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March 28, 2024

VIA ELECTRONIC FILING

The Honorable Debbie-Anne Resse
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: Midcontinent Independent System Operator, Inc.'s Filing to Reform MISO's Resource Accreditation Requirements Docket No. ER24-____-000

Dear Secretary Reese:

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 implement a direct loss of load ("DLOL") based accreditation methodology. The proposed DLOL-based methodology will be used both for the purpose of accrediting resources participating in MISO's annual Planning Resource Auction ("PRA") as well as calculating the Planning Reserve Margin Requirement ("PRMR") that Load Serving Entities ("LSE") participating in MISO's markets must meet in order to be considered resource adequate for each Season during the applicable Planning Year. MISO requests an effective date of September 1, 2024 for the proposed Tariff revisions. In order to provide stakeholders and regulators sufficient time to evaluate and comment on the instant proposal MISO requests that the Commission establish a comment date of thirty (30)-days from the date of this filing.

As discussed in detail below, Commission action is needed at this time to ensure that market participants have the information necessary to make long-term investment decisions to address the growing risks to reliability in the MISO Region. These risks result from a changing resource mix, extreme weather, increasing demand, and shrinking excess reserve margins. Moreover, recommendations from the North American Electric Reliability Corporation ("NERC")

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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 Regulatory 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 Tariff.

2023 Long-term Reliability Assessment ("LTRA")[2] and MISO's Attributes Roadmap[3] reinforce the need for, and urgency of, the proposed reforms to resource accreditation and calculation of the PRMR. Ultimately, this proposal is another step in the direction of ensuring Planning Resources are available to convert capacity to energy when and where they are most needed, and are consistent with recent resource adequacy related Tariff enhancements already accepted by this Commission.[4]

To accommodate implementation of the indicative reporting requirement included in this proposal in advance of Planning Year ("PY") 2025 / 2026, MISO requests an effective date of September 1, 2024 for the Tariff revisions submitted herewith. Implementation of the two-step marginal accreditation methodology defined herein will begin with PY 2028 / 2029; however, MISO will begin using the methodology September 1, 2024, to produce Resource Class-level indicative results. MISO will publish such indicative results for stakeholder evaluation and use as soon as reasonably possible after September 1, 2024, and in any event prior to the PY 2024 / 2025 PRA. MISO will continue publishing Resource Class level indicative results for PYs 2026 / 2027 and 2027 / 2028 as soon as reasonably possible and prior to each respective PRA. The Resource Class level indicative results produced during the three-year transition period are being provided at the request of stakeholders to provide an opportunity to adjust their business practices, especially long-term resource planning and retirement decisions, as a result of the proposed changes to the calculation of PRMR and resource accreditation. The proposed three-year transition period is reasonable and appropriate to allow stakeholders to adapt to the new methodology before requirements and the accreditation of resources are impacted by the change.

I. EXECUTIVE SUMMARY

MISO is at an inflection point in its portfolio evolution. Sizable segments of dispatchable thermal generation are aging into retirement and being replaced with increasing amounts of highly weather dependent, intermittent wind and solar resources. These retirements, combined with the significant penetration of intermittent resources and increased frequency of extreme weather events, are shifting the nature of system risk and creating challenges to maintaining reliable system operations. Moreover, these events are highlighting the fact that MISO's existing resource accreditation methods are no longer sufficiently robust to capture those risks and send the proper signals to state regulators and Load Serving Entities ("LSE") participating in integrated resource planning processes for the investment and retirement of resources needed to maintain reliability

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2 *See* NERC, 2023 Long-Term Reliability Assessment (December 2023) ("2023 LTRA"), available at: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf.

3 *See* MISO, Attributes Roadmap: A Reliability Imperative Report, available at: https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf.

4 *See, e.g.*, *Midcontinent Indep. System Operator, Inc*., 166 FERC ¶ 61,116 (Feb. 19, 2019) (approving Tariff revisions to more effectively assess the capabilities of LMRs); *Midcontinent Indep. System Operator, Inc.*, 166 FERC ¶ 61,235 (Mar. 29, 2019) (accepting Tariff revisions to enhance the testing requirements for Demand Resources that participate as LMRs); *Midcontinent Indep. System Operator, Inc*., 166 FERC ¶ 61,236 (Mar. 29, 2019) (accepting Tariff revisions to enhance Generator Planned Outage Scheduling); *Midcontinent Indep. Sys. Operator, Inc.*, 180 FERC ¶ 61,141 (Aug. 31, 2022) (approving Tariff changes to implement a seasonal resource adequacy construct).

into the future. Ultimately, the changing resource mix combined with extreme weather and shifting load profiles have created what the NERC has characterized as a "hyper-complex risk environment."[5]

MISO describes the shared responsibility of MISO, its members, and states to address the urgent and complex challenges to electric system reliability in the MISO Region as the "Reliability Imperative." MISO's updated response to the Reliability Imperative highlights the fact that generation fleet change is creating a gap between the region's levels of installed and accredited generation capacity. MISO's Attributes Roadmap[6] also 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 Attributes Roadmap recognizes that no single resource provides every needed system attribute; rather, the needs of the system have always been met by a fleet of diverse resources operated in a manner that most efficiently meet system needs. [7]

In response to these challenges and the continued need for diversity in the resource mix, MISO proposes to transition to a two-step resource accreditation method (the "DLOL-based methodology"). The proposed method measures a resources' availability when reliability risk is the greatest based on both prospective and retrospective risk assessments The instant proposal builds upon recent changes to MISO's Resource Adequacy construct, including the Federal Energy Regulatory Commission's ("FERC") acceptance of MISO's Seasonal Accreditation ("SAC") filing.[8] The SAC filing established a seasonal Planning Resource Auction ("PRA") market construct to replace MISO's annual PRA. The SAC filing also established a new accreditation mechanism for thermal resources in Schedule 53 of the Tariff. These prior changes to MISO's Resource Adequacy construct and accreditation methods provide the foundation for MISO's ongoing efforts to better align resource accreditation with the rapidly changing resource fleet and risk factors affecting reliability. In addition, the proposed accreditation reforms address certain priority attributes, and specifically the system adequacy attribute, identified in MISO's Attributes Roadmap.

In the instant filing, MISO's proposed DLOL-based methodology first measures a resource's expected marginal contribution to reliability using Resource Class-level performance during the loss of load expectation ("LOLE") analysis. The 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 (probabilistic approach). The second step in the DLOL-based methodology then uses historical

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[5] NERC, Challenges to Reliability and Resilience (December 2023), at p. 5, available at https://cdn.misoenergy.org/20231207%20Board%20of%20Directors%20Item%2007a%20NERC%20CEO%20Update631092.pdf.

[6] *See* Attributes Roadmap, A Reliability Imperative Report, ("Attributes Roadmap")available at: https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf.

[7] *Id*. at p.3.

[8] *Midcontinent Independent System Operator, Inc.*, 180 FERC ¶ 61,141 (2022).

resource-level performance (deterministic approach) during Tier 1 and Tier 2 RA Hours currently employed under MISO's Tariff to accredit individual resources within their respective Resource Class.

The DLOL-based methodology balances 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 may 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 (*i.e.*, low margin).

MISO's proposed approach to measure the availability of resources during Critical Hours in its probabilistic analysis is within the marginal effective load carrying capability ("ELCC") accreditation framework that is used by other market administrators (*e.g.*, PJM and NYISO). In addition, MISO's use of the DLOL-based accreditation methodology to determine Resource Class-level unforced capacity ("UCAP") values and to establish PRMR is an example of the kind of robust tool NERC stated would be necessary to plan for risks associated with the changing resource mix, extreme weather scenarios and load growth, all while continuing to operate a reliable grid. As NERC observed:

> Resource and system planners must have robust tools and capabilities for assessing energy needs, extreme weather scenarios, and grid stability. Planning Reserve Margins can fail to identify energy risks that stem from low [Variable Energy Resources] output or generator fuel supply issues, making them unsuitable as a sole basis of resource adequacy. Resource planners and wholesale markets must use enhanced modeling that accounts for energy risks, such as all-hours probabilistic assessments.[9]

The DLOL-based methodology is supported by MISO's Independent Market Monitor ("IMM"), who refers to the proposal as a "substantial improvement to MISO's current capacity accreditation and promises to provide efficient long-term economic incentives."[10] The IMM states that these incentives are urgently needed as MISO's generation portfolio transitions to a cleaner, less-carbon intense resource portfolio.[11] Ultimately, the IMM urges the Commission to accept the DLOL-based methodology as he concludes, "the economic signals and incentives produced under the proposed DLOL framework will help ensure that MISO will retain the resources needed to maintain reliability in the region as this transition occurs."[12]

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9 *See* NERC, 2023 Long-Term Reliability Assessment (December 2023) ("2023 LTRA"), available at: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf

10 Affidavit of David B. Patton, Ph.D. ("IMM Affidavit") at P 43.

11 *Id*.

12 IMM Affidavit at P 44.

MISO's proposal is also supported by the testimony of Zachary Ming, Director at E3. Mr. Ming's testimony supports the implementation of the DLOL-based methodology as a form of marginal resource accreditation that will refocus[ ] the determination of system capacity need and the accreditation of individual resources to meet this need around the hours that matter most for system reliability.[13] Mr. Ming's testimony further demonstrates that the proposed DLOL-based methodology "is inherently designed to adapt to changing system conditions as they evolve over time, creating a framework that is sustainable in the long run."[14]

The DLOL-based methodology will be fully implemented in the 2028 / 2029 PRA, after a three-year transition period. Beginning September 1, 2024, MISO will publish estimated Resource Class-level accreditation values prior to each PRA. In addition, MISO will provide LSEs with resource level indicative values during the transition period, as may be requested by individual resource owners. Finally, MISO has also committed to publishing longer term Resource Class-level indicative values (5 and 10 year forward) as part of the Regional Resource Assessment.

MISO has collaborated with stakeholders throughout the development of this proposal and some key elements are the direct result of stakeholder feedback and involvement. MISO also acknowledges that the DLOL-based methodology is a significant change to the way resources are accredited and is committed to working with stakeholders to assist them with understanding how the change will impact their resources and to continuing stakeholder discussions about potential further enhancements in resource adequacy going forward. These discussions will continue to address stakeholder requests for increased data accessibility and transparency, while preserving the confidential nature of certain underlying data. In addition, MISO is committed to discussing its ongoing efforts to enhance its probabilistic modeling with stakeholders.

II. BACKGROUND

A. MISO's RAN Initiative and Reliability Imperative

This filing is a continuation 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. MISO submits this filing to establish the design for additional Resource Adequacy reforms, including use of the DLOL-based methodology for accrediting resources participating in the MISO markets and establishing system-wide and local resource requirements.

MISO is facing a Reliability Imperative during this period of unprecedented change. There are urgent and complex challenges to electric system reliability in the MISO region and elsewhere. This fact is well documented throughout the electric industry. In fact, NERC, the agency whose mission it is to assure the effective and efficient reduction of risks to the reliability and security of

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13 Prepared Direct Testimony of Zachary Ming ("Ming Testimony") at p.33.

14 *Id.*

the grid, has described these challenges as a "hyper-complex risk environment."[15] These changes, challenges and risks 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. This process has become increasingly uncertain due to a dramatically changing landscape and the hyper-complex risk environment, which includes factors such as: resource fleet changes; changes in energy and environmental statutes, regulations, policies and permitting issues; changes in investment criteria; fuel assurance concerns; extreme weather events; load additions and incremental load growth, including increasing electrification and supply chain issues.

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 RAN- related filings began in December 2018 when MISO proposed revisions to its Tariff to more effectively assess the capabilities of LMRs[16] and enhance the testing requirements for Demand Resources that participate in MISO's markets as LMRs.[17] These RAN-related filings continued throughout 2019 and 2020 and resulted in additional changes to MISO's Tariff to address other aspects of LMR availability and Generator Planned Outage Scheduling. MISO has also submitted reforms related to the deliverability of both conventional and intermittent resources.

The early RAN-related filings were the initial step in addressing specific issues in the Resource Adequacy construct, but MISO consistently maintained that more comprehensive solutions were necessary and were being developed to address Resource Adequacy in the MISO Region. The more recent RAN-related filings are examples of the more comprehensive solutions that advance reliability in the MISO Region. For example, on September 29, 2023, MISO submitted a filing to replace its vertical demand curve with a Reliability Based Demand Curve ("RBDC") designed to improve price signals in the PRA.[18] MISO's 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

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15 NERC, Challenges to Reliability and Resilience (December 2023), at p. 5, available at https://cdn.misoenergy.org/20231207%20Board%20of%20Directors%20Item%2007a%20NERC%20CEO%20Update631092.pdf.

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

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

18 The RBDC proposal remains pending before the Commission in Docket No. ER23-2977.

capacity pricing is also crucial to make effective investment and retirement decisions. If accepted, full implementation of RBDC is planned for the 2025 PRA.

The Seasonal Accredited Capacity ("SAC") filing was another significant RAN-related filing that advanced the Reliability Imperative, which was accepted by the Commission in August of 2022 and implemented beginning with the 2023 / 2024 Planning Year.[19] MISO submitted the SAC filing to shift from a 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 risk factors described above. The accreditation changes established in the SAC filing, and now incorporated in Schedule 53 of the Tariff, were focused primarily on thermal resources and were designed to ensure that such resources will be available when they are needed most by aligning resource accreditation with availability during the high-risk periods in each season. The SAC filing resulted in thermal resources in the MISO Region being accredited based upon their actual performance during Resource Adequacy hours.

In approving the SAC filing as just and reasonable, the Commission found that MISO had proposed a reasonable basis to estimate a resource's expected availability and that the proposal provided resource owners with strong incentives to maximize availability during high-risk hours:

> 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.[20]

The Commission also found that MISO had 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 outcomes should provide benefits to MISO's entire system, not just a particular MISO region.[21]

While the changes to MISO's resource accreditation methodology discussed above have improved reliability, MISO continues to face a Reliability Imperative and must further enhance

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[19] *Midcontinent Indep. System Operator, Inc*., 180 FERC ¶ 61,141 (Aug. 31, 2022).

[20] *Id*. at P 243.

[21] *Id*. at P 245.

and refine its Resource Adequacy construct. For example, and as described in Mr. Joundi's direct testimony, MISO currently uses different methods to accredit thermal, wind, solar, and storage resources.[22] While there are historical reasons for MISO's development and use of different accreditation methodologies for different types of resources, this approach can lead to inaccurate, inconsistent, and even overstated accreditation results as these methodologies only examine past performance and do not focus on the probability of risk occurring during the times of greatest need going forward.[23] The proposed DLOL-based resource accreditation reforms submitted in this filing will better align accreditation across all relevant resources with observed resource availability during the periods of highest risk.

Specifically, MISO is proposing a change in how all Capacity Resources, except External Resources (hereinafter referred to as "Schedule 53A Resources"), receive capacity credit at the Resource Class-level, as well as how the Resource Class-level UCAP megawatts are allocated amongst the individual resources. In addition, MISO is proposing to use the same methodology to calculate the PRMR that it uses to accredit Resource Classes. The instant proposal thus preserves the deterministic element of resource accreditation established in Schedule 53 by accrediting *all* Schedule 53A Resources based upon their actual performance during Resource Adequacy Hours.[24] The DLOL-based accreditation proposal also enhances the Schedule 53 methodology by adding a probabilistic element to perform Resource Class-level UCAP calculations to align the class-level accreditation of all Schedule 53A Resources with the determination of PRMR. The proposal will award more relative accreditation to resources that have properly mitigated risks during each Season and will ensure that resources committed during the seasonal PRA receive accreditation based on their reliability contribution during the times of highest need. Consistent with the goals of the RAN initiative, and in response to the Reliability Imperative, MISO's proposal will better align planning reserve margin requirements, risk, resource availability, and accreditation.

B. Drivers of the Reliability Imperative

MISO's Vice President of Markets and Digital Strategy, Todd Ramey, explains that MISO is at an inflection point in its portfolio evolution, with increasing penetration of wind and solar generation is shifting the nature of system risk and existing accreditation methods are not robust enough to capture those risks and send the proper signals for the resources needed during periods of system risk.[25] MISO's updated response to the Reliability Imperative highlights the fact that generation fleet change is creating a gap between the region's levels of installed and accredited generation capacity.[26] 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

22 *See, e.g.,* Prepared Direct Testimony of Zakaria ("Zak") Joundi at pp. 9-10 ("Joundi Testimony").

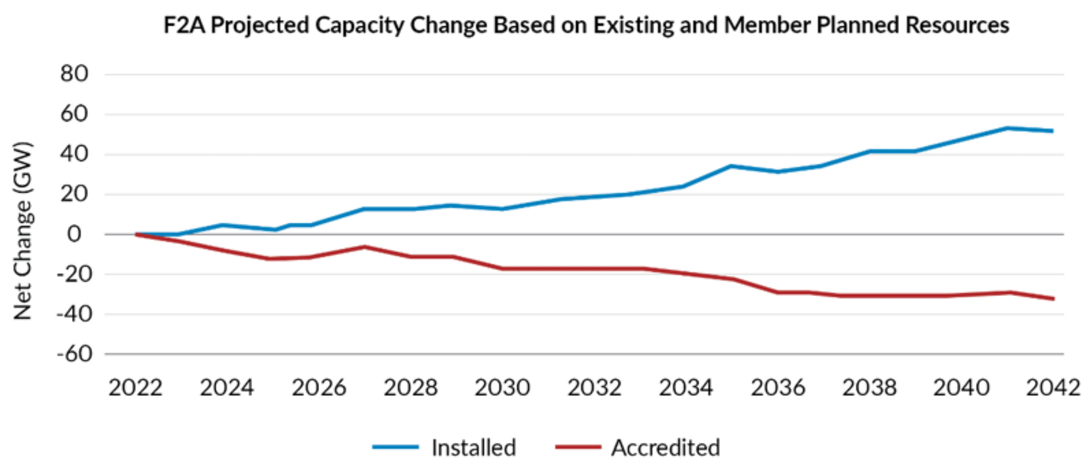
23 *Id*. at p. 10.

24 Schedule 53A includes the specific Resource Classes that will be subject to the proposed DLOL-based accreditation methodology.

25 Prepared Direct Testimony of Todd Ramey at pp. 3-4 ("Ramey Testimony").

26 MISO's Response to the Reliability Imperative, MISO (February 2024), at pp. 7-8, available at https://cdn.misoenergy.org/2024%20Reliability%20Imperative%20report%20Feb.%2021%20Final504018.pdf.

planned or unplanned reasons; whereas, 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, and the availability of wind or solar radiation for weather-dependent resources. The projected divergence of installed and accredited capacity in the MISO Region is shown in the figure below:



The figure above is from MISO Future 2A, which reflects the publicly announced decarbonization plans of MISO-member utilities and states.[27] 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. But because those new wind and solar resources have significantly lower accreditation values 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 forecasted to decline by a net 32 GW by 2042. As explained by Mr. Ramey, 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.[28] Given this information, it is necessary to implement a broader accreditation reform in the near term to address these projections.[29]

MISO's Attributes Roadmap also 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. Consistent with MISO's Response to the Reliability Imperative, the Attributes Roadmap shows that generation resource mix is diversifying; the surety of the fuel supply is

27 2023 MISO Futures Report, MISO, at p. 19, available at https://cdn.misoenergy.org/20231002%20LRTP%20Workshop%20-%20Draft%20Series1A%20Futures%20Report630365.pdfhttps://cdn.misoenergy.org/Series1A_Futures_Report630735.pdf.

28 Ramey Testimony at pp. 4-5.

29 *Id.*

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.[30]

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 meet system needs.[31] MISO's proposed DLOL-based methodology reflects the continued need for this diversity by grouping resources with similar operating characteristics into Resource Classes, while also recognizing the historical performance of each individual resource during periods of realized risk. Ultimately, by defining Resource Classes, the DLOL-based methodology will appropriately align resource accreditation on a broader level with the projected impacts resources with similar operating characteristics will have on reliability, and on a more granular level by accounting for the performance of individual resources within each Resource Class.

MISO's Independent Market Monitor, Dr. David Patton, recognizes the need for the instant filing in his affidavit supporting MISO's proposal:

> MISO's proposed changes in this docket address the supply side of the capacity market by instituting an accreditation framework for each class of capacity resources that reflects the resources' marginal contribution to the reliability of the system. This is an essential improvement to facilitate the reliable transition of the generation portfolio to sharply reduce MISO's carbon emissions. The large quantities of intermittent generation entering the MISO region during this transition provide less and less reliability as more enter because they lack key attributes provided by dispatchable resources that are increasingly retiring. Establishing accreditation that is accurately aligned with reliability will ensure that the capacity market provides efficient incentives to invest in and maintain a portfolio of resources that meet the reliability needs of the MISO system.[32]

III. RESOURCE ACCREDITATION REFORM EVALUATION PHASE

The discussion below details MISO's evaluation of potential resource accreditation methodologies both internally and through the stakeholder process. As shown, there are several potential methodologies that could produce just and reasonable accreditation results for a given region. The DLOL-based methodology proposed herein is an appropriate resource accreditation approach for the MISO Region as it balances a range of risks in the planning and operations horizons by considering the probabilistic and deterministic performance of all Schedule 53A

30 Attributes Roadmap at p. 3.

31 Attributes Roadmap at p. 3.

32 Affidavit of Dr. David Patton at P 9.

Resources during periods of high system risk. As such, the proposed DLOL-based methodology is a just and reasonable approach to resource accreditation in the MISO Region.

A. The Accreditation Problem Statement

MISO has distilled the multiple resource accreditation reform challenge into a "problem statement" that acknowledges the challenges facing the MISO Region and affirms that resource accreditation should reflect the availability of resources during the periods of highest need. This problem statement was first presented to stakeholders at the January 2022 RASC meeting.[33] 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.[34]

B. Evaluation Criteria Applied to Address the Problem Statement

MISO evaluated accreditation methodologies to address the challenges in the problem statement against the following five general criteria. These criteria, which are discussed in more detail below, are as follows: impact, feasibility, flexibility, stability, and comparability. These criteria were initially developed based on criteria previously used for the RAN initiative, and modified based upon stakeholder input. These criteria are all related to the "pillars of accreditation" identified by the Energy Systems Integration Group ("ESIG"). Each of the criteria are described in Mr. Joundi's testimony as follows: [35]

Impact. 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.

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[33] Joundi Testimony at p. 57. *See* also January 2022 RASC available at: https://cdn.misoenergy.org/20220126%20RASC%20Item%2005b%20Renewables%20Accreditation%20MISO%20Presentation620190.pdf

[34] Joundi Testimony at p. 57.

[35] Joundi Testimony at pp. 59-61.

Feasibility. 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.

Flexibility. 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.

Stability. 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.

Comparability. 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.

C. Consideration of Approaches to Accreditation

MISO considered both deterministic and probabilistic methods, as well as a blended approach to resource accreditation. Each method has its advantages and drawbacks, and each is discussed below. After engaging with stakeholders, MISO arrived at the DLOL-based accreditation methodology that is the subject of the instant proposal.

1. Deterministic versus Probabilistic Methods

Deterministic methods use estimates, generally based on historical performance, to determine resource accreditation.[36] Examples of deterministic methods are seasonal performance, performance during peak load hours, performance during peak net load hours, or performance during historical risk periods. 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 resources are currently accredited.[37]

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. Here, 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 by 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.[38]

MISO has performed LOLE analysis using the probabilistic model for more than fifteen years. 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.[39]

Each of the two approaches – probabilistic and deterministic – 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

[36] Joundi Testimony at p. 8.

[37] Joundi Testimony at pp. 8, 62.

[38] Joundi Testimony at pp. 8, 58.

[39] Joundi Testimony at p. 8.

backwards-looking only framework may fail to properly realize the value of a resource and create improper incentives towards investment and retirement decisions.[40]

2. The Blended Method

The blended method attempts to merge the probabilistic and deterministic perspectives into a single view to 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.[41]

D. Consideration of the Marginal vs. Average Approaches to Accreditation

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) an average accreditation approach, which includes options such as average ELCC, and (2) a marginal accreditation approach, which includes marginal ELCC, marginal reliability improvement, 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 Region. This 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 a blended method.[42]

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.[43]

The marginal accreditation approach is supported by MISO's IMM and E3 Director, Zachary Ming. When discussing the evolution of capacity accreditation methods Mr. Ming observes:

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[40] *Id*. at pp. 62-63.

[41] *Id*.

[42] *Id*. at pp. 58-59.

[43] *Id*. at p. 66.

> Many system operators have come to realize that the utilization of average ELCC does not sufficiently meet the principles of capacity market design and are either considering or have proposed to accredit resources using the concept of marginal ELCC, which is a statistically robust method for measuring the incremental or marginal contribution to system reliability for any resource that reflects its availability during the hours of highest reliability risk. Both PJM and NYISO are examples of system operators that have both had such marginal ELCC accreditation approaches accepted by FERC.[44]

When discussing his support for a marginal resource accreditation approach Dr. Patton explains that marginal accreditation is important because it recognizes the diminishing value received from a particular class of resources.[45] Dr. Patton asserts that this recognition of the diminishing value of a class of resources will limit over-saturation of a specific resource class that does not provide a comparable amount of reliability to other types of resources.[46]

Another key benefit of a marginal accreditation approach, as noted by Dr. Patton, is that accurate accreditation will inform the states' integrated resource planning ("IRP") processes and ensure state IRPs produce plans that will satisfy the reliability needs of the MISO Region while also substantially reducing costs to consumers by ensuring the market procures and compensates those resources that provide the highest value to the system.[47]

IV. DLOL-BASED METHODOLOGY

MISO ultimately selected the DLOL-based accreditation methodology after an extensive stakeholder process where several different accreditation methodologies were considered. MISO's DLOL-based methodology is a robust tool that combines both probabilistic and deterministic elements into a single resource accreditation process that will be used to accredit all Schedule 53A Resources and establish PRMR. As explained by Mr. Joundi, the proposed DLOL-based methodology is a balanced approach that captures a range of risks in the planning and operations horizons. [48]

In the simplest terms, the proposed two-step approach can be described as first determining the size of a pie and then second, allocating or divvying up the pie, as depicted in the figure below:

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44 Ming Testimony at p. 14. (Citing NYISO FERC Order: https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-nyiso-tariff-revisions-re-marginal-capacity;

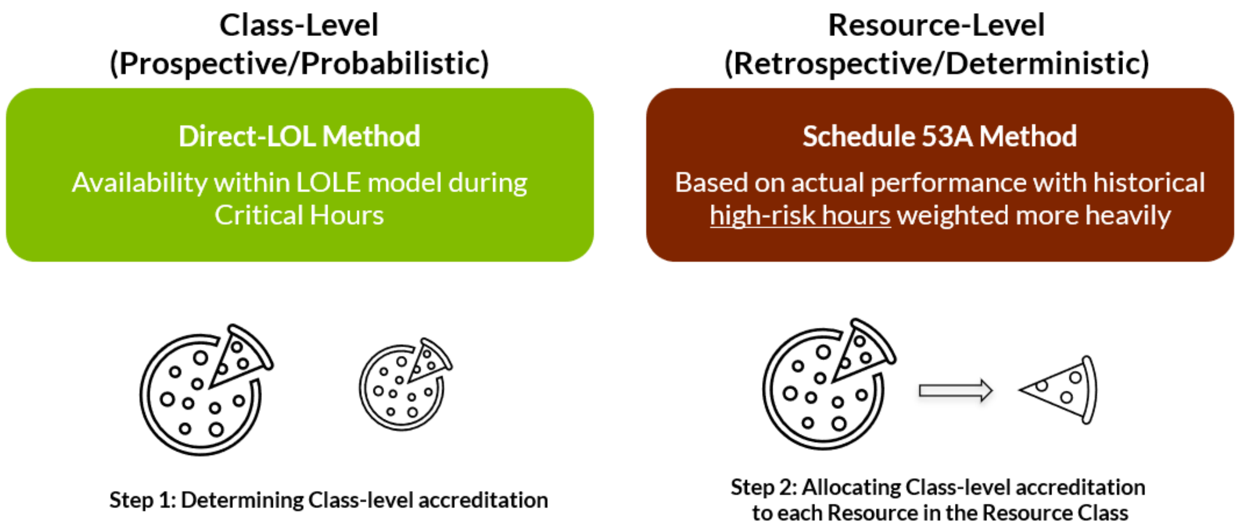
PJM FERC Order: https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-pjms-capacity-market-reform-filing-docket-no).

45 IMM Affidavit at P 23.

46 *Id*.

47 IMM Affidavit at PP 25 – 26.

48 Joundi Testimony at p. 14.



The proposed reform aligns 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.[49]

MISO's DLOL-based methodology is similar to the marginal ELCC method the Commission recently approved for PJM.[50] Like MISO's DLOL-based methodology, PJM uses a single model to set requirements and accredit resources. In approving PJM's proposal, the Commission stated:

> We accept as just and reasonable PJM's proposal to use the same hourly probabilistic model underlying its ELCC accreditation for the Reserve Requirement Study. Using the same model for determining the amount of capacity required and the amount of capacity a resource is capable of providing is a reasonable modeling methodology that allows risk to be evaluated on a more granular level and provides for consistency between the system's resource adequacy requirements and resource accreditation to meet those requirements. We agree with PJM that using the same model for both analyses allows the Reserve Requirement Study to benefit from the hourly interval modeling of all 8,760 hours in a delivery year that is used in the ELCC model, instead of just analyzing the peak hour of each day under the current Reserve Requirement Study model. We also note that this proposal allows PJM to ensure that its determination of the level of capacity needed to maintain a given

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49 Joundi Testimony at pp. 2-4.

50 *See PJM Interconnection, L.L.C.*, 186 FERC ¶ 61,080 (2024) ("PJM Order").

> level of resource adequacy is consistent with its accreditation of the contribution of capacity resources that are procured to meet that level.[51]

MISO's current approach to resource accreditation has served it well up to this point. However, with the resource mix changing and the "hyper-complex" environment in which MISO operates, the current mixed approach will simply not be sufficient in the future. Given a portfolio replete with dispatchable resources and fairly predictable load patterns, MISO has been able to reliably operate the grid year-round by ensuring sufficient resources to meet the summer coincident peak. That approach will not work in the future and MISO's DLOL-based methodology is the robust tool that it needs to meet its Reliability Imperative. In concurrence with the Commission Order approving PJM's ELCC proposal, Commissioner Clements stated:

> Over a decade's worth of extreme weather experience, along with other historical operational data, have made plain that the traditional model of procuring capacity solely based on summer peak demand is outmoded. Instead, grid operators' risk modeling must become more sophisticated to ensure capacity markets send accurate demand signals today and into the future. PJM's development of a new framework that seeks to assess the patterns, drivers, and probabilities of reliability risk across all hours of the year is an important advancement in this effort.[52]

Similar to PJM's marginal ELCC accreditation methodology, MISO's DLOL-based methodology sets requirements and accredits resources pursuant to a framework that seeks to assess the patterns, drivers, and probabilities of reliability risk across all hours of the year.

Ultimately, MISO's DLOL-based methodology as designed provides significant benefits compared to other accreditation methodologies. First, it provides direct alignment between system-wide PRMR, risk, availability, and accreditation. In addition, it provides a wider range of simulated conditions that better account for infrequent risks without penalizing individual resources. A more detailed discussion of the DLOL-based methodology is provided below.

A. DLOL-based Methodology Design Details

1. Resource Classes

To implement the DLOL-based methodology, MISO assigns all Schedule 53A Resources to a Resource Class. 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

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[51] *Id.* at P 177.

[52] *See* PJM Order at P 1.

based on similar operating characteristics of individual resources within the class and generally reflect the same or similar technologies.[53] MISO has added a criteria to define Resource Class in Schedule 53A and included the specific Resource Classes in that same section. Specifically, MISO has included the following list of proposed Resource Classes in the Tariff:

Gas (including Oil)	Storage
Combined Cycle	Solar
Coal	Wind
Hydro	Run-of-River
Nuclear	Biomass
Pumped Storage	

MISO recognizes that the "rule of reason" is the doctrine that governs whether an item should be placed in an RTO/ISO tariff or in a business practices manual.[54] The Commission has said that pursuant to the rule of reason, provisions that "significantly affect rates, terms, and conditions of service, are readily susceptible of specification, and are not generally understood in a contractual agreement must be included in the tariff, while items better classified as implementation details may be included in the business practice manual."[55]

In its recent accreditation filing, NYISO did not include Capacity Accreditation Resource Classes in its tariff and the Commission found NYISO's approach to be consistent with the rule of reason. On the other hand, PJM first sought approval of an average ELCC accreditation methodology, without including resource classes within its tariff, which the Commission rejected for various reasons. In the NYISO Order, the Commission distinguished between NYISO's approach to including resource classes within the tariff and PJM's approach to the matter as set forth in its average ELCC filing.

In rejecting PJM's initial average ELCC proposal, the Commission commented that the "rule of reason" policy would likely require PJM to include the definitions of the ELCC Classes in the tariff.[56]

> The situation before us is distinguishable from the situation in PJM because the average ELCC methodology requires that the administrator allocate the total capacity value of studied resources

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53 Joundi Testimony at pp.36-37.

54 *New York Indep. System Operator, Inc*., 179 FERC ¶ 61,102 (May 10, 2022).

55 *Energy Storage Ass'n v. PJM Interconnection, L.L.C.*, 162 FERC ¶ 61,296, at P 103 (2018); *see also City of Cleveland*, 773 F.2d at 1376-77 (affirming the Commission's decision not to include term in 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).

56 PJM ELCC I, 175 FERC ¶ 61,084 at P 66.

> among individual resource classes, while ensuring that the sum of the class-level capacity values equals the total capacity value of the studied resources. Therefore, the definition of a resource class under an average ELCC approach directly affects not only the capacity value of the subject class but also the capacity value of all other classes. In contrast, under NYISO's marginal ELCC approach, the marginal reliability contribution of a resource class does not depend on the number and type of other resource classes; it only depends on the definition of the subject class. As we note above, NYISO's proposed Services Tariff revisions bind NYISO to group resources into classes with similar marginal reliability contributions.[57]

MISO's DLOL-based accreditation methodology is similar to the marginal ELCC methodology approved by the Commission for NYISO. Like NYISO's marginal ELCC methodology, Resource Class-level UCAP values determined by the DLOL-based methodology do not depend upon the number and type of resource classes, they only depend on the definition of the subject class. By including in the Tariff a detailed explanation of how Resource Class-level UCAP values are determined, MISO has satisfied the rule of reason in similar fashion to NYISO. However, in response to stakeholder feedback, MISO has included Resource Classes within the Tariff. The decision to include Resource Classes within the Tariff provides stakeholders the certainty they need to engage in long-term resource planning, knowing that any proposed changes to the Resource Classes will be discussed in the stakeholder process and filed with the Commission. Until the Commission accepts any proposed changes as part of a Section 205 filing, the list of Resource Classes in the Tariff will remain unchanged.

2. DLOL-Based Methodology – Step 1 (Size of Pie)

The DLOL-based methodology consists of a two-step process. In step 1, MISO performs a Monte Carlo probabilistic simulation using 30 years of correlated load and weather data for each of five load forecasts to calculate Resource Class-level UCAP.

As described in Mr. Joundi's testimony, MISO completes the following procedure to calculate Resource Class-level accreditation:[58]

1. For each Season, the lowest 3% margin hours, where margin equals total available generation plus net imports minus load, are extracted. This selection includes two subsets of hours: a loss of load (LOL) hour, where there was a loss of load due to available generation being less than the required load (when margins are negative), and low margin hours, where there was no loss of load, but margin was equal to or less than 3% (positive margins).

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57 *New York Indep. System Operator*, 179 FERC ¶ 61,102 at P 112 (internal citations omitted).

58 Joundi Testimony at pp. 22-28.

2. Within each Season, the hour with the maximum positive margin is identified from all the low margin hours selected above. 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.

3. Next, for each hour, the 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.

$$effective\ margin = \max margin - margin$$

4. Then, the number of hours is capped within each Season using the following criteria:

    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. The figure below 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

5. 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 for each hour calculated earlier. 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.[59] 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 the figure 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%

6. Finally, the total availability is calculated for a Resource Class for each Critical Hour, and those values are averaged for each Season using the weights discussed above. This results in the Resource Class-level accreditation, referred to as Resource Class-level UCAP in the MISO Tariff.

3. DLOL-Based Methodology – Step 2 (Slice of Pie)

Step 2 of MISO's DLOL-based methodology is largely based upon the mechanism set forth in Schedule 53, which the Commission has previously found to be just and reasonable.[60] Step 2 of the DLOL-based methodology uses the availability of Schedule 53A Resources during Tier 1 and Tier 2 RA hours for the past three years for allocating Resource Class-level UCAP to individual Schedule 53A Resources within each Resource Class. Tier 1 availability is based upon each resource's real-time offered availability during normal operating conditions and Tier 2 availability is based upon each resource's real-time offered availability during hours with the most difficult operating conditions, including declared maximum generation events. Tier 2 is more heavily weighted so that most of a resource's accreditation will be based upon its availability during times of reliability need. The number of Tier 2 RA hours in a Season could exceed the target, 65 hours, when a high number of hours are accrued due to declared system or subregional

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[59] See Section 3.3.2 in the PY2023-2024 LOLE Study Report

[60] *Midcontinent Indep. System Operator, Inc.*, 180 FERC ¶ 61,141 (Aug. 31, 2022).

emergencies.

If there are fewer than 65 Tier 2 RA hours in a Season (deficient hours), seasonal Resource Class-level UCAP as percentage of Resource Class-level ICAP capacity is used for resource availability during those deficient hours. All other foundational aspects of the current Schedule 53 design, including outage exemptions, tier weighting, and lead time considerations remain unchanged.

Tier 1 and Tier 2 RA hours ensure 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 within that Resource Class would be affected in the same manner and the allocation within the Resource 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 value.[61]

The allocation of Resource Class-level UCAP among all Resources in the Resource Class can be described using the following equation:

$$SAC_i = Resource\ Class\text{-}Level\ UCAP * \frac{Resource\ ISAC_i}{Resource\ Class\text{-}level\ ISAC}$$

B. Requirements Determination

1. System-wide PRMR

MISO is proposing to maintain the calculations of the PRMR and simply account for the determination of UCAP for Capacity Resources, excluding External Resources, based on the proposed accreditation method. The PRMR will be determined as the sum of accredited values for all Capacity Resources, Load Modifying Resources, Firm External Resources, within the LOLE model plus the MW adjustment to drive the probabilistic model to the LOLE target. MISO expects the seasonal Planning Reserve Margin Requirements to decrease under the proposed DLOL-based method. This indicates that MISO's current accreditation methodologies are misaligned with a resource's marginal contribution to reliability risk leading to over-accrediting and 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 into more efficient market outcomes.[62]

2. Local Reliability Requirements

Like PRMR, Local Reliability Requirements ("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

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[61] Joundi Testimony at pp. 31-32.

[62] *Id*. at pp. 67-68.

capacity accreditation of the resources in the Zone, plus a MW adjustment used to bring the LOLE model of the isolated LRZ to criteria.[63]

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).[64] Ideally, the LRR would be determined by aggregating the final SAC values of all resources in a Zone.[65] Unfortunately, those two values are determined at different points in time.[66] 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.[67]

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:[68]

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.

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[63] *Id*. at pp. 68-70.

[64] *Id*.

[65] *Id*.

[66] *Id*.

[67] *Id*.

[68] *Id.* at pp. 69-70.

VI. TARIFF REVISIONS

MISO proposes the following revisions to its Tariff to implement the proposed DLOL-based methodology to align the accreditation of resources and calculation of the PRMR to periods of highest risk.

A. Proposed Revisions to Module A

MISO proposes to revise the definition of "Seasonal Accredited Capacity" and "Unforced Capacity" as follows:

1. Seasonal Accredited Capacity ("SAC")

"The amount of *accredited* Capacity, for a given Season, in MW, assigned to a Planning Resource ~~after accounting for its historic availability~~ *that is convertible to Zonal Resource Credits.*"

2. Unforced Capacity ("UCAP")

"The amount of Capacity in MW assigned to a Planning Resource after accounting for *either* its ~~forced outage rate~~ *availability in the LOLE analysis* or historic availability*, as applicable".*

B. Proposed Revisions to Module E – 1

The final sentence in Section 68A.2.1 of Module E – 1 will be revised as follows: "The PRM will be established as ~~an Unforced Capacity~~ *a* requirement ~~based upon the weighted average forced outage rate of all Planning Resources~~ *in terms of the total Unforced Capacity for* the Transmission Provider Region."

C. Proposed Addition of Schedule 53A – Extended Seasonal Accredited Capacity Calculation

MISO proposes to add Schedule 53A to its Tariff to be effective September 1, 2024, with implementation of the DLOL-based methodology slated for Planning Year 2028 – 2029. The word "Extended" has been added to the Schedule 53 title to create Schedule 53A; therefore, Schedule 53A shall be called "Extended Seasonal Accredited Capacity Calculation." Schedule 53A is largely based upon Schedule 53, except that certain provisions have been either added to or removed from Schedule 53 to create Schedule 53A to implement the DLOL-based methodology, as follows:

1. Section I. – Applicability

MISO proposes to add a new *Section I – Applicability* to Schedule 53 to create Schedule 53A. The addition of Section I – Applicability will move each subsequent section in Schedule 53 down by one position in Schedule 53A. For example, the section entitled "General" (originally

Section I of Schedule 53) will become Section II in Schedule 53A. Section I – Applicability of Schedule 53A shall consist of three subsections.

a. Subsection I.A. – Implementation Date of Schedule 53A

MISO proposes to add the following provision to Schedule 53A as *Section I.A. Implementation Date of Schedule 53A*: *"The provisions of this Schedule 53A, except Section I.B. Effective Date of Reporting Requirement, shall be effective on June 1, 2027 for implementation beginning with Planning Year 2028 – 2029 and continuing thereafter. The Transmission Provider shall make a filing to remove the currently effective Schedule 53 from the Tariff to be effective June 1, 2028."*

b. Subsection I.B. – Effective Date of Reporting Requirements

MISO proposes to add the following provision to Schedule 53A as *Section I.B. Effective Date of Reporting Requirement*: "*Commencing on September 1, 2024, the Transmission Provider will publish indicative results pursuant to the provisions set forth in this Schedule 53A. Such indicative results shall be published prior to the applicable Planning Resource Auction for Planning Year 2025–2026, and the two Planning Years thereafter, as further described in the Business Practices Manual for Resource Adequacy."*

c. Subsection I.C. – Resource Classes

MISO proposes to add the following provision to Schedule 53A as *Section I.C. Resource Classes*: "*The term "Resource Class" as used in this Schedule 53A shall mean 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 this Schedule 53A. All Capacity Resources, except External Resources, shall be assigned to one of the Resource Classes identified in this section for purposes of executing the two-step resource accreditation methodology defined in this Schedule 53A and determining the Planning Reserve Margin Requirement, as set forth in Module E-1. A DRR-Type I or DRR-Type II that is a behind the meter generation facility, and that qualifies as a Capacity Resource shall be assigned to an applicable Resource Class below. A DRR-Type I that interrupts or controls demand shall be accredited pursuant to Section VI below. Resource Classes shall include:*

Gas (including Oil)	*Storage*
Combined Cycle	*Solar*
Coal	*Wind*
Hydro	*Run-of-River*
Nuclear	*Biomass*
Pumped Storage	

Additional details regarding Resource Classes shall be included in Transmission Provider's Business Practices Manual for Resource Adequacy. The Transmission Provider will provide a mapping of each Capacity Resource to one of the above Resource Classes as per the *schedule listed in the Transmission Provider's Business Practices Manual for Resource Adequacy. Any dispute regarding Resource Class assignment must be submitted to the Transmission Provider in writing within ten (10) Business Days from the date such assignment was provided to the Market Participant."*

2. Section II – General

MISO proposes to revise Section I – General from Schedule 53, which will become *Section II* – General in Schedule 53A. In addition, MISO proposes to introduce two subparts to Section II to describe the two-step DLOL-based accreditation methodology. Proposed revisions to Section II – General in Schedule 53A (formerly Section I. – General in Schedule 53) are as follows: "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, External Resource, or Use Limited Resource~~, *except an External Resource*, will be determined pursuant to this Schedule ~~53~~ 53*A*. The resources accredited pursuant to this Schedule ~~53~~ *53A*, as described above, are ~~here and after~~ *hereinafter* referred to as 'Schedule ~~53~~ 53*A* Resources.'

The SAC calculation for Schedule 53A Resources will be performed using a two-step process. First, the Resource Class-level UCAP will be determined by the method described in section II.A. Second, the Resource Class-level UCAP will be allocated amongst the individual resources in the Resource Class using the individual resource performance during Tier 1 and Tier 2 Hours based on the prior three years of operational performance as described in section II.B."

a. Subsection II.A. – Resource Class-level UCAP and ICAP Calculation

MISO proposes to add the following provision as *Subsection II.A Resource Class-level UCAP and ICAP Calculation* of Schedule 53A: "*Resource Class-level UCAP in a Season will be determined by calculating the combined expected availability and performance of all resources within that Class during Critical Hours from the probabilistic LOLE analysis as set forth in Module E-1. For each Season, "Critical Hours" are defined as the set of all 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. For those Seasons with 1,950 or more loss of load hours, Critical Hours will only include loss of load hours. Once Critical Hours are determined for each Season, weights are calculated for each of the Critical Hours using a weighting system that assigns greatest weight to the hours with the highest risk (i.e. hour with most unserved energy), as further described in the Business Practices Manual for Resource Adequacy. After calculating the weights for each Critical Hour, Critical Hours will be capped at 1,950 hours for each Season during which there are less than 1,950 loss of load hours. Finally, Seasonal Resource Class-level UCAP will be calculated as the weighted average of the Resource Class performance during Critical Hours in the Season.*

Resource Class-level ICAP will be calculated as the sum of the ICAP values of all Resources in the Resource Class."

b. Subsection II.B. – Resource-level Extended Seasonal Accredited Capacity Calculation

MISO proposes to further revise Section I of Schedule 53 by adding the word "Extended" before the phrase "Seasonal Accredited Capacity" in two places and changing Schedule 53 to Schedule 53A in two places. With the following revisions, former Section I of Schedule 53 will become *Subsection II.B. Resource-level Extended Seasonal Accredited Capacity Calculation*, in Schedule 53A: "A two-tiered weighting structure is used to calculate *Extended* Seasonal Accredited Capacity for Schedule ~~53~~ 53*A* Resources. Outage exemptions for planned outages and exemptions for any operating limitations, such as thermal, voltage, or stability limits referenced in the BPM for Outage Operations, provided by the Transmission Provider or Transmission Operator to preserve the reliability of the Transmission System, that modify the must offer obligation set forth in Section 69A.5.a will be factored into calculating the Tiers of a Schedule ~~53~~ 53*A* Resource's *Extended* Seasonal Accredited Capacity."

3. Section III. – Tier 1 and Tier 2 Planned Outage Exemption Requirements

MISO proposes to revise Section II of Schedule 53, which will become Section III in Schedule 53A, by making the following revisions: "Generator Planned Outages~~ scheduled to begin before September 1, 2022 will be granted a Tier 1 and Tier 2 exemption based on Section 38.2.5.g.ix., and as set forth in the Business Practices Manual for Resource Adequacy. Generator Planned Outages scheduled to begin on or after September 1, 2022~~ will be evaluated for Tier 1 and Tier 2 exemptions based on the following requirements. Only full *(Out-of-Service)* Generator Planned Outages or full *(Out-of-Service)* Proposed Generator Planned Outages shall be eligible for the Tier 1 and Tier 2 planned outage exemptions set forth below. *Resources in the Solar Resource Class shall not be eligible for Tier 1 and Tier 2 Planned Outage Exemptions for Generator Planned Outages and Proposed Generator Planned Outages that are scheduled during nighttime hours for each Season. Nighttime hours will be defined by Local Resource Zone, as set forth in the Business Practices Manual for Resource Adequacy."*

4. Section IV. – Resource Adequacy Hours

MISO proposes to modify Section III of Schedule 53 and include the modified version in Schedule 53A as *Section IV. Resource Adequacy Hours* by making the following revisions: "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 beginning 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)~~. ~~Both ~~Seasonal RA Hours ~~and Annual RA Hours ~~will be determined for the First Planning Area and Second Planning Area separately. The RA Hours determined in subpart ~~III.A & III.B~~ *IV.A. & IV.B.* below are the only RA Hours that will be used to calculate Tier 2 ISAC in subpart ~~V.C~~ *VI.B* below. Where certain Seasonal RA Hours do not apply for a Resource due to a Tier 2 Planned Outage exemption or for periods where the Resource was not designated for RAR under Module E-1 of the Tariff and the Resource does not otherwise have 65 RA Hours identified for the Season then a Seasonal RA Hour Deficiency exists per subpart ~~III.A.iii and the Resource's Annual Average Offered Capacity is~~ multiplied by the ~~Seasonal RA Hour Deficiency per subpart V.C of this Schedule 53~~ *IV.A.iii. To address the Seasonal RA Hour Deficiency, a Resource Class-level UCAP as a percentage of the corresponding Resource Class-level ICAP will be multiplied by the Resource's ICAP and the product will be applied for purposes of determining ISAC for only the deficient Seasonal RA Hours."*

a. Subsection IV.A. – Seasonal RA Hours

MISO is proposing to rename subsection III.A., and all references thereto, from Schedule 53 to subsection IV.A. Seasonal RA Hours in Schedule 53A; however, the provision will otherwise remain unchanged.

b. Subsection IV.B. – Seasonal Non-RA Hours and IV.C. – Tier 1 Planned Outage exemption apply only to Non-RA Hours.

MISO proposes to delete subsection III.B. of Schedule 53 and rename each of the two remaining subsections in Section III. For example, subsection III.C. from Schedule 53 will become subsection *IV.B.* Seasonal Non-RA Hours in Schedule 53A and subsection III.D. from Schedule 53 will become subsection *IV.C.* Tier 1 Planned Outage exemptions apply only to Non-RA Hours in Schedule 53A. Except for updated section references, the provisions otherwise remain unchanged.

5. Section VI. – Seasonal Accredited Capacity Calculation

MISO proposes revisions to Section V. of Schedule 53, which will become Section VI. in Schedule 53A. MISO proposes to delete subsection V.A. of Schedule 53 and begin Section VI. in Schedule 53A with subsection V.B from Schedule 53. Each subsequent subsection will be renamed accordingly.

a. Subsection VI.A.

MISO proposes the following revision to subsection V.B. of Schedule 53, which will become subsection VI.A in Schedule 53A: "Tier 1 Intermediate SAC (ISAC) is calculated as the sum of ~~Hourly Emergency Maximum Limit~~ *hourly real time availability*, or Targeted Demand Reduction Level for DRR-*Type* 1, during each of the Resource's Seasonal Non-RA Hours, divided by the total number of Seasonal Non-RA Hours for each Season within the three (3) most recent periods beginning September 1st and ending August 31st."

b. Subsection VI.B.

MISO proposes the following revisions to subsection V.C. in Schedule 53, which will become subsection VI.B in Schedule 53A: "Tier 2 ISAC is calculated as the sum of ~~Hourly Emergency Maximum Limit~~ *hourly real time availability*, or Targeted Demand Reduction Level for ~~DDR~~ *DRR-Type* 1, for the Resource's Seasonal RA Hours, plus the product of: ~~Annual Average Offered Capacity~~ *seasonal Resource Class-level UCAP as a percentage of the corresponding Resource Class-level ICAP will be multiplied by the Resource's ICAP* multiplied by the Seasonal RA Hour Deficiency; divided by the total number of Seasonal RA Hours plus the Seasonal RA Hour Deficiency for each Season within the three (3) most recent periods beginning September 1st and ending August 31st. For any Seasonal RA Hour where a Resource is offline and the sum of the Resource's Start-Up Time and Start-Up Notification Time Offers exceeds 24 hours, the Resource's ~~Hourly Emergency Maximum Limit~~ *hourly real time availability*, or Targeted Demand Reduction Level for DRR-*Type* 1, will be set to zero (0)."

c. Subsection VI.C.

MISO proposes the following revision to subsection V.D. in Schedule 53, which will become subsection VI.C of Schedule 53A: "For *Resources required to submit GVTC values and for* purposes of paragraphs A through C above, the ~~Hourly Emergency Maximum Limit~~ *hourly real time availability*, or Targeted Demand Reduction Level for DRR- *Type* 1, will be capped at the currently effective GVTC value of the Resource. If a Resource is committed for a portion of its ICAP due to partial clearing, the partial clearing will not reduce the values in the Offers considered in the accreditation calculations, which will be capped at the currently effective GVTC value of the Resource."

d. Subsection VI.D.

MISO proposes the following revisions to subsection V.E. from Schedule 53, which will become subsection VI.D. in Schedule 53: "In the case of an increase in generating Capacity of a Generation Resource, for purposes of paragraphs A through C above, the historical values for ~~Hourly Emergency Maximum Limit~~ *the hourly real time availability* will be adjusted up for those hours prior to such increase going into effect as set forth in the Business Practices Manual for Resource Adequacy."

e. Subsection VI.E.

Although MISO is proposing to rename subsection V.F., and all references thereto, from Schedule 53 to subsection IV.E. in Schedule 53A, the provision will otherwise remain unchanged.

f. Subsection VI.F.

MISO proposes the following revisions to subsection V.G from Schedule 53, which will become subsection VI.F in Schedule 53A: "ISAC will be calculated using the following equation:

$ISAC = ISAC_{Tier1\_value} \times ISAC_{Tier1\_weighting} + ISAC_{Tier2\_value} \times ISAC_{Tier2\_weighting}$ “

~~Where:~~

	~~Weighting by Planning Year~~		
~~Tier~~	~~2023- 2024 Planning Year~~	~~2024-2025 Planning Year~~	~~2025-2026 Planning Year and beyond~~
~~$ISAC_{Tier1\_weighting}$~~	~~40%~~	~~30%~~	~~20%~~
~~$ISAC_{Tier2\_weighting}$~~	~~60%~~	~~70%~~	~~80%~~

Where Tier 1 weighting equals twenty percent (20%) and Tier 2 equals eighty percent (80%).

g. Subsection VI.G.

MISO proposes to delete subsections V. H. and V.I. from Schedule 53 and add the following provision as subsection VI.G. in Schedule 53A: “*Resource Class-level ISAC is the sum of individual resource ISAC values within the Resource Class. The calculation of the Resource Class-level UCAP and Resource Class-level ISAC will exclude Resources that have yet to qualify for the applicable PRA at the time of these calculations and include those in both the relevant LOLE study and ISAC calculations.”*

h. Subsection VI.H.

MISO proposes to add the following provision as subsection VI.H in Schedule 53A: “*The SAC for each Resource will be calculated as its pro-rata share of the Resource Class-level UCAP based on its individual ISAC value using the following equation:*

$$SAC_i = Resource\ Class\text{-}Level\ UCAP * \frac{Resource\ ISAC_i}{Resource\ Class\text{-}level\ ISAC}$$

for each resource, i.”

i. Subsection VI.I.

MISO proposes to add the following provision as subsection VI.I. in Schedule 53A: *“The Transmission Provider will post initial values for ISAC, SAC, Resource Class-level UCAP, and Resource Class-level ISAC (“Initial SAC Posting”), for each Season, by December 15 prior to the applicable Planning Resource Auction. Any dispute related to the initial ISAC values shall be submitted to the Transmission Provider in writing within thirty (30) Calendar Days of such posting. The Transmission Provider will post final values for ISAC, SAC, Resource Class-level UCAP, and Resource Class-level ISAC (“Final SAC Posting”), for each Season, by February 15 prior to the applicable Planning Resource Auction. No changes will be made to the Final SAC values following the February 15 posting, unless the Resource Class-level ISAC changes more than three percent (3%) and at least 30 MW.”*

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

MISO proposes to revise Section VI. of Schedule 53, which will become Section VII. in Schedule 53A as follows: "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. For Planning Year 2022/23 Schedule 53 Resources that were not committed under the annual construct during the period considered in the SAC calculations can direct MISO to accredit them in accord with their offers as described in Section IV above instead of using a class average~~ *its respective seasonal Resource Class-level UCAP as a percentage of the corresponding Resource Class-level ICAP will be multiplied by the Resource's ICAP*. 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 to ICAP Ratio for~~ its *respective* Resource ~~type~~ *Class's UCAP percentage multiplied by its ICAP* 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. STAKEHOLDER ENGAGEMENT

A. Stakeholder Outreach and Meetings

MISO has engaged in detailed discussions with stakeholders at the RASC, various workshops, and other dedicated meetings about these proposed reforms since January 2022. Moreover, these reforms to resource accreditation and PRMR calculation are the most recent developments in a long line of RAN-related initiatives that have been discussed in various stakeholder forums since early 2015. As discussed above, MISO has already taken action with FERC filings related to implementation of the RBDC in 2023, the move to a seasonal RA construct and a methodology to accredit thermal resource based on their availability during high-risk periods in 2022, and outage coordination and LMRs in 2020, 2019, and 2018. Regarding the current proposal, MISO evaluated several different approaches, discussed them with stakeholders, and ultimately selected the DLOL approach for implementation. These discussions have occurred for the past two years through the RASC and specific workshops dedicated to resource accreditation reform. Attached to Mr. Ramey's testimony as Exhibit A is a table outlining the numerous meetings and topics covered with stakeholders during the development of this proposal. As indicated by the table, stakeholder involvement in the development and evaluation of this proposal has been extensive.

In addition to hosting meetings and workshops on this topic, MISO published several iterations of the Accreditation Whitepaper[69] designed to educate stakeholders on its resource accreditation reform efforts. Each version of the Accreditation Whitepaper builds upon the last

[69] The Accreditation Whitepaper was initially published in May 2023; the second iteration of the Whitepaper was published in November 2023, the third iteration of the Whitepaper was published in February 2024, and the latest iteration was published in March 2024.

and documents the evolution of MISO's thinking related to its resource accreditation reform efforts. The version published in February 2024 included incremental updates and design details pertaining to DLOL-based method for class-level accreditation calculations, PRMR and LRR calculations. The latest version published in March 2024 includes clean ups and clarifications identified in the previously posted version.

Throughout the stakeholder engagement period, MISO solicited feedback from stakeholders, and provided written and verbal responses. During the numerous stakeholder discussions, MISO made several refinements and improvements to the proposal. These modifications include the following:

- application of DLOL-based methodology to all resources except External Resources;[70]
- inclusion of a three-year transition period;
- use of expanded hours;
- use of weights and caps;
- use of the DLOL-based methodology to determine PRMR; and
- inclusion of resource classes in the Tariff.

Some of these changes were proposed by stakeholders through written and verbal feedback. MISO evaluated each proposal to determine consistency with the objectives of the current proposal and potential for 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 Tariff changes described below reflect these stakeholder proposals 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.

In addition to the RASC meetings that have occurred over the past two years, MISO's External Affairs ("EA") team has been meeting with individual Load Serving Entities to educate them about MISO's proposal and answer questions. EA provided unit-level indicative results to Market Participants during the course of those meetings and EA facilitated MISO's response to a wide range of questions. Many of the questions revolved around how the new methodology impacts the accreditation of their specific resources.

B. Responses To Key Issues Raised By Stakeholders

As described above, MISO has engaged in substantial stakeholder discussions relating to the development of the DLOL-based methodology proposed in this filing. As part of those

[70] In Docket No. ER22-495, FERC approved Schedule 53, which is applicable to thermal resources. As a result of stakeholder discussions, MISO realized that the DLOL-based methodology could be applied more broadly to both thermal and non-thermal resources and adjusted its proposal accordingly.

discussions, stakeholders have raised various issues that have been documented, vetted and, as appropriate, incorporated into 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. This list is not exhaustive, but is intended to address the major issues presented by stakeholders:

- **Resource Classes** – MISO's position on this topic shifted based upon stakeholder feedback but did not satisfy all stakeholder requests. MISO's initial plan was to include a criteria for defining Resource Class in the Tariff and add specific resource classes to the Business Practices Manual for Resource Adequacy. Based upon stakeholder feedback, MISO decided to expand the definition in the Tariff to include a list of resource classes. MISO heard from several stakeholders that they wanted resource classes defined in the Tariff and MISO agreed. While this change satisfied some stakeholders, others demanded more details within the Tariff. While MISO expanded the Resource Class definition in the Tariff to include specific Resource Classes in the Tariff in direct response to feedback, additional details related to Resource Classes are best suited for the Business Practices Manual for Resource Adequacy.

- **Modification of Unforced Capacity Definition** – Stakeholders requested that MISO not modify the definition of UCAP. Their rationale was that the term has a generally accepted use and definition within the broader industry and that MISO should not diverge from that. MISO maintains that its revised definition of UCAP remains consistent with how the term is generally used within the industry and that each RTO/ISO defines the term in a slightly different way. At MISO, the Unforced Capacity of a Resource is the term used to measure a Resource's Capacity after accounting for its unavailability due to forced outage or other reasons. As the resource fleet is transitioning and the industry is evolving, now is an appropriate time for MISO to refine the definition of UCAP to reflect how it will be accounting for a resource's capacity based upon its availability in the LOLE model in the future.

- **Critical Hours / Expanded Hours** – MISO's position on this issue shifted based upon stakeholder feedback but did not fully satisfy all stakeholder requests. MISO's initial design was focused only on LOL hours, or hours where there was expected unserved energy. Stakeholders pushed back and encouraged MISO to expand the hours used in class-level accreditation calculations to include other low margin hours. After careful consideration and additional analysis, MISO agreed to expand the hours to include those with both loss of load events and those with the smallest differences between available generation and load. Stakeholders then requested that MISO include additional details in the Tariff related to expanded hours, but MISO responded that the Tariff includes the appropriate policy level details and additional information related to Critical Hours are implementation details that are best included in the Business Practices Manual for Resource Adequacy.

- **Use of Weights for Resource Class-level UCAP Calculations** – Once MISO agreed to expand hour selection to include low-margin hours, it confirmed the need to add weights to ensure the reliability risk that is expected during those hours is being appropriately accounted for in the accreditation calculation. Equal weighting for LOL hours and low-margin hours would assume the same level of reliability risk during those two sets of hours even though the probabilistic model indicates expected unserved energy only during the LOL hours. Some stakeholders supported the proposal, while others said that MISO did not provide sufficient policy justification for use of weights and caps and that MISO's selection of 3% of margin to determine critical hours is arbitrary. MISO disagrees. MISO decided to include the expanded hours to capture the additional high-risk hours which may not be captured as LOL hours and to improve the stability of results by improving the sample size for non-summer months. The 3% margin provides a reasonable sample size without compromising the fundamental object of capturing availability of the resources during the periods of highest reliability risks. Weights are applied to each hour that gets selected as a "critical hour" to ensure the reliability risk that is expected during those hours is being appropriately accounted for in the accreditation calculation.

- **Use of Caps for Resource Class-level UCAP Calculations** – Stakeholders expressed concerns that MISO's proposed cap of 1950 would limit the total number of LOL hours to a small number of modeled weather years thereby creating year-over-year volatility. MISO disagrees. MISO explained that its design will include all LOL hours, and the cap of 1950 hours only applies when there are not sufficient LOL hours identified in a season. MISO's proposed method for expanding hours is increasing the total number of selected critical hours in each Season without reaching the proposed cap of 1950 hours. (E.g. Fall Season goes from 265 to 934 hours; Winter goes from 201 to 1118 hours; and Spring goes from 240 to 1562 hours.) These critical hours capture risks distributed across multiple simulation years. MISO's proposed method improves year-over-year stability of results by accounting for an adequate number of high-risk hours, which may not be captured as LOL hours.

- **Impact of DLOL-based methodology on dispatchable intermittent resources** – Several stakeholders complained that MISO's proposal undervalues solar generation's contributions to resource adequacy and that the DLOL-based methodology results in lower class level accreditation for the nuclear class. Similarly, other stakeholders complained that the DLOL-based methodology does not encourage retaining or adding dispatchable energy-producing resources. In addition, stakeholders encouraged MISO to ensure that the proposed DLOL-based methodology is not unduly discriminatory. In response to these stakeholder concerns, MISO explained that its proposal ensures that the accredited capacity value of a resource reflects the capability and availability of the resource during periods of highest reliability risk. MISO said that its proposal is technology agnostic and is sufficiently robust to provide results for each resource class consistent with their reliability contribution during periods of highest risk. MISO's proposed 2-step accreditation approach provides a balanced result by incorporating beneficial aspects of prospective (probabilistic analysis) and retrospective (RA hours) risk assessments. Resource Class-level accreditation using the DLOL-based methodology is based on a prospective method that examines many potential system conditions and risks that may be observed. Allocation of Resource Class-level accreditation to each Resource in the class is based on the retrospective method that accounts for performance during actual operational risk realized. By design, the values coming out of the above two step method are not expected to align fully. The DLOL-based methodology captures each Resource Class's expected availability based on a much broader set of system conditions (100s of possible scenarios) while the actual realized risk is just one possibility out of that broader set.

- **LRR Calculations** – Stakeholders provided feedback on MISO's initial proposal for LRR calculations that it does not account for different resource mixes in each zone and recommended LRR calculations using individual accreditation rating for each unit in an LRZ. Based upon stakeholder feedback, MISO revised its proposal to use Unit ISAC to Class ISAC percentage from previous planning year to allocate Resource Class-level accreditation values to individual LRZs.

- **Filing Timeline** – Several stakeholders complained that MISO's proposal for the accreditation reform filing at FERC is premature and requested MISO delay the filing by 3 months or whatever time is necessary to complete a transparent stakeholder process. Those stakeholders commented that a premature filing could cause more uncertainty, which would be bad for investment. MISO disagrees. MISO's final proposal, which was presented at the Jan 17th and Feb 28th RASC meetings, is a culmination of a comprehensive design effort and robust stakeholder process that occurred over the last two years. MISO has added sufficient policy level details about the proposed method in the Tariff and has saved the technical details regarding implementation to be included in the Business Practices Manual for Resource Adequacy. A successful tariff filing will provide certainty of direction for LSEs and regulators that engage in resource planning for their respective jurisdictions, and the transition period will provide an opportunity for everyone to adjust to the new methodology prior to implementation. The filing is not premature. The design is complete and receiving approval of the design sooner rather than later will provide MISO, LSEs, regulators and other interested stakeholders the certainty necessary to plan for the changing future.

- **Implementation timeline** – Some stakeholders have complained that the Implementation timeline is unreasonable because it does not allow sufficient time to plan and build new generation resources to resolve resource adequacy shortfalls. MISO disagrees. MISO's proposed 3-year transition allows time to better understand and plan for the changes to accreditation and reserve margin calculations pursuant to the DLOL-based methodology. Waiting to implement this DLOL-based method beyond three years could pose unreasonable reliability risks to the system. Significant growth of weather dependent intermittent 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. Approximately 50 GW of resources (32 GW of which are solar resources) approved through MISO's interconnection processes are under or awaiting construction. If these resources start coming online at a much faster pace than the historical trend, MISO may experience shifting risk profiles much earlier than current expectations. The three-year transition period proposed by MISO strikes the appropriate balance between: (1) providing LSES, regulators and other impacted stakeholders time to adjust to the new methodology and align resource plans to meet their future needs; and (2) timely responding to the reliability risks presented by the changing resource mix.

- **PRMR Allocation** – Several stakeholders recommended delaying the filing to provide time for MISO and stakeholders to work through and include LSE allocation of PRMR in this filing. MISO disagrees that allocation of PRMR is a necessary component of the instant filing. If MISO's proposal is approved, then MISO's PRMR calculation will be based on accredited values of Resource Classes that are calculated based on the proposed DLOL-based methodology.

The PRMR will be converted to PRM (%) based on coincident peak load and hence will be applied to LSEs based on their submitted coincident peak load. FERC has previously found MISO's current method for allocating PRMR to be just and reasonable and that method can be used to allocate the DLOL-based PRMR until such time as MISO proposes a new PRMR allocation methodology. Also, depending on changes to the allocation method, LSEs may need to change their load forecast submission which would also need to be evaluated from feasibility and timing perspective. MISO will work with stakeholders to evaluate options to change the allocation approach for PRMR and will make a FERC Filing, when necessary. However, changing the PRMR allocation is not a necessary component for either approval of or successful implementation of MISO's proposed DLOL-based accreditation methodology.

- **Additional LOLE Enhancements** – Several stakeholders recommended delaying the filing to later in 2024, after additional conversation on LOLE enhancements have occurred. Those stakeholders suggested making a list of all planned LOLE modeling enhancements, the issues MISO is intending to solve with these enhancements and any known solutions at this time. They wanted MISO to address LOLE planned outage modeling improvements, provide high-level concept of the LOLE modeling of storage, and explore an Energy Equity Dispatch methodology for storage resources in the SERVM LOLE software. MISO responded to these stakeholders by confirming that LOLE modeling improvements and enhancements are part of MISO's standard practice for its Resource Adequacy construct and are done in the ordinary course of business. MISO said there is no need to delay the filing to address improvements and enhancements to the model. MISO recognizes that refinements to the model are necessary but disagrees that stakeholder support for the DLOL-based methodology should be contingent upon how the model performs. It is MISO's position that adoption of the DLOL-based methodology is necessary to address the reliability risks presented by the changing the resource mix and that enhancements to the model will certainly improve the outcome of accredited values. MISO is committed to working with stakeholders to identify LOLE model improvements and enhancements. In fact, MISO has prioritized that effort, which was kicked off at the Feb 28th RASC meeting. However, LOLE model enhancements and improvements are not within the scope of this filing and delaying the filing to address those issues is unnecessary.

- **Data Transparency** – Stakeholders have expressed an interest in being able to run the models and replicate the accreditation values. Given that the models use confidential data, MISO has been working with stakeholders to develop a process for them to access the data they need without violating the confidentiality provisions included within its Tariff. MISO has confirmed to stakeholders that Attachment Z of the MISO Tariff establishes a presumption that entity/asset specific Market Participant data, including load forecasts, are confidential. As a result, MISO has agreed to share aggregated, masked and class average data consistent with past practice and industry standards. MISO has said that Market Participants who seek more granular information will need to demonstrate that aggregated, masked and class average data is not sufficient to meet legitimate needs. Development of a process regarding MISO's Resource Adequacy data transparency is an ongoing effort and MISO will continue to work with stakeholders to find a mutually acceptable process that maintains confidentiality and provides stakeholders the information they need to replicate accreditation values.

VIII. Documents Submitted with this Filing

In addition to this Transmittal Letter, this submission includes:

- Tab A – Redline Tariff[71]
- Tab B – Clean Tariff
- Tab C – Redline comparison of Schedule 53 to Schedule 53A[72]
- Tab D – Testimony of Todd Ramey
- Tab E – Testimony of Zakaria Joundi
- Tab F – Testimony of Zachary Ming, Energy+Environmental Economics (E3)
- Tab G – Affidavit of Dr. David Patton, Independent Market Monitor

IX. Proposed Effective Date and Implementation Timeline

MISO requests an effective date of September 1, 2024 for the Tariff provisions 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.

Beginning September 1, 2024, MISO will provide Resource Class-level indicative accreditation values to stakeholders each Planning Year, beginning with PY 2025 – 2026 and continuing for two Planning Years. Indicative results will be provided for each Planning Year as soon as reasonably possible and prior to the PRA to be held each Spring of the respective Planning Year. Such indicative results shall include Resource Class-level accreditation values and PRMRs and LRRs/LCRs calculated using the DLOL methodology defined in Schedule 53A.

In addition, the Tariff provisions proposed herein include an implementation date of June 1, 2027, for calculation of requirements and accreditation of resources pursuant to the DLOL-based methodology defined in Schedule 53A commencing with PY 2028 – 2029. MISO commits to making a subsequent Section 205 filing with the Commission to remove Schedule 53 in its

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[71] Language currently pending before the Commission in the following, unrelated docket is highlighted in yellow: ER23-2977-000. MISO requests that the Commission treat such highlighted language as subject to the outcome of that pending proceeding. If needed, MISO commits to file any revisions to this highlighted language as necessary to comply with any Commission orders in that proceeding.

In addition, MISO has removed language that has a future effective date of 10/1/2029 and is pending under Docket No. ER22-1640-000. 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 date of the language in Docket No. ER22-1640-000.

[72] MISO is only providing a comparison of proposed Schedule 53A to the current version of Schedule 53 for ease of review. The current Schedule 53 is not included in this instant filing.

entirety and replace it with Schedule 53A prior to June 1, 2028.

MISO requests that the Commission establish a comment date of thirty (30)-days from the date of this filing to provide stakeholders and regulators sufficient time to evaluate and comment on the instant proposal. 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.

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) (2023), to the extent necessary to permit the designation of more than two persons for service on behalf of MISO in this proceeding and request 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 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 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 that Commission deems applicable to this filing in order for the Commission to accept it as proposed.

Respectfully submitted,

/s/ Michelle Quinn

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Attachments

Tab A

Sample Membership Agreement: The document that establishes the rights and obligations between the Electric Generation and Transmission Cooperative (Coop) and its members.

Scarcity Price: The LMP and MCP price levels determined by Demand Curves when insufficient Operating Reserves or Short-Term Reserves are cleared to meet the Operating Reserve or Short-Term Reserve requirements, respectively.

Schedule 16 Costs: The monthly charge of costs to be recovered under Schedule 16 of this Tariff shall include any deferred pre-operating costs, direct and indirect capital costs, direct and indirect operating expenses and all other costs associated with administrating the Financial Transmission Rights Administrative Service under this Tariff.

Schedule 17 Costs: The costs to be recovered under Schedule 17 of this Tariff shall include any deferred pre-operating costs, direct and indirect capital costs, direct and indirect operating expenses and all other costs associated with administering the Energy and Operating Reserve Market Support Administrative Service under this Tariff.

Scheduled Injections: Energy scheduled in the Day Ahead Energy and Operating Reserve Market to be injected over an Hour of the Operating Day.

Scheduled Withdrawals: Energy withdrawals scheduled in the Day Ahead Energy and Operating Reserve Market over a given Hour of the Operating Day.

Scheduling Agent: An entity designated by a Market Participant that has the authority to conduct business in the Transmission Provider Region on behalf of the Market Participant.

Scheduling Instructions: Directives issued by the Transmission Provider or Local Balancing Authority to Market Participants with Load Modifying Resources indicating MW quantities to be reduced during Emergencies.

SCUC Instructed Hours of Operation: The period beginning when a Resource is synchronized to the Facilities within the MISO Balancing Authority Area in response to the Transmission Provider selecting the Resource in the unit commitment portion of the SCUC process and ends at the later of: (i) the time incorporating the sum of the time when the Resource is synchronized and the Resource's Minimum Run Time and (ii) the earlier of the time the Resource is forced out of service or the time when the Transmission Provider notifies the Market Participant that the Resource is no longer needed. The SCUC Instructed Hours of Operation cannot extend beyond the Operating Day.

Seams Operating Agreement: An agreement between adjacent balancing authorities or transmission providers for the coordination of operations, including joint operating agreements.

Season: The four (4) seasons are (i) Winter – December, January, February; (ii) Spring – March, April, May; (iii) Summer – June, July, August; and (iv) Fall – September, October, November.

Seasonal Accredited Capacity (SAC): The amount of accredited Capacity, for a given Season, in MW, assigned to a Planning Resource ~~after accounting for its historic availability~~that is convertible to Zonal Resource Credits.

SEC: Securities and Exchange Commission.

Second Planning Area: The area of the Transmission Provider Region where Entergy Corporation and its Operating Companies that own and/or operate transmission facilities (i.e., located in Arkansas, Louisiana, Mississippi, or Texas) that are conveyed to the functional control of the Transmission Provider to provide Transmission Service pursuant to Module B of the Tariff. The Second Planning Area shall be formed when the first Entergy Operating Company conveys functional control of its transmission facilities to the Transmission Provider, and may be expanded if other Entergy Operating Companies or adjacent utilities in Arkansas, Louisiana, Mississippi or Texas, join MISO later in the Second Planning Area's Transition Period.

Second Planning Area's Transition Period: The period: (i) commencing when the first Entergy Operating Company conveys functional control of its transmission facilities to the Transmission Provider to provide Transmission Service under Module B of this Tariff; (ii) consisting of at least five consecutive (5) years, plus the time needed to complete the MTEP approval cycle pending at the end of the fifth year; (iii) ending on the day after the conclusion of such MTEP approval cycle, which in no case shall be more than six years after the start of that period; and (iv) during which the Transmission Provider shall review and compare the current states of the transmission systems in the First Planning Area and the Second Planning Area and, if a lack of comparability is found, shall identify transmission projects necessary to achieve comparability. The processes for identifying transmission projects necessary to achieve comparability and allocating costs associated with the projects that are so identified during the Second Planning Area's Transition Period are set forth in Attachment FF-6.

Security Constrained Economic Dispatch (SCED): An algorithm capable of clearing, dispatching, and pricing Energy, Operating Reserve, Up Ramp Capability, Down Ramp

Capability, and Short-Term Reserve in a simultaneously co-optimized basis that minimizes Production Costs and Operating Reserve Costs while enforcing multiple security constraints. The algorithm keeps the commitment of Resources fixed in the dispatch. The model is described in Schedule 29.

Security Constrained Economic Dispatch Pricing (SCED-**Pricing**): An algorithm capable of clearing, dispatching, and pricing Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, and Short-Term Reserve in a simultaneously co-optimized basis that minimizes Production Costs and Operating Reserve Costs while enforcing multiple security constraints. The model is described in Schedule 29A.

Security Constrained Unit Commitment (SCUC): An algorithm capable of committing Resources to supply Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, and Short-Term Reserve on simultaneously co-optimized basis that minimizes Capacity costs while enforcing multiple security constraints.

Selected Developer(s): The RFP Respondent(s) identified in the Selected Proposal. Selected Developers shall not include Proposal Participants.

Selected Developer Agreement (SDA): An agreement, in the form provided in Appendix 1 of Attachment FF of the Tariff, between a Selected Developer, including existing Transmission Owners, ITCs, and Non-owner Members, and the Transmission Provider establishing the terms and conditions under which the Selected Developer will construct and implement the Competitive Transmission Facilities specified in its Selected Proposal. Among other terms, the Selected Developer Agreement shall include any binding cost control measures, including cost caps, which the Selected Developer specified in its Selected Proposal.

Selected Proposal: The Proposal selected for implementation by the Competitive Transmission Executive Committee, pursuant to Attachment FF of the Tariff.

Self Schedule: The designation by a Market Participant of a specific amount of Energy and/or Operating Reserve and/or capacity to be supplied from a specific Resource or Planning Resource as a Price Taker.

Self-Scheduled Resource: A Resource that is scheduled by a Market Participant and controlled by the same Market Participant under the overall coordination of the Transmission Provider. A Self-Scheduled Resource is a Price Taker for the portion of the Resource that is Self Scheduled.

Service Agreement: The initial agreement and any amendments or supplements thereto entered into by the Tariff Customer and the Transmission Provider for service under this Tariff, including, without limitation, any service agreement executed pursuant to Section 27A (an HVDC Service Agreement), Module F, and Attachment KK of the Tariff.

Service Commencement Date: The date the Transmission Provider or ITC begins to provide service pursuant to the terms of an executed Service Agreement, or the date the Transmission Provider or ITC begins to provide service in accordance with Section 15.3 or Section 29.1 under this Tariff.

Setpoint Instruction: The real-time desired MW output signal calculated for a specific Resource by the Transmission Provider's control system on a specified periodicity that is equal to the current Energy Dispatch Target plus the Regulating Reserve Deployment instruction (which may be positive or negative) plus an adjustment to the Energy Dispatch Target to account for Contingency Reserve Deployment Instructions. The Setpoint Instruction represents the desired output level of the Resource.

Settlement: The process of determining charges to be paid to or by a Market Participant in the Energy and Operating Reserve Markets operated by the Transmission Provider under this Tariff.

Settlement Statements: Reports provided by the Transmission Provider to Market Participants containing some aggregate and some detailed charge type information and determinant data regarding financial obligations for Energy and Operating Reserve Market activities and services, allowing for the verification by the Market Participant of Settlements invoiced amounts.

Shadow Price: The marginal value of relieving a particular constraint.

Shortfall Amount: The difference between a Resource's Contingency Reserve Deployment Instruction and the actual amount of Contingency Reserve deployed by that Resource at the end of the Contingency Reserve Deployment Period; or the difference between a Resource's Economic Minimum Dispatch and the Actual Energy Injection of the Resource at the end of the Short-Term Reserve Deployment Period.

Short-Term Firm Point-To-Point Transmission Service: Firm Point To Point Transmission Service under Module B of this Tariff with a term of less than one (1) Year.

Short-Term High-Voltage Direct Current Service: HVDC Service under Section 27A of this Tariff with a term of less than one (1) year.

Short-Term Reserve: Rampable Capacity provided by eligible Resources available to the Transmission Provider to be converted to Energy within the Short-Term Reserve Deployment Period to address market-wide, sub-regional and/or local short-term needs for reserves as specified in Schedule 51 of this Tariff.

Short-Term Reserve Deployment Failure Charge: A charge assessed to any Resource that fails to achieve the Economic Minimum Dispatch within a Short-Term Reserve Deployment Period. Resources that clear Off-Line Short-Term Reserve will be made available for Operator commitment as a part of the Transmission Provider's Look Ahead Commitment process.

Short-Term Reserve Deployment Period: The thirty (30)-minute period of time within which the Resource must deploy Short-Term Reserve following the issuance of a Short-Term Reserve Deployment Instruction. The Short-Term Reserve Deployment Period is also the duration of time beyond the Resource Dispatch Target time that is used to determine on-line Resource participation capabilities for the Short-Term Reserve product.

Short-Term Reserve Dispatch Status: A specification submitted by a Market Participant in its Generation Offer for each hour to indicate whether the Transmission Provider is authorized to economically clear Short-Term Reserve on the Resource for the Hour. Valid Short-Term Reserve Dispatch Status specifications include: Economic and Not Participating.

Short-Term Reserve Qualified Resource: A Generation Resource that is not a Dispatchable Intermittent Resource, an Intermittent Resource, Demand Response Resource – Type II, or External Asynchronous Resource that has met the requirements to be eligible to provide Short-Term Reserve, and an Electric Storage Resource that has met the requirements to be eligible to provide online Short-Term Reserve, by submitting a Short-Term Reserve Dispatch Status other than "Not Participating" and/or is an Off-Line Short-Term Reserve Qualified Resource.

Short-Term Reserve Requirements: The Market-Wide Short-Term Reserve Requirement, Sub-Regional Short-Term Reserve Requirements, and Local Short-Term Reserve Requirements.

Shut-Down Offer: The compensation required by a Market Participant for reducing the consumption of a Demand Response Resource Type-I.

Shut-Down Notification Time: The amount of notification time required by a Demand Response Resource-Type I prior to the initiation of demand reduction procedures.

Shut-Down Time: The time required for a Demand Response Resource Type I to reduce consumption equal to its Targeted Demand Reduction Level or the time required for a Demand Resource to reduce consumption equal to its targeted Load reduction level or firm service level.

Significant Trade Reference: Trade reference provided to Transmission Provider in the registration process which are of a significant nature, as determined by Transmission Provider in its sole discretion.

Simultaneous Feasibility Test: A test for a state in which each set of injections and withdrawals associated with receipt point-to-delivery point FTRs and ARRs, and power transfers associated with FTRs and ARRs, would not exceed any thermal, voltage, or stability limits within the Transmission Provider Region under normal operating conditions or for monitored contingencies.

Single-Developer Proposal: A Proposal submitted by a single RFP Respondent that would become the sole Selected Developer for the Competitive Transmission Project, should its Single-Developer Proposal be designated as the Selected Proposal by the Transmission Provider.

Single-Directional-Down Ramp Rate Curve: The MW/minute ramp rate curve, that may include up to ten (10) linear segments at which a Generation Resource or Demand Response Resource-Type II can respond to the Setpoint Instructions in the downward direction only.

Single-Directional-Up Ramp Rate Curve: The MW/minute ramp rate curve, that may include up to ten (10) linear segments, at which a Generation Resource or Demand Response Resource-Type II can respond to the Setpoint Instructions in the upward direction only.

Sink Point: The Commercial Pricing Node at which a Financial Schedule terminates.

Source Point: The Commercial Pricing Node at which a Financial Schedule originates.

Spin Qualified Resource: A Generation Resource, an External Asynchronous Resource, a Demand Response Resource-Type I, a Demand Response Resource-Type II, or an Electric Storage Resource that has met the requirements to be eligible to submit Spinning Reserve Offers into the Energy and Operating Reserve Markets.

Spinning Reserve: A specified percentage, based on Applicable Reliability Standards, of Contingency Reserve that must be synchronized to the Transmission System and that meets all Applicable Reliability Standards, and that can be converted to Energy within the Contingency Reserve Deployment Period following a deployment instruction.

Spinning Reserve Offer: The price, in dollars per MW per Hour, at which a Spin Qualified Resource has agreed to sell Spinning Reserve. The price shall reflect the costs required for the Spin Qualified Resource to be made available to provide Spinning Reserve; and may also include a dollar component reflecting an expectation of any Incremental Energy Costs, or costs in Shut-Down Offers and/or Hourly Curtailment Offers with respect to Demand Response Resource – Type I, that might exceed market revenues when the Spin Qualified Resource follows a Contingency Reserve Deployment Instruction.

Start-Up Notification Time: The amount of notification time required by a Generation Resource prior to the initiation of start-up procedures or the amount of notification time required for a Demand Response Resource Type II, or Electric Storage Resource prior to the initiation of demand reduction procedures, from a hot state, intermediate state and cold state.

Start Up Offer: The compensation required by a Market Participant for bringing an off line Generation Resource on line or for reducing consumption of a Demand Response Resource-Type II, or Electric Storage Resource.

Start-Up Time: The number of Hours required to start a Generation Resource, Demand Response Resource-Type II, LMR, or Electric Storage Resource and synchronize with the Transmission Provider Region to Hourly Economic Minimum Limit consistent with the Applicable Reliability Standards from a hot state, intermediate state or cold state.

State Estimator: A software program used by the Transmission Provider to create a real time assessment of the condition of the Transmission Provider Region.

State Estimator MWs: The megawatts that are determined by the State Estimator to be generated at a given location for each Dispatch Interval.

State of Charge: The Energy, Capacity, Spinning Reserve, Supplemental Reserve and/or Regulating Reserve available to the Transmission Provider's markets from an Electric Storage Resource.

Statement of Support: A document that the Transmission Provider provides to Transmission Developer Applicants for submission with a Transmission Developer Application, which: (1) is executed by an Affiliate of a Transmission Developer Applicant; (2) lists specific qualifications, capabilities, and/or competencies that the Affiliate possesses and intends to make available to the Transmission Developer Applicant in order to assist the Transmission Developer Applicant with meeting one or more of the prequalification requirements set forth in Sections VIII.B.4, VIII.B.4.1, VIII.B.4.2, VIII.B.4.3, and/or VIII.B.4.4 of Attachment FF to the Tariff; and (3) authorizes the Transmission Developer Applicant to represent during the annual prequalification and recertification processes set forth in Sections VIII.B.2 and VIII.B.3 of Attachment FF to the Tariff that such Transmission Developer Applicant will have access to the specified qualifications, capabilities, and/or competencies.

Station Power: The Energy used for operating the electrical equipment on the site of a Generation Resource and/or for the lighting, heating, air-conditioning and office equipment needs of buildings located on the site of such a Generation Resource that are used in the operation, maintenance, or repair of the facility. Station Power does not include Energy (i) used for pumping at a pumped storage facility; (ii) to power synchronous condensers; (iii) in association with power system restoration or blackstart service, or (iv) used for charging an Electric Storage Resource. Station Power may only be provided pursuant to Schedule 20 of this Tariff.

Storage As Transmission Only Asset (SATOA): An Electric Facility connected to or to be connected to the Transmission System and approved for inclusion in Appendix A of the MTEP, as a transmission facility that is part of the Transmission System, that is capable of receiving Energy from the Transmission System and storing Energy for injection to the Transmission System, and is operated only to support the Transmission System. The SATOA shall not participate in the Transmission Provider's markets except to the extent necessary to receive Energy from the Transmission System and to inject Energy into the Transmission System to provide the services for which the SATOA was included in the MTEP.

Sub-Area: A portion of the MISO Balancing Authority Area identified by MISO as described in MISO's emergency operating procedures, consisting of the entirety of one or more Local Balancing Authority Areas, or multiple Local Balancing Authority Areas comprising a sub-region, that may require the implementation of emergency actions to address Capacity shortage conditions.

Sub-Region: One or more Reserve Zones, or any other portion of the MISO Balancing Authority Area limited by physical or contractual constraints, including Sub-Regional Power Balance Constraints, used to establish Short-Term Reserve Requirements.

Sub-Regional Export Constraint (SREC): 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.

Sub-Regional Import Constraint (SRIC): The amount of Planning Resources in megawatts modeled in the PRA for each Season, not within an applicable Sub-Regional Resource Zone (SRRZ), 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.

Sub-Regional Power Balance Constraint: A net Energy injection and withdrawal constraint established to manage intra-regional flows in accordance with applicable seams agreements, coordination agreements, transmission service agreements, or operating procedures.

Sub-Regional Power Balance Constraint Demand Curve: A demand curve used to price Sub-Regional Power Balance Constraints.

Sub-Regional Resource Zone (SRRZ): A zone, comprised of a LRZ or combination of two or more LRZs, established by the Transmission Provider 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.

Sub-Regional Short-Term Reserve: Short-Term Reserve that is available to the Transmission Provider in a Sub-Region.

Sub-Regional Short-Term Reserve Requirements: The amount of Sub-Regional Short-Term Reserve, as determined pursuant to Module C of the Tariff, that the Transmission Provider is required to procure in a Sub-Region.

Supervisory Control and Data Acquisition (SCADA) Data: The electric system security data that is used to monitor the electrical state of facilities, as specified in NERC Policy 4.

Supplemental Qualified Resource: A Spin Qualified Resource, or a Demand Response Resource-Type I or, a Generation Resource, Demand Response Resource Type-II, Electric Storage Resource, or External Asynchronous Resource that is not a Spin Qualified Resource that has met the requirements to be eligible to submit Supplemental Reserve Offers into the Energy and Operating Reserve Markets.

Supplemental Reserve: Contingency Reserve that is not considered Spinning Reserve that can be converted to Energy within the Contingency Reserve Deployment Period and that meets all Applicable Reliability Standards.

Supplemental Reserve Offer: The price, in dollars per MW per Hour, at which a Demand Response Resource Type I or an External Asynchronous Resource that is a Supplemental Reserve Qualified Resource has agreed to sell Supplemental Reserve.

Suspend: The cessation of operation of a Generation Resource or an SCU for more than two (2) months commencing on a specified date that is provided to the Transmission Provider, that includes the right to rescind or modify the Attachment Y Notice for a period ending no later than thirty-six (36) months after the start date specified in an original (i.e. initial, first) Attachment Y Notice, consistent with the requirements in Section 38.2.7 and Attachment X.

Synchronous Condenser Unit (SCU): A facility that can be synchronized to the Transmission Provider's Transmission System without producing Energy.

System Auction Clearing Price (System ACP): 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 Final 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).

System Condition: A specified condition on the Transmission System or on a neighboring transmission system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm Point-To-Point Transmission Service or Long-Term Firm HVDC Service using the curtailment priority pursuant to Section 13.6 or 27A.1.5 of this Tariff, respectively. Such conditions must be identified in the Transmission Customer's Service Agreement or HVDC Service Agreement.

System Impact Study: An assessment by the Transmission Provider and ITC, as applicable, of (i) the adequacy of the Transmission System to accommodate a request for either Firm Point-To-Point Transmission Service or Network Integration Transmission Service and (ii) whether any additional costs may be incurred in order to provide Transmission Service. System Impact Studies for any transmission facilities not under the operational control of the Transmission Provider or ITC shall be performed by the Transmission Owner or applicable ITC Participant or any entity the Transmission Provider designates to perform the studies.

System Losses: The transmission losses experienced on the Transmission System as determined by the Network Model.

System Operating Limit (SOL): The value (such as MW) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. Also referred to as Operating Security Limit.

System Purchase Contracts: Agreements for the purchase of Energy that do not specify the Resource(s) that the seller shall select to supply such Energy at any particular time; provided, however, that such agreements may identify the group of Resources from which the seller may make its selection; provided, further that this term does not include agreements with Manitoba Hydro involving the supply of Energy from resources in Canada up to or at the U.S. border.

System Restoration Plans: The plans developed by the individual Transmission Operators, and coordinated by the Transmission Provider acting in its capacity as the Reliability Coordinator, to enable a system restoration zone to re-energize the Transmission System following a system-wide blackout.

System Support Resource (SSR): Generation Resources or Synchronous Condenser Units that have been identified in Attachment Y – Notification to this Tariff and are required by the Transmission Provider for reliability purposes, to be operated in accordance with the procedures described in Section 38.2.7 of this Tariff.

SSR Agreement: An agreement identified as Attachment Y 1 to this Tariff that the Transmission Provider, the owner or operator of an SSR Unit executes to provide the terms and conditions under which the SSR Unit will be operated and compensated.

SSR Notification: The form in Attachment Y of this Tariff that the owner or operator of a

Generation Resource or a Synchronous Condenser Unit must complete and send to the Transmission Provider at least twenty-six (26) weeks prior to Retiring or Suspending any Generation Resource or Synchronous Condenser Unit located within the Transmission Provider Region, consistent with the requirements in Section 38.2.7.

SSR Unit: A Generation Resource or a Synchronous Condenser Unit that is operated and compensated in accordance with an SSR Agreement.

Uncollectible Obligation: Any Past Due Amount that the Transmission Provider has concluded, pursuant to Section 7.10, is not reasonably expected to be paid in full within an acceptable period of time.

Undeployed Regulating Mileage: Any un-utilized Regulating Mileage that was considered for a Dispatch Interval during the market clearing.

Undeployed Regulating Mileage Revenue Sufficiency Guarantee: A Resource credit guaranteed by the Transmission Provider ensuring the recovery of any lost profit from charging back at Regulating Mileage MCP to resources for Undeployed Regulating Mileage.

Under-Forecast: The negative difference between the forecasted Demand and actual measured Demand, after adjustment for actual weather conditions, retail Load changes and actual LMPs. LSEs with Load whose withdrawals vary based on LMP and who provide verifiable statistical analysis to support the associated price elasticity can normalize actual measured Demand to reflect differences between forecasted and actual LMPs.

Unforced Capacity (UCAP): The amount of Capacity in MW assigned to a Planning Resource after accounting for either its forced outage rateavailability in the LOLE analysis or historic availability, as applicable.

Unloaded Capacity Requirement: The amount of online, available generation Capacity above the generation Capacity needed to meet instantaneous total Load obligations that must be maintained to ensure online Resources are able to meet ramping requirements of all products cleared in the co-optimized market solutions. It is determined by the Transmission Provider's real-time operations personnel after reviewing historical periods and setting specific levels of generation Capacity needed for maintaining reliable and efficient operations.

Unsecured Credit: Any credit granted by Transmission Provider to an Applicant and/or Tariff Customer that is not secured by a form of Financial Security.

Unsecured Credit Allowance: Unsecured Credit extended by Transmission Provider in an amount determined by Transmission Provider's evaluation of the creditworthiness of the Applicant and/or Tariff Customer.

Unsecured Credit Floor: For credit scoring purposes, the minimum amount of Unsecured Credit to be extended to a creditworthy Public Power entity.

Up and Down Ramp Capability Qualified Resource: A Generation Resource that is not a Dispatchable Intermittent Resource, External Asynchronous Resource, Demand Response Resource-Type II, or Electric Storage Resource that has met the requirements to be eligible to provide Up and Down Ramp Capability by submitting Up and Down Ramp Capability dispatch status other than "Not Participating" into the Energy and Operating Reserve Markets.

Up Ramp Capability (URC): The product representing the ability of dispatchable resources to respond to future upward changes in demand within the Ramp Capability Response Time after a given dispatch. The Real-Time Market-Wide Up Ramp Capability Requirement is defined by expected market-wide upward variation in dispatchable generation to account for forecasted changes in load and Scheduled Interchange while considering the contribution of non-dispatchable generation (negative for a downward variation) plus the upward short-term uncertainty associated with the Load Forecast, non-dispatchable generation forecast, and units not responding to their Setpoint, all evaluated over the Ramp Capability Response Time. If the resulting requirement is negative, the requirement is set to 0 so that the requirement is always non-negative.

Up to TUC Interchange Schedule: Interchange Schedules that specify a willingness to pay the Transmission Usage Charge (dollars per MWh) represented by a maximum amount beyond which the Market Participant agrees to be curtailed.

Use Limited Resource: Generation Resources, Electric Storage Resources or External Resource(s), that due to design considerations, environmental restrictions on operations, cyclical requirements, such as the need to recharge or refill, or for other non economic reasons, are unable to operate continuously on a daily basis, but must be able to operate for a minimum set of consecutive operating Hours.

Users: Transmission Customers or other entities that are parties to transactions under this Tariff.

Loss of Load Expectation Analysis

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. This probabilistic analysis shall use a Loss of Load Expectation (LOLE) study which assumes that there are no internal transmission limitations within the Transmission Provider Region.

The 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. If 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. If 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 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.

The minimum amount of capacity above Coincident Peak Demand in the Transmission Provider Region required to meet the reliability criteria will be used to establish the PRM for each Season.

The PRM will be established as an Unforced Capacitya requirement based upon the weighted average forced outage rate of all Planning Resources inin terms of the total Unforced Capacity for the Transmission Provider Region.

Schedule 53A

Extended Seasonal Accredited Capacity Calculation

I. Applicability

A. Implementation Date of Schedule 53A

The provisions of this Schedule 53A, except Subsection I.B Effective Date of Reporting Requirement, shall be effective on June 1, 2027 for implementation beginning with Planning Year 2028-2029 and continuing thereafter. The Transmission Provider shall make a filing to remove the currently effective Schedule 53 from the Tariff to be effective June 1, 2028.

B. Effective Date of Reporting Requirement

Commencing on September 1, 2024, the Transmission Provider will publish indicative results pursuant to the provisions set forth in this Schedule 53A. Such indicative results shall be published prior to the applicable Planning Resource Auction for Planning Year 2025–2026, and the two Planning Years thereafter, as further described in the Business Practices Manual for Resource Adequacy.

C. Resource Classes

The term "Resource Class" as used in this Schedule 53A shall mean 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 this Schedule 53A. All Capacity Resources, except External Resources, shall be assigned to one of the Resource Classes identified in this section for purposes of executing the two-step resource accreditation methodology defined in this Schedule 53A and determining the Planning Reserve Margin Requirement, as set forth in

Module E-1. A DRR-Type I or DRR-Type II that is a behind the meter generation facility, and that qualifies as a Capacity Resource shall be assigned to an applicable Resource Class below. A DRR-Type I that interrupts or controls demand shall be accredited pursuant to Section VI below. Resource Classes shall include:

Gas (including Oil)	Storage
Combined Cycle	Solar
Coal	Wind
Hydro	Run-of-River
Nuclear	Biomass
Pumped Storage	

Additional details regarding Resource Classes shall be included in Transmission Provider's Business Practices Manual for Resource Adequacy. The Transmission Provider will provide a mapping of each Capacity Resource to one of the above Resource Classes as per the schedule listed in the Transmission Provider's Business Practices Manual for Resource Adequacy. Any dispute regarding Resource Class assignment must be submitted to the Transmission Provider in writing within ten (10) Business Days from the date such assignment was provided to the Market Participant.

II. General

Seasonal Accredited Capacity (SAC) for a Capacity Resource, except an External Resource, will be determined pursuant to this Schedule 53A. The resources accredited pursuant to this Schedule 53A, as described above, are hereinafter referred to as "Schedule 53A Resources".

The SAC calculation for Schedule 53A Resources will be performed using a two-step process. First, the Resource Class-level UCAP will be determined by the method described in section II.A. Second, the Resource Class-level UCAP will be allocated amongst the individual resources in the Resource Class using the individual resource performance during Tier 1 and Tier 2 Hours based on the prior three years of operational performance as described in section II.B.

A. Resource Class-level UCAP and ICAP Calculation

Resource Class-level UCAP in a Season will be determined by calculating the combined expected availability and performance of all resources within that Class during Critical Hours from the probabilistic LOLE analysis as set forth in Module E-1. For each Season, "Critical Hours" are defined as the set of all 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. For those Seasons with 1,950 or more loss of load hours, Critical Hours will only include loss of load hours. Once Critical Hours are determined for each Season, weights are calculated for each of the Critical Hours using a weighting system that assigns greatest weight to the hours with the highest risk (i.e. hour with most unserved energy), as further described in the Business Practices Manual for Resource Adequacy. After calculating the weights for each Critical Hour, Critical Hours will be capped at 1,950 hours for each Season during which there are less than 1,950 loss of load hours. Finally, Seasonal Resource Class-level UCAP will be calculated as the weighted average of the Resource Class performance during Critical Hours in the Season.

Resource Class-level ICAP will be calculated as the sum of the ICAP values of all Resources in the Resource Class.

B. Resource-level Extended Seasonal Accredited Capacity Calculation

A two-tiered weighting structure is used to calculate Extended Seasonal Accredited Capacity for Schedule 53A Resources. Outage exemptions for planned outages and exemptions for any operating limitations, such as thermal, voltage, or stability limits referenced in the BPM for Outage Operations, provided by the Transmission Provider or Transmission Operator to preserve the reliability of the Transmission System, that modify the must offer obligation set forth in Section 69A.5.a will be factored into calculating the tiers of a Schedule 53A Resource's Extended Seasonal Accredited Capacity.

III. Tier 1 and Tier 2 Planned Outage Exemption Requirements

Generator Planned Outages will be evaluated for Tier 1 and Tier 2 exemptions based on the following requirements. Only full (Out-of-Service) Generator Planned Outages or full (Out-of-Service) Proposed Generator Planned Outages shall be eligible for the Tier 1 and Tier 2 planned outage exemptions set forth below. Resources in the Solar Resource Class shall not be eligible for Tier 1 and Tier 2 Planned Outage Exemptions for Generator Planned Outages and Proposed Generator Planned Outages that are scheduled during nighttime hours for each Season. Nighttime hours will be defined by Local Resource Zone, as set forth in the Business Practices Manual for Resource Adequacy.

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	Exempt Tier 1 Only	No Exemption

between 31-119 days Prior to outage start date		
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 or Tier 1 only at Transmission Provider's discretion

A. Tier 2 Planned Outage exemptions

i. The Generator Owner or Generator Operator: (a) 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 generator unit; and (b) the Proposed Generator Planned Outage is to occur entirely during a period in which there is adequate Maintenance Margin at the time advance notice of 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.

ii. The Generator Owner or Generator Operator reschedules its Generator Planned Outage at the Transmission Provider's request: (a) the Proposed Generator Planned Outage is to occur 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 generator unit; and (b) Generator

Planned Outage has inadequate Maintenance Margin at time of submittal and moves to a time of adequate Maintenance Margin.

iii. The Transmission Provider may, at its discretion, grant a Tier 2 Planned Outage exemption if the Generator Owner or Generator Operator reschedules its Generator Planned Outage at the Transmission Provider's request due to weather, forced outages, or other conditions listed in the Business Practices Manual for Outage Operations without regard to how many days in advance the outage was submitted or whether there was projected to be adequate Maintenance Margin for the duration of the outages.

B. Tier 1 Planned Outage exemptions

i. The Generator Owner or Generator Operator receives a Tier 2 Planned Outage exemption under section A.i above.

ii. The Generator Owner or Generator Operator: (a) 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 generator unit; and (b) the Proposed Generator Planned Outage is to occur during a period when there is inadequate Maintenance Margin at the time the outage is provided to the Transmission Provider. There is inadequate margin when the Maintenance Margin is less than or equal to zero megawatts, for any day of outage, after subtracting the megawatts of the requested Proposed

Generator Planned Outage. The request shall be determined based on highest queued request.

iii. Subsequent generator unit outage requests 120 days or more in advance and/or Generator Owners or Generator Operators Generator Planned Outage less than 120 days in advance and at least 31 days in advance of outage start date. Proposed Generator Planned Outage to occur entirely during a period in which 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.

iv. Generator Owners or Generator Operators Generator Planned Outage less than 31 days in advance and at least 14 days in advance of outage start date. A Proposed Generator Planned Outage to occur entirely during a period the generator unit has an adequate Maintenance Margin at the time the outage is provided to the Transmission Provider and the outage passes the No Harm Test. 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.

v. Generator Owner or Generator Operator reschedules its Generator Planned Outage at the Transmission Provider's request due to inadequate Maintenance

Margin for the duration of outage, at the time the outage is provided to the Transmission Provider. Maintenance Margin is less than zero megawatts after subtracting the megawatts of the requested Proposed Generator Planned Outage. This requirement does not include outages submitted less than 14 days in advance of the start date.

vi. The Transmission Provider may, at its discretion, grant a Tier 1 Planned Outage exemption if the Generator Owner or Generator Operator reschedules its Generator Planned Outage at the Transmission Provider's request due to weather, forced outages, or other conditions listed in Business Practices Manual for Outage Operations without regard to how many days in advance the outage was submitted or whether there was projected to be adequate Maintenance Margin for the duration of the outages.

C. No Harm Tests

Outages submitted between 14 to 30 days of start date will be evaluated for final approval and exemption status together. The 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 Business Practices Manual for Generator Outage.

D. Limitation Provided by Transmission Provider or Transmission Operator

The Transmission Provider will grant the equivalent of a Tier 2 Planned Outage exemption if a Schedule 53A Resource is provided an operating limitation, such as thermal, voltage, or stability limits referenced in the BPM for Outage Operations, provided by the Transmission Provider or the Transmission Operator to preserve the reliability of the Transmission System, that is lower than the must offer obligation described in Section 69A.5.a.

IV. Resource Adequacy Hours

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 beginning September 1st and ending August 31st, which will be used to determine Resource Adequacy Hours for each Season (Seasonal RA Hours). Seasonal RA Hours will be determined for the First Planning Area and Second Planning Area separately. The RA Hours determined in subpart IV.A & IV.B below are the only RA Hours that will be used to calculate Tier 2 ISAC in subpart VI.B below. Where certain Seasonal RA Hours do not apply for a Resource due to a Tier 2 Planned Outage exemption or for periods where the Resource was not designated for RAR under Module E-1 of the Tariff and the Resource does not otherwise have 65 RA Hours identified for the Season then a Seasonal RA Hour Deficiency exists per subpart IV.A.iii. To address the Seasonal RA Hour Deficiency, a Resource Class-level UCAP as a percentage of the corresponding Resource Class-level ICAP will be multiplied by the

Resource's ICAP and the product will be applied for purposes of determining ISAC for only the deficient Seasonal RA Hours.

A. Seasonal RA Hours. Seasonal RA Hours will include a target of 65 hours for each Season consisting of:

i. All operating hours during any declared Maximum Generation Emergency in a Season, excluding any operating hour where a Resource has a Tier 2 Planned Outage exemption or has periods where the Resource was not designated for RAR under Module E-1 of the Tariff. If more than 65 of such hours exists for any Season, all will be considered Seasonal RA Hours, and;

ii. If there are fewer than 65 hours identified for the Season in Section IV.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 Planned Outage exemption or has periods where the Resource was not designated for RAR under Module E-1 of the Tariff, and;

iii. If 65 hours have still not been identified, then a Seasonal RA Hours Deficiency exists which is the number of hours less than 65 for any Season.

B. Seasonal Non-RA Hours. Seasonal Non-RA Hours will consist of all hours not included in Section IV.A.i-iii. If a Resource has a Tier 1 and/or Tier 2 Planned Outage exemption for any of the operating hours identified as Seasonal Non-RA

Hours or has periods where the Resource was not designated for RAR under Module E-1 of the Tariff, such hours will not be included in the applicable Seasonal Accredited Capacity calculation.

C. Tier 1 Planned Outage exemptions apply only to Non-RA Hours. Tier 2 Planned Outage exemptions apply for both RA Hours and Non-RA Hours referenced in this Schedule 53.

V. Operating Margin Calculation

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.

Operating Margin Equation

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

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) is not on outage.

VI. Seasonal Accredited Capacity Calculation

A. Tier 1 Intermediate SAC (ISAC) is calculated as the sum of hourly real time availability, or Targeted Demand Reduction Level for DRR-Type 1, during each of the Resource's Seasonal Non-RA Hours, divided by the total number of Seasonal Non-RA Hours for each Season within the three (3) most recent periods beginning September 1st and ending August 31st.

B. Tier 2 ISAC is calculated as the sum of hourly real time availability, or Targeted Demand Reduction Level for DRR-Type 1, for the Resource's Seasonal RA Hours, plus the product of: seasonal Resource Class-level UCAP as a percentage of the corresponding Resource Class-level ICAP will be multiplied by the Resource's ICAP multiplied by the Seasonal RA Hour Deficiency; divided by the total number of Seasonal RA Hours plus the Seasonal RA Hour Deficiency for each Season within the three (3) most recent periods beginning September 1st and ending August 31st. For any Seasonal RA Hour where a Resource is offline and the sum of the Resource's Start-Up Time and Start-Up Notification Time Offers exceeds 24 hours, the Resource's hourly real time availability, or Targeted Demand Reduction Level for DRR-Type 1, will be set to zero (0).

C. For Resources required to submit GVTC values and for purposes of paragraphs A through C above, the hourly real time availability, or Targeted Demand Reduction Level for DRR-Type 1, will be capped at the currently effective GVTC value of the Resource. If a Resource is committed for a portion of its ICAP due to partial clearing, the partial clearing will not reduce the values in the Offers considered in the accreditation calculations, which will be capped at the currently effective GVTC value of the Resource.

D. In the case of an increase in generating Capacity of a Generation Resource, for purposes of paragraphs A through C above, the historical values for the hourly real time availability will be adjusted up for those hours prior to such increase going into effect as set forth in the Business Practices Manual for Resource Adequacy.

E. RA Hours will receive a greater weight than non-RA hours.

F. ISAC will be calculated using the following equation:

$$ISAC = ISAC_{Tier1\_value} \times ISAC_{Tier1\_weighting} + ISAC_{Tier2\_value} \times ISAC_{Tier2\_weighting}$$

Where Tier 1 weighting equals twenty percent (20%) and Tier 2 equals eighty percent (80%).

G. Resource Class-level ISAC is the sum of individual resource ISAC values within the Resource Class. The calculation of the Resource Class-level UCAP and Resource Class-level ISAC will exclude Resources that have yet to qualify for the applicable PRA at the time of these calculations and include those in both the relevant LOLE study and ISAC calculations.

H. The SAC for each Resource will be calculated as its pro-rata share of the Resource Class-level UCAP based on its individual ISAC value using the following equation:

$$SAC_i = Resource\ Class\text{-}Level\ UCAP * \frac{Resource\ ISAC_i}{Resource\ Class\text{-}level\ ISAC}$$

for each resource, *i*.

I. The Transmission Provider will post initial values for ISAC, SAC, Resource Class-level UCAP, and Resource Class-level ISAC ("Initial SAC Posting"), for each Season, by December 15 prior to the applicable Planning Resource Auction. Any dispute related to the initial ISAC values shall be submitted to the Transmission Provider in writing within thirty (30) Calendar Days of such posting. The Transmission Provider will post final values for ISAC, SAC, Resource Class-level UCAP, and Resource Class-level ISAC ("Final SAC Posting"), for each Season, by February 15 prior to the applicable Planning Resource Auction. No changes will be made to the Final SAC values following the February 15 posting, unless the Resource Class-level ISAC changes more than three percent (3%) and at least 30 MW.

VII. New Resources or Resources with Insufficient Performance Data

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 its respective seasonal Resource Class-level UCAP as a percentage of the corresponding Resource Class-level ICAP will be multiplied by the Resource's ICAP. Resources on a Catastrophic Generator Outage during a Season they are designated for RAR may elect to use a SAC based on its respective Resource Class's UCAP percentage multiplied by its ICAP 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.

Tab B

Sample Membership Agreement: The document that establishes the rights and obligations between the Electric Generation and Transmission Cooperative (Coop) and its members.

Scarcity Price: The LMP and MCP price levels determined by Demand Curves when insufficient Operating Reserves or Short-Term Reserves are cleared to meet the Operating Reserve or Short-Term Reserve requirements, respectively.

Schedule 16 Costs: The monthly charge of costs to be recovered under Schedule 16 of this Tariff shall include any deferred pre-operating costs, direct and indirect capital costs, direct and indirect operating expenses and all other costs associated with administrating the Financial Transmission Rights Administrative Service under this Tariff.

Schedule 17 Costs: The costs to be recovered under Schedule 17 of this Tariff shall include any deferred pre-operating costs, direct and indirect capital costs, direct and indirect operating expenses and all other costs associated with administering the Energy and Operating Reserve Market Support Administrative Service under this Tariff.

Scheduled Injections: Energy scheduled in the Day Ahead Energy and Operating Reserve Market to be injected over an Hour of the Operating Day.

Scheduled Withdrawals: Energy withdrawals scheduled in the Day Ahead Energy and Operating Reserve Market over a given Hour of the Operating Day.

Scheduling Agent: An entity designated by a Market Participant that has the authority to conduct business in the Transmission Provider Region on behalf of the Market Participant.

Scheduling Instructions: Directives issued by the Transmission Provider or Local Balancing Authority to Market Participants with Load Modifying Resources indicating MW quantities to be reduced during Emergencies.

SCUC Instructed Hours of Operation: The period beginning when a Resource is synchronized to the Facilities within the MISO Balancing Authority Area in response to the Transmission Provider selecting the Resource in the unit commitment portion of the SCUC process and ends at the later of: (i) the time incorporating the sum of the time when the Resource is synchronized and the Resource's Minimum Run Time and (ii) the earlier of the time the Resource is forced out of service or the time when the Transmission Provider notifies the Market Participant that the Resource is no longer needed. The SCUC Instructed Hours of Operation cannot extend beyond the Operating Day.

Seams Operating Agreement: An agreement between adjacent balancing authorities or transmission providers for the coordination of operations, including joint operating agreements.

Season: The four (4) seasons are (i) Winter – December, January, February; (ii) Spring – March, April, May; (iii) Summer – June, July, August; and (iv) Fall – September, October, November.

Seasonal Accredited Capacity (SAC): The amount of accredited Capacity, for a given Season, in MW, assigned to a Planning Resource that is convertible to Zonal Resource Credits.

SEC: Securities and Exchange Commission.

Second Planning Area: The area of the Transmission Provider Region where Entergy Corporation and its Operating Companies that own and/or operate transmission facilities (i.e., located in Arkansas, Louisiana, Mississippi, or Texas) that are conveyed to the functional control of the Transmission Provider to provide Transmission Service pursuant to Module B of the Tariff. The Second Planning Area shall be formed when the first Entergy Operating Company conveys functional control of its transmission facilities to the Transmission Provider, and may be expanded if other Entergy Operating Companies or adjacent utilities in Arkansas, Louisiana, Mississippi or Texas, join MISO later in the Second Planning Area's Transition Period.

Second Planning Area's Transition Period: The period: (i) commencing when the first Entergy Operating Company conveys functional control of its transmission facilities to the Transmission Provider to provide Transmission Service under Module B of this Tariff; (ii) consisting of at least five consecutive (5) years, plus the time needed to complete the MTEP approval cycle pending at the end of the fifth year; (iii) ending on the day after the conclusion of such MTEP approval cycle, which in no case shall be more than six years after the start of that period; and (iv) during which the Transmission Provider shall review and compare the current states of the transmission systems in the First Planning Area and the Second Planning Area and, if a lack of comparability is found, shall identify transmission projects necessary to achieve comparability. The processes for identifying transmission projects necessary to achieve comparability and allocating costs associated with the projects that are so identified during the Second Planning Area's Transition Period are set forth in Attachment FF-6.

Security Constrained Economic Dispatch (SCED): An algorithm capable of clearing, dispatching, and pricing Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, and Short-Term Reserve in a simultaneously co-optimized basis that minimizes Production Costs and Operating Reserve Costs while enforcing multiple security constraints. The algorithm keeps the commitment of Resources fixed in the dispatch. The model is described in Schedule 29.

***Security Constrained Economic Dispatch Pricing (SCED-*Pricing**)**: An algorithm capable of clearing, dispatching, and pricing Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, and Short-Term Reserve in a simultaneously co-optimized basis that minimizes Production Costs and Operating Reserve Costs while enforcing multiple security constraints. The model is described in Schedule 29A.

Security Constrained Unit Commitment (SCUC): An algorithm capable of committing Resources to supply Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, and Short-Term Reserve on simultaneously co-optimized basis that minimizes Capacity costs while enforcing multiple security constraints.

Selected Developer(s): The RFP Respondent(s) identified in the Selected Proposal. Selected Developers shall not include Proposal Participants.

Selected Developer Agreement (SDA): An agreement, in the form provided in Appendix 1 of Attachment FF of the Tariff, between a Selected Developer, including existing Transmission Owners, ITCs, and Non-owner Members, and the Transmission Provider establishing the terms and conditions under which the Selected Developer will construct and implement the Competitive Transmission Facilities specified in its Selected Proposal. Among other terms, the Selected Developer Agreement shall include any binding cost control measures, including cost caps, which the Selected Developer specified in its Selected Proposal.

Selected Proposal: The Proposal selected for implementation by the Competitive Transmission Executive Committee, pursuant to Attachment FF of the Tariff.

Self Schedule: The designation by a Market Participant of a specific amount of Energy and/or Operating Reserve and/or capacity to be supplied from a specific Resource or Planning Resource as a Price Taker.

Self-Scheduled Resource: A Resource that is scheduled by a Market Participant and controlled by the same Market Participant under the overall coordination of the Transmission Provider. A Self-Scheduled Resource is a Price Taker for the portion of the Resource that is Self Scheduled.

Service Agreement: The initial agreement and any amendments or supplements thereto entered into by the Tariff Customer and the Transmission Provider for service under this Tariff, including, without limitation, any service agreement executed pursuant to Section 27A (an HVDC Service Agreement), Module F, and Attachment KK of the Tariff.

Service Commencement Date: The date the Transmission Provider or ITC begins to provide service pursuant to the terms of an executed Service Agreement, or the date the Transmission Provider or ITC begins to provide service in accordance with Section 15.3 or Section 29.1 under this Tariff.

Setpoint Instruction: The real-time desired MW output signal calculated for a specific Resource by the Transmission Provider's control system on a specified periodicity that is equal to the current Energy Dispatch Target plus the Regulating Reserve Deployment instruction (which may be positive or negative) plus an adjustment to the Energy Dispatch Target to account for Contingency Reserve Deployment Instructions. The Setpoint Instruction represents the desired output level of the Resource.

Settlement: The process of determining charges to be paid to or by a Market Participant in the Energy and Operating Reserve Markets operated by the Transmission Provider under this Tariff.

Settlement Statements: Reports provided by the Transmission Provider to Market Participants containing some aggregate and some detailed charge type information and determinant data regarding financial obligations for Energy and Operating Reserve Market activities and services, allowing for the verification by the Market Participant of Settlements invoiced amounts.

Shadow Price: The marginal value of relieving a particular constraint.

Shortfall Amount: The difference between a Resource's Contingency Reserve Deployment Instruction and the actual amount of Contingency Reserve deployed by that Resource at the end of the Contingency Reserve Deployment Period; or the difference between a Resource's Economic Minimum Dispatch and the Actual Energy Injection of the Resource at the end of the Short-Term Reserve Deployment Period.

Short-Term Firm Point-To-Point Transmission Service: Firm Point To Point Transmission Service under Module B of this Tariff with a term of less than one (1) Year.

Short-Term High-Voltage Direct Current Service: HVDC Service under Section 27A of this Tariff with a term of less than one (1) year.

Short-Term Reserve: Rampable Capacity provided by eligible Resources available to the Transmission Provider to be converted to Energy within the Short-Term Reserve

Deployment Period to address market-wide, sub-regional and/or local short-term needs for reserves as specified in Schedule 51 of this Tariff.

Short-Term Reserve Deployment Failure Charge: A charge assessed to any Resource that fails to achieve the Economic Minimum Dispatch within a Short-Term Reserve Deployment Period. Resources that clear Off-Line Short-Term Reserve will be made available for Operator commitment as a part of the Transmission Provider's Look Ahead Commitment process.

Short-Term Reserve Deployment Period: The thirty (30)-minute period of time within which the Resource must deploy Short-Term Reserve following the issuance of a Short-Term Reserve Deployment Instruction. The Short-Term Reserve Deployment Period is also the duration of time beyond the Resource Dispatch Target time that is used to determine on-line Resource participation capabilities for the Short-Term Reserve product.

Short-Term Reserve Dispatch Status: A specification submitted by a Market Participant in its Generation Offer for each hour to indicate whether the Transmission Provider is authorized to economically clear Short-Term Reserve on the Resource for the Hour. Valid Short-Term Reserve Dispatch Status specifications include: Economic and Not Participating.

Short-Term Reserve Qualified Resource: A Generation Resource that is not a Dispatchable Intermittent Resource, an Intermittent Resource, Demand Response Resource – Type II, or External Asynchronous Resource that has met the requirements to be eligible to provide Short-Term Reserve, and an Electric Storage Resource that has met the requirements to be eligible to provide online Short-Term Reserve, by submitting a Short-

Term Reserve Dispatch Status other than "Not Participating" and/or is an Off-Line Short-Term Reserve Qualified Resource.

Short-Term Reserve Requirements: The Market-Wide Short-Term Reserve Requirement, Sub-Regional Short-Term Reserve Requirements, and Local Short-Term Reserve Requirements.

Shut-Down Offer: The compensation required by a Market Participant for reducing the consumption of a Demand Response Resource Type-I.

Shut-Down Notification Time: The amount of notification time required by a Demand Response Resource-Type I prior to the initiation of demand reduction procedures.

Shut-Down Time: The time required for a Demand Response Resource Type I to reduce consumption equal to its Targeted Demand Reduction Level or the time required for a Demand Resource to reduce consumption equal to its targeted Load reduction level or firm service level.

Significant Trade Reference: Trade reference provided to Transmission Provider in the registration process which are of a significant nature, as determined by Transmission Provider in its sole discretion.

Simultaneous Feasibility Test: A test for a state in which each set of injections and withdrawals associated with receipt point-to-delivery point FTRs and ARRs, and power transfers associated with FTRs and ARRs, would not exceed any thermal, voltage, or stability limits within the Transmission Provider Region under normal operating conditions or for monitored contingencies.

Single-Developer Proposal: A Proposal submitted by a single RFP Respondent that would become the sole Selected Developer for the Competitive Transmission Project, should its Single-Developer Proposal be designated as the Selected Proposal by the Transmission Provider.

Single-Directional-Down Ramp Rate Curve: The MW/minute ramp rate curve, that may include up to ten (10) linear segments at which a Generation Resource or Demand Response Resource-Type II can respond to the Setpoint Instructions in the downward direction only.

Single-Directional-Up Ramp Rate Curve: The MW/minute ramp rate curve, that may include up to ten (10) linear segments, at which a Generation Resource or Demand Response Resource-Type II can respond to the Setpoint Instructions in the upward direction only.

Sink Point: The Commercial Pricing Node at which a Financial Schedule terminates.

Source Point: The Commercial Pricing Node at which a Financial Schedule originates.

Spin Qualified Resource: A Generation Resource, an External Asynchronous Resource, a Demand Response Resource-Type I, a Demand Response Resource-Type II, or an Electric Storage Resource that has met the requirements to be eligible to submit Spinning Reserve Offers into the Energy and Operating Reserve Markets.

Spinning Reserve: A specified percentage, based on Applicable Reliability Standards, of Contingency Reserve that must be synchronized to the Transmission System and that meets all Applicable Reliability Standards, and that can be converted to Energy within the Contingency Reserve Deployment Period following a deployment instruction.

Spinning Reserve Offer: The price, in dollars per MW per Hour, at which a Spin Qualified

Resource has agreed to sell Spinning Reserve. The price shall reflect the costs required for the Spin Qualified Resource to be made available to provide Spinning Reserve; and may also include a dollar component reflecting an expectation of any Incremental Energy Costs, or costs in Shut-Down Offers and/or Hourly Curtailment Offers with respect to Demand Response Resource – Type I, that might exceed market revenues when the Spin Qualified Resource follows a Contingency Reserve Deployment Instruction.

Start-Up Notification Time: The amount of notification time required by a Generation Resource prior to the initiation of start-up procedures or the amount of notification time required for a Demand Response Resource Type II, or Electric Storage Resource prior to the initiation of demand reduction procedures, from a hot state, intermediate state and cold state.

Start Up Offer: The compensation required by a Market Participant for bringing an off line Generation Resource on line or for reducing consumption of a Demand Response Resource-Type II, or Electric Storage Resource.

Start-Up Time: The number of Hours required to start a Generation Resource, Demand Response Resource-Type II, LMR, or Electric Storage Resource and synchronize with the Transmission Provider Region to Hourly Economic Minimum Limit consistent with the Applicable Reliability Standards from a hot state, intermediate state or cold state.

State Estimator: A software program used by the Transmission Provider to create a real time assessment of the condition of the Transmission Provider Region.

State Estimator MWs: The megawatts that are determined by the State Estimator to be generated at a given location for each Dispatch Interval.

State of Charge: The Energy, Capacity, Spinning Reserve, Supplemental Reserve and/or Regulating Reserve available to the Transmission Provider's markets from an Electric Storage Resource.

Statement of Support: A document that the Transmission Provider provides to Transmission Developer Applicants for submission with a Transmission Developer Application, which: (1) is executed by an Affiliate of a Transmission Developer Applicant; (2) lists specific qualifications, capabilities, and/or competencies that the Affiliate possesses and intends to make available to the Transmission Developer Applicant in order to assist the Transmission Developer Applicant with meeting one or more of the prequalification requirements set forth in Sections VIII.B.4, VIII.B.4.1, VIII.B.4.2, VIII.B.4.3, and/or VIII.B.4.4 of Attachment FF to the Tariff; and (3) authorizes the Transmission Developer Applicant to represent during the annual prequalification and recertification processes set forth in Sections VIII.B.2 and VIII.B.3 of Attachment FF to the Tariff that such Transmission Developer Applicant will have access to the specified qualifications, capabilities, and/or competencies.

Station Power: The Energy used for operating the electrical equipment on the site of a Generation Resource and/or for the lighting, heating, air-conditioning and office equipment needs of buildings located on the site of such a Generation Resource that are used in the operation, maintenance, or repair of the facility. Station Power does not include Energy (i) used for pumping at a pumped storage facility; (ii) to power synchronous condensers; (iii) in association with power system restoration or blackstart service, or (iv) used for charging an Electric Storage Resource. Station Power may only be provided pursuant to Schedule 20 of this Tariff.

Storage As Transmission Only Asset (SATOA): An Electric Facility connected to or to be connected to the Transmission System and approved for inclusion in Appendix A of the MTEP, as a transmission facility that is part of the Transmission System, that is capable of receiving Energy from the Transmission System and storing Energy for injection to the Transmission System, and is operated only to support the Transmission System. The SATOA shall not participate in the Transmission Provider's markets except to the extent necessary to receive Energy from the Transmission System and to inject Energy into the Transmission System to provide the services for which the SATOA was included in the MTEP.

Sub-Area: A portion of the MISO Balancing Authority Area identified by MISO as described in MISO's emergency operating procedures, consisting of the entirety of one or more Local Balancing Authority Areas, or multiple Local Balancing Authority Areas comprising a sub-region, that may require the implementation of emergency actions to address Capacity shortage conditions.

Sub-Region: One or more Reserve Zones, or any other portion of the MISO Balancing Authority Area limited by physical or contractual constraints, including Sub-Regional Power Balance Constraints, used to establish Short-Term Reserve Requirements.

Sub-Regional Export Constraint (SREC): 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.

Sub-Regional Import Constraint (SRIC): The amount of Planning Resources in megawatts modeled in the PRA for each Season, not within an applicable Sub-Regional Resource Zone (SRRZ), 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.

Sub-Regional Power Balance Constraint: A net Energy injection and withdrawal constraint established to manage intra-regional flows in accordance with applicable seams agreements, coordination agreements, transmission service agreements, or operating procedures.

Sub-Regional Power Balance Constraint Demand Curve: A demand curve used to price Sub-Regional Power Balance Constraints.

Sub-Regional Resource Zone (SRRZ): A zone, comprised of a LRZ or combination of two or more LRZs, established by the Transmission Provider 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.

Sub-Regional Short-Term Reserve: Short-Term Reserve that is available to the Transmission Provider in a Sub-Region.

Sub-Regional Short-Term Reserve Requirements: The amount of Sub-Regional Short-Term Reserve, as determined pursuant to Module C of the Tariff, that the Transmission Provider is required to procure in a Sub-Region.

Supervisory Control and Data Acquisition (SCADA) Data: The electric system security data that is used to monitor the electrical state of facilities, as specified in NERC Policy 4.

Supplemental Qualified Resource: A Spin Qualified Resource, or a Demand Response Resource-Type I or, a Generation Resource, Demand Response Resource Type-II, Electric Storage Resource, or External Asynchronous Resource that is not a Spin Qualified Resource that has met the requirements to be eligible to submit Supplemental Reserve Offers into the Energy and Operating Reserve Markets.

Supplemental Reserve: Contingency Reserve that is not considered Spinning Reserve that can be converted to Energy within the Contingency Reserve Deployment Period and that meets all Applicable Reliability Standards.

Supplemental Reserve Offer: The price, in dollars per MW per Hour, at which a Demand Response Resource Type I or an External Asynchronous Resource that is a Supplemental Reserve Qualified Resource has agreed to sell Supplemental Reserve.

Suspend: The cessation of operation of a Generation Resource or an SCU for more than two (2) months commencing on a specified date that is provided to the Transmission Provider, that includes the right to rescind or modify the Attachment Y Notice for a period ending no later than thirty-six (36) months after the start date specified in an original (i.e. initial, first) Attachment Y Notice, consistent with the requirements in Section 38.2.7 and Attachment X.

Synchronous Condenser Unit (SCU): A facility that can be synchronized to the Transmission Provider's Transmission System without producing Energy.

System Auction Clearing Price (System ACP): 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 Final 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).

System Condition: A specified condition on the Transmission System or on a neighboring transmission system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm Point-To-Point Transmission Service or Long-Term Firm HVDC Service using the curtailment priority pursuant to Section 13.6 or 27A.1.5 of this Tariff, respectively. Such conditions must be identified in the Transmission Customer's Service Agreement or HVDC Service Agreement.

System Impact Study: An assessment by the Transmission Provider and ITC, as applicable, of (i) the adequacy of the Transmission System to accommodate a request for either Firm Point-To-Point Transmission Service or Network Integration Transmission Service and (ii) whether any additional costs may be incurred in order to provide Transmission Service. System Impact Studies for any transmission facilities not under the operational control of the Transmission Provider or ITC shall be performed by the Transmission Owner or applicable ITC Participant or any entity the Transmission Provider designates to perform the studies.

System Losses: The transmission losses experienced on the Transmission System as determined by the Network Model.

System Operating Limit (SOL): The value (such as MW) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. Also referred to as Operating Security Limit.

System Purchase Contracts: Agreements for the purchase of Energy that do not specify the Resource(s) that the seller shall select to supply such Energy at any particular time; provided, however, that such agreements may identify the group of Resources from which the seller may make its selection; provided, further that this term does not include agreements with Manitoba Hydro involving the supply of Energy from resources in Canada up to or at the U.S. border.

System Restoration Plans: The plans developed by the individual Transmission Operators, and coordinated by the Transmission Provider acting in its capacity as the Reliability Coordinator, to enable a system restoration zone to re-energize the Transmission System following a system-wide blackout.

System Support Resource (SSR): Generation Resources or Synchronous Condenser Units that have been identified in Attachment Y – Notification to this Tariff and are required by the Transmission Provider for reliability purposes, to be operated in accordance with the procedures described in Section 38.2.7 of this Tariff.

SSR Agreement: An agreement identified as Attachment Y 1 to this Tariff that the Transmission Provider, the owner or operator of an SSR Unit executes to provide the terms and conditions under which the SSR Unit will be operated and compensated.

SSR Notification: The form in Attachment Y of this Tariff that the owner or operator of a

Generation Resource or a Synchronous Condenser Unit must complete and send to the Transmission Provider at least twenty-six (26) weeks prior to Retiring or Suspending any Generation Resource or Synchronous Condenser Unit located within the Transmission Provider Region, consistent with the requirements in Section 38.2.7.

SSR Unit: A Generation Resource or a Synchronous Condenser Unit that is operated and compensated in accordance with an SSR Agreement.

Uncollectible Obligation: Any Past Due Amount that the Transmission Provider has concluded, pursuant to Section 7.10, is not reasonably expected to be paid in full within an acceptable period of time.

Undeployed Regulating Mileage: Any un-utilized Regulating Mileage that was considered for a Dispatch Interval during the market clearing.

Undeployed Regulating Mileage Revenue Sufficiency Guarantee: A Resource credit guaranteed by the Transmission Provider ensuring the recovery of any lost profit from charging back at Regulating Mileage MCP to resources for Undeployed Regulating Mileage.

Under-Forecast: The negative difference between the forecasted Demand and actual measured Demand, after adjustment for actual weather conditions, retail Load changes and actual LMPs. LSEs with Load whose withdrawals vary based on LMP and who provide verifiable statistical analysis to support the associated price elasticity can normalize actual measured Demand to reflect differences between forecasted and actual LMPs.

Unforced Capacity (UCAP): The amount of Capacity in MW assigned to a Planning Resource after accounting for either its availability in the LOLE analysis or historic availability, as applicable.

Unloaded Capacity Requirement: The amount of online, available generation Capacity above the generation Capacity needed to meet instantaneous total Load obligations that must be maintained to ensure online Resources are able to meet ramping requirements of all products cleared in the co-optimized market solutions. It is determined by the Transmission Provider’s real-time operations personnel after reviewing historical periods and setting specific levels of generation Capacity needed for maintaining reliable and efficient operations.

Unsecured Credit: Any credit granted by Transmission Provider to an Applicant and/or Tariff Customer that is not secured by a form of Financial Security.

Unsecured Credit Allowance: Unsecured Credit extended by Transmission Provider in an amount determined by Transmission Provider's evaluation of the creditworthiness of the Applicant and/or Tariff Customer.

Unsecured Credit Floor: For credit scoring purposes, the minimum amount of Unsecured Credit to be extended to a creditworthy Public Power entity.

Up and Down Ramp Capability Qualified Resource: A Generation Resource that is not a Dispatchable Intermittent Resource, External Asynchronous Resource, Demand Response Resource-Type II, or Electric Storage Resource that has met the requirements to be eligible to provide Up and Down Ramp Capability by submitting Up and Down Ramp Capability dispatch status other than "Not Participating" into the Energy and Operating Reserve Markets.

Up Ramp Capability (URC): The product representing the ability of dispatchable resources to respond to future upward changes in demand within the Ramp Capability Response Time after a given dispatch. The Real-Time Market-Wide Up Ramp Capability Requirement is defined by expected market-wide upward variation in dispatchable generation to account for forecasted changes in load and Scheduled Interchange while considering the contribution of non-dispatchable generation (negative for a downward variation) plus the upward short-term uncertainty associated with the Load Forecast, non-dispatchable generation forecast, and units not responding to their Setpoint, all evaluated over the Ramp Capability Response Time. If the resulting requirement is negative, the requirement is set to 0 so that the requirement is always non-negative.

Up to TUC Interchange Schedule: Interchange Schedules that specify a willingness to pay the Transmission Usage Charge (dollars per MWh) represented by a maximum amount beyond which the Market Participant agrees to be curtailed.

Use Limited Resource: Generation Resources, Electric Storage Resources or External Resource(s), that due to design considerations, environmental restrictions on operations, cyclical requirements, such as the need to recharge or refill, or for other non economic reasons, are unable to operate continuously on a daily basis, but must be able to operate for a minimum set of consecutive operating Hours.

Users: Transmission Customers or other entities that are parties to transactions under this Tariff.

Loss of Load Expectation Analysis

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. This probabilistic analysis shall use a Loss of Load Expectation (LOLE) study which assumes that there are no internal transmission limitations within the Transmission Provider Region.

The 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. If 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. If 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 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.

The minimum amount of capacity above Coincident Peak Demand in the Transmission Provider Region required to meet the reliability criteria will be used to establish the PRM for each Season.

The PRM will be established as a requirement in terms of the total Unforced Capacity for the Transmission Provider Region.

Schedule 53A

Extended Seasonal Accredited Capacity Calculation

I. Applicability

A. Implementation Date of Schedule 53A

The provisions of this Schedule 53A, except Subsection I.B Effective Date of Reporting Requirement, shall be effective on June 1, 2027 for implementation beginning with Planning Year 2028-2029 and continuing thereafter. The Transmission Provider shall make a filing to remove the currently effective Schedule 53 from the Tariff to be effective June 1, 2028.

B. Effective Date of Reporting Requirement

Commencing on September 1, 2024, the Transmission Provider will publish indicative results pursuant to the provisions set forth in this Schedule 53A. Such indicative results shall be published prior to the applicable Planning Resource Auction for Planning Year 2025–2026, and the two Planning Years thereafter, as further described in the Business Practices Manual for Resource Adequacy.

C. Resource Classes

The term “Resource Class” as used in this Schedule 53A shall mean 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 this Schedule 53A. All Capacity Resources, except External Resources, shall be assigned to one of the Resource Classes identified in this section for purposes of executing the two-step resource accreditation methodology defined in this Schedule 53A and determining the Planning Reserve Margin Requirement, as set forth in

Module E-1. A DRR-Type I or DRR-Type II that is a behind the meter generation facility, and that qualifies as a Capacity Resource shall be assigned to an applicable Resource Class below. A DRR-Type I that interrupts or controls demand shall be accredited pursuant to Section VI below. Resource Classes shall include:

Gas (including Oil)	Storage
Combined Cycle	Solar
Coal	Wind
Hydro	Run-of-River
Nuclear	Biomass
Pumped Storage	

Additional details regarding Resource Classes shall be included in Transmission Provider's Business Practices Manual for Resource Adequacy. The Transmission Provider will provide a mapping of each Capacity Resource to one of the above Resource Classes as per the schedule listed in the Transmission Provider's Business Practices Manual for Resource Adequacy. Any dispute regarding Resource Class assignment must be submitted to the Transmission Provider in writing within ten (10) Business Days from the date such assignment was provided to the Market Participant.

II. General

Seasonal Accredited Capacity (SAC) for a Capacity Resource, except an External Resource, will be determined pursuant to this Schedule 53A. The resources accredited pursuant to this Schedule 53A, as described above, are hereinafter referred to as "Schedule 53A Resources".

The SAC calculation for Schedule 53A Resources will be performed using a two-step process. First, the Resource Class-level UCAP will be determined by the method described in section II.A. Second, the Resource Class-level UCAP will be allocated amongst the individual resources in the Resource Class using the individual resource performance during Tier 1 and Tier 2 Hours based on the prior three years of operational performance as described in section II.B.

A. Resource Class-level UCAP and ICAP Calculation

Resource Class-level UCAP in a Season will be determined by calculating the combined expected availability and performance of all resources within that Class during Critical Hours from the probabilistic LOLE analysis as set forth in Module E-1. For each Season, "Critical Hours" are defined as the set of all 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. For those Seasons with 1,950 or more loss of load hours, Critical Hours will only include loss of load hours. Once Critical Hours are determined for each Season, weights are calculated for each of the Critical Hours using a weighting system that assigns greatest weight to the hours with the highest risk (i.e. hour with most unserved energy), as further described in the Business Practices Manual for Resource Adequacy. After calculating the weights for each Critical Hour, Critical Hours will be capped at 1,950 hours for each Season during which there are less than 1,950 loss of load hours. Finally, Seasonal Resource Class-level UCAP will be calculated as the weighted average of the Resource Class performance during Critical Hours in the Season.

Resource Class-level ICAP will be calculated as the sum of the ICAP values of all Resources in the Resource Class.

B. Resource-level Extended Seasonal Accredited Capacity Calculation

A two-tiered weighting structure is used to calculate Extended Seasonal Accredited Capacity for Schedule 53A Resources. Outage exemptions for planned outages and exemptions for any operating limitations, such as thermal, voltage, or stability limits referenced in the BPM for Outage Operations, provided by the Transmission Provider or Transmission Operator to preserve the reliability of the Transmission System, that modify the must offer obligation set forth in Section 69A.5.a will be factored into calculating the tiers of a Schedule 53A Resource's Extended Seasonal Accredited Capacity.

III. Tier 1 and Tier 2 Planned Outage Exemption Requirements

Generator Planned Outages will be evaluated for Tier 1 and Tier 2 exemptions based on the following requirements. Only full (Out-of-Service) Generator Planned Outages or full (Out-of-Service) Proposed Generator Planned Outages shall be eligible for the Tier 1 and Tier 2 planned outage exemptions set forth below. Resources in the Solar Resource Class shall not be eligible for Tier 1 and Tier 2 Planned Outage Exemptions for Generator Planned Outages and Proposed Generator Planned Outages that are scheduled during nighttime hours for each Season. Nighttime hours will be defined by Local Resource Zone, as set forth in the Business Practices Manual for Resource Adequacy.

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	Exempt Tier 1 Only	No Exemption

between 31-119 days Prior to outage start date		
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 or Tier 1 only at Transmission Provider's discretion

A. Tier 2 Planned Outage exemptions

i. The Generator Owner or Generator Operator: (a) 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 generator unit; and (b) the Proposed Generator Planned Outage is to occur entirely during a period in which there is adequate Maintenance Margin at the time advance notice of 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.

ii. The Generator Owner or Generator Operator reschedules its Generator Planned Outage at the Transmission Provider's request: (a) the Proposed Generator Planned Outage is to occur 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 generator unit; and (b) Generator

Planned Outage has inadequate Maintenance Margin at time of submittal and moves to a time of adequate Maintenance Margin.

iii. The Transmission Provider may, at its discretion, grant a Tier 2 Planned Outage exemption if the Generator Owner or Generator Operator reschedules its Generator Planned Outage at the Transmission Provider's request due to weather, forced outages, or other conditions listed in the Business Practices Manual for Outage Operations without regard to how many days in advance the outage was submitted or whether there was projected to be adequate Maintenance Margin for the duration of the outages.

B. Tier 1 Planned Outage exemptions

i. The Generator Owner or Generator Operator receives a Tier 2 Planned Outage exemption under section A.i above.

ii. The Generator Owner or Generator Operator: (a) 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 generator unit; and (b) the Proposed Generator Planned Outage is to occur during a period when there is inadequate Maintenance Margin at the time the outage is provided to the Transmission Provider. There is inadequate margin when the Maintenance Margin is less than or equal to zero megawatts, for any day of outage, after subtracting the megawatts of the requested Proposed

Generator Planned Outage. The request shall be determined based on highest queued request.

iii. Subsequent generator unit outage requests 120 days or more in advance and/or Generator Owners or Generator Operators Generator Planned Outage less than 120 days in advance and at least 31 days in advance of outage start date. Proposed Generator Planned Outage to occur entirely during a period in which 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.

iv. Generator Owners or Generator Operators Generator Planned Outage less than 31 days in advance and at least 14 days in advance of outage start date. A Proposed Generator Planned Outage to occur entirely during a period the generator unit has an adequate Maintenance Margin at the time the outage is provided to the Transmission Provider and the outage passes the No Harm Test. 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.

v. Generator Owner or Generator Operator reschedules its Generator Planned Outage at the Transmission Provider’s request due to inadequate Maintenance

Margin for the duration of outage, at the time the outage is provided to the Transmission Provider. Maintenance Margin is less than zero megawatts after subtracting the megawatts of the requested Proposed Generator Planned Outage. This requirement does not include outages submitted less than 14 days in advance of the start date.

vi. The Transmission Provider may, at its discretion, grant a Tier 1 Planned Outage exemption if the Generator Owner or Generator Operator reschedules its Generator Planned Outage at the Transmission Provider's request due to weather, forced outages, or other conditions listed in Business Practices Manual for Outage Operations without regard to how many days in advance the outage was submitted or whether there was projected to be adequate Maintenance Margin for the duration of the outages.

C. No Harm Tests

Outages submitted between 14 to 30 days of start date will be evaluated for final approval and exemption status together. The 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 Business Practices Manual for Generator Outage.

D. Limitation Provided by Transmission Provider or Transmission Operator

The Transmission Provider will grant the equivalent of a Tier 2 Planned Outage exemption if a Schedule 53A Resource is provided an operating limitation, such as thermal, voltage, or stability limits referenced in the BPM for Outage Operations, provided by the Transmission Provider or the Transmission Operator to preserve the reliability of the Transmission System, that is lower than the must offer obligation described in Section 69A.5.a.

IV. Resource Adequacy Hours

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 beginning September 1st and ending August 31st, which will be used to determine Resource Adequacy Hours for each Season (Seasonal RA Hours). Seasonal RA Hours will be determined for the First Planning Area and Second Planning Area separately. The RA Hours determined in subpart IV.A & IV.B below are the only RA Hours that will be used to calculate Tier 2 ISAC in subpart VI.B below. Where certain Seasonal RA Hours do not apply for a Resource due to a Tier 2 Planned Outage exemption or for periods where the Resource was not designated for RAR under Module E-1 of the Tariff and the Resource does not otherwise have 65 RA Hours identified for the Season then a Seasonal RA Hour Deficiency exists per subpart IV.A.iii. To address the Seasonal RA Hour Deficiency, a Resource Class-level UCAP as a percentage of the corresponding Resource Class-level ICAP will be multiplied by the

Resource's ICAP and the product will be applied for purposes of determining ISAC for only the deficient Seasonal RA Hours.

A. Seasonal RA Hours. Seasonal RA Hours will include a target of 65 hours for each Season consisting of:

i. All operating hours during any declared Maximum Generation Emergency in a Season, excluding any operating hour where a Resource has a Tier 2 Planned Outage exemption or has periods where the Resource was not designated for RAR under Module E-1 of the Tariff. If more than 65 of such hours exists for any Season, all will be considered Seasonal RA Hours, and;

ii. If there are fewer than 65 hours identified for the Season in Section IV.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 Planned Outage exemption or has periods where the Resource was not designated for RAR under Module E-1 of the Tariff, and;

iii. If 65 hours have still not been identified, then a Seasonal RA Hours Deficiency exists which is the number of hours less than 65 for any Season.

B. Seasonal Non-RA Hours. Seasonal Non-RA Hours will consist of all hours not included in Section IV.A.i-iii. If a Resource has a Tier 1 and/or Tier 2 Planned Outage exemption for any of the operating hours identified as Seasonal Non-RA

Hours or has periods where the Resource was not designated for RAR under Module E-1 of the Tariff, such hours will not be included in the applicable Seasonal Accredited Capacity calculation.

C. Tier 1 Planned Outage exemptions apply only to Non-RA Hours. Tier 2 Planned Outage exemptions apply for both RA Hours and Non-RA Hours referenced in this Schedule 53.

V. Operating Margin Calculation

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.

Operating Margin Equation

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

Where:

$$Online\ margin\ (MW)_j = \textstyle\sum_{unit\ i\ in\ region\ j}(EmergencyMax_i - \ Energy\ MW_i - cleared\ operating\ reserve_i)$$

For all Resources online and under normal dispatch control.

$$Offline\ margin\ (MW)_j = \textstyle\sum_{unit\ i\ in\ region\ j} Emergency\ Max_i - cleared\ offline\ supplemental\ reserve(MW)_j$$

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) is not on outage.

VI. Seasonal Accredited Capacity Calculation

A. Tier 1 Intermediate SAC (ISAC) is calculated as the sum of hourly real time availability, or Targeted Demand Reduction Level for DRR-Type 1, during each of the Resource's Seasonal Non-RA Hours, divided by the total number of Seasonal Non-RA Hours for each Season within the three (3) most recent periods beginning September 1st and ending August 31st.

B. Tier 2 ISAC is calculated as the sum of hourly real time availability, or Targeted Demand Reduction Level for DRR-Type 1, for the Resource's Seasonal RA Hours, plus the product of: seasonal Resource Class-level UCAP as a percentage of the corresponding Resource Class-level ICAP will be multiplied by the Resource's ICAP multiplied by the Seasonal RA Hour Deficiency; divided by the total number of Seasonal RA Hours plus the Seasonal RA Hour Deficiency for each Season within the three (3) most recent periods beginning September 1st and ending August 31st. For any Seasonal RA Hour where a Resource is offline and the sum of the Resource's Start-Up Time and Start-Up Notification Time Offers exceeds 24 hours, the Resource's hourly real time availability, or Targeted Demand Reduction Level for DRR-Type 1, will be set to zero (0).

C. For Resources required to submit GVTC values and for purposes of paragraphs A through C above, the hourly real time availability, or Targeted Demand Reduction Level for DRR-Type 1, will be capped at the currently effective GVTC value of the Resource. If a Resource is committed for a portion of its ICAP due to partial clearing, the partial clearing will not reduce the values in the Offers considered in the accreditation calculations, which will be capped at the currently effective GVTC value of the Resource.

D. In the case of an increase in generating Capacity of a Generation Resource, for purposes of paragraphs A through C above, the historical values for the hourly real time availability will be adjusted up for those hours prior to such increase going into effect as set forth in the Business Practices Manual for Resource Adequacy.

E. RA Hours will receive a greater weight than non-RA hours.

F. ISAC will be calculated using the following equation:

$$ISAC = ISAC_{Tier1\_value} \times ISAC_{Tier1\_weighting} + ISAC_{Tier2\_value} \times ISAC_{Tier2\_weighting}$$

Where Tier 1 weighting equals twenty percent (20%) and Tier 2 equals eighty percent (80%).

G. Resource Class-level ISAC is the sum of individual resource ISAC values within the Resource Class. The calculation of the Resource Class-level UCAP and Resource Class-level ISAC will exclude Resources that have yet to qualify for the applicable PRA at the time of these calculations and include those in both the relevant LOLE study and ISAC calculations.

H. The SAC for each Resource will be calculated as its pro-rata share of the Resource Class-level UCAP based on its individual ISAC value using the following equation:

$$SAC_i = Resource\ Class\text{-}Level\ UCAP * \frac{Resource\ ISAC_i}{Resource\ Class\text{-}level\ ISAC}$$

for each resource, i.

I. The Transmission Provider will post initial values for ISAC, SAC, Resource Class-level UCAP, and Resource Class-level ISAC ("Initial SAC Posting"), for each Season, by December 15 prior to the applicable Planning Resource Auction. Any dispute related to the initial ISAC values shall be submitted to the Transmission Provider in writing within thirty (30) Calendar Days of such posting. The Transmission Provider will post final values for ISAC, SAC, Resource Class-level UCAP, and Resource Class-level ISAC ("Final SAC Posting"), for each Season, by February 15 prior to the applicable Planning Resource Auction. No changes will be made to the Final SAC values following the February 15 posting, unless the Resource Class-level ISAC changes more than three percent (3%) and at least 30 MW.

VII. New Resources or Resources with Insufficient Performance Data

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 its respective seasonal Resource Class-level UCAP as a percentage of the corresponding Resource Class-level ICAP will be multiplied by the Resource's ICAP. Resources on a Catastrophic Generator Outage during a Season they are designated for RAR may elect to use a SAC based on its respective Resource Class's UCAP percentage multiplied by its ICAP 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.

Tab C

Schedule ~~53~~53A

Extended Seasonal Accredited Capacity Calculation

I. Applicability

A. Implementation Date of Schedule 53A

The provisions of this Schedule 53A, except Subsection I.B Effective Date of Reporting Requirement, shall be effective on June 1, 2027 for implementation beginning with Planning Year 2028-2029 and continuing thereafter. The Transmission Provider shall make a filing to remove the currently effective Schedule 53 from the Tariff to be effective June 1, 2028.

B. Effective Date of Reporting Requirement

Commencing on September 1, 2024, the Transmission Provider will publish indicative results pursuant to the provisions set forth in this Schedule 53A. Such indicative results shall be published prior to the applicable Planning Resource Auction for Planning Year 2025–2026, and the two Planning Years thereafter, as further described in the Business Practices Manual for Resource Adequacy.

C. Resource Classes

The term "Resource Class" as used in this Schedule 53A shall mean 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 this Schedule 53A. All Capacity Resources, except External Resources, shall be assigned to one of the Resource Classes identified in this section for purposes of executing the two-step resource accreditation methodology defined in this Schedule 53A and determining the Planning Reserve Margin Requirement, as set forth in

Module E-1. A DRR-Type I or DRR-Type II that is a behind the meter generation facility, and that qualifies as a Capacity Resource shall be assigned to an applicable Resource Class below. A DRR-Type I that interrupts or controls demand shall be accredited pursuant to Section VI below. Resource Classes shall include:

Gas (including Oil)	Storage
Combined Cycle	Solar
Coal	Wind
Hydro	Run-of-River
Nuclear	Biomass
Pumped Storage	

Additional details regarding Resource Classes shall be included in Transmission Provider's Business Practices Manual for Resource Adequacy. The Transmission Provider will provide a mapping of each Capacity Resource to one of the above Resource Classes as per the schedule listed in the Transmission Provider's Business Practices Manual for Resource Adequacy. Any dispute regarding Resource Class assignment must be submitted to the Transmission Provider in writing within ten (10) Business Days from the date such assignment was provided to the Market Participant.

II. General

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,~~, except an External Resource, ~~or Use Limited Resource~~ will be determined pursuant to this Schedule ~~53~~53A. The resources accredited pursuant to this Schedule ~~53~~53A, as described above, are ~~here and after~~hereinafter referred to as "Schedule ~~53~~53A Resources".

The SAC calculation for Schedule 53A Resources will be performed using a two-step process. First, the Resource Class-level UCAP will be determined by the method described in section II.A. Second, the Resource Class-level UCAP will be allocated amongst the individual resources in the Resource Class using the individual resource performance during Tier 1 and Tier 2 Hours based on the prior three years of operational performance as described in section II.B.

A. Resource Class-level UCAP and ICAP Calculation

Resource Class-level UCAP in a Season will be determined by calculating the combined expected availability and performance of all resources within that Class during Critical Hours from the probabilistic LOLE analysis as set forth in Module E-1. For each Season, "Critical Hours" are defined as the set of all 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. For those Seasons with 1,950 or more loss of load hours, Critical Hours will only include loss of load hours. Once Critical Hours are determined for each Season, weights are calculated for each of the Critical Hours using a weighting system that assigns greatest weight to the hours with the highest risk (i.e. hour with most unserved energy), as further described in the Business Practices Manual for Resource Adequacy. After calculating the weights for each Critical Hour, Critical Hours will be capped at 1,950 hours for each Season during which there are less than 1,950 loss of load hours. Finally, Seasonal Resource Class-level UCAP will be calculated as the weighted average of the Resource Class performance during Critical Hours in the Season.

Resource Class-level ICAP will be calculated as the sum of the ICAP values of all

Resources in the Resource Class.

B. Resource-level Extended Seasonal Accredited Capacity Calculation

A two-tiered weighting structure is used to calculate Extended Seasonal Accredited Capacity for Schedule 5353A Resources. Outage exemptions for planned outages and exemptions for any operating limitations, such as thermal, voltage, or stability limits referenced in the BPM for Outage Operations, provided by the Transmission Provider or Transmission Operator to preserve the reliability of the Transmission System, that modify the must offer obligation set forth in Section 69A.5.a will be factored into calculating the tiers of a Schedule 5353A Resource's Extended Seasonal Accredited Capacity.

IIIII. Tier 1 and Tier 2 Planned Outage Exemption Requirements

Generator Planned Outages scheduled to begin before September 1, 2022, will be granted a Tier 1 and Tier 2 exemption based on Section 38.2.5.g.ix., and as set forth in the Business Practices Manual for Resource Adequacy. Generator Planned Outages scheduled to begin on or after September 1, 2022, will be evaluated for Tier 1 and Tier 2 exemptions based on the following requirements. Only full (Out-of-Service) Generator Planned Outages or full (Out-of-Service) Proposed Generator Planned Outages shall be eligible for the Tier 1 and Tier 2 planned outage exemptions set forth below. Resources in the Solar Resource Class shall not be eligible for Tier 1 and Tier 2 Planned Outage Exemptions for Generator Planned Outages and Proposed Generator Planned Outages that are scheduled during nighttime hours for each Season. Nighttime hours will be defined by Local Resource Zone, as set forth in the Business Practices Manual for Resource Adequacy.

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 or Tier 1 only at Transmission Provider's discretion

A. Tier 2 Planned Outage exemptions

i. The Generator Owner or Generator Operator: (a) 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 generator unit; and (b) the Proposed Generator Planned Outage is to occur entirely during a period in which there is adequate Maintenance Margin at the time advance notice of 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.

ii. The Generator Owner or Generator Operator reschedules its Generator Planned Outage at the Transmission Provider's request: (a) the Proposed Generator Planned Outage is to occur 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 generator unit; and (b) Generator Planned Outage has inadequate Maintenance Margin at time of submittal and moves to a time of adequate Maintenance Margin.

iii. The Transmission Provider may, at its discretion, grant a Tier 2 Planned Outage exemption if the Generator Owner or Generator Operator reschedules its Generator Planned Outage at the Transmission Provider's request due to weather, forced outages, or other conditions listed in the Business Practices Manual for Outage Operations without regard to how many days in advance the outage was submitted or whether there was projected to be adequate Maintenance Margin for the duration of the outages.

B. Tier 1 Planned Outage exemptions

i. The Generator Owner or Generator Operator receives a Tier 2 Planned Outage exemption under section A.i above.

ii. The Generator Owner or Generator Operator: (a) 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 generator unit; and (b) the Proposed Generator Planned Outage is to occur during a period when there is inadequate Maintenance Margin at the time the outage is provided to the Transmission Provider. There is inadequate margin when the Maintenance Margin is less than or equal to zero megawatts, for any day of outage, after subtracting the megawatts of the requested Proposed Generator Planned Outage. The request shall be determined based on highest queued request.

iii. Subsequent generator unit outage requests 120 days or more in advance and/or Generator Owners or Generator Operators Generator Planned Outage less than 120 days in advance and at least 31 days in advance of outage start date. Proposed Generator Planned Outage to occur entirely during a period in which 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.

iv. Generator Owners or Generator Operators Generator Planned Outage less than 31 days in advance and at least 14 days in advance of outage start date. A Proposed Generator Planned Outage to occur entirely during a period the generator unit has an adequate Maintenance Margin at the time the outage is provided to the Transmission Provider and the outage passes the No Harm Test. 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.

v. Generator Owner or Generator Operator reschedules its Generator Planned Outage at the Transmission Provider's request due to inadequate Maintenance Margin for the duration of outage, at the time the outage is provided to the Transmission Provider. Maintenance Margin is less than zero megawatts after subtracting the megawatts of the requested Proposed Generator Planned Outage. This requirement does not include outages submitted less than 14 days in advance of the start date.

vi. The Transmission Provider may, at its discretion, grant a Tier 1 Planned Outage exemption if the Generator Owner or Generator Operator reschedules its Generator Planned Outage at the Transmission Provider's request due to weather, forced outages, or other conditions listed in Business Practices Manual for Outage Operations without regard to how many days in advance the outage was submitted or whether there was projected to be adequate Maintenance Margin for the duration of the outages.

C. No Harm Tests

Outages submitted between 14 to 30 days of start date will be evaluated for final approval and exemption status together. The 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 Business Practices Manual for Generator Outage.

D. Limitation Provided by Transmission Provider or Transmission Operator

The Transmission Provider will grant the equivalent of a Tier 2 Planned Outage exemption if a Schedule 5353A Resource is provided an operating limitation, such as thermal, voltage, or stability limits referenced in the BPM for Outage Operations, provided by the Transmission Provider or the Transmission Operator to preserve the reliability of the Transmission System, that is lower than the must offer obligation described in Section 69A.5.a.

IIIIV. Resource Adequacy Hours

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 beginning 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). Both). Seasonal RA Hours and Annual RA Hours will be determined for the First Planning Area and Second Planning Area separately. The RA Hours determined in subpart IIIIV.A & IIIIV.B below are the only RA Hours that will be used to calculate Tier 2 ISAC in subpart V.CVI.B below. Where certain Seasonal RA Hours do not apply for a Resource due to a Tier 2 Planned Outage exemption or for periods where the

Resource was not designated for RAR under Module E-1 of the Tariff and the Resource does not otherwise have 65 RA Hours identified for the Season then a Seasonal RA Hour Deficiency exists per subpart III.A.iii and the Resource's Annual Average Offered Capacity is multiplied by the Seasonal RA Hour Deficiency per subpart V.C of this Schedule 53IV.A.iii. To address the Seasonal RA Hour Deficiency, a Resource Class-level UCAP as a percentage of the corresponding Resource Class-level ICAP will be multiplied by the Resource's ICAP and the product will be applied for purposes of determining ISAC for only the deficient Seasonal RA Hours.

A. Seasonal RA Hours. Seasonal RA Hours will include a target of 65 hours for each Season consisting of:

i. All operating hours during any declared Maximum Generation Emergency in a Season, excluding any operating hour where a Resource has a Tier 2 Planned Outage exemption or has periods where the Resource was not designated for RAR under Module E-1 of the Tariff. If more than 65 of such hours exists for any Season, all will be considered Seasonal RA Hours, and;

ii. If there are fewer than 65 hours identified for the Season in Section IIIIV.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 Planned Outage exemption or has periods where the Resource was not designated for RAR under Module E-1 of the Tariff, and;

iii. If 65 hours have still not been identified, then a Seasonal RA Hours Deficiency exists which is the number of hours less than 65 for any Season.

B. ~~Annual RA Hours will include of a target of 260 hours for each of the three (3) most recent periods beginning September 1st and ending August 31st consisting of:~~

~~i. All hours during Maximum Generation Emergency declarations excluding any operating hour where a Resource has a Tier 2 Planned Outage exemption or has periods where the Resource was not designated for RAR under Module E-1 of the Tariff. If more than 260 of such hours exists for any period, all will be considered Annual RA Hours, and;~~

~~ii. If there are fewer than 260 hours identified for the period in Section III.B.i above, additional hours will be identified up to a total of 260 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 Planned Outage exemption or has periods where the Resource was not designated for RAR under Module E-1 of the Tariff.~~

~~C.~~ Seasonal Non-RA Hours. Seasonal Non-RA Hours will consist of all hours not included in Section ~~III~~IV.A.i-iii. If a Resource has a Tier 1 and/or Tier 2 Planned Outage exemption for any of the operating hours identified as Seasonal Non-RA Hours or has periods where the Resource was not designated for RAR under Module E-1 of the Tariff, such hours will not be included in the applicable Seasonal Accredited Capacity calculation.

~~D~~C. Tier 1 Planned Outage exemptions apply only to Non-RA Hours. Tier 2 Planned Outage exemptions apply for both RA Hours and Non-RA Hours referenced in this Schedule 53.

~~IV~~V. Operating Margin Calculation

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.

Operating Margin Equation

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

Where:

$$Online\ margin\ (MW)_j = \sum\nolimits_{unit\ i\ in\ region\ j}(EmergencyMax_i - Energy\ MW_i - cleared\ operating\ reserve_i)$$

For all Resources online and under normal dispatch control.

$$Offline\ margin\ (MW)_j = \sum\nolimits_{unit\ i\ in\ region\ j} Emergency\ Max_i - cleared\ offline\ supplemental\ reserve(MW)_j$$

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) is not on outage.

~~V~~VI. Seasonal Accredited Capacity Calculation

~~A. Annual Average Offered Capacity (AAOC) will be determined for each Resource subject to this Schedule 53 and utilized in the Seasonal Accredited Capacity~~

~~calculation as applicable. The AAOC for a Resource is calculated by averaging Hourly Emergency Maximum Limit, or Targeted Demand Reduction Level for DRR-1, during the Annual RA Hours identified in Section III.B above for each 12-month period within the three (3) most recent periods beginning September 1st and ending August 31st. For any Annual RA Hour where a Resource is offline and the sum of the Resource's Start-Up Time and Start-Up Notification Time Offers exceeds 24 hours, the Resource's Hourly Emergency Maximum Limit, or Targeted Demand Reduction Level for DRR-1, will be set to zero (0).~~

~~B~~A. Tier 1 Intermediate SAC (ISAC) is calculated as the sum of ~~Hourly Emergency Maximum Limit~~hourly real time availability, or Targeted Demand Reduction Level for DRR-Type 1, during each of the Resource's Seasonal Non-RA Hours, divided by the total number of Seasonal Non-RA Hours for each Season within the three (3) most recent periods beginning September 1st and ending August 31st.

~~C~~B. Tier 2 ISAC is calculated as the sum of ~~Hourly Emergency Maximum Limit~~hourly real time availability, or Targeted Demand Reduction Level for ~~DDR-~~DRR-Type 1, for the Resource's Seasonal RA Hours, plus the product of: ~~Annual Average Offered Capacity~~seasonal Resource Class-level UCAP as a percentage of the corresponding Resource Class-level ICAP will be multiplied by the Resource's ICAP multiplied by the Seasonal RA Hour Deficiency; divided by the total number of Seasonal RA Hours plus the Seasonal RA Hour Deficiency for each Season within the three (3) most recent periods beginning September 1st and ending August 31st. For any Seasonal RA Hour where a Resource is offline and the sum of the Resource's Start-Up Time and Start-Up Notification Time Offers exceeds 24 hours, the Resource's ~~Hourly Emergency Maximum Limit~~hourly real time availability, or Targeted Demand Reduction Level for DRR-Type 1, will be set to zero (0).

~~D~~C. For Resources required to submit GVTC values and for purposes of paragraphs A through C above, the ~~Hourly Emergency Maximum Limit~~hourly real time availability, or Targeted Demand Reduction Level for DRR-Type 1, will be capped at the currently effective GVTC value of the Resource. If a Resource is committed for a portion of its ICAP due to partial clearing, the partial clearing will not reduce the values in the Offers considered in the accreditation calculations, which will be capped at the currently effective GVTC value of the Resource.

~~E~~D. In the case of an increase in generating Capacity of a Generation Resource, for purposes of paragraphs A through C above, the historical values for ~~Hourly Emergency Maximum Limit~~the hourly real time availability will be adjusted up for those hours prior to such increase going into effect as set forth in the Business Practices Manual for Resource Adequacy.

~~F~~E. RA Hours will receive a greater weight than non-RA hours.

~~G~~F. ISAC will be calculated using the following equation:

ISAC = $ISAC_{Tier1\_value} \times ISAC_{Tier1\_weighting} + ISAC_{Tier2\_value} \times ISAC_{Tier2\_weighting}$

~~Where:~~

	Weighting by Planning Year		
Tier	2023–2024 Planning Year	2024-2025 Planning Year	2025-2026 Planning Year and beyond
$ISAC_{Tier1\_weighting}$	40%	30%	20%
$ISAC_{Tier2\_weighting}$	60%	70%	80%

H. A system-wide conversion ratio will be determined using the following equation:

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

The system-wide conversion ratio will be determined on an annual basis consistent with the schedule established in the BPM.

I. Seasonal Accredited Capacity will be calculated for each Resource by multiplying its ISAC by the system-wide conversion ratio determined above using the following equation:

$$SAC_{Resource_i} = ISAC_{Resource_i} \times (RATIO\frac{UCAP}{ISAC})$$

VIWhere Tier 1 weighting equals twenty percent (20%) and Tier 2 equals eighty percent (80%).

G. Resource Class-level ISAC is the sum of individual resource ISAC values within the Resource Class. The calculation of the Resource Class-level UCAP and Resource Class-level ISAC will exclude Resources that have yet to qualify for the applicable PRA at the time of these calculations and include those in both the relevant LOLE study and ISAC calculations.

H. The SAC for each Resource will be calculated as its pro-rata share of the Resource Class-level UCAP based on its individual ISAC value using the following equation:

$$SAC_i = Resource\ Class\text{-}Level\ UCAP * \frac{Resource\ ISAC_i}{Resource\ Class\text{-}level\ ISAC}$$

for each resource, *i*.

I. The Transmission Provider will post initial values for ISAC, SAC, Resource Class-level UCAP, and Resource Class-level ISAC ("Initial SAC Posting"), for each Season, by December 15 prior to the applicable Planning Resource Auction. Any dispute related to the initial ISAC values shall be submitted to the Transmission Provider in writing within thirty (30) Calendar Days of such posting. The Transmission Provider will post final values for ISAC, SAC, Resource Class-level UCAP, and Resource Class-level ISAC ("Final SAC Posting"), for each Season, by February 15 prior to the applicable Planning Resource Auction. No changes will be made to the Final SAC values following the February 15 posting, unless the Resource Class-level ISAC changes more than three percent (3%) and at least 30 MW.

VII. New Resources or Resources with Insufficient Performance Data

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. For Planning Year 2022/23 Schedule 53 Resources that were not~~

~~committed under the annual construct during the period considered in the SAC calculations can direct MISO to accredit them in accord with their offers as described in Section IV above instead of using a class average.~~its respective seasonal Resource Class-level UCAP as a percentage of the corresponding Resource Class-level ICAP will be multiplied by the Resource's ICAP. 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 to ICAP Ratio for~~ its respective Resource ~~type~~Class's UCAP percentage multiplied by its ICAP 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.

Tab D

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Midcontinent Independent System Operator, Inc.	**)** **)**	**Docket No. ER24-___-000**

PREPARED DIRECT TESTIMONY OF
TODD RAMEY
SENIOR VICE PRESIDENT, MARKETS AND DIGITAL STRATEGY

I. PROFESSIONAL BACKGROUND AND QUALIFICATION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION WITH THE MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC.

A. My name is Todd Ramey. I am employed by the Midcontinent Independent System Operator, Inc. (MISO) as its Senior Vice President, Markets and Digital Strategy. MISO is located at 701 and 720 City Center Drive, Carmel, Indiana 46032.

Q. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL BACKGROUND.

A. I graduated from Purdue University where I earned an undergraduate degree in engineering. In addition, I received a Master of Business Administration degree from Butler University. I have more than thirty-five years of experience in the electric industry. For the first thirteen years of my career, I worked in generation and transmission system operations for a vertically integrated utility in the Midwest. I began my tenure with MISO in 2001 and have held various management positions in areas related to wholesale market design, development, and operations.

Q. PLEASE DESCRIBE YOUR CURRENT ROLE AND JOB RESPONSIBILITIES.

A. In my current role as Senior Vice President, Markets and Digital Strategy, I lead MISO's markets and technology transformation efforts. I manage teams focused on emerging technologies, transforming, and maturing capabilities, and developing and executing market design and evaluation enhancements. This work drives reliability and helps to meet the needs of MISO's customers in the future.

II. PURPOSE OF TESTIMONY AND FILING OVERVIEW

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to support MISO's proposed reforms to resource accreditation by providing information regarding MISO's resource adequacy construct, the reasons the reforms to accreditation are necessary and beneficial to help ensure reliability in the MISO Region, and key policy considerations supporting the proposed reforms to resource accreditation.

Q. PLEASE PROVIDE A BRIEF SUMMARY OF YOUR TESTIMONY.

A. My testimony begins with a discussion of Resource Adequacy (RA), including what it is and who is responsible for achieving it in the MISO Region. I provide a brief history of the RA construct in the MISO Region and discuss the recent move to a seasonal RA construct. I explain that this resource accreditation reform filing is the most recent change to the construct, designed to assist with the transformation that is occurring in the energy industry. I also explain why reforms to resource accreditation are necessary and how MISO worked with stakeholders to arrive at the proposal.

Q. PLEASE PROVIDE AN OVERVIEW OF THE FILING.

A. In this filing, MISO is requesting approval to implement a resource accreditation methodology based on measuring a resource's expected marginal contribution to reliability. Specifically, MISO proposes to use the direct loss of load (DLOL) based accreditation methodology beginning with Planning Year 2028 – 2029 to accredit Capacity Resources, except External Resources.[1] The proposed accreditation methodology consists of a two-

[1] Although the term "Capacity Resources" as defined in the Tariff includes External Resources, references to Capacity Resources herein excludes External Resources consistent with the applicability with the DLOL based methodology.

step process. In step one, MISO uses a probabilistic loss of load expectation (LOLE) analysis considering 30 weather years to determine Resource Class-level accreditation values. In step two, MISO assigns a value to each resource in the respective Resource Class based upon the resource's historical availability during Tier 1 and Tier 2 Resource Adequacy Hours (RA Hours) as currently established in Schedule 53 of MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff). As discussed below, and in other supporting testimonies to this filing, the proposed accreditation methodology is necessary to address the shifting risk profile and rapidly changing resource mix in the MISO footprint and to send appropriate signals to inform state regulators and Load Serving Entities (LSE) for the purposes of their integrated resource planning processes as well as individual resource investment and retirement decisions.

Q. WHY IS MISO PROPOSING TO CHANGE ITS RESOURCE ACCREDITATION METHODOLOGY AT THIS TIME?

A. MISO is at an inflection point in its portfolio evolution. Increasing penetration of wind and solar generation is shifting the nature of system risk. As described more fully in the Testimonies of Messrs. Joundi and Ming and Dr. Patton, existing accreditation methods are not sufficiently robust to capture the contribution of the rapidly growing penetration of intermittent resources during shifting periods of reliability risk. Moreover, the proposed accreditation changes are needed to send the proper signals to help ensure that needed resources are available during periods of system risk. As discussed in MISO's updated response to the Reliability Imperative, generation 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 expected performance, including factors such as their forced outage rates, and the availability of wind or solar radiation for weather-dependent resources.

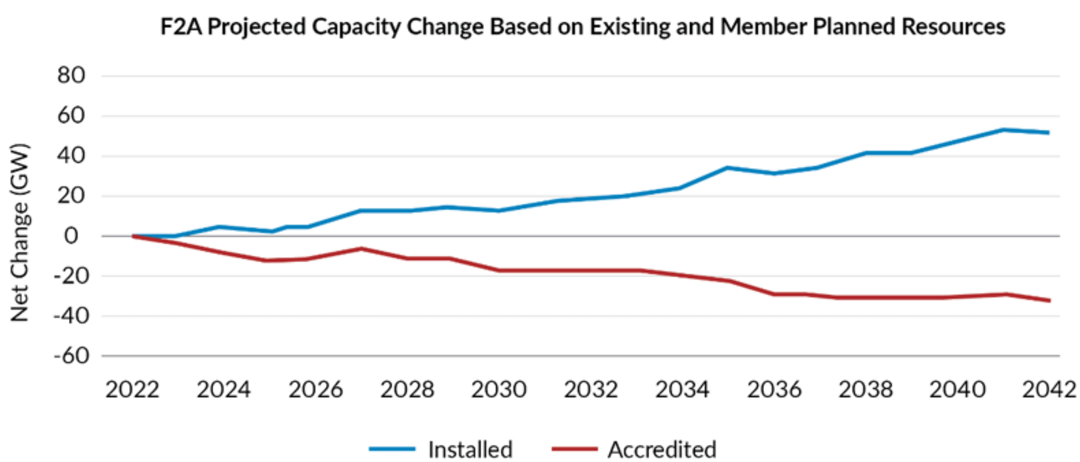

Figure 1 – Projected change in Installed and Accredited capacity for MISO Future 2A

Figure 1 above is from MISO Future 2A and reflects the publicly announced decarbonization plans of MISO-member utilities and states.[2] As the chart shows, the region's level of installed capacity — the blue line — is forecasted 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. But because those new wind and solar resources have significantly lower accreditation values than the conventional resources that utilities and states plan to retire in the same 20-year period, the

[2] *See* https://cdn.misoenergy.org/Series1A_Futures_Report630735.pdf. To hedge uncertainty and "bookend" a range of economic, political, and technological possibilities over the 20-year study period, MISO's regional resource expansion analysis is performed on multiple planning scenarios called the MISO Futures. Future 2A is one of three Future scenarios, that MISO refreshed in 2023, and fully incorporates the plans of states and members and includes a significant increase in load driven by electrification.

region's level of accredited capacity — the red line — is forecasted 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. Given this information, it is necessary to implement a broader accreditation reform in the near term to address these projections and start sending indicative accreditation values to inform investment, retirement and state resource planning decision making.

III. RESOURCE ADEQUACY

Q. WHAT IS RESOURCE ADEQUACY?

A. The term "Resource Adequacy" refers to the electric industry's ability to serve peak demand while also providing enough excess supply to achieve an agreed-upon level of grid reliability. The level of reliability of a one day in ten-year loss of load expectation (LOLE) is widely accepted and most commonly used in the industry today.

Q. WHO IS RESPONSIBLE FOR ACHIEVING RESOURCE ADEQUACY IN THE MISO REGION?

A. Within the MISO Region, responsibility for planning for and achieving Resource Adequacy rests primarily with LSEs, with oversight by state and other Relevant Electric Retail Regulatory Authorities (RERRA), as applicable by jurisdiction. MISO supports these Resource Adequacy efforts by administering Tariff-defined Resource Adequacy Requirements (RAR), which LSEs use to demonstrate their ability to serve peak demand and maintain a sufficient margin of excess supply. These RARs help to ensure that the MISO Region will have ample supply to meet peak demand, which has historically been in the Summer.

Q. WHAT RESOURCE ADEQUACY REQUIREMENTS MUST LSES MEET IN THE MISO REGION?

A. In accordance with the Tariff provisions in Module E-1, LSEs must procure sufficient accredited resources to meet their forecasted seasonal coincident peak load, plus a reserve margin, for each season in the coming Planning Year. MISO works with Market Participants to establish a Planning Reserve Margin (PRM) by season, which defines the percentage volume of resources required by each LSE above its forecasted peak load plus transmission losses to reliably meet demand when considering risk factors such as generator forced outages and weather uncertainty. By procuring resources to meet this margin above peak load expectations for each season, MISO and LSEs ensure the MISO Region is resource adequate.

Q. HOW DOES MISO ESTABLISH RESOURCE ADEQUACY REQUIREMENTS?

A. MISO's PRM for each season is based on a maximum LOLE of no more than one day in 10 years (1-in-10 LOLE). The PRM is then used to determine how much accredited capacity (in megawatts) each LSE is required to procure to meet its local needs for each season. The accredited capacity each LSE must procure under MISO's current Resource Adequacy construct is referred to as the LSE's Planning Reserve Margin Requirement (PRMR). The locational component of MISO's Resource Adequacy construct is accomplished through the identification of Local Resource Zones (LRZs), which are then used to define local resource requirements throughout the MISO Region. Additionally, a Local Clearing Requirement (LCR) is defined for each LRZ for each Season to ensure sufficient resources are available to meet the demand for that LRZ at non-coincident peak conditions for each Season.

Q. HOW DO LSES MEET RESOURCE ADEQUACY REQUIREMENTS IN THE MISO REGION?

A. LSEs have several means available to meet their PRMR. One option for LSEs is to voluntarily participate in MISO's annual Planning Resource Auction (PRA) to procure their capacity needs. The PRA selects the least-cost set of Planning Resources necessary to meet both regional and local requirements for each LRZ for each season, considering Zonal transmission limits. The PRA is conducted in April of each year, in advance of the Planning Year, which is segmented into seasons beginning with Summer (June – August) of the current year and runs through Fall (September – November), Winter (December – January) and Spring (March – May) of the next year. LSEs may elect to be excluded from the PRA through submission of a Fixed Resource Adequacy Plan (FRAP) or by paying a Capacity Deficiency Charge. An LSE may choose to participate in the PRA by submitting a self-schedule (i.e., submitting a $0 offer and being a "price taker"). Historically, approximately 92% of LSEs either submitted a FRAP or participated by self-scheduling in the PRA; with only about 8% of ZRCs being offered economically in the PRA.

Q. WHAT IS THE SIGNIFICANCE OF RESOURCE ACCREDITATION IN THE CONTEXT OF MISO'S RESOURCE ADEQUACY CONSTRUCT?

A. Each resource participating in MISO's Resource Adequacy construct, whether it is offered into the PRA, is included in a FRAP, or is self-scheduled, is assigned an accredited capacity value that reflects how much energy the resource is 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 and the availability of wind or solar radiation for weather-dependent resources. As discussed above, LSEs must procure resources with sufficient accredited capacity to meet their respective PRMR. Therefore, establishing appropriate accreditation values for each resource is critical in order to avoid over or under procurement of capacity. Mr. Joundi and MISO's Independent Market Monitor (IMM) both discuss the importance of appropriately accrediting resources to help ensure MISO meets reliability needs cost-effectively by providing appropriate investment and retirement signals.

Q. HAS MISO'S CURRENT RESOURCE ADEQUACY CONSTRUCT HELPED ENSURE RESOURCE ADEQUACY IN THE MISO REGION?

A. Yes, historically MISO's Resource Adequacy construct has supported meeting Resource Adequacy needs in the MISO Region.

Q. WHAT RECENT STEPS HAS MISO TAKEN TO HELP ENSURE CONTINUED RESOURCE ADEQAUCY NEEDS ARE MET FOR THE REGION?

A. As discussed further below, MISO has taken multiple steps to further refine its Resource Adequacy construct in order to ensure continued Resource Adequacy in anticipation of shifting risks. Beginning in the 2023 – 2024 Planning Year, MISO implemented its seasonal Resource Adequacy construct in which Resource Adequacy requirements are established, and met, on a seasonal basis. Also, for the 2023 – 2024 PRA, MISO transitioned to an availability-based resource accreditation methodology for the majority of generating capacity in the MISO footprint. More specifically, the resources subject to availability-based accreditation beginning in the 2023 – 2024 PRA are Capacity Resources that are Generation Resources but not Dispatchable Intermittent Resources, Intermittent Generation Resources, Electric Storage Resources, External Resources or Use Limited Resources, but including Demand Response Resources ("Schedule 53 Resources"). MISO is already experiencing benefits relating to implementation of its initial availability-based accreditation methodology, including better coordinated generator outage scheduling.

Q. WHAT ADDITIONAL STEPS HAS MISO TAKEN TO ENSURE RESOURCE ADEQUACY IN THE MISO REGION?

A. MISO has taken steps to address the demand side of the PRA by filing a proposal to implement a Reliability Based Demand Curve (RBDC) in the PRA. MISO's RBDC filing is currently pending Commission action in FERC Docket No. ER23-2977. As discussed in the RBDC filing, implementation of the proposed RBDC in the PRA will: (i) properly reflect the reliability value of capacity above the established PRM; (ii) provide capacity prices that better inform resource investment, retirement and replacement decisions of Market Participants; and, (iii) produce more economically efficient market outcomes reflecting the appropriate price of capacity and reducing price volatility created by the currently effective vertical demand curve. It is important to note that the RBDC proposal is completely independent of the accreditation reform proposed in this filing.

To further enhance reliability, the instant filing continues to refine the Resource Adequacy construct to ensure the MISO Region will have ample supply to meet peak demand in each season throughout the year. In fact, in its filing to implement the seasonal and availability-based accreditation approach discussed above ("SAC Filing"), MISO signaled its plans for future filings to further enhance the accreditation of other resource types, beyond Schedule 53 Resources, to better reflect availability during times of need. In that filing, MISO said that it expected to commence discussions with stakeholders regarding further enhancements in early 2022, which it did. This filing is the culmination of those discussions.

IV. TRANSFORMATION OF THE INDUSTRY

Q. PLEASE DESCRIBE THE TRANSFORMATION TAKING PLACE IN THE ELECTRIC INDUSTRY.

A. Sizable segments of dispatchable thermal generation are aging and the resource portfolio is shifting to increasing amounts of intermittent and highly weather dependent wind and solar resources. In its 2023 Long Term Resource Assessment (LTRA), the North American Electric Reliability Corporation (NERC) said that it accounted for over 83 GW of fossil-fired and nuclear generator retirements that are currently anticipated through 2033. In the 2023 LTRA, NERC found that, "Wind, solar PV and hybrid generation are projected to be the primary additions to the resource mix over this 10-year assessment period, leading the continued energy transition as older thermal generators retire."

Q. HOW HAVE GENERATION RETIREMENTS IMPACTED THE MISO REGION.

A. More than 23 GW of capacity has retired from the MISO Region during the last ten years, the majority of which were dispatchable thermal resources. The 2023 MISO Regional Resource Assessment indicates approximately 60 GW of installed capacity retirements in the next 20 years. Thermal resource retirements during the same time period are projected to be approximately 50 GW of installed capacity, as show in the figure below.[3]

[3] *See* 2023 Regional Resource Assessment, MISO (November 2023), at p. 20, available at https://cdn.misoenergy.org/2023%20Regional%20Resource%20Assessment%20Report630736.pdf

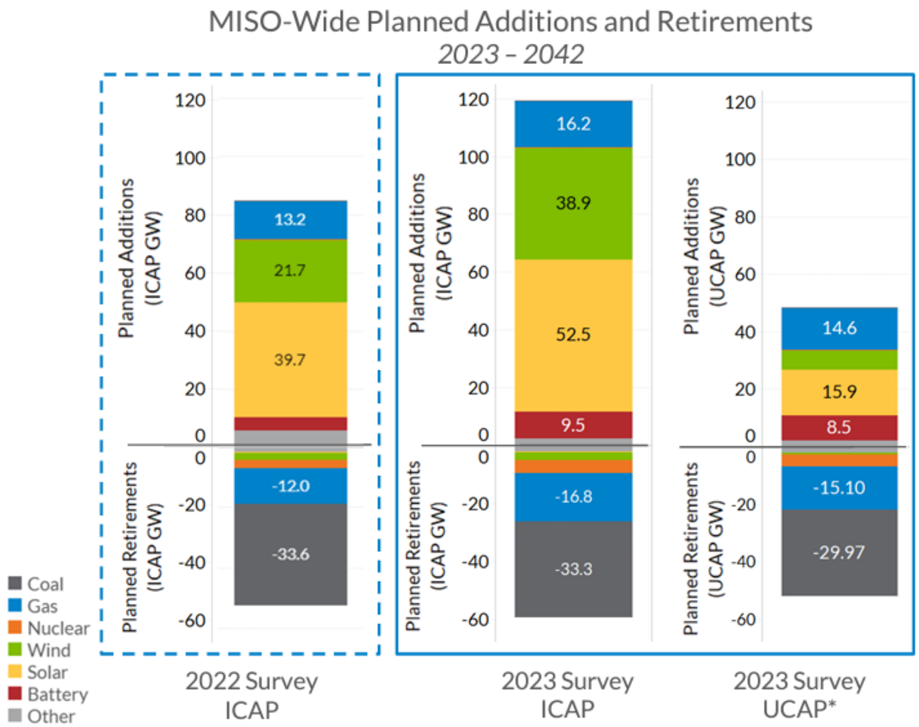

Figure 2 – MISO-Wide Planned Additions and Retirements

Q. PLEASE DISCUSS THE TYPES OF RESOURCES MISO ANTICIPATES WILL REPLACE THE RETIRING GENERATION UNITS WITHIN THE MISO REGION.

A. Based on MISO operational data, wind resources have grown from 12.4 GW in service in 2014 to 30.8 GW in service in 2024. In addition, solar resources have grown from 0 GW to 5.1 GW in service during the same time frame, with substantial additional capacity in the MISO generator interconnection queue. Moreover, Figure 3 below, from MISO Futures Report, provides the following projections of resource additions through 2042:[4]

[4] Series1A_Futures_Report630735.pdf (misoenergy.org) at p.3

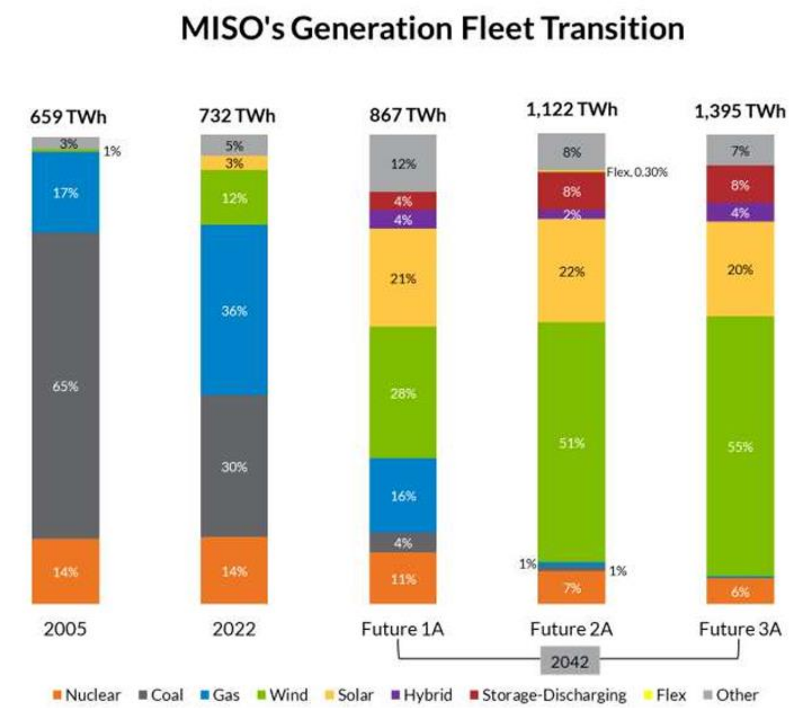

Figure 3 – Overview of MISO's Generation Fleet Mix Transition

Public announcements by MISO's members indicate that over a third of annual electricity production is shifting to wind and solar sources by 2030, if not earlier, with significantly higher production during certain times of the year. While the exact pace of this transformation is not yet clear given the varying estimates provided above, the trend is clear. In fact, as early as 2020 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.[5]

[5] 2020 Long Term Reliability Assessment, NERC (December 2020), at p. 7, available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf

To highlight the priority and urgency of this transformation, NERC recently stated:

> The addition of variable energy resources (primarily wind and solar PV) and the retirement of conventional generation are fundamentally changing how the [Bulk Power System] is planned and operated. With electricity supplies coming increasingly from [Variable Electric Resources] and natural gas fired generators, there is a growing risk that supplies can fall short of demand during some periods. To ensure energy shortfall risks are identified and addressed, resource contributions to serving load must be accurately represented in resource planning and operating models as well as in the design of wholesale electricity market designs.[6]

The NERC report goes on to state,

> Resource and system planners must have robust tools and capabilities for assessing energy needs, extreme weather scenarios, and grid stability. Planning Reserve Margins can fail to identify energy risks that stem from low [Variable Electric Resource] output or generator fuel supply issues, making them unsuitable as a sole basis of resource adequacy. Resource planners and wholesale markets must use enhanced modeling that accounts for energy risk, such as all-hours probabilistic assessments.

[6] 2023 Long Term Reliability Assessment, NERC (December 2023), at p. 11, available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf.

Q. DOES MISO AGREE WITH THE STATEMENTS MADE BY NERC IN THE LTRA?

A. Yes. MISO agrees with these statements and the proposed reforms to resource accreditation are consistent with NERC's concerns. Consequently, MISO must make substantive changes to the way resources are accredited in order to ensure continued reliability and address these emerging issues as the transition progresses and accelerates in the coming years.

Q. PLEASE DESCRIBE THE TRENDS MISO HAS IDENTIFIED THAT WILL CONTINUE TO IMPACT RESOURCE ADEQUACY AND PRESENT OPERATIONAL CHALLENGES.

A. I have discussed several trends previously in this testimony and MISO has identified additional important trends impacting the MISO Region in published Resource Availability and Need (RAN) whitepapers. These trends increase the complexity in managing reliability in the operating horizon throughout the year, and it is expected that they will become more challenging in upcoming years. As a result, reforms to the process through which capacity resources are accredited based upon their contribution to the reliability of the system during times of greatest need are necessary at this time.

Trend 1: Aging and retirement of the portfolio's generating units and the resulting impact on MISO's operations.

Retirements and increasing generator outage levels (both planned and forced) require MISO to operate with less available capacity than in the past. The effect of this trend is to reduce the redundancy provided by excess resource availability. In the past, MISO had a larger buffer of dispatchable generation that provided flexibility in responding to higher-than-expected load (or lower-than-expected supply) while still allowing energy market price signals to optimize unit commitment and dispatch. Less resource availability results in reduced operational flexibility during periods of shifting and increasing risk. These challenges are compounded by an aging thermal resource fleet, which can also reduce energy availability and lead to higher forced, planned, and maintenance outage rates. While new generation may be forecasted to come online, anticipated new generation does not fully alleviate existing reliability challenges due to the long timeframes needed to develop, construct, and bring generation online. In addition, a significant percentage of new generation is expected to be from intermittent resources, which have not historically provided the higher level of availability and reliability as thermal generation, as discussed further in Trend 4 below. The implications of misaligned investment signals and reduced confidence in resource availability during periods of the highest reliability risk across the year are key focuses in this filing.

Trend 2: Increase in Emergencies and Outage Correlation.

The MISO Region has year-round load and supply needs that have historically been served by a Summer-focused capacity requirement. In recent years, lower overall capacity levels and higher generator outage rates have reduced available capacity in non-Summer periods. As a result, MISO has seen emergency conditions tied to both planned and forced outages increase during non-Summer periods. The figure below shows the number and timing of MaxGen Alerts, Warnings or Events since the 2016–2017 Planning Year. As the graphic below indicates, these emergencies have occurred in all seasons, not just the Summer. This trend imposes a growing challenge to ensure sufficient available capacity in all seasons.

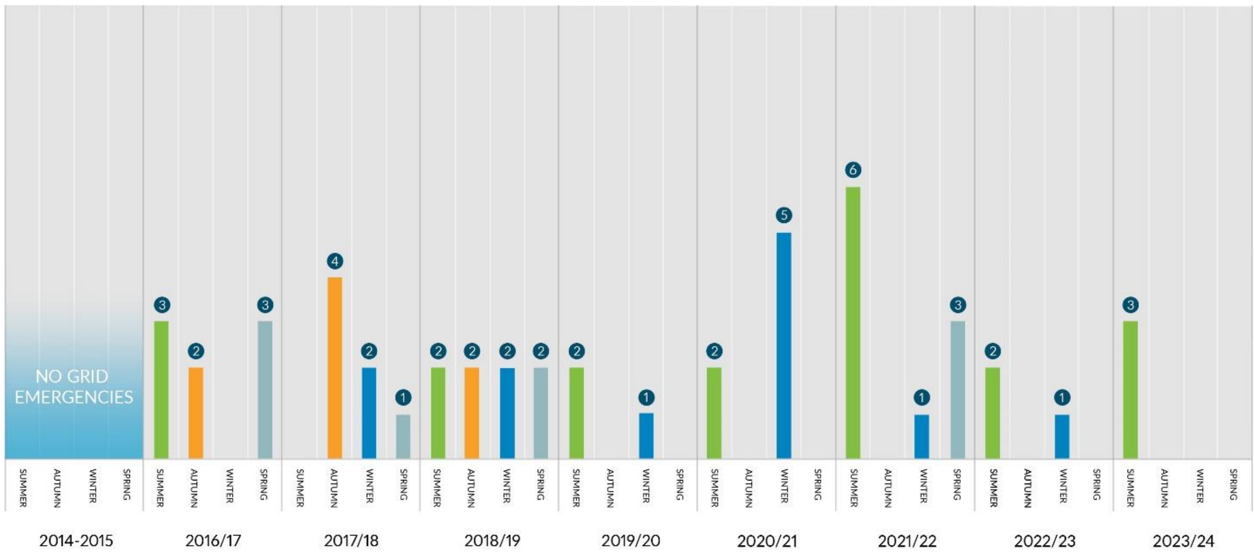

Chart indicates the number of days under a max gen alert, warning or event.

Figure 4 –MaxGen Alerts, Warnings or Events since the 2016–2017 Planning Year

Trend 3: Growth in demand-side and other emergency-only capacity as a percentage of the overall portfolio.

MISO has experienced growth in demand side and other emergency-only capacity as a percentage of the overall portfolio. In 2023, for example, LSEs committed nearly 12 GW of emergency-only capacity resources, which was roughly 10 percent of the Summer peak load forecast. These 12 GW of resources are not available to MISO's operators without the declaration of a maximum generation event under the existing framework and, in many cases, are made even further unavailable as a result of state and local contractual or regulatory limitations, including air permitting limits. In addition, as MaxGen declarations become more frequent, MISO has progressed further into its Emergency Operating Procedures during the events. These challenges are compounded by other issues, specifically: (1) it can be difficult for MISO's operators to access emergency-only resources in time to respond to evolving system conditions; (2) the performance of individual load modifying resources (LMRs) often does not match the MWs accredited for the resource in the PRA process; and (3) the amount of committed LMRs, which are only available during emergency conditions and only for a limited number of calls per year, continues to increase. These and additional types of demand resources are anticipated to participate in MISO's markets as a result of technology trends. Past MISO filings partially help address these issues, but further actions will be necessary.

Trend 4: Growing reliance on unscheduled resources.

As the resource fleet has evolved, the MISO Region has become more reliant on uncertain, uncommitted resources during tight operating periods. MISO has always been a net importer of energy from neighboring systems, and in the last few years MISO's reliance on such imports has become increasingly significant. About half of this imported energy is typically scheduled in real time with submission of interchange due just 20 minutes prior to each 15-minute interval.[19] While MISO has arrangements in place for the purchase of emergency energy from neighboring systems during declared emergency conditions, availability of such energy remains highly uncertain. Therefore, MISO continually reassesses its assumptions for imports in Resource Adequacy to ensure the region is not unduly relying on such imports, especially non-firm imports. As witnessed in the winter event of February 2021, MISO benefitted from very high levels of such imports from PJM. MISO does not and cannot assume such high levels of imports for planning purposes of Resource Adequacy, however, and must ensure that MISO's resources are sufficient and available in the absence of such imports, most notably during periods of tight operating margins. This underlies the importance of having sufficient confidence in the availability of MISO scheduled resources (a key focus of this filing), absent the benefits of unscheduled imports.

Trend 5: Growth of variable energy resources as a major element of the fleet.

Trend 1 will be further exacerbated by the projected growth in variable energy weather dependent resources, such as wind and solar generation. This resource category, by its very nature, has different characteristics than the legacy thermal Planning Resources they are partially replacing. Historically, such resources were accredited based on historic contributions during past system peaks, but that approach does not ensure that the accredited capacity will be available during tight grid conditions or a particular emergency event. If wind or solar happen to contribute less during a particular time of need, the difference must be made up elsewhere. This fact underlies the importance of having sufficient confidence in the availability of all resources, including wind and solar, during times of greatest need, which is the focus of this filing.

Q. WHY DO THESE CHALLENGES REQUIRE A NEW ACCREDITATION METHODOLOGY?

A. Historically, periods of risk have been aligned with times of high demand that are generally predictable (i.e., Summer peak). Additionally, resource availability was largely driven by uncorrelated outages and minimally dependent on weather patterns. Because of this certainty and stability, Resource Adequacy mainly entailed ensuring enough generation capacity existed to reliably serve the annual peak load. The electric grid is going through a period of rapid transformation due to the increased penetration of intermittent resources, increased frequency of large-scale weather events, and electrification. These drivers are expected to increase the number of random events on the system with a corresponding shift of reliability risks to off-peak hours and non-Summer periods. As Mr. Joundi describes in detail in his testimony, MISO's current accreditation approaches vary amongst resource types, but most of them do not focus on the contribution of resources during the periods of highest reliability risk, which results in inaccurate, inconsistent, and oftentimes overstated accreditation. As a result, MISO proposes the DLOL-based method as a robust and uniform accreditation methodology that can properly estimate availability of resources during periods of highest risk.

V. MISO'S RESPONSE TO THE RELIABILITY IMPERATIVE

Q. HOW WILL MISO RESPOND TO THE RAPID TRANSFORMATION OF THE MISO REGION?

A. MISO originally published a report in December 2020 that documents these trends identified above and explains why these trends create a "Reliability Imperative" for the region. MISO's Response to the Reliability Imperative was updated in February of 2024, but maintains the four primary pillars: (1) Market Redefinition, (2) Long Range Transmission Planning, (3) Operations of the Future, and (4) Market Systems Enhancements. The report continues to emphasize that the sharing of responsibility between MISO, LSEs, and RERRAs is necessary to address the factors that pose a threat to reliability in the MISO Region, including rapid fleet change, and increased frequency and severity of extreme weather events. As explained by MISO's Chief Executive Officer, John Bear in the latest report:

> 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**.

The instant proposal is a necessary step in a successful transition to the decarbonized end state desired and a key element in the Market Redefinition pillar of MISO's Reliability Imperative. Among other things, accrediting resources based upon Critical Hours and RA Hours, as proposed, will provide both LSEs and regulators engaged in integrated resource planning the right investment and retirement signals to help ensure the availability of resources with the attributes necessary to maintain reliability into the future, as the transition progresses.

Q. WHAT IS MARKET REDEFINITION?

A. Market Redefinition is one of four primary pillars of MISO's Response to the Reliability Imperative, and is illustrated in the graphic below:

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

Figure 5 – Four pillars of MISO's Response to the Reliability Imperative

Q. HOW IS MISO'S PROPOSAL IN THIS FILING PART OF MISO'S RESPONSE TO THE RELIABILITY IMPERATIVE?

A. Among other things, the Market Redefinition pillar of the Reliability Imperative, aims to ensure that resources with needed capabilities and attributes will be available during the highest risk periods across the year. The purpose of this filing is to propose a methodology for setting resource requirements and accrediting Schedule 53A Resources , using an approach that aligns resource availability to the highest risk periods across the year. That alignment is one of the aims of the Market Redefinition pillar and is the next planned step to achieving MISO's Reliability Imperative. Previous initiatives have included outage coordination, enhancement to LMRs, changes to ICAP deliverability, movement to the seasonal capacity construct, and the proposed implementation of an RBDC in the PRA. Broader resource accreditation reform is the next logical step in the progression.

Q. WHAT IS MISO'S ATTRIBUTES ROADMAP?

A. The Attributes Roadmap is a Reliability Imperative Report published by MISO in December 2023. 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 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 levels and 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 reforms and requirements to meet the changing system needs.

Q. WHAT ATTRIBUTES DOES MISO FOCUS ON IN ITS ATTRIBUTES ROADMAP?

A. In 2023, MISO completed a foundational analysis of the system reliability attributes. As indicated in Figure 6 below, the analysis focused on three priority attributes where risk to the MISO system is most acute: system adequacy, flexibility, and system stability. MISO also identified the near-term risk factors that align with each of the identified system attributes, including: energy assurance, availability fuel assurance, rapid start-up, ramp up capability, and voltage stability. MISO developed recommended approaches and solutions based on input from various expert sources that are outlined in the Attributes Roadmap.

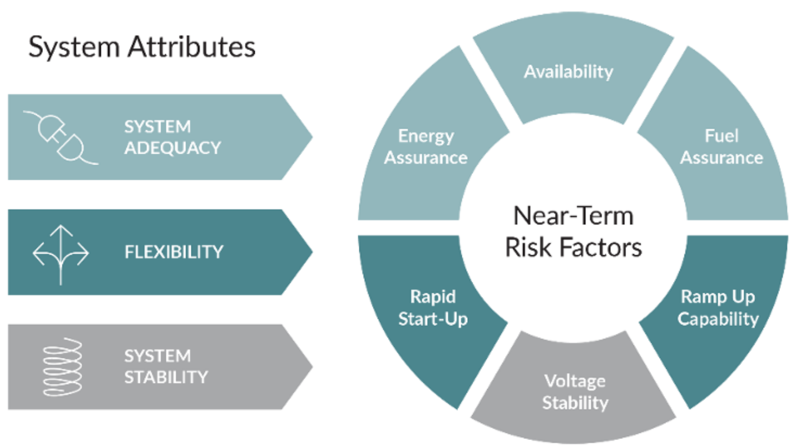

Figure 6 – Top priority System Attributes

Q. WHAT IS SYSTEM ADEQUACY?

A. System Adequacy refers to the ability to meet electric load requirements during periods of high risk. 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. 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 twenty-four 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.

Q. WHAT IS FLEXIBILITY?

A. 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 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 needs access to adequate system attributes so that operators are able to respond in time and balance the system needs.

Q. WHAT IS SYSTEM STABILITY?

A. 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 the 2023 analysis was on the voltage stability family of issues. 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 systems to provide the power required by the loads. Voltage stability is often thought of as load-driven rather than resource-driven, though resource characteristics effect voltage stability outcomes.

Q. WHICH OF THE THREE PRIORITY ATTRIBUTES DOES THE INSTANT PROPOSAL ADDRESS?

A. The instant proposal directly addresses system adequacy. The modernization of MISO's resource adequacy construct is well-underway with recent and proposed changes to incorporate industry best practices to address shifting risk. MISO's recently implemented seasonal PRA better acknowledges seasonal risks and resource capabilities throughout the year. The current accreditation methodology for thermal resources, approved by the FERC in 2022, aligns the accreditation of thermal resources with their availability in the highest risk periods. The proposed next step for resource adequacy reform is to accredit all resources using the DLOL-based methodology. MISO has determined that the DLOL-based methodology addresses system adequacy risk by aligning the determination of MISO's capacity requirements (PRMR) with accreditation based upon the performance of resources during times of highest reliability risk, as identified through the use of its two-step probabilistic and deterministic analyses. LMRs and Available Max Emergency Resources will be addressed in separate filings.

Q. PLEASE DESCRIBE HOW THE INSTANT PROPOSAL SATISFIES A PROPOSED SOLUTION IN THE SYSTEM ADEQUACY SECTION OF THE ATTRIBUTES ROADMAP.

A. One of the solutions in the System Adequacy section of the Attributes Roadmap states, "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 requirement 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. In the instant proposal, MISO is seeking to align capacity accreditation with system risk to estimate the capacity contribution of MISO resources. The DLOL-based method measures resource accreditation during periods of both highest potential and realized system risks consistently across all Schedule 53A Resources, and therefore provides the most meaningful investment signal for resources that provide sufficient reliability attributes to manage through risky periods. In addition, as illustrated in Figure 7 below, the current proposal is part of an ongoing effort to modernize MISO's resource adequacy construct as part of its Reliability Imperative.

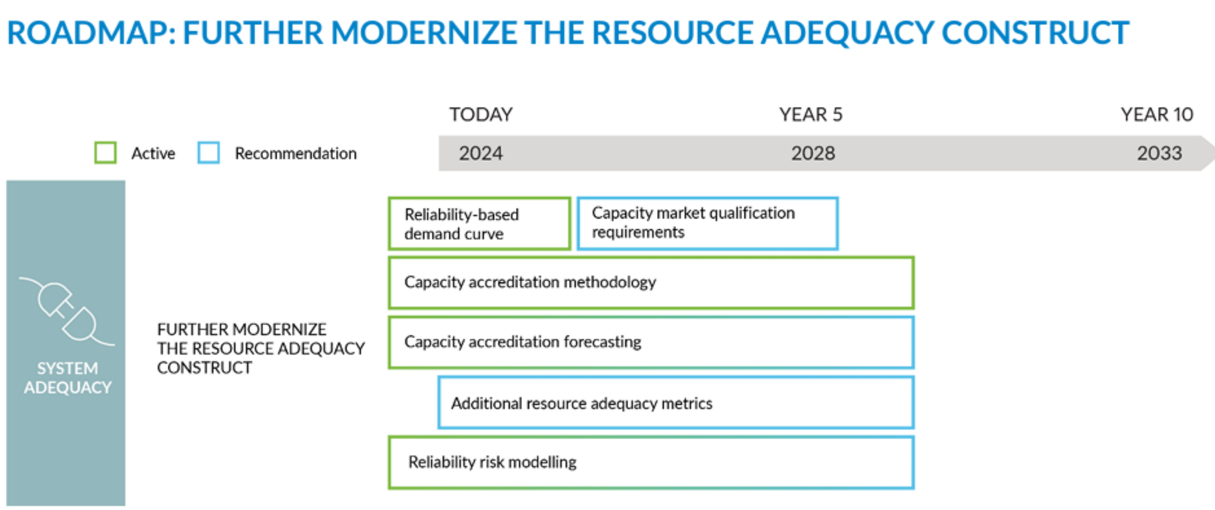

Figure 7 – Resource Adequacy Construct Roadmap

VI. PROPOSAL DEVELOPMENT AND STAKEHOLDER PROCESS

Q. HOW DID MISO ARRIVE AT THE CURRENT PROPOSAL?

A. In January 2022, following MISO's SAC filing, MISO initiated a stakeholder process through the Resource Adequacy Subcommittee (RASC) to work with stakeholders to develop the resource accreditation reform that is the subject of this filing. As discussed in greater detail by Mr. Joundi, MISO has followed the product development process shown in Figure 8 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 both internally and through the stakeholder process, and ultimately recommended the proposed accreditation methodology that is the subject of this filing.

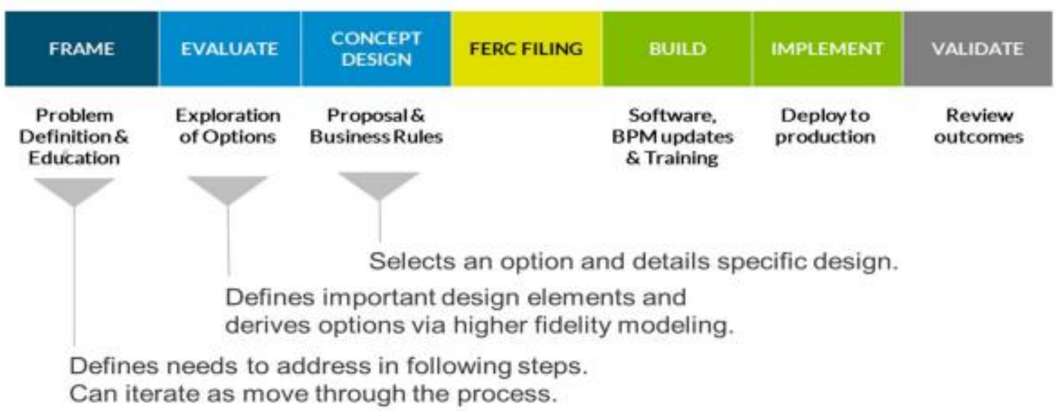

Figure 8 – Market Design development process

Q. WHAT IS THE PROBLEM STATEMENT THAT MISO DEVELOPED AS PART OF ITS EVALUATION PROCESS?

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 ARE MISO'S MARKET VISION AND MARKET DESIGN GUIDING PRINCIPLES?

A. 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, which are listed below, support an economically efficient wholesale market system that minimizes cost to distribute and deliver electricity. The guiding principles are:

- 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.

Q. HOW DOES THE DLOL-BASED METHOD ALIGN WITH MISO'S MARKET VISION AND MARKET DESIGN GUIDING PRINCIPLES?

A. The proposed DLOL-based method is consistent with MISO's Market Design Guiding Principles by supporting efficient wholesale markets as it aligns market requirements with system reliability requirements, facilitates non-discriminatory market participation, results in transparent market prices that reflect reliability contributions during highest-risk hours, and supports efficient operational and investment decisions.

Q. DID MISO SOLICIT AND CONSIDER STAKEHOLDER INPUT IN DEVELOPING THE DLOL-BASED METHOD?

A. As further discussed in Mr. Joundi's Testimony, MISO engaged in an extensive stakeholder process that spanned two years and included multiple opportunities for stakeholders to weigh in on the various accreditation methodologies under consideration, as MISO evaluated different approaches to resource accreditation. Furthermore, once MISO selected the proposed approach, stakeholders were afforded the opportunity to provide feedback on the design details as MISO worked to finalize them. The RASC was the stakeholder entity where accreditation was addressed. Over the course of the two-year period, MISO held at least eighteen RASC meetings where accreditation was a topic on the agenda. In addition, MISO conducted five workshops during which MISO facilitated discussions that focused solely on the accreditation matters that are the subject of this filing.[7] Moreover, MISO discussed accreditation with its IMM at least ten times and met with the Organization of MISO States, Inc. (OMS) and individual state regulators on this topic on multiple occasions. Out of the eighteen RASC meetings where accreditation was a topic on the agenda, MISO specifically requested and received feedback from stakeholders thirteen times. Mr. Joundi discusses specific changes MISO made to its proposal as a result of feedback received from stakeholders at key points throughout the process.

Q. DID MISO ENGAGE IN SPECIFIC OUTREACH TO THE OMS AND INDVIDUAL STATE COMMISSIONS?

A. Yes. MISO recognizes the important role that state and other retail regulators play in ensuring resource adequacy within the MISO region. Over the past year, in addition to the general stakeholder meetings and workshops, MISO held five meetings with OMS focusing exclusively on resource accreditation education and reform. MISO also met with multiple states individually that reached out for further discussion, assistance, or education on resource accreditation, generally, and MISO's proposal. State regulators were able to voice their concerns and ask questions during those meetings. In addition, MISO was able to gain valuable insight into crafting its proposal to address some of those questions and concerns along the way. The dedicated sessions went a long way to clearing up misconceptions about the proposal and provided an opportunity for MISO to discuss the concerns of regulators within its region.

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[7] *See* Exhibit A – Table of Stakeholder Meetings and Materials

Q. DID MISO ENGAGE IN SPECIFIC OUTREACH TO LOAD SERVING ENTITIES WITHIN THE MISO REGION?

A. Yes. The DLOL-based method represents a significant change to the way MISO accredits resources and calculates the PRMR within the MISO region. As a result, MISO's External Affairs team has been periodically meeting with stakeholders to answer questions about the proposal and to provide information regarding the impact of the change to their specific resources. MISO's External Affairs team provided each LSE who requested it with unit level indicative results for their specific resources. These unit-level indicative results are the specific kind of information MISO will continue to provide to LSEs requesting such information during the transition period. Those LSEs can use the data to understand how their resources will be impacted by the change and to engage in long-term resource planning. MISO will provide all Market Participants with Resource Class-level indicative accreditation values prior to the 2028 – 2029 PRA, consistent with the proposed Schedule 53A. In addition, MISO has committed to publish indicative projected accreditation values over the longer term as part of its Regional Resource Assessment report.

Q. PLEASE DESCRIBE MISO'S EDUCATIONAL EFFORTS RELATED TO RESOURCE ACCREDITATION REFORM.

A. In addition to allowing stakeholders to present their thoughts on the DLOL-based methodology and other resource accreditation reform efforts, MISO brought in experts along the way to help educate its staff and stakeholders. In January 2022, The Brattle Group presented on the Motivation for Reforming Accreditation for Renewables: Jurisdictional Review. In September 2022, MISO's IMM presented on Marginal vs. Average Capacity Accreditation. In March 2023, Telos Energy and Energy Systems Integration Group

(ESIG) presented on Ensuring Efficient Reliability: New Design Principles for Capacity Accreditation. In June 2023, CAISO presented its approach to Resource Adequacy in its service area. The information presented during these sessions were helpful to MISO in shaping its proposal and were designed to be educational for MISO stakeholders.

VII. CONCLUSION

Q. PLEASE IDENTIFY THE OTHER WITNESSES PROVIDING EVIDENCE TO SUPPORT THIS FILING.

A. The other witnesses providing testimony to support this filing include:

Zakaria ("Zak") Joundi – as Executive Director of Market and Grid Strategy for MISO, Mr. Joundi manages the market design team, which is the group at MISO responsible for spearheading the accreditation reforms proposed in this filing through the stakeholder process. In his testimony in this proceeding, Mr. Joundi explains the actions MISO took to develop the accreditation reforms proposed herein. He discusses the evaluation stage, where MISO defined the problem it was trying to solve and analyzed various solutions before selecting the DLOL-based method. He then discusses the various DLOL-based methodology design elements and why that method was selected by MISO. He also talks about key changes to the proposal that occurred along the way, as MISO worked with and responded to stakeholder feedback and comments, over the last two years, beginning in January 2022.

Zachary Ming – a Director at Energy and Environmental Economics ("E3"), provides expert testimony to explain why changes are required to MISO's capacity accreditation framework in order to ensure optimal market outcomes and the reasons the proposed DLOL-based method best meets the needs of MISO's evolving system.

Dr. David Patton – an economist, President of Potomac Economics and MISO's IMM" provides support for proposed revisions to MISO's Tariff related to the accreditation of capacity. Specifically, Dr. Patton discusses how the proposed changes in accreditation improve its alignment with the reliability provided by different types of resources.

Q. DOES THIS CONCLUDE YOUR TESTIMONY IN THIS PROCEEDING?

A. Yes, at this time, this answer concludes my testimony in this proceeding.

Affidavit of Todd Ramey

COUNTY OF HAMILTON)
)
STATE OF INDIANA)

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

Todd A. Ramey

Todd Ramey

SUBSCRIBED AND SWORN BEFORE ME, this 26 day of March, 2024.

Rhiannon Rena Shelley

(*Notary Public Signature*)

Commissioned in Clinton county.

Commission Number: 705772

Commission Expires: 9/27/2025

NOTARY PUBLIC NOTARY SEAL STATE OF INDIANA
RHIANNON RENA SHELLEY
Clinton County
My Commission Expires
September 27, 2025

Exhibit A – Table of Stakeholder Meetings and Materials

MEETING DATE	MATERIALS
January 26, 2022	20220126 RASC Item 05b Renewables Accreditation MISO Presentation
January 26, 2022	20220126 RASC Item 05b Renewables Accreditation Brattle Group Presentation
March 9, 2022	20220309 RASC Item 06a Accreditation Reforms for Non Thermal Resources (RASC 2020 4 2019 2)
April 20, 2022	20220420 RASC Item 06a Non Thermal Accreditation Presentation (RASC 2020 4 RASC 2019 2)
May 25, 2022	20220525 RASC Item 06b Non Thermal Accreditation
June 21, 2022	20220621 Non Thermal Accreditation Workshop.pdf
August 24, 2022	20220824 RASC Item 07c Non-Thermal Accreditation Presentation (RASC-2019-2 2020-4).pdf
September 21, 2022	Non-Thermal Accreditation Workshop - September 21, 2022
October 5, 2022	Non-Thermal Accreditation Workshop – October 5, 2022
October 12, 2022	20221012 RASC Item 12a iii Non-Thermal Accreditation MISO Presentation.pdf
November 30, 2022	20221130 RASC Item 07b Non-Thermal Accreditation Presentation (RASC-2020-4 2019-2).pdf
January 17, 2023	20230117-18 RASC Item 14b Non-Thermal Resource Accreditation (RASC-2020-4, RASC-2019-2) Presentation.pdf
February 28, 2023	20230228-0301 RASC Item 09a Non-Thermal Accreditation (RASC-2020-4 RASC-2019-2).pdf
March 17, 2023	Capacity Accreditation Workshop with Energy Systems Integration Group - March 17, 2023

Exhibit A – Table of Stakeholder Meetings and Materials

April 18, 2023	20230418-19 RASC Item 12a Non-Thermal Accreditation Presentation.pdf
May 24, 2023	MISO Draft Resource Accreditation Design White Paper.pdf
July 11, 2023	20230711-12 RASC Item 08ai Resource Accreditation Presentation (RASC-2020-4, 2019-2).pdf
August 22, 2023	20230822-23 RASC Item 09bi Resource Accreditation Presentation (RASC-2020-4, 2019-2).pdf
September 22, 2023	LOLE Modeling & Accreditation Reform Workshop - September 22, 2023
October 4, 2023	20231004 RASC Item 05ai Resource Accreditation Presentation.pdf
November 7, 2023	20231107-08 RASC Item 11ai Resource Accreditation Presentation (RASC-2020-4 2019-2).pdf
November 7, 2023	Resource Accreditation White Paper Version 1.1.pdf
January 17, 2024	20240117 RASC Item 07a Accreditation Presentation (RASC-2020-4 and 2019-2.pdf
February 27, 2024	Resource Accreditation White Paper Version 2.pdf
February 28, 2024	20240228 RASC Item 05a Accreditation Presentation RASC-2020-4 2019-2.pdf
March 28, 2024	Resource Accreditation White Paper Version 2.1

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.

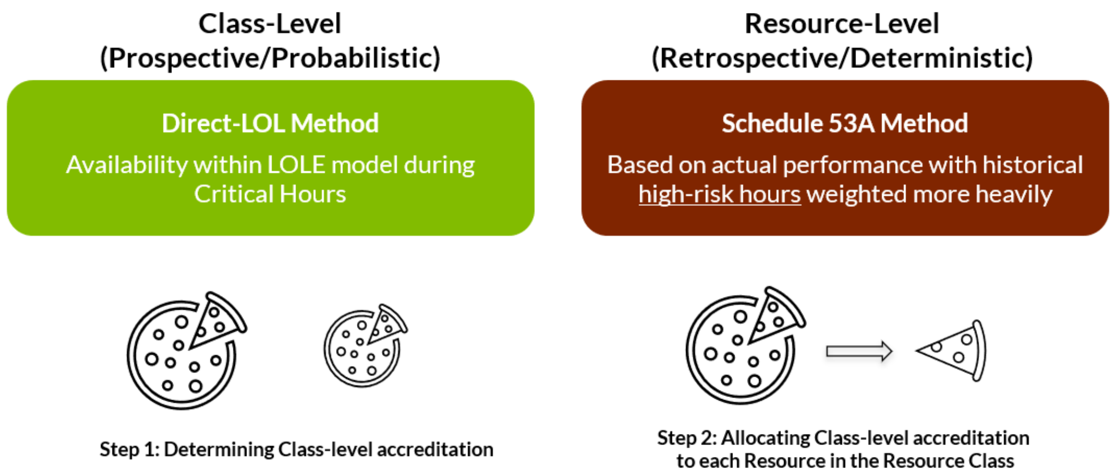

Figure 1: MISO's proposed accreditation methodology

III. <u>OVERVIEW OF MISO'S APPROACH TO RESOURCE ADEQUACY</u>

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

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[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]

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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.

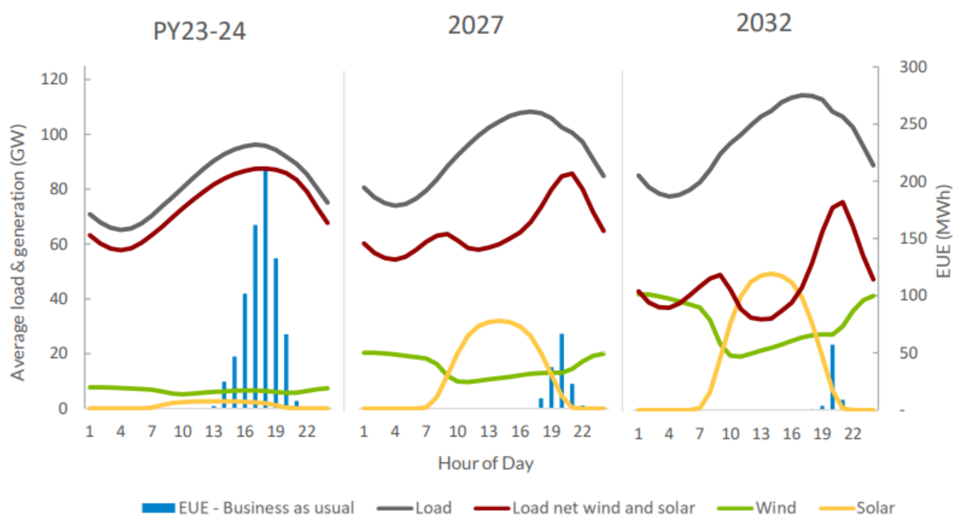

Figure 2.a. Estimated evolution of summer load, net load, wind and solar and expected unserved energy in the MISO footprint

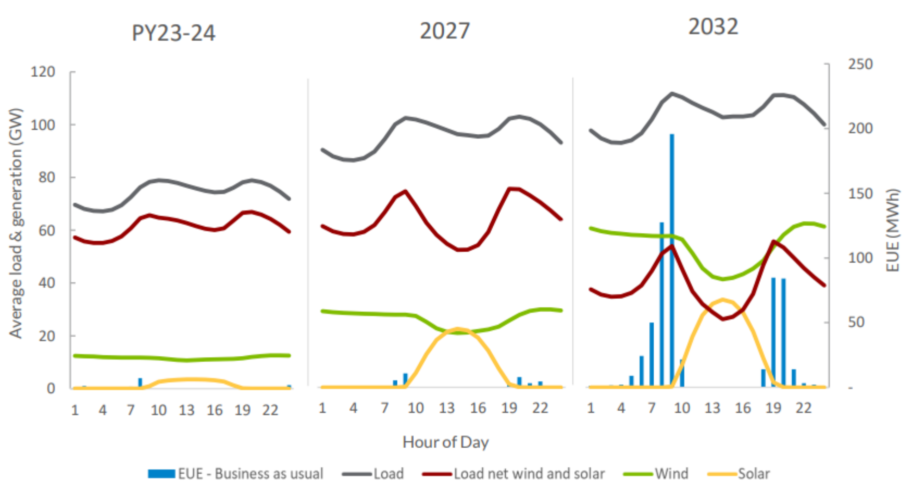

Figure 2.b. Estimated evolution of winter load, net load, wind and solar and expected unserved energy in the MISO footprint

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%.

[7] ESIG "New Design Principles for Capacity Accreditation" https://www.esig.energy/new-design-principles-for-capacity-accreditation/

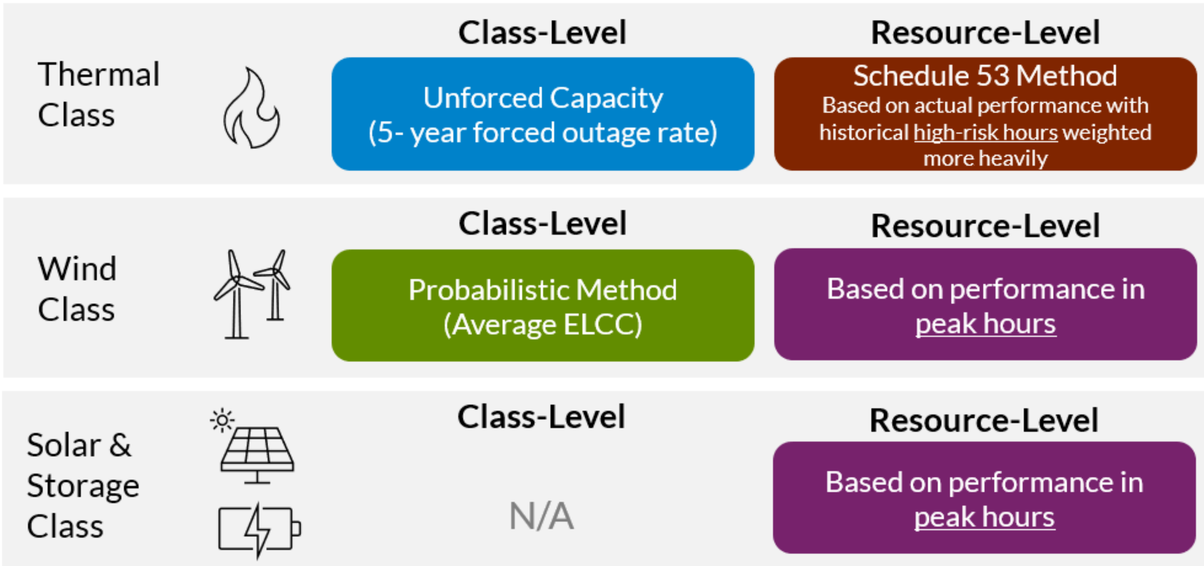

Figure 3: MISO's current accreditation methodology

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).

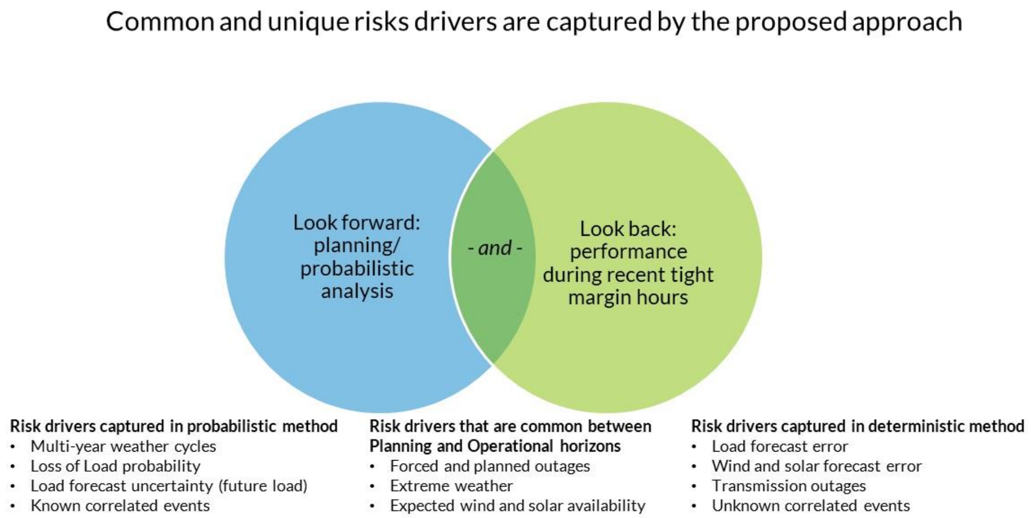

Figure 4: A wide range of risks challenge resource adequacy; a new accreditation approach is needed to capture different risk factors

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

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[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. <u>CLASS-LEVEL ACCREDITATION CALCULATION</u>

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.

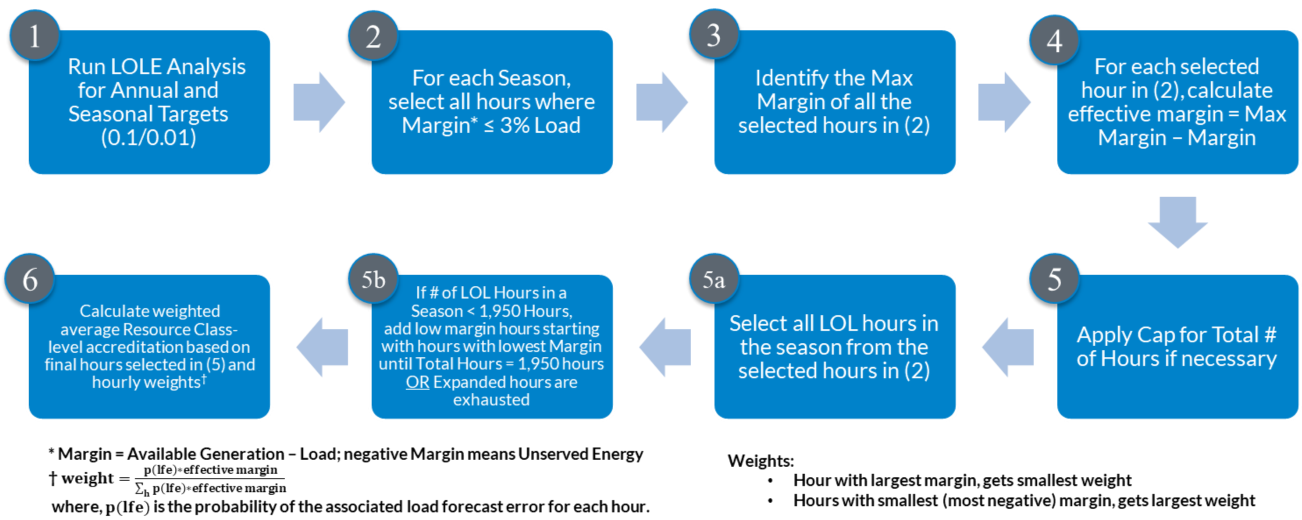

Figure 6: Flow chart of Resource Class-level Accreditation Calculation

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. <u>ALLOCATION OF CLASS-LEVEL UCAP TO INDIVIDIUAL RESOURCES</u>

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. <u>SUMMARY OF KEY TARIFF CHANGES AND DESIGN CONSIDERATIONS FOR THE PROPOSED METHOD</u>

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

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[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 (± 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 ±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.

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[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

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[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.

[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.

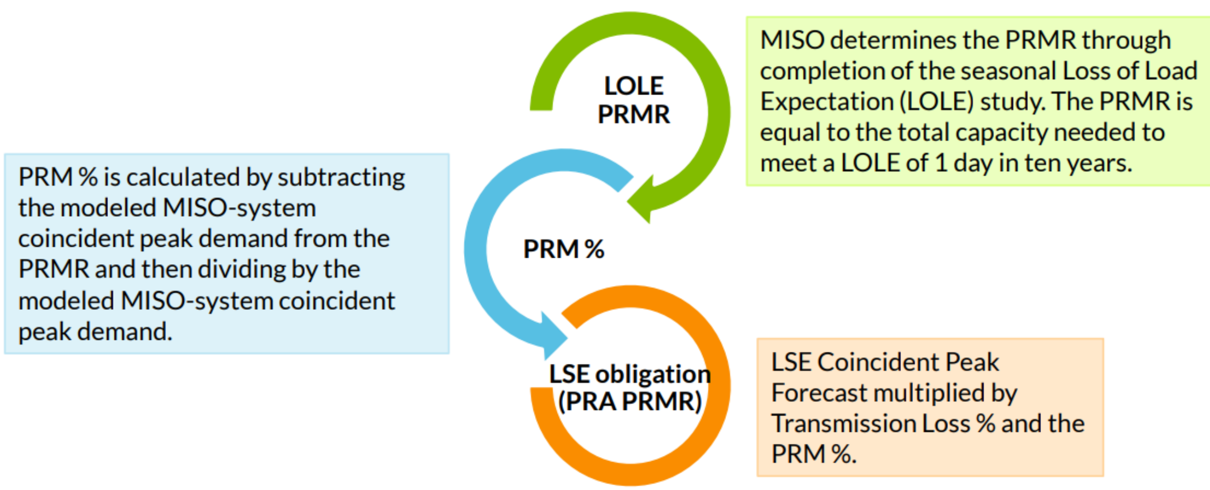

Figure 13: PRM % for Planning Resource Auction

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

[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.

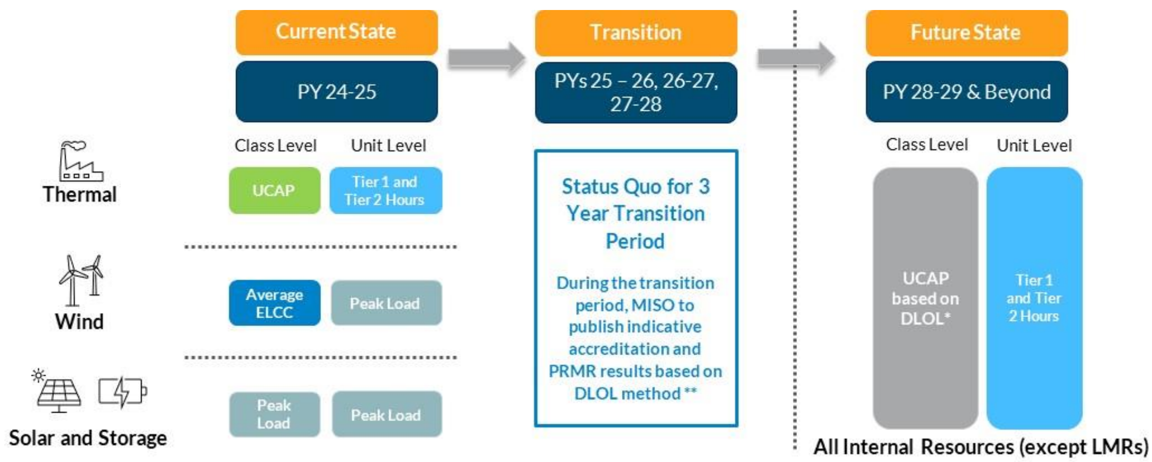


Figure 15: Effective Date and Transition Plan shared with stakeholders

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. <u>CONCLUSION</u>

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.

Rhiannon Rena Shelley

(*Notary Public Signature*)

Commissioned in Clinton county.

Commission Number: 705772

Commission Expires: 9/27/2025

NOTARY PUBLIC SEAL STATE OF INDIANA
RHIANNON RENA SHELLEY
Clinton County
My Commission Expires
September 27, 2025

Tab F

Testimony of Zachary Ming
Director
Energy and Environmental Economics, Inc. ("E3")

On behalf of
the Midcontinent Independent System Operator ("MISO")

March 26, 2024

Energy+Environmental Economics

Table of Contents

Midcontinent Independent System Operator (“MISO”)

Benefits of MISO’s Proposed Direct Loss-of-Load (“DLOL”) Capacity Requirement and Resource Accreditation Framework

<u>Testimony of Zachary Ming, Director, Energy and Environmental Economics, Inc. (“E3”)</u>

1 Introduction

Q1. PLEASE STATE YOUR NAME, OCCUPATION, BUSINESS ADDRESS.

A1. My name is Zachary Ming. My current position is Director at Energy and Environmental Economics (“E3”). My business address is 44 Montgomery Street Suite 1500, San Francisco, California 94104.

Q2. PLEASE STATE ON WHOSE BEHALF YOU ARE FILING TESTIMONY.

A2. I am filing this testimony as an independent expert, and it represents my own positions and perspectives. This testimony was funded by the Midcontinent Independent System Operator, Inc. (“MISO”).

Q3. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND AND EXPERIENCE.

A3. I received a B.S. in Civil and Environmental Engineering (Atmosphere and Energy program) with a Minor in Economics, and an M.S. in Management Science and Engineering (Energy track), both from Stanford University. For 10 years, I have held various roles at E3, an energy consulting firm specializing in the economics of the electricity system where I am currently a Director. In addition to full-time consulting work at E3, I teach a graduate-level course at Stanford University titled *Electricity Economics*.

Q4. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS DIRECTOR AT E3.

A4. In my role as Director, I oversee E3 projects across a number of areas including reliability and resource adequacy, rate design, system planning, and market design. I have authored several reports related to resource adequacy including *Long-Run Resource Adequacy under Deep Decarbonization Pathways for California*,[1] *Resource Adequacy in the Pacific Northwest*,[2] and *Assessment of Market Reform Options to Enhance Reliability of the ERCOT System*.[3] I have worked on resource adequacy and market design topics in MISO, PJM, ERCOT, CAISO, SPP, NYISO, and ISONE. Most broadly, I work with E3 staff and clients to understand the current challenges facing the electricity system and to implement solutions that are economic, environmentally sustainable, and reliable.

Q5. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION ("FERC")?

A5. Yes, I have previously testified before FERC in Docket ER24-99-000 regarding PJM's filing to update its tariff to use marginal effective load carrying capability ("ELCC") as the basis for accreditation in the capacity market. Additionally, I have

[1] https://www.ethree.com/wp-content/uploads/2019/06/E3_Long_Run_Resource_Adequacy_CA_Deep-Decarbonization_Final.pdf

[2] https://www.ethree.com/wp-content/uploads/2019/03/E3_Resource_Adequacy_in_the_Pacific-Northwest_March_2019.pdf

[3] https://www.ethree.com/wp-content/uploads/2023/05/E3-PUCT_Assessment-of-Market-Reform-Options-to-Enhance-Reliability-of-the-ERCOT-System_11.10.22-Sent.pdf

testified before state public utility commissions in Oregon, Texas, and South Carolina on topics including reliability, resource adequacy, and market design.

Q6. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A6. The purpose of my testimony is to explain why the changes to MISO's capacity market framework being presented in this docket are necessary in order to ensure optimal market outcomes, and why the proposed framework utilizing the direct loss-of-load ("DLOL") method best meets the needs of the evolving MISO system.

Q7. PLEASE PROVIDE AN OUTLINE OF YOUR TESTIMONY.

A7. My testimony is organized as follows.

- In Section 2, I provide a general background on "Resource Adequacy" and the evolving challenges faced in today's electricity system;
- In Section 3, I provide an overview of market constructs that are designed to ensure Resource Adequacy and the principles that such markets should seek to achieve;
- In Section 4, I describe MISO's proposal to implement reforms to resource accreditation using the DLOL approach in their capacity market design;
- In Section 5, I outline why the DLOL approach is consistent with both a theoretically ideal marginal ELCC framework and capacity accreditation approaches adopted by NYISO and PJM. I also provide additional supporting arguments for why this method should be adopted;
- In section 6, I summarize the key takeaways of my testimony.

2 Resource Adequacy Background

Q8. PLEASE PROVIDE AN OVERVIEW OF RESOURCE ADEQUACY.

A8. Resource Adequacy refers to the ability of the electric power system to ensure sufficient generation is available to meet loads across a broad range of weather and system operating conditions, subject to a defined reliability standard. The resource adequacy of a system depends on both the characteristics of load—its magnitude, seasonal patterns, weather sensitivity, hourly patterns—as well as resources—their size, dispatchability, outage rates, and other limitations on availability, such as the variable production of renewable resources. If the availability of resources is sufficient to meet load across a wide range of conditions and limit loss-of-load events to a reasonable level—where "reasonable" is defined by a reliability target—then a system is considered resource adequate. No electricity system is perfectly reliable; there is always some chance that generator failures and/or extreme weather conditions impacting supply and demand could coincide in a way that results in loss of load. MISO maintains a resource adequacy standard such that loss-of-load events should occur no more frequently than one day in every ten years. The technical specification of this standard is loss-of-load-expectation ("LOLE") of 0.1 days/year.[4]

[4] A day with any quantity of loss-of-load (e.g. 1-hour event or a 12-hour event or two separate 4-hour events) counts as a "day" in the loss-of-load-expectation metric

Q9. PLEASE DESCRIBE THE KEY RESOURCE ADEQUACY DYNAMICS OF THE TRADITIONAL ELECTRICITY SYSTEM.

A9. In most electricity systems (including MISO), the preponderance of generating resources have historically been thermal, which are generally available to produce power at full capacity at any time for sustained periods. Examples of thermal resources include nuclear, coal, and natural gas generators. In electricity systems relying primarily on these resources, *the periods with the highest risk of loss-of-load generally coincide with the highest electricity system loads*, when demand could exceed the aggregate capability of all resources.

Q10. HOW HAVE SYSTEM PLANNERS DEFINED THE TOTAL NEED FOR RESOURCES IN THE TRADITIONAL ELECTRICITY SYSTEM?

A10. System planners have traditionally calculated the minimum quantity of thermal generation capacity required to ensure a specific reliability standard using loss-of-load-expectation ("LOLE") modeling. While the end result of this calculation process is a megawatt ("MW") value, it is common to divide this value by a 50/50 (i.e. median) peak load value.[5] Because the MW capacity requirement exceeds the 50/50 peak load, this results in a planning reserve margin ("PRM") of resources that must be held above and beyond 50/50 peak load. There are three primary reasons for the existence of the PRM (i.e. a MW capacity requirement that exceeds 50/50 peak load):

[5] Median peak load is defined as a level where 50% of all years would be expected to have a peak load greater than this value and 50% of all years would be expected to have a peak load less than this value

1) **Higher than normal peak loads:** because the total capacity requirement is traditionally contextualized relative to 50/50 peak load, this means that a system that only has enough capacity to meet this median value would expect to shed load in 50% of all years, since there is a 50% probability that peak load will exceed the peak in a given year. This frequency of outages is unreasonable by most standards, and therefore additional capacity is required.

2) **Generation resource outages:** because installed thermal capacity is not perfectly reliable (i.e. is subject to forced outages), additional capacity is required to ensure that there will be sufficient available generation on peak load days to meet all generation requirements.

3) **Operating reserve requirements:** At any given moment in time, electricity systems require available on-line generation capacity that is not being used to serve load in order to ensure there is immediate backfill for any unexpected generator failures. Because it is not being used to serve load, excess capacity is required above the actual peak load.

It should be noted that, while the PRM is a useful construct to help participants understand the resource adequacy needs of the system, it is a derivative calculation that is not, in itself, determinative of the system need. Rather, the total system capacity need is the total quantity of thermal resources in MW, which then serves as the numerator of the PRM equation.

Q11. HOW HAVE SYSTEM PLANNERS ACCREDITED THE ABILITY OF RESOURCES TO CONTRIBUTE TOWARD THIS TOTAL SYSTEM CAPACITY NEED?

A11. Traditionally, when the vast majority of resources were thermal resources, resources were credited toward meeting the total system capacity need at their installed nameplate capacity. This is not to say that system planners assumed these resources would always be available at their installed nameplate capacity, but rather that, *by convention*, expected forced outages were accounted for through a higher system capacity need (via the PRM) rather than lower resource accreditation values.

As weather-dependent intermittent renewable resources (referred to as "intermittent" resources in this testimony) began to increasingly enter electricity systems (namely wind and solar), system planners realized that these resources could not be counted toward the system capacity need at their nameplate capacity because they were often available only at much lower levels. As a result, system planners devised methods to accredit the capacity of intermittent resources based on their ability to contribute to the reliability requirements of the system, which I discuss in more detail later.

Q12. HOW IS THE NATURE OF RELIABILITY RISK CHANGING?

A12. The growth in renewable and energy storage resources is expected to cause (and in some systems already causing) profound changes to the nature of reliability risk for electricity systems, including MISO. Specifically, there are two key shifts in the nature of reliability risk:

- **Shift of reliability risk to hours of low supply:** The timing of reliability risk is no longer concentrated exclusively in peak load periods (when solar energy, for example, may be abundant) but rather may occur during periods of low generator availability. In MISO, there are two relevant reasons for this:

    i. Higher penetration of intermittent resources such as wind and solar mean that periods when these resources have low availability may result in high reliability risks, particularly when they coincide with relatively high (though not necessarily peak) loads. This results in high "net load" periods, defined as periods when load minus wind and solar production is high, that become more important than the high "gross load" periods that have historically seen the highest reliability risk. The MISO system is beginning to experience this shift today and is expected to continue to see a corresponding increase in periods of "net load" risk with the growth of intermittent resources and the retirement of thermal resources.

    ii. Low resource availability due to widespread forced outages or fuel supply induced by extreme weather issues can also lead to reliability risks. Winter Storm Elliott, during which 19 GW of unplanned outages occurred on December 23, 2023, is an example of this.[6] Most of the capacity that suffered outages were coal and natural gas plants.

[6] Slide 3: https://cdn.misoenergy.org/20230117%20RSC%20Item%2005%20Winter%20Storm%20Elliott%20Preliminary%20Report627535.pdf

Coal outages were generally due to equipment failure (i.e., boiler problems and tube leaks); gas outages were generally due to both equipment failure *and* gas supply-related outages.[7] Accounting for the risk of gas fuel supply constraints will become increasingly important as coal capacity retires over the next decade in MISO and the risk of large-scale extreme weather events persists.

- **<u>Elongation of reliability risk periods:</u>** The timing of reliability risk to be spread across longer periods of energy deficiency rather than concentrated in a single hour or short-duration period. There are two relevant reasons for this:

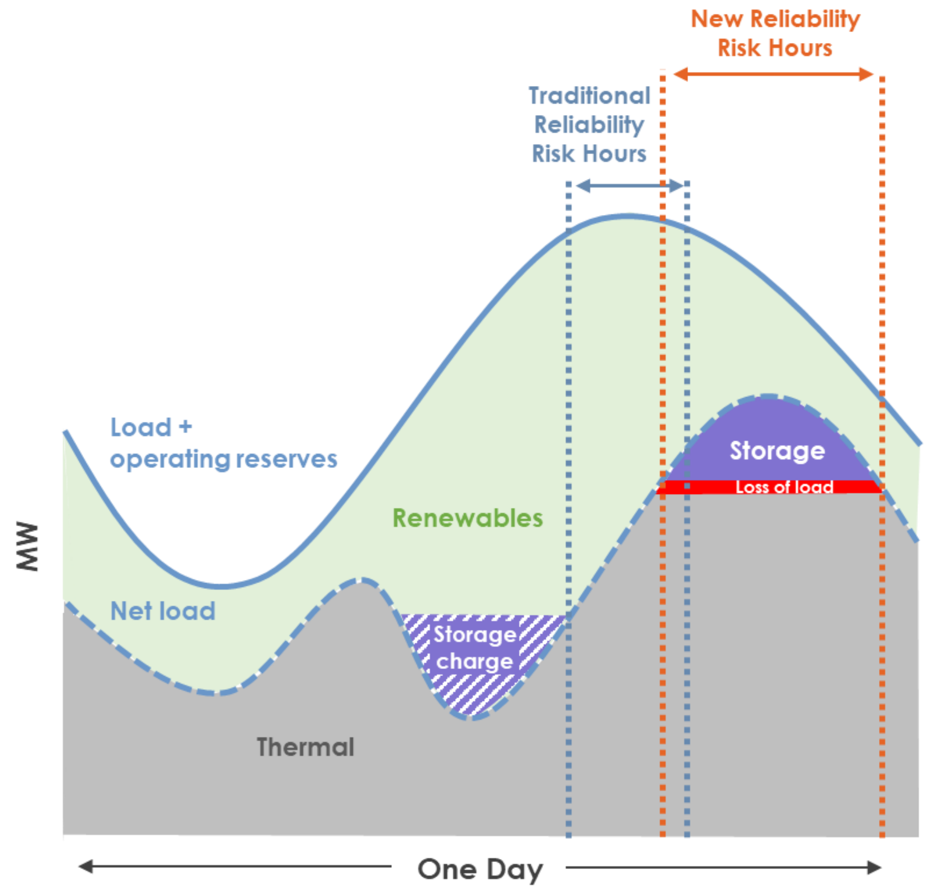
  i. Energy storage resources—in helping to meet reliability requirements—will tend to "flatten" the net peak over longer periods. This means that the introduction of energy storage will increasingly lead to longer reliability risk events.

  ii. Intermittent resources (such as solar and wind) depend on weather conditions to generate electricity. Multi-day periods of wind drought or cloud cover can lead to longer periods of reliability risk than is present on a system where daily peak loads drive reliability risk.

  Both of these dynamics are illustrated in the figure below.

[7] Ibid.

Figure 1: Illustration of Changing Loss-of-Load Dynamics in the Evolving Electricity System



Q13. AS THE SYSTEM HAS EVOLVED, HOW HAVE METHODS TO ACCREDIT THE CAPACITY OF INTERMITTENT RESOURCES (SUCH AS WIND AND SOLAR) CHANGED?

A13. Generally, three approaches to accredit the capacity of intermittent resources have been either used or proposed: (1) statistical calculations of availability during peak load, (2) average effective load carrying capability ("ELCC"), and (3) marginal ELCC.

1. **<u>Availability During Peak:</u>** When wind and solar resources began to be developed at scale in the 2000s and 2010s, market operators developed heuristics to accredit renewable resources through the traditional lens of

availability during gross peak load periods. These calculations were generally performed through statistical calculations such as average, median, or 20th percentile capacity factor during peak load windows. When the penetration of renewable resources was small, these accreditation methods were generally sufficient because gross peak load periods were aligned with peak reliability risk periods.

2. **<u>Average ELCC:</u>** as the penetration of renewable energy resources grew, system operators recognized that availability during the gross peak load periods did not adequately capture the saturation effects resulting from increasing penetrations of renewables, which cause the “net peak” (and highest reliability risk) to shift to other times of the day. To rectify this issue, system planners began to accredit renewable resources using the concept of “average ELCC,” which is calculated using loss-of-load-expectation modeling to compare a specified portfolio against a counterfactual in which an entire class of resources (e.g. solar or wind) are removed (or multiple classes, sometimes referred to as a “portfolio”). This approach reflects a composite contribution to the system peak, both in the system as it exists and a counterfactual system without the class or portfolio. In other words, it accredits resources’ aggregate contribution to the system peak, accounting for how they may have shifted risk away from periods in which the availability of the resource is concentrated. This approach allowed planners to account for saturation effects while *maintaining the historical convention*

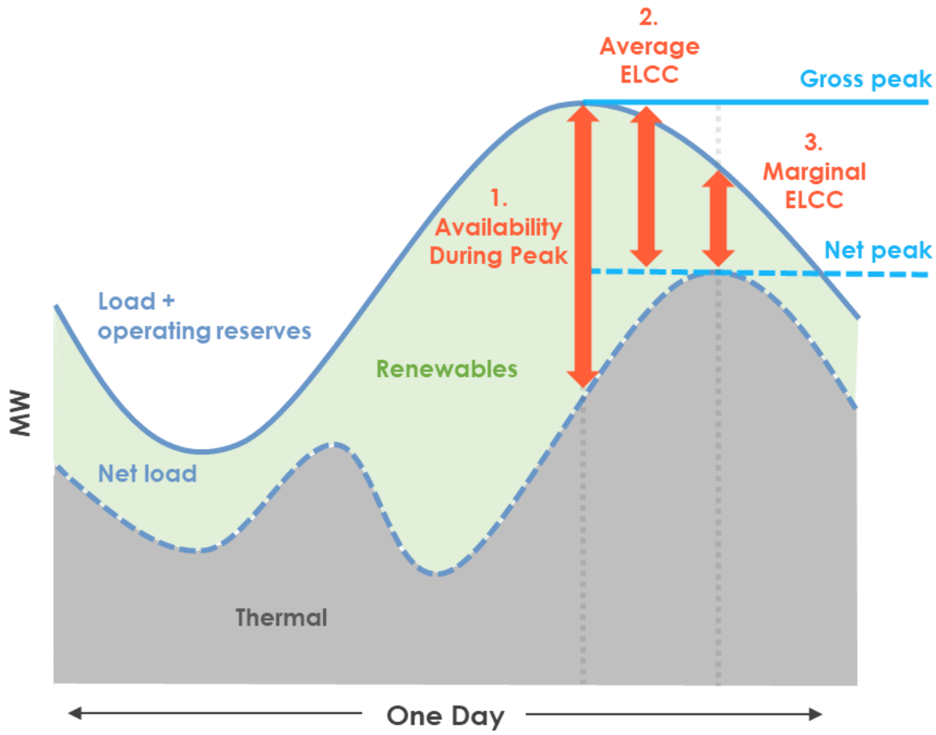
of setting the total reliability requirement to peak demand plus a planning reserve margin.

3. **<u>Marginal ELCC:</u>** For reasons that I will discuss in more detail later, many system operators have come to realize that the utilization of average ELCC does not sufficiently meet the principles of capacity market design and are either considering or have proposed to accredit resources using the concept of marginal ELCC, which is a statistically robust method for measuring the incremental or marginal contribution to system reliability for any resource that reflects its availability during the hours of highest reliability risk. Both PJM and NYISO are examples of system operators that have both had such marginal ELCC accreditation approaches accepted by FERC.[8]

These three paradigms for capacity accreditation are shown in the figure below, which is illustrative of the general approach underlying each but does not reflect the precise or exact methodology.

[8] NYISO FERC Order: https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-nyiso-tariff-revisions-re-marginal-capacity;
PJM FERC Order: https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-pjms-capacity-market-reform-filing-docket-no

Figure 2: Evolution of Resource Accreditation Methodologies



While the illustration above is provided for a system with only thermal and renewable resources, the concepts are equally applicable to a system with any portfolio of resources, including energy storage.

3 Market Design in Resource Adequacy

Q14. PLEASE DISCUSS RESOURCE ADEQUACY WITHIN THE CONTEXT OF A COMPETITIVE ELECTRICITY MARKET.

A14. Ensuring resource adequacy in the competitive electricity market framework that emerged in the U.S. more than two decades ago is challenging because there is no central procurement entity responsible for ensuring there are sufficient resources to achieve a defined reliability standard for the entire system. This differs significantly from the traditional vertically-integrated utility framework, in which a single entity was responsible for procuring a portfolio of resources to meet the total system capacity need. In MISO, ensuring resource adequacy is a responsibility MISO shares with state and other utility regulatory authorities. Moreover, in a competitive electricity market, participants respond to economic signals, meaning that those signals should be designed to encourage the desired outcomes. Therefore, achieving resource adequacy in this context has the dual challenge of both determining the technical needs of the system and structuring an appropriate market design to achieve the desired reliability outcome. In many competitive electricity market regions, including MISO, the specific electricity market product designed to ensure resource adequacy is the capacity market.

Q15. PLEASE DESCRIBE HOW CAPACITY MARKETS HAVE TRADITIONALLY ENSURED RESOURCE ADEQUACY.

A15. Capacity markets have traditionally focused on ensuring sufficient resource availability during peak load periods. The market operator, MISO, sets requirements for loads to purchase capacity based on their usage during the system coincident peak load hour and accredits resources to sell capacity based on their ability to contribute to peak load requirements. When properly implemented, transacting capacity through the market provides economic signals for investment to hit the target, that is, to be resource adequate.

Q16. WHAT ARE THE PRINCIPLES OF CAPACITY MARKET DESIGN?

A16. Designing any market often involves trying to satisfy multiple principles, which in some cases may be in tension with each other. Any capacity market should consider, at minimum, the following four principles:

- **Reliability:** Does the market achieve target reliability (i.e., the 0.1 days/yr. LOLE standard)?
- **Economic Efficiency:** Does the market minimize the total resource costs of achieving target reliability by sending appropriate signals for entry and exit from the market?
- **Fairness / Equity:** Is the market technology neutral? Does it minimize the need for subjectivity? Does it allow all resource to compete on an equal playing field?
- **Acceptability:** Is the market tractable for the system operator to implement? Is it understandable and transactable for market participants?

These principles are consistent with prior E3 publications on resource adequacy program market design.[9]

[9] https://www.ethree.com/wp-content/uploads/2020/08/E3-Practical-Application-of-ELCC.pdf

Q17. PLEASE DESCRIBE THE RELIABILITY PRINCIPLE IN MORE DETAIL.

A17. The reliability principle ensures that the system will achieve the target reliability set forth by the system operator. MISO's standard allows for one day with loss-of-load every ten years, technically referred to as 0.1 days/year loss of load expectation (LOLE).

Q18. PLEASE DESCRIBE THE ECONOMIC EFFICIENCY PRINCIPLE IN MORE DETAIL.

A18. The economic efficiency principle ensures that the total resource costs of achieving target reliability is minimized. The primary means by which a market can minimize resource costs is through efficient entry and exit of resources, such that costly resources are incentivized to retire (exit), and economic resources are incentivized to build (enter).

Q19. HOW CAN A RESOURCE ADEQUACY MARKET DESIGN FACILITATE EFFICIENT ENTRY AND EXIT OF RESOURCES?

A19. A market design facilitates efficient entry and exit of resources through non-discriminatory resource accreditation and participation in the capacity auction. In other words, the market design should ensure that resource accreditation is technology-neutral, such that two different resources with the same ability to provide for system reliability requirements will receive the same resource accreditation. This ensures that the only differentiating factor between resources that can equivalently contribute to system reliability is their cost, which allows resources to efficiently compete on economics.

Q20. PLEASE DESCRIBE THE FAIRNESS / EQUITY PRINCIPLE IN MORE DETAIL.

A20. The fairness / equity principle ensures that the system is fair for all market participants. While this principle is ultimately in the eye of the beholder, it provides a mechanism for the market design to deviate from the overall least cost outcome in an effort to ensure that each market participant feels as though they are being fairly charged/compensated for their requirements/contribution to the system.

Q21. PLEASE DESCRIBE THE ACCEPTABILITY PRINCIPLE IN MORE DETAIL.

A21. The acceptability principle ensures that the market design is acceptable to market participants, stakeholders, and policy requirements. Satisfying this principle should consider, at minimum, the market is:

- Transparent and understandable to market participants;
- Tractable for the market operator to implement;
- Compliant with all applicable laws, policies, and regulations.

Q22. PLEASE DESCRIBE MISO'S CURRENT CAPACITY MARKET DESIGN.

A22. For the purposes of this testimony, MISO's current capacity market design can be characterized through two primary features:

1) A total capacity need based on the quantity of resources required to meet the system coincident peak;

2) A resource-class capacity accreditation framework that uses availability during times of need for thermal resources[10], average ELCC for wind resources, and availability during peak for solar resources.

Q23. HOW WOULD MISO'S CURRENT CAPACITY MARKET DESIGN PERFORM PROSPECTIVELY AS THE SYSTEM EVOLVES?

A23. As the penetrations of renewable and storage resources continue to grow on MISO's system, the use of average ELCC and availability during peak methods for intermittent resources will cause distortions that will also grow. This is primarily due to the disconnect between the fact that both of these methods rely meaningfully in part on availability during the system coincident peak, while prospective reliability risk may lie outside of peak hours entirely (due to an abundance of renewable generation in these hours). Thus, reforms to the existing paradigm are imperative for sound market design.

[10] Per Schedule 53 of MISO's Tariff

4 Direct Loss-of-Load ("DLOL") Method

Q24. WHAT CHANGES IS MISO PROPOSING TO MAKE TO THE CAPACITY MARKET FRAMEWORK?

A24. MISO is proposing to transition to a Direct Loss-of-Load ("DLOL") methodology to accredit the capacity and calculate the unforced capacity ("UCAP") of all generation resources in the capacity market.

Q25. PLEASE PROVIDE AN OVERVIEW OF THE DLOL METHOD.

A25. The DLOL method is a means of determining capacity accreditation for all MISO-defined "Capacity Resources"[11] participating in MISO's capacity market. Most generally, the DLOL method accredits resources based on their availability during the hours of highest reliability risk. MISO summarizes the DLOL method as follows:

> *The DLOL resource class-level method examines an individual resource's [resource adequacy] contribution by measuring its ability to serve load during system scarcity in the probabilistic LOLE model. [... the] DLOL method matches critical hours to resource performance during those hours.*[12]

Specifically, the DLOL method will calculate a Seasonal Accredited Capacity ("SAC") value for each individual resource using the following process:

[11] Includes all generation resources, except external resources and emergency-only Load Modifying Resources

[12] MISO, "Resource Accredatition White Paper (Version 2)", February 2024; https://cdn.misoenergy.org/Resource%20Accreditation%20White%20Paper%20Version%202630728.pdf

1) Calculate resource-class UCAP (MW) using the DLOL method;

2) Calculate individual resource Intermediate Seasonal Accredited Capacity ("ISAC") (MW); and

3) Use resource-class UCAP and individual ICAP to determine individual SAC (MW).

The SAC assigned to each individual resource is its resource-class UCAP, divided by sum of ISACs for all resources within that class, multiplied by its individual ISAC. Each of these steps is described in more detail below.

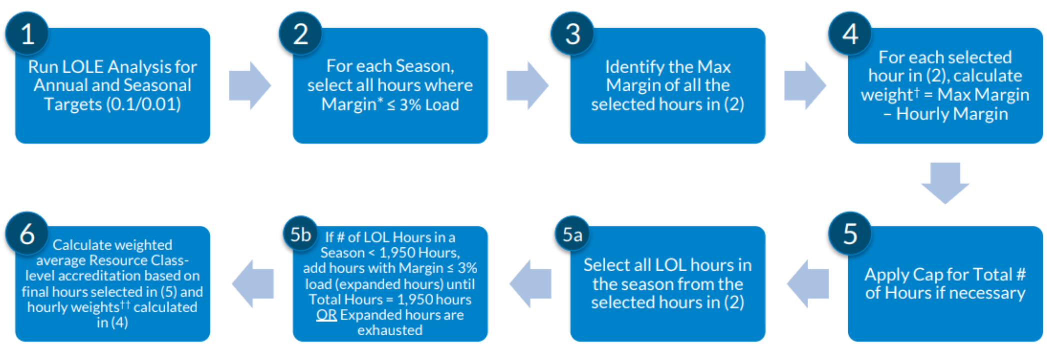
Q26. PLEASE DESCRIBE THE PROCESS TO CALCULATE RESOURCE-CLASS UCAP VALUES IN MORE DETAIL.

A26. A prerequisite to calculating resource-class UCAP MW values using the DLOL method requires the development of a loss-of-load expectation ("LOLE") model that can simulate the reliability risks that the system faces and identify which hours are likely to entail the highest risk of loss of load. MISO has utilized LOLE modeling for many years for the establishment of Planning Reserve Margin Requirements ("PRMR"), and the same model can be used in the implementation of the DLOL method.

Once the LOLE model has been developed, the first step requires grouping resources with similar characteristics (e.g. technology and operating characteristics) into "resource classes". Defining resource classes should balance the need for accuracy (which would imply more classes) and simplicity (which would imply fewer classes). MISO is proposing to create 10 resource classes.[13]

After defining resource classes, the outputs of the LOLE model are evaluated to determine the availability of each resource class during the hours of highest reliability risk, for which MISO uses loss-of-load and near loss-of-load hours (“critical hours”).[14] The resource-class level UCAP is a MW value determined by the average resource availability during the critical hours, weighted by the capacity margin—defined as incremental available capacity—for each hour.[15] The overall process to calculate resource class level capacity accreditation can be seen in the figure below.

Figure 3: MISO’s Proposed DLOL Resource Class Level Capacity Accreditation Process[16]



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[13] The 10 resource classes MISO is proposing to create are: “Gas”, “Combined Cycle”, “Coal”, “Hydro”, “Nuclear”, “Pumped Storage”, “Storage”, “Solar”, “Wind”, Run-of-River”.

[14] MISO’s definition of critical hours includes both loss-of-load and, as well as near loss-of-load hours in seasons when the number of loss-of-load hours does not exceed 1,950 hours across all simulation years. MISO defines near loss-of-load hours are defined as the hours when the capacity margin in the system is equal to or lower than 3% of load in that hour.

[15] The capacity margin is calculated as the available capacity minus the load for each hour. The capacity margin weight is determined as the difference between the maximum margin value (across all critical hours within that season) and the individual hour margin.

[16] Slide 8: https://cdn.misoenergy.org/20240117%20RASC%20Item%2007a%20Accreditation%20Presentation%20(RASC-2020-4%20and%202019-2631379.pdf

For each resource class, a capacity accreditation percentage value is then calculated by dividing the resource-class UCAP by the total installed capacity ("ICAP") of that same resource class.

Q27. HOW ARE CRITICAL HOURS DETERMINED IN THE PRIOR CALCULATION STEP?

A27. Critical hours include all hours with loss-of-load and hours in which the capacity margin in the system—defined as incremental available capacity—is less than or equal to 3% of load in that hour. The total quantity of critical hours is capped at 1,950 hours per season across the thousands of simulation years. In all cases, all loss-of-load hours will be included as critical hours.

Q28. WHY IS INCLUDING BOTH LOSS-OF-LOAD AND NEAR LOSS-OF-LOAD HOURS PREFERRED OVER ONLY USING LOSS-OF-LOAD HOURS?

A28. Defining critical hours to include both loss-of-load and near loss-of-load conditions yields two primary benefits to the resource accreditation process. First, it captures potential conditions in the system with significant scarcity that could plausibly result in loss of load, even if they were not directly captured in the modeling due to the data inputs and assumptions used for the analysis. Second, it ensures more consistency with the calculation of individual resource performance values, which do not exclusively rely on loss of load hours.

Q29. PLEASE DESCRIBE THE PROCESS TO CALCULATE INDIVIDUAL RESOURCE PERFORMANCE VALUES – CALLED "INTERMEDIATE SEASONAL ACCREDITED CAPACITY" IN MISO – IN MORE DETAIL.

A29. Outside of the LOLE modeling framework, actual historical data is used to calculate each individual resource's recent availability. Availability is calculated using MISO's Schedule 53 methodology. Under this methodology, the availability of each individual resource during Tier 1 and Tier 2 hours are defined and weighted as follows:

- **Tier 2 ("RA hours"):** weighted at 80%, captures resource performance in the top 65 lowest capacity margin hours of each season for the past 3 years, and;
- **Tier 1 ("Non-RA hours"):** weighted at 20%, captures average availability by season.

The resulting ISAC is a MW value for each individual resource. The individual resource ISAC is then divided by sum of ISACs for all resources within that class, resulting in individual resource multipliers that add up to 1.0 across all generators in the same resource class. These multipliers are used to allocate resource-class level UCAP to individual resources in each class, as described below.

Q30. PLEASE DESCRIBE THE PROCESS TO CALCULATE INDIVIDUAL RESOURCE ACCREDITATION VALUES.

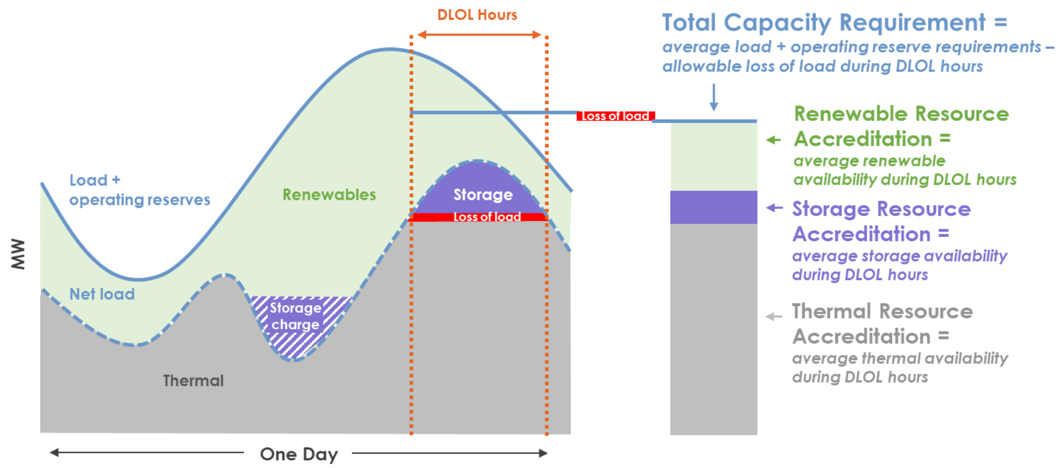
A30. Individual resource accreditation MW values, called SAC, are calculated by dividing 1) the resource-class UCAP (MW) value by 2) the sum of ISACs (MW) for all resources within that class, and then multiplying by 3) the individual resource ISAC (MW) value.

Q31. HOW DOES THE TOTAL ACCREDITED CAPACITY OF ALL RESOURCES RELATE TO THE TOTAL SYSTEM CAPACITY NEED IN THE DLOL METHOD?

A31. In the DLOL method, the total system capacity need is equal to the availability of all resources *during critical hours for a system at an annual 0.1 LOLE target reliability plus the capacity adjustment needed to reach target reliability*. Under MISO's seasonal resource adequacy construct, individual LOLE targets are established for each season. Using critical hours to determine both the total system capacity need and resource accreditation values ensures apples-to-apples consistency. It is possible that total capacity supply could be greater or less than the total capacity requirement if the system is not exactly at the target reliability standard.

For a system with higher penetrations of renewable and storage resources, it is likely that critical hours will *not be* peak load hours that have traditionally been used to determine the total system capacity need. An overview of this relationship is provided in the figure below.

Figure 4: Illustration of Total System Capacity Need and Resource Accreditation in DLOL Method



Q32. IS THE DLOL METHOD CONSISTENT WITH A PARTICULAR CAPACITY ACCREDITATION FRAMEWORK?

A32. Yes, the DLOL method is consistent with a marginal ELCC framework. As I previously described, a marginal ELCC framework accredits resources based on their incremental or marginal contribution to system reliability. This is equivalent to measuring the availability of resources during the hours of highest reliability risk since availability during these hours is what marginally impacts system reliability.

Q33. HAVE OTHER U.S. ELECTRICITY MARKETS ADOPTED A MARGINAL ELCC CAPACITY ACCREDITATION FRAMEWORK?

A33. Yes. On May 11, 2022, FERC issued an order approving NYISO's proposal to "accredit all resources' capacity value based on their marginal contribution to resource adequacy." (Docket No. ER22-772-001). In Commissioner Christie's concurrence he notes:

I strongly support NYISO's proposal to adopt a marginal capacity accreditation design that would accredit resources based on their marginal contribution to power system reliability thereby aligning capacity payments with a resource's reliability value and reflecting a resource's marginal value to the system. The use of marginal valuations is more accurate, and thus superior, to a methodology that uses average valuations. Getting capacity valuations right is essential both for reliability purposes and to ensure consumers do not pay for capacity that does not perform when needed.[17]

Similarly, on January 30, 2024, FERC issued an order approving PJM's proposal to move its resource accreditation framework to marginal ELCC (Docket No. ER24-99). In Commissioner Christie's concurrence he notes:

In particular, PJM finally moves from an average ELCC methodology to a marginal one, which I and the IMM both strongly advocated in a recent major PJM capacity reform filing.[4] So better late than never.[18]

It is important to note that any implementation of a marginal ELCC framework requires heuristic simplifications to ensure that it is computationally tractable and understandable to market participants. Each system operator can approach this step differently while yielding functionally equivalent end results. The PJM "marginal ELCC" method, the NYISO "marginal reliability improvement" method, and the

[17] https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-nyiso-tariff-revisions-re-marginal-capacity
[18] https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-pjms-capacity-market-reform-filing-docket-no

MISO "direct loss of load" method are all functionally equivalent and fall within the marginal ELCC capacity accreditation family.

Q34. IN WHAT WAYS IS THE DLOL METHOD DIFFERENT THAN MARGINAL ELCC?

A34. Any implementation of marginal ELCC will require application of heuristic methods to make the process computationally tractable for the system operator, since it is impractical to calculate an individual marginal ELCC value for each individual resource. The DLOL is a method that accomplishes that and is consistent with other heuristic simplifications that other ISOs have utilized in their implementation of marginal ELCC. For example, FERC has approved PJM's proposed method of calculating resource-class ELCC values using modeled values with adjustments for individual resources based on resource-specific performance adjustment factors using actual historical data.[19] Such a process is analogous to MISO's proposed methodology.

Q35. IS A MARGINAL ELCC FRAMEWORK, AS IMPLEMENTED THROUGH THE DLOL METHOD, CONSISTENT WITH OTHER MISO MARKET PRODUCTS?

A35. Yes, energy, ancillary service, and capacity market products in MISO are structured to compensate resources based on the *marginal value* that they provide to the system. Such a framework is well-established in the field of microeconomics as necessary to achieve economic efficiency. In addition to consistency with other

[19] 186 FERC ¶ 61,080

MISO market products, the price of goods in non-electricity markets (e.g. oil) is set based on the marginal value that these resources provide. Thus, a marginal ELCC framework, as implemented through the DLOL method, is consistent with sound economic principles used in both electricity and non-electricity markets.

Q36. IS A MARGINAL ELCC FRAMEWORK SUPPORTED BY RELEVANT ACADEMIC OR INDUSTRY LITERATURE?

A36. Yes. In 2016, Dr. Cynthia Bothwell and Dr. Benjamin F. Hobbs of Johns Hopkins published a working paper investigating the impacts of resource accreditation methodologies on market efficiency. They modeled different capacity counting methodologies using ERCOT data and concluded that "a least-cost capacity market design should reward marginal capacity contributions by different resources considering how renewable penetrations affects the timing of load peaks, net of renewable contributions." Further, they warn that "granting capacity credits that differ appreciably from their marginal contribution to system reliability can yield significant distortions, which in our case study amounted up to 0.37% of generation costs, which equals more than a hundred million dollars per year in a market the size of Texas." They also determined that the costs of these inefficiencies were more severe under higher penetrations of renewable resources.[20]

Additionally, in a presentation for MISO, Dr. David Patton, President of Potomac Economics (the Independent Market Monitor for MISO, ERCOT, ISO-NE, and NYISO) similarly concluded that efficient payments should reflect what is

[20] https://www.caiso.com/Documents/BriefingonRegionalResourceAdequacyInitiative-MSCBothwellHobbs_WorkingPaper-June2016.pdf

needed to attract or retain capacity according to the current level of reliability and that "under average accreditation, capacity payments to some resources exceed what is needed to attract or retain capacity." He concludes simply: "In accrediting resources whose availability is highly correlated, marginal accreditation is the only economically sound choice."[21] In his affidavit for MISO's accreditation filing, Dr. Patton indicates that "marginal accreditation provides strong incentives to invest in and maintain high-value resources with the attributes needed to maintain system reliability."[22]

Q37. IS A MARGINAL ELCC FRAMEWORK WELL-SUITED TO MEET EVOLVING RESOURCE ADEQUACY NEEDS?

A37. Yes. One of the most important aspects of a marginal ELCC framework is that it can be used in any electric system—regardless of the composition of its resource portfolio—to send cost-optimal signals for entry and exit while maintaining reliability. In this respect, it provides a durable foundation for the continued transition towards a system increasingly reliant on renewables and storage resources. As the portfolio of resources changes, the hours of highest reliability risk (i.e. critical hours) will also change.

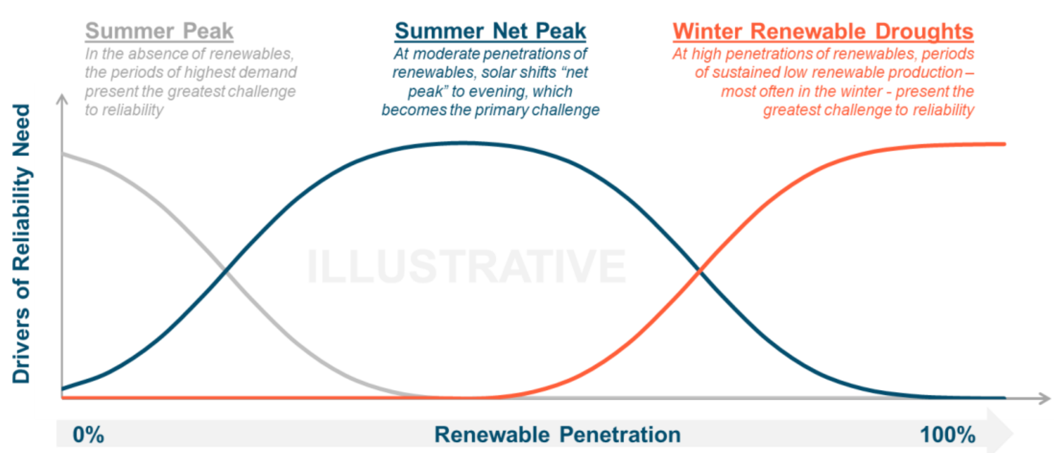
Because a marginal ELCC framework values resources based on their availability during the hours of highest reliability risk, the capacity value of resources will inherently adjust as the portfolio of resources change. The illustrative

[21] https://cdn.misoenergy.org/20220921%20Non%20Thermal%20Accreditation%20Workshop%20IMM%20Presentation626397.pdf

[22] Affidavit of Dr. David Patton, ¶ 24.

example below shows how these reliability risks are expected to change as the penetration of renewable resources increases. For a system with mostly thermal resources, most of the reliability risk concentrated in the gross peak (e.g. summer afternoon) when cooling loads are highest. As the penetration of renewable resources increases (particularly solar), the risk will shift away from daylight hours when the availability of solar is high and into summer evening hours when loads are still relatively high but solar output is low. At higher penetrations of renewables and storage, the sheer quantity of solar and storage on the system will substantially reduce risk in even summer evening hours when solar can easily charge from solar during the middle of the day. The remaining reliability risk will be winter months when 1) electric loads have grown due to building electrification and 1) the potential for multi-day renewable droughts is generally higher since there is overall less solar availability.

Figure 5: Illustrative Example of the Evolution of Reliability Needs



5 Support for DLOL Method

Q38. WHAT ARE THE PRIMARY BENEFITS OF MOVING TOWARD THE DLOL METHOD, AS PROPOSED BY MISO?

A38. The proposed DLOL resource adequacy framework refocuses the determination of system capacity need and the accreditation of individual resources to meet this need around the hours that matter most for system reliability. To a large degree, this is what the resource adequacy framework was *always* intended to do, but it is only in recent years that the growth of renewables and storage has led to a misalignment in the hours used in the existing capacity market framework (i.e. peak hours) and the hours that matter most for system reliability (i.e. critical hours). A realignment around critical hours will create appropriate signals for resources that will incentivize efficient behavior, ultimately minimizing the costs of reliability. Finally, the DLOL framework is inherently designed to adapt to changing system conditions as they evolve over time, creating a framework that is sustainable in the long run.

Q39. IS MISO'S PROPOSED DLOL METHOD SUITED TO ACHIEVE THE PRINCIPLES OF CAPACITY MARKET DESIGN?

A39. Yes. The DLOL method is the ideal solution to achieve each of the principles of capacity market design described above, including: 1) Reliability, 2) Economic Efficiency, 3) Fairness/Equity, and 4) Acceptability.

Q40. HOW IS MISO'S PROPOSED DLOL METHOD BEST SUITED TO ACHIEVE THE PRINCIPLE OF RELIABILITY?

A40. MISO's determination of the total system need will consider all hours of the year and a wide range of resource conditions. Accreditation based on DLOL appropriately focuses on those hours of the year having the highest reliability risk. By definition, an electricity system that has sufficient capacity to provide an acceptable level of reliability during the hours with highest reliability risk also has sufficient capacity to ensure reliability in other hours. If that were not the case, then the other hours would have reliability risk as well. Such an assertion is consistent with traditional planning practices for systems with a preponderance of thermal capacity; a system with sufficient capacity during peak load hours would also have sufficient capacity during all other hours. To the extent that there is not sufficient available energy during any time of the year for any reason, then these hours would be reliability risk hours and would be relevant in the accreditation of all resources, sending an economic signal for investment in more resources that are available during these periods.

Additionally, accrediting resources based on their marginal impact to system reliability yields MW of capacity that are interchangeable on the margin. This ensures that substituting MW of capacity from different resources (or resource classes) will not negatively impact system reliability.

Q41. HOW IS MISO'S PROPOSED DLOL METHOD BEST SUITED TO ACHIEVE THE PRINCIPLE OF ECONOMIC EFFICIENCY?

A41. MISO's proposal achieves economic efficiency (i.e., the minimization of total resource costs) by sending appropriate signals for new resources to enter or existing resources to remain in the market or exit. Under the DLOL method, resources are accredited and compensated based on their marginal impact to system reliability. This incentivizes incremental investments in system reliability where benefits that are greater than or equal to costs. Any market design where compensation is misaligned from marginal value creates the potential to 1) incentivize incremental investment that is uneconomic or 2) disincentivize investment that may be economic.

As an example, sending an economic signal for resources to enter the market (because they are available during gross peak hours) that do not provide incremental reliability value (because they are not available during hours of highest reliability risk) increases the total cost of providing electricity due to unnecessary expenditures.

Q42. HOW IS MISO'S PROPOSED DLOL METHOD BEST SUITED TO ACHIEVE THE PRINCIPLE OF FAIRNESS/EQUITY?

A42. With respect to resource accreditation in a competitive market context, a methodology will meet the criteria for fairness and equity if it is non-discriminatory, that is, it treats all generators alike using a consistent methodology. Because the DLOL method accredits *all* resources (except resources external to MISO and emergency-only Load Modifying Resources) based on their availability during the same critical hours, the framework is inherently technology neutral and values all resources on a level playing field. The framework uses a direct measure of reliability contribution without any subjective allocations of portfolio ELCC (as is necessary in the average ELCC framework). Because the DLOL method provides an objective method to value the reliability contribution of all resources on a level playing field, it is inherently non-discriminatory and best suited to achieve the principle of fairness/equity. Conversely, frameworks that *do not* rely on marginal accreditation are inherently discriminatory; an average ELCC framework benefits the class of resources whose accreditation is above its marginal value through a subjective allocation of a portion of portfolio effects, relative to other resources that do not receive an additional accreditation value.

Q43. HOW IS MISO'S PROPOSED DLOL METHOD BEST SUITED TO ACHIEVE THE PRINCIPLE OF ACCEPTABILITY?

A43. The DLOL method is best suited to achieve the principle of acceptability for two primary reasons: 1) it is tractable for the system operator and 2) it creates an understandable and fungible capacity product for market participants.

From the perspective of MISO, resource class availability during critical hours is readily calculable using the existing LOLE study model that is already used in determining capacity market requirements. Grouping resources into "classes" with similar characteristics creates a tractable number of values that can be vetted and understood. Additionally, because LOLE models are readily available across the industry[23], market participants can also perform their own calculations to forecast future DLOL values, just as is done for other electricity market products today such as future energy prices using industry-standard production cost models. Additionally, the DLOL method also creates a single understandable and fungible product that can be transacted within each capacity market auction (and bilaterally) that is independent of which load-serving entity may own the resource. The fact that a single value can be ascribed to each resource provides significant benefits from the perspective of complexity.

Q44. IS A MARGINAL ELCC RESOURCE ACCREDITATION FRAMEWORK (AS IMPLEMENTED THROUGH THE DLOL METHOD) PREFERABLE TO AN AVERAGE ELCC FRAMEWORK?

A44. Yes, a marginal ELCC resource accreditation framework, such as the DLOL method, is preferrable to an average ELCC framework for a number of reasons:

- One of the most important shortcomings of an average ELCC framework is that it represents a break with one of the most basic foundational principles of competitive markets: that resources should be compensated based on their marginal value to the system. As a result, an average ELCC framework will provide economic signals for entry and exit that lead to inefficient behaviors and increase resource costs. On the other hand, a marginal ELCC framework incentivizes resources that generate during high reliability risk hours, by giving them a higher capacity accreditation.

[23] For example, the Astrapé SERVM model, the GE MARS model, the E3 RECAP model, and the NREL PRAS model are all commercially available probabilistic models that can perform planning reserve margin and effective load carrying capability calculations

- An average ELCC framework requires significant subjectivity in how capacity credits are assigned to individual resources, because the total capacity value of a portfolio is different than the sum of its parts due to interactive effects. Thus, the portfolio ELCC must be “allocated” across individual resources to ensure that the sum of the capacity credits of individual resources equals the capacity value of the portfolio. There is no single correct or objective method to allocate those effects, meaning that the results of the capacity accreditation process will inherently depend on discretionary design choices in how to handle this phenomenon. In contrast, the marginal ELCC of each resource *is* a single, directly measurable quantity that can be calculated without the need to account for subjective allocations.
- In an average ELCC framework, the capacity value assigned to each resource does not represent its expected production during any particular time period. The lack of a direct physical interpretation of the capacity credit has been a source of confusion for regulators, operators, and market participants and makes it difficult to evaluate resource performance retrospectively. For instance, in its root cause analysis following the August 2020 blackouts, CAISO observed “The CPUC has improved the methods for estimating the reliability megawatt (MW) value of solar and wind over the years, but the reliability value of intermittent resources is still over-estimated during the net peak hour.” In contrast, the marginal ELCC of a resource can be directly interpreted or understood as a measure of its availability across loss-of-load periods.

For these reasons, a marginal ELCC framework, such as the DLOL method, is a more economically efficient capacity accreditation framework.

Q45. WHY IS THE DLOL APPROACH PREFERABLE TO THE MISO STATUS QUO CAPACITY ACCREDITATION METHOD FOR WIND RESOURCES?

A45. MISO accredits current wind capacity using an "average ELCC" framework, but even such a descriptor is not fully accurate because it is a calculation performed only for one class of resources (wind) without any consideration of interactive effects with other classes of intermittent resources (such as solar and storage) on the system.

Aside from MISO's current approach not being scalable to multiple resource classes without additional adjustments, the primary issue with MISO's current approach (and any average ELCC approach) is that it accredits resources meaningfully in part based on their availability during the gross peak. As previously discussed, this creates a distortionary signal that compensates and incentivizes new resources to enter the system that may not provide any incremental contribution to reliability, ultimately increasing costs. The proposed DLOL method ensures that wind resources are efficiently and fairly accredited for their contribution to system-wide reliability, by accrediting based on their availability during the hours of highest reliability risk.

Q46. WHY IS THE DLOL APPROACH PREFERABLE TO THE MISO STATUS QUO CAPACITY ACCREDITATION METHOD FOR SOLAR RESOURCES?

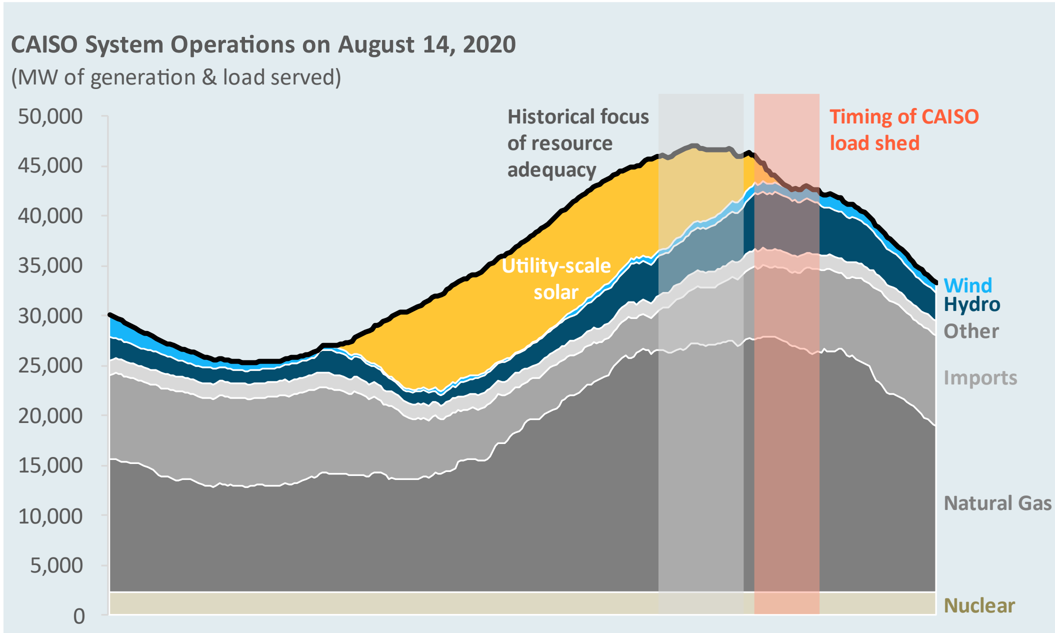
A46. MISO's current solar capacity accreditation is based on the unit-specific three-year historical average output[24] for the following hours each season:

- **Spring, Summer, and Fall:** 15, 16 and 17 EST
- **Winter:** 8, 9, 19 and 20 EST

The issue with MISO's current solar capacity accreditation approach is that it credits solar resources for their contribution to a static set of hours that might not align with the hours of highest system risk, particularly as rising penetrations of solar resources cause the net peak to shift into the evening—a phenomenon that has been well-documented in other jurisdictions and was a contributing factor to California's rotating outages in August 2020 (see Figure 6). On the other hand, MISO's proposed DLOL method dynamically ensures that solar accreditation is based on availability during the hours of highest reliability risk. This ensures that solar resources are efficiently and fairly accredited for their contribution to system-wide reliability in an evolving system.

[24] Note that curtailment is added to the actual output to ensure it captures all potential solar generation in those hours

Figure 6. Illustration of shift to net peak in California (Source: CAISO and E3)



Q47. WHY IS THE DLOL APPROACH PREFERABLE TO THE MISO STATUS QUO CAPACITY ACCREDITATION METHOD FOR THERMAL RESOURCES?

A47. MISO's current thermal capacity accreditation methodology has two steps:

1. Determine resource-class capacity accreditation based on the unit-specific equivalent forced outage rate on demand ("EFORd") output for the five years prior to the planning year.
2. Determine individual resource capacity accreditation based on historical availability during times of need for thermal resources, as described in Schedule 53 of MISO's Tariff (from FERC's acceptance of MISO's 11/2021 filing).

The primary issue with MISO's current thermal capacity accreditation approach lies in the determination of thermal resource-class capacity accreditation (step 1 above). The current methodology credits thermal resources based on their availability anytime they are called upon to operate—since EFORd is utilized to discount nameplate capacity—rather than focusing on the hours of highest system risk. On the other hand, MISO's proposed DLOL method focuses on thermal availability during the hours of highest reliability risk, when availability may be different due to unique circumstances such extreme weather that can lead to correlated outages. MISO's approach therefore ensures that thermal resources are appropriately accredited based on their marginal contribution to system reliability.

Q48. WHY IS THE DLOL APPROACH PREFERABLE TO CALCULATING MARGINAL ELCC VALUES DIRECTLY FOR EACH INDIVIDUAL RESOURCE?

A48. Calculating marginal ELCC values for each individual resource would be a theoretically accurate approach to satisfying the reliability and efficiency principle. However, performing such calculations for each individual resource would require an intractable number of model runs for the market operator, assuming there was even sufficient data for each resource. The DLOL method yields functionally similar results to individual resource marginal ELCC values but through a method that is tractable for the market operator to implement, relies on data that is available and auditable, and requires significantly less effort.

Q49. WHAT ARE COMMON CRITICISMS OF THE DLOL METHOD?

A49. Some common criticisms of the DLOL method, and marginal ELCC frameworks more broadly, include:

- Criticism #1: The DLOL method could potentially yield a total capacity requirement that is lower than gross peak load, resulting in a "negative planning reserve margin."
- Criticism #2: The total capacity requirement using the DLOL method is dependent on the resource portfolio since it is a function of peak loss-of-load probability hours which are themselves a function of the resource portfolio.
- Criticism #3: The DLOL method undervalues the *portfolio* capacity value of all combined resources, resulting in "missing megawatts."
- Criticism #4: The DLOL method leads to inequitable outcomes for customers that made investments in certain resources by allowing for "free-riders."
- Criticism #5: The DLOL method that ascribes a single *capacity* accreditation value to each resource does not appropriately capture the ability of resources to generate energy and does not address potential *energy sufficiency* requirements.
- Criticism #6: The DLOL method shift over time and do not provide the stability or predictability necessary to facilitate investment in the market.

For each of these potential criticisms, there are compelling counterarguments and rebuttals.

Q50. PLEASE RESPOND TO THE CRITICISM THAT THE DLOL METHOD RESULTS IN A NEGATIVE PLANNING RESERVE MARGIN.

A50. The PRM is calculated as the total requirement for accredited capacity divided by the median peak load. While it is perhaps initially counter-intuitive that this value would become negative when using the DLOL method, this is not a technical shortcoming of the method. In fact, the eventual negative reserve margins resulting from this approach reflect an important dynamic. Namely, the periods of reliability risk will eventually shift to periods where demand is lower than the expected gross peak—and when it does, the amount of accredited capacity needed to ensure reliability will also be lower than the expected gross peak. Most importantly, this does not imply that there are not sufficient resources to meet peak demand, as this dynamic will only occur once there is no longer material reliability risk during peak demand due to an abundance of resources in those periods.

It is worth noting that, especially in the context of the DLOL method, the choice to calculate the reserve margin by dividing the total need for accredited capacity by the median peak demand is an arbitrary (and ultimately inconsequential) convention. This convention was a logical one in the traditional paradigm, when both the numerator (available resources) and denominator (load) were related directly to system conditions during the peak. Under the DLOL method, once reliability risk shifts away from the peak, the division of total accredited capacity by peak demand is a comparison of resource availability during one period of time with demand during another. In other words, a PRM of -15%

simple means that loads during loss-of-load probability hours are simply 15% lower than loads during peak demand.

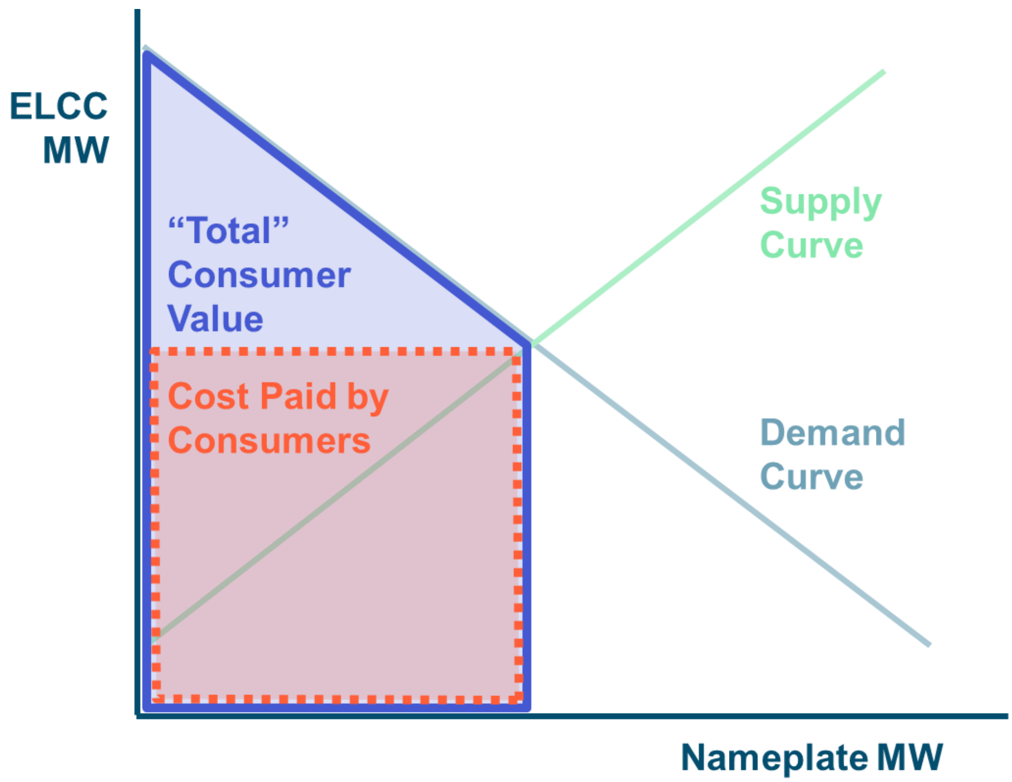
Q51. PLEASE RESPOND TO THE CRITICISM THAT THE TOTAL CAPACITY REQUIREMENT UNDER THE DLOL METHOD IS PORTFOLIO DEPENDENT.

A51. The total capacity requirement under the DLOL method *is* portfolio dependent; in fact, that is a feature, rather than a shortcoming, of the method. This is the case because the hours in which reliability risk is highest depend on both the characteristics of system load and the resource portfolio; this is inherently (and increasingly) true in systems with increasing supplies of variable and energy-limited resources. The statement that the resource accreditation under the DLOL method, or a marginal ELCC framework more broadly, is portfolio dependent therefore should not be viewed as a criticism; rather, it accurately reflects that the reliability needs of the system depend on both loads and resources to determine when periods of scarcity are likely to occur.

Q52. PLEASE RESPOND TO THE CRITICISM THAT THE DLOL METHOD UNDERVALUES THE 'PORTFOLIO' CAPACITY VALUE, RESULTING IN 'MISSING MEGAWATTS'.

A52. The premise of such a criticism is rooted in the false notion that the compensation to individual capacity resources should be based on the "total" value that those resources provide in aggregate. Such a notion conflicts with the principles of basic microeconomics where resources are compensated at their marginal value in competitive markets. In many markets (both electricity and non-electricity) the total value that accrues to consumers exceeds the price paid by consumers in aggregate. The difference between these values is analogous to "consumer surplus" and is not "missing" but rather properly accounted for as a benefit to consumers in the reduction of the capacity requirement. An illustration of this phenomenon is provided below.

Figure 7: Illustration of Consumer Surplus



Similar dynamics already occur today in other wholesale electricity markets. For example, an abundance of solar reduces mid-day energy prices and the costs to consumers during these periods. The price paid by consumers and the revenues earned by solar resources are not based on a counterfactual of the system's costs without solar or of the total value that accrues to consumers. Rather, it is appropriately based on the marginal value that the solar energy provides in the electricity market for a given hour.

Q53. PLEASE RESPOND TO THE CRITICISM THAT THE DLOL METHOD LEADS TO INEQUITABLE OUTCOMES BY ALLOWING FOR "FREE-RIDERS."

A53. Some industry stakeholders have raised a related concern that the DLOL method, or a marginal ELCC framework in general, facilitates "free-riding" by lowering the capacity requirements for certain load-serving entities due to investment in renewable resources made by other load-serving entities. It is true that load-serving entities may benefit from lower capacity requirements as a result of the DLOL method. The fact that markets yield benefits through the aggregation of loads and resources is well-understood and generally not characterized as free-riding. For example, capacity requirements for individual load-serving entities under MISO's current coincident peak approach are lower than if each load-serving entity were required to procure sufficient resources to meet their own non-coincident peak. In fact, this is one of the major drivers of MISO's Value Proposition.[25]

Attempting to "remedy" to this perceived inequity would necessarily yield *discriminatory* outcomes. For example, assigning some resources a higher accreditation because of their association with specific loads (or perhaps their vintage) would accredit otherwise identical resources differently, and prior FERC rulings have already precluded this approach as discriminatory.[26] An average

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[25] *See* https://cdn.misoenergy.org/2022%20Value%20Proposition%20Annual%20View%20-%20Presentation628395.pdf

[26] https://www.pjm.com/directory/etariff/FercOrders/5696/20210430-er21-278-001.pdf

ELCC appears to mitigate this issue, but in addition to being economically inefficient for all of the reasons previously provided, an average ELCC approach is also discriminatory among different classes (or technologies) because it accredits two resources that *identically* improve system reliability (i.e. have equivalent marginal ELCC) *differently* (due to the subjective allocation of portfolio effects).

Q54. PLEASE RESPOND TO THE CRITICISM THAT THE DLOL METHOD DOES NOT ACCOUNT FOR ENERGY SUFFICIENCY REQUIREMENTS.

A54. Some industry stakeholders have raised the concern that any framework, including the DLOL method, that ascribes a single *capacity* accreditation value to each resource does not appropriately account for the *energy* requirements of the electricity system or the ability of resources to help ensure energy sufficiency. This concern is misplaced and is based on a misunderstanding of the nature of loss-of-load modeling and capacity accreditation calculations under the DLOL method. The DLOL method inherently captures both the energy requirements of the system and the ability of individual resources to contribute to these requirements. In fact, the projection that the DLOL accreditation value (i.e. marginal ELCC) of short-duration storage is expected to decline as the penetration of this resource increases over time is precisely *because* it is capturing both the energy and capacity requirements of the system.[27]

For example, consider an electricity system that has sufficient nameplate capacity and energy storage capability but is energy deficient. Such a system would

[27] https://www.utilitydive.com/news/moving-beyond-rules-of-thumb-for-smart-cost-effective-storage-deployment/553674/

have unique characteristics that are appropriately captured by the DLOL-based capacity accreditation system:

- This system would experience very long duration loss-of-load events in which energy storage resources run out of charge and renewable energy for charging is insufficient. Thus, capacity accreditation values would be based on a large number of consecutive critical hours, and economic signals would be sent to resources that availability across the entire period was necessary to be accredited at full nameplate capacity.
- The accreditation of resources that do not generate energy, e.g., short-duration energy storage, would be extremely low since it would run out of charge a few hours into the elongated DLOL period.
- The accreditation of resources that can generate during the event would be approximately equal to their average capacity factor during this period, because their energy can be stored and used anytime during the period.

All of these factors are appropriately captured by the DLOL method, which is ideally suited to ensure both capacity *and* energy sufficiency.

Q55. PLEASE RESPOND TO THE CRITICISM THAT RESOURCE ACCREDITATION VALUES UNDER THE DLOL METHOD ARE INHERENTLY UNSTABLE OVER TIME, CREATING INVESTMENT CHALLENGES.

A55. This criticism is misplaced for two reasons. First, capacity accreditation values under the DLOL method change relatively slowly over time, particularly as compared to observed volatility in other areas of the electricity market. These accreditation values change at the same pace as electricity generation infrastructure changes and generally do not change more than a few percentage points in any single year. In comparison to the volatility of the energy market due to factors like extreme weather or geopolitical events, the DLOL accreditation values are remarkably stable.

Second, changes in resource accreditation values under the DLOL method provide important signals that reflect *actual* changes in the electricity system, and those values will adjust as quickly or as slowly as the needs of the system change. To the extent that resource accreditation values change over time or are uncertain in the future, this simply reflects the fact that their contribution to system reliability is changing over time and that we cannot perfectly predict the future. The advent of competitive electricity markets was premised on the notion that market participants were best positioned to manage such changes/risks. A capacity accreditation framework that does not reflect changes to the marginal value does not eliminate changes in the physical marginal ELCC of resources but rather socializes the discrepancy between the physical and accredited values, requiring loads to purchase additional capacity to make up for inaccurate accreditation.

In summary, capacity accreditation values under the DLOL method are sufficiently stable, and to the extent that values shift over time, individual market participants are best positioned to manage these shifts without socializing discrepancies in inaccurate accreditation.

6 Summary of Evidence

Q56. CAN YOU PLEASE SUMMARIZE YOUR TESTIMONY?

A56. Yes. The key takeaways of my testimony are:

- The nature of reliability risks in the electricity system are changing significantly on the MISO system due to the expected growth in renewable and storage resources;
- MISO's current resource adequacy framework leads to higher total cost of providing reliability due to incentivizing unnecessary expenditures on resources that do not incrementally contribute to system reliability which is ultimately manifested through a higher than necessary reliability requirement. Additionally, it yields an inequitable allocation of reliability value across resources by focusing non-critical reliability risk hours in the determination individual resource capacity accreditation values;
- The DLOL method best achieves the principles of sound capacity market design and will deliver reliability, economic efficiency, fairness/equity, and acceptability. Such a framework is critical to meet the evolving MISO resource adequacy needs;
- An average ELCC framework is ill-suited to achieve the capacity market principle of economic efficiency and will ultimately increase the resource costs of delivered electricity;

- Many of the criticisms of the DLOL method (or marginal ELCC more generally) are unfounded or rooted in misunderstandings of the capacity product being transacted.

Q57. DOES THIS CONCLUDE YOUR TESTIMONY?

A57. Yes.

Affidavit of Zachary Ming

COUNTY OF SAN FRANCISCO)
)
STATE OF CALIFORNIA)

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

[signature]
Zachary Ming

SUBSCRIBED AND SWORN BEFORE ME, this 26 day of March, 2024.

____
(*Notary Public Signature*)

Commissioned in __________ county.

Commission Number: __________

Commission Expires: __________

A notary public or other officer completing this certificate verifies only the identity of the individual who signed the document to which this certificate is attached, and not the truthfulness, accuracy, or validity of that document.

State of California
County of San Francisco
Subscribed and sworn to (or affirmed) before me on this 26th day of March, 2024, by Zachary Ming
__________, proved to me on the basis of satisfactory evidence to be the person(s) who appeared before me.

Signature [signature] (Seal)

APRIL M. JOHNSON
Notary Public - California
San Francisco County
Commission # 2380962
My Comm. Expires Nov 13, 2025

Tab G

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Midcontinent Independent System	)	
Operator, Inc.	)	Docket No. ER24-___-000

Affidavit of David B. Patton, Ph.D.

I. Qualifications and Purpose

1. My name is David B. Patton. I am an economist and the President of Potomac Economics Ltd. Our offices are located at 10560 Arrowhead Drive, Fairfax, VA 22030. Potomac Economics is a firm specializing in expert economic analysis and monitoring of wholesale electricity markets. Potomac Economics has served as the Independent Market Monitor ("IMM") for Midcontinent Independent System Operator, Inc. ("MISO") since 2002. Potomac Economics serves in a substantially similar role for the New York Independent System Operator, Inc., ISO New England, Inc., and the Electric Reliability Council of Texas.

2. As the Market Monitor for MISO, Potomac Economics is responsible for assessing the competitive performance of the MISO markets, including identifying and remedying market design flaws and abuses of market power. This work has included preparing reports that assess the performance of these markets and providing advice on numerous issues related to market design and economic efficiency. Among the issues that we monitor are MISO's resource adequacy construct and Planning Resource Auction ("PRA"), which is particularly relevant to this filing.

3. I have worked as an energy economist for more than 30 years, focusing primarily on the electric utility and natural gas industries. I have provided strategic advice, analysis, and expert testimony in the areas of electric power industry restructuring, pricing, mergers, and market power. I have also advised Regional Transmission Organizations on transmission pricing, market design, and congestion management issues. I have provided expert testimony and analysis of market power issues and competition in a number of mergers and

market-based pricing cases before the Federal Energy Regulatory Commission ("the Commission"), state regulatory commissions, and the U.S. Department of Justice.

4. Prior to my experience as a consultant, I served as a Senior Economist in the Office of Economic Policy at the Commission, advocating on a variety of policy issues including transmission pricing and open-access policies, market design issues, and electric utility mergers. As a member of the Commission's advisory staff, I worked on policies reflected in Order No. 888, particularly on issues related to power pool restructuring, independent system operators ("ISOs"), and functional unbundling. I also analyzed alternative transmission pricing and electricity auctions proposed by ISOs.

5. Before joining the Commission, I worked as an economist for the U.S. Department of Energy. During this time, I helped to develop and analyze policies related to investment in oil and gas exploration, electric utility demand-side management, residential and commercial energy efficiency, and the deployment of new energy technologies. I have a Ph.D. in Economics and an M.A. in Economics from George Mason University, and a B.A. in Economics with a minor in Mathematics from New Mexico State University.

6. The purpose of this affidavit is to support certain proposed revisions to MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff"). In particular, MISO proposes changes to its accreditation of capacity. Accreditation is key to the performance of the capacity market because it determines the quantity of capacity a generating resource can sell in MISO's Planning Resource Auction (PRA). I will explain how the proposed changes in accreditation improve its alignment with the reliability provided by different types of resources.

II. Introduction and Summary

7. The PRA is a part of the MISO resource adequacy construct, which aims to ensure load serving entities (LSEs) have enough capacity (planning resources) available to meet system planning requirements. LSEs must meet their individual Planning Reserve Margin Requirement (PRMR) either through a PRA purchase or through a resource plan reflecting its owned or contract resources. The PRA allows market participants to sell capacity among themselves to meet capacity requirements set by MISO. Capacity requirements are set for each region and each season of the planning year beginning June 1 and ending May 31.

8. An efficiently designed PRA can provide a range of important economic benefits by setting prices that facilitate efficient investment and retirement decisions. The structure of the PRA in the past failed to fully realize these benefits because both the supply and the demand were not well aligned with reliability. MISO has proposed changes recently to address the demand side of the market by implementing Reliability-Based Demand Curves (RBDCs).[1]

9. MISO's proposed changes in this docket address the supply side of the capacity market by instituting an accreditation framework for each class of capacity resources that reflects the resources' marginal contribution to the reliability of the system. This is an essential improvement to facilitate the reliable transition of the generation portfolio to sharply reduce MISO's carbon emissions. The large quantities of intermittent generation entering the MISO region during this transition provide less and less reliability as more enter because they lack key attributes provided by dispatchable resources that are increasingly

[1] See Docket No. ER23-2977.

retiring. Establishing accreditation that is accurately aligned with reliability will ensure that the capacity market provides efficient incentives to invest in and maintain a portfolio of resources that meet the reliability needs of the MISO system.

10. In Section III of this affidavit, I discuss in more depth the purpose of a capacity market and the elements of an efficient design. I explain how an effectively designed capacity market is a critical part of establishing long-run price signals for capital investment in new and existing resources. I also discuss why marginal accreditation of capacity resources is essential, and why average accreditation would undermine the performance of the capacity market by distorting the incentives it provides.

11. Section IV of my affidavit discusses my evaluation of MISO's proposed Direct Loss of Load (DLOL) methodology. I explain why this proposal is a vast improvement over MISO's current accreditation rules and constitutes a marginal accreditation approach. I discuss how this approach will allow the PRA to produce more efficient capacity market incentives. Section V provides my conclusions and recommendation.

III. The Role of the Capacity Market and the Importance of Marginal Accreditation

1. Purpose of Capacity Markets

12. In centralized RTO electricity markets, net revenue earned by selling energy and ancillary services typically will not be adequate to support investment in capacity to meet an RTO's resource adequacy requirements. This is known as the "missing money" problem. To address this problem and create efficient long-term price signals, RTOs have established capacity markets to compensate resources for undertaking obligations to be available to

satisfy the systems' needs. If designed efficiently, capacity markets will provide efficient prices to inform long-term investment, retirement, and maintenance decisions.

13. Additionally, prices in well-designed capacity markets will be equitable for consumers because they will reflect the marginal value of the capacity procured. In other words, consumers will enjoy reliability that is consistent with the costs they incur for it.

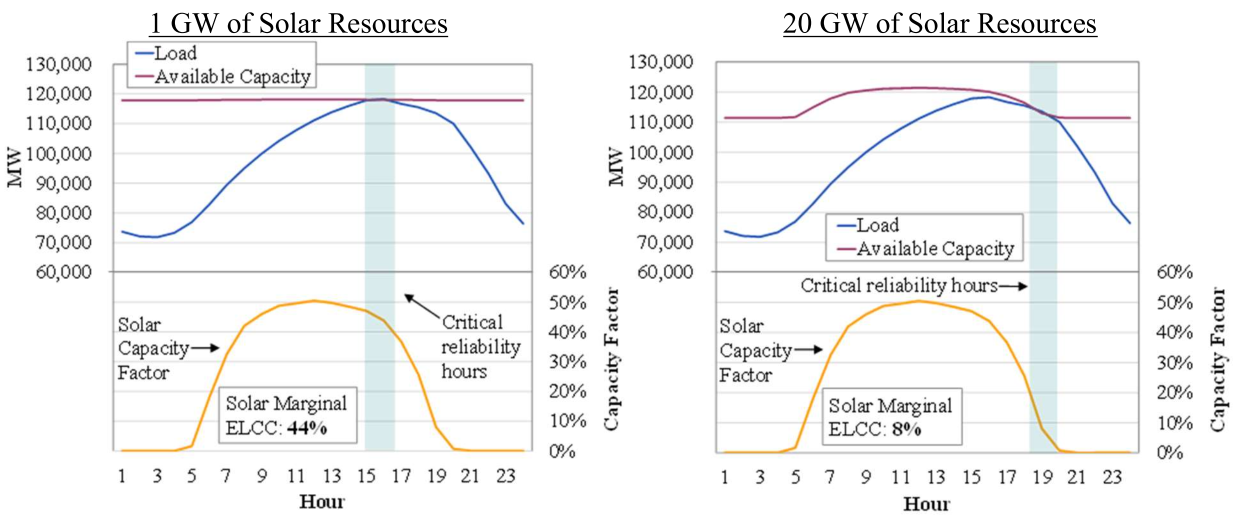
2. Marginal Accreditation of Capacity Resources

14. A resource's true reliability value is its expected availability to provide energy or reserves when the system is at risk of load shedding. This value depends on (a) the timing of the system's hours of greatest need and (b) the factors that affect the availability of a resource in those hours. Importantly, the hours of greatest need are affected by the portfolio of generation and the output profile of the portfolio. Because the value of each additional MW is determined in part by the portfolio of existing generation, this value can be characterized as a "marginal value". For resources to be accredited accurately, RTOs must utilize methods that determine the marginal value of different types of resources.

15. The reliability value of new resources is based on the extent to which the resource reduces the probability of MISO failing to be able to service the load. Two measures of this probability that are commonly produced by RTOs' planning models are: the Loss of Load Expectation (LOLE) and the Expected Unserved Energy (EUE). The first is the probability of load shedding occurring, while second reflected the expected quantity of potential load shedding. Regardless of which metric is used, an RTO can use its planning model to estimate how a new resource improves reliability as measured by these metrics. These models perform a stochastic analysis that estimates the frequency and extent of potential load shedding that may occur caused by random contingencies.

16. The following figure shows how the increasing penetration of one type of resource with similar output profile can affect the critical reliability hours and alter the marginal ELCC of the resources. This figure shows an illustrative example of the marginal ELCC value of solar resources in MISO based on a hypothetical peak summer day based on two different levels of solar resource penetration (1 GW and 20 GW).

Figure 1: Marginal Reliability Value of Solar Resources
Under 1 GW and 20 GW Penetration Scenarios



17. This figure shows that in a system with relatively low solar penetration (left panel), critical reliability hours occur in late afternoon when load is peaking and solar output is relatively high. Under these conditions, we estimate a marginal accreditation level ELCC of 44 percent.

18. With high solar penetration (right panel), there is abundant available generation in the afternoon, which shifts the timing of critical hours towards the evening. The marginal value of solar falls under these conditions to a marginal ELCC of 8 percent because additional solar generation provides less reliability benefit when critical hours mostly occur in the evening.

19. The same principles apply to other types of generation, such as natural gas-only resources in the winter. Increasingly, critical reliability hours in the winter are likely to occur when natural gas availability is limited, causing natural gas-only resources that rely on non-firm fuel purchases to provide diminishing levels of reliability to the system. These changes must be reflected in the capacity accreditation framework to ensure that the market will perform well and maintain resources with attributes that are needed to maintain reliability.

3. The Problems with Average Accreditation

20. Some advocate for an "average" accreditation where accreditation levels are not based on the marginal value of a particular class of resources, but rather on the average value of all of the resources in the class. When an excessive amount of a particular class of resources has entered the market, the difference between the marginal and average value of the class of resources may be extremely large. Such is the case in solar example shown in Figure 1.

21. To the extent that MISO accredits resources based on their average value, it will inflate the accreditation of low-value (over-saturated) resources. Ultimately, this will substantially increase costs to consumers and undermine incentives to the high-value resources the system will need as it transitions to a lower-carbon portfolio of generation.

22. These cost increases would occur because over-accrediting certain classes of resources will ultimately require MISO to increase its capacity requirements to compensate for the reliability value it is not realizing from the over-accredited resources. These compensating increases will grow larger and larger as increasingly substantial quantities of resources with low marginal reliability values are added to the system.

4. Advantages of Marginal Accreditation

23. Marginal accreditation is important because it recognizes the diminishing value received from a particular class of resources. The value of a class of resources diminishes as more enter the market when the availability of the resources is correlated. This occurs for wind resources when the wind speed falls or for solar resources when the sun goes down. This can also be the case for non-firm natural gas resources in the winter when gas supply is limited. By recognizing this diminishing value, the market will limit over-saturation by a class of resources that do not provide comparable reliability to other types of resources.

24. In addition to mitigating over-saturation of classes of technologies that provide low reliability value, marginal accreditation provides strong incentives to invest in and maintain high-value resources with the attributes needed to maintain system reliability. This includes incenting investment in storage that becomes increasingly valuable as more intermittent resources enter the market.

25. Importantly, accurate accreditation will inform the states' integrated resource planning processes and ensure that these processes produce resource plans that will satisfy the reliability needs of the MISO region.

26. Additionally, accurate marginal accreditation will substantially reduce costs to consumers by ensuring that the market procures and compensates those resources that provide the highest value to the system. Likewise, it will avoid the inflation of MISO's capacity requirements that would otherwise be necessary as described above.

27. Finally, marginal capacity accreditation is consistent with the principles that underlie MISO's market design. All of MISO's market products are priced based on marginal value

and marginal cost. In MISO's capacity market, all sellers are paid a marginal clearing price. Hence, it is appropriate and necessary to determine capacity credit values such that an additional unit of capacity from any source provides the same amount of incremental reliability. This is only accomplished by a marginal accreditation approach.

5. Common Misconceptions About Marginal Accreditation

28. In the industry discussions of marginal accreditation, market participants often raise common misconceptions about marginal accreditation. The first is that it can lead to over-procurement as accreditation for certain classes of resources decline. I believe the misunderstanding underlying this concern is the capacity demand is unaffected by accreditation. If this were true, then as MISO reduces the accreditation of some classes of resources, it would have to buy more of other classes of resources. The important concept to understand here is that the demand for capacity must always align with the accredited supply. Therefore, all else equal, a reduction in the accreditation of one class of resources will result in a reduction in the overall demand for capacity. This is a corollary to the concern discussed above about average accreditation where deliberate over-accreditation will raise capacity requirements. A proper understanding of this concept eliminates any potential over-procurement concern.

29. Some are concerned that capacity accreditation will be volatile. There is no evidence to support this. Marginal capacity value should rise and fall gradually with the entry and exit of classes of resources whose availability is correlated. Additionally, although the accreditation levels can change substantially over a number of years, this change is not arbitrary. It is directly related to the changing reliability that new resources in each class provide to the system. Hence, these are necessary and justified changes.

30. Finally, some argue that marginal accreditation discriminates against clean energy resources. This is not true because the same principle is applied to all resources. However, it is unavoidable that the output of similar intermittent resources is highly correlated. For example, when wind speeds drop due to weather patterns, the aggregate output of all wind resources tend to decline together. Likewise, when the sun sets in the MISO footprint, aggregate solar output falls. Saturation of any class of resource whose output is highly correlated in this manner will result in falling marginal accreditation because it will shift reliability risks to hours with relatively low output. Similar correlation exists for non-firm gas resources that have no back-up fuel supply. Under winter peak conditions when natural gas becomes scarce, the availability of all non-firm gas resources tend to fall. Therefore, the marginal value of one more non-firm gas resource to address winter reliability risks is low and will fall as the penetration of such resources increases.

IV. Discussion MISO Proposed DLOL

1. Summary of MISO's DLOL Proposal

31. MISO's proposed resource accreditation method is a form of marginal capacity accreditation that is consistent with the principles described in the prior section. It combines two important factors to determine the expected marginal contribution of each resource to the reliability of the system:

a) The expected availability or output of a typical resource in a technology class of the specific resource. This is based on a probabilistic analysis that estimates the expected availability and output of each class of resources in hours when reliability is threatened.

b) The resource-specific performance of the resource relative to other resources in the class. This is based on the historical performance of the resource over the past three years using the current availability framework specified in Schedule 53.

32. This approach will be applied to all resource classes, with the exception of external resources and Load Modifying Resources (LMRs). I note that changes to the accreditation of LMRs, which are resources available to MISO only during emergency conditions, are being addressed separately. Hence, it applies a unified accreditation framework to intermittent and conventional resources that are currently each accredited under very different accreditation approaches, none of which are true marginal accreditation approaches.

2. Benefits of the MISO Proposal

33. The MISO DLOL proposal represents a substantial improvement over the current accreditation rules in a number of ways. First and foremost, it applies a truly marginal framework to all generating resources, which is essential for all of the reasons articulated in Section III.

34. Second, the addition of the probabilistic assessment of each class of generating resource is a much more accurate means to estimate the availability of different types of resources. It includes the analysis of a full array of potential contingencies and uncertainties that could occur in any hour. Deterministic historical approaches include only those contingencies and uncertainties that actually occurred, which is a vastly smaller sample of potential conditions than is included in the probabilistic analysis.

35. Third, by aligning accreditation with the true marginal reliability value of each class of resource and recognizing the unique performance of each individual resource, the market will procure the highest value resources at the lowest cost. Ultimately, this minimizes costs to consumers. As discussed in the prior section, accreditation approaches that over-accredit major classes of resources will compel RTOs to procure additional capacity to achieve the same reliability standards, which can substantially increase total costs to MISO's consumers.

36. Fourth, MISO's DLOL proposal will inform the States' and utilities' planning processes. Because this proposal will cause resources with attributes the system needs to receive higher accreditation, it will send clear signals to regulators and utilities to invest in and maintain resources that can provide these attributes.

37. Fifth, MISO's DLOL proposal will provide key information needed by MISO's own planning department to forecast the development of new resources and, as a result, the potential transmission needs MISO should be planning to address. Under the DLOL proposal, MISO's future expectations should change substantially, along with the portfolio of transmission it deems needed or economic.

38. Finally, applying a consistent and reasonable accreditation framework to all generating resources ensures that the market incentives do not inefficiently favor or discourage any class of generation.

3. Other Considerations Regarding the DLOL Proposal

39. We have considered other potential concerns and effects of the DLOL proposal and provide two additional conclusions regarding the proposal.

40. First, the proposal does not raise any new or unique market power concerns. Therefore, no changes to MISO's Module D are necessary as a result of the changes proposed by MISO. However, we will continue to monitor the performance of the capacity market and the conduct of each of the participants and will identify potential issues if they arise.

41. Second, MISO proposes to expand the hours used to determine the expected availability of resources in its probabilistic analysis beyond those that show loss of load to capture additional high-risk hours – when supply is within 3% of demand – when reliability is potentially threatened. While adding these additional hours is not strictly consistent with a marginal accreditation based on expected loss of load, MISO proposes a reasonable weighting approach that does not substantially or unduly change the accreditation levels. Therefore, I find that MISO's proposed approach achieves reasonable accreditation levels for each resource class.

42. Lastly, I have no other specific concerns regarding MISO's proposal that would limit my support for its adoption. Therefore, I respectfully recommend that the Commission approve the changes proposed by MISO in this docket.

V. Conclusion

43. For these reasons described in the prior section, I support MISO's DLOL proposal. It represents a substantial and necessary improvement to MISO's current capacity accreditation and promises to provide efficient long-term economic incentives. These incentives are urgently needed as MISO's generation portfolio transitions to a cleaner, less carbon-intense resource portfolio.

44. MISO has done substantial work to identify the supply attributes that will be needed in the future to ensure that it continues to provide reliable electricity to the region. The proposed DLOL aligns MISO's accreditation with the marginal reliability value provided by different types of resources based on their attributes. Therefore, resources with essential attributes or attributes that are in short supply will receive relatively high accreditation levels while those lacking such attributes that provide little marginal reliability value will receive lower accreditation. In this way, the proposal will allow the capacity market to produce economic signals and incentives to help ensure that MISO will retain the resources needed to maintain reliability in the region as this transition occurs. Therefore, I respectfully recommend that the Commission approve MISO's proposed tariff changes.

45. This concludes my affidavit.

ATTESTATION

I am the witness identified in the foregoing Affidavit of David B. Patton, Ph.D. I have read the affidavit and am familiar with its contents. The facts set forth therein are true to the best of my knowledge, information, and belief.

David B. Patton, Ph.D.

Subscribed and sworn before me this 28 day of March, 2023.

Notary Public

My commission expires: Nov. 30, 2025

MATTHEW JAMES CARRIER
NOTARY PUBLIC
REG. #7233763
COMMONWEALTH OF VIRGINIA
MY COMMISSION EXPIRES NOVEMBER 30, 2025