NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2023–2024 Winter Reliability Assessment

November 2023

[WRA Infographic](#) | [WRA Video](#)

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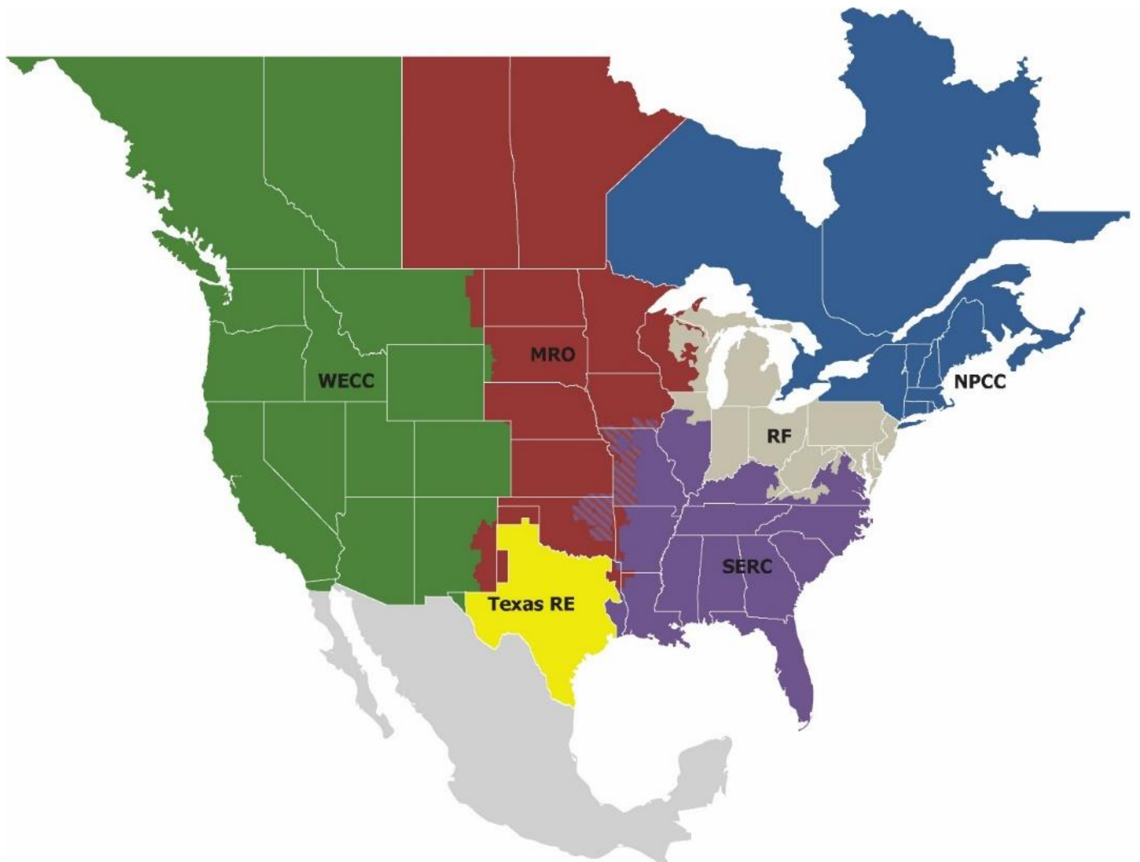
Preface

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 Entity as shown in the map and 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 *2023–2024 Winter Reliability Assessment (WRA)* identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming winter season. In addition, the *WRA* presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might affect the reliability of the BPS.

This reliability assessment process is a coordinated evaluation between the 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 the ERO Enterprise (i.e., NERC and the six Regional Entities) 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 the industry to discuss plans and preparations to ensure reliability for the upcoming winter period.

Key Findings

This *WRA* covers the upcoming three-month (December–February) winter period. This assessment provides an evaluation of the generation resource and transmission system adequacy necessary to meet projected winter peak demands and operating reserves. This assessment identifies potential reliability issues of interest and regional risks. The following findings are the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as the potential operational concerns that may need to be addressed for the upcoming winter:

1. **A large portion of the North American BPS is at risk of insufficient electricity supplies during peak winter conditions** (Figure 1). Prolonged, wide-area cold snaps threaten the reliable performance of BPS generation and the availability of fuel supplies for natural-gas-fired generation. As observed in recent winter reliability events, over 20% of generating capacity has been forced off-line when freezing temperatures extend over parts of North America that are not typically exposed to such conditions. When electricity supplies become constrained, BPS system operators can face a simultaneous sharp increase in demand as electric heating systems consume more power in cold temperatures. These areas (see Figure 1) are at greatest risk for electricity supply shortfalls this winter:

    - **Midcontinent ISO (MISO):** New wind and natural-gas-fired generation and the extension of some older fossil-fired plants have increased available resources this winter by over 9 GW from 2022. Recently, MISO implemented a seasonal resource adequacy construct that more effectively values risks and resource contributions that vary by time of year. Like prior years, an extreme cold-weather event that extends into MISO's southern areas can cause high generator outages from inadequate weatherization or insufficient natural gas fuel supplies.

    - **MRO-SaskPower:** Reserve margins have fallen this winter by eight percentage points when compared to the previous winter due to increased peak demand projections, the retirement of a natural-gas-fired unit (95 MW), and planned generator maintenance. High numbers of forced generator outages or wind turbine cold temperature cutouts can lead to operating reserves shortfalls at peak winter demand levels.

    - **NPCC-Maritimes:** Peak demand growth has been offset by additional resource capacity and import agreements for the upcoming winter, causing reserve margins to rise by over two percentage points compared to 2022. Demand levels at the forecasted peak can still strain the area's firm supplies and lead to operating mitigations or energy emergencies.

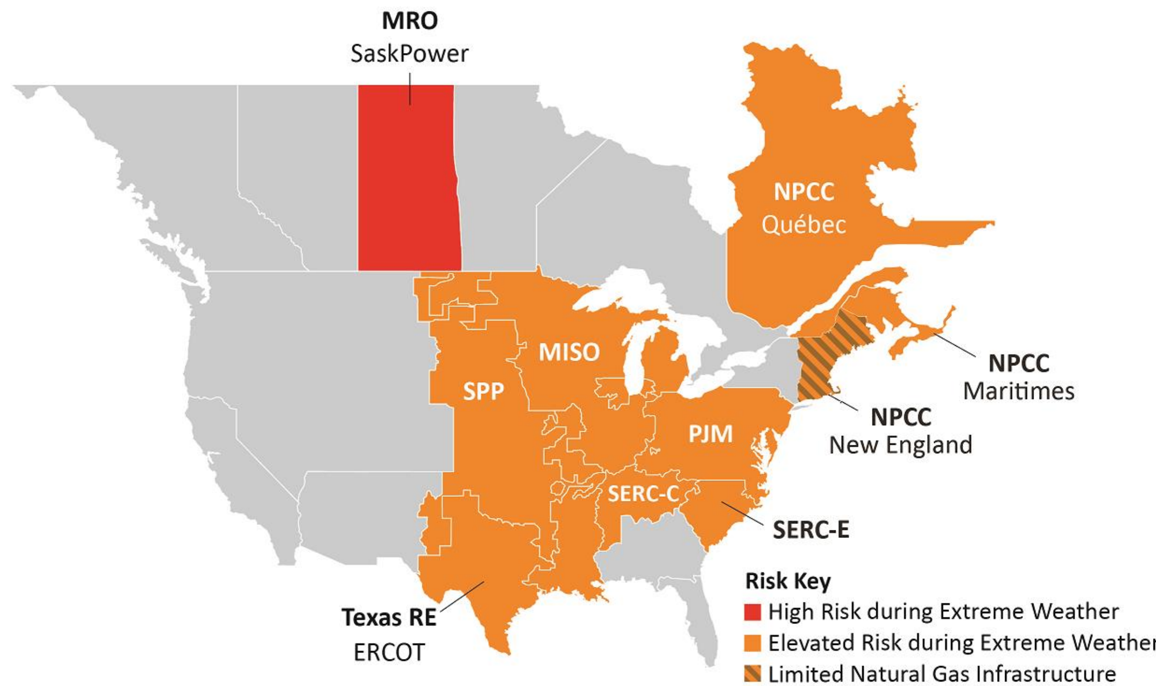


Figure 1: Winter Reliability Risk Area Summary

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

- **NPCC-New England:** The capacity of natural gas transportation infrastructure could be constrained when cold temperatures cause peak demand for both electricity generation and consumer space-heating needs. Potential constraints on the fuel delivery systems and the limited inventory of liquid fuels may exacerbate the risks for fuel-based generator outages and output reductions that result in energy emergencies during extreme weather. ISO-New England (ISO-NE) introduced the Inventoried Energy Program this year as an interim measure to address energy security concerns. The program provides compensation for generators that maintain inventoried energy for their assets during extreme cold periods. The program is also planned for 2024–2025 winter while ISO-NE develops more comprehensive energy security measures for regulatory approval.

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- **NPCC-Québec:** An increase in forecasted peak demand and additional firm export commitments have resulted in lower reserve margins for the upcoming winter. Despite having reliable performance from hydroelectric generation in winter, non-firm imports may be needed to meet operating reserve requirements if demand levels exceed the forecasted peak.
- **PJM, SERC-East, and SERC-Central:** A severe cold weather event that extends to the Southern United States can lead to energy emergencies as operators face sharp increases in generator forced outages and electricity demand. Forecasted peak demand has risen while resources have changed little in these areas since Winter Storm Elliot caused energy emergencies across the area in 2022. PJM and SERC have adequate resources for normal winter conditions; however, their generators are vulnerable to derates and outages in extreme conditions.
- **Southwest Power Pool (SPP):** The Anticipated Reserve Margin (ARM) of 38.8% is over 30 percentage points lower than last winter; this is driven by higher forecasted peak demand and less resource capacity. While the reserve margin is adequate for normal forecasted peak demand and expected generator outages, higher demand levels and outages that have occurred during extreme cold weather result in shortfalls that can trigger energy emergencies. The vast wind resources in the area can alleviate firm capacity shortages under the right conditions; however, energy risks emerge during periods of low wind or forecast uncertainty and high electricity demand.
- **Texas RE-ERCOT:** Like other assessment areas in the Southern United States, the risk of a significant number of generator forced outages in extreme and prolonged cold temperatures continues to threaten reliability where generators and fuel supply infrastructure are not designed or retrofitted for such conditions. The risk of reserve shortage is greater than last winter due primarily to robust load growth that is not being met by corresponding growth in dispatchable resources. ERCOT is taking steps to procure additional capacity ahead of winter that can reduce the likelihood of energy emergencies. Additionally, ERCOT implemented a new firm fuel supply service in its market that is expected to partially offset the lost generation capacity that can occur when natural gas supplies are limited. Electricity demand in Texas rises sharply as extreme cold temperatures add to winter operating challenges and energy shortfall risks.

2. **Generator fuel supplies remain at risk during extreme, long-duration cold weather events.** Fuel assurance is vitally important to meeting winter electricity demand across North America. Natural-gas-fired generator availability and output can be threatened when natural gas supplies are insufficient or when the flow of fuel cannot be maintained. During Winter Storm Elliott, natural gas production rapidly declined with the onset of extreme cold temperatures, contributing to wide-area electricity and natural gas shortages.

Currently, natural gas production, transportation, storage, and a significant portion of the BPS link together to form a single interconnected energy delivery system that extends from the natural gas wellhead to end-use electricity and natural gas customers. The operation of this interconnected energy system can be disrupted when natural gas fuel supplies are not available for electricity generation as well as when electricity is not available to operate electricity-driven compressors and other critical infrastructure components in the natural gas supply chain. Recent extreme cold weather events have shown that energy delivery disruptions can have devasting consequences for electric and natural gas consumers in impacted areas.

Winter Storm Elliott demonstrated the wide-area consequences for BPS reliability that can result from reduced natural gas production during periods of extreme cold weather. In addition to wellhead impacts on production, natural-gas-fired generating units that lacked firm supply or transportation contracts to meet their winter peak electrical output faced challenging and often insurmountable fuel procurement issues when natural gas supply and available pipeline capacity became scarce. During Winter Storm Elliott, natural-gas-related fuel outages occurred alongside generator outages, derates, and failures to start that resulted from freezing issues and mechanical/electrical issues that are closely correlated with falling temperatures.

The joint *FERC-NERC-Regional* Entity *Joint Inquiry into Winter Storm Elliott* made the following recommendations related to adequate fuel supply assurance and other matters:[1]

- Establishing reliability rules for natural gas infrastructure
- Improving communication and business practices between industries
- Assessing Balancing Authority (BA) reliability commitment processes for addressing potential capacity shortages during forecasted cold weather events

To enhance situational awareness across impacted interconnected energy delivery systems, the FERC-NERC report also included a more immediate recommendation that BPS operators and natural gas industry controllers convene to establish control room to control room operational communications protocols that can be invoked when extreme cold weather approaches and that these protocols remain in place over the duration of the event.

[1] FERC Winter Storm Elliott Report

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Coal is also an important fuel for electricity generation in winter. Generator owners report fewer coal supply issues compared to last winter. Normal rail transportation services are available and coal stocks are at a high level compared to historical averages. Some coal fired generation that relies on barge shipments in inland waterways could be impacted by drought restrictions that limit barge loading.

3. **Load forecasting in winter is growing in complexity. Underestimating demand is a risk to reliability in extreme cold temperatures.** Extreme cold temperatures and irregular weather patterns characterized by strong cold fronts, wind, and precipitation can cause demand for electricity to deviate significantly from historical forecasts. Electrification of the heating sector is increasing temperature-sensitive load components while increasing levels of variable-output solar photovoltaic (PV) distributed energy resources (DER) add to the load forecast uncertainty. Underestimating electricity demand prior to the arrival of cold temperatures can lead to ineffective operations planning and insufficient resources being scheduled. Generator performance and fuel issues are more likely to occur when generators are called upon with short notice; this can expose BAs to potential resource shortfalls. Load serving entities and BAs should apply lessons from prior winter operating experience to operational load forecasts and pay particular attention to the risk of demand underestimation ahead of extreme winter conditions.

4. **Curtailment of electricity transfers to areas in need during periods of high regional demand is a growing reliability concern.** During energy emergencies and periods of transmission system congestion, Reliability Coordinators (RC) and BAs may curtail transfers for various reasons with established procedures and protocols. While the curtailments alleviate an issue in one part of the system, curtailments can contribute to supply shortages or affect local transmission system operations in another area. During Winter Storm Elliott, firm exports were curtailed from PJM during a period of widespread energy emergencies in the U.S. Eastern Interconnection. For winter 2023–2024, several areas identified as having capacity or energy risks are relying on imports of electricity supplies. These areas include MRO-SaskPower, NPCC-Maritimes, NPCC-New England, SERC-Central, and SERC-East. A wide-area cold snap that severely affects regional demand or generator availability presents an added concern in areas that are dependent on imports for managing high electricity demand.

5. **New cold weather Reliability Standards in place at the start of the 2023–2024 winter are aimed at improving coordination between Generator Owners/Operators and BPS Operators.** New cold weather Reliability Standards adopted by the NERC Board of Trustees (Board) in June 2021 went into effect in the United States earlier this year. Generator Owners (GO) and Generator Operators (GOP) are required to implement plans for cold weather preparedness and provide cold weather operating parameters to their RCs, Transmission Operators (TOP), and BAs for use in operating plans. Additional Reliability Standard requirements have been developed by NERC and industry to address further recommendations of the *FERC-NERC-Regional Entity staff report—The February 2021 Cold Weather Outages in Texas and Southcentral United States.* The NERC Board adopted these requirements in October 2023 and directed NERC to file them with regulatory authorities for approval and industry implementation.

6. **Industry responses to NERC's Level 3 Alert - Cold Weather Preparations for Extreme Weather Events–III indicate that generator winter preparations are on a positive trend, but freezing temperatures remain a concern for some generators.** In May, NERC issued a Level 3 essential actions alert to BAs, TOPs, and GOs. The alert highlighted actions to increase readiness and enhance plans to reduce risk for the upcoming winter and beyond. Additionally, recipients of the alert were required to respond to questions that support NERC's review of progress toward mitigating winter reliability risks. The responses indicate GOs have determined cold weather temperature limits for their generators and taken steps to assess and prepare critical components to operate at these temperatures. Many GOs, however, noted that generator unit and auxiliary component mechanical failures from past cold weather events remain a concern for the upcoming winter. Problem areas include improper heat tracing, frozen instrumentation and control equipment, generator circuit breaker tripping in low temperatures or low air pressures, and wind turbine blade icing.

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Recommendations

To reduce the risks of energy shortfalls on the BPS this winter, NERC recommends the following:

- RCs, BAs, and TOPs in the elevated risk areas identified in the key findings should review seasonal operating plans and the protocols for communicating and resolving potential supply shortfalls in anticipation of potentially high generator outages and extreme demand levels. Operators should be trained and familiar with manual load shedding plans prior to winter and review procedures in advance of severe winter weather.
- TOPs, BAs, and GOs should implement the essential actions identified in the NERC Level 3 alert, Cold Weather Preparations for Extreme Weather Events–III, and should take recommended weatherization steps prior to winter.
- BAs should be cognizant of the potential for short-term load forecasts to underestimate load in extreme cold weather events and be prepared to take early action to implement protocols and procedures for managing potential reserve deficiencies.
- RCs and BAs should implement generator fuel surveys to monitor the adequacy of fuel supplies. They should prepare their operating plans to manage potential supply shortfalls and take proactive steps for generator readiness, fuel availability, load curtailment, and sustained operations in extreme conditions.
- State and provincial regulators can assist grid owners and operators in advance of and during extreme cold weather by supporting requested environmental and transportation waivers as well as public appeals for electricity and natural gas conservation.

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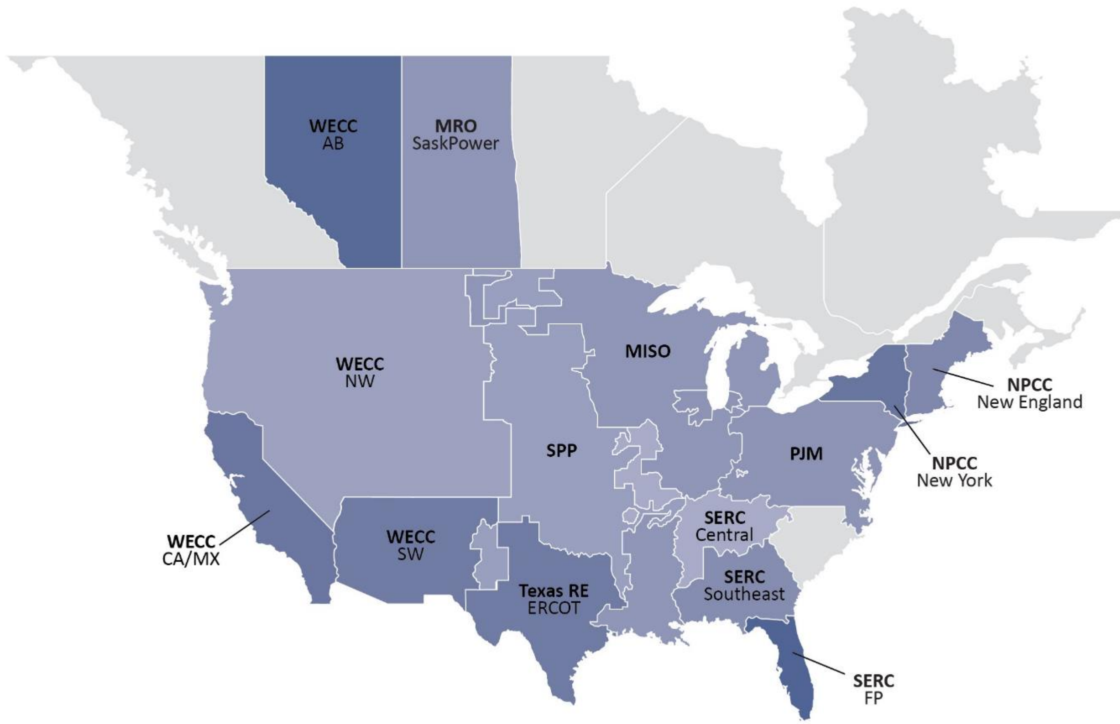
Risk Highlights

Over the past 11 years, five cold weather events have jeopardized Bulk Electric System (BES) reliability by triggering unplanned cold weather-related generation outages. To maintain BES reliability during Winter Storm Uri in February 2021 and Winter Storm Elliott in December 2022, BES operators were required to shed firm load. During both winter storms, numerous electrical and mechanical issues rendered significant portions of the impacted areas' thermal generation fleet unavailable while natural gas supply and transportation issues prevented numerous otherwise available natural-gas-fired generators from supplying much needed electrical energy. Moreover, a significant portion of generating units failed to perform at temperatures above their own documented minimum operating temperatures.

Generator Fuel Supply Risk

As noted in past winter reliability assessments, the performance of the thermal generating fleet is critical to winter operations. The electric and natural gas industries continue to work through the recommendations contained in the *FERC-NERC-Regional Entity Staff Report: The February 2021 Cold Weather Outages in Texas and the South-Central United States.*[2] The final report on Winter Storm Elliott—the 2022 storm that contributed to power outages for millions of electricity customers in the Eastern half of the United States—recommends completion of cold weather reliability standard revisions stemming from 2021's Winter Storm Uri and improvements to reliability for the U.S. natural gas infrastructure.[3] What has become clear is that the natural-gas-electric system has now become fully interconnected, each requiring the other to remain reliable (i.e., impacts on one system can impact the other). These considerations should drive higher levels of coordination to ensure sustained reliable operation of this interconnected system.



All other assessment areas have less than 35% natural gas fired generation contribution to winter resource mix.

Natural-Gas-Fired Generation

	Peak Winter Capacity	Contribution to Total Winter Resource Mix
MISO	67.5 GW	46%
MRO-SaskPower	2.1 GW	46%
NPCC-New England	17.3 GW	54%
NPCC-New York	24.5 GW	66%
PJM	84.9 GW	47%
SERC-Central	22.7 GW	44%
SERC-Florida Peninsula	50.6 GW	79%
SERC-Southeast	31.5 GW	51%
SPP	27.4 GW	41%
Texas RE-ERCOT	54.2 GW	62%
WECC-AB	11.4 GW	75%
WECC-CA/MX	39.9 GW	65%
WECC-NW	31.0 GW	39%
WECC-SW	18.2 GW	62%

Figure 2: Natural-Gas-Fired Generation Capacity Contributions to 2023–2024 Winter Generation Mix

Natural Gas Supply to Generators

Natural-gas-fired generation is vitally important to meeting winter electricity demand across much of North America (**Figure 2**). Furthermore, the natural gas industry relies on electricity to power some of its critical components. For instance, some compressors run on electricity while others are fueled by natural gas. This means that the natural gas industry depends on the delivery of electricity to run as intended, and as stated in many other places, the electric industry depends on the delivery of natural gas. This can exacerbate the scale of impacts when either industry is threatened.

[2] The February 2021 Cold Weather Outages in Texas and the South-Central United States | FERC, NERC and Regional Entity Staff Report | Federal Energy Regulatory Commission

[3] FERC Winter Storm Elliott Report

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Generator availability and output can be threatened when natural gas supplies are insufficient or when natural gas infrastructure is unable to maintain the flow of fuel. The BES's ability to deliver electricity was put at risk by past natural gas production declines during periods of extreme cold weather. As Winter Storm Elliott demonstrated, this is the case even in areas of North America where cold weather is common. Wide-area extreme cold events increase the likelihood of natural gas production declines and result in increased demand for natural gas by local distribution company (LDC) customers and natural-gas-fired electric generators. Wide-area events can also concurrently render multiple grid BA areas energy deficient and thus preclude an impacted BA from importing the electricity it requires to meet BA load even when transmission to support such transfers is available. Longer duration events increase the risk that the imbalances resulting from declining natural gas production and increased natural gas demand approach unsustainable levels. For areas that are pipeline constrained, high natural gas demand during extreme cold weather presents risks for generators that lack firm natural gas transportation arrangements.

Coal Transportation

While many factors that contributed to uncertain rail shipment of coal to electric generators prior to the 2022–2023 winter assessment have subsided, other transport issues could emerge for this winter. Drought conditions that impact the Missouri River and other major navigable waterways could restrict coal availability and cause units to run at a derated level to conserve coal inventory. Low water levels can also affect generators that rely on once-through cooling processes and limit the generator's capacity output.

Extreme Cold Temperatures and Demand Forecasting

Accurate load forecasting is essential for reliable operations. BAs and load-serving entities frequently update the load forecasts that serve as key inputs for long-range resource planning, seasonal outage coordination, and operational plans from day-ahead to real-time. Cold weather patterns and the temperature-correlated behavior of some end-use loads present some of the most challenging issues and complex load forecasting, adding to winter reliability risk.

Most assessment areas can experience a wide range of winter peak demand from one year to the next, largely depending upon the severity of winter conditions. Load forecasts for normal winter peak (referred to as 50/50 peak demand or net internal demand elsewhere in this report) reflect the highest expected system load for an average winter. A higher level of demand used throughout this report is the load forecast for extreme 90/10 peak demand, which generally represents the highest 10% of the winter peak demand forecast distribution.[4] Actual winter peak demand in each area is expected to be below this level most (but not all) years. Figure 3 shows these two demand levels for assessment areas where the extreme peak demand forecast is 9% or greater than the normal peak demand forecast. Year-to-year differences in winter weather conditions are key drivers of the large variation in normal and extreme demand forecasts, but changing load characteristics also contribute in many areas. ARMs, which measure resource levels above the normal 50/50 peak demand, have limited ability to identify resource adequacy risk when peak demand is highly variable from year to year.

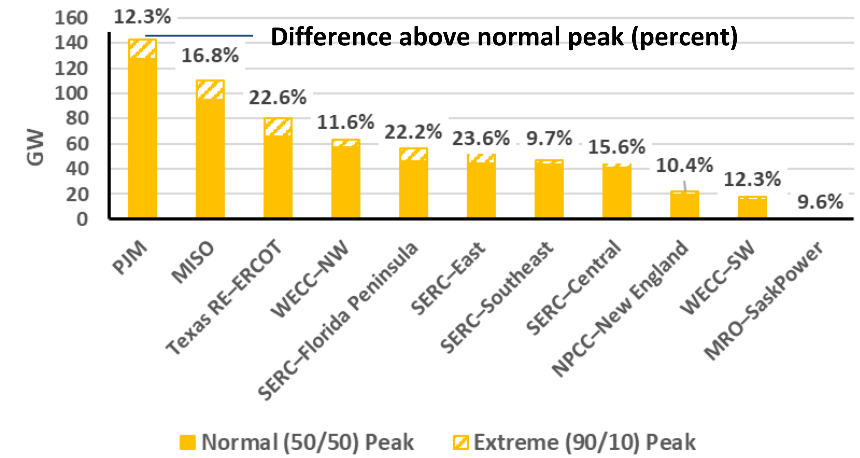

Figure 3: Normal and Extreme Peak Demand Forecasts for 2023–2024 Winter

The growing complexity in load forecasting and increasing load forecast uncertainty adds to winter reliability risks. Extreme cold temperatures and unfamiliar weather patterns characterized by strong cold fronts, wind, and precipitation can cause demand for electricity to deviate significantly from historical forecasts. Electrification of the heating sector is increasing temperature-sensitive load components while increasing levels of variable-output solar PV DERs add to load forecast uncertainty. Underestimating electricity demand prior to the arrival of cold temperatures can lead to ineffective operations planning and insufficient resources being scheduled. Generator performance and fuel issues are more likely to occur when generators are called upon with short notice, exposing BAs to potential resource shortfalls. Load serving entities and BAs should apply lessons from prior winter operating experience to operational load forecasts and pay particular attention to the risk of demand underestimation ahead of extreme cold temperatures.

[4] Anticipated Reserve Margins (ARM) are calculated from this demand level. NERC assesses winter reliability risk using this extreme 90/10 peak demand level (see the risk scenario summary for each assessment area in the Regional Assessments Dashboards section).

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Seasonal Risk Scenario Margins

Seasonal risk scenarios for each assessment area are presented in the **Regional Assessments Dashboards** section. The on-peak reserve margins and seasonal risk scenario chart in each dashboard provide potential winter 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 below the seasonal risk scenario charts; see the **Data Concepts and Assumptions** section for more information about these charts.

The seasonal risk scenario charts can be expressed in terms of reserve margins. In **Table 1**, each assessment area's ARM is 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. The typical outages reserve margin is comprised of anticipated resources less 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 ARM, 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.

Table 1: Seasonal Risk Scenario Margins

Assessment Area	Anticipated Reserve Margin	Typical Outages	Extreme Conditions
MISO	55.8%	26.5%	-5.9%
MRO-Manitoba	15.3%	13.2%	6.6%
MRO-SaskPower	20.6%	6.9%	7.7%
NPCC-Maritimes	19.7%	13.5%	-0.5%
NPCC-New England	67.2%	47.3%	6.3%
NPCC-New York	76.3%	49.9%	12.4%
NPCC-Ontario	28.2%	28.2%	20.3%
NPCC-Quebec	10.5%	6.5%	-2.2%
PJM	39.8%	26.4%	4.2%
SERC-C	30.1%	22.6%	5.2%
SERC-E	24.4%	19.6%	9.3%
SERC-FP	41.0%	37.8%	12.7%
SERC-SE	41.6%	35.7%	13.7%
SPP	38.8%	14.5%	-14.1%
TRE-ERCOT	41.2%	27.3%	-6.6%
WECC-AB	27.1%	24.3%	5.5%
WECC-BC	15.1%	15.0%	-8.6%
WECC-CA/MX	65.3%	57.4%	32.2%
WECC-NW	43.5%	37.5%	-4.1%
WECC-SW	90.4%	85.1%	43.4%

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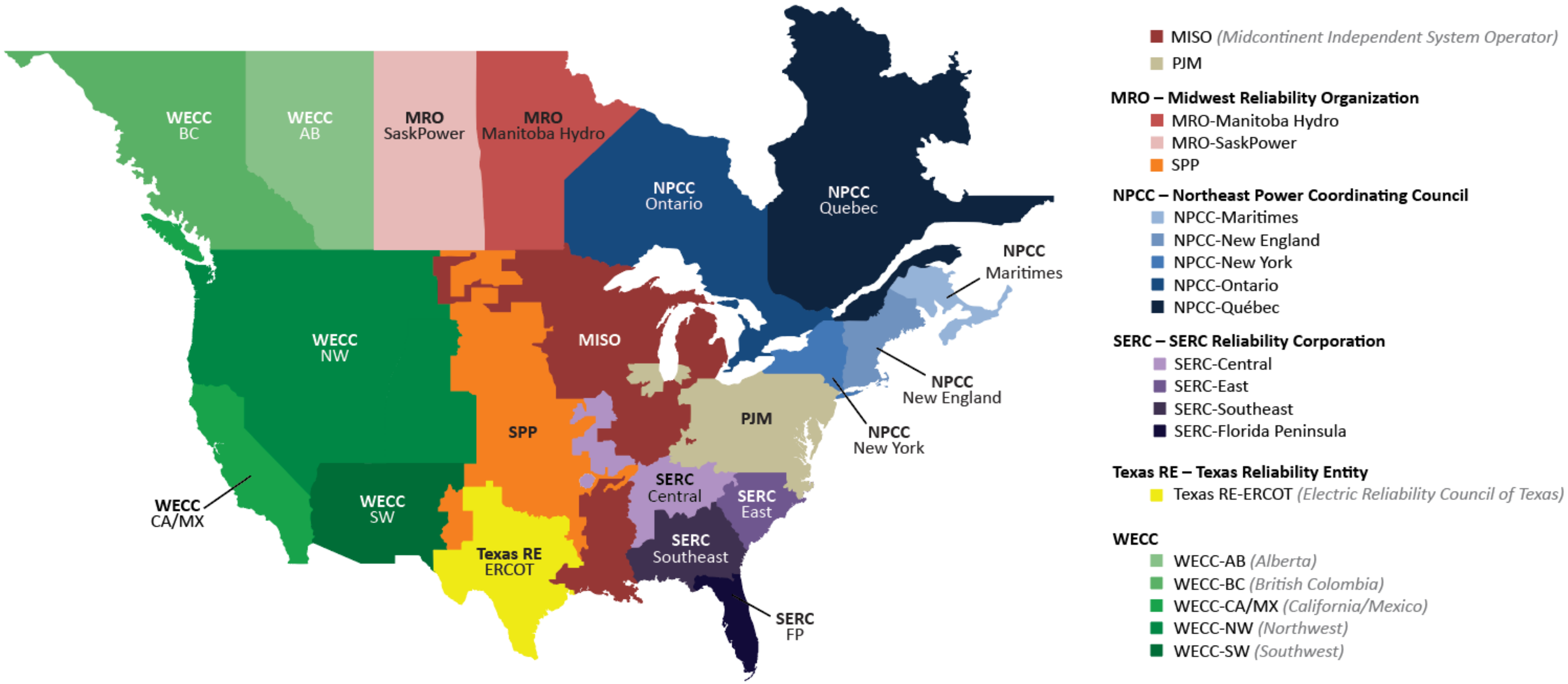
Regional Assessments Dashboards

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 ARM 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 two orange columns at the right show the two demand scenarios of the normal peak net internal demand (from the **Demand and Resource Tables**) and the extreme winter 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 WRA 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 vary by assessment area and provide further insights into the risk conditions forecasted for this upcoming winter period.



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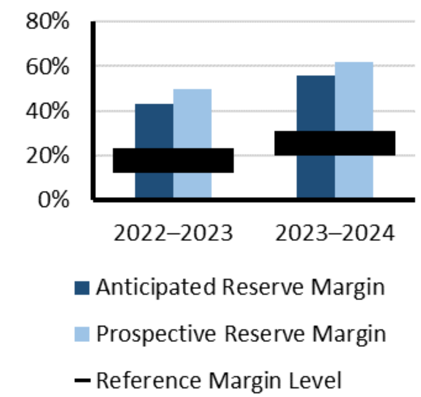
MISO

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 39 local BAs and over 500 market participants, serving approximately 45 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

- Though some risk has been identified for this upcoming winter season in a high generation outage and high winter load scenario, reliability is expected to be maintained by the use of any number of measures, including load modifying resources, non-firm energy transfers into the system, energy-only resources that do not have a must-offer requirement for the winter but may still offer into the energy markets, or internal transfers that exceed the sub-regional import/export constraint between MISO North/Central and MISO South. MISO continues to coordinate extensively with neighboring RCs and BAs to improve situational awareness and vet any needs for firm or non-firm transfers to address extreme system conditions.
- The extreme cold weather of last winter is a reminder of just how critical resource adequacy and proper planning are for all seasons of the year, not just for a systems summer peak. Acknowledging this, MISO continues to survey and coordinate with its members on winter preparedness and fuel sufficiency. In addition, MISO has filed and implemented a seasonal resource adequacy construct and seasonal unit accreditation to better affirm adequate supply in all seasons. As a result, MISO has raised Reference Margin Levels for the 2023–2024 winter season. The 2023–2024 Planning Resource Auction conducted in April 2023 was the first implemented under the seasonal construct.

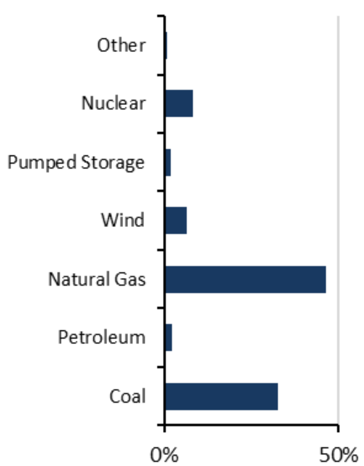
On-Peak Reserve Margin



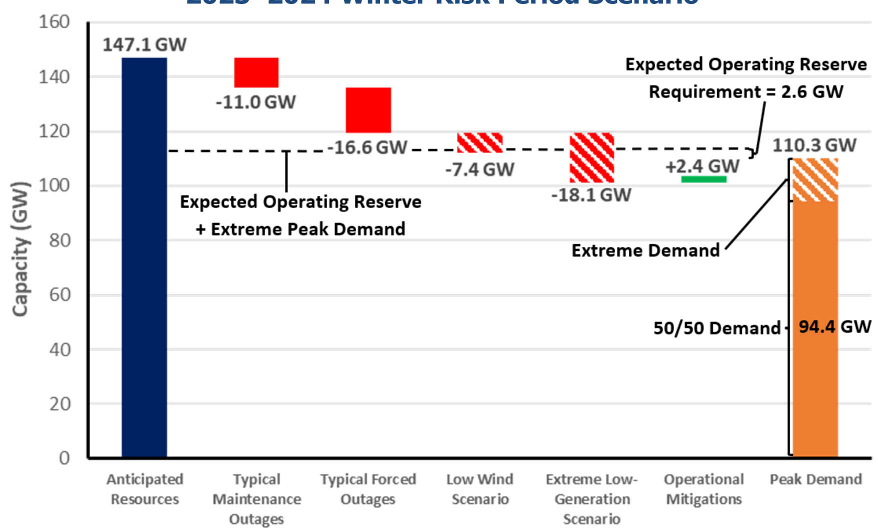
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and energy emergency alerts (EEA). Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Fuel Mix



2023–2024 Winter 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 winter average of maintenance and planned outages

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

Low Wind Scenario: Below average wind contributions

Extreme Low-Generation: Maximum historical generation outages

Operational Mitigations: A total of 2.6 GW capacity resources available during extreme operating conditions

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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 electricity customers in Manitoba and provides approximately 293,000 customers with natural gas in Southern Manitoba. The 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. MISO is the RC for Manitoba Hydro.

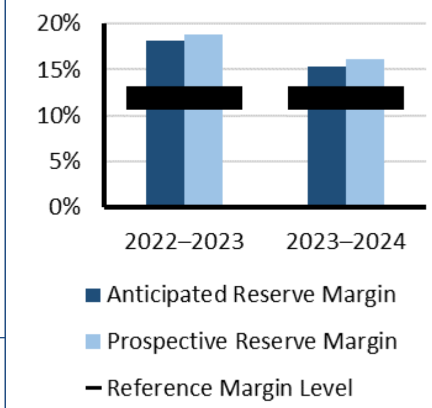
Highlights

- The ARM for winter 2023–2024 exceeds the 12% Reference Margin Level.
- No emerging reliability issues are anticipated for the upcoming winter season that are pertinent to Manitoba Hydro.
- Manitoba Hydro continues to monitor a number of issues, including extreme weather events like drought, decarbonization-driven changes to supply and demand, and asset health.
- All seven units at the Keeyask hydro station (630 MW net addition) are anticipated to be in commercial operation for winter 2023–2024.

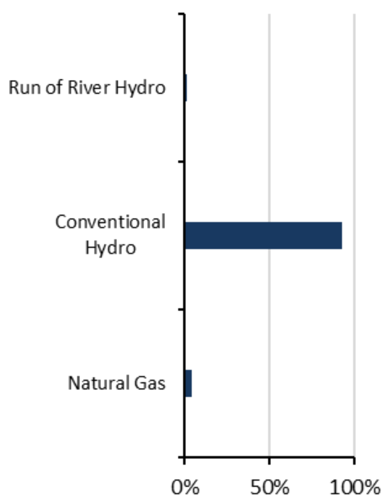
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

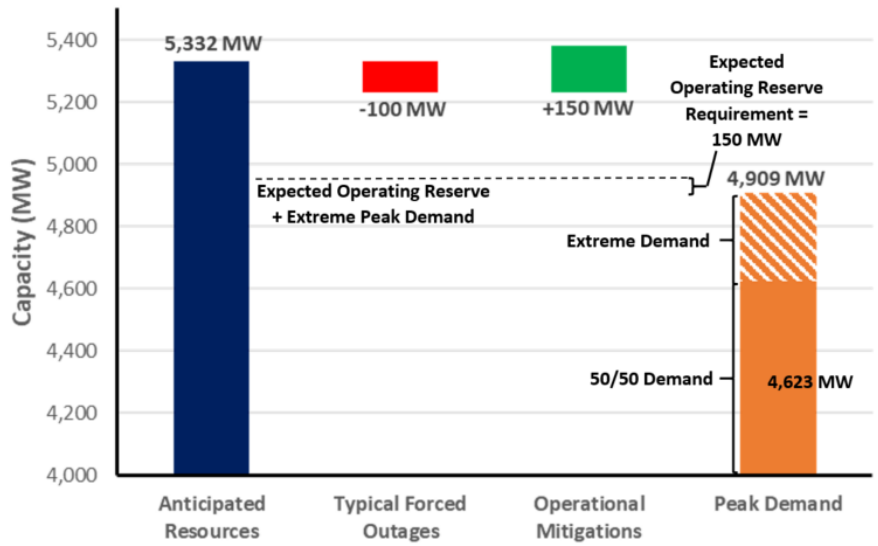
On-Peak Reserve Margin



On-Peak Fuel Mix



2023–2024 Winter 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 scales additional load experienced during all-time peak actual versus forecasted load (January 2019)

Forced Outages: Accounts for average forced outages

Operational Mitigations: Emergency Operating Procedures

Schedule MM-D1

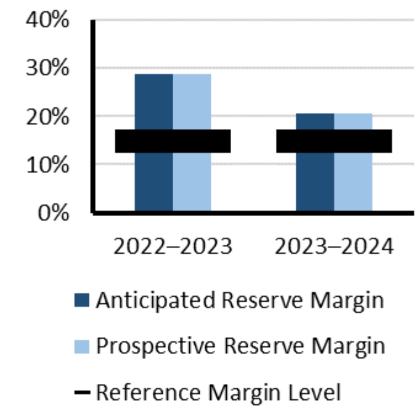
MRO-SaskPower

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 1.2 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

- Saskatchewan experiences peak load in winter because of extreme cold weather. Reserve margins have fallen this winter by about 8% when compared to the previous winter due to increased peak demand projections, the retirement of a natural gas unit (95 MW), and an increase of planned maintenance.
- The risk of operating reserve shortage or EEA during peak load times exists if a large generation forced outage occurs during peak load times combined with transmission tie-line maintenance work or generation maintenance work scheduled during winter months.
- In case of extreme winter conditions combined with large generation forced outages, SaskPower would utilize available demand response programs, short-term power transfers from neighboring utilities, maintenance rescheduling, and/or short-term load interruptions.

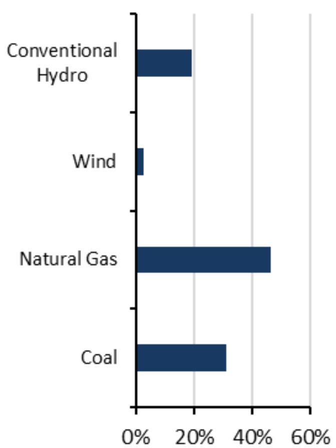
On-Peak Reserve Margin



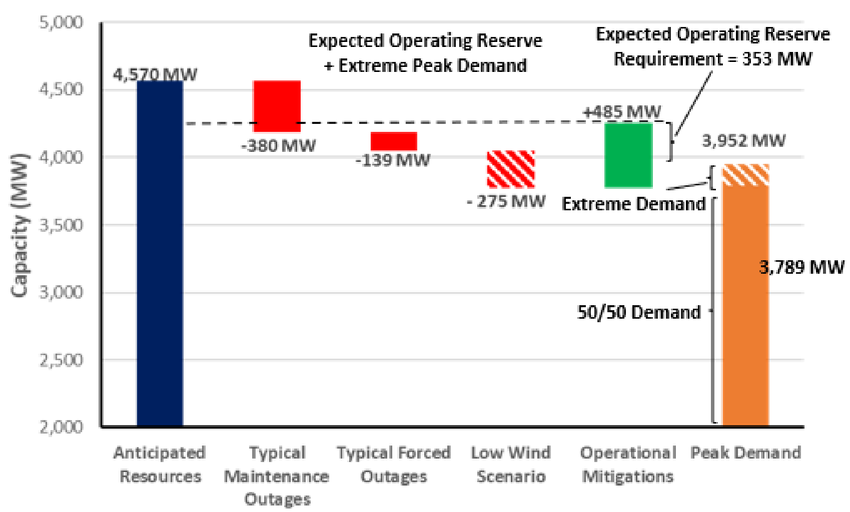
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand scenarios. Normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, appeals) and EEAs. The risk of load shedding is low.

On-Peak Fuel Mix



2023–2024 Winter 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 potential system peak load increased by average forecast error of previous five years

Maintenance Outages: Average of planned maintenance outages for the winter months, December–February, over the past three years

Forced Outages: Estimated using SaskPower forced outage model

Low Wind Scenario: Estimated using SaskPower forced outage model

Operational Mitigations: Estimated average value based on short term transfer capability from neighboring utilities (150 MW) and reserved generating units (135 MW) for the upcoming 2023–2024 winter. This also includes 200 MW in demand-side resources and non-firm loads that require 15 minutes to 2 hours of advanced notification.

Schedule MM-D1

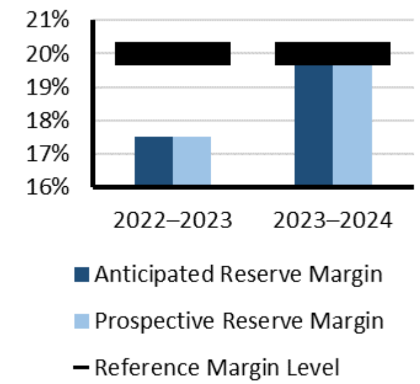
NPCC-Maritimes

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 was to occur, there are emergency operations and planning procedures in place. All of the area's declared firm capacity is expected to be operational for the winter operating period.
- The Maritimes area is a winter-peaking system.
- As part of the planning process, dual-fueled units will have sufficient supplies of heavy fuel oil on-site to enable sustained operation in the event of natural gas supply interruptions.

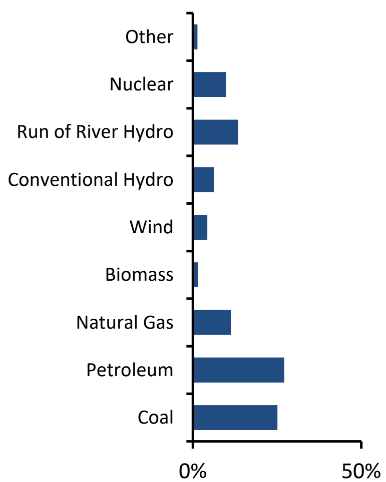
On-Peak Reserve Margin



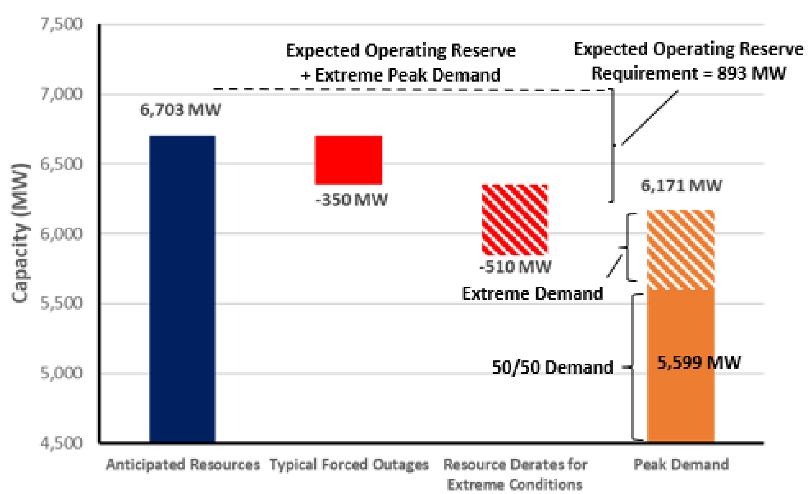
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand scenarios. Normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, appeals) and EEAs. NPCC probabilistic analysis indicates that the risk of load shedding is low. See **Probabilistic Assessment** section.

On-Peak Fuel Mix



2023–2024 Winter 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 20 years of historical data

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

Schedule MM-D1

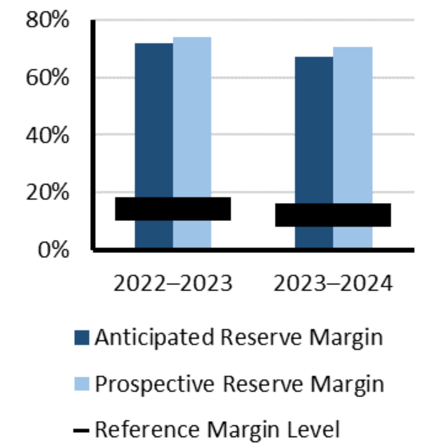
NPCC-New England

NPCC-New England is an assessment area that is served by ISO-NE, and it consists of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. ISO-NE is a regional transmission organization that is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS. The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

Highlights

- ISO-NE expects to meet its regional resource adequacy requirements this 2023–2024 winter operating period for a mild or moderate winter similar to 2021–2022 or 2017–2018. A standing concern is whether there will be sufficient energy available to satisfy electricity demand during an extended cold period given the existing resource mix, fuel delivery infrastructure, and expected fuel arrangements without considerable effort to replenish stored fuels (i.e., fuel oil and liquified natural gas).
- ISO-NE is offering an interim program to compensate certain resources that provide fuel security. The Inventoried Energy Program is a voluntary, interim program designed to provide incremental compensation for participants that maintain inventoried energy for their assets during extreme cold periods when winter energy security is most stressed.
- ISO-NE expects to have sufficient capacity resources to meet the 2023–2024 90/10 winter peak demand forecast of 21,032 MW for the weeks beginning January 7, January 14, and January 21, 2024.
- ISO-NE evaluates an above 90/10 scenario, which captures the area's coldest day in the last 25 years while using both their current and future load models. The above 90/10 winter peak demand forecast is 21,746 MW for the three previously identified peak weeks. ISO-NE currently has sufficient resources to meet this demand however if a cold snap were to occur the area may have to rely on its external ties and emergency procedures to operate reliably.

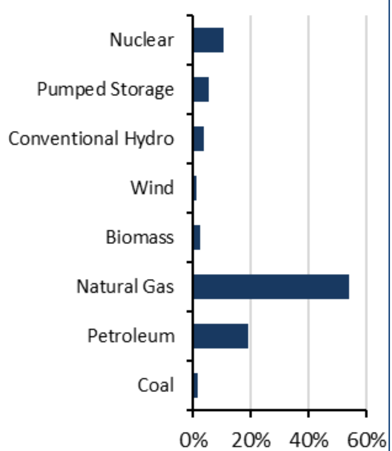
On-Peak Reserve Margin



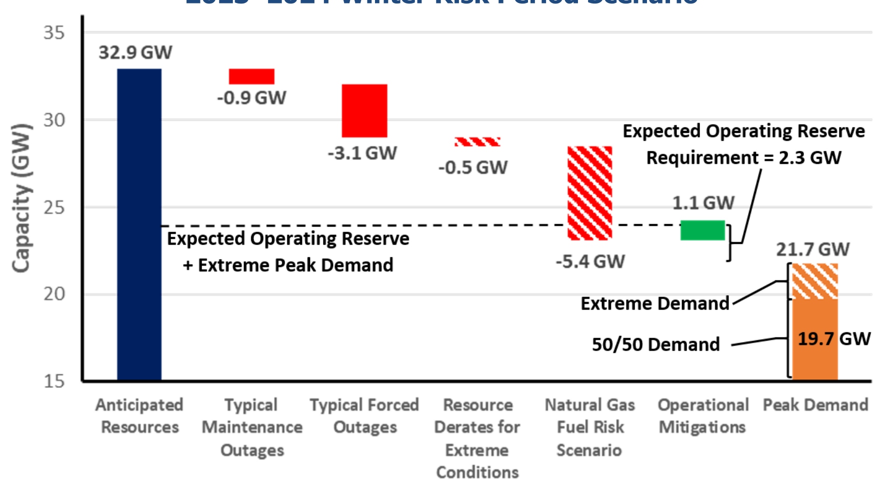
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area prolonged cold weather events. See **Probabilistic Assessment** section.

On-Peak Fuel Mix



2023–2024 Winter 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 for coldest day from the last 25 years

Maintenance and Forced Outages: Based on weekly averages

Extreme Derates and Natural Gas Scenario: Represent a case that is beyond the (90/10) conditions based on historical observation of force outages and additional reductions for generation at risk due to natural gas supply and cold weather-related outages reported by generators

Operational Mitigations: Based on ISO-NE operating procedures

Schedule MM-D1

NPCC-New York

NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only BA within the state of New York. The BPS encompasses over 11,000 miles of transmission lines, 760 power generation units, and serves 20.2 million customers. For this WRA, the established Reference Margin Level is 15%; wind, grid-connected solar PV, and run-of-river totals were derated for this calculation. However, New York requires load-serving entities to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council. New York State Reliability Council approved the 2023–2024 IRM at 20.0%.

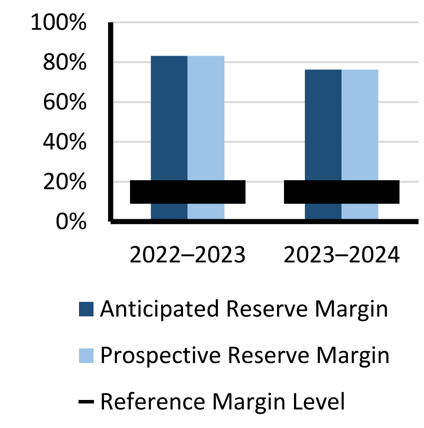
Highlights

- New York is a summer-peaking area, and no emerging reliability issues are anticipated during the 2023–2024 winter assessment period. Surplus capacity margins above the NYISO's operating reserve requirements are projected.

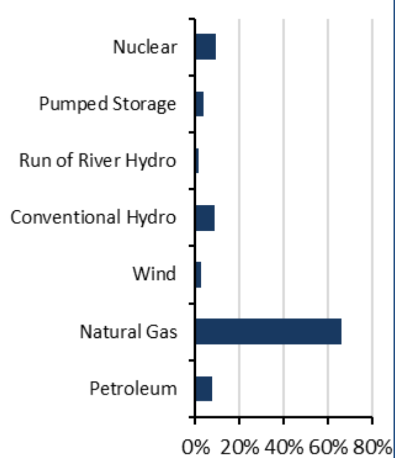
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

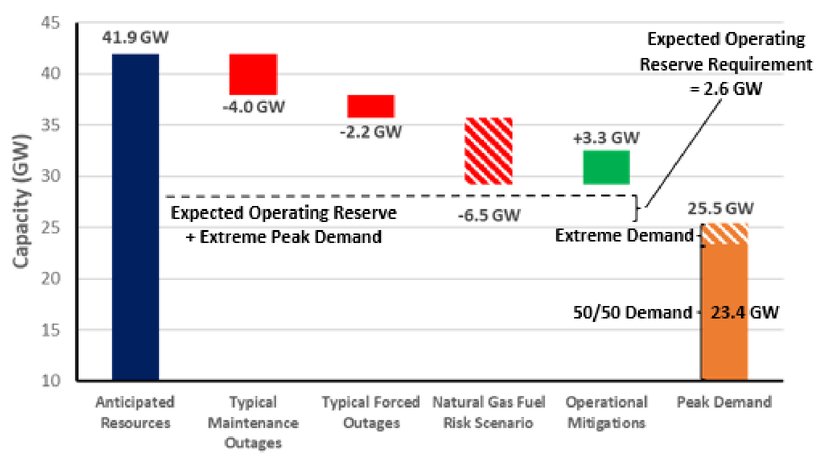
On-Peak Reserve Margin



On-Peak Fuel Mix



2023–2024 Winter 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

Maintenance Outages: Based on planned scheduled maintenance

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

Natural Gas Fuel Scenario: Potential natural gas generation at risk if non-firm supply is unavailable in a period of extended cold weather

Operational Mitigations: Based on NYISO operating procedures

Schedule MM-D1

NPCC-Ontario

NPCC-Ontario is an assessment area in the Ontario province of Canada. The Independent Electricity System Operator (IESO) is the BA for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of more than 15 million. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

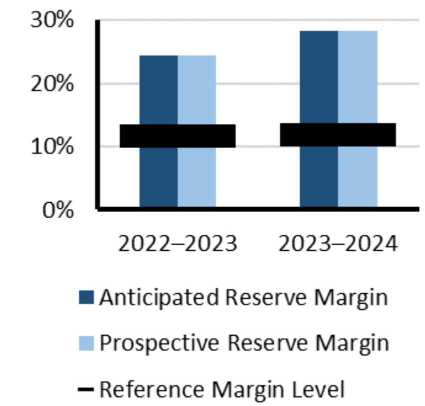
Highlights

- IESO anticipates that it will maintain reliability on its system through the winter of 2023–2024.
- Reference margins are forecast to remain at adequate levels in both normal and extreme weather scenarios.
- Ontario regularly experiences extreme cold weather; its generation fleet, transmission system, and fuel delivery infrastructure are well prepared for and adapted to such conditions.
- Unit 3 at the Darlington Nuclear Generating Station was reconnected to the provincial grid following refurbishment in July 2023, nearly six months ahead of schedule. Bruce Nuclear Generating Station's Unit 6 was returned to service following a successful refurbishment that began in January 2020.
- The IESO's December 2022 Annual Capacity Auction secured 1,160 MW of capacity for winter 2023–2024.

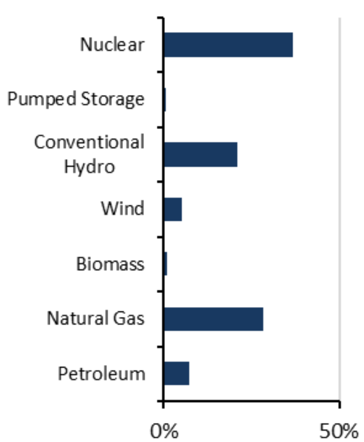
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

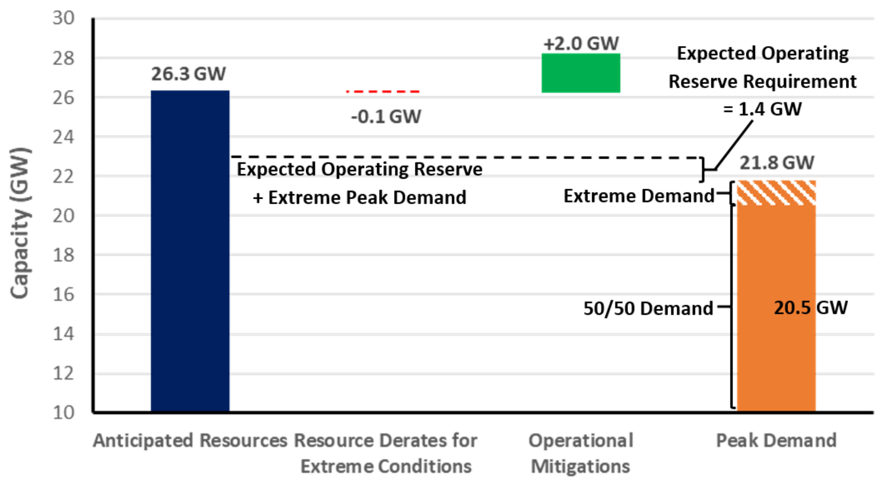
On-Peak Reserve Margin



On-Peak Fuel Mix



2023–2024 Winter 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 from 31 years of winter demand history

Extreme Derates: Generation unavailability in an extreme event using temperature derates

Operational Mitigations: Imports anticipated from neighbors during emergencies

Schedule MM-D1

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, and it has ties to Ontario, New York, New England, and the Maritimes that consist of either high voltage direct current ties, radial generation, or load to and from neighboring systems.

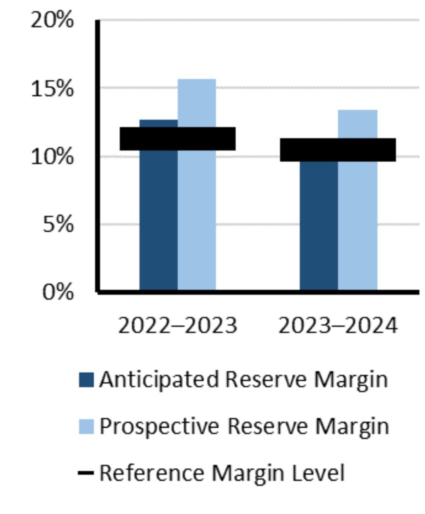
Highlights

- Québec predicts that it will maintain system resource adequacy this winter.
- Forecasted demand increase and additional firm export commitments have resulted in shrinking reserve margins.
- The Québec area is a winter-peaking system with predominately hydroelectric generation resources. Adequate capacity margins above its reference reserve requirements are projected for the 2023–2024 winter assessment period.
- No changes have been made to the assessment area's winter preparedness programs.

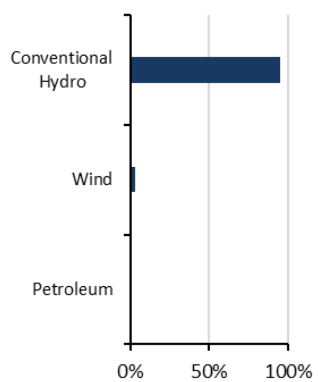
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand scenarios. Normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, appeals) and EEAs. NPCC probabilistic analysis indicates that the risk of load shedding is low. See the **Probabilistic Assessment** section.

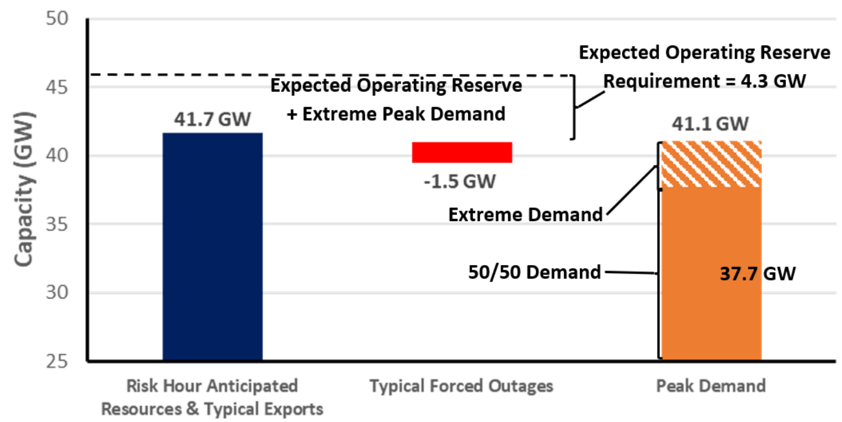
On-Peak Reserve Margin



On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at hour ending 8:00 a.m.

Demand Scenarios: Net internal demand (50/50) and (95/5) demand forecast

Forced Outages: Rare scenario of 1,500 MW in unplanned outages

Schedule MM-D1

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.

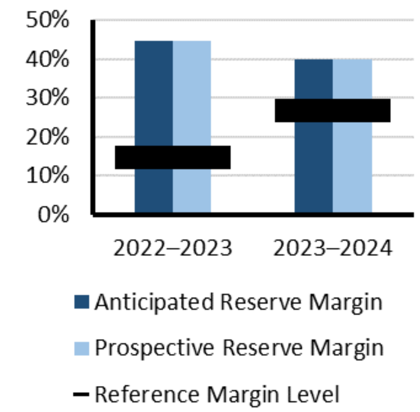
Highlights

- Installed capacity is significantly higher (13 percentage points) than PJM's Reserve Requirements. PJM does not expect to encounter resource problems for anticipated conditions over the 2023–2024 winter Peak season.
- A severe cold weather event that extends to the South can lead to energy emergencies as operators face sharp increases in generator forced outages and electricity demand. Forecasted peak demand has risen while resources have decreased since 2022 when Winter Storm Elliot caused energy emergencies in PJM and surrounding areas.

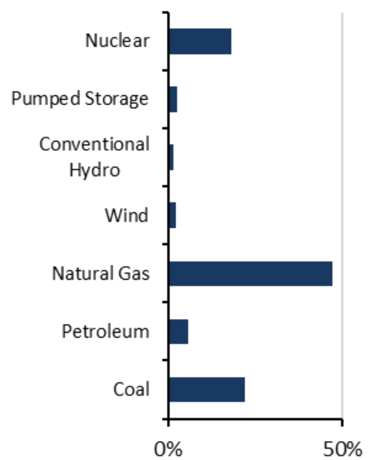
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed normal and extreme scenarios. Generator outages on a level of those experienced during Winter Storm Elliot would lead to energy emergencies.

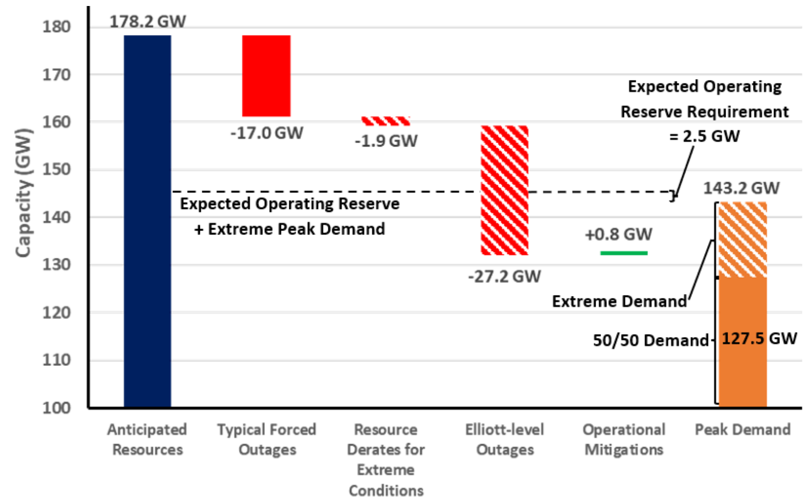
On-Peak Reserve Margin



On-Peak Fuel Mix



2023–2024 Winter 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

Elliott-level Outages: Additional forced outages equal to the total MW capacity on outage due to freezing and fuel issues during winter storm Elliott in 2022.

Operational Mitigations: A total of 0.8 GW based on operational/emergency procedures

* See PJM Report *Winter Storm Elliott Event Analysis and Recommendations Report*, July 17, 2023, available here.

Schedule MM-D1

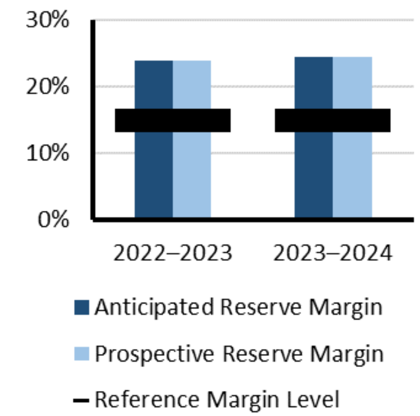
SERC-East

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 Regional Entities across North America that are responsible for the work under Federal Energy Regulatory Commission (FERC) approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central United States. The SERC Regional Entity covers approximately 630,000 square miles with a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities (PA), and 6 RCs.

Highlights

- Based on the projected non-coincident net peak demand forecast as well as existing and planned generation resources, the ARM for the SERC East assessment area is projected to exceed the 15% NERC Reference Reserve Margin.
- The entities do not anticipate any significant reliability issues because of fuel supply, inventory, or transportation.
- Many entities have extensive weatherization processes that include developed procedures specific to freezing events. The entities are prepared to respond to unanticipated operational events and coordinate with neighboring entities to promote overall system reliability.

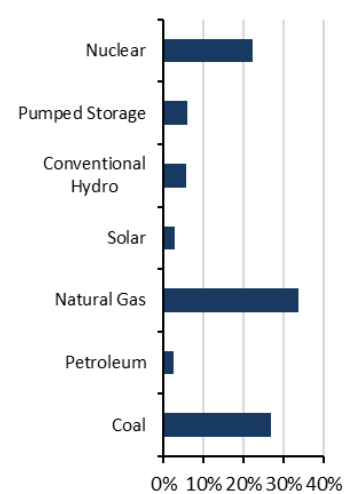
On-Peak Reserve Margin



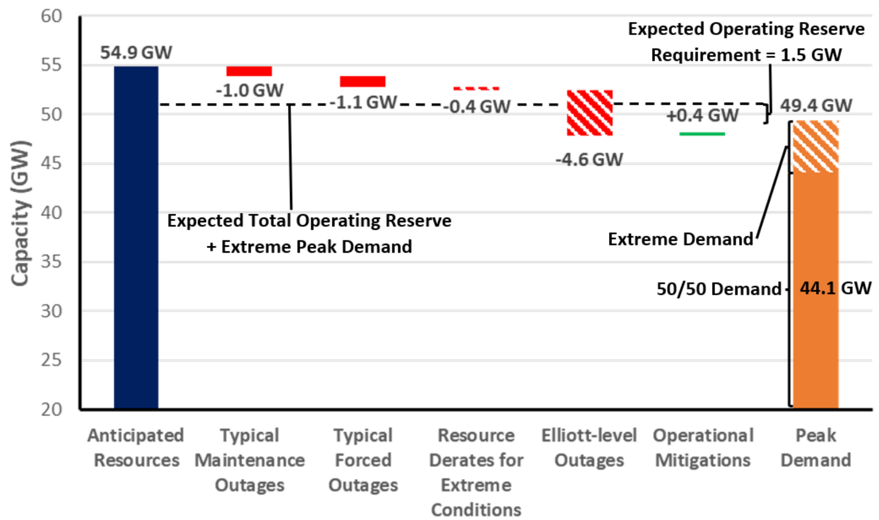
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. A severe cold weather event extending to the south could lead to energy emergencies as operators face sharp increases in generator forced outages and electricity demand. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Fuel Mix



2023–2024 Winter 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

Maintenance Outages: Data collected through a survey of members for outages during December through February

Forced Outages: Weighted average forced outage rates on-peak are factored into the anticipated resources calculation

Extreme Derates: Maximum historical generation outages (excluding 2022-2023)

Elliott-level Outages: Additional forced outages that, when added to the typical outage scenario, equal the total MW capacity on outage due to freezing and fuel issues during Winter Storm Elliott in 2022

Operational Mitigations: A total of 0.4 GW based on operational/emergency procedures

Schedule MM-D1

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 Regional Entities across North America that is 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 United States. The SERC Regional Entity area covers approximately 630,000 square miles with a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities (PA), and 6 RCs.

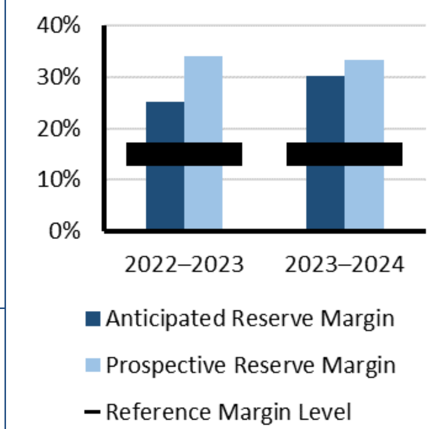
Highlights

- Based on the projected non-coincident net peak demand forecast as well as existing and planned generation resources, the ARM for the SERC-Central assessment area is projected to exceed the 15% NERC Reference Reserve Margin.
- While short-term issues (e.g., forced outages, colder than normal temperatures, or supply issues) around neighboring systems or natural gas pipelines are possibilities, the SERC-Central assessment area expects to maintain real-time operating reserves at all times. Therefore, SERC-Central does not anticipate any significant reliability issues because of fuel supply, inventory, or transportation.
- SERC-Central has extensive weatherization processes that include developed procedures specific to freezing events. SERC-Central is prepared to respond to unanticipated operational events and coordinate with neighboring entities to promote overall system reliability.

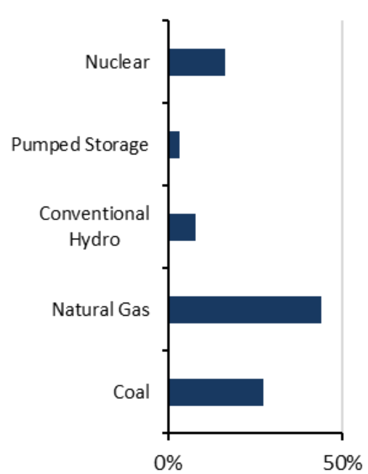
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios. A severe cold weather event that extends to the South could lead to energy emergencies as operators face sharp increases in generator forced outages and electricity demand. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

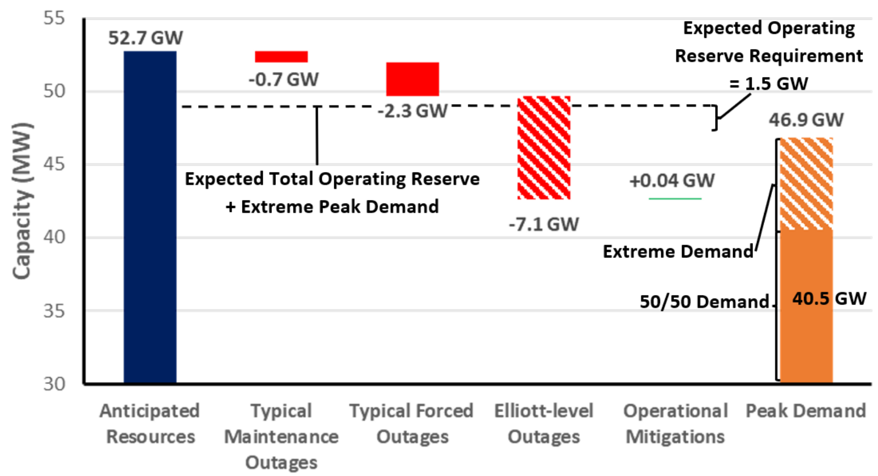
On-Peak Reserve Margin



On-Peak Fuel Mix



2023–2024 Winter 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: Data collected through a survey of members for outages during December through February

Forced Outages: Includes any weighted average forced outage rates on-peak that are not factored into the anticipated resources calculation

Elliott-level Outages: Additional forced outages that, when added to the typical outage scenario, equal the total MW capacity on outage due to freezing and fuel issues during Winter Storm Elliott in 2022

Operational Mitigations: A total of 0.04 GW based on operational/emergency procedures

Schedule MM-D1

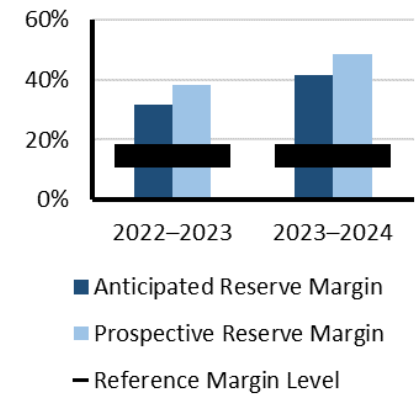
SERC-Southeast

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 Regional Entities across North America that is 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 United States. The SERC Regional Entity covers approximately 630,000 square miles with a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities (PA), and 6 RCs.

Highlights

- Based on the projected non-coincident net peak demand forecast as well as existing and planned generation resources, the ARM for the SERC-Southeast assessment area is projected to exceed the 15% NERC Reference Reserve Margin.
- The entities do not anticipate any significant reliability issues because of fuel supply, inventory, or transportation.
- Many entities have extensive weatherization processes that include developed procedures specific to freezing events. The entities are prepared to respond to unexpected, day-to-day events and coordinate with neighboring entities to promote overall system reliability.

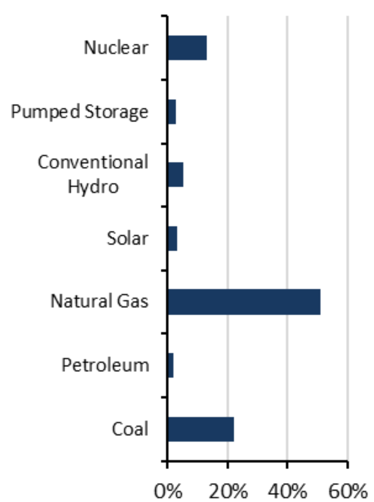
On-Peak Reserve Margin



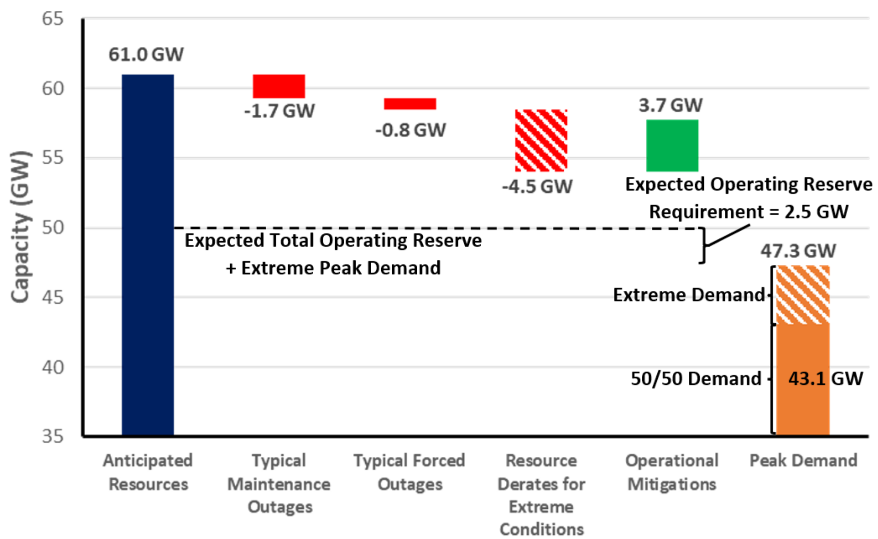
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2023–2024 Winter 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: Data collected through a survey of members for outages during December through February

Forced Outages: Weighted average forced outage rates on-peak are factored into the anticipated resources calculation

Extreme Derates: Maximum historical generation outages

Operational Mitigations: A total of 3.7 GW based on operational/emergency procedures

Schedule MM-D1

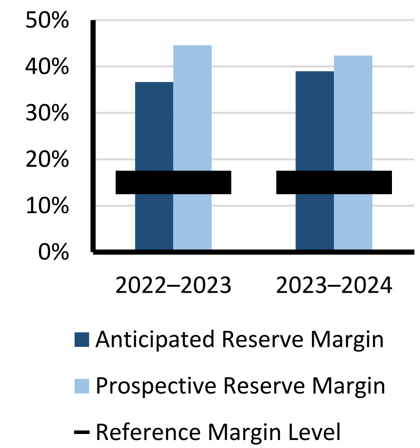
SERC-Florida Peninsula

SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six Regional Entities across North America that is 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 United States. The SERC Regional Entity area covers approximately 630,000 square miles with a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities (PA), and 6 RCs.

Highlights

- Based on the projected non-coincident net peak demand forecast as well as existing and planned generation resources, the ARM for the SERC Florida-Peninsula assessment area is projected to exceed the 15% NERC Reference Reserve Margin.
- Although the entities do not currently anticipate reliability impacts in the upcoming winter season, some entities have expressed concerns about the difficulty of scheduling and receiving coal deliveries on a consistent basis, which would affect unit availability.
- The entities have performed a summary review of their winterization plans as well as the coordination of generation and transmission outages through the Florida Reliability Coordinating Council (FRCC) Operations PC and RC functions.

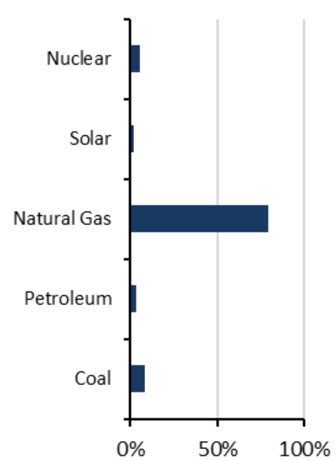
On-Peak Reserve Margin



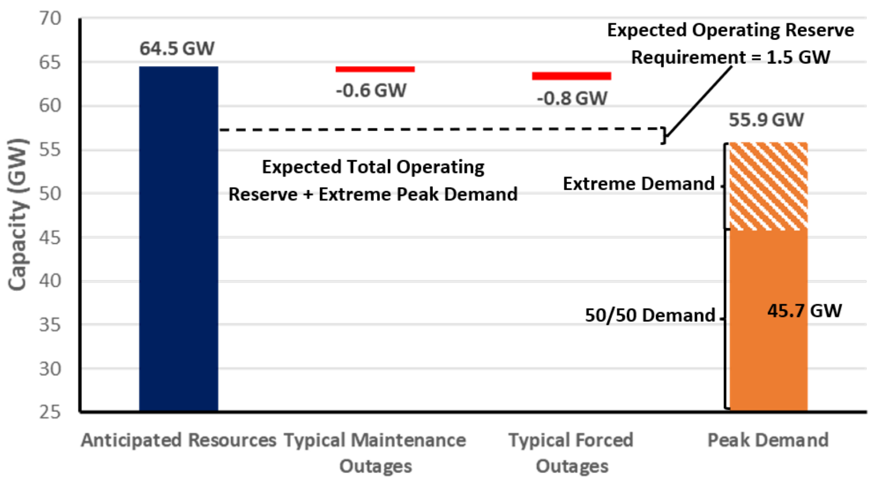
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2023–2024 Winter 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: Data collected through a survey of members for outages during December through February

Forced Outages: Weighted average forced outage rates on-peak are factored into the anticipated resources calculation

Schedule MM-D1

SPP

SPP PC 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 Midwest Reliability Organization 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 serves a population of more than 18 million.

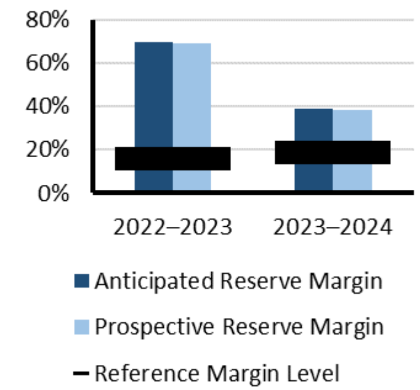
Highlights

- SPP anticipates that planning reserves are adequate for the upcoming winter season. Reserve margins have fallen this winter because of increased peak demand projections and declining anticipated resources.
- SPP does not anticipate any emerging reliability issues impacting the area for the 2023–2024 winter season but realizes that interruptions to fuel supply could create unique operation challenges.
- SPP continues to work with neighboring areas to address potential electricity deliverability issues associated with extreme weather events. Efforts are aimed at enhancing communications and operator preparedness.
- To minimize conservative operations, EEAs, and the response to mid-range forecast error uncertainty in wind forecasts, SPP created some new mitigation processes to deal with high-impact areas of concern. SPP has developed operational mitigation teams, processes, and procedures that have been put in place to maintain real-time reliability needs.
- SPP created a Resource and Energy Adequacy Leadership Team that is addressing numerous resource adequacy initiatives that are addressing an expected unserved energy (EUE) standard, fuel assurance, winter requirements, winter PRM, outage policies, demand response, accreditation, and other areas of impact.
- SPP hosted its winter preparedness workshop in October 2023.

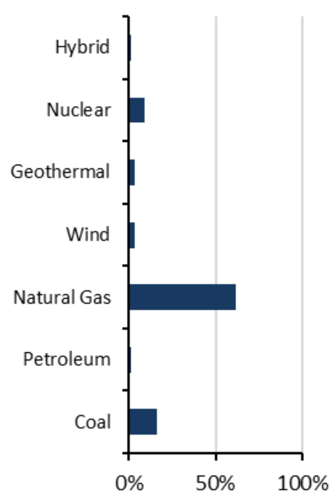
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

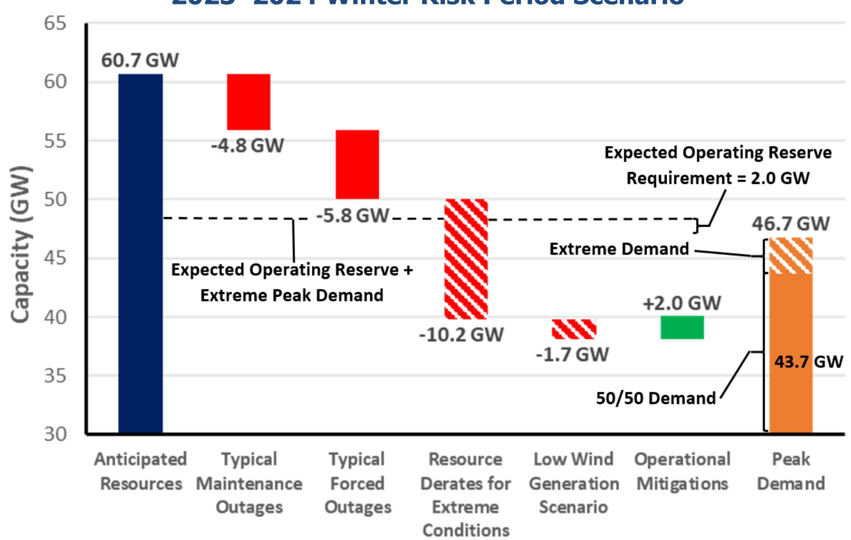
On-Peak Reserve Margin



On-Peak Fuel Mix



2023–2024 Winter 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 using historical data

Maintenance and Forced Outages: A capacity derate for maintenance outages, forced outages, and performance in extreme weather based on historical data

Extreme Derates: A capacity derate for generator performance in extreme weather based on historical data

Low Wind Scenario: 1.7 GW of wind potentially off-line when temperatures fall below their cold weather performance packages

Operational Mitigations: A total of 2 GW based on operational/emergency procedures (External Assistance)

Schedule MM-D1

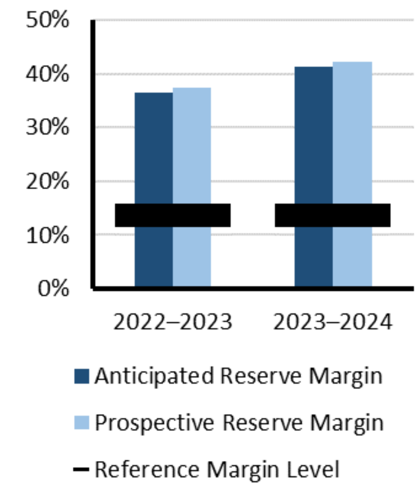
Texas RE-ERCOT

ERCOT is the 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 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 power grid.

Highlights

- For the upcoming winter season, Texas RE-ERCOT will face reserve shortage risks during high net load hours. In winter, solar generation is not available to serve peak demand, making the system dependent on wind generation and dispatchable resource availability to serve load.
- Reserve scarcity risks are greater than last winter due primarily to robust load growth along with insufficient new dispatchable resources to serve the higher net peak loads.
- The area has also experienced a large increase in thermal units planned to be indefinitely mothballed to operate under a summer-only availability schedule; a loss of 1,283 MW of winter-rated capacity is expected.
- The risk of reserve shortages leading to EEA declarations has increased from “low” to “elevated” for hour-ending 8:00 a.m. based on ERCOT’s probabilistic risk assessment. ERCOT is investigating the option to procure additional capacity to reduce this reserve shortage risk on a competitive basis.
- ERCOT does not expect any significant fuel supply issues for the winter. However, fuel-related outages during Winter Storm Elliott (December 22–25, 2023) indicated that natural gas-fired generators that normally experience fuel restrictions during cold weather are expected to continue to face such restrictions. ERCOT’s new Firm Fuel Supply Service was deployed during this storm and is expected to partially offset the lost generation capacity due to these natural gas restrictions.
- ERCOT has observed increasing transmission congestion from South Texas to South-Central Texas (including the San Antonio area) that will limit transfers during the winter. A transmission project that includes a new 345 kV double circuit transmission line was recommended with an expected in-service date of June 2027 to address this congestion.

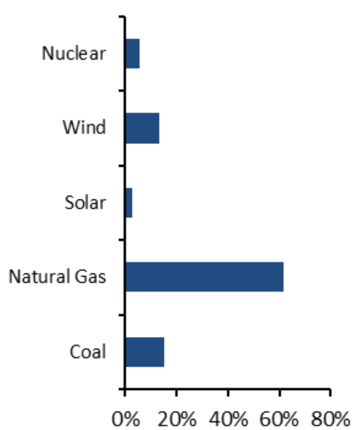
On-Peak Reserve Margin



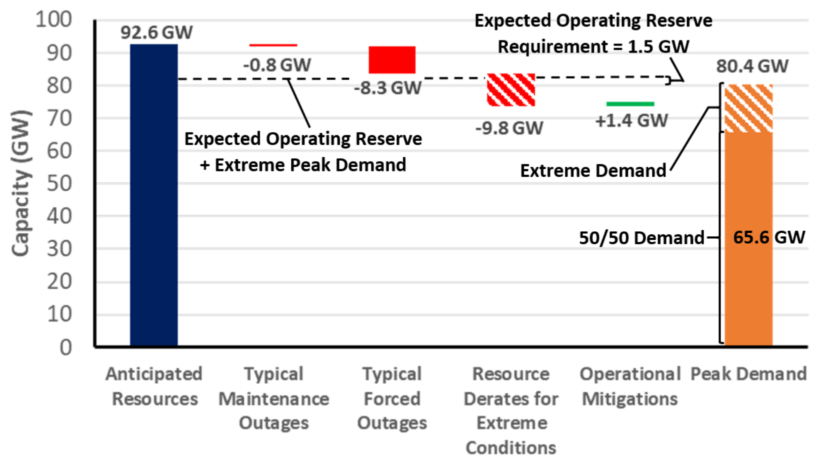
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Fuel Mix



2023–2024 Winter 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 winter peak demand based on 2020–2021 Winter Storm Uri peak demand

Maintenance Outages: Based on historical winter data and consideration of ERCOT’s allowed maximum system daily planned outage capacity

Forced Outages: Based on the historical averages of maintenance or forced outages respectively for December through February weekdays, hours ending 7:00–10:00 a.m. local time for the last three (2020/2021, 2021/2022, and 2022/2023) winter seasons (Winter Storm Uri-related forced outages between February 15–18, 2021, were excluded from this calculation.)

Extreme Derates: Accounts for reduced thermal, wind, and solar PV capacity contributions due to performance in extreme conditions (uses averages from Winter Storm URI with adjustments to account for implemented weatherization improvements)

Operational Mitigations: Additional potential capacity from switchable generation and imports

Schedule MM-D1

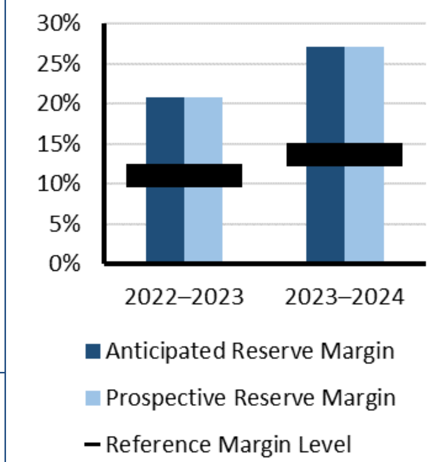
WECC-Alberta

WECC-Alberta is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of Alberta, Canada. WECC is responsible for coordinating and promoting BES reliability across the entire Western Interconnection. WECC is geographically the largest and most diverse Regional Entity serving an area of nearly 1.8 million square miles and more than 82 million customers. The WECC Regional Entity area includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of 14 western U.S. states in between. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES.

Highlights

- WECC-Alberta shows some risk highlighted by the risk period scenario; however, the area is expected to be able to be covered through imports if not islanded.
- WECC- Alberta's operating reserve margins are met before imports in all scenarios except the Low Wind Scenario, which leaves a gap of 0.5 GW, and the Extreme Combined Scenario, which leaves a gap of 1.0 GW under extreme peak demand conditions. Both of these scenarios are anticipated to be able to be covered through imports. WECC-Alberta is a winter-peaking area and did see a few EEA-3s last season due to a combination of extreme demand peaks from cold temperatures, low wind, and the loss of a baseload unit.

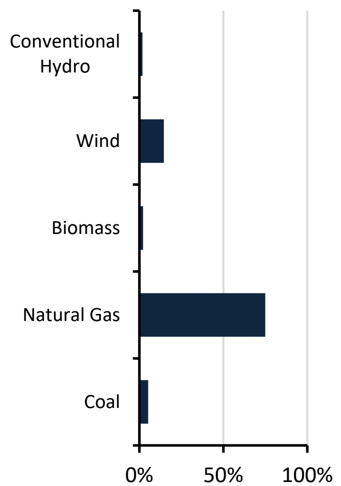
On-Peak Reserve Margin



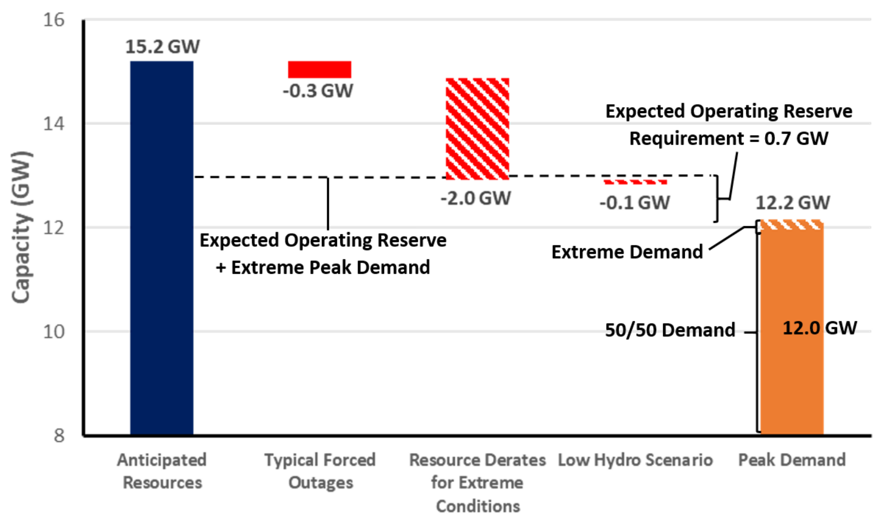
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Fuel Mix



2023–2024 Winter 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: Calculated using (90/10) scenario

Extreme Derates: Resources derates based on (90/10) scenario

Low Hydro Scenario: Estimated derate for lower hydro output

Schedule MM-D1

WECC-British Columbia

WECC-British Columbia is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of British Columbia, Canada. WECC is responsible for coordinating and promoting BES reliability across the entire Western Interconnection. WECC is geographically the largest and most diverse Regional Entity serving an area of nearly 1.8 million square miles and more than 82 million customers. The WECC Regional Entity area includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of 14 western US states in between. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES.

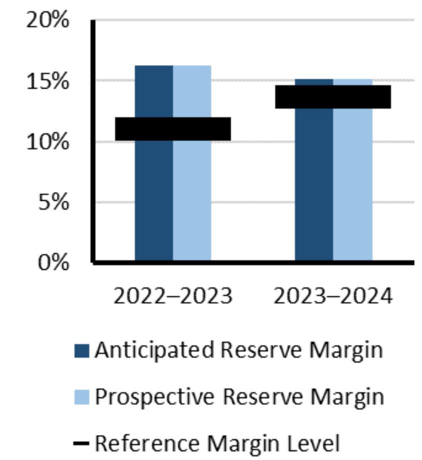
Highlights

- WECC-British Columbia has adequate resources for anticipated winter conditions. If peak demand exceeds normal forecasts or hydroelectric generation is lower than normal, non-firm imports may be needed to meet required operating reserves.
- WECC-British Columbia could require a range of import levels for extreme demand or low-resource scenarios. For expected demand, the area falls short of its operating reserve requirements if hydro output is abnormally low (low likelihood scenario). During the Extreme Peak Demand Scenario (90th percentile), operating reserve margins fall short by 0.6 GW with anticipated resources and could increase for more extreme outages or low-hydro scenarios. Sufficient imports from neighbors in the Western Interconnection are expected to be available, provided that BC does not become electrically islanded.

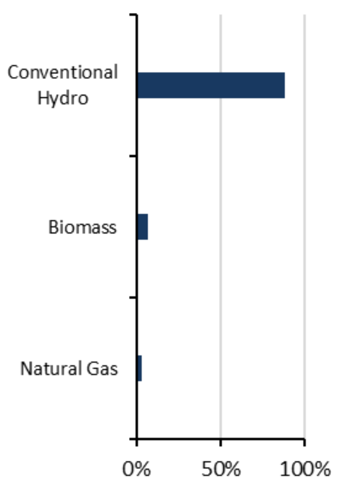
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

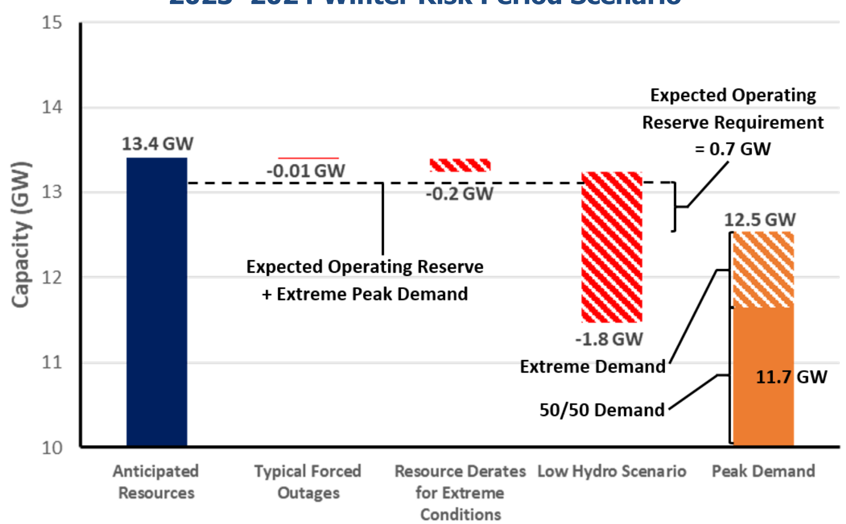
On-Peak Reserve Margin



On-Peak Fuel Mix



2023–2024 Winter 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: Calculated using (90/10) scenario

Extreme Derates: Resources derates based on (90/10) scenario

Low Hydro Scenario: Estimated derate for lower hydro output

Schedule MM-D1

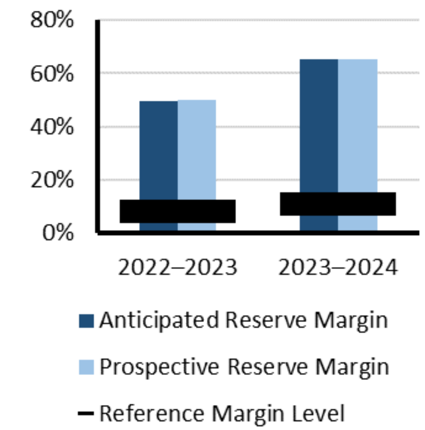
WECC-California/Mexico

WECC-Californica/Mexico 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 across the entire Western Interconnection. WECC is geographically the largest and most diverse Regional Entity serving an area of nearly 1.8 million square miles and more than 82 million customers. The WECC Regional Entity area includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of 14 western US states in between. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES.

Highlights

- WECC-Californica/Mexico shows adequate energy availability under both expected and extreme scenarios.

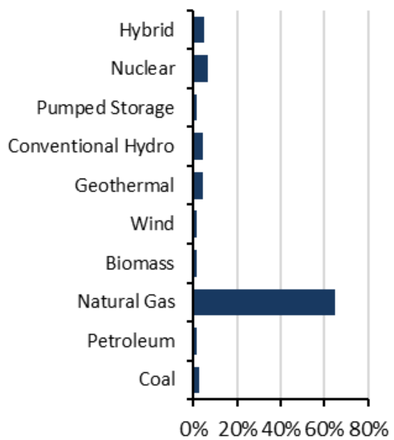
On-Peak Reserve Margin



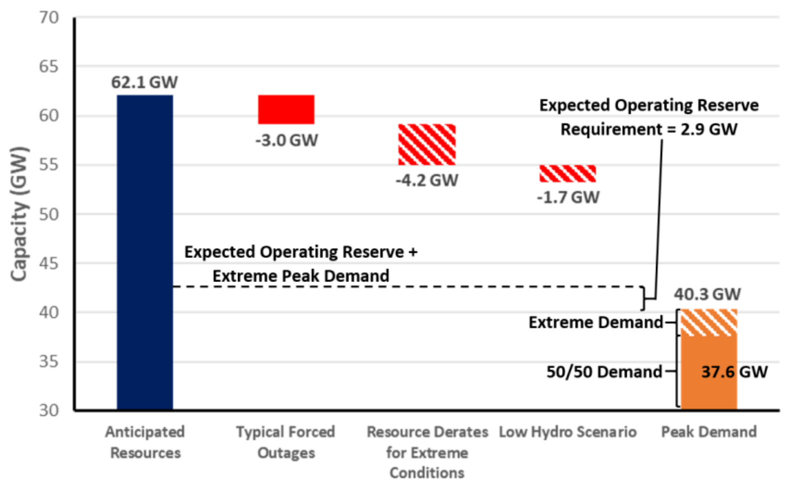
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

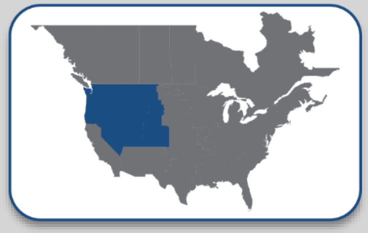
Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Calculated using (90/10) scenario

Extreme Derates: Resources derates based on (90/10) scenario

Low Hydro Scenario: Estimated derate for lower hydro output

Schedule MM-D1



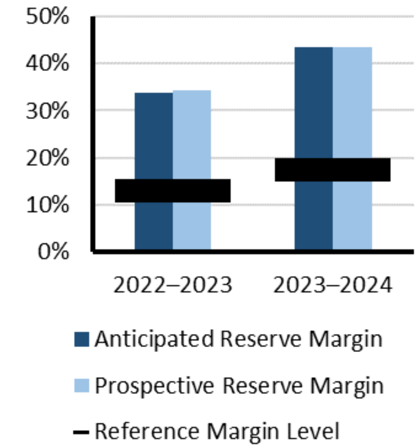
WECC-Northwest

WECC-Northwest is a summer-peaking assessment area in the WECC Regional Entity that includes Colorado, Idaho, Montana, Oregon, Utah, Washington, Wyoming and parts of California, Nebraska, Nevada, and South Dakota. WECC is responsible for coordinating and promoting BES reliability across the entire Western Interconnection. WECC is geographically the largest and most diverse Regional Entity serving an area of nearly 1.8 million square miles and more than 82 million customers. The WECC Regional Entity area includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of 14 western US states in between. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES.

Highlights

- WECC-Northwest shows some risk highlighted by the risk period scenario; however, the area is expected to be able to be covered through imports.
- WECC-Northwest has historically been a mixed-season peaking area. Operating reserve margins are met at the expected peak demand hour under all but the Extreme Combined Scenario, where 5.3 GW of imports would be needed to meet operating reserve margins at an expected peak demand (50th percentile) and 10 GW for an extreme peak load level (90th percentile). Depending on the situation in neighboring areas, imports are expected to be available to fill the gap.

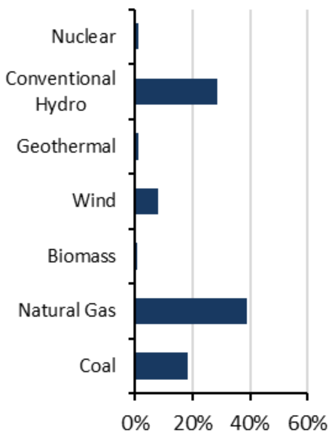
On-Peak Reserve Margin



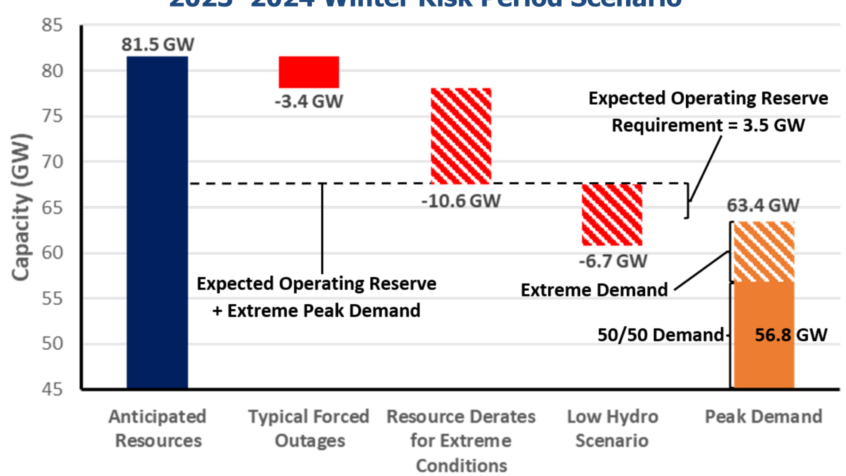
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Fuel Mix



2023–2024 Winter 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: Calculated using (90/10) scenario

Extreme Derates: Resources derates based on (90/10) scenario

Low Hydro Scenario: Estimated derate for lower hydro output

Schedule MM-D1

WECC-Southwest

WECC-Southwest is a summer-peaking assessment area in the WECC Regional Entity that includes Arizona, New Mexico, and part of California and Texas. WECC is responsible for coordinating and promoting BES reliability across the entire Western Interconnection. WECC is geographically the largest and most diverse Regional Entity serving an area of nearly 1.8 million square miles and more than 82 million customers. The WECC Regional Entity area includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of 14 western US states in between. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES.

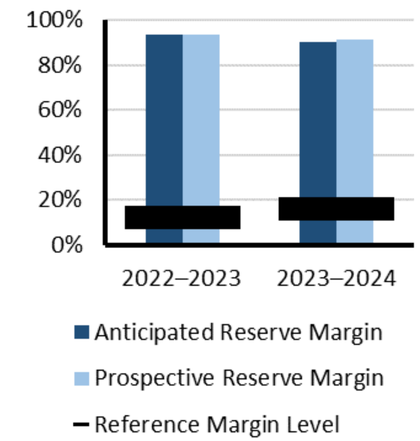
Highlights

- WECC-Southwest shows adequate energy availability under both expected and extreme scenarios.

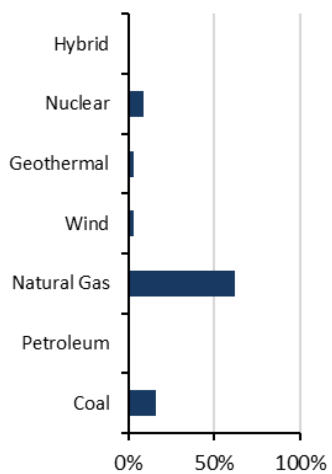
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

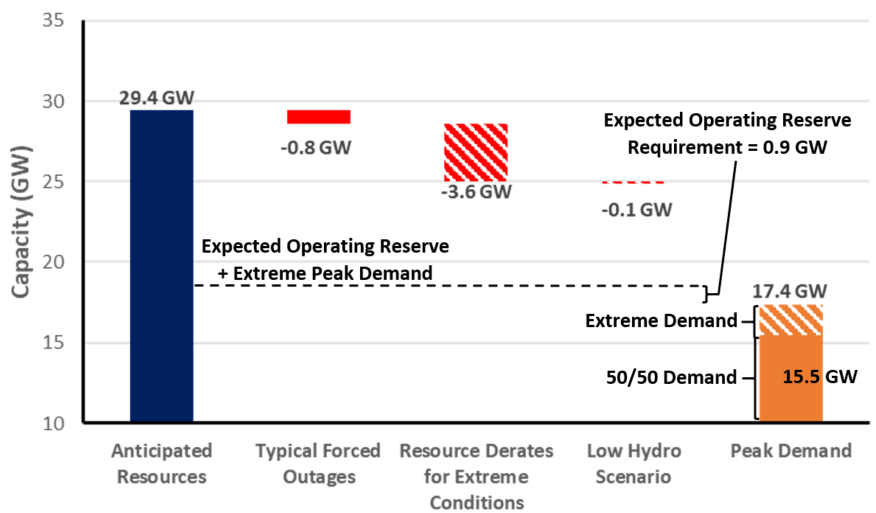
On-Peak Reserve Margin



On-Peak Fuel Mix



2023–2024 Winter 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: Calculated using (90/10) scenario

Extreme Derates: Resources derates based on (90/10) scenario

Low Hydro Scenario: Estimated derate for lower hydro output

Schedule MM-D1

Data Concepts and Assumptions

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

General Assumptions
• The reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
▪ Adequacy is the ability of the electricity system to supply the aggregate electric power and energy requirements of consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
▪ Operating reliability is the ability of the electricity 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 2023–2024 assessment period augmented by updated load and capacity data provided by Regional Entities and assessment areas.
• 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[5] or total internal demand for the summer and winter of each year.[6]
• Total internal demand projections are based on normal weather (50/50 distribution[7]) and are provided on a coincident[8] basis for most assessment areas.
• Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.
Resource Assumptions
Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. Because the electrical output of variable energy resources (e.g., wind, solar) depends on weather conditions, their contribution to reserve margins and other on-peak resource adequacy analysis is less than their nameplate capacity.

[5] *Glossary of Terms* used in NERC Reliability Standards
[6] The summer season represents June–September and the winter season represents December–February.
[7] 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.
[8] 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 and FRCC calculate total internal demand on a noncoincidental basis.

Anticipated Resources: • **Existing-Certain Capacity**: Included in this category are commercially operable generating unit or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the winter season: unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or where energy-only markets exist, unit must be a designated market resource eligible to bid into the market. • **Tier 1 Capacity Additions**: This category includes capacity that either is under construction or has received approved planning requirements. • **Net Firm Capacity Transfers (Imports minus Exports)**: This category includes transfers with firm contracts.
Prospective Resources: This 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 Reference Margin Level 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 a Reference Margin Level 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, a Reference Margin Level is established by a state, provincial authority, ISO/RTO, or other regulatory body. In some cases, the Reference Margin Level is a requirement. Reference Margin Levels may be different for the summer and winter seasons. If a Reference Margin Level 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 (from the resource adequacy data table), and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand from the resource adequacy data table and the extreme winter 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, 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 winter 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.[9] Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. NPCC-Maritimes marginally does not meet their RML for the upcoming winter. Other than NPCC-Maritimes, all assessment areas have sufficient ARMs to meet or exceed their Reference Margin Level for the 2023 winter as shown in **Figure 4**.

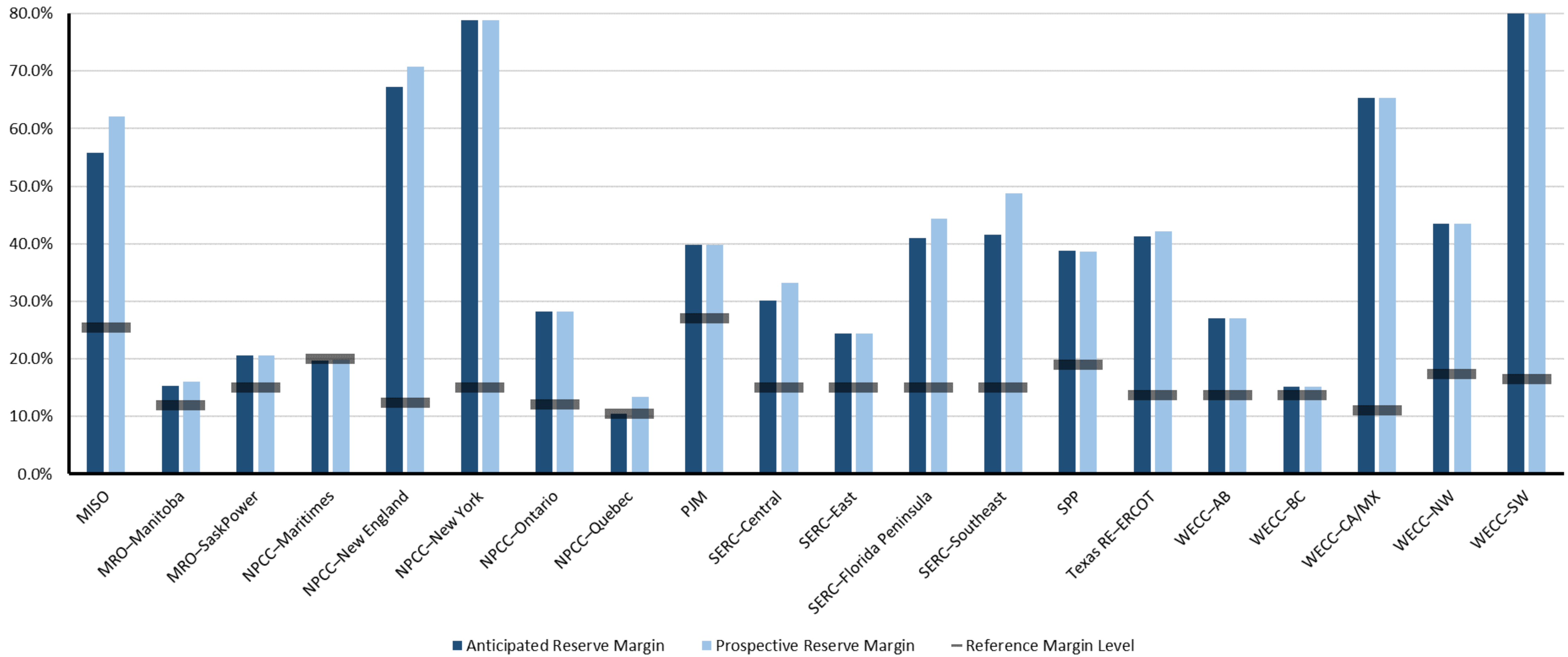


Figure 4: Winter 2023–2024 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[9] 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 Reference Margin Levels.

Changes from Year-to-Year

Figure 5 provides the relative change in the forecast Anticipated Reserve Margins (ARM) from the 2022–2023 winter to the 2023–2024 winter. Note that the Reference Margin Level is unchanged for areas that don't have a 2022–2023 Reference Margin Level shown. A significant decline can indicate potential operational issues that emerge between reporting years. MRO-Manitoba, MRO-SaskPower, NPCC-Québec, and WECC-BC have noticeable reductions in anticipated resources between the 2022–2023 winter and the 2023–2024 winter. All areas except NPCC-Maritimes remain above their Reference Margin Levels for 2023–2024 winter. NPCC-Québec is marginally above its Reference Margin Level. The lower ARMs for MRO-Manitoba, MRO-SaskPower, NPCC-Québec, and WECC-BC do not result in reliability concerns during expected conditions for this upcoming winter. The Canadian winter-peaking systems of MRO-Manitoba, MRO-SaskPower, NPCC-Maritimes and NPCC-Québec have reserve margins that are near Reference Margin Levels but are unlikely to experience high outage rates from their winterized generators. Additional details are provided in the **Data Concepts and Assumptions** section.

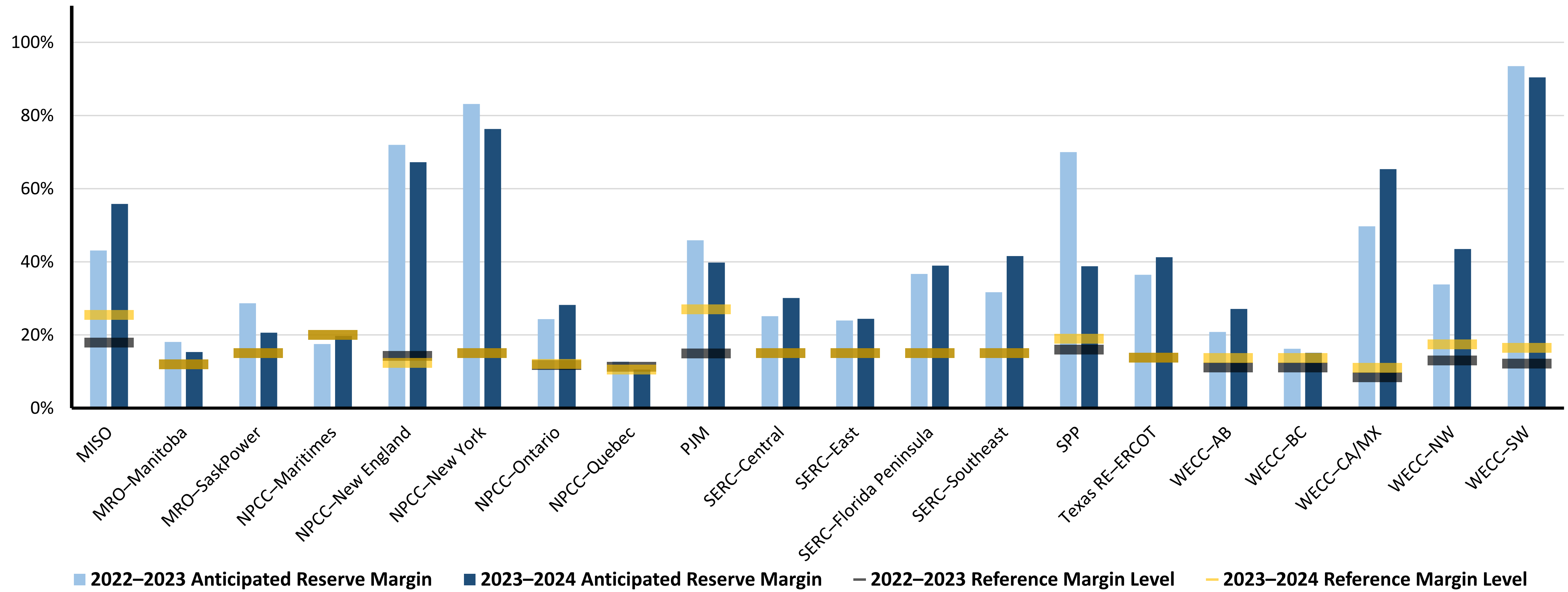


Figure 5: Winter 2022–2023 and Winter 2023–2024 Anticipated Reserve Margins Year-to-Year Change

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Net Internal Demand

The changes in forecasted Net Internal Demand for each assessment area are shown in **Figure 6**.[10] Assessment areas develop these forecasts based on historic load and weather information as well as other long-term projections. Most assessment areas are showing increasing demand for the upcoming winter compared with the last WRA.

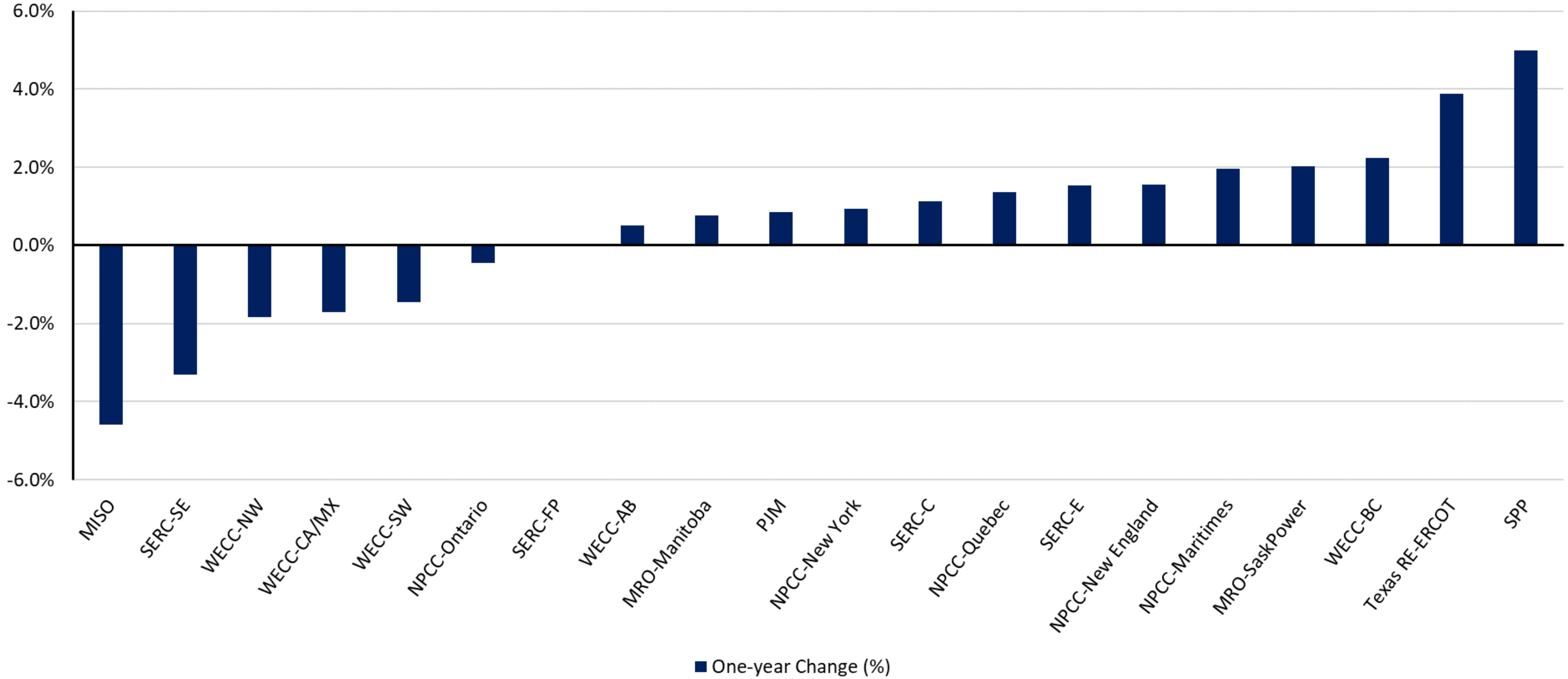

Figure 6: Change in Net Internal Demand—Winter 2022–2023 Forecast Compared to Winter 2023–2024 Forecast

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

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Demand and Resource Tables

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

MISO			
Demand, Resource, and Reserve Margins	2022–2023 WRA	2023–2024 WRA	2022–2023 vs. 2023–2024
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	102,611	102,075	0.5%
Demand Response: Available	3,672	7,681	109.2%
Net Internal Demand	98,939	94,394	-4.6%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	137,926	146,976	6.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,352	121	91.1%
Anticipated Resources	141,565	147,097	3.9%
Existing-Other Capacity	669	2,614	290.8%
Prospective Resources	148,125	153,003	3.3%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	43.1%	55.8%	12.7
Prospective Reserve Margin	49.7%	62.1%	12.4
Reference Margin Level	17.9%	25.5%	7.6

MRO-Manitoba Hydro			
Demand, Resource, and Reserve Margins	2022–2023 WRA	2023–2024 WRA	2022–2023 vs. 2023–2024
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	4,588	4,623	0.8%
Demand Response: Available	0	0	-
Net Internal Demand	4,588	4,623	0.8%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	5,705	5,864	2.8%
Tier 1 Planned Capacity	279	90	-67.8%
Net Firm Capacity Transfers	-566	-622	9.9%
Anticipated Resources	5,418	5,332	-1.6%
Existing-Other Capacity	33	36	9.5%
Prospective Resources	5,451	5,368	-1.5%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	18.1%	15.3%	-2.8
Prospective Reserve Margin	18.8%	16.1%	-2.7
Reference Margin Level	12.0%	12.0%	0.0

MRO-SaskPower			
Demand, Resource, and Reserve Margins	2022–2023 WRA	2023–2024 WRA	2022–2023 vs. 2023–2024
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	3,781	3,839	1.5%
Demand Response: Available	67	50	-25.4%
Net Internal Demand	3,714	3,789	2.0%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	4,488	4,320	-3.8%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	290	250	-13.8%
Anticipated Resources	4,778	4,570	-4.4%
Existing-Other Capacity	0	0	-
Prospective Resources	4,778	4,570	-4.4%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	28.7%	20.6%	-8.1
Prospective Reserve Margin	28.7%	20.6%	-8.1
Reference Margin Level	15.0%	15.0%	0.0

NPCC-Maritimes			
Demand, Resource, and Reserve Margins	2022–2023 WRA	2023–2024 WRA	2022–2023 vs. 2023–2024
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	5,784	5,863	1.4%
Demand Response: Available	282	264	-6.4
Net Internal Demand	5,502	5,599	1.8%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	6,461	6,622	2.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	4	81	1925.0%
Anticipated Resources	6,465	6,703	3.7%
Existing-Other Capacity	0	0	-
Prospective Resources	6,465	6,703	3.7%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	17.5%	19.7%	2.2
Prospective Reserve Margin	17.5%	19.7%	2.2
Reference Margin Level	20.0%	20.0%	0.0

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NPCC-New England			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	20,009	20,269	1.3%
Demand Response: Available	610	570	-6.6%
Net Internal Demand	19,399	19,699	1.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	32,129	31,795	-1.0%
Tier 1 Planned Capacity	162	187	15.2%
Net Firm Capacity Transfers	1,070	958	-10.5%
Anticipated Resources	33,361	32,940	-1.3%
Existing-Other Capacity	142	201	42.1%
Prospective Resources	33,769	33,641	-0.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	72.0%	67.2%	-4.8
Prospective Reserve Margin	74.1%	70.8%	-3.3
Reference Margin Level	14.3%	12.3%	-2.0

NPCC-Ontario			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	21,255	21,402	0.7%
Demand Response: Available	614	853	39.0%
Net Internal Demand	20,641	20,549	-0.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	26,051	26,301	1.0%
Tier 1 Planned Capacity	112	24	-78.6%
Net Firm Capacity Transfers	-500	17	-103.4%
Anticipated Resources	25,662	26,342	2.6%
Existing-Other Capacity	0	0	-
Prospective Resources	25,662	26,342	2.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.3%	28.2%	3.9
Prospective Reserve Margin	24.3%	28.2%	3.9
Reference Margin Level	11.8%	12.0%	0.2

NPCC-New York			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	23,893	24,220	1.4%
Demand Response: Available	695	803	15.5%
Net Internal Demand	23,198	23,417	0.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	40,393	39,697	-1.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	2,097	1,589	-24.2%
Anticipated Resources	42,490	41,285	-2.8%
Existing-Other Capacity	0	0	-
Prospective Resources	42,490	41,285	--2.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	83.2%	76.3%	-6.9
Prospective Reserve Margin	83.2%	76.3%	-6.9
Reference Margin Level	15.0%	15.0%	-4.6

NPCC-Québec			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	39,699	40,642	2.4%
Demand Response: Available	2,759	2,914	5.6%
Net Internal Demand	37,217	37,728	1.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	42,113	42,423	0.7%
Tier 1 Planned Capacity	255	0	-100.0%
Net Firm Capacity Transfers	-417	-726	74.1%
Anticipated Resources	41,951	41,697	-0.6%
Existing-Other Capacity	0	0	-
Prospective Resources	43,051	42,797	-0.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	12.7%	10.5%	-2.2
Prospective Reserve Margin	15.7%	13.4%	-2.3
Reference Margin Level	11.3%	10.5%	-0.8

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PJM			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	132,980	132,667	-0.2%
Demand Response: Available	6,583	5,189	-21.2%
Net Internal Demand	126,397	127,478	0.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	185,102	179,060	-3.3%
Tier 1 Planned Capacity	0	0	0%
Net Firm Capacity Transfers	-726	-872	20.1%
Anticipated Resources	184,376	178,188	-3.4%
Existing-Other Capacity	0	0	-
Prospective Resources	184,376	178,188	-3.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	45.9%	39.8%	-6.1
Prospective Reserve Margin	45.9%	39.8%	-6.1
Reference Margin Level	14.9%	27.0%	12.1

SERC-East			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	44,648	45,044	0.9%
Demand Response: Available	1,180	912	-22.7%
Net Internal Demand	43,468	44,132	1.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	53,287	54,229	1.8%
Tier 1 Planned Capacity	75	55	-26.6%
Net Firm Capacity Transfers	513	624	21.6%
Anticipated Resources	53,875	54,908	1.9%
Existing-Other Capacity	3	3	0.0%
Prospective Resources	53,877	54,910	1.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	23.9%	24.4%	0.5
Prospective Reserve Margin	23.9%	24.4%	0.5
Reference Margin Level	15.0%	15.0%	0.0

SERC-Central			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	41,745	42,282	1.3%
Demand Response: Available	1,671	1,753	4.9%
Net Internal Demand	40,074	40,529	1.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	51,008	50,196	-1.6%
Tier 1 Planned Capacity	0	1,386	-
Net Firm Capacity Transfers	-868	1,145	-231.9%
Anticipated Resources	50,140	52,727	5.2%
Existing-Other Capacity	3,601	1,255	-65.1%
Prospective Resources	53,741	54,002	0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.1%	30.1%	5.0
Prospective Reserve Margin	34.1%	33.2%	-0.9
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	48,582	48,470	-0.2%
Demand Response: Available	2,870	2,753	-4.1%
Net Internal Demand	45,712	45,717	0.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	61,987	62,679	0.8%
Tier 1 Planned Capacity	237	344	522.2%
Net Firm Capacity Transfers	250	509	103.6%
Anticipated Resources	62,474	63,531	3.2%
Existing-Other Capacity	3,618	1,563	-56.8%
Prospective Resources	66,092	65,094	-0.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	36.7%	39.0%	4.3
Prospective Reserve Margin	44.6%	42.4%	-0.2
Reference Margin Level	15.0%	15.0%	0.0

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SERC-Southeast			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	46,513	45,101	-3.0%
Demand Response: Available	1,954	2,018	3.3%
Net Internal Demand	44,559	43,083	-3.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	60,097	60,640	-0.8%
Tier 1 Planned Capacity	1,102	1,165	105.6%
Net Firm Capacity Transfers	-2,524	-815	-67.7%
Anticipated Resources	58,674	60,990	3.9%
Existing-Other Capacity	2,895	3,090	6.8%
Prospective Resources	61,569	64,081	4.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	31.7%	41.6%	9.9
Prospective Reserve Margin	38.2%	48.7%	10.5
Reference Margin Level	15.0%	15.0%	0.0

SPP			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	41,650	43,996	5.6%
Demand Response: Available	13	278	2006.1%
Net Internal Demand	41,637	43,718	5.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	71,131	61,173	-14.0%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-359	-498	-38.4%
Anticipated Resources	70,772	60,676	-14.3%
Existing-Other Capacity	0	0	-
Prospective Resources	70,496	60,630	-14.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	70.0%	38.8%	-31.2
Prospective Reserve Margin	69.3%	38.7%	-30.6
Reference Margin Level	16.0%	19.0%	3.0

Texas RE-ERCOT			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	66,436	70,451	6.0%
Demand Response: Available	3,302	4,868	47.4%
Net Internal Demand	63,134	65,583	3.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	85,478	92,387	8.1%
Tier 1 Planned Capacity	644	228	-64.6%
Net Firm Capacity Transfers	20	20	0.0%
Anticipated Resources	86,142	92,635	7.5%
Existing-Other Capacity	0	0	-
Prospective Resources	86,710	93,203	7.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	36.4%	41.2%	4.8
Prospective Reserve Margin	37.3%	42.1%	4.8
Reference Margin Level	13.75%	13.75%	0.0

WECC-AB			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,901	11,961	0.5%
Demand Response: Available	0	0	-
Net Internal Demand	11,901	11,961	0.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,144	13,694	4.2%
Tier 1 Planned Capacity	1,234	1511	22.5%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	14,378	15,205	5.8%
Existing-Other Capacity	0	0	-
Prospective Resources	14,378	15,205	5.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.8%	27.1%	6.3
Prospective Reserve Margin	20.8%	27.1%	6.3
Reference Margin Level	11.1%	13.7%	2.6

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WECC-BC			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,395	11,651	2.2%
Demand Response: Available	0	0	-
Net Internal Demand	11,395	11,651	2.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,223	13,166	-0.4%
Tier 1 Planned Capacity	20	134	574.4%
Net Firm Capacity Transfers	0	110	-
Anticipated Resources	13,243	13,410	1.3%
Existing-Other Capacity	0	0	-
Prospective Resources	13,243	13,410	1.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	16.2%	15.1%	-1.1
Prospective Reserve Margin	16.2%	15.1%	-1.1
Reference Margin Level	11.1%	13.7%	2.6

WECC-CA/MX			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	38,978	38,328	-1.7%
Demand Response: Available	749	755	0.9%
Net Internal Demand	38,230	37,573	-1.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	55,287	56,405	2.0%
Tier 1 Planned Capacity	1,943	5400	177.9%
Net Firm Capacity Transfers	0	315	-
Anticipated Resources	57,231	62,120	8.5%
Existing-Other Capacity	0	0	-
Prospective Resources	57,326	62,136	8.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	49.7%	65.3%	15.6
Prospective Reserve Margin	50.0%	65.4%	15.4
Reference Margin Level	8.4%	11.0%	2.6

WECC-NW			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	58,605	57,408	-2.0%
Demand Response: Available	707	578	-18.3%
Net Internal Demand	57,898	56,829	-1.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	76,477	77,389	1.2%
Tier 1 Planned Capacity	988	2188	121.4%
Net Firm Capacity Transfers	0	1,964	-
Anticipated Resources	77,465	81,541	5.3%
Existing-Other Capacity	0	0	-
Prospective Resources	77,730	81,558	4.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	33.8%	43.5%	9.7
Prospective Reserve Margin	34.3%	43.5%	9.2
Reference Margin Level	13.1%	17.4%	4.3

WECC-SW			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	16,004	15,743	-1.6%
Demand Response: Available	318	285	-10.6%
Net Internal Demand	15,686	15,458	-1.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	29,799	28,306	-5.0%
Tier 1 Planned Capacity	553	1129	104.1%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	30,352	29,435	-3.0%
Existing-Other Capacity	0	0	-
Prospective Resources	30,352	29,587	-2.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	93.5%	90.4%	-3.1
Prospective Reserve Margin	93.5%	91.4%	-2.1
Reference Margin Level	12.2%	16.4%	4.2

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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. In many areas, winter demand peaks in the early morning hours or other times of darkness, resulting in little or no electrical resource output from solar PV resources. 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.

BPS Variable Energy Resources by Assessment Area									
	Wind			Solar			Hydro		
Assessment Area / Interconnection	Nameplate Wind (MW)	Expected Wind (MW)	Expected Share of Nameplate (%)	Nameplate Solar PV (MW)	Expected Solar (MW)	Expected Share of Nameplate (%)	Nameplate Hydro (MW)	Expected Hydro (MW)	Expected Share of Nameplate (%)
MISO	26,082	9,683	37%	2,559	130	5%	4,884	4,688	96%
MRO-Manitoba Hydro	259	52	20%	0	0	0%	6,220	5,548	89%
MRO-SaskPower	615	124	20%	0	0	0%	851	797	94%
NPCC-Maritimes	1,207	261	22%	42	0	0%	1,312	1,180	90%
NPCC-New England	1,463	397	27%	107	1	1%	3,565	2,472	69%
NPCC-New York	2,720	870	32%	154	13	9%	6,731	5,067	75%
NPCC-Ontario	4,943	1,433	29%	0	0	0%	8,985	5,185	58%
NPCC-Québec	3,820	1,375	36%	-	10	-	40,307	32,974	82%
PJM	11,992	3,695	31%	0	0	0%	3,027	3,027	100%
SERC-Central	28	8	28%	774	230	30%	4,967	3,315	67%
SERC-East	0	0	0%	6,245	1,483	24%	3,064	3,013	98%
SERC-Florida Peninsula	0	0	0%	3,499	1,264	36%	-	-	0%
SERC-Southeast	0	0	0%	5,234	1,889	36%	3,288	3,288	100%
SPP	33,120	6,856	21%	351	118	34%	5,465	4,996	91%
Texas RE-ERCOT	37,974	11,910	31%	16,403	2,547	16%	563	477	85%
WECC-AB	4,931	2,221	45%	0	0	0%	894	416	47%
WECC-BC	747	111	15%	0	0	0%	16,519	10,124	61%
WECC-CA/MX	9,443	848	9%	0	0	0%	13,957	4,606	33%
WECC-SW	3,121	994	32%	2,494	103	4%	1,202	844	70%
WECC-NW	20,697	6,319	31%	0	0	0%	41,860	22,752	54%
EASTERN INTERCONNECTION	120,404	35,318	29%	26,673	7,676	29%	52,316	42,578	81%
QUÉBEC INTERCONNECTION	3,820	1,375	36%	-	10	-	40,307	32,974	82%
TEXAS INTERCONNECTION	37,974	11,910	31%	16,403	2,547	16%	563	477	85%
WECC INTERCONNECTION	38,940	10,494	27%	2,494	103	4%	74,432	38,742	52%
INTERCONNECTION TOTAL:	**201,137**	**59,098**	**29%**	**45,579**	**10,337**	**23%**	**167,618**	**114,771**	**68%**

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Probabilistic Assessment

Regional Entities and assessment areas provided a resource adequacy risk assessment that was probability-based for the winter season. Results are summarized in the table below.[11] The risk assessments account for the hour(s) of greatest risk of resource shortfall. For most areas, the hour(s) of risk coincides with the time of forecasted peak demand; however, some areas incur the greatest risk at other times based on the varying demand and resource profiles. Various risk metrics are provided and include loss of load expectation (LOLE), loss of load hours (LOLH), EUE, and the probabilities of EEA occurrence.

Probability-Based Risk Assessment		
Area	**Type of Assessment**	**Results and Insight from Assessment**
MRO-Manitoba	Verification of NERC 2022 Probabilistic Assessment (2022 ProbA)	The annual probabilistic statistics for model year 2024 for the 2022 Probabilistic Assessment (ProbA) show: • Base Case: 29 MWh per year of EUE • Risk Scenario (10th percentile water flow conditions): 477 MWh per year of EUE An expected unserved energy in the 29 to 477 MWh range is a reasonable estimate for the winter 2023–2024 based on the 2022 NERC ProbA Base Case for the year 2024 given comparable loads and resources, and that water flow conditions are, as of late summer 2023, below average but still above the 10^{th} percentile.
MRO-SaskPower	Probability-based capacity adequacy assessment	Results indicate that the expected number of hours with operating reserve deficiency for the 2023–2024 winter season is 0.31 hours. The estimated probability of having generation forced outages of 350 MW or greater in the winter season is 11.2%. A Risk of supply shortfall exists when generation forced outages at this level coincide with periods of high demand.
NPCC	NPCC conducted an all-hour probabilistic reliability assessment that consisted of a base case and severe case examining low resources, reduced imports, and higher loads. The highest peak load scenario has a 7% probability of occurring. Preliminary results are included in this table. NPCC will publish final probabilistic assessment results in December. [12]	The assessment forecasts that the NPCC Regional Entity will have an adequate supply of electricity this winter and a low risk of disconnecting load. Necessary strategies and procedures are in place to deal with operational challenges and emergencies as they may develop. Results of the probabilistic analysis by assessment area are below. The assessment evaluates the probabilistic indices of LOLE, LOLH and EUE.
NPCC-Maritimes		NPCC's assessment preliminary results indicate that operating procedures are sufficient to maintain a balance between electricity supply and demand, if needed. Only the low likelihood reduced resource case, highest peak load scenario resulted in an estimated cumulative LOLE risk of ~0.1 days/period, with associated LOLH (<1 hour/period) and EUE (10.6 MWh) over the November–March winter period. The Maritimes area low likelihood resource case assumed that wind capacity would be de-rated by half (1,200 to 600 MW) for every hour in December through February to simulate icing conditions and a 50% natural gas capacity curtailment (610 to 305 MW) to simulate a reduction in gas supply for December through February (dual fuel units assumed reverting to oil) and reduced transfer capabilities.

[11] A probabilistic assessment for the 2023-2024 winter is not available for SPP at the time of publication. SPP's 2023 Loss of Load Expectation (LOLE) Study incorporates modeling assumptions based on recent winter events. SPP expects to complete the study prior to the end of 2023. For more information see the study scope document here: **2023 LOLE Scope**

[12] Based on October 2023 revised results. The final NPCC 2023–2024 Winter Reliability Assessment be available in December 2023.

Probability-Based Risk Assessment		
Area	**Type of Assessment**	**Results and Insight from Assessment**
NPCC-New England		NPCC's assessment preliminary results indicate that operating procedures were not needed to maintain a balance between electricity supply and demand. No cumulative LOLE, LOLH or EUE risks were indicated over the November–March winter period, for all the scenarios modeled. The New England Area low likelihood resource case assumed 500 MW of additional maintenance outages, ~4,817 MW of gas-fired generation unavailable due to fuel supply constraints, and 50% reduced import capabilities of external ties (i.e., 1,850 MW total). The NPCC Probabilistic Assessment did not evaluate a prolonged, extreme cold weather event that threatens to exhaust stored liquid fuels.
NPCC-New York		NPCC's assessment preliminary results indicate that operating procedures were not needed to maintain a balance between electricity supply and demand. No cumulative LOLE, LOLH or EUE risks were indicated over the November–March winter period for all the scenarios modeled.
NPCC-Ontario		NPCC's assessment preliminary results indicate that operating procedures were not needed to maintain a balance between electricity supply and demand. No cumulative LOLE, LOLH or EUE risks were indicated over the November–March winter period for all the scenarios modeled.
NPCC-Québec		NPCC's assessment preliminary results indicate that operating procedures are sufficient to maintain a balance between electricity supply and demand, if needed. Only the low likelihood reduced resource case, highest peak load scenario resulted in an estimated cumulative LOLE risk of ~0.1 days/period, with associated LOLH (<1 hour/period) and EUE (92.7 MWh) over the November–March winter period. The Québec Area low likelihood resource case assumed: 1,000 MW of generation reductions.
PJM	Based on 2022 PJM Reserve Requirement Study (RRS)	PJM is expecting a low risk of resources falling below required operating reserves. PJM forecasts a 40% installed reserve margin, well above the target of 27%. 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. The RRS report was also influenced by the extreme weather experienced in December of 2022. NERC assesses an elevated risk of energy shortfall for the upcoming winter due to the potential for a weather event on the scale of Winter Storm Elliott to cause similar generation outages from fuel and winterization issues.
SERC	Verification of NERC 2022 ProbA Results	The 2022 Base Case results indicated adequate resources for the SERC Regional Entity. The base case did not include high-outage conditions similar to those experienced during Winter Storm Elliott.
Texas RE-ERCOT	ERCOT Probabilistic Reserve Risk Model	There is a 11.6% probability that ERCOT will declare an EEA1 during the highest-risk hour ending at 8:00 am. The Probabilistic Reserve Risk Model, which performs Monte Carlo simulations, determines the probability that capacity available for operating reserves for a seasonal peak load day is at or below the various EEA risk thresholds.
WECC	The 2022 Western Assessment of Resource Adequacy provides the most recent probability-based resource adequacy risk assessment for Summer 2023 across WECC's areas.	The Western Interconnection is experiencing heightened reliability risks heading into Summer 2023 due to increased supply-side shortages and fuel constraints along with ongoing drought impacts in some areas, continued wildfire threats, and expanding heat wave events. The installation of new resources for the summer and the availability of the imports, especially during wide-area heat events, affects resource adequacy for the U.S. assessment areas. The reliability and resource adequacy of the Western Interconnection depends on the ability to move power throughout the footprint.
WECC-AB		Alberta is expected to have sufficient resource availability to meet demand and cover reserves under a winter peak defined at the 90th percentile. When wind output is below average, imports are likely to be needed to meet operating reserves for normal and above-normal peak demand.

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Probability-Based Risk Assessment		
Area	**Type of Assessment**	**Results and Insight from Assessment**
WECC-BC		BC is expected to have sufficient resource availability to meet demand and cover reserves under a winter peak defined at the 90th percentile. When hydroelectric generation output is below average, imports are likely to be needed to meet operating reserves for normal and above-normal peak demand.
WECC-CA/MX		WECC-CA/MX is expected to have sufficient resource availability to meet demand and cover reserves under a winter peak defined at the 90th percentile.
WECC-NW		WECC-NW is expected to have sufficient resource availability to meet demand and cover reserves under a winter peak defined at the 90th percentile. In a scenario involving high thermal generation outages, low wind output, and low hydroelectric generation output, imports are likely to be needed to meet operating reserves for normal and above-normal peak demand.
WECC-SW		WECC-SW is expected to have sufficient resource availability to meet demand and cover reserves under a winter peak defined at the 90th percentile.

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Errata

December 2023

- Updated On-Peak Reserve Margin graphics for NPCC-New York (page 18) and SERC-Florida Peninsula (page 25)
- Updated fuel mix chart for WECC-Alberta (Page 28)
- Updated Figure 5 to reflect NPCC-New York 2022-2023 Reference Margin Level and SERC-Florida Peninsula reserve margins (page 36)
- Updated capacity numbers provided by SERC-East, SERC-Florida Peninsula, and SERC-Southeast (pages 40–41)
- Revised percentage change numbers for SPP (page 41)
- Added footnote to reference SPP's probabilistic study (page 44)

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