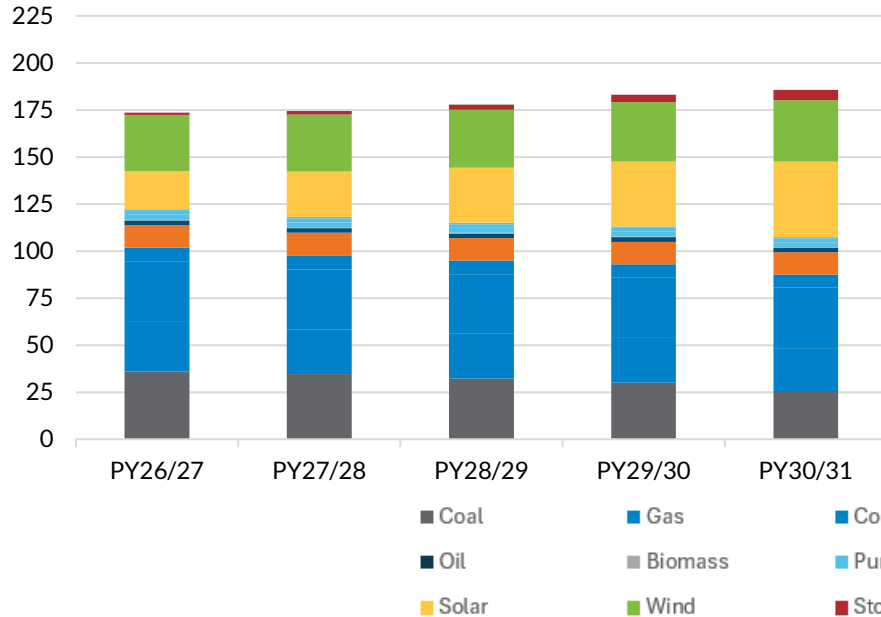
Emerging + Replacement Projection New Resource Nameplate (GW)



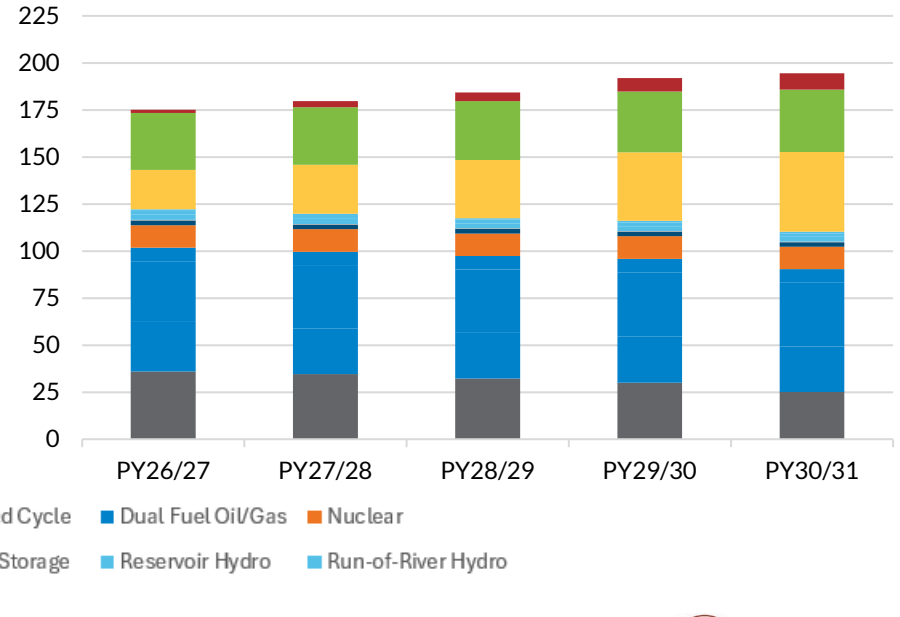
OMS-MISO Survey projections of fleet total deliverable nameplate

Combined Projections of Fuel Mix, Fleet Composition by Nameplate (ICAP)

Historical Projection Total Nameplate (GW)



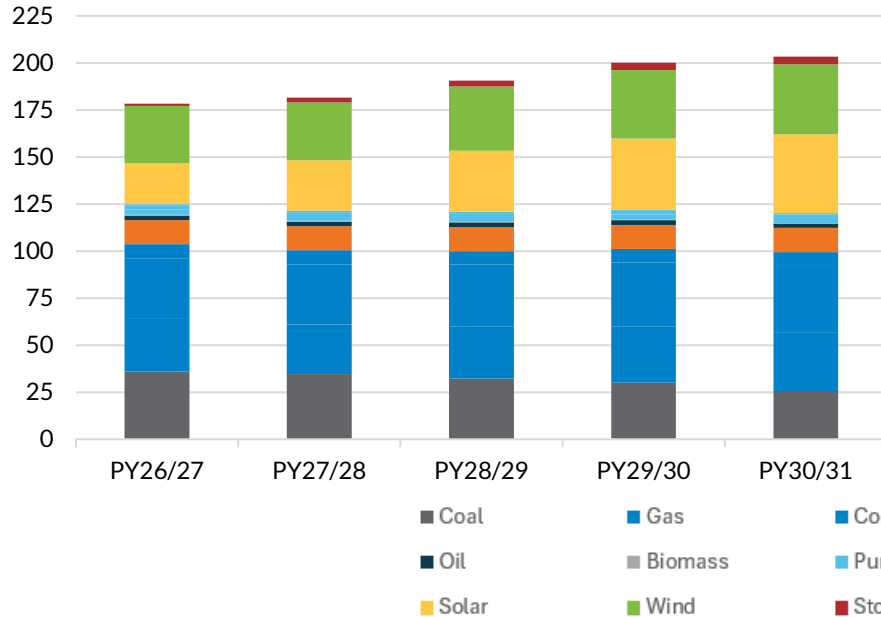
Historical + Replacement Projection Total Nameplate (GW)



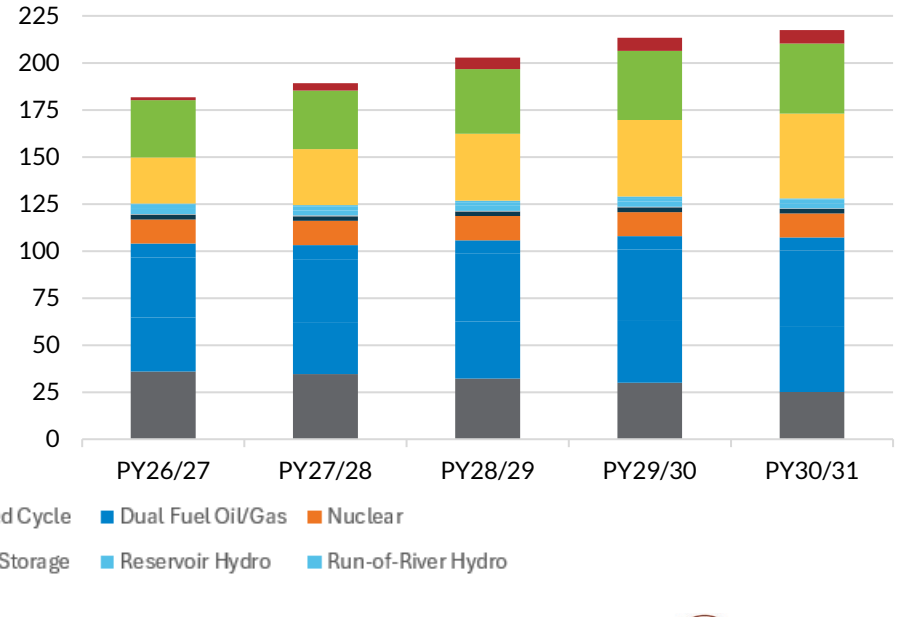
OMS-MISO Survey projections of fleet total deliverable nameplate

Combined Projections of Fuel Mix, Fleet Composition by Nameplate (ICAP)

Emerging Projection Total Nameplate (GW)



Emerging + Replacement Projection Total Nameplate (GW)



Attachment X

Consumers, Complaint, FERC Docket No. EL25-90

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Consumers Energy Company)	
)	Docket No. EL25-____-000
v.)	
)	
Midcontinent Independent System Operator, Inc.)	

COMPLAINT REQUESTING FAST TRACK PROCESSING

Consumers Energy Company (“Consumers Energy” or “Company”) files this complaint and request for Fast Track processing against Midcontinent Independent System Operator, Inc. (“MISO”), pursuant to sections 202(c), 306, and 309 of the Federal Power Act (“FPA”),¹ and Rule 206 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission (“FERC” or “Commission”).²

On May 23, 2025, the U.S. Secretary of Energy issued an order pursuant to FPA section 202(c) and section 301(b) of the Department of Energy Organization Act³ declaring that “an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes.”⁴ On that basis, the DOE Order directs both Consumers Energy and MISO to “take all measures necessary to ensure” that Consumers Energy’s J.H. Campbell generation facility in West Olive, Michigan (the “Campbell Plant”), which had been scheduled to cease operations on May 31, 2025, continues to operate.⁵ Since its issuance, Consumers Energy has complied with its obligations

¹ 16 U.S.C. §§ 824a(c), 825e, 825h.

² 18 C.F.R. § 385.206 (2025).

³ 42 U.S.C. § 7151(b).

⁴ U.S. Department of Energy, Order No. 202-25-3, at 2 (May 23, 2025) (“DOE Order”).

⁵ *Id.*

under the DOE Order, and the Campbell Plant is currently being offered into the MISO market and is producing energy when dispatched.

The DOE Order makes clear that “[r]ate recovery is available pursuant to [FPA section 202(c)],” and further directs Consumers Energy to “file with the Federal Energy Regulatory Commission Tariff revisions or waivers necessary to effectuate this order.”⁶ This Complaint is being filed in furtherance of that directive and to ensure that there is a mechanism for Consumers Energy to obtain such rate recovery as is available pursuant to FPA section 202(c) at the appropriate time in the future, likely after the DOE Order expires.

To be clear, *the specific costs, if any, to be recovered by Consumers Energy are not at issue in this Complaint.* Rather, Consumers Energy plans to make a section 202(c) filing after the conclusion of the extended service required by the DOE Order in which it will present, explain, and support what it believes are its just and reasonable costs associated with running the Campbell Plant from the date of the DOE Order, netting out applicable market revenues (its “Order Costs”).⁷ Thus, the determination of recoverable costs will be the subject of a separate FERC proceeding under section 202(c) after the conclusion of the extended service required by the DOE Order. The instant Complaint is limited to ensuring that MISO has the requisite Tariff-based *mechanism* to effectuate Consumers Energy’s cost recovery.

Both Consumers Energy and MISO agree that (1) existing MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (“Tariff”) does not include a mechanism for Consumers Energy to recover costs associated with complying with the Order; and

⁶ *Id.*

⁷ For the avoidance of doubt, consistent with Section 202(c)’s cost recovery language, Consumers Energy reserves all rights to make a demonstration of its just and reasonable Order Costs (net of market revenues) in the subsequent Section 202(c) filing discussed herein, which will be made after the conclusion of the extended service required by the DOE Order.

(2) MISO lacks Tariff authority to unilaterally offer Consumers Energy a section 202(c) rate agreement. Accordingly, Consumers Energy requests that the Commission exercise its authority pursuant to FPA sections 202(c) and 309 to order MISO to adopt a Tariff revision to provide a cost recovery mechanism for Consumers Energy’s Order Costs. Consumers Energy requests that the requested MISO Tariff revision will be effective as of the issuance of the DOE Order on May 23, 2025, or such other date as the Commission determines will still permit recovery of Consumers Energy’s Order Costs back to the referenced date of the DOE Order.⁸

I. EXECUTIVE SUMMARY

Pursuant to the DOE Organization Act, the authority under section 202(c) to “determine[] that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes” is vested in the Secretary of Energy. That section’s authority to “order such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest” is similarly vested in the Secretary. The Commission’s role under this particular statutory framework is limited to cost recovery.

As detailed below, the Campbell Plant is a roughly 1400 MW coal-fired generating station that had been scheduled to retire as of May 31, 2025. As soon as the DOE Order was issued, Consumers Energy began incurring and will continue to incur costs to comply with the DOE Order’s directive to “take all measures necessary to ensure that the Campbell Plant is available to

⁸ The Company believes that FPA sections 202(c) and 309 provide ample authority for the Commission to grant the relief requested herein. Nonetheless, if the Commission finds it must invoke its FPA Section 206 authority to grant the relief requested herein, Consumers Energy moves for relief under Section 206 in the alternative. *See infra* Section V. Under section 206, the Commission could make the requested Tariff revision effective as of the date of this Complaint.

operate” for the duration of the DOE Order. The precise Order Costs will not be known until after the DOE Order expires on August 21, 2025. Soon thereafter, Consumers Energy will make a separate request to the Commission under section 202(c) for the “compensation or reimbursement” of its Order Costs, net of market revenues, as provided by the statute.

The more immediate issue is that the MISO Tariff currently contains no mechanism to provide compensation to generators in the MISO footprint operating pursuant to section 202(c) emergency orders, and no basis to allocate such costs to reflect the nature of an emergency declared pursuant to section 202(c). This Complaint, therefore, asks the Commission to order MISO to revise its Tariff to provide for allocation of Consumers Energy’s (later-to-be-determined) Order Costs, net of market revenues. This relief is necessary and appropriate for several reasons. For its part, Consumers Energy has no contractual privity or Tariff authority to allocate costs directly to MISO customers. Ordering paragraph (F) of the DOE Order instructs Consumers Energy to “file with the Federal Energy Regulatory Commission Tariff revisions or waivers necessary to effectuate this order.” The same passage further makes clear that “[r]ate recovery is available pursuant to 16 U.S.C. § 824a(c).” Ordering paragraph (E) provides that, “[t]he extent to which MISO’s current Tariff provisions are inapposite to effectuate the dispatch and operation of the units for the reasons specified herein, the relevant governmental authorities are directed to take such action and make accommodations as may be necessary to do so.” Finally, DOE sent “carbon copies” of the DOE Order to each sitting FERC Commissioner.

The Commission’s duties and authority to address this Complaint and issue the requested relief are found in sections 202(c), 306, and 309 of the FPA. Importantly, cost recovery under section 202(c) does not invoke the normal ratemaking strictures of FPA sections 205 or 206. Section 202(c) provides independent authority to empower the Commission to “prescribe by

supplemental order such terms as it finds to be just and reasonable, including the compensation or reimbursement which should be paid to or by any such party.” And, to the extent necessary, FPA section 309 supplements the Commission’s authority to take action to implement its section 202(c) responsibilities. Specifically, FPA section 309 grants the Commission “power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules, and regulations as it may find necessary or appropriate to carry out the provisions of this Act.”⁹ To effectuate Consumers Energy’s right to recover the costs of complying with the DOE Order, the MISO Tariff must be amended to create a recovery mechanism. In the absence of an agreement between the parties affected by a 202(c) order, the Commission has the responsibility for determining cost recovery and allocation. As noted above, the actual costs, if any, Consumers Energy seeks to recover will be the subject of a separate filing with the Commission. However, at this juncture, FPA section 309 authorizes the Commission to take measures to ensure its ability “to carry out” its role, pursuant to section 202(c), by requiring adoption of the 202(c) Cost Recovery Mechanism.

Finally, the relief requested herein meets the “just and reasonable” standard of section 202(c)(1). In addition to providing MISO the authority to implement a mechanism for cost recovery, Consumers Energy asks the Commission to order MISO to adopt specific Tariff provisions to allocate its Order Costs (net of market revenues) proportionally to load in MISO Zones 1 through 7 – referred to in the DOE Order as the northern and central regions of MISO.¹⁰ This proposed cost allocation is just and reasonable because, under section 202(c), costs should be allocated based on the scope and nature of the emergency that prompted issuance of the order in question. The DOE Order’s emergency declaration is substantially based on concerns about

⁹ 16 U.S.C. § 825h.

¹⁰ DOE Order at 2.

resource adequacy in MISO generally, and the northern and central regions in particular.¹¹ In other words, the beneficiaries for cost allocation purposes are best determined by reference to the Secretary's definition of the emergency. Under such a regional allocation, Michigan load will of course pay its fair share of Consumers Energy's Order Costs (net of market revenues) because, as the DOE Order points out, MISO Zones 1-7 (*i.e.*, the northern and central zones) include Michigan. But Consumers Energy believes that, whatever the Order Costs turn out to be after netting market revenues, they should be allocated beyond the State of Michigan. Consumers Energy customers are already paying for the cost to fulfill the capacity needs of Zone 7.

In sum, the Commission's duties and authority to address this cost allocation are clear. Consumers Energy respectfully requests that the Commission set a 10-day comment period on this complaint, and issue an order at the earliest opportunity directing MISO to adopt the referenced cost allocation mechanism for the Order Costs of the Campbell Plant.

II. BACKGROUND

A. The Parties

1. Consumers Energy Company

Consumers Energy is a public utility that serves approximately 1.9 million electric customers and 1.8 million natural gas customers in Michigan's Lower Peninsula. Consumers Energy is wholly owned by, and one of the two principal subsidiaries of, CMS Energy Corporation, which is a publicly traded company. Consumers Energy owns and operates generating facilities and non-jurisdictional distribution facilities. Consumers Energy is a member of MISO, a market participant in the MISO wholesale markets, and takes transmission service in MISO.

¹¹ Because the Order cites the "northern and central zones," Consumers Energy believes the best read of the DOE Order is that the emergency identified in the Order exists in Zones 1-7 and would not reach "MISO South."

2. MISO

MISO is an Independent System Operator and Regional Transmission Organization and is authorized by the Commission to provide open access transmission service and to administer wholesale energy, capacity, and ancillary services markets in portions of the Midwest region of the United States, as well as certain other regions. MISO also administers the MISO Tariff, which governs such markets. MISO includes ten separate zones. MISO's northern and central regions are zones 1 through 7.

B. Factual Background

1. The Campbell Plant

The Campbell Plant is a coal-fired electric generation plant located in West Olive, Michigan, with a summer capacity of approximately 1400 MW. The Campbell Plant consists of three units:

- Unit 1, which commenced commercial operations in 1962, has a summer capacity of approximately 260 MW and is wholly owned by the Company;
- Unit 2, which commenced commercial operations in 1967, has a summer capacity of approximately 280 MW and is wholly owned by the Company; and
- Unit 3, which commenced commercial operations in 1980, has a summer capacity of approximately 840 MW and is majority owned by the Company.¹²

Pursuant to an integrated resource plan the Company filed with the Michigan Public Service Commission ("MPSC") in 2021,¹³ and a settlement arising from that filing that was

¹² Wolverine Power Supply Cooperative, Inc. ("Wolverine") and the Michigan Public Power Agency ("MPPA") own, respectively, 1.89% and 4.80% interests in Unit 3. As such they may have costs associated with the DOE Order and they may also realize market revenue due to Campbell Plant operation under the DOE Order. Consumers Energy has been in communication with Wolverine and MPPA and all three parties agree to cooperate to ensure appropriate cost recovery by Wolverine and MPPA in connection with the DOE Order.

¹³ In the Matter of the Application of Consumers Energy Company for Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief, Application MPSC

approved by an order of the MPSC in 2022, the Campbell Plant was scheduled to be retired on May 31, 2025.¹⁴

The planned retirement of the Campbell Plant was also studied and approved by MISO, pursuant to MISO Tariff provisions. The DOE Order recognizes that the planned retirement of the Campbell Plant has been incorporated into supply forecasts for MISO, but notes that the North American Electric Reliability Corporation’s 2025 Summer Reliability Assessment “still anticipates ‘elevated risk of operating reserve shortfalls.’”¹⁵ The DOE Order also cites MISO’s Planning Resource Action Results for Planning Year 2025-26, which “note that for the northern and central zones, which includes Michigan, ‘new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources.’”¹⁶

2. The DOE Order

The DOE Order states that MISO “faces potential tight reserve margins during the summer 2025 period, particularly during periods of high demand or low generation resource output,” “that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes,” and that “additional dispatch of the Campbell Plant is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c).”¹⁷ The DOE Order also points out that

Case No. U-21090-003, (filed June 30, 2021), <https://mipsc.my.site.com/sfc/servlet.shepherd/version/download/068t000000Nib8YAAR>.

¹⁴ *Order Approving Settlement*, MPUC Case No. U-21090-0901 (June 23, 2022), <https://mipsc.my.site.com/sfc/servlet.shepherd/version/download/0688y000003KjSDAA0>.

¹⁵ DOE Order at 2 (citations omitted).

¹⁶ *Id.* (citation omitted).

¹⁷ *Id.* at 1, 2.

“MISO’s Planning Resource Auction Results for Planning Year 2025-26, released in April 2025, note that for the northern and central zones, which includes Michigan, ‘new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources.’”¹⁸

Based on the foregoing determination, the DOE Order directs the Company and MISO to “take all measures necessary to ensure that the Campbell Plant is available to operate” until the DOE Order’s expiration in August 2025.¹⁹ The DOE Order explains that “[r]ate recovery is available pursuant to 16 U.S.C. § 824a(c)” and directs Consumers “to file with the Federal Energy Regulatory Commission Tariff revisions or waivers necessary to effectuate” the DOE Order.²⁰ The DOE Order also directs MISO, among other things, to “take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers”²¹ and “provide the Department of Energy . . . with information concerning the measures it has taken and is planning to take to ensure the operational availability and economic dispatch of the Campbell Plant consistent with the public interest.”²² The DOE Order further directs that “[t]he extent to which MISO’s current Tariff provisions are inapposite to effectuate the dispatch and operation of the units for the reasons specified herein, the relevant governmental authorities are directed to take such action and make accommodations as may be necessary to do so.”²³

¹⁸ *Id.* at 2 (citation omitted).

¹⁹ *Id.* at Ordering Paragraph A.

²⁰ *Id.* at Ordering Paragraph F.

²¹ *Id.* at Ordering Paragraph A.

²² *Id.* at Ordering Paragraph D.

²³ *Id.* at Ordering Paragraph E.

3. Company Actions to Comply with the DOE Order

Upon receiving the DOE Order, Consumers Energy has undertaken significant efforts to comply with its directives, including procurement of fuel, review and planning for maintenance, and numerous other undertakings.

The Company has established a regulatory asset to account for all costs of running the Campbell Plant from the date the DOE Order was issued and will seek recovery of such costs in a future filing. The 202(c) Cost Recovery Mechanism being requested herein will be the Tariff mechanism for the approved recovery.

C. Overview of FPA Section 202 and DOE's Implementing Regulations

FPA section 202(c) was established by the Public Utility Act of 1935 and originally provided the emergency authority to the Federal Power Commission.²⁴ In 1977, the Department of Energy Organization Act (“DOE Organization Act”) transferred the authority to determine the existence of an emergency to the Secretary of the Energy.²⁵

Section 202(c) of the FPA provides, in relevant part, as follows:

During the continuance of any war in which the United States is engaged, or whenever the Commission determines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes, the Commission shall have authority, either upon its own motion or upon complaint, with or without notice, hearing, or report, to require by order such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest. *If the parties affected by such order fail to agree upon the terms of any*

²⁴ See Public Utility Holding Company Act of 1935, Pub. L. No. 74-333, pt. II at 849 (1935) (codified at 16 U.S.C. § 824a(c)).

²⁵ See Department of Energy Organization Act, Pub. L. No. 95-91, tit. III, 91 Stat. 577-78 (1977) (codified at 42 U.S.C. § 7151). As a result, the word “Commission” refers to the Secretary of Energy for purposes of determining the emergency and ordering the emergency generation.

arrangement between them in carrying out such order, the Commission, after hearing held either before or after such order takes effect, may prescribe by supplemental order such terms as it finds to be just and reasonable, including the compensation or reimbursement which should be paid to or by any such party.

16 U.S.C. 824a(c)(1) (emphasis added).

In 1981, the DOE promulgated a rule to implement the rate aspects of FPA section 202(c).

That rule provides, in relevant part:

In the event that the DOE determines that an emergency exists under [FPA] section 202(c), and the “entities” are unable to agree on the rates to be charged, the DOE shall prescribe the conditions of service and refer the rate issues to the Federal Energy Regulatory Commission for determination by that agency in accordance with its standards and procedures.

10 C.F.R. § 205.376 (emphasis added) (“DOE Referral Regulation”).

III. RELIEF REQUESTED

Consumers Energy requests that the Commission direct MISO to revise the MISO Tariff to include a 202(c) Rate Recovery Mechanism in the form included herewith as Attachment A in such manner as to provide recovery of Consumers Energy’s Order Costs dating back to the issuance of the DOE Order.

IV. ARGUMENT

A. The Company Has a Right to Recover Costs Associated with the DOE Order, and Such Costs Can Be Determined After-the-Fact

FPA section 202(c) confers the right to recover costs associated with an order issued pursuant to its emergency authority. When the parties affected cannot agree on such costs, the statute charges the Commission with the responsibility to determine them. Importantly, FERC’s rate determinations pursuant to section 202(c) can occur after a section 202(c) order terminates, and after the conclusion of the compelled generation or provision of jurisdictional service.

1. Parties Subject to a Section 202(c) Order Are Entitled to Recover Associated Costs, Subject to Commission Approval

There can be no question that Consumers Energy has a right to recover its Order Costs, net of market revenues. This is confirmed by the plain language of FPA section 202(c), the DOE Referral Regulation, and the DOE Order, itself:

- FPA section 202(c): If the parties affected by such order fail to agree upon the terms of any arrangement between them in carrying out such order, the Commission, after hearing held either before or after such order takes effect, may prescribe by supplemental order such terms as it finds to be just and reasonable, *including the compensation or reimbursement* which should be paid to or by any such party.²⁶
- DOE Referral Regulation: In the event that the DOE determines that an emergency exists under [FPA] section 202(c), and the “entities” are unable to agree on the rates to be charged, *the DOE shall* prescribe the conditions of service and *refer the rate issues to the Federal Energy Regulatory Commission for determination by that agency in accordance with its standards and procedures.*²⁷
- DOE Order: “Rate recovery is available pursuant to [FPA section 202(c)].”²⁸

Indeed, recovery of Order Costs is mandated by the U.S. Constitution. Specifically, the Fifth Amendment Takings Clause bars the federal government from taking private property for

²⁶ 16 U.S.C. § 824a(c)(1) (emphasis added).

²⁷ 10 C.F.R. § 205.376 (emphasis added).

²⁸ DOE Order at Ordering Paragraph E.

public use without just compensation.²⁹ For the avoidance of doubt, Consumers Energy only seeks to recover its Order Costs *net of market revenues* earned from the Campbell Plant’s operation.

2. Pursuant to the Commission’s Section 202(c) Rate Authority, Costs Can Be Determined and Recovered *After* the Emergency Generation or Provision of Jurisdictional Service

As described below, both the plain language of section 202(c) and prior Commission precedent demonstrate that appropriate compensation can be determined and recovered after the term of an order declaring an emergency and/or requiring provision of jurisdictional service. Moreover, the prior notice requirements and related filed rate doctrine and rule against retroactive ratemaking pursuant to FPA sections 205 and 206 do not apply in the context of determining compensation pursuant to FPA section 202(c), which provides independent ratemaking authority and includes its own “just and reasonable” standard.

First, section 202(c)’s plain language: After an emergency section 202(c) order “takes effect,” the statute expressly contemplates “supplemental” orders regarding “compensation or reimbursement.”³⁰ The use of the word “reimbursement” indicates an after-the-fact approach. Together, this language demonstrates that, unlike FPA section 205 (which requires prior notice and approval of rates), or section 206 (which allows only prospective fixing of rates or charges by the Commission), the Commission’s rate authority under section 202(c) is broader, and not constrained in the same ways that it is under sections 205 and 206.

Second, Commission precedent: A prior FERC ratemaking proceeding pursuant to section 202(c) demonstrates that costs can be determined and recovered after-the-fact. Specifically, in

²⁹ U.S. Const. amend. V (“[N]or shall private property be taken for use, without just compensation.”); *see, e.g., Duquesne Light Co. v. Barasch*, 488 U.S. 299, 308 (1989) (“If the rate does not afford sufficient compensation, the State has taken the use of utility property without paying just compensation . . .”).

³⁰ 16 U.S.C. § 824a(c).

2002, the Secretary of Energy issued an order determining that an emergency existed on Long Island and directing Cross-Sound Cable Company, LLC (“CSC”) “to operate the Cross-Sound Cable and related facilities in order to transmit and deliver electric capacity and/or energy [when and in such amounts] as may be scheduled and purchased by the Long Island Power Authority (LIPA).”³¹ The DOE Order was effective from the date of issuance until October 1, 2002. On December 6, 2002, pursuant to the DOE Referral Regulation, the Secretary referred to FERC “the matter of compensation to [CSC] for costs incurred providing transmission to [LIPA] in compliance with Emergency Order No. 202-02-1.”³² On December 30, 2002, the Commission issued an order establishing procedures for the resolution of the compensation question.³³ After some initial briefing, the Commission suspended the procedural schedule and directed the parties to engage in mediation.³⁴ On June 4, 2004, the Commission issued an order approving an uncontested settlement between LIPA and CSC that resolved all issues regarding compensation to CSC in connection with the 202(c) order that terminated on October 1, 2002.³⁵

Third, the inapplicability of constraints on the Commission’s ratemaking authority pursuant to FPA sections 205 and 206: The Commission’s core responsibility of ensuring just and reasonable rates for jurisdictional sales and services is typically carried out pursuant to FPA sections 205 and 206 – and it is subject to certain well-established doctrines that arise directly from the statutory language of those two FPA provisions.

³¹ *U.S. Dept. of Energy*, 101 FERC ¶ 61,389 at P 3 (2002) (citing Emergency Order No. 202-02-1).

³² *U.S. Dept. of Energy*, 107 FERC ¶ 61,258 at P 1 (2004).

³³ *U.S. Dept. of Energy*, 101 FERC ¶ 61,389.

³⁴ *U.S. Dept. of Energy*, 107 FERC ¶ 61,258 at P 1.

³⁵ *Id.* P 3.

Section 205 of the FPA requires public utilities to file with the Commission any rates and charges that are subject to the Commission’s jurisdiction, with the required prior notice, and it requires the Commission to ensure the justness and reasonableness of such rates.³⁶ A public utility is only authorized to charge the rate on file with the Commission, and changes to such rates must be prospective.³⁷

Section 206 of the FPA empowers the Commission, upon its own motion or in response to a complaint, to address existing rates that may have become unjust or unreasonable.³⁸ If FERC makes such a determination, it has the authority to determine the “just and reasonable rate, charge, classification, rule, regulation, practice or contract to be thereafter observed” – but this authority is prospective.

These statutory provisions “mandating the open and transparent filing of rates and broadly proscribing their retroactive adjustment are known collectively as the ‘filed rate doctrine.’”³⁹ The filed rate doctrine prevents “‘a regulated seller of [power] . . . from collecting a rate other than the one filed with the Commission,’ and ‘the Commission itself’ cannot retroactively ‘impos[e] a rate increase for [power] already sold.’”⁴⁰ Similarly, the rule against retroactive ratemaking “prohibits the Commission from adjusting current rates to make up for a utility’s over- or under-collection in prior periods.”⁴¹

³⁶ 16 U.S.C. § 824d(c).

³⁷ *W. Deptford Energy, LLC v. FERC*, 766 F.3d 10, 12 (D.C. Cir. 2014) (“[U]tilities are forbidden to charge any rate other than the one on file with the Commission.”); *Okla. Gas & Elec. Co. v. FERC*, 11 F.4th 821, 829 (D.C. Cir. 2021).

³⁸ 16 U.S.C. § 824e(a).

³⁹ *Old Dominion Elec. Coop. v. FERC*, 892 F.3d 1223, 1226-27 (D.C. Cir. 2018).

⁴⁰ *Id.* at 1227 (quoting *Ark.-La. Gas Co. v. Hall*, 453 U.S. 571, 578 (1981)).

⁴¹ *Towns of Concord, Norwood, and Wellesley Mass. v. FERC*, 955 F.2d 67, 71 n.2 (D.C. Cir. 1992).

The prior notice and other strictures associated with ratemaking pursuant to FPA sections 205 and 206 do not apply under section 202(c) because those requirements are recognized to be rooted in the statutory language of FPA sections 205 and 206.⁴² In contrast to FPA sections 205(c) and 206(a), FPA section 202(c) does not have a prior notice requirement and it does not mandate the filing of rate schedules or the prospective fixing of charges. Rather, in the absence of agreement between “the parties affected by such [emergency] order,” section 202(c) permits the Commission to “prescribe by supplemental order such terms as it finds to be just and reasonable, including the compensation or reimbursement which should be paid to or by any such party.”⁴³

The independent nature of the Commission’s rate authority under section 202(c) is further supported by the fact that it is only triggered if the parties affected by the relevant 202(c) order are unable to reach an agreement.⁴⁴ In *San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Services*, the Commission explained that “[t]he statute provides *no role* for the Commission in the event the parties agree on the rates that will apply to the transactions [pursuant to FPA section 202(c)].”⁴⁵ The primacy that the FPA accords to the 202(c) rate determination reached by agreement of the parties is very different from traditional ratemaking rules under sections 205 and 206, which prescribe detailed filing and cost support requirements.⁴⁶

⁴² *Id.* at 71-72 (“[I]t is generally agreed that with respect to the Federal Power Act, the filed rate doctrine rests on two provisions: section 205(c), which requires utilities to file rate schedules with the Commission, and section 206(a), which allows the Commission to fix rates and charges, but only prospectively.”) (footnote omitted).

⁴³ 16 U.S.C. § 824a(c)(1).

⁴⁴ *Id.* (“If the parties affected by such order fail to agree upon the terms of any arrangement between them in carrying out such order, the Commission, . . . may prescribe . . .”).

⁴⁵ 97 FERC ¶ 61,275, at 62,196 (2001) (emphasis added) (subsequent history omitted).

⁴⁶ *See, e.g.*, 18 C.F.R. § 35.13 and § 385.206 (2024).

Finally, section 202(c) includes its own “just and reasonable” standard when making rate determinations.

For all of the foregoing reasons, the recovery of costs associated with a FPA section 202(c) order is separate and distinct from rate determinations made under FPA sections 205 and 206.

B. The Commission Should Require MISO to Revise the Tariff to Include the Proposed 202(c) Rate Recovery Mechanism

1. Regional Allocation of Costs is Appropriate to Reflect the Scope and Nature of the Emergency Identified by the Secretary

As discussed above in Section II.B.2, the DOE Order identifies reliability risks in MISO, particularly in the northern and central zones, as the basis for declaring an emergency and ordering the continued operation of the Campbell Plant until August 21, 2025. In light of the scope and nature of the declared emergency, allocating Consumers Energy’s Order Costs (net of market revenues) to load serving entities (“LSEs”) in MISO’s northern and central zones (which would include Michigan) comports with section 202(c)’s just and reasonable standard because the DOE Order identified reliability risks in those MISO zones as the basis for declaring the emergency.

While this case is not governed by sections 205 or 206, general beneficiary pays/cost-causation principles commonly invoked in connection with the Commission’s rate authority nevertheless provide a useful framework for analyzing cost allocation under 202(c).⁴⁷ Here, the Secretary of Energy has determined the scope and nature of an emergency, and the compelled generation or jurisdictional service needed to address it. Consequently, to determine appropriate cost recovery pursuant to FPA section 202(c), the beneficiary pays/cost-causation determination should track the emergency identified in the 202(c) order at issue. Any other approach would

⁴⁷ The beneficiary pays/cost-causation principle requires costs to be allocated to those who cause the costs to be incurred and reap the resulting benefits. *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 87 (D.C. Cir. 2014) (citing *Nat’l Ass’n of Regul. Util. Comm’rs v. FERC*, 475 F.3d 1277, 1285 (D.C. Cir. 2007)).

create a risk of conflict between the emergency 202(c) order and a subsequent analysis of cost-causation and benefits.

As applied here, this means that LSEs in MISO's northern and central zones should share the costs associated with the DOE Order on a load ratio share basis. The 202(c) Cost Recovery Mechanism set forth in Attachment A is designed to accomplish this outcome.

2. No MISO Tariff Provision Presently Would Permit Such Allocation and Recovery

Currently, there is no MISO Tariff provision that would permit Consumers Energy's costs of complying with the DOE Order to be allocated to LSEs in MISO's northern and central zones, which, if unaddressed, would effectively prevent Consumers Energy from recovering its costs via FPA section 202(c) even though, as discussed above, that statute, as well as DOE regulations and the DOE Order, all provide for full cost recovery. While full cost recovery is clearly contemplated, there is no MISO provision in the MISO Tariff that would allow Consumers Energy to recover costs associated with the DOE Order, Consumers Energy has no authority to bill anyone in MISO for such costs, and MISO cannot unilaterally offer Consumers Energy a section 202(c) rate agreement. Therefore, in order for Consumers Energy to have a means of recovering the costs that it has a right to recover, the MISO Tariff must be amended to include an appropriate recovery mechanism.

C. The Commission Has Authority Pursuant to FPA Section 309 to Require Revisions to the MISO Tariff to Implement the DOE Order

FPA section 309 authorizes the Commission "to perform any and all acts . . . as it may find necessary or appropriate to carry out the provisions of [the FPA]."⁴⁸ Courts have made clear that the Commission has significant authority under section 309 when employed to give effect to other

⁴⁸ *Id.*

substantive authority under the Act.⁴⁹ Here, the Commission’s underlying substantive authority is clearly provided by section 202(c). Because section 202(c) makes the Commission responsible for ensuring just and reasonable compensation for emergency generation or service, and because the MISO Tariff does not presently have a mechanism for addressing the Company’s Order Costs, the Commission should order MISO to implement the 202(c) Cost Recovery Mechanism the Company has included in Attachment A. This requested relief falls squarely within the Commission’s broad implementation authority under FPA section 309 and is “necessary . . . to carry out the provisions of”⁵⁰ FPA section 202(c).

V. ALTERNATIVE REQUEST FOR RELIEF PURSUANT TO FPA SECTION 206

The Company believes that FPA sections 202(c) and 309 provide ample authority for the Commission to grant the relief requested herein. Nonetheless, if the Commission finds it must invoke its FPA section 206 authority to grant the relief requested herein, Consumers Energy moves for relief under section 206 in the alternative. Under section 206, the Commission could make the requested Tariff revision effective as of the date of this Complaint.

“Section 206 permits, indeed requires, the Commission to determine whether an existing rate is ‘unjust, unreasonable, unduly discriminatory, or preferential.’”⁵¹ This statutory mandate includes determining whether a rate is unjust and unreasonable *as applied* to certain parties or to certain circumstances.⁵² Upon reaching a determination that an existing rate is unjust and

⁴⁹ *TNA Merchant Projects, Inc. v. FERC*, 857 F.3d 354, 359 (D.C. Cir. 2017); *Verso Corp. v. FERC*, 898 F.3d 1, 11-12 (D.C. Cir. 2018); *Xcel Energy Servs. Inc. v. FERC*, 815 F.3d 947 (D.C. Cir. 2016).

⁵⁰ 16 U.S.C. § 825h.

⁵¹ *Emera Me. v. FERC*, 854 F.3d 9, 21 (D.C. Cir. 2017) (quoting 16 U.S.C. § 824e(a)) (alteration incorporated).

⁵² *See, e.g., See, e.g., Pub. Serv. Elec. & Gas Co. v. FERC*, 989 F.3d 10, 18 (D.C. Cir. 2021) (“[T]he Commission reasonably found that the solution-based DFAX method was unjust and unreasonable as applied to the Artificial Island Project.”); *Am. Wind Energy Ass’n v. Sw. Power Pool, Inc.*, 167 FERC ¶

unreasonable, section 206 mandates that the Commission “determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order.”⁵³

As explained above, the Secretary of Energy has determined “that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes,” and that “additional dispatch of the Campbell Plant is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c).”⁵⁴ Consumers Energy will incur costs associated with the DOE Order, but the MISO Tariff does not presently include a mechanism that would allow MISO to compensate Consumers Energy for such costs or allocate those costs to load in the MISO region.

The MISO Tariff is thus unjust and unreasonable as applied to Consumers Energy and its compliance with the DOE Order, and the Commission should order MISO to adopt a Tariff revision to provide a cost recovery mechanism for Consumers Energy’s Order Costs net of market revenues. Should the Commission proceed under FPA section 206, however, Consumers Energy respectfully notes that the refund effective date that the Commission establishes pursuant to FPA section 206(b) has no bearing on, and does not limit, Consumers Energy’s right to recover the Order Costs it has already incurred and will continue to incur going forward.

61,033 at P 49 (2019) (“We find that SPP’s membership exit fee, as applied to non-transmission owners, is unjust and unreasonable because it creates a barrier to SPP membership for non-transmission owners and because it appears to be excessive based on the record before us.”), *order denying stay*, 168 FERC ¶ 61,006 (2019); *PJM Interconnection, L.L.C.*, 169 FERC ¶ 61,049 at P 138 (2019) (opening an FPA section 206 proceeding to, *inter alia*, examine “the justness and reasonableness of PJM’s minimum run-time requirements as applied to Capacity Storage Resources”); *PJM Interconnection, L.L.C.*, 137 FERC ¶ 61,145 at P 99 (2011) (“[T]he ultimate vehicle that will be required to establish that mitigation rules are unjust and unreasonable as applied to a particular project is a section 206 complaint.”) (subsequent history omitted).

⁵³ 16 U.S.C. § 824e(a).

⁵⁴ DOE Order at 1, 2.

VI. REQUEST FOR FAST TRACK PROCESSING AND EXPEDITED ACTION

Consumers Energy respectfully requests Fast Track processing and expedited action on this Complaint under Rule 206(h) of the Commission's Rules of Practice and Procedure. The Complaint merits expeditious resolution because Consumers Energy must establish a cost recovery mechanism for the costs that have been incurred, and are continuing to be incurred, to comply with the DOE Order. Expeditious action from the Commission to modify the MISO Tariff is appropriate in order to avoid challenges to Consumers Energy's right to cost recovery.

Consumers Energy respectfully requests that the Commission issue its ruling on the Complaint as soon as possible. Consumers Energy also respectfully requests a shortened comment period of ten days.

VII. ADDITIONAL INFORMATION REQUIRED BY RULE 206 OF THE COMMISSION'S RULES OF PROCEDURE

To the extent not already provided herein, the Company provides the following additional information required by Rule 206(b) of the Commission's Rules of Practice and Procedure:

- 1. Clearly identify the action or inaction which is alleged to violate applicable statutory standards or regulatory requirements; explain how the action or inaction violates applicable statutory standards or regulatory requirements.**

Despite Consumers Energy's right to recover costs incurred associated with the DOE Order, the MISO Tariff does not presently include a mechanism for the recovery and allocation of such costs, and MISO lacks Tariff authority to unilaterally offer Consumers Energy a section 202(c) rate agreement. The Commission should therefore require MISO to revise the MISO Tariff to include the proposed 202(c) Cost Recovery Mechanism.

- 2. Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the complainant.**

The information in Sections I through V of this Complaint sets forth the business, commercial, and economic issues at stake for the Company.

- 3. Make a good faith effort to quantify the financial impact or burden (if any) created for the complainant as a result of the action or inaction.**

Consumers Energy has established a regulatory asset to track all costs of operating the Campbell Plant from the date of the DOE Order. The total of such costs, net of market revenues, is not presently known. After the DOE Order expires, any costs that Consumers Energy seeks to recover through the 202(c) Cost Recovery Mechanism will be addressed in a future filing with the Commission.

- 4. Indicate the practical, operational, or other nonfinancial impacts imposed as a result of the action or inaction, including, where applicable, the environmental, safety or reliability impacts of the action or inaction.**

The DOE Order concludes that it is in the public interest for the Company to ensure that the Campbell Plant is “available to operate” in order to address the emergency conditions identified by the Secretary. The Company has a constitutional and statutory right to recover costs associated with the DOE Order. Failure of the Commission to provide the relief requested herein would conflict with the DOE Order and create unfair and unwarranted risk for the Company’s right to cost recovery.

- 5. State whether the issues presented are pending in an existing Commission proceeding or a proceeding in any other forum in which the complainant is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum.**

The issues raised in this Complaint are not pending in an existing Commission proceeding or a proceeding in any other forum in which Consumers Energy is a party. Resolution of these issues cannot be achieved in any pending docket.

6. **State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief.**

The specific relief requested is identified in Sections I and III of this Complaint.

7. **Include all documents that support the facts in the complaint in possession of, or otherwise attainable by, the complainant, including, but not limited to, contracts and affidavits.**

The only relevant document is the DOE Order, which is attached as Attachment C.

8. **State (i) whether the Enforcement Hotline, Dispute Resolution Service, tariff-based dispute resolution mechanisms, or other informal dispute resolution procedures were used, or why these procedures were not used; (ii) whether the complainant believes that alternative dispute resolution (ADR) under the Commission's supervision could successfully resolve the complaint; (iii) what types of ADR procedures could be used; and (iv) Any process that has been agreed on for resolving the complaint.**

As discussed above, Consumers Energy and MISO have cooperated extensively to evaluate and implement their respective responsibilities pursuant to the DOE Order. However, the MISO Tariff does not include a mechanism for the Company to recover costs associated with the DOE Order, and MISO does not possess unilateral authority to offer the Company a 202(c) rate agreement. Therefore, Consumers Energy believes Commission action on this Complaint is required in order to effectuate the relief requested.

9. **Include a form of notice of the complaint suitable for publication in the *Federal Register* in accordance with the specifications in § 385.203(d) of this part. The form of notice shall be on electronic media as specified by the Secretary.**

A form of notice suitable for publication in the *Federal Register* is attached to this Complaint as Attachment B.

- 10. Any person filing a complaint must serve a copy of the complaint on the respondent, affected regulatory agencies, and others the complainant reasonably knows may be expected to be affected by the complaint. Service must be simultaneous with filing at the Commission for respondents. Simultaneous or overnight service is permissible for other affected entities. Simultaneous service can be accomplished by electronic mail in accordance with § 385.2010(f)(3), facsimile, express delivery, or messenger.**

A copy of this Complaint has been served on the following via email:

Timothy Caister
Vice President, Legal and Federal Affairs
Midcontinent Independent System Operator, Inc.
720 City Center Drive
Carmel, IN 46032
Telephone: 317-220-2166
Fax: 317-249-5912
Email: misolegal@misoenergy.org

Jacob Krouse
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Midcontinent Independent System Operator, Inc.
720 City Center Drive
Carmel, IN 46032
Telephone: 317-408-7401
Fax: 317-249-5912
Email: jkrouse@misoenergy.org

VIII. CORRESPONDENCE AND COMMUNICATIONS

All correspondence and communications regarding this Complaint should be addressed to the following persons:⁵⁵

⁵⁵ To the extent necessary, Consumers Energy respectfully requests waiver of Rule 203(b)(3) of the Commission's Rules of Practice and Procedure to permit all of the following representatives to be placed on the official service list for this proceeding.

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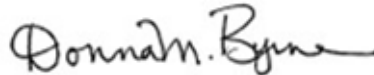
IX. CONCLUSION

For the reasons discussed above, Consumers Energy respectfully requests that the Commission swiftly issue an order granting the Complaint.

/s/ Emerson J. Hilton
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Respectfully submitted,



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Counsel to Consumers Energy

Attachment A

MISO
FERC Electric Tariff
SCHEDULES

SCHEDULE {XYZ}
Allocation of Costs Associated with DOE Order No. 202-25-3
{00.0.0}

SCHEDULE {XYZ}

Allocation of Costs Associated with Continued Availability of J.H. Campbell Plant Pursuant to DOE Order No. 202-25-3

On May 23, 2025, the U.S. Secretary of Energy (“Secretary”) issued an order pursuant to section 202(c) of the Federal Power Act (“FPA”), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), determining that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes (“202(c) Emergency”). *See* Department of Energy, Order No. 202-25-3 (“DOE Order”). The DOE Order compelled MISO and Consumers Energy to ensure the continued operation and availability of the 1,560 MW J.H. Campbell coal-fired power plant (“Campbell Plant”) from May 23, 2025, through August 21, 2025 (the “Order Duration Period”).

The Secretary ordered MISO and Consumers Energy to take all measures necessary to ensure that the Campbell Plant is available to operate during the Order Duration Period. The DOE Order also orders MISO to “take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers.” The DOE Order confirms that rate recovery is available pursuant to FPA section 202(c).

Costs associated with the DOE Order have been incurred, and will continue to be incurred, during the Order Duration Period (“Order Costs”). Consumers Energy (on its own behalf and, as necessary, on behalf of the minority interest owners in Campbell Unit 3, Wolverine Power Supply

Cooperative, Inc. and the Michigan Public Power Agency) shall petition FERC to approve recovery of Order Costs, net of market revenues, that FERC determines are recoverable pursuant to section 202(c) (“Recoverable Order Costs”).

This Schedule {XYZ} shall allocate the Recoverable Order Costs incurred during the Order Duration Period, and any extensions of the same by the Secretary, in the following manner. MISO shall allocate the Recoverable Order Costs to LSEs in the Zones 1-7 (or such successor zone designations reflecting the Northern and Central MISO Zones) (“Affected LSEs”) on a load ratio share basis.

The charge to each Affected LSE (AFF_LSE_CHG) is obtained by multiplying Affected LSE load ratio share (AFF_LSE_SHARE) by the Recoverable Order Costs (REC_EMERG_ORDER_COSTS):

$$\text{AFF_LSE_CHG} = \text{AFF_LSE_SHARE} \times \text{REC_EMERG_ORDER_COSTS}$$

Effective On: {DATE}

Attachment B

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Consumers Energy Company)	
)	Docket No. EL25-____-000
v.)	
)	
Midcontinent Independent System Operator, Inc.)	

NOTICE OF COMPLAINT

(_____)

Take notice that on June 6, 2025, Consumers Energy Company (“Consumers Energy”) filed a complaint (“Complaint”) against Midcontinent Independent System Operator, Inc. (“MISO”) pursuant to sections 202(c), 306, and 309 of the Federal Power Act (“FPA”)¹ and Rule 206 of the Federal Energy Regulatory Commission’s (“FERC” or “Commission”) Rules of Practice and Procedure.² Consumers Energy requests the Commission direct MISO to revise its Open Access Transmission, Energy and Operating Reserve Markets Tariff to effectuate an emergency order issued by the Secretary of Energy on May 23, 2025, pursuant to FPA section 202(c).³

Consumers Energy certifies that a copy of the Complaint was served on representatives of MISO.

Any person desiring to intervene or protest this filing must file in accordance with Rules 211 and 214 of the Commission’s Rules of Practice and Procedure (18 C.F.R. §§ 385.211 and 214). Protests will be considered by the Commission in determining the appropriate action to be taken but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. The Respondent’s answer and all interventions or protests must be filed on or before the comment date. The Respondent’s answer, motions to intervene, and protests must be served on the Complainant.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the “eFiling link at <http://www.ferc.gov>. Persons unable to file electronically should submit an original and five (5) copies of the protest to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426.

¹ 16 U.S.C. §§ 824e, 825e, 825h.

² 18 C.F.R. § 385.206 (2024).

³ U.S. Department of Energy, Order No. 202-25-3 (May 23, 2025) (“DOE Order”).

This filing is accessible online at <http://www.ferc.gov>, using the “eLibrary” link and is available for review in the Commission’s Public Reference Room in Washington, DC. There is an “eSubscription” link on the website that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email FERCOnlineSupport@ferc.gov, or call (866) 208-3676 (toll-free). For TTY, call (202) 502-8659.

Comment Date: 5:00 pm Eastern Time on (_____).

Debbie-Anne A. Reese
Secretary

Attachment C

Order No. 202-25-3

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

The Midcontinent Independent System Operator (MISO) faces potential tight reserve margins during the summer 2025 period, particularly during periods of high demand or low generation resource output. The North American Electric Reliability Corporation (NERC) released its 2025 Summer Reliability Assessment on May 14, 2025. In its assessment, NERC indicated that “[d]emand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output.”¹ In particular, the retirement of thermal generation capacity creates the potential for electricity supply shortfalls. NERC anticipates that the near-term period of highest capacity shortfall for MISO will occur in August.²

Multiple generation facilities in Michigan have retired in recent years. According to the U.S. Energy Information Administration (EIA), “[s]ince 2020, about 2,700 megawatts of coal-fired generating capacity have been retired and no new coal-fired facilities are planned.”³ Additionally EIA stated, “[t]ypically Michigan’s nuclear power plants have supplied about 30% of in-state electricity, but the amount of electricity generated by nuclear power plants in Michigan has declined as plants have been decommissioned.”⁴ The state’s Big Rock Point nuclear power plant shut down in 1997 and the Palisades nuclear power plant closed in 2022. While the Palisades nuclear power plant may reopen in 2025, it will not be available during the peak demand period this summer.

The 1,560 MW J.H. Campbell coal-fired power plant in West Olive, MI, is scheduled to cease operations on May 31, 2025. Its retirement would further decrease available dispatchable generation within MISO’s service territory, removing additional such generation along with the other 1,575 MW of natural gas and coal-fired generation that has retired since the summer of 2024. In 2021, Consumers announced that it planned to “speed closure” of Campbell in 2025, several years before the end of its scheduled design life.⁵ Although MISO and Consumers have

¹ 2025 summer reliability assessment. (May 14, 2025).

https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf

² *Id.*

³ U.S. Energy Information Administration, Michigan State Energy Profile, Oct. 17, 2024, *available at*: <https://www.eia.gov/state/print.php?sid=mi>.

⁴ *Id.*

⁵ <https://www.consumersenergy.com/news-releases/news-release-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-clean-energy-transformation>

incorporated the planned retirement into their supply forecasts and acquired a 1,200 MW natural gas power plant in Covert, MI, the NERC Assessment still anticipates “elevated risk of operating reserve shortfalls.”

MISO’s Planning Resource Auction Results for Planning Year 2025-26, released in April 2025, note that for the northern and central zones, which includes Michigan, “new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources.” While the results “demonstrated sufficient capacity,” the summer months reflected the “highest risk and a tighter supply-demand balance” and the results “reinforce the need to increase capacity.”⁶

ORDER

Given the determination that an emergency exists as discussed above, the responsibility of MISO to ensure reliability of its system, and the ability of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, additional dispatch of the Campbell Plant is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on the insufficiency of dispatchable capacity and anticipated demand during the summer months, and the potential loss of power to homes and local businesses in the areas that may be affected by curtailments or outages, presenting a risk to public health and safety.

This Order is limited in duration to align with the emergency circumstances. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation on the conditions contained in this Order, with reporting requirements as described below.

FPA section 202(c) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the “hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable,” be consistent with any applicable environmental law and minimize any adverse environmental impacts.

Based on my determination of an emergency set forth above, I hereby order:

- A. From the time this Order is issued on May 23, 2025, MISO and Consumers Energy shall take all measures necessary to ensure that the Campbell Plant is available to operate. For the duration of this order, MISO is directed to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers. Following conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Consumers Energy is directed to comply with all orders from MISO related to the availability and dispatch of the Campbell Plant.

⁶ <https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250428694160.pdf>

- B. To minimize adverse environmental impacts, this Order limits operation of dispatched units through the expiration of the Order. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Campbell Plant has operated in compliance with the allowances contained in this Order.
- C. All operation of the Campbell Plant must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.
- D. By June 15, 2025, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability and economic dispatch of the Campbell Plant consistent with the public interest. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.
- E. The extent to which MISO's current Tariff provisions are inapposite to effectuate the dispatch and operation of the units for the reasons specified herein, the relevant governmental authorities are directed to take such action and make accommodations as may be necessary to do so.
- F. Consumers is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers necessary to effectuate this order. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).
- G. This Order shall not preclude the need for the Campbell Plant to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.
- H. This Order shall be effective upon its issuance, and shall expire at 00:00 EDT on August 21, 2025, with the exception of the reporting requirements in paragraph D and applicable compliance obligations in paragraph E.
- I. Issued in Washington, D.C. at 3:15:pm Eastern Daylight Time on this 23rd day of May 2025.



Chris Wright
Secretary of Energy

cc: **FERC Commissioners**

Chairman Mark Christie
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang

Michigan Public Service Commissioners

Chairman Dan Cripps
Commissioner Katherine Peretick
Commissioner Alessandra Carreon

Attachment Y

MISO, Grid Conditions Explainer



Grid Conditions At a Glance

The grid conditions gauge is a visual representation of MISO's active market capacity emergency notifications. The tool, designed for situational awareness only, shows real-time generation (capacity) and/or weather conditions impacting the MISO grid. The gauge needle moves when an alert, advisory, warning, event, or termination instruction takes effect (not when a notification is sent).

Disclaimer: MISO notifications are official communications authored by the control room shift manager. The notification takes precedence over what may be shared visually on the Grid Conditions gauge.



Grid Conditions Normal

Green

Under normal grid conditions, the needle points to the green section of the gauge signifying the grid is stable.

Should operators issue a weather related alert, e.g. Severe Weather Alert, the needle remains in the green. However, a "View Notification" button will appear under the gauge. By clicking on the button, users can read the alert issued by the control room shift manager. The alert includes information on the affected MISO region and expected weather conditions.

All MISO notifications are operator-to-operator communications.



Grid Advisories/Warnings Issued

Grid Stable

[View Notification](#)

Yellow

The grid is stable and MISO has issued one or more of the following notifications:

Conservative Operations: Used for situational awareness, the conservative operations notification asks MISO members to defer, delay, or recall any non-essential maintenance. This notification provides MISO member operators an indication that system conditions *may* require special attention.

Capacity Advisory: Used for situational awareness, this notification informs MISO member operators that, based on projected system conditions and capacity (supply) levels, there *may* be a need in the coming days to bring additional generation on-line.

Maximum Generation Alert: Used for situational awareness, this notification serves as an early alert that system conditions *may* require emergency actions.

Maximum Generation Warning: This notification asks member operators to prepare for a *possible* situation (an energy emergency alert) where operating reserve requirements may not be met without taking actions.



Energy Emergency Alert 1 (EEA1)

Power demand could exceed available supply
Grid Stable

[View Notification](#)

Orange

The grid is stable and MISO has issued an Energy Emergency Alert 1 (EEA1).

EEA1 is the first level of emergency action, triggered when MISO can no longer meet the forecasted demand and operating reserve requirements without intervention. In other words, it indicates that power demand may exceed supply if no action is taken.

By declaring EEA1, MISO operators can access additional generation to boost the electricity supply and maintain grid reliability.



Energy Emergency Alert 2 (EEA2)

Emergency power and/or reduced demand necessary

[View Notification](#)

Dark Orange

The grid is stable and MISO has issued an Energy Emergency Alert 2 (EEA2).

EEA2 is the second level of emergency action, triggered as operating reserves continue to decline. It means MISO is facing an energy shortage and needs to reduce energy demand.

By declaring EEA2, MISO operators can access emergency generation not available under normal conditions. They may also purchase emergency energy from neighboring grids (if available) and implement measures to reduce electricity demand. One option is for MISO to ask member utilities to encourage consumers to conserve power. However, an EEA2 declaration does not automatically mean this step will be taken.



Energy Emergency Alert 3 (EEA3)

Power interruptions imminent or happening

[View Notification](#)

Red

MISO has issued an Energy Emergency Alert 3 (EEA3).

EEA3 is the final level of emergency action, triggered to prevent cascading outages and ensure grid reliability for as many consumers as possible. It indicates that energy supply and demand are unbalanced, and power interruptions are imminent or already occurring.

Power interruptions are a last resort to protect the grid's stability. In these rare situations, MISO's role is to identify the areas where interruptions are needed and determine how much electricity must be reduced to balance supply and demand. MISO's member utilities are responsible for carrying out the interruptions and deciding which customers will temporarily lose power.



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Attachment Z

NERC, Attachment 1-EOP-011-1 Energy Emergency Alerts.

A. Introduction

1. **Title:** Emergency Operations
2. **Number:** EOP-011-1
3. **Purpose:** To address the effects of operating Emergencies by ensuring each Transmission Operator and Balancing Authority has developed Operating Plan(s) to mitigate operating Emergencies, and that those plans are coordinated within a Reliability Coordinator Area.
4. **Applicability:**
 - 4.1. **Functional Entities:**
 - 4.1.1 Balancing Authority
 - 4.1.2 Reliability Coordinator
 - 4.1.3 Transmission Operator
5. **Effective Date:**

See *Implementation Plan for EOP-011-1*
6. **Background:**

EOP-011-1 consolidates requirements from three standards: EOP-001-2.1b, EOP-002-3.1, and EOP-003-2.

The standard streamlines the requirements for Emergency operations for the Bulk Electric System into a clear and concise standard that is organized by Functional Entity. In addition, the revisions clarify the critical requirements for Emergency Operations, while ensuring strong communication and coordination across the Functional Entities.

B. Requirements and Measures

- R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*
 - 1.1. Roles and responsibilities for activating the Operating Plan(s);
 - 1.2. Processes to prepare for and mitigate Emergencies including:
 - 1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency;
 - 1.2.2. Cancellation or recall of Transmission and generation outages;
 - 1.2.3. Transmission system reconfiguration;
 - 1.2.4. Redispatch of generation request;

- M2.** Each Balancing Authority will have a dated Operating Plan(s) developed in accordance with Requirement R2 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R2.
- R3.** The Reliability Coordinator shall review the Operating Plan(s) to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority regarding any reliability risks that are identified between Operating Plans. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- 3.1.** Within 30 calendar days of receipt, the Reliability Coordinator shall:
- 3.1.1.** Review each submitted Operating Plan(s) on the basis of compatibility and inter-dependency with other Balancing Authorities' and Transmission Operators' Operating Plans;
 - 3.1.2.** Review each submitted Operating Plan(s) for coordination to avoid risk to Wide Area reliability; and
 - 3.1.3.** Notify each Balancing Authority and Transmission Operator of the results of its review, specifying any time frame for resubmittal of its Operating Plan(s) if revisions are identified.
- M3.** The Reliability Coordinator will have documentation, such as dated e-mails or other correspondences that it reviewed Transmission Operator and Balancing Authority Operating Plans within 30 calendar days of submittal in accordance with Requirement R3.
- R4.** Each Transmission Operator and Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R3 and resubmit its Operating Plan(s) to its Reliability Coordinator within a time period specified by its Reliability Coordinator. *[Violation Risk Factor: High] [Time Horizon: Operation Planning]*
- M4.** The Transmission Operator and Balancing Authority will have documentation, such as dated emails or other correspondence, with an Operating Plan(s) version history showing that it responded and updated the Operating Plan(s) within the timeframe identified by its Reliability Coordinator in accordance with Requirement R4.
- R5.** Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

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- M5.** Each Reliability Coordinator that receives an Emergency notification from a Balancing Authority or Transmission Operator within its Reliability Coordinator Area will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that will be used to determine if the Reliability Coordinator communicated, in accordance with Requirement R5, with other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators .
- R6.** Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall declare an Energy Emergency Alert, as detailed in Attachment 1. [*Violation Risk Factor: High*]
[*Time Horizon: Real-Time Operations*]
- M6.** Each Reliability Coordinator, with a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area, will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that it declared an Energy Emergency Alert, as detailed in Attachment 1, in accordance with Requirement R6.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The Balancing Authority, Reliability Coordinator, and Transmission Operator shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Transmission Operator shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R1 and R4 and Measures M1 and M4.
- The Balancing Authority shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R2 and R4, and Measures M2 and M4.
- The Reliability Coordinator shall maintain evidence of compliance since the last audit for Requirements R3, R5, and R6 and Measures M3, M5, and M6.

If a Balancing Authority, Reliability Coordinator or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

As defined in the NERC Rules of Procedure; “Compliance Monitoring and Assessment Processes” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real-time Operations, Operations Planning, Long-term Planning	High		The Transmission Operator developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area but failed to maintain it.	The Transmission Operator developed an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area but failed to have it reviewed by its Reliability Coordinator.	The Transmission Operator failed to develop an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. OR The Transmission Operator developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area but failed to implement it.

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R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Real-time Operations, Operations Planning, Long-term Planning	High	N/A	The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area but failed to maintain it.	The Balancing Authority developed an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area but failed to have it reviewed by its Reliability Coordinator.	The Balancing Authority failed to develop an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area. OR The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area but failed to implement it.

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R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Operations Planning	High	N/A	N/A	The Reliability Coordinator identified a reliability risk but failed to notify the Balancing Authority or Transmission Operator within 30 calendar days.	The Reliability Coordinator identified a reliability risk but failed to notify the Balancing Authority or Transmission Operator.
R4	Operations Planning	High	N/A	N/A	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator within the timeframe specified by its Reliability Coordinator.	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator.
R5	Real-time Operations	High	N/A	N/A	The Reliability Coordinator that received an Emergency	The Reliability Coordinator that received an Emergency

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R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					notification from a Transmission Operator or Balancing Authority did notify neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators but failed to notify within 30 minutes from the time of receiving notification.	notification from a Transmission Operator or Balancing Authority failed to notify neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators.
R6	Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to declare an Energy Emergency Alert.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	November 13, 2014	Adopted by Board of Trustees	Merged EOP-001-2.1b, EOP-002-3.1 and EOP-003-2.
1	November 19, 2015	FERC approved EOP-011-1. Docket Nos. RM15-7-000, RM15-12-000, and RM15-13-000. Order No. 818	

Attachment 1-EOP-011-1 Energy Emergency Alerts

Introduction

This Attachment provides the process and descriptions of the levels used by the Reliability Coordinator in which it communicates the condition of a Balancing Authority which is experiencing an Energy Emergency.

A. General Responsibilities

- 1. Initiation by Reliability Coordinator.** An Energy Emergency Alert (EEA) may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of an energy deficient Balancing Authority.
- 2. Notification.** A Reliability Coordinator who declares an EEA shall notify all Balancing Authorities and Transmission Operators in its Reliability Coordinator Area. The Reliability Coordinator shall also notify all neighboring Reliability Coordinators.

B. EEA Levels

Introduction

To ensure that all Reliability Coordinators clearly understand potential and actual Energy Emergencies in the Interconnection, NERC has established three levels of EEAs. The Reliability Coordinators will use these terms when communicating Energy Emergencies to each other. An EEA is an Emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC Reliability Standards.

The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

1. EEA 1 — All available generation resources in use.

Circumstances:

- The Balancing Authority is experiencing conditions where all available generation resources are committed to meet firm Load, firm transactions, and reserve commitments, and is concerned about sustaining its required Contingency Reserves.
- Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. EEA 2 — Load management procedures in effect.

Circumstances:

- The Balancing Authority is no longer able to provide its expected energy requirements and is an energy deficient Balancing Authority.
- An energy deficient Balancing Authority has implemented its Operating Plan(s) to mitigate Emergencies.

- An energy deficient Balancing Authority is still able to maintain minimum Contingency Reserve requirements.

During EEA 2, Reliability Coordinators and energy deficient Balancing Authorities have the following responsibilities:

2.1 Notifying other Balancing Authorities and market participants. The energy deficient Balancing Authority shall communicate its needs to other Balancing Authorities and market participants. Upon request from the energy deficient Balancing Authority, the respective Reliability Coordinator shall post the declaration of the alert level, along with the name of the energy deficient Balancing Authority on the RCIS website.

2.2 Declaration period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators.

2.3 Sharing information on resource availability. Other Reliability Coordinators of Balancing Authorities with available resources shall coordinate, as appropriate, with the Reliability Coordinator that has an energy deficient Balancing Authority.

2.4 Evaluating and mitigating Transmission limitations. The Reliability Coordinator shall review Transmission outages and work with the Transmission Operator(s) to see if it's possible to return to service any Transmission Elements that may relieve the loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).

2.5 Requesting Balancing Authority actions. Before requesting an EEA 3, the energy deficient Balancing Authority must make use of all available resources; this includes, but is not limited to:

2.5.1 All available generation units are on line. All generation capable of being on line in the time frame of the Emergency is on line.

2.5.2 Demand-Side Management. Activate Demand-Side Management within provisions of any applicable agreements.

3. EEA 3 — Firm Load interruption is imminent or in progress.

Circumstances:

- The energy deficient Balancing Authority is unable to meet minimum Contingency Reserve requirements.

During EEA 3, Reliability Coordinators and Balancing Authorities have the following responsibilities:

3.1 Continue actions from EEA 2. The Reliability Coordinators and the energy deficient Balancing Authority shall continue to take all actions initiated during EEA 2.

3.2 Declaration Period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities, and Transmission Operators.

3.3 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator shall evaluate the risks of revising SOLs and IROLs for the possibility of delivery of energy to the energy deficient Balancing Authority. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Transmission Operator whose Transmission Owner (TO) equipment would be affected. SOLs and IROLs shall only be revised as long as an EEA 3 condition exists, or as allowed by the Transmission Owner whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

3.3.1 Energy deficient Balancing Authority obligations. The energy deficient Balancing Authority, upon notification from its Reliability Coordinator of the situation, it will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include Load shedding.

3.4 Returning to pre-Emergency conditions. Whenever energy is made available to an energy deficient Balancing Authority such that the Systems can be returned to its pre-Emergency SOLs or IROLs condition, the energy deficient Balancing Authority shall request the Reliability Coordinator to downgrade the alert level.

3.4.1 Notification of other parties. Upon notification from the energy deficient Balancing Authority that an alert has been downgraded, the Reliability Coordinator shall notify the neighboring Reliability Coordinators (via the RCIS), Balancing Authorities and Transmission Operators that its Systems can be returned to its normal limits.

Alert 0 - Termination. When the energy deficient Balancing Authority is able to meet its Load and Operating Reserve requirements, it shall request its Reliability Coordinator to terminate the EEA.

0.1 Notification. The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the neighboring Balancing Authorities and Transmission Operators.

Guidelines and Technical Basis

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

The EOP SDT examined the recommendation of the EOP Five-Year Review Team (FYRT) and FERC directive to provide guidance on applicable entity responsibility that was included in EOP-001-2.1b. The EOP SDT removed EOP-001-2.1b, Attachment 1, and incorporated it into this standard under the applicable requirements. This also establishes a separate requirement for the Transmission Operator to create an Operating Plan(s) for mitigating operating Emergencies in its Transmission Operator Area.

The Operating Plan(s) can be one plan, or it can be multiple plans.

“Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency” was retained. This is a process in the plan(s) that determines when the Transmission Operator must notify its Reliability Coordinator.

To meet the associated measure, an entity would likely provide evidence that such an evaluation was conducted along with an explanation of why any overlap of Loads between manual and automatic load shedding was unavoidable or reasonable.

An Operating Plan(s) is implemented by carrying out its stated actions.

If any Parts of Requirement R1 are not applicable, the Transmission Operator should note “not applicable” in the Operating Plan(s). The EOP SDT recognizes that across the regions, Operating Plan(s) may not include all the elements listed in this requirement due to restrictions, other methods of managing situations, and documents that may already exist that speak to a process that already exists. Therefore, the entity must provide in the plan(s) that the element is not applicable and detail why it is not applicable for the plan(s).

With respect to automatic Load shedding schemes that include both UVLS and UFLS, the EOP SDT’s intent is to keep manual and automatic Load shed schemes as separate as possible, but realizes that sometimes, due to system design, there will be overlap. The intent in Requirement R1 Part 1.2.5. is to minimize, as much as possible, the use of manual Load shedding which is already armed for automatic Load shedding. The automatic Load shedding schemes are the important backstops against Cascading outages or System collapse. If any entity manually sheds a Load which was included in an automatic scheme, it reduces the effectiveness of that automatic scheme. Each entity should review their automatic Load shedding schemes and coordinate their manual processes so that any overlapping use of Loads is avoided to the extent reasonably possible.

Application Guidelines

Rationale for R2:

To address the recommendation of the FYRT and the FERC directive to provide guidance on applicable entity responsibility in EOP-001-2.1b, Attachment 1, the EOP SDT removed EOP-001-2.1b, Attachment 1, and incorporated it into this standard under the applicable requirements. EOP-011-1 also establishes a separate requirement for the Balancing Authority to create its Operating Plan(s) to address Capacity and Energy Emergencies.

The Operating Plan(s) can be one plan, or it can be multiple plans.

An Operating Plan(s) is implemented by carrying out its stated actions.

If any Parts of Requirement R2 are not applicable, the Balancing Authority should note “not applicable” in the Operating Plan(s). The EOP SDT recognizes that across the regions, Operating Plan(s) may not include all the elements listed in this requirement due to restrictions, other methods of managing situations, and documents that may already exist that speak to a process that already exists. Therefore, the entity must provide in the plan(s) that the element is not applicable and detail why it is not applicable for the plan(s).

The EOP SDT retained the statement “Operator-controlled manual Load shedding,” as it was in the current EOP-003-2 and is consistent with the intent of the EOP SDT.

With respect to automatic Load shedding schemes that include both UVLS and UFLS, the EOP SDT’s intent is to keep manual and automatic Load shedding schemes as separate as possible, but realizes that sometimes, due to system design, there will be overlap. The intent in Requirement R2 Part 2.2.8. is to minimize as much as possible the use manual Load shedding which is already armed for automatic Load shedding. The automatic Load shedding schemes are the important backstops against Cascading outages or System collapse. If an entity manually sheds a Load that was included in an automatic scheme, it reduces the effectiveness of that automatic scheme. Each entity should review its automatic Load shedding schemes and coordinate its manual processes so that any overlapping use of Loads is avoided to the extent possible.

The EOP SDT retained Requirement R8 from EOP-002-3.1 and added it to the Parts in Requirement R2.

Rationale for R3:

The SDT agreed with industry comments that the Reliability Coordinator does not need to approve BA and TOP plan(s). The SDT has changed this requirement to remove the approval but still require the RC to review each entity’s plan(s), looking specifically for reliability risks. This is consistent with the Reliability Coordinator’s role within the Functional Model and meets the FERC directive regarding the RC’s involvement in Operating Plan(s) for mitigating Emergencies.

Rationale for Requirement R4:

Requirement R4 supports the coordination of Operating Plans within a Reliability Coordinator Area in order to identify and correct any Wide Area reliability risks. The EOP SDT expects the Reliability Coordinator to make a reasonable request for response time. The time period requested by the Reliability Coordinator to the Transmission Operator and Balancing Authority to update the Operating Plan(s) will depend on the scope and urgency of the requested change.

Application Guidelines

Rationale for R5

The EOP SDT used the existing requirement in EOP-002-3.1 for the Balancing Authority and added the words “within 30 minutes from the time of receiving notification” to the requirement to communicate the intent that timeliness is important, while balancing the concern that in an Emergency there may be a need to alleviate excessive notifications on Balancing Authorities and Transmission Operators. By adding this time limitation, a measurable standard is set for when the Reliability Coordinator must complete these notifications.

Rationale for Introduction

LSEs were removed from Attachment 1, as an LSE has no Real-time reliability functionality with respect to EEAs.

EOP-002-3.1 Requirement R9 was in place to allow for a Transmission Service Provider to change the priority of a service request, as permitted in its transmission tariff, informing the Reliability Coordinator so that the service would not be curtailed by a TLR; and since the Tagging Specs did not allow profiles to be changed, this was the only method to accomplish it. Under NAESB WEQ E-tag Specification v1811 R3.6.1.3, this has been modified and now the TSP has the ability to change the Transmission priority which, in turn, is reflected in the IDC. This technology change allows for the deletion of Requirement R9 in its entirety. Requirement R9 meets with Criterion A of Paragraph 81 and should be retired.

Rationale for (2) Notification

The EOP SDT deleted the language, “*The Reliability Coordinator shall also notify all other Reliability Coordinators of the situation via the Reliability Coordinator Information System (RCIS). Additionally, conference calls between RCs shall be held as necessary to communicate system conditions. The RC shall also notify the other RCs when the alert has ended*” as duplicative to proposed IRO-014-3 Requirement R1:

R1. Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following:

- 1.1 Communications and notifications, and the process to follow in making those notifications.
- 1.2 Energy and capacity shortages.
- 1.3 Control of voltage, including the coordination of reactive resources.
Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments.
- 1.5 Authority to act to prevent and mitigate system conditions which could adversely impact other Reliability Coordinator Areas.
- 1.6 Provisions for weekly conference calls.

Application Guidelines

Rationale for EEA 2:

The EOP SDT modified the “Circumstances” for EEA 2 to show that an entity will be in this level when it has implemented its Operating Plan(s) to mitigate Emergencies but is still able to maintain Contingency Reserves.

Rationale for EEA 3:

This rationale was added at the request of stakeholders asking for justification for moving a lack of Contingency Reserves into the EEA3 category.

The previous language in EOP-002-3.1, EEA 2 used “Operating Reserve,” which is an all-inclusive term, including all reserves (including Contingency Reserves). Many Operating Reserves are used continuously, every hour of every day. Total Operating Reserve requirements are kind of nebulous since they do not have a specific hard minimum value. Contingency Reserves are used far less frequently. Because of the confusion over this issue, evidenced by the comments received, the drafting team thought that using minimum Contingency Reserve in the language would eliminate some of the confusion. This is a different approach but the drafting team believes this is a good approach and was supported by several commenters.

Using Contingency Reserves (which is a subset of Operating Reserves) puts a BA closer to the operating edge. The drafting team felt that the point where a BA can no longer maintain this important Contingency Reserves margin is a most serious condition and puts the BA into a position where they are very close to shedding Load (“imminent or in progress”). The drafting team felt that this warrants categorization at the highest level of EEA.