BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-26-16

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 76

Secretary Wright's West Virginia Remarks

https://www.wvnews.com/news/wvnews/energy-secretary-chris-wright-future-of-u-s-coal-is-long-and-bright/article_948eb88e-2509-42a3-b985-07c47f1ee151.html

TOP STORY

Energy Secretary Chris Wright: Future of U.S. coal Is 'long and bright'

by Charles Young SENIOR STAFF WRITER
Jul 5, 2025

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Some coal-fired facilities have been closed before the end of their useful lives, said U.S. Energy Secretary Chris Wright Morgantown.

Staff photo by Charles Young

MORGANTOWN (WV News) — “The future for coal is long and bright,” said U.S. Energy Secretary



Wright, while visiting the National Energy Technology Laboratory facility, said the Trump administration wants to work to reverse the industry's decades of decline by encouraging greater production and use of coal, along with preventing the premature closure of still-viable coal-fired power plants.

The administration views coal as a valuable asset needed to gain an economic edge over China, especially when it comes to AI, Wright said.

"We're going to need 50 to maybe 150 gigawatts of new capacity, and if you're going to add a lot of new capacity, the first thing you should do is stop shrinking the capacity you have," he said.

Wright calls the need to increase the nation's electrical capacity the "second Manhattan Project," in reference to the program that created the first atomic weapons.

"AI is the second parallel — a huge innovation where we can't get second," he said. "China put on about 90 new coal plants last year, and about a similar amount of new plants will come on this year. They've rapidly grown their electricity for industrial processes, also for AI."

Recommissioning a retired coal-fired facility is a difficult process, but his team plans to look into the possibility of bringing some closed plants back online, Wright said.

"We're looking at that, and I think you will see some coal plants reopened," he said.

Meanwhile, his department will work to prevent the imminent closure of facilities throughout the country, Wright said.

"I think our biggest impact by far is going to be — there are like 40 coal plants that are supposed to close this year — and our biggest impact is going to be to stop the closure of most of those," he said.

As U.S. energy secretary, he has the authority to prevent the planned closure of some power plants, Wright said.

"It's been very politically fashionable to close, really for the last 15 or 20 years, coal power

West Virginia has a long history of energy production, dating back more than a century, Wright said.

“West Virginia has been an energy industrial powerhouse since it has been a state,” he said. “I think the outlook in energy and industry is quite bright.”

In April, Trump signed a series of executive orders to reinvigorate the “Beautiful Clean Coal Industry,” prevent regulatory overreach by state governments, and strengthen the reliability of the national electric grid.

“These executive orders are a direct investment in America’s energy future and in the communities that have long powered our nation,” Trump said during the event.

The orders mark a major shift for the industry, according to Coal Association President Chris Hamilton.

“We are deeply grateful to President Trump, Energy Secretary Wright, Secretary [Doug] Burgum, and EPA Administrator Lee Zeldin for their leadership in rolling back these anti-coal regulations,” he said. “For years, our industry has faced undue pressure from excessive regulatory measures that have led to job loss and stifled industry growth and innovation.”

Sen. Shelley Moore Capito, R-W.Va., recently said the administration’s efforts to support the coal industry will “keep our coal miners working and our coal facilities open, I think will increase employment just because of increased production but also the increased use of coal.”



Hamilton

However, it’s unlikely any new coal-fired power plants will be built any time soon, Capito said.

“You and I both know that’s a pretty steep hill to climb,” she said. “There have been no new coal

The Longview Power Plant in Monongalia County, near Maidsville, went into operation in 2011.



Capito



The Longview Power Plant in Monongalia County, near Maidsville, went into operation in 2011.
Staff file photo by Charles Young

The president's plan instead calls for the industry to "modernize what we have," Capito said.

"So that we can run them through their entire life and then keep that employment very robust," she said.

There are nine coal-fired electrical generation facilities in West Virginia: Pleasants Power Station, Harrison Power Station, Mountaineer Power, John Amos, Mount Storm, Morgantown Energy Associates, Longview Power, Fort Martin Power Station and Mitchell Power.

West Virginia is the second-largest coal producer in the nation, after Wyoming, and accounts

West Virginia has 16% of U.S. recoverable coal reserves, the third-largest state reserves after Wyoming and Illinois.

In 2023, coal-fired power plants accounted for 86% of West Virginia's total electricity net generation. Renewable energy resources, primarily wind energy and hydroelectric power, contributed 7%, and natural gas also provided about 7%.

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Exhibit 77

MISO 2021 Transmittal Letter

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November 30, 2021

VIA ELECTRONIC FILING

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: Midcontinent Independent System Operator, Inc.'s Filing to Include Seasonal and Accreditation Requirements for the MISO Resource Adequacy Construct Docket No. ER22-____-000

Dear Secretary Bose:

The Midcontinent Independent System Operator, Inc. ("MISO"), through this filing, proposes revisions to its Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff")[1] to establish Resource Adequacy Requirements on a seasonal basis for each of the Summer, Fall, Winter and Spring Seasons, and to implement an availability-based Seasonal Accredited Capacity ("SAC") methodology for resources participating in MISO's annual Planning Resource Auction ("PRA"). As discussed in detail below, Commission action is needed at this time in order to ensure that MISO has in place the proposed enhancements to its Resource Adequacy construct necessary to address the growing risks to reliability in the MISO Region resulting from a changing resource mix and shrinking excess reserve margins. Moreover, the recommendations from the Federal Energy Regulatory Commission ("FERC") and the North American Electric Reliability Corporation ("NERC") Final Report,[2] as well as MISO's internal report,[3] following the February 2021 Winter event reinforces the need for and urgency of the proposed reforms to the Resource Adequacy construct. Ultimately, MISO's proposal will help ensure Planning Resources are available to convert capacity procured in the PRA to energy when and where they are most needed.

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1 MISO submits these amendments pursuant to section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, and section 35.12 of the Federal Energy Commission's ("FERC" or "Commission") regulations, 18 C.F.R. § 35.12 (2018). All capitalized terms in this filing not otherwise defined have the same meaning as they have under the current MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff").

2 *See* FERC, Final Report on February 2021 Freeze Underscores Winterization Recommendations November 16, 2021 (November 2021) ("FERC Final Report"), available at: https://www.ferc.gov/news-events/news/final-report-february-2021-freeze-underscores-winterization-recommendations.

3 *See* https://cdn.misoenergy.org/2021%20Arctic%20Event%20Report554429.pdf ("MISO Arctic Report").

In order to accommodate the implementation of this proposal in advance of the 2023 / 2024 Planning Year, MISO requests the Commission issue an order on this proposal within 120-days of this filing granting an effective date of September 1, 2022 for the proposed revisions. The requested timeline for acceptance and implementation of the instant proposal will accommodate all necessary stakeholder and MISO actions well in advance of the initial PRA in the Spring of 2023. Commission action within the requested 120-day period also is needed to help ensure MISO has adequate time to implement the changes to its software and systems prior to the 2023 / 2024 PRA, and to help guide decisions and investments that resource owners should be making to improve their accreditation under the proposed construct. Importantly, the software and system changes necessary to implement this proposal are not dependent upon MISO's ongoing Market System Enhancement initiative.

I. EXECUTIVE SUMMARY

The MISO Region is experiencing significant shifts in generation resource retirement, increased reliance on intermittent resources, significant weather events with correlated generator outages, and declining excess reserve margins. To highlight the priority and urgency of this transformation, the North American Electric Reliability Corporation ("NERC") in its Long-Term Reliability Assessment report recently stated:

> The addition of variable energy resources, primarily wind and solar, and the retirement of conventional generation is fundamentally changing how the [Bulk Power System] is planned and operated. Resource planners must consider greater uncertainty across the resource fleet as well as uncertainty in electricity demand that is increasingly being effected [*sic*] by demand-side resources. As a result, reserve margins and capacity-based estimates can give a false sense of comfort and need to be supplemented with energy adequacy assessments.[4]

In the Reliability Assessment, NERC also stated, "To ensure reliability during the transition to greater reliance on wind and solar resources, emerging resource and energy adequacy issues must be addressed. Planning for long-term Resource Adequacy is becoming increasingly complex with a resource mix that is more unpredictable and less energy-assured."[5] To address these issues, NERC recommended that: "Regulators and policy makers should consider revising their resource adequacy requirements to consider new risks that emerge during non-peak hours, limitations from neighboring systems during system-wide events, and the reduced resource diversity and/or increased reliance on a single fuel source or delivery mode."[6] Pointedly, FERC and NERC have also recently made recommendations in light of the extensive resource outages of the February 2021 Winter event. These recommendations support both improved seasonal risk

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4 NERC, 2020 Long Term Reliability Assessment (LTRA), at 6 (Dec. 2020), ("NERC Reliability Assessment") available at: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf (NERC 2020 LTRA).

5 *Id.* at 7.

6 *Id.*

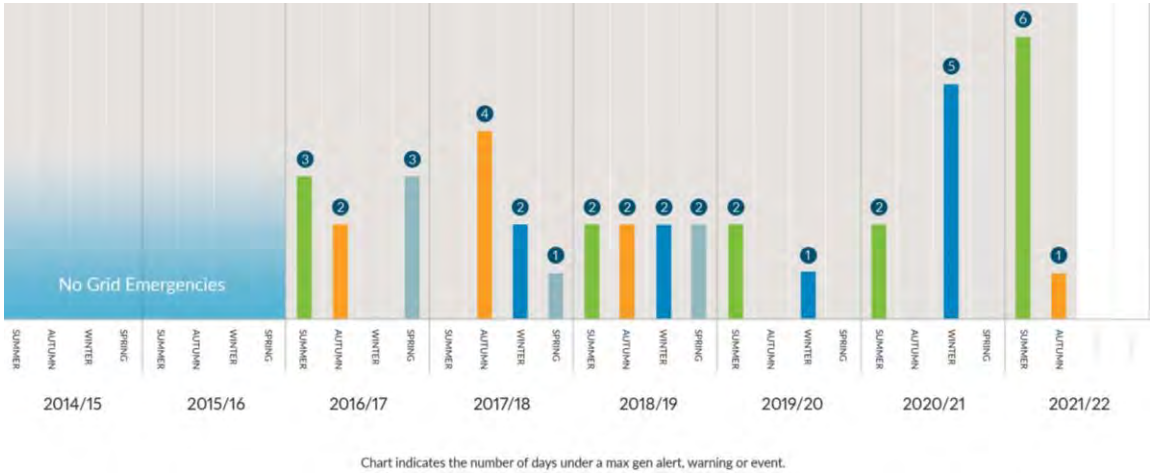
assessments and the stronger alignment between accreditation and expectations of availability during times of highest need.[7]

MISO agrees with these statements and as discussed in the testimony of Mr. Wright, MISO's Executive Director of Market Development and Design, these shifts, coupled with lower excess reserve margins, increases in extreme weather events, correlated generator outages, and emergency operations, will have a profound impact on the reliability of the grid in the coming years.[8] Ultimately, all industry participants have a shared responsibility to plan for these impacts and implement new policies and practices to ensure the continued reliability of the grid. MISO refers to this shared responsibility as the "Reliability Imperative." As part of its response to the Reliability Imperative, MISO must make substantive changes to its Resource Adequacy construct to address these emerging issues as the transition accelerates in the coming years.

MISO's response to the Reliability Imperative is being accomplished through a number of initiatives that work in concert to mitigate the challenges facing the MISO Region. MISO organizes this work into four major categories: (1) Market Redefinition; (2) Long Range Transmission Planning; (3) Operations of the Future; and, (4) Market Systems Enhancements.

Through Market Redefinition, MISO aims to ensure that sufficient resources with the capabilities and attributes the MISO Region needs will be available during the highest risk periods across the year. MISO's current Resource Adequacy construct, which focuses on the procurement of capacity for an entire Planning Year to meet demand during one peak day of the Summer Season was not designed to address the trends currently facing the MISO Region.

Reliability risks associated with Resource Adequacy have shifted from "Summer only" to a year-round concern. Since 2016 MISO has experienced 40 Maximum Generation declarations (including alerts, warnings and events) ("MaxGens") with more than 60% occurring outside of the Summer months, as evidenced in the graph below.



7 *See* FERC Final Report at 6.

8 Wright at 11.

MaxGens are governed by MISO's emergency operations procedures and include a number of emergency actions, up to and including shedding firm load. Consistent with NERC's Reliability Assessment, the significant increase in MaxGens is being driven by the confluence of: the retirement of traditional, baseload generation resources; planned and forced generator outages in non-Summer months; an increased reliance on intermittent generation such as wind and solar, which has reached nearly 30 percent of the generation resource mix in certain portions of the MISO Region and is projected to continue to grow; and, extreme weather events resulting in numerous forced generator outages, including multiple polar vortex and arctic storms reaching south to the Gulf of Mexico.

The causes of the increase in MaxGens cannot be addressed through one-off, quick fixes; rather, they require a robust solution that incentivizes capacity resources to be available when and where they are needed. Ultimately, the existence of resources, even if ample in quantity and well-located, is meaningless if those resources do not provide energy or reserves when needed. MISO cannot reliably operate the system if the resources it depends on do not or cannot perform — that is, do not provide energy or reserves as offered during periods of highest risk. A well-designed market construct is inclusive of both the planning horizon and the operating horizon. The planning horizon includes the identification and incorporation of risks across the year in Resource Adequacy Requirements. The operating horizon ensures that those resources are appropriately incentivized to provide the energy and reserves when and where needed. More closely aligning the planning horizon with the operating horizon is a central goal of the proposed reforms in the instant filing.[9]

To address these critical issues, MISO's Resource Adequacy reform proposals focus on related areas including: the establishment of a seasonal Resource Adequacy construct coupled with availability-based accreditation for certain Planning Resources; and, a Minimum Capacity Obligation that promotes securing capacity well in advance of the Planning Resource Auction. The instant filing presents MISO's Seasonal and Accreditation proposal.

A. Seasonal Resource Adequacy Construct

MISO intends to transition from the current Summer-based, annual construct to four distinct Seasons: June to August for Summer, September to November for Fall, December to February for Winter, and March to May for Spring. Under the proposed construct MISO will establish Planning Reserve Margin Requirements ("PRMR") for all Market Participants ("MPs") representing Load Serving Entities ("LSEs") on a seasonal basis. MISO will then conduct the PRA and establish an Auction Clearing Price for each Local Resource Zone ("LRZ") for each Season. The PRA will still be conducted one time per year, in the Spring before the applicable Planning Year, but will clear the requirements for each Season.

Overall, the shift to a seasonal construct is expected to further mitigate Resource Adequacy risks across the year, not just in the peak Summer Season, by establishing more granular, seasonal Resource Adequacy Requirements to help ensure sufficient resources are committed and obligated to be available when needed. Expected outcomes from this transition are to: (1) identify reliability

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[9] Wright at 14.

needs unique to each Season; (2) align resource availability with seasonal needs; and (3) facilitate and better account for seasonal outages or partial year operations.

B. Availability-Based Resource Accreditation

MISO's Resource accreditation reforms seek to assure that Resources are available when needed the most by aligning Resource accreditation with availability during the highest risk periods in each Season. To accomplish this in a seasonal construct, MISO proposes to determine the Seasonal Accredited Capacity ("SAC") for certain classes of Resources. MISO also proposes a tiered weighting structure, with a transition period, to determine individual resource accreditation by Season based on each resource's real-time offered availability, accounting for coordinated planned outages.

The expected outcomes of MISO's efforts are to: (1) increase confidence in the capacity MISO can count upon when needed by shrinking the gap between cleared capacity within the PRA and realized capacity during tight conditions; (2) provide improved signals for availability and coordination; and (3) improve outage coordination processes. Measuring and accrediting Planning Resources based on availability and performance during Resource Adequacy Hours (or "RA Hours"), as described in the testimony of Mr. Wright, will better align expectations during times of highest need. Actual historic Resource availability and performance during times of highest need is a useful and reasonable indicator of what to expect in the future. Relying on installed capacity, adjusted for forced outages and reflecting average availability throughout the year, no longer provides an accurate expectation of availability, as proven by recent emergency events, especially those driven by extreme weather.

II. BACKGROUND

This filing is a component of the next phase of MISO's ongoing Resource Availability and Need ("RAN") initiative. The factors giving rise to the need for MISO to explore various short- and longer-term RAN initiatives, and related Tariff enhancements, have by now been well-documented, including a series of MISO-published White Papers dating back to March 2018,[10] as well as MISO's prior RAN filings and related Commission Orders. As described in those documents, MISO established its RAN initiative to identify strategies to better convert committed Planning Resources into energy during times of need.[11] MISO submits this filing to establish the design for additional Resource Adequacy reforms, including a Seasonal Resource Adequacy Construct, Availability-Based Accreditation, and Seasonal Planning Resource Auctions. MISO is

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[10] *See* Resource Availability and Need, *Issues Statement Whitepaper*, March 30, 2018; Load Modifying Resources, *Capacity Instruments affecting Resource Availability and Need*, May 25, 2018; Resource Availability and Need, *Evaluation Whitepaper*, September 10, 2018; Aligning Resource Availability and Need, December 2019, MISO Forward, March 2019, and MISO Forward 2020, *Utilities of the Future: What do they need from a grid operator?*, March 2020. *See generally* Resource Availability and Need (RAN) (IR025). Available at https://www.misoenergy.org/stakeholder-engagement/issue-tracking/resource-availability-and-need-ran/

[11] *See* Aligning Resource Availability and Need, December 2019, MISO, pp. 2-3. Available at https://cdn.misoenergy.org/Aligning%20Resource%20Availability%20and%20Need%20(RAN)410587.pdf

making a concurrent filing related to the establishment of a new Minimum Capacity Obligation. The details of this additional reform will be addressed in the concurrent filing.

MISO is facing a Reliability Imperative during this period of unprecedented change. While MISO and its stakeholders have successfully managed reliability there has been a significant increase in the number of MaxGens occurring outside of the traditional Summer peak months. These changes have prompted MISO to evaluate the alignment of resource availability and need to determine how today's processes can be improved to ensure the reliable and efficient conversion of procured capacity to energy throughout the year.[12] This process has become increasingly uncertain as a result of a dramatically changing landscape and factors such as retiring and aging generation units, lower overall capacity levels and higher outage rates, growth in demand-side and other emergency-only capacity as a percent of the portfolio, growing reliance on unscheduled resources (notably non-firm imports), and the growth of intermittent energy resources as a percentage of the fleet.[13]

MISO has proactively engaged with stakeholders and developed its RAN initiative to mitigate these and other challenges. The RAN program initially identified four goals: (1) Improve outage scheduling and expectations; (2) Link Resource accreditation and requirements with initial focus on Load Modifying Resources ("LMRs"); (3) Align the PRA resource commitments with energy needs all year; and (4) Ensure flexible Resource availability to address changing fleet characteristics. Each goal corresponds to a group of potential solutions discussed with stakeholders that address related gaps, such as a lack of transparency in outage scheduling or limited access to LMRs.

To achieve these goals, MISO proposed and implemented several incremental changes, each of which was intended to improve reliability within the MISO Region. These changes are known as MISO's RAN Phase I initiative, and are outlined below:

- MISO's first RAN Phase I filing was submitted on December 21, 2018. There, MISO filed proposed revisions to its Tariff to more effectively assess the capabilities of LMRs.[14] MISO proposed to require an LMR to (1) offer its capability based on its actual availability in all Seasons, including maintaining the current requirement that LMRs be available for the entire Summer Season, and (2) deploy based on the shortest notification requirement that it can consistently meet, while maintaining that LMRs must be available in less than 12 hours.[15] MISO also proposed Tariff revisions that would allow it to issue Scheduling Instructions to LMRs in advance of anticipated Emergency

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12 *See* Resource Availability and Need, *Issues Statement Whitepaper*, March 30, 2018, at pp. 2-3. Available at https://cdn.misoenergy.org/20180405%20RSC%20Item%2007%20RAN%20Issues%20Statement%20White%20Paper164746.pdf

13 *Id.*

14 *Midcontinent Indep. System Operator, Inc.*, 166 FERC ¶ 61,116 (Feb. 19, 2019).

15 *Id.*

conditions.[16] The Commission accepted those revisions subject to certain revisions in an order dated February 19, 2019.[17]

- MISO's second RAN Phase I filing was also submitted on December 21, 2018. There, MISO filed proposed revisions to its Tariff to enhance the testing requirements for Demand Resources that participate in MISO's markets as LMRs.[18] Additionally, MISO proposed to revise its Tariff to require all Demand Resources to conduct a real power test annually, starting with qualification for the 2020/21 Planning Year.[19] MISO also set forth certain proposed waiver and opt-out provisions.[20] The Commission accepted those revisions subject to certain revisions in an order dated March 29, 2019.[21]

- On January 30, 2019, MISO filed proposed revisions to its Tariff to enhance Generator Planned Outage scheduling.[22] These proposed incremental changes were intended to supplement MISO's then-existing Generator Planned Outage process by improving transparency through forward signals and incentives.[23] The Commission accepted those revisions subject to certain revisions in an order dated March 29, 2019.[24]

- On March 18, 2019—in compliance with the Commission's prior February 19, 2019 Order—MISO filed a request to revise its Tariff provisions regarding MISO's advanced access of the capabilities of LMRs, as previously directed by the Commission.[25] The Commission accepted MISO's submittal, as requested, in an entry dated April 29, 2019.[26]

As recognized by FERC and NERC, MISO's first RAN Phase I filing constituted "a broad analysis and plan to confront the increase in Maximum Generation emergencies even though sufficient capacity appeared to be available through the Planning Reserve Auction."[27] "Some of

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16 *Id*.

17 *Id*.

18 *Midcontinent Indep. System Operator, Inc*., 166 FERC ¶ 61,235 (Mar. 29, 2019).

19 *Id*.

20 *Id*.

21 *Id*.

22 *Midcontinent Indep. System Operator, Inc*., 166 FERC ¶ 61,236 (Mar. 29, 2019).

23 *Id*.

24 *Id*.

25 April 29, 2019 Letter to J. Krouse, Docket No. ER-19-650-001 (Apr. 29, 2019).

26 *Id*.

27 *See* The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018, 2019 FERC and NERC Staff Report, at p. 75, fn 101.

the early fruits of the initiative [have been] tariff changes to better insure capacity availability[.]"[28] "MISO's revisions, which included a penalty for planned outages and derates that occur during Max Generation events, were intended to: (1) provide additional incentives for Generator Owners to schedule Generator Planned Outages and derates well in advance of the scheduled start time and (2) identify times with increased system risk due to correlation of outages and derates."[29] "The Commission agreed with MISO's efforts, believing that MISO's proposal [would] 'promote advanced scheduling of Generator Planned Outages, improve Generator Planned Outage coordination, and help MISO address the recent increase in the number of declared Emergency events during non-summer seasons.'"[30]

Following the initial RAN Phase I filings, MISO made a number of additional RAN-related filings with the Commission, including the following:

- On May 18, 2020 MISO filed to enhance the LMR accreditation provisions of the Tariff to ensure LMRs are appropriately accredited for their participation in the PRA based on the LMRs actual availability and notification times. The Commission accepted this proposal on August 14, 2020 and the enhanced LMR accreditation were implemented on August 16, 2020.[31]

- On December 21, 2020 MISO submitted a filing to clarify the LMRs that are chosen to be deployed by Market Participants in response to MISO's Scheduling Instructions will be evaluated on an individual resource basis, rather than in aggregate across a Market Participant's portfolio of LMRs. The Commission accepted this clarification by letter order on February 3, 2021.[32]

- On January 30, 2019, MISO filed with the Commission a proposal to enhance Generator Planned Outage scheduling. MISO explained in this filing that the proposed revisions were necessary due in part to base load generation retirements that were contributing to the MISO Region operating with actual capacity margins that were approaching its minimum Planning Reserve Margin Requirements. MISO explained in that filing that operating at or near its minimum Planning Reserve Market Requirements exposed the MISO Region to greater impacts from correlated risks, such as extreme weather events and natural gas availability. The Commission accepted this filing on March 29, 2019.[33]

- On October 16, 2019, MISO submitted a filing to limit the ability of resources to participate in the PRA if the resource is expected to be on full or partial outage for any ninety (90) or

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28 *Id*. at p. 77.

29 *Id*.

30 *Id*., citing *Midcontinent Indep. System Operator, Inc*., 166 FERC ¶ 61,236 (Mar. 29, 2019) at P. 60.

31 *See Midcontinent Independent System Operator, Inc.,* 172 FERC ¶ 61,138 (August 14, 2020).

32 February 3, 2021 Letter to J. Krouse, Docket No. ER21-693-000 (February 3, 2021).

33 *See Midcontinent Independent System Operator, Inc.*, 166 FERC ¶ 61,236 (March 29, 2019).

more of the first one hundred twenty (120) Calendar Days in the Planning Year. The Commission accepted this filing on January 30, 2020.[34]

- MISO has also submitted reforms related to the deliverability of both conventional and intermittent resources. On October 27, 2020 the Commission accepted MISO's proposal to require conventional (*i.e.,* non-intermittent) Capacity Resources to demonstrate deliverability through Energy Resource Interconnection Service ("ERIS") coupled with firm Transmission Service up to the Capacity Resource's Installed Capacity level in order to be eligible to convert the entire Unforced Capacity of the Resource to ZRCs.[35] In addition, on November 13, 2020 the Commission accepted MISO's proposal to implement a long-term deliverability requirement for Intermittent Capacity Resources, including a methodology to determine the level of firm Transmission Service needed to convert Unforced Capacity into ZRCs.[36]

The proposed Resource Adequacy construct reforms also align with MISO IMM recommendations dating back to 2014. The IMM first recommended a transition to seasonal capacity procurement in its 2014 State of the Market Report.[37] In recommendation 2014-5 the IMM noted that the system and available system supply change substantially from one season to the next, which could be recognized by clearing the PRA on a seasonal basis rather than an annual basis.[38] The IMM also suggested that the shift to a seasonal PRA construct would produce benefits including: better alignment of revenues with the value of capacity; opportunities for high-cost resources to achieve savings by taking seasonal outages during shoulder seasons; and, more flexible mid-year retirements for resources without having to procure significant capacity to satisfy post-retirement capacity obligations.[39]

In the 2018 State of the Market Report, MISO's IMM noted that MISO's January 2019 filing to reduce the accreditation of resources taking short-notice outages during emergency conditions was a slight improvement but recommended that MISO file with FERC a more complete accreditation solution that would: a) expand the Generator Planned Outage scheduling enhancements filed in January 2019 to include all unforced and unreported outages and debates; and b) calculate the accreditation based on outages and derates that occur during the tightest supply conditions.[40] The IMM suggested that these changes would result in sizable accreditation

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34 *See Midcontinent Independent System Operator, Inc.* (Docket No. ER20-129-000)*; Wolverine Power Supply Cooperative, Inc. v. Midcontinent Independent System Operator, Inc.* (Docket No. ER19-102-000) (Not Consolidated), 170 FERC ¶ 61,066 (January 20, 2020).

35 *See Midcontinent Independent System Operator, Inc.* 173 FERC ¶ 61,095 (October 27, 2020).

36 *See Midcontinent Independent System Operator, Inc.* 173 FERC ¶ 61,139 (November 13, 2020).

37 2014 State of the Market Report for the MISO Electricity Markets Prepared by Potomac Economics (June 2015) at 99-100.

38 *Id.*

39 *Id.*

40 2018 State of the Market Report for the MISO Electricity Markets Prepared by Potomac Economics (June 2019) at 110-111.

improvements and eliminate the current incentive for suppliers to not report their outages and derates. Ultimately, the IMM argues that adopting the proposed accreditation reform would better represent the reliability value that resources provide to MISO (in periods when the resources are needed) and can be easily adapted to a seasonal capacity accreditation construct.[41]

While the changes implemented through MISO's RAN Phase I initiative and subsequent RAN-related filings have been helpful, MISO continues to face a Reliability Imperative and correspondingly needs to implement further reforms to its Resource Adequacy construct. MISO was clear that the RAN Phase I filings were the initial step in addressing specific issues in the Resource Adequacy construct and that more comprehensive solutions were being developed to address Resource Adequacy in the MISO Region. As such, the proposed Resource Adequacy reforms, submitted in this filing, better align accreditation with observed Resource availability during the periods of highest risk.

While true across all Seasons of the year, MISO has experienced notable reliability challenges during the Winter Season.[42] Consistent with Key Recommendation 2 in NERC's recent "Cold Weather Report," MISO's proposal would give Generator Owners accreditation values that align with the reliability benefits of winterization and Winter preparedness. These measures will enable Resources to operate in the temperature and weather conditions that have occurred during times of need during recent Winters.

In line with the guiding principles of the RAN initiative and the response to the Reliability Imperative, MISO's proposal will create better availability, flexibility, and visibility of resources to meet MISO's changing system needs including the need to address generator reliability for extreme cold weather. Seasonal requirements, including seasonal auctions, will ensure MISO's Resource Adequacy Requirements reflect reliability needs and required capabilities across the year. Accreditation reforms will ensure resources committed during the seasonal Planning Resource Auction receive accreditation based on their reliability contribution during the times of highest need. The proposed availability based seasonal construct will award more relative accreditation to resources that have properly mitigated risks during all Seasons.

III. SEASONAL RESOURCE ADEQUACY CONSTRUCT

A. Establishment of Seasonal Resource Adequacy Requirements

MISO proposes continuing its Resource Adequacy reform efforts – in part – by establishing seasonal Resource Adequacy Requirements. MISO intends to transition from its current annual construct, which focuses on the historic Summer peak period, to a seasonal construct with four distinct Seasons: (1) Summer (June to August); (2) Fall (September to November); (3) Winter (December to February); and (4) Spring (March to May).[43] Under the proposed seasonal Resource

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41 *Id.*

42 MISO Arctic Event at 5, 7.

43 Wright at 26.

Adequacy construct, MISO will perform an LOLE evaluation to establish PRMRs for all Market Participants representing LSEs[44] and Local Clearing Requirements ("LCR") for all LRZs on a seasonal basis.[45] MISO will then conduct the Planning Resource Auction and establish an Auction Clearing Price for each LRZ for each Season.[46] The Planning Resource Auction will continue to be conducted once per year, in the Spring preceding the applicable Planning Year, but the PRA will clear the requirements separately for each Season.[47]

As explained by Mr. Wright, this shift to a seasonal Resource Adequacy construct is designed to ensure that resources with needed capabilities and attributes will be available during the highest risk periods across the year.[48] Under the current construct, the requirements of the annual PRA are based on Summer Coincident Peak Demand forecasts, and transmission capability and most Resource accreditation is also based on Summer conditions.[49] As a result, actual needs outside the Summer Season are not explicitly determined and defined, leaving potential risks unmitigated.[50] Such risks are intensifying as indicated by the increased incidence of MaxGens occurring in the Seasons outside of the traditional Summer peak.[51] Moreover, sizeable segments of dispatchable thermal generation are aging with correlated increased outage rates, and MISO's resource portfolio is shifting to increasing amounts of intermittent and highly weather-dependent wind and solar resources, all against a backdrop of lower excess reserve margins.[52] In his testimony, Mr. Smith notes that the trends and generation resource fleet transition driving the challenges to reliable market operations are only expected to accelerate, leading to further reduced operating margins.[53] Moving to a seasonal Resource Adequacy construct will align seasonal resource accreditation with seasonal resource availability to meet this changing risk.[54]

MISO proposes several changes to implement the seasonal Resource Adequacy construct, including accrediting resources by Season based on their availability during times of need and developing seasonal values for several construct parameters such as: (1) LOLE sub-annual modeling; (2) PRMRs; (3) Local Reliability Requirements ("LRR") and LCRs; and (4) Capacity

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44 As used throughout this transmittal letter, references to LSE is intended to also include Market Participants representing LSEs.

45 Wright at 26.

46 *Id*.

47 *Id*.

48 Wright at 13.

49 Smith at 18.

50 *Id*. at 18-19.

51 McFarlane at 4.

52 Wright at 16.

53 Smith at 22-23.

54 McFarlane at 6.

Import Limits ("CIL") and Capacity Export Limits ("CEL").[55] Each of these changes is discussed more fully below.

MISO proposes changes to the modeling and methodology of the LOLE study to more accurately model seasonally-sensitive variables and calculate the construct parameters through: (1) seasonal LOLE risk allocation; and (2) improving seasonal LOLE modeling, including the modeling of planned outages, modeling of non-firm external support (*i.e.,* imports), and hourly modeling of intermittent resources.[56] As explained by Mr. McFarlane, this new LOLE model needs to have a defined LOLE threshold for each Season to calculate seasonal Resource Adequacy reserve requirements.[57] Seasonal requirements will be determined under a two-step LOLE analysis.[58] For the first step, the LOLE model will be solved to an annual LOLE value of 0.1 day per year to determine the natural LOLE distribution.[59] If after the first step there is a minimum of 0.01 day per year LOLE in all four Seasons, then the seasonal requirements will be determined directly from this step and there will be no need for additional analysis.[60] If a Season has an LOLE of less than 0.01 day per year from step 1, then an additional step will be performed to solve that Season to an LOLE of 0.01 day per year.[61] In the second step, if required, MISO proposes to round LOLE targets up to a minimum of 0.01 day per year for any Season with LOLE less than 0.01 day per year, and to maintain LOLE targets for Seasons with LOLE greater than 0.01 day per year.[62]

In order to determine a Planning Reserve Margin ("PRM") for the four Seasons, MISO proposes performing an additional two-step LOLE analysis with seasonal input assumptions.[63] The LOLE model will be used to meet the seasonal LOLE targets by adjusting the capacity within the model up or down as needed.[64] If the LOLE is less than the target for a Season, then a "perfect unit" with a negative capacity value and zero forced outage rate will be added to the model.[65] If the LOLE is greater than the target for a Season, then proxy combustion turbine generators of typical size (160 MW) and class average Equivalent Forced Outage Rate Demand ("$XEFOR_d$") will be added to the model until the seasonal LOLE target is achieved.[66] Once the seasonal LOLE targets are met, the seasonal PRM values in terms of Unforced Capacity ("UCAP") will be

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55 *Id*. at 7.

56 *Id*. at 8.

57 *Id*. at 11.

58 *Id*.

59 *Id*. at 12.

60 *Id*.

61 *Id*.

62 *Id*.

63 *Id*.

64 *Id*. at 11.

65 *Id*. at 11-12.

66 *Id*.

calculated and expressed as a percentage of seasonal coincident peak demand.[67] The PRM for each Season is multiplied by the 50/50 forecast of coincident peak load to determine the PRMR (in MWs) for that Season.[68]

To determine zonal Local Reliability Requirements, MISO proposes using the same two-step process as the PRM analysis with each zone treated as an isolated system consistent with the existing LRR analysis methodology under the current annual PRA construct.[69] Seasonal LRR values will be calculated in terms of UCAP and expressed as a percentage of seasonal zonal coincident peak demand once the model has been solved to the appropriate LOLE targets.[70] The seasonal LRR values will be used to determine the seasonal LCR values by subtracting the seasonal CIL from the seasonal LRR.[71]

MISO proposes performing seasonal transfer analyses to determine seasonal CILs and CELs, capturing the seasonal variation of transfer limits for each LRZ.[72] Planning Year seasonal peak powerflow models and input files developed from MISO Transmission Expansion Plan studies will be used to perform transfer analysis for each Season including Summer Peak, Fall Peak, Winter Peak, and Spring Peak study models.[73] The resulting seasonal Zonal Import Ability ("ZIA"), in conjunction with controllable exports, will be used to determine the seasonal LCR for each LRZ.[74]

The proposed Resource Adequacy construct more accurately represents Resource capabilities at different times during the year, improves certainty of Resource availability outside the Summer Season, better incentivizes Resources to be available when needed, establishes seasonal reserve requirements that better align with risks, and delivers additional visibility into the risks throughout the year – which are not currently captured in the annual construct.[75] When discussing the expected impact of the seasonal approach on MISO's operations, Mr. Smith explains that the proposed reforms measure and mitigate non-Summer reliability risk. This is accomplished by calculating seasonal requirements using seasonal inputs based on demonstrated seasonal resource availability to ensure that seasonal risks are known and mitigated. In general, resource owners and LSEs benefit from lower non-Summer peak loads, resulting in lower non-Summer PRMRs that reduce the required cleared capacity and allow for seasonal operation and

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67 *Id*. at 13.

68 *Id*.

69 *Id*. at 13.

70 *Id*.

71 *Id*.

72 *Id*. at 13-14.

73 *Id*. at 14.

74 *Id*.

75 *Id*. at 7.

related cost savings.[76] Overall, this proposed seasonal shift is expected to identify and mitigate reliability risks across the year during the periods of highest reliability risk.

B. Revisions to the Planning Resource Auction

As discussed above, the annual PRA will continue to be administered in the Spring of each year in advance of the upcoming Planning Year beginning in June. In most instances, MISO's PRA processes will remain the same but will be applied on a seasonal basis rather than an annual basis. The PRA offer window will continue to be the last four business days in March. In addition, the "must offer" requirement for resources that clear the PRA will only apply in the Season or Seasons in which the Resource clears.[77] Moreover, MISO will increase the amount of time it has available to clear the PRA from 10 to 20 business days in order to clear the four Seasons. The following graphic shows the Seasonal PRA timeline:



C. Planning Resource Replacement and Capacity Replacement Non-Compliance Charge

MISO's current capacity replacement requirements are limited to suspensions and retirements of resources and carry no specific financial non-compliance provisions. As Mr. McFarlane explains, these limited requirements are no longer sufficient as the performance and availability of committed capacity to meet seasonal requirements will be critical.[78] As such, MISO proposes to require replacement for any Planning Resource that will be on planned outage or planned derate for more than 31 days in a Season in which they clear. Consistent with current Tariff requirements, replacement can only be made from uncleared ZRCs.[79] The capacity replacement requirement will also apply to resources that have received exemptions through the updated outage coordination process discussed below. MISO is also adding provisions allowing the replacement of resources that have experienced catastrophic outages, enabling such resources to maintain class average accreditation upon return to service, with further details to be established in the Business Practices Manual for Resource Adequacy. It is important to note that existing rules regarding deliverability and zonal transfer limits will still apply.

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76 Smith at 19

77 *Id*. at 37.

78 *Id*. at 38.

79 *Id*. at 40.

Given the critical impacts non-replacement of resources could have on reliability, MISO proposes a Capacity Replacement Non-Compliance Charge for Resource owners that do not replace Planning Resources that retire or suspend during the Season, or are on planned outage or planned derate for more than 31 days in a Season. Mr. McFarlane explains that the Capacity Replacement Non-Compliance Charge will be a be a daily charge, equal to the amount of ZRCs that failed to be replaced multiplied by sum of the Auction Clearing Price and the daily CONE value.[80] Capacity Replacement Non-Compliance Charges will be distributed to Market Participants representing LSEs on a *pro rata* basis, based upon the LSE's share of total PRMR for the MISO Region. Mr. McFarlane notes that the billing, invoicing, default, and uplift provisions will be similar to the existing Installed Capacity ("ICAP") Deferral Non-Compliance Charge.[81]

IV. AVAILABILITY-BASED ACCREDITATION

The shift to seasonal Resource Adequacy Requirements will impact all resources in the MISO Region; however, the availability-based accreditation provisions only apply to Capacity Resources that are Demand Response Resources or Generation Resources (collectively referred to as "Schedule 53 Resources"), but not Dispatchable Intermittent Resources, Intermittent Generation, Electric Storage Resources, External Resources or Use Limited Resources. MISO refers to these resources as "Schedule 53 Resources" because it submits herewith a new Schedule 53 to the MISO Tariff entitle Seasonal Accredited Capacity Calculation.

Mr. McFarlane explains that the proposed changes align resource accreditation for Schedule 53 Resources with historic availability and performance during the highest risk periods while also accounting for general availability of resources across the year.[82] To accomplish this, MISO proposes a two-tiered calculation to determine individual Resource accreditation by Season, as described below.[83]

A. Determination of RA Hours

Pursuant to MISO's proposal, resource accreditation for Schedule 53 Resources will no longer be based on forced outage rates from Generator Availability Data System (or "GADS"). Instead, accreditation for Schedule 53 Resources will primarily be based on the average real-time offered availability from MISO's Day-Ahead and Real-Time market system during times of highest need, which are referred to as "RA Hours" in MISO's proposal. Other factors such as the type and volume of interconnection service and a seasonally corrected Generation Verification Test Capacity ("GVTC") will be utilized as well. Mr. McFarlane explains that the proposed construct will continue to base accreditation on the three prior years starting September 1 through August 31 of the year prior to the Planning Year, which reflects the cumulative availability of a

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80 *Id*. at 39.

81 *Id*.

82 *Id*. at 16.

83 *Id*.

resource.[84] MISO proposes a tiered weighting structure to determine individual resource accreditation by Season based on each Resource's real-time offered availability during Tier I hours (*i.e.,* all hours not including RA Hours) and Tier 2 hours (*i.e.,* RA Hours) while incentivizing the coordination of Generator Planned Outages by providing exemptions when certain conditions are met, as discussed in further detail below.[85]

As indicated, MISO's Seasonal Accredited Capacity approach will shift to the application of RA Hours, which Mr. McFarlane explains represent the periods of highest risk and greatest need during a Season and throughout the year.[86] These periods include declared MaxGens and the hours when the operating margin is at its lowest. MISO proposes to determine RA Hours for each Season based on MaxGens and the 65 hours with the tightest operating margin, subject to a maximum operating margin threshold established at 25 percent.[87] Mr. McFarlane explains that RA Hours will be defined within the First Planning Area and Second Planning Area separately to reflect the growing frequency of MaxGens and emergencies that occur on either side of the Sub-Regional Power Balance Constraint, which have been driven by: trapped capacity in one sub-region due to the contractual transfer limits, increasing sub-regional challenges driven by portfolio differences, and the impacts of extreme weather including hurricanes, cold weather events, and renewable penetration.[88]

Pursuant to MISO's proposal, each Season will have a target of 65 RA Hours based on three (3) percent of the hours in a Season. Mr. McFarlane explains that the number of RA Hours in a Season can exceed the target when declared MaxGens during that Season have a cumulative duration greater than 65 hours.[89] The number of RA Hours in a Season can be less than the target because of the 25 percent maximum operating margin threshold, which will ultimately lead to a deficiency equal to the difference between the target RA Hours and the actual number of RA Hours.

B. Resource Specific Accreditation

1. Schedule 53 Resources

MISO's resource accreditation proposal is intended to reflect the anticipated capability and availability of Planning Resources during times when they are most needed. Mr. McFarlane explains that utilizing offered availability, including actual performance data during RA Hours provides an improved measure of expected availability.[90] Ultimately, MISO proposes a two-tiered

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84 *Id*. at 19.

85 *Id*. at 19-20.

86 *Id*. at 20.

87 *Id*. at 20.

88 *Id*. at 22.

89 *Id*. at 20.

90 *Id*. at 15.

weighting structure to calculate resource accreditation for Schedule 53 Resources that will reflect general availability while emphasizing availability during times of greatest need based on a tiered weighting structure.

Pursuant to the proposed Schedule 53, a Resource will have its Intermediate Seasonal Accredited Capacity ("ISAC") determined based on its real-time offered availability (Emergency Maximum Limit, or Targeted Demand Reduction Level for Demand Response Resources Type I) during seasonal RA Hours (Tier 2) and Non-RA Hours (Tier 1). The number of Tier 2 RA Hours may vary during individual Seasons when the 25% maximum margin threshold is applied or individual resources receive outage exemptions, impacting sample sizes of RA Hours and corresponding accreditation calculations. If Tier 2 RA Hours for a Season or a specific resource fall below the 3% target of 65 hours, a Resource's Annual Average Offered Capacity ("AAOC") will be used to supplement the deficient number of hours as part of the Tier 2 portion of the accreditation calculation. Seasonal Tier 1 Non-RA Hours on the other hand include all hours in a Season of a Planning Year, excluding except Tier 2 RA Hours and any hours where a Resource had an exemption or was not designated for Resource Adequacy Requirements ("RAR"). Mr. McFarlane's testimony provides a detailed description of this process, along with hypothetical examples.[91]

As described by Mr. McFarlane, MISO will determine ISAC values for each Resource for each Season in the upcoming Planning Year while the final SAC calculation is "in process."[92] The final ISAC value will be the weighted average over its values from the two tiers as described in Mr. McFarlane's testimony.[93] MISO proposes an 80% Tier 2 and 20% Tier 1 weighting as assigning the heavier weighting to Tier 2 tight conditions ensures the alignment between a resource's SAC value and its availability and performance during times of highest risk and greatest need. The basis for the 80% Tier 2 and 20% Tier 1 weighting is discussed further in section VII below.

In response to stakeholder feedback on the SAC proposal, MISO has implemented a transition to the full 80% Tier 2 weighting in the third Planning Year to account for the fact that the historical real-time offers, outages, and notification times used in the Schedule 53 calculations were submitted for resources without knowledge of the final accreditation methodology proposed in the instant filing. Under the proposal, Tier 2 weighting would start at 60% in PY 2023 / 24, rise to 70% in PY 2024 / 25 and then reach the full 80% in PY 2024 / 25.

In addition, MISO has adopted a UCAP to ISAC ratio proposed by its Independent Market Monitor to avoid undesirable impacts to PRA requirements and non-Schedule 53 resources. Application of this ratio addresses stakeholder concerns on deliverability and auction revenue reduction. The IMM presented its new ratio recommendation at the October 6, 2021 Resource Adequacy Subcommittee ("RASC") meeting, and formal feedback was solicited. Feedback

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91 *Id.* at 25-30.

92 *Id.* at 27.

93 *Id.* at 27-28.

received from stakeholders generally supported the revised conversion method and MISO adopted the revised method and shared related Tariff redlines at the November 3, 2021 meeting of the RASC.

2. Non-Schedule 53 Resources

As indicated, the majority of MISO's proposed resource accreditation revisions address Schedule 53 Resources. While MISO intends to address potential accreditation enhancements to non-Schedule 53 Resource accreditation in a future filing after development and stakeholder discussions, non-Schedule 53 Resources will receive a SAC value based on Resource type consistent with their current accreditation rules adjusted for seasonality. As explained by Mr. McFarlane, wind resources will receive accreditation for each Season based on seasonal Effective Load Carrying Capability studies with capacity credit allocated based on eight peak hours for each Season.[94] In addition, non-wind intermittent resources such as run-of-river hydro, solar, Behind the Meter Generation ("BTMG") and biomass will be based on historic output during hours ending 15, 16 and 17 Eastern Standard Time ("EST") for the relevant Spring, Summer, and Fall months. Winter accreditation will be based on hours 8, 9, 19 and 20 EST for the Winter months. Mr. McFarlane explains in his testimony that the selected hours represent the typical seasonal peak demand hours for the specified Seasons.[95] Finally, Demand Resources registered as LMRs will be accredited based on lead-time and number of calls per year consistent with current LMR rules, with adjustments to establish a minimum number of calls for each Season – five for Summer, five for Winter, three for Spring and three for Fall.[96]

C. Generator Outage Coordination

MISO's current Resource Adequacy construct provides for exemptions for generator planned outages if certain criteria are met.[97] MISO has since worked collaboratively with stakeholders to develop an exemption process that integrates with the tiered accreditation calculations in Schedule 53.[98] The three levels are: (1) full exemption for Generator Planned Outages from Tier 1 and Tier 2 SAC calculations in Schedule 53; (2) partial exemption (only exempt in Tier 1 SAC calculations); and (3) no exemption.[99] The table below detailing the proposed exemption requirements is also in Schedule 53 of the Tariff:

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94 *Id.* at 31.

95 *Id.* at 32.

96 *Id.*

97 *Id.* at 46.

98 *Id.* at 47.

99 *Id.*

Generator Outage Submission Criteria	**Maintenance Margin >=0 for duration of outage**	**Maintenance Margin <0 for any day in the duration of outage**
>120 days prior to outage start date, and >120 days from end of previous outage for unit	Exempt Tier 1 & 2	Exempt Tier 1 Only
>120 days Prior to Outage Start date and <120 days from end of Previous outage for unit or Outage submitted between 31-119 days Prior to outage start date	Exempt Tier 1 Only	No Exemption
14-30 days prior to outage start date and passes No Harm Test	Exempt Tier 1 Only	No Exemption
Outage moved per MISO request	Exempt Tier 1 & 2 (Weather, forced outages, other conditions in BPM-008)	Exempt Tier 1 & 2 (Weather, forced outages, other conditions in BPM-008) at Transmission Provider's discretion

MISO's outage exemption analysis will apply no harm tests that include, but will not be limited to, outage approval, compliance with all applicable operation guides, review of possible conflicting outages or system conditions, and forecasts of system capacity.[100] The tests will also include criteria outlined in the Business Practices Manual for Outage Coordination and will apply only to specific categories of outages.[101]

For those planned outages submitted before MISO's proposal goes into effect, MISO proposes a transition with a bright-line distinction based on whether the outage is scheduled to start before September 1, 2022.[102] Planned outages submitted since Spring 2019 are coded as exempt or not in the Control Room Operations Window ("CROW") under RAN Phase 1.[103] Exempt resources will be treated as fully exempt for Tier 1 and 2 even though they may not have met both of the primary requirements of: (1) being submitted 120 days or greater in advance; and, (2) leaving positive Maintenance Margin in the subregion for the duration of the outage.[104] As explained by Mr. McFarlane, MISO believes this approach is appropriate given the risks to

100 *Id.* at 48.

101 *Id.*

102 *Id.*

103 *Id.*

104 *Id.*

capacity sufficiency from correlated planned outages and its ongoing efforts to encourage sufficient outage coordination.[105]

In light of the strong correlation between high outage levels and MaxGen events, MISO proposes to implement processes and procedures to enhance SAC determinations for Schedule 53 resources.[106] Under MISO's proposed framework, outage exemptions will usually be given at the time of outage submittal review or in response to a CROW ticket change request.[107] Partial and full exemptions ensure that a Resource's accreditation is appropriately impacted based on adherence to the outage coordination criteria.[108] The criteria for exemptions are outage lead time and adequate Maintenance Margin.[109] Mr. McFarlane notes that outage approvals and outage exemptions have separate purposes and criteria but bridge the gap between the planning and operational horizons.[110] As is the case today, approvals will be based on reliability analysis in the Outage Coordination process.[111]

MISO is also developing enhancements to Maintenance Margin to improve the information available to Resource owners scheduling outages. Maintenance Margin is the maximum megawatt of additional generation that can be taken out of service for planned maintenance for a given time-period without undue risk to supply adequacy for MISO's Balancing Authority Area, including MISO sub-regions.

Full outage-related exemptions (exempt Tier 1 and Tier 2) will be provided if: (1) the generator owner or operator schedules its first planned outage 120 days or more in advance of the outage start date and 120 days or more beyond the end date of any previously scheduled outages for the unit, and certain projected Maintenance Margin levels are met; and (2) the generator owner or operator reschedules its planned outage at MISO's request due to certain enumerated conditions.[112] These criteria are set forth in additional detail in Schedule 53 and the Testimony of Mr. McFarlane.

Partial outage-related exemptions (exempt Tier 1 only) will be provided if one of the following conditions are met: (1) the generator owner or operator schedules its first generator planned outages 120 days or more in advance of the outage start date and 120 days or more beyond the end date of any previously scheduled outages for the unit; (2) a subsequent generator unit outage requests 120 days or more in advance and/or generator owner or operator's planned outage is less than 120 days in advance but at least 31 days in advance of outage start date; (3) the planned

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105 *Id.* at 48-49.

106 *Id.* at 49.

107 *Id.*

108 *Id.*

109 *Id.* at 49-50.

110 *Id.* at 50.

111 *Id.*

112 *Id.* at 47.

outage is less than 31 days in advance but at least 14 days in advance of outage start date; or (4) the generator owner or operator reschedules its planned outage at the Transmission Provider's request. These criteria are set forth in additional detail in Schedule 53 and the Testimony of Mr. McFarlane.

V. OTHER RELATED ENHANCEMENTS

A. Market Monitoring and Mitigation Revisions

MISO also intends to modify its market monitoring and mitigation provisions in Module D of the Tariff. More specifically, the revisions to Module D of the Tariff focus, in part, on substantive enhancements regarding physical and economic withholding.[113] With regard to physical withholding, the shift to a seasonal construct requires minor modifications to ensure existing protections continue to work in the future.[114] MISO proposes to remove the preclusion from participation for resources that expect to be on outage for greater than 90 of the first 120 days of the Planning Year and replace that with a provision that states that a Market Participant with a Resource that has submitted an outage for greater than 31 days of a Season can ask the IMM for a determination ahead of the auction allowing it to forego offering excess Zonal Resource Credits from the Resource into the PRA, without being deemed to have engaged in physical withholding.[115]

The shift to a seasonal construct could mean that a Resource may only be able to recover capacity revenues in a single Season, which need to cover its relevant costs of being designated for Resource Adequacy Requirements.[116] The threshold for economic withholding remains at 10% of daily CONE but it is expected that more Resources will request facility-specific Reference Levels or use Default Technology Specific Avoidable Costs to help ensure they can cover their costs when they might only clear for one Season in contrast to the full Planning Year under the current construct.[117] The threshold for economic withholding remains at $0 when a Resource has a facility-specific Reference Level at which it can offer.[118]

B. Make-Whole Payment / Revenue Sufficiency Guarantee

When evaluating the shift to the seasonal PRA construct, MISO identified rare circumstances that result in the potential for over or underpayment. As explained by Mr. McFarlane, historical PRA results suggest that these situation will not occur frequently but,

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113 *Id.* at 50.

114 *Id.* at 51.

115 *Id.*

116 *Id.*

117 *Id.*

118 *Id.*

nonetheless, it is reasonable to ensure mitigation for such potential instances.[119] To address this potential risk, MISO proposes enhancements to its offer caps and will add the ZRC Offer Revenue Sufficiency Guarantee Credit to ensure Resources clearing the PRA recover their costs reflected in their offer while also ensuring the LSEs are not exposed to Auction Clearing Prices that result in charges that amount to multiples of the annual CONE value as a result of participation in the PRA. Mr. McFarlane's testimony contains specific descriptions of the proposed Auction Clearing Price adjustments and make whole payment provisions.[120]

Charges to fund the ZRC Offer Revenue Sufficiency Guarantee will be allocated to Market Participants representing LSEs in the LRZ(s) experiencing shortage or near shortage conditions *pro rata,* based on their respective LSEs' share of the PRMR within the LRZs during the Season or Seasons where the Auction Clearing Prices were reduced.[121] Mr. McFarlane notes in his testimony that this allocation of ZRC Offer Revenue Sufficiency Guarantee charges is similar to the allocation of the Zonal Deliverability Benefit, which occurs when an LRZs' Auction Clearing Price separates from the Region-wide Auction Clearing Price due to limited import or expert capability.[122]

VI. STAKEHOLDER ENGAGEMENT

MISO has been engaged in dedicated, detailed discussions with stakeholders at the RASC and RAN workshops about these proposed reforms since March 2020. As previously referenced, however, issues identified prior to and throughout the RAN initiative were discussed with stakeholders as early as 2015. As described above, MISO has already taken action with FERC filings related to outage coordination and LMRs in 2018, 2019 and 2020. Regarding the current proposals, MISO has discussed a variety of alternatives since 2017 through the stakeholder issues process and the publication of various "white-papers." Attached to Mr. Wright's testimony as Exhibit A is a table outlining the numerous meetings and topics covered with stakeholders during the development to this proposal. As indicated by the table, stakeholder involvement in the development and evaluation of this proposal has been extensive.

Stakeholders have passed three motions requesting that MISO delay its filing, specifically citing the need for additional time to understand MISO's proposal. The details of these motions and related vote tallies are described in detail in the testimony of Mr. Wright. MISO responded to a stakeholder motion passed at the September 2021 RASC requesting that MISO delay the instant filing beyond the planned September 30, 2021 filing date and provided stakeholders with an additional two months to continue discussions. While the filing was not delayed into 2022 as requested by the motion, MISO held three additional RASC meetings and three additional stakeholder workshops to further discuss stakeholder questions and concerns. In addition, MISO established a formal question and answer process with written and verbal responses. This included

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119 *Id.* at 40.

120 *Id.* at 39-46.

121 *Id.* at 45.

122 *Id.*

the cataloging and responding to over 120 questions through the formal stakeholder feedback process.[123] In parallel to the RASC and RAN workshops mentioned above focusing on MISO's proposal, MISO held one implementation workshop to solicit stakeholder inputs on MECT tool enhancements in support of transitioning to proposed Resource Adequacy reforms.

During these additional stakeholder discussions, MISO made several refinements and improvements to the proposal. These modifications include the following: implementation of the UCAP/ISAC ratio; provisions for catastrophic outage replacements; resource capacity increases during the Planning Year; transitional Tier 1 and Tier 2 weightings of 20% and 80%, respectively; Auction Clearing Price adjustment during scarce and near-scarce conditions; and, provisions to address revenue sufficiency under rare circumstances. Many of these changes were proposed by stakeholders through written and verbal feedback. MISO evaluated each proposal to determine consistency with the objectives of current proposal and potential reliability or efficiency impacts. Based on that evaluation and upon discussions with the IMM, MISO believes these changes to be reasonable and has included them in its final proposal. The specific Tariff changes described below reflect these changes and their merits are discussed in the testimony submitted with this filing.

MISO appreciates the willingness of all its stakeholders and state regulators to review and comment on this final proposal, which MISO believes reasonably accommodates concerns raised by stakeholders.

VI. TARIFF REVISIONS

MISO proposes the following revisions to its Tariff to implement its proposed Resource Adequacy reforms including Seasonal Resource Adequacy Construct and Availability-Based Accreditation.

A. Module A - Common Tariff Provisions – Definitions

1. Allowable ZRC Offer Costs

MISO proposes adding the definition of Allowable ZRC Costs to specify that Allowable ZRC Offer Costs means "[c]osts associated with a Planning Resource reflected in its ZRC offer, or the CONE, or facility-specific Reference Level costs, considered in determining ZRC Offer Revenue Sufficiency Credits for a Planning Year."

2. Auction Clearing Price (ACP)

MISO proposes modifying the definition of Auction Clearing Price by inserting the phrase "for a Season" into the definition to clarify that Auction Clearing Price means the price associated with the MW quantity that clears in the Planning Resource Auction for a given LRZ or ERZ for a Season for the applicable Planning Year.

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123 *See* https://cdn.misoenergy.org/20211118%20RA%20Construct%20Workshop%20Item%2002c%20Review%20Q%20and%20A605111.pdf

3. Border External Resource

MISO proposes modifying the definition of Border External Resource by replacing "Unforced Capacity" with "Capacity" in the definition to clarify that a Border External Resource means an External Resource that: (i) has direct interconnection facilities to a substation that contains the terminal of a transmission line under the Transmission Provider's functional control; (ii) will schedule in response to notification by the Transmission Provider during a declared Energy Emergency solely from unit(s) connected to each substation; and, (iii) whose Capacity offered into MISO may be accommodated on those transmission line(s) under the Transmission Provider's functional control.

4. Capacity Deficiency Charge

MISO proposes modifying the definition of Capacity Deficiency Charge by inserting language into the definition to clarify that Capacity Deficiency Charge means a charge that is assessed to an LSE that has provided notification prior to the Planning Resource Auction that it will meet its PRMR in part or in whole by paying the Capacity Deficiency Charge so that the Transmission Provider does not clear associated Zonal Resource Credits ("ZRC") for the associated PRMR through the PRA.

5. Capacity Export Limit (CEL)

MISO proposes modifying the definition of Capacity Export Limit by inserting the phrase "for each Season" into the definition to clarify that Capacity Export Limit means the amount of Planning Resources in MWs for an LRZ or ERZ determined by the Transmission Provider that can be reliably exported from that LRZ or ERZ for each Season.

6. Capacity Import Limit (CIL)

MISO proposes modifying the definition of Capacity Import Limit by inserting the phrase "for each Season" into the definition to clarify that Capacity Import Limit means the amount of Planning Resources in MWs for an LRZ determined by the Transmission Provider that can be reliably imported into that LRZ for each Season.

7. Capacity Replacement Non-Compliance Charge

MISO proposes adding the definition of Capacity Replacement Non-Compliance Charge to specify that Capacity Replacement Non-Compliance Charge means "[t]he charge assessed to a Market Participant for failing to replace ZRCs that were designated for RAR and did not fulfill their performance obligations as set forth in Module E-1."

8. Catastrophic Generator Outage

MISO proposes adding the definition of Catastrophic Generator Outage to specify that Catastrophic Generator Outage means a forced outage that results in a unit being, or reasonably expected to be unavailable for a minimum of six (6) continuous months, which is not the result of a planned maintenance outage.

9. Coincident Peak Demand

MISO proposes modifying the definition of Coincident Peak Demand by inserting the phrase "for each Season" into the definition to clarify that Coincident Peak Demand means the

demand in MWs, for an LSE and/or EDC, that occurs coincident to the peak Demand for each Season, where all Demand has been augmented to include any known reductions in Demand related to LMRs and/or Energy Efficiency Resources.

10. Deliverability Benefit Zone

MISO proposes modifying the definition of Deliverability Benefit Zone by inserting the phrase "for a Season" into the definition to clarify that Deliverability Benefit Zone means a group of Local Resource Zones that have equal Auction Clearing Prices for a Season in a Planning Resource Auction resulting from the same auction constraint.

11. Diversity Contract

MISO proposes modifying the definition of Diversity Contract by removing the phrases "for the period between June 1st and September 30th" and "for any period during October 1st to May 31st" to clarify that Diversity Contract means a type of power purchase agreement between an LSE in the Transmission Provider Region and an LSE with demand external to the Transmission Provider Region that includes a one for one MW exchange of capacity which is committed to the Transmission Provider Region in exchange for capacity committed outside of the Transmission Provider Region.

12. Fixed Resource Adequacy (FRAP)

MISO proposes modifying the definition of Fixed Resource Adequacy Plan by inserting the phrase "in a Season" into the definition to clarify that Fixed Resource Adequacy Plan means a plan submitted by an LSE through the MECT to the Transmission Provider that is approved by the Transmission Provider which demonstrates that the LSE has sufficient ZRCs to meet all or part of its PRMR for one or more LRZs in a Season.

13. ICAP Deferral Non-Compliance Charges

MISO proposes modifying the definition of ICAP Deferral Non-Compliance Charges by inserting the phrase "start of any Season for which a Market Participant has an ICAP deferral" into the definition to clarify that ICAP Deferral Non-Compliance Charges means a charge that is assessed by a Market Participant that fails to submit GVTC results, demonstrate deliverability, demonstrate commercial operation, and/or replace ZRCs by the last Business Day prior to the start of any Season for which a Market Participant has an ICAP deferral associated with Planning Resources that participate in the Resource Adequacy Requirements provisions, including the Planning Resource Auction and the Fixed Resource Adequacy Plan.

14. Local Clearing Requirement (LCR)

MISO proposes modifying the definition of Local Clearing Requirement by replacing "Unforced Capacity" with "Seasonal Accredited Capacity" and inserting the phrase "for each Season" into the definition to clarify that Local Clearing Requirement means the minimum amount of Seasonal Accredited Capacity for an LRZ that is required to meet its LOLE for each Season while fully using the Zonal Import Ability for such LRZ and accounting for controllable exports.

15. Local Clearing Requirement Charge

MISO proposes modifying the definition of Local Clearing Requirement Charge by inserting the phrase "for a Season" into the definition to clarify that Local Clearing Requirement

Charge means a charge that is assessed to Load Serving Entities whenever an LRZ's Auction Clearing Price for a Season is increased due to its LCR being greater than the sum of individual PRMR of the LSEs.

16. Local Reliability Requirement (LRR)

MISO proposes modifying the definition of Local Reliability Requirement by inserting the phrase "for each Season" into the definition to clarify that Local Reliability Requirement means the minimum of amount of Unforced Capacity for an LRZ to meet its LOLE for each Season, without considering transmission ties to systems outside of the LRZ.

17. Local Resource Zone Peak Demand

MISO proposes modifying the definition of Local Resource Zone Peak Demand by removing the word "annual" and inserting the phrase "for each Season" into the definition to clarify that Local Resource Zone Peak Demand means the Demand in MWs, for an LSE and/or EDC, in a Local Resource Zone that occurs coincident to the peak Demand for each Season in the Local Resource Zone, where all Demand has been augmented to include any known reductions in Demand related to LMRs and/or Energy Efficiency Resources.

18. Loss of Load Expectations (LOLE)

MISO proposes modifying the definition of Loss of Load Expectation by removing the phrase "[t]he requirement is set such that the loss of Load is no greater than 0.1 day in one (1) year" from the definition to clarify that Loss of Load Expectation means the sum of the loss of Load probability for the integrated daily peak Hour for each Day of the year.

19. Planning Reserve Margin Requirement (PRMR)

MISO proposes modifying the definition of Planning Reserve Margin Requirement by inserting the phrase "in each Season" into the definition to clarify that Planning Reserve Margin Requirement means the amount of ZRCs required of each LSE with Coincident Peak Demand in an LRZ to meet the LSE's Resource Adequacy Requirements in each Season.

20. Planning Resource Auction (PRA)

MISO proposes modifying the definition of Planning Resource Auction by replacing the phrase "annual" with the phrase "each Season in" in the definition to clarify that Planning Resource Auction means auctions conducted by the Transmission Provider to determine the ACP and the cleared ZRC Offers for each LRZ and ERZ for each Season in the applicable Planning Year.

21. Seasonal Accredited Capacity (SAC)

MISO proposes adding the definition of Seasonal Accredited Capacity to specify that Seasonal Accredited Capacity means the amount of Capacity, for a given Season, in MW, assigned to a Planning Resource after accounting for its historic availability.

22. Sub-Regional Export Constraint (SREC)

MISO proposes modifying the definition of Sub-Regional Export Constraint by inserting the phrase "for each Season" into the definition to clarify that Sub-Regional Export Constraint means the amount of Planning Resources in megawatts modeled in the PRA for each Season within an applicable Sub-Regional Resource Zone ("SRRZ") that can be cleared in excess of the total

individual LRZ's PRMR comprising the SRRZ in accordance with applicable seams agreements, coordination agreements, or transmission service agreements.

23. Sub-Regional Import Constraint (SRIC)

MISO proposes modifying the definition of Sub-Regional Import Constraint by inserting the phrase "for each Season" into the definition to clarify that Sub-Regional Import Constraint means the amount of Planning Resources in megawatts modeled in the PRA for each Season, not within an applicable Sub-Regional Resource Zone ("SSRZ"), that can be cleared to meet the total PRMR of the individual LRZs comprising the SRRZ in accordance with applicable seams agreements, coordination agreements, or transmission service agreements.

24. Sub-Regional Resource Zone (SRRZ)

MISO proposes modifying the definition of Sub-Regional Resource Zone by removing the reference to Module E-2 and inserting the phrase "for each Season" into the definition to clarify that Sub-Regional Resource Zone means a zone, comprised of a LRZ or combination of two or more LRZs, established by the Transmission Provider for each Season for Resource Adequacy Requirements under Module E-1 to administer constraints in accordance with applicable seams agreements, coordination agreements, or transmission service agreements.

25. System Auction Clearing Price (System ACP)

MISO proposes modifying the definition of System Auction Clearing Price by inserting the phrase "for a Season" into the definition to clarify that System Auction Clearing Price means the marginal value ("shadow price") associated with the system-wide Demand constraint for a Season. This Demand constraint ensures that the amount cleared, in all LRZs, is at least equal to the total PRMR in all LRZs. The marginal value of this constraint provides a quantitative result of the value of obtaining the marginal MW from the non-export constrained LRZ(s).

26. Zonal Resource Credit (ZRC)

MISO proposes modifying the definition of Zonal Resource Credit by replacing "Unforced Capacity" with "Seasonal Accredited Capacity" in the definition to clarify that Zonal Resource Credit means a MW unit of Planning Resource which has been converted from a MW of Seasonal Accredited Capacity to a credit in the MECT, which is eligible to be offered by a Market Participant into the PRA, to be sold bilaterally, and/or to be submitted through a FRAP.

27. ZRC Near-Shortage Conditions

MISO proposes adding the definition of ZRC Near-Shortage Conditions to specify that ZRC Near-Shortage Conditions means any Season in a Planning Resource Auction in which there is sufficient volume of ZRC Offers in the LRZ, group of LRZs, or SRRZ to cover PRMR and locational requirements minus the PRMR associated with the Capacity Deficiency Charge for the LRZ, group of LRZs, or SRRZ, but the Season's ACP is greater than the daily CONE value (i.e. 1/365 times CONE).

28. ZRC Offer Revenue Sufficiency Credit

MISO proposes adding the definition of ZRC Offer Revenue Sufficiency Credit to specify that ZRC Offer Revenue Sufficiency Credit means a Resource credit guaranteed by the Transmission Provider ensuring the minimum recovery of the actual costs a Planning Resource

that has been cleared for one or more Seasons in the Planning Resource Auction needed to be incurred by the Planning Resource to be available for the cleared Season(s).

29. ZRC Shortage Conditions

MISO proposes adding the definition of ZRC Shortage Conditions to specify that ZRC Shortage Conditions means any Season in a Planning Resource Auction in which there is an insufficient volume of ZRC Offers to cover LCR or the total PRMR for the LRZ, group of LRZs, or SRRZ minus the amount of PRMR associated with the Capacity Deficiency Charge for an LRZ, group of LRZs, or SRRZ, or the total PRMR for the SRRZ minus the SRIC minus the amount of PRMR associated with the Capacity Deficiency Charge for a SRRZ.

30. Transitional Planning Resource Auction (TPRA) and Module E-2 References

MISO proposes deleting the definition of Transitional Planning Resource Auction ("TPRA") as well as all references to the TPRA and to Module E-2 (which establishes the TPRA) throughout the Tariff. Such references are no longer needed because new transitional auction provisions will need to be developed in order to accommodate the proposed seasonal Resource Adequacy construct. For example, any new Market Participant proposing to integrate Schedule 53 type Resources into MISO mid-Planning Year will not have available data necessary for MISO to establish appropriate accreditation. In this regard, MISO notes that, upon acceptance of this filing by the Commission, MISO proposes to submit a separate Section 205 filing to cancel Module E-2 and remove it from the Tariff. In addition, MISO expects to establish and file with the Commission new transitional seasonal PRA provisions, as may be necessary.

B. Module A - Section 7.11 - Billing Procedure for Capacity Deficiency Charge and Capacity Replacement Non-Compliance Charge

MISO proposes adding Tariff language to Section 7.11 of the Tariff to clarify that the billing procedure for Capacity Deficiency Charges set forth in Section 7.11 of the Tariff will also apply to Capacity Replacement Non-Compliance Charges. Specifically, the language will require that five business days after the assessment of the Capacity Deficiency Charge or Capacity Replacement Non-Compliance Charge; or as soon as practical thereafter the Transmission Provider shall submit an invoice to Market Participants for charges owed that are associated with capacity deficiencies or the Capacity Replacement Non-Compliance Charge pursuant to the Tariff.

C. Module A - Section 7.13 - Default and Past Due Capacity Deficiency Charge, Capacity Replacement Non-Compliance Charge and ICAP Deferral Non-Compliance Charges

MISO proposes adding Tariff language to Section 7.13 of the Tariff to clarify that the rights and remedies for default and past due Capacity Deficiency Charges set forth in Section 7.13 of the Tariff will also apply to Capacity Replacement Non-Compliance Charges.

D. Attachment L – Credit Policy

MISO proposes modifying Attachment L of the Tariff by inserting language to clarify that Capacity Replacement Non-Compliance Charges will also be excluded from the Resource Adequacy Requirements Estimated Exposure calculation as they are settled all at once rather than daily.

E. Attachment UU – Energy Efficiency Resources Measurement & Verification Procedures

MISO proposes modifying Attachment UU of the Tariff by replacing coincident peak load with "Coincident Peak Demand" throughout the attachment and adding language related to "Season(s) in the" Planning Year, "Season", "in any Season", "applicable Season(s)", and "each Season in the Planning Year which the EE Resource expects to qualify" throughout the attachment.

MISO proposes inserting language into Attachment UU specifying that the hours in the Season for which the coincident peak is likely to occur "currently include the hours 15:00, 16:00, and 17:00 Eastern Prevailing Time (EPT) for the Spring, Summer, and Fall Seasons and hours 08:00, 09:00, 19:00, and 20:00 EPT for the Winter Season."

F. Module C - Energy and Operating Reserve Markets

1. Section 38.2.5 - Market Participant Obligations

MISO proposes modifying Sections 38.2.5 of the Tariff by adding language to Section 38.2.5.g.vii of the Tariff to clarify that if a Market Participant refuses to reschedule a Proposed Generator Planned Outage as requested by the Transmission Provider, then during the next Planning Year, the Transmission Provider shall determine the Seasonal Accredited Capacity value for such Generation Resource under RAR by treating the outage as a Forced Outage. MISO proposes inserting Section 38.2.5.g.viii specifying that "[a] Resource may be eligible for accreditation adjustments for purposes of RAR pursuant to Schedule 53 based on the advance notification requirements set forth in Sections 38.2.5.g.ix and 38.2.5.g.x." MISO proposes removing language from Section 38.2.5.g.ix-xi regarding the forced outage rate adjustment.

2. Section 39.2.5A - Demand Response Resource-Type 1 Offer Rules

MISO proposes modifying Section 39.2.5A.b.ix of the Tariff by replacing "Unforced Capacity" with "Seasonal Accredited Capacity".

3. Section 40.2.5 - Generation Offer, DRR-II Offer, or SER-II Offer

MISO proposes modifying Section 40.2.5.b.xv of the Tariff by replacing "Unforced Capacity" with "Seasonal Accredited Capacity".

G. Module D - Market Monitoring and Mitigation Measures

1. Section 53.1 – Conditions, Functions or Actions Monitored

MISO proposes modifying Section 53.1 of the Tariff by removing the phrase "other than ZRCs" from Section 53.1.b regarding the IMM's analysis of conditions, functions, or actions.

2. Section 53.1A – Auditing Physical Withholding

MISO proposes modifying Section 53.1A of the Tariff by inserting the phrase "Stored Energy Resources," "Electric Storage Resources," and "Generator Planned Outages" to clarify that "[i]n order to prevent and/or discern the exercise of market power by Stored Energy Resources, Electric Storage Resources, and certain Generation Resources, including Stored Energy Resources – Type II through Physical Withholding, the IMM shall audit Generator Forced Outages, Generator Planned Outages, and Generator deratings" and other changes.

3. Section 64.1.1 - Thresholds for Identifying Physical Withholding

MISO proposes modifying Section 64.1.1 of the Tariff by removing Section 64.1.1.g.ix regarding the 2015-2016 Planning Year, inserting the phrase "Season of the applicable" Planning Year into Sections 64.1.1.g.i-iii, and modifying renumbered Section 64.1.1.g.xi to clarify that "Market Participants with capacity expected to be on outage for greater than thirty-one (31) Days in a Season of the Planning Year may submit documentation of such circumstances to the IMM, and the IMM shall provide a written explanation upon request of its determination to the Market Participant regarding whether that capacity can forego participation without being deemed to have engaged in Physical Withholding. The portion of a Resource that the IMM has determined can forego participation based on full or partial outage expected to exceed thirty-one (31) Days in a Season of the Planning Year can still offer the excluded portion of the Resource in the relevant Season, if it so chooses, up to the annual CONE value divided by the number of days in the Season without needing to request a facility-specific Reference Level and will not be investigated for economic withholding in that Season."

4. Section 64.1.2 - Thresholds for Identifying Economic Withholding

MISO proposes modifying Section 64.1.1 of the Tariff by inserting the phrase "a threshold equal to the sum of 10% of the applicable CONE value divided by the number of days in the Planning Year for the Local Resource Zone where the Zonal Resource Credit is located and the applicable Reference Level for the Zonal Resource Credit" into section 64.1.2.d and by clarifying that "[i]f the Zonal Resource Credit Offer is associated with a Planning Resource that has a facility-specific Reference Level pursuant to Section 64.1.4.f, for which the IMM shall instead use a threshold of $0/MW-day above the facility-specific Reference Level."

5. Section 64.1.4 - Reference Levels

MISO proposes modifying Section 64.1.4 of the Tariff by replacing "Unforced Capacity" with "Seasonal Accredited Capacity" in Section 64.1.4.f.ii and by inserting language throughout Section 64.1.4 clarifying that Reference Levels shall be calculated based on Seasons and seasonal costs and inserting language regarding seasonal operations and seasonal shutdowns.

MISO proposes modifying Section 61.1.4.f.iii.c.2.ii-iii specifying with respect to forecasts for the Planning Resource to be in service that "[a]fter the applicable Season, the remainder of the 24 months should reflect the anticipated operations of the Planning Resource in the absence of capacity revenues. Typically, the Operating Forecast would show the costs of proceeding with retiring or suspending the Resource as applicable at the conclusion of the Season but it may show suspensions for just select Seasons of the year" and with respect to a forecast of the cost to retire, suspend, or keep a Planning Resource in suspension that "[a]fter the applicable Season, the remainder of the 24 months should reflect the anticipated operations of the Planning Resource in the absence of capacity revenues. Typically, the Operating Forecast would show the costs of proceeding with retiring or suspending the Resource as applicable at the conclusion of the Season but it may show suspensions for just select Seasons of the year."

6. Section 64.2.1 - Market Impact Thresholds

MISO proposes modifying Section 64.2.1 of the Tariff by inserting the phrase "divided by the number of days in the Planning Year" into Section 64.2.1.e to clarify that "[t]he threshold to determine a substantial effect on Auction Clearing Prices for Planning Resources shall be an

increase in the Auction Clearing Price equal to ten (10) percent of the CONE value divided by the number of days in the Planning Year."

7. Section 65.3.2 - Base Penalty Amount

MISO proposes modifying Section 65.3.2 of the Tariff by inserting language regarding the "Season of the" Planning Year into Section 65.3.2.c to clarify that the Penalty Period will be based on the Season of the Planning Year in which capacity was deemed to be withheld by a Market Participant from the auction and the phrase "applicable Season of the" Planning Year into Section 65.3.2.d to clarify that the Penalty Price for conduct affecting the outcomes of a PRA will be based on the Auction Clearing Price for the applicable Season of the Planning Year.

H. Module E-1 – Resource Adequacy

1. 68A – Introduction

MISO proposes modifying the Introduction to Module E-1 to clarify that "Module E-1 includes provisions for establishing Local Resource Zones and associated limits (*i.e.*, Capacity Import Limits (CIL) and Capacity Export Limits (CEL)); establishing Local Reliability Requirements (LRR); establishing Local Clearing Requirements (LCR); establishing External Resource Zones and associated limits (i.e. Capacity Export Limits (CEL)); determining the Planning Reserve Margin, Coincident Peak Demand forecasting; Local Resource Zone Peak Demand forecasting; qualifying and quantifying Planning Resources; participation of Demand and Planning Resources in the Planning Resource Auction process; settlement provisions; and Planning Resource performance requirements for each Season."

2. Section 68A.1 – Establishment of Planning Reserve Margins

MISO proposes modifying Section 68A.1 of the Tariff by inserting the phrases "in terms of Unforced Capacity for each Season" and "regulatory authority" into the Establishment of Planning Reserves Margins section to clarify that the PRM will be determined for each Season and that if a state regulatory authority establishes a PRM that is higher or lower than the PRM determined by the Transmission Provider, then the state regulatory authority-established PRM will apply to the Coincident Peak Demand of LSEs under that state's jurisdiction.

3. Section 68A.2 – Planning Reserve Margin Analysis

MISO proposes modifying Section 68A.2 of the Tariff by inserting the phrase "for each Season" to clarify that the Transmission Provider shall perform a technical analysis on an annual basis to establish the PRM for each Season for the Transmission Provider Region and by removing the word "resource" from the phrase specific Planning Resource reserve requirements.

4. Section 68A.2.1 – Loss of Loss Expectation Analysis

MISO proposes modifying Section 68A.2.1 of the Tariff by inserting the phrase "Season in the" Planning Year to clarify that the Transmission Provider shall coordinate with Market Participants to determine the appropriate PRM for the applicable Season in the Planning Year based upon the probabilistic analysis of being able to reliably serve the Transmission Provider Region's Demand for the applicable Season in the Planning Year.

MISO proposes modifying Section 68A.2.1 of the Tariff by inserting language into Section 68A.2.1 to clarify that "[t]he following process will be utilized to determine the minimum PRM

requirement for each Season in the Planning Year using the LOLE analysis. First, an LOLE analysis for the Planning Year will be conducted such that the LOLE for the Planning Year is one (1) day in ten (10) years, or 0.1 day per year, by either adding or removing capacity."

MISO proposes inserting additional language into Section 68A.2.1 to clarify that "[i]f the LOLE for the Planning Year is less than 0.1 day per year, a perfect negative unit with zero forced outage rate will be added until the LOLE reaches 0.1 day per year. If the LOLE for the Planning Year is greater than 0.1 day per year, proxy units based on a unit of typical size and forced outage rate will be added to the model until the LOLE reaches 0.1 day per year."

MISO proposes inserting additional language into Section 68A.2.1 to clarify that "[i]f the LOLE for a Season is equal to or greater than 0.01 day per year, the minimum PRM requirement for that Season will be calculated based on this LOLE analysis. If the LOLE for any Season is less than 0.01 day per year, an additional LOLE analysis will be performed to determine a minimum PRM requirement for that Season by adding a perfect negative unit with zero forced outage rate to that Season until the LOLE in that Season reaches 0.01."

MISO proposes inserting additional language into Section 68A.2.1 clarifying that the PRM will first be established as an Unforced Capacity requirement based upon the weighted average forced outage rate of all Planning Resources in the Transmission Provider Region.

5. Section 68A.3.1 – Establishment of SRRZs, SRECs, and SRICs

MISO proposes modifying Section 68A.3.1 of the Tariff by inserting language to clarify that the provisions regarding establishing SRRZs, SRECs, and SRICs apply to each "Season" and that the Transmission Provider's feasibility analysis is to review operation events from "each Coincident Peak Demand hour during the previous Planning Year."

6. Section 68A.4 – Establishment of CIL and CEL Limits

MISO proposes modifying Section 68A.4 of the Tariff by inserting language to clarify that the provisions regarding establishing CIL and CEL Limits apply to each "Season."

7. Section 68A.5 – Establishment of Local Reliability Requirements

MISO proposes modifying Section 68A.5 of the Tariff by inserting language to clarify that the LRR metric for each LRZ relates to "each Season", the forecasted Local Resource Zone Peak Demand relates to "each Season", and that "[f]irst, the LOLE analysis for the Planning Year will be conducted," that "[i]f the LOLE for the Planning Year is less than 0.1 day per year, a perfect negative unit with zero forced outage rate will be added until the LOLE reaches 0.1 day per year. If the LOLE for the Planning Year is greater than 0.1 day per year, proxy units based on a unit of typical size and forced outage rate will be added to the model until the LOLE reaches 0.1 day per year," and that "[i]f the LOLE for a Season is equal or greater than 0.01 day per year for the LRZ, the LRR for that Season will be calculated based on this LOLE analysis. If the LOLE for any Season is less than 0.01 day per year for the LRZ, an additional LOLE analysis will be performed to determine the LRR for that Season by adding a perfect negative unit with zero forced outage rate to that Season until the LOLE in that Season reaches 0.01 day per year for the LRZ."

8. Section 68A.6 – Establishment of Local Clearing Requirements

MISO proposes modifying Section 68A.6 of the Tariff by inserting language to clarify that "[t]he Local Clearing Requirement for each LRZ for each Season will be determined by subtracting Zonal Import Ability and controllable exports from the LRR, as set forth in the Resource Adequacy Business Practices Manual. Controllable exports are exports from MISO resources that have firm capacity commitments to non-MISO load and that may be committed and dispatched by the Transmission Provider during a declared Energy Emergency."

9. Section 68A.7 – Establishing Planning Reserve Margin Requirements

MISO proposes modifying Section 68A.7.a of the Tariff by inserting language to clarify that the PRMR relates to "each Season" and to insert the language that the PRMR "will be determined by multiplying the LSE's forecasted Coincident Peak Demand for each Season, including transmission losses, by (1 + Transmission Provider Region PRM)."

MISO proposes modifying Section 68A.7.b of the Tariff by inserting language to clarify that when an alternative PRM is established by a state "regulatory authority" the Transmission Provider will use the alternate PRM that a state regulatory "authority" has created for the geographic area in which the state has jurisdiction, and the Transmission Provider will convert any state "regulatory authority" provided PRM for a comparable Unforced Capacity basis.

10. Section 68A.8 – Calculation of Transmission Losses

MISO proposes modifying Section 68A.8.a of the Tariff by inserting the phrases "Coincident Peak Demand" and "for each Season" to clarify that the Transmission Provider shall calculate the LBA transmission loss percentages for each Season and that the total transmission loss value (MW) for each LBA will based on Coincident Peak Demand instead of system peak.

11. Section 69A – RAR Process

MISO proposes modifying Section 69A of the Tariff by inserting language to clarify that LSEs and EDCs shall provide forecasted Coincident Peak Demand and Local Resource Zone Peak Demand data "for the Planning Year", the Transmission Provider will calculate each LSE's PRMR "for each Season", and an ACP will be determined through the PRA process for each LRZ and ERZ "for each Season" and the ACP will be used to credit ZRCs and debit LSEs.

12. Section 69A.1 – Load Serving Entities Responsibilities

MISO proposes modifying Section 69A.1 of the Tariff by inserting language into Section 69A.1.b to clarify that the Transmission Provider will use Coincident Peak Demand, Local Resource Zone Peak Demand, and Energy forecasts "for each Season", by removing Section 69A.1.c regarding what happens when the EDC does not provide a procedure for assigning LSE obligations as described in Section 69A.1.b, and by inserting language into the renumbered Section 69A.1.c to clarify that all LSEs shall report to the Transmission Provider whether such LSE will meet their PRMR for each LRZ "for each Season" in which the LSE serves Load.

13. Section 69A.1.1 – Forecasted Demand Identification

MISO proposes modifying Section 69A.1.1 of the Tariff by removing the phrase "annual" throughout and inserting the word a/any/each "Season" throughout.

MISO proposes modifying Section 69A.1.1.b of the Tariff by inserting the phrase "including Demand from any retail demand side management programs" into that section to clarify that "[t]he supplied Coincident Peak Demand and Local Resource Zone Peak Demand forecasts shall include the Demand expected for the forecast time period (*e.g.* the Coincident Peak Demand hour) augmented to include the normal Demand from forecasted demand resources, whether registered or not registered with the Transmission Provider, including Demand from any retail demand side management programs."

MISO proposes modifying Section 69A.1.1.d of the Tariff by removing the phrase "(e.g., annually for Coincident Peak Demand and Local Resource Zone Peak Demand, and monthly for non-coincident peak Demand" from that section to clarify that "[a]ll Coincident Peak Demand and Local Resource Zone Peak Demand forecasts shall reflect a 50% probability that the Demand will not exceed the forecasted Demand for the relevant period.

MISO proposes modifying Section 69A.1.1.e of the Tariff by inserting the clarifying language that "[c]onsistent" with Section 69A.1.2.1, the EDC must provide both the Transmission Provider and the respective LSEs with each retail customer's peak load contribution (PLC) "in each Season", including transmission losses and PRM as determined by the Transmission Provider, in the EDC's service territory by December 15th and by removing the phrase "[i]f an EDC uses the daily peak load default methodology in Section 69A.1.2.1, then the EDC must provide both the Transmission Provider and each of the respective LSEs with the LSE's historic share of the EDC's Coincident Peak Demand, by December 15th."

14. Section 69A.1.1.1 – Accounting for total Demand Forecasts Given Wholesale and Retail Load Switching

MISO proposes modifying Section 69A.1.1.1 of the Tariff by replacing the phrase "June 1 of the next Planning Year" with "the 1st day of each Season in the next Planning Year" in Section 69A.1.1.1.a, replacing the phrase "June 1 of the next Planning Year" with "the 1st day of any Season in the next Planning Year" in Section 69A.1.1.1.b, adding the phrase "for such Season" in Section 69A.1.1.1.b, and adding the phrase "each Season in the" in Section 69A.1.1.1.b.

15. Section 69A.1.2 – Daily Assignment of Coincident Peak Demand Obligations

MISO proposes modifying Section 69A.1.2 of the Tariff by removing Section 69A.1.2.c regarding states that permit retail load switching and satisfy other criteria, removing language from Section 69.A.1.2.b stating "and where the EDC has adopted the preferred default method in Section 69A.1.2.1", and inserting language into Section 69A.1.2.b specifying that that in a state that permits retail load switching the Transmission Provider shall allocate Resource capacity on a daily basis to LSEs through an outlined formula "consistent with Section 69A.1.2.1."

16. Section 69A.1.2.1 – Default Methods

MISO proposes modifying Section 69A.1.2.1 of the Tariff by inserting clarifying language into Section 69A.1.2.1.b that "EDC will assign a Peak Load Contribution ("PLC") value to each retail customer, based on the most recent PLC values derived for each Season from each retail customer's Demand at the time of the Transmission Provider's peak Demand (*i.e.*, the Prior Seasonal Retail Customer Coincident Peak ("PSRCCP"))" and by inserting the phrase "for each Season" to clarify that the PLCs determined by the EDC must equal the PRMR that is calculated

from the forecast Coincident Peak Demand provided by the EDC "for each Season" and that this equality is achieved by multiplying each retail customer's demand at the time of the Transmission Provider's peak Demand during "each Season" prior to the Planning Year by the same adjustment factor. MISO proposes further modifying Section 69A.1.2.1 by replacing "Prior Summer Retail Customer Coincident Peak" with "PRSCCP" throughout the section, by deleting the phrase "[t]he specific methods used by the EDC to compute each retail customer's PLC must be submitted to the Transmission Provider by December 1, and requires approval by, the Transmission Provider" from Section 69A.1.2.1.b, and by deleting Section 69A.1.2.1.c in its entirety because this method is no longer supported by MISO.

17. Section 69A.1.3 – Load Switching

MISO proposes modifying Section 69A.1.3 of the Tariff by removing Section 69A.1.3.b and replacing the phrase "[b]eginning June 1 of each Planning Year" in Section 69A.1.3.a with the phrase "[b]eginning the first Calendar Day of each Season in the Planning Year." and by deleting Section 69A.1.3.b in its entirety because this method is no longer supported by MISO.

18. Section 69A.3 – Planning Resource Requirements

MISO proposes modifying Section 69A.3 of the Tariff by removing language regarding resources with full or partial outages expected to last for ninety days or more of the first one-hundred and twenty days in the Planning Year being precluded from a FRAP or the PRA.

19. Section 69A.3.1 – Capacity Resources

MISO proposes modifying Section 69A.3.1 of the Tariff by inserting the phrase "any applicable Season in the" upcoming Planning Year into the sentence in Section 69A.3.1 "[t]he Transmission Provider will qualify a Capacity Resource for any applicable Season in the upcoming Planning Year, in accordance with processes specified in the BPM for Resource Adequacy" and by replacing the phrase "Capacity Resources cannot be Stored Energy Resources" with the phrase "Stored Energy Resources cannot be Capacity Resources."

20. Section 69A.3.1.a – Generation Resources that are not Dispatchable Intermittent Resources

MISO proposes modifying Section 69A.3.1.a of the Tariff by inserting the phrase "Season in the" into Section 69A.3.1.a.1.b to clarify that it relates to each Season in the Planning Year.

21. Section 69A.3.1.b – Demand Response Resources

MISO proposes modifying Section 69A.3.1.b of the Tariff by inserting language into Sections 69A.3.1.b.1 and 69A.3.1.b.3 to clarify that those sections relate to the applicable "Season" in the Planning Year rather than the Planning Year as a whole.

22. Section 69A.3.1.c – External Resources

MISO proposes modifying Section 69A.3.1.c.1 of the Tariff by inserting the phrases each "Season that the resource will be registered in" and "for each Season that the resource is to be registered in" into Section 69A.3.1.c to clarify that demonstrating GVTC capability relates to each Season and not the Planning Year on an annual basis.

MISO proposes modifying Section 69A.3.1.c.3 of the Tariff by inserting the phrase "applicable Season in the" upcoming Planning Year into Section 69A.3.1.c.3 to clarify that the section relates to the applicable Season and not the upcoming Planning Year.

MISO proposes adding Section 69A.3.1.c.6 of the Tariff stating "Existing Resources that modify their registration, scheduling and market participation in the Energy and Operating Reserves Markets and become pseudo-tied External Resources after September 1, 2022 will be accredited at the lesser of class average SAC in Schedule 53 or the accreditation provisions governing External Resources in section 69A.4.1.b."

23. Section 69A.3.1.d – Use Limited Resources

MISO proposes modifying Section 69A.3.1.d of the Tariff by inserting the phrase "each applicable Season" to clarify that the request that "[a] Use Limited Resource must be able to operate for a minimum set of four (4) consecutive operating Hours across the Transmission Provider's coincident peak for each day in each applicable Season in order to qualify as a Capacity Resource" relates to each Season and not to the Planning Year as a whole.

24. Section 69A.3.1.h – Retirement, Suspension and Replacement of Planning Resources

MISO proposes modifying Section 69A.3.1.h by replacing "Unforced Capacity" with "Seasonal Accredited Capacity" throughout, by removing "or TPRA" throughout, and by inserting language throughout regarding the relevant "Season" of or during the Planning Year. MISO proposes inserting language into Section 69A.3.1.h.a clarifying that "[i]f a Planning Resource for which a Market Participant converts Seasonal Accredited Capacity into ZRCs is Retired or Suspended prior to the end of the Season during the Planning Year in which the ZRCs cleared, such Market Participant must replace the cleared ZRCs with uncleared ZRCs." MISO proposes inserting language into Section 69A.3.1.h.a clarifying that "[i]f a Market Participant does not replace such ZRCs associated with a Retired or Suspended Planning Resource, a Capacity Replacement Non-Compliance Charge will be assessed as determined below in this Section."

MISO proposes modifying Section 69A.3.1.h by inserting language into Section 69A.3.1.h.a clarifying that "[i]f a Planning Resource for which a Market Participant converts Seasonal Accredited Capacity into ZRCs is unable to meet the applicable performance requirements for the cleared ZRCs as described in Section 69A.5 for greater than thirty-one (31) Days in total due to full or partial Generator Planned Outage during the Season of the Planning Year in which the ZRCs cleared, or for Capacity Resources that are the subject to Diversity Contracts for greater than one (1) Month during any Season of the Planning Year in which the ZRCs cleared, such Market Participant must replace the cleared ZRCs with uncleared ZRCs to transfer the performance requirements applicable to the Planning Resource."

MISO further proposes inserting language into Section 69A.3.1.h.a clarifying that "[a]ny combination of cleared or replaced ZRCs that are on full or partial Generator Planned Outage for greater than thirty-one (31) Days in total during a Season, or for any other reason including full or partial Generation Outages that were not planned but were known or could have been reasonably anticipated at the time of the PRA, as set forth in the Market Monitoring and Mitigation Business Practices Manual, or unavailable because subject to a Diversity Contract that is not available for greater than one (1) Month during a Season, will be assessed a Capacity Replacement Non-

Compliance Charge. If a Planning Resource for which a Market Participant converts Seasonal Accredited Capacity into ZRCs is unable to meet the applicable performance requirements for the cleared ZRCs as described in Sections 69A.3.3.1 and 69A.5 due to a Catastrophic Generator Outage any time during the Season of the Planning Year in which the ZRCs cleared such Market Participant may replace the cleared ZRCs with uncleared ZRCs to transfer the performance requirements applicable to the Planning Resource. A Planning Resource may not transfer its performance requirements by replacing the cleared ZRCs with uncleared ZRCs other than in the case of suspension, retirement, Catastrophic Generator Outage or full or partial Generator Planned Outages that may exceed thirty-one (31) Days in the Season as discussed immediately above."

MISO proposes modifying Section 69A.3.1.h by inserting language into Section 69A.3.1.h.a clarifying that "ZRC replacement shall have no impact on settlements from the PRA and FRAPs, including any assessed Capacity Replacement Non-Compliance Charges." MISO proposes further modifying Section 69A.3.1.h by creating Section 69A.3.1.h.b with language specifying that Capacity Replacement Non-Compliance Charges will be assessed for the number of days the Market Participant had an obligation to replace and failed to do so and calculated based on the amount of ZRCs that failed to be replaced multiplied by the sum of the ACP and the daily CONE Value which will be based on the LRZ where the Planning Resource cleared those ZRCs and that revenues from such charges received by the Transmission Provider will be distributed to LSEs that have met their PRMR during the applicable Season of the Planning Year on a *pro rata* basis based upon the LSEs share of total PRMR for the Transmission Provider Region.

25. Section 69A.3.2 – Energy Efficiency Resources (EE Resource)

MISO proposes modifying Section 69A.3.2 of the Tariff by replacing "annually" with "for each Season" to clarify that "[a]n EE Resource can qualify as a Planning Resource for ZRCs for each Season for up to four (4) Planning Years immediately following the EE Resource's initial qualification provided that the energy efficiency measures are fully implemented prior to each Planning Year."

26. Section 69A.3.3 – Load Modifying Resource

MISO proposes modifying Section 69A.3.3 of the Tariff by removing "TPRA", inserting the phrase "for a Season" to describe that all LMRs that are cleared in the PRA or were submitted in a FRAP for a Season needing to be available for use in the event of an Emergency as declared by the Transmission Provider, inserting the phrase "the applicable Season in" in the sentence "[i]n accordance with the BPM for Resource Adequacy, the Transmission Provider will qualify an LMR for the applicable Season in the upcoming Planning Year", and replacing the phrase coincident peak with "Coincident Peak Demand."

27. Section 69A.3.3.1 – Deployment Procedures for LMR

MISO proposes modifying Section 69A.3.3.1 of the Tariff by inserting the language "minimum" and "for the applicable Season" into the sentence "[a] Market Participant that acknowledge Scheduling Instructions for its LMR(s) as required by the BPM for Resource Adequacy will receive credit for one (1) of the minimum deployments or interruptions required for the LMR for the applicable Season whether or not an emergency is declared" and by inserting the language that an LMR which does not perform consistent with the Market Participant's

response to its Scheduling Instructions will not receive credit "as one (1) of the minimum deployments or interruptions required for such resource for the applicable Season."

28. Section 69A.3.4 – Demand Resources (DR)

MISO proposes modifying Section 69A.3.4 of the Tariff by inserting the word "authority" into the phrase "applicable state regulatory authority" and by inserting the phrase "each Season in" into the sentence "[i]n accordance with the BPM for Resource Adequacy, the Transmission Provider will qualify a DR for each Season in the upcoming Planning Year."

29. Section 69A.3.5 – Demand Resource Eligibility

MISO proposes modifying Section 69A.3.5 by inserting language into Section 69A.3.5.a clarifying that a grouping of smaller resources aggregated together than can reduce an LSE's Coincident Peak Demand "for the applicable Season" may qualify in meeting the requirement that a Demand Resource must be equal to or greater than 100 kW.

MISO proposes modifying Section 69A.3.5 by inserting language into Section 69A.3.5.b clarifying that beginning in the 2023/2024 Planning Year, a Demand Resource must have a notification time requirement "less than or equal to six (6) hours to receive credit as a Planning Resource in the applicable Seasons."

MISO proposes modifying Section 69A.3.5 by inserting language into Section 69A.3.5.e clarifying that the prior requirements of that section will apply to the 2022/2023 Planning Year but that for the 2023/2024 Planning Year a Demand Resource must have a notification time equal to or less than "six (6) hours and be capable of being interrupted for: (i) at least the first five (5) times requested in the Summer Season; and, at least the first five (5) times in the Winter Season; and, (iii) for at least the first three (3) times requested in the Spring Season; and (iv) for at least the first three (3) times in the Fall Season, based on their physical availability when called upon by the Transmission Provider for an Emergency during any applicable Season in the Planning Year for which the Demand Resource receives credit as a Planning Resource." MISO proposes modifying Section 69A.3.5.e by removing the provisions related to limitations due to contractual obligations and the requirement that the Demand Resource's availability must include the entire Summer Season.

MISO proposes modifying Section 69A.3.5 by inserting language into Section 69A.3.5.j that a Demand Resource for which a real power test is conducted will receive credit as one (1) of the "minimum" deployments or interruptions required for such Resource for the "applicable Season of the" Planning Year in which such a test occurs.

30. Section 69A.3.6 – Behind the Meter Generation Eligibility

MISO proposes modifying Section 69A.3.6 by inserting language into Section 69A.3.6.1 clarifying that the Transmission Provider will qualify as BTMG for the "applicable Season in the" upcoming Planning Year.

MISO proposes modifying Section 69A.3.6 by inserting language into Section 69A.3.6.1.b clarifying that a BTMG can request accreditation for such BTMG - in part - by demonstrating GVTC capability for "applicable Season in" each Planning Year on an annual basis.

MISO proposes modifying Section 69A.3.6 by removing language in Section 69A.3.6.1.d regarding limitations due to contractual obligations that are more restrictive than the physical limitations of the BTMG in place as of December 21, 2018.

MISO proposes modifying Section 69A.3.6 by inserting language into Section 69A.3.6.1.f clarifying that a BTMG can request accreditation for such BTMG - in part – by demonstrating that the BTMG is capable of being deployed at the accredited MW level for: (i) at least the first five (5) times requested in the Summer Season; and, (ii) at least the first five times requested in the Winter Season; and (iii) at least the first three (3) times requested in the Spring Season; and (iv) at least the first three (3) times requested in the Fall Season", by removing language in Section 69A.3.6.1.f that "[t]his availability must include at least the entire Summer Season", and by removing language in Section 69A.3.6.1.f regarding limitations due to contractual obligations that are more restrictive than the physical limitations of the BTMG in place as of December 21, 2018.

31. Section 69A.4 – Planning Resource Capacity Values

MISO proposes modifying Section 69A.4 of the Tariff by inserting language clarifying that Capacity Resources will be given "a capacity value for each applicable Season based on the Seasonal Accredited Capacity calculation applicable to its Resource type."

32. Section 69A.4.1 – Seasonal Accredited Capacity of Capacity Resources

MISO proposes modifying Section 69A.4.1 of the Tariff by replacing "Unforced Capacity" with "Seasonal Accredited Capacity" throughout the section.

MISO proposes modifying Section 69A.4.1.a of the Tariff by inserting clarifying language that "[t]he Seasonal Accredited Capacity for a Capacity Resource that is a Generation Resource, but not a Dispatchable Intermittent Resource, Intermittent Generation, Electric Storage Resource, External Resource or Use Limited Resource, is based on an evaluation of the type and volume of the interconnection service, GVTC value, and Real-Time offered availability of such Generation Resource for each Season as set forth in Schedule 53" and by removing language regarding resources that are not required to report generator availability.

MISO proposes modifying Section 69A.4.1.b of the Tariff by inserting clarifying language that "[t]he Seasonal Accredited Capacity for a Capacity Resource that is an External Resource, but not a Dispatchable Intermittent Resource, Intermittent Generation or Use Limited Resource, is based on the GVTC value and $XEFOR_d$ values of such External Resource for each Season."

MISO proposes modifying Section 69A.4.1.c of the Tariff by inserting clarifying language that "[t]he Transmission Provider will determine the appropriate capacity value for DRR that qualifies as a Capacity Resource and that interrupts or controls Load, based upon historical performance and availability, for each Season, as set forth in Schedule 53" and by removing language regarding resources that are not required to report generator availability.

MISO proposes modifying Section 69A.4.1.d of the Tariff by inserting clarifying language that "[t]he Transmission Provider will determine the Seasonal Accredited Capacity for each DRR that qualifies as a Capacity Resource and that is a behind the meter generation facility based on an evaluation of the GVTC value and Real-Time offered availability for such behind the meter generation facility for each Season as set forth in Schedule 53."

MISO proposes modifying Section 69A.1.e of the Tariff by inserting the phrase "or Use Limited Resource" into that section.

MISO proposes adding Section 69A.1.h of the Tariff stating that "[t]he Seasonal Accredited Capacity for a Capacity Resource that is a Use Limited Resource will be determined by the Transmission Provider based on the type and volume of interconnection service, the GVTC and $XEFOR_d$ values of such Use Limited Resource in accordance with the BPM for Resource Adequacy."

33. Section 69A.4.2 – Seasonal Accredited Capacity of Demand Resources

MISO proposes modifying Section 69A.4.2 of the Tariff by replacing "Unforced Capacity" with "Seasonal Accredited Capacity."

34. Section 69A.4.3 – Seasonal Accredited Capacity of Behind the Meter Generation

MISO proposes modifying Section 69A.4.3 of the Tariff by replacing "Unforced Capacity" with "Seasonal Accredited Capacity" when stating that "[t]he Transmission Provider will determine the Seasonal Accredited Capacity for each BTMG that qualifies as an LMR as set forth in the Resource Adequacy Business Practices Manual" and when stating that "[i]f such BTMG is interconnected to the Transmission System, the Transmission Provider will consider the type and volume of interconnection service when determining Seasonal Accredited Capacity." MISO proposes modifying Section 69A.4.3 of the Tariff by removing the phrase that the Transmission Provider will determine capacity for each BTMG that qualifies as an LMR "based on an evaluation of the GVTC value and $XEFOR_d$ values of such BTMG."

35. Section 69A.4.4 – EE Resources

MISO proposes modifying Section 69A.4.4 of the Tariff by replacing "Unforced Capacity" with "Seasonal Accredited Capacity" when describing how capacity will be determined for a qualified EE Resource by the Transmission Provider.

36. Section 69A.4.5 – Attributes of ZRCs

MISO proposes modifying Section 69A.4.5 of the Tariff by replacing "Unforced Capacity" with "Seasonal Accredited Capacity" throughout that section and by removing language related to the calculation of the convertible Unforced Capacity. MISO proposes further modifying Section 69A.4.5 of the Tariff to include language in Section 69A.4.5.A regarding the allocation of Seasonal Accredited Capacity and the calculation of Seasonal Accredited Capacity value.

37. Section 69A.5 – Capacity Resource Must Offer and Performance Requirements

MISO proposes modifying Section 69A.5 of the Tariff by replacing the phrase "Unforced Capacity" with "Seasonal Accredited Capacity" throughout the section, removing the word "TPRA" from the section, inserting language regarding a/any/each "Season" into the section to clarify that the Capacity Resource Must Offer and Performance Requirements relate to each Season in the Planning Year and not to the Planning Year as a whole.

MISO proposes further modifying Section 69A.5 of the Tariff by inserting language into Section 69A.5.a clarifying that Market Participants that convert Seasonal Accredited Capacity

from Capacity Resources into ZRCs that clear in a Season in the PRA or are used in a FRAP (and that do not replace such ZRCs in accordance with Section 69A.3.1.h), "including Capacity Resources that are the subject of Diversity Contracts," must submit Self-Schedules or Offers for Energy, and Contingency Reserve if qualified, and offers for Short-Term Reserve if qualify, for the Installed Capacity value of the Capacity Resources converted to ZRCS "and clear in a Season in the PRA or used in a FRAP" for each Hour of each Day during the applicable Season in the Planning Year, in the Day-Ahead Energy Market and all pre Day-Ahead and the first post Day-Ahead Reliability Assessment Commitment process."

MISO proposes modifying Section 69A.5.a by adding the sentence "[a]ny such Capacity Resource with full or partial Generator Planned Outages that exceeds thirty-one (31) Days during any Season will be deemed not to have met its performance requirement for any days greater than thirty-one (31) days and must replace ZRCs in accordance with Section 69A.3.1.h, provided that Capacity Resources subject to Diversity Contracts that are unavailable for greater than one Month during any Season will be deemed not to have met its performance requirement and will be subject to the ZRC replacement provisions set forth in Section 69A.3.1.h."

MISO proposes modifying Section 69A.5.b by inserting language clarifying that "[i]f a Capacity Resource that has ZRCs cleared in the PRA during any Season or is used in a FRAP during any Season is capable of performing but fails to perform when called upon by the Transmission Provider for an Emergency, the Transmission Provider shall assess the owner of such Capacity Resource the costs that were otherwise incurred to replace the energy from the deficient Capacity Resource at the time that the Capacity Resource is called upon by the Transmission Provider and does not respond in full or in part, for each day of non-performance of such Capacity Resource, provided that the planned or forced outage of the Capacity Resource is not properly reported in the Transmission Provider's Outage Scheduler, as set forth in the Business Practices Manual for Outage Operations."

38. Section 69A.6.3 – Facilitation of a Bilateral Capacity Bulletin Board

MISO proposes modifying Section 69A.6.3 of the Tariff by replacing "Unforced Capacity" with "Seasonal Accredited Capacity" with respect to the Transmission Provider's electronic bulletin board platform that may be used by Market Participants.

39. Section 69A.7 – Planning Resource Auction

MISO proposes modifying Section 69A.7 of the Tariff by replacing "ten (10)" with "twenty (20)" with respect to the number of Business Days after the last Business Day in March when the Transmission Provider will conduct a RA to determine the ACP in each LRZ and ERZ.

40. Section 69A.7.1 – PRA Procedures

MISO proposes modifying Section 69A.7.1 of the Tariff by replacing "Unforced Capacity" with "Seasonal Accredited Capacity" throughout the section, removing "TPRA", clarifying that "[t]he price associated with these ZRC Offers cannot exceed the annual CONE value divided by the number of days in the Season for the LRZ where the ZRC is represented", inserting the sentence in Section 69A.7.1.x that "[t]he maximum Auction Clearing Price will be based on the annual CONE and the number of Seasons deficient in the Planning Resource Auction", replacing "tenth" Business Day in Section 69A.7.1.xi with "twentieth" Business Day, specifying in Section 69A.7.1.c.i that "[a]fter a maximum of two (2) successive iterations per Season to address network

violations, the auction clearing iteration with the fewest megawatts of network violations will be deemed as the final auction result", and adding language regarding "each Season" throughout.

MISO proposes modifying Section 69A.7.1.c.x by inserting language clarifying that "[t]he final Auction Clearing Price (ACP) for a LRZ, group of LRZs, or SRRZ with Seasons in ZRC Shortage Conditions will be set as the amount obtained by dividing the applicable LRZ's annual CONE value by the number of days in Seasons which the LRZ, group of LRZs, or a SRRZ were in ZRC Shortage Conditions and Near ZRC Shortage Conditions in the Planning Resource Auction. The final Auction Clearing Price (ACP) for a LRZ, group of LRZs, or SRRZ with Seasons in Near ZRC Shortage Conditions will be set as the minimum of: (a) the original ACP as determined in section 69A.7.1.c.(v) or section 69A.7.1.c.(vi) as applicable; or (b) the amount obtained by dividing the applicable LRZ's annual CONE value by the number of days in Seasons which the LRZ, group of LRZs, or SRRZ were in ZRC Shortage Conditions and Near ZRC Shortage Conditions in the Planning Resource Auction."

41. Section 69A.7.3 – Uncleared ZRCs

MISO proposes modifying Section 69A.7.3 of the Tariff by replacing "Unforced Capacity" with "Seasonal Accredited Capacity" and removing "TPRA."

42. Section 69A.7.6 – PRA Settlement

MISO proposes modifying Section 69A.7.6 of the Tariff by inserting language into Section 69A.7.6.a to clarify that "[t]he reduced compensation will be based on the total number of days the capacity from the Diversity Contract is dedicated to demand in the Transmission Provider Region in each Season divided by the total number of days in the Season."

MISO proposes adding Section 69A.7.6.d specifying that "[f]or instances where a LRZ, group of LRZs, or SRRZ clears under ZRC Shortage Conditions or ZRC Near-Shortage Conditions in more than one Season in a Planning Resource Auction and final ACPs are adjusted per Section 69A.7.1.c.(x), certain cleared ZRC Offers may exceed the final ACPS" and clarifying the circumstances under which certain ZRCs may be eligible for a ZRC Offer Revenue Sufficiency Credit and how that credit would be calculated and allocated.

MISO proposes adding Section 69A.7.6.e specifying that ZRC Offer Revenue Sufficiency Charges "will be assessed as the sum of all ZRC Offer Revenue Sufficiency Credits for a Season distributed to Market Participants representing LSEs in an LRZ, group of LRZs, or SRRZ clearing under ZRC Shortage Conditions or Near ZRC Shortage Conditions on a *pro rata* basis, based upon their respective LSE's share of total PRMR in the appropriate LRZ, group of LRZs, or SRRZ."

43. Section 69A.7.9 – Installed Capacity (ICAP) Deferral Requirements and Charges

MISO proposes modifying Section 69A.7.9 by inserting language to clarify that the ICAP Deferral Notice, ICAP Deferral Non-Compliance Charges, and Distribution of ICAP Deferral Non-Compliance Charges are based on the "Season" and not the "Planning Year."

44. Section 69A.9 – Opting out of the Planning Resource Auction

MISO proposes modifying Sections 69A.9.a of the Tariff by inserting language clarifying that an LSE electing to opt out of the PRA "for any Season" can continue to use its existing

resource planning processes to meet their PRMR by providing the Transmission Provider with a FRAP for each LRZ which must include the forecasted Coincident Peak Demand for "each Season" and must also identify its load ratio share for "each Season." MISO proposes modifying Sections 69A.9.b of the Tariff by inserting language clarifying and that an LSE that submits a FRAP for a LRZ will be able to opt out of the PRA for such "Season" for such LRZ to the extent that the LSE's ZRC's satisfy the LSE's PRMR "for the applicable Season(s)." MISO proposes to clarify the provisions relating to the Capacity Deficiency Charge by modifying Section 69A.9.c of the Tariff by removing the phrase "[a]n LSE that is capacity deficient will be assessed a Capacity Deficiency Charge in accordance with Section 69A.10."

45. Section 69A.10 – Capacity Deficiency Charge

MISO proposes modifying Section 69A.10 of the Tariff by inserting language clarifying that the Transmission Provider will impose a Capacity Deficiency Charge on an LSE that has "provided notification prior to the Planning Resource Auction that they will meet their PRMR in part or in whole for the Planning Year by paying the Capacity Deficiency Charge." MISO proposes modifying further language clarifying that "[t]he CONE value for the LRZ(s) where the LSE has provided notice it will be meeting its PRMR by paying the Capacity Deficiency Charge for the Planning Year will be multiplied by 2.748 times the PRMR volume indicated by the LSE for Planning Year."

MISO proposes modifying Section 69A.10.b to clarify that the distribution of Capacity Deficiency Charge revenues will not be distributed to any Market Participant representing an LSE that has provided notice it will be meeting its PRMR by paying the Capacity Deficiency Charge, and specifying details of the distribution calculation.

I. Schedule 53 – Seasonal Accredited Capacity Calculation

1. Section I – General

MISO proposes creating Schedule 53 Section I of the Tariff by inserting language specifying that "Seasonal Accredited Capacity (SAC) for a Capacity Resource that is a DRR or Generation Resource but not a Dispatchable Intermittent Resource, Intermittent Generation Electric Storage Resource, or Use Limited Resource will be determined pursuant to this Schedule 53." MISO proposes inserting language into Section I clarifying that "[a] two-tiered weighting structure is used to calculate Seasonal Accredited Capacity for such Resource".

2. Section II – Tier 1 and Tier 2 Planned Outage Exemptions Requirements

MISO proposes creating Schedule 53 Section II of the Tariff by adding Section II.A-B to specify the requirements for Tier I and Tier 2 outage exemptions for Generator Planned Outages after September 1, 2022. The language in Section II.A specifies the Tier 2 Planned Outage exemption requirements. The language in Section II.B specifies the Tier 1 Planned Outage exemption requirements. MISO further proposes that "Generator Planned Outages scheduled to begin before September 1, 2022 will be granted a Tier 2 exemption based on Section 38.2.5.g.ix., and as set forth in the Business Practices Manual for Resource Adequacy."

Section II.C will contain language specifying that under the No Harm Test "[o]utages submitted between 14 to 30 days of start date will be evaluated for final approval and exemption status together. The No Harm Test includes, but is not limited to, outage approval, compliance

with all applicable operation guides, review of possible conflicting outages or system conditions, and system capacity (Maintenance Margin, Multiday Operational Margin, 30-day margin). It also includes the criteria outlined in the Business Practices Manual for Generator Outage."

3. Section III – Resource Adequacy Hours

MISO proposes creating Schedule 53 Section III of the Tariff by inserting language specifying that "Resource Adequacy (RA) Hours represent the periods of highest risk and greatest need during a Season and throughout the year. They include hours during Maximum Generation Emergency declarations and the hours when the operating margin, a measure of available supply capacity above demand and reserve requirements, is at its lowest." "Resource Adequacy Hours will be identified based on an evaluation of the three (3) most recent completed years using the period September 1st and ending August 31st which will be used to determine Resource Adequacy Hours for each Season (Seasonal RA Hours) and for each annual period (Annual RA Hours)."

MISO proposes inserting language into Section III.A describing how Seasonal RA Hours will be determined, inserting language into Section III.B describing how Annual RA Hours will be determined, and inserting language into Section III.C describing how Seasonal Non-RA Hours will be determined. MISO proposes inserting language into Section III.D specifying that Tier 1 exemptions apply only to Non-RA Hours whereas Tier 2 exemptions apply to any Hours referenced in Schedule 53 and that Tier 1 and Tier 2 outage exemption requirements are set forth in Section II of Schedule 53.

4. Section IV – Operating Margin Calculation

MISO proposes creating Schedule 53 Section IV of the Tariff by inserting language specifying that "[t]he Operating Margin is determined using historical information to identify Seasonal RA Hours and Annual RA Hours within the three (3) most recent periods beginning September 1st and ending August 31st." MISO proposes inserting language into Section IV defining the equation used to calculate Operating Margin.

5. Section V –Seasonal Accredited Capacity Calculation

MISO proposes creating Schedule 53 Section V of the Tariff by inserting language into Section V.A-C specifying that Annual Average Offered Capacity, Tier 1 Intermediate SAC (ISAC), and Tier 2 ISAC will all be calculated in part utilizing either the Hourly Emergency Maximum Limit or the Targeted Demand Reduction Level for DRR-1. The proposed language specifies that for any Annual RA Hour or Seasonal RA Hour where a Resource is offline and the sum of the Start-Up Time and Start-Up Notification Time Offers exceeds 24 hours, the Resource "will have its Hourly Emergency Maximum Limit, or Targeted Demand Reduction Level for DRR-1, set to zero (0)."

MISO proposes inserting language into Section V.D specifying that "the Hourly Emergency Maximum Limit, or Targeted Demand Reduction Level for DDR-1, will be capped at the currently effective GVTC value of the Resource and whether or not a Resource was only committed for a portion of its ICAP due to partial clearing will not impact the offers considered in the accreditation calculations.

MISO proposes inserting language into Section V.E specifying that "the historical values for Hourly Emergency Maximum Limit, or Targeted Demand Reduction Level for DDR-1, will

be increased for those hours prior to the upgrade going into effect to account for the upgrade as set forth in the Business Practices Manual for Resource Adequacy."

MISO proposes inserting language into Section V.F specifying that "RA Hours will receive a greater weight than non-RA hours", inserting language into Section V.G defining the equation used to calculate ISAC, inserting language into Section V.H defining the equation used to calculate "[a] system-wide conversion ratio", and inserting language into Section V.I defining the equation used to calculate SAC.

6. Section VI – New Resources or Resources with Insufficient Performance Data

MISO proposes creating Schedule 53 Section VI of the Tariff by inserting language into specifying that "New Resources or existing Resources that do not have at least 60 days of Real-Time offered availability when designated for RAR over the last three (3) years for each Season (Summer, Fall, Winter, Spring) will have a SAC based on the Class Average SAC to ICAP Ratio for its Resource type." MISO proposes inserting language specifying that "Resources on a Catastrophic Generator Outage during a Season they are designated for RAR may elect to use a SAC based on the Class Average SAC or ICAP Ratio for its Resource type the next time it is accredited for that Season provided all of its committed ZRCs were replaced with uncleared ZRCs and that it has successfully returned from the Catastrophic Generator Outage."

VII. RESPONSE TO KEY STAKEHOLDER ISSUES

As described above, MISO has engaged in substantial stakeholder discussions relating to the development of the Resource Adequacy enhancements proposed in this filing. As part of those discussions, stakeholders have raised various issues that have been documented, vetted and, as appropriate, incorporated in this filing. MISO also has determined that a number of stakeholder suggested modifications are either outside the scope of this filing and/or should be addressed through alternative means. Following is a list of key issues raised by stakeholders and MISO's responses. It should be noted that this list is not exhaustive, but MISO believes represents the major issues presented.

- *Implementation of seasonal reforms only* – Stakeholders have requested that MISO implement only the proposed PRA seasonal reforms separate from the proposed accreditation reforms. Moreover, stakeholders have requested that MISO delay filing and implementation of any accreditation changes to allow the opportunity for additional discussions.

As discussed with stakeholders during the RASC presentation on June 9, 2020, in order to meet future reliability risks, there needs to be an alignment between Resource Adequacy Requirements and Resource accreditation. To adjust requirements on a seasonal basis without making corresponding adjustments to a resource's seasonal accreditation could potentially create more risk for the MISO system. As further described in the Testimony of Mr. Wright, by transitioning to a seasonal construct only, requirements may decrease and true availability of resources may be overstated and adversely impact system reliability.[124] Since 2016, over 60% of

[124] Wright at 2-3.

MaxGen events have occurred outside of the Summer. Creating a scenario where requirements are lower when considered on a seasonal basis and resource accreditation continues to be based on the current method with only muted and weak linkages to actual resource availability during times of highest need could exacerbate the risk of capacity shortfalls. Further, the proposed seasonal construct facilitates stakeholder preferences for increased seasonal outages, possibly lowering excess reserve margins. In light of this, MISO must have higher confidence in the availability of the resources that do clear for any given Season, as accomplished through the proposed improvements to accreditation and outage coordination processes.

Furthermore, as detailed in the Testimonies of Messrs. Wright, McFarlane, and Smith, the proposed seasonal and accreditation changes are urgently required at this time in response the Reliability Imperative. MISO cannot afford to wait any longer to implement this integrated package of changes needed to enhance its Resource Adequacy construct and to help ensure reliability in the MISO Region.

- *Determination of Resource Adequacy Hours* – Stakeholders have argued that MISO has not adequately justified the proposed use of 65 RA Hours per Season (which, as described above, is based upon 3% of the hours during each Season). In addition, stakeholders have objected to the manner in which MISO proposes to "backfill" seasonal RA Hours with AAOC hours.

As described above, RA Hours represent the periods of highest risk and greatest need during a Season and throughout the year. They include emergency declaration periods and the hours when the operating margin, a measure of available supply capacity above demand and reserve requirements, is at its lowest. MISO's analysis indicates that the tightest 3 percent of hours align with emergency event occurrence is reasonable. Further, MISO examined the operating margins during the times of highest risk, which also informed the selection of 3 percent.

As proposed, RA Hours will be determined seasonally, based on emergency events, the tightest 3 percent of operating margin hours, and a maximum operating margin threshold established at 25 percent. RA Hours will be used to determine each resource availability for calculating its seasonal accreditation. To ensure that MISO includes all appropriate RA Hours, the total number of RA Hours in a Season can exceed the minimum target (*i.e.,* 65 hours) when a higher number of hours during declared system or sub-regional emergencies occurs. Moreover, in some Seasons (or for resources with Tier 2 planned outage exemptions for seasonal RA Hours) there may not be 65 hours during the Season to use for the Schedule 53 calculations. The proposal strikes a balance between identifying RA Hours that represent the times of high risk and having sufficient RA Hour sample sizes to avoid undue volatility. MISO's proposal supplements the seasonal RA Hours for a resource with the average offers over the tightest operating conditions during the same Planning Year where it was not on an exempt outage.

For any Season that a resource lacks sufficient hours, set at 65 hours minimum, the accreditation will augment the deficient number of hours less than 65 for that Resource with its AAOC, which is determined over the tightest 3 percent of hours during the year, or 263 hours. Certain stakeholders have expressed concern that the availability of a resource in one Season may not accurately represent the availability of that resource during a different Season. MISO believes

that the use of RA Hour availability during the other tight margin hours in the Planning Year is a reasonable substitute in the determination of accreditation as it reflects actual resource availability during tight conditions throughout the year. Some stakeholders suggested using all-hours availability during the Season to "backfill" RA Hours would be more appropriate. However, MISO believes this approach would inappropriately dilute assessments of a Resource's availability during tight conditions because it effectively substitutes the resource's availability during non-tight conditions.

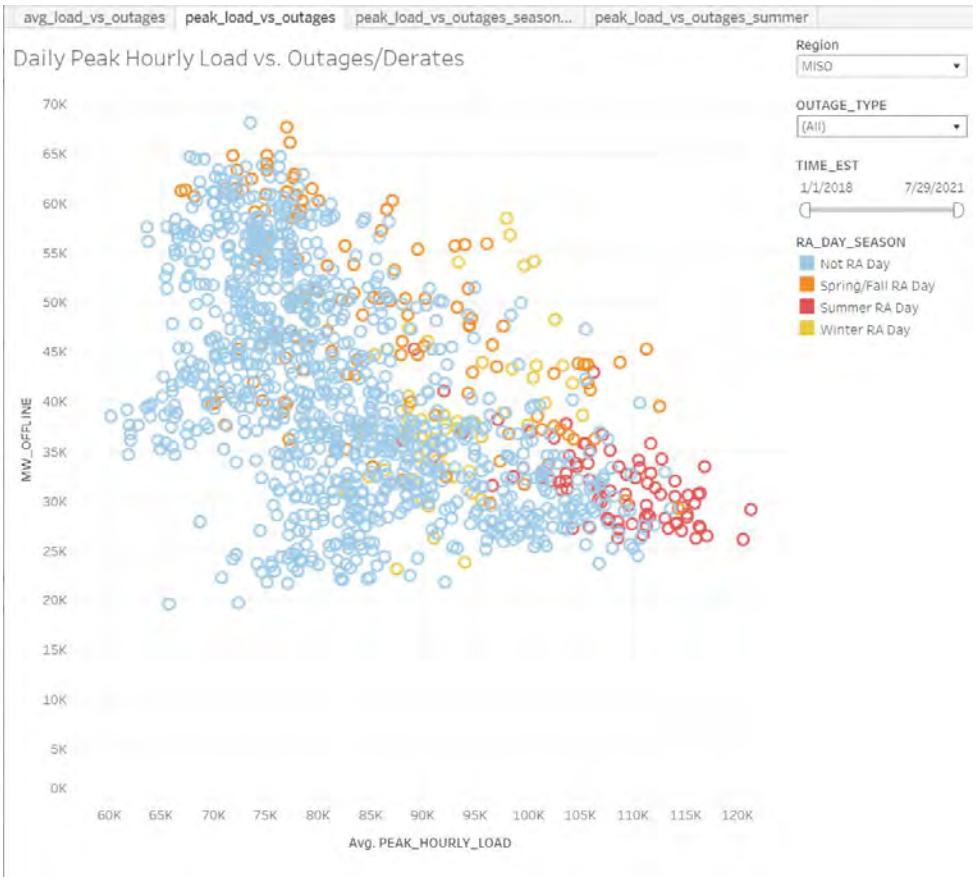
- *Schedule 53 Tier weighting and volatility of requirements* – Stakeholders have asked for further support regarding the basis for the proposed 20/80 weighting of Tier 1 vs. Tier 2 hours in Schedule 53. Stakeholders also requested that MISO phase in the proposed Tier 1 vs. Tier 2 weighting over a period of time in order to provide stakeholders the opportunity to adjust their planning and operations. In addition, stakeholders have raised concerns about the potential volatility of the proposed changes as they may impact Resource accreditation year over year.

The initial Resource accreditation proposal shared with Stakeholders in January of 2021 essentially weighted RA Hours (*i.e.,* Tier 2 hours) at 100% towards a Resource's offered availability. This solely emphasized the importance of resource availability during the tightest operating conditions. In a recent State of the Market Report, MISO's IMM recommended a similar approach to align a resource's auction value with its true contribution to reliability.[125] Seasonal requirements also necessitate accreditation align with actual expectations during times of highest risk during each Season. In response to the initial proposal, stakeholders requested a method that also recognized a resource's reliability contribution during non-RA Hours, basing some portion of accreditation on general availability.

MISO recognizes the value of general availability, however, as the IMM's analysis of the current UCAP method illustrates, it does not adequately reflect availability during times of highest risk and the true reliability value. As a result, MISO responded by developing the two-tier accreditation proposal, which sets the Tier 1 (*i.e,* non-RA Hours) weighting to 20%, acknowledging a Resource's general availability and its contribution to avoiding capacity emergency events. Importantly, however, MISO sets the Tier 2 (RA Hour) weighting at 80% to emphasize Resource reliability contribution during times of greatest reliability needs. The data plot below illustrates how RA Hours occur on days with high peak load, high outage rates or a combination of both, and supports the rationale for the heavier weighting of Tier 2 hours in resource accreditation.

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125 *See* fn. 40 *supra*.



To address stakeholder requests to phase in the proposed Schedule 53-tiered weighting, MISO has adopted a three-year phased in approach proposed by stakeholders. Beginning in PY 2023/2024, the Tier 1/Tier 2 weighting will be 40/60, increasing to 30/70 in PY 2024/2025, and ending up with the full adoption of the 20/80 weighting in PY 2025/2026. Adopting this transition will generally lessen the impact of these accreditation changes in the near-term while providing more time for stakeholders to adjust planning and operations before the entire weighting takes effect.

With respect to stakeholder concerns regarding volatility, analysis of Market Participant level, zonal and MISO-wide results indicate reasonably low levels of volatility and appropriate relative accreditation based on resource performance during times of need.[126] The key principle of the proposed accreditation is to determine the relative accredited values among different resources to align with their actual performance during times of needs while maintaining the overall supply and demand balance at the footprint level. By design, more resource level volatility with the proposed accreditation methodology would be expected, but in aggregate the proposal leads to very little volatility at the MISO Region-wide level from year to year, especially over time. As

126 *See* Resource Adequacy Reforms, MISO RASC (September 2021) at 6.

presented at the September RASC meeting, the proposal leads to, less than 2% volatility at MISO Region-wide level, in part as a result of the application of the UCAP to SAC ratio.[127]

- *Generator Planned Outage exemptions* – Stakeholders have argued that MISO's proposal does not offer sufficient flexibility to permit Generator Planned Outages without exposing them to potential accreditation impacts.

In its initial proposal, MISO was outage agnostic, choosing to base availability solely on availability during RA Hours with no exemption for effective coordination regarding Generator Planned Outages. This also aligned with IMM State of the Market recommendations regarding availability-based accreditation, discussed above. Stakeholders requested that MISO consider enhancements to the RAN Phase 1 outage exemption process for incorporation in the proposal, as those processes involved significant stakeholder engagement in the past and have provided reliability benefits. MISO agreed with the stakeholder suggestion, noting improved outage coordination was one of the goals of these reforms. However, MISO also cautioned that any exemptions must be strongly aligned with effective coordination processes to ensure reliable outcomes and incent coordination. If all planned outages receive exemptions, resources will not be deterred from scheduling outages during the tightest operating conditions.

Ultimately, in response to stakeholder feedback, MISO built upon the RAN Phase 1 outage process when developing its proposal to exempt certain outages under the revised accreditation proposal. As set forth in Schedule 53, the exemption rules specifically consider whether an outage is submitted 120 days or more in advance, whether there is a positive Maintenance Margin for the duration of the outage, and whether the outage is scheduled to start less than 120 days from the end of a previous outage. MISO believes the proposed exemption rules reasonably accommodate the needs of stakeholders to take appropriate planned outages with the need for MISO to ensure that resources will be available during times of greatest risk. Moreover, the proposed rules appropriately reflect a resource's unavailability in its accredited value, whether such unavailability is a result of planned, forced or maintenance outages that put the system at increased risk.

- *Capacity replacement requirement* – Stakeholders have suggested that the capacity replacement requirement, and associated Capacity Replacement Non-Compliance Charge, impose unfair obligations. Some stakeholders specifically object to the requirement that they replace resources that are unavailable for more than 31 days, and that MISO is imposing a charge for failure to replace.

MISO believes the proposed replacement requirements are reasonable to ensure that resources that clear for a Season will be available to contribute to reliability when committed. As MISO shifts from an annual to a seasonal construct, it is reasonable to require replacement of resources that are unavailable more than 31 days out of an approximately 91-day Season as a result of Generator Planned Outages. The proposed replacement requirement also is consistent with the existing Tariff requirement that resources that are not available for 90 out of the 120 days preceding the PRA are not eligible to participate in the PRA for that Planning Year.

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127 *Id.*

Moreover, a resource contemplating a Generator Planned Outage in excess of 31 days can request approval from the IMM prior to the PRA for exclusion from physical withholding market mitigation measures, and if approved, not offer the resource into the PRA. If such a request is approved, the IMM has indicated a resource could still offer at its discretion and would be able to offer the excluded portion of the resource at any price up to the offer cap without the need to obtain a facility specific Reference Level. MISO has added the IMM's recommended provisions in section 64.1.1.g.xi of Module D.

The Capacity Replacement Non-Compliance Charge ensures that Market Participants whose resources clear the PRA for a Season are sufficiently available for a majority of the Season to contribute to reliability. Currently, there is no specified financial non-compliance provisions for failure to replace a resource that clears the PRA and subsequently retires or suspends. Increased flexibility for Market Participants to choose whether to participate in a Season requires financial consequences for the failure to replace unavailable units. The proposed Capacity Replacement Non-Compliance Charge reasonably addresses this need. In addition, the proposal generally indicates lower requirements for non-Summer Seasons compared to today's construct. Accordingly, it is reasonable to impose a financial non-compliance charge to incent availability of sufficient resources to meet the lower requirements. As noted above, MISO is also adding provisions allowing the replacement of resources that have experienced catastrophic outages, enabling such resources to maintain class average accreditation upon return to service.

- *Need for additional analysis* – Stakeholders have argued that MISO has not provided sufficiently detailed analysis for them to determine the impact of the proposed changes on their specific resources.

Contrary to some stakeholder assertions, MISO has provided stakeholders many elements of required analysis, including: seasonal SAC values and requirements at the portfolio level (highlighting the changes relative to their current requirements); unit-level SAC values on a seasonal basis; and, extensive and detailed data for at least one individual resource, for each stakeholder requesting such data, including all the inputs and calculations necessary to allow stakeholders to independently validate how MISO derived the SAC values for that resource. This information was provided more than once for those stakeholders requesting this data over the course of the conceptual design.

MISO also provided preliminary and revised impact analysis results at the system-wide and zonal levels at multiple RASC stakeholder meetings over the course of the RA construct conceptual design. In addition, MISO:

- Provided preliminary and revised historical RA Hours including MaxGen hours, and hourly operating margins for the past four Planning Years at multiple RASC stakeholder meetings; and

- Posted and walked through a step-by-step resource accreditation calculation example worksheet at a RAN workshop and provided a revised example calculation worksheet to reflect the refined proposal; and

- Provided preliminary and revised Resource accreditation SAC values for all resources within each Market Participant portfolio, Market Participant level surplus/shortfall, and at least one CP node with detailed raw information for SAC calculation to illustrate how SAC is calculated; and

- Engaged in one-on-one meetings with Market Participants, upon request, to walk through detailed SAC calculations of their fleet and address any discrepancies or questions.

MISO appreciates that replicating MISO's calculation is important to stakeholders to gain a better understanding of the potential impacts of the proposed changes. To this end, MISO will continue engaging with stakeholders prior to implementation of the proposed changes to provide additional transparency on new accreditation values. For example, MISO has already provided a workshop for stakeholders to solicit their ideas for Module E Capacity Tracking Tool improvements. MISO will have additional workshops in 2022 to further help prepare stakeholders.

- *Transition periods and deferral of reforms* – Stakeholders have requested that MISO phase in various aspects of its proposal to allow more time to adjust to the changes. In addition, stakeholders have requested that MISO delay implementation of the proposal overall for at least another year, and in some cases, significantly longer.

As MISO responds to the Reliability Imperative, the need to transition to a new Resource Adequacy construct requires adoption sooner rather than later. This need has been detailed extensively in the Testimonies of Messrs. Wright, McFarlane, and Smith.

With respect to a transition period, MISO has proposed a number of changes in response to stakeholder requests. First, MISO has adopted the Schedule 53 tiered weighting transition described above. In addition, MISO has proposed a transition period with respect to the implementation of the planned outage provisions established in Schedule 53. Specifically, this transition recognizes planned outages coordinated through the existing processes, with the new proposal being phased over three years.

- *Number of changes* – A number of stakeholders have expressed concern about the number of changes MISO has made to its proposal since extending stakeholders discussions over the last few months.

MISO acknowledges that it has made refinements to its proposal during this period of time. These changes have largely been in response to stakeholder feedback, IMM collaboration, and other improvements identified by MISO to ensure the completeness of the proposal.

VIII. DOCUMENTS SUBMITTED WITH THIS FILING

In addition to this Transmittal Letter, this submission includes:

- Tab A – Redline Tariff[128]
- Tab B – Clean Tariff
- Tab C – Testimony of Shawn McFarlane
- Tab D – Testimony of Jameson Smith
- Tab E – Testimony of Scott Wright

IX. PROPOSED EFFECTIVE DATE

MISO requests an effective date of September 1, 2022 for the Tariff revisions submitted herein. MISO recognizes that this date is beyond 120-days from the date of this filing and therefore requests waiver of Section 35.3(a) of the Commission's regulations to permit this effective date.

As discussed above, MISO also requests that FERC issue an order accepting the proposed Tariff revisions within 120 days from the date of this filing. MISO's request for Commission action on this filing within 120 days from the date of filing is intended to provide regulatory certainty to both stakeholders and MISO with respect to the Tariff provisions applicable to the 2023 / 2024 Planning Year well in advance of the Planning Resource Auction that will be held in the Spring of 2023. Prior to the 2023 / 2024 Planning Year auction, MISO will be working to both enhance the software used in administering the Resource Adequacy Requirements and PRA as well as training stakeholders on how they will demonstrate and monitor their compliance through the tool enhancements.

MISO commits to making a subsequent Section 205 filing with the Commission to update the Tariff sheets to reflect the most up-to-date versions of the then-current Tariff provisions. The update filing will be submitted at least 60 days prior to the proposed effective date of the Tariff provisions as discussed above.

In addition, MISO requests waiver of any requirements of 18 C.F.R. Part 35 the Commission deems applicable to this filing to the extent that the specific requirement is not addressed herein.

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[128] MISO has revised metadata of several sections to change the Tariff Record Titles. MISO's eTariff software does not redline changes to the metadata associated with its Tariff Records, thus no redlines will be shown in the Tariff Record Title.

X. COMMUNICATIONS

MISO respectfully requests waiver of Rule 203(b)(3) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.203(b)(3) (2019), to the extent necessary to permit the designation of more than two persons for service on behalf of MISO in this proceeding and requests all communications related to this filing be directed to:

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XI. NOTICE AND SERVICE

MISO has served a copy of this filing electronically, including attachments, upon all Tariff Customers, MISO Members, Member representatives of Transmission Owners and Non-Transmission Owners, as well as all state commissions within the region. The filing has been posted electronically on MISO's website currently at https://www.misoenergy.org/legal/ferc-filings/ for other parties interested in this matter.

XII. CONCLUSION

For all of the foregoing reasons, MISO respectfully requests that the Commission accept these proposed revisions for filing, grant the proposed effective date, and grant waiver of any Commission regulation the Commission deems applicable to this filing in order for the Commission to accept it as proposed.

Respectfully submitted,

/s/ Michael Kessler

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Attachments

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-26-16

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 78

McFarlane Testimony

Tab C

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PREPARED DIRECT TESTIMONY OF SHAWN MCFARLANE

I. PROFESSIONAL BACKGROUND AND QUALIFICATIONS

Q. Please state your name, business address, and position with your employer.

A. My name is Shawn F. McFarlane. I am employed by the Midcontinent Independent System Operator, Inc. ("MISO"), which is located at 720 City Center Drive, Carmel, Indiana, 46032. My current position is Executive Director of Market Operations, which I have held since October 2015. During that time, I have had executive oversight of various functions under MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff"), including Resource Adequacy, Day-Ahead Energy and Operating Reserve Market, Auction Revenue Rights and Financial Transmission Rights markets, as well as the Forward Reliability Assessment Commitment, and Market and Transmission Settlements. I joined MISO in April of 2014 and served as Executive Director of Strategy through September 2015.

Q. Please briefly describe your educational and professional background before you joined MISO.

A. I hold a Bachelor of Science Degree in Petroleum Engineering at Pennsylvania State University and an MBA in Finance from Rutgers University. Prior to joining MISO, I was employed at Reliant Energy and successor companies from 1998-2013 as a Director and then as Vice President in various roles in Business Development, Commercial Analytics, and Wholesale Strategy in the merchant generation, energy trading, and retail energy marketing businesses. Prior to joining Reliant Energy, I was an Engagement Manager at a management consulting firm, McKinsey & Company, in their energy consultancy group from 1996-1998; in various finance

roles at Texaco, Inc. from 1990-1996; and, as a petroleum engineer in Southern California Gas Company's natural gas storage unit from 1985-1988.

Q. Please describe your job responsibilities as they relate to this filing.

A. As MISO's Executive Director of Market Operations, I have executive oversight of Resource Adequacy, including administration of MISO's Planning Resource Auction, within which accreditation of resources is a key parameter to better ensure that the Planning Reserve Margin Requirement and Planning Resource volumes are appropriately accurate to better ensure that resources are available to satisfy needs in real time. Additionally, accurate accreditation enables that cleared resources in the Planning Resource Auction are priced appropriately, based on their expected availability.

II. PURPOSE OF TESTIMONY AND RAN PROGRAM OVERVIEW

Q. What is the purpose of your testimony?

A. My testimony supports MISO's filing in this docket and provides operational and implementation detail associated with MISO's proposal.

III. SEASONAL RESOURCE ADEQUACY CONSTRUCT

Q. How does MISO propose to meet the challenges of the Reliability Imperative in this filing?

A. As discussed in Mr. Wright's Testimony, the Reliability Imperative is the term MISO uses to describe the shared responsibility of MISO, Load Serving Entities, and Relevant Electric Retail Regulatory Authorities to address the challenges that rapid fleet change, increased frequency and severity of extreme weather events, and other factors are posing to the reliability of the MISO Region. As part of

MISO's Market Redefinition efforts in response to the Reliability Imperative, MISO proposes Resource Adequacy enhancements in two primary areas: (1) establishing seasonal Resource Adequacy Requirements ("RAR); and (2) improving availability-based accreditation. These enhancements are designed to verify sufficient generation adequacy within each Season of the year and to provide the right incentives for resources to maintain system reliability. MISO will be submitting a separate, but related, Minimum Capacity Obligation proposal in another filing concurrent with this filing.

Q. Please describe MISO's current Resource Adequacy (RA) Construct.

A. In accordance with MISO's Resource Adequacy Tariff provisions contained in Module E-1, Market Participants representing Load Serving Entities ("LSEs") are expected to procure sufficient resources to meet their forecast coincident peak load, plus a reserve margin, for the upcoming Planning Year. A detailed description of the provisions of MISO's existing RAR, including the specific requirements established in Module E-1 of the Tariff, is included in the Testimony of Mr. Scott Wright.

Q. Why is MISO proposing to move to a seasonal RA construct with accreditation based on availability during times of need?

A. MISO is proposing to move to a seasonal RA construct so that it can better manage reliability risks brought about by the key trends impacting resource availability identified in 2018 as part of MISO's Resource Availability and Need

("RAN") initiative.[1] As described in the Testimony of Mr. Scott Wright, MISO now faces a Reliability Imperative. As part of its response with respect to Resource Adequacy, MISO is focused on addressing the following: (1) Improving outage scheduling and expectations; (2) Linking resource accreditation and requirements with initial focus on Load Modifying Resources ("LMRs"); (3) Aligning Planning Resource Auction ("PRA") commitments with energy needs all year; and (4) Ensuring flexible resource availability to address changing fleet characteristics. The proposed Tariff enhancements presented in this filing are necessary to further address the Reliability Imperative. Moreover, the urgency of implementing the proposed Tariff enhancements is evidenced by the increased incidence of capacity emergency maximum generation alerts, warnings, and events (collectively referred to as "MaxGens"),[2] particularly in the Seasons outside of Summer as demonstrated in the chart below. The reasons for and impacts of these changes are described in more detail in the Testimonies of Mr.

[1] *See* https://cdn.misoenergy.org/20180405%20RSC%20Item%2007%20RAN%20Issues%20Statement%20White%20Paper164746.pdf

[2] *See* https://cdn.misoenergy.org/SO-P-EOP-00-002%20Rev%2012%20MISO%20Market%20Capacity%20Emergency554411.pdf

Scott Wright and Mr. Jameson Smith supporting this filing.

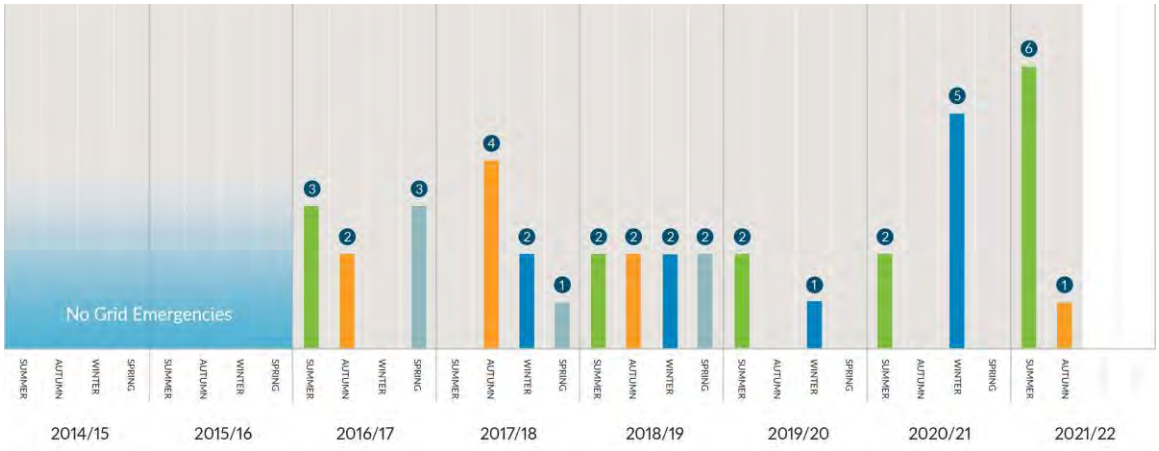


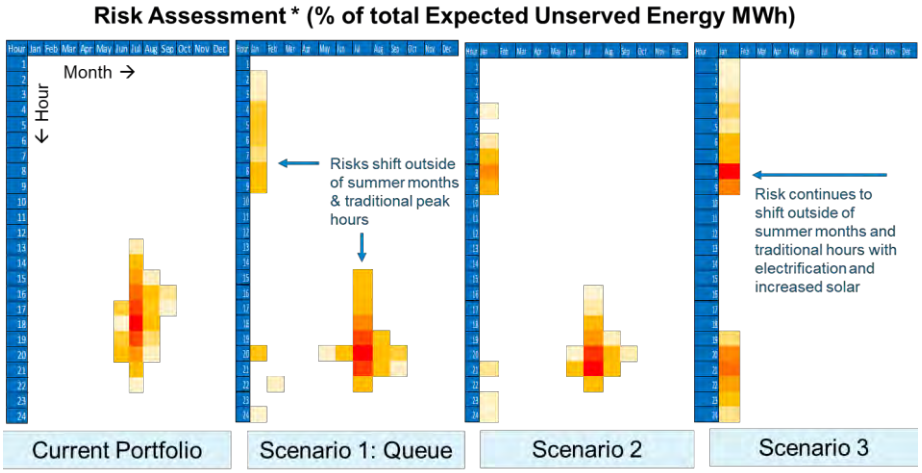
Chart indicates the number of days under a max gen alert, warning or event.

Q. How will reliability risks change as MISO's resource portfolio continues to evolve?

A. In addition to the increasing number of non-Summer MaxGens that MISO has experienced in the past several years, Loss of Load risks are projected to continue shifting outside of Summer and traditional peak hours. This is expected to be the case under a broad range of plausible future resource portfolio scenarios that MISO has developed and analyzed, as illustrated in the Figure below. Scenario 1 represents a 2025 resource mix outlook based on current MISO Generator Interconnection Queue and OMS-MISO survey projected retirements. Scenario 2 models a continuation of current trends and largely represents MISO member resource plans and provides a 2030 resource mix as defined in MISO Future 1.[3] Scenario 3 represents a 2035 resource mix outlook with accelerated existing fleet

[3] *See* https://cdn.misoenergy.org/MISO%20Futures%20Report538224.pdf

retirements and adoption of renewables and electrification as defined in MISO Future 3.[4]



Q. How will a seasonal RA construct address the concerns identified by MISO?

A. Moving to a seasonal RA construct will align seasonal resource accreditation with seasonal resource availability to meet the changing risk profile that is emerging and is expected to increase dramatically in the near future. The proposed change to a seasonal Resource Adequacy construct is expected to mitigate risks to reliability within the MISO footprint by promoting Availability, Visibility, and Flexibility, which are "Key Needs" MISO outlined in the 2019 and 2020 MISO Forward Reports.[5] For Availability, a seasonal RA construct enables a more accurate representation of resource capability at different times during the year, improves certainty of resource availability outside the Summer Season, and better incentivizes resources to be available when needed. For Visibility, a seasonal RA

[4] *Id.*
[5] https://www.misoenergy.org/about/miso-strategy-and-value-proposition/MISO_Strategy/strategy-papers/#nt=%2Fstrategypapertype%3AMISO%20FORWARD&t=10&p=0&s=strategypaperpublisheddate&sd=desc

construct establishes seasonal reserve requirements, both system-wide and in LRZs, that better align with risks and deliver additional visibility into the risks throughout the year, which are not currently captured in the annual RA construct. There are also indirect improvements to the flexibility of resources that operators may not have had previously. These resources may improve their characteristics to be able to take shorter outages or need less time to respond. Additionally, consideration of unit lead time for offline units for the purposes of accreditation is a part of the proposal. At implementation, the flexibility required for accreditation purposes is a lead time that does not exceed 24 hours allowing the resource to be committed the day ahead in MISO's existing commitment processes. Finally, these reforms considered together provide the ability for resource owners to commit resources only when they are needed and expands opportunities for resources to participate in the PRA, suspend, or retire.

Q. What changes are necessary to implement the proposed RA construct?

A. Changes include developing seasonal values for a number of construct parameters: MISO's Loss of Load Expectation ("LOLE"); Planning Reserve Margin Requirements ("PRMR"); Local Reliability Requirements ("LRR"); Local Clearing Requirements ("LCR"); Capacity Import Limits ("CIL"); and Capacity Export Limits ("CEL"). In addition, the changes will require accrediting resources by Season based on their availability during times of need.

Q. How does MISO define the various Seasons for its proposed seasonal RA construct?

A. The seasonal RA construct will follow the definition of Season as defined in Module A of MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff"): Winter (December, January, February); Spring (March, April, May); Summer (June, July, August); and Fall (September, October, November). This definition of Season is used in various MISO processes, including Financial Transmission Rights and seasonal resource assessments.

Q. Why does MISO need to update its LOLE modeling and methodology to implement a Seasonal RA construct?

A. The modeling and methodology of the LOLE study needs to change to model seasonally sensitive variables and calculate the construct parameters outlined above more accurately. This can be achieved through: (1) improving sub-annual LOLE modeling, including the modeling of planned outages, modeling of non-firm external support, and hourly modeling of intermittent resources; and (2) seasonal LOLE risk targets and requirement calculations.

Q. What does seasonal forced and planned outage modeling entail?

A. Seasonal forced outage rates based on historic North American Electric Reliability Corporation's ("NERC") Generator Availability Data System ("GADS") data will be used in the LOLE analysis for all thermal units. Additionally, an adjustment will be applied within the model to account for increased forced outages during extreme cold weather events. When the temperature drops below a certain threshold in the model, the outage rates for

thermal resources will be increased to reflect the correlation between extreme weather and temperatures and forced outages that are observed in real-time, especially during the Winter Season. This correlation was developed based on five years of historical outage and weather data. Five-year average planned outage rates from GADS by Season, including the observed increases during extreme cold in the Winter Season, will be included in the seasonal modeling for all thermal resources. SERVM (the software used to conduct the LOLE study) will schedule planned outages using a flexible outage method. This outage modeling method requires a portion of the planned outages to be fixed and then optimally schedules the remaining outages to reflect the actual operational flexibility to do so and maintain reliability.

Q. What does the improvement of non-firm external support in the LOLE model entail?

A. Non-firm external support (*i.e.,* imports) will be modeled as a probabilistic distribution input in SERVM, an enhancement from current modeling practice that uses an annual fixed value. One of the benefits of being part of the Eastern Interconnection is the ability to import energy from neighboring regions as needed, subject to availability. Hourly historical non-firm imports during emergency pricing hours, for the period 2016 to 2019, calculated by subtracting firm import MWs from total import MWs, will be used to determine the probabilistic distribution of non-firm imports into the MISO Region as an input to the LOLE model. During the LOLE simulations, SERVM randomly draws from this distribution of non-firm imports, which is used to serve the hourly load. This

methodology is a better representation of non-firm imports when compared to the current annual approach (which assumes a static value) as it captures the variability observed in operations.

Q. Please describe the enhancements to the treatment of intermittent resources in the LOLE model.

A. Instead of modeling wind and solar resources as monthly fixed capacity values under current practice, wind and solar resources will be modeled as hourly profiles that correspond to each of the 30 load shapes within SERVM to better reflect the availability and variability of these resources across the year. Hourly wind profiles are developed for 30 historical weather years by normalizing historical hourly wind outputs for recent weather years from 2011 to 2019 and constructing synthetic hourly wind shapes for weather years from 1990 to 2010 based on temperature correlation.[6] Figures 4 to 13 in the MISO published sub-annual LOLE Modeling Methodology Document illustrate the close correlation between historical wind output and temperature/load.[7] MISO believes it is appropriate to use the correlation between wind and temperature to develop wind profiles to reasonably model the relationship of load to wind outputs and have a similar distribution of wind outputs as a function of the 1990-2010 load shapes as seen in the 2011-2019 shapes where actual historical wind outputs are available. Hourly solar profiles for 42 selected sites across the MISO Region are developed using the NREL National Solar Radiation Database Data Viewer from 1998 to

[6] *See* https://cdn.misoenergy.org/20201104 RASC Item 04a Astrape MISO Sub-annual LOLE Modelling Methodology Document489436.pdf

[7] *Id.* at 5 – 10.

2019 and processed through the System Advisor Model to generate fixed and tracking solar profiles. The hourly solar profiles for 1990 to 1997 weather years are then selected by using daily solar profiles from the day that most closely matched the peak temp out of all days (+/- 2 days) of the source day from 1998 to 2019.[8] Similar to wind profiles, using the correlation between solar outputs and temperature reasonably models the relationship between load and solar outputs and creates a similar distribution of solar output as a function of load for 1990 to 1997 as is seen in the 1998 to 2019 time frame.

Q. How will seasonal LOLE targets be determined and Resource Adequacy Requirements be calculated?

A. To determine seasonal Resource Adequacy reserve requirements, the LOLE model needs to have a defined LOLE target for each Season. MISO proposes to round LOLE targets up to a minimum of 0.01 day per year for any Season(s) with LOLE less than 0.01 day per year and maintain LOLE targets for the Seasons with LOLE greater than 0.01 day per year. MISO believes this approach is reasonable considering the practicality of solving the model to a reasonably small LOLE target to determine reserve requirements, as described further below.

The following process will be utilized to determine the seasonal requirements via the LOLE analysis. First, an LOLE analysis for the Planning Year will be conducted to solve the model to an annual LOLE of 0.1day per year to determine the natural LOLE distribution, by either adding proxy combustion turbine units with typical size (160 MW) and class average Forced Outage Rate Demand

[8] *See* https://cdn.misoenergy.org/20201104 RASC Item 04a Astrape MISO Sub-annual LOLE Modelling Methodology Document489436.pdf

("EFORd") if the LOLE for the Planning Year is greater than 0.1 day per year or a perfect negative unit with zero forced outage rate if the LOLE for the Planning Year is less than 0.1 day per year, consistent with the approach under the current annual construct.[9] If the LOLE for a Season is equal or greater than 0.01 day per year, the reserve requirement for that Season will be calculated based on this LOLE analysis. If the LOLE for any Season is less than 0.01 day per year, an additional LOLE analysis will be performed to determine the reserve requirement for that Season by adding a perfect negative unit with zero forced outage rate to that Season until the LOLE in that Season reaches 0.01 day per year. In collaboration with stakeholders, the 0.01 day per year LOLE minimum target is chosen for each Season because it is a large enough target to allow the LOLE model to accurately solve to determine seasonal reserve requirements while keeping an annual LOLE largely close to 0.1 day per year. This method also ensures that requirements in Seasons where the LOLE is naturally greater than 0.01 day per year are not artificially inflated, which would result in increased cost to Market Participants.

Q. Please describe the seasonal Planning Reserve Margin and Planning Reserve Margin Requirements.

A. A Planning Reserve Margin ("PRM") (expressed as a percentage) will be determined for each of the four Seasons by performing an LOLE analysis with seasonal input assumptions. The LOLE model will be used to meet the seasonal LOLE targets by adjusting the capacity within the model up or down as needed,

[9] https://cdn.misoenergy.org/PY%202021%2022%20LOLE%20Study%20Report489442.pdf

as described above. The seasonal PRM values in terms of Unforced Capacity ("UCAP") will be calculated and expressed as a percentage of seasonal coincident peak demand. The PRM for each Season is multiplied by the 50/50 forecast of coincident peak load to determine the PRMR (in MWs) for that Season.

Q. Please describe the seasonal zonal Local Reliability Requirements and Local Clearing Requirements.

A. The zonal Local Reliability Requirements ("LRR") will be determined using the same two-step process as the PRM analysis. Each Zone will be treated as an isolated system, consistent with the existing LRR analysis methodology under the current annual PRA construct.[10] The seasonal LRR values will be calculated in terms of UCAP and expressed as a percentage of seasonal zonal Coincident Peak Demand once the model has been solved to the appropriate LOLE targets. The seasonal LRR values will be used to determine the seasonal LCR values by subtracting the seasonal Capacity Import Limits ("CIL") from the seasonal LRR.

Q. Please describe seasonal Capacity Import/Export Limits.

A. Consistent with the existing transfer limit analysis methodology defined in MISO's Resource Adequacy Business Practices Manual ("BPM"), BPM-011, seasonal transfer analyses will be performed to determine seasonal CILs and Capacity Export Limits ("CELs"), capturing the seasonal variation of transfer limits for each LRZ. Planning Year seasonal peak powerflow models and input files developed from MISO Transmission Expansion Plan ("MTEP") studies built for timeframes matching the effective periods of transfer limit analysis will be

[10] *See* https://cdn.misoenergy.org/PY%202021%2022%20LOLE%20Study%20Report489442.pdf

used to perform transfer analyses for each Season, including Summer Peak, Fall Peak, Winter Peak, and Spring Peak study models. Seasonal MTEP powerflow models will include both approved and planned transmission projects through the MTEP planning process with effective dates on or before the effective date of the study models. Single-element contingencies in MISO and its seams areas will be evaluated and all facilities under MISO functional control and all seams facilities of 100kV and higher will be monitored. First Contingency Incremental Transfer Capacity ("FCITC") analysis will be performed for each of the seasonal powerflow models to identify limiting constraints with a generation-to-generation transfer model. Additional Generation Limited Transfer and voltage limited transfer analyses may be performed on an as needed basis if certain scenarios occur as described in the BPM for Resource Adequacy. The resulting seasonal Zonal Import Ability ("ZIA"), in conjunction with controllable exports, will be used to subtract from the LRR to determine the seasonal LCR for each LRZ.

IV. RESOURCE ACCREDITATION OVERVIEW

Q. What is MISO's current approach to Resource Accreditation?

A. The current resource accreditation process, which for thermal resources is based on Unforced Capacity ("UCAP"), is determined using resource performance between September 1 and August 31 of the three years prior to the Planning Year. Market Participants submit GADS data to MISO on a quarterly basis. This data is utilized to determine Equivalent Forced Outage Rate Demand ("XEFORd"), excluding events outside of management control, which is then used as a component in the calculation of Unforced Capacity. The UCAP is calculated by

taking Installed Capacity ("ICAP"), which is the lesser of Generator Verification Test Capacity ("GVTC") and Total Interconnection Service, multiplied by one minus the XEFORd. UCAP values are communicated to Market Participants on December 15 prior to the Planning Resource Auction. The proposed rules will continue to utilize the same period to evaluate availability for determining Seasonal Accredited Capacity ("SAC").

Q. How does MISO propose to calculate Resource Accreditation going forward?

A. Resource accreditation should primarily reflect the anticipated capability and availability of Planning Resources during times when they are most needed. Utilizing offered availability and actual performance provides an improved measure of expected availability for each Season.

Q. Which resources will the Resource accreditation proposal affect?

A. All resource types will be generally affected by moving to a seasonal Resource Adequacy construct. However, accreditation for certain resources will be determined based on their availability during times of need, as described in detail below. Specifically, Demand Response Resources and Capacity Resources that are Generation Resources (collectively "Schedule 53 Resources"), but not Dispatchable Intermittent Resources, Intermittent Generation, Electric Storage Resources, External Resources or Use Limited Resources, will be subject to these new availability-based accreditation requirements. The resources designated as Schedule 53 Resources will be subject to the proposed availability-based accreditation methodology established in new Schedule 53 of the Tariff. Resources that are not subject to Schedule 53 will continue to have their

accreditation determined generally as it is done today, with appropriate adjustments made to convert their accreditation to a seasonal basis. I note that MISO plans to further evaluate the accreditation methodologies of non-Schedule 53 Resources commencing with stakeholder discussions in 2022.

Q. What changes does MISO propose with respect to Resource Accreditation for Schedule 53 Resources?

A. The proposed changes align Resource accreditation for Schedule 53 Resources with historic availability and performance during the highest risk periods while also accounting for general availability of resources across the year. More specifically, MISO proposes a two-tiered calculation to determine individual resource accreditation by Season. The first tier will determine each resource's real time offered availability during non-tight operating condition hours, and the second tier will determine each resource's real-time offered availability during hours with the tightest operating conditions, including declared MaxGens. The second tier will be more heavily weighted so that the majority of a resource's accreditation will be based on its availability during times of need. Additional details about the weighting and the proposed transition period to phase in the full 80% weighting for Tier 2, are described in detail below.

MISO supported its Independent Market Monitor's ("IMM") recommendation to base 100% of accreditation on availability during times of need but introduced a revised two-tier proposal in May 2021 with 20% weighting based on availability during hours that aren't tight to accommodate stakeholder requests that these hours should still be relevant to resource accreditation. The proposal was

modified to recognize that general resource availability supports reliability by allowing resources to take needed maintenance outages. Moreover, general resource availability reduces the time the system is operating within the margin of error for capacity sufficiency.

Each tier calculation also will account for exemptions obtained by sufficiently coordinating planned outages when determining availability, as described in detail below.

Q. Why are MISO's proposed changes necessary?

A. Historically, most if not all LOLE occurred at or near the annual Coincident Peak Demand for the system, which occurred in the Summer. However, MISO has experienced an increasing number of days with tight operating margins in all four Seasons of the year despite clearing the targeted level of reserves in the PRA each year. This is attributable, in part, to a wave of retirements that began before the start of the 2016/17 Planning Year. Given this and recent operational experiences, including involuntary load shed outside of Summer, MISO has worked with stakeholders to provide tools and incentives to improve the availability, flexibility, and visibility of our resource fleet to mitigate the risks of capacity insufficiency.

Resource accreditation should reflect the anticipated capability and availability of Planning Resources during times when they are most needed. Historically, accreditation for conventional generation has been based only on forced outage rates defined in GADS. Recent experience shows this approach does not effectively reflect the actual availability and capability of resources during times

when capacity needs are highest – during periods of peak demand, high generation outages, low levels of renewable generation output, or a combination of these which can occur in any Season. Additionally, the current approach to accreditation for conventional thermal resources does not provide the proper incentives to improve availability, especially during critical periods, as described more fully in the Testimony of Mr. Smith.

Q. What benefits does MISO expect to receive from these proposed changes to Resource Accreditation?

A. MISO expects the proposed Tariff changes to achieve several important and necessary benefits, including: (1) increased confidence in the accredited capacity MISO can count upon during times of need; (2) improved signals for resource availability during times of need; (3) improved outage coordination processes; and (4) lower non-Summer Season requirements, which will enable seasonal operation of resources, as requested by many resource owners.

Q. How does the proposal mitigate reliability risks during extreme weather events?

A. The proposal incentivizes resource availability during times of need and does so specific to each Season. For example, Winter RA Hours have been observed to occur during extreme cold events and decisions and investments which impact resource availability in such conditions (*e.g.*, winterization and firming up of fuel procurement) are expected to have a significant impact on resource availability.

Q. How will MISO's Resource accreditation proposal apply to Schedule 53 Resources?

A. Resource accreditation for Schedule 53 Resources will no longer be based on forced outage rates from GADS as MISO intends on using energy market offers and related parameters to determine these resources' accreditation. Specifically, their accreditation will be based on Real Time Hourly Emergency Maximum Limits (or Targeted Demand Reduction Level ("TDRL") for Demand Response Resources) information in MISO's Day-Ahead and Real-Time system. If a unit is offline, then its lead time and outage status are also relevant to determine if it could be reasonably committed today to be used tomorrow during a time of need. Other factors such as the type and volume of interconnection service and seasonally corrected GVTC values will be utilized as well to account for changes to deliverability or unit capability not reflected in past offers. The proposed construct will continue to base accreditation on the three prior years starting September 1 through August 31 of the year prior to the Planning Year, which reflects the cumulative availability of a Resource. As noted above, MISO proposes a tiered weighting structure with more emphasis on low operating margin RA Hours to determine individual resource accreditation by Season. Accreditation will be based on each resource's real-time offered availability during all hours with heavier weighting for hours with the tightest operating conditions (*i.e.,* RA Hours) while incentivizing the coordination of planned outages by offering exemptions that remove hours when offers were zero when certain conditions are met.

Q. What are Resource Adequacy hours?

A. Resource Adequacy Hours ("RA Hours") represent the periods of highest risk and greatest need both during a Season and throughout the Planning Year. They include declared MaxGens and the hours when the operating margin, a measure of available economic supply capacity above demand and reserve requirements, is at its lowest. RA Hours will be determined seasonally, based on declared MaxGens and the tightest operating margin hours subject to a maximum operating margin threshold established at 25 percent. Each Season will have a target of 65 RA Hours (which represents approximately three (3) percent of the hours in a Season). The number of RA Hours in a Season can exceed the target when declared MaxGens during that Season have a duration greater than 65 hours. The number of RA Hours in a Season can be less than the target because of the 25 percent maximum operating margin threshold. In this latter case, these Seasons will have an RA Hour deficiency equal to the difference between the target of 65 RA Hours and the actual number of RA Hours.

Q. How does MISO ensure resources have a minimum target number of Resource Adequacy Hours?

A. MISO proposes to ensure resources have a minimum of 65 RA Hours for any Season for which they were designated for RAR by multiplying the number of deficient hours for a Season with the Annual Average Offered Capacity ("AAOC") over all RA hours for that resource during the same annual period (*i.e.,* September to August). It is necessary to have a minimum number of RA Hours to support stability of accreditation values and avoid situations where a Resource loses most of its capacity value for the Season because it happened not to be

available on the one or two days when operating margins were at their lowest for the Season. The RA Hours used for determining the AAOC for a resource are the tightest 3 percent of operating margin hours and declared MaxGen hours whenever they occur over the same annual period provided a resource was designated for RAR and had not secured an exemption. The target number of hours for AAOC is 260 for the annual period (*i.e.*, 65 hours per Season multiplied by four Seasons) with the distribution based on tightness and MaxGens rather than a specified target in any Season. Historical analysis shows many of these hours have occurred in the Summer during recent Planning Years. MISO believes it is prudent to supplement deficient seasonal RA Hours with a proxy-based on AAOC as it reflects the next best available information about a resource's availability during times of need, which is a core focus of MISO's proposed enhancements to resource accreditation.

It is important to note that, despite the general discussion above about how RA Hours are identified for a Season, ultimately the set of RA Hours are specific to each resource being accredited because of outage exemptions, capacity replacement requirements (each as described later in my testimony), and differences in resource commitment over the three-year look back period. No resource can have more RA Hours than the amount that has been identified for a Season or year, but many resources will have fewer RA Hours requiring more of a resource's accreditation to be based on availability during times of need during the annual period and not just the specific Season to ensure sufficient sample sizes for RA Hours to support stability of resource accreditation.

Q. How will the location of a resource impact its RA Hours?

A. To reflect the varying risk of capacity insufficiency across the MISO Region, Resource Adequacy hours are defined within the First Planning Area (*i.e.*, MISO North/Central) and the Second Planning Area (*i.e.,* MISO South) separately. RA Hours will be determined on this sub-regional basis to reflect the growing frequency of MaxGens that occur on either side of the Sub-Regional Power Balance Constraint, as demonstrated in the below chart:

Region of highest severity	# of MaxGens
Central	3
North/Central	9
South	21
Footprint	7
Total	40

MaxGen Events are often the result of issues that disproportionately impact one Planning Area or the other but are usually not felt uniformly across the entire MISO region. Typically, these issues include: trapped capacity in one sub-region due to the contractual transfer limits; increasing sub-regional challenges driven by portfolio differences; and, the varying locational impacts of extreme weather, including hurricanes, cold weather events, and renewable penetration.

Q. How is the hourly Operating Margin percentage calculated?

A. As described in Schedule 53, the Operating Margin is determined using historical information to identify Seasonal RA Hours and Annual RA Hours within the three

(3) most recent periods beginning September 1st and ending August 31st. The Operating Margin Equation is as follows:

$$Operating\ Margin\ (\%)_j = \frac{Online\ margin\ (MW)_j + \ offline\ margin\ (12 - hour\ lead\ time)(MW)_j}{Real\ Time\ (RT)\ Load\ (MW)_j}$$

Where:

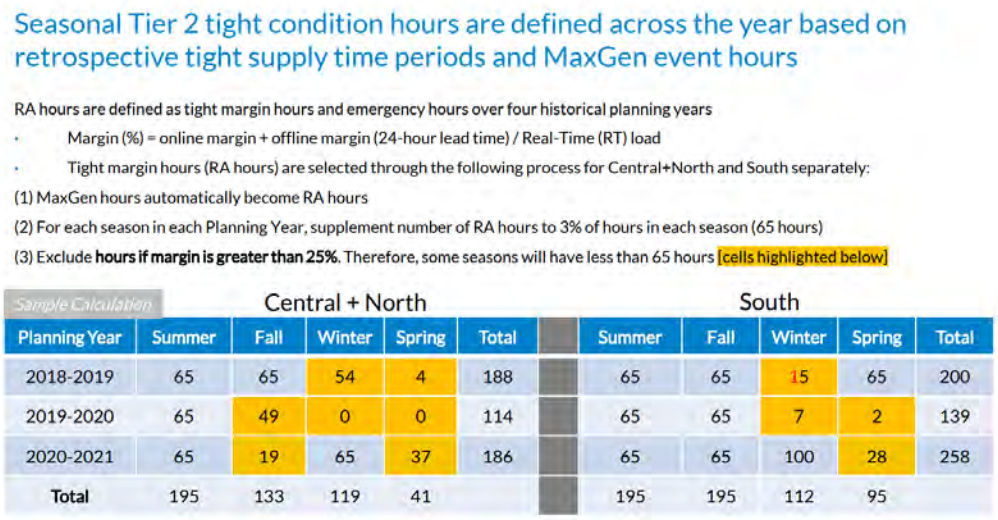
$Online\ margin\ (MW)_j = \sum_{unit\ i\ in\ region\ j}(EmergencyMax_i - Energy\ MW_i - cleared\ operating\ reserve_i)$ For all Resources online and under normal dispatch control.

$Offline\ margin\ (MW)_j = \sum_{unit\ i\ in\ region\ j} Emergency\ Max_i - cleared\ offline\ supplemental\ reserve(MW)_j$ For Resources where all of the following is true: (i) Resource is Offline; (ii) it's cold-start lead-time is less than or equal to 12 hours; and (iii) it's not on outage.

Q. Why does MISO propose to use a 12-hour lead time for offline resources in the Operating Margin calculations?

A. Previously MISO proposed a 24-hour lead time but the IMM suggested that use of a shorter lead time would better reflect the actual operating margins MISO is seeing in real-time operations, which may be impacted by uncertainty that occurs after the deadline to commit longer lead resources has passed. MISO agrees that the use of a shorter threshold better reflects historical margins in the recent past, as evidenced by the chart below. It also leads to the identification of more RA Hours below the 25% operating margin threshold used to identify RA Hours. Moreover, twelve hours leads to more RA Hours being identified in each Season,

allowing resource accreditation to be based on availability during a specific Season with less need to fill in deficient hours through the use of the AAOC, as explained above.



Seasonal Tier 2 tight condition hours are defined across the year based on retrospective tight supply time periods and MaxGen event hours

RA hours are defined as tight margin hours and emergency hours over four historical planning years

- Margin (%) = online margin + offline margin (24-hour lead time) / Real-Time (RT) load
- Tight margin hours (RA hours) are selected through the following process for Central+North and South separately:

(1) MaxGen hours automatically become RA hours

(2) For each season in each Planning Year, supplement number of RA hours to 3% of hours in each season (65 hours)

(3) Exclude **hours if margin is greater than 25%**. Therefore, some seasons will have less than 65 hours [cells highlighted below]

Sample Calculation

	Central + North						South				
Planning Year	Summer	Fall	Winter	Spring	Total		Summer	Fall	Winter	Spring	Total
2018-2019	65	65	54	4	188		65	65	15	65	200
2019-2020	65	49	0	0	114		65	65	7	2	139
2020-2021	65	19	65	37	186		65	65	100	28	258
Total	195	133	119	41			195	195	112	95	

Q. Why is MISO using a 12-hour lead time to identify RA Hours but a 24-hour lead time for accreditation in Schedule 53?

A. As described above, due to the operational uncertainties that MISO faces, tight conditions are more likely to be identified 12 hours before a projected capacity shortfall than 24 hours. Use of a 12-hour threshold better identifies RA Hours that represent "times of need." On the other hand, the use of a 24-hour threshold for accreditation with respect to offline resources better reflects whether MISO could have reasonably committed a resource in its Day-Ahead Market or Forward Reliability Assessment Commitment processes. This is consistent with the goal of MISO's RAN initiative to close the gap between planning and operational outcomes. MISO's proposal bases most of a resource's accreditation on its offers during times of need but the process of identifying RA Hours that reflect times of

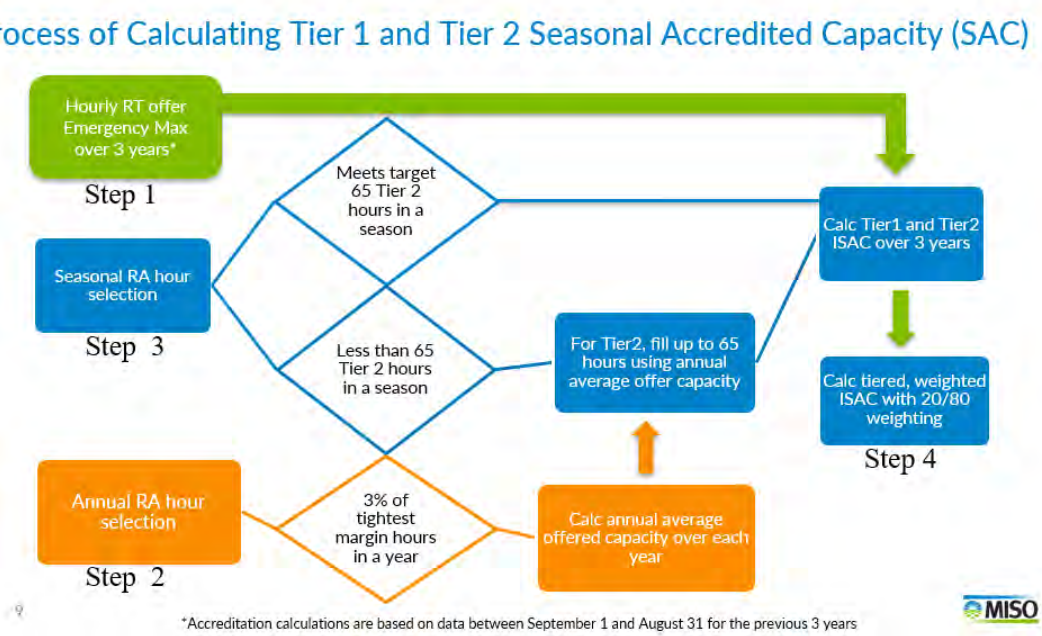
need must also account for resources that could not be accessed due to long start-up and notification times.

Q. Why is a 25% margin threshold applied in identifying Resource Adequacy hours?

A. MISO has examined the distribution of Operating Margin and Operating Margin levels for historical MaxGen events. The evaluation indicates that a 25% margin threshold captures the vast majority of declared MaxGens events. Also, by examining the cumulative count of hours at different levels of Operating Margin in each Season, MISO found that the 25% threshold provides a reasonable balance between having an adequate number of RA Hours for each Season and selecting the set of RA Hours that are truly tight.

Q. Please provide a step-by-step description of the Intermediate SAC calculations in Schedule 53.

A. First, a Resource will have its Intermediate Seasonal Accredited Capacity ("ISAC") determined based on offers of its Real-Time Hourly Emergency Maximum Limit, or TDRL for Demand Response Resources, during both seasonal RA Hours (Tier 2) and Non-RA Hours (Tier 1), as set forth in Schedule 53. References to "RT offers" in the steps below refer to Hourly Emergency Maximum Limit or TDRL as applicable. The following graphic illustrates the process of calculating Tier 1 and Tier 2 ISAC for a Resource.



Step 1: Cap Real-Time offers for the three-year look back period by the relevant seasonally corrected GVTC value to account for a resource's most recently demonstrated capability. For resource's that have increased their capacity, MISO will increase the RT offers based on a class average SAC percentage for hours prior to such increased capacity to reflect the additional capacity. Ensure RT offers equal zero when a Resource is on outage or is offline and has a combined Start-Up Time and Start-Up Notification Time greater than 24 hours to reflect that the resource was not available in the Day-Ahead commitment processes.

Step 2: For each year in the three-year look back period (September 1 – August 31) identify declared MaxGen hours and then the tightest non-MaxGen hours needed to reach 260 hours (3%) for the relevant Planning Area in which the resource is located and then remove any hours during which the Resource had a Tier 2 Planned Outage Exemption. The remaining hours are the Annual RA Hours for the resource. Sum the RT offers and divide by the number of Annual

RA Hours for the Resource to calculate its Average Annual Offer Capacity ("AAOC") for each year in the three-year look back period.

Step 3: For each Season, identify declared MaxGen hours and then the tightest non-MaxGen hours with operating margin less than 25% for the Planning Area that needed to reach the target of 65 hours (3%). Then remove any hours during which the Resource had a Tier 2 Planned Outage Exemption. If the Resource has less than 65 hours in any Season MISO will add hours with RT offers equal to the relevant AAOC for any deficient hours. MISO will sum up the RT offers during RA Hours for the Season over the 3-year look back period and divide by the total number of hours (195 or greater) to determine the Tier 2 ISAC value for each Season. Calculate the Resource's Tier 1 ISAC value for each Season by summing the RT offers for any non-RA hours over the 3-year look back period (after first removing any hours for which the Resource had a Tier 1 Planned Outage Exemption) and then dividing by the total number of hours.

Step 4: Multiply the Resource's Tier 1 and Tier 2 ISAC values for each Season by their weightings (20% for Tier 1 and 80% for Tier 2 after the proposed transition) to calculate its final ISAC value.

Q. What does "Intermediate SAC (ISAC)" mean in Schedule 53?

A. Schedule 53 describes various steps in the calculation of SAC and until the very end the "in process" value is referred to as "intermediate" SAC or "ISAC." Each Resource will have four ISAC values (one for each Season of the upcoming Planning Year) while the SAC calculation is in process.

Q. How does the ISAC value become SAC?

A. Once the final ISAC for each Resource has been determined for each Season of the upcoming Planning Year, then a system-wide conversion ratio is determined for each Season and applied to each Resource's ISAC to determine a Resource's final SAC value for each Season.

$$RATIO\frac{UCAP}{ISAC} = \frac{Sum(UCAP_{Schedule\ 53\ Resources})}{Sum(ISAC_{Schedule\ 53\ Resources})}$$

Q. Why is a conversion ratio necessary and why is it applied as the final step to calculate SAC in Schedule 53?

A. MISO's IMM originally suggested, and MISO adopted, a proposal that would scale seasonal requirements by the change in accreditation under Schedule 53 to ensure alignment with how requirements were determined during the LOLE study conducted under a UCAP approach. However, this approach required changes to how PRMR and LCRs are determined and appeared likely to have several unintended consequences, including the relative share of accreditation between Schedule 53 (generally thermal resources) and non-Schedule 53 Resources. Subsequently, the IMM proposed a simpler methodology that avoided the issues noted by having the required scaling occur at the end of the calculations proposed in Schedule 53, thereby removing the unneeded and unintended impacts to auction requirements and non-Schedule 53 resources. Additionally, the revised proposal addressed stakeholder concerns on deliverability and revenue reduction. The IMM presented its new recommendation at the October 6, 2021 meeting of the RASC, and formal feedback was solicited. Feedback received from

stakeholders was generally in support of the revised conversion method and MISO adopted the revised method and shared related Tariff redlines at the November 11, 2021, meeting of the RASC.

Q. How will the tiers be weighted?

A. The ISAC value is the weighted average over its values from the two tiers as calculated in the steps above. Ultimately assigning heavier weighting for Tier 2 tight condition hours ensures the alignment between a resource's Seasonal Accredited Capacity value and its availability and performance during times of highest risk and greatest need in MISO's Planning Areas. The corresponding tier weightings, which will be effective following a two Planning Year transition (described below), are:

$$ISAC_{Tier1_weighting} = 20\%$$

$$ISAC_{Tier2_weighting} = 80\%$$

$$ISAC = ISAC_{Tier1_value} \times ISAC_{Tier1_weighting} + ISAC_{Tier2_value} \times ISAC_{Tier2_weighting}$$

Q. Is there a transition to the 80% weighting for Tier 2?

A. Yes. Stakeholders requested a transition and MISO felt it would be appropriate to phase in the full 80% weighting until the third Planning Year ("PY") following initial implementation (*i.e.,* the 2025/2026 Planning Year). Doing so will account for the fact that the historical RT offers, outages, and notification times used in the Schedule 53 calculations were submitted for resources without knowledge of the final accreditation methodology proposed in the instant filing. Under the proposal, Tier 2 would start at 60% in PY 2023/24, rise to 70% in PY 2024/25 and then reach the full 80% in PY 2025/26.

Q. What is the ultimate product of this process?

A. The ultimate product of Schedule 53 is four SAC values for each Resource, one to be used for each Season commencing with the upcoming Planning Year 2023/24.

Q. How will MISO account for resources with insufficient performance data, such as new resources?

A. Units with insufficient performance data will utilize a class average proxy for accreditation as done today, but this class average will be based on SAC rather than UCAP. Class averages will be determined for each resource type as they are today. However, the class average will be a ratio of SAC to ICAP for a particular class. A new resource will apply this ratio to its ICAP to determine its SAC. A resource will only use a class average for a Season when there is less than 60 days of real-time offered availability for that Season during a time when the resource was designated for RAR. However, for Planning Year 2023/24 MISO accommodated a stakeholder request by adding Tariff language giving a resource that hadn't been designated for RAR in a recent annual PRA the option to have its accreditation based on its real-time offers rather than a class average.

Q. Does MISO's proposal account for seasonal resource deliverability?

A. Yes, it does. For seasonal deliverability, similar to the current process, if a Resource does not have full Network Resource Interconnection Service ("NRIS") granted for its seasonal GVTC, to the extent the output is within the total granted Energy Resource Interconnection Service ("ERIS") and does not violate the generator's Generator Interconnection Agreement ("GIA"), it can: (1) request

additional NRIS through the established process in Attachment X; or (2) procure firm Transmission Service Requests to align with seasonal deliverability needs.

Q. How will MISO's proposal address deliverability requirements?

A. The recently accepted ICAP deliverability Tariff changes remain in effect without modification as these requirements are appropriately applied to each Season under the proposal. However, based on stakeholder feedback, MISO will continue to evaluate whether additional modifications to these requirements are needed in the future.

Q. How will MISO's accreditation proposal apply to wind resources?

A. Wind resources are currently accredited through an annual Effective Load Carrying Capability ("ELCC") methodology with capacity credits allocated based on each individual wind resource's performance over eight peak demand hours for the year, historically occurring in the Summer. Similarly, under a seasonal construct, accreditation for each Season will be based on seasonal ELCC studies with capacity credit allocated based on eight peak hours for each Season.

Q. How will MISO's accreditation proposal apply to non-wind intermittent and Energy Efficiency Resources?

A. Seasonal accreditation for non-wind intermittent resources (such as run-of-river hydro, solar, and biomass) and for Energy Efficiency Resources will be based on historic output during hours ending 15, 16 and 17 EST for the relevant Spring, Summer, and Fall months. Winter accreditation will be based on hours 8, 9, 19 and 20 EST for the Winter months. The selected hours represent the typical seasonal peak demand hours for the specified Seasons.

Q. How will MISO's accreditation proposal apply to Demand Resources?

A. MISO's May 2020 Tariff filing that was accepted by FERC will also be implemented with the 2022-2023 Planning Year. That filing accredits Demand Resources registering as Load Modifying Resources ("LMRs") based on lead time and number of calls per year.[11] The lead time requirements will remain unchanged, but the number of calls will be modified to transition to a seasonal construct. LMRs must be available for a minimum number of calls for each Season as follows: five for Summer, five for Winter, three for Spring, and three for Fall to be eligible to offer into the PRA for each respective Season. Establishing a minimum number of calls per Season rather than per Planning Year is consistent with procuring seasonal capability to meet seasonal needs and incurs a minimum obligation to inform offers into each Season. Demand Response Resources that are not registering as LMRs will be accredited pursuant to Schedule 53 since they submit offers in the day-ahead markets and can be appropriately accredited based on their availability during times of need.

Q. How will MISO's accreditation proposal apply to behind-the-meter generation?

A. Intermittent Behind the Meter Generation ("BTMG") will be accredited like all other non-wind intermittent resources (such as run-of-river hydro and solar), under a seasonal construct. As described above, accreditation will be based on historic output during hours ending 15, 16 and 17 EST for the relevant Spring, Summer, and Fall months. Winter accreditation will be based on hours 8, 9, 19

[11] *See Midcontinent Independent System Operator, Inc.,* 127 FERC ¶ 61,138 (August 14, 2020).

and 20 EST for the Winter months. Thermal BTMG with historic GADS data (*i.e.,* with capacity greater than or equal to 10 MW) will be accredited based on their seasonal forced outage rates as it is today. Thermal BTMG with no GADS history will be accredited based on the class average seasonal forced outage rates. FERC approved notification times for LMRs and call limits for DR in MISO's May 2020 filing described in the answer to the prior question. In transitioning to the proposed seasonal capacity construct, all LMRs, including, BTMG, will be subject to those same call limits on a seasonal basis: five for Summer, five for Winter, three for Spring, and three for Fall.

Q. How Will Generation Verification Test Capacity ("GVTC") requirements change under MISO's proposal?

A. The current GVTC process has three steps: (1) Generator Operators ("GO") conduct a real power test or base GVTC on operational data between September 1 and August 31 prior to the Planning Year; or (2) Correct to historical MISO Summer coincident peak conditions, and (3) Submit in PowerGADS through the MISO Market Portal by October 31 prior to the Planning Year. A GADS integration is run to bring the GVTC from PowerGADS to the Module E Capacity Tracking ("MECT") tool. Under a seasonal construct, the GO would still conduct a real power test or base GVTC on operational data between September 1 and August 31. MISO would publish four historical MISO coincident seasonal peak dates and times for the last five years. The GO will correct the single test to each of the seasonal peak conditions for temperature and submit four seasonally corrected GVTC values by October 31.

Q. Will MISO still permit Installed Capacity deferral?

A. Installed Capacity ("ICAP") deferral, formerly known as GVTC Deferral, requires a Market Participant to submit notice by February 15, post credit no later than March 1, and test and submit test results before the last business day of May prior to the start of the Planning Year. The February 15 notice and March 1 credit posting timeline still apply, and the credit requirement will continue to be calculated as the deferred ICAP megawatts multiplied by 90 days of the annual Cost of New Entry ("CONE"). However, the deferral notice will be modified to indicate to which Season the deferral applied and the credit would be held until the resource tested. The testing would need to be performed and submitted prior to the last business day prior to the start of the applicable Season, otherwise the existing ICAP Deferral Non-Compliance Charges would apply. No changes are proposed to the ICAP Deferral Non-Compliance Charges.

V. PLANNING RESOURCE AUCTION

Q. What changes to the PRA will be needed to implement the Seasonal construct?

A. The seasonal construct will require a number of important changes relative to the annual construct, including: how MISO conducts the Simultaneous Feasibility Test ("SFT"); time needed to run the PRA; need for non-Summer seasonal forecasts; calculation of non-Summer transmission losses; seasonal must offer requirements, capacity replacement requirements, and non-compliance charges; calculation of the Auction Clearing Price ("ACP") during shortage or near-

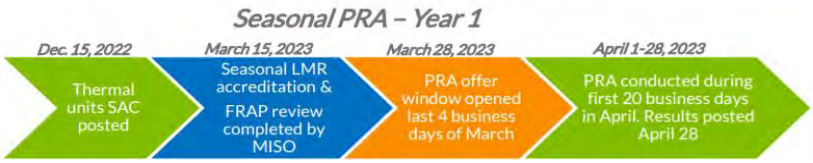
shortage conditions; calculation of offer cap impacts; and, establishing a new make whole payment mechanism. Each of these changes is discussed below.

Q. How will MISO conduct the SFT as part of the seasonal PRA?

A. Participants in the PRA may offer resources for each Season in the upcoming Planning Year during the PRA offer window period, which occurs over the last four business days in March. During the first 20 business days in April, MISO will build four SFT models to meet seasonal requirements. Results for each upcoming Season of the Planning Year that pass the SFT auction run will be posted and valid by the 20th business day in April. Results for Seasons where unacceptable constraints are found will have their SFT model rebuilt and re-run for one additional iteration. MISO will accept the result with fewest MWs of network violations of the two iterations for that Season and post the result by the 20th business day of April.

Q. How will the proposed seasonal construct affect auction timing?

A. Under a seasonal construct, all four seasonal auctions will occur at approximately the same time as the current annual PRA. The PRA offer window will remain as the last four business days of March. The auction period will be expanded from 10 business days to occur within the first 20 business days of April, allowing a maximum of two SFT auction run iterations per Season. PRA Results for each Season will be posted on the 20th business day in April. The following graphic summarizes the timeline leading up to the start of the 2023/2024 Planning Year on June 1:



Q. Will LSEs be required to submit seasonal load forecasts?

A. Yes, the current annual load forecast submittal process will be repeated for each Season. LSEs will supply Coincident Peak Demand and LRZ Peak Demand forecasts for each Season including the estimated demand from forecasted demand resources, whether registered as LMRs or not registered with MISO. The forecasts will also include demand that would have occurred but for the existence of energy efficiency resources that have been in operation less than 4 years. All submissions for such forecast values will include distribution losses but not transmission losses. All demand forecasts will reflect a 50 percent probability that the demand will not exceed the forecasted demand for the relevant time period.

Q. How will the proposal impact the treatment of transmission losses?

A. Under the current annual PRA construct, MISO calculates annual transmission losses for each Local Balancing Authority Area and LRZ based on the MISO coincident peak hour. Under the seasonal PRA construct, transmission losses will be calculated at each of the four published MISO seasonal peak hours and will be made available on both the market portal and its public website.

Q. How will must offer obligations for cleared Capacity Resources be impacted by MISO's seasonal proposal?

A. Currently resources are committed for an entire Planning Year and their must-offer obligation is the same throughout the year despite lower load expectations

outside of Summer. Under a seasonal approach, resource capabilities and capacity requirements will be tailored to each Season and resources may be committed for one Season but not committed in other Seasons. The must-offer obligation only applies for those Seasons when a Resource is committed. The must offer obligation will be ICAP multiplied by the percentage of total ZRCs a resource clears (*e.g.,* a unit eligible for 10 ZRCs that clears 5 will have a must offer of 50% of its ICAP).

Q. Will MISO require replacement of ZRCs if a resource has a planned outage or derate?

A. Yes, but only if the Generator Planned Outage or derate exceeds 31 days during a Season when the resource is committed. The proposal establishes a maximum threshold number of 31 days of full or partial Generator Planned Outages per Season that will require replacement when exceeded. A threshold of 31 days is reasonable as it retains much of the latitude resources need to schedule Generator Planned Outages while putting an upper limit on the amount of a Season that a committed resource can choose to miss without consequence under MISO's Resource Adequacy construct. Additionally, resources with unplanned outages that were known or could have been reasonably anticipated at the time of the PRA will also have a capacity replacement requirement where the full or partial outages exceeds 31 days since the outage was expected despite not being a Planned Generation Outage. An after-the-fact determination will be made following each Season to determine if resources were on planned outages or planned derates that exceeded the threshold and if such resources met the

replacement requirements. Future non-Summer seasonal PRMRs are expected to be lower than today's annual Summer-peak target, representing an efficiency in the amount of required capacity for the MISO Region. Currently, capacity replacement requirements are only in place for capacity suspensions and retirements. Under a seasonal construct with lower PRMRs, the performance and availability of committed capacity to meet seasonal requirements will be critical. Relying on resources that have submitted planned outages for a large portion of a Season is not consistent with availability-based accreditation and seasonal requirements.

A non-compliance charge will be assessed for days exceeding the threshold (as described further below) since some resource owners may not be willing or able to replace their capacity with uncleared ZRCs deliverable to the needed LRZ in the relevant Season. It should be noted that exemptions granted through the outage coordination process are not relevant to capacity replacement and will not relieve a resource owner of the ZRC replacement obligation. MISO systems and processes will continue to accommodate ZRC replacement transactions. Current replacement rules regarding deliverability and zonal transfer limits will still apply.

Q. Why is MISO imposing a charge for failure to replace ZRCs associated with a retired or suspended resource or a resource that exceeds its maximum outage or derate threshold in a season?

A. Currently, resources that convert UCAP to ZRCs and retire or suspend prior to the end of the Planning Year and fail to replace do not face any explicit non-compliance charges under the Tariff. This creates uncertainty and fails to

quantify the consequences of failure to replace. In the past, this has led Market Participants to seek waivers from FERC as opposed to complying with the Tariff requirements. The proposal is to implement a financial charge that incentivizes replacement of ZRCs that are retired, suspended, or have outages that exceed 31 days in a Season. This non-compliance charge is reasonable because, despite the owner of the resource benefitting from its committed ZRCs each day of the Season, the resource owner has decided to make itself unavailable for more than one month of the three-month Season, thus possibly failing to be available when needed to support reliability in line with our one day in ten-year standard. The proposed Capacity Replacement Non-Compliance Charge will be based on the number of days where a Market Participant had a replacement requirement but failed to do so multiplied by the amount of ZRCs that failed to be replaced multiplied by the sum of the Auction Clearing Price and the daily CONE value. Effectively the resource will stop receiving the Auction Clearing Price for clearing and start paying a daily CONE payment that reflects the missing capacity in the applicable LRZ. Distribution of Capacity Replacement Non-Compliance Charges will be distributed to Market Participants representing LSEs that have met their PRMR during the Planning Year on a pro rata basis, based upon the Market Participant's share of total PRMR for the MISO Region. Billing, invoicing, default, and uplift provisions will be similar to the ICAP Deferral Non-Compliance Charge.

Q. What are the eligibility criteria for ZRCs to be used for capacity replacement?

A. As is the case today, only uncleared ZRCs can be used for capacity replacement. ZRCs must be registered and converted in advance as part of the PRA process.

Q. With the proposed move to seasonal auctions how is MISO mitigating the risk of capacity revenue insufficiency for resources or payment above annual CONE for LSEs?

A. The move to seasonal auctions could lead to concerns about over or underpayment in certain circumstances. Based on historical PRA results, MISO does not expect such circumstances to occur frequently but considers it prudent to ensure reasonable mitigation in the unlikely event of such outcomes. MISO's proposal incorporates enhancements to offer caps and make whole provisions that ensure appropriate resources recover their costs when committed for the PRA while also ensuring that LSEs are not exposed to ACPs that result in charges that amount to multiples of annual CONE value as result of auction participation. Additional details about these enhancements are provided below.

Q. Will the PRA continue to include offer caps?

A. Yes. An LRZ may fail to clear its target PRMR in fewer than all four Seasons. Seasonal offer caps and facility-specific reference levels need to take this into account to enable some resources to economically participate in the seasonal auctions. Offers higher than the daily allocation of the annual CONE value (*i.e.*, "daily CONE" or CONE/365) could be cleared and/or set prices when needed to enable resources to cover their avoidable costs. Therefore, ZRC Offers will be enabled to recover a resource's costs if they only clear in one Season by enabling the Auction Clearing Price to be set at a level up to annual CONE divided by the

number of days in each Season, (*e.g.,* CONE/91 days, up to approximately $1,000 per megawatt day). As a result, the Auction Clearing Prices for individual LRZs and Seasons may clear above the current daily value of Annual CONE (CONE/365 or ~$250/MW-day), which is the highest price at which the current annual Planning Resource Auction can clear when there are insufficient ZRC Offers to meet auction requirements. Consequently, if no further action is taken, the auction could provide revenues up to four (4) times Annual CONE if all Seasons cleared in shortage conditions.

Q. Will the proposal mitigate the potential for recovering above the annual CONE?

A. Yes. The proposal includes provisions to mitigate, but not completely eliminate, the potential for annual auction revenue charges to exceed CONE on a per Megawatt-Year basis. An ex-post adjustment will set reduced Auction Clearing Prices when more than one Season clears in ZRC Shortage Conditions or ZRC Near-Shortage Conditions. The final Auction Clearing Price will be set based on annual CONE and the number days in all applicable Seasons when an LRZ, group of LRZs, or the MISO footprint clear with less than the required number of ZRCs or the Season's initial Auction Clearing Price clears above daily CONE in a Planning Resource Auction.

Q. Given the mitigation described above, could annual auction revenue charges exceed CONE on a per Megawatt-Year basis?

A. Yes, whenever the Planning Resource Auction clears at least one Season, but fewer than all Seasons with Auction Clearing Prices above the daily value of

CONE, it is possible that the Planning Resource Auction charges for all four Seasons could exceed annual CONE on a per Megawatt-Year basis. For example, when one Season clears at CONE due to shortage and the other three Seasons clear less than the daily CONE value. In this situation, MISO will not adjust any of the Auction Clearing Prices and any revenues collected in the non-shortage Seasons would increase the annual auction charge amounts beyond annual CONE which is being fully collected in the one Season which has a shortage. For example, if Summer clears in shortage conditions at CONE divided by 92 days ($1,001 MW-day) and then Fall at $20/MW-day, Winter at $25/MW-day, and Spring at $15/MW-day the total annual auction revenue charges would equal $97,575 per MW for the Planning Year, 6% above the CONE value for the Local Resource Zone of $92,100/MW-year.

Q. Are the mitigation provisions sufficient to minimize annual charges above CONE?

A. Yes. While the proposed offer caps and Auction Clearing Price adjustments could result in annual charges exceeding CONE, the likelihood should be infrequent and minimized. Historically, the Planning Resource Auction, has only cleared above the default economic withholding threshold two times: the first was during the 2016-2017 PRA where Zones 2-7 cleared at $72/MW-day (the economic threshold was approximately $26/MW-day); the second was during the 2020-2021 PRA when Zone 7 cleared in shortage at CONE. Even during the 2015-2016 Planning Resource Auction, when the ACP in LRZ 4 cleared at $150/MW-day, the economic withholding threshold was $180/MW-day. MISO is

not proposing further mitigation so as to prevent shortage price suppression which could exacerbate potential revenue sufficiency issues. Existing ZRC Offer mitigation measures will be retained, including the threshold for economic withholding which remains set at 10% of CONE (approximately $25/MW-day) above a default reference level of $0. Market Participants desiring to offer above the economic withholding threshold will need to request and obtain facility or technology specific reference levels in consultation with the IMM that consider relevant costs per section 64.1.4 of Module D. Such Reference Levels have historically accounted for a small fraction of ZRC Offers in the annual Planning Resource Auctions.

Q. How could the Auction Clearing Price adjustments result in revenue sufficiency issues for Market Participants that clear ZRCs in Seasons where adjustments occur?

A. Market Participants that obtain facility-specific Reference Levels or are otherwise not subject to the economic withholding provisions of Module D, for example Demand Response, may submit ZRC Offers for individual Seasons up to a cap which will be set at annual CONE divided by the number of days in the Season, approximately $1,000/MW-day. When an LRZ clears with two or more Seasons in shortage or near shortage conditions, the final ACPs for those Seasons are reduced below the marginal offer (or CONE when short) that was used to clear the auction. As a result, cleared ZRC Offers would exceed the final ACPs. Assuming the cleared ZRC Offers reflect the actual costs associated with the Planning Resource, Market Participants may not recover their costs. This would

necessitate a payment or credit to ensure the Resource recovers its costs, but no more, to incentivize it to meet its capacity commitment in all Seasons in which it cleared.

Q. How is MISO proposing to formulate make-whole provisions?

A. In concept, make-whole payments compare market revenues to costs and provide credits to the extent costs exceed revenues. In energy markets, costs are computed based upon resource offers, assuming they reflect the costs of producing energy. ZRC Offers may not reflect the actual costs of providing capacity if a Planning Resource clears in multiple Seasons but its annual costs are compressed into each season's ZRC Offer to ensure recovery if the Resource only clears in a single Season. To account for this, MISO proposes a make-whole provision, defined as the ZRC Offer Revenue Sufficiency Credit, that considers a Resource's revenues from all cleared Seasons and credits a Resource if needed to meet the minimum of the following amounts: (i) the sum of cleared ZRC Offer price segments multiplied by the cleared ZRC Offer Volumes multiplied by the number of days in the Season; (ii) annual CONE; or (iii) the applicable reference level costs for resources that obtained technology or facility-specific Reference Levels for cleared Seasons. This formulation will prevent the ZRC Offer Revenue Sufficiency Credit from contributing to over-recovery of costs.

Q. Who will pay for ZRC Offer Revenue Sufficiency Guarantee Credits and how will they be distributed?

A. Charges to fund ZRC Offer Revenue Sufficiency Guarantee Credits will be distributed to Market Participants representing LSEs in the LRZs experiencing

shortage or near shortage conditions *pro rata*, based on their respective LSEs' share of PRMR minus the PRMR associated with the Capacity Deficiency Charge within the LRZs during the Seasons where ACPs were reduced. The allocation is similar to the allocation of the Zonal Deliverability Benefit which occurs when an LRZs ACP separates from the systemwide ACP due to limited import or export capability, which will occur whenever LRZs experience shortage or near shortage conditions.

Q. Should ZRC Offer Revenue Sufficiency Guarantee Credits occur frequently?

A. MISO expects that payment of ZRC Offer Revenue Sufficiency Guarantee Credits will be infrequent due to the conditions necessitating the payments that include: (i) LRZs, a group of LRZs, or a Sub-Regional Resource Zone must clear in shortage or near shortage conditions in more than one Season; (ii) ZRC Offers must exceed the final ACP for the applicable LRZs and Seasons; (iii) in order for ZRC Offers to exceed the economic withholding threshold, they must obtain facility-specific reference levels or be excluded from the economic withholding provisions of Module D; and (iv) the Planning Resource's actual costs associated with its ZRC Offer must exceed auction revenue credits for the Seasons cleared. As noted above, in past PRAs very low volumes of ZRCs have offered above the economic withholding threshold and the PRA has only cleared above the economic withholding threshold twice since the PRA began in 2013.

VI. <u>OUTAGE COORDINATION</u>

Q. What are the current RAN Phase 1 exemption rules for Generator Planned Outages?

A. Under the current RAN Phase 1 generator outage exemption rules, exemptions will be provided if one of the following conditions are met:
(1) The Generator Owner or Generator Operator schedules its first Generator Planned Outage 120 days or more in advance of the outage start date and 120 days or more beyond the end date of any previously scheduled outages for the unit; (2) Subsequent generator unit outage requests 120 days or more in advance and Generator Owners or Generator Operators Generator Planned Outage less than 120 days in advance and at least 14 days in advance of outage start date. Proposed Generator Planned Outage to occur entirely during a period that the subregion containing the generator unit has an adequate projected margin, at the time the outage is provided to the Transmission Provider. There is adequate margin when the Maintenance Margin is greater than or equal to zero megawatts after subtracting the megawatts of the requested Proposed Generator Planned Outage. The request shall be determined based on highest queued request; or (3) Generator Owner or Generator Operator reschedules its Generator Planned Outage at the Transmission Provider's request, including outages submitted less than 14 days in advance of the start date.

Q. What is MISO's proposal for exemption of Generator Planned Outages?

A. MISO worked with stakeholders to develop an exemption process that integrates with the tiered accreditation calculations in Schedule 53. The three levels are: Full exemption for Generator Planned Outages (from Tier 1 and Tier 2 SAC calculations in Schedule 53), partial exemption (only exempt in Tier 1 SAC calculations), and no exemption. The following chart illustrates the proposed

exemption requirements, please note that Maintenance Margin is currently calculated and posted for MISO's north, central, and south sub-regions separately:

Generator Outage Submission Criteria	**Maintenance Margin >=0 for duration of outage**	**Maintenance Margin <0 for any day in the duration of outage**
>120 days prior to outage start date, and >120 days from end of previous outage for unit	Exempt Tier 1 & 2	Exempt Tier 1 Only
>120 days Prior to Outage Start date and <120 days from end of Previous outage for unit or Outage submitted between 31-119 days Prior to outage start date	Exempt Tier 1 Only	No Exemption
14-30 days prior to outage start date and passes No Harm Test	Exempt Tier 1 Only	No Exemption
Outage moved per MISO request	Exempt Tier 1 & 2 (Weather, forced outages, other conditions in BPM-008)	Exempt Tier 1 & 2 (Weather, forced outages, other conditions in BPM-008) at Transmission Provider's discretion

A more detailed description of how to procure Generator Planned Outage Exemptions are provided in proposed Schedule 53.

Q. What is the No Harm Test?

A. No harm tests will include, but will not be limited to outage approval, compliance with all applicable operation guides, review of possible conflicting outages or system conditions, and forecasts of system capacity (Maintenance Margin, Multiday Operational Margin, 30-day margin). It will also include criteria outlined in the Business Practices Manual for Outage Coordination, specifically: the ability to maintain voltage required by nuclear generation resources, or to

meet any other nuclear plant interface requirements; the ability to maintain the Transmission System within system operating limits using normal (non-emergency) operating procedures or restore the Transmission System to normal operating conditions following a single contingency with the use of normal (non-emergency) operating procedures; or does not have the potential for credible contingencies to significantly affect Transmission System reliability of metropolitan areas.

Q. How will MISO treat planned outages that were submitted before this proposal goes into effect?

A. MISO proposes a transition with a bright line distinction based on whether a planned outage is scheduled to start prior to September 1, 2022. Planned outages submitted since spring 2019 are coded as exempt or not in the Control Room Operations Window ("CROW") under RAN Phase 1. Where coded exempt, those resources will be treated as fully exempt for Tier 1 & 2 in the calculations proscribed in Schedule 53 even though they may not have met both of the primary requirements of (1) being submitted 120 days or greater in advance and (2) leaving positive Maintenance Margin in the subregion for the duration of the outage. MISO believes this approach is appropriate as it has been highlighting the risks to capacity sufficiency from correlated planned outages since September 2017 and ongoing efforts to encourage sufficient outage coordination and improve tools and processes have greatly reduced the frequency of MaxGens declared in Spring and Fall since RAN Phase 1 went into effect.

Q. Describe MISO's authority related to coordination of generator outages.

A. Under the Tariff (section 38.1.1.e titled "Scope of Services") MISO is required to "Coordinate maintenance schedules for Generation Resources and approve, coordinate, and reschedule as necessary Planned Transmission Outages operated within the Transmission Provider Region." MISO does not have the authority to deny generation outages, but the existing tariff does allow MISO's accreditation of Planning Resources to be reduced based on insufficient coordination of Generator Planned Outages.

Q. What changes are being proposed to MISO's generation outage exemption rules under the proposal?

A. Given the strong correlation between high outage levels and MaxGens, modifications to MISO's outage coordination processes and procedures will be implemented to enhance the determination of SAC for Resources subject to Schedule 53.

Q. What changes are being proposed to the rules governing the exemption of Generator Planned Outages for accreditation purposes?

A. Outage exemptions will usually be given at the time of outage submittal review or in response to a CROW ticket change request. The purpose of the exemption is to ensure that a Resource's accreditation is not negatively impacted by unavailability associated with a sufficiently coordinated outage. Exemptions are granted based outage lead time criteria and adequate Maintenance Margin as outlined above. A generation outage ticket submitted into CROW will be reviewed to determine if such outage is exempt from accreditation impacts under Schedule 53. Outage approvals and exemptions have separate purposes and criteria but bridge the gap

between the planning and operational horizons. As is the case today, approvals will be based on reliability analysis in the Outage Coordination process. The outage will receive exemption from the SAC calculation if it meets the criteria outlined above. It should be noted that the exemption status of an outage does not impact whether it is "approved" in the Outage Coordination processes. Outage exemptions will usually be given at the time of outage submittal review or in response to a CROW ticket change request. The purpose of the exemption is to ensure that resources are not penalized for unavailability for a sufficiently coordinated outage. The criteria for exemptions are outage lead time and adequate Maintenance Margin.

VII. MARKET MONITORING AND MITIGATION

Q. Will MISO's current market monitoring and mitigation provisions be modified to address market power concerns in the new seasonal construct?

A. Yes, current market monitoring and mitigation provisions have been modified in the submitted tariff redlines and substantive enhancements regarding physical and economic withholding are discussed below.

Q. Please describe how physical withholding of Zonal Resource Credit offers into the PRA will be affected.

A. The move to seasonal auctions calls for minor modifications that ensure these same protections continue to work going forward. Primarily, it is the exclusions from auction participation in Section 64.1.1.g of Module D that need to be adapted for a seasonal approach. In one more substantive change in that section, MISO proposes removing the preclusion from participation for a resource that

expects to be on outage for greater than 90 of the first 120 days of the Planning Year and replacing that with a provision that says an Market Participant with a resource that has submitted an outage for greater than 31 days of a Season can ask the IMM for a determination ahead of the auction allowing it to forego offering excess ZRCs from the resource without being deemed to have engaged in Physical Withholding.

Q. Please explain about how Economic Withholding will be affected.

A. MISO is not proposing to change the initial reference level, economic withholding threshold. The initial reference level remains at $0 and the economic withholding threshold is 10% of CONE above $0, which currently would make ~$25/MW-day the effective offer cap unless an MP gets a facility-specific Reference Level or uses Default Technology Specific Avoidable Costs at which point it becomes the economic withholding threshold for the resource. It is expected that more resources will request facility-specific Reference Levels or use Default Technology Specific Avoidable Costs to help ensure they can cover their costs when they might only clear for one Season instead of the full Planning Year under the current construct.

Q. Do you believe the proposed enhancements are just and reasonable changes to the MISO Tariff?

A. Yes. For the reasons set forth above and in the supporting testimonies of Messrs. Wright and Smith, the proposal set forth in this filing is both just and reasonable and is needed now to help ensure the continued reliability of the MISO Region through enhancements to MISO's Resource Adequacy construct. For this reason,

MISO urges the Commission to accept the proposed Tariff enhancements to be effective for the 2023 – 2024 PRA.

Q. Does this conclude your testimony?

A. Yes.

Affidavit of Shawn McFarlane

COUNTY OF HAMILTON)
)
STATE OF INDIANA)

Shawn McFarlane, being duly sworn, deposes and states that he prepared the Prepared Direct Testimony of Shawn McFarlane, and the statements contained therein are true and correct to the best of his knowledge and belief.

/s/ Shawn McFarlane

Shawn McFarlane

SUBSCRIBED AND SWORN BEFORE ME, this 30th day of November, 2021.

My Commission Expires:

My County of Residence:

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-26-16

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 79

MISO 2022 Accreditation Order

180 FERC ¶ 61,141
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Richard Glick, Chairman;
James P. Danly, Allison Clements,
Mark C. Christie, and Willie L. Phillips.

Midcontinent Independent System Operator, Inc. Docket Nos. ER22-495-000
ER22-495-001

ORDER ACCEPTING PROPOSED TARIFF REVISIONS SUBJECT TO CONDITION

(Issued August 31, 2022)

1. On November 30, 2021, as amended on April 8, 2022,[1] pursuant to section 205 of the Federal Power Act (FPA),[2] Midcontinent Independent System Operator, Inc. (MISO) submitted proposed revisions to MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff) to establish a seasonal resource adequacy construct. As discussed below, we accept MISO's proposed Tariff revisions, effective September 1, 2022, subject to condition.

I. Background

2. MISO's currently effective resource adequacy construct, primarily located in Module E-1 of its Tariff, requires that MISO establish annually a system-wide Planning Reserve Margin, which the Tariff defines as the percentage of Planning Resources[3] above the system's forecasted Coincident Peak Demand required to meet the Loss of Load Expectation (LOLE).[4] The Tariff requires that the Planning Reserve Margin be based on

[1] MISO's April 8, 2022 amendment was a response to a Commission staff deficiency letter.

[2] 16 U.S.C. § 824d.

[3] A Planning Resource is a Capacity Resource, Energy Efficiency Resource, or Load Modifying Resource that can be used to satisfy resource adequacy requirements. MISO, FERC Electric Tariff, Module A, § 1.P (65.0.0).

[4] MISO, FERC Electric Tariff, Module A, § 1.P (65.0.0). MISO's Planning Year begins on June 1 and ends on May 31 of the following year. *Id.*

an LOLE study, which assumes an LOLE of one day in 10 years (0.1 day per year).[5] MISO then calculates the Planning Reserve Margin Requirement (Reserve Requirement) for each Load Serving Entity (LSE) based on the LSE's Coincident Peak Demand and MISO's system-wide Planning Reserve Margin.[6]

3. LSEs must demonstrate that they satisfy their respective Reserve Requirements for each Planning Year. An LSE can satisfy its Reserve Requirement in any of the following four ways: (1) purchase Zonal Resource Credits (ZRC) through the Planning Reserve Auction (Auction) process; (2) submit a Fixed Resource Adequacy Plan (FRAP) to demonstrate that it has designated ZRCs to meet all or a portion of its Reserve Requirement; (3) self-schedule ZRCs and bid them into the Auction at a price of zero; and/or (4) pay the Capacity Deficiency Charge.[7]

4. MISO conducts the Auction annually in the first 10 business days of April and posts the results approximately six weeks prior to the Planning Year, which begins on June 1 and ends on May 31 of the following year.[8] The Auction uses a fixed reliability target, represented by a vertical demand curve, to indicate the total amount of ZRCs each Local Resource Zone (Zone) needs to satisfy the Reserve Requirements for each LSE located in that Zone. The Auction selects the least-cost set of Planning Resources needed to meet each Zone's total required Reserve Requirement, while respecting local and sub-regional constraints, and establishes the Auction Clearing Price for each Zone for the upcoming Planning Year.[9]

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[5] *Id.*, Module E-1, § 68A.2.1 (32.0.0). The LOLE study also assumes that there are no internal transmission limitations within MISO. *Id.*

[6] MISO, FERC Electric Tariff, Module E-1, § 68A.7 (32.0.0). If a state regulatory authority establishes an alternate Planning Reserve Margin, MISO will use the alternate Planning Reserve Margin for the geographic area under that state's jurisdiction. *Id.*

[7] *Id.* § 69A (35.0.0). The Capacity Deficiency Charge is equal to the Cost of New Entry (CONE) in the Zone where the LSE is deficient ZRCs, multiplied by 2.478, for each ZRC. *Id.*, Module E-1, § 69A.10 (31.0.0).

[8] *Id.*, Module A, § 1.P (65.0.0); Module E-1, § 69A.7 (35.0.0).

[9] *Id.*, Module E-1, § 69A.7.1 (46.0.0).

5. Planning Resources are eligible to convert Unforced Capacity (UCAP)[10] to ZRCs, which indicate the units of capacity (in MW) a given market participant can offer into the Auction, sell bilaterally, or submit through a FRAP.[11] MISO currently determines the UCAP value of Planning Resources based on resource type. For example, MISO will determine the UCAP for a Generation Resource based on an evaluation of the type and volume of interconnection service, Generator Verification Test Capacity (GVTC)[12] value, and forced outage rating of such Generation Resource.[13] MISO determines the UCAP for a Dispatchable Intermittent Resource or Intermittent Generation based on historical performance, availability, and type and volume of interconnection service, in accordance with MISO's Business Practices Manual (BPM) for Resource Adequacy.[14]

II. Filing

6. MISO states that generation resource retirements, increased reliance on intermittent resources, significant weather events with correlated generator outages, and declining excess reserve margins will profoundly impact future grid reliability, and that all industry participants have a shared responsibility to plan for these impacts and implement new policies and practices to ensure the continued reliability of the grid. MISO states that, as part of this responsibility, MISO must make substantive changes to its resource adequacy construct to address these emerging issues.[15]

7. MISO states that its current resource adequacy construct, which focuses on the procurement of capacity for an entire 12-month Planning Year to meet demand during one peak day of the Summer Season, was not designed to address the trends currently facing the MISO Region.[16] MISO explains that reliability risks associated with resource

[10] UCAP is the amount of Capacity in megawatt (MW) assigned to a Planning Resource after accounting for its forced outage rate or historical availability. *Id.*, Module A, § 1.U (36.0.0).

[11] *Id.* § 1.Z (38.0.0).

[12] GVTC is the maximum output, in MW, that a Generation Resource, External Resource, or Behind-the-Meter-Generation (BTMG) can sustain over the specified period of time. *Id.* § 1.G (41.0.0).

[13] *Id.*, Module E-1, § 69A.4.1 (36.0.0).

[14] *Id.*

[15] Transmittal at 2-3.

[16] *Id.* at 3. The months included in the Summer Season are June, July, and August.

adequacy have shifted from "Summer only" to a year-round concern, noting that, since 2016, MISO has declared 40 Maximum Generation Emergencies[17] (MaxGen Events), with more than 60% occurring outside of the Summer months. MISO states that the significant increase in MaxGen Events is being driven by the confluence of: the retirement of traditional, baseload generation resources; planned and forced generator outages in non-Summer months; an increased reliance on intermittent generation such as wind and solar; and extreme weather events resulting in numerous forced generator outages, including multiple polar vortex and Arctic storms.[18]

8. MISO argues that the causes of the increase in MaxGen Events cannot be addressed through "one-off, quick fixes" but rather require a robust solution that creates incentives for Capacity Resources[19] to be available when and where they are needed, as the existence of Capacity Resources is meaningless if those resources do not provide energy or reserves when needed.[20] MISO contends that a well-designed market construct includes both the planning horizon, which entails the identification and incorporation of risks across the planning year in developing resource adequacy requirements, and the operating horizon, which ensures that those resources have the incentive to provide energy and reserves when and where needed. MISO states that aligning the planning horizon with the operating horizon is a central goal of the proposed reforms in the instant filing.[21]

9. MISO states that its resource adequacy reform proposals focus on two related proposals: (1) the establishment of a seasonal resource adequacy construct coupled with availability-based accreditation for certain Planning Resources, and (2) a Minimum Capacity Obligation (MCO) that promotes securing capacity well in advance of the

[17] MISO, FERC Electric Tariff, Module A § 1.M (71.0.0).

[18] Transmittal at 3-4.

[19] Capacity Resources are the Generation Resources, Demand Response Resource-Type I, Demand Response Resource-Type II, Dispatchable Intermittent Resources, External Resources, Intermittent Generation, Stored Energy Resources – Type II, or Electric Storage Resources that are available to meet Demand. MISO, FERC Electric Tariff, Module A § 1.C (67.0.0).

[20] Transmittal at 4.

[21] *Id.*

Auction.[22] MISO states that the instant filing presents MISO's seasonal and accreditation proposal.

10. MISO states that it expects the shift to a seasonal construct will further mitigate resource adequacy risks throughout the year, not just in the peak Summer Season, by establishing more granular, seasonal resource adequacy requirements to help ensure sufficient Planning Resources are committed and obligated to be available when needed. MISO expects this transition to: (1) identify reliability needs unique to each Season; (2) align Planning Resource availability with seasonal needs; and (3) facilitate and better account for seasonal outages or partial year operations.[23]

11. MISO states that its accreditation reforms seek to ensure that resources are available when needed the most by aligning resource accreditation with availability during the highest risk period in each Season. MISO proposes a new Seasonal Accredited Capacity (SAC) methodology to determine the capacity accreditation of certain classes of resources. MISO states that it also proposes a tiered weighting structure, with a transition period, to determine individual resource accreditation by Season based on each resource's Real-Time offered availability, accounting for coordinated planned outages. MISO explains that expected outcomes of MISO's accreditation reforms are to: (1) increase confidence in the capacity MISO can count upon when needed by shrinking the gap between cleared capacity within the Auction and realized capacity during tight system conditions; (2) provide improved signals for availability and coordination; and (3) improve resource outage coordination processes. MISO states that measuring and accrediting Planning Resources based on their availability and performance during Resource Adequacy Hours (RA Hours) will better align expectations during times of highest need. MISO argues that the current practice of relying on installed capacity, adjusted for forced outages and reflecting average availability throughout the Planning Year, no longer provides an accurate expectation of availability, as proven by recent emergency events, especially those driven by extreme weather.[24]

12. To address these trends, MISO proposes to: (1) replace its single annual resource adequacy requirement with four seasonal resource adequacy requirements; (2) implement seasonal, availability-based accreditation called SAC for thermal resources and modify

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[22] *Id.* Concurrently with this filing, MISO submitted, in Docket No. ER22-496-000, a proposal to establish an MCO on LSEs. Concurrently with this order, the Commission rejects MISO's MCO Filing. *Midcontinent Indep. Sys. Operator, Inc.*, 180 FERC ¶ 61,142 (2022).

[23] Transmittal at 4-5.

[24] *Id.* at 5.

non-thermal resource accreditation to align with MISO's proposed seasonal resource adequacy construct; and (3) modify MISO's outage procedures and establish new requirements for resources to replace capacity during outages under certain conditions. MISO requests an effective date of September 1, 2022 for its proposed Tariff revisions.[25]

III. Notice of Filing and Responsive Pleadings

13. Notice of the filing was published in the *Federal Register*, 86 Fed. Reg. 69,024 (Dec. 6, 2021), with interventions and protests due on or before December 21, 2021. On December 3, 2021, Entergy Services, LLC (Entergy), acting on behalf of the Entergy Operating Companies[26] and the Supporting Parties,[27] filed a motion for an extension of the comment date, from December 21, 2021, to January 14, 2022. On December 9, 2021, the Commission granted Entergy's motion for an extension of the comment date to January 14, 2022.

14. Notices of intervention were filed by: the Mississippi Public Service Commission and Mississippi Public Utilities Staff (Mississippi Commission); the Missouri Public Service Commission; the Illinois Commerce Commission (Illinois Commission); the Michigan Public Service Commission (Michigan Commission); the City Council of the City of New Orleans; the Public Service Commission of Wisconsin; the Organization of MISO States (OMS); the Arkansas Public Service Commission; the Louisiana Public Service Commission (Louisiana Commission); the Public Utility Commission of Texas;

[25] *Id.* at 52.

[26] The Entergy Operating Companies are: Entergy Arkansas, LLC; Entergy Louisiana, LLC; Entergy Mississippi, LLC (Entergy Mississippi); Entergy New Orleans, LLC; and Entergy Texas, Inc.

[27] The Supporting Parties are: Alliant Energy Corporate Services, Inc.; Ameren Services Company (Ameren), as agent for Union Electric Company, Ameren Illinois Company (Ameren Illinois) and Ameren Transmission Company of Illinois (Ameren Transmission); American Municipal Power, Inc. (AMP); Cleco Power LLC (Cleco Power); Consumers Energy Company (Consumers Energy); Dairyland Power Cooperative; DTE Electric Company (DTE Electric); Duke Energy Business Services, LLC for Duke Energy Indiana, LLC; EDF Renewables; Hoosier Energy Rural Electric Cooperative, Inc. (Hoosier); Illinois Municipal Electric Agency (IMEA); Indiana Municipal Power Agency; Indianapolis Power & Light Company (IPL); Madison Gas & Electric Company; Midland Cogeneration Venture; Minnesota Power; Northern Indiana Public Service Company; Otter Tail Power Company; Prairie Power Inc.; Rockland Capital; Southern Illinois Power Cooperative; Vistra; Wabash Valley Power Alliance; and WEC Energy Group.

the Indiana Utility Regulatory Commission (Indiana Commission); and the Kentucky Public Service Commission.

15. Timely motions to intervene were filed by: Cooperative Energy; NRG Power Marketing LLC; AMP; Energy Michigan, Inc. (Energy Michigan); Alliant Energy Corporate Services (Alliant); Wabash Valley Power Association, Inc.; Indiana Municipal Power Agency; Hoosier; Exelon Generation Company, LLC (Exelon); Solar Energy Industries Association (SEIA); American Clean Power Association (ACP) and Clean Grid Alliance (CGA); Fresh Energy; the Sustainable FERC Project and Natural Resources Defense Council (Sustainable FERC Project and NRDC); Duke Energy Corporation (Duke Energy); IPL; Calpine Corporation; Ameren; NextEra Energy Resources, LLC; Entergy; MidAmerican Energy Company (MidAmerican); Great River Energy; IMEA; Xcel Energy Services Inc.; Indiana Office of Consumer Counselor; Illinois Industrial Energy Consumers (IIEC); Association of Businesses Advocating Tariff Equity (ABATE); Indiana Industrial Group (IIG); the Louisiana Energy Users Group (LEUG); Texas Industrial Energy Consumers (TIEC); the Coalition of MISO Transmission Customers (CMTC); Southwest Louisiana Electric Membership Corporation and Concordia Electric Cooperative, Inc.; Arkansas Electric Cooperative Corporation (AECC); EDF Trading North America, LLC and EDF Energy Services, LLC; and East Texas Electric Cooperative (East Texas).

16. Additional timely motions to intervene were filed by: the MISO Transmission Owners;[28] Wisconsin Electric Power Company, Wisconsin Public Service Corporation and Upper Michigan Energy Resources Corporation (collectively, WEC Utilities); DTE Electric; Coalition of Midwest Power Producers, Inc. (COMPP); Sierra Club; Consumers

[28] The MISO Transmission Owners for this filing consist of: Ameren, Ameren Illinois, and Ameren Transmission; Big Rivers Electric Corporation (Big Rivers); Central Minnesota Municipal Power Agency; City Water, Light & Power (Springfield, IL); Cleco Power; Cooperative Energy; Dairyland Power Cooperative; Duke Energy Business Services, LLC for Duke Energy Indiana, LLC; East Texas; Entergy Arkansas, LLC; Entergy Louisiana, LLC; Entergy Mississippi; Entergy New Orleans, LLC; Entergy Texas, Inc.; Hoosier Energy Rural Electric Cooperative, Inc.; Indiana Municipal Power Agency; Indianapolis Power & Light Company; Lafayette Utilities System; Minnesota Power (and its subsidiary Superior Water, L&P) (Minnesota Power); Missouri River Energy Services; Montana Dakota Utilities Co.; Northern Indiana Public Service Company LLC; Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation, subsidiaries of Xcel Energy Inc.; Northwestern Wisconsin Electric Company; Otter Tail Power Company; Prairie Power, Inc.; Southern Illinois Power Cooperative; Southern Indiana Gas & Electric Company; Southern Minnesota Municipal Power Agency; Wabash Valley Power Association, Inc.; and Wolverine Power Supply Cooperative, Inc.

Energy; Great Lakes Utilities, Madison Gas and Electric Company, Midwest Municipal Transmission Group, Missouri Joint Municipal Electric Utility Commission, Missouri River Energy Services, Southern Minnesota Municipal Power Agency, Southwest Louisiana Electric Membership Corporation, and WPPI Energy (collectively, Midwest TDU); American Electric Power Service Corporation; Retail Energy Supply Association (RESA); Southern Illinois Power Cooperative (SIPC); Cleco Corporate Holdings LLC; Cleco Cajun LLC; COMPP; Big Rivers; Steel Producers; GridLab; International Transmission Company, Michigan Electric Transmission Company, LLC, and ITC Midwest LLC (collectively, ITC); and Manitoba Hydro.

17. On January 18, 2022, Potomac Economics, Ltd. (Potomac Economics), which is the MISO Independent Market Monitor (Market Monitor), filed a motion to intervene out-of-time.

18. Protests were filed by: the Louisiana Commission; the Mississippi Commission; Alliant; Consumers Energy; Entergy, AECC, and Cleco Power (collectively, Entergy Coalition); Steel Producers; Midwest TDUs; DTE Electric; Ameren; IIEC, ABATE, IIG, LEUG, TIEC, and CMTC (collectively, Industrial Customers); ITC; COMPP; IPL; and East Texas. Comments were filed by: MidAmerican; the Indiana Commission; the Michigan Commission; OMS; Duke Energy; Manitoba Hydro; Entergy; Great River Energy; WEC Utilities; the MISO Transmission Owners; Big Rivers, Hoosier, and SIPC (collectively, Joint Commenters); CGA, Sierra Club, Sustainable FERC Project, and NRDC, Fresh Energy, GridLab, ACP, and SEIA (collectively, Clean Energy Coalition); Minnesota Power; and Potomac Economics.

19. On February 10, 2022, MISO filed a motion for leave to answer and answer to comments and protests (MISO February 10 Answer). Motions for leave to answer and answers to the MISO February 10 Answer were filed by: Alliant; the Mississippi Commission; Midwest TDUs (Midwest TDUs February 25 Answer); WEC Utilities; Entergy; and Industrial Customers.

IV. Deficiency Letter and Deficiency Letter Response

20. On March 9, 2022, Commission staff issued a deficiency letter and requested additional information. On April 8, 2022, MISO filed a response to the deficiency letter (Deficiency Letter Response).

V. Notice of Deficiency Letter Response and Responsive Pleadings

21. Notice of MISO's Deficiency Letter Response was published in the *Federal Register*, 87 Fed. Reg. 22,529 (Apr. 15, 2022), with interventions and protests due on or before April 29, 2022. Timely comments were filed by: Alliant; Consumers Energy; Minnesota Power; Entergy; Clean Energy Coalition; Duke Energy; and Potomac

Economics. Timely protests were filed by: DTE Electric; Industrial Customers; and Midwest TDUs. On May 4, 2022, the Mississippi Commission filed a late protest.

22. On May 20, 2022, MISO filed a motion for leave to answer and answer to the comments and protests of its Deficiency Response (MISO May 20 Answer). On June 6, 2022, Midwest TDUs filed a motion for leave to respond and response to the MISO May 20 Answer (Midwest TDUs June 6 Answer).

VI. Discussion

A. Procedural Matters

23. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2021), the notices of intervention and timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding.

24. Pursuant to Rule 214(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214(d), we grant Potomac Economics' late-filed motion to intervene, given its interest in the proceeding, the early stage of the proceeding, and the absence of undue prejudice or delay. In addition, we will accept the late-filed protest of the Mississippi Commission, as this will not unduly delay the proceeding or cause undue prejudice to any party.

25. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2021), prohibits an answer to a protest or answer unless otherwise ordered by the decisional authority. We accept the answers because they have provided information that assisted us in our decision-making process.

B. Substantive Matters

26. As discussed below, we find MISO's proposal to be just, reasonable, and not unduly discriminatory or preferential. Accordingly, we accept MISO's proposed Tariff revisions, effective September 1, 2022, as requested, subject to condition.[29] Below, we address MISO's proposal to: (1) implement a seasonal resource adequacy construct; (2) accredit certain resources using the SAC methodology; and (3) require replacement of any Planning Resource that will be on planned outage or planned derate for more than 31 days in a Season which they are designated for Resource Adequacy Requirements. We

[29] The United States Court of Appeals for the District of Columbia Circuit has held that, in certain circumstances, the Commission has "authority to propose modifications to a utility's [FPA section 205] proposal *if the utility consents to the modifications*." *NRG Power Mktg., LLC v. FERC*, 862 F.3d 108, 114-15 (D.C. Cir. 2017).

also address concerns regarding MISO's stakeholder process, as well as other comments raised in the pleadings.

1. Seasonal Resource Adequacy Construct

a. MISO Filing

27. MISO states that, under the proposed seasonal resource adequacy construct, MISO will perform an LOLE evaluation to establish Reserve Requirements for all Market Participants representing LSEs and Local Clearing Requirements for all Zones on a seasonal basis for four Seasons: Summer; Fall; Winter; and Spring. MISO further states that it will then conduct the Auction and establish an Auction Clearing Price for each Zone for each Season. MISO explains that it will continue to conduct the Auction annually, in the Spring preceding the applicable Planning Year, but the Auction will clear the requirements separately for each Season.[30]

28. MISO states that shifting to a seasonal resource adequacy construct is designed to ensure that resources with needed capabilities and attributes will be available during the highest risk periods across the Planning Year. MISO explains that the current resource adequacy construct is based on the Summer Coincident Peak Demand forecasts, and, as a result, actual needs outside the Summer Season are not explicitly determined and defined, leaving potential risks unmitigated.[31] MISO contends that moving to a seasonal resource adequacy construct will align seasonal resource accreditation with seasonal resource availability to meet MISO's changing risk.[32]

29. MISO proposes to develop seasonal values for several construct parameters, including: (1) LOLE sub-annual modeling; (2) Planning Reserve Margin and Reserve Requirements; (3) Local Reliability Requirements and Local Clearing Requirements; and (4) Capacity Import Limits and Capacity Export Limits.[33]

30. MISO proposes changes to the modeling and methodology of the LOLE study to more accurately model seasonally sensitive variables and calculate resource adequacy construct parameters through: (1) seasonal LOLE risk allocation; and (2) improving seasonal LOLE modeling, including the modeling of planned outages, modeling of non-firm external imports, and hourly modeling of intermittent resources. MISO submits that

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[30] Transmittal at 10-11.

[31] *Id.* at 11 (citing Tab E (Testimony of Scott Wright), at 13 (Wright Test.)).

[32] *Id.* (citing Tab D (Testimony of Jameson Smith, at 18 (Smith Test.)).

[33] *Id.* at 11-12.

this new LOLE model needs to have a defined LOLE threshold for each Season to calculate seasonal resource adequacy Reserve Requirements, which will be determined under a two-step LOLE analysis. MISO states that, in the first step, the LOLE model will be solved to an annual LOLE value of 0.1 day per year to determine the natural LOLE distribution. MISO explains that, if after the first step there is a minimum of 0.01 day per year LOLE in all four Seasons, then the seasonal requirements will be determined directly from this step and there will be no need for additional analysis. MISO states that, if the first step determines that a Season has an LOLE of less than 0.01 day per year, then an additional step will be performed to solve that Season to an LOLE of 0.01 day per year. MISO states that in the second step, MISO will round LOLE targets up to a minimum of 0.01 day per year for any Season with an LOLE less than 0.01 day per year, and to maintain LOLE targets for Seasons with an LOLE greater than 0.01 day per year.[34]

31. MISO states that, to determine a Planning Reserve Margin for the four Seasons, MISO proposes performing an additional two-step LOLE analysis with seasonal input assumptions. MISO explains that the LOLE model will be used to meet the seasonal LOLE targets, which can differ from the annual LOLE target, by adjusting the capacity within the seasonal model up or down as needed.[35] MISO explains that, once the seasonal LOLE targets are met, the seasonal Planning Reserve Margin values in terms of UCAP will be calculated and expressed as a percentage of seasonal coincident peak demand. MISO states that the Planning Reserve Margin for each Season is multiplied by the 50/50 forecast of coincident peak load to determine the Reserve Requirements (in MW) for that Season.[36]

32. MISO asserts that, to determine zonal Local Reliability Requirements, MISO proposes using the same two-step process as the Planning Reserve Margin analysis with each Zone treated as an isolated system consistent with the existing Local Reliability Requirements analysis methodology under the current annual resource adequacy construct. MISO explains that seasonal Local Reliability Requirements values will be calculated in terms of UCAP and expressed as a percentage of seasonal zonal coincident peak demand once the model has been solved to the appropriate LOLE targets. MISO

[34] *Id.* at 12.

[35] MISO states that if the LOLE is less than the target for a Season, then a "perfect unit" with a negative capacity value and zero forced outage rate will be added to the model. If the LOLE is greater than the target for a Season, then proxy combustion turbine generators of typical size (160 MW) and class average Equivalent Forced Outage Rate Demand (XEFORd) will be added to the model until the seasonal LOLE target is achieved. *See* Transmittal at 12-13; McFarlane Testimony at 11-12.

[36] Transmittal at 12-13.

states that the seasonal Local Reliability Requirements values will be used to determine the seasonal Local Clearing Requirement values by subtracting the seasonal Capacity Import Limited from the seasonal Local Reliability Requirement.[37]

33. MISO proposes to modify its existing determination of Capacity Import Limits and Capacity Export Limits capturing the seasonal variation of transfer limits for each Zone to account for four seasons. MISO explains that Planning Year seasonal peak power flow models and input files developed from MISO Transmission Expansion Plan studies will be used to perform transfer analyses for each Season including Summer Peak, Fall Peak, Winter Peak, and Spring Peak study models. MISO states that the resulting seasonal Zonal Import Ability,[38] in conjunction with controllable exports, will be used to determine the seasonal Local Clearing Requirements for each Zone.[39]

34. MISO contends that the proposed resource adequacy construct more accurately represents resource capabilities at different times during the year, improves certainty of resource availability outside the Summer Season, provides better incentives for resources to be available when needed, establishes seasonal reserve requirements that better align with risks, and delivers additional visibility into risks throughout the Planning Year. According to MISO, these advantages are not currently captured in the annual construct. MISO adds that, in general, resource owners and LSEs benefit from lower non-Summer peak loads, resulting in lower non-Summer Reserve Requirements that reduce the required cleared capacity and allow for seasonal resource operation and related cost savings to loads.[40]

35. MISO states that the Auction will continue to be administered in the spring of each year, and that, in most cases, the process will remain the same but will be applied on a seasonal basis rather than on an annual basis. MISO explains that the Auction offer window will continue to be the last four business days in March. MISO states that the "must offer" requirement for resources that clear the Auction will only apply in the Season or Seasons in which the resource clears. Finally, MISO notes that it will increase

[37] *Id.* at 13.

[38] MISO defines Zonal Import Ability as "[t]he ability of a[] [Zone] to import capacity from areas outside of that [Zone]. MISO, FERC Electric Tariff, Module A § 1.Z (38.0.0).

[39] Transmittal at 13.

[40] *Id.* at 13-14.

the time available to clear the Auction from 10 to 20 business days in order to clear the four Seasonal auctions.[41]

36. MISO proposes to modify its market monitoring and mitigation provisions in Module D of the Tariff. With regard to physical withholding provisions, MISO proposes to remove provisions that prohibit resources that expect to be on outage for more than 90 of the first 120 days of the Planning Year to participate in the Auction and replace that with a provision that states that a Market Participant with a resource that has submitted an outage for more than 31 days of a given Season can ask the Market Monitor for a determination ahead of the Auction allowing it to forego offering excess ZRCs from the resource into the Auction, without being deemed to have engaged in physical withholding. MISO states that the threshold for economic withholding remains at 10% of daily Cost of New Entry (CONE),[42] but MISO expects that more resources will request facility-specific Reference Levels or use Default Technology Specific Avoidable Costs to help ensure they can cover the costs when they might only clear for one Season, rather than the full Planning Year under the current construct.[43] MISO notes that the threshold for economic withholding remains at $0/MW-day when a resource offers at a facility-specific Reference Level.[44]

37. MISO states that, under the proposed seasonal construct, there are rare circumstances that could result in over or underpayment to Planning Resources. MISO's proposal includes an ex-post adjustment to reduce the Auction Clearing Price when more than one Season clears in ZRC Shortage Conditions or ZRC Near-Shortage Conditions.[45] If this occurs, the final Auction Clearing Price will be set based on annual CONE and the

[41] *Id.* at 14.

[42] Cost of New Entry (CONE) is the "capital, operating, financial and other costs of acquiring a new Generation Resource within the Transmission Provider Region for any designated [Zone]." MISO, FERC Electric Tariff, Module A § 1.C (67.0.0).

[43] In MISO, facility-specific Reference Levels may be established for certain Planning Resources if a market participant provides documentation of going-forward costs of keeping a Planning Resource in operation or going-forward costs of returning a Planning Resource from suspension. *See* MISO, FERC Electric Tariff, Module D § 64.1.4(f) (65.0.0).

[44] Transmittal at 21.

[45] ZRC Near-Shortage Conditions occur in a Zone in any Season that has sufficient volume of ZRC Offers to cover that Zone's Reserve Requirements, but the Season's Auction Clearing Price is greater than the daily CONE value. *See* MISO, FERC Electric Tariff, Module A, § 1.Z (40.0.0) (proposed).

number of days in all applicable Seasons when a Zone clears below the required number of ZRCs or the Season's initial Auction Clearing Price clears above daily CONE. MISO explains that, to address this potential risk, MISO proposes enhancements to the offer caps in the seasonal Auctions and will add the ZRC Offer Revenue Sufficiency Guarantee Credit, a make-whole payment provision, to ensure that resources that clear the Auction recover the costs reflected in their seasonal offer, while also ensuring that the LSEs are not exposed to Auction Clearing Prices and capacity charges that amount to multiples of the annual CONE value as a result the proposed seasonal construct.[46] MISO states that charges to fund the ZRC Offer Revenue Sufficiency Guarantee Credit will be allocated to Market Participants representing LSEs in the Zone(s) experiencing shortage or near shortage conditions *pro rata*, based on their respective LSEs' share of the Reserve Requirement within the Zones during the Season or Seasons where the Auction Clearing Prices were reduced.[47]

b. Comments and Protests

38. Some commenters note that MISO's proposal supports resource adequacy throughout the 12-month Planning Year by recognizing that MaxGen Events are occurring more frequently outside of the Summer Season, and by providing for a more granular assessment of risk across the year.[48] OMS states that MISO's proposal builds on previously accepted Tariff provisions and modifies them to fit the proposed seasonal construct.[49] The Indiana Commission states that a more granular assessment of risks across the year will allow MISO to plan and provide for each Season's own unique reliability needs.[50] ITC states that the use of a four-Season construct will allow MISO to anticipate the supply needs of its members and ensure reserves to meet demand during all hours of the year.[51] Manitoba Hydro argues that the proposal will continue to allow and encourage bilateral trade, diversity exchange agreements, and external participation in

[46] Transmittal at 21-22.

[47] *Id.* at 22.

[48] Michigan Commission Comments at 3; OMS Comments at 3-4; Manitoba Hydro Comments at 2; Indiana Commission Comments at 3-5; ITC Comments at 3.

[49] OMS Comments at 4.

[50] Indiana Commission Comments at 4-5.

[51] ITC Comments at 3.

MISO, which it argues reduce overall costs to consumers and enhances overall grid security.[52]

39. Potomac Economics supports MISO's proposal to transition to a seasonal capacity market, and believes it is an improvement over MISO's current market design and rules.[53] Potomac Economics states that moving to a seasonal resource adequacy construct will provide suppliers better incentives to satisfy the unique needs of each Season while also allowing MISO the flexibility to establish market requirements on a seasonal basis and is better aligned with reliability needs.[54]

40. Potomac Economics explains that, compared to an annual construct, resources retiring mid-year would have more flexibility to select a retirement or suspension date without having to procure significant replacement capacity to satisfy post-retirement capacity obligations. Potomac Economics states that, over time, as new resources enter the market with distinct seasonal output patterns, such as intermittent wind and solar, the value of procuring capacity seasonality will rise.[55]

41. While Potomac Economics supports the transition to a seasonal construct, it suggests that conducting four simultaneous auctions unnecessarily increases uncertainty regarding the supply and demand for capacity in any given Season. Potomac Economics contends that sequential, rather than simultaneous, auctions would allow the decisions and offers in the remaining Seasons to be informed by results of the initial Seasons. Potomac Economics submits that this can be highly beneficial for suppliers that are making retirement and/or suspension decisions based on the seasonal capacity auctions they clear. As an example, Potomac Economics states that a resource that clears in the Summer Auction and covers its going-forward costs is likely to be willing to offer at a lower price in the remaining Seasons than in a simultaneous auction where the supplier is uncertain in which Season(s) the resource will clear, if any. Potomac Economics states that likewise, a supplier considering a suspension or seasonal shutdown may make a different decision or offer at the different level in one Season depending on whether the resource cleared in the prior Season.[56]

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[52] *Id.*

[53] Potomac Economics Comments at 2.

[54] *Id.*

[55] *Id.* at 3-4.

[56] *Id.* at 5.

42. East Texas states that it has repeatedly asked MISO to substantiate how the shift from an annual to a seasonal construct, with discrete Reserve Requirements for all LSEs, would enhance resource availability and forestall unnecessary capacity market shortfalls within MISO, and that MISO has failed to provide adequate data to justify its proposal. East Texas alleges that MISO instead attempts to justify its proposal with generalized and nebulous assertions concerning the supposed advantages of a more granular construct in mitigating reliability risks in non-Summer months. East Texas states that, for example, it requested MISO to provide a simulation showing how MISO's seasonal construct proposal would have strengthened MISO's response to Winter Storm Uri in February 2021 or any other non-Summer event in recent years. East Texas further states that it asked MISO to provide cost-benefit analyses illustrating how the seasonal construct's supposed advantages in mitigating reliability risks within the MISO footprint compared to the costs that this new capacity procurement paradigm would inflict on market participants representing LSEs, which MISO failed to do.[57]

43. East Texas alleges that MISO repeatedly invokes the specter of an impending reliability crisis, while asserting that its seasonal construct would address this crisis by mitigating MISO's reliability risks during the non-Summer months. East Texas argues that MISO fails to show why it could not employ more targeted reforms, nor does MISO specify what benefits this policy would garner for MISO market participants and other stakeholders. East Texas asserts that MISO should not be allowed to effect a broad overhaul of its capacity market without marshaling greater evidence of the ostensible benefits and impacts such a critical reform would yield, and, given the claimed benefits of MISO's seasonal construct as speculative and lacking in factual support, that the Commission should reject MISO's filing and instruct MISO to return to the stakeholder process to revise a better substantiated solution to its claimed resource adequacy challenges.[58]

44. Clean Energy Coalition argues that MISO has not explored whether the increased complexity of the proposal is manageable as part of utility planning processes. Clean Energy Coalition argues that, if LSEs cannot effectively plan to meet seasonal capacity requirements along the timeline contemplated, the proposal will result in building higher amounts of capacity than needed.[59]

45. Alliant states that generation investments are long-term decisions that require years of planning and implementation to bring a new resource online, and MISO's proposal does not provide market participants with timely actionable information to allow

[57] East Texas Protest at 4-5.

[58] *Id.* at 5.

[59] Clean Energy Coalition Protest at 17.

generation owners to make informed investment decisions. Alliant asserts that it is now put in the untenable position of potentially making inefficient resource planning decisions in the near-term in order to fall in line with MISO's unsubstantiated and overly conservative Planning Reserve Margins. Alliant submits that delaying the implementation date to no sooner than the 2024/2025 Planning Year will allow capacity resource owners time to reconfigure their resource plans and portfolios and for MISO to provide a reasonable path to obtain seasonal interconnection rights.[60]

46. Several protestors contend that MISO's proposed market structure lacks mitigation to ensure just and reasonable Auction revenues. Clean Energy Coalition and Midwest TDUs contend that there are multiple scenarios in which annual capacity revenues could be expected to exceed the current maximum Auction price of CONE, potentially due to one tight Season, thereby potentially resulting in a resource setting a Season's Auction Clearing Price at four times the current annual Auction's maximum price, and generating greater auction revenue from all four Seasons than is permitted under the current annual Auction.[61] Clean Energy Coalition argues that, even though MISO takes steps to mitigate the likelihood of price spikes in certain Zones for certain Seasons, MISO's proposal goes out of its way to establish the ZRC Offer Revenue Sufficiency Guarantee Credit to protect generation owners from any risk from Auction Clearing Price reductions.[62] Clean Energy Coalition states that, while it makes sense in theory to insulate capacity owners that may be forced to provide capacity while being paid less than they bid into the market, these make-whole payments will come from LSEs and their ratepayers and are defined in part by facility-specific Reference Levels that are calculated independently through a process involving the Market Monitor. Clean Energy Coalition argues that MISO has not provided enough information to justify the make-whole payment process and argues that ongoing tracking and evaluation of the market adjustment make-whole payment system is necessary.[63] Midwest TDUs add that MISO's ex post adjustment to Auction Clearing Prices proposal produces higher auction revenues when there are fewer Seasons in shortage conditions.[64]

47. Midwest TDUs contend that, because MISO has not demonstrated that allowing annual Auction revenues above annual CONE, and potentially more than double annual

[60] Alliant Protest at 7-8.

[61] Clean Energy Coalition Protest at 14; Midwest TDUs Protest at 38-40.

[62] Clean Energy Coalition Protest at 14.

[63] *Id.* at 15.

[64] Midwest TDUs Protest at 41.

CONE, is just and reasonable, the Commission should reject MISO's filing.[65] Midwest TDUs state that the current, Commission-approved cap for annual capacity supply offers in the Auction and the price for shortage conditions all treat annual CONE as the appropriate capacity price signal. Midwest TDUs submit, however, that, under MISO's proposal, if a resource that clears in just one Season sets the price for that Season at MISO's offer cap, other resources that clear in multiple Seasons could recover well above annual CONE. Midwest TDUs add that, if revenues above annual CONE produce over-recovery for individual resources, total Auction revenues above annual CONE would produce over-recovery on a much greater scale.[66]

48. Midwest TDUs suggest that MISO is attempting to minimize the potential for over-recovery by relying on the unlikelihood of such an event occurring, and contend that this is contrary to MISO's stated basis for the present filing, which is to address, among other things, shrinking excess margins. Midwest TDUs argue that, if a shift to a seasonal reliability construct is necessary to ensure adequate capacity, MISO cannot ignore the risk of inadequate capacity in the mitigation component of its proposal.[67]

49. Midwest TDUs argue that MISO claims that existing Tariff provisions to determine facility-specific Reference Levels are sufficient because "[s]uch Reference Levels have historically accounted for a small fraction of ZRC Offers in the annual [Auctions]."[68] Midwest TDUs suggest that this is contradicted by a different MISO statement that MISO "expect[s] that more resources will request facility-specific Reference Levels."[69] Midwest TDUs submit that this means that MISO expects that offers above the economic withholding thresholds will comprise a larger fraction of offers in the seasonal auction, weakening the protection of the initial economic withholding threshold and potentially driving up prices. Midwest TDUs further argue that the availability of make-whole payments that ensure cost-recovery for resources clearing in a single Season may also create incentives for resources to clear in just one Season and be relieved of the must-offer obligation in other Seasons, again potentially driving up prices.[70]

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[65] *Id.* at 44.

[66] *Id.* at 41-42.

[67] *Id.* at 42.

[68] *Id.* at 42-43 (citing McFarlane Test. at 42).

[69] *Id.* at 43 (citing McFarlane Test. at 51).

[70] *Id.* at 42-43.

50. Midwest TDUs claim that the proposed Tariff language does not appear to mitigate auction prices in the way described in the McFarlane Testimony. Midwest TDUs state that, according to the McFarlane Testimony, MISO would adjust auction prices "when more than one Season clears in ZRC Shortage Conditions or ZRC Near-Shortage Conditions."[71] However, Midwest TDUs note that revisions to Tariff section 69.A.7.1.c.x. state that MISO will adjust prices in two situations: (1) in Zones "with Seasons in ZRC Shortage Conditions," and (2) in Zones "with Seasons in ZRC Near-Shortage Conditions."[72] Midwest TDUs contend that this language does not appear to cover Zones with one Season in shortage conditions and one Season in Near-Shortage conditions and thus creates a gap in mitigation that could allow for two Seasons that each have prices producing revenues equal to annual CONE, allowing for total auction revenues that are more than double annual CONE.[73]

51. Alliant, East Texas, and Entergy Coalition raise concerns with MISO's proposed implementation schedule. East Texas points out that, should the Commission accept MISO's proposal within MISO's requested time frame, LSEs would have approximately 15 months before the proposal takes effect in June 2023. East Texas submits that generation owners would not have time to assess the impacts to their generation fleets, adjust their operations and planning functions to accommodate this new accreditation paradigm, and negotiate any necessary amendments to existing power supply agreements.[74] Alliant argues that MISO's request to implement the new construct in less than a year between filing the proposal and MISO's proposed September 1, 2022 effective date does not reflect the realities of the conditions under which MISO stakeholders and generation owners must operate, given the length of time required to get capacity projects through MISO's interconnection process.[75] East Texas and Entergy Coalition contend that LSEs will not have sufficient time to effectuate any significant generation or transmission investments to enhance their capacity positions, which could result with customers facing elevated prices in the Auction for several years.[76]

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[71] *Id.* at 43-44 (citing Tab C (Testimony of Shawn McFarlane), at 41 (McFarlane Test.)).

[72] *Id.* at 44 (citing MISO, FERC Electric Tariff, Module E-1, § 69A.7.1.c.x (45.0.0) (proposed)).

[73] *Id.*

[74] East Texas Protest at 7.

[75] Alliant Protest at 5-6.

[76] East Texas Protest at 7; Entergy Coalition Protest at 21-22.

52. Some commenters protest MISO's proposed methodology to determine seasonal Planning Reserve Margins and Reserve Requirements. Entergy Coalition submits that, while MISO states that one of the benefits MISO expects to achieve with the proposal is lowering non-Summer resource adequacy requirements, MISO's proposal fails to accomplish this goal. Entergy Coalition states that data provided by MISO during the stakeholder process indicates that under MISO's proposal many of the LSEs in MISO South would have Spring Reserve Requirements that are higher than their Summer requirements. Entergy Coalition states that, given that the Spring Season is traditionally considered an off-peak Season in MISO South during which significant maintenance outages are taken, this outcome is counterintuitive and would create significant planned maintenance scheduling challenges for these LSEs.[77]

53. Similarly, the Mississippi Commission argues that the proposal would decrease Zone 10's surplus generation by between 721 MW and 1,621 MW, depending on the Season, and cause economic hardship for Mississippi retail customers.[78] The Mississippi Commission states that, if Zone 10 does not have enough capacity to meet its Local Clearing Requirement, Entergy Mississippi's retail customers would be subjected to seasonal penalties of tens of millions of dollars; an amount that, according to the Mississippi Commission, negates the estimated net positive benefit of Entergy Mississippi's participation in MISO.[79]

54. Alliant argues that MISO's Planning Reserve Margin for non-Summer results is unnecessarily high. Alliant explains that MISO proposed to stakeholders the use of a 7.1% Planning Reserve Margin for the Summer Season, while Planning Reserve Margins for the non-Summer Seasons were between 14% and 22%. Alliant states that it is concerned that the non-Summer Planning Reserve Margins are driven by arbitrary inputs without a supporting sensitivity analysis. Alliant requests that the Commission delay implementation of MISO's filing until MISO can provide robust analysis for why Planning Reserve Margins in non-Summer months need to be excessively conservative for purposes of reliability.[80]

55. Alliant notes that MISO proposes to use a non-Summer LOLE as conservative as 0.1 day in 10 years, even though MISO currently uses a LOLE target of 1 day in 10 years. Alliant contends that using such a conservative assumption drives non-Summer capacity obligations to near-Summer requirements, despite lower load levels. Alliant

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[77] Entergy Coalition Protest at 19.

[78] Mississippi Commission Protest at 30-31.

[79] *Id*. at 30.

[80] Alliant Protest at 9-10.

states that, while the evolution of the generation portfolio may increase risk for Winter and other non-Summer Seasons, MISO's overly conservative assumptions and constrained implementation deadline will needlessly drive inefficient resource plans. Alliant states that Winter peak load in MISO is approximately 85% of Summer peak load, but Winter capacity requirements are approximately 93% of the Summer Reserve Requirements. Alliant contends that, as a result, MISO's approach to non-Summer Seasons does not accommodate efficiency gains for seasonal conditions in the generation portfolio.[81]

56. The Mississippi Commission argues that MISO's proposed CONE penalty does not promote resource adequacy because, according to the Mississippi Commission, MISO proposes to apply a total penalty of 100% CONE on a deficient LSE regardless of whether it is deficient for one Season or multiple.[82] The Mississippi Commission states that, if an LSE is deficient in multiple Seasons, MISO would impose fractions of the CONE penalty so that at the end of the year, the penalty would be the same amount. The Mississippi Commission states that this sends the message that, if an LSE is deficient for one Season, there is no need to cure that deficiency for subsequent Seasons. Further, the Mississippi Commission asserts that, if an LSE is informed that it will be deficient, there is not enough time to construct a new generating facility before MISO's proposed effective date, and the utility's retail customers will be subject to unreasonable penalty charges.[83]

57. Clean Energy Coalition argues that MISO's showing that risk occurs throughout the year does not necessarily demonstrate that the proposed seasonal construct would provide better reliability than the current annual construct.[84] Clean Energy Coalition argues that the proposed solution is not sufficient for addressing resource adequacy for a system with greater penetrations of energy limited resources and that MISO has not evaluated its proposed design under a renewable heavy scenario.[85]

58. Clean Energy Coalition asserts that MISO has not provided any data to demonstrate that its metrics to identify risk hours align with realized loss of load risk. Clean Energy Coalition states that MISO has not conducted a system-level loss of load

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[81] *Id.* at 10.

[82] Mississippi Commission Protest at 7.

[83] *Id*. at 7-8.

[84] Clean Energy Coalition Protest at 18.

[85] *Id.* at 18-19.

modeling analysis of a technically high quality to assess the periods or hours in which there is greatest risk of not serving load.[86]

59. Clean Energy Coalition argues that MISO's LOLE modeling lacks an accurate assessment of weather-related risks, which, according to Clean Energy Coalition, is necessary to understand whether MISO's proposal ensures reliability under a potentially radically different resource mix.[87] Clean Energy Coalition contends that MISO's flawed method to extrapolate wind and solar datasets to periods of synthetic load results in non-time synchronized data, and does not correctly identify periods where the combination of high loads and low wind and solar output create system risk.

60. Clean Energy Coalition argues that the assumption that solar or wind profile shape on a given day is a function of MISO-wide temperature data for nearby calendar days from other days is physically invalid. Clean Energy Coalition contends that correlating wind profiles to MISO-wide minimum temperature for November through March and MISO-wide maximum temperature for April through October is not substantiated, has no physical basis, and cannot possibly predict local wind speeds.[88] Clean Energy Coalition also argues that cloud cover is a much greater determinant of solar output than temperature and notes that there is a weak correlation between the two.[89] Clean Energy Coalition states that the validation provided by MISO indicated a poor match between actual and synthesized shapes even after smoothing for averaging. Clean Energy Coalition argues that the tails of the distribution in figures presented to validate the appropriateness of this method indicate a poor match between actual and simulated data during high load periods.[90] Clean Energy Coalition further argues that data presented for wind generation does not match regional attributes, as the average generation is low relative to current technology expectations and the diurnal shape is inconsistent with reality.[91] Finally, Clean Energy Coalition argues that methods used to develop future wind and solar generation profiles for the 2025 interconnection queue receive only

[86] *Id.* at 12.

[87] *Id.*

[88] *Id.*

[89] *Id.*

[90] *Id.*

[91] *Id.* at 13.

cursory mention and the information provided indicates that these methods do not capture physical processes or expected diversity increases in a meaningful way.[92]

c. MISO February 10 Answer

61. In response to comments about seasonal capacity prices, MISO argues that its proposal adequately mitigates against excessive prices in the seasonal Auctions. MISO explains that annual Auction revenue can only approach 1.75x CONE when one Season clears at CONE and the others clear just below 10% of CONE (approximately $250/MW-day), in which case the Auction Clearing Price is adjusted per the proposal.[93]

62. In response to the Mississippi Commission's assertion that MISO's proposal would convert Entergy Mississippi's capacity surplus into a shortage, MISO submits that the Mississippi Commission fails to recognize inherent differences in Seasonal Local Clearing Requirement positions that are driven by a number of factors, including resource performance and availability, load profiles, and Capacity Import Limits for each Season. MISO states that the current annual zonal Local Clearing Requirement positions are derived from Summer-focused assumptions and do not accurately reflect the seasonality of resource capabilities, load, and transfer capabilities under seasonal system conditions.[94] MISO argues that, compared to the overall average resource performance at the footprint level, Zone 10 resources have lower availability and are expected to see a reduction in their accredited values under the proposal to better reflect their reliability contribution during times of need. MISO states that, although varying levels of reduction in Zone 10 resource accredited values are projected for each Season, the projected seasonal zonal positions remain to be surpluses, not shortages, under the set of analysis parameters presented in the November 3, 2021 Resource Adequacy Subcommittee (RASC) meeting.[95]

63. In response to Alliant's argument that MISO's approach to set LOLE targets for non-Summer Seasons is overly conservative and drives non-Summer requirements to "near-Summer" requirements, MISO contends that Alliant fundamentally mischaracterizes MISO's proposal of defining seasonal LOLE targets in determining seasonal reserve requirements. MISO submits that its approach aims to set seasonal requirements reasonably while keeping the annual LOLE for the Planning Year largely close to 0.1 day per year. MISO states that this is accomplished by rounding LOLE

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[92] *Id.*

[93] MISO February 10 Answer at 44.

[94] *Id.* at 41-42.

[95] *Id.* at 42.

targets up to a minimum of 0.01 day per year for any Season(s) with an LOLE less than 0.01 day per year and maintaining LOLE targets for the Seasons with an LOLE greater than 0.01 day per year. MISO further states that Alliant fails to recognize that seasonal Planning Reserve Margins are in terms of percentage and seasonal peak demand forecasts will be applied to determine the MW requirements for each Season. MISO states that Reserve Requirements for non-Summer Seasons tend to be significantly lower than the Summer MW reserve requirement.[96]

64. In response to Clean Energy Coalition's assertion that MISO has not performed a system wide LOLE analysis of a technically high quality to assess loss of load risks, MISO states that it has enhanced its LOLE modeling to better reflect the seasonality of various types of resource capabilities, including seasonal forced outage rates with cold weather adjustments, a probabilistic representation of non-firm external support, and multi-year hourly wind and solar profiles. MISO explains that it has also spent many months conducting a suite of high-fidelity LOLE risk analysis under both current resource portfolio and a broad range of future resource portfolio scenarios to gain a good understanding of changing reliability risk profiles with the evolving resource portfolio. MISO further explains that it used historical hourly wind outputs for recent weather years from 2011 to 2019 to develop correlations between historical wind output and temperature/load to ensure the variation of wind output as a function of load is well represented. MISO argues that its approach to developing synthetic wind profiles for 1990-2010 reasonably captures the historical variability and volatility around the synthetic load shapes by developing a similar distribution of wind outputs as a function of the 1990-2010 load shapes as seen in the 2011-2019 load and wind shapes where actual historical wind outputs are available. MISO explains that, similarly, hourly solar profiles from 1998 to 2019 generated using the NREL National Solar Radiation Databased Data Viewer were used to develop synthetic solar profiles for 1990 to 1997 weather years to maintain a similar relationship between load and solar outputs as seen in the 1998 to 2019 time frame.[97]

d. Answers to MISO February 10 Answer

65. Midwest TDUs argue that MISO did not explain how its proposed departure from using annual CONE as the capacity price signal and the resulting excessive seasonal Auction prices and revenues allowed under its proposal are just and reasonable.[98] Midwest TDUs state that MISO concedes that its proposal could result in annual auction

[96] *Id.*at 44-45.

[97] *Id.* at 45-46.

[98] Midwest TDUs Answer at 26-27.

revenues that approach 1.75x CONE.[99] Regarding the calculation of Auction prices, Midwest TDUs assert that, if MISO intends to adjust Auction prices when there is more than one Season in or near shortage conditions, then the Tariff should make that clear.[100] According to Midwest TDUs, MISO fails to adequately mitigate unreasonable and unjust capacity prices, and its proposal actually produces less annual Auction revenue when more Seasons are in or near shortage conditions.[101]

66. Alliant states that MISO's February 10 Answer shows that non-Summer Reserve Requirements will be nearly as high as Summer Reserve Requirements, which Alliant contends could lead to inefficient resource planning based on overly conservative assumptions.[102] Alliant requests that the Commission delay implementation of the MISO proposal until MISO provides analysis to support the Planning Reserve Margins proposed in non-Summer months.[103]

e. Deficiency Letter Response and Responsive Pleadings

67. As noted above, on March 9, 2022, Commission staff issued a deficiency letter and requested additional information, and MISO submitted its Deficiency Letter Response on April 8, 2022. In response to a question requesting additional support for the proposal to allow Auction revenue to potentially exceed annual CONE, MISO states that it recognized the need to raise the $/MW-day offer cap so that resources only available or only needed in a single Season are still eligible to receive payments up to annual CONE. MISO states that, while this continues to ensure revenue adequacy, it could lead to scenarios where load pays capacity charges in excess of annual CONE. MISO asserts that its proposal mitigates this result by reducing Auction Clearing Prices for shortage and near-shortage Seasons so that, in the aggregate, such Seasons collect revenue up to annual CONE but no more. MISO states that the potential for charges above annual CONE comes from revenues based on the Auction Clearing Price in Seasons that were not in shortage or near-shortage conditions. MISO states that, by

[99] *Id.* at 26 (citing MISO February 10 Answer at 44).

[100] *Id.* at 28.

[101] *Id.*

[102] Alliant Answer at 3.

[103] *Id.*

definition, those prices will always be below the mitigated prices in the shortage or near-shortage conditions, which MISO contends is a reasonable result.[104]

68. In response to a question requesting additional information about the relationship between MISO's LOLE target of 0.01 day per year for each Season and the annual LOLE target of 0.1 day per year, MISO states that the annual 0.1 day per year target is cumulative across all Seasons. MISO states that, after performing the two-step LOLE analysis, it is possible for the summation of the LOLE across all Seasons to equal 0.1 days per year, with some Seasons having LOLE less than 0.01 days per year. MISO explains that, to determine a seasonal requirement for Seasons with LOLE less than 0.01 days per year, a minimum of 0.01 days per year LOLE target for the Season is used because a defined non-zero LOLE target is needed to solve the model. MISO states that the 0.01 days per year target allows the model to converge accurately and without significant computational burden while holding the Season to near 0 LOLE and staying as close as possible to an annual LOLE of 0.1 days per year. MISO submits that a target smaller than 0.01 makes it difficult for the model to converge while a target above 0.01 causes the total LOLE to increase too far beyond the annual 0.1 days per year.[105]

69. MISO states that it provided analysis to market participants indicating that between 14%-27% of approximately 110 market participants would experience higher non-Summer Reserve Requirements than their Summer Reserve Requirements, and that these results are driven by market participants with flatter seasonal load profiles and higher non-Summer MISO-system Planning Reserve Margins. MISO notes that it has yet to collect seasonal coincident peak load forecasts, so that the impact analysis was performed using proxy seasonal coincident peak load forecasts estimated based on seasonal load forecast factors and Summer coincident peak forecasts. MISO states that, as a result, the Reserve Requirement values are subject to change once market participants submit actual seasonal coincident peak load forecasts.[106]

70. Midwest TDUs, Clean Energy Coalition, Entergy, and Alliant submitted comments on MISO Deficiency Letter Response. Midwest TDUs argue that MISO has not justified its proposal to allow Auction revenues in excess of annual CONE. Midwest TDUs contend that the potential for Auction revenues tens of thousands of dollars per MW-year above CONE does not, as MISO claims, protect load from paying capacity charges that are well in excess of annual CONE. Midwest TDUs further argue that MISO

[104] MISO Deficiency Letter Response at 26.

[105] *Id.* at 21.

[106] *Id.* at 22.

does not respond to the fact that MISO's proposal allows for higher Auction revenues as fewer Seasons are in shortage or near-shortage conditions.[107]

71. Clean Energy Coalition states that artificially setting the LOLE seasonal target to 0.01 per year in a Season that has no risk ignores the results from annual LOLE modeling. Clean Energy Coalition argues that, while it agrees with MISO's statement that setting a seasonal LOLE target to 0.01 is the only way to get the model to solve, the model cannot find the Effective Load Carrying Capability (ELCC) of any resource if there is no risk in that Season. Clean Energy Coalition submits that artificially adding risk to a Season that has none, and then accrediting resources for mitigating this artificial risk, is not a just and reasonable approach to maintaining reliability. Clean Energy Coalition adds that, if MISO's modeling approach cannot quantify the risk that demonstrably occurs in all Seasons, then MISO is missing a key improvement necessary to identify reliability risks.[108]

72. Entergy states that MISO's response to a question requesting additional data on how often LSEs will experience higher non-Summer Reserve Requirements demonstrates that up to a quarter of LSEs will not realize one of the primary intended benefits of the seasonal construct as stated by MISO, which is that the seasonal construct will result in lower non-Summer Reserve Requirements, enabling seasonal operation of resources. Entergy argues that MISO's overly broad seasonal risk allocation of the 0.1 LOLE target is flawed and does not obtain the desired outcome of lower non-Summer Reserve Requirements for all LSEs.[109]

73. Alliant contends that MISO's Deficiency Letter Response demonstrates Alliant's initial argument that there are still important details that need to be resolved before implementation of the proposal can occur. Alliant contends that MISO still has not addressed concerns that non-Summer Planning Reserve Margins, which will be potentially two to three times higher than Summer Planning Reserve Margins, are a rational outcome. Alliant states that the higher Planning Reserve Margins for non-Summer Seasons results in Reserve Requirements for non-Summer Seasons that are nearly as high as the Reserve Requirements for the Summer Season, despite significant load differences. Alliant states that MISO has explained the modeling process and challenges with modeling limitations but has not addressed concerns that the proposed

[107] Midwest TDUs Response to MISO Deficiency Letter Response at 27-29.

[108] Clean Energy Coalition Response to MISO Deficiency Letter Response at 8.

[109] Entergy Response to MISO Deficiency Letter Response at 6-7.

obligation determination processes lead to an unreasonable outcome for the Planning Reserve Margin and Reserve Requirements.[110]

74. Alliant asserts that MISO continues to ignore the dramatic impact the seasonal construct will have on short-term portfolio plans. Alliant states that MISO has the data and tools available to assess this impact and could take its conceptual seasonal reserve margin obligations and apply those to the MISO/OMS survey data to illustrate indicative changes in projected capacity positions by year and Season for the footprint and each Zone. Alliant contends that this information is critical for the Commission, MISO, market participants, and state regulators to understand the true forecasted impact of the seasonal construct.[111]

f. MISO May 20 Answer

75. With regard to concerns about Auction revenues exceeding annual CONE, MISO states that its Deficiency Letter Response explained that the proposal mitigates, but cannot fully eliminate, the possibility. MISO states that its proposal strikes a balance between ensuring that resources designated for resource adequacy are revenue adequate even if they are only designated for a single Season, and protecting load from excessive capacity prices above the annual CONE value (expressed in a daily $/MW-day value) across multiple Seasons. MISO states that, under the proposal, a Zone that is short on capacity in all Seasons would pay revenues equal to annual CONE and a resource receiving the Auction Clearing Price in a Zone that is short would receive capacity payments equal to annual CONE. MISO states that, in some cases, where at least one but not all four Seasons are short, CONE would be charged in the short Seasons and additional charges paid in Seasons that were neither short nor near-shortage, driving total capacity charges for the year above CONE. MISO states that, however, in the most extreme case, where one Season is short and the others are close but not quite "near-shortage," then 25% of CONE could be collected in each of the other three Seasons, which would drive the total Auction revenues across the four Seasons to 175% CONE. MISO asserts that this would be highly unlikely but still a reasonable outcome as the Auction would be signaling a shortage in one Season and fairly tight conditions in the rest of the seasons.[112]

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[110] Alliant Response to MISO Deficiency Letter Response at 5.

[111] *Id.*

[112] MISO May 20 Answer at 12-13.

g. Midwest TDUs June 6 Answer

76. Midwest TDUs argue that the MISO May 20 Answer repeats the assertion that it would be a reasonable outcome for total Auction revenues across the four Seasons to be as high as 175% of CONE without explaining why it is appropriate to charge consumers significantly more than CONE, which is the current Commission-approved cap on annual Auction revenues. Midwest TDUs further argue that MISO has not provided any explanation for why Auction revenues well above CONE are an appropriate signal for short or tight capacity conditions. Midwest TDUs state that recent Auction results for the 2023/2023 Planning Year confirm the importance of this aspect of MISO's proposal and the need for the Commission to ensure that consumers do not pay excessive prices.[113]

h. Commission Determination

77. We find MISO's proposal to implement a seasonal resource adequacy construct is just, reasonable, and not unduly discriminatory or preferential. We find that MISO has demonstrated that its proposal would better align resource adequacy requirements with periods of increased risks on the MISO system, which, as MISO demonstrates, increasingly occur outside of the peak Summer Season.[114] Further, by providing a more granular assessment of seasonal resource adequacy needs, MISO's proposal will ensure that LSEs are not required to procure capacity beyond what is necessary to ensure resource adequacy in a given Season. This, combined with MISO's proposal to accredit resources based on their seasonal performance (discussed further in Section IV.B.2 below), will offer further assurance that MISO's resource adequacy provisions are sufficient to mitigate the system's resource adequacy risk throughout the Planning Year. As the Wright testimony explains, MISO's proposal will "incorporate changing risk drivers, including seasonal aspects, into a more precise determination of reliability requirements."[115]

78. In response to East Texas's request that MISO provide evidence that MISO's proposal would have strengthened MISO's response to Winter Storm Uri, we do not believe it is incumbent upon MISO to provide such a counterfactual to demonstrate that its proposal is just and reasonable. Similarly, a cost-benefit analysis is not necessary to evaluate MISO's proposal, but as noted above, we find that MISO has demonstrated that the proposal is likely to benefit MISO customers by enhancing reliability in the region

[113] Midwest TDUs June 6 Answer at 8-9.

[114] *See* Transmittal at 3 ("Since 2016 MISO has experienced 40 [MaxGen Events] with more than 60% occurring outside of the Summer months.").

[115] Wright Test. at 27.

with a more granular determination of resource adequacy risks that MISO has demonstrated vary throughout the Planning Year.

79. Some protestors prefer that MISO propose alternative, or more targeted, revisions to its resource adequacy construct. However, under FPA section 205, MISO bears the burden to show that its filing is *a* just and reasonable proposal, but need not show that it is the best or most just and reasonable option.[116] Further, we do not find MISO's proposal to be overly complex such that LSEs and other market participants will be unable to understand the new seasonal resource adequacy requirements or unable to plan for the upcoming Planning Year.

80. We disagree with claims that, because it is possible that the annual Auction revenues across all four Seasons can exceed the annual CONE value, MISO's proposal lacks sufficient mitigation to ensure just and reasonable annual Auction revenues. As an initial matter, we do not believe that an Auction construct that allows annual revenues to exceed CONE necessarily renders that construct to be unjust and unreasonable. We note that the Commission has accepted capacity market designs that allow annual auction revenues to exceed Net CONE.[117] As MISO explains, such outcomes will incent new entry in the event the MISO system is short capacity.

81. Further, MISO has proposed to mitigate customer cost impacts to reduce the Auction Clearing Prices in Seasons that clear in ZRC Shortage Conditions or ZRC Near-Shortage Conditions to ensure that, in aggregate, resources that clear the Auction in such Seasons collect revenue up to, but not above, annual CONE. Specifically, MISO's proposal includes an ex-post adjustment to reduce the Auction Clearing Price when more than one Season clears in ZRC Shortage Conditions or ZRC Near-Shortage Conditions. If this occurs, the final Auction Clearing Price will be set based on annual CONE and the

[116] *City of Winnfield, La v. FERC.*, 744 F.2d 871 at 874-76 (D.C. Cir. 1984); *PJM Interconnection, L.L.C.*, 170 FERC ¶ 61,243, at P 57 (2020) (citing *Petal Gas Storage, L.L.C. v. FERC*, 496 F.3d 695, 703 (D.C. Cir. 2007); *Cities of Bethany v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984); *Cal. Indep. Sys. Operator Corp.*, 128 FERC ¶ 61,282, at P 31 (2009)). *See also Neb. Pub. Power Dist. v. FERC*, 957 F.3d 932, 943 (8th Cir. 2020) (recognizing that "courts have made it clear that FERC 'restricts itself to evaluating the confined proposal'" and "[t]herefore, FERC 'need only find the *proposed* rates to be just and reasonable.'") (citations omitted).

[117] ISO New England Inc. (ISO-NE) sets the starting price of the Forward Capacity Auction as the higher of CONE or 1.6 times Net CONE. *See* ISO-NE Tariff, § III. 13.2 § 13.2.4 (66.0.0). PJM Interconnection, L.L.C. (PJM) sets the starting price of the Variable Resource Requirement Curve at the greater of CONE or 1.5 times Net CONE. *See* PJM, Tariff, OATT VI, attach. DD § 5.10 (1.0.1).

number of days in all applicable Seasons when a Zone clears below the required number of ZRCs or the Season's initial Auction Clearing Price clears above daily CONE. We find that the potential for outcomes resulting in annual Auction revenues at or exceeding CONE result from MISO attempting to enable sufficient compensation for resources that clear in few Seasons while protecting ratepayers from substantially increased aggregate capacity costs across the Planning Year. Finally, some protestors suggest that, because MISO's proposed ex post adjustments to Auction Clearing Prices may produce higher annual Auction revenues when there are fewer Seasons in shortage conditions, this suggests a fundamental price signaling flaw, inconsistent with supply and demand fundamentals. We disagree. In both scenarios, the total annual revenues demonstrate that MISO is in need of additional capacity and to provide a signal to attract additional resource adequacy investments.

82. We disagree with Midwest TDUs' characterization that MISO justified its facility-specific Reference Levels on the basis that they were rarely used. Rather, MISO was providing context that facility-specific Reference Levels are rarely used in MISO's current construct and that they expect more resource owners to use them, should the Commission accept MISO's proposal. We also disagree that this suggests that MISO expects increased use of facility-specific Reference Levels means that offers above the economic withholding conduct threshold will comprise a larger fraction of offers in the seasonal Auction. We find that nothing in the record indicates that increased use of facility-specific Reference Levels would weaken the protections of MISO's economic withholding conduct thresholds. Further, under MISO's market power mitigation provisions, capacity offers above a resource's economic withholding threshold are not subject to mitigation unless they also cause the Auction Clearing Price to exceed the impact threshold equal to 10% of the Zone's CONE value (or $0/MW-day in Zones where import constraints bind).[118] Therefore, we find MISO's mitigation provisions to be sufficient under MISO's proposed seasonal Auction construct. Similarly, we are also unpersuaded by Midwest TDUs' argument that make-whole payments to resources that only clear one Season may create incentives for resources to clear in only one Season so that they are relieved of the must-offer requirement in other Seasons, as Midwest TDUs does not explain why MISO's mitigation provisions are insufficient to protect against such potential gaming. Specifically, make-whole payments are only provided to resources that do not clear in certain Seasons, and offers in those Seasons are subject to the economic withholding thresholds noted above, including being limited to the facility-specific reference level.

83. We are not persuaded that additional information is required to justify MISO's proposed market adjustment make-whole payment system. Under the seasonal construct, Planning Resources will bid into each Season's Auction the cost of providing capacity in

[118] MISO, FERC Electric Tariff, Module D, § 64.2.1 (45.0.0) (proposed).

that Season. The ZRC Offer Revenue Sufficiency Guarantee Credit make-whole payments provide two important benefits: (1) they ensure that capacity sellers are not required to provide capacity at a loss; and (2) they shield consumers from excessive prices.

84. However, we agree with Midwest TDUs' claim that MISO's proposed Tariff language is inconsistent with MISO's statements and the McFarlane Testimony. Proposed Tariff section 69A.7.1.c.x states:

> The final Auction Clearing Price [] for a [Zone]. . .with Seasons in ZRC Shortage Conditions will be set as the amount obtained by dividing the applicable [Zone's] annual CONE value by the number of days in Seasons which the [Zone was] . . .in ZRC Shortage Conditions and ZRC Near-Shortage Conditions in the [] Auction. The final Auction Clearing Price [] for a [Zone]. . . with Seasons in ZRC Near-Shortage Conditions will be set as the minimum of: (a) the original [Auction Clearing Price] as determined in section 69A.7.1.c.(v) or section 69A.7.1.c.(vi) as applicable; or (b) the amount obtained by dividing the applicable [Zone's] annual CONE value by the number of days in Seasons which the [Zone was]. . . in ZRC Shortage Conditions and ZRC Near-Shortage Conditions in the [] Auction[119]

In contrast, the McFarlane Testimony states that "[a]n ex-post adjustment will set reduced Auction Clearing Prices when more than one Season clears in ZRC Shortage or ZRC Near-Shortage Conditions."[120] Further, MISO's Deficiency Letter Response indicates that the provisions of section 69A.7.1.c.x are only intended to apply "in situations where more than one Season is in Shortage or Near-Shortage Condition."[121]

85. The proposed Tariff language is unclear because the use of the singular "final Auction Clearing Price for a Zone" without reference to a *Season's* Auction Clearing Price implies that each Zone only has one Auction Clearing Price, rather than four (one for each Season). Thus, it is reasonable to interpret this provision as applying only in situations where a Zone has "Seasons in ZRC Shortage Conditions" *or* "Seasons in ZRC-Near-Shortage Conditions," and not, as Midwest TDUs explain, situations where a Zone has one Season in ZRC Shortage Conditions and a second Season in ZRC Near-Shortage Conditions. Therefore, we direct MISO to, within 30 days of the date of this order, to file

[119] *Id.*, Module E-1, § 69A.7.1.c.x (45.0.0) (proposed).

[120] McFarlane Test. at 41.

[121] MISO Deficiency Letter Response at 26.

revised tariff sheets that clarify section 69A.7.1.c.x, consistent with the McFarlane Testimony, the Deficiency Letter Response, and the MISO February 10 Answer.[122]

86. Clean Energy Coalition criticizes various aspects of MISO's LOLE modeling, including its use of weather data. We find that such concerns are beyond the scope of this filing insofar as they pertain to calculations that already occur independently of the addition of seasonality to the LOLE analysis.

87. In response to protestors' concerns regarding MISO's proposed LOLE target of 0.01 days per year for each Season, we find that MISO has demonstrated that a minimum seasonal LOLE target of 0.01 days per year is just and reasonable because without such a minimum LOLE target, the model will not produce accurate results. We find that MISO has sufficiently demonstrated that the model requires a non-zero LOLE target and that an LOLE target of 0.01 days per year allows MISO to maintain the annual LOLE target of 0.1 days per year, cumulative across all Seasons. We disagree with Clean Energy Parties' that Seasons with an LOLE less than 0.01 days per year indicates that such a Season has "no risk." In Seasons with a lower LOLE risk than other Seasons, it is reasonable for MISO to adjust the LOLE target to a value that allows its model to converge. Absent this adjustment, the accuracy of MISO's LOLE modeling could be impacted, which could have negative consequences for reliability. We also find that MISO's proposal to maintain LOLE targets for Seasons where the LOLE is greater than 0.01 days per year, without adjustment, is just and reasonable because those values are already sufficiently large for the model to solve accurately and that MISO has demonstrated that such an outcome would be consistent with an annual LOLE target of 0.1 days per year. As such, we do not agree with Alliant that the resulting Planning Reserve Margins are unnecessarily high.

88. MISO has demonstrated that its proposal will result in lower Reserve Requirements for non-Summer Seasons, at the MISO-wide level, which should in and of itself reduce costs to customers.[123] Although it may be the case that some LSEs may experience higher non-Summer Reserve Requirements as compared to their Summer Reserve Requirements, we do not find that to be an unjust and unreasonable result, so long as MISO's methodology to determine seasonal Reserve Requirements provides a reasonable assessment of seasonal risk, including the availability of imports and historical resource availability. MISO has demonstrated that its methodology does so. For example, MISO explains that the expected reduction in Zone 10's Local Clearing Requirement surplus in the Winter Season is primarily driven by a significant reduction in its Winter Capacity Import Limit value.

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[122] *See* MISO February 10 Answer at 43-44.

[123] MISO Deficiency Letter Response at 22.

89. To the extent that the Mississippi Commission's statement regarding MISO's "proposed CONE penalty" is referring to the Capacity Deficiency Charge, we note that MISO's revised Tariff states that the annual Capacity Deficiency Charge will be "the CONE value for the [Zone] . . . multiplied by 2.748 times the [Reserve Requirement] volume indicated by the LSE for the Planning Year."[124] We find that MISO's proposed Tariff revisions are unclear with regard to the seasonality of the Capacity Deficiency Charge and could be interpreted as being applied separately to each Season that an LSE is deficient ZRCs. Under such an interpretation, a Planning Resource that was deficient 10 ZRCs in all four Seasons would be assessed a charge of CONE multiplied by 2.748 times 40 ZRCs, whereas under the current annual construct, an LSE that is 10 ZRC deficient for the Planning Year would be assessed a charge of CONE multiplied by 2.748 times 10 ZRCs. Because MISO's proposed Tariff revisions are unclear on how the Capacity Deficiency Charge will be assessed to each Season, we direct MISO to, within 30 days of the date of this order, file revised tariff sheets that clarify the seasonality of the Capacity Deficiency Charge.

90. In response to protestors' concerns regarding MISO's proposal to implement the new construct for the next Planning Year, we note that the instant filing was made 16 months in advance of the 2023/24 Auction, after several years of stakeholder discussion. We disagree that LSEs will not have sufficient time to enhance their capacity positions, as LSEs have several options beyond "generation or transmission investments" to meet their Reserve Requirements, including bilateral contracting and Auction participation. Finally, we note that Zone 10 (Mississippi) and the MISO South subregion overall are expected to have a capacity surplus overall, suggesting that LSEs in MISO South will be able to purchase capacity to meet their Reserve Requirements for the Winter Season.[125]

2. Accreditation

a. MISO Filing

91. MISO proposes to implement a SAC proposal, which is an availability-based accreditation methodology for a newly defined set of resources called Schedule 53 Resources. MISO states that Schedule 53 Resources are Capacity Resources that are Demand Response Resources or Generation Resources, but not Dispatchable Intermittent

[124] MISO, FERC Electric Tariff, Module E-1, § 69A.10 (32.0.0) (proposed).

[125] *See* MISO February 10 Answer at 42 ("Although varying levels of reduction in [Zone] 10 resource accredited values is projected for each season, the projected Zone 10 seasonal zonal positions remain to be a surplus not a shortage."). *See* also RASC presentation at 8 (Nov. 3, 2021), https://cdn.misoenergy.org/20211103%20RASC%20Item%2004a%20Resource%20Adequacy%20Reforms%20Presentation%20(RASC010,%20011,%20012)600791.pdf.

Resources, Intermittent Generation, Electric Storage Resources, External Resources, or Use Limited Resources. MISO explains that resource accreditation for Schedule 53 Resources will no longer be based on installed capacity adjusted for forced outage rates from the Generation Availability Data System (GADS) but instead will primarily be based on the average capacity available in times of highest need given resource offers in MISO's Day-Ahead and Real-Time markets, i.e., RA Hours. MISO states that it proposes a tiered weighting structure to determine individual accreditation for Schedule 53 Resources by Season based on each Resource's Real-Time offered availability during Tier 1 hours, defined as all hours other than RA Hours; and Tier 2 hours, defined as RA Hours.

92. MISO proposes to define RA Hours for each Season as a 65-hour target that include all hours with declared MaxGen Events and the remaining hours with the tightest operating margin, subject to a maximum operating margin threshold of 25%.[126] MISO would determine RA Hours separately for MISO North and MISO South. MISO explains that the 65-hour target represents the tightest 3% of hours in a Season. MISO states that the number of RA Hours in a Season can exceed the target when declared MaxGen Events during that Season have a cumulative duration of greater than 65 hours. MISO explains that the number of RA Hours in a Season can be less than the 65-hour target because of the 25% maximum operating margin threshold, which will ultimately lead to a deficiency equal to the difference between the target RA Hours and the actual number of RA Hours.[127]

93. MISO proposes to accredit the capacity of a Schedule 53 Resource based on its Intermediate Seasonal Accredited Capacity (ISAC) determined based on its Real-Time offered availability (capped at the resource's GVTC value) during seasonal RA Hours and Non-RA Hours. MISO recognizes that the number of Tier 2 RA Hours may vary during individual Seasons when the 25% maximum margin threshold is applied or individual resources receive outage exemptions, impacting sample sizes of RA Hours and corresponding ISAC accreditation calculations. Therefore, MISO proposes that, if the number of Tier 2 RA Hours for a Season or a specific resource fall below the 3% target of 65 hours, a resource's Annual Average Offered Capacity (AAOC) will be used to

[126] MISO proposes to include offline resources with a 12-hour-or-less lead time in the operating margin calculations, arguing that a 12-hour-or-less lead time better reflects actual operating margins MISO sees in real-time operations, which may be impacted by uncertainty that occurs after the deadline to commit longer lead resources has passed. MISO adds that a 12-hour-or-less lead time leads to more RA Hours being identified in each Season, allowing resource accreditation to be based on availability during a specific Season, with less need to fill in deficient RA Hours. McFarlane Test. at 23-24.

[127] Transmittal at 16.

supplement the deficient number of hours as part of the Tier 2 portion of the accreditation calculation.[128] MISO states that Seasonal Tier 1 Non-RA Hours, in contrast, include all hours in a Season of a Planning Year, excluding Tier 2 RA Hours and any hours where a resource had an exemption or was not designated for Resource Adequacy Requirements.[129]

94. MISO states that the final ISAC value will be the weighted average over its values from the two tiers. MISO explains that it proposes an 80% Tier 2 and 20% Tier 1 weighting, arguing that assigning the heavier weighting to Tier 2 tight conditions ensures the alignment between a resource's SAC value and its availability and performance during times of highest risk and greatest need. MISO proposes a three-year transition period, such that Tier 2 weighting would start at 60% for Planning Year 2023/2024, rise to 70% in Planning Year 2024/2025, and reach the full 80% in Planning Year 2025/2026.[130]

95. To convert a Schedule 53 Resource's ISAC to its final SAC value, MISO proposes to apply a system-wide UCAP/ISAC ratio, which is the sum of MISO's fleet-wide UCAP accreditation of Schedule 53 Resources divided by the sum of MISO's fleet-wide ISAC accreditation of Schedule 53 Resources. MISO states that the UCAP/ISAC ratio is proposed to avoid undesirable impacts to Auction requirements and non-Schedule 53 resources.[131]

96. MISO explains that, while MISO intends to address potential accreditation enhancements to non-Schedule 53 Resources in a future filing after development and stakeholder discussions, non-Schedule 53 Resources will receive SAC values based on a resource type consistent with their current accreditation rules, adjusted for seasonality. MISO states that wind resources will receive accreditation for each Season based on seasonal ELCC studies with capacity accreditation allocated based on eight peak hours for each Season. MISO further states that non-wind intermittent resources such as run-

[128] A resource's AAOC is determined by calculating a resource's average offered availability during Annual RA Hours for each 12-month period within the three most recent periods beginning September 1st and ending August 31st. Annual RA Hours for each year are a 260-hour target that include all hours with declared MaxGen Events and the remaining hours with the tightest operating margin, subject to a maximum operating margin threshold of 25%. *See* MISO, FERC Electric Tariff, Module E-1 § Schedule 53 III.B (32.0.0) (proposed)).

[129] Transmittal at 17.

[130] *Id.*

[131] *Id.*

of-river hydro, solar, intermittent BTMG, and biomass SAC will be based on historical output during hours ending 15:00, 16:00, and 17:00 Eastern Standard Time (EST) for the relevant Spring, Summer, and Fall Seasons, and that Winter accreditation will be based on historical output in hours ending 8:00, 9:00, 19:00, and 20:00 EST in the Winter Season. MISO asserts that Load Modifying Resources (LMRs), which include both Demand Resources registered as LMRs (LMR DR) and BTMG registered as LMRs, will be accredited based on lead time and number of calls per year consistent with current LMR rules, with adjustments to establish a minimum number of calls for each Season—five for each Summer and Winter, and three for each Spring and Fall.[132]

97. MISO also argues that the SAC proposal will incent better coordination of Generator Planned Outages by limiting—through exemptions—the extent to which planned outages impact a resource's SAC, provided certain conditions are met.[133] MISO explains that its current resource adequacy construct provides for exemptions for generator planned outages if certain criteria are met. MISO states it worked collaboratively with stakeholders to develop the proposed exemption process that integrates with the SAC accreditation process in Schedule 53 to provide for three levels of exemptions: (1) full exemption for Generator Planned Outages from Tier 1 and Tier 2 SAC calculations; (2) exemption from Tier 1 SAC calculations only; and (3) no exemption. MISO states that Tier 1 and Tier 2 exemptions will be provided if: (1) the generator owner or operator schedules its first planned outage 120 days or more in advance of the outage date and 120 days or more beyond the end date of any previously scheduled outages for the unit, and the Maintenance Margin[134] for the time period of the outage is equal to or greater than 0; or (2) the generator owner or operator reschedules its planned outage at MISO's request. MISO further states that Tier 1 only exemptions will be provided if the following conditions are met: (1) the generator owner or operator schedules its first generator planned outages 120 days or more in advance of the outage start date and 120 days or more beyond the end date of any previously scheduled outages for the unit, and the Maintenance Margin is less than 0 for the time period of the outage; (2) a subsequent generator unit outage requests 120 days or more in advance and/or generator owner or operator's planned outage is less than 120 days in advance but at least 31 days in advance of the outage start date; (3) the planned outage is less than 31 days in advance but at least 14 days in advance of the outage start date and passes the No Harm

[132] *Id.* at 18.

[133] *Id.* at 15-16.

[134] Maintenance Margin is the maximum MW of additional generation that can be taken out of service for planned maintenance for a given time-period without undue risk to supply adequacy for MISO's Balancing Authority Area, including MISO sub-regions. Transmittal at 20.

Test;[135] or (4) the generator owner or operator reschedules its planned outage at MISO's request.[136] MISO explains that, for planned outages submitted before MISO's proposal goes into effect, outages that are scheduled to start prior September 1, 2022 will be treated as fully exempt for Tier 1 and 2.

b. Comments and Protests

98. OMS states that the seasonal component of this proposal will allow resources to take extended seasonal outages for both maintenance and economic reasons, and it will relieve those resources from any must-offer requirement, allowing for better maintenance and economic decisions.[137] The Indiana Commission considers MISO's SAC proposal a just and reasonable approach to determining what can be reasonably expected of a resource and reflecting that expectation in that resource's accreditation.[138] The Indiana Commission states that accrediting resources based on their Real-Time offered availability during tight system hours is both prudent and equitable. The Indiana Commission contends that a resource's accreditation should reflect "a realistic expectation of its performance, and resources should be rewarded for delivering when they are most needed."[139] The Indiana Commission submits that MISO's proposal achieves this standard.

99. Potomac Economics supports MISO's SAC proposal, stating that resources whose availability or capability varies significantly by Season would receive revenues that reflect those seasonal differences. Potomac Economics argues that relatively high-cost resources would have an opportunity to achieve savings by taking seasonal outages during shoulder Seasons.[140] Potomac Economics states that the MISO accreditation proposal will provide substantial benefits over the current construct where generating

[135] MISO proposes that the No Harm Test includes, but is not limited to, "outage approval, compliance with all applicable operation guides, review of possible conflicting outages or system conditions, and system capacity (Maintenance Margin, Multiday Operational Margin, 30-day margin)." It also includes the criteria outlined in the Generator Outage BPM. *See* MISO, FERC Electric Tariff, Schedule 53 § II.C (32.0.0) (proposed).

[136] Transmittal at 20-21.

[137] OMS Comments at 4-5.

[138] Indiana Commission Comments at 6-7.

[139] *Id.* at 7.

[140] Potomac Economics Comments at 3.

resources are accredited to sell capacity based on their self-reported forced outage performance, which is used to calculate their UCAP levels. Potomac Economics, though generally supportive of the filing, argues the accreditation portion of MISO's proposal is suboptimal for a number of reasons: (1) other types of outages and derates reduce MISO's access to Capacity Resources; (2) resources do not completely report their outages and derates; (3) less reliable resources that are rarely needed are credited as fully available when not asked to run, inflating their UCAP levels; and (4) long-lead time resources that are frequently offline provide far less capacity value than their UCAP value because, when tight conditions arise unexpectedly, they cannot be used.[141]

100. Potomac Economics states that the application of MISO's proposed UCAP/ISAC ratio is an important dimension of MISO's accreditation proposal because it maintains the relative supply and demand balance in the Auction. Potomac Economics acknowledges that, although MISO's proposed availability-based accreditation will generally be lower than the UCAP accreditation, the application of the UCAP/ISAC ratio is reasonable because it recognizes that each MW of ISAC provides more reliability than each MW of UCAP; therefore, less-available resources will receive less capacity accreditation while more-available resources will receive higher accreditation amounts. Potomac Economics contends that, by shifting capacity accreditation from less-available resources to more-available resources, the capacity market procurements will be better aligned with the reliability value provided by MISO's resources.[142]

101. Potomac Economics highlights some aspects of the proposed SAC methodology that are not consistent with its recommendations. First, Potomac Economics notes that an important aspect of MISO's proposal is how to calculate the operating margin MISO uses to determine whether an hour should be classified as an RA Hour or a non-RA Hour. Potomac Economic states that MISO's proposal includes resources with a lead time of 12 hours or less to calculate this operating margin. Potomac Economics suggests that, by including such resources in the operating margin calculation, MISO may calculate an artificially high margin and not designate an hour as an RA Hour even though the hour is among the tightest of the year. Therefore, Potomac Economics recommends that MISO only include resources with a lead time of less than 6 hours, which is the timeframe in which MISO often recognizes that emergency conditions are developing.[143]

102. Second, Potomac Economics states that it prefers a sliding scale to reduce an offline resource's deemed availability as its offered lead time increases, ranging from 100% at 2 hours to 0% at 12 hours. Potomac Economics contends that it is rare for any

[141] *Id.* at 6.

[142] *Id.* at 7.

[143] *Id.* at 8-9.

offline resource with lead times longer than 12 hours to provide any reliability contribution when reliability events occur. Potomac Economics contends that MISO's proposal to treat offline resources with lead times less than 24 hours as available up to their offered output intentionally overvalues less flexible, long-lead time units.[144] Potomac Economics suggests that, regardless of whether a resource could have reasonably been committed in MISO's day-ahead process, if most of the threats to reliability emerge during the operating day, only offline resources that can start once the threat is recognized can contribute to reliability. Potomac Economics adds that offline resources that theoretically could have been committed the prior day, but whose lead time is too long for them to start to mitigate the reliability threat provide no value in such events.[145]

103. Third, Potomac Economics argues that the 80%/20% weighting on availability in Tier 1 and Tier 2 hours MISO proposes for accreditation is not ideal because, according to Potomac Economics, resources provide very little marginal reliability value in non-RA Hours as virtually all resource marginal reliability value is captured in RA Hours. Potomac Economics suggests that the tiered approach is inferior to a simpler accreditation approach that would be based entirely on tight-margin RA Hours. Potomac Economic notes, however, that it does not deem MISO's approach to be a major shortcoming and certainly not a basis to find the proposal unreasonable.[146]

104. Finally, Potomac Economics contends that MISO's proposed outage exemptions are inconsistent with the principles underlying the availability-based accreditation. Potomac Economics states that resources that schedule more frequent or longer-duration outages are less likely to be available during reliability events, and, because reliability events are increasingly likely to occur when they are not expected, there is no reason to grant exemptions from the availability-based accreditation. Potomac Economics states that maintenance margins are deterministically calculated based on expected conditions at the time that the outages, therefore the proposed maintenance margin criteria ignore unexpected factors and conditions that may arise that trigger reliability events. Potomac Economics submits that since resources that take frequent or long-duration planned outages are less available to respond to these types of reliability events, planned outages should not exempted from the availability-based accreditation, and including such exemptions reduces the benefits of MISO's proposal.[147]

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[144] *Id.* at 9-10.

[145] *Id.* at 10.

[146] *Id.* at 11.

[147] *Id.* at 11-12.

105. The Michigan Commission argues that, while it has concerns about the ability to develop new resources in the MISO North region under the new seasonal construct in time to meet MISO's proposed implementation date of the proposals, set for the 2023/2024 Planning Year, these are issues that can be addressed by MISO to make any adjustments necessary in order to allow resources to be available by the proposed implementation date. In particular, the Michigan Commission notes that MISO filed its proposed Tariff revisions for reducing the generator interconnection queue from 505 to 365 days with the Commission in Docket No. ER22-661-000.[148] The Michigan Commission believes that ensuring that MISO meets this generator interconnection queue target will be critically important in meeting MISO's implementation timeline for MISO's instant proposal, particularly given the fact that the MISO generator interconnection queue currently has been experiencing more delays in the East Region due to PJM's Affected System Studies. The Michigan Commission states that, if MISO and its reliance on affected system studies from its neighbors cannot keep the interconnection queue to its proposed 365-day timeline to bring on necessary generation to meet the new Tariff requirements, then MISO may need to file to delay implementation by a year.[149]

106. ITC contends that the SAC provisions will ensure that committed generation capacity is accurately assessed for its ability to meet the needs of the MISO system at all times, and that generators have the incentive to ensure the delivery of all energy for which they are committed.[150]

107. Several protestors argue that MISO has not fully supported its proposed SAC methodology. DTE Electric contends that MISO has not demonstrated that its accreditation proposal will lead to an increase in the availability or mix of resources.[151] COMPP argues that SAC is unproven and, much like UCAP accreditation, inflates capacity by maintaining too many exemptions.[152] Clean Energy Coalition argues that the calculation process for Schedule 53 resources is data-intensive, time consuming, and susceptible to errors, and it is difficult to obtain intuition around how a change in the

[148] Michigan Commission Comments at 3. On March 14, 2022, the Commission accepted MISO's propose revisions to its Generator Interconnection Procedures (GIP). *See Midcontinent Indep. Sys. Operator, Inc.*, 178 FERC ¶ 61,141 (2022).

[149] Michigan Commission Comments at 3-4.

[150] ITC Comments at 3.

[151] DTE Electric Protest at 13.

[152] COMPP Protest at 13.

inputs will affect outputs.[153] While Ameren agrees with MISO that MISO's accreditation requirements need to be updated and strengthened, Ameren argues that the SAC proposal has not been shown to be just and reasonable.[154] The Mississippi Commission states that the SAC proposal is untested, has never been adequately modeled, offers no assurance that it will effect the intended changes, has not been linked to an actual problem, and has not been used by any other Regional Transmission Organization (RTO) or Independent System Operator (ISO).[155] The Mississippi Commission argues that the SAC proposal attempts to create a price signal to promote investment in certain types of generation, instead of focusing on better outage coordination to ensure generation is available to serve load.[156] The Mississippi Commission notes that, according to MISO's first proposed tranche of MISO's Long-Range Transmission Planning projects, the areas in immediate need of reliability upgrades are Minnesota and Iowa, which coincidently have extensive renewable generation penetration. The Mississippi Commission states that MISO has no plans to evaluate whether Long-Range Transmission Planning projects are needed in MISO South for two years, a strong indication that MISO South is not facing the same reliability concerns as the rest of MISO.[157]

108. East Texas argues that MISO's proposed accreditation process creates an unnecessary, unwarranted, and in many cases, unfair burden on generation owners. East Texas suggests that MISO's justifications for the proposed accreditation methodology are blanket assertions not tied to any basis for immediate change.[158] East Texas submits that MISO has not provided a more thorough analysis of MISO's accreditation proposal that would allow East Texas and other parties to develop a thorough understanding of what these new standards will mean to their operations. East Texas contends that, if the parties who know their resources the best are unable to ascertain the impacts of this complicated accreditation process, it is unreasonable for the Commission to assume that MISO has a full grasp of the potential consequences.[159]

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[153] Clean Energy Coalition Protest at 17.

[154] Ameren Protest at 4.

[155] The Mississippi Commission Protest at 2, 5.

[156] *Id*. at 36.

[157] *Id*. at 6-7.

[158] East Texas Protest at 7.

[159] *Id*.

109. Some protestors contend that the SAC methodology will be unable to predict future availability during times of highest need. Minnesota Power states that the proposal has no defined means to improve on MISO's objective of "converting the capacity procured in the [Auction] to energy when and where they are most needed," given that the SAC values are not reflected into any parameters used in the MISO Security Constrained Economic Dispatch.[160] Clean Energy Coalition argues that the methodology may not provide the intended incentive to utilities and market participants to improve performance of their generators.[161] DTE Electric argues that past performance in tight hours can provide little prediction of future performance.[162] East Texas states that MISO has not explained how concentrating on limited operational time periods would accurately portray the likelihood of a generating unit's availability in a future Season.[163]

110. Entergy Coalition asserts that MISO has not demonstrated that its SAC proposal aligns with MISO's Resource Availability and Need (RAN) initiative goal to close the gap between planning and operational outcomes.[164] Entergy Coalition emphasizes that MISO's SAC proposal is not a good predictor of a resource's future availability and moreover is subject to a high degree of randomness. Entergy Coalition contends that, as a consequence of this randomness, if LSEs base their supply planning decisions on data and information communicated via their SAC accreditation values, many of those decisions will be sub-optimal and will not help achieve MISO's desired operational goals.[165] Entergy Coalition argues that such uncertainty arising from MISO's proposal unnecessarily and unhelpfully complicates the already complex task of assessing the expected future accreditation for a given resource.[166]

111. Alliant is concerned that MISO's proposal is overly aggressive and can have unintended, long-term impacts that could thwart MISO's best intentions. Alliant requests that the Commission require MISO to further engage stakeholders before implementing the changes in the proposal and to postpone the implementation date by at least one

[160] Minnesota Power Comments at 1 (quoting Transmittal at 1).

[161] Clean Energy Coalition Protest at 17-18.

[162] DTE Electric Protest at 14.

[163] East Texas Protest at 8.

[164] Entergy Coalition Protest at 10 (citing McFarlane Test. at 24).

[165] *Id.* at 11.

[166] *Id.*

year.[167] Entergy Coalition argues that MISO's proposed implementation period is inappropriate for such a significant change in market design. Entergy Coalition notes that the Commission has accepted transition periods both for the establishment of new capacity markets and for significant changes in capacity markets, such as the Settlement Agreement that established PJM's capacity market, where the Commission accepted a four-year transition period for locational pricing.[168] Entergy Coalition further notes that the Commission accepted a five-year transition period for PJM's proposed Capacity Performance Resource,[169] as well as required PJM to apply its new rules to Fixed Resource Requirement[170] entities only after the conclusion of the Fixed Resource Requirement plans to which those entities were currently obligated as of the date of the order.[171] WEC Utilities state that MISO's proposed implementation leaves insufficient time for utilities to adjust preexisting business operations and decision processes, specifically insufficient time for LSEs to modify their resource planning or operational strategies to account for seasonal accreditation requirements and performance-based capacity accreditation. WEC Utilities explain that planned outages, which will directly affect seasonal availability, are often scheduled years in advance. WEC Utilities add that some resource owners will likely need to adjust their fuel supply provisions or to improve winterization to ensure availability and accreditation within the new seasonal construct. WEC Utilities argue that MISO's proposal provides "deceptively" little time for market participants to adjust commercial and operation plans to reflect the proposed seasonal requirements.[172] East Texas and Entergy Coalition add that using historic data for the 2023/2024 Planning Year means that resource owners will have little opportunity to take actions to improve their accreditation.[173]

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[167] Alliant Protest at 1.

[168] Entergy Coalition Protest at 20-21 (citing *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331, at P 68 (2006) (PJM Reliability Pricing Model Order)).

[169] *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208, at P 253 (2015) (PJM Capacity Performance Resource Order).

[170] Entergy Coalition states that PJM's Fixed Resource Requirement option is a self-supply option for LSEs to avoid the capacity market auction in PJM. Entergy Coalition Protest at 21.

[171] PJM Capacity Performance Resource Order, 151 FERC ¶ 61,208 at P 218.

[172] WEC Utilities Comments at 4-5.

[173] East Texas Protest 8-9; Entergy Coalition Protest at 22.

112. Some protestors argue that it is inappropriate to accredit resources based on their prior availability under an entirely different capacity accreditation construct. Consumers Energy and MISO TOs argue that the proposed transition framework may punish generators based on operational choices that were prudently made under the existing accreditation framework, because the proposed accreditation methodology will be applied to historical real-time energy offers, outages, and notification times on which those operational choices were based.[174] Consumers Energy asserts that it is inappropriate to impose a "different and controversial" accreditation framework over those choices based on the existing market construct, conditions, and accreditation framework.[175] DTE Electric objects to MISO's proposed implementation timeline, noting that it will require using historical data from before the proposal was approved to calculate accreditation and that it does not allow market participants time to adjust, especially if they will need to add capacity through the interconnection process.[176] East Texas states that, for the initial 2023/2024 Planning Year, two-thirds of the operational performance data would be based on how units operated and took outages in a completely different accreditation construct. East Texas argues that MISO's proposed use of historical data also undercuts one of its assertions for why a new accreditation methodology is needed—that the new methodology will improve incentives to improve availability. East Texas asserts that, because MISO will accredit based on operational data from the prior three years, a generator owner that makes improvements to its facility would not receive full credit for those enhancements until the third year after their completion. East Texas maintains that this delay of credit for an investment would discourage owners from improving current generating units.[177]

113. Entergy Coalition suggests that MISO's implementation plan could open accreditation values and Auction results to allegations of retroactive ratemaking because market participants were not given proper notice. Entergy Coalition states that, while it is common for various rates on file at the Commission to rely on historical information, at the time such rates were filed, ratepayers were prospectively put on notice about the use of their historical activity. In contrast, if a new or newly changed rate relies on historical information where ratepayers had no notice in the past as to how their past behavior would be used in the new rate, that is retroactive ratemaking.[178] Entergy Coalition states that MISO's implementation plan also violates the Commission's policy that changes in

[174] Consumers Energy Limited Protest at 1-2; MISO TOs Comments at 5-6.

[175] Consumers Energy Limited Protest at 6.

[176] DTE Electric Protest at 15.

[177] East Texas Protest at 9.

[178] Entergy Coalition Protest at 22-23.

rate design are appropriate only on a prospective basis. Entergy Coalition states that, at this point, it is too late for generation owners to alter previous accreditation and outage decisions they had made. Entergy Coalition argues that all aspects of MISO's proposal should be implemented on a prospective basis once the rate design is accepted by the Commission.[179]

114. On the other hand, COMPP avers that MISO's proposed three-year transition mechanism delays urgent reforms which are needed sooner. COMPP argues that under the current proposal MISO will only become aware of deficiencies in the SAC construct in Planning Year 2025/2026. COMPP adds that, if the Commission approves the SAC proposal, it should go into effect as soon as practicable.[180]

115. Some protestors express concerns about the specifics of MISO's SAC calculation. DTE Electric argues that MISO's proposal bases capacity accreditation on chance and that basing it on retroactively determined RA Hours will not improve system reliability or efficiency.[181] DTE Electric states that the MISO proposal will "handicap prudent planning" during periods of significant change in the resource mix.[182] DTE Electric argues that MISO's proposal "inappropriately" requires resource owners to predict tight system conditions in advance although MISO itself is not able to because some of these events are unpredictable and emergency scenarios are increasingly common.[183] DTE Electric states that MISO should have based resource accreditation on all hours in a Season if MISO expected generators to always be available as they are expected to be during RA Hours.[184] DTE Electric contends that basing accreditation on select RA Hours rather than on all hours in a Season decreases the impact of the proposal and will not achieve MISO's goal of increasing confidence that capacity is available when needed.[185] Similarly, the Mississippi Commission asserts that an 80%/20% weighting is biased towards periods with emergencies in tight hours because it over-values those hours when infrequent emergencies are forecasted to occur and when the system is tight, and ignores

[179] *Id.* at 23 (citing *Arkla Energy Res.*, 48 FERC ¶ 61,305, at 61,980 (1989); *Nat'l Fuel Gas Supply Corp.*, 140 FERC ¶ 61,114 (2012)).

[180] COMPP Protest at 16-17.

[181] DTE Electric Protest at 2.

[182] *Id.*

[183] *Id.* at 6.

[184] *Id.* at 7.

[185] *Id.*

the majority of hours when reliable resources ensure resource adequacy.[186] The Louisiana Commission and Ameren argue that the 80% weighting factor on RA hours (Tier 1) can be especially punitive to an otherwise reliable and well-performing generator that was unavailable during the often-times randomly occurring RA Hours.[187]

116. Other protestors dispute that RA Hours accurately capture the hours of highest risk. Midwest TDUs argue that MISO has not demonstrated that hours with reserve margins as high as 25% are truly tight and warrant the same heavy weighting as MaxGen hours. Midwest TDUs dispute MISO's suggestion that the 25% threshold "provides a reasonable balance between having an adequate number of RA Hours for each Season and selecting the set of RA Hours that are truly tight," suggesting that MISO's reasoning does not explain why MISO does not base accreditation on hours that are truly tight or represent true emergency conditions.[188] Clean Energy Coalition argues that MISO's attempt to separate high-risk hours from other hours is flawed because it arbitrarily uses a fixed 65 hours per Season and is not consistent with MISO's assertion that risk periods are changing with the adoption of more renewable resources. Clean Energy Coalition further argues that this may artificially create perceived times of risk when there is no risk and may result in periods that are overlooked if there are more than 65 hours of high risk in a Season.[189]

117. Midwest TDUs add that resources do not have the same advanced notice about RA Hours that are not MaxGen hours, as it is impossible to determine whether a particular hour is one with the lowest operating margins in a Season until the end of the Season.[190]

118. Clean Energy Coalition is concerned that the times of tight reserve margins, as defined by MISO, may or may not be the same as those with high Loss of Load Probability (LOLP) risk. Clean Energy Coalition argues that MISO's approach of allowing resources with a 12-hour lead time to count as available for purposes of determining the system's reserve margin fails to consider how unexpectedly tight hours typically arise in the range of 2-8 hours.[191]

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[186] Mississippi Commission Protest at 8.

[187] Ameren Comments at 5; Louisiana Commission Protest at 6.

[188] Midwest TDUs Protest at 7-8 (citing McFarlane Test. at 25).

[189] Clean Energy Coalition Protest at 10.

[190] Midwest TDUs Protest at 8.

[191] Clean Energy Coalition Protest at 11.

119. Several protestors contend that MISO's proposal to use AAOC to supplement deficit RA Hours in a particular Season highlights several flaws in MISO's proposal.[192] Midwest TDUs argue that MISO has not demonstrated that there is any connection between capacity needs in a given Season and a resource's availability during hours in other Seasons, or hours within MISO's 25% operating reserve margin threshold; therefore, it is unjust and unreasonable for MISO to include those hours as part of the 80% weighting in calculating SAC when those hours do not represent the "periods of highest risk and greatest need" during each Season.[193] Midwest TDUs state that this approach means that an in-Season RA Hour could be double-counted, both as part of a resource's Seasonal RA Hours and as part of its AAOC used to backfill Tier 2. Midwest TDUs contend that this use of AAOC means that a resource's accreditation value for a specific Season is based at least in part—and sometimes primarily—on its performance in other Seasons.[194] Clean Energy Coalition argues that AAOC use creates an artificial profile for these resources and assumes risk in a Season when there is none.[195] Similarly, DTE Electric, MISO TOs, and Minnesota Power argue that using AAOC when fewer than 65 RA Hours are available for a Season undermines the seasonality of the construct and does not accurately represent a unit's performance during a specific Season.[196] WEC argues that poor performance in one Season is not necessarily indicative of poor performance in another Season that contains fewer than 65 RA Hours. WEC Utilities suggests backfilling RA Hour deficiencies with the seasonal UCAP of a resource would be more indicative of each resource's seasonal availability.[197]

120. Midwest TDUs state that the use of AAOC to determine Tier 2 accreditation will not be an infrequent or insignificant part of the Tier 2 calculation. Midwest TDUs contend that MISO's Conceptual Design document for the proposal shows that, in MISO North, each of the past three Planning Years had at least one Season with fewer than 65 Seasonal RA Hours, and that, in some cases, a resource's RA Hours for a Season could be determined primarily based on out-of-Season hours. As an example, Midwest TDUs

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[192] Midwest TDUs Protest at 7-14; Clean Energy Coalition Protest at 10; DTE Electric Comments at 14; MISO TOs Comments at 9-10; Minnesota Power Protest at 2; WEC Utilities Comments at 10-12; East Texas Protest at 8.

[193] Midwest TDUs Protest at 14 (citing Transmittal at 16).

[194] *Id.* at 9.

[195] Clean Energy Coalition Protest at 10.

[196] DTE Electric Protest at 14; MISO TOs Comments at 9; Minnesota Power Comments at 2.

[197] WEC Utilities Comments at 10-12.

explain that the Conceptual Design document shows that the Winter of the 2019/2020 Planning Year had just one RA Hour, meaning that over 98% of the Tier 2 hours for that Season would be backfilled based on AAOC during Annual RA Hours. Midwest TDUs argue that, despite MISO's claim that its "proposed reforms measure and mitigate non-Summer reliability risk," MISO's proposal could accredit non-Summer Seasons based primarily on Summer performance, as most Annual RA Hours occur in the Summer.[198] Midwest TDUs argue that this fails to implement MISO's stated goal of "transition[ing] from the current Summer-based, annual construct to four distinct seasons."[199] Midwest TDUs further contend that, if a resource is unavailable during a Winter RA Hour because of extreme cold weather, there is no reason that hour should factor into its accreditation for Seasons that do not have extreme cold weather conditions. Midwest TDUs therefore argue that MISO's proposal to use AAOC to determine SAC fails to ensure seasonal accreditations that reasonably reflect availability in a particular Season.[200] Midwest TDUs contend that, rather than using a resource's availability during RA Hours in other Seasons to backfill RA Hours in one particular Season, it would be more appropriate to fill in deficient RA Hours based on average availability in all hours of that Season. Midwest TDUs argue that, in Seasons with very few MaxGen hours, average availability throughout the rest of that Season is a reasonable approximation of a resource's availability to meet capacity needs in that Season.[201]

121. Midwest TDUs suggest that MISO is inconsistent in describing how MISO will replace Seasonal RA Hours that are exempt from a resource's Tier 2 calculation. Midwest TDUs note that MISO's testimony states that MISO will identify RA Hours, then remove any hours where a resource received a Tier 2 Planned Outage exemption, and finally backfill any deficiency to reach the 65-hour target. Midwest TDUs argue that this implies that MISO will not attempt to identify additional hours with operating margins under the 25% threshold to reach the 65-hour Seasonal RA Hour target after it removes exempt hours, but instead backfill those exempt hours based on Annual RA Hours. Midwest TDUs submit that, in contrast, the proposed Tariff language excludes Planned Outage exemptions from the initial identification of Seasonal RA Hours, meaning that exempt hours are removed *before* MISO attempts to identify sufficient Seasonal RA Hours to reach the 65-hour target. Midwest TDUs state that, under this approach, MISO would first look to replace exempt hours with other non-MaxGen hours within the 25% operating margin threshold before backfilling based on Annual RA

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[198] Midwest TDUs at 9-10 (citing Smith Test. at 19).

[199] *Id.* at 10 (citing Transmittal at 4).

[200] *Id.* at 10-11.

[201] *Id.* at 13-14.

Hours, reducing the extent to which MISO would rely on problematic Annual RA Hours. Midwest TDUs submit that MISO should be required to clarify the inconsistency in its testimony and proposed Tariff language.[202]

122. Some entities argue that MISO's SAC methodology will create an unacceptable level of annual accreditation volatility. DTE Electric states that the current year-to-year accreditation volatility for its capacity resources is 0.8% and that MISO's own analysis indicates that under MISO's proposal, half of market participants will see volatility around 3% and a quarter will see volatility of 6%-12%.[203] DTE Electric argues that the increase in accreditation volatility will send a signal for market participants to overbuild, which will be an additional expense for consumers and is counter to the reserve-sharing purpose foundational to MISO.[204] Entergy Coalition contends that increased volatility is due, in large part, to MISO's placing an 80% weight on historic unit performance during a small subset of tight margin hours, which means randomness—rather than past or expected future unit performance—becomes a primary factor in determining a resource's seasonal accreditation year. Entergy Coalition claims that this, on its face, is unreasonable.[205]

123. Entergy Coalition explains that, if a generally high performing generator is unavailable for one or two days where RA Hours occur, then that resource will see a significant *reduction* in accredited capacity as the outage event is included in the three-year look back period, followed by a significant *increase* in accredited capacity as the forced outage event is excluded from (or rolls off of) the three-year look back period. Entergy Coalition contends that including planned maintenance outages in determining unit accreditation will also lead to higher levels of accreditation volatility.[206]

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[202] *Id.* at 11-12 (citing McFarlane Test. at 26-27).

[203] DTE Electric Protest at 8, 12 (citing RASC presentation, at 6 (Sep. 1, 2021), https://cdn.misoenergy.org/20210901%20RASC%20Item%2003%20RAN%20Resource%20Adequacy%20Contruct%20Presentation%20(RASC%20010,%20011,%20012)584259.pdf).

[204] *Id.* at 8-9.

[205] Entergy Coalition Protest at 4 (citing RASC presentation, at 6 (Sep. 1, 2021), https://cdn.misoenergy.org/20210901%20RASC%20Item%2003%20RAN%20Resource%20Adequacy%20Contruct%20Presentation%20(RASC%20010,%20011,%20012)584259.pdf).

[206] *Id.* at 5.

124. Entergy Coalition notes that MISO's analysis provided in the stakeholder process produced standard deviations of SAC values and found that 25% of market participants will experience a standard deviation between 7.6% and 15.5% from one Planning Year to the next. Entergy Coalition states that its calculations show that a 15.5% standard deviation corresponds with a 20% chance that a market participant's total accredited capacity will undergo a year-to-year change of 20%. Entergy Coalition contends that large year-to-year swings in any availability-based accreditation proposal are evidence that the proposal is a poor predictor of future unit availability, particularly given the small number of RA Hours. Entergy states that, as a result, it is not reasonable to believe that MISO's SAC proposal will be a good measure of a resource's anticipated capability and availability during times of need.[207]

125. Several comments raised the issue of how MISO will incorporate planned generator outages into the SAC accreditation proposal. OMS contends that MISO's proposed outage exemption framework affords generator owners the flexibility to schedule short-notice outages while incentivizing prudent outage planning done well in advance and provides grid operators greater levels of certainty. OMS states it is important to note that, from a utility operations perspective, as the operating day approaches, generator owners have the benefit of more accurate information on expected load and resource conditions to manage the risk associated with taking a short-lead time outage. OMS contends that it would be counterproductive to exempt resources from potential accreditation impacts if system conditions are expected to be tight. OMS argues that this proposal reduces the risk that resources will experience unfair accreditation impacts because resources can schedule outages as short as 14 days out if system conditions are favorable and the outage passes a no-harm test.[208] OMS contends that MISO's current outage classification framework fails to recognize many types of outages and assumes minimal planning outages during different seasonal peak periods, which does not align with observed history. OMS notes that this lack of accounting of correlated outages and past performance history is precisely why the North American Electric Reliability Corporation (NERC) has pointed out the shortcomings of the traditional Reserve Requirements approach.[209] Duke Energy supports MISO's proposed

[207] *Id.* at 6-7.

[208] OMS Comments at 6-7.

[209] *Id.* at 7 (citing NERC, 2020 Long Term Reliability Assessment at 6 (Dec. 2020), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf)

exemption process for full generator planned outages because it appropriately reduces the denominator to accurately reflect the capability of a generator.[210]

126. Consumers Energy agrees that increasing the impact of forced outages during tight hours on resource accreditation will create incentives for generators to appropriately invest in maintenance and supply; but argues that reducing the flexibility to prudently schedule planned outages is arbitrary and does not address MISO's identified issues.[211] Consumers Energy asserts that it is more important for market participants to have flexibility to schedule and plan outages when baseload generation is becoming less common and more consolidated.

127. Consumers Energy states that, if MISO's Maintenance Margin is increasingly insufficient, then MISO should reconsider how it determines the Maintenance Margin or increase how forced outages impact accreditation, as opposed to punishing generators that appropriately coordinate and schedule outages.[212] Consumers Energy asserts that MISO does not explain how modifying the exemption rules for prudently planned outages will improve operating or Maintenance Margins.[213] Consumers Energy also states that eliminating the ability for generators to schedule planned outages less than 120 days in advance without risking accreditation does not address the correlation between forced outages and insufficient investments in winterization or fuel supply.[214] Regarding the shift in resource types, Consumers Energy asserts that MISO also does not tie that concern to the timing of scheduling planned outages, and argues that the proposal will not improve the "confidence in the availability of remaining resources."[215] Furthermore, Consumers Energy argues that MISO's explanation that coordinating outages well in advance will provide more visibility into the resources available under tight conditions does not sufficiently explain how its proposal will improve reliability.[216]

128. Entergy Coalition disputes MISO's statements that resource owners currently have little to no incentive to minimize the length of planned outages. Entergy Coalition argues

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[210] Duke Energy Comments at 4.

[211] Consumers Energy Limited Protest at 7.

[212] *Id.* at 8-9.

[213] *Id.* at 8.

[214] *Id.* at 8-9 (citing Smith Test. at 18).

[215] *Id.* at 9 (citing Wright Test. at 23).

[216] *Id.* at 9-10 (citing Smith Test. at 20).

that resource owners have obvious economic and system reliability incentives to minimize the length of planned outages in order to ensure high availability of their resources, as each day a resource is offline is a day that resource does not collect revenue from energy and ancillary services markets.[217]

129. Several entities protest the requirement to schedule an outage at least 120 days in advance in order to receive a Tier 2 exemption for that outage. East Texas and DTE Electric contend that MISO has not adequately explained why outages must be scheduled 120 days ahead of time to be eligible for a full exemption, nor has MISO explained how such a cutoff would increase resource availability during RA Hours. Consumers Energy argues that increasing the advance notice period required to secure a full outage exemption from 14 days to 120 days is arbitrary, unsupported, and fails to address the issues identified by MISO.[218] East Texas further argues that MISO has not described why all MISO-approved, planned outages cannot receive a full exemption when the Maintenance Margin is greater than zero.[219] Entergy Coalition and Consumers Energy are concerned that the 120-day advance notice criterion could have the perverse effect of discouraging generation owners from performing some maintenance activities, resulting in worse unit performance.[220] Consumers Energy asserts that increasing the advance notice period creates incentives for risky, suboptimal plant operation by discouraging prudent, planned outages in the short to medium term.[221] Entergy Coalition argues that MISO's Tier 2 exemption requirements are unreasonable because, as long as there is a positive Maintenance Margin at the time of submission for the entire duration of a planned outage (with at least 14 days' notice, as currently required under RAN Phase I exemption criteria), it is unreasonable to conclude that the planned outage will materially increase system risk and therefore should lower the resource's accreditation value.[222] Ameren suggests that MISO should be directed to revise the tariff language to require that either the 120-day criterion *or* the Maintenance Margin is met, but not both.[223]

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[217] Entergy Coalition Protest at 13-14 (citing Smith Test. at 20-21).

[218] Consumers Energy Limited Protest at 2.

[219] East Texas Protest at 9; DTE Electric Protest at 10-11.

[220] Entergy Coalition Protest at 14; Consumers Energy Limited Protest at 3-5.

[221] Consumers Energy Limited Protest at 1.

[222] Entergy Coalition Protest at 14.

[223] Ameren Protest at 5-6.

130. Midwest TDUs argue that MISO has not explained why it requires 120 days between planned outages to receive a Tier 2 exemption. Midwest TDUs state that MISO's current Tariff specifically provides for an exemption from the forced outage rate adjustment in resource accreditation in this exact scenario, noting that, currently, a resource will be given an exemption if the market participant provides 120 days' notice and if there is adequate projected Maintenance Margin at the time the request is submitted. Midwest TDUs contend that MISO's proposal may make outage coordination harder, rather than easier, by effectively eliminating the option of scheduling planned outages during the 120-day windows if there is adequate Maintenance Margin during that time.[224] Midwest TDUs submits that, in a situation where a resource requires 30 days of non-consecutive outage, if one day in that 30 day period did not have a positive Maintenance Margin, a resource would be discouraged from splitting its planned outage in two parts to schedule around that one day because the second outage would not receive a Tier 2 Planned Outage exemption. Midwest TDUs argue that MISO's proposal to treat a resource as unavailable during that second outage bears no rational relationship to that resource's expected availability during times of need.[225] DTE Electric states that, compared to the current process, the proposal would limit the ability of market participants to plan outages and receive exemptions for accreditation impacts such that even prudently planned outages may not qualify for an exemption.[226]

131. The Mississippi Commission asserts that outage planning and coordination is an operational issue, not a marketplace issue, and that close coordination, rather than ambiguous price signals and penalties, will lead to better outage planning to avoid periods of shortage.[227] Clean Energy Coalition argues that planning solutions cannot address the underlying problem of scheduled maintenance events and that MISO should propose an operational solution to manage scheduling of outages that may include changes to outage protocols and Maintenance Margins.[228] Clean Energy Coalition contends that MISO has not conducted sufficient analysis to understand the implications of scheduled resource maintenance on grid reliability.[229] Clean Energy Coalition argues that MISO's main concern is the implications of scheduled resource maintenance on grid reliability and that MISO does not use LOLE modeling in a straightforward manner to

[224] Midwest TDUs Protest at 16-17.

[225] *Id.* at 15-16.

[226] DTE Electric Protest at 9-10.

[227] Mississippi Commission Protest at 37.

[228] Clean Energy Coalition Protest at 4.

[229] *Id.*

assess the maximum level of capacity that can be out of service without affecting reliability.[230] Clean Energy Coalition asserts that MISO's proposal resorts to inappropriate modeling that develops seasonal planning reserve margins based on inconsistent resource metrics and flawed inputs. Clean Energy Coalition argues that changing risk profiles throughout the year will make it increasingly difficult for MISO to ensure LOLE targets are met when scheduled resource maintenance may result in insufficient availability of capacity during periods that historically had little risk.[231]

132. Clean Energy Coalition argues that MISO's outage proposal provides a blanket exemption from availability-based accreditation that allows units to avoid an "unavailable" evaluation for an historical RA Hour as long as it gives four months' notice of a planned outage, up to three times a year. Clean Energy Coalition contends that MISO's proposed exemptions severely limit the reliability value of MISO's proposal and gives resource owners little motivation to think twice before scheduling an outage, even at peak times.[232]

133. WEC Utilities state that MISO's proposed filing fails to address potential hoarding of planned maintenance outage margin. WEC Utilities note that the proposed tariff revisions do not include any language to ensure that a resource owner does not hoard Maintenance Margin thereby precluding any other resource owners from scheduling their own outages. WEC Utilities state that nothing in the Tariff or proposed Tariff prohibits a resource owner from scheduling a planned outage every year when it might only need a planned outage every other year; as proposed, the unneeded outage can be simply withdrawn with no penalty and, if the withdrawal of the planned outage occurs within the 120-day window, the resulting increase in Maintenance Margin created by the withdrawal would not be available for other resource owners.[233]

134. Midwest TDUs state that MISO's exemption approach results in different resources having different RA Hours, which, according to Midwest TDUs, further increases the disconnect between MISO's SAC accreditation proposal and an accurate measure of the hours of highest need in a given Season. Midwest TDUs contends that, to avoid this, MISO should truly exempt a resource that qualifies for a Tier 2 Planned

[230] *Id.*

[231] *Id.*

[232] *Id.* at 16.

[233] WEC Utilities Comments at 8-9.

Outage exemption by treating it as if it were available during these hours for purposes of the accreditation determination.[234]

135. Midwest TDUs note that certain Tier 1 exemptions are given if a planned outage passes the No Harm Test. Midwest TDUs state that the No Harm Test includes, but is not limited to, outage approval compliance with all applicable operation guides, review of possible conflicting outages or system conditions, system capacity, and the criteria outlined in the BPM for Generator Outage. Midwest TDUs oppose deference of MISO's Tier 1 exemption criteria to the BPM, as well as the fact that MISO will consider additional unidentified factors beyond those in the BPM. Midwest TDUs add that, similarly, MISO's proposal allows MISO to, at its discretion, grant a Tier 1 Planned Outage exemption if a resource reschedules its Generator Planned Outage at MISO's request. Midwest TDUs argue that the language of these exemptions does not allow the Commission, or resource owners, to understand when MISO will grant Tier 1 exemptions, and, ultimately, how MISO will determine a resource's SAC. Midwest TDUs contend that MISO should be directed to provide greater detail in the Tariff describing the criteria for Planned Outage exemptions.[235]

136. Duke Energy and MISO TOs argue that MISO needs to provide more support for excluding prudently planned derates from accreditation exemptions.[236] Duke Energy states that, during the stakeholder process, it explained its concerns that to treat planned partial outages differently than full generator planned outages by not excluding hours with planned derates from the SAC calculation but doing so for full generator outages would result in an unjust, unreasonable, and unduly discriminatory accreditation calculation.[237] Midwest TDUs state that excluding partial outages from planned outage exemptions would unreasonably reduce a resource's accreditation because of properly coordinated partial outages, and it would create a problematic incentive to schedule full outages rather than partial ones.[238] Great River Energy requests clarification that planned outages scheduled to begin before September 1, 2022 will be granted both a Tier 1 and Tier 2 exemption.[239]

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[234] Midwest TDUs Protest at 12-13.

[235] *Id.* at 47-48.

[236] Duke Energy Comments at 3; MISO TOs Comments at 8.

[237] Duke Energy Comments at 4.

[238] Midwest TDUs Protest at 17-18.

[239] Great River Energy Comments at 2.

137. DTE Electric, Midwest TDUs, and Duke Energy protest MISO's proposal to cap a Schedule 53 Resource's maximum offer at its GVTC, arguing that the cap ignores a Schedule 53 Resource's available capacity.[240] Midwest TDUs assert that using GVTC values as a cap in the SAC methodology, even if those values are seasonally adjusted, is inconsistent with MISO's stated goal of "[u]tilizing offered availability and actual performance [to] provide[] an improved measure of expected availability for each Season."[241] Midwest TDUs state that a resource's capability may vary at different times due to temperature, humidity, and other conditions, and that operating conditions in late May can be much different than those in early March, even though both are within the Spring Season. Midwest TDUs assert that, just as it would be unreasonable to impose a cap on a resource's SAC based on an annual GVTC value that does not reflect capability within a particular Season, it is unreasonable to use a uniform GVTC throughout an entire Season.[242] Duke Energy asserts that MISO's proposed hourly GVTC cap creates a disincentive for reliable service at the top end of generator output and fails to give full accreditation value for the service actually provided to the grid in instances where a generator can and does operate above its GVTC limit.[243]

138. Duke Energy states that a unit's offered availability may be zero in a particular hour when the unit did generate power that was used and available to the market, potentially during times when that generation is needed most. Duke Energy explains that offered availability is commonly at zero during startup and shutdown when, per MISO's rules, generators are not permitted to enter offers. Duke Energy states that, in addition, there may be no offered availability when the generating unit is off-Automatic Generation Control returning from an outage, or entering an outage, but the unit may nevertheless be generating and producing energy. Duke Energy states it is common for a generator to be in-service, physically supporting the grid with its generation output, but have its offer show no availability, which will result in an understated value for accredited capacity. According to Duke, MISO's proposed availability metric would not provide any accredited availability to the generator in those circumstances, despite the fact that the generator actually injects net positive generation into the grid. Duke Energy contends that this will result in an understated value for accredited capacity, potentially

[240] DTE Electric Protest at 14; Midwest TDUs Protest at 18-19; Duke Energy Comments at 14.

[241] Midwest TDUS Protest at 18-19 (citing McFarlane Test. at 15).

[242] *Id.* at 19.

[243] Duke Energy Comments at 14.

increasing cost for customers, and also create a problematic misalignment of incentives.[244]

139. WEC Utilities, DTE Electric, Alliant, and MISO TOs raise concerns that MISO's proposal lacks a mechanism to transition Generator Interconnection Agreements (GIA) to higher Winter capacity values, explaining that some thermal generation resources, such as combustion turbine and combined-cycle generators, have Winter output capabilities that are higher than their Summer capabilities because of lower ambient air temperatures.[245] DTE Electric states that, while MISO recognizes that GVTC values are necessary to appropriately reflect non-Summer capabilities, MISO's proposal fails to recognize that Interconnection Service limitations will also be affected by a more granular construct.[246] WEC Utilities state that some GIAs, especially those that were executed several years ago, may reflect only Summer operating conditions and that the proposed seasonal approach to resource adequacy noted in the deliverability limits of these outstanding GIAs may limit the Winter capacity of some resources.[247] Alliant states that, as a result, as resources make their way through the multi-year interconnection process, significant amounts of existing capacity will be left unaccounted, but available. Alliant argues that MISO's rush to implement its proposal in one year could create artificial resource shortfalls, which could, in turn, force unreasonable costs on customers that would not occur if a complete and orderly transition to a seasonal construct was required.[248] In addition, MISO TOs contend that the SAC proposal may allow for SAC values to be higher than a resource's Network Resource Interconnection Service (NRIS) rights.[249]

140. Some commenters dispute MISO's proposed use of a 24-hour resource lead time in the SAC proposal. For example, Midwest TDUs state that, for an offline resource where "the sum of the Start-Up Time and Start-Up Notification Time Offers exceeds 24 hours," MISO proposes to treat its Hourly Emergency Maximum Limit or Targeted Demand Reduction Level as zero. Midwest TDUs note that this means that longer-lead time resources will be treated as if they were completely unavailable during these critical

[244] *Id.* at 13-14.

[245] WEC Utilities Comments at 9; DTE Electric Protest at 14; Alliant Protest at 6; MISO TOs Comments at 5.

[246] DTE Electric Protest at 14.

[247] WEC Utilities Comments at 9.

[248] Alliant Protest at 6-7.

[249] MISO TOs Comments at 5.

RA Hours. Midwest TDUs argue that MISO has not demonstrated why it proposes to treat an offline, but available, resource with a 26-hour lead time the same as a resource that is unexpectedly unavailable due to a non-exempt outage, as, according to Midwest TDUs, this fails to reflect the value of longer-lead time resources. Midwest TDUs contend that, if these resources have submitted offers but are offline due to MISO's decision not to commit them, that should not negatively impact their accreditation. Midwest TDUs add that many of the situations MISO seeks to address, such as extreme weather events, can be anticipated more than 24 hours in advance.[250]

141. Midwest TDUs contend that MISO should be required to take steps to facilitate the ability of these longer-lead time resources to avoid this extreme, negative impact on accreditation. Midwest TDUs explain that, unless these resources have been committed through the Reliability Assessment Commitment process, which is conducted seven days ahead of the operating day, or the Day-Ahead Reliability Assessment Commitment process, these resources must act proactively to self-commit in order to avoid a hit to their accreditation. Midwest TDUs argue that, if MISO is going to impose a harsh, bright-line threshold of 24 hours, it should provide resource owners with timely information about potential upcoming RA Hours so that they can make informed decisions about whether to self-commit.[251]

142. Entergy Coalition states that MISO's 24-hour lead time proposal would be impractical for many otherwise valuable resources due to either physical limitations or, more often, constraints and costs of contracting firm natural gas supply and delivery to those resources. Entergy Coalition argues that, as a result, the SAC proposal would likely result in substantial increased self-commitment of comparatively inefficient resources to avoid loss of accreditation and potentially significant increased fixed contractual costs for fuel, resulting in less efficient overall use of resources within the MISO region, contrary to MISO's broader goals to provide economic benefits to market participants.[252]

143. While supporting the filing overall as just and reasonable, Potomac Economics argues that treating offline resources with up to a 24-hour lead time as available up to their offered output overvalues less flexible, long lead time units. Potomac Economics asserts that tight conditions typically emerge due to load forecast errors, wind forecast errors, large unit forced outages, or other factors that are not known far in advance.[253]

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[250] Midwest TDUs Protest at 20-21.

[251] *Id.* at 21.

[252] Entergy Coalition Protest at 8.

[253] Potomac Economics Comments at 8.

According to Potomac Economics, most emergencies are recognized and declared between 30 minutes and 6 hours in advance.[254] Therefore, Potomac Economics contends that, despite MISO's assertion that MISO could have reasonably committed a resource in the Day-Ahead Market or Forward Reliability Commitment Process, if most reliability threats emerge during the operating day, then offline resources whose lead times are too long to mitigate the reliability threat provide no value in such events.[255]

144. Some commenters express concerns about MISO's proposal to use a UCAP/ISAC ratio to calculate the SAC accreditation for Schedule 53 Resources. COMPP contends that MISO's use of the UCAP/ISAC ratio highlights inconsistencies between capacity accreditation and MISO's LOLE studies. COMPP explains that, while MISO's Seasonal LOLE Study will determine the amount of UCAP MISO needs to procure to maintain resource adequacy, MISO's Capacity Resources will now be accredited ZRCs based on their SAC. COMPP avers that UCAP does not equal SAC, and the failure to align LOLE metrics with accreditation metrics amounts to MISO's proposal being unjust, unreasonable, and unlawful.[256] COMPP submits that, while MISO recognizes this disconnect, and proposes a conversion ratio between SAC value and the UCAP amount, MISO should instead be directed to conduct a LOLE study that determines needed capacity volumes using the same definition used in the Auction.[257] COMPP notes that no other organized market has approved separating the way capacity is defined in underlying reliability studies from the way capacity is procured.[258] Clean Energy Coalition argues that this ratio adjustment has not undergone independent analysis and its impact on overall system reliability is unclear.[259]

145. Clean Energy Coalition and Midwest TDUs submit that MISO's use of the UCAP/ISAC ratio is discriminatory against non-Schedule 53 Resources. Midwest TDUs assert that non-Schedule 53 Resources are similarly situated to Schedule 53 Resources in terms of accreditation, as well as the relationship between that accreditation and the methodology for determining Reserve Requirements. Midwest TDUs argue that MISO has not supported its proposal to apply a conversion ratio to some resources with accreditation based on historical performance but not others and that, as a result, MISO's

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[254] *Id.* at 9.

[255] *Id.* at 10-11.

[256] COMPP Protest at 12.

[257] *Id.*

[258] *Id.*

[259] Clean Energy Coalition Protest at 8.

proposal is unduly discriminatory and may distort the relative share of accreditation between similarly situated resources.

146. Clean Energy Coalition contends that, after ISAC values are calculated, MISO is proposing to use the UCAP/ISAC ratio to shift the supply curve of Schedule 53 resources to the right, benefitting thermal resources relative to renewable resources.[260] Clean Energy Coalition argues that Schedule 53 resources with better historical availability than their peers will be rewarded, whereas Schedule 53 resources that have worse historical availability will be penalized, while an average Schedule 53 resource will receive a capacity credit equal to its UCAP value, which takes into account forced outages only. Clean Energy Coalition asserts that MISO has not clarified whether widening the accreditation gap between the best performing and worst performing Schedule 53 resources will require the best performing resources to contribute to reliability at levels that exceed their nameplate, and whether the contribution would help or hurt reliability.[261] Clean Energy Coalition further argues that, while the total amount of Schedule 53 Resources accredited under this proposal would be unchanged, it is counterintuitive that high performing resources could be accredited at a level that exceeds their physical ability to perform in an effort to "make up" for the poorer performing units.[262] Similarly, Entergy Coalition contends that the use of the UCAP/ISAC ratio means that under the proposal a resource can have a final accreditation rating exceeding its GVTC. Entergy Coalition suggests that this is another indication that MISO's SAC proposal is a poor indicator of resource capability.[263]

147. COMPP argues that, under MISO's proposal, internal generation resources are accredited using the SAC methodology, while external resources are accredited using a seasonal GVTC methodology. COMPP submits that it is unclear why internal and external resources are subjected to different treatment, as external resources that commit capacity to MISO but fail to make themselves available during RA Hours will not be penalized.[264]

148. Several entities argue that intermittent resources should be accredited using MISO's proposed SAC methodology. Ameren and DTE Electric contend that the proposal to apply the SAC provisions to only Schedule 53 Resources and to except other

[260] *Id.*

[261] *Id.*

[262] *Id.*

[263] Entergy Coalition Protest at 7-8.

[264] COMPP Protest at 15.

resources until a future filing is made does not result in comparable treatment of all resource types and undermines the purpose of requiring accreditation.[265] Minnesota Power supports updating the wind and solar accreditation method to align with the SAC methodology to avoid discriminatory resource planning criteria.[266] COMPP states that, while MISO attempts to ease concerns by committing to a future ELCC effort, MISO has not started work on that effort and it could take years before an improved ELCC construct is adopted.[267] DTE Electric notes that the resources MISO excludes from the proposal are the same resources that MISO cites as in need of change.[268] MISO TOs state that, although MISO indicated that it would address accreditation enhancements to non-Schedule 53 Resources in the future, the Commission should require MISO to start stakeholder discussions prior to the effective date.[269] WEC Utilities argue that MISO has proposed an innovative SAC accreditation methodology for Capacity Resources that will be based on availability during times of need, which should be applied to all resources, not just Schedule 53 Resources.[270]

149. Clean Energy Coalition argues that MISO does not apply consistent risk metrics across different types of resources to evaluate a resource's contribution to risk mitigation.[271] Clean Energy Coalition further argues that MISO's use of average offered MW during times of system risk to measure thermal resource availability is an *ex post* approach based on actual historical performance to assess tight margin hours and measure LOLP or LOLE risk.[272] Clean Energy Coalition then argues that MISO will continue to use ELCC to calculate seasonal accreditation of wind resources (and potentially solar in the future).[273] Clean Energy Coalition contends that ELCC is a probabilistic metric that

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[265] Ameren Protest at 4; DTE Electric Protest at 15-16.

[266] Minnesota Power Comments at 2.

[267] COMPP Protest at 15.

[268] DTE Electric Protest at 2-3, 16.

[269] MISO TOs Comments at 10.

[270] WEC Utilities Comments at 6-7

[271] Clean Energy Coalition Protest at 5.

[272] *Id.*

[273] *Id.* (citing MISO, MISO's Responses to Stakeholder Questions, at 8 (Oct. 5, 2021) ("Further enhancements on solar accreditation will continue at the RASC after the RAN RA construct reform filing to evaluate ELCC or similar availability-based accreditation approaches."),

is based on a statistical expected value and represents an *ex ante* or forecasted capacity. Clean Energy Coalition further argues that MISO's proposal is deficient since it does not address seasonal accreditation for energy storage resources.[274]

150. Clean Energy Coalition further argues that this discrepancy persists even if a wind and thermal resource's performance were identical. Clean Energy Coalition argues that MISO's proposal to use alternative accreditation proposals for different resource types is not consistent with good market design, does not provide consistent signals for resources to respond to periods of reliability risk, and may not provide the level of reliability that MISO seeks.[275] Clean Energy Coalition further argues that MISO's proposal is unjust, unreasonable, and unduly discriminatory since it will compensate thermal generators more than other resources for providing the same amount of capacity.[276]

151. Clean Energy Coalition argues that MISO does not use the same input data to assess periods of risk to calculate thermal and wind resource accreditation. Clean Energy Coalition argues that under MISO's proposal, thermal resources would get credit based upon actual offers during tight margin hours, while wind resources would get credit based upon an expected value of generation during different hours.[277] Clean Energy Coalition argues that the use of ELCC for wind means that risk periods that wind can potentially mitigate are hours when there is a LOLP, measured *ex ante*, whereas tight margin hours for thermal resources, measured *ex post*, are not necessarily the same time periods.[278] Clean Energy Coalition argues that the proposal is therefore not comparing a resource's available capacity on the same basis.[279] Clean Energy Coalition explains that thermal resources are credited based on their performance during tight margin hours that may correspond with LOLP hours. Clean Energy Coalition then argues that MISO's own analysis shows that tight margin hours do not always occur during LOLP hours.[280] Clean

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https://cdn.misoenergy.org/20211006%20RASC%20Supplemental%20Q%20and%20A%20Document595123.pdf).

[274] *Id.* (citing McFarlane Test. at 31-33).

[275] *Id.*

[276] *Id.* at 6.

[277] *Id.* at 7.

[278] *Id.* at 6.

[279] *Id.*

[280] *Id.* at 6-7.

Energy Coalition argues that MISO has not examined whether it is better to pool tight margin hours and LOLE hours and use those periods to assess all resources, or adopt either the LOLP approach or the tight margin approach and apply it to all resources.[281]

152. Clean Energy Coalition argues that the Commission previously accepted MISO's ELCC construct for wind resource accreditation on an annual basis and that the approach would be inappropriate for calculating a seasonal construct as currently proposed by MISO.[282] Clean Energy Coalition argues that current flaws in MISO's ELCC methodology may credit wind resources during hours of no risk while not crediting wind resources for contributions during periods of high risk.[283] Clean Energy Coalition then argues that MISO's SAC proposal arbitrarily re-allocates annual LOLP risk to each Season by assuming that 25% of the annual risk occurs in each of the four Seasons, in direct contrast to the results of MISO's own LOLP modeling and the need for a seasonal construct.[284] Clean Energy Coalition then states that MISO's own analysis shows that risk is not equally spread into each of the four Seasons, creating periods of artificial risk.[285] Clean Energy Coalition finally argues that this arbitrary allocation method removes times of risk that were identified by the annual LOLE calculations used in the status quo approach.[286]

153. Clean Energy Coalition argues that MISO's proposal is unjust, unreasonable, and unduly discriminatory because it does not expressly consider fuel supply risk for coal and natural gas resources but does consider fuel supply risk for wind and solar resources. Clean Energy Coalition argues that MISO's proposal does not explain whether, or to what extent, the availability-based method for determining thermal resource capacity accreditation captures past limitations on fuel availability and whether historic fuel availability is representative of future periods given changes in the resource mix, extreme weather patterns, and other factors.[287] Clean Energy Coalition argues that, in contrast, the ELCC methodology applied to wind resources and the availability-based accreditation for solar resources does take into account fuel supply risks since the assessment of their

[281] *Id.* at 7.

[282] *Id.* at 13.

[283] *Id.*

[284] *Id.*

[285] *Id.*

[286] *Id.* at 14.

[287] *Id.* at 7.

ability to deliver power is directly tied to whether they have fuel (sun or wind) to generate power.[288]

154. Midwest TDUs state that MISO will determine the SAC of wind and non-wind resources, based on particular hours in each Season. Midwest TDUs contend, however, that MISO's proposed Tariff language merely states that SAC accreditation for Dispatchable Intermittent Resources and Intermittent Generation "will be determined by the Transmission Provider based on historical performance, availability, and type and volume of interconnection service, for each Season in accordance with the BPM for Resource Adequacy."[289] Midwest TDUs assert that, given the detailed methodology MISO is proposing to include in the Tariff for Schedule 53 Resources, it is not appropriate for MISO to propose vague changes to the accreditation process for intermittent resources that it will implement through its BPM. Midwest TDUs contend that resources should be on a level-playing field in terms of the level of detail the Tariff provides in terms of the accreditation methodology MISO applies, and the extent to which the Commission has reviewed and accepted those accreditation methodologies. Midwest TDUs state that including these critical details regarding accreditation provides certainty and ensures that the Commission has determined they are just, reasonable, and unduly discriminatory.[290]

155. Industrial Customers argue that MISO has not demonstrated that its proposal to increase the number of calls on LMR DRs who participate as an LMR are required to allow during the Planning Year from 10 to 16 to receive 100% capacity accreditation for the full Planning Year is just and reasonable.[291] Industrial Customers assert that MISO's transmittal letter and prepared testimony provide no information or analysis with respect to how MISO determined the need for 16 LMR calls per Planning Year for LMRs that are accredited for a full Planning Year. Industrial Customers contend that MISO completely ignores the fact that for an LMR that participates in all four Seasons of a Planning Year, the sum of the required allowed seasonal calls amounts to 16 calls per Planning Year, versus the currently required 10 calls per Planning Year.[292]

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[288] *Id.*

[289] Midwest TDUs Protest at 49 (citing MISO, FERC Electric Tariff, Module E-1, § 69A.4 (33.0.0) (proposed)).

[290] *Id.*

[291] Industrial Customers Protest at 4-5.

[292] *Id.* at 6.

156. Industrial Customers state that MISO identified the basis for the proposal in its initial August 4, 2021 presentation to the MISO RASC. According to Industrial Customers, MISO identified that the basis of its proposed requirement for five calls in Summer, three calls in Fall, five calls in Winter, and three calls in Spring is the result of MISO's 2020 LOLE analysis that it performed to support its proposal in Docket No. ER20-1846-000, which the Commission accepted in August 2020, to require LMR DRs receiving a 100% capacity accreditation for a full Planning Year to allow MISO 10 interruption calls per Planning Year.[293] Industrial Customers argue that MISO is essentially proposing to reinterpret its conclusion from the results of MISO's 2020 LOLE analysis to support further increasing the required number of allowed MISO interruption calls on LMR DRs that receive a 100% capacity accreditation for a full Planning Year to 16 calls per Planning Year. Industrial Customers argue that the results of MISO's 2020 LOLE analysis do not support requiring 16 interruption calls per Planning Year given MISO's very recent past interpretation of these results and given the saturation in the above capacity credit curve results beyond 10 calls per Planning Year.[294]

157. Industrial Customers contend that no more than 10 interruption calls in total, in any given Planning Year, should be required of any LMR DR that is receiving 100% capacity accreditation for an entire Planning Year. Further, Industrial Customers assert that MISO has historically never called any LMR more than three times in a given Planning Year. Industrial Customers argue that MISO's proposal would result in an unnecessary chilling of LMR DR participation merely because the risk of 16 interruptions would exist, even though MISO has not demonstrated any operational basis for calling more than four or five interruptions in any given Planning Year.[295]

158. Industrial Customers emphasize that the interruption of electric service when called upon by MISO results in significant costs and operational disruptions to these end-use customers. Industrial Customers state that such costs include, but are not necessarily limited to, lost production, process restart costs, and the cost for consumables, where necessary, to allow the interruptions. With respect to operational disruptions, Industrial Customers assert that, while the minimum MISO Tariff requirement for an LMR DR to remain curtailed is only at least four consecutive hours, many industrial facilities are

[293] *Id.* at 6-7 (citing *Midcontinent Indep. Sys. Operator, Inc.*, 172 FERC ¶ 61,138 (2020) (LMR DR Accreditation Order)).

[294] *Id.* at 7-8.

[295] *Id.* at 8-9.

incapable of ramping up their processes after only four hours of being down such that once they are shut down, they may have to stay at that level for 12 hours or longer.[296]

159. Steel Producers explain that the Tariff requires Demand Resources maintain interruptions for at least four continuous hours, meaning that MISO would effectively increase the amount of hours of interruption from a minimum of 40 to 64. Steel Producers argues that this increase is not supported by any new analysis.[297]

160. The Mississippi Commission argues that the SAC proposal, which it asserts favors quick start-flexible generation units over base-loaded gas and nuclear generation, will marginalize the value of existing generation and drive state utility investment toward MISO's preferred resources. The Mississippi Commission asserts that MISO's proposal would create an artificial shortage of generation that must be filled by flexible ramping generation that is needed in MISO North to address reliability concerns caused by overreliance on wind resources. However, the Mississippi Commission argues, MISO has no authority to marginalize generation that state regulatory authorities have sited, authorized for construction and cost recovery, and that are used to serve state load, based on operating characteristics.[298] The Mississippi Commission asserts that neither the Commission nor RTOs/ISOs may direct a utility to construct a specific type of generation resource, and that the SAC proposal indirectly does what MISO lacks the authority to do.[299]

161. Entergy Coalition contends that MISO's proposal will disrupt LSE resource planning activities and frustrate the state regulatory authority oversight and planning objectives and notes that the Commission has emphasized that the design of MISO's Auction is complementary to LSE integrated resource planning that takes place subject to the rules and procedures of state regulatory authorities.[300] Entergy Coalition argues that the unpredictability embedded in MISO's proposal will make it extremely difficult for: (1) state regulatory authorities and LSEs to replicate and predict future outcomes of

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[296] *Id.* at 9.

[297] Steel Producers Limited Protest at 4.

[298] Mississippi Commission Protest at 31.

[299] *Id.* at 32 (citing 16 U.S.C. § 824(b)(1); *Hughes v. Talen Energy Mktg, LLC.*, 136 S. Ct. 1288, 1292; *see also Pac. Gas & Elec. Co. v. State Energy Res. Conservation & Dev. Comm'n*, 461 U.S. 190, 205 (1983)).

[300] Entergy Coalition Protest at 9 & n.19 (citing *Midcontinent Indep. Sys. Operator, Inc.*, 162 FERC ¶ 61,176 (2018), *order on reh'g*, 170 FERC ¶ 61,215 (2020)).

MISO's proposal; and (2) for LSEs to conduct long term planning consistent with the objectives of the state regulatory authorities that regulate them.[301]

162. Duke Energy argues that MISO has not shown how the proposed SAC accreditation calculation will accurately account for jointly owned units.[302] Duke Energy submits that, in data MISO provided during the stakeholder process, it is not clear that MISO will accurately calculate the capacity accreditation of Capacity Resources that are jointly owned.[303]

c. MISO February 10 Answer

163. MISO reiterates that its proposal will result in demonstrable and effective increases in reliability, stating that protestors fail to recognize the improvements to reliability described in MISO's filing. MISO states that its SAC accreditation proposal will increase system reliability in multiple ways and is a substantial improvement over the current UCAP approach. MISO states that first, establishing seasonal SAC values will provide improved incentives for resources to be available outside of the traditional Summer peak months, in contrast to MISO's current UCAP approach which allows for resources to get capacity credit year-round without having to be available year-round outside of the Summer months. MISO adds that the three-year expected forced outage rating used for a resource's UCAP is highly diluted as it considers all hours over a three-year period and does not give MISO operators a true sense of what capacity can be relied upon when system conditions get tight. MISO contends this is especially critical outside the Summer months where MISO has seen an increase in MaxGen Events.[304] MISO states that establishing seasonal requirements and seasonal SAC values provides increased visibility to MISO operators of resource availability throughout the Planning Year, which will give operators more confidence in what Planning Resources they can expect and count upon when system conditions tighten. MISO adds that its SAC accreditation proposal will provide resources with incentives to be available during times of need because of the 80% weighting of Tier 2 RA Hours. MISO states that aligning accreditation incentives with real-time system needs will enhance operators' confidence in the availability of resources, further improving reliability. MISO states that under its

[301] *Id.* at 10.

[302] Duke Energy Comments at 17.

[303] *Id.*

[304] MISO February 10 Answer at 21-22.

proposal, as time goes on, average resource availability will improve, giving operators more resources to manage tight system conditions, improving reliability even further.[305]

164. MISO explains that its current UCAP approach only accounts for forced outages and derates not determined to be Outside Management Control and, as such, does not fully reflect real-time resource availability—especially during times of need. MISO asserts that using the Hourly Emergency Maximum Limit that resources submit in the Real-Time Market, which MISO proposes to use, among other things, for accreditation more accurately represents a resource's expected availability during tight system conditions than the current UCAP methodology.[306] MISO states that its proposal better aligns planning and operations efforts to ensure capacity sufficiency, closing a gap which has contributed to an overestimate of resource availability. MISO states that, ideally, MISO would be able to know exactly a resource's availability ahead of time, but, without a crystal ball, historical data is the best indicator of future performance.[307]

165. In response to arguments suggesting that MISO's proposed implementation timeline is unreasonable, MISO asserts that its proposed timeline balances the urgent need to address growing reliability risks with the countervailing stakeholder need for time to adjust to the new requirements. MISO submits that, the PJM capacity market precedent regarding a transition mechanism is inappropriate because MISO's proposal is fundamentally different from the changes PJM made to its Reliability Pricing Model for Capacity Performance Resources. First, MISO states that application of the UCAP/ISAC ratio will maintain the overall supply and demand balance at the footprint level, while aligning relative accredited values among different resources. Second, MISO states that Capacity Resources have a must offer obligation under the current resource adequacy requirements, therefore their offered capacity should already generally align with their availability and should already be driven by existing incentives provided by MISO's energy and ancillary services market. Third, MISO states that the proposed transition plan retains the RAN Phase 1 exemptions for generator outages in the initial years of SAC calculations, which MISO asserts are comparable to, if not more lenient than, the proposed Tier 1 and Tier 2 exemptions contained in the proposal.[308] Further, MISO explains that the three-year lookback period, which will begin in the 2023/2024 Planning Year, will only include outage behavior and resource availability that occurred after RAN Phase 1 was accepted and implemented. MISO states that, by that time, the evolving risks to reliability and focus on resource availability during times of need throughout the

[305] *Id.* at 22.

[306] *Id.* at 24-25.

[307] *Id.* at 25.

[308] *Id.* at 7-8.

year were well established and it is reasonable to consider resource performance from this period.[309]

166. In response to arguments that it is inappropriate for MISO to use historical offer and outage data from before SAC implementation because generation owners' operational decisions were based on the market construct and accreditation framework in place at the time, MISO submits that system operators need to know what is truly available to meet real time system conditions, and waiting or prolonging the use of data until after the implementation date of the SAC proposal will continue to provide MISO operators with a false sense of what is truly available. MISO adds that it has also provided a transition period to the 80% weighting of availability in prior Tier 2 RA Hours, which is intended to mitigate some of this concern.[310]

167. MISO states that it has provided detailed data to stakeholders, including seasonal SAC value and requirements at the portfolio level, unit-level SAC values on a seasonal basis, and extensive and detailed data for at least one individual resource for each stakeholder, including all the inputs and calculations necessary to allow stakeholders to independently validate how MISO derived the SAC values for that resource. MISO states that this information was provided more than once to stakeholders that requested the data over the course of the conceptual design.[311]

168. MISO disputes arguments suggesting that the proposal's approach to risk hour identification and compensation of resources for reducing loss of load risk is flawed by arguing that MISO has worked deliberately in recent years to explain and lay out evidence that changes to the generation portfolio, load patterns, and weather are driving uncertainty and variability that necessitate accreditation approaches that account for these changes' risks and their timing. MISO states that in the past it was considered sufficient to have enough capacity to cover a system's expected peak load, with a reasonable Reserve Requirement. MISO adds that it was also reasonable to assume that the same amount of capacity would also be sufficient during non-peak times of the year. MISO contends that, because MISO has experienced 41 MaxGen Events since June 2016 with more than 60% of those MaxGen Events occurring outside of the Summer Season, this is no longer a safe assumption. MISO states that it worked with stakeholders and the Market Monitor to craft a proposal that accounts for LOLE risk and carefully considers resource performance in each Season and the incentives needed to improve availability during times of need. MISO states that instead of being rigid, the proposal dynamically

[309] *Id.* at 29.

[310] *Id.*

[311] *Id.* at 31.

accounts for changing risks by basing most of a resource's accreditation on its availability during RA Hours that reflect the times of greatest need.[312]

169. MISO submits that its original proposal weighted Tier 2 hours at 100% toward a resource's offered availability, but stakeholders requested a method that also recognized a resource's reliability contribution during non-RA Hours. MISO states that it recognizes the value of general availability, especially as it supports needed generator planned outages; however, as the Market Monitor's analysis of the current UCAP method illustrates, general availability at all times does not adequately reflect availability during times of highest risk and availability during times of highest risk better represents a resource's true reliability value. MISO states that, as a result, MISO responded by developing the two-tier accreditation proposal, weighting offered availability in Tier 2 RA Hours at 80% to emphasize each resource's reliability contribution during times of greatest reliability needs.[313]

170. In response to comments regarding the potential impacts of missing an RA Hour due to Market Participants' self-commitments decision, MISO states that it is worth noting that the impacts to future accreditation and capacity revenues can be estimated by considering the probability of missing RA Hours and an expectation of Auction Clearing Prices and the reduction in accreditation over the upcoming three planning years. MISO adds that the quantified impacts of a resource missing an RA Hour and the potential impact to future capacity revenues can be compared to other relevant costs and energy market revenues to help inform decisions that impact resource operation and availability.[314]

171. MISO disputes arguments that MISO's proposal introduces unreasonable volatility into accreditation. MISO asserts that, by design, more resource level volatility with the proposed SAC accreditation methodology would be expected, but in aggregate the proposal leads to very little volatility at the MISO Region-wide level from year to year, especially over time. MISO states that its proposal leads to less than 2% volatility at the MISO Region-wide level, in part because of the application of the UCAP to SAC conversion ratio. MISO states that its proposal reduces the potential for individual resource volatility by retaining the three-year lookback period, which helps ensure that a resource's accreditation is not dramatically reduced as a result of a couple of bad days during a Season. MISO states that a key consideration for market participants is the stability of the accreditation of their resource portfolio in a Zone or subregion rather than

[312] *Id.* at 36-37.

[313] *Id.* at 25-26.

[314] *Id.* at 35-36.

the higher volatility expected from individual resources, which may move up or down due to specific conditions that impacted a particular resource's availability.[315]

172. MISO argues that its proposal will allow regulatory authorities and LSEs to continue to be able to replicate and predict future outcomes from the proposed SAC accreditation methodology and LSEs will still be able to conduct long term planning consistent with the objectives of the state regulatory authorities that regulate them. MISO states that resources may experience some volatility from one year to the next in the amount of accreditation they receive, but, on an aggregate basis, MISO does not expect large swings, especially as outage behavior changes and resources avoid unavailability during times of need.[316]

173. With regard to arguments that MISO's use of the AAOC may not accurately represent a resource's availability in a particular Season, MISO states that it believes that the use of RA Hour availability during out-of-Season RA Hours in a Planning Year is a reasonable substitute in the determination of accreditation as AAOC reflects actual resource availability during tight conditions throughout the year. MISO states that, while some stakeholders suggested using all-hours availability during the Season to "backfill" RA Hours, MISO believes that approach would inappropriately dilute the assessment of a resource's availability during tight conditions because it substitutes the resource's availability during non-tight conditions. In addition, MISO states that it does not support WEC Utilities' suggestion to use a Seasonal UCAP when there is a deficiency in RA Hours in a particular Season because, according to MISO, UCAP does not fully reflect a resource's actual availability, which is why MISO has proposed its accreditation reforms.[317]

174. MISO states that it is necessary to have a minimum number of RA Hours to support stability of accreditation values and avoid situations where a resource loses most of its capacity value for the Season because it happened to not be available on the one or two days during that Season's RA Hours. MISO asserts that the use of AAOC to backfill RA Hours is therefore appropriate when a Season has deficient RA Hours.[318]

175. MISO disputes arguments that in-Season RA Hours could be double counted in determining a resource's accreditation. MISO states that for any Season that lacks sufficient RA Hours, set at 65 hours minimum, the SAC accreditation will augment the

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[315] *Id.* at 20.

[316] *Id.*

[317] *Id.* at 27-28.

[318] *Id.* at 28.

deficient number of hours less than 65 for that resource with its AAOC over the tightest 3% of hours during the year, or 260 hours. MISO submits that, while referencing availability outside the Season is not the ideal metric, it is a reasonable proxy with which to supplement needed resource performance data. MISO adds that to the extent any of the Seasonal RA Hours are also in the set of Annual RA Hours, this would not statistically constitute double counting because the individual hours would be 1/65th (1.538%) of the resource performance for any seasonal RA Hour but would only be 1/260th of the AAOC, which itself would account for 1/65th (0.006% combined) of the resource performance in Tier 2. MISO adds that, even in the unlikely event that there were only 1 seasonal RA Hour, that hour would only account for 1.913% of the resource performance, which is less impactful than counting that same RA Hour twice. MISO states that, regardless, it is reasonable and appropriate to include these RA Hours in both cases as they successfully represent seasonal and annual availability during high-risk hours.[319]

176. With regard to transparency for planned outages, MISO states that it has been publishing information for years about submitted planned outages in its Maintenance Margin tool with results posted on the MISO Open Access Same-Time Information System (OASIS) every weekday. MISO states that in particular, the transparency report MISO provides on OASIS shows the total amount of submitted planned outages for future days and an after-the-fact accounting of the actual realized amount of planned outages for historical days, which is provided separately for each sub-region.[320]

177. MISO states that, as part of the RAN Phase 1 Tariff changes, a planned outage currently receives an exemption from being included in a resource's future accreditation by: (1) submitting the outage 120 days or more in advance; or (2) if there is positive Maintenance Margin for the duration of the outage. MISO argues that, rather than continuing this either-or approach, MISO proposes that both conditions from RAN Phase 1 should be met in order to completely disregard a unit's unavailability when it is on a planned outage during the times of greatest need.[321]

178. MISO disagrees with arguments that its proposal creates incentives for resources to delay full or partial outages. MISO states that, currently, the vast majority of forced outages count against accreditation without consideration of their timing and impact, and, as a result, the precipitating event for many MaxGen Events is higher than expected forced outages, especially during extreme weather or capacity scarcity. MISO asserts that under the proposal, forced outages during an RA Hour are much more impactful than

[319] *Id.* at 29-30.

[320] *Id.* at 11.

[321] *Id.* at 16.

under the current accreditation rules, which will create incentives for decisions such as preventive maintenance, winterization, and fuel assurance that will ultimately help avoid unavailability during RA Hours.[322] MISO submits that currently, a unit on a forced outage for one day would see an impact of .1% of potential UCAP accreditation, whereas under the proposal a unit missing 8 RA Hours out of the target 195 hours of a Season (accounting for the three-year averaging) amounts to 4.1% of the Tier 2 accreditation, which comprises 80% of the Seasonal SAC accreditation. MISO argues that the higher impact on accreditation from forced outages aligns with the intent of MISO's proposal to base accreditation on resource availability during times of needed.[323]

179. MISO suggests that it may not be prudent for generators to push needed outages out 120 days to secure a full exemption, and that, if delaying an outage is expected to risk grave harm, then the resource can and should do what it deems necessary. MISO states that, if instead the outage is not urgent and a resource is confident that there is little risk of capacity scarcity due to sufficient Maintenance Margin or other considerations, then taking an outage with a Tier 1 exemption or no exemption at all poses little if any risk to its accreditation. MISO contends, however, that should an RA Hour occur despite expectations of sufficient capacity, it is proper for accreditation to consider that the Resource Adequacy Requirements resource was not available when it was needed and had not sufficiently coordinated to obtain a Tier 2 exemption.[324]

180. MISO disagrees that its proposal will discourage generation owners from performing prudent maintenance activities. MISO states that its proposal provides exemptions for outages planned well in advance (i.e., 120 days), and, even if an outage is not planned well in advance, that does not mean a resource will automatically see a huge effect on accreditation due to MISO's proposed tiered accreditation and because a resource can choose not to participate in that Season's Auction. MISO states that it disagrees that resource owners will push planned outages off because the SAC proposal provides incentives for those resource owners to be available and minimize outages. MISO states that delaying outages could lead to future forced outages that may be catastrophic in nature and result in little or no future credit for that resource.[325]

181. MISO argues that its proposal does not fail to address the potential that a resource will hoard the Planned Outage Maintenance Margin because the proposal builds on its current generator outage provisions, which include protections against a generator

[322] *Id.* at 17-18.

[323] *Id.* at 18.

[324] *Id.* at 18-19.

[325] *Id.* at 21.

submitting frequent or long planned outages that did not reflect their actual outage needs. MISO states that, under its proposal, outages will not be considered timely and will not secure the related exemption if they occur less than 120 days from the end of the previous outage. MISO states that, while it is true that room for planned outages can be scarce due to capacity scarcity, MISO carefully coordinates outages and the proposal provides incentives for scheduling the duration of an outage during times of sufficient margin.[326]

182. MISO contends that its proposal does not unduly discriminate against certain resource types. MISO explains that under the current proposal non-Schedule 53 Resources will receive a SAC value based on resource type consistent with their current accreditation rules adjusted for each specific Season. MISO states that non-Schedule 53 Resources already receive credit based on their availability; therefore, MISO's proposed changes to the accreditation for Schedule 53 Resources would better align the accreditation for all resource types than the current UCAP approach that has been approved by the Commission as just and reasonable. MISO states that it recognizes that there are improvements that can be made to the accreditation of non-Schedule 53 Resources and has already commenced renewable accreditation discussions with stakeholders.[327]

183. In response to Clean Energy Coalition's claim that MISO arbitrarily allocates 25% of the annual LOLE risk to each Season to calculate seasonal wind ELCC, MISO explains that the purpose of LOLE risk target used in the wind ELCC accreditation calculation is fundamentally different from the risk target used in determining seasonal Reserve Requirements. MISO states that the ELCC calculation involves modeling and solving two cases, one with wind and one without wind, to the same reliability LOLE target in order to have an accurate comparison between the two cases to determine the reliability contribution of wind. MISO states that the LOLE target for the ELCC analysis needs to be large enough to produce a sufficient sample size of LOLE risk days to accurately calculate wind ELCC value. MISO states that it has performed a range of sensitivity analysis on various LOLE risk targets for the ELCC calculations and found that using a LOLE target of 0.025 day per year produces sufficient data samples for each Season and stabilizes seasonal ELCC values for wind resources.[328]

184. MISO explains that it proposes capping the Real-Time Emergency Maximum Limit offers used for SAC accreditation at the resource's GVTC value for two reasons: (1) to ensure a resource does not receive more capacity credit within a Season than it has demonstrated through seasonal correction of a GVTC test; and (2) to align the LOLE

[326] *Id.* at 39-40.

[327] *Id.* at 24.

[328] *Id.* at 46.

modeled capacity with the SAC values for purposes of the MISO-system wide UCAP/ISAC ratio. MISO states that, because GVTC is a basis for UCAP, if the SAC values were not capped the ratio would be skewed, further misaligning the capacity LOLE model and the Hourly Emergency Maximum Limits.[329]

185. In response to arguments that MISO's proposal unnecessarily restricts Winter capacity and that MISO should modify its interconnection provisions to reflect non-Summer Seasons, MISO notes that its existing GIP allows interconnection customers to request their desired interconnection service amount (in MW) within the Installed Generating Facility Capacity, which is the facility's maximum gross output. MISO states that as of today, higher Winter capacity amounts have already been requested by multiple interconnection customers. MISO argues that capacity restrictions may exist today under existing GIP and that it is appropriate and necessary for resource owners to initiate separate interconnection requests for additional interconnection service amounts. MISO contends that the proposal maintains the existing interconnection service amounts granted as is, and that the proposal provides additional incentives to encourage Interconnection Customers to request at higher seasonal capabilities with transitioning to the seasonal construct.[330]

186. MISO contends that it has supported the proposed provision to consider a resource unavailable for accreditation purposes when it is offline with a lead time that exceeds 24 hours. MISO states that a majority of capacity is either cleared or committed in the Day-Ahead Market and the first post Day-Ahead Reliability Assessment Commitment, and the 24-hour threshold assumes the resource could reasonably be economically committed if needed. MISO states that most MaxGen Events have been driven by events occurring after the Day-Ahead Market clears. MISO adds it intends to review the impact and appropriateness of this provision after sufficient time has passed after implementation to inform continued refinements should they be needed.[331]

187. MISO acknowledges that there is a "disconnect" between the LOLE model, which produces the seasonal requirements, and SAC accreditation. MISO states that it proposes a system-wide UCAP/ISAC ratio to address this "disconnect." MISO states that it will strive to produce SAC requirements directly from the LOLE model as it further develops

[329] *Id.* at 34.

[330] *Id.* at 38-39.

[331] *Id.* at 42-43 (citing Potomac Economics Comments at 10).

the LOLE model capabilities; however, MISO believes the proposed ratio is an appropriate solution that aligns the LOLE model requirements with accreditation.[332]

188. MISO states that its Tariff currently includes detail on how wind and non-intermittent resources are accredited, and that MISO is not proposing to make changes to those provisions. MISO contends that arguments raised by Midwest TDUs and others related to wind and non-intermittent resource accreditation should be addressed in any future filing involving those resources.[333]

189. MISO disagrees with arguments that it has failed to demonstrate the proposal to increase the minimum number of required allowed interruption calls for LMR DRs from 10 per Planning Year to 16 in order to receive 100% capacity accreditation is just and reasonable. MISO states it performed an analysis in early 2020 (2020 LOLE Analysis)—prior to the Commission-approved LMR filing in Docket No. ER20-1846-000—that showed on an annual basis that LMR DRs needed 15 calls to get 100% capacity accreditation.[334] MISO asserts that it used this analysis along with MaxGen Events in particular Seasons to distribute the number of annual calls across the four Seasons. MISO states that its proposal requires one additional call per Planning Year than the 2020 analysis indicated. MISO explains that under the proposed seasonal construct, all LMR DR resources have the option to participate in a respective Season's auction with no more than the five calls historically required for LMR qualification. MISO contends that, if an LMR DR cannot respond 16 times to qualify for all four Seasons in a Planning Year, it can offer in just those Seasons that correspond with its capabilities to participate.[335]

d. Answers to the MISO February 10 Answer

190. Alliant states that MISO's proposed seasonal accreditation methodology will inappropriately rely on limited data that includes anomalous values and/or fails to represent future resource performance.[336] Alliant expresses doubt that MISO's proposed SAC methodology will improve reliability in a cost-effective way or accurately reflect

[332] *Id.* at 34-35.

[333] *Id.* at 48.

[334] *Id.* at 33 (citing RASC presentation (Feb. 5, 2020), https://cdn.misoenergy.org/20200205%20RASC%20Item%2005b%20RAN%20LMR%20Accreditation%20and%20LOLE%20modeling423730.pdf).

[335] *Id.*

[336] Alliant Answer at 5.

resource availability.[337] The Mississippi Commission argues that MISO fails to demonstrate or offer evidence that the SAC proposal will improve reliability.[338] The Mississippi Commission notes that MISO acknowledges that Zone 10 resource accreditation is expected to decrease under the proposal and contends that MISO has not provided analysis to demonstrate that these resources are less reliable than other resources, and that MISO is overlooking the contribution of these resources during February 2021 cold weather event.[339]

191. WEC Utilities support the seasonal resource adequacy construct but seeks additional transition time to adjust resource planning and operational strategies.[340] WEC Utilities note that the MISO proposed transition timeframe will not mitigate the impact on decisions that require a long lead time or have already been made, such as the decision to add new generation resources.[341] WEC Utilities note that it can take 18 months to obtain a GIA and additional years are needed to complete construction of new resources.[342] WEC Utilities state that there is no exemption for accreditation impacts on resources with inadequate weatherization or non-firm fuel supplies, the way there is an exemption for planned outages.[343] WEC Utilities assert that activities such as capacity resource planning, fuel procurement, backup fuel readiness, winterization, and staffing levels require additional time but will enhance resource availability during times of highest risk.[344] WEC Utilities state that additional stakeholder discussions and time for preparation are necessary before MISO's proposed SAC can be implemented.[345]

192. Alliant states that MISO's proposed timeline is not realistic from a cost or scheduling perspective, especially if it relies on the GIP process to address some

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[337] *Id.*

[338] Mississippi Commission Answer at 4.

[339] *Id.* at 5.

[340] WEC Utilities Answer at 4.

[341] *Id.*

[342] *Id.*

[343] *Id.*

[344] *Id.* at 4-5.

[345] *Id.* at 5.

stakeholder concerns.[346] Alliant states that it is illogical for MISO to express concern with reliability in the footprint while capacity that is currently available is waiting to interconnect and access MISO markets.[347] Alliant argues that MISO's commitment to ignoring the practical realities of using existing processes to achieve overly aggressive short-term goals will result in resource owners purchasing high-cost, unnecessary capacity to meet overly conservative capacity need estimates.[348] Alliant requests that the Commission require MISO to delay the proposed implementation schedule.[349]

193. Entergy states that the MISO February 10 Answer does not alleviate concerns regarding MISO's implementation timeline. Entergy states that, while MISO may be correct that supply/demand balances will be maintained at the footprint level, the supply/demand balance at the Zonal level will change, and MISO does not provide an opportunity for LSEs to take actions to improve their supply/demand balance prior to the 2023/2024 Planning Year. Further, Entergy states that it agrees with MISO that the existing must-offer requirement for Capacity Resources means "their offered capacity should already generally align with their availability," but argues that these rules actually lend added support for rejecting MISO's availability-based SAC proposal because existing MISO rules already create such general alignment.[350]

194. Midwest TDUs argue that the MISO February 10 Answer fails to demonstrate that it is just and reasonable to determine seasonal accreditations by backfilling Tier 2 hours with Annual RA Hours (or AAOC) comprised of: (1) hours already included in Tier 2 for that Season; and (2) out-of-Season RA Hours.[351] Midwest TDUs state that in-Season RA Hours would factor into SAC twice and be weighted more heavily than other hours.[352] Midwest TDUs assert that MISO provides no evidence that availability during

[346] Alliant Answer at 7.

[347] *Id.*

[348] *Id.*

[349] *Id.*

[350] Entergy Answer at 7 (citing MISO February 10 Answer at 7-8).

[351] Midwest TDUs Answer at 6-7.

[352] *Id.* at 6.

out-of-Season tight hours is a better measure of seasonal availability than other in-Season hours, and that such an assumption is inapposite to a shift to a seasonal construct.[353]

195. Entergy states that the MISO February 10 Answer confirms the underlying uncertainty and volatility of its SAC proposal and argues that the proposal will make prudent resource planning extremely difficult.[354] Entergy argues that the aggregate effects of the volatility in MISO's SAC proposal will be evident in LSE Reserve Requirement surplus and deficit positions and Local Clearing Requirement surplus and deficit positions, but ignore and overlook the effects on individual LSEs and resource owners.[355] Entergy argues that a planning paradigm that cannot reasonably be predicted defies any reasonable effort to conduct long-term planning consistent with such an objective.[356]

196. Entergy argues that MISO's statement that "[i]deally, MISO would be able to know exactly a resource's availability ahead of time but, without a crystal ball, historical data is the best indicator of future performance" highlights the underlying uncertainty or randomness of the SAC proposal.[357] Entergy further states that, like MISO, resource owners do not have a "crystal ball" or know when events requiring the greatest need will occur and Entergy argues that it is not reasonable for MISO to claim it is incentivizing resources to be available during times of greatest need when those times are unpredictable.[358] Entergy argues that the minimum number of RA Hours in MISO's proposal (i.e., 65 hours) does not address concerns about the volatility of resources accreditation or inherent unpredictability of events that lead to times of greatest need.[359]

197. Alliant states that MISO's proposal would allow for significant volatility in accredited capacity at a local level, even if there is not excessive accredited capacity

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[353] *Id.*

[354] Entergy Answer at 3.

[355] *Id.* at 3-4.

[356] *Id.* at 5.

[357] *Id.* at 5 (citing MISO February 10 Answer at 25).

[358] *Id.* at 4.

[359] *Id.* at 5.

volatility across the MISO footprint.[360] Alliant asserts that local capacity resource accredited capacity volatility will not enhance reliability.[361]

198. Midwest TDUs argue that MISO offers no defense of its proposed requirement that outages must be scheduled at least 120 days from the last planned outage to qualify for a Tier 2 Planned Outage Exemption.[362] Midwest TDUs argue that MISO provides no explanation for its proposal to ignore historical performance and cap accreditation based on a seasonally corrected GVTC test.[363] Midwest TDUs assert that MISO fails to explain the relationship between its LOLE model, proposed GVTC adjustment, and proposed UCAP/ISAC ratio.[364] Midwest TDUs state that MISO's proposal does not resolve the disconnects between the various components of its resource adequacy construct, but rather includes a "patchwork of ad hoc adjustments."[365] Midwest TDUs also argue that MISO has not shown that it is just and reasonable to provide zero accreditation for offline resources with lead times longer than 24 hours.[366] Midwest TDUs assert that MISO does not explain why it is appropriate for such longer lead time resources to bear the entire risk of anticipating RA Hours more than 24 hours in advance, as opposed to MISO, or why these longer lead time resources are in a better position than MISO to anticipate RA Hours.[367] Midwest TDUs claim that self-commitments based on limited information would likely lead to less efficient dispatch, resulting in higher costs for consumers without providing meaningful reliability benefits.[368] Midwest TDUs assert that MISO provides no justification for applying a UCAP/ISAC conversion ratio to Schedule 53

[360] Alliant Answer at 4.

[361] *Id.*

[362] Midwest TDUs Answer at 7-8.

[363] *Id.* at 8-9.

[364] *Id.* at 9.

[365] *Id.* at 10.

[366] *Id.* at 10-11.

[367] *Id.* at 11.

[368] *Id.*

Resources but not to other similarly situated resources, such as intermittent resources that are also accredited based on actual availability.[369]

199. Regarding MISO's proposal to increase the number of required allowed calls for LMR DRs from 10 per Planning Year to 16 per Planning Year to receive 100% capacity accreditation, Industrial Customers argue that the MISO February 10 Answer does not clarify or correct any misstatements identified in their protest and does not address their concerns including the problematic nature of MISO's reliance on its early 2020 analysis.[370] Industrial Customers argue that, in Docket No. ER20-1846-000, MISO used the 2020 LOLE Analysis to support increasing the minimum number of required interruption calls for LMR DRs from 5 to 10 per Planning Year to receive 100% capacity accreditation for a full Planning Year, and that MISO concluded that only 10 required calls per Planning Year were needed. Industrial Customers argue that MISO has not produced a new analysis that shows different results and has not justified its reinterpretation of the 2020 LOLE Analysis to now support requiring LMR DRs to provide up to 16 interruption calls per Planning Year for 100% capacity accreditation for a full Planning Year rather than up to 10 calls per Planning Year.[371]

200. Industrial Customers contend that MISO has not demonstrated that past MaxGen Events support its proposal to require up to 16 interruption calls per Planning Year from LMR DRs in order for them to receive a 100% capacity accreditation for a full Planning Year.[372] Regarding MISO's assertion that that LMRs who cannot meet its proposed 16 interruption calls per Planning Year can still participate and receive 100% capacity accreditation for a single Season, Industrial Customers reiterate that unnecessarily decreasing the ability of end-use customers to participate as an LMR DRs for a full Planning Year and increasing their cost of such participation would unnecessarily harm the end-use customers that are participating as LMRs and unnecessarily decrease the total supply of capacity in the MISO footprint (through a reduction in full Planning Year LMR participation). Industrial Customers claim these impacts would unnecessarily increase the capacity costs of all end-use customers in the MISO footprint.[373]

201. Midwest TDUs argue that MISO inappropriately defers matters to the Market Monitor and BPMs that should otherwise be included in MISO's Tariff because they

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[369] *Id.* at 11-12.

[370] Industrial Customers Answer at 3-4.

[371] *Id.* at 4-5.

[372] *Id.* at 5.

[373] *Id.*

significantly affect rates, terms, and conditions of service.[374] Midwest TDUs assert that the following matters should be included in MISO's Tariff: (1) determination of whether an outage could have been reasonably anticipated; (2) Tier 1 Planned Outage Exemptions; (3) accreditation of non-Schedule 53 Resources.[375]

e. Deficiency Letter Response

202. As noted above, on March 9, 2022, Commission staff issued a deficiency letter and requested additional information, and MISO submitted its Deficiency Letter Response on April 8, 2022. In response to a question requesting quantitative evidence demonstrating the extent to which historical resource performance as reflected in the proposed SAC accreditation is more indicative of future resource performance than the current UCAP method, MISO reiterates that the current UCAP method only accounts for forced outages and derates deemed not outside management control. MISO explains that, by design, UCAP ignores many factors that impact resource availability resulting in significant overstatement of resource availability. MISO adds that the UCAP method does not differentiate between periods of high risk and low risk, resulting in overstating resource availability during emergency periods, especially when those risks occur outside of Summer. MISO submits that, by contrast, the SAC methodology emphasizes resource availability during times in need and accounts for factors described above that UCAP ignores.[376]

203. MISO argues its analysis demonstrates that the proposed SAC methodology is more indicative of future resource performance during emergency periods than the current UCAP methodology. MISO provides a table comparing actual resource offers to how that resource is accredited using UCAP, ISAC, and AAOC in two scenarios: (1) MISO North, Summer; and (2) MISO South, Winter. The table indicates that in MISO North, Summer, resources offered 73,280 MW during MaxGen Events. MISO's UCAP accreditation for that same period was 79,062 MW (a 7.8% deviation), and its ISAC accreditation was 73,885 (a 0.8% deviation). In MISO South, Winter, resources offered 30,588 MW during MaxGen Events. MISO's UCAP accreditation for that same period was 37,322 (a 22% deviation), and its ISAC accreditation was 30,223 MW (a -1.2% deviation).[377] MISO explains that MISO and the Market Monitor believe that ISAC is the most relevant basis for comparison to UCAP because ISAC is directly calculated

[374] Midwest TDUs February 25 Answer at 28-29.

[375] *Id.* at 29-30.

[376] MISO Deficiency Letter Response at 7.

[377] *Id.* at 5.

based on Real-Time offers and is highly correlated with historical and future resource performance during emergency periods.[378]

204. MISO states that its analysis indicates most Seasons reach 65 RA Hours based on the four years of historical data MISO examined, with only 2 of the 32 Seasons MISO evaluated falling significantly short of the 65-hour target. MISO state that, as a result, a resource's Schedule 53 SAC calculation for any specific Season was based primarily on the performance of a resource during the relevant Season.[379]

205. MISO states that it is theoretically possible for a resource's SAC to be calculated primarily based on its performance in other Seasons, but this would only happen if there were a large amount of RA Hour exemptions applicable to a specific resource. MISO states that, for example, a resource could miss the vast majority of RA Hours for a Season year after year due to lengthy planned outage exemptions. MISO states that, for the majority of SAC to be based on performance outside the Season a resource would have to average more than 40 exempt RA Hours in each Season. MISO states that simply missing 50% of RA Hours in a Season is not enough to make other Seasons more important to a resource's SAC accreditation because Tier 1 is weighted at only 20%.[380]

206. MISO submits that, when the full 65 RA Hours per Season does not exist for a resource, the AAOC is a reasonable proxy because it reflects the typical availability for the resource during times of need. MISO provides a table demonstrating that in MISO North, Summer, accrediting the MISO fleet with AAOC resulted in a -4.7% deviation from offers during MaxGen Events, while in MISO South Winter, AAOC accreditation resulted in a 0.5% deviation from actual offers.[381]

207. MISO contends that the AAOC was specifically developed to address small sample sizes of RA Hours in a given Season so that Tier 2 accreditation would not be based on a limited set of hours, which could under or overstate a resource's capacity value. MISO states that without AAOC to use as an indicative measure of a resource's availability during high-risk periods, a resource might have a limited sample of non-

[378] *Id.* at 7-8.

[379] *Id.* at 4.

[380] *Id.* at 5.

[381] *Id.*

exempt RA Hours over a three-year lookback period making its accreditation highly volatile.[382]

208. In response to a question regarding the UCAP/ISAC ratio, MISO states that the ratio has two primary benefits. First, MISO states that use of the UCAP/ISAC ratio prevents the need to convert Reserve Requirements and Local Clearing Requirements into SAC terms. Second, MISO states that the ratio eliminates the possibility that the Auction Clearing Price would need to be increased in order to offset the lower volume and to maintain the overall supply and demand balance. In addition, MISO asserts that the UCAP accreditation method overstates resource availability because it only considers forced outages when accounting for availability. Further, MISO submits that it is exploring whether the LOLE study can use SAC instead of UCAP, but explains that industry tools and modeling practices would have to be modified and then tested to ensure they accurately measure LOLE risk.[383]

209. With regard to proposed outage exemptions for the SAC, MISO states that the requirement that an exempt outage be 120 days or more since the end of a previous planned outage is designed to disincentivize frequent outages, which could reduce the Maintenance Margin available to other resources.[384] MISO clarifies that it does not intend for planned outage exemption provisions to apply to planned and unplanned partial generator outages, also known as derates. MISO states that exemptions for derates could be considered in a future enhancement as the current outage coordination processes do not evaluate derates, which are typically submitted with no or little advanced warning.[385]

210. In response to a question about why MISO is not proposing to accredit certain resources that are currently accredited based on availability as Schedule 53 Resources, MISO states that MISO has a long-standing history of different accreditation methods for different resource types, which the Commission has accepted as just and reasonable. MISO states that its ultimate goal is to align accreditation for all resources with the resource's availability during times of need. MISO states that, while accreditation methods are different across resource types, they are comparable and relevant to the characteristics of those resource types. MISO states that, as an example, wind resources will continue to be accredited based on seasonal ELCC with capacity credits allocated based on each wind resource's performance over eight peak demand hours per Season,

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[382] *Id.*

[383] *Id.* at 9.

[384] *Id.* at 13.

[385] *Id.* at 10.

and solar resources will be accredited based on historical availability during specific hours representing typical seasonal peak demand hours.[386]

211. MISO states that it recognizes the need to further align the proposed accreditation methodology for Schedule 53 Resources and the existing accreditation for non-Schedule 53 Resources, but submits that its proposal closes the gap that currently exists as it better aligns the resource accreditation for all resource types than under the current UCAP approach. MISO adds that wind and solar have different offer requirements and are not as easily incentivized to be available during times of need as compared to Schedule 53 Resources.[387]

212. In response to a question regarding the proposed increase of required calls for LMR DRs from 10 in a year to 16, MISO reiterates that its 2020 LOLE analysis demonstrates that LMR DRs needed 15 calls on an annual basis to receive 100% accreditation for the Planning Year. MISO explains that, with the proposed changes to a seasonal construct, MISO used this analysis, together with an analysis of past MaxGen Events, to distribute the number of annual calls across the four Seasons. MISO states that continuing to only require 10 interruption calls in a Planning Year would be over-stating LMR DR availability at times of system need.[388]

f. Responses to Deficiency Letter Response

213. Some commenters addressed the evidence MISO provided to support the proposed SAC accreditation method. Potomac Economic states that it finds MISO's data regarding SAC accreditation and expected performance to be compelling, and adds that SAC will be more accurate because it comprehensively addresses all reasons for resource availability compared to MISO's current UCAP accreditation, which only reflects forced outage rates. Potomac Economics states that, because UCAP accreditation only considers outages reported in GADS, it is not possible for UCAP accreditation to predict availability during emergencies.[389]

214. Alliant raises concerns that MISO's Deficiency Letter Response indicates that the piecemeal approach MISO proposes has the potential for costly and option-limiting consequences. Alliant reiterates its request for the Commission to require further

[386] *Id.* at 15-16.

[387] *Id.* at 16.

[388] *Id.* at 17-19.

[389] Potomac Economics Response to MISO Deficiency Letter Response at 4-5.

stakeholder process before implementing a seasonal resource adequacy construct.[390] Clean Energy Coalition argues that MISO's response to the Deficiency Letter's request to provide further quantitative evidence that SAC is a better indicator of expected future resource availability than UCAP is insufficient because MISO provides only aggregated data for two Seasons.[391] Minnesota Power argues that MISO did not provide quantitative evidence of SAC accreditation being more indicative of future performance in emergency periods than UCAP.[392]

215. The Mississippi Commission argues that MISO's Deficiency Letter Response fails to provide quantitative evidence demonstrating the extent to which historical performance as reflected in SAC accreditation is more indicative of future performance in emergency periods than the UCAP methodology. The Mississippi Commission suggests that MISO's rationale presupposes that a resource owner can predict when an emergency will occur, and that the occurrence of historical emergencies accurately reflects the occurrence of future emergencies. The Mississippi Commission argues that neither of these assumptions are true.[393] Further, the Mississippi Commission argues that the table MISO provided, which is based on 6 days in the Summer and 5 days in the Winter of 2021, is not sufficient evidence to support MISO's conclusion.

216. Midwest TDUs argue that MISO fails to provide quantitative evidence supporting final SAC values because MISO instead compares its existing UCAP methodology to ISAC, rather than final SAC values. Midwest TDUs also argue that MISO provides only data from a single Season in MISO North and MISO South, which, according to Midwest TDUs, is too small of a sample size to evaluate MISO's proposed methodology.[394]

217. Entergy states that MISO's response as to whether historical performance using the SAC accreditation methodology is more indicative of future performance than the existing UCAP accreditation is flawed. First, Entergy states that MISO's answer is not responsive to the Deficiency Letter because MISO provides ISAC values rather than SAC values. Second, Entergy states that MISO only provides analysis on one emergency period for MISO North and South, which, according to Entergy, is too small of a sample size to draw meaningful conclusions from. Third, Entergy contends that examining region-wide aggregated accreditation values does not provide insight into the ability of an

[390] Alliant Response to MISO Deficiency Letter Response at 6.

[391] Clean Energy Coalition Response to MISO Deficiency Letter Response at 5-6.

[392] Minnesota Power Response to MISO Deficiency Letter Response at 2.

[393] Mississippi Commission Response to MISO Deficiency Letter Response at 4.

[394] Midwest TDUs Response to MISO Deficiency Letter Response at 3-4.

accreditation methodology to predict the availability of individual units, and it would be much more insightful to investigate the correlation between the accreditation ratings of individual resources and those resources' availability during emergency periods. Entergy submits that this analysis would demonstrate whether units with higher SAC accreditation relative to their GVTC are more likely to be available during emergency periods than units with lower SAC ratings. Entergy contends that MISO's analysis provides no evidence as to whether SAC is a better predictor of a unit's availability during MaxGen hours than UCAP or any other alternative accreditation methodology. Entergy states that, for example, it is possible that a significant number of units with high SAC ratings were unavailable during the 2021 MaxGen emergency hours studied by MISO, which would undermine the predictive performance of SAC. Entergy states that MISO's analysis did not look at individual unit performance during the 2021 MaxGen hours so there is not enough information to properly judge SAC's or UCAP's ability to predict future performance during emergency periods.[395]

218. Several commenters discussed MISO's proposed use of AAOC in SAC accreditation. Potomac Economics agrees with MISO that AAOC is a reasonable approach in cases where RA Hours are deficient in a given Season. Potomac Economics submits that using data from other Seasons' RA Hours is preferable to using performance data during the same Seasons from non-RA Hours because RA Hours are not known in advance so resources that perform well must either be running in most hours or have the flexibility to be available on short notice. Potomac Economics argues that, because historical data from Non-RA Hours do not capture resource responsiveness to short-notice RA Hour events, it would be inferior to MISO's proposal.[396]

219. Minnesota Power argues that MISO failed to address the question raised in the Deficiency Letter regarding the inclusion of RA Hours from another Season being used to meet the 65-hour RA Hour target.[397] Similarly, the Mississippi Commission contends that MISO's Deficiency Letter Response fails to justify using data from other Seasons to supplement deficient RA Hours in a particular Season. The Mississippi Commission submits that, instead, MISO states it is unlikely that there will be fewer than 65 RA Hours in any given Season.[398]

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[395] Entergy Response to MISO Deficiency Letter Response at 3-4.

[396] Potomac Economics Response to MISO Deficiency Letter Response at 5.

[397] Minnesota Power Response to MISO Deficiency Letter Response at 2.

[398] The Mississippi Commission Response to MISO Deficiency Letter Response at 3.

220. Midwest TDUs argue MISO has not demonstrated that the AAOC method is just and reasonable because MISO's support for use of AAOC relies on too small of a sample size and MISO does not evaluate all Seasons.[399] Midwest TDUs argue that MISO compares AAOC to offers during emergency hours during Summer 2021, but because Summer 2021 would have met the 65 RA Hour target, there would have been no need to use AAOC in that situation. Midwest TDUs argue that, in contrast, the AAOC is most relevant in non-Summer Seasons, but MISO has not provided evidence demonstrating how well AAOC approximates performance during times of need during non-Summer Seasons.[400]

221. Clean Energy Coalition contends that using performance data from other Seasons for accreditation of a thermal resource in a given Season does not fulfill the objectives of the filing, which is to identify times of risk and credit resources to the extent they mitigate that risk. Clean Energy Coalition states that a resource's typical availability during times of need in other Seasons does not always correlate with availability during the Season for which it is being accredited.[401] Clean Energy Coalition states that, while on a system-wide basis, using performance hours from other Seasons may give similar results, this may not be true on an individual resource basis, violating the principle that generators must be compensated based on their actual contribution to resource adequacy and thus to reliability during the specific Season they are accredited.[402] Clean Energy Coalition argues that for the Winter Season, many generators would see higher accreditation using the AAOC methodology than they would if only RA hours from prior Winter Seasons were used. Clean Energy Coalition states that, conversely, wind generation tends to be higher in the Winter, and if a similar accreditation approach for wind generation is used in the future, wind accreditation for the Winter would likely be lower than wind's actual Winter capacity availability.[403]

222. Many commenters discussed MISO's proposed use of the UCAP/ISAC ratio to calculate final SAC accreditation values. Potomac Economics states that the foundation of MISO's availability-based accreditation is that it should not fundamentally alter the supply and demand balance in the capacity market. Potomac Economics explains that since the planning model calculates Planning Resource needs in UCAP terms and resources are accredited in SAC terms, a ratio must be used to adjust the demand for

[399] Midwest TDUs Response to MISO Deficiency Letter at 5.

[400] *Id.* at 6.

[401] Clean Energy Coalition Response to MISO Deficiency Letter Response at 3.

[402] *Id.* at 4.

[403] *Id.*

planning resources into SAC terms or the capacity supply values back into UCAP terms. Potomac Economics states that the proposed UCAP/ISAC ratio is superior to alternative approaches because of its relative effects on Schedule 53 and non-Schedule 53 Resources. Potomac Economics states that, if MISO were to adjust the UCAP demand downward into SAC terms, this would effectively increase the quantity of demand that can be served by every accredited MW of capacity. Potomac Economics contends that this would not be appropriate for non-Schedule 53 Resources because the proposal does not modify the accreditation of these resources. Potomac Economics states that this would result in a relative increase in accredited capacity for non-Schedule 53 Resources and provide for an "unjustified windfall" benefit at the expense of Schedule 53 Resources.[404]

223. Potomac Economics adds that the UCAP/ISAC ratio is needed to maintain the available accredited capacity consistent with MISO's LOLE planning process. Potomac Economics states that, although the planning study produces resource adequacy requirements in UCAP terms, it considers most of the factors that affect unit availability, not just forced outages. Potomac Economics states that, for example, if planned outages were to increase substantially over historic levels, the resource adequacy requirements (expressed in UCAP) would rise correspondingly. Potomac Economic submits that it is therefore necessary to resolve the difference between the UCAP-based demand for Planning Resource capacity and availability-based accreditation under SAC in order for the capacity market to achieve its objectives.[405]

224. Potomac Economics states that, with some changes, the LOLE planning models could produce requirements in SAC terms. Potomac Economics cautions, however, that it is important to recognize the model would not be assuming the SAC values for each resource in its modeling because many of the factors that affect the availability of resources are random factors that must be modeled in the planning model through a Monte Carlo process that produces thousands of random draws. Potomac Economic states that the result of this process indicates the amount of capacity that is needed (or demanded), which can be denominated in ICAP, UCAP or SAC. Potomac Economics concludes that, while transitioning the LOLE model to produce requirements in SAC terms could have some value, it is not essential to implement MISO's proposal.[406]

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[404] Potomac Economics Response to MISO Deficiency Letter Response at 2-3.

[405] *Id.* at 3.

[406] *Id.* at 4.

225. Minnesota Power argues that MISO did not provide any technical basis for the proposed UCAP/ISAC ratio.[407] Midwest TDUs argue that MISO continues to provide a reasonable explanation for its proposal to scale up Schedule 53 Resource accreditation but not non-Schedule 53 Resources. Midwest TDUs contend that MISO's explanation that accrediting non-Schedule 53 Resources based on UCAP overstates a resource's availability because it only considers forced outages does not describe the accreditation of all non-Schedule 53 Resources. Midwest TDUs explain that certain resources, such as wind and solar, are currently accredited based on their historical availability during times of need. Midwest TDUs argue that MISO has failed to explain why it is just and reasonable to apply a UCAP/ISAC conversion ratio to some resources, but not others.[408]

226. Entergy states that MISO's Deficiency Letter Response fails to explain how Local Clearing Requirements are impacted by the two options provided by the Market Monitor. Entergy states that in the first option, the MISO-wide Reserve Requirement was scaled by the UCAP/ISAC ratio and zonal Local Clearing Requirements were scaled by the zonal UCAP/ISAC ratio. Entergy states that as a result, MISO-wide supply/demand balance was maintained and each Zone's Summer Local Clearing Requirement supply/demand balance was also maintained. Entergy states that the Market Monitor's second proposal scales up SAC accreditation of thermal resources such that only the MISO-wide supply/demand balance is maintained and the zonal Local Clearing Requirement supply/demand balance is altered. Entergy states that MISO has not explained why it took the inconsistent approach of designing a proposal that maintains the MISO-wide supply/demand balance but does not maintain the zonal Local clearing Requirement supply/demand balance. Entergy states that the result of this decision means that some zones' Local Clearing Requirement supply/demand balance will be improved and other zones' Local Clearing Requirement supply/demand balance will be worsened. Entergy argues that given the importance of Local Clearing Requirement in determining zonal Auction Clearing Prices, it is unjust and unreasonable for MISO to drastically change the Local Clearing Requirement supply/demand balance of a zone due to a change in accreditation methodology without providing adequate time for market participants in the zone to procure additional capacity to restore the prior Local Clearing Requirement supply/demand balance.[409]

227. Commenters also raised concerns about MISO's proposed exclusion process for planned outages. Duke Energy asserts that MISO's Deficiency Letter Response demonstrates that more clarification is necessary and submits that MISO's justification

[407] Minnesota Power Response to MISO Deficiency Letter Response at 3.

[408] Midwest TDUs Response to MISO Deficiency Letter Response at 13-14.

[409] Entergy Response to MISO Deficiency Letter Response at 1-2.

for the exclusion of planned derates from outage exemptions fails to acknowledge other sources of reliable information on planned derates that could be used until MISO develops further system enhancements. Duke Energy suggests that MISO could use planned derate information submitted in GADS. Duke Energy states that the Commission should require MISO to commit to a timeline to file changes that would apply the Schedule 53 Resource planned outage exemptions to derates, as well.[410]

228. Midwest TDUs argue that MISO has not justified its proposal to disqualify derates from planned outage exemptions outside of the fact that its current outage provisions do not evaluate for derates. Midwest TDUs argue that MISO should be required to explain why it is just and reasonable to disqualify all planned outage derates from Schedule 53 planned outage exemptions.[411]

229. The Mississippi Commission argues that MISO fails to explain why a 120-day gap between planned outages to receive Tier 2 exemptions is an appropriate duration. The Mississippi Commission argues that MISO provides no evidence of prior excessive outages.[412]

230. Consumers Energy argues that planned derates should be eligible for the same exemptions as full scheduled outages. Consumers Energy contends that penalizing planned derates but not planned outages creates incentives for generator operators to fully shut down resources that could be partially operating and producing needed energy to ensure they receive a full Tier 2 exemption. Consumers Energy contends that this is a suboptimal outcome for all parties, hurting grid reliability, raising energy prices, and weakening generator economics.[413]

231. Midwest TDUs argue that MISO's attempt to justify its Tier 2 Planned Outage exemption requirements are largely unresponsive, as MISO does not explain why a requirement for 120 days between outages would increase Maintenance Margin availability for other resources. Midwest TDUs suggest that this requirement creates incentives for resources to schedule longer outages, thereby decreasing Maintenance Margin for others, because one 30-day outage could qualify for a Tier 2 exemption but

[410] Duke Energy Response to MISO Deficiency Letter Response at 2-3.

[411] Midwest TDUs Response to MISO Deficiency Letter Response at 12-13.

[412] The Mississippi Commission Response to MISO Deficiency Letter Response at 6-7.

[413] Consumers Energy Response to MISO Deficiency Letter Response at 2-3.

two 10-day outages could not.[414] Consumers Energy argues that MISO does not provide enough support for the required 120-day notice requirement for planned outages to receive a Tier 2 exemption. Consumers Energy asserts that MISO does not explain why this amount of lead time is necessary, how or why this amount of notice will be superior to the existing two-week requirement, or what risk assessments will be available that currently are not.[415]

232. Entergy argues MISO failed to answer why Tier 2 exemptions are not granted in the event that the Maintenance Margin is above zero. Entergy states that MISO's response fails to recognize that the use of Maintenance Margin already assists generation owners in coordinating planned outages, making MISO's proposed 120-day coordination period excessive and unnecessary. Entergy states that, when an outage is scheduled during a time with a positive Maintenance Margin, MISO should not need to conduct extensive coordination processes or risk assessments.[416]

233. Industrial Customers argues that MISO's Deficiency Letter Response does not provide any additional support to increase the minimum amount of allowed calls for LMR DRs to receive 100% capacity accreditation in a Planning Year. Industrial Customers states that, in particular, MISO does not address the problematic nature of relying on the 2020 LOLE analysis as the basis for requiring 16 interruptions per Planning Year.[417] Industrial Customers state that MISO's 2020 LOLE Analysis showed that 10 calls per Planning Year would provide 97.4% capacity accreditation, while requiring an additional call would only increase capacity accreditation by an additional 2.6%. Industrial Customers reiterate that MaxGen Events have never exceeded eight total in any given Planning Year, and MISO has historically never called any LMR more than three times in a Planning Year.[418] Industrial Customers argue that MISO's response demonstrates that its proposal does not provide prorated capacity credit for LMR DRs, even though MISO's analysis indicates support for 97.4% accreditation for LMR DRs that make themselves available for 10 calls in a Planning Year.[419]

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[414] Midwest TDUs Response to MISO Deficiency Letter Response at 11.

[415] Consumers Energy Response to MISO Deficiency Letter Response at 2-3.

[416] Entergy Response to MISO Deficiency Letter Response at 5.

[417] Industrial Customers Response to MISO Deficiency Letter Response at 7.

[418] *Id.* at 8-9.

[419] *Id.* at 9-10.

234. Clean Energy Coalition argues that MISO fails to adequately explain why it is inappropriate to include other resources that are currently accredited based on availability as Schedule 53 Resources. Clean Energy Coalition argues that MISO must "demonstrate that the two accreditation methodologies work together and assess capacity availability during the same risk hours in order for the construct to hold together both theoretically and practically to ensure a reliable system that can meet load during these high-risk hours."[420]

235. Clean Energy Coalition argues that accreditation should be consistent across all resource types, so as to not discriminate between different technologies. Clean Energy Coalition submits that several principles should be applied to avoid discrimination: (1) capacity accreditation for all resource types should be performed using the same methodology, including assessment during the same set of high-risk hours; (2) accreditation approach should be consistent so that a resource that mitigates more risk should receive a higher accreditation, and two resources that mitigate the same level of risk should receive the same accreditation; and (3) accreditation of each resource should be the same, regardless of the order in which resources' accreditation is calculated and accounted for. Clean Energy Coalition argues that MISO's proposal fails to meet these principles.[421]

236. Clean Energy Coalition states that it recognizes that the Commission recently approved PJM's capacity accreditation approach, which uses different accreditation methodologies for thermal and intermittent resources. Clean Energy Coalition states, however, that PJM recognizes in its filing that it would need to revisit its approach when its energy mix transition includes more intermittent resources. Clean Energy Coalition states that MISO's energy mix includes approximately 22% wind resources, with approximately 153 gigawatts of mostly solar and wind in its interconnection queue. Clean Energy Coalition believes that MISO should use a comparable accreditation approach for all resources now, rather than later.[422]

237. The Mississippi Commission argues that MISO's response does not justify treating External Resources differently from MISO internal resources, nor does MISO's response justify the exclusion of Stored Energy Resources – Type II from Schedule 53 Resource

[420] Clean Energy Coalition Response to MISO Deficiency Letter Response at 6.

[421] *Id.* at 7.

[422] *Id.* (citing *PJM Interconnection, L.L.C.*, 176 FERC ¶ 61,056, at P 67 (2021) (*PJM Interconnection*)).

accreditation.[423] The Mississippi Commission further argues that MISO does not explain why it proposes a 24-hour-or-less lead time requirement for Tier 2 accreditation. The Mississippi Commission asserts that MISO has not tied the requirement to modeling results, a contingency analysis, or operating parameters.[424]

g. MISO May 20 Answer

238. MISO states that its Deficiency Letter Response addresses the substance of the Commission's questions regarding the proposed 120-day requirement and application to Tier 2 exemptions. MISO states that the 120-day language in regard to granting a Generator Planned Outage exemption is included in MISO's Commission-approved Tariff. MISO states that the filed proposal resulted from a collaborative stakeholder process that sought to balance accurate capacity accreditation with proper incentives for prudent outage planning. MISO contends that, contrary to protestors' assertions, MISO provided support to establish that the proposal is just, reasonable, and non-discriminatory. MISO notes, for example, its Deficiency Letter Response explains that the proposal to require 120 days' notice of a planned outage in order to receive a Tier 2 exemption is designed to provide MISO the information needed prior to the start of a Season in order to identify and mitigate potential reliability issues.[425]

239. MISO states that it sufficiently explained the rationale for not including derates in the Schedule 53 Tier 2 exemption process by noting that its current outage processes do not evaluate planned derates, which are typically submitted with little to no advance notice.[426] MISO notes that over the last two years only 2.2% of derates were submitted with advanced notice of at least 14 days, which is the minimum amount of time needed to secure an exemption under MISO's proposal.[427]

240. MISO states that its Deficiency Letter Response provided a table showing that SAC is a better predictor of future offers than UCAP, which Potomac Economics found compelling. MISO states that it has demonstrated that its SAC methodology for Schedule 53 Resources would reasonably measure future availability during times of need in each

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[423] The Mississippi Commission Response to MISO Deficiency Letter Response at 2.

[424] *Id.* at 2-3.

[425] MISO May 20 Answer at 6 (citing Deficiency Letter Response at 13).

[426] *Id.* at 8 (citing Deficiency Letter Response at 12).

[427] *Id.* at 8-9.

Season and create powerful new incentives to offer as much availability as possible when MISO declares a MaxGen or when operating margin forecasts suggest tight conditions.[428]

h. Midwest TDUs June 6 Answer

241. Midwest TDUs dispute MISO's claim in its May 20 Answer that MISO has adequately responded to the Commission's request for quantitative evidence. Midwest TDUs argue that MISO does not, and cannot, explain how providing data from only a single Season in MISO North and a single Season in MISO South demonstrates how its SAC proposal is indicative of availability in all Seasons. Midwest TDUs assert that MISO's own emphasis on recent emergency events in other Seasons highlights the inability of this limited data to provide any basis for a Commission determination that MISO's proposed accreditation methodology is indicative of future performance during emergency periods in all seasons.[429]

242. Midwest further TDUs argue that the MISO May 20 Answer glosses over protestors' concerns regarding MISO's treatment of planned outage exemptions under Schedule 53. Midwest TDUs contends that MISO has not justified why planned derates that meet MISO's advanced notice requirements should be foreclosed from qualifying for exemptions.[430]

i. Commission Determination

243. We find MISO's proposed SAC accreditation is a just, reasonable, and not unduly discriminatory or preferential method for accrediting the capacity of Schedule 53 Resources because it will assign resources a capacity value based on their historical performance during high-risk hours in each Season. We find this approach is a reasonable basis to estimate a resource's expected availability during future times of need in a Season, which, in turn, is a reasonable basis to accredit the capacity of Schedule 53 Resources. MISO's SAC proposal provides resource owners with strong incentives to maximize resource availability during high-risk hours, which in turn will increase MISO operator confidence that those resources will perform when they are most needed.

244. We disagree that MISO's accreditation proposal is overly burdensome or complicated for resource owners. MISO's proposed SAC accreditation provides market participants with the specific calculations to determine how their resources will be valued under the new proposal. We also disagree that the SAC calculation process is overly

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[428] *Id.* at 10-11.

[429] Midwest TDUs June 6 Answer at 3.

[430] *Id.* at 3-4.

data-intensive or time-consuming. If MISO can calculate SAC values for all Schedule 53 Resources in its footprint and provide those values to resource owners within the timeframe provided for in MISO's Tariff, we believe that replicating and estimating or confirming those calculations will not be overly burdensome for individual resource owners.

245. We disagree with the Mississippi Commission that MISO has not supported the application of the SAC proposal to MISO South. We find that MISO has sufficiently demonstrated that its SAC proposal is just and reasonable and will result in several improvements to capacity accreditation in MISO, such as increased confidence in generator availability during high-risk hours, better coordination of resource outages, and stronger incentives for resources to be available in times of need. Collectively, these outcomes should provide benefits to MISO's entire system, not just a particular MISO region.[431] Further, as illustrated by 2021 Winter Storm Uri, MISO South can face capacity challenges for which additional accuracy in resource accreditation and incentives for resources throughout MISO to maximize their availability during peak periods would be beneficial.

246. We disagree with protestors' arguments that the SAC methodology will not predict the availability of Planning Resources during times of MISO's highest need. As an initial matter, the SAC methodology aligns a Schedule 53 Resource's reliability value with its historical availability at times of system needs throughout the Planning Year. While no capacity accreditation methodology can perfectly predict a resource's future availability or performance during all intervals, we find that MISO has demonstrated that the SAC methodology resource offers will reasonably predict resource availability in future Seasons.[432] We also disagree with claims that the SAC accreditation unduly increases volatility or otherwise is based on random data. We find that, by considering additional factors, including derates and planned outages that are not scheduled well in advance, the SAC methodology improves the accuracy of capacity accreditation by considering unit performance in times where the unit is most needed. We find that the resulting improved accuracy and alignment of performance incentives of the SAC value outweigh increased volatility.

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[431] *See., e.g.*, MISO February 10 Answer at 22 ("The more available resources become during these [high-risk] periods, the more future capacity credit they will receive. Aligning accreditation incentives with real time system needs will enhance operators' confidence in the availability of resources, further improving reliability.").

[432] *See* MISO Deficiency Letter Response at 7-8 (demonstrating that the ISAC accreditation was significantly more accurate in predicting MISO's fleet-wide offers during MaxGen hours in the Summer in North/Central and the Winter in MISO South).

247. While we find that MISO has supported its proposed SAC accreditation method, additional information regarding SAC's accuracy after the MISO's proposal is fully implemented would benefit the Commission and the public. Accordingly, we direct MISO to submit an informational report covering the first three Planning Years SAC accreditation is implemented. Specifically, we require MISO to, within 90 days of the conclusion of the 2025/2026 Planning Year, submit an informational report that compares the results of SAC accreditation to actual resource availability. The report should include data providing the SAC accreditation, resource availability, and UCAP accreditation (as a point of reference) for all RA Hours in all Seasons for the 2023/2024, 2024/2025, and 2025/2026 Planning Years. The data report should include the requested data (1) by Season, both in aggregate and for each sub-region; (2) by Season and by resource type (e.g., combined cycle, combustion turbine, coal units, and LMRs); and (3) for individual resources (specifically the weighted average percent variance for individual resources across the Planning Year).[433]

248. We disagree that MISO's proposed implementation timeline is unjust and unreasonable. MISO filed its proposal 16 months ahead of the 2023/2024 Auction, after several years of stakeholder discussion. Further, MISO's proposal includes a three-year transition process that gradually increases the accreditation weight of RA Hours each Planning Year. Further, the three-year rolling average used to calculate ISAC values reduces the extent to which resource availability in any one Season will impact a resource's capacity value, and over time the SAC will update to reflect resource performance under the new capacity accreditation methodology. Finally, MISO's proposal to treat resources that are scheduled to go on outage prior to September 1, 2022, the effective date of this proposal, as fully exempt from both Tier 1 and Tier 2 Hours will assist in the transition to a new accreditation framework, as the largest operational decision that resource owners will likely face as a result of this proposal is whether, and how, to adjust their planned outage schedules going forward. In response to arguments suggesting that MISO has not provided resource owners with sufficient time to account for a performance-based capacity accreditation, we agree with MISO that Capacity Resources are currently subject to a must-offer obligation under the current resource adequacy requirements and, therefore, resources should already have an expectation that they should be available and offering into MISO's energy markets. The transition period appropriately balances the need to implement the SAC methodology with the recognition that resource owners and LSEs may need to adjust their operations—including outage timing—and their contractual arrangements to maximize their potential SAC values. Accordingly, we disagree with COMPP that the transition period unduly delays needed reforms. For the same reasons, we are unpersuaded by arguments that MISO's

[433] This informational filing will not be noticed for comment or require Commission action.

accreditation will unduly harm resource owners because of their past operational decisions.

249. We disagree that the Commission's acceptance of longer transition mechanisms in PJM binds the Commission to reject a shorter timeframe in the instant filing. In the order accepting PJM's proposed Reliability Pricing Model, the Commission accepted PJM's proposed transition timeline because it "allows the participants in the market a period of time to understand and get used to the dynamics of the new capacity market prior to its full implementation."[434] We are not persuaded that market participants require the same transition period for MISO's proposal to *modify* its existing capacity market as PJM's proposal to *create* a capacity market.[435] In the PJM Capacity Performance Order, the Commission noted that the proposed five year transition period would: (1) allow resources to make gradual improvements and reduce the burden such improvements may impose; and (2) mitigate the potential for short-term shortage that might result from an immediate requirement of 100% Capacity Performance Resources.[436] We agree with MISO that, because the three-year lookback period will be based on operational experience from after MISO's RAN Phase 1's implementation, resources already have an expectation of needing to be available and therefore, it is reasonable for resources to have a shorter transition period.

250. However, with respect to Great River Energy's request for clarification that planned outages scheduled to begin before September 1, 2022 will be granted both a Tier 1 and Tier 2 exemption, we agree that additional clarification is required. The McFarlane Testimony states that such planned outages will be treated as fully exempt for Tier 1 and Tier 2 for accreditation purposes. However, MISO's proposed Tariff language states that "Generator Planned Outages scheduled to begin before September 1, 2022, will be granted a Tier 2 exemption."[437] While section II.B of proposed Schedule 53 notes that resource owners receiving a Tier 2 exemption will receive a Tier 1 exemption as well, it appears that this only applies if a resource owner receives a Tier 2 exemption under the normal Tier 2 exemption provisions of section II.A. Therefore, we require MISO to,

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[434] PJM Reliability Pricing Model Order, 117 FERC ¶ 61,331 at P 68.

[435] We also note that, in the order establishing MISO's Planning Reserve Auction construct, MISO proposed, and the Commission accepted, a two-year (from the filing date) transition period for the full implementation of MISO's capacity market. *Midwest Indep. Sys. Operator, Inc.*, 139 FERC ¶ 61,199 (2012). Protestors have not demonstrated why a longer transition period is necessary for MISO's proposed modifications to its existing capacity market construct.

[436] PJM Capacity Performance Resource Order, 151 FERC ¶ 61,208 at P 253.

[437] MISO, FERC Electric Tariff, Schedule 53 § II (32.0.0) (proposed).

within 30 days of the date of this order, file revised tariff sheets that clarify that generator planned outages scheduled to begin before September 1, 2022, will receive both a Tier 2 and Tier 1 exemption, consistent with the McFarlane Testimony.

251. Some protestors contend that resource owners will not have sufficient time to ensure preparedness through fuel supply planning and weatherization. We disagree. Resource owners should already make investments in their units to ensure future availability; to the extent that they have not done so, or have been insufficiently incented to do so under MISO's current capacity accreditation rules, we find that this lends further support to MISO's argument that its current construct does not appropriately incent resource owners to ensure their units remain available. Furthermore, the proposal includes a three-year transition period that will gradually increase the weight of RA Hours for purposes of SAC accreditation.

252. We disagree with Entergy Coalition's arguments that acceptance of MISO's proposal constitutes retroactive ratemaking. As noted above, MISO filed the instant proposal 16 months in advance of its proposed implementation; and it will become effective prospectively only. Moreover, although rates must take effect prospectively, there is no prohibition against the use of historical inputs, which MISO proposes to do so here.[438] This is commonly the case for formula rates that use past inputs. MISO's proposal does not alter its rate retroactively. Thus, MISO's proposal does not constitute retroactive ratemaking.

253. We find that MISO has demonstrated that the proposed weighting of RA Hours in determining a resource's SAC accreditation is just and reasonable. Specifically, MISO proposes a tiered weighting structure to determine individual resource accreditation by Season based on each Resource's Real-Time energy offers during Tier 1 hours (*i.e.*, all hours not including RA Hours) and Tier 2 hours (*i.e.*, RA Hours). We are not persuaded by protestors' arguments that MISO's proposed weighting over- or underemphasizes certain hours or by arguments that a resource's entire accreditation should be based on Tier 2 Hours. We find that MISO's proposed weighting of 80% Tier 2 Hours and 20% Tier 1 Hours, which will occur after a three-year transition, is an acceptable approach that reasonably recognizes the importance of a resource's contributions during times of greatest need, recognizes a resource's reliability contributions during all other times, and appropriately accounts for and allows for generator planned outages. In contrast to those who suggest that using a small number of hours to determine the majority of a Schedule

[438] *See, e.g.*, *PJM Interconnection, L.L.C.*, 172 FERC ¶ 61,054, at P 58 (2020) ("Longstanding practice, Commission and court precedent allow the use of reasonably representative historic test period data to craft rates, terms and conditions of service."). *See also id.* P 54 ("the use of past data to determine prospective costs is not retroactive ratemaking") (citing *Old Dominion Elec. Coop.*, 162 FERC ¶ 61,262, at P 50 (2018)).

53 Resource's accreditation, we find that MISO's 65-hour Tier 2 RA Hour target strikes a reasonable balance between being small enough to ensure that a resource's availability during the most needed hours is captured, while being large enough such to reduce volatility, as we discuss further below.[439]

254. We find that MISO has demonstrated that it is reasonable to supplement MaxGen hours with hours that have operating reserve margins as high as 25% in order to meet the 65-hour RA Hour target. While another cutoff may also be just and reasonable, on balance we find it just and reasonable that MISO consider hours other than just MaxGen hours and MISO has supported the proposed 25% cutoff. Performance during hours surrounding MaxGen hours also appear indicative of future performance during times of greatest system need, and reliance only on MaxGen hours, of which there are few, could dramatically increase the need to use AAOC hours.[440] We also note that the 65-hour target intends to include the tightest 3% of hours, which may exceed the number of MaxGen hours. Using a smaller target number of hours could increase accreditation volatility. Relatedly, while resource owners may not know whether an hour with less than 25% operating margin will be considered an "RA Hour" until after the conclusion of a Season, resource owners are on notice that any hour with less than 25% operating margin could potentially be an RA Hour and are thus able to adjust their operations accordingly. Additionally, resource owners can gain some visibility into high-risk hours through MISO's notices of Conservative Operations, which MISO declares based on system conditions including severe weather, hot/cold weather, or geomagnetic disturbance warnings, and Capacity Advisories that indicate the potential for limited operating margins.[441]

255. We find MISO's proposal to use resources with a 12-hour lead time for purposes of calculating the operating margin needed to determine RA Hours and non-RA Hours to be just and reasonable. We recognize that Potomac Economics and Clean Energy Coalition argue that a shorter lead time could also be reasonable given that emergency

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[439] Clean Energy Protest argues that MISO's proposal may overlook periods of increased risk because, according to Clean Energy Protests, MISO's proposal limits RA Hours to 65 hours in a Season. We note that the 65 hours is a minimum target, not a cap, and MISO's proposal designates all MaxGen hours as RA Hours.

[440] *See* MISO Deficiency Letter Response at 4-5 (table demonstrating that the number of MaxGen hours in most seasons is less than or equal to 65).

[441] *See* MISO Operating Procedures at 1, https://cdn.misoenergy.org/Three%20Pager%20-%20MISO%20Operating%20Procedures%2009202018318965.pdf.

conditions may develop with a less-than-12-hour notice.[442] MISO explains that, although it initially considered proposing a 24-hour lead time, it determined that, due to the operational concerns it faces, tight conditions are more likely to be identified 12 hours before a projected capacity shortfall than 24 hours ahead of time.[443] Therefore, we find the 12-hour requirement is a reasonable timeframe to ensure that such resources' contributions are accounted for in the determination of RA Hours.

256. We find MISO has demonstrated that AAOC is a just and reasonable proxy to reflect expected resource availability in Seasons that have not met their 65-hour RA Hour target. Some protestors suggest that, because MISO has proposed a seasonal construct, using non-RA Hours from a particular Season would be a better predictor of resource availability in that Season. However, we are persuaded by MISO and Potomac Economics that using AAOC (which reflects a unit's availability during high-risk hours throughout the year) is a reasonable approach to estimate availability during high risk hours because MISO's proposal intentionally weights RA Hours more heavily than non-RA Hours and including non-RA Hours in a resource's Tier 2 accreditation calculation could overestimate their expected availability in tight conditions. We disagree with protestors that it is unreasonable for certain hours to be used for both a Seasonal RA Hour and as part of a unit's AAOC. MISO explains that such hours "would not statistically constitute double counting because the individual hours would be 1/65th (1.538%) of the resource performance for any RA Hour but would only be 1/260th of the AAOC".[444] We agree with MISO that using a particular hour for both a Seasonal RA Hour and as part of a unit's AAOC has a *de minimis* effect on a resource's overall accreditation and find that MISO's use of AAOC is a reasonable proxy when a season is deficient RA Hours.

257. In response to Midwest TDUs' concern that there is an inconsistency between MISO's testimony and its proposed Tariff language regarding how MISO will replace Seasonal RA Hours that are exempt from a resource's Tier 2 calculation, we note that section III.A.ii of MISO's proposed Schedule 53 states that:

> If there are fewer than 65 hours identified for the Season in Section III.A.i above, additional hours will be identified up to a total of 65 starting with those hours with the lowest Operating Margin that is below a threshold of 25 percent excluding any operating hour where a Resource has a Tier 2

[442] We note that Potomac Economics states that it finds MISO's filing reasonable as proposed. Potomac Economics Comments at 5.

[443] *See* McFarlane Test. at 23-24.

[444] MISO February 10 Answer at 30.

> Planned Outage exemption or has periods where the Resource was not designated for RAR under Module E-1 of the Tariff.[445]

Regardless of any inconsistency with the testimony, we find that the Tariff is clear with respect to the replacement Seasonal RA Hours.

258. We are not persuaded by arguments that MISO's proposal introduces an unreasonable level volatility in capacity accreditation for a given resource. We find that any seasonal or year-over-year volatility in a resource's SAC accreditation will reasonably reflect supply fundamentals, principally the resource's seasonal availability, and demand fundamentals, through the identification and weighting of RA Hours and non-RA Hours.

259. Regarding arguments that any increased volatility in SAC accreditation is due to MISO's proposed weighting of historical unit performance (as measured by offer behavior) in RA Hours, MISO indicates that volatility, in aggregate, is expected to be very low (less than 2%).[446] As noted above, we find MISO's RA proposal strikes a reasonable balance between identifying RA Hours that represent the times of high risk and having sufficient RA Hour sample sizes, and avoids an undue level of volatility into MISO's resource accreditation. Additionally, we note that MISO's proposal mitigates volatility by using a three-year rolling average. Further, MISO's proposal contains a transition mechanism that mitigates the potential for volatility in the first three years of SAC implementation by gradually scaling up the percentage of a resource's accredited capacity that is based on offers in Tier 2 RA Hours.

260. We are not persuaded by arguments that MISO's proposal will lead to levels of volatility in resource accreditation that disrupt resource planning or inappropriately interfere with state regulatory resource planning. We find that regulatory authorities, LSEs, and resource owners will continue to be able to plan in accordance with MISO's resource adequacy requirements and the objectives of state regulatory authorities. While we acknowledge that individual resource accreditation volatility is possible as a result of MISO's SAC proposal, we expect that any additional volatility to be low and that LSEs will be able to look to historical performance to reasonably estimate future accreditation of their individual resources and resource fleet as a whole to meet their Reserve Requirements. Additionally, MISO's seasonal accreditation construct is premised on the need to better account for resource availability in each Season and matching expected resource availability with the needs in that Season. Accordingly, to the extent a

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[445] MISO, FERC Electric Tariff, Schedule 53 § III.A.ii (32.0.0) (proposed).

[446] *See* MISO February 10 Answer at 19-20 (citing RASC presentation at 6 (Sept. 1, 2021)).

resource's availability to meet MISO system needs varies across Seasons or year-over-year, volatility in that resource's accreditation is warranted and is appropriately captured in MISO's SAC accreditation proposal. Further, we are not persuaded by protestors' concerns that an LSE's entire portfolio will undergo drastic changes. Many LSEs have diverse resource fleets, which mitigates the planning implications of accreditation volatility for individual resources. LSEs that fulfill their resource adequacy obligations with a small number of resources can engage in bilateral arrangements or other hedging vehicles, or procure capacity from the Auction to manage any new accreditation volatility from this proposal.

261. We disagree with Consumers Energy's contention that MISO's proposal arbitrarily reduces the flexibility of resource owners to prudently schedule planned outages and does not address MISO's identified issues. MISO has demonstrated that current system conditions of reduced reserve margins necessitate greater outage coordination to maintain resource adequacy. We find MISO's proposed exemption requirements with respect to the notice and time between outages provide resources with economic incentives to give MISO more advance notice of outages, which should help MISO improve coordinated outage scheduling and maximize availability of resources in all hours, including hours with tight reserve margin conditions.

262. Consumers Energy asserts that MISO does not explain how modifying the exemption rules for prudently planned outages will improve operating or Maintenance Margins. As MISO explains, an "[a]fter the fact review of MaxGen Events often show the significant contribution of planned and maintenance outage to unit unavailability during times of realized LOLE risk."[447] By having additional tools to coordinate planned generator outages and to incent resource owners to submit planned outages with sufficient notice (120 days) through its accreditation rules, MISO and resource owners will have more accurate expectations regarding whether resources will be available when they are needed.

263. We disagree with Consumers Energy's claim that eliminating the ability for generators to schedule planned outages less than 120 days in advance without risking accreditation does not address the correlation between forced outages and insufficient investments in winterization or fuel supply. MISO explains the purpose of this provision is to encourage resource owners to plan outages well in advance to improve outage coordination—not to specifically encourage sufficient investment in winterization of fuel supply. We find that MISO's overall proposal, however, will create incentives for winterization investments when a market conditions warrant, such as higher capacity prices in the Winter Season, which should incent more resources to be available during the Winter Season through either winterization, revised planned outage scheduling, or

[447] MISO May 20 Answer at 9.

other means. The seasonality, combined with the accreditation methodology, dramatically increases the economic incentives for resource owners to take steps including maintenance and weatherization to maximize resource availability, including in non-Summer Seasons.

264. We agree with Entergy Coalition that resource owners may already have economic and system reliability incentives to minimize the length of planned outages. Nevertheless, as discussed above, MISO's planned outage exemption proposals are intended to do more than to solely minimize planned outage length. They are intended to maximize coordination of outages by timing them for when the Maintenance Margin is sufficient. Further, even if such incentives exist in MISO's current provisions, Entergy Coalition does not dispute that MISO's proposal will introduce additional incentives to minimize and coordinate planned outages, which should enhance resource adequacy.

265. We disagree with East Texas and DTE Electric's arguments that MISO has not adequately explained why outages must be scheduled 120 days in advance to be eligible for a Tier 2 exemption. MISO's outage exemption criteria with respect to the 120-day lead time encourages resource owners to give MISO more visibility and advance notice of available resources, which is needed in order to ensure resource adequacy in future periods. We find that the 120-day lead time appropriately balances the need for resources to have flexibility to schedule planned outages and the need for MISO have such visibility. We also disagree with Entergy Coalition and Consumers Energy's contentions that MISO's proposed 120-day lead time criteria could have the perverse effect of discouraging resources from performing maintenance activities, and thereby resulting in worse unit performance. Given the functional relationship between resource accreditation and resource availability, we believe that resources will not risk delaying necessary maintenance, because such delays could result in resource underperformance, unavailability, or forced outages, which would negatively impact that resource's future accreditation. We believe that together, the incentives will encourage resource owners to appropriately balance maximizing short-term availability when it is most needed and to perform maintenance, which requires scheduling planned outages, to ensure long-term resource performance.

266. We find that MISO has sufficiently explained and supported the proposed requirement to have a planned outage no sooner than 120 days after the previous planned outage to receive full exemptions. As MISO explains, this requirement serves to disincentivize frequent planned outages.[448] We find that MISO's proposal limiting outages reasonably balances resource owner flexibility with the need to coordinate outages. While there may be efficiencies and advantages to allowing additional flexibility (for example, being able to "split" a planned outage around days where the

[448] MISO Deficiency Letter Response at 13.

Maintenance Margin is negative, rather than having to submit two outages 120 days apart), we do not find that the lack of such flexibility renders the proposal unjust and unreasonable. We further find that this provision largely addresses concerns, articulated by WEC Utilities, about the potential to "hoard" outage dates.

267. We disagree with Entergy Coalition and East Texas arguments that outage exemptions should be granted whenever the Maintenance Margin is greater than zero. MISO's Maintenance Margin calculation is a forward-looking calculation based on Planning Year inputs from resource adequacy and the annual LOLE study. Maintenance Margin results subtract current planned generator outages in the Control Room Operations Window from the Maintenance Limit provided by resource adequacy and provides the number of MW that are available for scheduling generator outages while still allowing MISO to meet all its obligations.[449] Since the Maintenance Margin is a function of planned generator outages it does not take into account resources that may be on unplanned or forced outage. To this end, the Maintenance Margin does not give a complete picture of system reliability, but rather projects a snapshot which is intended to be used to identify time periods where there is available margin for a generator to take a planned outage.[450] Furthermore, as described above, there is a value in MISO having more advance notice and improved visibility into planned outages. Granting exemptions whenever the Maintenance Margin is above zero, as suggested by Entergy Coalition and East Texas, would reduce the incentive for resource owners to schedule outages well in advance and would reduce information available to MISO operators about resource outages, thereby decreasing operator confidence in future projections of future resource availability.

268. We disagree with the Mississippi Commission and Clean Energy Coalition arguments that outage planning and coordination is an operational issue and not a "marketplace issue." As an initial matter, no Commission policy precludes Tariff proposals pertaining to "operational issues" if the primary substance of the filing pertains to markets. Market and operational issues are inextricably linked as these markets are

[449] MISO, FERC Electric Tariff, Module A, § 1.M (71.0.0) ("Projected megawatts of additional generation that can be taken out of service for planned maintenance within MISO during a given time period without impacting adequacy of generation supply. The projection will be based on a forward looking [LOLE] analysis with known Proposed Generator Planed Outages of entire units.").

[450] We note that, to the extent that system conditions change as a planned outage start date near, MISO's proposal allows MISO to grant exemptions if a generator owner reschedules its planned outage at MISO's request due to "weather, forced outages, or other conditions listed in the [BPM] for Outage Operations. . ." *See* MISO, FERC Electric Tariff, Module E-1, § Schedule 53.II.A.iii (32.0.0)

designed to price, schedule, and dispatch energy and ancillary services over the operational timeframe (i.e., the 24-hour operating day). Furthermore, MISO's filing recognizes the interaction between operational and marketplace issues. Operational decisions can affect market outcomes, and market prices and incentives can affect operational decisions. Additionally, precedent exists for the Commission accepting proposals regarding Tariff revisions for how resource outages affect their participation in capacity constructs. Specifically, the Commission accepted MISO's 2019 proposed Tariff revisions limiting the ability of resources to participate in the Auction if that resource has full or partial outages that last for any 90 or more of the first 120 Calendar Days in the Planning Year.[451]

269. We disagree with Duke Energy and MISO TOs' contention that MISO needs to provide more support for excluding prudently planned derates from accreditation exemptions. As MISO explains, such derates have tended to be short-term in nature and would require further modifications to MISO's current outage coordination process which does not consider derates. However, we encourage MISO to continue to evaluate whether its current outage coordination process could be improved in light of MISO's instant proposal, including how derates impact SAC accreditation as MISO gains experience with the SAC exemptions over time.

270. We accept as just and reasonable MISO's proposal to outline in the BPM for Generator Outage additional criteria that MISO would use to determine whether a planned outage passes the No Harm Test.[452] We find that MISO's proposed Tariff language provides sufficient detail regarding what circumstances MISO will grant Tier 1 exemptions: (1) when resource owners submit a planned outage less than 31 days in advance and at least 14 days in advance of the outage start date; (2) when the planned outage occurs entirely during a period with adequate Maintenance Margin; and (3) when the planned outage does not cause harm, with the Tariff detailing the possible ways that the planned outage could cause harm. We do not believe that it is necessary to require that the Tariff contain further detail.[453]

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[451] *Midcontinent Indep. Sys. Operator, Inc.*, 170 FERC ¶ 61,066 (2020) (2020 Summer Outage Order).

[452] Section II.C of proposed Schedule 53 states that "[t]he No Harm Tests include, but are not limited to, outage approval, compliance with all applicable operation guides, review of possible conflicting outages or system conditions, and system capacity (Maintenance Margin, Multiday Operational Margin, 30-day margin). It also includes the criteria outlined in the [BPM] for Generator Outage." MISO, FERC Electric Tariff, Schedule 53 § II.C (32.0.0) (proposed).

[453] *Energy Storage Ass'n v. PJM Interconnection, L.L.C.*, 162 FERC ¶ 61,296, at

271. Similarly, we disagree that MISO's Tariff should be revised to contain additional detail on accreditation for Dispatchable Intermittent Resources and Intermittent Generation. MISO's effective Tariff provides the same level of detail in this regard as MISO's proposed Tariff. As MISO is merely proposing to use its current accreditation process for Dispatchable Intermittent Resources and Intermittent Generation and apply it seasonally, rather than annually, further detail is unnecessary.

272. We find that it is just and reasonable to cap a resource's offer at its GVTC for purposes of SAC accreditation, as MISO proposes. First, as protestors acknowledge, MISO will use seasonally corrected GVTC values, which are calculated by conducting a single real power test or using operational data that is adjusted for each Season using that Season's peak conditions. We agree with MISO that capping SAC accreditation at GVTC, which is the basis for UCAP, prevents the UCAP/ISAC ratio from being skewed, which could misalign accreditation values with the LOLE model. Although it is possible that in some specific circumstances resources can produce energy above their GVTC, such performance may be less certain in future circumstances than amounts at the GVTC. Further, nothing in the record indicates that resource output frequently exceeds their GTVC such that allowing ISAC accreditations to exceed GVTC would materially impact the final SAC accreditation values of resources.

273. With respect to Duke Energy's arguments, as discussed above, we find it just and reasonable for MISO to accredit Schedule 53 Resources based on their prior offered availability, which MISO's determines through a resource's Hourly Emergency Maximum Limit (or Targeted Demand Reduction Level). To the extent that a resource is unable to submit an Hourly Emergency Maximum Limit (or Targeted Demand Reduction Level) because there is no expectation of that resource being able to inject into the grid at that level, we find it reasonable for MISO to not consider a resource as having offered availability in those hours. We further note that nothing in the record indicates that a Schedule 53 Resource's accreditation will be materially impacted by not including intervals where the resource is being committed or decommitted.

274. We are not persuaded that a mechanism to transition GIAs to higher Winter capacity values is necessary. We disagree that the lack of a mechanism unduly harms units that have Winter output capabilities that exceed the level of interconnection service that they receive under their GIA. Under MISO's proposal, Schedule 53 Resources will

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P 103 (2018); *see also City of Cleveland v. FERC*, 773 F.2d 1368, 1376-77 (D.C. Cir. 1985) (*City of Cleveland*) (affirming the Commission's decision not to require that certain terms be included in the tariff, explaining that "only those practices that affect rates and service *significantly*, that are reasonably *susceptible* of specification, and that are not so generally understood in any contractual arrangement as to render recitation superfluous" must be included in a tariff) (emphasis in original).

be accredited based on their availability and output, which may be limited not only by the resource's operating characteristics but on the level and amount of interconnection service that it receives under its GIA. Under MISO's GIP, MISO studies resources in the interconnection queue based on the level of requested interconnection service requested by the customer in order to preserve system reliability, and allowing resources to go above that level could compromise system reliability.[454] As MISO notes, its existing GIP allows interconnection customers to request incremental interconnection service, and all resource owners are free to do so should they wish to take advantage of potentially higher Winter output capabilities.[455] We find that the seasonal provisions contemplated in this proposal are just and reasonable without further revisions to MISO's GIP. With regard to the fact that some SAC values may be higher than a resource's existing interconnection service, we note that, under MISO's current resource adequacy construct, a resource's UCAP value can exceed its existing interconnection service.

275. We find that MISO's proposal to treat offline resources with lead times in excess of 24 hours as unavailable during RA hours, such that they receive zero credit for purposes of SAC accreditation, is just and reasonable because they provide little reliability value to MISO. As MISO explains, MISO's proposed 24-hour lead time threshold for SAC accreditation appropriately reflects whether MISO could have reasonably committed the resource in its Day-Ahead Market or Forward Reliability Assessment Commitment process.[456] Resources that can be committed through the Day-Ahead or Forward Reliability Assessment Commitment process contribute to MISO's resource adequacy needs and thus we find MISO's proposal to accredit these resources to be just and reasonable.

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[454] *See, e.g., Ariz. Pub. Serv. Co.*, 170 FERC ¶ 61,111, at P 39 (2020) (noting that in Order No. 845, the Commission required, in *pro forma* LGIP revised section 3.1, that transmission providers have a process in place to consider requests for interconnection service below the generating facility capacity and that the Commission stipulated that such requests should be studied at the level of interconnection service requested for purposes of determining interconnection facilities, network upgrades, and associated costs, but that such requests may be subject to other studies at the full generating facility capacity to ensure safety and reliability of the system.) (citing *Reform of Generator Interconnection Procs. & Agreements*, Order No. 845, 163 FERC ¶61,043, at PP 383-384 (2018)); *see also Midcontinent Indep. Sys. Operator, Inc.*, 108 FERC ¶ 61,027, at P 26 (2004) (generators operating above the output limits, which the generators themselves provide, can compromise system reliability).

[455] *See* MISO February 10 Answer at 38-39.

[456] *See* McFarlane Test. at 24.

276. We are not persuaded by arguments that MISO should use a shorter lead time than 24 hours (e.g., 12 hours) in SAC accreditation because a lead time less than 24 hours could inappropriately ignore the role that resources with lead times of up to 24 hours play in meeting MISO's resource adequacy needs. Although MISO notes that tight conditions are "more likely" to be identified 12 hours beforehand than 24 hours beforehand, this suggests that some resource adequacy needs are identified 24 hours beforehand.[457] The Day-Ahead Market or Forward Reliability Assessment Commitment process can be used to address MISO's resource adequacy needs and we disagree with arguments or suggestions that resources that can be committed through either of these processes (i.e., resources with startup times up to 24 hours) should not be accredited at a level commensurate with their ability to meet those needs. For example, MISO could identify certain capacity needs over a longer time horizon than 12 hours, such as resources being out on an extended planned or forced outage, transmission maintenance that creates a capacity need, or certain meteorological events forecast 24 or more hours in advance. To the extent that MISO uses either the Day-Ahead Market or Forward Reliability Assessment Commitment processes to meet these or other needs, we find it appropriate to accredit resources commensurate with their ability to meet those needs. Further, we believe that a resource being unavailable within 12 (or fewer) hours because MISO did not select it through a day-ahead or FRAC commitment process is not a reasonable basis to penalize that resource by assigning it a zero SAC accreditation value for those hours.

277. We find MISO's proposed UCAP/ISAC conversion ratio to determine a Schedule 53 Resource's final SAC value to be just and reasonable. Acknowledging MISO's own admission of the disconnect between the UCAP-based resource valuation in the LOLE model and the availability-based SAC accreditation, we accept the use of a UCAP/ISAC ratio as just and reasonable because it is necessary to address the misalignment between MISO's current LOLE planning model that produces UCAP-based Reserve Requirements and the proposed SAC accreditation method. The UCAP/ISAC ratio also prevents the need to modify its LOLE model and convert Reserve Requirements and Local Clearing Requirements into SAC terms, and maintains an appropriate supply and demand balance in the Auction. We agree with MISO and Potomac Economics that the proposed ratio is reasonable and that applying the ratio to the ISAC (supply) side prevents some of the unintended consequences that would occur by applying a similar ratio to Reserve Requirements, such as the possibility that the Auction Clearing Price would increase. In addition, as discussed further below, the proposed UCAP/ISAC ratio prevents inappropriate impacts on the accreditation of non-Schedule 53 resources. Further, noting MISO has already pledged to do so, we encourage MISO to continue exploring whether its LOLE study can use SAC instead of UCAP.

[457] *See* McFarlane Test. at 24.

278. While Entergy Coalition notes that the application of the UCAP/ISAC ratio means that some Schedule 53 Resources may have final SAC ratings that exceed their GVTC rating, Entergy Coalition does not explain why this this is unreasonable, or why SAC, rather than ISAC, is appropriate to compare to GVTC. We find that this potential outcome, which Entergy Coalition has not demonstrated will have a material impact on the reliability or the Auction, or occur frequently, is a byproduct of the UCAP/ISAC conversion ratio, which as noted above, we find to be just and reasonable.

279. We find, contrary to Clean Energy Coalition's argument, that the UCAP/ISAC ratio does not lead to unduly discriminatory treatment between Schedule 53 and non-Schedule 53 Resources. While Clean Energy Coalition is correct that Schedule 53 Resources and certain non-schedule Resources will be both accredited based on availability, that alone does not necessitate application of the UCAP/ISAC ratio to non-Schedule 53 Resources. As MISO explains, the purpose of the UCAP/ISAC ratio is to ensure continued alignment between MISO's UCAP-based Reserve Requirements and its SAC proposal, such that the overall supply/demand balance of MISO's capacity market generally remains unchanged. In addition, the UCAP/ISAC ratio recognizes that, although Schedule 53 Resources are likely to be accredited less ZRCs using the SAC method (as compared to the current UCAP-based method), one ZRC of SAC accreditation provides more reliability value than one ZRC of UCAP accreditation. In contrast, non-Schedule 53 Resources will continue to be accredited using their existing accreditation framework, with modifications to account for a seasonal construct. As such, they will not experience the same level of accreditation reduction as Schedule 53 Resources. Clean Energy Coalition has provided no evidence that the existing accreditation methodologies for non-Schedule 53 Resources such as wind undervalue their resource adequacy contributions. Applying the UCAP/ISAC ratio to non-Schedule Resources will result in overvaluing those resources, potentially harming resource adequacy due to insufficient resources being used to meet the Reserve Margin while maintaining the 0.1 LOLE target.

280. We find that MISO has sufficiently justified excluding External Resources from the Schedule 53 Resource definition and SAC accreditation. MISO explains that External Resources do not submit Generation Offers into MISO's real-time market, meaning that MISO does not have the data to accredit those resources using the SAC method.

281. We disagree with protestors that contend that the SAC methodology should be applied to both Schedule 53 Resources and intermittent resources. As an initial matter, we note that these two resource groups are already accredited using different methodologies. Having different accreditation methodologies for different types of resources does not necessarily present undue discrimination; in fact, it is often the case that the operating characteristics of different resource classes require various different

accreditation frameworks.[458] Further, we agree with MISO that it is appropriate that the LOLE risk target used in the wind ELCC accreditation calculation be distinct from the risk target used in determining seasonal Reserve Requirements. Clean Energy Coalition's concern with MISO's use of ELCC for purposes of wind accreditation under a seasonal construct rests on the assumption that MISO must "demonstrate that the two accreditation methodologies do work together and assess capacity availability during the same risk hours in order for the construct to hold together both theoretically and practically to ensure a reliable system that can meet load during these high-risk hours."[459] MISO has, in this instant filing, proposed: (1) an availability-based accreditation methodology for Schedule 53 Resources, to be applied to MISO's new seasonal resource adequacy construct; and (2) revisions to its existing methodologies for non-Schedule 53 Resources to allow those resources to be accredited on a seasonal basis. We find these revisions to be just and reasonable, and we do not believe that further revisions to non-Schedule 53 Resource accreditation is required at this time.

282. We also disagree with Clean Energy Coalition's argument that MISO's proposal is unjust and reasonable because it does not expressly consider fuel supply risk for coal and gas resources but does consider fuel supply risk for wind and solar resources. While it is true that the SAC methodology is indifferent as to *why* a resource is available or unavailable during emergency periods, the SAC accreditation implicitly accounts for fuel availability because it is specifically designed to ensure that, if a resource is unavailable and has not received a Tier 1 or Tier 2 exemption—whether due to fuel or other reasons—it will not receive credit for those hours and the resource's SAC accreditation will be lower as a result. Arguably, MISO's availability-based SAC proposal brings conventional Schedule 53 generators and intermittent accreditation closer together in this regard, as MISO's current accreditation construct assumes 100% fuel availability for conventional generators. However, to the extent that Clean Energy Coalition is concerned that certain gas or coal units are overvalued because they have not able to contribute in emergency periods due to fuel supply issues, we believe that MISO's proposal should alleviate, rather than exacerbate, those concerns.

283. Contrary to Industrial Customers' argument that MISO's proposal to increase the minimum number of required interruption calls for LMR DRs to receive 100% capacity accreditation for the full Planning Year from 10 to 16 per Planning Year is unjust and unreasonable, we find that MISO's proposal, in conjunction with the move to a seasonal

[458] In PJM's ELCC proposal, the Commission explicitly found that PJM, which uses a rating based on UCAP for unlimited resources, "need not extend the ELCC framework to Unlimited Resources to demonstrate that its filing is just and reasonable." *PJM Interconnection*, 176 FERC ¶ 61,056 at P 70.

[459] Clean Energy Coalition Response to MISO Deficiency Letter Response at 6.

resource adequacy construct, is just and reasonable and sufficiently supported. MISO's current requirement of a minimum of 10 interruption calls during a Planning Year for LMR DRs to receive 100% capacity accreditation is based on an annual resource adequacy construct. As an initial matter, increasing the number of interruption calls on LMR DRs to receive full capacity accreditation from the status quo is not in and of itself unjust and unreasonable. Such an increase occurred in 2020, when the Commission accepted MISO's proposal to increase the minimum number of required interruption calls for LMR DRs to receive 100% capacity accreditation from 5 to 10 per Planning Year based on "a reasonable methodology through its reliability analysis to account for [LMR DR] potential unavailability."[460] Here too, we find that MISO has developed a reasonable methodology to account for LMR DR unavailability. However, MISO now does so on a seasonal basis. To receive 100% capacity accreditation in a particular Season under the proposed seasonal resource adequacy construct, LMR DRs are, required to allow for at most five interruption calls per Season. Under this proposal, an LMR DR is able to receive a level of capacity accreditation below 100% if it allows the minimum number of interruption calls for a particular Season, as opposed to the current construct which requires at least five interruption calls in a Planning Year to receive 80% capacity accreditation (LMR DRs that do not allow for at least five interruption calls in a Planning Year do not receive any capacity accreditation). Furthermore, we find that the 16-call requirement (to receive 100% capacity accreditation for all four Seasons) is consistent with the 2020 LOLE Analysis that MISO cites to support the need for 15 annual calls to receive 100% accreditation, while allowing for consistency among Seasons.

284. We disagree with the Mississippi Commission argument that MISO's proposal marginalizes state decisions regarding generation investment and construction, and thus would be beyond the Commission's authority to accept. Our acceptance of MISO's proposal does not prevent states from exercising their jurisdiction to make generation-related decisions under FPA section 201.[461] As the Commission has held:

> The Commission does not interfere with the states' authority over generation facilities, local reliability, retail sales or other matters the FPA reserved to the states merely by implementing wholesale rules affecting matters within the states' jurisdiction. We recognize that the FPA reserves to the state decisions concerning

[460] LMR DR Accreditation Order, 172 FERC ¶ 61,138 at P 49.

[461] *See, e.g.*, *Calpine Corp.*, 169 FERC ¶ 61,239, at P 174 n.345 (2019) ("States may choose to acquire whatever generation resources they like, but it remains the duty of this Commission to ensure that those choices do not cause unjust, unreasonable, or unduly discriminatory or preferential rates for wholesale transactions in interstate commerce." (citing *Conn. Dept. of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009)).

> generation; but the FPA provides the Commission with the jurisdiction and authority to regulate rates for wholesale sales made by those generation resources, and we are obligated to ensure that such rates are just and reasonable and not unduly discriminatory or preferential.[462]

285. In response to Duke Energy's argument that MISO has not shown how the proposed SAC accreditation calculation will accurately account for jointly owned units, we are not persuaded that additional clarity is needed at this time. MISO's current Tariff provisions do not explicitly account for jointly owned units, and we do not find that MISO's Schedule 53 Resource accreditation provisions requires any additional explanation.

3. Capacity Replacement

a. MISO Filing

286. MISO states that its current capacity replacement requirements are limited to suspensions and retirements of resources and carry no specific financial non-compliance provisions. MISO argues that these limited requirements are no longer sufficient as the performance and availability of committed capacity to meet seasonal requirements will be critical. MISO proposes to require replacement for any Planning Resource that will be on planned outage or planned derate for more than 31 days in a Season in which they clear. MISO states that it is also proposing provisions allowing the replacement of resources that have experienced catastrophic outages, enabling such resources to maintain class average accreditation upon return to service.[463]

287. MISO proposes a Capacity Replacement Non-Compliance Charge for Resource owners that do not replace Planning Resources that retire or suspend during a Season, or are on planned outage or planned derate for more than 31 days in a Season. MISO states that the Capacity Replacement Non-Compliance Charge will be a daily charge, equal to the amount of ZRCs that failed to be replaced multiplied by sum of the Auction Clearing Price and the daily CONE value. MISO states that the Capacity Replacement Non-Compliance Charges will be distributed to Market Participants representing LSEs on a *pro rata* basis, based upon the LSE's share of total Reserve Requirements for the MISO Region.[464]

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[462] *N.Y. State Pub. Serv. Comm v. N.Y. Indep. Sys. Operator, Inc.*, 173 FERC ¶ 61,060, at P 37 (2020) (footnotes omitted).

[463] Transmittal at 14.

[464] *Id.* at 15.

b. Comments and Protests

288. OMS contends that it is entirely reasonable for MISO to require resources that receive capacity credit and capacity payments to be available to offer energy for a large part of a given Season.[465]

289. Clean Energy Coalition argues that MISO's proposed capacity replacement provisions invalidate the proposed methodology for availability-based accreditation, since there may not be a strong correlation between a resource's historic performance at peak times and its future inclination to perform.[466] Clean Energy Coalition also argues that the replacement methodology fails to consider transmission constraints of the replacement resource and provides replacement resources with a class average rating even if it were not historically available.[467] COMPP argues that existing Tariff provisions that prevent Capacity Resources from participating in the Auction or being included in a FRAP if they are on outages expected to last 90 or more days of the first 120 Calendar Days in the Planning Year is not a creature of intentional physical withholding but rather the result of litigation stemming from resources committing capacity, getting paid to provide capacity, and then going on outage for an extended period and not being available for MISO dispatch. COMPP suggests that MISO's proposal would allow resources to commit capacity despite advanced knowledge of being unavailable for more than one-third of a Season and reinstate a similar flaw to its previously fixed construct.[468]

290. Several entities argue that MISO has not justified requiring replacement of capacity for outages lasting more than 31 days in a Season.[469] The Louisiana Commission suggests that the 31 day cutoff is random and imposes a discriminatory impact on generating units that require regular maintenance exceeding 31 days.[470] COMPP argues that MISO's blanket 31 day availability exemption is inconsistent with MISO's stated objectives of better aligning resource commitments with periods of

[465] OMS Comments at 4.

[466] Clean Energy Coalition Protest at 16.

[467] *Id.* at 17.

[468] COMPP Protest at 9 (citing 2020 Summer Outage Order, 170 FERC ¶ 61,066).

[469] Mississippi Commission Protest at 7-8; MISO TOs Comments at 7; Louisiana Commission Protest at 3-4; Duke Energy Comments at 7-8; COMPP Protest at 10; Entergy Coalition Protest at 15; Midwest TDUs Protest at 26; IPL Protest at 3.

[470] Louisiana Commission Protest at 3-4.

resource availability.[471] COMPP recommends instead that the Commission preclude Capacity Resources from committing capacity to a Season in which a planned or forced outage is expected to exceed 20 days, and to provide a physical withholding exemption to Capacity Resources unavailable due to a planned or forced outage for 20 days or more in each Season. Alternatively, COMPP proposes that the Commission install eligibility rules that permit outages for 40 days in the Spring and Fall, and 20 days in the Winter and Summer.[472] Entergy Coalition contends that MISO has not provided any support, explanation or demonstration for its claim that planned outages more than 31 days in duration are causing system reliability issues. Entergy Coalition has requested MISO provide this type of analysis, but MISO has yet to do so.[473] IPL proposes that the 31-day threshold be changed to 45-days.[474]

291. MISO TOs contend that the accelerated timeframe of developing MISO's proposal did not allow for a complete assessment of modeling the expected extended planned outages and simulation of the Auction to indicate the amount of capacity available for capacity replacement transactions.[475] MISO TOs state that resource owners who are short of capacity will have approximately eight months to add capacity, and that it is unclear whether market participants will "reserve" capacity for replacement or rely on the capacity market, which may be short.[476] MISO TOs assert that explicit Tariff language is necessary for market participants to incorporate the risk of replacement capacity within capacity offers without the reservation being treated as withholding.

292. Midwest TDUs, MISO TOs, and Entergy argue that, if an outage is planned in accordance with the Tariff to receive an outage exemption, then there is no reason to assume that the planned outage will materially increase system reliability risk and therefore, it is unreasonable to penalize the resource.[477] Midwest TDUs add that MISO's proposed requirements for Planned Outage exemptions for accreditation purposes do not include any 31-day limit, yet MISO proposes to subject such resources to replacement

[471] COMPP Protest at 10.

[472] *Id.* at 12.

[473] Entergy Coalition Protest at 15.

[474] IPL Protest at 3.

[475] MISO TOs Comments at 7.

[476] *Id.* at 8.

[477] Midwest TDUs Protest at 26-27; MISO TOs Comments at 7; Entergy Coalition Protest at 16-17.

capacity requirements and associated penalties, even if they schedule planned maintenance more than 120 days in advance and during times of adequate maintenance margin.[478]

293. Entergy Coalition and Midwest TDUs contend that planned outages that exceed 31 days can provide efficiencies and benefits that cannot be realized by shorter duration outages.[479] Entergy Coalition states that, based on its experience with steam units, for example, 7-10 days of the outage is associated with a cool down time required for the turning gear before primary maintenance work can start, and a 2-3 day post-outage start-up preparation. Entergy Coalition explains that this means that 29% to 42% of the 31-day planned outage period would be consumed by complying with original equipment manager asset protection guidelines instead of performing primary maintenance activities.[480] Entergy Coalition states that, in contrast, if a planned outage period longer than 31 days is used, then a higher percentage of the outage period is being used to perform primary maintenance work instead of prep-work and post-outage startup tasks. Entergy Coalition states that MISO's more-than-31-days outage rule is at odds with industry experience and will restrict generation owners' ability to perform necessary planned maintenance activities in the most cost-effective manner.[481] Midwest TDUs argue that imposition of the capacity replacement requirement is inconsistent with the basis for MISO's Planning Reserve Margin, as MISO's Tariff expressly requires MISO to consider long outages when it sets the Planning Reserve Margin applied to LSEs. Midwest TDUs contend that, because the Planning Reserve Margin is set at a level to assure sufficient capacity to cover long outages, it is unnecessary and inappropriate to additionally require a resource experiencing an extended planned outage to replace that resource or pay Capacity Replacement Non-Compliance Charges. Midwest TDUs state that MISO's filing does not justify the need to procurement of capacity above and beyond the amount MISO determined was required in establishing its Planning Reserve Margin.[482]

294. Others allege that the lack of a robust and transparent bilateral market for replacing ZRCs create the potential for the exercise of market power.[483] Ameren states

[478] Midwest TDUs Protest at 26.

[479] Entergy Coalition Protest at 17; Midwest TDUs Protest at 26.

[480] Entergy Coalition Protest at 17.

[481] *Id.* at 17-18.

[482] Midwest TDUs Protest at 27.

[483] Ameren Protest at 6; Midwest TDUs Protest at 34.

that, while MISO's proposal assumes there is a robust and liquid market for replacement capacity, Ameren's experience in finding replacement capacity under the current construct is already challenging because liquidity is often low. Ameren submits that it has no confidence that moving to a shorter period to find replacement capacity will improve liquidity or that there will be interest in selling replacement capacity for days and not weeks or months. Ameren argues that MISO fails to acknowledge the lack of liquidity in the bilateral replacement market and thus the potential for the exercise of market power. [484] Midwest TDUs add that the limitation to procure replacement capacity to capacity deliverable to the same Zone raises market power concerns, as well. [485]

295. East Texas asserts that MISO has not justified the new capacity replacement requirements for facilities with planned outages greater than 31 days, nor why such an approach would not provide incentives for owners with a planned extended outage to simply withhold the unit from the seasonal auction, thereby artificially tightening the planning margin. [486]

296. Entergy Coalition argues that MISO's proposal systematically and unreasonably penalizes nuclear resources. Entergy Coalition submits that MISO's own data provided in the stakeholder process shows that over 50% of historic nuclear planned outages exceed 31 days. [487] Entergy Coalition states that focused outages at nuclear plants make these plants even more efficient because they offer the opportunity to perform maintenance that would be more difficult if the plant remained online, and that by conducting inspections and performing maintenance at the same time as refueling, workers can eliminate the need to power down the plant at other times to perform the same work. Entergy Coalition states that this allows nuclear plants to produce electricity continuously for months and even years at a time—a feature no other electricity source provides. [488]

297. Energy Coalition states that it is concerned that MISO's proposal will create additional risks of supply shortfalls and CONE pricing because it allows generation owners to withhold a resource from a Season's Auction if that resource is scheduled to have a planned outage that exceeds 31 days during that Season. Entergy Coalition further states that in addition to concerns about supply shortfalls and elevated CONE pricing, it

[484] Ameren Protest at 6.

[485] Midwest TDUs Protest at 33.

[486] East Texas Protest at 9-10.

[487] Entergy Coalition Protest at 16-17.

[488] *Id.*

is also concerned that the auction withholding option may allow some market participants to manipulate Auction clearing prices and result in less generation being available to meet system reliability needs.[489]

298. Midwest TDUs submit that MISO's Tariff language is inconsistent with its proposal as described. As one example, Midwest TDUs note that MISO explains that Capacity Replacement Non-Compliance Charges apply when a resource exceeds the 31-day outages threshold and fails to replace the ZRCs associated with those days; however, elsewhere in the same proposed Tariff provision, MISO states that "ZRC replacement shall have no impact on settlements from the [Auction] and FRAPs, including any assessed Capacity Replacement Non-Compliance Charges."[490] Midwest TDUs assert that this wording suggests that capacity replacements "have no impact" on Capacity Replacement Non-Compliance Charges, contrary to other proposed language in the Tariff and the purpose of the charge.[491]

299. Midwest TDUs assert that MISO's proposal is arbitrary in that it treats outages differently depending on whether they occur in a single Season or span across Seasons. According to Midwest TDUs, a 32-day planned outage in one Season would be treated more harshly than a 60-day planned outage that falls evenly across two Seasons. Midwest TDUs argue that this distinction creates perverse incentives for resources to seek to schedule planned outages to fall over two Seasons, which could undermine MISO's reliability goals. Midwest TDUs contend that this is particularly discriminatory with respect to smaller LSEs. Midwest TDUs state that smaller LSEs tend to participate as minority owners in larger plants to take advantage of economies of scale, and that minority interest may constitute a significant portion of its resource portfolio. Midwest TDUs add that the majority owner typically has authority to operate the resource and schedule planned outages, and minority owners generally have no control over planned outage scheduling. Midwest TDUs state that MISO's proposal could impose harsh penalties and disproportionate burdens on smaller LSEs based on factors beyond their control.[492]

300. Midwest TDUs state that MISO's filing exposes LSEs to additional burdens and charges when their resources are unavailable due to planned or reasonably anticipated unplanned outages exceeding 31 days in a Season, regardless of whether the LSE had a

[489] *Id.* at 18.

[490] Midwest TDUs Protest at 25 (citing MISO, FERC Electric Tariff, Module E-1 § 69A.3.1.h.b.i (39.0.0) (proposed)).

[491] *Id.*

[492] *Id.* at 27-28.

choice in the matter. Midwest TDUs submit that this proposal would effectively remove such an LSE from the benefits of MISO's reserve-sharing pool, contrary to long-established precedent. Midwest TDUs argue that MISO frequently touts the benefits of reserve sharing, yet MISO's proposal leaves an LSE to fend for itself when it faces outages in excess of 31 days in a Season.[493]

301. Midwest TDUs contends that nothing in MISO's proposed Tariff provides any information about how MISO will distinguish unplanned outages that are subject to the capacity replacement obligation from those that are not. Midwest TDUs contend that the Commission should direct MISO to include all significant elements of its proposal in the Tariff itself.[494] Midwest TDUs add that MISO proposes to replace existing physical withholding provisions, found in section 64.1.1.g.xi of the Tariff, with one stating that a Market Participant submitting an outage for greater than 31 days of a Season can ask the Market Monitor for a determination ahead of the Auction allowing it to forego offering excess ZRCs from the resource without being deemed to have engaged in physical withholding. Midwest TDUs state that neither MISO's proposed Tariff language nor its filing explains what criteria the Market Monitor will use to make this determination. Midwest TDUs argue that this information should be included in the Tariff because the outcome of this determination may be relevant to the decision on whether and when to take a planned outage that exceeds 31 days.[495]

302. Some entities argue that it may be difficult for resources to replace their capacity. Midwest TDUs state that even if the resource has sufficient notice of an outage exceeding 31 days within a Season such that it could seek to line up replacement capacity in advance of the Auction, the resource may be competing with those seeking ZRCs for a full Season, rather than a more limited period. Midwest TDUs further state that, because replacement ZRCs must be from a resource that is not scheduled for a planned outage during the period when the resources at issue needs to be replaced, the replacement process is more complicated because maintenance schedules are confidential.[496] IPL contends that market participants should be authorized to hold some reasonable quantity of capacity as a reserve or hedge against non-performance of a cleared capacity to avoid non-performance penalties. IPL contends that a safe harbor percentage above the

[493] *Id.* at 28-29.

[494] *Id.* at 45-46.

[495] *Id.* at 46-47.

[496] *Id.* at 33-34.

existing 50 MW physical withholding threshold quantity for Planning Resources designated to satisfy resource adequacy requirements should be authorized.[497]

303. Midwest TDUs contend that MISO's replacement capacity requirement for resources with outages exceeding 31 days in a Season penalizes the resource owner when combined with the proposed accreditation rules, creating a "double-whammy" effect. Midwest TDUs state that, unless the outage is exempted, a planned outage exceeding 31 days could both: (1) trigger Capacity Replacement Non-Compliance Charges if the capacity is not replaced; and (2) impact future accreditation, particularly if the resource was not available during RA Hours. Midwest TDUs explain that, on top of paying Capacity Replacement Non-Compliance Charges, a resource subject to a planned outage exceeding 31 days in a Season that did not satisfy accreditation exemption requirements would be deemed unavailable during the outage period, thus reducing its accredited capacity for that Season for the next three years. Midwest TDUs state that an unplanned outage that MISO retrospectively deems could have been reasonably anticipated would never qualify for a Tier 2 Planned Outage exemption for accreditation purpose and thus would always impact accreditation if such an outage happens to occur in an RA Hour.[498] Midwest TDUs argue that resources experiencing an extended outage should be able to avoid adverse impacts on accreditation if they replace the capacity. Midwest TDUs state that Seasonal RA Hours will exclude Tier 2 Planned Outage exemptions, as well as periods where the resource was not committed for capacity under Module E-1 of the Tariff. Midwest TDUs state that this could be read to exclude from RA Hours the period where a Capacity Resource on a non-exempt outage beyond 31 days had, by securing a replacement, transferred its commitment for the relevant period to the replacement resource, so the resource at issue was not considered "committed capacity" for that period. Midwest TDUs state that, if MISO intends for these provisions to protect against adverse accreditation impacts for resources on extended outage that procure replacement resources, MISO should be required to revise them to clarify. Midwest TDUs contend that the Tariff should expressly describe the relationship between replaced capacity and Schedule 53's accreditation calculation, as well as consistently include the unplanned outages to which MISO proposes to apply the capacity replacement requirements.[499] IPL agrees that, if a Capacity Replacement Non-Compliance Charge has been assessed, then there should be no further penalty.[500]

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[497] IPL Protest at 6.

[498] Midwest TDUs Protest at 35-36.

[499] *Id.* at 36-37.

[500] IPL Protest at 3.

c. MISO February 10 Answer

304. In response to arguments against MISO's proposal to require replacement for any Planning Resource that will be on planned outage or planned derate for more than 31 days in a Season, MISO asserts that an after the fact review of MaxGen Events often shows the significant contribution of planned and maintenance outages to unit unavailability during times of realized LOLE risk—typically from many resources designated to satisfy resource adequacy requirements. MISO states that it originally proposed a requirement that would bar Auction participation for resources that expect to be on outage more than 30 days in a Season, which mirrored the provision added to the Tariff in 2020 that a resource not be on planned outage more than 90 days of the first 120 days of the Planning Year. MISO states that a number of stakeholders sought flexibility in Auction participation and outage planning, opposing the prohibition of participation and instead suggesting a capacity replacement requirement with a corresponding financial penalty, a proposal which MISO adopted from stakeholders.[501]

305. In response to arguments regarding the proposed Capacity Replacement Non-Compliance Charge, MISO states that the Capacity Replacement Non-Compliance Charges is modeled on the GVTC Deferral Non-Compliance Charge that was accepted by the Commission in 2016.[502]

306. MISO disputes COMPP's argument that a threshold of 20 days in each Season or up to 40 days in the Spring and Fall would be reasonable, arguing that MISO has experienced more MaxGen Events in the shoulder Seasons than it has in the Summer and that a 31-day threshold provides a reasonable amount of flexibility in a Season for resources to take needed planned and maintenance outages. In response to IPL's argument that the threshold should be 45 days, MISO asserts that the proposed requirement is 31 days in a Season and that there is no proposed restriction to arbitrarily limit outages from spanning more than one Season, a method which could be used to accommodate longer outages while still incentivizing capacity designated to satisfy resource adequacy requirements in a Season to be available for most of that Season.[503]

307. In response to Midwest TDU's argument that MISO is imposing Capacity Replacement Non-Compliance charges on LSEs, MISO notes that this is only the case when an LSE owns the resource that fails to replace or has obtained contractual rights to the capacity and submitted its ZRCs via a FRAP such that MISO is not settling capacity

[501] MISO February 10 Answer at 9-10.

[502] *Id.* at 11 (citing *Midcontinent Indep. Sys. Operator, Inc.*, 154 FERC ¶ 61,094 (2016)).

[503] *Id.* at 12.

charges and credits with the owner of the resource directly. MISO asserts that this is just and reasonable, as the proposed capacity replacement requirement is aligned with the interest of LSEs by helping them demonstrate that they will have access to the capacity needed to meet resource adequacy requirements in line with the one-day-in-10-year reliability planning standard. MISO states that requiring LSEs to pay for the procurement of resources that expect to, or later decide to, become largely unavailable during the Season is inconsistent with the proposed resource adequacy reforms in the SAC filing, which seek to ensure sufficient resources will be available during times of need.[504] MISO further adds that, despite Midwest TDU's assertion that MISO's existing Tariff, which states "ZRC replacement shall have no impact on settlements from the [Auction]," is inconsistent and made confusing with the addition of Capacity Replacement Non-Compliance Charges, the original and enduring meaning of this language is that the settlement of capacity charges and credits will remain with the original Market Participant whose ZRCs are being replaced. MISO states that the financial obligation will not be shifted to a different market participant, where applicable, that registered the uncleared resource used to replace the originally designated resource.[505]

308. MISO states that, in response to comments from Midwest TDUs related to outage modeling in the annual LOLE study, MISO notes that, while the LOLE study does account for historical planned outages, the study largely optimizes their timing to have little impact to LOLE. MISO adds that the study does not account for future resource behavior that deviates from the 5-year historical average used in LOLE. MISO states that the proposed outage provisions, including the exemptions and replacement requirements, further close a gap in the current rules to create incentives for market participants to optimize planned outages and their impacts to reliability and resource adequacy. MISO states that an accredited unit with high historical availability, such as a nuclear unit, can clear in a Season in which it plans to be on a refueling outage and still be relied upon to meet the Reserve Requirements even though it will not be available when needed. MISO states that in such a situation, it is reasonable for the resource not to clear, to fit the outage within the 31-day threshold, or to replace the ZRCs for outage periods exceeding the threshold.[506]

309. Regarding too many resources potentially seeking outages in the Spring and Fall, MISO states that it has shown Reserve Requirement targets tend to be significantly lower than the status quo annual Reserve Requirements that is currently enforced all year. MISO asserts that its analysis has shown that its proposed resource adequacy

[504] *Id.*

[505] *Id.* at 13.

[506] *Id.*

enhancements will result in lower Reserve Requirements and higher aggregate excess Planning Reserve Margins outside the Summer Season, which should provide significant amounts of uncleared ZRCs for use as replacement capacity where supply is in excess of the capacity needed.[507]

310. In response to concerns about a "double whammy," MISO notes that the Capacity Replacement Non-Compliance Charge applies when a resource designated for resource adequacy submits planned outages greater than 31 days in a Season, thus depriving LSEs from the benefit of the availability procured in the Auction. MISO adds that accreditation impacts for Schedule 53 Resources are about future expectations of resource availability, noting that if the outage is submitted with lengthy notice and if the outage is sufficiently coordinated, then the fact that the resource is not available during a planned outage will not impact accreditation. MISO states that, in contrast, if an outage is submitted with short notice or during a time when too many MW of capacity have already submitted outages, then it is reasonable to consider how the insufficiently coordinated planned outage might help predict future resource availability. MISO argues that it does not propose exemptions for unplanned outages since, by definition, unplanned outages are not timely or coordinated to ensure sufficient Maintenance Margin. Further, MISO notes that resources that have been replaced are not designated for resource adequacy and Schedule 53 has language explicitly excluding those hours in Tier 1 and Tier 2 of the SAC calculations.[508]

311. MISO argues that its proposal does not need to allow a percentage of seasonal capacity to be held in reserve for replacement capacity purposes and would not create an artificial supply shortage. MISO suggests that predetermining a percentage of seasonal capacity to be held in reserve could lead to some Zones in certain Seasons being short capacity and having to pay CONE.[509]

312. MISO states that its proposed Tariff revisions do not violate the rule of reason, nor is a Generation Outage that was not planned but was known or could have been reasonably anticipated at the time of the Auction a term or condition of service that must be included in the Tariff. MISO states that, consistent with Commission precedent, MISO's determination of what entails Generation Outages that were not planned but were known or could have reasonably anticipated are correctly viewed as implementation details that may be properly included in MISO's BPM rather than the Tariff. MISO

[507] *Id.* at 14-15.

[508] *Id.* at 15-16.

[509] *Id.* at 41.

contends that the rule of reason states that only those provisions significantly affecting rates, terms, and conditions of service must be filed for Commission approval.[510]

313. In response to Midwest TDUs' argument that neither the proposed Tariff language nor MISO's filing explain what criteria the Market Monitor will use to determine whether a resource that has submitted an outage for greater than 31 days of a Season has engaged in physical withholding, MISO states that, while the section referenced by Midwest TDUs, section 64.1.1.g.xi of the Tariff, does not contain the criteria for determining when resources will have been deemed to have engaged in physical withholding, those thresholds are contained elsewhere in Section 64.1.1.1, and there is no reason to include them again in Section 64.1.1.g.xi.[511]

d. Answers to MISO February 10 Answer

314. Entergy argues that MISO's answer did not address its concerns. Entergy states that planned outages provide some contribution towards periods of elevated LOLE risk but argues that MISO has not shown that planned outages exceeding 31 days are a source of higher system risk.[512] Entergy argues that describing nuclear units as "not being available when needed" because of refueling is flawed. Entergy argues that, if a non-nuclear generating unit were to take a 30-day planned outage every Season over a 2-year period it, would be unavailable for 240 days in total and this unit would not be subject to any capacity replacement requirements under MISO's SAC proposal. Entergy then argues that, if a nuclear unit were offline only once over this same 2-year period for a 40-day planned refueling outage, MISO argues that the unit is "not available when needed" and would subject the resource owner to the replacement capacity requirement, even though the unit was available for 200 more days over the 2-year period than the unit in the first example which was not subject to any capacity replacement requirements.[513] Entergy then argues that by conducting inspections and performing maintenance at nuclear plants at the same time as refueling eliminates the need to power down the nuclear plant at other times to perform the same work.[514] Entergy argues that MISO's

[510] *Id.* at 47 (citing *City of Cleveland*, 773 F.2d at 1376).

[511] *Id.* at 48.

[512] Entergy Answer at 8.

[513] *Id.* at 9.

[514] *Id.* at 9-10.

planned outage proposal is unjust and unreasonable and that MISO has not justified the application of the more-than-31-days proposal to nuclear plants.[515]

315. Midwest TDUs argue that MISO fails to demonstrate the just and reasonableness of its capacity replacement proposal as applied to planned outages.[516] Midwest TDUs assert that MISO's characterization of its proposal as "mirror[ing]" the prohibition of planned outages extending more than 90 of the first 120 days of the Planning Year overlooks that it only applies to extended outages planned for the Summer Season in a resource adequacy construct that is singularly focused on the resources needed during that specific period.[517] Midwest TDUs claim that MISO's proposed 31-day seasonal capacity replacement obligation would significantly burden or penalize shorter planned outages.[518] Midwest TDUs state that MISO's 90-day threshold for banning Summer peak period planned outages highlight the unreasonableness of the 31-day limitation, and that MISO should encourage longer outages that may be necessary to maintain resources in good working order with high availability.[519] Midwest TDUs also argue that MISO's suggestion to schedule longer outages across Seasons creates incentives for scheduling longer outages into the Summer and Winter Seasons to the maximum extent permitted by the Maintenance Margin despite the higher risk, rather than scheduling in other Seasons.[520] According to Midwest TDUs, MISO's suggestion that resources not participate in the Auction for an entire Season if they have a 32-day planned outage artificially reduces the resources MISO can call upon to meet MaxGen Events.[521]

316. Midwest TDUs argue that MISO fails to explain its proposal's inconsistency with the basis for its Planning Reserve Margin and reserve sharing fundamentals.[522] Midwest TDUs assert that the MISO Tariff already considers long outages when establishing Reserve Margins and that MISO fails to demonstrate the need for additional capacity procurement, especially when the LOLE study accounts for historical planned outages by

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[515] *Id.* at 10.

[516] Midwest TDUs Answer at 13.

[517] *Id.* at 14.

[518] *Id.* at 15.

[519] *Id.*

[520] *Id.* at 16 (citing MISO February 10 Answer at 12)

[521] *Id.* at 16-17.

[522] *Id.* at 17.

using a 5-year historical average.[523] Midwest TDUs state that MISO attempts to discount the LOLE study factors by describing the LOLE study as optimizing the timing of planned outages to have little impact on LOLE, but according to Midwest TDUs, MISO fails to account for recent improvements to its LOLE study methodology as well as its obligation to accurately account for planned outages.[524] Midwest TDUs claim that MISO's capacity replacement proposal would require procurement that would produce availability far exceeding the historical availability on which the Reserve Requirement targets are based.[525] Midwest TDUs also state that MISO fails to acknowledge the concern that its capacity replacement proposal effectively eliminates LSEs' benefits of MISO's reserve sharing pool.[526]

317. According to Midwest TDUs, MISO fails to acknowledge concerns that replacement is not a realistic option for planned outages, especially for smaller LSEs.[527] Midwest TDUs assert that MISO also did not address concerns about the potential for exercise of market power in the bilateral market.[528] Midwest TDUs claim that, contrary to MISO's assertion that plenty of replacement capacity will be available outside the Summer Season, MISO's analyses show that securing capacity replacement during non-Summer Seasons will not be easy and that Spring may be very challenging.[529]

318. Midwest TDUs argue that MISO fails to meet its burden that its replacement capacity and related non-compliance charge proposal is just and reasonable.[530] For example, Midwest TDUs state that MISO fails to justify imposing a capacity replacement obligation on unplanned outages greater than 31 days, given the lack of Tariff parameters or procedures governing how the Market Monitor will make a subject determination as to whether an outage could have been reasonably anticipated.[531] Midwest TDUs assert that

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[523] *Id.*

[524] *Id.* at 18.

[525] *Id.* at 19.

[526] *Id.*

[527] *Id.* at 20-21.

[528] *Id.* at 21.

[529] *Id.* at 22.

[530] *Id.* at 24.

[531] *Id.* at 23.

MISO's explanation that such implementation details may be included in the BPMs "flies in the face of the Commission's FPA Section 205 obligation to ensure just and reasonable rates."[532] Midwest TDUs also assert that MISO does not address how applying a capacity replacement obligation "after-the-fact" on such unplanned outages nullifies the opportunity to replace that capacity.[533] Midwest TDUs claim that MISO never explains why an appropriately planned 28-day outage should be subjected to a replacement requirement if the resource incurs a four-day unplanned outage in that same Season.[534] According to Midwest TDUs, MISO's proposal is an unavoidable Capacity Replacement Non-Compliance Charge penalty, even assuming capacity replacement was realistic in the planned outage context.[535]

319. Midwest TDUs argue that MISO's proposed Tariff revisions will not work as intended, and that the Commission should require corrections and clarifications to the Tariff.[536] Regarding the treatment of replacement capacity that has been secured, Midwest TDUs state that MISO fails to clarify the impact on Capacity Replacement Non-Compliance Charges.[537] Midwest TDUs also state that MISO intends to treat a resource that has been replaced as not designated for resource adequacy during that period, however MISO refers to language that excludes resources not designated for resource adequacy from the accreditation calculation, but does not make the connection between such exclusion and successful capacity replacement.[538]

e. Deficiency Letter Response and Responsive Pleadings

320. In response to a question requesting additional support for the Capacity Replacement Non-Compliance penalty value, MISO states that it is appropriate to model the penalty after ICAP Deferral Non-Compliance Charge because a resource that offers

[532] *Id.*

[533] *Id.*

[534] *Id.* at 24.

[535] *Id.*

[536] *Id.*

[537] *Id.* at 25.

[538] *Id.* at 25-26.

and clears capacity for a Season but then chooses not to make it available for much of that Season should forfeit the capacity revenues received.[539]

321. In response to a question regarding the relationship between MISO's proposed Capacity Replacement Non-Compliance Charge and MISO's LOLE studies, MISO states that the results of LOLE studies would largely remain the same as current LOLE studies assume the use of replacement capacity for all outages, not just those over 31 days. MISO states that under its proposal, where a resource clears for a Season but decides to go on planned outage for greater than 31 days in that Season, the obligation to replace or pay a non-compliance charge creates incentives for the Market Participant to provide the availability the resource was otherwise cleared to supply. MISO submits that this helps ensure the Reserve Requirement planning targets are being satisfied.[540]

322. In response to a question regarding whether the Capacity Replacement Non-Compliance Charge may incent withholding resources as a hedge against the penalty, MISO states that it has no intention to disincentivize participation in the bilateral markets. MISO states that it is reasonable to expect that bilateral trading for replacement capacity will be much more robust under the new construct than it is today. MISO adds that its models indicate that the move to seasonal Auctions will result in nearly double the amount of uncleared ZRCs in non-Summer Seasons, providing liquidity to the market for replacement capacity.[541]

323. In response to a question asking MISO to describe the expected methodology that the Market Monitor will employ to determine whether unplanned outages could be reasonably anticipated at the time of the Auction, MISO states that the proposed Tariff language indicates that details necessary to implement the capacity replacement requirement will be included in the Market Monitoring and Mitigation BPM, which MISO believes to be the appropriate place.[542]

324. MISO's Deficiency Letter Response clarifies that the availability of replacement resources does not contribute to the SAC value for the replaced resource but does contribute to the Tier 1 and Tier 2 SAC value of the replacement resource. MISO states that Schedule 53 only considers offers during times when a resource was designated for

[539] MISO Deficiency Letter Response at 27.

[540] *Id.*

[541] *Id.* at 27-28.

[542] *Id.* at 29.

resource adequacy, and when a resource is replaced it is no longer designated for resource adequacy as that obligation has been transferred to the replacement resource.[543]

325. Midwest TDUs argue that MISO has not provided sufficient clarity that resources designated for RAR but later replaced are considered by MISO as not designated for RAR. Midwest TDUs argue that this ambiguity is amplified by other confusing Tariff language related to capacity replacement. Midwest TDUs state that Tariff language suggesting that ZRC replacement shall have no impact on settlements from the Auction and FRAP, including any Capacity Replacement Non-Compliance Charge suggests that capacity replacement may not protect a resource on a greater than 31-day outage from Capacity Replacement Non-Compliance Charges. Midwest TDUs state that it is not reasonable to include Tariff language regarding the effect of capacity replacement on Capacity Replacement Non-Compliance Charges that can be read in a manner contrary to other proposed language.[544]

326. Midwest TDUs suggest that MISO's Deficiency Letter Response reinforces concerns about the practicality and consequences of MISO's proposed capacity replacement provisions. Midwest TDUs argue that MISO's proposal may incent resources to not offer excess ZRCs into the bilateral market as a hedge against the penalty. Midwest TDUs argue that MISO has provided no evidence that today's limited, non-transparent bilateral market will become robust and therefore make capacity replacement feasible.[545]

327. Midwest TDUs argue that MISO has provided no guidance on how it would have the Market Monitor make the determination that an unplanned outage could have reasonably been anticipated at the time of the Auction. Midwest TDUs allege that MISO fails to explain why broad considerations for such a determination are not included in the Tariff and instead simply asserts that it believes the BPM to be the appropriate place. Midwest TDUs contend that MISO's unsupported belief cannot trump the FPA and well-established Commission policies.[546] Duke Energy further requests that the Commission direct MISO to document, prior to the next outage, how the Market Monitor will determine whether unplanned outages could have been reasonably anticipated at the time of the Auction. Duke Energy submits that it is imperative that market participants understand in advance of the auction how reasonably anticipated unplanned outages will

[543] *Id.*

[544] Midwest TDUs Response to MISO Deficiency Letter Response at 15.

[545] *Id.* at 16-20.

[546] *Id.* at 23 (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 106 FERC ¶ 61,251, at P 89 (2004)).

be determined, yet MISO makes no commitment as to the timing of the stakeholder process to clarify this important detail.[547]

328. Midwest TDUs state that MISO's response on the relationship between LOLE studies and the Capacity Replacement Non-Compliance provision demonstrates that MISO is not proposing to change the LOLE analysis to account for its new requirement. Midwest TDUs add that MISO's response suggests that it conducts its current LOLE studies on the assumption that all capacity will be replaced, meaning, according to Midwest TDUs, that MISO's current LOLE analysis somehow simulates the case in which capacity beyond the Planning Reserve Margin is available to backfill any outages, even though that capacity is not committed to do so. Midwest TDUs submits that MISO's response makes it unclear whether its LOLE studies are appropriately determining the Planning Reserve Margins needed to achieve MISO's reliability targets.[548] Midwest TDUs state that, if MISO's response is accurate, it would suggest that MISO has been mismanaging its resource adequacy construct because it has failed to require the capacity replacement that is presumed in the LOLE analysis, which in turn determines the Reserve Margin. Midwest TDUs state that it logically cannot be the case that the current LOLE analysis formulation yields the correct Planning Reserve Margin under both: (1) its current Tariff, in which no capacity replacement obligation is imposed for any planned or unplanned outages; and (2) its proposed Tariff, in which capacity replacement is required for a subset of outages. Midwest TDUs concludes that as a result, MISO's description of its LOLE process cannot support the justness and reasonableness of its capacity replacement proposal.[549]

329. Entergy argues that the Capacity Replacement Non-Compliance Charge creates incentives for market participants to not offer excess capacity into the bilateral capacity market to ensure they have a hedge against the risk that an extended outage could subject their own resources to the Capacity Replacement Non-Compliance Charge. Entergy states that the end result could be a very weak bilateral capacity replacement market, making it difficult for market participants to shore up capacity, leaving some generators with no choice but to pay the Capacity Replacement Non-Compliance Charge.[550]

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[547] Duke Energy Response to MISO Deficiency Letter Response at 3.

[548] Midwest TDUs Response to MISO Deficiency Letter Response at 25-26.

[549] *Id.* at 26.

[550] Entergy Response to MISO Deficiency Letter Response at 7-8.

f. MISO May 20 Answer to Responsive Pleadings

330. MISO states that it provided support that its capacity replacement obligation improves resource adequacy while setting Reserve Requirement targets specific to each Season which are expected to increase the amount of uncleared ZRCs that can be used for replacement in most Seasons and locations. MISO states that where uncleared ZRCs are not available, it is even more important that capacity designated for resource adequacy not be unavailable for greater than 31 days in a Season for reasons that can be controlled. MISO states that the capacity replacement obligation is not only feasible, it exists and is required under the current Tariff for suspended and retired units and is an option for units that suffer a catastrophic outage.[551]

331. MISO states that it has established its Capacity Replacement Non-Compliance charge as just and reasonable. MISO explains that this charge was requested by the Market Monitor to disincentivize ZRC offers from resources that were not expected to be available for a significant portion of the Season. MISO states that requiring LSEs to pay for the procurement of resources that expect to, or later decide to, become largely unavailable during the Season is inconsistent with the proposed resource adequacy reforms in the filing.[552]

332. MISO states that it has worked with the Market Monitor to draft language that will be included in the BPM for Market Monitoring and Mitigation that addresses the application of capacity replacement obligations to unplanned outages. MISO states that the language is intended to protect against ZRCs being offered that are not reasonably expected to be available. MISO states that the proposed language will be added to section 5.15 of the BPM and reads:

> Resources that clear in a given [Auction], and subsequently are in full or partial unplanned (i.e., urgent, emergency, or forced) outages or derates below their commitment amount for more than 31 days in a Season and were not replaced with uncleared ZRCs must submit documentation of such circumstances to the [Market Monitor]. [Market Monitor] review of the documentation seeks to determine if the outage/derate durations could have been reasonably expected at the time of the closing of the [Auction]. If the outage/derate durations in the judgement of the [Market Monitor] could have been reasonably expected, a Capacity Replacement Non-Compliance Charge may be assessed by the

[551] MISO May 20 Answer at 11-12.

[552] *Id.* at 14-15.

> Transmission Provider pursuant to the Tariff. This provision applies to changes in equipment status, operation limitations and/or resource reliability known prior to the closing of the [Auction] window but are too recent to be captured in the last three (3) years of history of the applicable Season used in the Seasonal Accredited Capacity Calculations. One example of such a case would be a participant who offered and cleared a generation resource in the [Auction] for the summer season despite knowing that the generator would be unavailable to that offer amount for most of the summer after suffering a substantial or even catastrophic outage or derate prior to the closing of the [Auction] window.
>
> If prior to the [Auction], a Market Participant does not have a reasonable expectation that outages or derates will be less than 32 days in the Season, it can request an exemption of the capacity in question per the Tariff (Section 66.1.1.g.xi) and not include it in a ZRC transaction or FRAP, and not offer it into the [Auction].

MISO states that it believes this level of implementation detail is appropriately included in the BPM.[553]

g. Midwest TDUs June 6 Answer

333. Midwest TDUs argue that MISO's May 20 Answer does not justify requiring capacity replacement in situations where outages exceed the 31-day threshold due to, in whole or in part, unplanned outages deemed reasonably anticipatable. Midwest TDUs further contend that MISO's May 20 Answer reinforces the filing's fundamental failure to provide any criteria or process governing the Market Monitor's rate-critical determination as to whether an unplanned outage could have been reasonably anticipated. Midwest TDUs argue that, as an initial matter, the draft BPM language provided by MISO belongs in the Tariff, rather than a BPM, because it directly affects rates. Midwest TDUs further argue that the draft language provides no methodology or even broad considerations governing how the Market Monitor is to determine whether an outage could have been reasonably anticipated, instead leaving that determination to the judgment of the Market Monitor. Midwest TDUs contend that the language therefore provides no guidance whatsoever on how the Market Monitor will determine if an

[553] *Id.* at 17-18.

unplanned outage could have been reasonably been anticipated at the time of the Auction.[554]

h. Commission Determination

334. We find MISO's proposed Capacity Replacement Non-Compliance Charge to be just, reasonable, and not unduly discriminatory or preferential. MISO's proposed capacity replacement provisions reflect a reasonable expectation that a Planning Resource receiving capacity payments for a given Season should not be unavailable for a significant portion of that Season. In the 2020 Summer Outage Order, the Commission noted that MISO's Tariff did not, at the time, contemplate consequences for resources that clear the Auction but expected to be unavailable. The Commission found MISO's proposal to preclude resources that are unavailable for 90 days or more of the first 120 days in the Planning Year from participation in the Auction or in a FRAP as a just and reasonable method to ensure that resources do not clear the Auction, receive capacity payments, and are subsequently unavailable for the majority of the Summer, which is MISO's highest risk period.[555] We find that MISO's proposal builds on the provisions accepted by the Commission in the 2020 Summer Outage Order by requiring Planning Resources that will be on a planned outage or derate for more than 31 days in a Season to either not offer into that Season's Auction or to procure replacement capacity for days beyond the 31-day threshold.

335. We find that MISO has demonstrated that the 31-day threshold in a given Season is reasonable. While we recognize that other thresholds could also be just and reasonable, we find that MISO's proposed 31-day threshold appropriately balances providing flexibility to resource owners to plan needed and prudent maintenance and/or requiring a minimum amount of expected future availability to receive capacity payments in a given Season. We also find that MISO has demonstrated that the 31-day threshold reasonably ensures LSEs are receiving the benefits of those resources in the Seasons for which they were procured.

336. We are not persuaded that more time is needed to accommodate resource-owning LSEs. Market participants have had 17 months from the time of the filing to assess the impact of MISO's filing on their business and operating decisions. We find MISO TOs' argument that it is unclear whether market participants will "reserve" capacity for replacement or rely on the capacity market, which may be short, to be speculative. Mitigation provisions that require unused capacity to be offered into the Auction at an economic price prevent such concerns. The only "reserving" would be limited to resources that did not clear in the Auction or external resources, both of which resource

[554] Midwest TDUs June 6 Answer at 6-8.

[555] *See* 2020 Summer Outage Order, 170 FERC ¶ 61,066 at P 37.

owners have always had wide latitude to decide how to use. Similarly, MISO TOs have not demonstrated that it is necessary to allow market participants to incorporate the risk of replacement capacity within their capacity market without being treated as withholding. Doing so would circumvent physical withholding thresholds, would raise market power concerns, and would reduce the amount of resources offered into the Auction, potentially affecting both Auction prices and resource adequacy.

337. Protestors contend that it may be difficult for resource owners to find replacement ZRCs to cover a short time period. As an initial matter, we agree with MISO that, under its proposal, Reserve Requirements will generally be lower in non-Summer Seasons, meaning that resource owners are likely to have excess ZRCs for those Seasons that they are willing to sell as replacement capacity. Moreover, we note that the capacity replacement provisions provide additional flexibility to resource owners that will allow a resource to go on outage for more than 31 days without penalty, if they are able to replace those ZRCs for the time period beyond the 31-day threshold. To the extent that a resource owner believes that it may be unable to find replacement ZRCs for an outage that exceeds 31 days in a Season, the optimal choice for that resource owner may be to forego participation in capacity Auction for that Season. Similarly, we are unpersuaded that MISO's proposal creates market power concerns in bilateral markets to purchase replacement capacity. LSEs have long used bilateral agreements to acquire capacity, including replacement capacity, under MISO's current construct, and nothing in the record indicates that such bilateral contracting will be unavailable during the planning year for capacity replacement for resources on outages exceeding 31 days in a Season.[556]

338. We disagree with arguments that suggest that, if a planned outage receives an exemption for purposes of accreditation, it is unreasonable to penalize that resource if it remains on outage for more than 31 days. We agree with MISO that it is unreasonable for an LSE to be burdened with the full cost of procuring capacity if that Capacity Resource is expected to be, or otherwise becomes, unavailable for more than 31 days in a Season, even if that time period occurs in a period with relatively low reliability risks.

339. Some protestors suggest that restricting a planned outage to 31 days may limit efficiencies gained by longer maintenance periods, leading to increased costs. Although we recognize that resources may vary in their maintenance patterns, we find that MISO's proposal appropriately balances the need for flexibility with the need to ensure that a resource is available for a Season to which it commits. We further find that MISO's capacity replacement provisions afford resource owners sufficient flexibility, as it permits

[556] Currently, Planning Resources with cleared ZRCs that retire, suspend, or are otherwise unable to meet the performance requirements applicable to the Planning Resource must replace the cleared ZRCs with uncleared ZRCs. *See* MISO, FERC Electric Tariff, § 69A.3.1.h (38.0.0).

them to determine whether it is more cost effective to: (1) perform necessary maintenance within the 31-day period; (2) opt out of participating in the capacity market for a Season and perform maintenance over the course of that Season; or (3) perform maintenance for a period longer than 31 days and procure replacement ZRCs for the time period beyond the 31-day threshold. In addition, we note that MISO's proposal permits a resource owner to schedule maintenance straddling two Seasons, which would allow for a resource be on a 62-day outage while still participating fully in both Seasons. This may be particularly useful for resources with longer maintenance periods that are planned far in advance. Similarly, we do not find that MISO's capacity replacement provision unduly discriminates against particular resource types. To the extent that certain resource types require maintenance periods beyond 31 days, we find that it is appropriate for resource owners to determine which option is best for those particular units.

340. We find that it is appropriate for a resource on a planned outage that has not received an exemption that lasts more than 31 days in a Season to both trigger the Capacity Replacement Non-Compliance Charge and to receive a reduction to its capacity accreditation. The proposed Capacity Replacement Non-Compliance Charge and MISO's proposed accreditation exemptions for planned outages serve distinct purposes. As MISO explains, while the capacity replacement provisions are intended to ensure that a resource expected to be unavailable for a significant portion of a Season does not participate in the capacity markets absent the procurement of replacement capacity, MISO's SAC provisions value resources based on their historical availability. We find that it is reasonable to exempt resources that follow MISO's planned outage requirements and receive a Tier 2 exemption from accreditation reductions because there is no reason for that outage to affect future expectations of availability. In contrast, should a resource experience an unplanned outage that lasts longer than 31 days in a Season, it is reasonable for MISO to require that resource to replace the capacity that it is receiving payments for, and, because the outage is unplanned and uncoordinated with MISO, for MISO to adjust its expectations of that resource's future availability and thus reduce its accreditation accordingly.

341. We are not persuaded by Entergy Coalition's argument that MISO's proposal could create additional risks of supply shortfalls. To the contrary, we find that MISO's proposal will help to increase supply availability certainty. Under MISO's current provisions, some Capacity Resources can clear the Auction and receive capacity payments for the entire year even if they expect to be unavailable for 89 days in the Summer. For these units, the capacity payments they receive may not accurately reflect reliability contribution that they bring to MISO. Under MISO's proposal, all market participants will have additional confidence that Capacity Resources that clear the Auction expect to be available for at least 66% of each Season. While this could potentially result in a lower amount of capacity being available to offer into the Auction, we believe that it is critical that MISO be able to depend on such resources, even if such dependability corresponds with fewer resources available for the Auction or FRAPs.

342. We do not find MISO's proposed Tariff language regarding settlements to be inconsistent. As MISO explains, this language explains that the settlement of capacity charges and credits will remain with the original market participants whose ZRCs are being replaced, and that the financial obligation will not be shifted to a different market participant that registered uncleared ZRCs to replace the original Capacity Resource.

343. We disagree that MISO's Tariff should provide further detail regarding MISO's determination as to whether an outage could have been reasonably anticipated. We find, similar to our discussion regarding the "rule of reason" in the above section, that these determinations are implementation details that may be included in the BPM and are consistent with the level of detail of other areas that are found in MISO's Tariff where MISO or Market Monitor has discretion.[557]

4. Stakeholder Engagement

a. MISO Filing

344. MISO states that it has proactively engaged with its stakeholders to develop the proposal and mitigate its resource adequacy challenges.[558] MISO states that stakeholders have passed three motions for MISO to delay the filling, citing the need for additional time to understand MISO's proposal. MISO states that, in response, MISO provided stakeholders with an additional two months to continue discussions. MISO further states that it has modified its proposal in response to stakeholder feedback, including: (1) implementing a transition period to the full 80% Tier 2 weighting; (2) adopting the UCAP/ISAC ratio; and (3) including Auction Clearing Price adjustments during rare circumstances. MISO states that its proposal reasonably accommodates concerns raised in the stakeholder process.[559]

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[557] *See, e.g.*, MISO, FERC Electric Tariff, Module D, § 64.2.2 (31.0.0) ("Pending the development of the capability to use the market models, the [Market Monitor] shall determine the effect on prices of questioned conduct using the best available data and such models and methods, as it shall deem appropriate."); *see also* MISO, FERC Electric Tariff, Module D § 64.1.4.h (65.0.0) ("If cost data or other information submitted by a Market Participant indicates to the satisfaction of the [Market Monitor] that the Reference Levels for that Market Participant should be changed, revised Reference Levels shall be determined, communicated to the Market Participant, and implemented, as soon as practicable.").

[558] MISO Transmittal at 6.

[559] *Id.* at 22-23.

b. Comments and Protests

345. Manitoba Hydro asserts that MISO has made concerted and lengthy efforts to address stakeholder concerns and made several improvements to its original proposal.[560] However, some protestors argue that MISO's proposal is not just and reasonable because MISO did not adequately address stakeholder concerns. The Mississippi Commission contends that MISO has not incorporated stakeholder feedback in its White Papers, and that MISO will use its unvetted White Papers to justify future steps to address a problem that may not exist.[561] According to the Mississippi Commission, MISO has not proactively engaged with stakeholders and MISO has routinely ignored or marginalized concerns raised with the SAC proposal.[562] The Mississippi Commission states that Order No. 719 established four criteria—(1) inclusiveness; (2) fairness in balancing diverse interests; (3) representation of minority interests; and (4) ongoing responsiveness—intended to "balance customers' and other stakeholders' need for effective access to the boards of RTOs and ISOs, with the need for the independent management of each RTO and ISO."[563] The Mississippi Commission argues that MISO ignored stakeholder feedback; therefore, MISO's SAC proposal violates Order No. 719.[564]

346. DTE Electric claims that the proposal was challenged extensively in stakeholder meetings with minimal response from MISO to valid concerns.[565] East Texas states that MISO stakeholders had to evaluate a significant new resource adequacy construct where the details of the proposal were in considerable flux until shortly before this filing was submitted, and, because of this, MISO's proposal still poses a number of conceptual and operational concerns. According to East Texas, nor did MISO provide all of the relevant information to stakeholders so they could scrutinize it and ensure that it would garner the desired benefits.[566] East Texas adds that market participants have not reliably assessed its intended or unintended consequences, let alone the potential cost of those

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[560] Manitoba Hydro Comments at 3.

[561] Mississippi Commission Protest at 9.

[562] *Id*.

[563] *Id*. at 29 (citing *Wholesale Competition in Regions with Organized Elec. Mkts.*, Order No. 719, 125 FERC ¶ 61,071 (2008), *order on reh'g*, Order No. 719-A, 128 FERC ¶ 61,059, *order on reh'g*, Order No. 719-B, 129 FERC ¶ 61,252 (2009)).

[564] *Id*.

[565] DTE Electric Protest at 3.

[566] East Texas Protest at 3.

consequences. East Texas asserts that the fundamental problem is that one cannot presently grasp what repercussions MISO's various changes will have on its capacity market, and thus, MISO is unable to establish that its proposal is just and reasonable under section 205 of the FPA.[567]

347. Industrial Customers assert that MISO failed to consider a reasonable modification to MISO's proposal presented by Industrial Customers in the MISO stakeholder process. Industrial Customers state that, within the MISO stakeholder process, they participated in joint End-Use Sector comments to MISO pointing out the same concerns with MISO's proposal that they raise in their protest. Industrial Customers assert that they offered a constructive solution that would allow MISO to move forward with its proposed seasonal allowed calls on LMRs without violating 10 calls per Planning Year, but MISO ignored their suggestion. Industrial Customers argue that MISO's failure to reasonably consider stakeholder feedback (that would have allowed MISO to move forward with the underlying objectives in its proposal) is another reason to reject MISO's proposal in this proceeding.[568]

c. MISO February 10 Answer

348. MISO contends that its filing reflects substantial engagement with stakeholders over the last several years and particularly in 2021, noting that it conducted six workshops, in addition to monthly RASC meetings, in May, August, September, October, and November of 2021. MISO further contends that the proposal was modified in several areas compared to the original proposal based on stakeholder discussions, including: rules related to Auction participation, outage exemptions, converting SAC to UCAP, including offered availability in all hours, and transition provisions, which provide stakeholders three years from the requested effective date to adjust to the proposal.[569]

349. MISO argues that the Commission should dismiss arguments suggesting that MISO violated Commission policy by ignoring stakeholder feedback. MISO argues that nothing in Order No. 719 requires MISO or any other RTO/ISO to implement or take action on any and all issues raised during the stakeholder feedback process. MISO contends that despite the Mississippi Commission's claim that MISO ignored stakeholder feedback, MISO has responded to more than 150 questions, comments, and requests in its Q&A document, held a multitude of stakeholder meetings specifically focused on addressing stakeholder questions and feedback, and has provided a forum for

[567] *Id*.

[568] Industrial Customers Protest at 11-12.

[569] MISO February 10 Answer at 6-7.

stakeholders to provide comments directly to the MISO Board of Directors on multiple occasions.[570]

d. Answers to MISO February 10 Answer

350. WEC Utilities argues that MISO is misleading when using the number of stakeholder meetings as evidence that further stakeholder engagement is not necessary when this is instead evidence of the level of complexity of the proposal and transition.[571] WEC Utilities states that several stakeholder identified issues remain unresolved.[572] WEC Utilities claims that MISO exaggerated the ability of stakeholders to discuss the proposal with the Board of Directors, asserting that such opportunities were limited to public comment periods that did not allow for a constructive dialogue.[573]

351. The Mississippi Commission claims that there was near unanimous opposition to MISO moving forward with the SAC proposal, including four motions against advancing that were approved by stakeholders in the RASC.[574] The Mississippi Commission further contends that MISO focuses on form over function in the stakeholder process.[575] The Mississippi Commission asserts that MISO inaccurately characterizes how their concerns were addressed and notes that they were not presented with any detail to the Board of Directors in a public meeting in 2021.[576] The Mississippi Commission cites the statement in MISO's February 10 Answer that additional stakeholder engagement is necessary prior to implementing the SAC proposal as evidence that the proposal was incomplete.[577]

e. Commission Determination

352. We are not persuaded by protestor arguments that MISO's proposal fails to adequately consider stakeholder concerns expressed in the stakeholder process, as

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[570] *Id.* at 49-50.

[571] WEC Utilities Answer at 2-3.

[572] *Id.* at 3.

[573] *Id.*

[574] Mississippi Commission Answer at 2.

[575] *Id.* at 3.

[576] *Id.* at 3-4.

[577] *Id.* at 4-5.

required by Order No. 719. In Order No. 719, the Commission adopted the proposed rule to require each RTO or ISO to increase its responsiveness to the needs of customers and other stakeholders.[578] In particular, the Commission found that RTOs and ISOs must provide an avenue for customers and other stakeholders to present their views on RTO and ISO decision-making and to have those views considered.[579] Here, we find that MISO's stakeholder process satisfied those requirements of Order No. 719 with respect to the instant proposal. MISO has worked with stakeholders on the proposal for several years, holding numerous meetings since at least March 2020. Stakeholders have been on notice of the proposed Tariff changes since November 30, 2021, thus giving them nearly 17 months to prepare for the 2023/2024 Auction in the Spring of 2023. Moreover, MISO incorporated some stakeholders' suggestions into the eventual proposal. In addition, with respect to MISO's statement that additional stakeholder engagement is necessary prior to implementation of the proposal, we do not consider that to be a flaw in the stakeholder process that renders the proposal unjust and unreasonable.

5. Other Comments

a. Comments

353. Joint Commenters submitted comments attaching their comments on MISO's MCO Filing. In their comments on MISO's MCO Filing, Joint Commenters argue that MISO failed to adequately evaluate the effects of the 50% threshold or the 50 MW exemption and that such failure becomes even more significant when one considers the impact of the 31-day replacement capacity requirement in MISO's availability-based resource accreditation proposal. Joint Commenters also express concern that the relationship between the MCO Filing and the instant seasonal construct filing will produce costly unintended consequences that were not adequately evaluated by MISO. Joint Commenters express concern that these changes will lead to increased costs for LSEs without a tangible increase in reliability.[580]

354. MidAmerican is concerned that the policies contained in MISO's proposal do not have corresponding market commitment changes that will allow MidAmerican to be successful under the new paradigm. MidAmerican contends that MISO needs to further improve its forecasting tools and market clearing processes in order to effectively stage generators for real-time operations in advance of potential weather events or capacity shortfalls. MidAmerican argues that, with the increased penetration of intermittent

[578] Order No. 719, 125 FERC ¶ 61,071 at PP 481, 502.

[579] *Id.* P 503.

[580] Joint Commenters Comments, attach. A (citing Joint Commenters' Comments in Docket No. ER22-496-000 (filed Jan. 14, 2022)).

resources, MISO must recognize that solving for these increasing levels of forecast error in the real-time market will become increasingly difficult and will need to be managed on a day ahead basis. MidAmerican contends that, without additional consideration for day-ahead forecast uncertainty, the number of resources MISO will need to call on in the real-time market will increase, further putting pressure on the intraday gas market and gas storage capability, and, ultimately, penalizing resources for their inability to acquire the necessary fuel due to the limited time frame in which MISO is attempting to dispatch a large number of resources.[581]

355. COMPP agrees with MISO that capacity market reform is necessary but argues that MISO has failed to demonstrate that the proposed Tariff changes will be sufficient to solve MISO's ongoing reliability problems. COMPP avers that MISO's revisions have not been shown to be just and reasonable and, if the Commission does not reject the proposal, it should hold a technical conference on the shortfalls of MISO's capacity market to establish a record.[582] Specifically, COMPP argues that MISO's proposal does not include mechanisms to measurably improve resource performance.

356. COMPP argues that, as it argues in the MISO MCO proceeding in Docket No. ER22-495-000, a sloped demand curve in the seasonal Auction would provide the economic signals and winterization incentives MISO needs. COMPP contends that the Market Monitor has found that the Auction has not produced meaningful prices that reflect the actual marginal value of reliability. COMPP requests the Commission to direct MISO to make a subsequent filing implementing a downward sloping demand curve and/or explore the implementation of a sloped demand curve in a larger technical conference covering MISO Resource Adequacy issues.[583]

b. Commission Determination

357. We reject these protests. First, we note that, concurrently with this order, we are issuing an order rejecting MISO's MCO Filing.[584] Second, while MidAmerican raises concerns that MISO needs to update its market commitment tools and processes, MidAmerican does not provide any specific evidence to suggest that MISO's proposal is unjust and unreasonable absent those updates. Because we are accepting MISO's instant proposal, we reject COMPP's request to institute a technical conference on MISO's capacity reforms. Finally, we find that COMPP's request for the Commission to direct

[581] MidAmerican Protest at 3.

[582] COMPP Protest at 2.

[583] *Id.* at 17-19.

[584] *Midcontinent Indep. Sys. Operator, Inc.*, 180 FERC ¶ 61,142.

MISO to make a subsequent filing to institute a downward sloping demand curve and/or explore the implementation of a sloped demand curve in a technical conference is beyond the scope of the instant filing.[585]

The Commission orders:

(A) MISO's Filing is hereby accepted, effective September 1, 2022, as requested, subject to condition, as discussed in the body of this order.

(B) MISO is hereby directed to submit a compliance filing within 30 days of this order, as discussed in the body of this order.

(C) MISO is hereby directed to submit an informational report within 90 days of the conclusion of the 2025/2026 Planning Year, as discussed in the body of this order.

By the Commission. Commissioner Danly is concurring with a separate statement attached.
Commissioner Clements is dissenting with a separate statement attached.
Commissioner Christie is concurring with a separate statement attached.

(S E A L)

Debbie-Anne A. Reese,
Deputy Secretary.

[585] *See, e.g.*, *Qualifying Facility Rates & Requirements; Implementation Issues Under the Publ. Util. Regul. Policies Act of 1978*, Order No. 872, 172 FERC ¶ 61,041, at PP 202, 524, 568, 594, 596 (denying requests for Commission actions as beyond the scope of the proceeding), *order on reh'g*, Order No. 872-A, 173 FERC ¶ 61,158 (2020). *See also, e.g.*, *PJM Interconnection, L.L.C.*, 146 FERC ¶ 61,127, at P 26 (2014) (in finding the protestors' argument beyond the scope of the proceeding, the Commission held that while the protestors' recommended revisions to the applicants' filing might have been an improvement, the existing proposal was not unjust, unreasonable or unduly discriminatory without them).

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Midcontinent Independent System Operator, Inc. Docket Nos. ER22-495-000
ER22-495-001

(Issued August 31, 2022)

DANLY, Commissioner, *concurring*:

1. I join the Commission's decision to accept Midcontinent Independent System Operator, Inc.'s (MISO) proposed tariff revisions, effective September 1, 2022, subject to condition.[1] As an initial matter, I agree with MISO that changes are needed to its resource adequacy construct in light of "[t]he MISO Region . . . experiencing significant shifts in generation resource retirement, increased reliance on intermittent resources, significant weather events with correlated generator outages, and declining excess reserve margins."[2]

2. I have become increasingly concerned by MISO's ever-decreasing excess reserve margins[3] and MISO's apparent inability to retain sufficient dispatchable generation to

[1] *See Midcontinent Indep. Sys. Operator, Inc.*, 180 FERC ¶ 61,141 (2022).

[2] Transmittal at 2.

[3] *See 2022 Summer Reliability Assessment*, N. Am. Elec. Reliability Corp., at 4 (May 2022), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2022.pdf ("Midcontinent ISO (MISO) faces a capacity shortfall in its North and Central areas, resulting in high risk of energy emergencies during peak summer conditions."); *id.* ("Capacity shortfall projections reported in the *2021 [Long-Term Reliability Assessment (LTRA)]* and as far back as the *2018 LTRA* have continued. Load serving entities in 4 of 11 zones entered the annual planning resource auction (PRA) in April 2022 without enough owned or contracted capacity to cover their requirements."); *id.* ("More extreme temperatures, higher generation outages, or low wind conditions expose the MISO North and Central areas to higher risk of temporary operator-initiated load shedding to maintain system reliability."); *id.* at 15 ("Tighter than normal operating conditions are anticipated, particularly in the MISO North/Central region[s], which cleared too little capacity in the 2022–2023 PRA. The PRA capacity shortfall of 1,230 MW signals a potential for operating risk during peak summer conditions."); *id.* ("Expected resources do not meet operating reserve requirements under normal peak-demand and outage scenarios.").

ensure reliability and resource adequacy. MISO's interconnection queue, which is composed almost entirely of intermittent generation,[4] shows that MISO is unlikely to obtain much more dispatchable generation any time soon. Right now, the combined effects of the market's price signals and the state and federal policies under which the market must operate has brought MISO to the point where the total quantity of nameplate capacity is rising, but the quantity of accredited capacity is decreasing.[5] This is a problem that should not be ignored, and the need for dispatchable generation cannot be overstated.[6] A market's failure to procure sufficient capacity with the needed characteristics is a flaw so fundamental that it calls the justness and reasonableness of a market's resulting rates into question. Perhaps, given this systemic failure, Vistra Corp. was correct in describing MISO's capacity market as "irreparably dysfunctional."[7]

3. And perhaps the Commission should consider action pursuant to Federal Power Act section 206.[8] While I think that further action is needed, even with the Commission's approval of this proposal, to address the reliability and resource adequacy

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[4] *See Managing Reliability Risk in the MISO Footprint*, MISO, at 8 (June 16, 2022), https://cdn.misoenergy.org/20220616%20Board%20of%20Directors%20Item%2008a%20Reliability%20Imperative625168.pdf.

[5] *See id.* at 5.

[6] *See 2021 State of the Market Report for the MISO Electricity Markets*, Potomac Economics (The Independent Market Monitor for MISO), at 22 (June 2022), https://www.potomaceconomics.com/wp-content/uploads/2022/06/2021-MISO-SOM_Report_Body_Final.pdf (explaining "the importance of having sufficient dispatchable resources available to satisfy the system demands when intermittent generation is not available").

[7] *Vistra Accelerates Pivot to Invest in Clean Energy and Combat Climate Change*, Vistra Corp., https://investor.vistracorp.com/2020-09-29-Vistra-Accelerates-Pivot-to-Invest-in-Clean-Energy-and-Combat-Climate-Change (Sept. 29, 2020) (announcing that Vistra Corp. "expects to retire seven Luminant power plants, of which the company owns a combined capacity of more than 6,800 MW, between 2022 and 2027," explaining that "[t]hese plants, especially those operating in the irreparably dysfunctional MISO market, remain economically challenged"); *see also* Edward Klump, E&E News, *Vistra touts major zero-carbon push as it unplugs coal*, E&E News (Sept. 30, 2020), https://www.eenews.net/articles/vistra-touts-major-zero-carbon-push-as-it-unplugs-coal/ ("Vistra pointed to a number of issues, including what it called a systematic failure of the MISO capacity market to provide Illinois power plants with adequate revenues.").

[8] 16 U.S.C. § 824e.

risks faced by the MISO region, MISO's decision to establish a seasonal resource adequacy construct is a just and reasonable step in the right direction to mitigate the effects on reliability of MISO's increasing reliance on intermittent generation and the decreasing excess reserve margins. And the question before the Commission is not whether there are other changes that should be made to MISO's construct, or whether this proposal is better than MISO's existing tariff; rather, the question is whether MISO has demonstrated that this proposal is just and reasonable[9]—which indeed it has.

For these reasons, I respectfully concur.

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James P. Danly
Commissioner

[9] *See Neb. Pub. Power Dist. v. FERC*, 957 F.3d 932, 943 (8th Cir. 2020) (recognizing that "courts have made it clear that FERC 'restricts itself to evaluating the confined proposal'" and "[t]herefore, FERC 'need only find the *proposed* rates to be just and reasonable.'") (citations omitted); *Advanced Energy Mgmt. All. v. FERC*, 860 F.3d 656, 662 (D.C. Cir. 2017) ("When acting on a public utility's rate filing under section 205, the Commission undertakes 'an essentially passive and reactive role' and restricts itself to evaluating the confined proposal.") (quoting *City of Winnfield v. FERC*, 744 F.2d 871, 875-76 (D.C. Cir. 1984)).

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Midcontinent Independent System Operator, Inc. Docket Nos. ER22-495-000
ER22-495-001

(Issued August 31, 2022)

CLEMENTS, Commissioner, *dissenting*:

1. I dissent from today's order accepting a suite of resource adequacy reforms filed by Midcontinent Independent System Operator (MISO) because I cannot conclude they will yield just and reasonable rates for capacity in the region. While I agree that reforms are needed, I believe critical design details of MISO's proposal are flawed such that capacity may not be accredited consistent with its availability during times of greatest reliability risk. In addition, MISO's support for its proposed mitigation revisions contains an inconsistency that I fear could provide a loophole for excessive customer costs.

2. Because MISO's proposal addresses reliability risks present in the current tariff and offers the potential to better align capacity payments with services provided, I would have rejected MISO's filing with specific guidance and given MISO the opportunity to expeditiously re-file with necessary revisions. I note, however, that MISO's chosen path to a seasonal construct, the Seasonal Accredited Capacity (SAC) methodology, is not well aligned with the Expected Load Carrying Capability (ELCC) methodology it currently uses for calculating the seasonal accreditation of wind resources and plans to use for solar resources. As MISO takes next steps beyond the market changes proposed herein, I urge MISO to rethink this misalignment and provide a more consistent framework that fairly credits all resource types.

3. I have spoken publicly about the need for the Commission to focus on emerging reliability challenges driven by the changing resource mix and increasing extreme weather and to show leadership in fostering market-based solutions to those challenges.[1] The wind, solar, storage, and hybrid resources entering the market have different operating characteristics and capabilities than the thermal resources that have dominated the electric system for decades. Many of those thermal resources are also retiring, adding to the pace of generation fleet change. At the same time, extreme weather events are

[1] *See, e.g.*, July 2022 Commission Meeting: Opening Remarks of Commissioner Allison Clements, available at www.ferc.gov/news-events/news/july-2022-commission-meeting-opening-remarks-commissioner-allison-clements.

becoming more frequent, disrupting fuel delivery systems, stressing generator performance, and causing correlated generator outages.[2] With these factors converging, it comes as no surprise that the services, attributes, and resource performance required to maintain grid reliability are also changing.

4. In some cases these changes have driven RTOs/ISOs to modify energy and ancillary services market rules,[3] and the Commission has recognized a potential need for broader adoption of such revisions.[4] In other cases these changes have motivated resource adequacy reforms, including a ramp product in CAISO,[5] penalties when capacity resources fail to deliver energy during emergencies in ISO New England[6] and

[2] *See, e.g.*, National Oceanic and Atmospheric Administration, National Centers for Environmental Information "U.S. Billion-Dollar Weather and Climate Disasters" (2022), available at https://www.ncei.noaa.gov/access/billions/.

[3] For example, the Commission has approved a number of energy and ancillary services market reforms in recent years, including new ramp products. *See, e.g.*, *Midcontinent Independent System Operator, Inc.*, 149 FERC ¶ 61,095 (2014) (conditionally accepting, subject to a compliance filing, MISO's proposal to introduce a new ramp capability product); *Midcontinent Independent System Operator, Inc.*, 170 FERC ¶ 61,075 (2020) (accepting MISO's proposal to implement a 30-minute Short-Term Reserve product in its Day-Ahead and Real-Time Market); and *Southwest Power Pool, Inc.*, 180 FERC ¶ 61,088 (2022) (accepting SPP's proposal to implement an Uncertainty Reserve product).

[4] At two technical conferences held in September and October 2021, the Commission heard extensive testimony about operators' increasing need for operational flexibility, market mechanisms already employed to seek to acquire that flexibility, and ideas for additional market reforms to address the growing need for flexibility. *See* Supplemental Notice of Technical Conference on Energy and Ancillary Services in the Evolving Electricity Sector, Docket No. AD21-10 (filed Sept. 3, 2021); Supplemental Notice of Technical Conference on Energy and Ancillary Services in the Evolving Electricity Sector, Docket No. AD21-10 (filed Oct. 7, 2021).

[5] *California Independent System Operator Corporation*, 156 FERC ¶ 61,226 (2016).

[6] *ISO New England Inc.*, 147 FERC ¶ 61,172 (2014).

PJM,[7] and effective load carrying capability capacity accreditation changes in PJM,[8] NYISO,[9] and SPP.[10] While I have not agreed with the specific path taken in some of these proposals, it is essential that grid operators update their market rules to adapt to changing market conditions, and this diversity of efforts demonstrates that there is no single, one-size-fits all fix across all regions. At the same time, however, the Commission must review each particular proposed rule change in detail, ensuring that it does not create unjust and unreasonable, or unduly discriminatory rates. It is not sufficient that a proposal represents an improvement over the status quo, which itself may no longer be just and reasonable in light of current and future market conditions.

5. Here, MISO proposes two significant resource adequacy reforms: a new capacity accreditation methodology for Schedule 53 resources, which include thermal and demand response resources,[11] and a shift to seasonal capacity auctions. MISO states that the reforms in this filing are part of MISO's broader "Reliability Imperative" effort and fit within the "Market Redefinition" pillar of that effort, which aims "to ensure that resources with needed capabilities and attributes will be available during the highest risk periods across the year."[12] MISO explains that its objectives include providing a deeper assessment of system needs in the highest risk periods, including required capabilities such as flexibility; improving how resources are accredited for capacity; and developing market products that provide the right incentives for resources to maintain system reliability.[13] MISO asserts that it "cannot reliably operate the system if the resources it depends on do not or cannot perform (that is, do not provide energy or reserves) during

[7] *PJM Interconnection, L.L.C.*, Docket No. ER15-623-000 (March 31, 2015) (delegated order).

[8] *PJM Interconnection, L.L.C.*, 176 FERC ¶ 61,056 (2021).

[9] *New York Independent System Operator, Inc.*, 179 FERC ¶ 61,102 (2022).

[10] *Southwest Power Pool, Inc.*, 180 FERC ¶ 61,074 (2022). I note that I dissented from this order because SPP failed to submit tariff revisions that comported with the rule of reason and thus it was impossible to conclude that SPP's proposal was just and reasonable. Also, as is the case in MISO's proposal, I was concerned that SPP did not adequately justify certain aspects of its proposal. *See id.* (Clements, Comm'r, dissenting).

[11] *See* Majority Order at P 91 (discussing MISO's definition for Schedule 53 resources).

[12] Wright Testimony at 13.

[13] *Id.* at 13-14.

periods of highest reliability risk."[14] It argues that its proposed reforms will foster efficient investment decisions by capacity resource owners consistent with resource performance during times of need.[15]

6. MISO's justification for its proposed reforms is therefore that they will value capacity consistent with its actual availability during periods of highest reliability risk and will incentivize capacity resource owners to invest and maintain their facilities so that they are more likely to be available during those periods.

7. Properly calibrated, I agree that MISO's proposal could satisfy these objectives and produce just and reasonable capacity rates. However, while the general thrust of MISO's proposal is appropriate, it contains several design flaws that will impede the proposal's ability to satisfy these objectives, and result in compensation for resources that does not match their true capacity contribution to the region. It also contains ambiguous tariff language inconsistent with MISO's expert testimony that creates the potential for the exercise of market power. Considering the significance of MISO's proposal, the Commission's duty to engage with the details to ensure grid reliability and consumers are protected was particularly important. But the Majority Order glosses over these critical details. While a narrow rejection order could have set the stage for MISO to return with an improved proposal that addresses these issues, today's order cements flaws into the region's market design, thereby undermining a just and reasonable outcome.

VII. Seasonal Accredited Capacity Methodology

8. In transitioning to a seasonal market, MISO's proposal devises a new method of crediting resources for each season based on their historical performance during 65 hours when emergency conditions or tight operating conditions were present. While MISO justifies this general framework, it includes several unsupported design features that cause MISO to look to the wrong set of hours, and to credit resources that are unlikely to be capable of performing when called upon. These flaws threaten system reliability and make for a poor foundation on which MISO's new proposal rests.

9. MISO argues that "[r]esource accreditation should reflect the anticipated capability and availability of Planning Resources during times when they are most needed,"[16] but unfortunately its SAC methodology for valuing thermal resources falls short of this goal. The SAC methodology seeks to measure each resource's anticipated availability by assessing its prior performance during 65 hours of emergency or other

[14] *Id.* at 14.

[15] Smith Testimony at 19-20.

[16] McFarlane Testimony at 17.

tight operating conditions, which MISO calls "RA Hours." Critical design decisions include (1) determining what constitutes an RA Hour; (2) determining what constitutes "availability" during each of those RA Hours, particularly if the resource was offline at the time; and (3) determining under what circumstances a resource that was on outage during RA Hours will be exempted from having its future accreditation reduced due to its unavailability. Each of these elements of MISO's proposal has flaws, as identified by MISO's Independent Market Monitor (IMM) and other stakeholders.

10. I recognize that the IMM supports MISO's overall proposal despite these flaws. The IMM states that "MISO made a number of changes in the course of the stakeholder process that are likely to reduce the benefits" of the proposal, but the IMM clarifies that it is supporting the proposal nonetheless "because we believe they are improvements over MISO's current market design and rules."[17] While I agree that, on balance, MISO's proposal likely provides a better framework than the status quo, a rate revision submitted pursuant to section 205 of the Federal Power Act is not necessarily just and reasonable solely because it is an improvement to the existing rate.[18] Rather, the filing utility bears the burden to demonstrate that the rate revision is itself just and reasonable.[19] Because MISO has failed to demonstrate through substantial evidence and sound economic logic that the market design choices discussed above are just and reasonable, the Commission's duty is to reject the proposal. Rejecting with guidance would have created the opportunity for MISO to revise it and submit an improved proposal that is truer to MISO's intent to accredit capacity consistent with its likely availability during periods of greatest reliability risk.

A. MISO looks to the wrong set of hours to determine capacity performance

11. With regard to setting RA Hours, MISO acknowledges that in many seasons, particularly non-summer seasons, it is unlikely there will be 65 hours of emergency conditions. MISO proposes to backfill the remainder with other historical hours that saw the tightest operating margins.[20] The calculation of operating margin (i.e. resource

[17] IMM Comments at 2.

[18] *See PJM Interconnection, L.L.C.*, 180 FERC ¶ 61,089, at P 47 n.111 (2022) (finding that even if PJM's contention that its Intelligent Reserve Deployment proposal is an improvement over its current approach is correct, that does not render the proposal just and reasonable).

[19] 16 U.S.C. § 824d(e).

[20] McFarlane Testimony at 20-21. While the Commission finds this approach of defining RA hours for seasonal auctions in part based on hours from different seasons to be just and reasonable, I note that this determination is specific to the context of MISO

supply minus demand at any given point in time) is therefore of great consequence because it will determine in which hours each resources' availability is evaluated. MISO proposes to include in operating margin the capacity of any offline resource with a lead time of 12 hours or less. But offline capacity with a lead time of more than 6 or 8 hours is not "available" in any given hour, so MISO's approach inaccurately excludes some tighter hours from the "RA Hours" designation by overcounting supply, while including as RA Hours some periods where operating margin is comparatively less tight.

12. As the IMM and Clean Energy Coalition argue, unexpectedly tight hours typically arise on a shorter timeframe, requiring a response time faster than many of the resources counted within that operating margin can deliver.[21] As the IMM explains, a 2-6 hour lead time is appropriate, because that "is the timeframe in which MISO often recognizes that emergency conditions are developing."[22] Resources with lead times as long as 12 hours "are not relevant" to the reliability threat during these events "because the conditions were not recognized 12 hours in advance."[23]

13. Defining tight operating conditions assuming that resources with a 12-hour lead time are available, as MISO does, could cause MISO to ignore hours where offline resources with a lead time between 6 and 12 hours are comparatively abundant, when in fact uncertainties like load forecast errors, wind forecast errors, large unit forced outages, and other factors that are not known far in advance pose a reliability risk for the system for which these resources are of no use. MISO's approach thereby inappropriately shifts RA Hours toward more foreseeable conditions where operating conditions are not truly as

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applying it to schedule 53 resources and the evidence put forth to demonstrate alignment of its choice of hours with the historical availability of those resources. *See* Majority Order at P 246. Continuing this approach would not necessarily be just and reasonable if the SAC methodology were to be extended beyond schedule 53 resources, which may have greater variation between seasons. As DTE, MISO TOs, and Minnesota Power argue, using hours from other seasons undermines the seasonality of the construct. DTE Protest at 14; MISO TOs Comments at 9; Minnesota Power Comments at 2. And while a thermal resource's performance during tight hours in one season may strongly correlate with performance in tight hours in another season, that may not be the case for other types of resources such as wind and solar, whose performance may be more closely linked to the weather.

[21] *See* IMM Comments at 9; Clean Energy Coalition Comments at 11.

[22] IMM Comments at 8. *See also* Clean Energy Coalition Comments at 11 (arguing that MISO's approach "fails to consider how unexpectedly tight hours typically arise in the range of 2 to 8 hours because reality diverges from forecasts").

[23] IMM Comments at 9.

tight, while excluding hours that are in fact tighter when considering the system's true ability to respond to uncertainties. The IMM notes that as the uncertainties on the system grow, the adverse effect of MISO's 12-hour lead time assumption are likely to increase.[24]

14. While MISO must necessarily make some qualitative judgments in determining how to design its seasonal capacity mechanism (including whether to use such an "RA hour" construct and, if so, which RA hours to look at), it fails to offer sufficient defense of its 12-hour lead time rule. In support of the 12-hour threshold, MISO's witness only emphasizes that its starting point was an even longer 24-hour lead time threshold, which it shortened based on the feedback from the IMM.[25] But in endorsing the IMM's general logic, MISO provides no explanation as to why it did not choose a shorter lead time threshold that better matched likely system conditions contributing to the concerns this construct is intended to address.

B. MISO's capacity accreditation does not match resource contribution to system reliability

15. MISO repeats this same mistake of crediting resources incapable of contributing to system reliability when determining resource availability for purposes of accreditation. MISO proposes to credit a resource as having been available during an RA Hour if it was offline but had a lead time of 24 hours or less. But as the IMM explains, this lax crediting includes many resources that will not be able to deliver any value when called upon.[26] Further, MISO's attempted rationale to justify the inconsistency of its approach of using a longer 24-hour window for resource accreditation while using a shorter 12-hour lead time used for purposes of determining RA Hours does not make sense. MISO argues that while the 12-hour threshold better represents "times of need," the 24-hour threshold "better reflects whether MISO could have reasonably committed a resource in its Day-Ahead Market or Forward Reliability Assessment Commitment processes."[27]

16. But examining whether a resource *could* have been committed answers the wrong question. As the IMM explains:

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[24] *Id.*

[25] McFarlane testimony at 23. The Majority Order likewise justifies the 12-hour threshold as superior to a 24-hour threshold, but does not explain why it finds 12 hours to be reasonable in light of the criticisms that a shorter threshold was necessary to align with resources' true ability to serve the system. *See* Majority Order at P 255.

[26] IMM Comments at 10.

[27] McFarlane testimony at 24.

> [MISO's] logic is flawed . . . If most of the threats to reliability emerge during the operating day, only offline resources that can [be] started once the threat is recognized can contribute to reliability. Offline resources that could theoretically have been committed the prior day, but whose lead time is too long for them to start to mitigate the reliability threat provide no value in such events.[28]

17. In other words, whether a resource could have been committed if MISO knew about a reliability situation in advance is beside the point when assessing contribution to tight operating hours that arise on a shorter timeframe.[29] By MISO's own admission, "[h]istorically most MaxGen Events have been driven by events occurring after the Day-Ahead Market clears."[30]

18. The majority declares that "[r]esources that can be committed through the Day-Ahead or Forward Reliability Assessment Commitment process contribute to MISO's resource adequacy needs." Majority Order at P 275. But this runs contrary to the evidence in the record that *offline* resources with response times longer than 6 or 8 hours are incapable of contributing to the system during times of need. The majority hypothesizes that there may be capacity needs that could be identified with longer than 12 or even 24 hours of advanced notice, "such as resources being out on an extended planned or forced outage . . . or certain meteorological events forecast 24 or more hours in advance."[31] But those events, to the extent they may exist, could be responded to by resources with a lead time of longer than 24-hours, making the 24-hour requirement arbitrary. In setting a lead time of 24 hours, MISO divorces its accreditation determination from the question whether a resource contributes to reliability during RA

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[28] IMM Comments at 10.

[29] *See* IMM Comments at 10 ("It is irrelevant whether MISO theoretically 'could have reasonably committed a resource' through the day-ahead process. If most of the threats to reliability emerge during the operating day, only offline resources that can started once the threat is recognized can contribute to reliability.").

[30] MISO February 10 Answer at 43. While this supports declining to offer credit to resources with lead times in excess of 24 hours, it runs contrary to MISO's decision to credit resources with lead times between 6 and 24 hours, and also does not explain the inconsistency between the lead time threshold used for measuring RA hours and the threshold used for accreditation.

[31] Majority Order at P 276. It is notable that neither MISO nor any party in the record makes this argument, meaning that the majority's contention is only a guess as to why such resources may have value.

Hours. This is at odds with the design of its proposal and lacks any reasonable basis in the record.[32] It is worth noting that were a shorter response time requirement implemented, this would not give slow-response resources zero capacity credit. Rather, resources that were online during RA Hours and therefore contributing to resource adequacy would still get credit for contributing to system needs.[33]

19. Over-valuing less flexible units is unjust and unreasonable not only because it gives resources more credit than they deserve, but also because pursuant to the SAC's design it will necessarily under-value more flexible and available resources.[34] This misalignment between payment and reliability contribution is unjust and unreasonable due to its financial implications, and also because it undermines system reliability. The IMM suggests a reasonable alternative of a sliding scale, which would "recognize that certain units (e.g., fast-starting units) provide more reliability value than other units (long-lead time units)," and measure windows with tight operating conditions accordingly.[35] While MISO was not required to propose this alternative, it does have the burden under section 205 of justifying why the threshold it has chosen properly credits resources for their contribution to reliability and is therefore just and reasonable. It has not done so.

C. MISO's outage framework is unjust and unreasonable

20. Another significant flaw in MISO's proposed framework is its proposal to exempt resources from negative impacts to their accreditation if the resource owner provides 120-days' notice of the outage to MISO and MISO determines there is an adequate "maintenance margin." This proposal is logically inconsistent and inadequately

[32] To the extent MISO seeks to serve a different need besides contribution to RA Hours, such as the hypothetical need for resources to provide energy adequacy for events that are known long in advance, it has not demonstrated such a need in this record, nor justified why a 24-hour lead time requirement is the right threshold to accredit capacity for serving such a need.

[33] The majority confusingly states that "a resource being unavailable within 12 (or fewer) hours because MISO did not select it through a day-ahead or FRAC commitment process is not a reasonable basis to penalize that resource by assigning it a zero SAC accreditation value for those hours." Majority Order at P 276. This is hard to understand, given that when a resource with a long lead time is not selected it does not and cannot contribute to resource adequacy during RA Hours, whereas a resource that is selected does contribute.

[34] IMM Comments at 10.

[35] *Id.*

supported. As the IMM states, "[r]esources that schedule more frequent or longer-duration outages are less likely to be available during reliability events than resources that take less frequent or shorter-duration outages."[36] Further, as the IMM asserts, MISO's maintenance margin calculation is incapable of accounting for any and all unexpected factors and conditions that may lead to reliability risk, including extreme weather, system contingencies, unusual intermittent output levels, and load forecast errors.[37] In approving an outage—and the attendant accreditation exemption—MISO will have no way of knowing months in advance if challenging operating conditions will arise and the resource will be needed. Indeed, the very need for an exemption suggests the opposite. If in fact MISO could be sure that tight operating conditions would not occur where it has "maintenance margin," then resources could schedule during that period without fear that RA Hours would occur and their accreditation would be penalized. But the truth is that MISO may find itself short during those periods.

21. MISO does not adequately justify why it proposes to give full credit to resources as though they are providing reliability value during these periods when that is not the case. The Majority Order accepts MISO's rationale, that it "appropriately balances the need for resources to have flexibility to schedule planned outages and the need for MISO to have such visibility."[38] But as Clean Energy Coalition argues, MISO's framework "offer[s] little motivation for a resource owner—even one with a commitment under the Planning Resource Auction—to think twice before scheduling an outage, even at peak times."[39] And MISO provides no information to suggest that full accreditation is necessary in order to incent resources to give MISO adequate notice as to planned outages, or to engage in necessary maintenance activities.

22. To the contrary, the Majority Order's own logic suggests that the accreditation rules themselves give resources ample built-in incentive to perform maintenance: "Given the functional relationship between resource accreditation and resource availability," resources likely "will not risk delaying necessary maintenance" even if that means losing some accreditation in the short run because that could "result in resource underperformance, unavailability, or forced outages, which would negatively impact that resource's future accreditation."[40] In other words, the accreditation rules "encourage resource owners to appropriately balance maximizing short-term availability when it is

[36] *Id.* at 12.

[37] *Id.*

[38] Majority Order at P 265.

[39] Clean Energy Coalition Comments at 16.

[40] Majority Order at P 265.

most needed and perform[ing] maintenance, which requires scheduling planned outages, to ensure long-term resource performance."[41] Neither MISO nor the majority explain why an outage exemption is necessary given the presence of these incentives, much less reason why resources should be given full credit as opposed to a more limited incentive to provide advanced outage notification.

23. Moreover, beyond overcompensating resources when they are not contributing to system reliability, MISO's proposed maintenance framework also draws arbitrary lines that many market participants have rightly protested as lacking a logical basis. For example, several entities note that MISO has not explained how the proposed 120-day notice cutoff would increase resource availability during RA Hours,[42] pointing out that the proposal provides a relative disincentive against short to medium term maintenance.[43] They persuasively argue that this framework arbitrarily discourages non-consecutive outage days, as well as conducting any maintenance during each 120-day window even if there is an adequate maintenance margin during that time.[44] Others ask why, when resources that fully de-power are eligible for full credit, are those that de-rate for a period subject to an accreditation haircut?[45] MISO's framework also includes a capacity replacement obligation for any resource whose outage lasts more than 31 days in a single season,[46] providing an incentive for resources to arbitrarily stack outage requests at the

[41] *Id.*

[42] *See* Majority Order at P 129 (citing Consumers Energy Limited Protest at 2, East Texas Protest at 9).

[43] Consumers Energy Limited Protest at 1. The majority cannot have it both ways. If accreditation rules provide ample incentive for short to medium term maintenance without an exemption, then they should also be expected to adequately incent long term maintenance on their own.

[44] Midwest TDUs Protest at 15-17.

[45] *See* Duke Energy Comments at 4-5; MISO TOs Comments at 8. MISO justified the lack of eligibility of de-rates merely by stating that its current outage coordination process does not contemplate de-rates, which have traditionally been submitted with little advanced warning. *See* MISO Deficiency Letter Response at 10. But given MISO's changes to its accreditation framework and the opportunity for resource owners to receive an exemption for a scheduled outage, MISO has an obligation to explain why such a process should not be available for de-rates beyond merely invoking past practice in a different regulatory context.

[46] *See* Majority Order at P 286.

last 31 days of the season leading into the first 31 days of the next, regardless of whether that timing is appropriate from the perspective of grid reliability.

24. As with the elements discussed above, the negative effects of MISO's decision to credit unavailable resources as though they were serving the system are likely to grow in the future "[s]ince reliability events are increasingly likely to occur when they are not expected because of the uncertainties described earlier" such as load forecast errors, wind forecast errors, large unit forced outages, and other factors that are not known far in advance.[47]

D. The Commission should have rejected MISO's proposal given its capacity accreditation design flaws

25. By choosing to support its SAC accreditation on the grounds that it aligns accreditation with resources' likely availability in the future during times of greatest reliability risk, MISO bears the burden of demonstrating how these critical design choices support that objective or otherwise lead to just and reasonable outcomes. Using assumptions that over-value less flexible, longer lead-time resources and under-value more flexible, shorter lead-time resources undercuts MISO's justification. So, too, does an outage exemption approach that ignores that resources that require more frequent or longer outages provide less reliability value than those that require less frequent or shorter planned outages. By failing to accredit resources consistent with their actual value in time of greatest reliability risk, these design choices will hinder efficient capacity procurement, cause unjust and unreasonable capacity rates, and pose a threat to system reliability.

26. Rejecting MISO's proposal for its failure to properly align capacity credit with reliability value is supported by precedent, as the Commission has previously found that rules that do not adequately align capacity payment with a resource's true contribution to system reliability are not just and reasonable.[48]

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[47] IMM Comments at 12.

[48] *ISO New England, Inc.*, 147 FERC ¶ 61,172, at P 23 (2014) (finding ISO New England's capacity market rules unjust and unreasonable because they failed to provide adequate incentives for resource performance, thereby threatening reliable operation of the system and forcing consumers to pay for capacity without receiving commensurate reliability benefits); *see also PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208, at P 22 (2015) (approving a proposal to better align capacity payment with true contribution to system reliability).

VIII. Seasonal Capacity Auctions

27. MISO's proposal is also flawed because it may provide an opportunity for capacity sellers to exercise market power and potentially expose consumers to unjust and unreasonable capacity prices. MISO proposes to conduct auctions for all four seasons simultaneously, which requires revisions to its market power mitigation framework. I am not convinced by the record before us that the revisions MISO has offered protect consumers against inflated capacity prices.

28. MISO's proposal to conduct four seasonal auctions simultaneously for each Planning Year is novel. NYISO, the only RTO with an existing seasonal auction framework, conducts sequential auctions.[49] Conducting four auctions simultaneously adds complexity beyond that involved in conducting a single annual auction or sequential seasonal auctions. A capacity seller must determine how to offer into each seasonal auction without knowing the results—whether its resource cleared and at what price—of the other three.

29. A critical question for purposes of market mitigation under these circumstances is what constitutes an economic offer that allows a resource's costs of providing capacity (i.e., its "avoidable" or "going-forward" costs) to be reflected and adequately compensated while preventing excessive compensation. MISO's proposal and accompanying testimony send mixed signals as to how this critical question will be answered. As explained below, the tariff appears to prevent excessive compensation, but MISO's testimony suggests that it may be permissible. Given the complexity introduced by MISO's proposed simultaneous auction process, I fear that this ambiguity may provide a basis for excessive market offers, leading to unjust and unreasonable costs for consumers.

30. Part of MISO's proposed mitigation framework involves calculating a facility-specific reference level under certain circumstances (i.e. it requires calculating an "economic" offer from the unit). Tariff Module D, Section 64.1.4.f details what going-forward costs are permissible in a facility-specific reference level. It states, in relevant part:

> The Going-Forward Costs of a Planning Resource . . . shall be calculated by determining the costs that can be avoided by the . . . seasonal operation of the Planning Resource. Thus, Going-Forward Costs are equal to the costs that will be borne by a Planning Resource supplier by either maintaining in, or

[49] *See* NYISO Market Services Tariff § 2.3 (defining a winter and summer Capability Periods, for which auctions are conducted no later than 30 days prior to the start of each such period).

> returning a Planning Resource to, commercial operation for a specific Season of a Planning Year minus the costs that would be borne by such supplier resulting from retiring, suspending, or keeping a Planning Resource in suspension.

31. This appears to say that going-forward costs—and by extension a seller's seasonal auction offer price—may only include costs associated with providing capacity *for that season*.

32. However, MISO's testimony suggests something different. MISO's expert witness Shawn McFarlane, testifying in support of the proposal, states: "[Capacity] Offers may not reflect the actual costs of providing capacity if a Planning Resource clears in multiple Seasons but *its annual costs are compressed into each season's [capacity] Offer to ensure recovery if the Resource only clears in a single Season*."[50]

33. So here is what I am worried about: If, contrary, to the wording of section 64.1.4.f.iii, a seller may include in *each* of its seasonal auction offers up to its *annual* going-forward costs, and that seller clears multiple auctions, it could receive in excess—potentially up to two, three, or four times—its legitimate costs of providing capacity.[51] Even worse is if that resource sets the clearing price, such that all cleared resources would be paid not based on the marginal cost of providing capacity for the season, but based on a multiple thereof. Such an outcome cannot constitute just and reasonable rates for capacity.

34. MISO's proposal includes other mechanisms to limit under- and over-compensation that can result from its simultaneous auction design: a clearing price adjustment coupled with a new make-whole payment.[52] But as MISO acknowledges, there is a scenario where those mechanisms are not triggered despite the potential for auction revenues to exceed CONE on a per-MW basis,[53] in which case prices could unjustly and unreasonable rise to excessive levels should MISO's facility-specific

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[50] McFarlane Testimony at 44 (emphasis added).

[51] It appears this could occur when the clearing price adjustment is not triggered, meaning there is no *ex post* curb on compensation.

[52] *See* Majority Order at P 37 (discussing these design features).

[53] MISO's witness Shawn McFarlane explains that this will occur "whenever the Planning Resource Auction clears at least one Season, but fewer than all Seasons with Auction Clearing Prices above the daily value of CONE." McFarlane Testimony at 41-42.

reference calculation allow resources to make offers that would recoup up to that resource's annual costs in each of the four seasonal auctions as Mr. McFarlane suggests.

35. This is not the only case of inconsistency between MISO's proposed tariff and Mr. McFarlane's testimony. The Majority Order highlights another such inconsistency, regarding the applicability of Tariff section 69A.7.1.c.x governing the pricing for Zones in ZRC Shortage and Near-Shortage Conditions, and in that case reasons that the approach in the McFarlane testimony is more appropriate and orders MISO to file revised tariff sheets reflecting the testimony.[54] While the absence of such clarification with regard to facility-specific reference levels should dictate that the tariff governs, the McFarlane testimony presents concerns about how it will be applied in practice. Before approving MISO's proposal, the Commission should have insisted on obtaining a clear answer to this question from MISO. I dissent from the decision to approve such a significant market change in the face of this ambiguity on a critical consumer protection measure.

36. The Commission's approval of MISO's ambiguous proposal is especially discouraging because, as NYISO's experience shows, a proven alternative market design is readily available: sequential auctions that take place at different times in advance of each particular season.[55]

IX. MISO's proposal further entrenches disparate treatment between Schedule 53 non-Schedule 53 resources

37. As discussed above, but for the flaws I have identified, I would have approved MISO's proposal as a reasonable near-term mechanism to enhance system reliability. At the same time, however, I am concerned that the proposal may set MISO on a course that makes it more difficult to arrive at a future system of capacity accreditation and market design that treats all resources equally.

38. Clean Energy Coalition urges the adoption of three principles in order to prevent discrimination between different technologies: (1) "a resource that mitigates more risk should receive higher accreditation"; "(2) two resources that mitigate the same level of risk should receive the same accreditation"; and (3) "accreditation of each resource should be the same, regardless of the order in which resources' accreditation is calculated

[54] *See* Majority Order at PP 84-85.

[55] The IMM suggests approaches that would be more similar to the NYISO construct and accordingly derive similar benefits: offering "prompt seasonal auctions," or at minimum conducting each seasonal auction sequentially, even if all such auctions are carried out in a single time period far in advance of some of the relevant seasons. *See* IMM Comments at 4-5.

and accounted for."[56] While our precedent has traditionally permitted the application of different capacity accreditation methodologies to different resource types as not undue discrimination given the different characteristics of various technologies,[57] the Clean Energy Coalition rightly highlights that equal treatment should be the goal to the extent it is achievable.

39. Grid operators have gained extensive experience with wind and solar resources over the past decade, and are beginning to rapidly integrate energy storage resources in the wake of market developments and the Commission's Order No. 841.[58] As methodologies for valuing these resources mature, and as grid operators engage in efforts to more accurately value thermal and demand response resources, it becomes reasonable to expect grid operators to move toward methodologies that are more consistent across resource types. And even where uniformity is not fully achieved, the Commission should assess valuation methodologies side by side to ensure that even if different, the methodologies when taken together treat different resource types fairly relative to one another.

40. Many of the changes proposed in MISO's new SAC methodology are motivated by the same fundamental concern underlying ELCC methodologies that are being pursued in other regions: the need to value capacity more accurately. But as Clean Energy Coalition points out, MISO's chosen "*ex post* approach based on actual historical performance" is at odds with MISO's ELCC valuation methods that use an *ex ante* approach "based on a statistical expected value."[59] MISO's proposal therefore creates a significant concern that it may further entrench the differences between Schedule 53 and non-Schedule 53 resource accreditation in a manner that makes it more and not less difficult to arrive at a consistent framework for all resources.

41. Further, MISO's chosen approach entails the use of a UCAP/ISAC ratio "to ensure continued alignment between MISO's UCAP-based Reserve Requirements and its SAC proposal," but declines to apply this same ratio to non-Schedule 53 resources because those resources "will not experience the same level of accreditation reduction as Schedule

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[56] Clean Energy Coalition Response to MISO Deficiency Letter Response at 7.

[57] *See, e.g., PJM Interconnection*, 176 FERC ¶ 61,056 at P 70 (finding that PJM "need not extend the ELCC framework to Unlimited Resources to demonstrate that its filing is just and reasonable").

[58] *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators* (Order No. 841), 162 FERC ¶ 61,127 (Feb. 15, 2018).

[59] Majority Order at P 149 (citing Clean Energy Coalition Protest at 5).

53 Resources."[60] But while MISO justifies this approach as a reasonable mechanism to avoid raising demand to a level not necessary to maintain system reliability, a natural consequence of it is that it does not change the relative valuation of Schedule 53 versus non-Schedule 53 resources despite the acknowledged shortcomings of the capacity valuation methodology MISO is applying to Schedule 53 resources before the proposed tariff changes go into effect. If MISO's current method over-credits Schedule 53 resources as compared to non-Schedule 53 resources, MISO's proposal accepted by the Commission today does not address that concern. Further, should MISO undertake future efforts to more accurately value non-Schedule 53 resources, unfairness could be introduced if MISO does not employ a similar ratio for those resources, or address the relative valuation of Schedule 53 and non-Schedule 53 resources in a different way. While the Majority Order finds that the Clean Energy Coalition has not provided evidence demonstrating that Schedule 53 resources are over-credited as compared to non-Schedule 53 resources,[61] that finding does not preclude a conclusion that the tariff is unjust and unreasonable should the Clean Energy Coalition or another stakeholder bring forth such evidence in the future.

42. MISO is not alone in proposing a new capacity accreditation method that raises potential fairness concerns with regard to relative treatment of different resource types. SPP's recently-accepted ELCC methodology raises a similar concern, as it reduces the credit given to wind, solar, and run-of-the-river hydroelectric resources while leaving an outdated Installed Capacity methodology in place for other resources.[62] The Commission should keep a keen eye on this fairness issue as capacity valuation methodologies develop across regions, gathering data and potentially interceding as appropriate to ensure just and reasonable and not unduly discriminatory rates.

43. Ultimately, whether MISO initiates changes itself or is forced to do so through a section 206 proceeding, MISO's long run direction should be toward equal treatment of all resources across capacity types. It is therefore lamentable that, in making a much-needed shift toward a seasonal capacity construct that more accurately values resources' contributions to the system, MISO has chosen an approach that sets Schedule 53 and non-Schedule 53 resources on different courses. In the coming months and years, it should work to bring its divergent resource valuation techniques into alignment.

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[60] *Id.* at P 278.

[61] *Id.*

[62] *See Southwest Power Pool, Inc.*, 180 FERC ¶ 61,074 (2022) (Clements, Comm'r, dissenting, at PP 12-14).

X. Conclusion

44. I conclude by highlighting the difficult position the Commission is in with regard to responding to MISO's proposal and similar recent initiatives to improve capacity valuation. In the wake of the D.C. Circuit's decision in *NRG v. FERC*,[63] the Commission faces a significant temptation to accept rather than reject any rate proposal that improves upon the status quo, even where a portion of such a proposal is unjust and unreasonable or unduly discriminatory. The reality is that the Commission does not have the capacity to open a section 206 investigation in every instance where an existing rate may be unjust and unreasonable or unduly discriminatory. Even if it did, modifying rates via section 206 processes is time consuming, contentious, and triggers *ex parte* rules that make open discussion of challenging issues more difficult. So, it is understandable that accepting a proposal despite its flaws is compelling.

45. The temptation to accept rate proposals is particularly strong where they address reliability challenges, given the Commission's paramount responsibility of ensuring system reliability. But giving in to this temptation does not ensure proposals will be sufficient to address any given reliability challenge, and risks significant costs. Today's decision and the recent decision accepting Southwest Power Pool's ELCC valuation methodology[64] have together set a low bar for RTO filings. Together, they effectively say that omissions and inconsistencies in tariff filings will be tolerated, with the Commission doing the work of the RTO to fill in the gaps in the filing and push it across the finish line. They leave stakeholders guessing as to the meaning of critical provisions even after the Commission issues its decision, depriving them of notice and due process in responding to proposed changes. Even more concerningly, today's order suggests that, when it comes to reliability, market design flaws are permissible. In my view the opposite is true: the Commission should be particularly insistent that market design is sound in carrying out our bedrock responsibility of ensuring a reliable grid.

46. Today's decision bakes troubling flaws into MISO's capacity rules that may jeopardize reliability for years to come. While the majority urges MISO to continue working to improve its capacity rules,[65] it is not clear how some of these improvements could be made within the confines of MISO's stakeholder process absent Commission action forcing such an outcome. Taking just one example, the IMM observes that MISO's proposed outage "exemptions were introduced in response to stakeholder

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[63] 862 F.3d 108 (D.C. Cir. 2017).

[64] *Southwest Power Pool, Inc.*, 180 FERC ¶ 61,074 (2022).

[65] *See* Majority Order at P 269 ("[W]e encourage MISO to continue to evaluate whether its current outage coordination process could be improved. . . .").

feedback from entities concerned that such outages would reduce their accreditation."[66] The Commission has no reason to believe that these stakeholder dynamics will change such that MISO will better align capacity payments with system value in the future. Today's order therefore puts a flawed short-term improvement ahead of long-term results, leaving it to industry to regulate themselves. In my view, it would be better for us to insist the job is done right. "Measure twice, cut once," as the old adage goes.

For these reasons, I respectfully dissent.

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Allison Clements
Commissioner

[66] IMM Comments at 12.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Midcontinent Independent System Operator, Inc.	Docket Nos.	ER22-495-000 ER22-495-001
Midcontinent Independent System Operator, Inc.	Docket Nos.	ER22-496-000 ER22-496-001

(Issued August 31, 2022)

CHRISTIE, Commissioner, *concurring*:

1. I support accepting MISO's proposed seasonal resource adequacy construct in Docket Nos. ER22-495-000 and ER22-495-001. It is now a truism, established through numerous Commission precedents,[1] that in an FPA section 205 filing, we are not looking for the perfect proposal, or even one that we may prefer as relatively better than the specific one proposed in the filing. Instead, we look to see if the specific proposal filed

[1] *E.g.*, *City of Winnfield v. FERC*, 744 F.2d 871, 875-76 (D.C. Cir. 1984); *PJM Interconnection, L.L.C.*, 170 FERC ¶ 61,243, at P 57 (2020) (citing *Petal Gas Storage, L.L.C. v. FERC*, 496 F.3d 695, 703 (D.C. Cir. 2007); *Cities of Bethany v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984); *Cal. Indep. Sys. Operator Corp.*, 128 FERC ¶ 61,282, at P 31 (2009)); *see also Midcontinent Indep. Sys. Operator, Inc.*, 180 FERC ¶ 61,141, at P 79 (2022) (citations omitted).

meets the "just and reasonable" rates requirement of section 205.[2] I believe MISO's proposal herein meets that standard.[3]

2. I also support rejecting MISO's proposed Minimum Capacity Obligation (MCO) in Docket Nos. ER22-496-000 and ER22-496-001 because I believe the Market Monitor's concerns about the potential exercise of market power cast sufficient doubt on the proposal's claim to meet the section 205 standard.[4] However, I emphasize that we are rejecting only the MCO proposal before us and that we are not prejudging a future MCO filing by MISO.

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[2] I agree generally with the concern expressed by Commissioner Clements in paragraphs 44 and 45 of her dissent to the order, which I understand to mean that we are constrained by the precedents related to section 205 filings, including, of course, *NRG v. FERC*, 862 F.3d 108 (D.C. Cir. 2017), that do not let us make non-minor improvements to RTO proposals. I also agree that trying to address every existing market design flaw through individual section 206 proceedings may simply not be workable. I would favor a more comprehensive approach to evaluating threats to reliability that are increasingly becoming evident in RTO markets, and in a manner not subject to the *ex parte* communications limits of contested individual filings. As I note herein in P 3 and Note 6, among the issues that should be examined in such a general proceeding should be the continued use of single-clearing price mechanisms in RTO markets. The European Union is already re-evaluating such mechanisms in light of skyrocketing prices in EU power markets. *See* Sam Fleming and Valentina Pop, *EU to unveil emergency measures to curb soaring prices: Pressure grows for bloc to reform markets by cutting link between electricity and the cost of gas*, FINANCIAL TIMES, August 29, 2022 ("Wholesale electricity costs reflect the price of the last unit of energy bought via auctions held in member states. In practice, this currently mirrors the price of natural gas rather than renewable energy or nuclear power. . . . However, [EU President Ursula] von der Leyen hinted in June that the commission would have to reconsider the system."), https://www.ft.com/content/02f848fc-3b80-4ddc-ba4f-26109d79db89.

[3] I note that the Organization of MISO States, Inc. (OMS) supports the seasonal resource adequacy filing, along with Michigan and Indiana individually. Louisiana supports the concept of a seasonal resource adequacy construct, but not the details of the proposal filed. Mississippi opposes the proposal. I also note that, while critiquing aspects of the filing, the MISO Independent Market Monitor (Market Monitor) overall supports it.

[4] *See* Market Monitor Protest, Docket No. ER22-496-000, at 13-18. I further note that OMS has filed no comments at all in the MCO proceeding, whether in support or opposition. Only two individual states filed comments, with Indiana in support and Illinois opposed.

3. Both cases serve to illustrate a much bigger issue: Regardless of the details of the market designs of the various RTOs/ISOs — which are not true markets at all but administrative constructs using an increasingly opaque, complex and questionable pricing mechanism [5] — it is the *states* which retain the primary responsibility to ensure their load-serving entities (LSEs) have adequate resources to serve their states' consumers. While regional system operators — RTOs and ISOs — are responsible for balancing the system on a real-time operational basis to keep the lights on, RTOs/ISOs are not regional long-term Integrated Resource Plan (IRP) planners of generating or other resources. Rather, it is the states which have the ultimate authority to decide which resources get built and which get retired and whether and how their regulated LSEs have sufficient generating capacity or demand-side programs to ensure that the lights stay on for their states' residents. Yes, the market design of federally regulated RTO/ISO markets certainly affects the entry or exit of generating resources from those markets, but even in RTOs/ISOs the states still retain their inherent police-power authority to direct their LSEs to achieve resource adequacy in ways other than through RTO/ISO markets — including various forms of self-supply, such as rate-basing, or purchased power agreements or other bilateral arrangements.

4. This is particularly true in MISO. No one disputes that the MISO capacity market has always been a purely *residual* option; it is not the primary option for an LSE to obtain the resources needed to ensure reliability.[6] Importantly, states need to focus on their own

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[5] For an excellent analysis of the theory behind Locational Marginal Pricing (LMP) and how it is supposed to work in RTO markets (and why it increasingly may not work any longer), see Tony Clark and Vince Duane, *Stretched to the Breaking Point: RTOs and the Clean Energy Transition* (July 2021), https://www.wbklaw.com/wp-content/uploads/2021/07/Wholesale-Electricity-Markets-White-Paper-07.08.21.pdf.

[6] As the Commission has explained:

> Notably, approximately 90% of the load in MISO is served by vertically integrated LSEs, the vast majority of which are subject to state integrated resource planning processes. To accommodate the make-up of the MISO's footprint, MISO's proposed Tariff provisions accepted in the February 2018 Order provide that its resource adequacy requirements "are complementary to the reliability mechanisms of the states and the Regional Entities . . . within the [MISO] region." Moreover, MISO's proposed Tariff language explains that the resource adequacy requirements "are not intended to and shall not in any way affect state actions over entities under the states' jurisdiction." In other words, unlike the centralized capacity constructs used in the Eastern RTOs/ISOs, MISO's

authority to ensure adequate generating resources to serve their citizens and not default to an administrative construct regulated by FERC.[7] I am encouraged by recent efforts by the Organization of MISO States to address this critical issue.[8]

For the reasons given above, I respectfully concur.

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Mark C. Christie
Commissioner

> Auction is not—*and has never been*—the primary mechanism for its LSEs to procure capacity.

Midcontinent Indep. Sys. Operator, Inc., 170 FERC ¶ 61,215, at P 13 (2020) (emphasis in original) (quoting MISO, FERC Electric Tariff, Module E-1, § 68A (33.0.0)); *see also Midcontinent Indep. Sys. Operator, Inc.*, 180 FERC ¶ 61,142, at P 110 (2022) (citation omitted).

[7] Indeed, although the MISO tariff provides that MISO will calculate the Planning Reserve Margin Requirements (Reserve Requirements) for LSEs, the MISO tariff also provides that, if a state regulatory authority establishes an alternate Planning Reserve Margin, MISO will use the alternate Planning Reserve Margin to calculate LSEs' Reserve Requirements for the geographic area under that state's jurisdiction. MISO, FERC Electric Tariff, Module E-1, § Module E-1, § 68A.7 (Establishing Planning Reserve Margin Requirements) (32.0.0).

[8] *See* OMS Resource Adequacy Summit (Aug. 8-10, 2022), https://www.misostates.org/index.php/meetings/other-meetings/2-uncategorised/380-ra-summit; *see also* Darren Sweeney, *Midwest Utilities Delay Plant Retirements To Offset Reliability, Cost Concerns*, S&P Global Market Intelligence, Aug. 19, 2022, https://www.capitaliq.spglobal.com/web/client?auth=inherit#news/articleabstract?id=71797391.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-26-16

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 80

MISO 2023–24 LOLE Study Report



Planning Year 2023-2024 Loss of Load Expectation Study Report

MISO — Resource Adequacy

Highlights

- MISO's seasonal construct, accepted by FERC in September 2022, introduces seasonal requirements to the Planning Resource Auction (PRA) to account for the unique risk profile of each season.
- MISO made several modeling improvements to the LOLE study to support the new seasonal construct.
- MISO's annual Loss of Load Expectation (LOLE) study sets the system-wide Planning Reserve Margin and the zonal Local Reliability Requirements for each season of the upcoming Planning Year.

Update (5/1/2023): outyear Planning Reserve Margin (PRM) and Local Reliability Requirement (LRR) results added to study report

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Executive Summary

Midcontinent Independent System Operator (MISO) conducts an annual Loss of Load Expectation (LOLE) study to determine a Planning Reserve Margin Unforced Capacity (PRM UCAP), zonal per-unit Local Reliability Requirements (LRR), Zonal Import Ability (ZIA), Zonal Export Ability (ZEA), Capacity Import Limits (CIL) and Capacity Export Limits (CEL) for each season (Summer, Fall, Winter, & Spring) of the upcoming Planning Year. The results of the study and its deliverables supply inputs to the MISO Planning Resource Auction (PRA).

The Planning Year 2023-2024 (PY 2023-2024) LOLE Study:

- Establishes PRM UCAP for each season to be applied to the Load Serving Entity (LSE) seasonal coincident peaks for the Planning Year starting June 2023 and ending May 2024:
    - Summer 2023 PRM UCAP of 7.4%
    - Fall 2023 PRM UCAP of 14.9%
    - Winter 2023-2024 PRM UCAP of 25.5%
    - Spring 2024 PRM UCAP of 24.5%
- Uses the Strategic Energy Risk Valuation Model (SERVM) software for Loss of Load analysis to provide results applicable across the MISO market footprint.
- Provides zonal ZIA, ZEA, CIL and CEL for each Local Resource Zone (LRZ) (Figure ES-1). These values may be adjusted in March 2023 based on changes to MISO units with firm capacity commitments to non-MISO load, and equipment rating changes since the LOLE analysis. The Simultaneous Feasibility Test (SFT) process can further adjust CIL and CEL to ensure the resources cleared in the auction are simultaneously reliable.
- Determines a minimum planning reserve margin for each season of the studied Planning Year that would result in the MISO system experiencing a less than one-day loss of load event every 10 years, as per the MISO Tariff.[1] The MISO analysis shows that the system would achieve this reliability level for the summer 2023 season when the amount of installed capacity available (considering external support) is 1.159 times that of the MISO system summer 2023 coincident peak.
- Sets forth initial zonal-based (Table 1-1) PRA deliverables in the LOLE charter.

The stakeholder review process played an integral role in this study. The MISO staff would like to thank the Loss of Load Expectation Working Group (LOLEWG) for its assistance and input. There were several process improvements made to the LOLE study this year including updated transfer limits due to improved redispatch and four major LOLE modeling enhancements: seasonal outage rates, wind and solar hourly profiles, probabilistic modeling of non-firm support, and correlated cold weather outages.

[1] A one-day loss of load in 10 years (0.1 day/year) is not necessarily equal to 24 hours loss of load in 10 years (2.4 hours/year).

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
Summer 2023 PRM UCAP	7.4%	7.4%	7.4%	7.4%	7.4%	7.4%	7.4%	7.4%	7.4%	7.4%
LRR UCAP per-unit of LRZ Peak Demand	1.139	1.120	1.299	1.212	1.333	1.172	1.171	1.473	1.157	1.538
Capacity Import Limit (CIL) (MW)	5,301	3,477	6,108	7,884	3,576	8,492	5,087	4,139	5,268	3,064
Capacity Export Limit (CEL) (MW)	3,959	2,550	4,310	No Limit Found[2]	No Limit Found	2,703	3,953	5,503	1,574	1,794
Zonal Import Ability (ZIA) (MW)	5,299	3,477	6,043	6,992	3,576	8,092	5,087	4,091	4,456	3,064
Zonal Export Ability (ZEA) (MW)	3,961	2,550	4,375	No Limit Found	No Limit Found	3,109	3,953	5,551	2,386	1,794

Table ES-1: Initial Planning Resource Auction Deliverables — Summer 2023

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
Fall 2023 PRM UCAP	14.9%	14.9%	14.9%	14.9%	14.9%	14.9%	14.9%	14.9%	14.9%	14.9%
LRR UCAP per-unit of LRZ Peak Demand	1.274	1.218	1.408	1.254	1.452	1.247	1.345	1.490	1.278	1.619
Capacity Import Limit (CIL) (MW)	6,528	4,411	14,375[2]	5,173	5,380	6,070	4,285	4,705	6,045	2,425
Capacity Export Limit (CEL) (MW)	3,804	3,577	4,354	4,878	1,992	1,701	3,990	5,080	1,526	2,878
Zonal Import Ability (ZIA) (MW)	6,526	4,411	14,310[2]	4,281	5,380	5,670	4,285	4,657	5,233	2,425
Zonal Export Ability (ZEA) (MW)	3,806	3,577	4,419	5,770	1,992	2,101	3,990	5,128	2,338	2,878

Table ES-2: Initial Planning Resource Auction Deliverables — Fall 2023

[2] "No Limit Found" reflects no valid constraint identified.

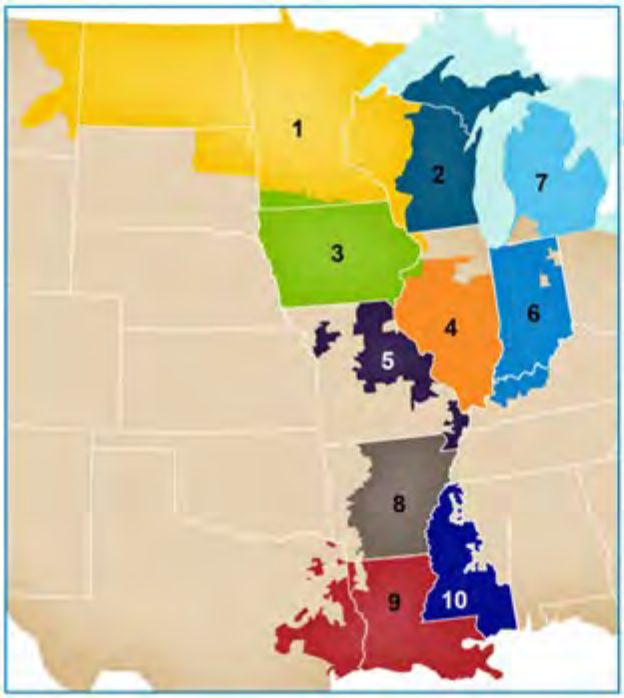
PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
Winter 23-24 PRM UCAP	25.5%	25.5%	25.5%	25.5%	25.5%	25.5%	25.5%	25.5%	25.5%	25.5%
LRR UCAP per-unit of LRZ Peak Demand	1.403	1.422	1.850	1.365	1.474	1.301	1.573	1.503	1.323	1.777
Capacity Import Limit (CIL) (MW)	4,937	4,905	11,039[2]	3,928	3,811	8,818	6,340	4,729	6,080	2,396
Capacity Export Limit (CEL) (MW)	3,501	4,198	7,002	3,445	6,348	1,242	4,350	5,351	877	1,980
Zonal Import Ability (ZIA) (MW)	4,935	4,905	10,974[2]	3,036	3,811	8,418	6,340	4,681	5,268	2,396
Zonal Export Ability (ZEA) (MW)	3,503	4,198	7,067	4,337	6,348	1,642	4,350	5,399	1,689	1,980

Table ES-3: Initial Planning Resource Auction Deliverables — Winter 2023-2024

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
Spring 2024 PRM UCAP	24.5%	24.5%	24.5%	24.5%	24.5%	24.5%	24.5%	24.5%	24.5%	24.5%
LRR UCAP per-unit of LRZ Peak Demand	1.375	1.267	1.623	1.454	1.610	1.320	1.329	1.627	1.315	1.747
Capacity Import Limit (CIL) (MW)	6,185	4,454	7,675	5,906	3,881	8,162	5,559	4,606	6,250	2,144
Capacity Export Limit (CEL) (MW)	4,321	3,679	6,173	3,745	3,724	2,344	4,413	5,472	2,240	2,720
Zonal Import Ability (ZIA) (MW)	6,183	4,454	7,610	5,014	3,881	7,762	5,559	4,558	5,438	2,144
Zonal Export Ability (ZEA) (MW)	4,323	3,679	6,238	4,637	3,724	2,744	4,413	5,520	3,052	2,720

Table ES-4: Initial Planning Resource Auction Deliverables — Spring 2024

LRZ3 Fall and Winter ZIA and CIL were updated after the final results were presented at the October LOLEWG. Both studies resulted in No Limit found and the equation was updated to include Tier 2, the October 3rd 2022 LOLEWG presentation has also been updated accordingly.



Local Resource Zone	Local Balancing Authorities
1	DPC, GRE, MDU, MP, NSP, OTP, SMP
2	ALTE, MGE, MIUP, UPPC, WEC, WPS
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, CIN, HE, HMPL, IPL, NIPS, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	EMBA, SME

Figure ES-1: Local Resource Zones (LRZ)

1 LOLE Study Process Overview

In compliance with Module E-1 of the MISO Tariff, MISO performed its annual LOLE study to determine, for each season of Planning Year 2023-2024, the system unforced capacity (UCAP) Planning Reserve Margin (PRM) and the per-unit Local Reliability Requirements (LRR) of Local Resource Zone (LRZ) Peak Demand.

In addition to the LOLE analysis, MISO performed seasonal transfer analyses to determine seasonal Zonal Import Ability (ZIA), Zonal Export Ability (ZEA), Capacity Import Limits (CIL) and Capacity Export Limits (CEL). CIL, CEL, and ZIA are used, in conjunction with the LOLE analysis results, in the Planning Resource Auction (PRA). ZEA is informational and not used in the PRA.

The PY 2023-2024 per-unit seasonal LRR UCAP multiplied by the updated LRZ seasonal Peak Demand forecasts submitted for the 2023-2024 PRA determines each LRZ's seasonal LRR. Once the seasonal LRR is determined, the ZIA values and non-pseudo tied exports are subtracted from the seasonal LRR to determine each LRZ's seasonal Local Clearing Requirement (LCR) consistent with Section 68A.6 of Module E-1[3]. An example calculation pursuant to Section 68A.6 of the current effective Module E-1 shows how these values are reached (Table 1-1).

Local Resource Zone (LRZ) EXAMPLE	Example LRZ	Formula Key
Installed Capacity (ICAP)	17,442	[A]
Unforced Capacity (UCAP)	16,326	[B]
Adjustment to UCAP (1d in 10yr)	50	[C]
Local Reliability Requirement (LRR) (UCAP)	16,376	[D]=[B]+[C]
LRZ Peak Demand	14,270	[E]
LRR UCAP per-unit of LRZ Peak Demand	114.8%	[F]=[D]/[E]
Zonal Import Ability (ZIA)	3,469	[G]
Zonal Export Ability (ZEA)	2,317	[H]
Proposed PRA (UCAP) EXAMPLE	**Example LRZ**	**Formula Key**
Forecasted LRZ Peak Demand	14,270	[I]
Forecasted LRZ Coincident Peak Demand	13,939	[J]
Non-Pseudo Tied Exports UCAP	150	[K]
Local Reliability Requirement (LRR) UCAP	16,376	[L]=[F]x[I]
Local Clearing Requirement (LCR)	12,757	[M]=[L]-[G]-[K]
Planning Reserve Margin (PRM)	7.4%	[N]
Zone's System Wide PRMR	14,970	[O]=[1.074]x[J]
PRMR	14,970	[P]=Higher of [M] or [O]

Table 1-1: Example LRZ Calculation

[3] https://www.misoenergy.org/legal/tariff
Effective Date: November 1, 2018

The actual effective PRM Requirement (PRMR) for each season of Planning Year 2023-2024 will be determined after the updated LRZ Seasonal Peak Demand forecasts are submitted by November 1, 2022, for the 2023-2024 PRA. The ZIA, ZEA, CIL and CEL values are subject to updates in March 2023 based on changes to exports of MISO resources to non-MISO load, changes to pseudo tied commitments, and updates to facility ratings following the completion of the LOLE study.

Finally, the simultaneous feasibility test (SFT) is performed as part of the PRA where cleared generation is tested to ensure transmission reliability and if constraints arise, they are mitigated by adjusting CIL and CEL values as needed.

1.1 Study Improvements

The Planning Year 2023-2024 LOLE study incorporated a number of study improvements as a result of the approved seasonal construct. These improvements include seasonal outage rates, correlated cold weather outages, probabilistic distribution of non-firm support, and hourly wind and solar profiles.

Historically, the LOLE model utilized a 5-year average EFORd, based on historic GADS data, which was constant throughout the simulated year for all resources. This year, seasonal EFORd was calculated using the same GADS data but outages were classified by season to produce four unique seasonal EFORd values for each resource. This change better captures the seasonal availability of resources observed in operations.

Additional outages are added to the model during times of extreme cold temperatures to better capture the magnitude of correlated outages observed. The magnitude of forced outages added increases as temperatures decrease based on the relationship between outages and temperature determined from historic GADS and weather data. Each LRZ has a unique outage/temperature curve based on actual performance. The incremental cold weather outages are not assigned to a particular resource but instead represent the aggregate impact on the system for coal and gas resources.

For the last several years MISO has accounted for non-firm support in the LOLE process by simply reducing the PRM by a fixed amount on a 1-for-1 MW basis. This year's study incorporated seasonal distributions of non-firm support directly in the model which are based on historic Net Scheduled Interchange (NSI) data. As the model steps through time chronologically, SERVM will randomly draw import values from this distribution to be used to serve load.

In previous LOLE studies, wind resources were modeled as perfect units with a constant output equal to their monthly ELCC values while solar resources were modeled as perfect units with constant output equal to their capacity credit. For Planning Year 2023-2024, wind and solar resources were modeled as variable energy resources with 30 unique hourly profiles corresponding to the 30 unique weather years within SERVM.

2 Transfer Analysis

2.1 Calculation Methodology and Process Description

Transfer analyses determined CIL and CEL values for LRZs in each season for Planning Year 2023-2024. Annual adjustments are made for Border External Resources (BERs) and Coordinating Owner Resources (COs) to determine the ZIA and ZEA in each season. Further adjustments are made for exports to non-MISO Loads to arrive at the CIL and CEL values. The objective of transfer analysis is to determine constraints caused by the transfer of capacity between zones and the associated transfer capability. Multiple factors impacted the analysis when compared to previous studies, including:

- 3.7 GW of Retirements / Suspensions
- New Intermittent Resources
- Base Model Dispatch in MISO and Seams

2.1.1 Generation Pools

To determine an LRZ's import or export limit, a transfer is modeled by ramping generation up in a source subsystem and ramping generation down in a sink subsystem. The source and sink definitions depend on the limit being tested. The LRZ studied for import limits is the sink subsystem and the adjacent MISO LBA's are the source subsystem. The LRZ studied for export limits is the source subsystem and the rest of MISO is the sink subsystem. These are the same in all seasons for the upcoming Planning Year.

Transfers can cause potential issues, which are addressed through the study assumptions. First, an abundantly large source pool spreads the impact of the transfer widely which can cause differences in studied zones transfer capabilities and constraints identified. Second, ramping up generation from remote areas could cause electrically distant constraints for any given LRZ, which should not determine a zone's limit. For example, export constraints due to dispatch of LRZ 1 generation in the northwest portion of the footprint should not limit the import capability of LRZ 10, which covers the MISO portion of Mississippi.

To address these potential issues, the transfer studies limit the source pool for the import studies to the Tier 1 and Tier 2 adjacent LBA's to the study zone. Since the generation that is ramped up in export studies are contained in the study LRZ, these issues only apply to import studies. Generation within the zone studied for an export limit is ramped up and constraints are expected to be near or in the study zone.

2.1.2 Redispatch

Limited redispatch is applied after performing transfer analyses to mitigate constraints. Redispatch ensures constraints are not caused by the base dispatch and aligns with potential actions that can be implemented for the constraint in MISO operations. Redispatch scenarios can be designed to address multiple constraints as required and may be used for constraints that are electrically close to each other or to further optimize transfer limits for several constraints requiring only minor redispatch. The redispatch assumptions include:

- The use of no more than 10 conventional fuel plants or intermittent resources
- Redispatch limit at 2,000 MW total (1,000 MW up and 1,000 MW down)
- No adjustments to nuclear units
- No adjustments to the portions of pseudo-tied units committed to non-MISO load

2.1.3 Generation Limited Transfer for CIL/CEL and ZIA/ZEA

When conducting transfer analysis to determine import or export limits, the source subsystem might run out of generation to dispatch before identifying a valid constraint caused by a transmission limit. MISO developed a Generation Limited Transfer (GLT) process to identify transmission constraints in these situations, when possible, for both imports and exports.

After running the First Contingency Incremental Transfer Capability (FCITC) analysis to determine limits for each LRZ, MISO will determine whether a zone is experiencing a GLT (e.g. whether the first constraint would only occur after all the generation is dispatched at its maximum amount). If the LRZ experiences a GLT, MISO will adjust the base model depending on whether it is an import or export analysis and re-run the transfer analysis.

For an export study, when a transmission constraint has not been identified after dispatching all generation within the exporting system (LRZ under study) MISO will decrease load and generation dispatch in the study zone. The adjustment creates additional capacity to export from the zone. After the adjustments are complete, MISO will rerun the transfer analysis. If a GLT reappears, MISO will make further adjustments to the load and generation of the study zone.

For an import study, when a transmission constraint has not been identified after dispatching all generation within the source subsystem, MISO will decrease load and generation in the source subsystem. This increases the export capacity of the adjacent LBA's for the study zone. After the adjustments are complete, MISO will run the transfer analysis again. If a GLT reappears, MISO will make further adjustments to the model's load and generation in the source subsystem.

FCITC could indicate the transmission system can support larger thermal transfers than would be available based on installed generation for some zones. However, large variations in load and generation for any zone may lead to unreliable limits and constraints. Therefore, MISO limits load scaling for both import and export studies to 50 percent of the zone's load. In a GLT, redispatch, or GLT plus redispatch scenario, the FCITC of the most limiting constraint might exceed Zonal Export/Import Capability. If the GLT does not produce a limit for a zone(s), due to a valid constraint not being identified, or due to other considerations as listed in the prior paragraph, MISO shall report that LRZ as having no limit and ensure that the limit will not bind in the first iteration of the Simultaneous Feasibility Test (SFT).

2.1.4 Voltage Limited Transfer for CIL/CEL and ZIA/ZEA

Zonal imports may be limited by voltage constraints due to a decrease in the generation in the study zone. Voltage constraints might occur at lower transfer levels than thermal limits determined by linear FCITC. As such, LOLE studies may evaluate Power-Voltage curves for LRZs with known voltage-based transfer limitations identified through existing MISO or Transmission Owner studies. Such evaluation may also occur if an LRZ's import reaches a level where the majority of the zone's load would be served using imports from resources outside of the zone. MISO will coordinate with stakeholders as it encounters these scenarios. For Planning Year 2023-2024, all seasons only Zones 1, 4 and 7 import analysis included voltage screening and study. Only LRZ4 Summer identified a voltage limit with lower transfer capability than the thermal limit.

2.2 Powerflow Models and Assumptions

2.2.1 Tools Used

MISO used the Siemens PTI Power System Simulator for Engineering (PSS/E) and Transmission Adequacy and Reliability Assessment (TARA) for analysis tools.

2.2.2 Inputs Required

Thermal transfer analysis requires powerflow models and related input files. MISO used contingency files from MTEP[4] reliability assessment studies. Single-element contingencies in MISO/seam areas were also evaluated.

MISO developed a subsystem file to monitor its footprint and seam areas which was used for all seasons. LRZ definitions were developed as sources and sinks in the study. See Appendix B for tables containing adjacent area definitions (Tiers 1 and 2) used for this study. The monitored file includes all facilities under MISO functional control and single elements in the seam areas of 100 kV and above.

2.2.3 Powerflow Modeling

The MTEP22 models were built using MISO's Model on Demand (MOD) model data repository, with the following base assumptions (Table 2-1).

Scenario	Effective Date	Projects Applied	External Modeling	Load and Generation Profile	Wind %	Solar %
Summer 2023	July 15th	MTEP Appendix A and Target A	2021 Series 2023 Summer ERAG MMWG	Summer Peak	Capacity Credit ~15.5%	50%
Fall 2023	October 15th	MTEP Appendix A and Target A	2021 Series 2023 Summer ERAG MMWG	Fall Peak	32%	28.5%
Winter 2023-2024	January 15th	MTEP Appendix A and Target A	2021 Series 2023 Summer ERAG MMWG	Winter Peak	67%	0%
Spring 2024	April 15th	MTEP Appendix A and Target A	2021 Series 2023 Summer ERAG MMWG	Spring Peak	28.5%	32%

Table 2-1: Model Assumptions

MISO excluded several types of units from the transfer analysis dispatch—these units' base dispatch remained fixed.

- Nuclear dispatch does not change for any transfer
- Wind and solar resources can be ramped down, but not up
- Pseudo-tied resources were modeled at their expected commitments to non-MISO load, although portions of these units committed to MISO could participate in transfer analyses

System conditions such as load, dispatch, topology, and interchange have an impact on transfer capability. The model was reviewed as part of the base model build for MTEP22 analyses, with study files made available on MISO

[4] Refer to the Transmission Planning BPM (BPM-20) for more information regarding MTEP input files. https://www.misoenergy.org/legal/business-practice-manuals/

ShareFile. MISO worked closely with transmission owners and stakeholders in order to model the transmission system accurately, as well as to validate constraints and redispatch. Like other planning studies, transmission outage schedules were not included in the analysis. This is driven partly by limited availability of outage information as well as current transmission planning standards. Although no outage schedules were evaluated, single element contingencies were evaluated. This includes BES lines, transformers, and generators.

Contingency coverage covers most of category P1 and some of category P2 outlined in Table 1 of TPL-001: (https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-5.pdf).

2.2.4 General Assumptions

MISO uses TARA to process the powerflow model and associated input files to determine the import and export limits of each LRZ in each season by determining the transfer capability. Transfer capability measures the ability of interconnected power systems to reliably transfer power from one area to another under specified system conditions. The incremental amount of power that can be transferred is determined through FCITC analysis. FCITC analysis and base power transfers provide the information required to calculate the First Contingency Total Transfer Capability (FCTTC), which indicates the total amount of transferrable power before a constraint is identified. FCTTC is the base power transfer plus the incremental transfer capability (Equation 3-1). All published limits are based on the zone's FCTTC and may be adjusted for capacity exports.

$$First\ Contingency\ Total\ Transfer\ Capability\ (FCTTC) = FCITC + Base\ Power\ Transfer$$

Equation 2-1: Total Transfer Capability

FCITC constraints are identified under base case situations in each season or under P1 contingencies provided through the MTEP process. Linear FCITC analysis identifies the limiting constraints using a minimum transfer Distribution Factor (DF) cutoff of 3 percent, meaning the transfer must increase the loading on the overloaded element, under system intact or contingency conditions, by 3 percent or more.

A pro-rata dispatch is used, which ensures all available generators will reach their maximum dispatch level at the same time. The pro-rata dispatch is based on the MW reserve available for each unit and the cumulative MW reserve available in the subsystem. The MW reserve is found by subtracting a unit's base model generation dispatch from its maximum dispatch, which reflects the available capacity of the unit.

Table 2-2 and Equation 2-2 show an example of how one unit's dispatch is set, given all machine data for the source subsystem.

Machine	Base Model Unit Dispatch (MW)	Minimum Unit Dispatch (MW)	Maximum Unit Dispatch (MW)	Reserve MW (Unit Dispatch Max – Unit Dispatch Min)
1	20	20	100	80
2	50	10	150	100
3	20	20	100	80
4	450	0	500	50
5	500	100	500	0
			Total Reserve	**310**

Table 2-2: Example Subsystem

$$\textbf{\textit{Machine 1 Incremental Post Transfer Dispatch}} = \frac{\textbf{\textit{Machine 1 Reserve MW}}}{\textbf{\textit{Source Subsystem Reserve MW}}} \times \textbf{\textit{Transfer Level MW}}$$

$$Machine\ 1\ Incremental\ Post\ Transfer\ Dispatch = \frac{80}{310} \times 100 = 25.8$$

$$Machine\ 1\ Incremental\ Post\ Transfer\ Dispatch = 25.8$$

Equation 2-2: Machine 1 Dispatch Calculation for 100 MW Transfer

2.3 Results for CIL/CEL and ZIA/ZEA

Study constraints and associated ZIA, ZEA, CIL, and CEL for each LRZ for each season were presented and reviewed through the LOLEWG with final results for Planning Year 2023-2024 presented at the October 3rd, 2022 meeting. Table 2-3 below shows the Planning Year 2023-2024 CIL and ZIA with corresponding constraint, GLT, and redispatch (RDS) information.

All zones had an identified ZIA this year. If there is no valid constraint identified the following equation will be used where the FCITC will be replaced by the Tier 1 & 2 capacity.

$$\textbf{\textit{ZIA}} = \textbf{\textit{FCITC}} + \textbf{\textit{AI}} - \textbf{\textit{Border External Resources and Coordinating Owners}}$$

Equation 2-3: Zonal Import Ability (ZIA) Calculation

LRZ1	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2023	North Appleton - Werner W 345kV	North Appleton - Morgan 345kV	15%	494MWx2	5299	5301
Fall 2023	North Appleton - Werner W 345kV	North Appleton - Morgan 345kV	None	636MWx2	6526	6528
Winter 2023/24	Council Bluffs - Sarpy County 345kV	Arbor Hill - Raccoon Trail 345kV	None	681MWx2	4935	4937
Spring 2024	North Appleton - Werner W 345kV	North Appleton - Morgan 345kV	None	328MWx2	6183	6185
LRZ2	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2023	Elk Mound - Wheaton 161kV	King - Eau Claire 345kV	10%	1000MWx2	3477	3477
Fall 2023	Arpin - Sigel 138kV	Rocky Run - Arpin 345kV	None	1000MWx2	4411	4411
Winter 2023/24	Arpin - Sigel 138kV	Rocky Run - Arpin 345kV	None	1000MWx2	4905	4905
Spring 2024	Arpin - Sigel 138kV	Rocky Run - Arpin 345kV	None	603MWx2	4454	4454
LRZ3	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2023	S3458 3 - S3456 3 345kV	S3455 - S3740 345kV	10%	113MWx2	6043	6108
Fall 2023	No Limit Found		None	None	14,310	14,375
Winter 2023/24	No Limit Found		None	None	10,974	11,039
Spring 2024	Prairie Island - North Rochester 345kV	North Rochester - Hampton Corner 345kV	None	345MWx2	7610	7675
LRZ4	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2023	Bus 636410 Sub P Iowa City 161kV	Hills 345/161kV Transformer	None	None	6992	7884
Fall 2023	Marblehead 161/138kV Transformer	Herlman - Maywood 345kV	None	1000MWx2	4281	5173
Winter 2023/24	Marblehead 161/138kV Transformer	Herlman - Maywood 345kV	None	1000MWx2	3036	3928
Spring 2024	Marblehead 161/138kV Transformer	Herlman - Maywood 345kV	None	935MWx2	5014	5906
LRZ5	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2023	Pike - Cryene 161kV	Maywood - Spencer Creek 345kV	10%	81MWx2	3576	3576
Fall 2023	Mississippi Tap - Sioux 138kV	Loss of Sioux Generation	15%	708MWx2	5380	5380
Winter 2023/24	Overton 345/161kV Transformer	Mc Credie - Overton 345kV	None	1000MWx2	3811	3811
Spring 2024	Calif - Apache Tap 161kV	Mc Credie - Montgomery 345kV	None	244MWx2	3881	3881
LRZ6	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2023	Cayuga Sub - Cayuga 345kV	Kansas - Sugar Creek 345kV	20%	619MWx2	8092	8492
Fall 2023	Jord - West Frankfort 138kV	Mount Vernon - West Frankfort 345kV	None	1000MWx2	5670	6070
Winter 2023/24	Cayuga Sub - Cayuga 345kV	Kansas - Sugar Creek 345kV	None	923MWx2	8418	8818
Spring 2024	Cayuga Sub - Cayuga 345kV	Kansas - Sugar Creek 345kV	None	620MWx2	7762	8162
LRZ7	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2023	Argenta - Tompkins 345kV	Argenta - Battle Creek 345kV	15%	1000MWx2	5087	5087
Fall 2023	Benton Harbor - Segreto 345kV	Cook - Segreto 345kV	None	1000MWx2	4285	4285
Winter 2023/24	Stillwell 345kV/138kV Transformer	Dumont - Stillwell 345kV	None	1000MWx2	6340	6340
Spring 2024	Benton Harbor - Segreto 345kV	Cook - Segreto 345kV	None	1000MWx2	5559	5559
LRZ8	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2023	Lyon - Jonestown 115kV	Crossroads - Moonlake 230kV	None	180MWx2	4091	4139
Fall 2023	Moon Lake - Ritchie 230kV	Clarksdale - Crossroads 230/115kV Transformer	None	372MWx2	4657	4705
Winter 2023/24	Mount Olive - Vienna 115kV	Mount Olive - El Dorado 500kV	None	1000MWx2	4681	4729
Spring 2024	Mount Olive - Vienna 115kV	Mount Olive - El Dorado 500kV	None	181MWx2	4558	4606

LRZ9	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2023	Bogalusa - Barkers Corner 230kV	McKnight - Franklin 500kV	None	1000MWx2	4456	5268
Fall 2023	Braswell - Franklin 500kV	Franklin - Grand Gulf 500kV	None	325MWx2	5233	6045
Winter 2023/24	Camden - Smackover 115kV	McNeil - Camden 115kV	None	963MWx2	5268	6080
Spring 2024	Boogalusa 500/230kV Transformer	McKnight - Franklin 500kV	None	1000MWx2	5438	6250
LRZ10	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2023	Braswell - Northside 230kV	Braswell - Lakeover 500kV	None	38MWx2	3064	3064
Fall 2023	Braswell - Northside 230kV	Braswell - Lakeover 500kV	None	33MWx2	2425	2425
Winter 2023/24	Adams Creek - Angie 230kV	Slidel - Logtown 230kV	None	134MWx2	2396	2396
Spring 2024	Hernando - Coldwater 115kV	Moonlake - Ritchie 230kV	None	31MWx2	2144	2144

Table 2-3: Planning Year 2023–2024 Import Limits

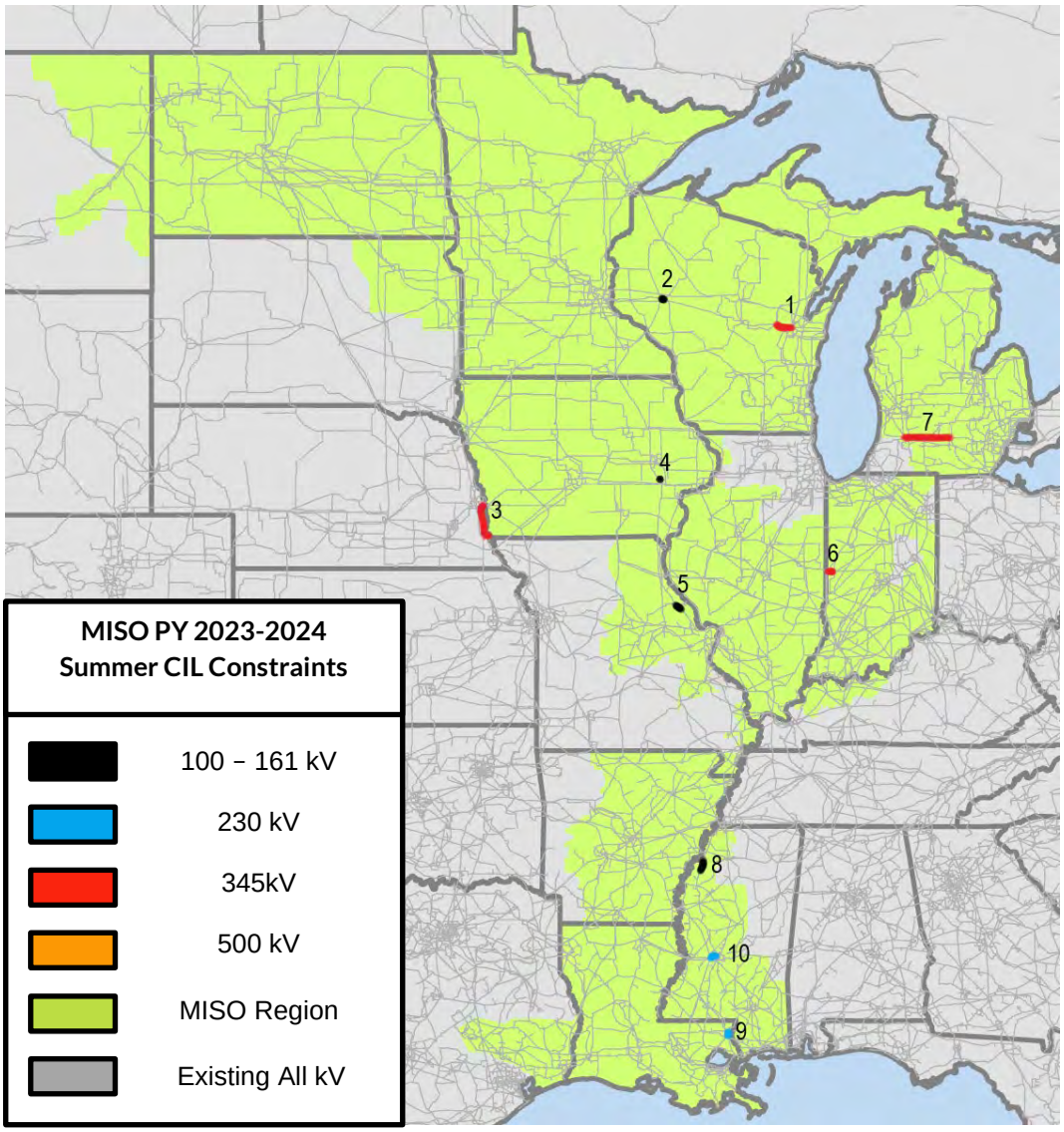


Figure 2-1: Planning Year 2023-2024 Summer Capacity Import Constraints Map

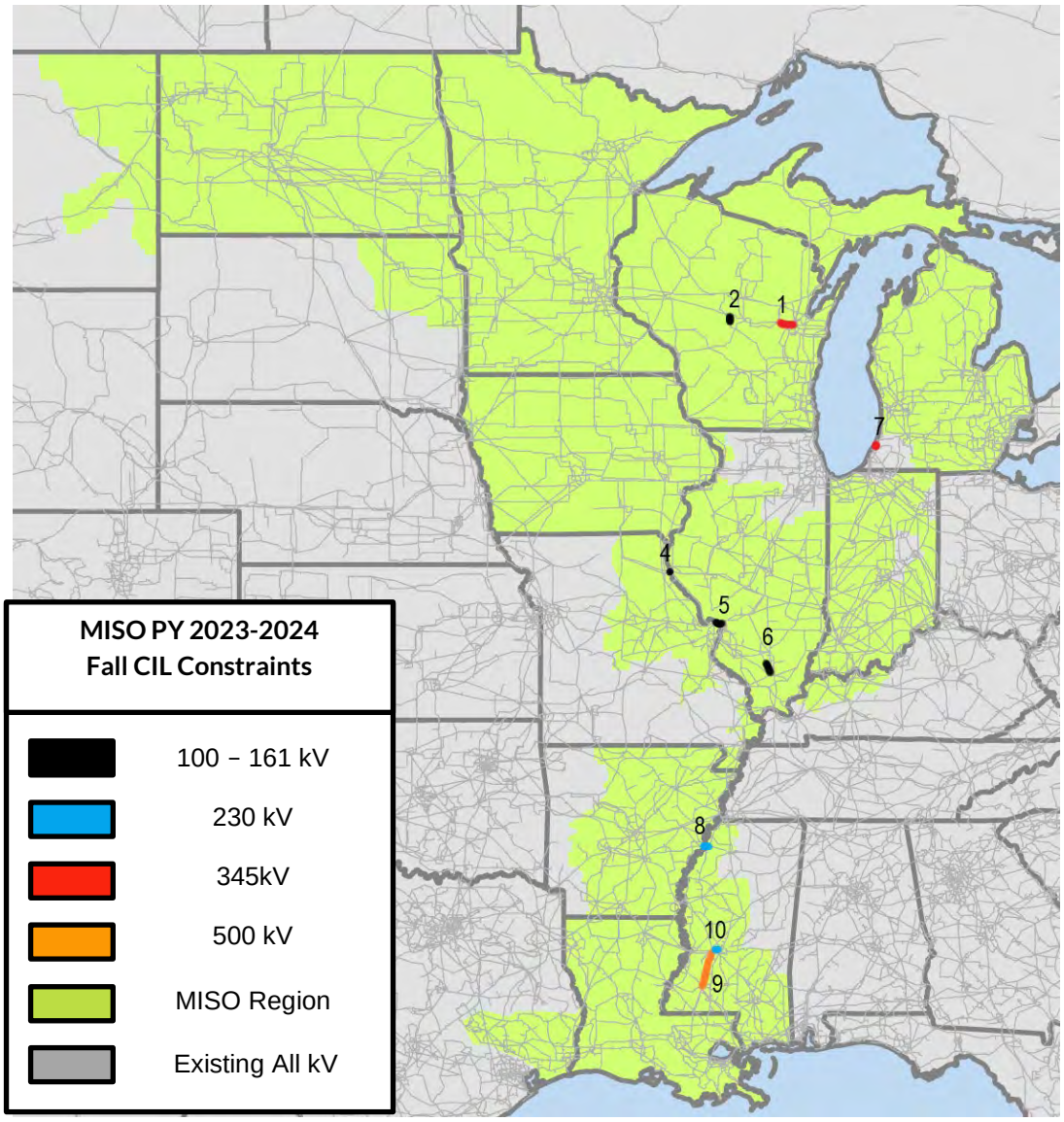


Figure 2-2: Planning Year 2023-2024 Fall Capacity Import Constraints Map

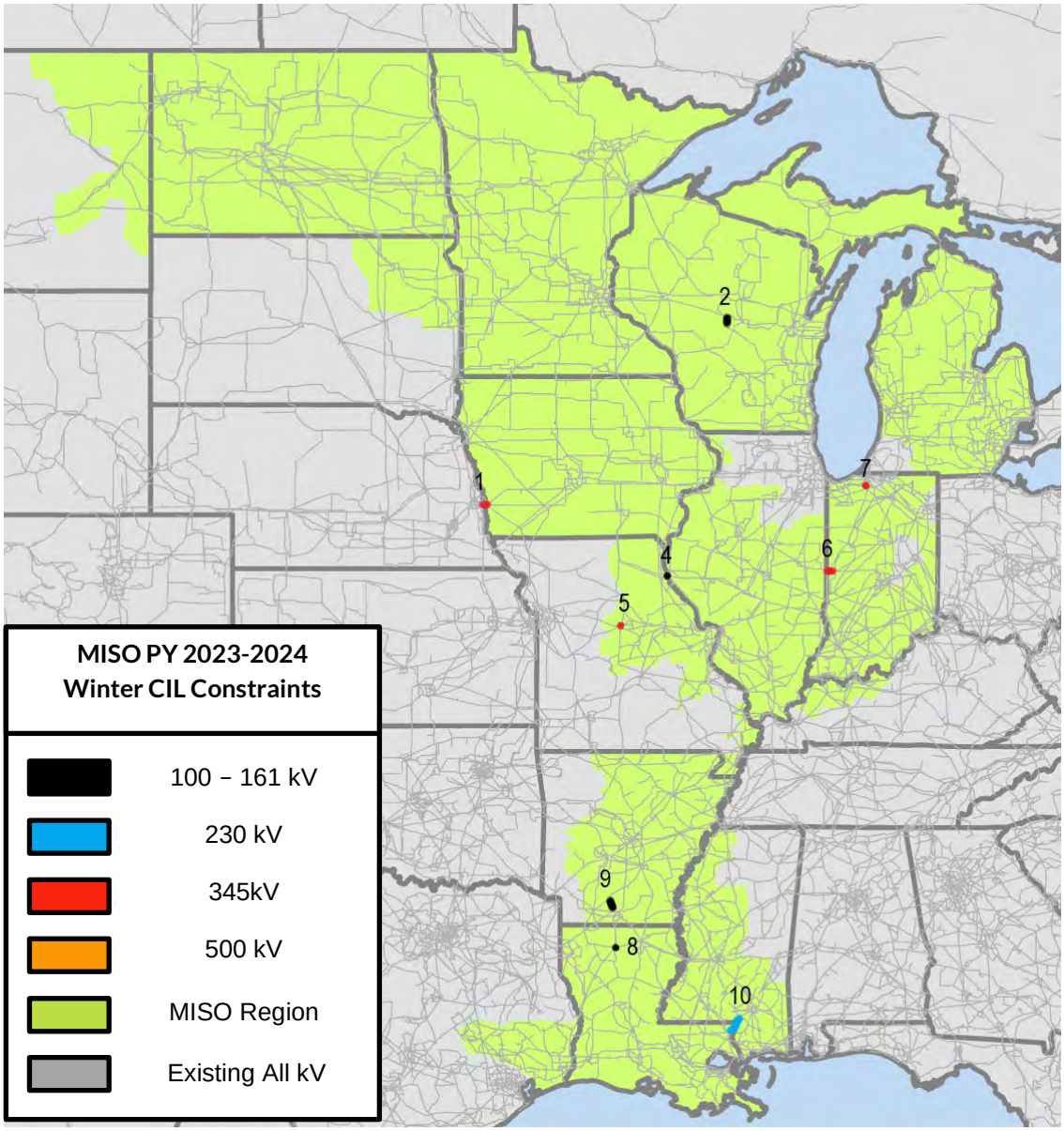


Figure 2-3: Planning Year 2023-2024 Winter Capacity Import Constraints Map

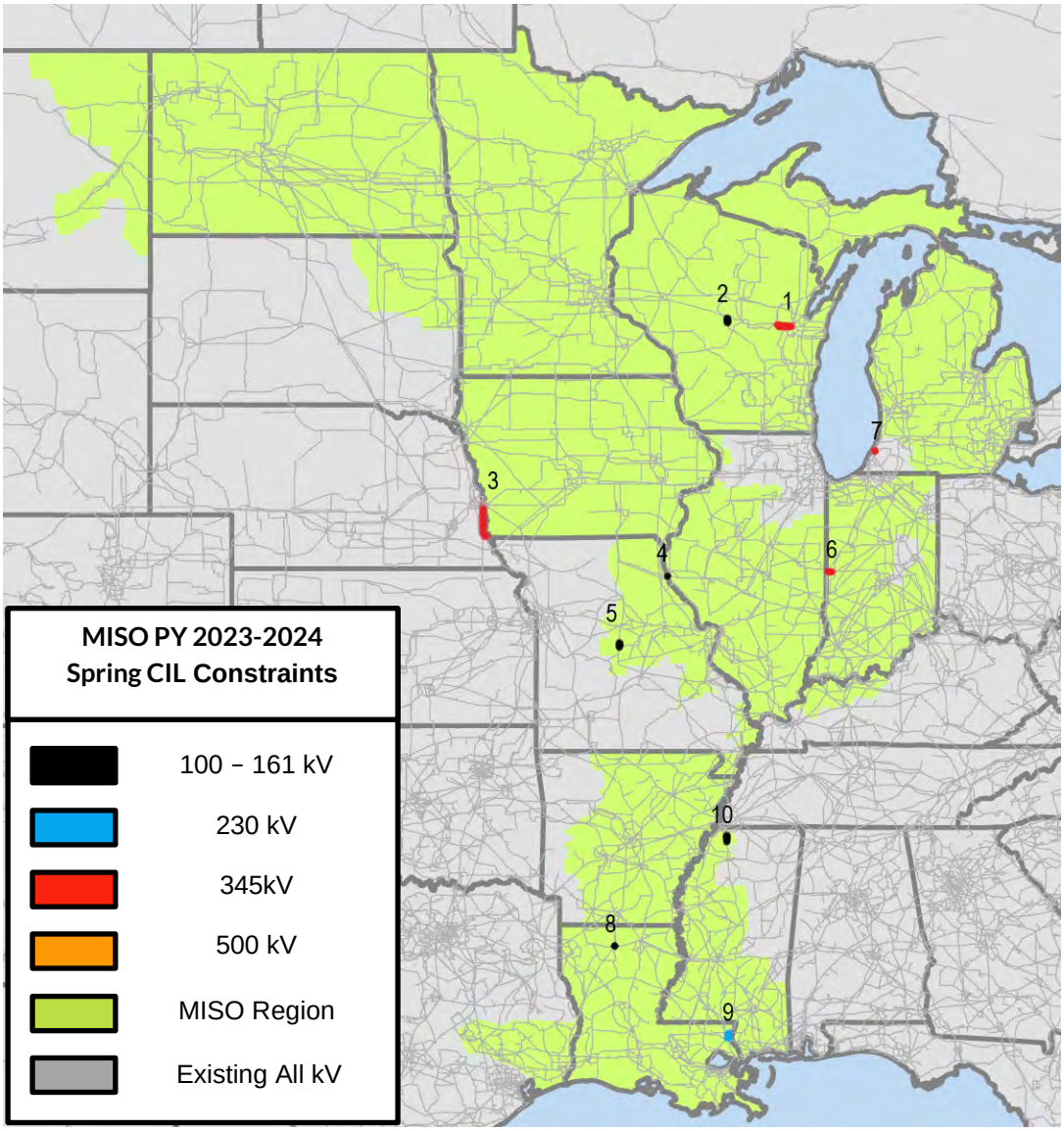


Figure 2-4: Planning Year 2023-2024 Spring Capacity Import Constraints Map

Capacity Exports Limits are found by increasing generation in the study zone and decreasing generation in the rest of the MISO footprint to create a transfer. Table 2-4 below shows the Planning Year 2023-2024 CEL and ZEA with corresponding constraint, GLT, and redispatch information.

LRZ1	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2023	Granville - Butler 138kV	Granville - Arcadian 345kV	15%	None	3961	3959
Fall 2023	Arpin - Sigel 138kV	Rocky Run - Arpin 345kV	None	18MWx2	3806	3804
Winter 2023/24	Arpin - Sigel 138kV	Rocky Run - Arpin 345kV	None	29MWx2	3503	3501
Spring 2024	Rocky Run - Werner 345kV	Highway 22 - Gardner Park 345kV	None	21MWx2	4323	4321
LRZ2	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2023	Wempletown 345/138kV Transformer	Cherry Valley - Wempleton 345kV	20%	None	2550	2550
Fall 2023	Elm Road - Racine 345kV	Base Case	None	None	3577	3577
Winter 2023/24	Pleasant Prairie - Zion EC 345kV	Pleasant Prairie - Zion 345kV	15%	None	4198	4198
Spring 2024	Elm Road - Racine 345kV	Base Case	None	None	3679	3679
LRZ3	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2023	Mercer - Sandburg 161kV	Sandburg - Oak Grove 345kV	45%	None	4375	4310
Fall 2023	Prar Creek - Marion 115	Prar Creek - Bertram 115kV	None	147MWx2	4419	4354
Winter 2023/24	Sandburg 161/138kV Transformer	Sandburg - Oak Grove 345kV	None	109MWx2	7067	7002
Spring 2024	Sandburg 161/138kV Transformer	Sandburg - Oak Grove 345kV	40%	None	6238	6173
LRZ4	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2023	No CEL Found	No CEL Found	50%	None	9999	9999
Fall 2023	No CEL Found	No CEL Found	50%	None	9999	9999
Winter 2023/24	No CEL Found	No CEL Found	50%	None	9999	9999
Spring 2024	No CEL Found	No CEL Found	50%	None	9999	9999
LRZ5	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2023	No CEL Found	No CEL Found	45%	None	9999	9999
Fall 2023	Jord - West Frankfort 138kV	Mount Vernon - West Frankfort 345kV	None	None	1992	1992
Winter 2023/24	Miles Avenue - Moro 138kV	Roxford - Moro 345kV	35%	121MWx2	6348	6348
Spring 2024	Mass 345/161 kV Transformer	Joppa - Mass 345kV	None	None	3724	3724
LRZ6	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2023	Franscisco - Duff 345kV	AB Brown - Reid 345kV	15%	206MWx2	3109	2703
Fall 2023	Newtonville - Coleman 161kV	Duff - Coleman 345kV	None	493MWx2	2101	1701
Winter 2023/24	Newtonville- Grandview 138kV	Cutley - Dubois 138kV	None	42MWx2	1642	1242
Spring 2024	Newtonville - Coleman 161kV	AB Brown - Reid 345kV	None	65MWx2	2744	2344
LRZ7	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2023	Monroe - Lulu 345kV	Monroe - Lallendorf 345kV	25%	None	3953	3953
Fall 2023	Monroe - Lulu 345kV	Monroe - Lallendorf 345kV	None	None	3990	3990
Winter 2023/24	Monroe - Lulu 345kV	Monroe - Lallendorf 345kV	None	None	4350	4350
Spring 2024	Monroe - Lulu 345kV	Monroe - Lallendorf 345kV	None	None	4413	4413
LRZ8	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2023	Cash - Jonesboro 161kV	Ises - Powerlane Road 500kV	50%	218MWx2	5551	5503
Fall 2023	Arklahoma - HS EHV 115kV 2	Arklahoma - HS EHV 115kV 2	None	177MWx2	5128	5080
Winter 2023/24	Cash - Jonesboro 161kV	Ises - Powerlane Road 500kV	25%	134MWx2	5399	5351
Spring 2024	Cash - Jonesboro 161kV	Ises - Powerlane Road 500kV	None	177MWx2	5520	5472

LRZ9	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2023	Adams Creek - Angie 230kV	Slidel - Log Town 230kV	None	None	2386	1574
Fall 2023	Wrightsville - Keo 500kV	White Bluff - Keo 500kV	None	None	2338	1526
Winter 2023/24	Adams Creek - Angie 230kV	Slidel - Log Town 230kV	None	None	1689	877
Spring 2024	Adams Creek - Angie 230kV	Slidel - Log Town 230kV	None	None	3052	2240
LRZ10	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2023	Andrus 230/115kV Transformer	Andrus - Indianola	None	510MWx2	1794	1794
Fall 2023	Clarksdale - Lyon 115kV	Crossroads - Moon Lake 230kV	None	284MWx2	2878	2878
Winter 2023/24	Batesville - Tallahachie 161kV	Choctaw - Clay 500kV	None	690MWx2	1980	1980
Spring 2024	Clarksdale - Lyon 115kV	Crossroads - Moon Lake 230kV	None	535MWx2	2720	2720

Table 2-4: Planning Year 2023–2024 Export Limits

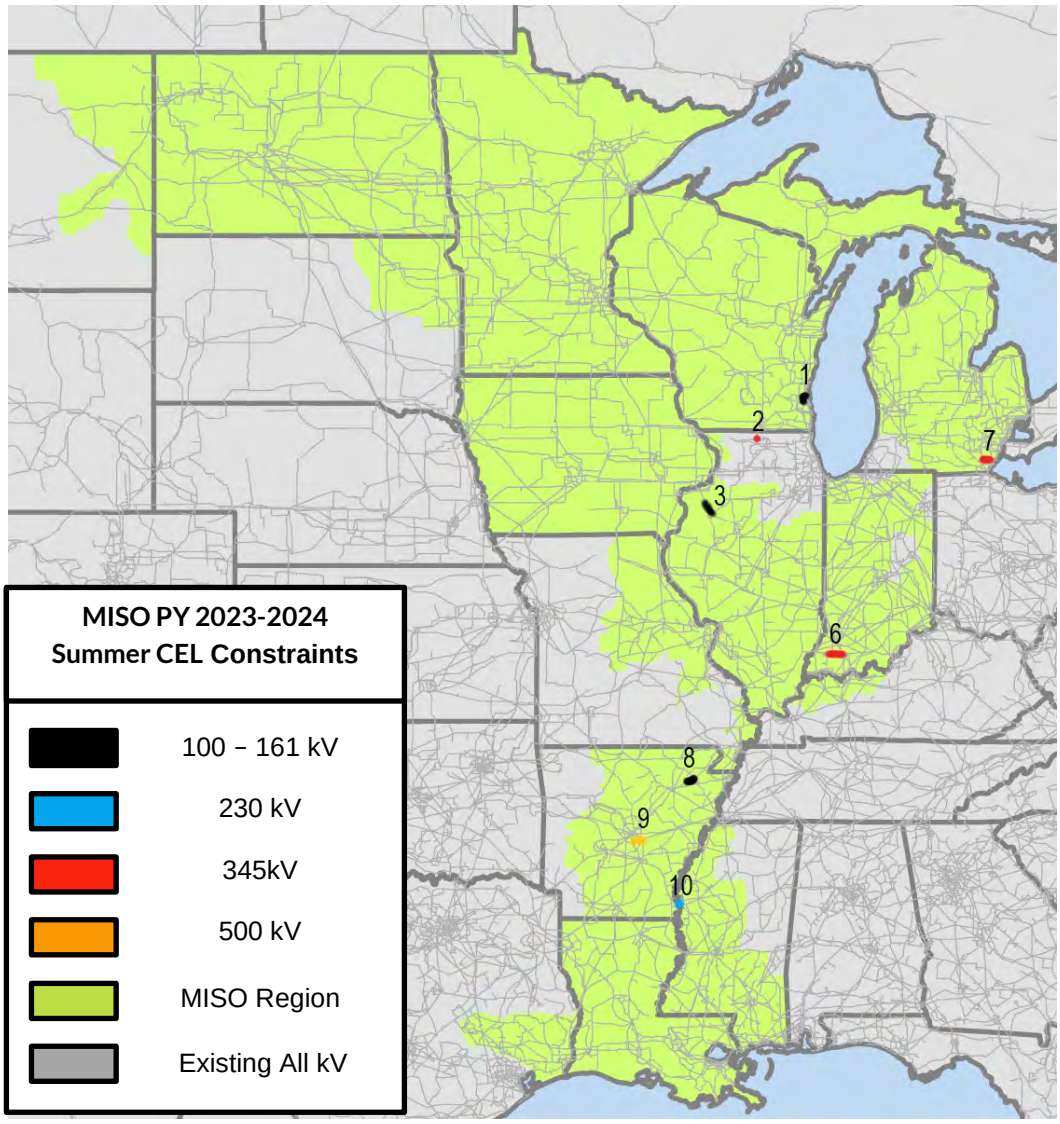


Figure 2-5: Planning Year 2023-2024 Summer Export Constraint Map

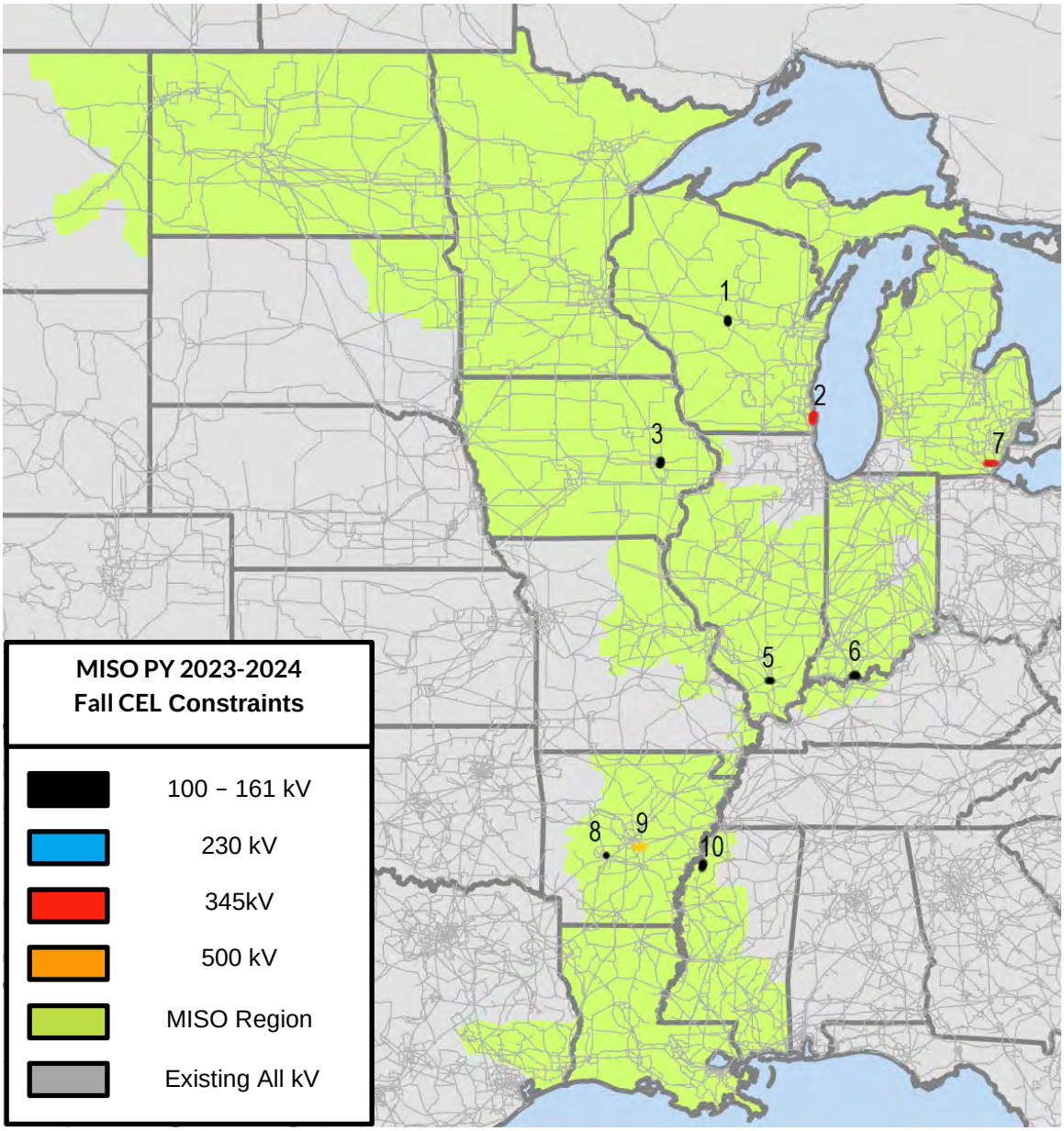


Figure 2-6: Planning Year 2023-2024 Fall Export Constraint Map

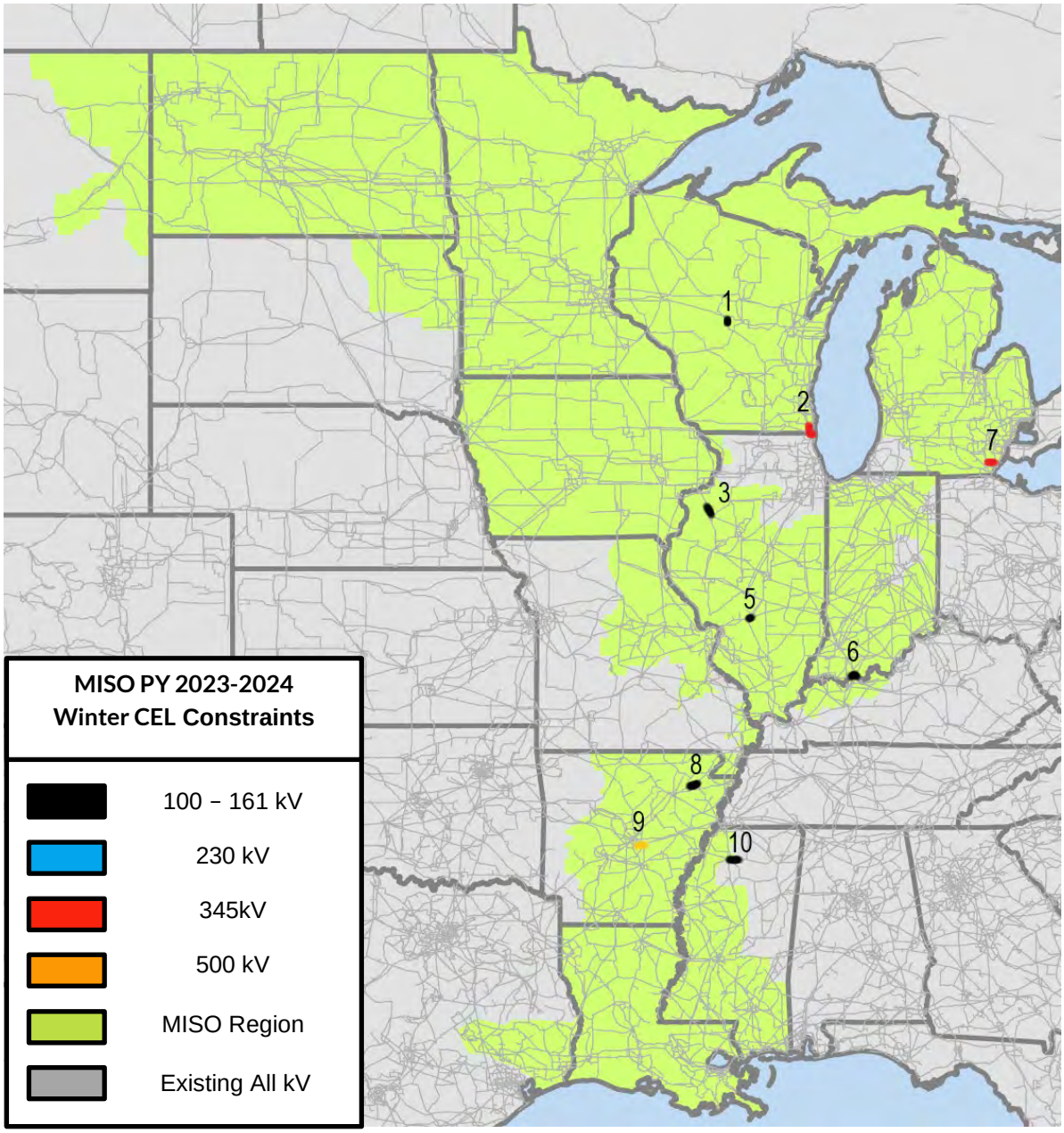


Figure 2-7: Planning Year 2023-2024 Winter Export Constraint Map

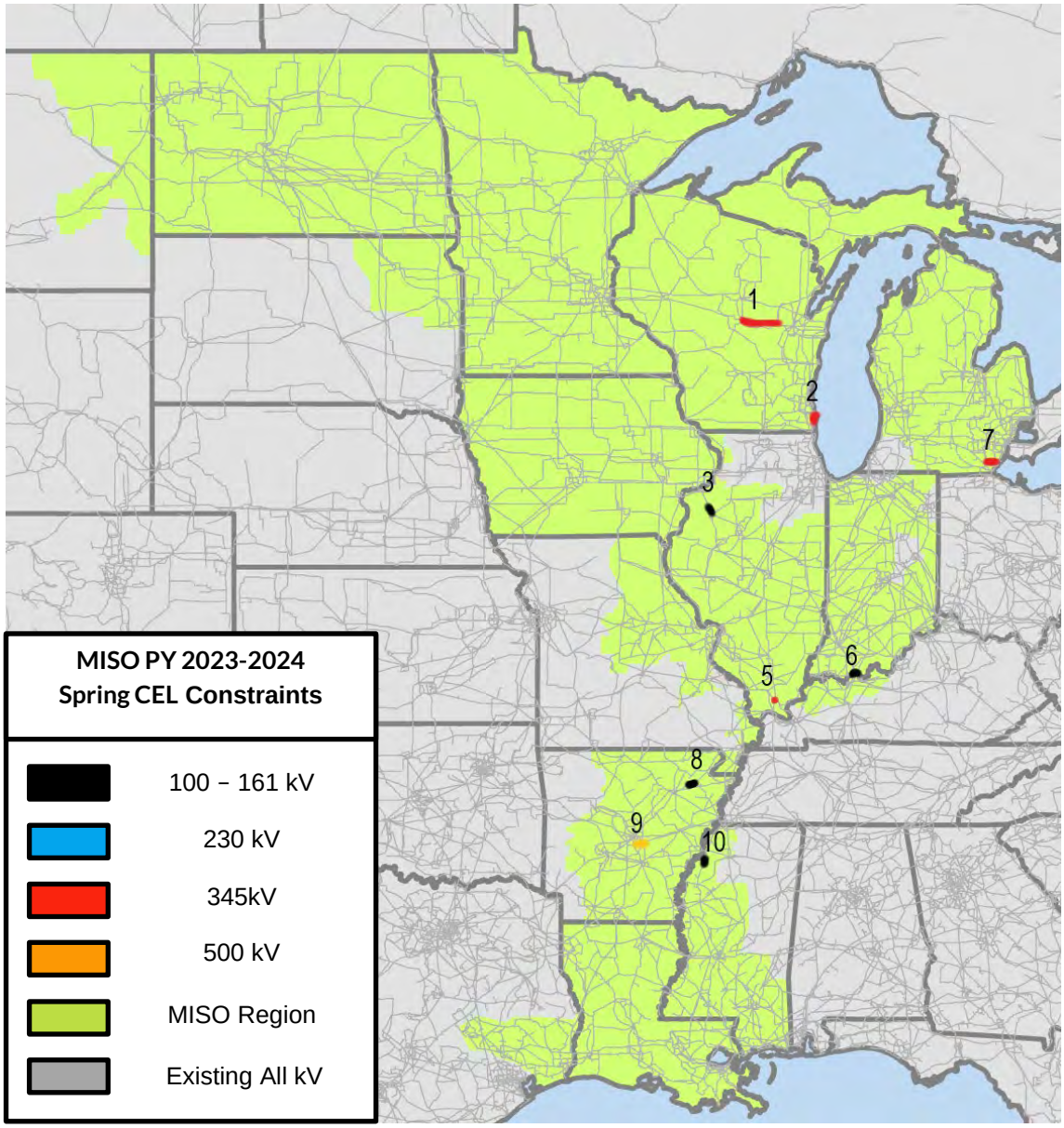


Figure 2-8: Planning Year 2023-2024 Spring Export Constraint Map

2.3.1 Outyear Analysis

In 2018, MISO and its stakeholders redesigned the outyear LOLE transfer analysis process through the LOLEWG and Resource Adequacy Subcommittee (RASC). The outyear analysis is now performed after the prompt Planning Year analyses are complete. The outyear results are informational only. The zones identified for outyear analysis are determined by BPM-011 criteria. The results will be documented outside of the LOLE report and recorded in RASC meeting materials in Q2 of 2023 and memorialized at a later date as an addendum to the LOLE report in 2023.

3 Loss of Load Expectation Analysis

3.1 LOLE Modeling Input Data and Assumptions

MISO uses a program managed by Astrapé Consulting called Strategic Energy & Risk Valuation Model (SERVM) to calculate the LOLE for the applicable Planning Year. SERVM uses a sequential Monte Carlo simulation to model a generation system and to assess the system's reliability based on any number of interconnected areas. SERVM calculates the LOLE for the MISO system and each LRZ by stepping through the year chronologically and taking into account generation, load, load modifying and energy efficiency resources, equipment forced outages, planned and maintenance outages, weather and economic uncertainty, and external support.

Building the SERVM model is the most time-consuming task of the LOLE study. Many scenarios are built in order to determine how certain variables impact the results. The base case models determine the seasonal MISO PRM Installed Capacity (ICAP), PRM UCAP, and the LRRs for each LRZ for future Planning Years one, four and six.

3.2 MISO Generation

3.2.1 Thermal Units

The Planning Year 2023-2024 LOLE study used the 2022-2023 PRA converted capacity as a starting point for which resources to include in the study. This ensured that only resources eligible as a Planning Resources were included in the LOLE study. An exception was made for resources with a signed GIA with an anticipated in-service date for PY 2023-2024—these resources were also included. All internal Planning Resources were modeled in the LRZ in which they are physically located. Additionally, Coordinating Owners and Border External Resources were modeled as being internal to the LRZ in which they are committed to serving load.

Forced outage rates and planned maintenance factors were calculated over a five-year period (January 2017 to December 2021) and modeled as four seasonal values for each unit. Some units did not have five years of historical data in MISO's Generator Availability Data System (PowerGADS)—however, if they had at least 3 consecutive months of seasonal data, unit-specific information was used to calculate their seasonal forced outage rates and maintenance factors. Units with fewer than 3 consecutive months of seasonal unit-specific data were assigned the corresponding MISO seasonal class average forced outage rate and seasonal planned maintenance factor based on their fuel type. The overall MISO ICAP-weighted seasonal class average forced outage rate and seasonal planned maintenance factor are applied in lieu of class averages for classes with fewer than 30 units. When the units are populated into the LOLE model, the weighted outage rate in SERVM may be different from the calculated MISO-wide weighted average because the MISO-wide weighted average excludes units with insufficient operating history. Therefore, the weighted outage rate is recalculated to include units that were assigned class average outage rates to gauge how SERVM views the MISO-wide weighted average. This value is for information only and is not assigned to any units.

Each nuclear unit has a fixed maintenance schedule, which was pulled from publicly available information and was modeled for each of the study years.

The historical class average outage rates as well as the MISO system-wide weighted average forced outage rate are provided in Table 3-1 to show the year-over-year trends, as well as in Table 3-2 on a seasonal basis.

Pooled EFORd GADS Years	2017-2021 (%)	2016-2020 (%)	2015-2019 (%)	2014-2018 (%)	2013-2017 (%)	2012-2016 (%)
LOLE Study Planning Year	**PY 2023-2024 LOLE Study – Summer 2023**	**PY 2022-2023 LOLE Study**	**PY 2021-2022 LOLE Study**	**PY 2020-2021 LOLE Study**	**PY 2019-2020 LOLE Study**	**PY 2018-2019 LOLE Study**
Combined Cycle	5.54	5.85	5.52	5.70	5.370	4.62
Combustion Turbine (0-20 MW)	23.40	35.20	36.38	40.39	23.18	29.02
Combustion Turbine (20-50 MW)	6.30	13.65	14.20	15.29	15.76	13.48
Combustion Turbine (50+ MW)	4.07	4.36	4.76	4.65	5.18	6.19
Diesel Engines	12.79	7.25	10.05	23.53	10.26	10.42
Fluidized Bed Combustion	*	*	*	*	*	*
Hydro (0-30 MW)	*	*	*	*	*	*
Hydro (30+ MW)	*	*	*	*	*	*
Nuclear	*	*	*	*	*	*
Pumped Storage	*	*	*	*	*	*
Steam - Coal (0-100 MW)	*	*	*	5.33	4.60	5.14
Steam - Coal (100-200 MW)	*	*	*	*	*	*
Steam - Coal (200-400 MW)	*	*	10.47	10.16	9.82	9.77
Steam - Coal (400-600 MW)	*	*	*	*	*	*
Steam - Coal (600-800 MW)	*	*	*	*	8.22	7.90
Steam - Coal (800-1000 MW)	*	*	*	*	*	*

Steam - Gas	11.26	11.84	12.91	12.54	11.56	11.94
Steam - Oil	*	*	*	*	*	*
Steam - Waste Heat	*	*	*	*	*	*
Steam - Wood	*	*	*	*	*	*
MISO Weighted System-wide	8.23	9.04	9.36	9.24	9.28	9.16
MISO Weighted as seen in SERVM	7.64	8.95	9.17	9.22	9.18	-

**MISO system-wide weighted forced outage rate used in place of class data for those with less than 30 units reporting 12 or more months of data*

Table 3-1: Historical Class Average Forced Outage Rates

Pooled EFORd GADS Years	**2017-2021 (%)**	**2017-2021 (%)**	**2017-2021 (%)**	**2017-2021 (%)**
LOLE Study Planning Year 2023-2024	**Summer 2023**	**Fall 2023**	**Winter 2023-2024**	**Spring 2024**
Combined Cycle	5.54	8.32	4.70	6.19
Combustion Turbine (0-20 MW)	23.40	53.44	42.92	58.75
Combustion Turbine (20-50 MW)	6.30	16.79	56.52	25.23
Combustion Turbine (50+ MW)	4.07	6.60	9.68	4.81
Diesel Engines	12.79	9.32	14.84	8.07
Fluidized Bed Combustion	*	*	*	*
Hydro (0-30 MW)	*	*	*	*
Hydro (30+ MW)	*	*	*	*

Nuclear	*	*	*	*
Pumped Storage	*	*	*	*
Steam - Coal (0-100 MW)	*	*	*	*
Steam - Coal (100-200 MW)	*	*	*	*
Steam - Coal (200-400 MW)	*	*	*	*
Steam - Coal (400-600 MW)	*	*	*	*
Steam - Coal (600-800 MW)	*	*	*	*
Steam - Coal (800-1000 MW)	*	*	*	*
Steam - Gas	12.48	13.66	8.28	11.26
Steam - Oil	*	*	*	*
Steam - Waste Heat	*	*	*	*
Steam - Wood	*	*	*	*
MISO Weighted System-wide	8.23	9.48	12.47	11.42

**MISO system-wide weighted forced outage rate used in place of class data for those with less than 30 units reporting 12 or more months of data*

Table 3-2: Planning Year 2023-2024 Seasonal Class Average Forced Outage Rates

3.2.2 Behind-the-Meter Generation

Behind-the-Meter Generation data came from the Module E Capacity Tracking (MECT) tool. Behind-the-Meter Generation backed by thermal resources were explicitly modeled just as any other thermal generator with a monthly capacity and forced outage rate. Performance data was pulled from PowerGADS. Behind-the-Meter Generation backed by wind or solar resources had their hourly generation tied to the hourly wind and solar profiles in the model.

3.2.3 Attachment Y

MISO obtained information on generating units with approved suspensions or retirements (as of June 1, 2022) through MISO's Attachment Y process. Any unit with approved retirement or suspension in Planning Year 2023-2024

was excluded from the year-one analysis during the months the unit has been approved to be out-of-service for. This same methodology is used for the four- and six-year analyses.

3.2.4 Future Generation

Future thermal generation and upgrades were added to the LOLE model based on unit information in the MISO Generator Interconnection Queue. The LOLE model included units with a signed generator interconnection agreement (as of June 1, 2022). These new units were assigned seasonal class average forced outage rates and planned maintenance factors based on their particular unit class. Units upgraded during the study period reflect the megawatt increase for each month, beginning the month the upgrade was finished. The LOLE analysis also included future wind and solar generation, tied to the same hourly wind and solar profiles used for existing wind and solar resources in the model.

3.2.5 Intermittent Resources

Intermittent resources such as run-of-river hydro, biomass, wind and solar were explicitly modeled as demand-side resources. Run-of-river hydro and biomass provide MISO with a minimum of 3 years and up to 15 years of historical output data during seasonal peak hours, defined as hours ending 15, 16, & 17 EST for summer, fall, and spring, and hours ending 8, 9, 19, & 20 for winter. This data is averaged at the seasonal level and modeled in the LOLE analysis as UCAP for all months within a given season. Each individual unit is modeled and put in the corresponding LRZ.

As a process improvement to the LOLE model for this year's study, in collaboration with the SERVM vendor Astrapé, hourly wind and solar profiles were developed and introduced into the model to better simulate the variance in renewable generation on an hourly basis.

Using historical hourly wind data from 246 front-of-meter wind resources from 2013 to 2021, normalized hourly capacity profiles were developed and aggregated at the LRZ level to represent wind in the model. As a result of the LOLE analysis being based on 30 weather years (1992 – 2021), synthetic shapes were created for the 1992 – 2013 period based on historical wind performance and temperatures. Once the weather and wind performance matching has been performed, the data is analyzed as a function of load to ensure the variability around the load profiles is reasonable.

Solar profiles were developed using historical solar irradiance data from the NREL National Solar Radiation Database (NSRDB) from 1998 – 2021.

For more details, refer to the supporting documentation Astrapé provided for stakeholders at the LOLEWG detailing the development of the wind and solar profiles: MISO Seasonal Inputs for the 2022 LOLE Study

3.2.6 Demand Response

Demand response data came from the MECT tool. These resources were explicitly modeled as dispatch-limited resources. Each demand response program was modeled individually with a monthly capacity, limited to the number of times each program can be called upon, and limited by duration.

3.3 MISO Load Data

The Planning Year 2023-2024 LOLE analysis used a load training process with neural net software to create a neural-net relationship between historical weather and load data. This relationship was then applied to 30 years of hourly historical weather data to create 30 different load shapes for each LRZ in order to capture both load diversity and seasonal variations. The average monthly loads of the predicted load shapes were adjusted to match each LRZ's

Module E 50/50 monthly zonal peak load forecasts for each study year. The results of this process are shown as the MISO System Peak Demand (Table 4-1) and LRZ Peak Demands (Table 5-1, Table 5-2, Table 5-3, & Table5-4).

Direct Control Load Management and Interruptible Demand types of demand response were explicitly included in the LOLE model as resources. These demand resources are implemented in the LOLE simulation before accumulating LOLE.

3.3.1 Weather Uncertainty

MISO has adopted a six-step load training process in order to capture the weather uncertainty associated with the 50/50 load forecasts. The first step of this process requires the collection of five years of historical real-time load modifying resource (LMR) performance and load data, as well as the collection of 30 years of historical weather data. Both the LMR and load data are taken from the MISO market for each LBA, while the historical weather data is collected from the National Oceanic and Atmospheric Administration (NOAA) for each LRZ. After collecting the data, the hourly gross load for each LRZ is calculated using the five years of historical data.

The second step of the process is to normalize the five years of load data to consistent economics. With the load growth due to economics removed from 5 years of historical LRZ load, the third step of the process utilizes neural network software to establish functional relationships between the five years of historical weather and load data. In the fourth step of the process the neural network relationships are applied to the 30 years of historical weather data in order to predict/create 30 years' worth of load shapes for each LRZ.

In the fifth step of the load training process, MISO undertakes extreme temperature verification on the 30 years of load shapes to ensure that the hourly load data is accurate at extremely hot or cold temperatures. This is required since there are fewer data points available at the temperature extremes when determining the neural network functional relationships. This lack of data at the extremes can result in inaccurate predictions when creating load shapes, which will need to be corrected before moving forward.

The sixth and final step of the load training process is to average the monthly peak loads of the predicted load shapes and adjust them to match each LR's Module E 50/50 monthly zonal peak load forecasts for each study year. In order to calculate this adjustment, the ratio of the first year's non-coincident peak forecast to the zonal coincident peak forecast is applied to future year's non-coincident peak forecast.

By adopting this new methodology for capturing weather uncertainty MISO is able to model multiple load shapes based off a functional relationship with weather. This modeling approach provides a variance in load shapes, as well as the peak loads observed in each load shape. This approach also provides the ability to capture the frequency and duration of severe weather patterns.

3.3.2 Economic Load Uncertainty

To account for economic load uncertainty in the Planning Year 2023-2024 LOLE model, MISO utilized a normal distribution of electric utility forecast error accounting for projected and actual Gross Domestic Product (GDP), as well as electricity usage. The historic projections for GDP growth were taken from the Congressional Budget Office (CBO), the actual GDP growth was taken from the Bureau of Economic Analysis (BEA), and the electric use was taken from the U.S. Energy Information Administration (EIA). Due to lack of statewide projected GDP data MISO relied on United States aggregate level data when calculating the economic uncertainty.

In order to calculate the electric utility forecast error, MISO first calculated the forecast error of GDP between the projected and actual values. The resulting GDP forecast error was then translated into electric utility forecast error

by multiplying by the rate at which electric load grows in comparison to the GDP. Finally, a standard deviation is calculated from the electric utility forecast error and used to create a normal distribution representing the probabilities of the load forecast errors (LFE) as shown in Table 3-3.

	LFE Levels				
	-2.0%	-1.0%	0.0%	1.0%	2.0%
Standard Deviation in LFE	Probability assigned to each LFE				
0.90%	4.8%	24.1%	42.1%	24.1%	4.8%

Table 3-3: Economic Uncertainty

As a result of stakeholder feedback MISO is exploring possible alternative methods for determining economic uncertainty to be used in the LOLE process.

3.4 External System

Firm imports from external areas to MISO are modeled at the individual unit level. The specific external units were modeled with their specific installed capacity amount and their corresponding Equivalent Forced Outage Rate demand (EFORd). This better captures the probabilistic reliability impact of firm external imports. These units are only modeled within the MISO PRM analysis and are not modeled when calculating the LRZ LRRs. Due to the locational Tariff filing, Border and Coordinating Owners External Resources are no longer considered firm imports. Instead, these resources are modeled as internal MISO units and are included in the PRM and LRR analysis. The external resources to include for firm imports were based on the amount offered into the Planning Year 2022-2023 Planning Resource Auction (PRA).

The LOLE analysis incorporates firm exports to neighboring regions where information was available. For units with capacity sold off-system, their monthly capacities were reduced by the megawatt amount exported. These values came from PJM's Reliability Pricing Model (RPM) as well as information on exports to other external areas taken from the Independent Market Monitor (IMM) exclusion list.

Firm exports from MISO to external areas were modeled the same as previous years. Capacity ineligible as MISO capacity due to transactions with external areas is removed from the model. Table 3-4 shows the amount of firm imports and exports in this year's study.

Contracts	Summer ICAP (MW)	Summer UCAP (MW)	Fall ICAP (MW)	Fall UCAP (MW)	Winter ICAP (MW)	Winter UCAP (MW)	Spring ICAP (MW)	Spring UCAP (MW)
Imports (MW)	1,731	1,673	1,734	1,672	1,874	1,819	1,803	1,755
Exports (MW)	2,543	2,287	2,543	2,287	2,543	2,287	2,543	2,287
Net	**-812**	**-614**	**-809**	**-615**	**-669**	**-468**	**-740**	**-532**

Table 3-4: Planning Year 2023-2024 Firm Imports and Exports

Non-firm imports in the Planning Year 2023-2024 LOLE study were modeled as a probabilistic distribution of capacity value. These distributions were developed using historic seasonal NSI data which accounted for imports into MISO during emergency pricing hours. Firm imports cleared in the PRA for each planning year were subtracted from the NSI data to isolate the non-firm values. An additional region was included in SERVM which contained 12,000 MW of perfect generation connected to the MISO system. A distribution of the regions export capability was modeled up to the upper and lower bounds. As SERVM steps through the hourly simulation, random draws on the export limits of the external region were used to represent the amount of capacity MISO could import to meet peak demand. The probability distribution of non-firm external imports used in the LOLE model has been provided in Table 3-5.

	Summer	Fall	Winter	Spring
p5	1,456	649	-	1,777
p10	2,663	1,259	205	2,144
p25	3,674	2,199	1,142	2,768
p50	4,708	3,393	3,143	4,031
p75	5,608	4,537	4,941	5,265
p90	6,465	5,453	7,249	6,271
p95	6,807	6,217	8,452	7,055

Table 3-5: Non-Firm External Import Distribution During Emergency Pricing Hours

3.5 Loss of Load Expectation Analysis and Metric Calculations

Upon completion of the annual LOLE study model refresh, MISO performed probabilistic analyses to determine the seasonal PRM ICAP and PRM UCAP for the Planning Year 2023-2024 as well as the seasonal Local Reliability Requirement for each of the 10 LRZs. These metrics were derived through probabilistic modeling of the system, first solving to the industry standard annual LOLE risk target of 1 day in 10 years, or 0.1 day per year, and then solving to the seasonal LOLE targets.

3.5.1 Seasonal LOLE Distribution

To determine the seasonal LOLE distribution that will be used to calculate the PRM and LRRs, MISO followed the process described in Section 68A.2.1 of Module E-1 of the MISO Tariff. This process involves first solving the LOLE model to an annual value of 0.1 and then checking the seasonal distribution of the annual LOLE of 0.1. If a season had an LOLE value of at least 0.01, then it met the minimum seasonal criteria and would be set to that LOLE. If a season had less than 0.01 LOLE, additional analysis was performed until the minimum seasonal criteria of 0.01 LOLE was met.

Example: Assume the model is solved to an annual LOLE of 0.1 with 0.05 occurring in both summer and winter while spring and fall had LOLE values of 0 from this simulation. In this case the summer and winter seasons would not need additional analysis since both had at least 0.01 LOLE naturally when the model was solved to an annual value of 0.1. Since spring and fall had 0 LOLE they would be assigned the LOLE minimum seasonal criteria of 0.01 and additional LOLE simulations would be performed until the minimum seasonal criteria was met.

The seasonal LOLE distribution determined in the Planning Year 2023-2024 LOLE study are shown in Table 3-6.

Region	Summer	Fall	Winter	Spring
MISO-wide	0.1	0.01	0.01	0.01
1	0.08	0.01	0.02	0.01
2	0.1	0.01	0.01	0.01
3	0.07	0.01	0.03	0.01
4	0.04	0.01	0.04	0.01
5	0.04	0.01	0.05	0.01
6	0.05	0.01	0.04	0.01
7	0.07	0.03	0.01	0.01
8	0.01	0.01	0.08	0.01
9	0.06	0.01	0.02	0.01
10	0.05	0.04	0.01	0.01

Table 3-6: Planning Year 2023-2024 Seasonal LOLE Distribution

3.7.1 MISO-Wide LOLE Analysis and PRM Calculation

MISO will determine the appropriate PRM for each season of the applicable Planning Year based upon probabilistic analysis of reliably serving expected demand. The probabilistic analysis will utilize a Loss of Load Expectation (LOLE) study which assumes that there are no internal transmission limitations.

To determine the PRM, the LOLE model will initially be run with no adjustments to the capacity. If the LOLE is less than 0.1 day per year, a negative unit with zero forced outage rate will be added until the LOLE reaches 0.1 day per year. This is comparable to adding load to the model. If the LOLE is greater than 0.1 day per year, proxy units based on a unit of typical size and forced outage rate will be added to the model until the LOLE reaches 0.1 day per year.

MISO's annual LOLE study will calculate the seasonal PRMs based on the LOLE targets identified in the previous section. The minimum seasonal PRM requirement will be determined using the LOLE analysis by either adding a zero EFORd, negative output unit or adding proxy units until a minimum LOLE of 0.01 day per season is reached.

The formulas for the PRM values for the MISO system are:

PRM ICAP % = (Installed Capacity + Firm External Support ICAP + ICAP Adjustment to meet LOLE target – MISO Coincident Peak Demand)/MISO Coincident Peak Demand

PRM UCAP % = (Unforced Capacity + Firm External Support UCAP + UCAP Adjustment to meet LOLE target – MISO Coincident Peak Demand)/MISO Coincident Peak Demand

Where Unforced Capacity (UCAP) = Installed Capacity (ICAP) x (1 – XEFORd)

3.7.2 LRZ LOLE Analysis and Local Reliability Requirement Calculation

For the LRZ analysis, each LRZ included only the generating units within the LRZ (including Coordinating Owners and Border External Resources) and was modeled without consideration of the benefit of the LRZ's import capability. Much like the MISO analysis, unforced capacity is either added or removed in each LRZ such that an LOLE of 0.1 day per year is achieved when solving for the annual target and a minimum LOLE at least 0.01 day per season when solving for a seasonal target. The minimum amount of unforced capacity above each LRZ's Peak Demand that was required to meet the reliability criteria was used to establish each LRZ's LRR.

The Planning Year 2023-2024 seasonal LRRs were determined using the LOLE analysis by first either adding or removing capacity until the annual LOLE reaches 0.1 day per year for the LRZ. If the LOLE is less than 0.1 day per year, a perfect negative unit with zero forced outage rate will be added until the LOLE reaches 0.1 day per year. If the LOLE is greater than 0.1 day per year, proxy units based on a unit of typical size and forced outage rate will be added to the model until the LOLE reaches 0.1 day per year.

After solving each LRZ for to the annual LOLE target of 0.1 day per year, MISO will calculate each seasonal LRR such that the summation of seasonal LOLE across the year in each zone is 1 day in 10 years, or 0.1 day per year. An LOLE target of 0.01 will be used to calculate the LRR in seasons with less than 0.01 LOLE risk. The seasonal Local Reliability Requirement will be determined using the LOLE analysis by either adding a zero EFORd, negative output unit or adding proxy units until a minimum LOLE of 0.01 day per season is reached.

For Planning Year 2023-2024, only LRZ-1 had sufficient capacity internal to the LRZ to achieve any of the seasonal LOLE targets as an island. In the nine zones without sufficient capacity as an island, proxy units of typical size (160 MW) and class average seasonal EFORd were added to the LRZ. When needed, a fraction of the final proxy unit was added to achieve the exact seasonal LOLE target for the LRZ.

LRR UCAP % = (Unforced Capacity + UCAP Adjustment to meet LOLE target – Zonal Coincident Peak Demand)/Zonal Coincident Peak Demand

4 MISO System Planning Reserve Margin Results

4.1 Planning Year 2023-2024 MISO Planning Reserve Margin Results

For Planning Year 2023-2024, the ratio of MISO capacity to forecasted MISO system peak demand yielded a planning ICAP reserve margin of 15.9 percent and a planning UCAP reserve margin of 7.4 percent for the summer season. Numerous values and calculations went into determining the MISO system PRM ICAP and PRM UCAP (Table 4-1).

MISO Planning Reserve Margin (PRM)	2023/2024 PY Summer	2023/2024 PY Fall	2023/2024 PY Winter	2023/2024 PY Spring	Formula Key
MISO System Peak Demand (MW)	123,711	111,012	103,455	99,113	[A]
Installed Capacity (ICAP) (MW)	144,268	144,992	150,673	145,366	[B]
Unforced Capacity (UCAP) (MW)	133,764	132,911	134,503	130,753	[C]
Firm External Support (ICAP) (MW)	1,731	1,734	1,874	1,803	[D]
Firm External Support (UCAP) (MW)	1,707	1,714	1,857	1,778	[E]
Adjustment to ICAP {1d in 10yr} (MW)	-2,650	-7,100	-6,500	-9,150	[F]
Adjustment to UCAP {1d in 10yr} (MW)	-2,650	-7,100	-6,500	-9,150	[G]
ICAP PRM Requirement (PRMR) (MW)	143,349	139,626	146,047	138,019	[H]=[B]+[D]+[F]
UCAP PRM Requirement (PRMR) (MW)	132,821	127,525	129,860	123,381	[I]=[C]+[E]+[G]
MISO PRM ICAP	**15.9%**	**25.8%**	**41.2%**	**39.3%**	[J]=([H]-[A])/[A]
MISO PRM UCAP	**7.4%**	**14.9%**	**25.5%**	**24.5%**	[K]=([I]-[A])/[A]

Table 4-1: Planning Year 2023-2024 MISO System Planning Reserve Margins

4.2 Comparison of PRM Targets Across 10 Years

Figure 4-1 compares the PRM UCAP values over the last 10 Planning Years. The last endpoint of the green line shows the Planning Year 2023-2024 Summer PRM value.

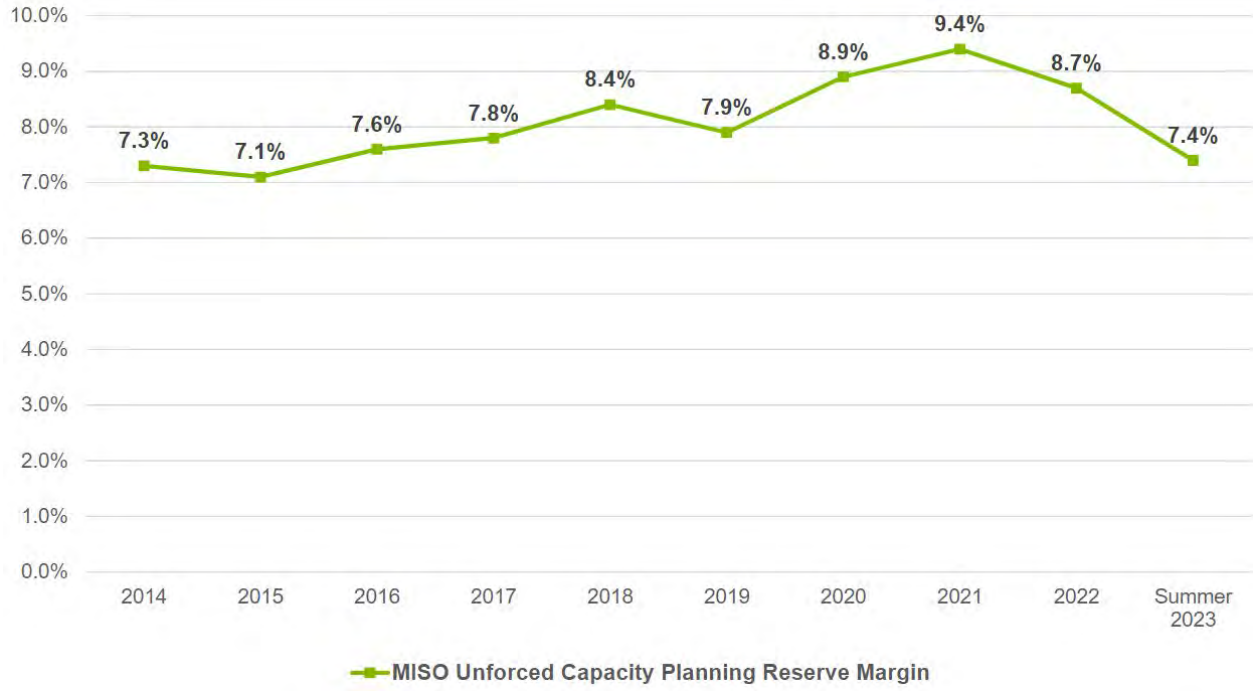


Figure 4-1: Comparison of PRM Targets Across 10 Years

4.3 Future Years 2023 through 2032 Planning Reserve Margins

Beyond the Planning Year 2023-2024 LOLE study analysis, an LOLE analysis will be performed for the four-year-out Planning Year of 2026-2027, as well as for the six-year-out Planning Year of 2028-2029. All other future Planning Years in scope will be derived from interpolation and extrapolation of the three modeled Planning Years.

5 Local Resource Zone Analysis – LRR Results

5.1 Planning Year 2023-2024 Local Resource Zone Analysis

MISO calculated the per-unit LRR of LRZ Seasonal Peak Demand for Planning Year 2023-2024 on a seasonal basis (Table 5-1, Table 5-2, Table 5-3, and Table 5-4). The UCAP values in the seasonal LRR tables reflect the assumed seasonal UCAP within each LRZ, including Border External Resources and Coordinating Owners. The adjustments to UCAP values are the megawatt adjustments needed in each LRZ so that the reliability criterion of 0.1 days per year LOLE is met. The LRR is the summation of the UCAP and adjustment to UCAP megawatts. The LRR is then divided by each LRZ's Seasonal Peak Demand to determine the per-unit LRR UCAP. The Planning Year 2023-2024 per-unit LRR UCAP values will be multiplied by the updated seasonal peak demand forecasts submitted for the 2023-2024 PRA to determine each LRZ's LRR. The zonal LRR LOLE targets have been provided for peak demand timestamps for all 30 weather years modeled in SERVM is shown in Table 5-5. These peak demand timestamps are the result of the SERVM load training process and are not necessarily the actual peaks for each year.

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2023-2024 Local Reliability Requirements – Summer 2023											
Installed Capacity (ICAP) (MW)	21,839	13,026	11,651	8,734	7,917	17,585	21,512	11,290	24,264	6,449	[A]
Unforced Capacity (UCAP) (MW)	20,843	12,145	11,225	7,986	7,410	15,973	20,476	10,866	21,097	5,743	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-255	2,062	1,583	3,242	2,859	4,844	3,952	403	2,897	1,209	[C]
LRR (UCAP) (MW)	20,588	14,207	12,808	11,228	10,269	20,817	24,428	11,269	23,994	6,952	[D]=[B]+[C]
Peak Demand (MW)	18,077	12,686	9,859	9,263	7,704	17,760	20,855	7,652	20,739	4,521	[E]
LRR UCAP per-unit of LRZ Peak Demand	**113.9%**	**112.0%**	**129.9%**	**121.2%**	**133.3%**	**117.2%**	**117.1%**	**147.3%**	**115.7%**	**153.8%**	[F]=[D]/[E]

Table 5-1: Planning Year 2023-2024 LRZ Local Reliability Requirements for Summer 2023

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2023-2024 Local Reliability Requirements – Fall 2023											
Installed Capacity (ICAP) (MW)	21,895	13,096	12,134	8,748	8,068	17,659	21,574	11,149	24,245	6,424	[A]
Unforced Capacity (UCAP) (MW)	20,460	12,097	11,545	7,787	7,201	16,014	20,269	10,190	21,787	5,561	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-1,230	1,289	1,046	3,138	2,625	4,170	3,848	28	2,821	1,177	[C]
LRR (UCAP) (MW)	19,230	13,386	12,591	10,925	9,825	20,184	24,117	10,218	24,607	6,738	[D]=[B]+[C]
Peak Demand (MW)	15,093	10,991	8,942	8,713	6,767	16,180	17,933	6,858	19,258	4,162	[E]
LRR UCAP per-unit of LRZ Peak Demand	**127.4%**	**121.8%**	**140.8%**	**125.4%**	**145.2%**	**124.7%**	**134.5%**	**149.0%**	**127.8%**	**161.9%**	[F]=[D]/[E]

Table 5-2: Planning Year 2023-2024 LRZ Local Reliability Requirements for Fall 2023

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2023-2024 Local Reliability Requirements – Winter 2023-2024											
Installed Capacity (ICAP) (MW)	22,449	13,578	14,291	9,028	8,528	18,244	21,710	11,298	24,921	6,626	[A]
Unforced Capacity (UCAP) (MW)	20,931	12,041	13,353	7,125	7,032	16,480	20,151	9,901	21,775	5,714	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-255	1,536	1,491	3,054	2,692	4,562	1,789	379	2,728	1,138	[C]
LRR (UCAP) (MW)	20,676	13,577	14,844	10,179	9,724	21,042	21,940	10,280	24,503	6,852	[D]=[B]+[C]
Peak Demand (MW)	14,738	9,549	8,025	7,456	6,599	16,173	13,945	6,839	18,523	3,856	[E]
LRR UCAP per-unit of LRZ Peak Demand	**140.3%**	**142.2%**	**185.0%**	**136.5%**	**147.4%**	**130.1%**	**157.3%**	**150.3%**	**132.3%**	**177.7%**	[F]=[D]/[E]

Table 5-3: Planning Year 2023-2024 LRZ Local Reliability Requirements for Winter 2023-2024

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2023-2024 Local Reliability Requirements – Spring 2024											
Installed Capacity (ICAP) (MW)	21,224	13,196	12,339	8,776	8,281	18,041	21,224	11,228	24,631	6,427	[A]
Unforced Capacity (UCAP) (MW)	19,769	11,963	11,601	7,265	7,342	16,150	19,638	9,700	21,470	5,856	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-1,330	626	1,147	2,907	2,371	3,615	1,836	152	2,601	726	[C]
LRR (UCAP) (MW)	18,439	12,590	12,748	10,172	9,713	19,765	21,475	9,852	24,071	6,582	[D]=[B]+[C]
Peak Demand (MW)	13,407	9,938	7,856	6,998	6,034	14,977	16,157	6,055	18,310	3,768	[E]
LRR UCAP per-unit of LRZ Peak Demand	**137.5%**	**126.7%**	**162.3%**	**145.4%**	**161.0%**	**132.0%**	**132.9%**	**162.7%**	**131.5%**	**174.7%**	[F]=[D]/[E]

Table 5-4: Planning Year 2023-2024 LRZ Local Reliability Requirements for Spring 2024

Weather Year Time of Peak Demand (ESTHE)	MISO	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS
1992	7/9/92 16:00	8/9/92 17:00	8/10/92 18:00	7/8/92 17:00	7/2/92 15:00	7/2/92 17:00	1/16/92 8:00	7/2/92 16:00	7/16/92 17:00	7/11/92 18:00	7/12/92 17:00
1993	7/27/93 17:00	8/11/93 17:00	8/27/93 14:00	8/22/93 19:00	7/17/93 17:00	7/27/93 16:00	7/25/93 16:00	7/9/93 15:00	7/31/93 17:00	8/14/93 16:00	7/31/93 18:00
1994	7/6/94 15:00	6/14/94 17:00	6/15/94 17:00	7/19/94 17:00	7/5/94 17:00	7/19/94 18:00	1/19/94 6:00	6/18/94 17:00	6/29/94 18:00	8/14/94 17:00	7/5/94 17:00
1995	7/13/95 17:00	7/13/95 18:00	7/13/95 16:00	7/14/95 17:00	7/14/95 17:00	7/13/95 16:00	7/13/95 17:00	7/13/95 17:00	8/17/95 14:00	7/27/95 17:00	7/12/95 15:00
1996	6/29/96 17:00	8/6/96 17:00	6/29/96 17:00	7/18/96 17:00	7/18/96 18:00	7/18/96 17:00	7/19/96 17:00	8/7/96 15:00	7/20/96 15:00	2/5/96 7:00	7/3/96 18:00
1997	7/26/97 16:00	7/16/97 16:00	7/16/97 17:00	7/25/97 18:00	7/18/97 16:00	7/26/97 17:00	7/26/97 16:00	7/16/97 16:00	7/25/97 18:00	8/16/97 16:00	7/25/97 18:00
1998	7/20/98 16:00	7/13/98 16:00	6/25/98 18:00	7/20/98 18:00	7/20/98 18:00	7/19/98 16:00	7/19/98 17:00	6/25/98 18:00	7/6/98 17:00	8/28/98 18:00	8/27/98 15:00
1999	7/30/99 14:00	7/25/99 15:00	7/13/95 16:00	7/30/99 18:00	7/18/99 22:00	7/30/99 17:00	7/26/97 16:00	7/30/99 14:00	7/25/99 17:00	8/14/99 18:00	8/20/99 18:00
2000	8/31/00 16:00	6/8/00 19:00	9/1/00 17:00	8/31/00 16:00	9/1/00 15:00	8/17/00 16:00	9/1/00 15:00	9/1/00 14:00	7/19/00 17:00	8/30/00 16:00	8/30/00 17:00
2001	8/8/01 16:00	8/7/01 16:00	8/9/01 16:00	7/31/01 16:00	7/23/01 17:00	7/23/01 17:00	8/7/01 17:00	8/8/01 16:00	7/11/01 16:00	7/10/01 16:00	7/20/01 17:00
2002	7/3/02 16:00	7/6/02 18:00	8/1/02 15:00	7/20/02 18:00	7/5/02 17:00	8/1/02 16:00	8/3/02 16:00	7/3/02 16:00	7/9/02 17:00	8/2/02 19:00	10/4/02 15:00
2003	8/21/03 16:00	8/24/03 17:00	8/21/03 16:00	7/26/03 18:00	8/21/03 16:00	8/21/03 18:00	8/27/03 17:00	8/21/03 17:00	7/18/03 14:00	8/10/03 16:00	7/17/03 17:00
2004	7/22/04 16:00	6/7/04 17:00	7/22/04 16:00	7/20/04 17:00	7/13/04 17:00	7/13/04 16:00	1/31/04 9:00	7/22/04 16:00	7/14/04 17:00	7/24/04 17:00	7/25/04 15:00
2005	7/24/05 17:00	7/17/05 17:00	7/24/05 16:00	7/25/05 17:00	7/24/05 16:00	7/24/05 18:00	7/25/05 17:00	7/24/05 18:00	8/21/05 18:00	7/25/05 16:00	8/21/05 15:00
2006	7/31/06 17:00	7/31/06 17:00	8/1/06 17:00	7/19/06 18:00	7/31/06 18:00	7/31/06 16:00	7/31/06 16:00	7/31/06 16:00	7/31/93 17:00	8/15/06 18:00	7/16/06 15:00
2007	8/1/07 17:00	7/26/07 15:00	8/2/07 15:00	7/17/07 17:00	8/15/07 18:00	8/15/07 18:00	8/29/07 17:00	7/31/07 18:00	8/17/95 14:00	8/14/07 15:00	8/14/07 15:00

2008	7/16/08 17:00	7/11/08 18:00	7/17/08 17:00	8/3/08 17:00	7/20/08 17:00	7/20/08 16:00	8/23/08 16:00	8/24/08 12:00	8/17/95 14:00	7/20/08 17:00	7/27/08 16:00
2009	6/25/09 16:00	6/22/09 19:00	7/28/09 16:00	7/24/09 18:00	8/9/09 16:00	8/9/09 16:00	1/16/09 8:00	6/25/09 16:00	6/22/09 16:00	7/2/09 16:00	7/2/09 18:00
2010	8/10/10 17:00	8/8/10 18:00	8/20/10 14:00	7/17/10 19:00	7/15/10 15:00	8/3/10 16:00	8/2/91 18:00	9/1/10 17:00	8/17/95 14:00	8/1/10 17:00	8/2/10 17:00
2011	7/20/11 18:00	6/7/11 19:00	7/13/95 16:00	7/20/11 16:00	9/1/11 16:00	8/31/11 16:00	7/26/97 16:00	7/20/11 19:00	7/31/93 17:00	7/2/11 17:00	7/10/11 18:00
2012	7/6/12 17:00	7/6/12 18:00	7/13/95 16:00	7/7/12 16:00	7/7/12 17:00	7/25/12 18:00	7/26/97 16:00	7/6/12 17:00	7/30/12 17:00	6/26/12 16:00	7/3/12 15:00
2013	7/19/13 16:00	7/18/13 19:00	8/27/13 16:00	8/30/13 16:00	9/11/13 16:00	8/31/13 17:00	8/31/13 15:00	7/19/13 14:00	6/27/13 18:00	8/7/13 16:00	8/8/13 17:00
2014	7/22/14 16:00	7/22/14 17:00	7/22/14 16:00	7/22/14 16:00	9/5/14 16:00	7/26/14 15:00	2/7/14 9:00	7/22/14 17:00	7/27/14 17:00	8/23/14 16:00	7/26/14 17:00
2015	7/29/15 16:00	8/14/15 15:00	8/14/15 17:00	7/13/15 15:00	9/3/15 16:00	7/13/15 16:00	7/18/15 17:00	8/2/15 16:00	8/7/15 18:00	8/10/15 16:00	7/30/15 16:00
2016	7/20/16 15:00	7/21/16 17:00	8/10/16 17:00	7/22/16 16:00	9/22/16 16:00	7/23/16 17:00	6/11/16 14:00	8/10/16 14:00	7/20/16 13:00	9/1/16 16:00	7/20/16 15:00
2017	7/20/17 16:00	7/6/17 17:00	6/12/17 14:00	7/21/17 17:00	9/26/17 15:00	7/12/17 15:00	9/26/17 16:00	6/12/17 14:00	7/21/17 15:00	8/19/17 15:00	7/20/17 15:00
2018	6/29/18 15:00	6/29/18 15:00	6/29/18 15:00	5/28/18 14:00	9/5/18 15:00	8/6/18 16:00	9/5/18 16:00	9/5/18 15:00	1/17/18 6:00	1/17/18 6:00	9/19/18 16:00
2019	7/19/19 14:00	7/19/19 18:00	7/19/19 16:00	7/19/19 14:00	9/12/19 16:00	10/1/19 15:00	9/13/19 16:00	7/19/19 13:00	8/13/19 14:00	10/4/19 15:00	10/2/19 16:00
2020	7/9/20 15:00	7/2/20 17:00	8/27/20 14:00	7/8/20 14:00	7/8/20 15:00	7/11/20 15:00	8/25/20 15:00	7/9/20 15:00	7/12/20 15:00	7/11/20 15:00	9/4/20 16:00
2021	8/24/21 15:00	7/27/21 16:00	8/10/21 15:00	7/28/21 16:00	8/27/21 15:00	8/25/21 16:00	8/24/21 16:00	8/24/21 15:00	8/10/21 14:00	8/23/21 16:00	7/29/21 14:00

Table 5-5: Historical Peak Days/Hours by Local Resource Zone

6 Appendix A: Comparison of Planning Year 2022 to 2023

Multiple study sensitivity analyses were performed to compute changes in the PRM target on an UCAP basis, from Planning Year 2022-2023 to Planning Year 2023-2024. These sensitivities included one-off incremental changes of input parameters to quantify how each change affected the PRM result independently. Note the impact of the incremental PRM changes from Planning Year 2022-2023 to Planning Year 2023-2024 in the waterfall chart of Figure A-1. Summer was determined to be the season most comparable to the annual PRM from last year's study. The following subsections provide more details around each of the sensitivities.

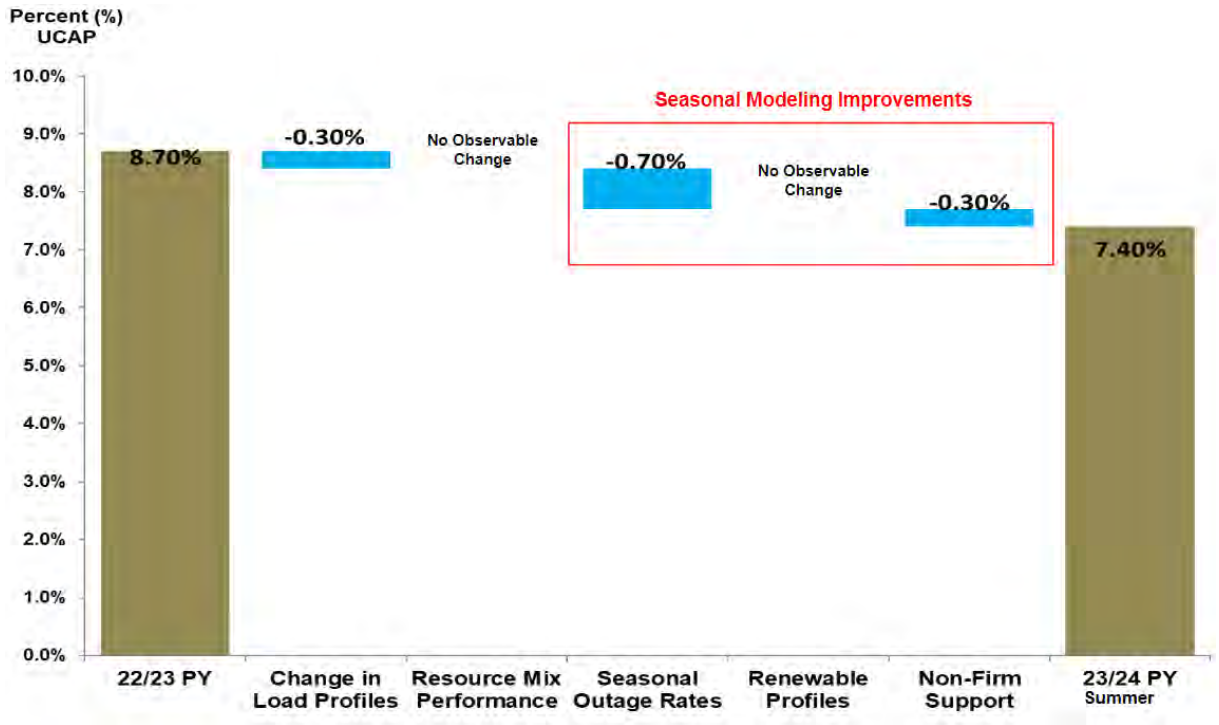


Figure A-1: Waterfall Chart of PY 2022-2023 Annual PRM UCAP to PY 2023-2024 Summer PRM UCAP

6.1 A.1 Waterfall Chart Details

6.1.1 A.1.1 Load

The MISO Coincident Peak Demand increased from the 2021-2022 planning year, which was driven by the updated actual load forecasts submitted by the LSEs. Overall, the magnitude of changes in the load profiles and economic uncertainty resulted in a slight decrease in the PRM.

6.1.2 A.1.2 Units

Changes from 2022-2023 planning year values are due to changes in Generation Verification Test Capacity (GVTC), seasonal EFORd or equivalent forced outage rate demand, new units, retirements, suspensions, and changes in the resource mix. The MISO fleet weighted average forced outage rate decreased from an annual 9.04 percent to a summer value of 8.23 percent from the previous study to this study. A general decrease in unit outage rates lead to a decrease in summer reserve margin. Non-firm support was included in the model which resulted in a slight decrease to the summer PRM.

7 Appendix B: Capacity Import Limit Tier 1 & 2 Source Subsystem Definitions

MISO Local Resource Zone 1

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
XEL / 600	ITCM / 627	WEC / 295
MP / 608	ALTE / 694	MIUP / 296
SMMPA / 613	WPS / 696	AMMO / 356
GRE / 615	MGE / 697	AMIL / 357
OTP / 620		MPW / 633
MDU / 661		MEC / 635
BEPC-MISO / 663		
DPC / 680		

MISO Local Resource Zone 2

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
WEC / 295	METC / 218	NIPS / 217
MIUP / 296	XEL / 600	ITCT / 219
ALTE / 694	MP / 608	SMMPA / 613
WPS / 696	DPC / 680	GRE / 615
MGE / 697		OTP / 620
UPPC / 698		ITCM / 627

MISO Local Resource Zone 3

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #	
ITCM / 627	AMMO / 356	DEI / 208	GRE / 615
MPW / 633	AMIL / 357	NIPS / 217	OTP / 620
MEC / 635	XEL / 600	CWLP / 360	ALTE / 694
	SMMPA / 613	SIPC/ 361	WPS / 696
	DPC / 680	GLHB / 362	MGE / 697
		MP / 608	

MISO Local Resource Zone 4

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #	
ITCM / 627	AMMO / 356	DEI / 208	GRE / 615
MPW / 633	AMIL / 357	NIPS / 217	OTP / 620
MEC / 635	XEL / 600	CWLP / 360	ALTE / 694
	SMMPA / 613	SIPC/ 361	WPS / 696
	DPC / 680	GLHB / 362	MGE / 697
		MP / 608	

MISO Local Resource Zone 5

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #	
CWLD / 333	AMIL / 357	DEI / 208	XEL / 600
AMMO / 356	GLHB / 362	NIPS / 217	SMMPA / 613
	ITCM / 627	CWLP / 360	MPW / 633
	MEC / 635	SIPC / 361	DPC / 680

MISO Local Resource Zone 6

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
HE / 207	METC / 218	ITCT / 219
DEI / 208	AMIL / 357	MIUP / 296
SIGE / 210	SIPC / 361	AMMO / 356
IPL / 216		CWLP / 360
NIPS / 217		GLHB / 362
BREC / 314		ITCM / 627
HMPL / 315		MEC / 635

MISO Local Resource Zone 7

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
HE / 207	METC / 218	ITCT / 219
DEI / 208	AMIL / 357	MIUP / 296
SIGE / 210	SIPC / 361	AMMO / 356
IPL / 216		CWLP / 360
NIPS / 217		GLHB / 362
BREC / 314		ITCM / 627
HMPL / 315		MEC / 635

MISO Local Resource Zone 8

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
HE / 207	METC / 218	ITCT / 219
DEI / 208	AMIL / 357	MIUP / 296
SIGE / 210	SIPC / 361	AMMO / 356
IPL / 216		CWLP / 360
NIPS / 217		GLHB / 362
BREC / 314		ITCM / 627
HMPL / 315		MEC / 635

MISO Local Resource Zone 9

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
LAGN / 332	EES-EMI / 326	Cooperative Energy / 349
EES / 351	EES-EAI / 327	
CLEC / 502		
LAFA / 503		
LEPA / 504		

MISO Local Resource Zone 10

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
EES-EMI / 326	EES-EAI / 327	LAGN / 332
Cooperative Energy / 349	EES / 351	CLEC / 502
		LAFA / 503

8 Appendix C: Compliance Conformance Table

Requirements under: Standard BAL-502-RF-03	Response
R1 The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall:	The Planning Year 2023-2024 LOLE Study Report is the annual Resource Adequacy Analysis for the peak season of June 2023 through May 2024 and beyond. Analysis of Planning Year 2023-2024 is in Sections 4.1 and 5.1. Analysis of Future Years 2024-2033 is in Section 10.
R1.1 Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year[1] analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 year" criterion).	Section 3.5 of this report outlines the utilization of LOLE in the reserve margin determination. "These metrics were determined by a probabilistic LOLE analysis such that the LOLE for the planning year was one day in 10 years, or 0.1 day per year."
R1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability.	Section 3.3 of this report. "Direct Control Load Management and Interruptible Demand types of demand response were explicitly included in the LOLE model as resources. These demand resources are implemented in the LOLE simulation before accumulating LOLE or shedding of firm load."
R1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median forecast peak Net Internal Demand (planning reserve margin).	Section 4.1 of this report. "…the ratio of MISO capacity to forecasted MISO system peak demand yielded a planning ICAP reserve margin…"
R1.2 Be performed or verified separately for each of the following planning years.	Covered in the segmented R1.2 responses below.
R1.2.1 Perform an analysis for Year One.	In Sections 4.1 and 5.1, a full analysis was performed for Planning Year 2023-2024.
R1.2.2 Perform an analysis or verification at a minimum for one year in the 2 through 5 year period and at a minimum one year in the 6 though 10 year period.	Sections 4.3 and 5.1 show a full analysis was performed for future planning years 2025 and 2027.
R1.2.2.1 If the analysis is verified, the verification must be supported by current or past studies for the same planning year.	Analysis was performed.
R1.3 Include the following subject matter and documentation of its use:	Covered in the segmented R1.3 responses below.

R1.3.1 Load forecast characteristics: • Median (50:50) forecast peak load • Load forecast uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts). • Load diversity. • Seasonal Load variations. • Daily demand modeling assumptions (firm, interruptible). • Contractual arrangements concerning curtailable/Interruptible Demand.	Median forecasted load – In Section 3.3 of this report: "The average monthly loads of the predicted load shapes were adjusted to match each LRZ's Module E 50/50 monthly zonal peak load forecasts for each study year." Load Forecast Uncertainty – A detailed explanation of the weather and economic uncertainties are given in Sections 3.3 and 3.3.2. Load Diversity/Seasonal Load Variations — In Section 3.3 of this report: "The Planning Year 2023-2024 LOLE analysis used a load training process with neural net software to create a neural-net relationship between historical weather and load data. This relationship was then applied to 30 years of hourly historical weather data to create 30 different load shapes for each LRZ in order to capture both load diversity and seasonal variations." Demand Modeling Assumptions/Curtailable and Interruptible Demand — All Load Modifying Resources must first meet registration requirements through Module E. As stated in Section 3.2.6: "Each demand response program was modeled individually with a monthly capacity and was limited to the number of times each program can be called upon as well as limited by duration."
R1.3.2 Resource characteristics: • Historic resource performance and any projected changes • Seasonal resource ratings • Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area. • Resource planned outage schedules, deratings, and retirements. • Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration. • Criteria for including planned resource additions in the analysis.	Section 3.2 details how historic performance data and seasonal ratings are gathered, and includes discussion of future units and the modeling assumptions for intermittent capacity resources. A more detailed explanation of firm capacity purchases and sales is in Section 3.4.
R1.3.3 Transmission limitations that prevent the delivery of generation reserves	Annual MTEP deliverability analysis identifies transmission limitations preventing delivery of generation reserves. Additionally, Section 2 of this report details the transfer analysis to capture transmission constraints limiting capacity transfers.
R1.3.3.1 Criteria for including planned Transmission Facility additions in the analysis	Inclusion of the planned transmission addition assumptions is detailed in Section 2.2.3.

R1.3.4 Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area.	Section 3.4 provides the analysis on the treatment of external support assistance and limitations.
R1.4 Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included: • Availability and deliverability of fuel. • Common mode outages that affect resource availability. • Environmental or regulatory restrictions of resource availability. • Any other demand (Load) response programs not included in R1.3.1. • Sensitivity to resource outage rates. • Impacts of extreme weather/drought conditions that affect unit availability. • Modeling assumptions for emergency operation procedures used to make reserves available. • Market resources not committed to serving Load (uncommitted resources) within the Planning Coordinator area.	Fuel availability, environmental restrictions, common mode outage and extreme weather conditions are all part of the historical availability performance data that goes into the unit's EFORd statistic. The use of the EFORd values is covered in Section 3.2.1. The use of demand response programs is mentioned in Section 3.2.6. The effects of resource outage characteristics on the reserve margin are outlined in Section 3.7.1 by examining the difference between PRM ICAP and PRM UCAP values.
R1.5 Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included	Transmission maintenance schedules were not included in the analysis of the transmission system due to the limited availability of reliable long-term maintenance schedules and minimal impact to the results of the analysis. However, Section 2 treats worst-case theoretical outages by Perform First Contingency Total Transfer Capability (FCTTC) analysis for each LRZ, by modeling NERC Category P0 (system intact) and Category P1 (N-1) contingencies.
R1.6 Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis	MISO internal resources are among the quantities documented in the tables provided in Sections 4 and 5.
R1.7 Document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis	MISO load is among the quantities documented in the tables provided in Sections 4 and 5.
R2 The Planning Coordinator shall annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis.	In Sections 4 and 5, the peak load and estimated amount of resources for Planning Years 2023-2024, 2026-2027, and 2028-2029 are shown. This includes the detail for each transmission constrained sub-area.

R2.1 This documentation shall cover each of the years in year one through ten.	Section 10.3 and Tables 10-3, 10-4, 10-5, and 10-6 show the three calculated study years, in-between years estimated by interpolation, and future outyears estimated by extrapolation. Estimated transmission limitations may be determined through a review of the PY 2023-2024 LOLE study transfer analysis shown in Section 2 of this report, along with the results from previous LOLE studies.
R2.2 This documentation shall include the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis.	Covered in Sections 10.1 and 10.2.
R2.3 The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One.	The 2023-2024 LOLE Study Report documentation is posted on November 1 prior to the planning year.
R3 The Planning Coordinator shall identify any gaps between the needed amount of planning reserves defined in Requirement R1, Part 1.1 and the projected planning reserves documented in Requirement R2.	In Sections 4 and 5, the difference between the needed amount and the projected planning reserves for Planning Years 2023-2024, 2026-2027, and 2028-2029 are shown in the adjustments to ICAP and UCAP in Table 4-1, Table 10-1, and Table 10-2.

9 Appendix D: Acronyms List Table

CEL	Capacity Export Limit
CIL	Capacity Import Limit
CPNode	Commercial Pricing Node
DF	Distribution Factor
EFORd	Equivalent Forced Outage Rate demand
ELCC	Effective Load Carrying Capability
ERZ	External Resource Zone
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
FCITC	First Contingency Incremental Transfer Capability
FCTTC	First Contingency Total Transfer Capability
GADS	Generator Availability Data System
GLT	Generation Limited Transfer
GVTC	Generation Verification Test Capacity
ICAP	Installed Capacity
LBA	Local Balancing Authority
LCR	Local Clearing Requirement
LFE	Load Forecast Error
LFU	Load Forecast Uncertainty
LOLE	Loss of Load Expectation
LOLEWG	Loss of Load Expectation Working Group
LRR	Local Reliability Requirement
LRZ	Local Resource Zones
LSE	Load Serving Entity
MARS	Multi-Area Reliability Simulation
MECT	Module E Capacity Tracking
MISO	Midcontinent Independent System Operator
MOD	Model on Demand
MTEP	MISO Transmission Expansion Plan
MW	Megawatt
MWh	Megawatt hours
NERC	North American Electric Reliability Corp.

PRA	Planning Resource Auction
PRM	Planning Reserve Margin
PRM ICAP	PRM Installed Capacity
PRM UCAP	PRM Unforced Capacity
PRMR	Planning Reserve Margin Requirement
PSS E	Power System Simulator for Engineering
RCF	Reciprocal Coordinating Flowgate
RDS	Redispatch
RPM	Reliability Pricing Model
SERVM	Strategic Energy & Risk Valuation Model
SPS	Special Protection Scheme
TARA	Transmission Adequacy and Reliability Assessment
UCAP	Unforced Capacity
XEFORd	Equivalent forced outage rate demand with adjustment to exclude events outside management control
ZIA	Zonal Import Ability
ZEA	Zonal Export Ability

10 Appendix E: Outyear PRM and LRR Results

Beyond the prompt Planning Year 2023-2024, LOLE analyses were performed for the four-year-out Planning Year of 2026-2027, and the six-year-out Planning Year of 2028-2029. Tables 10-1 and 10-2 show the capacity and demand values that went into the MISO system seasonal Planning Reserve Margin for outyears four and six, respectively. Tables 10-3, 10-4, 10-5, and 10-6 show the seasonal outyear PRM projections ten years out based on future capacity and demand assumptions. Tables 10-7, 10-8, 10-9, and 10-10 show the MISO zonal seasonal Local Reliability Requirements for outyear four while Tables 10-11, 10-12, 10-13, and 10-14 show the Local Reliability Requirements for outyear six.

10.1 Planning Year 2026-2027 MISO Planning Reserve Margin Results

For Planning Year 2026-2027, the ratio of MISO capacity to forecasted MISO system peak demand yielded a planning ICAP reserve margin of 17.9 percent and a planning UCAP reserve margin of 8.8 percent for the summer season. Numerous values and calculations went into determining the four-year-out MISO system seasonal PRM ICAP and PRM UCAP (Table 10-1).

MISO Planning Reserve Margin (PRM)	**2026/2027 PY** Summer	**2026/2027 PY** Fall	**2026/2027 PY** Winter	**2026/2027 PY** Spring	**Formula Key**
MISO System Peak Demand (MW)	125,138	111,950	104,946	99,950	[A]
Installed Capacity (ICAP) (MW)	155,038	152,619	155,210	149,975	[B]
Unforced Capacity (UCAP) (MW)	144,623	139,494	138,423	133,904	[C]
Firm External Support (ICAP) (MW)	1,731	1,734	1,874	1,803	[D]
Firm External Support (UCAP) (MW)	1,707	1,714	1,857	1,778	[E]
Adjustment to ICAP {1d in 10yr} (MW)	-9,200	-11,000	-9,200	-11,850	[F]
Adjustment to UCAP {1d in 10yr} (MW)	-9,200	-11,000	-9,200	-11,850	[G]
ICAP PRM Requirement (PRMR) (MW)	147,569	143,353	147,884	139,928	[H]=[B]+[D]+[F]
UCAP PRM Requirement (PRMR) (MW)	136,130	130,208	131,080	123,832	[I]=[C]+[E]+[G]
MISO PRM ICAP	**17.9%**	**28.1%**	**40.9%**	**40.0%**	[J]=([H]-[A])/[A]
MISO PRM UCAP	**8.8%**	**16.3%**	**24.9%**	**23.9%**	[K]=([I]-[A])/[A]

Table 10-1: Planning Year 2026-2027 MISO System Planning Reserve Margins

10.2 Planning Year 2028-2029 MISO Planning Reserve Margin Results

For Planning Year 2028-2029, the ratio of MISO capacity to forecasted MISO system peak demand yielded a planning ICAP reserve margin of 18.4 percent and a planning UCAP reserve margin of 9.2 percent for the summer season. Numerous values and calculations went into determining the six-year-out MISO system seasonal PRM ICAP and PRM UCAP (Table 10-2).

MISO Planning Reserve Margin (PRM)	**2028/2029 PY** Summer	**2028/2029 PY** Fall	**2028/2029 PY** Winter	**2028/2028 PY** Spring	**Formula Key**
MISO System Peak Demand (MW)	125,794	112,548	105,525	100,486	[A]
Installed Capacity (ICAP) (MW)	157,656	155,189	157,826	152,532	[B]
Unforced Capacity (UCAP) (MW)	146,097	141,837	140,816	136,237	[C]
Firm External Support (ICAP) (MW)	1,731	1,734	1,874	1,803	[D]
Firm External Support (UCAP) (MW)	1,707	1,714	1,857	1,778	[E]
Adjustment to ICAP {1d in 10yr} (MW)	-10,400	-14,360	-10,400	-13,165	[F]
Adjustment to UCAP {1d in 10yr} (MW)	-10,400	-14,360	-10,400	-13,165	[G]
ICAP PRM Requirement (PRMR) (MW)	148,987	142,563	149,300	141,170	[H]=[B]+[D]+[F]
UCAP PRM Requirement (PRMR) (MW)	137,404	129,191	132,272	124,850	[I]=[C]+[E]+[G]
MISO PRM ICAP	**18.4%**	**26.7%**	**41.5%**	**40.5%**	[J]=([H]-[A])/[A]
MISO PRM UCAP	**9.2%**	**14.8%**	**25.3%**	**24.2%**	[K]=([I]-[A])/[A]

Table 10-2: Planning Year 2028-2029 MISO System Planning Reserve Margins

10.3 MISO Planning Reserve Margin Outyear Projections

Tables 10-3, 10-4, 10-5, and 10-6 show the outyear seasonal PRM projections. Years one, four, and six were probabilistically modeled. PRM projections in years two, three, and five are the result of interpolation of the years studied and years seven through ten are the resulting extrapolations of the outyear analyses.

Metric	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
PRM ICAP	15.9%	16.6%	17.2%	17.9%	18.2%	18.4%	19.6%	20.1%	20.7%	21.2%
PRM UCAP	7.4%	7.9%	8.3%	8.8%	9.0%	9.2%	10.1%	10.4%	10.8%	11.2%
Demand (GW)	123.7	124.3	124.9	125.5	125.7	125.8	126.9	127.3	127.8	128.2
ICAP (GW)	144.3	150.5	153.0	155.0	155.0	157.7	157.7	157.7	157.7	157.7

Table 10-3: MISO Summer Planning Reserve Margin Outyear Projections

Metric	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
PRM ICAP	25.8%	26.6%	27.3%	28.1%	27.4%	26.7%	27.8%	28.1%	28.3%	28.5%
PRM UCAP	14.9%	15.4%	15.8%	16.3%	15.6%	14.8%	15.4%	15.4%	15.5%	15.5%
Demand (GW)	111.0	111.3	111.7	112.0	112.3	112.5	113.1	113.4	113.8	114.1
ICAP (GW)	144.3	148.8	150.3	152.6	152.6	155.2	155.2	155.2	155.2	155.2

Table 10-4: MISO Fall Planning Reserve Margin Outyear Projections

Metric	23-24	24-25	25-26	26-27	27-28	28-29	29-30	30-31	31-32	32-33
PRM ICAP	41.2%	41.1%	41.0%	40.9%	41.2%	41.5%	41.4%	41.5%	41.5%	41.5%
PRM UCAP	25.5%	25.3%	25.1%	24.9%	25.1%	25.3%	25.0%	25.0%	24.9%	24.8%
Demand (GW)	103.5	104.0	104.4	104.9	105.2	105.5	106.4	106.8	107.2	107.6
ICAP (GW)	150.7	154.0	154.7	155.2	155.2	157.8	157.8	157.8	157.8	157.8

Table 10-5: MISO Winter Planning Reserve Margin Outyear Projections

Metric	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
PRM ICAP	39.3%	39.5%	39.8%	40.0%	40.3%	40.5%	41.0%	41.2%	41.4%	41.7%
PRM UCAP	24.5%	24.3%	24.1%	23.9%	24.1%	24.2%	23.9%	23.8%	23.8%	23.7%
Demand (GW)	99.1	99.4	99.7	100.0	100.3	100.5	101.1	101.4	101.7	101.9
ICAP (GW)	145.4	148.9	149.9	150.0	150.0	152.5	152.5	152.5	152.5	152.5

Table 10-6: MISO Spring Planning Reserve Margin Outyear Projections

10.4 Planning Year 2026-2027 MISO Local Reliability Requirement Results

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2026-2027 Local Reliability Requirements – Summer 2026											
Installed Capacity (ICAP) (MW)	22,350	15,251	12,350	9,629	9,494	19,595	21,761	12,368	25,425	6,814	[A]
Unforced Capacity (UCAP) (MW)	21,349	14,232	11,903	8,881	8,690	17,946	20,388	11,944	22,182	6,108	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-317	48	2,369	3,060	2,235	3,935	4,012	278	2,230	1,113	[C]
LRR (UCAP) (MW)	21,032	14,280	14,272	11,942	10,925	21,881	24,400	12,222	24,412	7,221	[D]=[B]+[C]
Peak Demand (MW)	18,622	13,121	9,976	9,384	8,121	18,517	21,003	7,880	22,036	4,802	[E]
LRR UCAP per-unit of LRZ Peak Demand	**112.9%**	**108.8%**	**143.1%**	**127.3%**	**134.5%**	**118.2%**	**116.2%**	**155.1%**	**110.8%**	**150.4%**	[F]=[D]/[E]

Table 10-7: Planning Year 2026-2027 LRZ Local Reliability Requirements for Summer 2026

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2026-2027 Local Reliability Requirements – Fall 2026											
Installed Capacity (ICAP) (MW)	22,303	14,924	12,708	9,267	9,296	19,057	21,756	11,773	24,952	6,584	[A]
Unforced Capacity (UCAP) (MW)	20,862	13,680	12,104	8,306	8,124	17,356	20,120	10,815	22,406	5,721	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-1,150	-608	1,303	2,861	2,032	3,138	3,906	-296	2,172	1,083	[C]
LRR (UCAP) (MW)	19,712	13,072	13,407	11,167	10,156	20,495	24,026	10,519	24,577	6,805	[D]=[B]+[C]
Peak Demand (MW)	18,622	13,121	9,976	9,384	8,121	18,517	21,003	7,880	22,036	4,802	[E]
LRR UCAP per-unit of LRZ Peak Demand	**105.9%**	**99.6%**	**134.4%**	**119.0%**	**125.1%**	**110.7%**	**114.4%**	**133.5%**	**111.5%**	**141.7%**	[F]=[D]/[E]

Table 10-8: Planning Year 2026-2027 LRZ Local Reliability Requirements for Fall 2026

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2026-2027 Local Reliability Requirements – Winter 2026-2027											
Installed Capacity (ICAP) (MW)	22,576	15,148	14,708	9,272	9,380	19,027	21,721	11,471	25,252	6,654	[A]
Unforced Capacity (UCAP) (MW)	21,048	13,357	13,748	7,369	7,698	17,193	20,149	10,074	22,044	5,742	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-317	45	2,231	2,882	2,105	3,706	1,915	262	2,100	1,048	[C]
LRR (UCAP) (MW)	20,731	13,402	15,980	10,251	9,803	20,899	22,064	10,336	24,145	6,790	[D]=[B]+[C]
Peak Demand (MW)	18,622	13,121	9,976	9,384	8,121	18,517	21,003	7,880	22,036	4,802	[E]
LRR UCAP per-unit of LRZ Peak Demand	**111.3%**	**102.1%**	**160.2%**	**109.2%**	**120.7%**	**112.9%**	**105.0%**	**131.2%**	**109.6%**	**141.4%**	[F]=[D]/[E]

Table 10-9: Planning Year 2026-2027 LRZ Local Reliability Requirements for Winter 2026-2027

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2026-2027 Local Reliability Requirements – Spring 2027											
Installed Capacity (ICAP) (MW)	21,384	14,796	12,729	9,040	9,196	18,876	21,235	11,457	24,783	6,480	[A]
Unforced Capacity (UCAP) (MW)	19,924	13,355	11,985	7,528	7,922	16,950	18,781	9,929	21,622	5,908	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-1,085	-700	1,023	2,827	1,980	2,719	2,722	53	1,994	647	[C]
LRR (UCAP) (MW)	18,839	12,655	13,008	10,356	9,902	19,669	21,503	9,982	23,616	6,556	[D]=[B]+[C]
Peak Demand (MW)	18,622	13,121	9,976	9,384	8,121	18,517	21,003	7,880	22,036	4,802	[E]
LRR UCAP per-unit of LRZ Peak Demand	**101.2%**	**96.5%**	**130.4%**	**110.4%**	**121.9%**	**106.2%**	**102.4%**	**126.7%**	**107.2%**	**136.5%**	[F]=[D]/[E]

Table 10-10: Planning Year 2026-2027 LRZ Local Reliability Requirements for Spring 2027

10.5 Planning Year 2028-2029 MISO Local Reliability Requirement Results

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2028-2029 Local Reliability Requirements – Summer 2028											
Installed Capacity (ICAP) (MW)	22,350	16,418	12,350	9,629	9,494	19,595	23,212	12,368	25,425	6,814	[A]
Unforced Capacity (UCAP) (MW)	21,349	15,324	11,903	8,881	8,690	17,946	21,769	11,944	22,182	6,108	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-232	-463	1,981	3,089	2,294	4,020	2,628	39	2,283	1,132	[C]
LRR (UCAP) (MW)	21,117	14,861	13,884	11,970	10,983	21,967	24,398	11,983	24,465	7,240	[D]=[B]+[C]
Peak Demand (MW)	18,177	13,132	10,172	9,485	8,001	18,099	20,705	7,725	21,417	4,716	[E]
LRR UCAP per-unit of LRZ Peak Demand	**116.2%**	**113.2%**	**136.5%**	**126.2%**	**137.3%**	**121.4%**	**117.8%**	**155.1%**	**114.2%**	**153.5%**	[F]=[D]/[E]

Table 10-11: Planning Year 2028-2029 LRZ Local Reliability Requirements for Summer 2028

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2028-2029 Local Reliability Requirements – Fall 2028											
Installed Capacity (ICAP) (MW)	22,303	16,090	12,708	9,267	9,296	19,057	23,160	11,773	24,952	6,584	[A]
Unforced Capacity (UCAP) (MW)	20,862	14,727	12,104	8,306	8,124	17,356	21,415	10,815	22,406	5,721	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-1,035	-1,100	1,275	2,903	2,078	3,260	2,559	-281	2,223	1,102	[C]
LRR (UCAP) (MW)	19,827	13,627	13,379	11,209	10,202	20,616	23,975	10,534	24,629	6,823	[D]=[B]+[C]
Peak Demand (MW)	18,177	13,132	10,172	9,485	8,001	18,099	20,705	7,725	21,417	4,716	[E]
LRR UCAP per-unit of LRZ Peak Demand	**109.1%**	**103.8%**	**131.5%**	**118.2%**	**127.5%**	**113.9%**	**115.8%**	**136.4%**	**115.0%**	**144.7%**	[F]=[D]/[E]

Table 10-12: Planning Year 2028-2029 LRZ Local Reliability Requirements for Fall 2028

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2028-2029 Local Reliability Requirements – Winter 2028-2029											
Installed Capacity (ICAP) (MW)	22,576	16,326	14,708	9,272	9,380	19,027	23,159	11,471	25,252	6,654	[A]
Unforced Capacity (UCAP) (MW)	21,048	14,468	13,748	7,369	7,698	17,193	21,430	10,074	22,044	5,742	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-232	-463	1,866	2,909	2,160	3,786	1,301	289	2,150	1,066	[C]
LRR (UCAP) (MW)	20,816	14,005	15,614	10,278	9,858	20,980	22,731	10,363	24,194	6,808	[D]=[B]+[C]
Peak Demand (MW)	18,177	13,132	10,172	9,485	8,001	18,099	20,705	7,725	21,417	4,716	[E]
LRR UCAP per-unit of LRZ Peak Demand	**114.5%**	**106.6%**	**153.5%**	**108.4%**	**123.2%**	**115.9%**	**109.8%**	**134.2%**	**113.0%**	**144.4%**	[F]=[D]/[E]

Table 10-13: Planning Year 2028-2029 LRZ Local Reliability Requirements for Winter 2028-2029

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2028-2029 Local Reliability Requirements – Spring 2029											
Installed Capacity (ICAP) (MW)	21,384	15,965	12,729	9,040	9,196	18,876	22,622	11,457	24,783	6,480	[A]
Unforced Capacity (UCAP) (MW)	19,924	14,365	11,985	7,528	7,922	16,950	20,104	9,929	21,622	5,908	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-1,030	-1,072	1,471	2,932	1,995	2,970	1,774	50	2,266	652	[C]
LRR (UCAP) (MW)	18,894	13,293	13,456	10,460	9,917	19,920	21,878	9,979	23,887	6,560	[D]=[B]+[C]
Peak Demand (MW)	18,177	13,132	10,172	9,485	8,001	18,099	20,705	7,725	21,417	4,716	[E]
LRR UCAP per-unit of LRZ Peak Demand	**103.9%**	**101.2%**	**132.3%**	**110.3%**	**123.9%**	**110.1%**	**105.7%**	**129.2%**	**111.5%**	**139.1%**	[F]=[D]/[E]

Table 10-14: Planning Year 2028-2029 LRZ Local Reliability Requirements for Spring 2029

11 Appendix F: Outyear CIL/CEL Results

MISO will not be conducting the outyear CIL/CEL study as part of the PY 2023-2024 LOLE study report. This has been communicated to stakeholders at the February 2023 RASC: https://cdn.misoenergy.org/20230228-0301%20RASC%20Item%2004d%20Out-Year%202027-28%20CIL-CEL%20Study%20Update627986.pdf

The usefulness and value created by the outyear CIL/CEL study is being evaluated by MISO. Any updates or changes to the outyear CIL/CEL study going forward will be communicated through the RASC and/or LOLEWG.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-26-16

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 81

Joundi Testimony

Tab E

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Midcontinent Independent System Operator, Inc.	**)**	**Docket No. ER24-___-000**

PREPARED DIRECT TESTIMONY OF ZAKARIA JOUNDI EXECUTIVE DIRECTOR, MARKET & GRID STRATEGY

I. PROFESSIONAL BACKGROUND AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION WITH THE MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC.

A. My name is Zakaria (Zak) Joundi. I am the Executive Director, Market & Grid Strategy for the Midcontinent Independent System Operator, Inc. (MISO). My business address is 720 City Center Drive, Carmel, Indiana 46032.

Q. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL BACKGROUND.

A. I hold a Bachelor of Science degree in electrical engineering, with an emphasis in power systems, from Iowa State University and a Master of Business Administration degree, with an emphasis in finance, from the Indiana University Kelley School of Business. I joined MISO in 2006 and have held multiple positions of increasing responsibilities that span across generation and transmission planning, market administration, seams administration, data and analytics, and resource adequacy (RA). I have also supported numerous MISO initiatives and filings with the Federal Energy Regulatory Commission (Commission), including financial transmission rights (FTR), seams, and RA matters.

Q. PLEASE DESCRIBE YOUR CURRENT ROLE AND JOB RESPONSIBILITIES.

A. In my current role as Executive Director, Market & Grid Strategy, I oversee the team responsible for the design of the MISO markets and the assessment of its performance. One of my primary responsibilities has been serving as the MISO liaison to the Resource Adequacy Subcommittee (RASC), which is the stakeholder led group at MISO focused on RA matters.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to support the resource accreditation reform proposed in this filing.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony begins with a brief discussion of MISO's current approach to resource adequacy, including the challenges with the current accreditation approach and the problem statement MISO developed with stakeholders to address those challenges. Next, I discuss MISO's proposed resource accreditation method and describe the design details associated with that approach. I then discuss MISO's approach to loss of load expectation (LOLE) modeling. From there, I describe the evaluation criteria MISO used to analyze the various options for proposed resource accreditation reforms. Finally, I discuss MISO's implementation timeline, stakeholder engagement, and other key considerations.

Q. PLEASE PROVIDE AN OVERVIEW OF MISO'S PROPOSED RESOURCE ACCREDITATION METHODOLOGY.

A. MISO's proposed resource accreditation methodology is a two-step approach that first measures a resource's expected marginal contribution to reliability using class-level performance (probabilistic approach) and then uses historical resource-level performance (deterministic approach) to accredit individual resources within the class of comparable

resources (Resource Class).[1] The proposed accreditation methodology accounts for a range of reliability risks in the planning and operations horizons by incorporating forward-looking probabilistic analysis and measuring a resource's performance during recent periods of high system risk. Under the proposal, MISO defines the periods of highest system risk identified in the probabilistic analysis as "Critical Hours". Critical Hours include all loss of load hours and, as needed, low margin hours,[2] as further described below. MISO's proposed approach to measure the availability of resources during Critical Hours in its probabilistic analysis is within the marginal Effective Load Carrying Capacity (ELCC) accreditation framework that is used by other market administrators (e.g., PJM Interconnection, L.L.C. (PJM) and New York Independent System Operator, Inc. (NYISO)).[3] MISO refers to its approach as the Direct Loss of Load (DLOL)-based methodology and proposes to use it as the single uniform method for accrediting all Capacity Resources, except External Resources (hereinafter referred to as "Schedule 53A Resources"), that currently participate in its Planning Resource Auction (PRA). In the simplest terms, the proposed two-step approach can be described as first determining the size of a pie (accreditation for an entire resource class) and then second, allocating or divvying up the pie (individual resource level accreditation) as shown in Figure 1 below.

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[1] The term "Resource Class" as used in Schedule 53A and this testimony means a group of Capacity Resources, except External Resources, with similar operating characteristics whose Resource Class-level UCAP has been determined based on the LOLE analysis and is further described in Schedule 53A.

[2] Low margin hours are comprised of those hours where available generation in excess of load is less than or equal to 3% of load in that hour (*i.e.*, low margin) up to a cap of 1,950 hours in each Season.

[3] *See PJM Interconnection, L.L.C.*, 186 FERC ¶ 61,080 (2024). *See* also *New York Indep. System Operator, Inc*., 179 FERC ¶ 61,102 (May 10, 2022).

The proposed reform is consistent with MISO's Market Design Guiding Principles. It aligns operational needs with non-discriminatory market and planning requirements, and results in transparent market prices that reflect marginal contributions to reliability during highest risk hours.

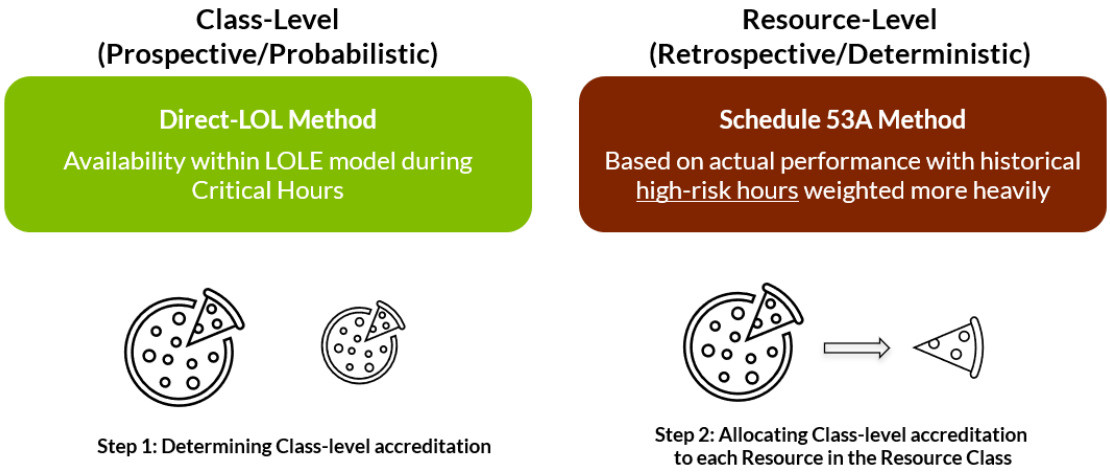


Figure 1: MISO's proposed accreditation methodology

III. OVERVIEW OF MISO'S APPROACH TO RESOURCE ADEQUACY

Q. WHAT IS RESOURCE ADEQUACY?

A. Resource adequacy refers to the ability of the bulk electric system to serve electricity demand while also providing enough excess supply to achieve a threshold level of grid reliability. One such measure of reliability is the industry-accepted Loss-of-Load Expectation (LOLE) target of one day of loss of load every ten years. Following the Commission's acceptance of MISO's Seasonal Resource Adequacy Construct and Seasonal Accredited Capacity filing in August 2022,[4] and commencing with MISO's

[4] *See Midcontinent Independent System Operator, Inc.*, 180 FERC ¶61,141 (2022).

Planning Year 2023/2024 PRA, MISO now makes such LOLE determinations on a seasonal basis, for each PRA.

Q. WHICH ENTITIES ARE RESPONSIBLE FOR ACHIEVING RESOURCE ADEQUACY IN THE MISO FOOTPRINT?

A. In the MISO footprint, the primary responsibility for achieving resource adequacy rests with Load Serving Entities (LSE) with oversight by Relevant Electric Retail Rate Authorities (RERRA), as applicable by jurisdiction. MISO facilitates these efforts by administering its Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff)-defined Resource Adequacy Requirements (RAR) and the PRA, which LSEs use to demonstrate their ability to serve seasonal peak demand and provide a sufficient margin of excess supply.

Q. BRIEFLY DESCRIBE THE RESOURCE ADEQUACY CHALLENGES THAT ACCOMPANY THE ONGOING TRANSFORMATION OF THE ELECTRICITY SECTOR.

A. Historically, periods of risk have been driven primarily by periods of high demand. The composition of that demand would evolve over time, but the periods of highest load were generally relatively consistent and forecastable, historically based on the Summer peak. At the same time, generation availability was largely driven by uncorrelated unit outages, which were thus assumed to be independent. Because of this relative stability, grid reliability was achieved by ensuring enough generation capacity existed to reliably serve the peak load based on a single occurrence during the year (e.g., the Summer coincident peak). In addition, frequent, large-scale weather events on the Transmission System have presented challenges to maintaining resource adequacy in the recent past.

A number of factors now require the application of a new approach for determining resource accreditation in MISO, consistent with developments in other parts of the country, to ensure reliable grid operations are maintained going forward. The transformation of the grid is accelerating, resulting in increasing reliance on newer types of generation, such as weather-dependent, highly variable wind and solar resources and energy-limited storage resources. Moreover, projected electrification is expected to increase challenges in the MISO footprint. These drivers are decoupling periods of risk from periods of high demand, upending traditional methods to establish reliability requirements and ensure resource adequacy. Figure 2.a shows how the timing of expected unserved energy[5] (in blue) for the average summer day is expected to shift and move away from times of highest load (in grey), and better align with times of highest load net of wind and solar (in red). The same information and trend is observed for an average winter day, as shown in Figure 2.b. Further, the comparison of the two figures shows how the seasonal distribution of events is expected to shift from summer to winter over the next decade.[6]

[5] The proposed Tariff definition of Expected Unserved Energy as follows: "In the probabilistic study, an estimate of the energy that would otherwise have been used by end use customers but for a supply interruption." See *Midcontinent Independent System Operator, Inc.,* Docket No. ER23-2977-000.

[6] Additional information on this analysis can be found in MISO's 2023 Attributes Roadmap.

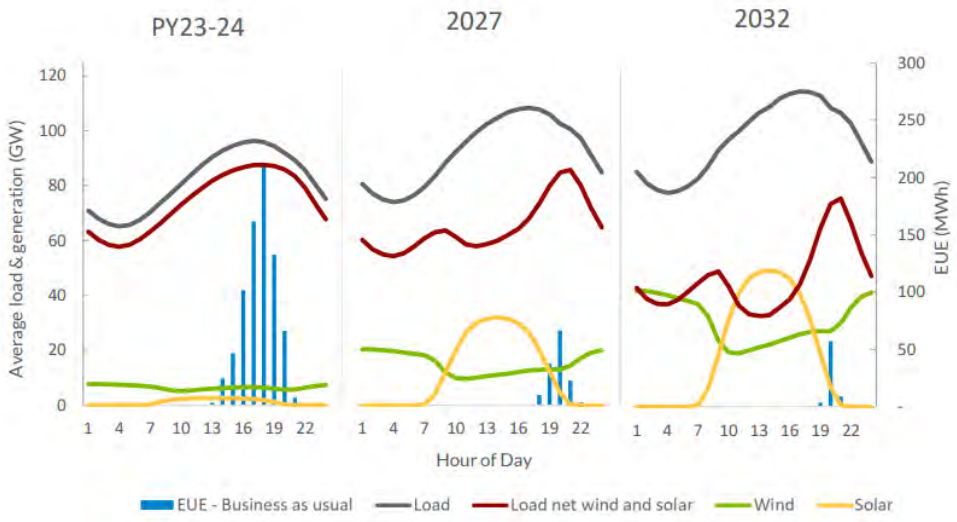


Figure 2.a. Estimated evolution of summer load, net load, wind and solar and expected unserved energy in the MISO footprint

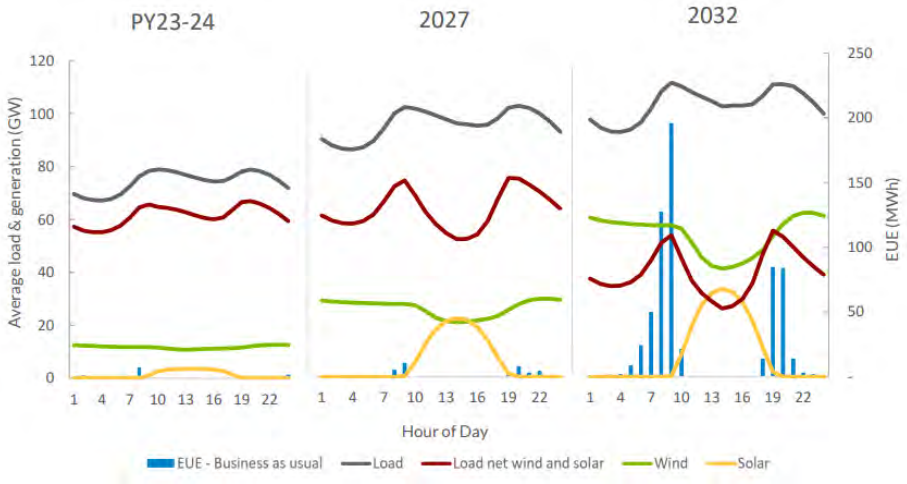


Figure 2.b. Estimated evolution of winter load, net load, wind and solar and expected unserved energy in the MISO footprint

Q. WHAT ROLE DOES ACCREDITATION PLAY IN MISO'S PRA?

A. MISO defines resource accreditation as the capacity value of a resource based on its contribution to system reliability during periods of highest risk. MISO accredits resources for three primary reasons: first, to ensure seasonal reserve requirements are met by

appropriately accounting for resource availability during periods of highest risk; second, to inform long-term investment and retirement decisions by accurately representing the capacity value of a resource in the prompt year; and finally, to appropriately compensate resources for operating practices and attributes that serve the greatest system need. If the accreditation methodology does not align risk, resource availability, and system needs, it results in inefficient market outcomes as well as improper market signals that may leave the system in danger of not having a reliable, cost-effective mix of resources.

Q. WHAT METHODS ARE COMMONLY USED FOR RESOURCE ACCREDITATION FOR THE PURPOSES OF RESOURCE ADEQUACY?

A. One effective way to classify accreditation methods is by separating them into deterministic and probabilistic methods.

Deterministic methods use estimates, generally based on historical performance, to determine resource accreditation. Examples of deterministic methods are seasonal performance, performance during peak load hours, performance during peak net load hours, or performance during historical risk periods.

Probabilistic methods rely on a probabilistic model to examine the loss-of-load probability in the system and how it relates to the performance of resources within that model. The most common probabilistic methods for accreditation include ELCC, equivalent firm capacity (EFC), and marginal reliability improvement (MRI).

The Energy Systems Integration Group (ESIG) provides a comprehensive review of accreditation methods used in the industry.[7] The methods relevant to this filing are further described in this testimony.

Q. HOW DOES MISO CURRENTLY ACCREDIT THE RESOURCES RELEVANT TO THIS FILING?

A. MISO currently uses multiple methods to accredit resources, based on the resource type. See Figure 3 below for an overview of current accreditation methodologies, which can be summarized as follows:

- Thermal resources are accredited pursuant to Schedule 53 of MISO's Tariff.
- Wind resources are accredited through a probabilistic modeling approach to calculate the average ELCC. The class level accredited value is then allocated to individual wind resources based on their actual performance during seasonal peak hours.
- Existing solar resources receive capacity credit based on their actual performance during seasonal peak hours. New solar resources receive a seasonal class average value of 50% for the Summer, Fall, and Spring Seasons, and 5% for Winter.
- Similarly, storage resources receive capacity credit based on their actual performance during seasonal peak hours and new storage resources receive a seasonal class average value of 95%.

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[7] ESIG "New Design Principles for Capacity Accreditation" https://www.esig.energy/new-design-principles-for-capacity-accreditation/

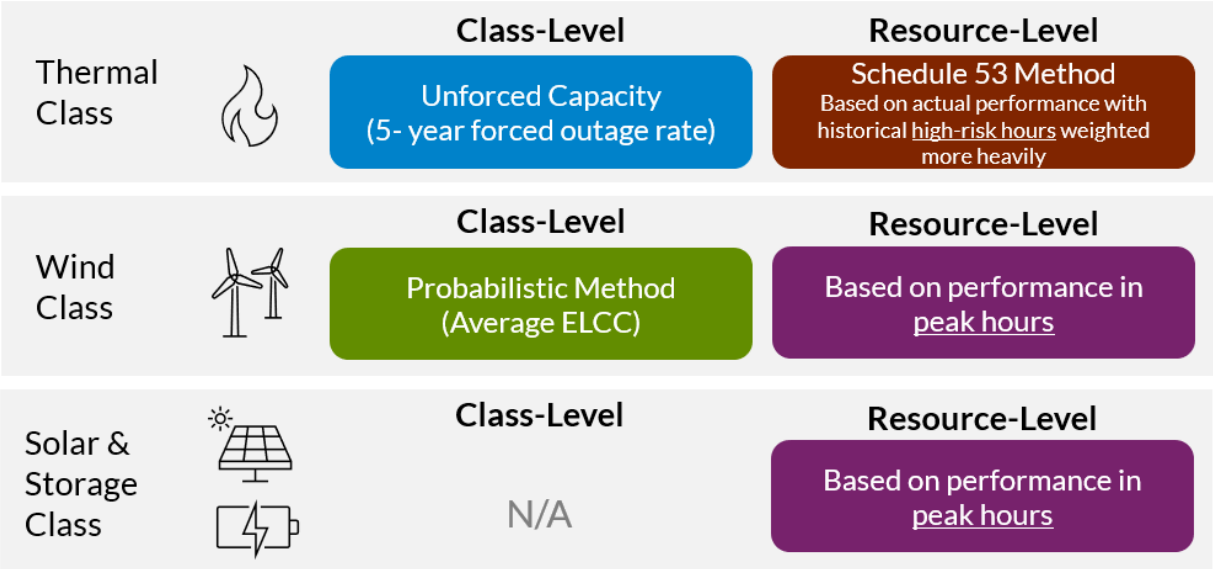


Figure 3: MISO's current accreditation methodology

Q. WHAT ARE THE KEY ISSUES WITH OR LIMITATIONS OF MISO'S CURRENT ACCREDITATION METHODOLOGIES?

A. MISO's current accreditation methodologies have been developed and implemented over time as the resource fleet and reliability needs evolved in the MISO footprint. The application of these different methodologies was appropriate relative to the reliability risks presented at the time of their development. However, and as previously stated, one of the biggest challenges for MISO's Resource Adequacy construct is that periods of highest reliability risk are shifting and are decoupling from times of highest demand. MISO's current accreditation approaches vary amongst resource types, but none of them focus on the marginal contribution of resources during expected periods of highest reliability risk in the probabilistic model. The current approaches thus may result in inaccurate, inconsistent, and potentially overstated accreditation values.

For instance, the Commission recently accepted changes to the accreditation of thermal resources as part of MISO's Seasonal Accreditation (SAC) filing, which established

Schedule 53 of the Tariff.[8] While Schedule 53 enhances the accreditation of thermal resources, it is based on performance across all hours in a Season during the past three years, which does not take into account the effects of possible future events that drive periods of higher risk (such as widespread winter storms). Moreover, by its terms, Schedule 53 is applicable only to thermal resources and Demand Response Resources. Solar and storage resources continue to be accredited based on performance during historic peak load hours, while the risk continues to shift outside of those timeframes. And wind resource accreditation is based on the average ELCC, which can overestimate the capacity value of resources. This issue is further discussed in both the Testimony of Mr. Ming and the Affidavit of Dr. Patton.[9]

This disparity in methods leads to resource accreditation results that are not consistent across resource classes and, importantly, does not allow for the substitution of the accredited capacity of resources on a comparable basis. Similarly, all these methods have the potential to inflate accredited values at the class level, which would lead to an overestimation of how resources contribute to reliability during times of risk and leads to higher reliability requirements. Relying on resources that have received capacity accreditation higher than their actual contribution can lead to incorrect signals for long-term investment and retirement decisions, as well as inefficient market outcomes because even more resources are needed to maintain system reliability.

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[8] *Midcontinent Indep. System Operator, Inc*., 180 FERC ¶ 61, 141 (2022).

[9] *See* Testimony of Mr. Ming ("Ming Testimony") at Q44 and Affidavit of Dr. Patton ("IMM Affidavit") at P21.

Q. IS MISO'S DLOL-BASED METHODOLOGY A TYPE OF MARGINAL ACCREDITATION?

A. Yes.

Q. DESCRIBE HOW MISO'S DLOL-BASED ACCREDITATION METHDOLOGY IS SIMILAR TO A MARGINAL ELCC ACCREDITATION METHOD.

A. MISO's DLOL-based accreditation methodology is consistent with a marginal ELCC framework. The proposed method measures each resource's marginal contribution to reliability during periods of the highest risk (i.e., Critical Hours), and by design it will always capture the risk driven by the evolving resource portfolio in the MISO footprint. As discussed in the Direct Testimony of Mr. Zachary Ming, the marginal ELCC framework measures the reliability value of the next incremental addition of a specific resource type, which is equivalent to measuring the availability of all resources of that resource type during the periods of highest reliability risk. Moreover, the proposed DLOL-based methodology enhances MISO's application of a marginal ELCC accreditation framework by accrediting individual resources based on their historical availability during times of risk.

Q. WHY DOES MISO REFER TO ITS PROPOSED METHODOLOGY AS THE DLOL-BASED METHODOLOGY?

A. While MISO's proposed accreditation methodology is conceptually similar to marginal ELCC, MISO refers to its methodology as "DLOL" because it uses the Critical Hours (loss of load hours plus low margin hours) directly from the probabilistic model to determine the accredited value of each Resource Class (as described in detail below). It is effectively marginal because it measures each resource's marginal contribution during the Critical

Hours, which are representing the periods of highest reliability need. And it is inherently dynamic such that it will always capture the risk driven by the evolving resource portfolio in the MISO footprint.

Q. HOW DOES THE PROPOSED ACCREDITATION METHODOLOGY ALIGN WITH MISO'S MARKET VISION AND MARKET DESIGN GUIDING PRINCIPLES?

A. As discussed in Mr. Ramey's testimony, MISO's market vision is to foster wholesale electricity markets that deliver reliable and economically efficient outcomes. MISO's Market Design Guiding Principles are an important guide to evaluating and developing market enhancements, including this proposed accreditation reform. These guiding principles are listed below:

- Support an economically efficient wholesale market system that minimizes cost to distribute and deliver electricity;
- Facilitate non-discriminatory market participation regardless of resource type, business model, sector or location;
- Develop transparent market prices reflective of marginal system cost and cost allocation reflective of cost-causation and service beneficiaries;
- Support Market Participants in making efficient operational and investment decisions; and,
- Maximize alignment of market requirements with system reliability requirements.

The proposed accreditation methodology is consistent with MISO's Market Design guiding principles supporting efficient wholesale markets as it aligns market requirements with system reliability requirements, facilitates non-discriminatory market participation, results

in transparent market prices that accurately reflect the marginal reliability contributions during Critical Hours, and supports efficient operational and investment decisions.

Q. WHAT ARE THE PRIMARY BENEFITS OF THE PROPOSED ACCREDITATION APPROACH?

A. The proposed accreditation methodology is a balanced approach that captures a range of reliability risks in both the planning and operations horizons by incorporating forward-looking probabilistic analysis along with a resource's actual performance during recent periods of high system risk. The DLOL-based methodology uses a probabilistic model to estimate the expected contribution to reliability of each Resource Class under a wide range of system conditions, while Tier 1 and Tier 2 RA Hours (as currently defined in Schedule 53 and to be incorporated in Schedule 53A of the Tariff) deterministically measure the actual performance of individual resources during historical periods of highest system risk. The combination of the Resource Class-level accreditation and resource-level allocation methodologies accounts for both expected risks in the future and operational risk that has been realized in the recent past (Figure 4 below).

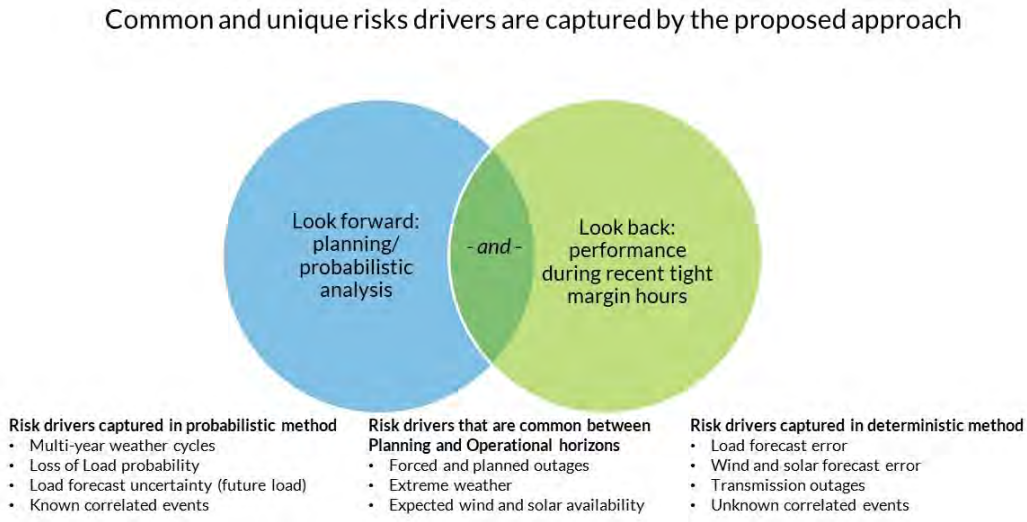


Figure 4: A wide range of risks challenge resource adequacy; a new accreditation approach is needed to capture different risk factors

The proposed DLOL-based accreditation methodology provides the following significant benefits when compared to other accreditation methodologies including:

1. Aligns accredited resource values with expected performance during high-risk hours of operation;
2. Provides a consistent determination of accreditation across all Resource Classes, which is an improvement over the current practice of employing different approaches for different classes. By accrediting all resources during the same time periods and using the same methodology, direct substitution from one class to another is possible as they offer equivalent marginal reliability contribution per accredited MW. This allows resource owners to make the most rational decision for their needs and occurs without altering the overall reliability of the system;
3. Aligns the determination of the system Planning Reserve Margin Requirements (PRMR), Local Reliability Requirements (LRR), and resource accreditation

values used to meet these requirements through the same underlying probabilistic model;

4. Reflects interactions between Resource Classes. Under the DLOL-based methodology, correlations between Resource Classes and their availability during periods of highest system risk are accounted for through the use of a single probabilistic analysis. As each Resource Class has a unique set of operating characteristics, there is value in having a diversified system portfolio and capturing the interactions between all Resource Classes within the same probabilistic analysis. This results in more accurate accreditation and recognizes how the composition of Resource Classes within the system influences system risk;
5. Disentangles random factors that may have occurred historically, such as severe weather or catastrophic outages, from the expected performance characteristics of a resource under the wide variety of events that are captured in the probabilistic model. Relying only on historic events may distort a resource's accreditation causing that resource to appear to have a reliability value that is different than what it truly possesses. The DLOL-based methodology allows the true reliability value of all resources to be more accurately estimated;[10]

[10] A good example of this is provided by wind resources. During a three-year lookback period, there may have been random events that can cause wind resources to have performed significantly better or worse than their expected performance. By using a probabilistic model that captures a wide variety of conditions, the true expected performance signal can be distinguished from the short-term fluctuations that may cause a resource to be mis-accredited.

6. Unlike certain other accreditation methodologies (e.g., those based on average resource accreditation), the DLOL-based methodology does not alter the risk profile on the system and allows for measurement of the actual contribution of resources during times of greatest risk; and,
7. Informs efficient investment in and retirement decisions of resources. By accrediting Resource Classes using the DLOL-based methodology, resource owners are sent the proper signals to invest in resources that offer the greatest reliability value and most economically achieve target reliability. The DLOL-based accreditation methodology provides resource owners with the information necessary to ensure integrated resource plans include resources with the necessary attributes to maintain resource adequacy within the MISO Region.

These benefits work together to generate a system that is economically efficient and achieves the target reliability performance level. The proposed method provides the proper incentives to maintain a diversified resource mix while recognizing the different performance characteristics of the designated Resource Classes. It does this in a computationally and intuitively efficient way without the need for artificial adjustments that may be arbitrary and complex. Additional benefits of this "blended" approach are further described in Section VI of my testimony.

Q. WHY IS THE PROPOSED DLOL-BASED METHODOLOGY (OR MARGINAL ACCREDITATON) A JUST AND REASONABLE RESOURCE ACCREDITATION APPROACH IN THE MISO REGION?

A. The proposed accreditation methodology is just and reasonable for the MISO region because of the following key benefits and aspects that I have described in detail above:

1. It is non-discriminatory and equally applicable to all types of Resources irrespective of fuel-type and/or technology;
2. It addresses the challenges I described above with the current methodologies – specifically, it accredits resources based on their expected performance during the periods of highest reliability risks; and provides direct alignment between accreditation and planning reserve requirements;
3. It provides appropriate signals for long-term investment and retirement decisions by accurately capturing resources' marginal contribution to reliability; and,
4. It will reduce overall cost and improve the ability to achieve and maintain target system reliability during operations, by accurately capturing resources' marginal contribution to reliability.

I also note that the Commission has already accepted the resource-specific accreditation methodology incorporated in the current proposal, which is currently set forth in Schedule 53 of the Tariff. The proposed DLOL-based methodology builds on the deterministic, resource-specific accreditation approach set forth in Schedule 53 by adding a probabilistic component to determine Resource Class accreditation values, and by applying the proposed methodology to all Schedule 53A Resources.

Q. WHY IS IT IMPORTANT THAT MISO CHANGE ITS RESOURCE ACCREDITATION METHODOLOGY AT THIS TIME?

A. As described above and in Mr. Ramey's testimony, MISO is at an inflection point in its resource portfolio evolution. Increasing penetration of wind and solar generation are shifting the nature of system risk.[11] Existing accreditation methods are not sufficiently robust to capture those risks and are unable to send the proper signals to help ensure the availability of resources needed during Critical Hours. As Market Participants plan rapid changes to their generation fleet, it is important for MISO to adopt an accreditation method that captures performance and availability of resources during the periods of system risks to ensure Resources needed to maintain overall reliability of the Bulk Electric System are appropriately incentivized. Inaccurate accreditation sends the wrong signals for the resources needed to maintain system reliability and can leave the MISO system ill-prepared for high-risk operations when resources are most needed. It is essential to make a course correction in MISO's accreditation methodology as soon as possible to provide proper guidance to Market Participants and regulators who are actively planning future resource additions and changes to the grid.

IV. PROPOSED ACCREDITATION METHODOLOGY

A. OVERVIEW OF DLOL-BASED ACCREDITATION METHODOLOGY

[11] *See* MISO's Attributes Roadmap (December 2023), available at: https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf;

See also MISO's Renewable Integration Impact Assessment, Summary Report (February 2021), available at: https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf

Q. PLEASE DESCRIBE THE ACCREDITATION METHODOLOGY MISO IS PROPOSING.

A. MISO is proposing to reform its capacity accreditation methodology for all Schedule 53A Resources, using a two-step process.

First, Resource Class-level accreditation, in megawatts (MW), will be calculated directly from MISO's LOLE analysis (which is a probabilistic analysis). This step calculates the expected availability of each resource during Critical Hours, which include loss-of-load hours and low margin hours, within the probabilistic model and aggregates these values to the Resource Classes that are established in Schedule 53A of the Tariff.

The second step of the proposed accreditation methodology utilizes the same concept that has been previously accepted by the Commission and currently implemented for Schedule 53 Resources. The Resource Class-level accredited value (MW), determined by the probabilistic component of DLOL-based methodology described above, is allocated among the individual resources in a Resource Class on a pro-rata basis using their contribution to the class-level historical performance. Historical performance, or Intermediate Seasonal Accredited Capacity (ISAC), is calculated using a two-tiered weighting structure based on an individual resource's average real-time availability during Tier 1 and Tier 2 RA Hours, as currently defined in Schedule 53 of the Tariff and as incorporated in the proposed Schedule 53A. Tier 2 RA Hours are identified based upon the prior three years of operational experience. These hours represent the periods of highest risk and greatest need during a Season and throughout the year during the past three-year period. They include Emergency Declaration periods and the hours when the operating margin is at its lowest. Tier 2 RA Hours receive 80 percent of the weight, while Tier 1

Hours, which include all other hours during the Season, are weighted at 20 percent. Allocating the Resource Class-level accredited value among the individual resources in a Resource Class based on their historical performance during the periods of highest risk will create performance incentives for individual resources and is expected to improve performance over time when those resources are needed the most. Figure 5 below provides a high-level summary of the design features of the proposed accreditation methodology.

Design Feature	Resource Class-level UCAP	Individual Resource ISAC
Approach	Probabilistic/Prospective	Deterministic/Retrospective
Hours Used	Critical Hours = Loss of Load (LOL) hours + low margin hours Loss of load hours = hours with unserved energy Low margin hours = hours with incremental generation ≤ 3% of the load	Tier 1 and Tier 2 RA hours
Hour Cap	If # of LOL hours ≥ 1,950 in a Season, No Cap If # of LOL hours < 1,950 in a Season, Cap of 1,950 Hours per Season	If # Max Gen hours per Season per Planning Year < 65 Hours, Tier 2 RA Hours capped at 65 Hours
Margin Calculation	Low margin hours are determined from the difference between modeled generation and load + net imports then capped at 3% of load	Operating margin to determine the hours to use for Tier 2 RA hours is based on historical margin as defined in the Schedule 53A
Availability Calculation	Average availability during Critical Hours	(Average availability in Tier 1 hours * 20%) + (average availability in Tier 2 RA hours * 80%)
Planned and forced outage treatment	Included utilizing 5-year annualized planned maintenance rates and 5-year seasonal forced outage rates	Included unless a planned outage meets exemption criteria
# of years analyzed	30 historical correlated load and weather years, 5 load forecast errors and numerous outage draws	3 years

Figure 5: Comparison of key design features for each step of the proposed two-step accreditation methodology

B. CLASS-LEVEL ACCREDITATION CALCULATION

Q. PLEASE DESCRIBE THE KEY COMPONENTS OF THE PROPOSED DLOL-BASED ACCREDITATION METHODOLOGY?

A. The key components of the proposed accreditation methodology include: the determination of Resource Classes; identification of Critical Hours; the determination of LOLE and PRMR through MISO's probabilistic analysis; and, the determination of Tier 1 and Tier 2 RA Hours. Each of these key components is described in detail below.

Q. PLEASE DESCRIBE HOW THE RESOURCE CLASS-LEVEL ACCREDITATION IS CALCULATED USING THE DLOL-BASED METHODOLOGY.

A. The Resource Class-level accreditation value will be determined directly from MISO's probabilistic analysis that is currently used by MISO to meet its annual and seasonal LOLE targets. This step determines the expected availability of each Resource Class during Critical Hours observed in the probabilistic model. Critical Hours are defined as the set of loss of load hours (all hours with unserved energy) and hours in which the difference between available generation (including net imports) and load is equal to or less than three percent (3%) of the load in the probabilistic model. For those Seasons with greater than or equal to 1,950 loss of load hours, Critical Hours will include all loss of load hours. For any Season with less than 1,950 loss of load hours, Critical Hours will also include low margin hours comprised of those hours where available generation in excess of load is less than or equal to 3% of load in that hour in the Season. Once the Critical Hours are identified for each Season, weights are calculated for each of the Critical Hours such that the hours with lowest margin (or highest unserved energy) receive the largest weight while the highest margin hours will receive the lowest weight. After calculating the weights for each Critical Hour, Critical Hours will be capped at 1,950 hours for each Season that has less than 1,950 loss of load hours. Finally, the Resource Class-level accredited value (MW) will be calculated as the weighted average of each Resource Class's performance during the Critical Hours by Season. MISO has proposed to adjust its definition of Unforced Capacity (UCAP), to reflect this Resource Class-level accredited value. Figure 6 illustrates the sequence of events described above.

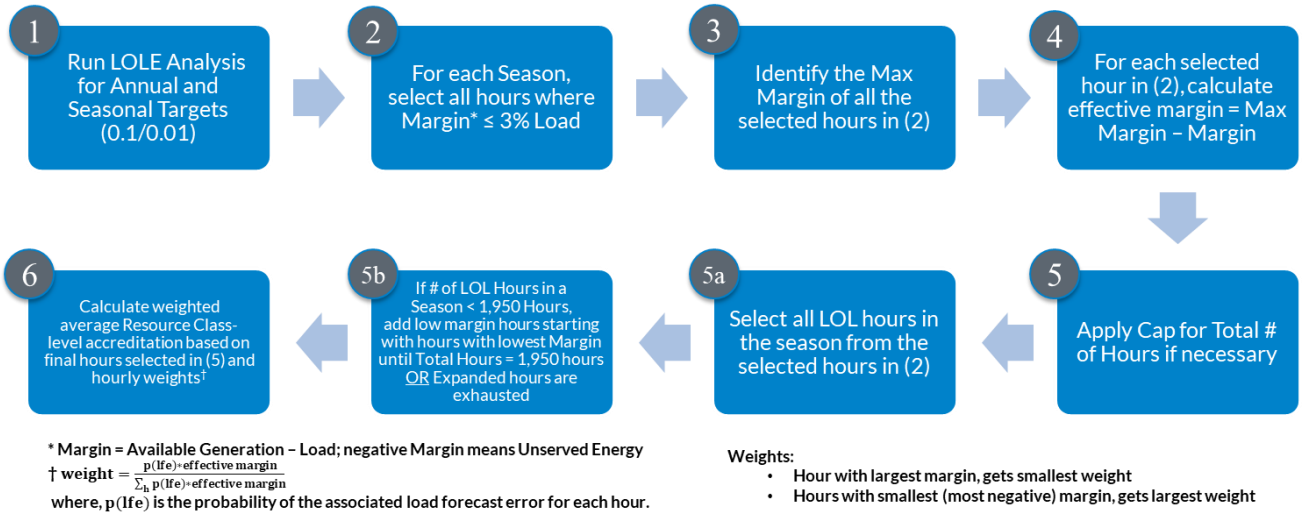


Figure 6: Flow chart of Resource Class-level Accreditation Calculation

Q. PLEASE GIVE AN OVERVIEW OF MISO'S PROBABILISTIC ANALYSIS USED FOR CALCULATION OF RESOURCE CLASS-LEVEL ACCREDITATION.

A. As described above, the Resource Class-level accreditation value will be determined directly from MISO's probabilistic analysis that is currently used by MISO to meet its annual and seasonal LOLE targets. MISO's LOLE analysis includes a Monte Carlo probabilistic simulation using 30 years of correlated load and weather data for each of five load forecasts that incorporates economic uncertainties and associated probabilities into the forecasts. MISO determines the adjustment to capacity in the probabilistic model that would bring the MISO system to the 1 day in 10 years LOLE standard on an annual basis. Under MISO's Seasonal Resource Adequacy Construct, the annual LOLE of 0.1 days/year is not evenly applied across each Season and is dependent on observed risk in the model, although each Season must show a minimum LOLE of 0.01 days/year. If, on an annual basis, a Season is not showing a minimum of 0.01 LOLE, modeled capacity is further reduced through a negative adjustment unit to find the point at which risk is at least equal to the minimum LOLE target of 0.01 days/year. Further details about the application of

MISO's resource adequacy LOLE modelling process are described in Section V of my testimony.

Once the Monte Carlo simulations are complete and seasonal LOLE targets are met, MISO will calculate the Resource Class-level accreditation and seasonal Resource Adequacy Requirements as further described below.

Q. PLEASE DESCRIBE HOW MARGIN IS CALCULATED TO IDENTIFY CRITICAL HOURS FROM THE LOLE MODEL.

A. MISO calculates margin for each hour of each Season for all iterations included in its LOLE analysis. The margin is calculated as the difference between total available generation, including net imports, and load, for the hour. The MW adjustment to reach the seasonal LOLE targets is included in the total available generation.

$$margin = \sum generation - load + net\ imports$$

Once margin is calculated, MISO identifies all hours with margin that is equal to or less than 3% of the load for the hour in each Season. This includes two subsets of hours: i) a loss of load hour, where there was a loss of load due to available generation being less than the required load, i.e. when margin is negative, and ii) low-margin hours, where there was no loss of load, i.e. when margin is positive, but less than 3% positive margin.

Q. WHY WAS A 3% MARGIN CHOSEN FOR USE IN THE DETERMINATION OF CRITICAL HOURS?

A. MISO chose a margin of 3% as it provides a good balance between stability of results and highest-risk hours. These highest-risk hours are representative of periods when MISO typically would issue Emergency Declarations in real-time. MISO originally considered only the loss of load hours as the Critical Hours in its proposed design. Through the review

of preliminary results based on its original design of considering loss of load hours only, and stakeholder discussions on the proposed original design, MISO identified possible scenarios where Seasons may experience too few loss of load hours and where hours with increased reliability risks may not otherwise be included. This could occur, for example, where the available generation is just enough and slightly higher than the load but not enough where there is sufficient margin to be considered as low reliability risk. Additionally, the scenario of low number of loss of load hours in any Season also introduces the possibility of instability in the year-over-year results. In response to these issues, MISO expanded the number of hours used to develop the Resource Class-level accreditation to include low margin hours.

The decision to expand hours for stability and accredit performance during the highest risk hours, however, also creates a tension. Margins as high as 5% dilute the signal being sent by the highest-risk hours, while a margin as low as 1% may potentially skip hours with increased reliability risks and may potentially introduce instability in the results year-over-year, especially for the Seasons when LOLE target is as small as 0.01 day in a year. The proposal to use 3% margin to identify low margin hours for inclusion in Critical Hours from the probabilistic model provides an appropriate balance between the need for stability and the need for accurately reflecting the resource performance during the periods of highest reliability risks.

Q. PLEASE DESCRIBE HOW MISO CALCULATES WEIGHTS AND THE CAP FOR CRITICAL HOURS.

A. After selecting all loss of load hours and low margin hours for each Season, MISO will use the following steps to calculate weights for each selected hour and then apply a cap, if necessary, to calculate Resource Class-level accreditation:

1) Within each Season, the hour with the maximum positive margin is identified from all the low margin hours. This "max margin" is the single maximum margin across all 30 weather years such that there are four (4) total max margin values, one (1) for each Season.

2) Next, for each hour identified in Step 1, effective margin is calculated relative to the max margin hour. This ensures that all values are positive, which is necessary for a weighted sum operation and ensures that the hour with largest unserved energy has the greatest weight, while the hour with the largest margin receives the smallest weight. If the hour with the max margin is included, this hour will receive zero weight.

$$effective\ margin = \max margin - margin$$

3) The number of Critical Hours to be used is capped within each Season based on the following procedure:

   i. All loss of load hours are used in the final calculation, regardless of the number of loss of load hours. Using all loss of load hours regardless of the number of loss of load hours is vital to fully capture all the expected reliability risks observed in the probabilistic model.

ii. If there are fewer than 1,950 loss of load hours per Season, MISO proposes to use low margin hours for the Resource Class-level accreditation calculations but cap the total number of Critical Hours at 1,950. For this step, hours with positive margin are selected beginning with the smallest effective margin until the cap is reached or until all low-margin hours within the Season have been selected. If the total number of Critical Hours are fewer than 1,950 hours between the loss of load hours and low-margin hours, then all loss of load hours and low-margin hours are used, and the cap will not be reached. Loss of load hours will never be excluded, and hours with greater than a 3% margin will never be included in the final selection of Critical Hours for Resource Class-level accreditation calculations. Figure 7 provides an example of how MISO will utilize loss of load hours and low margin hours to identify Critical Hours used for the Resource Class-level accreditation calculations.

Case	Type of hour	Summer	Fall	Winter	Spring
PY23-24	Loss of Load (LOL)	2,703	265	201	240
	LOL + low margin hours*	7,394	934	1,118	1,562
	Used for Resource Class-level UCAP calculations	2,703	934	1,118	1,562

*Low margin hours are all non-LOL hours with margin < 3% load

Figure 7: Example of loss of load hours and low margin hours to identify Critical Hours

4) Next, the weights are calculated and normalized using: a) the probability associated with the load forecast error scenario within the probabilistic model that the selected Critical Hour belongs to, and b) the effective margin developed in Step 2 above. The weights are normalized so that the sum equals one (1).

$$weight = \frac{p(lfe) * effective\ margin}{\sum_h p(lfe) * effective\ margin},$$

where $p(lfe)$ is the probability of the associated load forecast error for each hour. The load forecast error (LFE) values are included in the probabilistic analysis to account for economic load uncertainty and is documented in further detail in MISO's LOLE Study Report.[12] By way of example, the probability associated with each load forecast error that was used in the Planning Year 2023-2024 LOLE Study can be found in Figure 8 below.

LFE Levels				
-2.0%	-1.0%	0.0%	1.0%	2.0%
Probability assigned to each LFE				
4.8%	24.1%	42.1%	24.1%	4.8%

Figure 8: Probability associated with each load forecast error

5) Finally, the total availability is calculated for a Resource Class for each Critical Hour designated in step 3, and those values are averaged for each Season using the weights discussed in step 4. This results in the Resource Class-level accreditation, referred to as Resource Class-level UCAP in the MISO Tariff.

The seasonal Resource Class-level UCAP calculated using the steps described above represents the megawatts that a Resource Class is expected to contribute during times of highest reliability risk expected during the Season.

[12] See Section 3.3.2 in the PY2023-2024 LOLE Study Report

Q. WHY IS MISO WEIGHTING THE HOURS?

A. Weighting the hours based on margin recognizes that not all the simulated events are equal, by assigning greater weights to those hours that have the highest unserved energy. It also provides a distinction between loss of load hours (with negative margins) and low margin hours (with zero or small positive margins), by providing higher weights to the former. The weighting system ensures that the expected reliability risk during Critical Hours is being appropriately accounted for in the Resource Class-level accreditation calculation.

Q. WHY WAS THE PROPOSED WEIGHTING SCHEME CHOSEN?

A. MISO considered alternative weighting schemes, ranging from equal weights for all hours, weights based on the amount of unserved energy, combining the loss of load hours and low margin hours with a fixed ratio (similar to the combination of Tier 1 and Tier 2 RA hours in Schedule 53), and alternative weighting based on margin. The selected scheme was chosen because it provides consistent emphasis on the hours with highest unserved energy, thereby appropriately accounting for the magnitude of expected reliability risks in each hour. Moreover, the approach chosen preserves the ordering of hours with respect to margins (so hours with larger positive margins always receive smaller weights), and it is numerically stable regardless of whether the group of hours include only loss-of-load hours, a few low margin hours, or a large number of low margin hours.

Q. PLEASE EXPLAIN WHY A CAP ON THE NUMBER OF LOW MARGIN HOURS IS NEEDED.

A. Because system risk is not evenly distributed across Seasons, the number of loss of load hours found in the probabilistic model varies widely across Seasons. Figure 7 above, shows that for the Planning Year 2023-2024 simulations, the Summer Season experienced

2,703 hours with unserved energy, but the rest of the Seasons did not exceed 265 hours. Critical Hours were considered to avoid calculating accreditation values in a small group of hours for the less critical Seasons, which could lead to numerical instability and large variations in results year over year.

Hours are capped to establish a balance between improving numerical instability (by including low number of hours) and diluting the contribution of loss of load hours, if they represent too small of a fraction of the total Critical Hours. The cap for number of system hours and the use of the weighting described above work together to prioritize the hours that are most critical from reliability risk perspective and take advantage of the larger pool of hours for the calculations.

Q. WHY IS A CAP OF 1,950 HOURS WHEN LOW MARGIN HOURS ARE INCLUDED IN THE CRITICAL HOURS REASONABLE?

A. Applying the logic of 65 Tier 2 Resource Adequacy (RA) hours per Season from the current Schedule 53 calculations for each of the 30 weather years used in the probabilistic model, MISO selected 65 hours times 30 weather years, which equals 1,950 hours per Season as the cap when low margin hours are included in the number of hours for the Resource Class-level UCAP calculations. As Figure 7 above shows, the number of loss of load hours in the Summer exceeds the cap in the example for Planning Year 2023-24 and the cap is not binding in the rest of the Seasons.

C. ALLOCATION OF CLASS-LEVEL UCAP TO INDIVIDIUAL RESOURCES

Q. PLEASE DESCRIBE HOW RESOURCE CLASS ACCREDITATION IS ALLOCATED TO INDIVIDUAL RESOURCES WITHIN A RESOURCE CLASS.

A. MISO's resource-level accreditation proposal builds on the Commission-approved SAC methodology for Schedule 53 Resources. As described above, once Resource Class-level accreditation values have been determined based on the probabilistic analysis, MISO will then allocate the Resource Class-level accreditation values (MW) to individual resources within the Resource Class based on their historic performance (ISAC) as set forth in Schedule 53A.

Tier 1 and Tier 2 RA Hours over the previous three years of operations are used to determine resource availability for calculating seasonal ISAC. Tier 1 Hours will determine each resource's real-time availability during normal operating condition hours, and Tier 2 RA Hours will determine each resource's real-time availability during hours with the most difficult operating conditions, including declared maximum generation events. Tier 2 RA Hours are more heavily weighted so that most of a resource's real-time availability will be based on its availability during times of greatest reliability need.

All foundational aspects of MISO's current Schedule 53 Tariff, including outage exemptions, tier weighting, and lead time considerations, remain unchanged except the process to determine a resource's availability for the deficient hours (currently referred as Annual Average Offered Capacity in Schedule 53), when there are less than 65 Tier 2 RA hours in a Season, as discussed further below.

The use of Tier 1 and Tier 2 RA Hours ensures that individual resources are compared to other resources within their Resource Class when the system experiences the highest operational risk. For instance, resources in the solar class may have no output during evening risk hours, but all resources would be affected in the same manner and the allocation within the class would not be impacted. Resources with better performance

during Tier 1 and Tier 2 RA Hours receive a larger slice of the overall Resource Class-level UCAP.

The allocation of Resource Class-level UCAP among all Resources in the Resource Class can be described using the following equation:

$$SAC_i = Resource\ Class\text{-}Level\ UCAP * \frac{Resource\ ISAC_i}{Resource\ Class\text{-}level\ ISAC}$$

Q. PROVIDE AN EXAMPLE OF HOW RESOURCE CLASS-LEVEL UCAP IS ALLOCATED TO INDIVIDUAL RESOURCES WITHIN A RESOURCE CLASS TO DETERMINE THE SEASONAL ACCREDITED CAPACITY.

A. Figure 9 below provides a simplified example of how the Resource Class-level UCAP determined by the DLOL-based methodology is allocated to individual resources in a five-resource class. First, the ISAC for each resource is calculated by weighing Tier 1 Hours at 20% and Tier 2 RA Hours at 80%. The Seasonal Accredited Capacity (SAC) for each resource is calculated by distributing the Resource Class-level UCAP from the probabilistic model, 50 MW, among the units, proportional to their ISAC value. Lastly, each resource's percentage credit is calculated by dividing the resource's SAC by its Installed Capacity (ICAP) value.

Resource	ICAP	Tier 1 Hour Availability	Tier 2 RA Hour Availability	Intermediate SAC (ISAC)	Final SAC	% Credit (SAC/ICAP)
Resource Class-Level UCAP determined by DLOL method from LOLE analysis = 50 MW [U]						
Unit 1	5	2	3	2.8	2.6	52%
Unit 2	10	7	8	7.8	7.3	73%
Unit 3	15	12	14	13.6	12.7	85%
Unit 4	20	10	16	14.8	13.9	69%
Unit 5	25	12	15	14.4	13.5	54%
Total	75	43	56	53.4	50	67%
Formula	[A]	[B]	[C]	[D] = 0.2 * [B] + 0.8 * [C]	[E] = [U]*([D]/Total of [D])	[F] = [E]/[A]

ISAC = (Avg. Tier 1 Hour Availability x 20%) + (Avg. Tier 2 RA Hour Availability x 80%)

Final SAC = Resource Class-level UCAP * (Individual Resource ISAC/Resource Class-level ISAC)

Figure 9: Example of allocation of Resource Class-level accreditation among all Resources within the Resource Class.

Q. WHY IS MISO PROPOSING TO REPLACE ANNUAL AVERAGE OFFERED CAPACITY (AAOC) WITH SEASONAL RESOURCE CLASS-LEVEL UCAP, AS A PERCENTAGE OF RESOURCE CLASS-LEVEL INSTALLED CAPACITY?

A. If there are less than 65 Tier 2 RA Hours in a Season (deficient hours), seasonal Resource Class-level UCAP, as a percentage of Resource Class-level ICAP, is used to determine a resource's availability during those deficient hours. The Resource Class-level ICAP is the sum of the individual ICAP of all resources in a Resource Class. This is a slight deviation from the existing Schedule 53 methodology for filling deficient hours as this process will replace AAOC. MISO is proposing to change only this aspect of the current Schedule 53 methodology to ensure both that the availability of highly variable resources (e.g., wind and solar) is appropriately accounted for in the calculation of a resource's ISAC and to have a uniform method for accreditation of all resources. The current AAOC approach for the deficient RA Hours in any Season works well with Schedule 53 Resources because

their availability across the year does not significantly vary. In contrast, intermittent resources are highly variable in nature and their availability during an RA Hour (or Maximum Generation event) in a Season is likely to be different than their availability during RA Hours in other Seasons. For example, the availability of wind resources in a deficient RA Hour occurring during Summer peak conditions would not likely be similar to the average availability of those resources during RA Hours in the rest of the Seasons. Applying the AAOC approach, however, would result in application of those otherwise non-comparable hours during Seasons when there is an RA Hour deficiency. MISO therefore adopted the new proposed methodology to "backfill" deficient RA Hours to help ensure the comparability of all RA Hours being evaluated. When there is a deficient RA Hour in any Season, it is better to use the expected availability of such resources from the probabilistic model than to use their availability during other times of the year. MISO considered having a different approach than AAOC only for the intermittent resources but decided to not pursue that option to have a consistent approach for all resources.

D. SUMMARY OF KEY TARIFF CHANGES AND DESIGN CONSIDERATIONS FOR THE PROPOSED METHOD

Q. WHY IS MISO PROPOSING TO UPDATE THE DEFINITION OF UCAP AND SAC IN MODULE A?

A. MISO is proposing to change the definition of UCAP because UCAP sets the baseline expected availability of a resource for capacity accreditation and the proposal changes the way that baseline is calculated. The existing UCAP definition sets this baseline based on historic forced outage rates or historic availability and does not adequately account for resource availability observed in the probabilistic model. The DLOL-based methodology

marks a fundamental change in determining UCAP such that the probabilistic model is used to set baseline resource availability at the class level, which is then used in place of the previous baseline. Changing the definition of UCAP does not otherwise fundamentally change subsequent Resource Adequacy processes and calculations such that modifying the definition of UCAP is most consistent with MISO's Resource Adequacy construct. I note that both PJM and NYISO have taken similar approaches within their recent capacity market reforms.[13]

Upon receiving stakeholder feedback related to the Tariff redline changes shared with the RASC, MISO reconsidered the definition of SAC and decided to update it to better reflect how the term is currently used in the PRA. This modification is needed to align with the updated definition of UCAP so that the two definitions are distinguishable. SAC is the final accredited capacity, after accounting for the two-step accreditation process, that is convertible to Zonal Resource Credits for use in the PRA.

Q. WILL THE SYSTEM-WIDE UCAP TO ISAC CONVERSION RATIO STILL EXIST UNDER MISO'S ACCREDITATION REFORM PROPOSAL?

A. No. The system-wide UCAP to ISAC conversion ratio that is currently included in Schedule 53 of MISO's Tariff is no longer relevant under the proposed DLOL-based accreditation methodology. As explained in detail above, the proposed methodology is a two-step process. The first step is to calculate the Resource Class-level UCAP from the probabilistic model and the second step is to allocate the Resource Class-level accreditation to individual Resources within the same Resource Class based on their historical

[13] *See* fn.3, supra.

performance in last three Planning Years. The proposed two-step accreditation process no longer requires the system wide UCAP to ISAC conversion ratios to scale the ISAC values.

Q. WHY DID MISO REMOVE THE SYSTEM-WIDE UCAP TO ISAC CONVERSION RATIO IN SCHEDULE 53A?

A. The system wide UCAP to ISAC conversion ratio was put in place to ensure SAC was aligned with how requirements were determined during the probabilistic analysis. In other words, it brought accreditation into the same terms or currency as the requirements. MISO's proposed accreditation methodology naturally aligns accreditation with requirements since both are produced from the same probabilistic model. Therefore, there is no longer a need for the system wide UCAP to ISAC conversion ratio. As a result, MISO decided to adjust the language in Schedule 53A to better describe the process to establish the final SAC value for each resource. The proposed Tariff language aligns with the two-step process described above.

Q. HOW DID MISO ESTABLISH THE PROPOSED RESOURCE CLASSES?

A. The proposed Tariff includes general criteria for determining Resource Classes as well as establishing the specific Resource Classes that will initially apply. MISO considered the operating characteristics, technology, fuel type, and the expected performance of resources in its forward-looking probabilistic model to evaluate the criteria for defining Resources Classes. Ultimately, MISO decided to establish Resource Classes based on similar operating characteristics of individual resources within the class and generally reflect the same or similar technologies. The specific Resource Classes are: Gas (including oil), Combined Cycle, Coal, Hydro, Nuclear, Pumped Storage, Solar, Wind, Storage, Run-of-River, and Biomass. These Resource Classes each possess unique properties that

differentiate themselves from one another and produce a complete set of classes into which each resource can be uniquely assigned. Although Resource Classes are being defined in the Tariff with this filing, MISO intends to periodically review the set of Resource Classes and work with Stakeholders on any proposed changes before making a Tariff filing that would update the defined Resource Classes.

Q. DID MISO CONSIDER COMBINING ALL THERMAL RESROUCES INTO A SINGLE RESOURCE CLASS?

A. Yes. MISO evaluated combining all thermal resources into a single Resource Class. However, MISO decided not to pursue this approach for three reasons. First, there is a significant disparity in the operating characteristics of the different types of thermal resources during various weather events (e.g. cold weather snaps affect Gas resources differently than Nuclear resources). Second, thermal resources are appropriately modeled differently in the probabilistic analysis corresponding to their respective operating characteristics (e.g. Coal, Gas, and Combined Cycle resources have a cold weather outage adder modeled in MISO's probabilistic analysis). Third, such an approach will not provide the appropriate signals to inform retirement and investment decision making with respect to specific Resource Classes, which is one of the primary objectives of the proposed reforms.

Q. HOW WILL MISO DETERMINE WHETHER THE LIST OF RESOURCE CLASSES NEEDS TO BE UPDATED?

A. MISO will continue to monitor its generator interconnection queue, and the changes in its generation fleet to evaluate if the proposed Resource Classes established in the Tariff (Schedule 53A) need to be updated. MISO will also work with stakeholders to determine

whether additional Resource Classes should be established in the future as new technologies emerge and as MISO gains experience with the performance of resources under the DLOL-based methodology.

Q. HOW DOES MISO ENSURE THAT THE PERFORMANCE OF A SINGLE RESOURCE IN THE PROBABILISTIC MODEL DOES NOT UNDULY INFLUENCE THE RESOURCE CLASS-LEVEL UCAP FOR SMALL RESOURCE CLASSES?

A. MISO acknowledges that a single resource can theoretically unduly influence the Resource Class-level UCAP of a small Resource Class. MISO has evaluated preliminary results calculated using the probabilistic model for Planning Year 2023 – 2024 to determine how individual resources in a small Resource Class may impact the Resource Class-level UCAP. For small Resource Classes, particularly Nuclear and Pumped Storage, each resource's modeling and assumptions within the class were consistent in the probabilistic analysis relative to the other resources within the class.

Nevertheless, MISO is planning to establish a quality control/quality assurance (QA/QC) procedure in the Resource Adequacy Business Practices Manual that will track year-over-year changes for the main parameters that determine the performance of each resource in the probabilistic model (e.g., forced outages rates or maintenance rates for thermal units). If this QA/QC check determines that a single resource is unduly influencing the Resource Class-level UCAP, MISO will address the modeling of such resource and/or Resource Class-level UCAP calculations for the corresponding Resource Class on a case-by-case basis.

Q. CAN AN INDIVIDUAL RESOURCE HAVE A HIGHER SAC, AS A PERCENTAGE OF ICAP, THAN THE RESOURCE CLASS-LEVEL UCAP, AS A PERCENTAGE OF ICAP?

A. Yes, some individual Resources will perform better than the Resource Class when comparing their SAC as a percentage of their ICAP if they have better historical performance relative to other resources within their Resource Class. The only situation in which all resources in a Resource Class would have their SAC as a percentage of their corresponding ICAP match the Resource Class-level UCAP to the Resource Class-level ICAP percentage is if all the resources have the exact same behavior during Tier 1 and Tier 2 RA Hours, so that their individual ISAC values are all proportional to ICAP. In all other situations, some individual resources will perform better, and some will perform worse than the Resource Class average. As illustrated by way of the example in Figure 9 above, the Resource Class-level UCAP percentage is 67% of Resource Class-level ICAP, but individual resource SAC values range from 52% to 85% of their respective ICAP values.

Q. HOW WILL PLANNED OUTAGES AFFECT RESOURCE CLASS-LEVEL UCAP?

A. Planned outages are modeled using maintenance rates for each resource in the probabilistic model. Planned outages will reduce capacity availability of Resource Classes within the probabilistic model and commensurately reduce accreditation. By incorporating planned outages, the model will appropriately make resources unavailable to meet load for a period that correlates with their historic average maintenance rates, and along with other resources' availability in the model provides an overall picture of the Resource Class's availability in the probabilistic model. Recognizing planned outages in the probabilistic

model is essential to identify periods of reliability risks and allows the simulated outcomes to better reflect expected availability of resources, especially given that MISO has implemented a seasonal resource adequacy construct. Accounting for planned outages in Resource Class-level UCAP calculations will ensure each Resource Class's contribution to reliability is appropriately accounted for and the approach is aligned with the key objectives of resource accreditation.

Q. HOW ARE ACTUAL PLANNED OUTAGES IN THE RECENT PAST ACCOUNTED FOR IN THE ISAC CALCULATION OF INDIVIDUAL RESOURCES?

A. MISO essentially is leveraging the existing planned outage exemption process that is used for the calculation of ISAC for all Schedule 53 Resources. Under MISO's proposed accreditation methodology, exemptions will also be granted for planned outages as described in Schedule 53A and in MISO's Business Practice Manual (BPM) for Outage Operations. Without an exemption, a planned outage is treated like any other outage and a resource receives zero (0) credit of availability for that hour. With an exemption, the availability of a resource will be calculated by multiplying the seasonal Resource Class-level UCAP as a percentage of Resource Class-level ICAP by the resource's ICAP instead of a zero (0) for that hour during the exempted planned outage. As set forth in Schedule 53A, however, solar resources will not receive planned outage exemptions at night. The specific hours for this exception will be provided in MISO's Business Practices Manual for Resource Adequacy and will be Local Resource Zone (LRZ) and local time specific, in such a way that any daytime operating hour interval will allow for an exemption. As an example, if the sun sets at 20:01, then an exemption will be allowed for

the hour beginning at 20:00. If the sun rises at 06:59, then there will be an exemption allowed for the hour beginning at 06:00 hour. However, no exemption would be provided in this example for a solar resource planned outage scheduled to take place between 21:00 hours and 06:00 hours.

Q. WHY ARE EXEMPTIONS FOR PLANNED OUTAGES APPROPRIATE FOR CALCULATIONS USING THE DETERMINISTIC APPROACH BUT NOT FOR RESOURCE CLASS-LEVEL UCAP CALCULATIONS USING THE PROBABILISTIC APPROACH?

A. Exemptions for planned outages under current Schedule 53 provide an incentive for resource owners to plan outages for their resources in advance and at times most beneficial to operational reliability. Exemptions are also only used to allocate the Resource Class-level UCAP to the individual resources within the Resource Class. This provides an incentive for resource owners with resources within each Resource Class to plan their outages well in advance because they will receive a bigger slice of the overall Resource Class-level UCAP compared to resources within the class that do not plan their outages well in advance. Applying exemptions for planned outages in the prospective probabilistic analysis under Schedule 53A, which is used to calculate Resource Class-level UCAP, would be inappropriate because the probabilistic model needs to identify all possible risks that may impact the reliability of the system. All outages need to be captured to ensure target system reliability is maintained. A planned outage increases the probability of reliability risk being present and this risk should not be ignored in the establishment of a resource's contribution to reliability and determination of Resource Adequacy Requirements. Therefore, for the planning horizon an exemption for a planned outage is

inappropriate while over the operating horizon an exemption is appropriate and improves reliability through prudent outage planning. MISO's operations and outage coordination groups have already started seeing changes in outage scheduling patterns and have also begun to realize some of the associated benefits through the implementation of Schedule 53 outage exemption rules effective for Planning Year 2023 - 2024.

Q. IS THERE A RISK OF "DOUBLE COUNTING" BECAUSE PLANNED OUTAGES ARE CONSIDERED IN THE RESOURCE CLASS-LEVEL UCAP CALCULATIONS AND IN THE CALCULATION OF AN INDIVIDUAL RESOURCE'S ISAC?

A. No. Although planned outages are included in each step of the two-step proposed accreditation process, they are treated differently by design. As described in the two-step process above, Resource Class-level UCAP determines the size of the pie and individual resource ISAC will determine how that pie is split up. The fact that planned outages are included in the two calculations has no bearing on the result because the ISAC is merely used to determine how much of the Resource Class-level UCAP each resource in the Resource Class will receive. All resources within the class are treated the same in regard to outages in their ISAC calculation. Additionally, properly planned resource outages are eligible to receive an exemption for purposes of the ISAC calculation pursuant to Schedule 53A. Providing this exemption for properly planned outages is a mechanism to encourage Market Participants to minimize the number of planned outages during expected periods of highest reliability risk. Resources that plan their outages well in advance will receive a larger portion of the Resource Class-level UCAP. For these reasons, planned

outages are not double-counted in either the Resource Class-level UCAP or ISAC calculation.

Q. SHOULD CRITICAL HOURS IDENTIFIED IN THE LOLE MODEL BE EXPECTED TO MATCH RESOURCE ADEQUACY HOURS THAT ARE USED TO ALLOCATE RESOURCE CLASS-LEVEL UCAP TO INDIVIDUAL RESOURCES?

A. No. As explained previously, the proposed accreditation methodology is a balanced approach that captures a range of reliability risks in both the planning and operations horizons by incorporating forward-looking probabilistic analysis with a resource's actual performance during recent periods of high system risk. By design, therefore, perfect alignment between Critical Hours and RA Hours is not expected. Critical Hours identified in the probabilistic model include a wide range of system conditions (e.g., 30 years of weather data, five different load forecast errors, and hundreds of random outage draws). On the other hand, the three years of operational data used to determine RA Hours represent a limited number of snapshots of different system conditions that were experienced operationally. It is also important to note that Tier 1 and Tier 2 RA Hours are only used to distribute the Resource Class-level UCAP to individual resources and every resource in the Resource Class and Planning Region will utilize the same set of hours.

Also, it is important to note that results from the probabilistic analysis are not expected to and should not exactly match results of the deterministic approach. As indicated previously in my testimony, one of the benefits of the proposed approach is that it disentangles random factors that may have occurred historically from the expected performance characteristics

of a resource and Resource Class under the wide variety of events that are captured in the probabilistic model.

Q. WHY ARE SOLAR RESOURCES TREATED DIFFERENTLY REGARDING SCHEDULE 53A PLANNED OUTAGE EXEMPTIONS?

A. Exemptions are provided to incentivize minimizing the number of planned outages in any given hour. To receive an exemption, a resource generally must plan the outage to occur at least 120 days in advance. Solar is a unique resource where knowledge of fuel unavailability (i.e., when the sun will rise and set) is known 120 days in advance. For other resources, such as wind or gas, fuel unavailability cannot be predicted 120 days in advance. Therefore, there is the ability for solar resource owners to claim exemptions when they know they cannot provide energy. Allowing solar resources to receive an exemption for planned outages taken during night-time hours, and thereby receiving the corresponding seasonal Resource Class-level UCAP value as a percentage of the Resource Class-level ICAP, would distort the accredited capacity value of such solar resources as they appear to be available when it would otherwise be impossible to inject energy into the grid.

Q. HOW IS MISO PROPOSING TO ACCREDIT HYBRID AND CO-LOCATED RESOURCES?

A. Co-located resources that share an interconnection service limit will be accredited according to each of the resources' chosen participation model and their accreditation would equal the sum of the individual components. For example, co-located solar and storage resources will be accredited under the solar and storage Resource Classes, respectively. Because the resources share an Interconnection Service Limit, though, their total Intermediate SAC will be limited by that Interconnection Service Limit since the

combined set of resources cannot deliver MWs above that limit. Resource-level metering and sum of the parts accreditation for co-located resources allows for proper resource accreditation for each potential combination while accounting for a shared interconnection constraint. Even if separate component capabilities could exceed the interconnection service limit, the interconnection limit provides a total upper bound on possible contributions for each interconnection agreement.

Given the above, MISO proposes accrediting single-offer hybrid resources according to their chosen participation model. For example, a solar plus storage hybrid resource operating as a solar Dispatchable Intermittent Resource (DIR) will be accredited under the Solar Resource Class. Creating an accreditation Resource Class for hybrid resources is potentially intractable given the countless combinations of resources that could make up a hybrid resource. Moreover, creating different Resource Classes for each hybrid combination is unmanageable. Solar and storage resources in combination can have significantly different operating characteristics such that a single class for this fuel-type combination would not be meaningful (e.g., differing storage and solar capacity ratios, DC- or AC-coupled design, grid charging or non-grid charging).

Q. ARE LOAD MODIFYING RESOURCES (LMR) INCLUDED IN MISO'S ACCREDITATION REFORM PROPOSAL?

A. No, the proposed methodology does not apply to LMRs. MISO will continue to determine LMR accreditation through the current methods, derived from their past performance (forced outage rates for Behind the Meter Generation LMRs, and testing documentation submitted to MISO for Demand Resource LMRs), as provided in the Business Practice Manual for Resource Adequacy. MISO is currently engaging with stakeholders through its

RASC to improve the accreditation methodology for LMRs, but that effort is separate from the proposed accreditation methodology discussed in this testimony. MISO expects to make a separate filing for LMR accreditation reforms in the future after the design for the proposed changes is final and discussed with the stakeholders.

Q. WHAT IS MISO'S PLAN FOR ACCREDITING EXTERNAL RESOURCES?

A. MISO will continue to accredit External Resources through the current methods, which are derived from historical forced outage rates. Hourly real-time availability data is not currently collected for External Resources as these resources do not participate in MISO markets analogously to other resources. Because External Resources do not participate in the same manner as resources internal to MISO, they are also being treated differently here. MISO will evaluate methods to move all resources, including External Resources, under the proposed methodology in the future.

V. RESOURCE ADEQUACY MODELING

Q. WHAT IS THE LINK BETWEEN MISO'S PROBABILISTIC MODEL AND THE PROPOSED ACCREDITATION METHODOLOGY?

A. The probabilistic model is at the heart of MISO's proposed accreditation methodology because resource accreditation and Resource Adequacy Requirements will be directly determined using the same probabilistic model. Because the probabilistic model is central to the proposed accreditation methodology, I will briefly describe certain aspects of that model in this section of my testimony. Further information on MISO's probabilistic model

is available on MISO's website on the Resource Adequacy page and the Loss of Load Expectation Working Group page.[14]

Q. PLEASE BRIEFLY DESCRIBE THE PROBABILISTIC MODEL USED BY MISO IN ITS RESOURCE ADEQUACY CONSTRUCT.

A. MISO uses Astrapé's Strategic Energy Risk Valuation Model (SERVM) software to conduct the LOLE analysis. The SERVM software uses a sequential Monte Carlo simulation to step through time chronologically on an hourly basis and considers many combinations of random system conditions to evaluate how often system load can be covered by resources. The random system conditions include features such as planned and forced outages at the resource-level, import availability from neighboring system, as well the representation of 30 years of correlated load and other weather-dependent datasets, such as wind or solar generation and cold-weather outages.

Aside from assumed future capacity additions, typically only Capacity Resources that have cleared the most recent PRA are considered in the model. The probabilistic model data is generally updated on a yearly basis. Enhancements to modeling inputs and assumptions are constantly incorporated, based on the needs identified for the MISO footprint, new developments, industry best-practices, and stakeholder feedback.

Q. HOW HAS THIS MODEL PREVIOUSLY BEEN USED FOR MISO'S PRA?

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[14] *See* MISO's Resource Adequacy site, available at: https://www.misoenergy.org/planning/resource-adequacy2/resource-adequacy/#t=10&p=0&s=FileName&sd=desc

See MISO's Loss of Load Expectation Working Group site, available at: https://www.misoenergy.org/engage/committees/loss-of-load-expectation-working-group/

A. MISO has performed LOLE analysis using a probabilistic model for more than fifteen years, and has used the current software, SERVM, since 2015 in establishing Resource Adequacy Requirements (both PRMR and LRR). MISO's probabilistic model has also been used to perform the studies that determine the seasonal capabilities of wind and solar resources for the determination of requirements, as well as to accredit wind resources that plan to participate in the PRA. The proposed accreditation methodology will improve the alignment between accreditation and requirements in the MISO RA construct. MISO will continue to use the probabilistic model to set Resource Adequacy Requirements and will expand the use of the model to establish Resource Class-level UCAP.

Q. PLEASE EXPLAIN LOLE.

A. As discussed above, LOLE is the measure of how often, on average, the probabilistic model experiences days in which resource availability falls short of the load demand. LOLE is a commonly used metric in the electric industry, particularly in North America, to measure the expected frequency of resource adequacy events in a year, a season, or any other pre-defined period. As part of the LOLE analysis process, MISO calculates the following three probabilistic risk metrics:

- LOLE, which measures the frequency (in days) of load shed events;
- Loss of Load Hours (LOLH), which measures the expected number of hours per year expected to experience load shed events; and
- Expected Unserved Energy (EUE), which is an estimate of the energy that would otherwise have been used by end use customers but for a supply interruption during a predefined period (e.g., a year).

Q. PLEASE DISCUSS THE LOLE CRITERION TO WHICH MISO PLANS.

A. The MISO Resource Adequacy criteria for determining the Planning Reserve Margin Requirements is the industry-accepted LOLE objective of 1 day in 10 years on an annual basis. This LOLE criterion is also used by other ISOs, including NYISO and PJM, as discussed in their recent accreditation filings. Commencing with implementation of MISO's seasonal PRA in the Planning Year 2023-24, MISO evaluates LOLE for each Season and establishes corresponding seasonal Planning Reserve Margins. The seasonal LOLE analysis is determined as follows:

a) the system is adjusted until the annual LOLE reaches 1 day in 10 years;

b) the seasonal distribution of annual LOLE values is measured ;

c) any Season with a LOLE value below 0.01 is further adjusted until the LOLE in that Season reaches that value; and

d) any Season with a LOLE value at or above 0.01 receives the adjustment to capacity that drives that annual LOLE to 1 day in 10 years.

In the most recent LOLE analysis, most of the annual LOLE has been concentrated in the Summer Season, and all other Seasons had to be adjusted to meet the minimum of 0.01 LOLE.

Q. PLEASE DISCUSS THE LOLE MODEL INPUTS.

A. There are three broad categories of LOLE model inputs: load, generation resources, and system parameters. Load inputs consist of a demand and energy forecast, and load forecast errors. Generation inputs include operating parameters, unit forced outage rates, planned maintenance rates, hourly generation level for variable renewable resources, and dispatch

limits for demand response and interruptible load. System parameter inputs include zone and pool definitions, external tie limits, and external system energy imports.

Q. PLEASE DISCUSS HOW MISO MODELS LOAD IN ITS LOLE ANALYSIS.

A. MISO develops hourly load profiles that are used in the simulation of the probabilistic models. To ensure a representation of a wide range of system conditions, 30 load profiles are created, based on observed weather for the last 30 weather years, primarily driven by temperature values. The process to create the load data profiles can be summarized as follows:

MISO uses the previous 5 years of historical load data with Load Modifying Resource load reductions added back into the load, as an input to train a neural-net model to predict weather-correlated load shapes for each of these 30 weather years.

MISO also performs validations and corrections on the predicted neural-net load shapes to ensure proper load shape and peak values. This training allows the model to evaluate the risk that could materialize in the upcoming Planning Year if similar weather patterns were to be experienced again.

MISO applies the Zonal Coincident Peak Forecasts provided by the Load Serving Entities to develop zonal- and monthly-specific load forecast scaling factors which scale the average of the 30 load shapes based on provided forecasts.

This procedure creates hourly load profiles for the 30 weather years, which are consistent with expected load forecasts. During the LOLE simulations, each load profile is further adjusted to account for economic load uncertainty using economic load forecast error (LFE) scalars, resulting in five load profiles for each weather year. These include the expected load profiles, plus an increase of the load by ±1% and ±2%. Corresponding

probabilities are assigned to each load forecast error level, which are published by MISO every year. These probabilities can vary depending on the Planning Year. For example, the probabilities for Planning Year 2023-2024 were previously provided in Section IV. The 30 years of load data are also provided to Market Participants by MISO prior to the beginning of each Planning Year.

Q. PLEASE DISCUSS HOW MISO MODELS GENERATION IN ITS LOLE ANALYSIS.

A. MISO uses data from several different sources to model generation in its LOLE analysis. MISO begins with its annual, base Commercial Model and uses eligible capacity as determined by the annual PRA. Thermal units are modeled as must-run and perform at their full capacity whenever units are not on outage. The primary data source for forced outage rate statistics, planned maintenance statistics, and net dependable capacity (NDC) for monthly capacity profiles are obtained from the Generator Availability Data System (GADS).

Retirements are accounted for based upon the Attachment Y process in the MISO Tariff, while new resources are included based upon their position in the Generator Interconnection Queue. Imports are modeled based on firm capacity contracts from external areas to serve MISO load, as well as a probabilistic distribution of non-firm support from external areas.

MISO models wind and solar resources using hourly output profiles that reflect their variable nature. Each of the 30 weather years modeled have a unique hourly output for wind and solar resources to align with the load profiles which are described in more detail

below. Prior to each Planning Year, MISO shares the 30 weather years of hourly data for wind and solar resources with Market Participants.

Other renewable resources, like run-of-river and biomass are modeled at a flat capacity value.

Q. DOES MISO CONSIDER HOW COLD-WEATHER OUTAGES IMPACT GENERATION IN ITS LOLE ANALYSIS?

A. Yes, Astrapé, the entity that manages the SERVM software used for LOLE analysis, performed an analysis showing that as the temperatures decreased, the average megawatts (MW) of forced outages for coal and gas resources increases.[15] Based on that analysis, a MW/degree relationship was developed and modeled so that at each temperature, there is a specific MW amount of incremental cold weather outage captured for each zone. The incremental cold weather outages are not assigned to a particular resource but rather represent the aggregate Resource Class-level impact on the system to the Coal, Gas, and Combined Cycle Resource Classes.

Q. HOW ARE WIND RESOURCES SPECIFICALLY MODELED IN THE LOLE MODEL?

A. MISO models wind resources with hourly generation profiles for each of the 30 weather years. Profiles from 2013 and on use observed historical data, aggregated by LRZ. Minor increases to the profile are included from 2013 to 2015 to account for technology improvements as detailed in the Astrapé Seasonal Inputs Study.[16] Synthetic profiles are

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[15] Section 5 of the report available at 20220707 LOLEWG Supplemental MISO Seasonal Inputs Documentation Astrape625466.pdf (misoenergy.org).

[16] Astrapé Seasonal Inputs Study: Astrapé Seasonal Inputs Study.

generated for each LRZ and weather year prior to 2013 by choosing wind output from the observed days based on (a) the maximum daily temperature in the April through October months, and (b) the minimum daily temperature during November through March. The temperature to provide a match is aggregated at the LRZ level.[17]

Q. HOW ARE SOLAR RESOURCES SPECIFICALLY MODELED IN THE LOLE MODEL?

A. Solar generation profiles are created in a similar fashion to that for the wind resources. First, hourly irradiance data for sites across the MISO footprint are downloaded from the National Renewable Energy Laboratory's (NREL's) National Solar Radiation Database (NSRDB). The irradiance data is converted to hourly power generation data using NREL's System Advisory Model software. Given that the NREL irradiance data is only available starting with year 1998, data for prior weather years are developed by selecting daily solar profiles from the day that most closely matched the peak temperature out of all days ($\pm$ 6 days) from the available data.

Q. HOW ARE STORAGE RESOURCES MODELED IN THE LOLE MODEL?

A. Storage resources are treated as energy-limited resources in the LOLE model. Pumped storage resources are currently modeled with seasonalized forced outage rates, an annualized planned outage rate, and monthly capability. Electric Storage Resources have a

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[17] This matching procedure begins by matching a day prior to 2013 to the same calendar day for a year that is observed, where the matching occurs if the temperatures on the two dates are equal. If they are not equal, the previous and subsequent calendar date is evaluated. This continues until a band of $\pm$10 days has been searched. If no matches have occurred, the temperature is allowed to be different by 1°, and the search repeats. For example, for April 11th, 1998, the dates April 11th, 2013, April 11th, 2014, and so on are evaluated. If one of these days has the same max temperature as the 1998 year, then the wind profile from that matched day is used. If not, April 10th and April 12th are evaluated. This continues until a range encompassing April 1st through April 20th has been searched.

4-hour duration with a cycle efficiency of 85% and a maximum hourly output value determined by the capacity of the individual resource. Electric Storage Resources are dispatched in the model when load cannot be served by other resources (except emergency resources). The probabilistic model keeps track of the stored energy in these resources and will allow generation until the energy is exhausted. At that point, the storage resources will need to replenish its stored energy before they are available for dispatch in the model.

As a part of its LOLE modeling enhancements effort, MISO intends to continue working with stakeholders to evaluate how the modeling of storage resources in the LOLE model needs to be adjusted to reflect how they are being operated in the operational time frames or real time markets, and how their energy-limited nature may influence the determination of risk across simulated hours.

Q. HOW DOES MISO CONDUCT EXTERNAL SUPPORT MODELING FOR THE LOLE ANALYSIS?

A. Firm imports from the most recent PRA are included in the LOLE analysis and modeled as resources. In addition, MISO models non-firm imports as a probabilistic distribution based on historic imports from the most recent 3 planning years. As the model steps through the simulated hours, it randomly draws from this distribution of imports to serve the demand. Non-firm imports reduce the PRMR, which results in MISO relying on neighboring regions to serve some of its demand. Historic non-firm imports during historical Tier 2 RA hours are used to create a probabilistic distribution of non-firm support. This process is completed for each of the four Seasons to capture seasonal variability. As SERVM steps through the hourly Monte Carlo simulations, the model will randomly draw import values from seasonal distributions.

Q. WHY IS IT REASONABLE TO RELY ON THE CURRENT PROBABILITIC MODEL TO DETERMINE RESOURCE CLASS-LEVEL UCAP?

A. MISO has relied on a probabilistic model to determine the Resource Adequacy Requirements for over 15 years. Over that time, MISO has continually improved the underlying modeling and input data, incorporating best practices as they are developed by the industry and in collaboration with stakeholders. Use of MISO's current probabilistic model is therefore fully appropriate to be applied to the proposed DLOL-based accreditation methodology.

MISO is committed to further the evolution of the probabilistic model as this is both necessary and appropriate to better capture the changing composition of the Bulk Electric System and to continually improve the representation of the sources of system risk. MISO has communicated a plan to stakeholders to research, design, and implement specific aspects of the probabilistic model, including a revision of planned outages, cold-weather outages, load forecasting, and storage modeling.[18] The planned model enhancements will further refine that alignment between risk, needs, and availability, as will other additional improvements made in the future.

VI. DEVELOPMENT OF THE PROPOSED METHODOLOGY

Q. PLEASE PROVIDE AN OVERVIEW OF THE PROCESS MISO USED TO DEVELOP THE ACCREDITATION PROPOSAL THAT IS THE SUBJECT OF THIS FILING.

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[18] *See* 20240228 RASC Item 05c RA Model Enhancement Presentation631891.pdf (misoenergy.org)

A. In January 2022, following MISO's Seasonal Construct and SAC filing, MISO initiated a stakeholder process through the RASC to work with stakeholders to develop the resource accreditation reform that is the subject of this filing. MISO has followed the product development process shown in Figure 10 below. The goal of the product development process is to ensure the right solutions are built at the right time and solve the right issues. MISO began by defining the scope of the initiative, which included drafting a problem statement. Once the problem statement and scope were defined, MISO began evaluating potential solutions and ultimately recommended the proposed accreditation methodology that is the subject of this filing. From there, MISO began working through and refining the conceptual design. Once that process was complete, MISO made this filing with the Commission and, if accepted, will implement the proposed accreditation methodology for Planning Year 2028-2029. Pursuant to the proposed Schedule 53A, during the three-year period leading up to actual implementation, MISO will provide stakeholders with indicative information about expected Resource Class and resource level accreditation values to assist state regulators and LSEs with integrated resource planning.



Figure 10: MISO Product Development Process

Q. WHAT IS THE PROBLEM STATEMENT THAT MISO DEVELOPED IN COLLABORATION WITH THE STAKEHOLDERS AT THE BEGINNING OF THE ACCREDITATION REFORM EFFORTS?

A. The resource accreditation reform problem statement was first presented to stakeholders at the January 2022 RASC meeting. Stakeholders were provided an opportunity to comment on the problem statement, but generally agreed with it as presented. The problem statement has essentially remained the same and remains the focus of the resource accreditation reform effort. The problem statement is:

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's existing accreditation methods for non-thermal resources require further evaluation to ensure that the accredited capacity value reflects the capability and availability of the resource during the periods of highest reliability risk.

Q. WHAT IS THE SCOPE OF MISO'S RESOURCE ACCREDITATION REFORM EFFORT?

A. The scope of the accreditation reform as identified at the January 2022 RASC was to revisit the established accreditation practices for non-thermal resources with a priority focus on those with the greatest reliability impact in the near-term (i.e., wind and solar). In response to stakeholder feedback concerning comparability between resources and the Commission's comments in response to MISO's Seasonal Resource Adequacy Construct and SAC filing, MISO recommended extending the scope of the resource accreditation

reform effort to cover additional accreditation changes for all Capacity Resources (excluding external resources) at the January 2023 RASC.

Q. WHY DID MISO RECOMMEND EXTENDING THE SCOPE OF ACCREDITATION REFORM TO INCLUDE ALL CAPACITY RESOURCES AND NOT JUST NON-THERMAL RESOURCES?

A. The methodology developed for non-thermal resources was resource type agnostic and found to be applicable to all resources in the MISO footprint. This provided several advantages: (a) it does not discriminate based on resource type, which allows all Schedule 53A Resources to be treated equally, (b) it improves consistency and efficiency by bringing the entire accreditation process under one probabilistic modeling effort compared to many different methods under the existing process, (c) it provides alignment between the determination of the need (requirements) and availability of resources (accreditation) by ensuring both processes are performed with the same information and model, (d) it improves the thermal accreditation process by including new sources of risk, such as correlated and coincidental risks and weather-dependent derates, and (e) it allows for reliability-neutral substitution between resource types.

Q. WHAT WAS MISO'S APPROACH TO EVALUATING ACCREDITATION METHODOLOGIES?

A. MISO approached the evaluation of accreditation reform by examining a wide range of possible methods to address the problem statement. The evaluated methodologies for accreditation can be broadly divided into two categories: 1) average accreditation approach, such as average ELCC, and 2) marginal accreditation approach, which includes marginal ELCC, marginal reliability improvement (MRI) and DLOL. MISO developed

evaluation criteria and an analysis framework to compare modeling results and help guide decisions on which method was best for the MISO footprint. This larger list of options was ultimately reduced to a smaller set of three options that were examined in quantitative analysis and discussed with MISO stakeholders: ELCC method, a fully deterministic method, and blended method.

Q. WHAT CRITERION DID MISO CONSIDER WHEN EVALUATING ACCREDITATION METHODOLOGIES?

A. MISO evaluated accreditation methodologies against the following five general criteria: impact, feasibility, flexibility, stability, and, after receiving feedback from stakeholders, comparability. These were developed based on criteria previously used for the Resource Availability and Need (RAN) initiative, presented at the October 2020 RASC, and modified based upon stakeholder input. These criterion are all related to the "pillars of accreditation" identified by the Energy Systems Integration Group (ESIG).[19]

Q. PLEASE DISCUSS THE IMPACT CRITERION.

A. A method's impact is identifying and sufficiently mitigating actual risk under current and future portfolios and grid conditions in conjunction with markets and operations. Impact ensures sufficient capacity in the planning horizon when it's needed to maintain reliability. The method should measure performance in scarcity conditions and link planning to operations. This criterion is related to the reliability pillar identified by ESIG.

[19] Energy Systems Integration Group, "Ensuring Efficient Reliability: New Design Principles for Capacity Accreditation" (2023), available at: https://www.esig.energy/new-design-principles-for-capacity-accreditation/.

Q. PLEASE DISCUSS THE FEASIBILITY CRITERION.

A. Feasibility is the practicality, scalability, and ability of MISO and its Market Participants to implement the proposed methodology. The feasibility criterion also takes into consideration the clarity and transparency of the process. Both MISO and Market Participants need to be able to reasonably predict the expected accredited values of resources to ensure a reliable resource mix and make appropriate investment and retirement decisions. The feasibility criterion is rooted in the transparency pillar identified by ESIG.

Q. PLEASE DISCUSS THE FLEXIBILITY CRITERION.

A. Flexibility is a measure of how robustly a method holds up over time and responds to a changing system portfolio. As the resource portfolio evolves and technologies develop that change the load profile, an accreditation methodology needs to remain relevant and capable of properly accrediting resources. Without this flexibility, a system becomes in danger of mis-accrediting capacity values potentially leading to system reliability risks and an inefficient allocation of resources. This criterion is tied to the robust pillar identified by ESIG.

Q. PLEASE DISCUSS THE STABILITY CRITERION.

A. Stability is the ability to reasonably inform state and utility resource planning processes that rely on accreditation information as an input to long-term decision making. The method should not only remain robust under changing conditions but should be able to reflect changing conditions as system resource mix and load profiles evolve. Finally, these capacity values should remain predictable over time and only move when structural changes to the system have occurred which shift risk and alter the generation profile of the fleet. Greater volatility in capacity accreditation leads to lower investments as decision

makers face greater risk. A method that minimizes accreditation volatility increases investment certainty resulting in a more efficient system. This criterion aligns with the predictable pillar identified by ESIG.

Q. PLEASE DISCUSS THE COMPARABILITY CRITERION.

A. The comparability criteria refers to how comparable two different resource class accreditation values are to one another. Utility planners should be able to directly compare one resource class to another across a broad range of factors to make the most efficient investment and retirement decisions. A methodology that makes comparison between resource classes difficult may result in a less efficient and riskier resource portfolio. Conversely, a methodology that allows for comparability makes investment and retirement decisions easier to analyze and provides an accurate measure of the marginal cost and benefits associated with different amounts of different resource classes. This criterion is related to the non-discriminatory pillar identified by ESIG.

Q. PLEASE DESCRIBE THE ELCC METHOD.

A. The ELCC method belongs to a class of accreditation methodologies that determine capacity values based upon a probabilistic assessment of availability during loss of load hours. MISO analyzed two different types of ELCC methodologies. The first method, average ELCC, determines accreditation for each resource class by first modeling the system at the LOLE target criteria. Next, the resource class of interest is removed from the system and perfect capacity is added until the model returns to criteria. The amount of perfect capacity added is the accredited value of the class and referred to as the ELCC MW. This option is currently used at MISO for wind resources and served as the reference case. The second method, marginal ELCC, is identical in procedure to the average ELCC

approach, except instead of removing a resource class, an incremental resource is removed (or added) to the system.

Q. PLEASE DESCRIBE THE DETERMINISTIC METHOD CONSIDERED.

A. The deterministic method considered would have measured accreditation using only historical performance. This approach could take several forms, such as applying only the Schedule 53 Tier 1 and Tier 2 RA hours framework, relying upon historical GADS data, or some other strictly backward-looking approach based upon historical resource performance. This method is conceptually similar to how thermal units are currently accredited.

Q. PLEASE DESCRIBE THE BLENDED METHOD.

A. The blended method combines a probabilistic and deterministic approach. Each of the two approaches has its merits and shortcomings. A probabilistic approach allows for the expected capacity value of a resource to be estimated under a broad range of conditions. However, the quality of this assessment is limited by the standard modeling limitations, namely quality of the inputs and the model. Deterministic approaches have the advantage of demonstrating what has occurred and do not rely upon a model to calculate. Their drawback is that what happened yesterday may not accurately reflect what may happen tomorrow. If there are structural differences in events that are not captured, then a backwards-looking only framework may fail to properly realize the value of a resource and create improper incentives towards investment and retirement decisions.

The blended method attempts to merge these two perspectives into a single view and capitalize on each method's strengths while minimizing each method's weaknesses. With a blended method, accreditation would be based upon expected performance during

projected probabilistic risk periods as well as historical performance. Additionally, proper signals can be sent in both the operational and planning horizons by tying accreditation to both periods. Resource owners are rewarded for improving the operation of their units from the deterministic portion of the accreditation while sending more reliable signals about which assets to invest in or retire based upon the probabilistic portion.

Q. WHAT ACCREDITATION METHODOLOGY IS MISO PROPOSING?

A. MISO has chosen a blended approach combining a probabilistic approach, capacity values determined through the probabilistic modeling (the first step in the proposed DLOL-based methodology), with a deterministic approach, historical performance measured by the proposed Schedule 53A Tier 1 and Tier 2 RA hours for all Capacity Resources, excluding External Resources.

Q. WHEN WEIGHING THE IMPACT CRITERIA, EXPLAIN HOW MISO DECIDED TO RECOMMEND THE PROPOSED APPROACH.

A. MISO's proposed methodology identifies expected risk by accrediting resources during periods when the system is at highest risk, as measured by the margin between generation and load in the probabilistic model. The identification of these risky periods is independent of the resource portfolio. Because availability during Critical Hours is used to set Resource Class-level UCAP, the method naturally measures performance during scarcity conditions. Further, it also uses historical performance to establish capacity values and therefore incentivizes resources to perform in a manner that increases system reliability. Therefore, it links planning to operations and provides the greatest impact of the options considered.

Q. WHEN WEIGHING THE FEASIBILITY CRITERION, EXPLAIN HOW MISO DECIDED TO RECOMMEND THE PROPOSED APPROACH.

A. The proposed methodology uses a single probabilistic model run to set Resource Class-level UCAP and Resource Adequacy Requirements, limiting the computational complexity of the required calculations. It can be implemented in the same manner no matter the size of the resource portfolio, which gives it scalability. With similar input data, MISO and Market Participants could implement and replicate results. This feasibility allows for the ability for efficient investment and retirement decisions to be made with confidence that the projected accreditation values would be realized.

Q. WHEN WEIGHING THE FLEXIBILITY CRITERION, EXPLAIN HOW MISO DECIDED TO RECOMMEND THE PROPOSED APPROACH.

A. The proposed accreditation methodology will be applied to all Capacity Resources, except External Resources, in the same manner which gives it the flexibility needed to handle any resource portfolio composition. Therefore, as MISO's fleet evolves, the proposed accreditation methodology will inherently adapt to such changes. Moreover, MISO will continue to evaluate the efficacy of the DLOL-based methodology and continue discussions with stakeholders about potential enhancements going forward.

Application of the proposed accreditation methodology to all Capacity Resources, except External Resources, contrasts with the current accreditation methodologies, which are not robust enough to account for significant changes to the generation fleet. Lastly, as electrification and technological progress alters the shape of the load profile, the methodology will remain robust and provide a proper measure of the high-risk hours. Therefore, the proposed methodology satisfies the flexibility criterion as it is sufficiently robust to change in both load and generation.

Q. WHEN WEIGHING THE STABILITY CRITERION, EXPLAIN HOW MISO DECIDED TO RECOMMEND THE PROPOSED APPROACH.

A. It is important to have stability in the results. Accrediting a resource using only historical performance may subject it to significant shifts in its final accredited value, and worse off, may be lagging in representing the operational risk being experienced. By using a probabilistic model to measure the expected performance of a resource during critical hours, the method provides stability and certainty that resource accreditation will not suddenly decrease. Conversely, a method that focuses only on future expected performance could also subject a resource to dramatic shifts in capacity values if there is a significant shift in system risk. Therefore, a method that uses both historical performance and expected future performance attenuates any large shifts providing stability of accredited values. Finally, because the model is portfolio agnostic, the addition or subtraction of a set of resources will not have significant effects on existing resources, ensuring stability of capacity values for existing resources even as other Market Participants make investment decisions.

Q. WHEN WEIGHING THE COMPARABILITY CRITERION, EXPLAIN HOW MISO DECIDED TO RECOMMEND THE PROPOSED APPROACH.

A. The proposed methodology satisfies the comparability criterion by calculating accredited values for each type of Capacity Resource, except External Resources, in an identical manner. This means that a MW of accredited capacity from one type of resource can be substituted for a MW of accredited capacity from another resource without fear of the capacity values changing. Therefore, resource owners and Market Participants can directly make a cost-benefit calculation without requiring any additional calculations. This reduces

the uncertainty of investments leading to a more efficient resource portfolio. This also ensures a technology agnostic capacity valuation ensuring a non-discriminatory result.

Q. PLEASE DISCUSS THE KEY DIFFERENCES BETWEEN MARGINAL ELCC AND AVERAGE ELCC.

A. Average accreditation approaches (including average ELCC) accredit the entire class of a resource based on the contribution of the entire fleet of that class of resources, while marginal accreditation approaches measure the contribution of the next incremental addition to the resource class. By utilizing a marginal addition to the system, the marginal ELCC approach better captures how that incremental resource contributes to the needs of the system at criteria. This concept aligns with the assumption that capacity exchange in the capacity market is fungible and aligns best with something the average ELCC method is not able to provide.

VII. IMPACTS OF THE PROPOSED METHODOLOGY TO OTHER ASPECTS OF THE PRA

Q. BRIEFLY DESCRIBE HOW THE PRMR IS CURRENTLY DETERMINED.

A. The PRMR for each Season is determined as the sum of UCAP values for all resources, plus the MW adjustment to drive the probabilistic model to criteria in that Season. The current determination of UCAP values relies on a combination of accreditation methods, including EFORd based UCAP for thermal resources, seasonal capabilities for LMRs, contracted MW for firm External Resources, and average ELCC for wind and solar resources as shown in Figure 11 below.



Resource Type	Current method to establish capacity for PRMR*
Thermal	GVTC * (1 – Seasonal EFORd)
Wind/Solar	Effective Load Carrying Capability (ELCC)
Run-of-River/Biomass	Hourly output during peak hours
Storage	GVTC * 95% or hourly output during peak hours
Demand Response	Seasonal capability and # of calls
BTMG	GVTC* (1 – Seasonal EFORd)
External Resources	Firm external seasonal capability

*July for Summer, September for Fall, January for Winter and May for Spring

Figure 11: Overview of current methods for PRMR calculation

Q. PLEASE DESCRIBE HOW MISO IS PROPOSING TO CHANGE THE DETERMINATION OF PLANNING RESERVE REQUIREMENTS.

A. MISO is proposing to maintain the calculations of the PRMR and simply account for the determination of UCAP for Schedule 53A Resources, based on the proposed accreditation method. The PRMR will be determined as the sum of accredited values for all Schedule 53A Resources, Load Modifying Resources, Firm External Resources, within the LOLE model plus the MW adjustment to drive the probabilistic model to the LOLE target. As shown in Figure 12 below, MISO expects the seasonal PRMR to decrease under the proposed DLOL-based methodology compared to current season PRMR due to the

expected reduction in Resource Class-level accreditation. This result is further discussed in the Affidavit of Dr. Patton.[20]

MISO's current accreditation methodologies are misaligned with a resource's marginal contribution to reliability risk leading to over-accrediting and similarly results in higher PRMR that increases total cost to maintain Resource Adequacy at the target. The proposed accreditation method will improve alignment between accreditation and PRMR, lower PRMR and result in more efficient market outcomes.



PY 23/24 - PRMR	Summer		Fall		Winter		Spring		Formula Key
Resource Class	Current	Proposed	Current	Proposed	Current	Proposed	Current	Proposed	
Gas	30,251	29,541	28,595	29,745	28,582	23,605	28,962	23,657	[A]
Combined Cycle	27,558	27,326	28,635	27,015	28,552	23,650	27,929	22,997	[B]
Coal	40,545	39,955	39,888	38,812	39,914	32,539	39,280	32,641	[C]
Hydro (includes diversity contracts)	2,120	2,122	2,104	2,118	926	916	1,350	1,287	[D]
Nuclear	11,410	10,850	11,522	10,304	11,627	10,493	11,063	9,640	[E]
Pumped Storage	2,530	2,523	2,345	2,504	2,299	1,216	2,359	1,763	[F]
Storage	28	28	28	28	54	52	55	55	[G]
Solar	2,151	1,700	1,603	1,937	698	188	1,824	2,221	[H]
Wind	4,639	2,731	5,993	3,859	11,389	4,477	6,500	4,601	[I]
Run-of-River	966	966	966	966	966	966	966	966	[J]
BTMG	4,196	4,196	4,218	4,218	4,163	4,163	4,240	4,240	[K]
Demand Response	7,397	7,397	7,041	7,041	5,388	5,388	6,280	6,280	[L]
Firm External Support	1,707	1,707	1,714	1,714	1,857	1,857	1,778	1,778	[M]
Adj. {1d in 10yr}	(4,000)	(4,000)	(10,000)	(10,000)	(6,200)	(6,200)	(12,750)	(12,750)	[N]
PRMR	**131,498**	**127,042**	**124,652**	**120,261**	**130,215**	**103,310**	**119,836**	**99,376**	[O]= sum of [A] through [N]

Figure 12: Comparison of Current PRMR vs Proposed PRMR

Q. PLEASE DESCRIBE HOW MISO CURRENTLY CALCULATES LRR.

A. The calculation of LRR is similar to that of the PRMR, wherein the capacity is accounted for in the same way, but each LRZ is modeled independently without support from other

[20] IMM Affidavit at P 26.

LRZs or external areas, and each LRZ has its own MW adjustment to reach the seasonal LOLE criteria. Each LRZ's LRR MW is divided by the corresponding modeled zonal coincident peak forecast (LRZ load at the time of MISO's Coincident Peak Demand) to determine the LRR % that is applied to the updated LSE load forecasts for the PRA. This establishes each LRZ's LRR MW for the PRA.

Q. PLEASE DISCUSS HOW MISO PLANS TO CALCULATE LRR USING THE PROPOSED METHODOLOGY.

A. Like PRMR, LRR calculations are being updated to use accreditation by Resource Class as determined by the DLOL-based methodology. The overall approach will remain unchanged. The LRR for each LRZ is determined by aggregating the capacity accreditation of the resources in the Zone, plus a MW adjustment used to bring the LOLE model of the isolated LRZ to criteria.

As is the case with the PRMR, the main difference introduced in this proposal is the capacity accreditation for the internal resources in each LRZ (excluding LMRs). Ideally, the LRR would be determined by aggregating the final SAC values of all resources in an LRZ. However, those two values are determined at different points in time. LRR values need to be finalized in November prior to the Planning Year and final SAC values are not determined until the following February 15.

Given these scheduling challenges, MISO will produce LRR with an approximation of the final resource SAC values by combining data of the current and previous Planning Years, as follows:

1. The total Resource Class-level UCAP are determined for the current Planning Year (same values used to determine the current Planning Year PRMR).

2. Resource Class-level UCAP will be allocated to individual resources in the Resource Class using the Proposed Schedule 53A logic described earlier but utilizing the ratio of individual resource's ISAC to the corresponding Resource Class ISAC from the previous Planning Year. This provides estimated SAC values for individual resources that will only be utilized for LRR calculations.

3. The estimated SAC values are aggregated to the LRZ level, and that value is used as an input into the LRR calculations, similar to how the current method utilizes UCAP, average ELLC, or established capacity for thermal, wind, and solar resources, respectively.

Because the Schedule 53A process proposes to use the previous three years to determine Tier 1 and Tier RA 2 hours, the current and previous Planning Years, should have an overlap equal to two thirds of the hours. These should ensure a reasonable alignment between preliminary estimated and final SAC values at both the resource and LRZ levels. MISO presented an illustrative example of a system with two LRZs and four resources at the February 28, 2024 RASC meeting to explain proposed methodology for LRRs.[21]

Q. PLEASE DESCRIBE HOW MISO ALLOCATES PRMR TO INDIVIDUAL LOAD SERVING ENTITIES TODAY.

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[21] See Slides 11-12 of the MISO accreditation presentation from Feb 28th RASC meeting.

A. Through the probabilistic analysis, MISO establishes PRMR for each Season for an LSE's Load within any given LRZ. The seasonal PRMR values are converted to a Planning Reserve Margin (PRM) percentage by subtracting the modeled seasonal Coincident Peak Demand from the PRMR and dividing by the modeled seasonal Coincident Peak Demand. The PRMR used in the PRA is set by applying the seasonal PRM percentage determined from the previous step plus a transmission loss percentage to the LSE-submitted updated Coincident Peak Forecasts. MISO uses PRM % as established through the process described above and in Figure 13 unless an alternate PRM is established by a state regulatory authority. In such an event, MISO will use the alternate PRM set by the state regulatory authority for the geographic area in its jurisdiction. MISO converts any state regulatory authority provided PRM to a comparable UCAP basis.

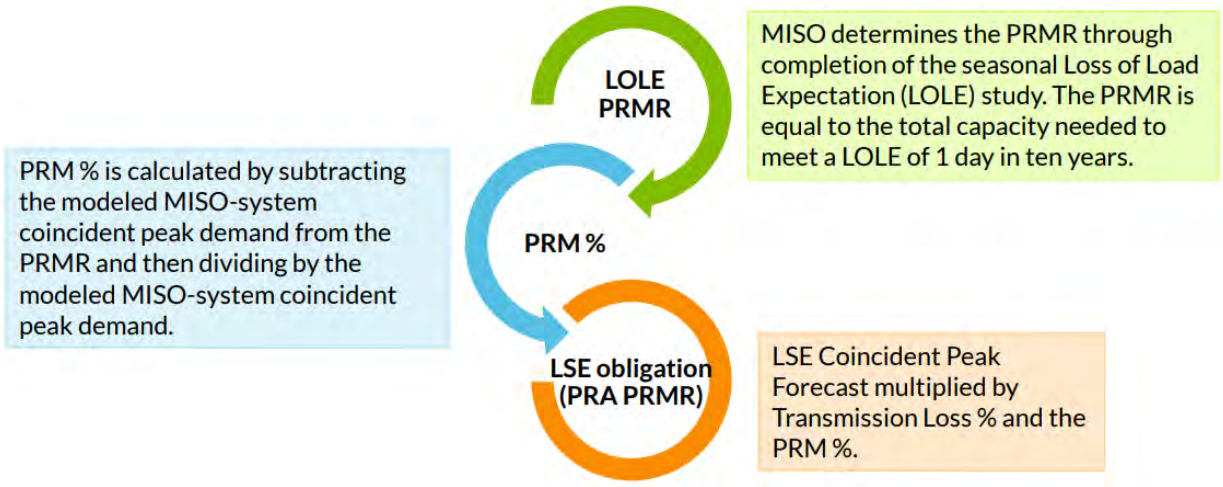


Figure 13: PRM % for Planning Resource Auction

Q. DOES MISO ADDRESS THE ALLOCATION OF PRMR TO LOAD SERVING ENTITIES WITHIN THIS FILING?

A. No. MISO is not proposing any change to the process of allocating PRMR to Load Serving Entities (LSEs) within this filing. MISO initiated stakeholder discussion on allocation of

PRMR in 2023 and concluded that any changes to the allocation process will require deliberate and careful considerations regarding substantive changes that may be needed to the processes and potentially to the systems used by LSEs to submit load forecast data to MISO. The current allocation methodology has been deemed by FERC to be just and reasonable and MISO is not proposing any changes to it. And as noted above, the proposed DLOL-based methodology will improve alignment between resource accreditation and establishment of the PRMR.

Q. DOES MISO PLAN TO ADDRESS THE ALLOCATION OF PRMR IN THE FUTURE?

A. Yes. MISO has already started conversations with stakeholders to transition from today's allocation mechanism that purely relies on the contribution to MISO's seasonal Coincident Peak Demand. MISO will consider alternative mechanisms that also incorporate recognition that risk periods in the future may not solely be determined by times of high load, as drivers of risk evolve over the next decades. MISO will evaluate these allocation mechanisms against a comprehensive set of criteria, which will be used, along with stakeholder discussions and input, to develop a final design for any future changes to how the PRMR is allocated.

Q. HOW DOES MISO'S RESOURCE CLASS-LEVEL UCAP (DLOL-BASED METHODOLOGY) ALLOW ALIGNMENT BETWEEN ACCREDITATION AND RESOURCE ADEQUACY REQUIREMENTS?

A. Under the proposed methodology, the Resource Class-Level UCAP becomes an input to the determination of PRMR and LRR. Accreditation and Resource Adequacy Requirements under the proposed accreditation methodology are determined based on the

same probabilistic model simulation and hours, increasing consistency in the process and alignment between system risks, needs, and accreditation. This improves the current situation where accreditation is separated across three different, distinct processes for thermal, wind, and solar resources, which is currently disconnected between how capacity is accounted for in the requirement calculations.

Q. HOW WILL THIS SEND THE RIGHT SIGNALS TO INVEST IN THE RIGHT MIX OF RESOURCES NEEDED TO MAINTAIN RELIABILITY IN THE MISO FOOTPRINT?

A. The proposed accreditation methodology aligns the times of system risk and need with the contribution of each Resource Class during those same periods. By consistently applying this approach to all Resource Classes, Market Participants will be able to compare how each Resource Class's ability to contribute to resource adequacy changes over time and continue to find the right balance to ensure system reliability. These signals will be complemented with forward-looking estimates for Resource Class accreditation values, which are described in Section IX.

Q. WHAT IMPACT DOES MISO'S RELIABILITY BASED DEMAND CURVE (RBDC) PROPOSAL HAVE ON THE INSTANT FILING?

A. There is no change to the RBDC proposal because of the proposed accreditation reforms. The seasonal Planning Reserve Margin Requirements, that act as the starting point of the Marginal Reliability Impact (MRI) Curve calculations, will be based on the Resource Class-level UCAP as determined through the proposed DLOL-based methodology as described above.

VIII. STAKEHOLDER ENGAGEMENT

Q. HAS MISO SOLICITED AND CONSIDERED STAKEHOLDER INPUT IN DEVELOPING THE PROPOSED ACCREDITATION METHODOLOGY?

A. Yes, MISO's proposed accreditation methodology is based on robust stakeholder discussions over the last two years (Figure 14). The stakeholder discussions on accreditation reforms began in January 2022 following Tariff filings for reforms to thermal resource accreditation and seasonal Resource Adequacy construct. As described in Section VI above, MISO used its product development process to frame the issue or problem statement and evaluate options throughout 2022. In November 2022, MISO recommended the proposed two-step accreditation methodology for wind and solar resources. At the January 2023 RASC, MISO recommended extending the scope of the accreditation reform effort to cover accreditation changes for all Capacity Resources, except External Resources. One of the main reasons for this extension of scope was the stakeholder feedback to have a uniform accreditation methodology for all resources. Subsequently, throughout 2023 and in early 2024, MISO engaged stakeholders at the RASC and solicited their input to develop a detailed design for the proposed methodology.



Figure 14: Accreditation Reform Stakeholder Engagement Timeline

Q. DID MISO CHANGE ITS PROPOSED DESIGN TO ADDRESS STAKEHOLDER FEEDBACK?

A. MISO has made several improvements to its accreditation proposal based on feedback provided as a part of the stakeholder process. Stakeholder discussion and feedback played a substantial role in shaping the design of the accreditation reform proposed herein.

As discussed earlier, the initial scope of the instant accreditation reform included non-thermal resources including solar and wind resources. Stakeholders provided feedback and MISO agreed that accreditation across all fuel types should be comparable. In response to this feedback and to bring resources under the same accreditation methodology, MISO extended the scope of the accreditation reform to apply to all applicable Capacity Resources. This change, in response to stakeholder feedback, provides improved and consistent accreditation across resources of different fuel types.

Stakeholders also had concerns that basing accreditation on only modeled loss of load hours may not adequately account for reliability risks. Feedback from stakeholders suggested that MISO expand the hours considered in the DLOL-based methodology to include additional hours with increased reliability risk. After evaluation, MISO agreed with stakeholders that relying on only loss of load hours could result in scenarios where reliability risks during hours, when available generation is just sufficient to meet the demand (e.g., total available generation is 50 MW above load in a given hour), is not captured in the calculation. Additionally, relying on only loss of load hours could also result in year-over-year volatility especially when the number of loss of load hours in a particular Season is smaller. Upon consideration, MISO expanded its definition of Critical

Hours to include additional low margin hours in addition to loss of load hours. The expanded Critical Hours provides stability improvements to the resulting accreditation.

Along with expanding hours, MISO also considered Stakeholder feedback that modeled results should be weighted by expected unserved energy (EUE) in the probabilistic model that would weight results by the severity of modeled risk. Although the MISO design team was in favor of weighting hours by severity of risk, using only EUE to weight results would provide weight for only loss of load hours, giving any low margin hours no weight at all. To provide both weighting and consideration of expanded hours, the weighting methodology proposed above provides the most weight to the hours with the greatest reliability risk and provides comparable weights to hours with similar risk around the loss of load threshold.

Although occurring late in the design process, Stakeholder feedback helped shape the Local Resource Requirement design provided above. The revised LRR design proposal is a result of substantial opposition to the originally proposed design. In response to this overwhelming opposition, the MISO design team crafted a new LRR proposal. The resulting positive stakeholder feedback suggests that the revised approach described above is the right balance within the proposed accreditation reform.

Throughout the Stakeholder process, the feedback was clear that there was a need for better understanding of the probabilistic model. To help stakeholders better understand MISO business practices around LOLE modeling and probabilistic analysis, MISO hosted a LOLE modeling and Accreditation Reform workshop for stakeholders in September

2023.[22] As a part of stakeholder process for the proposed accreditation reforms, MISO and stakeholders discussed and agreed that LOLE modeling improvements are important to align the probabilistic model with the expected operation of resources. As discussed further below, improving and enhancing the probabilistic model is an iterative and ongoing process. In response to extensive stakeholder feedback, MISO has recently kicked off a formal stakeholder process for LOLE modeling enhancements.

Stakeholders also voiced concerns about the timing for implementation of the proposed accreditation methodology. Among other concerns, stakeholders noted that resource planning and investment decisions are already being implemented and that sufficient time is needed before applying the new accreditation methodology in the Planning Resource Auction. In response to this stakeholder feedback, MISO is proposing the three-year transition period described below. In addition, MISO is committed to providing stakeholders with indicative information about the impact of the proposed changes both during the transition period and going forward.

Q. WHAT ARE MISO'S PLANS AND COMMITMENTS TO IMPROVING THE PROBABILISTIC MODEL?

A. As described above, the Resource Class accreditation values established through the proposed methodology are a direct outcome from the probabilistic model. It is important to note that MISO regularly evaluates its LOLE process to determine whether enhancements can be implemented to reflect changing system conditions more accurately. Recent improvements that have been made to the probabilistic model include the addition

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[22] *See* MISO's LOLE Modeling & Accreditation Reform Workshop - September 22, 2023 (misoenergy.org)

of a cold-weather outage adder, use-limited modeling of Electric Storage Resources, renewable profiles, inclusion of a probabilistic distribution of non-firm external support, and the addition of seasonal forced outage rates. This is an ongoing process that is necessary to help ensure the LOLE results are consistent with the underlying risk parameters. MISO is committed to continuing this process of enhancing the probabilistic model to better reflect risks across the year. Any future changes to the probabilistic model to better reflect risk will then be reflected in both the Resource Adequacy Requirements and accreditation values. Improving the probabilistic model is the best way to capture risk more accurately, which will better reflect the contribution to reliability of the resources modeled. As mentioned previously in Section V, MISO has communicated a plan to stakeholders to research, design, and implement specific aspects of the probabilistic model, including a revision of planned outages, cold-weather outages, load forecasting, and storage modeling. For example, through several discussions with stakeholders, MISO recognizes that SERVM may not currently distribute planned outages consistently across Resource Classes which may have inadvertent impacts on Resource Class-level UCAP. MISO has already initiated discussions at the RASC to further investigate this potential issue and address it as needed prior to implementation. The planned model improvements will further refine alignment between risk, needs, and availability, as will further improvements performed in the future.

Q. IS MISO COMMITTED TO IMPROVING STORAGE DISPATCH MODELING?

A. Starting with Planning Year 2024-2025, MISO started representing Electric Storage Resources with SERVM's native model for energy-limited resources. MISO is planning to simulate future-looking cases, with increased penetration of storage to better understand

how the advent of these resources affect the probabilistic model results and the distribution of risk in the MISO footprint in the future.

Q. WHAT IS MISO DOING TO PROVIDE MORE TRANSPARENCY REGARDING THE DATA AND INPUTS TO THE PROBABILISTIC MODEL?

A. MISO currently makes available to stakeholders many of the inputs to the probabilistic model, e.g., shapes for 30 years of load, wind, and solar, as well as documents the development process for other inputs.[23] Throughout the stakeholder engagement period, MISO has produced Resource Class estimates for the proposed accreditation methodology under a variety of assumptions and configurations, as well as the resulting impacts on PRMR and LRR values. MISO has also shared with individual Market Participants their specific resource-level estimates.

Additionally, MISO has engaged with stakeholders on several occasions to explain the current limitations, including specific data items, that prevent MISO from sharing the probabilistic model and has requested feedback to overcome said limitations. MISO's Tariff, however, prohibits MISO from sharing resource-specific information, which is the property of the various Market Participants, including outage rates and granular load forecasts without express approval from all Market Participants. MISO has initiated conversations at the January and February 2024 RASC meetings to improve upon data transparency.[24] MISO is committed to establishing a new process to provide additional data

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[23] *See* Astrapé Consulting: *MISO Seasonal Inputs for the 2022 LOLE Study* available at: https://cdn.misoenergy.org/20220707%20LOLEWG%20Supplemental%20MISO%20Seasonal%20Inputs%20Documentation%20Astrape625466.pdf

[24] See LOLE Model Data Transparency, February 28, 2024 RASC available at: https://cdn.misoenergy.org/20240228%20RASC%20Item%2005b%20LOLE%20Data%20Transparency631895.pdf

annually to stakeholders related to the probabilistic model's generation inputs while continuing to share shapes for 30 years of load, wind and solar. The additional data will be masked, rolled up, or provided with class averages so that stakeholders can replicate results while maintaining data confidentiality, consistent with the requirements of its Tariff and recent stakeholder feedback.

IX. TRANSITION PERIOD AND IMPLEMENTATION TIMELINE

Q. WHAT EFFECTIVE DATE HAS MISO REQUESTED FOR THE RESOURCE ACCREDITATION REFORM PROPOSAL?

A. MISO has requested an effective date of September 1, 2024, for the reporting requirement included in the Tariff. Pursuant to the proposed Tariff Schedule 53A, beginning September 1, 2024, MISO will be required to publish Resource Class-level indicative results and provide resource-level indicative results by Market Participant to individual resource owners as requested prior to the PRA beginning with the 2025 PRA for Planning Year 2025 – 2026 and continuing for the next two Planning Years.

Q. WHEN DOES MISO PLAN TO IMPLEMENT THE PROPOSED ACCREDITATION METHODOLOGY?

A. MISO plans to use the proposed accreditation methodology to accredit resources beginning with the 2028 PRA for Planning Year 2028 – 2029 (Figure 15). During the three-year transition period, beginning with Planning Year 2025 – 2026, MISO will provide resource-level results as requested to Market Participants using the proposed methodology so that they understand the impact on their resources prior to implementation.

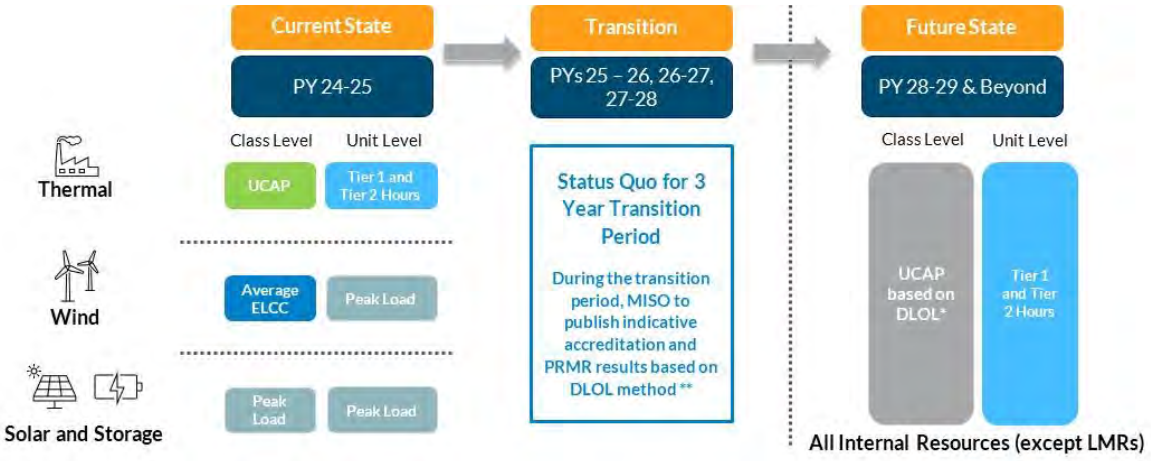


Figure 15: Effective Date and Transition Plan shared with stakeholders

Q. WHY HAS MISO CHOSEN A SEPTEMBER 1, 2024 EFFECTIVE DATE GIVEN IT DOES NOT INTEND TO IMPLEMENT THE PROPOSED METHODOLOGY UNTIL PLANNING YEAR 2028 – 2029?

A. The three-year transition period is an important aspect of the overall proposal and, as discussed above, was developed to address stakeholder concerns regarding implementation timing. MISO recognizes that the change in the accreditation methodology is a significant one and has designed the transition period to provide Market Participants an opportunity to adjust to the change. This transition period will assist LSEs with integrated resource planning by equipping them with the data they need to make long-term investment decisions.

Q. HOW WILL MISO PROVIDE INDICATIVE RESULTS TO STAKEHOLDERS DURING THE TRANSITION PERIOD?

A. For each of the Planning Years during the transition period, MISO will provide indicative results for the proposed accreditation methodology. The Resource Class-level UCAP, PRMR, and LRR estimates will be made available to stakeholders and will be based on the same probabilistic model simulation results used to determine the PRMR in that Planning

Year. Market Participants will also be provided with the indicative Schedule 53A SAC values for their own resources as requested. Indicative results will be generated concurrent with existing processes and MISO will produce them as soon as feasible.

Q. HOW WILL MISO PROVIDE FORWARD-LOOKING RESOURCE ACREDITATION ESTIMATES?

A. To assist LSEs with integrated resource planning needed to make long-term investment and retirement decisions, MISO will provide future year (5 and 10 year forward) estimated Resource Class-level accreditation values annually as part of MISO's Renewable Resource Assessment (RRA) study starting in 2024. Additional data needs and sensitivities will be considered as these estimates are developed. Just as with all future predictions, the degree of uncertainty in the inputs alone (future demand growth, change in consumer behavior, future generation technologies, rate of retirements and deployment, etc.) can substantially vary the outcome of RA needs and LOLE analysis for such long timeframes.

Q. HOW WILL RESOURCES BE ACCREDITED DURING THE TRANSITION PERIOD?

A. The transition proposal includes keeping the status quo accreditation methodologies for all resource types until PY 2028-2029. Following the transition period, MISO intends to apply the proposed accreditation methodology to all Capacity Resources including thermal, wind, solar and Electric Storage Resources.

X. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Affidavit of Zakaria Joundi

COUNTY OF HAMILTON)
)
STATE OF INDIANA)

Zakaria Joundi, being duly sworn, deposes and states that he prepared the Prepared Direct Testimony of Zakaria Joundi, and the statements contained therein are true and correct to the best of his knowledge and belief.

Zakaria Joundi

SUBSCRIBED AND SWORN BEFORE ME, this 27 day of March, 2024.

(Notary Public Signature)

Commissioned in Clinton county.

Commission Number: 705772

Commission Expires: 9/27/2025

RHIANNON RENA SHELLEY
Clinton County
My Commission Expires
September 27, 2025

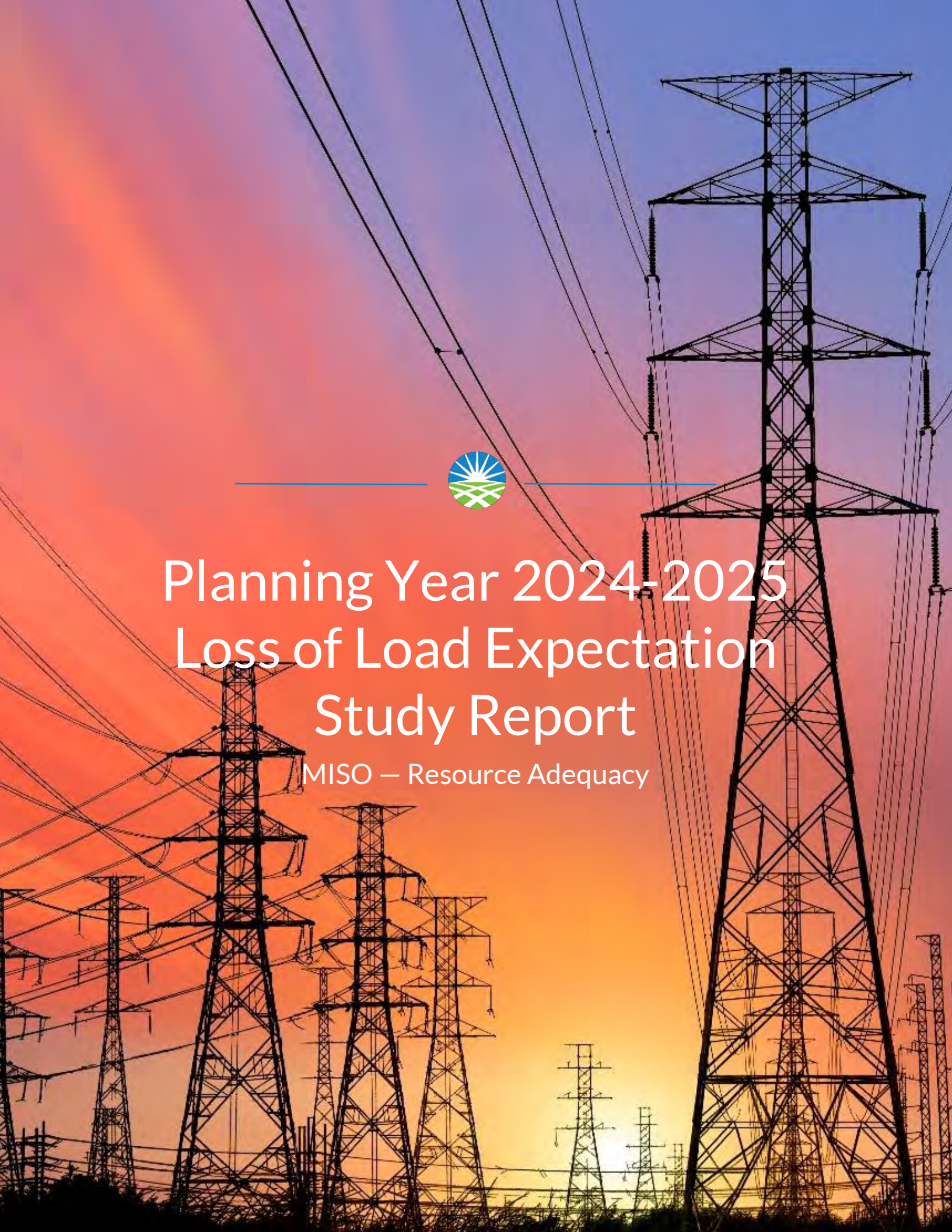
BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-26-16

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 82

MISO 2024–25 LOLE Study Report



Planning Year 2024-2025 Loss of Load Expectation Study Report

MISO — Resource Adequacy

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April 2024 Update: Outyear Planning Reserve Margin (PRM) and additional EFORd results added to report.

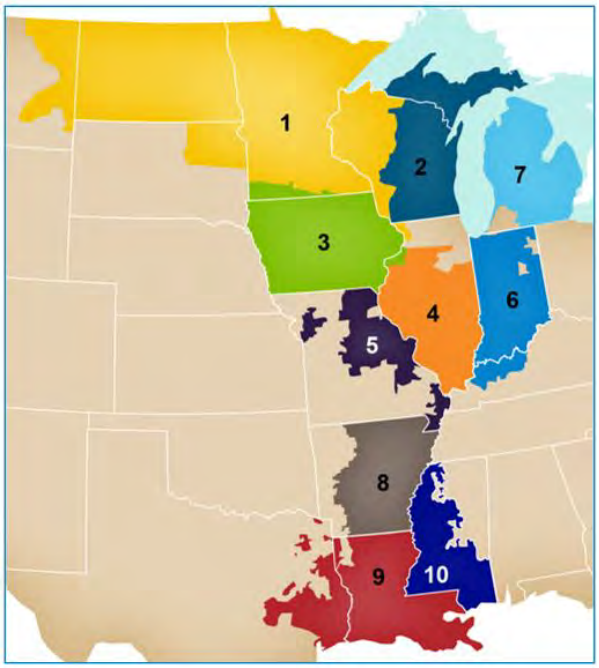
Executive Summary

In preparation for the annual Planning Resource Auction, MISO conducts an annual Loss of Load Expectation (LOLE) study to determine Resource Adequacy Requirements for the upcoming Planning Year 2024-2025. These requirements are identified on a seasonal basis for each Local Resource Zone within MISO.

Planning Reserve Margin (PRM) determined through this year's study are:

Season	PRM UCAP %
Summer 2024	9.0%
Fall 2024	14.2%
Winter 2024-2025	27.4%
Spring 2025	26.7%

MISO is divided into ten Local Resource Zones (LRZs) as shown in the figure below.



Local Resource Zone	Local Balancing Authorities
1	DPC, GRE, MDU, MP, NSP OTP, SMP
2	ALTE, MGE, MIUP, UPPC, WEC, WPS
3	ALTW, MEC, MPW
4	AMIL, CWLP, GLH, SIPC
5	AMMO, CWLD
6	BREC, CIN, HE, HMPL, IPL, NIPS, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	EMBA, SME

The report also determines zonal Local Reliability Requirements (LRRs). Additionally, initial values for zonal Capacity Import Limits (CIL), Capacity Export Limits (CEL), Zonal Import Ability (ZIA), and Zonal Export Ability (ZEA) for each season are also determined. These quantities are described in section 2.3.

Tables ES-1 through ES-4 below show results for each season.

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
Summer 2024 PRM UCAP	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%
LRR UCAP per-unit of LRZ Peak Demand	1.132	1.113	1.278	1.291	1.331	1.190	1.161	1.392	1.135	1.518
Capacity Import Limit (CIL) (MW)	6,462	4,506	5,009	10,790	3,208	7,463	4,500	3,536	5,613	3,564
Capacity Export Limit (CEL) (MW)	4,537	3,971	5,450	2,730	4,644	5,637	5,709	6,171	2,359	1,840
Zonal Import Ability (ZIA) (MW)	6,460	4,506	4,911	9,857	3,208	7,197	4,490	3,444	4,794	3,564
Zonal Export Ability (ZEA) (MW)	4,539	3,971	5,548	3,663	4,644	5,903	5,719	6,263	3,178	1,840

Table ES-1: Initial Planning Resource Auction Deliverables — Summer 2024

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
Fall 2023 PRM UCAP	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%
LRR UCAP per-unit of LRZ Peak Demand	1.235	1.199	1.345	1.323	1.441	1.257	1.311	1.496	1.190	1.667
Capacity Import Limit (CIL) (MW)	6,502	5,719	6,789	6,637	3,786	8,954	4,400	5,040	6,435	4,736
Capacity Export Limit (CEL) (MW)	5,711	4,512	6,913	3,863	5,402	3,519	5,381	4,212	3,602	2,889
Zonal Import Ability (ZIA) (MW)	6,500	5,719	6,684	5,699	3,786	8,661	4,390	4,942	5,608	4,736
Zonal Export Ability (ZEA) (MW)	5,713	4,512	7,018	4,801	5,402	3,812	5,391	4,310	4,429	2,889

Table ES-2: Initial Planning Resource Auction Deliverables — Fall 2024

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
Winter 24-25 PRM UCAP	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%
LRR UCAP per-unit of LRZ Peak Demand	1.442	1.363	2.006	1.338	1.285	1.227	1.607	1.560	1.328	1.864
Capacity Import Limit (CIL) (MW)	4,693	5,523	5,704	6,731	4,477	8,526	4,666	4,336	5,420	3,219
Capacity Export Limit (CEL) (MW)	5,174	4,772	8,975	4,650	6,229	1,407	5,743	5,808	2,103	2,993
Zonal Import Ability (ZIA) (MW)	4,691	5,523	5,600	5,811	4,477	8,286	4,656	4,262	4,623	3,219
Zonal Export Ability (ZEA) (MW)	5,176	4,772	9,079	5,570	6,229	1,647	5,753	5,882	2,900	2,993

Table ES-3: Initial Planning Resource Auction Deliverables — Winter 2024-2025

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
Spring 2024 PRM UCAP	26.7%	26.7%	26.7%	26.7%	26.7%	26.7%	26.7%	26.7%	26.7%	26.7%
LRR UCAP per-unit of LRZ Peak Demand	1.329	1.363	1.531	1.662	1.618	1.371	1.322	1.610	1.334	1.878
Capacity Import Limit (CIL) (MW)	4,943	5,034	6,626	6,003	3,892	8,015	4,893	6,124	6,417	4,628
Capacity Export Limit (CEL) (MW)	6,318	4,601	5,761	5,081	4,984	3,444	5,591	4,936	3,994	2,740
Zonal Import Ability (ZIA) (MW)	4,941	5,034	6,514	5,083	3,892	7,730	4,883	6,030	5,598	4,628
Zonal Export Ability (ZEA) (MW)	6,320	4,601	5,873	6,001	4,984	3,729	5,601	5,030	4,813	2,740

Table ES-4: Initial Planning Resource Auction Deliverables — Spring 2025

The stakeholder review process played an integral role in this study. MISO would like to thank the Loss of Load Expectation Working Group (LOLEWG) and the Resource Adequacy Subcommittee (RASC) for its assistance and input.

1 LOLE Study Process Overview

In compliance with Module E-1 of the MISO Tariff, MISO performed its annual LOLE Study to determine, for each season of Planning Year 2024-2025, the system Unforced Capacity (UCAP) Planning Reserve Margin (PRM) and the per-unit Local Reliability Requirements (LRR) of Local Resource Zone (LRZ) Peak Demand.

In addition to the LOLE analysis, MISO performed seasonal transfer analyses to determine seasonal Zonal Import Ability (ZIA), Zonal Export Ability (ZEA), Capacity Import Limits (CIL) and Capacity Export Limits (CEL). CIL, CEL, and ZIA are used, in conjunction with the LOLE analysis results, in the Planning Resource Auction (PRA). ZEA is informational and not used in the PRA.

The PY 2024-2025 per-unit seasonal LRR UCAP multiplied by the updated LRZ seasonal Peak Demand forecasts submitted for the 2024-2025 PRA determines each LRZ's seasonal LRR. Once the seasonal LRR is determined, the ZIA values and non-pseudo tied exports are subtracted from the seasonal LRR to determine each LRZ's seasonal Local Clearing Requirement (LCR) consistent with Section 68A.6 of Module E-1[1]. An example LCR calculation pursuant to Section 68A.6 of the current effective Module E-1 shows how these values are reached (Table 1-1).

Local Resource Zone (LRZ) EXAMPLE	Example LRZ	Formula Key
Installed Capacity (ICAP)	17,442	[A]
Unforced Capacity (UCAP)	16,326	[B]
Adjustment to UCAP (1d in 10yr)	50	[C]
Local Reliability Requirement (LRR) (UCAP)	16,376	[D]=[B]+[C]
LRZ Peak Demand	14,270	[E]
LRR UCAP per-unit of LRZ Peak Demand	114.8%	[F]=[D]/[E]
Zonal Import Ability (ZIA)	3,469	[G]
Zonal Export Ability (ZEA)	2,317	[H]
Local Clearing Requirement (LCR) EXAMPLE	**Example LRZ**	**Formula Key**
Non-Pseudo Tied Exports (UCAP)	150	[J]
Local Reliability Requirement (LRR) (UCAP)	16,376	[K]=[F]*[E]
Local Clearing Requirement (LCR)	12,757	[L]=[K]-[G]-[J]

Table 1-1: Example Local Clearing Requirement Calculation

The actual effective PRM Requirement (PRMR) for each season of Planning Year 2024-2025 will be determined after the updated LRZ Seasonal Peak Demand forecasts are submitted by November 1, 2023, for the 2024-2025 PRA. The ZIA, ZEA, CIL and CEL values are subject to updates in March 2024 based on changes to exports of MISO resources to non-MISO load, changes to pseudo tied commitments, and updates to facility ratings following the completion of the LOLE Study.

[1] https://www.misoenergy.org/legal/tariff
Effective Date: September 1, 2022

Finally, the Simultaneous Feasibility Test (SFT) is performed as part of the PRA where the deliverability of cleared generation is validated through transfer analysis modeling to ensure transmission reliability. If constraints arise, they are mitigated by adjusting CIL and CEL values as needed.

1.1 Study Improvements

The Planning Year 2024-2025 LOLE Study incorporated additional study improvements, building on those incorporated in the prior studies. Improvements for the PY 2023-2024 LOLE Study included modeling of seasonal outage rates, correlated cold weather outage adder profiles, a probabilistic distribution of non-firm support, and 30 years of hourly wind and solar profiles. Details for these changes can be found in the PY 2023-2024 LOLE Study Report.

The PY 2024-2025 LOLE Study included the following improvements:

- **Enhanced modeling of battery storage resources:** Previously, battery storage was modeled as a must-run resource that is always available at nameplate capacity, unless on a forced outage (assumed to be a rate of 5% for every season). Now, battery storage is modeled as use-limited with a duration of 4 hours.

- **Realistic commercial operation dates for future resources**: PY 2024-2025 study considered more realistic anticipated commercial operation dates (CODs) for future resource additions with executed generation interconnection agreements (GIAs), factoring in macroeconomic and regulatory realities. Interconnection customers have indicated to MISO that factors such as supply-chain issues, regulatory approvals, contractor availability, and other economic factors such as PPAs, are requiring GIA projects to delay commercial operations. Correspondingly, declared anticipated CODs were adjusted based on GIA projects in the queue per customer feedback.

- **Improved consideration of outages driven by extreme cold temperatures**: Accounting of additional forced outages during extreme cold temperatures in the Winter season was updated in the PRM and LRR calculations. For context, the LOLE model has historically utilized a 5-year average EFORd based on historic GADS data. These resource-specific forced outage rates were annualized under the prior annual construct and were seasonalized in the PY 2023-2024 LOLE Study, which better captured the seasonal availability of resources as observed in operations.

  Additional thermal forced outages are added to the model during times of extreme cold temperatures to better capture the magnitude of observed correlated outages. The magnitude of forced outages added increases as temperatures decrease based on the relationship between outages and temperature determined from historic GADS and weather data. The modeling of additional forced outages in the Winter season due to the adder induces a higher volume of forced outages in the model beyond just the average Winter EFORd. Each LRZ has a unique outage/temperature profile based on actual historical forced outages. The incremental cold weather outages are not assigned to a particular resource but instead represent the aggregate impact on the system for coal, gas, and combined cycle resources.

  The accounting of reduced Winter Unforced Capacity resulting from additional extreme cold weather outages was improved in the most recent PRM and LRR calculations. A comparative probabilistic analysis, with and without the cold weather outage adder, was performed to quantify the impact of modeling the cold weather outage adder profiles on the system-wide requirements. This impact was distributed pro-rata to the zonal level based on the average magnitude of the zonal cold weather outage adder profiles used in the LRR calculations.

2 Transfer Analysis

2.1 Calculation Methodology and Process Description

Transfer analyses determined CIL and CEL values for LRZs in each season for Planning Year 2024-2025. Annual adjustments are made for Border External Resources and Coordinating Owner Resources to determine the ZIA and ZEA in each season. Further adjustments are made for exports to non-MISO loads to arrive at the CIL and CEL values. The objective of the transfer analyses is to determine constraints caused by the transfer of capacity between zones and the associated transfer capability. Multiple factors impacted the analysis when compared to previous studies, including:

- Approximately 800 MW of retirements and/or suspensions
- New intermittent resources
- Base model dispatch in MISO and seams

2.1.1 Generation Pools

To determine an LRZ's import or export limit, a transfer is modeled by ramping generation up in a source subsystem and ramping generation down in a sink subsystem. The source and sink definitions depend on the limit being tested. The LRZ studied for import limits is the sink subsystem and the adjacent MISO LBAs are the source subsystem. The LRZ studied for export limits is the source subsystem and the rest of MISO is the sink subsystem. These are the same in all seasons for the upcoming Planning Year.

Transfers can cause potential issues, which are addressed through the study assumptions. First, an abundantly large source pool spreads the impact of the transfer widely which can cause differences in studied zones' transfer capabilities and the identified constraints. Second, ramping up generation from remote areas could cause electrically distant constraints for any given LRZ, which should not determine a zone's limit. For example, export constraints due to dispatch of LRZ 1 generation in the northwest portion of the footprint should not limit the import capability of LRZ 10, which covers the MISO portion of Mississippi.

To address these potential issues, the transfer studies limit the source pool for the import studies to the Tier 1 and Tier 2 adjacent LBAs to the study zone. Since the generation that is ramped up in export studies are contained in the study LRZ, these issues only apply to import studies. Generation within the zone studied for an export limit is ramped up and constraints are expected to be near or in the study zone.

2.1.2 Redispatch

Limited redispatch is applied after performing transfer analyses to mitigate constraints. Redispatch ensures constraints are not caused by the base dispatch and aligns with potential actions that can be implemented for the constraint by MISO control room operators. Redispatch scenarios can be designed to address multiple constraints, as required, and may be used for constraints that are electrically close to each other or to further optimize transfer limits for several constraints requiring only minor redispatch. The redispatch assumptions include:

- The use of no more than 10 conventional fuel plants or intermittent resources
- Redispatch limit at 2,000 MW total (1,000 MW up and 1,000 MW down)
- No adjustments to nuclear units
- No adjustments to the portions of pseudo-tied units committed to non-MISO load

2.1.3 Sensitivity

New to the transfer analyses this year is the ability for Transmission Owners in a specific zone to request a sensitivity be included in the generation-to-generation transfer to allow for the True Transfer Limit to be identified. The sensitivity would allow excluded units to be included in the generation-to-generation transfer for a zone's CIL. Excluded units mainly include nuclear units and units not to be used in zonal transfers from the latest MTEP model. This sensitivity can only be requested for a CIL study. A sensitivity would only be accepted for a particular zone if they are in the situation portrayed below by the chart in Figure 2-1.

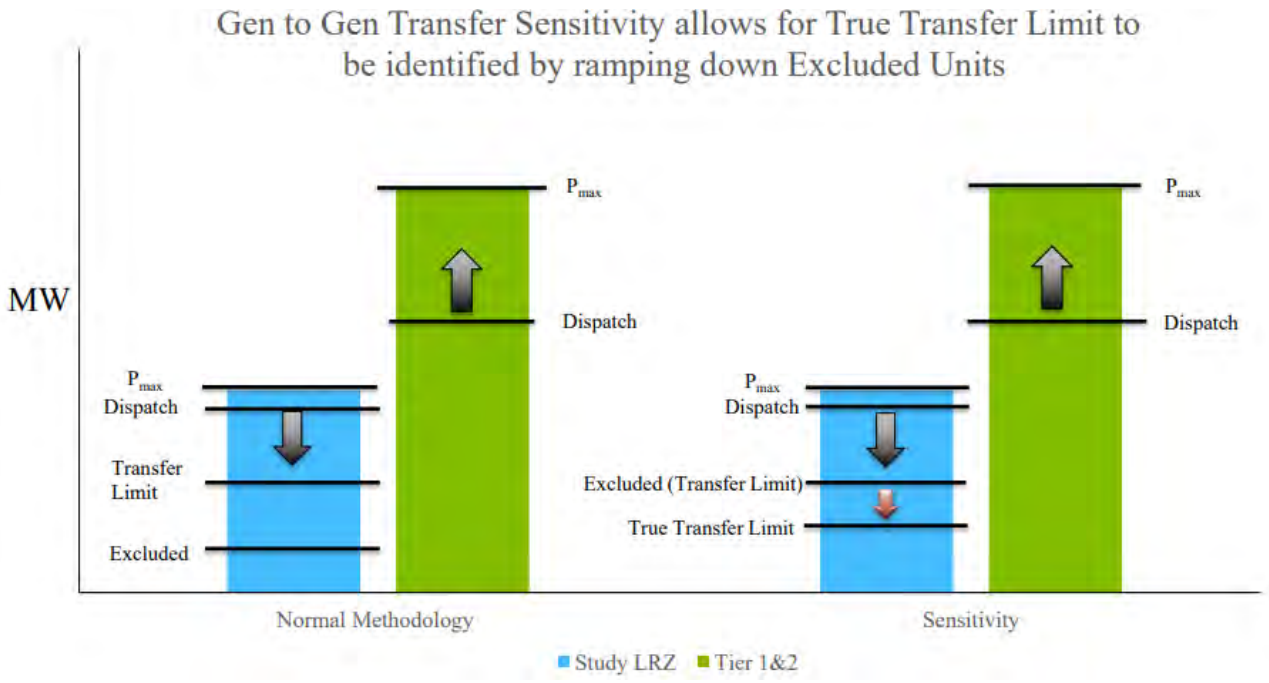


Figure 2-1: Generation-to-Generation Transfer Sensitivity

The two bars shown for the Normal Methodology would not allow for a sensitivity to be requested by a Transmission Owner. In this situation, since the transfer limit is already identified before hitting the excluded units, a request for a generation-to-generation transfer sensitivity would not be accepted. The two bars shown for the Sensitivity identify a situation where a request for a generation-to-generation transfer sensitivity would be accepted. When ramping down generation, the excluded units are hit before the True Transfer Limit, but since the rest of the units are excluded, the transfer limit would be identified as the point where the generation-to-generation stops at the excluded units. With a sensitivity in place, the generation-to-generation transfer would continue into the excluded units and the True Transfer Limit would be identified.

LRZ 10 was the only Local Resource Zone to utilize a generation-to-generation transfer sensitivity and have the results of which included in their Capacity Import Limit for Planning Year 2024-2025.

2.1.4 Generation Limited Transfer for CIL/CEL and ZIA/ZEA

When conducting transfer analysis to determine import or export limits, the source subsystem might run out of generation to dispatch before identifying a valid constraint caused by a transmission limit. MISO developed a Generation Limited Transfer (GLT) process to identify transmission constraints in these situations, when possible, for both imports and exports.

After running the First Contingency Incremental Transfer Capability (FCITC) analysis to determine limits for each LRZ, MISO will determine whether a zone is experiencing a GLT (e.g. whether the first constraint would occur only after all the generation is dispatched at its maximum amount). If the LRZ experiences a GLT, MISO will adjust the base model depending on whether it is an import or export analysis and re-run the transfer analysis.

For an export study, when a transmission constraint has not been identified after all generation has been dispatched within the exporting system (LRZ under study), MISO will decrease load and generation dispatch in the study zone. The adjustment creates additional capacity to export from the zone. After the adjustments are complete, MISO will re-run the transfer analysis. If a GLT reappears, MISO will make further adjustments to the load and generation of the study zone.

For an import study, when a transmission constraint has not been identified after all generation has been dispatched within the source subsystem, MISO will decrease load and generation in the source subsystem. This increases the export capacity of the adjacent LBAs for the study zone. After the adjustments are complete, MISO will run the transfer analysis again. If a GLT reappears, MISO will make further adjustments to the model's load and generation in the source subsystem.

FCITC could indicate the transmission system can support larger thermal transfers than would be available based on installed generation for some zones—however, large variations in load and generation for any zone may lead to unreliable limits and constraints. Therefore, MISO limits load scaling for both import and export studies to 50 percent of the zone's load. In a GLT, redispatch, or GLT plus redispatch scenario, the FCITC of the most limiting constraint might exceed Zonal Export/Import Capability. If the GLT does not produce a limit for a zone, either due to a valid constraint not being identified or due to other considerations as listed in the prior paragraph, MISO shall report that LRZ as having no limit and ensure that the limit will not bind in the first iteration of the Simultaneous Feasibility Test (SFT).

2.1.5 Voltage Limited Transfer for CIL/CEL and ZIA/ZEA

Zonal imports may be limited by voltage constraints due to a decrease in the generation in the study zone. Voltage constraints might occur at lower transfer levels than thermal limits determined by linear FCITC. As such, LOLE studies may evaluate power-voltage curves for LRZs with known voltage-based transfer limitations identified through existing MISO or Transmission Owner studies. Such evaluation may also occur if an LRZ's import reaches a level where the majority of the zone's load would be served using imports from resources outside of the zone. MISO will coordinate with stakeholders as it encounters these scenarios. For Planning Year 2024-2025, only Local Resource Zones 1, 4, and 7 import analyses included voltage screening and study. No studies identified a voltage limit with lower transfer capability than the thermal limit for Planning Year 2024-2025.

2.2 Powerflow Models and Assumptions

2.2.1 Tools Used

MISO used the Siemens PTI Power System Simulator for Engineering (PSS/E) and PowerGEM Transmission Adequacy and Reliability Assessment (TARA) tools.

2.2.2 Inputs Required

Thermal transfer analysis requires powerflow models and related input files. MISO used contingency files from MTEP[2] reliability assessment studies. Single-element contingencies in MISO and seam areas were also evaluated.

MISO developed a subsystem file to monitor its footprint and seam areas which was used for all seasons. LRZ definitions were developed as sources and sinks in the study. See Appendix C for tables containing adjacent area definitions (Tiers 1 and 2) used for this study. The monitored file includes all facilities under MISO functional control and single elements in the seam areas of 100 kV and above.

2.2.3 Powerflow Modeling

The MTEP23 models were built using MISO's Model on Demand (MOD) model data repository, with the following base assumptions (Table 2-1).

Scenario	Effective Date	Projects Applied	External Modeling	Load and Generation Profile	Wind %	Solar %
Summer 2024	July 15th	MTEP Appendix A and Target A	ERAG MMWG 2022 Series 2024 Summer Peak Load Model	Summer Peak	18%	50%
Fall 2024	October 15th	MTEP Appendix A and Target A	ERAG MMWG 2022 Series 2024 Spring Light Load Model	Fall Peak	28.5%	0%
Winter 2024-2025	January 15th	MTEP Appendix A and Target A	ERAG MMWG 2022 Series 2024 Winter Peak Load Model	Winter Peak	67%	0%
Spring 2025	April 15th	MTEP Appendix A and Target A	ERAG MMWG 2022 Series 2024 Spring Light Load Model	Spring Peak	28.5%	0%

Table 2-1: Model Assumptions

MISO excluded several types of units from the transfer analysis dispatch—these units' base dispatch remained fixed.

- Nuclear dispatch does not change for any transfer without a sensitivity
- Wind and solar resources can be ramped down, but not up
- Pseudo-tied resources were modeled at their expected commitments to non-MISO load, although portions of these units committed to MISO could participate in transfer analyses

System conditions such as load, dispatch, topology, and interchange have an impact on transfer capability. The model was reviewed as part of the base model built for MTEP23 analyses, with study files made available on MISO ShareFile.

[2] Refer to the Transmission Planning BPM (BPM-20) for more information regarding MTEP input files. https://www.misoenergy.org/legal/business-practice-manuals/

MISO worked closely with Transmission Owners and stakeholders to model the transmission system accurately, as well as to validate constraints and redispatch. Like other planning studies, transmission outage schedules were not included in the analyses. This is driven partly by limited availability of outage information as well as current transmission planning standards. Although no outage schedules were evaluated, single element contingencies were evaluated. This includes Bulk Electric System lines, transformers, and generators.

Contingency coverage covers most of category P1 and some of category P2 outlined in Table 1 of NERC Reliability Standard TPL-001.

2.2.4 General Assumptions

MISO uses TARA to process the powerflow model and associated input files to determine the seasonal import and export limits of each LRZ by determining the transfer capability. Transfer capability measures the ability of interconnected power systems to reliably transfer power from one area to another under specified system conditions. The incremental amount of power that can be transferred is determined through FCITC analysis. FCITC analysis and base power transfers provide the information required to calculate the First Contingency Total Transfer Capability (FCTTC), which indicates the total amount of transferrable power before a constraint is identified. FCTTC is the base power transfer plus the incremental transfer capability (Equation 2-1). All published limits are based on the zone's FCTTC and may be adjusted for capacity exports.

$$First\ Contingency\ Total\ Transfer\ Capability\ (FCTTC) = Base\ Power\ Transfer + FCITC$$

Equation 2-1: Total Transfer Capability

FCITC constraints are identified under base case situations in each season or under P1 contingencies provided through the MTEP process. Linear FCITC analysis identifies the limiting constraints using a minimum transfer Distribution Factor (DF) cutoff of 3 percent, meaning the transfer must increase the loading on the overloaded element, under system intact or contingency conditions, by 3 percent or more.

A pro-rata dispatch is used, which ensures all available generators will reach their maximum dispatch level at the same time. The pro-rata dispatch is based on the MW reserve available for each unit and the cumulative MW reserve available in the subsystem. The MW reserve is found by subtracting a unit's base model generation dispatch from its maximum dispatch, which reflects the available capacity of the unit.

Table 2-2 and Equation 2-2 show an example of how one unit's dispatch is set, given all machine data for the source subsystem.

Machine	Base Model Unit Dispatch (MW)	Minimum Unit Dispatch (MW)	Maximum Unit Dispatch (MW)	Reserve MW (Unit Dispatch Max – Unit Dispatch Min)
1	20	20	100	80
2	50	10	150	100
3	20	20	100	80
4	450	0	500	50
5	500	100	500	0
			Total Reserve	**310**

Table 2-2: Example Subsystem

$$\textbf{\textit{Machine 1 Incremental Post Transfer Dispatch}} = \frac{\textbf{\textit{Machine 1 Reserve MW}}}{\textbf{\textit{Source Subsystem Reserve MW}}} \times \textbf{\textit{Transfer Level MW}}$$

$$Machine\ 1\ Incremental\ Post\ Transfer\ Dispatch = \frac{80}{310} \times 100 = 25.8$$

$$Machine\ 1\ Incremental\ Post\ Transfer\ Dispatch = 25.8$$

Equation 2-2: Machine 1 Dispatch Calculation for 100 MW Transfer

2.3 Results for CIL/CEL and ZIA/ZEA

Study constraints and associated ZIA, ZEA, CIL, and CEL for each LRZ for each season were presented and reviewed through the LOLEWG with final results for Planning Year 2024-2025 presented at the October 17th, 2023 meeting. Table 2-3 below shows the Planning Year 2024-2025 CIL and ZIA with corresponding constraint, GLT, and redispatch (RDS) information.

All zones had an identified ZIA this year. If there is no valid constraint identified, the following equation will be used where the FCITC will be replaced by the Tier 1 and Tier 2 capacity.

$$\textbf{\textit{ZIA}} = \textbf{\textit{FCITC}} + \textbf{\textit{Area Interchange}} - \textbf{\textit{Border External Resources and Coordinating Owners}}$$

Equation 2-3: Zonal Import Ability (ZIA) Calculation

LRZ1	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2024	Wien - T Corners 115 kV	Arpin - Eau Claire 345 kV	10%	826MWx2	6460	6462
Fall 2024	Mitchell County - Adams 345 kV	Sherburne Country Generator	None	977MWx2	6500	6502
Winter 2024/25	Pleasant Valley - Byron 161 kV	Byron - Pleasant Valley 345 kV	None	670MWx2	4691	4693
Spring 2025	Coal Creek CR4 - Coal Creek TP4 230 kV	Coal Creek - Stanton 230 kV	None	1000MWx2	4941	4943
LRZ2	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2024	Paddock 345/138 kV Transformer	Riverside Generator	None	586MWx2	4506	4506
Fall 2024	Arpin - Sigel 138 kV	Pow STG20 Generator	None	1000MWx2	5719	5719
Winter 2024/25	Rockdale - Lakehead Cambridge Tap 138 kV	Cambridge Tap - Rockdale 138 kV	None	614MWx2	5523	5523
Spring 2025	Arpin - Sigel 138 kV	Arpin - Rocky Run 345kV	None	1000MWx2	5034	5034
LRZ3	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2024	Ottumwa 345/161 kV Transformer	Ottumwa Generator	None	617MWx2	4911	5009
Fall 2024	Ottumwa 345/161 kV Transformer	Ottumwa Generator	None	365MWx2	6684	6789
Winter 2024/25	Sub 3458 (Nebraska City) - Sub 3456 345 kV	Sub 3455 - Sub 3740 345 kV	None	440MWx2	5600	5704
Spring 2025	Ottumwa 345/161 kV Transformer	Ottumwa Generator	None	527MWx2	6514	6626
LRZ4	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2024	None	None	20%	None	9857	10790
Fall 2024	Palmyra - Marblehead North 161 kV	Herleman - Palmyra Tap 345 kV	10%	533MWx2	5699	6637
Winter 2024/25	Palmyra 345/161 kV Transformer	Herleman - Palmyra Tap 345 kV	None	1000MWx2	5811	6731
Spring 2025	Palmyra - Marblehead North 161 kV	Herleman - Palmyra Tap 345 kV	None	1000MWx2	5083	6003
LRZ5	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2024	Moro - Miles 138 kV	Roxford - Moro 345 kV	None	1000MWx2	3208	3208
Fall 2024	Moro - Miles 138 kV	Roxford - Moro 345 kV	None	202MWx2	3786	3786
Winter 2024/25	Moro - Miles 138 kV	Roxford - Moro 345 kV	None	1000MWx2	4477	4477
Spring 2025	Moro - Miles 138 kV	Roxford - Moro 345 kV	None	356MWx2	3892	3892
LRZ6	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2024	Cayuga Sub- Cayuga 345 kV	Kansas West - Sugar Creek 345 kV	5%	712MWx2	7197	7463
Fall 2024	Cayuga Sub - Cayuga 345 kV	Kansas West - Sugar Creek 345 kV	None	282MWx2	8661	8954
Winter 2024/25	Sullivan - Petersburg 345 kV	Rockport - Jefferson 765 kV	None	890MWx2	8286	8526
Spring 2025	Lawrenceville South - Vincennes 138 kV	Albion South - Gibson 345 kV	None	294MWx2	7730	8015
LRZ7	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2024	Monroe 1&2 - Brownstown (Superior) 345kV	Monroe 1&2 - Wayne 345 kV	None	1000MWx2	4490	4500
Fall 2024	Verona - J758 138 kV	J758 - Verona West 138 kV	None	373MWx2	4390	4400
Winter 2024/25	Argenta - Tompkins 345 kV	Argenta - Battle Creek 345 kV	None	1000MWx2	4656	4666
Spring 2025	Stillwell - Dumont 345 kV	Wilton Center - Dumont 765 kV	None	927MWx2	4883	4893
LRZ8	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2024	Winnfield 230/115 kV Transformer	Montgomery - Clarence 230 kV	None	1000MWx2	3444	3536
Fall 2024	Mount Olive - Vienna 115 kV	Mount Olive - Eldorado 500 kV	None	1000MWx2	4942	5040
Winter 2024/25	Little Gypsy - Fairview 230 kV	Michoud - Front Street 230 kV	None	1000MWx2	4262	4336
Spring 2025	Winnfield 230/115 kV Transformer	Mount Olive - Layfield 500 kV	10%	1000MWx2	6030	6124
LRZ9	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2024	Danville - Dodson 115 kV	Mount Olive - Layfield 500 kV	None	1000MWx2	4794	5613
Fall 2024	Daniel - Daniel Intermediate 1 230 kV	Daniel - Daniel Intermediate 2 230 kV	None	1000MWx2	5608	6435
Winter 2024/25	Bogalusa 500/230 kV Transformer	Mcknight - Franklin 500 kV	None	1000MWx2	4623	5420
Spring 2025	Bogalusa 500/230 kV Transformer	Mcknight - Franklin 500 kV	None	1000MWx2	5598	6417
LRZ10	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2024	Perryville - Baxter Wilson 500 kV	Grand Gulf Generator	None	1000MWx2	3564	3564
Fall 2024	Mcknight - Franklin 500 kV	Baxter Willson - Perryville 500 kV	21%	929MWx2	4736	4736
Winter 2024/25	Perryville - Baxter Wilson 500 kV	Grand Gulf Generator	None	1000MWx2	3219	3219
Spring 2025	Mcknight - Franklin 500 kV	Baxter Willson - Perryville 500 kV	34%	284MWx2	4628	4628

Table 2-3: Planning Year 2024–2025 Import Limits

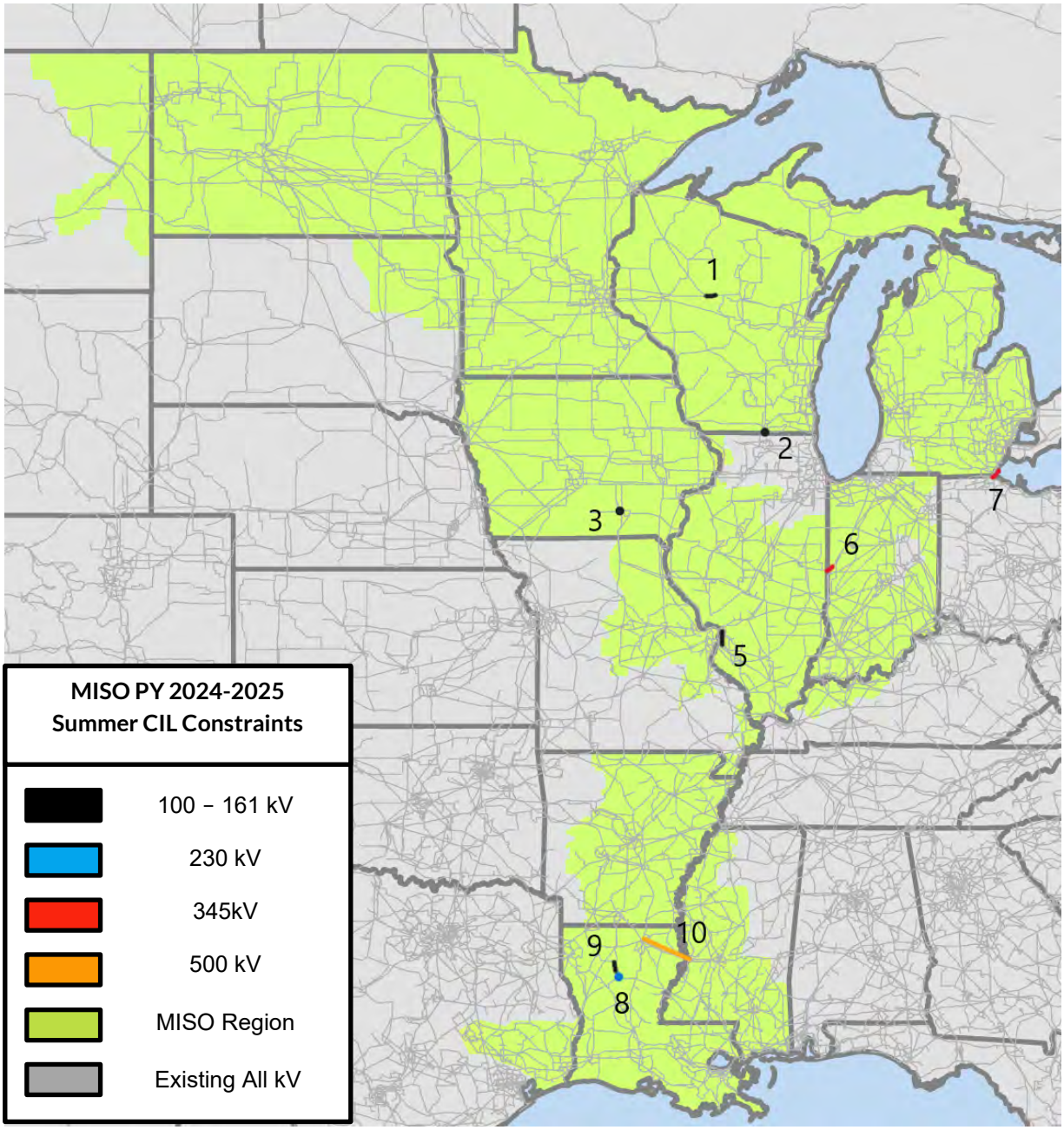


Figure 2-2: Planning Year 2024-2025 Summer Capacity Import Constraints Map

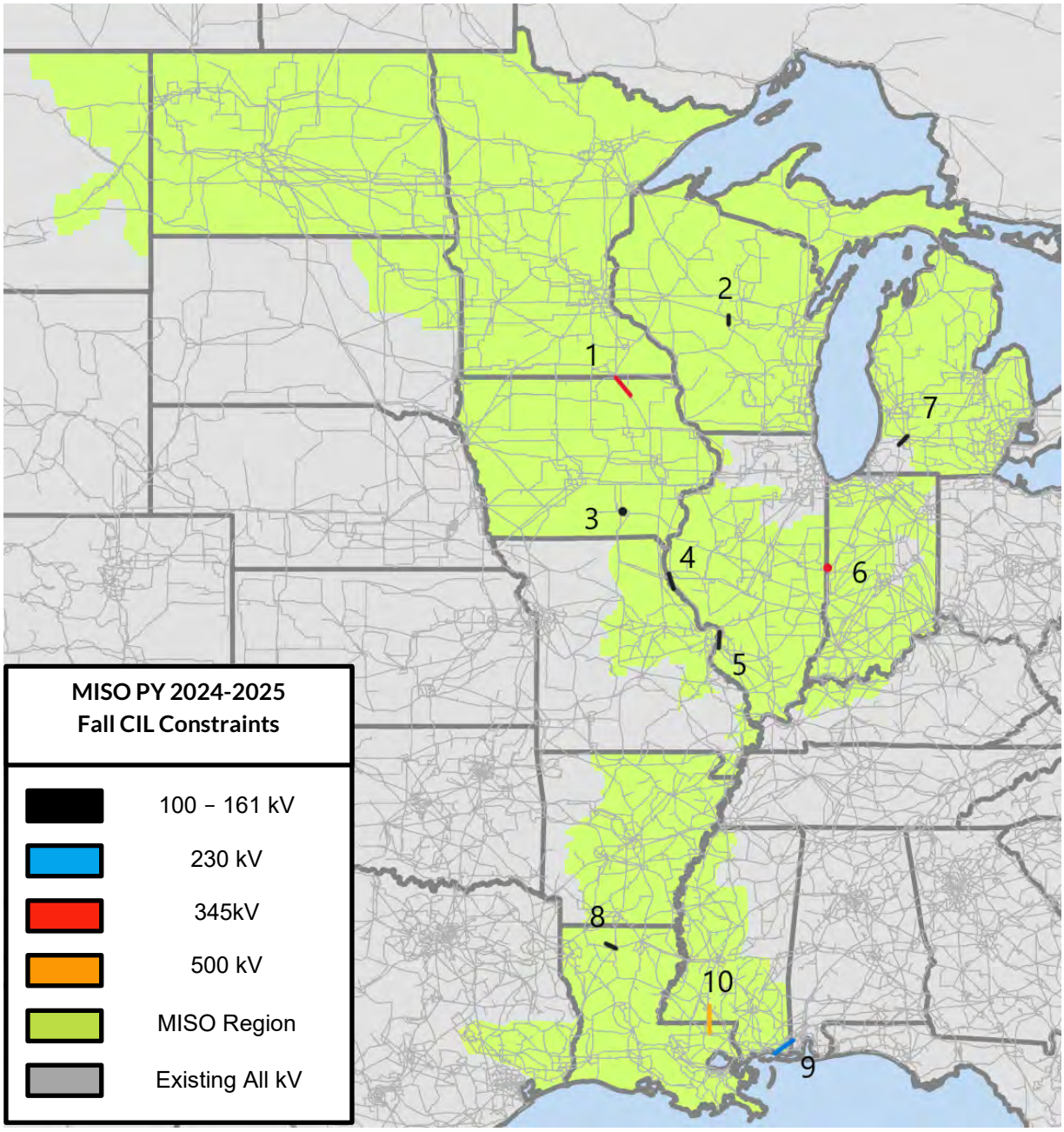


Figure 2-3: Planning Year 2024-2025 Fall Capacity Import Constraints Map

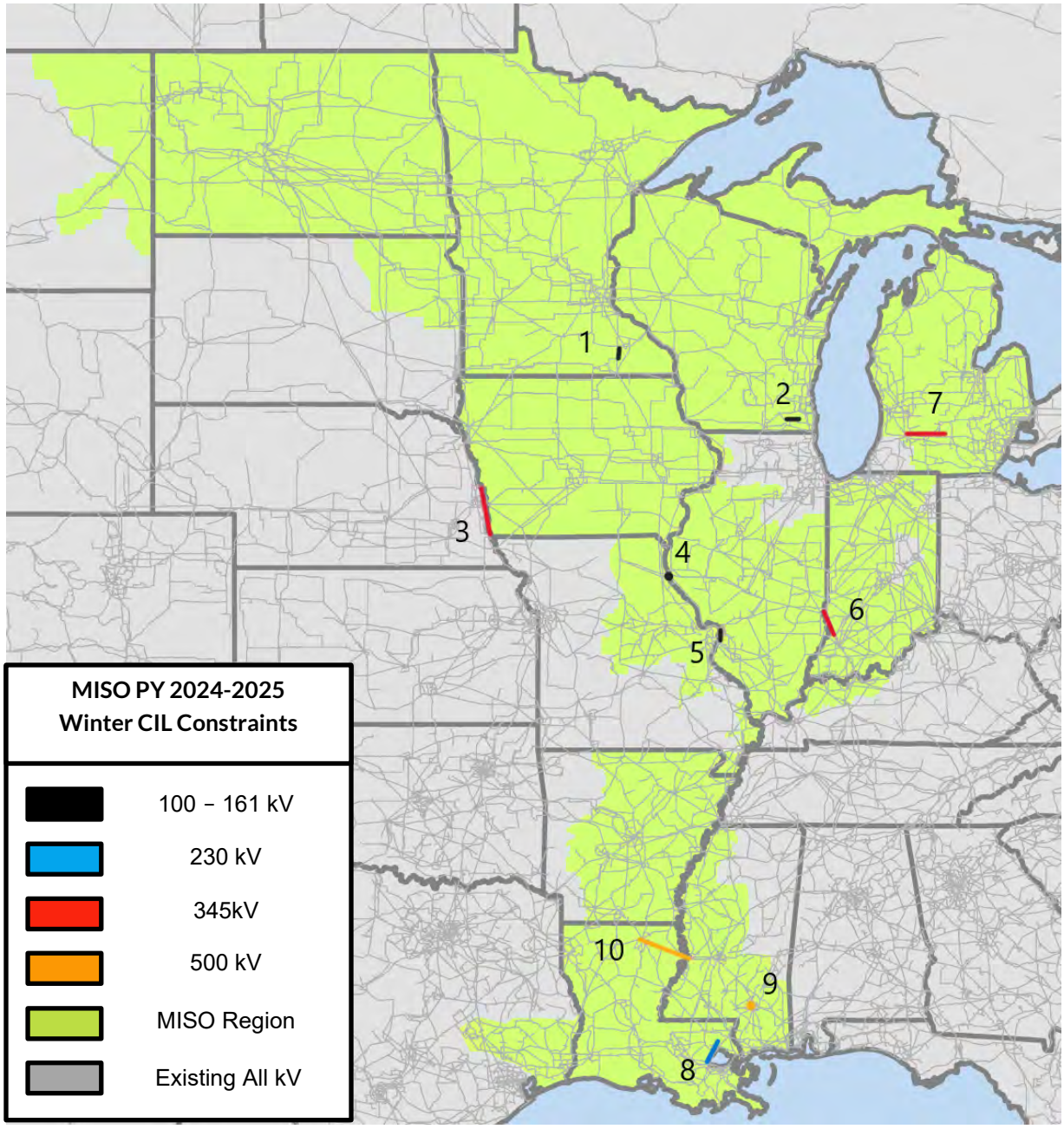


Figure 2-4: Planning Year 2024-2025 Winter Capacity Import Constraints Map

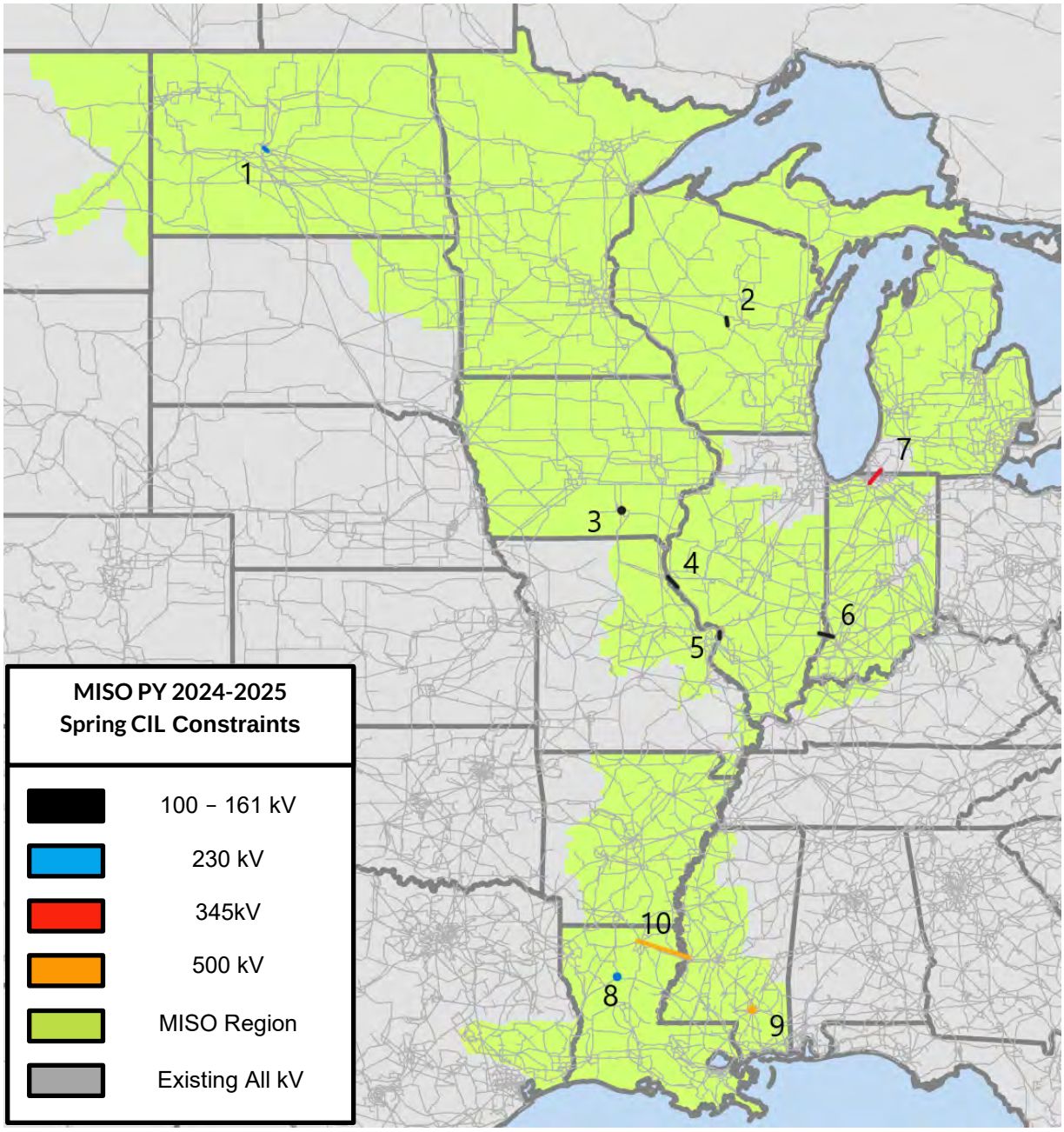


Figure 2-5: Planning Year 2024-2025 Spring Capacity Import Constraints Map

Capacity Exports Limits are found by increasing generation in the study zone and decreasing generation in the rest of the MISO footprint to create a transfer. Table 2-4 below shows the Planning Year 2024-2025 CEL and ZEA with corresponding constraint, GLT, and redispatch information.

LRZ1	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2024	Split Rock - Sioux Falls 230 kV	Split Rock - Sioux City 345 kV	10%	1000MWx2	4539	4537
Fall 2024	Arpin - Sigel 138 kV	Arpin - Rocky Run 345kV	None	302MWx2	5713	5711
Winter 2024/25	Split Rock - Sioux Falls 230 kV	Split Rock - Sioux City 345 kV	None	847MWx2	5176	5174
Spring 2025	Split Rock - Sioux Falls 230 kV	Split Rock - Sioux City 345 kV	None	194MWx2	6320	6318
LRZ2	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2024	Pleasant Prairie - Zion 345 kV	Pleasant Prairie - Zion EC 345 kV	40%	295MWx2	3971	3971
Fall 2024	Pleasant Prairie - Zion 345 kV	Pleasant Prairie - Zion EC 345 kV	None	936MWx2	4512	4512
Winter 2024/25	Pleasant Prairie - Zion EC 345 kV	Pleasant Prairie - Zion 345 kV	30%	1000MWx2	4772	4772
Spring 2025	Pleasant Prairie - Zion EC 345 kV	Pleasant Prairie - Zion 345 kV	None	1000MWx2	4601	4601
LRZ3	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2024	None	None	50%	None	5548	5450
Fall 2024	Sandburg 161/138 kV Transformer	Galesburg - Oak Grove 345 kV	40%	515MWx2	7018	6913
Winter 2024/25	Wapello County - Appanoose County 161 kV	Zachary - Hughes 345kV	None	1000MWx2	9079	8975
Spring 2025	Sandburg 161/138 kV Transformer	Galesburg - Oak Grove 345 kV	50%	285MWx2	5873	5761
LRZ4	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2024	None	None	50%	None	3663	2730
Fall 2024	None	None	50%	None	4801	3863
Winter 2024/25	None	None	50%	None	5570	4650
Spring 2025	None	None	50%	None	6001	5081
LRZ5	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2024	None	None	40%	None	4644	4644
Fall 2024	Mass 345/161 kV Transformer	Mass - Joppa 345 kV	None	360MWx2	5402	5402
Winter 2024/25	None	None	50%	None	6229	6229
Spring 2025	Mass 345/161 kV Transformer	Shawnee - Mass 345 kV	None	1000MWx2	4984	4984
LRZ6	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2024	BR Tap - Paradise 161 kV	Paradise - Paradise CC Units 3-4 161 kV	35%	93MWx2	5903	5637
Fall 2024	South - Southeast 138 kV	Hanna - Franklin Township 138 kV	None	624MWx2	3812	3519
Winter 2024/25	Grandview - Newtonville 138 kV	Daviess - Coleman EHV Substation 345 kV	None	388MWx2	1647	1407
Spring 2025	South - Southeast 138 kV	Hanna - Franklin Township 138 kV	None	575MWx2	3729	3444
LRZ7	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2024	Lallendorf - Fostoria Central 345 kV	Lemoyne - Fostoria Central 345 kV	30%	921MWx2	5719	5709
Fall 2024	Monroe 1&2 - Lallendorf 345 kV	Morocco - Allen Jct 345 kV	None	1000MWx2	5391	5381
Winter 2024/25	Morocco - Allen Jct 345 kV	Lallendorf - Monroe 345 kV	None	1000MWx2	5753	5743
Spring 2025	Monroe 1&2 - Lallendorf 345 kV	Morocco - Allen Jct 345 kV	None	564MWx2	5601	5591
LRZ8	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2024	Perryville - Baxter Wilson 500 kV	Grand Gulf Generator	30%	1000MWx2	6263	6171
Fall 2024	Independence - Moorefield 161 kV	Independence - Power Line Road EHV 500 kV	None	35MWx2	4310	4212
Winter 2024/25	Arklahoma - Hot Springs East 115 kV	Hot Springs West - Arklahoma 115 kV	50%	155MWx2	5882	5808
Spring 2025	Cash - Jonesboro 161 kV	Independence - Power Line Road EHV 500 kV	None	177MWx2	5030	4936
LRZ9	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2024	PPG - Verdine 230 kV	PPG - Manena 230 kV	None	1000MWx2	3178	2359
Fall 2024	White Bluff - Keo 500 kV	Sheridan - Mabelvale 500 kV	None	1000MWx2	4429	3602
Winter 2024/25	Adams Creek - Angie 230 kV	French Branch - Slidell 230 kV	None	1000MWx2	2900	2103
Spring 2025	Michoud - Front Street 230 kV	Mcknight - Franklin 500 kV	None	1000MWx2	4813	3994
LRZ10	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2024	Clarksdale - Lyon 115 kV	MEPS Clarkesdale - Moon Lake 230kV	None	377MWx2	1840	1840
Fall 2024	Clarksdale - Lyon 115 kV	MEPS Clarkesdale - Moon Lake 230kV	None	535MWx2	2889	2889
Winter 2024/25	Clarksdale - Lyon 115 kV	MEPS Clarkesdale - Moon Lake 230kV	None	284MWx2	2993	2993
Spring 2025	Clarksdale - Lyon 115 kV	MEPS Clarkesdale - Moon Lake 230kV	None	535MWx2	2740	2740

Table 2-4: Planning Year 2024–2025 Export Limits

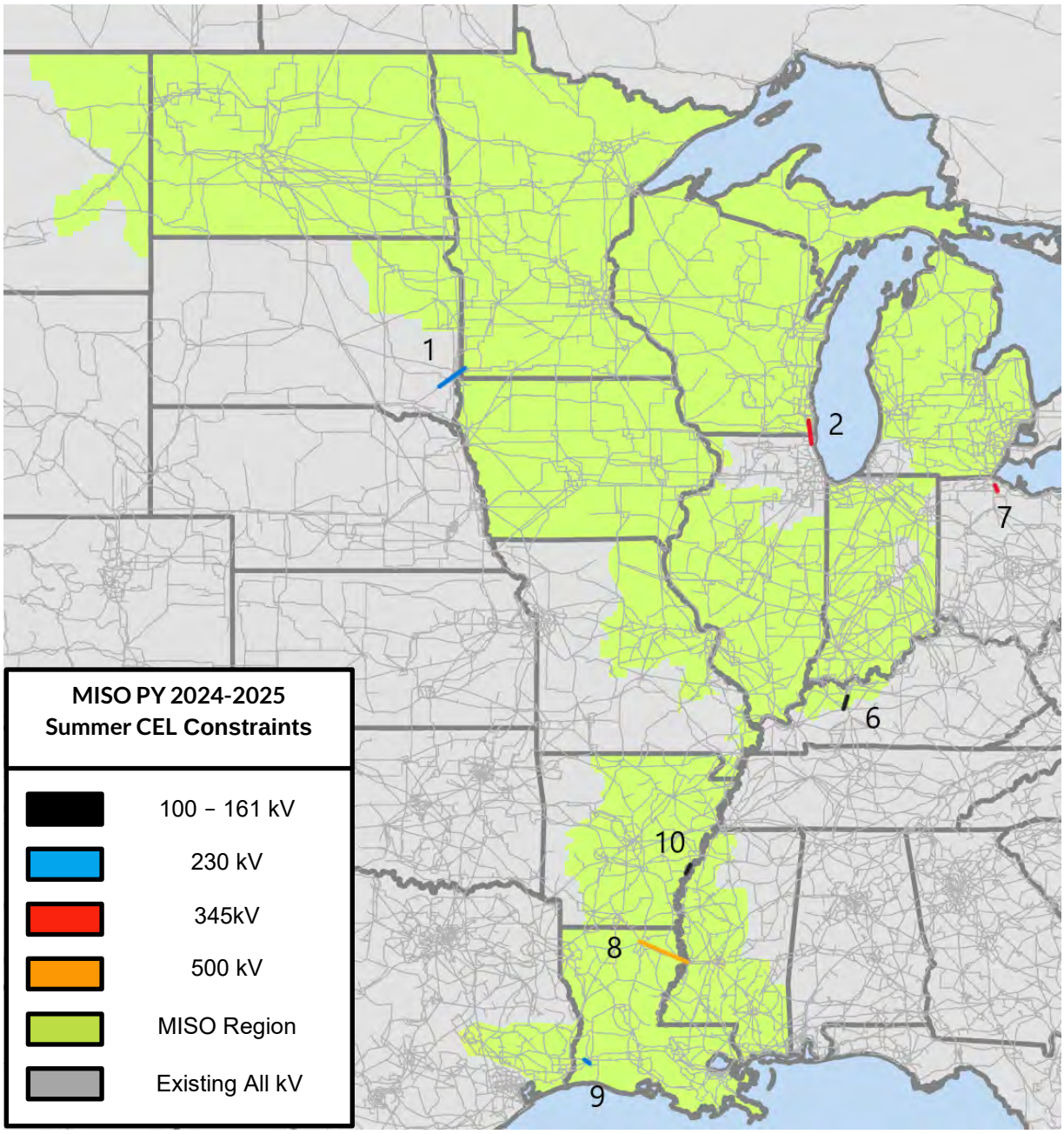


Figure 2-6: Planning Year 2024-2025 Summer Export Constraint Map

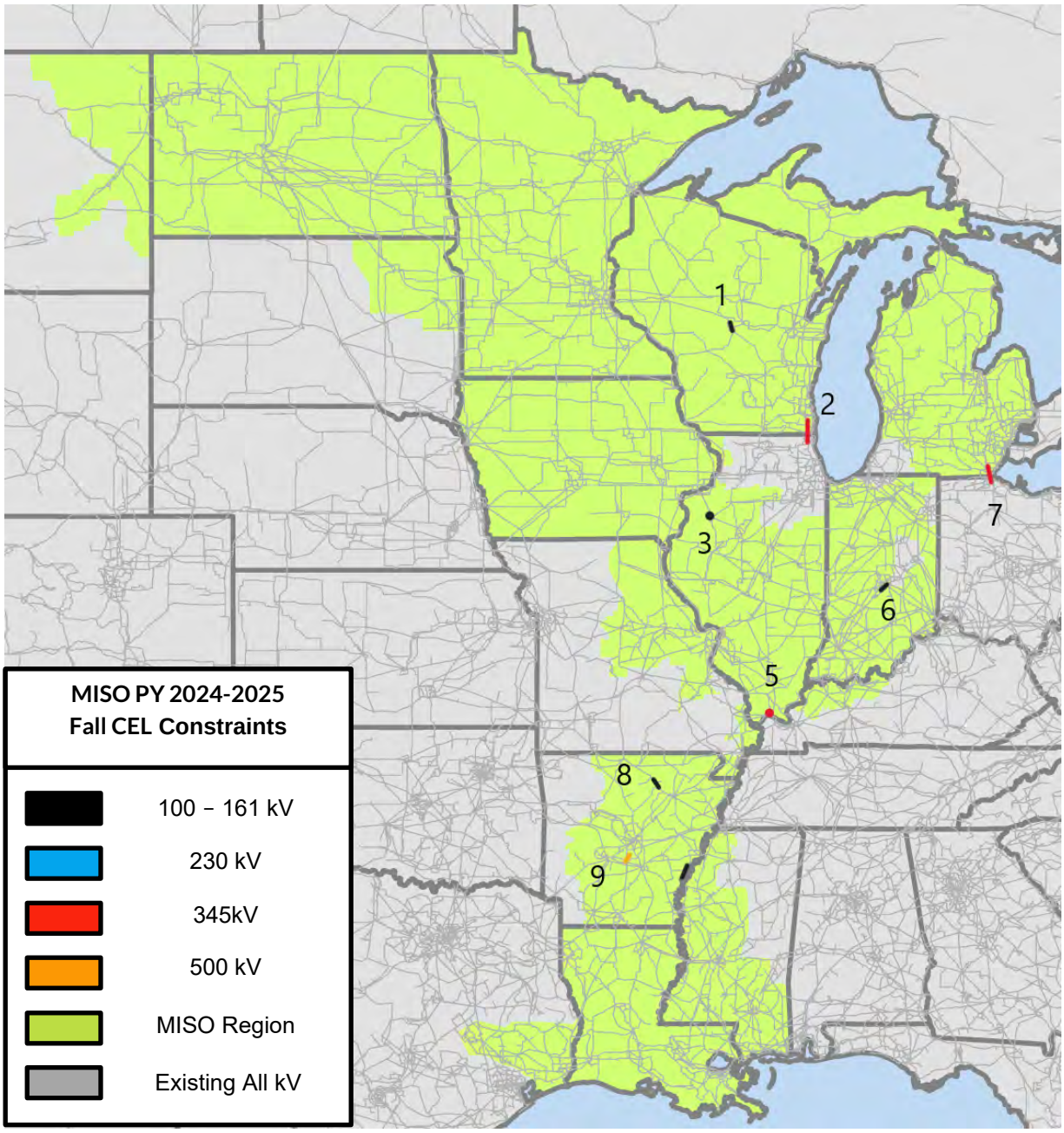


Figure 2-7: Planning Year 2024-2025 Fall Export Constraint Map

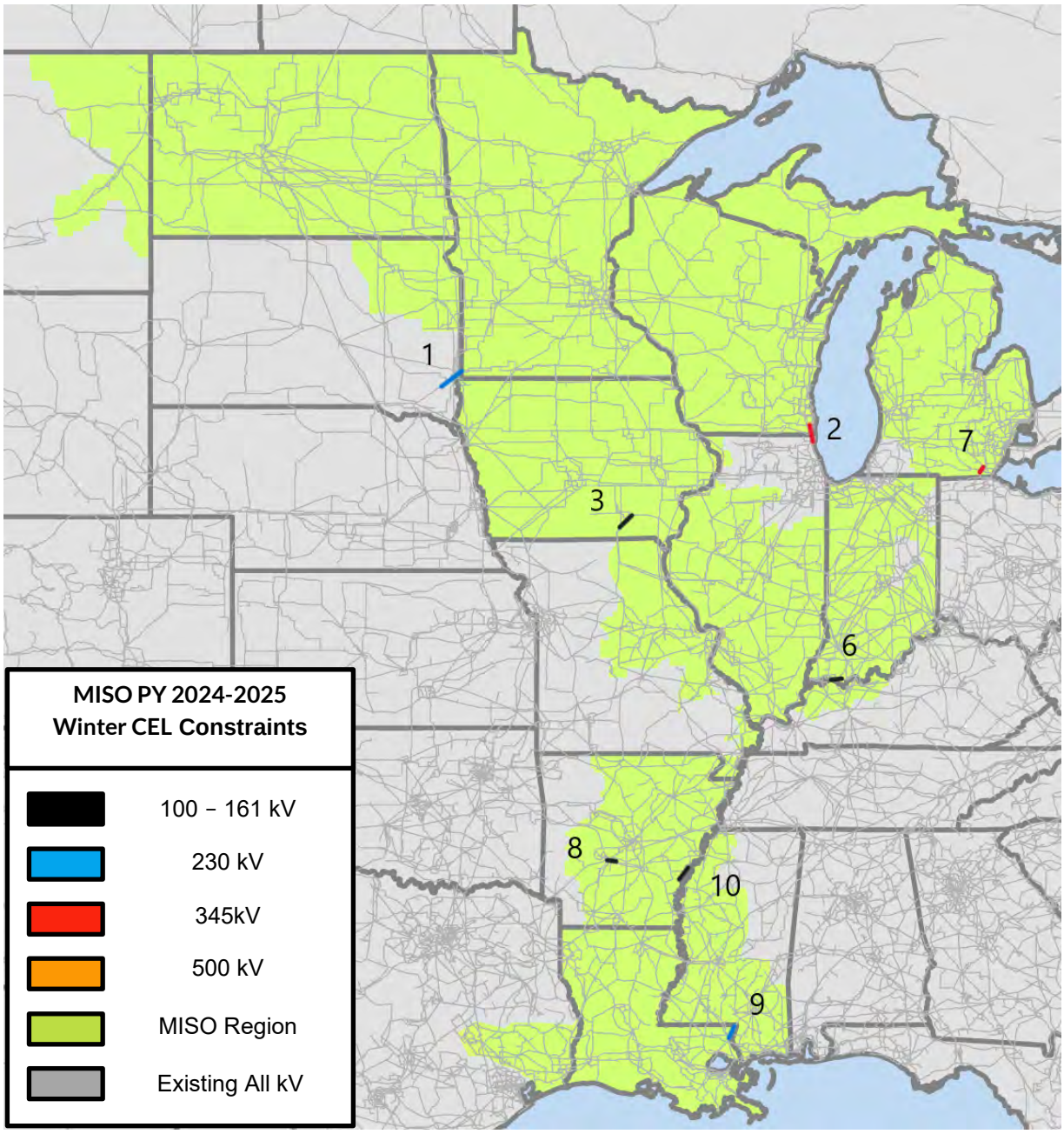


Figure 2-8: Planning Year 2024-2025 Winter Export Constraint Map

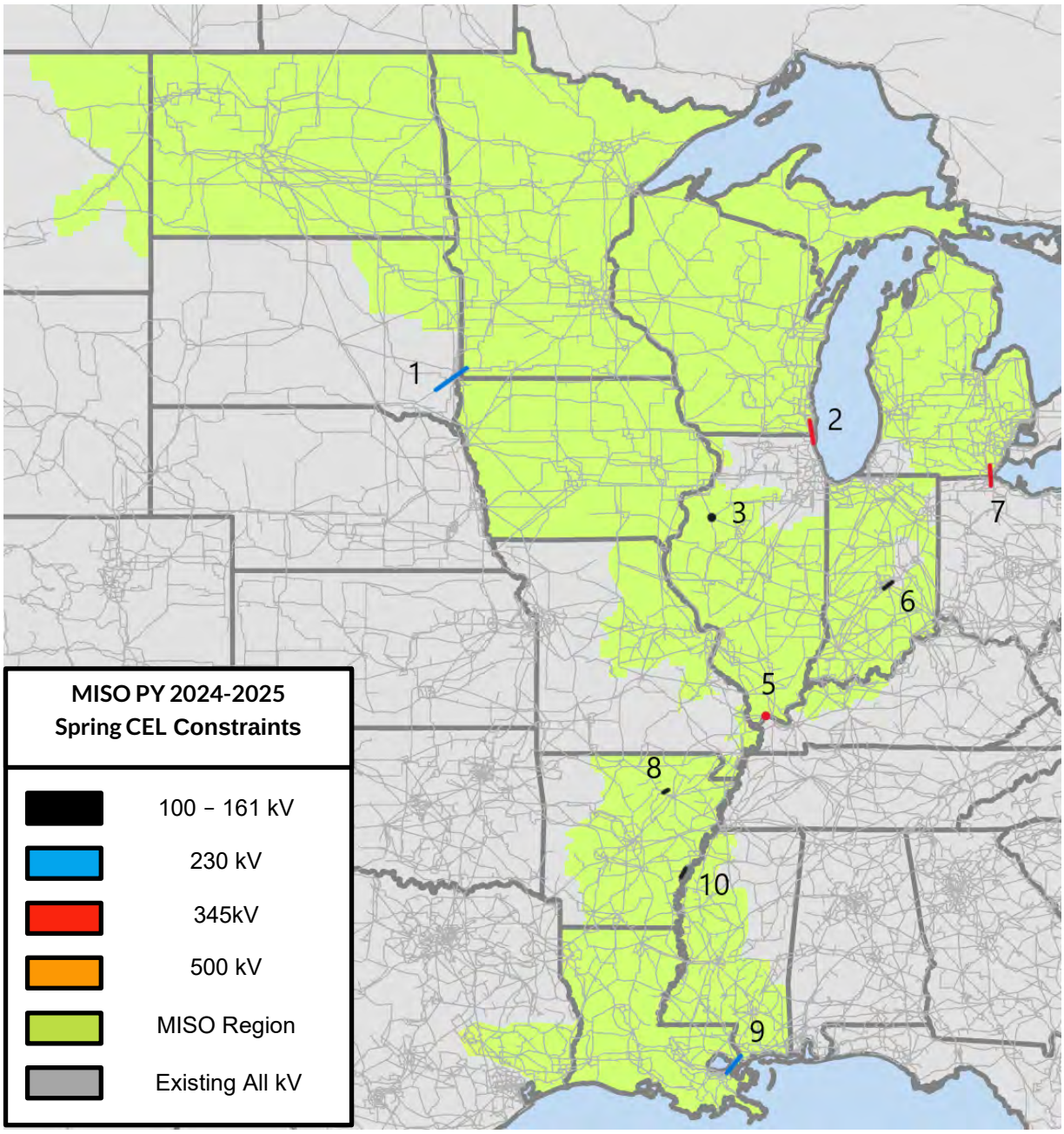


Figure 2-9: Planning Year 2024-2025 Spring Export Constraint Map

3 Loss of Load Expectation Analysis

3.1 LOLE Modeling Input Data and Assumptions

MISO uses a program developed and maintained by Astrapé Consulting called Strategic Energy & Risk Valuation Model (SERVM) to calculate LOLE for the applicable Planning Year. SERVM uses a sequential Monte Carlo simulation to model a generation system and to assess the system's reliability, based on any number of interconnected areas. SERVM calculates LOLE for the MISO system and for each LRZ by stepping through the year chronologically and taking into account generation, load, load modifying and energy efficiency resources, equipment forced outages, planned and maintenance outages, weather and economic uncertainty, and external support.

Building the SERVM model is the most time-consuming task of the LOLE Study. Several sensitivities are built in order to determine how specific inputs and variables impact the results. The base case models determine the seasonal MISO PRM Installed Capacity (ICAP), PRM Unforced Capacity (UCAP), and the Local Reliability Requirements (LRRs) for each LRZ for future Planning Years one, four, and six.

3.2 MISO Generation

3.2.1 Thermal Units

The Planning Year 2024-2025 LOLE Study used the 2023-2024 PRA converted capacity as a starting point for which resources to include in the study. This ensured that only resources eligible as Planning Resources were included in the LOLE Study. An exception was made to include resources with a signed and executed GIA that have an anticipated in-service date (adjusted for average GI delays) for PY 2024-2025. All internal Planning Resources were modeled in the LRZ in which they are physically located. Additionally, Coordinating Owner External Resources and Border External Resources were modeled as being internal to the LRZ in which they are committed to serving load.

Seasonal forced outage rates and annualized planned maintenance outage rates were calculated over a five-year period (January 2016 to December 2022) for each resource. Some resources did not have five years of historical data in MISO's Generator Availability Data System (PowerGADS)—however, if they had at least 3 consecutive months of outage data, resource-specific information was used to calculate their seasonal forced and planned maintenance outage rates. Resources with fewer than 3 consecutive months of resource-specific outage data were assigned the corresponding MISO seasonal class average forced outage rate and annualized planned maintenance outage rate based on their resource type. The overall MISO ICAP-weighted seasonal class average forced outage rates and annualized planned maintenance outage rate were applied in lieu of class averages for classes with fewer than 30 resources reporting 12 or more months of data.

Each nuclear unit has a fixed maintenance schedule, which was pulled from publicly available information and was modeled for each of the study years.

The historical class average outage rates as well as the MISO system-wide weighted average forced outage rate are provided in Table 3-1 to show the year-over-year trends, as well as in Table 3-2 on a seasonal basis.

Pooled EFORd GADS Years	2018-2022 (%)	2017-2021 (%)	2016-2020 (%)	2015-2019 (%)	2014-2018 (%)	2013-2017 (%)
LOLE Study Planning Year	**PY 2024-2025** Summer	**PY 2023-2024** Summer	**PY 2022-2023** Annualized	**PY 2021-2022** Annualized	**PY 2020-2021** Annualized	**PY 2019-2020** Annualized
Combined Cycle	5.92	5.54	5.85	5.52	5.70	5.37
Combustion Turbine (0-20 MW)	24.42	23.40	35.20	36.38	40.39	23.18
Combustion Turbine (20-50 MW)	6.54	6.30	13.65	14.20	15.29	15.76
Combustion Turbine (50+ MW)	4.88	4.07	4.36	4.76	4.65	5.18
Diesel Engines	17.14	12.79	7.25	10.05	23.53	10.26
Fluidized Bed Combustion	*	*	*	*	*	*
Hydro (0-30 MW)	*	*	*	*	*	*
Hydro (30+ MW)	*	*	*	*	*	*
Nuclear	*	*	*	*	*	*
Pumped Storage	*	*	*	*	*	*
Steam – Coal (0-200 MW)	7.91	6.34	8.72	7.12	6.34	5.83
Steam - Coal (200-600 MW)	7.81	7.57	10.27	10.20	9.85	9.60
Steam - Coal (600-1,000 MW)	9.57	8.47	8.83	8.38	8.41	8.05
Steam - Gas	14.04	12.48	11.84	12.91	12.54	11.56
Steam - Oil	*	*	*	*	*	*
Steam - Waste Heat	*	*	*	*	*	*
Steam - Wood	*	*	*	*	*	*
MISO Weighted System-wide	8.24	8.23	9.04	9.36	9.24	9.28

Table 3-1: Historical Class Average Forced Outage Rates

Pooled EFORd GADS Years	2018-2022 (%)	2018-2022 (%)	2018-2022 (%)	2018-2022 (%)
LOLE Study Planning Year 2024-2025	**Summer 2024**	**Fall 2024**	**Winter 2024-2025**	**Spring 2025**
Combined Cycle	5.92	7.43	5.38	6.55
Combustion Turbine (0-20 MW)	24.42	24.17	46.17	51.36
Combustion Turbine (20-50 MW)	6.54	18.59	50.59	34.26
Combustion Turbine (50+ MW)	4.88	7.23	10.53	5.15
Diesel Engines	17.14	14.26	24.94	8.89
Fluidized Bed Combustion	*	*	*	*
Hydro (0-30 MW)	*	*	*	*
Hydro (30+ MW)	*	*	*	*
Nuclear	*	*	*	*
Pumped Storage	*	*	*	*
Steam – Coal (0-200 MW)	7.91	9.69	8.71	11.85
Steam - Coal (200-600 MW)	7.81	10.91	9.07	8.28
Steam - Coal (600-1,000 MW)	9.57	7.78	10.32	11.41
Steam - Gas	14.04	13.26	11.11	12.07
Steam - Oil	*	*	*	*
Steam - Waste Heat	*	*	*	*
Steam - Wood	*	*	*	*
MISO Weighted System-wide	8.24	9.15	11.23	10.33

Table 3-2: Planning Year 2024-2025 Seasonal Class Average Forced Outage Rates

3.2.2 Behind-the-Meter Generation

Behind-the-Meter Generation data came from the Module E Capacity Tracking (MECT) tool. Behind-the-Meter Generation backed by thermal resources were explicitly modeled just as any other thermal generator with a monthly capability and forced outage rate. Behind-the-Meter Generation backed by intermittent resources were modeled at their expected seasonal availability.

3.2.3 Attachment Y

MISO obtained information on generating resources with approved suspensions or retirements (as of June 1, 2023) through MISO's Attachment Y process. Any resource with an approved retirement or suspension in Planning Year 2024-2025 was excluded from the year-one analysis during the months the resource has been approved to be out of service for. This same methodology is used for the four- and six-year analyses.

3.2.4 Future Generation

The LOLE model included resources with a signed and executed Generator Interconnection Agreement (as of June 1, 2022). These future resources were assigned seasonal class average forced outage rates and planned maintenance outage rates based on their resource class. Future thermal generation and upgrades were added to the LOLE model based on resource information in the MISO Generator Interconnection Queue. Resources with a planned upgrade during the study period reflect the megawatt increase for each month, beginning the month the upgrade is expected to be completed. The LOLE analysis includes future wind and solar generation, tied to the same hourly wind and solar profiles used for existing wind and solar resources in the model.

3.2.5 Intermittent Resources

Intermittent resources include solar, wind, biomass, battery storage, and run-of-river hydro. Most intermittent resources submit historical output data during seasonal peak hours, defined as hours ending 15, 16, & 17 EST for Summer, Fall, and Spring, and hours ending 8, 9, 19, & 20 for Winter. Non-CPNode wind and battery storage resources are exceptions to this and only submit historical output data for the top 8 seasonal coincident peaks for the last 3 Planning Years for which data is available. This data is averaged at the seasonal level and modeled in the LOLE analysis as seasonal effective capacity for all months within a given season. Each individual resource is modeled in the LRZ corresponding to its load obligation.

Using historical wind operational data from 253 front-of-meter wind resources from 2013 to 2022, normalized hourly capacity profiles were developed and aggregated at the LRZ level to represent hourly wind capability in the model. As a result of the LOLE analysis being based on 30 weather years (1993 – 2022), synthetic shapes were developed by Astrapé for the 1992 – 2013 period based on historical wind performance and temperatures. Once the weather and wind performance matching has been performed, the data is analyzed as a function of load to ensure the variability around the load profiles is reasonable.

Solar profiles were also developed by Astrapé using historical solar irradiance data from the NREL National Solar Radiation Database (NSRDB) from 1998 – 2022.

For more details on profile development methodology, refer to the supporting documentation Astrapé provided stakeholders at the LOLEWG detailing the development of the wind and solar profiles:
MISO Seasonal Inputs for the 2022 LOLE Study

3.2.6 Demand Response

Demand response programs and their corresponding capabilities came from the MECT tool. These resources were explicitly modeled as dispatch-limited resources. Each demand response program was modeled individually with a monthly capacity, limited by duration and the number of times each program can be called upon for each season.

3.3 MISO Load Data

The Planning Year 2024-2025 LOLE analysis used a load training process with neural net software to establish a correlated relationship in the trained and predicted load shapes between historical weather and load data. This relationship was then applied to 30 years of hourly historical load data to create 30 different load shapes for each LRZ to capture both load diversity and seasonal variations. The Zonal Coincident Peak Forecasts provided by the Load Serving Entities were used to develop zonal- and monthly-specific load forecast scaling factors which scale the average of the 30 load shapes based on provided forecasts. The results of this process are shown as the MISO System Peak Demand (Table 4-1) and LRZ Peak Demands (Table 5-1, Table 5-2, Table 5-3, & Table5-4).

Direct Control Load Management and Interruptible Demand types of demand response were explicitly included in the LOLE model as resources. Demand response is dispatched in the LOLE model to avoid load shed during simulation when all other available generation has been exhausted.

3.3.1 Weather Uncertainty

MISO has adopted a six-step load training process in order to capture the weather uncertainty associated with the most recent 50/50 load forecasts submitted by the Load Serving Entities for the development of the 30 years of hourly zonal correlated load and weather shapes in the LOLE model.

The first step of the load training process is to collect the most recent year of historical hourly net load data, as well as any hourly load reductions. Since Load Modifying Resources are modeled in the LOLE Study, the hourly load reductions are added to the net load data. MISO also collects historical temperature data from a zonal-specific weather station for the most recent weather year included in the study. Both the hourly LMR deployment and load data are taken from historical MISO energy market data for each LBA, while the historical weather data is collected from the National Oceanic and Atmospheric Administration (NOAA) for each LRZ. After collecting the data, the hourly gross load for each LRZ is calculated using the most recent five years of historical data.

The second step of the process is to normalize the five years of load data to consistent economics. This process involves zonal load growth adjustments by comparing the most recent 5 years of historical load at extreme temperatures and shifting the shapes up or down if they do not reasonably overlay on top of each other. Regression analysis is then performed at the zonal level, focusing on Summer and Winter peak periods in order to compensate for the fact that the neural net training software can occasionally over- or under-predict results for extremely high or extremely low temperatures.

The third step of the process utilizes neural net software to establish functional relationships between the most recent five years of historical weather and load data. After the load growth adjustments and regressions have been performed, the treated historical load and weather data are input into the neural net software. MISO utilizes the NeuroShell Predictor software which performs neural net training and predicting using a genetic algorithm. The neural net trains each month of zonal data individually to predict a total of 120 datasets.

In the fourth step of the process and after the neural net has finished, we check the results of the neural net at extreme temperatures to smooth out any over- or under-predicted loads by comparing against the entire 30 years of

historical correlated load and weather years. MISO looks for hours where the load is plus or minus 30% different than the previous hour and corrects those hours.

In the fifth step of the load training process, MISO undertakes extreme temperature verification on the 30 years of load shapes to ensure that the hourly load data is reasonably accurate at extremely hot or cold temperatures. This is required since there are fewer data points available at the temperature extremes when determining the neural net functional relationships. This lack of data at the extremes can result in inaccurate predictions when creating load shapes, which will need to be corrected before moving forward.

The sixth and final step of the load training process is to average the monthly peak loads of the predicted load shapes and adjust them to match each LRZ's monthly Zonal Coincident Peak Forecast provided by the Load Serving Entities for each of the study years. To calculate this adjustment, the ratio of the first year's Non-Coincident Peak Forecast to the Zonal Coincident Peak Forecast is applied to future outyears' Non-Coincident Peak Forecasts.

By adopting this methodology for capturing weather uncertainty, MISO can model multiple load shapes based on a functional relationship with weather. This modeling approach provides diversity in the load shapes, as well as in the peak loads observed within each load shape. This approach also provides the ability to capture the frequency and duration of historical severe weather patterns.

3.3.2 Economic Load Uncertainty

To account for economic load uncertainty in the Planning Year 2024-2025 LOLE model, MISO utilized a normal distribution of electric utility forecast error accounting for projected and actual Gross Domestic Product (GDP), as well as electricity usage. The historic projections for GDP growth were taken from the Congressional Budget Office (CBO), the actual GDP growth was taken from the Bureau of Economic Analysis (BEA), and the electricity usage was taken from the U.S. Energy Information Administration (EIA). Due to a lack of state-wide projected GDP data, MISO relied on aggregated United States data when calculating economic uncertainty.

To calculate the electric utility forecast error, MISO first calculated the forecast error of GDP between historical projections and actual values. The resulting GDP forecast error was then translated into electric utility forecast error by multiplying by the rate at which electric load grows in comparison to GDP. Finally, a standard deviation is calculated from the electric utility forecast error and used to create a normal distribution representing the probabilities of the load forecast errors (LFE) as shown in Table 3-3.

	LFE Levels				
	-2.0%	-1.0%	0.0%	1.0%	2.0%
Standard Deviation in LFE	Probability assigned to each LFE				
0.90%	4.8%	24.1%	42.1%	24.1%	4.8%

Table 3-3: Economic Uncertainty

3.4 External System

Firm imports from external areas to MISO are modeled at the individual resource level. The specific firm external resources were modeled with their Installed Capacity amount and their corresponding seasonal forced outage rates, or at the contracted capacity from their corresponding Power Purchase Agreement (PPA). These resources are only modeled within the system-wide MISO PRM analysis and are not modeled when calculating the zonal LRRs, as the determination of the Local Reliability Requirements is an island-type analysis. Border External Resources and Coordinating Owner External Resources are modeled as internal MISO units and are included in the PRM and LRR analyses. The external resources included as firm imports in the LOLE Study were based on the amount of capacity that was either part of a Fixed Resource Adequacy Plan (FRAP) or that offered and cleared in the Planning Year 2023-2024 Planning Resource Auction (PRA).

The LOLE analyses incorporate firm exports from MISO internal units to neighboring regions, where information was available. For units with capacity sold off-system, their monthly capacities were reduced by the megawatt amount exported. These values came from PJM's Reliability Pricing Model (RPM) as well as information on exports to other external areas taken from the Independent Market Monitor (IMM) exclusion list.

Firm exports from MISO to external areas were modeled the same as in previous years. Capacity ineligible as MISO capacity due to transactions with external areas was removed from the model. Table 3-4 shows the amount of firm imports and exports in this year's study. MISO went from being a net firm exporter to a net firm importer in the most recent PRA.

Contracts	Summer ICAP (MW)	Summer UCAP (MW)	Fall ICAP (MW)	Fall UCAP (MW)	Winter ICAP (MW)	Winter UCAP (MW)	Spring ICAP (MW)	Spring UCAP (MW)
Imports (MW)	3,217	3,052	2,865	2,758	3,771	3,613	3,247	3,105
Exports (MW)	1,142	1,086	1,160	1,124	1,125	1,062	1,159	1,094
Net	**2,075**	**1,966**	**1,705**	**1,634**	**2,646**	**2,552**	**2,088**	**2,010**

Table 3-4: Planning Year 2023-2024 Firm Imports and Exports

Non-firm imports in the Planning Year 2024-2025 LOLE Study were modeled as a probabilistic distribution of capacity value. These distributions were developed using historic seasonal NSI data which accounted for imports into MISO during emergency pricing hours. Firm imports cleared in the PRA for each Planning Year were subtracted from the NSI data to isolate the non-firm values. An additional region was included in SERVM which contained 12,000 MW of perfect generation connected to the MISO system. A distribution of the region's export capability was modeled to the upper and lower bounds. As SERVM steps through the hourly simulation, random draws on the export limits of the external region were used to represent the amount of capacity MISO could import to meet peak demand. The probability distribution of non-firm external imports used in the LOLE model has been provided in Table 3-5.

	Summer	Fall	Winter	Spring
p5	1,138	525	9	1,384
p10	1,440	903	288	1,626
p25	2,959	1,749	1,223	2,283
p50	4,260	2,601	3,292	3,717
p75	5,198	3,632	5,785	4,987
p90	5,921	4,935	8,097	6,221
p95	6,520	5,748	9,197	6,497

Table 3-5: Non-Firm External Import Distribution During Emergency Pricing Hours (MW)

3.5 Loss of Load Expectation Analysis and Metric Calculations

Upon completion of the annual LOLE Study model refresh, MISO performed probabilistic analyses to determine the seasonal PRM ICAP and PRM UCAP for Planning Year 2024-2025 as well as the seasonal Local Reliability Requirement for each of the ten Local Resource Zones. These metrics were derived through probabilistic modeling of the system, first solving to the industry standard annual LOLE risk target of 1 day in 10 years, or 0.1 day per year, and then solving to the minimum seasonal LOLE criteria of 0.01 LOLE for seasons demonstrating minimal risk.

3.5.1 Seasonal LOLE Distribution

To determine the seasonal LOLE distribution that will be used to calculate the PRM and LRRs, MISO followed the process described in Section 68A.2.1 of Module E-1 of the MISO Tariff. This process involves first solving the LOLE model to an annual value of 0.1 and then checking the seasonal distribution of the annual LOLE of 0.1. If a season had a LOLE value of at least 0.01, then it met the minimum seasonal LOLE criteria and would be set to that LOLE. If a season had less than 0.01 LOLE, additional simulations were performed until the minimum seasonal LOLE criteria of 0.01 was met.

Example: Assume the model is solved to an annual LOLE of 0.1 with 0.05 occurring in both Summer and Winter while Fall and Spring had LOLE values of 0 from this simulation. In this case, the Summer and Winter seasons would not need additional analysis since both had at least 0.01 LOLE naturally when the model was solved to an annual value of

0.1. Since Fall and Spring had 0 LOLE, they would be assigned the minimum seasonal LOLE criteria of 0.01 and additional LOLE simulations would be performed until the minimum seasonal LOLE criteria was met.

The annual distribution of LOLE across the four seasons at the industry standard of 1 day in 10 years, or 0.1 day per year, determined through the Planning Year 2024-2025 LOLE Study are shown in Table 3-6. The MISO-wide distribution results from the PRM analysis and the zonal distributions result from the LRR analyses.

Region	Summer	Fall	Winter	Spring
MISO-wide	0.1	0.01	0.01	0.01
LRZ 1	0.094	0.01	0.01	0.01
LRZ 2	0.099	0.01	0.01	0.01
LRZ 3	0.091	0.01	0.01	0.01
LRZ 4	0.022	0.01	0.075	0.01
LRZ 5	0.01	0.01	0.083	0.01
LRZ 6	0.085	0.01	0.015	0.01
LRZ 7	0.037	0.061	0.01	0.01
LRZ 8	0.014	0.01	0.078	0.01
LRZ 9	0.042	0.036	0.014	0.01
LRZ 10	0.058	0.019	0.015	0.01

Table 3-6: Planning Year 2024-2025 Seasonal LOLE Distribution

3.5.2 MISO-Wide LOLE Analysis and PRM Calculation

MISO determines the appropriate PRM for each season of the applicable Planning Year based upon probabilistic analysis of reliably serving expected demand. The probabilistic analysis will utilize a Loss of Load Expectation (LOLE) study which assumes that there are no internal transmission limitations.

To determine the PRM, the LOLE model will initially be run with no adjustments to the capacity. If the LOLE is less than the minimum seasonal LOLE criteria, a negative output unit with no outage rates will be added until the LOLE reaches the minimum seasonal LOLE criteria. This is comparable to adding load to the model. If the LOLE is greater than the minimum seasonal LOLE criteria, proxy units based on a typical combustion turbine unit of 160 MW with class average seasonal forced outage rates will be added to the model until the LOLE reaches the minimum seasonal LOLE criteria.

MISO's annual LOLE Study will calculate the seasonal PRMs based on the LOLE criteria identified in the previous section. The minimum seasonal PRM requirement will be determined using the LOLE analysis by either adding a perfectly available negative output unit or by adding proxy units until a minimum LOLE of 0.01 day per season is reached.

The formulas for the PRM values for the MISO system are:

PRM ICAP % = (Installed Capacity + Firm External Support ICAP + ICAP Adjustment to meet LOLE target – MISO Coincident Peak Demand)/MISO Coincident Peak Demand

PRM UCAP % = (Unforced Capacity + Firm External Support UCAP + UCAP Adjustment to meet LOLE target – MISO Coincident Peak Demand)/MISO Coincident Peak Demand

Where Unforced Capacity (UCAP) = Installed Capacity (ICAP) x (1 – XEFORd)

3.5.3 LRZ LOLE Analysis and Local Reliability Requirement Calculation

For the Local Resource Zone analysis, each zone included only the generating units within the LRZ (including Coordinating Owner External Resources and Border External Resources) and was modeled without consideration of the benefit of the LRZ's import capability. Similar to the MISO PRM analysis, Unforced Capacity is either added or removed in each LRZ such that an LOLE of 0.1 day per year is achieved when solving for the annual target and a minimum LOLE at least 0.01 day per season when solving for the minimum seasonal LOLE criteria. The minimum amount of Unforced Capacity above each LRZ's seasonal peak demand that was required to meet the reliability criteria was used to establish each LRZ's LRR.

The Planning Year 2024-2025 seasonal LRRs were determined using the LOLE analysis by first either adding or removing capacity until the annual LOLE reaches 0.1 day per year for the LRZ. If the LOLE is less than 0.1 day per year, a perfectly available negative output unit with no outage rates will be added until the LOLE reaches 0.1 day per year. If the LOLE is greater than 0.1 day per year, proxy units based on a typical combustion turbine unit of 160 MW with class average seasonal forced outage rates will be added to the model until the LOLE reaches 0.1 day per year.

After solving each LRZ for to the annual LOLE target of 0.1 day per year, MISO will calculate each seasonal LRR such that the summation of seasonal LOLE across the year in each zone is 1 day in 10 years, or 0.1 day per year. A minimum seasonal LOLE criteria of 0.01 will be used to calculate the LRR in seasons with less than 0.01 LOLE risk under the annual case. The seasonal Local Reliability Requirement will be determined using the LOLE analysis by either adding a perfectly available negative output unit or by adding proxy combustion turbine units until a minimum LOLE of 0.01 day per season is reached. When needed, a fraction of the marginal proxy unit was added to achieve the exact minimum seasonal LOLE criteria for the LRZ.

LRR UCAP % = (Unforced Capacity + UCAP Adjustment to meet LOLE target – Zonal Coincident Peak Demand)/Zonal Coincident Peak Demand

4 MISO System Planning Reserve Margin

4.1 Planning Year 2024-2025 MISO Planning Reserve Margin Results

For Planning Year 2024-2025, the ratio of MISO capacity to forecasted MISO system peak demand yielded a Planning Reserve Margin ICAP of 17.7 percent and a Planning Reserve Margin UCAP of 9.0 percent for the Summer season. Numerous values and calculations went into determining the MISO system PRM ICAP and PRM UCAP (Table 4-1).

MISO Planning Reserve Margin (PRM)	PY 2024-2025 Summer	PY 2024-2025 Fall	PY 2024-2025 Winter	PY 2024-2025 Spring	Formula Key
MISO System Peak Demand (MW)	124,669	112,232	104,303	99,496	[A]
Installed Capacity (ICAP) (MW)	150,187	148,755	165,924	152,092	[B]
Unforced Capacity (UCAP) (MW)	139,444	136,572	143,201	138,251	[C]
Firm External Support ICAP (MW)	3,217	2,865	3,771	3,247	[D]
Firm External Support UCAP (MW)	3,052	2,758	3,613	3,105	[E]
Adjustment to ICAP (MW)	(6,650)	(11,145)	(13,890)	(15,275)	[F]
Adjustment to UCAP (MW)	(6,650)	(11,145)	(13,890)	(15,275)	[G]
ICAP PRM Requirement (PRMR) (MW)	146,754	140,475	155,805	140,064	[H] = [B]+[D]+[F]
UCAP PRM Requirement (PRMR) (MW)	135,846	128,185	132,925	126,081	[I] = [C]+[E]+[G]
MISO PRM ICAP	**17.7%**	**25.2%**	**49.4%**	**40.8%**	[J]=[H]-[A]/[A]
MISO PRM UCAP	**9.0%**	**14.2%**	**27.4%**	**26.7%**	[K]=[I]-[A]/[A]

Table 4-1: Planning Year 2024-2025 MISO System Planning Reserve Margins

4.1.1 Additional Risk Metric Statistics

In addition to the LOLE results, SERVM has the ability to calculate several other probabilistic metrics, shown below in Table 4-2. The values for Loss of Load Hours (LOLH) and Expected Unserved Energy (EUE) are calculated at the point where the annual LOLE is at 1 day in 10 years, or 0.1 LOLE. Loss of Load Hours is defined as the number of hours during a given time period where system demand will exceed the generating capacity. Expected Unserved Energy is energy-centric and analyzes all hours of a particular Planning Year. Results are calculated in megawatt-hours (MWh). EUE is the summation of the expected number of MWh of load that will not be served in a given Planning Year as a result of demand exceeding the available generation across all deficient hours.

MISO LOLE Statistics	
Loss of Load Expectation (LOLE) [days/year]	0.100
Loss of Load Hours (LOLH) [hours/year]	0.289
Expected Unserved Energy (EUE) [megawatt-hours/year]	989.451

Table 4-2: Additional Risk Metric Statistics

4.2 Comparison of PRM Targets Across 10 Years

Figure 4-1 compares the PRM UCAP values over the last 10 Planning Years. The last two data points show the Summer PRM UCAP values following FERC acceptance of MISO's seasonal capacity construct, while the prior data points are indicative of the PRM UCAP under the annual capacity construct.

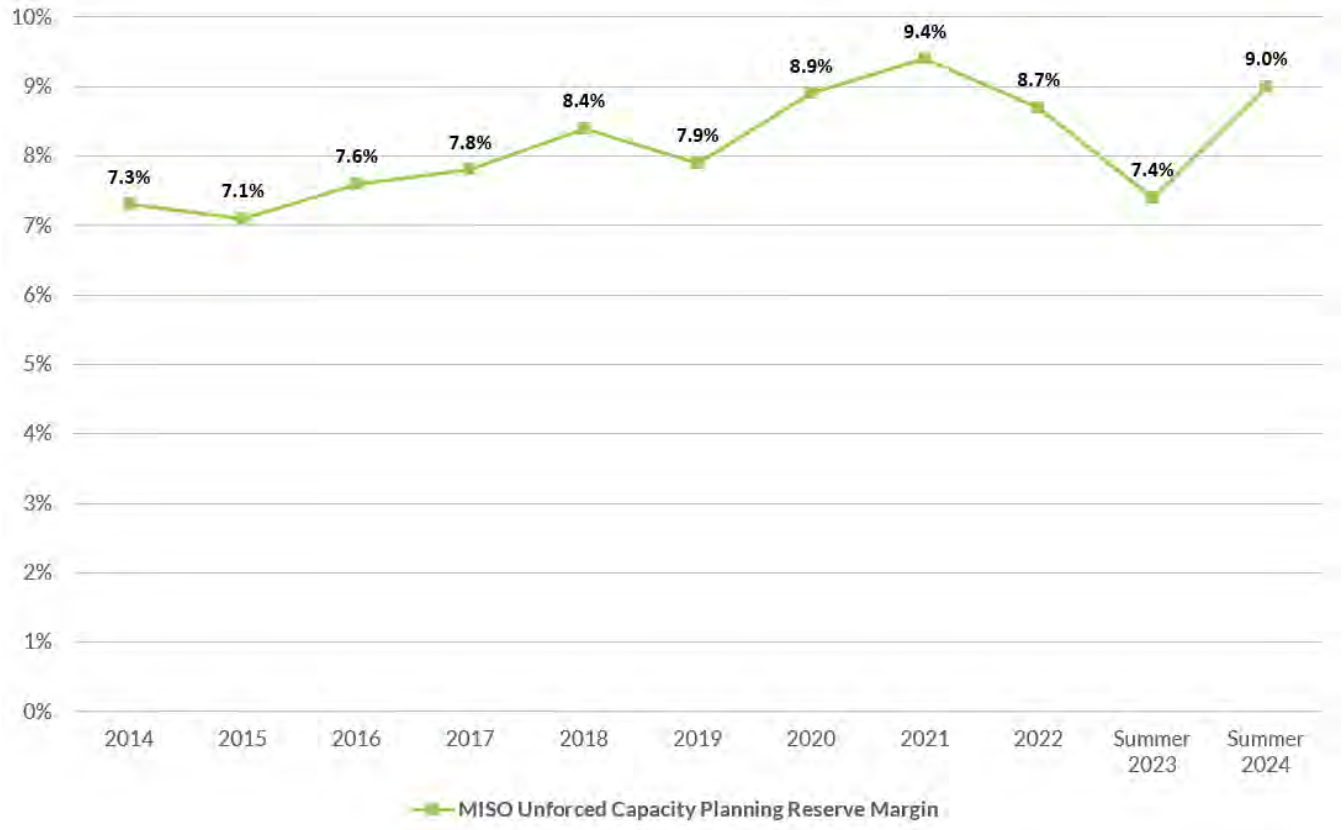


Figure 4-1: Comparison of PRM Targets Across 10 Years

5 Local Resource Zone Analysis – LRR Results

5.1 Planning Year 2024-2025 Local Resource Zone Analysis

MISO calculated the per-unit LRR of LRZ seasonal peak demand for Planning Year 2024-2025 on a seasonal basis (Table 5-1, Table 5-2, Table 5-3, & Table 5-4). The UCAP values in the seasonal LRR tables reflect the assumed seasonal UCAP within each LRZ, including Coordinating Owner External Resources and Border External Resources. The adjustments to UCAP values are the megawatt adjustments needed in each LRZ so that the seasonal LOLE criteria is met. The LRR is the summation of the zone's UCAP and adjustment to UCAP megawatts. The LRR is then divided by each LRZ's seasonal peak demand to determine the per-unit LRR UCAP. The Planning Year 2024-2025 per-unit LRR UCAP values will be multiplied by the updated seasonal peak demand forecasts submitted for the 2024-2025 PRA to determine each LRZ's LRR. Zonal peak demand timestamps for all 30 weather years modeled in SERVM are shown in Table 5-5. These peak demand timestamps are the result of the SERVM load training process and are not necessarily the actual peaks for each year.

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2024-2025 Local Reliability Requirements – Summer 2024											
Installed Capacity (ICAP) (MW)	22,031	14,680	12,032	9,635	7,942	17,184	25,178	11,749	24,009	5,748	[A]
Unforced Capacity (UCAP) (MW)	20,970	13,866	11,487	8,745	7,361	15,348	23,578	10,915	22,113	5,061	[B]
Adjustment to UCAP (MW)	380	590	1,503	3,245	3,044	5,209	980	692	2,502	2,093	[C]
LRR (UCAP) (MW)	21,351	14,456	12,990	11,990	10,405	20,557	24,558	11,607	24,615	7,153	[D]=[B]+[C]
Peak Demand (MW)	18,854	12,990	10,165	9,288	7,814	17,279	21,160	8,336	21,689	4,712	[E]
LRR UCAP per-unit of LRZ Peak Demand	**113.2%**	**111.3%**	**127.8%**	**129.1%**	**133.1%**	**119.0%**	**116.1%**	**139.2%**	**113.5%**	**151.8%**	[F]=[D]/[E]

Table 5-1: Planning Year 2024-2025 LRZ Local Reliability Requirements for Summer 2024

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2024-2025 Local Reliability Requirements – Fall 2024											
Installed Capacity (ICAP) (MW)	21,604	14,808	11,765	9,543	8,092	17,140	24,487	11,568	23,995	5,753	[A]
Unforced Capacity (UCAP) (MW)	20,167	13,723	11,151	8,300	7,428	15,491	22,832	10,923	21,477	5,081	[B]
Adjustment to UCAP (MW)	-847	-402	1,007	2,303	2,486	4,040	956	427	2,440	2,041	[C]
LRR (UCAP) (MW)	19,320	13,321	12,157	10,604	9,914	19,531	23,787	11,349	23,917	7,122	[D]=[B]+[C]
Peak Demand (MW)	15,645	11,113	9,037	8,014	6,880	15,537	18,142	7,585	20,095	4,272	[E]
LRR UCAP per-unit of LRZ Peak Demand	**123.5%**	**119.9%**	**134.5%**	**132.3%**	**144.1%**	**125.7%**	**131.1%**	**149.6%**	**119.0%**	**166.7%**	[F]=[D]/[E]

Table 5-2: Planning Year 2024-2025 LRZ Local Reliability Requirements for Fall 2024

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2024-2025 Local Reliability Requirements – Winter 2024-2025											
Installed Capacity (ICAP) (MW)	24,143	15,861	16,846	11,141	8,737	18,366	26,118	12,347	26,054	6,312	[A]
Unforced Capacity (UCAP) (MW)	21,941	13,894	15,443	7,142	6,199	14,464	23,949	11,108	23,558	5,504	[B]
Adjustment to UCAP (MW)	143	-500	1,432	3,053	2,936	4,899	-1,153	651	2,353	1,968	[C]
LRR (UCAP) (MW)	22,084	13,394	16,874	10,195	9,136	19,363	22,796	11,760	25,911	7,472	[D]=[B]+[C]
Peak Demand (MW)	15,312	9,830	8,413	7,622	7,110	15,779	14,186	7,539	19,513	4,009	[E]
LRR UCAP per-unit of LRZ Peak Demand	**144.2%**	**136.3%**	**200.6%**	**133.8%**	**128.5%**	**122.7%**	**160.7%**	**156.0%**	**132.8%**	**186.4%**	[F]=[D]/[E]

Table 5-3: Planning Year 2024-2025 LRZ Local Reliability Requirements for Winter 2024-2025

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2024-2025 Local Reliability Requirements – Spring 2025											
Installed Capacity (ICAP) (MW)	21,887	15,164	12,479	10,301	8,322	17,448	24,391	11,755	24,434	5,911	[A]
Unforced Capacity (UCAP) (MW)	20,576	14,079	11,568	8,579	7,082	15,812	22,221	10,549	22,516	5,269	[B]
Adjustment to UCAP (MW)	-1,500	-260	730	2,652	2,957	4,098	-920	292	2,491	2,077	[C]
LRR (UCAP) (MW)	19,076	13,819	12,298	11,231	10,040	19,909	21,301	10,841	25,007	7,346	[D]=[B]+[C]
Peak Demand (MW)	14,356	10,137	8,034	6,756	6,206	14,523	16,109	6,733	18,746	3,911	[E]
LRR UCAP per-unit of LRZ Peak Demand	**132.9%**	**136.3%**	**153.1%**	**166.2%**	**161.8%**	**137.1%**	**132.2%**	**161.0%**	**133.4%**	**187.8%**	[F]=[D]/[E]

Table 5-4: Planning Year 2024-2025 LRZ Local Reliability Requirements for Spring 2025

Weather Year Time of Peak Demand (ESTHE)	MISO	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS
1993	7/27/93 17:00	8/11/93 17:00	8/27/93 14:00	8/22/93 19:00	7/17/93 17:00	7/27/93 16:00	7/25/93 16:00	7/9/93 15:00	7/31/93 17:00	8/14/93 16:00	7/31/93 18:00
1994	7/6/94 15:00	6/14/94 17:00	6/15/94 17:00	7/19/94 17:00	7/5/94 17:00	7/19/94 18:00	1/19/94 6:00	6/18/94 17:00	6/29/94 18:00	8/14/94 17:00	7/5/94 17:00
1995	7/13/95 17:00	7/13/95 18:00	7/13/95 16:00	7/14/95 17:00	7/14/95 17:00	7/13/95 16:00	7/13/95 17:00	7/13/95 17:00	8/17/95 14:00	7/27/95 17:00	7/12/95 15:00
1996	6/29/96 17:00	8/6/96 17:00	6/29/96 17:00	7/18/96 17:00	7/18/96 18:00	7/18/96 17:00	7/19/96 17:00	8/7/96 15:00	7/20/96 15:00	2/5/96 7:00	7/3/96 18:00
1997	7/26/97 16:00	7/16/97 16:00	7/16/97 17:00	7/25/97 18:00	7/18/97 16:00	7/26/97 17:00	7/26/97 16:00	7/16/97 16:00	7/25/97 18:00	8/16/97 16:00	7/25/97 18:00
1998	7/20/98 16:00	7/13/98 16:00	6/25/98 18:00	7/20/98 18:00	7/20/98 18:00	7/19/98 16:00	7/19/98 17:00	6/25/98 18:00	7/6/98 17:00	8/28/98 18:00	8/27/98 15:00
1999	7/30/99 14:00	7/25/99 15:00	7/13/95 16:00	7/30/99 18:00	7/18/99 22:00	7/30/99 17:00	7/26/97 16:00	7/30/99 14:00	7/25/99 17:00	8/14/99 18:00	8/20/99 18:00
2000	8/31/00 16:00	6/8/00 19:00	9/1/00 17:00	8/31/00 16:00	9/1/00 15:00	8/17/00 16:00	9/1/00 15:00	9/1/00 14:00	7/19/00 17:00	8/30/00 16:00	8/30/00 17:00
2001	8/8/01 16:00	8/7/01 16:00	8/9/01 16:00	7/31/01 16:00	7/23/01 17:00	7/23/01 17:00	8/7/01 17:00	8/8/01 16:00	7/11/01 16:00	7/10/01 16:00	7/20/01 17:00
2002	7/3/02 16:00	7/6/02 18:00	8/1/02 15:00	7/20/02 18:00	7/5/02 17:00	8/1/02 16:00	8/3/02 16:00	7/3/02 16:00	7/9/02 17:00	8/2/02 19:00	10/4/02 15:00
2003	8/21/03 16:00	8/24/03 17:00	8/21/03 16:00	7/26/03 18:00	8/21/03 16:00	8/21/03 18:00	8/27/03 17:00	8/21/03 17:00	7/18/03 14:00	8/10/03 16:00	7/17/03 17:00
2004	7/22/04 16:00	6/7/04 17:00	7/22/04 16:00	7/20/04 17:00	7/13/04 17:00	7/13/04 16:00	1/31/04 9:00	7/22/04 16:00	7/14/04 17:00	7/24/04 17:00	7/25/04 15:00
2005	7/24/05 17:00	7/17/05 17:00	7/24/05 16:00	7/25/05 17:00	7/24/05 16:00	7/24/05 18:00	7/25/05 17:00	7/24/05 18:00	8/21/05 18:00	7/25/05 16:00	8/21/05 15:00
2006	7/31/06 17:00	7/31/06 17:00	8/1/06 17:00	7/19/06 18:00	7/31/06 18:00	7/31/06 16:00	7/31/06 16:00	7/31/06 16:00	7/31/93 17:00	8/15/06 18:00	7/16/06 15:00
2007	8/1/07 17:00	7/26/07 15:00	8/2/07 15:00	7/17/07 17:00	8/15/07 18:00	8/15/07 18:00	8/29/07 17:00	7/31/07 18:00	8/17/95 14:00	8/14/07 15:00	8/14/07 15:00
2008	7/16/08 17:00	7/11/08 18:00	7/17/08 17:00	8/3/08 17:00	7/20/08 17:00	7/20/08 16:00	8/23/08 16:00	8/24/08 12:00	8/17/95 14:00	7/20/08 17:00	7/27/08 16:00
2009	6/25/09 16:00	6/22/09 19:00	7/28/09 16:00	7/24/09 18:00	8/9/09 16:00	8/9/09 16:00	1/16/09 8:00	6/25/09 16:00	6/22/09 16:00	7/2/09 16:00	7/2/09 18:00

Weather Year Time of Peak Demand (ESTHE)	MISO	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS
2010	8/10/10 17:00	8/8/10 18:00	8/20/10 14:00	7/17/10 19:00	7/15/10 15:00	8/3/10 16:00	8/2/91 18:00	9/1/10 17:00	8/17/95 14:00	8/1/10 17:00	8/2/10 17:00
2011	7/20/11 18:00	6/7/11 19:00	7/13/95 16:00	7/20/11 16:00	9/1/11 16:00	8/31/11 16:00	7/26/97 16:00	7/20/11 19:00	7/31/93 17:00	7/2/11 17:00	7/10/11 18:00
2012	7/6/12 17:00	7/6/12 18:00	7/13/95 16:00	7/7/12 16:00	7/7/12 17:00	7/25/12 18:00	7/26/97 16:00	7/6/12 17:00	7/30/12 17:00	6/26/12 16:00	7/3/12 15:00
2013	7/19/13 16:00	7/18/13 19:00	8/27/13 16:00	8/30/13 16:00	9/11/13 16:00	8/31/13 17:00	8/31/13 15:00	7/19/13 14:00	6/27/13 18:00	8/7/13 16:00	8/8/13 17:00
2014	7/22/14 16:00	7/22/14 17:00	7/22/14 16:00	7/22/14 16:00	9/5/14 16:00	7/26/14 15:00	2/7/14 9:00	7/22/14 17:00	7/27/14 17:00	8/23/14 16:00	7/26/14 17:00
2015	7/29/15 16:00	8/14/15 15:00	8/14/15 17:00	7/13/15 15:00	9/3/15 16:00	7/13/15 16:00	7/18/15 17:00	8/2/15 16:00	8/7/15 18:00	8/10/15 16:00	7/30/15 16:00
2016	7/20/16 15:00	7/21/16 17:00	8/10/16 17:00	7/22/16 16:00	9/22/16 16:00	7/23/16 17:00	6/11/16 14:00	8/10/16 14:00	7/20/16 13:00	9/1/16 16:00	7/20/16 15:00
2017	7/20/17 16:00	7/6/17 17:00	6/12/17 14:00	7/21/17 17:00	9/26/17 15:00	7/12/17 15:00	9/26/17 16:00	6/12/17 14:00	7/21/17 15:00	8/19/17 15:00	7/20/17 15:00
2018	6/29/18 15:00	6/29/18 15:00	6/29/18 15:00	5/28/18 14:00	9/5/18 15:00	8/6/18 16:00	9/5/18 16:00	9/5/18 15:00	1/17/18 6:00	1/17/18 6:00	9/19/18 16:00
2019	7/19/19 14:00	7/19/19 18:00	7/19/19 16:00	7/19/19 14:00	9/12/19 16:00	10/1/19 15:00	9/13/19 16:00	7/19/19 13:00	8/13/19 14:00	10/4/19 15:00	10/2/19 16:00
2020	7/9/20 15:00	7/2/20 17:00	8/27/20 14:00	7/8/20 14:00	7/8/20 15:00	7/11/20 15:00	8/25/20 15:00	7/9/20 15:00	7/12/20 15:00	7/11/20 15:00	9/4/20 16:00
2021	8/24/21 15:00	7/27/21 16:00	8/10/21 15:00	7/28/21 16:00	8/27/21 15:00	8/25/21 16:00	8/24/21 16:00	8/24/21 15:00	8/10/21 14:00	8/23/21 16:00	7/29/21 14:00
2022	7/19/22 17:00	7/19/22 18:00	6/15/22 16:00	7/23/22 16:00	8/13/22 18:00	7/23/22 15:00	7/11/22 17:00	6/21/22 17:00	7/8/22 16:00	9/21/22 17:00	8/15/22 17:00

Table 5-5: Modeled Peak Demand Days/Hours by Local Resource Zone

6 Appendix A: Comparison of Planning Year 2023-2024 to Planning Year 2024-2025

Multiple study sensitivity analyses were performed to compute changes in the PRM target on a UCAP basis for each season, from Planning Year 2023-2024 to Planning Year 2024-2025. These sensitivities included one-off incremental changes of input parameters to quantify how each change affected the PRM result independently. Note the impact of the incremental PRM changes from Planning Year 2023-2024 to Planning Year 2024-2025 in the waterfall charts below (Figure A-1, Figure A-2, Figure A-3, & Figure A-4). The following subsections provide more details around each of the sensitivities.

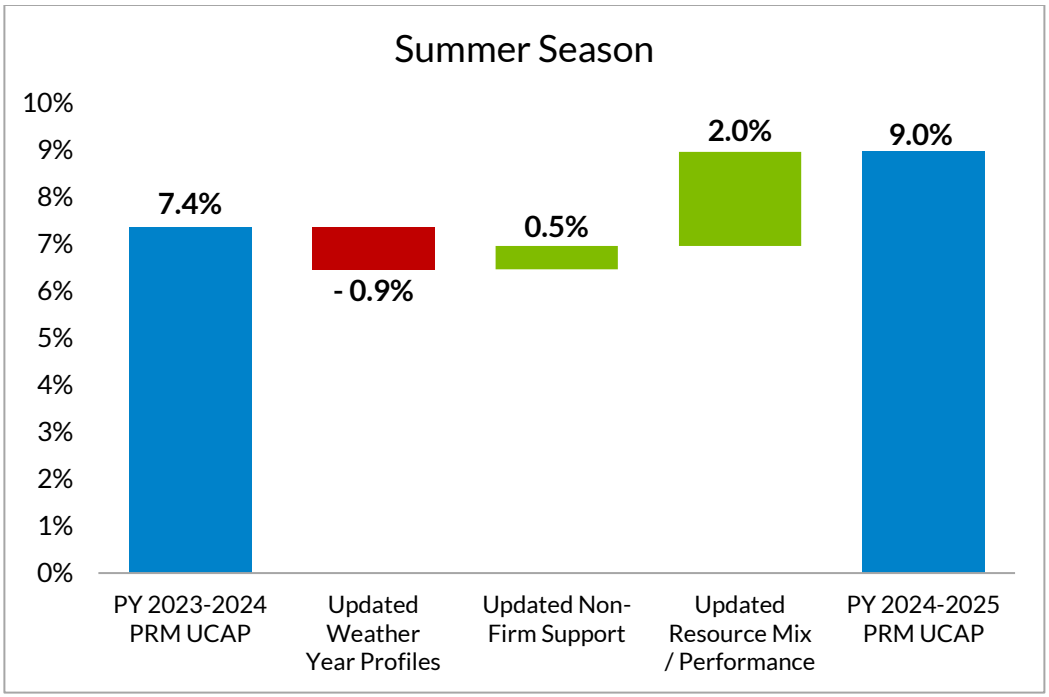


Figure A-1: Waterfall Chart of Summer PRM UCAP from PY 2023-2024 to PY 2024-2025

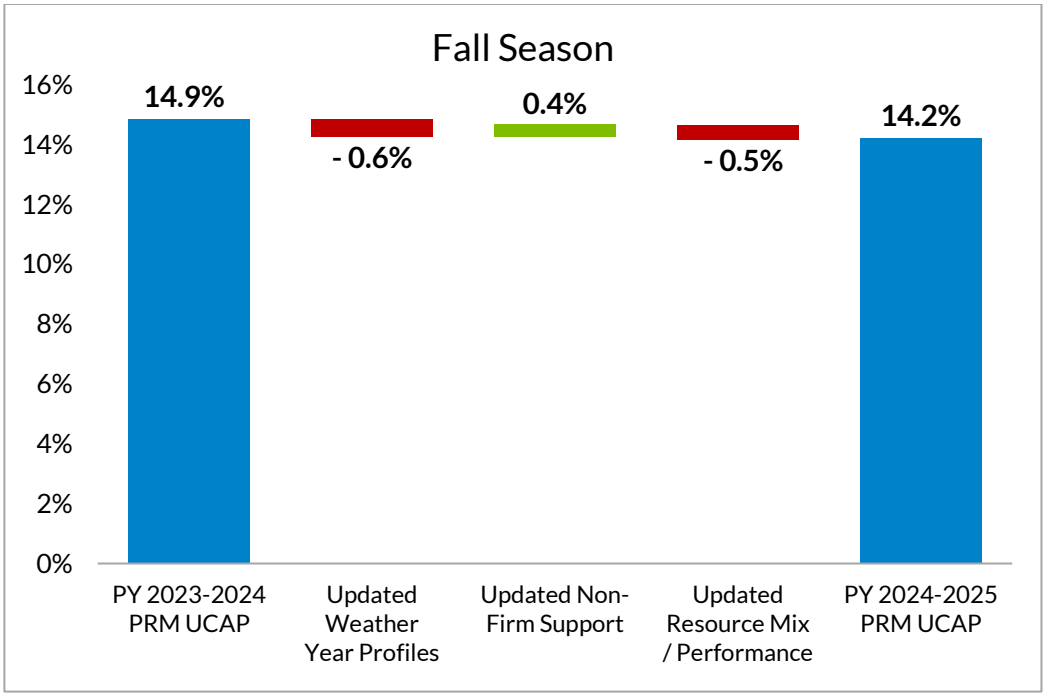


Figure A-2: Waterfall Chart of Fall PRM UCAP from PY 2023-2024 to PY 2024-2025

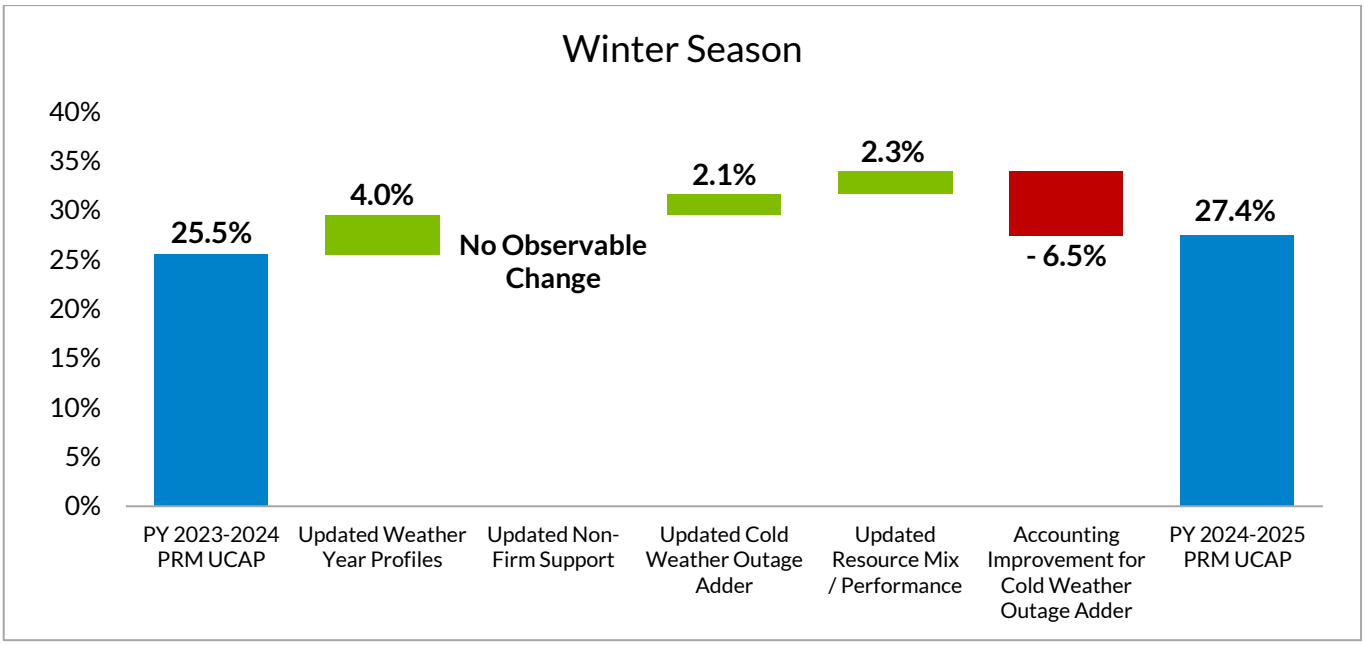


Figure A-3: Waterfall Chart of Winter PRM UCAP from PY 2023-2024 to PY 2024-2025

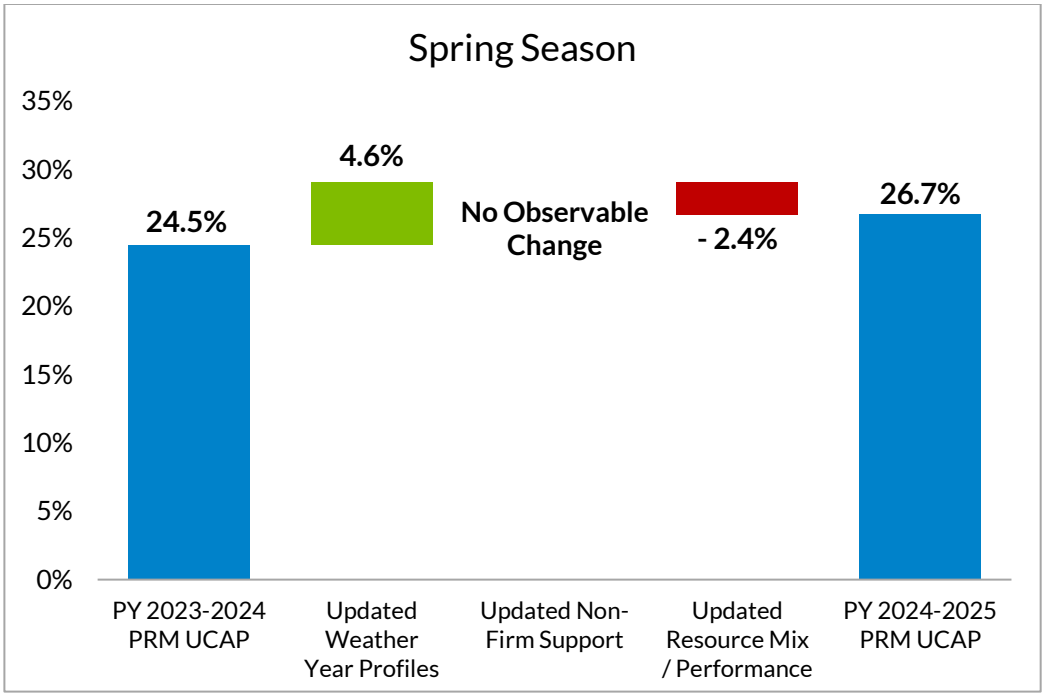


Figure A-4: Waterfall Chart of Spring PRM UCAP from PY 2023-2024 to PY 2024-2025

6.1 Waterfall Chart Details

6.1.1 Updated Weather Year Profiles

With the annual refresh to the LOLE model, the oldest weather year is dropped off and a new weather year is added. Previously, only load shapes were tied to the weather years. Now, with the addition to the model of hourly profiles for renewables and the cold weather outage adder, it is no longer possible to isolate just the updated load profiles as stakeholders may be used to seeing in prior reports.

6.1.2 Updated Non-Firm Support

The probabilistic distribution of seasonal non-firm support is not tied to any specific weather years and is the next input dataset to be replaced in the LOLE model.

6.1.3 Updated Resource Mix / Performance

Changes in resource capability from Planning Year 2023-2024 are primarily driven by a methodology change in the Planning Resource Auction (PRA) to request from generation owners seasonally corrected Generation Verification Test Capacity (GVTC). Other drivers include updated seasonal forced outage rates, updated annualized planned maintenance outage rates, new units, retirements, suspensions, and changes in the resource mix. There was also a modeling improvement to make battery storage use-limited in the model that would also be a driver for change.

6.1.4 Updated Cold Weather Outage Adder (Winter only)

The isolated impact on the system-wide PRM requirement of modeling outage adder during extreme cold temperatures was found to be 6,710 MW. When compared to the cold weather outage adder from the prior year study, this represents an approximately 2.2 GW impact increase year-over-year.

6.1.5 Accounting Improvement for Cold Weather Outage Adder (Winter only)

The modeling of additional forced outages in the Winter season due to the adder induces a more elevated volume of forced outages in the model beyond the average Winter forced outage rates, but this was previously not reflected in the PRM and LRR accounting. ELCC-type analysis was performed to quantify the system-wide impact of modeling the cold weather outage adder profiles. Including these additional Winter forced outages in the numerator of the requirement calculations as a reduction in total Unforced Capacity lowers Winter requirements.

7 Appendix B: Increased Winter Thermal Capability Sensitivity

As requested by stakeholders at the LOLEWG, MISO performed a sensitivity for the Winter season to better understand the impact of including increased Winter capabilities of certain thermal resources to the Winter Planning Reserve Margin Requirement. For this sensitivity, MISO utilized generation owners' seasonal GVTC values for the Planning Year 2023-2024 Planning Resource Auction and scaled the thermal Winter capabilities by, approximately, an additional 20% to see how the adjustment to capacity in the model changed to maintain the same LOLE criteria. This sensitivity demonstrated that there are diminishing returns for the ability to reduce risk in the model when there is a saturated increase in resource capability. Increased capability across the same set of resources may not translate to increased availability, as non-risk hours that already had excess generation may see no benefit whereas risk hours may be exacerbated, or more risk hours may emerge, from an elevated volume of outages when forced and planned maintenance outage rates are applied to a higher thermal capability.

8 Appendix C: Capacity Import Limit Tier 1 & 2 Source Subsystem Definitions

MISO Local Resource Zone 1

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
XEL / 600	ITCM / 627	WEC / 295
MP / 608	ALTE / 694	MIUP / 296
SMMPA / 613	WPS / 696	AMMO / 356
GRE / 615	MGE / 697	AMIL / 357
OTP / 620		MPW / 633
MDU / 661		MEC / 635
BEPC-MISO / 663		
DPC / 680		

MISO Local Resource Zone 2

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #	
WEC / 295	METC / 218	NIPS / 217	OTP / 620
MIUP / 296	XEL / 600	ITCT / 219	MPW / 633
ALTE / 694	MP / 608	AMMO / 356	MEC / 635
WPS / 696	ITCM / 627	AMIL / 357	
MGE / 697	DPC / 680	SMMPA / 613	
UPPC / 698		GRE / 615	

MISO Local Resource Zone 3

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #	
ITCM / 627	AMMO / 356	DEI / 208	MP / 608
MPW / 633	AMIL / 357	NIPS / 217	GRE / 615
MEC / 635	XEL / 600	WEC / 295	OTP / 620
	SMMPA / 613	CWLP / 360	WPS / 696
	DPC / 680	SIPC/ 361	MGE / 697
	ALTE / 694	GLHB / 362	

MISO Local Resource Zone 4

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #	
AMIL / 357	DEI / 208	HE / 207	SMMPA / 613
CWLP / 360	NIPS / 217	SIGE / 210	MPW / 633
SIPC / 361	BREC / 314	IPL / 216	DPC / 680
GLHB / 362	AMMO / 356	METC / 218	ALTE / 694
GLH / 373	ITCM / 627	HMPL / 315	
	MEC / 635	XEL / 600	

MISO Local Resource Zone 5

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #	
CWLD / 333	AMIL / 357	DEI / 208	SMMPA / 613
AMMO / 356	GLHB / 362	NIPS / 217	MPW / 633
	ITCM / 627	CWLP / 360	DPC / 680
	MEC / 635	SIPC / 361	ALTE / 694
		XEL / 600	

MISO Local Resource Zone 6

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
HE / 207	METC / 218	ITCT / 219
DEI / 208	AMIL / 357	MIUP / 296
SIGE / 210	SIPC / 361	AMMO / 356
IPL / 216		CWLP / 360
NIPS / 217		GLHB / 362
BREC / 314		ITCM / 627
HMPL / 315		MEC / 635

MISO Local Resource Zone 7

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
METC / 218	NIPS / 217	DEI / 208
ITCT / 219	MIUP / 296	WEC / 295
		AMIL / 356
		WPS / 696
		UPPC / 698

MISO Local Resource Zone 8

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
EES-EAI / 327	EES-EMI / 326	LAGN / 332
	EES / 351	Cooperative Energy / 349
		CLEC / 502
		LAFA / 503

MISO Local Resource Zone 9

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
LAGN / 332	EES-EMI / 326	Cooperative Energy / 349
EES / 351	EES-EAI / 327	
CLEC / 502		
LAFA / 503		
LEPA / 504		

MISO Local Resource Zone 10

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
EES-EMI / 326	EES-EAI / 327	LAGN / 332
Cooperative Energy / 349	EES / 351	CLEC / 502
		LAFA / 503

9 Appendix D: Compliance Conformance Table

Requirements under: Standard BAL-502-RF-03	Response
R1 The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall:	The Planning Year 2024-2025 LOLE Study Report is the annual Resource Adequacy Analysis for the peak season of June 2024 through May 2025 and beyond. Analysis of Planning Year 2024-2025 is in Sections 4.1 and 5.1. Analysis of Future Years 2025-2034 are included in Appendix F as an addendum to the study report.
R1.1 Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year[1] analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 years" criterion).	Section 3.5 of this report outlines the utilization of LOLE in the reserve margin determination. "These metrics were derived through probabilistic modeling of the system, first solving to the industry standard annual LOLE risk target of 1 day in 10 years, or 0.1 day per year, and then solving to the minimum seasonal LOLE criteria of 0.01 LOLE for seasons demonstrating minimal risk."
R1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability.	Section 3.3 of this report. "Direct Control Load Management and Interruptible Demand types of demand response were explicitly included in the LOLE model as resources. Demand response is dispatched in the LOLE model to avoid load shed during simulation when all other available generation has been exhausted."
R1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median forecast peak Net Internal Demand (planning reserve margin).	Section 4.1 of this report. "…the ratio of MISO capacity to forecasted MISO system peak demand yielded a planning ICAP reserve margin…"
R1.2 Be performed or verified separately for each of the following planning years.	Covered in the segmented R1.2 responses below.
R1.2.1 Perform an analysis for Year One.	In Sections 4.1 and 5.1, a full analysis was performed for Planning Year 2024-2025.
R1.2.2 Perform an analysis or verification at a minimum for one year in the 2 through 5-year period and at a minimum one year in the 6 though 10 year period.	Analysis of Planning Years 2027-2028 and 2029-2030 are included in Appendix F as an addendum to the study report.

Requirements under: Standard BAL-502-RF-03	Response
R1.2.2.1 If the analysis is verified, the verification must be supported by current or past studies for the same planning year.	Analysis was performed.
R1.3 Include the following subject matter and documentation of its use:	Covered in the segmented R1.3 responses below.
R1.3.1 Load forecast characteristics: • Median (50:50) forecast peak load • Load forecast uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts) • Load diversity • Seasonal Load variations • Daily demand modeling assumptions (firm, interruptible) • Contractual arrangements concerning curtailable/Interruptible Demand	Median forecasted load – In Section 3.3 of this report: "The sixth and final step of the load training process is to average the monthly peak loads of the predicted load shapes and adjust them to match each LRZ's monthly Zonal Coincident Peak Forecast provided by the Load Serving Entities for each of the study years." Load Forecast Uncertainty – A detailed explanation of the weather and economic uncertainties is given in Section 3.3. Load Diversity / Seasonal Load Variations — In Section 3.3 of this report: "MISO has adopted a six-step load training process in order to capture the weather uncertainty associated with the most recent 50/50 load forecasts submitted by the Load Serving Entities for the development of the 30 years of hourly zonal correlated load and weather shapes in the LOLE model. The third step of the process utilizes neural net software to establish functional relationships between the most recent five years of historical weather and load data." Demand Modeling Assumptions / Curtailable and Interruptible Demand — All Load Modifying Resources must first meet registration requirements through Module E of the MISO Tariff. As stated in Section 3.2.6: "Each demand response program was modeled individually with a monthly capability, limited by duration, and the number of times each program can be called upon for each season."

Requirements under: Standard BAL-502-RF-03	Response
R1.3.2 Resource characteristics: • Historic resource performance and any projected changes • Seasonal resource ratings • Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area • Resource planned outage schedules, deratings, and retirements • Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration • Criteria for including planned resource additions in the analysis	Section 3.2 details how historic performance data and seasonal ratings are gathered and includes discussion of future units and the modeling assumptions for intermittent capacity resources. A more detailed explanation of firm capacity purchases and sales is in Section 3.4.
R1.3.3 Transmission limitations that prevent the delivery of generation reserves	Annual MTEP deliverability analysis identifies transmission limitations preventing delivery of generation reserves. Additionally, Section 2 of this report details the transfer analysis to capture transmission constraints limiting capacity transfers.
R1.3.3.1 Criteria for including planned Transmission Facility additions in the analysis	Inclusion of the planned transmission addition assumptions is detailed in Section 2.2.3.
R1.3.4 Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area.	Section 3.4 provides the analysis on the treatment of external support assistance and limitations.

Requirements under: Standard BAL-502-RF-03	Response
R1.4 Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included: • Availability and deliverability of fuel • Common mode outages that affect resource availability • Environmental or regulatory restrictions of resource availability • Any other demand (Load) response programs not included in R1.3.1 • Sensitivity to resource outage rates • Impacts of extreme weather/drought conditions that affect unit availability • Modeling assumptions for emergency operation procedures used to make reserves available • Market resources not committed to serving Load (uncommitted resources) within the Planning Coordinator area	Fuel availability, environmental restrictions, common mode outage, and extreme weather conditions are all part of the historical availability performance data that goes into the unit's EFORd statistic. The use of the EFORd values is covered in Section 3.2.1. The use of demand response programs is mentioned in Section 3.2.6. The effects of resource outage characteristics on the reserve margin are outlined in Section 3.5.2 by examining the difference between PRM ICAP and PRM UCAP values.
R1.5 Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included	Transmission maintenance schedules were not included in the analysis of the transmission system due to the limited availability of reliable long-term maintenance schedules and minimal impact to the results of the analysis. However, Section 2 treats worst-case theoretical outages by performing First Contingency Total Transfer Capability (FCTTC) analysis for each LRZ, by modeling NERC Category P0 (system intact) and Category P1 (N-1) contingencies.
R1.6 Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis	MISO internal resources are among the quantities documented in the tables provided in Sections 4 and 5.
R1.7 Document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis	MISO load is among the quantities documented in the tables provided in Sections 4 and 5.
R2 The Planning Coordinator shall annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis.	In Sections 4 and 5, the peak load and estimated amount of resources for Planning Year 2024-2025 are shown. This includes the detail for each transmission constrained sub-area.
R2.1 This documentation covers each of the years in year one through ten.	Appendix F covers the future Planning Years.

Requirements under: Standard BAL-502-RF-03	Response
R2.2 This documentation includes the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis.	The prompt Planning Year seasonal PRM values are covered in Sections 4.1. The outyear Planning Years 4 (2027-2028) and 6 (2029-2030) are covered in Appendix F.
R2.3 The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One.	The final Planning Year 2024-2025 LOLE Study Report was posted publicly in December 2023, several months prior to the start of the applicable Planning Year.
R3 The Planning Coordinator shall identify any gaps between the needed amount of planning reserves defined in Requirement R1, Part 1.1 and the projected planning reserves documented in Requirement R2.	Sections 4 and 5 show the differences between the needed amount and the projected planning reserves for Planning Year 2024-2025. The needed amount of planning reserves for the outyear Planning Years 4 (2027-2028) and 6 (2029-2030) are covered in Appendix F.

10 Appendix E: Acronyms List Table

CEL	Capacity Export Limit
CIL	Capacity Import Limit
CPNode	Commercial Pricing Node
DF	Distribution Factor
EFORd	Equivalent Forced Outage Rate demand
ELCC	Effective Load Carrying Capability
ERZ	External Resource Zone
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
FCITC	First Contingency Incremental Transfer Capability
FCTTC	First Contingency Total Transfer Capability
GADS	Generator Availability Data System
GLT	Generation Limited Transfer
GVTC	Generation Verification Test Capacity
ICAP	Installed Capacity
LBA	Local Balancing Authority
LCR	Local Clearing Requirement
LFE	Load Forecast Error
LFU	Load Forecast Uncertainty
LOLE	Loss of Load Expectation
LOLEWG	Loss of Load Expectation Working Group
LRR	Local Reliability Requirement
LRZ	Local Resource Zones
LSE	Load Serving Entity
MARS	Multi-Area Reliability Simulation
MECT	Module E Capacity Tracking
MISO	Midcontinent Independent System Operator
MOD	Model on Demand
MTEP	MISO Transmission Expansion Plan
MW	Megawatt
MWh	Megawatt hours
NERC	North American Electric Reliability Corporation

PRA	Planning Resource Auction
PRM	Planning Reserve Margin
PRM ICAP	PRM Installed Capacity
PRM UCAP	PRM Unforced Capacity
PRMR	Planning Reserve Margin Requirement
PSS E	Power System Simulator for Engineering
RCF	Reciprocal Coordinating Flowgate
RDS	Redispatch
RPM	Reliability Pricing Model
SERVM	Strategic Energy & Risk Valuation Model
SPS	Special Protection Scheme
TARA	Transmission Adequacy and Reliability Assessment
UCAP	Unforced Capacity
XEFORd	Equivalent Forced Outage Rate demand with adjustment to exclude events outside management control
ZIA	Zonal Import Ability
ZEA	Zonal Export Ability

11 Appendix F: Outyear PRM Results

Beyond the prompt Planning Year 2024-2025, LOLE analyses were performed for the four-year-out Planning Year of 2027-2028, and the six-year-out Planning Year of 2029-2030. Tables 11-1 and 11-2 show the capacity and demand values that went into the MISO system seasonal Planning Reserve Margin for outyears four and six, respectively. Tables 11-3, 11-4, 10-5, and 11-6 show the seasonal outyear PRM projections ten years out based on future capacity and demand assumptions.

11.1 Planning Year 2027-2028 MISO Planning Reserve Margin Results

For Planning Year 2027-2028, the ratio of MISO capacity to forecasted MISO system peak demand yielded a Planning Reserve Margin ICAP of 18.9 percent and a Planning Reserve Margin UCAP of 9.6 percent for the Summer season. Numerous values and calculations went into determining the four-year-out MISO system seasonal PRM ICAP and PRM UCAP (Table 11-1).

MISO Planning Reserve Margin (PRM)	PY 2027-2028 Summer	PY 2027-2028 Fall	PY 2027-2028 Winter	PY 2027-2028 Spring	Formula Key
MISO System Peak Demand (MW)	126,218	113,712	105,726	100,853	[A]
Installed Capacity (ICAP) (MW)	158,145	157,720	170,335	164,536	[B]
Unforced Capacity (UCAP) (MW)	146,508	144,619	147,165	150,185	[C]
Firm External Support ICAP (MW)	3,217	2,865	3,771	3,247	[D]
Firm External Support UCAP (MW)	3,052	2,758	3,613	3,105	[E]
Adjustment to ICAP (MW)	(11,250)	(15,600)	(16,750)	(19,400)	[F]
Adjustment to UCAP (MW)	(11,250)	(15,600)	(16,750)	(19,400)	[G]
ICAP PRM Requirement (PRMR) (MW)	150,112	144,984	157,356	148,383	[H] = [B]+[D]+[F]
UCAP PRM Requirement (PRMR) (MW)	138,309	131,777	134,028	133,890	[I] = [C]+[E]+[G]
MISO PRM ICAP	**18.9%**	**27.5%**	**48.8%**	**47.1%**	[J]=[H]-[A]/[A]
MISO PRM UCAP	**9.6%**	**15.9%**	**26.8%**	**32.8%**	[K]=[I]-[A]/[A]

Table 11-1: Planning Year 2027-2028 MISO System Planning Reserve Margins

11.2 Planning Year 2029-2030 MISO Planning Reserve Margin Results

For Planning Year 2029-2030, the ratio of MISO capacity to forecasted MISO system peak demand yielded a Planning Reserve Margin ICAP of 19.0 percent and a Planning Reserve Margin UCAP of 9.4 percent for the Summer season. Numerous values and calculations went into determining the six-year-out MISO system seasonal PRM ICAP and PRM UCAP (Table 11-2).

MISO Planning Reserve Margin (PRM)	**PY 2029-2030** Summer	**PY 2029-2030** Fall	**PY 2029-2030** Winter	**PY 2029-2030** Spring	**Formula Key**
MISO System Peak Demand (MW)	127,512	114,908	106,860	101,932	[A]
Installed Capacity (ICAP) (MW)	167,877	165,485	177,850	173,032	[B]
Unforced Capacity (UCAP) (MW)	155,733	151,779	153,853	157,958	[C]
Firm External Support ICAP (MW)	3,217	2,865	3,771	3,247	[D]
Firm External Support UCAP (MW)	3,052	2,758	3,613	3,105	[E]
Adjustment to ICAP (MW)	(19,330)	(21,830)	(22,500)	(25,000)	[F]
Adjustment to UCAP (MW)	(19,330)	(21,830)	(22,500)	(25,000)	[G]
ICAP PRM Requirement (PRMR) (MW)	151,764	146,520	159,121	151,279	[H] = [B]+[D]+[F]
UCAP PRM Requirement (PRMR) (MW)	139,454	132,707	134,967	136,063	[I] = [C]+[E]+[G]
MISO PRM ICAP	**19.0%**	**27.5%**	**48.9%**	**48.4%**	[J]=[H]-[A]/[A]
MISO PRM UCAP	**9.4%**	**15.5%**	**26.3%**	**33.5%**	[K]=[I]-[A]/[A]

Table 11-2: Planning Year 2029-2030 MISO System Planning Reserve Margins

11.3 MISO Planning Reserve Margin Outyear Projections

Tables 11-3, 11-4, 11-5, and 11-6 show the outyear seasonal PRM projections. Years one, four, and six were probabilistically modeled. PRM projections in years two, three, and five are the result of interpolation of the years studied and years seven through ten are the resulting extrapolations of the outyear analyses.

Metric	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
PRM ICAP	17.7%	18.1%	18.5%	18.9%	19.0%	19.0%	19.3%	19.5%	19.8%	20.1%
PRM UCAP	9.0%	9.2%	9.4%	9.6%	9.5%	9.4%	9.4%	9.5%	9.6%	9.7%
Demand (GW)	124.7	125.2	125.7	126.2	126.9	127.5	128.1	128.6	129.2	129.8
ICAP (GW)	150.2	152.8	155.5	158.1	163.0	167.9	171.4	175.0	178.5	182.0

Table 11-3: MISO Summer Planning Reserve Margin Outyear Projections

Metric	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
PRM ICAP	25.2%	25.9%	26.7%	27.5%	27.5%	27.5%	28.0%	28.4%	28.9%	29.4%
PRM UCAP	14.2%	14.8%	15.3%	15.9%	15.7%	15.5%	15.7%	16.0%	16.3%	16.5%
Demand (GW)	112.2	112.7	113.2	113.7	114.3	114.9	115.4	116.0	116.5	117.0
ICAP (GW)	148.8	151.7	154.7	157.7	161.6	165.5	168.8	172.2	175.5	178.9

Table 11-4: MISO Fall Planning Reserve Margin Outyear Projections

Metric	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
PRM ICAP	49.4%	49.2%	49.0%	48.8%	48.9%	48.9%	48.8%	48.7%	48.6%	48.5%
PRM UCAP	27.4%	27.2%	27.0%	26.8%	26.5%	26.3%	26.1%	25.8%	25.6%	25.4%
Demand (GW)	104.3	104.8	105.3	105.7	106.3	106.9	107.4	107.9	108.4	108.9
ICAP (GW)	165.9	167.4	168.9	170.3	174.1	177.8	180.2	182.6	185.0	187.4

Table 11-5: MISO Winter Planning Reserve Margin Outyear Projections

Metric	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
PRM ICAP	40.8%	42.9%	45.0%	47.1%	47.8%	48.4%	49.9%	51.5%	53.0%	54.5%
PRM UCAP	26.7%	28.7%	30.7%	32.8%	33.1%	33.5%	34.8%	36.2%	37.5%	38.9%
Demand (GW)	99.5	99.9	100.4	100.9	101.4	101.9	102.4	102.9	103.4	103.9
ICAP (GW)	152.1	156.2	160.4	164.5	168.8	173.0	177.2	181.4	185.6	189.8

Table 11-6: MISO Spring Planning Reserve Margin Outyear Projections

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-26-16

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 83

MISO 2025–26 LOLE Study Report



Planning Year 2025-2026 Loss of Load Expectation Study Report

The Planning Year 2025-2026 Loss of Load Expectation (LOLE) Study Report details the various inputs, assumptions, and methodologies utilized in both the probabilistic and the power flow analyses to establish the seasonal Planning Reserve Margin (PRM), Local Reliability Requirement (LRR), and Capacity Import/Export Limit (CIL/CEL) values.

Highlights

- Summer, Winter, and Spring Planning Reserve Margin (PRM) decreased from Planning Year 2024-2025, while the Fall PRM increased slightly.

- In the Planning Year 2025-2026 study, significant year-over-year differences in wind and solar Effective Load Carrying Capability (ELCC) were observed for the Fall, Winter, and Spring seasons.

- An enhanced load development process and improved outage rates were the primary factors for the changes in the Planning Year 2025-2026 results. Additionally, shifting risk hours and ongoing changes to the generation fleet impacted this year's results.

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Executive Summary

In preparation for the annual Planning Resource Auction (PRA), MISO conducts an annual Loss of Load Expectation (LOLE) Study to determine Resource Adequacy Requirements for the upcoming Planning Year. These requirements are identified on a seasonal basis for each Local Resource Zone within MISO.

Review processes played an integral role in this study. MISO would like to thank the Loss of Load Expectation Working Group (LOLEWG), the Resource Adequacy Subcommittee (RASC), and the Independent Market Monitor (IMM) for their assistance and input in this year's study.

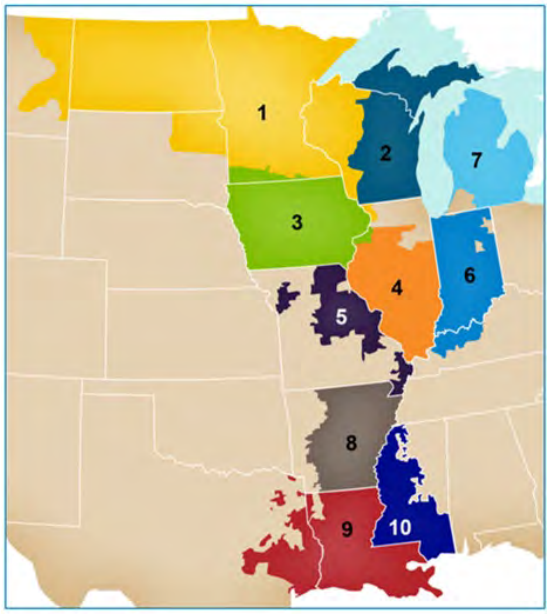
The seasonal Planning Reserve Margin (PRM) values determined through the Planning Year 2025-2026 LOLE study are provided in the table below.

Planning Year 2025-2026 Seasons	Summer 2025	Fall 2025	Winter 2025-2026	Spring 2026
MISO PRM UCAP	7.9%	14.9%	18.4%	25.3%

Table ES-1: Planning Reserve Margin Summary and Comparison

This study also determines zonal Local Reliability Requirements (LRRs). Additionally, initial values for zonal Capacity Import Limits (CIL) and Capacity Export Limits (CEL) for each season are also determined. These quantities are described in greater detail in Section 4.3.

MISO is divided into 10 Local Resource Zones (LRZs) as shown in the figure and table below.



Local Resource Zone	Local Balancing Authorities
1	DPC, GRE, MDU, MP, NSP OTP, SMP
2	ALTE, MGE, MIUP, UPPC, WEC, WPS
3	ALTW, MEC, MPW
4	AMIL, CWLP, GLH, SIPC
5	AMMO, CWLD
6	BREC, CIN, HE, HMPL, IPL, NIPS, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	EMBA, SME

Figure ES-2: Map of MISO Local Resource Zones
Table ES-2: Local Balancing Authority to Local Resource Zone Designations

Tables ES-3 through ES-6 below show results for each season.

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
LRR UCAP per-unit of LRZ Peak Demand	1.195	1.135	1.318	1.280	1.301	1.262	1.138	1.350	1.136	1.447
Capacity Import Limit (CIL) (MW)	6,025	4,370	5,518	8,649	4,117	8,650	3,579	2,522	4,872	4,474
Capacity Export Limit (CEL) (MW)	3,991	4,614	4,655	4,460	3,939	6,881	5,716	6,345	3,775	2,097

Table ES-3: Initial Planning Resource Auction Deliverables — Summer 2025

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
LRR UCAP per-unit of LRZ Peak Demand	1.288	1.222	1.537	1.320	1.365	1.312	1.255	1.469	1.198	1.557
Capacity Import Limit (CIL) (MW)	5,690	6,537	7,766	7,908	4,679	8,970	5,125	5,870	5,242	4,508
Capacity Export Limit (CEL) (MW)	6,165	4,259	5,862	4,174	5,816	5,173	5,158	4,024	3,672	3,164

Table ES-4: Initial Planning Resource Auction Deliverables — Fall 2025

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
LRR UCAP per-unit of LRZ Peak Demand	1.267	1.353	1.632	1.186	1.254	1.247	1.447	1.566	1.297	1.628
Capacity Import Limit (CIL) (MW)	5,575	6,435	5,853	7,353	4,922	7,936	4,762	3,534	4,995	3,458
Capacity Export Limit (CEL) (MW)	3,591	4,793	7,412	4,635	4,814	1,665	5,712	3,681	3,041	2,028

Table ES-5: Initial Planning Resource Auction Deliverables — Winter 2025-2026

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
LRR UCAP per-unit of LRZ Peak Demand	1.283	1.331	1.588	1.495	1.459	1.388	1.319	1.587	1.292	1.788
Capacity Import Limit (CIL) (MW)	6,398	6,439	7,784	8,272	4,453	9,491	5,166	6,250	5,370	4,365
Capacity Export Limit (CEL) (MW)	5,283	6,119	5,981	4,981	5,797	6,391	5,499	3,559	3,631	3,072

Table ES-6: Initial Planning Resource Auction Deliverables — Spring 2026

1 MISO System Planning Reserve Margin

1.1 LOLE Study Process Overview

In compliance with Module E-1 of the Tariff, MISO performed its annual LOLE study to determine, for each season of Planning Year 2025-2026, the system Planning Reserve Margin Unforced Capacity (PRM UCAP) and the Local Reliability Requirement (LRR) for each Local Resource Zone.

In addition to the LOLE analysis, MISO performed seasonal transfer analyses to determine seasonal Zonal Import Ability (ZIA), Zonal Export Ability (ZEA), Capacity Import Limits (CIL), and Capacity Export Limits (CEL). ZIA and controllable exports are used in conjunction with the Local Reliability Requirement (LRR) values to establish the seasonal Local Clearing Requirement (LCR) values in the Planning Resource Auction (PRA). Seasonal CIL and CEL values determine the maximum amount of capacity that can be imported or exported respectively to or from a zone. These variables are covered in Section 4 of this report.

The PY 2025-2026 per-unit seasonal LRR UCAP multiplied by the updated LRZ seasonal Peak Demand forecasts submitted for the 2025-2026 PRA determines each LRZ's seasonal LRR. Once the seasonal LRR is determined, the ZIA values and controllable exports are subtracted from the seasonal LRR to determine each LRZ's seasonal Local Clearing Requirement (LCR) consistent with Section 68A.6 of Module E-1[1]. An example LCR calculation pursuant to Section 68A.6 of the current effective Module E-1 shows how these values are reached (Table 1-1).

Local Resource Zone (LRZ) EXAMPLE	Example LRZ	Formula Key
Installed Capacity (ICAP)	17,442	[A]
Unforced Capacity (UCAP)	16,326	[B]
Adjustment to UCAP (1d in 10yr)	50	[C]
Local Reliability Requirement (LRR) (UCAP)	16,376	[D]=[B]+[C]
LRZ Peak Demand	14,270	[E]
LRR UCAP per-unit of LRZ Peak Demand	114.8%	[F]=[D]/[E]
Zonal Import Ability (ZIA)	3,469	[G]
Zonal Export Ability (ZEA)	2,317	[H]
Local Clearing Requirement (LCR) EXAMPLE	**Example LRZ**	**Formula Key**
Controllable Exports (UCAP)	150	[J]
Local Reliability Requirement (LRR) (UCAP)	16,376	[K]=[F]*[E]
Local Clearing Requirement (LCR)	12,757	[L]=[K]-[G]-[J]

Table 1-1: Example Local Clearing Requirement Calculation

The actual effective Planning Reserve Margin Requirement (PRMR) for each season of the 2025-2026 Planning Resource Auction will be determined after the updated LRZ Seasonal Peak Demand forecasts are submitted by November 1, 2024. The ZIA, ZEA, CIL, and CEL values are subject to updates in March 2025 based on changes to

[1] https://www.misoenergy.org/legal/tariff
Effective Date: September 1, 2022

exports of MISO resources to non-MISO load, changes to pseudo-tied commitments, and updates to facility ratings following the completion of the LOLE study.

Finally, the Simultaneous Feasibility Test (SFT) is performed as part of the PRA where the deliverability of cleared generation is validated through transfer analysis modeling to ensure transmission reliability. If constraints arise, they are mitigated by adjusting CIL and CEL values as needed.

1.1.1 Study Improvements

The Planning Year 2025-2026 LOLE study incorporated the following improvements:

- **SERVM Improvements:** Enhancements made to SERVM resulted in reliability improvements driven primarily by a more realistic dispatch of demand response resources. In version 9 of SERVM, used for the Planning Year 2025-2026 LOLE analysis, demand response dispatch logic was improved to randomly cycle through demand response resources. This change had a positive impact on reliability because in version 7, used for the Planning Year 2024-2025 LOLE analysis, the dispatch order was fixed and would often happen to have more of the larger demand response units being called first. This in turn caused these larger units to achieve their seasonal run limits more frequently. This new random cycling logic for demand response resources modified the dispatch order for each iteration which allowed smaller demand response units to get called first more often. The overall impact is a modest improvement in reliability because the larger demand response units are not exhausted as often in the simulations as they were in prior models.
- **Improved Load Development Process:** This enhanced process aimed to better account for the correlation between load, weather, and the time of day, and to resolve unrealistic high-risk hours in the early mornings of the Winter season that were identified through concerns expressed by the IMM last year. The PY 2025-2026 load development process also better captured the relationship between higher load and temperature values that establishes a stronger representation of load behavior at more extreme temperatures than the prior load development process. Additional information on this load development process may be found in Section 3.4 of this study report.
- **Expanded consideration of outages driven by extreme cold temperatures**: The accounting of additional forced outages during extreme cold temperatures in the Fall, Winter, and Spring seasons was updated in the PRM and LRR calculations. For context, the LOLE model has historically utilized resource-specific five-year average EFORd values based on historical GADS data, which were updated from annualized EFORd to seasonalized EFORd in the PY 2023-2024 LOLE study. The cold weather outage adder was included in the LOLE model, starting with the PY 2024-2025 LOLE study, to better capture the historic seasonal availability of thermal resources during extreme cold temperatures. This was expanded upon in the PY 2025-2026 LOLE study to include the Fall and Spring seasons.

  Additional thermal forced outages are added to the model during times of extreme cold temperatures to better capture the magnitude of observed correlated outages. The magnitude of additional forced outages increases as temperatures decrease based on the relationship between forced outages and temperature determined from historical GADS and weather data. The modeling of additional forced outages in the Fall, Winter, and Spring seasons due to the adder induces a higher volume of forced outages in the model beyond just the average Fall, Winter, and Spring EFORd. Each LRZ has a unique outage/temperature profile based on actual historical forced outages. The incremental cold weather outages are not assigned to a particular resource but instead represent the aggregate impact on the system for coal, gas, and combined cycle resources.

  The accounting of reduced Unforced Capacity resulting from additional extreme cold weather outages was addressed in the most recent PRM and LRR calculations for the Fall and Spring seasons. A comparative

probabilistic analysis (with and without the cold weather outage adder) quantified the impact of modeling the cold weather outage adder profiles on the system-wide requirements for each season. This impact was distributed pro-rata to the zonal level based on the average magnitude of the zonal cold weather outage adder profiles used in the LRR calculations. The comparative probabilistic analysis resulted in the largest effects for the Winter season (7,265 MW) and minimal effects for the Fall (45 MW) and Spring (1,100 MW) seasons. Summer was not affected by these outages.

1.2 Planning Year 2025-2026 MISO Planning Reserve Margin Results

For Planning Year 2025-2026, the ratio of MISO capacity to forecasted MISO system peak demand yielded a Planning Reserve Margin UCAP of 7.9 percent for the Summer season. Numerous values and calculations went into determining the MISO system PRM ICAP and PRM UCAP (Table 1-2).

MISO Planning Reserve Margin (PRM)	PY 2025-2026 Summer	PY 2025-2026 Fall	PY 2025-2026 Winter	PY 2025-2026 Spring	Formula Key
MISO System Peak Demand (MW)	123,576	108,109	103,910	98,680	[A]
Installed Capacity (ICAP) (MW)	141,908	142,746	147,430	144,513	[B]
Unforced Capacity (UCAP) (MW)	132,389	131,554	126,573	131,289	[C]
Firm External Support ICAP (MW)	1,986	2,315	2,738	2,423	[D]
Firm External Support UCAP (MW)	1,935	2,215	2,594	2,309	[E]
Adjustment to ICAP (MW)	(960)	(9,590)	(6,110)	(10,000)	[F]
Adjustment to UCAP (MW)	(960)	(9,590)	(6,110)	(10,000)	[G]
ICAP PRM Requirement (PRMR) (MW)	142,934	135,472	144,058	136,937	[H] = [B]+[D]+[F]
UCAP PRM Requirement (PRMR) (MW)	133,363	124,179	123,058	123,598	[I] = [C]+[E]+[G]
MISO PRM ICAP	**15.7%**	**25.3%**	**38.6%**	**38.8%**	[J]=[H]-[A]/[A]
MISO PRM UCAP	**7.9%**	**14.9%**	**18.4%**	**25.3%**	[K]=[I]-[A]/[A]

Table 1-2: Planning Year 2025-2026 MISO System Planning Reserve Margins

1.2.1 Additional Risk Metric Statistics

In addition to the LOLE results, SERVM has the ability to calculate several other probabilistic metrics, shown below in Table 1-3. The values for Loss of Load Hours (LOLH) and Expected Unserved Energy (EUE) are calculated at the point where the annual LOLE is at 1 day in 10 years, or 0.1 LOLE for the Summer season, and for the off seasons, values of LOLH and EUE are calculated at the point where the seasonal LOLE is at 1 day in 100 years, or 0.01 LOLE. Loss of Load Hours is the number of hours during a given time period where demand exceeds generation. Like LOLE, LOLH is only measured on the daily peak hour. Expected Unserved Energy is the magnitude of the shortfall when demand exceeds generation and is measured on all hours of simulation.

MISO LOLE Statistics	PY 2025-2026 Summer	PY 2025-2026 Fall	PY 2025-2026 Winter	PY 2025-2026 Spring
Loss of Load Expectation (LOLE) [days/year]	0.100	0.010	0.010	0.010
Loss of Load Hours (LOLH) [hours/year]	0.252	0.015	0.021	0.013
Expected Unserved Energy (EUE) [megawatt-hours/year]	626.161	18.936	24.378	12.807

Table 1-3: PY 2025-2026 Additional Risk Metric Statistics

1.3 Comparison of PRM Targets Across 10 Years

Figure 1-1 compares the PRM UCAP values over the last 10 Planning Years. The last three data points show the Summer PRM UCAP values following FERC's acceptance of MISO's seasonal capacity construct, while the prior data points are indicative of the PRM UCAP under the annual capacity construct.

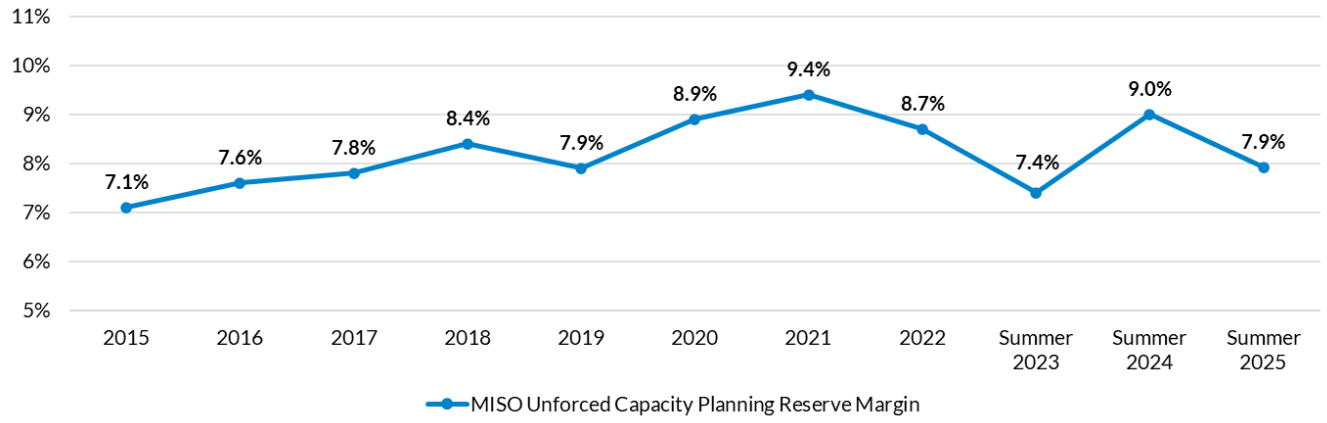


Figure 1-1: Comparison of UCAP PRM Targets Across 10 Years

1.4 Comparison of Planning Year 2024-2025 to Planning Year 2025-2026

Multiple sensitivity analyses were performed to independently quantify the year-over-year changes to the seasonal Planning Reserve Margin (PRM) values driven by various model improvements or model data replacement. The incremental impact to the seasonal PRM values from Planning Year 2024-2025 to Planning Year 2025-2026 due to specific changes to the LOLE model are shown in the waterfall charts below (Figure 1-2, Figure 1-3, Figure 1-4, and Figure 1-5). The following subsections provide more details around each of the sensitivities.

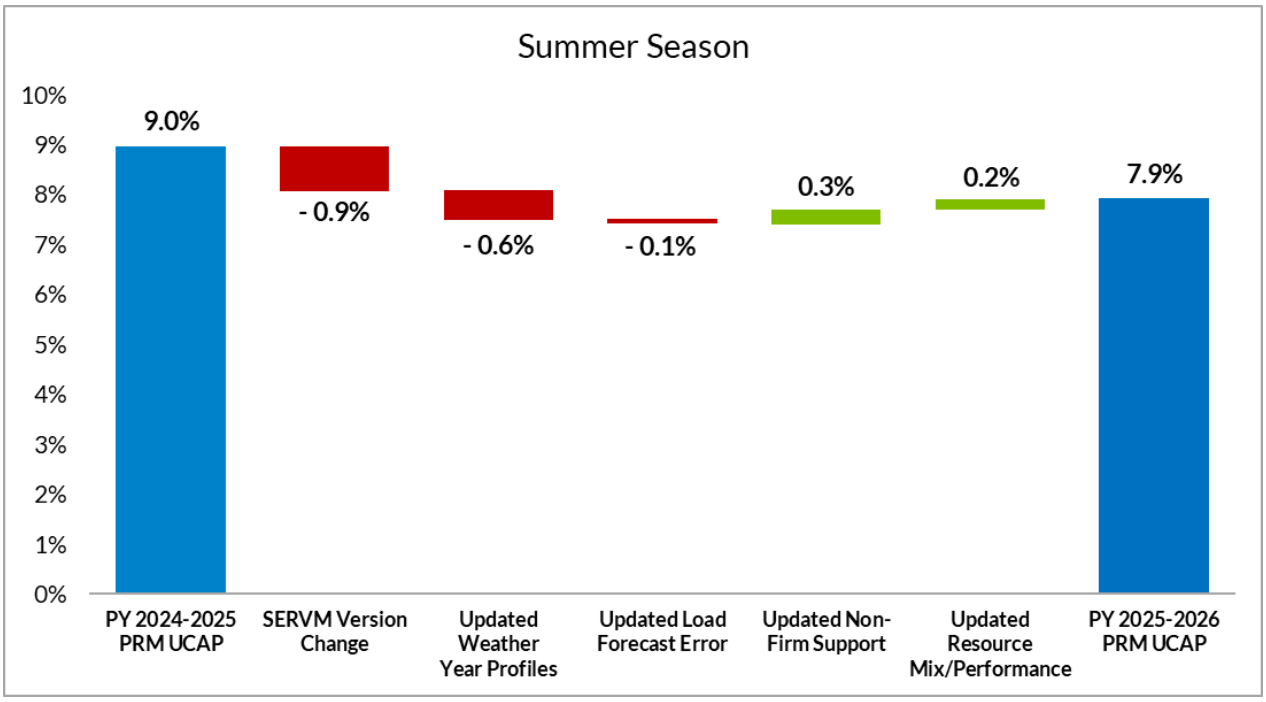


Figure 1-2: Waterfall Chart of Summer PRM UCAP from PY 2024-2025 to PY 2025-2026

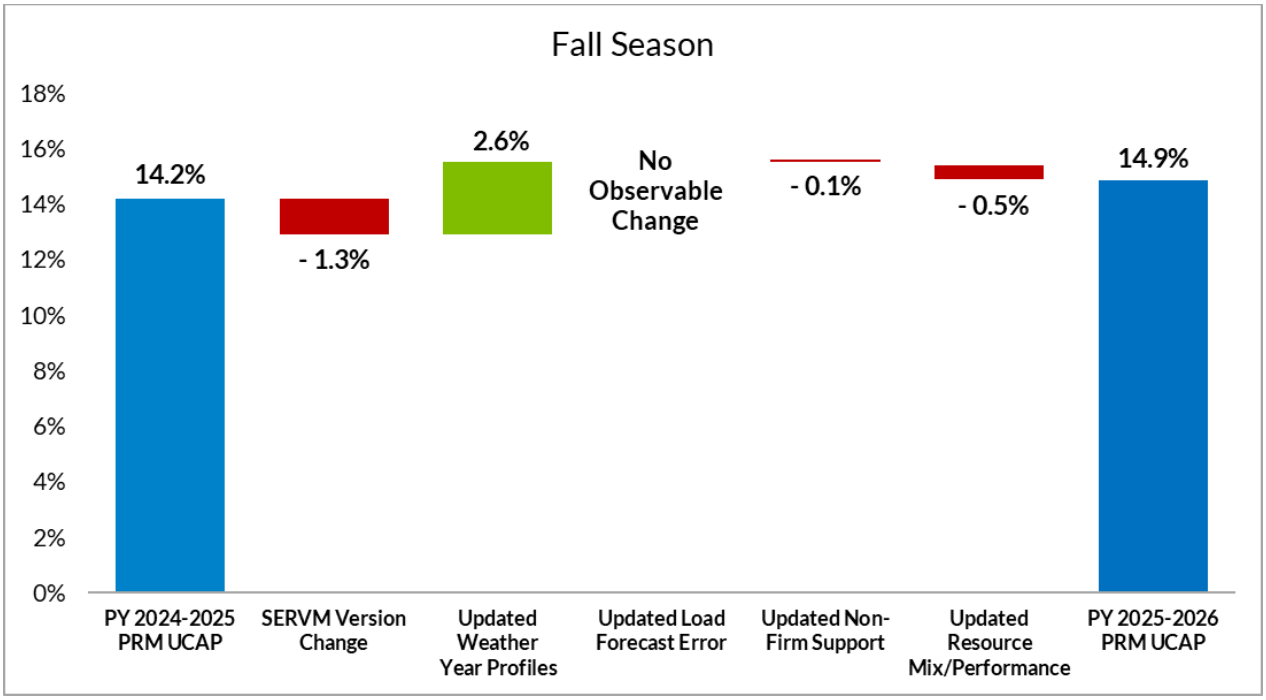


Figure 1-3: Waterfall Chart of Fall PRM UCAP from PY 2024-2025 to PY 2025-2026

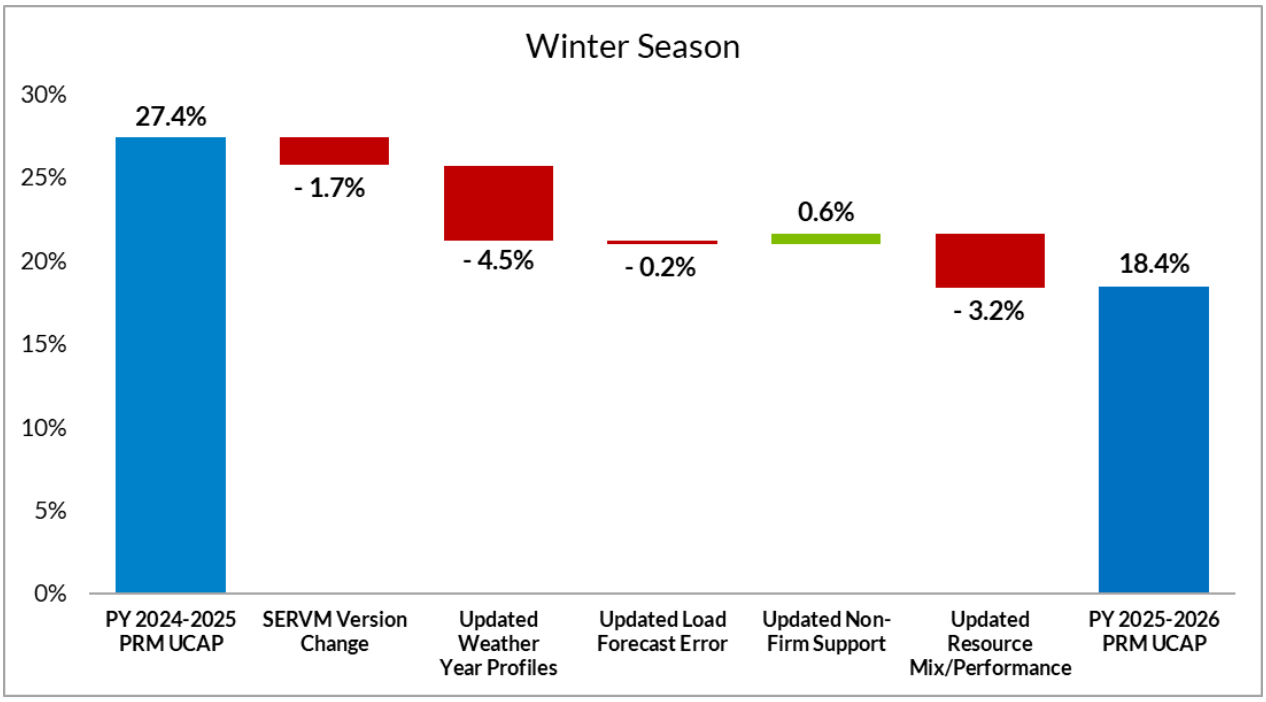


Figure 1-4: Waterfall Chart of Winter PRM UCAP from PY 2024-2025 to PY 2025-2026

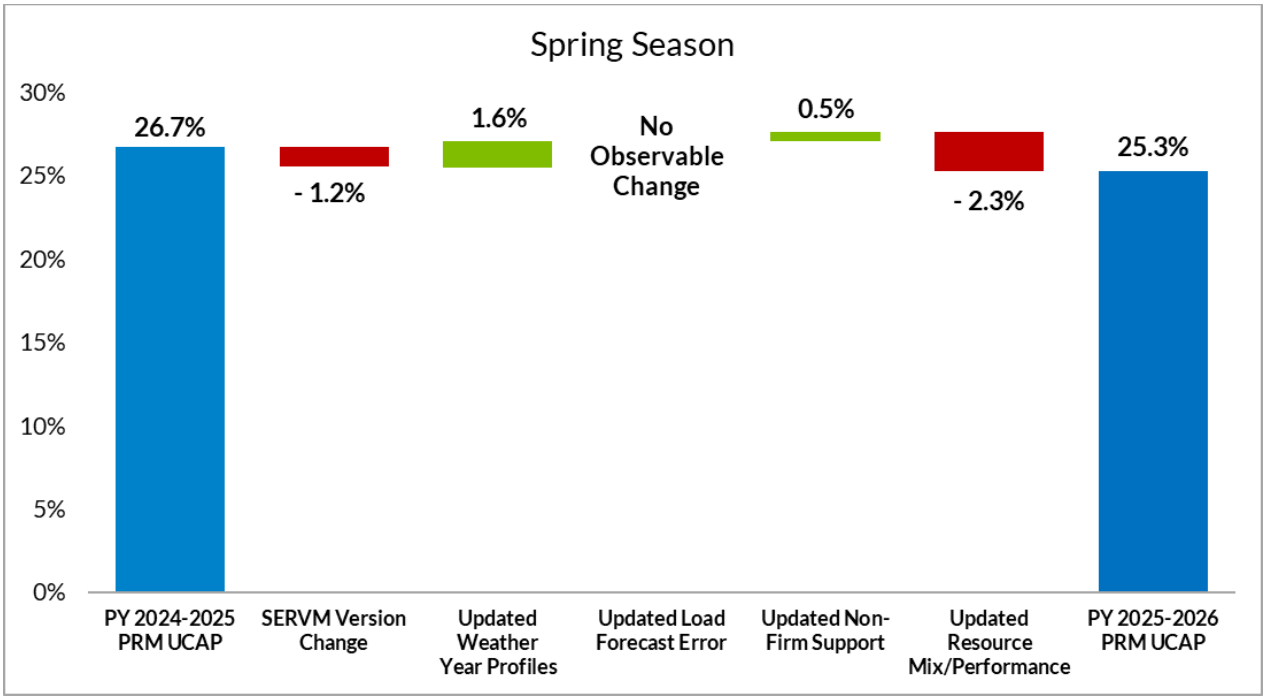


Figure 1-5: Waterfall Chart of Spring PRM UCAP from PY 2024-2025 to PY 2025-2026

1.4.1 Waterfall Chart Details

1.4.1.1 SERVM Improvements

Enhancements made to SERVM for the Planning Year 2025-2026 LOLE study resulted in reliability improvements driven primarily by a more realistic dispatch of demand response and storage resources. Version 9 of SERVM was used in this year's LOLE study.

1.4.1.2 Updated Weather Year Profiles

Every year during the annual refresh of the LOLE model, the oldest weather year is removed and a new weather year is added. In this sensitivity category, MISO analyzes the impacts of all updated hourly profiles that are tied to specific weather years, including profiles for load, wind generation, solar generation, and cold weather outage adders. Since all these variables are tied to specific weather years in the model, it is not possible to isolate the individual impacts of these variables.

1.4.1.3 Updated Non-Firm Support

The probabilistic distribution of seasonal non-firm support is independent of specific weather years and is the next input dataset that is replaced in the year-over-year LOLE model refresh. More information on the modeling of non-firm support can be found in Section 3.5.

1.4.1.4 Updated Resource Mix / Performance

Changes in resource capabilities from Planning Year 2024-2025 are driven by updated seasonal forced outage rates, updated annualized planned maintenance outage rates, new units, retirements, suspensions, replacements, and general changes in the MISO resource fleet.

2 Local Resource Zone Analysis – LRR Results

2.1 Planning Year 2025-2026 Local Resource Zone Analysis

MISO calculated the per-unit LRR of LRZ seasonal peak demand for Planning Year 2025-2026 on a seasonal basis (Table 2-1, Table 2-2, Table 2-3, and Table 2-4). The Unforced Capacity (UCAP) values in the seasonal LRR tables reflect the assumed seasonal UCAP within each LRZ, including Coordinating Owner External Resources and Border External Resources. The adjustments to UCAP values are the megawatt adjustments needed in each LRZ so that the seasonal LOLE criteria are met. LRR is the summation of the zone's total capacity and adjustment to capacity needed to achieve the seasonal LOLE criteria. The LRR is then divided by each LRZ's forecasted seasonal peak demand to determine the per-unit LRR UCAP. The Planning Year 2025-2026 per-unit LRR UCAP values will be multiplied by the updated seasonal peak demand forecasts submitted for the 2025-2026 PRA to determine each LRZ's LRR. The MISO system-wide and zonal peak demand timestamps for all 30 years modeled in the LOLE study are shown in Table 2-5. The peak demand timestamps are subject to the load development process and are not necessarily the actual historical peak days and times.

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2025-2026 Local Reliability Requirements - Summer 2025											
Installed Capacity (ICAP) (MW)	20,621	14,053	11,537	9,290	6,452	17,290	22,708	11,194	22,675	6,086	[A]
Unforced Capacity (UCAP) (MW)	19,636	13,339	11,047	8,726	5,925	15,581	21,136	10,453	21,046	5,501	[B]
Adjustment to UCAP (MW)	1,733	1,067	2,527	2,520	4,318	6,570	2,708	956	3,570	1,975	[C]
Local Reliability Requirement (LRR) UCAP (MW)	21,369	14,406	13,574	11,246	10,243	22,151	23,844	11,408	24,616	7,476	[D]=[B]+[C]
Peak Demand (MW)	17,889	12,694	10,295	8,786	7,873	17,555	20,953	8,448	21,676	5,166	[E]
LRR UCAP per-unit of LRZ Peak Demand	**119.5%**	**113.5%**	**131.8%**	**128.0%**	**130.1%**	**126.2%**	**113.8%**	**135.0%**	**113.6%**	**144.7%**	[F]=[D]/[E]

Table 2-1: Planning Year 2025-2026 LRZ Local Reliability Requirements for Summer 2025

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2025-2026 Local Reliability Requirements - Fall 2025											
Installed Capacity (ICAP) (MW)	20,658	14,203	12,874	9,171	6,442	17,232	22,539	10,910	22,618	6,099	[A]
Unforced Capacity (UCAP) (MW)	19,554	13,196	12,295	8,486	5,883	15,652	20,755	10,184	20,175	5,374	[B]
Adjustment to UCAP (MW)	165	50	1,590	1,565	3,785	5,154	1,937	888	3,449	1,908	[C]
Local Reliability Requirement (LRR) UCAP (MW)	19,719	13,246	13,885	10,051	9,668	20,806	22,692	11,072	23,624	7,282	[D]=[B]+[C]
Peak Demand (MW)	15,313	10,839	9,034	7,616	7,084	15,859	18,085	7,537	19,721	4,676	[E]
LRR UCAP per-unit of LRZ Peak Demand	**128.8%**	**122.2%**	**153.7%**	**132.0%**	**136.5%**	**131.2%**	**125.5%**	**146.9%**	**119.8%**	**155.7%**	[F]=[D]/[E]

Table 2-2: Planning Year 2025-2026 LRZ Local Reliability Requirements for Fall 2025

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2025-2026 Local Reliability Requirements - Winter 2025-2026											
Installed Capacity (ICAP) (MW)	20,600	13,959	12,919	9,288	6,879	17,115	23,377	12,008	24,649	6,635	[A]
Unforced Capacity (UCAP) (MW)	18,563	12,282	11,640	6,065	4,655	13,672	21,359	10,503	22,163	5,671	[B]
Adjustment to UCAP (MW)	995	950	1,950	3,023	4,152	5,950	-840	1,278	3,279	1,617	[C]
Local Reliability Requirement (LRR) UCAP (MW)	19,558	13,232	13,591	9,088	8,806	19,622	20,519	11,781	25,442	7,288	[D]=[B]+[C]
Peak Demand (MW)	15,442	9,781	8,328	7,664	7,023	15,729	14,177	7,524	19,613	4,477	[E]
LRR UCAP per-unit of LRZ Peak Demand	**126.7%**	**135.3%**	**163.2%**	**118.6%**	**125.4%**	**124.7%**	**144.7%**	**156.6%**	**129.7%**	**162.8%**	[F]=[D]/[E]

Table 2-3: Planning Year 2025-2026 LRZ Local Reliability Requirements for Winter 2025-2026

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2025-2026 Local Reliability Requirements - Spring 2026											
Installed Capacity (ICAP) (MW)	19,862	14,049	12,380	9,293	7,423	17,188	22,881	11,694	23,337	6,406	[A]
Unforced Capacity (UCAP) (MW)	18,613	13,073	11,555	7,865	5,961	15,273	20,822	10,613	21,646	5,869	[B]
Adjustment to UCAP (MW)	990	600	1,540	1,910	3,470	4,948	668	199	3,333	1,963	[C]
Local Reliability Requirement (LRR) UCAP (MW)	19,604	13,673	13,094	9,775	9,431	20,221	21,490	10,811	24,979	7,832	[D]=[B]+[C]
Peak Demand (MW)	15,285	10,270	8,246	6,537	6,465	14,570	16,293	6,813	19,333	4,381	[E]
LRR UCAP per-unit of LRZ Peak Demand	**128.3%**	**133.1%**	**158.8%**	**149.5%**	**145.9%**	**138.8%**	**131.9%**	**158.7%**	**129.2%**	**178.8%**	[F]=[D]/[E]

Table 2-4: Planning Year 2025-2026 LRZ Local Reliability Requirements for Spring 2026

Weather Year Time of Peak Demand (EST HE)	MISO	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS
1994	7/6/94 16:00	8/25/94 17:00	8/25/94 16:00	7/19/94 18:00	7/6/94 17:00	1/18/94 15:00	1/19/94 8:00	7/6/94 15:00	1/18/94 21:00	7/3/94 18:00	1/18/94 20:00
1995	7/12/95 17:00	7/13/95 19:00	7/13/95 16:00	7/12/95 16:00	7/12/95 17:00	8/18/95 19:00	7/14/95 19:00	7/14/95 14:00	7/28/95 17:00	7/11/95 18:00	7/28/95 16:00
1996	8/6/96 16:00	7/18/96 16:00	8/14/96 16:00	7/18/96 17:00	7/18/96 18:00	7/18/96 19:00	2/2/96 19:00	8/7/96 16:00	6/30/96 21:00	2/5/96 6:00	7/3/96 16:00
1997	7/14/97 17:00	7/16/97 19:00	7/16/97 17:00	7/25/97 17:00	7/18/97 17:00	7/18/97 19:00	7/14/97 16:00	7/14/97 17:00	7/24/97 17:00	1/17/97 8:00	7/24/97 17:00
1998	7/20/98 16:00	7/14/98 18:00	7/14/98 18:00	7/20/98 19:00	7/21/98 18:00	7/21/98 16:00	7/21/98 17:00	7/21/98 15:00	7/7/98 15:00	8/28/98 18:00	8/27/98 18:00
1999	7/29/99 17:00	7/29/99 17:00	7/30/99 13:00	7/29/99 18:00	7/18/99 18:00	7/29/99 16:00	7/30/99 16:00	7/30/99 16:00	7/29/99 18:00	8/5/99 17:00	8/19/99 17:00
2000	8/31/00 17:00	7/8/00 17:00	7/14/00 16:00	9/2/00 17:00	7/10/00 18:00	8/17/00 18:00	8/9/00 18:00	6/10/00 16:00	7/20/00 14:00	8/26/00 17:00	8/30/00 16:00
2001	7/31/01 17:00	7/31/01 17:00	7/31/01 17:00	7/31/01 16:00	7/23/01 16:00	7/23/01 17:00	8/8/01 17:00	8/8/01 17:00	7/11/01 17:00	8/20/01 16:00	7/11/01 16:00
2002	7/8/02 16:00	7/1/02 19:00	7/18/02 15:00	7/8/02 18:00	7/9/02 17:00	7/23/02 17:00	8/23/02 16:00	7/1/02 16:00	8/6/02 17:00	7/18/02 16:00	7/9/02 17:00
2003	8/26/03 16:00	8/18/03 19:00	8/21/03 16:00	8/25/03 17:00	8/26/03 16:00	8/21/03 16:00	8/27/03 17:00	8/21/03 18:00	8/18/03 15:00	1/24/03 10:00	8/18/03 18:00
2004	7/22/04 16:00	7/21/04 19:00	6/8/04 14:00	7/13/04 18:00	7/22/04 16:00	7/22/04 17:00	12/24/04 10:00	6/9/04 12:00	7/14/04 17:00	8/1/04 16:00	7/31/04 16:00
2005	7/25/05 16:00	7/22/05 18:00	8/10/05 14:00	7/25/05 17:00	7/25/05 18:00	7/25/05 18:00	7/25/05 17:00	6/28/05 16:00	7/22/05 18:00	7/25/05 16:00	7/25/05 18:00
2006	7/31/06 17:00	7/31/06 17:00	7/31/06 18:00	7/19/06 19:00	7/31/06 17:00	8/2/06 18:00	7/31/06 17:00	7/31/06 17:00	7/21/06 15:00	12/8/06 8:00	7/18/06 17:00
2007	8/1/07 17:00	7/26/07 15:00	7/10/07 15:00	7/17/07 18:00	8/28/07 17:00	8/15/07 16:00	8/29/07 17:00	7/31/07 18:00	8/9/07 17:00	8/11/07 18:00	8/14/07 17:00
2008	7/16/08 17:00	7/29/08 18:00	7/17/08 15:00	7/17/08 17:00	7/18/08 17:00	7/18/08 17:00	8/23/08 16:00	8/24/08 12:00	8/2/08 18:00	7/26/08 16:00	7/28/08 17:00
2009	6/24/09 17:00	5/19/09 19:00	6/24/09 17:00	6/22/09 18:00	6/22/09 17:00	6/22/09 17:00	1/16/09 8:00	6/24/09 16:00	6/22/09 16:00	7/2/09 16:00	6/22/09 18:00

Weather Year Time of Peak Demand (EST HE)	MISO	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS
2010	8/10/10 17:00	8/9/10 18:00	7/9/10 17:00	7/14/10 17:00	7/5/10 17:00	8/3/10 16:00	8/10/10 18:00	7/6/10 16:00	8/3/10 17:00	8/2/10 15:00	8/2/10 16:00
2011	7/20/11 17:00	7/18/11 18:00	7/20/11 15:00	8/2/11 17:00	8/24/11 14:00	9/1/11 16:00	9/2/11 18:00	7/21/11 15:00	8/3/11 18:00	8/18/11 16:00	7/13/11 16:00
2012	7/6/12 16:00	7/6/12 18:00	7/4/12 13:00	7/25/12 18:00	7/6/12 16:00	6/28/12 18:00	7/7/12 18:00	7/6/12 14:00	7/28/12 16:00	6/25/12 18:00	7/4/12 16:00
2013	7/19/13 16:00	8/27/13 18:00	7/19/13 14:00	8/30/13 17:00	8/30/13 17:00	8/30/13 16:00	8/30/13 16:00	7/19/13 14:00	8/30/13 17:00	8/5/13 17:00	7/30/13 17:00
2014	7/22/14 17:00	7/21/14 18:00	7/22/14 16:00	7/22/14 17:00	8/22/14 17:00	8/26/14 16:00	8/26/14 16:00	6/17/14 17:00	1/7/14 9:00	1/7/14 9:00	1/28/14 20:00
2015	7/28/15 17:00	7/14/15 18:00	8/3/15 17:00	7/13/15 15:00	7/28/15 18:00	7/28/15 17:00	9/8/15 16:00	7/29/15 16:00	7/29/15 16:00	1/8/15 7:00	7/30/15 15:00
2016	7/20/16 16:00	7/21/16 18:00	8/10/16 14:00	7/20/16 17:00	8/10/16 15:00	7/23/16 16:00	8/10/16 17:00	8/4/16 15:00	7/21/16 15:00	8/31/16 16:00	7/7/16 15:00
2017	7/20/17 16:00	7/6/17 17:00	7/20/17 14:00	7/20/17 16:00	7/20/17 16:00	7/22/17 18:00	9/22/17 15:00	6/12/17 15:00	7/20/17 15:00	7/19/17 16:00	7/20/17 16:00
2018	7/5/18 14:00	6/29/18 15:00	8/15/18 15:00	8/3/18 16:00	8/16/18 16:00	8/6/18 16:00	1/16/18 19:00	7/5/18 14:00	1/2/18 8:00	8/14/18 16:00	1/17/18 9:00
2019	7/19/19 15:00	7/19/19 17:00	7/16/19 16:00	7/19/19 16:00	7/1/19 17:00	9/17/19 16:00	7/2/19 16:00	7/19/19 13:00	8/13/19 14:00	7/7/19 15:00	7/10/19 14:00
2020	7/18/20 16:00	7/8/20 18:00	7/8/20 16:00	8/26/20 15:00	8/26/20 15:00	7/11/20 16:00	8/25/20 15:00	7/3/20 16:00	7/18/20 15:00	7/10/20 16:00	7/18/20 14:00
2021	7/28/21 15:00	7/5/21 17:00	8/20/21 15:00	6/17/21 16:00	7/7/21 15:00	2/14/21 10:00	8/24/21 16:00	7/7/21 13:00	2/16/21 7:00	8/23/21 16:00	8/11/21 15:00
2022	6/21/22 16:00	6/20/22 16:00	6/21/22 16:00	8/2/22 16:00	7/20/22 16:00	7/22/22 16:00	7/5/22 16:00	6/21/22 16:00	7/26/22 15:00	6/23/22 17:00	6/21/22 16:00
2023	8/23/23 17:00	8/23/23 17:00	8/23/23 15:00	8/23/23 16:00	7/5/23 14:00	8/25/23 16:00	8/24/23 17:00	8/23/23 17:00	7/28/23 16:00	8/27/23 15:00	8/24/23 15:00

Table 2-5: Modeled Peak Demand Days/Hours by Local Resource Zone

3 Loss of Load Expectation Analysis

3.1 LOLE Modeling Input Data and Assumptions

MISO uses a program developed and maintained by Astrapé Consulting called Strategic Energy & Risk Valuation Model (SERVM) to calculate LOLE for the applicable Planning Year. SERVM uses a sequential Monte Carlo simulation to model a generation system and to assess the system's reliability, based on any number of interconnected areas. SERVM calculates LOLE for the MISO system and for each LRZ by stepping through the year chronologically and taking into account generation, load, load modifying resources, generator forced outages, generator planned maintenance outages, weather and economic uncertainty, and external support from neighboring regions.

Building the SERVM model is the most time-consuming task of the LOLE study. Several sensitivities are built to determine how specific inputs and variables impact the results. The base case models determine the seasonal MISO Planning Reserve Margin Unforced Capacity (PRM UCAP) and Local Reliability Requirement (LRR) values for each LRZ for future Planning Years one, four, and six.

3.1.1 Resource Inclusion

Planning Year 2025-2026

The Planning Year 2025-2026 LOLE study used converted capacity from the 2024-2025 PRA as a starting point for which resources to include in the study. This ensured that only resources eligible as Planning Resources were included in the LOLE study. For the PY 2025-2026 LOLE study, internal MISO CPNode resources that were excluded from the auction clearing process but were used to satisfy Resource Adequacy Requirements through a Fixed Resource Adequacy Plan (FRAP) or that offered and subsequently cleared the 2024-2025 PRA in any season were included in the LOLE model for all seasons. Resources that were on an approved Attachment Y suspension or retirement, or had an approved IMM exemption, were excluded from the LOLE model in their respective seasons. External resources were included for only the corresponding seasons in which they were included in a FRAP or offered in the 2024-2025 PRA.

Upcoming changes for Planning Year 2026-2027

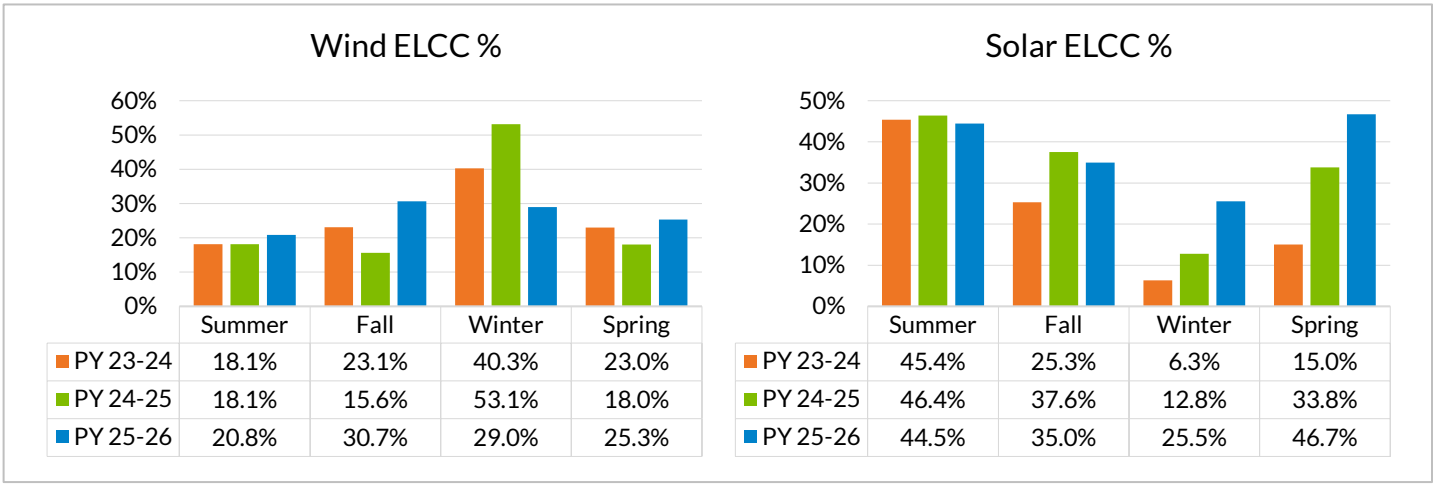
In July 2024, MISO opened a formal feedback request with stakeholders to better define a set of criteria for resource inclusion within the LOLE model that would be implemented for the PY 2026-2027 LOLE study and beyond. From the feedback, it was determined that MISO will include resources for each season a resource is included in a FRAP or offered into the most recent PRA, with an exception for external resources. External resources will be included in the LOLE model for each season that an external resource is included in a FRAP or cleared in the most recent PRA. The rationale is that external resource offer behavior can differ from one year to the next, as they are not subject to economic withholding in MISO and do not have any obligation to serve MISO load if they do not make a commitment to do so through the PRA.

3.1.2 Effective Load Carrying Capability (ELCC)

Each year, MISO performs seasonal Effective Load Carrying Capability (ELCC) analyses for wind and solar resources to quantify their average capacity contribution to determine season-wide capacity values for use in the seasonal Planning Reserve Margin (PRM) and Local Reliability Requirement (LRR) calculations. Wind and solar generation is represented in the model with 30-year hourly capacity factor profiles.

Seasonal wind ELCC determines the allocable Seasonal Accredited Capacity (SAC) for in-service CPNode wind resources for the prompt year PRA. Solar ELCC is not used for accreditation and is only used for calculating solar UCAP in the PRM and LRR equations. More details regarding wind and solar accreditation will be provided in the Planning Year 2025-2026 Wind and Solar Capacity Credit Report.

The Figure 3-1 below details the resulting LOLE study ELCC percentages over the last three Planning Years.



	Summer	Fall	Winter	Spring
PY 23-24	18.1%	23.1%	40.3%	23.0%
PY 24-25	18.1%	15.6%	53.1%	18.0%
PY 25-26	20.8%	30.7%	29.0%	25.3%

	Summer	Fall	Winter	Spring
PY 23-24	45.4%	25.3%	6.3%	15.0%
PY 24-25	46.4%	37.6%	12.8%	33.8%
PY 25-26	44.5%	35.0%	25.5%	46.7%

Figure 3-1: Planning Year 2025-2026 Wind and Solar ELCC Trends

Over the past several years, variability in the non-Summer season results have been observed for both wind and for solar. This is largely driven by the evolving resource mix within the MISO system and the resulting hours of risk for each year's model. Additionally, due to the Summer season having a higher LOLE criterion of 0.1 LOLE (or 1 day of loss of load in 10 years) at the system-wide level, there is a greater volume of impacted Loss of Load Hours (LOLH) in the Summer compared to the other seasons. This results in a larger sampling of wind and solar generation used in the ELCC analyses for Summer than in the other seasons.

Seasonal Drivers of Change from Planning Year 2024-2025 to Planning Year 2025-2026 are detailed below:

- **Summer**: The majority of the risk in the Planning Year 2024-2025 Summer season was observed in July. However, in Planning Year 2025-2026, there was an increase in prolonged risk observed in August. This resulted in wind generation impacting more hours during the Summer season and solar impacting slightly less as LOLH extended further into evening hours.
- **Fall**: In Planning Year 2024-2025, September was the only month that exhibited risk for the MISO system in the Fall season. In Planning Year 2025-2026, September risk increased and November demonstrated some morning and evening risk hours. Due to the shift in Fall risk hours, the number of hours where wind generation was able to be impactful increased, while the number of hours where solar could be impactful decreased.
- **Winter**: Changes in ELCC values for the Winter season were primarily driven by Planning Year 2025-2026 load development process enhancements. These enhancements shifted risk hours to later in the day where wind performed worse and solar was able to perform better during the full set of risk hours.
- **Spring**: During this season, MISO saw an increase in both wind and solar ELCC values. In Planning Year 2025-2026, Spring risk materialized during several evening hours in March, and the overall magnitude of risk increased in comparison with Planning Year 2024-2025. This allowed both wind and solar generation to become more impactful during hours of greater renewable output.

3.2 MISO Generation

3.2.1 Thermal Units

All MISO internal thermal Planning Resources were modeled in the LRZ in which they are physically located, except for pseudo-tied resources. Additionally, Coordinating Owner External Resources and Border External Resources were modeled as being internal to the LRZ in which they are committed to serving load.

Seasonal forced outage rates and annualized planned maintenance outage rates were calculated over a five-year period (January 2019 to December 2023) for each resource. Some resources did not have five years of historical data in MISO's Generator Availability Data System (PowerGADS). However, if they had at least three consecutive months of outage data, resource-specific information was used to calculate their seasonal forced and planned maintenance outage rates. Resources with fewer than three consecutive months of resource-specific outage data were assigned the corresponding MISO seasonal class average forced outage rate and annualized planned maintenance outage rate based on their resource type. The overall MISO ICAP-weighted seasonal class average forced outage rates and annualized planned maintenance outage rate were applied in lieu of class averages for classes with fewer than 30 resources reporting 12 or more months of data.

The historical class average outage rates as well as the MISO system-wide weighted average forced outage rate are provided in Table 3-1 to show the year-over-year trends, as well as in Table 3-2 on a seasonal basis for the prompt Planning Year.

Pooled EFORd GADS Years	**2019-2023 (%)**	**2018-2022 (%)**	**2017-2021 (%)**	**2016-2020 (%)**	**2015-2019 (%)**	**2014-2018 (%)**
LOLE Study Planning Year	**PY 2025-2026** Summer	**PY 2024-2025** Summer	**PY 2023-2024** Summer	**PY 2022-2023** Annualized	**PY 2021-2022** Annualized	**PY 2020-2021** Annualized
Combined Cycle	5.26	5.92	5.54	5.85	5.52	5.70
Combustion Turbine (0-50 MW)	10.80	7.65	7.37	15.25	15.83	17.88
Combustion Turbine (50+ MW)	4.72	4.88	4.07	4.36	4.76	4.65
Diesel Engines	17.52	17.14	12.79	7.25	10.05	23.53
Fluidized Bed Combustion	*	*	*	*	*	*
Hydro (0-30 MW)	*	*	*	*	*	*
Hydro (30+ MW)	*	*	*	*	*	*
Nuclear	*	*	*	*	*	*
Pumped Storage	*	*	*	*	*	*
Steam – Coal (0-400 MW)	11.76	8.22	7.03	9.91	8.78	8.15
Steam - Coal (400-1,000 MW)	8.84	8.62	8.06	9.00	9.02	8.87
Steam - Gas	11.32	14.04	12.48	11.84	12.91	12.54
Steam - Oil	*	*	*	*	*	*
Steam - Waste Heat	*	*	*	*	*	*
Steam - Wood	*	*	*	*	*	*
MISO Weighted System-wide	7.76	8.24	8.23	9.04	9.36	9.24

Table 3-1: Historical Class Average Forced Outage Rates

Pooled EFORd GADS Years	2019-2023 (%)	2019-2023 (%)	2019-2023 (%)	2019-2023 (%)
LOLE Study Planning Year 2025-2026	**Summer 2025**	**Fall 2025**	**Winter 2025-2026**	**Spring 2026**
Combined Cycle	5.26	6.95	5.16	5.93
Combustion Turbine (0-50 MW)	10.80	13.42	33.67	15.79
Combustion Turbine (50+ MW)	4.72	7.96	12.50	5.31
Diesel Engines	17.52	31.84	24.53	23.91
Fluidized Bed Combustion	*	*	*	*
Hydro (0-30 MW)	*	*	*	*
Hydro (30+ MW)	*	*	*	*
Nuclear	*	*	*	*
Pumped Storage	*	*	*	*
Steam – Coal (0-400 MW)	11.76	15.27	12.68	11.17
Steam - Coal (400-1,000 MW)	8.84	9.20	9.83	9.94
Steam - Gas	11.32	12.91	9.83	9.32
Steam - Oil	*	*	*	*
Steam - Waste Heat	*	*	*	*
Steam - Wood	*	*	*	*
MISO Weighted System-wide	7.76	8.93	10.48	9.70

Table 3-2: Planning Year 2025-2026 Seasonal Class Average Forced Outage Rates

3.2.2 Behind-the-Meter Generation

Behind-the-Meter Generation data came from the Module E Capacity Tracking (MECT) tool. Behind-the-Meter Generation backed by thermal resources were explicitly modeled as any other thermal generator with a monthly capability and forced outage rate. Behind-the-Meter Generation backed by intermittent resources were modeled at their expected seasonal availability.

3.2.3 Attachment Y

MISO obtained information on generating resources with approved suspensions or retirements (as of June 1, 2024) through MISO's Attachment Y process. Any resource with an approved retirement or suspension in Planning Year 2025-2026 was excluded from the year-one analysis during the months in which the resource had been approved to be out of service. This same methodology is used for the four- and six-year analyses.

3.2.4 Future Generation

The LOLE model included resources with a signed and executed Generator Interconnection Agreement (as of June 1, 2024). These future resources were assigned seasonal class average forced outage rates and planned maintenance outage rates based on their resource class. Future thermal generation and upgrades were added to the LOLE model based on resource information in the MISO Generator Interconnection Queue. Resources with a planned upgrade during the study period reflect the megawatt increase for each month, beginning the month the upgrade is expected to be completed. The LOLE analysis includes future wind and solar generation, tied to the same hourly wind and solar profiles used for existing wind and solar resources in the model. In the LOLE model, resources with a signed and

executed GIA receive a postponement to their anticipated in-service dates relative to the average delays per resource type observed by the Generation Interconnection team at MISO.

3.2.5 Intermittent Resources

Intermittent resources include solar, wind, biomass, battery storage, and run-of-river hydro. Most intermittent resources submit historical output data during seasonal peak hours, defined as hours ending 15, 16, and 17 EST for Summer, Fall, and Spring, and hours ending 8, 9, 19, and 20 for Winter. Non-CPNode wind and battery storage resources are exceptions to this and only submit historical output data for the top eight seasonal coincident peaks for the last three Planning Years for which data is available. This data is averaged at the seasonal level and modeled in the LOLE analysis as seasonal effective capacity for all months within a given season. Each individual resource is modeled in the LRZ corresponding to its load obligation.

Using historical wind operational data from 279 front-of-meter wind resources from 2013 to 2023, normalized hourly capacity profiles were developed and aggregated at the LRZ level to represent hourly wind capability in the model. As a result of the LOLE analysis that is based on 30 weather years (1994 – 2023), synthetic shapes were developed by Astrapé for the 1994 – 2013 period based on historical wind performance and temperatures. Once the weather and wind performance matching has been performed, the data is analyzed as a function of load to ensure the variability around the load profiles is reasonable.

Solar profiles were also developed by Astrapé using historical solar irradiance data from the NREL National Solar Radiation Database (NSRDB) from 1998 – 2023.

3.2.6 Demand Response

Demand response programs and their capabilities came from their corresponding registrations in the MECT tool. These resources were explicitly modeled as dispatch-limited resources and are the last set of resources dispatched by the model in an effort to avoid LOLE. Each demand response program was modeled individually with a monthly capability, limited by duration and the number of times each program can be called upon for each season.

3.3 MISO Capacity

The following charts and tables below list the total Installed Capacity (ICAP) values by resource type and LRZ in the PY 2025-2026 LOLE model. Every July, MISO presents the preliminary capacity in the prompt year LOLE model at the LOLEWG and, starting with PY 2025-2026, MISO published the final ICAP values per zone and per season in its LOLE study report.

PY 2025-2026 ICAP MW, Summer											
Resource Type	**LRZ1**	**LRZ2**	**LRZ3**	**LRZ4**	**LRZ5**	**LRZ6**	**LRZ7**	**LRZ8**	**LRZ9**	**LRZ10**	**MISO**
Thermal	15,467	11,882	7,659	7,532	5,946	14,049	19,291	9,831	21,917	5,743	119,315
Demand Response	1,879	693	504	435	184	1,695	1,294	790	335	45	7,852
BTMG	1,460	339	603	310	97	351	1,073	17	20	104	4,373
Battery Storage	0	0	0	0	0	101	0	0	0	0	101
Wind	7,285	893	12,782	1,897	406	1,281	3,606	0	0	185	28,335
Solar	212	1,891	224	1,390	0	1,393	639	1,108	392	351	7,599
Run-of-River/Biomass	205	113	10	0	142	208	15	64	229	0	986
Total	**26,507**	**15,810**	**21,782**	**11,564**	**6,774**	**19,078**	**25,917**	**11,810**	**22,892**	**6,427**	**168,561**

Table 3-3: Summer Total Installed Capacity by Resource Type and Local Resource Zone

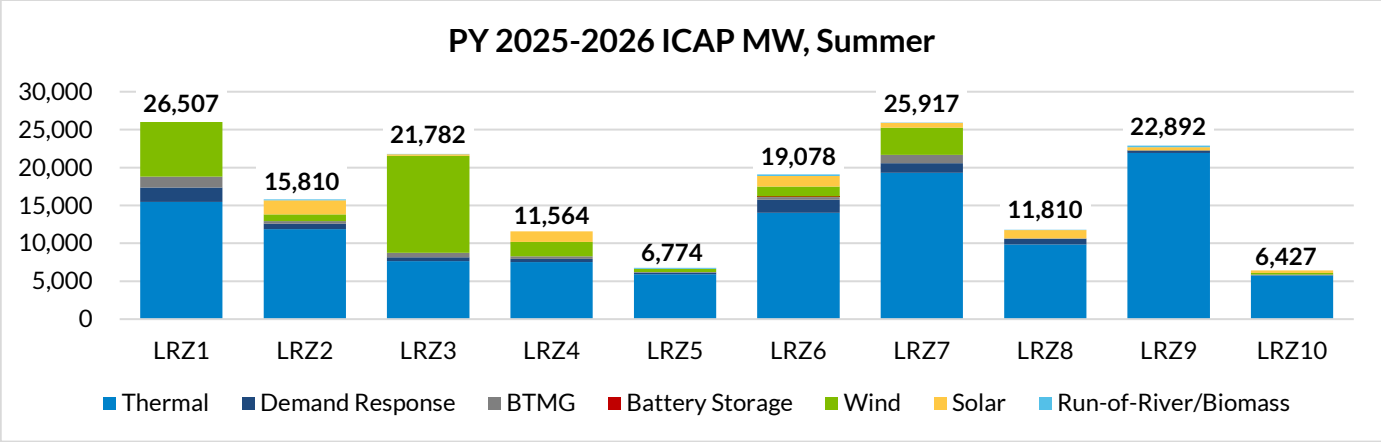


Figure 3-2: Summer Total Installed Capacity by Resource Type and Local Resource Zone

PY 2025-2026 ICAP MW, Fall											
Resource Type	**LRZ1**	**LRZ2**	**LRZ3**	**LRZ4**	**LRZ5**	**LRZ6**	**LRZ7**	**LRZ8**	**LRZ9**	**LRZ10**	**MISO**
Thermal	15,477	12,095	7,765	7,357	6,043	14,203	19,506	9,884	22,001	5,812	120,142
Demand Response	1,435	719	512	440	47	1,515	627	586	334	5	6,220
BTMG	1,235	337	591	305	96	344	1,061	13	19	103	4,103
Battery Storage	0	0	0	0	0	101	0	0	0	0	101
Wind	7,285	893	12,782	1,897	406	1,281	3,606	0	0	185	28,335
Solar	212	1,891	224	1,390	0	1,393	639	1,108	392	351	7,599
Run-of-River/Biomass	201	117	5	0	133	189	16	39	127	0	828
Total	**25,846**	**16,052**	**21,879**	**11,389**	**6,723**	**19,025**	**25,454**	**11,630**	**22,873**	**6,456**	**167,328**

Table 3-4: Fall Total Installed Capacity by Resource Type and Local Resource Zone

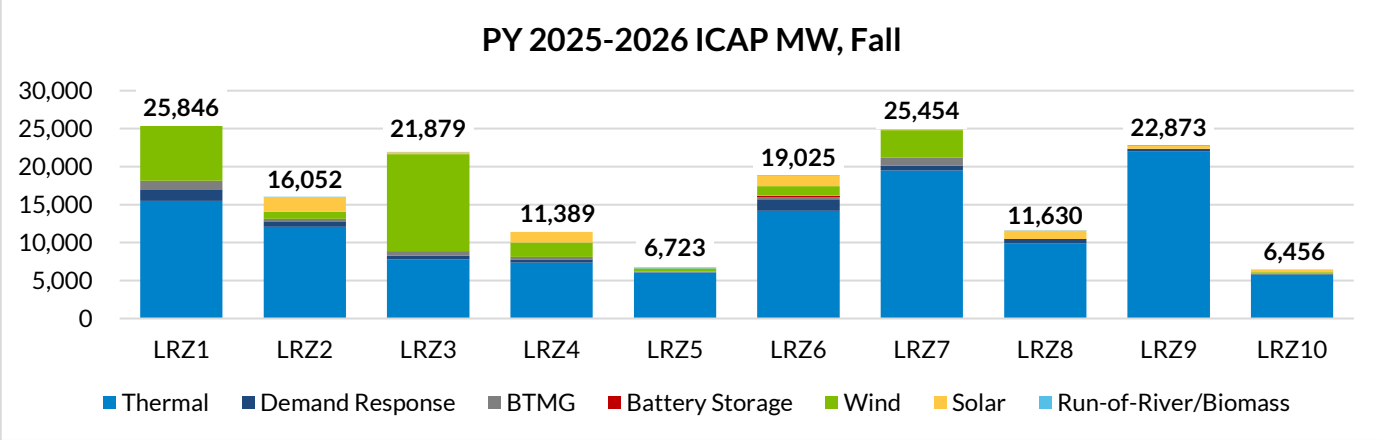


Figure 3-3: Fall Total Installed Capacity by Resource Type and Local Resource Zone

PY 2025-2026 ICAP MW, Winter											
Resource Type	**LRZ1**	**LRZ2**	**LRZ3**	**LRZ4**	**LRZ5**	**LRZ6**	**LRZ7**	**LRZ8**	**LRZ9**	**LRZ10**	**MISO**
Thermal	15,955	12,056	8,142	7,739	6,504	14,392	20,471	10,561	23,999	6,384	126,202
Demand Response	1,560	701	391	325	33	1,407	660	1,088	334	5	6,504
BTMG	756	343	616	318	92	334	1,020	17	10	103	3,609
Battery Storage	0	0	0	0	0	101	0	0	0	0	101
Wind	7,285	893	12,782	1,897	406	1,281	3,606	0	0	185	28,335
Solar	212	1,891	224	1,390	0	1,393	639	1,108	392	351	7,599
Run-of-River/Biomass	162	118	5	0	133	154	18	59	206	0	853
Total	**25,930**	**16,001**	**22,160**	**11,669**	**7,168**	**19,062**	**26,413**	**12,833**	**24,941**	**7,028**	**173,204**

Table 3-5: Winter Total Installed Capacity by Resource Type and Local Resource Zone

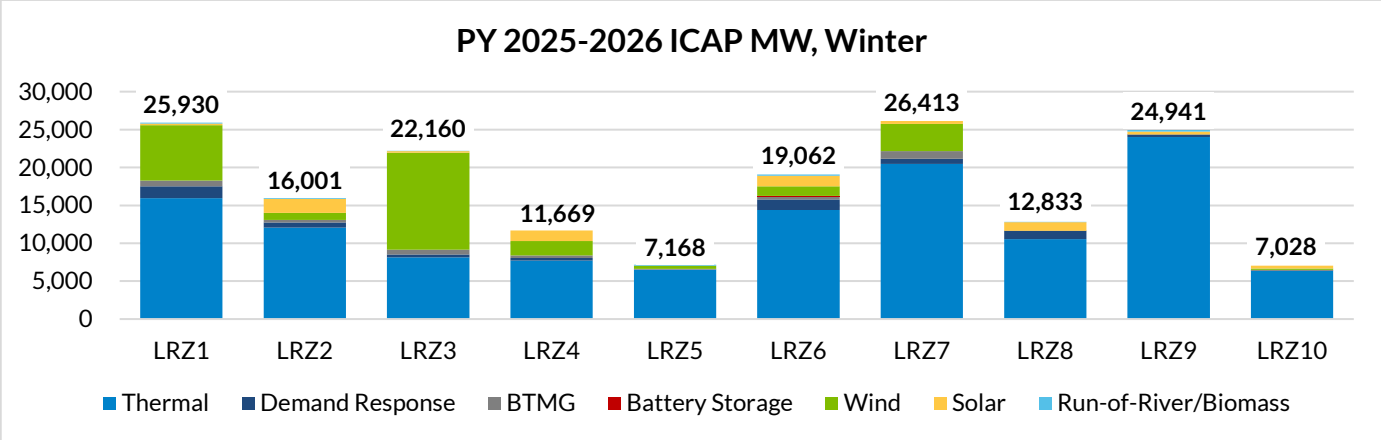


Figure 3-4: Winter Total Installed Capacity by Resource Type and Local Resource Zone

PY 2025-2026 ICAP MW, Spring											
Resource Type	**LRZ1**	**LRZ2**	**LRZ3**	**LRZ4**	**LRZ5**	**LRZ6**	**LRZ7**	**LRZ8**	**LRZ9**	**LRZ10**	**MISO**
Thermal	14,895	11,695	7,928	7,470	6,960	13,910	19,783	10,072	22,307	5,959	120,980
Demand Response	1,404	719	387	386	57	1,522	670	887	334	5	6,370
BTMG	1,390	388	619	309	95	352	1,127	27	23	104	4,433
Battery Storage	0	0	50	0	0	301	0	0	25	0	376
Wind	7,285	893	12,982	1,897	406	1,281	3,606	0	0	185	28,535
Solar	212	1,891	224	1,390	180	1,393	788	1,383	867	626	8,953
Run-of-River/Biomass	229	138	4	0	124	129	20	62	243	0	949
Total	**25,415**	**15,724**	**22,195**	**11,451**	**7,822**	**18,888**	**25,994**	**12,432**	**23,799**	**6,878**	**170,596**

Table 3-6: Spring Total Installed Capacity by Resource Type and Local Resource Zone

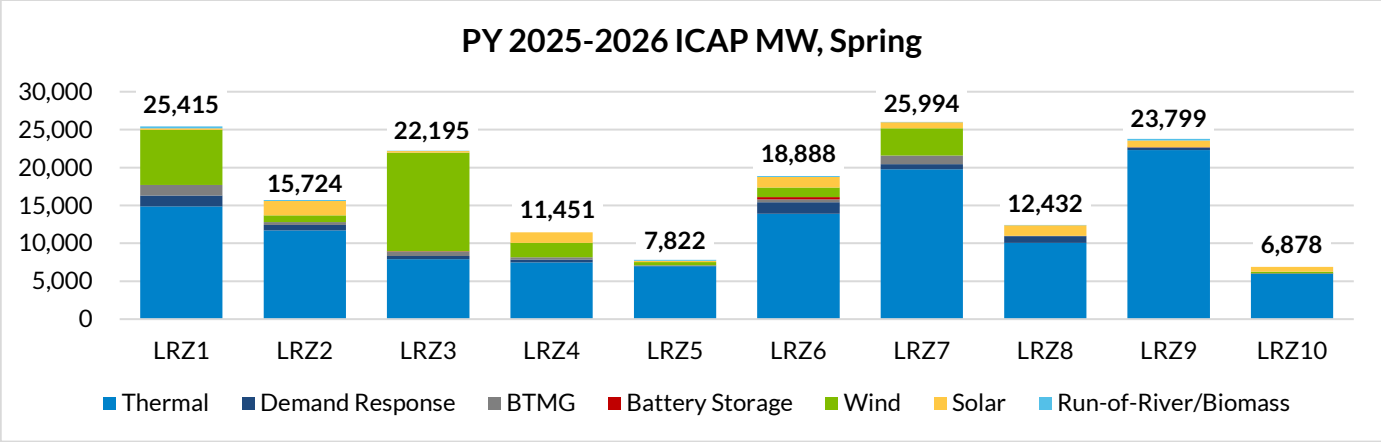


Figure 3-5: Spring Total Installed Capacity by Resource Type and Local Resource Zone

3.4 MISO Load Data

Every year, the Load Serving Entities submit new load forecasts to MISO by November 1 and, every year, MISO utilizes these load forecasts in the load development process for the LOLE study to align the load in the model with the anticipated load growth forecasted within each Local Resource Zone. At the request of stakeholders, MISO expanded its load data section to provide additional information about the LOLE study load development process.

The load development process for the Planning Year 2025-2026 LOLE analysis was enhanced through a peak correcting step regression. The regression was broadened to better account for correlations between the time of day, temperature, and load. While in the prior Planning Year 2024-2025, peak regressions factored in correlations between temperature and load without much consideration to the time of day. The Planning Year 2025-2026 LOLE analysis used a load training process pared with neural net software to establish a correlated relationship between the most recent five years of historical weather and load data. This relationship was then applied to 30 years of hourly historical load data to create 30 years of load shapes for each LRZ to capture both load diversity and seasonal variability. Zonal Coincident Peak Forecasts provided by the Load Serving Entities were used to develop zonal- and monthly-specific load forecast scaling factors which scale the average of the 30-year load shapes based on provided forecasts. The results of this process are shown as the MISO System Peak Demand (Table 1-2) and zonal Peak Demand (Table 2-1, Table 2-2, Table 2-3, and Table 2-4).

Direct Control Load Management and Interruptible Demand types of demand response were included in the LOLE model as resources. Demand response is dispatched in the LOLE model to avoid load shed during simulation when all other available generation has been exhausted.

The load development process is composed of several steps outlined in this section and will continue to be refined as needed in order to better capture weather uncertainty associated with the most recent load forecasts submitted by the Load Serving Entities.

The first step of the load development process includes data collection of the most recent year of historical hourly load data and the most recent historical temperature data from a zonal-specific weather station. This data is then consolidated with prior load and temperature data for a total historical dataset comprised of 30 years of hourly weather data and five years of hourly load data. For the PY 2025-2026 LOLE study, five years of historical data (2019 - 2023) was used in the neural net training/prediction portion of the load development process.

Data Sources:

- Historical load data is collected from MISO Resource Assessment in compliance with NERC standard MOD-032-2 requirements.
- Weather data is collected through the National Oceanic and Atmospheric Administration (NOAA) and collected from the following weather stations for each zone.

LRZ	Station	Name	State	Latitude	Longitude	Elevation
1	72658014922	MINNEAPOLIS ST. PAUL INTERNATIONAL AIRPORT, MN US	Minnesota	44.89	-93.23	254.5
2	72640014839	MILWAUKEE MITCHELL AIRPORT, WI US	Wisconsin	42.95	-87.90	203.3
3	72546014933	DES MOINES INTERNATIONAL AIRPORT, IA US	Iowa	41.53	-93.65	286.3
4	72439093822	SPRINGFIELD ABRAHAM LINCOLN CAPITAL AIRPORT, IL US	Illinois	39.85	-89.68	176.7
5	72434013994	ST LOUIS LAMBERT INTERNATIONAL AIRPORT, MO US	Missouri	38.75	-90.37	162
6	72438093819	INDIANAPOLIS INTERNATIONAL AIRPORT, IN US	Indiana	39.73	-86.28	241.3
7	72539014836	LANSING CAPITAL CITY AIRPORT, MI US	Michigan	42.78	-84.60	261.2
8	72340313963	LITTLE ROCK AIRPORT ADAMS FIELD, AR US	Arkansas	34.73	-92.24	76.4
9	72231012916	NEW ORLEANS AIRPORT, LA US	Louisiana	30.00	-90.28	-1
10	72235003940	JACKSON INTERNATIONAL AIRPORT, MS US	Mississippi	32.32	-90.08	90.2

Table 3-7: Local Resource Zone Weather Stations

The second step of the process is to normalize the five years of load data to consistent economics. Each zone is analyzed and isolated to remove economic impacts on load to ensure that load levels at different temperatures provide an appropriate range across the most recent five years of historical data. This process involves zonal load growth adjustments by comparing the most recent five years of historical load at extreme temperatures and shifting the shapes up or down if they do not reasonably overlay on top of each other. A regression analysis is then performed at the zonal level, focusing on Summer, Winter, and off-peak periods in order to compensate for the fact that the neural net training software can occasionally over- or under-predict results for extremely high or extremely low temperatures.

The third step of the process utilizes neural net software to establish functional relationships between the most recent five years of historical weather and load data. The NeuroShell Predictor software performs neural net training and predicting using a genetic algorithm. Since temperature data is not a direct input into the SERVM model, the relationships and effects it has on the MISO system are included in the 30-year hourly load shapes.

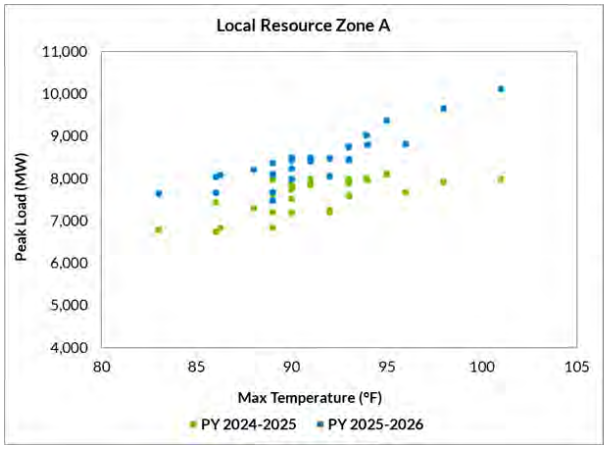
During the temperature and load training portion of this process, MISO evaluated each of the 10 LRZs by the following seasonal groupings: Summer, Winter, and off-season. Starting in the PY 2025-2026 LOLE study, the off-season grouping included both the Fall and Spring seasons. This was done to ensure there were enough extreme temperature data points and account for a larger sampling of temperature and load variability when the neural net predicts future load uncertainty. This process change resulted in an improved correlation between historical temperature and load data for the Fall and Spring seasons. The peak load and intra-hour load predictions drove some general load increases in these seasons during periods of extreme temperatures.

The graphs in Figure 3-6 below show how load responds to higher observed temperatures for months within the Fall and Spring seasons.

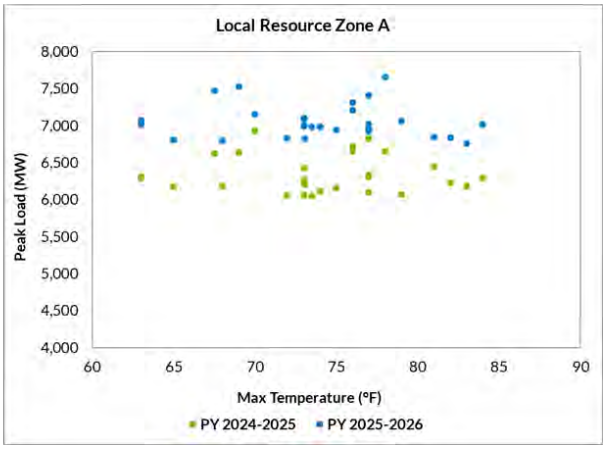
Comparable to off-season periods, the neural net software established functional relationships between historical temperature and load for the Summer and Winter seasons. However, unlike the off-season periods, the correlations between temperature and load for Summer and Winter seasons remained stable in the PY 2025-2026 LOLE study. When comparing the current Planning Year to the prior, no major outliers or concerns were identified in these correlations, and both years showed a general trend of increases in load at extreme temperatures.

The graphs in Figure 3-7 below show how load responds to higher observed temperatures for months within the Summer and Winter seasons.

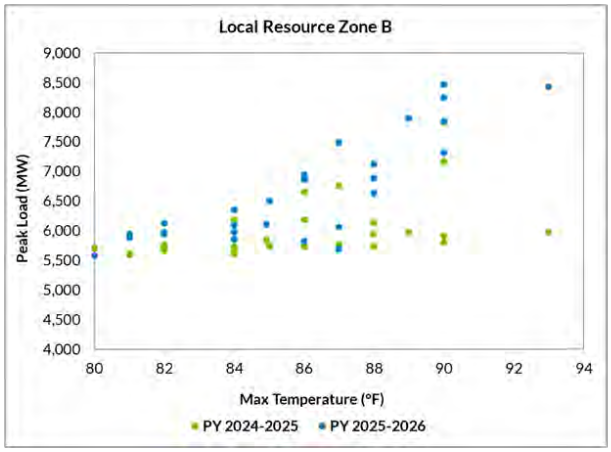
Fall Season
Temperature and Load Correlation
September



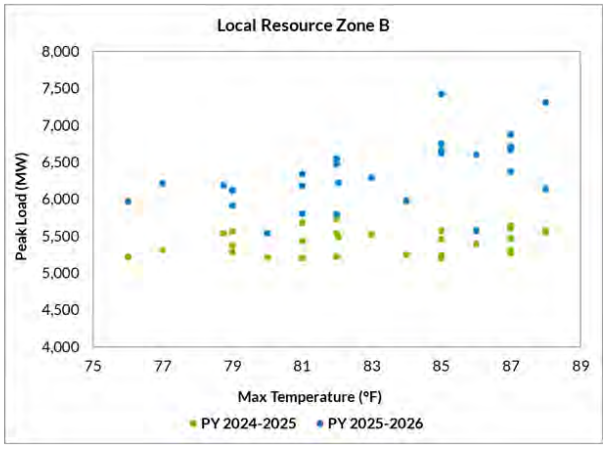
Spring Season
Temperature and Load Correlation
March



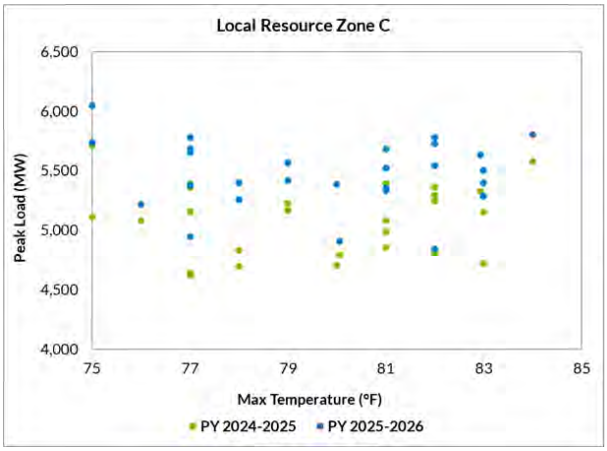
October



April



November



May

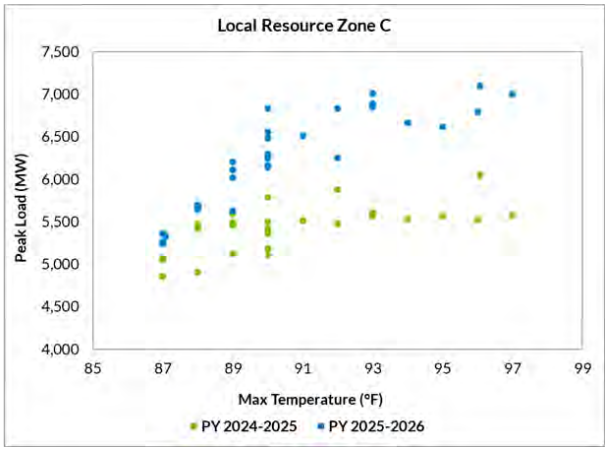
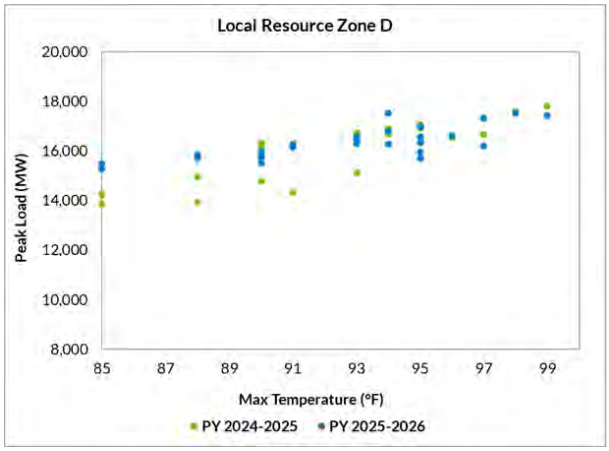
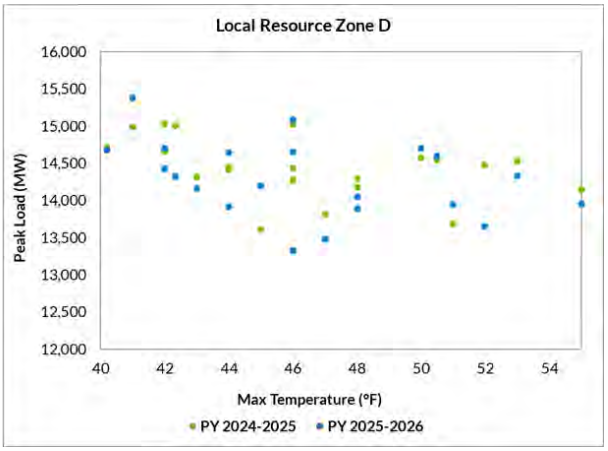


Figure 3-6: Temperature and Load Correlation for Fall and Spring Months

Summer Season
Temperature and Load Correlation
June



Winter Season
Temperature and Load Correlation
December



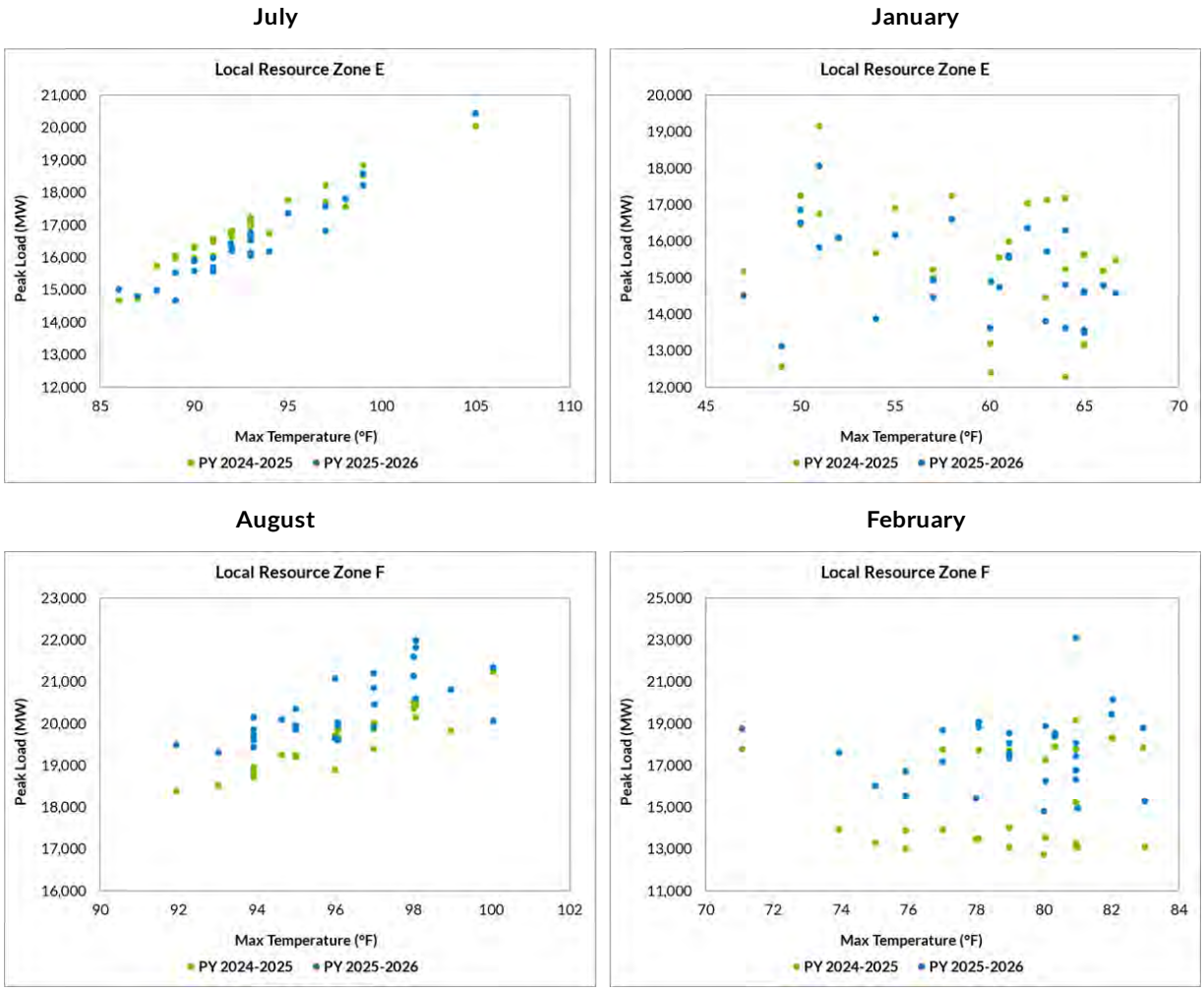


Figure 3-7: Temperature and Load Correlation for Summer and Winter Months

In the fourth step of the process and after the neural net has finished, MISO will validate the results of the neural net at extreme temperatures to smooth out any over- or under-predicted loads by comparing it against the entire 30 years of historical correlated load and weather data. During this step of the process, MISO will create a regression for the most extreme high and low temperatures in each zone to forecast out to temperatures in the 30-year range that the neural net may not have seen in the trained five-year historical load and temperature dataset.

In the fifth step of the load training process, MISO conducts a comparison of the synthetic 30-year hourly load shapes developed through the prior steps and the historical five years of hourly load data collected in the beginning of this process. During this comparative effort, MISO expects to see that the synthetic shapes are relatively in line with the historical shapes, but they should be slightly higher to account for any load reductions that were included in the historical net load shapes. If the resulting shapes are not in line with expectations, MISO will revisit step four and make any necessary changes in the regression during extreme temperatures. This may include reducing or increasing the number of data points to represent a more discrete trend.

The sixth and final step of the load training process is to average the monthly peak loads of the 30 years of predicted load shapes and adjust the load dataset to match each LRZ's total monthly zonal Coincident Peak Demand forecast

provided by the Load Serving Entities for each of the study years. To calculate the total monthly zonal Coincident Peak Demand forecasts for each year of study, the ratio of the monthly zonal Coincident Peak Demand forecast to the prompt seasonal Non-Coincident Peak Demand forecast is applied to the prompt and outyear seasonal Non-Coincident Peak Demand forecasts.

By adopting this methodology for capturing weather uncertainty, MISO can model multiple load shapes based on a functional relationship with weather. This modeling approach provides diversity in the load shapes, as well as in the peak loads observed within each zonal load shape. This approach also provides the ability to capture the frequency and duration of historical severe weather patterns.

3.4.1 Economic Load Uncertainty

To account for economic load uncertainty in the LOLE model, MISO utilized a normal distribution of electric utility forecast error accounting for projected and actual Gross Domestic Product (GDP), as well as electricity usage. The historic projections for GDP growth were taken from the Congressional Budget Office (CBO), the actual GDP growth was taken from the Bureau of Economic Analysis (BEA), and the electricity usage was taken from the U.S. Energy Information Administration (EIA). Due to a lack of state-wide projected GDP data, MISO relied on aggregated United States data when calculating economic uncertainty.

To calculate the electric utility forecast error, MISO first calculated a comparison factor representing the forecast error of actual GDP growth and historic projections. The resulting GDP forecast error was then translated into an electric utility load growth forecast error by multiplying by the rate at which electric load grew over the course of the analysis period in comparison to projected and realized GDP. Finally, a standard deviation is calculated from the electric utility load growth forecast error and used to create a normal distribution representing the probabilities of the load forecast errors (LFE) as shown in Table 3-8.

	LFE Levels				
	-2.0%	-1.0%	0.0%	1.0%	2.0%
Standard Deviation in LFE	Probability assigned to each LFE				
0.63%	0.9%	20.5%	57.3%	20.5%	0.9%

Table 3-8: Economic Uncertainty

3.5 External System

Firm imports from external areas to MISO are modeled at the individual resource level. Each firm external resource was modeled with its Installed Capacity amount and its corresponding seasonal forced outage rates, or at the contracted capacity from its corresponding Power Purchase Agreement (PPA). These resources are only modeled within the system-wide MISO PRM analyses and are not modeled when calculating the zonal LRRs, as the determination of the Local Reliability Requirements is an island-type analysis. Border External Resources and Coordinating Owner External Resources are modeled as internal MISO units and are included in the PRM and LRR analyses. External resources included as firm imports in the LOLE study were based on the amount of capacity that was either part of a Fixed Resource Adequacy Plan (FRAP), or that offered and subsequently cleared in the Planning Year 2024-2025 Planning Resource Auction (PRA).

The LOLE analyses incorporate firm exports from MISO internal units to neighboring regions, where information was available. For units with capacity sold off-system, their monthly capacities were reduced by the megawatt amount exported. These values came from PJM's Reliability Pricing Model (RPM) as well as information on exports to other external areas taken from the Independent Market Monitor (IMM) exclusion list.

Firm exports from MISO to external areas were modeled the same as in previous years. Capacity ineligible as MISO capacity due to transactions with external areas was removed from the model. Table 3-9 shows the number of firm import and export MW values in this year's study. Based on data from the Planning Year 2024-2025 PRA, MISO remained a net firm exporter.

Contracts	Summer ICAP (MW)	Summer UCAP (MW)	Fall ICAP (MW)	Fall UCAP (MW)	Winter ICAP (MW)	Winter UCAP (MW)	Spring ICAP (MW)	Spring UCAP (MW)
Imports (MW)	1,986	1,935	2,315	2,215	2,738	2,594	2,423	2,309
Exports (MW)	1,239	1,183	1,179	1,125	1,190	1,109	1,201	1,183
Net	**748**	**752**	**1,136**	**1,091**	**1,548**	**1,486**	**1,223**	**1,126**

Table 3-9: Planning Year 2025-2026 Firm Imports and Exports

Non-firm imports in the Planning Year 2025-2026 LOLE study were modeled as a seasonal probabilistic distribution representing three-year average energy imports, net of firm imports (already accounted for at the resource level), and off-system exports from MISO's internal generation. This modeling parameter is referred to as non-firm support. The distributions were developed using historic seasonal Net Scheduled Interchange (NSI) data which accounted for imports into MISO during emergency pricing hours. Firm imports cleared in the PRA for each season were subtracted from the NSI data to isolate the non-firm import values. An additional region was included in SERVM, which contained 12,000 MW of perfect generation connected to the MISO system. A distribution of the region's export capability was modeled to the upper and lower bounds. As SERVM steps through the hourly simulation, random draws on the export limits of the external region were used to represent the amount of capacity MISO could import to meet peak demand. The probability distribution of non-firm external imports used in the LOLE model is provided in Table 3-10.

	Summer	Fall	Winter	Spring
p5	1,033	-71	-377	565
p10	1,371	561	-24	829
p25	2,413	1,485	642	1,736
p50	4,351	3,346	1,817	3,720
p75	6,073	5,111	4,242	5,383
p90	7,287	6,105	5,786	6,408
p95	7,657	6,436	6,380	6,710

Table 3-10: Non-Firm External Import Distribution During Emergency Pricing Hours (MW)

3.6 Loss of Load Expectation Analysis and Metric Calculations

Upon completion of the annual LOLE study model refresh, MISO performed probabilistic analyses to determine the seasonal Planning Reserve Margin (PRM) values for Planning Year 2025-2026, as well as the seasonal Local Reliability Requirement (LRR) values for each of the 10 Local Resource Zones. The risk metrics were derived through

probabilistic modeling of the system, first solving to the industry standard annual LOLE risk target of 1 day in 10 years, or 0.1 day per year, and then solving to the minimum seasonal LOLE criteria of 0.01 LOLE for seasons demonstrating minimal risk.

3.6.1 Seasonal LOLE Distribution

To determine the seasonal LOLE distribution that is used to calculate the PRM and LRRs, MISO followed the process described in Section 68A.2.1 of Module E-1 of the MISO Tariff. This process involves first solving the LOLE model to an annual value of 0.1, then checking the seasonal distribution of the annual LOLE of 0.1. If a season had a LOLE value of at least 0.01, then it met the minimum seasonal LOLE criteria and would be set to that LOLE. If a season had less than 0.01 LOLE, additional simulations were performed until the minimum seasonal LOLE criteria of 0.01 was met.

Example: Assume the model is solved to an annual LOLE of 0.1 with 0.05 occurring in both Summer and Winter, while Fall and Spring had LOLE values of 0.00 from this simulation. In this case, the Summer and Winter seasons would not need additional analysis since both had at least 0.01 LOLE naturally when the model was solved to an annual value of 0.1. Since Fall and Spring had 0.00 LOLE, they would be assigned the minimum seasonal LOLE criteria of 0.01, and additional LOLE simulations would be performed until the minimum seasonal LOLE criteria was met through further negative adjustments to capacity in these seasons.

The annual distribution of LOLE across the four seasons at the industry standard of 1 day in 10 years, or 0.1 day per year, determined through the Planning Year 2025-2026 LOLE study, is shown in Table 3-11. The MISO-wide seasonal LOLE distribution results from the PRM analyses, and the zonal distributions result from the LRR analyses.

Region	Summer	Fall	Winter	Spring
MISO-wide	0.10	0.01	0.01	0.01
LRZ 1	0.099	0.01	0.01	0.01
LRZ 2	0.091	0.01	0.01	0.01
LRZ 3	0.098	0.01	0.01	0.01
LRZ 4	0.01	0.01	0.10	0.01
LRZ 5	0.01	0.01	0.094	0.01
LRZ 6	0.091	0.01	0.01	0.01
LRZ 7	0.099	0.01	0.01	0.01
LRZ 8	0.01	0.01	0.093	0.01
LRZ 9	0.026	0.047	0.02	0.01
LRZ 10	0.069	0.015	0.01	0.012

Table 3-11: Planning Year 2025-2026 Seasonal LOLE Distribution

3.6.2 MISO-Wide LOLE Analysis and PRM Calculation

MISO determines the appropriate PRM for each season of the applicable Planning Year based upon probabilistic analysis of reliably serving expected demand. The probabilistic analysis will utilize a Loss of Load Expectation (LOLE) study which assumes that there are no internal transmission limitations.

To determine the PRM, the LOLE model will initially be run with no adjustments to the capacity. If the LOLE is less than the minimum seasonal LOLE criteria, a negative output unit with no outage rates will be added until the LOLE

reaches the minimum seasonal LOLE criteria. This is comparable to adding load to the model. If the LOLE is greater than the minimum seasonal LOLE criteria, proxy units based on a typical combustion turbine unit of 160 MW with class average seasonal forced outage rates will be added to the model until the LOLE reaches the minimum seasonal LOLE criteria.

MISO's annual LOLE study will calculate the seasonal PRM values based on the LOLE criteria identified in the previous section. The minimum seasonal PRM requirement will be determined using the LOLE analysis by either adding a perfectly available negative output unit or by adding proxy units until a minimum LOLE of 0.01 day per season is reached.

The formulas for the PRM values for the MISO system are:

PRM ICAP % = (Installed Capacity + Firm External Support ICAP + ICAP Adjustment to meet LOLE target – MISO Coincident Peak Demand) / MISO Coincident Peak Demand

PRM UCAP % = (Unforced Capacity + Firm External Support UCAP + UCAP Adjustment to meet LOLE target – MISO Coincident Peak Demand) / MISO Coincident Peak Demand

Where Unforced Capacity (UCAP) = Installed Capacity (ICAP) x (1 – EFORd)

3.6.3 LRZ LOLE Analysis and Local Reliability Requirement Calculation

For the Local Resource Zone analyses, each zone included only the generating units within the LRZ (including Coordinating Owner External Resources and Border External Resources) and was modeled without consideration of the benefit of the LRZ's import capability. Similar to the MISO PRM analysis, Unforced Capacity is either added or removed in each LRZ such that a LOLE of 0.1 day per year is achieved when solving for the annual target and a minimum LOLE at least 0.01 day per season when solving for the minimum seasonal LOLE criteria. The minimum amount of Unforced Capacity above each LRZ's seasonal peak demand that was required to meet the reliability criteria was used to establish each LRZ's LRR.

The Planning Year 2025-2026 seasonal LRRs were determined using the LOLE analysis by first either adding or removing capacity until the annual LOLE reaches 0.1 day per year for the LRZ. If the LOLE is less than 0.1 day per year, a perfectly available negative output unit with no outage rates was added until the LOLE reaches 0.1 day per year. If the LOLE is greater than 0.1 day per year, proxy units based on a typical combustion turbine unit of 160 MW with class average seasonal forced outage rates was added to the model until the LOLE reaches 0.1 day per year.

After solving each LRZ for to the annual LOLE target of 0.1 day per year, MISO will calculate each seasonal LRR such that the summation of seasonal LOLE across the year in each zone is 1 day in 10 years, or 0.1 day per year. A minimum seasonal LOLE criterion of 0.01 will be used to calculate the LRR in seasons with less than 0.01 LOLE risk under the annual case. The seasonal Local Reliability Requirement will be determined using the LOLE analysis by either adding a perfectly available negative output unit or by adding proxy combustion turbine units until a minimum LOLE of 0.01 day per season is reached. When needed, a fraction of the marginal proxy unit was added to achieve the exact minimum seasonal LOLE criteria for the LRZ.

LRR UCAP % = (Unforced Capacity + UCAP Adjustment to meet LOLE target – Zonal Coincident Peak Demand) / Zonal Coincident Peak Demand

4 Transfer Analysis

4.1 Calculation Methodology and Process Description

Transfer analyses determined Capacity Import Limit (CIL) and Capacity Export Limit (CEL) values for LRZs in each season for Planning Year 2025-2026. Annual adjustments are made for Border External Resources and Coordinating Owner resources to determine the ZIA and ZEA in each season. Further adjustments are made for controllable exports, which are defined as exports from MISO resources that have firm capacity commitments to non-MISO load and that may be committed and dispatched by the Transmission Provider during a declared Energy Emergency. Controllable exports are subtracted from seasonal ZIA to determine seasonal CIL values. The objective of the transfer analyses is to determine constraints caused by the transfer of capacity between zones and the associated transfer capability. Multiple factors impacted the analysis when compared to previous studies, including:

- Generation
    - Loss of baseload resources being replaced by renewable resources, which impacted generation dispatch, base flows, and transmission line loadings
    - +7 GW in net installed nameplate capacity
- Transmission
    - 700+ Transmission projects at $5B
    - Approximately 150 Transmission projects above 200 kV
- Demand
    - Approximately a 4% increase in all seasons

4.1.1 Generation Pools

To determine an LRZ's import or export limit, a transfer is modeled by ramping generation up in a source subsystem and ramping generation down in a sink subsystem. The source and sink definitions depend on the limit being tested. The LRZ studied for import limits is the sink subsystem, and the adjacent MISO LBAs are the source subsystem. The LRZ studied for export limits is the source subsystem, and the rest of MISO is the sink subsystem. These are the same in all seasons for the upcoming Planning Year.

Transfers can cause potential issues, which are addressed through study assumptions. First, an abundantly large source pool spreads the impact of the transfer widely, which can cause differences in studied zones' transfer capabilities and the identified constraints. Second, ramping up generation from remote areas could cause electrically distant constraints for any given LRZ, which should not determine a zone's limit. For example, export constraints due to dispatch of LRZ 1 generation in the northwest portion of the footprint should not limit the import capability of LRZ 10, which covers the MISO portion of Mississippi.

To address these potential issues, the transfer studies limit the source pool for the import studies to the Tier 1 and Tier 2 adjacent LBAs to the study zone. Since the generation that is ramped up in export studies are contained in the study LRZ, these issues only apply to import studies. Generation within the zone studied for an export limit is ramped up and constraints are expected to be near or in the study zone.

4.1.2 Redispatch

Limited redispatch is applied after performing transfer analyses to mitigate constraints. Redispatch ensures constraints are not caused by the base dispatch and aligns with potential actions that can be implemented for the constraint by MISO control room operators. Redispatch scenarios can be designed to address multiple constraints, as

required, and may be used for constraints that are electrically close to each other or to further optimize transfer limits for several constraints requiring only minor redispatch. The redispatch assumptions include:

- The use of no more than 10 conventional fuel plants or intermittent resources
- Redispatch limit at 2,000 MW total (1,000 MW up and 1,000 MW down)
- No adjustments to nuclear units
- No adjustments to the portions of pseudo-tied units committed to non-MISO load

4.1.3 Sensitivity

Transmission Owners in a specific zone can request that a sensitivity be included in the generation-to-generation transfer to allow for the True Transfer Limit to be identified. The sensitivity would allow excluded units to be included in the generation-to-generation transfer for a zone's CIL. Excluded units mainly include nuclear units and units not to be used in zonal transfers from the latest MTEP model. This sensitivity can only be requested for a CIL study. A sensitivity would only be accepted for a particular zone if they are in a situation like that seen in Figure 4-1 below.

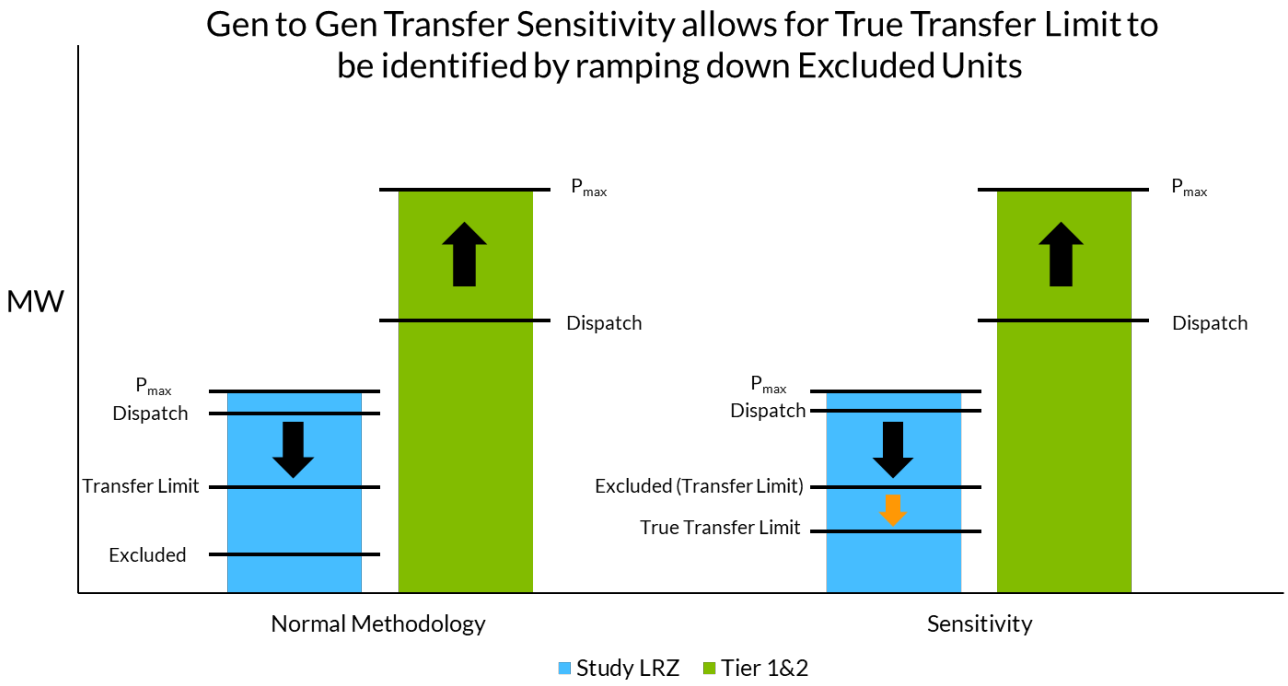


Figure 4-1: Generation-to-Generation Transfer Sensitivity

The two bars shown for the Normal Methodology category would not allow for a sensitivity to be requested by a Transmission Owner. In this situation, since the transfer limit is already identified before hitting the excluded units, a request for a generation-to-generation transfer sensitivity would not be accepted. The two bars shown for the Sensitivity category identify a situation where a request for a generation-to-generation transfer sensitivity would be accepted. When ramping down generation, the excluded units are hit before the True Transfer Limit, but since the rest of the units are excluded, the transfer limit would be identified as the point where the generation-to-generation

stops at the excluded units. With a sensitivity in place, the generation-to-generation transfer would continue into the excluded units, and the True Transfer Limit would be identified.

LRZ 10 was the only Local Resource Zone to utilize a generation-to-generation transfer sensitivity and have these results included in their Capacity Import Limit for Planning Year 2025-2026.

4.1.4 Generation Limited Transfer for CIL/CEL and ZIA/ZEA

When conducting a transfer analysis to determine import or export limits, the source subsystem might run out of generation to dispatch before identifying a valid constraint caused by a transmission limit. MISO developed a Generation Limited Transfer (GLT) process to identify transmission constraints in these situations, when possible, for both imports and exports.

After running the First Contingency Incremental Transfer Capability (FCITC) analysis to determine limits for each LRZ, MISO will determine whether a zone is experiencing a GLT (e.g., whether the first constraint would occur only after all the generation is dispatched at its maximum amount). If the LRZ experiences a GLT, MISO will adjust the base model depending on whether it is an import or export analysis and re-run the transfer analysis.

For an export study, when a transmission constraint has not been identified after all generation has been dispatched within the exporting system (LRZ under study), MISO will decrease load and generation dispatch in the study zone. The adjustment creates additional capacity to export from the zone. After the adjustments are complete, MISO will re-run the transfer analysis. If a GLT reappears, MISO will make further adjustments to the load and generation of the study zone.

For an import study, when a transmission constraint has not been identified after all generation has been dispatched within the source subsystem, MISO will decrease load and generation in the source subsystem. This increases the export capacity of the adjacent LBAs for the study zone. After the adjustments are complete, MISO will run the transfer analysis again. If a GLT reappears, MISO will make further adjustments to the model's load and generation in the source subsystem.

FCITC could indicate the transmission system can support larger thermal transfers than would be available based on installed generation for some zones—however, large variations in load and generation for any zone may lead to unreliable limits and constraints. Therefore, MISO limits load scaling for both import and export studies to 50 percent of the zone's load. In a GLT, redispatch, or GLT plus redispatch scenario, the FCITC of the most limiting constraint might exceed Zonal Export/Import Capability. If the GLT does not produce a limit for a zone, either due to a valid constraint not being identified or due to other considerations as listed in the prior paragraph, MISO shall report that LRZ as having no limit and ensure that the limit will not bind in the first iteration of the Simultaneous Feasibility Test (SFT).

4.1.5 Voltage Limited Transfer for CIL/CEL and ZIA/ZEA

Zonal imports may be limited by voltage constraints due to a decrease in the generation in the study zone. Voltage constraints might occur at lower transfer levels than thermal limits determined by linear FCITC. As such, LOLE studies may evaluate power-voltage curves for LRZs with known voltage-based transfer limitations identified through existing MISO or Transmission Owner studies. Such evaluation may also occur if an LRZ's import reaches a level where the majority of the zone's load would be served using imports from resources outside of the zone. MISO will coordinate with stakeholders as it encounters these scenarios. For Planning Year 2025-2026, only Local Resource Zones 1, 4, and 7 import analyses included voltage screening and study. No studies identified a voltage limit with lower transfer capability than the thermal limit for Planning Year 2025-2026.

4.2 Powerflow Models and Assumptions

4.2.1 Tools Used

MISO used the Siemens PTI Power System Simulator for Engineering (PSS/E) and PowerGEM Transmission Adequacy and Reliability Assessment (TARA) tools.

4.2.2 Inputs Required

Thermal transfer analysis requires Powerflow models and related input files. MISO used contingency files from MTEP[2] reliability assessment studies. Single-element contingencies in MISO and seam areas were also evaluated.

MISO developed a subsystem file to monitor its footprint and seam areas which were used for all seasons. LRZ definitions were developed as sources and sinks in the study. See Appendix A for tables containing adjacent area definitions (Tiers 1 and 2) used for this study. The monitored file includes all facilities under MISO functional control and single elements in the seam areas of 100 kV and above.

4.2.3 Powerflow Modeling

The MTEP23 models were built using MISO's Model on Demand (MOD) model data repository, with the following base assumptions (Table 4-1).

Scenario	Effective Date	Projects Applied	External Modeling	Load and Generation Profile	Wind %	Solar %
Summer 2025	July 15th	MTEP Appendix A and Target A	ERAG MMWG 2023 Series 2025 Summer Peak Load Model	Summer Peak	18%	50%
Fall 2025	October 15th	MTEP Appendix A and Target A	ERAG MMWG 2023 Series 2025 Spring Light Load Model	Fall Peak	28.5%	31%
Winter 2025-2026	January 15th	MTEP Appendix A and Target A	ERAG MMWG 2023 Series 2025 Winter Peak Load Model	Winter Peak	67%	0%
Spring 2026	April 15th	MTEP Appendix A and Target A	ERAG MMWG 2023 Series 2025 Spring Light Load Model	Spring Peak	28.5%	31%

Table 4-1: Model Assumptions

MISO excluded several types of units from the transfer analysis dispatch; these units' base dispatch remained fixed.

- Nuclear dispatch does not change for any transfer without a sensitivity
- Wind and solar resources can be ramped down, but not up
- Pseudo-tied resources were modeled at their expected commitments to non-MISO load, although portions of these units committed to MISO could participate in transfer analyses

System conditions such as load, dispatch, topology, and interchange have an impact on transfer capability. The model was reviewed as part of the base model built for MTEP24 analyses, with study files made available on MISO ShareFile. MISO worked closely with Transmission Owners and stakeholders to model the transmission system accurately, as

[2] Refer to the Transmission Planning BPM (BPM-20) for more information regarding MTEP input files. https://www.misoenergy.org/legal/business-practice-manuals/

well as to validate constraints and redispatch. Like other planning studies, transmission outage schedules were not included in the analyses. This is driven partly by limited availability of outage information as well as current transmission planning standards. Although no outage schedules were evaluated, single-element contingencies were evaluated. This includes Bulk Electric System lines, transformers, and generators.

Contingency coverage covers most of category P1 and some of category P2 outlined in Table 1 of NERC Reliability Standard TPL-001.

4.2.4 General Assumptions

MISO uses TARA to process the Powerflow model and associated input files to determine the seasonal import and export limits of each LRZ by determining the transfer capability. Transfer capability measures the ability of interconnected power systems to reliably transfer power from one area to another under specified system conditions. The incremental amount of power that can be transferred is determined through FCITC analysis. FCITC analysis and base power transfers provide the information required to calculate the First Contingency Total Transfer Capability (FCTTC), which indicates the total amount of transferable power before a constraint is identified. FCTTC is the base power transfer plus the incremental transfer capability (Equation 4-1). All published limits are based on the zone's FCTTC and may be adjusted for capacity exports.

$$First\ Contingency\ Total\ Transfer\ Capability\ (FCTTC) = Base\ Power\ Transfer + FCITC$$

Equation 4-1: Total Transfer Capability

FCITC constraints are identified under base case situations in each season or under P1 contingencies provided through the MTEP process. Linear FCITC analysis identifies the limiting constraints using a minimum transfer Distribution Factor (DF) cutoff of three percent, meaning the transfer must increase the loading on the overloaded element, under system intact or contingency conditions, by three percent or more.

A pro-rata dispatch is used, which ensures all available generators will reach their maximum dispatch level at the same time. The pro-rata dispatch is based on the MW reserve available for each unit and the cumulative MW reserve available in the subsystem. The MW reserve is found by subtracting a unit's base model generation dispatch from its maximum dispatch, which reflects the available capacity of the unit.

Table 4-2 and Equation 4-2 show an example of how one unit's dispatch is set, given all machine data for the source subsystem.

Machine	Base Model Unit Dispatch (MW)	Minimum Unit Dispatch (MW)	Maximum Unit Dispatch (MW)	Reserve MW (Unit Dispatch Max – Unit Dispatch Min)
1	20	20	100	80
2	50	10	150	100
3	20	20	100	80
4	450	0	500	50
5	500	100	500	0
			Total Reserve	**310**

Table 4-2: Example Subsystem

$$\textbf{\textit{Machine 1 Incremental Post Transfer Dispatch}} = \frac{\textbf{\textit{Machine 1 Reserve MW}}}{\textbf{\textit{Source Subsystem Reserve MW}}} \times \textbf{\textit{Transfer Level MW}}$$

$$\textit{Machine 1 Incremental Post Transfer Dispatch} = \frac{80}{310} \times 100 = 25.8$$

$$\textit{Machine 1 Incremental Post Transfer Dispatch} = 25.8$$

Equation 4-2: Machine 1 Dispatch Calculation for 100 MW Transfer

4.3 Results for CIL/CEL and ZIA/ZEA

Study constraints and associated ZIA, ZEA, CIL, and CEL for each LRZ for each season were presented and reviewed through the LOLEWG with final results for Planning Year 2025-2026 presented at the October 24th, 2024 meeting. Table 4-3 below shows the Planning Year 2025-2026 CIL and ZIA with corresponding constraint, GLT, and redispatch (RDS) information.

All zones had an identified ZIA this year. If there is no valid constraint identified, the following equation will be used where the FCITC will be replaced by the Tier 1 and Tier 2 capacity.

$$\textbf{\textit{ZIA}} = \textbf{\textit{FCITC}} + \textbf{\textit{Area Interchange}} - \textbf{\textit{Border External Resources and Coordinating Owners}}$$

Equation 4-3: Zonal Import Ability (ZIA) Calculation

LRZ1	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2025	North Appleton - Werner West 345 kV	North Appleton - Morgan 345 kV	10%	460MWx2	6023	6025
Fall 2025	Stone Lake 345/161 kV Transformer	Arrowhead 345/230 kV Transformer	None	515MWx2	5688	5690
Winter 2025-26	Laurel - Jasper 161 kV	Story County - Fernald 161 kV	None	601MWx2	5573	5575
Spring 2026	Mound City - Bismark 230 kV	Ft Thompson 1 - Chapelle 345 kV	None	352MWx2	6396	6398
LRZ2	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2025	Two Harbors - Silver Bay 115 kV	Taconite Harbor - LTV Hoyt Lakes 115 kV	None	439MWx2	4370	4370
Fall 2025	Zion - Pleasant Prairie 345 kV	Zion EC - Pleasant Prairie 345 kV	None	666MWx2	6537	6537
Winter 2025-26	Nelson Dewey 161/138 kV Transformer	Hickory Creek - Hill Valley 345 kV	None	1000MWx2	6435	6435
Spring 2026	Zion EC - Pleasant Prairie 345 kV	Zion - Pleasant Prairie 345 kV	None	624MWx2	6439	6439
LRZ3	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2025	Sub 3458 (Nebraska City) - Sub 3456 345 kV	Sub 3455 - Sub 3740 345 kV	None	302MWx2	5460	5518
Fall 2025	Sub 1211 - Sub 701 161 kV	Sub 3456 - Council Bluffs 345 kV	None	177MWx2	7704	7766
Winter 2025-26	Split Rock 7 - Split Rock 4 115 kV	Split Rock 3 - Sioux City 345 kV	None	1000MWx2	5785	5853
Spring 2026	Sub 1211 - Sub 701 161 kV	Sub 3456 - Council Bluffs 345 kV	None	138MWx2	7726	7784
LRZ4	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2025	Kincaid - Austin 345 kV	Lincoln Land Generator	5%	247MWx2	7757	8649
Fall 2025	Palmyra - Marblehead North 161 kV	Herleman - Palmyra Tap 345 kV	25%	880MWx2	7013	7908
Winter 2025-26	Sandburg 161/138 kV Transformer	Galesburg - Oak Grove 345 kV	None	1000MWx2	6457	7353
Spring 2026	Palmyra - Marblehead North 161 kV	Herleman - Palmyra Tap 345 kV	25%	866MWx2	7373	8272
LRZ5	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2025	Rezzy - Moro 138 kV	Redhawk - Moro 345 kV	None	697MWx2	4117	4117
Fall 2025	Rezzy - Moro 138 kV	Redhawk - Moro 345 kV	25%	608MWx2	4679	4679
Winter 2025-26	Hannibal West - Spalding 161 kV	Palmyra - Spencer Creek 345 kV	None	1000MWx2	4922	4922
Spring 2026	Mississippi Tap - Sioux 138 kV	Sioux Generator	10%	217MWx2	4453	4453
LRZ6	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2025	Cayuga - Nucor 345 kV	Dresser - Sugar Creek 345 kV	10%	571MWx2	8366	8650
Fall 2025	Cayuga - Cayuga Sub 345 kV	Kansas West - Sugar Creek 345 kV	None	162MWx2	8672	8970
Winter 2025-26	Kokomo Highland Park - Tipton 230 kV	Cayuga - Nucor 345 kV	None	1000MWx2	7690	7936
Spring 2026	Eugene - Cayuga Sub 345 kV	Kansas West - Sugar Creek 345 kV	None	431MWx2	9176	9491
LRZ7	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2025	Amo - Qualitech Steel 345 kV	Gibson - Wheatland 345 kV	None	1000MWx2	3569	3579
Fall 2025	Benton Harbor - Segreto 345 kV	Cook - Segreto 345 kV	None	1000MWx2	5115	5125
Winter 2025-26	Benton Harbor - Segreto 345 kV	Cook - Segreto 345 kV	None	1000MWx2	4762	4762
Spring 2026	Benton Harbor - Segreto 345 kV	Cook - Segreto 345 kV	None	643MWx2	5166	5166
LRZ8	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2025	J620 - Dermott 115 kV	Lake Village Bagby - Reed SS 115 kV	None	697MWx2	2358	2522
Fall 2025	Mount Olive - Vienna 115 kV	Mount Olive - Eldorado 500 kV	None	1000MWx2	5675	5870
Winter 2025-26	Clarksdale - Lyon 115 kV	Moon Lake - Clarkesdale 230 kV	None	1000MWx2	3432	3534
Spring 2026	Mount Olive - Vienna 115 kV	Mount Olive - Eldorado 500 kV	None	1000MWx2	6085	6250
LRZ9	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2025	Sterlington - Downsville 115 kV	Mount Olive - Eldorado 500 kV	None	1000MWx2	4361	4872
Fall 2025	Danville - Dodson 115 kV	Mount Olive - Layfield 500 kV	None	1000MWx2	4741	5242
Winter 2025-26	Arklahoma - Hot Springs East 115 kV	Arklahoma - Hot Springs West 115 kV	None	1000MWx2	4418	4995
Spring 2026	Daniel - Daniel Intermediate 1 230 kV	Daniel - Daniel Intermediate 2 230 kV	None	1000MWx2	4855	5370
LRZ 10	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2025	Ritchie - Moon Lake 230 kV	Perryville - Baxter Wilson 500 kV	None	1000MWx2	4474	4474
Fall 2025	Ritchie - Moon Lake 230 kV	Perryville - Baxter Wilson 500 kV	None	602MWx2	4508	4508
Winter 2025-26	Little Gypsy - Fairview 230 kV	Michoud - Front Street 230 kV	None	1000MWx2	3458	3458
Spring 2026	Perryville - Baxter Wilson 500 kV	Grand Gulf Generator	None	1000MWx2	4365	4365

Table 4-3: Planning Year 2025–2026 Import Limits

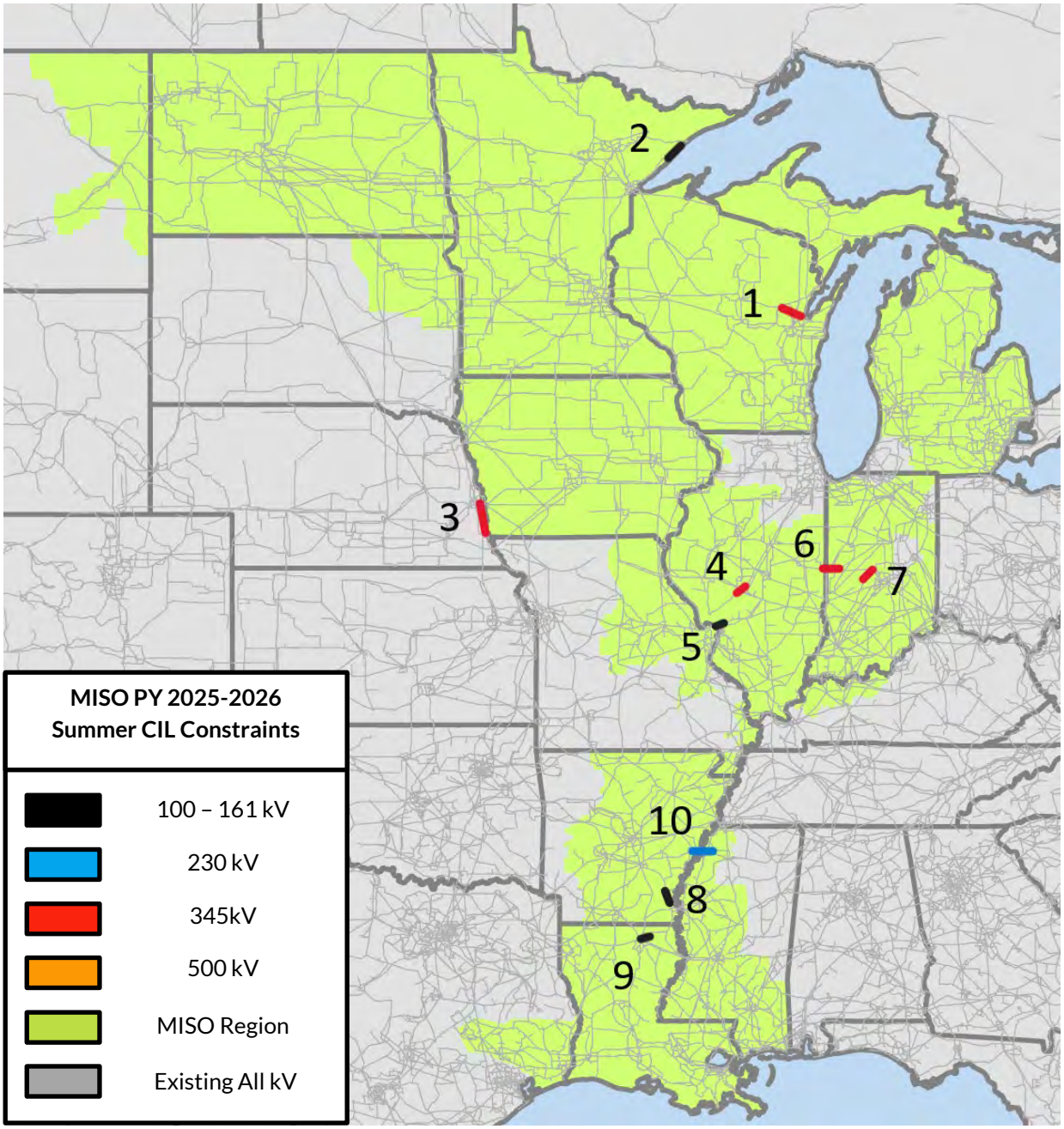


Figure 4-2: Planning Year 2025-2026 Summer Capacity Import Constraints Map

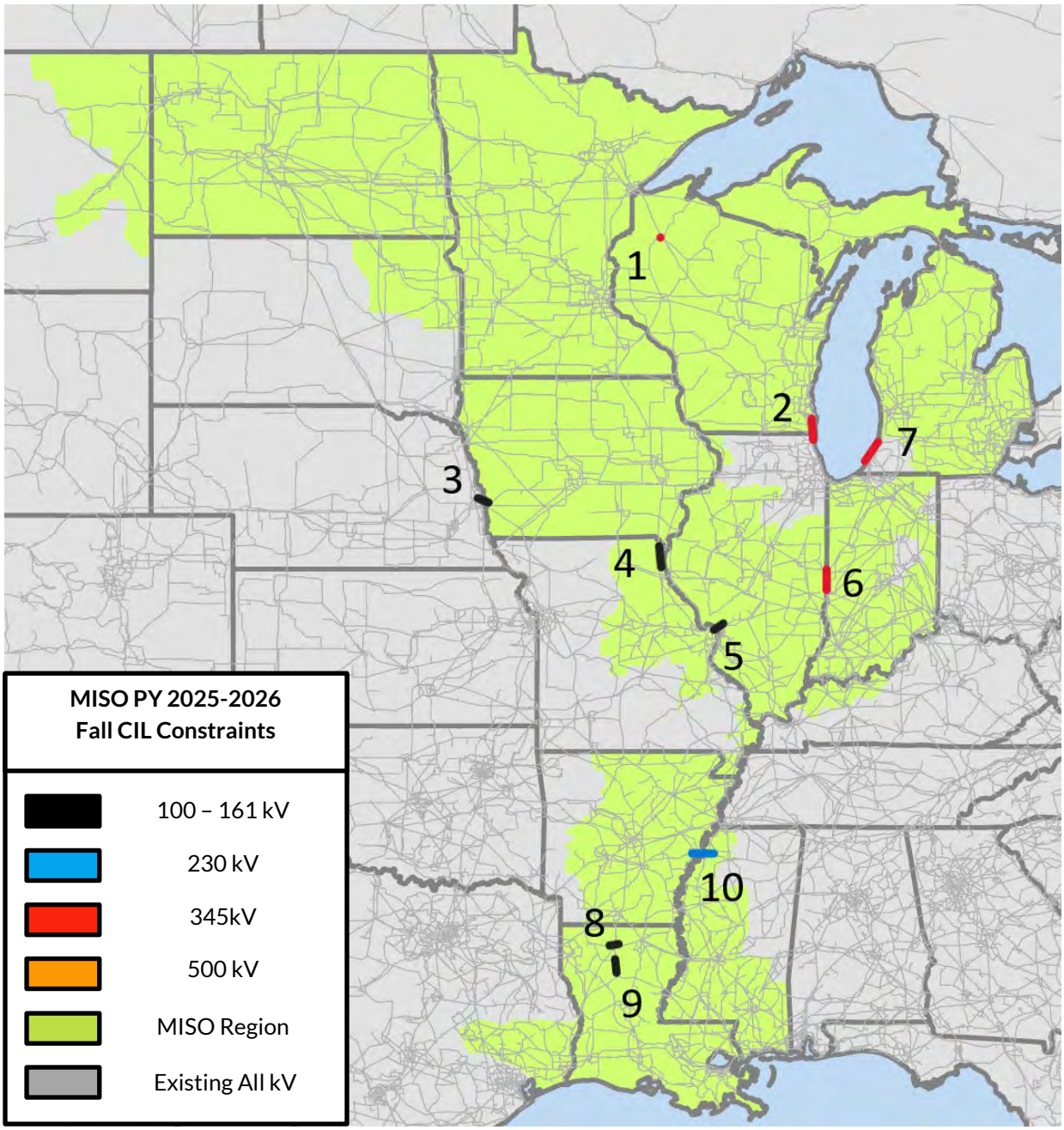


Figure 4-3: Planning Year 2025-2026 Fall Capacity Import Constraints Map

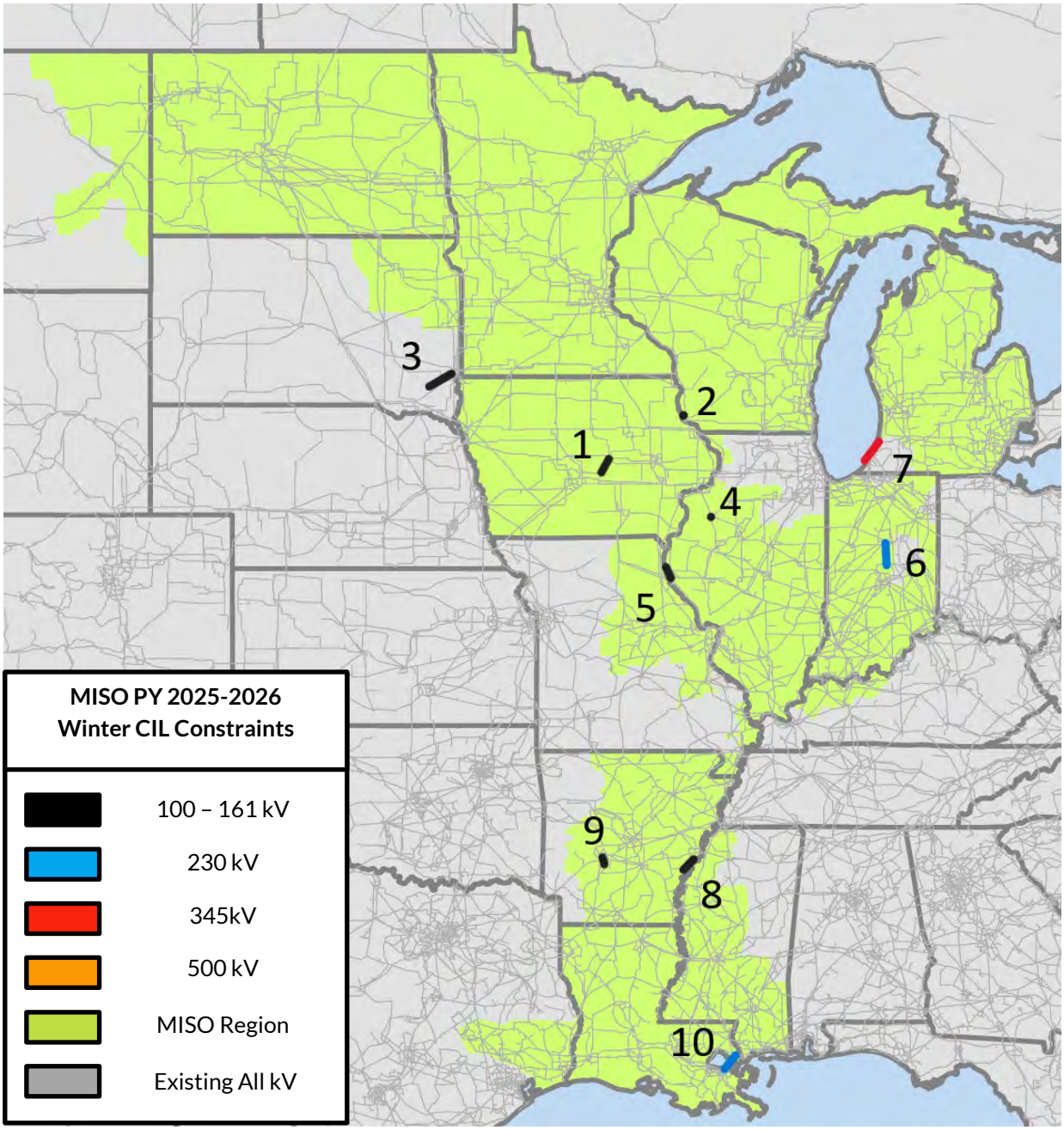


Figure 4-4: Planning Year 2025-2026 Winter Capacity Import Constraints Map

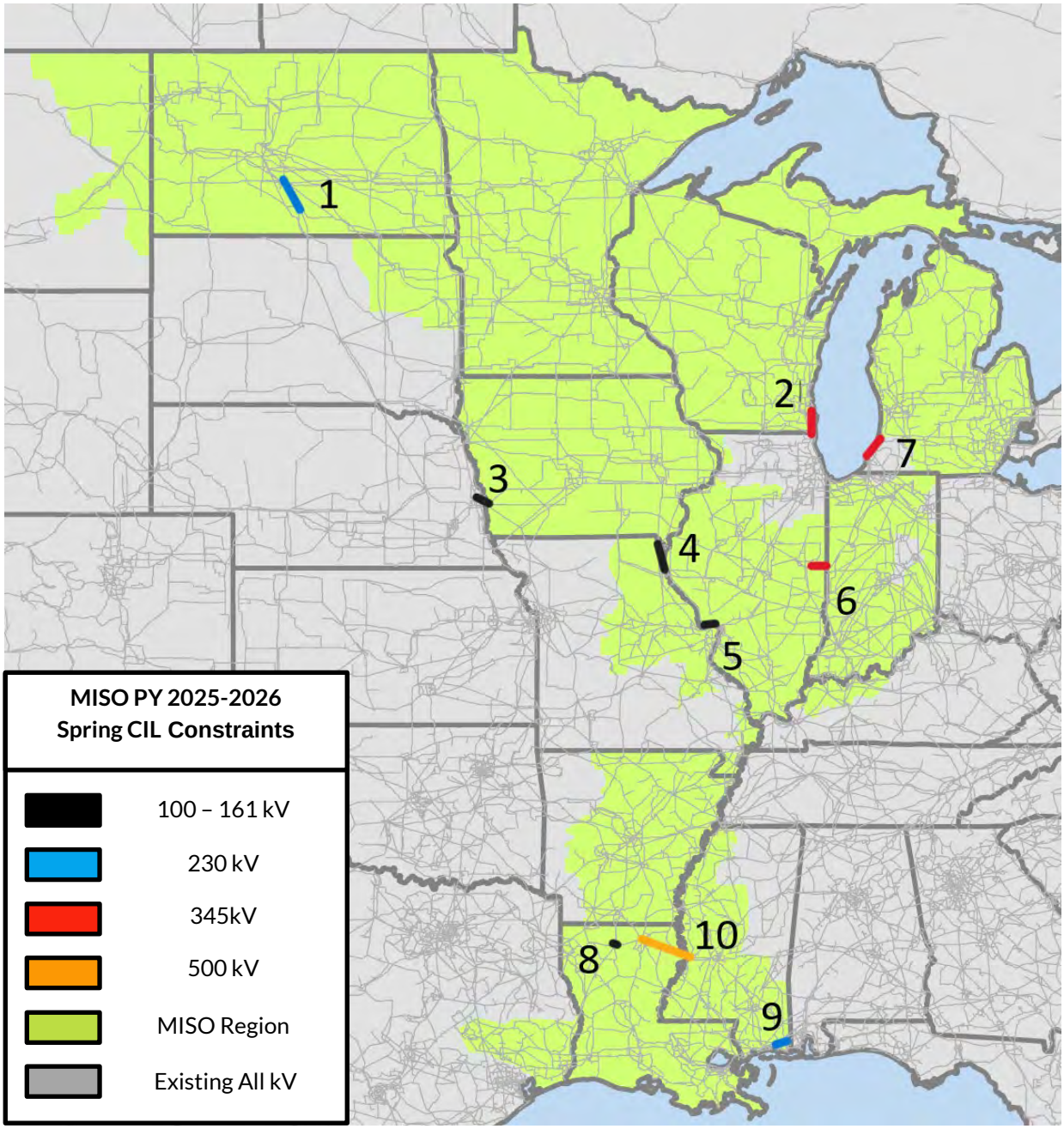


Figure 4-5: Planning Year 2025-2026 Spring Capacity Import Constraints Map

Capacity Exports Limits are found by increasing generation in the study zone and decreasing generation in the rest of the MISO footprint to create a transfer. Table 4-4 below shows the Planning Year 2025-2026 CEL and ZEA with corresponding constraint, GLT, and redispatch information.

LRZ1	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2025	Split Rock 4 - Sioux Falls 230 kV	Split Rock 3 - Sioux City 345 kV	None	293MWx2	3993	3991
Fall 2025	Adams - Mitchell County 345 kV	Disconnect Blackhawk Reactor	None	270MWx2	6167	6165
Winter 2025-26	Split Rock 7 - Split Rock 4 115 kV	Split Rock - Sioux City 345 kV	None	721MWx2	3593	3591
Spring 2026	Adams - Mitchell County 345 kV	Disconnect Blackhawk Reactor	None	279MWx2	5285	5283
LRZ2	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2025	Neevin - Butte Des Morts 138 kV	Neevin-Woodenshoe 138 kV	25%	633MWx2	4614	4614
Fall 2025	Sherman Street - Sunnyvale 115 kV	Arpin - Rocky Run 345 kV	10%	909MWx2	4259	4259
Winter 2025-26	Granville - Butler 138 kV	Arcadian-Granville 345 kV	20%	561MWx2	4793	4793
Spring 2026	Berryville - Paris 138 kV	Paris 345/138 kV Transformer	30%	674MWx2	6119	6119
LRZ3	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2025	No Limiting Element	None	50%	None	4713	4655
Fall 2025	No Limiting Element	None	50%	None	5924	5862
Winter 2025-26	Council Bluffs - Sub 3456 345 kV	Arbor Hill - Raccoon Trail 345 kV	None	561MWx2	7480	7412
Spring 2026	No Limiting Element	None	50%	None	6039	5981
LRZ4	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2025	Alsey - Winchester 138 kV	Alsey - Ballard 138 kV	40%	577MWx2	5352	4460
Fall 2025	Marion - Marion South 161 kV	Silver Mine Substation	None	1000MWx2	5069	4174
Winter 2025-26	No Limiting Element	None	50%	None	5531	4635
Spring 2026	Marion - Marion South 161 kV	Silver Mine Substation	None	212MWx2	5880	4981
LRZ5	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2025	No Limiting Element	None	45%	None	3939	3939
Fall 2025	No Limiting Element	None	50%	None	5816	5816
Winter 2025-26	No Limiting Element	None	50%	None	4814	4814
Spring 2026	No Limiting Element	None	50%	None	5797	5797
LRZ6	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2025	Gibson - Douglas 345 kV	AB Brown - Posey East 345 kV	40%	70MWx2	7165	6881
Fall 2025	AEP Rockport - Grandview 138 kV	AB Brown - Reid 345 kV	None	539MWx2	5471	5173
Winter 2025-26	AB Brown - AB Brown Reactor 138 kV	AB Brown - Reid 345 kV	None	518MWx2	1911	1665
Spring 2026	Holland - Dubois 138 kV	Duff - Francisco 345 kV	None	487MWx2	6706	6391
LRZ7	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2025	Monroe - Lallendorf 345 kV	Morocco - Allen Junction 345 kV	15%	1000MWx2	5726	5716
Fall 2025	Monroe - Lallendorf 345 kV	Morocco - Allen Junction 345 kV	None	1000MWx2	5168	5158
Winter 2025-26	Morocco - Allen Junction 345 kV	Monroe - Lallendorf 345 kV	None	1000MWx2	5712	5712
Spring 2026	Monroe - Lallendorf 345 kV	Morocco - Allen Junction 345 kV	None	1000MWx2	5499	5499
LRZ8	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2025	No Limiting Element	None	50%	641MWx2	6509	6345
Fall 2025	Cash - Jonesboro 161 kV	Independence - Power Line Road 500 kV	None	1000MWx2	4219	4024
Winter 2025-26	Freeport - Cordova 500 kV	Sans Souci - Driver 500 kV	20%	422MWx2	3783	3681
Spring 2026	Freeport - Cordova 500 kV	Sans Souci - Driver 500 kV	None	382MWx2	3724	3559
LRZ9	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2025	Montgomery - Clarence 230 kV	Montgomery - Winfield 230 kV	None	1000MWx2	4286	3775
Fall 2025	Ray Braswell - Northside Drive 230 kV	Ray Braswell - Lakeover 500 kV	None	1000MWx2	4173	3672
Winter 2025-26	Little Gypsey - Fairview 230 kV	Michoud - Front Street 230 kV	None	1000MWx2	3618	3041
Spring 2026	Ray Braswell - Northside Drive 230 kV	Ray Braswell - Lakeover 500 kV	None	1000MWx2	4146	3631
LRZ10	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2025	Batesville - Tallahatchie 161 kV	Batesville - East Batesville 161 kV	None	710MWx2	2097	2097
Fall 2025	Lake Village Bagby - Macon Lake 115 kV	Lake Village Bagby - Reed 115 kV	None	650MWx2	3164	3164
Winter 2025-26	Batesville - Tallahatchie 161 kV	Choctaw - Clay 500 kV	None	710MWx2	2028	2028
Spring 2026	Batesville - Tallahatchie 161 kV	Batesville - East Batesville 161 kV	None	526MWx2	3072	3072

Table 4-4: Planning Year 2025–2026 Export Limits

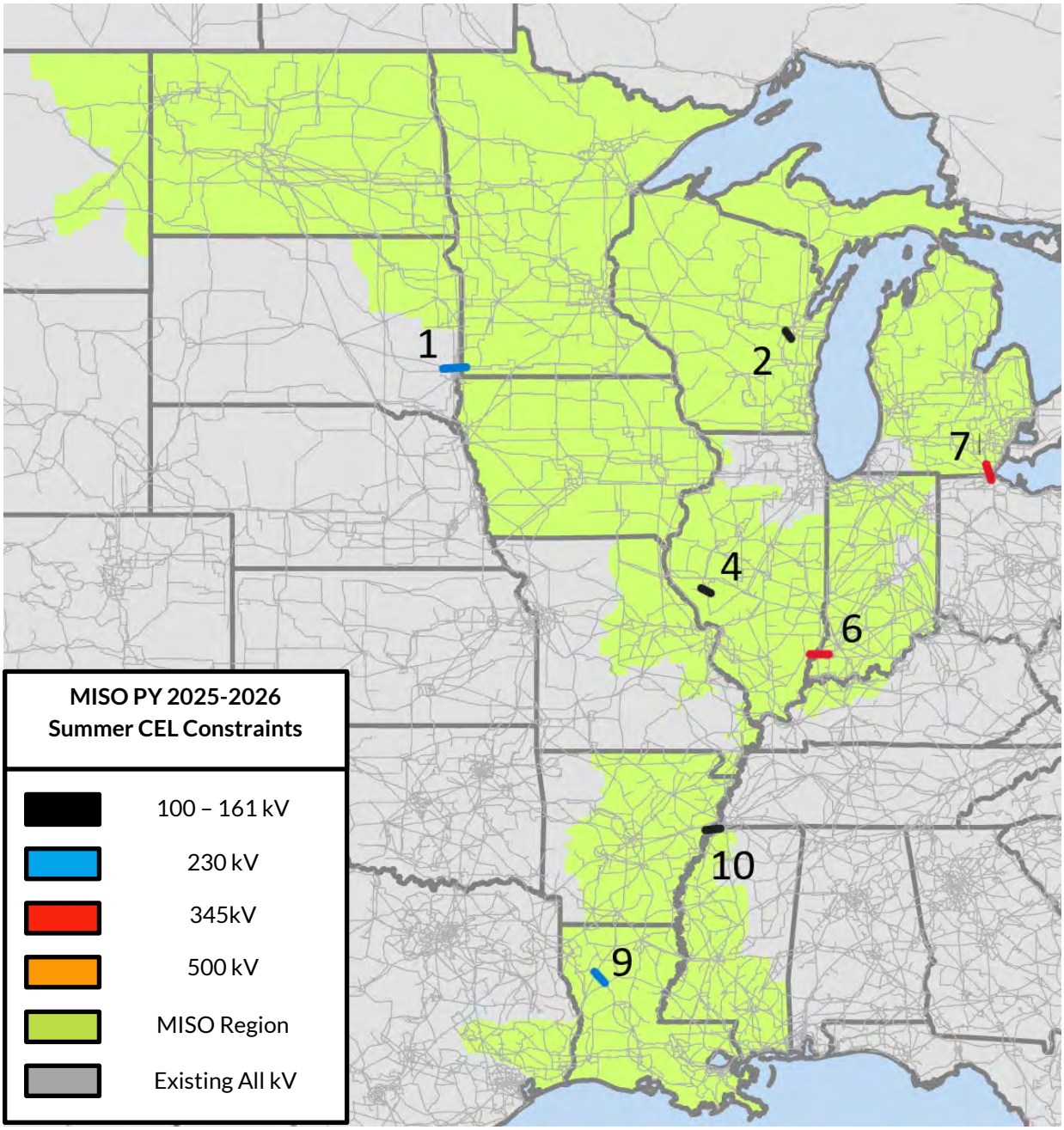


Figure 4-6: Planning Year 2025-2026 Summer Export Constraint Map

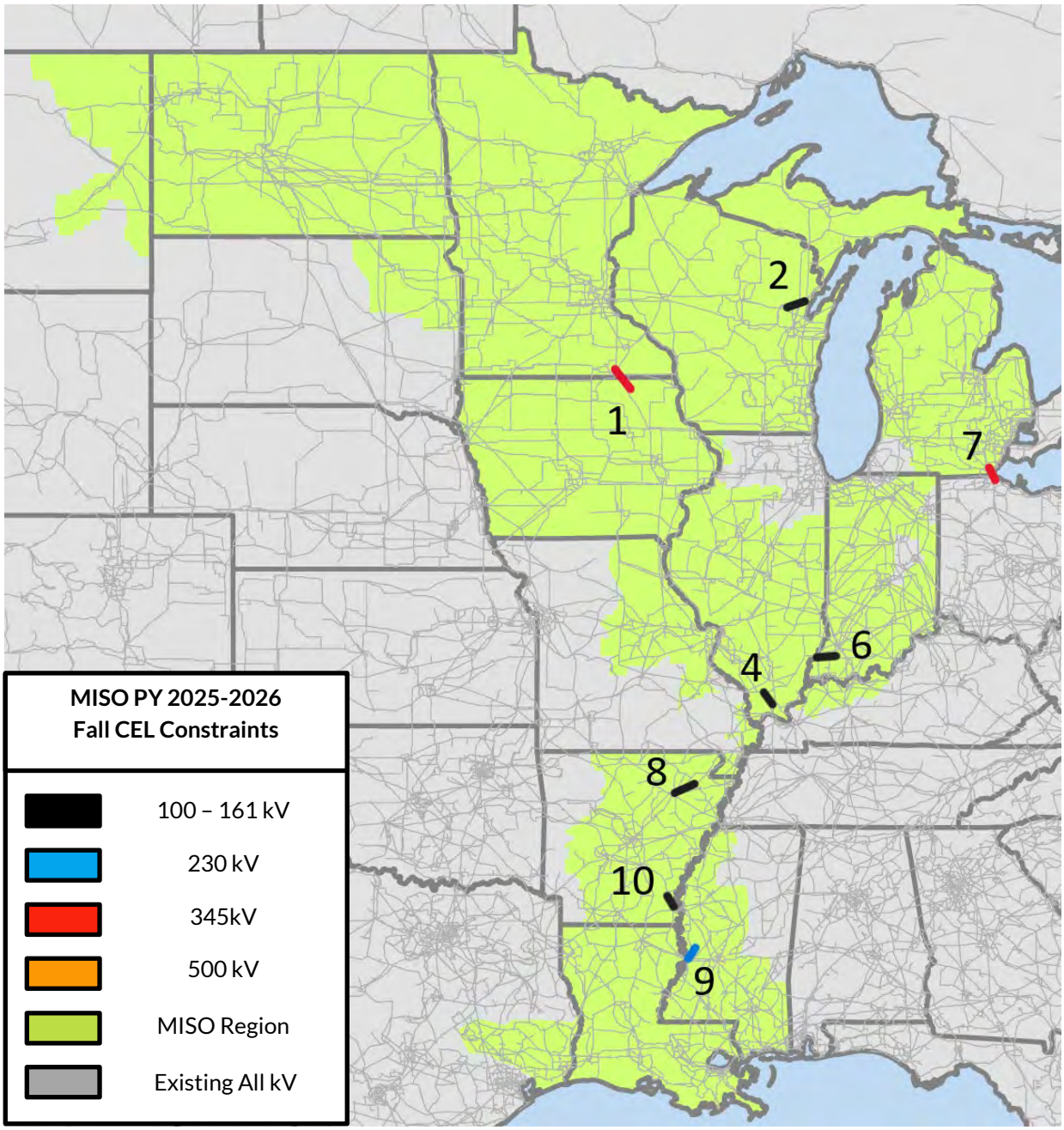


Figure 4-7: Planning Year 2025-2026 Fall Export Constraint Map

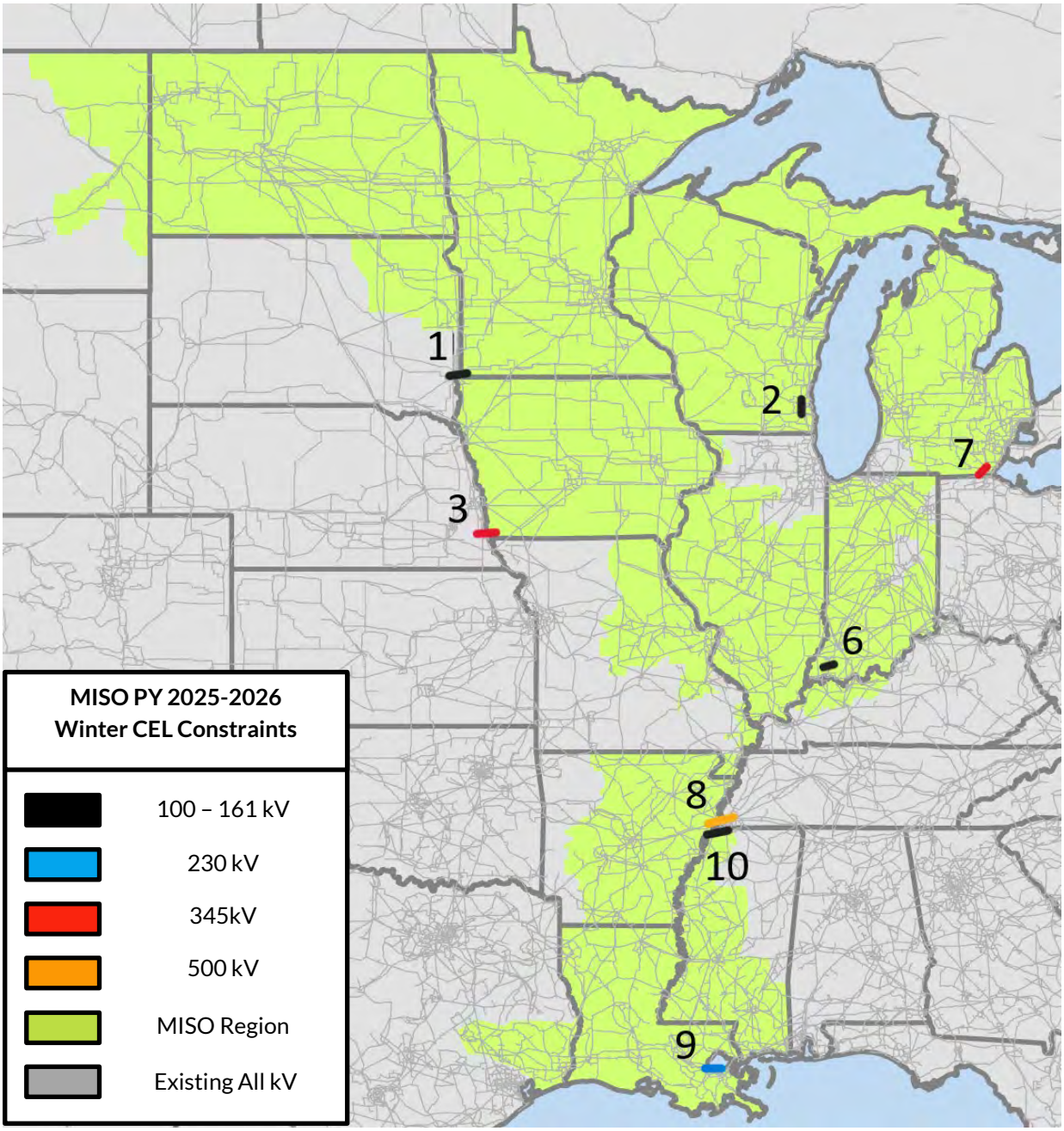


Figure 4-8: Planning Year 2025-2026 Winter Export Constraint Map

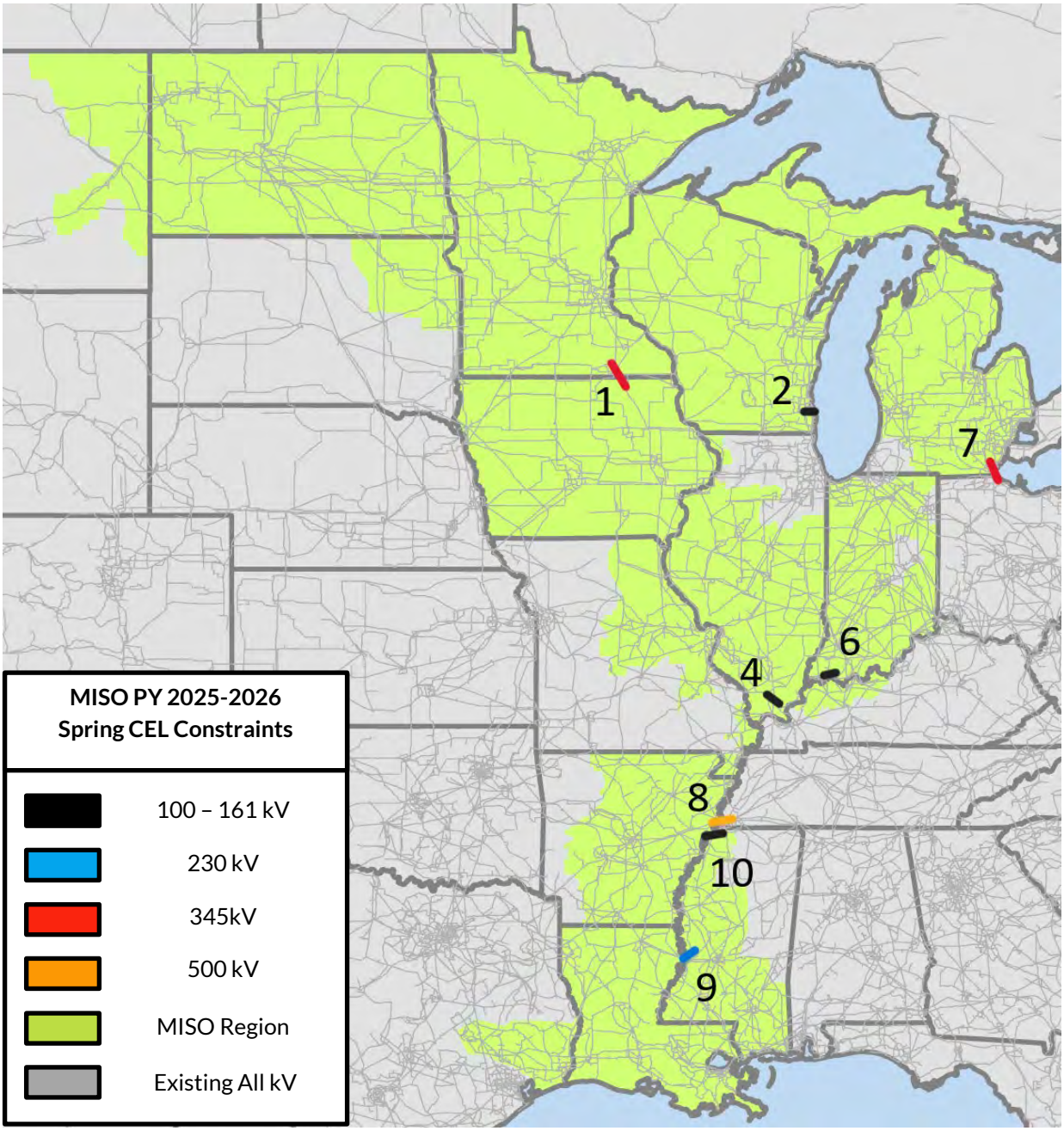


Figure 4-9: Planning Year 2025-2026 Spring Export Constraint Map

Appendix A: Capacity Import Limit Tier 1 & 2 Source Subsystem Definitions

MISO Local Resource Zone 1

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
XEL / 600	ALTW / 627	WEC / 295
MP / 608	ALTE / 694	MIUP / 296
SMMPA / 613	WPS / 696	AMMO / 356
GRE / 615	MGE / 697	AMIL / 357
OTP / 620		MPW / 633
MDU / 661		MEC / 635
BEPC-MISO / 663		
DPC / 680		

MISO Local Resource Zone 2

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #	
WEC / 295	METC / 218	NIPS / 217	OTP / 620
MIUP / 296	XEL / 600	ITCT / 219	MPW / 633
ALTE / 694	MP / 608	AMMO / 356	MEC / 635
WPS / 696	ALTW / 627	AMIL / 357	
MGE / 697	DPC / 680	SMMPA / 613	
UPPC / 698		GRE / 615	

MISO Local Resource Zone 3

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #	
ITCM / 627	AMMO / 356	HE / 207	GLHB / 362
MPW / 633	AMIL / 357	DEI / 208	MP / 608
MEC / 635	XEL / 600	NIPS / 217	GRE / 615
	SMMPA / 613	WEC / 295	OTP / 620
	DPC / 680	CWLP / 360	WPS / 696
	ALTE / 694	SIPC / 361	MGE / 697

MISO Local Resource Zone 4

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #	
AMIL / 357	HE / 207	SIGE / 210	DPC / 680
CWLP / 360	DEI / 208	IPL / 216	ALTE / 694
SIPC / 361	NIPS / 217	METC / 218	
GLHB / 362	BREC / 314	HMPL / 315	
GLH / 373	AMMO / 356	XEL / 600	
	ITCM / 627	SMMPA / 613	
	MEC / 635	MPW / 633	

MISO Local Resource Zone 5

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #	
CWLD / 333	AMIL / 357	HE / 207	SMMPA / 613
AMMO / 356	GLHB / 362	DEI / 208	MPW / 633
	ALTW / 627	NIPS / 217	DPC / 680
	MEC / 635	CWLP / 360	ALTE / 694
		SIPC / 361	
		XEL / 600	

MISO Local Resource Zone 6

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
HE / 207	METC / 218	ITCT / 219
DEI / 208	AMIL / 357	MIUP / 296
SIGE / 210	SIPC / 361	AMMO / 356
IPL / 216		CWLP / 360
NIPS / 217		GLHB / 362
BREC / 314		ALTW / 627
HMPL / 315		MEC / 635

MISO Local Resource Zone 7

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
METC / 218	NIPS / 217	DEI / 208
ITCT / 219	MIUP / 296	WEC / 295
		AMIL / 356
		WPS / 696
		UPPC / 698

MISO Local Resource Zone 8

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
EES-EAI / 327	EES-EMI / 326	LAGN / 332
	EES / 351	SMEPA / 349
		CLEC / 502
		LAFA / 503

MISO Local Resource Zone 9

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
LAGN / 332	EES-EMI / 326	SMEPA / 349
EES / 351	EES-EAI / 327	
CLEC / 502		
LAFA / 503		
LEPA / 504		

MISO Local Resource Zone 10

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
EES-EMI / 326	EES-EAI / 327	LAGN / 332
SMEPA / 349	EES / 351	CLEC / 502
		LAFA / 503

Appendix B: Compliance Conformance Table

Requirements under: Standard BAL-502-RF-03	Response
R1 The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall:	The Planning Year 2025-2026 LOLE Study Report is the annual Resource Adequacy Analysis for the peak season of June 2025 through May 2026 and beyond. Analysis of Planning Year 2025-2026 is in Sections 1.2 and 2.1. Analysis of Future Years 2025-2034 is included in Appendix D as an addendum to the study report.
R1.1 Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year[1] analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 years" criterion).	Section 3.6 of this report outlines the utilization of LOLE in the reserve margin determination. "The risk metrics were derived through probabilistic modeling of the system, first solving to the industry standard annual LOLE risk target of 1 day in 10 years, or 0.1 day per year, and then solving to the minimum seasonal LOLE criteria of 0.01 LOLE for seasons demonstrating minimal risk.
R1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability.	Section 3.4 of this report. "Direct Control Load Management and Interruptible Demand types of demand response were included in the LOLE model as resources. Demand response is dispatched in the LOLE model to avoid load shed during simulation when all other available generation has been exhausted."
R1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median forecast peak Net Internal Demand (planning reserve margin).	Section 1.2 of this report. "…the ratio of MISO capacity to forecasted MISO system peak demand yielded a Planning Reserve Margin UCAP…"
R1.2 Be performed or verified separately for each of the following planning years.	Covered in the segmented R1.2 responses below.
R1.2.1 Perform an analysis for Year One.	In Sections 1.2 and 2.1, a full analysis was performed for Planning Year 2025-2026.
R1.2.2 Perform an analysis or verification at a minimum for one year in the 2 through 5-year period and at a minimum one year in the 6 though 10-year period.	Analysis of Planning Years 2028-2029 and 2030-2031 are included in Appendix D as an addendum to the study report.

Requirements under: Standard BAL-502-RF-03	Response
R1.2.2.1 If the analysis is verified, the verification must be supported by current or past studies for the same planning year.	Analysis was performed.
R1.3 Include the following subject matter and documentation of its use:	Covered in the segmented R1.3 responses below.
R1.3.1 Load forecast characteristics: • Median (50:50) forecast peak load • Load Forecast Uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts) • Load Diversity • Seasonal Load Variations • Daily demand modeling assumptions (firm, interruptible) • Contractual arrangements concerning curtailable/Interruptible Demand	Median forecasted load – In Section 3.4 of this report: "The sixth and final step of the load training process is to average the monthly peak loads of the 30 years of predicted load shapes and adjust the load dataset to match each LRZ's total monthly zonal Coincident Peak Demand forecast provided by the Load Serving Entities for each of the study years." Load Forecast Uncertainty – A detailed explanation of the weather and economic uncertainties is given in Section 3.4. Load Diversity / Seasonal Load Variations — In Section 3.4 of this report: "Every year, the Load Serving Entities submit new load forecasts to MISO by November 1 and, every year, MISO utilizes these load forecasts in the load development process for the LOLE study to align the load in the model with the anticipated load growth forecasted within each Local Resource Zone. The Planning Year 2025-2026 LOLE analysis used a load training process pared with neural net software to establish a correlated relationship between the most recent 5 years of historical weather and load data. This relationship was then applied to 30 years of hourly historical load data to create 30 years of load shapes for each LRZ to capture both load diversity and seasonal variability." Demand Modeling Assumptions / Curtailable and Interruptible Demand — All Load Modifying Resources must first meet registration requirements through Module E of the MISO Tariff. As stated in Section 3.2.6: "Each demand response program was modeled individually with a monthly capability, limited by duration and the number of times each program can be called upon for each season."

Requirements under: Standard BAL-502-RF-03	Response
R1.3.2 Resource characteristics: • Historic resource performance and any projected changes • Seasonal resource ratings • Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area • Resource planned outage schedules, deratings, and retirements • Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration • Criteria for including planned resource additions in the analysis	Section 3.2 details how historic performance data and seasonal ratings are gathered and includes discussion of future units and the modeling assumptions for intermittent capacity resources. A more detailed explanation of firm capacity purchases and sales is in Section 3.5.
R1.3.3 Transmission limitations that prevent the delivery of generation reserves.	Annual MTEP deliverability analysis identifies transmission limitations preventing delivery of generation reserves. Additionally, Section 4 of this report details the transfer analysis to capture transmission constraints limiting capacity transfers.
R1.3.3.1 Criteria for including planned Transmission Facility additions in the analysis.	Inclusion of the planned transmission addition assumptions is detailed in Section 4.2.3.
R1.3.4 Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area.	Section 3.5 provides the analysis on the treatment of external support assistance and limitations.

Requirements under: Standard BAL-502-RF-03	Response
R1.4 Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included: • Availability and deliverability of fuel • Common mode outages that affect resource availability • Environmental or regulatory restrictions of resource availability • Any other demand (Load) response programs not included in R1.3.1 • Sensitivity to resource outage rates • Impacts of extreme weather/drought conditions that affect unit availability • Modeling assumptions for emergency operation procedures used to make reserves available • Market resources not committed to serving Load (uncommitted resources) within the Planning Coordinator area	Fuel availability, environmental restrictions, common mode outage, and extreme weather conditions are all part of the historical availability performance data that goes into the unit's EFORd statistic. The use of the EFORd values is covered in Section 3.2.1. The use of demand response programs is mentioned in Section 3.2.6. The effects of resource outage characteristics on the reserve margin are outlined in Section 3.6.2 by examining the difference between PRM ICAP and PRM UCAP values.
R1.5 Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included.	Transmission maintenance schedules were not included in the analysis of the transmission system due to the limited availability of reliable long-term maintenance schedules and minimal impact to the results of the analysis. However, Section 4 treats worst-case theoretical outages by performing First Contingency Total Transfer Capability (FCTTC) analysis for each LRZ, by modeling NERC Category P0 (system intact) and Category P1 (N-1) contingencies.
R1.6 Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis.	MISO internal resources are among the quantities documented in the tables provided in Sections 1 and 2.
R1.7 Document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis.	MISO load is among the quantities documented in the tables provided in Sections 1 and 2.
R2 The Planning Coordinator shall annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis.	In Sections 1 and 2, the peak load and estimated amount of resources for Planning Year 2025-2026 are shown. This includes the detail for each transmission constrained sub-area.
R2.1 This documentation covers each of the years in year one through ten.	Appendix D details the future Planning Year analysis.

Requirements under: Standard BAL-502-RF-03	Response
R2.2 This documentation includes the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis.	The prompt Planning Year seasonal PRM values are covered in Section 1.2. The outyear Planning Years 4 (2028-2029) and 6 (2030-2031) are covered in Appendix D.
R2.3 The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One.	The final Planning Year 2025-2026 LOLE Study Report was posted publicly in November 2024, several months prior to the start of the applicable Planning Year.
R3 The Planning Coordinator shall identify any gaps between the needed amount of planning reserves defined in Requirement R1, Part 1.1 and the projected planning reserves documented in Requirement R2.	Sections 1 and 2 show the differences between the needed amount and the projected planning reserves for Planning Year 2025-2026. The amount of planning reserves needed for the outyear Planning Years 4 (2028-2029) and 6 (2030-2031) are covered in Appendix D.

Appendix C: Acronyms List Table

CEL	Capacity Export Limit
CIL	Capacity Import Limit
CPNode	Commercial Pricing Node
DF	Distribution Factor
EFORd	Equivalent Forced Outage Rate demand
ELCC	Effective Load Carrying Capability
ERZ	External Resource Zone
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
FCITC	First Contingency Incremental Transfer Capability
FCTTC	First Contingency Total Transfer Capability
GADS	Generator Availability Data System
GLT	Generation Limited Transfer
GVTC	Generation Verification Test Capacity
ICAP	Installed Capacity
LBA	Local Balancing Authority
LCR	Local Clearing Requirement
LFE	Load Forecast Error
LFU	Load Forecast Uncertainty
LOLE	Loss of Load Expectation
LOLEWG	Loss of Load Expectation Working Group
LRR	Local Reliability Requirement
LRZ	Local Resource Zones
LSE	Load Serving Entity
MARS	Multi-Area Reliability Simulation
MECT	Module E Capacity Tracking
MISO	Midcontinent Independent System Operator
MOD	Model on Demand
MTEP	MISO Transmission Expansion Plan
MW	Megawatt
MWh	Megawatt hours
NERC	North American Electric Reliability Corporation

PRA	Planning Resource Auction
PRM	Planning Reserve Margin
PRM ICAP	PRM Installed Capacity
PRM UCAP	PRM Unforced Capacity
PRMR	Planning Reserve Margin Requirement
PSS E	Power System Simulator for Engineering
RCF	Reciprocal Coordinating Flowgate
RDS	Redispatch
RPM	Reliability Pricing Model
SAC	Seasonal Accredited Capacity
SERVM	Strategic Energy & Risk Valuation Model
SPS	Special Protection Scheme
TARA	Transmission Adequacy and Reliability Assessment
UCAP	Unforced Capacity
XEFORd	Equivalent Forced Outage Rate demand with adjustment to exclude events outside management control
ZIA	Zonal Import Ability
ZEA	Zonal Export Ability

Appendix D: Outyear PRM Results

For Planning Year 2028-2029, the ratio of MISO capacity to forecasted MISO system peak demand yielded a Planning Reserve Margin UCAP of 8.5 percent for the Summer season. Numerous values and calculations went into determining the four-year-out MISO system seasonal PRM UCA, supporting values are seen in Table D-1. In addition to the LOLE results, SERVM has the ability to calculate several other probabilistic metrics, resulting values for Loss of Load Hours (LOLH) and Expected Unserved Energy (EUE) for each season of the 2028-2029 Planning Year are shown below in Table D-2.

D.1 Planning Year 2028-2029 MISO Planning Reserve Margin Results

MISO Planning Reserve Margin (PRM)	PY 2028-2029 Summer	PY 2028-2029 Fall	PY 2028-2029 Winter	PY 2028-2029 Spring	Formula Key
MISO System Peak Demand (MW)	129,963	114,031	109,039	104,253	[A]
Installed Capacity (ICAP) (MW)	153,551	150,473	157,792	158,083	[B]
Unforced Capacity (UCAP) (MW)	143,488	138,424	137,443	144,560	[C]
Firm External Support ICAP (MW)	1,986	2,315	2,738	2,423	[D]
Firm External Support UCAP (MW)	1,935	2,215	2,594	2,309	[E]
Adjustment to ICAP (MW)	(4,350)	(9,400)	(8,640)	(14,850)	[F]
Adjustment to UCAP (MW)	(4,350)	(9,400)	(8,640)	(14,850)	[G]
ICAP PRM Requirement (PRMR) (MW)	151,187	143,388	151,890	145,657	[H] = [B]+[D]+[F]
UCAP PRM Requirement (PRMR) (MW)	141,073	131,239	131,398	132,019	[I] = [C]+[E]+[G]
MISO PRM ICAP	**16.3%**	**25.7%**	**39.3%**	**39.7%**	[J]=[H]-[A]/[A]
MISO PRM UCAP	**8.5%**	**15.1%**	**20.5%**	**26.6%**	[K]=[I]-[A]/[A]

Table D-1: Planning Year 2028-2029 MISO System Planning Reserve Margins

D.1.1 Additional Risk Metric Statistics

MISO LOLE Statistics	PY 2028-2029 Summer	PY 2028-2029 Fall	PY 2028-2029 Winter	PY 2028-2029 Spring
Loss of Load Expectation (LOLE) [days/year]	0.100	0.010	0.010	0.010
Loss of Load Hours (LOLH) [hours/year]	0.143	0.011	0.013	0.013
Expected Unserved Energy (EUE) [megawatt-hours/year]	307.123	12.808	11.574	14.615

Table D-2: PY 2028-2029 Additional Risk Metric Statistics

D.2 Planning Year 2030-2031 MISO Planning Reserve Margin Results

For Planning Year 2030-2031, the ratio of MISO capacity to forecasted MISO system peak demand yielded a Planning Reserve Margin UCAP of 8.5 percent for the Summer season. Numerous values and calculations went into determining the six-year-out MISO system seasonal PRM UCA, supporting values are seen in Table D-3. In addition to the LOLE results, SERVM has the ability to calculate several other probabilistic metrics, resulting values for Loss of Load Hours (LOLH) and Expected Unserved Energy (EUE) for each season of the 2030-2031 Planning Year are shown below in Table D-4.

MISO Planning Reserve Margin (PRM)	**PY 2030-2031** Summer	**PY 2030-2031** Fall	**PY 2030-2031** Winter	**PY 2030-2031** Spring	**Formula Key**
MISO System Peak Demand (MW)	131,381	115,692	110,450	105,291	[A]
Installed Capacity (ICAP) (MW)	158,093	155,519	162,465	160,212	[B]
Unforced Capacity (UCAP) (MW)	147,627	143,109	141,998	146,462	[C]
Firm External Support ICAP (MW)	1,986	2,315	2,738	2,423	[D]
Firm External Support UCAP (MW)	1,935	2,215	2,594	2,309	[E]
Adjustment to ICAP (MW)	(7,075)	(11,500)	(10,687)	(14,600)	[F]
Adjustment to UCAP (MW)	(7,075)	(11,500)	(10,687)	(14,600)	[G]
ICAP PRM Requirement (PRMR) (MW)	153,004	146,335	154,516	148,036	[H] = [B]+[D]+[F]
UCAP PRM Requirement (PRMR) (MW)	142,487	133,825	133,906	134,171	[I] = [C]+[E]+[G]
MISO PRM ICAP	**16.5%**	**26.5%**	**39.9%**	**40.6%**	[J]=[H]-[A]/[A]
MISO PRM UCAP	**8.5%**	**15.7%**	**21.2%**	**27.4%**	[K]=[I]-[A]/[A]

Table D-3: Planning Year 2030-2031 MISO System Planning Reserve Margins

D.2.1 Additional Risk Metric Statistics

MISO LOLE Statistics	**PY 2030-2031** Summer	**PY 2030-2031** Fall	**PY 2030-2031** Winter	**PY 2030-2031** Spring
Loss of Load Expectation (LOLE) [days/year]	0.100	0.010	0.010	0.010
Loss of Load Hours (LOLH) [hours/year]	0.138	0.010	0.012	0.012
Expected Unserved Energy (EUE) [megawatt-hours/year]	309.609	15.855	10.990	11.952

Table D-4: PY 2030-2031 Additional Risk Metric Statistics

D.3 MISO Planning Reserve Margin Outyear Projections

Tables D-5, D-6, D-7, and D-8 show the outyear seasonal PRM projections. Years one, four, and six were probabilistically modeled. PRM projections in years two, three, and five are the result of interpolation of the years studied and years seven through ten are the resulting extrapolations of the outyear analyses.

Metric	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
PRM ICAP	15.7%	15.9%	16.1%	16.3%	16.4%	16.5%	16.6%	16.8%	16.9%	17.1%
PRM UCAP	7.9%	8.1%	8.3%	8.5%	8.5%	8.5%	8.6%	8.7%	8.8%	8.9%
Demand (GW)	123.6	125.7	127.8	130.0	130.7	131.4	132.9	134.5	136.1	137.6
ICAP (GW)	141.9	145.8	149.7	153.6	155.8	158.1	161.3	164.6	167.8	171.0

Table D-5: MISO Summer Planning Reserve Margin Outyear Projections

Metric	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
PRM ICAP	25.3%	25.5%	25.6%	25.7%	26.1%	26.5%	26.7%	27.0%	27.2%	27.4%
PRM UCAP	14.9%	14.9%	15.0%	15.1%	15.4%	15.7%	15.8%	16.0%	16.2%	16.3%
Demand (GW)	108.1	110.1	112.1	114.0	114.9	115.7	117.2	118.7	120.2	121.8
ICAP (GW)	142.7	145.3	147.9	150.5	153.0	155.5	158.1	160.6	163.2	165.7

Table D-6: MISO Fall Planning Reserve Margin Outyear Projections

Metric	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
PRM ICAP	38.6%	38.9%	39.1%	39.3%	39.6%	39.9%	40.1%	40.4%	40.7%	40.9%
PRM UCAP	18.4%	19.1%	19.8%	20.5%	20.9%	21.2%	21.8%	22.4%	22.9%	23.5%
Demand (GW)	103.9	105.6	107.3	109.0	109.7	110.4	111.8	113.1	114.4	115.7
ICAP (GW)	147.4	150.9	154.3	157.8	160.1	162.5	165.5	168.5	171.5	174.5

Table D-7: MISO Winter Planning Reserve Margin Outyear Projections

Metric	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
PRM ICAP	38.8%	39.1%	39.4%	39.7%	40.2%	40.6%	41.0%	41.3%	41.7%	42.1%
PRM UCAP	25.3%	25.7%	26.2%	26.6%	27.0%	27.4%	27.9%	28.3%	28.7%	29.2%
Demand (GW)	98.7	100.5	102.4	104.3	104.8	105.3	106.6	107.9	109.3	110.6
ICAP (GW)	144.5	149.0	153.6	158.1	159.1	160.2	163.4	166.5	169.6	172.8

Table D-8: MISO Spring Planning Reserve Margin Outyear Projections

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-26-16

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 84

MISO 2024–25 Auction Results

CORRECTIONS

Reposted 4/26/24

Slides Updated : 28, 40

Planning Resource Auction

Results for Planning Year 2024-25

April 25, 2024

MISO is projected to meet most Planning Year 2024-25 resource adequacy requirements; however, pressure persists with reduced capacity surplus across the region and a shortfall in Zone 5

- The Planning Resource Auction (PRA) clearing prices are flat across the region, except for fall and spring in Zone 5 (Missouri)
  - Zone 5 cleared at seasonal Cost of New Entry (CONE) in fall and spring due to inadequate capacity to meet its Local Clearing Requirement, driven by resource retirements and seasonal outages

All Zones (except Zone 5)	Zone 5:
• **Summer:** $30/MW-day	• **Summer:** $30/MW-day
• **Fall:** $15/MW-day	• **Fall:** $719.81/MW-day
• **Winter:** $0.75/MW-day	• **Winter:** $0.75/MW-day
• **Spring:** $34.10/MW-day	• **Spring:** $719.81/MW-day

- Capacity surplus across MISO eroded 30% in summer, primarily in the North/Central region
  - Retirements, reduced imports and higher requirements are insufficiently offset by new capacity
  - Trends are similar across other seasons except for winter which has a higher surplus
- Receding surplus, coupled with emerging risks due to fleet transition and new load additions, continue to pressure resource adequacy
- MISO's efforts under the Reliability Imperative — Reliability-Based Demand Curve, accreditation and attributes — are timely and responsive to the evolving resource adequacy risk

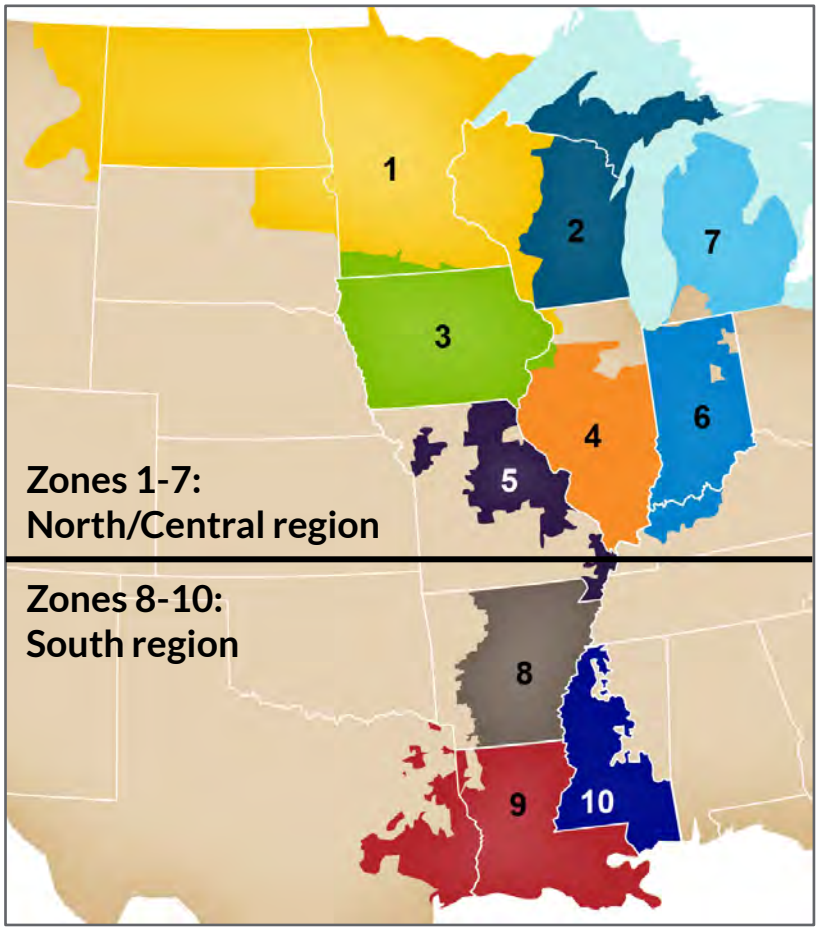
The 2024 PRA demonstrated sufficient capacity at the regional, sub-regional and zonal levels except for Zone 5

2024 PRA Results

Zone	Local Balancing Authorities	Summer	Fall	Winter	Spring
			(Price $/MW-Day)		
1	DPC, GRE, MDU, MP, NSP, OTP, SMP	30.00	15.00	0.75	34.10
2	ALTE, MGE, UPPC, WEC, WPS, MIUP	30.00	15.00	0.75	34.10
3	ALTW, MEC, MPW	30.00	15.00	0.75	34.10
4	AMIL, CWLP, SIPC, GLH	30.00	15.00	0.75	34.10
5	AMMO, CWLD	30.00	719.81	0.75	719.81
6	BREC, CIN, HE, IPL, NIPS, SIGE	30.00	15.00	0.75	34.10
7	CONS, DECO	30.00	15.00	0.75	34.10
8	EAI	30.00	15.00	0.75	34.10
9	CLEC, EES, LAFA, LAGN, LEPA	30.00	15.00	0.75	34.10
10	EMBA, SME	30.00	15.00	0.75	34.10
ERZ	KCPL, OPPD, WAUE (SPP), PJM, OVEC, LGEE, AECI, SPA, TVA	30.00	15.00	0.75	34.10

Highlighted values are CONE pricing

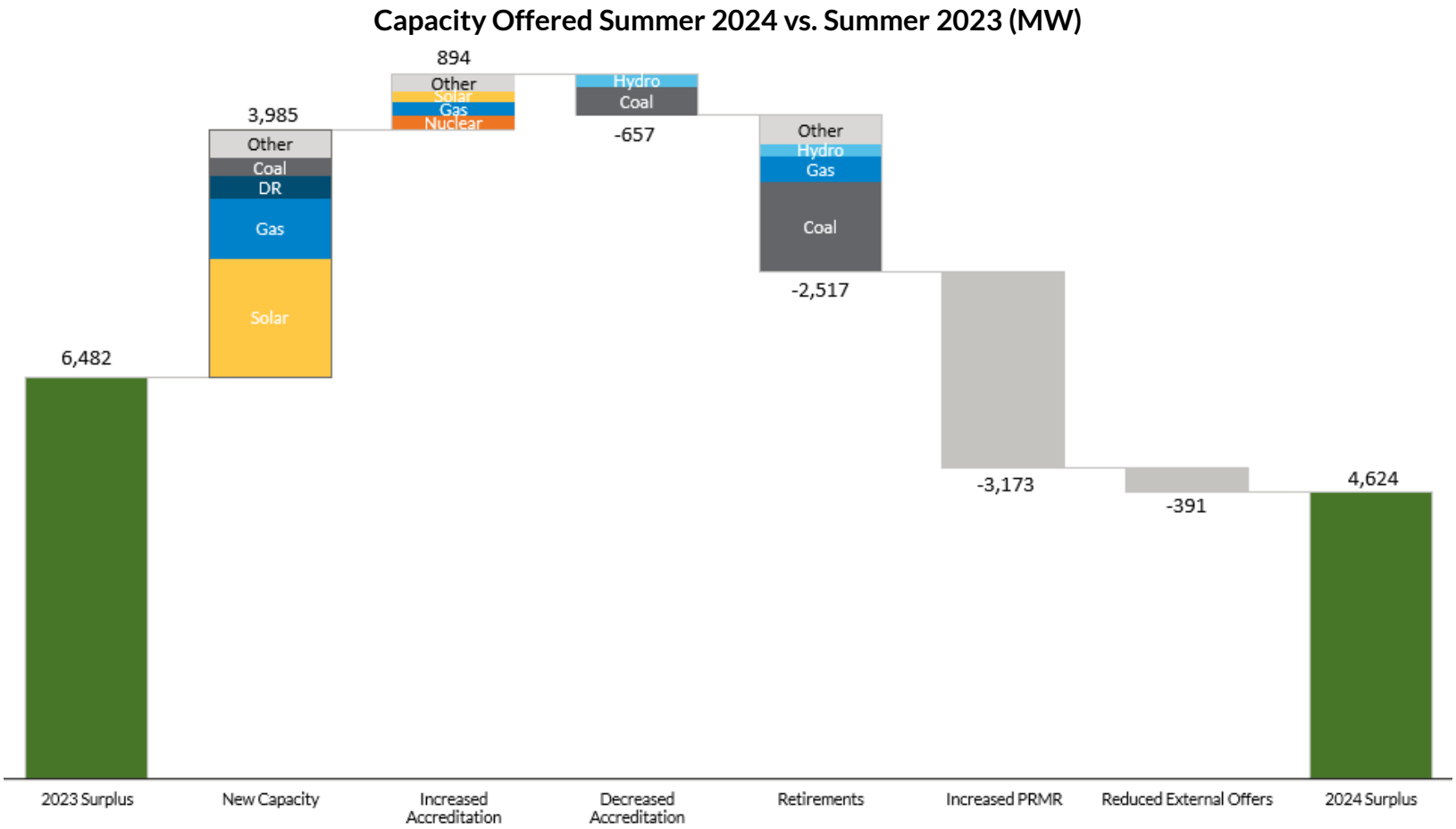
MISO Resource Adequacy Zones



ERZ: External Resource Zones

The MISO footprint showed approximately a 30% decrease in surplus but remained adequate

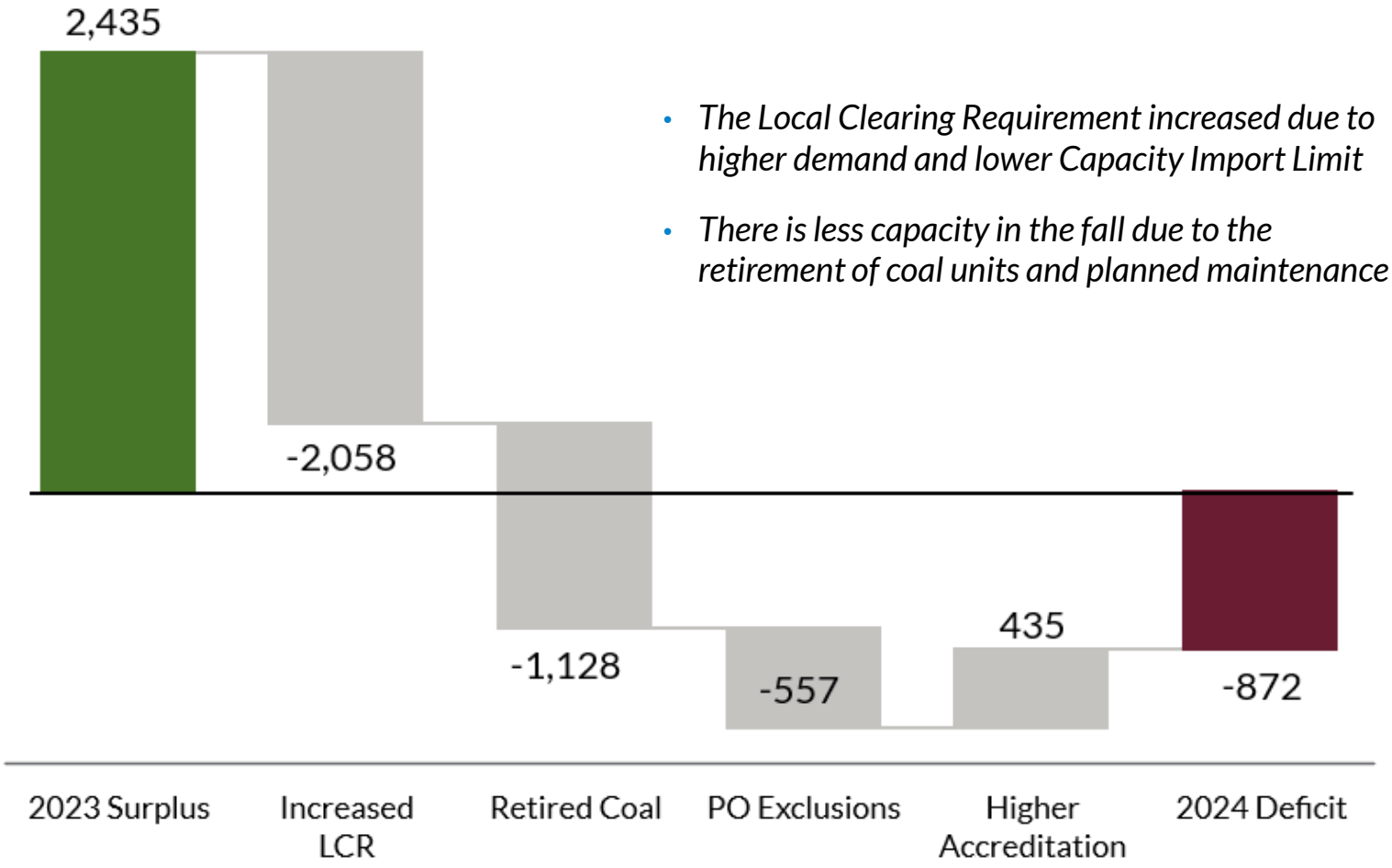
Reduced surplus driven by retirements, increased PRMR and reduced external offers



DR: Demand Response *Capacity indicated is offered accredited value*

A combination of higher Local Clearing Requirement and reduced capacity contributed to Zone 5 deficiency in the fall

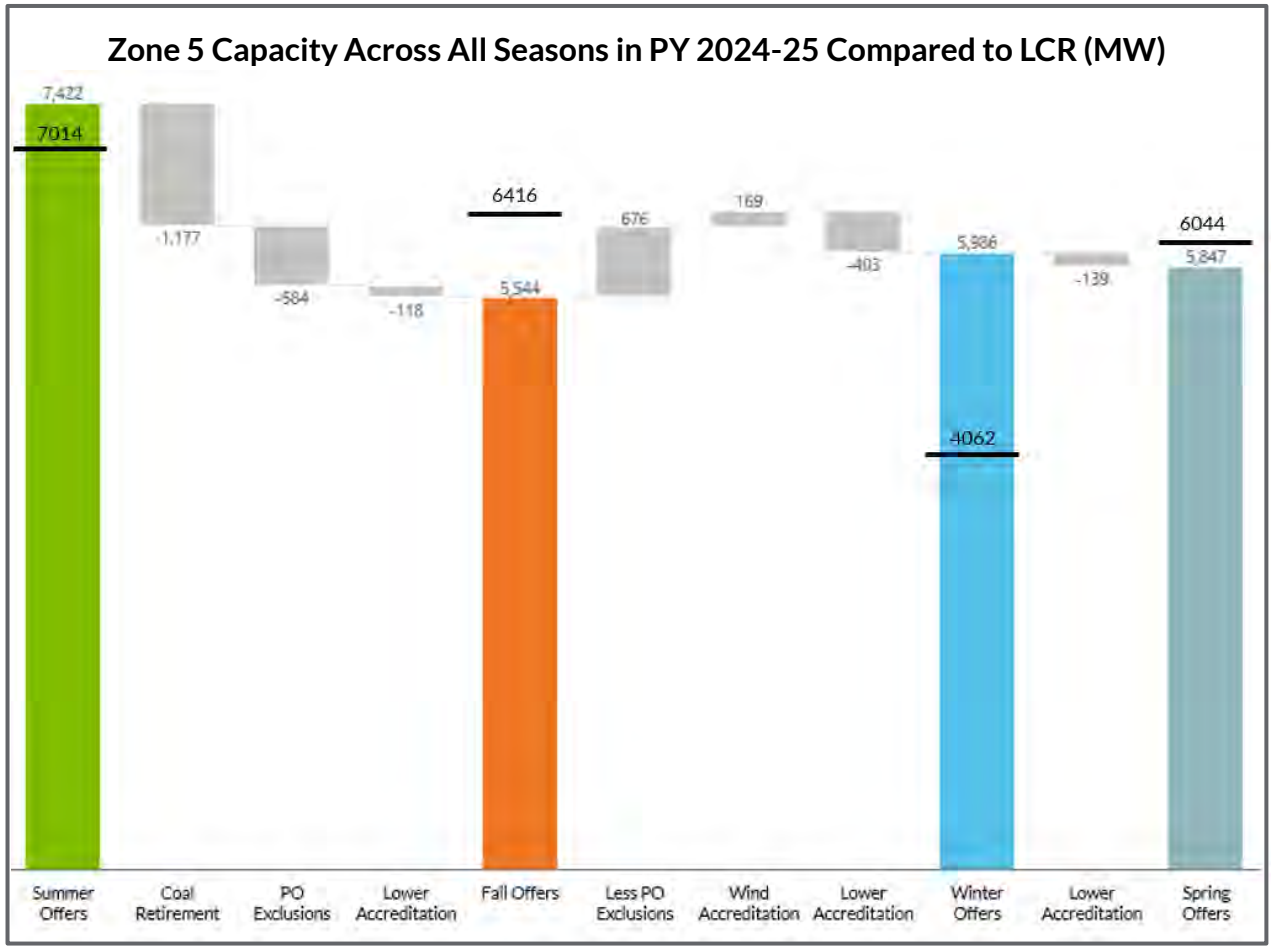
Zone 5 Fall 2024 Capacity Changes Year-Over-Year (MW)



- *The Local Clearing Requirement increased due to higher demand and lower Capacity Import Limit*
- *There is less capacity in the fall due to the retirement of coal units and planned maintenance*

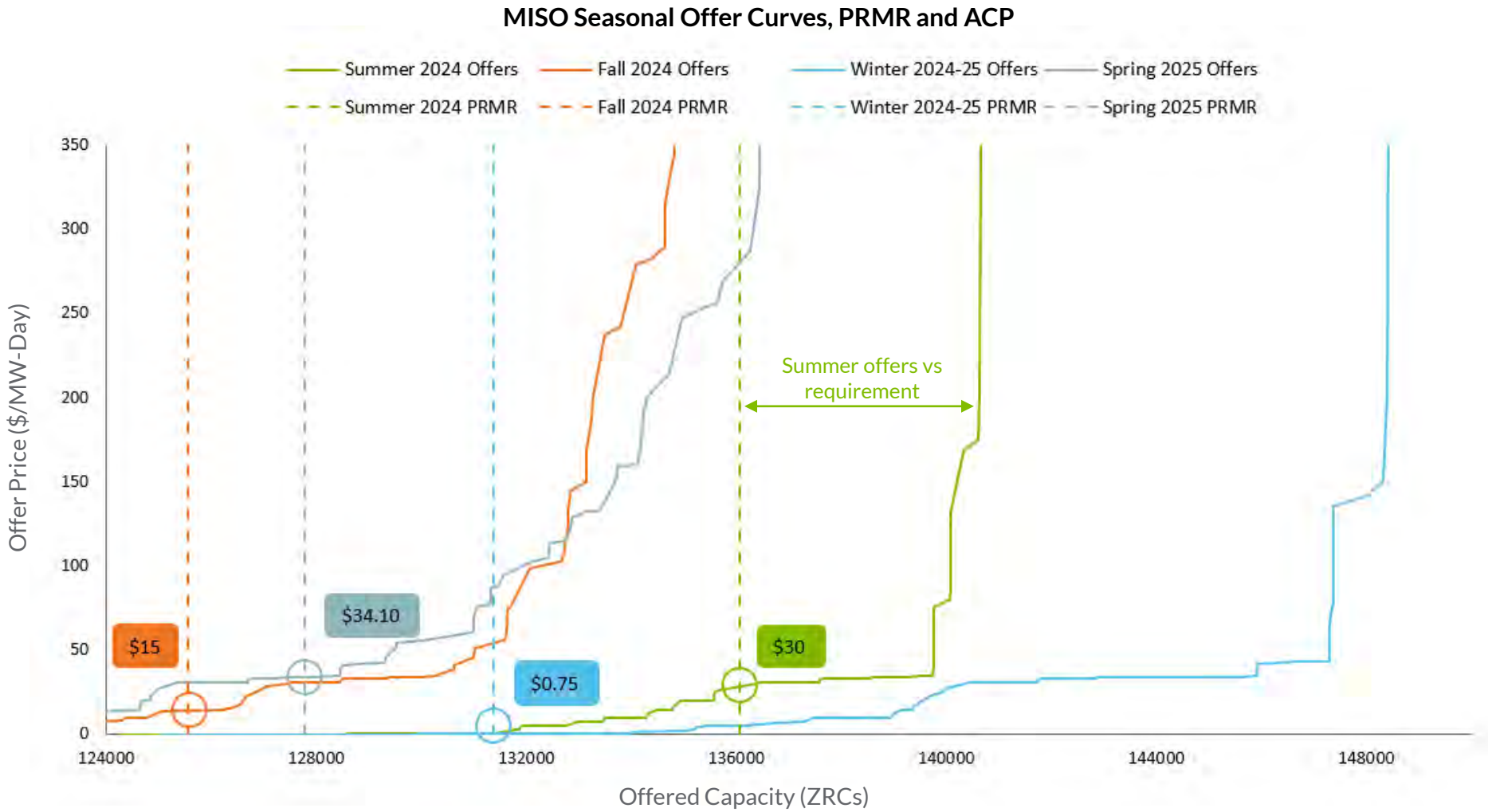
PO: Planned Outage

Seasonal variation in requirements and available capacity help explain the resource adequacy position in Zone 5



- Large coal retirements contribute to capacity deficiency; planned outages increase the gap in fall
- Lower Local Clearing Requirement in winter aids winter sufficiency
- Winter Local Clearing Requirement driven by relatively lower demand, Local Reliability Requirement and a higher import limit

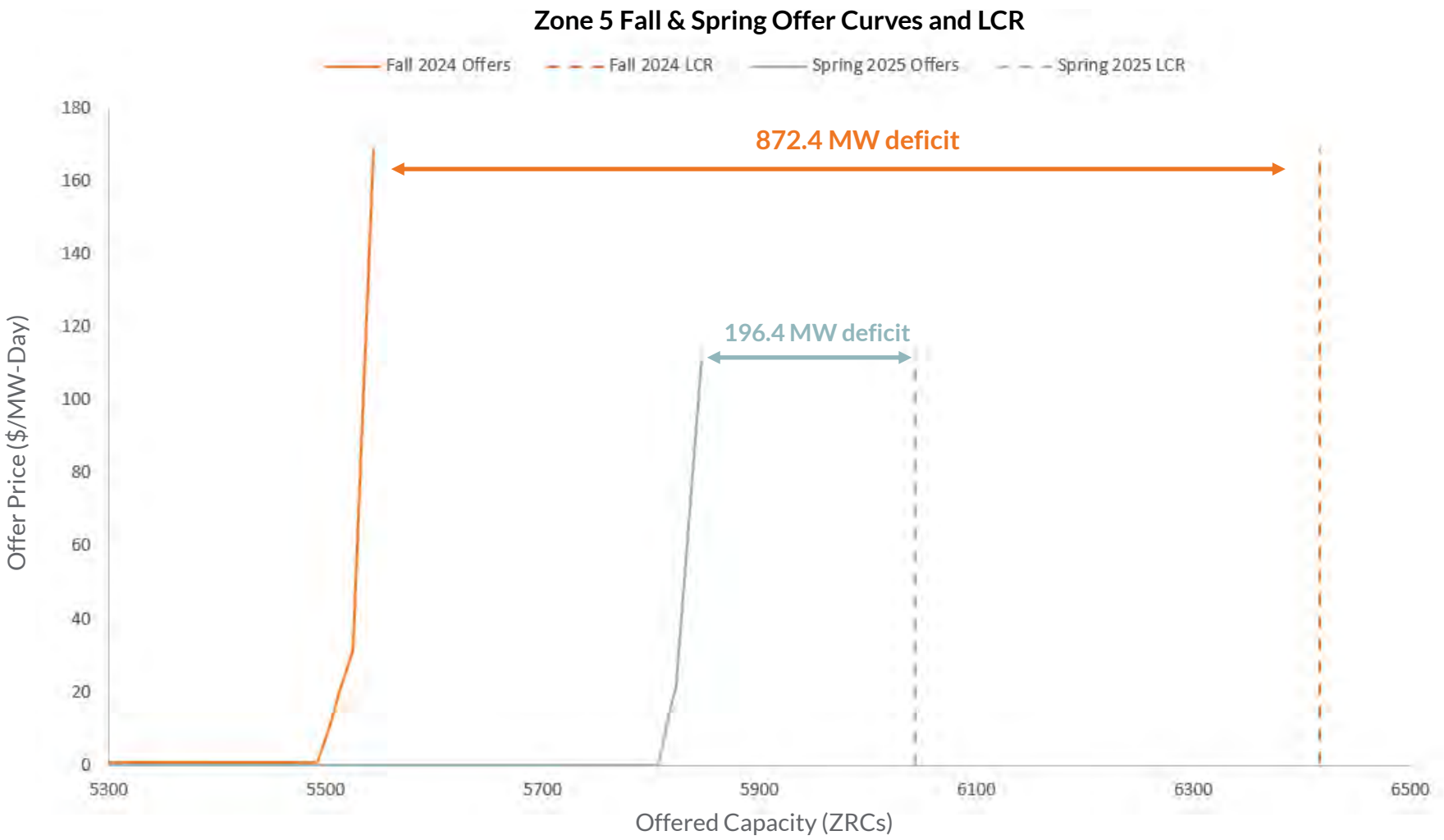
Adequate supply resulted in level auction clearing prices in each season across MISO, except for Zone 5



Y-axis truncated to provide a zoomed-in view.

PRMR: Planning Reserve Margin Requirement

Zone 5 did not have adequate capacity to meet Local Clearing Requirement in fall and spring, driving prices to seasonal CONE



Decreasing capacity surplus and the zonal deficiency, coupled with emerging risks due to fleet transition and new load additions, reinforce the urgency for ongoing reforms

Reforms under the Reliability Imperative are timely and responsive to the drivers contributing to resource adequacy challenges

DRIVERS

- Premature retirement of dispatchable resources
- Slow pace of resource additions
- Loss of accredited capacity & reliability attributes
- New load additions

MISO RESPONSE

Implemented
- Seasonal construct & thermal accreditation: implemented PY 2023-24

Filed
- Reliability-based demand curve: implementation PY 2025-26
- Resource accreditation: implementation PY 2028-29

Ongoing
- Load modifying resources accreditation: Target PY 2028-29
- Attributes roadmap and associated reforms

Next Steps

- **May 22**
  - Zonal deliverability benefits available at the May RASC
  - MISO publishes cleared Load Modifying Resources to Operations tools
- **May 24**
  - Posting of PRA masked offer data per Module E 69 A.7.4
- **June 1**
  - New Planning Year starts

Appendix

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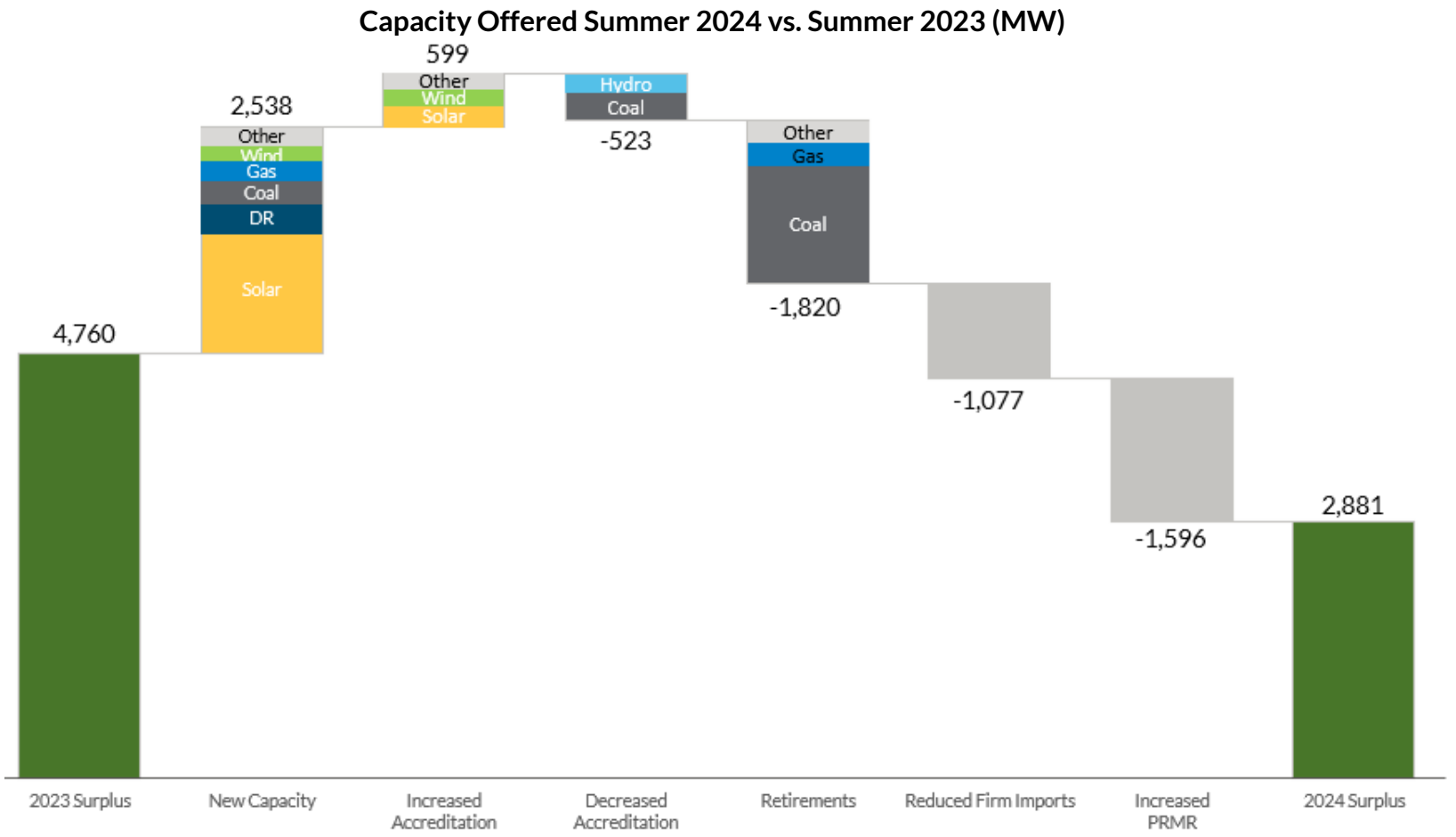
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Acronyms

ACP: Auction Clearing Price
ARC: Aggregator of Retail Customers
BTMG: Behind the Meter Generator
CIL: Capacity Import Limit
CEL: Capacity Export Limit
CONE: Cost of New Entry
DR: Demand Resource
ELCC: Effective Load Carrying Capability
EE: Energy Efficiency
ER: External Resource
ERZ: External Resource Zones
FRAP: Fixed Resource Adequacy Plan
ICAP: Installed Capacity
IMM: Independent Market Monitor
LCR: Local Clearing Requirement
LMR: Load Modifying Resource
LRR: Local Reliability Requirement
LRZ: Local Resource Zone
LSE: Load Serving Entity
PO: Planned Outage
PRA: Planning Resource Auction
PRM: Planning Reserve Margin
PRMR: Planning Reserve Margin Requirement
RASC: Resource Adequacy Sub-Committee
SAC: Seasonal Accredited Capacity
SS: Self Schedule
UCAP: Unforced Capacity
ZIA: Zonal Import Ability
ZRC: Zonal Resource Credit

The North/Central region showed a 40% decrease in surplus but remained adequate

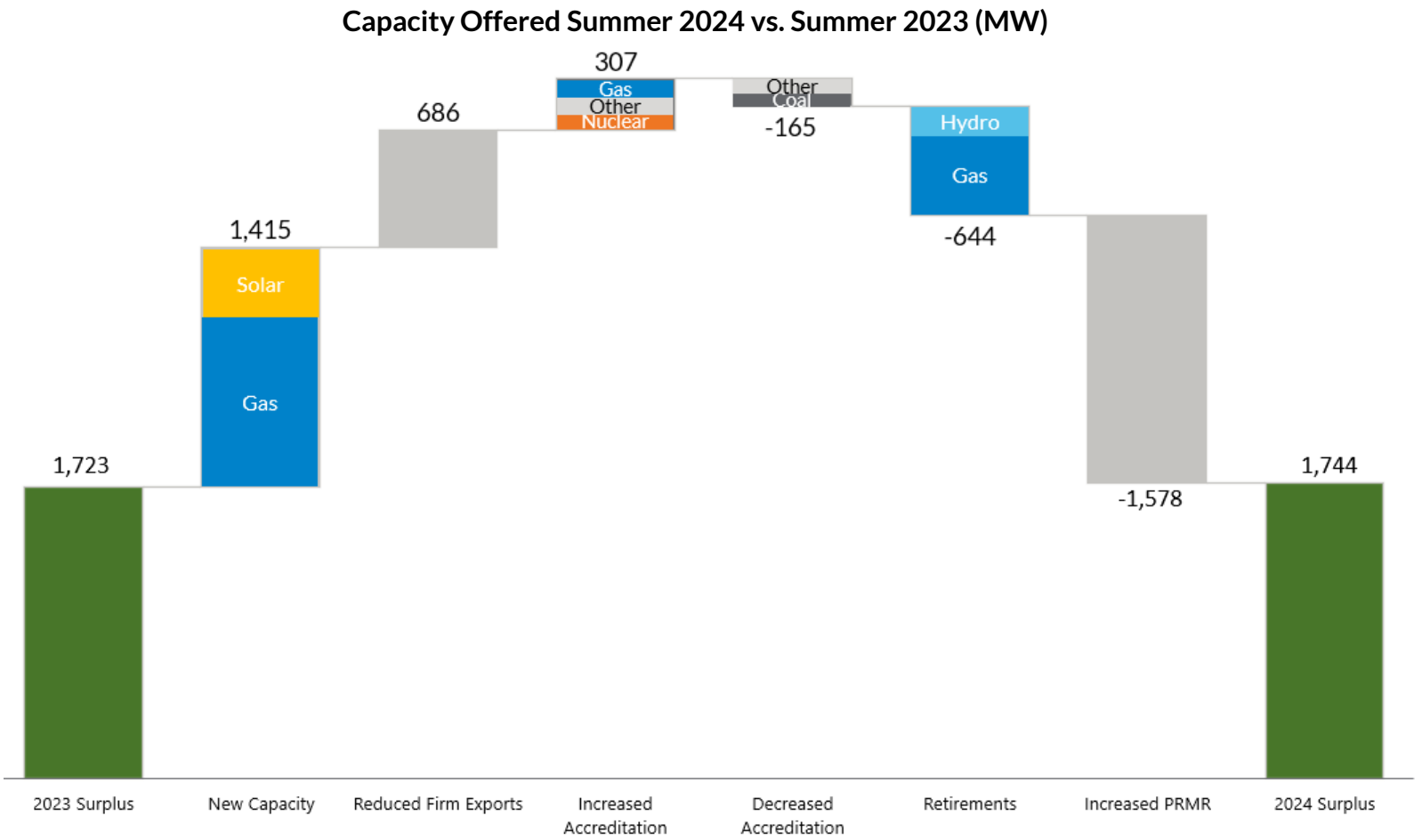
Reduced surplus driven by retirements, less imports and higher Planning Reserve Margin Requirement (PRMR)



DR: Demand Response *Capacity indicated is offered accredited value*

The South region continues to remain adequate with a comparable surplus to 2023

New generation and lower exports made up for the retirements and increased PRMR



Capacity indicated is offered accredited value

Summer 2024 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	System
PRMR	18,697	13,396	10,787	9,403	8,297	18,565	21,565	8,431	21,888	5,038	N/A	136,067
Offer Submitted (Including FRAP)	20,746	14,820	11,215	8,826	7,422	15,738	21,914	10,727	21,542	5,681	2,058	140,689
FRAP	13,961	11,216	4,248	636	0	1,109	1,352	349	166	1,616	201	34,852
Self Scheduled (SS)	4,754	3,150	6,618	5,185	7,414	9,152	20,283	9,614	18,172	3,368	1,698	89,408
Non-SS Offer Cleared	376	454	342	2,543	8	4,964	36	663	1,887	372	159	11,804
Committed (Offer Cleared + FRAP)	19,091	14,820	11,208	8,364	7,422	15,224	21,671	10,625	20,225	5,356	2,058	136,064
LCR	13,591	9,354	7,662	452	7,014	12,788	19,271	7,523	18,380	3,652	-	N/A
CIL	6,462	4,506	4,969	10,749	3,208	7,481	4,500	3,608	5,305	3,564	-	N/A
ZIA	6,460	4,506	4,911	9,857	3,208	7,197	4,490	3,444	4,794	3,564	-	N/A
Import	0	0	0	1,039	875	3,340	0	0	1,663	0	-	6,917
CEL	4,357	3,971	5,490	2,771	4,644	5,619	5,709	6,099	3,025	1,840	-	N/A
Export	394	1,424	421	0	0	0	107	2,195	0	318	2,058	6,917
ACP ($/MW-Day)	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	N/A

Values displayed in MW SAC

Fall 2024 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	System
PRMR	16,254	12,001	9,944	8,715	7,970	17,770	19,893	7,602	20,653	4,750	N/A	125,552
Offer Submitted (Including FRAP)	19,802	14,551	10,818	8,437	5,544	15,443	21,019	10,293	20,808	5,773	2,392	134,879
FRAP	11,904	10,092	3,411	547	0	918	1,240	340	151	1,531	208	30,341
Self Scheduled (SS)	4,670	2,590	6,095	6,109	5,492	7,625	19,165	8,990	17,167	3,444	1,677	83,023
Non-SS Offer Cleared	820	187	1,195	1,606	52	5,108	286	300	1,795	707	132	12,188
Committed (Offer Cleared + FRAP)	17,394	12,870	10,701	8,262	5,544	13,651	20,691	9,629	19,112	5,681	2,016	125,551
LCR	12,337	7,152	5,281	3,674	6,416	10,750	19,443	5,499	16,631	2,482	-	N/A
CIL	6,502	5,719	6,746	6,594	3,786	8,959	4,400	5,137	6,109	4,736	-	N/A
ZIA	6,500	5,719	6,684	5,699	3,786	8,661	4,390	4,942	5,608	4,736	-	N/A
Import	0	0	0	453	2,426	4,119	0	0	1,541	0	-	8,539
CEL	5,711	4,512	6,956	3,906	5,402	3,514	5,381	4,115	2,803	2,889	-	N/A
Export	1,140	868	757	0	0	0	799	2,027	0	931	2,016	8,539
ACP ($/MW-Day)	15.00	15.00	15.00	15.00	719.81	15.00	15.00	15.00	15.00	15.00	15.00	N/A

Values displayed in MW SAC

Winter 2024/2025 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	System
PRMR	18,528	11,704	10,628	9,300	8,375	19,180	17,366	8,977	22,194	5,127	N/A	131,377
Offer Submitted (Including FRAP)	23,738	14,545	15,243	8,097	5,986	15,888	23,032	10,121	22,877	6,338	2,575	148,438
FRAP	12,907	9,576	4,630	667	0	975	1,161	357	152	1,987	178	32,591
Self Scheduled (SS)	6,780	3,119	7,726	5,690	5,963	9,163	19,620	9,754	18,763	3,903	1,978	92,459
Non-SS Offer Cleared	0	0	484	1,563	0	2,341	55	1	1,866	7	10	6,327
Committed (Offer Cleared + FRAP)	19,687	12,695	12,840	7,920	5,963	12,479	20,836	10,112	20,782	5,897	2,167	131,377
LCR	16,972	7,189	10,804	3,133	4,062	10,219	17,597	7,379	18,888	4,809	-	N/A
CIL	4,693	5,523	5,668	6,707	4,477	8,532	4,656	4,364	5,200	3,219	-	N/A
ZIA	4,691	5,523	5,600	5,811	4,477	8,286	4,656	4,262	4,623	3,219	-	N/A
Import	0	0	0	1,380	2,412	6,701	0	0	1,412	0	-	11,905
CEL	5,174	4,772	9,011	4,674	6,229	1,401	5,753	5,780	2,323	2,993	-	N/A
Export	1,159	992	2,212	0	0	0	3,471	1,135	0	770	2,167	11,905
ACP ($/MW-Day)	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	N/A

Values displayed in MW SAC

Spring 2025 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	System
PRMR	17,217	12,183	9,992	7,981	7,711	17,847	19,670	7,891	22,066	5,234	N/A	127,792
Offer Submitted (Including FRAP)	19,201	14,896	10,946	8,654	5,847	15,173	21,218	11,029	21,026	6,144	2,480	136,615
FRAP	12,319	9,949	3,950	638	0	1,039	1,256	329	152	1,559	197	31,387
Self Scheduled (SS)	4,226	3,458	6,220	5,790	5,806	7,979	18,316	9,504	15,711	3,387	1,823	82,219
Non-SS Offer Cleared	783	801	166	1,751	41	5,374	390	687	2,959	849	385	14,185
Committed (Offer Cleared + FRAP)	17,328	14,208	10,335	8,178	5,847	14,393	19,961	10,520	18,822	5,794	2,404	127,791
LCR	13,945	8,370	5,781	4,560	6,044	11,386	16,372	4,413	18,684	3,558	-	N/A
CIL	4,943	5,034	6,572	6,982	3,892	8,045	4,883	6,195	6,113	4,628	-	N/A
ZIA	4,941	5,034	6,514	5,083	3,892	7,730	4,883	6,030	5,598	4,628	-	N/A
Import	0	0	0	0	1,864	3,454	0	0	3,244	0	-	8,562
CEL	6,318	4,601	5,815	5,102	4,984	3,414	5,601	4,865	4,298	2,740	-	N/A
Export	111	2,025	344	197	0	0	291	2,629	0	561	2,404	8,562
ACP ($/MW-Day)	34.10	34.10	34.10	34.10	719.81	34.10	34.10	34.10	34.10	34.10	34.10	N/A

Values displayed in MW SAC

Summer Supply Offered and Cleared Comparison Trend

	Offered (ZRC)			Cleared (ZRC)		
Planning Resource	2022-23	Summer 2023	Summer 2024	2022-23	Summer 2023	Summer 2024
Generation	121,506.5	122,375.6	123,395.6	118,745.0	116,989.7	119,479.2
External Resources	3,563.9	4,514.6	4,430.4	3,563.9	4,072.5	4,309.8
Behind the Meter Generation	4,169.3	4,175.2	4,180.2	4,169.3	4,129.4	4,143.5
Demand Resources	7,574.9	8,303.5	8,660.2	7,525.0	7,694.6	8,109.4
Energy Efficiency	0.0	5.0	22.5	0.0	5.0	22.5
Total	**136,814.6**	**139,373.9**	**140,688.9**	**134,003.2**	**132,891.2**	**136,064.4**

Fall Supply Offered and Cleared Comparison Trend

	Offered (ZRC)		Cleared (ZRC)	
Planning Resource	Fall 2023	Fall 2024	Fall 2023	Fall 2024
Generation	121,403.5	119,745.3	111,713.8	111,791.5
External Resources	4,095.4	4,366.8	3,979.6	3,990.2
Behind the Meter Generation	3,874.2	3,877.9	3,842.8	3,789.7
Demand Resources	6,999.2	6,866.1	6,254.4	5,957.5
Energy Efficiency	4.9	22.5	4.8	22.5
Total	**136,377.2**	**134,878.6**	**125,795.4**	**125,551.4**

Winter Supply Offered and Cleared Comparison Trend

	Offered (ZRC)		Cleared (ZRC)	
Planning Resource	Winter 2023-2024	Winter 2024-2025	Winter 2023-2024	Winter 2024-2025
Generation	124,632.7	133,457.4	114,886.6	118,253.8
External Resources	3,937.1	3,973.0	3,334.6	3,313.3
Behind the Meter Generation	3,257.8	3,111.5	3,173.9	2,957.3
Demand Resources	7,644.4	7,866.4	6,702.4	6,822.7
Energy Efficiency	6.7	29.7	6.7	29.7
Total	**139,478.7**	**148,438.0**	**128,104.2**	**131,376.8**

Spring Supply Offered and Cleared Comparison Trend

	Offered (ZRC)		Cleared (ZRC)	
Planning Resource	Spring 2024	Spring 2025	Spring 2024	Spring 2025
Generation	119,254.7	121,303.8	110,195.8	113,091.4
External Resources	3,794.1	3,481.8	3,409.1	3,406.5
Behind the Meter Generation	4,096.4	4,201.6	4,058.9	4,180.5
Demand Resources	7,282.9	7602.9	6,720.0	7,087.2
Energy Efficiency	5.3	25.0	5.3	25.0
Total	**134,433.4**	**136,615.1**	**124,389.1**	**127,790.6**

Zone 5 Supply Offered and Cleared Comparison Trend

	Offered (ZRC)				Cleared (ZRC)			
Planning Resource	Summer 2024	Fall 2024	Winter 2024-2025	Spring 2025	Summer 2024	Fall 2024	Winter 2024-2025	Spring 2025
Generation	7,139.9	5,414.3	5,864.9	5,695.9	7,139.9	5,414.3	5,850.2	5,695.9
Behind the Meter Generation	79.9	78.5	77.1	84.0	79.9	78.5	77.1	84.0
Demand Resources	202.5	51.2	43.8	67.2	202.5	51.2	35.3	67.2
Energy Efficiency	0	0	0	0	0	0	0	0
Imports (External & Imports from other zones)	874.7	2,425.8	2,411.9	1,864.1	874.7	2,425.8	2,411.9	1,864.1
Total	**8,297.0**	**7,969.8**	**8,397.7**	**7,711.2**	**8,297.0**	**7,969.8**	**8,374.5**	**7,711.2**

Historical Summer Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
2015-2016	$3.48			$150.00	$3.48			$3.29		N/A	N/A
2016-2017	$19.72	$72.00						$2.99			N/A
2017-2018	$1.50										N/A
2018-2019	$1.00	$10.00									N/A
2019-2020	$2.99						$24.30	$2.99			
2020-2021	$5.00						$257.53	$4.75	$6.88	$4.75	$4.89-$5.00
2021-2022	$5.00							$0.01			$2.78-$5.00
2022-2023	$236.66							$2.88			$2.88-236.66
Summer 2023	$10.00										
Summer 2024	$30.00										

- Auction Clearing Prices shown in $/MW-Day
- Conduct Threshold is 10% of Cost of New Entry (CONE) and applies to all seasons.

Fall Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Fall 2023	$15.00								$59.21	$15.00	
Fall 2024	$15.00				$719.81	$15.00					
IMM Conduct Threshold	34.12	33.35	32.22	33.27	36.09	32.97	34.83	31.18	30.91	30.76	36.09
Cost of New Entry (Daily)	341.21	333.51	322.19	332.70	360.89	329.70	348.32	311.81	309.05	307.57	360.89
Cost of New Entry (Annual)	124,541	121, 731	117,600	121,434	131,725	120,340	127,135	113,810	112,804	112,263	131,725

- There was price separation in the fall for Zone 5 since it did not have sufficient supply within the zone to meet its local clearing requirement
- Auction Clearing Prices shown in $/MW-Day
- Conduct Threshold is 10% of Daily Cost of New Entry (CONE) and applies to all seasons
- For Zone 5, there were 183 shortage-days (fall and spring); ACP is Annual CONE / # of shortage-days: 131,725 / 183 = $719.81

Winter Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Winter 2023-24	$2.00								$18.88	$2.00	
Winter 2024-25	$0.75										

- Auction Clearing Prices shown in $/MW-Day
- Conduct Threshold is 10% of Cost of New Entry (CONE) and applies to all seasons

Spring Auction Clearing Price Comparison

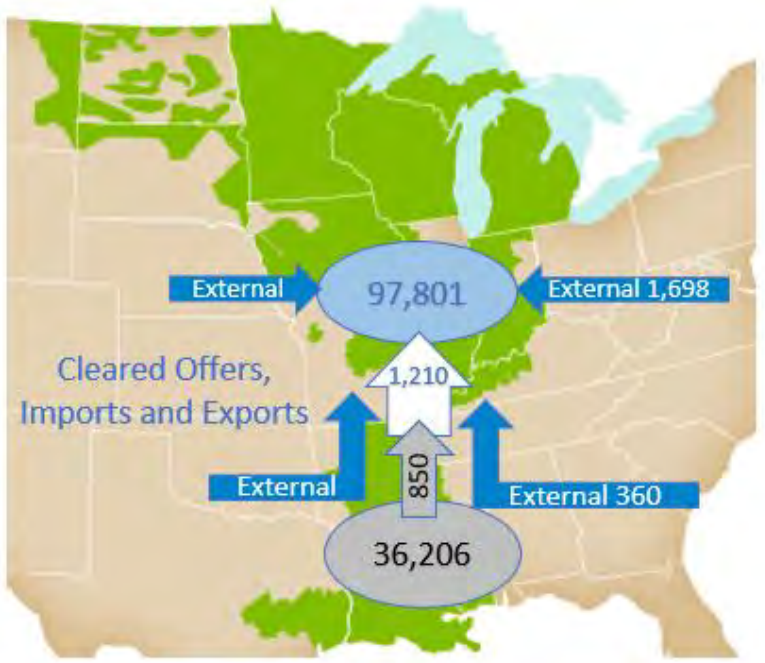
PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Spring 2024	$10.00										
Spring 2025	$34.10				$719.81	$34.10					

- There was price separation in the Spring for Zone 5 since it did not have sufficient supply within the zone to meet its local clearing requirement
- Auction Clearing Prices shown in $/MW-Day
- Conduct Threshold is 10% of Cost of New Entry (CONE) and applies to all seasons

Summer 2024
Offered Capacity & PRMR (MW)



Summer 2024
Cleared Capacity, Imports & Exports (MW)



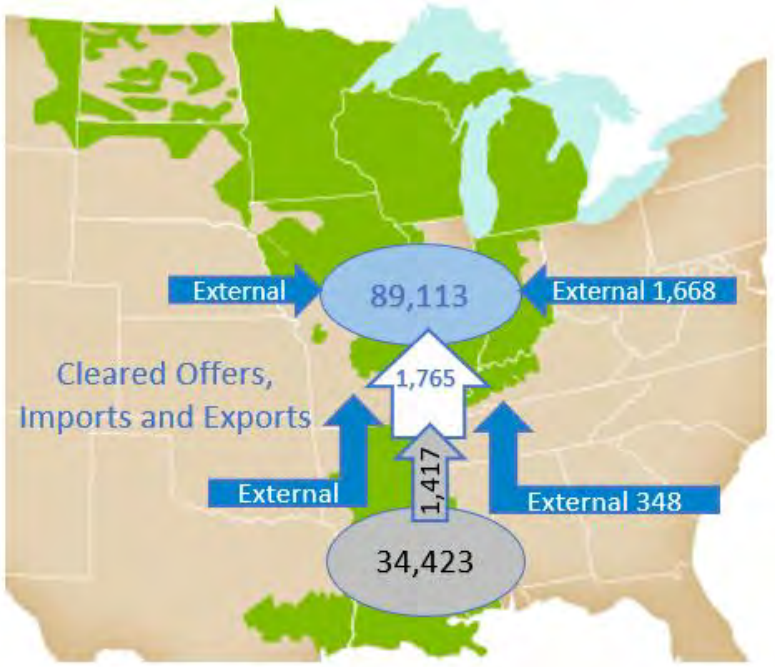
PRMR: Planning Reserve Margin Requirement
Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers

04/26/2024: MISO Planning Resource Auction (PRA) for Planning Year 2024-2025 Results Posting

Fall 2024
Offered Capacity & PRMR (MW)



Fall 2024
Cleared Capacity, Imports & Exports (MW)

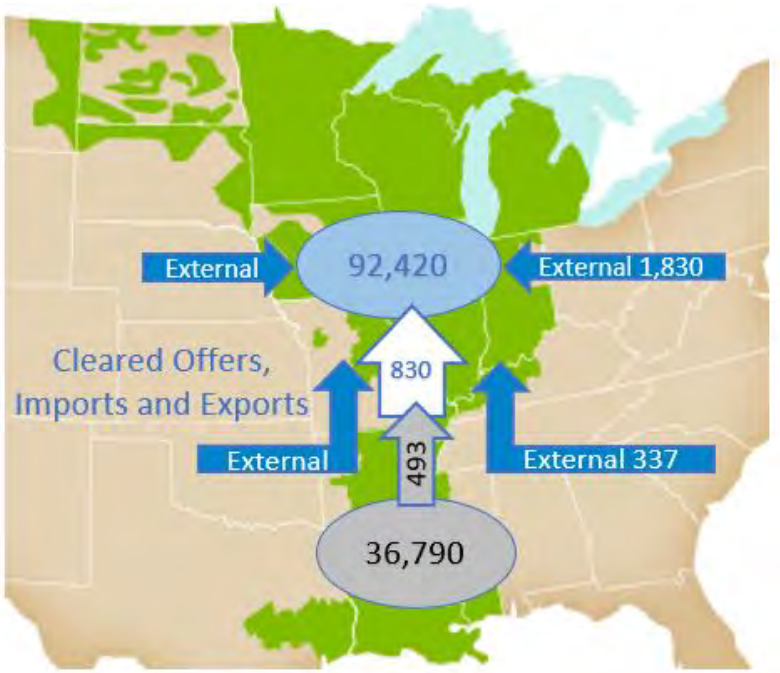


PRMR: Planning Reserve Margin Requirement
Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers
04/26/2024: MISO Planning Resource Auction (PRA) for Planning Year 2024-2025 Results Posting

Winter 2024/25
Offered Capacity & PRMR (MW)



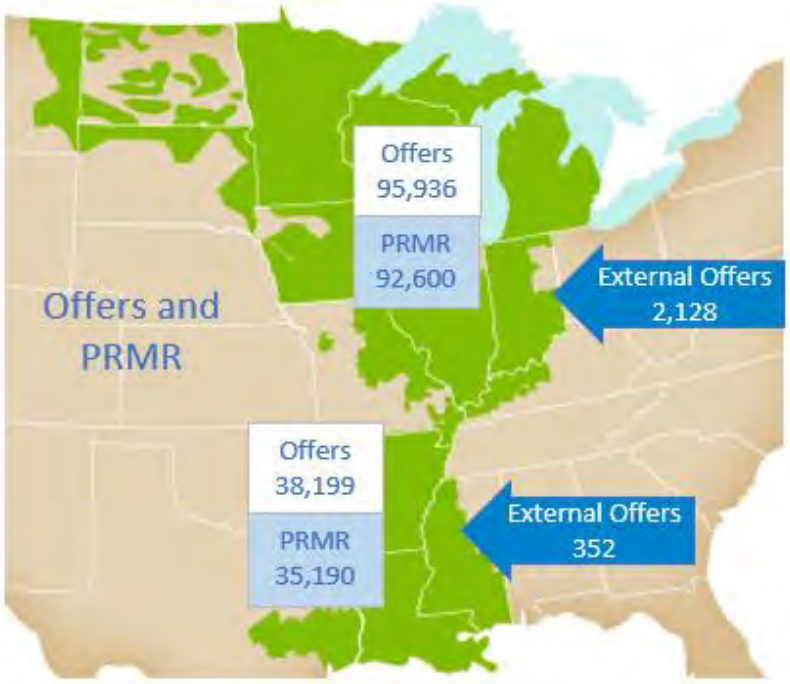
Winter 2024/25
Cleared Capacity, Imports & Exports (MW)



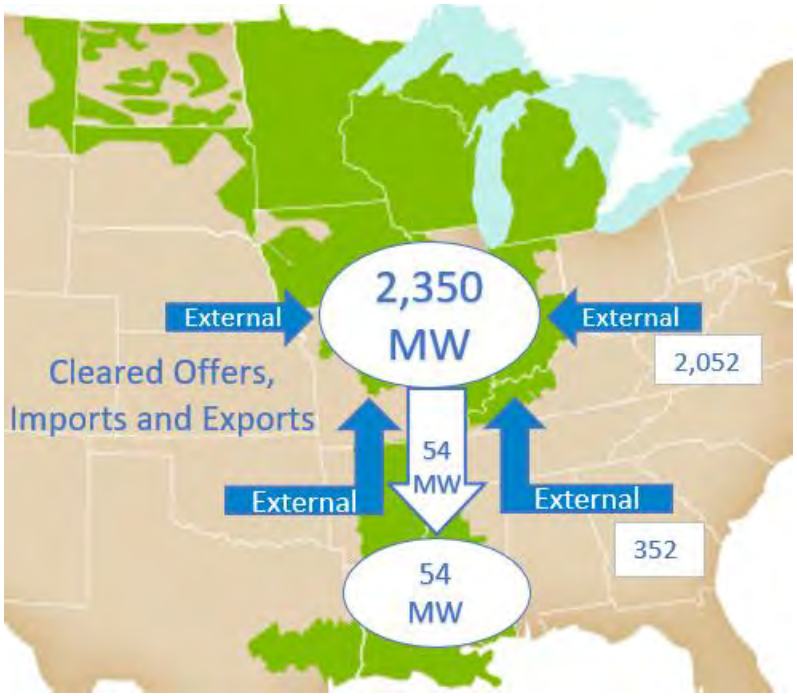
PRMR: Planning Reserve Margin Requirement
Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers

04/26/2024: MISO Planning Resource Auction (PRA) for Planning Year 2024-2025 Results Posting

Spring 2025
Offered Capacity & PRMR (MW)



Spring 2025
Cleared Capacity, Imports & Exports (MW)



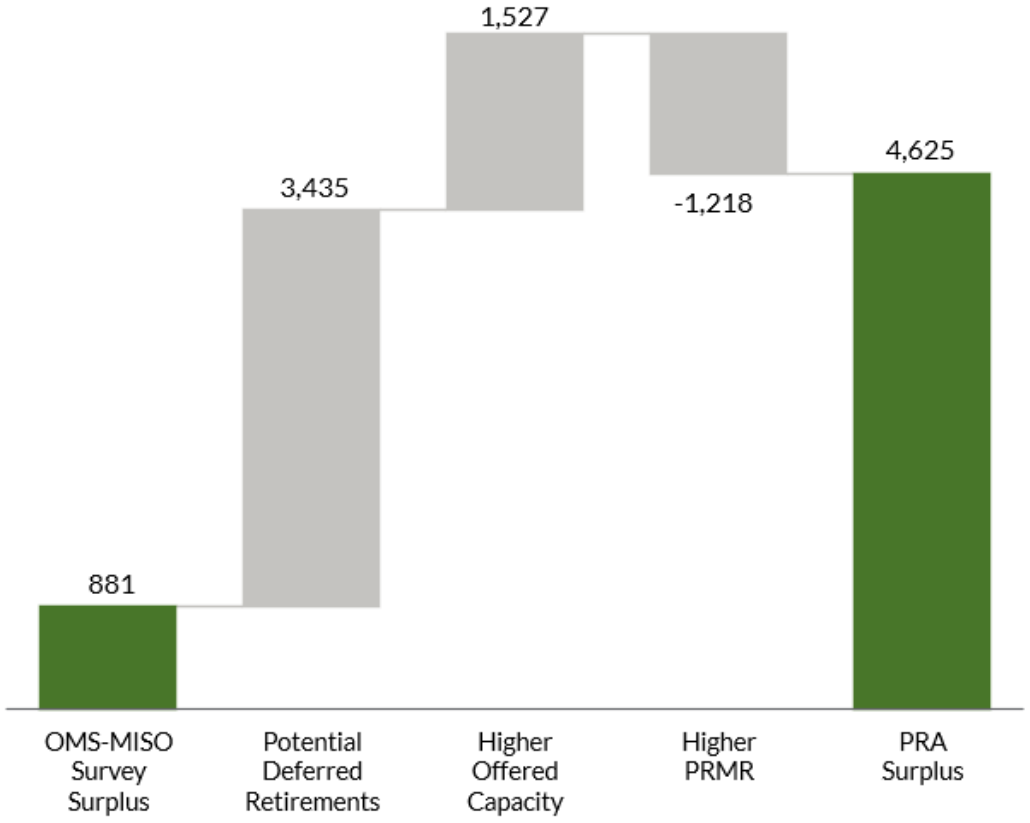
PRMR: Planning Reserve Margin Requirement
Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers

04/26/2024: MISO Planning Resource Auction (PRA) for Planning Year 2024-2025 Results Posting

2024 PRA showed a higher surplus relative to the 2023 OMS-MISO survey projection, driven primarily by deferred retirements

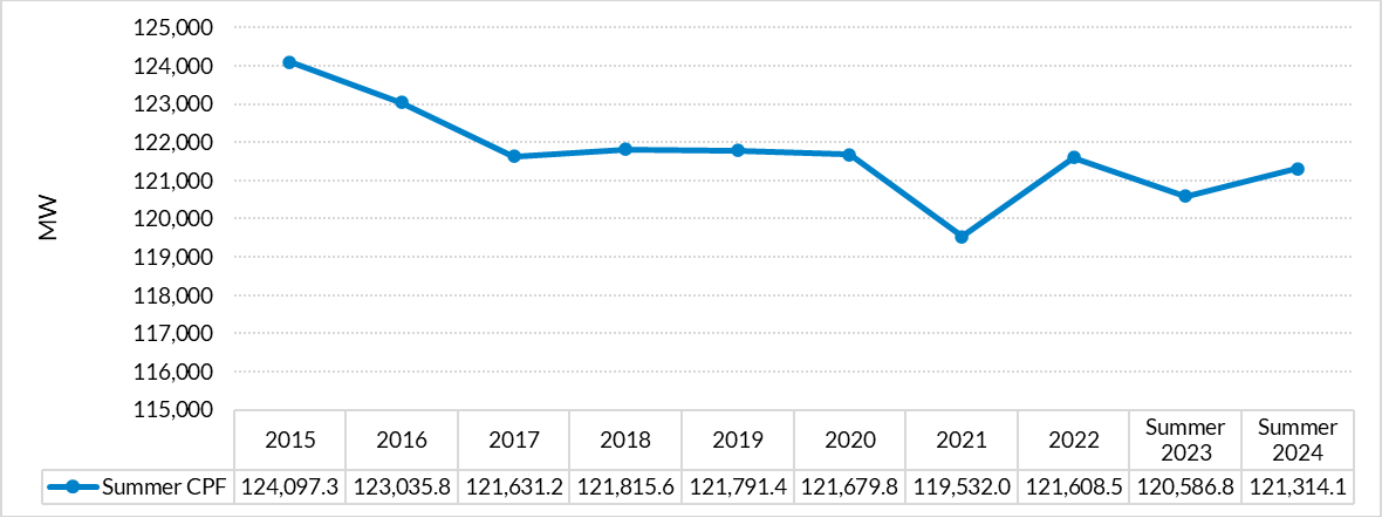
Summer 2024 PRA outcomes vs. 2023 OMS-Survey results

- 3.4 of the 3.5 GW of potential deferred retirement participated in the PRA
- Resources offered in the PRA at 1.5 GW higher than projected in the OMS-MISO Survey
- 1.2 GW higher PRMR MISO-wide because of a higher PRM % than forecasted in the 2023 survey (9% versus 7.9%)

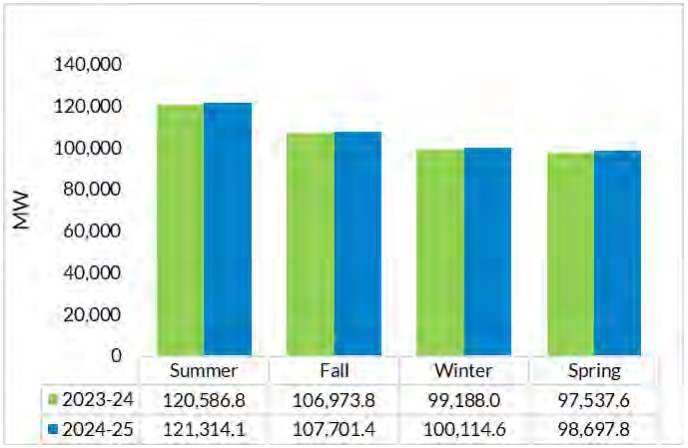


Coincident Peak Forecast

Year over year the Summer CPF (+0.7 GW), PRM (+1.6%) and PRMR (+3.2 GW) are higher.

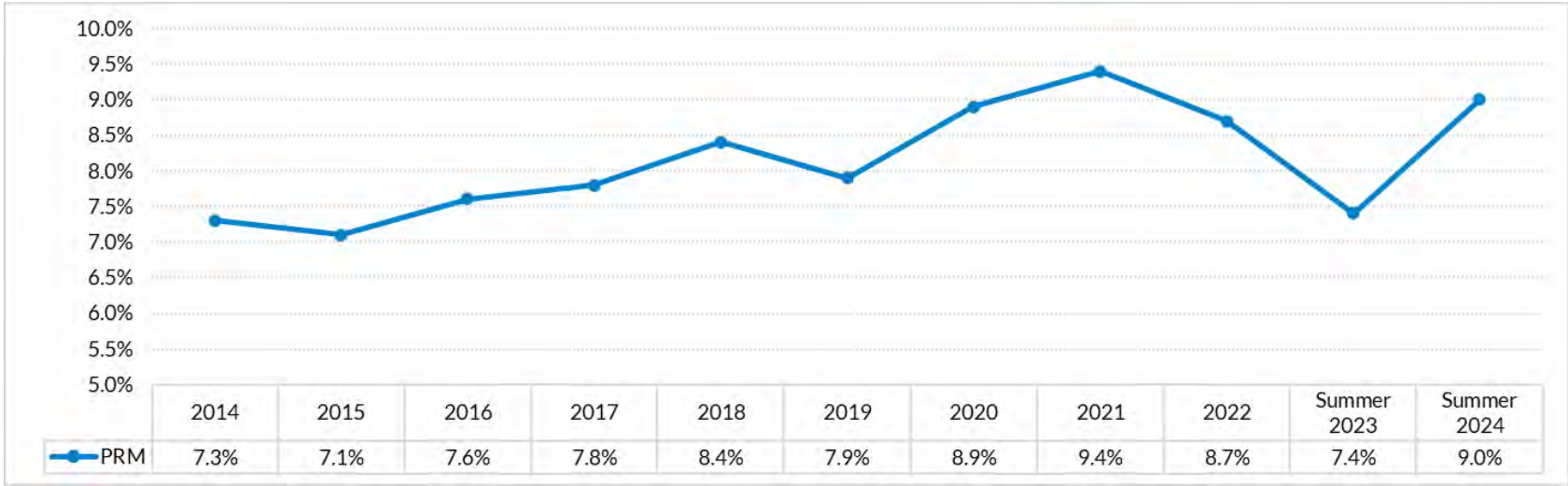


	2015	2016	2017	2018	2019	2020	2021	2022	Summer 2023	Summer 2024
Summer CPF	124,097.3	123,035.8	121,631.2	121,815.6	121,791.4	121,679.8	119,532.0	121,608.5	120,586.8	121,314.1

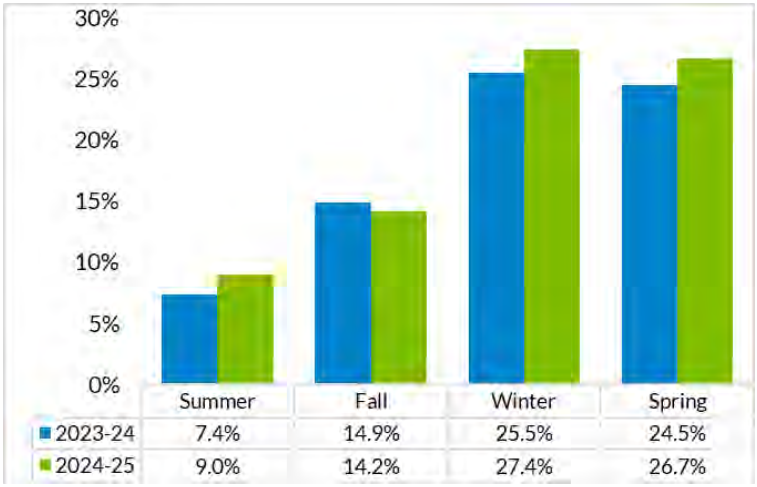


	Summer	Fall	Winter	Spring
2023-24	120,586.8	106,973.8	99,188.0	97,537.6
2024-25	121,314.1	107,701.4	100,114.6	98,697.8

Planning Reserve Margin (%)

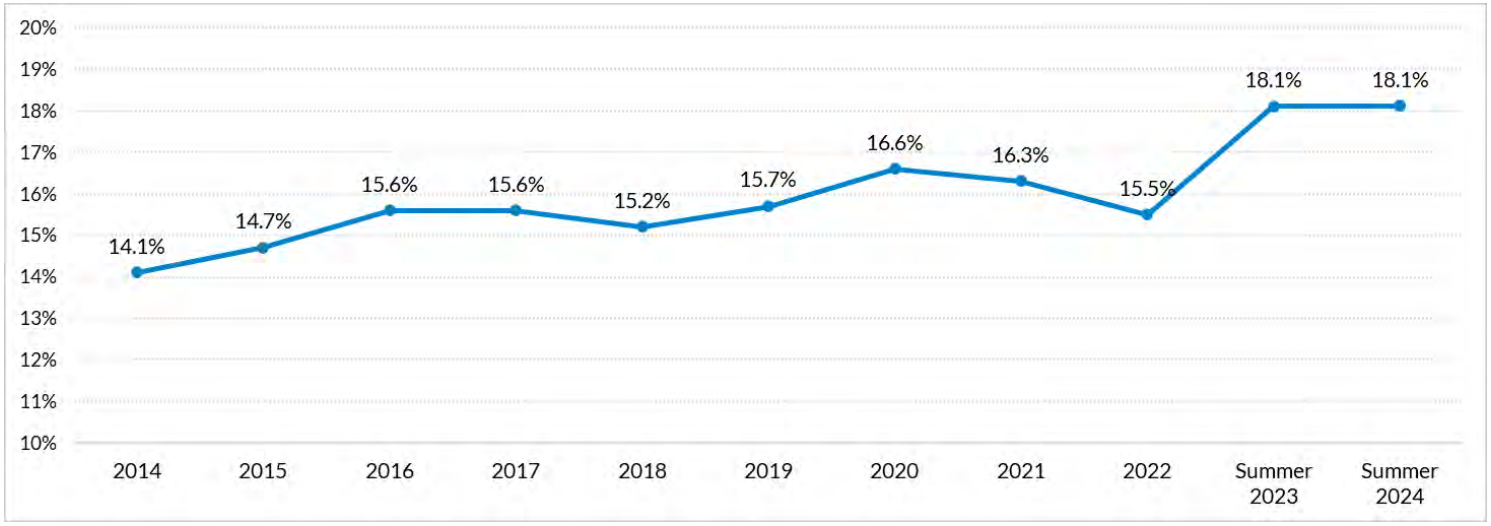


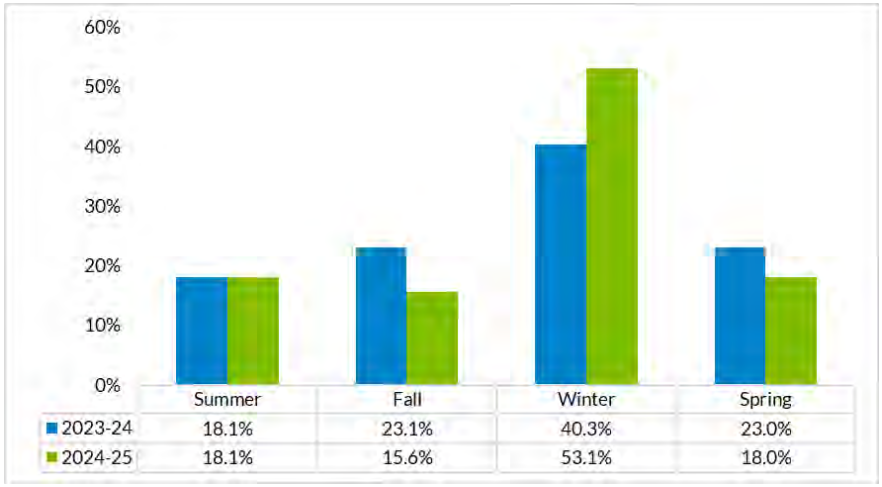
	2014	2015	2016	2017	2018	2019	2020	2021	2022	Summer 2023	Summer 2024
PRM	7.3%	7.1%	7.6%	7.8%	8.4%	7.9%	8.9%	9.4%	8.7%	7.4%	9.0%



	Summer	Fall	Winter	Spring
2023-24	7.4%	14.9%	25.5%	24.5%
2024-25	9.0%	14.2%	27.4%	26.7%

Wind Effective Load Carrying Capacity (%)



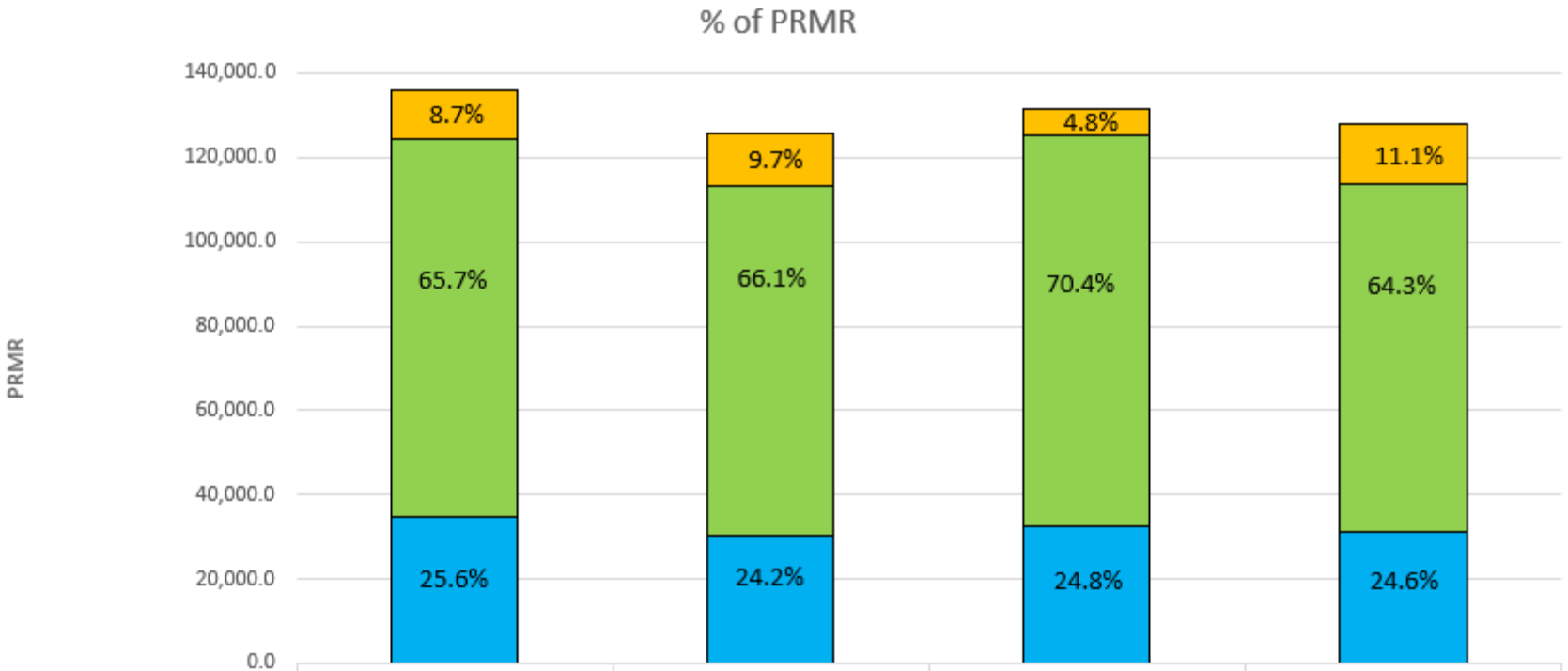


	Summer	Fall	Winter	Spring
2023-24	18.1%	23.1%	40.3%	23.0%
2024-25	18.1%	15.6%	53.1%	18.0%

- No change to wind or solar accreditation methodology from previous years.
- Methodology applied on a seasonal basis.
- Wind ELCC and new solar capacity is established in the LOLE Study
- New solar
  - summer, fall, spring 50%
  - winter 5%

ELCC: Effective Load Carrying Capability LOLE: Loss of Load Expectation

2024-2025 Seasonal Resource Adequacy Requirements are fulfilled similarly across all four seasons



	Summer 2024	Fall 2024	Winter 2024-25	Spring 2025
Cleared Non-Self Scheduled	11,800.8	12,184.1	6,323.9	14,181.5
Self Scheduled	89,408.1	83,023.4	92,459.0	82,219.3
FRAP	34,855.5	30,343.9	32,593.9	31,389.8

PRMR: Planning Reserve Margin Requirement

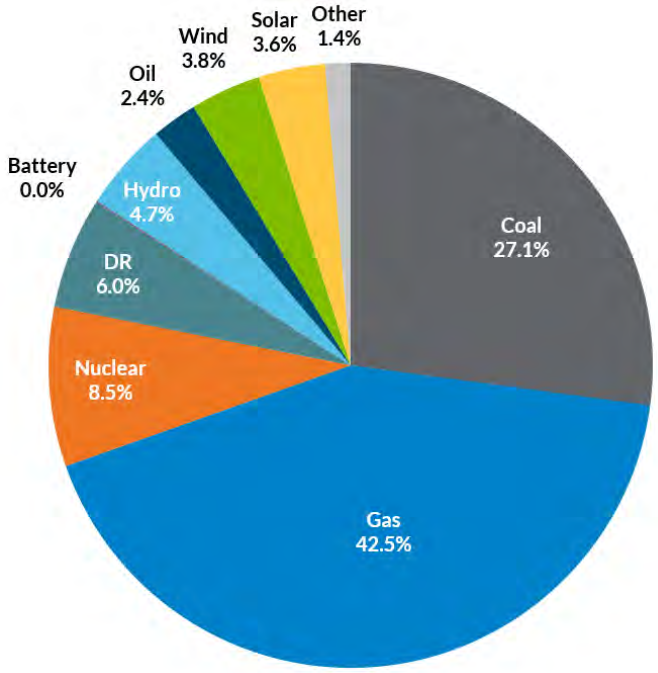
Although conventional generation still comprises most of the capacity, wind and solar continue to grow

- 4.9 GW of solar cleared this year's auction, an increase of 61% from Planning Year 2023-24 (3.0 GW)
- 5.2 GW of wind cleared this year, an increase of 4% compared to last year (5.0 GW)



Winter PRMR is 4.7 GW (3.4%) lower than the summer. There were less thermal, hydro and solar resources and significantly more wind to meet PRMR in the Winter versus the Summer

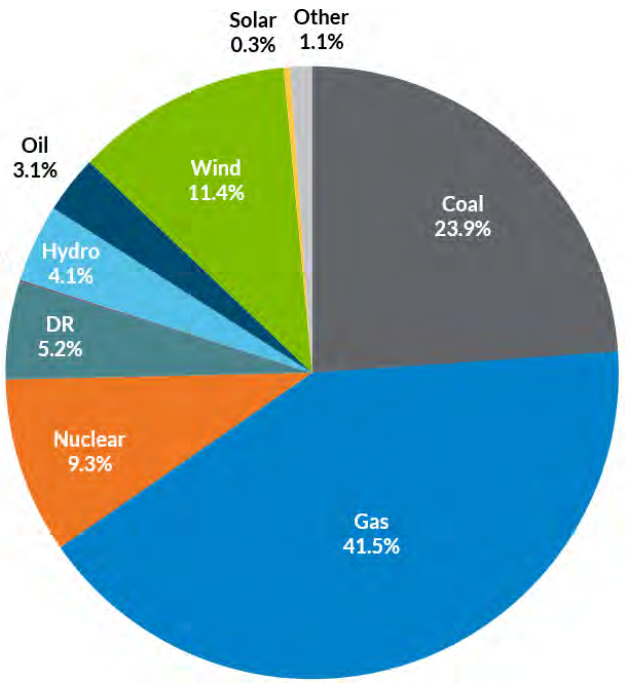
Summer 2024



MISO-wide

Cleared ZRC	Summer 2024	Winter 2024-25	Difference
Coal	36,894.8	31,391.7	5,503.1
Gas	57,799.3	54,460.7	3,338.6
Nuclear	11,594.6	12,218.0	-623.4
DR	8,109.4	6,822.7	1,286.7
Battery	59.0	59.1	-0.1
EE	22.5	29.7	-7.2
Hydro	6,427.1	5,398.9	1,028.2
Oil	3,316.6	4,010.9	-694.3
Wind	5,150.0	15,034.7	-9,884.7
Solar	4,851.7	445.0	4,406.7
Misc	1,839.4	1,505.4	334.0
PRMR	136,064.4	131,376.8	4,687.6

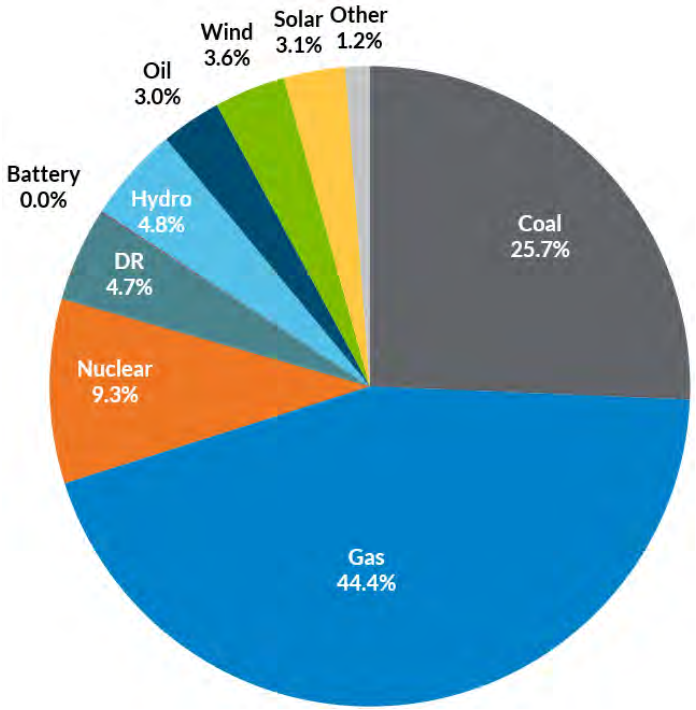
Winter 2024-25



PRMR: Planning Reserve Margin Requirement

Fall 2024 and Spring 2025 - Cleared ZRCs and PRMR

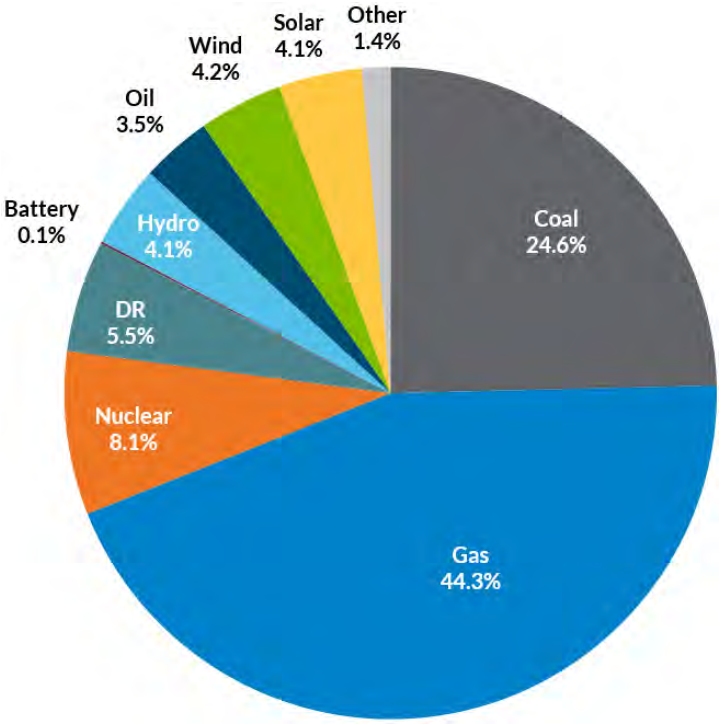
Fall 2024



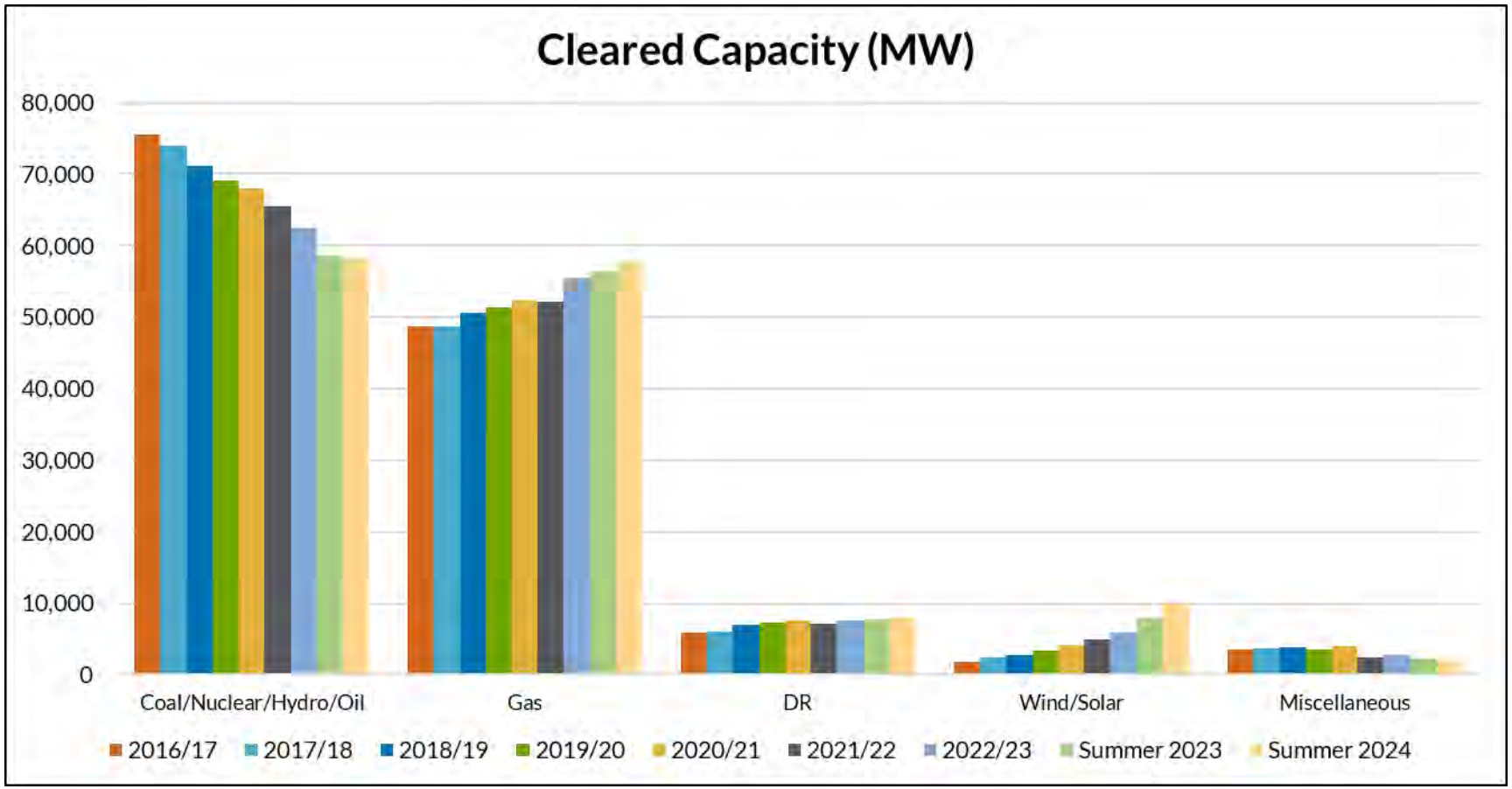
MISO-Wide

Cleared ZRC	Fall 2024	Spring 2025
Coal	32,221.7	31,469.1
Gas	55,793.3	56,667.0
Nuclear	11,682.3	10,338.7
DR	5,957.5	7,087.2
Battery	58.8	112.3
EE	22.5	25.0
Hydro	6,037.8	5,215.6
Oil	3,819.2	4,464.0
Wind	4,521.8	5,322.7
Solar	3,894.4	5,282.1
Misc	1,542.1	1,807.0
PRMR	125,551.4	127,790.6

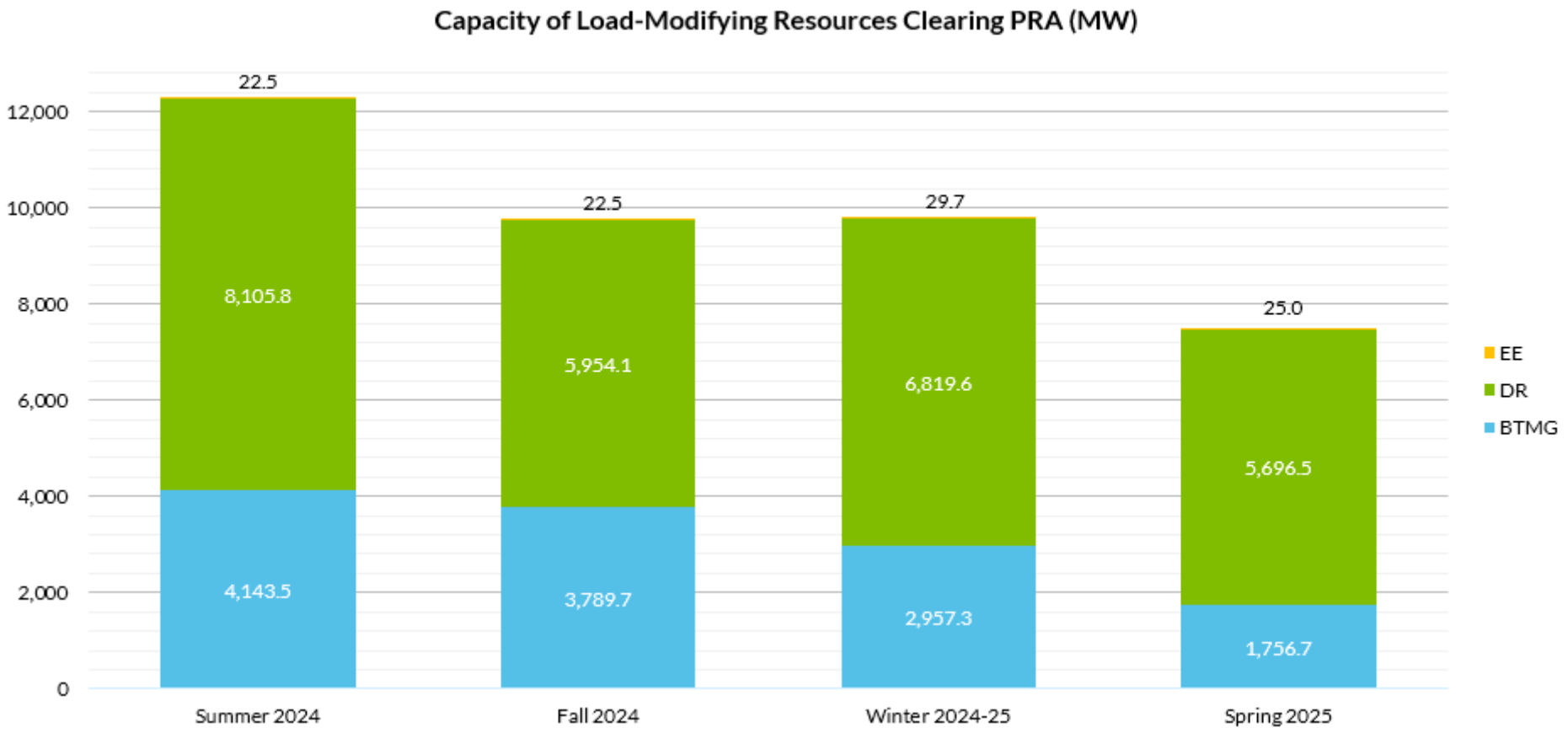
Spring 2025



The planning resource mix shows the continuation of a multi-year trend towards less coal/nuclear/hydro/oil and increased gas and non-conventional resources

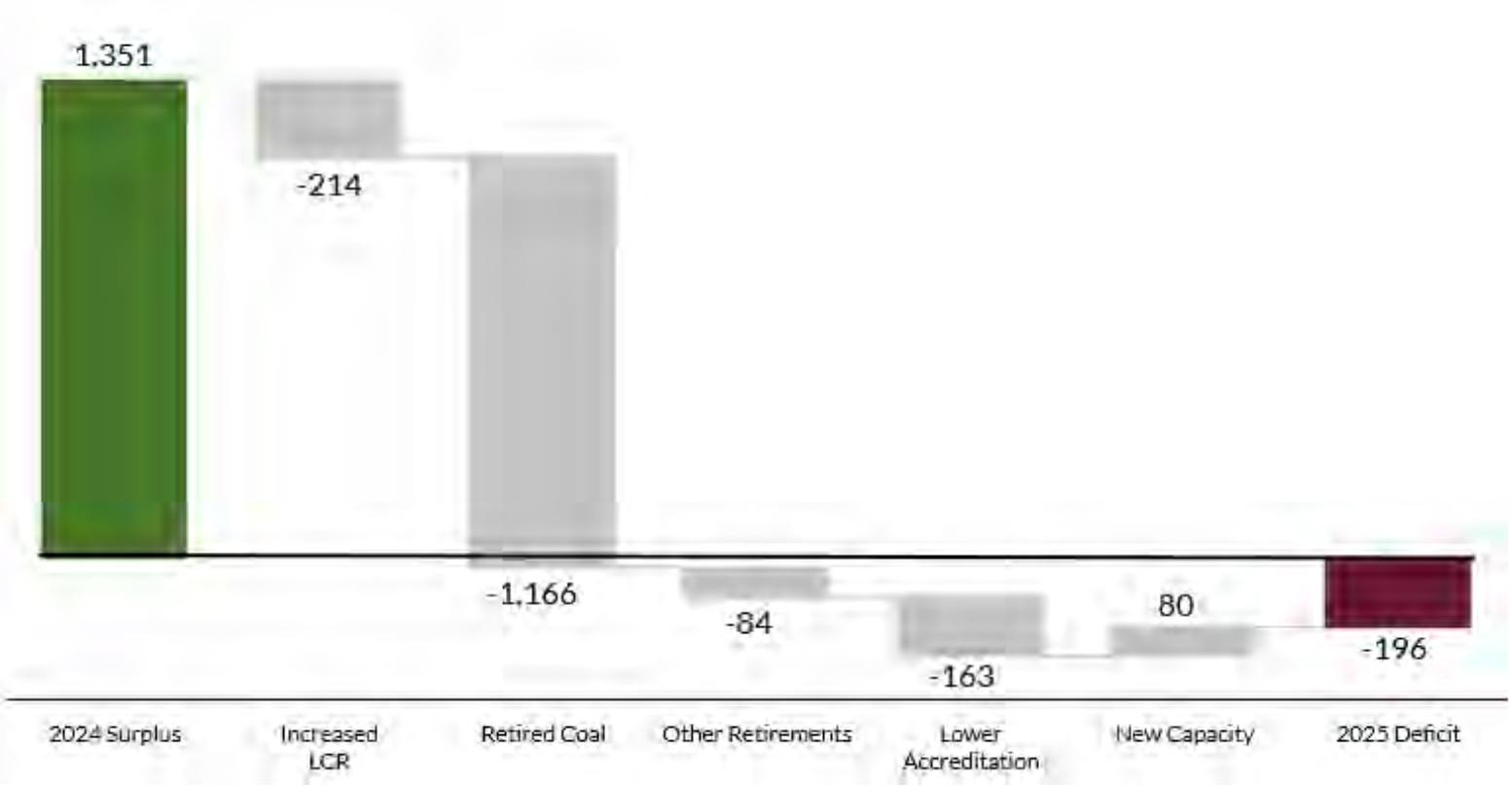


2024-2025 Seasonally Cleared Load Modifying Resources Comparison



A combination of higher Local Clearing Requirement and reduced capacity contributed to Zone 5 deficiency in the spring

Zone 5 Spring 2025 Capacity Changes Year-Over-Year



PO: Planned Outage

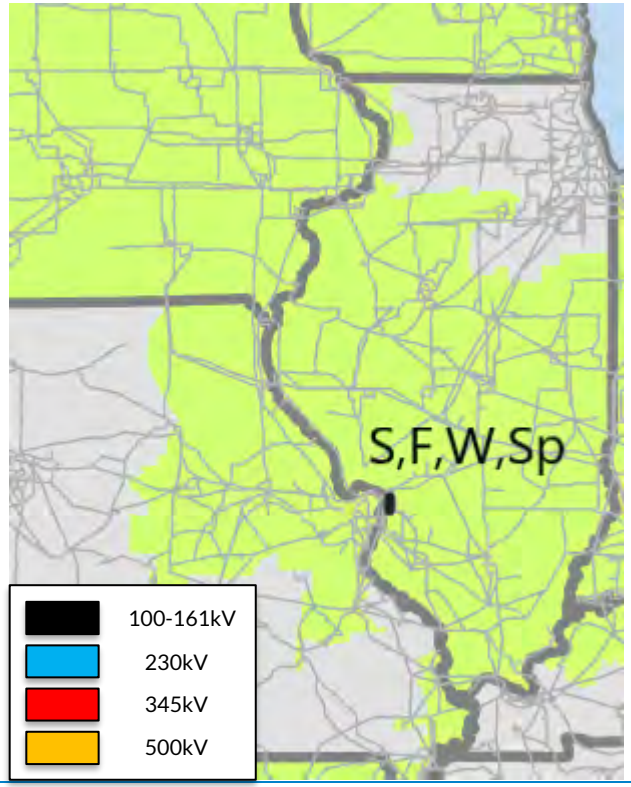
Zone 5 Local Clearing Requirement

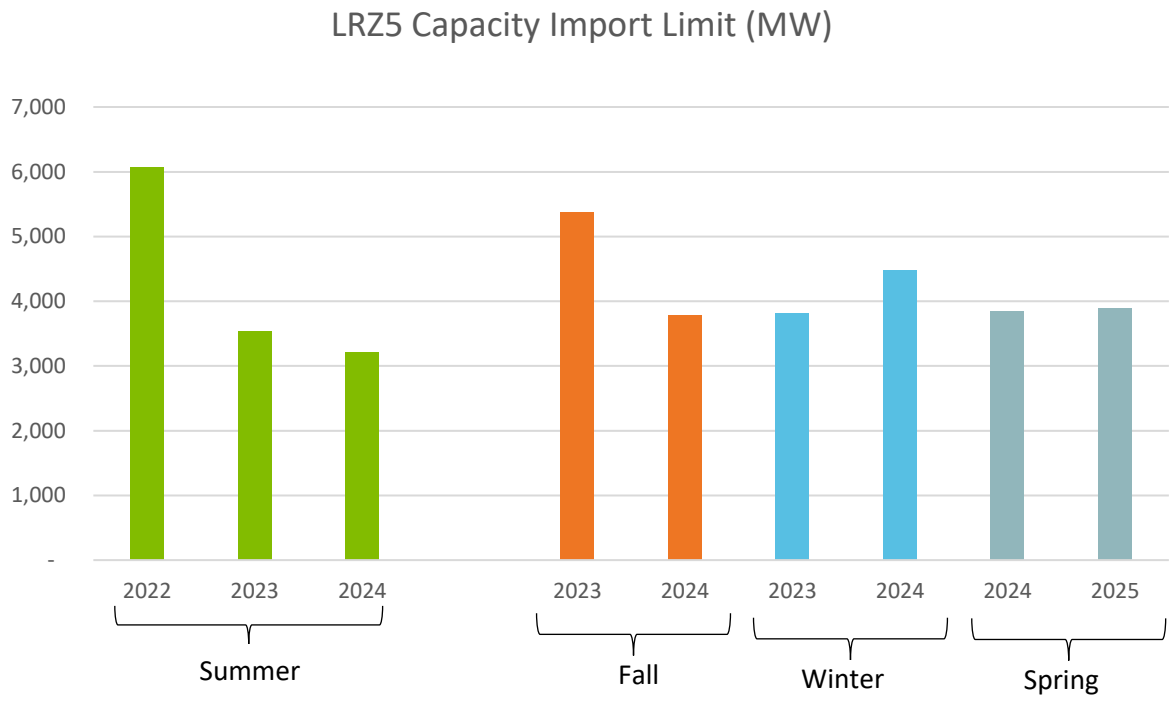
		Summer		Difference		Fall		Difference	
		2024	2023	MW	%	2024	2023	MW	%
(A)	Zonal Coincident Peak Forecast (ZCPF)	7,532.3	7,450.3			6,911.9	6,591.9		
(B)	Transmission Loss (TL) for ZCPF (MW)	147.9	130.7			168.2	115.2		
(C)=(A)+(B)	LRZ Peak Demand	7,680.2	7,581.0	99.2	1.3%	7,080.1	6,707.1	373.0	5.6%
(D)	LRR UCAP/LRZ Peak Demand from LOLE	1.331	1.333			1.441	1.452		
(E)=(C)*(D)	Local Reliability Requirement (LRR)	10,222.3	10,105.5	116.9	1.2%	10,202.4	9,738.7	463.7	4.8%
(F)	Zonal Import Ability (ZIA)	3,208.0	3,576.0	(368.0)	-10.3%	3,786.0	5,380.0	(1,594.0)	-29.6%
(G)	Controllable Exports	0.0	0.0			0.0	0.0		
(H)=(E)-(F)-(G)	Local Clearing Requirement (LCR)	7,014.3	6,529.5	484.9	7.4%	6,416.4	4,358.7	2,057.7	47.2%

		Winter		Difference		Spring		Difference	
		2024-25	2023-24	MW	%	2025	2024	MW	%
(A)	Zonal Coincident Peak Forecast (ZCPF)	6,397.0	6,483.2			6,023.0	5,921.4		
(B)	Transmission Loss (TL) for ZCPF (MW)	247.8	188.3			117.6	109.8		
(C)=(A)+(B)	LRZ Peak Demand	6,644.8	6,671.5	(26.7)	-0.4%	6,140.6	6,031.2	109.4	1.8%
(D)	LRR UCAP/LRZ Peak Demand from LOLE	1.285	1.474			1.618	1.610		
(E)=(C)*(D)	Local Reliability Requirement (LRR)	8,538.6	9,833.8	(1,295.2)	-13.2%	9,935.5	9,710.2	225.3	2.3%
(F)	Zonal Import Ability (ZIA)	4,477.0	3,811.0	666.0	17.5%	3,892.0	3,881.0	11.0	0.3%
(G)	Controllable Exports	0.0	0.0			0.0	0.0		
(H)=(E)-(F)-(G)	Local Clearing Requirement (LCR)	4,061.6	6,022.8	(1,961.2)	-32.6%	6,043.5	5,829.2	214.3	3.7%

Capacity Import Limits
Zone 5: Missouri

LRZ5	Monitored Element	Monitored Element Rating	Contingency	CIL
Summer 2024	Moro - Miles 138 kV	305 MVA	Roxford - Moro 345 kV	3208
Fall 2024	Moro - Miles 138 kV	305 MVA	Roxford - Moro 345 kV	3786
Winter 2024/25	Moro - Miles 138 kV	329 MVA	Roxford - Moro 345 kV	4477
Spring 2025	Moro - Miles 138 kV	305 MVA	Roxford - Moro 345 kV	3892





From 10/17/23 LOLEWG: Item 04 PY 2024-25 Final CIL-CEL Results Slide 11

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-26-16

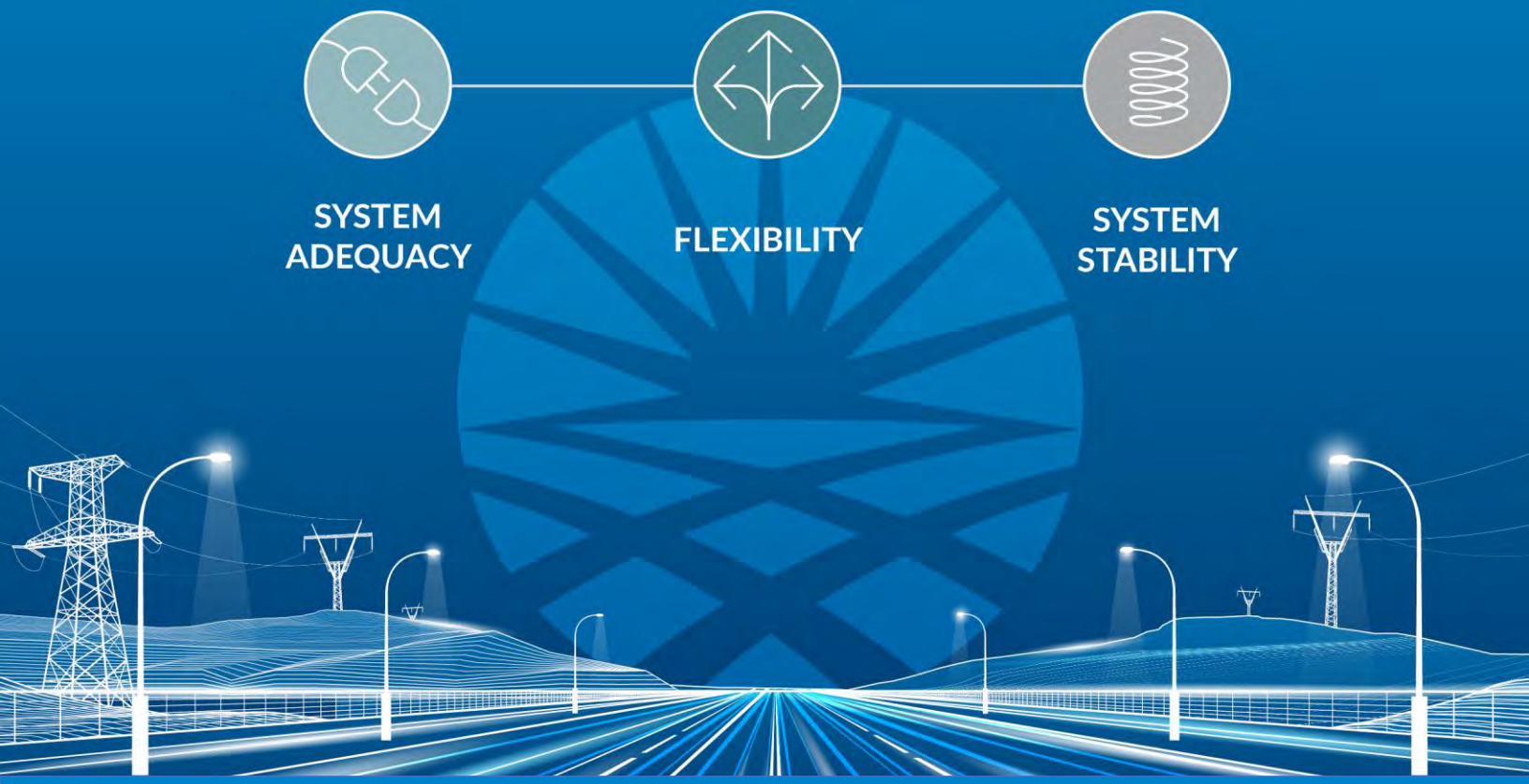
Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 85

MISO Attributes Roadmap

Attributes Roadmap

A RELIABILITY IMPERATIVE REPORT



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 *Technical Appendix* and the *Attributes Roadmap* 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.

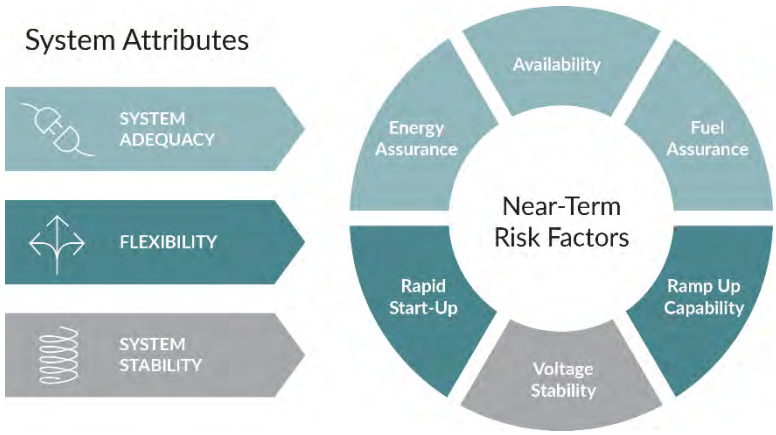


Figure 1: Three priority system reliability attributes and their near-term risk factor focus areas

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.

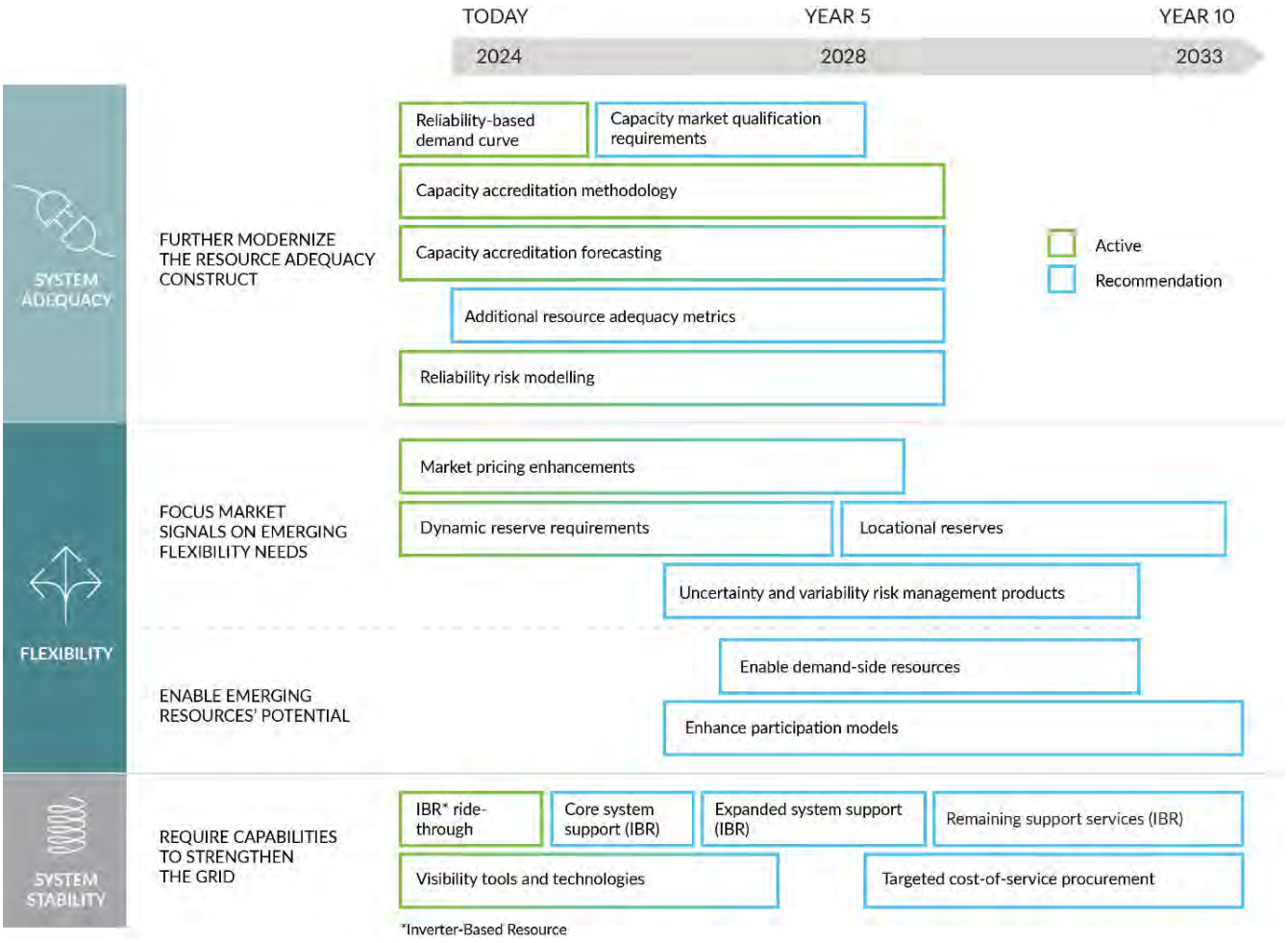


Figure 2: Hypothesis for attributes solution roadmap with approximate timing for projects currently underway (active) and proposed future projects (recommendation). The *Attributes Roadmap* discusses each recommendation in detail as well as the analysis and supporting research.

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:

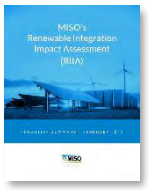
Markets of the Future: Illustrated how and when MISO's existing market structures will need to evolve to accommodate the profound changes that are occurring in the energy sector. The needs were presented in four broad categories: (1) Uncertainty and Variability; (2) Resource Models and Capabilities; (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.

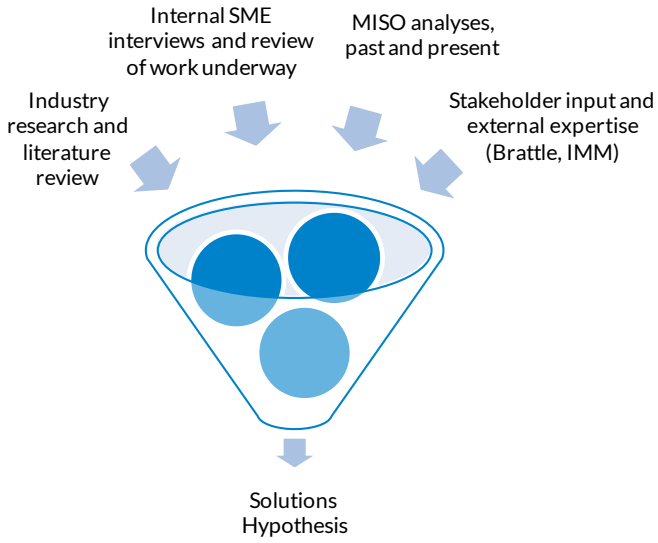


Figure 3: Sources of solutions considered

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) method[5] at the class level and the previously defined Resource Adequacy hours[6] 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.

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

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.

[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.

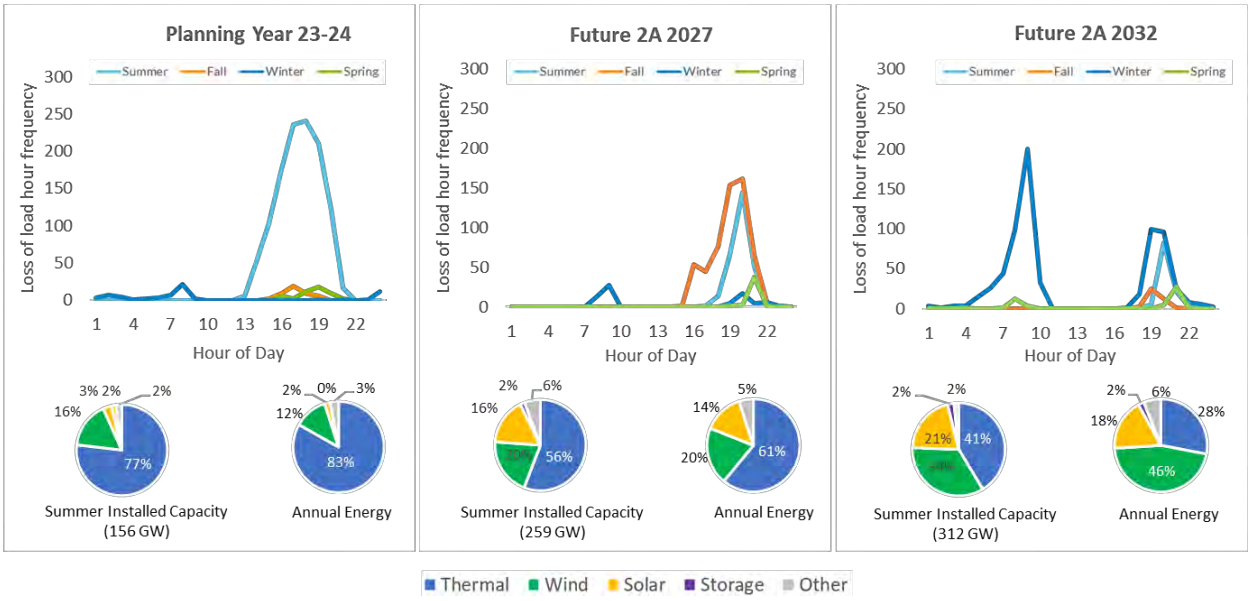


Figure 5: Evolution of risk distribution in future portfolios

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.

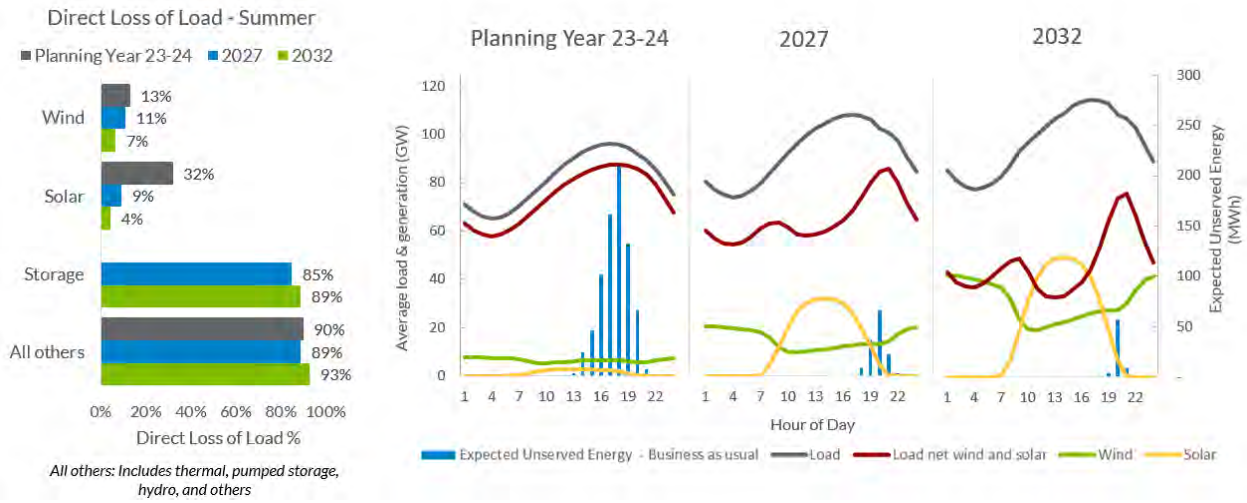


Figure 6: On the left, estimated summer season, class-level DLOL accreditation values for the three portfolios (today, 2027, and 2032) by fuel type. On the right, summer diurnal plots from the LOLE simulations showing average load, net load, and renewable generation for each hour.

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 resources[10], as their ability to mitigate risk is proportional to their state of charge at the beginning of the event and total energy available.

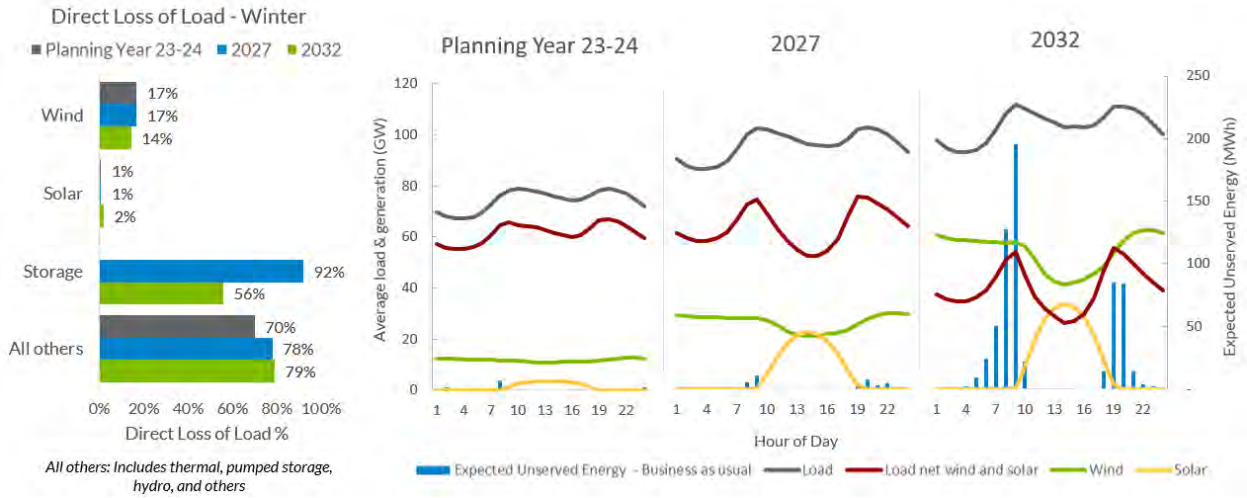


Figure 7: On the left, estimated winter season, class-level DLOL accreditation values for the three portfolios (today, 2027, and 2032) by fuel type. On the right, winter diurnal plots from the LOLE simulations showing average load, net load, and renewable generation for each hour.

[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" units[11] 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]

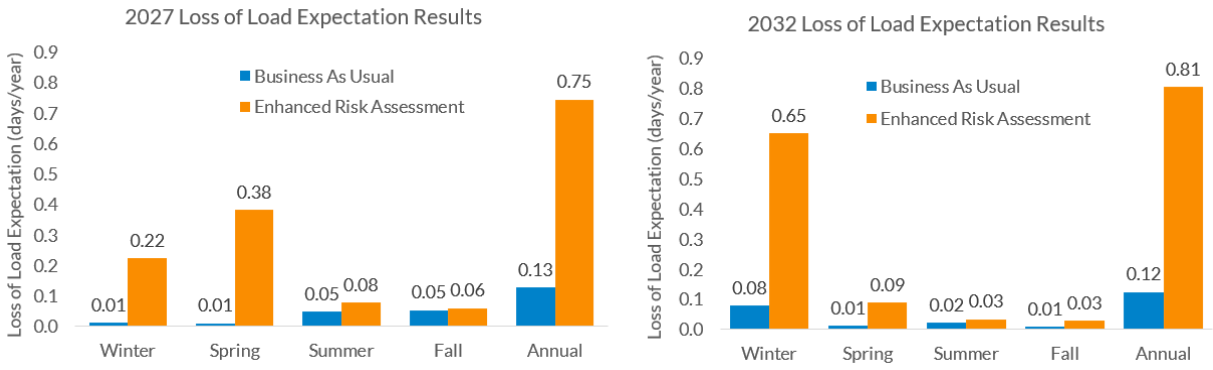


Figure 8: Seasonal LOLE results for the business-as-usual and enhanced risk assessment cases when both at the same adjustment.

The inclusion of the RDT constraint also had an impact on wind and storage accreditation values; the difference in DLOL 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.

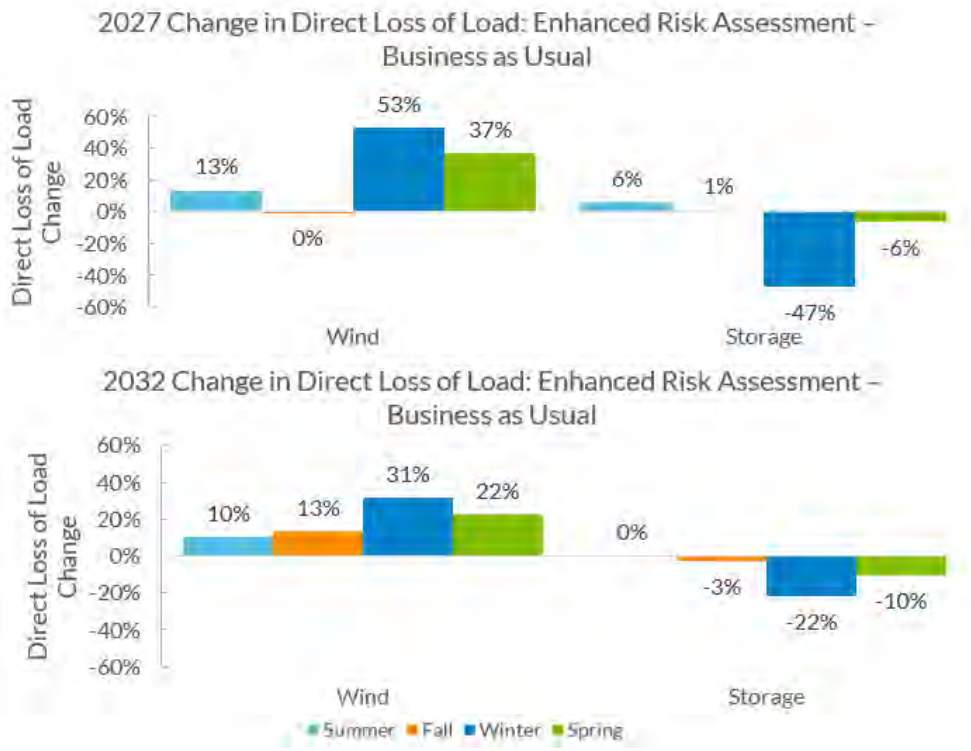


Figure 9: DLOL deltas between the enhanced risk assessment and business-as-usual cases for wind and battery storage resource classes when both cases are adjusted to seasonal LOLE targets.

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.

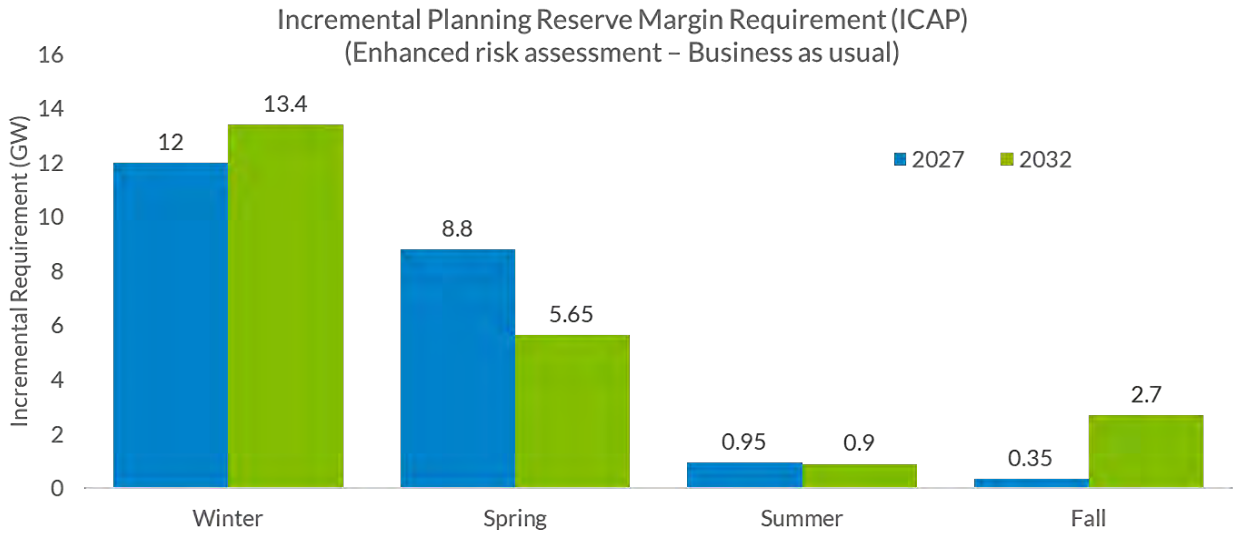


Figure 10: Incremental planning reserve margin requirement (PRMR) by season

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

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 ramping[13]) was selected for the planning year 22-23 and 2032 business-as-usual models.

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

[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.

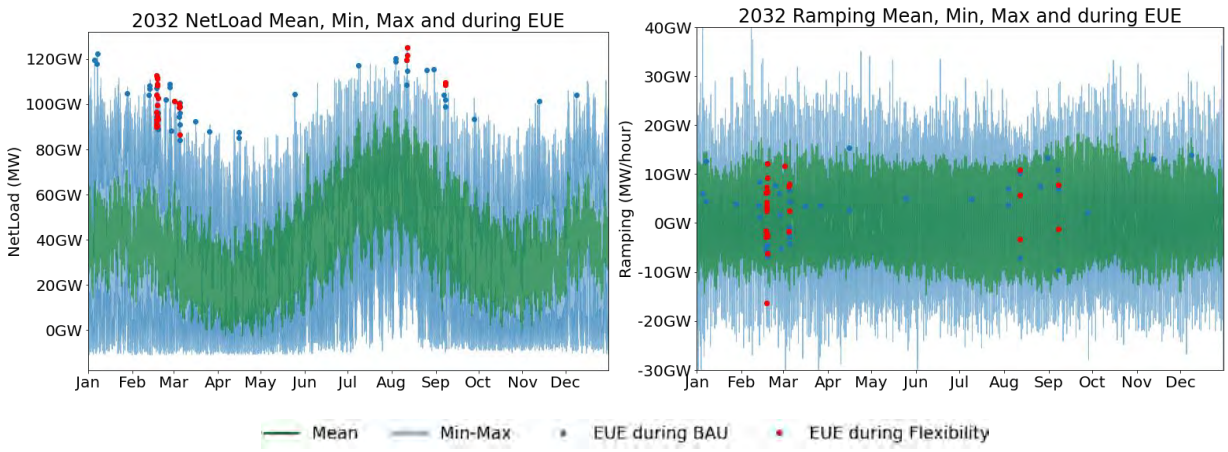


Figure 11: 2032 average, minimum, and maximum netload (left) and netload ramping (right). Blue and red dots signify netload and ramping at the event sample in business-as-usual and Flexibility

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

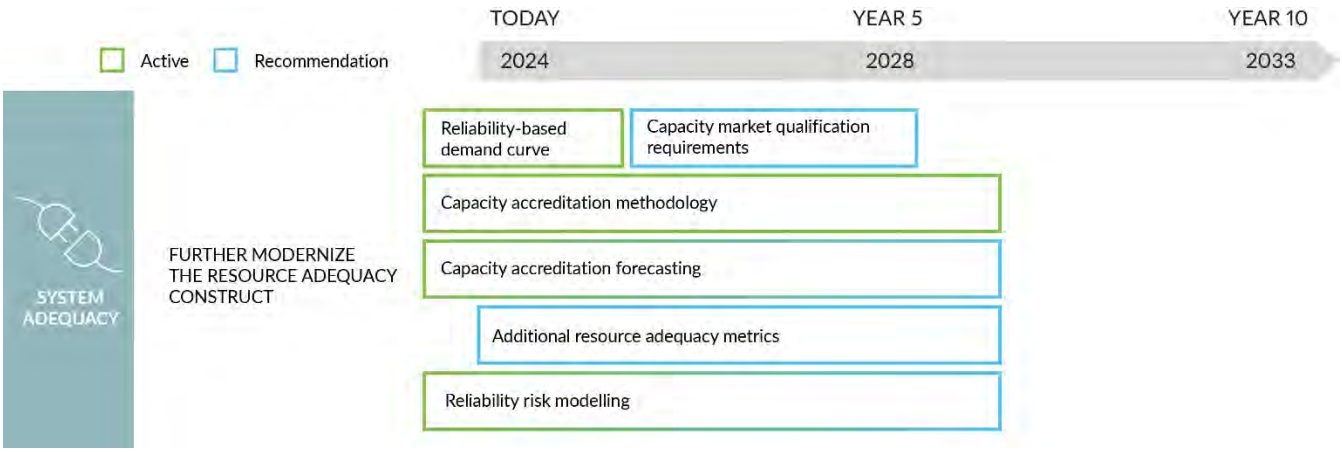
The *Attributes Roadmap* does not recommend new discrete capacity products (e.g., ramp capacity, energy reserves, or winter fuel programs). Capacity products outside the current construct may suppress energy and capacity prices. Additional products will increase complexity, requiring careful operational 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 approach[14] 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.

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[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 technologies[19] 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.

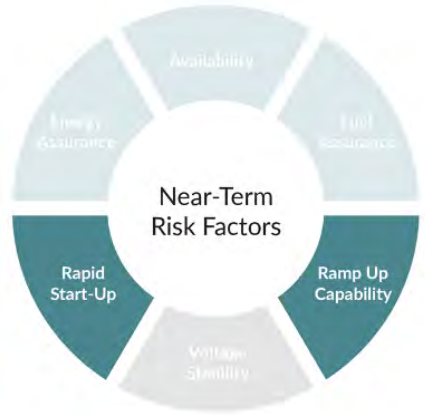


Figure 12: Flexibility near-term risk factor focus areas

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.

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 load[23] 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.

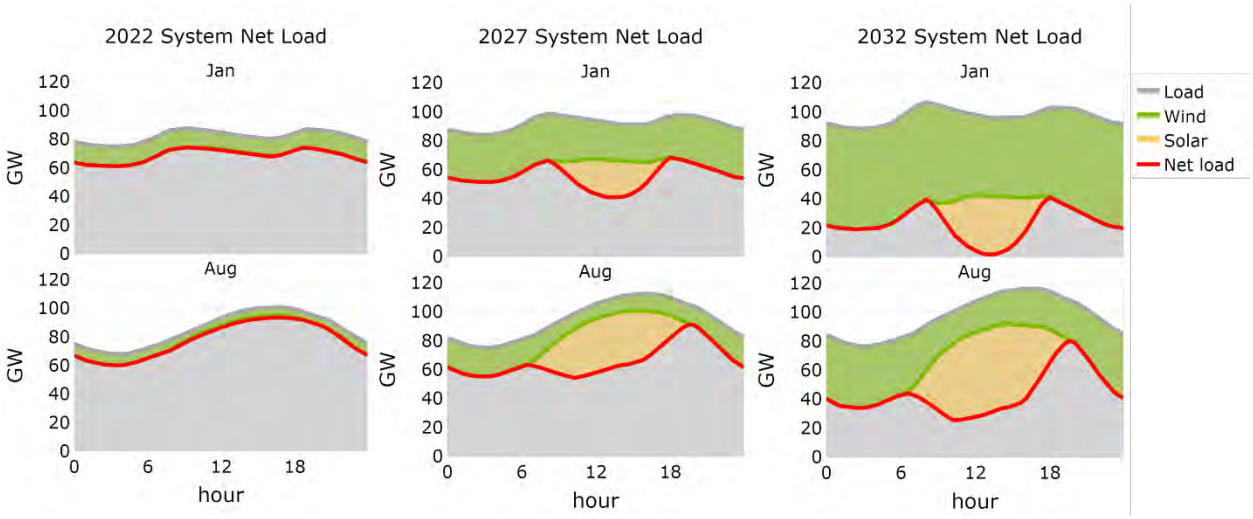


Figure 13: Monthly averages of diurnal net load components for January and August

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.

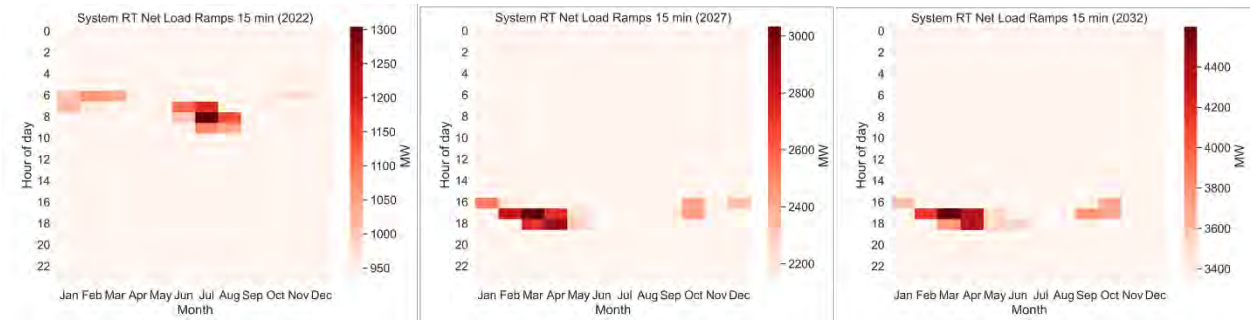


Figure 14: Highest 10 percentile of short duration net load up-ramps

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.

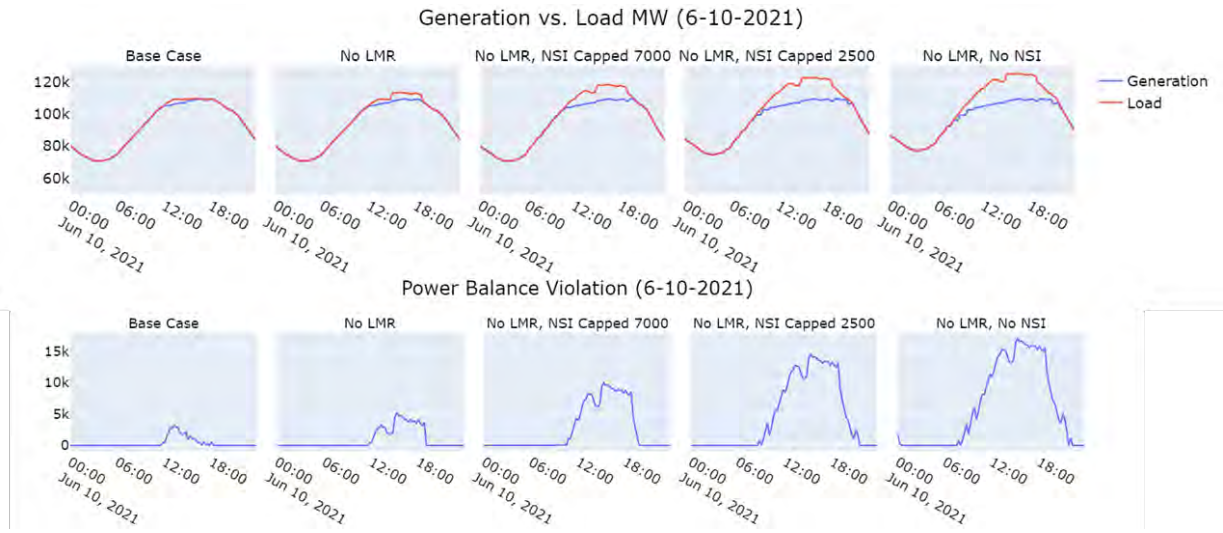


Figure 15: Simulation results for the summer event under different LMR and NSI scenarios

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).

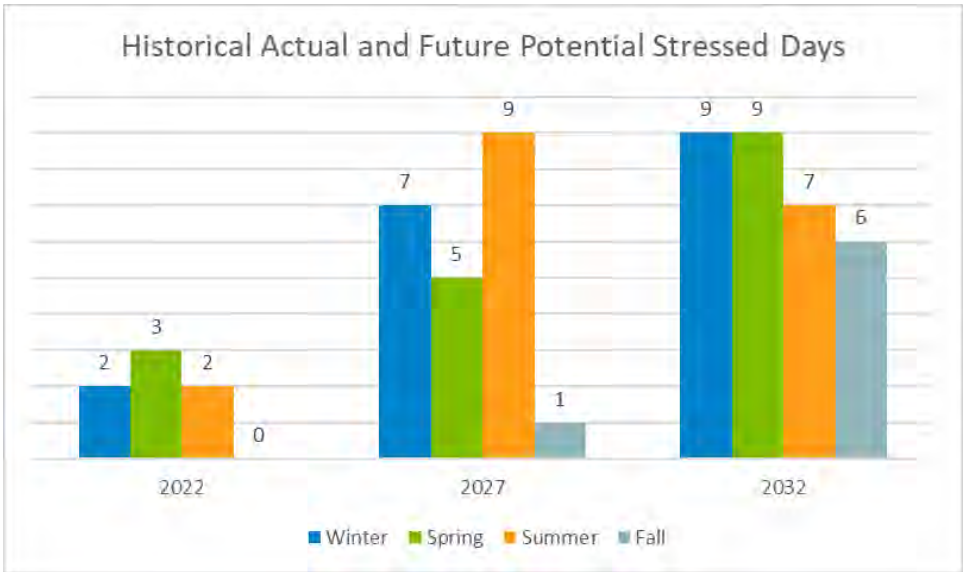


Figure 16: Historical events and future potential stressed days by season

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.

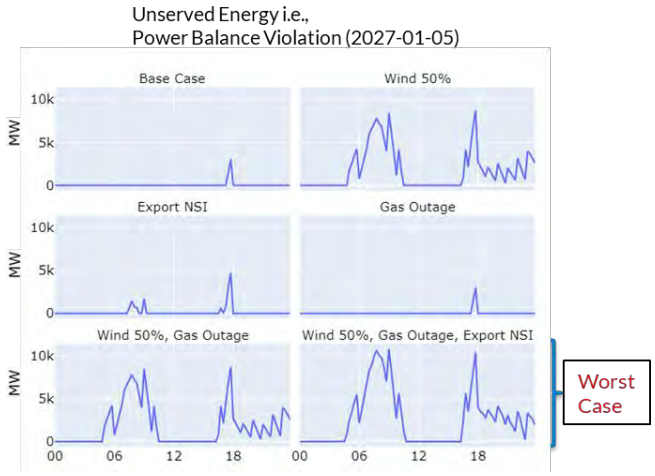


Figure 17a: Simulation results for base case and stressed scenarios for the winter 2027 event

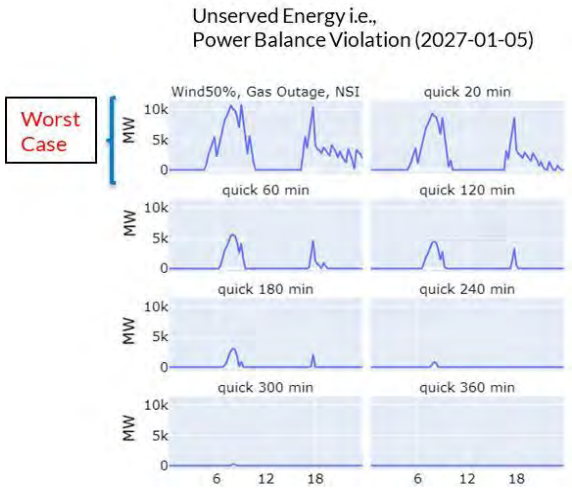


Figure 17b: Simulation results for worst stress case and mitigation using quick start units for the winter 2027 event

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.

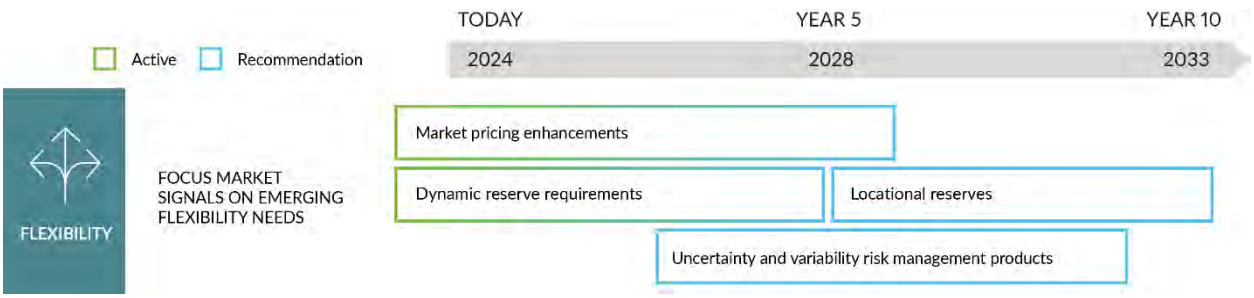
WHAT NOT TO DO NOW

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

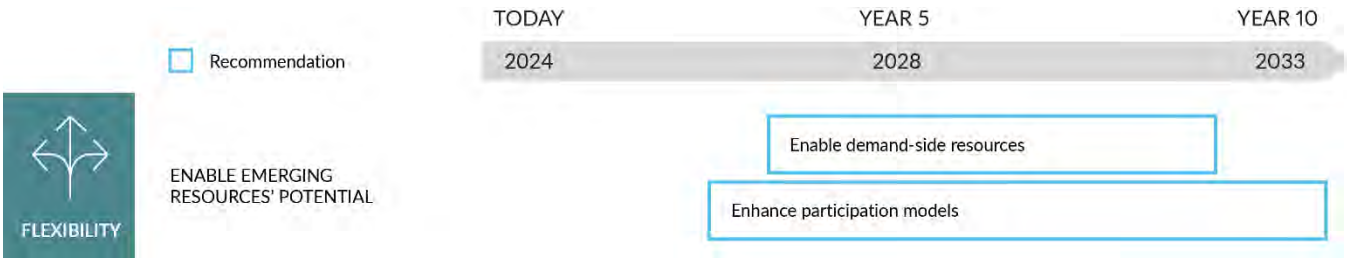
Currently in MISO's market resources must be able to provide both upward and downward ramp to participate in the ramp capability product. This places limitations on some types of resources from participating in the ancillary services market. MISO should separate the qualification requirements for upward 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 • 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 • 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]



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

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.

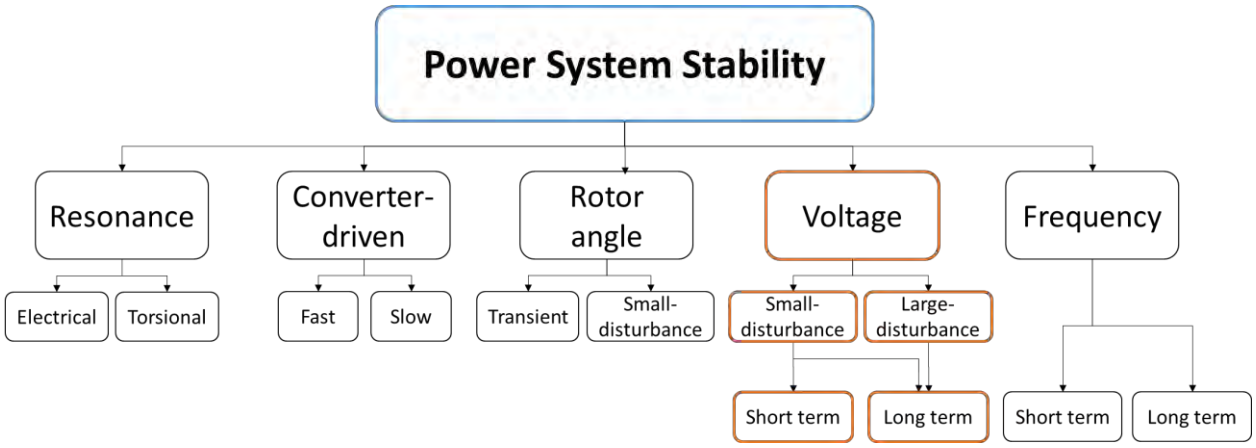


Figure 19: Taxonomy of power system stability considerations

[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.

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[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.

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.

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]

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.

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[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".

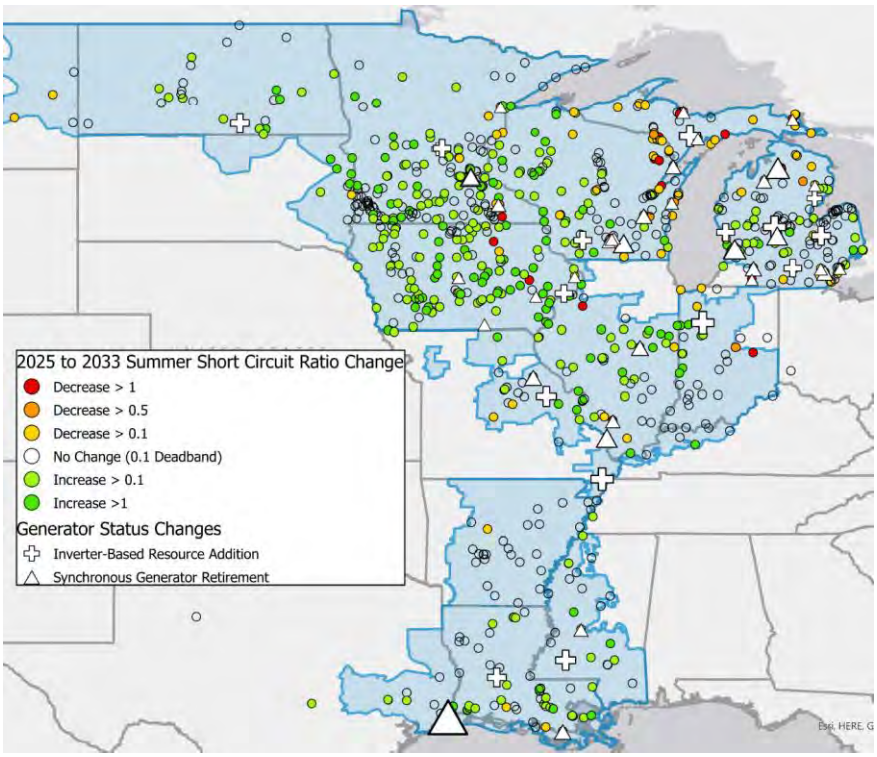


Figure 20: Change in short circuit ratio (SCR) between MTEP23 2025 summer peak and MTEP23 2033 summer peak cases[34]

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.

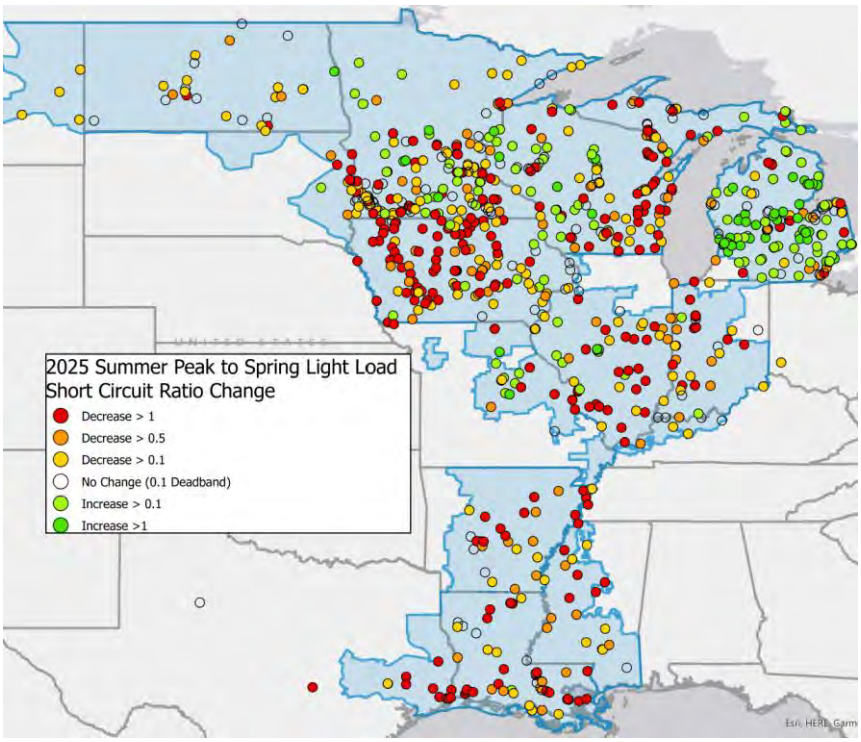


Figure 21: Change in short circuit ratio (SCR) between MTEP23 2025 summer peak and spring light load

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.

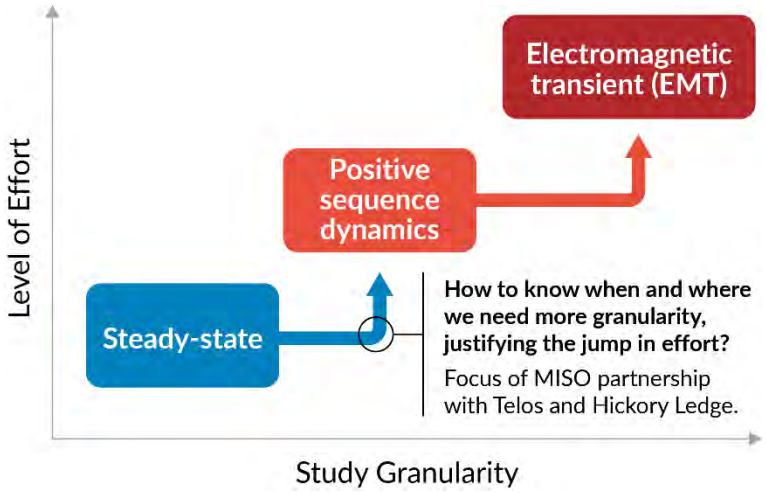


Figure 22: Illustration of effort-granularity tradeoff of common power system analysis tools

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*.

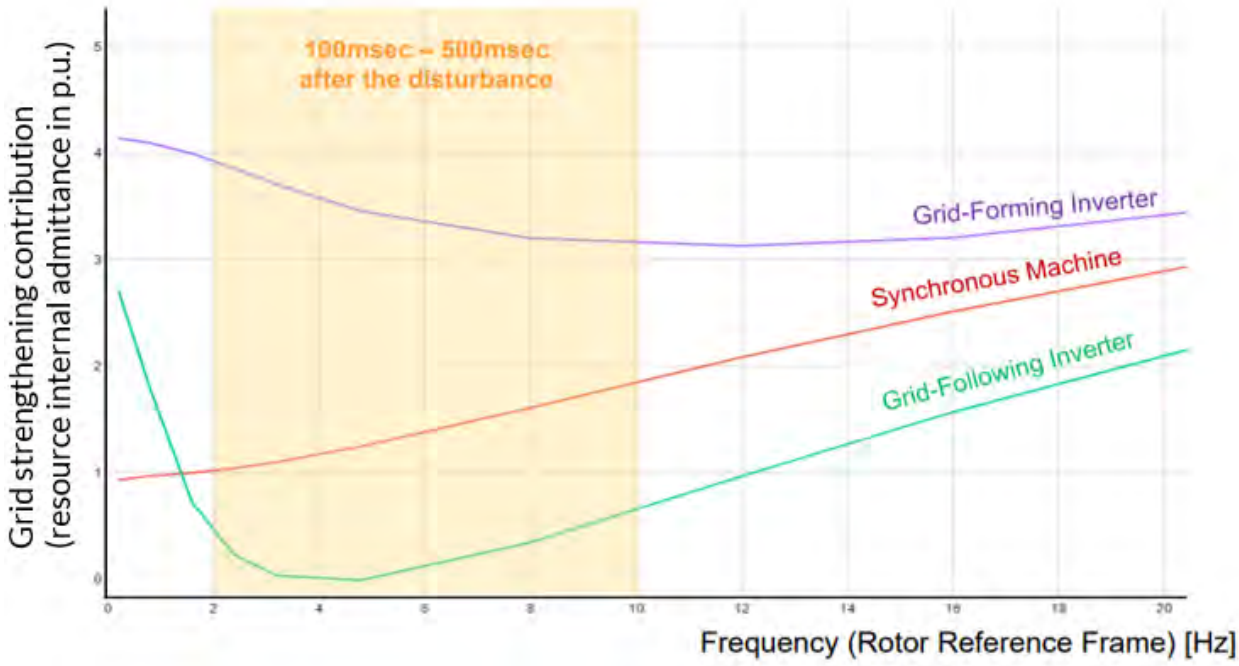


Figure 23: Resource characterization results from a series of detailed electromagnetic transient (EMT) simulations using detailed models. ***Image source: Telos Energy***

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.

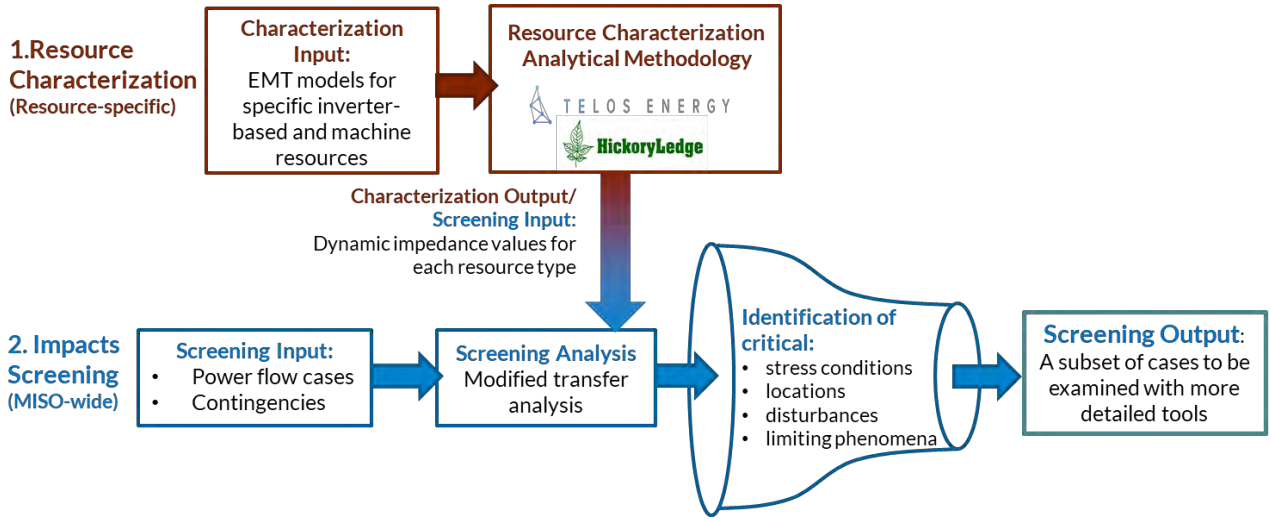


Figure 24: Overview of resource characterization and dynamic impedance screening process, described in greater detail in the Technical Appendix.

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.

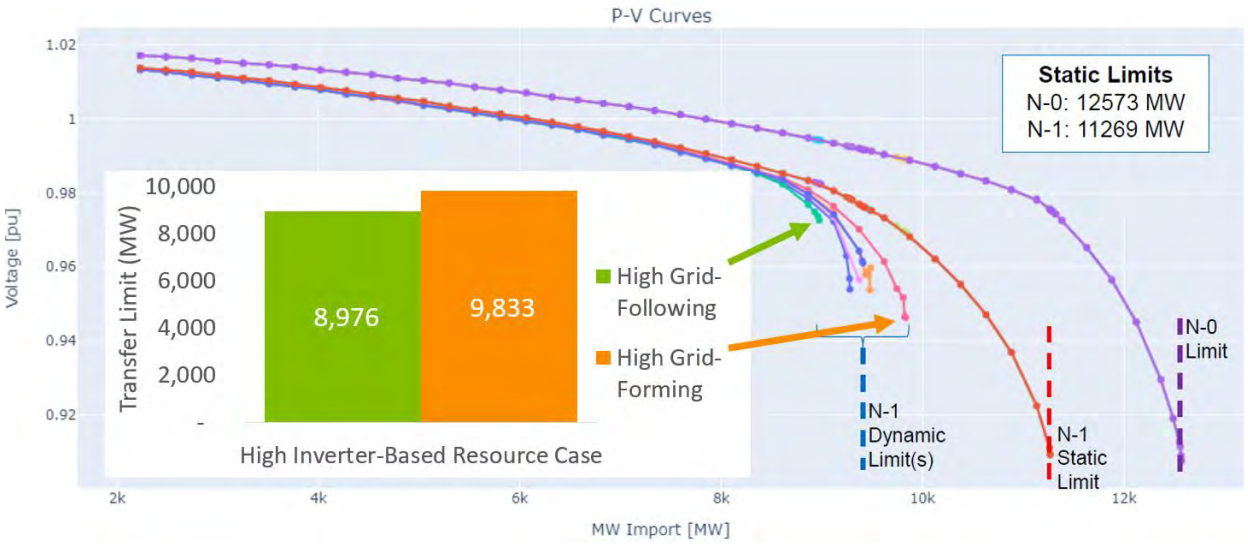


Figure 25: Dynamic impedance screening results comparing four select cases, varying IBR levels and grid-forming to grid-following proportions.

[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

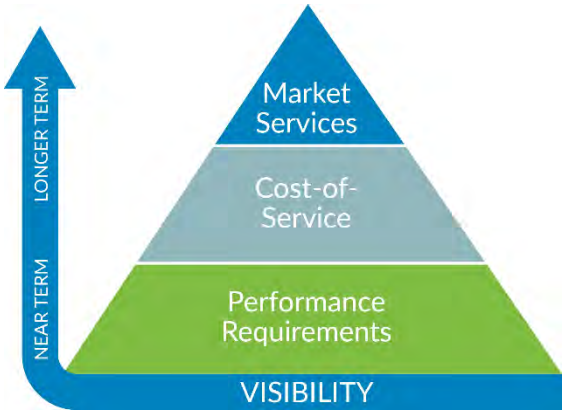
Stability challenges, including voltage stability, are best addressed in the planning timeframe by regulatory solutions because reactive deficiencies and solutions are highly localized. Obvious, low-cost solutions may be coordinated by technology standards and controls. Functionally, the types of solutions 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.

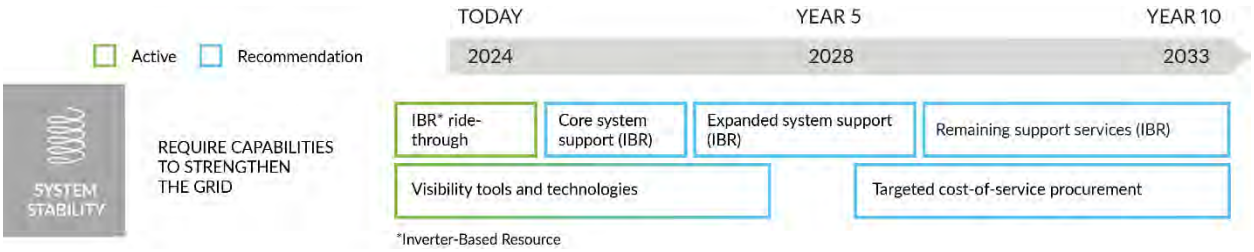


WHAT NOT TO DO NOW

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 services[38], 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
Require **ride-through capabilities** for interconnection of inverter-based resources (IBR) to address unexpected tripping • 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
Require **core system support** capabilities for interconnection of IBRs to support system stability more actively • 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
Require **expanded system support** with more active IBR controls to support a system with high levels of IBR • 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
Require **remaining support services** to enable an IBR-dominant system • 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
Evaluate **targeted cost-of-service procurements** to incentivize other technologies and the "energy buffer" required for more advanced grid-forming IBR performance • 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
Advance **visibility tools and technologies** to make visible of shifting risks and support further solution evaluation • 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).

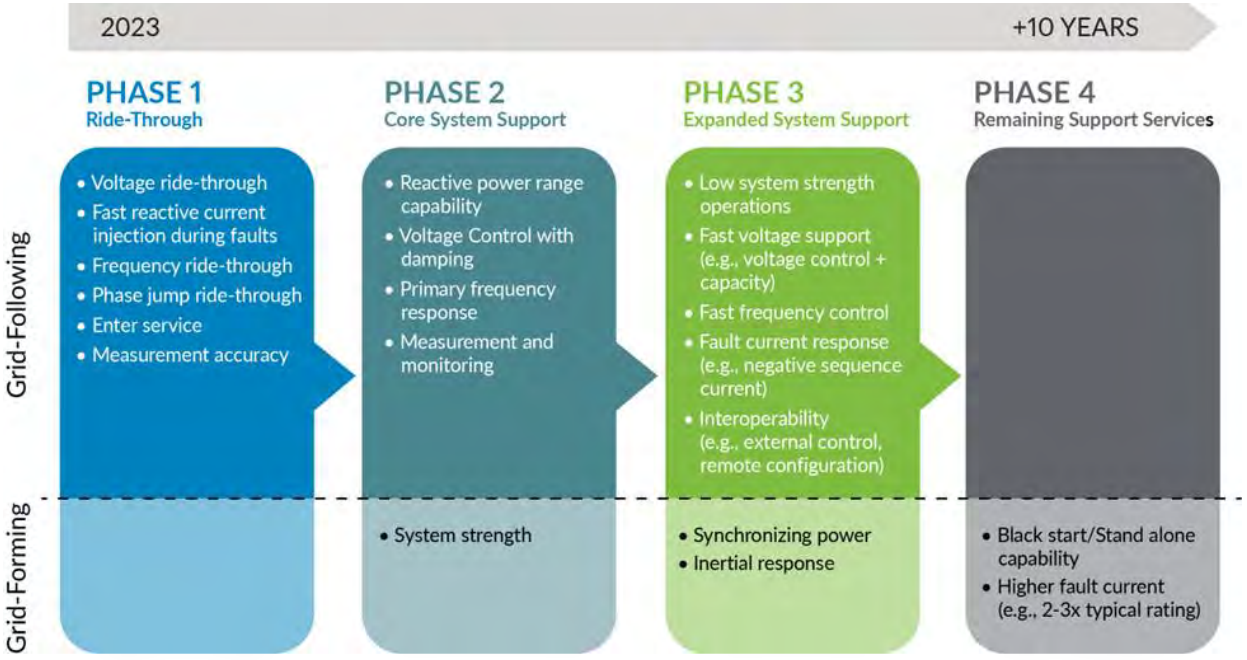


Figure 27: Summary of MISO's phased recommendation on grid-following and grid-forming capabilities and performance requirements

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.

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 Operator [1] 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.*

Regarding grid-following performance, MISO recommends expanding adoption of the IEEE 2800-2022[43] 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.

[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 P2800.2[44] will aide 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 response[45], 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]

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[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

MISO thanks The Brattle Group, Telos Energy, and HickoryLedge LLC for their contributions to this effort.

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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

AEMO: Australian Energy Market Operator

BESS: Battery Energy Storage System

CCGT: combined-cycle gas turbine51

CVaR: Conditional Value at Risk

DER: Distributed Energy Resource

DLOL: Direct Loss of Load

EGRET: Electric Grid Research & Engineering Tool

EMS: Energy Management System

EMT: Electromagnetic Transient

EPRI: Electric Power Research Institute

EUE: Expected Unserved Energy

FERC: Federal Energy Regulatory Commission

GFL: Grid Following

GFM: Grid Forming

HVDC: High Voltage Direct Current

IBR: Inverter-Based Resource

IEEE: Institute of Electrical and Electronics Engineers

IMM: Independent Market Monitor

LAC: Look-Ahead Commitment

LMR: Load Modifying Resource

LOLE: Loss of Load Expectation

LOLH: Loss of Load Hours

MISO: Midcontinent Independent System Operator

MTEP: MISO Transmission Expansion Plan

NERC: North American Reliability Corporation

NOPR: Notice of Proposed Rulemaking

NSI: Net Scheduled Interchange

PRA: Planning Resource Auction

PRM: Planning Reserve Margin

PRMR: Planning Reserve Margin Requirement

RAN: Resource Availability and Need

RBDC: Reliability-based demand curve

RDT: Regional Directional Transfer

RIIA: Renewable Integration Impact Assessment

RRA: Regional Resource Assessment

RTO: Regional Transmission Organization

SCR: Short Circuit Ratio

STATCOM: Static Var Compensators, Static Synchronous Compensators

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-26-16

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 86

MISO Attributes Roadmap Technical Appendix

Technical Appendix: Attributes Roadmap

Version Number	Purpose / Change	Date
1.0	Initial posting.	December 2023
1.1	Updated with hyperlinks between the *Technical Appendix* and the *Attributes Roadmap* per stakeholder feedback.	June 2024

Introduction

This technical appendix provides a detailed discussion of the data inputs, analytical tools, methods, modeling assumptions and results that support the insights presented in MISO's 2023 *Attributes Roadmap*. The analysis of current and future portfolios informed the selection and prioritization of the solution hypothesis in that document.

MISO's attributes effort began by studying industry research and the experiences and approaches of other grid operators facing similar challenges. This landscape review, in addition to MISO's past analyses and experiences, led to the identification of three priority system attributes where near-term risk for the MISO system is most acute: system adequacy, flexibility, and system stability (Figure 1).

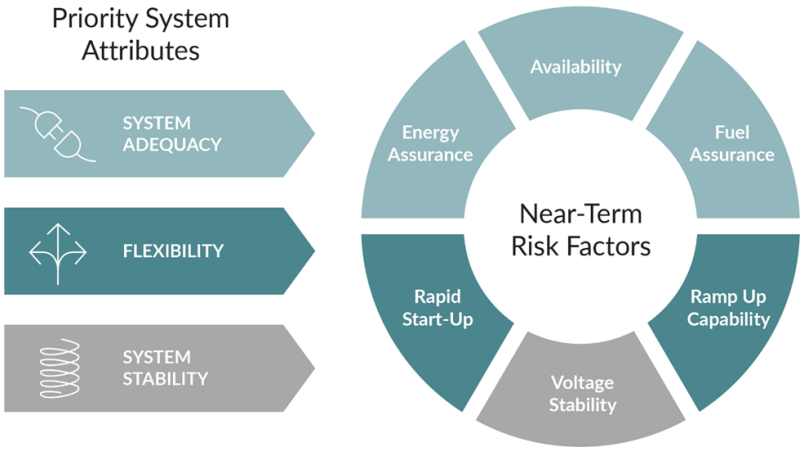


Figure 1. Three priority system attributes and near-term risk factor focus areas

System Adequacy is the ability to serve load in all realistic scenarios, including the most challenging periods, by having enough supply to meet demand when and where it is needed. Generation capacity is considered when measuring this attribute, as well as actual availability every hour of the year. As the system adds more weather-dependent generators, the risk hours shift away from the traditional summer peak and increasingly to non-summer months. Maintaining reliability through multi-day periods of low renewable resource output, or correlated outages due to fuel supply or utilization issues presents new and additional energy and fuel assurance risk factors.

Flexibility is the ability to meet the ramping needs of the system with multiple response timeframes and durations. As generation becomes more weather-dependent and electrification trends change traditional load patterns, the complexity of forecasting and operations increases significantly, leading to greater system uncertainty and variability. MISO has identified rapid start-up and ramp up capability as near-term risk factors, but flexibility in a broader sense includes ramp rates, shut-down times, and minimum generation levels. A more flexible future system will be required to meet the emerging challenges and ensure reliability while maximizing economically efficient operations and system investments.

System stability is the ability to remain in a state of operating equilibrium under normal conditions and to recover from disturbance events, including unplanned generation outages and rapid changes in generation output driven by changing weather. MISO identified voltage stability as the nearest term stability risk. Voltage stability is often thought of as load-driven rather than resource-driven, though resource characteristics affect stability outcomes. The addition of inverter-based resources and retirement of resources that historically provided sufficient reactive power, requires a new approach to ensure ongoing reliability and stable outcomes.

Over the course of 2023, MISO has designed and performed foundational quantitative analyses to gain improved insights and understanding to better describe and define the system attributes today and under five-year and 10-year future scenarios. The team studied potential market reforms from two perspectives: (1) the planning horizon (long-range investment and retirement timeframe) where the risk is not having sufficient resources, and (2) the operating horizon (near real-time timeframe) where the risk is not using available resources efficiently.

This technical appendix summarizes this effort and is organized in the following sections:

A. System Adequacy

B. Operational Adequacy

C. Voltage Stability

D. Attribute Support from MISO's Market Structures

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A.System Adequacy

This section of the appendix provides supplemental information on the analysis described in the System Adequacy section of MISO's 2023 *Attributes Roadmap*. The analysis informs the development of the solution hypothesis by quantifying the impact of emerging risk factors (availability, energy, and fuel assurance) on MISO-wide accreditation and planning requirements using a resource adequacy analysis that follows best practices. This analysis also explored the implications of including operational constraints in resource adequacy models. This approach was used to analyze both the current portfolio and future portfolios using MISO's Future 2A[1].

A.1 Methodology

A.1.1 Resource Adequacy Analysis

Resource adequacy analysis, as required by the North American Electric Reliability Council (NERC) Standard BAL502-RFC-0211, aims to ensure sufficient installed generation capacity to meet electric load, measured against a prescribed target. The objective of the resource adequacy analysis in the System Adequacy portion of the Attributes work is to understand how the risk of unserved energy changes with the evolving resource mix over the next decade. The resource adequacy analysis aims to identify changes to the planning reserve margin requirement (PRMR) and accreditation of resources through the direct loss of load (DLOL) method[2]. As the resource mix rapidly changes with the addition of renewable and storage resources, it becomes clear that these resources play an important role in serving load and maintaining system reliability. The stochastic and energy-limited nature of these resources result in changes to the reliability risk profile and a shift in the probability of loss of load to periods outside of the traditional risk periods.

The System Adequacy analysis uses a seasonal resource adequacy construct to estimate DLOL using MISO's currently established metric of a loss of load expectation (LOLE) of 1 day in 10 years. The LOLE analysis uses a sequential Monte Carlo simulation to model a wide range of system conditions and assess the system's reliability. The LOLE analysis is a chronological, 8,760-hour simulation and includes multiple weather years. Multiple samples are developed for generator forced outage profiles for each weather year. LOLE, and other metrics, are calculated using an average across samples and weather years.

To capture the interannual variability of weather-related patterns, synchronized load, wind, and solar hourly datasets were used for the study. Thermal outages are accounted for in the form of planned and forced outages. The former is determined by the maintenance rate and mean time to repair while the latter uses the forced outage rate. In summary, the analysis considers the variability of load, wind, and solar output along with planned maintenance and forced outages of generation units. The modeling inputs vary slightly from the standard business practice to incorporate the expanded scope of the attributes work.

Following current practices at MISO, the LOLE model was adjusted and brought to criteria. First, the simulation is run without any adjustments and the resulting natural LOLE is determined. Next, annual adjustments are performed by adding or removing fixed load so that the average LOLE across all weather years reaches 0.1 days/year. For seasons with no LOLE resulting from this process, seasonal adjustments are then made to the system until each season results in a LOLE of at least 0.01 days/year. If the LOLE is less than the target for a season, then fixed load is added to the model. If the LOLE is greater than the target for a season, then proxy combustion turbine generators

[1] MISO, *MISO Futures Report, Series 1A*, November 2023.

[2] MISO, *Resource Accreditation White Paper, Version 1.1*, November 2023.

with a size of 160 MW and class average equivalent forced outage rate (EFORd) are added to the model until the seasonal LOLE target is achieved.

A.1.2 Tools

The Planning Adequacy analysis uses a program developed by Energy Exemplar called PLEXOS to perform the resource adequacy assessment. The PLEXOS model is a probabilistic, hourly chronological simulation over the study year, which uses the sequential Monte Carlo method to develop random forced outage samples. Planned thermal outages are determined by the maintenance rate and mean time to repair, while forced outages use historical forced outage rates. Both the planned maintenance and sequential Monte Carlo are based on optimization techniques.

A.1.3 Datasets

In Planning Adequacy analysis, weather-dependent characteristics of load, wind and solar generation, and extreme weather-dependent thermal generation outage were collected to represent the diverse operating conditions. For the PY23-24 model, the 2022 Regional Resource Assessment (RRA) model was aligned with MISO's LOLE study[3] model. The equivalent datasets for F2A 2027 and 2032 models are sourced as below:

- Load: Actual load recorded for the operation years 2007-2021 was collected and scaled based on energy and capacity peaks specified by MISO Future 2A's assumptions[4].
- Wind and solar generation: For all existing and planned siting, hourly forecasted generation was calculated based on each siting's geographical location, using National Renewable Energy Laboratory's (NREL) and Vibrant Clean Energy's dataset of weather years 2007-2021. The generation was aggregated per Local Resource Zone (LRZ) for the simulations.
- Extreme weather-dependent thermal generation outage: Temperature- and fuel-dependent outages were analyzed to create hourly correlated outages, scaled to the capacity of thermal generation in each model.

A.1.4 Accreditation

In addition to examining how risk evolves in LOLE models under different assumptions, MISO studied the impact on the capacity value of different resources. Accreditation estimates were calculated for different resource classes and followed MISO's DLOL class accreditation proposal,[5] as of September 2023. The DLOL method calculates a resource's resource adequacy contribution by measuring its ability to serve load during times of system shortfall events in the LOLE model.

Resource availability during modeled loss-of-load hours, across all samples, is aggregated by resource class. Average class-level availability is averaged by season and load forecast error (LFE) tranche, and the weighted average across LFE tranches results in the DLOL in MW terms. To express DLOL as a percentage, the available DLOL MW is divided by the resource class installed capacity. The standard MISO resource adequacy LOLE model includes the effect of LFE, but that feature was excluded from this analysis to reduce the amount of processing required for the scenarios in this analysis. Therefore, DLOL results in this study are not weighted by LFE probabilities. Similarly, the non-thermal technologies were aggregated into a single class for reporting purposes. Figure A-1 presents the DLOL calculation process as shown in MISO's accreditation white paper, which includes the LFE tranche steps.

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[3] MISO, *Planning Year 2023-2024 Loss of Load Expectation Study Report*, Updated May 2023.

[4] MISO, "Future 2A Energy Adequacy and Siting", Presented at MISO's LRTP Workshop, April 28, 2023.

[5] MISO, *Resource Accreditation White Paper, Version 1.1*, November 2023.

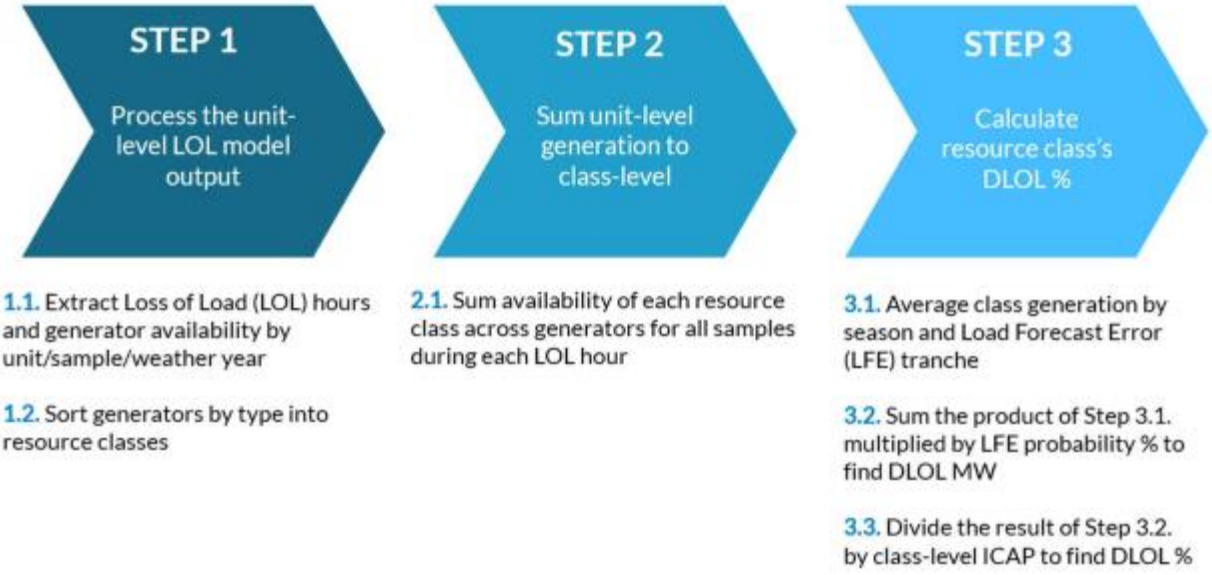


Figure A-1: DLOL calculation process from MISO's Resource Accreditation White Paper (v1.1)[5]

A high-level verification was performed to compare the outcomes of the planning year 23-24 (PY23-24) LOLE Study[6] and this work. Inputs were aligned as much as possible, but the use of different tools and techniques lead to small differences in the results[7].

A.2 Study Years and Data Sources

The System Adequacy analysis was designed to cover the energy transition that is expected to occur over the next decade to inform near term decisions about actions MISO should take to ensure system reliability attribute sufficiency. To that end three study years were selected: PY23-24, the year 2027, and 2032. Figure A-2 summarizes the major assumptions for these years. The first year was intended to represent current system conditions and its assumptions are aligned with the PY23-24 LOLE Study[8]. 2027 and 2032 represent medium- and longer-term forecasts and they are consistent with the Future 2A expansions in the MISO Futures Report[9].

[6] MISO, "Market Redefinition: Accreditation Reform", slide 6, presented at MISO's RASC, October 4, 2023.

[7] A benchmark of the results was shared at MISO "System Reliability Attributes Analysis and Roadmap Workshop #2" presented at MISO's RASC workshop, October 31, 2023.

[8] MISO, *Planning Year 2023-2024 Loss of Load Expectation Study Report*, Updated May 2023.

[9] MISO, *MISO Futures Report, Series 1A*, November 2023.

PY23-24	•Probabilistic model •PY23-24 LOLE Study as basis for resource portfolio and load •30 weather years (1992-2021) •125 random outage samples per weather year
2027 & 2032	•Probabilistic models •Future 2A expansion as basis for resource portfolio and load •15 weather years (2007-2012, 2014-2021) •250 random outage samples per weather year •Load includes electrification and energy efficiency forecasts

Figure A-2: Main assumptions and sources by study year

The transition in the resource mix is presented in Figure A-3, which highlights the increase in variable renewable generation, coupled with the retirement of coal generation. The remainder of this subsection presents more details on the assumptions used across the study years, including those that lead to the capacity mix presented in the figure.

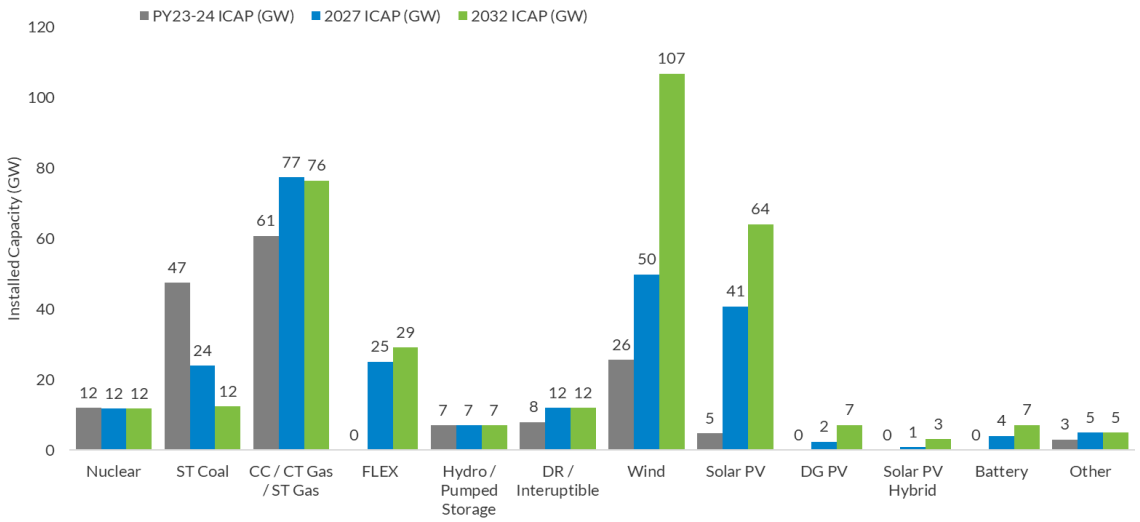


Figure A-3. Capacity mix assumed for the three study years

A.2.1 PY23-24 Base Model

The basis for the model in PLEXOS was the 2022 Regional Resource Assessment (RRA)[10], but data used for MISO's PY2023-2024 LOLE study[11] was incorporated into the PLEXOS model for the current year analysis. The study used 125 samples per weather year, and 30 weather years were included (1992-2021).

[10] MISO, *Technical Appendix: RRA Assumptions and Methodology*, from MISO, *2022 Regional Resource Assessment*, November 2022.

[11] MISO, *Planning Year 2023-2024 Loss of Load Expectation Study Report*, Updated May 2023.

Load

Hourly load data for each LRZ for each weather year was taken from the PY23-24 LOLE Study.

Generation

Installed capacity (ICAP) values were adjusted from 2022 RRA values to match the PY23-24 capacity values.

Seasonal forced outage rates (FOR) were incorporated into the model. These values were taken from the PY23-24 LOLE study on a unit-by-unit basis when units could be mapped, otherwise class average values were used. Mean, minimum, and maximum time to repair for forced outages were taken from the 2022 RRA, which used 2013-2018 GADS data.

Annual maintenance rates from the 2022 RRA were used in the model. Maintenance was scheduled in one event per unit per year using daily peak load resolution.

Renewable Profiles

Solar and wind profiles for each LRZ for each weather year were taken from the PY23-24 LOLE Study.

External Units (Firm and Non-Firm)

Non-firm external imports were included in the model, following the distribution in Table 3-5 from the PY23-24 LOLE study.

Firm external generation units were also included in the model from the PY23-24 LOLE study. PY23-24 data for the specific units was used for ICAPs, FORs, forced outage mean time to repair, and maintenance rates. Class averages from the F2A data were used to assign fixed operation and maintenance cost, variable operation and maintenance, and heat rates for each external unit.

A.2.2 Future 2A Base Model

The 2027 and 2032 generation portfolios were taken directly from the Future 2A (F2A) output[12], so most assumptions about generation mix match those in the Futures assumptions documents. 250 samples were used per weather year.

Load

F2A load was the basis for load assumptions. Applied Energy Group (AEG) provided the MISO Futures group with annual peak load and annual energy data, that were based upon State Utility Forecasting Group values from the Futures Series 1. The base weather year for F2A load was 2018, and to provide load shapes for weather years 2007–2012 and 2014 – 2021, historical hourly load was gathered and scaled. Next, AEG's electrification, energy efficiency, and demand side management assumptions were adjusted to align days of the week with each historical weather year to develop an electrified load shape for each weather year. Each electrified weather year was then shaped in PLEXOS to reach the F2A zonal peak and annual energy assumptions. Figure A-4 presents two weather year samples for modeled, final load, and Table A-1presents 2027 and 2032 annual energy and zonal peak assumptions.

[12] MISO, *LRTP Tranche 2 – Futures Refresh, Assumptions Book*, Updated April 2023

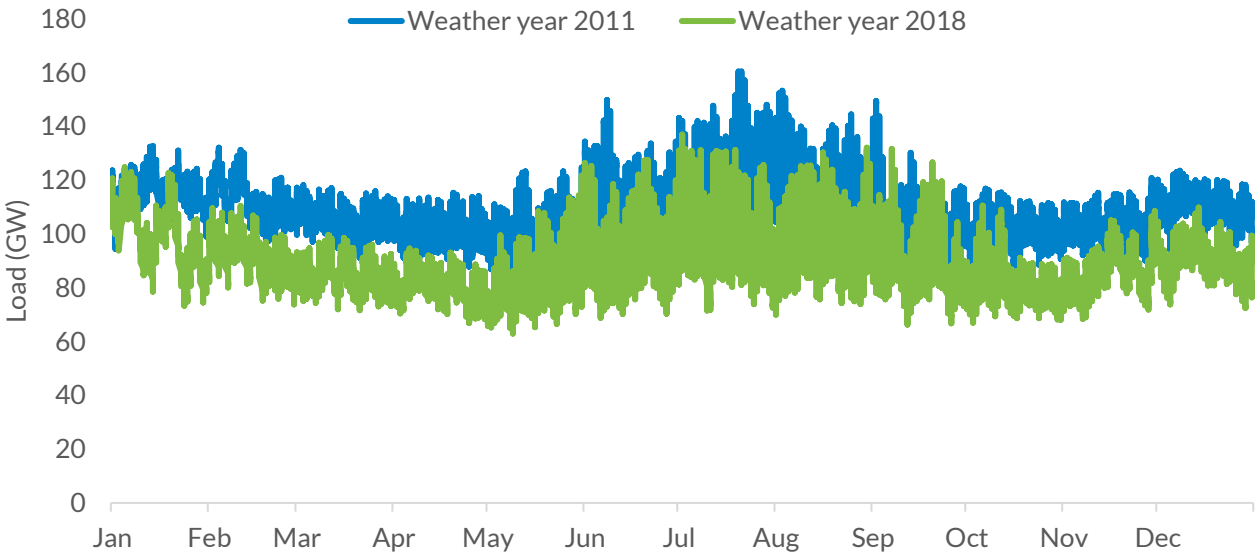


Figure A-4: Sample MISO-wide load profiles for study year 2027

LRZ	Annual Energy (GWh)		Annual Zonal Peak (MW)	
	2027	2032	2027	2032
LRZ 1	114,950	123,255	19,576	20,945
LRZ 2	73,097	80,374	13,268	14,578
LRZ 3	57,446	62,123	10,190	10,843
LRZ 4	55,684	59,790	10,222	10,909
LRZ 5	42,830	45,890	8,655	9,080
LRZ 6	113,354	121,692	19,718	21,207
LRZ 7	118,702	127,942	23,129	24,374
LRZ 8	44,109	45,961	8,527	8,964
LRZ 9	138,646	144,936	22,703	23,773
LRZ 10	24,297	24,950	4,756	4,851

Table A-1. Future 2A annual energy (GWh) and annual zonal peak demand (MW)

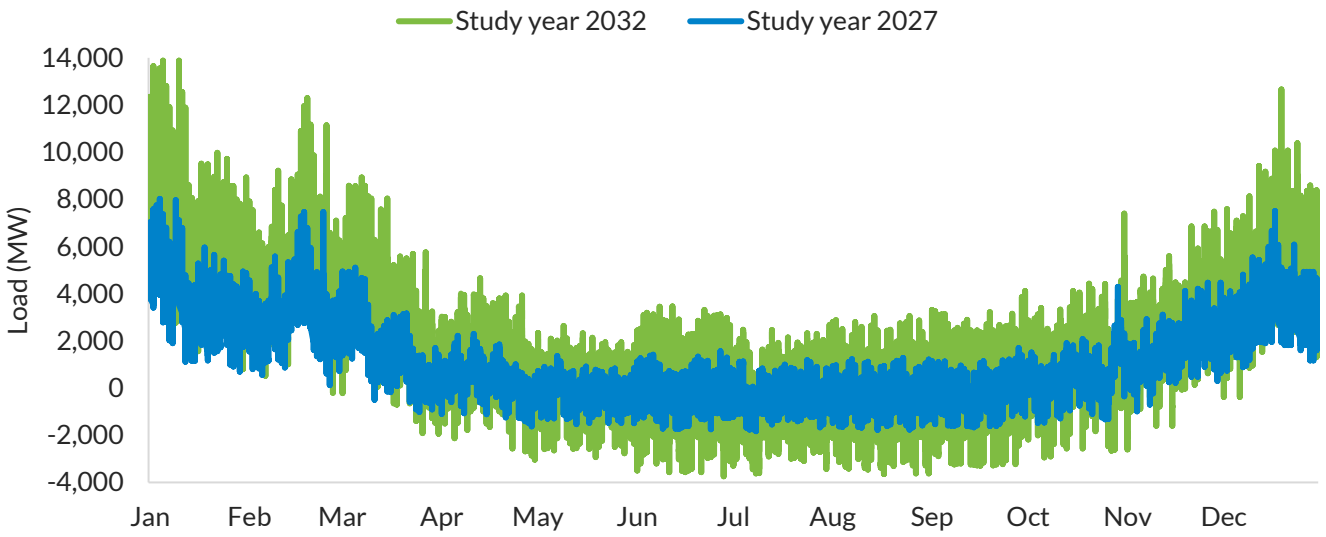


Figure A-5: MISO-wide net electrification (electric vehicle and building electrification load minus energy efficiency)

Generation

Generator capacities and retirement/installation dates were taken from the F2A expansion.

Seasonal FORs were incorporated into the model, along with annual forced outage mean time to repair (MTTR). These values were taken from the PY23-24 LOLE study on a unit-by-unit basis for existing units, and class averages by LRZ were used to assign FORs to future thermal units. FLEX units in the F2A model were assumed to have FORs similar to combustion turbine units.

Annual maintenance rates were incorporated into the model. These values were taken from the PY23-24 LOLE study on a unit-by-unit basis for existing units, and class averages by LRZ were used to assign maintenance rates to future thermal units. FLEX units in the F2A model were assumed to have the maintenance rates of an average gas combustion turbine unit. Maintenance was scheduled in one event per unit per year, matching PY23-24 LOLE study assumptions.

FORs were used and maintenance was scheduled for all unit types except the following:

- Demand response
- DG photovoltaic (PV)
- Interruptible
- Solar PV
- Solar PV Hybrid
- Wind
- Batteries

Additional generator properties were included for thermal units from F2A data. Unit-specific data was used for fixed operation and maintenance cost, variable operation and maintenance cost, heat rates (not used for hydro), and monthly maximum rating values.

Hybrid Units

For hybrid units, 70% of the capacity defined in F2A was assumed to be PV and 30% of the capacity was assumed to be battery. This matches the assumptions used in the 2022 Regional Resource Assessment.

Additionally, there were two constraints for hybrid units implemented in the model. The first is a point of interconnection constraint, which ensures that the solar output and battery output combined cannot be greater than the total hybrid unit capacity at any given time. The second constraint is that the battery portion of the hybrid unit can only charge from the output of the PV portion of that unit.

Specific assumptions relating to batteries, both stand-alone and hybrids, are listed in Table A-2.

Consideration	Modeling Assumption
Battery Capability	Four-hour discharge capability at rated output
Battery Efficiency	Charging efficiency 85% and discharging efficiency 100%
State of Charge	Initial SOC set at 100% and changes as a function of dispatch decisions. Does not reset at the beginning of each day.
Operation	Maximize contribution during loss of load events.
Charging Source – Stand-Alone Battery	Battery can charge from the grid.
Charging Source – Hybrid Battery	Battery component may only be charged from solar PV and not directly via grid.

Table A-2. Modeling assumptions used for stand-alone and hybrid batteries.

Renewable profiles

Hourly wind energy production profiles were gathered from NREL's Wind Integration National Dataset (WIND) Toolkit for the years 2007-2012. Solar data was sourced from NREL's Solar Integration National Dataset (SIND) Toolkit for the same years. Additional data was supplied by Vibrant Clean Energy for the years 2014-2021.

Each wind and solar resource were assigned specific energy-production profiles based on their location, one profile with hourly granularity for each of the 14 years (2007-2012, 2014-2021) studied. Exact latitude and longitude data for future units came from the F2A siting. Exact location data for existing units came from PROMOD when available or was otherwise manually approximated.

Figure A-6 and Figure A-7 present sample MISO-wide solar and wind profiles, respectively, for study year 2027.

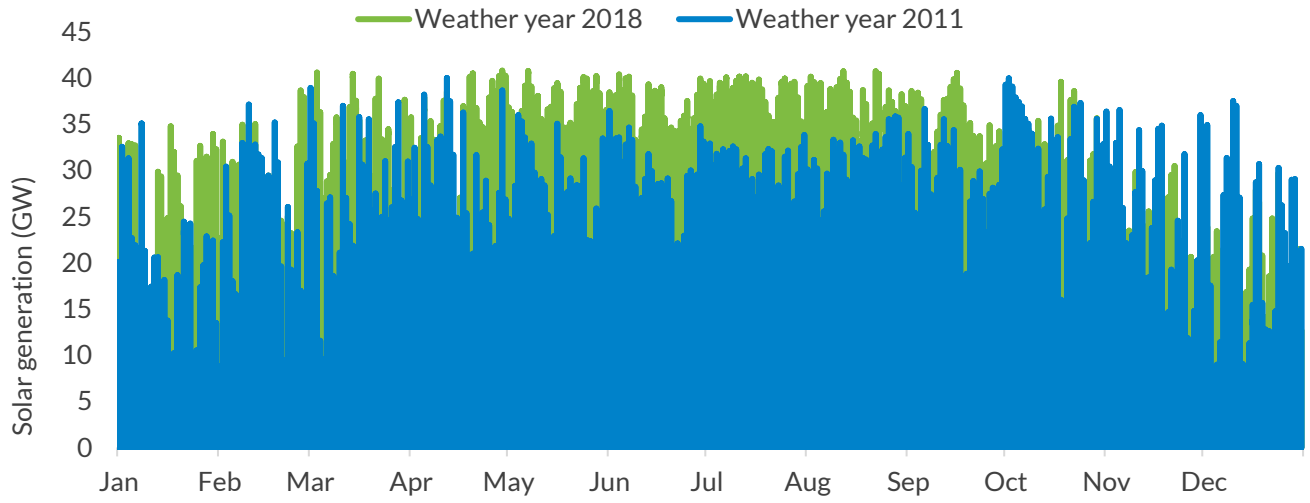


Figure A-6: Sample MISO-wide solar profiles for study year 2027

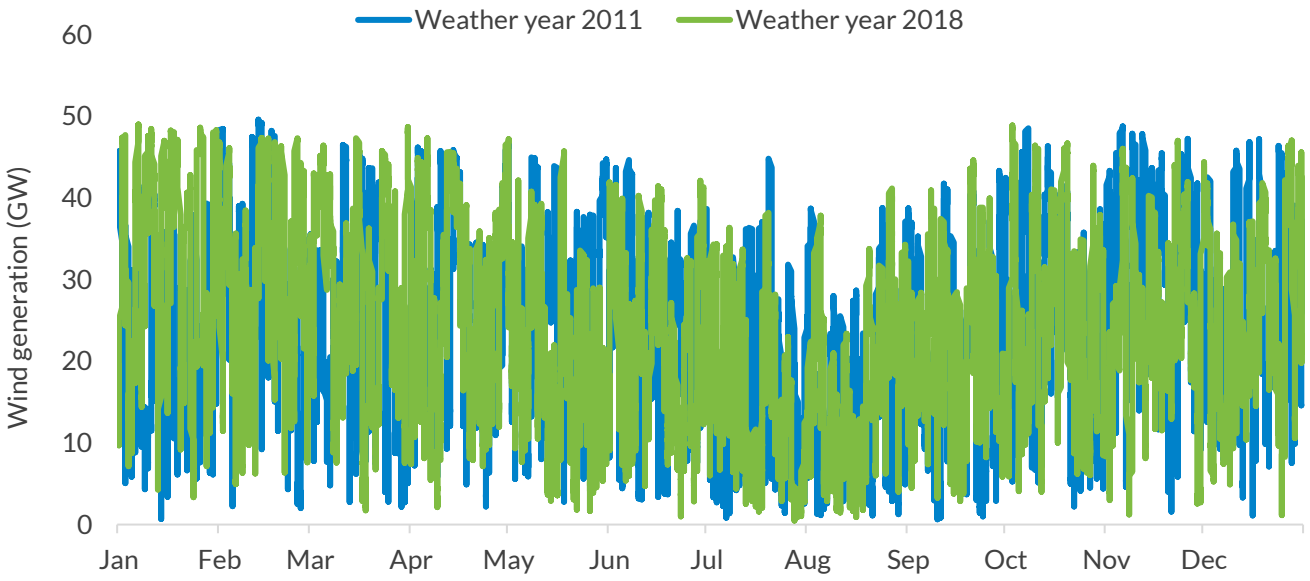


Figure A-7: Sample MISO-wide wind profiles for study year 2027

External Units (Firm and Non-Firm)

Non-firm external imports were included in the model, following the distribution in Table 3-5 from the PY23-24 LOLE study.

Firm external generation units were also included in the model from the PY23-24 LOLE study, and data for the specific units was used for monthly ratings, forced outage parameters (rates and mean time to repair), and maintenance rates. Class averages from the F2A data were used to assign fixed- and variable-operation and maintenance costs, and heat rates for each external unit.

A.3 Scenarios

The model year portfolios were analyzed under three scenarios: business as usual (BAU), enhanced risk assessment (ERA), and flexibility. Figure A-8 summarizes the design behind these three scenarios and how they align with the overall risk factors in the Attributes framework.

- **Business as usual (BAU)**
  - Aligns with base business RA modeling practices and includes cold-weather dependent thermal forced outages
  - *Risk factors:* Availability and Fuel Assurance
- **Enhanced risk assessment (ERA)**
  - Add regional directional transfer (RDT) constraint between MISO North/Central and South, heat rates, fuel prices, and price-responsive storage dispatch to the BAU scenario
  - *Risk factors:* Availability, Fuel Assurance, and Energy Assurance
- **Flexibility**
  - Add generator ramp rates (MW/min) and minimum stable levels to the BAU scenario
  - *Risk factors:* Availability, Fuel Assurance, Rapid Start-Up, and Ramp Up

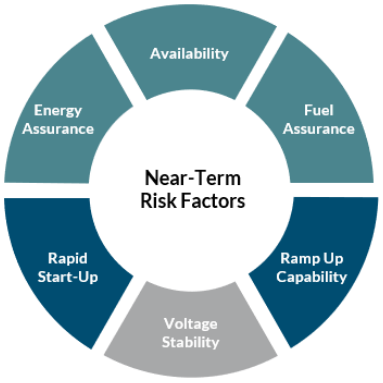


Figure A-8: System adequacy risk factor scenarios

The rest of this subsection introduces the specific assumptions of each scenario.

A.3.1 Business as Usual

In the PY23-24 LOLE study, weather-dependent outages[13] for coal and gas resources were first included in the LOLE study model. Historical MISO GADS[14] data from 2017-2021 was gathered and analyzed to develop forced outages and hourly temperatures by LRZ. From the analysis, which showed a strong relationship between cold temperatures and forced GADS outages for many LRZs, hourly outages in MW were developed for each LRZ and included in the PY23-24 LOLE study model as negative perfect generation.

This analysis implemented the PY23-24 LOLE study outages as hourly MW "adders," with one fixed shape for each weather year. Figure A-9 presents two samples of the MISO-wide weather-dependent outages for the PY23-24 model.

[13] Astrapé Consulting, *MISO Seasonal Inputs for the 2022 LOLE Study*, July 2022.

[14] NERC, Generating Availability Data System

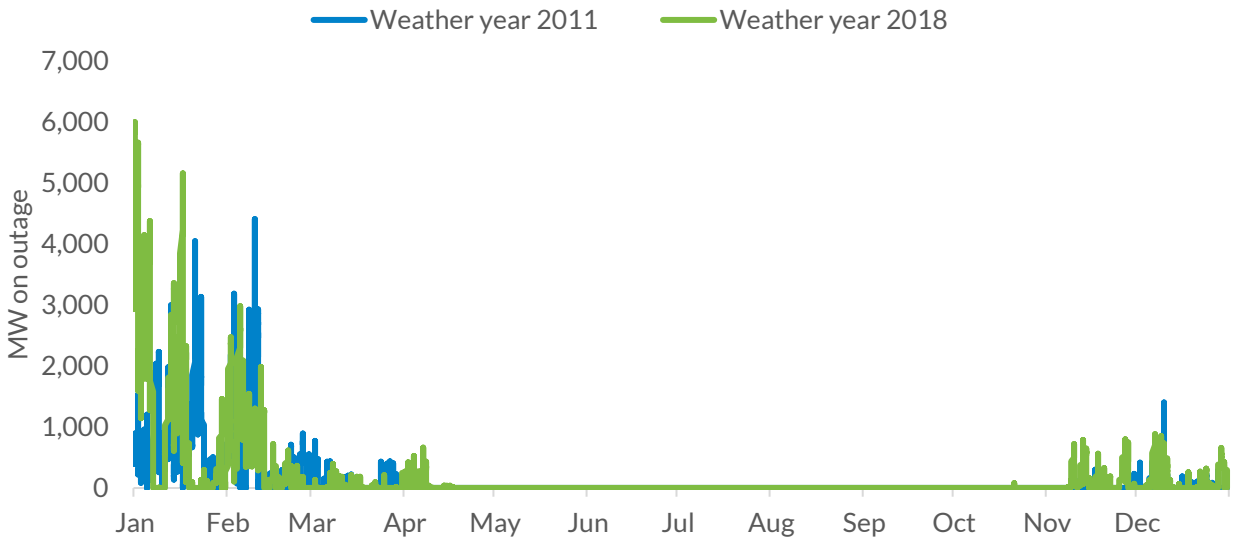


Figure A-9: Sample MISO-wide modeled, weather-dependent outage profiles for study year PY23-24

For the 2027 and 2032 models the hourly outages were scaled based on ICAP in PY23-24 compared to 2027 and 2032. The study represented the Flex units as gas units, so the gas ICAP increased by 65% for 2027 and 70% for 2032, compared to PY23-24. Coal ICAP decreased by 51% for 2027 and 74% for 2032. In all, the hourly outages increased by 35% for 2027 and 32% for 2032, compared to PY23-24.

A.3.2 Enhanced Risk Assessment (ERA)

MISO included the regional directional transfer constraint between MISO North/Central and MISO South in the ERA cases. This constraint places a transfer limit of 3,000 MW from North/Central to South and 2,500 MW from South to North/Central, as shown in Figure A-10. There is no other transmission modeled between individual LRZs.

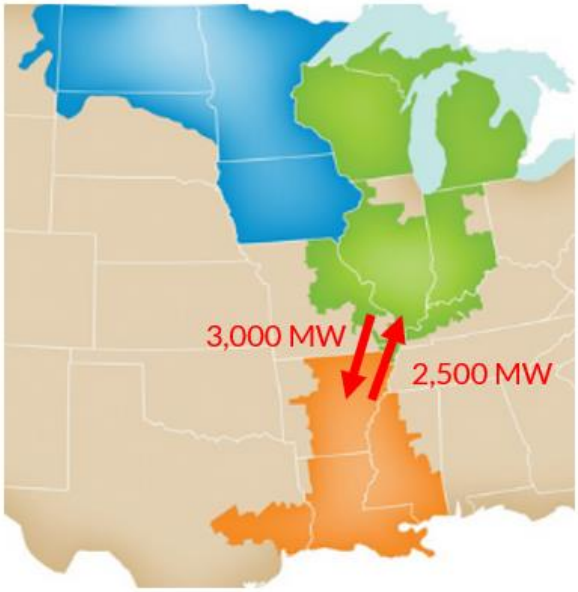


Figure A-10: MISO sub-regions with the regional directional transfer (RDT) constraint highlighted.

Adding transmission constraints complicates the LOLE adjustment process, which is straightforward in traditional copper sheet resource adequacy models. There are multiple ways to reach LOLE targets, depending on 1) whether the LOLE target is enforced at the system level or for each region individually and 2) how adjustments are distributed across the regions. Balance of risk between regions shown in the results section is highly dependent on the selected adjustment method and LOLE target area. Changing the methodology used to adjust may have an impact on simulation results, however, the direction of the results (e.g., shift in risk) are expected to be unchanged.

For the ERA scenario, fixed load adjustment for LOLE analysis was added to each region based on their contribution to MISO coincident peak load. Each region was not adjusted to an independent LOLE target. Instead, all of MISO was adjusted to the 0.1 days/year target, which resulted in a risk profile that was not evenly distributed between the two regions (North/Central and South).

A.3.3 Adequacy-Flexibility Constraint

The goal of this scenario was to further test the BAU model's ability to respond to ramping constraints within the resource adequacy simulations. Both the BAU (without flexibility constraints) and adequacy-flexibility models (with the constraints) were run as rounded relaxation problems for equivalent comparisons.

The historical five year's economic minimum and maximum dispatch and maximum ramping up and down data of thermal units was collected from MISO's historic operation data archive. When commercial pricing node match was available between the unit in operation and the existing unit modeled in PLEXOS, the five-year average of each property was used directly. For the future units and units with missing mapping, a class average was used. To calculate the class average, a class was first defined based on the fuel type of the unit. Among each fuel type, individual units were classified between large, medium, and small categories to form three aggregation groups. PLEXOS units with missing economic mappings were separated into the same classes, first by fuel type and then by their maximum capacity and were assigned the corresponding class average values. Wind and solar curtailment were not considered during the simulation, posing some limitations to the system's capacity to react to net load ramping.

A.4 Results

This subsection summarizes the findings of the analysis. The three scenarios presented in the last subsection were run across study years.

A.4.1 Business as Usual

As expected, LOLE for the PY23-24 model was only present in the summer season with the annual adjustment, and fixed load was added to the remaining seasons to reach a LOLE of 0.01 days/year.

For the 2027 model, LOLE was present in both summer and fall with the annual adjustment, and for the 2032 model, LOLE was present in both summer and winter, which suggests seasonal shifts in risk as the resource portfolio evolves. Figure A-11 presents the loss of load results for the BAU case, showing seasonal loss of load hour frequency from the models, as well as expected unserved energy (EUE) and LOLE for each model. The results show the highest risk in summer for PY23-24, summer and fall for 2027, and summer and winter for 2032.

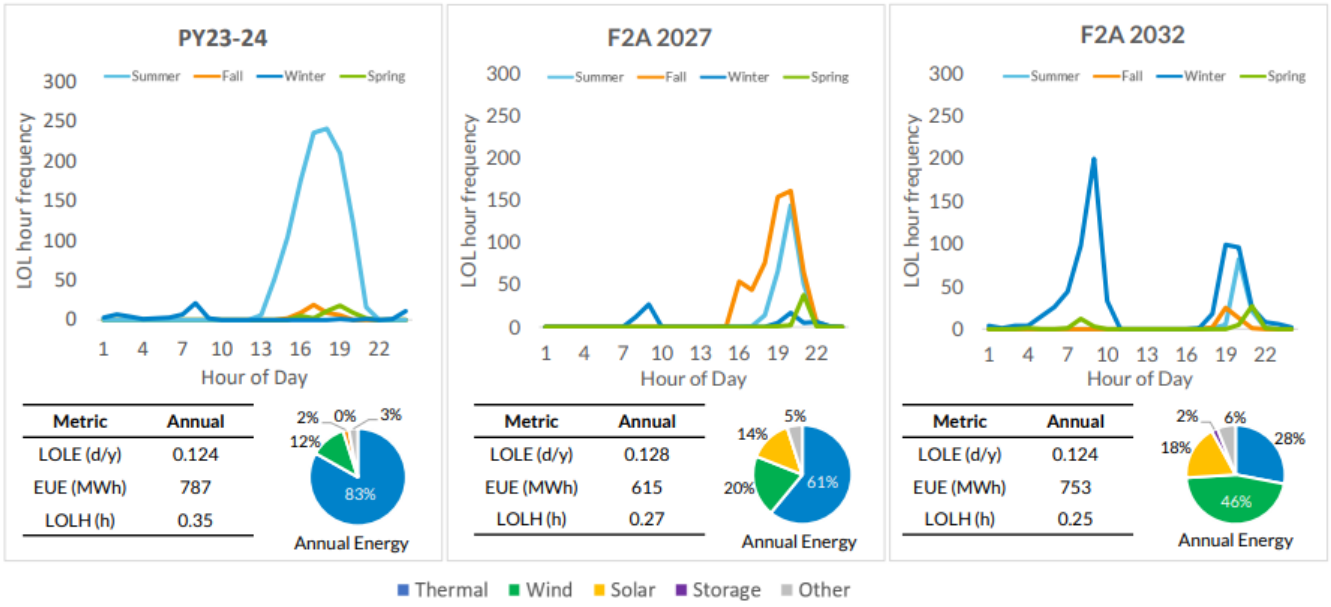


Figure A-11: Loss of load results for the business-as-usual case

DLOL class accreditation estimates were also found for each model year. Due to processing limitations, DLOL results were calculated for wind, solar, storage, and "all other" resource types, which includes all thermal resources and hydro and pumped storage.[15]

Figure A-12 through Figure A-15 present the DLOL results for the summer season, as well as seasonal average diurnal charts which indicate the hours of the season with EUE and average load, load net wind and solar generation, and average wind and solar generation across the season.

Generally, as solar increases in the resource portfolio, risk shifts into evening and early morning hours. At those times solar generation is low, which reduces the solar DLOL across model year portfolios. The charts also show an increase in the "duck curve" shape of net load, as solar increases in the portfolios. Changes to wind DLOLs across model years are mixed as risk shifts into or away from weather years with lower-than-average generation and is less dependent on the time of day of the risk than is solar. Storage DLOLs result in lower values for spring and winter for 2032, as longer-duration EUE events occur which limit the assumed 4-hour ability to fully charge and discharge across the duration of events.

System Adequacy Insight #1:

Accreditation is aligned with the risk distribution, regardless of the underlying sources of risk modeled, and tracks the contribution of individual resources.

[15] All other resource types include nuclear, steam turbine coal, combined cycle, combustion turbine gas, steam turbine gas, flex units, hydro and pumped storage, demand response and interruptible load, solar / storage hybrid, and other.

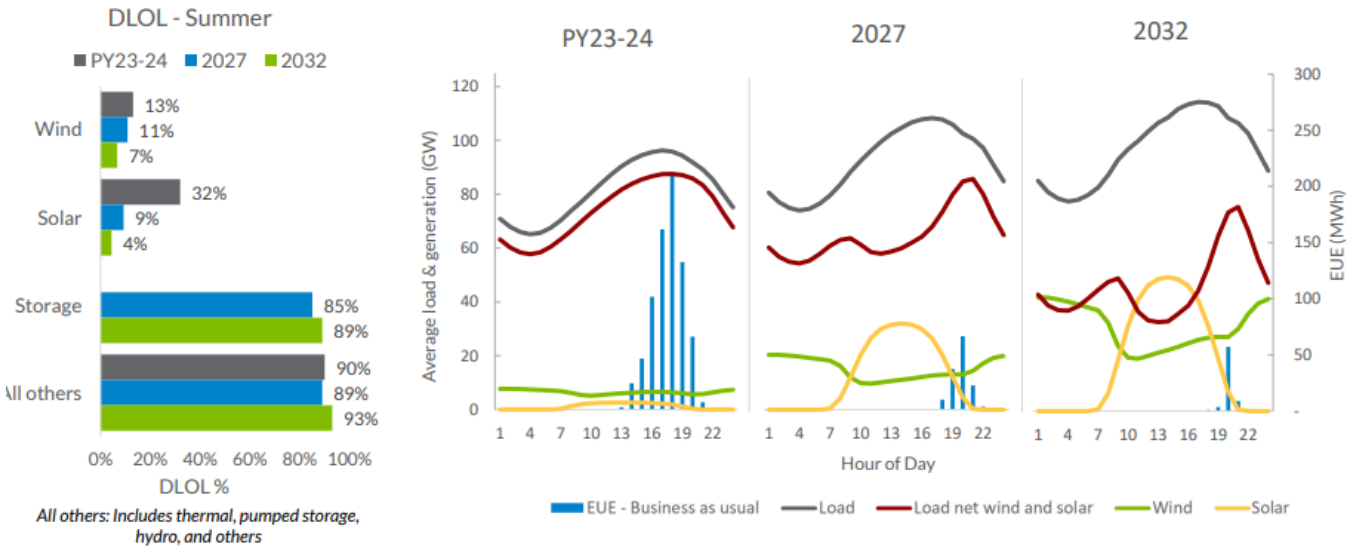


Figure A-12: Summer DLOL results for BAU case

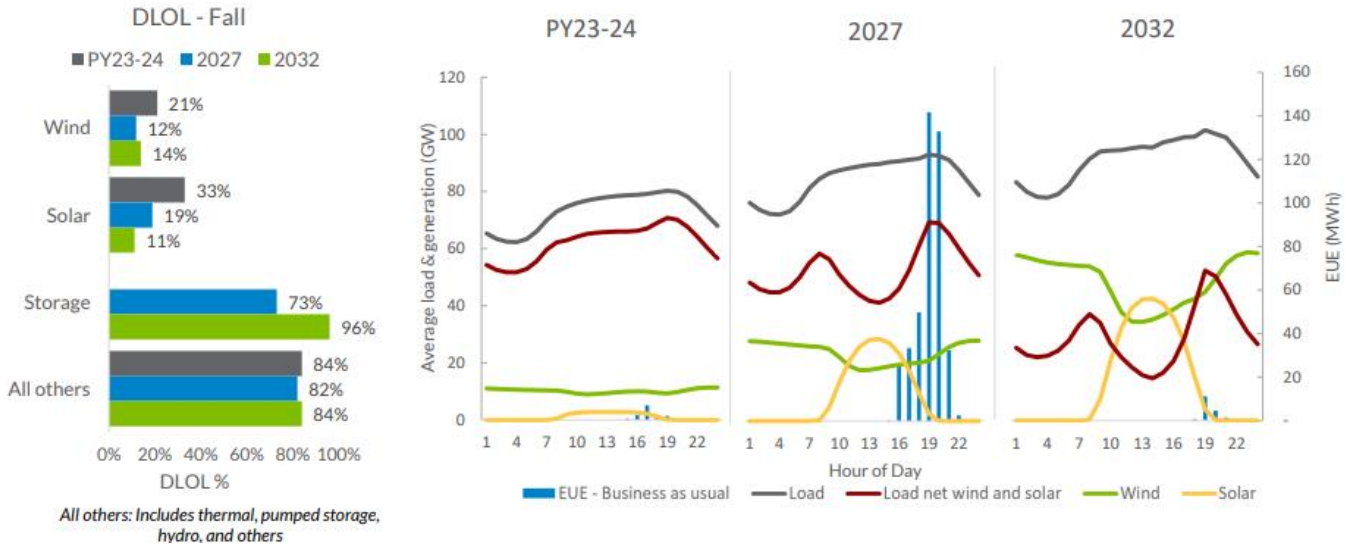


Figure A-13: Fall DLOL results for BAU case

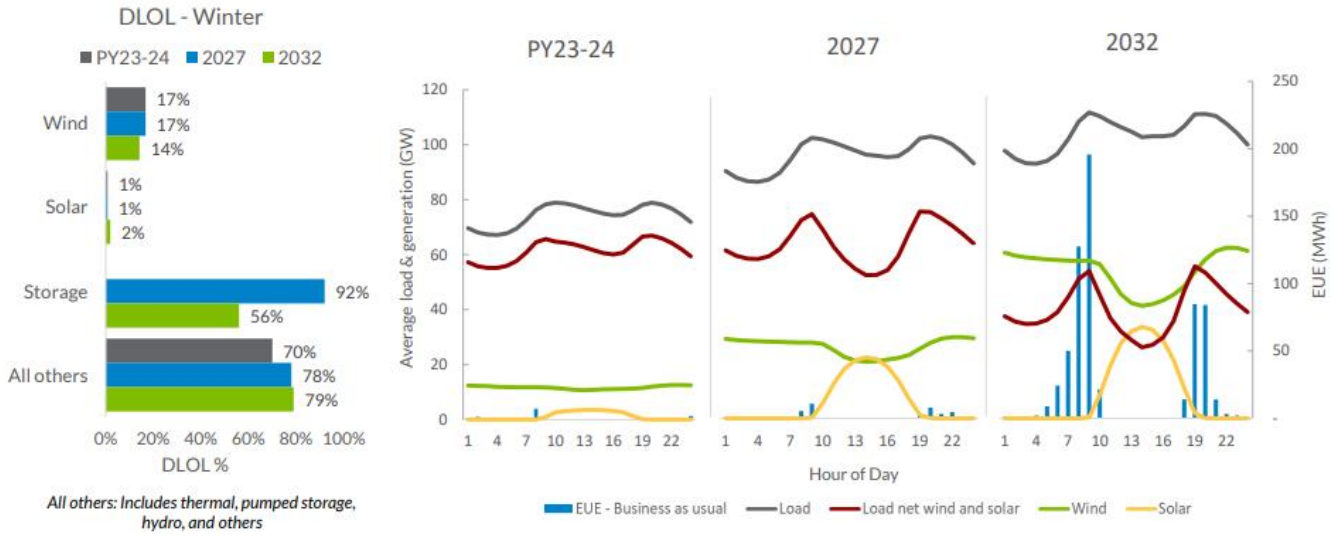


Figure A-14: Winter DLOL results for BAU case

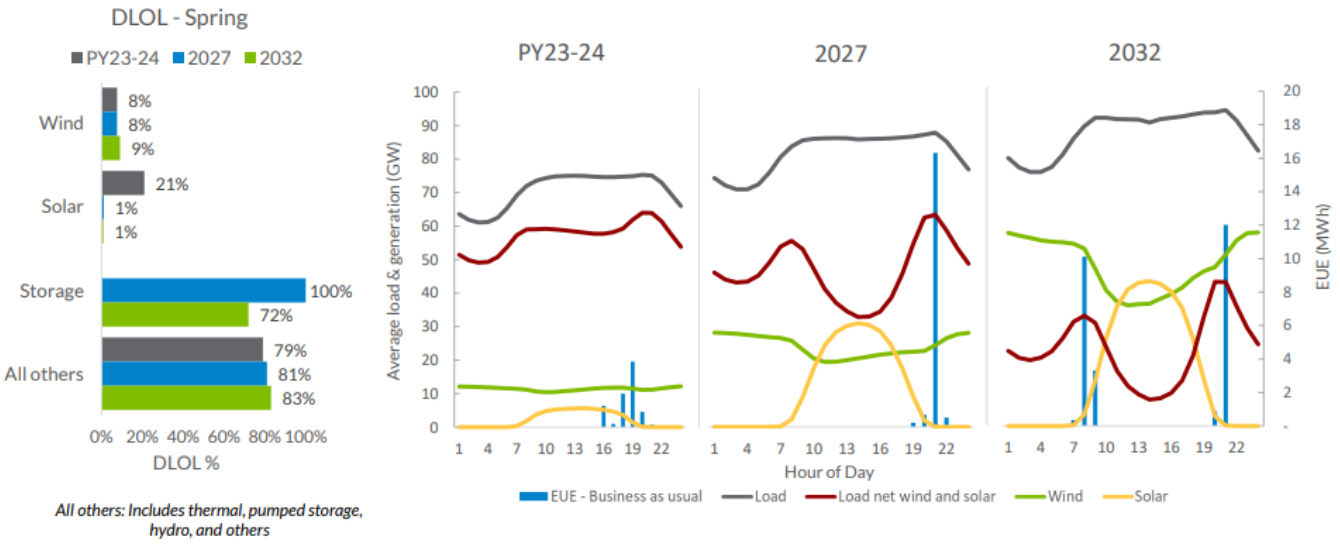


Figure A-15: Spring DLOL results for BAU case

A.4.2 Enhanced Risk Assessment (ERA)

The same adjustments that drove the BAU cases to criteria (0.1 days/year annual LOLE and at least 0.01 days/year LOLE per season) were applied to the ERA cases. The ERA cases, which incorporated the regional directional transfer limits between MISO North/Central and South, had a higher LOLE than the BAU case when at the same adjustment. As shown in Figure A-16, in 2027 LOLE experienced its largest increase in spring and winter when the regional directional

System Adequacy Insight #2:

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

transfer constraint was added, indicating those seasons had the most deliverability limitations between the two MISO regions. Similarly, in 2032 the LOLE increase was concentrated in the winter months for the ERA case, with minimal impacts during the rest of the year coming from the inclusion of the regional directional transfer constraint. The 2032 winter risk increase for the ERA case is driven mainly by deliverability constraints during the 2021 weather year (during Winter Storm Uri).

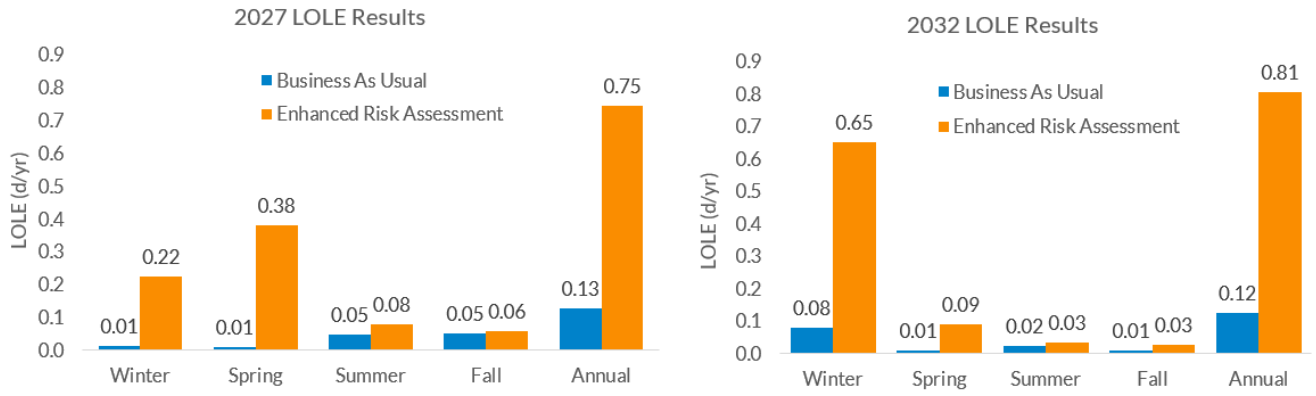


Figure A-16: LOLE comparison between the BAU And ERA cases at the same adjustment

The ERA cases were then adjusted to match the seasonal LOLE values of the BAU cases, to compare the resulting risk profiles and metrics before and after transmission is added in resource adequacy analysis. Figure A-17 shows that in both 2027 and 2032, the ERA case had a smaller EUE value than the BAU case when both were adjusted to the same LOLE target of 0.1 days/year. Loss of load hours (LOLH) did not present a clear trend; LOLH decreased for the ERA case in 2027, but it remained nearly the same between the BAU and ERA case in 2032.

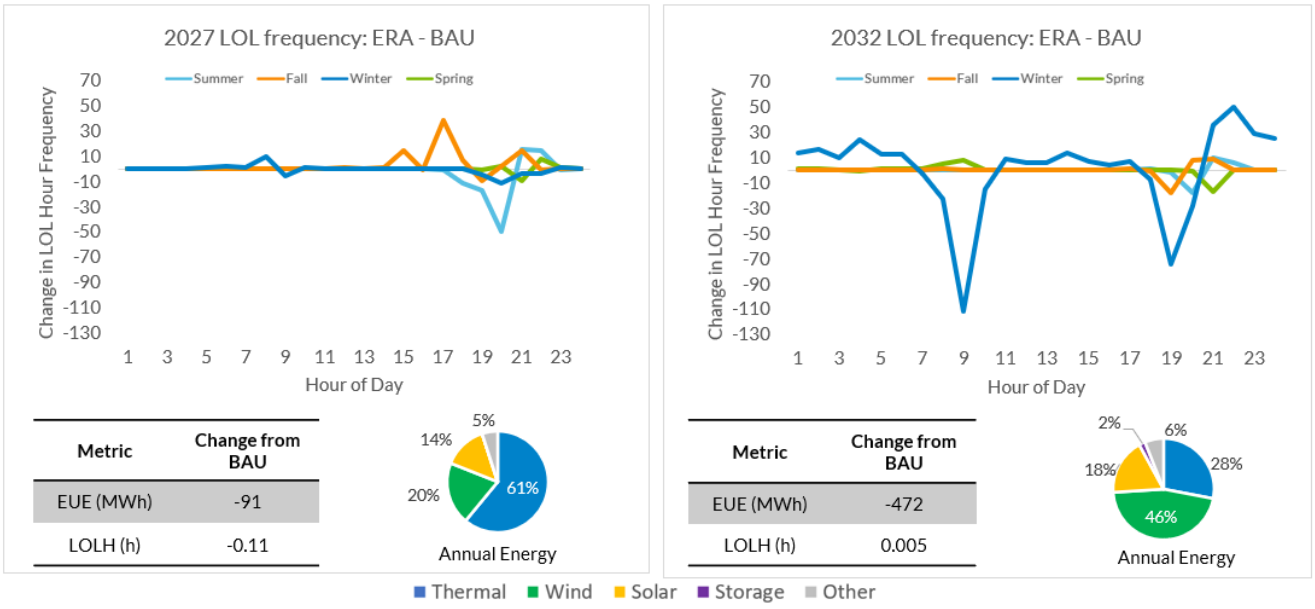


Figure A-17: Loss of load hour frequency and metric changes from the BAU to ERA cases when both are adjusted to the same LOLE targets

The reason for the difference in EUE between the two cases when they are both adjusted to a LOLE target of 0.1 days/year can be explained in part by Figure A-18. For both 2027 and 2032, the BAU cases have a higher average amount of unserved energy per loss of load hour compared to the ERA cases. Additionally, Figure A-19 the ERA cases have a much higher number of unique hours with loss of load across all weather years, despite having a similar LOLH. This indicates that events are smaller in magnitude in the ERA cases and are spread out over a larger portion of the year, rather than a few hours with severe conditions.

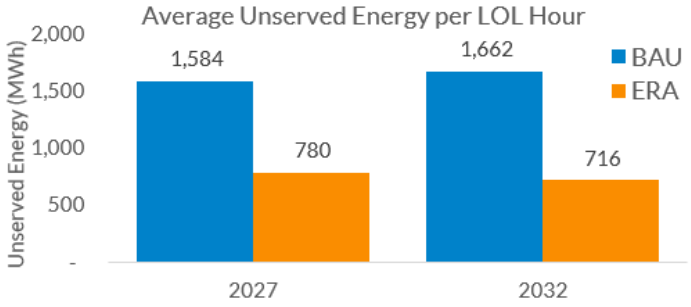


Figure A-18: Average unserved energy per loss of load hour for BAU and ERA cases when both are adjusted to the same LOLE targets

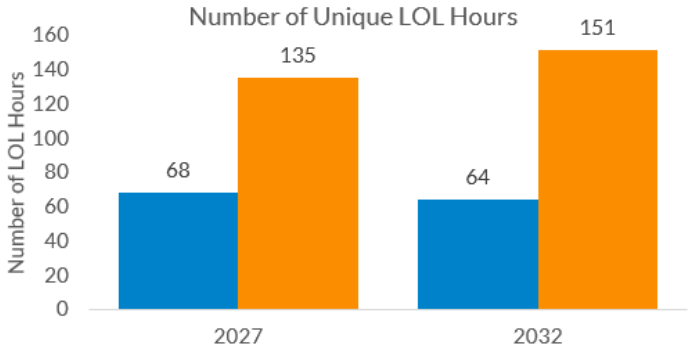


Figure A-19: Number of unique hours across weather years with loss of load when BAU and ERA cases are adjusted to the same LOLE targets

Figure A-20 and Figure A-21 show the accreditation change for each resource class when transmission constraints are added to the model. Wind DLOL increased in almost every season in both 2027 and 2032 from the BAU to the ERA case. This is because most of the wind capacity in the early years of the Future 2A model in the North/Central region, and wind was high in the North during loss of load events in the South in the ERA cases. The details of renewable and storage resource capacity by region for both 2027 and 2032 is shown in Table A-3.

Similarly, storage DLOL decreased in most seasons in the ERA cases because the majority of storage capacity is in the North/Central region and was charging during loss of load events in the South. An example of these two drivers of accreditation changes can be seen in Figure A-22, which isolates a portion of the 2021 weather year that corresponds with Winter Storm Uri — an event that drives a large portion of the LOLE for the 2032 model year.

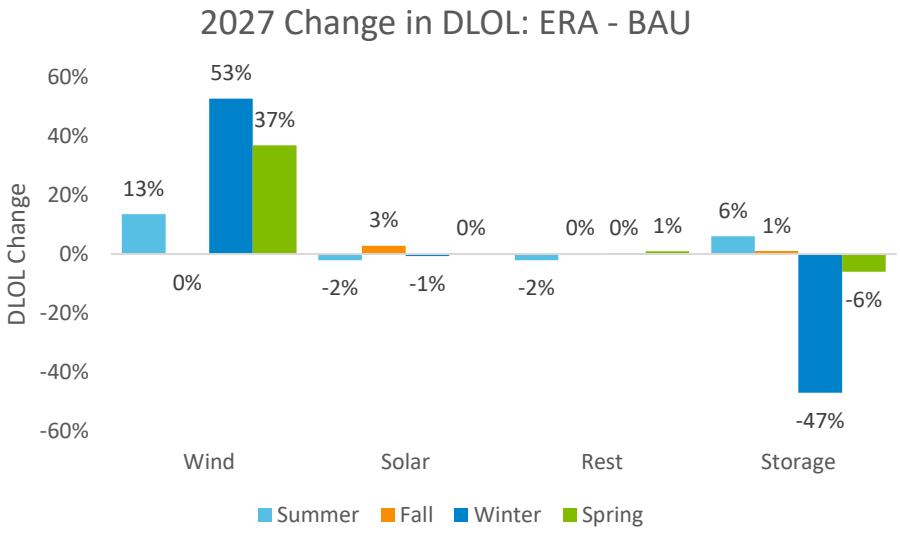


Figure A-20: Change in DLOL by resource class between the ERA and BAU cases in 2027 when both are adjusted to the same LOLE targets

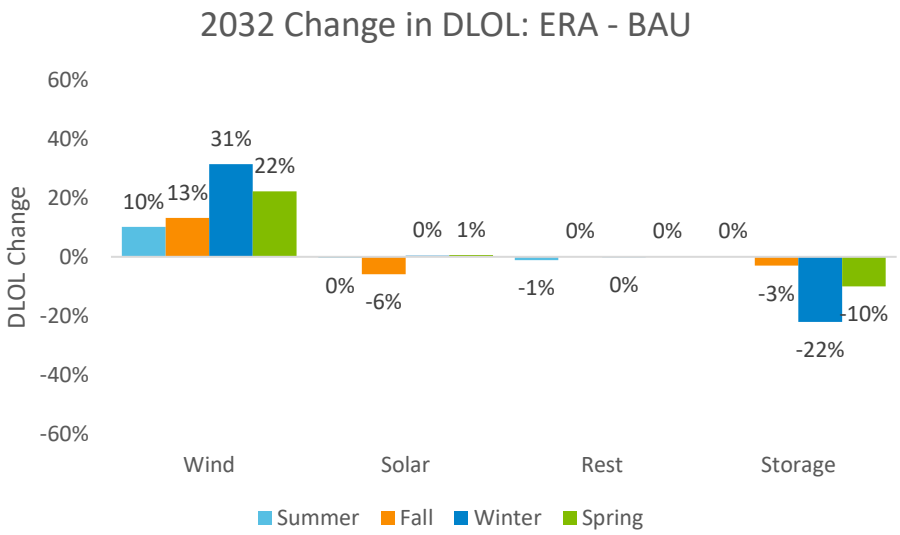


Figure A-21: Change in DLOL by resource class between the ERA and BAU cases in 2032 when both are adjusted to the same LOLE targets

Generator class	2027 ICAP (GW)		2032 ICAP (GW)	
	North/Central	South	North/Central	South
Wind	48.5	1.3	105.1	1.7
Storage	3.6	0.02	6.0	1.3
Solar	28.9	11.9	45.2	18.8

Table A-3. Renewable and storage installed capacities (ICAPs) by region from the Future 2A expansion

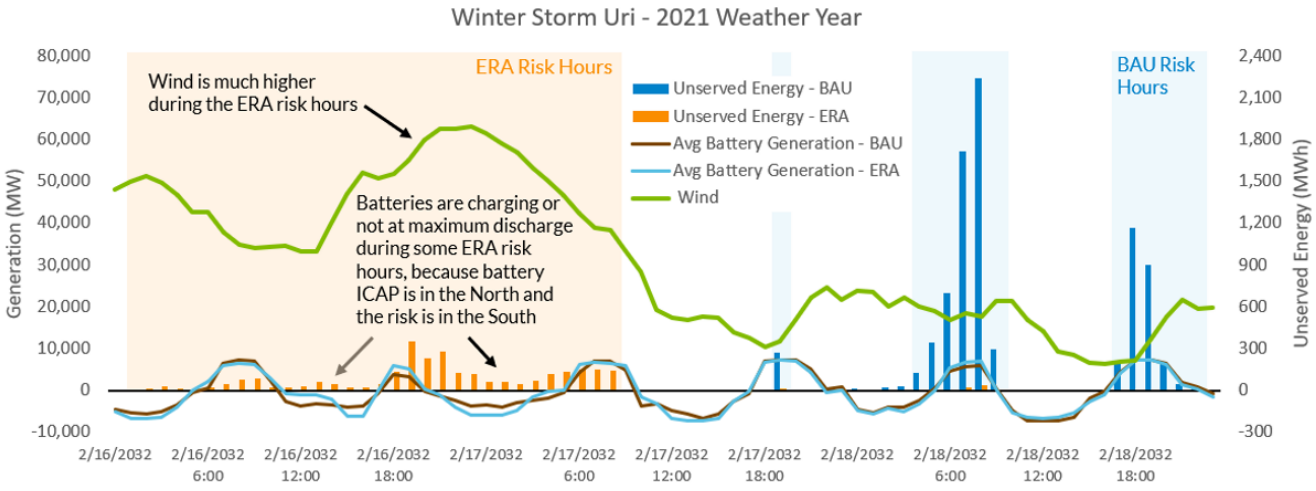


Figure A-22: Example of wind and battery generation and unserved energy from the BAU and ERA cases during Winter Storm Uri in the 2021 weather year simulation

A.4.3 Adequacy-Flexibility Analysis

The adequacy-Flexibility study model used the 2032 BAU model at criteria, i.e., after the LOLE adjustment was completed on a seasonal basis. No additional calibration of the LOLE was applied in this part of the analysis.

System Adequacy Insight #3:

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

The analysis focused on finding the most challenging event the system might experience, by adding further constraints to the period in which the BAU model's adequacy was most tested. In each season, a week with the highest unserved energy amongst all weather years simulated in BAU was chosen as the starting point. Figure A-23 shows the weeks with high EUE present high correlation of net load and net-load ramping, making the period suitable for testing Adequacy-Flexibility constraints.

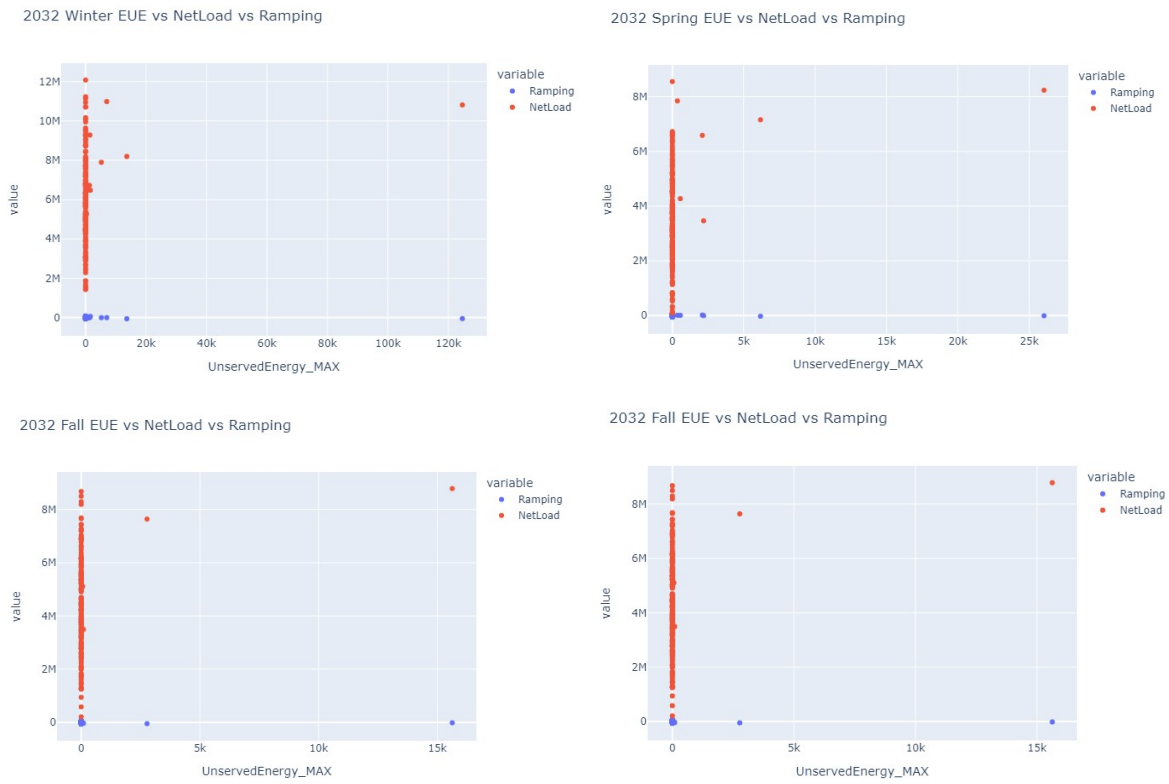


Figure A-23. Weekly unserved energy (MWh) vs net load (MW) and net load ramping (MW) of BAU

Table A-4 shows the final week and weather year chosen for the analysis. The corresponding week of event dates were simulated for the 2032 study year.

Season	Study Year	Weather Year	Week	Dates
Winter	2032	2021	8	February 22-28
Spring	2032	2019	10	March 4-10
Summer	2032	2010	33	August 16-22
Fall	2032	2012	37	September 10-16

Table A-4: Adequacy-Flexibility Analysis Seasonal Simulation Period

No significant changes were observed between the BAU and the Adequacy-Flexibility scenarios for LOLE (number of expected days with events) or LOLH (number of expected hours with events). The EUE of the system showed a significant increase in all seasons, especially in Spring, as shown by Figure A-24. As illustrated in the System adequacy section of the *Attributes Roadmap*, high planned maintenance of thermal units was scheduled during spring and limited the availability of units with higher ramping capability.

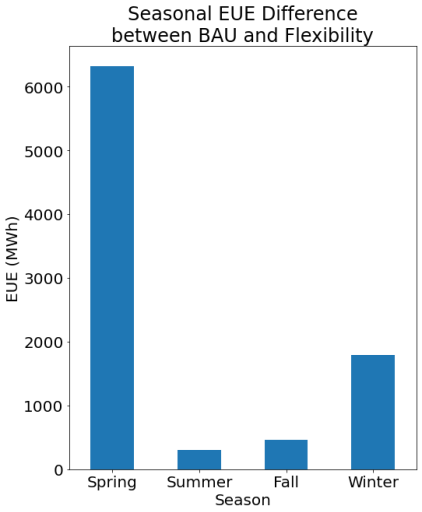


Figure A-24. Seasonal EUE Difference – BAU vs Adequacy-Flexibility

Winter showed the second highest increase in EUE between BAU and Adequacy-Flexibility scenarios. The weather year simulated, 2021, exhibited below average wind generation during its winter, causing longer duration of EUE event. Figure A-25 shows the seasonal comparison of EUE event duration between BAU and Adequacy-Flexibility. Both spring and winter show an increase in longer duration events when the flexibility constraints are applied to the resource adequacy model.

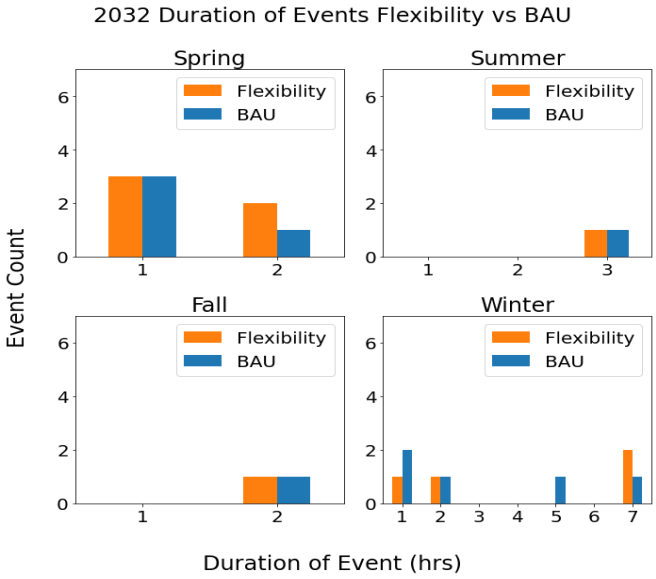


Figure A-25. Seasonal EUE Event Duration – BAU vs Flexibility

Future work may include enable wind/solar curtailment, five-minute simulation, and including operating reserves requirements.

A.5 Conclusions

This section described approaches, tools, and assumptions used in the system adequacy attributes analysis that informed insights and roadmap development. 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?

B.Operational Adequacy

The aim of the operational adequacy analysis was to evaluate MISO's current energy and ancillary services market products and rules, to ascertain whether they are able to procure adequate system reliability attributes, in particular under stressed system conditions. The approach taken was to run a two-stage simulation replicating a simplified version of MISO's two-settlement market, comprising of day-ahead market unit commitment followed by real-time market economic dispatch. This approach was used to analyze both the current portfolio and the future portfolio using MISO's Future 2A scenario. This analysis supports the insights and solution hypothesis presented in MISO's 2023 *Attributes Roadmap*.

B.1 Framework for Market Simulations

B.1.1 Tool

The energy market simulation portion of the system reliability attributes analysis work was carried out using a MISO-enhanced version of the Electrical Grid Research and Engineering Tool (MISO EGRET) that has implemented many of MISO's products, services, and commitment rules. The original EGRET is a Python-based unit commitment and economic dispatch tool that was developed by the Sandia National Lab. MISO EGRET is based on the original EGRET, and was developed jointly with Sandia National Lab, National Renewable Energy Laboratory (NREL), Nexant and Arizona State University under an ARPA-E funded project. For this analysis, MISO developed and tested a new two-stage (day ahead and real time) modeling framework suitable for the system reliability attributes analysis work.

B.1.2 Metric

For this analysis, it was assumed that in the operating timeframe unserved energy is more likely to occur on extreme days than days with normal system operating conditions. Hence the current and future portfolio simulations focused on specific individual days, rather than the whole year. Because only individual days were simulated, this report includes the amount of unserved energy for those days instead of expected unserved energy, which is typically used to assess a longer period such as a season or a year.

For the analysis of the current portfolio, four extreme days were selected from the recent history, one from each season. This provided a good representation across the year and captured seasonal variations. For the future portfolio only winter and summer days were selected because they had the highest potential risks, based on the screening methodology used in this study.

B.1.3 Two-Stage Simulation Framework

It is important to note that the simulation approach was not intended to replay the historical emergency events exactly as they occurred. During those historical events, MISO Operations (acting in coordination with MISO's neighbors) took multiple actions to manage the actual events successfully. Thus, the simulated scenarios will differ from the historical outcomes. This was an intentional modeling choice given that the purpose of these simulations was to analyze "what-if" scenarios and thus to learn key lessons for the System Attributes initiative.

The two-stage simulation framework is presented in Figure B-1 and is organized as follows:

- **Day-ahead stage**: generation unit data such as unit parameters and offers were taken from day-ahead production cases. For renewable units (wind and solar) their economic maximum values were taken from the data of the Forward Reliability Assessment Commitment (FRAC) process. MISO's FRAC load forecast was used rather than market participant demand bids, as is typically the case in the Day-Ahead

Market (DAM), since the aim was to judge the impact of MISO's forecast. The FRAC Net Scheduled Interchange amount was considered (i.e., the net imports from MISO's neighbors). Virtual transactions were excluded.

- **Real-time stage**: data from MISO's look-ahead commitment (LAC) process was used for simplicity. The 96 LAC production cases for the day were combined by taking the first interval from each of them and stitching them together.[16] The small differences between the first interval of LAC and the real-time market cases (such as in outages or forecasts) were ignored. The real-time load was assumed to be known in advance with perfect foresight for the economic dispatch simulation.

The simulations for both current and future portfolios did not consider transmission constraints other than the regional directional transfer limit.[17] This limit is 3,000 MW for transfers from North to South, and 2,500 MW for South to North.

This analysis focused solely on the energy and ancillary services market constructs. Intra-day commitments and other reliability actions usually taken by MISO operators were excluded from this framework.

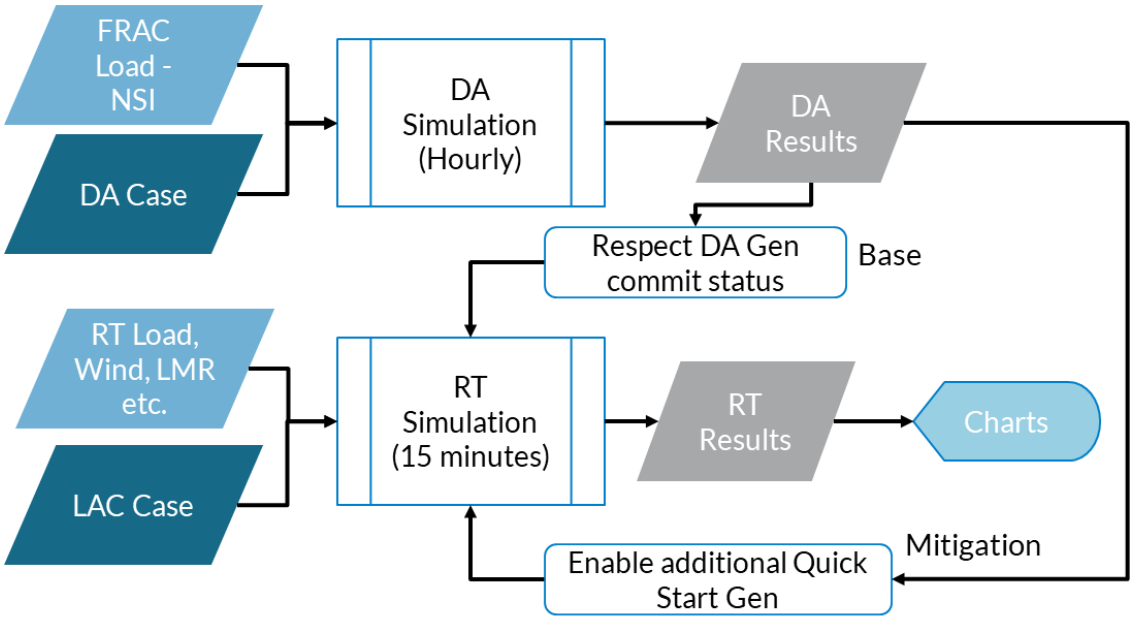


Figure B-1: Simulation framework for energy and ancillary services market

[16] LAC executes every 15 minutes throughout the day on a rolling basis, and the first interval of LAC has a 15-minute span. Thus, we get 96 LAC cases for the whole day.

[17] MISO's Settlement Agreement with SPP and the Joint Parties provides that the upper limit of SPP and the Joint Parties' Available System Capacity is 3,000 MW for flows from MISO North to MISO South and 2,500 MW for flows from MISO South to MISO North. These limits are referred to as Regional Directional Transfer (RDT) Limits.

B.1.4 Screening Methodology for Stressed Periods

The stressed period analysis aimed to find days in the future which have the highest potential for challenging operating conditions. The analysis was based on system net load[18], and associated variability and forecast uncertainty.

The screening analysis assumed that potential flexibility needs are likely to be highest during days with high amounts of net load, net load variability and forecast uncertainty. Net load is defined as load minus renewables (wind and solar PV). Variability is defined as net load changes between time intervals. Forecast uncertainty is defined as the difference between real-time net load and day-ahead forecasted net load.

For each season and future year, the potential stressed days are identified as follows:

- Find the days that contain three or more hours which are at or above the 95th percentile of system-wide net load
- Find the days that contain at least one hour at or above the 95th percentile of net load variability (net load ramp in GW/hour)
- Find the days that contain at least one hour at or above the 95th percentile of net load uncertainty between day-ahead to real-time (net load forecast error in GW)
- Find days in common that have been flagged in Steps 1, 2 and 3 and identify them as stressed days in each season
- The above steps were repeated for each future year, 2027 and 2032
- The days in each future year and season with the highest net load, net load variability and net load uncertainty were identified as the target days for the simulations

B.2 Scenarios

Different types of scenarios were developed to inform the solution hypothesis being considered:

- **Base Case**: this simulated a day-ahead unit commitment for a selected day followed by a real-time economic dispatch. The assumptions described above in the two-stage simulation framework section were used for this scenario. The commitment status for generator units selected in the day-ahead commitment were respected when executing the real-time stage.
- **Stressed Scenarios**: additional stressors were applied assuming the loss of resources that were important for managing the challenging days. This allowed checking whether the day-ahead commitment would have been sufficient to avoid unserved energy. For example, it was assumed that resources such as load-modifying resources or imports etc. were lower than on the given historical day.
- Mitigation Cases:
    - *Mitigation using Quick Start units*: any offline quick start units that were not already committed by the day-ahead process were available to be deployed, assuming perfect foresight
    - *Mitigation using load-modifying resources*: additional load-modifying resources were available to be deployed to mitigate the potential unserved energy, again assuming perfect foresight

[18] Net load is defined as gross minus wind and solar for this analysis.

B.3 Future Portfolio Assumptions

The analysis of the current portfolio used input data from MISO historical records. This section describes the data inputs, assumptions, and methodology for analysis of the future portfolio. The aim of the future portfolio analysis was to evaluate whether MISO's current market products and requirements are sufficient to meet the needs as the generation fleet evolves in the future, and to identify any gaps in the system reliability attributes.

Day-ahead "forecast" load profiles were generated from the real-time "actual" load profiles for future years 2027 and 2032. For wind and solar day-ahead "forecasts" were also generated from the real-time "actual" renewable production for those future years. For both the day-ahead and real-time stages, the net load was obtained by subtracting renewable production from the load and this net load data was used to analyze the potentially stressed periods. Finally, market simulations were conducted for those stressed periods using the MISO EGRET simulation tool developed by MISO.

B.3.1 Data Inputs and Assumptions

For historical time periods both actual and forecast data for load and renewables were available. However, for future years for load only "actual" projections were available, while for renewables "actual" and "forecasts" at the 6 hours ahead (6 HA) timeframe were available. Day-ahead "forecasts" were also needed for the market simulations.

Table B-1 summarizes the sources for the key data inputs needed for the market simulations of the future portfolio, as follows:

- Load: Data from MISO Future 2A was used for projections of future real-time "actual" load. The details of this dataset are described in the Planning Adequacy section (A.3.3).
- Wind and solar: For wind and solar units their locations were determined based on the siting work done under MISO Futures. Next, "actual" real-time and "6 HA forecasts" for renewable unit profiles were generated for these locations using the data supplied by Vibrant Clean Energy.

2027/2032 Input Data	Load	Wind	Solar
Actual	From MISO F2A	From Vibrant Clean Energy	From Vibrant Clean Energy
6 HA Forecast	MISO generated	From Vibrant Clean Energy	From Vibrant Clean Energy
Day-Ahead Forecast	MISO generated	MISO generated	MISO generated

Table B-1: Sources for input datasets needed for market simulation of the future portfolio

The assumptions for the load, renewables, and non-renewable generator units for the future portfolio are summarized in Table B-2.

Consideration	Assumption
Future real-time "Actual" Load	MISO Future 2A load data using the weather year 2018 was considered. The data which includes electrification was aggregated from local balancing authorities (LBAs) to system-level to create annual load profiles at hourly granularity for 2027 and 2032. For the sub-hourly analysis, the hourly profiles were linearly interpolated to generate five-minute granularity load profiles.
Renewable energy production	Offered prices for wind and solar units were assumed to be zero. Wind and solar units were modeled as dispatchable intermittent resources and their hourly generation MW profiles were based on projections made for the future years 2027 and 2032. Wind and solar hourly profiles, based on siting of individual units were created for 2027 and 2032 "actual" generation, using the Vibrant Clean Energy dataset for the 2018 weather year. Also, the Vibrant Clean Energy dataset was used to obtain "forecast" profiles for the six hours ahead timeframe for these units. The hourly profiles were interpolated to generate the five-minute granularity renewable profiles. Finally, all the individual wind and solar profiles were aggregated to the regional and systemwide levels.
Non-renewable generator units	The future portfolio capacity used in the simulations was checked to ensure consistency at the LBA level with the Future 2A capacity for each fuel type. Characteristics (lead time, ramp rate, etc.) for non-renewable generation units were consistent with those from the current portfolio.
Generation outages	Planned and forced outages per season were based on historical average rates for the previous three years. The impact of planned and forced outages in future years 2027 and 2032 were accounted for by derating maximum limits of generation resources for each fuel type.
Net scheduled interchange	The historical real-time systemwide net scheduled interchange profile from a selected event day (Dec. 24, 2022, Winter Storm Elliot) was used for current and future portfolio simulations.
Battery storage operation	Current electric storage resources unit dispatch operation was scaled up consistent with capacities in each MISO region (North/Central, South) based on Future 2A capacities for the future years 2027 and 2032.

Table B-2: Key Assumptions for the Flexibility Assessment

B.3.2 Methodology for Forecast Uncertainty Assumptions

The methodology that MISO used to generate the datasets labelled as "MISO generated" in Table B-1 is as follows:

- The historical day-ahead and real-time load datasets were used to calculate the Total Error in the historical load forecast
- A back-cast dataset that excludes the impacts of weather forecast errors in the load forecast model was used to provide the Model Error
- Assuming that the forecast errors were additive, Weather Error was calculated as the difference between Total Error and Model Error
- The ratio of Weather Error to Total Error for day-ahead load forecast was calculated
- From the available historical actual and 6 HA forecast data, the historical 6 HA load Total Error was calculated

- Using the same ratio of Weather Error to Total Error from the day-ahead case, the 6 HA historical Weather Error and Model Error were obtained
- For future years, MISO assumed that relative Weather Error remains the same, while the Model Error is reduced by 50% (due to assumed improvements in forecasting techniques), i.e., Future 6 HA load Total Error % = Weather Error % + 50% * Model Error %
- This Total Error % is applied to the future actual load profile to get the 6 HA forecast for each of 8,760 hours
- For future day-ahead load forecast error, the steps were similar to those for the 6 HA load forecast case, as described above, i.e., Future day-ahead load Total Error % = Weather Error % + 50% * Model Error %

The historical load Model Error in day-ahead is greater than 6 HA. MISO maintained this relationship in the future data for consistency.

For future day-ahead wind and solar errors, MISO scaled the 6 HA errors using the ratios of the historical day-ahead error to the historical 6 HA error. For example, if in a particular hour of the year the historical 6 HA error is 3% and the historical day-ahead error is 4%, then a scaling factor of 4/3 = 1.333 is applied to scale the future 6 HA error in order to obtain the future day-ahead error. A similar calculation is applied for each of the 8,760 future hours in 2027 and 2032 to obtain the respective day-ahead forecast profiles for wind and solar.

B.4 Results

The increase in renewable (wind and solar PV) penetration in the future fleet results in new patterns in the diurnal net load profiles. The monthly average diurnal net load profiles for the years 2022, 2027, and 2032 are shown in Figure B-2, Figure B-3, and Figure B-4, respectively.

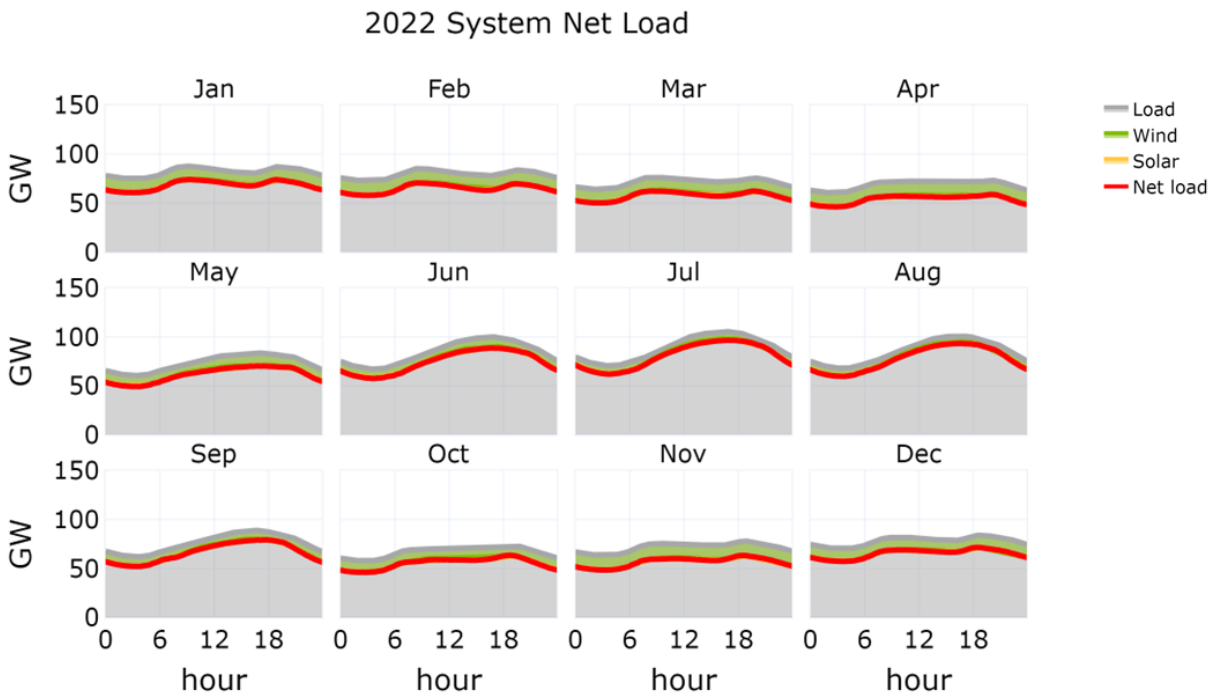


Figure B-2: Monthly averages of diurnal net load components for 2022

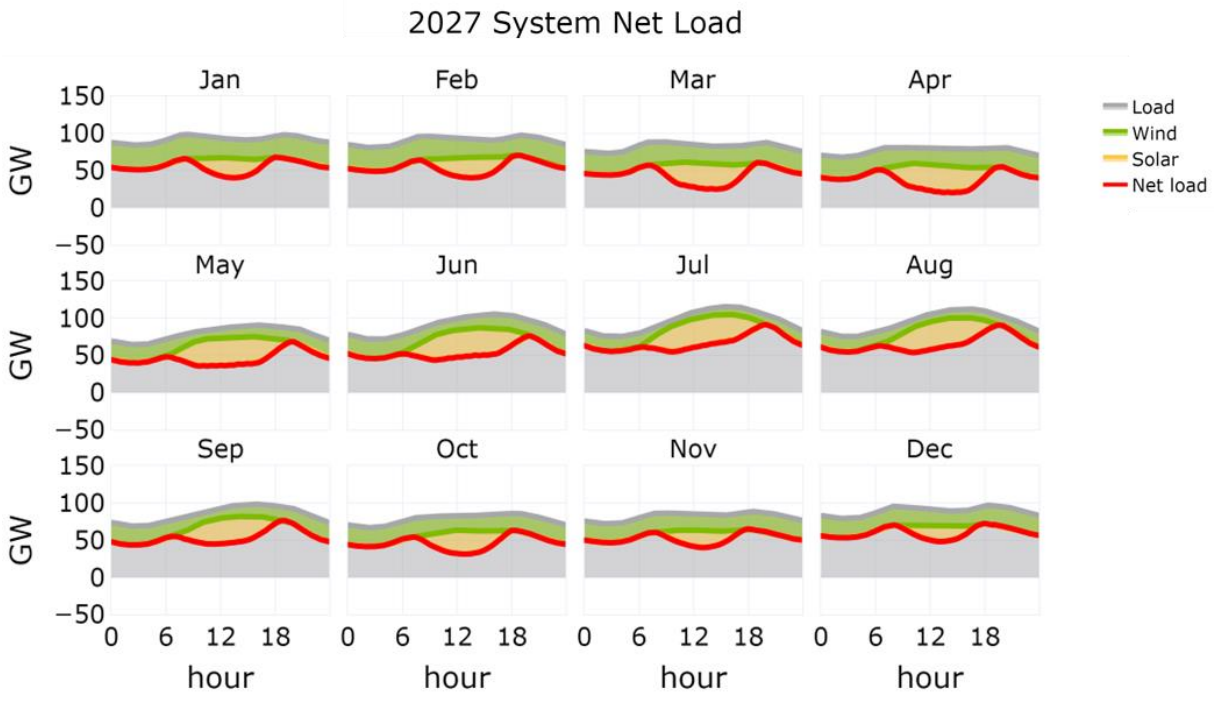


Figure B-3: Monthly averages of diurnal net load components for 2027

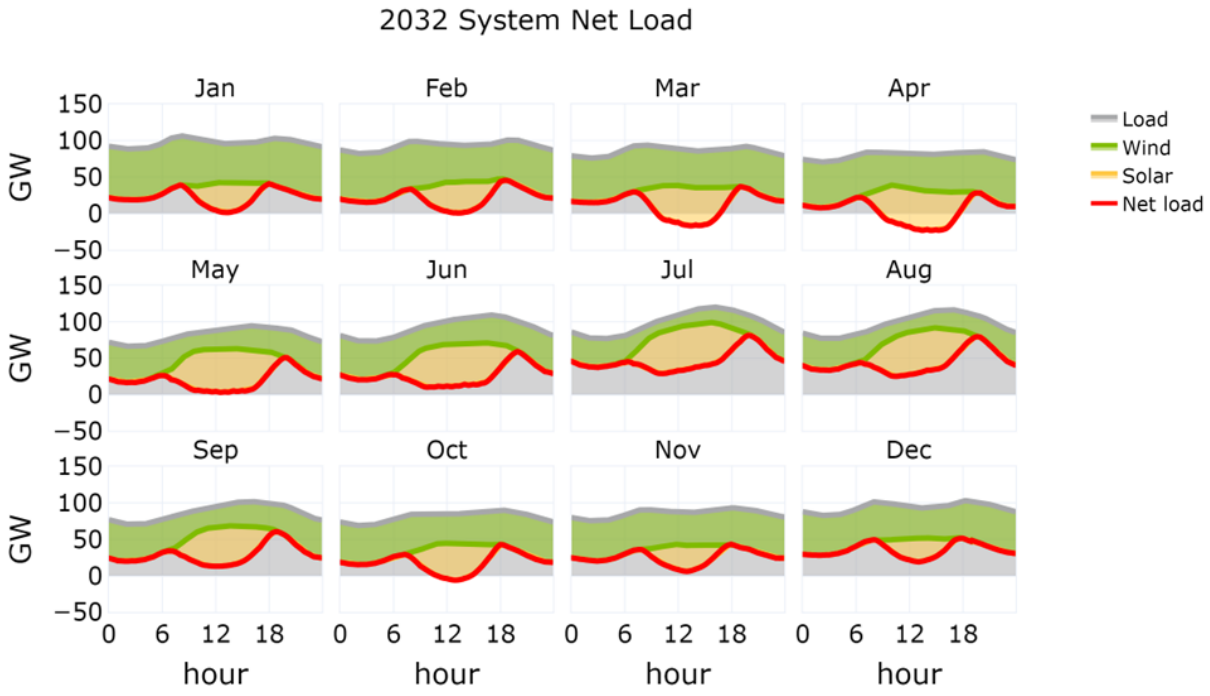


Figure B-4: Monthly averages of diurnal net load components for 2032

As these charts show, with increasing wind and solar penetration the duck-curve shape of net load appears between September and April in 2027 and becomes more pronounced in 2032. Assuming no curtailment of renewables, a number of hours in spring are shown to have negative net load in the afternoon.

Operational Adequacy Insight #1:

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.

Driven by the portfolio evolution and load profile changes, the future net load ramping need is projected to be much higher. The net load ramp needs in both up and down directions (Figure B-5, Figure B-6) are expected to increase by 2027 and 2032. This poses a challenge as resources with fast ramping capabilities will be needed to manage the larger ramps.

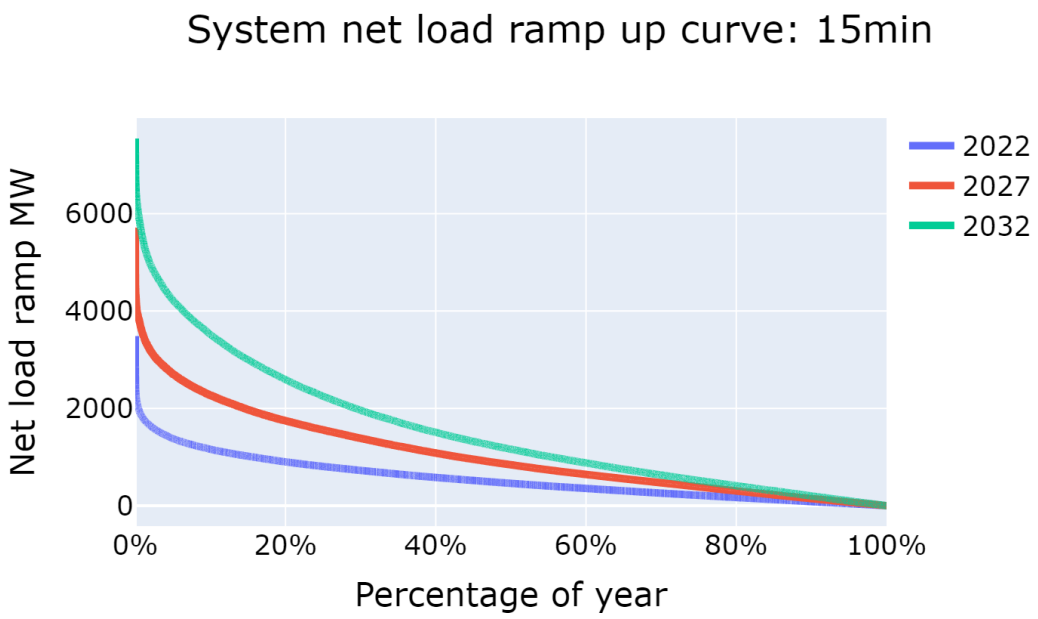


Figure B-5: Systemwide net-load ramp-up duration curve for 15 minutes

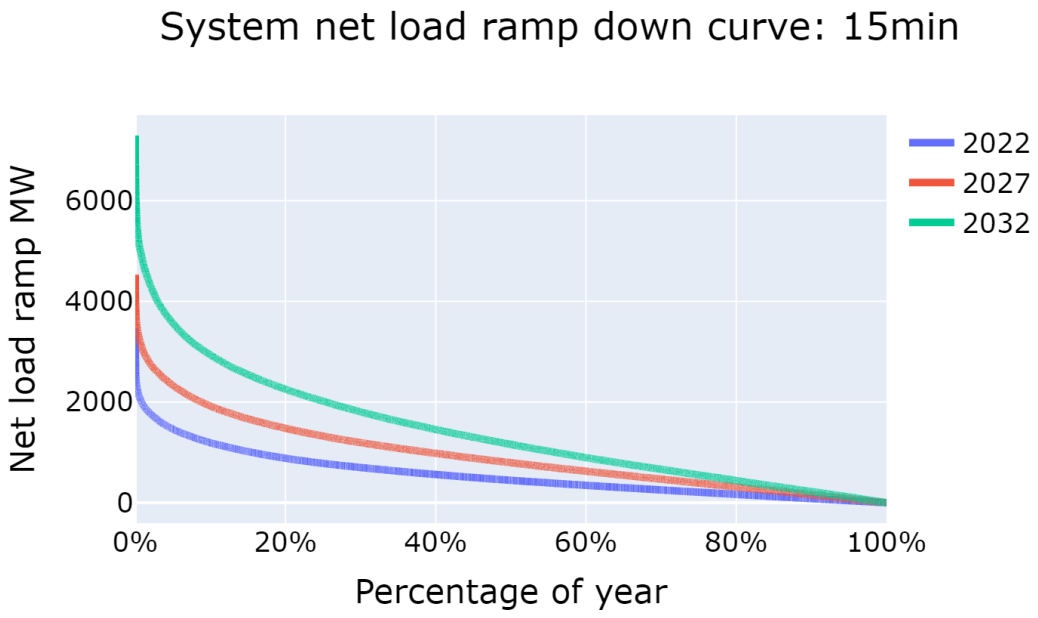
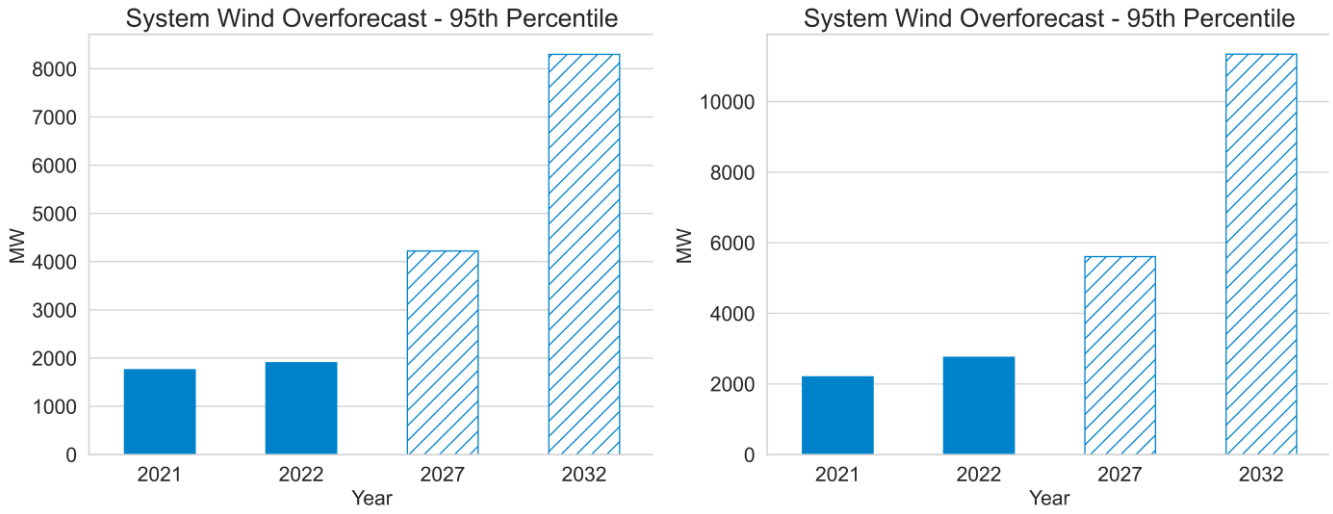


Figure B-6: Systemwide net-load ramp-down duration curve for 15 minutes

Forecast uncertainty for both wind and solar will increase in the day-ahead and short-term (6 HA) horizon from today to 2027 and 2032. For example, the 95th percentile of 6 HA wind over-forecast could increase from 1.9 GW in 2022 to 4.2 GW in 2027 and 8.3 GW in 2032 (Figure B-7a). While the 95th percentile of day-ahead wind over-forecast could increase from 2.8 GW in 2022 to 5.6 GW in 2027 and 11.3 GW in 2032 (Figure B-7b). These estimates assume an improvement in forecasting accuracy.



a) 95th percentile of six-hour ahead wind over-forecast b) 95th percentile of day-ahead wind over-forecast

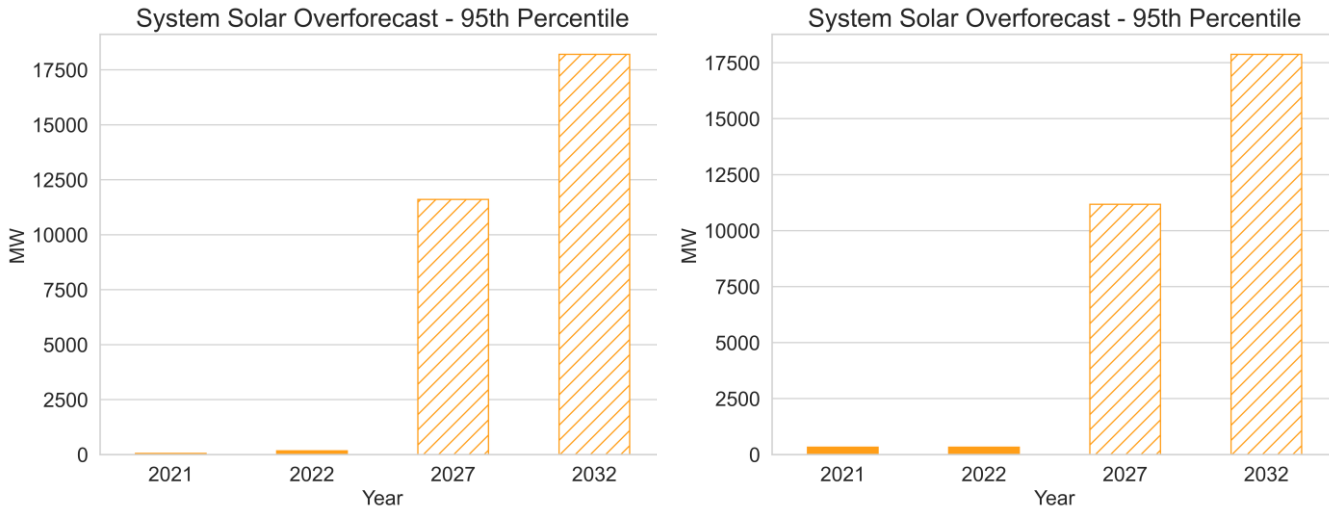
Figure B-7: Wind over-forecast errors in 2021, 2022, 2027 and 2032

Solar PV uncertainty could become larger than wind forecast uncertainty in the future, as solar penetration increases following the trends in Future 2A. The 95th percentile of six-hour-ahead solar over-forecast could increase from 0.17 GW in 2022 to 11.6 GW in 2027 and 18.2 GW in 2032 (Figure B-8a). The 95th percentile of day-ahead solar over-forecast could increase from 0.3 GW in 2022 to around 11.2 GW in 2027 and 17.9 GW in 2032 (Figure B-8b).

Literature on forecasting experience shows that shorter forecast lead times are correlated with lower forecast errors.[19] However, this was not the trend observed in MISO for 2021 and 2022, with the mean short-term solar forecast error being comparable or even larger than the day-ahead error. This analysis projected current MISO statistics for future years 2027 and 2032, so the trends did not match the expectation from literature. This could change in the future as the penetration of solar in the MISO footprint increases.[20]

[19] CAISO, "Day-ahead market enhancements discussion: Role of forecast uncertainty" Presented at CAISO's Market Surveillance Committee Meeting, Aug 27 2021.

[20] Penetration of solar PV in MISO footprint in 2021 and 2022 was much smaller than in California ISO (CAISO).



a) 95th percentile of six-hour ahead solar over-forecast b) 95th percentile of day-ahead solar over-forecast

Figure B-8: Solar over-forecast errors in 2021, 2022, 2027 and 2032

Figure B-9 shows the potential stressed days in 2027 and 2032 flagged by the screening method. Those days are highlighted as the cells in the calendar chart and are represented with their highest net load values (in GW).

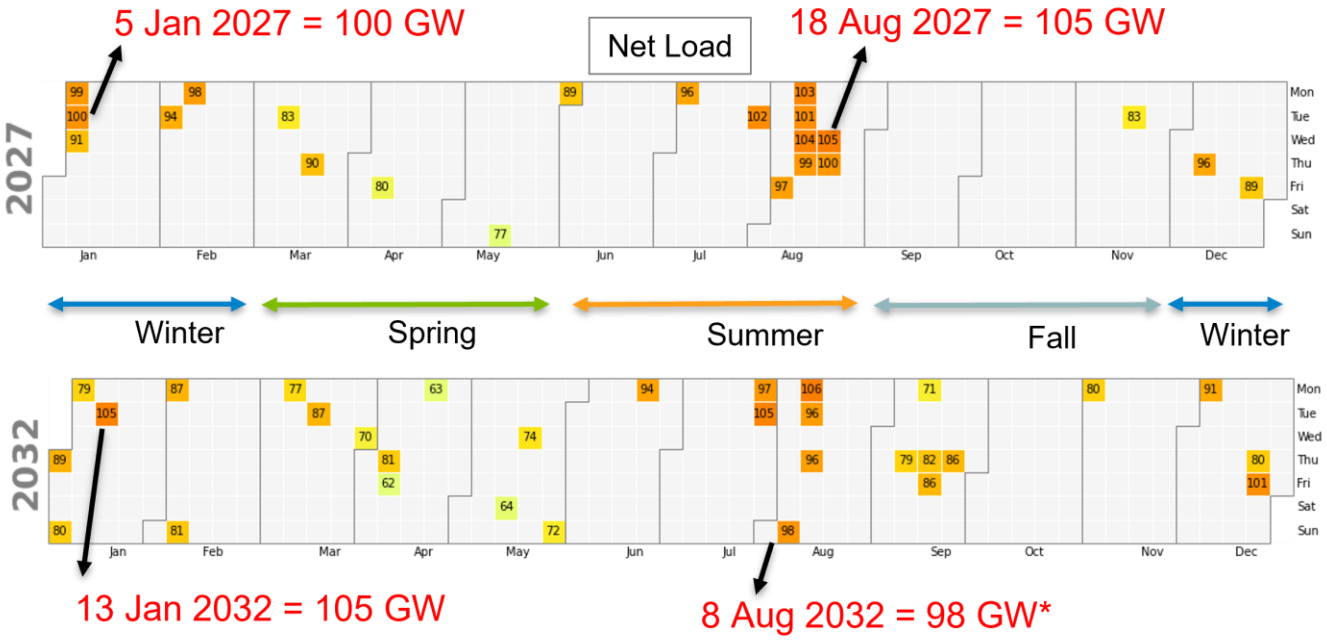


Figure B-9: Calendar chart of potential stressed days in 2027 and 2032

Figure B-10 presents a bar chart containing the actual maximum generation alert/warning/event days from 2022, as well as the potential stressed days from 2027 and 2032, grouped by the season. The operational risk in the future gets more spread out across the year as risky days begin to show up in the shoulder seasons. Additionally, the total number of risky days increases in the future.

Operational Adequacy Insight #2:

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.

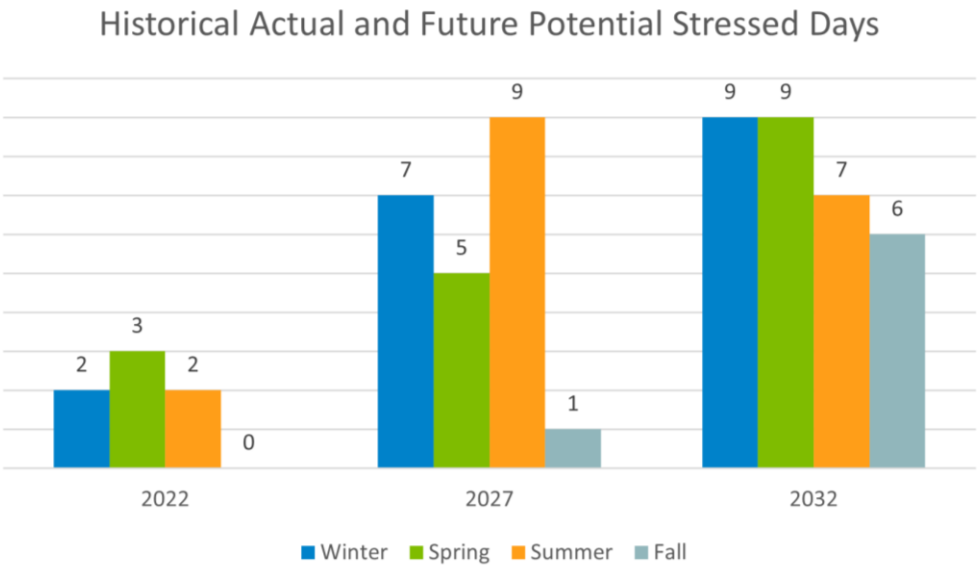


Figure B-10: Historical events and future potential stressed days by season

Figure B-11 shows the simulation results of various scenarios for the target potential stressed day for the event in winter of 2027. For the base case scenario (assuming no operator actions) the day-ahead commitment was inadequate to meet the real-time load, resulting in a small amount of unserved energy. Three individual stress scenarios are considered:

- A 50% drop in wind production throughout the day
- The removal of external imports (MISO rather ends up exporting power)
- A high-impact single gas pipeline outage

Operational Adequacy Insight #3:

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.

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 three stress conditions occur on the same day.

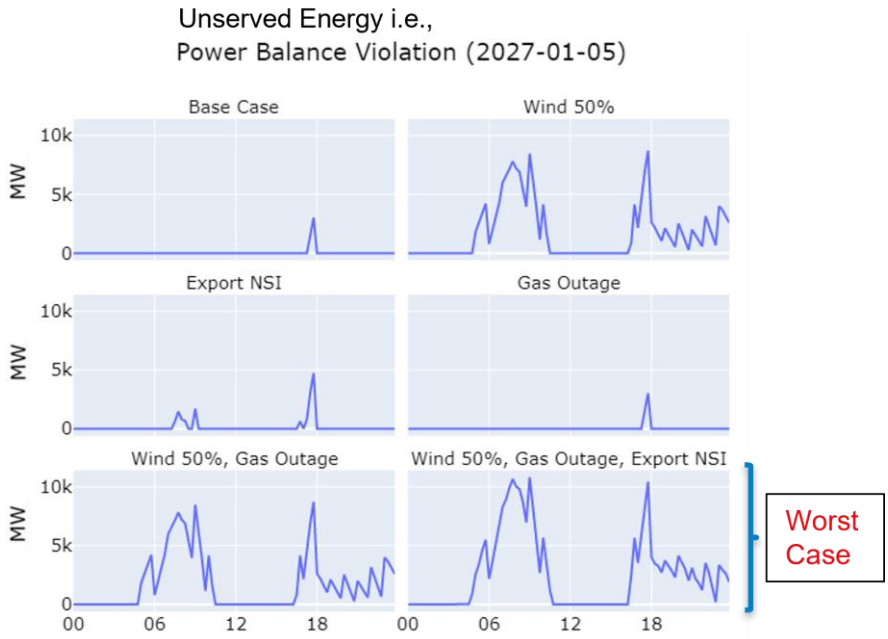


Figure B-11: Simulation results for base case and stressed scenarios for the winter 2027 event

Figure B-12 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 according to their lead time, starting with the fastest group (i.e., "quick 20 minutes"), followed by units with increasing lead times (e.g., up to 60 minutes or 120 minutes). The unserved energy is completely mitigated with units of lead-time of up to 5 hours.

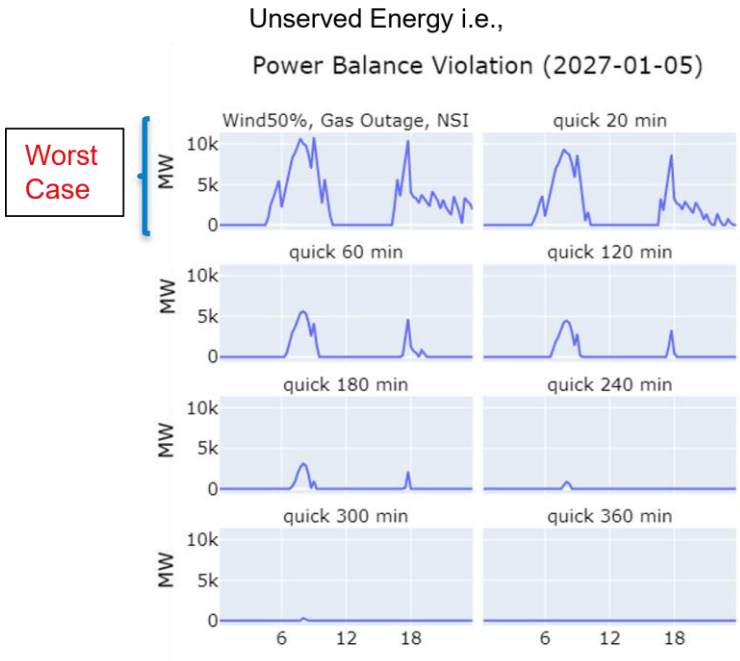


Figure B-12: Simulation for worst stress case and mitigation using quick start units for the winter 2027 event

Figure B-13 shows the available capacity of quick start units for different lead times throughout the day for the winter 2027 target day. Quick start capacity needs to be available during the high-risk hours to mitigate the unserved energy. This illustrates the need for resources to be available at the right time, and not just in an aggregate sense. MISO needs improvements in its commitment processes to ensure that adequate resources are always available to manage unanticipated changes in system conditions. This is relevant given the growing uncertainty in net load as the penetration of renewable generation increases.

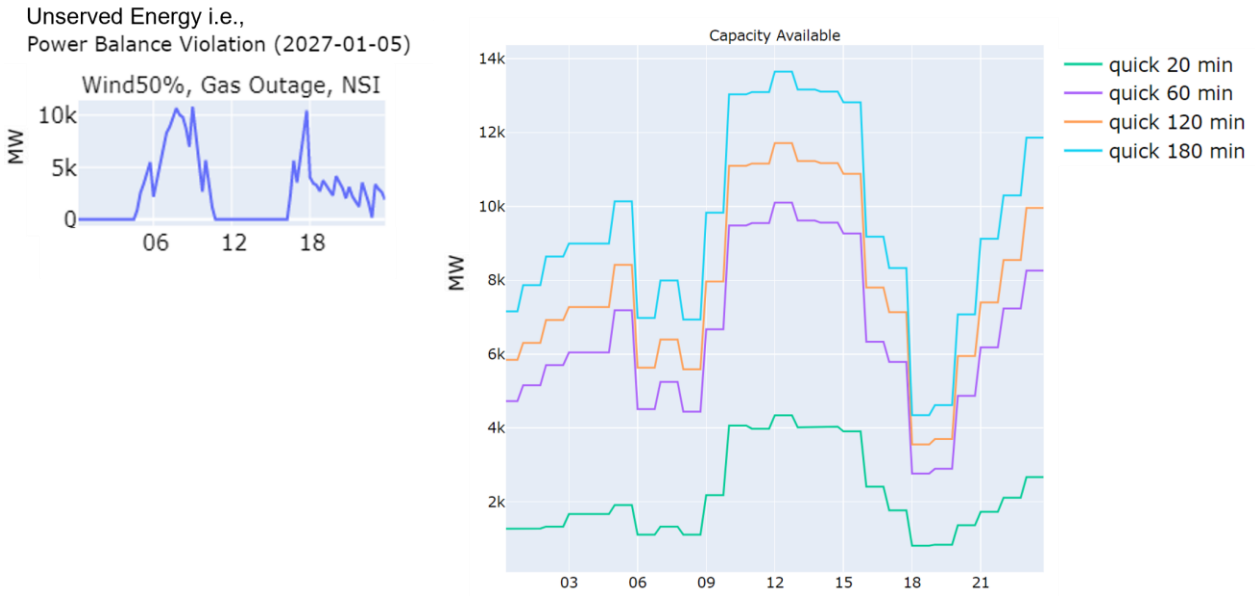


Figure B-13: (Left) Unserved energy result for the worst case of the winter 2027 event; and (Right) total capacity of quick start units for different lead times in minutes (≤20 min, ≤60 min, ≤120 min, ≤180 min)

B.5 Conclusions

This technical appendix describes approaches, tools, inputs, and assumptions used in the operational adequacy attributes analysis that informed the insights and the development of MISO's 2023 *Attributes Roadmap*. The insights and results were directionally indicative as to whether enhanced market practices or new products are needed to mitigate the risks in the operating timeframe.

C.Voltage Stability

This section in the technical appendix provides supplemental information on the analysis described in the System Stability section of MISO's 2023 *Attributes Roadmap*. Before addressing the analysis, voltage stability is defined within the broader stability landscape and an overview of MISO's current practices are provided. The context and current state information is not intended to be comprehensive, but rather to provide some information useful in understanding how MISO's voltage stability analysis relates to previous findings and existing practices.

C.1 Voltage Stability Definition

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.[21] It depends on the ability of the combined generation and transmission systems to provide the power requested by loads.[22] Voltage stability is often thought of as load-driven rather than resource-driven, though resource characteristics affect voltage stability outcomes.

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). Several factors can cause voltage instability, such as insufficient reactive power support, excessive loading, loss of transmission lines or generators, or inadequate voltage regulation. During the northeastern U.S. event in 2003, voltage instability resulted after multiple line tripping contingencies caused voltage fluctuations and reactive power deficiencies, in turn causing generators and transformers to trip or malfunction.

Voltage stability is one family of power system stability issues that can arise on the grid. Figure C-1 shows a taxonomy often used within engineering technical papers on the matter.[23] Voltage stability has the additional dimensions of small and large disturbance and short- and long-term timescales, described in greater detail below.

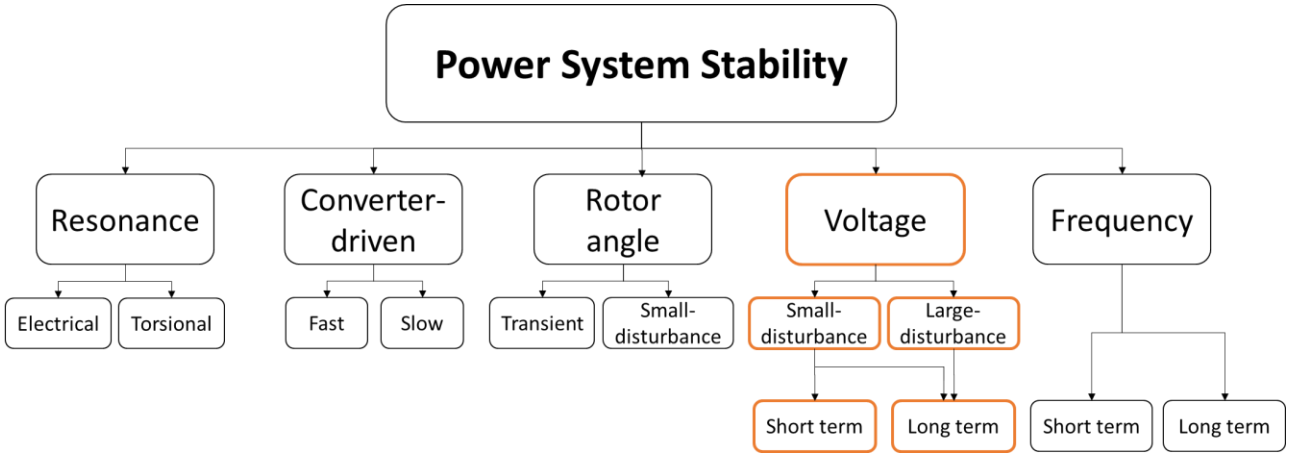


Figure C-1. Taxonomy of power system stability considerations

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

[22] T. Van Cutsem and C. Vournas, *Voltage Stability of Electric Power Systems*. Norwell, MA: Kluwer, 1998.

[23] 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.

Two different disturbance types are relevant for the voltage stability definition within Figure C-1.

- **Small signal** voltage stability refers to the ability of the power system to maintain stable voltage under small perturbations around the expected operating point. For instance, small increases or decreases in line active power loading and reactive power flows.
- **Large signal** voltage stability refers to the ability of the power system to maintain stable voltage following a large system disturbance, such as a line fault.

Small signal analysis can use linear system models whereas large signal analysis must account for non-linearities associated with large system disturbances.

For each of the disturbance types, two timescales apply within the voltage stability taxonomy illustrated in Figure C-1:

- **Short-term** typically considers effects of load dynamics short circuits near load, often worst case (e.g., motors stalling, electronically controlled load tripping). The timescale is typically on the order of seconds.
- **Long-term** (e.g., several minutes) typically considers progressive reductions in voltage under maximum power transfer limits, often during contingencies (e.g., tap changers, generator current limiters). The timescale is often on the order of minutes.

C.2 Current State of the MISO system

MISO has performed detailed planning analysis of future system stability impacts through long-range studies like the Renewable Integration Impacts Assessment. Further, stability analysis is included in MISO's standard MTEP planning process. Operational analysis is also performed to evaluate risks in near real-time based on actual system conditions, an analysis which is being expanded based on recent NERC standard revisions. The following sections describe past and current efforts underway at MISO.

C.2.1 Renewable Integration Impacts Assessment

MISO's Renewable Integration Impacts 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.[24] These challenges could arise when renewable resources serve roughly 30% 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.[25] In addition to the voltage stability challenges emerging earlier in the energy transition, the anticipated capital cost to mitigate the issues is expected to be the highest of all stability related challenges studied in RIIA. Figure C-2 recreates the RIIA report's summarized ranking of dynamics issues, with information on impacts, relevant penetration levels, and relative mitigation costs, among other factors.

[24] MISO, *MISO's Renewable Integration Impacts Assessment (RIIA) study*. Summary Report. February 2021.

[25] MISO, "Future 2A Expansion and Preliminary Siting", Presented at MISO's LRTP Workshop, March 10, 2023.

Area of stability	Ranked concern	Performance metric	Impacts	Possible mitigations	Concerned MISO group	Issue first seen	Impact of renewable penetration	Capital cost share to mitigate
Inverter-based stability and voltage stability	1. Transient voltage stability in weak areas	Short circuit ratio, undamped voltage and current oscillations, interactions between the controls of equipment	Local area, observed at many substations system-wide	• Control tuning • Synchronous condensers • STATCOM • HVDC	EP*, GI†	30%		
Frequency stability	2. Frequency response	Frequency nadir, rate of change of frequency (RoCoF), NERC BAL-003 obligations	Interconnection wide	• Additional planned online headroom • Batteries	Operations	50%		
	3. Small signal stability	Damping ratio of low frequency oscillations	Interconnection wide	• Must-run units with power system stabilizers • Specially tuned batteries	EP*, Operations	30%		
Rotor-angle stability	4. Transient rotor angle stability	TO's local planning criteria, NERC criteria	Local area	• Faster protection schemes • Transmission facilities	EP*, GI†	50%		–

*EP: Expansion Planning
†GI: Generator Interconnection

Figure C-2. RIIA summary of dynamic concerns

The RIIA analysis used a screening method based on short-circuit ratio (SCR) to identify "weak grid" areas and system locations with low available short-circuit current, which is an indication of potential stability issues. However, the determination of the type and magnitude of stability challenges necessitates detailed dynamics analysis using different tools such as positive sequence dynamics tools (e.g., TSAT, VSAT).

RIIA's detailed dynamics assessment showed the need for stability-related mitigations, another term for solutions that largely targeted STATCOMs, synchronous condensers, dispatch adjustments, HVDC, HVAC, batteries, and controls tuning. Small amounts of other solutions were contemplated. Figure C-3, reproduced from MISO's RIIA report, shows the level of complexity introduced by each solution for the renewable penetration milestones evaluated. In this context, complexity can roughly be treated as a proxy for investment needs. Grid-forming controls for inverter-based resources was not a solution that was considered in the RIIA study.

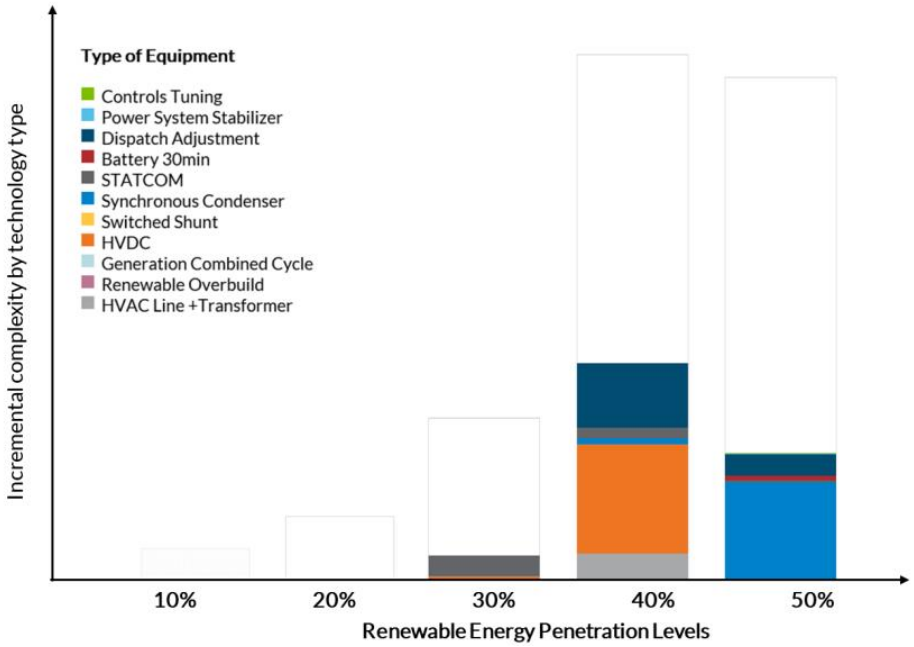


Figure C-3. RIIA dynamic stability solutions — incremental complexity by technology type for renewable penetration milestones

C.2.2 Planning

MISO's voltage stability analysis for reliability planning selects specific transfer scenarios, based on stakeholder and system operator input, with the goal of identifying potential reliability risks that could emerge in the future.

The voltage stability analysis uses a P-V study methodology where power is transferred between a defined source and sink. At different transfer levels, contingencies are introduced, and the resulting bus voltages calculated. The voltage stability limit is reached when the solution fails to converge due to voltage collapse or when a bus falls outside of planning criteria. MISO uses transmission owner (TO) local planning criteria (LPC) to define stability limits should TOs decide to institute criteria more restrictive compared to MISO defaults found in BPM-020. In absence of TO LPC, MISO uses a default margin value of 10%, with the margin being defined from the point of voltage collapse (i.e., nose point) of the PV curve. MISO also has criteria for each bulk electric system (BES) bus to maintain voltage at or above 90% of nominal voltage under contingency conditions. Figure C-4 shows an example PV curve with the 90% voltage decline criteria limit; the limit corresponding to 10% margin; and the nose point.

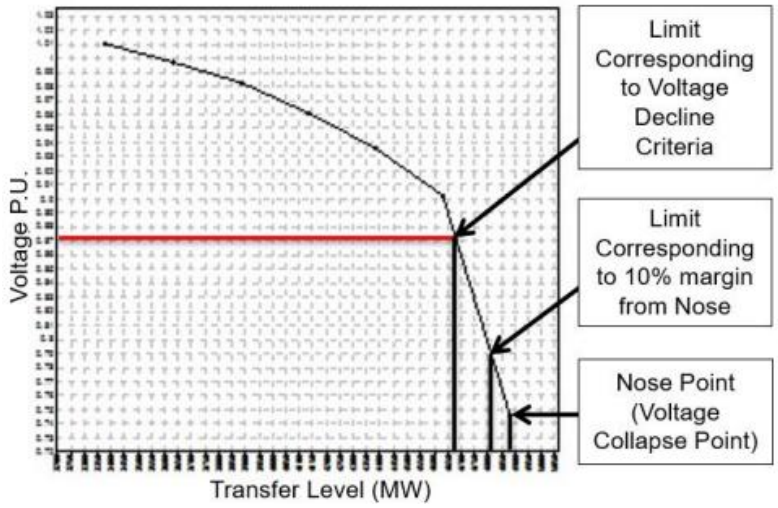


Figure C-4. Illustration of power-voltage (PV) curve with associated limits

To provide an idea of the scale of MISO's current voltage stability analysis, the MTEP23 cycle selected six transfer scenarios across the MISO region, as shown in Figure C-5. The assessment follows established methodologies pursuant to requirements in NERC Standards FAC-010 and FAC-014. FAC-010 requires that System Operating Limits (SOL) used in BES reliability planning are based on an established methodology or methodologies.[26] Voltage stability is specifically called out in Requirement 2 of this standard. FAC-014 serves the purpose of establishing how SOLs, including voltage stability limits, are communicated among the NERC registered entities.[27]

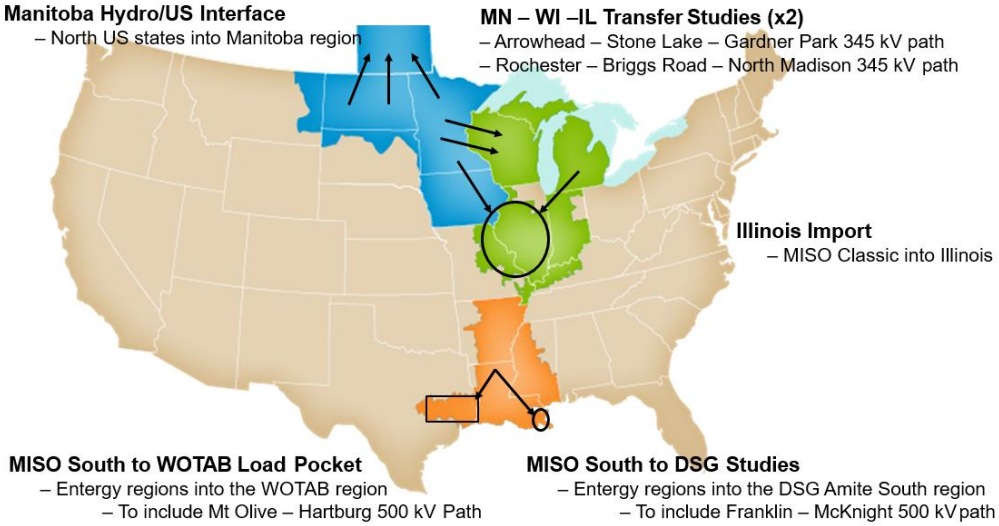


Figure C-5. Geographical representation of the six transfer scenarios selected for MTEP23

[26] NERC, Standard FAC-010-3 – System Operating Limits Methodology for the Planning Horizon.

[27] NERC, Standard FAC-014-3 – Establish Communication System Operating Limits, January 2009.

C.2.3 Operations

MISO real-time operations currently run around 30 contingencies, which primarily monitor two interfaces for stability issues. In what will amount to a large expansion of the current monitoring, recent changes to NERC's FAC-011-4 standard caused MISO to start developing a real-time, footprint wide transient stability analysis. Contingencies will be selected through a screening methodology. The project is planned for completion in December 2023, ahead of the April 2024 date on which the revised FAC-011-4 becomes active.

Voltage Stability Insight #1:

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

C.2.4 Markets

Currently, MISO does not offer market products directly related to voltage stability.

C.3 Attributes Voltage Stability Analysis

The voltage stability portion of the 2023 attributes analysis work focused on characterizing screening results using both the SCR and dynamic impedance approaches. Screening approaches, including those contemplated in this analysis, are often used to identify areas and conditions that require deeper analysis.

C.3.1 Limitations of Screening Tools

SCR is known to have limitations in areas of high inverter-based resource (IBR) penetration. This metric is most appropriate when considering an IBR connected to a strong grid without the interactions from other nearby IBR. Adaptations of SCR approaches intended to overcome known shortcomings are described below. However, modern inverter control topologies are beginning to decouple the IBR's fault contribution from system strength contributions, concepts that are tightly coupled in grids predominantly driven by synchronous machines.

While the dynamic impedance method is relatively new, and MISO is working with industry partners – Telos Energy and Hickory Ledge – to advance industry understanding of its use and usefulness, patterns around certain limitations are emerging. One insight thus far is that characterizing grid-following (GFL) IBR using the approach presents challenges, especially for large disturbances, such as faults resulting in severe voltage depressions. The method could potentially benefit from severity-sensitivity adjustments to the dynamic impedance for GFL. For grid-forming (GFM) IBR the large-signal and small-signal screening outcomes appear to be accurate, but MISO is still investigating the efficacy for this use based on other industry research evaluating similar approaches. [28] [29] [30]

C.3.2 Short-Circuit Ratio

SCR has traditionally represented the "voltage stiffness" or system strength of a grid.[31] It is used as a screening method to understand potential reliability implications, especially as IBR deployments and synchronous machine

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[28] 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.

[29] Sun J. "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.

[30] Shah, Shahil, 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".

[31] NERC, *Short-Circuit Modeling and System Strength*, February 2018.

resource retirements lower the available system short-circuit current. This reduction in available short-circuit current can drive weak grid conditions that may cause plant and inverter control instability, for instance plants oscillating against one another. Other potential challenges of low system strength include[32]:

- Delayed voltage recovery
- Wide area undamped voltage and power oscillations
- Instability of plant voltage control systems
- Deeper voltage dips and higher overvoltages
- Larger voltage step change for switched compensation equipment
- Generator fault ride-through degradation
- Protection misoperation

SCR is calculated at each bus location and is the ratio of the available three-phase fault current (in MVA) over the active power rating of the resources at a given bus. This is described by equation 1 below.

$$SCR = \frac{S_{SCMVA}}{P_{RMW}} \qquad (1)$$

Variations of SCR have been developed across the industry to counteract known limitations of SCR as a system strength screening metric. The SCR method assumes a system with predominantly synchronous generation[31], therefore its use on systems with high IBR penetration may result in a conservative estimation because it does not account for IBR interaction effects[33] [34] [35]. Weighted short-circuit ratio (WSCR), defined in footnote 33, determines the system strength across an area rather than a single bus and accounts for the short-circuit contribution of each bus and active power rating of each generator in the same equation. The main limitation of this method is that it assumes all interacting IBRs are connected at the same bus. The system strength represented in WSCR can provide a lower bound to the estimation from the SCR metric while still providing a limited measure of an IBR-dominant system. Other methods (ESCR, CSCR, SCRIF, etc.) that focus only on analyzing the line impedance generally share the same limitation.[31] [35]

While variations like WSCR can address certain shortcomings of SCR, such as IBR interactions, they cannot capture the stability benefits of new IBR technologies such as grid-forming controls. This indicates a need to evaluate other approaches for system strength screening, such as the dynamic impedance method described further below.

Tools

MISO's methodology uses a Python script to automate SCR calculation across all buses in the MISO footprint. The script interfaces with the PSS/E powerflow software through API commands to simulate three phase faults at different buses in the model, then calculates the resulting SCR at that bus. The PSS/E fault calculation method was automatic sequencing (ASCC) and used the subtransient generator reactance values.

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[32] AEMO, *System Strength*, March 2020.

[33] Y. Zhang *et al.*, "Evaluating system strength for large-scale wind plant integration," IEEE PES General Meeting, National Harbor, MD, pp. 1-5, July 2014.

[34] J. Schmall *et al.*, "Voltage stability of large-scale wind plants integrated in weak networks: An ERCOT case study," IEEE PES General Meeting, Denver, CO, pp. 1-5, July 2015.

[35] C. Henderson *et al.*, "Grid Strength Impedance Metric: An Alternative to SCR for Evaluating System Strength in Converter Dominated Systems," *IEEE Transactions on Power Delivery*. Institute of Electrical and Electronics Engineers (IEEE), pp. 1-10, January 2023

In addition, ArcGIS software was used to create the SCR map visualizations using MISO bus latitude and longitude data.

Models

MISO Transmission Expansion Plan 2023 (MTEP23) Appendix A powerflow models were used for the SCR analysis.[36] There are separate models for different future years (2025, 2028, and 2033) and dispatch cases (summer, spring light load, etc.). The MTEP models include resource additions based only on projects with signed GIAs and retirements based only on plants with finalized retirement studies.

To improve SCR calculation accuracy, machine subtransient reactance values for synchronous generators were pulled from the MTEP23 five-year-out dynamics data file and added into the sequence data of the base powerflow model. Subtransient reactance class averages were used for synchronous machines that did not have individual dynamics data available. For all non-synchronous machines a value of 0.91 p.u. subtransient reactance was assumed.

Results

MISO's refreshed SCR analysis confirms the RIIA study results showing localized pockets of declining system strength. However, the picture is nuanced as increasing SCR is projected in some areas as well. Figure C-6 through Figure C-8 below show the magnitudes of SCR for the MTEP23 2025, 2028, and 2033 summer dispatch cases. Potential areas of low system strength appear to be Michigan, SW Minnesota, and Louisiana.

SCR magnitude results were split into three categories:

- "Low" SCR was defined as an SCR value less than 3
- "Medium" SCR was defined as an SCR value less than 6
- "High" SCR was defined as an SCR value greater than or equal to 6

These categories are meant to be illustrative and are not meant to exactly indicate the system strength at which stability or control issues will arise. For example, industry sources have suggested Type 3 WTG have a potential for control problems with SCR < 2.5 and cannot maintain control for SCR < 1.5.[37] MISO understands that various manufacturers' equipment is designed to operate at different minimum SCR levels, sometimes stated in their technical materials. Therefore, the SCR evaluation is reserved for initial screening with detailed analysis determining stability risks and mitigations.

[36] MISO, *Draft MTEP 2023*, 2023.

[37] Electranix, "Why GFM?," presentation to UNIFI consortium, September 11, 2023.

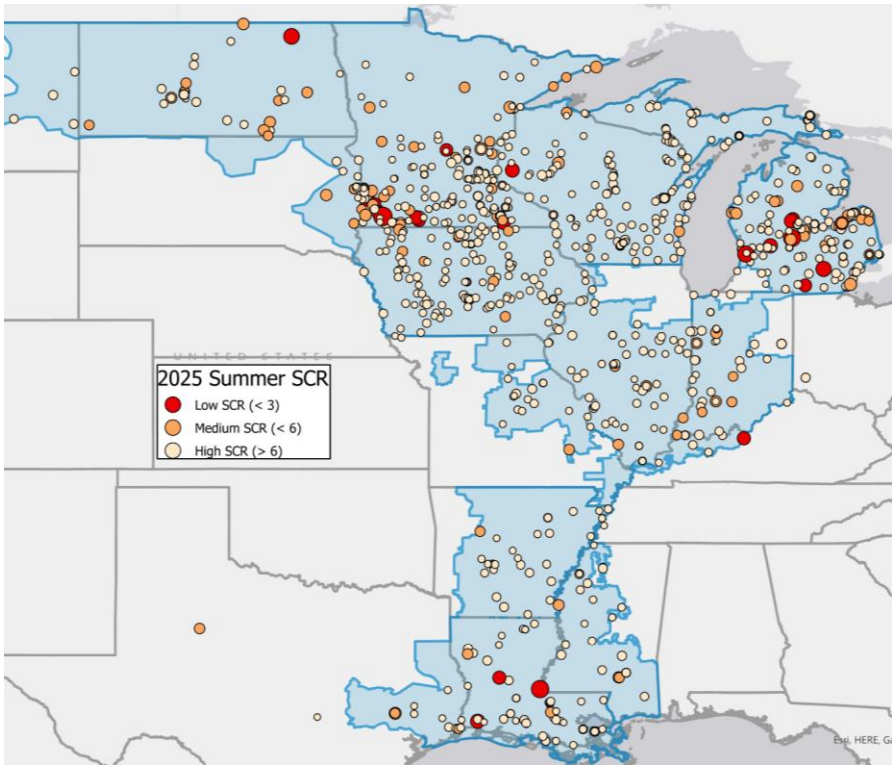


Figure C-6. SCR magnitudes for MTEP23 2025 summer dispatch model

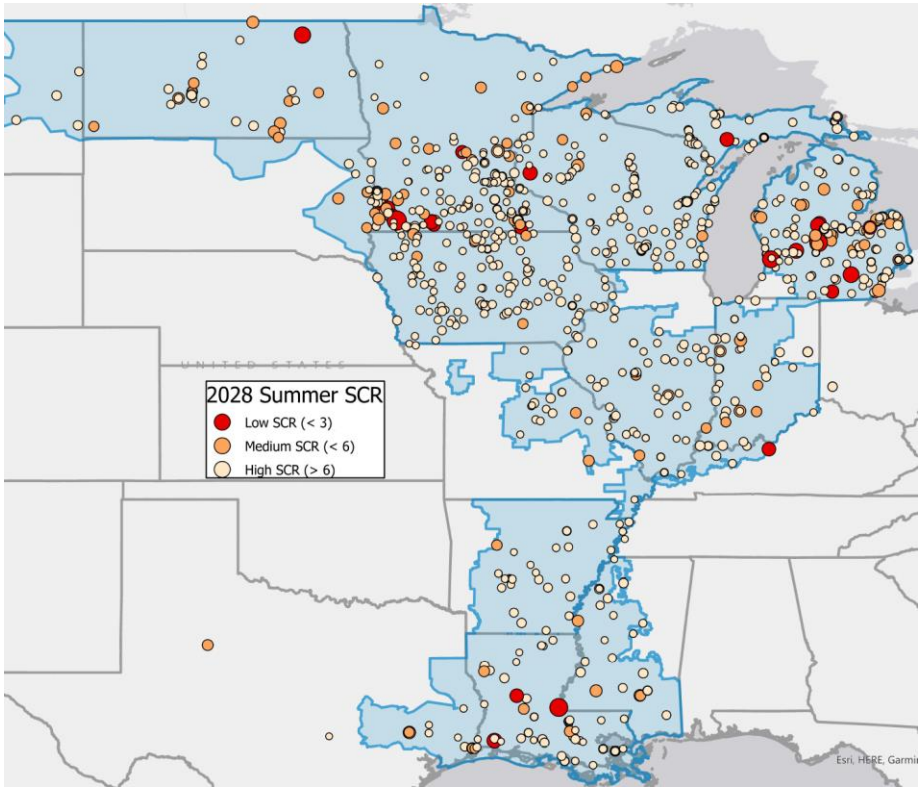


Figure C-7. SCR magnitudes for MTEP23 2028 summer dispatch model

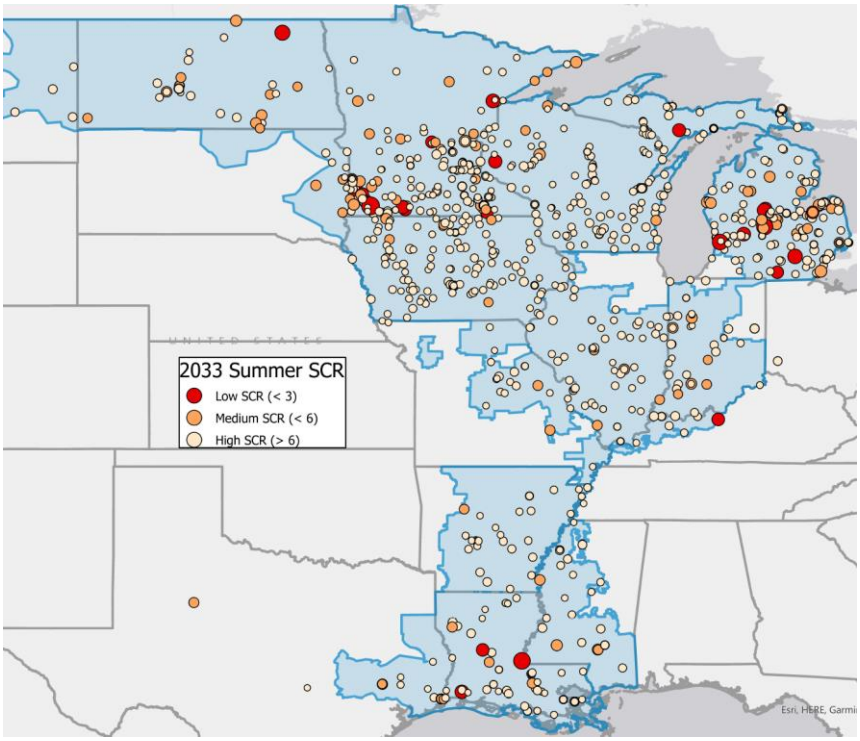


Figure C-8. SCR magnitudes for MTEP23 2033 summer dispatch model

SCR magnitudes are different based on the dispatch pattern selected for each model year, indicating that 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. Figure C-9 shows an example of the SCR values for buses in the 2025 model under the spring light load (SLL) dispatch assumption. In the SLL case, SCR is lower across much of Iowa, Wisconsin, and MISO South compared to the summer dispatch case.

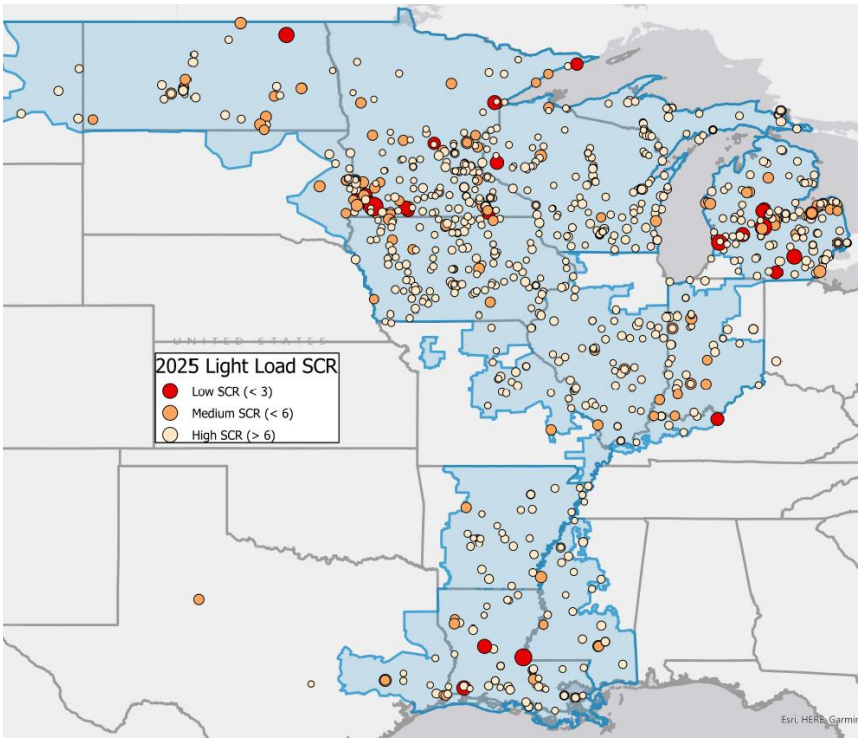


Figure C-9. SCR magnitudes for MTEP23 2025 spring light load dispatch model

The nature of the resource transition and transmission build-out will drive future system strength, affecting aspects of system stability. For example, between the 2025 and 2033 MTEP models, transmission build-out from LRTP Tranche 1 works to increase system strength while fleet changes decrease it.

Figure C-10 isolates the impacts of resource additions and retirements on SCR between 2025 and 2033. It compares the SCR of the 2025 model with the SCR of an altered 2033 model with MISO's LRTP Tranche 1 projects removed. The removal of these major transmission projects aims to isolate the impacts of resource changes, but it is acknowledged that the 2033 case still includes other transmission additions not associated with Tranche 1. There are some localized areas with synchronous generator retirements and IBR additions where SCR decreases, but there are also many areas where SCR increases over time.

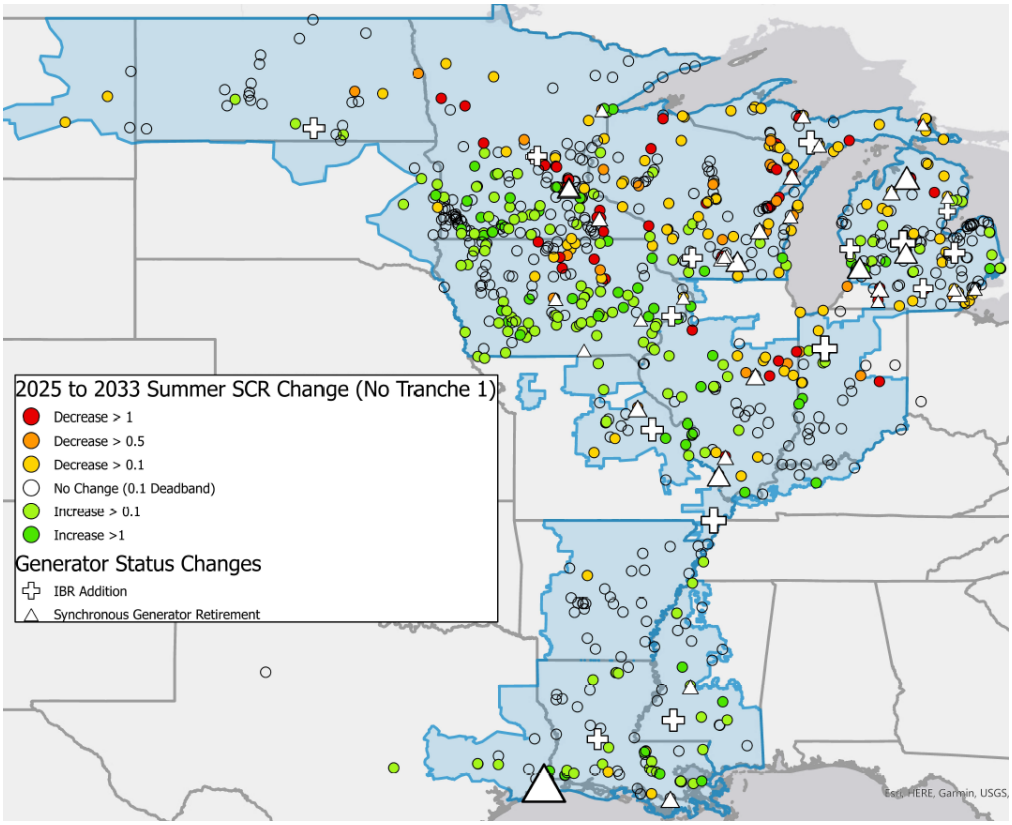


Figure C-10. Impact of resource additions and retirements on SCR, shows the change in SCR from the MTEP23 2025 summer model to the MTEP23 2033 summer model without LRTP Tranche 1 projects

Figure C-11, alternatively, isolates the impact of LRTP Tranche 1 by comparing the difference in SCR in the 2033 model before and after Tranche 1 projects are added. SCR increases when the Tranche 1 projects are added at nearly every bus across the MISO North and Central regions. There is no change in SCR due to Tranche 1 in MISO South as expected, because the transmission projects are limited to the North and Central region only.

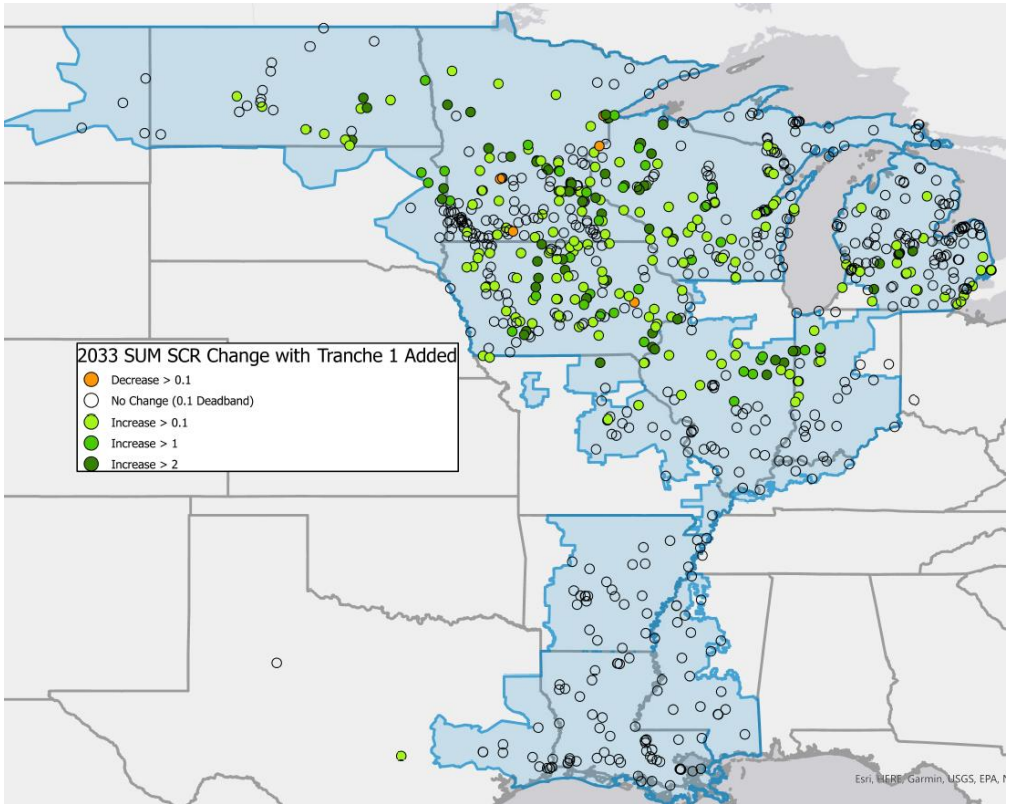


Figure C-11. Impact of LRTP Tranche 1 projects on SCR, shows the change in SCR for the MTEP23 2033 summer model with and without LRTP Tranche 1 projects

The SCR changes in Figure C-10 and Figure C-11 are summarized in Figure C-12 below. Across the entire MISO footprint, Tranche 1 increased average SCR by 0.7 (from 37.1 to 37.8) while resource changes and other transmission changes (e.g., projects generated by Local Planning Criteria) between 2025 and 2033 resulted in average SCR remaining the same (in both cases 37.1).

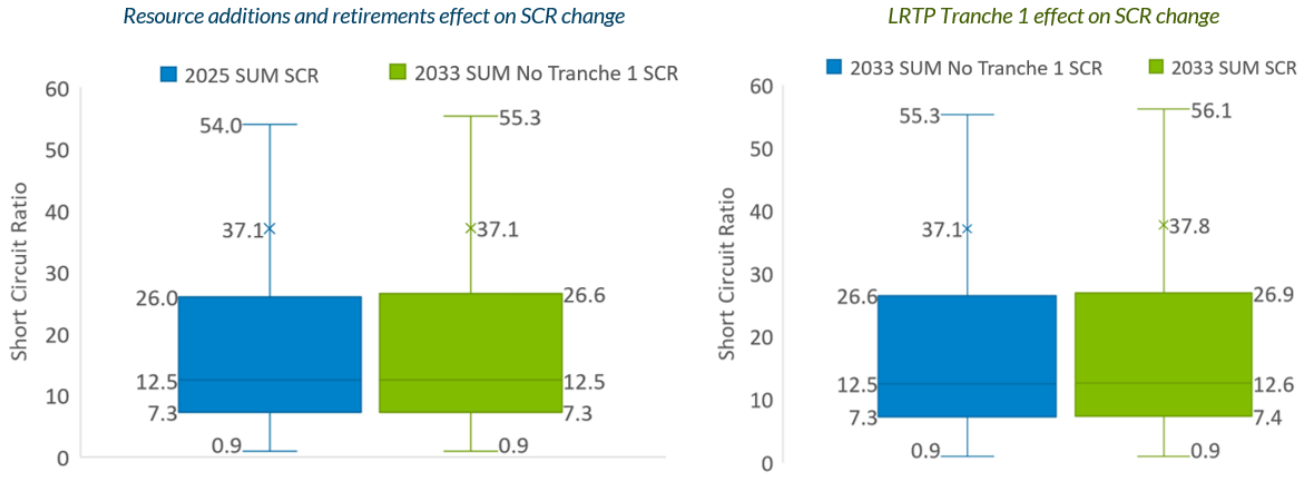


Figure C-12. Comparison of how resource change impacts SCR to how LRTP Tranche 1 projects impact SCR

C.3.3 Dynamic Impedance Method

The dynamic impedance approach development was led by Telos Energy and Hickory Ledge as part of a MISO engagement to understand potential IBR stability impacts. MISO's RIIA study did not incorporate grid-forming controls as a potential mitigation to voltage stability challenges due to the lack of industry available models and demonstration projects, which drove a need to better understand the potential of control solutions.

A paper describing the dynamic impedance method was presented at a recent industry conference in *22nd Wind and Solar Integration Workshop*[38]. MISO suggests readers refer to this paper for details on the method's purpose, formulation, and validation. This section will provide a brief overview of the method before discussing scaling the analysis to the full MISO system, which is not covered in the conference paper.

Voltage Stability Insight #2:

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

The dynamic impedance method consists of two main processes, a resource characterization and a screening analysis as shown in Figure C-13. First, the resource characterization is performed using detailed electromagnetic transient (EMT) analysis to determine the modeled IBR's dynamic responses to voltage and frequency disturbances. A "dynamic impedance" value is extracted from certain perturbation frequencies in the direct-quadrature-zero (dq0) domain, sometimes also referred to as the rotor reference frame. Then, this dynamic impedance value is fed into a screening analysis. The screening is a traditional voltage stability transfer analysis using a tool called TARA to approximate the dynamic voltage stability limits. Applying a steady-state type of analysis to approximate dynamic limits reduces complexity and computational burden.

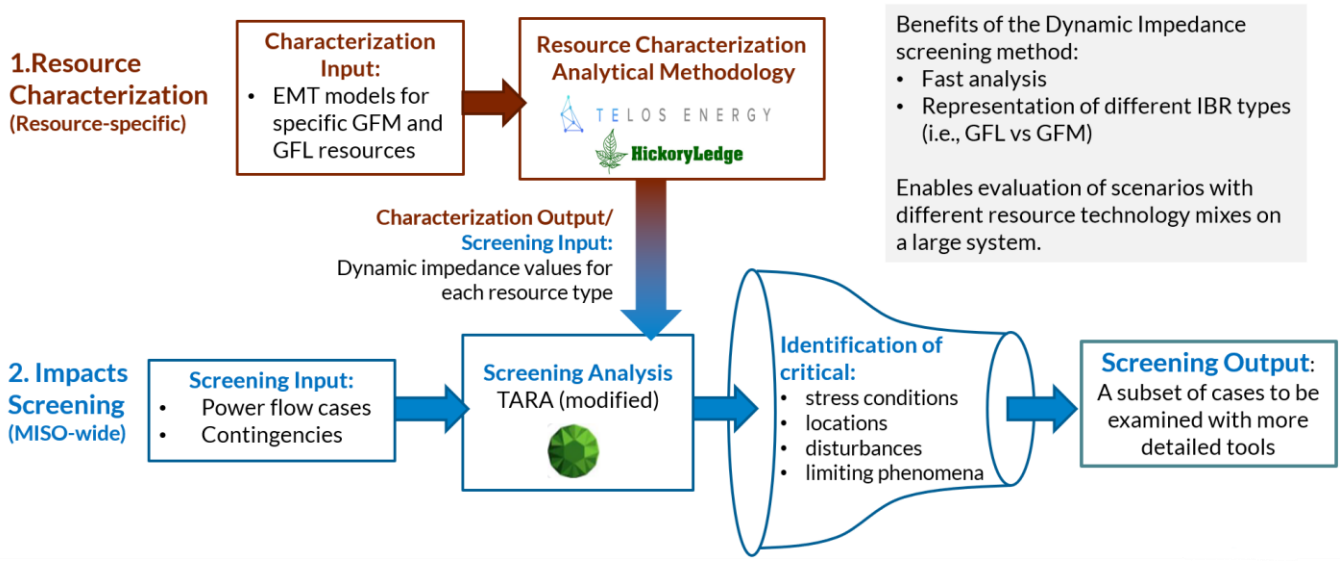


Figure C-13. Process diagram of the Dynamic Impedance screening method

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

Tools

A range of tools currently available at MISO are required to carry out the dynamic impedance method. Table C-1 summarizes the tools used in the dynamic impedance method.

Tool	Type	Dynamic impedance application
PSCAD	EMT Simulation	Extracting dynamic impedance from resource models.
PSS/E	Positive sequence domain power flow	Solving a power flow case for use in TARA.
TARA	Linear power flow transfer analysis	Performing PV curve analysis for screening.

Table C-1. Summary of tools used for dynamic impedance approach

First, an EMT simulation is required using PSCAD software to characterize a resource and extract the crucial dynamic impedance characteristics. Next, an iterative process is automated in PSS/E to generate a solved case while modifying the location of voltage regulation to effectively be internal to the resource rather than at the resource terminals. The reactive power limits (Q) still apply at the generator terminals. The process is iterative by nature as the internal voltage must be calculated based on terminal voltage and known impedance rather than directly controlled within a tolerance band. Figure C-14 illustrates the difference between conventional and dynamic impedance approach treatment of reactive power limits and voltage regulation.

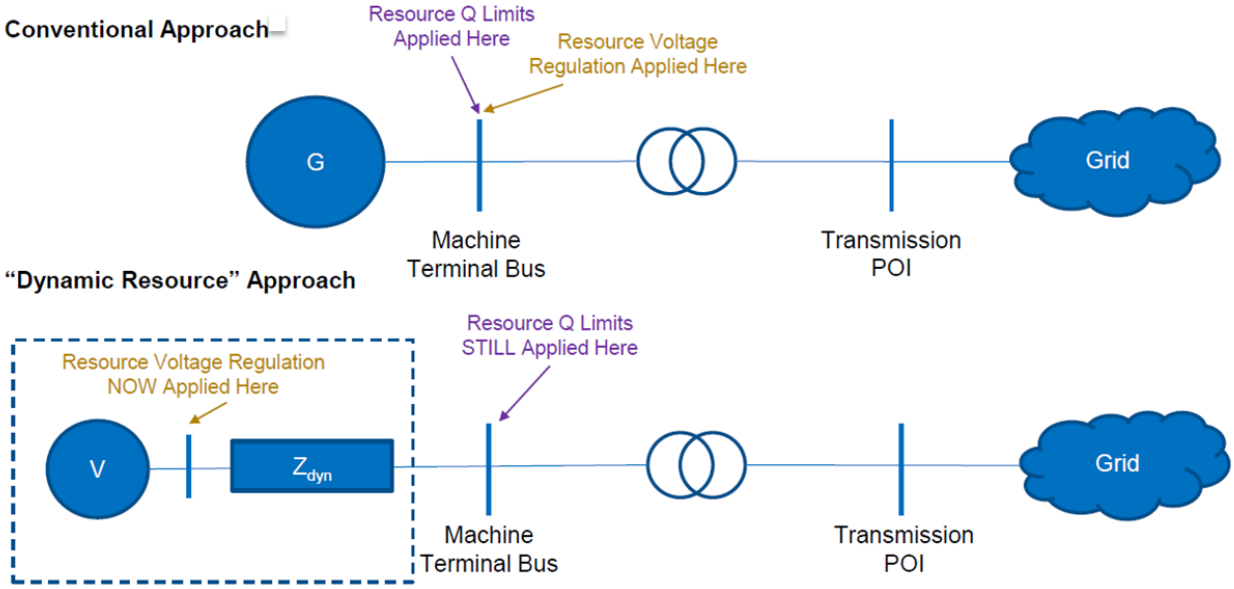


Figure C-14. Illustration of voltage regulation and active power limit application in conventional and dynamic impedance approaches (source: Telos Energy)

Finally, a tool called TARA is used to generate a PV curve used for estimating a dynamic voltage stability limit.

Models

The model used for validation was a six-bus reduced model that was roughly representing a portion of the MISO system that includes areas in South Dakota, Iowa, Minnesota, and Illinois. This area was selected based on existing

transfers resulting from wind generation to the west and load to the east. More information on the validation process and results are found in the technical paper referenced above.[39]

The scaled analysis started with the MTEP23_2033_SUM_AA model for the base case and used a modified version of this model – treating some of the synchronous machines as IBR – to generate a high penetration IBR case. The Illinois interface transfer was used as a starting point but was modified to stress a subset of this system sourced from ALTW and MEC and sunk in AMIL. The transfer was scaled up for this limited portion of the system to accentuate the results for demonstration purposes, making this an unrealistic transfer from the perspective of typical planning processes. Further, an extraordinary contingency (i.e., beyond NERC TPL Standards) was used to accentuate the difference in static and dynamic limits. Two 345 kV lines were taken out simultaneously to stress the system, which is labeled as "N-1" for this demonstration. MISO emphasizes the demonstration nature of this case. Figure C-15 shows a simplified system diagram with the green circle denoting the export area and the red circle denoting the import area. The two lines with "x" marks include the two 345 kV lines taken out for the contingency for demonstration purposes.

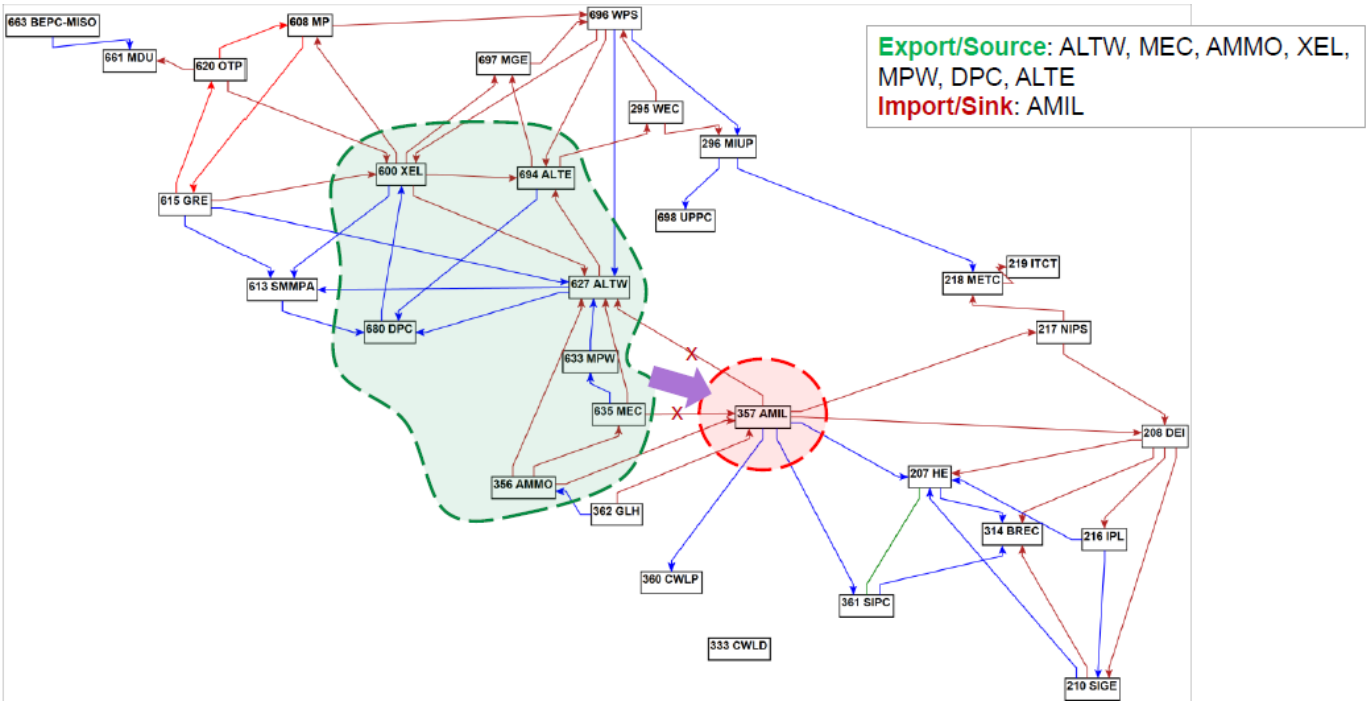


Figure C-15. Illustration of modified transfer used for demonstrating dynamic impedance approach on scaled MISO system model

The base case and high IBR case resource mix assumptions are shown in Table C-2. As previously noted, the base case assumptions are directly from the MTEP model and the high IBR penetration case treats some of the IBR in three of the areas as synchronous machines (SM) to stress the case for demonstration purposes.

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

Area	Base Case		High IBR Penetration	
	MVA SM	MVA IBR	MVA SM	MVA IBR
357 AMIL	12780	4840	8820	8810
627 ALTW	6670	5949	6280	6330
635 MEC	7230	8730	7230	8730

Table C-2. Resource assumptions for scaled dynamic impedance demonstration

Within the base case and high IBR penetration case, the proportion of IBR assumed to be GFM versus GFL was varied using 90%/10% weightings for each technology, generating additional scenarios. Figure C-16 shows the proportions of synchronous machines (SM), GFL, and GFM used in the scaled analysis.

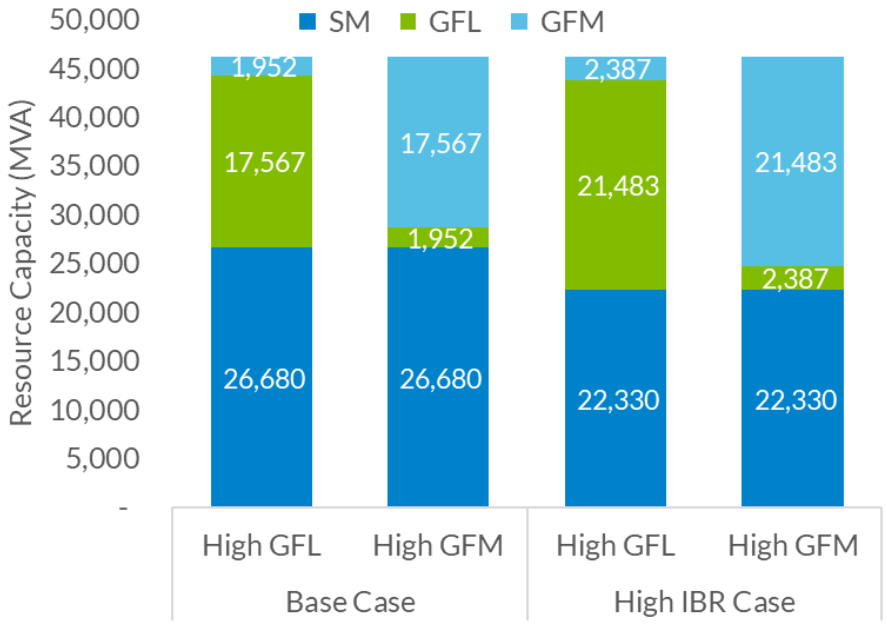


Figure C-16. Resource breakdown for each case and scenario

Dynamic impedances were applied to all large resources, amounting to approximately 1100 generators, using impedance values derived from resource characterization. For computational efficiency, small generators (e.g., less than 50 MVA) were excluded from dynamic impedance assumptions. The first step in modifying impedance of large generators was to map existing fuel types in the model to the three types of resources for which dynamic impedance is assigned: inverter-based resources and synchronous machines. Figure C-17 shows the mapping used in this analysis.

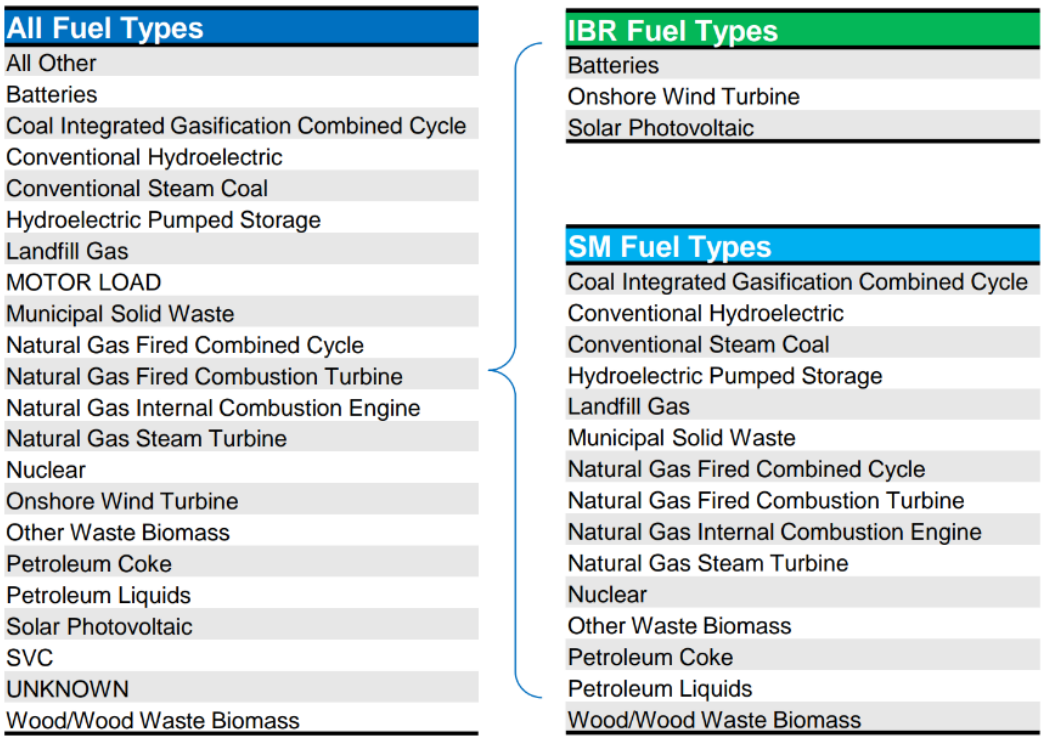


Figure C-17. Mapping of modeled fuel types to IBR and synchronous machines (SM)

The dynamic impedance values found from resource characterization were applied as assumptions in the power flow model. The demonstration used a prototypical value for each technology type, listed in Table C-3. Future work could increase granularity by using separate dynamic impedance assumptions for different IBR models and synchronous machine fuel types.

Technology type	Dynamic impedance assumption (p.u.)
Grid following IBR	1.2
Grid Forming IBR	0.1
Synchronous Machine	0.5

Table C-3. Dynamic impedance assumptions by technology type

Resource Characterization Results

The dynamic impedance method characterized six different inverters using detailed EMT models, as show in Figure C-18. The chart has admittance on the y-axis and frequency of disturbance on the x-axis (dq frame, or rotor reference frame). A high dynamic admittance translates to more effective voltage regulation over that specific frequency; this could be interpreted simply as higher system strength support. The different lines in the chart depict characterizations of commercially available makes and models of GFL and GFM technologies, representing several

major manufactures in the U.S. market. The analytical resource characterization extracts impedance information around the 10 Hz range, reflecting the time period of interest following a disturbance.[40]

MISO suspects a few causes to be driving differences in responses for a given technology type (e.g., GFM). Different control strategies could potentially drive differences. For instance, GFM technology can be implemented using virtual oscillator controls, droop-based controls, or virtual synchronous machine controls.[41] The parameterization, or settings for functional control, can also impact the IBR response and thus characterization. This means that each IBR must be characterized with the planned parameterization unless or until a standards-based approach steps in that would make generic models and parameterization more useful.

Voltage Stability Insight #3:

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.

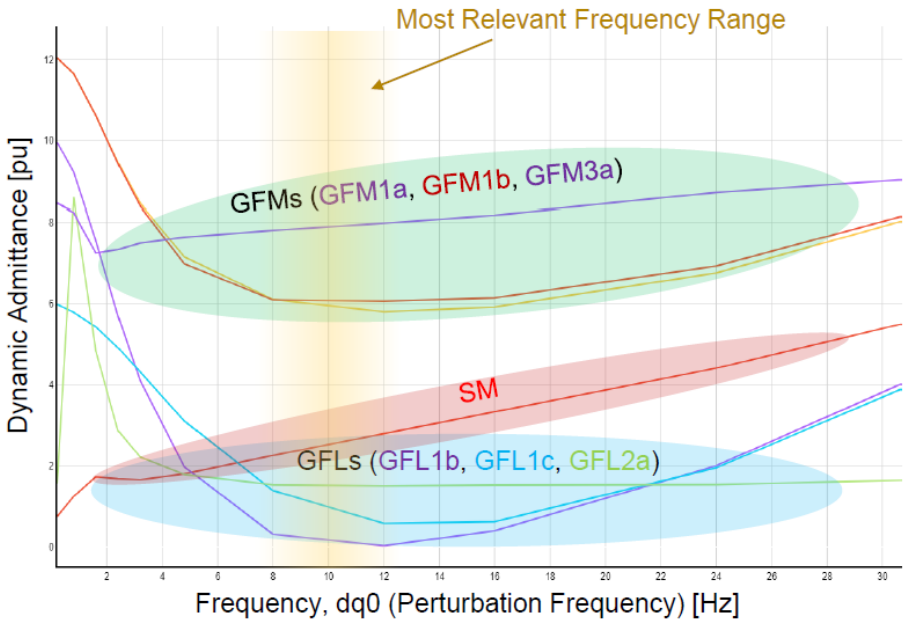


Figure C-18. EMT analysis characterizing three different commercially available grid forming (GFM) and grid following (GFL) inverter models (source: Telos Energy)

The resource characterization indicates that GFM controls are superior to GFL controls in terms of supporting stability. However, the comparison with synchronous machines is more nuanced, as the energy limitations of IBR must also be considered. Machine construction typically facilitates high current, short term overloads, whereas the energy limitations of IBR may not allow for such overloads.

[40] Selecting this range, and how to view impedance scans more generally, is an area of active research, with organizations like ESIG actively facilitating Task Force discussions that are considering a slightly different range; in to 4 Hz to 40 Hz range.

[41] NREL, *Stabilizing the Power System in 2035 and Beyond: Evolving from Grid-Following to Grid-Forming Distributed Inverter Controllers (Final Technical Report).* August 2021

It is important to note that the characterization results represent a specific range of disturbances. Further work is needed to understand the limitations associated with control non-linearities, as might be the case for a control under larger disturbances.

Transfer Capacity Results

Incorporating the resource characterization into the dynamic impedance process, Figure C-19 represents the output of the screening tool, which are PV curves that come out of the TARA tool. The vertical axis represents voltage and the horizontal axis is the MW transferred. The blue curve at the top is the same in both charts, representing a standard PV curve for a contingency without any modifications from the new method. At a high level, these curves represent the output of a voltage stability transfer analysis, showing declining voltages as transfer levels increase. The voltage magnitude is found at each transfer point, and the highest transfer point shows the voltage stability transfer limit. Voltage collapse is expected beyond this point.

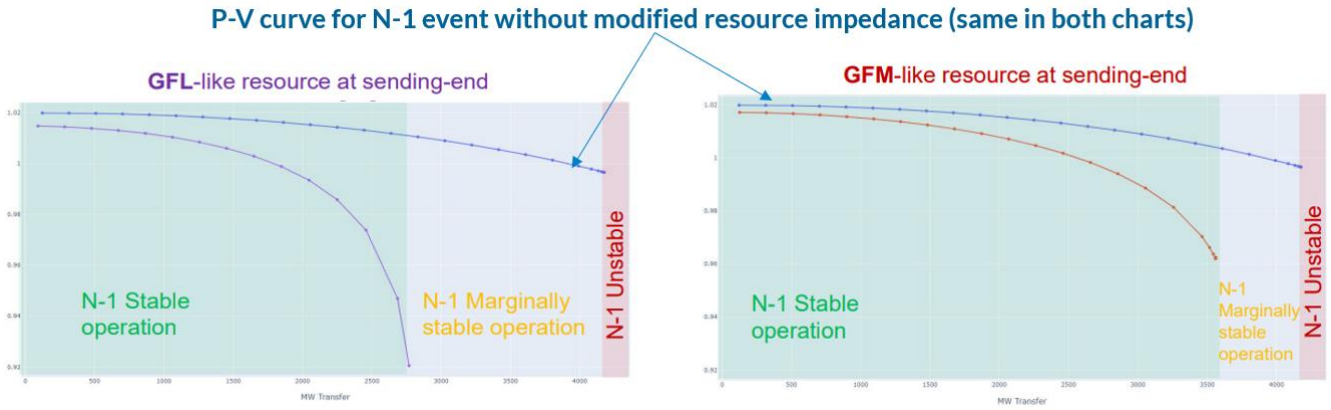


Figure C-19. Illustration of dynamic impedance screening results for GFL and GFM resources at the sending-end

The dynamic impedance screening analysis is a way to approximate dynamic stability limits using a tool and method (i.e., TARA's PV curve analysis) that is typically used to evaluate static transfer limits, under normal and contingency conditions. The lower PV curve on each chart in Figure C-19 represents analysis that incorporates the dynamic impedance values in the input assumptions. The left-hand side assumes GFL resources at the sending end, whereas the right-hand side assumes GFM. GFM resources show a greater contribution to dynamic stability, increasing the limit beyond what GFL supports. Dynamic stability limits are lower than the static limit in this test case, though voltage or thermal limits may often be the constraints in today's system analysis. The screening limit, marked by the yellow "marginally stable operation" region, would be used as a threshold for considering more detailed analysis methods (e.g., positive sequence domain simulations) to find the actual dynamic stability limit.

Applying this screening approach to the scaled MISO system described in the Models section, PV curves were generated for the different base case and high IBR case scenarios (i.e., high GFL versus high GFM). Figure C-20 shows the PV curves generated by TARA for each case, with the bookends of high GFL versus high GFM scenarios in the high IBR case. When considering dynamic voltage stability limits, the high GFL scenario in high IBR case resulted in a transfer limit of 8,976 MW whereas the high GFM scenario in high IBR case resulted in a limit of 9,833 MW. This result implies that GFM controls could improve dynamic stability limits by around 10% when compared to GFL controls in a high IBR case.

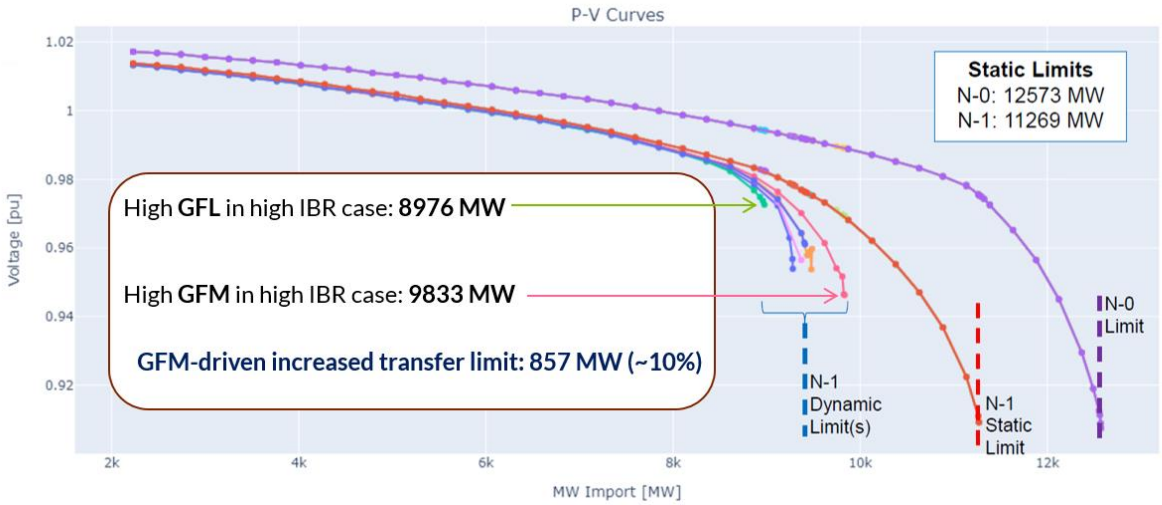


Figure C-20. Dynamic impedance screening results on the scaled-up MISO system

Another notable result from the analysis is how high levels of GFL controls in a high IBR scenario drive lower voltage stability transfer limits when compared to the base case, suggesting that high proliferation of GFL controls without GFM support could lead to new voltage stability constraints. The high GFL in a high IBR scenario has transfer levels that are 304 MW less than the base case. Consistent with the GFM stability gains discussed above, high GFM in the high IBR case leads to higher stability limits, by 347 MW, when compared to the base case with high GFM scenario. Figure C-21 shows select comparisons between the cases and scenarios, indicating transfer capability increases or decreases.

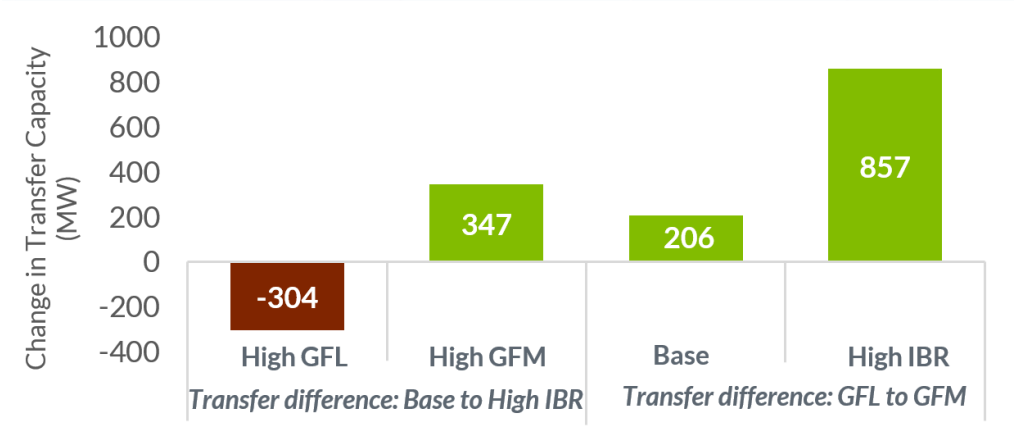


Figure C-21. Comparison of potential transfer capacity for select cases and scenarios

C.4 Conclusion

This technical appendix section described approaches, tools, and assumptions used in the voltage stability attributes analysis that informed insights and roadmap development. Please refer to the *Attributes Roadmap* for the proposed solution hypothesis based on this analysis.

D. Attribute Support from MISO's Market Structures

The following table summarizes the list of MISO's Markets, as of November 2023. The table summarizes how each Market structure supports the relevant attributes discussed in MISO's *Attributes Roadmap*. The voltage stability attribute risk-factor is excluded from Table D-1 given that MISO currently has no market products related to voltage stability.

Market	Attribute Risk-Factor	Market Product	Geographic Granularity	Requirement	Offer Cap	Max. Scarcity Price	Why does this market exist? What is the business case?
Resource Adequacy	**Availability/ Fuel Assurance/ Energy Assurance**	**Capacity Planning Resource Auction**	Local Resource Zone (LRZ)	MISO calculated LRZ needs and import/ export limits	Cost of New Entry (CONE)	Cost of New Entry (CONE)	Address resource adequacy needs in MISO's footprint
FTR	**N/A**	**Financial Transmissio n Rights**	Point-to-Point	n/a			FTRs are financial instruments used to hedge the risk of congestion cost in the Day-ahead Market.
		Auction Revenue Rights (ARRs)	Point-to-Point	Allocated based on firm historical usage	Allocation process; no market offer	n/a	ARRs are entitlements to a share of the revenues generated in the annual FTR Auction to address transmission investments.
Day-Ahead Energy and Operating Reserves Market	**Ramp Up Capability/ Rapid Start-Up**	**Energy**	Nodal	Demand Bids	$1,000 (soft cap), $2,000 (hard cap)	Value of Lost Load (VOLL) ($3,500)	The Energy market uses transmission and generation assets more efficiently and reduces the need of additional assets.
		Regulating Reserve	System-wide	300-500MW, depending on hour of day	$500	Regulation Demand Curve, up to VOLL	Address small deviations in frequency and tie-line flows, meeting NERC standards.
		Spinning Contingency Reserve	Reserve Zone with RPE	901 - 1201 MW, depending on hour of day	$100	ORDC* plus Spin Demand Curve, up to VOLL	Address larger deviations resulting from system contingencies, meeting NERC standards.
		Supplement al Contingency Reserve	Reserve Zone with RPE	1,109 MW	$100	ORDC, up to VOLL	Address larger deviations resulting from system contingencies, meeting NERC standards.
		Short Term Reserves	System-wide, Sub-Regional, Local	~3,600 MW (System-wide)	None for on-line; $100 for off-line	$100-200	Efficiently ensure capacity to manage imbalance and reserve replacement
	Ramp Up Capability	**Ramp Capability Product (Up and Down)**	System-wide	Based on estimated real-time needs	No offer	$5	Manage resource flexibility to address forecast uncertainties.

Table D-1: Current MISO's Markets and their support for attributes

Market	Attribute Risk-Factor	Market Product	Geographic Granularity	Requirement	Offer Cap	Max. Scarcity Price	Why does this market exist? What is the business case?
Real-Time Energy and Operating Reserves Market	**Ramp Up Capability/ Rapid Start-Up**	**Energy**	Nodal	Short Term Load Forecast	$1,000 (soft cap), $2,000 (hard cap)	Value of Lost Load ($3,500)	The Energy market uses transmission and generation assets more efficiently and reduces the need of additional assets.
		Regulating Reserve	System-wide	300-500MW, depending on hour of day	$500	Regulation Demand Curve, up to VOLL	Address small deviations in frequency and tie-line flows, meeting NERC standards.
		Spinning Contingency Reserve	Reserve Zone with RPE	901 - 1201 MW, depending on hour of day	$100	ORDC plus Spin Demand Curve, up to VOLL	Address larger deviations resulting from system contingencies, meeting NERC standards.
		Supplemental Contingency Reserve	Reserve Zone with RPE	1,109 MW	$100	ORDC, up to VOLL	Address larger deviations resulting from system contingencies, meeting NERC standards.
		Short Term Reserves	System-wide, Sub-Regional, Local	~3,600 MW (System-wide)	None for on-line; $100 for off-line	$100-200	Efficiently ensure capacity to manage imbalance and reserve replacement
	Ramp Up Capability	**Ramp Capability Product (Up and Down)**	System-wide	Based on short-term load forecast and uncertainty	No offer	$5	Manage resource flexibility to address forecast uncertainties.

Table D-1: Current MISO's Markets and their support for attributes (continued)

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-26-16

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 87

MISO's Response to the Reliability Imperative



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 *(partial list)*
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	• Ensure resources are accurately accredited • Identify critical system reliability attributes • Ensure accurate pricing of energy & reserves
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	• 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
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	• 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
SYSTEM ENHANCEMENTS Create flexible, upgradeable and secure systems that integrate advanced technologies to process increasingly complex information and evolve with the industry	• 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

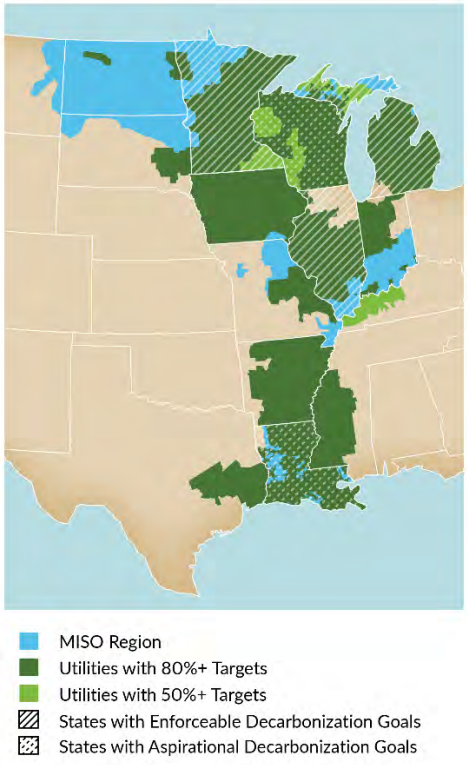
CONTINUED STAKEHOLDER INPUT IS CRUCIAL

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.

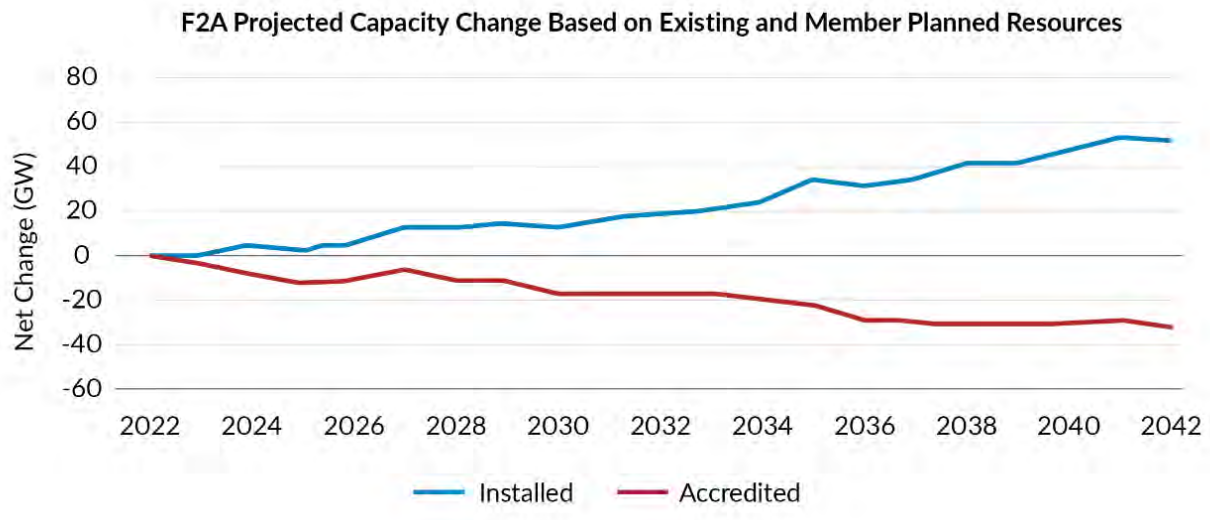
An annual planning tool called the **OMS-MISO Survey** tells a similar story. The survey compiles information about new resources utilities and states plan to build and older assets they intend to retire in the coming years. The 2023 survey shows the region's level of "committed" resources declining 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 —

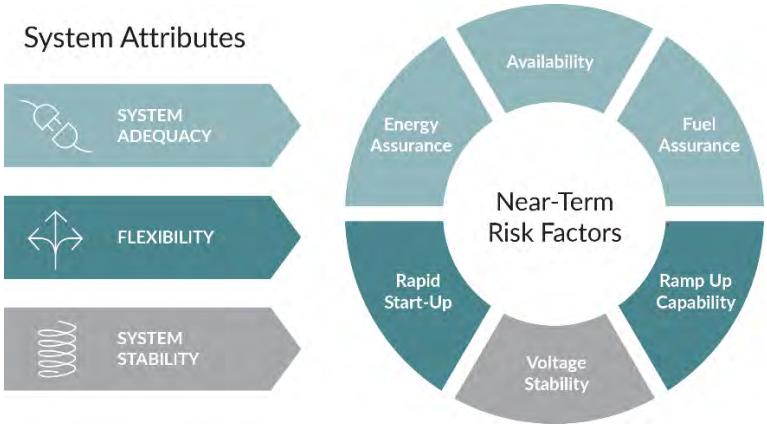
primarily wind and solar — that utilities and states plan to build in that 20-year time period.[1] But because those new wind and solar resources have significantly lower accreditation values[2] than the conventional resources that utilities and states plan to retire in the same 20-year period, the region's 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.

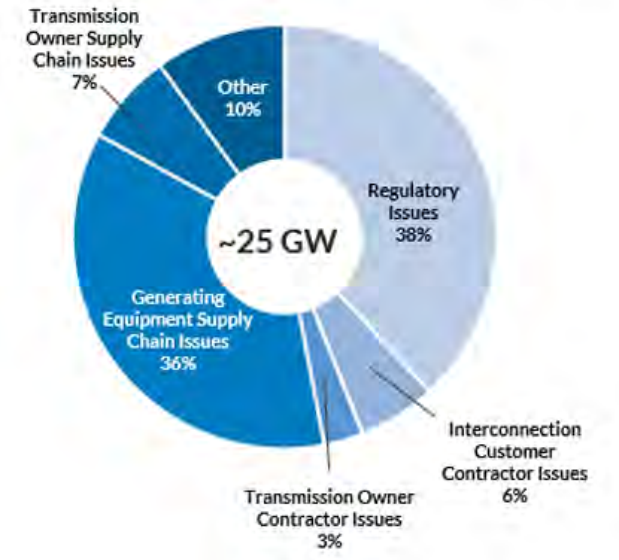
The impacts of these trends could be significant. In MISO's 2021 Electrification Insights report, MISO found that electrification could transform the region's grid from a summer-peaking to a winter-peaking system and that uncontrolled vehicle charging and daily heating and cooling load could result in 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.

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



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.

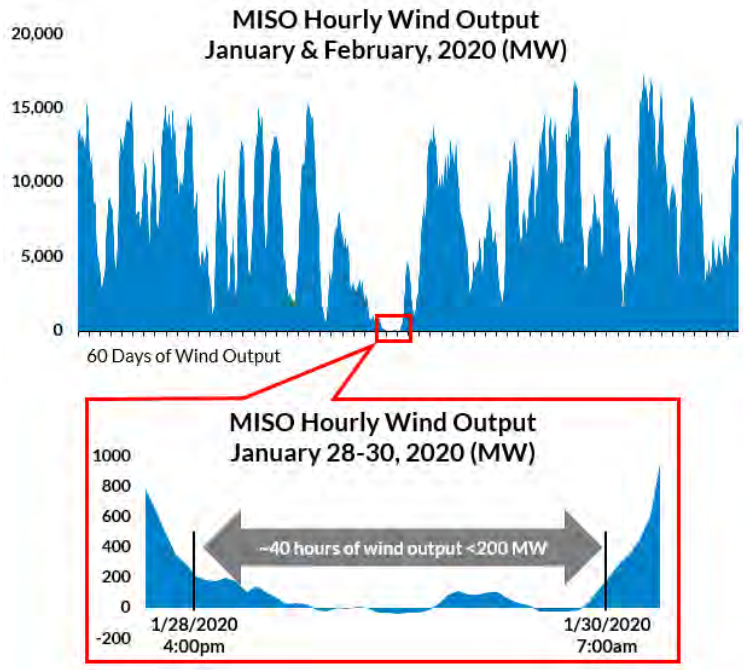
Gas-fired resources are also subject to fuel-assurance risks because they rely on pipelines to deliver gas to them. However, because the pipeline system was largely built for home-heating and manufacturing purposes, gas power plants sometimes face very challenging economic conditions to procure the fuel 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

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'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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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-26-16

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 88

August 20 weather report

The Wayback Machine - https://web.archive.org/web/20250820225303/https://weather.com/fo...

USA National Forecast

Share

Taste of Fall On The Way: Here's Who Will Feel The Big Cooldown First

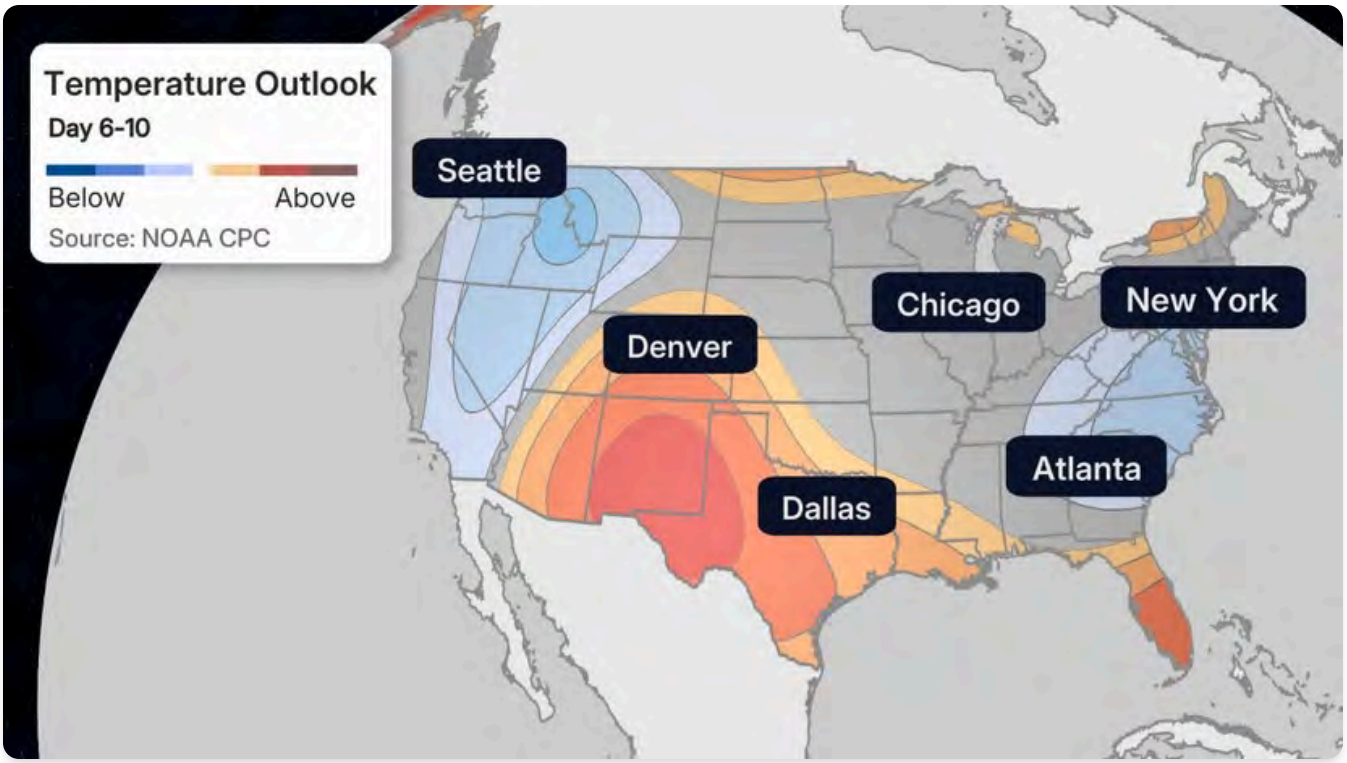
A refreshing blast of cooler air will sweep across the Plains, Midwest, and parts of the South this weekend into next week, giving millions a rare late-August taste of fall.

By Jennifer Gray • 2 hours ago

These Sled Dog Puppies Are Actually Rangers

A refreshing shot of cooler air is set to dive into the U.S. later this weekend and into next week, delivering some of the coolest temperatures of the season for millions across the country.

Who's ready for hoodies and pumpkin everything? Folks in the Midwest, Plains, and even parts of the South will get their first taste of crisp, fall-like air in the coming days.



This image shows the temperature trend for August 26-30, which shows a large pool of cool air settled over much of the Plains, Midwest and even parts of the South.

The Weather Setup

A slow-moving cold front will begin working its way into the northern U.S. Thursday and Friday. As it pushes southward and encounters the warm, humid air currently in place, showers and thunderstorms are likely to develop along the frontal boundary.

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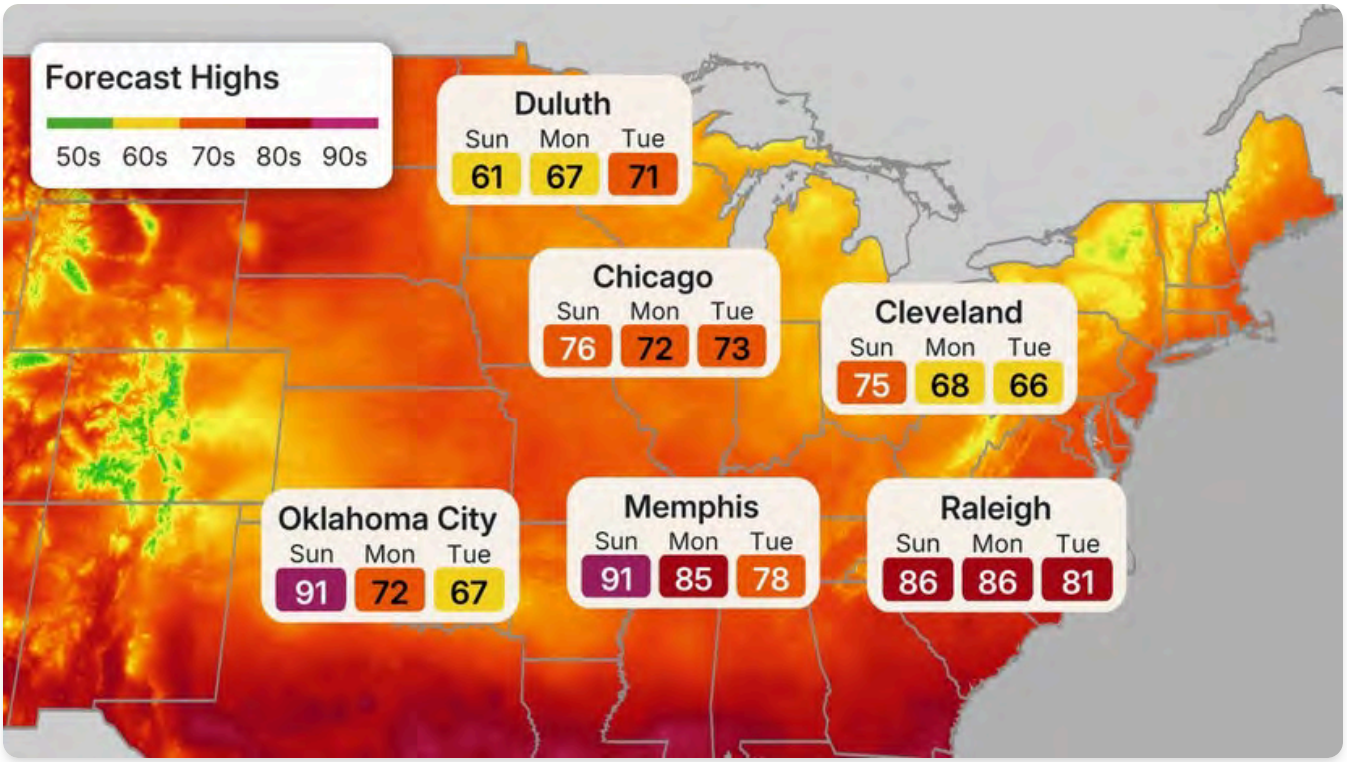
Thunderstorm Outlook
(Shaded on the map above is the likelihood of severe thunderstorms, according to NOAA's Storm Prediction Center. Note that not all categories apply for the severe weather risk on a particular day.)

The Storm Prediction Center has already highlighted areas across the Upper Midwest and Northern Plains for the potential of strong thunderstorms on Thursday.

That threat shifts farther south on Friday, as the front digs into the Central Plains and Midwest. A few of these storms could become strong to severe, so it’s something to keep an eye on.

The August Chill

Behind the front, cooler, drier air will sweep across a large portion of the country. Temperatures are expected to run 10 to 25 degrees below average from the Plains to the Midwest — and even reach into parts of the South.



Three Day Temperature Outlook

Sunday: Expect highs in the 60s and lows in the 40s across parts of the upper Midwest. Duluth, Minnesota, may struggle to reach 60 degrees, while Chicago will enjoy a comfortable day around 75.

Monday: The cool air pushes farther south. Highs in the low to mid-70s will be widespread across the Plains, Midwest, Ohio Valley, interior Northeast and even in parts of the Southern Plains.

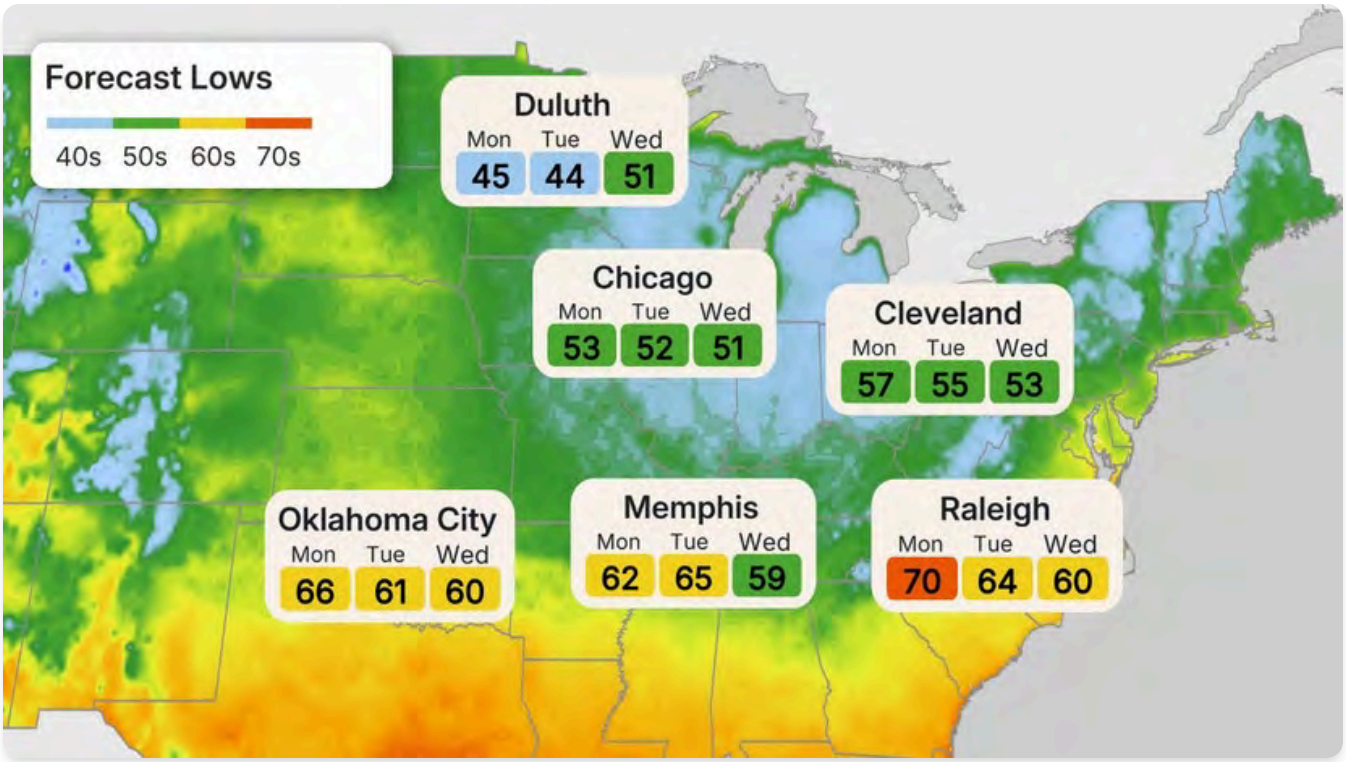
Search City or Zip Code

chance of rain in some spots.

The Ohio Valley will also enjoy highs in the low to mid-70s, with the Midwest continuing to bask in fall-like conditions.

Tuesday: By Tuesday, the cooler air won't be quite as intense, but even parts of the Southeast will feel a break from the brutal August heat.

Highs in Little Rock, Arkansas, may dip into the mid-70s, while cities like Nashville, Tennessee, could see temps in the upper 70s — not exactly sweater weather, but certainly a welcome reprieve from the dog days of summer.



Three Day Temperature Outlook

This kind of late August cool-down doesn't come around often. If you can, open the windows, head outside, and enjoy the fresh air. It may not last long, but hopefully this little taste of fall will be a welcome treat for millions.

Jennifer Gray is a weather and climate writer for weather.com. She has been covering some of the world's biggest weather and climate stories for the last two decades.

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-26-16

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 89

2025 OMS-MISO Survey

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

Executive Summary

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.

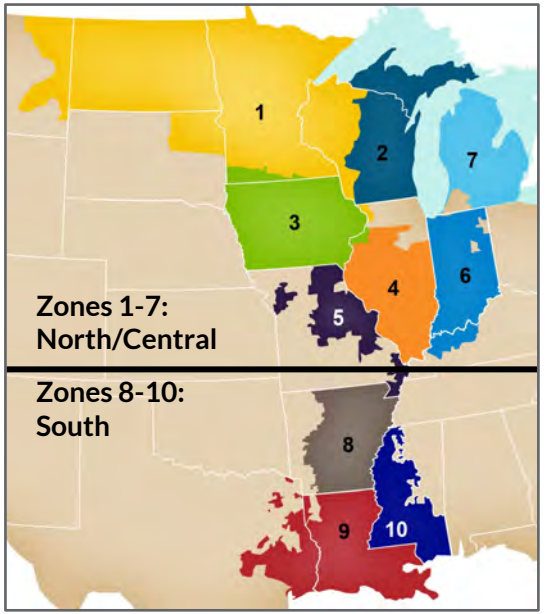
All references to capacity in this presentation indicate seasonal accredited capacity (SAC), unless noted otherwise.

*See slide 7 for data which illustrates the projected Planning Reserve Margin Requirement with Load Serving Entities' forecast (137.3 GW) minus Committed Capacity (134.2) for PY 2026/27.

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.



The survey serves as a point-in-time analysis based on data collected during April 2025.

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	• No Changes	• 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*	• **Historical Projection:** Results in **3.5 GW/yr**
	  • *Driven by 2022-2024 actuals*
	• **Emerging Projection:** Results in **6.2 GW/yr** average
	  • *Informed by member responses to OMS-MISO Survey request, these members represent 97% of the load in the footprint*
	  • *Fuel mix of new resources indicated by OMS-MISO Survey member responses*
		• **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*	• **Replacement Impact Highlighted:** Results in additional "new resources" to offset the impacts of retirements
	• **Historical Replacement** : Valued at **1.2 GW/yr**
	  • *50% replacement & surplus queue adoption*
	• **Emerging Replacement:** Valued at **2.4 GW/yr**
	  • *100% replacement & surplus queue adoption*
	  • *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*
		• Not included

Committed Capacity	• No Changes	• 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*

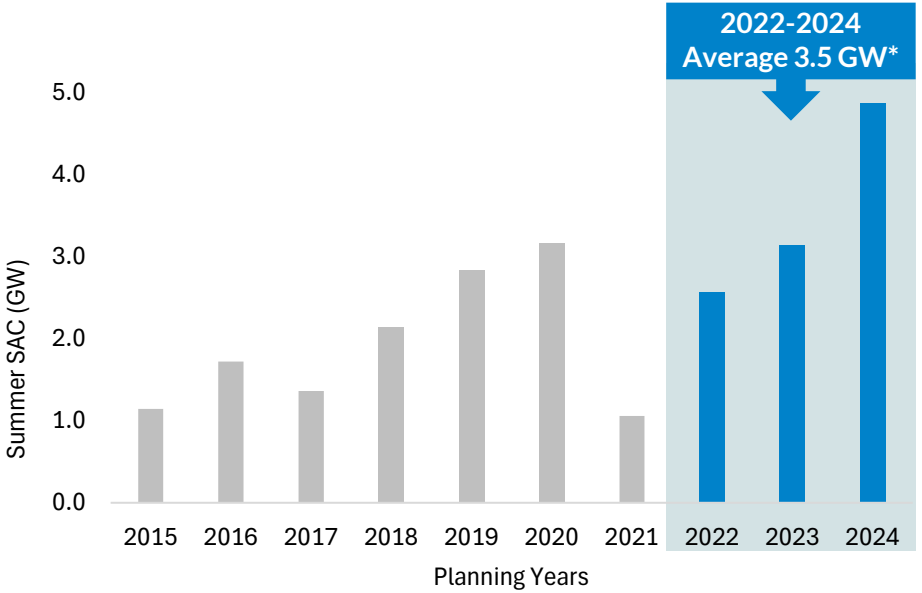
Trends and market pressures related to new capacity additions suggest that refinements are needed to better reflect uncertainty

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

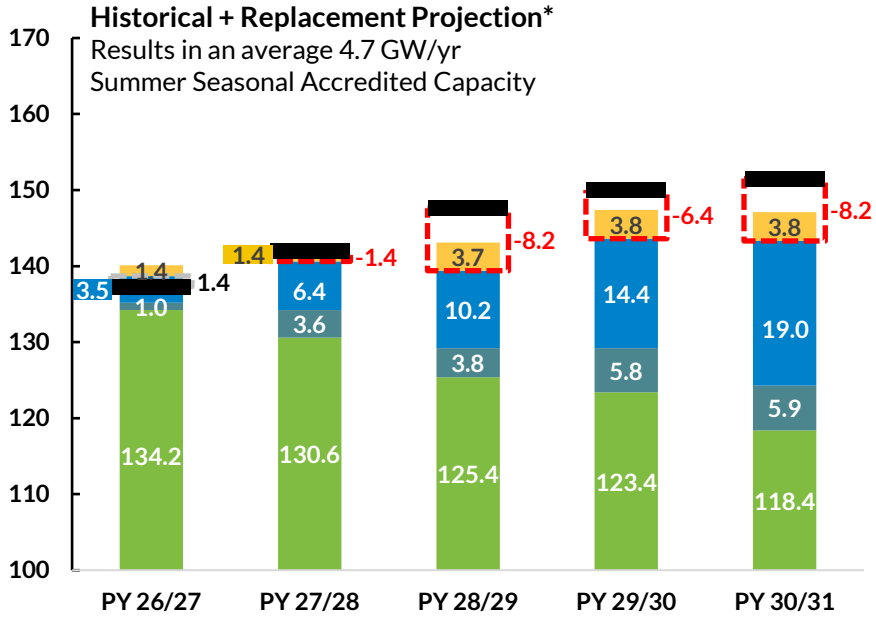


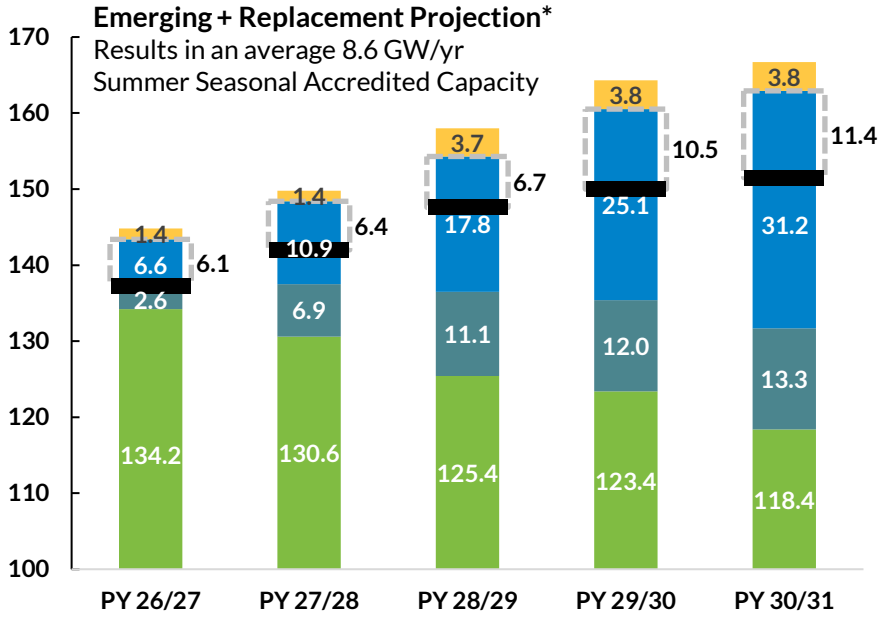
Queue applications: Nameplate 296 GW Queue & 54 GW Signed GIAs not yet online (as of 5/14/25)

**Summer seasonal accredited potential new capacity based on 2022-24 actuals*

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	• No Changes	• 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	• **Historical Projection:** Results in **1.4 GW/yr**
	  • *Driven by 2022-2024 actuals*
	• **Emerging Projection:** Results in **4.1 GW/yr** average
	  • *Informed by member responses to OMS-MISO Survey request, these members represent 97% of the load in the footprint*
	  • *Fuel mix of new resources indicated by OMS-MISO Survey member responses*
		• Not included

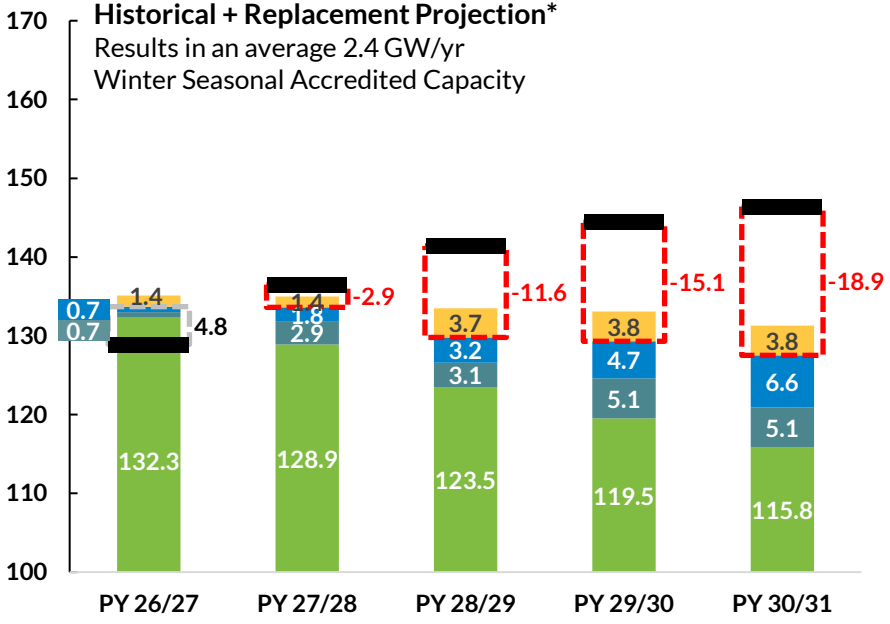
Replacement/ Surplus Project Impact Potential New Capacity – Existing Point of Interconnection	• **Replacement Impact Highlighted:** Results in additional "new resources" to offset the impacts of retirements
	• **Historical Replacement** : Valued at **1.0 GW/yr**
	  • *50% replacement & surplus queue adoption*
	• **Emerging Replacement :** Valued at **2.1 GW/yr**
	  • *100% replacement & surplus queue adoption*
	  • *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*
		• Not included

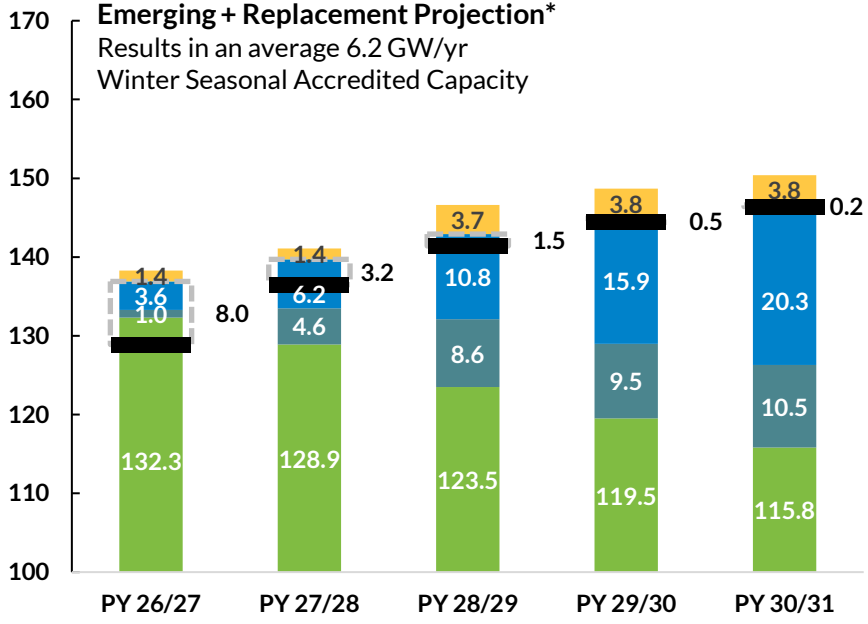
Committed Capacity	• No Changes	• Existing generation resources • External resources with firm contracts to MISO load • Assumes resources will be used to meet PRMR

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





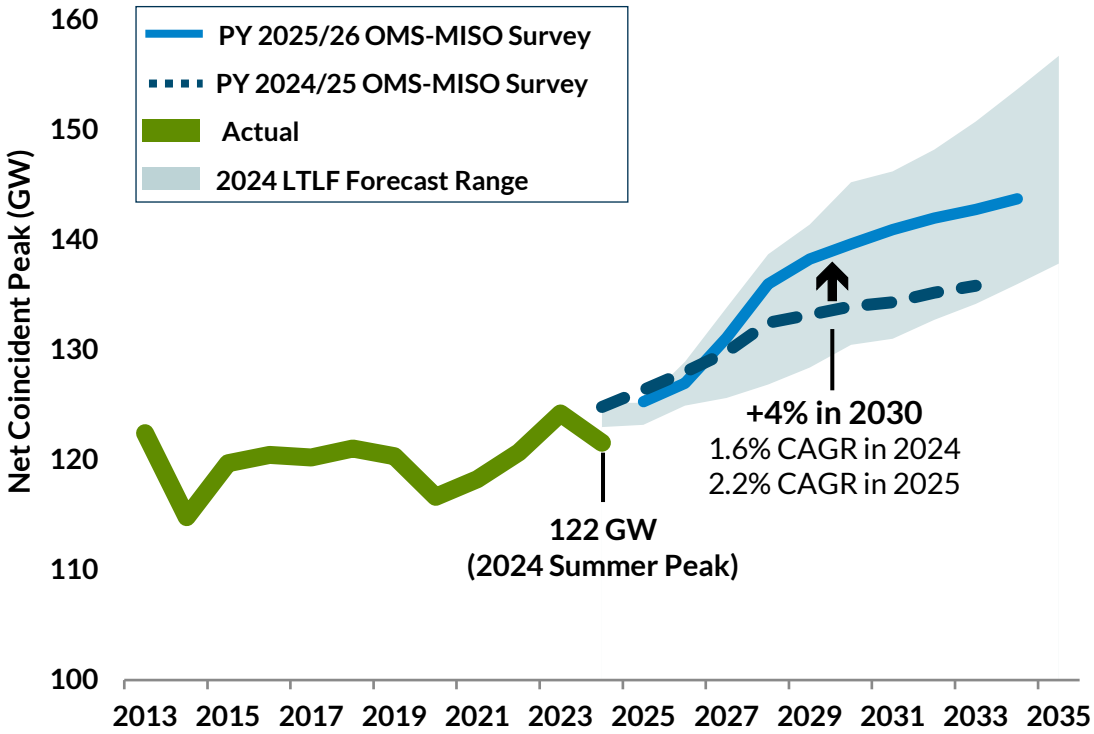
Projected PRMR with LSE forecast
Potentially Unavailable Resources
Potential New Capacity
Value of Replacement/Surplus Projects
Committed Capacity

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*



Data Centers (149-241)

Electric Vehicles (54-91)

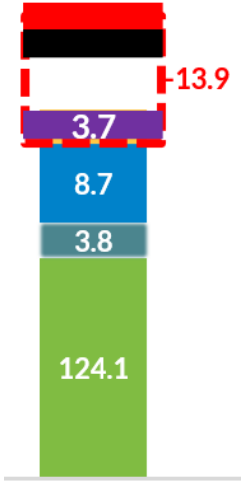
Industry Development & Offshoring (21-105)

Hydrogen (25-95)

Building Electrification (36-43)

LTLF: Long-Term Load Forecast, 2024 Long-Term Load Forecast White Paper; **CAGR:** Compound Annual Growth Rate
**Level of certainty based on expected likelihood of load growth materializing*

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 Forecast[1]
- 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"

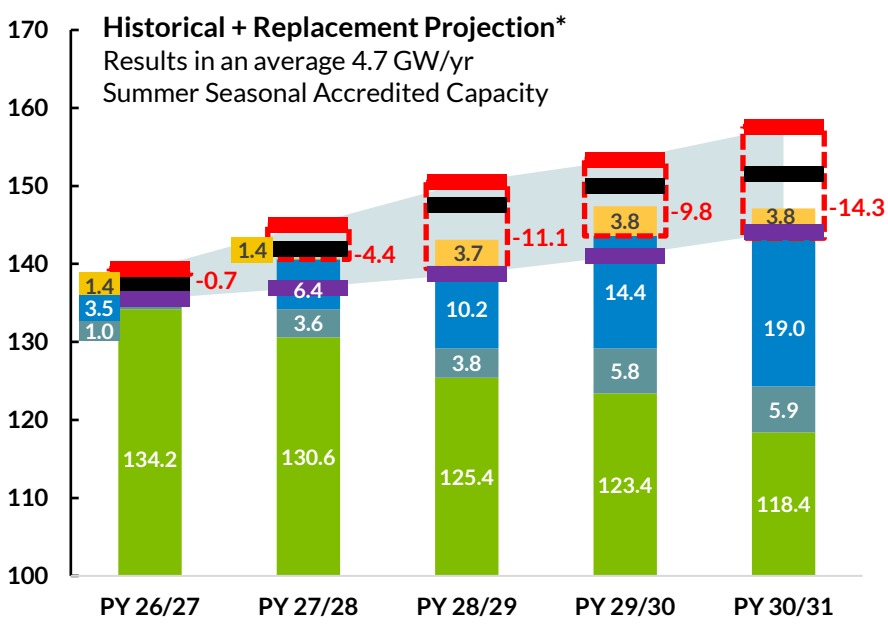
- Models lower load-growth scenario per Long-Term Load Forecast[1]

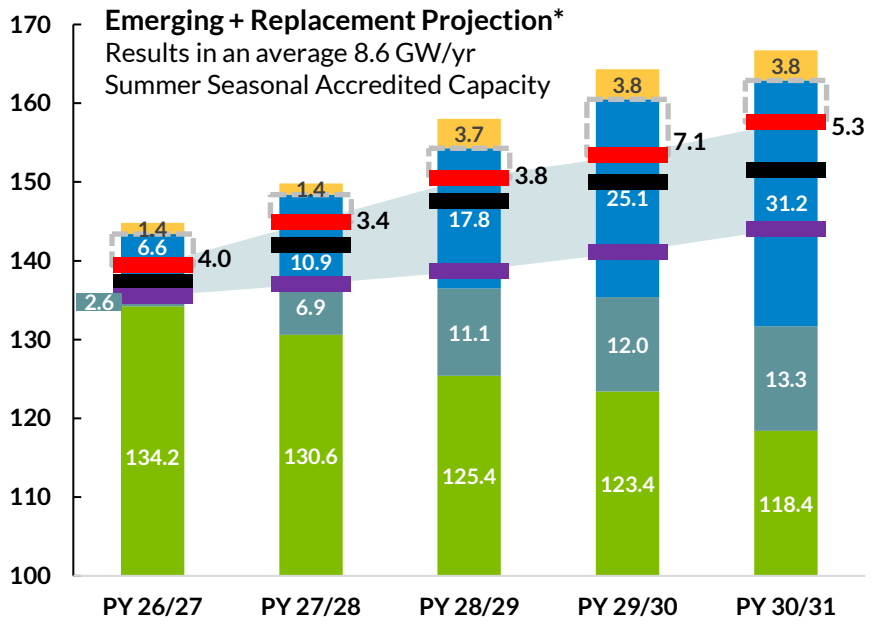
[1] MISO Long-Term Load Forecast White Paper, December 2024

PRMR: *Planning Reserve Margin Requirement* ***LSE:*** *Load Serving Entity* ***LOLE:*** *Loss of Load Expectation*

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

MISO Resource Adequacy Projections – Summer





Planning Reserve Margin

- 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*

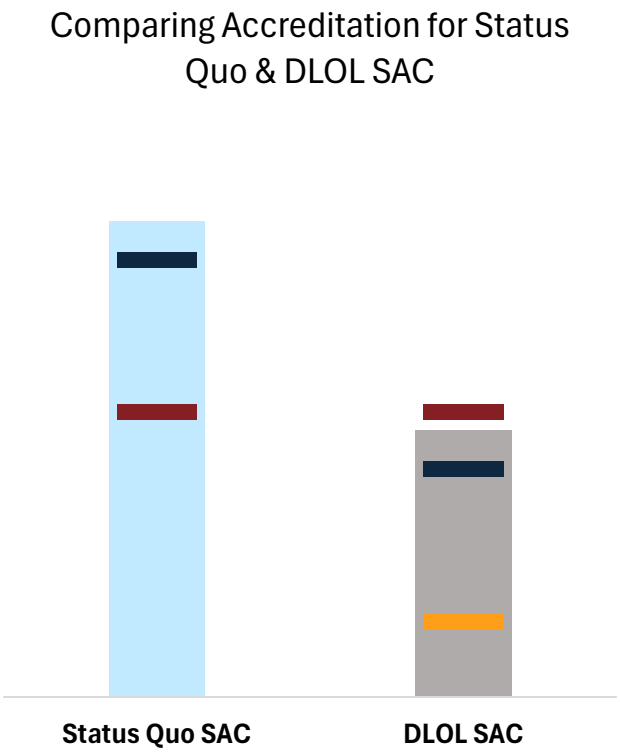
MISO's existing accreditation methods can overstate a resource's capacity value during the highest risk periods, especially as the region's risk profile changes, leading to understated risk

- 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.

*See Resource Accreditation White Paper, published March 2024

High Level Description of Status Quo vs Direct Loss of Load



Peak Load Forecast
- Submitted annually by members

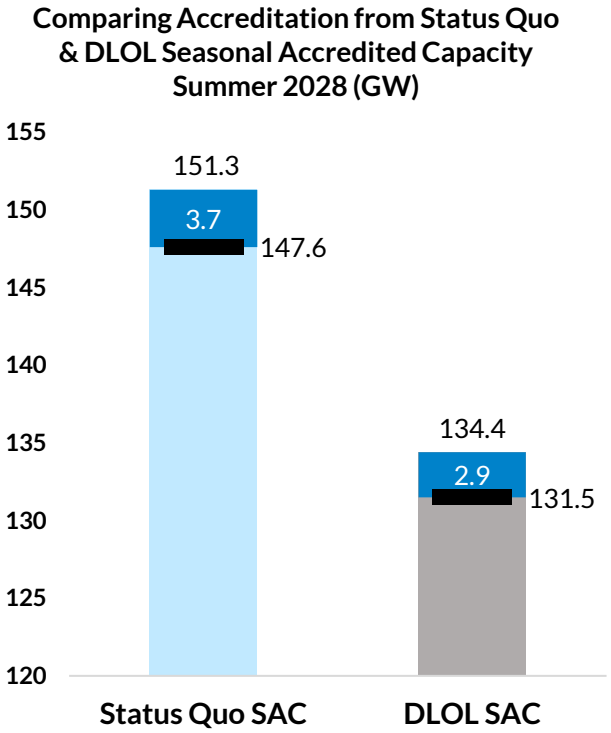
Critical Hours Load Forecast
- Illustrative only, not collected

Planning Reserve Margin Requirement (PRMR) at
- Status Quo: Peak Load
- DLOL: critical hours

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

DLOL SAC value of Resources during critical hours to meet PRMR

Status Quo vs Direct Loss of Load Accreditation for summer 2028



- 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

Key Takeaways

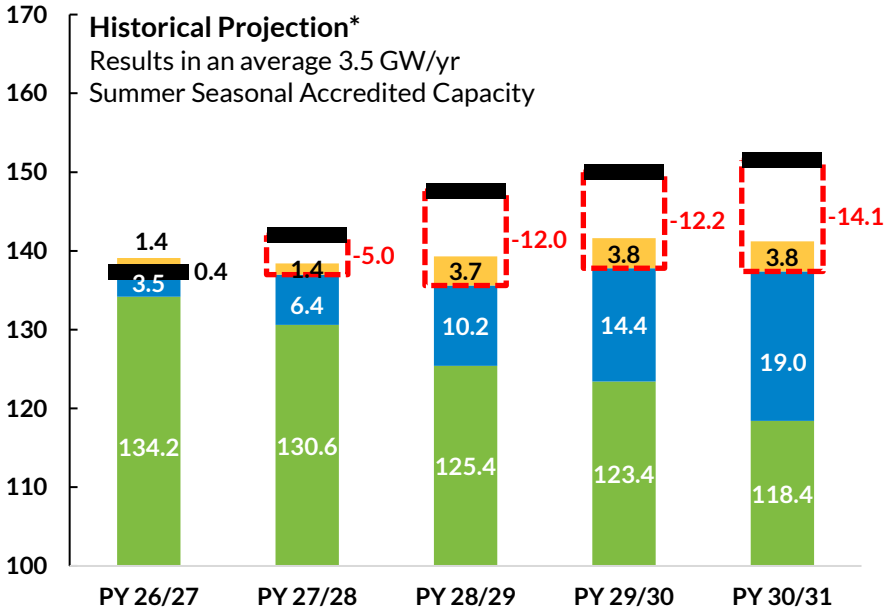
The 2025 OMS-MISO Survey emphasizes that decisions made today by utilities, regulators, MISO and its members will critically shape future resource adequacy

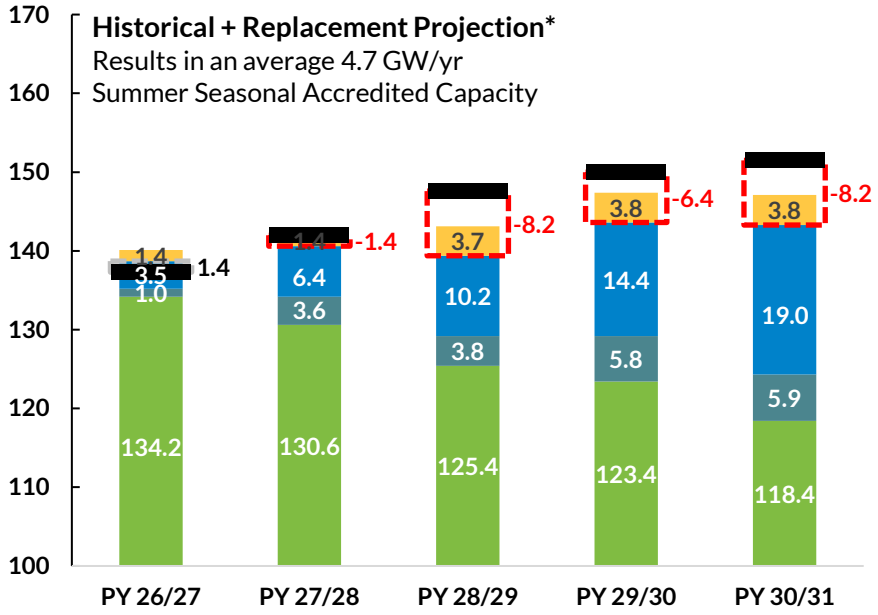
- This year's survey highlights significant uncertainty in projected resource adequacy, underscoring the urgent need for accelerated resource additions, strategic retirement planning, and proactive management of increasing load growth.
- Ongoing collaboration between OMS and MISO remains essential to 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

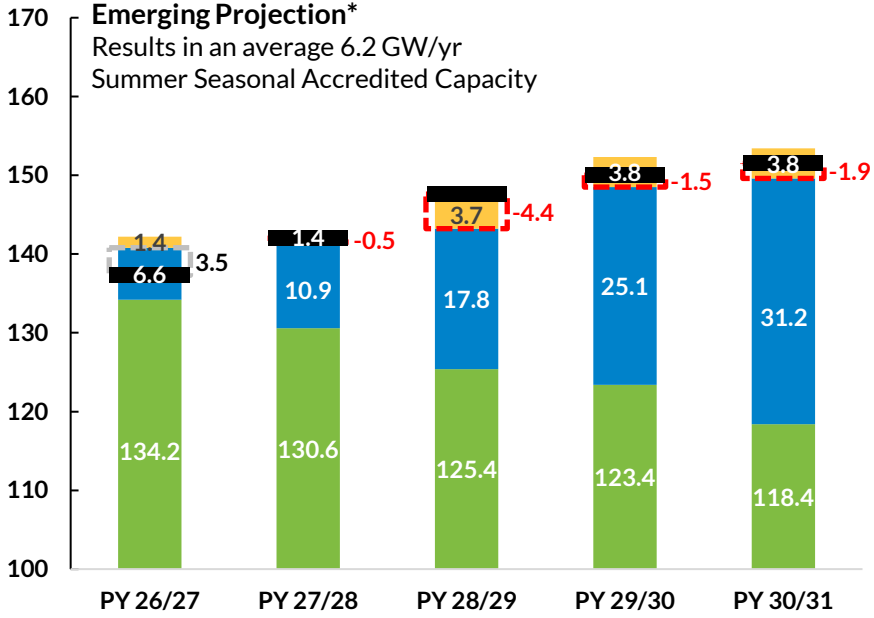
**Using methods for potential New Capacity described on Slide 5*
***PRMR:** Planning Reserve Margin Requirement*

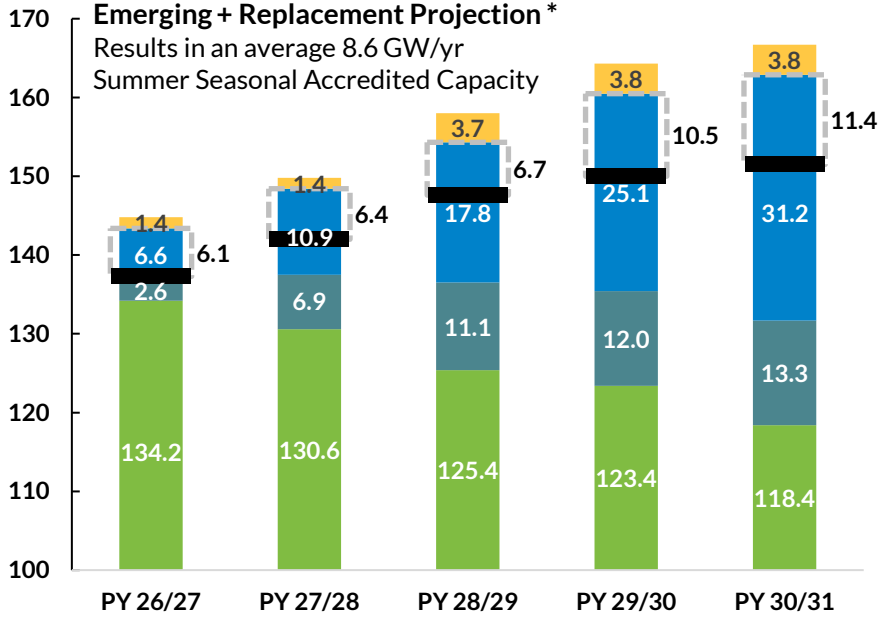
Red border values indicate the additional potential deficit against the Projected PRMR
Gray border values indicate the potential surplus against the Projected PRMR

- 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

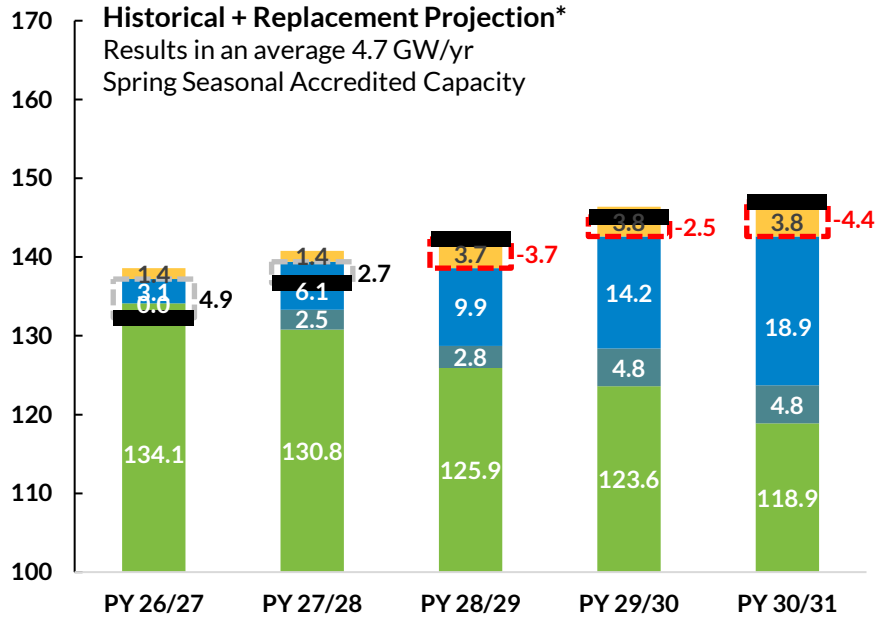
Using methods for potential New Capacity described on Slide 5
***PRMR:** Planning Reserve Margin Requirement*

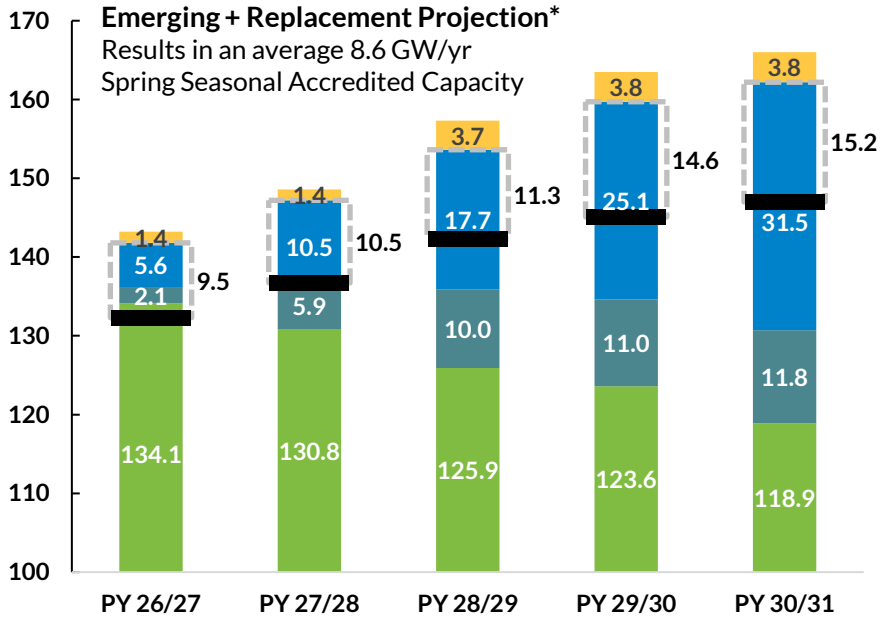
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- Capacity accreditation values and Planning Reserve Margin projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart

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

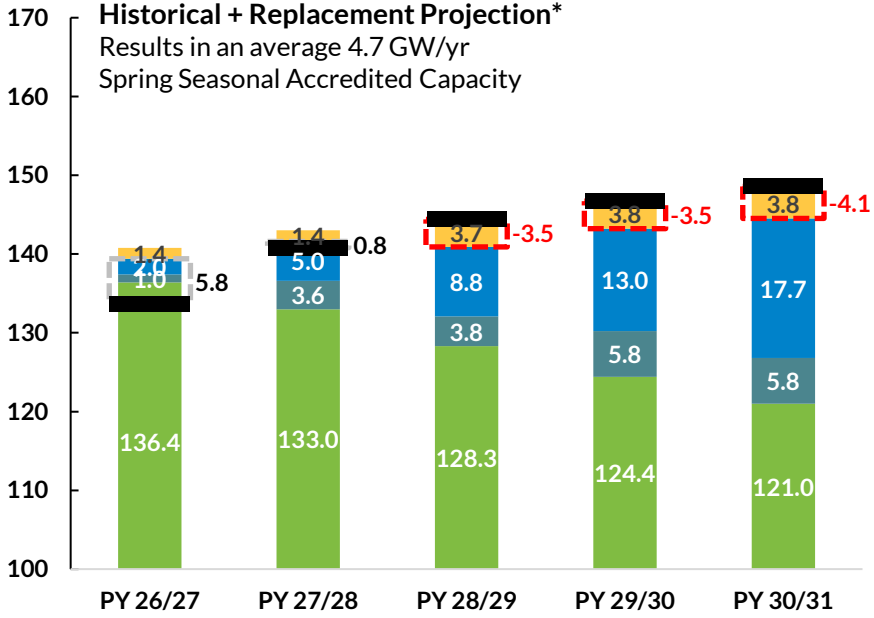
Using methods in line with potential New Capacity described on Slide 5
***PRMR:** Planning Reserve Margin Requirement*

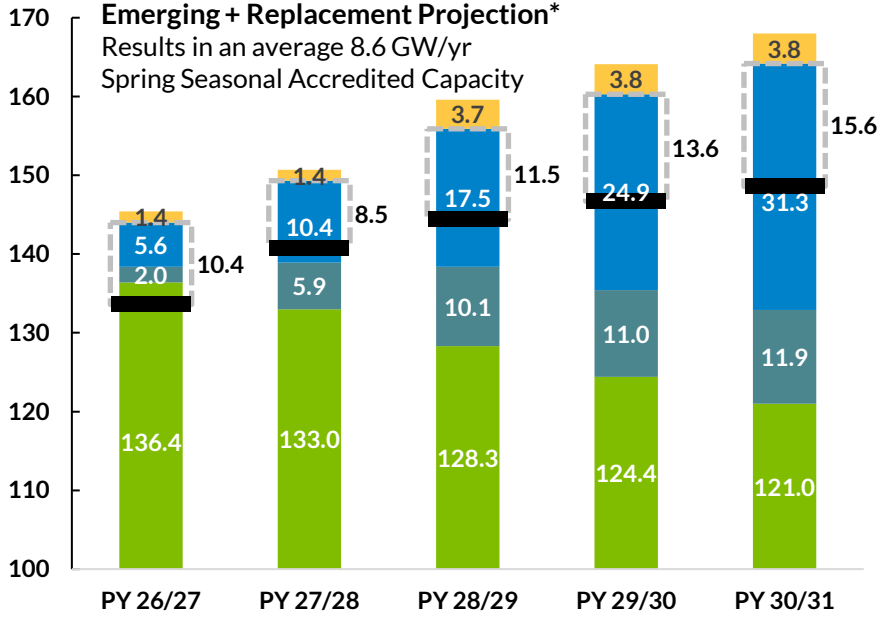
Red border values indicate the additional potential deficit against the Projected PRMR
Gray border values indicate the potential surplus against the Projected PRMR

- 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 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

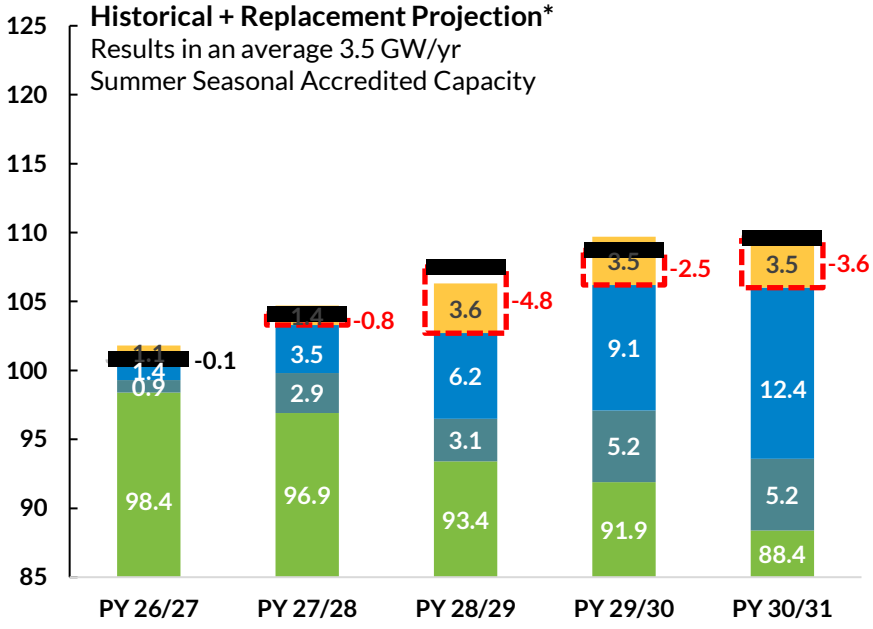
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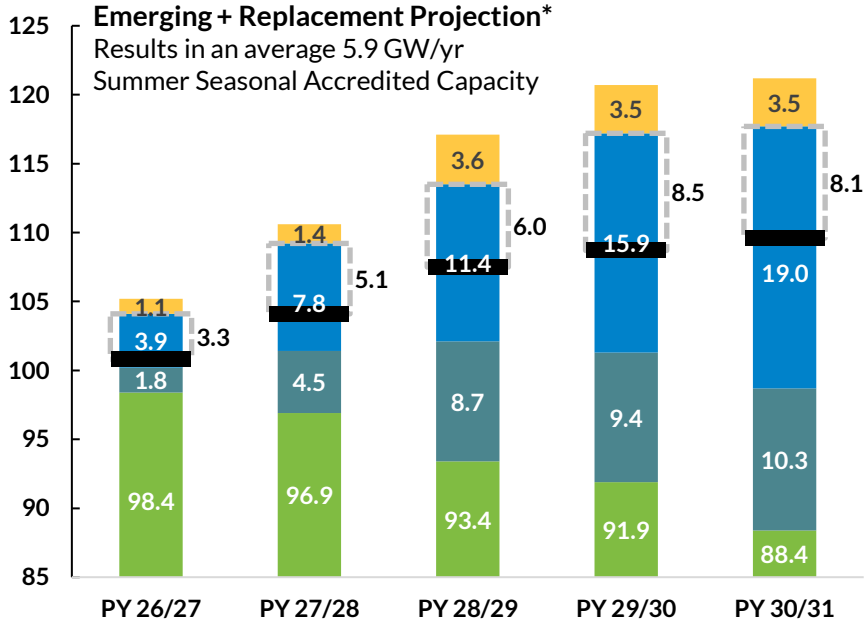
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Historical + Replacement & Emerging + Replacement Projections vs PRMR ~4.7 GW & 8.6 GW Status Quo Summer SAC Installation Rate

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

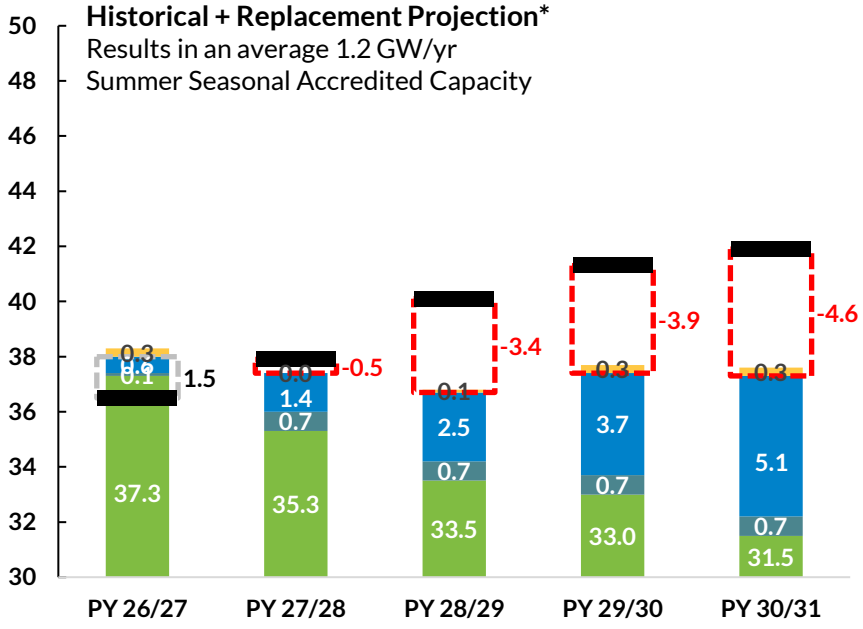
Using methods for potential New Capacity described on Slide 5
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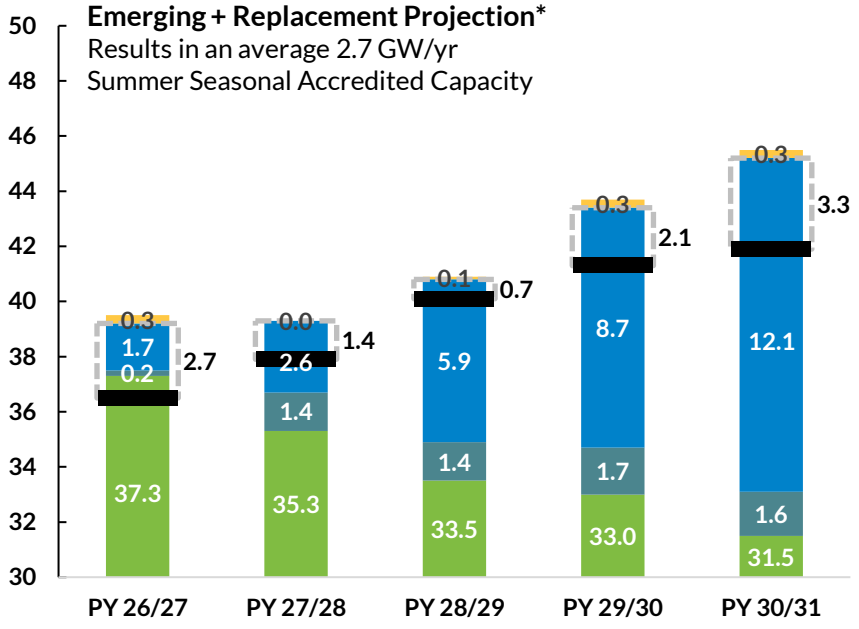
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Historical + Replacement & Emerging + Replacement Projections vs PRMR ~4.7 GW & 8.6 GW Status Quo Summer SAC Installation Rate

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

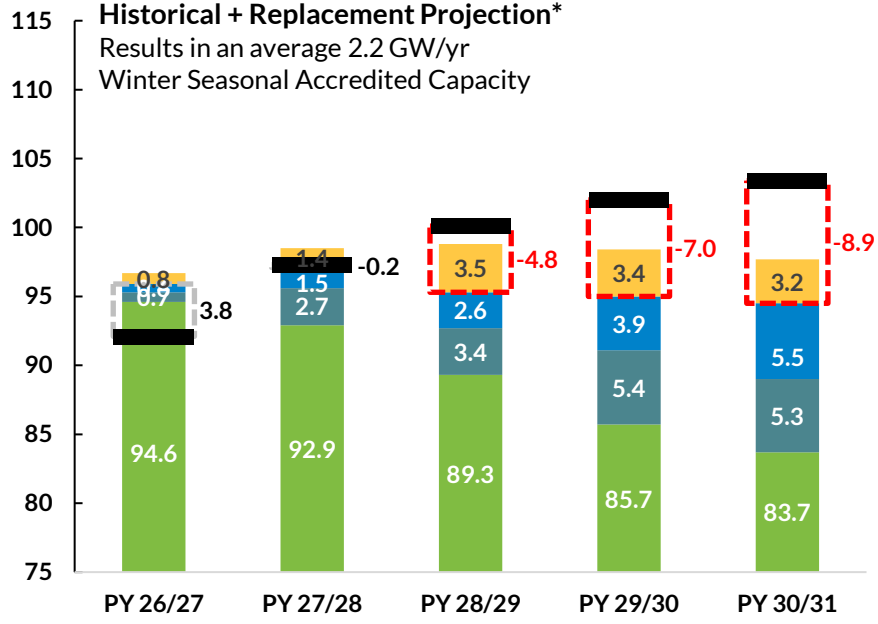
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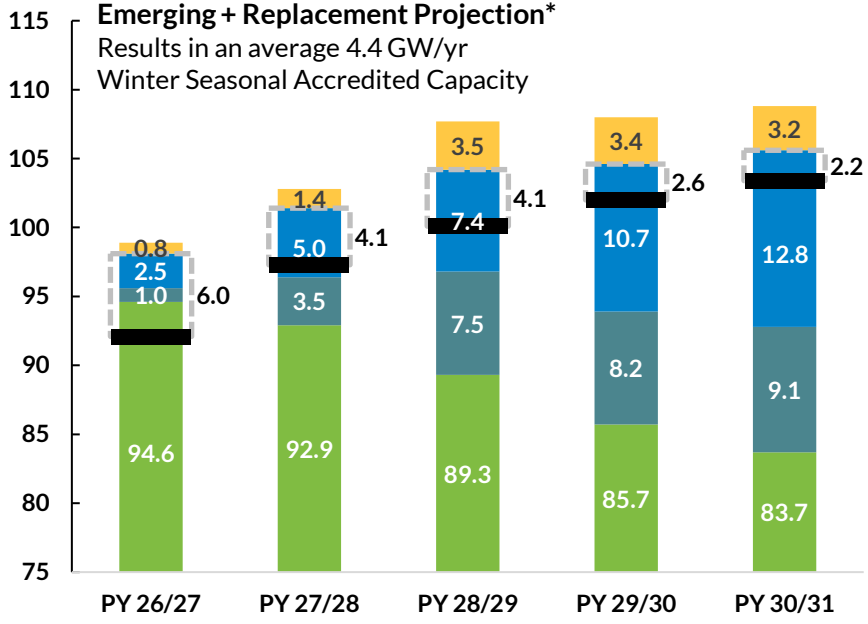
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Historical + Replacement & Emerging + Replacement Projections vs PRMR ~2.4 GW & 6.2 GW Status Quo Winter SAC Installation Rate

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

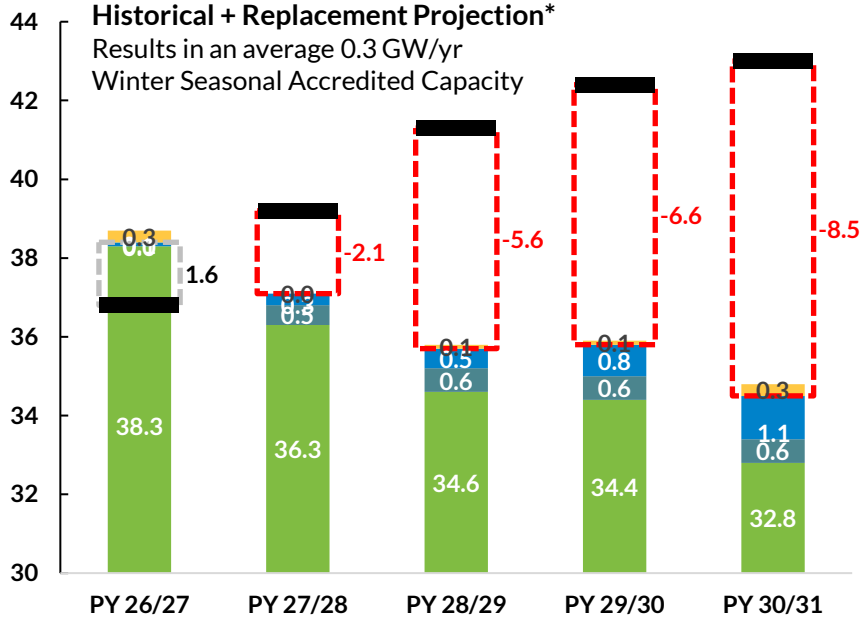
Using methods for potential New Capacity described on Slide 8
***PRMR:** Planning Reserve Margin Requirement*

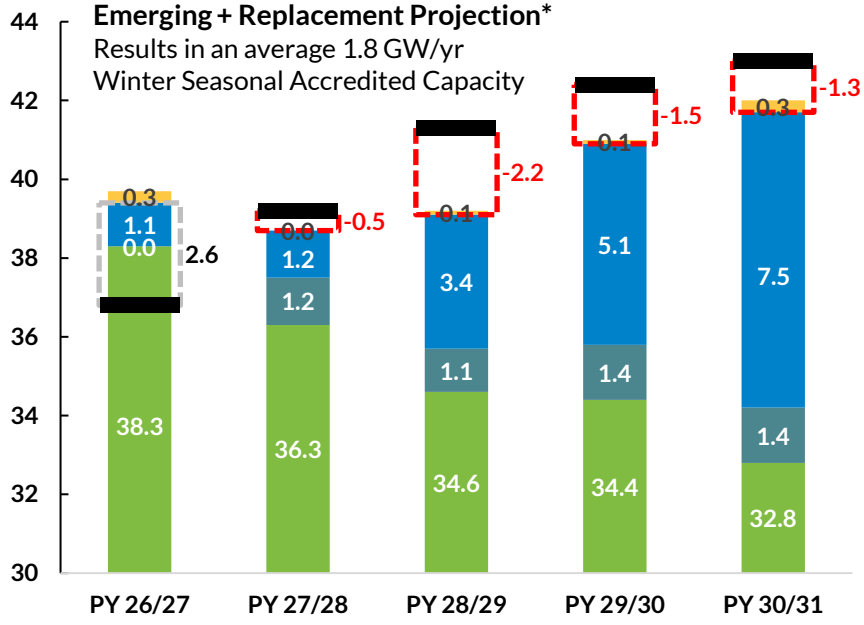
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Historical + Replacement & Emerging + Replacement Projections vs PRMR ~2.4 GW & 6.2 GW Status Quo Winter SAC Installation Rate

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

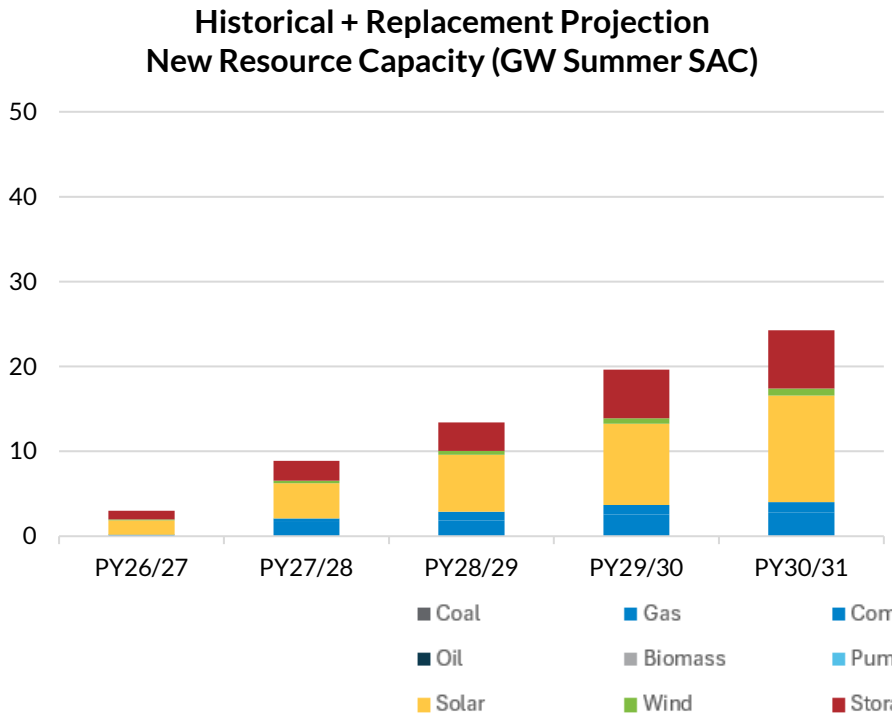
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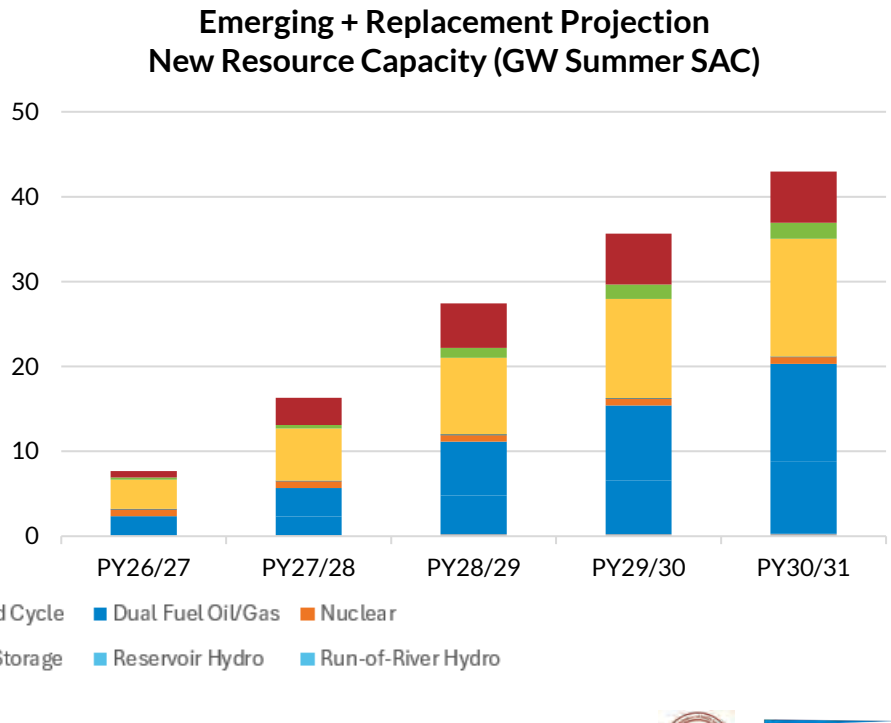
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OMS-MISO Survey projections of new resource accreditation value -Status Quo SAC calculations

Projections of New Resource Fuel Mix – Summer



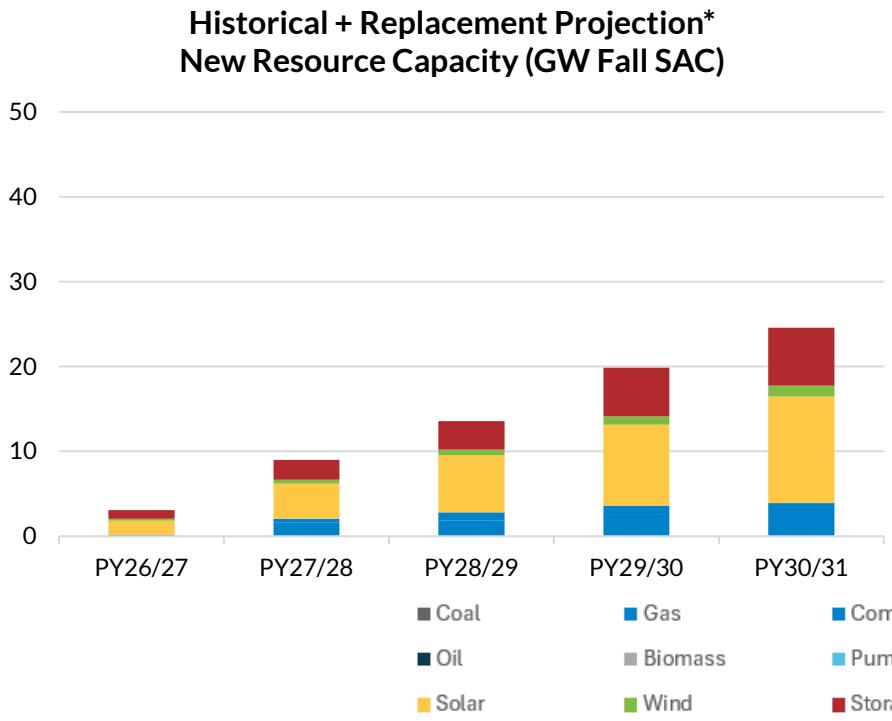


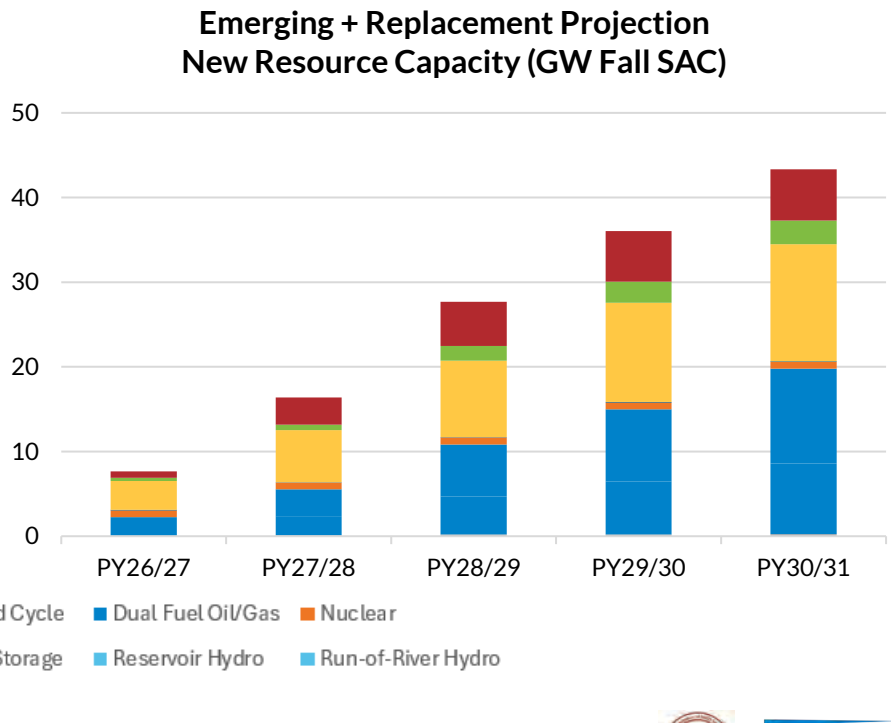
Coal | Gas | Combined Cycle | Dual Fuel Oil/Gas | Nuclear
Oil | Biomass | Pumped Storage | Reservoir Hydro | Run-of-River Hydro
Solar | Wind | Storage

SAC: *Seasonal Accredited Capacity*
All values are cumulative, and are based upon average fuel type resource accreditation from Planning Year 2025/26

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

Projections of New Resource Fuel Mix – Fall



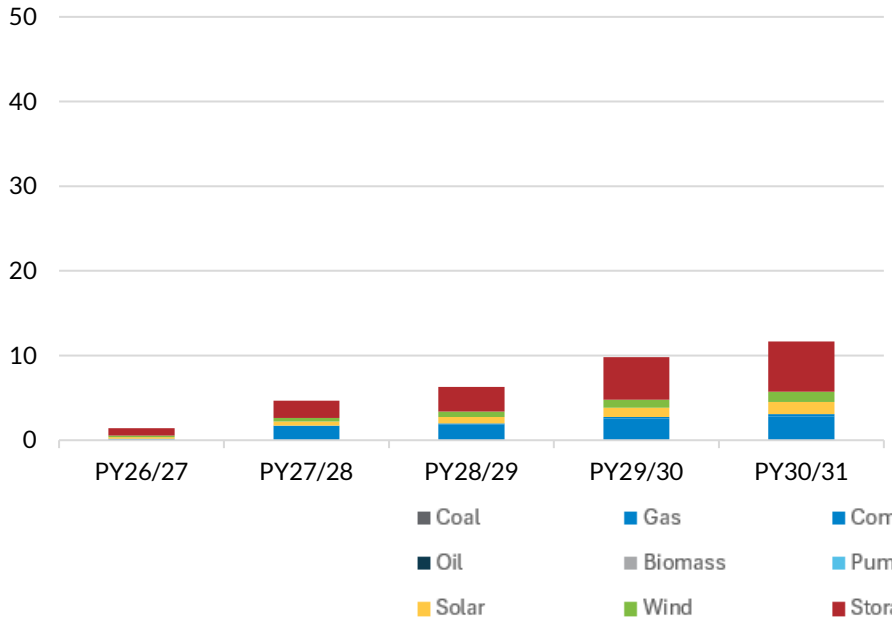


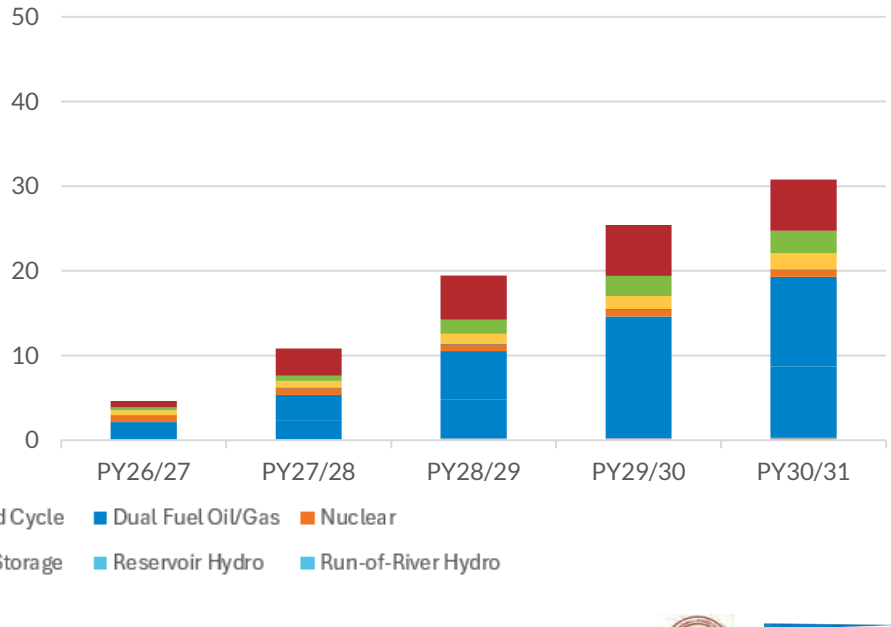
Coal | Gas | Combined Cycle | Dual Fuel Oil/Gas | Nuclear
Oil | Biomass | Pumped Storage | Reservoir Hydro | Run-of-River Hydro
Solar | Wind | Storage

SAC: *Seasonal Accredited Capacity*
All values are cumulative, and are based upon average fuel type resource accreditation from Planning Year 2025/26

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

Projections of New Resource Fuel Mix – Winter



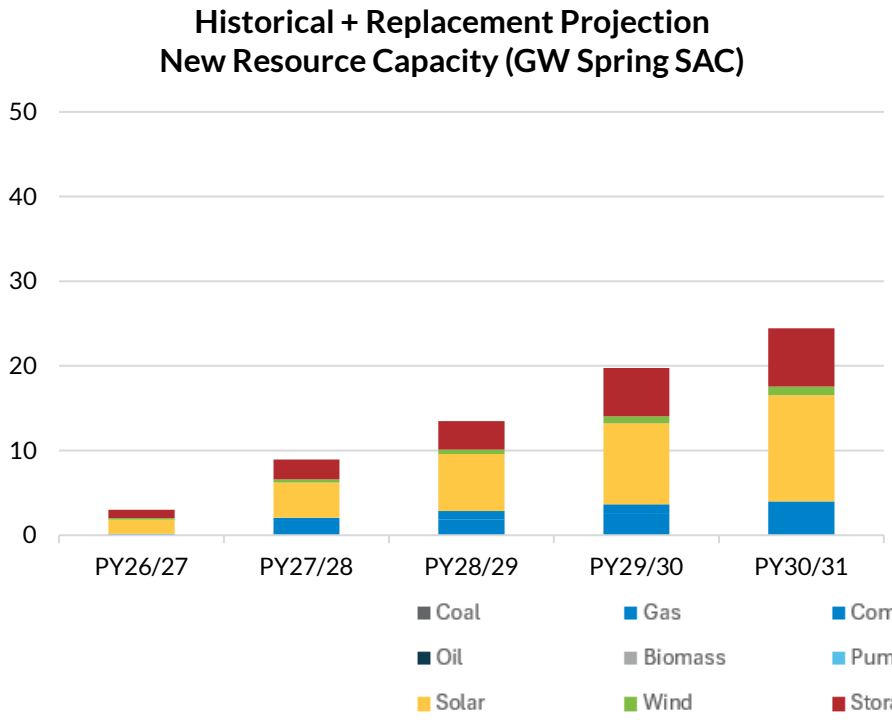


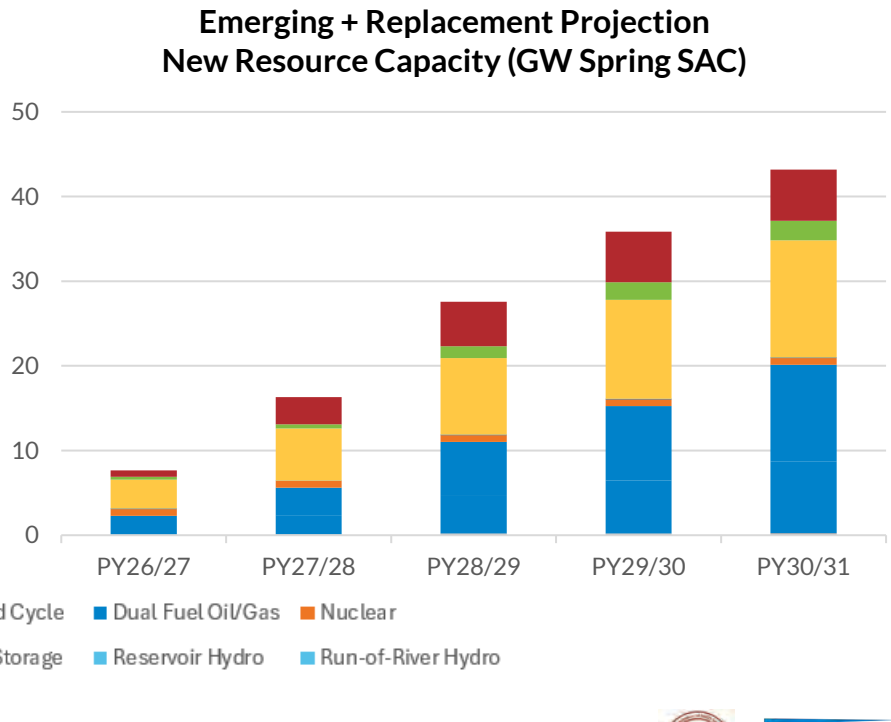
Coal | Gas | Combined Cycle | Dual Fuel Oil/Gas | Nuclear
Oil | Biomass | Pumped Storage | Reservoir Hydro | Run-of-River Hydro
Solar | Wind | Storage

SAC: *Seasonal Accredited Capacity*
All values are cumulative, and are based upon average fuel type resource accreditation from Planning Year 2025/26

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

Projections of New Resource Fuel Mix – Spring



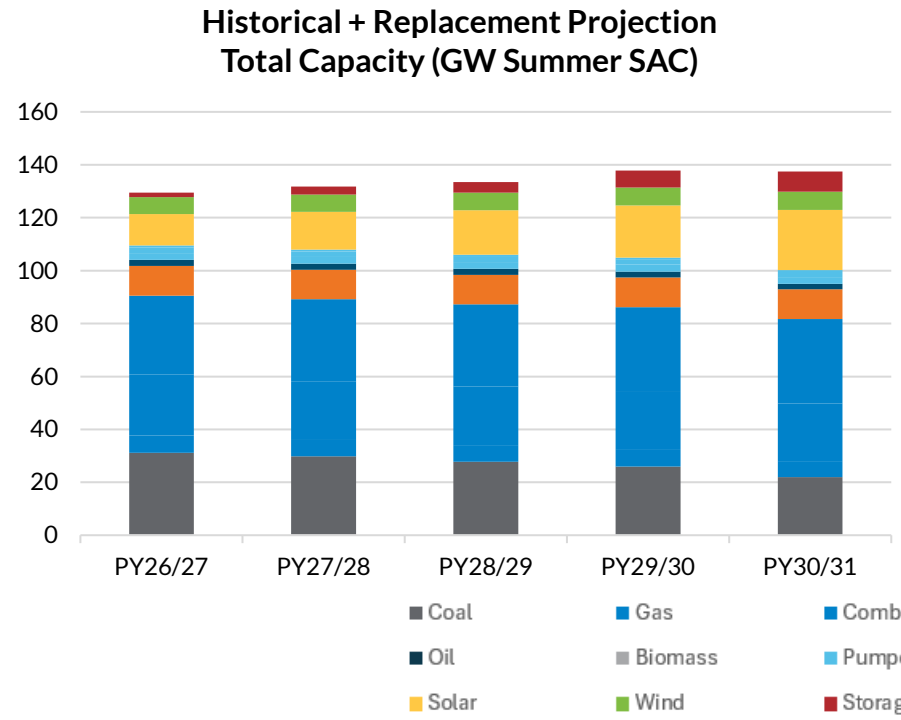


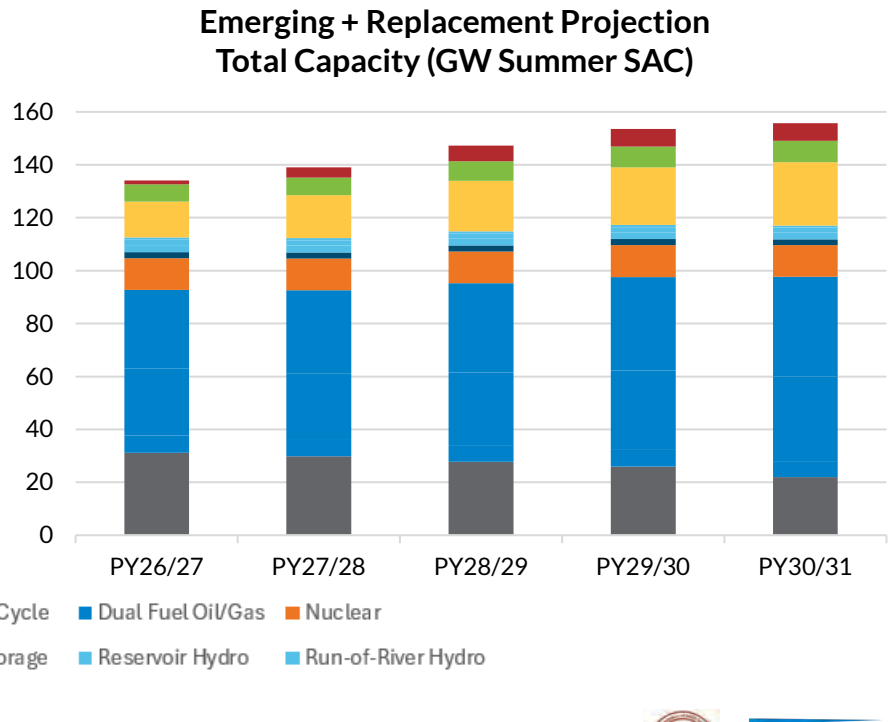
Coal | Gas | Combined Cycle | Dual Fuel Oil/Gas | Nuclear
Oil | Biomass | Pumped Storage | Reservoir Hydro | Run-of-River Hydro
Solar | Wind | Storage

SAC: *Seasonal Accredited Capacity*
All values are cumulative, and are based upon average fuel type resource accreditation from Planning Year 2025/26

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

Combined Projections of Fuel Mix – Summer



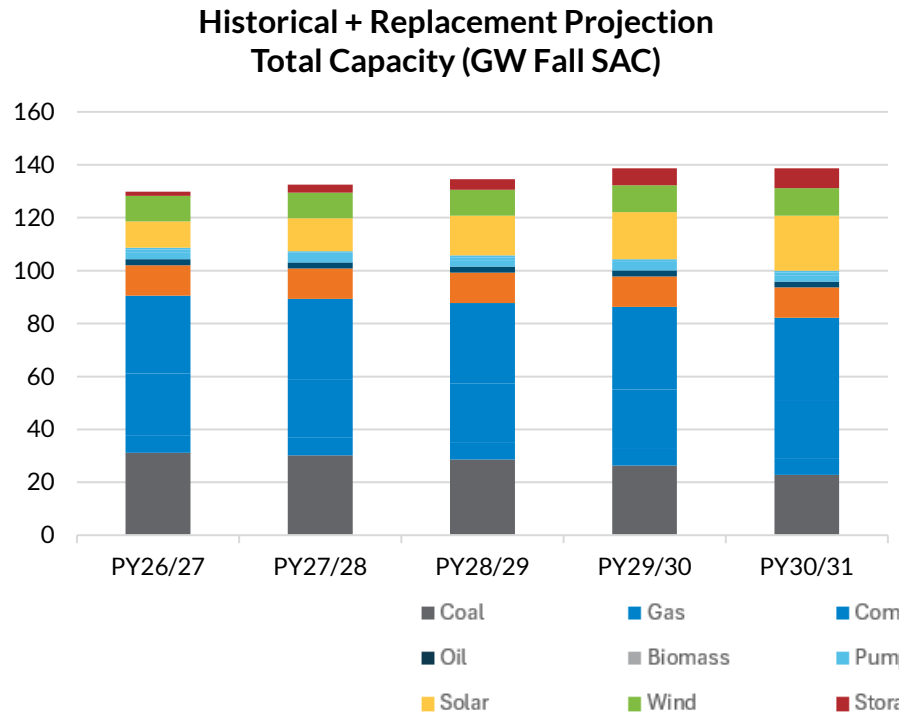


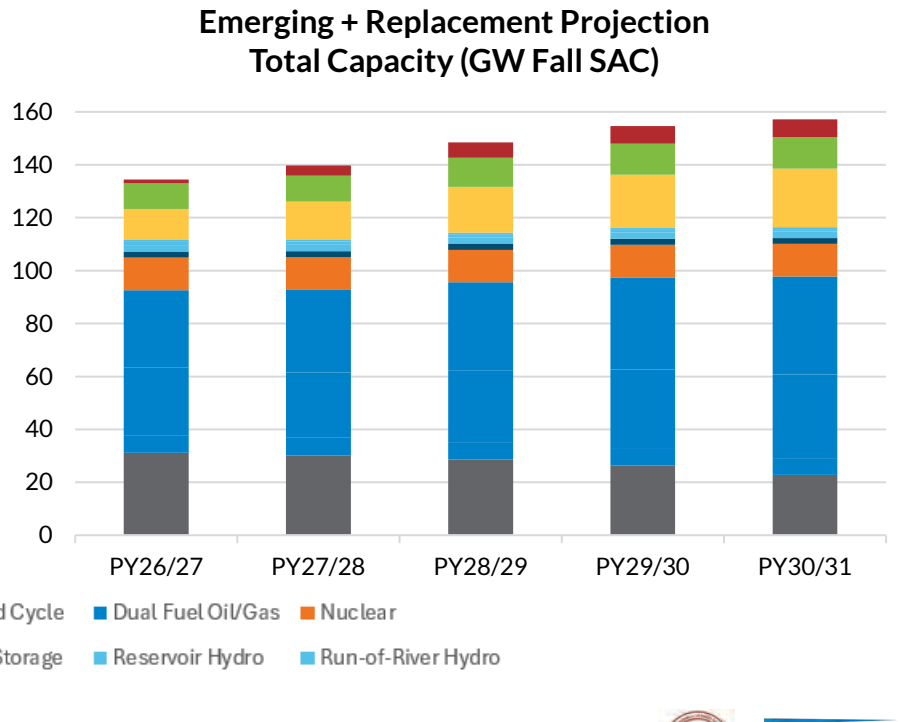
Coal | Gas | Combined Cycle | Dual Fuel Oil/Gas | Nuclear
Oil | Biomass | Pumped Storage | Reservoir Hydro | Run-of-River Hydro
Solar | Wind | Storage

SAC: *Seasonal Accredited Capacity*
New resources are based upon average fuel type resource accreditation from Planning Year 2025/26, existing based on seasonal Status Quo SAC

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

Combined Projections of Fuel Mix – Fall



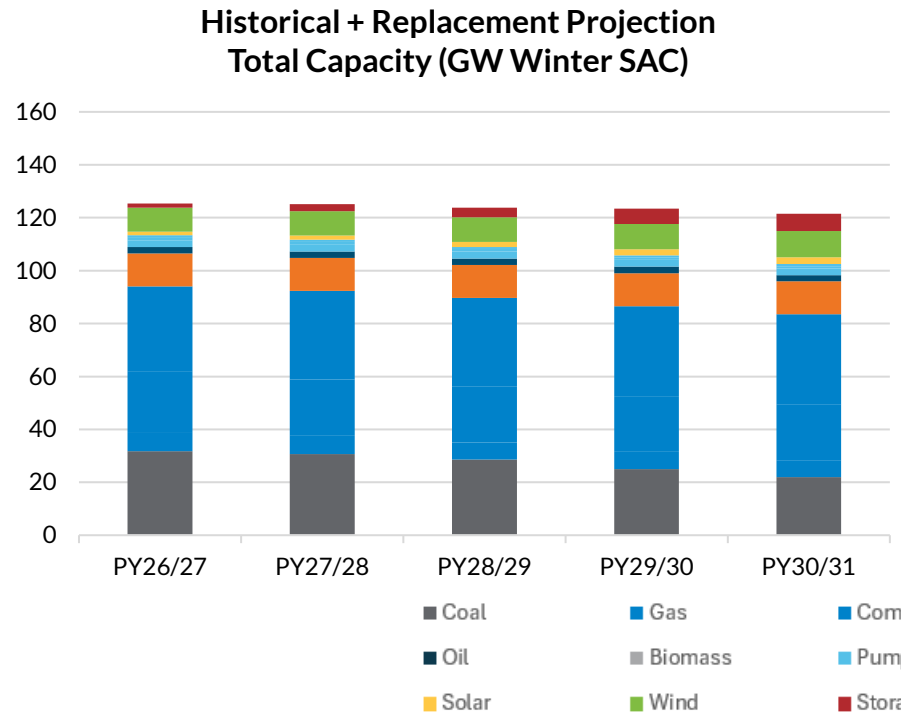


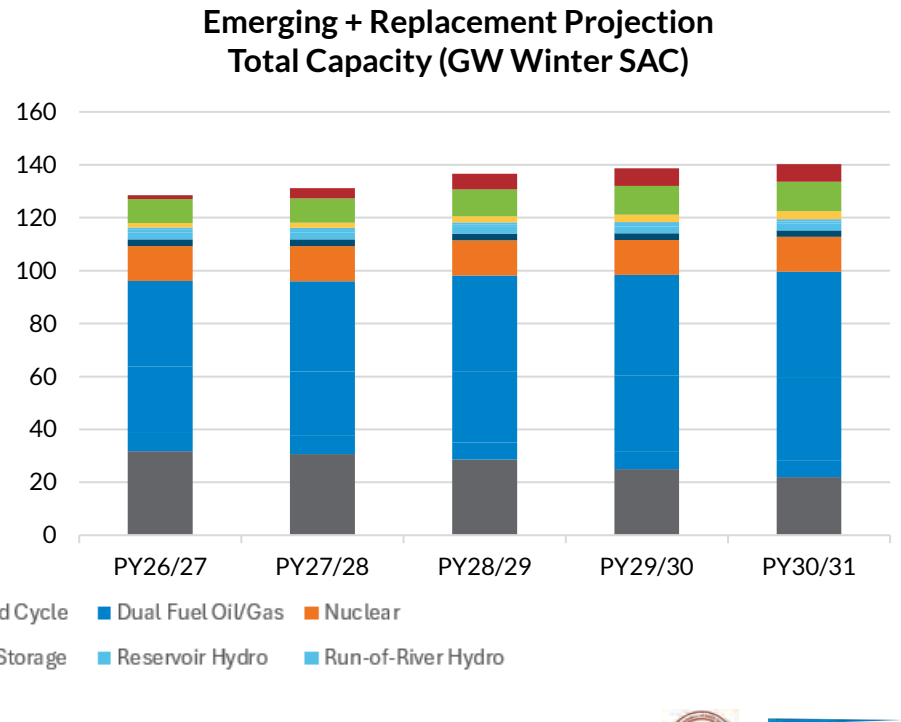
Coal | Gas | Combined Cycle | Dual Fuel Oil/Gas | Nuclear
Oil | Biomass | Pumped Storage | Reservoir Hydro | Run-of-River Hydro
Solar | Wind | Storage

SAC: *Seasonal Accredited Capacity*
New resources are based upon average fuel type resource accreditation from Planning Year 2025/26, existing based on seasonal Status Quo SAC

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

Combined Projections of Fuel Mix – Winter





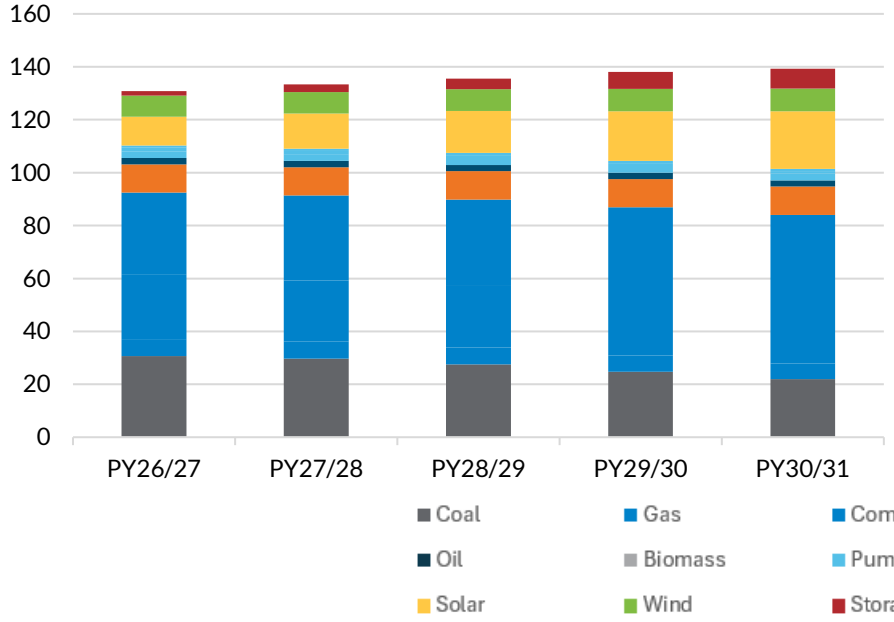
Coal | Gas | Combined Cycle | Dual Fuel Oil/Gas | Nuclear
Oil | Biomass | Pumped Storage | Reservoir Hydro | Run-of-River Hydro
Solar | Wind | Storage

SAC: *Seasonal Accredited Capacity*
New resources are based upon average fuel type resource accreditation from Planning Year 2025/26, existing based on seasonal Status Quo SAC

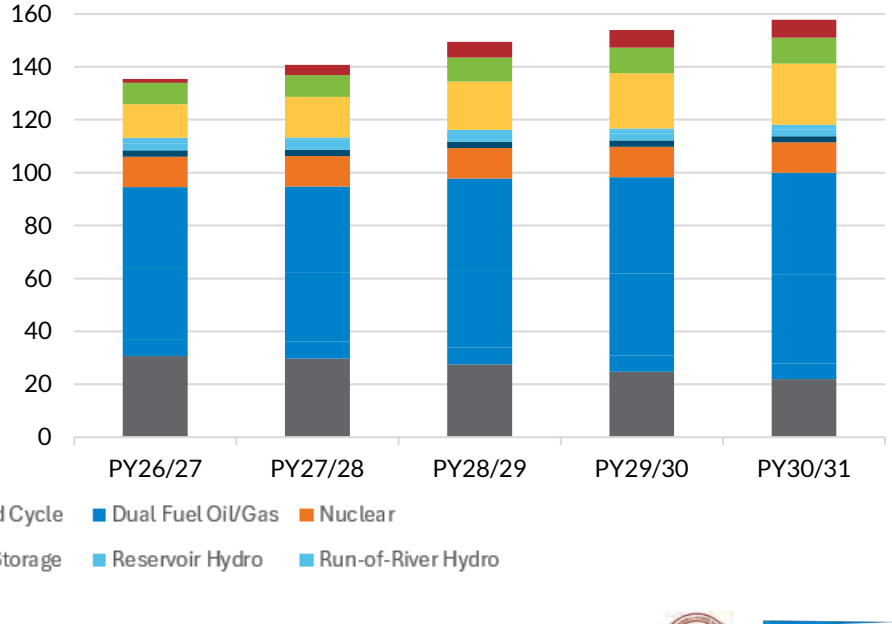
OMS-MISO Survey projections of fleet total resource accreditation value -Status Quo SAC calculations

Combined Projections of Fuel Mix – Spring

Historical + Replacement Projection
Total Capacity (GW Spring SAC)



Emerging + Replacement Projection
Total Capacity (GW Spring SAC)

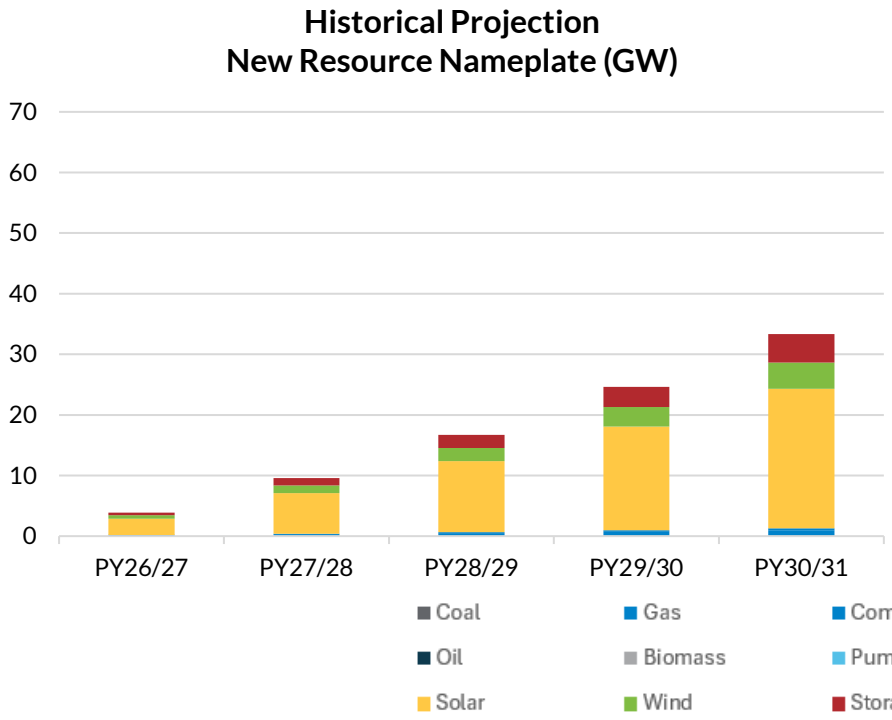


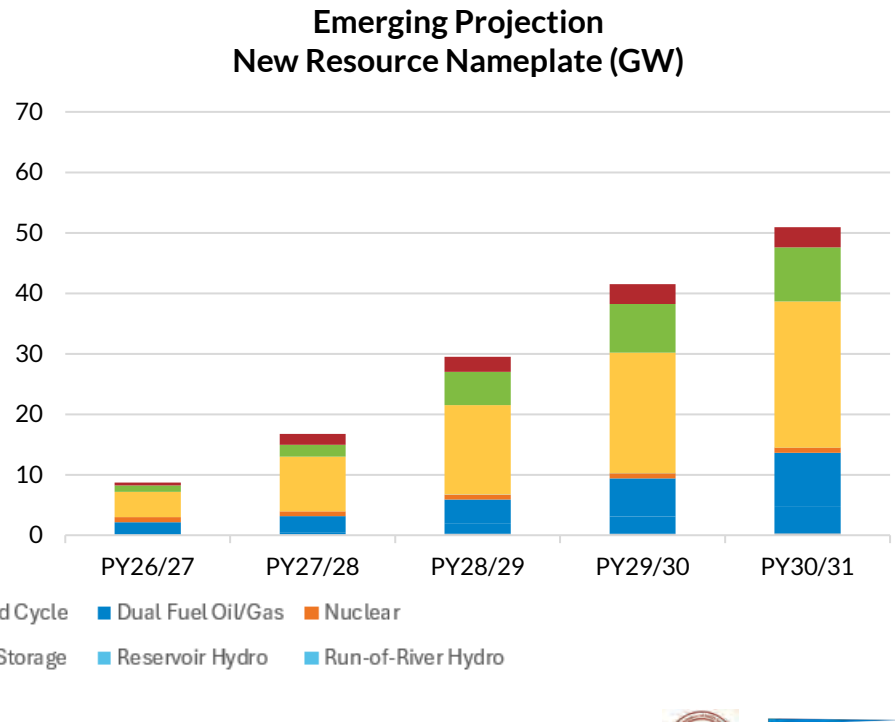
Coal | Gas | Combined Cycle | Dual Fuel Oil/Gas | Nuclear
Oil | Biomass | Pumped Storage | Reservoir Hydro | Run-of-River Hydro
Solar | Wind | Storage

SAC: *Seasonal Accredited Capacity*
New resources are based upon average fuel type resource accreditation from Planning Year 2025/26, existing based on seasonal Status Quo SAC

OMS-MISO Survey projections of new resource deliverable nameplate

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



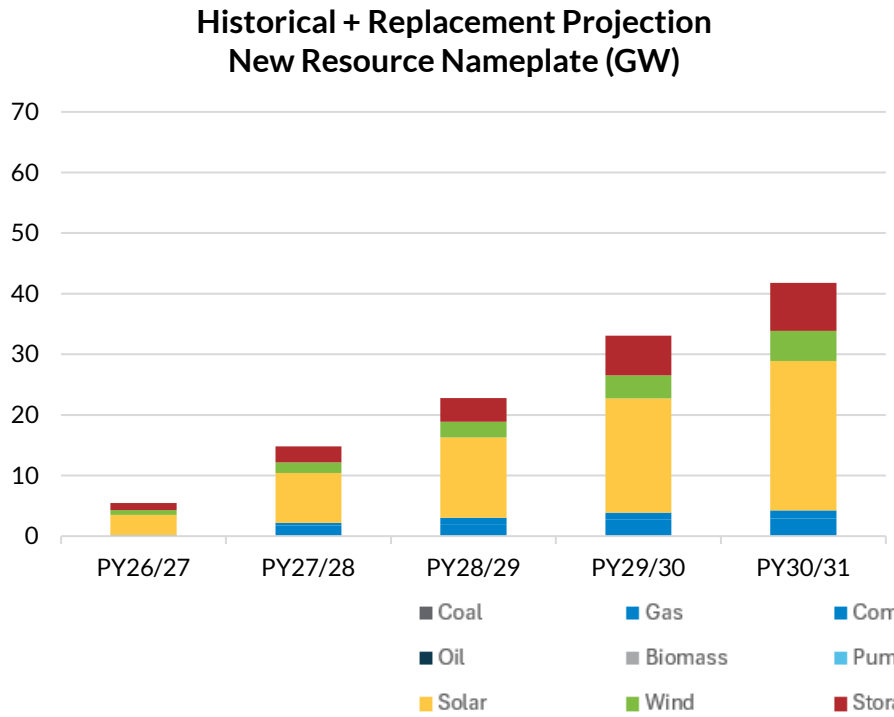


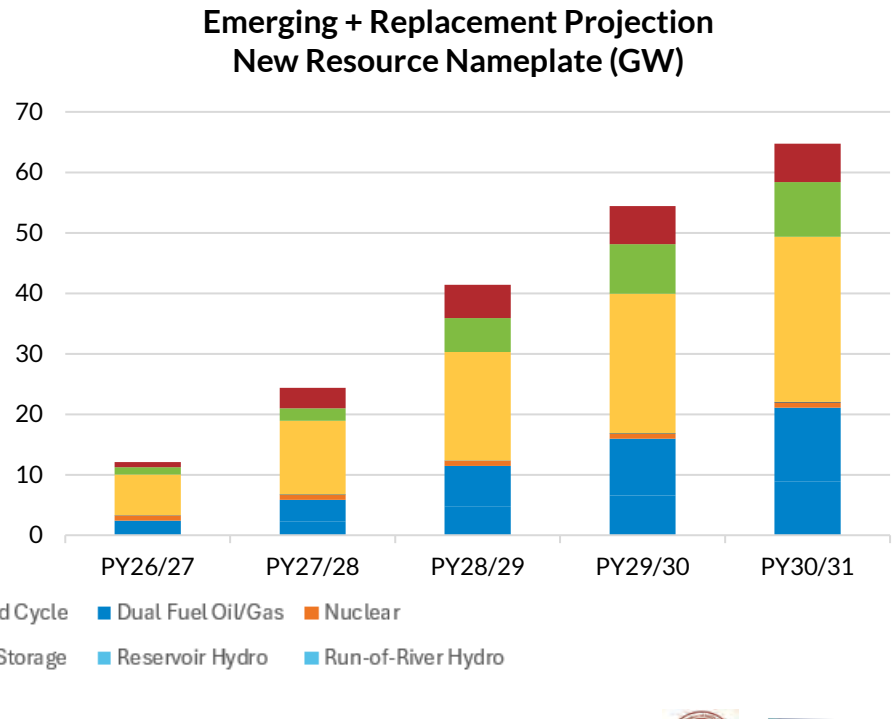
Coal | Gas | Combined Cycle | Dual Fuel Oil/Gas | Nuclear
Oil | Biomass | Pumped Storage | Reservoir Hydro | Run-of-River Hydro
Solar | Wind | Storage

ICAP: *Installed Capacity*
All values are cumulative, and are based on projected nameplate installation for each fuel type

OMS-MISO Survey projections of new resource deliverable nameplate

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



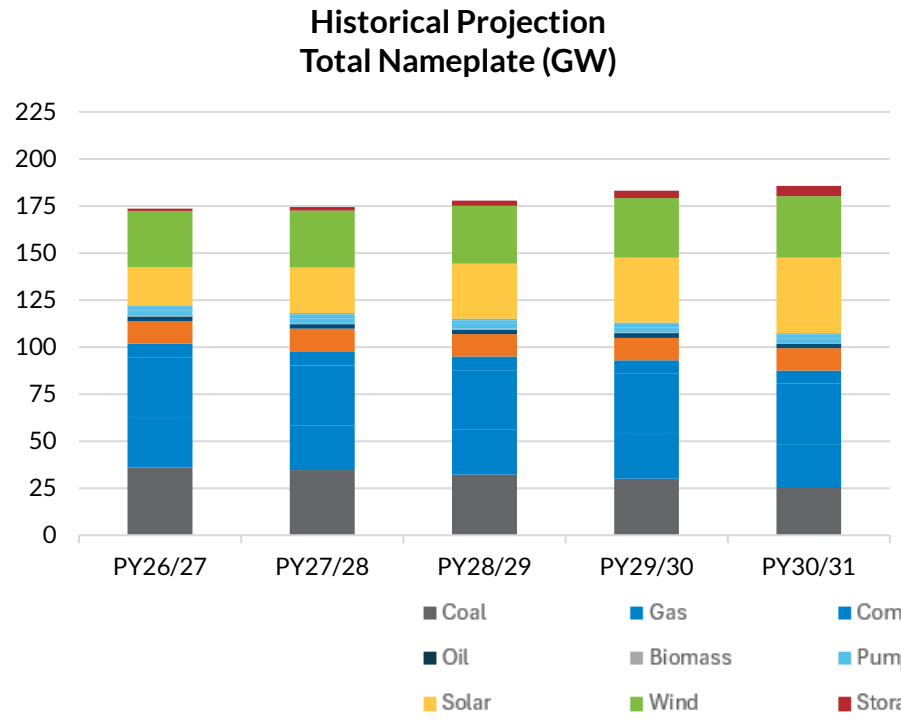


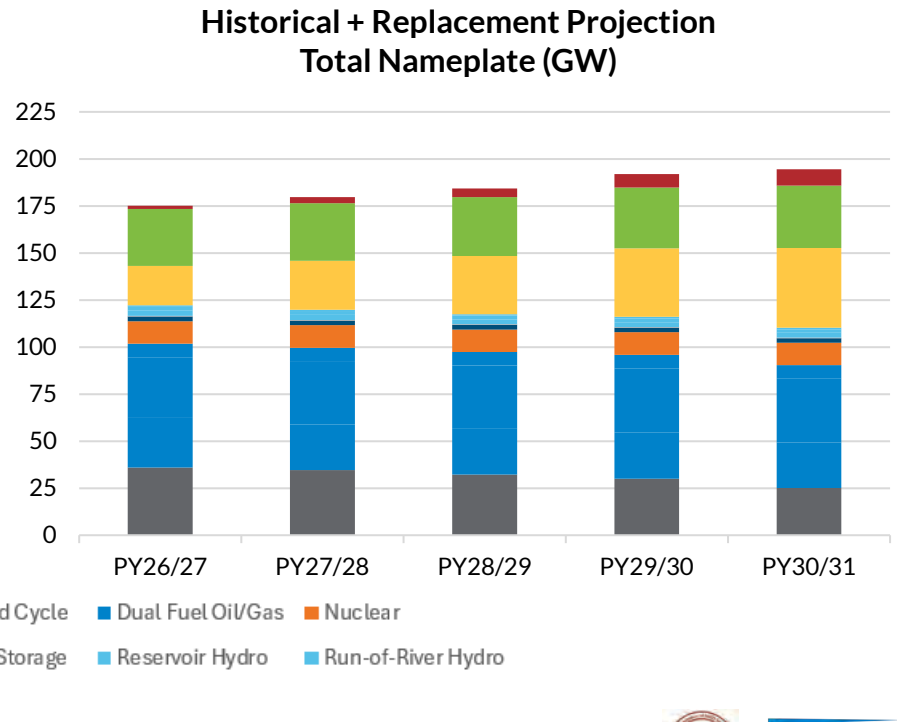
Coal | Gas | Combined Cycle | Dual Fuel Oil/Gas | Nuclear
Oil | Biomass | Pumped Storage | Reservoir Hydro | Run-of-River Hydro
Solar | Wind | Storage

ICAP: *Installed Capacity*
All values are cumulative, and are based on projected nameplate installation for each fuel type

OMS-MISO Survey projections of fleet total deliverable nameplate

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



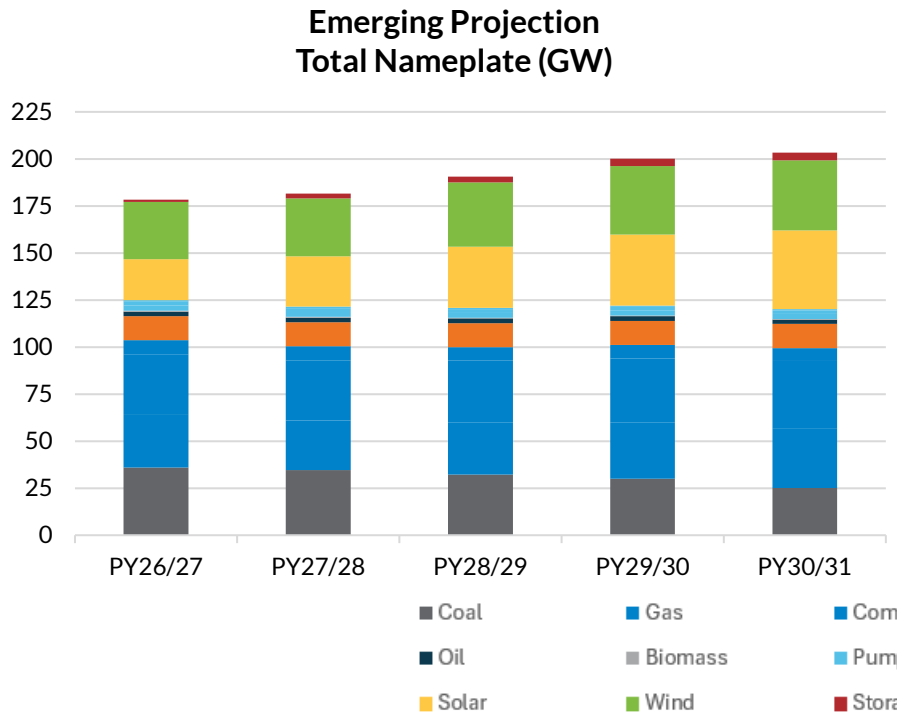


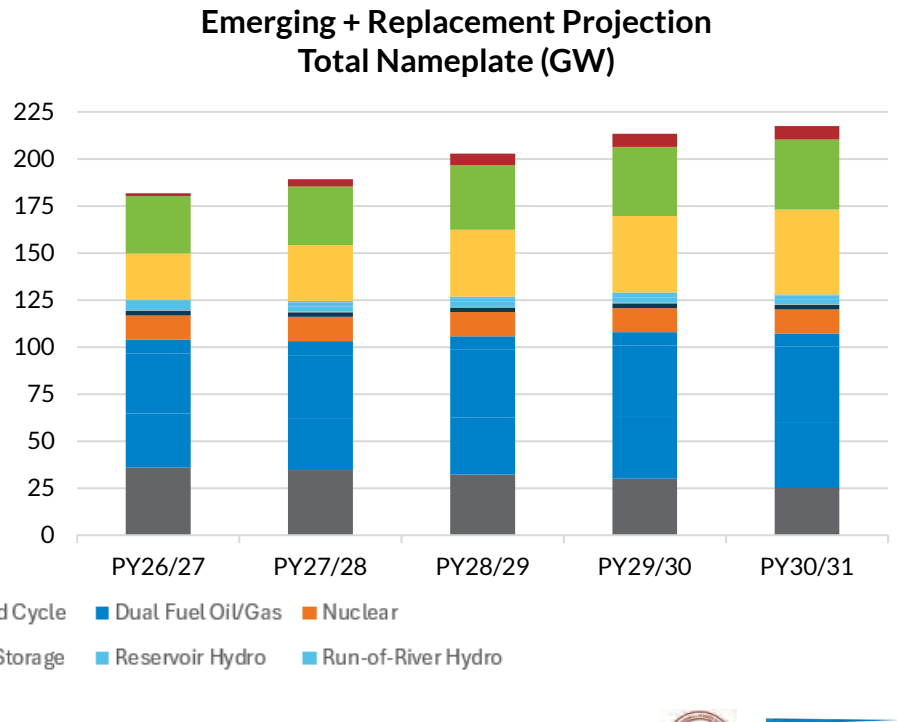
Coal | Gas | Combined Cycle | Dual Fuel Oil/Gas | Nuclear
Oil | Biomass | Pumped Storage | Reservoir Hydro | Run-of-River Hydro
Solar | Wind | Storage

ICAP: *Installed Capacity*

OMS-MISO Survey projections of fleet total deliverable nameplate

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





ICAP: *Installed Capacity*

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-26-16

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 90

MISO ERAS Transmittal Letter

Sarah Nieman
Associate Corporate Counsel
Direct Dial: 317-549-0041
Email: sanieman@misoenergy.org

June 6, 2025

VIA ELECTRONIC FILING

The Honorable Debbie-Anne A. Reese
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: Midcontinent Independent System Operator, Inc.
Revisions to the Open Access Transmission, Energy and Operating Reserve Tariff
Expedited Resource Addition Study Filing
Docket No. ER25-____-000

Dear Secretary Reese:

The Midcontinent Independent System Operator, Inc. ("MISO") submits this filing[1] to revise its Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff")[2] to amend its Attachment X, Generator Interconnection Procedures ("GIP").[3] MISO is grateful for the Commission's feedback on its previous ERAS proposal and for identifying the concerns it had with MISO's proposal.[4] MISO has taken this feedback and refined its original ERAS proposal to address these concerns and others that were shared by stakeholders. MISO now proposes a refined Expedited Resource Addition Study ("ERAS") process that addresses the concerns identified by the Commission and provides an improved framework for the accelerated study of generation projects that can address urgent resource adequacy and reliability needs in the near term.

This filing includes the authority and applicable procedures to implement the refined ERAS process, including how Interconnection Customers claim a new Interconnection Request will meet

[1] MISO makes this filing pursuant to Section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, and Part 35 of the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"), 18 C.F.R. § 35.1, *et seq*.

[2] All capitalized terms not otherwise defined herein shall have the meaning as set forth in the Tariff or the proposed revisions, as applicable.

[3] The GIP are set forth in Attachment X of the Tariff.

[4] *See Midcontinent Independent System Operator, Inc.*, 191 FERC ¶ 61,131 at P 203 (2025) ("ERAS Order").

a resource adequacy and/or reliability need and how the Relevant Electric Retail Regulatory Authority ("RERRA")[5] will submit a verification to MISO that states either: (i) the new, incremental load addition claimed by the Interconnection Customer is valid and not otherwise included in a resource plan or other process under the RERRA's purview or (ii) that the Generating Facility will address a resource adequacy deficiency. As the Commission recognized in the ERAS Order, "it is appropriate for RERRAs to communicate to MISO their resource adequacy and reliability needs, as well as their support for including interconnection requests in the ERAS process, to ensure that the RERRA's needs are met in a timely fashion."[6] Moreover, the Federal Power Act ("FPA") and FERC precedent both recognize the exclusive authority of state regulators and their jurisdictional utilities to plan for adequate generation resources to address resource adequacy needs within their jurisdictional footprints.[7] ERAS responds to this authority and current needs. It enables the timely development of generation that must be online in the near term to address claimed resource adequacy and/or reliability needs—needs for which the current processing time of MISO's queue presents a barrier to solution availability.

ERAS also complements the recent submittals implementing a proposed cap in the queue as well as other improvements to the GIP including increased milestone payments, withdrawal penalty requirements, and Site Control rules.[8] The Cap and GIP Improvement proposals were focused on longer-term improvements to the queue, while ERAS is focused on short-term improvements that will facilitate the addition of necessary resources in the MISO footprint. MISO has made refinements to its original ERAS proposal to include a total project cap and to structure this cap in a way that accommodates the needs of retail choice states and independent power producers ("IPPs"). MISO has also added several requirements to promote a tighter connection between proposed ERAS projects and the resource adequacy needs that the projects will address. The supporting evidence convincingly demonstrates that the refined ERAS process will provide the expedited path forward to bring projects online to meet near-term needs and will address certain challenges posed by the rapidly growing size of the queue.[9]

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5 A RERRA is defined as "[a]n entity that has jurisdiction over and establishes prices and/or policies for providers of retail electric service to end-customers, such as the city council for a municipal utility, the governing board of a cooperative utility, the state public utility commission or any other such entity." MISO, FERC Electric Tariff, Module A, § 1.R (72.0.0).

6 ERAS Order at P 203.

7 16 U.S.C. § 824 (1976); FERC has recognized that state-federal "bifurcated framework respects the jurisdictional boundaries of the FPA while recognizing the states' historical role in ensuring resource adequacy." *Cxa La Paloma, LLC*, 165 FERC ¶ 61,148 at P 70 (2018).

8 *See Midcontinent Independent System Operator, Inc.*, 186 FERC ¶ 61,054 (2024); *Midcontinent Independent System Operator, Inc.*, "Revisions to the Open Access Transmission, Energy and Operating Reserve Tariff Queue Cap Proposal and Exemptions to the Queue Cap Proposal," Docket No. ER25-507-000 (November 21, 2024).

9 *See* Prepared Direct Testimony of Andrew Witmeier ("Witmeier Testimony"), attached at Tab C.

MISO requests an effective date of August 6, 2025, for this filing. Moreover, given this filing is built on a proposal already reviewed extensively by stakeholders and the Commission and is tailored to address the Commission's guidance, MISO requests the Commission issue an order on this filing expeditiously by July 22, 2025. The grant of this request, in light of the totality of the factors, is reasonable. It will also be limited to the instant request here to effectuate a needed process. Given the resource adequacy and reliability needs identified below, MISO needs to implement that process as soon as possible. An expedited order will afford Interconnection Customers the certainty needed to prepare their Interconnection Requests to submit for the first ERAS Quarterly Study Period, which starts on September 2, 2025. The additional two weeks will provide material value to Interconnection Customers. Additionally, to enable the Commission's expedited decision making, MISO requests that the Commission establish a ten-day comment period for this filing, with June 16, 2025, as the comment date.

MISO acknowledges the expedited action requested places pressure on stakeholders and the Commission alike. This expedited treatment will ensure that Interconnection Customers have sufficient time to prepare for ERAS and have certainty that the proposed changes can be implemented to bring the ERAS process into alignment with other standard MISO practices and processes and to ensure that it will be in place prior to the September 2, 2025 Quarterly Study Period kickoff date for ERAS.[10] Just as this filing has been turned in a matter of a few weeks since receiving the Commission's guidance in the ERAS Order, the time afforded to MISO and Interconnection Customers by two weeks, assuming Commission acceptance, is time well spent to move this proposed process forward effectively. The requested order and effective dates will ensure that the proposed changes are implemented to accelerate the study of projects to address the looming resource adequacy and reliability needs in the MISO footprint in the next few years.

I. EXECUTIVE SUMMARY

A. Summary of MISO's First ERAS Filing

On March 17, 2025, MISO submitted its original filing with proposed revisions to Attachment X in the MISO Tariff, to establish the Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term.[11] MISO proposed that an ERAS Interconnection Request be required to demonstrate that it would meet an identified resource adequacy and/or reliability need by providing both: (1) a written notification from the RERRA that

[10] Witmeier Testimony at 7:6-10.

[11] *Midcontinent Independent System Operator, Inc.*, "Revisions to the Open Access Transmission, Energy and Operating Reserve Tariff Expedited Resource Addition Study Filing," Docket No. ER25-1674-000 (March 17, 2025) ("ERAS Transmittal Letter").

the project should be studied through ERAS; and (2) an executed agreement evidencing that the ERAS project was intended to be used by the entity with the claimed resource adequacy or reliability need. MISO also proposed that ERAS have strict eligibility requirements including: shorter commercial operation date (COD) requirements, greater (100%) site control requirements, higher application fee and milestone payments, and a requirement to pay for all network upgrades documented in the EGIA, even if the Interconnection Customer withdraws its request after the EGIA is executed or filed unexecuted with the Commission. Finally, MISO proposed that the original ERAS process would sunset by the end of 2028.

On May 16, the Commission issued an order rejecting MISO's proposed Tariff revisions and provided guidance on the proposed ERAS process.[12] The Commission found that MISO's ERAS proposal was not "a just and reasonable and not unduly discriminatory or preferential approach for addressing MISO's stated resource adequacy and reliability needs."[13] The Commission identified two issues with the ERAS framework: (1) that there was "no limit on the number of projects that could be entered into the ERAS process,"[14] and (2) "the proposal does not sufficiently describe how the ERAS process is sufficiently targeted to study only interconnection requests needed to meet the anticipated shortfall in generating capacity described by MISO."[15] The Commission also recognized that it was "appropriate for RERRAs to communicate to MISO their resource adequacy and reliability needs, as well as their support for including interconnection requests in the ERAS process, to ensure that the RERRA's needs are met in a timely fashion."[16] Each of the Commissioners also filed individual statements urging MISO to revise and refile its ERAS proposal.[17]

MISO is grateful for the Commission's guidance on how to better craft its ERAS proposal and appreciates the recommendations made within the order. MISO has worked swiftly to develop a refined ERAS process tailored to address the Commission's concerns, other issues raised by stakeholders, and one that can withstand legal review. MISO is now proposing a refined ERAS process that can be implemented by September 2, 2025 to quickly address the looming resource adequacy and reliability needs that it highlighted in its original ERAS filing.

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[12] ERAS Order at P 1.

[13] *Id.* at P 197.

[14] *Id.* at P 199.

[15] *Id.* at P 201.

[16] *Id.* at P 203.

[17] ERAS Order at P 3 (Comm'r Christie, dissenting);at P 6 (Comm'r Rosner, concurring); and at P 8 (Comm'r See, concurring).

B. Growing Resource Adequacy Concerns

The energy industry continues to change rapidly. Urgent resource adequacy and reliability challenges are arising because of continued electrification efforts, a resurgence in manufacturing, an unexpected demand for energy-hungry data centers to support artificial intelligence, the growing preference for low or no carbon emission resources, and the accelerated early retirement of generation.[18] These combined factors are driving resource adequacy and reliability concerns across the country and are resulting in a complex policy landscape. Additional changes and improvements must be made to MISO's processes to enable it to meet these urgent and important needs.

Several surveys and forecasts offer perspectives demonstrating the urgency for MISO to address significant resource adequacy needs in its footprint that are compounded by the addition of unexpected large spot loads. First, MISO's Reliability Imperative Report explained, "[i]n 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."[19]

MISO also works with the Organization of MISO States ("OMS") to produce the OMS-MISO Survey which in 2024 "reinforce[d] near-term risks and highlights key uncertainties impacting resource adequacy in the MISO region," and also "illustrate[d] a strong sensitivity to the pace of new capacity additions."[20] The 2025 OMS-MISO Survey will be published on the same day as this filing and further "reinforces near-term risks and highlights key uncertainties impacting resource adequacy."[21] In fact, one of the key takeaways from the 2025 survey is that

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[18] MISO recently highlighted how "[t]he expansion of data centers, fueled by AI and cloud-based applications, will raise MISO's energy demand by 149-241 TWh by 2044", "the growth of EVs, driven by federal incentives and declining battery costs, is projected to add 54-91 TWh of demand by 2044, with rapid adoption between 2030-2040", "the electrification of oil and gas industries and reshoring efforts are expected to increase energy demand by 21-105 TWh by 2044", and how "federal and state policies are driving electrification of heating systems and appliances, increasing energy demand by 36-43 TWh by 2044." Long-Term Load Forecast, at 4, December 2024, available at:https://cdn.misoenergy.org/MISO%20Long-Term%20Load%20Forecast%20Whitepaper_December%202024667166.pdf.

[19] *See MISO's Response to the Reliability Imperative* (updated January 2023), available at: https://cdn.misoenergy.org/MISO%20Response%20to%20the%20Reliability%20Imperative504018.pdf.

[20] *See 2024 OMS-MISO Survey Results* (Updated June 2024), available at: https://cdn.misoenergy.org/OMS%20MISO%20Survey%20Results%20Workshop%20Presentation628355.pdf.

[21] *Id.* at 2.

"[r]esource adequacy risk is intensifying."[22] Similarly, NERC's 2024 Long-Term Reliability Assessment projected that MISO will experience a 4.7 GW shortfall by 2028 if the current expected generator retirements occur.[23] NERC explained that MISO's resource additions were not keeping up with generator retirements and demand growth. As a result, NERC designated MISO's footprint as "high risk" for falling below established resource adequacy criteria in the next five years.[24] Collectively, these surveys and forecasts demonstrate that MISO *must* address resource adequacy and reliability needs in the next five years and that an accelerated interconnection study process must be established to address time-critical challenges. Compounding these generation challenges is the surge in load growth described above coming from economic development, a resurgence in manufacturing, increasing electrification, and data centers and other large load additions. As the Commission Staff's 2025 Summer Assessment stated: "Currently, the size and speed with which data centers and crypto mining facilities can be constructed and connect to the grid presents unique challenges for demand forecasting and planning. This increase in demand is currently challenging utilities to accelerate infrastructure upgrades and energy resource deployment and to reconsider scheduled resource retirements to maintain grid reliability."[25] As highlighted in MISO's presentation to the System Planning Committee of the MISO Board of Directors, MISO is indeed seeing a significant increase in load growth as well as transmission projects related to load growth over the last year, further evidencing growing demand and challenges in the MISO region.[26] Finally, FERC staff's recent 2025 Summer Assessment found possible reliability challenges in several RTO regions including MISO during extreme summer conditions.[27]

C. Summary of the ERAS Process

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[22] *2025 OMS-MISO Resource Adequacy Survey Results*, Fact Sheet, available at: https://cdn.misoenergy.org/2025%20OMS-MISO%20Survey%20Fact%20Sheet702641.pdf.

[23] *See NERC's 2024 Long-Term Reliability Assessment* (published December 2024), available at: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

[24] *Id.* at 6.

[25] *2025 Summer Energy Market and Electric Reliability Assessment*, May 15, 2025, https://www.ferc.gov/news-events/news/ferc-releases-2025-summer-assessment.

[26] *Reliability Imperative: Transmission Evolution*, System Planning Committee of the Board of Director at 6-7, June 10, 2025, https://cdn.misoenergy.org/20250610%20System%20Planning%20Committee%20of%20the%20BOD%20Item%2005%20Reliability%20Imperative_Transmission%20Evolution701586.pdf.

[27] *2025 Summer Energy Market and Electric Reliability Assessment*, May 15, 2025, https://www.ferc.gov/news-events/news/ferc-releases-2025-summer-assessment.

While developing the original ERAS, MISO engaged with stakeholders on a regular basis to solicit feedback and to discuss suggested changes to the proposal. As described in more detail below, MISO participated in numerous meetings with stakeholders including official committee meetings, ERAS-specific workshops, and small-group meetings with individual stakeholder groups. Based on stakeholder feedback obtained from these meetings and discussions, MISO made significant revisions to its first ERAS proposal presented to stakeholders including changing the mechanics of how a RERRA would notify MISO that a project is suitable for ERAS, establishing the sunset date, and determining some of the eligibility requirements for ERAS participation. OMS provided significant input on the appropriate method for states or RERRAs to notify MISO of projects suitable for MISO's first ERAS proposal. That engagement and feedback helped MISO produce its original ERAS filing to the Commission in March of this year. Following the Commission's order, MISO developed a proposed method for RERRAs to establish a connection between a proposed ERAS project and a resource adequacy deficiency or a spot load addition to address the Commission's guidance and shared its proposed method with individual states and OMS. MISO directly engaged in discussions to address any concerns and this resulting filing is responsive to these conversations and represents a significant step forward towards improving the interconnection process in MISO and enabling it to meet state and RERRA needs. MISO has developed this refiling on an expedited basis and MISO has shared updates with our states to keep them informed of MISO's direction as it finalized the refinements to the original ERAS proposal. While states recognized that a full review of the filing will be required to indicate their support, MISO believes many are generally supportive of the framework and recognize the urgency of having an expedited review process in place.

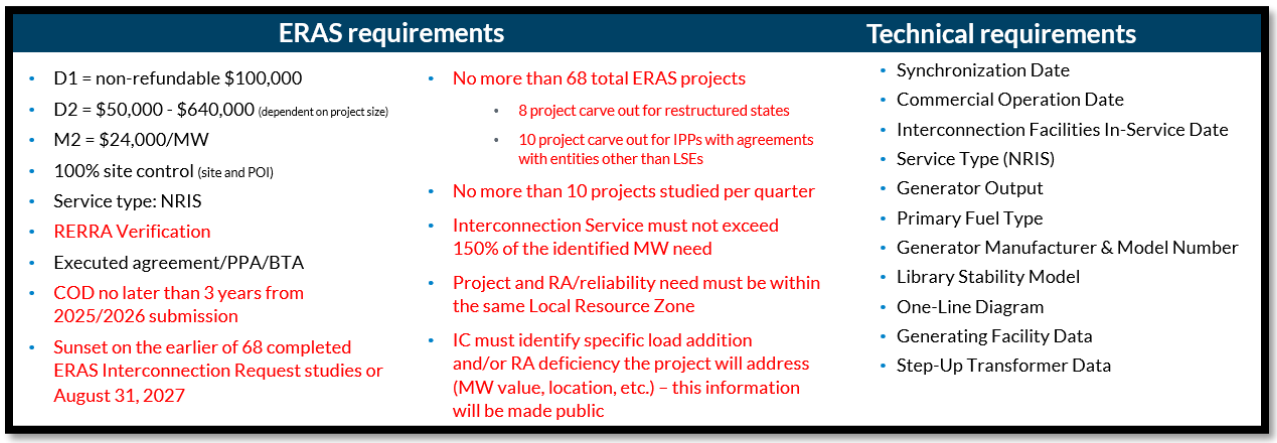
In preparing this filing and refining the ERAS process as described further below, MISO took substantive steps to mitigate the impact of these proposed changes on Interconnection Requests in the queue. MISO remains committed to reducing its general interconnection review period to one year and is utilizing industry-leading techniques, processes, and IT systems to achieve that goal. MISO's recent GIP Improvement and Cap filings were implemented to facilitate this process, but reaping the benefits of those changes will take longer than is necessary to address the looming resource adequacy and reliability needs faced by the states now. ERAS is a unique process that will enable a limited and now capped number of projects to address resource adequacy and reliability needs in the short term. The ERAS process remains structured to insulate projects in the queue from the negative impacts or cost shifts as the result of projects either entering ERAS or leaving the generator interconnection queue for ERAS. As such, the consideration of ERAS projects will not raise costs for or otherwise impact any of the projects currently in the queue.

D. Changes and Refinements to the ERAS Process

The refined Expedited Resource Addition Study ("ERAS") is MISO's answer to addressing the resource adequacy and reliability needs in the near-term. ERAS is a unique process which recognizes that the responsibility for providing grid reliability and resource adequacy in the MISO region is shared by Load Serving Entities ("LSEs"), the states, and MISO. Projects that enter ERAS—a process separate from the standard Generator Interconnection Queue—will be studied

serially in each ERAS quarterly study period and will be granted an EGIA within 90 days to facilitate new generation to come online in the short-term to meet valid new, incremental load additions and identified resource adequacy deficiencies. Since the original ERAS filing, MISO has worked to implement necessary changes to the proposal to better align the process with the timeline that is needed to address the looming resource adequacy and/or reliability needs. First, MISO is now proposing to implement a cap on the number of projects that can participate in ERAS. Second, MISO is requiring a stronger demonstration of a connection between the proposed project and the resource adequacy and/or reliability need that warrants its inclusion in ERAS as demonstrated by a verification from the relevant RERRA. The proposed ERAS project and the resource adequacy and/or reliability need must also be within the same Local Resource Zone. Finally, MISO is also proposing Tariff language to incorporate the retail choice states – Illinois and parts of Michigan – into the ERAS process.[28] MISO's goal with developing and refining ERAS is to quickly, efficiently, and effectively craft a process that can manage these looming needs while also addressing concerns raised in the Commission's order. The figure below highlights in red font what features of the original ERAS filing have been refined and added to this proposal.

Figure 1: Refined ERAS Requirements Comparison



Working together, MISO, the states, and other stakeholders established numerous guardrails around projects that could participate in the original ERAS to ensure that the process is used as intended, that only truly necessary and certain projects can enter ERAS, and to mitigate any impact on projects currently in the general interconnection queue. These guardrails continue to include stringent eligibility requirements such as demonstrating 100% site control for the Interconnection Customer's Interconnection Facilities, establishing a three year due date for Commercial Operation Dates ("COD") based on submission date, requiring a non-refundable deposit of $100,000, a $24,000/MW milestone payment, all of which are due upon application, and agreeing to paying for all necessary Network Upgrades per the executed GIA. MISO is also

[28] *See* Tab A Redlines, Attachment X, Section 3.9.1.1(iii).

proposing several changes to the Interconnection Request application to ensure that the necessary information is supplied by the Interconnection Customer when applying to participate in ERAS.

The refined ERAS framework continues to incorporate the role of states and RERRAs but requires a written verification from the RERRA that the proposed project will address a load addition not already planned for or an identified resource adequacy deficiency within its jurisdictional footprint. The Commission has previously recognized that "MISO's resource adequacy construct is designed specifically to complement state mechanisms."[29] MISO continues to support "the independent authority of state regulators for resource adequacy and facilitates resource adequacy goals with state regulators that have decision-making authority over the amount and types of resources that are necessary to meet shared objectives."[30] The ERAS process still provides a vehicle for the RERRA to verify to MISO that there is a valid, new incremental load addition that is not incorporated in relevant plans or that the proposed Generating Facility will address an identified resource adequacy deficiency. While this verification is not *confirmation* by the state/RERRA of a project's approval,[31] and should not be viewed as such, it does directly connect the proposed ERAS project with a specific load need. This, along with the requirement that the load need and the ERAS project must be located in the same LRZ region, better tailors the ERAS process to the resource adequacy and reliability needs.

This refined ERAS proposal also is in alignment with the open access principles establish by the Commission and consistent with the goals of Order Nos. 2003[32] and 2023.[33] Given the dramatic changes the electric industry is undergoing and the increasing demand for electricity expected in the MISO footprint, there is great urgency to establish a process that enables "shovel ready" projects addressing near term resource adequacy and/or reliability needs to be completed

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29 *Midcontinent Indep. Sys. Operator, Inc.*, 170 FERC ¶ 61,215 at P 118 (2020) (citing MISO, FERC Electric Tariff, Module E-1, § 68A (34.0.0). MISO's Module E-1 mandatory requirements for Market Participants serving Load "recognize and are complementary to the reliability mechanisms of the states" and nothing in Module E-1 "affects existing state jurisdiction over the construction of additional capacity or the authority of the states to set and enforce compliance with standards for adequacy."

30 *Id.*

31 As will be further explained Section III.A.2, *infra*, even if a project participates in the ERAS process, regulatory review and approval of the project by the state/RERRA is still required.

32 *See Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC Stats. & Regs. ¶ 31,146 (2003), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007), cert. denied, 552 U.S. 1230 (2008).

33 *See Improvements to Generator Interconnection Procs. & Agreements*, Order No. 2023, 184 FERC ¶ 61,054, *order on reh'g*, 185 FERC ¶ 61,063 (2023), *order on reh'g*, Order No. 2023-A, 186 FERC ¶ 61,199, *errata notice*, 188 FERC ¶ 61,134 (2024).

in a short period of time. As revised to address Commission guidance, ERAS provides that capability and will facilitate the quick completion of projects necessary to address resource adequacy and/or reliability needs in the next few years. The package presented in this filing is just and reasonable and supported by testimony and other evidence, and the Commission should approve it promptly to ensure that MISO can initiate the ERAS process as expeditiously as possible.

II. DEVELOPING THE ERAS PROCESS

A. Overview of MISO'S Generator Interconnection Process

In an effort to constantly improve its generator interconnection process, MISO implemented significant changes to the process over the last two years. First, in 2023, MISO submitted a proposal to make certain improvements to the interconnection process, which involved increasing milestone payments, establishing withdrawal penalty requirements, and implementing certain Site Control rules.[34] Second, in 2024, MISO submitted its Queue Cap Proposal, which established a cap on the total MW value of Interconnection Requests entering a given study cluster.[35] These changes to the queue were made primarily to address the unprecedented challenges MISO faced when evaluating the feasibility and certainty of a large number of projects proposing to connect to the MISO Transmission System. These proposals were necessary to address both the quality and quantity of interconnection requests – thus they were aimed at reducing speculative projects in the queue, making the current queue process more efficient, and reducing the causes of delay.

MISO's first cap proposal, submitted in 2023, included an exemption to the cap for any interconnection requests involving a proposed generation facility that was submitted by a RERRA.[36] The RERRA exemption was proposed in recognition that some proposed Generating Facilities may be required by one or more MISO States or other jurisdictional entities to meet their load serving obligations. As MISO explained in its filing, "[p]roviding this exemption is consistent with the cooperative federalism principles underlying the FPA and placing the primary responsibility over resource adequacy on state regulators."[37] Moreover, the Organization of MISO

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[34] *See Midcontinent Indep. Sys. Operator, Inc.*, Docket No. ER24-340-000, MISO's Transmittal Letter (filed Nov. 3, 2023) ("Queue Reform Filing").

[35] *See Midcontinent Indep. Sys. Operator, Inc.*, Docket No. ER25-507-000, MISO's Transmittal Letter (filed Nov. 21, 2024) ("2024 Cap Filing, Transmittal Letter").

[36] *See Midcontinent Indep. Sys. Operator, Inc.*, Docket No. ER24-341-000, MISO's Transmittal Letter (filed Nov. 3, 2023) ("2023 Cap Filing, Transmittal Letter").

[37] 2023 Cap Filing, Transmittal Letter at 16.

States ("OMS") supported the exemption and proposed a procedure for a RERRA to request that an Interconnection Request associated with a project be exempt from the cap.[38] Ultimately, FERC denied MISO's request to approve the 2023 Queue Cap Proposal with the RERRA exemption.[39]

MISO's second Cap Proposal, submitted in 2024, did not include the RERRA exemption. In the testimony, MISO explained that in lieu of the exemption, it would be proposing the ERAS process to "expedite the approval of new generation needed to address state resource adequacy goals."[40] MISO recognized that the RERRA exemption was attempting to address a distinct queue issue that warranted its own proposal to facilitate the approval process of new generation needed to address resource adequacy.[41] In the 2024 Cap Proposal, MISO committed to working on addressing the needs of RERRAs through a new process that would be developed with stakeholders and that would more comprehensively conduct the process for new generation that was addressing resource adequacy and reliability needs.[42]

MISO's original ERAS proposal, submitted in March of 2025, aimed at addressing short-term resource adequacy and reliability needs.[43] The previously proposed ERAS process required enhanced commitments from the Interconnection Customer including 100% Site Control and full commitment to pay for all the costs of identified Network Upgrades per the executed EGIA even if the project is later withdrawn and the EGIA terminated.[44] MISO also required ERAS projects to have written notification from a RERRA indicating that it should be studied in the ERAS process. MISO originally planned to offer 14 cycles of ERAS studies prior to its sunset in 2028. In May 2025, the Commission issued an order rejecting MISO's proposal and identified two main problems with the initial ERAS filing: 1) there was no limitation on the number of projects that could participate; and 2) the RERRA notification was insufficient to establish a connection between the proposed project and the identified resource adequacy and/or reliability need. The Order also included helpful guidance for MISO to follow when refining its proposal.[45]

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[38] *See Midcontinent Indep. Sys. Operator, Inc.*, Docket No. ER24-341-000, Comments of Organization MISO States ("OMS") in support of Midcontinent Independent System Operator, Inc.'s November 3, 2023 (filed Dec. 4, 2023).

[39] *See Midcontinent Indep. Sys. Operator, Inc.*, 186 FERC ¶ 61,054 (2024), *order on reh'g*, 187 FERC ¶ 61,031.

[40] 2024 Cap Filing, Tab C: Prepared Direct Testimony of Andrew Witmeier at 5:2-3.

[41] *See id.* at 29:10-21.

[42] *Id.* at 30:2-7.

[43] *Midcontinent Independent System Operator, Inc.*, "Revisions to the Open Access Transmission, Energy and Operating Reserve Tariff Expedited Resource Addition Study Filing," Docket No. ER25-1674-000 (March 17, 2025) ("ERAS Transmittal Letter").

[44] ERAS Original Filing, Witmeier Testimony at 41:4 –11.

[45] ERAS Order at P 199.

Following this feedback, MISO has made several refinements to its original ERAS proposal. First, MISO is now capping the number of projects that can participate in ERAS to 68 projects total—with a carve out of 8 projects that may only be submitted by retail states for resource adequacy deficiencies and 10 projects that may only be submitted by independent power producers ("IPPs").[46] In addition, MISO is capping the number of projects that can participate in each ERAS Quarterly Study Period to 10 projects no matter if they are proposed by retail states, IPPs, or other applicants.[47] MISO also changed the RERRA requirement to include a verification instead of a notification to better establish a nexus between the proposed ERAS project and the identified resource adequacy and/reliability need. MISO is now requiring that the ERAS project be within the same LRZ as the load it is addressing unless the project applicant can demonstrate that the use of a Generating Facility not in the same LRZ was included in a resource filing or other submission made to the relevant RERRA.[48] A project applicant for ERAS must now supply three documents: 1) the RERRA verification; 2) the off-taker agreement; and 3) the Interconnection Request for ERAS that contains additional information requirements. MISO believes that this documentation will serve to demonstrate that the proposed ERAS project is targeted at serving a specific resource adequacy deficiency and/or reliability need and will serve to identify the parties involved in the agreement. The refined ERAS process will only be offered until August 31, 2027, or when 68 ERAS Interconnection Request studies have been completed, whichever comes first.[49] And all ERAS projects must be completed and commercially operable three years after their submission date.[50]

ERAS is MISO's short-term solution to the resource adequacy and reliability problems that it is facing in its footprint. The revised proposal filed herein is temporary but critically necessary as a bridge to ensure time-sensitive new resource adequacy needs will be met while MISO works with its stakeholders to reduce the processing time of its queue by 2028. By necessity, the process is flexible enough to be utilized by all RERRAs in MISO's footprint that need such a tool and by any type of Interconnection Customer with a qualifying project. The stringent entry requirements, the newly instituted project cap, the modified RERRA verification, the additional application requirements, and robust process safeguards make ERAS a process that is flexible enough while

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[46] Witmeier Testimony at 4:3-9.

[47] *Id.* at 4:5-6, 17:3-5, 27:8-15.

[48] *Id.* at 4:6-15.

[49] Witmeier Testimony at 49:6-15. This time limitation also applies to the retail state projects. If the retail states do not submit their allotted eight projects by the sunset date, the ERAS process will still close on August 31, 2027.

[50] Witmeier Testimony at 47:14-17. One exception to this rule is if the project has been deferred to a future ERAS quarterly study cycle.

remaining narrowly scoped and appropriately bounded to prevent misuse or negative impacts for projects in the MISO queue.

B. Imminent Resource Adequacy and Reliability Concerns

Like the other RTOs and ISOs, MISO's resource adequacy concerns are driven by unexpected but significant load growth associated with large data center development, the accelerated retirement of baseload generation due to state and federal policies, a resurgence of manufacturing, and delays in the generator interconnection queue caused by speculative projects, late-stage dropouts, supply chain delays, and permitting or financing issues. What is unique to MISO as compared to other RTOs and ISOs is that it is almost completely comprised of vertically integrated utilities who are responsible for serving load within their jurisdictions. The LSEs are accountable for supplying their customers with consistent power and must ensure that they can address resource adequacy needs in a time-sensitive manner. Thus, MISO must partner *with* the states and their RERRAs and LSEs to provide a way for projects that have been identified as necessary for resource adequacy or reliability needs to be completed quickly. MISO's outlook on resource adequacy within its footprint is supported by several studies that are completed on a regular basis. As these studies demonstrate, the load growth outlook has changed dramatically in the past few years due to unforeseen changes in the electricity industry.

First, MISO's Reliability Imperative Report found that the transition towards decarbonization is "posing material, adverse challenges to electric reliability."[51] The Report recognized that major industry trends are "simultaneously changing the conditions of the system" and that demand for electricity is increasing to meet new needs, which is disrupting traditional load patterns.[52] MISO noted that over the last decade, surplus reserve margins in MISO have been exhausted through load growth and unit retirements.[53] "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."[54] MISO also published the MISO Futures Report, which provides the analysis of three scenarios to help MISO envision a set of possible resource adequacy outcomes up to 20 years in the future. The scenarios establish a range of economic, policy, and technological possibilities including load growth, electrification, decarbonization, renewable energy levels,

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[51] *See MISO's Response to the Reliability Imperative,* Executive Summary (updated February 2024) at 1, https://cdn.misoenergy.org/Executive%20Summary%202024%20Reliability%20Imperative%20report%20Feb.%2021%20Final631825.pdf.

[52] *Attributes Roadmap, A Reliability Imperative Report* (December 2023) at 6, https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf.

[53] *See MISO's Response to the Reliability Imperative,* (updated February 2024) at 6, ("Reliability Imperative"), https://cdn.misoenergy.org/2024%20Reliability%20Imperative%20report%20Feb.%2021%20Final504018.pdf?v=20240221104216.

[54] *Id.*

generator retirements, fuel prices, and generation capital costs. While MISO originally published the Series 1 analysis in 2022, due to the dramatic changes in the energy industry even in the last couple of years, MISO was required to update the outlook as its "members' and states' plans were refined, new legislation and policies took effect, and prices, along with incentives for various resources, saw significant changes."[55] As a result of these changes, MISO was required to revise the Series 1 Futures earlier than anticipated with updated data "to reflect a significant fleet transition over the next 20 years."[56] Both Futures Reports demonstrated the immediate need to add almost twice the generation that MISO currently has online, and that rate is increasing as a result of the unprecedented load growth.[57]

Second, the annual OMS-MISO Survey indicated similar results in 2024, "reinforc[ing] near-term risks and highlight[ing] key uncertainties impacting resource adequacy in the MISO region."[58] The survey compiles information about new resources that the utilities and states plan to build and about any older assets they intend to retire in the coming years. The 2024 survey finds that "resource adequacy risks could grow over time across all seasons, absent increased new capacity additions and actions to delay capacity retirements."[59] The survey noted that "significant economic development activities are spurring new, large spot-load additions (e.g., data centers, onshoring of manufacturing, new industrials) and increasing pressures on resource adequacy and requiring improved abilities for the timely addition of new resources."[60] EPRI, Grid Strategies, and MISO also anticipate strong long-term load growth that is driven by data centers, manufacturing, increased cooling demands, electric vehicles, and cryptocurrency.[61] Grid Strategies even noted "[o]ver the past year, grid planners nearly doubled the 5-year load growth

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55 *MISO Futures Report Series 1A* (Nov. 1, 2023) at 2, https://cdn.misoenergy.org/Series1A_Futures_Report630735.pdf.

56 *Id.*

57 *Id.* at 6-8; *see also*, *MISO Futures Report* (updated December 2021) at 4, https://cdn.misoenergy.org/MISO%20Futures%20Report538224.pdf.

58 *See 2024 OMS-MISO Survey Results* (June 20, 2024), ("2024 OMS-MISO Survey") at 2, https://cdn.misoenergy.org/OMS%20MISO%20Survey%20Results%20Workshop%20Presentation628355.pdf.

59 *Id.*

60 *Id.*

61 *2024 OMS-MISO Survey* at 12*; see also* EPRI, *Reindustrialization, Decarbonization, and Prospects for Demand Growth* (Jul. 27, 2023), https://www.epri.com/research/products/000000003002027930; John D. Wilson and Zach Zimmerman, Grid Strategies, *The Era of Flat Power Demand is Over* (December 2023), ("Grid Strategies Report"), https://gridstrategiesllc.com/wp-content/uploads/2023/12/National-Load-Growth-Report-2023.pdf.

forecast."[62] The 2024 OMS-MISO survey also noted that "immediate actions are needed to expedite the addition of new capacity, coordinate resources for new load additions, and potentially moderate the pace of resource retirements."[63]

The recently published 2025 OMS-MISO Survey further "reinforces near-term risks and highlights key uncertainties impacting resource adequacy."[64] The 2025 survey shows a range of outcomes but indicates that "[a]t least 3.1 GW of new resources are needed by summer 2026/27 to avoid a resource deficit, with greater needs in future years."[65] The survey responses "show increasing load forecasts year-over-year and are close to the high end of MISO Long-Term Load Forecast."[66] The 2025 survey noted that data centers, electric vehicles, and industry development are anticipated to have a high impact in MISO's footprint.[67] Finally, the 2025 Survey recognized that there is significant uncertainty in projected resource adequacy, underscoring the urgent need for accelerated resource additions, strategic retirement planning and proactive management of increasing load growth. Using both the Regional Resource Assessment ("RRA") and OMS-MISO Survey together provides a unique outlook for resource planners as the RRA is "a 20-year outlook based on publicly announced resource plans and policy goals" while the OMS-MISO Survey is "more focused on the near term and projects new installed capacity coming online at the pace at which resources have received interconnection agreements and come online in recent history."[68]

Third, the 2024 NERC Long-Term Reliability Assessment highlighted the mounting reliability challenges faced by the energy industry caused by accelerating generator retirements, declining dispatchable resources, and escalating demand growth.[69] NERC noted that "[e]lectricity peak demand and energy growth forecasts over the 10-year assessment period continue to climb;

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62 *Grid Strategies Report* at 3.

63 *2024 OMS-MISO Survey* at 16.

64 *See 2025 OMS-MISO Survey Results* at 2.

65 *See 2025 OMS-MISO Resource Adequacy Survey Results*, Fact Sheet, available at: https://cdn.misoenergy.org/2025%20OMS-MISO%20Survey%20Fact%20Sheet702641.pdf.

66 *Id.* at 10.

67 *Id.* at 10.

68 Comments of Todd Ramey on behalf of MISO at 9, Docket No. AD25-7, May 28, 2025 ("MISO RA Tech Conference Comments").

69 *See NERC 2024 Long-Term Reliability Assessment* (December 2024), ("NERC Report") https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

demand growth is now higher than at any point in the past two decades."[70] The assessment found that for 2025-2029, MISO was categorized as high risk for falling below established resource adequacy criteria.[71] The Report determined that resource additions were not keeping up with generator retirements and demand growth in the MISO footprint.[72] "MISO is at a high risk of experiencing electricity supply shortfalls beginning in Summer 2025 based on [prospective reserve margins] derived from anticipated resources and demand forecasts."[73] As part of NERC's assessment of MISO, it explained that "[i]ncreased coordination between MISO and its members will be critical to ensuring reliability throughout this resource transition of integrating new intermittent resources and continuing to retire conventional resources."[74]

More recently, NERC issued its summer reliability assessment for 2025.[75] In its report, NERC noted that "[s]ince last summer, the aggregate of peak electricity demand for NERC's 23 assessment areas has risen by over 10 GW – more than double the year-to-year increase that occurred between the summers of 2023 and 2024."[76] NERC also identified MISO has having resource adequacy or energy risks for the summer and noted elevated "potential for insufficient operating reserves in above-normal conditions."[77] NERC similarly highlighted 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."[78] Finally, in its assessment, NERC noted that "[t]he summer of 2024 was the fourth hottest on record for both the contiguous United States and Canada, with some areas experience their hottest summer ever. The result was record electricity demand in the United States as well as in Canada."[79]

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[70] *Id.* at 8.

[71] *Id.* at 6.

[72] *Id.* at 7.

[73] *Id.* at 13.

[74] *Id.* at 43.

[75] *2025 Summer Reliability Assessment*, North American Electric Reliability Corporation, May 2025, ("NERC 2025 Assessment"), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf.

[76] *Id.* at 5.

[77] *Id.* at 10.

[78] *Id.* at 16.

[79] *Id.* at 50.

Finally, MISO submitted comments prior to FERC's Technical Conference on the challenge of resource adequacy in RTO and ISO regions, which was held on June 4 and 5, 2025.[80] In its comments, MISO noted that "the MISO region faces resource adequacy and reliability challenges due to the changing characteristics of the electric generating fleet, insufficient transmission system infrastructure, growing pressures from extreme weather, and rapid load growth."[81] MISO explained that it is expecting significant growth in wind and solar development: "MISO's Future Planning Scenarios estimate that while the total amount of installed electric generation will increase significantly over the next 20 years due to the rapid growth of wind and solar, the actual amount of electricity available to the system during could face a net decline of about 32 GW due to the operational characteristics of these new resources."[82] MISO also emphasized that "based on the current trajectory, peak electric load in the MISO region is projected to grow at a 1.6% compound annual growth rate ('CAGR'). This compares to an average 0.5% CAGR between 2009 and 2024 and threatens to outpace new electric resource additions if urgent action isn't taken."[83] MISO concluded that "[w]ith the pace of change confronting the electricity system, the impending influx of large data centers and the evolving generation portfolio there is heightened urgency to ensure the system remains reliable."[84] NERC also submitted comments in this docket noting that "growth projections of electric demand have reached heights unseen in decades, disrupting resource adequacy plans across North America."[85]

Collectively, these reports and comments provide a perspective demonstrating that MISO and its members need to act quickly and collaboratively to address resource adequacy and reliability needs in the MISO footprint over the next five years.[86] The original ERAS proposal was developed by MISO in coordination with its stakeholders to address these needs and to enable projects addressing resource adequacy and/or reliability to be brought online quickly. As NERC recognized, "MISO's resource adequacy construct complements the jurisdiction that regulatory authorities have in determining the necessary level of adequacy."[87] The refined ERAS proposal

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80 MISO RA Tech Conference Comments at 1.

81 *Id.*

82 *Id.* at 2.

83 *Id.* at 3.

84 *Id.* at 27.

85 Prefiled Statement of Jim Robb, President and CEO of North American Electric Reliability Corporation at 1, Docket No. AD25-7, May 19, 2025 ("NERC RA Tech Conference Comments").

86 In fact, MISO updated the Futures Report from November 2023 used to study LRTP Tranche 2.1 because load assumptions changed so dramatically over the past year and half.

87 NERC Report at 43.

further enables MISO to work *with* its members to address resource adequacy and reliability needs in the short-term.

C. Development of ERAS and the Stakeholder Process

Between November of 2024 and March of 2025, MISO conducted an extensive stakeholder process, which included discussions, presentations, and numerous opportunities for stakeholder input at the Planning Advisory Committee ("PAC") and also in ERAS-specific workshops. The stakeholder engagement process for MISO's ERAS proposal went as follows:

- November 13, 2024: MISO introduced the need for ERAS at the PAC and requested formal written feedback from stakeholders.[88]

- November 18, 2024: MISO and stakeholders participated in a special ERAS-specific workshop in which the parties continued to discuss ERAS details. MISO sought feedback on the ERAS proposal.[89]

- December 6, 2024: MISO and stakeholders participated in a second ERAS-specific workshop in which the parties continued to discuss ERAS details. MISO sought feedback on the updated proposal.[90]

- January 22, 2025: MISO presented an updated ERAS proposal at the PAC.[91]

- February 19, 2025: MISO posted proposed tariff redlines, presented an updated ERAS proposal, and sought feedback at the PAC.[92]

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[88] *See Expedited Resource Adequacy Study (ERAS) Introduction* (November 13, 2024), https://cdn.misoenergy.org/20241113%20PAC%20Item%2009%20Expedited%20Resource%20Adequacy%20Study%20(ERAS)%20Introduction660245.pdf.

[89] *See Expedited Resource Adequacy Study (ERAS) Workshop* (November 18, 2024), https://cdn.misoenergy.org/20241118%20Expedited%20Resource%20Adequacy%20Study%20(ERAS)%20Workshop661622.pdf.

[90] *See Expedited Resource Adequacy Study (ERAS) Workshop* (December 6, 2024), https://cdn.misoenergy.org/20241206%20Expedited%20Resource%20Adequacy%20Study%20(ERAS)%20Workshop665747.pdf.

[91] *See Expedited Resource Addition Study (ERAS) Proposal* (January 22, 2025), https://cdn.misoenergy.org/20250122%20PAC%20Item%2006c%20Expedited%20Resource%20Addition%20Study%20(ERAS)%20Proposal%20(PAC-2023-1).pdf673403.pdf.

[92] *See Expedited Resource Addition Study (ERAS) Proposal* (February 19, 2025), https://cdn.misoenergy.org/20250219%20PAC%20Item%2009%20Expedited%20Resource%20Addition%20Study%20(ERAS)%20Proposal%20(PAC-2023-1)679608.pdf.

- March 7, 2025: MISO posted updated proposed tariff redlines and presented the final ERAS proposal at a special PAC meeting scheduled to review the ERAS proposal.[93]

- November 2024 – March 2025: MISO staff engaged in dozens of individual calls with stakeholders to discuss what changes they think should be made to the ERAS proposal.

In addition to these more general stakeholder meetings, OMS provided significant input on the appropriate method for states or RERRAs to notify MISO of projects suitable for ERAS. Collaboration between MISO and OMS on the mechanics of the RERRA notification process and the language added to MISO's Tariff was key. The input from OMS ensures that the ERAS process can be utilized across the footprint even though the regulatory processes differ in each state.

Following the Commission's rejection of MISO's original ERAS filing and the guidance provided in its Order, MISO re-engaged with its stakeholders to develop the refined ERAS proposal as developed in herein. MISO presented its refined ERAS proposal at the May 28, 2025 PAC meeting where MISO presented the disposition of its original ERAS filing in Docket No. ER24-1674.[94] MISO received feedback from stakeholders following the PAC meeting through its informal feedback tool.[95]

D. States Have Authority Over Resource Adequacy

Due to MISO's unique organizational structure consisting of almost exclusively vertically integrated utilities, resource adequacy determinations must be made in collaboration with the states. As MISO recently explained in comments filed with FERC, "[e]very effort in pursuit of the Reliability Imperative is centered around the shared responsibility between MISO-member electricity providers, states, and MISO to maintain a reliable grid."[96] FERC has recognized that state authority over resource adequacy is emphasized more in MISO than in other RTOs.[97] MISO

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93 *See Expedited Resource Addition Study (ERAS) Proposal* (March 7, 2025), https://cdn.misoenergy.org/20250307%20PAC%20Item%2002%20Expedited%20Resource%20Addition%20Study%20(ERAS)%20Proposal%20(PAC-2023-1)684427.pdf.

94 *See Expedited Resource Addition Study (ERAS) Next Steps* (May 28, 2025), https://cdn.misoenergy.org/20250528%20PAC%20Item%2008%20Expedited%20Resource%20Addition%20Study%20(ERAS)%20Next%20Steps%20(PAC-2023-1)699836.pdf.

95 *Informal Feedback (2025)*, MISO, https://www.misoenergy.org/engage/stakeholder-feedback/2025/informal-feedback-2025/.

96 MISO FERC RA Tech Conference Comments at 27.

97 ERAS Order at P 203 ("We recognize that, given their authority, responsibilities, and expert assessment of their resource adequacy needs, it is appropriate for RERRAs to communicate to MISO their resource adequacy and

firmly believes that it should not be selecting ERAS projects that may address resource adequacy or reliability needs, but rather that responsibility is firmly within the states' jurisdiction. In fact, "[s]ince MISO's inception, deference has been made to the jurisdictional authority of the states and other RERRAs with respect to resource adequacy rights and responsibilities that RERRAs take seriously."[98]

The overlap between state and federal authority in the electric industry is governed by the Federal Power Act ("FPA").[99] "The Commission is a creature of statute and has jurisdiction only over those matters that Congress has given it the authority to regulate."[100] To that end, FERC has jurisdiction over regulating interstate "wholesale" electricity sales and transmission markets, whereas the states have jurisdiction over "retail" sales and "over facilities used for the generation of electric energy."[101] Under the FPA, federal and state powers are "complementary" and "like all collaborative federalism statutes, envisions a federal-state relationship marked by interdependence."[102] Thus, determining "resource adequacy raises 'complex jurisdictional concerns' which at times are at the 'confluence of state-federal jurisdiction.'"[103] At this confluence, FERC has recognized that "this bifurcated framework respects the jurisdictional boundaries of the FPA while recognizing the states' historical role in ensuring resource adequacy."[104] FERC has clearly stated that "a workable approach to resource adequacy does not mean that we should ignore the states' traditional role in this area."[105] Thus, "[w]ith the exception of the broad authority of [FERC], over the need for and pricing of electrical power transmitted in interstate commerce … these economic aspects of electrical generation have been regulated for

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reliability needs, as well as their support for including interconnection requests in the ERAS process, to ensure that the RERRA's needs are met in a timely fashion.").

98 MISO FERC RA Tech Conference Comments at 12.

99 16 U.S.C. § 824 (1976).

100 *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,115 at P 66 (2025) ("Co-Location Order") (citing *Atl. City Elec. Co. v. FERC*, 295 F.3d 1, 8 (D.C. Cir. 2002)).

101 16 U.S.C. § 824(b)(1).

102 *Hughes v. Talen Energy Mktg., LLC*, 578 U.S. 150, 167 (2016) (Sotomayor, J., concurring); *see also FERC v. Electric Power Supply Ass'n*, 577 U.S. 260, 289 (2016) ("EPSA").

103 *Plan. Res. Adequacy Assessment Reliability Standard*, 134 FERC ¶ 61,212 at P 20 (2011) (citing *Cal. Indep. Sys. Operator Corp*., 116 FERC ¶ 61,274 at P 1112 (2006), *order on reh'g*, 119 FERC ¶ 61,076 (2007), *order on reh'g* 120 FERC ¶ 61,271 (2007)).

104 *See California Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274 at P 1117 (2006); *Cxa La Paloma, LLC*, 165 FERC ¶ 61,148 at P 70 (2018).

105 *California Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274 at P 1117 (2006).

many years and in great detail by the states."[106] Notably, the states have long relied on the FPA's reservation of state control over their own generation as an unambiguous sanction of states' authority to control their own resource mix.[107] Similarly, FERC has recognized this sanction of authority to the states to control their own resource mix.[108]

The Supreme Court has similarly recognized this jurisdictional overlap and the states' authority in this area. "Alongside those grants of power [under the FPA], however, the Act also limits FERC's regulatory reach, and thereby maintains a zone of exclusive state jurisdiction."[109] "But the law places beyond FERC's power, and leaves to the States alone, the regulation of 'any other sale' – most notably, any retail sale – of electricity."[110] This reserved authority to the states includes control over in-state "facilities used for the generation of electric energy."[111] The Supreme Court explained that the "need for new power facilities" is "characteristically governed by the states."[112] "These matters are consistent with those that the Supreme Court has long held to be within the states' historic police powers, and the Court has observed that the FPA's jurisdictional divide 'was drawn with meticulous regard for the continued exercise of state power, not to handicap or dilute it in any way.'"[113] Finally, the Supreme Court has similarly determined that, under the FPA, the states have authority over their generation resource mix.[114]

This unique jurisdictional overlap affects how MISO collaborates with the 15 states in its footprint in determining resource adequacy needs. Compared to other RTOs and ISOs, resource adequacy is viewed and treated differently in MISO, which runs a voluntary capacity market and

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106 *Pac. Gas & Elec. Co. v. State Energy Res. Conservation & Dev. Comm'n*, 461 U.S. 190, 205–06 (1983).

107 *See Hughes*, 578 U.S. at 166; *EPSA*, 577 U.S. at 266 (explaining that the FPA "limits FERC's regulatory reach, and thereby maintains a zone of exclusive state jurisdiction.").

108 *See California Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274 at P 1118 (2006) ("While we find that resource adequacy is necessary for the reliable operation of the grid, and to ensure that wholesale rates are just, reasonable and not unduly discriminatory, we are not establishing planning reserve requirements, but instead are adopting those set by state and Local Regulatory Authorities in the first instance.").

109 *EPSA*, 577 U.S. at 266.

110 *Id.* at 265 (citing § 824(b)).

111 *Hughes*, 578 U.S. at 154 (quoting § 824(b)(1)).

112 *Id.* (quoting *Pac. Gas & Elec. Co. v. State Energy Res. Conservation & Dev. Comm'n*, 461 U.S. at 205).

113 Co-Location Order, 190 FERC ¶ 61,115 at P 67 (2025) (citing *Munn v. People of State of Ill.*, 94 U.S. 113 (1876) and quoting *Oneok, Inc. v. Learjet, Inc.*, 575 U.S. 373, 384-85 (2015) (discussing the analogous provisions in the Natural Gas Act) (internal citations omitted)).

114 *See, e.g., Citizens Action Coal. of Ind., Inc. v. FERC*, 125 F.4th 229, 238 (D.C. Cir. 2025) (citing 16 U.S.C. § 824(b)(1)).

the states in the MISO footprint direct their utilities to meet resource adequacy requirements.[115] Notably, FERC "has consistently rejected a one-size-fits all approach to resource adequacy in the various RTOs/ISOs due, in large part, to significant differences between each region and also due to the well-established tenet that there can be more than one just and reasonable rate."[116] FERC has recognized that these differences set MISO apart from other RTOs/ISOs in meaningful ways. First, "[t]he vast majority (approximately 90 percent) of MISO's load is served by vertically integrated utilities over which state and local authorities play an active role in ensuring resource adequacy. In fact, even states with retail competition (i.e., Illinois and Michigan) have played an active role in ensuring resource adequacy."[117] Second, FERC has also recognized that "MISO's resource adequacy construct is designed specifically to complement state mechanisms" and "supports the independent authority of state regulators for resource adequacy and facilitates resource adequacy goals with state regulators that have decision-making authority over the amount and types of resources that are necessary to meet shared objectives."[118] Applying Section 201(b) of the FPA, the D.C. Circuit has similarly explained that states have the authority "to take any other action in their role as regulators of generation facilities without direct interference from the Commission."[119]

As the reliability operator, MISO is responsible for ensuring reliability for the 15 states that make up its footprint. As a result of this unique resource adequacy and reliability construct, collaborating closely with the states/RERRAs was a necessary part of creating the original ERAS process. Courts have recognized that FERC may not prevent a state "from using the resources [the state] has chosen to promote" and that "[t]he states may use any resource they wish to secure the capacity they need."[120] It is incumbent upon the Interconnection Customer to identify the specific need(s) its project will address and upon the states or RERRAs to notify MISO that these projects in fact merit expedited study so that they can be available promptly if approved through the

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[115] *See* MISO, *Planning Resource Auction*, MISO, ("MISO's resource adequacy construct complements the jurisdiction that regulatory authorities have in determining the necessary level of adequacy. It also works in concert utilities that provide demand forecasts that help drive the development of local and regional requirements.") https://www.misoenergy.org/planning/resource-adequacy2/resource-adequacy/#t=10&p=0&s=FileName&sd=desc. MISO runs a centralized capacity auction, known as the planning resource auction, but also allows LSEs to meet the resource adequacy requirement by submitting a fixed resource adequacy plan or through bilateral contracting. MISO, *Planning Resource Auction: Results for Planning Year 2024-25* (Apr. 25, 2024), 2024 PRA Results Posting 20240425632665.pdf.

[116] *Cxa La Paloma, LLC*, 165 FERC ¶ 61,148 at P 76 (2018).

[117] *Midcontinent Indep. Sys. Operator, Inc.*, 162 FERC ¶ 61,176 at P 67 (2018).

[118] *Midcontinent Indep. Sys. Operator, Inc.*, 170 FERC ¶ 61,215 at P 118 (2020).

[119] *Connecticut Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009).

[120] *New Jersey Board of Public Utilities v. FERC*, 744 F.3d 74, 96-97 (3d Cir. 2014) (quoting *Connecticut Dep't of Pub. Util. Control*, 569 F.3d at 481-82.

applicable RERRA's regulations and processes. The states have many different processes for identifying these needs—some utilize top-down integrated resource planning, some utilize subsidies to encourage certain resource classes, and others directly procure new generation mix toward resources. MISO simply facilitates the ERAS process, which enables projects addressing resource adequacy and/or reliability needs to be reviewed in an expedited manner.

MISO appreciates the Commission's recognition of the RERRAs' "authority, responsibilities, and expert assessment of their resource adequacy needs" and has worked to reflect their responsibility in its refined ERAS proposal.[121] In its refined proposal, MISO has worked to describe how the ERAS process is sufficiently targeted to study *only* interconnection requests that are needed to meet the anticipated shortfall in generating capacity. MISO cannot establish a process on its own—it must implement a process that all 15 of its member-states can participate in. To that end, MISO is looking to the RERRAs to verify that the new, incremental load addition claimed by the Interconnection Customer is valid and not otherwise included in a resource plan or other process under the RERRA's purview or a resource adequacy deficiency that the ERAS projects are being proposed to address. Certain elements are required and MISO needs several parties to be actively involved in ERAS for it to work both legally and practically: a time-critical resource adequacy and/or reliability need must exist, a project applicant must propose an ERAS project to address that need, the RERRA must verify that the new, incremental load is valid or the resource adequacy deficiency exists. Finally, MISO needs to provide the process to enable the load need to be timely addressed. MISO's refined proposal fully incorporates each of these requirements and in way that encourages participation across its footprint.

III. THE PROPOSED REVISIONS ARE JUST AND REASONABLE

FERC applies an independent entity variation standard to evaluate proposals by RTOs and ISOs for revisions to the procedures outlined in Order No. 2003 and Order No. 2023.[122] Consistent with Order Nos. 2003 and 2023, MISO may seek variations from the *pro forma* Large Generator Interconnection Procedures ("LGIP") and Large Generator Interconnection Agreement ("LGIA") if those variations "are just, reasonable, not unduly discriminatory or preferential, and accomplish the purpose of " the terms proposed in Order Nos. 2003 and Order 2023.[123]

MISO's refined ERAS proposal meets this standard. The instant filing addresses a significant and concrete need that was identified and confirmed in the MISO stakeholder process for the original ERAS filing, numerous load forecasts, and by MISO in its administration as the reliability operator for the midcontinent. The supporting evidence demonstrates that the current

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121 ERAS Order at P 203.

122 Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at PP 822-827; Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160 at P 759.

123 Order No. 2003, 104 FERC ¶ 61,103 at PP 825-826; Order No. 2023, 184 FERC ¶ 61,054 at P 1764.

queue mechanisms will not be able to effectively address the resource adequacy and/or reliability needs that the states have in the short-term. MISO is proposing to study a capped number of ERAS projects on a serial basis to accelerate the review time so that urgently needed and "shovel ready" projects are able to reach a GIA faster. Utilizing serial studies for ERAS accomplishes the purpose of Order Nos. 2003 and 2023 by minimizing the restudy risk that is inherent to multi-phase cluster studies so ERAS projects can be built quickly, without the risk of cascading restudies. Although the use of cluster studies is appropriate for the large queue volume seen in MISO's Definitive Planning Phase ("DPP") process, the use of serial studies for ERAS will allow MISO to quickly study ERAS projects to address resource adequacy and/or reliability concerns and to meet the goals of the temporary ERAS process. MISO requests that the Commission find all Tariff revisions proposed in this filing just and reasonable and consistent with the goals of Order No. 2003 and Order No. 2023 because "they foster[] increased development of economic generation by reducing interconnection costs and time[.]"[124]

The Tariff revisions proposed in this filing are limited in scope and in impact on the generator interconnection queue but offer significant benefits in terms of addressing resource adequacy and reliability concerns in MISO, and therefore the Commission should accept them as just and reasonable.[125] Redlined and clean versions of the revised Tariff sheets are included as Tabs A and B, respectively.[126] This filing is also supported by the Direct Testimony of Andrew Witmeier, MISO's Director of Resource Utilization, included as Tab C with this filing.

A. Refinements Made to the ERAS Process

Following the Commission's order on its original ERAS filing, which provided helpful guidance for how MISO could move forward with ERAS, MISO worked to quickly implement changes to the proposed ERAS process to address the Commission's concerns while also crafting a process that can be started this year. To that end, MISO is proposing several changes to its original ERAS proposal, which it believes will address the Commission's concerns and other feedback received from stakeholders. The following figure demonstrates how MISO's ERAS proposal has evolved since its inception.

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[124] *Id.* at PP 11-12.

[125] *See* Tab A Redlines. In the event of a discrepancy between the redlines as described in this letter and those included in the attached Tariff sheets, MISO intends for the language in the attached Tariff sheets to govern.

[126] MISO notes that its compliance filing for FERC Orders 2023 and 2023-A, 184 FERC ¶ 61,054 (2023) 186 FERC ¶ 61,199 (2024)) ("Order No. 2023-A"), remain pending before the Commission in Docket No. ER24-2046-000. Thus, some of the proposed Tariff sections will require renumbering once MISO has received orders on this filing and its Order 2023 compliance. MISO intends to make a "true up" filing to address reconcile these versions of its Tariff promptly after receiving Commission orders accepting the applicable Tariff sections.

Figure 2: ERAS Proposal Changes from Inception

	Where we began	Original ERAS filing	Refined ERAS filing
Cap	N/A	N/A	No more than 10 projects studied per quarter and no more than 68 projects studied overall with an 8 project carve out for restructured states and a 10 project carve out for IPPs with agreements with entities other than LSEs
Applicants	Load Serving Entities	LSEs, IPPs, and DPP transfer projects meeting all requirements	No change
Process timeline	Project studied and GIA issued in 60 days	Quarterly cadence following established MISO timelines, receiving GIA in ~90 days	No change
Required documentation	RERRA acknowledgement	RERRA acknowledgement and one of the following: • LSE acknowledgment to self-supply • PPA between IC and load or its LSE • Build-Own-Transfer Agreement • Other agreement between applicant and load, or its LSE, stating project will meet RA or reliability need	RERRA verification and one of the following: • LSE acknowledgment to self-supply • PPA between IC and load or its LSE • Build-Own-Transfer Agreement • Other agreement between applicant and load, or its LSE, stating project will meet RA or reliability need
Identification of need	N/A	Description of need in ERAS application	IC must identify specific load addition and/or RA deficiency the project will address (MW value band, approximate location, etc.) and this information will be made public
Locational requirement	N/A	N/A	Project and RA and/or reliability need must be within the same Local Resource Zone
Size requirement	N/A	N/A	Interconnection Service must not exceed 150% of the identified MW need
Commercial Operation Date	Expected COD with 2-5 years	2025/26 applicants: 3 years from submission plus 3-year grace period; 2027/28 applicants: 12/31/2028 COD plus 3-year grace period	All applicants must have a COD within 3 years of submission plus a 3-year grace period
Penalties	Requested feedback after first PAC	Projects transferring from DPP process will be subject existing tariff language (e.g. AWP and Harm Calculations)	No change
Sunset	2028 / 2029	12/31/2028 or on the completion date of the 2027 DPP queue cycle, whichever first	ERAS will sunset at the earlier of the completion of the sixty-eighth ERAS study or on August 31, 2027

This chart demonstrates how MISO has worked with stakeholders to address concerns related to ERAS implementation and how its revised proposal responds to these concerns and Commission guidance. MISO is committed to proposing a process that can and will be used by its member states, which has required numerous iterations of the ERAS proposal.

1. Implementation of an ERAS Project and Quarterly Study Period Project Cap

In the Commission's order rejecting MISO's original ERAS filing, it emphasized that "MISO's proposed Tariff places no limit on the number of projects that could be entered into the ERAS process" and was concerned that "an ERAS queue with processing times for interconnection requests that are too lengthy to meet MISO's stated resource adequacy and reliability needs similar to the challenges with the current DPP queue."[127] In response to this feedback, MISO is now implementing a cap on the number of projects that may participate in ERAS: 68 projects total that will be studied in ERAS until the sunset date of August 31, 2027.[128] Additionally, MISO has carved out a maximum of 8 projects (of the total 68 ERAS projects) that may be submitted to serve

[127] ERAS Order at P 199.

[128] Witmeier Testimony at 26:11-19, 27:1-7, 49:6-15.

retail choice load and a maximum of 10 projects (of the total 68 ERAS projects) that may be submitted by IPPs with agreements with entities other than LSEs.[129] Thus, of the total 68 ERAS projects – 8 projects may be submitted to serve retail choice load, 10 projects may be submitted by IPPs, and 50 projects may be submitted by the remaining project applicants for non-retail choice states.

In addition to the total ERAS project cap and the carve outs, MISO is also implementing a cap of 10 projects that will be accepted and studied per ERAS quarterly cycle. Implementing a project cap per ERAS quarterly study period will enable MISO to adequately study each of the proposed projects in the accelerated timeframe that is required by ERAS.[130] The 10 projects per quarterly study cycle will be selected based on time of submission, but MISO also plans to implement a wait list for any projects that apply beyond the 10th project. Then MISO will implement a screening process to ensure that each of 10 proposed ERAS projects are not within the same geographic area or do not impact the same constraint. If any of the 10 projects are found to be within the same area or impacting the same constraint as another project in that same ERAS quarterly study period, then the project that was submitted later in time will be deferred to the next available quarterly cycle.[131] Then MISO will review any projects in the future quarterly cycles' waitlist to determine whether one of them can be moved up into the previous project's slot, which will require MISO to confirm that the next project is also not in the same geographic zone or addressing the same constraint as one of the nine other proposed projects that were already selected. The remaining projects submitted in that specific cycle that are not accepted for processing will be deferred to future ERAS cycles in order of submission time.

Capping the number of projects per cycle provides numerous benefits for MISO and generators. First, MISO anticipated that a small number of projects would participate per ERAS quarterly cycle, but the cap will ensure that no more than ten are able to be studied per cycle. This will enable MISO to complete the ERAS process more efficiently per project per cycle, which will facilitate the project obtaining an EGIA faster.[132] Second, the cap allows MISO to better plan for the number of projects that will be studied per cycle, which will help MISO efficiently coordinate internal resource needs to complete the studies on time. Knowing the number of projects will also help MISO plan the quarterly study periods out in a more even manner, which will also assist with providing MISO with the necessary information to make additional employee hires if necessary.[133] Third, capping the total number of projects that can participate in ERAS will further minimize the

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[129] *Id.* at 4:3-5, 26:17-19, 27:1-3.

[130] *Id.* at 4:5-6, 17:3-5, 27:8-15.

[131] *Id.* at 27:19-21, 28:1-3, 28:17-23.

[132] *Id.* at 27:8-15.

[133] *Id.* at 17:1-8.

impact on the DPP queue. While MISO stands by its original assertions that the ERAS process will have no impact on projects in the DPP queue and that the strict entry requirements will effectively limit submissions, expressly capping the number of projects that can participate in ERAS will further ensure that there are no negative impacts to projects currently in the queue.[134] Finally, the Commission found PJM's RRI cap to be "reasonably balanced the need to address PJM's resource adequacy challenges with the need to avoid an influx of projects that could overwhelm PJM's interconnection process and lead to further delays, exacerbating the current inability of projects to come online in the near."[135] MISO has the same goal, but plans to spread the number of projects submitted over a slightly longer time period to allow parties time to fully prepare their projects to participate in ERAS.

2. Updating the RERRA Notification Requirement

To reflect the unique jurisdictional authority the states have over generation facilities and resource adequacy needs within their borders, MISO worked closely with OMS to craft the original language that would have allowed a state or RERRA to notify MISO that a proposed project should be considered for the ERAS process in order to meet a claimed resource adequacy and/or reliability need in its jurisdiction. Following the Commission's order, MISO recognized that it needed to change the RERRA requirement and has proposed updated language, which is provided below, in the tariff. In the ERAS application itself, the Interconnection Customer will identify the specific need that its project will address.[136] The Commission noted in its order that "MISO has not demonstrated that the proposed Tariff language is tailored to ensure that only those resources capable of addressing identified near-term resource adequacy or reliability needs are eligible for expedited study through the ERAS process."[137]

Over the past several weeks, MISO has made necessary adjustments to the RERRA language in the ERAS proposal based on FERC's guidance and stakeholder input. To better tailor the RERRA notification to resource adequacy needs, MISO updated the language of the requirement to the following:

> A request for processing through the Expedited Resource Addition Study made by an Interconnection Customer must meet the requirements listed in Section 3.3.1 above, plus the following requirements:

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134 Witmeier Testimony at 53:9-21, 54:1.

135 ERAS Order at P 200.

136 *See* Tab A Redlines, Attachment X, Section 3.3.1.

137 ERAS Order at P 202.

1. The Interconnection Request shall be accompanied by a written verification from the RERRA (or its documented representative) where the load to be served by the Generating Facility is located, subject to the procedures or methods the RERRA requires, that either:

i. the new, incremental load addition claimed by the Interconnection Customer is valid and not otherwise included in a resource plan or other process under the RERRA's purview.

a. The RERRA (or its documented representative) may provide such written verification in conjunction with another state or municipal agency or official (e.g. economic development authority or governor's office) to verify the new, incremental load addition above.

or

ii. the Generating Facility proposed by the Interconnection Customer will address a resource adequacy deficiency as determined by the RERRA, State, Load Serving Entity, or Interconnection Customer. The determination can be supported by:

a. A state energy forecast, or other forward-looking forecast;
b. Commencement of a state proceeding;
c. Review of a RERRA, LSE, or other state resource plan or document, which may include, but is not limited to: integrated resource plans, procurement plans, or other plan or study types;
d. Response to a Request for Proposals (RFP); or
e. Other process, or delegation of authority, as determined by the RERRA or RERRA regulations (including in retail choice states).

or

iii. If an Interconnection Customer's new Generating Facility will address a resource adequacy deficiency and will either:

(1) serve retail choice load located in a state that limits the amount of load that can select retail choice to a percentage of the electric utility's average weather-adjusted retail sales; or

(2) serve load in a retail choice state and will be located in a retail choice state other than one that limits the amount of load that can select retail choice to a percentage of the electric utility's average weather adjusted retail sales,

then the Interconnection Customer will indicate the specific load on the Interconnection Request in Section 4.s of Appendix 1 and provide the evidence of determination in (ii) above, but will not be required to include a written verification, from a RERRA as described in Section 3.9.1(a) or (b). The Transmission Provider shall notify the respective RERRA that an Interconnection Request for a new Generating Facility has been submitted requesting processing through the Expedited Resource Addition Study process and transmit a copy of the Interconnection Request to the respective RERRA. The RERRA shall have 10 Business Days from the date of the Transmission Provider's notification and the simultaneous transmittal of the copy of the Interconnection Request to notify the Transmission Provider that the Interconnection Request should not be considered in the ERAS process. If no such notice is received at the end of 10 Business Days or if the RERRA notifies the Transmission Provider of its non-opposition prior to the end of the 10 Business Days, the Interconnection Request shall be studied through the Expedited Resource Addition Study process provided it meets the requirements listed in Section 3.3.1 and Section 3.9.2.

A RERRA's written verification is not intended to constitute or provide evidence of any final determination of need or suitability of the project for any purpose by the issuing entity beyond requesting that the Transmission Provider apply the ERAS process for such project.

2. An executed agreement evidencing that the projects submitted for ERAS processing is intended to be used by the entity with the claimed resource adequacy and/or reliability need. Such agreement shall take one of the following forms:

a. A Load Serving Entity acknowledgement to self-supply;
b. A Power Purchase Agreement (PPA) or similar off-take agreement between the Interconnection Customer submitting the project for ERAS consideration and the entity with the load to be served (including, but not limited to, an Alternative Retail Electric Supplier or its Load Serving Entity);
c. An agreement that calls for the Interconnection Customer to develop the Generating Facility described in the Interconnection Request and subsequently transfer ownership or control of such Generating Facility (Build-Own-Transfer Agreement) to the entity with the load to be served (including, but not limited to, an Alternative Retail Electric Supplier or its Load Serving Entity); or

d. Other agreement between the entity submitting the Interconnection Request, including the RERRA verification letter as appropriate, and the entity with the load to be served (including, but not limited to, an Alternative Retail Electric Supplier or its Load Serving Entity), stating that the ERAS project will be used to meet an identified resource adequacy deficiency.[138]

There are several aspects of the RERRA language that MISO is proposing to add to its Tariff and that MISO wishes to highlight. First, the RERRA, where the load will be located, must verify to MISO that the new, incremental load addition is valid and is not currently included in a plan or other procedure under the RERRA's purview or the Generating Facility will address an identified resource adequacy deficiency within that RERRA's footprint.[139] The verification may take any form that works for a specific state, but it must be made by a RERRA or a RERRA's designated representative, and it must be submitted in writing to MISO. MISO changed the details of this requirement to better target the resource adequacy driver the ERAS project is addressing and to ensure that the RERRA verifies that project will address a new load addition or resource adequacy deficiency in its footprint. The ERAS construct is a vehicle intended to achieve a narrow but important purpose: address near-term resource adequacy and/or reliability need claimed by an Interconnection Customer in a RERRA. Requiring that the RERRA verify to MISO that there is a valid, new, incremental load not already planned for or that the proposed project will address an identified resource adequacy deficiency is critical to maintaining this limited scope. Assuming the proposed project meets all the other ERAS requirements, MISO will accept the RERRA's verification and the project will be processed accordingly.

As for the second section of the RERRA language, applicants are still required to provide an executed agreement evidencing that the project submitted for ERAS is intended to be used by the entity with the claimed resource adequacy or reliability need, MISO added this language to ensure that any proposed ERAS project is directly tied to a specific load need. The executed agreement ensures that the project is one that the entity with the load to be served plans to use to address the need, and not simply a speculative project whose developers do not have any commercial arrangement to satisfy the need.[140] For example, an Interconnection Customer that has an agreement with a data center developer for the generation to serve that load is differently situated from a group of Interconnection Customers who are entering the queue with the hope of pitching their generation project to the developer. If the proposed ERAS projects do not meet

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138 *See* Tab A Redlines, GIP Section 3.9.1.

139 *Id.*

140 Witmeier Testimony at 7:3-5, 41:1-3, 41:17-23, 42:1-2.While such optimistic submissions may be features of Interconnection Requests submitted into MISO's Definitive Planning Phase ("DPP"), these contribute to a high volume (and high drop out rate) of Interconnection Requests in the queue. ERAS is intended to have a narrower scope and be used by highly certain projects addressing urgent needs.

these requirements as well as the other ERAS eligibility requirements, then they may submit their project to the generator interconnection queue. This requirement pairs the proposed project with a specific need, mitigating overuse concerns.

Collectively, these requirements narrow ERAS projects to only those for which a claim of need is stated, for which the applicable RERRA has provided verification that there is a valid, new, incremental load not already planned for or that the proposed project will address an identified resource adequacy deficiency, and for which an executed agreement exists connecting that need to the specific project. MISO also added a third section to the RERRA language to incorporate the retail states—Illinois and a portion of Michigan—into the ERAS process to address resource adequacy deficiencies in those states.[141] The proposed language states that if an Interconnection Customer's new Generating Facility will serve a retail choice load then the Interconnection Customer will need to submit demonstration of the resource adequacy deficiency, but will not be required to include a written verification from a RERRA.[142] Rather, MISO will notify the respective RERRA in the retail state that an Interconnection Request was submitted requesting processing in ERAS and will send a copy of the request to the relevant RERRA. The RERRA will then have 10 business days from receipt of the notification from MISO to state that the Interconnection Request should *not* be considered in the ERAS process.[143] This proposal recognizes that these areas do not have to seek approval from their RERRA and recognizes the existence of Alternative Retail Electric Suppliers in these areas as other entities that serve load. Thus, the new proposal better facilitates use of the ERAS process in Illinois and the retail sections of Michigan without changing the role or requirements applicable to RERRAs in other parts of MISO's footprint.

To recognize and reflect the states' authority over resource adequacy, MISO retained the language indicating that a RERRA's written verification to MISO regarding a proposed ERAS project "was not intended to constitute or provide evidence of any final determination of need or suitability of the project for any purpose by the issuing entity" beyond requesting that MISO apply the ERAS process to the project.[144] MISO understands that each RERRA has a distinct and separate regulatory process for the approval of energy projects within its jurisdiction and did not want participation in the ERAS process to be interpreted as MISO *directing* the RERRA to approve certain projects over others. It also ensures that the notification does not pre-determine any outcome of an applicable state process. Even if a project is approved to participate in ERAS, the LSE or developer must still receive state approval through the state's corresponding regulatory review process whether that be before the state public utility commission or the RERRA. MISO is simply proposing ERAS as a tool that may be utilized to address short-term

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141 *See* Tab A Redlines, GIP Section 3.9.1.

142 *Id.*

143 *Id.*

144 *Id.*

resource adequacy and/or reliability needs—the states are not required to participate in or to utilize ERAS.

3. Establishing a Stronger Nexus to Resource Adequacy Deficiencies

In its ERAS order, the Commission also found that MISO's proposal did not "sufficiently describe how the ERAS process is sufficiently targeted to study only interconnection requests needed to meet the anticipated shortfall in generating capacity described by MISO."[145] The Commission also pointed to PJM utilizing its locational deliverability areas and CAISO's system need criterion to target the proposed projects to areas with resource adequacy and/or reliability needs.[146] To better establish the nexus between the load need and the ERAS project, MISO is now requiring that the proposed ERAS project and the load addressing the resource adequacy and/or reliability need be located in the same Local Resource Zone ("LRZ").[147] This will ensure that the generation will support Local Clearing Requirements ("LCR"), and prevent ERAS projects from driving import or export concerns if the ERAS project is located in a different zone, unless the project applicant can demonstrate that the use of a Generating Facility not in the same LRZ was included in a resource filing or other submission made to the RERRA. MISO has ten geographic areas that are identified as Local Resource Zones and generally consist of one state or portions of several states.

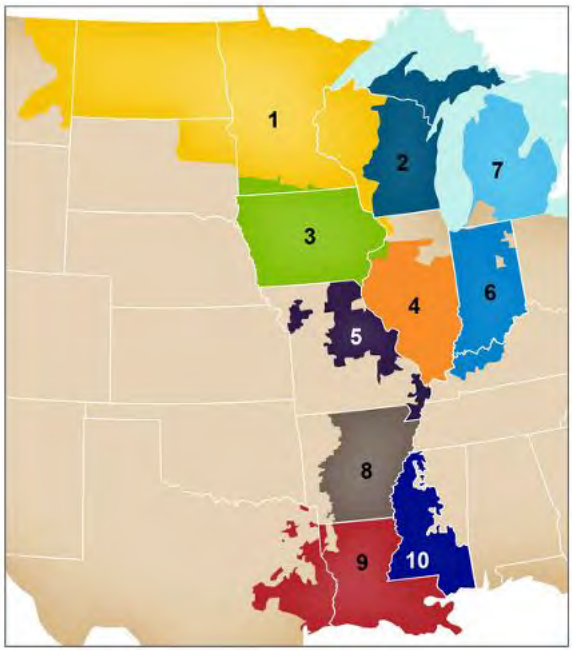
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[145] ERAS Order at P 201.

[146] *Id.* at P 202.

[147] Witmeier Testimony at 4:10-15, 30:10-16, 32:4-16, 41:14-15, 61:17-19.

Figure 3: MISO Local Resource Zones[148]



MISO recognizes that that some LSEs span multiple LRZs and that LSEs regularly rely on resources from other zones to support their load requirements. MISO is requiring that the ERAS project be within the same LRZ as the load it is addressing unless the project applicant can demonstrate that the use of a Generating Facility not in the same LRZ was included in a resource filing or other submission made to the relevant RERRA.[149] Thus, if the ERAS project is located outside of the LRZ where the load need is located, then it will need to provide an Integrated Resource Plan ("IRP") or a comparable document that has been filed with the RERRA with its ERAS application.[150]

When applying to ERAS, the Interconnection Customer must identify the specific load addition and/or resource adequacy deficiency that the project will address including the project location and the expected MW value. The project must also not exceed 150% of the identified need based

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148 Tariff FERC Electric Tariff, ATTACHMENT VV, *Map of Local Resource Zone Boundaries*, available at: https://docs.misoenergy.org/miso12-legalcontent/Attachment_VV_-_MAP_of_Local_Resource_Zone_Boundaries.pdf.

149 Witmeier Testimony at 4:10-15, 30:10-16, 32:4-16, 41:14-1516.

150 Witmeier Testimony at 30:10-16.

on interconnection service.[151] MISO recognizes that other RTOs have utilized accredited capacity limitations, but since accredited capacity depending on the fuel type can be lower than 100% for many resources, MISO's limitation is aimed at tightening the nexus between the need claimed and what facility is being built without creating different rules for different resource types. This will enable MISO to better establish a connection between the identified load need and the ERAS project while also limiting the amount of service that may be requested to address the load need plus a reasonable margin. This methodology will facilitate the efficient implementation of ERAS and is not an overly complicated formula for determining the amount of need the ERAS project may address.[152] These revisions ensure a stronger tie between the ERAS project and the resource adequacy deficiency that it is addressing.

4. Increasing Transparency in the ERAS Process

MISO understands that this is a unique process that is being implemented for a very specific purpose but is committed to being transparent about the projects that participate in ERAS. While refining the ERAS proposal, MISO is making several changes to the ERAS application in order to increase transparency in the process. MISO plans to publish an ERAS webpage that will provide a significant amount of information regarding each ERAS project. To that end, an ERAS Interconnection Request must identify the claimed resource adequacy and/or reliability need(s) for which it is being submitted. This must include the location of the project—i.e. the county and state of the Generating Facility site, the electrical bus location(s), and the Local Resource Zone. The ERAS Interconnection Request must identify the load to be served via the off-take agreement as well as the peak demand for electricity in MWs as the amount of Interconnection Service requested must not exceed 150% of the identified MW need, and the location of the load to be served (i.e. the county and state, and the Local Resource Zone).

As part of the ERAS application, project applicants are also required to include a non-confidential summary of information that MISO can publish on its webpage. The required information that will be provided by the project applicant must include the following: the developer proposing the ERAS project, the MW range of need the ERAS project is addressing, the LRZ region where the ERAS project is located, and a general description of the driver of the load need (i.e., data center, manufacturing plant, etc.). MISO will also publish the RERRA that submitted a verification for each ERAS project, the specific carve out the project falls within, and the specific ERAS quarterly study cycle that the proposed project will be studied in once MISO has completed its screening process per ERAS cycle.

MISO is committed to ensuring that information about the ERAS process is easily accessible both for potential project applicants but also for other stakeholders in the energy industry. MISO also plans to publish an informational guide for potential ERAS applicants that addresses many

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[151] *See* Tab A Redlines, GIP Section 3.3.1.

[152] Witmeier Testimony at 43:1-19, 42:1-2.

common questions and problems that an applicant might be faced with when submitting its ERAS project. MISO believes that providing numerous cycles for ERAS projects to participate in will ensure that the ideal projects are proposed for ERAS and that potential project applicants have time to fully prepare their project before applying.

B. The ERAS Process is Balanced and Narrowly Tailored

ERAS was crafted to target projects that can meet resource adequacy and reliability needs quickly while also maintaining developer, fuel, and technology neutrality. MISO developed this filing based on its determination of how to best address its resource adequacy needs given its unique make up of primarily vertically integrated utilities across many different state and RERRA jurisdictions. The revised filing now incorporates the retail states so that all states in the MISO footprint may participate in ERAS. The LRZ requirement ensures that the ERAS project is located in the same area as the load need but also provides an exception for Generating Facilities not in the same LRZ that are included in a resource filing or other submission made to the relevant RERRA. State and RERRA involvement in ERAS ensures that the proposed ERAS projects are necessary to meet resource adequacy and reliability needs while also not favoring one kind of project or project developer.

These proposed revisions are properly tailored to ensure that projects capable of addressing identified resource adequacy or reliability needs participate in the ERAS process. Moreover, the new ERAS quarterly project processing cap will ensure that the projects are spread over a longer time period, which allows for the studies to be completed on a regular cadence and allows MISO to better forecast its internal resource and employee needs. Due to these changes, ERAS will not risk "replicating the same backlogs and delays plaguing MISO's existing generation interconnection queue, which are what put MISO in its current situation in the first place."[153] This revised proposal has "practical limits on the volume of interconnection requests that will be studied, such that the proposal is tailored to meet the identified resource adequacy and reliability needs."[154]

The following section first describes the eligibility requirements that projects are expected to meet to participate in ERAS. These eligibility requirements are critical for ensuring that the projects that are studied in the ERAS process are truly "shovel ready" and can be implemented in the very near term. The section then explains how the refined ERAS proposal ensures that ERAS projects will not harm existing projects in the general interconnection queue and how the ERAS project cap is a further safeguard to that end. MISO is committed to ensuring this process works for as many stakeholders as possible while also addressing the near-term resource adequacy and reliability needs in its footprint.

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[153] ERAS Order, Comm'r Rosner concurrence at P 1.

[154] *Id.*

1. ERAS Has Strict Eligibility Requirements

Over the past several years, MISO has pursued numerous avenues to address its near-term resource adequacy issues including improving GIP procedures, implementing a queue cap, and making other queue improvements, but the benefits of these updates will be unable to address or fill the identified resource gap in the short-term.[155] The continued large volumes of Generator Interconnection requests and accumulating backlog have delayed resource additions from obtaining executed GIAs. These delays are exacerbated by supply chain bottlenecks, permitting delays, and other commercial challenges that plague projects in the queue and those with signed interconnection agreements. The current queue cycle takes 3-4 years and late-stage dropouts from 2020-2022 resulted in queue re-studies and prevented the processing of later cycles. Concurrently, states are seeing extreme load growth due to economic development and new, large spot load additions but lack the ability to quickly add new resources.[156] To address this clear and immediate need, ERAS was created to facilitate the completion of projects that are "shovel ready"—projects that can truly address the shortfalls identified by numerous load forecasts.

To that end, MISO is implementing stringent eligibility requirements for participation in ERAS to only allow projects that are commercially viable within the next few years. In addition to the requirements addressed in the previous section—the RERRA notification and executed agreement—proposed ERAS projects must also meet other eligibility requirements. First, to participate in ERAS, an Interconnection Customer must pay a non-refundable application fee of $100,000, a milestone M2 payment of $24,000 per MW, and, upon signing the EGIA, agree to pay for any associated network upgrades even if the project is ultimately withdrawn from ERAS. The purpose of these financial requirements is to minimize the number of speculative projects applying to ERAS and to ensure that the projects that are applying truly are ready to be built and will serve an identified need.[157] Second, MISO is requiring that an ERAS project's EGIA commercial operation date be within three years of project submission. This requirement is focused on identifying the projects that are truly "shovel ready" and can be fully operational in the next five years.[158] Third, an ERAS project must also be able to demonstrate 100% Site Control for the generator and point of interconnection upon submission to MISO. All evidence of Site Control must be supplied at the time the ERAS application is submitted to MISO.[159] Finally, ERAS

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[155] Witmeier Testimony at 8:3-21, 9:1-2.

[156] *Id.*

[157] *Id.*

[158] *Id.*

[159] *Id.*

projects must meet capacity resource requirements and therefore must request Network Resource Interconnection Service (NRIS).

Since MISO's intent in establishing ERAS is to identify projects that are able to address resource adequacy and/or reliability needs in the short-term, existing projects that have not reached Decision Point II ("DP2") in the 2022, 2023, and later cycles will be eligible to transfer to ERAS.[160] MISO is currently aware of several existing projects in the generator interconnection queue that could apply to participate in ERAS and have plans to consider that option.[161] Existing projects may remain in the DPP cycle while applying for ERAS, but once admitted to ERAS, the projects must withdraw from the DPP cycle and will be subject to Automatic Withdrawal Penalties and Harm Penalties.[162] MISO is requiring these penalties because it recognizes that when projects drop out of the generator interconnection queue, the withdrawal causes harm to the other projects in the cluster. Moreover, after applying, if the existing project is deemed ineligible to participate in ERAS process, then it will forfeit the $100,000 D1 payment provided with the ERAS application and remain in its original queue position.[163] When an existing project leaves the DPP process and successfully transfers to ERAS, it becomes a new Interconnection Request. Therefore, modifications may be made to the project at the time of application. Modifications are allowed to better tailor the Interconnection Request to the claimed need. Any transfers into ERAS is made under new Interconnection Request and is technically not tied to the original request.[164]

Limiting each ERAS cycle to 10 projects will allow MISO to study each project individually in the order submitted, rather than as a group.[165] This serial approach will also allow the developer to perform their own initial studies without the uncertainty of what other generation projects will be in the study as well. Enabling serial studies of the proposed projects is a key feature of ERAS. It affords ERAS Interconnection Requests a better understanding of their impact on the system when looking to address the load need. The traditional challenges related with reviewing projects on a serial basis are not present with ERAS because there will be a much smaller number of Interconnection Requests to process and they are expected to be geographically and

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[160] Witmeier Testimony at 15:5-17.

[161] Witmeier Testimony at 15:18-21.

[162] These penalties are outlined in Attachment X, Sections 7.6.2.1.1 and 7.8 respectively.

[163] Witmeier Testimony at 15:21-23, 16:1-4.

[164] *Id.*

[165] *Id.*

electrically dispersed across the MISO footprint.[166] This is distinguished from the DPP queue where serial studies are difficult, if not impossible, due to the extremely high number of applications per cycle and the high probability of those projects being in the same area.[167] If several ERAS projects in the same quarterly study cycle are located in the same geographical area or impact the same constraint, then MISO will study the project with the earliest submission time in that cycle, and will study the second request in the next available ERAS quarterly study cycle. However, MISO is not anticipating that this will occur very often due to the project cap per cycle, its large geographic footprint, and the strict eligibility requirements to participate in ERAS.[168]

Regarding Affected Systems Studies ("AFS"), neighboring systems will have the right to evaluate the impact of ERAS projects on their systems, just as with projects in the DPP. Any ERAS project that meets JTIQ criteria will be subject to JTIQ.[169] Where available, the affected system study Network Upgrades will be documented in the EGIA. Where AFS analysis is not available for inclusion in the final EGIA, the EGIA will be executed by all parties and MISO will provide any updated analysis when received from the applicable Affected System. But ERAS projects will still be responsible for all required Network Upgrades even if the ERAS project ultimately ends up terminating the EGIA.[170] MISO's proposal includes Tariff language to reflect that even if MISO only provided an estimate of potential network upgrade costs upon applying to ERAS, there will be a true up where either MISO would refund an overcollection of costs or the Interconnection Customer would pay the difference to meet the actual network upgrade costs.[171] MISO added this requirement to ensure that the ERAS project remains responsible for AFS costs. MISO is dedicated to protecting the Generator Interconnection Queue and views this requirement as a further guardrail to protect active projects in the DPP while ensuring that only eligible, ready projects are processed through ERAS.

Finally, to reflect that ERAS is a short-term solution for a near-term problem, MISO is requiring that ERAS projects have a COD three years after the project's submission date unless the project was deferred to a later quarterly study cycle. This caveat is necessary to insulate Interconnection Customers from the impact of deferrals due to the operation of the quarterly study cap. MISO has also written a sunset date for ERAS into the Tariff. ERAS will sunset by August

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[166] MISO processes hundreds of Interconnection Requests through its DPP each year with 600 in its 2023 cycle. Based on extensive discussion with RERRAs and other stakeholders, MISO projects fewer than twenty projects will qualify for ERAS in 2025.

[167] Witmeier Testimony at 5:16-19.

[168] *Id.*

[169] *See* Tab A Redlines, GIP Section 7.3.2.3.1.

[170] Witmeier Testimony at 6:12-16, 34:8-15.

[171] *See* Tab A Redlines, GIP Sections 3.9.6, 3.9.6.1, 3.9.6.2, and 3.9.6.3.

31, 2027, or when it has completed 68 ERAS Interconnection Request studies, whichever occurs first.[172] MISO made this requirement narrower in response to stakeholder feedback as well as Commission feedback stating that MISO's original ERAS proposal was unlimited in nature.[173]

MISO has implemented these stringent eligibility requirements for ERAS to ensure that the projects participating in it are truly "shovel ready" and capable of addressing the states' resource adequacy and/or reliability needs in the near-term. The ERAS eligibility requirements act as a filter to restrict ERAS entry to only those projects that are commercially ready, are needed to respond to a specific resource adequacy or reliability problem and can be completed in the next few years.

2. The Cap Will Expedite ERAS Studies and Prevent Harm to the Queue

A significant concern that was identified in the process of crafting ERAS is the impact ERAS will have on the other queue studies. ERAS has been cautiously crafted to avoid supplanting the DPP or harming projects in the queue. MISO worked carefully to address these concerns and emphasizes its commitment to prioritizing the use and improvement of MISO's generator interconnection queue. Projects in the generator interconnection queue will not be competing with ERAS projects for transmission capacity because although both ERAS and DPP projects will utilize the same MTEP base case, they will have different generator assumptions.[174] ERAS will include only approved Generating Facilities, where the DPP will include all queued projects which includes a significant amount of speculative projects.[175]

As Andrew Witmeier explains in his direct testimony attached to this letter, before every ERAS cycle, all Interconnection Requests with a GIA approved since the last base case was created will be added to the base case for the following ERAS cycle but they are not included in any ongoing DPP studies.[176] The base case for each DPP cycle is never updated once the study process is kicked off except for generation changes due to Interconnection Request withdraws or generator retirements.[177] This ensures that the transmission capacity made available for DPP projects is not

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[172] *Id.* at Section 3.9.9.

[173] *See* Tab A Redlines, GIP Section 3.3.1; ERAS Order at P 203.

[174] Witmeier Testimony at 17:9-19.

[175] *Id.*

[176] *Id.*

[177] *Id.*

being taken away by ERAS Interconnection Requests approved outside of the DPP cycle.[178] This also insulates existing DPP projects from negatives impacts or cost shifts due to the existence of the ERAS process.[179]

By providing ERAS as a tool for the states to utilize, MISO is not looking to displace or overshadow the generator interconnection queue, rather it is providing a process to address a near-term, identified resource adequacy need. The ERAS eligibility requirements are more rigorous than the DPP requirements and are capped both in total number of projects and number of study cycles, which ensures a smaller applicant pool of more earnest project applicants for ERAS and maintains the integrity of the generator interconnection queue. A comparison of the different eligibility requirements is included below.

C. The ERAS Process is Not Unduly Discriminatory and is Consistent with Open Access Requirements

In Order Nos. 888 and 2003, FERC aimed to prevent the discriminatory treatment of competitive generation by requiring open access transmission tariffs that are not "unduly discriminatory or anticompetitive" and that "offer third parties access on the same or comparable basis, and under the same or comparable terms and conditions …."[180] MISO's refined ERAS proposal remains in alignment with those requirements—it is not unduly discriminatory, it is not anticompetitive, and it provides third parties with access to the transmission system on the same or comparable basis. This section first explains why the ERAS proposal is not unduly discriminatory and then addresses how ERAS meets FERC's open access requirements.

1. ERAS is Not Unduly Discriminatory

There is no restriction on the type or sponsor of projects that can apply to the ERAS process, which makes the application process non-discriminatory. MISO has also created carve outs to the total project cap for applicants that are uniquely situated like Independent Power Producers and developers serving retail choice states. These carve outs will allow these groups of applicants to participate on equal footing with other applicants proposing ERAS projects and must meet the same eligibility requirements to participate in ERAS. MISO added the carve out for IPPs to address concerns that LSEs had an advantage over other entities when submitting projects to

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178 *Id.*

179 *Id.*

180 Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,647. *See also Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC Stats. & Regs. ¶ 31,146 (2003), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), order on reh'g, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007), cert. denied, 552 U.S. 1230 (2008).

ERAS. The carve out for the retail states also enables developers in those areas to participate in ERAS and set aside a portion of the projects to ensure they are able to participate.

Initially, MISO proposed only allowing LSEs, and those contracting with LSEs, to apply for ERAS. After receiving stakeholder feedback on this point while preparing its original ERAS filing, MISO expanded ERAS to allow any applicant to apply to ERAS as long as the applicant had an executed agreement for a specific load need. Under the revised ERAS process, an Independent Power Producer ("IPP"), LSE, or developer may apply to ERAS.[181] MISO's proposal to enable IPPs with an LSE offtake agreement to apply for ERAS addresses the unduly discriminatory concerns identified by the stakeholders and the 10 project carve out enables further participation for IPPs. Some stakeholders have protested that this is still favoring LSEs over other kinds of applicants and thus assert that ERAS is unduly discriminating against non-LSE participants. MISO disagrees. MISO has expanded the applicant pool to include developers that have contracted offtake agreements with a LSE to propose ERAS projects and added project cap carve outs to enable further participation by those IPPs that prefer to contract with the load source directly rather than the LSE. ERAS projects submitted by IPPs that have contracts with the LSE will not count towards the ten project cap. Thus, the ten project carve out exists to create a space designated specifically for IPPs, thus addressing concerns that LSEs may exhaust the ERAS cap before IPPs can submit their projects. This approach balances enabling broader participation with the need to ensure that ERAS does not become a general purpose alternative to the DPP or grow beyond a limited number of projects. Any Interconnection Customer that has a project that they believe is the most cost effective, ready, or best positioned resource to respond to an urgent resource adequacy need is encouraged to apply to participate in ERAS.

Under the revised ERAS proposal, developers will have comparable access to the ERAS process and may also execute commercial arrangements with load. Any other differences for project applicants are neither created nor exacerbated by MISO's Tariff.[182] The purpose of ERAS is to encourage the submission of projects that have been identified as responsive to a need and can be completed rapidly. Although MISO has previously stated that requiring executed agreements does not necessarily prove project readiness,[183] the executed agreement requirement serves a different purpose and provides additional value in the context of this filing. Specifically, requiring executed agreements for ERAS effectively ties the project to the claimed resource adequacy and/or reliability need. The process of securing the necessary agreements and acknowledgment by the RERRA may be competitive. The ERAS process simply moves that competition and development of commercial certainty to before the Interconnection Request is submitted, rather than while it is in queue. MISO has actively worked to reduce the risk of

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[181] Witmeier Testimony at 39:18-23, 1-7.

[182] ERAS offers a level playing field and contemplates that IPPs may be the entities that secure the agreement and RERRA notice for a given need.

[183] MISO Initial NOPR Comments, Docket No. RM22-14-000 (October 13, 2022).

speculative projects participating in ERAS and requiring executed agreements is one way to ensure that.

In addition to expanding the different kinds of applicants that can participate in ERAS, MISO is also allowing existing projects in the Generator Interconnection Queue to transfer to ERAS.[184] In the original ERAS filing, several stakeholders argued that ERAS would result in the unequal treatment of participants who have dutifully followed the traditional interconnection process. But MISO is allowing any existing projects to transfer to ERAS if the project is not past Decision Point II ("DP2"). MISO is prohibiting transfers after DP2 to protect the remaining projects in the queue by preventing any unplanned re-studies that could result from any late-stage transfers.[185] Also, MISO is requiring that existing projects that do transfer to ERAS pay all relevant withdrawal penalties in addition to making the non-refundable $100,000 D1 payment to participate in ERAS.[186] Due to these high financial stakes and the strict eligibility requirements for ERAS, MISO is not anticipating many transfers from the DPP process. Some stakeholders wanted greater transferability from the DPP to ERAS, MISO's proposal however reflects the compromise of protecting the existing queue while providing projects with the opportunity to transfer from the DPP to ERAS.

In addition to the different eligibility requirements between ERAS and the DPP process, MISO plans to coordinate the ERAS, EPR, and DPP studies to maximize efficiency and reduce any impact on each other.[187] MISO expects protestors to claim that the ERAS process will negatively impact existing projects that are currently included in the Generator Interconnection Queue. At numerous stakeholder meetings during the original ERAS filing, MISO stressed that this was not the case due to the way in which the studies are completed. The base case for MTEP, EPR, and ERAS projects is updated with all GIAs approved to date. Approved MTEP projects can be utilized for constraint mitigation in DPP, EPR, and ERAS projects studies. Additionally, Network Upgrades that are identified in ongoing MTEP studies that mitigate congestion in DPP and ERAS studies will remove the need for DPP and ERAS network upgrades once the MTEP project is approved.[188] Finally, ERAS projects will not harm projects currently studied in the DPP process by taking existing transmission capacity headroom from active projects ERAS and DPP use the same MTEP base case as a starting point and any headroom used by ERAS projects is not

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[184] Witmeier Testimony at 15:5-17.

[185] These projects are the ones that would receive the least benefit from ERAS given their degree of advancement through the DPP.

[186] Witmeier Testimony at 15:21-23, 16:1-4.

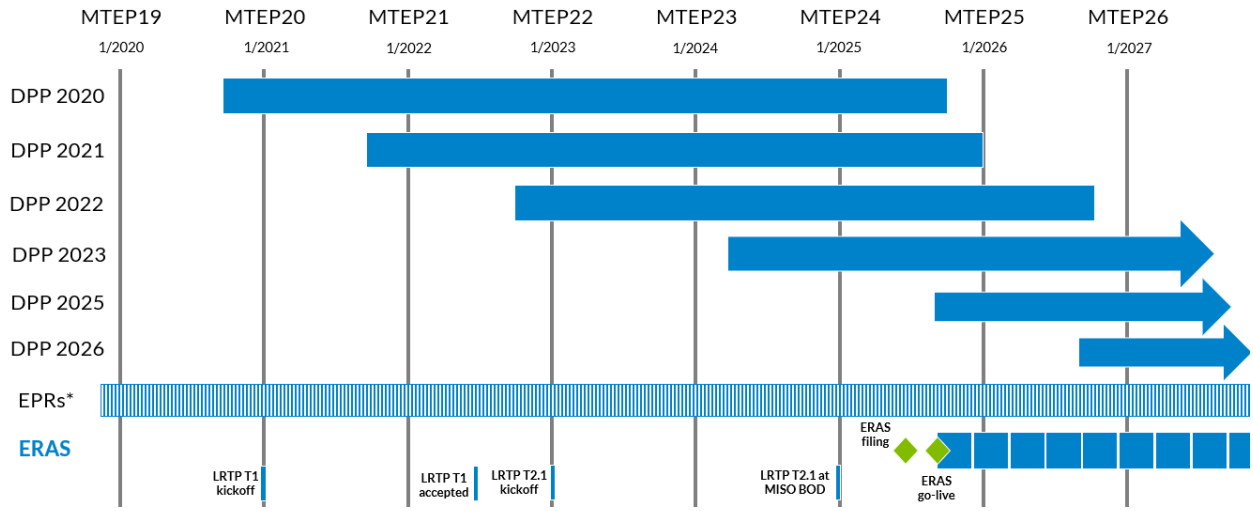
[187] The DPP is primarily described in section 7 of the GIP. See Tariff, Attach. X, GIP Section 7.

[188] *See* MISO BPM 15, Section 6.1.1.1.

deducted from the DPP model.[189] The output of the DPP and ERAS models are then reconciled in the next MTEP. This is consistent with how MISO reconciles currently effective parallel processes through the next MTEP base case. Thus, while it may be possible for over-allocation of capacity headroom to occur, this would not impact DPP projects and would be addressed through MTEP. Thus, ERAS projects will not have early access to newly available headroom related to Tranche 2.1 and will not disadvantage projects from 2025 queue cycle.

The chart below demonstrates the ongoing queue study cycles and the projects in those cycles are still using the transmission capacity that was available in the system at the time that model study started. If MISO approves an ERAS project that will utilize the transmission capacity in MTEP 24 and the DPP 23 is using MTEP 23, ERAS will not take away transmission capacity from any project in the 2023 queue cycle. Ongoing queue cycles interact with each other, but do not take transmission capacity or headroom from each other. Thus, ERAS projects will not take away transmission capacity for ongoing DPP cycles as the base case is not updated. Any overallocation that may occur will be identified and mitigated in the next MTEP cycle.

Figure 4: ERAS Will Integrate With Existing Study Processes[190]



ERAS provides all interconnection customers with a comparable opportunity to submit an interconnection request and compete to be studied under MISO's ERAS interconnection procedures. ERAS treats participants equally as long as they meet the eligibility criteria. All

189 Witmeier Testimony at 17:9-19.

190 *Expedited Resource Adequacy Study (ERAS) Workshop* at 10, (December 6, 2024), https://cdn.misoenergy.org/20241206%20Expedited%20Resource%20Adequacy%20Study%20(ERAS)%20Workshop665747.pdf.

ERAS applicants will be subject to the same rules and requirements on a comparable basis, regardless of fuel type, technology, or any other factors.

2. ERAS is Consistent with Open Access

MISO's interconnection procedures are part of an open access transmission tariff and thus MISO must offer access to the generator interconnection process on the same or comparable basis. Unlike some stakeholder assertions, ERAS is not providing priority access to its generator interconnection process for an exempted class of interconnection requests. The ERAS process is open, competitive, technology/fuel agnostic, and does not involve MISO favoring or selecting certain projects over others. This includes existing projects in the queue as MISO is not harming Interconnection Customers in the generator interconnection queue by using available headroom on the transmission system.

Once a project has met the strict eligibility requirements for ERAS, including the RERRA verification, it is allowed to participate in the ERAS process. Due to the jurisdictional split between the FERC and the states over resource adequacy and reliability, MISO's role is not to be in the middle of resource decision-making processes of the states or RERRAs.[191] Unlike PJM's Resource Reliability Initiative ("RRI") which clearly prioritizes projects on the ELCC Class Ratings, MISO is not going rank ERAS projects. The ERAS process does not unduly discriminate against or in favor of any type of resource or pre-existing project, which is unique from the PJM and CAISO's proposals that favor certain projects by giving higher weights to resources that are more reliable and consistent.[192] PJM's RRI process is aimed at enabling "a very limited injection of 50 projects that score high in measures PJM has identified as contributing to addressing reliability needs."[193] PJM specifically noted that 60% of its Transition Cycle #2 were intermittent resources but asserted its need for high-reliability value projects to meet its near-term resource adequacy needs.[194] Despite PJM's clear preference for certain kinds of projects that are not intermittent and placing a limit on the total number of projects that can participate, the Commission approved their proposal.[195]

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191 *See* 16 U.S.C. § 824(b)(1).

192 *PJM Interconnection, L.L.C.*, Docket No. ER25-712-000, PJM's Transmittal Letter (filed Dec. 13, 2024) ("PJM's RRI Transmittal Letter"); *California Independent System Operator Corporation*, Docket No. ER24-2671-000, CAISO's Transmittal Letter (filed Aug. 1, 2024).

193 PJM's RRI Transmittal Letter at 3.

194 *Id*.

195 *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084 at P 78 (2025). PJM awards 55 out of a possible 100 points for two attributes: unforced capacity ("UCAP") and effective load carrying capacity ("ELCC") that tend to favor certain, non-intermittent resource classes over others.

While the refined ERAS process is implementing a project cap, MISO will not rank or score submitted projects and is open to any applicant and any fuel source as long as the project meets ERAS eligibility requirements. Open access requirements and the states' jurisdiction over resource adequacy are not mutually exclusive. In the revised ERAS proposal, MISO is still not weighing any class of resources over others but rather is prioritizing projects that can be completed in the near-term to address specific looming resource adequacy shortfalls. MISO is also not sorting winner or loser ERAS applicants based on the specific attributes of each generating facility. Rather it is deferring to state jurisdiction over resource procurement and facilitating the identification of projects that will be completed in a short time period to address resource adequacy and reliability needs. The states can determine the best form of capacity that will meet their needs through the ERAS process. The ERAS process will also mitigate many of the identified co-location concerns heard in the industry as states will have the ability to quickly address large spot loads.[196]

In the original ERAS filing, some stakeholders asserted that ERAS violates open access by preferring certain LSE/RERRA-sponsored projects or that ERAS treats participants unequally by granting undue advantages to projects owned by LSEs. Many of the refinements made to the original ERAS filing address those complaints and aim to equalize the playing field between applicants. MISO's proposed Tariff language is clear that *any* Interconnection Customer may submit an ERAS project if it meets the requirement of supplying an executed agreement.[197] A non-LSE related Interconnection Customer could submit an agreement with a particular load that their generation will serve.[198] The RERRA will continue to have its applicable regulatory oversight over the LSE and still must verify the new, incremental load addition claimed by the Interconnection Customer is valid and not otherwise included in a resource plan or other process under the RERRA's purview or the Generating Facility will address a resource adequacy deficiency before the project can participate in ERAS.

Thus, the ERAS process treats all applicants on a comparable, not unduly discriminatory, basis that is consistent with FERC's open access requirements, subject to the ERAS eligibility requirements, which are applied uniformly across all applicants.

D. Substantial Evidence Supports the Need for ERAS

Substantial evidence supports MISO's need for ERAS. MISO has created ERAS to work in parallel with the DPP process to provide a process for non-speculative, shovel ready projects to be completed in 3-5 years. The ERAS process incorporates the states' primacy on resource adequacy while providing a pathway for those projects to be completed on an accelerated basis.

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196 *See* Co-Location Order, 190 FERC ¶ 61,115 (2025).

197 *See* Tab A Redlines, Section 3.9.1.

198 *See id.*

MISO's refined ERAS proposal addresses a real need that has been identified in numerous load forecasting reports, by the states, and in MISO's own experience as an independent system operator.[199] MISO's experience with a quickly changing industry and load growth is being witnessed across the country and by many other entities in the industry that have discussed similar experiences at technical conferences hosted by FERC including the recent conference on co-location.[200] Comments made during FERC's technical conference on resource adequacy recognized that there is a reliability crisis and that generators need to come online in the very near term to address the looming resource adequacy needs.[201] MISO recognizes these concerns and is working expeditiously to make changes to address those needs in the near-term. The supporting evidence demonstrates that the benefits of the current queue improvement mechanisms will take longer than is necessary to address the near-term resource adequacy needs.[202] The GIP improvement mechanism will improve the quality of the projects entering the queue, the Cap mechanism will address the quantity of projects entering the queue, and ERAS will supply the states with a mechanism to address resource adequacy and reliability needs in the next few years. The proposed ERAS revisions will benefit Interconnection Customers and other interconnection process participants by supplying a way for commercially ready, necessary projects to obtain a GIA quickly to address resource adequacy and reliability issues within the MISO footprint.

The original ERAS process was extensively reviewed and discussed in the stakeholder process and MISO adopted many stakeholder suggestions to ensure the process achieves what it aims to do.[203] The refined-ERAS procedures will ensure that Interconnection Customers applying to participate have projects that are ready to be completed.[204] MISO needs an effective tool to address resource adequacy and reliability needs now, which is why it worked expeditiously to refine its previous ERAS process and is now proposing an updated process that can be executed in a few months. By implementing the strict eligibility requirements, ERAS will increase certainty for Interconnection Customers by ensuring that all ERAS projects are "shovel ready" and are required to pay for any associated Network Upgrades even if they end up ultimately dropping out

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199 *See supra* notes 51-87; *see also*, Tab C, Direct Testimony of Andrew Witmeier.

200 *See supra* Section II.B.

201 *See supra* note 80.

202 2024 Cap Filing at 17 ("Although MISO's recent queue reforms contained many important measures to enhance the current queue process, these measures are expected to work over a period of time and may not allow MISO to immediately address the identified queue issues for the 2023 DPP cycle and reduce study cycle volume to a level that supports studies using realistic assumptions.").

203 *See supra* Section II.C.

204 *See supra* Section III.B.

of the process.[205] ERAS was carefully crafted to ensure that existing projects in the Generator Interconnection Queue will not be affected by the ERAS process, nor will those projects lose out on existing transmission capacity this is especially true now that MISO has capped the ERAS process to 68 projects total spread out over multiple cycles.[206] The existing queue will remain a priority for MISO. MISO does not view ERAS as infringing upon or negatively affecting the existing queue, but rather as an additional tool for states to utilize if eligible.

Establishing a separate process for projects addressing resource adequacy and/or reliability needs is not an unfamiliar concept at FERC. As it noted in the original ERAS Order, the Commission previously accepted similar proposals from CAISO and PJM.[207] MISO recognizes that the other RTOs utilized some form of a scoring matrix for proposed projects and that ERAS does not involve a similar methodology. Due to the states' responsibility for resource adequacy within their borders, MISO did not want to be considered the entity picking and choosing projects between the states. MISO also cannot require the states or RERRAs to participate in a specific way or impose a specific selection process for ERAS projects. Instead, it implemented a project cap, a cycle cap, a strengthened RERRA verification, more detailed application requirements, and strict eligibility requirements to ensure that only truly commercially viable projects will apply to participate in ERAS. MISO is striving to balance the unique differences found in its footprints with some of the characteristics found in other RTO/ISO's proposals.

Due to the very near-term, unexpected load growth that the MISO footprint is experiencing, MISO is proposing a refined process to review and finalize projects that can address these resource adequacy and/or reliability needs. ERAS strikes the right balance between significant competing interests and MISO providing the process to allow generation to come online to address short-term, claimed needs. The Generator Interconnection Queue will remain MISO's priority and focus as ERAS is a unique answer to a temporary and unanticipated problem and is capped both in number of projects and in length of time. Recognizing all the other changes MISO is making to the Generator Interconnection process, MISO fully expects that it will be reduced to one year by the time the ERAS process is designed to sunset. Complex problems commonly require creative solutions and ERAS is MISO's creative solution to the rapid evolution of the energy industry in our footprint.

MISO's refined ERAS proposal, described herein, is just and reasonable. ERAS is balanced in addressing the complex needs identified by numerous parties and is narrowly tailored to the identified resource adequacy and reliability needs. Addressing the looming resource adequacy needs in the MISO footprint requires that MISO and the states work together to provide solutions to the problem. Again, MISO views the ERAS process as simply a tool that states *may*

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[205] *See supra* Section III.B.2.

[206] *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084, at P 1 (2025) (RRI Order); *Cal. Indep. Sys. Operator Corp.*, 180 FERC ¶ 61,143.

[207] ERAS Order at P 202.

utilize to address their resource adequacy and/or reliability needs, even the retail choice states. But it also provides a process to ensure that proposed projects are shovel ready and are completed in a short time frame to address the looming resource adequacy and/or reliability needs. Finally, MISO is committed to working with stakeholders to address more generalized queue and industry challenges and ERAS will not change that.

IV. DESCRIPTION OF PROPOSED TARIFF REVISIONS[208]

The proposed Tariff revisions implement the ERAS process and are necessary to distinguish the key differences in how the ERAS process will operate in comparison to MISO's generator interconnection queue. Because the ERAS process is not a queue and is temporary in nature, it is important to clearly identify the differences for clarity and certainty. The instant filing includes ERAS-related revisions in Attachment X (Generator Interconnection Procedures), Attachment X, Appendix 1 (Interconnection Request), and Attachment X, Appendix 6 (Generator Interconnection Agreement).

A. Attachment X, Generator Interconnection Procedures

1. GIP Section 1

Section 1 contains definitions that are used throughout the GIP and its supporting attachments. The proposed new definitions are necessary to implement the ERAS process and to provide clarity and consistency throughout the GIP. In addition to new definitions related to ERAS processes, MISO proposes to revise the definition of "Commitment Projection," "Potential MW Total," and "JTIQ Screening Group, to incorporate MISO ERAS and SPP ERAS into the JTIQ Portfolio and reflect the capacity they will use.[209] "Interconnection Request" was edited to include a request for new generation capacity to be studied under ERAS. This change is necessary to properly document that ERAS projects will be studied separately from MISO's generator interconnection queue and will require a separate election in Appendix 1 to the GIP ("Interconnection Request for a Generating Facility") to be studied as an ERAS project. MISO added additional proposed revisions to include ERAS projects in JTIQ-related definitions to provide clarity that ERAS projects will be considered for JTIQ. MISO also added the definitions

[208] The proposed revisions for each proposal are presented together and in logical order for the purpose of discussion, not in order of importance.

[209] These updates reference both MISO's ERAS and SPP's ERAS projects given that SPP has filed its ERAS process in Commission Docket No. ER25-2296 and both MISO and SPP have filed revisions to update their JOA to reflect these processes in Commission Docket Nos. ER25-2297 and ER25-2298. The revised definitions proposed in this filing align with those filed in Commission Docket Nos. ER25-2297 and ER25-2298. In the event that the Commission accepts MISO' ERAS process but not SPP's, MISO would update the ERAS references in these definitions accordingly.

of Expedited Resource Addition Study (ERAS), Expedited Resource Addition Study Quarterly Study Period, Expedited Generator Interconnection Agreement (EGIA), Local Resource Zone (LRZ), and Relevant Electric Retail Regulatory Authority (RERRA), the latter two of which are defined in Module A.[210]

2. GIP Section 2.1

MISO proposes to add a subsection i to GIP Section 2.1 that governs the application of interconnection procedures.

> i. An Interconnection Request for a new Generating Facility to be studied through the Expedited Resource Addition Study process shall be evaluated pursuant to Section 3.9.2.

This subsection explains that a request for ERAS should be evaluated according to the procedure in GIP Section 3.9.2, which is a new Section MISO proposes to add for the implementation of the ERAS process. This addition is necessary to distinguish the process for evaluating requests for ERAS from other projects entering MISO's generator interconnection queue.

3. GIP Section 3.3.1

MISO proposes to revise Section 3.3.1, which encompasses the procedures for submitting an Interconnection Request. The revisions include clarifying language surrounding the timeline for submitting ERAS Interconnection Requests, where applications will be accepted while the ERAS process is in place, and where the application timeline will be posted to the MISO website. MISO also proposes to increase the Non-Refundable Deposit 1 (D1) to $100,000 for ERAS projects and to require an entry milestone (M2) of $24,000 per Megawatt for new Interconnection Service requested to ensure that ERAS projects are "shovel ready" and to prevent speculative projects from submitting to ERAS. MISO's DPP process contains three phases where three milestone payments are required. The PGIA process requires $8000 per Megawatt for each phase provided upfront, so to facilitate a similar, "one phase" ERAS study, MISO proposes to implement an equivalent milestone payment of $24,000 per Megawatt.

MISO also proposes revising Section 3.3.1 to require an ERAS Interconnection Request to identify the claimed resource adequacy and/or reliability need(s). The revisions include requiring the Interconnection Request to provide information including the location of any load as well as the MW amount of the proposed ERAS project. The revisions also require the ERAS project be located within the same Local Resource Zone, unless the project applicant can demonstrate that the use of a Generating Facility not in the same LRZ was included in a resource filing or other

[210] MISO Tariff, Module A.

submission made to the RERRA. Finally, the revisions limit the amount of Interconnection Service requested by the ERAS project to no more than 150% of the identified MW need. These changes were made to tighten the connection between the verified resource adequacy and/or reliability need with the relevant RERRA.

…

> An Interconnection Request for a Generating Facility requesting processing through the Expedited Resource Addition Study shall identify the claimed resource adequacy and/or reliability need(s) for which it is being submitted. This should include the location (i.e. the county and state, the electrical bus location(s), and the Local Resource Zone) of any load to be served via the off take agreement as well as the peak demand for electricity expected over any one hour period in MWs—the amount of Interconnection Service requested must not exceed 150 percent of the identified MW need. The Generating Facility and the associated resource adequacy and/or reliability need(s) must be within the same Local Resource Zone, unless the resource adequacy and/or reliability need is included in a resource filing made to the RERRA that is providing the verification required in Section 3.9.1.
> …

To further demonstrate that a project is "shovel ready," all documentation, milestone payments, deposits and any necessary data is required at the time of application. These up-front requirements will allow MISO to complete the study process within its estimated 90-day timeframe. Additionally, at the time of application, Interconnection Customers must identify the resource adequacy and/or reliability need for which the project is being submitted. MISO also proposes to require that ERAS projects have a Commercial Operation Date within three calendar years from the submission date of the Interconnection Request. All ERAS projects are eligible to use the grace period of up to three years as documented in GIA Article 2.3.1. MISO's accepted queue reform filing[211] and proposed Order No. 2023 compliance[212] will help MISO facilitate the reduction of the DPP cycle to the approximate one year timeline by 2028, and ERAS projects will help address documented load growth need prior to reducing the DPP cycle timeline.[213]

4. GIP Section 3.4

MISO proposes to add clarifying language stating, "except for projects submitted through the ERAS process as noted in Section 3.9," to this section governing OASIS posting requirements to clarify that MISO intends to publish the list of projects submitted for ERAS on its public

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211 *See* Queue Reform Filing.

212 *Midcontinent Independent System Operator, Inc.*, Compliance Filing for Order Nos. 2023 and 2023-A, Docket No. ER24-2046-000 (May 16, 2024) ("Order 2023 Compliance Filing").

213 *See Midcontinent Indep. Sys. Operator, Inc.*, 178 FERC ¶ 61,141 (2021) ("Timeline Reduction Filing").

website. Although MISO does not publish identifying information for projects submitted to the DPP interconnection queue, MISO believes that ERAS projects require additional transparency for interested parties in the MISO region.

5. GIP Section 3.5

MISO proposes to revise GIP Section 3.5 to add a reference to newly created GIP Section 3.5.2, explained further below, and to clarify that coordination procedures for affected systems apply except as provided by "Sections 3.5.1 and 3.5.2" of the GIP. MISO proposes to revise GIP Section 3.5.1.1 subsection (1) to clarify that ERAS projects shall be included in a JTIQ Screening Group, along with projects in the generator interconnection queue. As discussed in prior stakeholder meetings, MISO intends to consider ERAS projects for JTIQ. This revision is necessary to ensure that ERAS projects are properly included in JTIQ Screening Groups along with projects from MISO's DPP interconnection queue.

MISO proposes to add Section 3.5.2 to incorporate the application of the Affected Systems Coordination Procedures to Interconnection Requests included in ERAS. The revisions will enable MISO to promptly provide any affected systems analysis received from the affected system to the ERAS Interconnection Customer. The revisions also explain that if the affected systems studies and cost information are not available at the time the EGIA is tendered, the EGIA will include an obligation to execute any agreements for the studies. The proposed revisions state that ERAS Interconnection Requests will be submitted to the applicable system study individually and on serial basis. Finally, the revisions require the queue priority date for ERAS projects as the date MISO starts the ERAS System Impact Study unless the controlling agreement between MISO and the affected system provides an alternate queue priority date for ERAS projects. These revisions are needed given that ERAS projects will be studied serially and that existing affected systems coordination rules geared towards multi-phase group studies cannot apply without adjustment. The proposed rule set ensures timely affected systems review using a process appropriate for the accelerated ERAS study process while still allowing needed flexibility for MISO and individual seems partners to make adjustments needed for the specific seam.

6. GIP Sections 3.9 and 3.9.1

MISO proposes to add new GIP Section 3.9 to encompass the necessary processes and implementation details for ERAS Interconnection Requests. Proposed Section 3.9.1 explains the requirements for submitting a project to ERAS, which include the requirements listed in GIP Section 3.3.1, as well as a written verification from a RERRA that states either (1) the new, incremental load addition claimed by the Interconnection Customer is valid and not already included in a plan or other procedure under the RERRA's purview, or (2) addresses a resource adequacy deficiency as determined by the RERRA, state, LSE, or Interconnection Customer and supported by evidence from a state energy forecast, state proceeding, resource plan, response to a request for proposals, or other state or RERRA process.

The revisions to Section 3.9.1.1(iii) also enable retail choice states (Illinois and Michigan) to participate in ERAS. The revisions allow an Interconnection Customer to participate if the new facility addresses a resource adequacy deficiency and will serve retail choice load. If the Interconnection Customer is serving retail choice load, it will not be required to include a verification from a RERRA in accordance with state policy, but MISO will notify the respective RERRA about the request and give that RERRA an opportunity to object to the ERAS application. The Interconnection Customer will also provide evidence of determination of need as described in Section 3.9.1.1(ii). MISO is proposing this language to enable retail choice state participation in ERAS and to reflect how RERRAs operate differently in the retail choice states.

The proposed RERRA language also clarifies that the RERRA verification is not intended to provide evidence of need or suitability of an ERAS project in a separate state or RERRA regulatory process. It is simply a requirement of the MISO ERAS application process that will allow projects to have completed study and be available without prejudicing the ability of the RERRA to make final permitting or certificating decisions according to their laws and regulations.

In the revisions to Section 3.9.1.2, MISO also proposes to require the Interconnection Customer provide an agreement showing that the project submitted to ERAS is intended to be used to meet a claimed resource adequacy and/or reliability need. The agreement may take several forms, as documented in Section 3.9.1, depending on the type of project and associated parties. This language is intended to limit ERAS projects to those needed to meet a resource adequacy and/or reliability need, while also ensuring that certain project types or submitters are not excluded from participating in ERAS.

As previously explained above, the language developed in Section 3.9.1 regarding the RERRA verification and the Interconnection Customer's requirement to provide an executed agreement showing that the project submitted will be used to meet the claimed resource adequacy and/or reliability need were discussed at length with stakeholders and the MISO states before MISO's original ERAS filing and were adjusted to address the Commission's guidance. These proposed revisions are intended to provide sufficient documentation displaying the need to be included in ERAS while also taking into consideration the varied processes of the states in MISO's footprint and the need for the ERAS process to fit within the different regulatory requirements of the MISO states. Because the majority of MISO states are vertically integrated, it is important to consider the states' involvement in resource adequacy as discussed in this letter.

Finally, MISO proposes to add language stating that no changes shall be made to the Interconnection Request after submission. Because the timeline from submission to an executed EGIA is 90 days, this language is necessary to ensure that ERAS projects are studied expeditiously and can be online as soon as possible to meet the stated resource adequacy and/or reliability need.

7. GIP Section 3.9.2

MISO proposes to add GIP Section 3.9.2 to facilitate the evaluation process of projects seeking to use ERAS.

> The Transmission Provider will evaluate Expedited Resource Addition Study requests in the order in which they are submitted using the time stamp from submission. The Transmission Provider will limit the maximum number of the ERAS Interconnection Requests studied in the ERAS process to no more than 68 projects total until the sunset date noted in Section 3.9.9. The Transmission Provider has carved out a maximum of 8 Interconnection Requests of the total 68 Interconnection Requests that may be submitted in accordance with 3.9.1.1(iii) to serve retail choice load and a maximum of 10 Interconnection Requests of the total 68 Interconnection Requests that may be submitted by Independent Power Producers (IPPs) with agreements with entities other than Load Serving Entities to ERAS until the sunset date noted in Section 3.9.9.
>
> The Transmission Provider will limit the maximum size of each ERAS Quarterly Study Period to no more than 10 Interconnection Requests. If more than 10 Interconnection Requests are submitted for one ERAS Quarterly Study Period, those surpassing the limit will be studied in a subsequent ERAS study cycle in the order in which they were submitted. If an ERAS Interconnection Request is within a similar geographical area or impacts the same constraint as another ERAS Interconnection Request within the same ERAS Quarterly Study Period, as defined in the Generator Interconnection Business Process Manuals, then the later submitted request(s) will be studied in a subsequent ERAS study cycle.

The revised language sets out how MISO plans to implement the ERAS project cap. MISO will limit the maximum number of the ERAS Interconnection Requests studied in the ERAS process to no more than 68 projects total until the ERAS sunset date noted in Section 3.9.9. MISO has determined two separate carve outs from the total 68 projects: (1) a maximum of 8 Interconnection Requests that may be submitted to serve retail choice load, and (2) a maximum of 10 Interconnection Requests that may be submitted by Independent Power Producers ("IPP"). The remaining 50 Interconnection Requests may be utilized by other Interconnection Customers in non-retail states.

The proposed language explains that MISO will also cap the number of projects studied in each ERAS study cycle. MISO will limit the maximize size of each ERAS Quarterly Study Period to no more than 10 Interconnection Requests. MISO will complete a screening process on the first 10 Interconnection Requests received per ERAS cycle to determine whether any of the projects are located in the same geographic area or impacting the same constraint. If two or more projects are located in the same geographic area or impact the same constraint as defined by MISO's Generator Interconnection Business Process Manuals, then the first project received as determined

by submission time will remain in the cycle and the other project(s) will be deferred to the next available ERAS cycle.

Other proposed language explains that projects will be evaluated in the order in which they are submitted. It also provides that a project that does not meet the ERAS requirements will be automatically moved to the generator interconnection queue unless the Interconnection Customer informs MISO that it does not want to be processed through the DPP if it fails to qualify for ERAS. Although the project moving from ERAS will be required to meet all requirements of the generator interconnection queue, the automatic transfer to the interconnection queue will prevent projects from having to resubmit an additional Interconnection Request and will provide a more efficient application process. Proposed language also clarifies that if the project is found to be ineligible for ERAS, the project will lose its Non-Refundable Deposit D1. The risk of losing a large deposit if determined to be ineligible for ERAS will encourage parties to only submit projects that they are certain will meet the strict ERAS requirements.

Proposed Section 3.9.2 also documents the process for projects currently in the generator interconnection queue to transfer to ERAS for evaluation. In the situation where a project in the generator interconnection queue is eligible to participate in ERAS and chooses to transfer to the ERAS process, proposed language also clarifies that the project will forfeit its Non-Refundable Deposit D1 and will be subject to withdrawal penalties per Sections 7.6.2.1.1 and 7.8. This proposed addition is necessary to ensure that projects dropping out of the generator interconnection queue do not harm remaining projects in their respective cycles. Similarly, proposed language in Section 3.9.2 limits projects from transferring from the generator interconnection queue to ERAS to only those that have not reached Decision Point II. This language is required to ensure that projects remaining in the generator interconnection queue are not harmed by restudies that occur after projects drop out after Decision Point II. If a project withdraws after Decision Point II, the proposed ERAS revisions will allow it to submit to ERAS after a period of one year from the withdrawal date. This language is necessary to prevent late stage withdrawals from the generator interconnection queue that might harm other projects in the interconnection queue cycle.

8. GIP Section 3.9.3

MISO proposes to add a new GIP Section 3.9.3 to describe the studies that will take place for ERAS projects, which mirror those performed for Interconnection Requests in the DPP seeking NRIS, as described noted in GIP Sections 3.2.1.2 and 3.2.2.2. MISO intends to perform all ERAS studies within 60 Days after kickoff to help ERAS projects quickly obtain an executed EGIA. ERAS projects will be evaluated on a rolling basis during each Quarterly Study Period The studies will be performed serially, based on submission date. serial studies are ideal for ERAS projects since there will be a considerably smaller number of proposed projects spread over a larger geographic area, thus they will not be grouped into clusters which would require late stage restudies.

Proposed language also explains that any Affected System Study results, if available, will be included at the time of the final ERAS study. If the Affected System Study results are unavailable at the time of the final study, those results will be provided separately when received from the applicable Affected System.

9. GIP Section 3.9.4

MISO proposes to add the following Section 3.9.4, which is titled Notice to Proceed to EGIA.

> Interconnection Customer requesting to be included in ERAS shall inform Transmission Provider of its election to proceed within five (5) Calendar Days after receiving the draft results of the Expedited Resource Additions Study. Interconnection Customer that fails to provide an election to proceed within five (5) Calendar Days will result in withdrawal of the Interconnection Request pursuant to Section 3.6 of this GIP. EGIA execution shall occur no later than 30 Calendar Days after receiving Interconnection Customer's election to proceed.

This language is necessary to distinguish between the shorter timeline for ERAS and the general timeline for providing a notice to proceed for a DPP interconnection project. The shortened five Calendar Day timeline is necessary to allow Customers to execute their EGIA within 90 days from kickoff of the Quarterly Study Period.

10. GIP Section 3.9.5

Proposed GIP Section 3.9.5 governs the timeline and necessary requirements regarding tender of the draft pro forma EGIA and JTIQ applicability, and also points to Sections 11.1 through 11.4 of the GIP governing procedures such as MISO's tender of the draft EGIA, negotiations, and execution of the EGIA. This proposed Section provides a five Business Day timeline for MISO to tender a draft *pro forma* EGIA after receiving notification of the Customer's intent to proceed to EGIA.

Due to the varied nature of MISO's and SPP's processes related to JTIQ Service Agreements, proposed revisions provide a path forward for JTIQ eligible ERAS projects if SPP's JTIQ Service Agreement has not been provided to the Interconnection Customer prior to the tender of the draft EGIA. If the SPP JTIQ Service Agreement has not been received at the time of MISO's tender of the EGIA, proposed language requires JTIQ eligible ERAS projects to include a milestone in GIA Appendix B requiring the parties to execute or request the unexecuted filing of an SPP JTIQ Service Agreement within 15 Calendar Days after such agreement has been tendered to the Interconnection Customer. Proposed language also states that ERAS Interconnection Requests included in a JTIQ Participation Group shall adhere to all JTIQ procedures and execute JTIQ Service Agreements as applicable.

11. GIP Sections 3.9.6, 3.9.6.1, 3.9.6.2, and 3.9.6.3

Proposed GIP Section 3.9.6 and its subparts document the process for obtaining refunds of study deposits and milestone payments in the ERAS process.

Proposed GIP Section 3.9.6.1 governs applicable refunds of the Study Deposit (D2). As with generator interconnection requests, ERAS D2 study deposit amounts are based on Megawatt amount of new interconnection service of the ERAS project as stated in GIP Section 3.3.1. The Interconnection Customer will be charged the actual amount of the Expedited Resource Addition Study and will be required to pay any additional costs or will be refunded any overages as applicable.

Proposed GIP Section 3.9.6.2 details the process for receiving a refund of the ERAS milestone payment M2. ERAS projects are eligible to receive a 100% refund of M2 upon withdrawal prior to execution of the EGIA. If an ERAS project withdraws after execution of the EGIA, the project is only eligible to receive a refund of any remaining M2 milestone after meeting the Initial Milestone Payment and/or Network Upgrade costs memorialized in the EGIA.

Should a project withdraw after execution of the EGIA, proposed Section 3.9.6.3 documents the process for providing the initial payment to the Transmission Owner, which will occur within forty-five Calendar Days from the effective date of the EGIA. If the M2 provided by the Interconnection Customer exceeds the initial payment amount, MISO will provide a refund of any remaining M2 within 45 Calendar Days of the effective date of the EGIA. If the Interconnection Customer's M2 is less than the initial payment, the proposed language of 3.9.6.3 requires the Interconnection Customer to provide the remaining portion of the initial payment to the Transmission Owner.

Proposed language in GIP Section 3.9.6.3 also clarifies that Interconnection Customers that withdraw after execution of the EGIA by all parties, or upon the filing of an unexecuted EGIA, will be liable for any Network Upgrade costs documented in the EGIA, including Network Upgrades arising from the Affected System Study process. This language is necessary to ensure that only viable projects that can meet the requirements of ERAS apply to participate in the ERAS process. In the event that a viable project must withdraw after execution of the EGIA, this language is necessary to ensure that no remaining projects are harmed by the withdrawal and Network Upgrades are built as planned.

12. GIP Section 3.9.7

MISO proposes to add new GIP Section 3.9.7, which is titled Transfer of Ownership of Expedited Resource Addition Study Request.

> An Interconnection Customer participating in the Expedited Resource Addition Study may transfer its Interconnection Request to another entity only after execution of the EGIA or filing the EGIA unexecuted. The new entity must maintain the eligibility requirements per Sections 3.3.1 and 3.9.1.

This language is necessary to prevent transfers prior to EGIA execution that might slow down the timeline for studying an ERAS project and ultimately delay the ability for MISO to move ERAS projects to EGIA execution within 90 days from kickoff. Prohibiting any changes to an ERAS project prior to EGIA execution will allow MISO to maintain its proposed ERAS timeline while allowing projects the flexibility to transfer the project to a new owner after EGIA execution. Similar to requirements for the generator interconnection queue, any transferee must maintain the applicable requirements to remain a valid ERAS project after EGIA execution.

13. GIP Section 3.9.8

MISO proposes to add new GIP Section 3.9.8, titled Modifications of Expedited Resource Addition Study Request.

> After entering the Expedited Resource Addition Study as defined in Section 3.9.3, no changes to the In-Service Date or Commercial Operation Date of the Generating Facility is permitted via Section 4.4.4. An ERAS Interconnection Request that is deferred to the next available ERAS Quarterly Study Period will be allowed to extend its In-Service Date or Commercial Operation Date to be no more than three calendar years from the kickoff of the ERAS Quarterly Study Period in which its application is studied. At the completion of the Expedited Resource Addition Study, the Commercial Operation Date and In-Service Date shall be set forth in the EGIA.

This language is necessary to ensure that ERAS projects are able to meet the resource adequacy and/or reliability need within the timeframe allotted by ERAS. The proposed ERAS COD requirements set forth in GIP Section 3.3.1 are specifically for generation needed to meet load intended to come online while ERAS is in place. Disallowing changes to the In-Service Date or COD after entering ERAS creates the certainty necessary to ensure that these projects will meet the need identified in the Interconnection Request and will prevent projects with uncertain timelines from entering ERAS.

14. GIP Section 3.9.9

MISO proposes to add new GIP Section 3.9.9, titled Sunset of Expedited Resource Addition Study Process.

> Following the effective date of the Tariff revisions accepted in Commission Docket No. ER25-____, the Transmission Provider will terminate the ERAS process at the earlier of the completion of sixty-eight ERAS Interconnection Request studies or August 31, 2027. In the event the Transmission Provider determines the sunset date should be extended, the Transmission Provider shall submit an additional filing to the Commission pursuant to Section 205 of the Federal Power Act seeking such later sunset date. Upon termination of ERAS, the Transmission Provider will no longer accept new ERAS Interconnection Requests. Any ERAS Interconnection Requests accepted but cannot be studied due to the sunset of the ERAS process will automatically move to the standard Definitive Planning Phase queue unless the customer chooses to withdraw. If deemed ineligible for the ERAS process, the project will forfeit its Non-Refundable Deposit D1.

This language is necessary to provide certainty that ERAS is a temporary process and that MISO intends to use ERAS for a limited period of time to meet generation shortages due to reasons explained above. ERAS will automatically sunset at the earlier of the completion of 68 ERAS Interconnection Request studies or August 31, 2027. The ERAS process is intended to fill the gap created by current queue backlogs and projects with GIAs yet to come online by providing expedited treatment for needed projects to be studied and come online quickly. As previously stated, the ERAS process is intended to be temporary and to fulfill the purpose of meeting generation needs during the short time period prior to the ERAS sunset date. MISO does not intend to request additional time for ERAS, but should MISO determine that additional time is needed to process ERAS projects to fill the aforementioned gap, MISO will submit an additional 205 filing and will justify the need for additional time.

15. GIP Section 5.13

MISO proposes to add new GIP Section 5.13, titled Transition to ERAS Process.

> All requests for the Expedited Resource Addition Study that are submitted to the Transmission Provider after August 6, 2025 will be subject to the revised Tariff requirements accepted in Docket No. ER25-___.

MISO proposes to begin the first ERAS Quarterly Study Period on September 2, 2025, which will be the first Quarterly Study Period after the effective date of these revisions, August 6, 2025.

16. GIP Section 7.2.1

MISO proposes to revise GIP Section 7.2.1, subpart (ii) to add the following language:

> Reasonable evidence of Site Control for one hundred percent (100%) of the mileage of the Generating Facility's Interconnection Facilities for the Expedited Resource Addition Study request must be received at the time the application is submitted. The financial security in lieu of Site Control for the Generating Facility's Interconnection Facilities will not be accepted for an Expedited Resource Addition Study request.

Increased Site Control requirements for the Generating Facility's Interconnection Facilities (in conjunction with the accepted increased Site Control requirements under 7.2.1[214]) will ensure that projects submitted to ERAS are "shovel ready" and able to quickly meet the needs of the load they seek to service. Current interconnection queue Site Control requirements only require 50% Site Control of the Interconnection Customer's Interconnection Facilities at the time of submission, so this increased Site Control requirement will encourage only ready projects to submit to the ERAS process. Similarly, disallowing financial security in lieu of Site Control will prohibit any projects from being eligible for ERAS if it is unable to obtain the proper permits or siting requirements. Both updates to Site Control requirements will ensure that only "shovel ready" projects apply and will allow ERAS projects to quickly move to EGIA execution.

17. GIP Section 7.3.1.4

MISO proposes to add a reference to ERAS projects in Section 7.3.1.4 to clarify that projects from the DPP and ERAS will be notified if included in a JTIQ Screening Group. Although not part of the DPP, ERAS projects may impact a JTIQ Upgrade and should be subject to the same rules as DPP projects with respect to JTIQ. ERAS projects will be eligible for inclusion in the JTIQ Screening Group, Participation Group, and Commitment Groups based on the same criteria

[214] *See* Queue Reform Filing at 10.

that are applied to DPP projects. This revision is necessary to ensure that ERAS projects are included in the JTIQ construct and do not get a free ride.[215]

18. GIP Section 7.3.2.3.1

MISO proposes to add "including ERAS projects not otherwise subject to Transmission Provider's three-phase DPP" in subpart 1, to clarify that ERAS projects that are part of a JTIQ Screening Group will be subject to additional Affected System analysis, as well as analysis required in Section 7.3.2.3 of the GIP. The additional analysis determines the impact of an ERAS project on the SPP system through Expanded Scope Analysis and Supplemental Affected System Analysis as documented in subparts a and b of this section and the inclusion of the aforementioned edits ensures that applicable ERAS projects will be studied similarly to DPP projects in these instances.

19. GIP Section 11.1

MISO proposes to revise Section 11.1 to include the distinction that ERAS projects will not contain restudies and that tender of the draft EGIA will occur after the Interconnection Facilities Study initiated through ERAS. MISO also proposes to revise this Section to clarify that ERAS Interconnection Requests tender of the EGIA will occur on a different timeline than DPP projects, which timeline for tender is memorialized in new GIP Section 3.9.5. These edits are necessary to properly document the shortened timeline for tender of ERAS projects and the differences in timing between ERAS projects with one study and DPP projects with multiple studies.

20. GIP Section 11.2 and 11.2.1

MISO proposes to revise Section 11.2 to clarify that ERAS projects will have a shorter, 5 Business Day timeline to return comments on the draft EGIA. MISO also proposes to revise this Section to clarify that MISO shall tender a revised draft EGIA after 5 Business Days of receiving the comments. For ERAS projects, negotiations of EGIAS shall be no more than 20 Business Days from the notice to proceed in Section 3.9.4. Revisions to 11.2.1 clarify that ERAS projects are unable to postpone the start of the EGIA negotiation period.

These edits are needed to shorten the negotiations timeframe to keep the ERAS process to approximately 90 days from kickoff to EGIA execution. This shortened timeframe will ensure that ERAS projects are able to execute the EGIA quickly and come online within the timeframe allotted to serve the project's identified need.

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[215] MISO notes that it will be necessary to update some language in its Joint Operating Agreement with the Southwest Power Pool, Tariff Rate Schedule 6 ("SPP JOA"), which, for MISO, discussed JTIQ only in terms of DPP projects. This language reflects the fact that ERAS did not exist at the time. MISO has discussed updating the JOA with SPP and plans to make a joint filing to properly references ERAS before the requested effective date for this filing.

21. GIP Section 11.3

MISO proposes to revise Section 11.3 to provide that for ERAS projects the Transmission Provider shall provide the Interconnection Customer and Transmission Owner a final EGIA within 10 Business Days after completion of the negotiation period in accordance with Section 11.2. These revisions also provide that the parties must execute the EGIA or request to file unexecuted within 10 Business Days of tender of the final EGIA, otherwise the project will be deemed to have withdrawn its Interconnection Request. These revisions are required to properly document the shorter timeline for ERAS projects as compared to the timeline for DPP GIA execution as memorialized in this Section.

B. Attachment X, Appendix 6, Generator Interconnection Agreement

a. Article 1 Definitions

MISO proposes to revise Article 1 to include ERAS-related definitions consistent with the GIP, as applicable, and to provide updates to JTIQ-related definitions to clarify that MISO ERAS and SPP ERAS projects will be included in JTIQ, also as provided in the GIP.

b. Article 2.3.3

MISO proposes to revise Article 2.3.3 to state that ERAS projects must provide all security required in Section 2.4 prior to any termination request for an ERAS project becoming effective. This language is necessary to ensure that projects are held liable for any Network Upgrades that would be memorialized in an EGIA or related agreement and to prevent harm to other projects due to the withdrawal.

c. Article 2.4

MISO proposes to revise Article 2.4 to specify that should an ERAS project terminate, it will be liable for any Network Upgrade costs identified in the EGIA or that would be memorialized in an FCA, MPFCA, or JTIQ Service Agreement. If the final costs have not been determined, the Customer must provide security according to the most recent estimate. Additionally, the Transmission Provider will provide any applicable refunds of payments or security within 90 Calendar Days of providing the final invoice of NUs to the Customer. As stated above, the proposed language is necessary to ensure that only "shovel ready" projects submit to ERAS, knowing those projects will assume the risk of paying for any Network Upgrades identified in an EGIA or that would be memorialized in an FCA, MPFCA, or JTIQ Service Agreement. This language will ensure that no other projects are affected by the termination.

d. Appendix B Milestones

MISO proposes to add new milestone 1f to the *pro forma* Generator Interconnection Agreement:

1f.	Enter into any agreement required by an Affected System for the study, construction, or funding of a network upgrade to mitigate impacts (for Interconnection Requests processed through ERAS) pursuant to GIP Section 3.5.2.	Within 15 Calendar Days after tender.

This revision is needed to ensure that ERAS interconnection requests are subject to the same obligations as other Interconnection Requests with respect to network upgrades identified by affected systems. The requirement to execute an agreement with the affected system to mitigate any impacts from the ERAS Interconnection Request within 15 days after agreement tender is included in proposed GIP Section 3.5.2. It is appropriate to reflect this commitment in a GIA milestone given that, due to the accelerated timing of ERASs, an affected system may first be able to tender their form of agreement after the ERAS Interconnection Customer already has executed their GIA. Including milestone 1f in Appendix B ensures that this obligation remains enforceable even after the customer has an effective GIA. This puts ERAS Interconnection Customers on the same footing as DPP Interconnection Customers.

C. Attachment X, Appendix 1, Interconnection Request for a Generating Facility

MISO proposes to revise Attachment X, Appendix 1 to add a check box in Section 2 indicating that the interconnection Request is being submitted as an ERAS project.

MISO also proposes to add subpart s to Section 4, stating that at the time of application to ERAS, the Interconnection Customer must provide information about the resource adequacy and/or reliability need that the ERAS project is intended to address. These proposed revisions are needed to properly memorialize the requirements to be included in ERAS, which includes the Interconnection Customer identifying resource adequacy and/or reliability need the project claims to meet. The ERAS process is intended to facilitate matching generation with load within the next few years, so requiring a specific need will prevent projects from submitting to ERAS simply to circumvent the generator interconnection queue process. This proposed language will ensure that ERAS projects are limited to those that truly identify a claimed resource adequacy and/or reliability need.

V. DOCUMENTS SUBMITTED WITH THIS FILING

In addition to this Transmittal Letter, the documents submitted with this filing are:

Tab A – Redlined Tariff Sheets[216];

Tab B – Clean Tariff Sheets; and

Tab C – Prepared Direct Testimony of Andrew Witmeier

VI. PROPOSED EFFECTIVE DATE, AND REQUEST FOR EXPEDITED ACTION AND SHORTENED COMMENT PERIOD

MISO requests that the proposed Tariff revisions be made effective on August 6, 2025. To give certainty to stakeholders and allow them time to prepare Interconnection Requests in advance of the first ERAS deadline, MISO respectfully requests the Commission issue an order on an expedited basis by July 22, 2025. MISO needs to address the looming resource adequacy and reliability needs identified in this filing as expeditiously as possible and stakeholders will need to know if the process has been accepted sufficiently in advance of the deadline to plan their projects. Thus, MISO can accommodate the ordinary 60 day timeframe for revisions becoming effective and need not seek waiver for a shortened effective date provided that an order is issued within 45 days. The original ERAS proposal was discussed extensively with stakeholders and the main refinements made to that proposal were addressed in the May PAC Meeting and tailored to the Commission's guidance issued on May 16, 2025.

To enable the Commission's consideration of this filing, MISO also requests that the Commission establish a ten (10) day comment period for this filing – June 16, 2025. As noted above, this filing represents a refinement to MISO's original ERAS proposal and all affected parties have had ample notice of that filing and the Commission's guidance responded to in this submission. This effective date will ensure that the proposed changes can be implemented in advance of the September 2, 2025 ERAS Quarterly Study Period start date.

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[216] Language currently pending before the Commission in the following, unrelated docket is highlighted in yellow: Docket No. ER25-2417-000. MISO requests that the Commission treat such highlighted language as subject to the outcome of the pending proceeding. MISO commits to file any revisions to this highlighted language as necessary to comply with any Commission order in the proceeding. MISO has removed language that has a future effective date of June 1, 2029 and is pending under Docket No. ER22-1640-006. In addition, MISO has removed pending language filed in Docket No. ER24-2046-000, and any changes will be based on the outcome of that docket. If needed, MISO commits to make a subsequent filing with the Commission to reflect the most up-to-date version of the then-current Tariff provisions prior to the effective dates of the language in Docket Nos. ER22-1640-006 and ER24-2046-000.

MISO submits that the requirements of Section 35.13 of the Commission's regulations, 18 C.F.R. § 35.13 (2024), that have not been specifically addressed herein are inapplicable to this filing. To the extent that the Commission determines any of these sections to be applicable to this filing, MISO respectfully requests waiver of the requirements of such sections.

VII. COMMUNICATIONS, NOTICE, AND SERVICE

Correspondence and communication with respect to this filing should be sent to the following individuals, which MISO requests to also be included on the official service list:

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*Persons authorized to receive service

MISO notes that it has served a copy of this filing electronically, including attachments, upon all Tariff Customers under the Tariff, MISO Members, Member representatives of Transmission Owners and Non-Transmission Owners, as well as all state commissions within the Region. The filing has been posted electronically on MISO's website at https://www.misoenergy.org/legal/ferc-filings/ for other interested parties in this matter. In addition, MISO has served a copy of this filing electronically on all parties to this agreement.

IX. CONCLUSION

MISO's proposed ERAS reforms are just and reasonable, are not unduly discriminatory or preferential, and thus satisfy the requirements of FPA section 205(a). For all of the foregoing reasons, MISO respectfully requests that the Commission: (1) accept this filing with the August 6, 2025 effective date; (2) issue an order by July 22, 2025, and (3) grant waiver of any Commission regulations that the Commission may deem applicable to this filing.

Respectfully submitted,

/s/ Sarah Nieman

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Attachments