NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2024 Summer Reliability Assessment

May 2024

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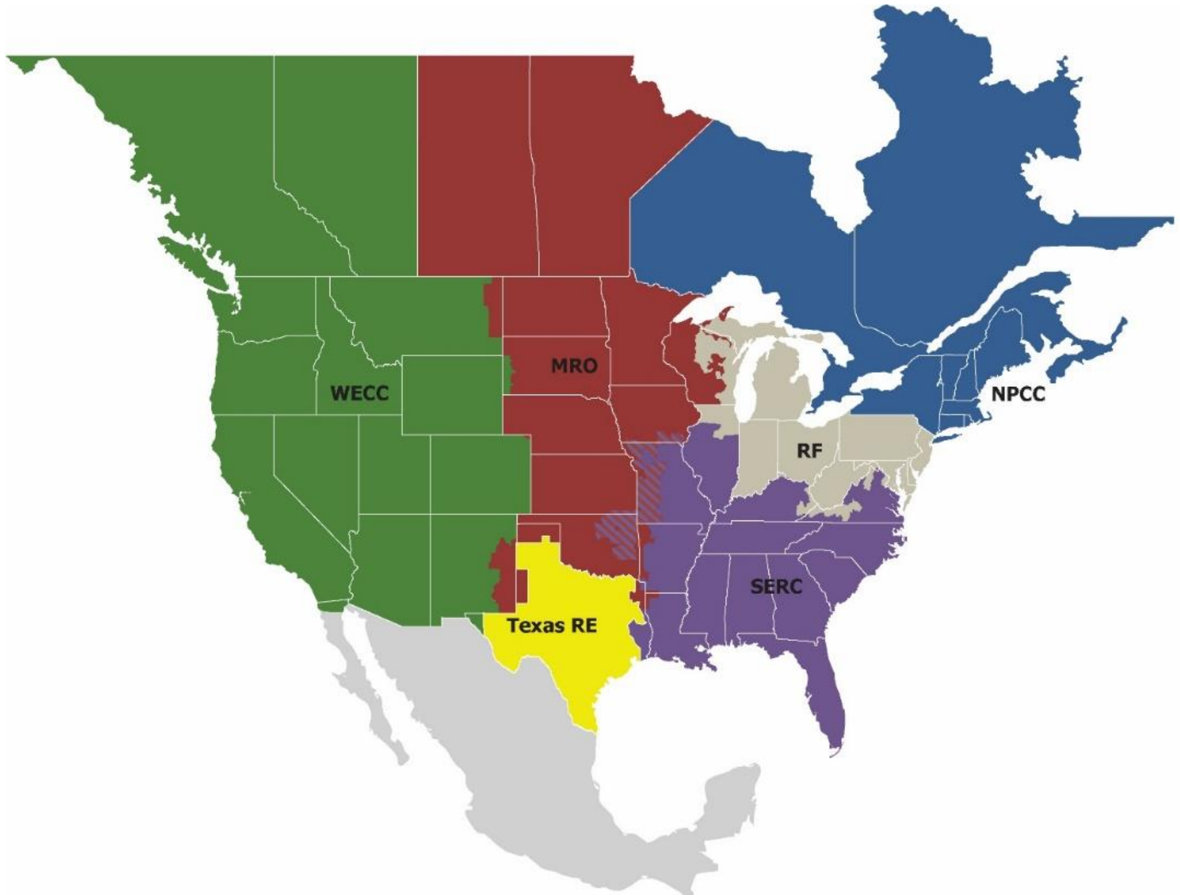
Preface

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 made up of 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 *2024 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 reliability 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 *2023 Long-Term Reliability Assessment (LTRA*), covering a 10-year horizon*,* and other earlier reliability assessments and reports.[1]

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 the 2024 summer.

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 photovoltaic (PV) energy conditions:

- **Midcontinent Independent System Operator (MISO):** New solar and natural-gas-fired generation and additional demand response (DR) resources are offset by generator retirements, lower firm imports, and increased reserve requirements. MISO is expected to have sufficient resources, including firm imports, for normal summer peak demand. However, it can be challenging for MISO to meet above-normal peak demand if wind and solar resource output is lower than expected. Wind generator performance during periods of high demand is a key factor in determining whether there is sufficient electricity supply on the system or if external (non-firm) supply assistance is required to maintain reliability.
- **MRO-SaskPower:** Despite being primarily a winter-peaking area, Saskatchewan can face high electricity demand during hot summer weather conditions. Since 2023, both electricity demand and supply resources have increased, resulting in a 1.2% increase in reserve margin for the summer. Unanticipated generator outages that coincide with peak demand can result in insufficient reserves, a condition that operators will seek to alleviate through short-term transfers from neighbors and demand-side management.
- **NPCC-New England:** With the retirement of two natural-gas-fired generators at Mystic Generating Station in May 2024 (1,400 MW combined summer capacity), ISO New England will have less capacity this summer. This makes it more likely that ISO New England will need to resort to operating procedures for obtaining resources or non-firm supplies from neighboring areas during periods of above-normal peak demand or low-resource conditions. Summer heat waves that extend over the entire area can limit the availability of excess supplies and increase the risk of energy emergencies in New England.
- **Texas RE-ERCOT:** As a result of continued vigorous growth in both loads and solar and wind resources, there is a risk of emergency conditions in the summer evening hours when solar generation begins to ramp down. Contributing to the elevated risk is a potential need, under certain grid conditions, to limit power transfers from South Texas into the San Antonio region. These grid conditions can occur when demand is high and wind and solar output is low in specific areas, straining the transmission system and necessitating South Texas generation curtailments and potential firm load shedding to avoid cascading outages.
- **WECC-BC:** The peak demand forecast in the province of British Columbia has increased by over 600 MW since 2023 (7.4%), contributing to a drop in Anticipated Reserve Margin by over 10 percentage points. Much of the province is experiencing significant drought, and long-term precipitation deficits can challenge electricity production at some hydropower generators. Above-normal demand and low-resource conditions can result in the need for imports from neighboring areas. However, external assistance can be at risk during wide-area heat events.
- **WECC-CA/MX:** New solar and battery resources are contributing to higher on-peak reserve margins (46.7%, up over 11 percentage points since 2023) for the upcoming summer. Winter precipitation and snowpack have alleviated drought conditions across California, making more output from the area's hydropower resources available to balance variability in wind and solar output. Probabilistic assessments performed by WECC show that the risks of load loss are similar to Summer 2023, ranging from negligible to 0.8 loss of load hours (LOLH) depending on how much of the area's new solar and battery resources (totaling nearly 6 GW of nameplate capacity) are completed over the summer. The loss-of-load risk in this analysis occurs primarily under above-normal demand and low-resource conditions (e.g., low solar output, below-normal imports due to wide-area heat conditions or transmission limitations). Furthermore, risk is concentrated in the Baja (Mexico) portion of the WECC-CA/MX

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

assessment area. The assessment area has adequate resources for normal summer conditions.

- **WECC-SW:** Both forecasted peak demand and resources have risen since last summer, yielding a modest increase in the anticipated on-peak reserve margin (22.0%, up 2.5 percentage points since 2023.) The area has sufficient resources for normal summer demand. However, extreme demand or low resource output scenarios will likely require additional non-firm imports from neighboring areas, which may be unavailable during wide-area heat events. The ongoing severe drought in the Southwest increases the risk that extreme conditions could impact the BPS this summer.

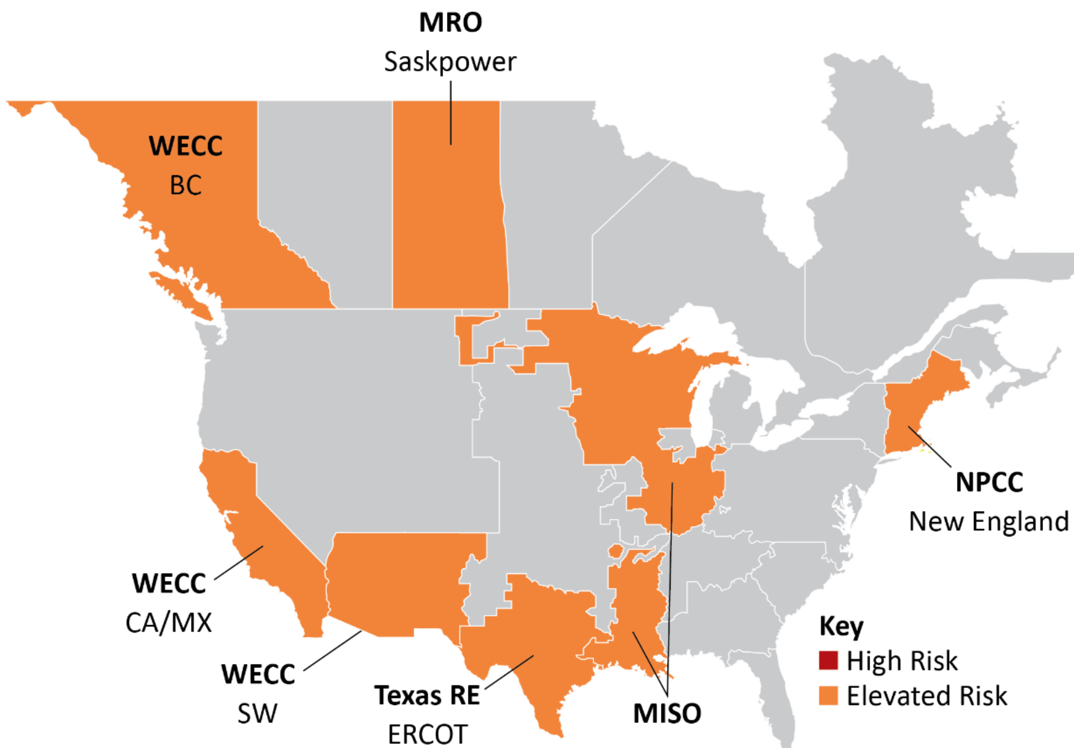


Figure 1: Summer Reliability Risk Area Summary

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

New resources including 25 GW of nameplate solar capacity have been added to the BPS since last summer. Resource additions in assessment areas that were identified as at risk in the *2023 SRA* have largely outpaced rising demand forecasts and resulted in higher on-peak reserve margins. Four elevated-risk assessment areas from the *2023 SRA* are considered normal risk for the upcoming summer: NPCC-Ontario, SERC-Central, SPP, and WECC-NW. New firm transfer agreements, growth in DR, and postponed generator retirements are also contributing to an overall improved resource outlook for the upcoming summer. Details of each area are contained in the assessment area pages.

The findings in the *SRA* are consistent with conclusions reported in NERC's *2023 LTRA*. In assessing potential future electricity supply shortfalls over the 10-year horizon, NERC found that resource additions and delayed generator retirements have improved the outlook for 2024 in comparison to results reported in prior *LTRA*s. However, the *2023 LTRA* also found that a growing number of areas in North America face adequacy risks as early as 2025. NERC will publish the next *LTRA* in December 2024 based on demand forecasts, resource and transmission projections, and other information collected this year. NERC will also publish the 2024–2025 *Winter Reliability Assessment* in November to identify, assess, and report on BPS reliability issues for the next winter season.

Other Reliability Issues

- **Weather services are expecting above-average summer temperatures across much of North America, potentially creating challenging summer grid conditions.** Peak electricity demand in most areas is directly influenced by temperature. Above-average seasonal temperatures can contribute to high peak demand as well as an increase in forced outages for generation and some BPS equipment. Last summer brought record temperatures, extended heat waves, and wildfires to large parts of North America. Although few high-level energy emergency alerts were issued and no electricity supply disruptions occurred as a result of inadequate resources, operators at BAs, TOPs, and RCs faced significant challenges and drew upon procedures and protocols to obtain all available resources, manage system demand, and ensure that energy is delivered over the transmission network to meet the system demand. Additionally, load-serving entities and state and local officials in many parts of North America used mechanisms and public appeals to lower customer demand during periods of strained supplies. Operators should review lessons and experience from the prior summer and incorporate insights into their seasonal operations planning. The **Review of 2023 Capacity and Energy Performance** section describes actual demand and resource levels in comparison with NERC's *2023 SRA* and summarizes 2023 resource adequacy events.

- **Rising demand is challenging resource and transmission adequacy in several areas.** Most areas are forecasting increases in peak demand compared to last summer. The extent that demand forecasts have increased and the drivers affecting growth vary by area. In ERCOT, SPP, and British Columbia, the increases are among the highest and build on similar growth from the prior year. New data centers and cryptocurrency mining facilities are contributing to higher demand forecasts in ERCOT this summer, and some of these loads participate in demand-side management programs that can offset their impacts (see **Evolving Demand-Side Management Programs**). While resource additions in Texas, primarily solar PV, are outpacing demand increases, energy risks are growing during the hours when solar output is diminished. Further, transmission development is straining to connect new resources and deliver electricity supplies to growing load areas.

- **Occurrences involving the unexpected tripping of inverter-based resources (IBR) during grid disturbances continue to spread, underscoring the need for operator vigilance in the near term and urgent industry action on long-term solutions.** The tripping of BPS-connected solar PV generating units during grid faults has caused sudden loss of generation resources (over wide areas in some cases). Industry experience with unexpected tripping of BPS-connected solar PV generation units can be traced back to the 2016 Blue Cut fire in California. Similar events have occurred as recently as Summer 2023.[2] New event reports published by NERC analyzing the Southwest Utah disturbance (April 2023) and the California Battery Energy Storage disturbances (April and May 2022) illustrate that the reliability concern extends to more geographic areas and more than just solar PV resources. IBRs include most solar and wind generation as well as new battery energy storage systems (BESS) or hybrid generation and account for over 70% of the new generation in development for connecting to the BPS. IBRs respond to disturbances and dynamic conditions based on programmed logic and inverter controls. A common thread with these tripping events is the lack of IBR ride-through capability that causes a minor system disturbance to become a major disturbance. In March 2023, NERC issued the *Inverter-Based Resource Performance Issues Alert* to Generator Owners (GO) of Bulk Electric System (BES) solar PV generating resources.[3] As a Level 2 alert, it contains recommended actions for GOs of grid-connected solar PV resources, including steps to coordinate protection and controller settings, so that the resources will remain reliable during grid disturbances. NERC's comprehensive Inverter-Based Resources Strategy and FERC Order No. 901 describe additional steps for the ERO and industry to ensure that IBRs operate reliably and that the system is planned with due consideration for their characteristics.[4,5]
- **Stored supplies of natural gas are at high levels, but continued vigilance is needed to ensure the reliability of fuel delivery to natural-gas-fired-generators.[6]** The natural gas supply and infrastructure is vitally important to electric grid reliability, particularly as variable energy resources satisfy more of our energy needs. Fuel supply and delivery infrastructure must be capable of meeting the ramp rates of natural-gas-fired generators as they balance the system when wind and solar generation output declines. No specific reliability issues have been identified for the upcoming summer, but Reliability Coordinators (RC) and Balancing Authorities (BA) should be cognizant of natural gas supply infrastructure outage and maintenance plans that could affect generators in their areas.
- **Expanded demand-side management programs are an added resource for operators that should be carefully considered in operating plans and monitored during peak demand periods.** Formal DR programs involving commercial and industrial customers that have agreements with their load-serving entities to curtail load during high-demand periods have grown in many assessment areas. Additionally, some entities have launched programs with retail customers that also provide operator-controlled demand-side management capabilities. Operators will need to give special attention to new or expanded demand-side management programs in their planning if they are unfamiliar with protocols or uncertain about the amount of load relief that will be realized. These new mechanisms and protocols for controlling demand can support operating reliability and energy adequacy needs when they are effectively implemented and monitored.
- **Supply chain issues are delaying some new resource and transmission projects, raising concerns that some may not be completed prior to peak summer conditions.** Lead times for transformers, circuit breakers, transmission cables, switchgears, and insulators have increased significantly since 2020. Additionally, PV panels are more difficult to procure. These longer lead times can affect new project construction, existing asset upgrades, pre-seasonal maintenance, and the interconnection of new resources and customers. Long-term mitigation strategies include lengthening ongoing construction timelines and ordering surplus inventory in advance. In the near term, supply chain issues can exacerbate concerns in elevated risk areas and add operating challenges for the summer across the BPS. Should project delays emerge, affected GOs and Transmission Owners (TO) must communicate changes to BAs, Transmission Operators (TOP), and RCs so that impacts are understood and steps are taken to reduce risks of capacity deficiencies or energy shortfalls.
- **Wildfire risk areas cover a smaller portion of North America at the start of summer, lowering the likelihood that the BPS will be affected by fire conditions.** At the start of summer, Canadian wildfire information system officials assess that there is potential for above-average fire activity over a large region that extends from British Columbia to northwest Manitoba

[2] See the ERO's extensive IBR event reporting here: NERC Major Event Reports
[3] NERC Alert: Inverter Based Resource Performance Issues
[4] NERC IBR Activities
[5] FERC Order No. 901 - Final Rule Reliability Standards to Address Inverter-Based Resources
[6] Short-Term Energy Outlook - U.S. Energy Information Administration (EIA)

and includes Alberta and Saskatchewan. In the United States, Climate Prediction Center and Predictive Services outlooks for early summer indicate that above-normal significant fire potential is limited to portions of the U.S. Southwest and West Texas.[7] Nonetheless, wildfire risk in North America typically increases in later summer months as hotter and drier weather increases fire potential. BPS operation can be impacted in areas where wildfires are active as well as areas where there is heightened risk of wildfire ignition due to weather and ground conditions.

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 the protocols for communicating and resolving potential supply shortfalls in anticipation of potentially extreme demand levels
  - Employ conservative generation and transmission outage coordination procedures commensurate with long-range weather forecasts to ensure adequate resource availability
  - 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.[8]
- 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 of 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.

[7] NIFC North American Outlook

[8] Industry Recommendation: Inverter-Based Resource Performance Issues

Discussion

Summer Temperature and Drought Forecasts

Peak electricity demand in most areas is directly influenced by temperature. Weather officials are expecting above-normal temperatures for much of the United States and Canada (see Figure 2). In addition, drought conditions continue across much of Canada and the U.S. Southwest, resulting in unique challenges to area electricity supplies and potential impacts on demand.[9] 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. Above-average seasonal temperatures can contribute to high peak demand as well as an increase in forced outages for generation and some BPS equipment. Effective preseason maintenance and preparations are particularly important to BPS reliability in severe or prolonged periods of above-normal temperatures.

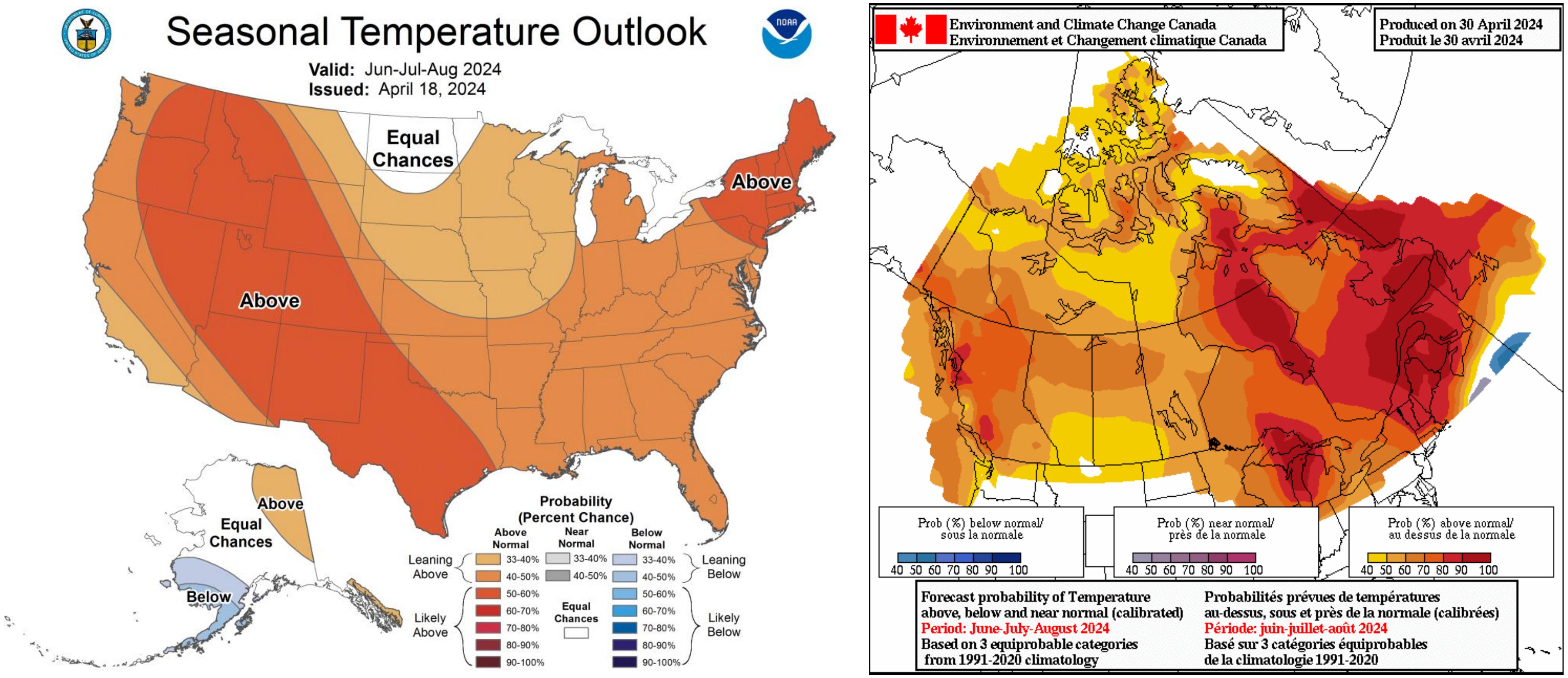


Figure 2: United States and Canada Summer Temperature Outlook[10]

[9] See North American Drought Monitor: https://www.ncdc.noaa.gov/temp-and-precip/drought/nadm/maps

[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; or • Probabilistic indices exceed benchmarks (e.g., LOLH of 2.4 hours over the season); or • 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); or • 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] or • 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	26.1%	8.7%	-6.3%
MRO-Manitoba	15.7%	11.7%	5.1%
MRO-SaskPower	30.3%	26.5%	10.3%
MRO-SPP	27.8%	17.6%	-2.5%
NPCC-Maritimes	44.9%	34.5%	6.0%
NPCC-New England	15.9%	6.3%	3.3%
NPCC-New York	30.4%	11.4%	4.0%
NPCC-Ontario	26.2%	26.2%	19.8%
NPCC-Québec	44.1%	23.8%	18.2%
PJM	27.6%	17.9%	9.0%
SERC-C	24.3%	14.9%	14.7%
SERC-E	22.2%	16.3%	10.8%
SERC-FP	26.3%	19.3%	12.3%
SERC-SE	44.6%	41.1%	34.9%
TRE-ERCOT	25.6%	19.2%	11.5%
WECC-AB	30.5%	28.1%	8.6%
WECC-BC	18.8%	18.7%	-5.6%
WECC-CA/MX	46.7%	40.8%	5.4%
WECC-NW	35.5%	29.7%	1.1%
WECC-SW	22.0%	12.9%	-10.8%

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's discussion. 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 coincide 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 loss of load expectation (LOLE), LOLHs, expected unserved energy (EUE), and the probabilities of energy emergency alert (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 2024. 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
EEA 1	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.
EEA 2	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.
EEA 3	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	NERC 2022 Probabilistic Assessment (2022 ProbA)	The 2022 ProbA results found 187 MWh EUE for Summer 2024 and <1 hour of LOLH. However, MISO has more resources and higher reserves for the summer than were considered in the 2022 ProbA, which should result in lower risk.
MRO-Manitoba	Verification of NERC 2022 Probabilistic Assessment (2022 ProbA)	The 2022 ProbA results indicate 29 MWh per year of EUE for 2024.
MRO-SaskPower	Probability-based capacity adequacy assessment	Results indicate that the expected number of hours with operating reserve deficiency for the 2024 summer season (June–September) is 0.68 hours. June is the month with highest risk.
MRO-SPP	Statistical analysis of the Summer 2022 real-time data and operating procedures	Potential risk of using operating reserves and EEA 1 or EEA 2 is 1 day per summer. Risk of EEA3 is 0.2 days per summer. Risk is associated with low wind generation output levels or unanticipated generation outages in combination with high-load periods.
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 early May].
NPCC-Maritimes		NPCC's assessment results indicate that Maritimes is unlikely to experience resource shortages that would require additional imports or operating procedures this summer. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios, including the severe low-likelihood cases.
NPCC-New England		NPCC's assessment results indicate that ISO-New England (ISO-NE) could experience resource shortages during high-demand and low-resource conditions and require limited use of operating procedures for mitigation. In NPCC's probabilistic assessment, the reduced resource case with the highest peak load scenario resulted in New England having a small estimated cumulative LOLE risk (0.66 days/summer) with associated LOLHs (2.7 hours/summer) and EUE (1,476 MWh/summer) with the highest risk occurring in June. This scenario is based exclusively on the two highest load levels with a 7% chance of occurring and a low-resource case consisting of extended summer maintenance across NPCC and reduced imports from PJM. Negligible cumulative LOLE (<0.022 days/summer), LOLH (<0.08hours/summer), and EUE (<17 MWh/summer) risks were estimated over the summer May–September period for the other scenarios modeled.
NPCC-New York		NPCC's assessment results indicate that New York ISO (NYISO) could experience resource shortages during high-demand conditions and require limited use of operating procedures for mitigation. In NPCC's probabilistic assessment, the highest peak load scenarios resulted in New York having a small estimated cumulative LOLE risk (1.6 days/summer) with associated LOLHs (5.9 hours/summer) and EUE (5,460 MWh/summer) with the highest risk occurring in July and August. Scenarios are based exclusively on the two highest load levels with a 7% chance of occurring. Negligible cumulative LOLE (<0.023 days/summer), LOLH (<0.07 hours/summer), and EUE (39 MWh/summer) were estimated over the summer period for the other scenarios modeled. Furthermore, the New York State Reliability Council conducts an annual study to determine the installed reserve margin (IRM) necessary to meet the 1 day in 10 years Loss of LOLE criterion. NYISO has procured capacity for the upcoming summer to meet the IRM requirement.

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
NPCC-Ontario		NPCC's assessment results indicate that Ontario is unlikely to experience resource shortages that would require additional imports or operating procedures this summer. In NPCC's probabilistic assessment, the reduced resource case with the highest peak load scenario resulted in Ontario having a negligible cumulative LOLE risk (0.03 days/summer) with associated LOLHs (0.07 hours/summer) and EUE (33 MWh/summer) with the highest risk occurring in August. This scenario is based exclusively on the two highest load levels with a 7% chance of occurring and a low-resource case consisting of additional summer maintenance and low hydroelectric output. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer for the other scenarios modeled.
NPCC-Québec		NPCC's assessment results indicate that Québec is unlikely to experience resource shortages that would require additional imports or operating procedures this summer. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios, including the severe low-likelihood cases.
PJM	Based on 2023 PJM Reserve Requirement Study (RRS)	PJM is expecting a low risk of resources falling below required operating reserves. PJM forecasts a 29% IRM, well above the target of 17.7%. The RRS 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 low penetration of variable energy resources in PJM relative to PJM's peak load, the hour with most loss of load risk remains the hour with highest forecasted demand.
SERC	Verification of NERC 2022 ProbA Results	The 2022 base case results indicated adequate resources for the SERC Regional Entity as a whole with an observed LOLE of 0.01 days/summer for 2024.
SERC-Central		Probabilistic analysis indicates no risk for resource shortfall.
SERC-East		Probabilistic analysis shows low risk for July and August with EUE of 2.38 MWh and LOLH 0.005 hours.
SERC-Florida Peninsula		SERC probabilistic analysis indicates no risk of resource shortfall.
SERC-Southeast		Probabilistic analysis indicates almost no risk of resource shortfall.
Texas RE-ERCOT	ERCOT probabilistic assessment using the Probabilistic Reserve Risk Model	The simulation indicates an elevated risk of having to declare an EEA during evenings on peak load days in August—the forecasted summer peak load month. The probability of declaring an EEA is 18.4% during the highest risk hour. The probability of firm load shedding is 14.6% during the highest risk hour. The model accounts for the risk of triggering the curtailment of coastal region wind generation due to transmission system constraints.
WECC	WECC performed a probabilistic assessment for Summer 2024 based on demand and resource forecasts provided by load-serving entities.	Resource adequacy remains a critical risk in the Western Interconnection and continues to challenge industry planners, operators, regulators, and partners. Resource adequacy risks over the medium and long terms have increased significantly compared to last year's assessment. Three risks merit particular attention: increasing variability, rate of demand growth and uncertainty of future load patterns, and the pace of new resource growth necessary to meet future energy demand.[11]
WECC-AB		Alberta is expected to have sufficient resource availability to meet demand and cover reserves on the peak hour at 5:00 p.m. under a summer peak defined at the 90th percentile with any combination or accumulation of derates.

[11] See 2023 Western Assessment of Resource Adequacy.pdf (wecc.org)

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
WECC-BC		British Columbia is expected to have sufficient resource availability to meet reserves at the peak demand hour (5:00–6:00 p.m.) under most conditions. However, above-normal demand that coincides with low hydro output could result in a reserve shortage. This evaluation considers a 1-in-10 probability (90th percentile) level for peak demand and a combination of resource derates including low hydro output.
WECC-CA/MX		WECC-CA/MX is projected to have negligible-to-low amounts of LOLH (<1 hours) this summer, primarily forecast in the Baja (Mexico) part of CA/MX. Resources are sufficient to meet demand and cover reserves on the peak demand hour at 5:00 p.m. under a summer peak demand defined at the 90th percentile with any combination or accumulation of resource derates. There is increased risk of insufficient reserves at later hours (up to 7:00 p.m.) due to the variability of energy resource output. Imports to the area are required to cover these risk periods.
WECC-NW		The Northwest is expected to have sufficient resource availability to meet reserves at the peak demand hour at 5:00 p.m. under a summer peak defined at the 90th percentile with any combination or accumulation of derates.
WECC-SW		Results of WECC's probabilistic analysis indicate that the WECC-SW assessment area is projected to have negligible LOLH and EUE this summer under assessed scenarios. NERC's assessment of elevated risk is influenced by the deterministic risk scenario on page 36. The scenario shows that the assessment area would have insufficient resources to meet operating reserve requirements at a 90/10 demand level with typical generation outages and a scenario involving low-resource output and normal peak demand.

Evolving Demand-Side Management Programs

Demand-side management programs are expanding in many assessment areas, providing operators with additional resources to reduce electricity demand during periods when electricity supplies may not be sufficient. **Figure 3** shows the assessment areas with a DR exceeding 1.5% of the total internal demand. Formal DR programs involving commercial and industrial customers that have agreements with their load-serving entities to curtail load during high demand periods have grown in many assessment areas (see **Demand and Resource Tables**). Additionally, some entities have launched programs with retail customers that provide similar operator-controlled demand-side management capabilities. Programs in use by the independent system operators in Texas and the province of Ontario, discussed below, provide examples of the types of DR programs in use this summer and the contributions to meeting operating reliability and resource adequacy needs.

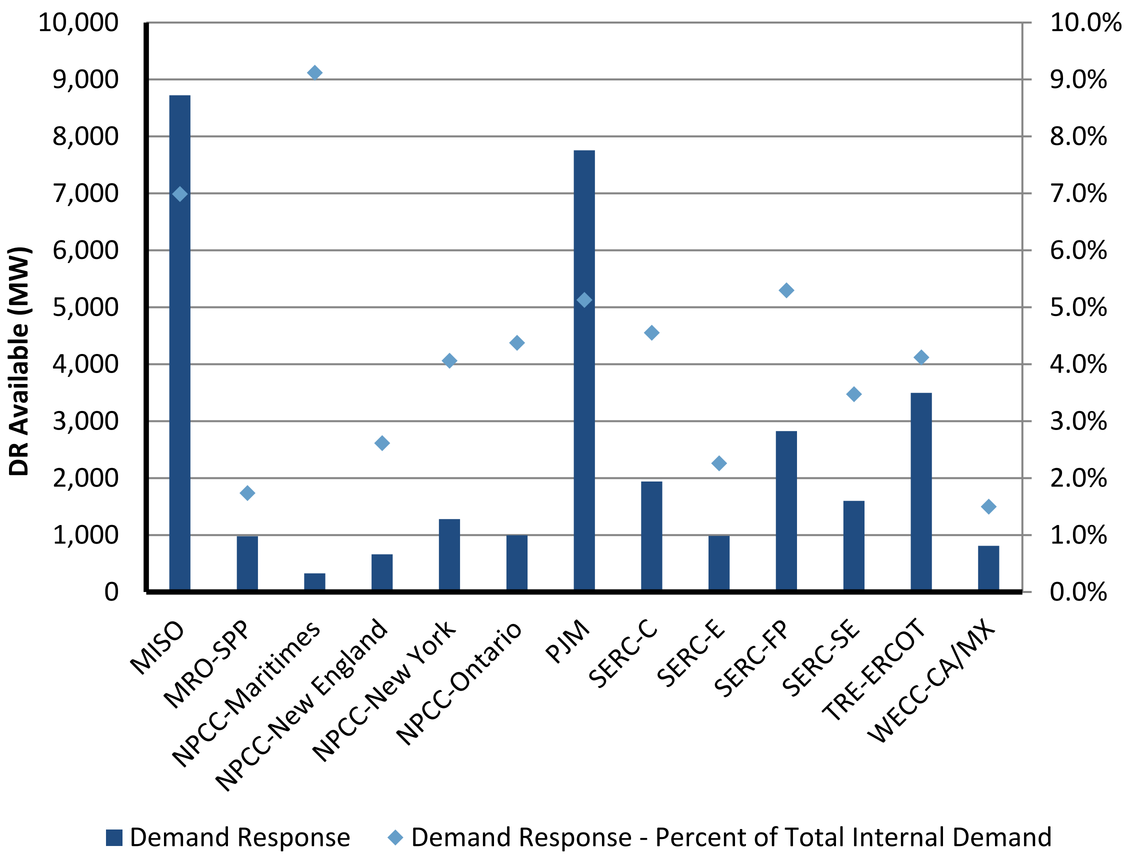


Figure 3: Demand Response in Assessment Areas Exceeding 1.5% Total Internal Demand

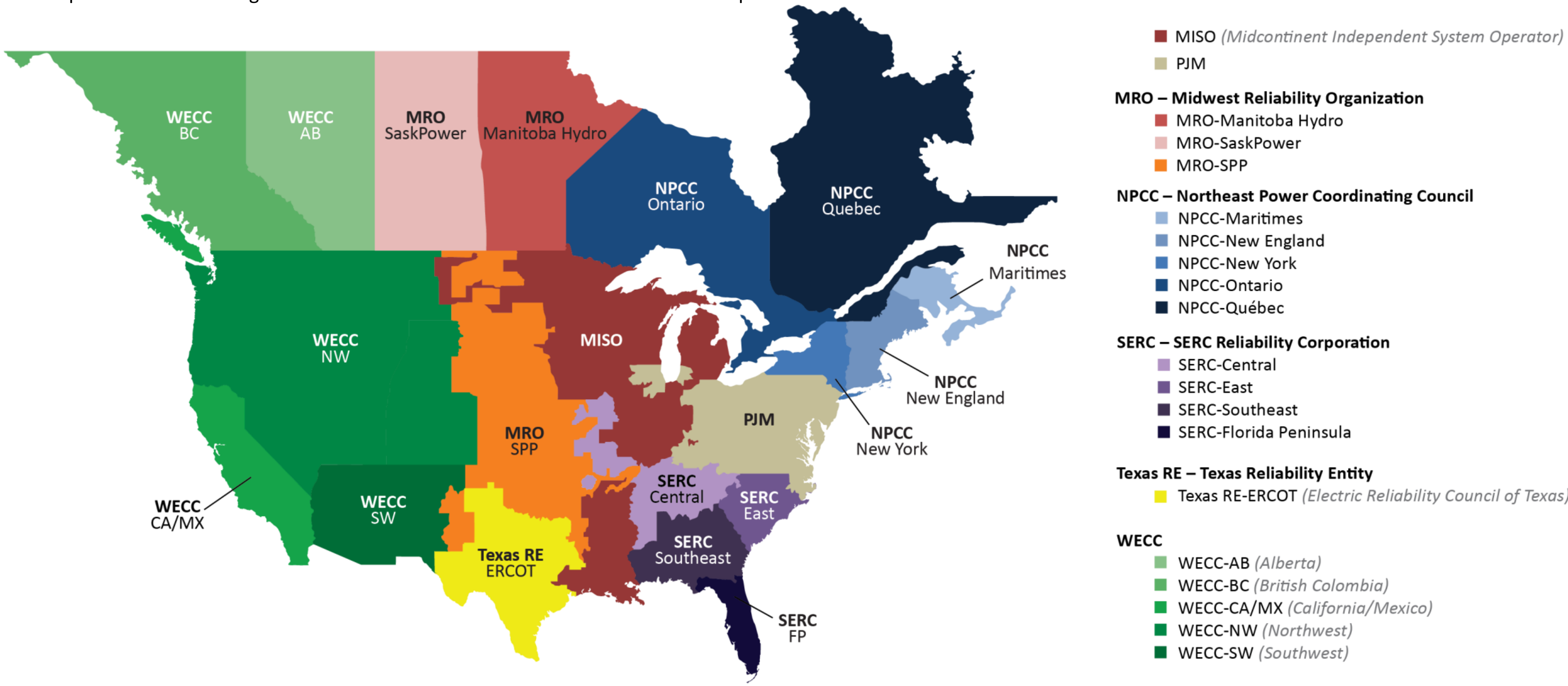
In ERCOT, nearly 3,500 MW of DR resources are expected for this summer, the equivalent of 4% of normal peak demand. Resources come from various programs, including several that are administered by ERCOT as well as those administered by other entities.

- ERCOT's controllable load resources (CLR) consist of large loads (e.g., data centers) and battery charging systems that can be dispatched by ERCOT to provide frequency regulation and short-notice resources for managing wind and solar ramps; 600 MW of CLRs are registered.
- Non-controllable load resources (NCLR) consist of "blocky" loads with both a 10-minute ramp capability for manual deployments and automatic deployment through underfrequency relay. NCLRs participate in ERCOT's Responsive Reserve Service market. ERCOT expects just over 1,100 MW of participation for the highest reserve risk hours for the upcoming summer.
- Some DR resources participate in ERCOT's Emergency Response Service (ERS), along with distributed generation. ERCOT's ERS consists of 10- and 30-minute-ramping DR and distributed generation that can first be deployed when physical responsive capability (PRC) drops to 3,000 MW to provide a contingency reserve. During the 2023 program year, ERS was deployed twice, once on August 17, and again on September 6 when ERCOT's PRC dropped below 3,000 MW. ERCOT expects approximately 1,000 MW to participate in ERS for the highest reserve risk hours for the upcoming summer.
- Transmission and distribution service provider (TDSP) load management programs provide price incentives for voluntary load reductions from commercial, industrial, and, most recently, residential loads during EEA Level 2 events. These programs have historically only been available for the months of June through September from 1:00–7:00 p.m. on weekdays (except holidays) and deployed via ERCOT instruction pursuant to agreements between ERCOT and the TDSPs. ERCOT forecasts that these programs can provide 330 MW in demand relief this summer. In addition, ERCOT Nodal Protocols allow ERCOT to instruct TDSPs to reduce customer load by using existing, in-service distribution voltage reduction measures to avoid an EEA. Conservation voltage reduction (CVR) can lower demand by nearly 575 MW.
- ERCOT accounts for load-reduction programs administered by retail entities in its load forecast. The 4-Coincident Peak (4CP) Load Reduction program incentivizes customers to reduce load during four anticipated 15-minute peak-load intervals, one each across the summer months of June, July, August, and September. The amount of load reduction for the four 4CP days in 2023 averaged 4,674 MW. Additionally, retail entities offer a variety of price-response programs that are factored into ERCOT's load forecast.

In the province of Ontario, the Independent Electricity System Operator (IESO) has expanded DR programs for summer. Overall, this summer, the effective capacity of Ontario's DR programs is 996 MW, the equivalent of 4% of normal peak demand. This includes 805 MW of DR from the capacity auction. The Peak Perks program, launched in June 2023, will contribute 92 MW of effective capacity this summer through enrolled residential customers with smart thermostats that may be controlled at peak times. The IESO also launched the Interruptible Rate Pilot in July 2023. The pilot is designed to provide large-load customers with an interruptible rate in exchange for agreeing to interrupt demand during up to 15 event periods, each up to four hours long. The pilot will run for a three-year period and has two participants that will provide 76 MW of interruptible demand.

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.

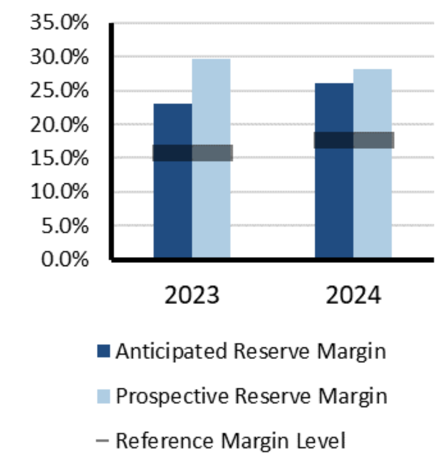
Highlights

- 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. MISO's resources are projected to be higher than in Summer 2023 while net internal demand decreased slightly. With increased resource availability for this summer, Anticipated Reserve Margin (ARM) of 31.6% (on an installed capacity basis) is higher than last summer's ARM of 23%.
- MISO conducted its annual probabilistic LOLE analysis and determined that a 2024 Reference Margin Level (RML) of 17.7% results in an LOLE of 1 day in 10 years. MISO's RML increased from 15.9% in 2023 to 17.7% in 2024 based on the summer seasonal capacity construct. A methodology change in the Planning Resource Auction (PRA) requesting GOs' seasonally corrected Generator Verification Test Capacity (GVTC), updated seasonal forced outage rates, and updated annualized planned maintenance outage rates as well as information on new units, retirements, suspensions, and changes in the resource mix contributed to the increase in reserve margin for the 2024 summer. Comparing the increased ARM to the lower RML indicates improved reliability from the LOLE base case at 1 day in 10 years.
- Performance of wind 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; however, the historically based on-peak capacity contribution is 5,616 MW.

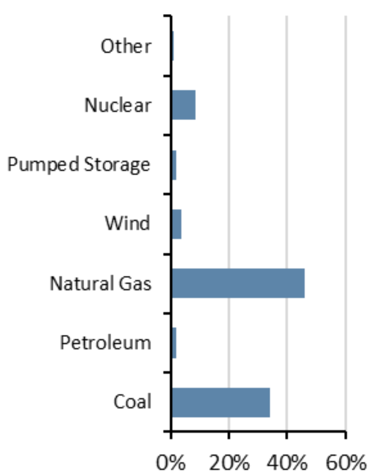
Risk Scenario Summary

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 (DR) when operating reserve shortfalls are projected.

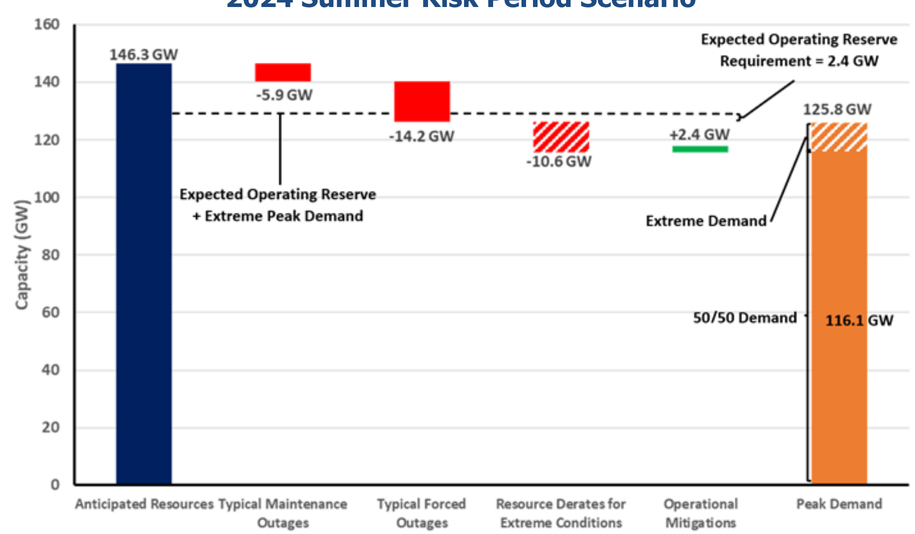
On-Peak Reserve Margin



On-Peak Fuel Mix



2024 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.

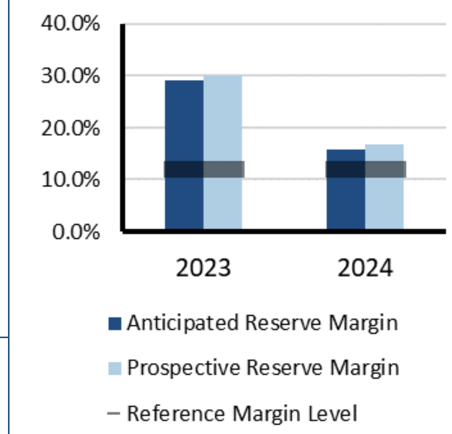
Highlights

- Manitoba Hydro is not anticipating any operational challenges and/or emerging reliability issues for Summer 2024.
- ARM has fallen since Summer 2023 due to higher peak demand forecast, more generator planned maintenance outages, and an increase in net firm capacity transfers. Nonetheless, ARM exceeds the 12% RML.
- Manitoba Hydro is experiencing below-average water supply conditions. However, above-average late-winter snowfall will favorably impact spring runoff. The Manitoba Hydro system is designed and operated such that reliable operations can be maintained under extreme drought. Manitoba Hydro expects to reliably supply its internal demand and export obligations even if drought continues through 2024/25.
- All units at Keeyask Generating Station have commercial operation status.

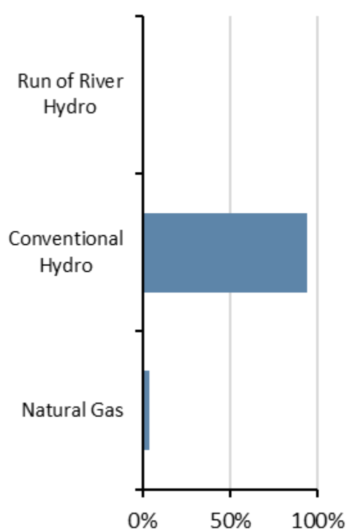
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

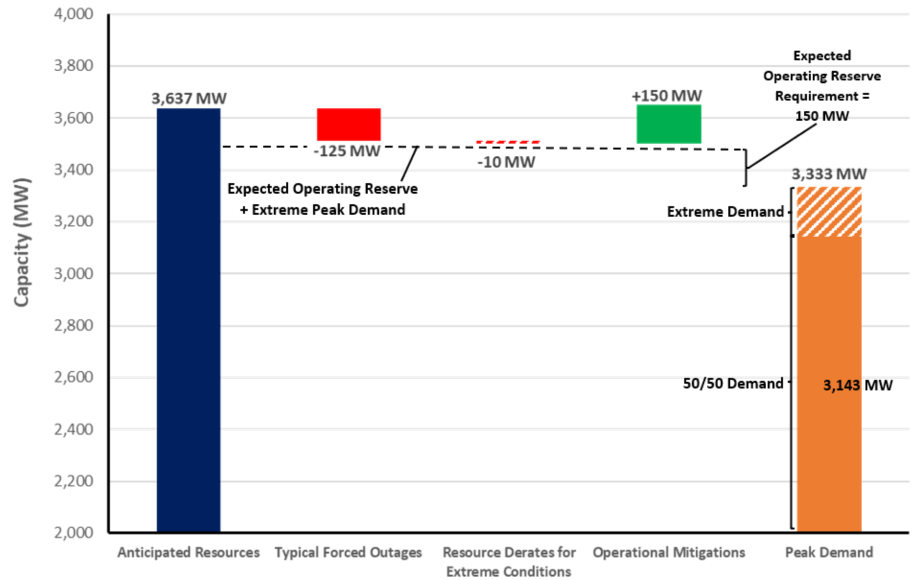
On-Peak Reserve Margin



On-Peak Fuel Mix



2024 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.

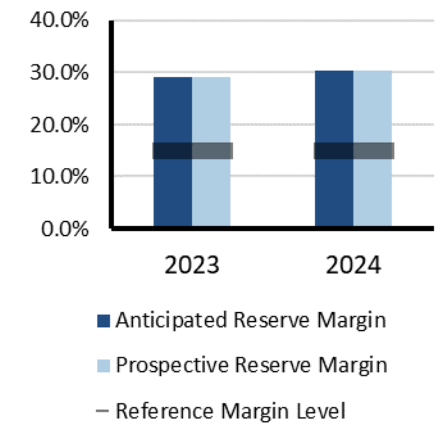
Highlights

- Despite being primarily a winter-peaking area, Saskatchewan also faces significant electricity demand in the summer during extremely hot weather conditions.
- SaskPower collaborates annually with Manitoba Hydro for a summer joint operating study, incorporating inputs from the Western Area Power Administration (WAPA) and Basin Electric to develop operational guidelines addressing any identified issues.
- The probability of experiencing a shortage in operating reserves during peak load periods, or EEAs, may increase if significant generation forced outages happen at the same time as planned maintenance outages during the high-demand months of June through September.
- If extreme thermal conditions align with significant generation outages, SaskPower will deploy available DR programs, engage in short-term power transfers from neighboring utilities, and implement temporary load interruptions as necessary to mitigate the situation.

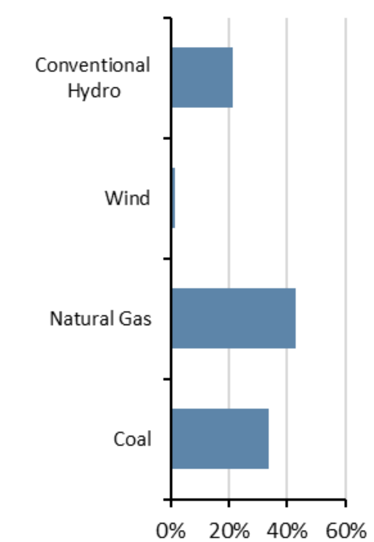
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios. Above-normal summer peak load and outage conditions similar to those observed in Summer 2023 are likely to result in the need to employ operating mitigations (e.g., DR and transfers) and EEAs.

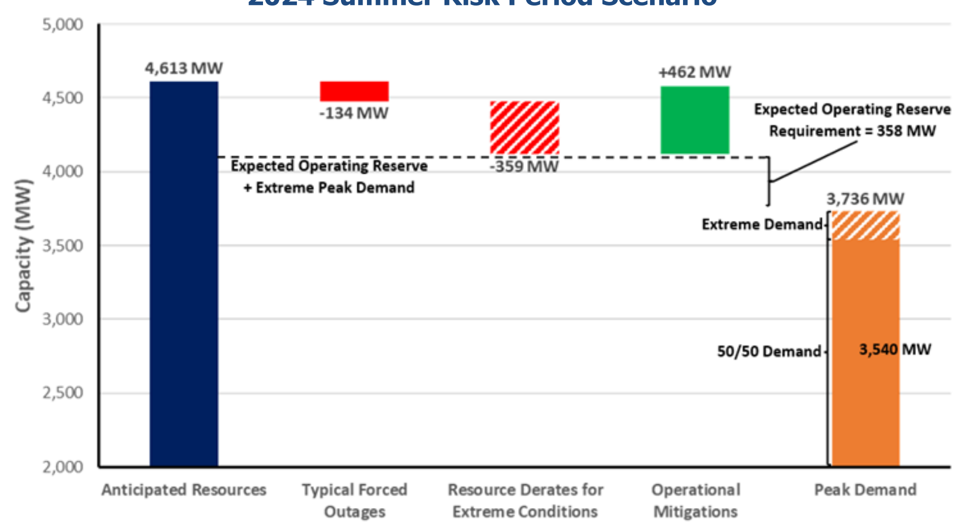
On-Peak Reserve Margin



On-Peak Fuel Mix



2024 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

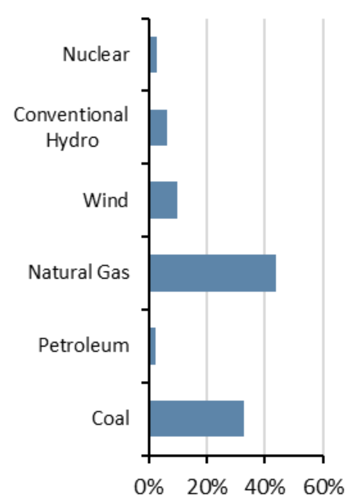
- ARMs are higher in SPP compared to Summer 2023. Increased capacity for the summer is coming from wind resource additions, higher expected wind contribution at peak demand, and commitments from switchable generators (i.e., resources capable of supplying SPP or a neighboring BA) to qualify as resources in SPP.
- SPP projects a low likelihood of any emerging reliability issues impacting the area for the 2024 summer season.
- 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 needs for the 2024 summer season and will adjust as needed to ensure that real-time reliability is maintained throughout the summer time frame.

Risk Scenario Summary

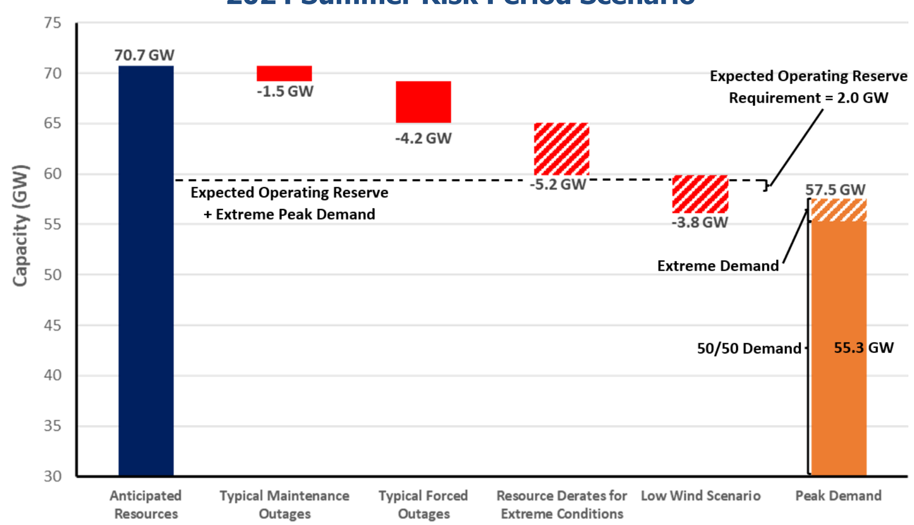
Expected resources are sufficient to meet operating reserve requirements under normal peak-demand and outage scenarios. Above-normal summer peak load and outage conditions could necessitate operating mitigations (e.g., DR and transfers from neighboring systems) and EEAs.

On-Peak Reserve Margin

On-Peak Fuel Mix



2024 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

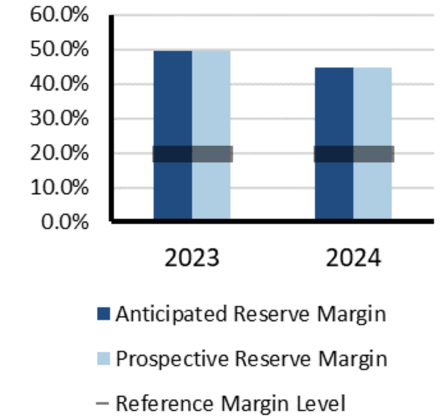
NPCC-Maritimes

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

- The Maritimes area has not identified any operational issues that are expected to impact system reliability. If an event were to occur, emergency operations and planning procedures are in place.
- All of the area's declared firm capacity is expected to be operational for the summer operating period.
- As part of the planning process, dual-fueled units will have sufficient supplies of heavy fuel oil (HFO) on site to enable sustained operation in the event of natural gas supply interruptions.

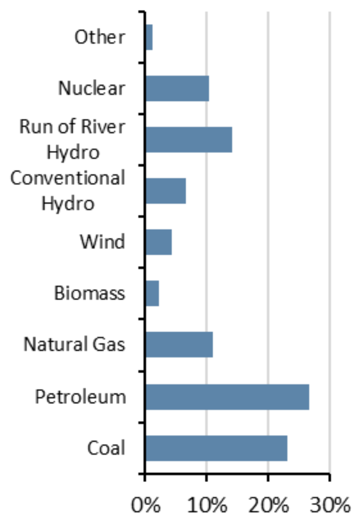
On-Peak Reserve Margin



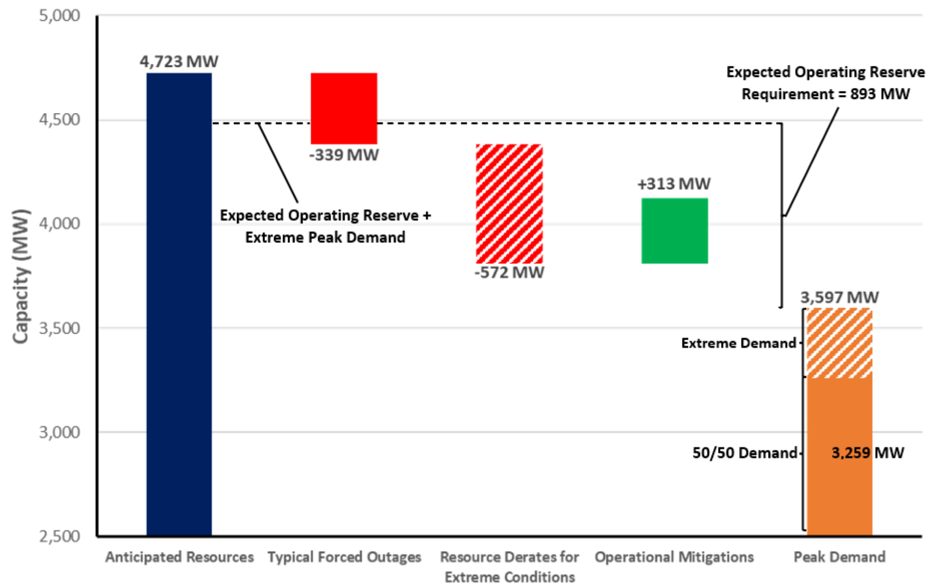
Risk Scenario Summary

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., DR and non-firm transfers) and EEAs.

On-Peak Fuel Mix



2024 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

NPCC-New England

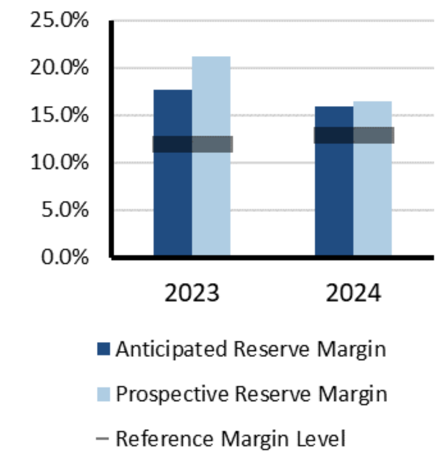
NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont that is served by ISO New England (ISO-NE) Inc. ISO-NE is a regional transmission organization that is responsible for the reliable day-to-day operation of New 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

- The New England area expects to have sufficient resources to meet the 2024 summer peak demand forecast.
- 330 MW of resources are currently on emergency outage but are scheduled to be available during the summer operating period.
- The 50/50 peak summer demand is forecast to be 24,633 MW for the weeks beginning June 2, 2024, through September 15, 2024, with a lowest projected net margin of -401 MW (-1.6%). This margin assumes a net interchange of 1,297 MW, which is capacity backed. However, ISO-NE typically imports around 3,000 MW during summer peak load conditions. For this *SRA*, the established Reference Margin Level is 12.9%. Wind, grid-connected solar PV, and run-of-river totals were derated for this calculation.
- The 2024 summer demand forecast factors in demand reductions associated with energy efficiency, load management, behind-the-meter photovoltaic (BTM-PV) systems, and distributed generation.

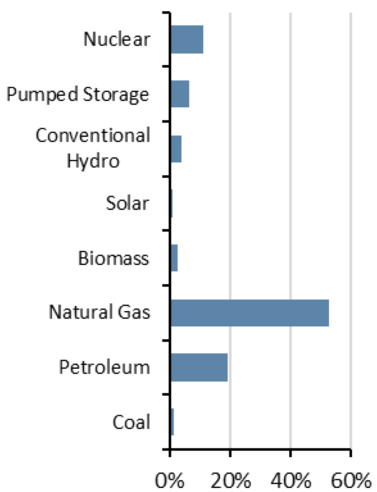
On-Peak Reserve Margin



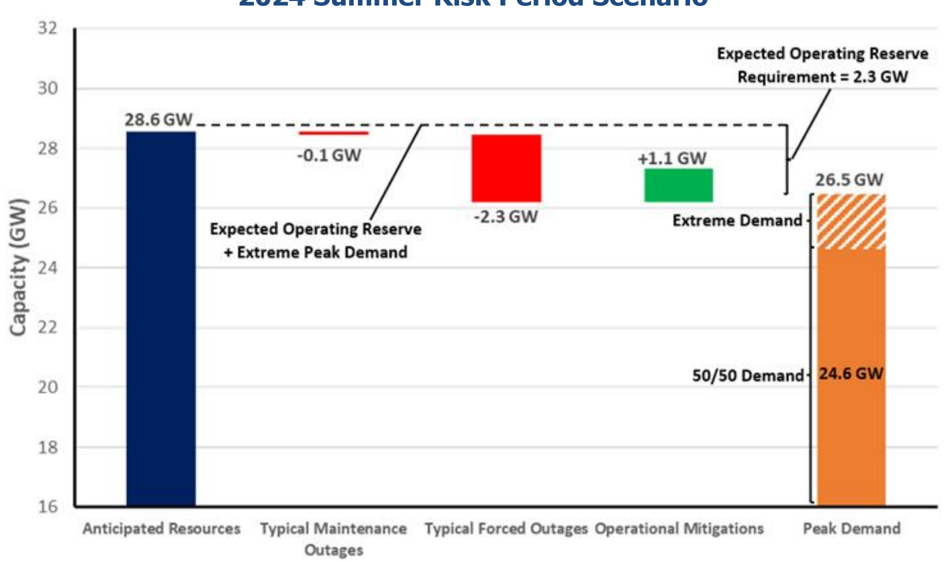
Risk Scenario Summary

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

On-Peak Fuel Mix



2024 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

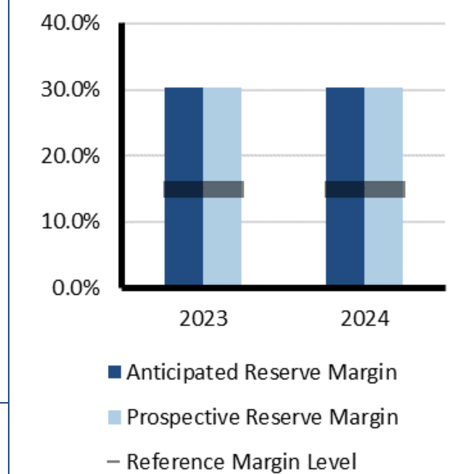
NPCC-New York

NPCC-New York is an assessment area consisting of the 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 RML 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 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 2024–2025 IRM at 22.0%.

Highlights

- NYISO is not anticipating any operational issues in the New York Control Area for the upcoming summer.
- No unanticipated operating conditions occurred during the summer 2023 season.
- Adequate capacity margins are anticipated, and existing operating procedures are sufficient to handle any issues that may occur.

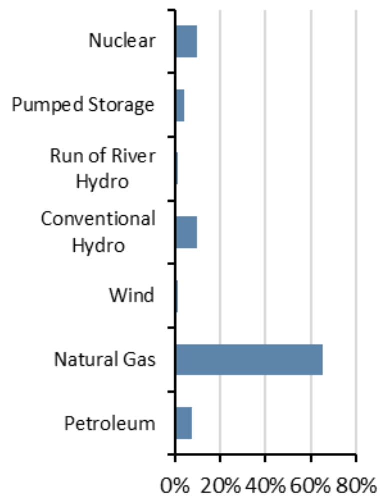
On-Peak Reserve Margin



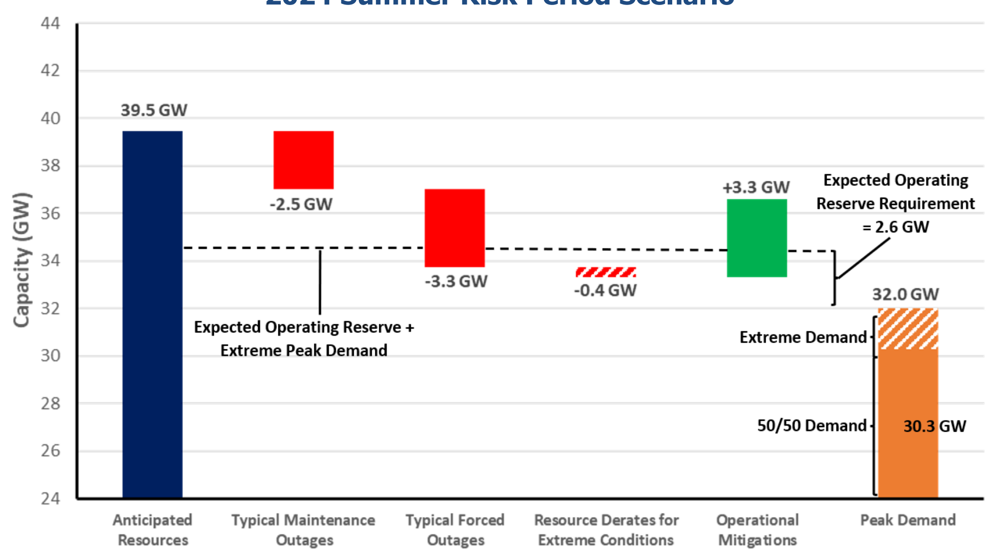
Risk Scenario Summary

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

On-Peak Fuel Mix



2024 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 3.3 GW based on operational/emergency procedures in area emergency operations manual

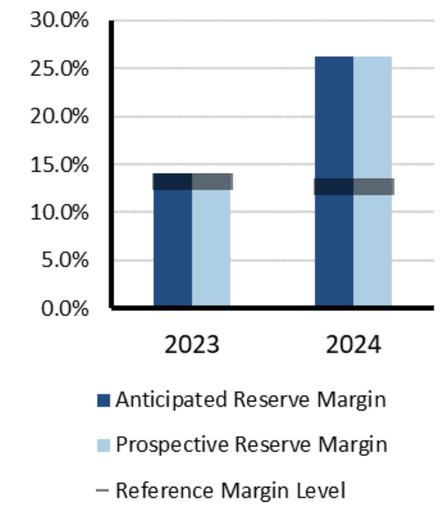
NPCC-Ontario

NPCC-Ontario is an assessment area in the Ontario province of Canada. The 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 more than 15 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 in which generation and transmission outages are more challenging to accommodate. The IESO has been actively coordinating and planning with market participants to maintain reliability.
- The Ontario grid is better positioned for Summer 2024 than it was for Summer 2023.
- This season, the grid will benefit from fewer coincident planned generator outages, progress being made on nuclear refurbishments, increased capacity secured through the capacity auction, and new demand-side management programs, including the Interruptible Rate Pilot and Peak Perks.
- The system will be adequate in Summer 2024 under normal weather conditions. It is also expected to be adequate during extreme weather conditions with the availability of up to 2,000 MW of imports from neighboring jurisdictions or other operating actions to ensure reliability.

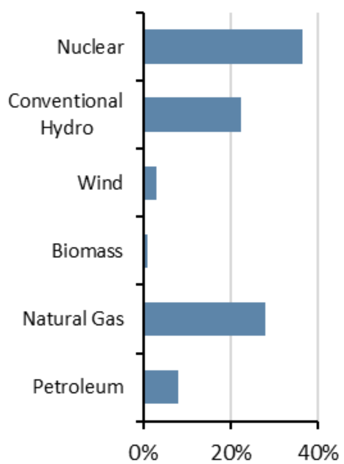
On-Peak Reserve Margin



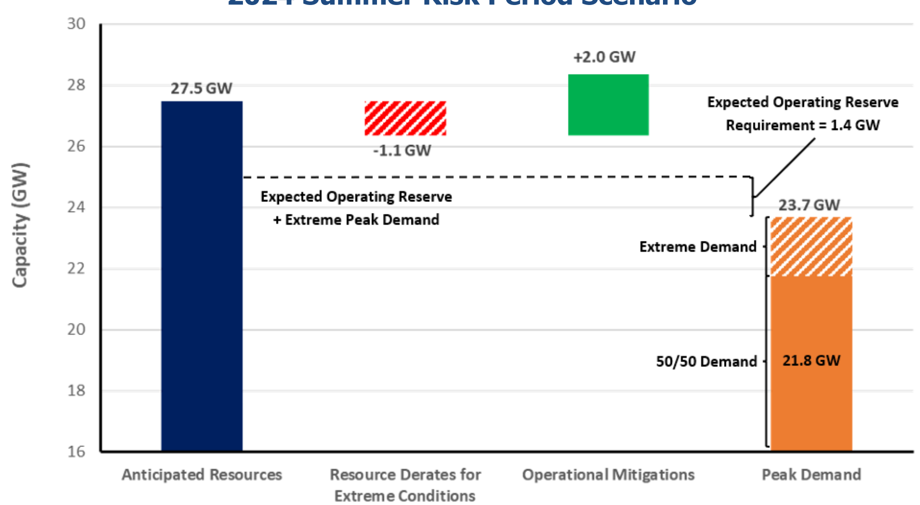
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2024 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

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

Operational Mitigations: Imports anticipated from neighbors during emergencies

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.

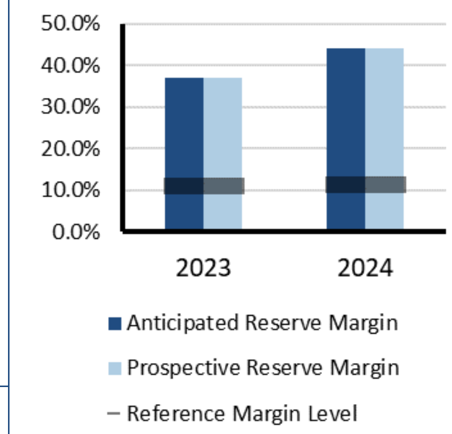
Highlights

- The Québec area forecasted summer peak demand (excluding April, May, and September) is 22,922 MW during the week beginning August 11, 2024, with a forecasted net margin of 7,423 MW (32.4%).
- Resource adequacy issues are not expected this summer.
- The Québec area expects to be able to assist other areas, if needed, up to the transfer capability available.

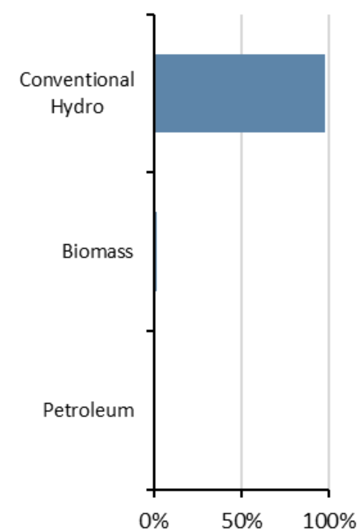
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

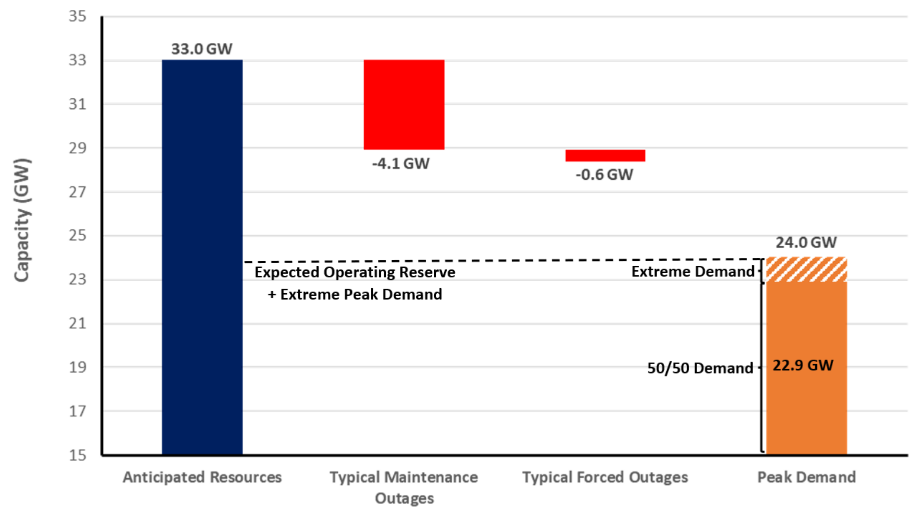
On-Peak Reserve Margin



On-Peak Fuel Mix



2024 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

Net Firm Transfers: Anticipated exports to neighbors during the risk hour

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.

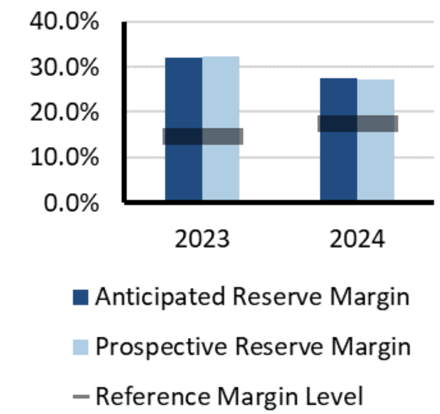
Highlights

- PJM expects no resource problems over the 2024 summer peak season. PJM is forecasting around 29% installed reserves (including expected committed DR), which is well above the target IRM of 17.7%. The increase of 1.8 percentage points of the reserve requirement is driven by adjusted load forecast parameters.
- Rising demand, generator retirements, and slower-than-anticipated resource additions contribute to lower reserve margins compared to last summer.
- The greatest load-loss risk remains the hour with highest forecasted demand due to the low penetration of variable energy resources relative to PJM's peak load.

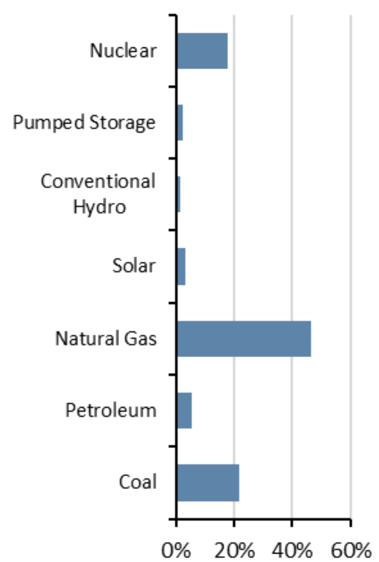
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

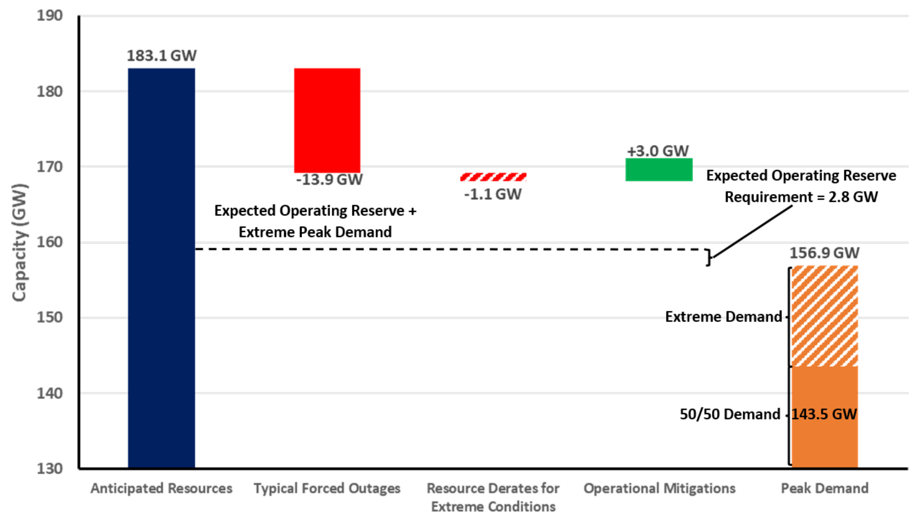
On-Peak Reserve Margin



On-Peak Fuel Mix



2024 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.

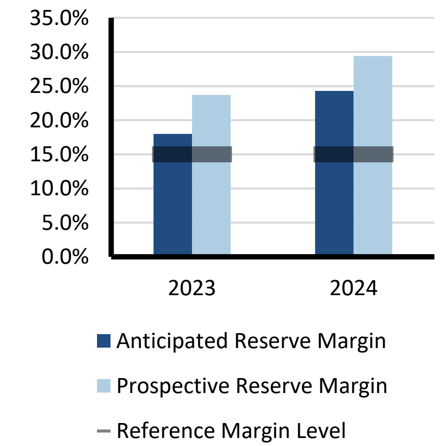
Highlights

- SERC-Central will have higher reserves compared to last summer due to increased firm imports and additions of gas and solar generation.
- Expected resources meet operating reserve requirements under the assessed scenarios.
- The probabilistic analysis metrics indicate adequate energy resources for the subregion.
- Entities perform resource studies to ensure resource adequacy to meet the summer peak demand and maintain the reliability of the system. They actively participate in the SERC Near-Term, Long-Term, and Resource Adequacy Working Groups, which identify emerging and potential reliability impacts on transmission and resource adequacy along with transfer capability.
- There is a moderate risk of transmission impacts due to severe weather. The advanced age and material condition of older coal- and gas-fired generators could result in potential reliability challenges. Entities are mitigating these risks through summer readiness processes, pursuing short-term market opportunities, and leveraging demand-side management programs as necessary.

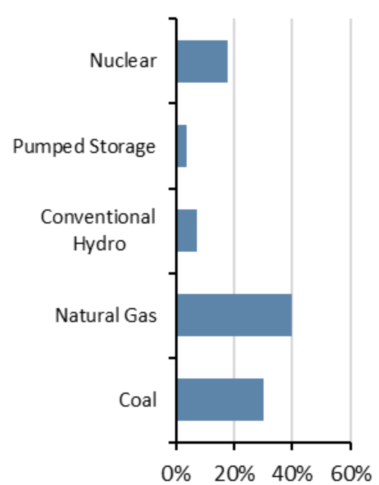
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

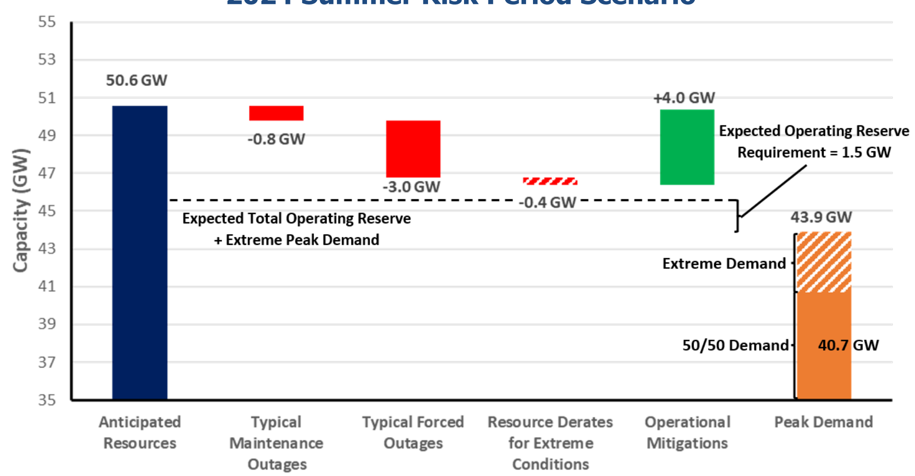
On-Peak Reserve Margin



On-Peak Fuel Mix



2024 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 1.9 GW based on operational/emergency procedures

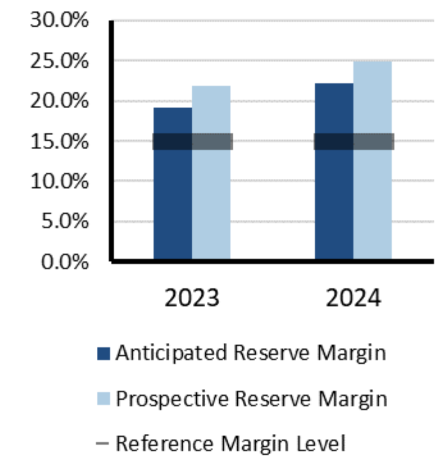
SERC-East

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

- Expected resources meet operating reserve requirements under the assessed scenarios.
- The probabilistic analysis metrics show some risk for energy resource adequacy during the summer months of July and August in the afternoon hours.
- Entities perform resource studies to ensure resource adequacy to meet the summer peak demand and maintain the reliability of the system. They actively participate in the SERC Near-Term, Long-Term, and Resource Adequacy Working Groups, which identify emerging and potential reliability impacts on transmission and resource adequacy along with transfer capability.
- Entities have not identified any emerging reliability issues or operational concerns for the upcoming summer season.

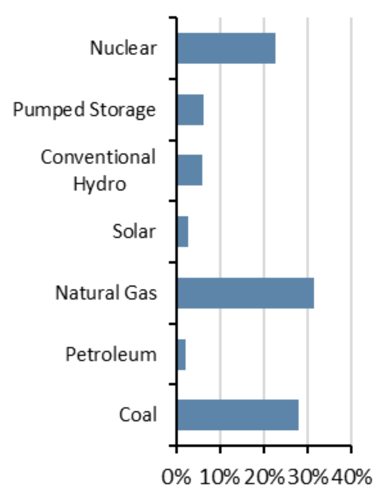
On-Peak Reserve Margin



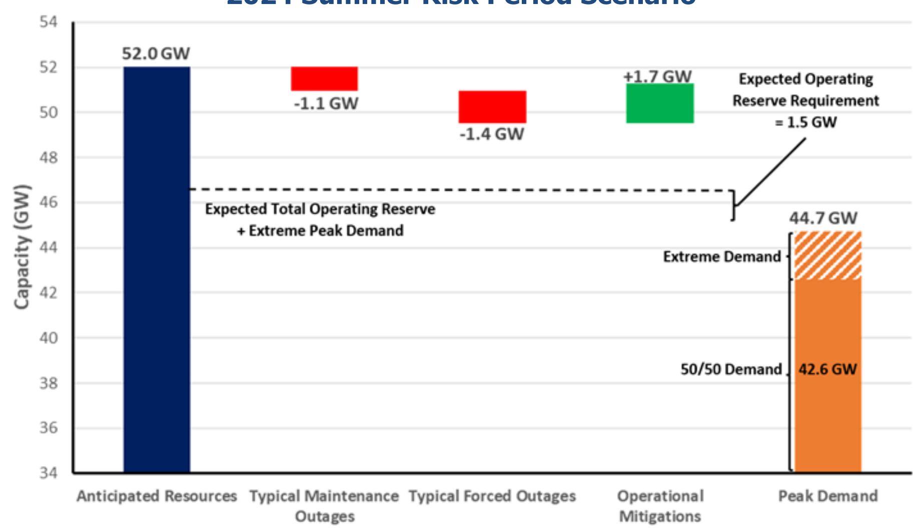
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2024 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 1.5 GW based on operational/emergency procedures

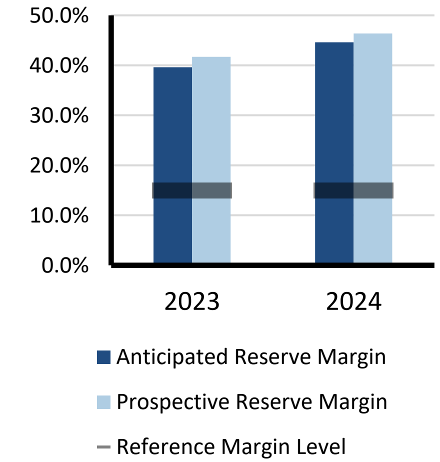
SERC-Florida Peninsula

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

- Expected resources meet operating reserve requirements under the assessed scenarios.
- The probabilistic analysis metrics indicate adequate energy resources for the subregion.
- Entities perform resource studies to ensure resource adequacy to meet the summer peak demand and maintain the reliability of the system. They actively participate in the SERC Near-Term, Long-Term, and Resource Adequacy Working Groups, which identify emerging and potential reliability impacts on transmission and resource adequacy along with transfer capability.
- Entities have not identified any emerging reliability issues or operational concerns for the upcoming summer season.

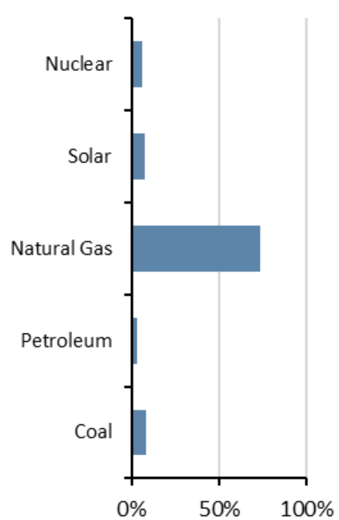
On-Peak Reserve Margin



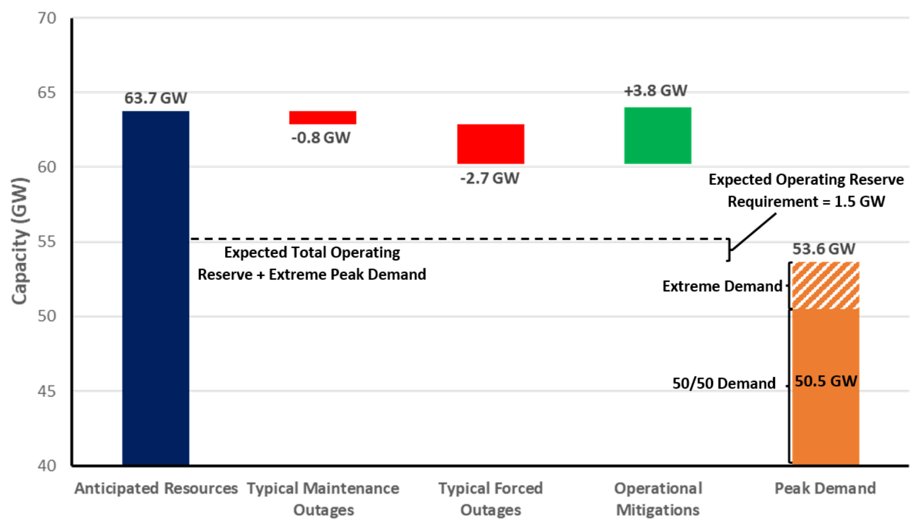
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2024 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 3.8 GW based on operational/emergency procedures

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.

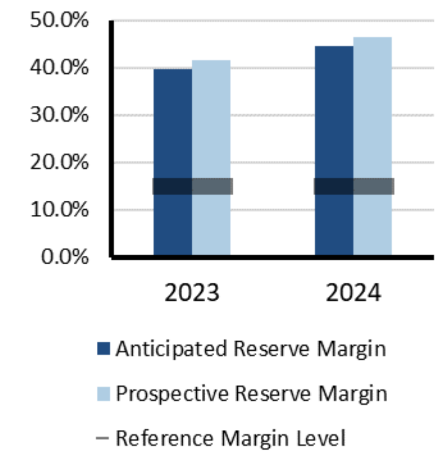
Highlights

- Expected resources meet operating reserve requirements under the assessed scenarios.
- A new 1,100 MW nuclear unit and additional solar generation will give SERC-Southeast higher reserves compared to last summer.
- The probabilistic analysis metrics indicate adequate energy resources for the subregion.
- With the increased penetration of variable energy resources (VER), the curtailment of VER during light-load conditions to support operations may become more prevalent. This, in combination with the retirement of resources, increases the operational challenges in managing the ramps in some areas of SERC-Southeast.
- Entities perform resource studies to ensure resource adequacy to meet the summer peak demand and maintain the reliability of the system. They actively participate in the SERC Near-Term, Long-Term, and Resource Adequacy Working Groups, which identify emerging and potential reliability impacts on transmission and resource adequacy along with transfer capability.

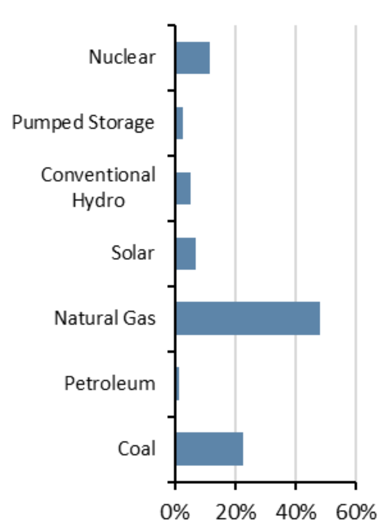
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

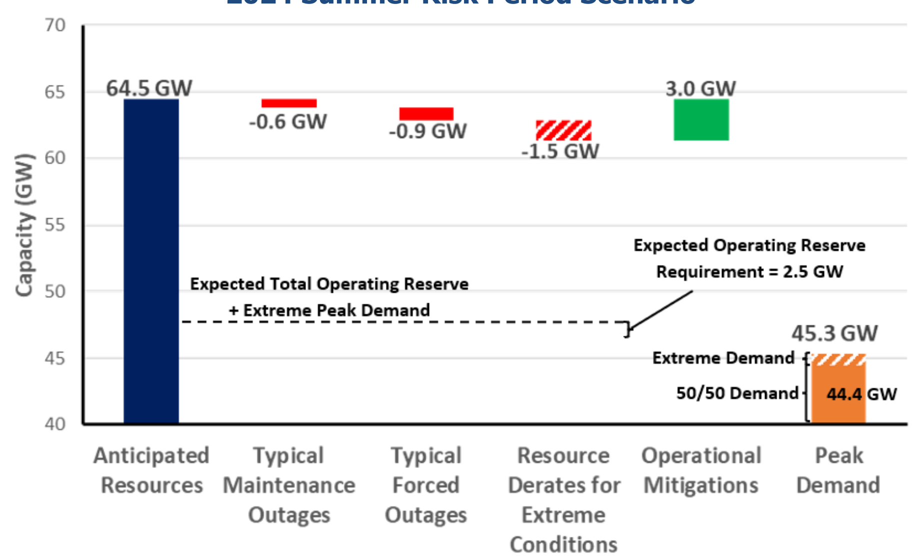
On-Peak Reserve Margin



On-Peak Fuel Mix



2024 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

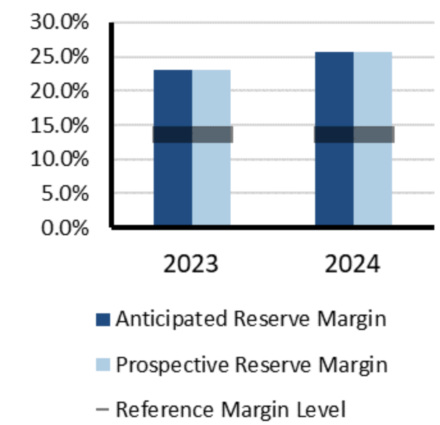
Texas RE-ERCOT

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

- Given an ARM of 25.6% and Reference Reserve Margin of 13.75%, ERCOT expects to have sufficient operating reserves for the August peak load hour given expected normal summer system conditions.
- Solar and battery energy storage installed capacity has grown by about 4,500 and 1,600 MW, respectively, since last August.
- Continued robust growth in both loads and intermittent renewable resources has elevated the risk of emergency conditions in the evening hours when solar generation begins to ramp down.
- ERCOT's probabilistic risk assessment indicates an elevated risk of having to declare EEAs during hours ending 8:00–9:00 p.m. Central on the August peak load day. ERCOT judges an hour to have elevated risk (as opposed to low risk) when the probability of an EEA is greater than 10%. The EEA probability for these two hours is about 16% and 18%, respectively.
- Contributing to the elevated risk is a potential need, under certain grid conditions, to limit power transfers from South Texas into the San Antonio region. Conditions could cause overloads on the lines that make up the South Texas export and import interfaces, necessitating South Texas generation curtailments and potential firm load shedding to avoid cascading outages. The risk is greatest when ERCOT has extremely high net loads in the early evening hours. This issue will be addressed with mitigation measures including the construction of the San Antonio South Reliability Project, which is anticipated to be completed by Summer 2027.

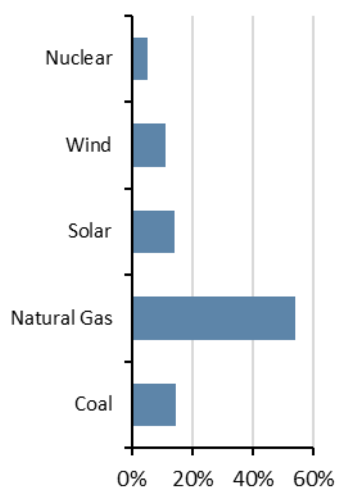
On-Peak Reserve Margin



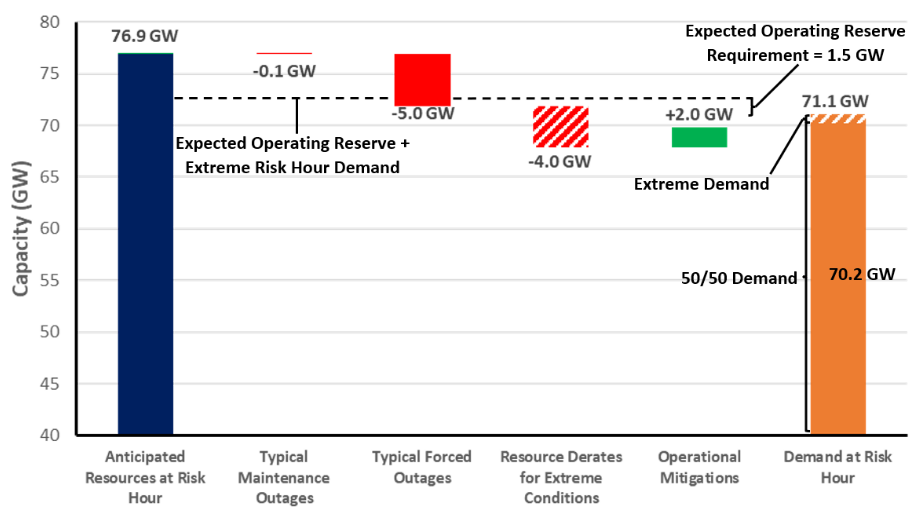
Risk Scenario Summary

Expected resources meet operating reserve requirements for the peak demand hour scenario. However, there is risk of supply shortages as solar generation ramps down during the early evening hours when system load is high and transmission constraints limit transfers.

On-Peak Fuel Mix



2024 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

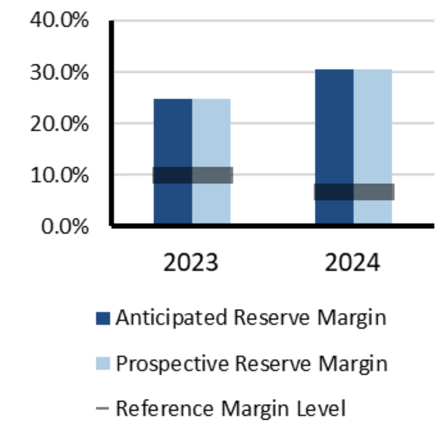
WECC-AB

WECC-AB (Alberta) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of Alberta. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 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 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada and the northern portion of Baja California in Mexico as well as all or portions of the 14 western U.S. states in between.

Highlights

- Thermal and renewable capacity are being added to the area to address rapid load growth, but supply chain issues causing project delays or cancellations may be an issue.
- Thermal tier 1 resources for this upcoming summer include a new 900 MW natural gas combined-cycle facility and the conversion of two existing coal units to two 1x1 natural gas combustion turbine sites with 932 MW (112 incremental MW) of capacity after the steam turbine tie in. The two coal sites undergoing conversion to natural gas are the only remaining coal facilities operating in the area.
- Issues maintaining rate of change of frequency (ROCOF) during islanded or near-islanded situations with high IBR output and low demand is also a concern.
- Alberta is expected to have sufficient resource availability to meet reserves at the peak demand hour (4:00–5:00 p.m.). This evaluation considers a 1-in-10 probability (90th percentile) level for peak demand and a combination of resource derates.
- Alberta shows no LOLH or EUE for the upcoming summer season.

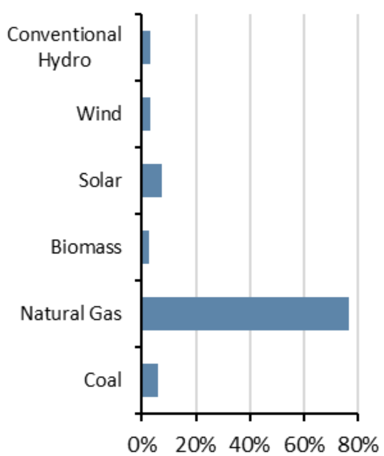
On-Peak Reserve Margin



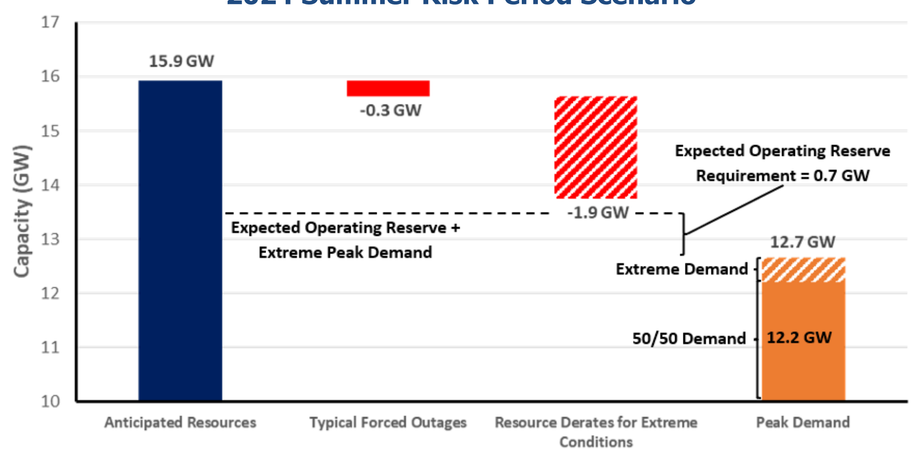
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2024 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

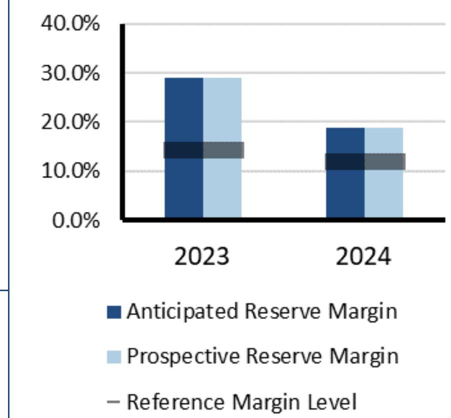
WECC-BC

WECC-British Columbia (BC) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of British Columbia. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 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 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada and the northern portion of Baja California in Mexico as well as all or portions of the 14 western U.S. states in between.

Highlights

- British Columbia faces operational challenges on multiple fronts, including drought, wildfires, and rapid electrification in the residential, commercial, industrial, and transportation sectors.
- British Columbia is expected to have sufficient resource availability to meet reserves at the peak demand hour (5:00–6:00 p.m.) under most conditions. However, above-normal demand that coincides with low hydro output could result in a reserve shortage. This evaluation considers a 1-in-10 probability (90th percentile) level for peak demand and a combination of resource derates including low hydro output.
- WECC's probabilistic analysis shows no LOLH or EUE for British Columbia during the upcoming summer season.

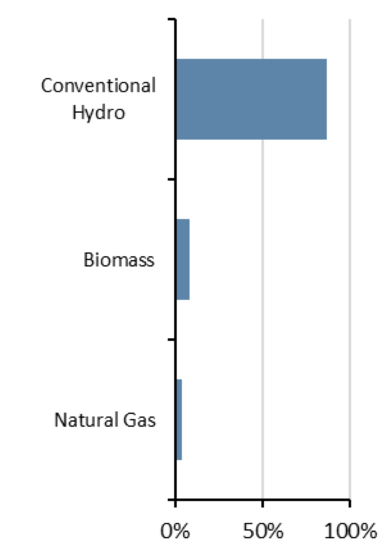
On-Peak Reserve Margin



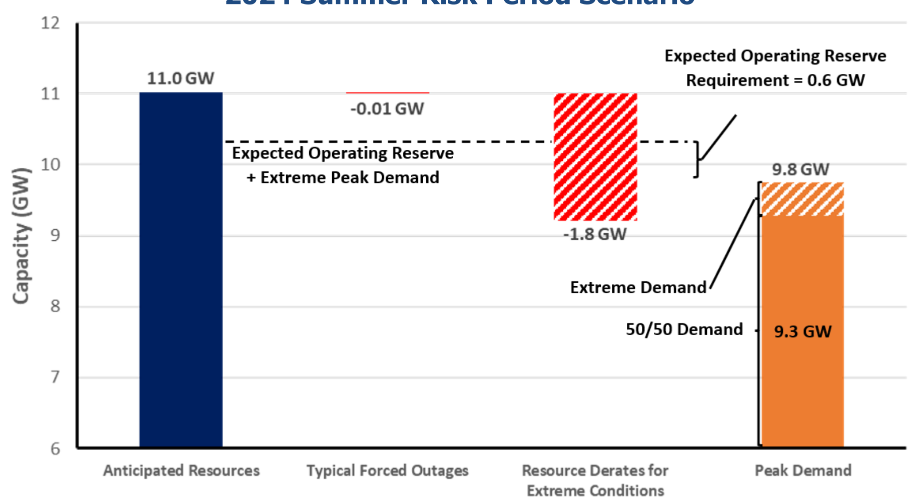
Risk Scenario Summary

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

On-Peak Fuel Mix



2024 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-CA/MX

WECC-CA/MX is a summer-peaking assessment area in the WECC Regional Entity that includes parts of California, Nevada, and Baja California, Mexico. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 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 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada and the northern portion of Baja California in Mexico as well as all or portions of the 14 western U.S. states in between.

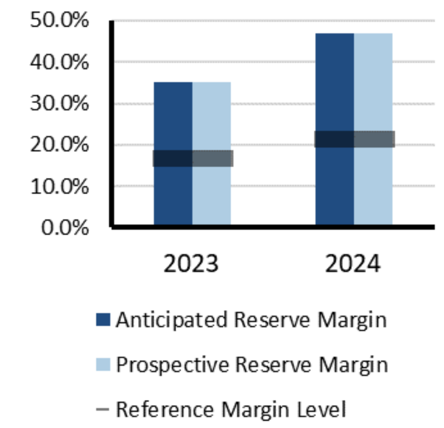
Highlights

- Drought conditions, which were a concern prior to 2023, have been alleviated for the upcoming summer.
- CA/MX is expected to have sufficient resource availability to meet reserves at the peak demand hour (4:00–5:00 p.m.). The riskiest hour for CA/MX is the hour ending 6:00–7:00 p.m. when solar output is low, causing the area to rely on imports to meet demand.
- In WECC's probabilistic analysis, CA/MX is projected to have LOLH ranging from negligible to 0.8 hours with the greatest risk of EUE and LOLH being in the Baja (Mexico) part of CA/MX. Variation in LOLH in the analysis is attributable to the amount of Tier 1 resource additions that connect before the later months. Supply chain issues resulting in the delay or cancellation of Tier 1 projects are a potential risk this summer for CA/MX.
- WECC's analysis considers a 1-in-10 probability (90th percentile) level for peak demand and a combination of resource derates.

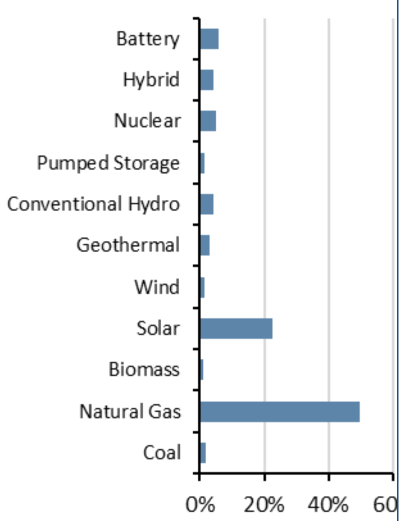
Risk Scenario Summary

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

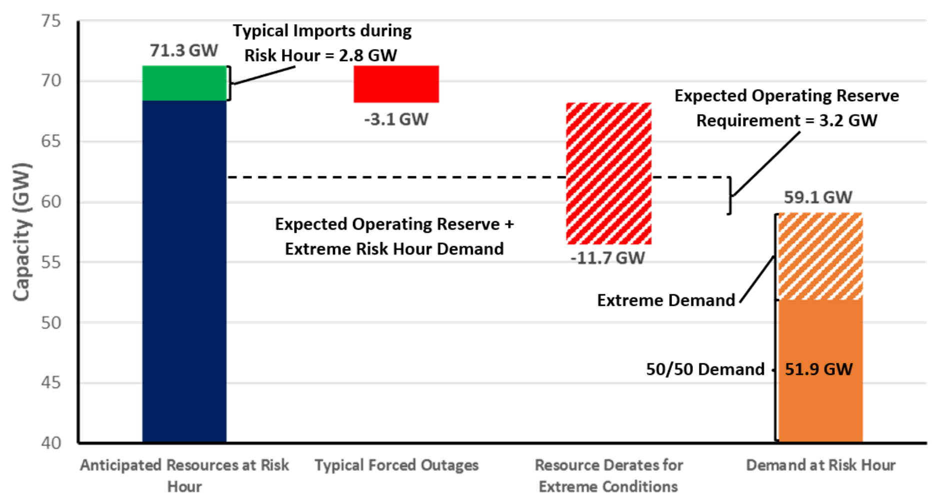
On-Peak Reserve Margin



On-Peak Fuel Mix



2024 Summer Risk Period Scenario (7 p.m. local time)



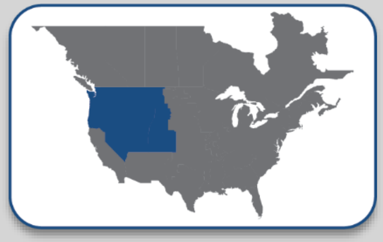
Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at hour ending 7:00 p.m. local time as solar PV output is diminished and demand remains high

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-NW

WECC-NW is a summer-peaking assessment area in the WECC Regional Entity. The area includes Colorado, Idaho, Montana, Oregon, Utah, Washington, and Wyoming and parts of California, Nebraska, Nevada, and South Dakota. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 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 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada and the northern portion of Baja California in Mexico as well as all or portions of the 14 western U.S. states in between.

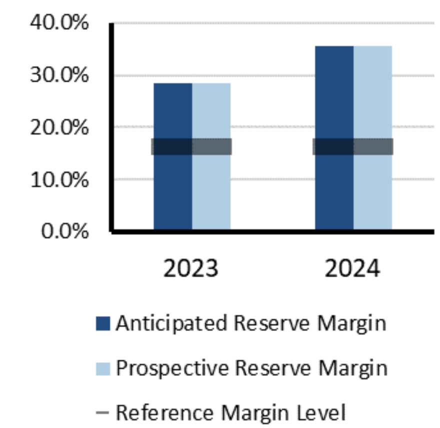
Highlights

- Operational challenges for the Northwest include supply chain issues potentially resulting in project delays or cancellations and unprecedented flow patterns associated with the expansion of IBRs.
- The Northwest is expected to have sufficient resource availability to meet reserves at the peak demand hour (4:00–5:00 p.m.). This evaluation considers a 1-in-10 probability (90th percentile) level for peak demand and a combination of resource derates.
- The Northwest shows no LOLH or EUE for the upcoming summer season.

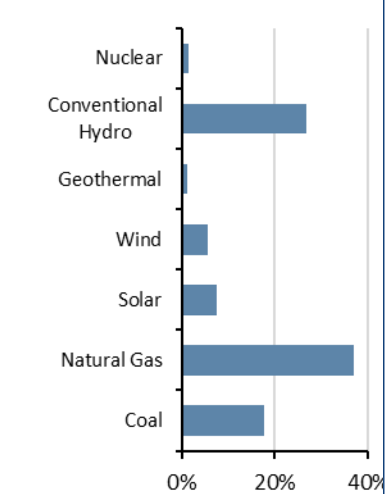
Risk Scenario Summary

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

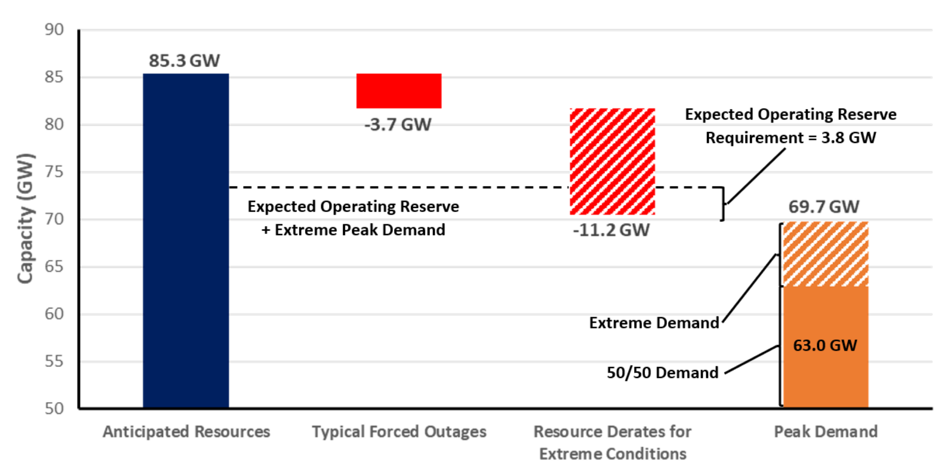
On-Peak Reserve Margin



On-Peak Fuel Mix



2024 Summer Risk Period Scenario



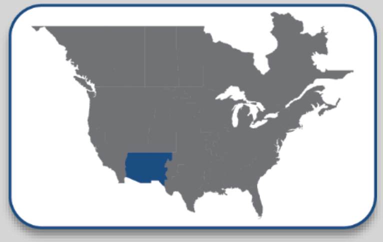
Scenario Description (See Data Concepts and Assumptions)

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



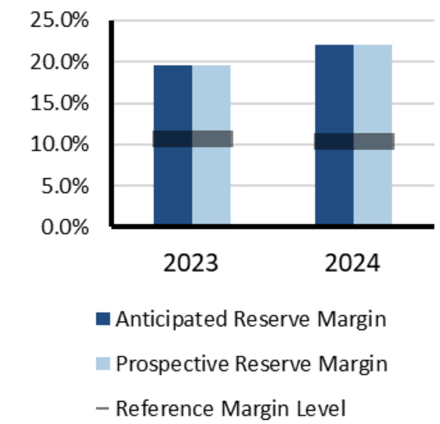
WECC-SW

WECC-SW is a summer-peaking assessment area in the WECC Regional Entity. It includes Arizona, New Mexico, and parts of California and Texas. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 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 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada as well as the northern portion of Baja California in Mexico and all or portions of the 14 western U.S. states in between.

Highlights

- Operational challenges for the Southwest include drought, wildfires, derates of gas facilities due to extreme heat, and supply chain issues potentially affecting thermal resource return to service dates and CODs.
- The Southwest is expected to have sufficient resource availability to meet reserves at the peak demand hour (4:00–5:00 p.m.) under most conditions. However, above-normal demand that coincides with high generator forced outages or other low-resource conditions could result in a reserve shortage. This evaluation considers a 1-in-10 probability (90th percentile) level for peak demand and a combination of resource derates.
- The Southwest shows no LOLH or EUE for the upcoming summer season in WECC's probabilistic analysis.

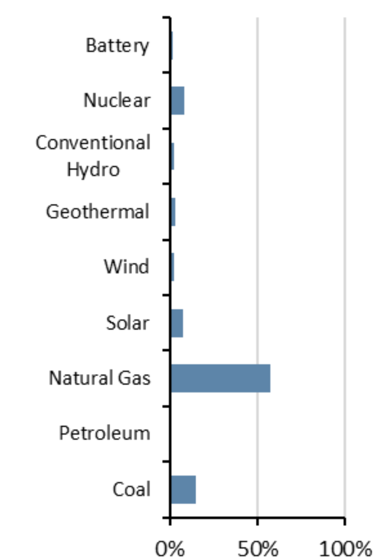
On-Peak Reserve Margin



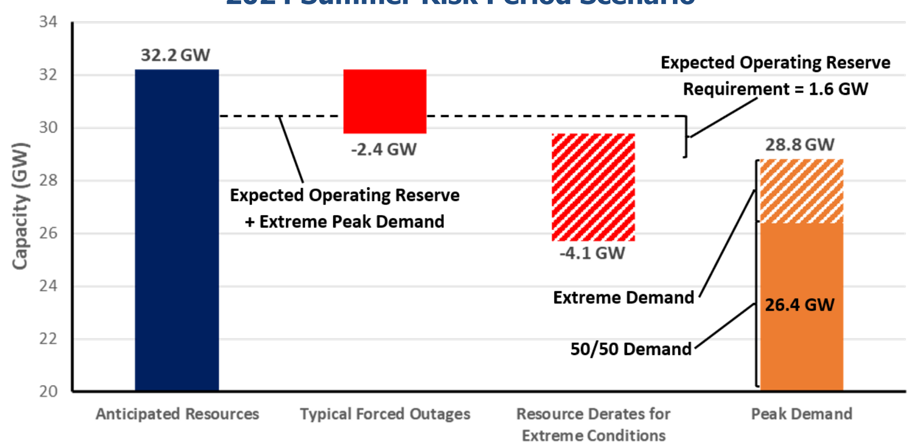
Risk Scenario Summary

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

On-Peak Fuel Mix



2024 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.
- *2023 Long-Term Reliability Assessment* data has been used for most of this 2024 summer assessment period augmented by updated load and capacity data.
- 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 DR 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 variable energy resources (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.

12 *Glossary of Terms* 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.

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.

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 predominately thermal systems and 10% for predominately 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 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 2024 summer as shown in **Figure 4**.

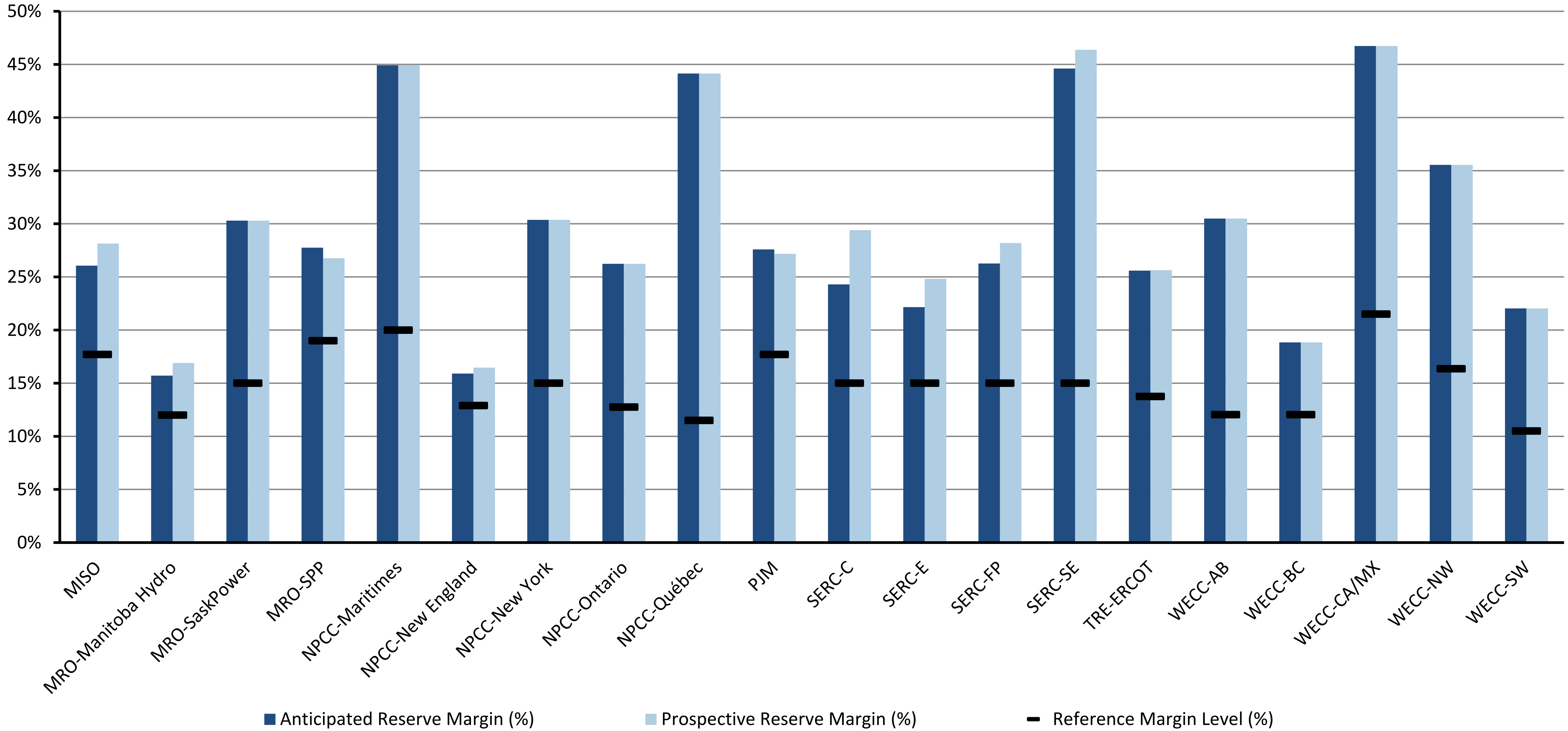


Figure 4: Summer 2024 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[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 2023 summer to the 2024 summer. A significant decline can signal potential operational issues for the upcoming season. Both MRO-Manitoba Hydro and WECC-BC have noticeable reductions in their ARM levels for the 2024 summer. MRO-Manitoba Hydro does not anticipate elevated risk for the upcoming summer, but WECC-BC is experiencing increasing forecasted demand and drought conditions, increasing risk heading into the 2024 summer. Additional details for each assessment area are provided in the **Data Concepts and Assumptions** and **Regional Assessments Dashboards** sections.

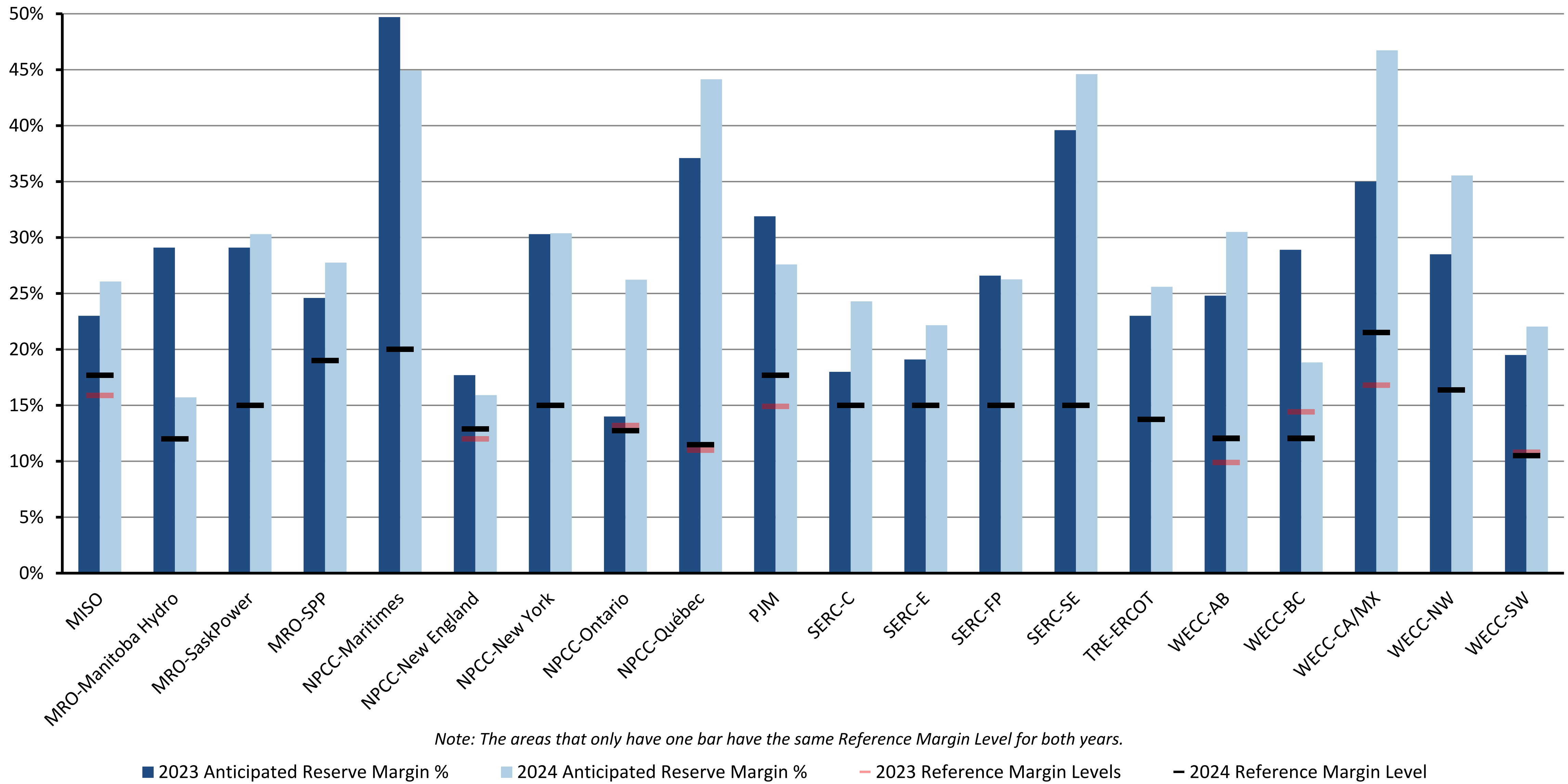


Figure 5: Summer 2023 and Summer 2024 Anticipated Reserve Margins Year-to-Year Change

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.

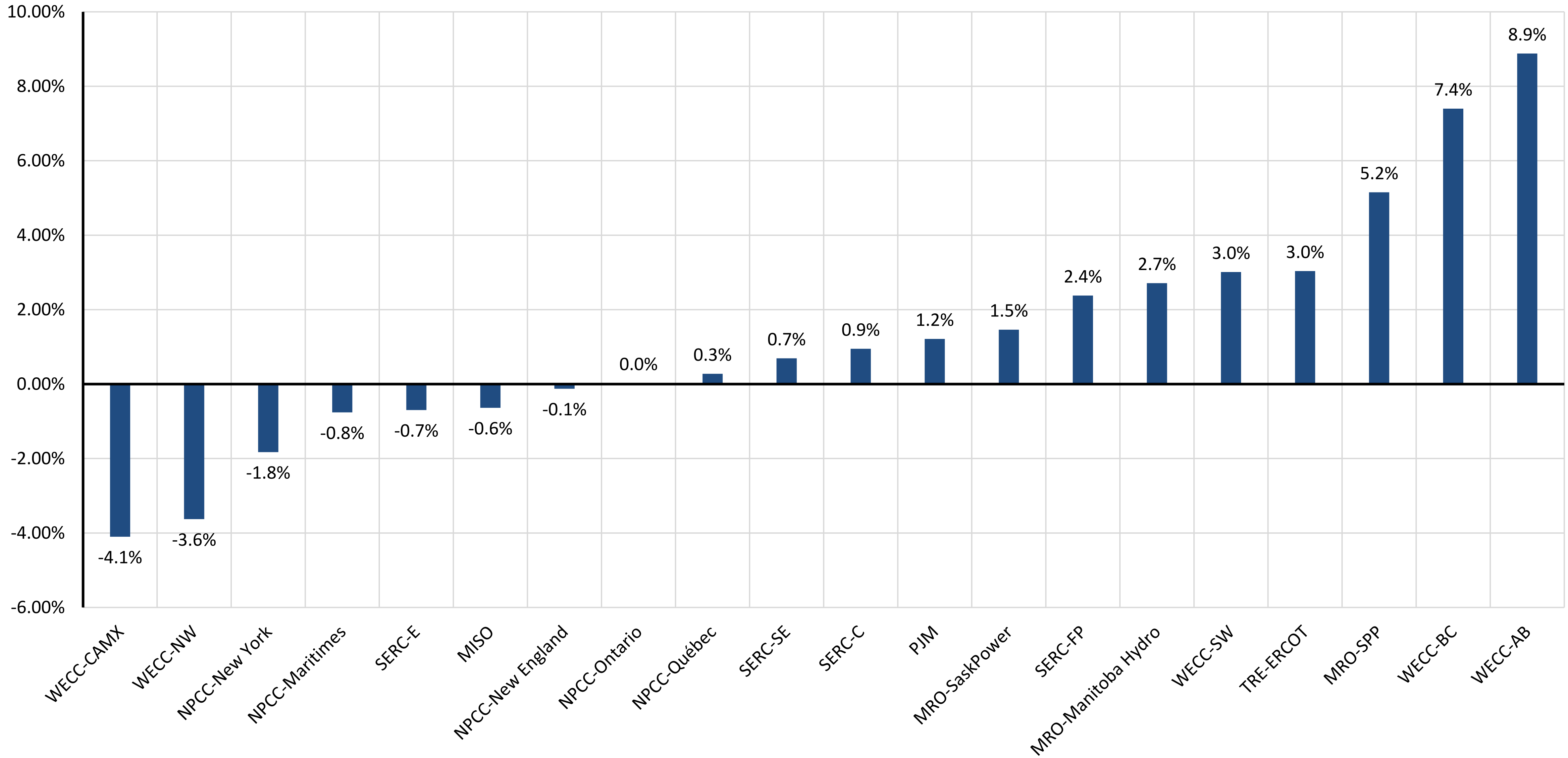


Figure 6: Changes in Net Internal Demand—Summer 2023 Forecast Compared to Summer 2024 Forecast

[17] Changes in modeling and methods may also contribute to year-to-year changes in forecasted net internal demand projections.

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	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	123,728	124,830	0.9%
Demand Response: Available	6,903	8,750	26.8%
Net Internal Demand	116,825	116,079	-0.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	140,650	143,866	2.3%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	3,018	2,471	-18.1%
Anticipated Resources	143,668	146,337	1.9%
Existing-Other Capacity	668	1,833	174.4%
Prospective Resources	151,579	148,740	-1.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	23.0%	26.1%	3.1
Prospective Reserve Margin	29.7%	28.1%	-1.6
Reference Margin Level	15.9%	17.7%	1.8

MRO-Manitoba Hydro			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,060	3,143	2.7%
Demand Response: Available	0	0	-
Net Internal Demand	3,060	3,143	2.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,731	5,615	-2.0%
Tier 1 Planned Capacity	91	0	-100.0%
Net Firm Capacity Transfers	-1,872	-1,978	5.7%
Anticipated Resources	3,950	3,637	-7.9%
Existing-Other Capacity	34	37	9.7%
Prospective Resources	3,984	3,674	-7.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	29.1%	15.7%	-13.4
Prospective Reserve Margin	30.2%	16.9%	-13.3
Reference Margin Level	12.0%	12.0%	0.0

MRO-SaskPower			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,539	3,590	1.4%
Demand Response: Available	50	50	0.0%
Net Internal Demand	3,489	3,540	1.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,213	4,323	2.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	290	290	0.0%
Anticipated Resources	4,503	4,613	2.4%
Existing-Other Capacity	0	0	-
Prospective Resources	4,503	4,613	2.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	29.1%	30.3%	1.2
Prospective Reserve Margin	29.1%	30.3%	1.2
Reference Margin Level	15.0%	15.0%	0.0

MRO-SPP			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	53,468	56,316	5.3%
Demand Response: Available	842	979	16.3%
Net Internal Demand	52,626	55,337	5.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	65,821	70,855	7.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-238	-157	-33.9%
Anticipated Resources	65,583	70,698	7.8%
Existing-Other Capacity	0	0	-
Prospective Resources	65,036	70,151	7.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.6%	27.8%	3.2
Prospective Reserve Margin	23.6%	26.8%	3.2
Reference Margin Level	19.0%	19.0%	0.0

NPCC-Maritimes			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,612	3,586	-0.7%
Demand Response: Available	328	327	-0.3%
Net Internal Demand	3,284	3,259	-0.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,834	4,660	-3.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	81	63	-22.2%
Anticipated Resources	4,915	4,723	-3.9%
Existing-Other Capacity	0	0	-
Prospective Resources	4,915	4,723	-3.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	49.7%	44.9%	-4.8
Prospective Reserve Margin	49.7%	44.9%	-4.8
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New York			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	32,049	31,541	-1.6%
Demand Response: Available	1,226	1,281	4.5%
Net Internal Demand	30,823	30,260	-1.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	37,216	37,867	1.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	2,932	1,585	-45.9%
Anticipated Resources	40,148	39,452	-1.7%
Existing-Other Capacity	0	0	-
Prospective Resources	40,148	39,452	-1.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.3%	30.4%	0.1
Prospective Reserve Margin	30.3%	30.4%	0.1
Reference Margin Level	15.0%	15.0%	0.0

NPCC-New England			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	25,111	25,294	0.7%
Demand Response: Available	447	661	47.9%
Net Internal Demand	24,664	24,633	-0.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	27,997	27,255	-2.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,030	1,297	25.9%
Anticipated Resources	29,027	28,552	-1.6%
Existing-Other Capacity	872	138	-84.2%
Prospective Resources	29,899	28,690	-4.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	17.7%	15.9%	-1.8
Prospective Reserve Margin	21.2%	16.5%	-4.7
Reference Margin Level	12.0%	12.9%	0.9

NPCC-Ontario			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,439	22,753	1.4%
Demand Response: Available	687	996	45.0%
Net Internal Demand	21,752	21,757	0.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	24,575	26,856	9.3%
Tier 1 Planned Capacity	9	9	-1.6%
Net Firm Capacity Transfers	223	600	169.1%
Anticipated Resources	24,807	27,465	10.7%
Existing-Other Capacity	0	0	-
Prospective Resources	24,807	27,465	10.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	14.0%	26.2%	12.2
Prospective Reserve Margin	14.0%	26.2%	12.2
Reference Margin Level	13.2%	12.8%	-0.5

NPCC-Québec			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,859	22,922	0.3%
Demand Response: Available	0	0	-
Net Internal Demand	22,859	22,922	0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	33,690	35,731	6.1%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-2,353	-2,689	14.3%
Anticipated Resources	31,337	33,042	5.4%
Existing-Other Capacity	0	0	-
Prospective Resources	31,337	33,042	5.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	37.1%	44.1%	7.0
Prospective Reserve Margin	37.1%	44.1%	7.0
Reference Margin Level	11.0%	11.5%	0.5

SERC-Central			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	42,223	42,636	1.0%
Demand Response: Available	1,910	1,941	1.6%
Net Internal Demand	40,313	40,695	0.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	46,964	48,677	3.6%
Tier 1 Planned Capacity	93	332	257.3%
Net Firm Capacity Transfers	1,068	2,592	142.7%
Anticipated Resources	47,556	51,601	8.5%
Existing-Other Capacity	2,313	2,074	-10.3%
Prospective Resources	49,868	51,083	2.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	18.0%	26.8%	8.8
Prospective Reserve Margin	23.7%	25.5%	1.8
Reference Margin Level	15.0%	15.0%	0.0

PJM			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	149,059	151,247	1.5%
Demand Response: Available	7,288	7,756	6.4%
Net Internal Demand	141,771	143,491	1.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	186,540	183,690	-1.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	463	-607	-231.1%
Anticipated Resources	187,003	183,083	-2.1%
Existing-Other Capacity	0	0	-
Prospective Resources	187,466	182,476	-2.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	31.9%	27.6%	-4.3
Prospective Reserve Margin	32.2%	27.2%	-5.0
Reference Margin Level	14.9%	17.7%	2.8

SERC-East			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	43,889	43,567	-0.7%
Demand Response: Available	1,008	985	-2.3%
Net Internal Demand	42,881	42,582	-0.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	50,452	51,304	1.7%
Tier 1 Planned Capacity	0	122	-
Net Firm Capacity Transfers	624	593	-5.0%
Anticipated Resources	51,076	52,019	1.8%
Existing-Other Capacity	1,182	1,131	-4.3%
Prospective Resources	52,258	52,557	0.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	19.1%	22.2%	3.1
Prospective Reserve Margin	21.9%	23.4%	1.5
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	52,195	53,293	2.1%
Demand Response: Available	2,898	2,824	-2.6%
Net Internal Demand	49,297	50,469	2.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	60,074	60,962	1.5%
Tier 1 Planned Capacity	1,742	34	-98.0%
Net Firm Capacity Transfers	589	200	-66.0%
Anticipated Resources	62,405	61,196	-1.9%
Existing-Other Capacity	776	985	27.0%
Prospective Resources	63,181	61,981	-1.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.6%	21.3%	-5.3
Prospective Reserve Margin	28.2%	22.8%	-5.4
Reference Margin Level	15.0%	15.0%	0.0

Texas RE-ERCOT			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	82,307	84,818	3.1%
Demand Response: Available	3,380	3,496	3.4%
Net Internal Demand	78,927	81,323	3.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	94,580	99,541	5.2%
Tier 1 Planned Capacity	2,445	2,578	5.4%
Net Firm Capacity Transfers	20	20	0.0%
Anticipated Resources	97,045	102,139	5.2%
Existing-Other Capacity	0	0	-
Prospective Resources	97,073	102,167	5.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	23.0%	25.6%	2.6
Prospective Reserve Margin	23.0%	25.6%	2.6
Reference Margin Level	13.75%	13.75%	0.0

SERC-Southeast			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	46,127	46,021	-0.2%
Demand Response: Available	2,010	1,599	-20.4%
Net Internal Demand	44,117	44,422	0.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	59,559	63,918	7.3%
Tier 1 Planned Capacity	2,865	1,738	-39.4%
Net Firm Capacity Transfers	-815	-1,192	46.3%
Anticipated Resources	61,609	64,463	4.6%
Existing-Other Capacity	908	785	-13.5%
Prospective Resources	62,517	66,441	6.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	39.6%	45.1%	5.5
Prospective Reserve Margin	41.7%	49.6%	7.9
Reference Margin Level	15.0%	15.0%	0.0

WECC-AB			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,206	12,201	8.9%
Demand Response: Available	0	0	-
Net Internal Demand	11,206	12,201	8.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,759	13,941	1.3%
Tier 1 Planned Capacity	227	1,981	772.7%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	13,986	15,922	13.8%
Existing-Other Capacity	0	0	-
Prospective Resources	13,986	15,922	13.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.8%	30.5%	5.7
Prospective Reserve Margin	24.8%	30.5%	5.7
Reference Margin Level	9.9%	6.7%	-3.2

WECC-BC			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	8,636	9,275	7.4%
Demand Response: Available	0	0	-
Net Internal Demand	8,636	9,275	7.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	11,135	11,022	-1.0%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	11,135	11,022	-1.0%
Existing-Other Capacity	0	0	-
Prospective Resources	11,135	11,022	-1.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	28.9%	18.8%	-10.1
Prospective Reserve Margin	28.9%	18.8%	-10.1
Reference Margin Level	9.7%	12.0%	-2.4

WECC-CA/MX			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	56,356	54,029	-4.1%
Demand Response: Available	862	810	-6.0%
Net Internal Demand	55,494	53,219	-4.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	69,408	70,841	2.1%
Tier 1 Planned Capacity	5,522	6,906	25.1%
Net Firm Capacity Transfers	0	340	-
Anticipated Resources	74,930	78,087	4.2%
Existing-Other Capacity	0	0	-
Prospective Resources	74,930	78,087	4.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	35.0%	46.7%	11.7
Prospective Reserve Margin	35.0%	46.7%	11.7
Reference Margin Level	16.8%	21.5%	4.7

WECC-SW			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	25,992	26,661	2.6%
Demand Response: Available	380	278	-26.8%
Net Internal Demand	25,612	26,383	3.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	26,206	28,336	8.1%
Tier 1 Planned Capacity	1,655	2,338	41.3%
Net Firm Capacity Transfers	2,747	1,523	-44.6%
Anticipated Resources	30,608	32,197	5.2%
Existing-Other Capacity	0	0	-
Prospective Resources	30,608	32,197	5.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	19.5%	22.0%	2.5
Prospective Reserve Margin	19.5%	22.0%	2.5
Reference Margin Level	10.8%	10.5%	-0.3

WECC-NW			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	66,366	63,865	-3.8%
Demand Response: Available	1,038	907	-12.6%
Net Internal Demand	65,328	62,958	-3.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	76,587	78,057	1.9%
Tier 1 Planned Capacity	2,350	4,089	74.0%
Net Firm Capacity Transfers	5,004	3,192	-36.2%
Anticipated Resources	83,941	85,338	1.7%
Existing-Other Capacity	0	0	-
Prospective Resources	83,941	85,338	1.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	28.5%	35.5%	7.0
Prospective Reserve Margin	28.5%	35.5%	7.0
Reference Margin Level	16.3%	16.4%	0.1

Variable Energy Resource Contributions

Because the electrical output of variable energy resources (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			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	30,931	5,599	18%	10,169	4,981	49%	1,621	1,488	92%	2,678	2,591	97%
MRO-Manitoba Hydro	259	48	19%	–	-	0%	202	92	46%	-	-	0%
MRO-SaskPower	616	208	34%	30	6	21%	848	655	77%	-	-	0%
NPCC-Maritimes	1,209	262	22%	69	-	0%	1,312	1,181	90%	13	13	100%
NPCC-New England	1,546	122	8%	3,246	1,111	34%	550	367	67%	2,077	2,038	98%
NPCC-New York	2,590	340	13%	370	53	14%	984	386	39%	20	-	0%
NPCC-Ontario	4,883	720	15%	478	66	14%	8,922	5,171	58%	-	-	0%
NPCC-Québec	3,820	-	0%	10	-	0%	446	446	100%	-	-	0%
PJM	10,495	1,703	16%	10,990	5,694	52%	2,505	2,505	100%	190	151	79%
SERC-Central	1,220	172	14%	2,074	996	48%	4,966	3,332	67%	166	70	42%
SERC-East	-	-	-	2,769	2,405	87%	3,072	3,016	98%	24	10	43%
SERC-Florida Peninsula	-	-	0%	10,023	5,643	56%	-	-	0%	538	538	100%
SERC-Southeast	-	-	0%	7,887	7,217	91%	3,303	3,259	99%	115	105	92%
SPP	34,783	5,876	17%	756	486	64%	107	54	50%	12	2	13%
Texas RE-ERCOT	39,069	9,070	23%	24,463	17,797	73%	575	450	78%	7,876	2,661	34%
WECC-AB	4,482	666	15%	1,650	786	48%	894	450	50%	190	185	97%
WECC-BC	747	140	19%	2	0	22%	16,521	9,757	59%	-	-	0%
WECC-CA/MX	7,694	1,124	15%	21,790	13,147	60%	13,725	6,265	46%	7,295	6,858	94%
WECC-NW	19,709	2,964	15%	8,853	2,595	29%	41,705	24,147	58%	779	707	91%
WECC-SW	3,329	542	16%	2,690	1,294	48%	1,201	670	56%	988	893	90%
EASTERN INTERCONNECTION	88,702	15,220	17%	48,862	28,657	59%	28,394	21,507	76%	5,832	5,517	95%
QUÉBEC INTERCONNECTION	3,820	-	0%	10	-	0%	446	446	100%	-	-	0%
TEXAS INTERCONNECTION	39,069	9,070	23%	24,463	17,797	73%	575	450	78%	7,876	2,661	34%
WECC INTERCONNECTION	35,961	5,436	15%	34,985	17,822	51%	74,046	41,289	56%	9,252	8,643	93%
All INTERCONNECTIONS	**167,552**	**29,725**	**18%**	**108,320**	**64,277**	**59%**	**103,461**	**63,692**	**62%**	**22,960**	**16,821**	**73%**

Review of 2023 Capacity and Energy Performance

High temperatures, wildfires, and weather conditions challenged electric grid operators in many parts of North America to maintain a reliable supply of electricity during 2023. Prior to summer, NERC warned that much of North America was at risk of having insufficient resources to meet electricity demand if extreme temperatures and weather conditions were to develop. It is noteworthy that, after a summer of soaring temperatures, extended heat waves, and new electricity demand records, few high-level EEAs were issued, and no disruptions occurred as a result of inadequate resources. Nonetheless, operators at BAs, TOPs, and RCs faced significant challenges and drew upon procedures and protocols to obtain all available resources, manage system demand, and ensure the flow of supplies over the transmission network. Additionally, load-serving entities and state and local officials in many parts of North America used mechanisms and public appeals to lower customer demand during periods of strained supplies. The following section describes actual demand and resource levels in comparison with NERC's *2023 SRA* and summarizes 2023 resource adequacy events.

Eastern Interconnection–Canada and Québec Interconnection

Systems in parts of Canada experienced challenging conditions early in the summer from high electricity demand and wildfires over large areas. Electricity transfers from Québec to neighboring Maritimes and New England were curtailed or disrupted during periods in May and June when wildfires affected transmission facilities. Peak electricity demand in Ontario occurred in early September at a level near the 90/10 demand forecast. Additional imports helped the area meet the extreme demand.

Manitoba Hydro and SaskPower both experienced peak electricity demand in excess of 90/10 summer forecasts. Manitoba Hydro's peak occurred at the start of summer in June. Operators had sufficient reserves and were able to export supplies during the peak period to neighboring areas.

SaskPower peak electricity demand occurred in late July. A forced outage at a large thermal generator early in the summer contributed to operating challenges over much of the summer period. At the time of peak demand, forced outages were significantly higher than typical for summer peak periods.

Eastern Interconnection–United States

In SPP, summer electricity demand peaked in August and exceeded 90/10 forecasts. At the hour of peak demand, SPP experienced near-normal levels of forced thermal generation outages. Wind resource performance at the time of peak demand exceeded seasonal peak forecasts, helping to alleviate the strain on supplies. However, during periods in June and July, operators at SPP issued resource advisories during periods of forecasted high demand and low or uncertain wind resource output.

MISO also experienced peak electricity demand during the same period in August; however, demand was between the normal and 90/10 summer peak forecast levels. Wind and solar resource output at the time of peak demand were below expectations for summer on-peak contributions. Forced outages of thermal units, however, were lower than expected. An EEA (level 2) was issued in August due to high forecasted loads and wind uncertainty. MISO used operating procedures to ensure that sufficient reserves were maintained during periods of high electricity demand and high forced generator outages at times throughout the summer.

PJM experienced peak electricity demand in late July at a level between normal summer peak and the 90/10 forecast. Wind and solar resource output were below seasonal peak expectations, while low thermal generator outages were reported.

Peak electricity demand at NYISO and ISO-NE occurred in early September and fell below average summer peak forecasts.

Systems in the U.S. Southeast experienced peak demand above the 90/10 forecasts in mid to late August. Solar resource output exceeded the expected contributions for the peak demand period. Electricity imports into resource-constrained areas helped BAs maintain reserves during high demand periods.

Texas Interconnection–ERCOT

Extended heat waves led to record-setting system electricity demand in the ERCOT system throughout Summer 2023. Peak electricity demand occurred in mid-August at a level exceeding the 90/10 demand forecast. At the time of peak demand, wind and solar generation were slightly below expected levels for peak demand periods, and thermal generator outages were also slightly higher than normal for peak periods. Nonetheless, operators were able to maintain sufficient reserves. At various times throughout the summer, ERCOT issued public appeals for conservation to help manage high demand periods and evening periods when output from the solar resources is diminished. On September 6, ERCOT declared an EEA (level 2) to address a low-frequency condition on the system during a period of unusually high demand, declining solar output, and low wind output. Transmission system constraints led to the curtailment of some supply from wind resources in southern parts of the system. No load was shed during the event.

Western Interconnection–Canada

At the start of summer, the province of Alberta was in a state of emergency as a result of active wildfires and the threat of spreading from hot and dry conditions. A period of high demand from heat and humidity that coincided with generator forced outages and low wind conditions triggered an EEA. Alberta's system peak demand occurred in late July at a level above normal summer peak demand forecasts but below the 90/10 level. Wind and solar resource outputs were above seasonal forecast levels for peak demand periods. High temperatures in late August led to high demand at a time of planned transmission system maintenance. An EEA (level 3) was triggered when low wind conditions and insufficient imports resulted in reserve shortage.

The BC Hydro system also experienced peak electricity demand in early August at a level near the 90/10 summer peak forecast.

Western Interconnection–United States

The California-Mexico assessment area, which consists of the CAISO, Northern California, and CENACE BAs, experienced system peak electricity demand in mid-August at a level between the average summer peak demand forecast and the 90/10 peak demand forecast. Public appeals to shift electricity use to off-peak hours were used during some high-demand periods. The Mexico portion of the assessment area faced reserve shortages during periods in July and August as a result of high demand, generator outages, and unavailability of imports.

System peak electricity demand in the U.S. Northwest also occurred in mid-August and was below normal summer peak demand forecasts.

The U.S. Southwest experienced extended heat conditions and demand levels that exceeded normal summer peak demand forecasts. Wind and solar output fell below expected levels during the peak demand period.

2023 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	120.8	116.8 123.9	8,598	5,488	2,096	3,750	6,638
MRO-Manitoba Hydro	3.5	3.1 3.4	83	47	-		95
MRO-SaskPower	3.7	3.5 3.6	381	203	15		737
MRO-SPP	56.0	52.6 55.1	8,278	4,500	130	378	6,533
NPCC-Maritimes	3.5	3.3 3.6	131	255	40	-	1,690*
NPCC-New England	23.5	24.7 26.5	186	186	145	1,163	1,969
NPCC-New York	30.2	30.8 32.7	223	331	-	84	9,716
NPCC-Ontario	23.7	21.8 23.7	786	771	200	126	3,419*
NPCC-Québec	22.5	22.9 22.9	496	-	8		12,287*
PJM	147.6	141.8 162.7	1,278	1,688	1,826	2,984	8,020
SERC-C	44.0	40.3 43.0	15	564	673	511	1,225
SERC-E	43.3	42.9 45.6	-	-	3,032	1,473	2,129
SERC-FP	54.1	49.3 52.4	-	-	4,590	4,534	1,610
SERC-SE	45.6	44.8	-	-	2,781	4,647	2,334
TRE-ERCOT	85.4	78.9 82.3	9,557	10,293	10,431	12,509	6,699
WECC-AB	11.5	11.2 11.6	906	309	894	763	-
WECC-BC	9.2	8.6 9.2	373	137	0	1	-

2023 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	52.3	49.5 58.1	1,074	1,111	6,930	14,489	2,444
WECC-NW	64.7	61.0 67.2	2,137	593	3,821	1,411	4,855
WECC-SW	27.3	25.6 28.0	835	3,968	1,731	5,062	2,507
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 *2023 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 *2023 SRA*.

[4] Values from NERC Generator Availability Data System for the 2023 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 2023 summer risk period scenarios in the *2023 SRA*.