NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2022–2023 Winter Reliability Assessment

November 2022

Schedule MM-S19

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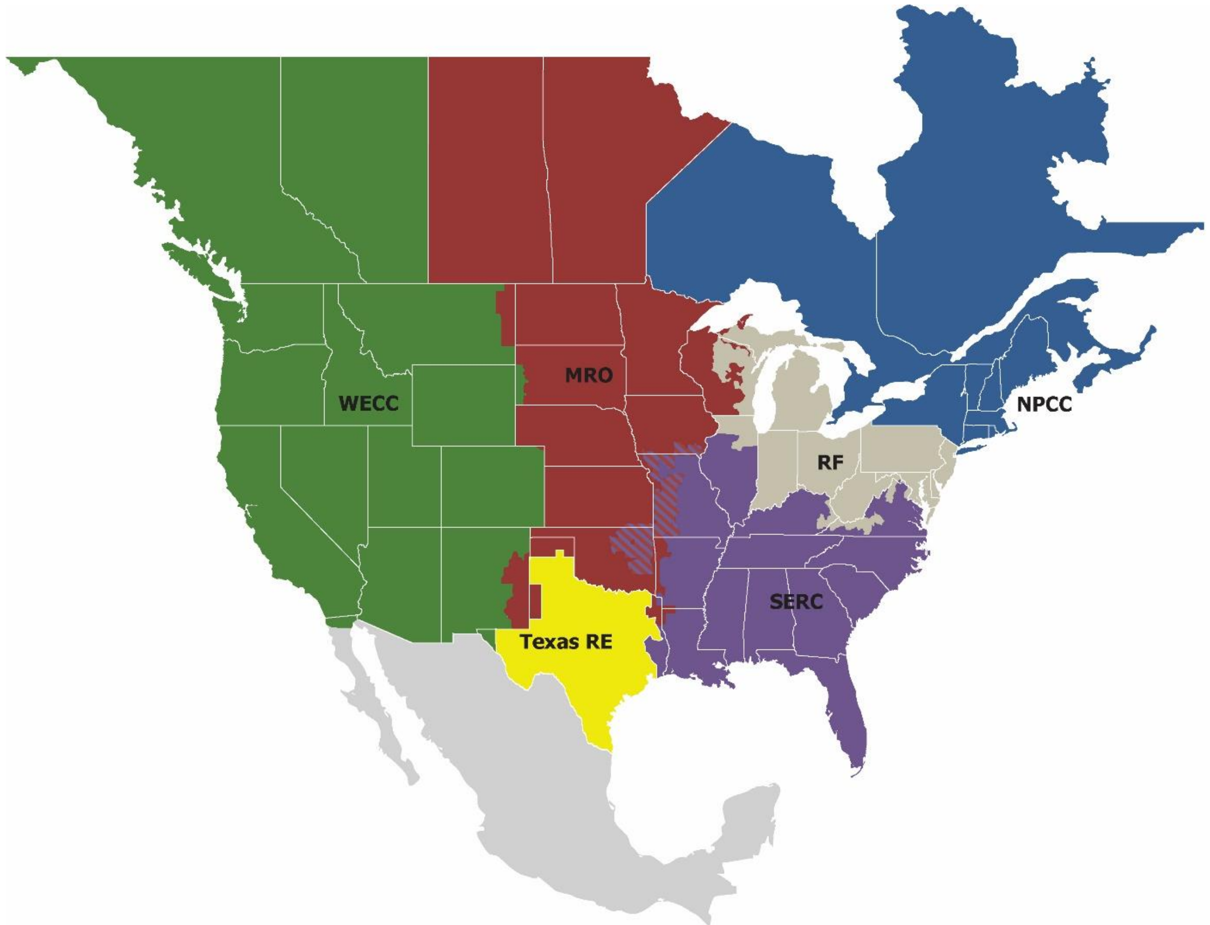
Preface

The vision for the Electric Reliability Organization Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities, is a highly reliable 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 boundaries as shown in the map below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another. Refer to the **Data Concepts and Assumptions** section for more information. A map and list of the assessment areas can be found in the **Regional Assessments Dashboards** section.



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

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About this Assessment

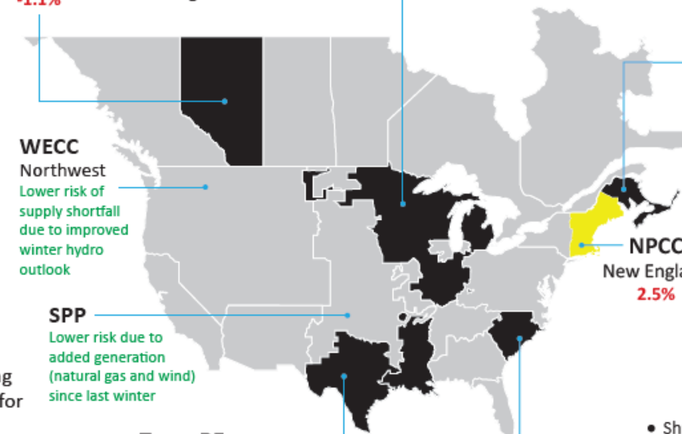
NERC's *2022–2023 Winter Reliability Assessment* (*WRA*) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming winter season. In addition, the *WRA* presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might impact the BPS. The reliability assessment process is a coordinated reliability evaluation between the Reliability Assessment Subcommittee (RAS), the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas. This report reflects NERC's independent assessment and is intended to inform industry leaders, planners, operators, policy makers, 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. Below is a summary of this *WRA.*

2022–2023 Winter Reliability Assessment

NERC's annual Winter Reliability Assessment evaluates the generation resource and transmission system adequacy needed to meet projected winter peak demands and operating reserves as well as identifies potential reliability issues for the 2022–2023 winter period. Under normal or mild winter weather, the BPS has a sufficient supply of capacity resources. However, some areas are highly vulnerable to extreme and prolonged cold weather and may require load-shedding procedures to maintain reliability. Generators face heightened fuel risk for this winter due to railroad transportation uncertainty and global energy supply issues.

Key Actions

- **Cold Weather Preparations:** Generators should, while considering NERC's cold weather preparations alert, prepare for winter conditions and communicate with grid operators.
- **Fuel:** Generators should take early action to assure fuel and communicate plant availability. Reliability Coordinators and Balancing Authorities should monitor fuel supply adequacy, prepare and train for energy emergencies, and test protocols.
- **State Regulators and Policymakers:** States regulators should preserve critical generation resources at risk of retirement prior to the winter season and support requests for environmental and transportation waivers. Support electric load and natural gas local distribution company conservation and public appeals during emergencies. In New England, the states should support fuel replenishment efforts using all means possible.



Percentages indicate the projected reserve margin with electricity demand, generation outages, and energy derates under extreme conditions.

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Extreme Weather Risk

Winter weather conditions that exceed projections could expose power system generation and fuel delivery infrastructure vulnerabilities. Increased demand caused by frigid temperatures, coupled with higher than anticipated generator forced outages and derates, could result in energy deficiencies that require system operators to take emergency operating actions, up to and including firm load shedding.

Fuel Limitations During Extended Cold

Limited natural gas infrastructure can impact winter reliability due to increased heating demand and the potential for supply disruptions. While New England expects to have sufficient energy during a mild or moderate winter, reliability risk is elevated during a period of extended extreme cold conditions. Oil reserves are below normal levels. During extreme cold, switching fuel types is not always successful.

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Key Findings

This *WRA* covers the upcoming three-month (December–February) winter period. This assessment provides an evaluation of 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 topics of concern. The following findings are NERC and the Regional Entities' (the ERO Enterprise's) independent evaluation of electricity generation and transmission capacity and potential operational concerns that may need to be addressed for the upcoming winter:

- **A large portion of the North American BPS is at risk of insufficient electricity supplies during peak winter conditions** (Figure 1). Higher peak-demand projections, inadequate generator weatherization, fuel supply risks, and natural gas infrastructure are contributing to risks seen in the following areas:
  - **Texas RE-ERCOT:** 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. Furthermore, a U.S. Environmental Protection Agency (EPA) decision regarding compliance with hazardous coal ash disposal regulations is expected before the end of 2022 that could impact the availability of two coal-fired generation units (combined total of 1,477 MW) in the last weeks of winter. These units could be important resources during extreme conditions, and an EPA decision can provide flexibility in scheduling outages for plant improvements. Demand volatility in Texas from extreme cold temperatures also contributes to energy shortfall risks.
  - **Midcontinent ISO (MISO):** Since the 2021/2022 winter, reserve margins in MISO have fallen by over 5%. Nuclear and coal-fired generation retirements total over 4.2 GW since the prior winter. Declining reserves are the result of few resource additions. An extreme cold-weather event that extends deep into MISO's area could lead to high generator outages from inadequate weatherization in southern units and unavailability of fuel for natural-gas-fired generators.
  - **SERC-East:** Like Texas RE-ERCOT and the southern parts of MISO, extreme cold could result in high generator outages and demand volatility. A rare cold weather event in the South could result in an energy emergency in this area.
  - **WECC-Alberta and NPCC-Maritimes:** Peak electricity demand is projected to grow in both of these winter-peaking systems. In Maritimes, this could strain capacity for normal winter peak conditions. Alberta has sufficient capacity for normal winter peak demand; however, extreme conditions that cause high generator forced outages are likely to cause energy emergencies.
  - **NPCC-New England:** The capacity of the 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 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.

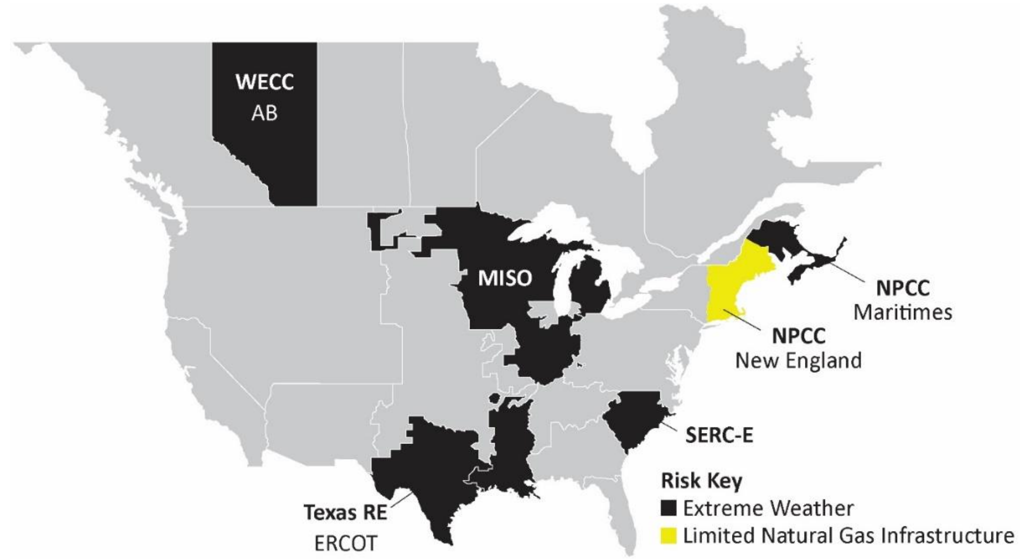

Figure 1: Winter Reliability Risk Area Summary

- **Generator Owners (GO) face additional fuel and supply risk.** Reliable operation of the thermal generating fleet is critical to winter reliability, and assured fuel supplies is an ongoing winter reliability concern. Current domestic and global affairs warrant even greater attention to generator fuel supplies, including natural gas, fuel oil, and coal for the upcoming winter. Inventories of coal and fuel oil in most areas are lower than usual due to a summer of high electricity demand and high natural gas prices that made other fuels more economically advantageous for electricity generation. Low fuel storage levels coupled with a range of potential fuel resupply challenges are creating additional risks for winter regional BPS reliability. Careful attention should be paid to periodic fuel surveys that provide early indication of fuel supply risks.

- **Steps have been taken since 2021's Winter Storm Uri to improve generator performance during extreme cold weather events.** The three areas hardest hit by the 2021 Winter Storm Uri[1]—Texas RE-ERCOT, SPP, and MISO—have implemented several improvements based on their operating experience. Texas weatherization standards for both generators and natural gas facilities designated as critical infrastructure aim to improve generator availability during extreme weather this winter. In SPP and MISO, where Winter Storm Uri impacts were less severe, a focus on operational coordination and situational awareness is intended to help operators ensure that sufficient resources are available for extreme conditions. While the risk of energy emergencies for the upcoming winter has not been eliminated, improvements—due to lessons learned from Winter Storm Uri—are expected to reduce the likelihood and lessen the severity of a future Winter Storm Uri scale event.
- **NERC's 2022 Level 2 Alert, *Cold Weather Preparations for Extreme Weather Events.*** In September 2022, the ERO issued a Level 2 NERC alert to Reliability Coordinators (RC), Balancing Authorities (BA), Transmission Operators (TOP), and GOs.[2] The alert includes recommendations as well as a series of questions to help evaluate the Bulk Electric System's winter readiness. The responses indicate the importance of grid operators being prepared to implement their operating plans to manage potential supply shortfalls in extreme weather.
- **Inadequate supply of distribution transformers could slow restoration efforts following winter storms.** The electricity industry is facing a shortage of distribution transformers as a result of production not keeping pace with demand. A survey by the American Public Power Association revealed that many utilities have low levels of emergency stocks that are used for responding to natural disasters and catastrophic events.[3] Severe winter storms often include high winds, icing, and precipitation that damage distribution power lines and transformers. Asset sharing programs used by utilities provide visibility and voluntary equipment sharing to maximize resources; however, electricity customers may experience delayed restoration of power following storms as crews must work to obtain new equipment.

Recommendations

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

- BAs and RCs should work with GOs to ensure fuel supplies are adequate for normal and extreme conditions prior to winter. Fill storage capacity, prepare fuel delivery systems, and coordinate with fuel providers to secure needed fuel as applicable. While short-term solutions are limited, firm supply arrangements should be pursued when feasible. Long-term solutions are needed to secure energy and maintain fuel assurance to support reliability and resilience. In addition, GOs should routinely and periodically keep BAs and RCs informed on fuel levels and readiness.
- RCs and BAs should implement fuel surveys early 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 province policy makers have the authority and jurisdiction to implement actions that preserve critical generation resources. State and provincial regulators should consider energy risks for the upcoming winter season and take steps to delay imminent generation retirements if essential to reliability. Additionally, state regulators can assist grid operators in advance of and during extreme cold weather by supporting requested environmental and transportation waivers as well as public appeals for electric load and natural gas conservation.
- Grid operators, GOs, and Generator Operators (GOP) should implement the mitigations identified in the NERC Level 2 alert*, Cold Weather Preparations for Extreme Weather Events–II*, and they should take recommended weatherization steps prior to winter.

[1] 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
[2] https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC%20Alert%20R-2022-09-12-01%20Cold%20Weather%20Events%20II.pdf
[3] https://www.publicpower.org/periodical/article/appa-survey-members-shows-distribution-transformer-production-not-meeting-demand

Risk Highlights

Additional Generator Fuel and Supply Risk

Reliable operation of the thermal generating fleet is critical to winter operations, and assured fuel supplies is an ongoing winter reliability concern. The current state of domestic and global affairs warrants even greater attention on generator fuel supplies, including natural gas, fuel oil, and coal. Low fuel storage levels coupled with a range of potential fuel resupply challenges are creating additional risks for winter regional BPS reliability.

Generator Fuel Supplies

Owners of coal, fuel oil, and dual-fueled generators in North America typically replenish stored fuels following the peak summer season in preparation for winter. Energy suppliers also increase inventories of natural gas, coal, and distillate fuels in preparation for high-demand winter periods. Several fuel supply challenges have emerged in the lead-up to the 2022–2023 winter that are being monitored by grid operators and GOs, including potential rail strikes, constrained and delayed rail deliveries, reduced stored natural gas and fuel oil inventories, and uncertainty from global markets in New England potentially impacting liquefied natural gas (LNG) deliveries. The following are two areas of concern:

Coal Inventories

Grid operators in the U.S. Southeast, MISO, and PJM are monitoring coal inventories (fuel and consumables) as GOs face limited stocks and resupply uncertainty. Across the United States, resupply by rail has been hampered throughout 2022 as staffing shortages and other issues have affected the rail industry. Some GOs in the Midwest and Southeast are experiencing delivery issues for coal and certain emissions-control chemicals. A small number of units currently have low coal inventory. Inventories in some areas are lower than typical following a summer of high electricity demand and high natural gas prices that made coal more economically advantageous. A milder fall in the Central and Eastern parts of North America has helped some coal stocks rebound. Monitoring performed by PJM, where coal-fired generation can be expected to contribute over 25% of peak demand needs, indicates that pre-winter coal supplies in November now exceed 85% of the levels reached at their peak in the prior winter (**Figure 2**).

Based on coal stock data from the Energy Information Administration,[4] fuel inventories have reached 96 days of bituminous supply and 81 days subbituminous across the coal generation fleet on average (**Figure 3**). Some plants reported as low as 15 days of supply during the past summer.

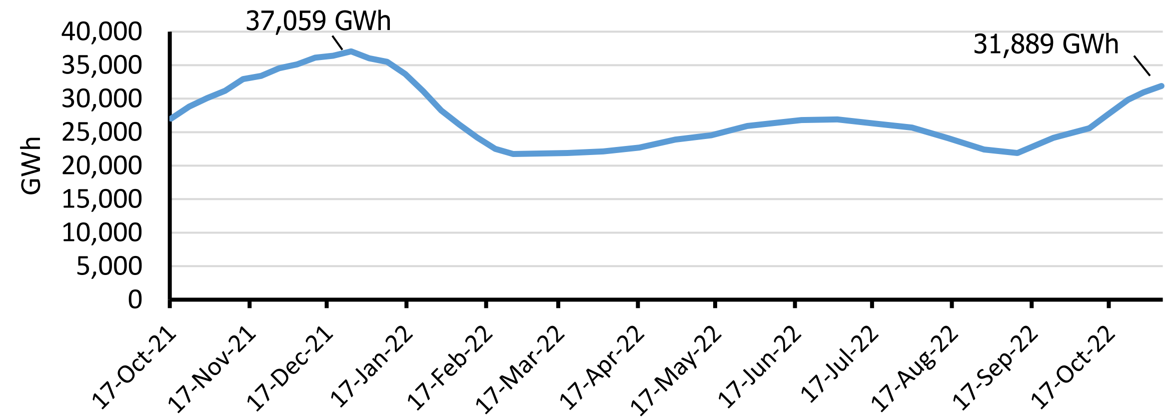

Figure 2: PJM Bi-weekly Fuel Inventory for October 10, 2022[5]

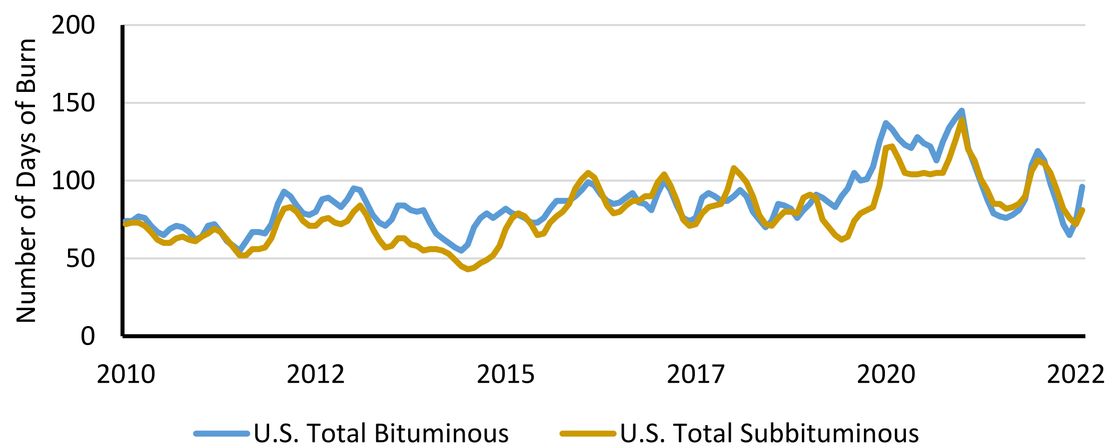

Figure 3: Days of Burn by Non-lignite Coal, January 2010–August 2022

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[4] EIA Electric Power Sector Coal Stocks: Electricity Monthly Update - U.S. Energy Information Administration (EIA)

[5] Displays the fuel inventory in GWh calculated by PJM based on data provided through PJM's Fuel Inventory and Supply Data Request. Information is available on PJM's Operating Committee page: https://www.pjm.com/committees-and-groups/committees/oc

Shipping availability by rail this winter is uncertain, reinforcing the need to monitor generator coal stockpiles and act early to reach peak winter levels. RCs in affected areas are continuing to mitigate the coal supply issues by working with their BAs to limit run time of low-inventory plants, using economics, de-rating units, reducing loading at night, and monitoring coal supply.

LNG and Fuel Oil Availability

Low fuel availability elevates winter reliability risk. LNG is critical to meeting energy needs in New England during cold weather, and the continuing disturbance to global energy markets creates supply uncertainty. LNG terminals in New England help alleviate pipeline constraints by providing access points for LNG shipped in tankers to be vaporized and injected into pipelines that serve many natural-gas-fired generators.

As a global energy commodity, LNG is experiencing record high demand that is straining supplies and transportation as well as increasing the risk of disruption. Fuel oil stores are also an important generator fuel in New England as well as in neighboring New York and the Maritimes Provinces of Canada.

Fuel oil is used as either a primary fuel or as a backup to natural gas. Replenishment of on-site generator fuel oil stores since last winter is lagging, and levels remain below historical norms. In New England, the Independent System Operator (ISO) survey of generators in October indicates that on-site stored fuel oil used for electricity generation is just over 92 million gallons, or 40% of available storage capacity (**Figure 4**). Most oil-fired generating capacity (70%) in New England uses lighter distillate fuel oil (DFO). The remaining 30% of the oil-fired fleet capacity uses residual fuel oil (RFO). The current level of combined fuel oil in storage is far lower than the 54% peak level of the prior winter. It is also close to being insufficient for the kind of extreme winter events that could occur in the area. For instance, during a 13-day cold snap over the 2017–2018 winter, over 80 million gallons of fuel oil was used for electricity generation in the New England area. [6]

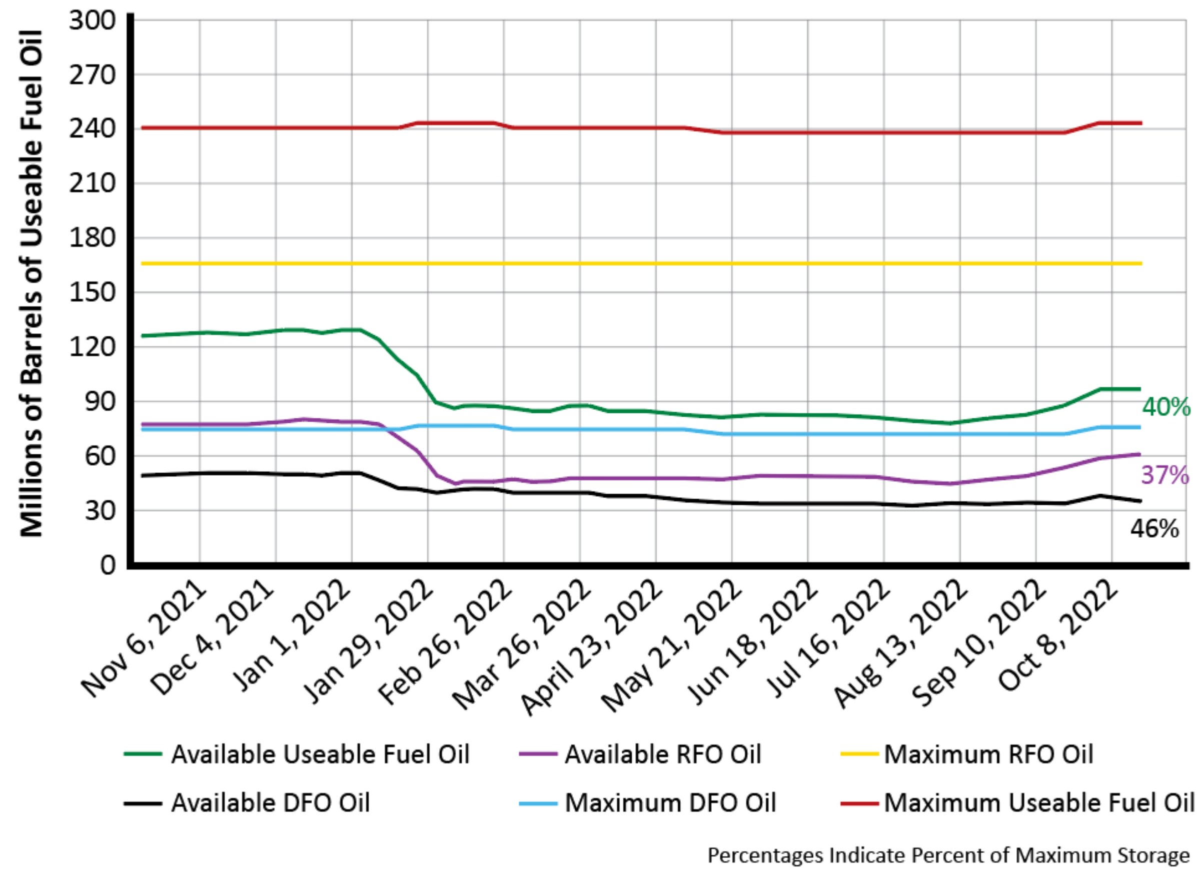


Figure 4: ISO New England 21-day Energy Assessment, Total Usable New England Fuel Oil Inventory Through October 8, 2022[7]

Assessment of Stored Fuel Risk

No specific issues have been identified that would prevent reaching the necessary fuel levels. However, weather, staffing, and general issues affecting transportation have the potential to either directly impact fuel delivery to generator storage sites or affect fuel production through disrupted chemical shipments. Careful attention to ISO's pre-winter and periodic fuel surveys is needed to provide early indication of fuel supply risks. Tools like ISO-New England's (ISO-NE) 21-day energy assessments can reduce these risks to operations.

[6] ISO-NE *Winter 2017/2018 Recap: Historic cold snap reinforces findings in Operational Fuel-Security Analysis*: https://isonewswire.com/2018/04/25/winter-2017-2018-recap-historic-cold-snap-reinforces-findings-in-operational-fuel-security-analysis/

[7] https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/21-Day-Energy-Assessment-Forecast-and-Report-Results

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** for more information about these chart.

The seasonal risk scenario charts can be expressed in terms of reserve margins. In **Table 1**, each assessment area's Anticipated Reserve Margins are shown alongside the reserve margins for a typical generation outage scenario (where applicable) and the extreme demand and resource conditions in their seasonal risk scenario. 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 anticipated reserve margin, it is because an assessment area has already factored typical outages into the anticipated resources. The extreme conditions margin includes all components of the scenario and represents the most severe operating conditions of an area's scenario. Note that any reserve margin below zero indicates that the resources fall below demand in the scenario.

Table 1: Seasonal Risk Scenario Margins

Assessment Area	Anticipated Reserve Margin	Typical Outages	Extreme Conditions
MISO	43.1%	14.0%	-7.6%
MRO-Manitoba	18.1%	16.2%	9.2%
MRO-SaskPower	28.7%	22.0%	12.6%
NPCC-Maritimes	17.5%	11.3%	-8.6%
NPCC-New England	72.0%	54.7%	2.5%
NPCC-New York	83.2%	58.9%	23.9%
NPCC-Ontario	24.3%	24.3%	9.5%
NPCC-Quebec	12.7%	12.7%	2.3%
PJM	45.9%	33.2%	16.0%
SERC-C	25.1%	18.4%	2.7%
SERC-E	23.9%	17.3%	1.0%
SERC-FP	36.7%	33.2%	0.0%
SERC-SE	31.7%	22.8%	8.4%
SPP	70.0%	44.5%	9.3%
TRE-ERCOT	36.4%	20.4%	-21.4%
WECC-AB	20.8%	18.3%	-1.1%
WECC-BC	16.2%	16.1%	6.4%
WECC-CAMX	49.7%	41.7%	18.6%
WECC-WPP	33.8%	31.3%	10.1%
WECC-SRSG	93.5%	84.7%	55.7%

Reliability Enhancements in Storm-Affected Assessment Areas

Industry, regulators, and the ERO Enterprise have taken significant actions to improve winter readiness following the devastating effects of the February 2021 Winter Storm Uri cold weather event. The first cold weather Reliability Standards, adopted by the NERC Board in June 2021, advance BPS reliability by requiring generators to implement plans for cold weather preparedness as well as to provide cold weather operating parameters to their RCs, TOPs, and BAs for use in operating plans. Though these requirements take effect in the United States in April 2023, just after the upcoming winter season, some reliability benefits of the new requirements may be realized sooner through cold weather planning and preparations that improve generator performance and operator coordination. Across industry, the recommendations of the FERC-NERC-Regional Entity staff report—*The February 2021 Cold Weather Outages in Texas and South Central United States.*—are shaping direction at ISO/RTOs, in technical committees and industry forums, and among industry planners and operators.

The three hardest-hit areas by the 2021 Winter Storm Uri—Texas RE-ERCOT, SPP, and MISO—have implemented several improvements based on their operating experience. Texas weatherization standards, applicable to generators and natural gas facilities designated as critical infrastructure, aim to improve generator availability during extreme weather this winter. In SPP and MISO, where Winter Storm Uri impacts were less severe, a focus on operational coordination and situational awareness should help operators prepare to have sufficient resources for extreme conditions.

Texas RE-ERCOT, SPP, and MISO continue to be at-risk for energy emergencies during the upcoming winter based on their expected resources, normal and extreme demand, and historical generator outage information. However, the enhancements described in the following Texas RE-ERCOT, SPP, and MISO sub-sections are expected to reduce the likelihood of emergencies and lessen the severity that an extreme winter cold weather event on the scale of Winter Storm Uri could cause.

Texas RE-ERCOT

Since February 2021, Texas regulators, ERCOT, and GOs have implemented winter preparedness programs and other reforms aimed at improving generator performance in extreme winter weather. These actions are expected to reduce generator outages in extreme conditions to reduce the likelihood of energy emergencies as well as to mitigate impacts to firm load should an energy emergency occur:

- Regulations in Texas require generator and transmission owners to winterize equipment and facilities. ERCOT conducts weather preparedness inspections of generation and transmission as well as tracks exceptions to requirements until completed.
- In August 2022 the Railroad Commission of Texas (RRC), which regulates the Texas fuel oil and natural gas industry, approved its Final Rule[8] on weather emergency preparedness standards for designated "critical [natural] gas facilities" in the state's new Electricity Supply Chain Map.[9] TRRC inspectors will begin inspecting facilities to determine compliance beginning December 1, 2022, based on submitted compliance attestations. Inspections will focus on infrastructure that produces, stores, processes, and/or transports large volumes of natural gas, and this TRRC effort will be prioritized by facility size.
- ERCOT procured over 2,900 MW of firm fuel supply resources for the upcoming winter. Under the new market product, the procured natural-gas-fired generators must have back-up fuel that would support operations for 48 hours in the event that natural gas supply is interrupted.
- ERCOT has reviewed load-shedding plans with area TOPs and conducts periodic training exercises. Additionally, they coordinate with TOPs to prepare enhanced manual load-shedding and rotating outage plans designed to minimize disruption to firm load.

SPP

SPP is implementing a set of actions—policy changes and assessments approved by the SPP Board of Directors—to address issues related to fuel assurance, resource planning and availability, emergency response, communications, and other critical areas. For the upcoming winter, these actions will improve generator preparedness and operator response:

- SPP held the Winter Preparedness Workshop to help inform members of forecasted conditions for the upcoming season and review SPP's seasonal preparedness steps outlined in its operating procedures.
- RC and BA staff have implemented a high risk scenario alerting system for managing risk periods. This system will identify and alert staff on potential upcoming records, such as load, wind, and wind penetration, to allow time for extra studies to be executed and analyzed as well as to be addressed by the SPP response team.

SPP established an Improved Resource Availability Task Force, which will take primary responsibility for addressing recommendations related to fuel assurance and resource planning as well as

[8] https://www.rrc.texas.gov/media/c5hdc4ga/rule-3-66.pdf
[9] https://www.puc.texas.gov/agency/resources/reports/mapping/2021_Mapping_Agency_Report.pdf

availability that is identified in SPP's *Comprehensive Review of SPP's Response to the February 2021 Winter Storm* report.[10]

MISO

MISO has implemented actions to provide situational awareness and early coordination for reducing risks from extreme winter weather:

- MISO continues to survey GOs and GOPs about unit preparedness and winter fuel sufficiency.
- Processes are in place for coordination with neighboring RCs and BAs on needs for firm or non-firm transfers to address extreme system conditions. Pre-season transfer studies for normal and extreme scenarios are underway.

For future years, MISO's new resource adequacy construct (filed with FERC for approval) is expected to deliver additional winter resource capacity by using a winter reserve margin and resource capacity accreditations that account for winter peak conditions.

MISO Neighboring Area Studies

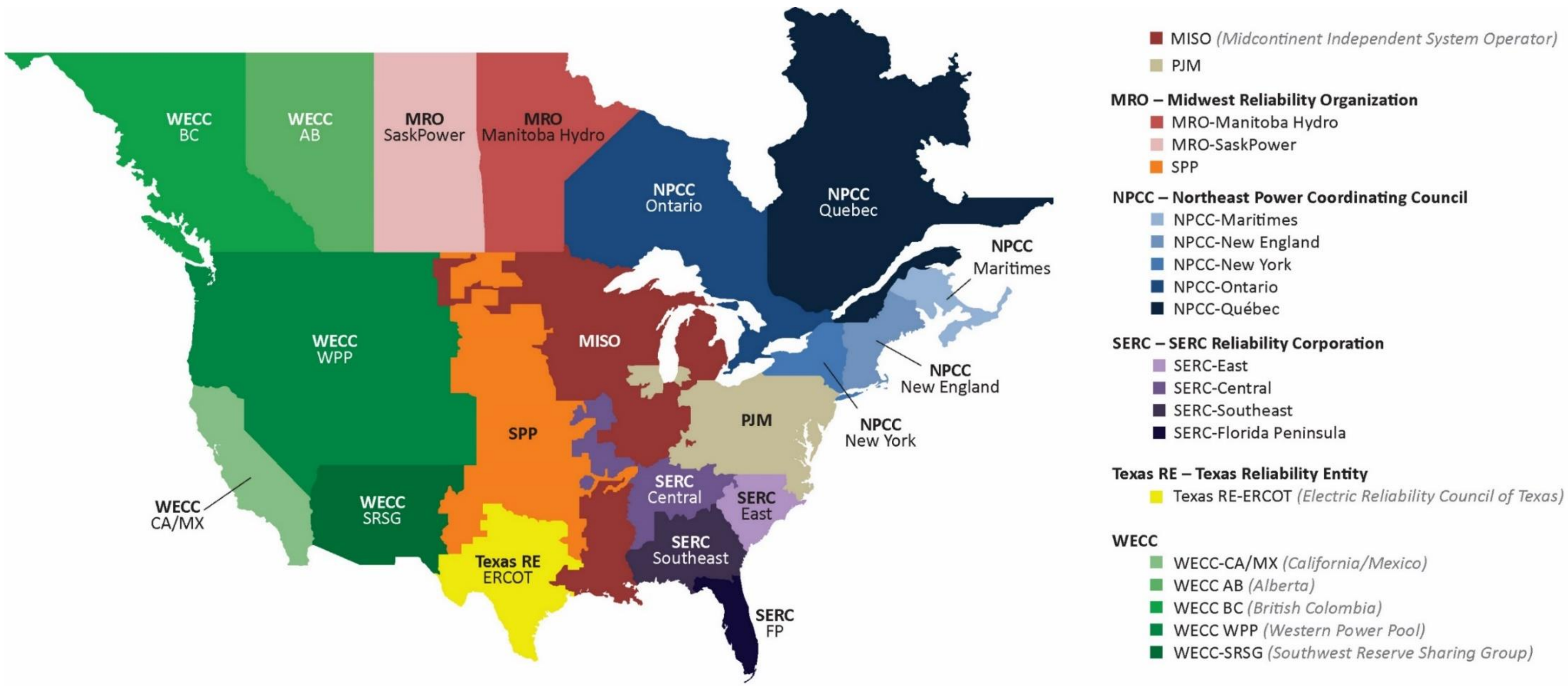
During Winter Storm URI, other areas in the Eastern Interconnection experienced localized transmission emergencies resulting from the large transfers flowing across the transmission system from generators in PJM to the affected areas in MISO and SPP. Accordingly, the *FERC-NERC-Regional Entity staff Joint Report* recommended planners and operators study large power transfers during stressed conditions. Transfer studies have been conducted in SERC to help prepare for the upcoming winter. During extreme cold temperatures, there is the potential for significant transfers through the area as excess power is shipped to meet power demands in affected areas outside of SERC.

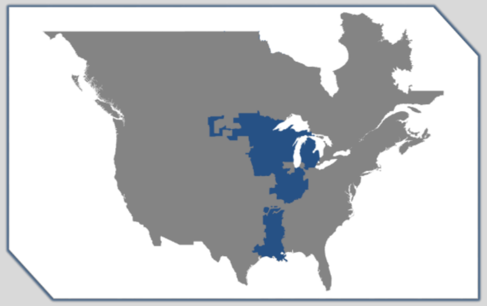
A SERC technical working group performed a 2022–2023 winter reliability study to determine the adequacy and reliability of the SERC transmission system using a 2022–2023 winter peak power flow model, which included 12 GW power transfer from PJM to MISO. The study also simulated the impacts of higher load demands due to colder than normal temperatures in each SERC sub-area by increasing generation throughout them all while simultaneously increasing load in a particular sub-area. SERC concluded that the transmission system was adequate for normal and extreme conditions and that localized transmission constraints, when observed, could be mitigated through system reconfiguration.

[10] https://www.spp.org/markets-operations/current-grid-conditions/2021-winter-storm-review/

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. Guidelines and definitions are in the **Data Concepts and Assumptions** table. On-Peak Reserve Margin bar charts show the Anticipated Reserve Margin compared to a Reference Margin Level established for the area 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.



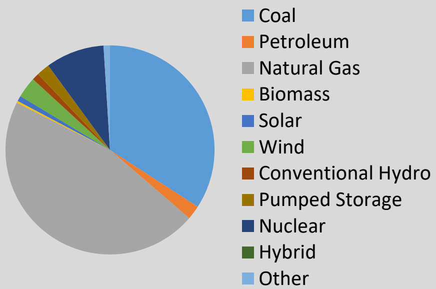


MISO

The Midcontinent Independent System Operator, Inc. (MISO) is a not-for-profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency.

MISO manages energy, reliability, and operating reserve markets that consist of 36 local Balancing Authority and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

On-Peak Fuel Mix



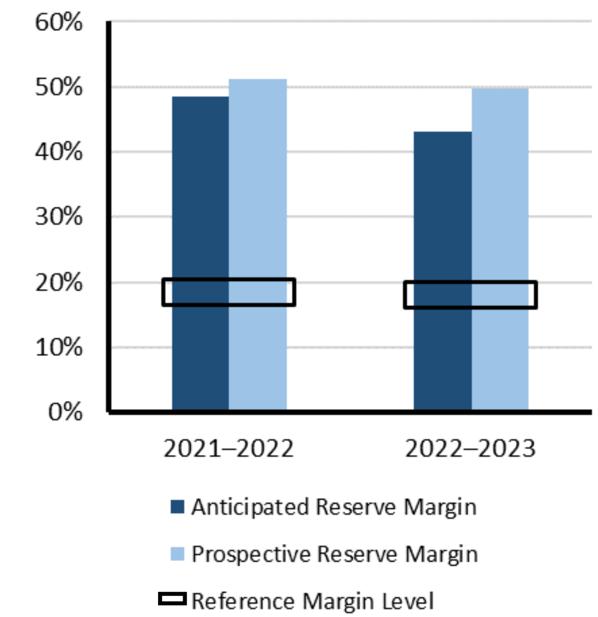
Highlights

- Since 2021–2022 winter, reserve margins in MISO have fallen by over 5%. Nuclear and coal-fired generation retirements total over 4.2 GW since the prior winter. Declining reserves are the result of few resource additions. Since last winter, more demand response (2,250 MW) and new wind generation (500 MW on-peak/3,200 MW nameplate) was added.
- MISO continues to survey and coordinate with its members on winter preparedness and fuel sufficiency. In addition, MISO is acknowledging that resource adequacy risk is not limited to the summer system peak season, MISO is filing changes to the resource adequacy construct to implement a seasonal resource adequacy construct and seasonal unit accreditation to better affirm adequate supply in all seasons.
- Though risk has been identified for this upcoming winter season in a high generation outage and high winter load scenario, MISO expects to maintain reliability through the use of measures that include load modifying resources (LMR) (MISO's demand response), non-firm transfers into the system, energy only interconnection service resources not receiving capacity credit, and/or internal transfers that exceed the sub-area import/export constraint between the MISO North/Central and South areas. MISO continues to coordinate extensively with neighboring RCs and BAs to improve situational awareness and vet needs for firm or non-firm transfers to address extreme system conditions.

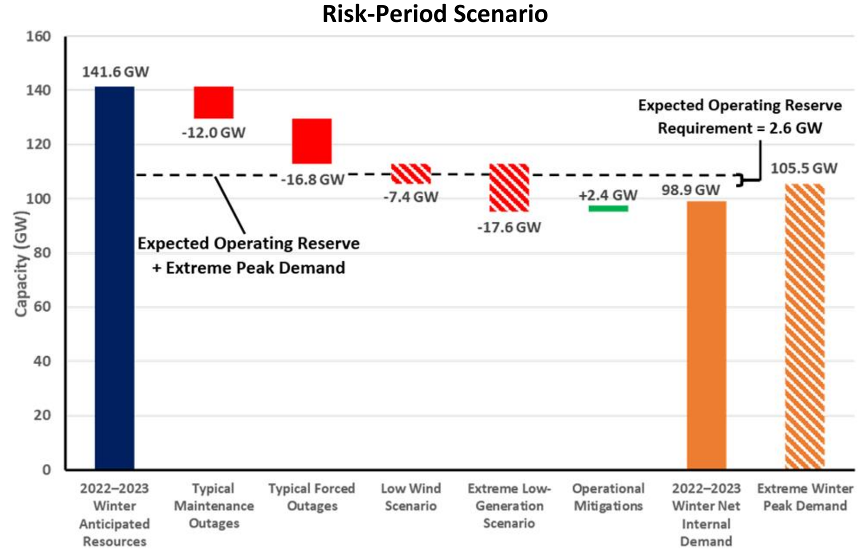
Risk Scenario Summary

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 (EEAs). Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Reserve Margins



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

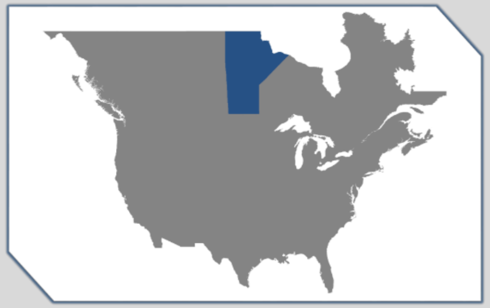
Forced Outages: Five-year average of all outages that were not planned

Low Wind Scenario: Below average wind contributions

Extreme Low-Generation: Maximum historical generation outages

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

Schedule MM-S19

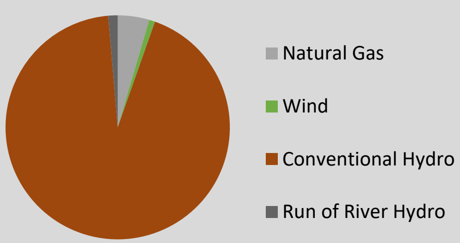


MRO-Manitoba Hydro

Manitoba Hydro is a provincial crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro provides electricity to approximately 601,000 electric customers in Manitoba and provides approximately 291,000 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 and Balancing Authority. Manitoba Hydro is a coordinating member of MISO. MISO is the Reliability Coordinator for Manitoba Hydro.

On-Peak Fuel Mix



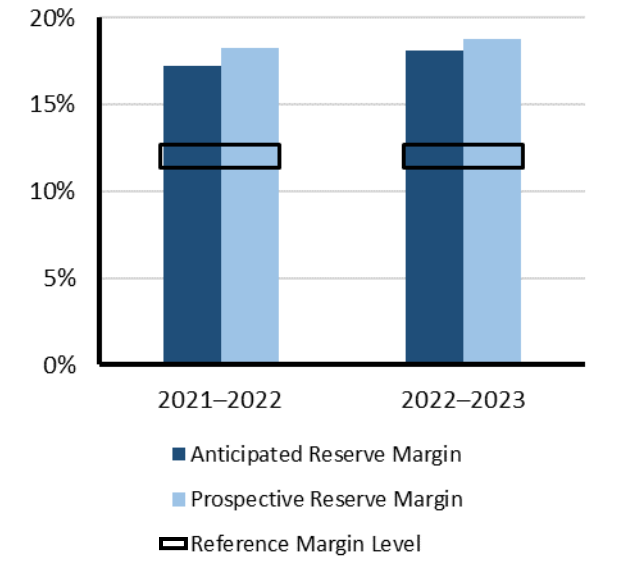
Highlights

- The Anticipated Reserve Margin for the 2022–2023 winter exceeds the 12% Reference Margin Level.
- There are no emerging reliability/resource adequacy issues anticipated for the upcoming winter season.
- All seven units at the Keeyask Hydroelectric Generating Station (630 MW net addition) are anticipated to be in commercial operation for the 2022–2023 winter.

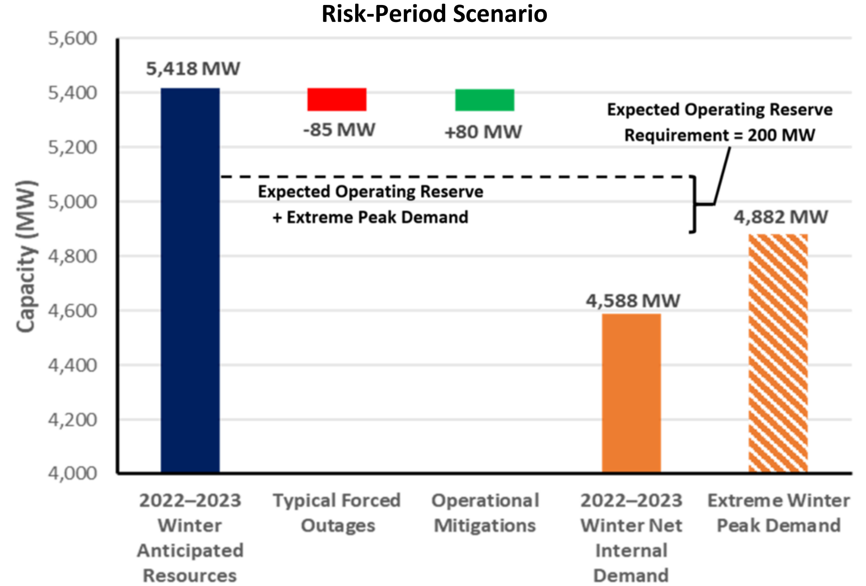
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



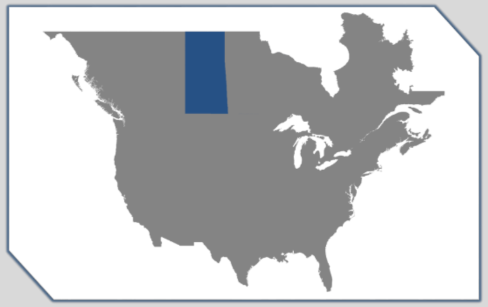
Scenario Description (See [Data Concepts and Assumptions](#))

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: Recall 80 MW of additional curtailable load



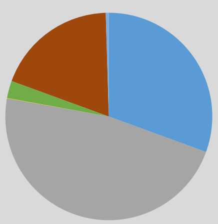
MRO-SaskPower

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 approximately 1.1 million customers. Peak demand is experienced in the winter.

The Saskatchewan Power Corporation (SaskPower) is the Planning Coordinator and Reliability Coordinator 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 Bulk Electric System and its interconnections.

On-Peak Fuel Mix



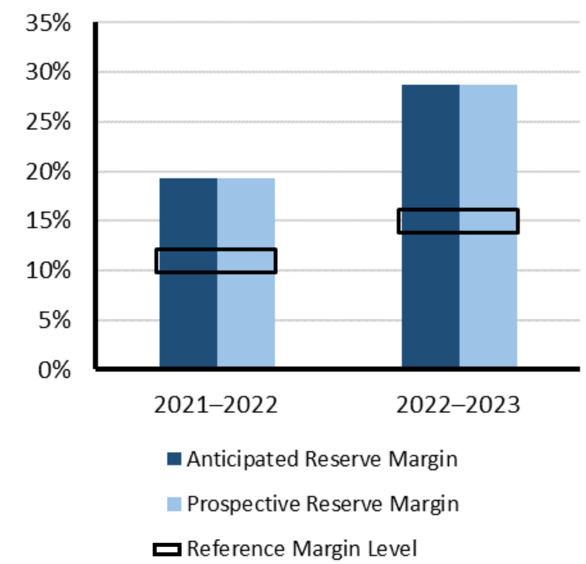
Highlights

- SaskPower experiences peak load in winter because of extreme cold weather. Reserve margins have increased since the 2021–2022 winter with the addition of new wind generators and increased firm capacity imports from Manitoba.
- SaskPower conducts an annual winter joint operating study with Manitoba Hydro with inputs from Basin Electric Power Cooperative (North Dakota) and prepares operating guidelines for any identified issues.
- The risk of operating reserve shortage or EEA during peak load times exists if 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 use available demand response programs, short-term power transfers from neighboring utilities, maintenance rescheduling, and/or short-term load interruptions.

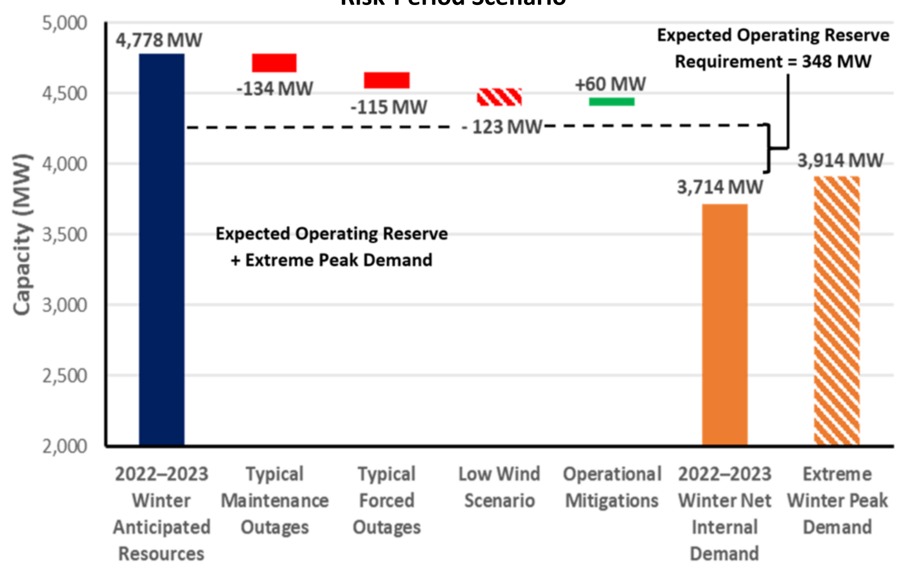
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See [Data Concepts and Assumptions](#))

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

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

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 for the upcoming 2022–2023 winter

NPCC-Maritimes

The Maritimes assessment area is a winter-peaking NPCC area that contains two Balancing Authorities. 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.

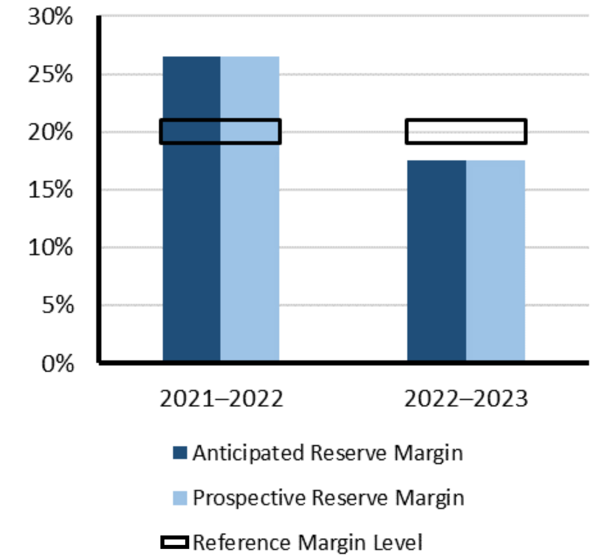
Highlights

- 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.
- The Maritimes area is a winter-peaking system. All of the area's declared firm capacity is expected to be operational for the winter operating period.
- 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.
- The results (preliminary) of NPCC's probabilistic assessment indicate that established operating procedures are sufficient to maintain a balance between electricity supply and demand.[11] Only the low likelihood reduced resource case, highest peak load scenario, resulted in an estimated cumulative loss of load expectation (LOLE) risk of ~0.2 days/period with associated loss of load hours (LOLH) (<1 hours/period) and expected unsupplied energy (EUE) (3.4 MWh) over the winter period. The Maritimes area's low likelihood resource case assumed that wind capacity was de-rated by half (1,100 to 550 MW) for every hour in the winter period, coupled with an assumed 50% reduction in natural-gas-fired generation and reduced transfer capabilities.

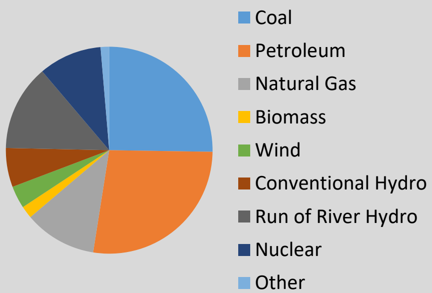
Risk Scenario Summary

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. As noted above, the risk of load shedding is low.

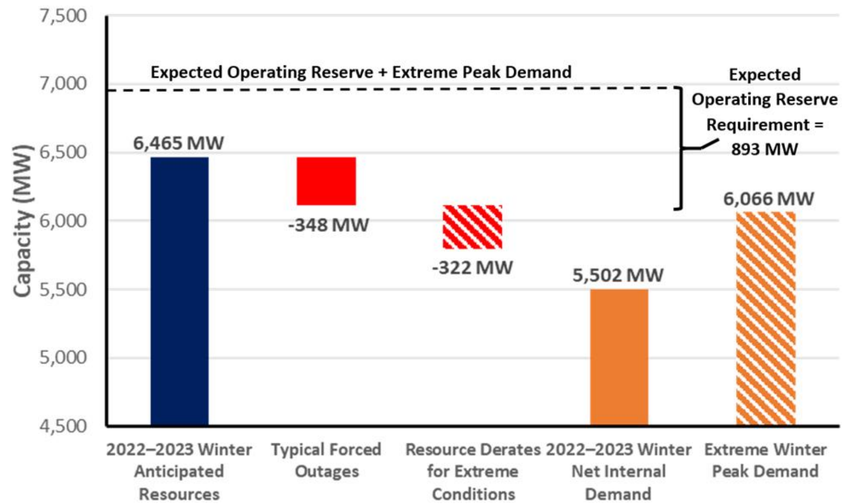
On-Peak Reserve Margins



On-Peak Fuel Mix



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

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.

[11] Final NPCC Assessment Results will be published at the NPCC Seasonal Assessments page: https://www.npcc.org/library/reports/seasonal-assessment

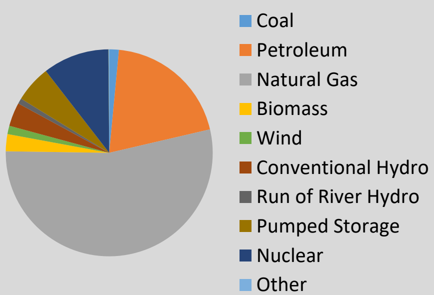
Schedule MM-S19

NPCC-New England

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

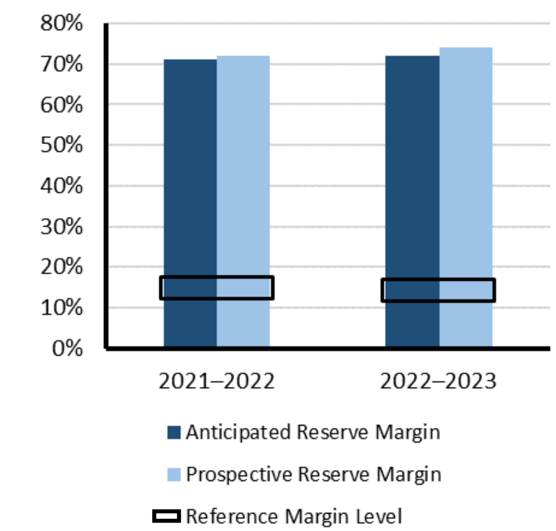
On-Peak Fuel Mix



Highlights

- ISO-NE expects to meet its regional resource adequacy requirements this 2022–2023 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 spell given the existing resource mix, fuel delivery infrastructure, and expected fuel arrangements without considerable effort to replenish stored fuels (i.e., fuel oil and LNG).
- ISO-NE expects to have sufficient capacity resources to meet the 2022–2023 90/10 winter peak demand forecast of 20,695 MW for the weeks beginning January 8, January 15, and January 22, 2023.
- ISO-NE evaluates an above 90/10 scenario that captures the area's coldest day in the last 25 years while using both our current and future load models. The above 90/10 winter peak demand forecast is 21,238 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.[12]

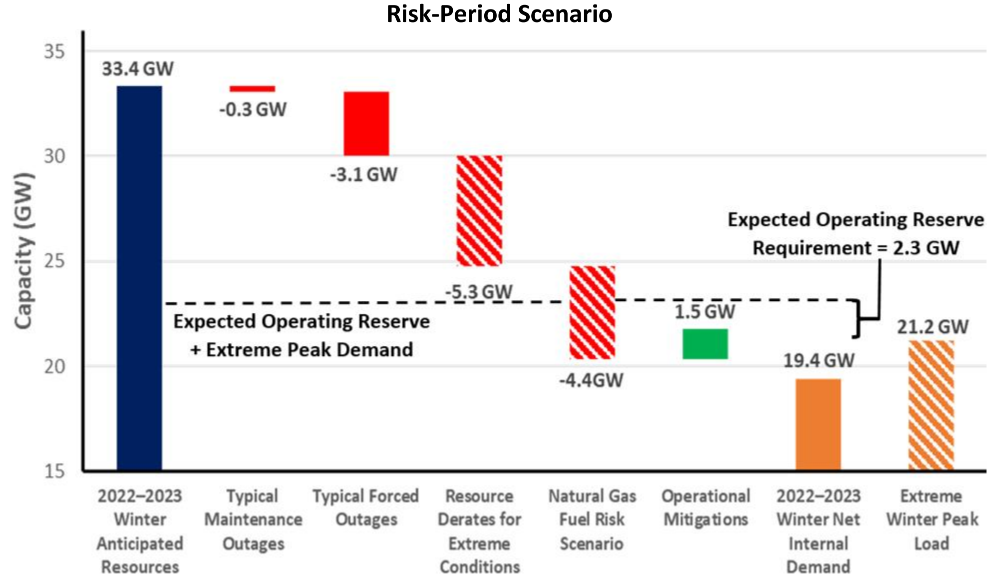
On-Peak Reserve Margins



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.

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 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

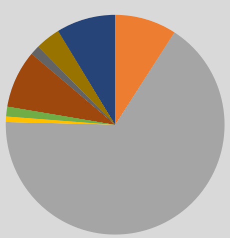
Operational Mitigations: Based on ISO-NE operating procedures

[12] Final NPCC Assessment Results will be published at the NPCC Seasonal Assessments page: https://www.npcc.org/library/reports/seasonal-assessment

Schedule MM-S19

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. The NYISO is the only Balancing Authority 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. The established Reference Margin Level is 15%. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. However, New York requires load serving entities to procure capacity for their loads equal to their peak demand plus an IRM. The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). NYSRC approved the 2022–2023 IRM at 19.6%.

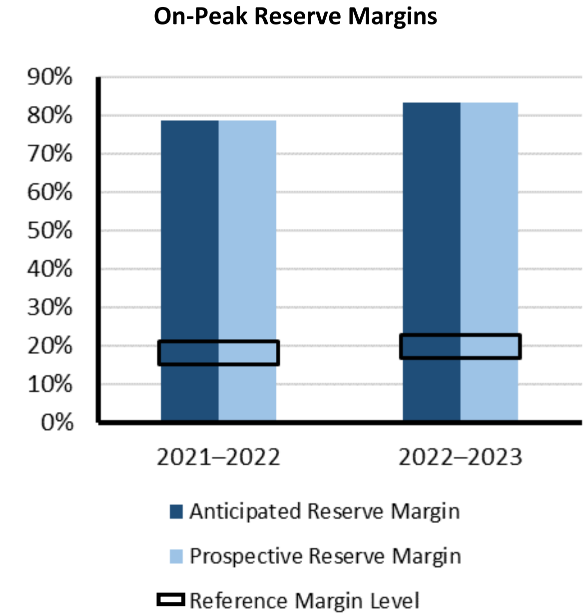


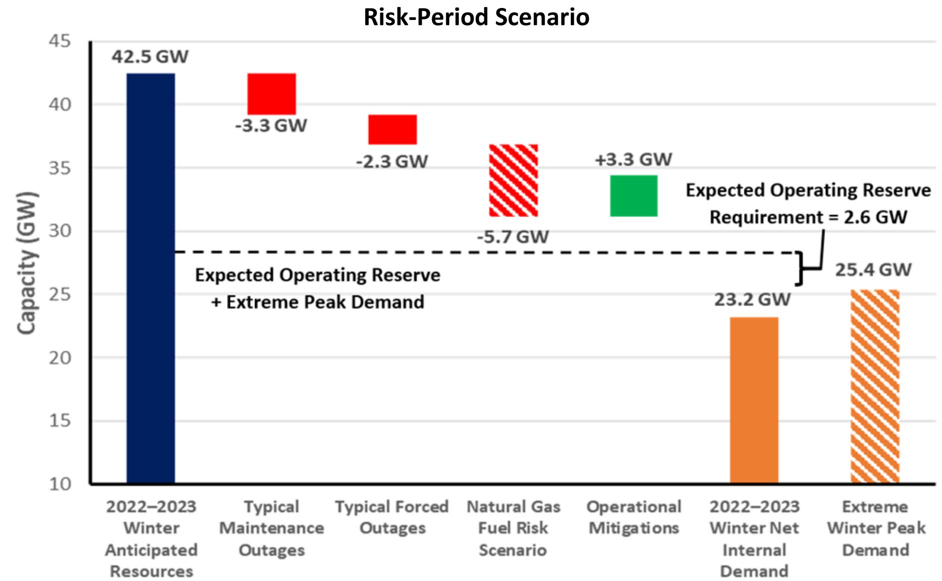
Highlights

- New York is a summer peaking area and no emerging reliability issues are anticipated during the 2022–2023 winter assessment period. Surplus capacity margins above the NYISO's operating reserve requirements are projected.
- The results (preliminary) of NPCC's probabilistic assessment for the area indicate that emergency operating procedures to maintain a balance between electricity supply and demand are not anticipated for the upcoming winter. No cumulative LOLE, LOLH, or EUE risks were found for the winter period for all modeled scenarios.[13]

Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.





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 (99/1) demand forecast with demand response adjustments

Maintenance Outages: Based on planned scheduled maintenance

Forced Outages: Based on historical 5-year averages

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

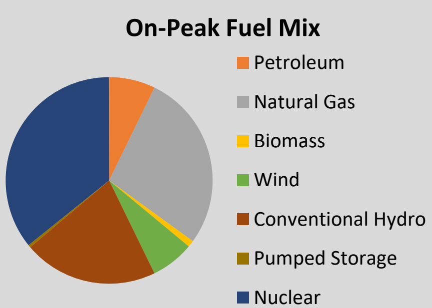
Operational Mitigations: Based on NYISO operating procedures

[13] Final NPCC Assessment Results will be published at the NPCC Seasonal Assessments page: https://www.npcc.org/library/reports/seasonal-assessment

NPCC-Ontario

NPCC-Ontario is an assessment area in the Ontario province of Canada. The Independent Electricity System Operator (IESO) is the Balancing Authority 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 14 million.

Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

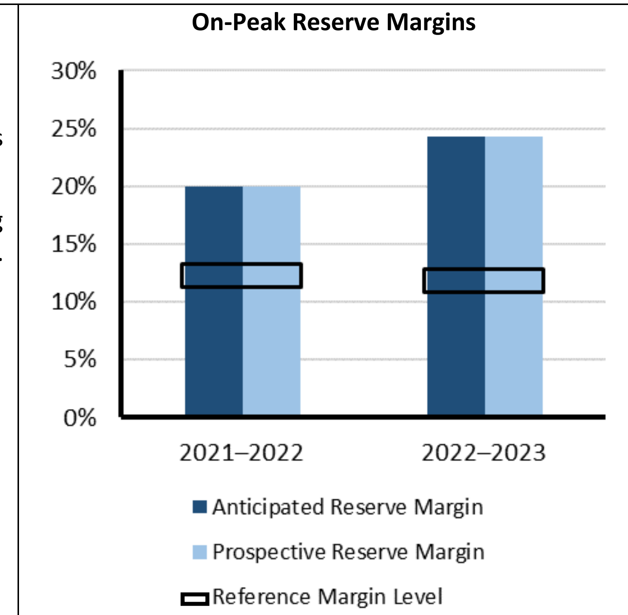


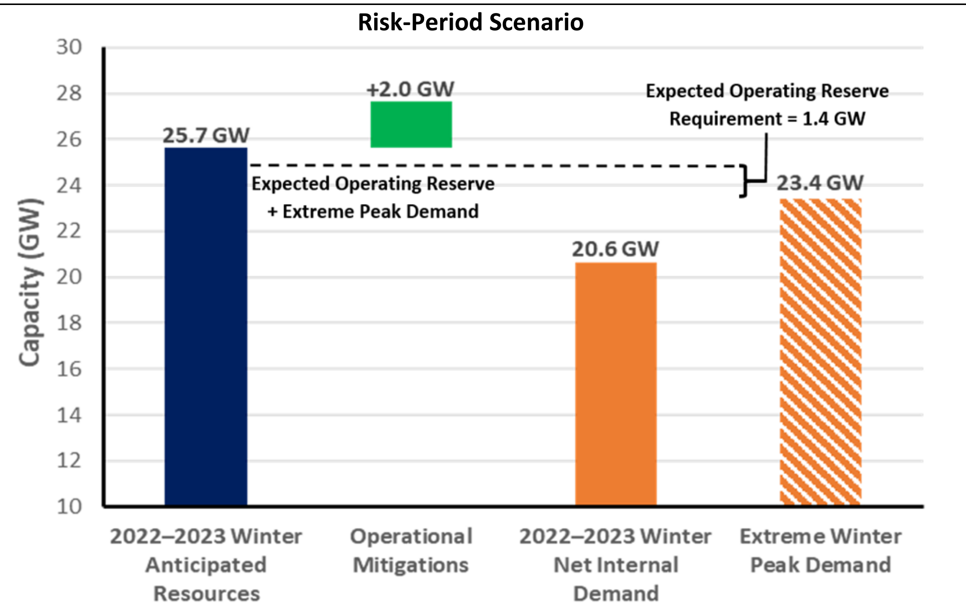
Highlights

- IESO anticipates that it will maintain reliability on its system through the 2022–2023 winter
- In spite of Ontario's ongoing nuclear refurbishment program, the IESO expects to have comfortable reserve margins throughout the winter season
- The results (preliminary) of NPCC's probabilistic assessment for the area indicate that emergency operating procedures to maintain a balance between electricity supply and demand are not anticipated for the upcoming winter. No cumulative LOLE, LOLH or EUE risks were found for the winter period for all modeled scenarios.[14]

Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.





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

Operational Mitigations: Imports anticipated from neighbors during emergencies

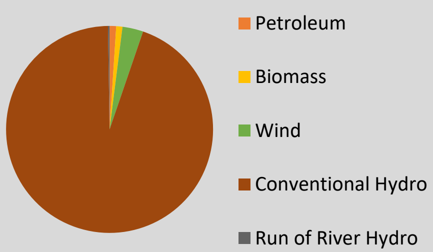
[14] Final NPCC Assessment Results will be published at the NPCC Seasonal Assessments page: https://www.npcc.org/library/reports/seasonal-assessment

NPCC-Québec

The Québec assessment area (Province of Québec) is a winter-peaking NPCC area that covers 595,391 square miles with a population of 8 million.

Québec is one of the four Interconnections in North America; it has ties to Ontario, New York, New England, and the Maritimes; consisting of either HVDC ties, radial generation, or load to and from neighboring systems.

On-Peak Fuel Mix



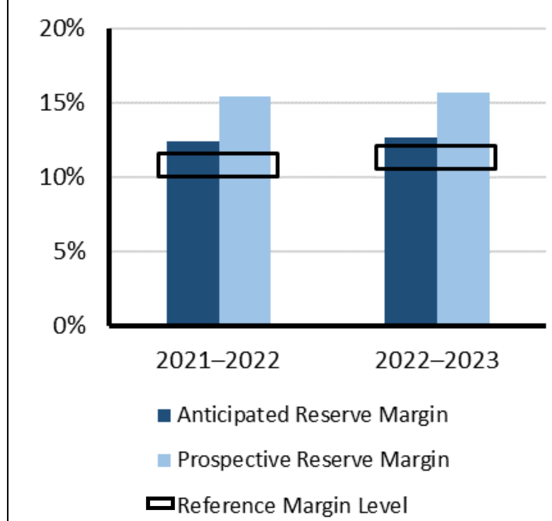
Highlights

- Québec is expecting to maintain system resource adequacy this winter.
- 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 2022–2023 winter assessment period.
- No changes have been made to the assessment area's winter preparedness programs since the previous winter season.
- The results (preliminary) of NPCC's probabilistic assessment for the area indicate that emergency operating procedures to maintain a balance between electricity supply and demand are not anticipated for the upcoming winter. No cumulative LOLE, LOLH, or EUE risks were found for the winter period for all modeled scenarios.[15]

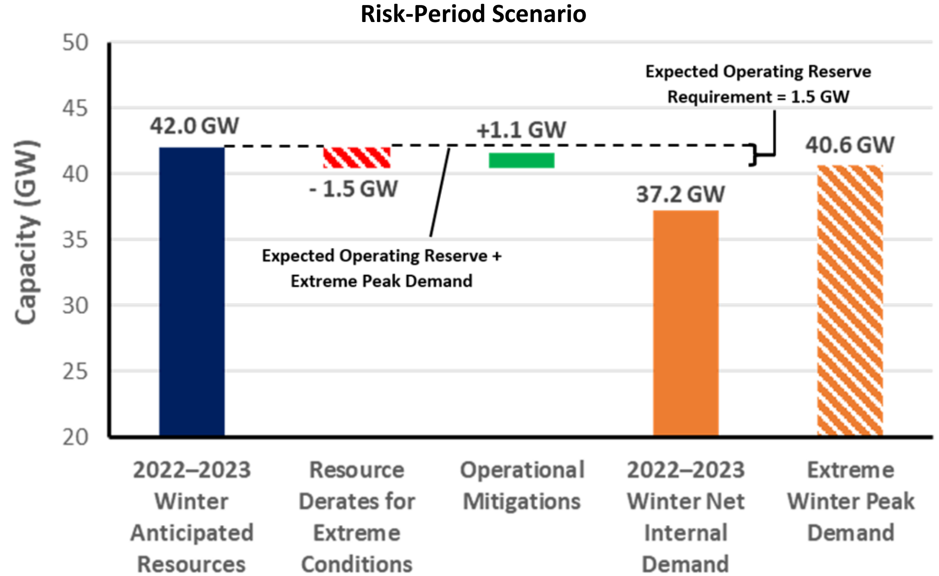
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Québec plans to use short-term capacity purchases in order to meet capacity requirements when needed. 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. As noted above, risk of load shedding is low.

On-Peak Reserve Margins



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 represents two standard deviations higher than the mean demand forecast

Extreme Derates: Rare scenario of 1,500 MW in unplanned outages

Operational Mitigations: Imports anticipated from neighbors during emergencies

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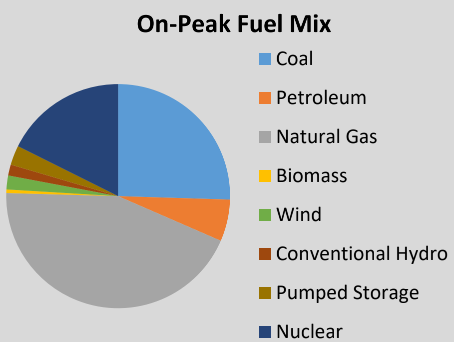
15 Final NPCC Assessment Results will be published at the NPCC Seasonal Assessments page: https://www.npcc.org/library/reports/seasonal-assessment

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 Balancing Authority, Planning Coordinator, Transmission Planner, Resource Planner, Interchange Authority, Transmission Operator, Transmission Service Provider, and Reliability Coordinator.

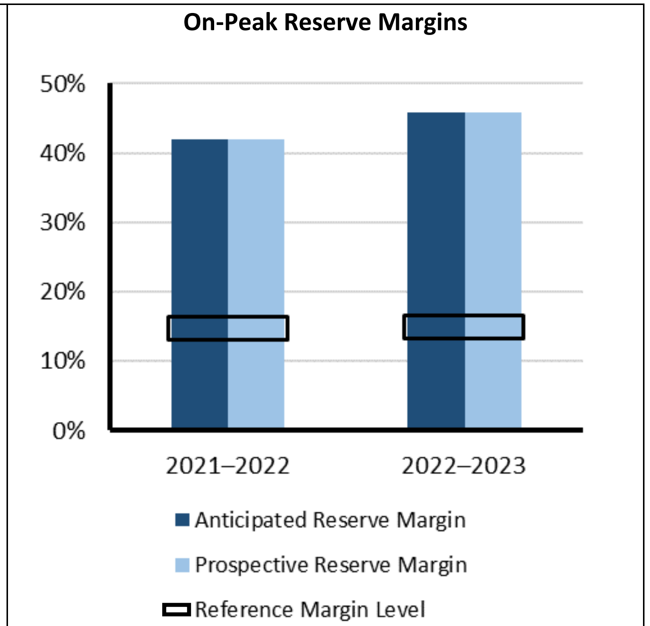


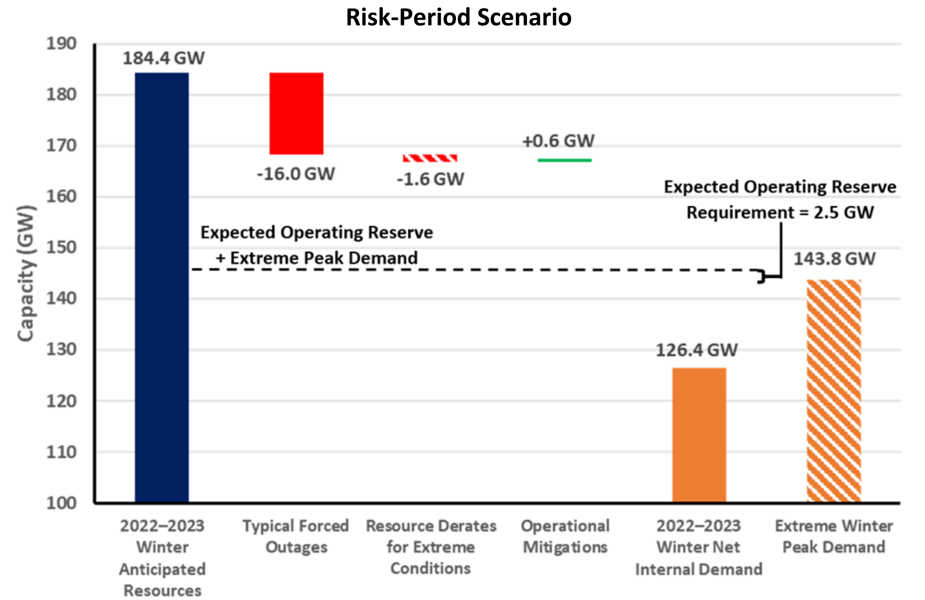
Highlights

- PJM expects no resource problems over the entire 2022–2023 winter peak season because installed capacity is almost three times the reserve requirement.
- No other reliability concerns are expected.

Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.





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

Outages: Based on historical data and trending

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

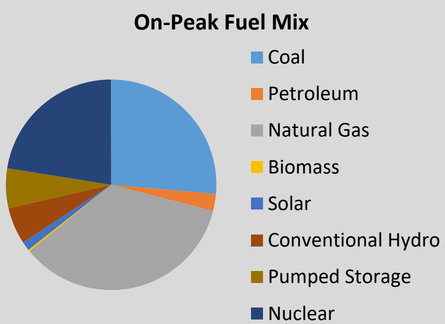
Operational Mitigations: A total of 0.6 GW based on operational/emergency procedures

SERC-East

SERC-East is a winter-peaking assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina.

SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million.

The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

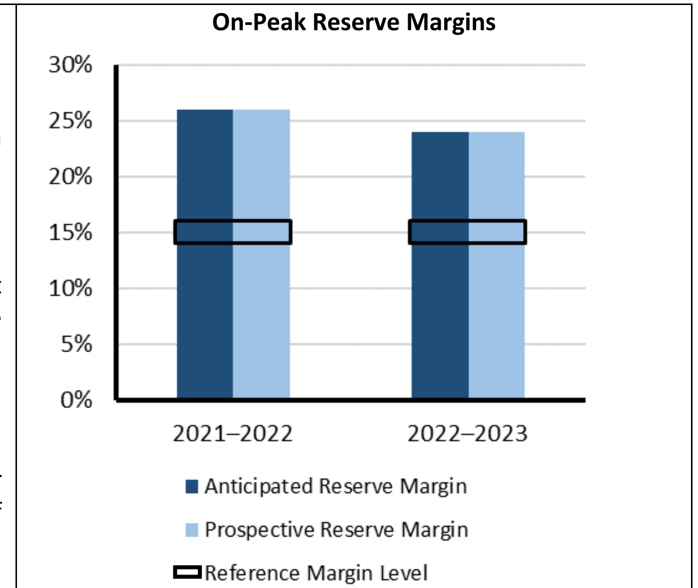


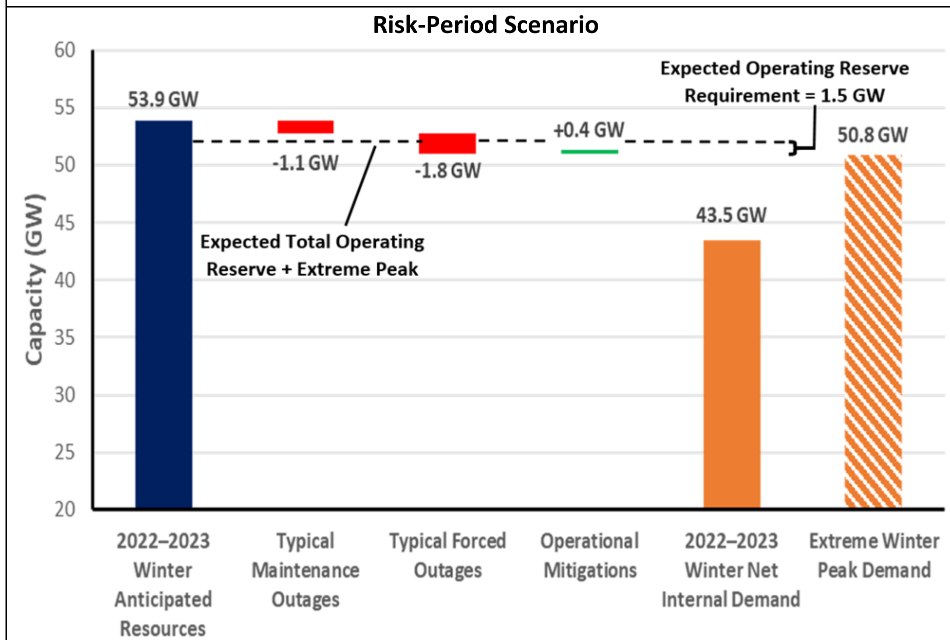
Highlights

- SERC-East has not identified any emerging or potential reliability issues for the upcoming winter season.
- Currently, there are issues with fuel supply and transportation in the SERC-East assessment area. Transportation providers and coal suppliers continue to struggle with post pandemic personnel shortages, volume increases, and inflationary cost increases. SERC-East does not anticipate any significant reliability issues because of fuel supply, inventory, or transportation.
- SERC-East has extensive weatherization processes that include procedures specific to freezing events. SERC-East is prepared to respond to unexpected day-to-day events and coordinate with neighboring entities to promote overall system reliability.

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 for non-firm transfers, operating mitigations and EEAs. Risk of load shedding is low.





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

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

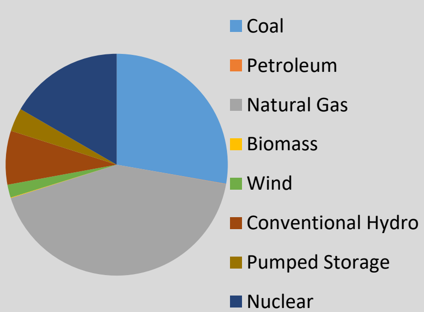
SERC-Central

SERC-Central is a winter-peaking assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky.

SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission approved delegation agreements with NERC. SERC-Central is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million.

The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

On-Peak Fuel Mix



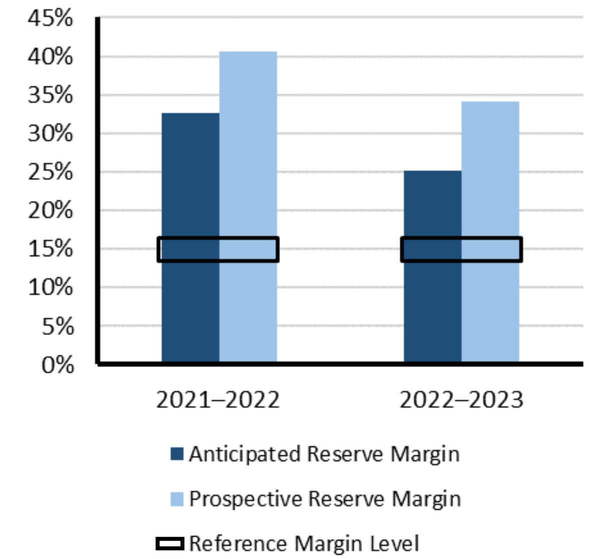
Highlights

- SERC-Central has not identified any emerging or potential reliability issues for the upcoming winter season.
- SERC-Central does not anticipate any significant reliability issues because of fuel supply, inventory, or transportation.
- SERC-Central has extensive weatherization processes that include procedures specific to freezing events and is prepared to respond to unexpected day-to day-events and coordinate with neighboring entities to promote overall system reliability.

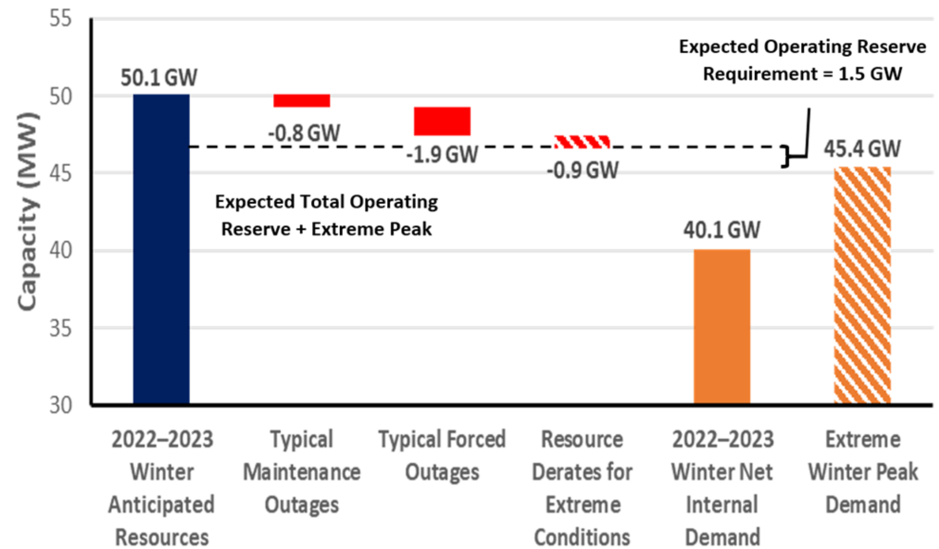
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See <u>Data Concepts and Assumptions</u>)

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

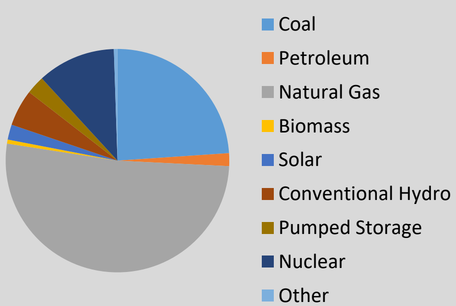
SERC-Southeast

SERC-Southeast is a winter-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi.

SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the southeastern and central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million.

The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

On-Peak Fuel Mix



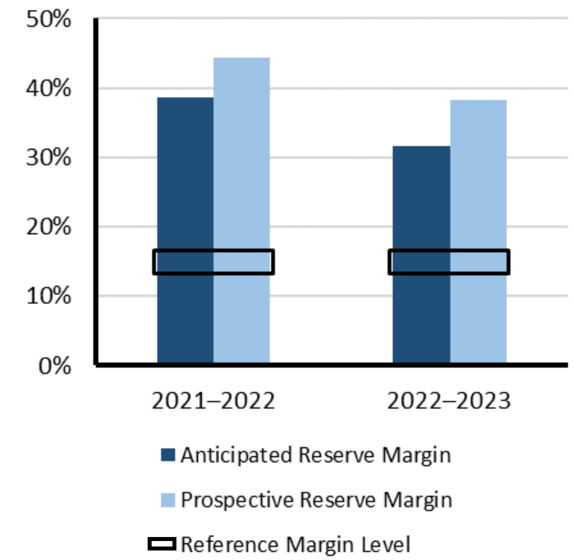
Highlights

- Aside from fuel availability concerns shared across the industry, SERC-Southeast have not identified any additional or emerging potential reliability related risks.
- SERC-Southeast has extensive weatherization processes that include procedures specific to freezing events and is prepared to respond to unexpected day-to-day events and coordinate with neighboring entities to promote overall system reliability.

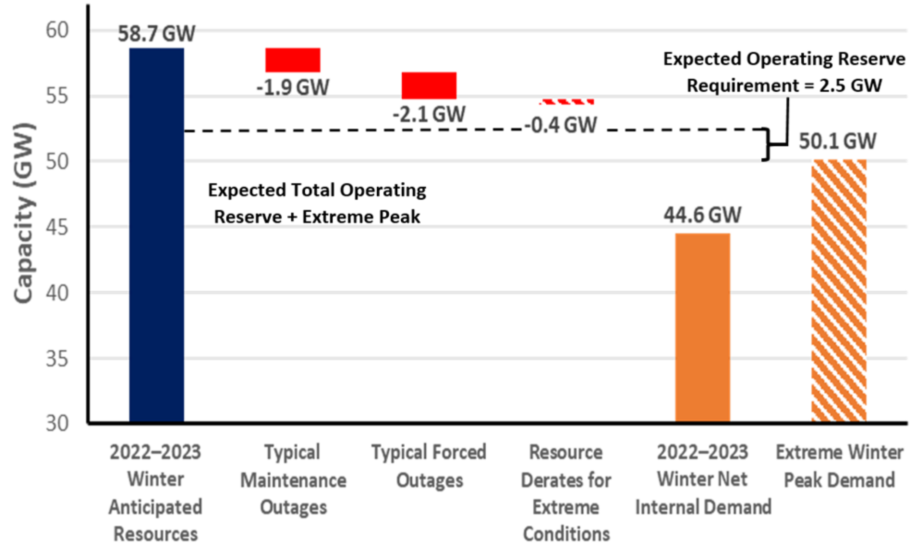
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

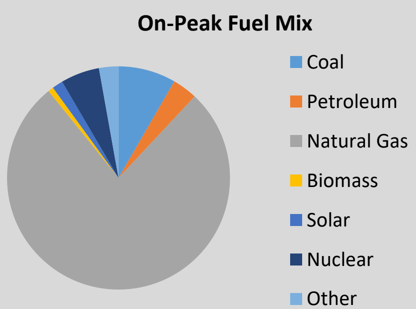
- **Risk Period:** Highest risk for unserved energy at peak demand hour
- **Demand Scenarios:** Net internal demand (50/50) and (90/10) demand forecast
- **Maintenance Outages:** Data collected through a survey of members for outages during December through February
- **Forced Outages:** Weighted average forced outage rates on-peak are factored into the anticipated resources calculation
- **Extreme Derates:** Accounts for reduced thermal capacity contributions due to performance in extreme conditions

SERC-Florida Peninsula

SERC-Florida Peninsula is a summer-peaking assessment area within SERC.

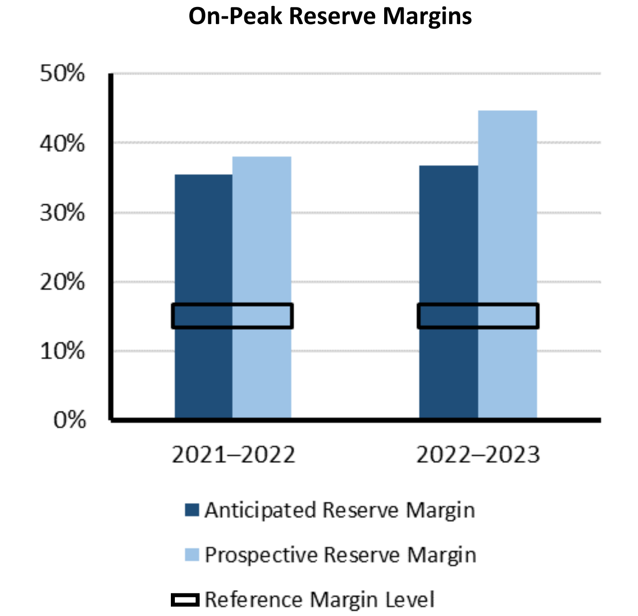
SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million.

The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.



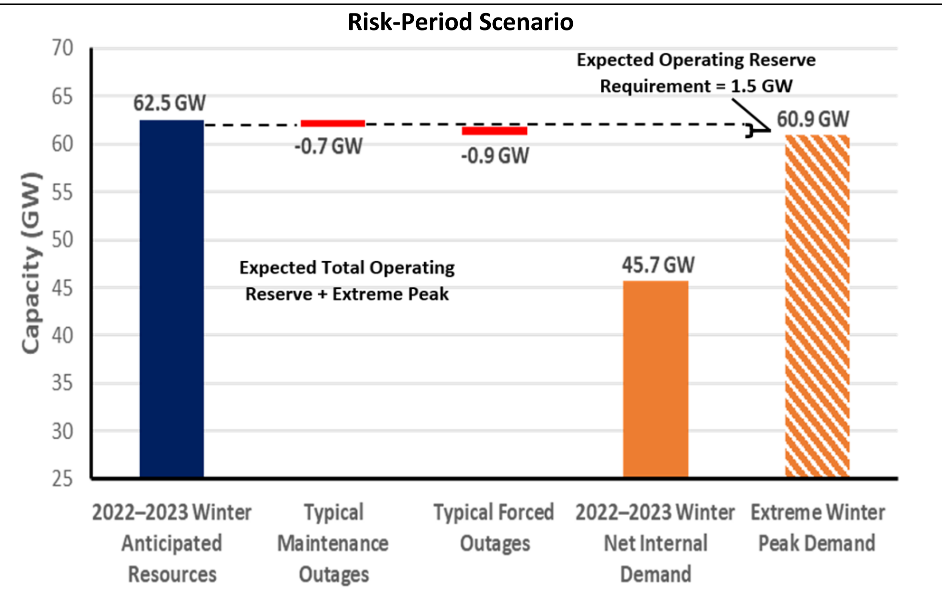
Highlights

- SERC-Florida Peninsula have not identified any emerging or potential reliability issues for the upcoming winter season.
- SERC-Florida Peninsula do not anticipate any significant reliability issues because of fuel supply, inventory, or transportation.
- SERC-Florida Peninsula have extensive weatherization processes that include developing procedures specific to freezing events.



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.



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 (95/5) 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

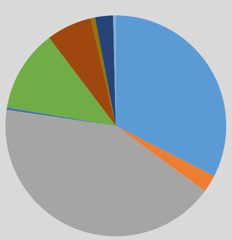
Schedule MM-S19

SPP

Southwest Power Pool (SPP) Planning Coordinator 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 Planning Coordinator 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 it serves a population of more than 18 million.

On-Peak Fuel Mix



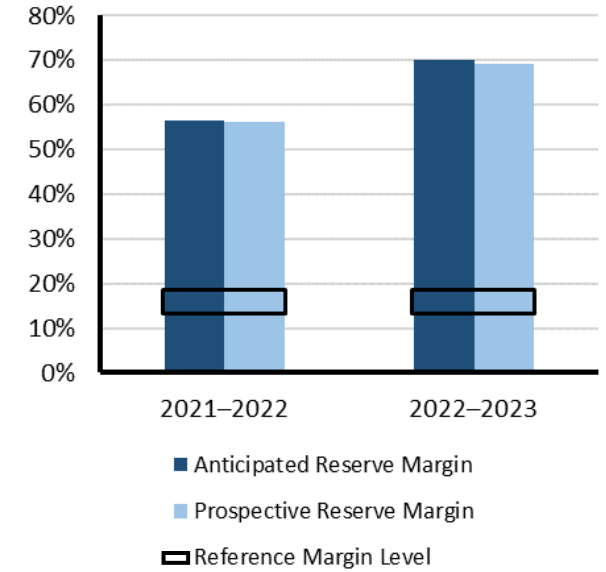
Highlights

- SPP's planning reserves are adequate for the upcoming winter season. Since the 2021–2022 winter, SPP has added 3,700 MW of natural-gas-fired generation.
- SPP does not anticipate any emerging reliability issues impacting the area for the 2022–2023 winter season but realizes that interruptions to fuel supply could create unique operation challenges.
- SPP continues to work with neighboring areas to address potential electric deliverability issues associated with extreme weather events. Efforts focus on enhancing communications and operator preparedness.
- In an effort to minimize the need for conservative operations, EEAs, and the responses 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 the Improved Resource Availability Task Force , which will take primary responsibility for addressing Tier 1 recommendations related to fuel assurance and resource planning and availability identified in the *Comprehensive Review of SPP's Response to the February 2021 Winter Storm* report.
- SPP hosts its winter preparedness workshop in October 2022.

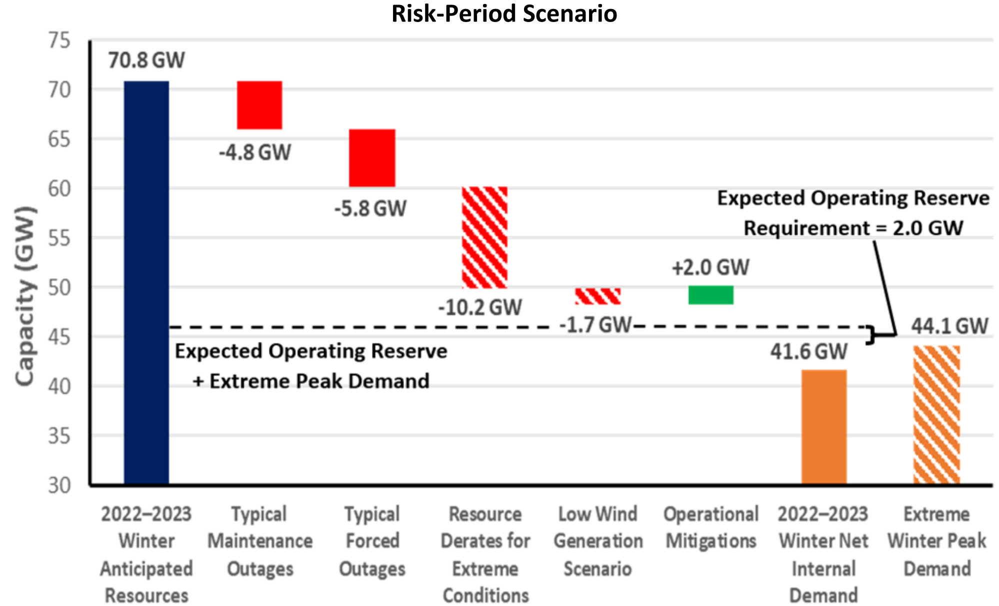
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



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 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)

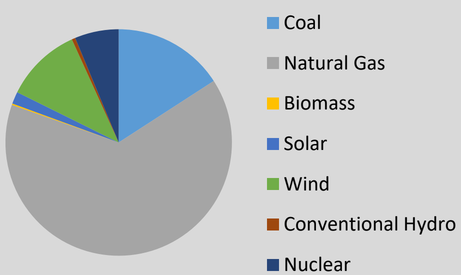
Schedule MM-S19

Texas RE-ERCOT

The Electric Reliability Council of Texas (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. It covers approximately 200,000 square miles, connects over 46,500 miles of transmission lines, has over 710 generation units, and serves more than 25 million people. Lubbock Power & Light joined the ERCOT grid on June 1, 2021. Texas Regional Entity is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT.

On-Peak Fuel Mix



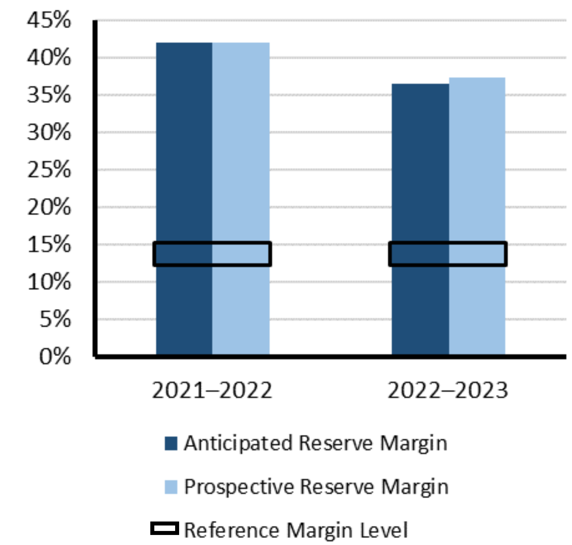
Highlights

- With an Anticipated Reserve Margin of 36.4%, capacity reserves are sufficient to meet forecasted peak demand to cover the types of weather events regularly experienced.
- Probabilistic risk assessment for the upcoming winter season confirms a low probability of energy emergency events occurring during the expected peak load hour (hour-ending 8:00 a.m.) and other higher-risk hours. The assessment accounts for the risk of another weather event like Winter Storm Uri as well as the impacts of winter preparedness standards implemented by the Public Utility Commission of Texas and the TRRC, which regulates the Texas fuel oil and natural gas industries.
- ERCOT conducted 324 weather preparedness inspections during 2021, covering 302 generation sites and 22 transmission service providers. These inspections focused on whether each reporting entity performed the weatherization activities described in their winter weather readiness reports required by the PUCT. ERCOT has been working with the PUCT on development of Phase II of the preparedness standards, which addresses both winter and summer preparedness compliance.
- The U.S. EPA is proposing a "conditional acceptance" of CPS Energy's plan to address two ponds at the coal-fired Calaveras Spruce station that are not in compliance with EPA regulations for coal combustion residuals. If the generation units at the site (J.K. Spruce 1 and 2: 1,477 MW) are found to be needed for grid reliability, then the EPA would allow ERCOT and CPS Energy to plan the outages to best minimize reliability issues during the outage period. If the EPA denies the conditional acceptance, then the Spruce units would cease operations 135 days after the EPA denial decision is made.

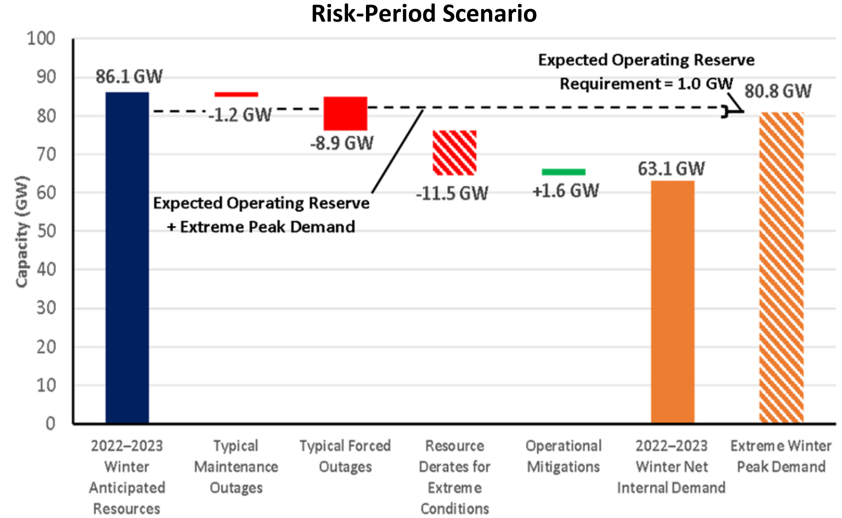
Risk Scenario Summary

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, including load shedding that may be needed under extreme peak demand and outage scenarios studied.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

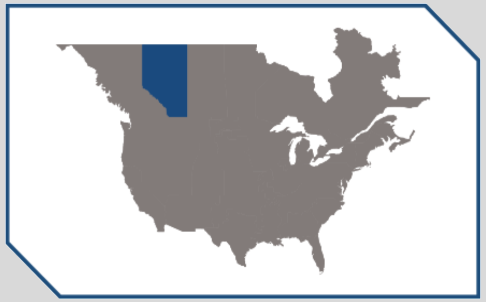
Demand Scenarios: Net internal demand (50/50) and extreme winter peak demand based on 2020–2021 winter storm Uri peak demand

Maintenance and 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 (2019/2020, 2020/2021, and 2021/2022) 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 capacity from switchable generation, additional imports, and voltage reduction

Schedule MM-S19

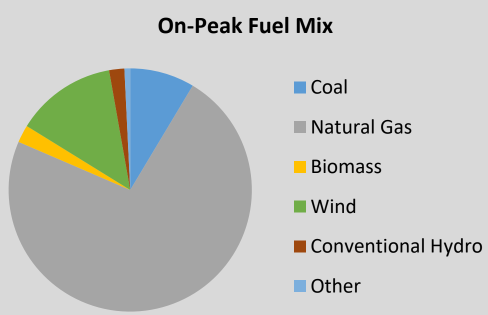


WECC-AB

WECC-AB (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 in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

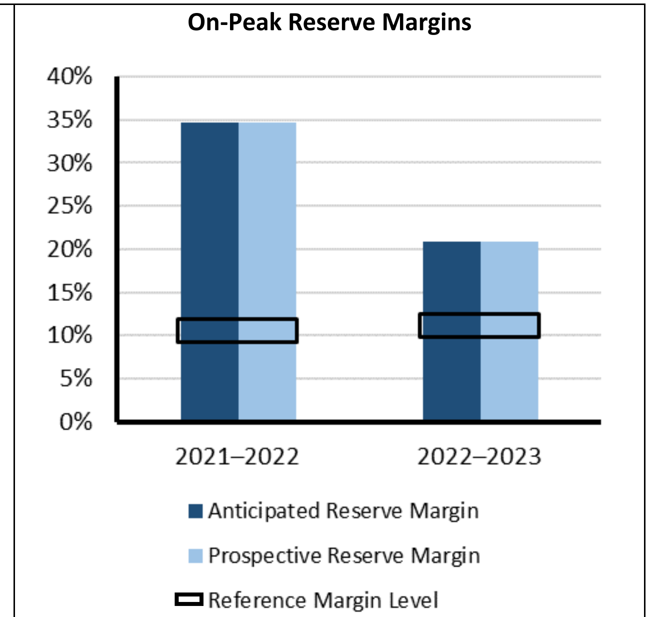


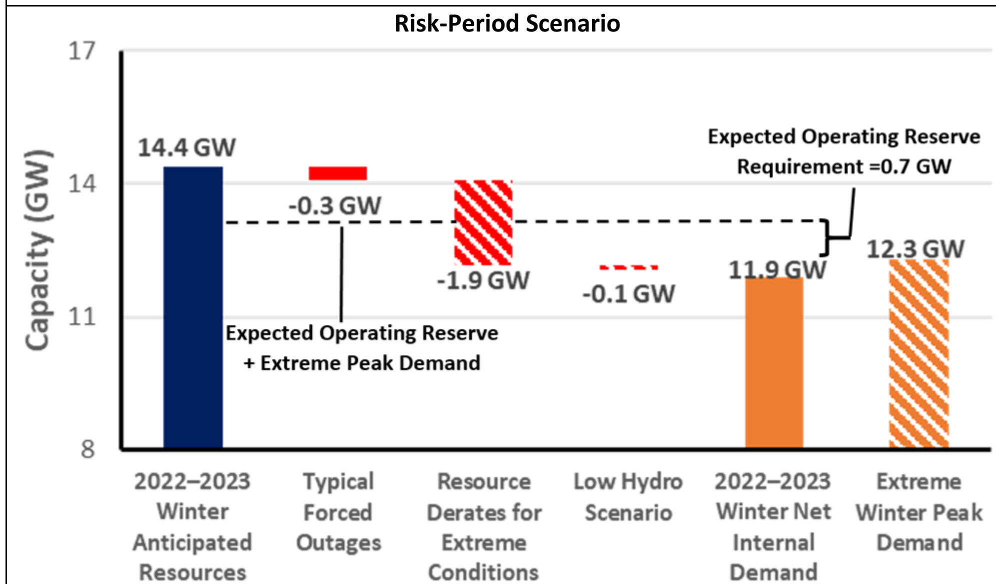
Highlights

- Alberta is a winter peaking area. Winter temperatures are forecast to be below normal. Alberta's operating reserve margins are met before imports in all scenarios except the Low Wind, which leaves a gap of 0.1 GW, and the extreme combined scenario, which leaves a gap of 0.6 GW under extreme peak demand conditions. Both are anticipated to be able to be covered through imports.
- The drop in on-peak reserve margins between last winter and the upcoming winter is a reflection of a slight demand increase of 330 MW combined with roughly 1,500 MW less Tier 1 resources than in the last plan.

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. Risk of load shedding is low due to the expected availability of transfers from neighboring areas.





Scenario Description (See Data Concepts and Assumptions)

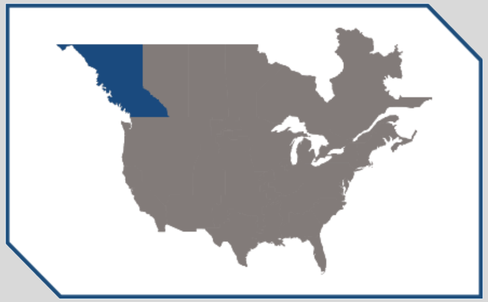
Risk Period: Highest risk for unserved energy at peak demand hour

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

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Low Hydro Scenario: Reduced hydro output due to drought conditions



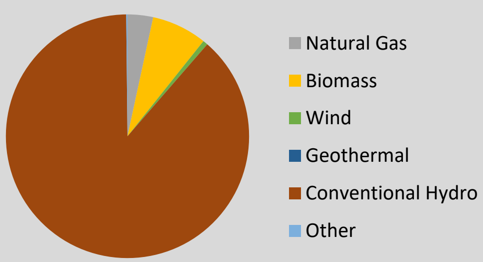
WECC-BC

WECC-BC (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 in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

On-Peak Fuel Mix



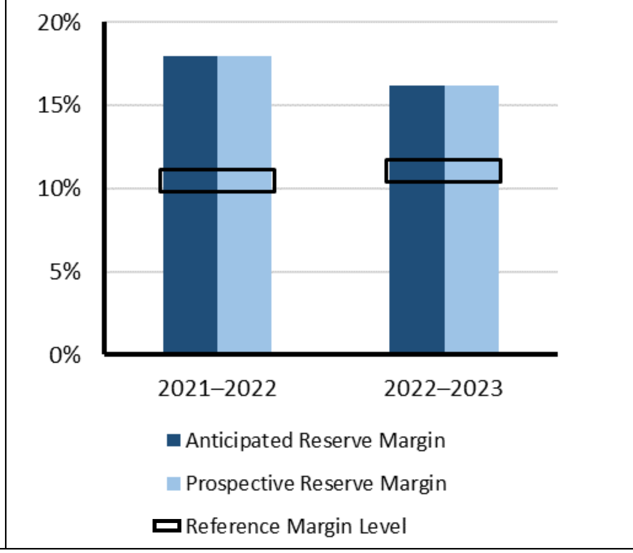
Highlight

- British Columbia is winter peaking with below normal temperatures forecast. In British Columbia before imports, operating reserve margins are not met by at least 0.4 GW in the occurrence of an extreme peak demand. However, the net internal demand is met before imports in all winter resource availability scenarios except under Low Hydro, which leaves an approximate gap of 1 GW, and Extreme Combined, which leaves a gap of 1.1 GW. Both of these are expected to be able to be covered through imports.

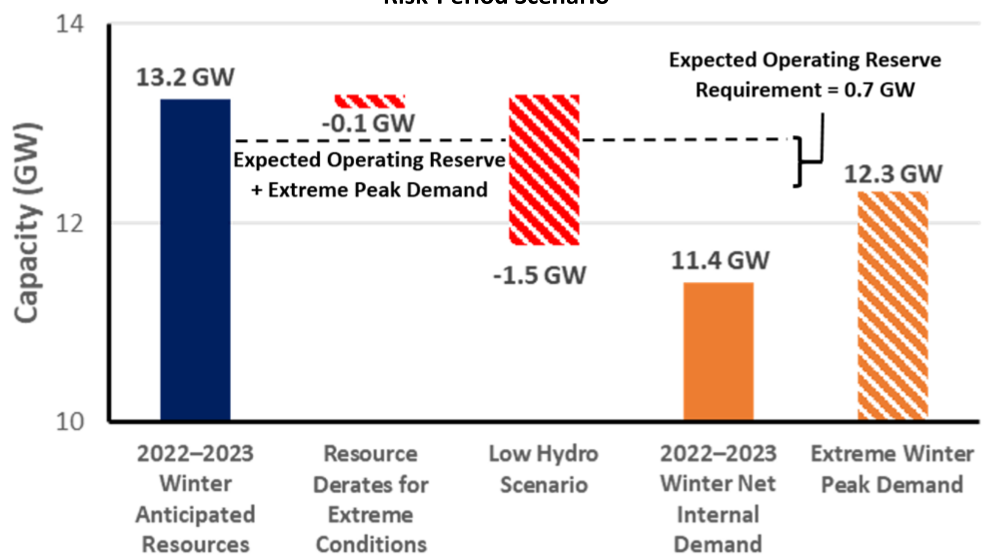
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions combined with an unlikely low-hydro scenario could result in the need to employ operating mitigations (e.g., demand response, transfers, short-term load interruption) and EEAs.

On-Peak Reserve Margins



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

Extreme Derates: Using (90/10) scenario

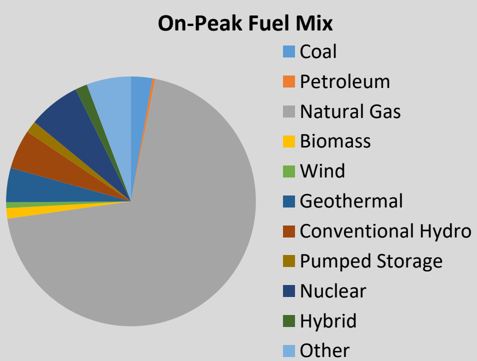
Low Hydro Scenario: Reduced hydro output due to drought conditions

WECC-CA/MX

WECC-CA/MX (California/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 in the Western Interconnection. WECC's 329 members include 39 Balancing Authorizes, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

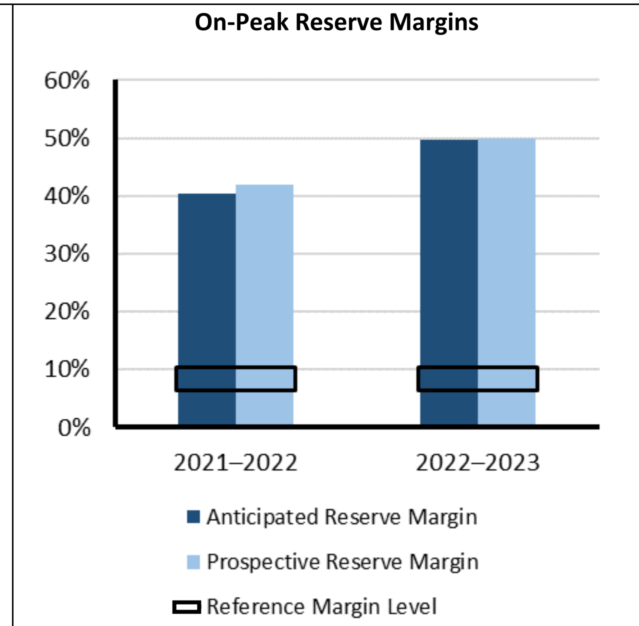


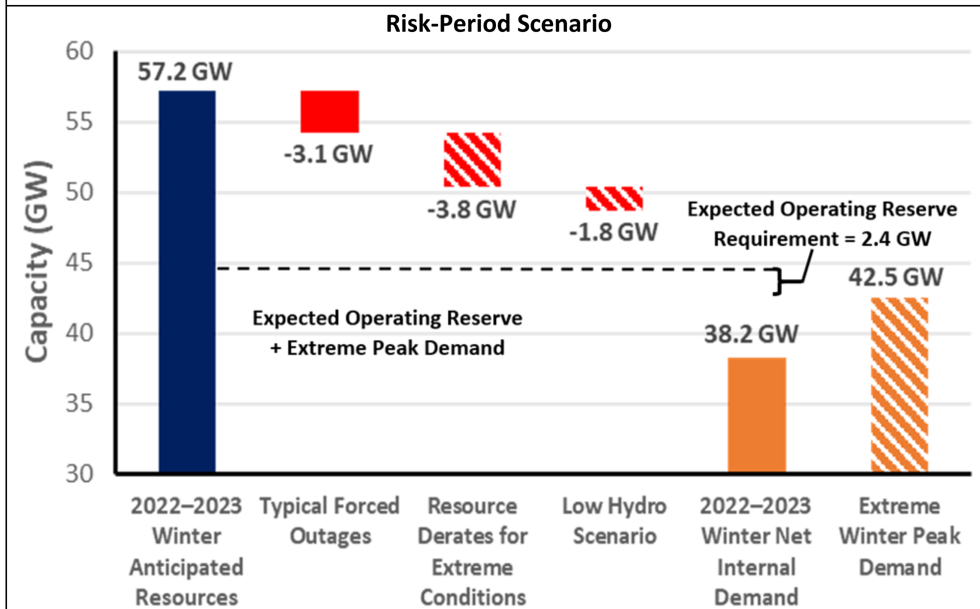
Highlight

- CA/MX is a summer-peaking area. Above average temperatures are forecasted for the upcoming winter. Operating reserve margins are met before imports in all winter resource availability scenarios.

Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.





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: Estimated using market forced outage model

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

Low Hydro Scenario: Reduced hydro output due to drought conditions

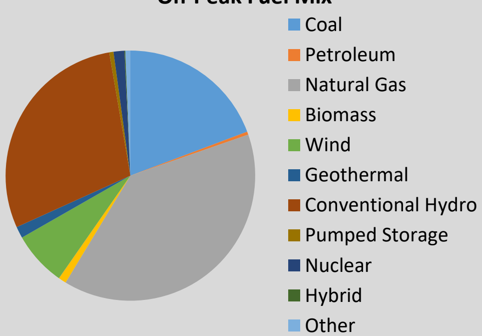
Schedule MM-S19

WECC-WPP

WECC-WPP (Western Power Pool) is a summer-peaking assessment area in the WECC Regional Entity. The area includes Colorado, Idaho, Montana, Oregon, Utah, Washington, Wyoming and parts of California, Nebraska, Nevada, and South Dakota.

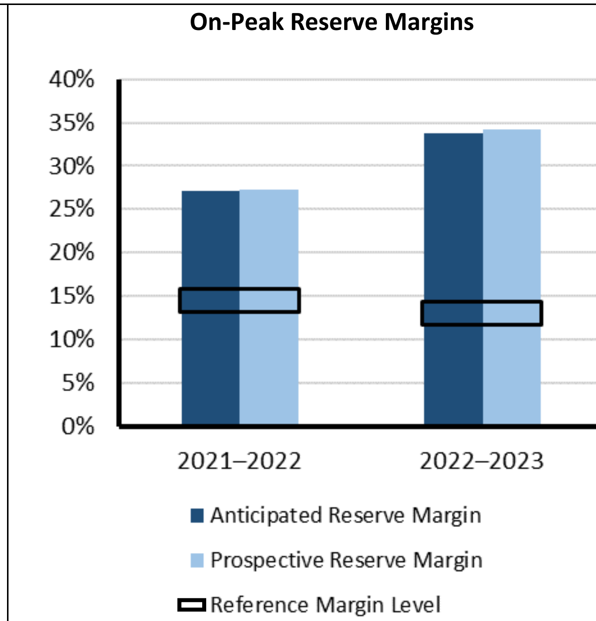
WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.



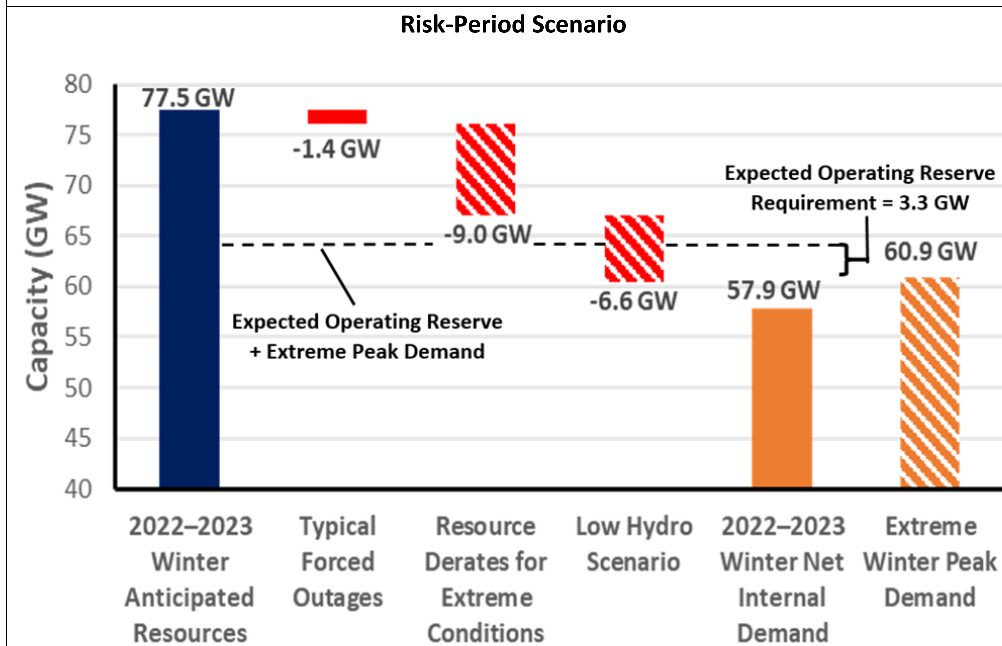
Highlight

- WPP has historically been a mixed season peaking area but is moving towards summer peaking. Operating reserve margins are met at the expected peak demand hour under all but the Extreme Combined scenario, where 1.6 GW of imports would be needed to meet operating reserve margins at an extreme peak demand.



Risk Scenario Summary

Expected resources meet operating reserve requirements under normal and extreme peak-demand scenarios. Low hydro output is unlikely, but could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. The risk of load shedding is low due to the expected availability of transfers from neighboring areas.



Scenario Description (See Data Concepts and Assumptions)

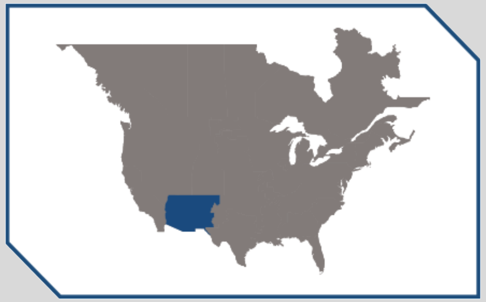
Risk Period: Highest risk for unserved energy at peak demand hour

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

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Low Hydro Scenario: Reduced hydro output due to drought conditions



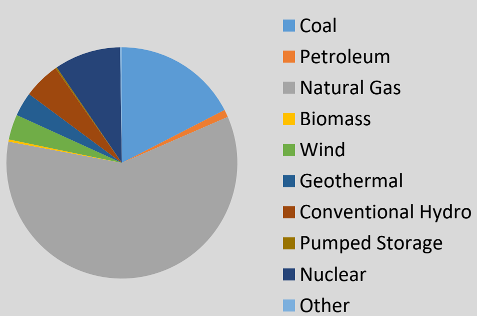
WECC-SRSG

WECC-SRSG (Southwest Reserve Sharing Group) is a summer-peaking assessment area in the WECC Regional Entity. It includes Arizona, New Mexico, and part of California and Texas.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada as well as the northern portion of Baja California in Mexico and all or portions of the 14 Western United States in between.

On-Peak Fuel Mix



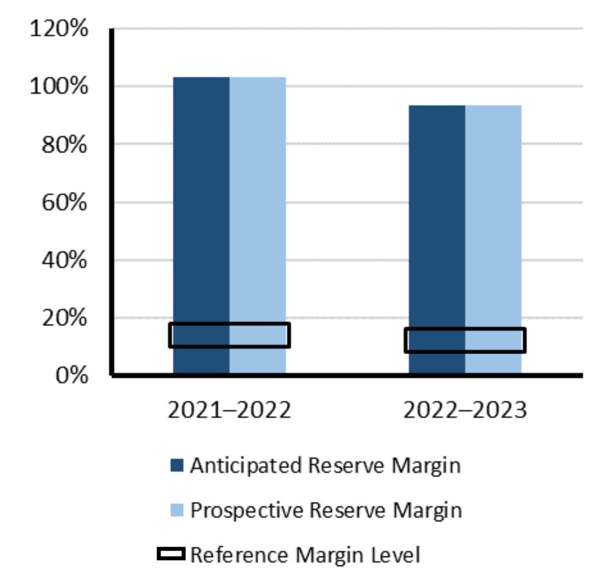
Highlight

- The summer peaking SRSG is expecting above average temperatures this winter. It is anticipated to be resource adequate under all winter extreme availability and demand scenarios. The higher margins compared to the summer season are due to a demand peak of 14 GW in the winter versus a peak of 26 GW in the summer.

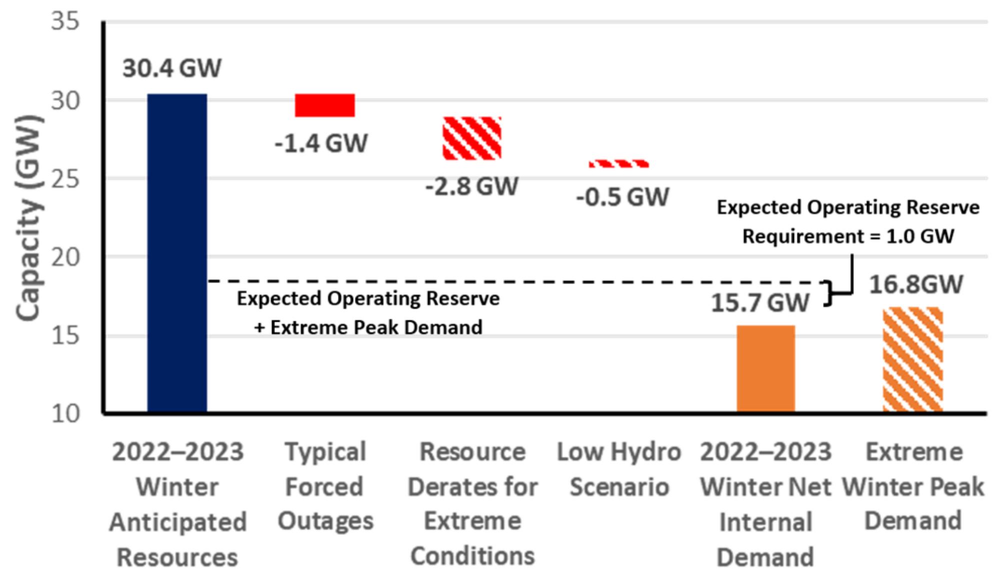
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See [Data Concepts and Assumptions](#))

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

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

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Low Hydro Scenario: Reduced hydro output due to drought conditions

Schedule MM-S19

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 the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
▪ Operating reliability is the ability of the 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.
• *2022 Long-Term Reliability Assessment* data has been used for most of this 2022–2023 assessment period augmented by updated load and capacity data.
• A positive net transfer capability would indicate a net importing assessment area; a negative value would indicate a net exporter.
Demand Assumptions
• Electricity demand projections, or load forecasts, are provided by each assessment area.
• Load forecasts include peak hourly load[16] or total internal demand for the summer and winter of each year.[17]
• Total internal demand projections are based on normal weather (50/50 distribution[18]) and are provided on a coincident[19] 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.

[16] Glossary of Terms used in NERC Reliability Standards
[17] The summer season represents June–September and the winter season represents December–February.
[18] 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.
[19] 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: 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. Further, 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 Anticipated Reserve Margin, 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.[20] Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. Other than in NPCC-Maritimes, all assessment areas have sufficient Anticipated Reserve Margins to meet or exceed their Reference Margin Level for the 2022–2023 winter as shown in **Figure 5**. The Canadian winter-peaking systems of 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. The potential limited availability of locally stored fuel supplies could result in additional generator outages due to depleted fuel inventories. Variable energy resources, such as wind and solar, often contribute significantly less of their installed capability at the period of peak demand in winter. Winter peaks in many areas occur in early morning hours or other times of darkness, resulting in little or no electrical resource output. Consequently the capacity contribution of variable energy resources to an area's anticipated resources may be a fraction of installed capability in winter.

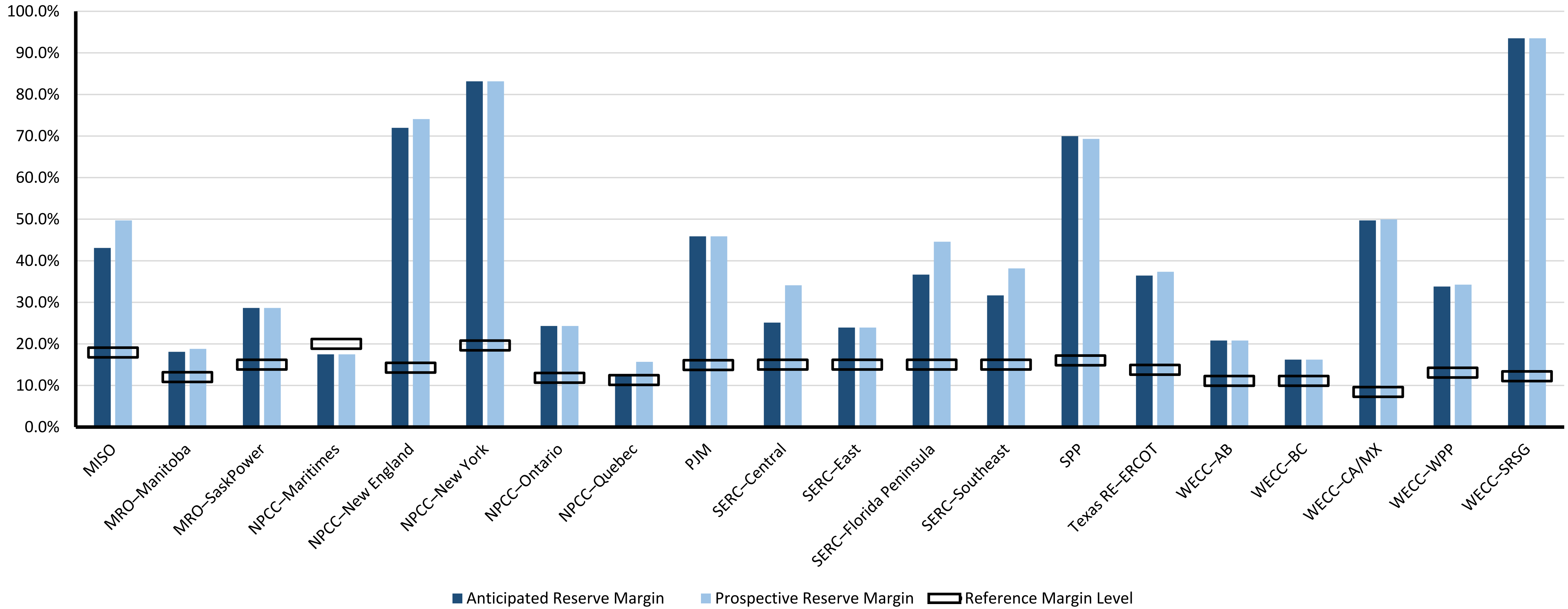


Figure 5: Winter 2022–2023 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[20] 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.

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Changes from Year-to-Year

Figure 6 provides the relative change in the forecast Anticipated Reserve Margins from the 2021–2022 winter to the 2022–2023 winter. Note that the Reference Margin Level is unchanged for areas that don't have a 2021–2022 Reference Margin Level shown. A significant decline can indicate potential operational issues that emerge between reporting years. MISO, NPCC-Maritimes, SERC-Central, SERC-Southeast, Texas RE-ERCOT, and WECC-AB have noticeable reductions in anticipated resources between the 2021–2022 winter and the 2022–2023 winter. All areas except NPCC-Maritimes remain above their Reference Margin Levels for 2022–2023 winter. The lower Anticipated Reserve Margins for MISO, SERC-Central, SERC-Southeast, Texas RE-ERCOT, and WECC-AB do not result in reliability concerns on peak for this upcoming winter. The Canadian winter peaking systems of 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.

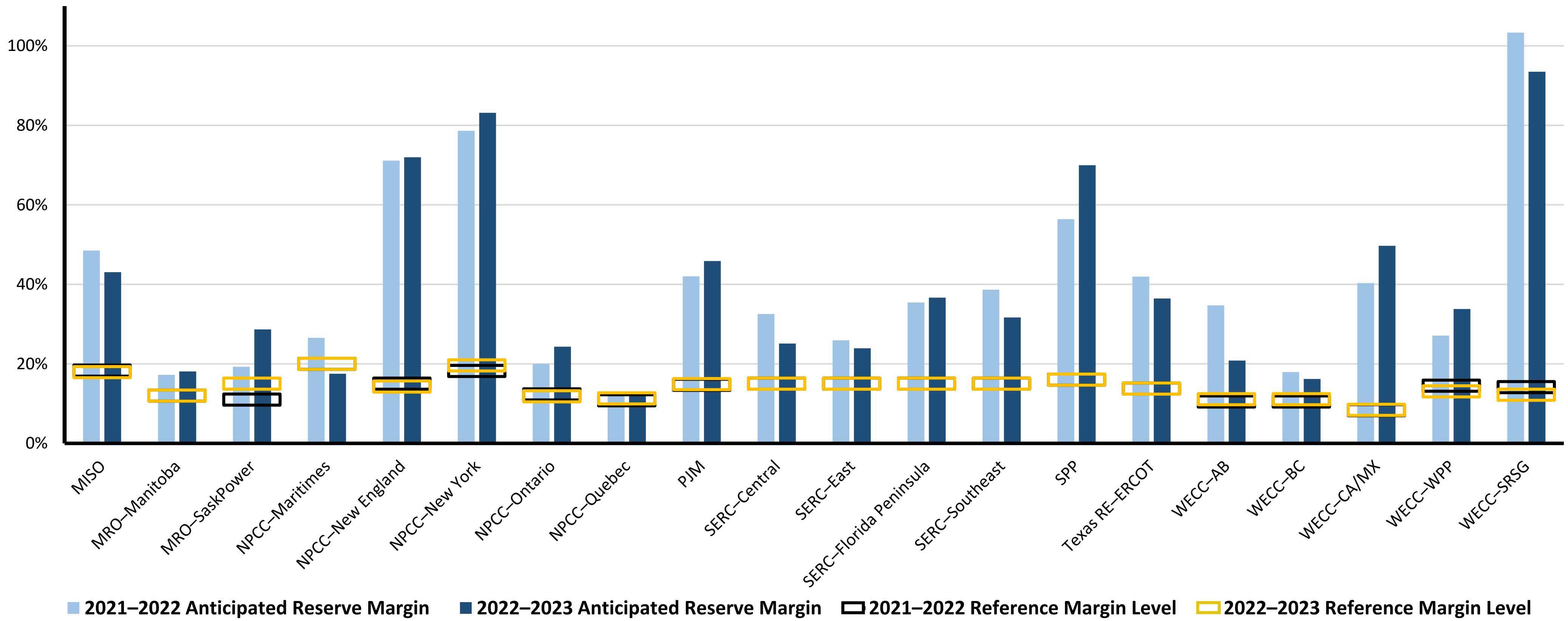

Figure 6: Winter 2021–2022 and Winter 2022–2023 Anticipated Reserve Margins Year-to-Year Change

Internal Demand

Winter peak demand forecasts in many assessment areas are increasing (see **Figure 7)**. The aggregate of winter peak demand forecasts for all areas in the North American BPS has increased by 4,381 MW (0.6%) since the 2021–2022 winter. Since the 2019–2020 winter projections (made prior to the COVID-19 pandemic), the aggregate of demand forecasts for all of North America has increased by 2,766 MW, a 0.4% increase.

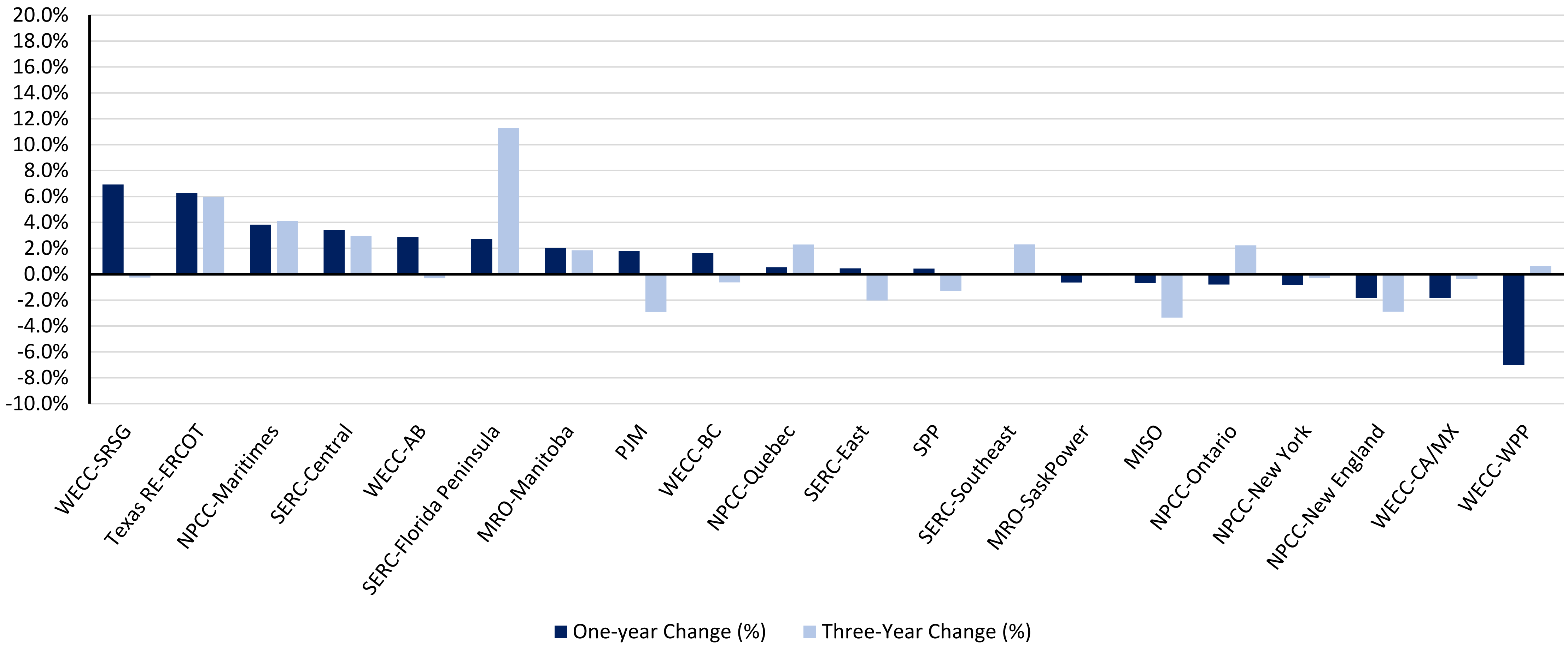

Figure 7: Change in Net Internal Demand: 2022–2023 Winter Forecast Compared To Prior Year Winter Forecasts

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Demand and Resource Tables

Peak demand and supply capacity data for each assessment area are provided below (in alphabetical order).

MISO Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	100,812	102,611	1.8%
Demand Response: Available	3,480	3,672	5.5%
Net Internal Demand	97,332	98,939	1.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	138,535	137,926	-0.4%
Tier 1 Planned Capacity	3,738	0	-100.0%
Net Firm Capacity Transfers	2,283	1,352	-40.8%
Anticipated Resources	144,556	141,565	-2.1%
Existing-Other Capacity	0	669	-
Prospective Resources	147,182	148,125	0.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	48.5%	43.1%	-5.4
Prospective Reserve Margin	51.2%	49.7%	-1.5
Reference Margin Level	18.3%	17.9%	-0.4

MRO-SaskPower Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,798	3,781	-0.4%
Demand Response: Available	60	67	11.7%
Net Internal Demand	3,738	3,714	-0.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,321	4,488	3.9%
Tier 1 Planned Capacity	13	0	-100.0%
Net Firm Capacity Transfers	125	290	132.0%
Anticipated Resources	4,459	4,778	7.2%
Existing-Other Capacity	0	0	-
Prospective Resources	4,459	4,778	7.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	19.3%	28.7%	9.4
Prospective Reserve Margin	19.3%	28.7%	9.4
Reference Margin Level	11.0%	15.0%	4.0

MRO-Manitoba Hydro Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	4,497	4,588	2.0%
Demand Response: Available	0	0	-
Net Internal Demand	4,497	4,588	2.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,438	5,705	4.9%
Tier 1 Planned Capacity	279	279	0.1%
Net Firm Capacity Transfers	-446	-566	26.9%
Anticipated Resources	5,271	5,418	2.8%
Existing-Other Capacity	46	33	-29.4%
Prospective Resources	5,318	5,451	2.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	17.2%	18.1%	0.9
Prospective Reserve Margin	18.3%	18.8%	0.5
Reference Margin Level	12.0%	12.0%	0.0

NPCC-Maritimes Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	5,616	5,784	3.0%
Demand Response: Available	317	282	-11.0%
Net Internal Demand	5,299	5,502	3.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	6,584	6,461	-1.9%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	121	4	-96.7%
Anticipated Resources	6,705	6,465	-3.6%
Existing-Other Capacity	0	0	-
Prospective Resources	6,705	6,465	-3.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.5%	17.5%	-9.0
Prospective Reserve Margin	26.5%	17.5%	-9.0
Reference Margin Level	20.0%	20.0%	0.0%

NPCC-New England Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	20,349	20,009	-1.7%
Demand Response: Available	587	610	4.0%
Net Internal Demand	19,762	19,399	-1.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	32,668	32,129	-1.6%
Tier 1 Planned Capacity	14	162	1057.0%
Net Firm Capacity Transfers	1,134	1,070	-5.6%
Anticipated Resources	33,816	33,361	-1.3%
Existing-Other Capacity	184	142	-23.0%
Prospective Resources	34,000	33,769	-0.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	71.1%	72.0%	0.9
Prospective Reserve Margin	72.0%	74.1%	2.1
Reference Margin Level	15.0%	14.3%	-0.7

NPCC-New York Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	24,025	23,893	-0.5%
Demand Response: Available	631	695	10.1%
Net Internal Demand	23,394	23,198	-0.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	40,239	40,393	0.4%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,547	2,097	35.6%
Anticipated Resources	41,786	42,490	1.7%
Existing-Other Capacity	0	0	-
Prospective Resources	41,786	42,490	1.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	78.6%	83.2%	4.6
Prospective Reserve Margin	78.6%	83.2%	4.6
Reference Margin Level	18.2%	19.6%	1.4

NPCC-Ontario Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	20,940	21,255	1.5%
Demand Response: Available	132	614	364.1%
Net Internal Demand	20,808	20,641	-0.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	25,403	26,051	2.6%
Tier 1 Planned Capacity	63	112	77.0%
Net Firm Capacity Transfers	-500	-500	0.0%
Anticipated Resources	24,966	25,662	2.8%
Existing-Other Capacity	0	0	-
Prospective Resources	24,966	25,662	2.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.0%	24.3%	4.3
Prospective Reserve Margin	20.0%	24.3%	4.3
Reference Margin Level	12.3%	11.8%	-0.5

NPCC-Québec Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	39,386	39,699	0.8%
Demand Response: Available	2,368	2,759	16.5%
Net Internal Demand	37,017	37,217	0.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	42,072	42,113	0.1%
Tier 1 Planned Capacity	27	255	838.2%
Net Firm Capacity Transfers	-499	-417	-16.4%
Anticipated Resources	41,600	41,951	0.8%
Existing-Other Capacity	0	0	-
Prospective Resources	42,700	43,051	0.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	12.4%	12.7%	0.3%
Prospective Reserve Margin	15.4%	15.7%	0.3%
Reference Margin Level	10.8%	11.3%	0.5%

PJM Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	132,632	132,980	0.3%
Demand Response: Available	8,466	6,583	-22.2%
Net Internal Demand	124,166	126,397	1.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	179,247	185,102	3.3%
Tier 1 Planned Capacity	19	0	-100.0%
Net Firm Capacity Transfers	-2,937	-726	-75.3%
Anticipated Resources	176,329	184,376	4.6%
Existing-Other Capacity	0	0	-
Prospective Resources	176,329	184,376	4.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	42.0%	45.9%	-3.9
Prospective Reserve Margin	42.0%	45.9%	-3.9
Reference Margin Level	14.7%	14.9%	-0.2

SERC-East Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	44,175	44,648	1.1%
Demand Response: Available	903	1,180	30.7%
Net Internal Demand	43,272	43,468	0.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	53,933	53,287	-1.2%
Tier 1 Planned Capacity	0	75	-
Net Firm Capacity Transfers	562	513	-8.7%
Anticipated Resources	54,495	53,875	-1.1%
Existing-Other Capacity	0	3	-
Prospective Resources	54,495	53,877	-1.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.9%	23.9%	-2.0
Prospective Reserve Margin	25.9%	23.9%	-2.0
Reference Margin Level	15.0%	15.0%	0.0

SERC-Central Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	40,320	41,745	3.5%
Demand Response: Available	1,564	1,671	6.8%
Net Internal Demand	38,756	40,074	3.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	51,271	51,008	-0.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	99	-868	-
Anticipated Resources	51,370	50,140	-2.4%
Existing-Other Capacity	3,135	3,601	14.9%
Prospective Resources	54,505	53,741	-1.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	32.5%	25.1%	-7.4
Prospective Reserve Margin	40.6%	34.1%	-6.5
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	46,074	48,582	5.4%
Demand Response: Available	1,571	2,870	82.7%
Net Internal Demand	44,503	45,712	2.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	57,694	61,987	7.4%
Tier 1 Planned Capacity	1,169	237	-79.7%
Net Firm Capacity Transfers	1,414	250	-82.3%
Anticipated Resources	60,277	62,474	3.6%
Existing-Other Capacity	1,147	3,618	215.5%
Prospective Resources	61,424	66,092	7.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	35.4%	36.7%	1.3
Prospective Reserve Margin	38.0%	44.6%	6.6
Reference Margin Level	15.0%	15.0%	0.0

SERC-Southeast Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	46,232	46,513	0.6%
Demand Response: Available	1,682	1,954	16.2%
Net Internal Demand	44,550	44,559	0.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	61,899	60,097	-2.9%
Tier 1 Planned Capacity	1,102	1,102	0.0%
Net Firm Capacity Transfers	-1,218	-2,524	107.2%
Anticipated Resources	61,782	58,674	-5.0%
Existing-Other Capacity	2,516	2,895	15.1%
Prospective Resources	64,298	61,569	-4.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	38.7%	31.7%	-7.0
Prospective Reserve Margin	44.3%	38.2%	-6.1
Reference Margin Level	15.0%	15.0%	0.0

SPP Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	41,669	41,650	0.0%
Demand Response: Available	211	13	-93.7%
Net Internal Demand	41,458	41,637	0.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	65,197	71,131	9.1%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-348	-359	3.3%
Anticipated Resources	64,850	70,772	9.1%
Existing-Other Capacity	0	0	-
Prospective Resources	64,820	70,496	8.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	56.4%	70.0%	13.6%
Prospective Reserve Margin	56.4%	69.3%	13.0%
Reference Margin Level	16.0%	16.0%	0.0

Texas RE-ERCOT Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	62,001	66,436	7.2%
Demand Response: Available	2,598	3,302	27.1%
Net Internal Demand	59,403	63,134	6.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	81,443	85,478	5.0%
Tier 1 Planned Capacity	2,665	644	-75.8%
Net Firm Capacity Transfers	210	20	-90.5%
Anticipated Resources	84,318	86,142	2.2%
Existing-Other Capacity	0	0	-
Prospective Resources	84,382	86,710	2.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	41.9%	36.4%	-5.5
Prospective Reserve Margin	42.1%	37.3%	-4.8
Reference Margin Level	13.75%	13.75%	0.0

WECC-AB Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,569	11,901	2.9%
Demand Response: Available	0	0	-
Net Internal Demand	11,569	11,901	2.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	12,842	13,144	2.3%
Tier 1 Planned Capacity	2,743	1,234	-55.0%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	15,585	14,378	-7.7%
Existing-Other Capacity	0	0	-
Prospective Resources	15,585	14,378	-7.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	34.7%	20.8%	-13.9
Prospective Reserve Margin	34.7%	20.8%	-13.9
Reference Margin Level	10.5%	11.1%	0.6

WECC-BC Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,213	11,395	1.6%
Demand Response: Available	0	0	-
Net Internal Demand	11,213	11,395	1.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,077	13,223	1.1%
Tier 1 Planned Capacity	146	20	-86.4%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	13,223	13,243	0.1%
Existing-Other Capacity	0	0	-
Prospective Resources	13,223	13,243	0.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	17.9%	16.2%	-1.7
Prospective Reserve Margin	17.9%	16.2%	-1.7
Reference Margin Level	10.5%	11.1%	0.6

WECC-CA/MX Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	39,779	38,978	-2.0%
Demand Response: Available	829	749	-9.7%
Net Internal Demand	38,950	38,230	-1.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	51,996	55,287	6.3%
Tier 1 Planned Capacity	2,205	1,943	-11.9%
Net Firm Capacity Transfers	449	0	-100.0%
Anticipated Resources	54,650	57,231	4.7%
Existing-Other Capacity	0	0	-
Prospective Resources	55,312	57,326	3.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	40.3%	49.7%	9.4
Prospective Reserve Margin	42.0%	50.0%	8.0
Reference Margin Level	8.3%	8.4%	0.1

WECC-SRSG Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	14,910	16,004	7.3%
Demand Response: Available	241	318	32.3%
Net Internal Demand	14,669	15,686	6.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	29,446	29,799	1.2%
Tier 1 Planned Capacity	381	553	45.1%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	29,827	30,352	1.8%
Existing-Other Capacity	0	0	-
Prospective Resources	29,836	30,352	1.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	103.3%	93.5%	-9.8
Prospective Reserve Margin	103.4%	93.5%	-9.9
Reference Margin Level	14.1%	12.2%	-1.9

WECC-WPP Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	62,822	58,605	-6.7%
Demand Response: Available	551	707	28.4%
Net Internal Demand	62,271	57,898	-7.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	74,865	76,477	2.2%
Tier 1 Planned Capacity	424	988	133.1%
Net Firm Capacity Transfers	3,877	0	-100.0%
Anticipated Resources	79,166	77,465	-2.1%
Existing-Other Capacity	0	0	-
Prospective Resources	79,205	77,730	-1.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.1%	33.8%	6.7
Prospective Reserve Margin	27.2%	34.3%	7.1
Reference Margin Level	14.5%	13.1%	-1.4

Errata

November 2022

- The Extreme Conditions reserve margin for SERC-FP in Table 1 was corrected (page 8)
- The Scenario Description language in Texas RE-ERCOT’s dashboard was corrected (page 26)