Attachment A

2025 NERC Summer Reliability Assessment

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2025 Summer Reliability Assessment

May 2025

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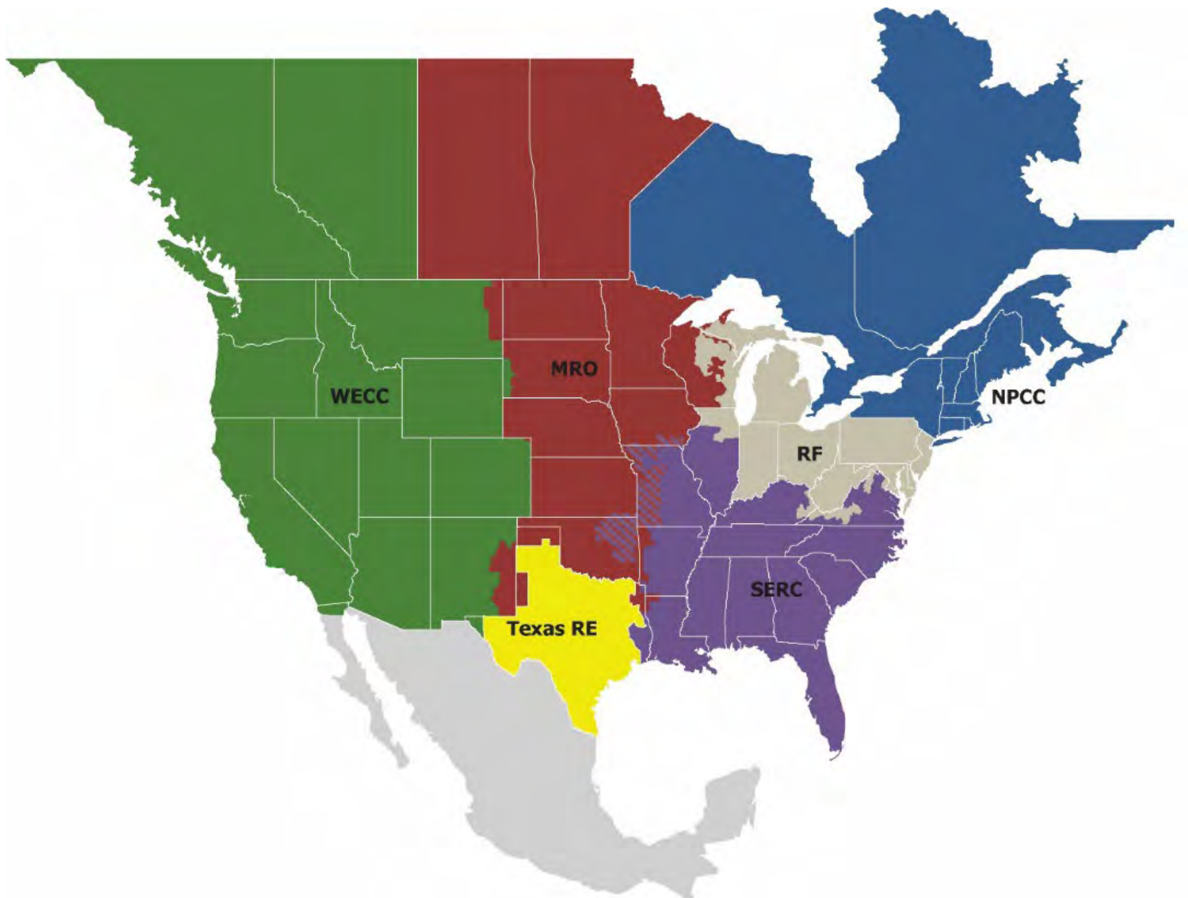
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is spans six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

About this Assessment

NERC's *2025 Summer Reliability Assessment* (*SRA*) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming summer season. In addition, the *SRA* presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might affect the reliability of the BPS. The reliability assessment process is a coordinated evaluation between the NERC Reliability Assessment Subcommittee, the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas. This report reflects an independent assessment by NERC and the ERO Enterprise and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to take necessary actions to ensure BPS reliability. This report also provides an opportunity for industry to discuss plans and preparations to ensure reliability for the upcoming summer period.

Key Findings

NERC's annual *SRA* covers the upcoming four-month (June–September) summer period. This assessment evaluates generation resource and transmission system adequacy as well as energy sufficiency to meet projected summer peak demands and operating reserves. This includes a deterministic evaluation of data submitted for peak demand hour and peak risk hour as well as results from recently updated probabilistic analyses. Additionally, this assessment identifies potential reliability issues of interest and regional topics of concern. While the scope of this seasonal assessment is focused on the upcoming summer, the key findings are consistent with risks and issues that NERC highlighted in the *2024 Long-Term Reliability Assessment* (*LTRA*), which covers a 10-year horizon, and other earlier reliability assessments and reports.[1]

Rising electricity demand forecasts, generation growth, and the increasing pace of change in the resource mix feature prominently in the summer risk profile. Since last summer, the aggregate of peak electricity demand for NERC's 23 assessment areas has risen by over 10 GW—more than double the year-to-year increase that occurred between the summers of 2023 and 2024. Over 7.4 GW of generator capacity (nameplate) has retired or become inactive for the upcoming summer, including 2.5 GW of natural-gas-fired and 2.1 GW of coal-fired generators.[2] Meanwhile, growth in solar photovoltaic (PV) and battery storage resources has accelerated with the addition of 30 GW of nameplate solar PV resources and 13 GW of new battery storage. The new solar and battery resource additions are expected to provide over 35 GW in summer on-peak capacity. New wind resources are expected to provide 5 GW on peak. Operators in many parts of the BPS face challenges in meeting higher demand this summer with a resource mix that, in general, has less flexibility and more variability.

The following findings are derived from NERC and the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as potential operational concerns that may need to be addressed for Summer 2025.

Resource Adequacy Assessment and Energy Risk Analysis

All areas are assessed as having adequate anticipated resources for normal summer peak load conditions (see **Figure 1**). However, the following areas face risks of electricity supply shortfalls during periods of more extreme summer conditions. This determination of elevated risk is based on analysis of plausible scenarios, including 90/10 demand forecasts and historical high outage rates as well as low wind or solar PV energy conditions:

- **Midcontinent Independent System Operator (MISO):** MISO is expecting to have an existing certain capacity of 142,793 MW in the *2025 SRA*, which is a slight reduction from the 143,866 MW submitted for the *2024 SRA*. The retirement of 1,575 MW of natural gas and coal-fired generation since last summer, combined with a reduction in net firm capacity transfers due to some capacity outside the MISO market opting out of the MISO planning resource auction, is contributing to less dispatchable generation in MISO. With higher demand and less firm resources, MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output. MISO's most recent energy assessment reveals that the period of highest energy shortfall risk has shifted from July to August. This shift is driven by the decline in dispatchable generation and the increasing share that solar and wind resources have in meeting demand. The risk of supply shortfalls increases in late summer as solar output diminishes earlier in the day, leaving variable wind and a more limited amount of dispatchable resources to meet demand.
- **NPCC-New England:** The New England area expects to have sufficient resources to meet the 2025 summer peak demand forecast. As of April 1, the 50/50 peak summer demand is forecast to be 24,803 MW for the weeks beginning June 1, 2025, through September 14, 2025, with a lowest projected net margin of -1,473 MW (6.0%). The lowest projected net margin assumes a net interchange of 1,245 MW, which is capacity-backed; however, ISO New England (ISO-NE) has typically imported around 3,000 MW during summer peak load conditions. ISO-NE anticipates an increase of approximately 500 MW in forced outages from its generating fleet compared to Summer 2024. Based on NPCC's most recent energy assessment, some use of New England's operating procedures for mitigating resource shortages is anticipated during Summer 2025. Cumulative loss of load expectation (LOLE) of <0.031 days/period, loss of load hours (LOLH) of <0.120 hours/period, and expected unserved energy (EUE) of <94 MWh/period were estimated for the expected load with expected summer resources while the reduced resources and highest peak load scenario resulted in an estimated cumulative LOLE risk of 4.369 days/period, with associated LOLH of 19.554 hours/period and EUE of 19,847 MWh/period.
- **MRO-SaskPower:** For the upcoming summer months, no capacity constraints or reliability issues are expected under normal conditions. However, in the event of generator forced outages of more than 350 MW, combined with above-normal peak demand, SaskPower may need to rely on short-term imports from neighboring utilities. Other remedial actions could include quickly activating demand-response programs, adjusting maintenance schedules, and, if necessary, implementing temporary load interruptions. SaskPower's modeling projects

[1] NERC's long-term, seasonal, and special reliability assessments are published on the Reliability Assessments webpage.

[2] Other retirements include 1.2 GW nuclear capacity following the retirement of some units at the Pickering Nuclear Generator Station in Ontario, and 1.6 GW of petroleum, hydro, and other generation. Source: NERC and EIA data.

the probability of experiencing a generation forced outage exceeding 350 MW to be 21.5%. Assuming maximum available imports, the same modeling projects the number of hours with an operating reserve shortfall this summer to be about 0.65 hours with the highest likelihood occurring in June, estimated at 0.43 hours.

- **MRO-SPP:** SPP's Anticipated Reserve Margin (28.5%) is similar to last summer, and resource shortfalls are not expected for the upcoming Summer 2025 season under normal conditions. However, SPP remains at risk for energy shortfalls if above-normal peak demand periods coincide with low wind output and high generator forced outages. Other known operational challenges for the upcoming season include managing wind energy fluctuations; SPP often experiences sharp ramps of its wind generation that can cause transmission system congestion as well as scarcity conditions.
- **Texas RE-ERCOT:** An additional 7 GW of installed solar PV resource capacity and nearly 7.5 GW in new battery storage is helping ERCOT meet rising summer peak demand. ERCOT is projected to have sufficient operating reserves for the August peak load hour given normal summer system conditions. Nevertheless, continued growth in both loads and intermittent renewable resources drives a risk of emergency conditions in the evening hours when solar generation ramps down and loads remain elevated. ERCOT's probabilistic risk assessment of energy emergency alert (EEA) likelihood for the highest risk periods associated with evening hours in the peak month of August is projected to fall to 3%, down from over 15% in 2024. Lower risk is attributed to a nearly doubling of battery energy storage capacity and improved energy availability from new battery storage and operational rules. The South Texas Interconnection reliability operating limit (IROL) continues to present a system constraint, which, under specific unlikely conditions, could ultimately require ERCOT system operators to direct firm load shedding to remain within IROL limits and prevent cascading load loss. For Summer 2025, this risk is being mitigated by updating transmission line dynamic ratings and switching actions to divert power away from the most limiting transmission circuits.
- **WECC-Mexico:** The WECC-Mexico assessment area in Baja California has a peak summer demand of 3,770 MW and is served by a resource mix that is mainly natural-gas-fired generation, with some geothermal, solar, wind, and oil-fired resources (5,636 MW total installed capacity, of which 4,125 MW are gas-fired generators). WECC-Mexico's 14% Anticipated Reserve Margin exceeds the Reference Margin Level for reliability (10%) calculated by WECC. For the upcoming summer, NERC assesses that historically average generator outage rates for peak demand periods can cause a supply shortfall within the WECC-Mexico assessment area and trigger the need for non-firm resources from neighboring areas. Note, in prior SRA reports, the Baja California portion of the BPS was included as part of the WECC-CA/MX assessment area. The *2025 SRA* includes a new assessment area map for the Western Interconnection. The new assessment area boundaries provide reliability risk information in more geographic detail for the United States and Mexico.

Resource additions since last summer have helped lower the risk of energy shortfalls in several areas. Across the U.S. portion of the Western Interconnection, over 6.5 GW of installed solar capacity has been added, along with nearly 7 GW in battery storage. The resources are expected to provide close to 14 GW in on-peak capacity. In British Columbia, new hydroelectric generators were commissioned, contributing to an additional 500 MW in capacity for the summer. The resource additions have alleviated capacity and energy shortfall risks identified in these assessment areas prior to Summer 2024 and provide supplies across the Western Interconnection.

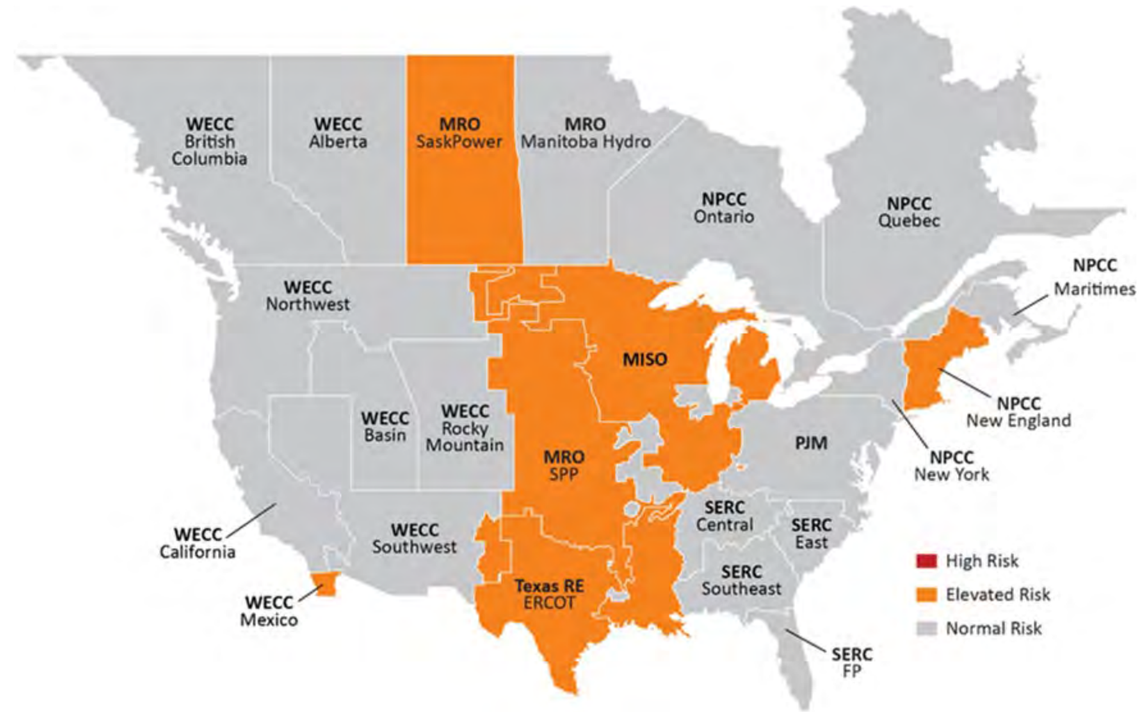


Figure 1: Summer Reliability Risk Area Summary

Seasonal Risk Assessment Summary	
High	Potential for insufficient operating reserves in normal peak conditions
Elevated	Potential for insufficient operating reserves in above-normal conditions
Normal	Sufficient operating reserves expected

Other Reliability Issues

- **Weather services are expecting above-average summer temperatures across much of North America and continued below-average precipitation in the Northwest and Midwest.** In summer-peaking areas, temperature is one of the main drivers of demand and can also contribute to forced outages for generation and other BPS equipment. Average temperatures last summer across the United States and Canada were not as hot as Summer 2023, but Summer 2024 still managed to rank in the top four hottest recorded summers with certain areas breaking records yet again. Few high-level EEAs were issued between June and September 2024, and there were no supply disruptions that resulted from inadequate resources as Balancing Authorities (BA), Transmission Operators (TOP), and Reliability Coordinators (RC) employed a variety of operational mitigations and demand-side management measures. Natural-gas-fired electricity generation broke records last year—highlighting the criticality of natural gas in meeting electric demand. This continuing trend will be key in operator preparations that help to ensure fuel availability for the coming summer. The **Review of 2024 Capacity and Energy Performance** section describes actual demand and resource levels in comparison with NERC's *2024 SRA* and summarizes 2024 resource adequacy events.
- **Load growth is driving higher peak demand forecasts and contributing to resource and transmission adequacy challenges in many areas.** Fifteen of the 23 assessment areas are expecting an increase in peak summer demand from Summer 2024. Aggregated peak demand across all assessment areas has increased by over 10 GW since 2024. This is more than double the increase in peak demand from 2023 to 2024. One of the largest increases is seen in the U.S. West (+5%), where a new peak demand record was set last summer. Extreme heat is reported as a main reliability concern this year among BAs in WECC. With precipitation expected to be lower than average in the Northwest, natural-gas-fired generation and demand-side management could be important in offsetting any lower-than-normal levels of hydroelectric generation availability. SERC Southeast is also projecting a sizable increase in peak demand of more than 2% from NERC's *2024 SRA.* Entities in the assessment area cite economic growth and increased industrial and data mining loads as the main drivers.
- **Aging generation facilities present increased challenges to maintaining generator readiness and resource adequacy.** Forced outage rates for conventional generators and wind resources have trended toward historically high levels in recent years.[3] System operators face increasing risk of resource shortfalls and operating challenges caused by forced generator outages, especially during periods of high demand or when relatively few conventional resources are dispatched to serve load. The threat to BPS reliability can be compounded in areas where aging resources are further depended upon to provide essential reliability services. In the Southwest, for example, a portion of capacity has been in operation for roughly 60 years. Electric utilities in SERC-Central have also described aging generation as a reliability challenge. Historical performance has demonstrated the need for planning assumptions that account for elevated forced outage rates for these generators. Older generators can also require extensive overhauls, such as generator rewinds, that take resources out of service for extended periods of time as discovery work can lead to additional unplanned maintenance.
- **Battery resource additions are helping reduce energy shortfall risks that can arise from resource variability and peaks in demand.** In Texas, California, and across the U.S. West, the influx of battery energy storage systems (BESS) in recent years has markedly improved the ability to manage energy risks during challenging summer periods. These areas can be exposed to energy shortfalls during hours of peak demand and into evening as solar PV output diminishes, but BESS resources that maintain their charge during the day can help meet peak demand and also overcome energy shortfalls on the system that might otherwise occur with solar down-ramps or variability. Natural-gas-fired generation also continues to play an important role in meeting peak demand and flexibly responding to fluctuations output from variable energy resources (VER).
- **Grid operators need to remain vigilant for the potential of inverter-based resources (IBR) to unexpectedly trip during grid disturbances.** While this near-term challenge persists, NERC continues to work diligently with industry to develop long-term solutions to this issue. In April, NERC published the *Aggregated Report on NERC Level 2 Recommendation to Industry: Findings from Inverter-Based Resource Model Quality Deficiencies Alert*.[4] In the report, NERC summarized the deficiencies identified in the Level 2 alert issued in June 2024. The report's findings were as follows:
  - Many grid operators indicated that they did not have the requested data readily available, supporting the previous finding that data acquisition and management was insufficient.
  - Interconnection process requirements are insufficient.
  - Two-thirds of the protection settings used by grid operators are not set to provide the maximum capability. This creates a significant artificial limitation of overall ride-through capability of BPS-connected solar photovoltaic (PV) facilities.
  - 20% of the surveyed facilities use a facility capability with a 0.95 power factor limit, which means that a significant amount of underused reactive capability exists on the BPS.
  - Dynamic model data is inconsistent.

[3] See Key Findings in NERC's *2024 State of Reliability* report

[4] *Findings from Inverter-Based Resource Model Quality Deficiencies Alert*

As solar, wind, and battery resources remain the predominant types of resources being added to the BPS, it is imperative for industry, vendors, and manufacturers to take the recommended steps for system modeling and study practices and IBR performance.

- **Operators of natural-gas-fired generators should maintain lines of communication with natural gas system operators to support electric grid reliability.** The 2024 summer season was the fourth hottest on record,[5] and natural-gas-fired generation broke records with a peak monthly average in July of 208 TWh, up 4% from July 2023, per the latest data from the Energy Information Administration (EIA). The EIA projects that rising demand for natural gas exports this year in the wake of ramped up liquefied natural gas (LNG) production combined with lower field production levels could tighten natural gas supplies relative to last summer. Amid year-over-year increases in load projections in most assessment areas, this summer could see another record year for natural-gas-fired generation, thereby stretching supplies even further. Given that late spring and early summer are seasons when natural gas system owners and operators typically perform maintenance requiring system outages, vigilance is needed to ensure the reliability of fuel delivery to natural-gas-fired-generators.[6]
- **Supply chain issues continue to affect lead times for Bulk Electric System (BES) equipment maintenance, replacement, and construction.** While no specific reliability issues for the upcoming summer have been identified, Transmission Owners (TO) and Generator Owners (GO) face delays in parts, materials, and skilled technicians. When summer maintenance preparations or installations are delayed, effects on equipment availability can challenge system operators. Over the long term, supply chain issues and uncertainty continue to affect development. Lead times for transformers remain virtually unchanged, averaging 120 weeks in 2024. Large transformer lead times averaged 80–210 weeks.[7]
- **Wildfire risks in the areas that comprise the Western Interconnection remain ever present.** Wildfire conditions can affect transmission operations by prompting preemptive circuit outages to reduce the risk of fire ignition as well as through fire impacts to transmission infrastructure. Transmission system congestion and reduced import capacity can accompany wildfire conditions. Moreover, fires near wind generation result in curtailment for safety reasons, and solar facilities can be susceptible to range fires. Fire damage to transmission lines interconnected to remote hydro sites in the Pacific Northwest can be particularly problematic with restoration typically taking weeks to months to accomplish.

Recommendations

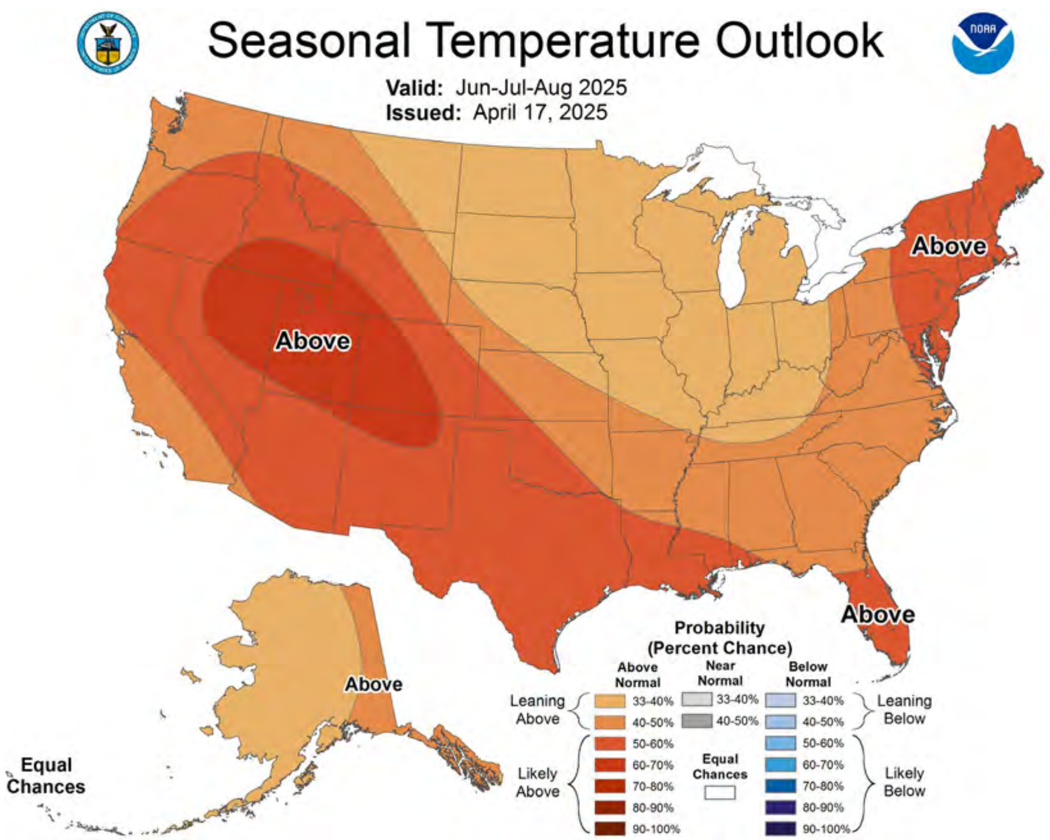
To reduce the risk of electricity shortfalls on the BPS this summer, NERC recommends the following:

- RCs, BAs, and TOPs in the elevated risk areas identified in the key findings should take the following actions:
  - Review seasonal operating plans and protocols for communicating and resolving potential supply shortfalls in anticipation of potentially extreme demand levels.
  - Consider the potential for higher-than-anticipated forced generator outage rates in operating plans due to plant age, operating patterns, or limited pre-seasonal maintenance availability.
  - Employ conservative generation and transmission outage coordination procedures and operate conservatively commensurate with long-range weather forecasts to ensure adequate resource availability. The review of system performance during the January 2025 cold weather event noted that early declaration of conservative operations in advance of extreme conditions helped reduce grid congestion and enhance transfer capability.[8]
  - Engage state or provincial regulators and policymakers to prepare for efficient implementation of demand-side management mechanisms called for in operating plans.
- GOs with solar PV resources should implement recommendations in the IBR performance issues alert that NERC issued in March 2023.[9]
- State regulators and industry should have protocols in place at the start of summer for managing emergent requests from generators for air-quality restriction waivers. If warranted, U.S. Department Energy (DOE) action to exercise emergency authority under the Federal Power Act (FPA) section 202(c) may be needed to ensure that sufficient generation is available during extreme weather conditions.

[5] US sweltered through its 4th-hottest summer on record – National Oceanic and Atmospheric Administration
[6] Short-Term Energy Outlook - U.S. Energy Information Administration (EIA)
[7] Supply shortages and an inflexible market give rise to high power transformer lead times | Wood Mackenzie
[8] See notable operations practices in Appendix 2 of the *January 2025 Arctic Events System Performance Review | FERC, NERC, and its Regional Entities: A Joint Staff Report*, April 2025.
[9] See NERC Level 2 Alert: Inverter-Based Resource Performance Issues, March, 2023. Owners and operators of BPS-connected IBRs that are currently not registered with NERC should consult NERC's IBR Registration Initiative for information on the registration process.

Summer Temperature and Drought Forecasts

During the summer season, heat drives peak electricity demand as consumers use more electricity to cool their homes and businesses. Summer 2024 was the fourth hottest summer on record for the United States and Canada, and Summer 2025 is expected to bring similar intensity. Assessment area load forecasts account for many years of historical demand data, often up to 30 years, to predict summer peak demand and prepare for more extreme conditions. According to their probabilistic assessments of the coming summer season, late July and early August are the periods most frequently identified among the assessment areas as the expected period of peak demand. Peak demand hours may not coincide with the highest risk hours in the summer as the resource mix shifts during a 24-hour cycle, particularly when there are prolonged periods of above-normal temperatures. Coordinating pre-season preparations and maintenance remains critical to avoiding forced outages where possible and mitigating risks to BPS reliability.



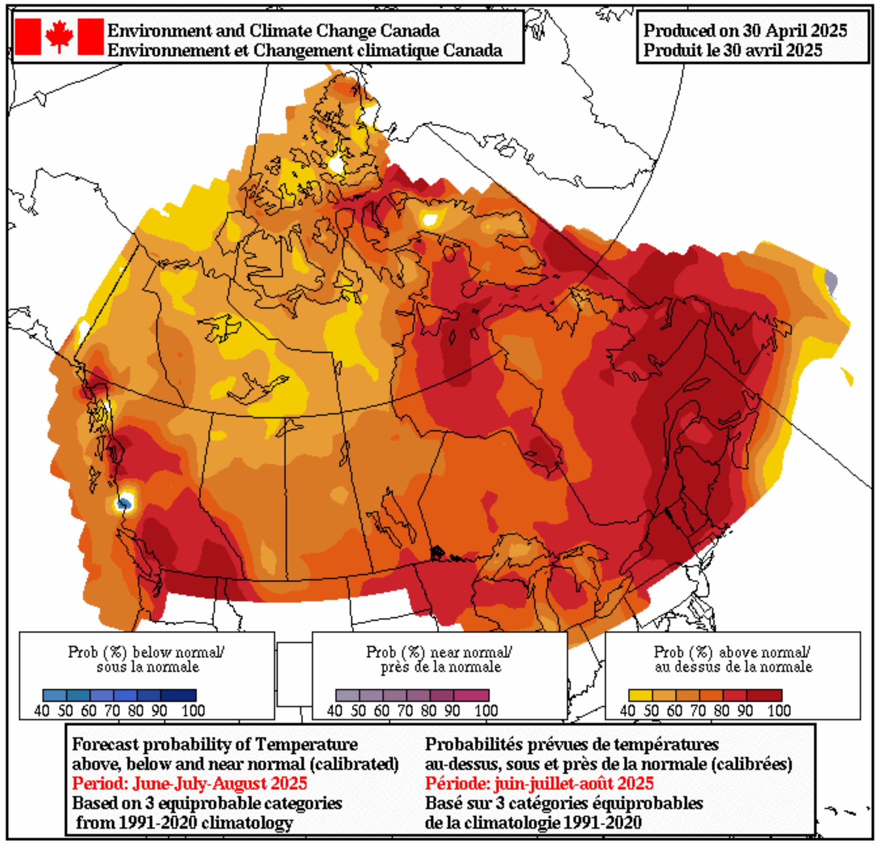


Figure 2: United States and Canada Summer Temperature Outlook[10]

[10] Seasonal forecasts obtained from U.S. National Weather Service and Natural Resources Canada: https://www.cpc.ncep.noaa.gov/products/predictions/long_range/ and https://weather.gc.ca/saisons/prob_e.html

Risk Assessment Discussion

NERC assesses the risk of electricity supply shortfall in each assessment area for the upcoming season by considering Planning Reserve Margins, seasonal risk scenarios, probability-based risk assessments, and other available risk information. NERC provides an independent assessment of the potential for each assessment area to have sufficient operating reserves under normal conditions as well as above-normal demand and low-resource output conditions selected for the assessment. A summary of the assessment approach is provided in **Table 1**.

Table 1: Seasonal Risk Assessment Summary

Category	Criteria[1]
High Potential for insufficient operating reserves in normal peak conditions	• Planning Reserve Margins do not meet Reference Margin Levels • Probabilistic indices exceed benchmarks (e.g., LOLH of 2.4 hours over the season) • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **normal peak-day demand and outage scenarios**[2]
Elevated Potential for insufficient operating reserves in above-normal conditions	• Probabilistic indices are low but not negligible (e.g., LOLH above 0.1 hours over the season) • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **extreme peak-day demand with normal resource scenarios** (i.e., typical or expected outage and derate scenarios for conditions)[2] • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **normal peak-day demand with reduced resources** (i.e., extreme outage and derate scenarios)[3]
Normal Sufficient operating reserves expected	• Probabilistic indices are negligible • Analysis of the risk hour(s) indicates resources will be sufficient to meet operating reserves under normal and extreme peak-day demand and outage scenarios[4]

Table Notes:
[1]The table provides general criteria. Other factors may influence a higher or lower risk assessment.
[2]**Normal resource scenarios** include planned and typical forced outages as well as outages and derates that are closely correlated to the extreme peak demand.
[3]**Reduced resource scenarios** include planned and typical forced outages and low-likelihood resource scenarios, such as extreme low-wind scenarios, low-hydro scenarios during drought years, or high thermal outages when such a scenario is warranted.
[4]Even in normal risk assessment areas, extreme demand and extreme outage scenarios that are not closely linked may indicate risk of operating reserve shortfall.

Assessment of Planning Reserve Margins and Operational Risk Analysis

Anticipated Reserve Margins, which provide the Planning Reserve Margins for normal peak conditions, as well as reserve margins for seasonal risk scenarios of more extreme conditions are provided in **Table 2**.

Table 2: Seasonal Risk Scenario On-Peak Reserve Margins

Assessment Area	Anticipated Reserve Margin	Anticipated Reserve Margin with Typical Outages	Anticipated Reserve Margin with Higher Demand, Outages, Derates in Extreme Conditions
MISO	24.7%	9.3%	-1.9%
MRO-Manitoba	14.6%	11.2%	3.8%
MRO-SaskPower	33.5%	28.3%	22.4%
MRO-SPP	28.5%	18.2%	3.4%
NPCC-Maritimes	42.2%	31.7%	18.6%
NPCC-New England	14.1%	3.9%	4.0%
NPCC-New York	31.6%	12.5%	5.2%
NPCC-Ontario	23.4%	23.4%	3.7%
NPCC-Québec	32.7%	28.2%	19.1%
PJM	24.7%	15.0%	5.3%
SERC-C	19.6%	12.7%	3.2%
SERC-E	29.1%	21.8%	13.0%
SERC-FP	20.2%	14.0%	11.8%
SERC-SE	41.3%	37.7%	12.5%
TRE-ERCOT	43.2%	33.0%	-5.1%
WECC-AB	42.6%	40.3%	20.5%
WECC-Basin	24.3%	15.9%	-27.2%
WECC-BC	24.3%	24.2%	-6.6%
WECC-CA	56.9%	51.0%	4.7%
WECC-Mex	14.1%	1.6%	-16.8%
WECC-NW	32.1%	29.4%	-13.0%
WECC-RM	25.7%	18.2%	-18.9%
WECC-SW	22.3%	14.0%	-13.0%

Seasonal risk scenarios for each assessment area are presented in the **Regional Assessments Dashboards** section. The on-peak reserve margin and seasonal risk scenario charts in each dashboard provide potential summer peak demand and resource condition information. The reserve margins on the right side of the dashboard pages provide a comparison to the previous year's assessment. The seasonal risk scenario charts present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. The assessment areas determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized in the seasonal risk scenario charts; more information about these dashboard charts is provided in the **Data Concepts and Assumptions** section.

The seasonal risk scenario charts can be expressed in terms of reserve margins: In **Table 2**, each assessment area's Anticipated Reserve Margins are shown alongside the reserve margins for a typical generation outage scenario (where applicable) and the extreme demand and resource conditions in their seasonal risk scenario.

Highlighted in **orange** are the areas identified as having resource adequacy or energy risks for the summer in the **Key Findings** section. The typical outage reserve margin includes anticipated resources minus the capacity that is likely to be in maintenance or forced outage at peak demand. If the typical maintenance or forced outage margin is the same as the Anticipated Reserve Margin, it is because an assessment area has already factored typical outages into the anticipated resources. The extreme conditions margin includes all components of the scenario and represents the most severe operating conditions of an area's scenario. Note that any reserve margin below zero indicates that the resources fall below demand in the scenario.

In addition to the peak demand and seasonal risk hour scenario charts, the assessment areas provided a resource adequacy risk assessment that was probability-based for the summer season. Results are summarized in **Table 3**. The risk assessments account for the hour(s) of greatest risk of resource shortfall. For most areas, the hour(s) of risk coincides with the time of forecasted peak demand; however, some areas incur the greatest risk at other times based on the varying demand and resource profiles. Various risk metrics are provided and include LOLE, LOLH, EUE, and the probabilities of an EEA occurrence.

Energy Emergency Alerts

Extreme generation outages, low resource output, and peak loads similar to those experienced in wide-area heat events and the heat domes experienced in western parts of North America during the last three summers are ongoing reliability risks in certain areas for Summer 2025. When forecasted resources in an area fall below expected demand and operating reserve requirements, BAs may need to employ operating mitigations or EEAs to obtain the capacity and energy necessary for reliability. A description of each EEA level is provided below.

Energy Emergency Alert Levels		
EEA Level	**Description**	**Circumstances**
EEA1	All available generation resources in use	• The BA is experiencing conditions in which all available generation resources are committed to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required contingency reserves. • Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
EEA2	Load management procedures in effect	• The BA is no longer able to provide its expected energy requirements and is an energy-deficient BA. • An energy-deficient BA has implemented its operating plan(s) to mitigate emergencies. • An energy-deficient BA is still able to maintain minimum contingency reserve requirements.
EEA3	Firm load interruption is imminent or in progress	• The energy-deficient BA is unable to meet minimum contingency reserve requirements.

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
MISO	The Planning Year 2025–2026 LOLE Study Report, an annual LOLE probabilistic study[11]	The values for LOLH and EUE are taken from the assessment report noted, where the annual LOLE is set at 1 day in 10 years, or 0.1 LOLE for the summer season. For Summer 2025, LOLH is 0.252 hrs/year and EUE is 626.2 MWH/year for the Reference Margin Level. Expectations for load-loss and unserved energy are less than these amounts because MISO's resources are above the Reference Margin Level.
MRO-Manitoba	The 2024 LOLE Study	Manitoba Hydro's probability-based resource adequacy risk assessment for the summer (June–September) season is that there is a low risk of resource adequacy issues. The study indicated Annual Probabilistic Indices for the Manitoba Hydro system for 2026 of 5 MWh per year of EUE, considering a range of flow conditions, and that all of this risk would be in the higher load winter season. The increases in Manitoba load since the 2022 LOLE Study were more than offset by a reduction in long-term exports contract with the expiration of a major export sale in April 2025.
MRO-SaskPower	Probability-based capacity adequacy assessment Summer 2025	According to the study, SaskPower's expected number of hours with an operating reserve shortfall between June and September is about 0.65 hours, assuming maximum available imports. June has the highest likelihood of an EEA, estimated at 0.43 hours. For Summer 2025, the projected probability of experiencing a generation forced outage exceeding 350 MW stands at 21.5%. This number represents an approximation of the likelihood, during any given hour of the summer period, of encountering a generation forced outage surpassing the 350 MW threshold.
MRO-SPP	2024 NERC *LTRA* with Probabilistic Assessment (ProbA)	With the current SPP fleet, the ProbA base case Year 2 produced no LOLE.
NPCC	NPCC conducted an all-hour probabilistic assessment that consisted of a base case and several more severe scenarios examining low resources, reduced imports, and higher loads. The highest peak load scenario has a 7% probability of occurring.	NPCC Regional Entity assesses that there will be an adequate supply of electricity across the Regional Entity this summer. Necessary strategies and procedures are in place to deal with operational challenges and emergencies as they may develop. Preliminary results of the probabilistic analysis by assessment area are below. NPCC anticipates releasing the assessment in May.
NPCC-Maritimes		NPCC's assessment results indicate that Maritimes expects minimal LOLE, LOLH, and EUE over the May–September period, with the highest risk occurring in July and August. The assessment projected LOLE at less than 0.089 days per period, LOLH at less than 0.4 hours per period, and EUE at less than 16.5 MWh per period under the reduced resources and highest peak demand scenario.
NPCC-New England		Based on NPCC's assessment, cumulative LOLE (<0.031 days/period), LOLH (<0.120 hours/period), and EUE (<94 MWh/period) risks were estimated over the summer May to September period for the expected load with expected resources scenario. The highest peak load level conditions with reduced resources scenario resulted in an estimated cumulative LOLE risk (4.369 days/period), with associated LOLH (19.554 hours/period) and EUE (19,847 MWh/period) with the highest risk occurring in June, with some in July and August.
NPCC-New York		Negligible cumulative LOLE (<0.018 days/period), LOLH (<0.054 hours/period), and EUE (33 MWh/period) risks were estimated over the summer May–September period for the expected load with expected resources for the summer. For highest peak load level with low likelihood, reduced resource conditions resulted in an estimated cumulative LOLE risk (1.7 days/period), with associated LOLH (6.5 hours/period) and EUE (4,860 MWh/period) with the highest risk occurring in July and August.

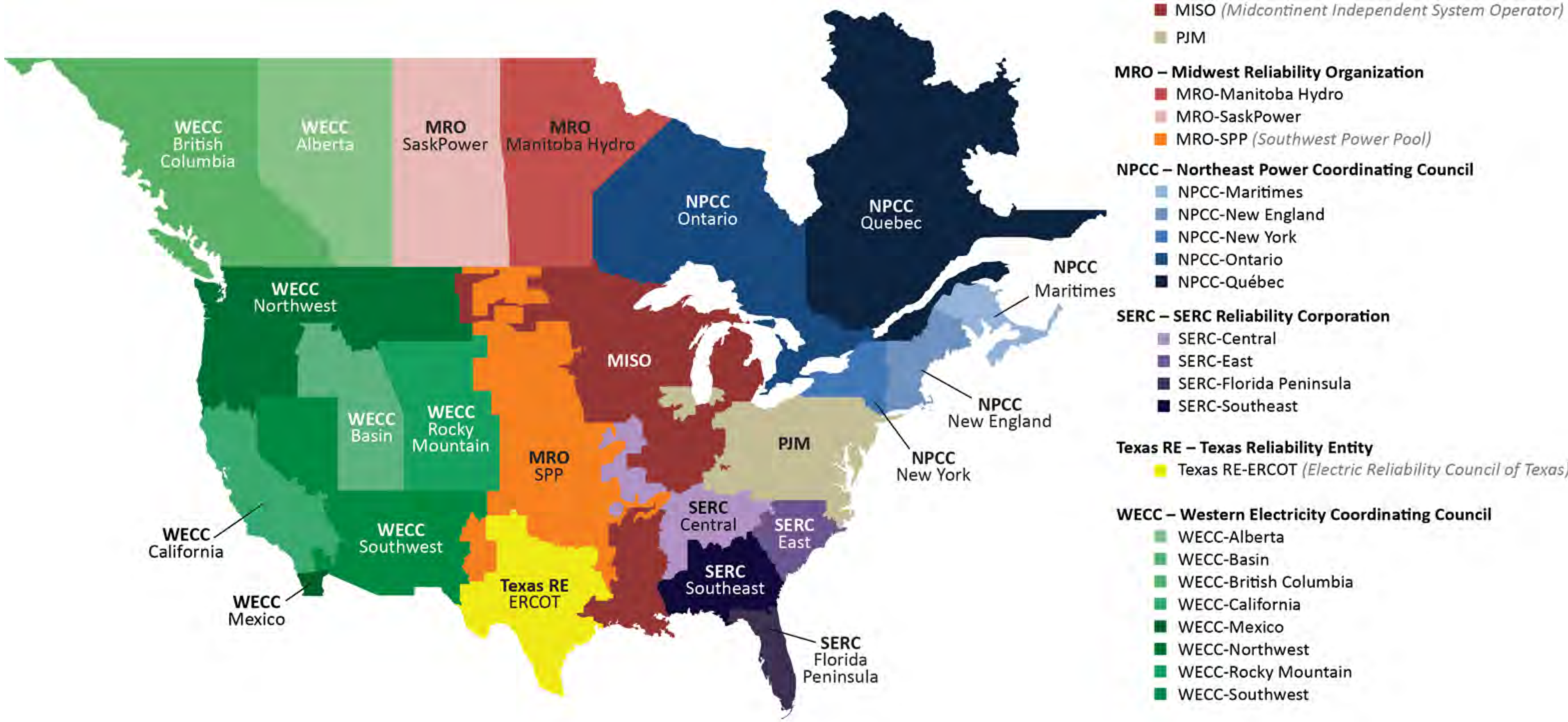
[11] PY 2025–2026 LOLE Study Report

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
NPCC-Ontario		NPCC's preliminary result of this assessment indicates that the low-likelihood resource case, highest peak load level conditions resulted in a negligible cumulative LOLE (0.081 days/period), with associated cumulative LOLH (0.212 hours/period) and EUE (145.4 MWh/period) with the highest risks occurring predominantly in July, with some in August. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the May–September summer period for the other scenarios modeled.
NPCC-Québec		The Québec assessment area is not expected to require use of their operating procedures designed to mitigate resource shortages during Summer 2025. Québec did not demonstrate any measurable amounts of cumulative LOLE, LOLH, or EUE risks over the May–September summer period for all the scenarios modeled since the system is winter peaking.
PJM	2023 PJM Reserve Requirement Study (RRS)	PJM is expecting a low risk of resources falling below required operating reserves during Summer 2025. PJM is forecasting around 27% installed reserves (including expected committed demand resources), which is above the target installed reserve margin of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion. The Reserve Requirement Study analyzed a wide range of load scenarios (low, regular, and extreme) as well as multiple scenarios for system-wide unavailable capacity due to forced outages, maintenance outages, and ambient derations. Due to the rather low penetration of limited and variable resources in PJM relative to PJM's peak load, the hour with the most loss-of-load risk remains the hour with the highest forecasted demand.
SERC-Central **SERC-East** **SERC-Florida Peninsula** **SERC-Southeast**	2024 NERC *LTRA* with ProbA. For the ProbA, SERC evaluates 8,760 hourly load and 1,900 sequential Monte Carlo simulations. The results are a probability weighted average of cases, including 38 historic weather-years that are applied to load forecasts for years 2026 and 2028. The model applies a range of economic load forecast errors from -4% to 4% and other noted assumptions.	The 2024 ProbA indicates some resource adequacy risk to SERC with the results for the year 2028 showing slightly higher risk than the year 2026. For the entire SERC footprint, Summer 2026 shows a low risk in summer afternoons into evenings, and for Summer 2028, that risk is still low but extends from summer evenings later into summer nights.
Texas RE-ERCOT	ERCOT probabilistic assessment using the Probabilistic Reserve Risk Model	The simulation indicates some risk of having to declare an EEA for hours ending 20 and 21 for the peak load day in August. These two hours have the highest EEA risk (reflecting corresponding high net load conditions) with probabilities of declaring an EEA 3.05% and 1.54%, respectively. This is categorized by ERCOT as "Low risk" per its criteria of hourly EEA probability that is equal to or less than 10%. For the *2024 SRA*, ERCOT reported EEA declaration probabilities for hours ending 20 and 21 of 18.4% and 9.2%, respectively. The large decrease in EEA probabilities is due to the addition of 7,414 MW of BESS capacity.
WECC	2024 Western Assessment on Resource Adequacy employs a probabilistic energy, area-wide assessment, using Multi Area Variable Resource Integration Convolution (MAVRIC) model	

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
WECC-AB		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. All resource margins have increased since last summer with the addition of new capacity, including almost 2,700 MW of new natural gas capacity, 1,200 MW of new wind (+27%), 200 MW of new solar (+13%), and 54 MW of new energy storage systems (+27.5%) on-line. The peak hour has moved earlier, to 3:00 p.m. from 4:00 p.m., still in late July.
WECC-Basin		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The reserve margins are not anticipated to fall below the reference margin (14%) for the upcoming summer—existing-certain is forecast at 19% with anticipated and prospective at 24%. The area is expected to peak in early July around 3:00 p.m.
WECC-BC		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The reserve margins are not anticipated to fall below the reference margin for the upcoming summer. All reserve margins have increased since 2024 due to increased capacity and energy availability. The peak hour for summer is forecast for early August around 4 p.m.
WECC-CA		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The reserve margins are not anticipated to fall below the reference margin for the upcoming summer. Reserve margins have increased since last summer with the increased existing-certain and Tier 1 planned capacity more than offsetting the decrease in available demand response.
WECC-Mex		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The peak hour is expected to occur in early August around 4:00 p.m. The reserve margins (14%) are not anticipated to fall below the reference margin (10%) for the upcoming summer. An extreme summer peak load is anticipated to be 4,067 MW. Under extreme conditions, typical forced outages are expected to be 472 MW and derates for thermal generation resources are expected to be 330 MW, requiring imports from neighboring areas. The expected operating reserve requirement on peak is 226 MW.
WECC-RM		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The peak hour is expected to occur in late July around 4:00 p.m. Summer 2025 reserve margins (existing-certain 25%, and anticipated and prospective 26%) are not anticipated to fall below the reference margin (17%). An extreme summer peak load may be around 15 GW, and the area has 17.3 GW of existing-certain capacity plus 104 MW of planned new resources. Typical forced outages could be 1,044 MW and derates under extreme conditions of 1,561 MW for thermal and 990 MW for wind. The expected operating reserve requirement on peak is 846 MW.
WECC-NW		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. Summer 2025 peak hour is expected to occur in early July around 5:00 p.m. Reserve margins (existing-certain 29% and anticipated and prospective 32%) are not anticipated to fall below the reference margin (23%). An extreme summer peak load may be around 32,740 MW. Typical forced outages are forecast to be 777 MW with derates for thermal under extreme conditions to be 1,584 MW and 2,649 MW for wind. The expected operating reserve requirement on peak is 1,750 MW.
WECC-SW		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The peak hour is expected to occur in early July around 5:00 p.m. The existing-certain 17% reserve margin does not fall below the reference margin (13%) for the upcoming summer. The anticipated and prospective reserve margin rises to 22%. An extreme summer peak load could approach 40 GW during the riskiest hour, while the region is anticipated to have 40.3 GW of existing-certain energy available and an additional 2 GW of Tier 1 planned resources. Typical forced outages are estimated near 3 GW, and derates for thermal under extreme conditions can shave another 3 GW from available energy. The expected operating reserve requirement is 2,119 MW.

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. Guidelines and definitions are in the **Data Concepts and Assumptions** table. On-peak reserve margin bar charts show the Anticipated Reserve Margin compared to a Reference Margin Level that is established for the areas to meet resource adequacy criteria. Prospective Reserve Margins can give an indication of additional on-peak capacity but are not used for assessing adequacy. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left **blue** column shows anticipated resources (from the **Demand and Resource Tables**), and the **orange** column at the right shows the two demand scenarios of the normal peak net internal demand (from the **Demand and Resource Tables**) and the extreme summer peak demand determined by the assessment area. The middle **red** or **green** bars show adjustments that are applied cumulatively to the anticipated resources. Adjustments may include reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools (if any) that are available during scarcity conditions but have not been accounted for in the *SRA* reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios. In addition, results from a probability-based resource adequacy assessment are shown in the Highlights section of each dashboard. Methods varied by assessment area and provided further insights into the risk conditions forecasted for the summer period.



MISO

MISO is a not-for profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy, reliability, and operating reserve markets that consist of 36 local BA and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

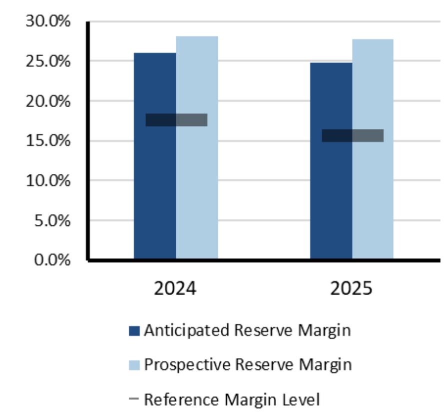
Highlights

- Demand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output.
- The performance of wind and solar generators during periods of high electricity demand is a key factor in determining whether system operators need to employ operating mitigations, such as maximum generation declarations and energy emergencies; MISO has over 31,000 MW of installed wind capacity and 18,245 MW of installed solar capacity; however, the historically based on-peak capacity contribution is 5,616 MW and 9,123 MW, respectively.
- Since last summer, over 1,400 MW of thermal generating capacity has been retired in MISO, and the new generation that has been added is predominantly solar (8,080 MW nameplate/4,140 MW on-peak).
- MISO's most recent energy assessment reveals that the period of highest energy shortfall risk has shifted from July to August.

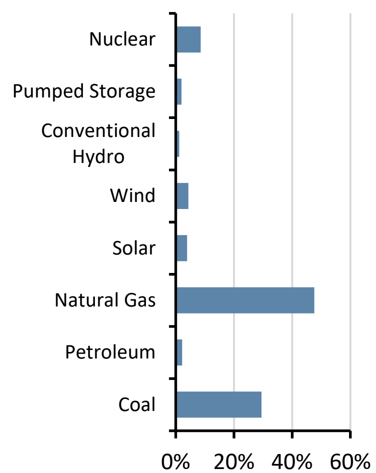
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and extreme generator outage conditions could result in the need to employ operating mitigations (e.g., load-modifying resources and energy transfers from neighboring systems) and EEAs. Emergency declarations that can only be called upon when available generation is at maximum capability are necessary to access load-modifying resources (demand response) when operating reserve shortfalls are projected.

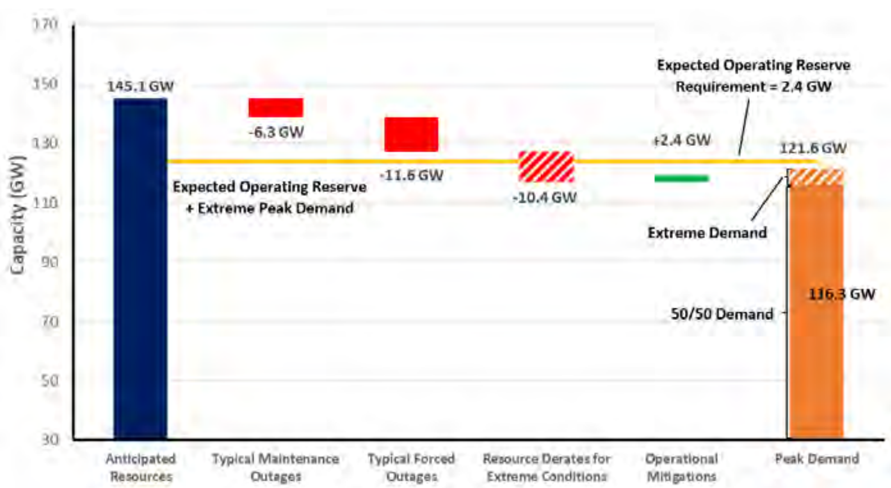
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Maintenance Outages: Rolling five-year summer average of maintenance and planned outages

Forced Outages: Five-year average of all outages that were not planned

Extreme Derates: Maximum historical generation outages

Operational Mitigations: A total of 2.4 GW capacity resources available during extreme operating conditions

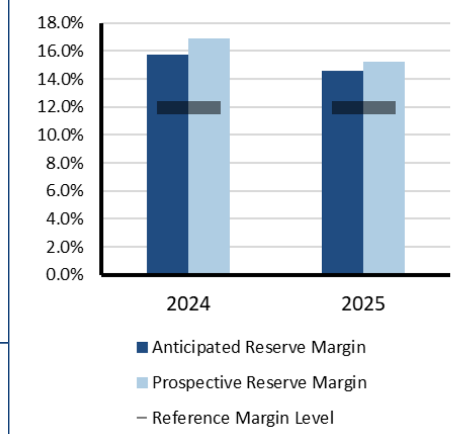
MRO-Manitoba Hydro

Manitoba Hydro is a provincial Crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro is a leader in providing renewable energy and clean-burning natural gas. Manitoba Hydro provides electricity to approximately 608,500 electric customers in Manitoba and natural gas to approximately 293,000 customers in southern Manitoba. Its service area is the province of Manitoba, which is 251,000 square miles. Manitoba Hydro is winter peaking. Manitoba Hydro is its own Planning Coordinator (PC) and BA. Manitoba Hydro is a coordinating member of MISO, which is the RC for Manitoba Hydro.

Highlights

- Manitoba Hydro is not anticipating any operational challenges and/or emerging reliability issues in its assessment area for Summer 2025; the Anticipated Reserve Margin for Summer 2025 exceeds the 12% Reference Margin Level.
- While Manitoba Hydro experienced demand growth in the past year, the growth is less than the recent reduction in firm export contracts.
- Manitoba Hydro water supply conditions are below average but improved from this time last year, and above-average winter snowfall will favorably impact spring runoff.
- Manitoba Hydro expects to reliably supply its internal demand and export obligations even if extreme drought develops throughout the year.

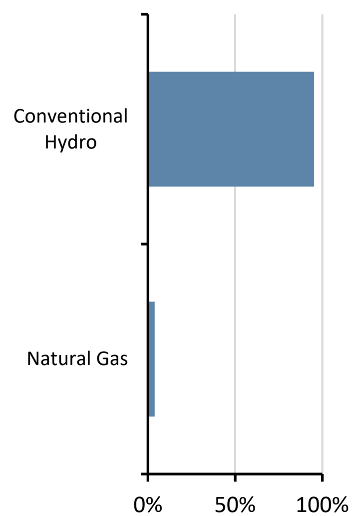
On-Peak Reserve Margin



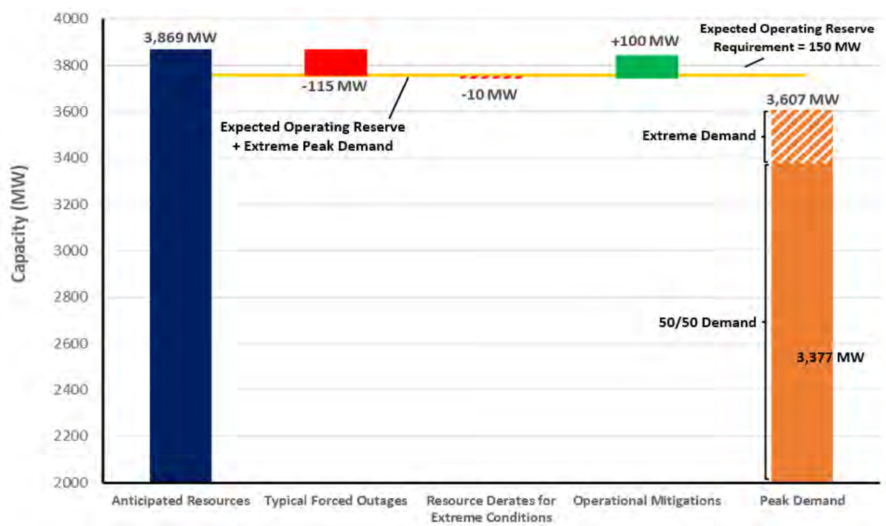
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: (50/50) Demand with allowance for extreme demand based on extreme summer weather scenario of 35.4 C (96 F)

Forced Outages: Typical forced outages

Extreme Derates: Summer wind capacity accreditation of 18.1% of nameplate rating based on MISO seasonal analysis

Normal hydro generation expected for this summer.

Operational Mitigations: Utilize Curtailable Rate Program to manage peak demand; utilize operating reserve if additional measures required

MRO-SaskPower

MRO-SaskPower is an assessment area in the Saskatchewan province of Canada. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and a population of approximately 1.1 million. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the PC and RC for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial Crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan BES and its Interconnections.

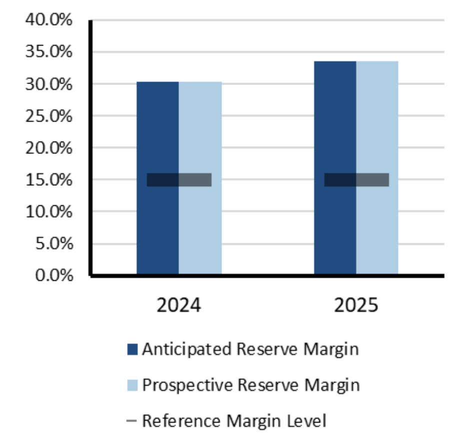
Highlights

- Although Saskatchewan is mainly a winter-peaking region, summer can also bring high electricity demand due to extreme heat.
- Each year, SaskPower works with Manitoba Hydro on a joint summer operating study with input from the Western Area Power Administration and Basin Electric to develop operational guidelines to address any potential challenges.
- The expected number of hours with an operating reserve shortfall between June and September is about 0.65 hours, assuming maximum available imports. The risk of shortfall increases if major unplanned generator outages coincide with scheduled maintenance during peak demand months (June to September). For Summer 2025, the projected probability of experiencing a generation forced outage exceeding 350 MW stands at 21.5%. This number represents an approximation of the likelihood of encountering a generation forced outage surpassing the 350 MW threshold during any given hour of the summer period.
- If extreme heat coincides with significant generation outages, SaskPower will act by activating demand-response programs, arranging short-term power imports from neighboring utilities, and, if necessary, implementing temporary load interruptions to maintain grid stability.

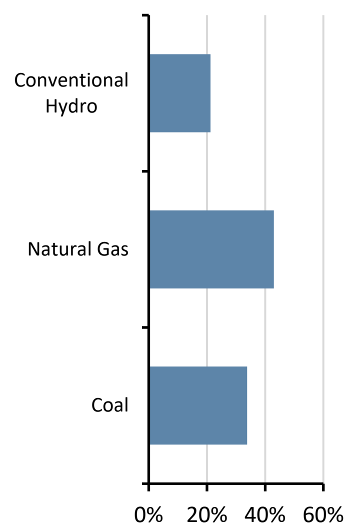
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand and outage conditions. Above-normal summer peak load and outage conditions are likely to result in the need to employ operating mitigations (e.g., demand response and transfers) and EEAs.

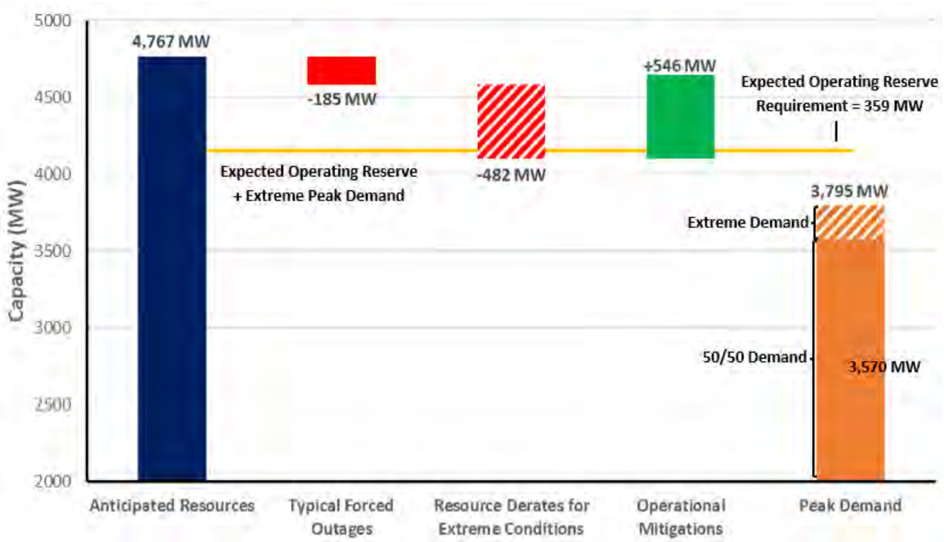
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and above-normal scenario based on peak demand with lighting and all consumer loads

Forced Outages: Estimated by using SaskPower forced outage model

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: Estimated non-firm imports and standby generators on 2–7-day notice

MRO-SPP

SPP PC’s footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the PC footprint, which touches parts of the MRO Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.

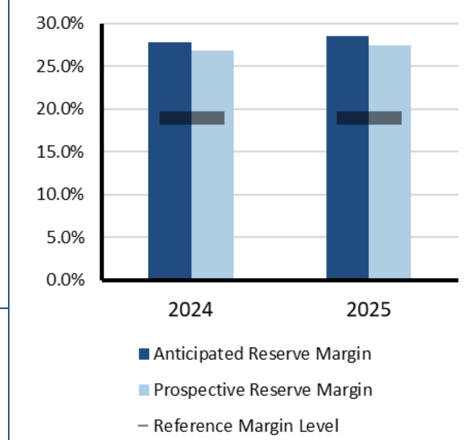
Highlights

- SPP projects a low likelihood of any emerging reliability issues impacting the area for the 2025 Summer season.
- Generation availability is not expected to be impacted by fuel shortages or river conditions this summer.
- BA generation capacity deficiency risks remain depending on wind generation output levels and unanticipated generation outages in combination with high load periods.
- Using the current operational processes and procedures, SPP will continue to assess the resource needs for the 2025 Summer season and will adjust generation and energy supply portfolios as needed to ensure that real-time energy sufficiency is maintained throughout the summer.

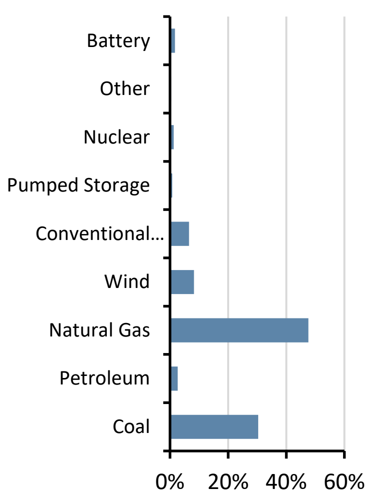
Risk Scenario Summary

Expected resources are sufficient to meet operating reserve requirements under normal peak-demand and outage scenarios. Above-normal summer peak load, low wind conditions, and higher-than-normal forced outages could result in the need for operating mitigations (e.g., demand response and transfers from neighboring systems) and EEAs.

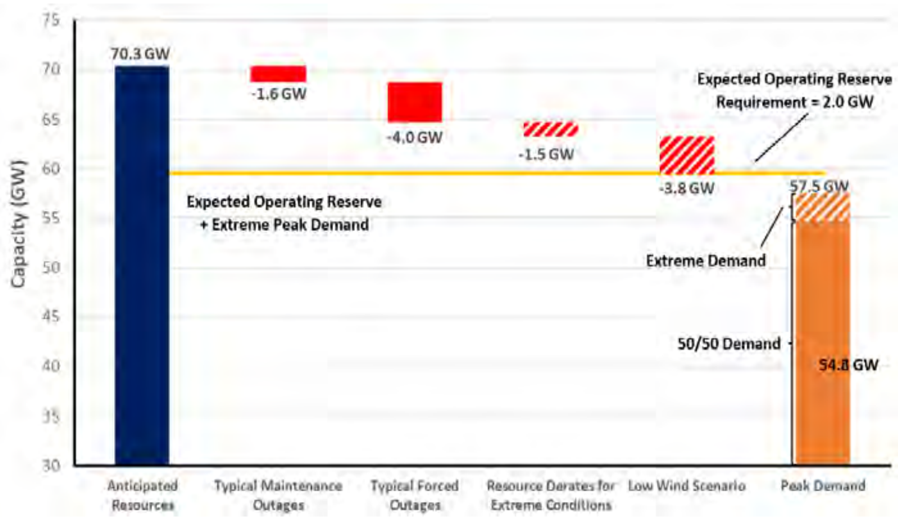
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand is a 5% increase from net internal demand

Maintenance and Forced Outages: Represent five-year historical averages; calculated from SPP’s generation assessment process

Extreme Derates: Additional unavailable capacity from operational data at high-demand periods

Low Wind Scenario: Derates reflecting a low-wind day in the summer

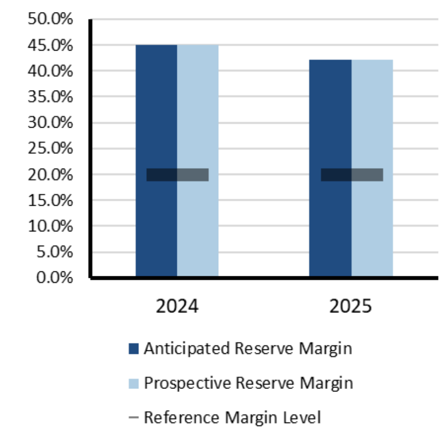
NPCC-Maritimes

The Maritimes assessment area is a winter-peaking NPCC area that contains two BAs. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, and Prince Edward Island and the northern portion of Maine, which is radially connected to the New Brunswick power system. The area covers 58,000 square miles with a total population of 1.9 million.

Highlights

- As Maritimes is a winter-peaking system, no issues are expected for the upcoming summer assessment period with sufficient firm capacity to meet forecast peak demand. If an event were to occur, emergency operations and planning procedures are in place.
- Probabilistic analysis performed by NPCC for the NPCC *Summer Reliability Assessment* found negligible LOLH and EUE for the expected load and resource levels this summer. A scenario with an extreme high load shape produced minimal amounts of cumulative LOLE (<0.089 days/period), LOLH (<0.4 hours/period), or EUE (< 16.5 MWh/period) over the May–September summer period with the highest risk occurring in July and August.
- Dual-fueled units will have sufficient supplies of heavy fuel oil (HFO) on site to sustain operations in the event of natural gas supply interruptions.

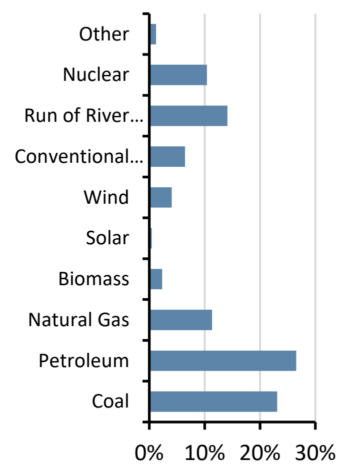
On-Peak Reserve Margin



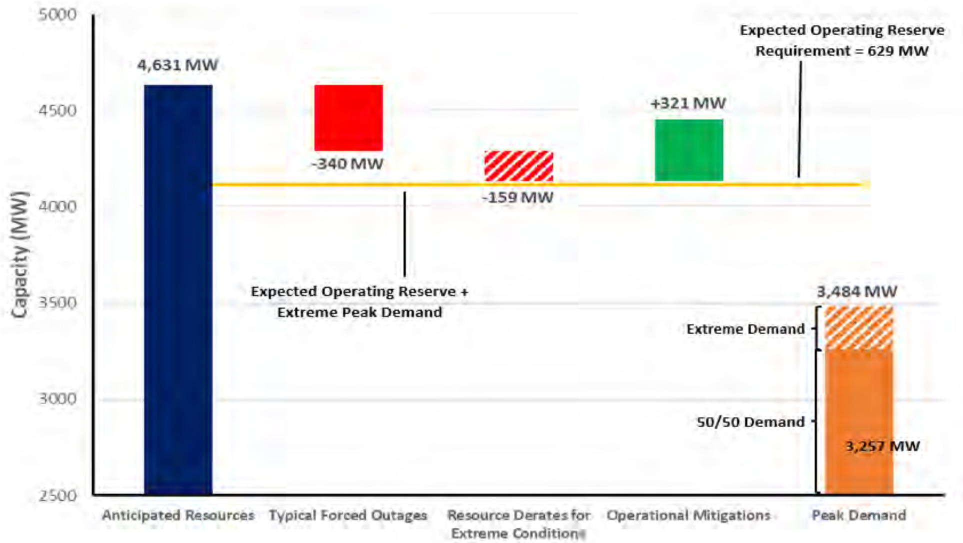
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load or extreme outage conditions could necessitate operating mitigations (e.g., demand response and non-firm transfers) and EEAs.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (above 90/10) extreme demand forecast

Forced Outages: Based on historical operating experience

Extreme Derates: A low-likelihood scenario resulting in an additional 50% derate in the remaining capacity of both natural gas and wind resources under extreme conditions

Operational Mitigations: Imports anticipated from neighbors during emergencies, (e.g. New Brunswick Power System Operator can increase import capability from 200 MW to 550 MW under emergency operations for up to 30 minutes)

NPCC-New England

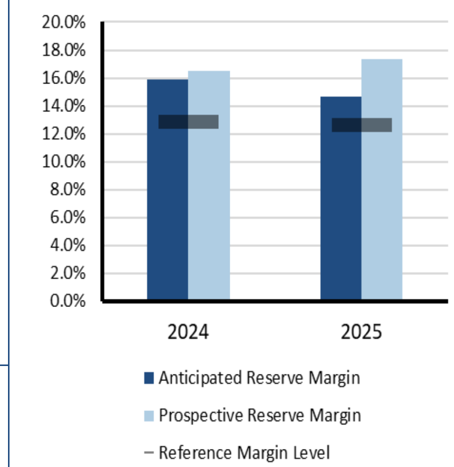
NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont that is served by ISO New England (ISO-NE) Inc. ISO-NE is a regional transmission organization that is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS.

The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

Highlights

- ISO-NE forecasts adequate transmission capability and manageable capacity margins to meet the expected peak demand.
- Probabilistic analysis performed by NPCC for the NPCC *Summer Reliability Assessment* identified small amounts of cumulative LOLE, LOLH, and EUE for the expected load with anticipated resources for the summer. A reduced resources and highest peak load level scenario resulted in an estimated cumulative LOLE risk of 4.369 days/period, with associated LOLH (19.554 hours/period) and EUE (19,847 MWh/period). The highest risk occurs in June, with some risk in July and August.
- The NPCC 2025 *Summer Reliability Assessment* will be approved on or about May 12, 2025, and posted on NPCC's website.

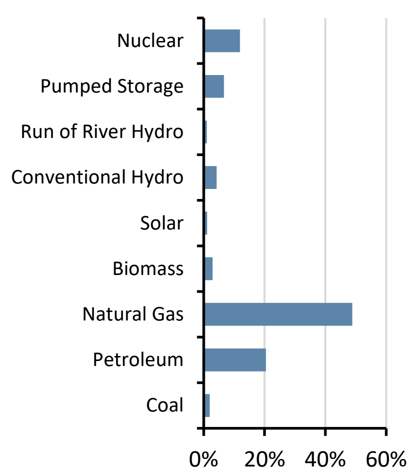
On-Peak Reserve Margin



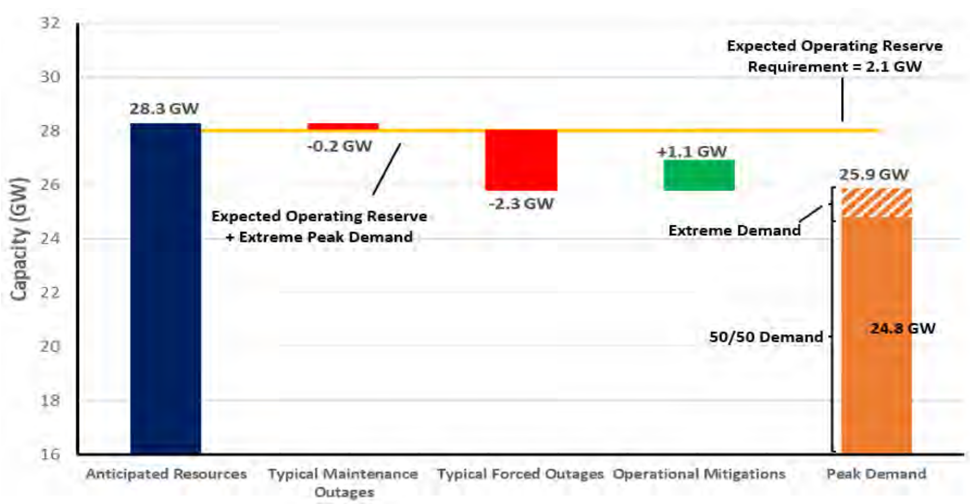
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand and outage scenarios. Additional non-firm transfers are likely to be needed and available from neighbors. More severe conditions (e.g., above-normal summer peak load and outage conditions) could result in an EEA.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Peak net internal demand (50/50) and (90/10) extreme demand forecast

Maintenance Outages: Based on historical weekly averages

Typical Forced Outages: Based on seasonal capacity of each resource as determined by ISO-NE

Operational Mitigations: Based on load and capacity relief assumed available from invocation of ISO-NE operating procedures

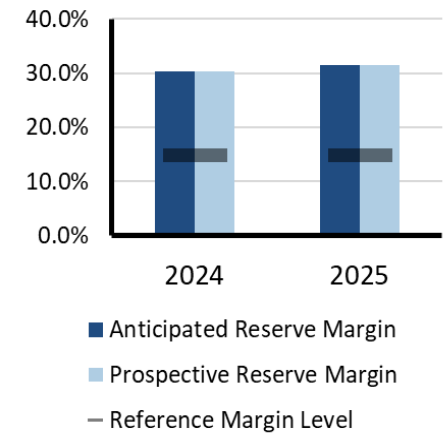
NPCC-New York

NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only BA within the state of New York. The BPS in New York encompasses over 11,000 miles of transmission lines and 760 power generation units and serves 20.2 million customers. For this *SRA*, the established Reference Margin Level is 15%. Wind, grid-connected solar PV, and run-of-river totals were derated for this calculation. However, New York requires load-serving entities to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council. The council approved the 2025–2026 IRM at 24.4%.

Highlights

- NYISO is not anticipating any operational issues for the upcoming summer operating period. Adequate reserve margins are anticipated.
- Probabilistic analysis performed by NPCC for the NPCC *Summer Reliability Assessment* found that use of New York's established operating procedures are sufficient to maintain a balance between electricity supply and expected 50/50 demand if needed to mitigate resource shortages during Summer 2025. Negligible cumulative LOLE (<0.018 days/period), LOLH (<0.054 hours/period), and EUE (33 MWh/period) risks were estimated over the summer May to September period for the expected load with expected resources for the summer. The highest peak load level with low likelihood reduced resource conditions resulted in an estimated cumulative LOLE risk (1.7 days/period), with associated LOLH (6.5 hours/period) and EUE (4860 MWh/period) with the highest risk occurring in July and August.
- The NPCC 2025 *Summer Reliability Assessment* will be approved on or about May 12, 2025, and posted on NPCC's website.

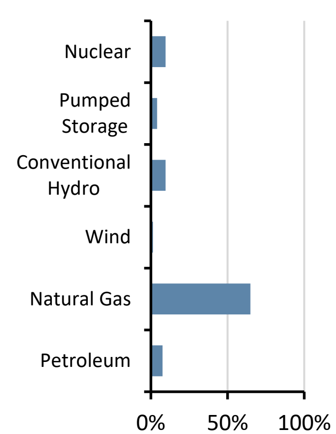
On-Peak Reserve Margin



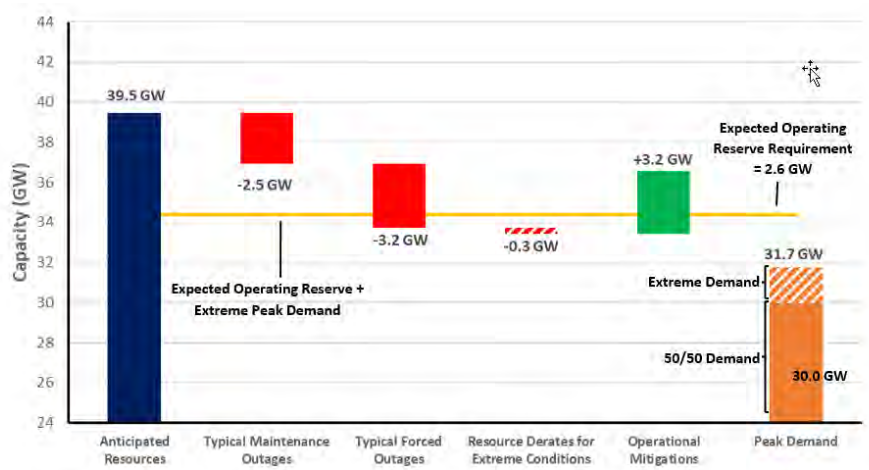
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios. Operating mitigations (e.g., demand response and transfers) may be needed to meet above-normal summer peak load and outage conditions.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) extreme demand forecast

Maintenance Outages: Based on historical performance and the new NYISO capacity accreditation process

Forced Outages: Based on historical five-year averages

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 3.2 GW based on operational/emergency procedures in area emergency operations manual

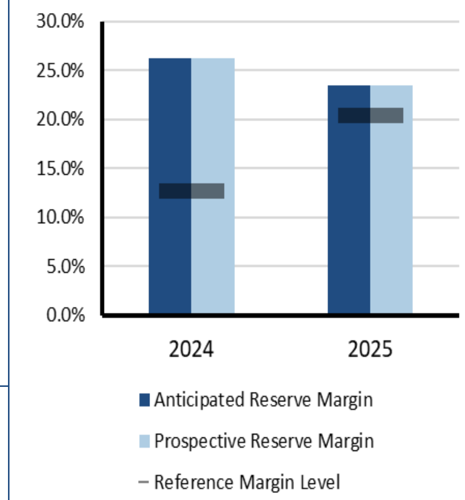
NPCC-Ontario

NPCC-Ontario is an assessment area in the Ontario province of Canada. The Independent Electricity System Operator (IESO) is the BA for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of m16 million. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

Highlights

- Overall, Ontario is operating within a period where generation and transmission outages are more challenging to accommodate. The IESO is prepared and expects to have adequate supply for Summer 2025.
- The IESO has been actively coordinating and planning with market participants to maintain reliability.
- This season, the grid will benefit from increased capacity secured through the capacity auction and more planned projects, including new storage, coming into service.
- The IESO is working throughout 2025 to better integrate storage solutions into the electricity markets.
- Starting with this seasonal assessment, demand is forecasted by using probabilistic weather modeling, comparable to the methodology used in the IESO 18-month *Reliability Outlook* as opposed to the previous approach of using weather scenarios."

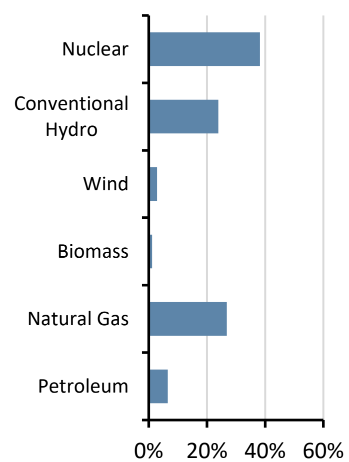
On-Peak Reserve Margin



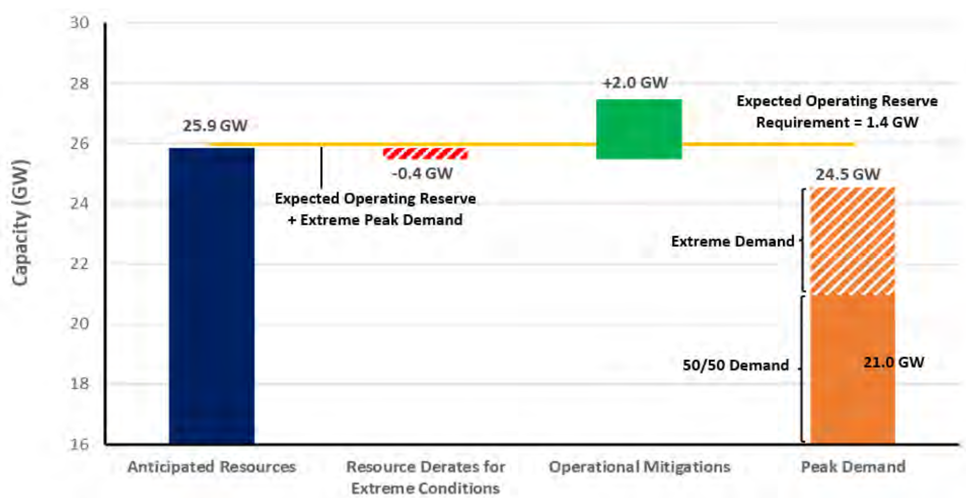
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50 forecast) and highest weather-adjusted daily demand based on 31 years of demand history, and extreme weather represents a 97/3 distribution of probabilistically modelled data

Extreme Derates: Derived from weather-adjusted temperature rating of thermal units and adjustments to expected hydro production for low water conditions

Operational Mitigations: The operational procedures used to mitigate extreme conditions total approximately 2,010 MW for the On-Peak Risk Scenario, consisting of imports, public appeals, and voltage reductions. Public appeals and voltage reductions were not included in the 2024 On-Peak Risk Scenario.

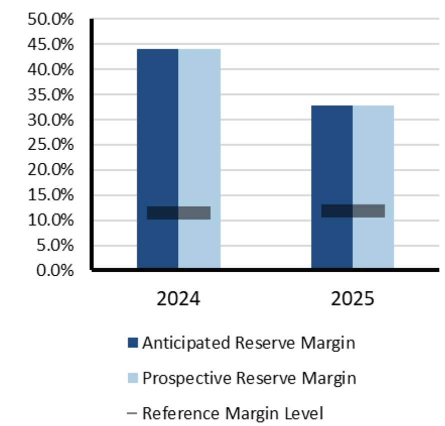
NPCC-Québec

The Québec assessment area (province of Québec) is a winter-peaking NPCC area that covers 595,391 square miles with a population of 8 million. Québec is one of the four Interconnections in North America; it has ties to Ontario, New York, New England, and the Maritimes consisting of either high-voltage direct current ties, radial generation, or load to and from neighboring systems.

Highlights

- The Québec area forecasted summer peak demand is 23,283 MW during the week beginning August 3, 2025, with a forecasted net margin of 5,698 MW (24.5%).
- Resource adequacy issues are not expected this summer.
- The Québec area expects to be able to assist other areas.
- Modeling was made more precise this year with the inclusion of summer demand-response programs, dispatchable demand-side management (DSM), and weekly modeling of the reserve requirements and bottled generation.

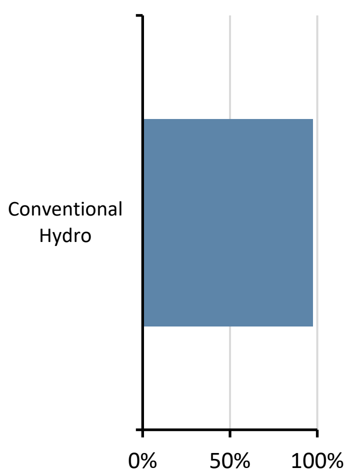
On-Peak Reserve Margin



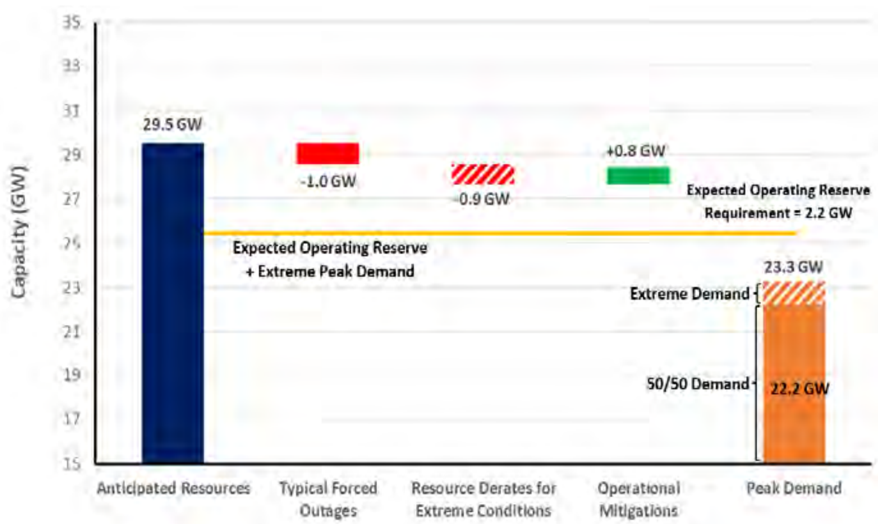
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenario: Net internal demand (50/50) and (90/10) demand forecast

Operational mitigations: An operational procedure used to mitigate extreme conditions and not already included in margins is the depletion of some operating reserves by 750 MW.

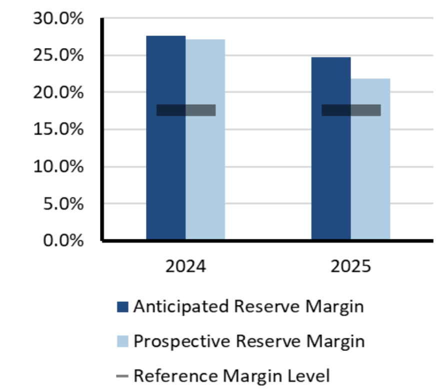
PJM

PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM serves 65 million customers and covers 369,089 square miles. PJM is a BA, PC, Transmission Planner, Resource Planner, Interchange Authority, TOP, Transmission Service Provider, and RC.

Highlights

- PJM is forecasting 27% installed reserves (including expected committed demand response), which is above the target installed reserve margin of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion.
- During extreme high temperatures that can cause record demand, PJM anticipates the need for demand-response resources to help reduce load at times this summer.

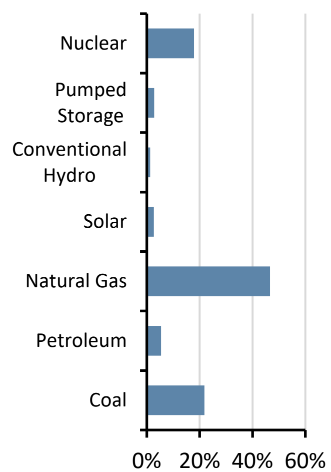
On-Peak Reserve Margin



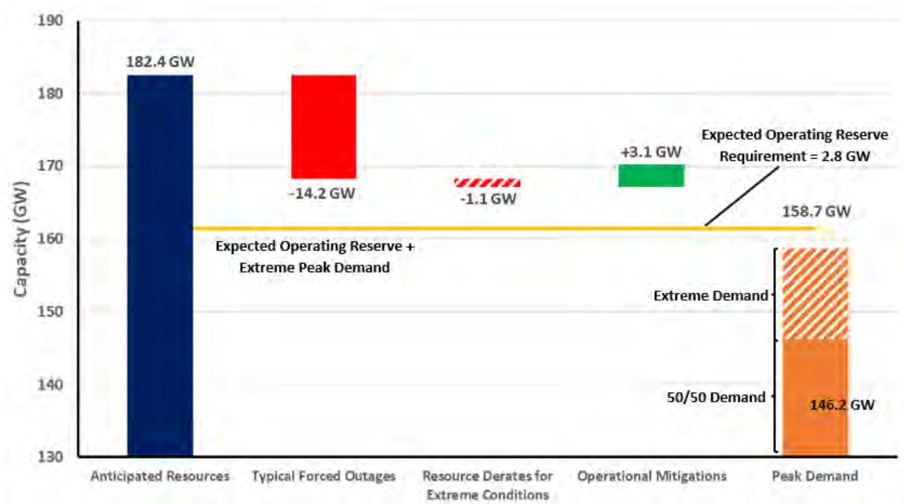
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Based on historical data and trending

Extreme Derates: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 3 GW based on operational/emergency procedures

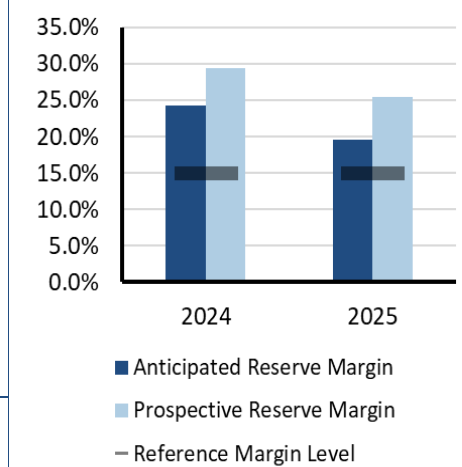
SERC-Central

SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission (FERC)-approved delegation agreements with NERC. SERC-Central is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

- SERC-Central saw a sizable increase in its reserves last summer, but coal retirements this summer will result in SERC-Central having lower reserves.
- SERC-Central's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- The probabilistic analysis metrics indicate adequate energy resources for the area.
- Entities perform resource studies to ensure resource adequacy to meet the summer peak demand and maintain the reliability of the system.
- Members of SERC-Central actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.

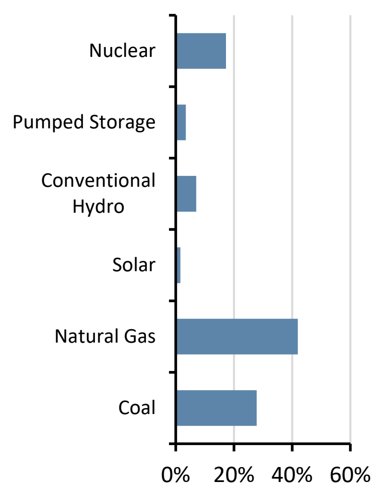
On-Peak Reserve Margin



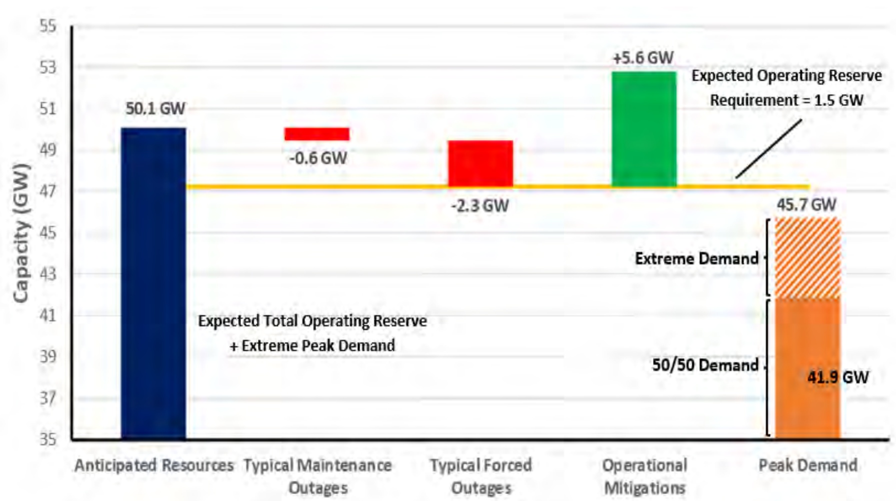
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios. More severe conditions (e.g., above-normal summer peak load and outage conditions) result in the need for additional non-firm transfers available from neighbors.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: 5.6 GW based on operational/emergency procedures

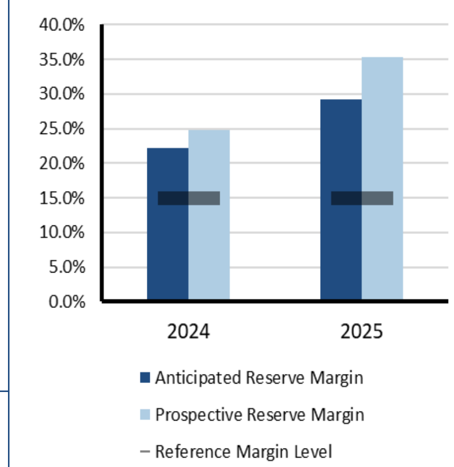
SERC-East

SERC-East is an assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina. Historically a summer-peaking area, SERC-East is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

- SERC-East's reserves are largely unchanged compared to the reference margin as compared to last summer's assessment.
- SERC-East's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- While the last probabilistic analysis indicated that SERC-East could face potential unserved energy in summer, the 2026 and 2028 probabilistic analysis found the SERC-East unserved energy risk has shifted to winter mornings.
- Members of SERC-East actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.

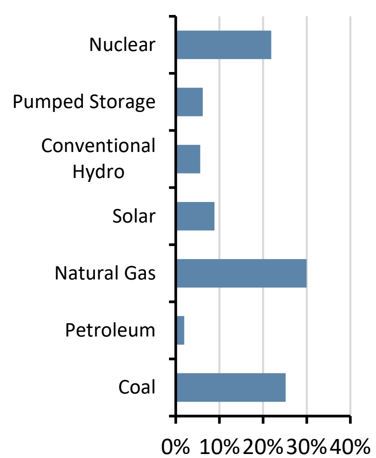
On-Peak Reserve Margin



Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario

Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 45 MW based on operational/emergency procedures

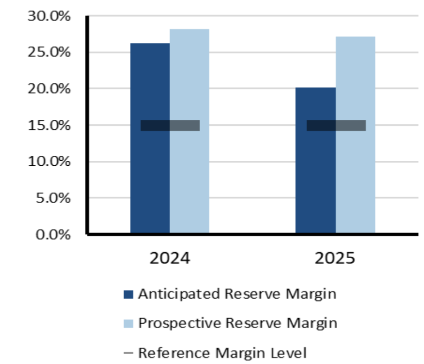
SERC-Florida Peninsula

SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

- SERC Florida-Peninsula's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- The probabilistic analysis metrics indicate adequate energy resources for the subregion during the summer.
- Members of SERC-Florida Peninsula actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.
- Entities have not identified any emerging reliability issues or operational concerns for the upcoming summer season.

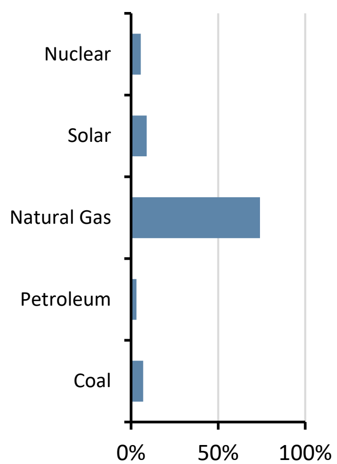
On-Peak Reserve Margin



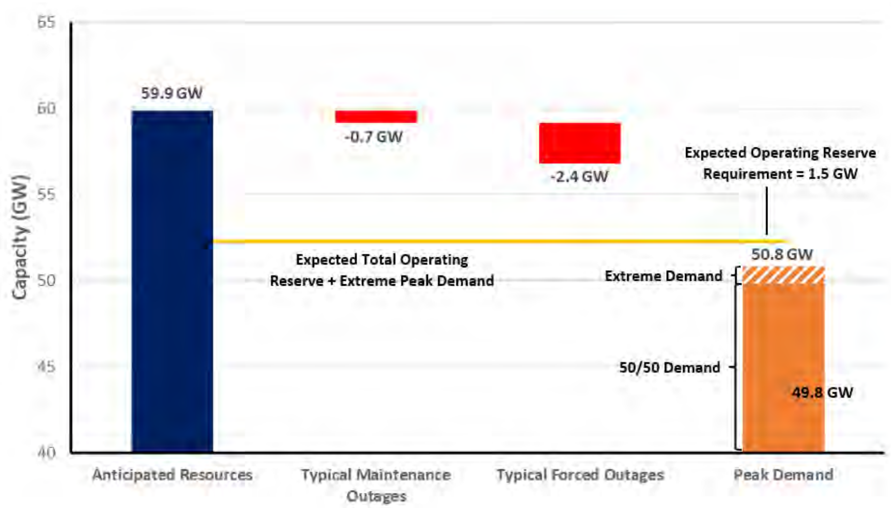
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

SERC-Southeast

SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

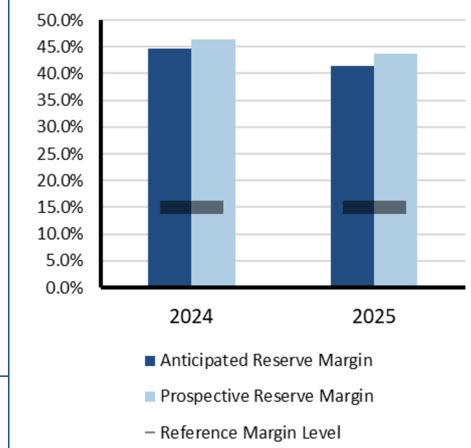
Highlights

- An area within SERC-Southeast notes that natural gas pipeline constraints could impact reliability in summer, but this is not expected to pose a significant summer operational challenge.
- SERC-Southeast's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- The probabilistic analysis metrics indicate adequate energy resources for the subregion.
- Members of SERC-Southeast actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.

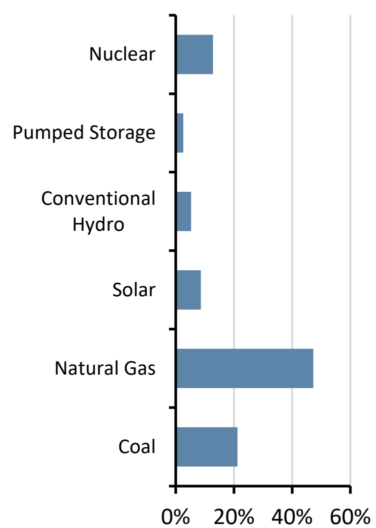
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

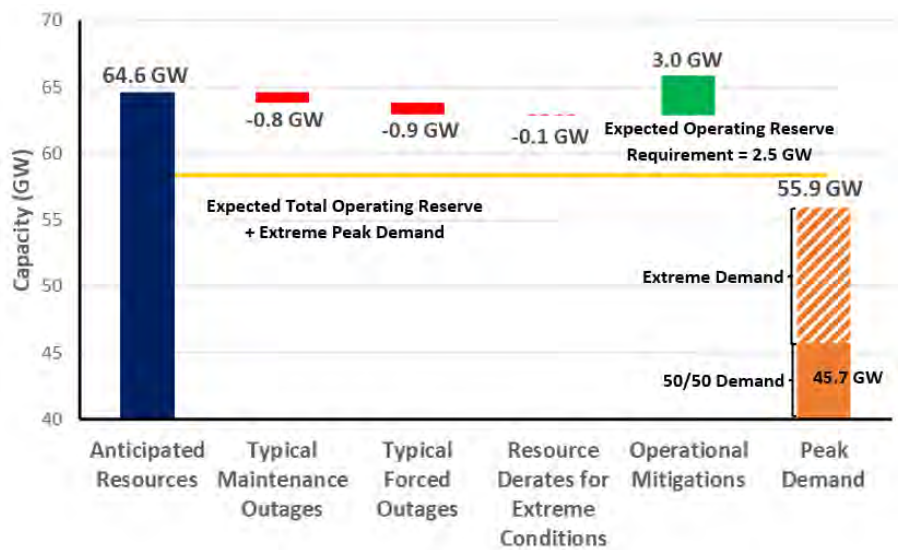
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 3 GW based on operational/emergency procedures

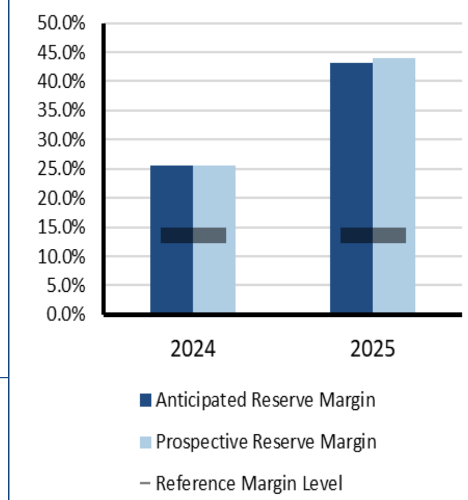
Texas RE-ERCOT

The Electric Reliability Council of Texas (ERCOT) is the independent system operator (ISO) for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is summer-peaking, and the forecasted summer peak load month is August. It covers approximately 200,000 square miles, connects over 52,700 miles of transmission lines, has over 1,100 generation units, and serves more than 26 million customers. Texas RE is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT. On November 3, 2022, the Public Utility Commission of Texas issued an order directing ERCOT to assume the duties and responsibilities of the reliability monitor for the Texas grid.

Highlights

- ERCOT expects to have sufficient operating reserves for the August peak load hour given normal summer system conditions.
- ERCOT's probabilistic risk assessment indicates a low risk of having to declare EEAs during the expected August (and summer) peak load day; the EEA probability for the highest-risk hour—hour ending 9:00 p.m.—is 3.6%. The likelihood of an EEA is down significantly from the 2024 SRA due to almost a doubling of battery energy storage capacity and improved energy availability reflecting new battery storage and operational rules.
- Continued robust growth in both loads and intermittent renewable resources drives a higher risk of emergency conditions in the evening hours when solar generation ramps down and loads remain elevated.
- The South Texas IROL continues to present a risk of ERCOT directing system-wide firm load shedding to remain within IROL limits. This risk has been mitigated by updating transmission line dynamic ratings and switching actions to divert power away from the most limiting transmission circuits. The South Texas transmission limits are expected to be needed at least until the San Antonio South Reliability Project is placed in service, which is anticipated to be in Summer 2027.
- ERCOT will release its own August 2025 Monthly Outlook for Resource Adequacy on June 6.

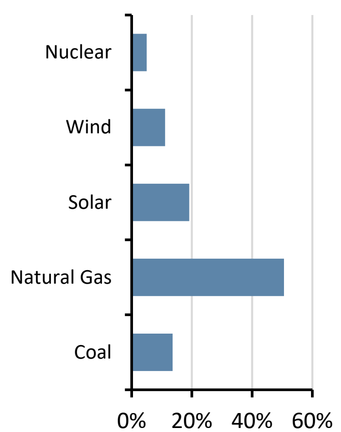
On-Peak Reserve Margin



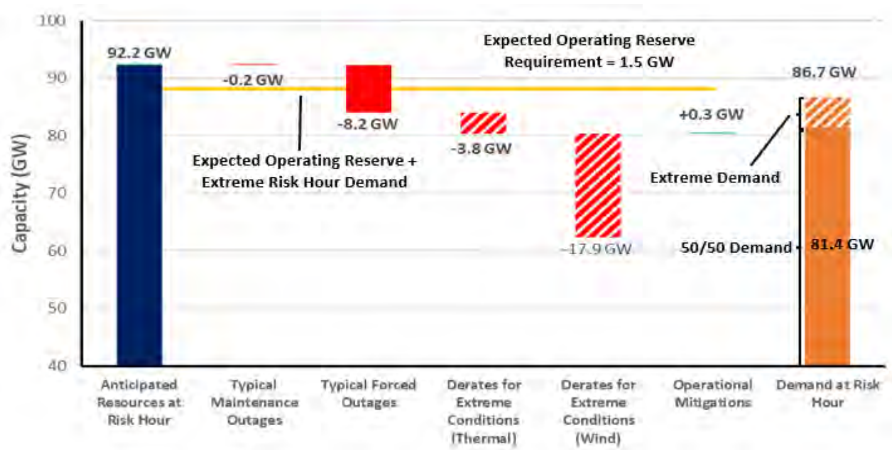
Risk Scenario Summary

Expected resources meet operating reserve requirements for the peak demand hour scenario. However, there is a risk of supply shortages during evening hours (when solar generation ramps down and demand remains high) if there are conventional generation forced outages or extreme low-wind conditions.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario (9:00 p.m. local time)



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at hour ending 9 p.m. local time as solar PV output is diminished and demand remains high

Demand Scenarios: Net internal demand (50/50) and extreme demand (95/5) based on August peak load

Forced Outages: Based on the 95th percentile of historical averages of forced outages for June through September weekdays, hours ending 3:00–8:00 p.m. local time for the last three summer seasons

Extreme Derates: Based on the 90th percentile of thermal forced outages for peak August load day

Low Wind Scenario: Based on the 10th percentile of historical averages of hourly wind for June through September, hours ending 1:00–9:00 p.m. local time

Operational Mitigations: Additional capacity from switchable generation and additional imports

WECC-Alberta

WECC-Alberta is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of Alberta. It has 16,369 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

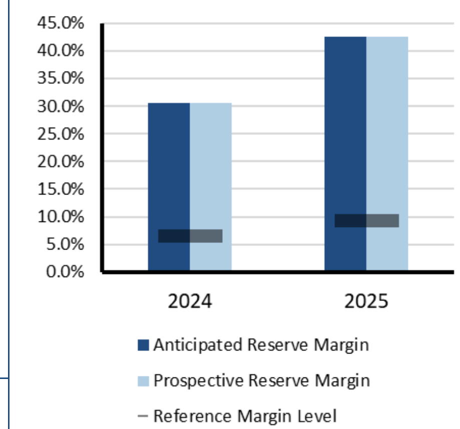
Highlights

- Anticipated and prospective reserve margins are projected to remain above the Reference Margin Level.
- All resource margins have increased by about 50% since last summer with the addition of 23.2% new capacity, including almost 2,700 MW of new natural gas capacity, 1,200 MW of new wind (+27%), 200 MW of new solar (+13%), and 54 MW of new energy storage systems (+27.5%).
- The peak hour has moved earlier, to 3:00 p.m. from 4:00 p.m., still in late July.
- High temperatures, import limitations, and low or declining renewable output during summer evenings can result in grid alerts.
- Wildfires can threaten generating assets and transmission infrastructure requiring invocation of Alberta Electric System Operator (AESO) protocols that include instructing available assets and long lead-time assets to deliver energy up to their maximum capability, calling upon demand response, and maximizing import capability.

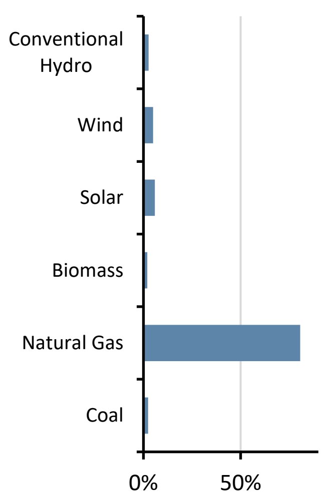
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

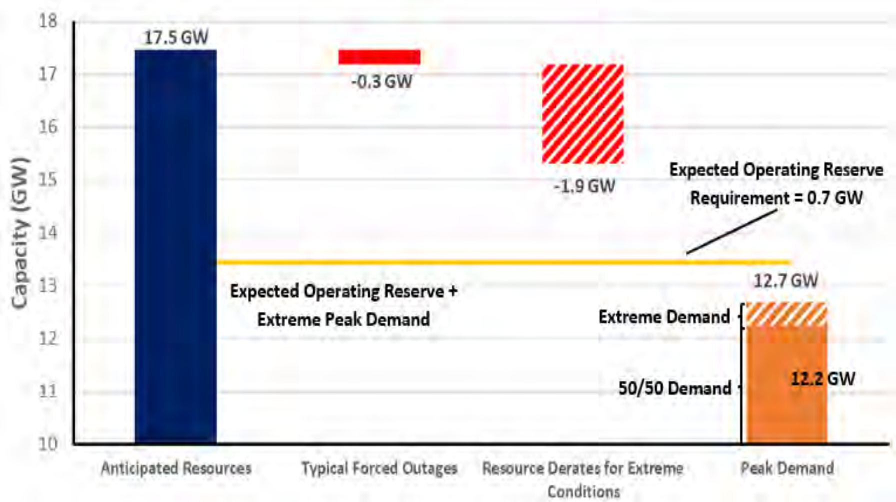
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Typical Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) point of resource performance distribution

WECC-Basin

WECC-Basin is a summer-peaking assessment area in the WECC Regional Entity that includes Utah, southern Idaho, and a portion of western Wyoming, covering Idaho Power and PacifiCorp's eastern Balancing Authority Area. The population of this area is approximately 5.4 million. It has 15,910 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024 SRA*.

Highlights

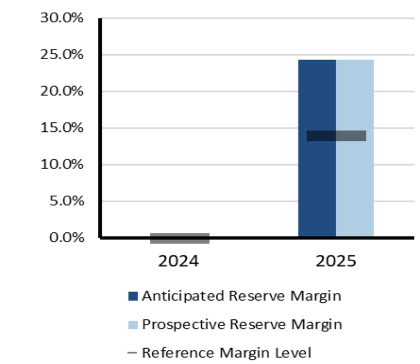
- Total internal expected demand has increased 8% and demand response has increased almost 28% for a net internal demand increase of 7.2%.
- Reserve margins are not anticipated to fall below the reference margin (14%) for the upcoming summer; an early July peak is expected at around 3:00 p.m.
- During periods of contingency reserve shortage, EEAs may be declared in the region to obtain reserves from the Northwest Power Pool.
- Seasonal fluctuations in hydro supply require monitoring and forecasting to have high certainty that these resources will meet anticipated capacity; the Summer 2025 drought outlook for the United States indicates minimal drought conditions in Idaho and some drought areas in Utah this summer.
- Wildfires near wind generation can result in safety curtailments, and fire damage to transmission lines interconnected to hydro sites can present restoration challenges.

Risk Scenario Summary

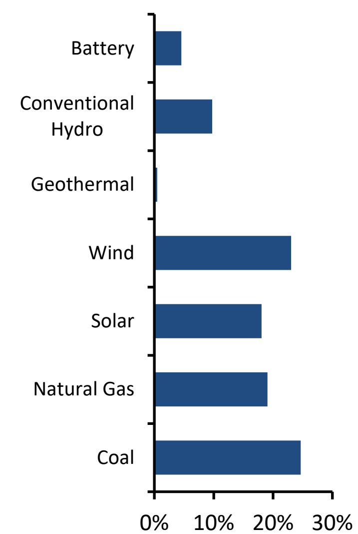
Expected resources meet operating reserve requirements under the assessed scenarios with imports.

On-Peak Reserve Margin

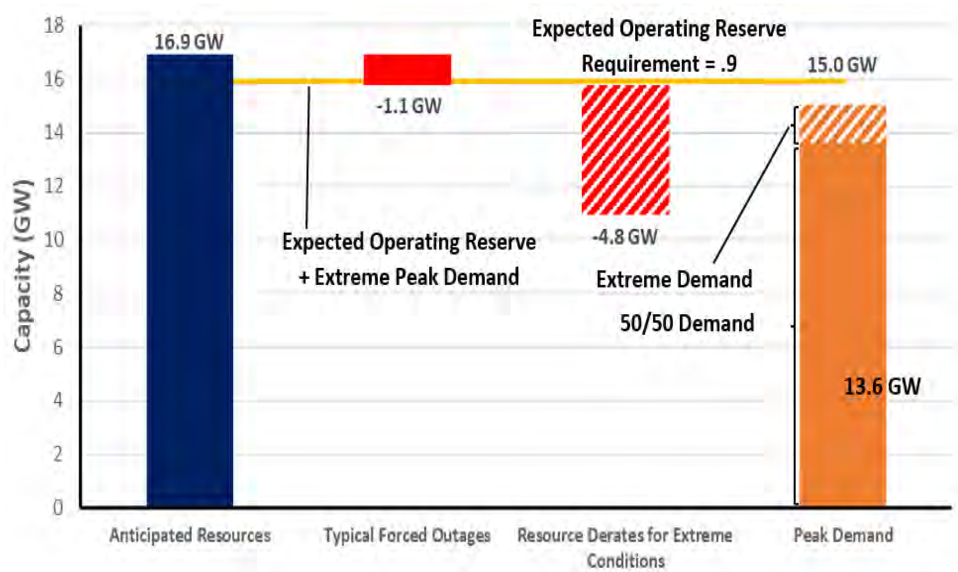
(Note: year comparison not available)



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) resource performance distribution at peak hour

WECC-British Columbia

WECC-British Columbia (BC) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of British Columbia. It has 11,184 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

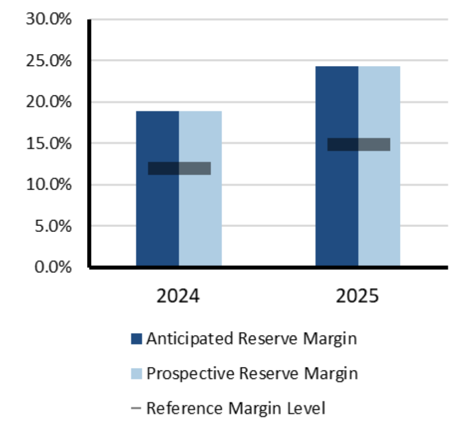
Highlights

- Existing capacity reserve margin has increased from 19% to 22%, and anticipated and prospective reserve margin from 19% to 24%.
- Reserve margins are not anticipated to fall below the reference margin for the upcoming summer.
- The peak hour is forecast for early August at 4:00 p.m., two hours earlier than last summer's outlook of 6:00 p.m.
- About 60% of hydro owned or contracted energy comes from the Columbia and Peace basins. Heavy precipitation in Fall 2024 mitigated the impact of below-average snowpack the previous winter, resulting in hydro storage tracking close to historical averages as of Spring 2025.
- Wildfires can affect the transmission network and generator availability and have caused energy emergencies on the electric system in the past.

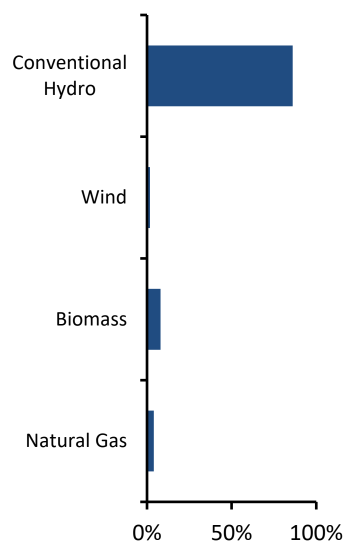
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

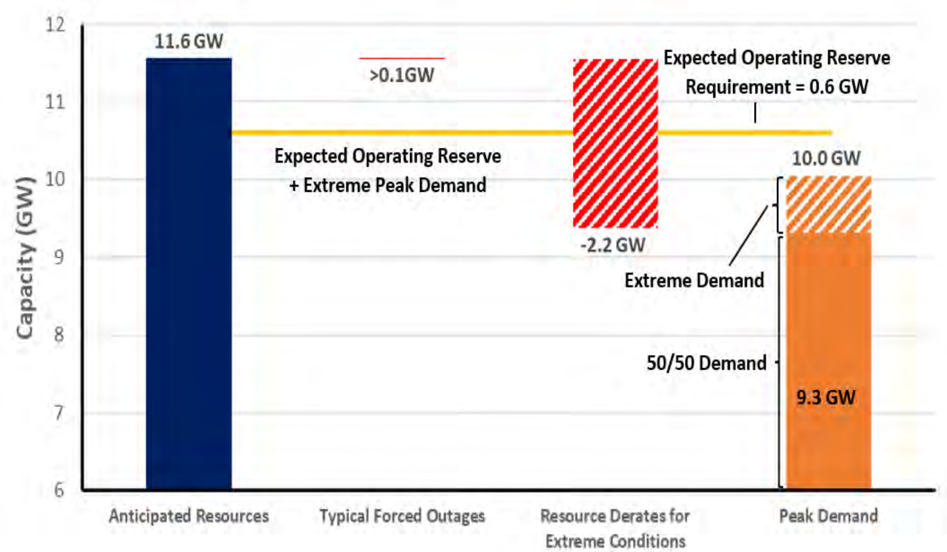
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) resource performance distribution at peak hour

WECC-California

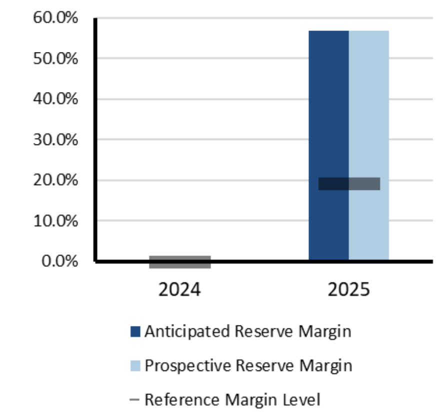
WECC-California is a summer-peaking assessment area in the Western Interconnection that includes most of California and a small section of Nevada. The assessment area has a population of over 42.5 million people. The area includes the California ISO, Los Angeles Department of Water and Power, Turlock Irrigation District, and the Balancing Area of Northern California. It has 32,712 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-California is a new assessment area in 2025 that was part of WECC-CA/MX in the 2024 SRA.*

Highlights

- Demand response is down 8.6% since last summer, existing-certain capacity is up 5.8%, and Tier 1 planned capacity is up 41.2% for a net increase in anticipated resources of 9%; anticipated and prospective reserve margins are up by 11.4%. The peak hour is still forecasted for early September around 4:00 p.m.
- Reserve margins are not anticipated to fall below the reference margin for the upcoming summer, and probabilistic assessment of normal and extreme resource/demand scenarios reveal no EUE or LOLH.
- Wildfires can and have threatened both the California Oregon Intertie line, resulting in import capability limitations.
- Prolonged elevated demand during heat waves in combination with thermal resource derates and forced outage rates present significant risk.
- An influx of IBRs and corresponding reduction in system inertia can potentially trigger system reliability issues and require additional regulation, flexible ramp, and future imbalance reserve requirements.
- Increased solar penetrations in this region along with changing load patterns from elevated temperatures and residential demand are shifting the hours with the most challenging resource adequacy needs later into the evening rather than traditional afternoon gross peak load periods.

On-Peak Reserve Margin

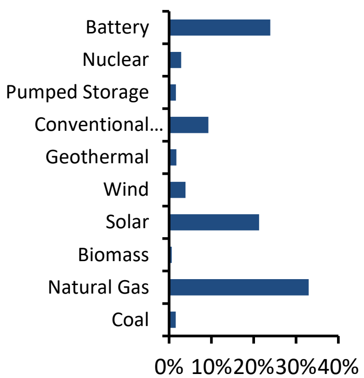
(Note: year comparison not available)



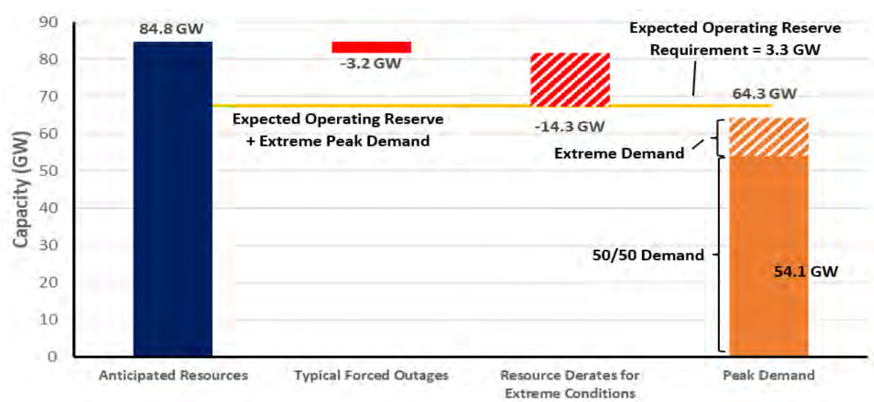
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios, and a probabilistic assessment of normal and extreme resource/demand scenarios reveals neither EUE nor LOLH.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Estimated using market forced outage model

Extreme Derates: On natural gas units based on historical data and manufacturer data for temperature performance and outages

WECC-Mexico

WECC-Mexico is a summer-peaking assessment area in the Western Interconnection that includes the northern portion of the Mexican state of Baja California, which has a population of 3.8 million people and includes CENACE. It has 1,568 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Mexico is a new assessment area in 2025 that was part of WECC-CA/MX in the 2024 SRA.*

Highlights

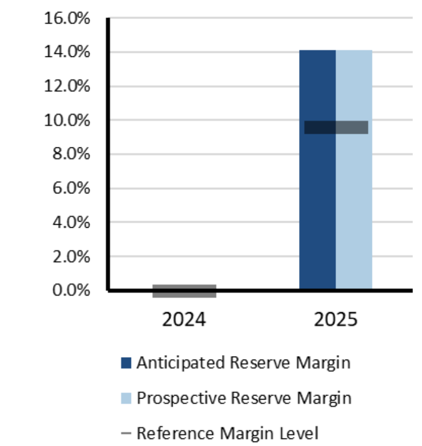
- Total and net internal expected (50/50) demand are up 6.8%, existing-certain capacity is up 29.8% or 989 MW, and Tier 1 planned capacity has fallen 100% to zero, leading to a decrease in the anticipated reserve margin from 22.9% down to 14.1%
- The peak hour is expected to occur in early August around 4:00 p.m.
- Operating reserves are a concern in this region during periods of extreme heat and elevated demand. High loading on Path 45 (See: WECC Path Rating Catalog) coupled with outages or derates to large thermal assets in this region can result in the declaration of an EAA and a request for assistance from RC West.

Risk Scenario Summary

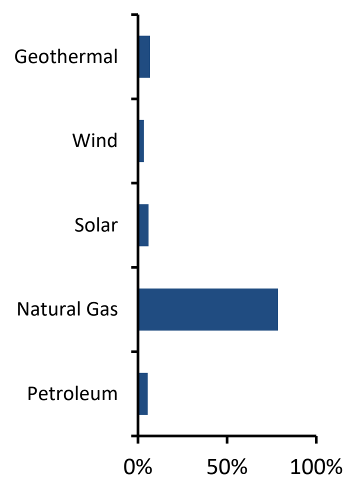
Expected resources at normal peak demand and outage conditions require some imports to maintain operating reserves. Thus, above-normal demand, high forced outage conditions, or transmission derates in the neighboring area could place WECC-Mexico in an energy emergency.

On-Peak Reserve Margin

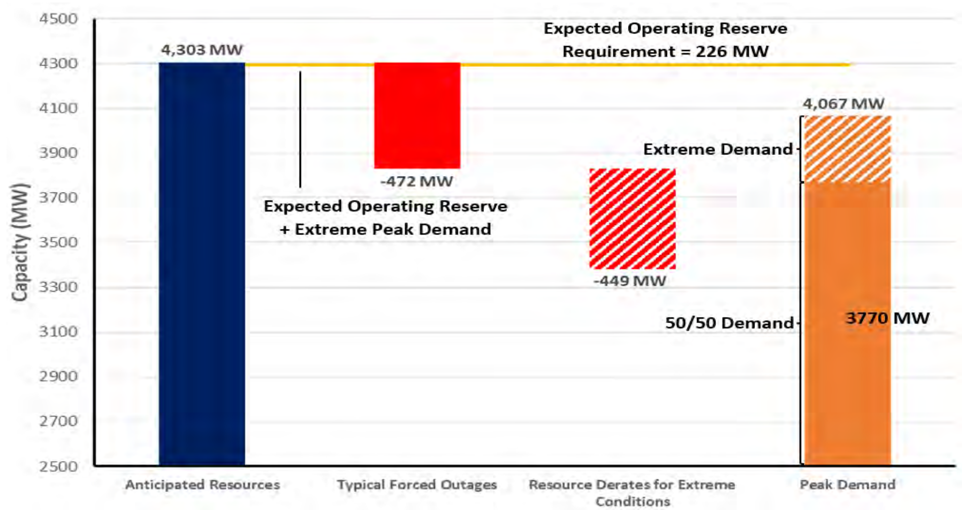
(Note: year comparison not available)



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) resource performance distribution at peak hour

WECC-Rocky Mountain

WECC-Rocky Mountain is a summer-peaking assessment area in the Western Interconnection that includes Colorado, most of Wyoming, and parts of Nebraska and South Dakota. The population of the area is approximately 6.7 million. It covers the balancing areas of the Public Service Company of Colorado and the Western Area Power Administration's Rocky Mountain Region. It has 18,797 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Rocky Mountain is a new assessment area in 2025 that was part of WECC-NW in the 2024 SRA.*

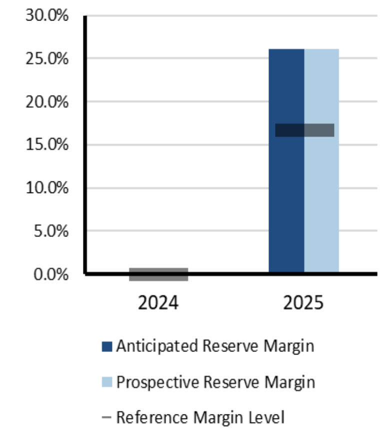
Highlights

- The reserve margins (existing-certain 25% and anticipated and prospective 26%) are not anticipated to fall below the reference margin (17%) for Summer 2025.
- Total and net internal demand (50/50) is up 25% or almost 2,800 MW, leading to a decline in the Anticipated Reserve Margin by almost a third.
- During the summer, there is increased load and decreased market purchase availability. Low wind availability and ramping scarcity events are a concern.
- Environmental and ecological factors have contributed to a rise in wildfire frequency and shortening of the fire return interval in the Rocky Mountain region, which, in addition to having caused generation outages, threatens rural co-ops disproportionately due to the extensive line buildout over remote regions.

Risk Scenario Summary

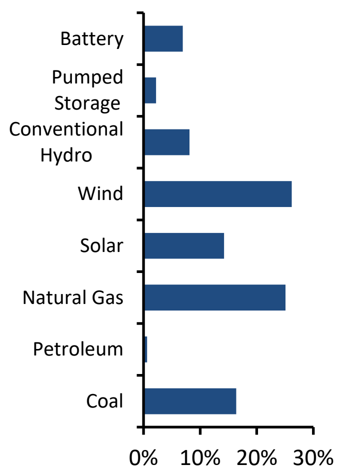
Expected resources meet operating reserve requirements under assessed scenarios with imports.

On-Peak Reserve Margin

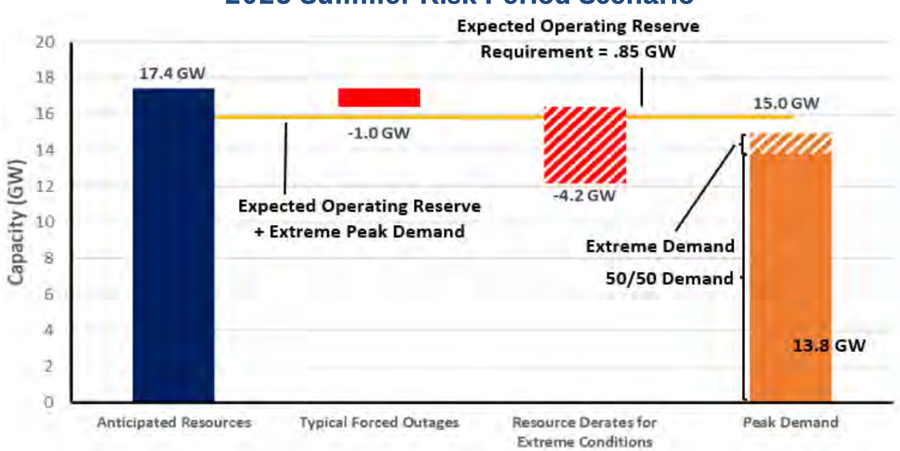


(Note: year comparison not available)

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

WECC-Northwest

WECC-Northwest is a winter-peaking assessment area in the WECC Regional Entity. The area includes Montana, Oregon, and Washington and parts of northern California and northern Idaho. The population of the area is approximately 13.6 million. It has 32,751 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Northwest is a new assessment area in 2025 that was part of a larger WECC-NW footprint in the 2024 SRA*.

Highlights

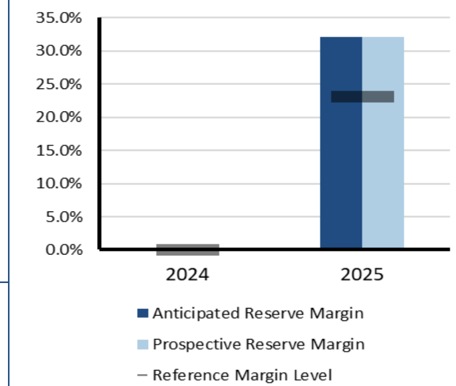
- The reserve margins (existing-certain 29% and anticipated and prospective 32%) are not anticipated to fall below the reference margin (23%) for the upcoming summer. An extreme summer peak load may be around 32,740 MW.
- Typical forced outages are forecast to be 771 MW, with derates for thermal under extreme conditions to be 1,584 MW and 2,649 MW for wind. The expected operating reserve requirement on peak is 1,750 MW.
- Extreme heat corresponds with elevated loads, reduced transmission ratings, and temperature derates of thermal resources, which can strain resource adequacy and grid reliability.
- Seasonal hydro variability is a risk.

Risk Scenario Summary

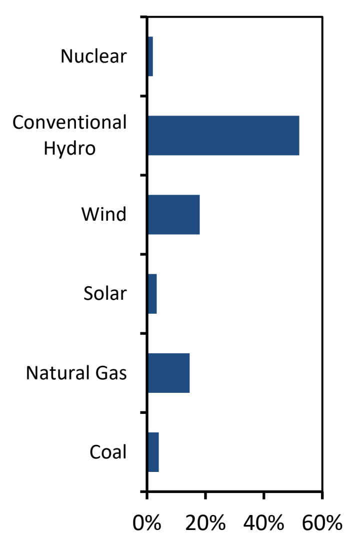
Expected resources meet operating reserve requirements under assessed scenarios with imports.

On-Peak Reserve Margin

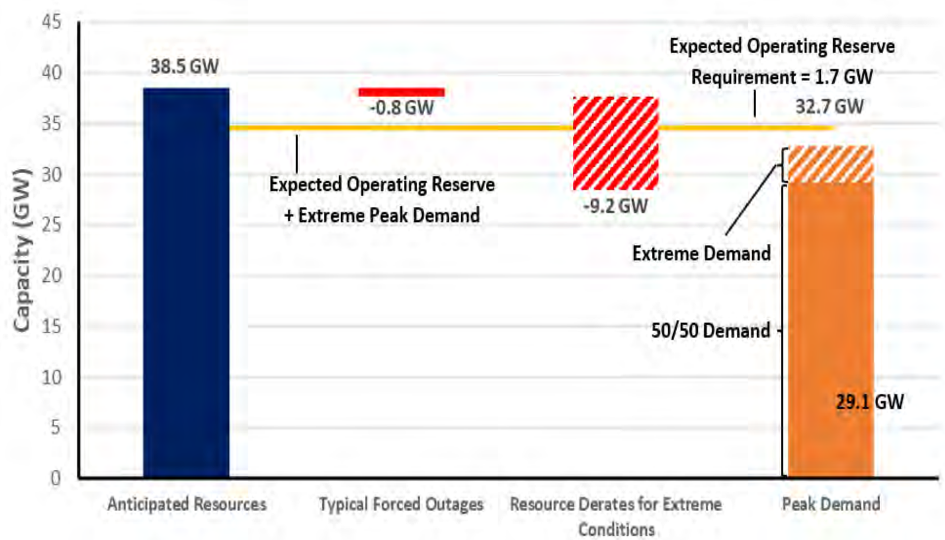
(Note: year comparison not available)



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

WECC-Southwest

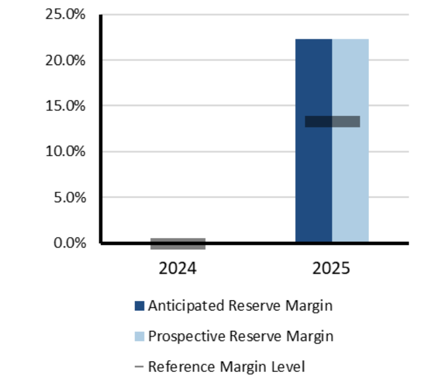
WECC-Southwest is a summer-peaking assessment area in the Western Interconnection that includes all of Arizona and New Mexico, most of Nevada, and small parts of California and Texas. The area has a population of approximately 13.6 million. It has 23,084 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Southwest is a new, larger assessment area in 2025 that now includes a portion of WECC-NW in the 2024 SRA.*

Highlights

- Anticipated Reserve Margins for the summer are 22%, exceeding the Reference Margin Level for reliability calculated by WECC.
- WECC's probabilistic analysis indicates that the area is not expected to encounter LOLH or EUE under a range of demand and resource conditions.
- The peak hour is expected to occur in early July around 5:00 p.m., when solar generation output begins to diminish.
- Wide-area heat events or wildfires that affect resource and transmission availability across the western interconnection area a reliability concern for the Southwest. Firm imports may be limited at this time if neighboring areas are also experiencing peak loads, limiting energy availability to export to the Southwest.

On-Peak Reserve Margin

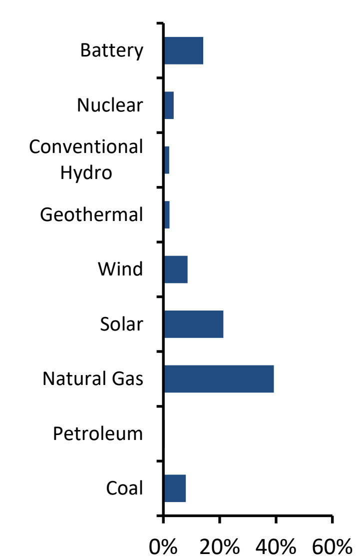
(Note: year comparison not available)



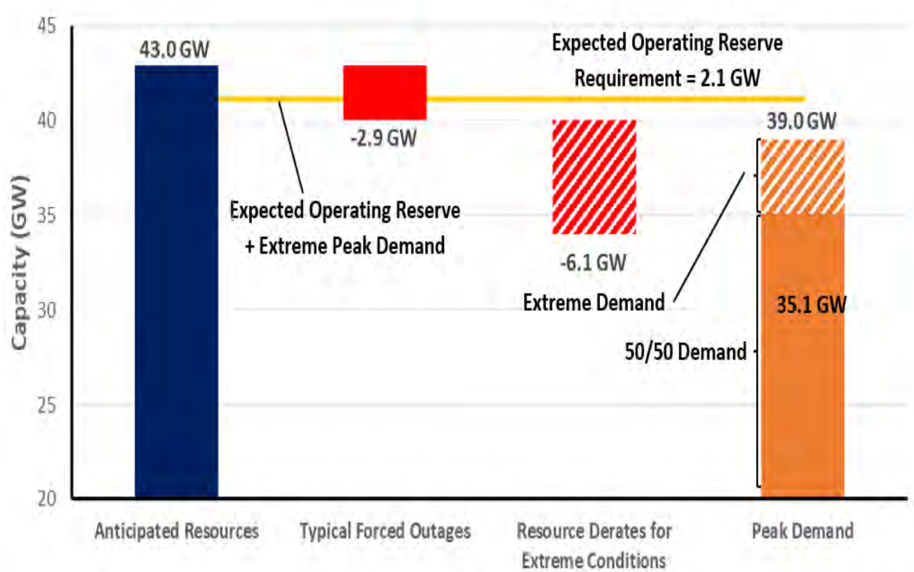
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios with imports.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand (5:00 p.m. local)

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Data Concepts and Assumptions

The table below explains data concepts and important assumptions used throughout this assessment.

General Assumptions
• Reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
▪ Adequacy is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
▪ Operating reliability is the ability of the electric system to withstand sudden disturbances, such as electric short-circuits or unanticipated loss of system components.
• The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
• All data in this assessment is based on existing federal, state, and provincial laws and regulations.
• Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
• A positive net transfer capability would indicate a net importing assessment area; a negative value would indicate a net exporter.
Demand Assumptions
• Electricity demand projections, or load forecasts, are provided by each assessment area.
• Load forecasts include peak hourly load[12] or total internal demand for the summer and winter of each year.[13]
• Total internal demand projections are based on normal weather (50/50 distribution)[14] and are provided on a coincident[15] basis for most assessment areas.
• Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.
Resource Assumptions
Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. Because the electrical output of VERs (e.g., wind, solar PV) depends on weather conditions, their contribution to reserve margins and other on-peak resource adequacy analysis is less than their nameplate capacity.
Anticipated Resources: • **Existing-Certain Capacity**: Included in this category are commercially operable generating units or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the summer season: unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or, where energy-only markets exist, unit must be a designated market resource eligible to bid into the market. • **Tier 1 Capacity Additions**: This category includes capacity that either is under construction or has received approved planning requirements. • **Net Firm Capacity Transfers (Imports minus Exports)**: This category includes transfers with firm contracts.
Prospective Resources: Includes all anticipated resources plus the following: **Existing-Other Capacity**: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.

[12] https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf used in NERC Reliability Standards

[13] The summer season represents June–September and the winter season represents December–February.

[14] Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.

[15] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval; this is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC calculates total internal demand on a noncoincidental basis.

Reserve Margin Descriptions

Planning Reserve Margin: This is the primary metric used to measure resource adequacy; it is defined as the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage.

Reference Margin Level: The assumptions and naming convention of this metric vary by assessment area. The RML can be determined using both deterministic and probabilistic (based on a 0.1/year loss-of-load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing an RML is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increase demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, an RML is established by a state, provincial authority, ISO/Regional Transmission Organization (RTO), or other regulatory body. In some cases, the RML is a requirement. RMLs may be different for the summer and winter seasons. If an RML is not provided by an assessment area, NERC applies 15% for predominantly thermal systems and 10% for predominantly hydro systems.

Seasonal Risk Scenario Chart Description

Each assessment area performed an operational risk analysis that was used to produce the seasonal risk scenario charts in the **Regional Assessments Dashboards**. The chart presents deterministic scenarios for further analysis of different resource and demand levels: The left **blue** column shows anticipated resources, and the two **orange** columns at the right show the two demand scenarios of the normal peak net internal demand and the extreme summer peak demand—both determined by the assessment area. The middle **red** or **green** bars show adjustments that are applied cumulatively to the anticipated resources, such as the following:

- Reductions for typical generation outages (i.e., maintenance and forced outages that are not already accounted for in anticipated resources)
- Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions that result in reduced thermal generation output)
- Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions

Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable.

The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Furthermore, the effects from extreme events can also be examined by comparing resource levels after applying extreme scenario derates and/or extreme summer peak demand.

Resource Adequacy

The Anticipated Reserve Margin (ARM), which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecast peak demand.[16] Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. All assessment areas have sufficient ARMs to meet or exceed their RML for the summer 2025 as shown in **Figure 4**.

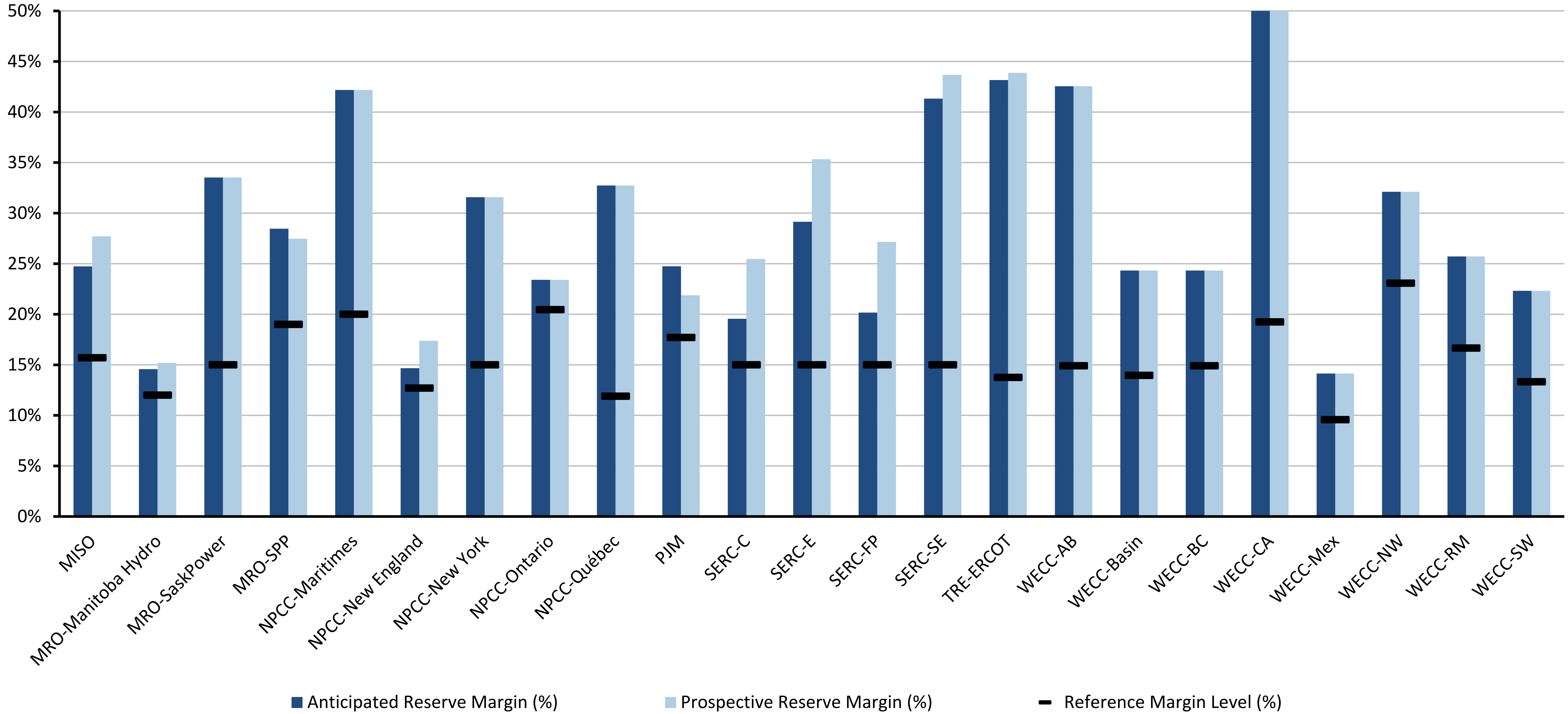


Figure 4: Summer 2025 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[16] Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during electrical peak loads for the season. Prospective resources are those that could be available but do not meet criteria to be counted as anticipated resources. Refer to the **Data Concepts and Assumptions** section for additional information on Anticipated/Prospective Reserve Margins, anticipated/prospective resources, and RMLs.

Changes from Year to Year

Figure 5 provides the relative change in the forecast ARMs from the 2024 Summer to the 2025 Summer. A significant decline can signal potential operational issues for the upcoming season. Additional details for each assessment area are provided in the **Data Concepts and Assumptions** and **Regional Assessments Dashboards** sections.

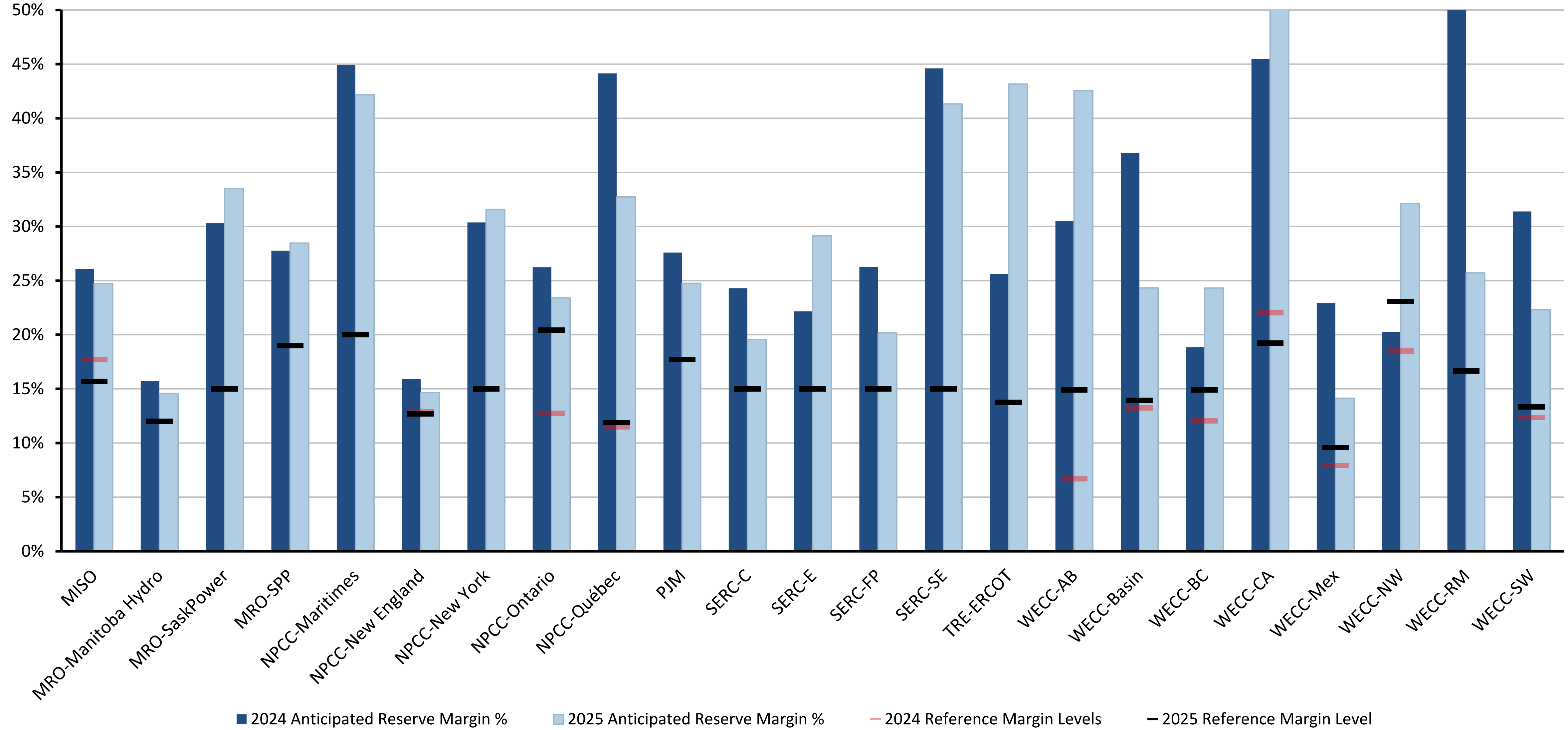


Figure 5: Summer 2024 and Summer 2025 Anticipated Reserve Margins Year-to-Year Change

Note: Yearly trends are not available for new WECC assessment areas in the United States and Baja California, Mexico.

Net Internal Demand

The changes in forecasted net internal demand for each assessment area are shown in **Figure 6**.[17] Assessment areas develop these forecasts based on historic load and weather information as well as other long-term projections.

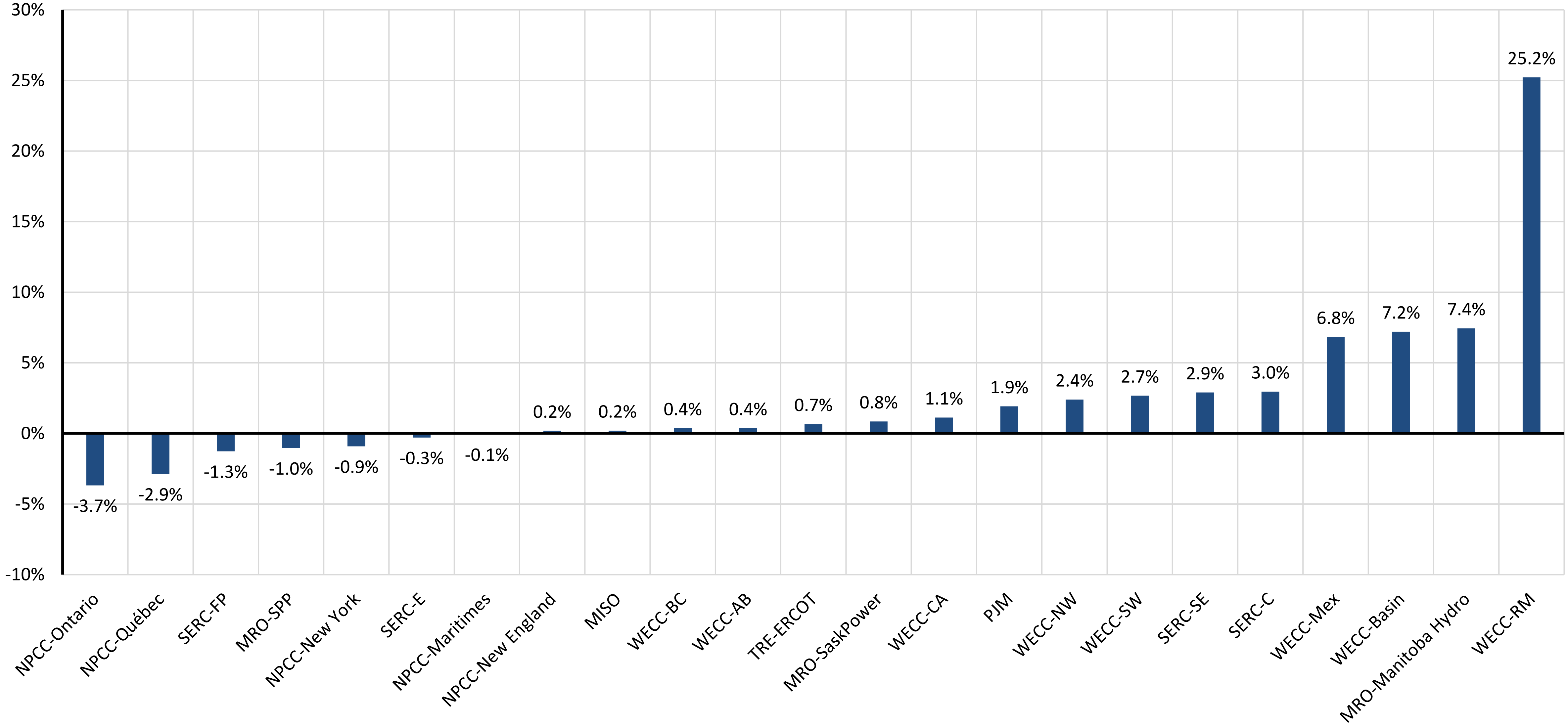


Figure 6: Changes in Net Internal Demand—Summer 2024 Forecast Compared to Summer 2025 Forecast

[17] Changes in modeling and methods are contributing to year-to-year changes in forecasted net internal demand projections in NPCC Maritimes and NPCC Ontario. See assessment area dashboards.

Demand and Resource Tables

Peak demand and supply capacity data—resource adequacy data—for each assessment area are as follows in each table (in alphabetical order).

MISO			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	124,830	125,313	0.4%
Demand Response: Available	8,750	9,004	2.9%
Net Internal Demand	116,079	116,309	0.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	143,866	142,793	-0.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	2,471	2,280	-7.7%
Anticipated Resources	146,337	145,073	-0.9%
Existing-Other Capacity	1,833	1,190	-35.1%
Prospective Resources	148,740	148,543	-0.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.1%	24.7%	-1.3
Prospective Reserve Margin	28.1%	27.7%	-0.4
Reference Margin Level	17.7%	15.7%	-2.0

MRO-Manitoba Hydro			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,143	3,377	7.4%
Demand Response: Available	0	0	-
Net Internal Demand	3,143	3,377	7.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,615	5,583	-0.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-1,978	-1,714	-13.3%
Anticipated Resources	3,637	3,869	6.4%
Existing-Other Capacity	37	21	-42.9%
Prospective Resources	3,674	3,890	5.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	15.7%	14.6%	-1.1
Prospective Reserve Margin	16.9%	15.2%	-1.7
Reference Margin Level	12.0%	12.0%	0.0

MRO-SaskPower			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,590	3,620	0.8%
Demand Response: Available	50	50	0.0%
Net Internal Demand	3,540	3,570	0.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,323	4,477	3.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	290	290	0.0%
Anticipated Resources	4,613	4,767	3.3%
Existing-Other Capacity	0	0	-
Prospective Resources	4,613	4,767	3.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.3%	33.5%	3.2
Prospective Reserve Margin	30.3%	33.5%	3.2
Reference Margin Level	15.0%	15.0%	0.0

MRO-SPP			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	56,316	56,168	-0.3%
Demand Response: Available	979	1,408	43.8%
Net Internal Demand	55,337	54,760	-1.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	70,855	70,549	-0.4%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-157	-201	27.5%
Anticipated Resources	70,698	70,348	-0.5%
Existing-Other Capacity	0	0	-
Prospective Resources	70,151	69,801	-0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.8%	28.5%	0.7
Prospective Reserve Margin	26.8%	27.5%	0.7
Reference Margin Level	19.0%	19.0%	0.0

NPCC-Maritimes			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,586	3,584	-0.1%
Demand Response: Available	327	327	0.0%
Net Internal Demand	3,259	3,257	-0.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,660	4,348	-6.7%
Tier 1 Planned Capacity	0	220	-
Net Firm Capacity Transfers	63	63	0.0%
Anticipated Resources	4,723	4,631	-1.9%
Existing-Other Capacity	0	0	-
Prospective Resources	4,723	4,631	-1.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.9%	42.2%	-2.7
Prospective Reserve Margin	44.9%	42.2%	-2.7
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New York			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	31,541	31,471	-0.2%
Demand Response: Available	1,281	1,487	16.1%
Net Internal Demand	30,260	29,984	-0.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	37,867	37,682	-0.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,585	1,769	11.6%
Anticipated Resources	39,452	39,451	0.0%
Existing-Other Capacity	0	0	-
Prospective Resources	39,452	39,451	0.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.4%	31.6%	1.2
Prospective Reserve Margin	30.4%	31.6%	1.2
Reference Margin Level	15.0%	15.0%	0.0

NPCC-New England			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	25,294	25,202	-0.4%
Demand Response: Available	661	399	-39.6%
Net Internal Demand	24,633	24,803	0.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	27,255	27,054	-0.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,297	1,245	-4.0%
Anticipated Resources	28,552	28,299	-0.9%
Existing-Other Capacity	138	668	384.1%
Prospective Resources	28,690	28,967	1.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	15.9%	14.1%	-1.8
Prospective Reserve Margin	16.5%	16.8%	0.3
Reference Margin Level	12.9%	12.7%	-0.2

NPCC-Ontario			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,753	21,955	-3.5%
Demand Response: Available	996	998	0.2%
Net Internal Demand	21,757	20,957	-3.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	26,856	24,760	-7.8%
Tier 1 Planned Capacity	9	413	4568.6%
Net Firm Capacity Transfers	600	689	14.8%
Anticipated Resources	27,465	25,862	-5.8%
Existing-Other Capacity	0	0	-
Prospective Resources	27,465	25,862	-5.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.2%	23.4%	-2.8
Prospective Reserve Margin	26.2%	23.4%	-2.8
Reference Margin Level	12.8%	20.5%	7.7

NPCC-Québec			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,922	23,283	1.6%
Demand Response: Available	0	1,020	-
Net Internal Demand	22,922	22,263	-2.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	35,731	32,132	-10.1%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-2,689	-2,582	-4.0%
Anticipated Resources	33,042	29,550	-10.6%
Existing-Other Capacity	0	0	-
Prospective Resources	33,042	29,550	-10.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.1%	32.7%	-11.4
Prospective Reserve Margin	44.1%	32.7%	-11.4
Reference Margin Level	11.5%	11.9%	0.4

SERC-Central			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	42,636	42,765	0.3%
Demand Response: Available	1,941	864	-55.5%
Net Internal Demand	40,695	41,900	3.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	47,674	46,949	-1.5%
Tier 1 Planned Capacity	332	592	78.1%
Net Firm Capacity Transfers	2,578	2,554	-0.9%
Anticipated Resources	50,584	50,095	-1.0%
Existing-Other Capacity	2,075	2,475	19.2%
Prospective Resources	52,659	52,570	-0.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.3%	19.6%	-4.7
Prospective Reserve Margin	29.4%	25.5%	-3.9
Reference Margin Level	15.0%	15.0%	0.0

PJM			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	151,247	154,144	1.9%
Demand Response: Available	7,756	7,898	1.8%
Net Internal Demand	143,491	146,246	1.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	183,690	186,638	1.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-607	-4,200	591.9%
Anticipated Resources	183,083	182,438	-0.4%
Existing-Other Capacity	0	0	-
Prospective Resources	182,476	178,238	-2.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.6%	24.7%	-2.8
Prospective Reserve Margin	27.2%	21.9%	-5.3
Reference Margin Level	17.7%	17.7%	0.0

SERC-East			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	43,567	44,015	1.0%
Demand Response: Available	985	1,558	58.2%
Net Internal Demand	42,582	42,457	-0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	51,304	54,665	6.5%
Tier 1 Planned Capacity	122	17	-86.0%
Net Firm Capacity Transfers	593	150	-74.7%
Anticipated Resources	52,019	54,832	5.4%
Existing-Other Capacity	1,131	2,628	132.3%
Prospective Resources	53,150	57,459	8.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.2%	29.1%	7.0
Prospective Reserve Margin	24.8%	35.3%	10.5
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	53,293	52,987	-0.6%
Demand Response: Available	2,824	3,158	11.8%
Net Internal Demand	50,469	49,829	-1.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	63,199	59,395	-6.0%
Tier 1 Planned Capacity	34	102	197.8%
Net Firm Capacity Transfers	491	381	-22.4%
Anticipated Resources	63,724	59,878	-6.0%
Existing-Other Capacity	972	3,482	258.2%
Prospective Resources	64,696	63,360	-2.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.3%	20.2%	-6.1
Prospective Reserve Margin	28.2%	27.2%	-1.0
Reference Margin Level	15.0%	15.0%	0.0

Texas RE-ERCOT			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	84,818	85,151	0.4%
Demand Response: Available	3,496	3,292	-5.8%
Net Internal Demand	81,323	81,859	0.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	99,541	112,321	12.8%
Tier 1 Planned Capacity	2,578	4,854	88.3%
Net Firm Capacity Transfers	20	20	0.0%
Anticipated Resources	102,139	117,195	14.7%
Existing-Other Capacity	0	0	-
Prospective Resources	102,167	117,770	15.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.6%	43.2%	17.6
Prospective Reserve Margin	25.6%	43.9%	18.2
Reference Margin Level	13.75%	13.75%	0.0

SERC-Southeast			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	46,021	47,049	2.2%
Demand Response: Available	1,599	1,338	-16.3%
Net Internal Demand	44,422	45,711	2.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	63,693	64,111	0.7%
Tier 1 Planned Capacity	1,738	0	-100.0%
Net Firm Capacity Transfers	-1,192	489	-141.0%
Anticipated Resources	64,238	64,600	0.6%
Existing-Other Capacity	785	1,077	37.1%
Prospective Resources	65,024	65,676	1.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.6%	41.3%	-3.3
Prospective Reserve Margin	46.4%	43.7%	-2.7
Reference Margin Level	15.0%	15.0%	0.0

WECC-AB			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	12,201	12,246	0.4%
Demand Response: Available	0	0	-
Net Internal Demand	12,201	12,246	0.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,941	17,176	23.2%
Tier 1 Planned Capacity	1,981	281	-85.8%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	15,922	17,457	9.6%
Existing-Other Capacity	0	0	-
Prospective Resources	15,922	17,457	9.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.5%	42.6%	12.1
Prospective Reserve Margin	30.5%	42.6%	12.1
Reference Margin Level	6.7%	9.0%	2.7

WECC-BC			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	9,275	9,309	0.4%
Demand Response: Available	0	0	-
Net Internal Demand	9,275	9,309	0.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	11,022	11,313	2.6%
Tier 1 Planned Capacity	0	260	-
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	11,022	11,573	5.0%
Existing-Other Capacity	0	0	-
Prospective Resources	11,022	11,573	5.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	18.8%	24.3%	5.5
Prospective Reserve Margin	18.8%	24.3%	5.5
Reference Margin Level	12.0%	14.9%	2.9

WECC-California			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	54,267	54,797	1.0%
Demand Response: Available	816	746	-8.6%
Net Internal Demand	53,451	54,051	1.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	71,564	75,726	5.8%
Tier 1 Planned Capacity	5,998	8,470	41.2%
Net Firm Capacity Transfers	197	598	203.6%
Anticipated Resources	77,759	84,794	9.0%
Existing-Other Capacity	0	0	-
Prospective Resources	77,759	84,794	9.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	45.5%	56.9%	11.4
Prospective Reserve Margin	45.5%	56.9%	11.4
Reference Margin Level	22.0%	19.2%	-2.8

WECC-Southwest			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	34,629	35,321	2.0%
Demand Response: Available	422	199	-52.9%
Net Internal Demand	34,207	35,122	2.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	37,716	40,300	6.9%
Tier 1 Planned Capacity	4,272	1,966	-54.0%
Net Firm Capacity Transfers	2,957	695	-76.5%
Anticipated Resources	44,945	42,961	-4.4%
Existing-Other Capacity	0	0	-
Prospective Resources	44,945	42,961	-4.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	31.4%	22.3%	-9.1
Prospective Reserve Margin	31.4%	22.3%	-9.1
Reference Margin Level	12.4%	13.3%	1.0

WECC-Northwest			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	28,475	29,157	2.4%
Demand Response: Available	30	30	0.0%
Net Internal Demand	28,445	29,127	2.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	33,164	36,388	9.7%
Tier 1 Planned Capacity	201	844	319.9%
Net Firm Capacity Transfers	838	1,249	49.0%
Anticipated Resources	34,203	38,481	12.5%
Existing-Other Capacity	0	0	-
Prospective Resources	34,203	38,481	12.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.2%	32.1%	11.9
Prospective Reserve Margin	20.2%	32.1%	11.9
Reference Margin Level	18.5%	23.1%	4.6

WECC-Basin			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	13,165	14,214	8.0%
Demand Response: Available	485	620	27.8%
Net Internal Demand	12,680	13,594	7.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,534	14,923	10.3%
Tier 1 Planned Capacity	2,436	704	-71.1%
Net Firm Capacity Transfers	1,376	1,274	-7.4%
Anticipated Resources	17,346	16,901	-2.6%
Existing-Other Capacity	0	0	-
Prospective Resources	17,346	16,901	-2.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	36.8%	24.3%	-12.5
Prospective Reserve Margin	36.8%	24.3%	-12.5
Reference Margin Level	13.3%	14.0%	0.7

WECC-Rocky Mountain			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,313	14,098	24.6%
Demand Response: Available	281	284	1.1%
Net Internal Demand	11,032	13,814	25.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	17,345	17,262	-0.5%
Tier 1 Planned Capacity	55	104	89.1%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	17,400	17,366	-0.2%
Existing-Other Capacity	0	0	-
Prospective Resources	17,400	17,366	-0.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	57.7%	25.7%	-32.0
Prospective Reserve Margin	57.7%	25.7%	-32.0
Reference Margin Level	18.0%	16.7%	-1.3

WECC-Mexico			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,529	3,770	6.8%
Demand Response: Available	0	0	-
Net Internal Demand	3,529	3,770	6.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	3,314	4,303	29.8%
Tier 1 Planned Capacity	874	0	-100.0%
Net Firm Capacity Transfers	150	0	-100.0%
Anticipated Resources	4,338	4,303	-0.8%
Existing-Other Capacity	0	0	-
Prospective Resources	4,338	4,303	-0.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.9%	14.1%	-8.8
Prospective Reserve Margin	22.9%	14.1%	-8.8
Reference Margin Level	7.9%	9.6%	1.6

Variable Energy Resource Contributions

Because the electrical output of VERs (e.g., wind, solar PV) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. The following table shows the capacity contribution of existing wind and solar PV resources at the peak demand hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS. For NERC's analysis of risk periods after peak demand (e.g., U.S. assessment areas in WECC), lower contributions of solar PV resources are used because output is diminished during evening periods.

BPS Variable Energy Resources by Assessment Area

	Wind			Solar PV			Hydro			Energy Storage Systems (ESS)		
Assessment Area / Interconnection	Nameplate Wind	Expected Wind	Expected Share of Nameplate (%)	Nameplate Solar PV	Expected Solar PV	Expected Share of Nameplate (%)	Nameplate Hydro	Expected Hydro	Expected Share of Nameplate (%)	Nameplate ESS	Expected ESS	Expected Share of Nameplate (%)
MISO	30,992	6,039	19%	18,246	9,123	50%	1,572	1,467	93%	3,159	3,107	98%
MRO-Manitoba Hydro	259	48	19%	-	-	0%	202	60	30%	-	-	0%
MRO-SaskPower	816	310	38%	30	9	29%	848	686	81%	-	-	0%
NPCC-Maritimes	1,230	314	26%	147	-	0%	1,313	1,313	100%	12	6	50%
NPCC-New England	1,546	142	9%	3,266	1,412	43%	575	175	31%	192	110	57%
NPCC-New York	2,586	446	17%	609	243	40%	976	478	49%	32	17	53%
NPCC-Ontario	4,943	742	15%	478	66	14%	8,862	5,320	60%	-	-	0%
NPCC-Québec	4,024	885	22%	10	-	0%	444	444	100%	-	-	0%
PJM	12,465	1,855	15%	13,731	6,244	45%	2,505	2,505	100%	310	288	93%
SERC-Central	1,324	370	28%	1,810	1,053	58%	4,991	3,418	68%	100	100	100%
SERC-East	-	-	0%	7,097	5,022	71%	3,078	3,008	98%	19	8	41%
SERC-Florida Peninsula	-	-	0%	8,295	5,749	54%	-	-	0%	631	631	100%
SERC-Southeast	-	-	0%	8,507	7,728	91%	3,258	3,308	102%	115	105	92%
SPP	35,613	5,556	16%	1,159	492	42%	114	56	49%	182	41	23%
Texas RE-ERCOT	40,102	9,396	23%	31,473	22,962	73%	572	439	77%	15,291	12,190	80%
WECC-AB	5,712	796	14%	2,174	1,480	68%	894	456	51%	250	235	94%
WECC-BC	747	149	20%	2	-	0%	16,918	10,181	60%	-	-	0%
WECC-Basin	4,859	911	19%	2,648	2,231	84%	2,637	2,022	77%	120	118	98%
WECC-CA	7,836	1,207	15%	25,059	14,756	59%	14,565	6,518	45%	11,459	11,115	97%
WECC-Mexico	300	50	17%	350	227	65%	-	-	0%	-	-	0%
WECC-NW	9,199	3,107	34%	1,349	666	49%	33,068	20,145	61%	11	10	91%
WECC-RM	5,681	1,359	24%	2,523	1,669	66%	3,251	2,446	75%	242	235	97%
WECC-SW	4,848	1,091	23%	9,288	4,293	46%	1,316	845	64%	4,187	3,982	95%
EASTERN INTERCONNECTION	91,773	15,822	17%	67,138	37,886	56%	28,294	21,794	77%	4,752	4,413	93%
QUÉBEC INTERCONNECTION	4,024	885	22%	10	-	0%	444	444	100%	-	-	0%
TEXAS INTERCONNECTION	40,102	9,396	23%	31,473	22,962	73%	572	439	77%	15,291	12,190	80%
WECC INTERCONNECTION	39,182	8,670	22%	43,393	25,322	58%	72,649	42,613	59%	16,269	15,695	96%
All INTERCONNECTIONS	**175,081**	**34,774**	**20%**	**142,014**	**86,170**	**61%**	**101,959**	**65,290**	**64%**	**36,311**	**32,298**	**89%**

Review of 2024 Capacity and Energy Performance

The summer of 2024 was the fourth hottest on record for both the contiguous United States[18] and Canada,[19] with some areas experiencing their hottest summer ever. The result was record electricity demand in the United States as well as in Canada, which was particularly pronounced in the Western Interconnection. While peak demand exceeded normal summer forecasts in most areas, only one area experienced demand that met or exceeded a 90/10 demand scenario as defined in the prior year's *SRA*. In addition, Hurricane Helene, the deadliest Atlantic hurricane to strike the US mainland since 2005, made landfall in Florida in September and led to widespread flooding and power outages from Florida to North Carolina. Helene was one of five hurricanes to impact the US last summer, joining other extreme weather incidents such as drought across the West and wildfires in the Southwest. To manage the challenging grid conditions brought about by heat domes and these other extreme weather events, grid operators across North America used various operating mitigations up to, and including, the issuance of EEAs. No disruptions to the BPS occurred due to inadequate resources. The following section describes actual demand and resource levels in comparison with NERC's *2024 SRA* and summarizes 2024 resource adequacy events.

Eastern Interconnection–Canada and Québec Interconnection

During the June heat wave that extended across the eastern half of the United States and Canada, system operators in Ontario and the Maritimes provinces followed conservative operating protocols and issued energy emergencies. A late-summer heat wave resulted in an energy emergency in Maritimes.

Eastern Interconnection–United States

MISO experienced peak electricity demand during late August. Demand was between the normal and 90/10 summer peak forecast levels. Wind and solar resource output at the time of peak demand were near expectations for summer on-peak contributions. Forced outages of thermal units, however, were lower than expected. On the day prior to MISO's peak demand, operators issued advisories to maximize generation. Similar advisories were issued earlier in the summer, coinciding with above-normal temperatures and periods of high generator forced outages.

In SPP, summer electricity demand peaked in mid-July at a level below normal 50/50 forecasts. Above-normal wind performance and sufficient generator availability contributed to sufficient electricity supplies during peak conditions. In late August, however, SPP operators issued an EEA1 due to high load forecasts, generator outages, and forecasts for low wind output. The period coincided with MISO's peak demand period, making excess supplies for import uncertain. Also in August during a period of high demand and low resource availability, operators issued public appeals for conservation when a 345 kV line outage caused a transmission emergency. During other summer periods, SPP operators responded to forecasts for high demand and low resource conditions with resource advisories intended to maximize available generators.

Like SPP, PJM also experienced peak electricity demand in mid-July and issued an EEA in August. Peak demand in July was near 90/10 forecast levels. Generator outages were below normal at the time of peak demand. In late August, PJM operators issued an EEA1 in expectation of extreme demand.

A period of unseasonably high demand in early summer brought on by high temperatures in the Northeast contributed to an EEA1 in NPCC-New England when a large thermal generator encountered a forced outage. Peak demand in New England occurred in mid-July at a near-normal summer peak demand level. At the time of peak demand, generator outages were below historical averages.

Peak demand in the NPCC-New York area occurred in early July at a level below the normal summer peak demand forecast. Generator outages were below historical levels for peak summer conditions.

[18] US sweltered through its 4th-hottest summer on record – National Oceanic and Atmospheric Administration
[19] Climate Trends and Variations Bulletin – Summer 2024 – Government of Canada

Systems in the U.S. Southeast saw successive heat waves beginning prior to the official start to summer and extending to early fall. Operators in the SERC region used conservative operations and resource advisories to maximize generation and transmission network availability and issued EEAs when warranted by conditions. In some instances, EEAs were issued when generator outages threatened supplies needed for high demand. Peak demand in all assessment areas within the SERC region exceeded normal summer peak demand levels and approached 90/10 demand forecasts.

Texas Interconnection–ERCOT

Peak demand in ERCOT was at or near record levels last summer, as load growth and extreme temperatures contributed to escalating summer electricity needs. Demand peaked in August well above the 90/10 demand forecast. At the time of peak demand, wind generation was below expected levels for peak demand periods, while output from solar generation was near forecasted levels. Forced generator outages were well below historical average levels for peak demand, helping to meet the extreme electricity demand. Unlike the prior summer, ERCOT did not issue any conservation appeals to customers to reduce demand during high-demand periods. New solar generation, battery resources, and some thermal generation additions since Summer 2023 boosted electricity supplies, enabling operators to meet demand records without demand-side management.

Western Interconnection

In July, the Western Interconnection set a new peak demand record of 167,988 MW. Operators in United States and Canada employed procedures throughout summer to manage challenging grid conditions from extended extreme heat and wildfires.

Western Interconnection–Canada

In the province of Alberta, the electric system operator issued an EEA3 in early July as high temperatures contributed to elevated demand that coincided with a forced generator outage. A new summer peak demand record was set in Alberta later in July at 12.2 MW (up from 11.5 GW in summer 2023). Alberta’s demand peak was slightly higher than the normal demand peak scenario projected in the spring of last year.

In British Columbia, peak demand reached 9.4 GW (up from 9.2 GW the previous year), also slightly above the normal peak demand that was projected last year.

In both Alberta and British Columbia, peak demand was still below the extreme peak demand scenarios previously projected, which lowered the risk profile of those provinces over Summer 2024.

Western Interconnection–United States

Demand peaked in July in the U.S. Northwest at a level below the normal summer peak demand. During a period of high demand in July, operators at a BA in the U.S. Northwest issued an EEA1 to address forecasted conditions.

The California-Mexico assessment area, which consists of the CAISO, Northern California, and CENACE BAs, experienced system peak electricity demand in early September at a level nearing the 90/10 peak demand forecast. The extreme demand contributed to localized supply concerns and led CAISO to declare a transmission emergency and use conservative operations protocols to posture the system. Despite the extreme demand, operators were able to maintain sufficient supply without resorting to public appeals, as was required in prior summers. New battery resources were instrumental in providing energy to meet high demand during late afternoon and early evenings. Natural-gas-fired generators also performed well and were important to meeting high demand during these same periods. Dry conditions from early summer prompted operators in CA/MX to frequently employ public safety power shutoff (PSPS) procedures beginning in June. Active wildfires led transmission operators to de-energize transmission lines in Northern California and declare transmission emergencies that affected operations across CAISO.

The U.S. Southwest experienced extended heat conditions and demand levels that exceeded 90/10 peak summer forecasts, with peak occurring in early August. Higher-than-expected wind and solar output and low generator outages helped maintain sufficient supplies.

2024 Summer Demand and Generation Summary at Peak Demand							
Assessment Area	Actual Peak Demand[1] (GW)	SRA Peak Demand Scenarios[2] (GW)	Wind – Actual[1] (MW)	Wind – Expected[3] (MW)	Solar – Actual[1] (MW)	Solar – Expected[3] (MW)	Forced Outages Summary[4] (MW)
MISO	118.6	116.1 125.8	4,565	5,599	5,858	4,981	4,412
MRO-Manitoba Hydro	3.6	3.1 3.3	50	48	0	0	290
MRO-SaskPower	3.7	3.5 3.7	170	208	22	6	0
MRO-SPP	54.3	55.3 57.5	10,869	5,876	442	486	6,046
NPCC-Maritimes	3.5	3.3 3.6	428	262	21	-	777
NPCC-New England	24.3	24.6 26.5	174	122	167	1,111	1,496
NPCC-New York	29	30.3 32	130	340	0	53	1,451
NPCC-Ontario	23.9	21.8 23.7	915	720	260	66	1,174
NPCC-Québec	23	22.9 24	2,270	-	0	-	10,500*
PJM	153.1	143.5 156.9	3,366	1,703	2,709	5,694	6,402
SERC-C	42.3	40.7 43.9	312	172	813	996	959
SERC-E	44	42.6 44.7	0	-	3,009	2,405	1,878
SERC-FP	52.4	50.5 53.6	0	-	5,376	5,643	
SERC-SE	44.9	44.4 45.3	0	-	3,507	7,217	1,007
TRE-ERCOT	85.5	81.3 82.3	6,286	9,070	17,566	17,797	3,622
WECC-AB	12.2	12.2 12.7	1,091	666	1,114	786	-**
WECC-BC	9.4	9.3 9.8	257	140	0.94	0	-**

2024 Summer Demand and Generation Summary at Peak Demand							
Assessment Area	Actual Peak Demand[1] (GW)	SRA Peak Demand Scenarios[2] (GW)	Wind – Actual[1] (MW)	Wind – Expected[3] (MW)	Solar – Actual[1] (MW)	Solar – Expected[3] (MW)	Forced Outages Summary[4] (MW)
WECC-CA/MX	58.9	53.2 61.6	1,633	1,124	10,112	13,147	921
WECC-NW	59.7	63 69.7	4,694	2,964	6,339	2,595	3,655
WECC-SW	30.8	26.4 28.8	1,179	542	3,357	1,294	2,042
Highlighting Notes	Actual peak demand in the highlighted areas met or exceeded extreme scenario levels.		Actual wind output in highlighted areas was significantly below seasonal forecast.		Actual solar output in highlighted areas was significantly below seasonal forecast.		Actual forced outages above or below forecast by factor of two

Table Notes:

[1] Actual demand, wind, and solar values for the hour of peak demand in U.S. areas were obtained from [EIA From 930 data](). For areas in Canada, this data was provided to NERC by system operators and utilities.

[2] See NERC *2024 SRA* demand scenarios for each assessment area (pp. 14–33). Values represent the normal summer peak demand forecast and an extreme peak demand forecast that represents a 90/10, or once-per-decade, peak demand. Some areas use other basis for extreme peak demand.

[3] Expected values of wind and solar resources from the *2024 SRA*.

[4] Values from NERC Generator Availability Data System for the 2024 summer hour of peak demand in each assessment area. Highlighted areas had actual forced outages that were more than twice the value for typical forced outage rates used in the 2024 summer risk period scenarios in the *2024 SRA*.

*Values include both maintenance and forced outages.

**Canadian assessment areas report to the NERC Generator Availability Data System on a voluntary basis, which can contribute to the absence of some values in certain assessment areas.

Attachment AA

MISO, Load Modeling Process and Results
(Apr. 24, 2025)

Load Modeling Process and Results

LOLE Working Group

April 24, 2025

Purpose & Key Takeaways

Purpose:

Provide an overview of the load development process and results for the Planning Year (PY) 2026-2027 Loss of Load Expectation (LOLE) model.

Key Takeaways:

- The load development process for the PY2026-2027 LOLE model was conducted in the same manor that was done for the PY2025-2026 LOLE model.
- Load development results for this round of the LOLE study showed slight growth for the upcoming prompt year in all seasons, with the largest growth seen in the Fall and Spring seasons.
- MISO will share final capacity input assumptions with stakeholders at the July LOLEWG.

Load Uncertainty in LOLE Analysis

- Loss of Load Expectation analysis is largely driven by two factors
  - Generation Uncertainty
  - Load Uncertainty
- Recent historic load and temperature data is used to capture load uncertainty
  - Variance in peak demand
  - Variance in load shape
  - Variance in temperature
- Train load and temperature data from recent five years utilizing neural network software to predict correlations between load and temperature for use in the LOLE study model

Load Development Process

- Historical load and weather data collection
- 5-year gross load adjustment
- Neural network training
- Neural network predicting
- Extreme temperature adjustment
- Load forecast adjustment

Load Forecast Adjustment

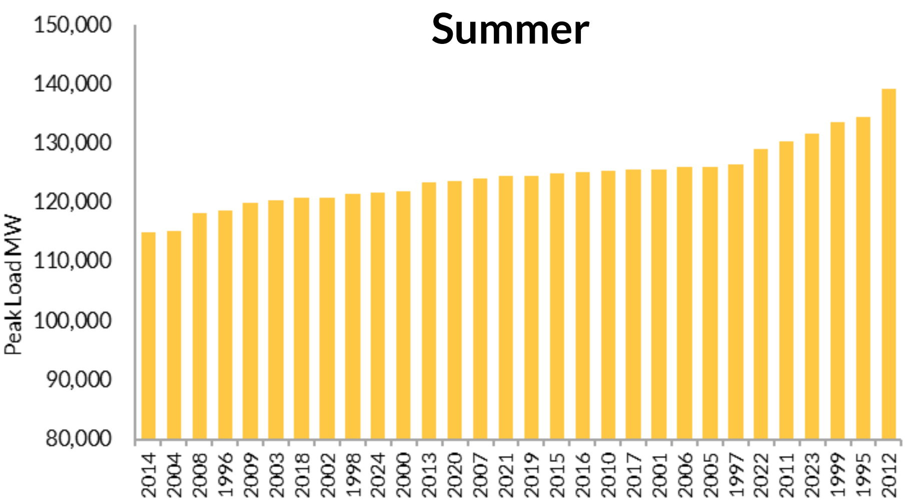
- Predicted load shapes are scaled so that the monthly and zonal peak averages of the 30-year load shapes match each Local Resource Zone's monthly Zonal Coincident Peak Load Forecast
  - Load reductions from LMRs are included in the LSE-provided gross load forecasts
- Ratio of prompt year Non-Coincident Peak Forecast to Zonal Coincident Peak Forecast is applied to future year Non-Coincident Peak Forecasts to develop outyear load forecast scalars
- Zonal load shapes are developed for the prompt year probabilistic analyses, as well as for outyear analyses
  - PY26-27 (prompt year), PY29-30 (outyear 4), and PY31-32 (outyear 6)

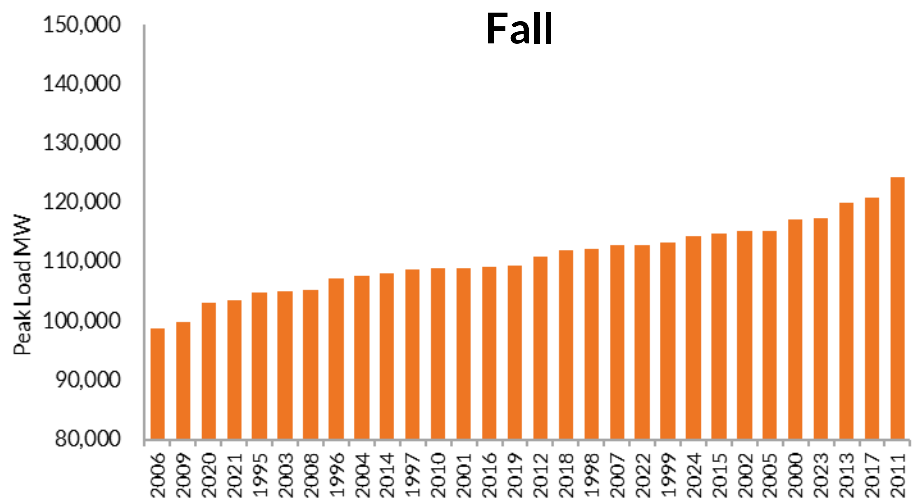
Seasonal peak demand trends slightly higher than last year's model inputs

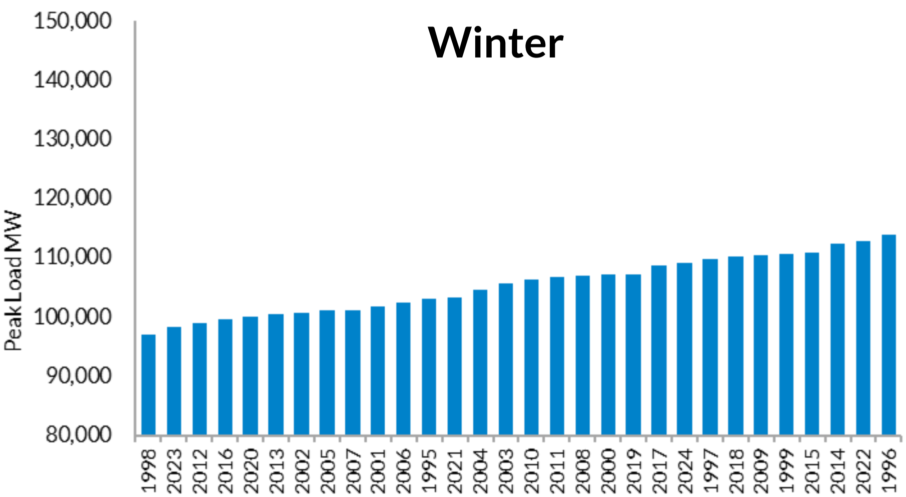
Zone	Summer (MW)	Fall (MW)	Winter (MW)	Spring (MW)
MISO	124,640	110,748	105,441	100,761
LRZ 1 (DPC, GRE, MDU, MP, NSP, OTP, SMP)	18,837	16,143	16,117	16,134
LRZ 2 (ALTE, MGE, MIUP, UPPC, WEC, WPS)	12,962	11,069	9,909	10,506
LRZ 3 (ALTW, MEC, MPW)	10,569	9,410	9,034	8,647
LRZ 4 (AMIL, CWLP, GLH, SIPC)	8,793	8,145	7,576	6,880
LRZ 5 (AMMO, CWLD)	8,261	7,142	7,247	6,845
LRZ 6 (BREC, CIN, HE, HMPL, IPL, NIPS, SIGE)	17,762	15,949	15,679	14,795
LRZ 7 (CONS, DECO)	21,251	18,715	14,486	16,560
LRZ 8 (EAI)	8,263	7,468	7,639	6,812
LRZ 9 (CLEC, EES, LAFA, LAGN, LEPA)	22,023	20,362	20,023	19,702
LRZ 10 (EMBA, SME)	5,171	4,802	4,691	4,519

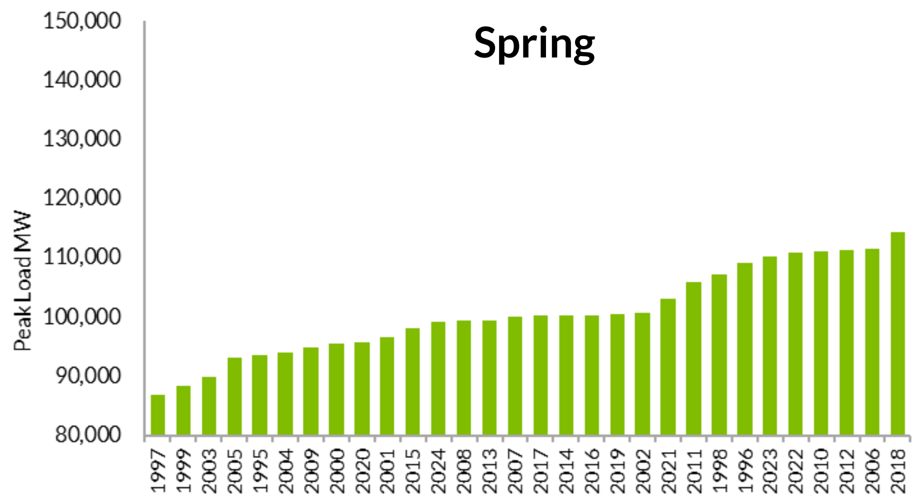
2026-2027 PY input load summary

Seasonal Peak Load Variability by Weather Year









Economic Load Uncertainty Development

Inputs

- Bureau of Economic Analysis (BEA): Actual GDP growth
- Congressional Budget Office (CBO): Historic projections for GDP growth
- U.S. Energy Information Administration (EIA): Annual electricity usage

Process

1. Develop comparison factor of actual GDP growth and historic projections of GDP growth (GDP forecast error)
2. Translate the GDP forecast error into an electric utility forecast error by multiplying by a scalar
   - Scalar: Rate at which electric load has grown over the course of the analysis period in comparison to projected and realized GDP
3. Determine standard deviations of electric load growth
   - Using the standard deviations, create a normal distribution of load forecast error

GDP: Gross Domestic Product

Economic Load Uncertainty Probability

- Over the last 15 years, the U.S. economy has experienced significant growth in GDP but minimal growth in electricity consumption, decoupling the relationship between economic uncertainty and electricity usage uncertainty
- Reasons for the stagnation in electricity consumption growth include energy efficiency improvements, slower population growth, and the continuing shift from a manufacturing to service economy
- Looking into the future, significant load growth has been forecasted across the MISO system, largely driven by the expansion of large data centers and electrification

	Load Forecast Error (LFE) Levels				
	-2.0%	-1.0%	0.0%	1.0%	2.0%
Standard Deviation in LFE	**Probability Assigned to Each LFE**				
0.63%	1.1%	21.0%	55.8%	21.0%	1.1%

SERVM Simulation Framework

30 Weather Years (Equal Probability) x 5 Economic Uncertainties (Normal Distribution) = 150 Load Scenarios

150 Load Scenarios x 50 Forced Outage Draws* = 45,000 Annual Hourly Simulations

**Number of forced outage draws used only as an example and are not fixed*

Appendix

LRZ Annual Average Peak Demand Summary

Zone	PY2026-27 (MW)	PY2029-30 (MW)	PY2031-32 (MW)	5-Year AAGR[1]
MISO	124,640	136,205	138,836	2.3%
LRZ1 (DPC, GRE, MDU, MP, NSP, OTP, SMP)	18,838	20,443	20,934	2.2%
LRZ2 (ALTE, MGE, MIUP, UPPC, WEC, WPS)	12,962	14,795	15,312	3.6%
LRZ3 (ALTW, MEC, MPW)	10,592	12,354	12,556	3.7%
LRZ4 (AMIL, CWLP, SIPC)	8,865	9,593	9,732	2.0%
LRZ5 (AMMO, CWLD)	8,309	8,952	8,872	1.4%
LRZ6 (BREC, CIN, HE, HMPL, IPL, NIPS, SIGE)	17,858	18,563	18,839	1.1%
LRZ7 (CONS, DECO)	21,287	21,923	22,256	0.9%
LRZ8 (EAI)	8,381	8,605	8,709	0.8%
LRZ9 (CLEC, EES, LAFA, LAGN, LEPA)	22,055	25,707	26,428	4.0%
LRZ10 (EMBA, SME)	5,229	6,071	6,158	3.6%

[1]AAGR = Average Annual Growth Rate

Average Monthly Peak Demand Load by Zone (MW) for Planning Year 2026-2027

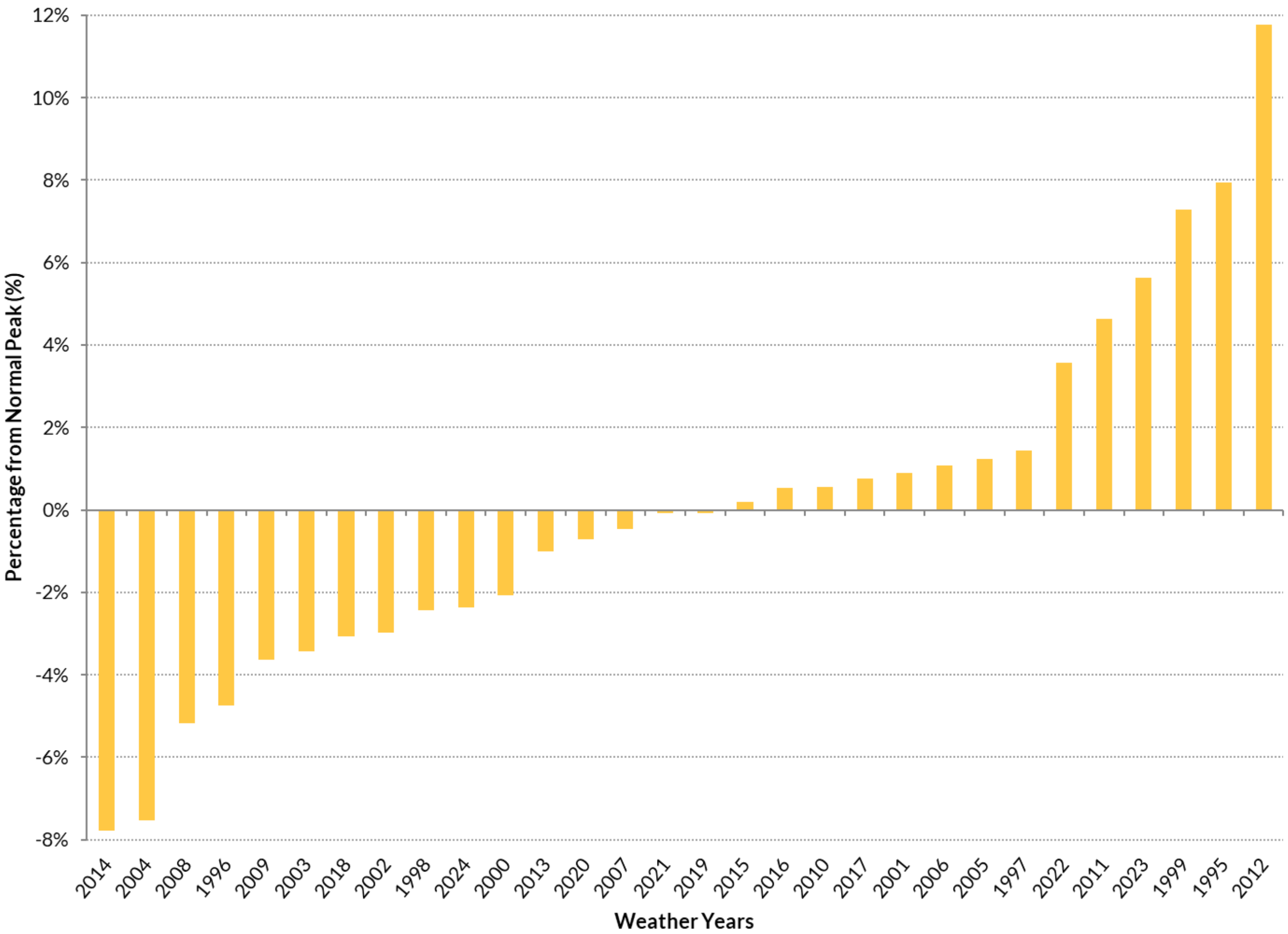
Month	LRZ1	LRZ2	LRZ3	LRZ4	LRZ5	LRZ6	LRZ7	LRZ8	LRZ9	LRZ10	MISO
1	15,852	9,792	8,883	7,358	7,016	15,407	14,248	7,426	19,778	4,553	104,105
2	15,145	9,452	8,545	7,234	6,774	14,536	13,965	6,763	17,391	4,055	98,111
3	14,782	9,155	7,815	6,039	6,183	13,528	12,617	6,195	17,471	3,720	92,346
4	13,252	8,614	7,367	5,323	5,317	11,968	12,430	5,764	17,517	3,535	82,932
5	15,144	10,376	8,516	6,726	6,609	14,453	16,531	6,666	19,654	4,512	99,701
6	17,398	11,742	9,589	8,017	7,525	16,178	19,910	7,550	20,734	4,800	115,724
7	18,627	12,658	10,412	8,623	7,909	17,157	20,416	8,136	21,708	5,052	123,632
8	18,083	12,433	10,001	8,426	7,892	17,117	20,108	7,942	21,296	5,055	119,920
9	16,130	11,069	9,342	8,124	7,072	15,898	18,715	7,418	20,351	4,775	110,748
10	13,468	8,952	7,784	6,181	5,705	12,842	13,407	6,457	18,554	4,116	90,567
11	14,034	8,961	7,918	6,543	5,697	13,016	13,169	6,026	16,717	3,780	89,685
12	15,330	9,669	8,539	6,903	6,326	14,041	14,128	6,757	18,244	4,158	98,585

SERVM Load Scaling Factors for Planning Year 2026-2027

Month	LRZ1	LRZ2	LRZ3	LRZ4	LRZ5	LRZ6	LRZ7	LRZ8	LRZ9	LRZ10
January	105.7%	109.9%	113.3%	100.6%	106.1%	106.4%	110.3%	114.1%	109.1%	116.4%
February	101.4%	108.3%	113.4%	100.3%	107.7%	105.7%	109.5%	111.7%	101.6%	114.3%
March	106.4%	108.6%	110.2%	91.8%	110.3%	107.5%	101.6%	112.4%	108.7%	116.0%
April	100.7%	105.2%	110.1%	85.0%	105.8%	106.4%	103.8%	114.3%	102.5%	116.1%
May	107.4%	110.5%	110.3%	89.0%	113.7%	105.3%	110.4%	111.9%	105.4%	125.9%
June	106.7%	102.4%	107.6%	94.7%	104.1%	102.4%	107.4%	107.2%	102.6%	111.5%
July	112.1%	108.0%	112.2%	100.8%	102.8%	105.4%	108.6%	109.4%	104.8%	111.9%
August	113.4%	107.7%	110.6%	99.2%	103.2%	106.9%	109.0%	105.2%	103.1%	112.0%
September	106.1%	102.1%	110.5%	100.8%	104.0%	103.9%	110.7%	106.6%	102.6%	112.5%
October	107.7%	106.8%	111.5%	95.5%	110.6%	109.0%	109.3%	117.7%	104.1%	123.4%
November	102.5%	107.2%	111.3%	108.5%	107.5%	107.1%	108.4%	112.0%	105.2%	117.2%
December	105.9%	110.5%	113.6%	101.4%	102.7%	103.5%	111.3%	110.4%	105.5%	115.0%

These factors were used to scale the average of the 30 load shapes to the LSE Module E forecasts

MISO Peak Load Variability Assuming Historical Weather



Based on PY2026-2027 annual peak data

Attachment B

MISO 2025 PRA Report

Planning Resource Auction
Results for Planning Year 2025-26

April 2025

CORRECTIONS
Reposted 05/29/25

Slides Updated: 7, 11, 18-20, 23, 32-34

MISO met the planning year 2025/26 resource adequacy requirements, but pressure persists with reduced capacity surplus across the region and is reflected through improved price signals in this year's auction

Summer
$666.50
–
Fall
$91.60 (North/Central)
$74.09 (South)
–
Winter
$33.20
–
Spring
$69.88
–
Annualized
$217 (North/Central)
$212 (South)

- MISO's Reliability-Based Demand Curve (RBDC) improves price signals, reflecting the increased value of accredited capacity beyond the seasonal Planning Reserve Margin (PRM) target
  - For example, the auction cleared 1.9% above the 7.9% summer PRM target
- Summer price reflects the lowest available surplus capacity
  - Fall price varied slightly due to transfer limitations between the North and South
- Consistent with past years, most Load Service Entities (LSEs) self-supplied or secured capacity in advance and are hedged with respect to auction prices
- Surplus above the target PRM dropped 43% compared to last summer, despite the slightly lower PRM target (7.9% vs. 9.0% last year)
  - New capacity additions did not keep pace with reduced accreditation, suspensions/retirements and slightly reduced imports
- The results reinforce the need to increase capacity, as demand is expected to grow with new large load additions

Auction outcomes are consistent with the design intent of the Reliability-Based Demand Curve (RBDC), and MISO and its members can expect more stable and predictable capacity pricing, especially in surplus situations

In the 2025 PRA, the RBDC…

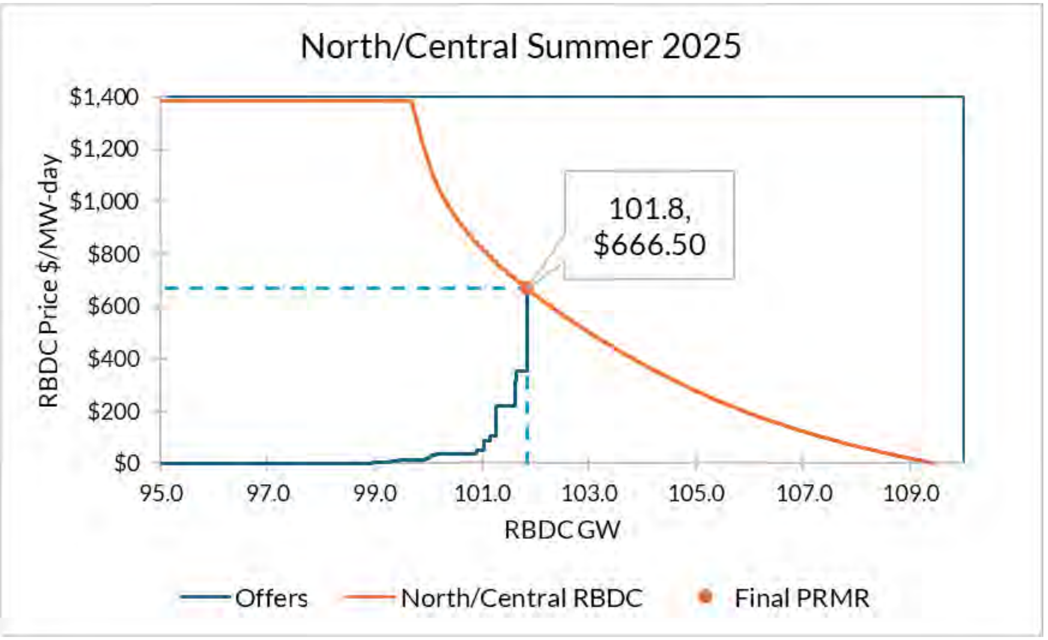
- Delivers competitive prices aligned with seasonal risks and tightening surplus
  - Prioritizes summer availability, the system's highest-risk season (based on 1-in-10 LOLE)
- Values incremental capacity above and below the LOLE target based on its reliability
  - Clears capacity above target Planning Reserve Margin based on its reliability value in each season
- Stabilizes prices in non-summer seasons, avoiding extreme volatility

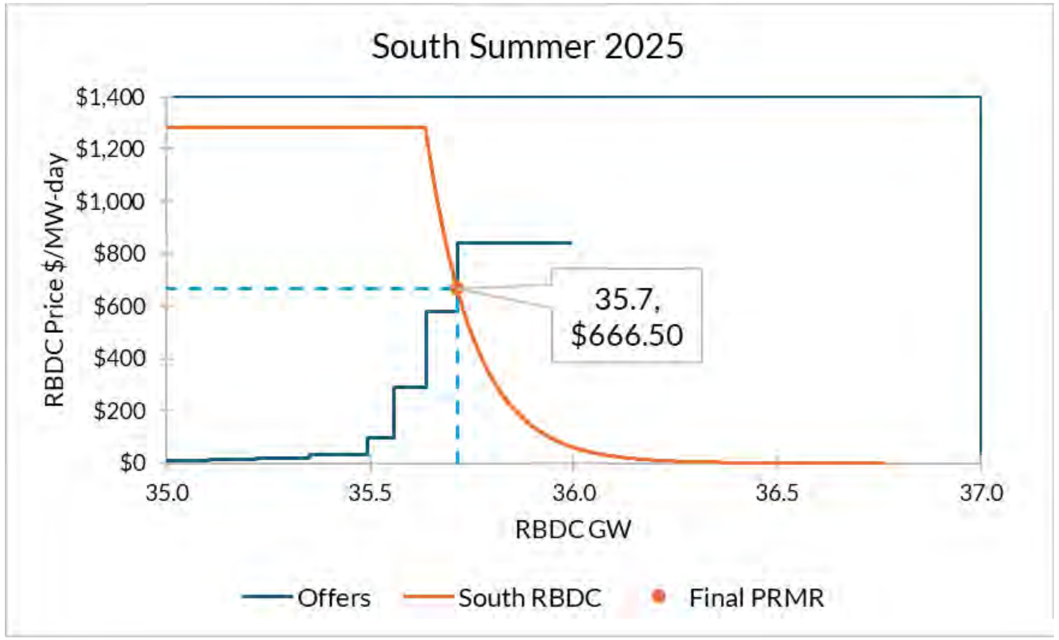
Why it Matters

- Sends clear and stable investment signals across the system, including to external resources
- Provides transparent value for capacity that exceeds the Planning Reserve Margin target
- Reflects subregional capacity needs and clears accordingly across all seasons

LOLE: Loss of Load Expectation

Auction pricing outcomes with the Reliability-Based Demand Curve (RBDC) better reflect value of capacity and resource adequacy risk across seasons





- Summer clearing of $666.50 reflects highest reliability risk and reducing surplus capacity year-over-year
  - Surplus capacity in the summer has reduced from approximately 6.5 GW in 2023, to 4.6 GW in 2024, to 2.6 GW in 2025
- Incremental capacity cleared beyond the target Planning Reserve Margin based on the value it adds to reliability (e.g., North/Central “effective” summer margin at 10.1% and South at 8.7% vs. target 7.9%)
  - A small quantity of capacity, that was offered at a price higher than the reliability value indicated through the demand curve, did not clear

LOLE: Loss of Load Expectation

MISO's Reliability-Based Demand Curve (RBDC) improves price signals, reflecting the increased value of accredited capacity beyond seasonal reliability targets

- Under RBDC, each season has an initial reliability target (PRM%)
- Auction cleared above seasonal final reliability target, representing additional reliability value at cost-competitive prices

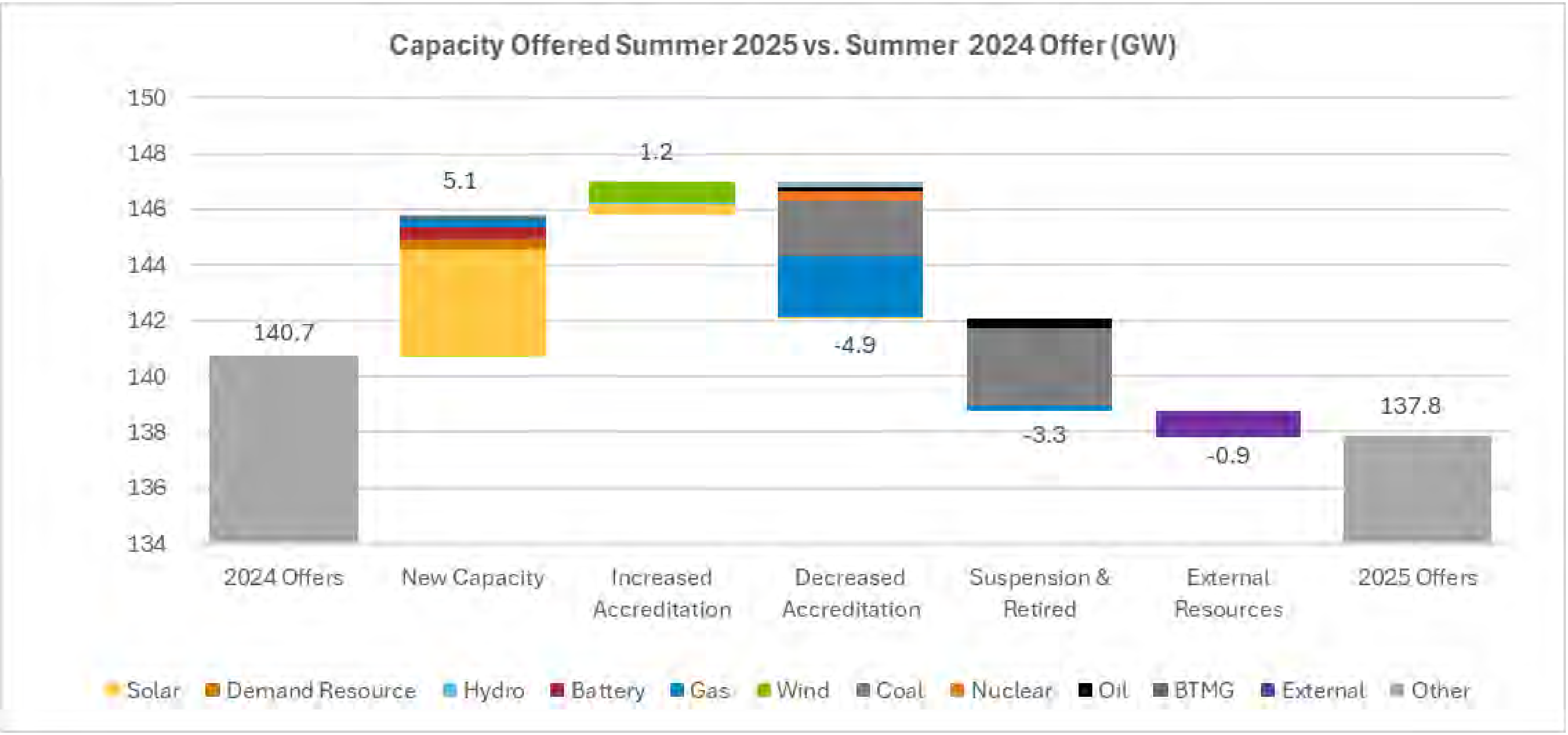
	2025 Planning Resource Auction Initial Target vs. Final Cleared	Additional Reliability	Auction Clearing Price
Summer	Initial, 7.90% Cleared, 9.80%	+1.9%	$666.50
Fall	Initial, 14.90% Cleared, 17.50%	+2.6%	$91.60 N/C $74.09 S
Winter	Initial, 18.40% Cleared, 24.50%	+6.1%	$33.20
Spring	Initial, 25.30% Cleared, 26.80%	+1.5%	$69.88

Annualized
$217 (North/Central)
$212 (South)

PRM: Planning Reserve Margin

05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

New capacity additions did not keep pace with decreased accreditation, suspensions/ retirements and external resources



BTMG: Behind the Meter Generation | Capacity indicated is offered accredited value

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

Ongoing Challenges

- Accelerating demand for electricity
- Rapid pace of generation retirements continue
- Loss of accredited capacity and reliability attributes
- Majority of new resources with variable, intermittent output and high weather correlation
- Delays of new resource additions
- More frequent extreme weather

Completed Initiatives

- ✓ Implemented Reliability-Based Demand Curve in 2025 PRA
- ✓ Non-emergency resource accreditation *(effective PY 2028/29)*
- ✓ Generation interconnection queue cap
- ✓ Improved generator interconnection queue process (*New application portal coming June 2025)*
- ✓ Approved over $30 billion in new transmission lines

Initiatives In Progress

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

Next Steps

April 28

2025 PRA Results Posted

May 21

Zonal deliverability benefits available at the May RASC
—
MISO publishes cleared Load Modifying Resources to Operations tools

May 28

Posting of PRA masked offer data per Module E-1 69 A.7.4

June 1

2025 PRA prices go into affect
—
New Planning Year starts

Appendix

Table of Contents

Acronyms

ACP: Auction Clearing Price

ARC: Aggregator of Retail Customers

BTMG: Behind the Meter Generator

CIL: Capacity Import Limit

CEL: Capacity Export Limit

CONE: Cost of New Entry

CPF: Coincident Peak Forecast

DLOL: Direct Loss-of-Load

DR: Demand Resource

ELCC: Effective Load Carrying Capability

EE: Energy Efficiency

ER: External Resource

ERAS: Expedited Resource Addition Study

ERZ: External Resource Zones

FRAP: Fixed Resource Adequacy Plan

ICAP: Installed Capacity

IMM: Independent Market Monitor

LBA: Load Balancing Authority

LCR: Local Clearing Requirement

LOLE: Loss of Load Expectation

LMR: Load Modifying Resource

LRR: Local Reliability Requirement

LRZ: Local Resource Zone

LSE: Load Serving Entity

OMS: Organization of MISO States

PO: Planned Outage

PRA: Planning Resource Auction

PRM: Planning Reserve Margin

PRMR: Planning Reserve Margin Requirement

RASC: Resource Adequacy Sub-Committee

RBDC: Reliability-Based Demand Curve

SAC: Seasonal Accredited Capacity

SREC: Sub-Regional Export Constraint

SRIC: Sub-Regional Import Constraint

SRPBC: Sub-Regional Power Balance Constraint

SS: Self Schedule

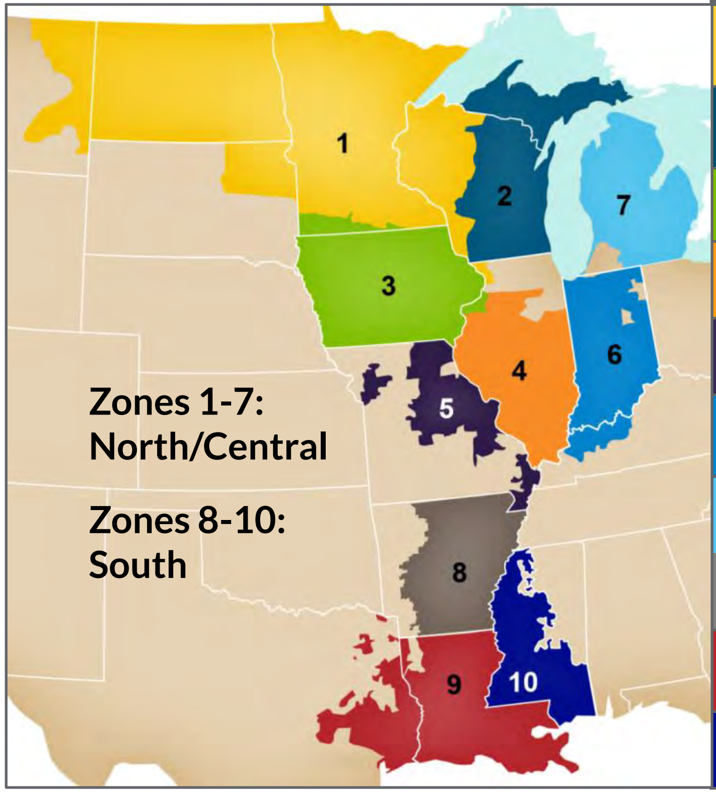
UCAP: Unforced Capacity

ZIA: Zonal Import Ability

ZRC: Zonal Resource Credit

The 2025 PRA demonstrated sufficient capacity at the regional, subregional and zonal levels, with the summer price reflecting the highest risk and a tighter supply-demand balance

MISO Resource Adequacy Zones



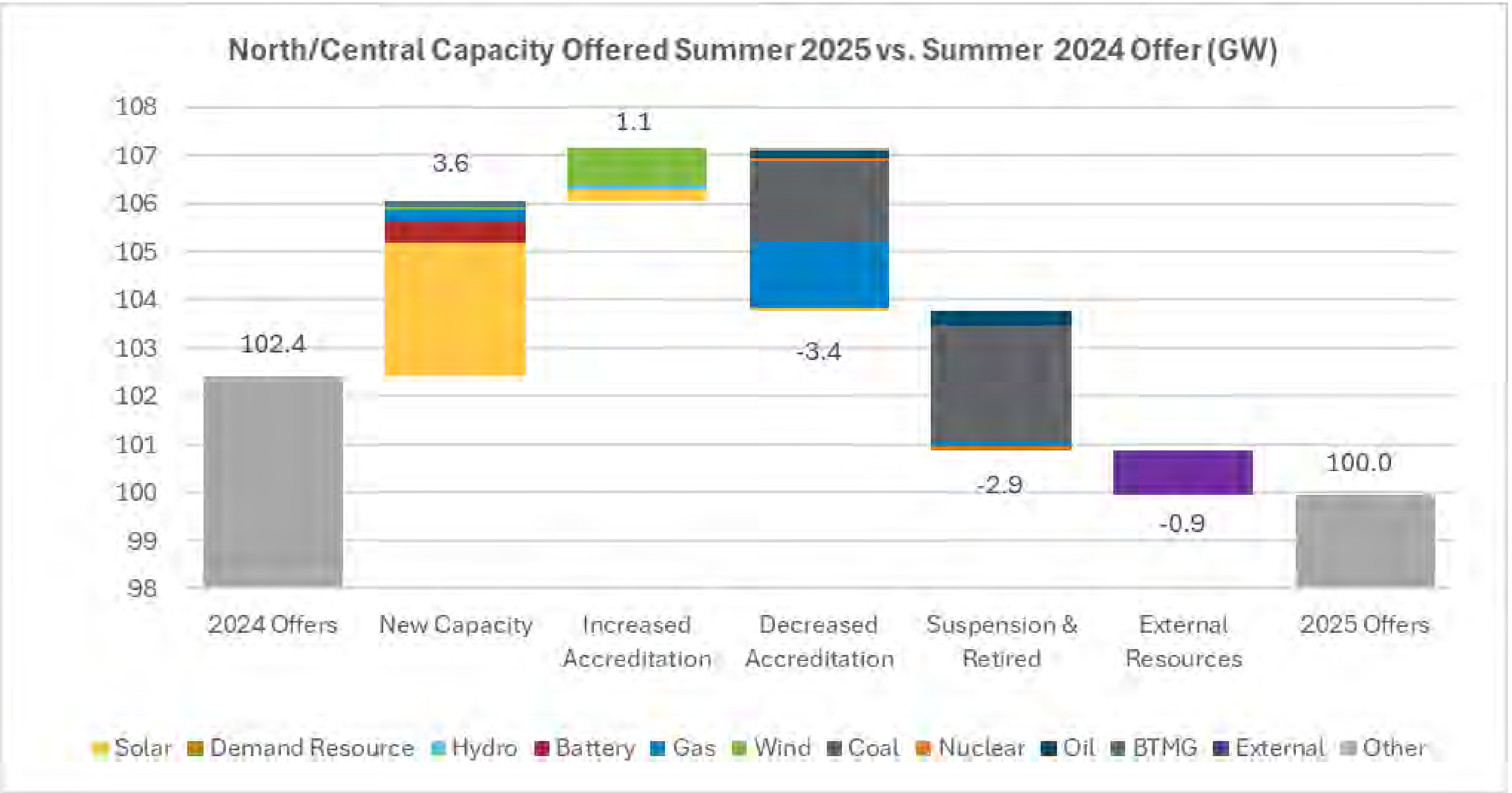
2025 PRA Results

<table>
<tr><th rowspan="2"></th><th colspan="4">Price/MW-Day</th></tr>
<tr><th>Summer</th><th>Fall</th><th>Winter</th><th>Spring</th></tr>
<tr><td>1</td><td rowspan="10">$666.50</td><td rowspan="7">$91.60</td><td rowspan="10">$33.20</td><td rowspan="10">$69.88</td></tr>
<tr><td>2</td></tr>
<tr><td>3</td></tr>
<tr><td>4</td></tr>
<tr><td>5</td></tr>
<tr><td>6</td></tr>
<tr><td>7</td></tr>
<tr><td>8</td><td rowspan="3">$74.09</td></tr>
<tr><td>9</td></tr>
<tr><td>10</td></tr>
</table>

Annualized
$217 (North/Central)
$212 (South)

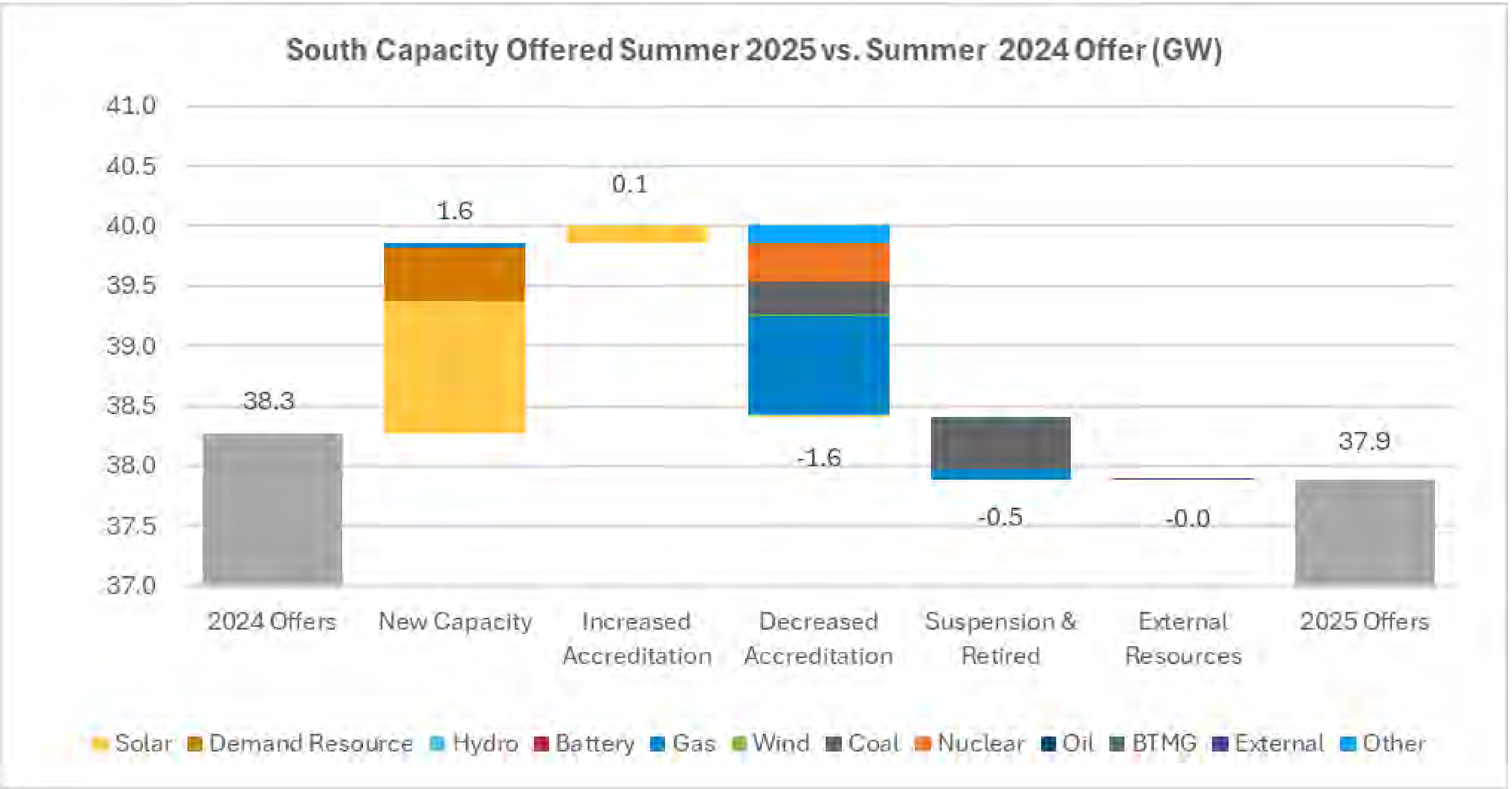
05/29/2025: *MISO Planning Resource Auction for Planning Year 2025/26 Results Posting*

For North/Central, new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources



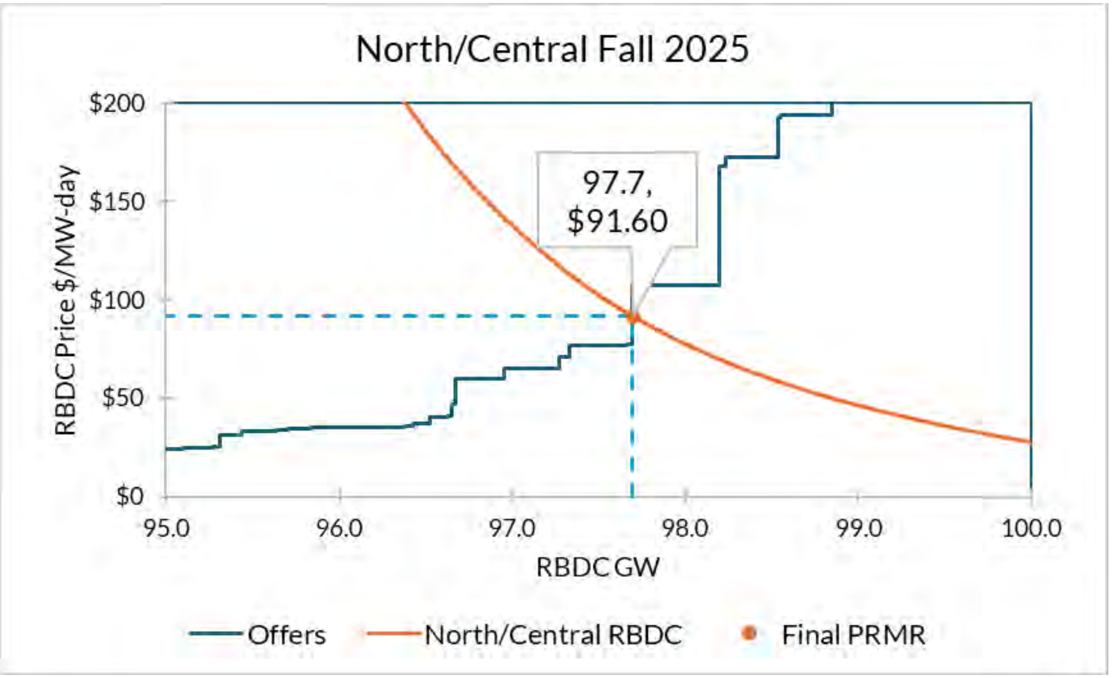
BTMG: Behind the Meter Generation | Capacity indicated is offered accredited value

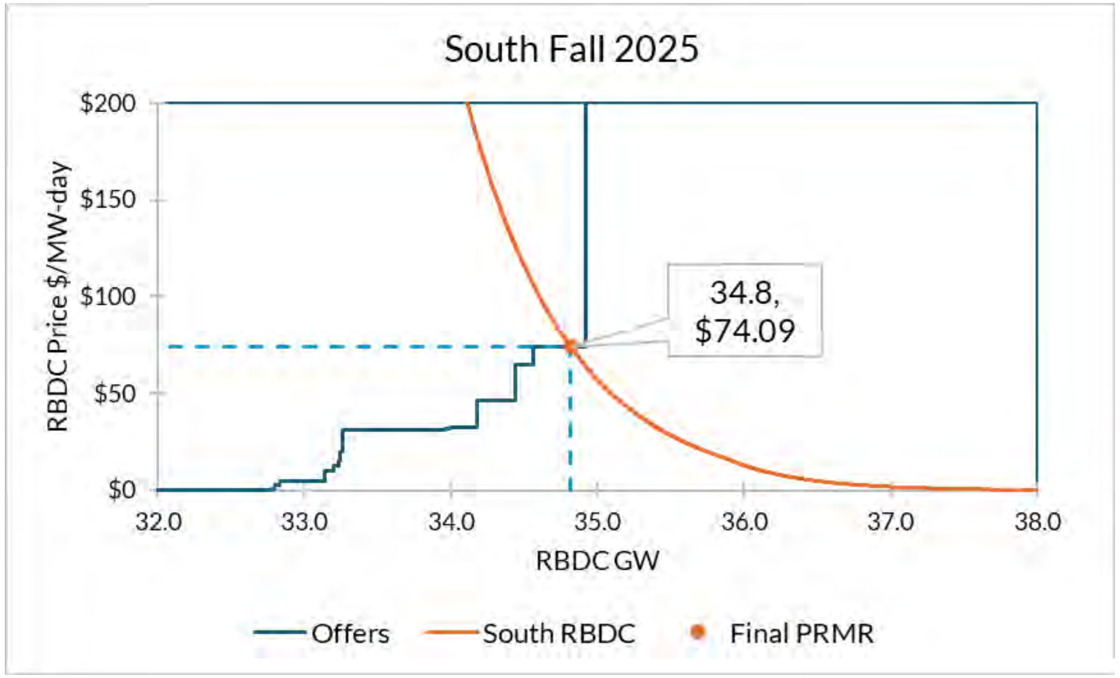
For the South, new capacity additions nearly offset the negative impacts of decreased accreditation, suspensions/retirements



BTMG: Behind the Meter Generation | Capacity indicated is offered accredited value

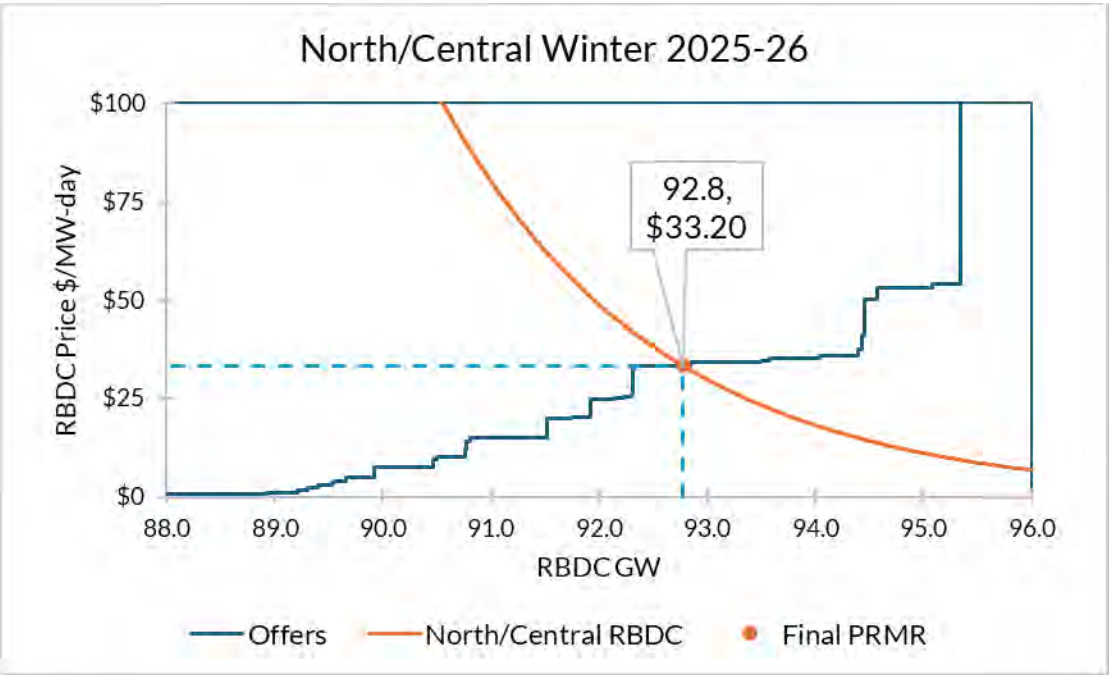
Fall 2025 Reliability-Based Demand Curve, Offer Curves and Auction Clearing Prices

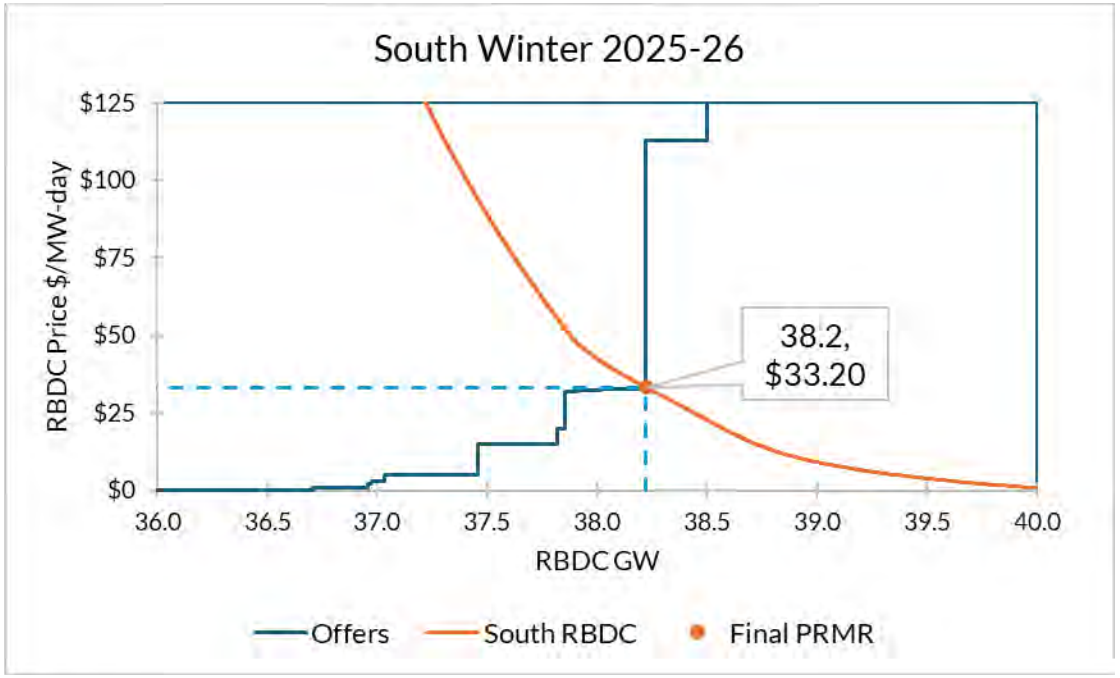




- Subregional RBDCs are determining clearing for both subregions
- Subregional Power Balance Constraint (SRPBC), South to North, is binding resulting in price separation between North/Central and South subregions in Fall season
  - ACP for North subregion is $91.60, and $74.09 South subregion
  - A marginal resource in the South sets the price in that subregion
- In fall season, “effective” margin for North/Central subregion is at 18.4% and 15.2 % for South subregion vs. target of 14.9%

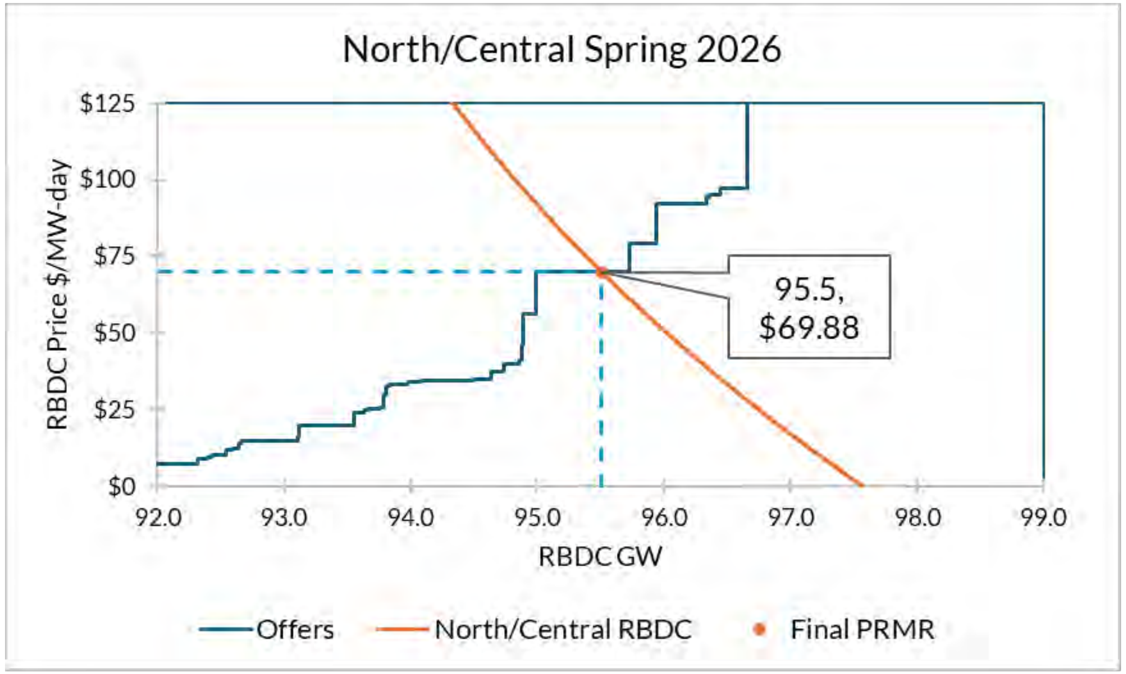
Winter 2025/26 Reliability-Based Demand Curve, Offer Curves and Auction Clearing Prices

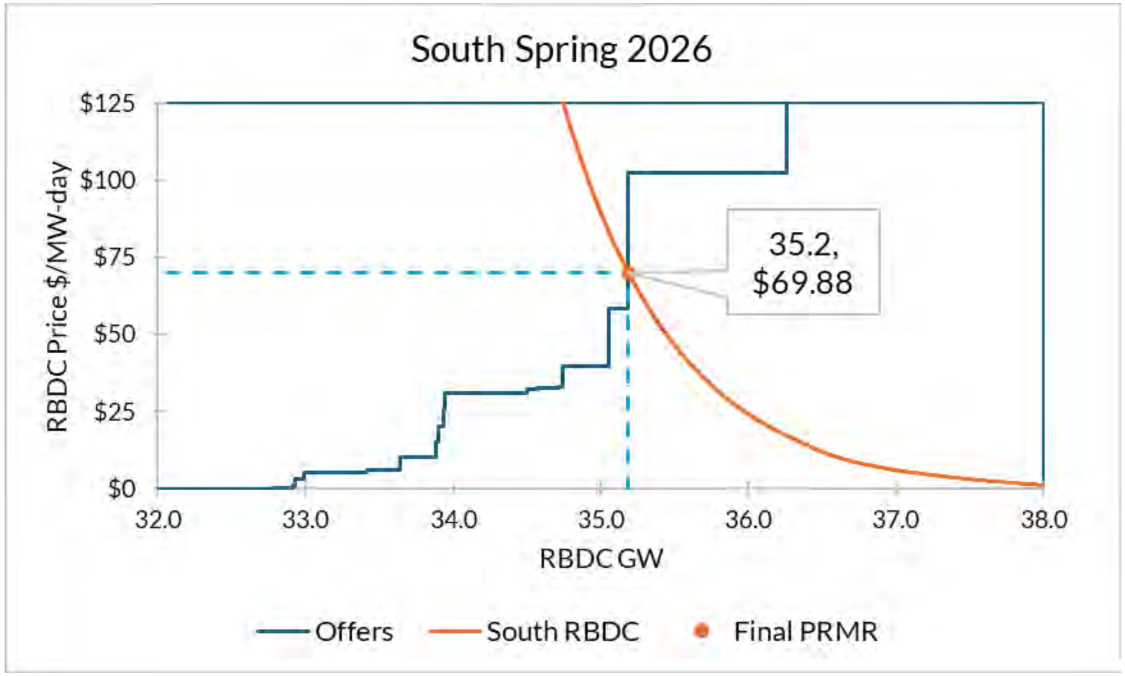




- Subregional RBDCs are determining clearing for both subregions
- No price separation between North/Central and South subregions in winter
  - ACP for both subregions is $33.20
  - Multiple marginal resources, cleared *pro rata*, sets the price
- In winter, “effective” margin for North/Central subregion is at 23.3% and $27.3% for South subregion vs. target of 18.4%

Spring 2026 Reliability-Based Demand Curve, Offer Curves and Auction Clearing





- Subregional RBDCs are determining clearing for both subregions
- No price separation between North/Central and South subregions in spring
    - ACP for both subregions is $69.88
    - A marginal resource sets the price
- In spring, "effective" margin for North/Central subregion is at 27.5% and 25% for South subregion vs. target of 25.3%

Summer 2025 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	North	South	System
Initial PRMR	18,459.4	13,190.2	10,889.2	9,237.6	8,281.3	18,484.8	21,228.0	8,487.8	21,812.2	5,142.9	N/A	99,770.5	35,442.9	135,213.4
Final PRMR	18,843.5	13,464.4	11,116.0	9,430.10	8,453.5	18,868.9	21,669.2	8,552.6	21,978.8	5,182.3	N/A	101,845.6	35,713.7	137,559.3
Offer Submitted (Including FRAP)	19,732.4	14,569.7	11,321.4	9,328.1	6,737.9	16,123.6	20,883.9	11,517.3	20,498.6	5,543.3	1580.1	99,952.6	37,883.7	137,836.3
FRAP	4,619.2	10,252.6	456.9	789.4	0.0	1,080.7	541.3	494.9	157.5	1,507.7	46.8	17,779.2	2,167.8	19,947.0
RBDC Opt-Out	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0
Self Scheduled (SS)	4,985.3	3,344.1	10,450.2	7,677.2	6,647.8	11,080.3	20,305.5	10,260.6	17,870.6	3,831.3	1,358.8	65,567.6	32,244,1	97,811.7
Non-SS Offer Cleared	10,127.9	973.0	414.3	861.5	90.1	3,962.6	37.1	761.8	2,193.5	204.3	174.5	16,605.8	3,194.8	19,800.6
Committed (Offer Cleared + FRAP)	19,732.4	14,569.7	11,321.4	9,328.1	6,737.9	16,123.6	20,883.9	11,517.3	20,221.6	5,543.3	1,580.1	99,952.6	37,606.7	137,559.3
LCR	15,696.9	9,719.3	8,049.3	2,577.8	6,071.1	13,051.7	19,681.4	8,487.0	19,615.0	2,523.8	-	N/A	N/A	N/A
CIL	6,025	4,370	5,555	8,525	4,117	8,651	3,569	2,568	4,361	4,474	-	N/A	N/A	N/A
ZIA	6,023	4,370	5,460	7,757	4,117	8,366	3,569	2,358	4,361	4,474	-	N/A	N/A	N/A
Import	0.0	0.0	0.0	101.7	1,715.5	2,745.5	785.5	0.0	1,757.1	0.0	-	1,893.0	0.0	1,580.1
CEL	3,991	4,614	4,618	4,584	3,939	6,881	5,726	6,299	4,286	2,097	-	N/A	N/A	N/A
Export	888.8	1105.2	205.5	0.0	0.0	0.0	0.0	2964.7	0.0	360.9	1,580.1	0.0	1,893.0	-
ACP ($/MW-Day)	666.50	666.50	666.50	666.50	666.50	666.50	666.50	666.50	666.50	666.50	666.50			N/A

Values displayed in MW SAC; ERZ: External Resource Zones | Final PRMR values provided at Zonal level given lack of RBDC Opt-Out.

Fall 2025 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	North	South	System
Initial PRMR	17,290.4	12,086.4	10,179.1	8,950.4	7,898.3	17,939.5	20,493.9	8,019.3	21,578.1	5,142.6	N/A	94,838.0	34,740.0	129,578.0
Final PRMR	17,811.9	12,450.7	10,486.0	9,220.4	8,136.0	18,480.2	21,111.9	8,037.4	21,627.1	5,154.2	N/A	97,697.1	34,818.7	132,515.8
Offer Submitted (Including FRAP)	18,893.1	14,291.7	13,615.9	8,887.5	6,839.6	15,518.1	19,517.6	11,000.8	21,112.5	5,516.6	1,582.1	98,835.3	37,940.2	136,775.5
FRAP	4,233.2	9,259.1	582.7	773.3	0.0	983.1	533.1	459.4	153.4	1,518.3	44.6	16,402.6	2,137.6	18,540.2
RBDC Opt-Out	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0
Self Scheduled (SS)	4,646.8	3,423.5	10,580.4	7,036.0	6,706.5	10,590.4	16,911.4	9,029.4	17,788.1	3,286.3	1,208.0	60,831.1	30,375.7	91,206.8
Non-SS Offer Cleared	9,019.0	834.8	2,452.8	1,078.2	133.1	3,728.7	1,089.1	1,512.0	2,406.6	254.9	259.6	18,563.3	4,205.5	22,768.8
Committed (Offer Cleared + FRAP)	17,899.0	13,517.4	13,615.9	8,887.5	6,839.6	15,302.2	18,533.6	11,000.8	20,348.1	5,059.5	1,512.2	95,797.1	36,718.7	132,515.8
LCR	14,691.0	6,591.1	6,331.4	2,588.7	4,857.2	11,725.4	18,196.1	5,006.3	18,963.6	2,577.6	-	N/A	N/A	N/A
CIL	5,740	6,537	7,797	7,773	4,679	8,952	5,115	5,839	4,741	4,508	-	N/A	N/A	N/A
ZIA	5,688	6,537	7,704	7,013	4,679	8,672	5,115	5,675	4,741	4,508	-	N/A	N/A	N/A
Import	0.0	0.0	0.0	332.8	1,296.8	3,178.0	2,578.2	0.0	1,278.9	94.7	-	1,900.0	0.0	1,512.2
CEL	6,115	4,259	5,831	4,309	5,816	5,191	5,168	4,055	4,173	3,164	-	N/A	N/A	N/A
Export	87.2	1,066.8	3,129.9	0.0	0.0	0.0	0.0	2,963.3	0.0	0.0	1,512.2	0.0	1,900.0	-
ACP ($/MW-Day)	91.60	91.60	91.60	91.60	91.60	91.60	91.60	74.09	74.09	74.10	83.24-91.60			N/A

Values displayed in MW SAC; ERZ: External Resource Zones | Final PRMR values provided at Zonal level given lack of RBDC Opt-Out.

Winter 2025/26 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	North	South	System
Initial PRMR	17,823.8	10,789.8	9,889.1	8,549.5	7,954.8	17,939.1	16,123.6	8,545.6	21,864.3	5,136.1	N/A	89,069.7	35,546.0	124,615.7
Final PRMR	18,565.8	11,238.7	10,300.9	8,905.1	8,285.9	18,685.7	16,794.7	9,189.0	23,511.0	5,522.7	N/A	92,776.8	38,222.7	130,999.5
Offer Submitted (Including FRAP)	19,750.7	13,217.2	12,059.1	7,547.1	6,339.9	14,679.5	19,957.3	10,751.9	22,273.0	5,939.7	1,746.5	94,964.8	39,297.1	134,261.9
FRAP	4,683.9	8,342.7	479.4	513.4	0.0	1,176.6	566.3	441.6	130.9	1,822.6	16.1	15,771.2	2,402.3	18,173.5
RBDC Opt-Out	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0
Self Scheduled (SS)	5,835.8	3,156.0	10,468.3	6,685.7	6,188.7	9,146.2	18,640.6	10,018.6	18,579.3	4,046.0	1,550.8	61,380.9	32,935.1	94,316.0
Non-SS Offer Cleared	7,977.9	1,062.6	1,044.5	271.5	99.9	4,008.7	397.0	291.7	3,105.5	71.1	179.6	15,007.6	3,502.4	18,510.0
Committed (Offer Cleared + FRAP)	18,497.6	12,561.3	11,992.2	7,470.6	6,288.6	14,331.5	19,603.9	10,751.9	21,815.7	5,939.7	1,746.5	92,159.7	38,839.8	130,999.5
LCR	13,462.0	5,951.6	8,008.4	1,371.4	3,644.7	11,074.8	15,500.2	8,014.7	20,593.7	3,534.1	-	N/A	N/A	N/A
CIL	6,177	6,522	5,877	7,232	4,922	7,927	4,762	3,613	4,418	3,458	-	N/A	N/A	N/A
ZIA	5,575	6,435	5,785	6,457	4,922	7,690	4,762	3,432	4,418	3,458	-	N/A	N/A	N/A
Import	68.0	0.0	0.0	1,434.8	1,997.3	4,354.1	0.0	0.0	1,695.2	0.0	-	617.1	0.0	1,746.5
CEL	2,991	4,706	7,388	4,756	4,814	1,674	5,712	3,602	3,618	2,028	-	N/A	N/A	N/A
Export	0.0	1,322.6	1,691.5	0.0	0.0	0.0	2,809.2	1,562.8	0.0	416.9	1,746.5	0.0	617.1	0.0
ACP ($/MW-Day)	33.20	33.20	33.20	33.20	33.20	33.20	33.20	33.20	33.20	33.20	33.20			N/A

Values displayed in MW SAC; ERZ: External Resource Zones | Final PRMR values provided at Zonal level given lack of RBDC Opt-Out.

Spring 2026 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	North	South	System
Initial PRMR	17,866.7	12,149.2	10,152.2	8,304.0	7,707.9	17,858.6	19,853.2	7,977.8	22,139.8	5,167.9	N/A	93,891.8	35,285.5	129,177.3
Final PRMR	18,174.5	12,358.6	10,327.0	8,447.2	7,841.0	18,166.7	20,195.5	7,955.2	22,076.1	5,157.7	N/A	95,510.5	35,189.0	130,699.5
Offer Submitted (Including FRAP)	18,662.6	14,525.3	12,333.3	9,178.5	6,118.7	15,824.7	19,451.0	11,495.2	21,064.7	5,864.0	1,542.6	97,313.7	38,746.9	136,060.6
FRAP	4,560.6	9,393.4	529.5	629.6	0.0	1,212.4	512.5	475.3	142.1	1,464.3	45.9	16,877.1	2,088.5	18,965.6
RBDC Opt-Out	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0
Self Scheduled (SS)	4,600.8	3,602.8	10,816.2	7,415.0	5,968.5	9,967.6	17,621.9	8,476.0	16,778.9	4,073.9	1,260.8	60,972.6	29,609.8	90,582.4
Non-SS Offer Cleared	8,578.5	1,069.5	589.6	1,133.9	150.2	4,001.0	719.2	1,470.2	2,947.5	325.8	166.1	16,372.9	4,778.6	21,151.5
Committed (Offer Cleared + FRAP)	17,739.9	14,065.7	11,935.3	9,178.5	6,118.7	15,181.0	18,853.6	10,421.5	19,868.5	5,864.0	1,472.8	94,222.5	36,477.0	130,699.5
LCR	12,239.1	6,737.5	5,014.7	1,823.8	4,700.3	10,377.1	16,453.6	4,243.1	19,790.5	3,178.8	-	N/A	N/A	N/A
CIL	6,598	6,439	7,829	8,142	4,453	9,457	5,166	6,289	4,855	4,365	-	N/A	N/A	N/A
ZIA	6,396	6,439	7,726	7,373	4,453	9,176	5,166	6,085	4,855	4,365	-	N/A	N/A	N/A
Import	434.5	0.0	0.0	0.0	1,722.2	2,985.6	1,341.9	0.0	2,210.8	0.0	-	1,288.0	0.0	1,472.8
CEL	5,083	6,119	5,936	5,111	5,797	6,425	5,499	3,520	4,146	3,072	-	N/A	N/A	N/A
Export	0.0	1,707.2	1,608.0	731.2	0.0	0.0	0.0	2,465.6	0.0	710.3	1,472.8	0.0	1,288.0	-
ACP ($/MW-Day)	69.88	69.88	69.88	69.88	69.88	69.88	69.88	69.88	69.88	69.88	69.88			N/A

Values displayed in MW SAC; ERZ: External Resource Zones | Final PRMR values provided at Zonal level given lack of RBDC Opt-Out.

Summer Supply Offered and Cleared Comparison Trend

	Offered (ZRC)			Cleared (ZRC)		
Planning Resource	Summer 2023	Summer 2024	Summer 2025	Summer 2023	Summer 2024	Summer 2025
Generation	122,375.6	123,395.6	121,015.6	116,989.7	119,479.2	120,738.6
External Resources	4,514.6	4,430.4	3,505.9	4,072.5	4,309.8	3,505.9
Behind the Meter Generation	4,175.2	4,180.2	4,282.8	4,129.4	4,143.5	4,282.8
Demand Resources	8,303.5	8,660.2	9,004.4	7,694.6	8,109.4	9,004.4
Energy Efficiency	5.0	22.5	27.6	5.0	22.5	27.6
Total	**139,373.9**	**140,688.9**	**137,836.3**	**132,891.2**	**136,064.4**	**137,559.3**

ZRC: Zonal Resource Credit

Fall Supply Offered and Cleared Comparison Trend

	Offered (ZRC)			Cleared (ZRC)		
Planning Resource	Fall 2023	Fall 2024	Fall 2025	Fall 2023	Fall 2024	Fall 2025
Generation	121,403.5	119,745.3	122,283.4	111,713.8	111,791.5	118,309.5
External Resources	4,095.4	4,366.8	2,833.5	3,979.6	3,990.2	2,763.6
Behind the Meter Generation	3,874.2	3,877.9	3,646.8	3,842.8	3,789.7	3,646.8
Demand Resources	6,999.2	6,866.1	7,983.7	6,254.4	5,957.5	7,767.8
Energy Efficiency	4.9	22.5	28.1	4.8	22.5	28.1
Total	**136,377.2**	**134,878.6**	**136,775.5**	**125,795.4**	**125,551.4**	**132,515.8**

ZRC: Zonal Resource Credit

Winter Supply Offered and Cleared Comparison Trend

	Offered (ZRC)			Cleared (ZRC)		
Planning Resource	**Winter 2023-2024**	**Winter 2024-2025**	**Winter 2025-2026**	**Winter 2023-2024**	**Winter 2024-2025**	**Winter 2025-2026**
Generation	124,632.7	133,457.4	120,225.1	114,886.6	118,253.8	117,392.0
External Resources	3,937.1	3,973.0	2,808.7	3,334.6	3,313.3	2,793.7
Behind the Meter Generation	3,257.8	3,111.5	3,082.9	3,173.9	2,957.3	3,082.6
Demand Resources	7,644.4	7,866.4	8,112.3	6,702.4	6,822.7	7,698.3
Energy Efficiency	6.7	29.7	32.9	6.7	29.7	32.9
Total	**139,478.7**	**148,438.0**	**134,261.9**	**128,104.2**	**131,376.8**	**130,999.5**

ZRC: Zonal Resource Credit

Spring Supply Offered and Cleared Comparison Trend

	Offered (ZRC)			Cleared (ZRC)		
Planning Resource	Spring 2024	Spring 2025	Spring 2026	Spring 2024	Spring 2025	Spring 2026
Generation	119,254.7	121,303.8	120,780.6	110,195.8	113,091.4	115,724.7
External Resources	3,794.1	3,481.8	2,640.1	3,409.1	3,406.5	2,570.3
Behind the Meter Generation	4,096.4	4,201.6	4,133.5	4,058.9	4,180.5	4,133.5
Demand Resources	7,282.9	7602.9	8,475.9	6,720.0	7,087.2	8,240.5
Energy Efficiency	5.3	25.0	30.5	5.3	25.0	30.5
Total	**134,433.4**	**136,615.1**	**136,060.6**	**124,389.1**	**127,790.6**	**130,699.5**

ZRC: Zonal Resource Credit

2025 PRA pricing compared with Independent Market Monitor (IMM) Conduct Threshold and Cost of New Entry (CONE)

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs	System CONE (Seasonal)	North/Central CONE (Seasonal)	South CONE (Seasonal)
Summer 2025	$666.50											$1,353.84	$1,384.36	$1,282.61
Fall 2025	$91.60							$74.09			$83.24-$91.60	$1,368.71	$1,399.58	$1,296.70
Winter 2025-26	$33.20											$1,383.92	$1,415.13	$1,311.11
Spring 2026	$69.88											$1,353.84	$1,384.36	$1,282.61
Cost of New Entry (Annual)	$127,720	$125,090	$121,220	$126,040	$136,170	$124,360	$130,930	$118,960	$117,710	$117,330	$136,170			
IMM Conduct Threshold*	$34.99	$34.27	$33.21	$34.53	$37.31	$34.07	$35.87	$32.59	$32.25	$32.15	-			

- *Zonal Auction Clearing Prices (ACP) shown in $/MW-day*

**Zonal Resource Credit (ZRC) offers that impact pricing should generally stay below the IMM Conduct Threshold and applies to all seasons.*

ERZ: External Resource Zones

Historical Summer Auction Clearing Price Comparison

<table>
<tr><th>PY</th><th>Zone 1</th><th>Zone 2</th><th>Zone 3</th><th>Zone 4</th><th>Zone 5</th><th>Zone 6</th><th>Zone 7</th><th>Zone 8</th><th>Zone 9</th><th>Zone 10</th><th>ERZs</th></tr>
<tr><td>2015-2016</td><td colspan="3">$3.48</td><td>$150.00</td><td colspan="3">$3.48</td><td colspan="2">$3.29</td><td>N/A</td><td>N/A</td></tr>
<tr><td>2016-2017</td><td>$19.72</td><td colspan="6">$72.00</td><td colspan="3">$2.99</td><td>N/A</td></tr>
<tr><td>2017-2018</td><td colspan="10">$1.50</td><td>N/A</td></tr>
<tr><td>2018-2019</td><td>$1.00</td><td colspan="9">$10.00</td><td>N/A</td></tr>
<tr><td>2019-2020</td><td colspan="6">$2.99</td><td>$24.30</td><td colspan="4">$2.99</td></tr>
<tr><td>2020-2021</td><td colspan="6">$5.00</td><td>$257.53</td><td>$4.75</td><td>$6.88</td><td>$4.75</td><td>$4.89-$5.00</td></tr>
<tr><td>2021-2022</td><td colspan="7">$5.00</td><td colspan="3">$0.01</td><td>$2.78-$5.00</td></tr>
<tr><td>2022-2023</td><td colspan="7">$236.66</td><td colspan="3">$2.88</td><td>$2.88-
236.66</td></tr>
<tr><td>Summer 2023</td><td colspan="11">$10.00</td></tr>
<tr><td>Summer 2024</td><td colspan="11">$30.00</td></tr>
<tr><td>Summer 2025</td><td colspan="11">$666.50</td></tr>
</table>

- Auction Clearing Prices shown in $/MW-Day

ERZ: External Resource Zones

Fall Auction Clearing Price Comparison

<table>
<tr><th>PY</th><th>Zone 1</th><th>Zone 2</th><th>Zone 3</th><th>Zone 4</th><th>Zone 5</th><th>Zone 6</th><th>Zone 7</th><th>Zone 8</th><th>Zone 9</th><th>Zone 10</th><th>ERZs</th></tr>
<tr><td>Fall 2023</td><td colspan="8">$15.00</td><td>$59.21</td><td colspan="2">$15.00</td></tr>
<tr><td>Fall 2024</td><td colspan="4">$15.00</td><td>$719.81</td><td colspan="6">$15.00</td></tr>
<tr><td>Fall 2025</td><td colspan="7">$91.60</td><td colspan="3">$74.09</td><td>$83.24-$91.60</td></tr>
</table>

- Auction Clearing Prices shown in $/MW-Day
- Price separation present in Fall 2025 between the North and South subregions since the Sub-Regional Import Constraint (SRIC) / Sub-Regional Export Constraint (SREC) bound

ERZ: External Resource Zones

Winter Auction Clearing Price Comparison

<table>
<tr><th>PY</th><th>Zone 1</th><th>Zone 2</th><th>Zone 3</th><th>Zone 4</th><th>Zone 5</th><th>Zone 6</th><th>Zone 7</th><th>Zone 8</th><th>Zone 9</th><th>Zone 10</th><th>ERZs</th></tr>
<tr><td>Winter 2023-24</td><td colspan="8">$2.00</td><td>$18.88</td><td colspan="2">$2.00</td></tr>
<tr><td>Winter 2024-25</td><td colspan="11">$0.75</td></tr>
<tr><td>Winter 2025-26</td><td colspan="11">$33.20</td></tr>
</table>

- Auction Clearing Prices shown in $/MW-Day

ERZ: External Resource Zones

Spring Auction Clearing Price Comparison

<table>
<tr><th>PY</th><th>Zone 1</th><th>Zone 2</th><th>Zone 3</th><th>Zone 4</th><th>Zone 5</th><th>Zone 6</th><th>Zone 7</th><th>Zone 8</th><th>Zone 9</th><th>Zone 10</th><th>ERZs</th></tr>
<tr><td>Spring 2024</td><td colspan="11">$10.00</td></tr>
<tr><td>Spring 2025</td><td colspan="4">$34.10</td><td>$719.81</td><td colspan="6">$34.10</td></tr>
<tr><td>Spring 2026</td><td colspan="11">$69.88</td></tr>
</table>

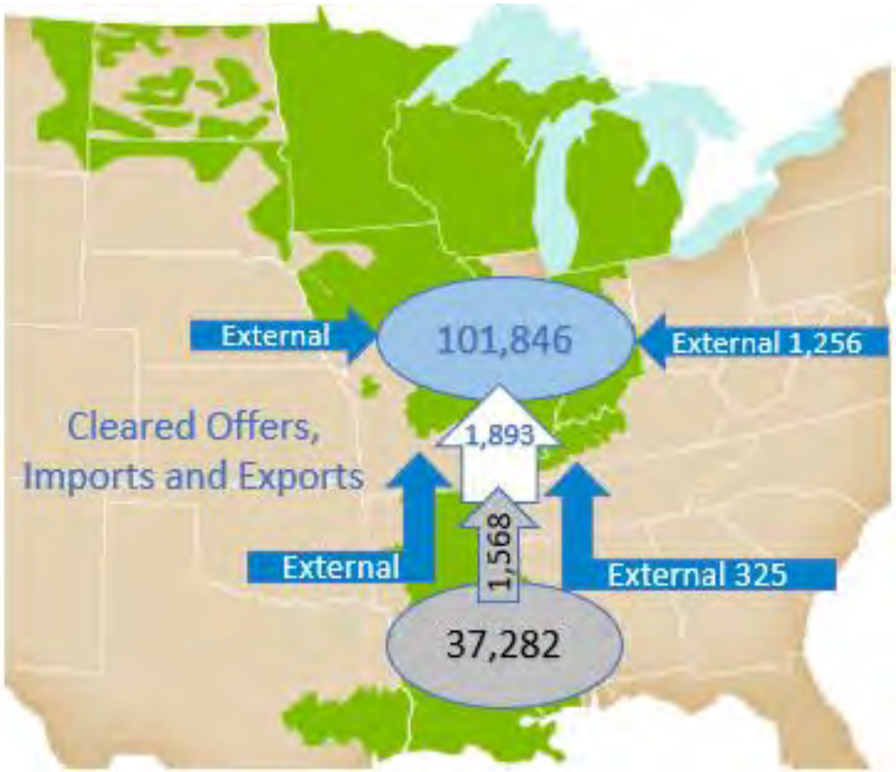
- Auction Clearing Prices shown in $/MW-Day

ERZ: External Resource Zones

Summer 2025 Capacity

Offered Capacity & Final PRMR (MW)

Cleared Capacity, Imports & Exports (MW)



PRMR: Planning Reserve Margin Requirement
Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers

05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Fall 2025 Capacity

Offered Capacity & Final PRMR (MW)

Cleared Capacity, Imports & Exports (MW)

PRMR: Planning Reserve Margin Requirement
Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Winter 2025/26 Capacity

Offered Capacity & Final PRMR (MW)

Cleared Capacity, Imports & Exports (MW)

PRMR: Planning Reserve Margin Requirement
Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Spring 2026 Capacity

Offered Capacity & Final PRMR (MW)

Cleared Capacity, Imports & Exports (MW)

PRMR: Planning Reserve Margin Requirement
Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

The 2025 auction resulted in a surplus compared to the PRMR target, in contrast to the 2024 OMS-MISO Survey projection of a shortfall

Summer 2025 auction outcomes vs. 2024 OMS-MISO Survey projection for 2025

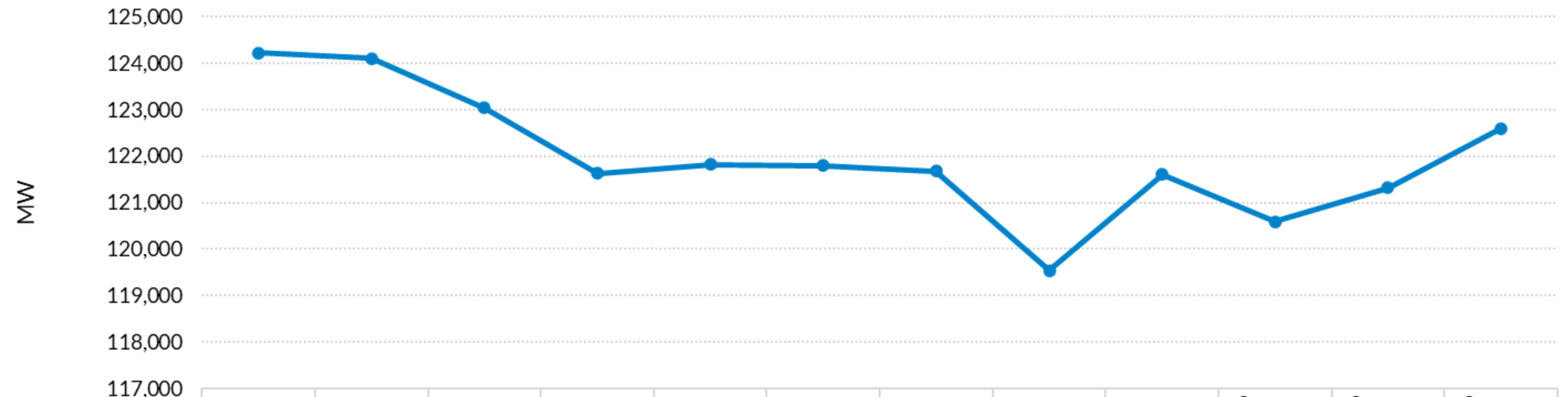
- Resource offers in the auction were comparable to “High Certainty” values projected in the OMS-MISO Survey
- Incremental accreditation reductions in the auction were offset by incremental increases in new resource additions
- Notably, initial PRMR was lower (5.5 GW) than projected in the OMS-MISO Survey

2024 OMS-MISO Survey Projection vs. 2025 PRA Actual PRMR Surplus (MW)

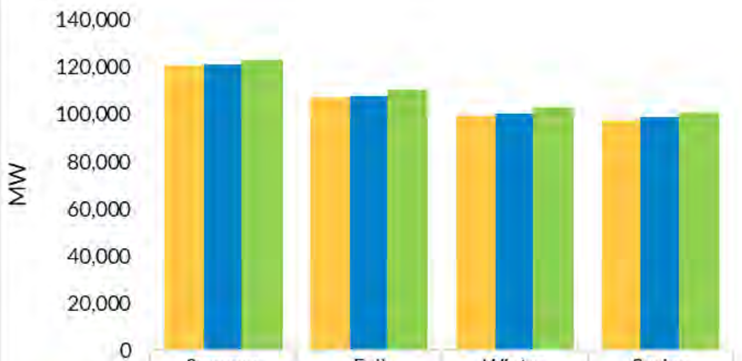
*PRA Shortfall/Surplus relative to Initial PRMR | PRMR: Planning Reserve Margin Requirement

Coincident Peak Forecast

Year over year the Summer CPF (+1.3 GW), PRM (-1.1%) and Final PRMR (+1.5 GW) are higher.



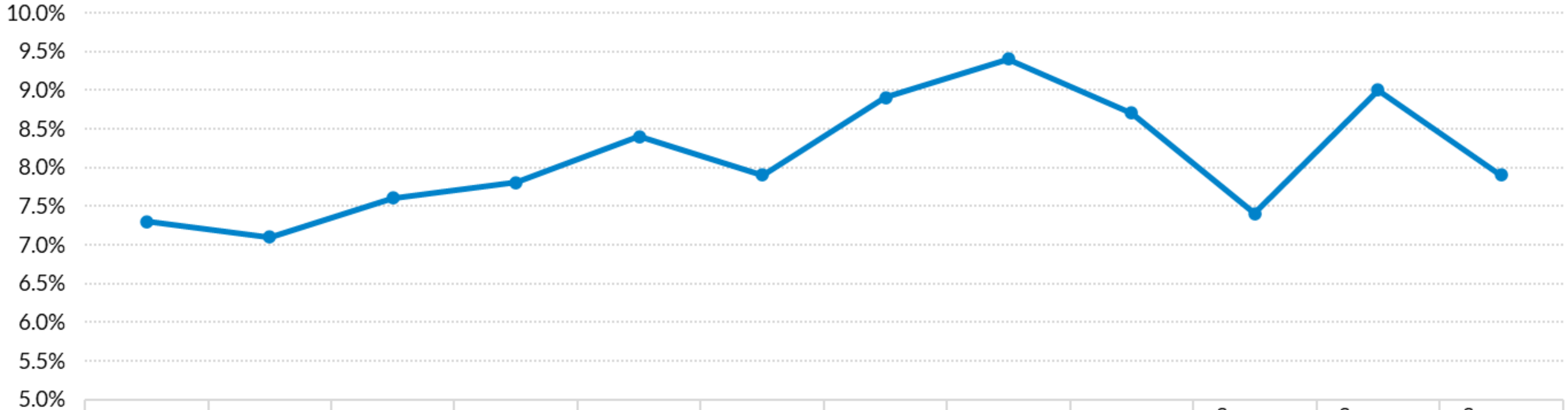
	2014	2015	2016	2017	2018	2019	2020	2021	2022	Summer 2023	Summer 2024	Summer 2025
Summer CPF	124,212.2	124,097.3	123,035.8	121,631.2	121,815.6	121,791.4	121,679.8	119,532.0	121,608.5	120,586.8	121,314.1	122,596.6



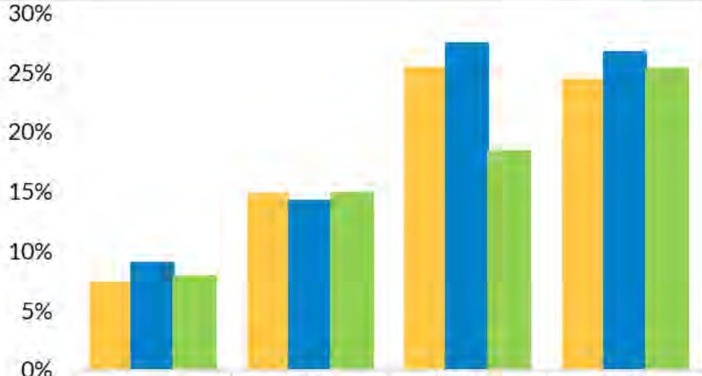
	Summer	Fall	Winter	Spring
2023-24	120,586.8	106,973.8	99,188.0	97,537.6
2024-25	121,314.1	107,701.4	100,114.6	98,697.8
2025-26	122,596.6	109,850.0	102,624.0	100,225.2

PRMR: Planning Reserve Margin Requirement

Planning Reserve Margin (%)

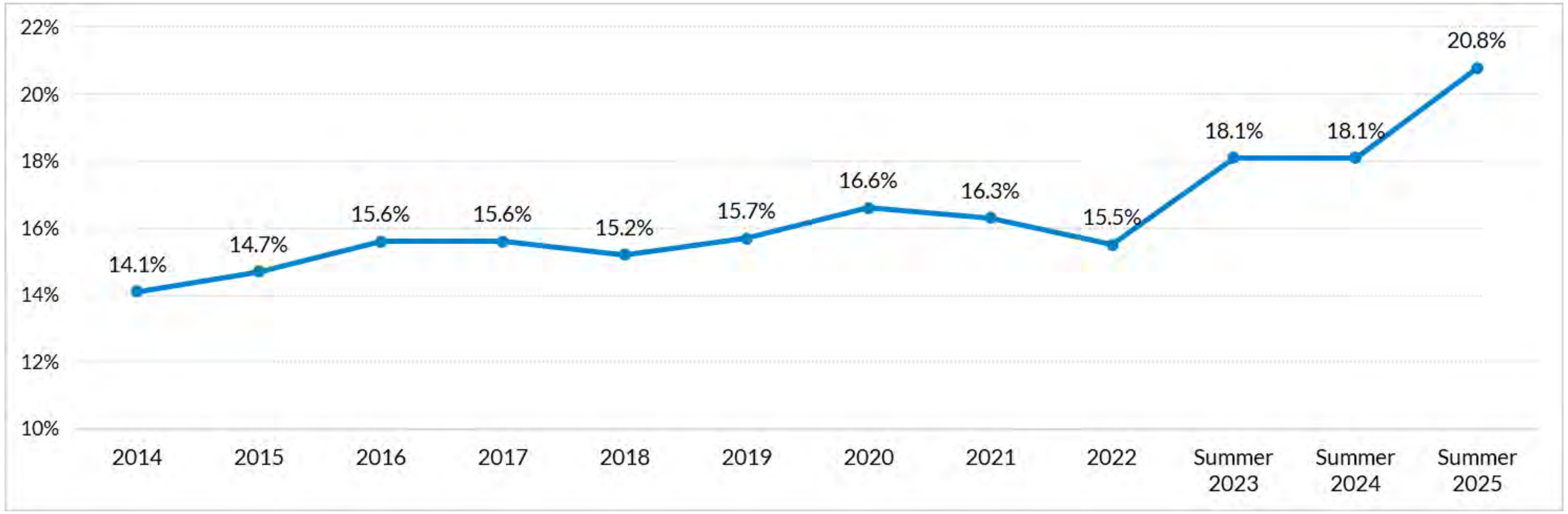


	2014	2015	2016	2017	2018	2019	2020	2021	2022	Summer 2023	Summer 2024	Summer 2025
PRM	7.3%	7.1%	7.6%	7.8%	8.4%	7.9%	8.9%	9.4%	8.7%	7.4%	9.0%	7.9%



	Summer	Fall	Winter	Spring
2023-24	7.4%	14.9%	25.5%	24.5%
2024-25	9.0%	14.2%	27.4%	26.7%
2025-26	7.9%	14.9%	18.4%	25.3%

Wind Effective Load Carrying Capacity (%)

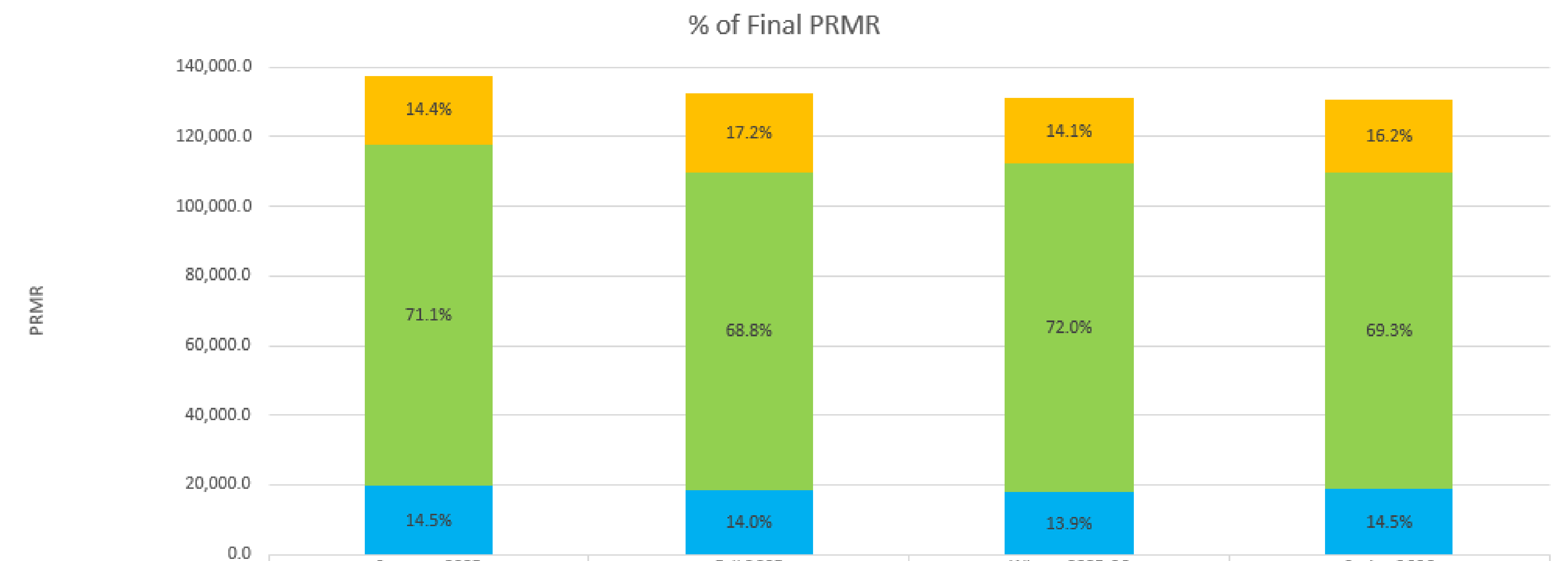


	Summer	Fall	Winter	Spring
2023-24	18.1%	23.1%	40.3%	23.0%
2024-25	18.1%	15.6%	53.1%	18.0%
2025-26	20.8%	30.7%	29.0%	25.3%

- No change to wind or solar accreditation methodology from previous years.
- Methodology applied on a seasonal basis.
- Wind ELCC and new solar capacity is established in the LOLE Study
- New solar class average
  - Summer, fall, spring 50%
  - Winter 5%

ELCC: Effective Load Carrying Capability LOLE: Loss of Load Expectation

2025/26 Seasonal Resource Adequacy Requirements are fulfilled similarly across all four seasons

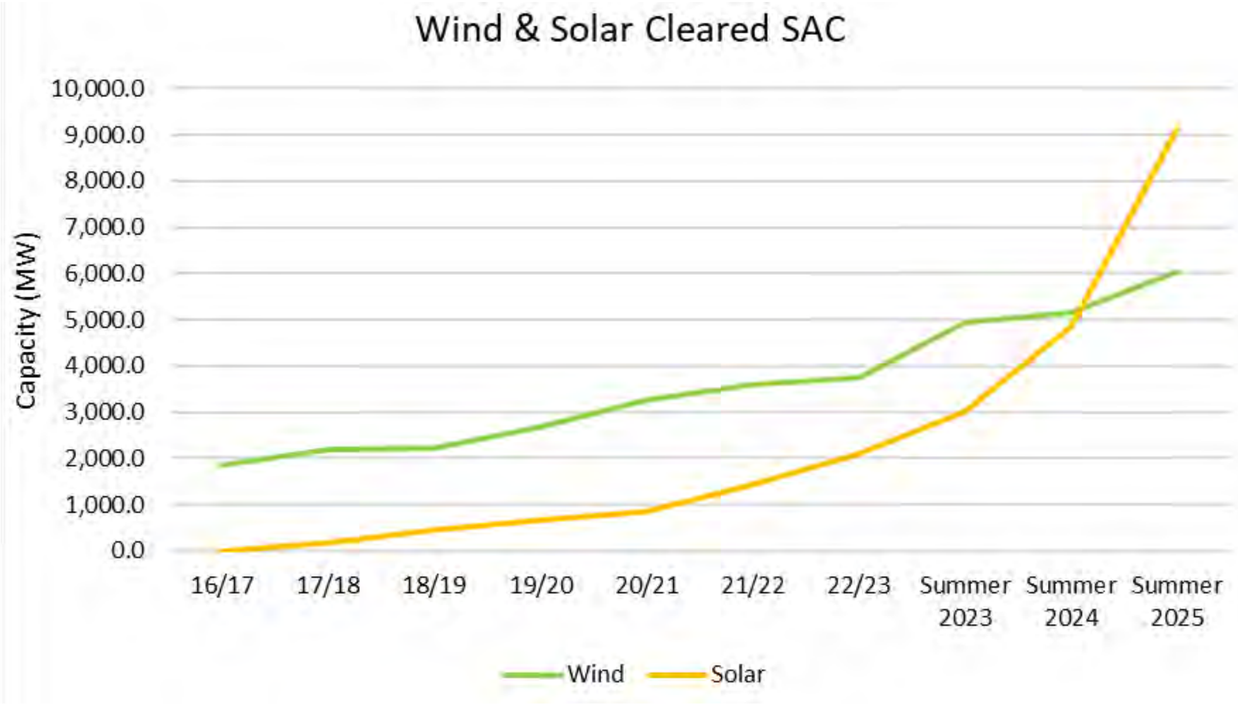


	Summer 2025	Fall 2025	Winter 2025-26	Spring 2026
Cleared Non-Self Scheduled	19,800.6	22,768.8	18,510.0	21,151.5
Self Scheduled	97,811.7	91,206.8	94,316.0	90,582.4
FRAP	19,947.0	18,540.2	18,173.5	18,965.6

PRMR: Planning Reserve Margin Requirement

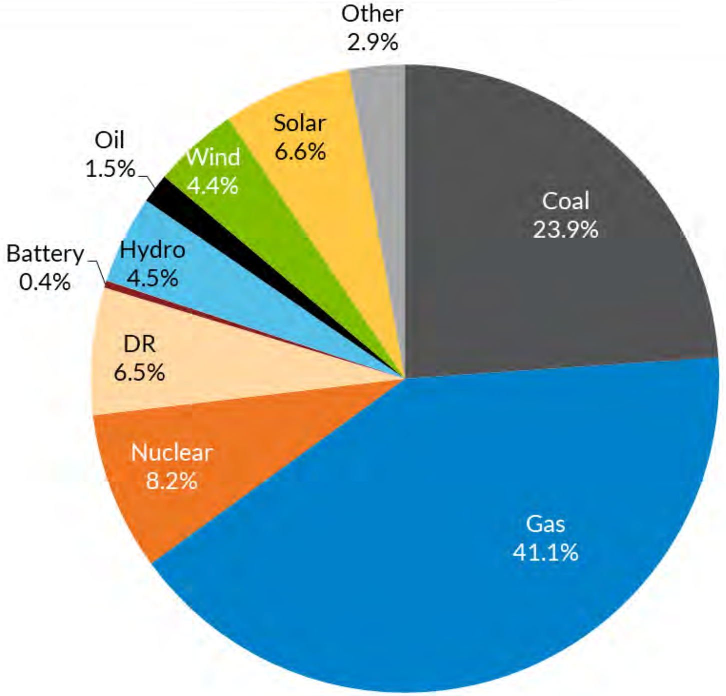
Although conventional generation still comprises most of the capacity, wind and solar continue to grow

- 9.1 GW of solar cleared this year's auction, an increase of 88% from Planning Year 2024/25 (4.9 GW)
- 6 GW of wind cleared this year, an increase of 17% compared to last year (5.2 GW)



Winter final PRMR is 6.6 GW (4.8%) lower than the summer with fewer solar resources to meet final PRMR in the winter versus the summer

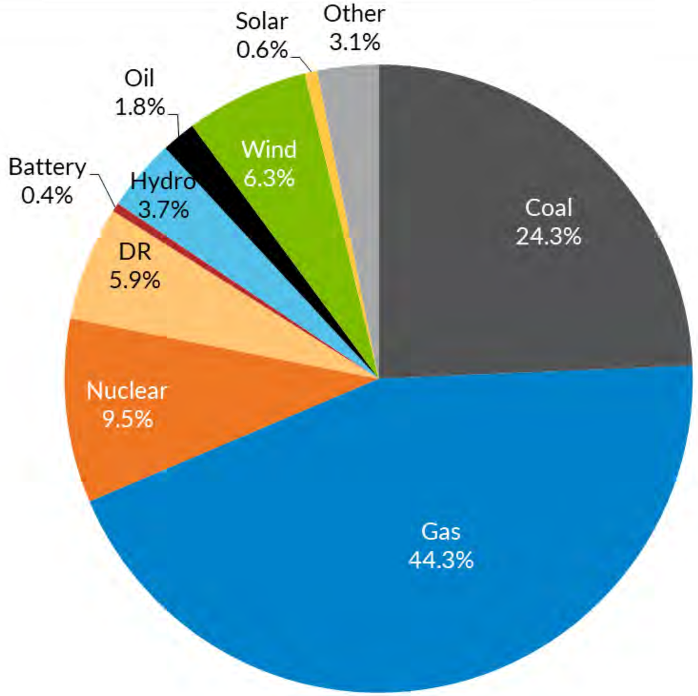
Summer 2025



MISO-wide

Cleared ZRC	Summer 2025	Winter 2025/26	Difference
Coal	32,909.6	31,887.2	1,022.4
Gas	56,470.0	57,990.5	-1,520.5
Nuclear	11,232.1	12,416.7	-1,184.6
DR	9,004.4	7,698.3	1,306.1
Battery	499.2	588.5	-89.3
EE	27.6	32.9	-5.3
Hydro	6,231.3	4,823.7	1,407.6
Oil	2,088.8	2,315.7	-226.9
Wind	6,039.1	8,282.9	-2,243.8
Solar	9,122.8	847.3	8,275.5
Misc	3,934.4	4,115.8	-181.4
PRMR	137,559.3	130,999.5	6,559.8

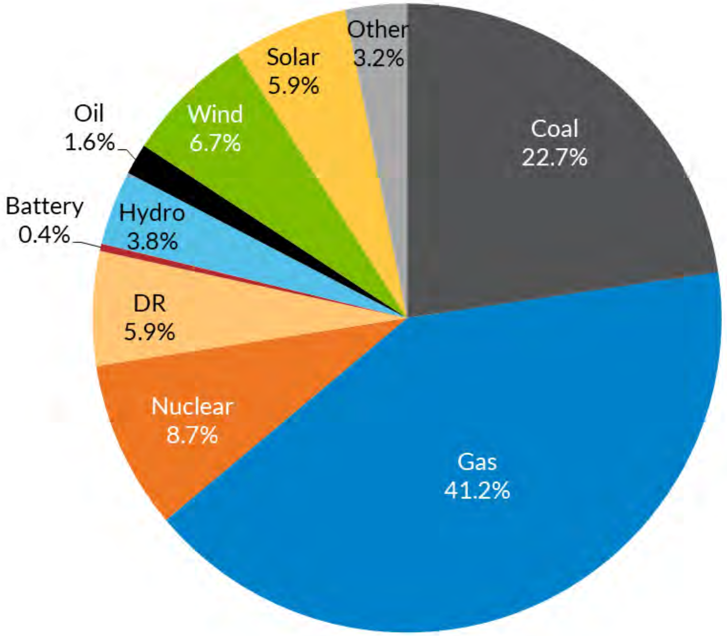
Winter 2025/26



PRMR: Planning Reserve Margin Requirement

Fall 2025 and Spring 2026 - Cleared ZRCs and Final PRMR

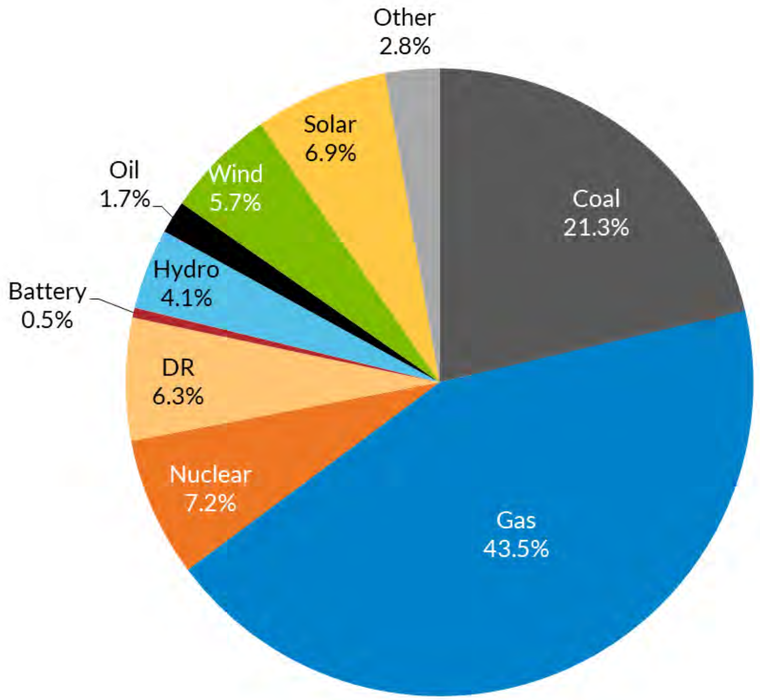
Fall 2025



MISO-Wide

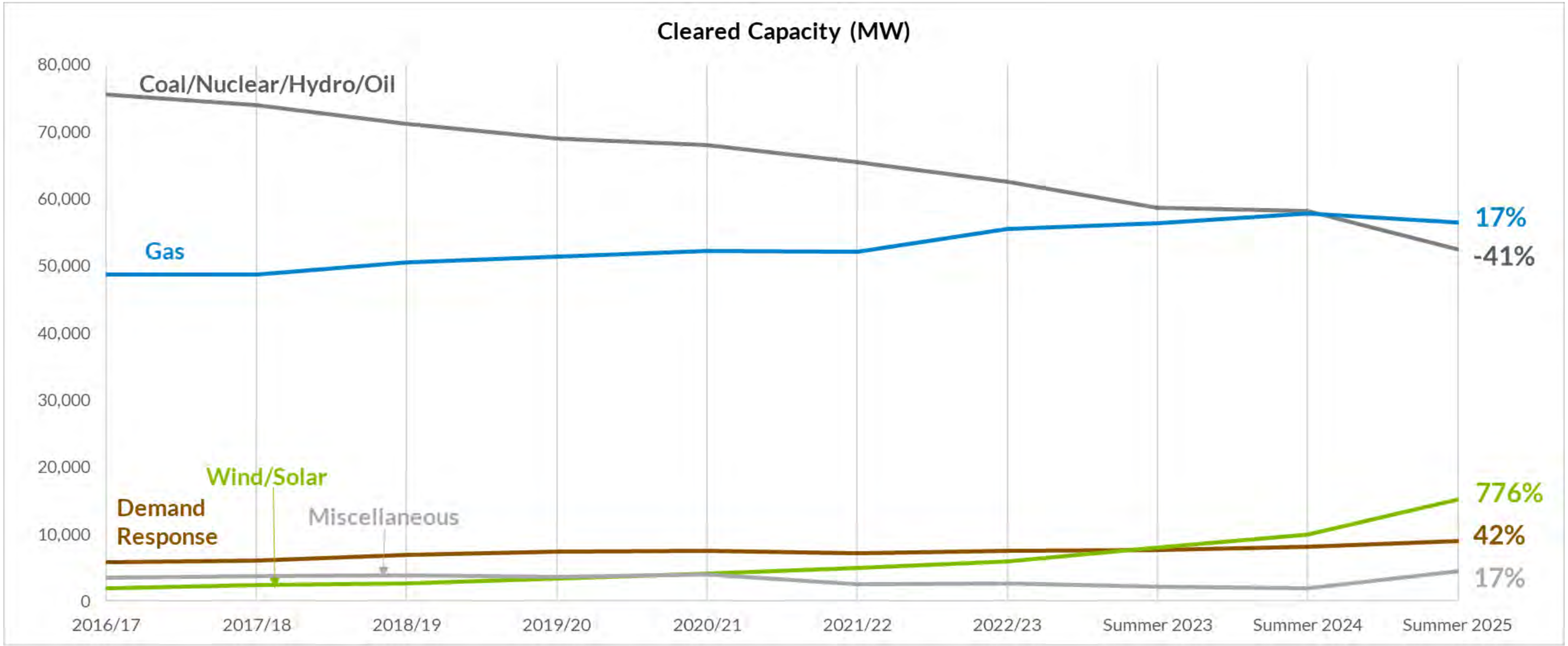
Cleared ZRC	Fall 2025	Spring 2026
Coal	30,038.9	27,886.8
Gas	54,636.4	56,820.7
Nuclear	11,482.1	9,405.4
DR	7,767.8	8,240.5
Battery	497.9	663.3
EE	28.1	30.5
Hydro	5,047.4	5,415.8
Oil	2,123.8	2,190.4
Wind	8,864.8	7,438.0
Solar	7,843.8	8,975.1
Misc	4,184.8	3,633.0
PRMR	132,515.8	130,699.5

Spring 2026

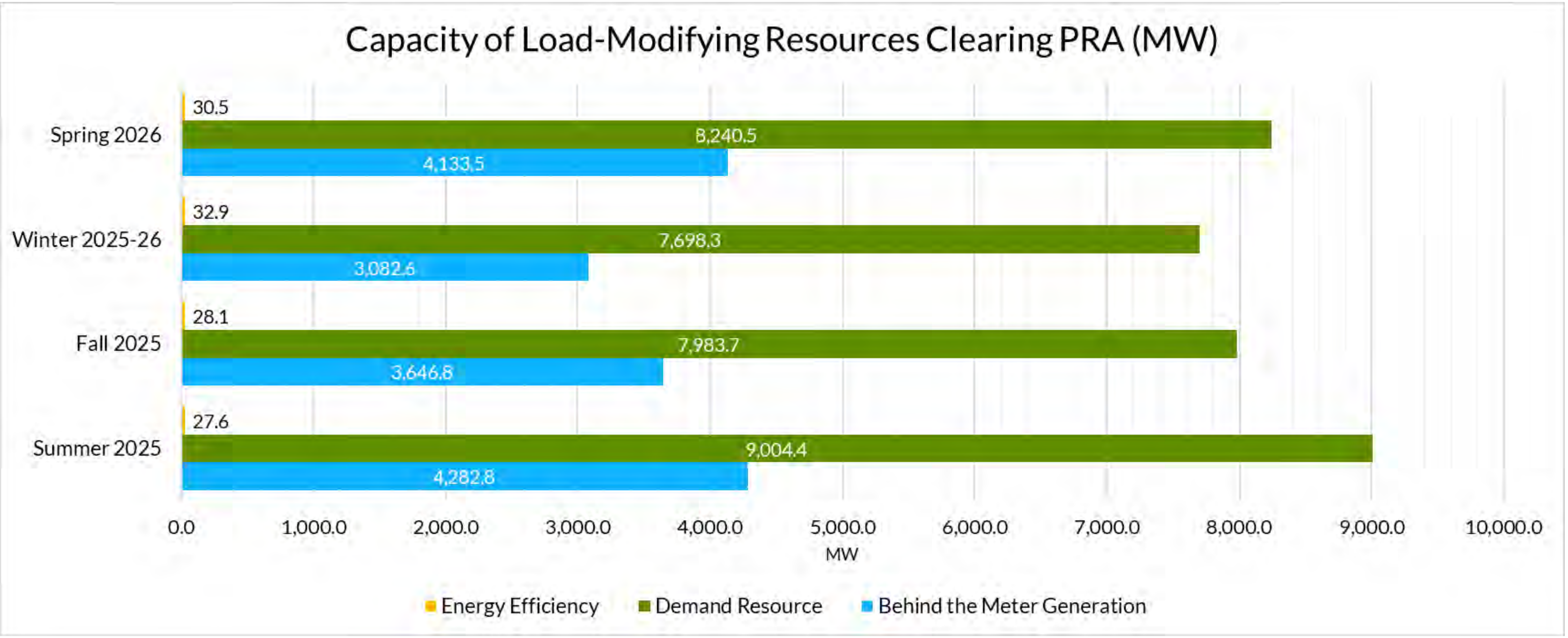


PRMR: Planning Reserve Margin Requirement

The planning resource mix shows the continuation of a multi-year trend towards less coal/nuclear/hydro/oil and increased gas and non-conventional resources



2025/26 Seasonally Cleared Load Modifying Resources Comparison



Visit MISO's Help Center
for more information
https://help.misoenergy.org/

Attachment BB

FERC Docket No. AD24-11-000

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Technical Conference Regarding The Challenge of Resource Adequacy In Regional Transmission Organization and Independent System Operator Regions	)	**Docket No. AD24-11-000**

COMMENTS OF TODD RAMEY ON BEHALF OF MIDCONTINENT ISO INC.

I. INTRODUCTION

MISO's Resource Adequacy Challenge

The electricity grid today is facing a significant transition at a pace never seen before. To ensure that our nation's bulk electric system remains reliable, it is important to recognize and stay ahead of the challenges and trends that are impacting electricity production and consumption. Today, the MISO region faces resource adequacy and reliability challenges due to the changing characteristics of the electric generating fleet, insufficient transmission system infrastructure, growing pressures from extreme weather, and rapid load growth. The ultimate responsibility for resource adequacy in the MISO region lies with its member states and other Relevant Electric Retail Regulatory Authorities ("RERRAs"). MISO works closely with stakeholders, including the states, to provide market tools and information necessary to support regional transparency that, in turn, support and inform resource investment decisions relating to resource adequacy. MISO has made significant advancements over the past several years enhancing its market price signals, improving resource accreditation, assessing expected resource needs and improving its generation interconnection queue processes and tools.

The MISO region predominantly consists of vertically integrated utilities with responsibility for providing adequate electric generation to meet load for their area and states having jurisdiction over resource adequacy decisions. This is distinct from some other RTOs, which rely more heavily on competitive markets to shape electric resource adequacy needs. A combination of state and federal policies and consumer demand for carbon free energy has resulted in rapid growth of wind and solar energy accompanied by the retirement of many coal and natural gas power plants. While weather-dependent resources like solar and wind are being added in large numbers and provide many benefits, including lower electricity production costs than natural gas or coal as well as the lack of carbon emissions, they typically do not provide the same 24/7 availability, flexibility, and duration attributes as the retiring power plants they are replacing. For example, MISO has experienced 11 wind droughts since 2020, including one lasting 40 consecutive hours. Similarly, solar output is dramatically reduced in overcast or cloudy weather conditions, as often occur in winter storms, and output is virtually zero in the overnight hours. While energy storage technology is beginning to integrate into MISO's markets, we are not expected to see the volume of such resources be deployable in order to help support meeting resource adequacy and reliability needs for several more years. MISO works collaboratively with the states, utilizing its regional perspectives and insights, to ensure they have an understanding of evolving system needs and conditions. This is accomplished, in part, through MISO's work on long-term load forecasting, resource accreditation, and Futures Planning Scenarios.

MISO has a healthy partnership with the Organization of MISO States ("OMS"), an independent organization with its own dedicated staff representing the collective interests of state and local utility regulators in the MISO region. Many of the changes MISO has implemented were made possible due to their collaboration and role in communicating and facilitating the insights of the RERRAs in the MISO region.

By coordinating with states and other RERRAs, MISO is able to develop a range of expected outcomes we call Future Planning Scenarios. MISO's Future Planning Scenarios estimate that while the total amount of installed electric generation will increase significantly over the next 20 years due to the rapid growth of wind and solar, the actual amount of electricity available to the system during could face a net decline of about 32 GW[1] due to the operational characteristics of these new resources. Emerging technologies with the needed characteristics, such as longer-duration battery storage and small modular nuclear reactors, hold great promise in the future but are likely years away from grid-scale viability.

MISO also creates significant value for the region, which is quantified in the MISO Value Proposition study.[2] While resource development is critical, we must also recognize that the existing electric transmission infrastructure is vital in supporting resource adequacy and is a significant value driver by reducing the overall resource obligation to each load serving entity in the MISO region. The largest value driver in the MISO Value Proposition is the savings associated with the reduction in reserve margin needed to meet resource adequacy targets. Our work to maintain reliability, administer wholesale markets and conduct transmission planning on a regional scale generates substantial benefits. In 2024 alone MISO created approximately $5.1 billion in savings for the region, and over $50 billion since 2007. Ultimately, this results in lower costs to consumers. To continue driving high levels of value and low costs, the transmission system needs to keep pace with the location of the resources that will be developed to provide the energy that will be

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[1] This projection is found in MISO Future 2A found in the MISO Futures Report developed in November 2023. More information on MISO Futures Series 2A Report can be found here https://cdn.misoenergy.org/Series1A_Futures_Report630735.pdf

[2] MISO's Value Proposition is an annual study that breaks MISO's business model into recognized categories of benefits and calculates a range of dollar values for each defined category. In 2024, MISO's annual benefit was valued at $5.1 billion. More information available at https://www.misoenergy.org/meet-miso/MISO_Strategy/miso-value-proposition/

needed in future years, and to provide the connectivity to move energy across the generation fleets to population centers.

MISO's region, like most of the country, is also experiencing changing weather patterns, including more frequent occurrences of extreme weather, particularly winter storms affecting large areas of the country. These extreme weather events create challenging operating conditions, with high demand for electricity sometimes accompanied by reduced solar or wind output and, in some instances, challenges with adequate fuel supplies for natural gas and coal power plants. This highlights the need for a diverse electric generation fleet and a robust transmission system to move energy over long distances.

Finally, demand for electricity is growing at an accelerated pace. Over the last few decades, we have experienced growth in electrification through electronic devices, smart home products, and electric vehicles, but minimal growth in electric peak demand, largely due to increasing energy efficiency. Looking ahead, however, we expect much stronger growth from continued electrification efforts, a resurgence in manufacturing, and an unexpected demand for energy hungry data centers to support artificial intelligence. In fact, based on the current trajectory, peak electric load in the MISO region is projected to grow at a 1.6% compound annual growth rate ("CAGR").[3] This compares to an average 0.5% CAGR between 2009 and 2024 and threatens to outpace new electric resource additions if urgent action isn't taken.

This combination of factors significantly increases operational challenges, uncertainty, and reliability risks to the electric grid. This, in turn, creates significant economic and security risks for our nation. If electricity production and delivery from all sources cannot keep up with growing demand, then the planned growth of manufacturing, artificial intelligence, and data centers cannot occur. A timely and coordinated approach is necessary if we are to continue meeting the nation's need for reliable and low-cost electricity. MISO is committed to meeting this challenge in coordination with our states, members and stakeholders as articulated by our Reliability Imperative effort.

MISO Reliability Imperative

The electric industry in general, and the MISO Region in particular, are changing in significant ways. In the past, MISO maintained a reliability standard significantly above the "one day in ten years" that is the minimum acceptable rate of reliability. However, as MISO has been emphasizing since 2022, we have seen resource margins and reliability standards decline due to policy drivers, aging resources and financial incentives. Today, the MISO region is meeting the 1:10 minimum, and we are working to maintain at least this level going forward.

Looking ahead, we have four tools for maintaining reliability: 1) maintain existing generation, as needed for resource adequacy; 2) enhance the utilization of demand response; 3) build new generation and transmission when existing resources are

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[3] More information on the current trajectory of peak load growth can be found in MISO's Long-Term Load Forecast published in December 2024 and found here https://cdn.misoenergy.org/MISO%20Long-Term%20Load%20Forecast%20Whitepaper_December%202024667166.pdf

unavailable to support new load growth; and 4) be prepared for more frequent instances of targeted load shed to ensure system reliability during extreme operating conditions.

The sharing of responsibility between MISO, Load Serving Entities ("LSEs"), and RERRAs is needed to address the challenges of rapid fleet change, increased frequency and severity of extreme weather events, and other factors that pose a threat to reliability in the MISO Region. MISO calls this shared responsibility the 'Reliability Imperative.' The word 'imperative' is appropriate for several reasons. First, the work we are doing is not optional—to maintain system reliability, we must respond to the unprecedented change we and our members face. Second, this work cannot be put off for months or years—much of it has long lead times, so we need to act now. And third, our stakeholders are counting on us—regulatory agencies, utilities and other entities are looking to MISO to identify problems and find solutions."[4]

MISO published a report in December 2020 that documents these trends and explains why these trends create a Reliability Imperative for the region.[5] MISO's response to these issues focuses on four pillars: (1) Market Redefinition; (2) Operations of the Future; (3) Transmission Evolution; and (4) Systems Enhancements (formerly called Market System Enhancements). Pillars #1 and #3 profoundly affect resource adequacy.

As explained by MISO's Chief Executive Officer, John Bear: "The industry's longtime reliance on conventional baseload power plants is declining sharply, driven by economic factors and consumer preferences for clean energy, among other things. Meanwhile, the grid is becoming increasingly reliant on wind and solar resources that are available only when the wind is blowing or the sun is shining. To be sure, there are upsides and opportunities associated with these trends. But the changes we are seeing also pose a host of complex and urgent challenges to electric system reliability in the MISO Region. Utilities, states, and MISO all have roles to play in addressing these challenges."[6]

Pillar #1: Market Redefinition

MISO's market design guiding principles are an important guide to evaluating and developing market enhancements that have been used as a foundation for conducting the Planning Resource Auction (PRA). MISO's Market Design Guiding Principles are as follows:

- 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,

[4] See MISO's Response to the Reliability Imperative (December 2020), available at https://cdn.misoenergy.org/MISO%20Response%20to%20the%20Reliability%20Imperative%20FINAL504018.pdf.

[5] More information on MISO's Reliability Imperative at https://www.misoenergy.org/meet-miso/MISO_Strategy/reliability-imperative/

[6] MISO's Response to the Reliability Imperative, found here https://cdn.misoenergy.org/MISO%20Response%20to%20the%20Reliability%20Imperative%20FINAL504018.pdf

- Support Market Participants ("MPs") in making efficient operational and investment decisions, and
- Maximize alignment of market requirements with system reliability requirements

All aspects of MISO's resource adequacy construct have been and are being evaluated to better ensure energy readiness under this Reliability Imperative. Specific efforts in this area include providing a longer-term and deeper assessment of system needs across all hours of the year, including required capabilities such as flexibility, shifting to verifying sufficient generation adequacy across all hours of the year, improving how resources are accredited, ensuring that prices accurately reflect market conditions, especially during emergencies, and developing market products that provide the right incentives for resources to maintain system reliability The initiatives in this category aim to ensure that resources with the types of capabilities and attributes the system needs will be available in all 8,760 hours of the year. Hence, MISO has moved from an annual auction to a seasonal one. This is important because as noted above, the region is increasingly facing reliability risks outside of the summer peak-load months that historically posed the greatest challenges. On the supply side, MISO has improved accreditation efforts, to reflect the availability of resources during hours in each season exhibiting low capacity margins.

On the demand side, MISO determined that the implementation of a Reliability Based Demand Curve ("RBDC") (sometimes referred to as a "sloped demand curve") in the PRA will support MPs by establishing more efficient capacity prices based on market fundamentals, where the marginal reliability benefit of the last MW procured is equal to its marginal cost.

With better price formation and improved capacity accreditation, MPs can make better informed operational, retirement, and investment decisions, and the PRA will significantly improve alignment of market requirements with system reliability requirements.

Pillar #3: Transmission Evolution

Over the last several years, MISO has approved over $30 billion in new transmission lines through a Reliability Imperative initiative called Long-Range Transmission Planning, or LRTP, with more expected in the coming years. These projects are projected to have a benefit-to-cost ratio of approximately 2.6 to 1 and will substantially improve electric transfer capabilities and enable the electric reliability and associated economic growth being planned across the nation.

Intermittent resources such as wind and solar work with the transmission system very differently than conventional power plants. For this reason, the ongoing trend of conventional resources retiring from service as intermittent renewables continue to grow poses significant challenges to the reliability of the transmission system in the MISO region. These challenges are framed up in MISO's Renewable Integration Impact Assessment work. Fortunately, MISO can leverage its large footprint and resources to ease some of the challenges. One of the keys will be transmission projects that support these new resources in the region. LRTP is designed to assess the region's future transmission needs, starting from a base of the utility and state plans on where to site and build new resources. LRTP does not replace other transmission-planning efforts that have long existed at MISO, such as the annual studies contained in the MISO Transmission Expansion Plan ("MTEP"). LRTP will coordinate closely with those efforts, and it will also be a transparent and cooperative part of the MISO stakeholder process.

LRTP is a comprehensive "transmission roadmap" that will identify and drive investments in transmission projects addressing all needs of the region as the resource fleet continues to evolve. The roadmap will be updated as needed to align with evolving resource fleets and business plans, state energy/environmental policies, and other dynamic factors that affect the region's transmission needs. As solutions are identified through LRTP, they are moved into the ongoing MTEP process for final approval by MISO management and Board of Directors.

Recent Accomplishments

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

> *Seasonal Resource Adequacy Construct*: In August 2022, the Federal Energy Regulatory Commission ("the Commission") approved MISO's proposal to shift from its summer-focused resource adequacy construct to a new, four-season construct that better reflects the risks the region now faces in winter and shoulder seasons due to fleet change, more frequent and severe extreme weather, electrification, and other factors. This new construct seeks to ensure that resources will be available when they are needed most by aligning resource accreditation with availability during the highest risk periods in each season.
>
> *LRTP Tranche 1*: The first of four planned portfolios of LRTP projects was approved by the MISO Board of Directors in July 2022. This tranche of 18 projects represents a total investment of $10.3 billion — the largest portfolio of transmission projects ever approved by a U.S. Regional Transmission Organization. These projects will integrate new generation resources built in MISO's North and Central subregions, supporting the reliable and affordable transition of the fleet and further hardening the grid against extreme weather events.
>
> *Reliability-Based Demand Curve*: MISO's Planning Resource Auction (PRA) was not originally designed to establish appropriate capacity clearing prices based on the reliability risk of clearing MWs above or below the one-day-in-ten reliability standard. This lack of a "warning signal" when reserve margins decline can mask an imminent shortfall — as occurred with the 2022 PRA. Efficient capacity pricing is also crucial to make effective investment and retirement decisions. MISO worked with its stakeholders to design an RBDC that will improve price signals in the PRA. Full implementation began in the 2025 PRA, with first year results demonstrating that the refined PRA is working as designed.
>
> *Futures Refresh*: The MISO Futures utilize a range of economic, policy and technological inputs to develop three scenarios that "bookend" what the region's resource mix might look like in 20 years. In 2023, MISO updated its Futures to

lay the groundwork for LRTP Tranche 2 and to better reflect evolving decarbonization plans of MISO members and states. The refreshed Futures also model how the financial incentives for clean energy in the 2022 Inflation Reduction Act could further accelerate fleet change. The refreshed Futures are indicated with an “A” (e.g., Future 2 was updated and renamed Future 2A).

Queue Reforms: MISO has instituted several reforms to speed up the queue cycles, including a cap on the number of projects that can enter the queue in a given cycle, and is working on several technological enhancements and process improvements to eventually get to a one-year queue cycle. In the interim, an Expedited Resource Addition Study, or ERAS, process was recently submitted to the Commission for consideration. If approved, this process would provide a temporary framework, sunsetting by the end of 2028, for the accelerated study of electric generation projects that are required to address urgent resource adequacy and reliability needs

MISO’s extensive analysis and operational experience make it clear that no single electric generating resource, transmission line, process improvement, emerging technology, or other solutions will solve all our challenges. Addressing our nation’s future electricity needs requires a multi-faceted and coordinated approach that leverages all of these tools.

Next Steps

The operational challenges and reliability risks of the MISO region are largely mirrored across the country. To address them, we need to take several important steps to turn around the decline in available energy and expedite the construction of new electric generation and the transmission lines necessary to move necessary energy from where it is produced to where it is needed. Specifically:

- Ensure that states and utilities have the information they need to make prudent electric resource decisions to support resource adequacy.

- Continue to improve the loss-of-load modeling effort which underpins the planning reserve margins determined to meet the reliability standards. This includes better representation of all resources’ availability and outage patterns, continued effort to model load growth and variability, and incorporate correlated impacts across both supply and demand.

- Let reliability needs help inform the pace of retirement of existing electric generating resources. Having the right mix of resources on the system means that we don’t have to choose between decarbonization and reliability.

- Continue developing new resources at a rapid pace. Streamline the approval of new electric generation and transmission projects, and work to mitigate the regulatory, supply chain, and workforce challenges that can hinder development of these projects.

- Leverage an “all of the above” approach that includes a mixture of solar, wind, natural gas, storage, emerging technologies, and transmission to achieve reliability.

- Continue reforms, like MISO's ERAS and Demand Response and Emergency Resource reforms, that enable the more effective and efficient utilization of existing resources and capabilities.
- Continue exploring Distributed Energy Resources ("DERs") as a potential additional tool to address resource adequacy and reliability challenges.
- Support and encourage continuous interregional collaboration on future transmission needs and operational protocols that maximize the use of the existing system.

II. PANEL 1: THE RESOURCE ADEQUACY CHALLENGE IN RTOs/ISOs

***Question 1*: What is the current state of resource adequacy across RTO/ISO regions?**

a. ***Is this static or variable? Are resource adequacy challenges more acute in RTO/ISO regions with capacity markets compared to those RTO/ISO regions with alternative resource adequacy constructs? Why or why not?***

MISO has seen surplus capacity margins declining over the last several years. When considering capacity margins, MISO particularly views the level of "accredited capacity" as the key factor to assess resource adequacy. It is essential to consider the accredited value of capacity, rather than the simple "nameplate" value, since accredited is the only value that can be relied upon to ensure that energy will be provided by a resource during the periods of greatest need. The decline in accredited capacity is primarily due to the retirement of existing dispatchable generation, while new capacity additions have generally been non-dispatchable resources with lower accreditation values.

The reduction in reserve margin is a significant concern. MISO has continued to work closely with the states and stakeholders to ensure that the region remains, in excess of the 1-day-in-10-year Loss of Load Expectation (LOLE) reliability standard. Over the past several years, MISO has (1) initiated reforms to improve capacity accreditation to better signal the value of needed resource additions, (2) converted to a seasonal capacity construct to better reflect differing seasonal operating needs and characteristics, (3) continued collaboration with states with a transparent survey of future capacity expectation to inform policy makers, (4) provided longer term assessment of the resource mix changes in our Regional Resource Assessment ("RRA") to further inform long term policy and investment decisions, and (5) enhanced risk modeling to better align between the manner in which seasonal risk is being evaluated and resources are being accredited to meet the designated need.

The 15 states in the MISO region take their rights and responsibilities towards resource adequacy seriously and the MISO capacity market recognizes that. The OMS has supported developments in pursuit of MISO's Reliability Imperative. The Reliability Imperative was developed in 2020 to address urgent and complex issues facing the grid and contains four pillars: Market Redefinition, Operations of the Future, Transmission Evolution, and System Enhancements. Collaboration between MISO and the OMS allows for a reliable grid amongst changes in the diverse MISO footprint. MISO provides transparency in expectations of future resource adequacy plans through Futures

Modeling, the RRA, and the OMS-MISO Survey. We are confident that the footprint will continue to be resource adequate in the near and longer term.

MISO uses a few tools to assess the state of resource adequacy in its footprint. The RRA[7] is one of the periodic studies MISO conducts to forecast how the mix of electricity-generating resources in the MISO region could evolve going forward. Another is the OMS-MISO Survey. While RRA and the OMS-MISO Survey are similar in some ways, there are some key differences that provide resource planners. The RRA is a 20-year outlook based on publicly announced resource plans and policy goals. It projects that members and states will add new generation capacity at an unprecedented rate of 17 GW/year (compared to the average of 4.7 GW/year added over the last decade) for the next 20 years to reliably achieve their publicly announced resource plans and policy goals.[i] Accordingly, the RRA projects capacity surpluses in 2030 and beyond. In contrast, the OMS-MISO Survey is more focused on the near term and projects new installed capacity coming online at the pace at which resources have received interconnection agreements and come online in recent history. The 2024 OMS-MISO Survey therefore forecasted a range of possible outcomes, varying from capacity deficits beginning in 2025 (which did not materialize) to capacity surpluses through 2029. Again, these divergent results reflect that the RRA and the OMS-MISO Survey were designed for different purposes and use different data inputs, methodologies, assumptions.

MISO is confident that its current capacity construct is the best tool to identify, analyze, and address resource adequacy issues in the MISO region. The MISO capacity construct works because:

- The Reliability Imperative describes the shared responsibility between LSEs, states and RERRAs, and MISO to maintain a reliable grid.
- MISO respects states' rights toward resource adequacy and acknowledges that LSEs have the obligation to serve their end-use customers. In fact, most LSEs engage in some form of integrated resource planning that is used to meet these obligations and filed with their appropriate RERRA.
- This type of resource planning makes sense because investments in generation have expected lifetimes of well over 30 years, so asset owners require some level of confidence that these builds can recover their capital costs.
- MISO works closely with the OMS and RERRAs to communicate regional needs to maintain resource adequacy. Both the OMS-MISO Survey and the RRA provide information to MISO and MISO members on where resource adequacy conditions are trending. From this state-specific information, MISO conducts analyses that are made public around the different types and amounts of resources necessary to meet the reliability standards being imposed by NERC.
- The "1-day-in-10-years" LOLE criterion established by NERC and codified in our Tariff has served the region well and sets the benchmark used to design an adequate system.[8] MISO translates this LOLE criterion into an amount of planning reserve margins that LSEs are obligated to have.

[7] More information on MISO's 2024 Regional Resource Assessment can be found here https://cdn.misoenergy.org/2024%20RRA%20Report_Final676241.pdf

[8] MISO's reply to question 6 below recognizes that other reliability metrics on resource adequacy may be of use in the future.

- MISO conducts its prompt PRA to inform LSEs and RERRAs of resource adequacy trends in MISO. A one year clearing price is akin to the role of energy prices in MISO's real time market; well over 95% of an LSE's obligation for energy is procured in the day-ahead market, the real time market is an imbalance market but real time prices can drive Power Purchase Agreements ("PPAs") and expected day-ahead prices. Well over 90% of the obligations of LSEs in any PRA are met with owned or contracted for resources, which is consistent with integrated resource planning processes of the LSEs.
- The PRA has, since inception, served as a residual capacity auction, giving those LSEs that are long or short an opportunity to sell or buy, but the PRA is a voluntary auction.
- The PRA is conducted a few months before the beginning of the Planning Year, and conducted on a seasonal basis to recognize the differences in risks across the seasons.
- The prompt nature of the PRA significantly reduces uncertainty around where demand is heading and which resources are available to meet that demand for the upcoming Planning Year.
- With the adoption of the RBDC design, capacity prices are more reflective of the reliability contributions of the amount of MWs cleared, but they can still vary based, in part, on the amount and offer prices of supply.
- MISO's Value Proposition, highlighted above, shows the savings MISO members achieve in reduced reserve margins while maintaining the 1-in-10 LOLE through the risk sharing pool they participate in.

MISO's recent shift to a seasonal capacity market with seasonal accredited capacity better reflects extreme weather conditions that have become more prevalent. These weather conditions affect both the seasonal peak demand and the available seasonal supply. In addition, the seasonal construct better reflects the seasonal planned & forced outage patterns of supply. The recent implementation of the RBDC reflects the contributions to reliability incremental MWs can add to the system. On the supply side, resources are being accredited based on availability during all times of need, across all seasons (Schedule 53, seasonal accredited capacity resources).

***Question 2*: Given load growth and generation forecasts, what are your resource adequacy challenges going forward?**

MISO's challenge is ensuring that the new generation in the region is able to keep pace to reliably meet the expected load growth while older generation resources with strong reliability attributes continue to retire. Existing dispatchable generation with flexibility attributes, such as natural gas and coal, is retiring rapidly and is being replaced by weather-dependent generation such as wind and solar that does not have the same 24/7 availability. Carbon-free resources that can provide the needed attributes – such as longer-duration battery, hydrogen, and small modular nuclear – is likely several years away from grid-scale viability.

This gap between dispatchable generation and highly accredited carbon-free replacements caused capacity shortfalls in the 2022/2023 planning year, being short in the North subregion by 1,230 MWs. Additionally, the extreme price volatility in the vertical demand curve auctions may have eroded confidence in the capacity construct by sending inefficient price signals, but this has been addressed with RBDC. Changes to the resource adequacy construct highlighted in the previous question, and the information provided through the OMS-MISO survey and RRA effort have initiated renewed efforts on the part of LSEs and RERRAs to address resource adequacy requirements.

Reliably navigating the energy transition requires more than just having sufficient generating capacity; it also requires urgent action to avoid a looming shortage of broader system reliability attributes. In 2023, MISO completed a foundational analysis of attributes, with a focus on three priority attributes where risk for the MISO system is most acute. System adequacy is the ability to meet electric load requirements during periods of high risk. MISO focused on the near-term risk factors of availability, energy assurance, and fuel assurance. Flexibility is the extent to which a power system can adjust electric production or consumption in response to changing system conditions. MISO focused on the near-term risk factors of rapid start-up and ramp-up capability. System stability is the ability to remain in a state of operating equilibrium under normal operating conditions and to recover from disturbances. MISO focused on the nearest-term risk factor of voltage stability. No single type of resource provides every needed system attribute; the needs of the system have always been met by a fleet of diverse resources. However, in many instances, the new weather-dependent resources that are being built today do not have the same characteristics as the dispatchable resources they are replacing. While studies show it is possible to reliably operate the system with substantially lower levels of dispatchable resources, the transformational changes require MISO and its members to study, measure, incentivize, and implement changes to ensure that new resources provide adequate levels of the needed system attributes.

In December 2023, MISO published an Attributes Roadmap report that recommends urgent action to advance a portfolio of market reforms and system requirements and to provide ongoing attributes visibility through regular reporting.[9]

<u>Question 3</u>: How do you reconcile your RTO's/ISO's resource adequacy objectives with state public policy requirements, which may accelerate the retirement of certain resource types or limit the entry of other resource types? For example, in light of such state public policy requirements and particularly in multi-state RTOs/ISOs, how does your RTO/ISO ensure resource adequacy?

MISO's resource adequacy objectives are formally communicated through the resource planning obligations on LSEs. As a general matter, the responsibility to assure resource adequacy belongs to the states. MISO runs an annual PRA to provide a tool for LSEs to complement their long-term resource adequacy procurement decisions under the supervision of their state regulatory authority.

MISO further supports adequacy objectives with state public policy requirements by assessing, analyzing, and providing states and other RERRAs with information on where resource adequacy conditions are moving. MISO uses the OMS-MISO Survey and RRA

[9] More information on the MISO Attributes Roadmap can be found here https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf.

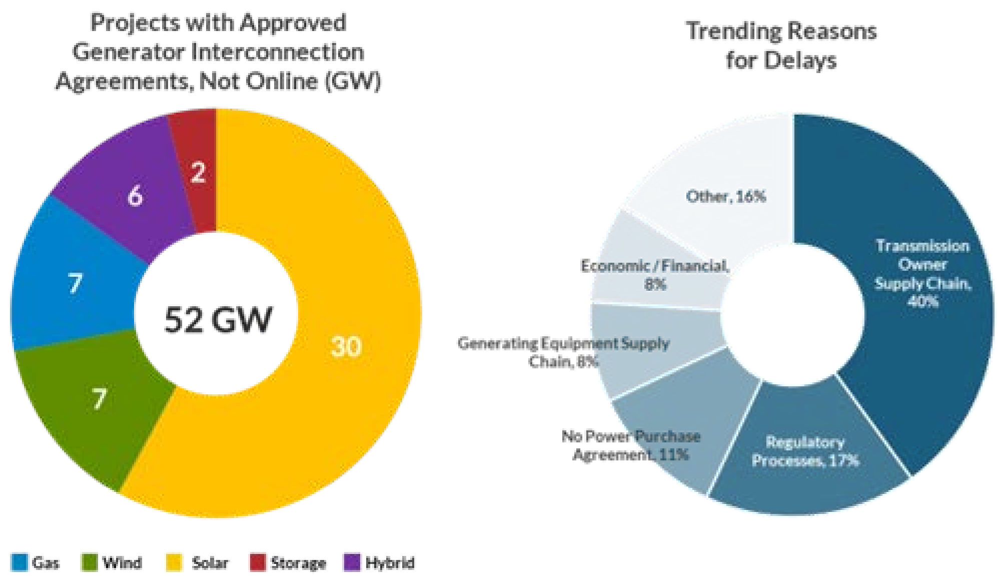
studies to highlight the needs of the entire footprint on a macro level. MISO is responsible for facilitating residual capacity transactions throughout the footprint through the PRA. Since MISO's inception, deference has been made to the jurisdictional authority of the states and other RERRAs with respect to resource adequacy rights and responsibilities that RERRAs take seriously. MISO respects states' rights towards resource adequacy and acknowledges that LSEs have an obligation to serve their end-use customers. As a result, MISO takes the resources offered into MISO's markets as given and procures resources to meet the margin requirements at least cost. This analysis is highlighted in the OMS-MISO survey and RRA studies. MISO has the obligation to translate the 1-in-10 LOLE requirements into planning reserve requirements and to facilitate residual capacity transactions through the PRA.

***Question 4**: What are the key drivers that cause delays in the construction and interconnection of generators in your RTO/ISO? What can be done to accelerate the interconnection of generators to help meet the resource adequacy challenge? How have factors external to your RTO/ISO, such as supply chains and siting/permitting, impacted generator interconnection timelines? What is the composition of resources in the queue? Will accelerating queue processes help address the challenge of resource adequacy? How many resources (by number and aggregate nameplate capacity) have received approval for interconnection but have not been constructed? How, if at all, are the expected resource adequacy contributions of a resource in the interconnection queue considered during the interconnection process?*

There is a combination of factors that contribute to delays in the construction and interconnection of new resources on the grid. This includes delays in the process to provide generation interconnection agreements to new generation resources and delays in those resource with generation interconnection agreements getting to commercial operation. MISO is taking significant steps to improve the queue processing delays and provide transparency to the delays in commercial operation dates to help facilitate identification of potential solutions to the problem.

The current reality is that study cycles are taking 3+ years in MISO's Generator Interconnection Queue process. This is, in part, due to the dramatic increase in the number of project submissions in recent years, which does not support the region's needs. Once a project receives a Generator Interconnection Agreement ("GIA") and is approved for construction, there may be construction delays due to supply chain challenges, regulatory hurdles, and other issues. More than half of all delays are attributable to transmission owner supply chain issues and regulatory processes. The next largest factor is lack of PPAs.

Figure I.A.[10]



An expedited study process that balances the responsibility for providing grid reliability and resource adequacy in the MISO region between MISO, LSEs, and the states can solve many of these problems. Projects that prove they have resolved the aforementioned barriers to success (such as funding, citing and permitting, etc.) should be able to enter a separate process to bring new generation online in the short-term to meet resource adequacy and reliability needs. This is especially needed in light of load growth and data center build out. Currently, data centers do not have a process in place to come online as quickly as the market would require. An expedited queue process can handle expected load growth, such as this, during a time when dispatchable resources are expected to leave the region at a rate much higher than accredited capacity can keep up with.

MISO found internal improvements to reduce study times as well. MISO's recently approved queue cap proposal will ensure a more manageable volume of projects, driving lower study times. Additionally, MISO's implementation of Suite of Unified Grid Analyses with Renewables ("SUGAR") software utilizes advanced data and analytics using machine learning and artificial intelligence to create reliable and informed planning and operations, as well as significantly lower study and modeling times. Full implementation of SUGAR will take study times from 3+ years to under 1 year. But it will likely take about 4 years for full implementation of SUGAR. Allowing for an accelerated study process for certain projects will address queue backlog until the entire queue process is improved to a 1-year timeframe.

To address supply chain issues MISO encourages long-term stability and certainty in federal energy policy. This will promote investments that are discouraged by volatility.

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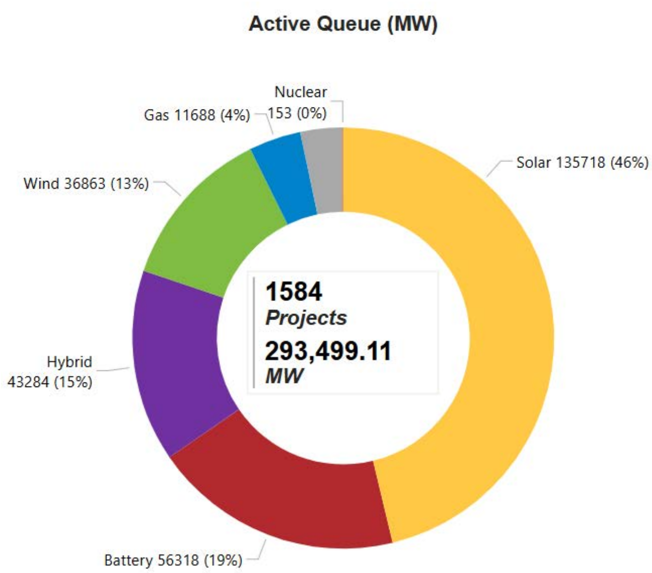
[10] Figure I.A. Compares 52 GW worth of generator interconnection projects with an Approved Generator Interconnection Agreement that have not come online with a breakdown of reported developmental delays. As of March 26, 2025.

Citing and permitting issues certainly causes delays, but these issues are not very different than they were 3-5 years ago. Generally, these factors should be addressed and resolved prior to entering the interconnection queue.

As a transmission planning organization, MISO is resource neutral and does not consider resource adequacy contributions during the interconnection process.

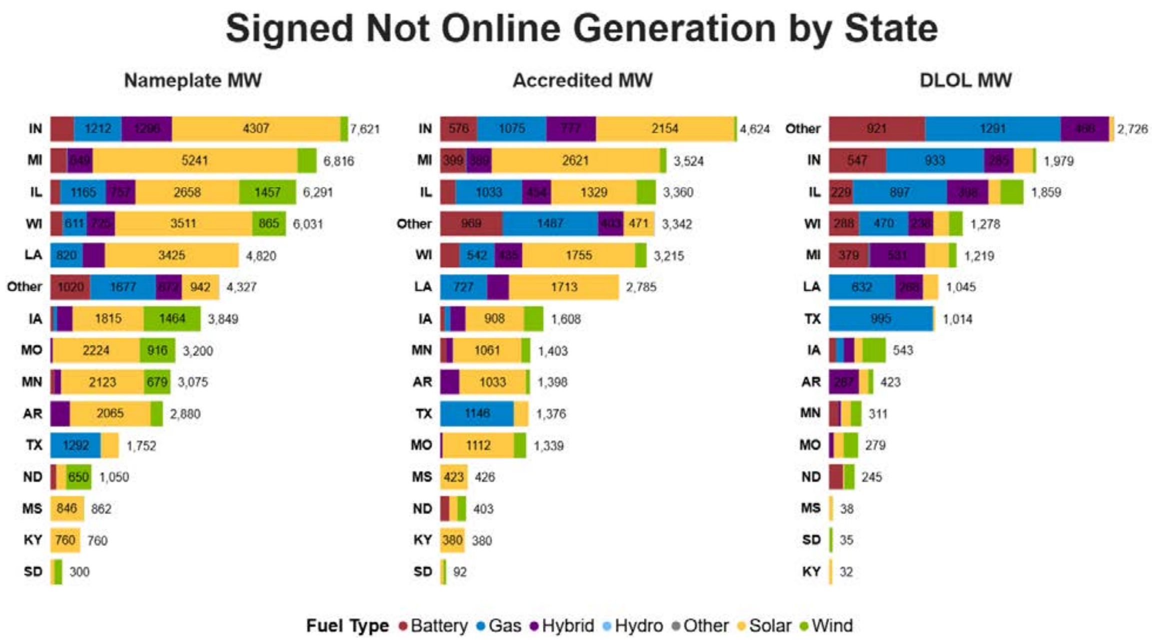
The current composition of resources in MISO's generation interconnection queue is illustrated in Figure I.B. This breakdown of capacity in the queue supports the points made in our answer to question 2 above about the potential looming shortage of broader system reliability attributes, being analyzed in the Attributes Roadmap report. Figure I.C. illustrates a breakdown of projects with signed GIAs that are not yet online.

Figure I.B.[11]



[11] MISO's Active Generator Interconnection Queue as of May 15, 2025.

<u>Figure I.C.</u>[12]



<u>Question 5</u>: Are there additional concerns that may affect resource adequacy in the near term (e.g., over the next five years) and in the longer term (e.g., ten years and beyond)?

In the long-term, an emerging gap between installed capacity[13] and accredited capacity[14] is a high priority. The MISO Futures utilize a range of economic, policy and technological inputs to develop three scenarios that "bookend" what the region's resource mix might look like in 20 years.[15]

Figure I.D. shows projected capacity change from 2022 to 2042 for all three Futures based on existing and member-planned resources, published in Series 1A MISO Futures Report. As the charts show, the region's level of *installed* capacity – the blue line – is forecasted to increase 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 forecast to decline by 2042. With each Future increasing the total retirement of highly accredited thermal resources, this negative net change is more pronounced across Futures: Future 1A projects an 18 GW negative

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[12] Figure I.C. is a breakdown of signed generator interconnection agreements that have not yet reached their commercial operation date. This is displayed in nameplate capacity, accredited capacity, and projected implementation of approved capacity using <u>Direct Loss of Load (DLOL)</u>-based methodology, which will be implemented in 2028/2029.[12]

[13] Installed capacity, or ICAP, is the hypothetical amount of energy that can be produced under optimal conditions.

[14] Accredited capacity is the actual amount of energy that can be expected under real-life conditions.

[15] More information on MISO Futures Scenarios can be found here https://www.misoenergy.org/planning/futures-development/

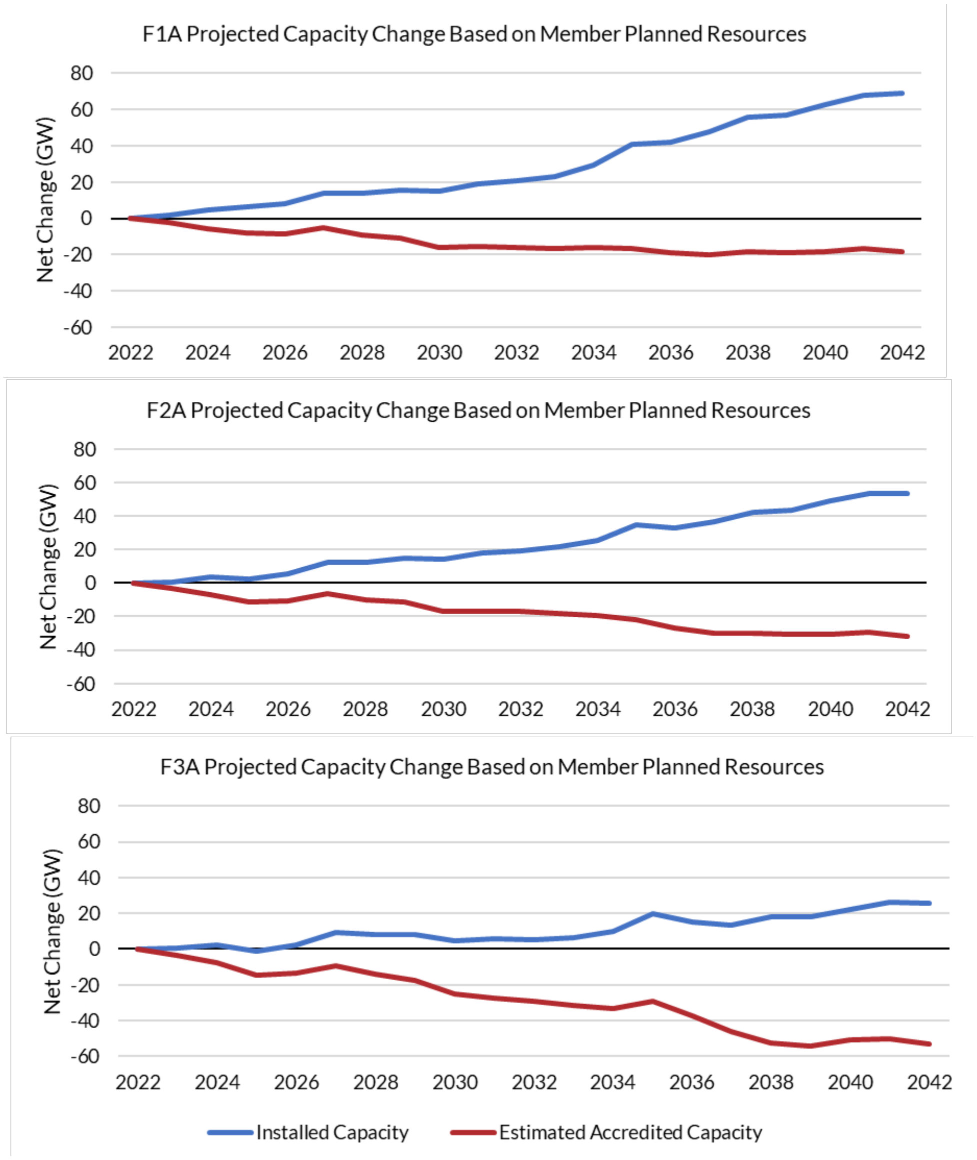
change in estimated accredited capacity across the study period, F2A projects a 32 GW negative net change, and F3A projects a 53 GW negative net change.

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

Futures modeling is the key to addressing this shortfall. The MISO Futures team added 29 GW of Flexible Attribute Unit ("Flex") capacity to the Future 2A expansion and siting. Flex units are proxy resources that refer to a non-exhaustive range of existing and nascent technologies, representing potential generation that is highly available, highly accredited, low- or non-carbon emitting, and long in duration. As a proxy, potential Flex resources could be, but are not limited to: Reciprocating Internal Combustion Engines ("RICE") units, long-duration battery[16], traditional peaking resources, combined-cycle with carbon capture and sequestration, nuclear Small Modular Reactors ("SMRs"), green hydrogen, enhanced geothermal systems, and other emerging technologies. Flex units do not take away the need for previously identified resources but rather supplement them in periods of energy inadequacy.

[16] Greater than four hours.

Figure I.D.[17]



***Question 6*: In NERC's view, what aspects of resource adequacy planning could be improved? For example, what type of reliability metric (or metrics) should be used in resource adequacy planning models? What elements of resource adequacy planning can be improved or could serve as best practices?**

The 1-in-10 LOLE has served the region well and set the benchmark used to design an adequate system. However, many industry experts, including NERC, have raised questions about this framework's effectiveness in addressing future system risks. Of particular concern is the ability of the future resource fleet to serve load over extended

[17] Figure I.D. comes from Series 1A MISO Futures Report published November 1, 2023. MISO is currently in the process of working with stakeholders to develop an updated Futures Report to reflect current circumstances. More information on Futures Redesign Workshop can be found here www.misoenergy.org/engage/committees/futures/

periods of time, with conditions that may lead to an energy-constrained system. For instance, a future system with no legacy thermal capacity and an abundance of variable and energy-limited generation may experience events much larger in magnitude and longer in duration than today's system. In response to Question 5, MISO's 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. In 2024, MISO reviewed industry recommendations and new trends in the use of resource adequacy metrics. MISO also reviewed and analyzed adequacy metrics calculated in previous MISO studies. The result of this recommends a collaborative approach with states and the industry to revisit the 1-in-10 LOLE criterion, explore alternatives, and provide visibility to complementary metrics.[18] The Resource Adequacy Metrics and Critical Roadmap explores this issue and identifies the next steps by collaborating with the jurisdictions responsible for ensuring resource adequacy in the MISO region, including through the recently formed OMS Resource Adequacy Committee. MISO intends to continue engaging with stakeholders, provide a gap analysis to identify conditions under which energy adequacy materially erodes in a MISO system planned to 1-in-10 LOLE, and collaborate with OMS to develop a framework for identifying thresholds in risk metrics that may warrant potential changes to criteria in MISO's resource adequacy construct. Additionally, MISO plans to publish additional metrics more consistently across resource adequacy studies. MISO also seeks to increase industry collaboration, notably collaborating with other ISOs and research organizations and participating in the NERC drafting team of the new Planning Energy Assurance standard.[19]

<u>Question 7</u>: How does your RTO/ISO approach capacity accreditation? What are the benefits and drawbacks of harmonizing capacity accreditation methods across regions versus allowing for regional variation?

a. ***the current 1-in-10 LOLE criterion and the identification of additional analysis needed to evaluate whether there are gaps that need to be addressed. The Resource Adequacy Metrics Given that many regions use the same probabilistic models for both evaluating resource adequacy and/or reserve margins and for Effective Load Carrying Capability (ELCC) accreditation, are there best practices in approaches that NERC is observing that could help align various regions across the country in using the best modeling methodologies or data sources, etc.?***
b. ***What are the potential strengths, weaknesses, and implementation considerations of alternatives to ELCC when evaluating the contribution of various types of resources in meeting resource adequacy requirements?***

MISO has made significant reforms to improve the resource accreditation methodology to meet the regional reliability needs in the region. These reforms provide a strong foundation to ensure that LSEs bring the resources needed for MISO's operators to

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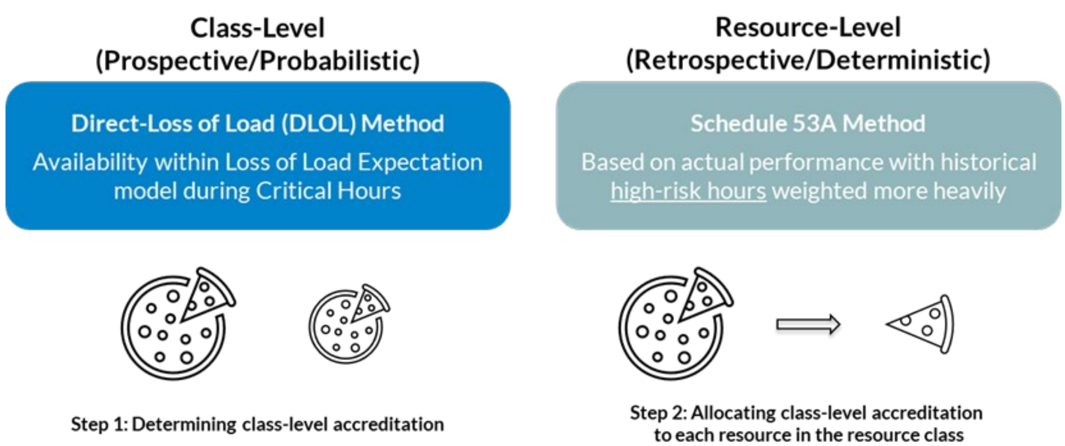
[18] Recommended through the Resource Adequacy Metrics and Criteria Roadmap document.
[19] More information on the NERC Planning Energy Assurance standard can be found here https://www.nerc.com/pa/Stand/Pages/Project-2024-02-Planning-Energy-Assurance.aspx

dispatch resources to meet customer demand for every hour in the day and the resource adequacy market provides a transparent signal for needed resource investment.

MISO is currently transitioning to a two-step accreditation approach (the "Direct Loss-of-Load" or "DLOL"-based methodology) that accredits capacity based on marginal contribution to reliability during periods of highest system risk ("marginal effective load carrying capability" or "marginal ELCC") and on Resource Class. MISO's DLOL-based methodology combines both probabilistic and deterministic elements into a single resource accreditation process. Simply described, the DLOL-based methodology takes two steps by first determining the size of the pie, and second, divvying up the pie.

Figure I.E.



Regional diversity evolved for various reasons and a prescriptive process is not optimal or productive. For example, the Tariff interregional study process with SPP, which has been in place 2020, has yielded no new projects. MISO supports allowing for regional variation to allow RTOs/ISOs to address the unique needs of their regions. MISO has a very diverse footprint: 6 out of 16 regulatory jurisdictions are elected, 4 jurisdictions have moderate to aggressive renewable portfolio standards, 7 jurisdictions lean towards a traditional, fossil fuel approach, and 5 jurisdictions take a balanced approach. The one uniform metric across all states and all RTOs/ISOs is 100% for grid reliability. But MISO does actively engage with all other RTOs in North America, in part through the ISO/RTO Council ("IRC") Markets Committee and also in part with direct discussions with RTO staff to follow best practices in the industry. If design attributes in another RTO look to potentially address MISO issues, we vet these before the stakeholder community and adopt them as appropriate. An example of this is the RBDC design being similar in nature to some of the eastern RTOs construct.

MISO does not speak on behalf of NERC, but MISO agrees with the Commission's previous statements that "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. This method 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."[20]

MISO strongly believes that, while respecting regional variations, capacity should be accredited based on performance during times of high risk to properly recognize that not all capacity is created equal, nor will all capacity perform equal in any given situation. Weighing 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 weight to the former. This ensures that the expected reliability risk during critical hours is being appropriately accounted for in the resource class-level accreditation calculation.

MISO has considered a number of approaches and has found that approaches that accredit an entire class of resources based on the average contribution of the entire fleet do not align with the assumption that capacity exchange in the capacity market is fungible. Instead, marginal accreditation that measures the contribution of the next incremental addition to the resource fleet 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.

The contribution of various resources in meeting resource adequacy requirements must be weighed in relation to their impacts on the system during high-risk hours. MISO has 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, and alternative weighting based on margin. None of these alternative schemes provide consistent emphasis on the hours with highest unserved energy to the level that weighing hours based on margin does. This properly accounts for the magnitude of expected reliability risks in each hour. This construct provides numerically stable results 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.

<u>Question 8</u>: How can the RTOs/ISOs ensure that their demand forecasts adequately take into account load growth from data centers and other large loads? How can the RTOs/ISOs ensure there is sufficient supply to meet these demands, and what will those sources of supply be?

Appropriately forecasting load growth from data centers and other large loads is a significant challenge across the industry. The issue is present in both RTO and non-RTO regions. The visibility and transparency of the RTO framework allows the challenge to be more clearly identified and visible in the RTO regions. MISO ensures that there is ample supply to meet demand through a prompt capacity market, resource forecasts provided by the OMS-MISO survey, conducted annually, and the RRA effort. MISO works closely with the OMS coordinating and collaborating with all potential PRA reforms to better support grid reliability.

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

Longer term load forecasts[21] originate with the LSEs. MISO validates and utilizes these forecasts to adequately take into account load growth from data centers and other large loads. MISO subject matter experts validate forecasts for the upcoming planning year through a random sampling approach. Included in this sampling is an assessment of the accuracy of the past year's forecasts which outlines a set of detailed questions related to the forecasts that each LSE must answer. Accounting for load growth from data centers and other large loads is asked directly to LSEs with a requirement on the LSE show support for their assumptions.

MISO recently updated our long-term[22] load forecasting process to better account for the impact of new sources of load growth on long-term planning. The process uses bottoms-up estimates of load for each of a set of drivers (e.g. data center announcements) along with assessed probabilities (e.g. likelihood of an announced data center being built on time) to develop a range of credible forecasts. These forecast are benchmarked against the LSE-provided forecast in the first few years. Longer-term load forecasts support MISO's transmission planning efforts and inform member resource planning decisions.

<u>Question 9</u>: How can demand flexibility and demand-side management solutions be utilized to address load growth and resource adequacy concerns?

Demand resources acting as supply are viable alternatives for LSEs to use in meeting their capacity obligations, and are used quite abundantly in MISO. MISO continues to explore future implementation of DERs to assist in resource adequacy challenges and is working closely with the OMS to be transparent around any future reliability issues. MISO has also recently filed reforms intended to better accredit demand-side resources to ensure those are resources appropriately valued as a resource adequacy tool.

<u>Question 10</u>: How do you reflect transmission availability—both regional and interregional—in your resource adequacy planning and requirements? To what extent do your transmission planning processes capture the resource adequacy benefits of regional and interregional transmission?

The changing resource mix requires more transmission to get generation to load. MISO's Tranche 2 portfolio of LRTP projects is progressing, with approval from MISO's Board of Directors in 2024. Planning is complex, but MISO has balanced the need to move quickly to meet resource adequacy objectives with the need to develop a robust, lowest-cost portfolio. Through the roll out of LRTP projects, transmission projects are in progress in areas with the greatest need based on ranges of economic, policy, and regulatory inputs. Availability of regional transmission capability affects the ability to import/export resources across the MISO footprint. MISO captures these capabilities in the capacity import and export limits modeled and respected in the PRA. These import/export limits are reevaluated annually and modeled in the PRA, allowing resources to meet local and regional capacity requirements.

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[21] Anything longer than a week or two out or any load forecasts that are not used in the Energy and Operating Reserve markets.

[22] 20-year.

To get customers to build out generation, they mainly need reasonable costs and cost certainty. MISO's JTIQ ("Joint Transmission Interconnection Queue") addresses this by spreading costs among interconnection customers so that customers do not hesitate to build out due to fear of being the project that triggers a higher cost than what is feasible. This allows all parties to pay reasonable costs that they can anticipate in advance.

Panel 5: MISO's Resource Adequacy Challenge

***Question 1*: What is the state of resource adequacy in MISO in the near term (e.g., over the next five years) and over the longer term (e.g., ten years and beyond)?**

a. ***Is MISO's resource adequacy construct delivering resource adequacy in MISO?***

b. ***What are the benefits and drawbacks to MISO's resource adequacy construct and residual capacity auction?***

There are urgent and complex challenges facing electric system reliability in the MISO region. These challenges include generation fleet change, regulatory hurdles, extreme weather events, and load additions, to name a few. In light of this, utilities, states and MISO have taken steps to coordinate with urgency to avoid any mismatch between the pace of adding new resources and the retirement of older resources. MISO is confident that by addressing the four pillars of the Reliability Imperative the region will remain in excess of the 1-in-10 LOLE Standard.

MISO uses a few tools to assess the state of resource adequacy in its footprint. The RRA is one of the periodic studies MISO conducts to forecast how the mix of electricity-generating resources in the MISO region could evolve going forward. In contrast, the OMS-MISO Survey is focused on the near term and is based on much lower expectations of new installed capacity, reflecting the pace at which resources have received interconnection agreements and come online in recent history. Each study was designed for a different purpose, uses different data inputs, covers different time periods, and uses different methodologies and modeling assumptions. Accordingly, the results differ. For example, the RRA assumes members and states will be able to add new generation capacity at an unprecedented rate of 17 GW/year for the next 20 years to reliably achieve their publicly announced resource plans and policy goals. Accordingly, the RRA projects capacity surpluses in 2030 and beyond. The 2024 OMS-MISO Survey therefore forecasted a range of possible outcomes, varying from capacity deficits beginning in 2025 to capacity surpluses through 2029. These divergent results reflect that the RRA and the OMS-MISO Survey were designed for different purposes and use different data inputs, methodologies, assumptions and time horizons.

In sum, given that the MISO states have rights towards resource adequacy, take their roles and responsibilities seriously, and MISO is providing transparency in expectations of future resource adequacy plans, we are confident that the footprint will continue to be resource adequate in the near and longer term. Capacity margins are declining but remain in excess of the 1-in-10 LOLE standard. MISO successfully implemented the RBDC in the capacity market for the 2025-2026 PRA. This construct provides more accurate price signals and encourages resource investments by reflecting the contributions to reliability incremental megawatts can add to the system. The capacity market has changed from an annual to a seasonal construct to better reflect the risks to resource adequacy shifting from mainly the summer peak demand conditions to periods across all seasons and time periods. On the supply side, resources are being accredited based on availability during all times of need, across all seasons. In the most recent PRA, the megawatts that cleared in the summer season exceeded 1-in-10 LOLE by an additional 2 percentage points because the reliability contribution of these additional megawatts exceeded the cost to procure them.

The RBDC construct values the reliability contribution of incremental MWs, the price signals that reflect that reliability value, and the prompt and residual nature of the capacity market. Prompt auctions have less uncertainty around demand values and supply availability. The residual nature recognizes that, in MISO, most LSEs come with resources that meet their requirements. There is the possibility that, without other actions, the prompt nature leaves little time to address any issues that arise, like shortfalls. This potential drawback is addressed through the OMS-MISO survey and RRA effort, providing more transparent information around future reliability requirements and resource margins.

<u>Question 2</u>: How have the recent outcomes of MISO's capacity auctions affected market participants and consumers in MISO? Do states and stakeholders have confidence that the MISO capacity market will be effective to achieve resource adequacy at just and reasonable rates?

The capacity shortfalls that occurred in the 2022/2023 planning year promoted a greater sense of urgency to MISO's ongoing efforts to continually enhance its market design. The vertical demand curve served the region well for many years but as the resource mix has changed and extreme weather events have increased, customer confidence in the capacity market eroded. The vertical demand curve created extreme price volatility that disincentivized investments. The RBDC, implemented for the first time in the 2025/26 PRA, has addressed this by providing more accurate price signals and encouraging resource investments by reflecting the contributions to reliability that incremental megawatts can add to the system. Most LSEs within MISO either have owned or contracted for resources that meet their obligations but, regardless, the more efficient capacity prices being established through the RBDC construct provide much better information to LSEs, RERRAs and generation owners to make more informed going forward investment decisions. This is akin to how Real Time energy market prices work – a very small percent of transactions are subject to real time prices, but Day Ahead prices are informed by what happens in real time. Changes to the resource adequacy construct highlighted above and the information provided through the OMS-MISO survey and RRA effort have initiated renewed efforts on the part of LSEs and RERRAs to address resource adequacy requirements.

States and stakeholders have shown confidence in the MISO capacity market to achieve resource adequacy at just and reasonable rates. This is in large part due to the collaborative relationship between MISO and its stakeholders. Since MISO's start, deference has been made to the states and other RERRAs with respect to resource adequacy rights. MISO has worked closely with OMS, the Independent Market Monitor ("IMM"), and other stakeholders to change the capacity market to a seasonal construct and implement the RBDC. OMS has reinforced the need for MISO's seasonal capacity construct and RBDC to properly accredit capacity in a world with more extreme weather and faster load growth than ever.

<u>Question 3</u>: How have the seasonal resource adequacy requirements and revised capacity accreditation methods worked in MISO to date? Have they helped MISO more accurately determine its resource adequacy needs? What issues or challenges has MISO experienced in implementing a seasonal construct and revising capacity accreditation, and how does MISO plan to address those issues or challenges?

The seasonal construct has highlighted the seasonal differences in the planning reserve margins required to meet the reliability standards, the varying Loss of Load Probability distributed across the seasons, the variability in the values of accreditation for resources by season (the Seasonal Accredited Capacity, or, "SAC") and significant differences in load variability season by season. This has helped MISO more accurately determine its resource adequacy needs as extreme weather has reconfigured what it means to be resource adequate. Being resource adequate on the hottest day in the summer does not necessarily mean that an LSE is resource adequate on the coldest day in the winter. SAC allows MISO to stay reliable throughout the entire year by targeting the unique needs of each season.

Accreditation changes, SAC in particular, are much more reflective of availability of resources to meet needs in each season.[23] The changes MISO has made to accreditation has a prospective and retrospective tint to it on purpose, as it captures the class level performance during projected risk conditions, while still being grounded and calibrated against the reality of how actual units performed over the last 3 years. This allows good performers to continue having a great incentive to continue that performance. Spring & fall seasons can be quite variable with summer and winter weather patterns bleeding into the shoulder seasons. For example, as the weather changes, winter weather may continue into early spring. Each successive planning year provides MISO with additional data to support market design. Currently there is a limited sample size for assessing accreditation. MISO is addressing these and other issues with renewed effort on appropriate LOLE modeling, shared with stakeholders.

<u>Question 4</u>: How does MISO establish its load and resource forecasts?

- ***a. How does MISO integrate the load forecasts provided by load-serving entities and electric distribution companies into their planning reserve margin requirements?***
- ***b. Does MISO verify the forecast methodologies and accuracy of forecasts?***
- **c.** ***Have the assumptions driving load and resource forecasts changed over time? If so, how?***

[23] The answer to question 7 in the above panel more fully describes the changes we have made.

d. ***How do the forecast models weight different inputs? Are some assumptions more uncertain, important, or impactful than others?***

e. ***How have the forecasts performed historically and are parties considering any changes to forecasting models or processes? For example, are you considering requiring demonstration of commercial readiness from prospective new large load additions?***

Anything longer than a few weeks or any load forecasts that are not used in the Energy and Operating Reserve markets are considered "longer-term forecasts" and originate with the LSEs. With such a wide and diverse footprint in MISO, LSEs are best positioned to have information on where energy & demand is moving in its localized area. Resource forecasts are provided by the OMS-MISO survey and the RRA efforts and are conducted annually.

MISO integrates previous LSE forecasts as direct inputs into the LOLE modeling which determines the planning reserve margin requirements. MISO verifies the forecast methodologies and accuracy of forecasts provided by LSEs. LSEs submit documentation, including a narrative with a complete description of the type of models being used, statistical model results, and spreadsheets with historic and forecast data, to MISO to support the LSEs' forecast demands. MISO then draws a random sample of these LSEs broken up into identified segments. Current segments are large LSEs (demand greater than 1000 MWs), medium LSEs (demand between 100 MWs and 1000 MWs), and small LSEs (demand less than 100 MWs). MISO subject matter experts then assess and validate the credibility of the LSE's submittals. Included in this is an assessment of the accuracy of the past year's forecasts.

The values for the variables used in the forecast have changed over time and been updated to weigh different inputs appropriately. The variables themselves have not necessarily changed. For example, LSEs consistently see new commercial and industrial facilities being built and older facilities being closed, but more recently, new load growth predominantly from data centers has driven expectations of higher load growth in the near term. Statistical models calculate the weights endogenously.

Certainly, some assumptions are more uncertain than others. On the resource side, getting through the queue process has significant uncertainty. On the demand side, for instance, significant load additions, like data centers, have to be studied for reliability impacts and come with uncertain timing of these additions.

The forecasts have performed to acceptable industry standards in the past, though load growth has been minimal over recent time periods. MISO, however, is strengthening its load forecast validation process, providing more guidance on acceptable practices, and looking for discrete changes to the load forecasts.

Given the prompt nature of the PRA, demonstration of commercial readiness of prospective new load additions has always been a consideration.

<u>Question 5</u>: To what extent are barriers to entry (e.g., the interconnection queue backlog, supply chain limitations, siting and permitting delays, etc.) affecting resource adequacy in the MISO footprint?

The barriers affecting resource adequacy in the MISO footprint are less to entry, but rather barriers to success once projects exit the interconnection queue. Factors such as funding, off-taker agreements, supply chain, and permitting and citing delay projects from being built once they exit the generator interconnection process. There is over 50 GW of projects that have a signed generator interconnection agreement and are not yet online. Over half of them are already signaling they are delayed and cannot meet their originally expected in service date. New long-term stability and certainty in federal energy policy has further worsened these expected delays. A clearer signal on federal energy policies and import tariffs impacting necessary electrical components would promote investments and ease these delays. To improve visibility into these generators with interconnection agreements signed but not yet online, MISO created a Commercial Operation Date Dashboard on our website to help stakeholders understand when these resources are expected to come online.[24]

Another concern is the queue backlogs themselves. Although there is a significant amount of generation with a GIA waiting to come online, these resources may not have all the attributes necessary to ensure long term resource adequacy. The MISO queue has historically represented wind, solar, and battery storage projects. This includes 86% of the resources with a GIA waiting to come online, and over 96% of the 300 GW of projects in ongoing queue cycles. A significant shift is occurring for MISO's next queue cycle that will close in September of 2025. Currently there are 44 GW of projects submitted in the 2025 queue, and 26% of that is new natural gas resources. The queue backlog and delays mean these new resources may have to wait years to get an interconnection agreement.

To aid in the development of resources needed to address resource adequacy, MISO introduced a new process to study select projects outside the interconnection queue. The ERAS process was filed at Commission in March. This process would allow MISO to study individual projects, acknowledged by their RERRA and an off-taker agreement, with load to be studied by MISO through ERAS. This process would allow these projects to receive a GIA within months instead of years. This temporary process will only be in place until the queue backlog and delays have been mitigated.

<u>Question 6</u>: To what extent does the availability of regional and interregional transmission capability affect resource adequacy planning in MISO? How can MISO better address the effect of transmission capability on resource adequacy?

[24] See the C.O.D. dashboard here https://app.powerbigov.us/view?r=eyJrIjoiOTU1ODlhNTktMjZjZC00N2I2LWJhYjMtMDEwOGNmZDM5ODk0IiwidCI6IjYwNDA5MTViLTlkZmYtNGQ0Ny1iYjM1LThhYzljOWE1ZGMxOCJ9&pageName=983a2cc8ca3ccf63608a.

Availability of regional transmission capability affects the ability to import/export resources across the MISO footprint. MISO captures these capabilities in the capacity import and export limits modeled and respected in the PRA.

MISO can increase study effectiveness to better address transmission capabilities. MISO is implementing the generator interconnection request cap ("queue cap") and interconnection process improvements to achieve this. The queue cap limits requests at 50% of each region's non-coincident peak load. This follows a first-in, first-selected approach to allow for more manageable request numbers which will improve effectiveness and efficiency. MISO is also implementing SUGAR software which has shown significant time reduction for preliminary studies so far. Additionally, a new application portal will be available for customers in June with improved interface and data quality.

***Question 7**: Would an alternative resource adequacy construct used by another RTO/ISO be more effective at delivering resource adequacy in MISO? If so, why?*

No, the enhanced reforms with the DLOL construct provide an effective tool to deliver resource adequacy. The DLOL-based methodology respects states' rights and responsibilities over resource adequacy. RERRAs have well established processes in place to meet the resource adequacy requirements determined by MISO and are expected to continue to do so. The residual nature of the resource adequacy construct is working as intended. The RRA studies and the OMS-MISO survey further support resource adequacy decision and planning across the footprint.

Additionally, MISO is not aware of any alternatives to the current residual market that would perform better in MISO at this time. Recent capacity market enhancements such as SAC, RBDC, and DLOL-based methodology will continue to be implemented, improve market signals, and support needed resource availability. MISO continues, however, to consider design changes to the resource adequacy construct that can enhance reliability and support needed resource investment decisions.

***Question 8**: What should be the allocation of roles and responsibilities between MISO and the states to ensure resource adequacy in the MISO region? How does MISO work with the states to identify and meet the region's resource adequacy needs at just and reasonable rates? Has MISO studied the effects of state public policy on either resource adequacy or capacity market outcomes?*

Every effort in pursuit of the Reliability Imperative is centered around the shared responsibility between MISO-member electricity providers, states, and MISO to maintain a reliable grid. MISO appreciates states' responsibility for resource adequacy and acknowledges that LSEs have the obligation to serve their end-use customers. Both LSEs and RERRAs take their responsibilities seriously. Continued coordination is critical. With the pace of change confronting the electricity system, the impending influx of large data centers and the evolving generation portfolio there is heightened urgency to ensure the system remains reliable. Given this, MISO can assess, analyze and provide transparency on where resource adequacy conditions are moving, providing additional macro level views on the issues to help inform states and LSEs. MISO translates the 1-in-10 LOLE into planning reserve requirements and the responsibility of MISO to facilitate residual capacity transactions through the PRA.

MISO works closely with the OMS and RERRAs to communicate regional needs to maintain resource adequacy. Both the OMS-MISO Survey and the RRA provide information to MISO on state-specific forecasts. From this state-specific information, MISO conducts analyses that are made public around the need for different types of resources to meet the reliability standards being imposed by NERC.

MISO has not directly studied the effects of state public policy. MISO has, however, in its RRA studies, provided detailed analyses around the implications of state public policy. One example of this is increasing renewable energy trends. MISO puts priority on maintaining independence from individual MPs. We are fuel source and policy neutral, meaning we do not favor, prefer, or advocate any particular fuel or policy outcome. That doesn't mean, however, that we are disinterested observers. Our mission is to ensure the continued reliability of the bulk electric system.

III. CONCLUSION

MISO appreciates the opportunity to provide these responses to the Commission's questions regarding Challenge of Resource Adequacy in Regional Transmission Organization and Independent System Operator Regions.

Respectfully submitted,

/s/ Todd Ramey

Todd Ramey

Senior Vice President of Markets and Digital Strategy
Midcontinent Independent System Operator, Inc.

Appendix I

Appendix I summarizes data provided in this written statement through graphs, charts, and other images.

Figure I.A.

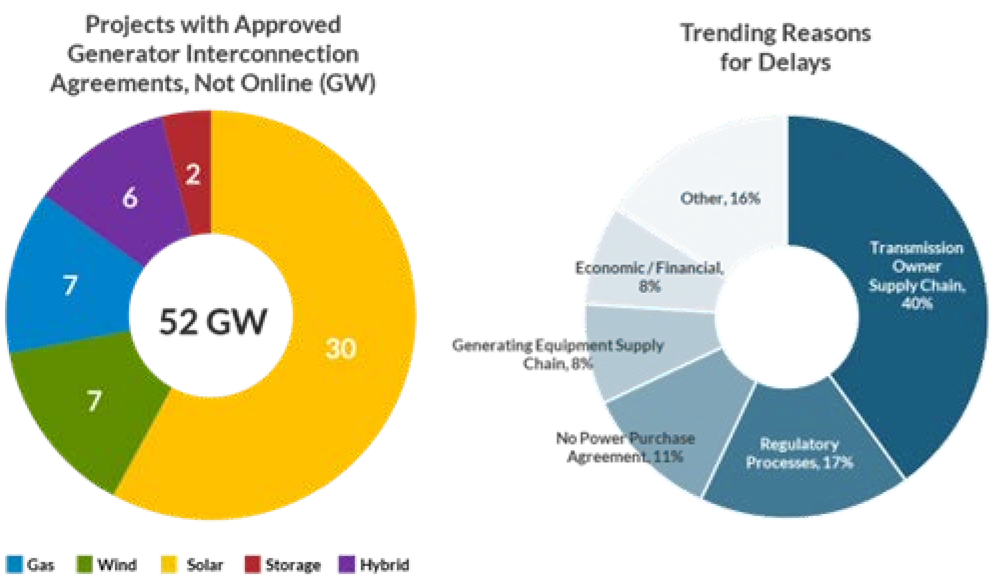

Figure I.A., found on page 13, compares 52 GW of Approved Generator Interconnection Requests in MISO with a breakdown of reasons for reported developmental delays and the percentage of delays affected by such set back.

Figure I.B.

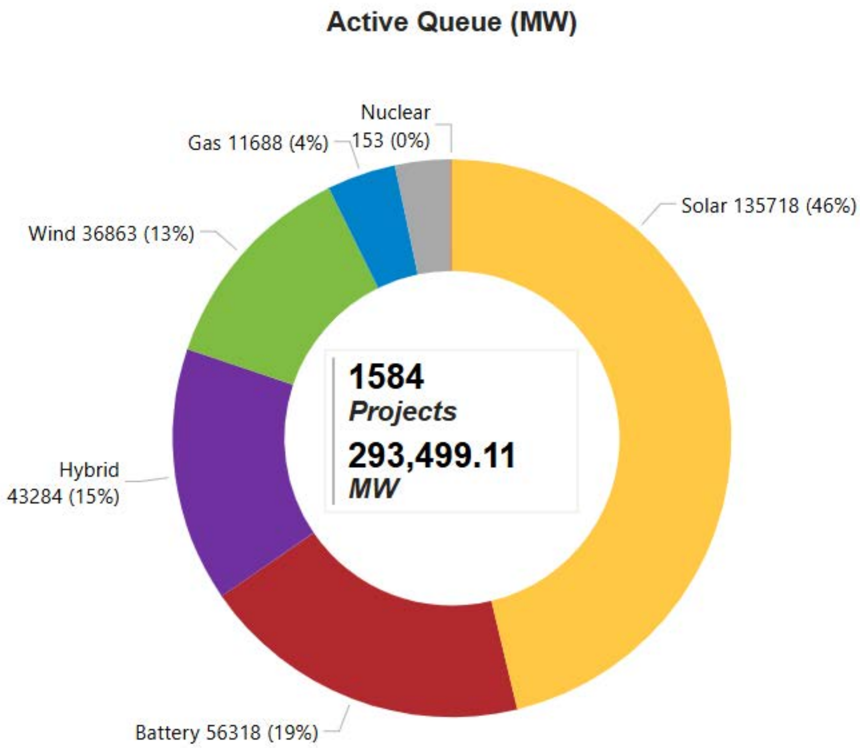

Figure I.B., found on page 14, illustrates the active MISO Generator Interconnection Queue by resource type. Does not reflect additional nameplate capacity from repowering existing generating facilities. As of February 6, 2025.

Figure I.C.

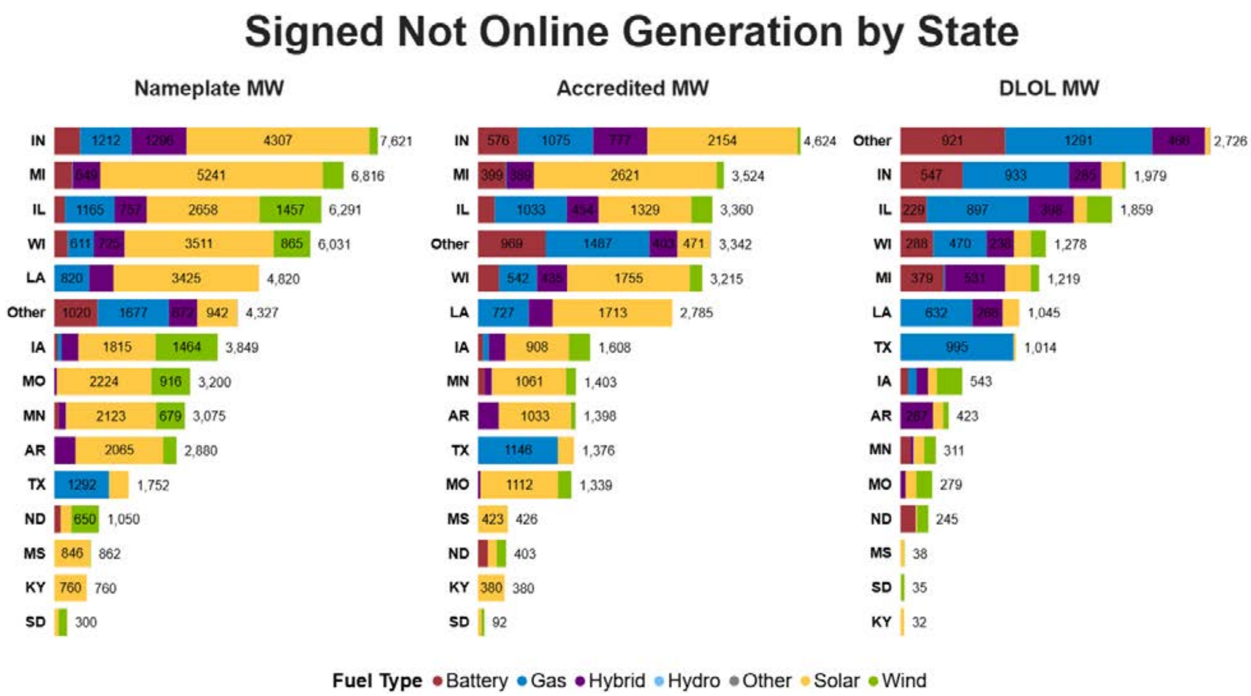

Figure I.C., found on page 15, illustrates a state-by-state comparison of MWs of Approved Generator Interconnection requests in nameplate capacity, accredited capacity, and DLOL-based methodology. The DLOL-based capacity accreditation assumptions are based on the fuel-based class average assumptions that are expected to be in place for the 2028/2029 planning year. The 2028/2029 Planning Resource Auction will be the first to utilize the DLOL-based methodology.

Figure I.D.

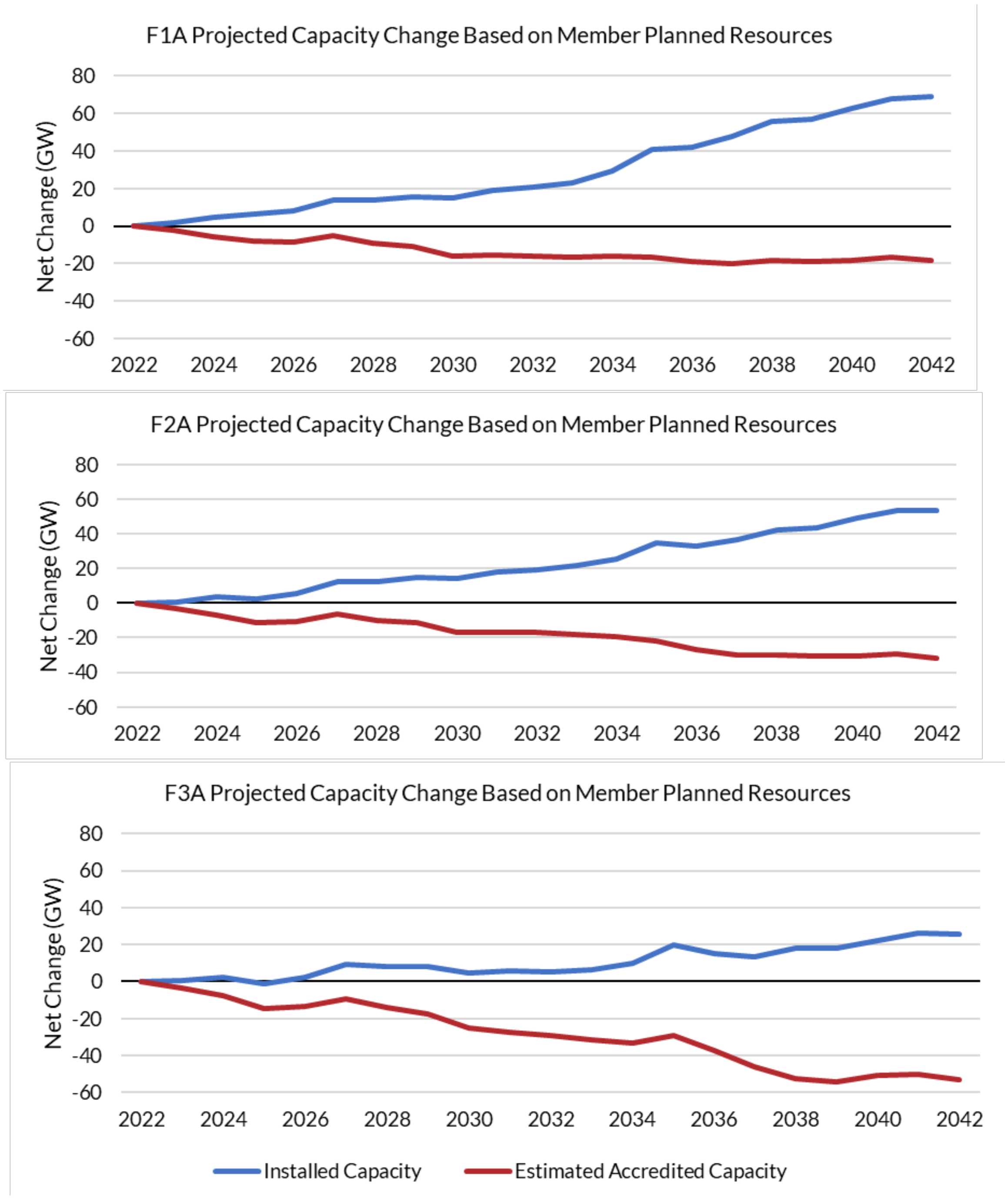

Figure I.D., found on page 17, shows projected capacity change from 2022 to 2042 for all three Futures based on existing and member-planned resources. Differences in the net change of installed and estimated accredited capacity are driven by the varying age-based retirement assumptions applied to existing resources across Futures. Figure I.D. is sourced from Series 1A MISO Futures Report. More information on this report can be found here https://cdn.misoenergy.org/Series1A_Futures_Report630735.pdf.

Figure I.E.

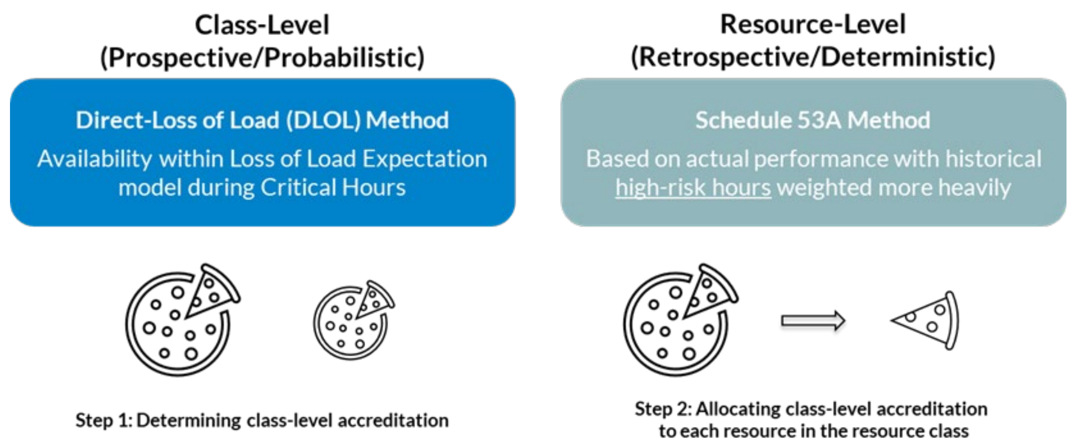

Figure I.E. explains the two-step DLOL-based resource accreditation methodology, further explained on pages 19. The DLOL-based capacity accreditation assumptions are based on the fuel-based class average assumptions that are expected to be in place for the 2028/2029 planning year. The 2028/2029 Planning Resource Auction will be the first to utilize the DLOL-based methodology.

Appendix II

Appendix II supplements information provided in this written statement with additional data on state generation retirements and additions.

Figure II.A.

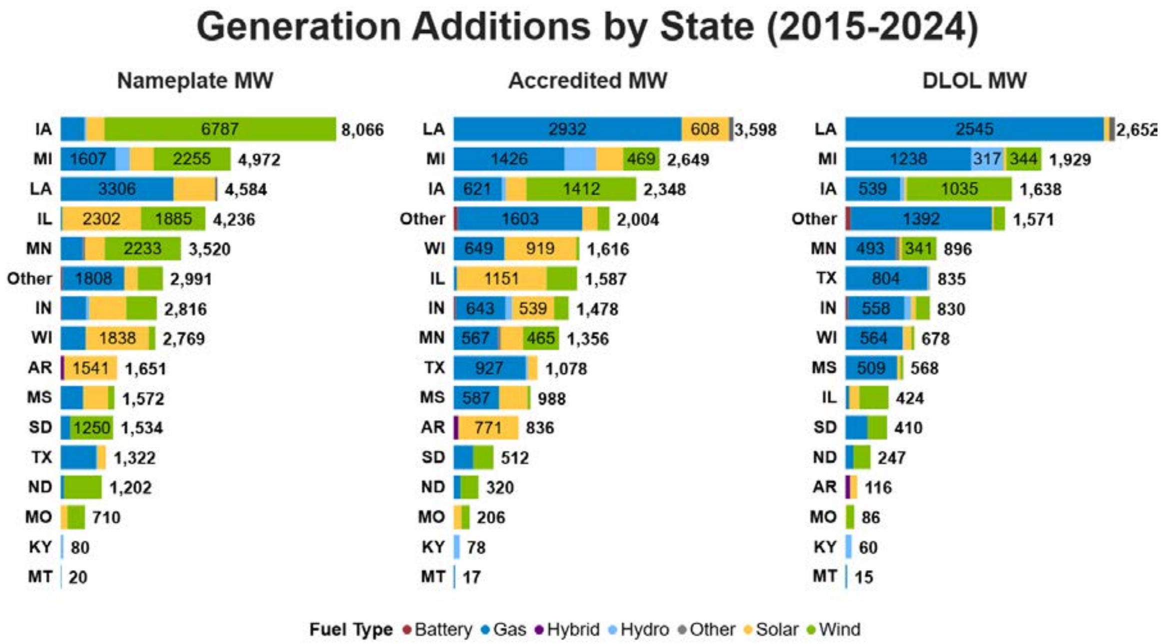

Figure II.A. illustrates a state-by-state comparison of generation that has come online over the last 10 years in the MISO region through new generation, surplus, and replacements. This is measured by nameplate capacity, current accredited capacity, and DLOL-based methodology. The DLOL-based capacity accreditation assumptions are based on the fuel-based class average assumptions that are expected to be in place for the 2028/2029 planning year. The 2028/2029 Planning Resource Auction will be the first to utilize the DLOL-based methodology.

Figure II.B.

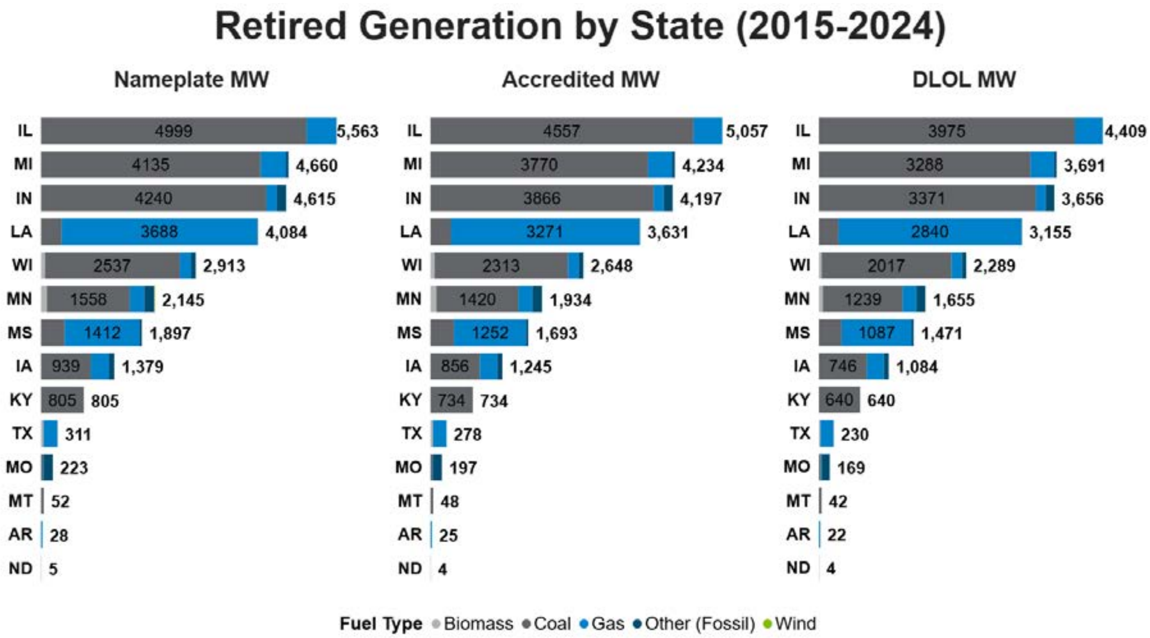

Figure II.B. illustrates a state-by-state comparison of retired generation over the last 10 years in the MISO region, measured by nameplate capacity, current accredited capacity, and DLOL-based methodology. The DLOL-based capacity accreditation assumptions are based on the fuel-based class average assumptions that are expected to be in place for the 2028/2029 planning year. The 2028/2029 Planning Resource Auction will be the first to utilize the DLOL-based methodology.

Figure II.C.

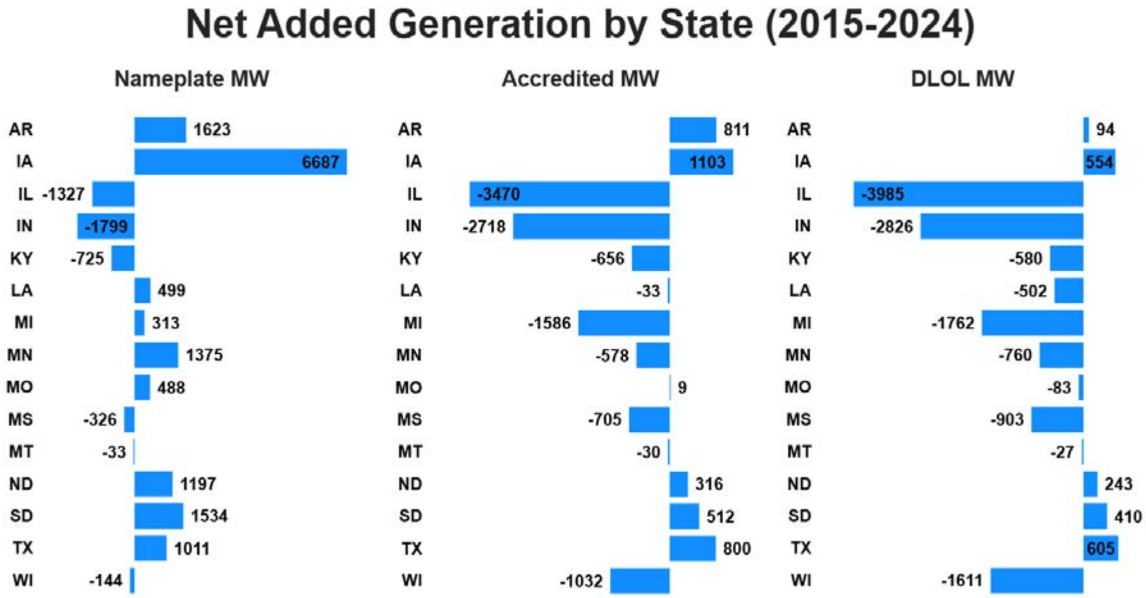

Figure II.C. illustrates a state-by-state comparison of net generation changes in megawatts over the last 10 years in the MISO region, measured by nameplate capacity, current accreditation, and DLOL-based methodology. The DLOL-based capacity accreditation assumptions are based on the fuel-based class average assumptions that are expected to be in place for the 2028/2029 planning year. The 2028/2029 Planning Resource Auction will be the first to utilize the DLOL-based methodology.

Attachment C

Collection of MISO Attachment Y materials

Consumers Energy
Count on Us®

A CMS Energy Company

Timothy J. Sparks, P.E.
Vice President Electric Grid Integration

VIA Electronic Mail

December 14,2021

Andrew Witmeier
Director of Resource Utilization
Midcontinent Independent System Operator, Inc.
720 City Center Drive
Carmel, IN 46032

Re: Suspension of Campbell Units 1, 2 & 3

Dear Mr. Witmeier:

Consumers Energy Company ("Company") hereby provides notice to the Midcontinent Independent System Operator, Inc. ("MISO") that it intends to suspend Campbell Units 1, 2 and 3 effective June 1, 2025. Attached is the notice of such intent in accordance with Section 38.2.7 and Attachment Y of MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff").

Campbell Unit 3 is jointly owned by the Company (93.3%), CPNode CONS.CAMPBELL3, Michigan Public Power Agency (4.8%), CPNode CONS.CA3.MPPA, and Wolverine Power Supply Cooperative (1.9%), CPNode CONS.CA3_WPSC. The Company attests that, pursuant to the relevant Operating Agreements, it is authorized to submit this Attachment Y notice on behalf of all Campbell Unit 3 owners.

In the event you have any questions regarding this matter, please contact Kathy Wetzel at (517) 788-2039.

Regards,

Timothy J. Sparks
Vice President Electric Grid Integration
Consumers Energy Company
1945 W. Parnall Rd.
Jackson, MI 49201

Cc: Kathy Wetzel
Thomas Clark

Electric Supply
Contract/Commitment Cover Sheet

(Note: Contracts, purchase orders, or other commitment instruments will not be signed unless this sheet is completed in full)

Subject/Commitment: **MISO Attachment Y Notification of Generating Resources /SCU/ Pseudo-tied Out Generator Change of Status / Including Notification of Rescission Form**

Reason: Notice to Suspend Karn Units 3 & 4 effective June 1, 2023.

Yes	No*	N/A	Check One
		x	1) Gateway Assessment Tool completed and attached
x			2) Legal Review / Approval to Form
		x	3) Credit Risk Management Approval
		x	4) Competitive Bid
		x	5) Sole Source Approval completed and attached

***If No is checked or special circumstances apply, please explain:**

Legal review by Emerson Hilton.

***Contract Owner:** **Kathy Wetzel**

Department Sign Off
(Signature & Date Required)

ML Metz
Merchant Ops & PSCR

KG Troyer
EGI Contracts & Settlements
Renewables

BD Gallaway
Fuel Supply

TP Clark
Electric Supply

12/14/2021

TJ Sparks
Electric Grid Integration

Form Revised: 04/16/21

**Contract Owner Responsible for Scanning & Placing on SharePoint Site*

ATTACHMENT Y

Notification of Generation Resource/SCU/Pseudo-tied Out Generator

Change of Status,

Including Notification of Rescission

This is a notification of change of status of a Generation Resource, Synchronous Condenser Unit ("SCU"), or Pseudo-tied out Generator in accordance with Section 38.2.7.a of the Tariff. An electronic copy of the completed form will be accepted by the Transmission Provider, however, a form will not be considered complete until the original form containing an original signature, including all attachments, is received by the Transmission Provider at the following address: MISO, Attention: Director of Transmission Planning; 720 City Center Drive, Carmel, IN 46032.

The Transmission Provider may request additional information as reasonably necessary to support operations under the Tariff.

Owner of the Generation Resource, SCU or Pseudo-tied out Generator:
Consumers Energy Company (see attached letter re: Campbell Unit 3)

Name of Market Participant: Consumers Energy Company - NERC ID: CETR

Owner's state of organization or incorporation Michigan

Generation Resource/SCU/Pseudo-tied Out Generator [plant and unit number(s)] Campbell Units 1, 2 & 3

Source/Identification of Generation Interconnection Service [name of agreement, parties, date, date filed and docket number, and any other information to identify an agreement] CAMPBELL UNITS 1+2: UMBRELLA GIA BETWEEN CONSUMERS, METC + MISO FERC DOCKET ER21-999. CAMPBELL UNIT 3: FERC DOCKET ER06-1441 FOR MISO SERVICE AGREEMENT NO. 1755

Pursuant to the terms of the MISO Tariff, Owner hereby certifies that it will

[X] Suspend for economic reasons operation of all or a portion of the Generation Resource/SCU/Pseudo-tied out Generator commencing on 1st [day] of June [month] of 2025 [year]

[ ] Rescind the current notice to SuspendThe facility is further described as follows:

Location: West Olive, Michigan

Unit Name	CPNode (if applicable)	Nameplate Capacity(MW)	Change in Capacity(MW)
Campbell Unit 1	CONS.CAMPBELL1	260	260
Campbell Unit 2	CONS.CAMPBELL2	360	360
Campbell Unit 3	CONS.CAMPBELL3	844	844

Owner understands and agrees that this notification is provided in accordance with Section 38.2.7 of the Transmission Provider's Tariff and will not be made public by the Transmission Provider except as provided for under Section 38.2.7 of the Tariff.

The undersigned certifies that he or she is an officer of the owner of the Generation Resource/SCU/Pseudo-tied out Generator, that he or she is authorized to execute and submit this notification, and that the statements contained herein are true and correct.

Signature

Name: TIMOTHY J SPARKS

Title: VP ELECTRIC GRID INTEGRATION

Date:

Contact Information

Email: TIMOTHY.SPARKS@CMSENERGY.COM

Phone: 517 788 1053

Andrew Witmeier
Director, Resource Utilization
317-249-5585
awitmeier@misoenergy.org

VIA OVERNIGHT DELIVERY

March 11, 2022

Timothy J. Sparks
Vice President, Electric Grid Integration
Consumers Energy Company
1945 W. Parnall Rd.
Jackson, MI 49201

Subject: **Approval of Campbell Units 1,2 &3 Attachment Y Suspension Notice**

Dear Mr. Sparks,

On December 14, 2021, Consumers Energy Company submitted an Attachment Y Notice to MISO for the suspension of Campbell Units 1,2 & 3, effective June 1, 2025. After being reviewed for power system reliability impacts as provided for under Section 38.2.7 of MISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff ("Tariff"), the suspension of Campbell Units 1,2 & 3 would not result in violations of applicable reliability criteria. Therefore, Campbell Units 1,2 & 3 may suspend without the need for the generators to be designated as a System Support Resource ("SSR") units as defined in the Tariff.

As there were no reliability criteria violations, MISO will continue to preserve the confidentiality of the Attachment Y Notice.

Please do not hesitate to contact me if you have any questions regarding this matter.

Respectfully,

Andrew Witmeier
Director, Resource Utilization

Consumers Energy
Count on Us

VIA EMAIL

Andrew Witmeier
Director of Resource Utilization
Midcontinent Independent System Operator, Inc.
720 City Center Drive
Carmel, IN 46032

May 28, 2025

Re: Modified Suspension Date for Campbell Units 1, 2, & 3

Mr. Witmeier:

On December 14, 2021, Consumers Energy Company ("Consumers Energy") submitted an Attachment Y Notice to the Midcontinent Independent System Operating, Inc. ("MISO") for the suspension of Units 1, 2, and 3 at the J.H. Campbell Generation Complex ("Campbell Plant"), effective June 1, 2025. After reviewing for power system reliability impacts as provided for under Section 38.2.7 of MISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff ("Tariff"), MISO determined the suspension of Campbell Plant Units 1, 2, and 3, would not result in violations of applicable reliability criteria, as outlined in the Tariff. On March 11, 2022, MISO approved the suspension of Campbell Plant Units 1, 2, and 3 without the need for the generators to be designated as System Support Resource units as defined in the Tariff.

On May 23, 2025, the U.S. Department of Energy ("DOE") issued Order No. 202-25-3 (the "Order"), requiring the Campbell Plant to be available to MISO through August 20, 2025.

In order to comply with the Order, Consumers Energy hereby provides notice to MISO, consistent with Section 38.2.7(d)(ii)(1) of the Tariff, of its intent to modify the current Attachment Y Notice such that the Campbell Plant will now suspend on August 21, 2025.

As noted in Consumers Energy's original Attachment Y Notice, Campbell Unit 3 is jointly owned by Consumers Energy (93.3%), CPNode CONS.CAMPBELL3, Michigan Public Power Agency (4.8%), CPNode CONS.CA3.MPPA, and Wolverine Power Supply Cooperative (1.9%), CPNode CONS.CA3_WPSC. The Company attests that it has notified all Campbell Unit 3 owners of this submittal.

In the event you have any questions regarding this matter, please contact Derek Anspaugh at (517) 788-1869.

Regards,

Sri M.

Sri Maddipati
VP Electric Supply
1945 W. Parnell Rd
Jackson, MI 49901

ATTACHMENT Y

Notification of Generation Resource/SCU/Pseudo-tied Out Generator

Change of Status,

Including Notification of Rescission

This is a notification of change of status of a Generation Resource, Synchronous Condenser Unit ("SCU"), or Pseudo-tied out Generator in accordance with Section 38.2.7.a of the Tariff. An electronic form must be submitted to the Transmission Provider via its online application tool in the manner specified by the Transmission Planning Business Practices Manual (BPM-020), and a form will be considered complete on the date of such online application.

The Transmission Provider may request additional information as reasonably necessary to support operations under the Tariff.

Owner of the Generation Resource, SCU or Pseudo-tied out Generator:
Consumers Energy Company (see attached letter re Campbell 3)

Name of Market Participant: Consumers Energy Company - NERC ID: CETR

Owner's state of organization or incorporation Michigan

Generation Resource/SCU/Pseudo-tied Out Generator [plant and unit number(s)] Campbell Units 1, 2 & 3

Source/Identification of Generation Interconnection Service [name of agreement, parties, date, date filed and docket number, and any other information to identify an agreement] ____________
Campbell Units 1 & 2: Umbrella GIA Between Consumers, METC, and MISO, FERC Docket No. ER24-1359
Campbell Unit 3: FERC Docket No. ER06-1441 for MISO Service Agreement No. 1755

Pursuant to the terms of the MISO Tariff, Owner hereby certifies that it will

[X] Suspend for economic reasons operation of all or a portion of the Generation Resource/SCU/Pseudo-tied out Generator commencing on 21 [day] of August [month] of 2025 [year]

[ ] Rescind the current notice to Suspend

The facility is further described as follows:

Location: West Olive, Michigan

Unit Name	CPNode (if applicable)	Nameplate Capacity(MW)	Change in Capacity(MW)
Campbell Unit 1	CONS.CAMPBELL1	260	260
Campbell Unit 2	CONS.CAMPBELL2	360	360
Campbell Unit 3	CONS.CAMPBELL3	844	844

Owner understands and agrees that this notification is provided in accordance with Section 38.2.7 of the Transmission Provider's Tariff and will not be made public by the Transmission Provider except as provided for under Section 38.2.7 of the Tariff.

The undersigned certifies that he or she is an officer of the owner of the Generation Resource/SCU/Pseudo-tied out Generator, that he or she is authorized to execute and submit this notification, and that the statements contained herein are true and correct.

Signature

Name: Srikanth Maddipati

Title: VP Electric Supply

Date: May 28, 2025

Contact Information

Email: sri.maddipati@cmsenergy.com

Phone: 517-788-0635

From:	Marc Keyser
To:	Rachael H. Moore; Huaitao Zhang; DEREK S. ANSPAUGH; Adam C. French; NICHOLAS B. TENNEY; Emerson J. Hilton
Cc:	Sumit Pal Brar
Subject:	RE: [EXT]RE: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required
Date:	Friday, May 30, 2025 4:05:01 PM

Rachael: I'm responding back on behalf of the team, after they briefly reviewed with legal here:

we received the Attachment Y, and the new cessation is 8/21/2025. Additionally, you have until 8/21/2027 to submit a new replacement request before the suspension period ends. In other words, the Attachment Y remains as is, still approved, except with a new/different start date.

From: Rachael H. Moore <Rachael.Moore@cmsenergy.com>
Sent: Friday, May 30, 2025 12:15 PM
To: Huaitao Zhang <HZhang@misoenergy.org>; Derek Anspaugh <Derek.Anspaugh@cmsenergy.com>; Adam French <adam.french@cmsenergy.com>; NICHOLAS B. TENNEY <NICHOLAS.TENNEY@cmsenergy.com>; Emerson J. Hilton <Emerson.Hilton@cmsenergy.com>
Cc: Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>
Subject: RE: [EXT]RE: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

Thank you, Huaitao. Can you confirm that this modification of the suspension start date provided consistent with Section 38.2.7(d)(ii)(1) of the Tariff does not impact the overall approval of the Attachment Y the Company previously received on March 11, 2022, and that the Company is still approved to enter suspension (now effective 8/21/25)?

Thank you!

Rachael Moore | Senior Attorney
[redacted]

From: Huaitao Zhang <HZhang@misoenergy.org>
Sent: Wednesday, May 28, 2025 1:47 PM

To: Rachael H. Moore <Rachael.Moore@cmsenergy.com>; DEREK S. ANSPAUGH <DEREK.ANSPAUGH@cmsenergy.com>; Adam C. French <ADAM.FRENCH@cmsenergy.com>; NICHOLAS B. TENNEY <NICHOLAS.TENNEY@cmsenergy.com>; Emerson J. Hilton <Emerson.Hilton@cmsenergy.com>
Cc: Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>
Subject: RE: [EXT]RE: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

Rachael,

Thanks for the quick response, and we are all good.

Thanks,
Huaitao

From: Rachael H. Moore <Rachael.Moore@cmsenergy.com>
Sent: Wednesday, May 28, 2025 12:40 PM
To: Huaitao Zhang <HZhang@misoenergy.org>; Derek Anspaugh <Derek.Anspaugh@cmsenergy.com>; Adam French <adam.french@cmsenergy.com>; NICHOLAS B. TENNEY <NICHOLAS.TENNEY@cmsenergy.com>; Emerson J. Hilton <Emerson.Hilton@cmsenergy.com>
Cc: Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>
Subject: [EXT]RE: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

Huaitao –

Attached is the modified Attachment Y with the amended suspension start date of 8/21/2025. Please let me know if we should send this notice of Modified Attachment Y to anyone else at MISO or if you would like us to mail a physical copy as well.

Thank you,
Rachael

Rachael Moore | Senior Attorney
[redacted]

From: Rachael H. Moore
Sent: Tuesday, May 27, 2025 11:52 AM
To: Adam C. French <adam.french@cmsenergy.com>; Huaitao Zhang <HZhang@misoenergy.org>; NICHOLAS B. TENNEY <nicholas.tenney@cmsenergy.com>
Cc: Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>
Subject: RE: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

Good afternoon,

Yes, I will be working with members of the Company to ensure we have the Attachment Y notice updated by 5/28. Please let me know if there is a specific contact at MISO we should plan to send this to.

Thank you!
Rachael

Rachael Moore | Senior Attorney
[redacted]

From: Adam C. French <ADAM.FRENCH@cmsenergy.com>
Sent: Tuesday, May 27, 2025 11:49 AM
To: Huaitao Zhang <HZhang@misoenergy.org>; NICHOLAS B. TENNEY <NICHOLAS.TENNEY@cmsenergy.com>; Rachael H. Moore <Rachael.Moore@cmsenergy.com>
Cc: Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>
Subject: RE: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

It is my understanding that is being handled by Rachael Moore
RACHAEL.MOORE@CMSENERGY.COM

From: Huaitao Zhang <HZhang@misoenergy.org>
Sent: Tuesday, May 27, 2025 11:41 AM
To: NICHOLAS B. TENNEY <NICHOLAS.TENNEY@cmsenergy.com>; Adam C. French <ADAM.FRENCH@cmsenergy.com>
Cc: Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>
Subject: FW: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

You don't often get email from hzhang@misoenergy.org. Learn why this is important [aka.ms]

##CAUTION##: This email originated from outside of CMS/CE. Remember your security awareness training: Stop, think, and use caution before clicking links/attachments.

Nick and Adam,

Marc pointed to me that you are the contact for this request.

Thanks,
Huaitao

From: Huaitao Zhang
Sent: Tuesday, May 27, 2025 11:05 AM
To: KATHY S. WETZEL <KATHY.WETZEL@cmsenergy.com>
Cc: timothy.sparks@cmsenergy.com; Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>; Jagdesh Shivani <JShivani@misoenergy.org>
Subject: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

Hi Kathy,

Pertain to the Order from Secretary of Energy regarding the suspension/cessation date of Campbell units 1,2&3, MISO requests Consumer Energy to submit the following application updates to MISO by 5/28/2025:

Attachment Y request with suspension start date as 8/21/2025

FYI, the order link is https://www.energy.gov/sites/default/files/2025-05/Midcontinent%20Independent%20System%20Operator%20%28MISO%29%20202%28c%29%20Order_1.pdf [energy.gov]

Thanks,
Huaitao Zhang
Resource Utilization Engineer

Integrity | Collaboration | Commitment | Creativity | Adaptability

Attachment CC

NREL, Resource Adequacy Basics

Research Areas
Facilities
Publications
Data & Tools
Directorates
Fellows
Collaborations
Energy Basics
Advanced Manufacturing
Biomass
Geothermal
Hydrogen
Hydropower
Marine Energy
Power Grid
- Resource Adequacy
- Operational Reliability Basics
- Power System Resilience
- Power System Protection
Solar
Transportation
Wind

Resource Adequacy Basics

An important aspect of grid reliability is resource adequacy—a power system's ability to supply enough electricity, at the right locations, to keep the lights on year-round during all hours.

This means system planners must ensure the mix of resources can meet demand during hot summer afternoons and cold winter nights.

Measuring Resource Adequacy

Resource adequacy is measured by the probability of an outage due to insufficient capacity. It is measured at the system level to capture the overall impact of outages of individual components including generators and transmission.

Several metrics are used for resource adequacy. For example, a resource adequacy standard might be less than 1 day in 10 years of outages caused by a lack of generation. Once the target or metric is established, power system planners perform grid simulations of many possible power plant outages under different system conditions to ensure the system can achieve the resource adequacy standard.

Planning Resource Adequacy With a Changing Grid Mix

Renewable energy can help maintain or enhance the resource adequacy of the U.S. power grid. A critical factor in maintaining resource adequacy under a changing grid mix is accurately assessing renewable energy potential and future demand for electricity, particularly when there will likely be stress on the power system, like a hot summer afternoon.

How much capacity a generator can reliably contribute to resource adequacy during periods of high system stress is known as its capacity credit. The capacity credit of solar photovoltaics and wind have traditionally been based on their historical performance during high-risk or high-stress periods, but that approach is not exact enough for planning.

More recently, utilities and system planners have started transitioning to what's called probabilistic reliability-based methods, which use thousands of detailed computer simulations of different conditions to precisely quantify a resource's contribution to resource adequacy.

An example modeling simulation to study the risk of the power grid failing to meet demand, as developed by NREL's Probabilistic Resource Adequacy Suite.

Increasingly, resource adequacy also accounts for the role of storage, changes in demand patterns, and impact of transmission outages and interregional coordination—which is important to deliver generation from many resources to load sites and enable access to a greater diversity of variable renewable resources and load across neighboring regions.

Resource Adequacy and Extreme Weather Events

Extreme weather events pose significant uncertainty to planning resource adequacy. These events can increase demand on the grid such as extremely hot days when lots of air conditioners are running. The changing duration, magnitude, and frequency of extreme weather events make planning challenging, but NREL is coming up with new ways to incorporate weather data into power sector modeling. Several organizations also monitor resource adequacy and the potential impact of extreme weather events, including the North American Electric Reliability Corporation that publishes seasonal assessments of resource adequacy projections.

Planning for extreme events on the power system also involves resilience—another key aspect of grid reliability.

Additional Resources

Causes of Three Recent Major Blackouts and What Is Being Done in Response, NREL Fact Sheet (2024)

Maintaining a Reliable Future Grid With More Wind and Solar, NREL Fact Sheet (2024)

An Introduction to Grid Services: Concepts, Technical Requirements, and Provision from Wind, NREL Technical Report (2021)

The Evolving Role of Extreme Weather Events in the U.S. Power System With High Levels of Variable Renewable Energy, NREL Technical Report (2021)

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Last Updated Aug. 27, 2025