NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2022 NERC Probabilistic Assessment (ProbA)

Regional Risk Scenario Sensitivity Case
June 2023

RELIABILITY | RESILIENCE | SECURITY




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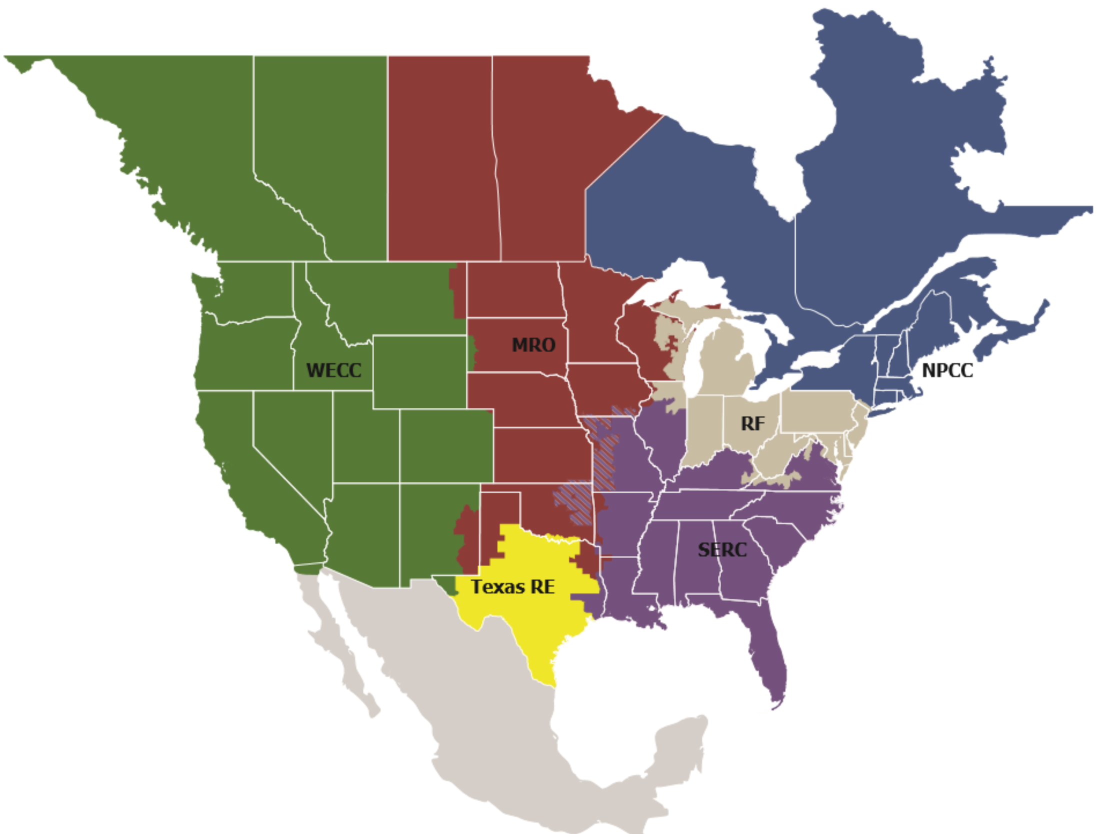
Preface

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

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

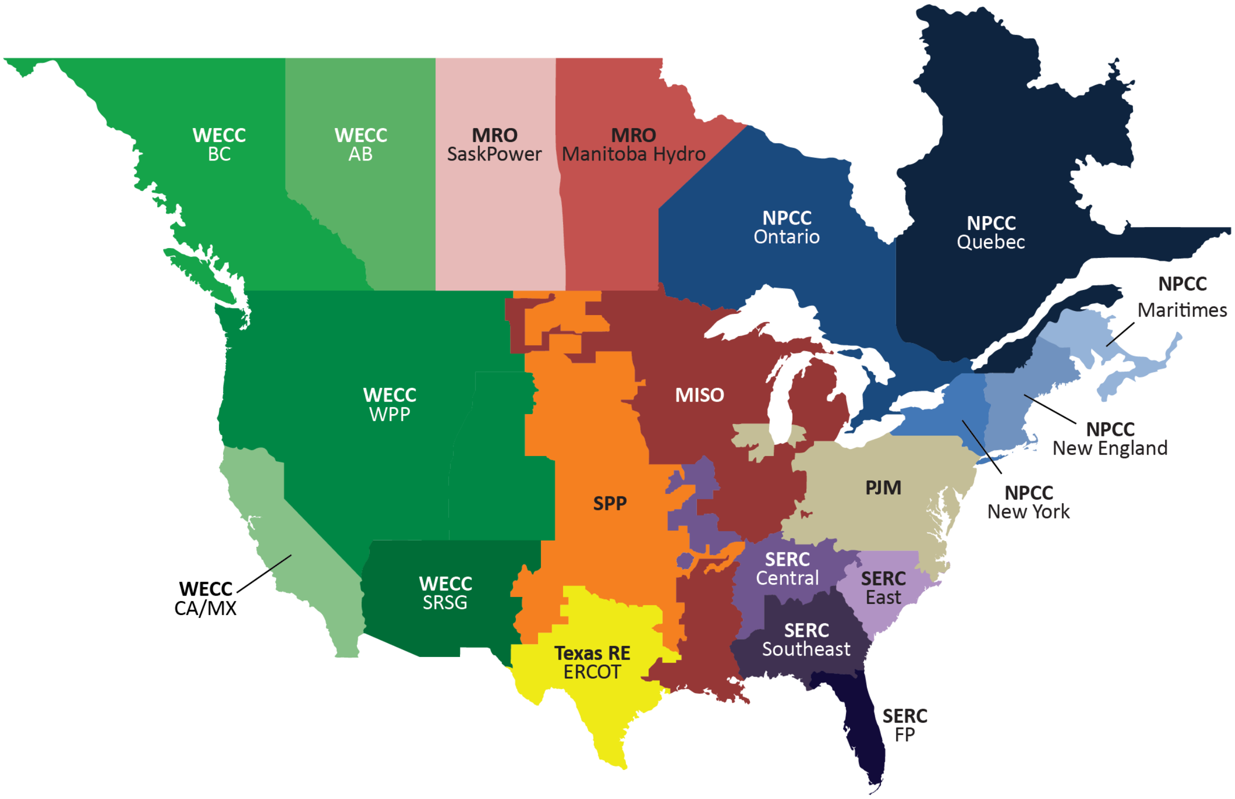
The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.

Regional Entities



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

Assessment Areas



- MISO *(Midcontinent Independent System Operator)*
- PJM

MRO – Midwest Reliability Organization

- MRO-Manitoba Hydro
- MRO-SaskPower
- SPP

NPCC – Northeast Power Coordinating Council

- NPCC-Maritimes
- NPCC-New England
- NPCC-New York
- NPCC-Ontario
- NPCC-Québec

SERC – SERC Reliability Corporation

- SERC-East
- SERC-Central
- SERC-Southeast
- SERC-Florida Peninsula

Texas RE – Texas Reliability Entity

- Texas RE-ERCOT *(Electric Reliability Council of Texas)*

WECC

- WECC-CA/MX *(California/Mexico)*
- WECC-AB *(Alberta)*
- WECC-BC *(British Colombia)*
- WECC-WPP *(Western Power Pool)*
- WECC-SRSG *(Southwest Reserve Sharing Group)*

Executive Summary

The *2021 ERO Reliability Risk Priorities Report*[1] defines and prioritizes risks to the reliable operation of the BPS. This report highlighted that the traditional methods of assessing resource adequacy (i.e., by focusing primarily on generating capacity, transmission and pipeline capacity, and fuel availability at traditional peak load times) may not accurately or fully reflect the ability of the new resource mix to supply energy and reserves for all operating conditions. To address this risk, the ERO has increasingly used probabilistic assessments as a tool to identify potential reliability risks for a multitude of operating conditions for all hours of the year. With various resource portfolios across the North American BPS and distinct plans to meet electricity reliability requirements, the Probabilistic Assessment Working Group (PAWG) recognizes that each area may have unique risks to consider and assess. This report describes and performs the assessments of risk scenarios for each area and compares them against the biennial Probabilistic Assessment (ProbA) Base Case, which was released with the *2022 NERC Long-Term Reliability Assessment* (*LTRA*) [2] in December 2022. This model, adopted with the 2020 NERC ProbA, allows system planners to more closely study area-specific reliability risks and any possible uncertainties using probabilistic methods. It is important to recognize that the Bulk Electric System (BES) (and by extension the BPS) across the six Regional Entities and assessment areas is diverse in terms of planning and operations processes as well as their associated risks. The assessment utilized a comprehensive, peer-review process for each assessment area's respective methods, assumptions, and results.

This *2022 Sensitivity Case Report* includes the scenarios described in **Figure E.1**.

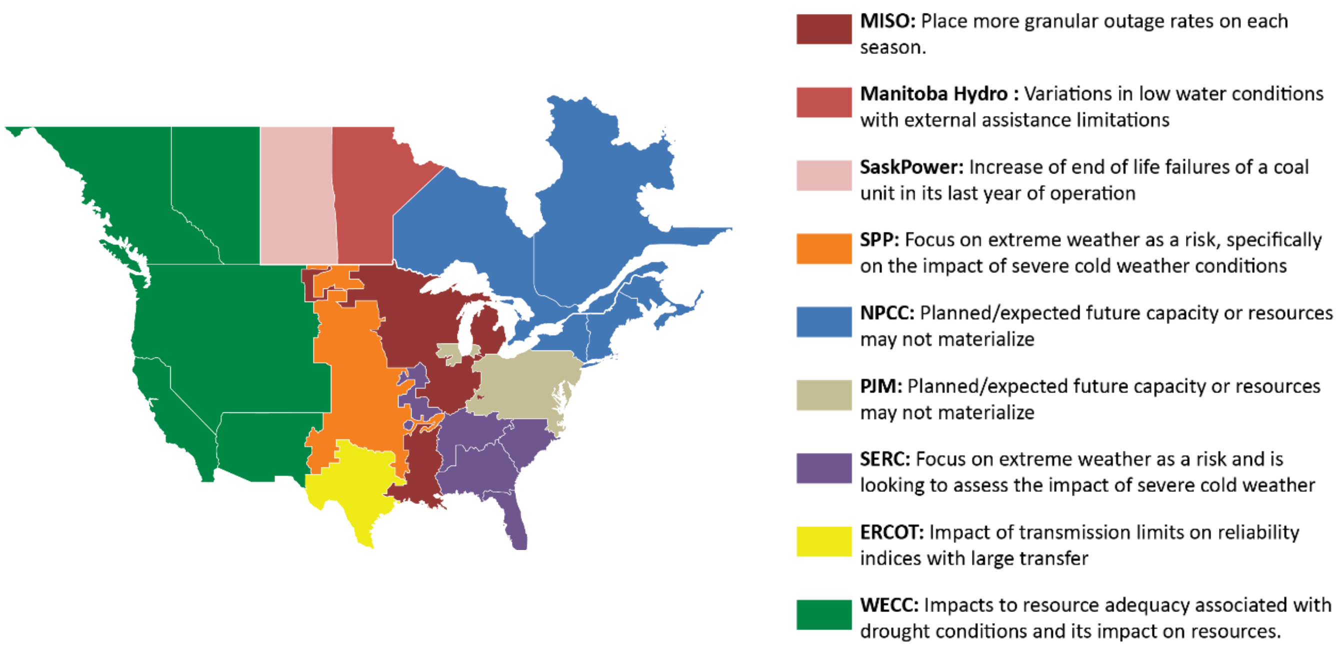


Figure E.1: ProbA Regional Risk Scenarios

Regional Entities were requested to compare the reported risk factor results in the Probabilistic Assessment (ProbA) Sensitivity Case to the ProbA Base Case results from the *2022 NERC LTRA*. These comparisons between the Base Cases and Sensitivity Cases, combined with the trending results compared from the 2020 ProbA (found in the *2020 NERC LTRA*), provide a complete analysis to better understand underlying uncertainties and benchmark system risks. At assessment area discretion, the scenarios intentionally stressed the assumptions to study their associated impacts on the probabilistic indices. Although mitigation efforts were not the intended focus of the study, some assessment areas provided rationale on potential methods to mitigate the chosen risk.

[1] ERO Reliability Risk Priorities Report: RISC Recommendations to the NERC Board of Trustees, August 2021

[2] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf

Key Findings

Sensitivity results were varied across the study and dependent on their underlying assumptions. The major Key findings are as follows:

- In MISO, the summer remains the season with the largest expected unserved energy (EUE) risk as MISO is a summer peaking system. However, the risk is more spread out throughout the year as the seasonal outages uncover EUE in several months that previously showed zero loss of load risk.
- Manitoba Hydro's analysis results show that loss of load hours (LOLH) and EUE values increase for both 2024 and 2026. However, proper management of energy in reservoir storage in accordance with good utility practice provides risk mitigation under low water flow conditions.
- SaskPower's scenario of a baseload coal unit experienced a critical failure in its last year of operation that resulted in a higher loss of load values in the first year of the assessment as compared to the Base Case. SaskPower is not anticipating any major reliability issues but expects to mitigate them by using the emergency assistance, if needed.
- NPCC assessment areas demonstrated that the risks associated with planned and expected resources that did not materialize were not significant, and they could be mitigated by using preventive planning and operating measures.
- PJM demonstrated that excluding Tier 1 resources showed no significant risk as its Anticipated Planning Reserve Margins are above the reference values.
- SERC results indicate a small risk of customer interruption and loss of energy under a severe winter case, combining both unusual weather with higher than anticipated unit outages.
- In Southwest Power Pool (SPP), the results showed an increase of potential EUE, reflecting the probability of increased forced outages during extreme winter weather events paired and an increase of load from the higher load scenario.
- ERCOT's analysis, with its study of the impact of transmission limits on reliability indices that had heavy inverter-based resources (IBR) in one area, uses transmission to get to its load in the central/east side of the state for the 2026 study year. The addition of internal transmission constraints had implications for reliability of the ERCOT system. A more dynamic representation of internal transmission constraints is required to fully quantify the total impact to reliability planning.
- WECC found that the potential shutdown of key hydroelectric units along the Colorado River dramatically impacts resource adequacy, increasing both the hours at risk and the energy at risk in many areas across the Western Interconnection. Results were also dependent on the amount of available external assistance from other balancing authorities (BA) in the Western Interconnection.

Recommendations

Given the findings from the 2022 Sensitivity Case results with an increasing amount of uncertainty expected on the BPS with assessment area resource constraints, the following are the PAWG recommendations:

- Increase the use of probabilistic methods and scenarios to adequately study the reliability risks and to determine the sensitivity of those risks for various scenarios
- Stress the importance of the coordination between industry operations and planning personnel to further develop assumptions and scenarios for use in probabilistic reliability assessments (These studies can illuminate industry discussions and decision-making, reinforcing the fundamental need for future scenarios that address reliability concerns.)
- Use the upcoming 2023 Reliability Risk Priorities Report to help inform future probabilistic reliability analyses

Introduction

Per the NERC Reliability Assessment Subcommittee (RAS) request, the PAWG peer-reviewed and submitted proposed Regional risk scenarios for the 2022 ProbA Scenario/Sensitivity Case. Objectives of this analysis are to increase assessment value by allowing assessment areas to identify and study their respective risk factors.

Assessment areas are to do the following:

- Maintain calculation of the (monthly) EUE and LOLH probabilistic indices for Base and Scenario/Sensitivity Cases
- Compare Base and Scenario/Sensitivity Cases to evaluate sensitivities against purported risks
- Required Year 2 and Year 4 for Base Case
- Recommended Year 4, optional Year 2 for Scenario/Sensitivity Case; each assessment area decides based on projected NERC LTRA resource changes

Background

The primary function of the PAWG is to advance and support probabilistic resource adequacy efforts of the ERO Enterprise in assessing the reliability of the North American BPS. The group's origins and ongoing activities stem from work initiated by the Probabilistic Assessment Improvement Task Force with the Probabilistic Assessment Improvement Plan. Specifically, the group researches, identifies, and details probabilistic enhancements applied to resource adequacy. The group's long-term focus addresses relevant aspects of the ERO Enterprise Long-Term Strategy and the Reliability Issues Steering Committee (RISC) report in conjunction with the RAS.

2022 Study Overview

NERC regularly perform reliability assessments to objectively evaluate the reliability of the North American BPS. On a biennial basis, the PAWG performs a ProbA to supplement the annual deterministic NERC LTRA analysis[3]. The ProbA calculates monthly EUE and LOLH indices for Years 2 and 4 of the 10-year LTRA outlook (2024 and 2026 for the *2022 NERC LTRA*, respectively) and contains two studies: the Base Case and the Scenario/Sensitivity Case, a standalone report.

The Base Case contains assumptions under normal anticipated operating conditions with peer-reviewed study results by the PAWG, the NERC RAS, and the NERC Reliability and Security Technical Committee to ensure that comparisons made in the LTRA can be applied across entities. Complete details and underlying assumptions of the 2022 ProbA Base Case analysis were included in the *2022 NERC LTRA*, published in December 2022.

The Scenario/Sensitivity Case provides NERC a way to evaluate risk scenarios utilizing probabilistic methods in each assessment area. For the 2022 ProbA Scenario/Sensitivity Case, the PAWG developed an assessment area risk scenario approach specific to each assessment area. Each assessment area has varied resource mixes that lead to different study focuses across the BPS. Assessment areas identified and studied respective risk factors to better understand the reliability implications across all hours (instead of just the traditional peak hour) by using probabilistic methods. The PAWG believes respective risk factors provide higher value than standardizing a Sensitivity Case study to capture the varied and complex reliability risks across the systems. Year 2 and Year 4 indices were reported for the Base Case study for comparison purposes. For the Sensitivity Case, assessment areas were recommended to perform the analysis on Year 4 while Year 2 was optional.

[3] https://www.nerc.com/comm/RSTC/RAS/ERO%20Reliability%20Assessment%20Process%20Document.pdf

Chapters in this assessment are primarily divided by the Regional Entity and assessment areas for the 2022 ProbA. While assessment area risk scenarios represent an analysis into potential reliability risk factors, there is no guarantee or indication that these scenarios are indicative of future occurrences; these results are used to inform system planners and operators about potential emerging reliability risk. The PAWG intends to utilize these study results in future probabilistic resource adequacy studies (such as trending applications) and other industry reports and activities to develop further guidance for future work activities with prominent key points and takeaways detailed.

Development and Progression from Previous Regional Risk Assessment

Given Base Case assumptions remain consistent over each ProbA report and the years being reported are the same; the base case results can be compared from one report to the next biennial update. For the Sensitivity Case, many of the same risks are present from the 2020 Probabilistic Assessment, leading some areas to study similar sensitivities. Some areas are experiencing new risks and changed their Sensitivity Case as shown in **Table I.1**. Therefore, results many not be comparative to the scenarios/sensitivity studies in the 2020 report

Table I.1: ProbA Scenario Comparison

Regional Entity/ Assessment Area	2020 Scenario Topic	2022 Scenario Topic
MISO	Demand Response	Seasonal Outage Rates
Manitoba Hydro (MRO)	Hydro Conditions	Hydro Conditions
SaskPower (MRO)	Hydro Conditions	Coal Unit Outages
SPP (MRO)	Wind Conditions	Extreme Cold Weather
NPCC	Resource Materialization	Resource Materialization
PJM	Resource Materialization	Resource Materialization
SERC	Planned Outages	Extreme Cold Weather
ERCOT (TRE)	Demand/Wind Correlations	Transmission Constraints
WECC	Coal Unit Retirements	Hydro Conditions

Chapter 1: MISO

Assessment Area Overview

MISO is a summer peaking system that spans 15 states—covers all or a portion of Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, North Dakota, South Dakota, Texas, and Wisconsin as well as the Canadian province of Manitoba—and consists of 36 Local Balancing Areas that are grouped into 10 local resource zones (LRZs). For the 2022 NERC Probabilistic Assessment, MISO utilized a multi-area modeling technique for the 10 LRZs internal to the MISO footprint. Firm external imports as well as non-firm imports were also modeled within the cases.

Risk Scenario Description

For the 2022 Probabilistic Assessment Risk Scenario, MISO performed a sensitivity analysis that examined the effects of modeling seasonal forced outage rates as well as correlated cold weather outages rather than annual average outage rates. Over the past several years, MISO has experienced a number of capacity emergencies outside of the typical summer peak season, particularly in the winter. Generator outages play a large role in seasonal risks and outage rates can vary significantly by season. When using annual average outage rates, some of this seasonal variation is smoothed out, which can underestimate seasonal risk.

To perform this analysis, MISO removed the annual outage rates from the base case for all units and replaced them with season specific outage rates that were determined from historic Generation Availability Data System (GADS) data. Additionally, MISO included a cold weather outage adder in the model that increases the amount of forced outages as the temperature decreases. This allows the model to more accurately capture the magnitude of coincident forced outages during extreme cold weather experienced in real-time.

Base Case Results

- The Forecast Operable Reserve Margin increases from 2024 to 2026 causing a reduction in both LOLH and EUE as shown in **Table 1.1**.
- The 2024 shortfall of the Operable Reserve Margin is larger than projected in the 2020 ProbA, which results in an increase in LOLH and EUE.

Table 1.1: Base Case Summary of Results

Reserve Margin (RM) %			
	2024*	**2024**	**2026**
Anticipated	17.6%	13.2%	8.9%
Reference	18.0%	17.9%	17.9%
ProbA Forecast Operable	13.7%	8.1%	13.9%
Annual Probabilistic Indices			
	2024*	**2024**	**2026**
EUE (MWh)	14.3	193.6	68.8
EUE (ppm)	0.020	0.304	0.108
LOLH (hours/year)	0.085	0.808	0.393

Risk Scenario Results

The sensitivity analysis shows a slight increase in the total EUE compared to the base case results; these values are 201.8 MWh for EUE and 0.824 hours/year for LOLH. LOLH was relatively unchanged in the Sensitivity Case, which indicates that the duration of load-shed events was similar to the Base Case, but the magnitude of load shed was greater. Summer remains the season with the largest EUE risk as MISO is a summer peaking system. However, the risk is more spread out throughout the year as the seasonal outages uncover EUE in several months that previously showed zero risk.

As a result of seasonal risk becoming more common, MISO has recently moved from an annual to a seasonal resource adequacy construct that includes seasonal capacity requirements and availability-based accreditation. MISO's seasonal resource adequacy construct will be effective for the 2023–2024 planning year; therefore, future ProbA studies will incorporate these seasonal outage rates in the base cases. A link to MISO's 2023–2024 planning year loss of load expectancy (LOLE) study report that includes descriptions of a number of seasonal modeling enhancements, can be found in the appendix.

Chapter 2: MRO-Manitoba Hydro

Assessment Area Overview

Currently the Manitoba Hydro system has approximately 6,050 MW of total accredited winter operation capacity. The system is characterized by approximately 4,130 MW of remote hydraulic generation located in Northern Manitoba, which is connected to the concentration of load in Southern Manitoba. MH also has approximately 1,585 MW of hydraulic generation distributed throughout the province, and they have approximately 50 MW of accredited wind generation and approximately 280 MW thermal generation distributed in the Southern part of the province. The MH system is interconnected to the transmission systems in the Canadian provinces of Saskatchewan and Ontario as well as the U.S. states of North Dakota and Minnesota. The 2022 probabilistic assessment for the Manitoba Hydro system was conducted using the Multi-Area Reliability Simulation (MARS) program developed by the General Electric Company (GE). The reliability indices of the annual loss of load hours (LOLH) and the expected unserved energy (EUE) for 2024 and 2026 were calculated considering different types of generating units (thermal, hydro, and wind), firm capacity contractual sales and purchases, non-firm external assistances, interface transmission constraints, peak load, load variations, load forecast uncertainty (LFU), and demand side management programs. The data used in the MARS simulation model are consistent with the data reported in the *2022 LTRA* submittals from Manitoba Hydro to NERC.

Risk Scenario Description

There are a number of influencing factors associated with Manitoba Hydro's resource adequacy performance, such as the water resource conditions, energy and capacity exchanges with neighboring jurisdictions, forecast load level, uncertainties in load forecast and load variation profiles, demand response (DR), wind penetration, and generation fleet availability. In the 2022 ProbA scenario analysis, Manitoba Hydro examined the impact of the most significant factor over the long-run (variations in water conditions) as detailed in the following:

- Analyze the system as is to establish base reliability indices (Base Case)
- Risk Scenario: model a tenth percentile low water conditions

Base Case Results

None zero LOLH and EUE are observed for both reporting years of 2024 and 2026 as shown in **Table 2.1**. These values are still small that are mainly due to the larger forecast reserve margins.

The LOLH and EUE indices calculated for 2024 increase slightly as compared to those results obtained in 2020 assessment that were mainly due to some difference in the modeling details as described in the study method in **Appendix B**:.

Table 2.1: Base Case Summary of Results

Reserve Margin (RM) %			
	2024*	2024	2026
Anticipated	N/A	16.0%	16.0%
Reference	N/A	12.0%	12.0%
ProbA Forecast Operable	N/A	13.5%	13.5%
Annual Probabilistic Indices			
	2024*	2024	2026
EUE (MWh)	3.3831	28.64	7.23
EUE (ppm)	0.1329	1.1410	0.2870
LOLH (hours/year)	0.0039	0.0360	0.0070

Risk Scenario Results

Scenario analysis results show that LOLH and EUE values increase for both 2024 and 2026 when a tenth percentile low-water scenario is modeled as shown in **Table 2.2**. Water flow conditions of a tenth percentile or lower tend to increase the loss of load probability. Since Manitoba Hydro is a small winter-peaking system on the northern edge of a summer peaking system, there is generally assistance available to provide energy to supplement hydro generation in low flow conditions in winter, particularly in off-peak hours. Management of energy in reservoir storage in accordance with good utility practice provides risk mitigation under low water-flow conditions.

Table 2.2: Scenario Case Summary of Results			
Reserve Margin (RM) %			
	2024*	**2024**	**2026**
Anticipated	N/A	16.0%	16.0%
Reference	N/A	12.0%	12.0%
ProbA Forecast Operable	N/A	13.5%	13.5%
Annual Probabilistic Indices			
	2024*	**2024**	**2026**
EUE (MWh)	56.38	477.34	120.41
EUE (ppm)	2.2150	19.02	4.78
LOLH (hours/year)	0.0643	0.596	0.114

Chapter 3: MRO-SaskPower

Assessment Area Overview

Saskatchewan is a province of Canada and comprises a geographic area of approximately 651,900 square kilometers (251,700 square miles) with approximately 1.1 million people. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the Planning Coordinator (PC) and Reliability Coordinator (RC) for the province of Saskatchewan. SaskPower is the principal supplier of electricity in the province and responsible for serving nearly 550,000 customer accounts. SaskPower is a provincial crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan BES and its interconnections.

Risk Scenario Description

For the Sensitivity Case, SaskPower proposed to analyze the impact on the system's reliability when a coal unit approaching its planned end-of-life experiences a critical failure. This scenario was selected to better understand the strategy for managing the coal units in Saskatchewan as they approach end of life in the next few years. For the purpose of this scenario, a single coal unit was retired a year in advance and thus assumed to be unavailable throughout the first year of assessment.

Base Case Results

Saskatchewan has planned for adequate resources to meet anticipated load and reserve requirements for the assessment period.

Table 3.1: Base Case Summary of Results

Reserve Margin (RM) %			
	2024*	**2024**	**2026**
Anticipated	30.0%	26.9%	28.4%
Reference	11.0%	15.0%	15.0%
Annual Probabilistic Indices			
	2024*	**2024**	**2026**
EUE (MWh)	26.4	169.5	117.0
EUE (ppm)	1.1	6.5	4.4
LOLH (hours/year)	0.28	1.4	0.9

The major contribution to the EUE/LOLH is in the winter peak season and shoulder months with large unit overhauls planned. Most of Saskatchewan's generation unit overhauls are planned during the off-peak months, but some of its hydroelectric units require extended maintenance during the winter peak season for life extension and refurbishment. The planned overhaul on the hydro units is segregated to minimize adverse impacts on the system reliability.

Since the 2020 Probabilistic Assessment, the reported Forecast Reserve Margin for 2024 has decreased from 30.0% to 26.9% as shown in **Table 3.1**. This is primarily due to an increase in the load forecast.

Risk Scenario Results

Retiring the coal unit a year in advance causes higher loss of load values in the first year of the assessment as compared to the Base Case as shown in **Table 3.2**. The majority of the EUE is in January due to winter peaking load and hydro unit overhauls. Saskatchewan is on track to add a large natural gas unit facility (377 MW) in-service by April 2024 that should enhance the system reliability for the remainder of the assessment period. SaskPower is also reviewing lay-up strategies for its existing units to support the system's reliability during peak periods. Saskatchewan is not anticipating any major reliability issues but expects to mitigate them by using the emergency assistance if needed.

Table 3.2: Sensitivity Case Summary of Results

	2024
Anticipated (RM%)	23.1%
EUE (MWh)	709.9
EUE (ppm)	27.1
LOLH (hours/year)	5.28

Chapter 4: NPCC

Regional Entity Overview

The Northeast Power Coordinating Council (NPCC) Regional Entity has five assessment areas, and the following pages contain the results for each. For each of the risk scenario result sections, a link to a more detailed report that covers the modeling assumptions and results can be found in **Appendix D:**. Note that the estimated metrics are consistent with NPCC's resource adequacy design criteria.[4]

NPCC-Maritimes

The Maritimes assessment area is a winter-peaking NPCC subregion with a single RC and two BA areas. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, Prince Edward Island, and the Northern portion of the U.S. state of Maine, which is radially connected to New Brunswick. The area covers 58,000 square miles with a population of 1.9 million. There is no regulatory requirement for a single authority to produce a forecast for the whole Maritimes area. Demand for the Maritimes area is determined to be the non-coincident sum of the peak loads forecasted by the individual subareas.

Risk Scenario Description

Similar to the 2020 NERC ProbA Sensitivity Analysis[5] NPCC Risk Scenario, Tier 1 future resources[6] included in the Base Case were removed that consisted primarily of planned wind and run-of-river hydro units. To address energy adequacy concerns and for testing with severe conditions, wind capacity was derated by half for every hour in the winter months (December, January, and February) to simulate widespread icing conditions. In addition, 50% natural gas capacity curtailments were assumed for the winter months to simulate a reduction in natural gas supply. Dual fuel units were assumed to revert to oil. The repeated risk scenario allows for a comparison to the 2024 study year results.

The area has a diverse resource mix, and this scenario reveals the reliability impacts associated with the most likely and therefore realistic shortages. Other scenarios did not meet the degree of severity and likelihood. This scenario was chosen to allow a direct comparison between the NERC and NPCC probabilistic analyses as the same severe scenario was used for both.

The results of this risk scenario are valuable to resource planners (RP) since they demonstrate a high level of reliability by meeting the NPCC LOLE target of not more than 0.1 days per year of exposure to load loss despite the severity of the scenario. Note that the required maximum LOLE for loss of load due to resource deficiencies is less than 0.1 days per year. Hence, since the LOLH value for both the Base Cases and Risk Scenario Cases are less than this value, NPCC meets its target for both study years.

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[4] i.e., they are calculated following all possible allowable "load relief from available operating procedures." For more information see the following: Directory #1 (npcc.org)

[5] 2020 Probabilistic Assessment – Sensitivity Case | June 2021

[6] The term "Tier"" is used to describe categories of resources. This document is to be read alongside the *2020 NERC Long-Term Reliability Assessment* that defines these categories.

Base Case Results

The previous study estimated an annual LOLH = 0.023 hours/year and a corresponding EUE equal to 0.04 (ppm) for the year 2024 as shown in **Table 4.1**. The 2024 forecast 50/50 peak demand in this assessment is nearly identical to what was reported in the previous assessment; the forecast capacity resources declined slightly as compared to the previous assessment. A slight increase in estimated LOLH and EUE is observed between the two assessments. The slightly decrease in reserves contributes to this result. The Maritimes area is winter peaking, and EUE risk occurs during the winter months. The estimated EUE is negligible.

Table 4. 1: Base Case Summary of Results

Reserve Margin (RM)			
	2024*	**2024**	**2026**
Anticipated (%)	20.9%	24.5%	25.6%
Reference (%)	20.0%	20.0%	20.0%
Operable On-peak Margin	16.7%	25.0%	22.9%
Annual Probabilistic Indices			
	2024*	**2024**	**2026**
EUE (MWh)	1.125	1.872	3.871
EUE (ppm)	0.039	0.067	0.138
LOLH (hours/year)	0.023	0.024	0.071

Risk Scenario Results

As expected, the LOLH and EUE results are observed to be higher than the ProbA Base Case when the Tier 1 future resources included in the Base Case were removed along with the aforementioned wind capacity derates and natural gas curtailments. For the two studied years, halving Maritimes' wind resource capacity gave rise to non-zero values of EUE and LOLH with pronounced weighting during the months of December, January, and February. Overall, the results are still low (being on the order of single digits or fractions of MWh and hours) and the NPCC LOLE target is met for both study years.

Table 4.2: Scenario Case Summary of Results

	2024	**2026**
EUE (MWh)	4.728	11.556
EUE (ppm)	0.168	0.411
LOLH (hours/year)	0.076	0.222

The EUE results for 2024 and 2026 are 4.728 and 11.556 MWh, respectively, as shown in **Table 4.2**; this is an increase from the Base Case 1.872 and 3.871 MWh. In comparison to the 2020 ProbA Scenario Case Summary of Results, the 2024 EUE results decrease from 6.718 to 4.728 MWh with a similar LOLH—from 0.077 to 0.076 (hours/year).

NPCC-New England

ISO New England (ISO-NE) Inc. is a regional transmission organization that serves the six New England states—Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. It is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administers the area's wholesale electricity markets, and manages the comprehensive planning of the regional BPS. The New England BPS serves approximately 14.5 million people over an area of 68,000 square miles.

Risk Scenario Description

Similar to the NPCC Risk Scenario within the 2020 NERC ProbA Sensitivity Analysis,[7] Tier 1 future resources that were included in the Base Case analysis were removed. In addition, the capacity ratings of wind and solar resources are assumed to shrink by 30% to reflect some uncertainty associated with their capacity contribution. Currently, these wind and solar resources are modeled with their seasonal claimed capability that are based on their historical median net real power output during reliability hours (2:00–6:00 p.m.). The repeated Risk Scenario allows for a comparison to the 2024 study year results.

The results of this risk scenario are valuable to RPs since they demonstrate a high level of reliability by meeting the NPCC LOLE target of not more than 0.1 days per year of exposure to load loss despite the severity of the scenario. Note that the required maximum LOLE for loss of load due to resource deficiencies is less than 0.1 days per year. Hence, since the LOLH value for both the Base Case and risk scenarios are less than this value, the NPCC target is met for both study years.

Base Case Results

The Forecast 50/50 peak demand for 2024 is slightly lower than reported in the previous study, but the estimated Forecast Planning Reserve Margin and Forecast Operable Reserve Margin have both significantly increased as shown in **Table 4.3**. As a result, the LOLH and EUE have decreased. The New England area is summer peaking and the LOLH risk occurs during the summer months. No significant LOLH was observed.

Table 4.3: Base Case Summary of Results

Reserve Margin (RM)			
	2024*	**2024**	**2026**
Anticipated (%)	18.95%	32.8%	28.4%
Reference (%)	12.7%	14.0%	12.5%
Operable On-peak Margin	9.8%	32.6%	27.8%
Annual Probabilistic Indices			
	2024*	**2024**	**2026**
EUE (MWh)	58.62	0.937	0.551
EUE (ppm)	0.471	0.007	0.004
LOLH (hours/year)	0.095	0.002	0.002

Risk Scenario Results

As expected, with increased capacity, decreasing demands, and no major reported Tier 1 resources after 2024, the EUE and LOLH remain close to zero as shown in **Table 4.4**. The New England area is summer peaking, and the EUE risk occurs during the summer months; however, the EUE values are negligible. In comparison to the 2020 ProbA Scenario Case Summary of Results, the 2024 EUE results decrease from 88.1 to 0.002 MWh with a corresponding LOLH decrease from 0.135 to 0.002 (hours/year).

Table 4.4: Scenario Case Summary of Results

	2024	**2026**
EUE (MWh)	1.071	0.651
EUE (ppm)	0.008	0.005
LOLH (hours/year)	0.002	0.002

[7] 2020 Probabilistic Assessment – Sensitivity Case | June 2021

NPCC-New York

The New York ISO (NYISO) is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only BA within the state of New York. The transmission grid of the state of New York serves the electricity needs of 20.2 million people and encompasses approximately 11,000 miles of transmission lines and 760 power generation units. This represents approximately 36,212 MW of existing-certain resources as well as the net firm transfers anticipated for 2023.[8] New York experienced its all-time peak demand of 33,956 MW in the summer of 2013.

Risk Scenario Description

Similar to the NPCC Risk Scenario within the 2020 NERC ProbA Sensitivity Analysis,[9] major Tier 1 proposed transmission and generation projects (as shown in **Table 4.5** and **Table 4.6)** were removed from the Base Case. The results provide an indication of the potential reliability risks related with developmentally advanced projects not materializing that are relied upon in the NYISO's *2022 Reliability Needs Assessment.*[10] The repeated risk scenario allows for a comparison to the 2024 study year results.

The results of this risk scenario are valuable to RPs since the planners demonstrate a high level of reliability by meeting the NPCC LOLE target of not more than 0.1 days per year of exposure to load loss despite the severity of the scenario. Note that the required maximum LOLE for loss of load due to resource deficiencies is less than 0.1 days per year. Hence, since the LOLH value for both the Base Case and risk scenarios are less than this value, the NPCC target is met for both study years.

[9] 2020 Probabilistic Assessment – Sensitivity Case | June 2021

[10] 2022 NERC Long Term Reliability Assessment (nerc.com)

Table 4.5: Queue Projects—Transmission and Generation in NYISO							
Queue #	**Project Name/(Owner)**	**Zone**	**Point of Interconnection**	**Type**	**COD or I/S Date**	**Summer Peak MW**	**Included Starting**
Proposed Transmission Additions, other than Local Transmission Owner Plans							
0545A	Empire State Line	A	Dysinger - Stolle 345kV	AC Transmission (WNYPP)	I/S July 2022	n/a	2018–2019 RPP
0543	Segment B Knickerbocker-Pleasant Valley 345 kV	F,G	Greenbush - Pleasant Valley 345kV	AC Transmission (ACPPTPP)	12/2023	n/a	2020–2021 RPP
0556	Segment A Double Circuit	E, F	Edic - New Scotland 345kV		12/2023	n/a	
0430	Cedar Rapids Transmission Upgrade	D	Dennison - Alcoa 115kV	AC Transmission	I/S	+80	
0631	NS Power Express (CHPE)	J	Hertel 735kV (Québec)-Astoria Annex 345kV (NYC)	HVDC Transmission	12/2025	1000	2022 RNA
0887	CH Uprate					250	
1125	Northern New York Priority Transmission Project (NNYPTP)	D, E	Moses/Adirondack/Porter Path	AC Transmission	12/2025	n/a	
Proposed Large Generation Additions							
396	Baron Winds	C	Hillside - Meyer 230kV	Wind	Dec-23	238.4	2020–2021 RPP
422	Eight Point Wind Enery Center	B	Bennett 115kV	Wind	Sep-22	101.8	
495	Mohawk Solar	F	St. Johnsville - Marshville 115kV	Solar	Nov-24	90.5	2022 RNA
505	Ball Hill Wind	A	Dunkirk - Gardenville 230kV	Wind	Nov-22	100.0	2020–2021 RPP
531	Number 3 Wind Energy	E	Taylorville - Boonville 115kV	Wind	Oct-22	103.9	2021 Q3 STAR
579	Bluestone Wind	E	Afton - Stilesville 115kV	Wind	Oct-22	111.8	2022 RNA
612	South Fork Wind Farm	K	East Hampton 69kV	Offshore Wind	Aug-23	96.0	
617	Watkins Glen Solar	C	Bath - Montour Falls 115kV	Solar	Nov-23	50.0	
618	High River Solar	F	Inghams - Rotterdam 115kV	Solar	Nov-22	90.0	
619	East Point Solar	F	Cobleskill - Marshville 69kV	Solar	Nov-22	50.0	
637	Flint Mine Solar	G	LaFarge - Pleasant Valley 115kV, Feura Bush - North Catskill 115kV	Solar	Sep-23	100.0	
678	Calverton Solar Energy Center	K	Edwards Substation 138kV	Solar	Jun-22	22.9	2020–2021 RPP
695	South Fork Wind Farm II	K	East Hampton 69kV	Offshore Wind	Aug-23	40.0	2022 RNA
720	Trelina Solar Energy Center	C	Border City - Station 168 115 KV	Solar	Nov-23	80.0	
721	Excelsior Energy Center	A	N. Rochester - Niagara 345 kV	Solar	Nov-22	280.0	
758	Independence GS1 to GS4 *+9MW ERIS only*	C	Scriba 345 kV	Gas	I/S	9.0	

Table 4.6: Queue Projects—Transmission and Generation in NYISO							
Queue #	**Project Name/(Owner)**	**Zone**	**Point of Interconnection**	**Type**	**COD or I/S Date**	**Summer Peak MW**	**Included Starting**
545	Sky High Solar* (Sky High Solar, LLC)	C	Tilden -Tully Center 115 kV	Solar	06/2023	20	2021 Q3 STAR
565	Tayandenega Solar* (Tayandenega Solar, LLC)	F	St. Johnsville - Inghams 115kV	Solar	10/2022	20	
570	Albany County 1* (Hecate Energy Albany 1 LLC)	F	Long Lane - Lafarge 115 kV	Solar	12/2022	20	
572	Greene County 1* (Hecate Energy Greene 1 LLC)	G	Coxsackie - North Catskill 69kV	Solar	01/2023	20	
573	Greene County 2* (Hecate Energy Greene 2 LLC)	G	Coxsackie Substation 13.8kV	Solar	03/2023	10	
584	Dog Corners Solar* (SED NY Holdings LLC)	C	Aurora Substation 34.5 kV	Solar	05/2022	20	
586	Watkins Road Solar* (SED NY Holdings LLC)	E	Watkins Rd - Ilion 115 kV	Solar	06/2023	20	
590	Scipio Solar (Duke Energy Renewables Solar, LLC)	C	Scipio 34.5kV Substation	Solar	05/2023	18	
592	Niagara Solar (Duke Energy Renewables Solar, LLC)	B	Bennington 34.5kV Substation	Solar	05/2023	20	
598	Albany County 2* (Hecate Energy Albany 2 LLC)	F	Long Lane - Lafarge 115 kV	Solar	12/2022	20	
638	Pattersonville* (Pattersonville Solar Facility, LLC)	F	Rotterdam - Meco 115 kV	Solar	12/2022	20	
666	Martin Solar* (Martin Solar LLC)	A	Arcade - Five Mile 115 kV	Solar	10/2022	20	
667	Bakerstand Solar* (Bakerstand Solar LLC)	A	Machias - Maplehurst 34.5kV	Solar	10/2022	20	2021 Q3 STAR
682	Grissom Solar* (Grissom Solar, LLC)	F	Ephratah - Florida 115 kV	Solar	06/2022	20	
730	Darby Solar* (Darby Solar, LLC)	F	Mohican - Schaghticoke 115 kV	Solar	12/2022	20	
731	Branscomb Solar* (Branscomb Solar, LLC)	F	Battenkill - Eastover 115 kV	Solar	I/S	20	
735	ELP Stillwater Solar (ELP Stillwater Solar LLC)	F	Luther Forest - Mohican 115 kV	Solar	09/2022	20	
748	Regan Solar* (Regan Solar, LLC)	F	Market Hill - Johnstown 69kV	Solar	06/2022	20	
768	Janis Solar* (Janis Solar, LLC)	C	Willet 34.5 kV	Solar	04/2022	20	

Table 4.6: Queue Projects—Transmission and Generation in NYISO							
Queue #	**Project Name/(Owner)**	**Zone**	**Point of Interconnection**	**Type**	**COD or I/S Date**	**Summer Peak MW**	**Included Starting**
775	Puckett Solar* (Puckett Solar, LLC)	E	Chenango Forks Substation 34.5kV	Solar	04/2022	20	
564	Rock District Solar* (Rock District Solar, LLC)	F	Sharon - Cobleskill 69 kV	Solar	12/2022	20	
670	Skyline Solar* (SunEast Skyline Solar LLC)	E	Campus Rd - Clinton 46 kV	Solar	04/2022	20	
581	Hills Solar (SunEast Hills Solar LLC)	E	Fairfield - Inghams 115 kV	Solar	08/2023	20	2022 RNA
734	Ticonderoga Solar* (ELP Ticonderoga Solar LLC)	F	ELP Ticonderoga Solar LLC	Solar	8/1/2022	20	
759	KCE NY 6* (KCE NY 6, LLC)	A	Gardenville - Bethlehem Steel Wind 115 kV	Storage	04/2022	20	
769	North County Energy Storage (New York Power Authority)	D	Willis 115 kV	Storage	03/2022	20	
807	Hilltop Solar (SunEast Hilltop Solar LLC)	E	Eastover - Schaghticoke 115 kV	Solar	07/2023	20	
848	Fairway Solar (SunEast Fairway Solar LLC.)	E	McIntyre - Colton 115 kV	Solar	10/1/2023	20	
855	NY13 Solar (Bald Mountain Solar LLC)	F	Mohican - Schaghticoke 115 kV	Solar	11/1/2023	20	

*Only these proposed small generators obtained capacity resource interconnection service; therefore, they are modeled for the resource adequacy Base Cases.

Base Case Results

The forecast 50/50 peak demand for 2024 is similar to that reported in the previous study with comparable estimated forecast reserve margins, resulting in slightly decreased LOLH and EUE for 2024 as shown in Table 4.7. The New York area is summer peaking, and the EUE risk occurs during the summer months; however, the EUE values are negligible.

Table 4.7: Base Case Summary of Results			
Reserve Margin (RM)			
	2024*	**2024**	**2026**
Anticipated (%)	18.6%	18.5%	23.5%
Reference (%)	15.0%	15.0%	15.0%
Operable On-peak Margin (%)	11.3%	11.6%	16.7%
Annual Probabilistic Indices			
	2024*	**2024**	**2026**
EUE (MWh)	6.837	0.508	0.103
EUE (ppm)	0.046	0.003	0.001
LOLH (hours/year)	0.029	0.003	0.000

Table 4.8: Scenario Case Summary of Results		
	2024	**2026**
EUE (MWh)	0.508	0.105
EUE (ppm)	0.003	0.001
LOLH (hours/year)	0.003	0.000

Risk Scenario Results

As expected, the EUE and LOLH are similar to the Base Case and close to zero with decreasing demands and a low number of reported Tier 1 resources after 2024. The New York area is summer peaking, and the EUE risk occurs during the summer months; however, the EUE values are negligible. In comparison to the 2020 scenario case summary of results, the 2024 EUE results decrease from 6.837 to 0.508 MWh with a corresponding LOLH decrease from 0.029 to ~0 (hours/year) as shown in Table 4.8.

NPCC-Ontario

The Ontario Independent Electricity System Operator is the PC, RP, and BA for Ontario, and it serves more than 14 million people. As detailed in Section 8 of the *Ontario Resource and Transmission Assessment Criteria,*[11] the IESO follows the Northeast Power Coordinating Council resource adequacy criterion. ORTAC Section 8.2 states that the IESO will not consider emergency operating procedures (EOP) for long-term capacity planning. The IESO also currently does not consider assistance over interconnections with neighboring PC areas as contributing to resource adequacy needs in the annual planning outlook resource adequacy assessments.

Risk Scenario Description

Future resources (Tier 1) included in the Base Case were removed. The results of this risk scenario are valuable to RPs since they demonstrate a high level of reliability by meeting the NPCC LOLE target of not more than 0.1 days per year of exposure to load loss despite the severity of the scenario. Note that the required maximum LOLE for loss of load due to resource deficiencies is less than 0.1 days per year. Hence, since the LOLH value for both the Base Case and risk scenarios are less than this value, the NPCC target is met for both study years.

Base Case Results

The previous ProbA estimated an annual LOLH of 0.0 hours/year and EUE of 0.049 MW for the year 2024. There is negligible difference in the estimated LOLH and EUE observed between the two assessments. There is an increase in the EUE and LOLH of 112.785 MWh and 0.494 hours/year for 2026, respectively, as shown in **Table 4.9**. For 2026, nuclear refurbishments at Bruce and Darlington nuclear generating stations are expected to reduce the generation capacity availability in the coming years. During the refurbishment period, one to four units at these stations are expected to be on outage at any given time, including peak seasons. Once they return to service, they will continue to help meet Ontario's adequacy requirements in the mid/longer term.

Table 4.9: Base Case Summary of Results

Reserve Margin (RM)			
	2024*	**2024**	**2026**
Anticipated (%)	11.3%	17.4%	8.7%
Reference (%)	16.8%	16.3%	16.0%
Operable On-peak Margin (%)	4.4%	7.9%	-6.7%
Annual Probabilistic Indices			
	2024*	**2024**	**2026**
EUE (MWh)	0.049	0.000	112.785
EUE (ppm)	0.000	0.000	0.769
LOLH (hours/year)	0.001	0.000	0.494

On September 29, 2022, Ontario's Ministry of Energy announced that it was supporting a plan by Ontario Power Generation to extend operation of its Pickering Nuclear Generating Station through September 2026. Ontario Power will need approval from the Canadian Nuclear Safety Commission to proceed with this plan, and that decision is not expected until 2024. The IESO has initiated a suite of actions aimed at meeting its resource adequacy needs, including a series of procurement activities with varying forward periods designed to acquire capacity from both new and existing capacity as outlined in the IESO's *2022 Annual Acquisitions Report*[12]. In response, on October 7, 2022, the Ministry of Energy directed the IESO to proceed with its procurement program, targeting 4,000 MW of new capacity through three separate procurements, including up to 2,500 MW of storage. Separately, the IESO announced a suite of new energy efficiency (EE) programs that could further reduce capacity shortfalls by up to 285 MW in the 2025–2027 period.

The target capacities for the December 2022 capacity auction will be 1,200 MW for the summer of 2023 obligation period, and 750 MW for the winter of 2023/2024 obligation period as announced in the IESO's *2022 Annual Acquisition Report*.

11 http://www.ieso.ca/-/media/Files/IESO/Document-Library/Market-Rules-and-Manuals-Library/market-manuals/connecting/IMO-REQ-0041-TransmissionAssessmentCriteria.pdf

12 https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Acquisition-Report

Risk Scenario Results

As expected, the LOLH and EUE results for 2026 are observed to be higher than the ProbA Base Case with the removal of the Tier 1 resources as shown in Table 4.10. While there is no significant difference between the Base and Scenario Case LOLH, the EUE increases ~26% from 72.164 to 135.108 MWh between the two cases for 2026.

Table 4.10: Scenario Case Summary of Results

	2024	2026
EUE (MWh)	0.000	135.108
EUE (ppm)	0.000	0.922
LOLH (hours/year)	0.000	0.525

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 NERC Interconnections in North America and has ties to Ontario, New York, New England, and the Maritimes. These ties consist of either high-voltage direct current (HVDC) ties, radial generation, or load to and from neighboring systems.

Risk Scenario Description

Similar to the NPCC Risk Scenario within the 2020 NERC ProbA Sensitivity Analysis,[13] Tier 1 future resources included in the Base Case were removed that consisted of conventional hydro, biomass, and wind units. Given the level of its reservoirs and projected area margins, no energy adequacy concerns are expected over the period of the assessment. The Repeated Risk Scenario allows for a comparison to the 2024 study year results.

Base Case Results

The Forecast 50/50 Peak Demand for 2024 is higher than reported in the previous study with smaller estimated Forecast Planning Margins and Forecast Operable Reserve Margins. No LOLH and EUE difference is observed from the last assessment as shown in Table 4.11. Québec's probabilistic assessment results continue to indicate little risk of energy or capacity shortfall. The highest risk occurs in winter months and coincides with the hour of peak demand.

Table 4.11: Base Case Summary of Results

Reserve Margin (RM)			
	2024*	2024	2026
Anticipated (%)	14.0%	12.2%	13.9%
Reference (%)	10.1%	11.3%	11.3%
Operable On-peak Margin (%)	7.1%	-1.6%	-2.3%
Annual Probabilistic Indices			
	2024*	2024	2026
EUE (MWh)	0.00	0.014	0.041
EUE (ppm)	0.00	0.000	0.000
LOLH (hours/year)	0.00	0.000	0.000

Risk Scenario Results

As expected, the LOLH and EUE results are observed to be higher than the ProbA Base Case with the Tier 1 future resources included in the Base Case were removed. However, the EUE and LOLH remain close to zero for the two studied years as shown in Table 4.12. Again, the highest risk occurs in winter months and coincides with the hour of peak demand. The results are consistent with the 2020 ProbA Risk Scenario Case Summary of Results.

Table 4.12: Scenario Case Summary of Results

	2024	2026
EUE (MWh)	0.052	0.048
EUE (ppm)	0.000	0.000
LOLH (hours/year)	0.000	0.000

[13] 2020 Probabilistic Assessment – Sensitivity Case | June 2021

Chapter 5: PJM

Assessment Area Overview

PJM is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of 13 states—Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia—and the District of Columbia. It is part of the Eastern Interconnection and serves approximately 65 million people over 369,089 square miles.

Risk Scenario Description

The Risk Scenario considers the removal of all Tier 1 units from the simulation. This scenario serves as a proxy for potential withdrawals or delays of queue projects in the PJM Interconnection queue that can occur due to the current backlog in the interconnection process. Furthermore, it provides an opportunity to analyze the impact of a higher RTO-wide forced outage rate on reliability metrics and of a lower Anticipated Reserve Margin.

Base Case Results

The Base Case results in LOLH and EUE equal zero for both 2024 and 2026 due to large Anticipated Planning Reserve Margins (38.2% and 37.2%, respectively). These reserve margins are significantly above the reference values of 14.7%.

Table 5.1: Base Case Summary of Results			
Reserve Margin (RM) %			
	2024*	2024	2026
Anticipated	41.9%	38.2%	37.2%
Reference	14.8%	14.7%	14.7%
Annual Probabilistic Indices			
	2024*	2024	2026
EUE (MWh)	0.00	0.00	0.00
EUE (ppm)	0.00	0.00	0.00
LOLH (hours/year)	0.00	0.00	0.00

The 2024 LOLH and EUE in the 2022 study are identical to the corresponding values reported in the 2020 study. The 2024 LOLH and EUE values in the 2020 study were zero due to a large Anticipated Planning Reserve Margin. In the 2022 study, the 2024 Anticipated Planning Reserve Margin is slightly lower but still significantly above the reference value, which explains the zero value for LOLH and EUE as shown in **Table 5.1**.

Risk Scenario Results

The regional risk scenario yields LOLH and EUE values that are practically zero for both 2024 and 2026 (the EUE value of 0.016 MWh in 2026 is a negligible value) as shown in **Table 5.2**.

These results are driven by Anticipated Planning Reserve Margins that are well above the reference values even after excluding Tier 1 resources (i.e., 26.5% versus a reference value of 14.7% in 2024 and 23.9% versus a reference value of 14.7% in 2026).

Table 5.2: Risk Scenario Summary of Results		
Reserve Margin (RM) %		
	2024	2026
Anticipated	26.5%	23.9%
Reference	14.7%	14.7%
Annual Probabilistic Indices		
	2024	2026
EUE (MWh)	0.000	0.016
EUE (ppm)	0.000	0.000
LOLH (hours/year)	0.000	0.000

Note that PJM's Anticipated Reserve Margins in the Base Case and the Risk Scenario are largely driven by past and expected outcomes of PJM's capacity market, the reliability pricing model, which allows for the possibility of procuring reserve margin levels above the reference levels by design.[14]

[14] Sections 3.1–3.4 in PJM Manual 18 available at the following: https://www.pjm.com/~/media/documents/manuals/m18.ashx

An internal PJM study,[15] released in early 2023, examined retirement scenarios that go well beyond what is considered in the NERC Probabilistic Assessment Risk Scenario. In particular, the study examined 6 GW of announced generator deactivations as well as 25 GW of potential policy-driven retirements and 3 GW of potential economic retirements. In contrast, the scenarios analyzed in the NERC Probabilistic Assessment (including the Risk Scenario) only consider announced generator deactivations. As a result, the internal PJM study concludes that PJM could face decreasing reserve margins in the near future. This finding is different from the results of the Risk Scenario shown in **Table 5.2** and shows that higher levels of generator retirements and demand growth can negatively impact resource adequacy in the PJM area.

[15] https://www.pjm.com/-/media/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx

Chapter 6: SERC

Regional Entity Overview

SERC covers approximately 630,000 square miles and serves a population of more than 91 million people. The SERC probabilistic model includes all areas in the SERC footprint and portions of MISO and PJM. However, only the results of the NERC assessment areas are reported here. The NERC assessment areas within the SERC footprint are SERC-Central, SERC-East, SERC-Southeast, and SERC-Florida Peninsula.

Risk Scenario Description

SERC chose to study a severe cold weather scenario. While other options were considered, including high renewable penetration and reduced unit reliability scenarios, recent cold weather events across the country and concerns about increasing weather volatility gave this scenario importance and relevancy. The 2018 Extreme Cold Weather Event and 2021 Winter Storm Uri event both impacted parts of the SERC footprint. RPs typically use median weather conditions for planning studies. While this is sufficient to plan resources for more likely conditions, there is a need to assess system conditions for severe cold weather events that are not as common but could be high impact. Sensitivity scenarios, such as to use abnormal weather conditions to stress test the system and assess factors contributing to risk. SERC's sensitivity scenario assumes severe cold weather load assumptions as well as correlated outages. Individual utility PCs may do independent planning studies for these scenarios, but a regional assessment factors in the wide-area impact of extreme cold weather events and power transfers within neighboring assessment areas; the Sensitivity Case study year is 2026.

Base Case Results

SERC's Base Case results show that assessment areas have resources available above the reference margin of 15%. EUE and LOLH metrics calculated over all hours of the year indicate adequate resources in general. The snippets of the 2022 LTRA tables for the Base Case results for all SERC assessment areas are found below in **Table 6.1**, **Table 6.2**, **Table 6.3** and **Table 6.4**. While comparing results with the previous ProbA, it is worth noting that in 2022, Gulf Power moved from SERC-Southeast into the northwest part of SERC-Florida Peninsula.

Table 6. 1: SERC-Central Base Case Summary of Results			
Reserve Margin (RM) %			
	2024*[16]	**2024**	**2026**
Anticipated	27.0%	26.9%	25.4%
Reference	15.0%	15.0%	15.0%
Annual Probabilistic Indices			
	2024*	**2024**	**2026**
EUE (MWh)	0.00	0.00	0.00
EUE (ppm)	0.00	0.00	0.00
LOLH (hours/year)	0.00	0.00	0.00

Table 6.2: SERC-East Base Case Summary of Results			
Reserve Margin (RM) %			
	2024*	**2024**	**2026**
Anticipated	23.9%	22.9%	24.0%
Reference	15.0%	15.0%	15.0%
Annual Probabilistic Indices			
	2024*	**2024**	**2026**
EUE (MWh)	5.26	64.33	92.49
EUE (ppm)	0.024	0.272	0.389
LOLH (hours/year)	0.01	0.06	0.081

Table 6.3: SERC-Southeast Base Case Summary of Results			
Reserve Margin (RM) %			
	2024*	**2024**	**2026**
Anticipated	39.1%	36.5%	40.7%
Reference	15.0%	15.0%	15.0%
Annual Probabilistic Indices			
	2024*	**2024**	**2026**
EUE (MWh)	0.03	0.00	0.00
EUE (ppm)	0.00	0.00	0.00
LOLH (hours/year)	0.00	0.00	0.00

Table 6.4: SERC-FP Base Case Summary of Results			
Reserve Margin (RM) %			
	2024*	**2024**	**2026**
Anticipated	22.8%	26.8%	26.9%
Reference	15.0%	15.0%	15.0%
Annual Probabilistic Indices			
	2024*	**2024**	**2026**
EUE (MWh)	2.26	1.09	1.13
EUE (ppm)	0.009	0.004	0.004
LOLH (hours/year)	0.004	0.002	0.002

[16] 2024* refers to metrics for study year 2024 as calculated in the 2020 Probabilistic Assessment

Risk Scenario Results

As in the Base Case, 38 historic years of weather were used to scale projected future load for the study. **Figure 6.1** compares the assumptions of historical years of weather of the Base Case and Sensitivity Case. In the Base Case, each year from 1980–2017 was assumed to be equally likely to occur in the future (for year 2026).

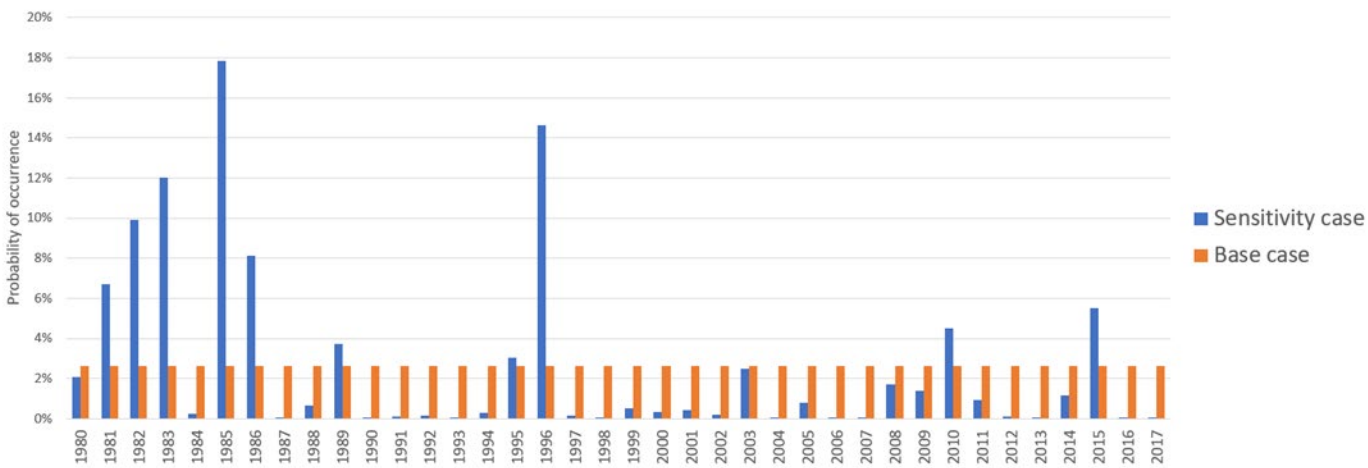

Figure 6.1: Probability of Occurrence of Historic Years of Weather (1980–2017) in the Base Case and Sensitivity Case for SERC Overall

For the Sensitivity Case, the model increases the probability of occurrence of historical severe cold weather years such that the new probability weighted average load for winter is increased to the 90/10 forecast of the Base Case. In addition to the reweighting of historic years, the model assumes a correlation of thermal outages to severe cold weather.

Table 6.5 indicates the LOLH and EUE metrics for the assessment areas.

Table 6.5: Winter Months Stress Test Metrics

	SERC -Central	SERC-East	SERC-Southeast	SERC-Florida Peninsula
LOLH	2	5	4	3
EUE	2,028	3,436	10,713	7,235
EUE (ppm)	33	56	164	117

The following are three key assumptions contributing to the loss of load metrics:

- The probability occurrence of historical severe cold weather years was increased such that the new probability weighted average load for winter is increased to the 90/10 forecast of the Base Case. The reweighting of years brings the new probability weighted average load for SERC overall to 260,000 MW as compared to approximately 240, 000 MW of the Base Case.
- The sensitivity scenario is not designed to show likely system outcomes but to intentionally assess maximum system stress by using the following modelling assumptions:
  - There could be multiple ways to reweight the occurrence of historic years to get the probability weighted load average to 90/10 of the Base Case. Other approaches could have a lesser impact on loss of load. Our weather year reweighting was intentionally chosen to use more extreme conditions for assessment.
  - Given the geographic diversity of the SERC footprint, it is unlikely that all assessment areas will experience a cold weather condition at the same time. For example, while 1985 was a cold weather year that impacted a large part of the SERC footprint, it was not a significantly cold year for the Florida Peninsula.

The model assumes reweighting of weather years on a subregional level such that all the SERC footprint is at its 90/10 load condition on average of all the runs.

- In addition to the reweighting of historic years, the model assumes a correlation of thermal outages to severe cold weather. The base outage rates used in the Strategic Energy & Risk Valuation Model (SERVM) simulations for the ProbA were calculated from historical GADs data from the past five years. The Sensitivity Case assumes that the time to repair forced outages is two times of the Base Case for all hours of the winter months. Actual outage data under these weather conditions was not available. The 2X factor was selected to provide a conservative generation availability scenario.

The results indicate a small risk of customer interruption of services due to loss of energy under a severe winter case combining both unusual weather with higher than anticipated unit outages. This is indicative of the risk of short, sharp periods of load loss when high loads coincide with weather driven outages exceeding the normal planned reserves. While the results indicate a risk of interruption for some customers, they do not indicate a risk of a catastrophically large failure that would result in a system wide collapse even under this severe stress. A secondary case for the scenario was also analyzed with historical average (base scenario) outage rates. This secondary case with lower outage rates resulted in less than 25% of the LOLH risk compared to the higher outage case used here. The results from the secondary case indicate that good weatherization practices can be a significant step in mitigating potential impacts even in historically severe winter weather.

Chapter 7: SPP (MRO)

Assessment Area Overview

The SPP PC footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP assessment area is reported based on the PC footprint, which touches parts of the Midwest Reliability Organization Regional Entity, and the WECC Regional Entity. The SPP assessment area footprint has approximately 70,025 miles of transmission lines, ~949 generating plants, 5,180 transmission-class substations, and serves a population of more than 18 million.

The SPP assessment area has 105,464 MW (nameplate) of total generation, including over 32,000 MW of nameplate wind generation. SPP is also a summer-peaking assessment area with an all-time coincident summer peak demand of 53,243 MW. A Monte-Carlo based software, SERVM, was used in the 2022 SPP Probabilistic Assessment by randomly selecting LFU errors that were derived from historical probability of occurrence while varying the availability of thermal, hydro, and DR resources. The generating resources modeled in the probabilistic assessment reflect the data supplied in the *2022 LTRA*. Existing and projected resources were included in the probabilistic assessment along with reported confirmed retirements. Wind and solar resources as well as historical weather years were modeled at historical hourly values using 2012–2021 weather years. Study improvements from the 2020 NERC Probabilistic Assessment include *2022 LTRA* data updates, increased weather years (from 2012 to 2019, to 2012 to 2021) and modeling an economic dispatch with forced derate seasonal metrics.

A total of six zones were used, and SPP modeled a projected 8,760 hourly demand profile for each area to provide load variability and volatility for chronological hours during simulation. Each zone was modeled with an import and export limit based on power flow transfer analysis. SPP utilized unit specific outage rates within the analysis based on five years of NERC GADS data. External assistance only included contracts from external entities with firm transmission service.

Risk Scenario Description

SPP has seen an increase in demand and thermal unit outages during the past winter seasons. Therefore, SPP chose to perform a winter risk scenario that paired an increase in conventional forced generation outages and peak demand as the 2022 ProbA Regional Risk Scenario. The 90/10 winter load forecast from the 2022 ProbA data form was used in place of the 50/50 load forecast and the forced outage rate of the conventional fleet was doubled. The increase of the probability of the 90/10 load forecast increases the amount of simulations with high winter demand to simulate the increase probability of this scenario. Through this analysis, each individual weather year (2012–2021) was modeled in the risk scenario. The weighted forced outage rate for all conventional resources were increased proportionally and applied to each resource to achieve an SPP weighted forced outage rate. The regional risk scenario was performed on year 2026 to reflect additional generation retirements and projected variable energy resource (VER) penetrations.

Base Case Results

A minimal amount of EUE was indicated for the Base Case study due to increased conventional generation retirements and a VER capacity increase capacity in the SPP assessment area as shown in **Table 7.1**. Reserve Margins for the 2024 case show an increase from the 2020 ProbA. In addition, the 2022 Base Case results showed an increase from the 2020 ProbA analysis for EUE, which is believed to be a direct relation to the increased percentage of VERs in the resource mix.

Table 7.1: Base Case Summary of Results

Reserve Margin (RM) %		
	2024	**2026**
Anticipated	34.7%	34.4%
Reference	15.8%	15.8%
ProbA Forecast Operable	19.7%	19.6%
Annual Probabilistic Indices		
	2024	**2026**
EUE (MWh)	0.27	0.84
EUE (ppm)	0.00	0.00
LOLH (hours/year)	0.00	0.00

Risk Scenario Results

The results of the risk scenario showed an increase of potential EUE, reflecting the probability of increased forced outages during extreme winter weather events paired with the increase of load from the 90/10 load scenario. Scenario analysis results show that EUE values increase for 2026 when compared to the Base Case results. The EUE from the Base Case to the regional risk scenario almost doubles as shown in **Table 7.2**. In the Base Case scenario, all of the EUE occurs in the summer season while the increase in the risk scenario is reflected in the winter season.

Table 7.2: Scenario Case Summary of Results

	2024	**2026**
EUE (MWh)	--	1.36
EUE (ppm)	--	0.00
LOLH (hours/year)	--	0.00

Chapter 8: Texas RE-ERCOT

Assessment Area Overview

ERCOT encompasses about 75% of Texas, and the grid delivers approximately 90% of the electricity used by more than 26 million consumers. At the request of ERCOT, Astrapé Consulting simulated the ERCOT market with its Strategic Energy Risk Valuation Model. The model captured the uncertainty of weather, economic growth, unit availability, and external assistance from neighboring areas as stochastic variables. The model performed 5,250 hourly simulations for each study year to calculate physical reliability metrics. The simulations used 42 synthetic load, wind, solar, and hydro profiles (based on historical years 1980–2021) to represent expected conditions in the study years if historical weather conditions were to take place again.

Risk Scenario Description

ERCOT studied the impact of transmission limits on reliability indices as heavy IBRs in one area uses transmission to get to its load in the Central and Eastern parts of Texas for the 2026 study year. Transmission limits were included in the reliability assessment in order to reflect the dependence of IBRs on transmission to deliver to load.

Base Case Results

The Base Case study results in much more risk than what was presented in the 2020 ProbA Study as shown in **Table 8.1**. Essentially all of the risk is in the winter, largely driven by the incorporation of additional forced outage risk. With the modeling updates and solar penetration increases, the highest risk hours shifted from June–August to December–February even though the system is still a summer-peaking system. While the projected reserve margin for 2024 is much higher than what was projected in the 2020 ProbA Study, the additional reserves are from solar, which do not provide significant winter reliability value. The high level of reliability modeled in the summer is contingent on the projected construction of over 20 GW. The assumed solar installed capacity (ICAP) in 2024 is more than 17.6 GW higher than projected for the same year in the 2020 ProbA Study.

Table 8.1: Base Case Summary of Results

Reserve Margin (RM) %			
	2024*	**2024**	**2026**
Anticipated	15.5%	45.0%	44.0%
Reference	13.8%	13.8%	13.8%
Annual Probabilistic Indices			
	2022*	**2022**	**2024**
EUE (MWh)	12.86	492.03	1,235.40
EUE (ppm)	0.03	1.09	2.63
LOLH (hours/year)	0.01	0.15	0.30

Risk Scenario Results

For the 2026 study year, ERCOT studied the impact of transmission limits on reliability indices as a large number of IBRs use transmission to serve load in the Central and Eastern parts of the Texas RE-ERCOT area. The base ProbA study and prior ProbA studies of Texas RE-ERCOT have assumed full deliverability of all generation within the ERCOT system. To study the Regional Risk Scenario, the ERCOT system was divided into five different pipe-and-bubble zones. The constraints imposed on the simulations were single simplified import/export constraints between the zones as shown in **Figure 8.1**.

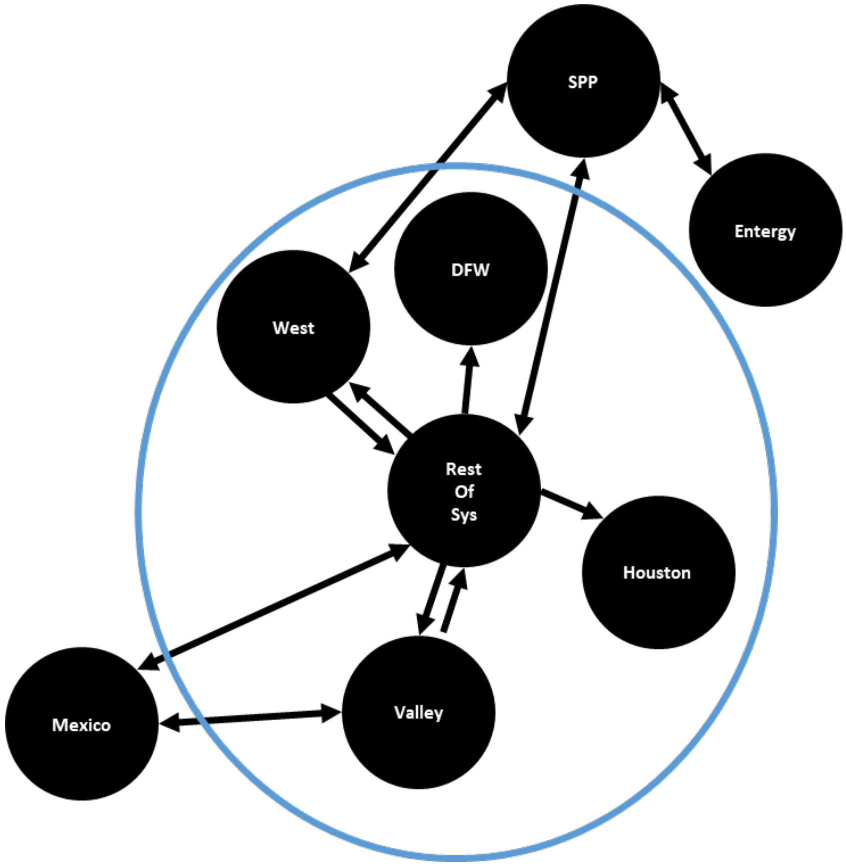

Figure 8.1: Study Topology

The monthly EUE results of the Base Case and the constrained transmission limit simulations are presented inTable 8.2. The ERCOT aggregate measures EUE or LOLH when any one or more areas sheds firm load. The EUE increase was modest, but the LOLH change was more drastic since events are occurring in different hours in different zones.

Table 8.2: Zonal Results—Monthly EUE

Month	Base	Regional Risk Scenario: Constrained					
		ERCOT Aggregate	Dallas	Houston	Rest of System	Valley	West
January	0.8	2.0	0.4	0.4	0.4	0.4	0.4
February	578.9	646.5	198.8	66.9	126.5	127.1	127.2
March	-	-	-	-	-	-	-
April	-	-	-	-	-	-	-
May	-	0.1	-	0.1	-	-	-
June	-	2.8	0.0	2.7	0.0	0.0	0.0
July	-	18.8	0.0	18.8	0.0	0.0	0.0
August	0.6	53.7	0.1	53.3	0.1	0.1	0.1
September	0.1	26.9	0.3	26.7	-	-	-
October	-	1.9	-	1.9	-	-	-
November	-	-	-	-	-	-	-
December	655.0	624.1	142.3	76.0	135.3	135.3	135.3
Annual	**1,235.4**	**1,376.8**	**341.9**	**246.8**	**262.3**	**262.9**	**263.0**

The monthly LOLH results of the Base Case and the constrained transmission limit simulations are presented in **Table 8.3**. In the Constrained Scenario, the aggregate LOLH is not simply the sum of the LOLH in all ERCOT zones because load shed can occur in different days in different zones that result in an aggregate LOLH that is greater than the maximum but less than the sum of the individual areas.

Table 8.3: Zonal Results—Monthly LOLH

Month	**Base**	**Regional Risk Scenario: Constrained**					
		ERCOT Aggregate	**Dallas**	**Houston**	**Rest of System**	**Valley**	**West**
January	0.00	0.00	0.00	0.00	0.00	0.00	0.00
February	0.14	0.21	0.21	0.09	0.15	0.15	0.15
March	-	-	-	-	-	-	-
April	-	-	-	-	-	-	-
May	-	0.00	-	0.00	-	0.00	0.00
June	-	0.01	0.00	0.01	0.00	0.00	0.00
July	-	0.05	0.00	0.05	0.00	0.00	0.00
August	0.00	0.17	0.00	0.17	0.00	0.00	0.00
September	0.00	0.05	0.00	0.05	-	-	-
October	-	0.01	-	0.01	-	-	-
November	-	-	0.00	-	-	-	-
December	0.15	0.18	0.18	0.11	0.17	0.17	0.17
Annual	0.30	0.68	0.39	0.49	0.32	0.32	0.32

The addition of internal transmission constraints had implications for reliability of the ERCOT system. A more dynamic representation of internal transmission constraints is required to fully quantify the total impact to reliability planning.

Chapter 9: WECC

Regional Entity Overview

The Western Interconnection serves a population of around 82 million people. The Interconnection spans 1.8 million square miles in all or part of 14 states between the Canadian provinces of British Columbia and Alberta, to the northern part of Baja California in Mexico. Due to its unique geography, demography, and history, the Western Interconnection is distinct in many ways from the other North American Interconnections.

Risk Scenario Description

WECC's reliability risk priorities focus on four reliability concerns categories: Resource Adequacy and Performance, Changing Resource Mix, Distribution System and Customer Load Impacts on the BPS, and Extreme Natural Events. It would be appropriate to study any of these topics, but the Resource Adequacy and Performance category incorporates elements of each category and serves as the basis for additional studies in each of these priorities.

The WECC Regional Risk Scenario examines the impacts on resource adequacy associated with the potential shutdown of key hydroelectric units along the Colorado River. The generation resources included in this scenario started with the LTRA resources and then the forced shutdown of Glen Canyon and Hoover hydro generation. These units are at risk of power production being shut down due to extremely low water levels.

This scenario specifically analyzes the reliability impacts of forced shutdown of these plants beyond those that are being retired in the LTRA. This scenario also provides insights into where additional wildfire risk may occur with transmission constraints being pushed to their limits and examines the effects of these potential shutdowns to help mitigate reliability risks to the BPS.

For further information, see *WECC's Western Assessment of Resource Adequacy* report.[17]

[17] WECC's Western Assessment of Resource Adequacy

California/Mexico (CA/MX)

Base Case Results

CA/MX resource adequacy measures are showing potential LOLH in the Base Case, indicating that anticipated reserves of 27% for the peak hour are not adequate for all hours of the year. The loss of load occurrences are expected in the months of July through September for 2024 and 2026. The hours of occurrence for 2024 and 2026 are expected after 4:00 p.m., one hour to three hours past the peak demand for the day in California. The EUE occurs in the same months and hours as the LOLH. The magnitudes range from less than a MW to 16k MW in any one hour per LOLH period as summarized in **Table 9.1**.

Table 9.1: Base Case Summary of Results

Reserve Margin (RM) %			
	2024*	**2024**	**2026**
Anticipated	26.28%	27.42%	22.47%
Reference	19.14%	17.68%	18.88%
ProbA Forecast Operable	15.3%	30.3%	25.7%
Annual Probabilistic Indices			
	2024*	**2024**	**2026**
EUE (MWh)	2,402,976	37,305	498,885
EUE (ppm)	8,818	136	1,785
LOLH (hours/year)	56	0.721	9.792

This probabilistic assessment only includes Tier 1 resources. This means the entire Interconnection does not benefit from Tier 2 or 3 resources, significantly limiting the external assistance that CA/MX can rely upon. For after 4:00 p.m., one to three hours past the peak demand for the day, the model shows 16 GWh. However, a probabilistic methodology is used, so the range of potential risk outcomes is heighted around this time of day and year. This includes a 97th percentile net peak demand and a 3rd percentile of resource availability with just T1 resources across the Western Interconnection and diminishing import capabilities. For that hour, the expected demand and the expected energy available still show a positive margin; however, if these extreme conditions were to occur (a small probability), WECC believes there could be 16 GWh of demand at risk for that hour but does not expect that amount of demand to be unserved as summarized in **Table 9.1**.

Risk Scenario Results

CA/MX is summer peaking and consists of most of the state of California and a portion of Baja California, Mexico. CA/MX has two distinct peak periods, one in Southern California and one in Northern California that benefits the subregion as there are resources available in one area when the other is experiencing their demand peak.

Demand

CA/MX is expected to peak in early-September at approximately 57,800 MW in 2024 and 59,200 MW in 2026. In 2024, there is a 5% possibility that CA/MX could peak as high as 71,000 MW, equating to a 28% LFU, and CA/MX could peak as high as 74,000 MW in 2026.

Resource Availability

For this scenario, there were approximately 1,100 MW of additional force shutdowns included in CA/MX. Forced shutdowns that occurred in the other subregions did have an impact in the amount of energy available to transfer to CA/MX.

The expected availability of resources on the peak hour in 2024 is 69,400 MW. Under low resource availability conditions, CA/MX may only have 52,000 MW available to meet a 57,800 MW expected peak. The expected availability of resources on the peak hour in 2026 is 67,800 MW. Under low resource availability conditions, CA/MX may only have 50,850 MW available to meet a 59,200 MW expected peak. Although there is only a 5% probability of this occurring, a large amount of external assistance would be needed to meet demand under low-availability conditions.

Planning Reserve Margin

Given the growing variability, a 18% margin for the CA/MX area is close to the median level of reserve margin needed to maintain reliability; it should not be considered the maximum for all hours. The highest reserve margin needed is expected to be around 42%. Therefore, it is important to look at reserve margins in terms of MWs. The highest reserve margin needed equates to approximately 12,500 MW, or 21% of the expected peak demand.

Annual Demand at Risk

In 2024, the Base Case reveals 964 hours of islanded risk. A total of 389 of these hours can be satisfied with internal transfers from other BA's within the assessment area, leaving 575 hours of demand at risk; external assistance is needed to satisfy these hours. The area is able to import over 387 GW of energy from other areas, which eliminates all but 56 hours of the demand at risk hours. Of the 387 GW of external transfers, most of it, 293 GW comes from low wildfire risk corridors.

When removing the hydro resources in the scenario case, given that CA/MX own some of the energy associated with these resources, the number of islanded hours at risk increases from 964 to 1,030 hours. Of these hours, 420 of them can be satisfied from internal transfers; however, of the 66 new islanded hours at risk, only 31 of those can be satisfied internally, meaning there are 35 new hours that will have to be addressed by external assistance. Over the 610 remaining hours of risk that require external assistance, the CA/MX area is able to import over 417 GW of energy from other areas; however, not all hours can be satisfied with external assistance as in the Base Case. Of the 417 GW of external assistance, 101 GW are now being imported through higher wildfire risk corridors, an increase of 7 GW. The analysis on where external assistance is coming from clearly shows that the ability to meet demand at risk hours has increased the risk in the system due to higher reliance on potential wildfire corridors.

Hours at Risk

In 2024, for the scenario, CA/MX could experience up to 59 hours where the one-day-in-ten-years threshold of resource adequacy is not maintained; this increases to 148 hours in 2026. CA/MX could experience as many as 55 hours where the one-day-in-ten-years threshold of resource adequacy is not maintained and up to 75 hours by 2026 for the Base Case. Given that CA/MX will need to rely heavily on external assistance to maintain resource adequacy, the impacts to demand at risk of the scenario came from both forced shutdowns and less transfers availability from other subregions.

Energy at Risk

In 2024, about 52,796 MWh of energy is at risk in the scenario case, growing to nearly 555,429 MWh by 2026 as shown in **Table 9.2**. In the Base Case, the results were 37,305 and 498,885 MWh respectively. A system wide high-demand scenario would eliminate much of the external assistance available for CA/MX, and a low availability scenario would lead to a highly constrained external assistance scenario throughout the system. Even under expected conditions, CA/MX is expected to have many hours where the one-day-in-ten-years threshold of reliability is not maintained through the inclusion of new resources and/or external assistance.

Table 9.2: Scenario Case Summary of Results

	2024	2026
EUE (MWh)	52,796	555,429
EUE (ppm)	193	1,988
LOLH (hours/year)	1.02	10.70

Southwest Reserve Sharing Group (SRSG)

Base Case Results

Table 9.3: Base Case Summary of Results			
Reserve Margin (RM) %			
	2024*	**2024**	**2026**
Anticipated	14.74%	32.78%	29.54%
Reference	17.16%	13.27%	12.07%
ProbA Forecast Operable	5.50%	28.08%	24.85%
Annual Probabilistic Indices			
	2024*	**2024**	**2026**
EUE (MWh)	81.33	83.58	9,352.15
EUE (ppm)	0.750	0.68	71.17
LOLH (hours/year)	0.004	0.003	0.368

WECC-SRSG resource adequacy measures are minimal in the Base Case, indicating that the anticipated peak reserve above 32% percent leads to insignificant levels of expected loss of load and minimal EUE. The loss of load occurrences are expected in the months of July and August for 2024 and the months of July, August, and September for 2026. The hours of occurrence for 2024 and 2026 are expected at 6:00 p.m., one hour past the peak demand for the day. The EUE occurs in the same months and hours as the LOLH. The magnitudes range from less than 1 MW to 9 MW in one hour to as much as 1 to 3 hours per LOLH period. This probabilistic assessment only includes Tier 1 resources. This means that the entire Interconnection does not benefit from Tier 2 or 3 resources; this significantly limits the external assistance that SRSG could rely upon. The model shows 9 MWh for that hour but it uses a probabilistic methodology, so the range of potential risk outcomes is heighted around this time of day and year. This includes a 97th percentile net peak demand and a 3rd percentile of resource availability with just T1 resources across the Western Interconnection and diminishing import capabilities. If these extreme conditions were to occur (a small probability of occurring), WECC believes there could be 9 MWh of demand at risk for that hour, but WECC does not expect that amount of demand to be unserved as highlighted in **Table 9.3**.

Risk Scenario Results

SRSG is a summer peaking area that consists of the entire states of Arizona and New Mexico and a portion of the states Texas and California.

Demand

SRSG is expected to peak in mid-July at approximately 27,100 MW in 2024 and 28,500 MW in 2026. In 2024, there is a 5% possibility SRSG could peak as high as 30,000 MW, which equates to a 10% LFU, and could peak as high as 32,000 MW in 2026.

Resource Availability

For this scenario, there were approximately 400 MW of additional force shutdowns included in SRSG. Forced shutdowns that occurred in the other subregions did have an impact in the amount of energy available to transfer to SRSG.

The expected availability of resources on the peak hour in 2024 is 30,600 MW. Under low resource availability conditions, SRSG may only have 24,700 MW available to meet a 30,600 MW expected peak. The expected availability of resources on the peak hour in 2026 is 30,200 MW. Under low resource availability conditions, SRSG may only have 24,000 MW available to meet a 30,600 MW expected peak. Although there is only a 5% probability of this occurring, a large amount of external assistance would be needed to meet demand under low-availability conditions.

Planning Reserve Margin

Given the growing variability, a 13% margin for SRSG is close to the median level of reserve margin needed to maintain reliability; it should not be considered the maximum for all hours. The highest reserve margin needed is expected to be around 33%. Therefore, it is important to look at reserve margins in terms of MWs. The highest reserve margin needed equates to approximately 4,927 MW or 18% of the expected peak demand. As more variable resources are added to the system, both on the demand side through roof-top resources and the resource side through generation plants, a larger reserve margin is needed to account for variability in the system.

Annual Demand at Risk

In 2024, the Base Case reveals 50 hours of islanded risk. A total of 20 of these hours can be satisfied with internal transfers from other BA's within the assessment area, leaving 30 hours of demand at risk; external assistance is needed to satisfy these hours. The area is able to import over 7 GW of energy from other areas, which eliminates all but 17 hours of the demand at risk hours. Most of the 7 GW of external transfers (6.98 GW) comes from low wildfire risk corridors.

When removing the hydro resources in the scenario case, the number of islanded hours at risk increases from 50 hours to 286 hours given that SRSG owns some of the energy associated with these resources. Of these hours, 4 of them can be satisfied from internal transfers; however, of the 236 new islanded hours at risk, only 24 of those can be satisfied internally, meaning there are 240 new hours that will require external assistance. Over the 262 remaining hours of risk that require external assistance, SRSG is able to import over 159 GW of energy from other areas. However, as in the Base Case, not all hours can be satisfied with external assistance. More so, of the 159 GW of external assistance, 5 GW is now being imported through higher wildfire risk corridors, an increase of 4.74 GW. However, the analysis on where external assistance is coming from clearly shows that the ability to meet demand at risk hours has increased the risk in the system due to higher reliance on potential wildfire corridors.

Hours at Risk

In 2024, SRSG could experience up to 37 hours where the one-day-in-ten-years threshold of resource adequacy is not maintained and up to 143 by 2026 for the scenario. For the Base Case, SRSG could experience as many as 17 hours where the one-day-in-ten-years threshold of resource adequacy is not maintained and up to 66 hours by 2026. The impacts of the scenario came from the 400 MW forced shutdowns as well as impacts from external assistance in other subregions.

Energy at Risk

In 2024, 8,271 MWh of energy is at risk in the Scenario Case and grows to 479,277 MWh by 2026 as shown in **Table 9.4**. In the Base Case, the results were 84 MWh and 9,352 MWh, respectively. A system-wide high demand scenario would eliminate much of the external assistance available for SRSG, causing this to be exacerbated, and a low availability scenario would lead to a highly constrained external assistance scenario throughout the system. Even under expected conditions, SRSG is expected to have many hours where the one-day-in-ten-years threshold of reliability is not maintained through the inclusion of new resources and/or external assistance.

Table 9.4: Scenario Case Summary of Results

	2024	2026
EUE (MWh)	8,271	479,277
EUE (ppm)	67	3,647
LOLH (hours/year)	0.33	18.92

Western Power Pool (WPP)

Base Case Results

Table 9.5: Base Case Summary of Results			
Reserve Margin (RM) %			
	2024*	2024	2026
Anticipated	38.35%	23.35%	16.01%
Reference	15.08%	12.91%	13.67%
ProbA Forecast Operable	24.9%	25.8%	21.0%
Annual Probabilistic Indices			
	2024*	2024	2026
EUE (MWh)	248,573	1,722	11,280
EUE (ppm)	621.8	4.22	27.18
LOLH (hours/year)	4.389	0.036	0.233

WECC-WPP resource adequacy measures are beginning to show a potential loss of load expectation in the Base Case, indicating that anticipated reserves of 23% for the peak hours in 2024 are not adequate for all hours of the year. The loss of load occurrences are expected in the months of June through September for 2024 and 2026. The hours of occurrence for 2024 and 2026 are expected after the peak hour for one to five hours past the peak demand for the day. The EUE occurs in the same months and hours as the LOLH. The magnitudes range from less than a MW to ~ 13GW in one hour and as much as 1 to 5 hours per LOLH period. This probabilistic assessment only includes Tier 1 resources. This means the entire interconnection does not benefit from Tier 2 or 3 resources that significantly limits the external assistance that WPP could rely upon. The model shows 13 MWh for that hour but it uses a probabilistic methodology, so the range of potential risk outcomes is heighted around this time of day and year. This includes a 97th percentile net peak demand and a 3rd percentile of resource availability with just T1 resources across the Western Interconnection and diminishing import capabilities. If these extreme conditions were to occur, WECC believes there could be 13 GWh of demand at risk for that hour but does not expect that amount of demand to be unserved as summarized in Table 9.5.

Risk Scenario Results

WPP consists of the Northern and Central portions of the Western Interconnection. WPP is summer or winter peaking depending on location. The area covers all the states of Washington, Oregon, Idaho, Nevada, Utah, Colorado, and Wyoming as well as portions of the states of Montana, California, South Dakota, and Nebraska.

Demand

WPP is expected to peak in early August at approximately 69,000 MW in 2024 and 70,000 MW in 2026. In 2024, there is a 5% possibility WPP could peak as high as 76,100 MW, which equates to a 10% LFU and could peak as high as 77,300 MW in 2026.

Resource Availability

For this scenario, there were approximately 1,800 MW of additional force shutdowns included in WPP. Forced shutdowns that occurred in the other subregions did have an impact in the amount of energy available to transfer to WPP.

The expected availability of resources on the peak hour in 2024 is 30,600 MW. Under low resource availability conditions, WPP may only have 79,700 MW available to meet a 69,000 MW expected peak. The expected availability of resources on the peak hour in 2026 is 75,700 MW. Under low resource availability conditions, WPP may only have 58,200 MW available to meet a 69,600 MW expected peak. Although there is only a 5% probability of this occurring, a large amount of external assistance would be needed to meet demand under low-availability conditions.

Planning Reserve Margin

Given the growing variability, a 13% margin for WPP is close to the median level of reserve margin needed to maintain reliability; it should not be considered the maximum for all hours. The highest reserve margin needed is expected to be around 40%. Therefore, it is important to look at reserve margins in terms of MWs. The highest reserve margin needed equates to approximately 15,100 MW or 22% of the expected peak demand. As more variable resources are added to the system, both on the demand side through roof-top resources and the resource side through generation plants, a larger reserve margin is needed to account for variability in the system.

Annual Demand at Risk

In 2024, the Base Case reveals 4,877 hours of islanded risk. A total of 4,764 of these hours can be satisfied with internal transfers from other BA's within the assessment area, leaving 113 hours of demand at risk; external assistance is needed to satisfy these hours. WPP is able to import over 103 GW of energy from other areas, which eliminates all but 16 hours of the demand at risk hours. Of the 103 GW of external transfers, 102 GW come from low wildfire risk corridors.

When removing the hydro resources in the scenario case, given that WPP owns some of the energy associated with these resources, the number of islanded hours at risk increases from 4,877 hours to 5,988 hours. Of these hours, 909 of them can be satisfied from internal transfers, and there are 5,079 hours that will have to rely on external assistance. WPP is able to import over 1,510 GW of energy from other areas. However, not all hours can be satisfied with external assistance as in the Base Case. More so, of the 1,510 GW of external assistance, 10 GW is now being imported through higher wildfire risk corridors, an increase of 9 GW.

Hours at Risk

In 2024, for the scenario, WPP could experience 12 hours where the one-day-in-ten-years threshold of resource adequacy is not meet and 98 hours by 2026; for the Base Case, the results were 8 hours in 2024 and 75 hours in 2026. The impacts of the scenario came from the 1,800 MW of forced shutdowns as well as the impacts from external assistance in other subregions.

Energy at Risk

In 2024, 531 MWh of energy is at risk in the scenario case and grows to 40,878 MWh by 2026 as shown in **Table 9.6**. In the Base Case, the results were 1,722 and 11,280 MWh respectively. A system-wide high demand scenario would eliminate much of the external assistance available for WPP, causing this to be exacerbated, and a low availability scenario would lead to a highly constrained external assistance scenario throughout the system. Even under expected conditions, WPP is expected to have many hours where the one-day-in-ten-years threshold of reliability is not maintained through the inclusion of new resources and/or external assistance.

Table 9.6: Scenario Case Summary of Results

	2024	2026
EUE (MWh)	531	40,878
EUE (ppm)	1.30	99
LOLH (hours/year)	0.23	0.69

WECC-Alberta (WECC-AB) and WECC-British Columbia (WECC-BC)

Base Case Results

WECC-AB resource adequacy measures are zero in the Base Case, indicating that anticipated reserves above 25% percent lead to no expected loss of load or EUE as shown in **Table 9.7**.

Table 9.7: Base Case Summary of Results—Alberta			
Reserve Margin (RM) %			
	2024*	2024	2026
Anticipated	23.98%	25.14%	30.95%
Reference	14.15%	15.24%	11.50%
ProbA Forecast Operable	20.2%	22.4%	33.5%
Annual Probabilistic Indices			
	2024*	2024	2026
EUE (MWh)	0	0	0
EUE (ppm)	0	0	0
LOLH (hours/year)	0	0	0

WECC-BC resource adequacy measures are zero in the Base Case, indicating that anticipated reserves above 15% percent lead to insignificant levels of expected loss of load or EUE. The loss of load occurrences are expected in the month of January and February for 2024 and the months of February, October, and November for 2026. The hours of occurrence for 2024 and 2026 are expected at 6:00 a.m., one hour before the peak demand for the day. The EUE occurs in the same months and hours as the LOLH. The magnitudes range from less than 2 MW to 51 MW in one hour and as much as 1 to 3 hours per LOLH period as shown in **Table 9.8**.

Risk Scenario Results

WECC-AB covers the Alberta province of Canada while WECC-BC covers the British Columbia province. Both are winter peaking.

Table 9.8: Base Case Summary of Results—British Columbia			
Reserve Margin (RM) %			
	2024*	2024	2026
Anticipated	21.23%	15.53%	23.10%
Reference	14.15%	15.24%	11.50%
ProbA Forecast Operable	21.10%	18.5%	20.62%
Annual Probabilistic Indices			
	2022*	2024	2026
EUE (MWh)	8.452	24.229	281.047
EUE (ppm)	0.137	0.37	4.13
LOLH (hours/year)	0.001	0.002	0.034

Demand

WECC-AB is expected to peak in late January at approximately 11,900 MW in 2022 and 12,000 MW in 2026. In 2024, there is a 5% possibility that WECC-AB could peak as high as 12,300 MW, which equates to a 1% LFU.

WECC-BC is expected to peak in late January at approximately 11,400 MW in 2024 and 11,700 MW in 2026. In 2024, there is a 5% possibility WECC-BC could peak as high as 12,400 MW, which equates to a 9% LFU.

Resource Availability

In WECC-AB the expected availability of resources on the peak hour in 2024 is 14,000 MW and 13,800 MW in 2026. Under low resource availability conditions, WECC-AB may only have 11,500 MW available to meet a 11,900 MW expected peak. Although there is only a 5% probability of this occurring, external assistance would be needed to meet demand under low-availability conditions.

In WECC-BC the expected availability of resources on the peak hour in 2024 is 13,200 MW and 2026 is 13,500 MW. Under low resource availability conditions, WECC-BC may only have 10,700 MW available to meet an 11,400 MW expected peak. Although there is only a 5% probability of this occurring, external assistance would be needed to meet demand under low-availability conditions.

For this scenario, there were no forced shutdowns included in WECC–AB or WECC-BC.

Planning Reserve Margin

Given the growing variability, a 15% margin for WECC-AB is close to the median level of reserve margin needed to maintain reliability; it should not be considered the maximum needed for all hours. The highest reserve margin needed is expected to be around 21%. Therefore, it is important to look at reserve margins in terms of MWs. The highest reserve margin needed equates to approximately 2,230 MW or 19% of the expected peak demand.

Given the growing variability, a 15% margin for WECC-BC is close to the median level of reserve margin needed to maintain reliability; it should not be considered the maximum for all hours. The highest reserve margin needed is expected to be around 38%. Therefore, it is important to look at reserve margins in terms of MWs. The highest reserve margin needed equates to approximately 2,800 MW or 25% of the expected peak demand.

Annual Demand at Risk

Hours at Risk

WECC-AB showed no expected LOLH. In 2024, for the scenario, WECC-BC show no changes from the Base Case as shown in **Table 9.9**. For the base case, the results were 5 hours in 2024 and 4 hours in 2026

Energy at Risk

WECC-AB showed no expected EUE. In 2024, for the scenario, WECC-BC show no changes from the Base Case. In the Base Case, the results were 24 MW and 281 MWh in 2026. The slight impacts of the scenario came from external assistance in other subregions.

Table 9.9: Scenario Case Summary of Results

WECC-AB	2024	2026
EUE (MWh)	0	0
EUE (ppm)	0	0
LOLH (hours/year)	0	0
Scenario Case Summary of Results		
WECC-BC	**2024**	**2026**
EUE (MWh)	24	281
EUE (ppm)	0.37	4.13
LOLH (hours/year)	0.001	0.03

Appendix A: Assessment Preparation, Design, and Data Concepts

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Assessment Data Questions

Direct all data inquiries to NERC staff (assessments@nerc.net). References to the data and/or findings of the assessment are welcome with appropriate attribution of the source to the NERC *2022 Probabilistic Assessment*. However, extensive reproduction of tables and/or charts will require permission from NERC staff.

NERC Probabilistic Assessment Working Group Members

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Appendix B: Description of Study Method in the ProbA

MRO and MISO

General Description

MISO utilized the Strategic Energy Risk Valuation Model to perform the 2020 ProbA Base Case and scenario. A total of 30 historic weather years were modeled with five different economic uncertainty multipliers and 125 outage draws, resulting in 18,750 unique load/outage scenarios being analyzed.

In SERVM, the MISO system was represented as a transportation model with each of MISO's 10 LRZ's modeled with their respective load forecasts and resource mixes. The LRZ's were able to import and export energy with each other within the model, and the results of the study were aggregated up to the MISO level.

Demand and Load Forecast Uncertainty

To account for load uncertainty due to weather, MISO modeled 30 unique load shapes based on historic weather patterns. These load shapes were developed by using a neural-net software to create functional relationships between demand and weather with the most recent five years of actual demand and weather data within MISO. These neural-net relationships were then applied to the most recent 30 years of weather data to create 30 synthetic load shapes based on historic weather. Finally, the average of these 30 load shapes was scaled to the 50:50 forecasts from MISO's load serving entities (LSE).

To capture economic uncertainty in peak demand forecasts, MISO modeled each of the 30 load shapes with five different scalars (-2%, -1%, 0%, 1%, 2%). This resulted in 150 unique load scenarios (30 load shapes X 5 uncertainty scalars) being modeled.

Thermal Resources

All thermal resources in MISO were modeled as two-state units (i.e., either dispatched to full ICAP or offline). Units with at least one year of operating history were modeled with their actual equivalent forced outage rate on demand (EFORd) based on GADS data (up to five historic years). Units with insufficient operating history to determine an EFORd were assigned the class average EFORd.

Wind and Solar

Wind units were modeled with monthly effective load carrying capability (ELCC) values, which can be found in MISO's 2021-22 PY LOLE Study Report.[18] Solar resources were modeled at 50% of installed capacity. Both wind and solar were treated as a net-load reduction within the model.

Hydroelectric

Hydro units in MISO were modeled as a resource with an EFORd except for run-of-river units; these were modeled at their individual capacity credit, which is determined by the resource's historic performance during peak hours.

Demand-Side Resources

DR was modeled as dispatchable call limited resources. These resources were only dispatched when needed during emergency conditions to avoid shedding load. EE resources were modeled as load modifiers, which were netted from the load within the model.

Transmission

Capacity import limits and capacity export limits were modeled for each of the 10 LRZs. If an LRZ was expected to be unable to meet its peak demand, then that zone would import capacity up to its capacity import limits provided there was sufficient exports available from other zones.

[18] 2021-22 PY LOLE Study Report.

MRO-Manitoba Hydro

General Description

The 2022 Manitoba Hydro probabilistic assessment was conducted with the MARS program. The LOLH and EUE indices calculated for 2024 increased slightly as compared to the results obtained in 2020, but the loss of load expectation remains below 0.1 days per year. The slight increase in the reliability indices was mainly due to an increase in the number of load shapes modeled from 7 to 10 historical years. Hourly historical wind generation output corresponding to the historical load was also incorporated. These modeling refinements better capture the historical load and wind generation uncertainties associated with load profiles and peak load forecast.

Demand and Load Forecast Uncertainty

A hybrid method is used to model uncertainties in both peak load forecast and load profile changes. In this method, uncertainties associated with load are captured through 8,760-point hourly load shape of ten representative years for the period from 2012 to 2022 and an additional ±3% of variations in each of the ten peak values using a seven-step normal distribution. The Manitoba Hydro annual load shape is strongly winter peaking.

Thermal Resources

Thermal generation represents less than 5% of the total ICAP in Manitoba Hydro. These thermal units follow a two-state on-or-off sequence based on Monte Carlo simulation, which on average is equivalent to de-rating Manitoba Hydro thermal generating resources by 53 MW or 19%.

Wind and Solar

VERS (I.E,. wind) in Manitoba Hydro are modeled as a load modifier with actual hourly wind farm data collected for the period from 2012–2021 to capture the uncertainties in wind variations. In 2020 assessment, wind resources in Manitoba were modeled as deterministic load modifiers considering the seasonal variations, which was approximately equivalent to 16% and 20% of the maximum wind generation capacity respectively for summer and winter seasons. In 2022 assessment, actual wind farm data collected for the period from 2012–2021 has been used to capture the uncertainties in wind variations.

Hydroelectric

The vast majority of generating facilities in Manitoba Hydro are use-limited or energy-limited hydro units. All hydro plants are modeled as energy limited based on several historical flow conditions of the river systems. The peaking capabilities of the hydro generation can be constrained by load shape and flow conditions, which are constraints to the modeling of the hydro as an energy-limited resource.

Demand-Side Resources

EE and conservation programs are modeled as a simple load modifier by reducing the peak load.

Transmission

Manitoba Hydro and its neighboring systems are modeled as three areas consisting of Manitoba, Saskatchewan, and the Northwest part of MISO. Each of the three interconnected areas is modeled as a copper sheet and the transmission between areas is modeled with interface transfer limits. The external systems were modeled in the same detail as the Manitoba system rather than a simple equivalent model. It is assumed that potential assistances from external systems are based on their anticipated reserve margins for the 2024 and 2026 planning years.

MRO-SaskPower

General Description

Saskatchewan is a province of Canada and comprises a geographic area of approximately 652,000 square kilometers (251,739 square miles) with approximately 1.2 million people. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the PC and RC for the province of Saskatchewan. SaskPower is the principal supplier of electricity in the province and responsible for serving nearly 550,000 customer accounts. SaskPower is a provincial crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan BES and its interconnections.

Saskatchewan utilizes the MARS program for reliability planning. The software performs the Monte Carlo simulation by stepping through the time chronologically and calculates the standard reliability indices of daily and hourly Loss of Load Expectation (LOLE) and EUE.

Demand and Load Forecast Uncertainty

This reliability study is based on the 50:50 load forecast that includes data, such as annual peak, annual target energy, and load profiles. The model distributes the annual energy into hourly data based on the load shape. Saskatchewan develops energy and peak demand forecasts based on provincial econometric model forecasted industrial load data and weather normalization model.

The forecasts also take into consideration of the Saskatchewan economic forecast, historic energy sales, customer forecasts, weather normalized sales, and system losses. The LFU is explicitly modeled utilizing a seven-step normal distribution with a standard deviation of plus 3%, 5%, and 10%.

Thermal Resources

Natural gas units are typically modeled as a two-state unit so that natural gas unit is either available to be dispatched up to full load or is on a full forced outage with zero generation. Coal facilities are typically modeled as a three-state unit. A coal unit can be at a full load, a derated forced outage or a full forced outage state. Forecast derated hours are based on the percentage of the time the unit was derated out of all hours, excluding planned outages, based on the 5-year historical average. Generally, UFOP is used when forecasting reliability for the natural gas turbine units and FOR/DAFOR for the steam units.

Wind and Solar

For reliability planning purposes, Saskatchewan plans for 10% of wind nameplate capacity to be available to meet summer peak and 20% of wind nameplate capacity to be available to meet winter peak demand. Two methods were utilized to carry out the analysis for determining wind capacity credit. First method approximates the ELCC of the wind turbines by determining the wind capacity during peak load hours of each month by looking at historical wind generation in those hours. A period of four consecutive hours was selected and the actual wind generation in those four hours was used to determine the ELCC of the wind turbines. The median capacity value of wind generation in those four hours of each day of the month is calculated and is converted to a percent capacity by dividing that number by the maximum capacity of the wind turbine. The second method to estimate the ELCC is utilized by looking at the top 1%, 5%, 10%, and 30% of load hours in each month. Using these methods, the lowest averages is then looked at in each of the winter and summer months to come up with the wind capacity credit value.

Currently, Saskatchewan has low penetration level of solar resources and most of it is DER, which is netted off the load forecast.

Hydroelectric

Hydro generation is modeled as energy-limited resource and utilized based on deterministic and as-needed scheduling on a monthly basis. Hydro units are modelled by specifying maximum rating, minimum rating, and monthly available energy. The first step is to dispatch the minimum rating for all the hours in the month. Remaining capacity is then scheduled to reduce the peak loads and mitigate loss of load events as much as possible. Hydro generation is calculated based on the historical data that has been accumulated over the last 30 plus years.

Demand-Side Resources

***Controllable and Dispatchable Demand Response Program**:* DR is modelled as an EOP by assigning a fixed capacity value (67 MW); thus, configured as a negative margin state for which MARS evaluates the required metrics. An EOP is initiated when the reserve conditions on a system approach critical level.

Energy provided from EE and conservation programs is netted off the load forecast.

Transmission

No transmission facility data is used in this assessment as the model assumes that all firm capacity resources are deliverable within the assessment area. Separate transmission planning assessments indicate that transmission capability is expected to be adequate to supply firm customer demand and planned transmission service for generation sources.

MRO-SPP

General Description

Southwest Power Pool (SPP) PC footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP 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. SPP assessment area has over 90,000 MW (name plate) of total generation, which includes over 28,000 MW of nameplate wind generation. SPP is also a summer peaking assessment area at approximately 51,000 MW of summer peak demand.

Demand and Load Forecast Uncertainty

Eight years (2012–2019) of historical hourly load data were individually modeled to produce 8,760 hourly load profiles for each zone in the SPP assessment area. In order to not overestimate the peak demand, the forecasted peak demand for 2022 and 2024 were assigned to the load shape from 2014 (the median year of the eight historical years). The other seven years were also scaled to a forecasted peak demand calculated by distributing the variance between the peaks of the non-median years to the median year.

Microsoft Excel was used to regress the daily peak values against temperatures, economics, and previous daily peak loads observed at key weather stations throughout the SPP footprint to derive the LFU components. The load multipliers were determined from a uniform distribution and assigned seven discrete steps with the applicable probability occurrence weighting. All seven of the LFU steps were modeled at or above the 50/50 peak forecast.

Thermal Resources

SPP modeled seasonal maximum net capabilities reported in the LTRA for thermal resources. Physical and economic parameters were modeled to reflect physical attributes and capabilities of the resources. Full and partial forced outages from NERC GADS data in the SPP footprint were applied on a resource basis.

Wind and Solar

SPP included wind and solar resources currently installed, under construction, or that have a signed interconnection agreement. Wind and solar resources were modeled in SERVM with an hourly generation profile assigned to each individual resource. Hourly generation is based upon historical profiles correlating with the yearly load shapes (2012–2019). Any resources that did not have historical shapes were supplemented by the nearest resource.

Hydroelectric

Hydro generation was modeled as energy-limited resources while considering monthly hydro energy limitations calculated using historical data from 2012–2019. Hydro resources also considered historical daily max energies and the software dispatched by the resources as needed to maintain reliability.

Demand-Side Resources

Controllable and dispatchable DR programs were modelled as equivalent thermal units with high fuel costs so that those units would be dispatched last to reflect demand-response operating scenarios to prevent loss of load events.

Transmission

The SPP transmission system was represented as "pipes" between six zones modeled in the SPP assessment area. A First Contingency Incremental Transfer Capability analysis was performed outside of the SERVM software, which determined transfer limits modeled between zones. All resources and loads in their respective zone were modeled as a "copper sheet" system.

NPCC-Maritimes

General Description

The Maritimes assessment area is winter peaking and part of NPCC with a single RC and two BA areas. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, Prince Edward Island, and Northern Maine, which is radially connected to New Brunswick. New Brunswick Power is the RC for Maritimes with its system operator functions performed by its Transmission and System Operator division under a regulator approved Standards of Conduct. The area covers 58,000 square miles with a total population of 1.9 million.

Demand and Load Forecast Uncertainty

The Maritimes demand is the maximum of the hourly sums of the individual sub-area load forecasts. Except for the Northern Maine sub-area that uses a simple scaling factor, all other sub-areas use a combination of some or all of efficiency trend analysis, anticipated weather conditions, econometric modeling, and end-use modeling to develop their load forecasts.

The effects on reliability of uncertainties within the load forecast, due to weather and economic conditions, were captured through the LFU model in the GE MARS program; the program computes the reliability indices at each of the specified load levels (for this study, seven load levels were modeled) and calculates weighted-average values based on input probabilities of occurrence.

Annual peak demand in Maritimes varies by +9% of the forecasted Maritimes demand based upon the 90/10 percentage points of LFU distributions.

Thermal Resources

Maritimes uses seasonal dependable maximum net capability to establish combustion turbine capacity for resource adequacy. During summer, these values are derated accordingly.

Wind

Maritimes provides an hourly historical wind profile for each of its four sub-areas based on actual wind shapes for the period from 2012–2021. The wind in any particular hour is a probabilistic amount determined by selecting a random wind and load shape from the historic years. Each sub-area's actual MW wind output was normalized by the total ICAP in the sub-area during that calendar year. These profiles, when multiplied by current sub-area total installed wind capacities, yield an annual wind forecast for each sub-area. The sum of these four sub-area forecasts is Maritimes hourly wind forecast.

Solar
Solar capacity in the Maritimes is behind-the-meter (BTM) and netted against load forecasts. It does not currently count as capacity.

Hydroelectric
Hydro capacity in Maritimes is predominantly run-of-river, but enough storage is available for full rated capability during daily peak load periods.

Demand-Side Resources
DR in Maritimes is currently comprised of contracted interruptible loads.

Transmission
Construction of a 475 MW +/-200 kV HVDC undersea cable link (the Maritime Link) between Newfoundland, Labrador, and Nova Scotia was completed in late 2017. This cable, in conjunction with the construction of the Muskrat Falls hydro development in Labrador, it presently provides for a 150 MW firm capacity import to Nova Scotia. Due to short-term maintenance outages and the ongoing commissioning work on the HVDC transmission link from Labrador to Newfoundland, a 150 MW (nameplate) coal-fired unit will be retained in Nova Scotia, if needed, to provide firm capacity and maintain an adequate planning reserve margin for the upcoming winter 2022–2023. The unconfirmed retirement of this coal unit is shown in 2023 for this assessment. The Maritime Link could also potentially provide a source for imports from Nova Scotia into New Brunswick that would reduce transmission loading in Southeastern New Brunswick.

Other
The current amount of DERs in Maritimes is currently insignificant at about 29 MW in winter. During this LTRA period, additions of solar (mainly rooftop) resources in Nova Scotia are expected to increase this value to about 184 MW. The capacity contribution of rooftop solar during the peak is zero as system winter peaks occur during darkness. As more installations are phased in, operational challenges, like ramping and light load conditions, will be considered and mitigation techniques investigated.

NPCC-New England

General Description
ISO New England (ISO-NE) Inc. is a regional transmission organization that serves the six New England states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. It is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administers the area's wholesale electricity markets, and manages the comprehensive planning process for the regional BPS. The New England BPS serves approximately 14.5 million people over 68,000 square miles.

Demand and Load Forecast Uncertainty
ISO-NE develops an independent demand forecast for its BA area by using historical hourly demand data from individual member utilities. This data is used to develop the regional hourly peak demand and energy forecasts. ISO-NE then develops a forecast of both state and system hourly peak and energy demands. The regional peak and state demand forecast are considered coincident. This demand forecast is the gross demand forecast that is then decreased to a net forecast by subtracting the impacts of EE measures and BTM solar photovoltaic (PV). Annual peak demand in the New England area varies by +11% of forecasted demand based upon the 90/10 percentage points[19] of LFU distributions.

[19] https://www.iso-ne.com/static-assets/documents/2019/09/p1_load_forecast_methodology.pdf

The effects on reliability of uncertainties within the load forecast, due to weather and economic conditions, were captured through the LFU model in the GE MARS program. The program computes the reliability indices at each of the specified load levels (for this study, seven load levels were modeled) and calculates weighted-average values based on input probabilities of occurrence.

Thermal Resources

The seasonal claimed capability, as established through claimed capability audits, is used to rate the sustainable maximum capacity of non-intermittent thermal resources. The seasonal claimed capability[20] for intermittent thermal resources is based on their historical median net real power output during ISO-New England defined seasonal reliability hours.

Wind

New England models the wind resources using the seasonal claimed capability as determined based on their historical median net real power output during seasonal reliability hours.

Solar

The majority of solar resource development in New England is the state-sponsored distributed BTM solar PV resources that does not participate in the wholesale electric markets but reduces the real-time system load observed by ISO-New England system operators. These resources are modeled as a load modifier on an hourly basis, based on the 2002 historical hourly weather profile.

Hydroelectric

New England uses the seasonal claimed capability to represent hydroelectric resources. The seasonal claimed capability for intermittent hydroelectric resources is based on their historical median net real power output during seasonal reliability hours.

Demand-Side Resources

On June 1, 2018, ISO-NE integrated price-responsive DR into the energy and reserve markets. Passive and active demand resources participate in the New England Forward Capacity Market (FCM) and are represented as supply-side resources in this study. The qualified capacity of passive demand resources under the FCM are used for the years 2019–2021, and a forecast amount is used for the future years. For the active demand resources, the study assumes the actual amount procured under the FCM. Active demand capacity resources participate in the ISO New England capacity market and are offered into the energy market on a daily basis and dispatched according to price. These demand resources are discounted in the assessment to account for performance based on the observed availability factors of DR programs in the past.

Transmission

The New England area has constructed several major reliability-based transmission projects within the past few years to strengthen the regional BPS. While several major projects are nearing completion, two significant projects remain under construction: Greater Boston and Southeastern Massachusetts and Rhode Island. The majority of the Greater Boston project will be in-service by December 2021 while the addition of a 115 kV line between Sudbury and Hudson is expected to be in service by December 2023. The Southeastern Massachusetts and Rhode Island project is in the early stages of construction. Additional future reliability concerns have been identified in Boston and are being addressed through a development request-for-proposal.

Other

New England has 174 MW (1,379 MW nameplate) of wind generation and 787 MW (2,164 MW nameplate) of BTM solar PV. Approximately 12,400 MW (nameplate) of wind generation projects have requested generation

[20] ISO-NE conducts CCAs to establish the winter and summer seasonal claimed capability (SCC) values for generator assets. See: FAQs: Claimed Capability Audits

interconnection studies. BTM solar PV is forecast to grow to 1,062 MW (4,306 MW nameplate) by 2029. The BTM solar PV peak load reduction values are calculated as a percentage of ac nameplate. The percentages include the effect of diminishing solar PV production at the time of the system peak as increasing solar PV penetrations shift the timing of peaks later in the day, decreasing from 34.3% of nameplate in 2020 to about 23.8% in 2029.

NPCC-New York

General Description

The NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. The NYISO is the only BA within the state of New York. The transmission grid of New York State encompasses approximately 11,000 miles of transmission lines, 760 power generation units, and serves the electric needs of 19.5 million people. New York experienced its all-time peak demand of 33,956 MW in the summer of 2013.

Demand and Load Forecast Uncertainty

The energy and peak load forecasts are based upon end-use models that incorporate forecasts of economic drivers and end-use technology efficiency and saturation trends. The impacts of EE and technology trends are largely incorporated directly in the forecast model with additional adjustments for policy-driven EE impacts made where needed. The impacts of DERs, EVs, other electrification, energy storage, and BTM solar PV are made exogenous to the model. At the system level, annual peak demand forecasts range from 6% above the baseline for the ninetieth percentile forecast to 8% below the baseline for the tenth percentile forecast. These peak forecast variations due to weather are reflected in the LFU distributions applied to the load shapes within the GE MARS model. The effects on reliability of uncertainties within the load forecast, due to weather and economic conditions, were captured through the LFU model in the GE MARS program. The program computes the reliability indices at each of the specified load levels (for this study, seven load levels were modeled) and calculates weighted-average values based on input probabilities of occurrence.

Thermal Resources

Installed capacity values for thermal units are based on the minimum of seasonal Dependable Maximum Net Capability (DMNC) test results and the capacity resource interconnection service (CRIS) MW values from the *2022 NYISO's Gold Book*. Generator availability is derived from the most recent calendar five-year period forced outage data. Units are modeled in the MARS program with a multi-state representation that represents an EFORd. Planned and scheduled maintenance outages are modeled based upon schedules received by the New York ISO and adjusted for historical maintenance.

Wind

New York provides 8,760 hours of historical wind profiles for each year of the most recent five-year calendar period for each wind plant based on production data. Wind seasonality is captured by using the-MARS functionality to randomly select an annual wind shape for each wind unit in each draw. Each wind shape is equally weighted.

Solar

New York provides 8,760 hours of historical solar profiles for each year of the most recent five-year calendar period for each solar plant based on production data. Solar seasonality is captured by using GE-MARS functionality to randomly select an annual solar shape for each solar unit in each draw. Each solar shape is equally weighted. Both behind the meter and front of the meter solar is modeled using this method.

Hydroelectric

Large hydro units are modeled as applicable, either as thermal units with a corresponding multi-state representation that represents an EFORd or as energy-limited resources. For run-of-river units, New York provides 8,760 hours of historical unit profiles for each year of the most recent five-year calendar period for each facility based on production data. Run-of-river unit seasonality is captured by using GE-MARS functionality to randomly select an annual shape for each run-of-river unit in each draw. Each shape is equally weighted.

Demand-Side Resources

Demand-side resources consists of Special Case Resources (SCR) and Emergency Demand Response Programs (EDRP). The Installed Capacity (ICAP) SCR program allows demand resources that meet certification requirements to offer Unforced Capacity ("UCAP') to load serving entities. SCRs are modeled as one of the Emergency Operating Procedure (EOP) step in MARS using monthly MW values discounted for historic availability and performance. The EDRP resources are not modeled at this time as the program enrollment was less than 2 MW.

Transmission

The 2020–2021 reliability planning process includes proposed transmission projects and transmission owner local transmission plans that have met the Reliability Planning Process inclusion rules. The NYISO Board of Directors selected projects under two public policy transmission planning processes: the first for Western New York and the second for Central New York and the Hudson Valley, which is known as the ac transmission need. When completed, these projects will add more transfer capability in Western New York and between Upstate and Downstate New York.

Other

The NYISO is currently implementing a three to five-year plan to integrate DERs, including DR resources, into its energy, capacity, and ancillary services markets. The NYISO published a DER roadmap document in February 2017 that outlined NYISO's vision for DER market integration. FERC approved the NYISO's proposed tariff changes in January 2020. The NYISO is currently identifying the related software and procedure changes and is targeting implementation in Q4 2021.[21]

NPCC-Ontario

General Description

The IESO is the BA for the province of Ontario. The province of Ontario covers more than one million square kilometers (415,000 square miles) and has a population of more than 14 million people. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

Demand and Load Forecast Uncertainty

Each zone has an hourly load from the demand forecast as well as a monthly LFU distribution. The LFU is derived by simulating the effect of many years of historical weather on forecasted loads. Monthly distributions of simulated demand peaks are generated at a zonal level and then adjusted to match the equivalent distribution at the provincial level.

The adjusted LFU distributions are used to create a seven-step approximation of the actual distribution. When generating reliability indices, the MARS model assesses all seven steps of the LFU distribution, weighted by probability. Annual peak demand in Ontario varies by +11% of forecasted Ontario demand based upon the 90%/10% points of LFU distributions.

Thermal Resources

The capacity values and planned outage schedules for thermal units are based on information submitted by market participants. The available capacity states and state transition rates for each existing thermal unit are derived based on analysis of a rolling five-year history of actual forced outage data. For existing units with insufficient historical data, and for new units, capacity states and state transition rate data of existing units with similar size and technical characteristics are applied.

[21] Distributed Energy Resources (DER) - NYISO

Wind and Solar
Historical hourly load profiles are used to model both wind and solar generation.

Hydroelectric
Hydroelectric resources are modelled in the MARS program as capacity-limited and energy-limited resources. Minimum capacity, maximum capacity, and monthly energy values are determined on an aggregated basis for each zone based on historical data since market opening in 2002.

Demand-Side Resources
Ontario's demand-side resources are comprised of DR resources procured through auction and dispatchable loads These resources can be dispatched in the same way that generators are.

Transmission
The IESO-controlled grid is modelled with 10 electrical zones and connecting transmission interfaces. Transmission transfer capabilities are developed according to NERC standard requirements; the methodology for developing transmission transfer capabilities is described in IESO's *Transfer Capability Assessment Methodology: For Transmission Planning Studies.*[22]

NPCC-Québec

General Description
The Québec assessment area (province of Québec) is winter-peaking and part of NPCC. It covers 595,391 square miles with a population of 8.5 million. Québec is one of the four NERC Interconnections in North America with ties to Ontario, New York, New England, and the Maritimes. These ties consist of either HVDC ties, radial generation, or load to and from neighboring systems.

Demand and Load Forecast Uncertainty
Demand requirements are obtained by adding transmission and distribution losses to the sales forecasts. The monthly peak demand is then calculated by applying load factors to each end-use and/or sector sale. The sum of these monthly end-use sector peak demands is the total monthly peak demand. EE and conservation programs are integrated in the demand forecasts.

The effects on reliability of uncertainties within the load forecast, due to weather and economic conditions, were captured through the LFU model in the GE MARS program. The program computes the reliability indices at each of the specified load levels (for this study, seven load levels were modeled) and calculates weighted-average values based on input probabilities of occurrence.

Annual peak demand in Québec varies by +9% of forecasted Ontario area demand based upon the 90%/10% points of load forecast LFU distributions.

Thermal Resources
For thermal units, maximum capacity is defined as the net output a unit can sustain over a two-consecutive hour period.

[22] Transfer Capability Assessment Methodology: For Transmission Planning Studies

Wind

In Québec, wind capacity credit is set for the winter period as the system is winter peaking. Capacity credit of wind generation is based on a historical simulated data adjusted with actual data of all wind plants in service in 2015. For the summer period, wind power generation is derated by 100%.

Solar

Behind-the-meter generation (solar) is estimated at approximately 29 MW and does not affect the load monitored from a network perspective. Solar PV ICAP is expected to be 9.5 MW by the end of 2023. The impact of this resource at the peak time period is not significant.

Hydroelectric

For hydro resources, maximum capacity is set equal to the power that each plant can generate at its maximum rating during two full hours while expected on-peak capacity is set equal to maximum capacity minus scheduled maintenance outages and restrictions.

Demand-Side Resources

In Québec, DR programs are specifically designed for peak-load reduction during winter operating periods. No DR is expected for the summer period. DR consists of interruptible demand programs mainly for large industrial customers. DR programs are usually used in situations where either the load is expected to reach high levels or when resources are expected to be insufficient to meet peak load demand. Interruptible load program specifications differ among programs and participating customers; they usually allow for one or two calls for reduction per day and between 40 to 120 hours load interruption per winter period. Interruptible load programs are planned with participating industrial customers with whom contracts are signed. Before the peak period, generally during the fall season, all customers are regularly contacted in order to reaffirm their commitment to provide capacity when called, during peak periods.

Québec has various types of DR resources specifically designed for peak-time shaving during winter operating periods. The first type of DR resource is the interruptible load program that is mainly designed for large industrial customers; it has an impact of 1,563 MW on winter 2022–2023 peak demand. The area is also expanding its existing interruptible load program for commercial buildings, which will grow from 424 MW in Winter 2022–2023 to 505 MW in Winter 2024–2025. Another similar program for residential customers is in operation and should gradually rise from 47 MW for Winter 2022–2023 to 621 MW for Winter 2028–2029. The enhancement of the interruptible program for large industrial customers will have an additional potential capacity that varies from 330 MW in Winter 2023–2024 to 512 MW at the end of the study period. Dynamic rate options for residential and small commercial or institutional customers will also contribute to reducing peak load during winter periods by 203 MW for Winter 2021–2022, increasing to 371 MW for Winter 2024–2025.

Transmission

A new 735 kV line extending some 250 km (155 miles) between Micoua substation in Côte-Nord and the Saguenay substation in Saguenay–Lac-Saint-Jean. The project also includes adding equipment to both substations and expanding of the Saguenay substation. This project is now under construction phase and planned to be in service in 2023.

Other

The Romaine-4 unit (245 MW) is fully operational. The integration of small hydro unit accounts for 41 MW new capacity during the assessment period. For other renewable resources, 204 MW of wind generation (73 MW on-peak value) is expected to be in service for Winter 2024–2025 and 10 MW of biomass by the end of last year. Total installed BTM capacity (solar PV) is expected to increase to more than 500 MW in 2031, solar PV is accounted for in the load forecast. Nevertheless, since Québec is winter-peaking, DERs on-peak contribution ranges from 1 MW for Winter 2020–2021 to 10 MW for Winter 2030–2031. No potential operational impacts of DERs are expected in the Québec area, considering the low DER penetration in the area.

SERC

General Description

SERC covers approximately 308,900 square miles and serves a population estimated at 39.4 million. SERC utilizes General Electric (GE) MARS software an 8,760-hourly load, generation, and transmission sequential Monte Carlo simulation model consisting of fifteen interconnected areas, four of which are SERC's assessment areas (SERC-E, SERC-C, SERC-SE, and SERC-FP). All assumptions and methods are described below and apply to the assessment areas.

Demand and Load Forecast Uncertainty

For this study, annual load shapes for the seven years between 2007 and 2013 were used to develop the Base Case load model. Each of the hourly load profiles developed from the historical loads were then adjusted to model the seasonal peaks and annual energies reported in the 2020 SERC LTRA filings. Except for SERC-FP, all assessment areas are winter peaking. This study accounted for LFU in two ways: the first was to utilize seven different load shapes, representing seven years of historical weather patterns from 2007 through 2013 and the second way is through multipliers on the projected seasonal peak load and the probability of occurrence for each load level. Annual peak demand varies by the following LFU, SERC-C by 4.75%, SERC-E by 3.95%, SERC-SE by 6.11%, and SERC-FP by 4.04%.

Thermal Resources

The three categories modeled in this study were thermal, energy-limited, and hourly resources. Most of the generating units were modeled as thermal units for which the program assumes that the unit is always available to provide capacity unless it is on planned or forced outage. All the thermal units were modeled with two capacity states, either available or on forced outage.

The data for the individual units modeled in the SERC assessment areas was taken from the 2020 LTRA filings.

Wind and Solar

Wind and solar profiles for the units in the SERC footprint were represented with hourly generation time series. To represent the 2007–2013 meteorology, simulated production profiles corresponding to the historical hourly load profiles were used. These profiles were extracted from available datasets from the National Renewable Energy Laboratory.

Five distinct sites were chosen for each assessment area to represent existing wind farm locations. Similarly, five locations per SERC MRA were selected to create the solar profiles. Each site data was converted to power and aggregated to produce a typical solar shape per assessment area. To improve the robustness of the results, the study team used a 7-day sliding window method in the selection of wind and solar data.

Hydroelectric

MARS schedules the dispatch of hydro units in two steps. The minimum rating of each unit is set to 20% of nameplate capacity, which represents the run-of-river portion of the unit, and is dispatched across all hours of the month. Any remaining capacity and energy are then scheduled on an hourly basis as needed to serve any load that cannot be met by the thermal generation on the system. For hydro units, which are modeled as energy-limited resources, their capacity factors (the ratio of the energy output to the maximum possible if operated at full output for all of the hours in the period) are an indication of their contribution to meeting load. Energy-limited resources have a zero forced-outage rate.

The hydro unit data was extracted from the ABB Velocity Suite database and then adjusted to match the seasonal ratings of the units from the *2020 LTRA* data. The monthly energy available is the average over the last 10 years of generation for each plant.

Demand-Side Resources

Demand-side resources are incorporated as an energy-limited resource with an annual energy megawatt hour limitation. These resources will be second in priority to thermal and variable generation to serve load. DR is modeled for all SERC assessment areas. For externals areas, these resources are modeled as emergency operating procedures, using the values from their LTRA submissions.

Transmission

The transmission system between interconnected areas is modeled through transfer limits on the interfaces between pairs of areas. First contingency incremental transfer capability values for interface limits are modeled for the system. The assumption within areas is a copper sheet system (full capacity deliverability).

Texas-RE-ERCOT

General Description

ERCOT encompasses about 75% of the land area in Texas. The grid delivers approximately 90% of the electricity used by more than 26 million consumers in Texas. The probabilistic assessment using the Strategic Energy Risk Valuation Model captured the uncertainty of weather, economic growth, unit availability, and external assistance from neighboring areas as stochastic variables. The model performed 5,250 hourly simulations for each study year to calculate physical reliability metrics. The 5,250 hourly simulations were derived from 42 weather years, 5 load forecast multipliers, and 25 Monte Carlo unit outage draws.

Demand and Load Forecast Uncertainty

ERCOT developed a 50/50 peak load forecast, which represented the average peak load from 42 synthetic load profiles, each representing the expected load in a future year given the weather patterns from each of the last 42 years of history. Annual peak demand in ERCOT varied by +2.4% based upon the 90^{th} percentile distribution. Each synthetic weather year was given equal probability of occurring. Five LFU multipliers were applied to each of the 42 synthetic weather years. The multipliers, which range from -4% to +4%, captured economic load growth uncertainty.

Thermal Resources

Conventional generators were modeled in detail with maximum capacities, minimum capacities, heat rate curves, startup times, minimum up and down times, and ramp rates. The winter and summer capacity ratings were based on ERCOT's LTRA Report. SERVM's Monte Carlo forced outage logic incorporated full and partial outages based on historical operations.

Wind and Solar

Wind and solar resources were modeled as capacity resources with 42 historical weather years consisting of hourly profiles, which coincide with the load and hydro years. The assumed peak capacity contributions for reserve margin accounting were 57% for coastal wind, 30% for panhandle wind, 20% for other wind, and 81% for solar. The actual reliability contributions were based on the hourly modeled profiles.

Hydroelectric

Dispatch heuristics for hydro resources were developed from eight years of hourly data provided by ERCOT, applied to 42 years of monthly data from FERC 923 and ERCOT, and they were modeled with different parameters for each month, including total energy output, daily maximum and minimum outputs, and monthly maximum output. A separate energy-limited hydro resource was modeled to represent additional capability during emergency conditions.

Demand-Side Resources

Interruptible load and DR resources were captured as resources with specific price thresholds at which each resource is dispatched. These resources were also modeled with call limits and Energy Emergency Alert (EEA) level.

Transmission

SERVM is a state-of-the-art reliability and hourly production cost simulation tool that performs an hourly chronological economic commitment and dispatch for multiple zones using a transportation/pipeline representation. ERCOT was modeled as a single area for the Base Case and divided into five zones for the regional risk scenario with ties to SPP, Entergy, and Mexico to reflect historical import/export activity and potential assistance. 1,220 MW of high voltage direct current interties were included in this study.

WECC

General Description

The Multiple Area Variable Resource Integration Convolution (MAVRIC) model was developed to capture many of the functions needed in the Western Interconnection for probabilistic modeling. The Western Interconnection has many transmission connections between demand and supply points with energy transfers being a large part of the interconnection operation. A model was needed that could factor in dynamic imports from neighboring areas. The Western Interconnection has a large geographical footprint with winter-peaking and summer-peaking load-serving areas as well as a large amount of hydro capacity that experiences large springtime variability. The ability to study all hours of the year on a timely run-time basis was essential for the probabilistic modeling of the Interconnection. Additionally, the large portfolio penetration of VERs, and the different generation patterns depending on the geographical location of these resources, called for correlation capability in scenario planning. MAVRIC is a convolution model that calculates resource adequacy through loss of load probabilities (LOLP) on each of the stand-alone (without transmission) load-serving areas. The model then calculates the LOLP through balancing the system with transmission to a probabilistic LOLP. Finally, MAVRIC can supply hourly demand, VER output, and baseload generation profiles that can be used in production cost and scenario planning models. Figure B.1 provides the high-level logic diagram of the processes MAVRIC performs.

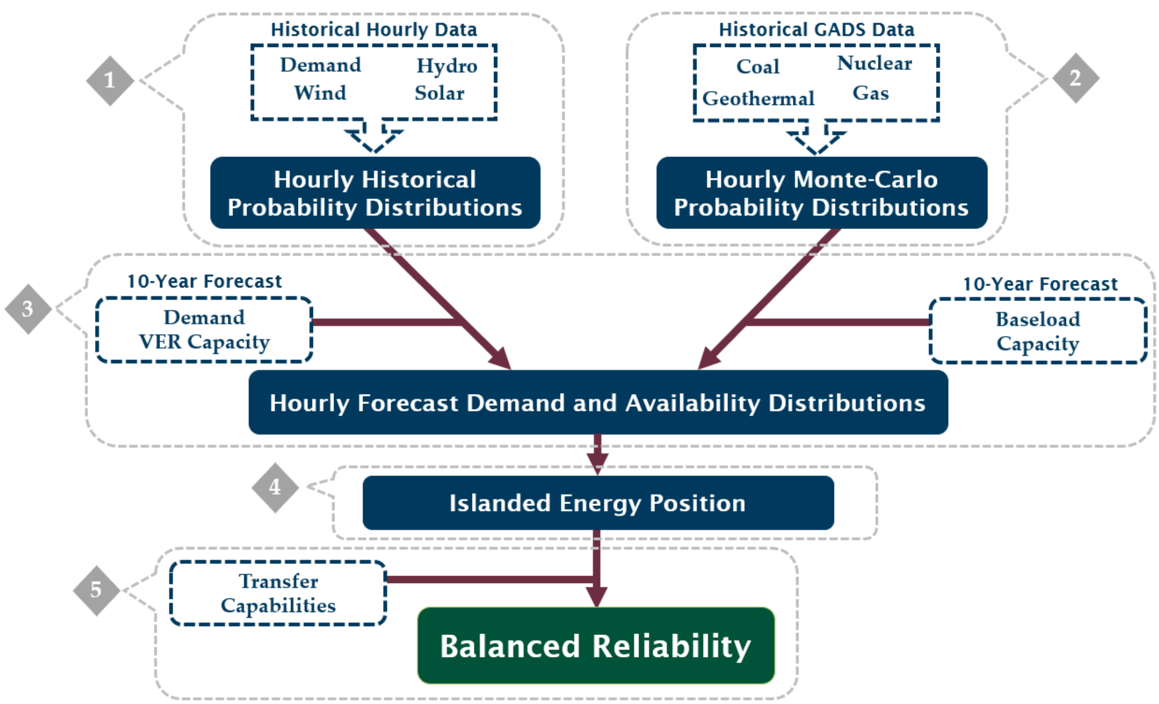

Figure B.1: MAVRIC Process Flowchart

There are many ways to perform probabilistic studies, each with its strengths and weaknesses. The tool used to perform the calculations depends on the system and the desired output that is being analyzed. The MAVRIC model was developed to enhance the probabilistic capabilities at WECC. It allows WECC to perform independent reliability assessments of the Western Interconnection, a system that is geographically diverse and dependent on transfer capabilities. Using convolution techniques and Monte-Carlo simulations, and with the ability to use transfers dynamically, the tool models the overall resource adequacy of the Western Interconnection while maintaining adequate run-time and computing capabilities.

Demand and Load Forecast Uncertainty

Probability distributions for the demand variability are determined by aligning historical hourly demand data to each of the BAs in the database. The first Sundays of each historical year are aligned so that weekends and weekdays are consistent. Each hour is then compared against a rolling seven-week average for the same hour of the same weekday. This establishes the difference between the historical hour and the average. MAVRIC uses each of these percentages to calculate a percentile probability for a given hour based on the variability of the three weeks before and three weeks after the given hour for each of the historical years. The output is a series of hourly percentile profiles with different probabilities of occurring.

Thermal Resources

The distributions of the baseload resources—nuclear, coal-fired, nature gas-fired, and in some cases, biofuel and geothermal—are determined by using the historical rate of unexpected failure and the time to return to service from the NERC GADS. Generator operators submit data that summarizes expected and unexpected outages that occur to their generating units. The annual frequency and recovery time for the unexpected outages is used to calculate the availability probability distributions for baseload resources. Through Monte-Carlo random sampling, MAVRIC performs 1,000 iterations for each resource, calculating the available capacity on an hourly basis for all hours of a given year. The model randomly applies outages to units throughout the year, adhering to the annual frequency of outage rates for those units. Once a unit is made unavailable, the mean time to recovery is adhered to, meaning for a certain period of hours after the unexpected failure that unit remains unavailable. The total available baseload capacity for each load serving area for each hour is then computed and stored as a sample in a database. After 1,000 iterations, the data points of availability for each hour are used to generate availability probability distributions. The output of this process is consistent with the VER distributions in that a series of hourly percentile profiles with different probabilities of occurring is produced.

Wind, Solar, and Hydroelectric

Determining the availability probability distributions for the VERs (water, wind, and solar-fueled resources) is conducted like the demand calculations but with two notable differences of which the first, and most significant, difference is the time frame used in calculating the VER availability probability distributions. For VER fuel sources, the day of the week does not influence variability as weather is variable weekday or weekends. Therefore, the need to use the data from the same day of the week is not necessary. This allows the VER distributions to be condensed to a rolling seven-day window using the same hour for each of the seven days of the scenario. The other difference is that the historical generation data is compared against the available capacity to determine the historical capacity factor for that hour to be used in the percentile probability calculation. The output of this process is a series of hourly percentile profiles with different probabilities of occurring.

Demand-Side Resources

A significant portion of the controllable DR/demand-side management programs within the Western Interconnection are associated with large industrial facilities, air conditioner cycling programs, and water pumping—both canal and underground potable water and for irrigation. These programs are created by LSEs who are responsible for their administration and execution when needed. In some areas, the programs are market driven (CAISO and AESO) and can be called upon for economic considerations. However, most areas in the Western Interconnection are not parties to organized markets, and DSM programs are approved by local authorities and used only for the benefit of the approved LSE. DSM programs in the Western Interconnection often have limitations, such as limited number of times they can be called on, and some can only be activated during a declared local emergency. Entities within WECC are not forecasting significant increases in controllable demand response.

Transmission

MAVRIC goes through a step-by-step balancing logic where excess energy—energy above an area's planning reserve margin to maintain the resource adequacy threshold—can be used to satisfy another area's resource adequacy shortfalls. This is dependent on the neighboring areas having excess energy as well as there being enough transfer capability between the two areas allowing the excess energy to flow to the deficit area. MAVRIC analyzes first order transfers (external assistance from an immediate neighbor) and second order transfers (external assistance from an immediate neighbor's immediate neighbors) and in all cases checking for sufficient transfer capacity. After balancing all areas in the system for a given hour, MAVRIC then moves to the next hour and balances the system where needed. The end result is an analysis of the entire system that reflects the ability of all load-serving areas to maintain a resource adequacy planning reserve margin equal to or less than the threshold. Analysis is then done on any areas where the threshold margin cannot be maintained even after external assistance from excess load-serving areas.

Other

Planning Reserve Margins for each hour the demand and availability distributions are compared to one another to determine the amount of "overlap" in the upper tail of the demand distribution with the lower tail of the generation availability distribution. The amount of overlap and the probabilities associated with each percentile of the distributions represents the LOLP. This would be the accumulative probability associated with the overlap. If the probability is greater than the selected threshold, then there is a resource adequacy shortfall in that area for that hour. A resource adequacy threshold Planning Reserve Margin can be determined to identify the Planning Reserve Margin needed to maintain a level of LOLP at or less than the threshold.

Appendix C: Summary of Inputs and Assumptions in the ProbA

Table C.1: Summary of Inputs and Assumptions in the ProbA

		NPCC	PJM	SERC	FRCC	MISO	Manitoba	Sask.	SPP	ERCOT	WECC
Model Used	**Name**	GE MARS	GE MARS	GE MARS	TIGER	GE-MARS	GE MARS	MARS	GridView	SERVM	MAVRIC
	Model Type	Monte Carlo	Monte Carlo	Monte Carlo	Convolution	Monte Carlo	Monte Carlo	Monte Carlo	Monte Carlo	Monte Carlo	Convolution
	# Trials	1,000*10*7	1,000*7	1,000*7*7	500	50000 * 7	10000	20000 x 7	4000	25 x 42 x 5 = 5,250	N/A
	Total Run Time	4 hours * 50 CPUs	2 hours * 72 CPUs	50 min * 50 CPUs*7*4	30 Minutes	3 Hours	35 min	2 hours	96 hours/study	7 hours on 25 cores	N/A
Load	**Internal Load Shape**	Typ. Yr. S-2021; W-2013-14	Typ. Yr. S-2002; W-2004	07 yrs; 2007-2013; Risk-based weighted load shapes	Synthetic Year: from 10+ years	Typical Year 2005 for North/Central; 2006 for South	Typical year 2002	Peak(2008)	One year load shape; Highest energy and peak output for years 2007 - 2012, 2011	42 years 1980-2021	2004-2014
	External Load Shape	Typ. Yr. S-2021; W-2013-14	Typ. Yr. S-2002; W-2004	MISO North-Typ. Yr. 2005; MISO South-Typ. Yr. 2006; PJM- Typ. Yr. 2002; FRCC-Typ. Yr. 2005; SPP- Typ. Yr. 2005	N/A	N/A	Typical year 2002	None	N/A	42 years 1980-2021	N/A
	Adjustment to Forecast	Monthly Peak & Energy	Monthly Peak	Monthly Peaks and Energy	Monthly Peaks and Energy for up to 2018; Seasonal Peak for 2018+	Monthly Peaks	Monthly Peak & Energy	Monthly Peaks and Energy	Annual Peak	Annual peak.	N/A

Table C.1: Summary of Inputs and Assumptions in the ProbA											
		NPCC	**PJM**	**SERC**	**FRCC**	**MISO**	**Manitoba**	**Sask.**	**SPP**	**ERCOT**	**WECC**
Load Forecast Uncertainty	**Modeling**	7-step Discrete Distribution	7-step Discrete Distribution	19 Historic Years (18 Y-1 data points); Assumed weather uncertainty; normal distribution; 7 multipliers (3 sigma either side mean) Seasonal-Summer, Winter, Spring, Fall-LFU modeled	Not Modeled	7 discrete steps normally distributed capturing weather and economic uncertainty	7-step Discrete Normal Distribution, weather	Normal Distribution	7 discrete steps	42 weather years x 5 load forecast uncertainty multipliers = 210 load scenarios	3%-97% probability distribution
	90th %ile (% above 50/50 peak)	Varies by Area; asymmetrical	2018-7.6%; 2020-7.8%	Summer: 5.13% at 90%ile (1.28 Standard Deviation); Winter: 10.25% at 90%ile (1.28 Standard Deviation);	2018 - 2.3% 2020 - 2.9%	5.11%	2018-3.9% 2020-5.2%	2024-2.6%; 2026-2.6%	6% at 90%ile	+2.4%	Varies by Area
	Uncertainties Considered	weather, economic, forecast	Weather, Economic, Forecast	Weather Forecast	Weather, economic, forecast	Weather and Economic	Weather, economic, forecast	Weather, Economic	weather, forecast	Weather and Economic Forecast Error	Weather and Economic Variability
Behind-the-Meter	**Percentage of Peak Load at Peak**	Unknown	2018-2%; 2020-3.5%	Minimal; ~1%	Unknown	N/A	N/A	0	Unknown	Resource	N/A
	Thermal Generation	Resource	Netted From Load	Within the load	Netted from Load	Resource	N/A	N/A	Within the load	Resource	N/A

Table C.1: Summary of Inputs and Assumptions in the ProbA

		NPCC	PJM	SERC	FRCC	MISO	Manitoba	Sask.	SPP	ERCOT	WECC
	Variable Generation	Resource	Netted From Load	Within the load	Netted from Load	Resource	N/A	N/A	Within the load	Resource	N/A
	Demand Management	Resource or Netted From Load (varies by Area)	Netted From Load	Within the load	N/A	Resource	NA	N/A	Within the load	Resource	N/A
Demand-Side Management	**Modeling**	Dispatchable resource, Operating procedure (varies by area)	Operating procedure	Energy-Limited Resources	Load Modifier	Energy-Limited Resource	Load Modifier	DSM adjusted Load Forecast	Dispatchable Resource	Dispatchable, Energy-Limited Resource	N/A
	Load shape / Derates /FOR	N/A	N/A	Monthly Probability Distribution Curves / FOR	Not derated for use	Count and Duration Limited	Reduction in Peak	None	Available for 6 hours on each daily peak	Variety of Operating Limitations	N/A
	Correlation to load	When modeled as EOP (varies by area)	Not modeled	Not Modeled	N/A	not explicitly modeled	NA	None	not modeled	Dispatched based on shadow price	N/A
Variable Generation - Wind	**Modeling**	Resource, Fixed resource	Resource	Load Modifier	None	Load Modifier	Resource	Load Modifier	Resource	Resource	Energy-Limited Resource
	Load shape / Derates /FOR	Hourly shape, Monthly	Modeled at Capacity Value	Hourly Shape	N/A	Modeled at capacity credit value	NA	Weekly	hourly shape	Hourly Shape for 42 years matching load profile	Hourly Shape
	Correlation to load	Consistent with load, Not modeled	Not Modeled	Consistent with load (time series)	N/A	Not Modeled	Consistent with load	Not Modeled	Match load	Match load	N/A
	Capacity Value	0% to 35% (varies by area)	13%	Approx. 19% during peak	N/A	By wind farm. MISO System Capacity Credit is 15.6%	20% winter and 16% summer	20% Win 10% Sum	0% to 25% of nameplate, Area dependent	Summer: 57% for coastal wind, 30% for panhandle wind, and	Varies by Area

Table C.1: Summary of Inputs and Assumptions in the ProbA

		NPCC	PJM	SERC	FRCC	MISO	Manitoba	Sask.	SPP	ERCOT	WECC
										20% for other wind Winter: 46% for coastal wind, 34% for panhandle wind, and 19% for other wind	
Variable Generation - Solar	**Modeling**	Resource	Resource	Load Modifier	Dispatchable Resource	Load Modifier	None	None	Resource	Resource	Energy-Limited Resource
	Load shape / Derates /FOR	Hourly shape, Monthly	Modeled at Capacity Value	Hourly Shape	At minimum firm capacity	Modeled at capacity credit value	NA	N/A	hourly shape	Hourly Shape for 42 years matching load profile	Hourly Shape
	Correlation to load	Consistent with load, Not modeled	Not Modeled	Consistent with load (time series)	Not Modeled	Not Modeled	NA	N/A	2011 Solar Shape	Match load	N/A
	Capacity Value	Not specified	0% Winter; 38% Summer	Approx. 36% during peak	N/A	MISO System Capacity Credit is 50%	NA	N/A	10% to 95% of nameplate, Area dependent	Summer: 81% ; Winter: 11%	Varies by Area
Hydro - Electric Generation	**Modeling**	Energy Limited Res., Dispatched after Thermal	Resource	Energy Limited Resource, 20% Dispatched and remainder available as emergency assistance	Dispatchable resource	Resource unless Run-Of-River. Run-of-River submit 3 years of historical data at peak	Energy Limited Resource	Energy Limited Resource	Energy Limited Resource	Energy Limited Peak Shaving Component and Emergency Component	Energy-Limited Resource

Table C.1: Summary of Inputs and Assumptions in the ProbA

		NPCC	PJM	SERC	FRCC	MISO	Manitoba	Sask.	SPP	ERCOT	WECC
	Energy Limits	Average	N/A	Average 10 years monthly output	N/A	Summer Months, Peak Hours 14 - 17 HE	Different below average water conditions including extreme drought	Median	Yearly Energy Limitation based on historical performances	42 years of historical hydro conditions were modeled 1980-2021	Hourly Shape
	Capacity Derates	Monthly	Monthly	Monthly	Firm Capacity	At Firm Capacity	Monthly	Monthly	Monthly	Monthly values	N/A
	Planned Outages	Model schedule, Within Capacity Derates	Model scheduled	Model scheduled	Not Modeled	Model Scheduled	Not modeled	First five years are scheduled maintenance. Remaining is scheduled by program.	Not modeled	Netted out based on modeling actual monthly hydro energies	Varies by Area
	Forced Outages	Monte Carlo, Not modeled (varies by area)	Monte Carlo	Not Modeled	GADS average	Monte Carlo, Run-of-River has none	N/A	Not Modeled	Not modeled	N/A	N/A
Thermal Generation	**Modeling**	MC; 2 state - some areas up to 7-state	MC; 2-state	MC; 2-state	Convolution	MC; 2-state	MC 2-state	MC up to 5 state	MC; 2-state	MC; 25 iterations of annual simulations with unique forced outage draws performed for each weather year and load forecast error	2-State 3%-97% Probability Distribution
	Energy Limits	None	None	None	None	None explicitly	None	None	None	None	None

Table C.1: Summary of Inputs and Assumptions in the ProbA

		NPCC	PJM	SERC	FRCC	MISO	Manitoba	Sask.	SPP	ERCOT	WECC
	Capacity Derates	Monthly	Monthly	Equivalized Annual Average	Seasonal	Monthly	Monthly	Monthly, Monthly derates inputted into the model	Consideration of Capacity Derates in random forced outage variable during Simulation	Used a seasonal capacity value for each unit	Seasonal
	Planned Outages	By model, External Input	By Model	By Model (Planned Outage Rate-Optimized	External Input	By Model	By Model	By Model & Manual Input	by Model & Manual Input	By model calibrated to total historical planned outages	By Model
	Forced Outages	EFORd	5 yr EEFORd	EFORd	Forecasted FOR based on actuals applied to individual unit	5 yr unit specific EFORd	EFORd	5-year historical average	EFORd	GADS data; Historical events modeled discretely; additional forced outage probabilities were modeled at temperatures below 20°F	Historical 12 year EFOR
Firm Capacity Transfers	**Modeling**	Explicitly Modeled	Explicitly Modeled	Explicitly Modeled-Modeled as perfect pseudo-tied units (neg (-) from seller and pos (+) for purchaser)	Imports treated as resource; Exports not modeled	Imports treated as Resource; Exports derated from monthly unit capacities	Imports treated as resource, Exports added as load	Explicitly Modeled	Explicitly Modeled	Not Modeled. All firm resources are modeled inside the ERCOT zone	Explicitly Modeled
	Hourly Shape Issues	None	None	N/A	N/A	None	Weekly capacities	None	None	N/A	N/A

Table C.1: Summary of Inputs and Assumptions in the ProbA

		NPCC	PJM	SERC	FRCC	MISO	Manitoba	Sask.	SPP	ERCOT	WECC
	Capacity Adjustments - Transmission Limitations	None	None	N/A	N/A	None	None	N/A	N/A	N/A	N/A
	Transmission Limit Impact of Firm Transfers	Impact derived within model	Endogenously modeled	Limits adjusted	N/A	None	Accounted for in interface limits	N/A	Accounted for in interface limits	N/A	N/A
	Forced Outages	N/A	No	By Contract	Yes	5 yr unit specific EFORd	No	No	No	N/A	N/A
Internal Representation	**Assessment Areas**	5	1	3	1	1	1	1	1	1	6
	Total Nodes	56	5	4	1	10	1	1	Detailed bus modeling; Approximately 650 generator buses and 4,500 load buses	1 for Base; 5 for Regional Risk Scenario	49
	Node Definition	Determined by potentially limiting transmission interfaces	Market-Defined Areas	2 Assessment Areas = 2 Nodes; 1 Assessment Area = 2 nodes defined by BA boundaries	N/A	Local Resource Zone	N/A	N/A	Load and Generation modeled at bus level from powerflow model	N/A	BA
	Transmission Flow Modeling in ProbA Model	Transportation/Pipeline	Transportation/Pipeline	AC/DC in PSSE, Transportation/ Pipeline in MARS	N/A	Transfer Analysis Import/Export Limit for each Local Resource Zone	Transportation/ Pipeline	N/A	DC Load Flow	N/A	Transportation/Pipeline

Table C.1: Summary of Inputs and Assumptions in the ProbA											
		NPCC	PJM	SERC	FRCC	MISO	Manitoba	Sask.	SPP	ERCOT	WECC
	Transmission Limit Ratings	NY and Maritimes - short-term emergency; all other - normal	Short-term Emergency	normal and short-term emergency ratings	N/A	N/A	Normal	N/A	Long-Term Emergency	N/A	Normal
	Transmission Uncertainty	Selected Lines	No	No	N/A	No	No	N/A	No	N/A	No
External Representation	**# Connected Areas**	3	4	7	1	7	1	3	2	3	0
	# External Areas in Study	8	4	10	0	7	1	0	5	3 (SPP, MISO LRZ 8/9/10, Mexico)	0
	Total External Nodes	8	59	10	0	1	1	N/A	Detailed bus level powerflow modeling	3	0
	Modeling	Detailed	Detailed and At planning reserve margin	Detailed	N/A	Less Detailed	Detailed at their Planning Reserve Margin	N/A	Detailed; source/sink for transfers	Detailed at their Planning Reserve Margin	0
Other Demands	**Operating Reserve**	Yes	Yes	No	No	No	Not Considered	Yes	Yes	Yes,, regulation up, regulation down, responsive reserve, and non-spin requirements modeled. Firm load shed to maintain 1,150 MW of operating reserves (split between regulation and	No

Table C.1: Summary of Inputs and Assumptions in the ProbA											
		NPCC	PJM	SERC	FRCC	MISO	Manitoba	Sask.	SPP	ERCOT	WECC
										responsive reserves with magnitude of regulation varying by season and time of day)	
Operating Procedures (pre LOL)	Forgo Operating Reserve	OR to 0 in all Areas except Québec and New England.	Fully	Fully	N/A	N/A	N/A	Fully	Fully	Partially	Fully
	Other	DR, public appeals, voltage reductions	DR, 30-min reserves, voltage reduction, 10-min reserves, public appeals	Reduce OR; RSG Purchases	None	None	None	Demand Response, Emergency	DR	DR	None

Appendix D: Additional Assessment by Regional Entity or Assessment Area

This informational Appendix serves as a list of references for more detailed information on assessments or assessment methods used by Regional Entities or assessment areas.

NERC Webpage

The NERC webpage[23] contains valuable information regarding its mission. For information on its assessments, see the Reliability Assessment and Performance Analysis page on the NERC webpage. It also contains valuable information regarding the statistics for assessing BES reliability.

NPCC

NPCC publishes an annual report[24] that contains a more detailed look at the multi-area probabilistic reliability assessment for the NPCC Regional Entity, referenced in the NERC ProbA and this year's regional risk scenario.

[23] www.nerc.com

[24] https://www.npcc.org/content/docs/public/library/resource-adequacy/2022/2022-npcc-long-range-adequacy-overview-nerc-probabilistic-assessment-rcc-approved.pdf