NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2022 Long-Term Reliability Assessment

December 2022

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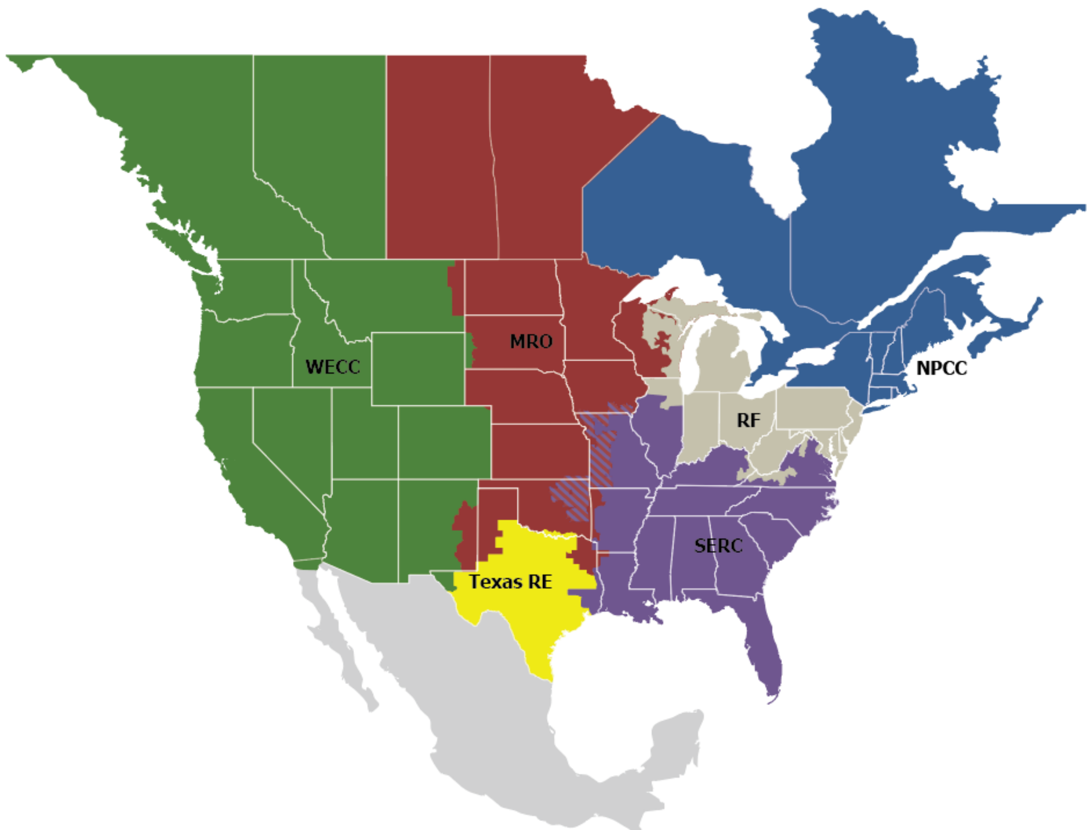
Preface

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 the North American Electric Reliability Corporation (NERC) and the six Regional Entities, is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entity boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities (LSE) participate in one Regional Entity while associated Transmission Owners/Operators participate in another. A map and list of the assessment areas can be found in the **Regional Assessments** section.



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

About this Assessment

NERC is a not-for-profit international regulatory authority with the mission to assure the reliability of the BPS in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the ERO for North America and is subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC, also known as the Commission) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the North American BPS and serves more than 334 million people. Section 39.11(b) of FERC's regulations provides that "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

Development Process

This assessment was developed based on data and narrative information NERC collected from the six Regional Entities (see **Preface**) on an assessment area (see **Regional Assessments**) basis to independently evaluate the long-term reliability of the North American BPS while identifying trends, emerging issues, and potential risks during the upcoming 10-year assessment period. The Reliability Assessment Subcommittee, at the direction of NERC's Reliability and Security Technical Committee (RSTC), supported the development of this assessment through a comprehensive and transparent peer review process that leverages the knowledge and experience of system planners, Reliability Assessment Subcommittee members, NERC staff, and other subject matter experts; this peer review process ensures the accuracy and completeness of all data and information. This assessment was also reviewed by the RSTC, and the NERC Board of Trustees (Board) subsequently accepted this assessment and endorsed the key findings.

NERC develops the Long-Term Reliability Assessment (LTRA) annually in accordance with the ERO's Rules of Procedure[1] and Title 18, § 39.11[2] of the Code of Federal Regulations,[3] also required by Section 215(g) of the Federal Power Act, which instructs NERC to conduct periodic assessments of the North American BPS.[4]

Considerations

Projections in this assessment are not predictions of what will happen; they are based on information supplied in July 2022 about known system changes with updates incorporated prior to publication. This *2022 LTRA* assessment period includes projections for 2023–2032; however, some figures and tables examine data and information for the 2022 year. This assessment was developed by using a consistent approach for projecting future resource adequacy through the application of the ERO Reliability Assessment Process.[5] NERC's standardized data reporting and instructions were developed through stakeholder processes to promote data consistency across all the reporting entities that are further explained in **Demand Assumptions and Resource Categories**. Reliability impacts related to cyber and physical security risks are not specifically addressed in this assessment; this assessment is primarily focused on resource adequacy and operating reliability. NERC leads a multi-faceted approach through NERC's Electricity-Information Sharing and Analysis Center (E-ISAC) to promote mechanisms to address physical and cyber security risks, including exercises and information-sharing efforts with the electricity industry.

The LTRA data used for this assessment creates a reference case dataset that includes projected on-peak demand and system energy needs, demand response (DR), resource capacity, and transmission projects. Data from each Regional Entity is also collected and used to identify notable trends and emerging issues. This bottom-up approach captures virtually all electricity supplied in the United States, Canada, and a portion of Baja California, Mexico. NERC's reliability assessments are developed to inform industry, policy makers, and regulators as well as to aid NERC in achieving its mission to ensure the reliability of the North American BPS.

[1] NERC Rules of Procedure - Section 803
[2] Section 39.11(b) of FERC's regulations states the following: "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."
[3] Title 18, § 39.11 of the Code of Federal Regulations
[4] BPS reliability, as defined in the **How NERC Defines BPS Reliability** section of this report, does not include the reliability of the lower-voltage distribution systems that account for 80% of all electricity supply interruptions to end-use customers.
[5] *ERO Reliability Assessment Process Document*, April 2018: https://www.nerc.com/comm/PC/Reliability%20Assessment%20Subcommittee%20RAS%202013/ERO%20Reliability%20Assessment%20Process%20Document.pdf

Assumptions

In this *2022 LTRA*, the baseline information on future electricity supply and demand is based on several assumptions:[6]

- Supply and demand projections are based on industry forecasts submitted and validated in July 2022. Any subsequent demand forecast or resource plan changes may not be fully represented; however, updated data submitted throughout the report drafting time frame have been included where appropriate.
- Peak demand is based on average peak weather conditions and assumed forecast economic activity at the time of submittal. Weather variability is discussed in each Regional Entity's self-assessment.
- Generation and transmission equipment will perform at historical availability levels.
- Future generation and transmission facilities are commissioned and in service as planned, planned outages take place as scheduled, and retirements take place as proposed.
- Demand reductions expected from dispatchable and controllable DR programs will yield the forecast results if they are called on.
- Other peak demand-side management programs, such as energy efficiency (EE) and price-responsive DR, are reflected in the forecasts of total internal demand.

Reading this Report

This report is compiled into two major parts:

- A reliability assessment of the North American BPS with the following goals:
  - Evaluate industry preparations that are in place to meet projections and maintain reliability
  - Identify trends in demand, supply, and reserve margins
  - Identify emerging reliability issues
  - Focus the industry, policy makers, and the general public's attention on BPS reliability issues
  - Make recommendations based on an independent NERC reliability assessment process
- A regional reliability assessment that contains the following:
  - 10-year data dashboard
  - Summary assessments for each assessment area
  - Focus on specific issues identified through industry data and emerging issues
  - Identify regional planning processes and methods used to ensure reliability

[6] Forecasts cannot precisely predict the future. Instead, many forecasts report probabilities with a range of possible outcomes. For example, each regional demand projection is assumed to represent the expected midpoint of possible future outcomes. This means that a future year's actual demand may deviate from the projection due to the inherent variability of the key factors that drive electrical use, such as weather. In the case of the NERC regional projections, there is a 50% probability that actual demand will be higher than the forecast midpoint and a 50% probability that it will be lower (50/50 forecast).

Executive Summary

Introduction

This *2022 LTRA* is the ERO's independent assessment and comprehensive report on the adequacy of planned BPS resources to reliably meet the electricity demand across North America over the next ten years. This *2022 LTRA* also identifies reliability trends, emerging issues, and potential risks that could impact the long-term reliability, resilience, and security of the BPS.

The findings in this 2022 LTRA are vitally important to understand the reliability risks to the North American BPS as it is currently planned and as it is being shaped by government policies, regulations, consumer preferences, and economic factors. Energy systems and the electricity grid are undergoing unprecedented change on a scope, scale, and speed that challenges the ability to foresee—and design for—their future states. This report contains future energy sufficiency metrics that serve as guideposts for the reliability of the North American electric grid on its current trajectory. It also describes the relevant trends that are propelling the grid's transformation and have the potential to alter the ability of the BPS to service the energy needs of communities and industries in North America.

Projected Area Supply Shortfalls

The **Resource Capacity and Energy Risk Assessment** section of this report identifies potential electricity supply shortfalls under normal and more severe conditions. NERC's assessment assumes the latest demand forecasts, resource levels, and area transfer commitments as well as accounts for expected generator retirements, resource additions, and demand-side resources.

High Risk Areas[7]

Most areas are projected to have adequate electricity supply resources to meet demand forecasts associated with normal weather. However, areas shown in red (high risk) in Figure 1 do not meet resource adequacy criteria, such as the 1-day-in-10 year load-loss metric during periods of the assessment horizon. This indicates that the supply of electricity for these areas is more likely to be insufficient in the forecast period and that more firm resources are needed. The following is a summary of the high-risk areas (details are discussed in later sections of this *2022 LTRA*):

- **In the Midcontinent Independent System Operator (MISO)** area, the previously-reported reserve margin shortfall has advanced by one year, resulting in a 1,300 MW capacity deficit for the summer of 2023. The projected shortfall continues an accelerating trend since both the *2020 LTRA* and the *2021 LTRA* as older coal, nuclear, and natural gas generation exit the system faster than replacement resources are connecting.
- **NPCC-Ontario** also continues to project a reserve margin shortfall in 2025 and beyond. The capacity deficit of 1,700 MW is driven by generation retirements and lengthy planned outages at nuclear units undergoing refurbishment.
- Resource additions in the **California/Mexico (CA/MX) part of WECC** are alleviating capacity risks, but energy risks persist. Planned reserve margins meet annual reserve margin targets for the duration of the 10-year horizon. However, overall variability in both the resource mix and demand profile contributes to shortfall risk periods, mainly in summer months around sunset, when expected supplies are not sufficient to meet the demand.

Elevated Risk Areas[8]

Extreme temperatures and prolonged severe weather conditions are increasingly impacting the BPS. Extreme weather impacts the system by increasing electricity demand and forcing generation and other resources off-line. While a given area may have sufficient capacity to meet resource adequacy requirements, it may not have sufficient availability of resources during extreme and prolonged weather events. Therefore, **long-duration weather events increase the risk of electricity supply shortfalls**.

In many parts of North America, peak electricity demand is increasing, and forecasting demand and its response to extreme temperatures and abnormal weather is increasingly uncertain. Electrification and distributed energy resource (DER) trends can be expected to further contribute to demand growth and sensitivity to weather patterns. Specifically, electrification of residential heating requires the system to serve especially high demand on especially cold days.

[7] An assessment area is deemed to be "high risk" by failing to meet the established resource adequacy target or requirement. The established resource adequacy target is not established by NERC, but instead by the prevailing regulatory authority or market operator. Generally, these targets/requirements are based on a 1 day/event load-loss in a 10-year planning requirement. High risk areas have a probability of load shed greater than the requirement/target. Simply said, high risk areas do not meet resource adequacy requirements.

[8] An assessment area is deemed to be "elevated risk" when it meets the established resource adequacy target or requirement, but the resources fail to meet demand and reserve requirements under the probabilistic or deterministic scenario analysis. The established resource adequacy target is not established by NERC, but instead the prevailing regulatory authority or market operator. Simply, elevated risk areas meet resource adequacy requirements, but they may face challenges meeting load under extreme conditions.

Electricity supplies can decline in extreme weather for many reasons. Generators that are not designed or prepared for severe cold or heat can be forced off-line in increasing amounts. Wide area weather events can also impact multiple balancing and transmission operations simultaneously that limit the availability of transfers. Fuel production or transportation disruptions could limit the amount of natural gas or other fuels available for electric generation. Wind, solar, and other variable energy resource (VER) generators are dependent on the weather.

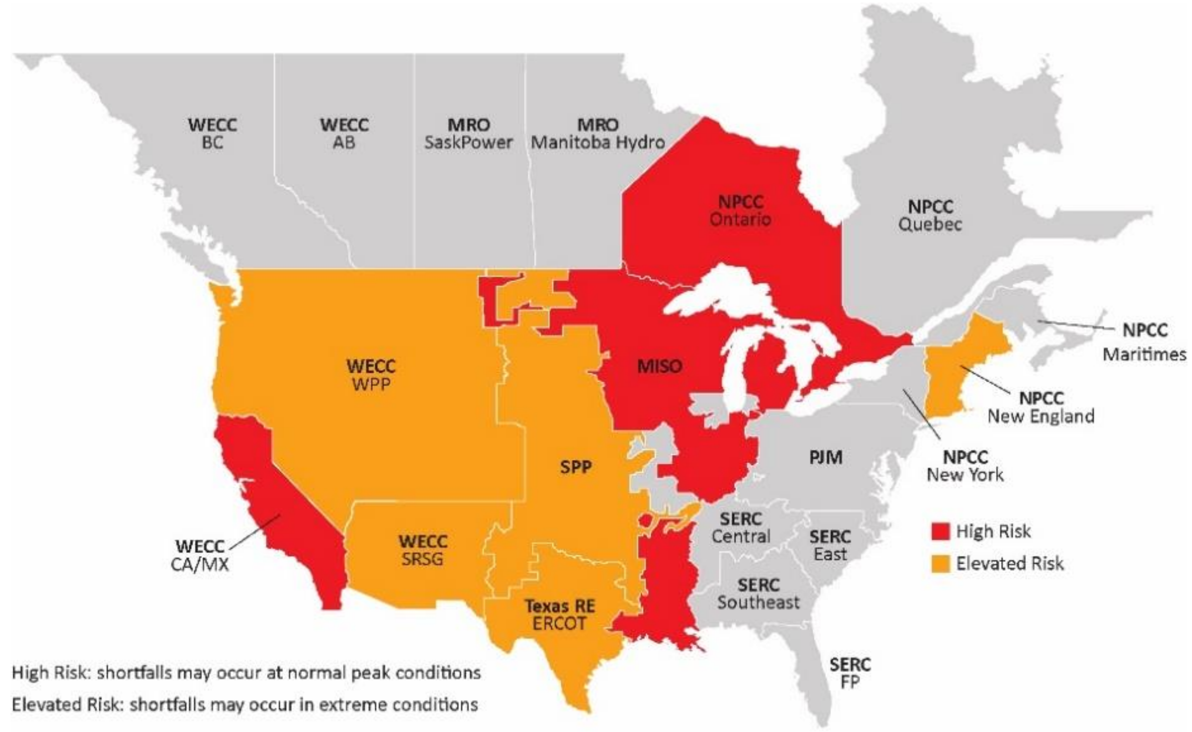


Figure 1: Risk Area Summary 2023–2027

Areas in orange (elevated risk) in Figure 1 meet resource adequacy criteria and have sufficient energy and capacity for normal forecasted conditions, but they are at risk of shortfall in extreme conditions:

- All three assessment areas in the **U.S. West—CA/MX, Western Power Pool (WPP), and the Southwest Reserve Sharing Group (SRSG)—**have increasing demand and resource mix variability. In normal conditions, the expected demand and resource variability is balanced across the area as excess supply from one part of the system is delivered through the transmission network to places where demand is higher than supply. However, more extreme summer temperatures that stress large portions of the Interconnection reduce the availability of excess supply for transfer while also reducing the transmission network's ability to transfer the excess.
- Reliability during extreme winter weather remains a concern in **Texas**. ERCOT's winter peak load varies substantially (as much as 12.5%) between the coldest temperatures of an average year and a more extreme year as might be experienced once per decade. A high number of forced outages of the thermal and wind generation fleet have been an issue in severe winter weather. Improved generator availability resulting from winter preparedness programs and reforms implemented by Texas regulators, ERCOT, and Generator Owners since February 2021 are expected to reduce the risk that electricity supplies will be insufficient during a severe winter storm.
- **SPP** is exposed to energy risks in ways that are similar to both Texas and the U.S. West. Severe weather in SPP is likely to cause high generator outages and poses a risk to natural gas fuel supplies. In addition, the penetration of wind generation makes the resource mix variable and exposed to insufficient energy during low wind periods.
- In **New England**, limited natural gas infrastructure can impact winter reliability due to increased heating demand and the potential for supply disruptions to generators. Liquefied natural gas facilities and sufficient generators with stored backup fuels are critical to electric reliability.

Continuing Resource Mix Changes and Implications for Reliability

This *2022 LTRA* contains the latest industry projections for generation and other resources, including DR, DERs, and the resulting Continuing Resource Mix Changes and Implications for Reliability found at this link. Highlights of these trends and the implications for reliability include the following:

- **Reliable Interconnection of Inverter-Based Resources:** Reliably integrating inverter-based resources (IBR), which include most solar and wind generation, onto the grid is paramount. Over 70% of the new generation in development for connecting to the BPS over the next 10 years is solar, wind, and hybrid (a generating source combined with a battery).
- **Accommodating Large Amounts of Distributed Energy Resources:** Preparing the grid to operate with increasing levels of distribution resources must also be a priority in many areas. Solar photovoltaic (PV) DERs are projected to reach over 80 GW by the end of this 10-year assessment, a 25% increase in projection since the *2021 LTRA*; a total of 12 assessment areas project to double the amount of DERs in their areas by 2032.

- **Managing the Pace of Generation Retirements:** As new resources are introduced and older traditional generators retire, careful attention must be paid to power system and resource mix reliability attributes. Within the 10-year horizon, over 88 GW of generating capacity is confirmed for retirement through regional transmission planning and integrated processes. Effective regional transmission and integrated resource planning processes are the key to managing the retirement of older nuclear, coal-fired, and natural gas generators in a manner that prevents energy risks or the loss of necessary sources of system inertia and frequency stabilization that are essential for a reliable grid.
- **Maintaining Essential Reliability Services:** The changing composition of the North American resource mix calls for more robust planning approaches to ensure adequate essential reliability services.[9] Retiring conventional generation is being replaced with large amounts of wind and solar; planning considerations must adapt with more attention to essential reliability services. As replacement resources are interconnected, these new resources should have the capability to support voltage, frequency, and dispatchability. Various technologies can contribute to essential reliability services, including variable energy resources; however, policies and market mechanisms need to reflect these requirements to ensure these services are provided and maintained. Regional transmission organizations, independent system operators, and FERC have taken steps in this direction, and these positive steps must continue.

Trends and Implications for Reliability

Demand Trends and Implications as well as **Transmission Development Trends and Implications** found at these links affect long-term reliability and the sufficiency of electricity supplies. Several key insights emerge from the latest industry data:

- **Peak Demand and Energy Growth:** Projected growth rates of electricity peak demand and energy in North America are increasing for the first time in recent years. Government policies for the adoption of electric vehicles (EVs) and other energy transition programs have the potential to significantly influence demand. Demand-side management programs, including conservation, EE, and DR continue to offset demand and contribute to load management. Where rapid transition is proposed, early alignment and coordination on energy and infrastructure are needed.
- **Insufficient Transmission for Large Power Transfers:** Transmission development projections remain near the averages of the past five NERC LTRAs. There has been some increase in the number of miles of transmission line projects for integrating renewable generation over the next 10 years compared to the *2021 LTRA* projections. Transmission investment is important for reliability and resilience as well as the integration of new generation resources.
- **Emerging Electrification Challenges:** Several emerging issues and trends have the potential to impact future long-term projections of demand and resources. In addition to EV and electrification issues, cryptocurrency mining may have a notable impact on demand and resources in some areas. Resource development may be significantly altered by supply chain issues and differ from projections used in this *2022 LTRA*. Notable emerging issues and their potential implications are discussed in this report.

Conclusions and Recommendations

The energy and capacity risks identified in this assessment underscore the need for reliability to be a top priority for the resource and system planning community of stakeholders. Planning and operating the grid must increasingly account for different characteristics and performance in electricity resources as the energy transition continues. General actions for industry and policymakers to address the reliability risks described in this *2022 LTRA* include the following:

- Manage the pace of generator retirements until solutions are in place that can continue to meet energy needs and provide essential reliability services
- Include extreme weather scenarios in resource and system planning
- Address IBR performance and grid integration issues
- Expand resource adequacy evaluations beyond reserve margins at peak times to include energy risks for all hours and seasons
- Increase focus on DERs as they are deployed at increasingly impactful levels
- Mitigate the risks that arise from growing reliance on just-in-time fuel for electric generation and the interdependent natural gas and electric infrastructure
- Consider the impact that the electrification of transportation, space heating, and other sectors may have on future electricity demand and infrastructure

Specific *LTRA* recommendations are provided on the following page and in the appropriate sections of this report.

[9] Essential Reliability Services: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/ERS%20Abstract%20Report%20Final.pdf

Reducing the Risk of Insufficient Energy

The impact of wide-area and long-duration extreme weather events, such as the February 2021 South Central U.S. cold weather event and the August 2020 Western U.S. wide-area heat event, have underscored the need to consider extreme scenarios for resource planning. Energy risks emerge when weather-dependent generation is impacted by abnormal atmospheric conditions or when extreme conditions disrupt fuel supplies. In areas with a high dependence on VERs and natural-gas-fired generation, Prospective Reserve Margins (PRM) are not sufficient for measuring resource adequacy:

- Industry and regulators should conduct all-hours energy availability analyses for evaluating and establishing resource adequacy and include extreme condition criteria in integrated resource planning and wholesale market designs.
- The ERO and industry should prioritize the development of Reliability Standard requirements to address energy risks in operations and planning. NERC's Reliability Standards Project 2022-03 should be closely monitored, and stakeholder experts should contribute to developing effective requirements for entities to assess energy risks and implement corrective actions in all time horizons.
- State and provincial regulators and independent system operators (ISO)/regional transmission operators (RTO) should have mechanisms they can employ to prevent the retirement of generators that they determine are needed for reliability, including the management of energy shortfall risks.
- Regulatory and policy-setting organizations should use their full suite of tools to manage the pace of retirements and ensure that replacement infrastructure can be timely developed and placed in service. If needed, the Department of Energy should use its 202(c) authority as called upon by electric system operators.
- Resource planners and policymakers must pay careful attention to the pace of change in the resource mix as well as update capacity and energy risk studies (including all-hours probabilistic analysis) with accurate resource projections.

Planning and Adapting for IBRs and DERs

IBRs, including most solar and wind as well as new battery or hybrid generation, respond to disturbances and dynamic conditions based on programmed logic and inverter controls. The tripping of BPS-connected solar PV generating units and other control system behavior during grid faults has caused a sudden loss of generation resources over wide areas in some cases. As areas become more reliant on IBRs for their electricity generation, it is critically important to reduce risks from IBR performance issues. Likewise, explosive growth in DERs underscores the need to incorporate them into system planning:

- The ERO and Industry should take steps to ensure that IBRs operate reliably and the system is planned with due consideration for their unique attributes. NERC has developed an IBR strategy document to address IBR performance issues that illustrates current and future work to mitigate emerging risks in this area.[10] Regulators, industry-standards-setting organizations, trade forums, and manufacturers each have a role to play to address IBR performance issues.
- Industry should increase its focus on the technical needs for the BPS to reliably operate with increased amounts of DERs. Growth promises both opportunities and risks for reliability. Increased DER penetrations can improve local resilience at the cost of reduced operator visibility into loads and resource availability. Data sharing, models, and information protocols are needed to support BPS planners and operators. DER aggregators will also play an increasingly important role for BPS reliability in the coming years. Increasing DER participation in wholesale markets should be considered in connection with potential impacts to BPS reliability, contingency selection, and how any reliability gaps might be mitigated.

Addressing the Reliability Needs of Interdependent Electricity and Natural Gas Infrastructures

Natural gas is an essential fuel for electricity generation that bridges the reliability needs of the BPS during this period of energy transition. As natural-gas-fired generation continues to increase, vulnerabilities associated with natural gas delivery to generators can potentially result in generator outages. Energy stakeholders must urgently act to solve reliability challenges that arise from interdependent natural gas and electricity infrastructure:

- ERO and Industry planners should enhance guidelines for assessing and reducing risks through system and resource planning studies and develop appropriate Reliability Standards requirements to ensure corrective actions are put in place.
- Regulators and other energy stakeholders must also take steps to promote coordination on interdependencies. The forum convened by the North American Energy Standards Board is one such important action that should be broadly supported.[11]

[10] https://www.nerc.com/comm/Documents/NERC_IBR_Strategy.pdf
[11] https://www.nerc.com/news/Pages/-FERC,-NERC-Encourage-NAESB-to-Convene-Gas-Electric-Forum-to-Address-Reliability-Challenges.aspx

Capacity and Energy Assessment

Resource Capacity and Energy Risk Assessment

NERC is using two approaches in this *LTRA* to assess future resource capacity and energy risk:

- Comparing the margin between projected resources and peak demand, or reserve margin, to a reference margin level (RML) that represents the accepted level of risk based on a probability-based loss of load analysis
- Assessing load-loss metrics determined from probability-based simulation of projected demand and resource availability over *all* hours to identify high risk periods and energy constraints. Loss-of-load hours (LOLH) and expected unserved energy (EUE) from NERC's biennial Probabilistic Assessment (ProbA) are used to identify risk levels. LOLH greater than two hours and EUE greater than 0.2% of total energy is considered high risk for the purposes of this LTRA.

See the **Demand Assumptions and Resource Categories** for further details on these approaches. Supplemental tables and figures throughout this *LTRA* as well as assessment area dashboards (see **Regional Assessments**) provide resource capacity and energy risk assessment results for all areas.

Finding: Parts of the North American BPS face resource capacity or energy risks as early as the summer of 2023 (**Figure 1**). Capacity deficits, where they are projected, are largely the result of generator retirements that have yet to be replaced. While some areas have sufficient capacity resources, energy limitations and unavailable generation during certain conditions (e.g., low wind, extreme and prolonged cold weather) can result in the inability to serve all firm demand.

Future Capacity Shortfall in MISO

Anticipated reserves fall below the RML in the MISO assessment area beginning in the summer of 2023—one year earlier than reported in the *2021 LTRA* and two years earlier than reported in the *2020 LTRA*. Resources below the RML indicate that the area lacks adequate resources to limit load loss events to less than 1-day-in-10 years, an established resource planning criterion. The 1,300 MW shortfall that is projected for next summer follows the retirement of 5,900 MW of coal-fired and natural gas generation since 2021. Anticipated resources for the 2023 summer include 6,600 MW of planned (Tier 1) resources made up of 56% solar, 37% natural gas, and 7% wind. MISO's anticipated reserve margins (ARM) and PRMs for the next five years are in **Figure 2**.

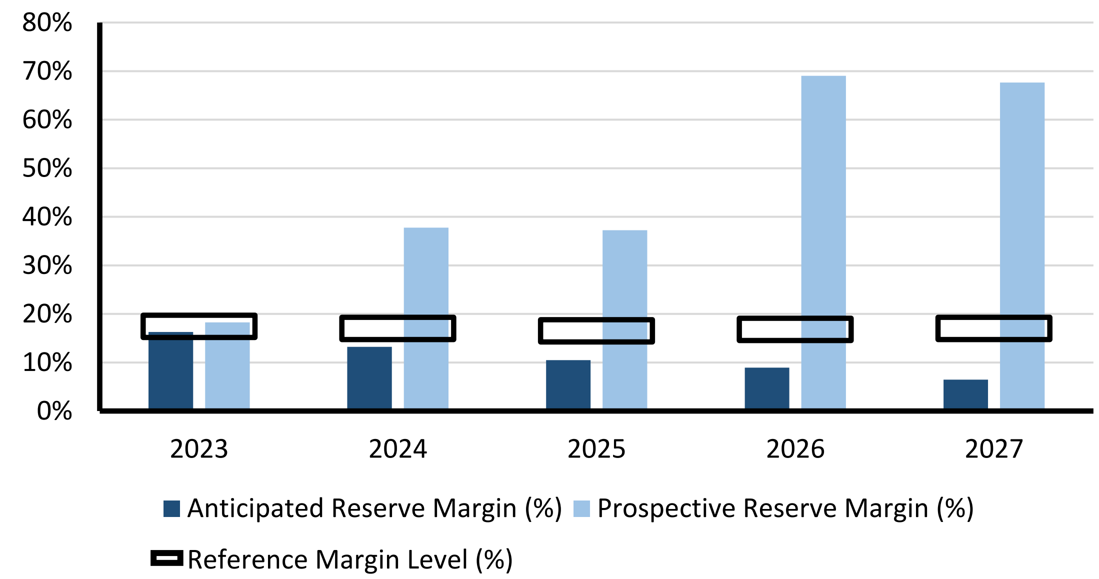


Figure 2: MISO Five-Year Projected Reserves (ARM and PRM)

Future Energy Risks in MISO

Results of the biennial ProbA conducted as part of this year's *LTRA* (2022 ProbA) confirm LOLH for 2024 are expected to increase from less than 0.1 hours per year to approaching one hour per year. Most risk occurs in June through August, corresponding to the months during which demand in MISO peaks. The ProbA also reveals risk periods in September and October when seasonal planned outages overlap with high demand. Another risk period is associated with winter, when extreme cold temperatures can push demand higher than normal in the morning and evening hours.

Future Capacity Shortfall in NPCC-Ontario

The ARMs in NPCC-Ontario fall below the RML in 2025 and beyond (see **Figure 3**). Anticipated shortfalls of about 1,700 MW are forecast for 2025 and 2026. As reported in the *2021 LTRA*, the main drivers for Ontario's projected shortfall are planned retirements and lengthy outages for nuclear units undergoing refurbishment. In September 2022, Ontario's Ministry of Energy announced that it was supporting a plan by Ontario Power Generation to extend operation of Pickering Nuclear Generating Station beyond its planned retirement in 2025 through September 2026. If approval is received from the Canadian Nuclear Safety Commission, this extension would reduce the potential capacity shortfall in 2026 described in the *2021 LTRA*. The ARM in **Figure 3** is calculated with an assumed retirement of Pickering units in late 2026.

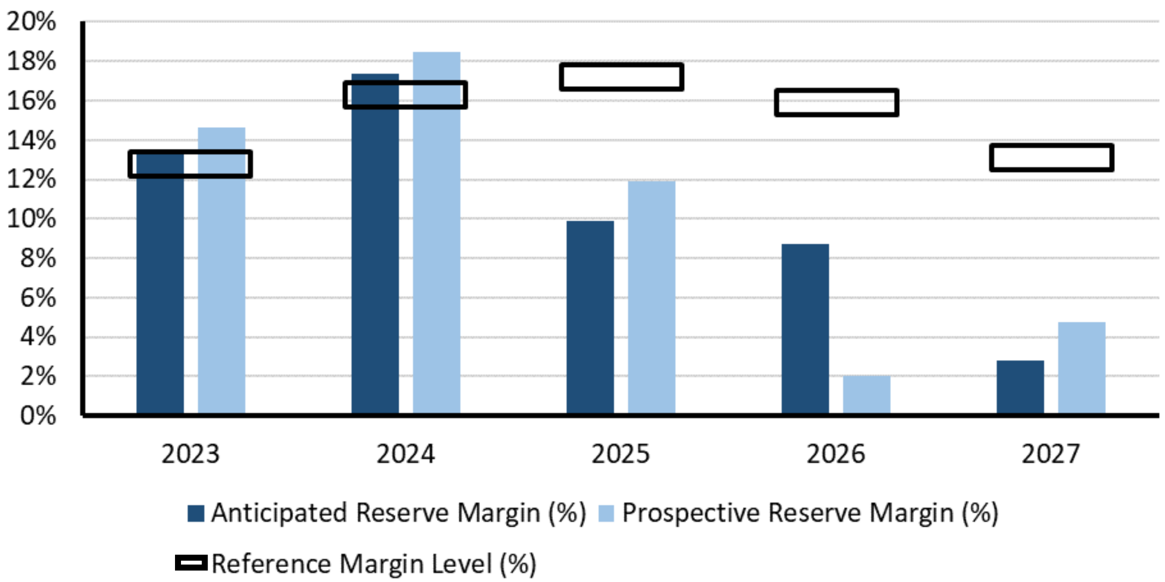


Figure 3: NPCC-Ontario Five-year Projected Reserves (ARM and PRM)

In order to address these emerging resource adequacy needs, the Independent Electricity System Operator's (IESO) established a Resource Adequacy Framework in 2021 to provide a flexible and cost-effective approach for competitively securing resources.[12] The Resource Adequacy Framework sets out a multi-pronged approach to cumulatively address needs over varying time frames with the annual acquisition report specifying the mechanisms and targets that will be used to meet the needs. In addition to supporting the Pickering Nuclear Generating Station extension, Ontario's Ministry of Energy also directed the IESO to obtain 4,000 MW of new capacity through three separate procurements. The IESO also announced new energy efficiency programs targeting needs in 2025–2027.

Energy Risks in U.S. Western Interconnection

Throughout the U.S. assessment areas in WECC, both demand and resource variability are increasing, and the challenges they present are accelerating. CA/MX, SRSG, and WPP show hours at risk of load loss over the next five years despite having adequate capacity for the peak demand hour.

Energy Risks in WECC-CA/MX

Resource additions in WECC-CA/MX are alleviating capacity risks, but energy risks persist. In the *2021 LTRA*, a capacity shortfall was projected beginning in 2026. Now the ARM in 2026 has risen to over 22% and is above the RML throughout the 2023–2027 period (see **Figure 4**). This indicates that the anticipated resources are sufficient to meet peak demand of a normal summer. However, the area remains dependent on electricity imports to manage periods of extreme electricity demand or low resource output. Heat events spanning a wide area that reduce the availability of electricity imports into California are likely to continue to raise concerns and be an area of risk that could induce energy shortfalls in the near term.

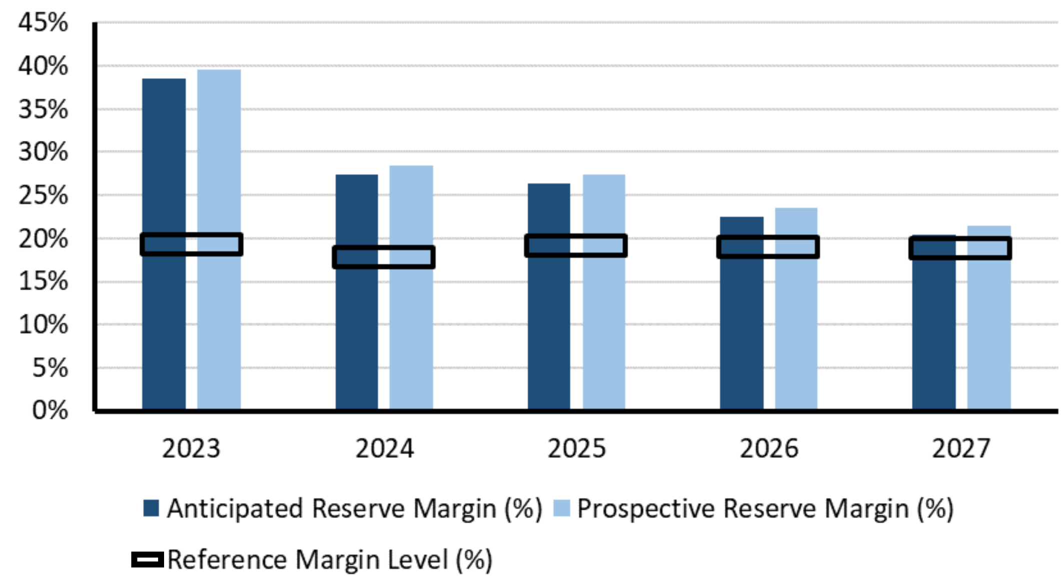


Figure 4: WECC-CA/MX Five-Year Projected Reserves (ARM and PRM)

[12] https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Resource-Adequacy-Framework

Added capacity in California has resulted in improved ProbA metrics and reduced energy risks; however, calculated load loss hours and unserved energy risks remain high. Since the 2020 ProbA, LOLH for 2024 has decreased from 56 hours per year to less than 1 hour per year, but projections for 2026 increase to nearly 10 hours per year. **Figure 5** shows a summary of CA/MX monthly energy shortfall risks for 2024 from the ProbA. Risk periods are spread across the months of July–September, coinciding with some of the warmest temperatures and potentially volatile electricity demand. Output from solar begins to fall off earlier in the day during the late summer months as well, and hydro output is lower from seasonal water flow patterns.

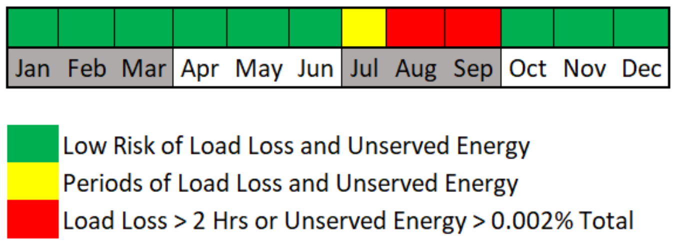


Figure 5: 2024 Monthly Energy Risk Summary for WECC-CA/MX

Examining the projected resource performance for the full 24 hours of the day that the peak risk hour occurs demonstrates the drivers of the energy risk in California. The bars in **Figure 6** show the variation in capacity resource output over the day. Each curve represents a demand forecast that ranges from a normal year forecast (e.g., Demand 50 indicates levels are equally likely to be above or below the actual demand on that day) to an extreme year forecast with higher demand levels that are unlikely to be exceeded by actual demand (e.g., Demand 05 indicates that statistically only 5 in 100 years are likely to have a day in which actual demand exceeds this forecast). As solar decreases as sunset approaches, the total of all available resources can fall short of the demand, especially for the higher demand levels represented in the load forecast. Imports are limited and cannot satisfy the increased demand levels in the CA/MX area, resulting in significant EUE.

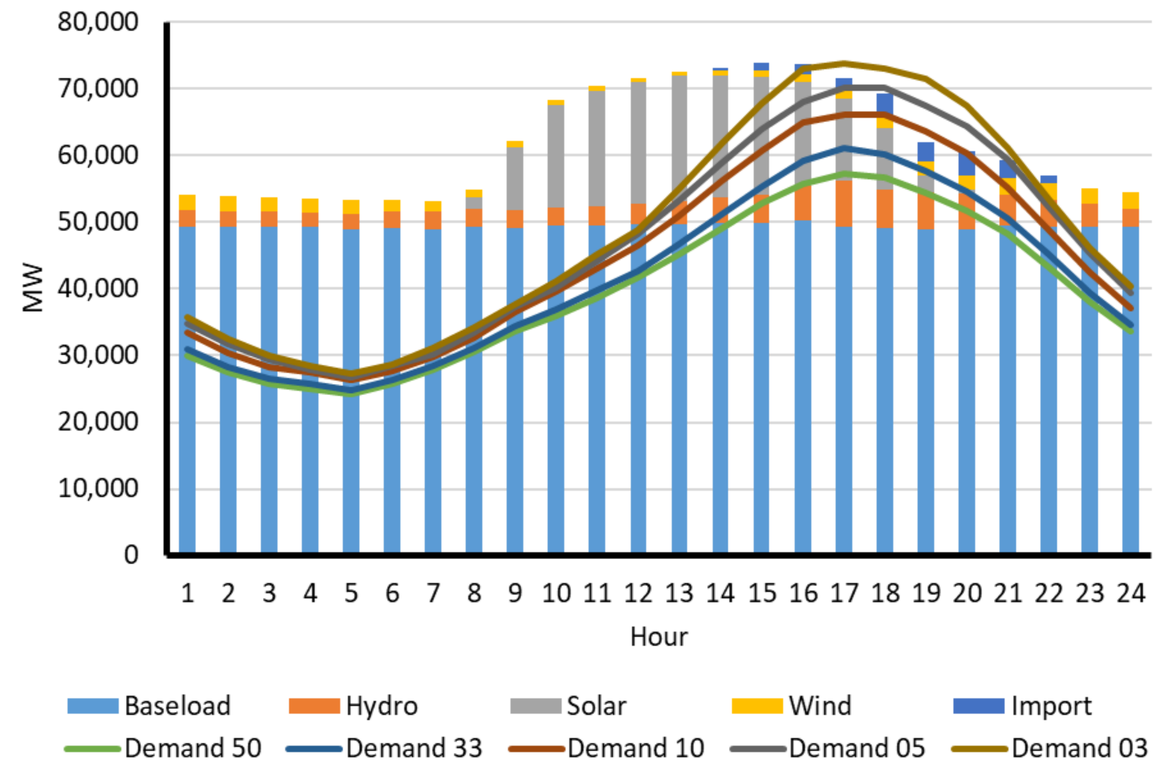


Figure 6: Hourly Demand and Resources for 2024 Summer Peak in WECC-CA/MX

Energy Risks in WECC-SRSG and WECC-WPP

Assessment areas in the U.S. Southwest and Northwest are also projecting summer periods of energy shortfall risks in the next five years. Risk months for WECC-SRSG and WECC-WPP are summarized in **Figure 7** and **Figure 8**. These areas have an increasingly variable generation resource mix and peak summer demand profile. Like CA/MX, late summer periods in the Southwest have the greatest risk of energy shortfalls due to the hot temperatures and potential for volatile electricity demand along with drop-off in solar that begins to occur earlier each day. In the Northwest, risk is spread across all summer months; this is driven primarily by declining on-peak capacity as coal-fired generators retire and less generation capacity is in the interconnection queue to replace it. ProbA results indicate that the risk of energy shortfall is increasing from 2024 to 2026 study years in both assessment areas.

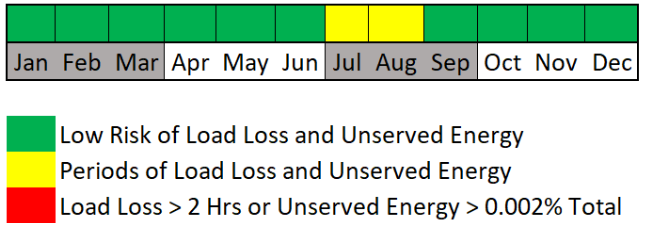


Figure 7: 2026 Monthly Energy Risk Summary for WECC-SRSG

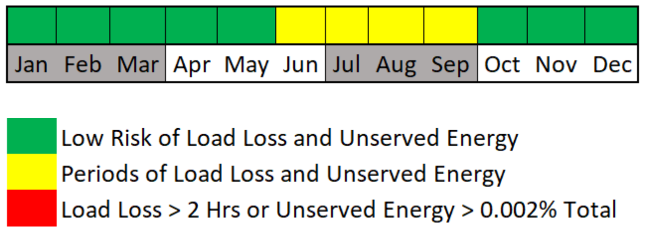


Figure 8: 2026 Monthly Energy Risk Summary for WECC-WPP

ERCOT Energy Risks

Generation resources, primarily solar and wind, continue to be added to the grid in Texas in large quantities, increasing on-peak planning reserve margins but also elevating concerns of energy risks that result from the variability of these resources and the potential for delays in implementation.

The summer on-peak ARM is projected to stay above the RML of 13.75% through 2027 (see **Figure 9**). The ARM increases significantly for the summers of 2023 and 2024 due to the expected addition of over 22,000 MW of summer Tier 1 capacity, most of which is solar.

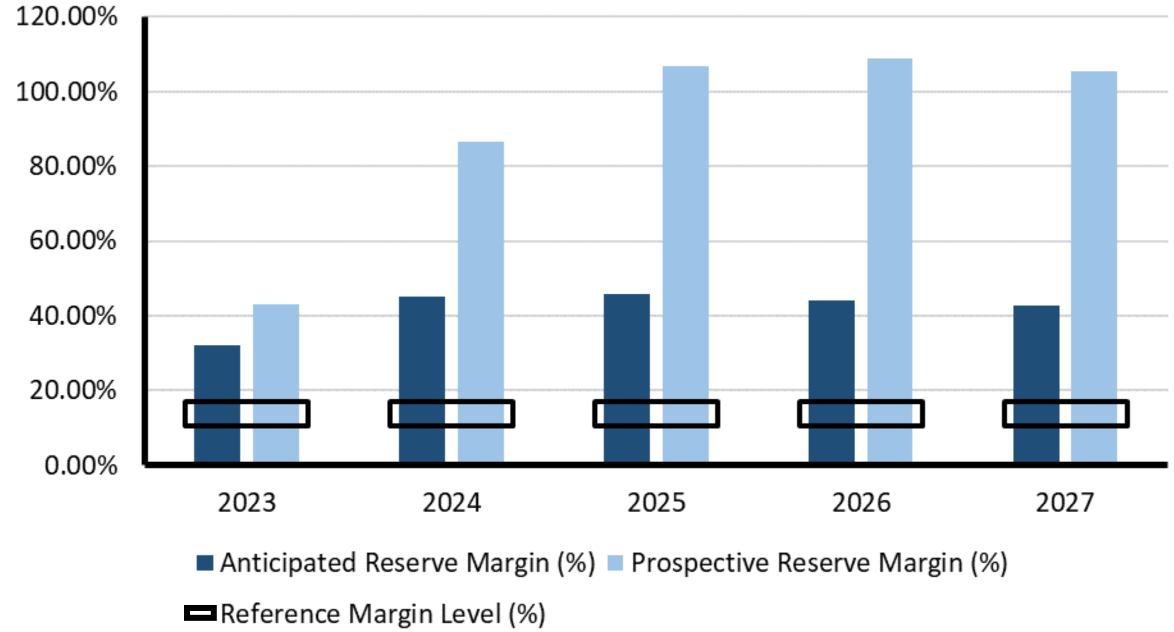


Figure 9: Texas RE-ERCOT Five-Year Projected Reserves (ARM and PRM)

The growing penetration of solar in ERCOT is increasing the risk of tight operating reserves during hours after the daily peak load hour when planning reserve margins are measured. Like California, this issue is most acute for the summer season when solar generation ramps down during the early evening hours while load is still relatively high. Studies by ERCOT show that the highest risk of energy emergencies occurs during summer months from early afternoon through early evening hours, peaking during the 7:00–8:00 p.m. hour. See **Texas RE-ERCOT** in the assessment area pages. ERCOT's summer LOLH and EUE are relatively small; however, these results are contingent upon completion of nearly 20 GW of Tier 1 solar resources by 2024.

Finding: Parts of North America are exposed to energy shortfall risks in the near-term assessment period from wide-area and long duration extreme weather events like the 2020–2021 U.S. Western area heat wave and the South Central Winter Storm Uri in 2021.

Extreme Winter Weather Risks in Texas

Though typical winters in Texas are mild and pose little risk of energy shortfalls, extreme winter weather similar to Winter Storm Uri in February 2021 are likely to challenge grid operators to maintain reliability in the near-term. ERCOT's winter peak load varies substantially (as much as 12.5%) between the coldest temperatures of an average year and a more extreme year as might be experienced once per decade. This is in contrast to the relative stability of ERCOT's summer peak demand, which does not vary by more than a few percentage points between an average year and an extremely hot year. With such demand variability, long-range weather and demand forecasting becomes more important to ensuring sufficient resources are available and ready to operate.

In winter, demand in Texas peaks during cold early morning hours before ERCOT's vast solar resources are producing electrical output. Demand must be met primarily with the fleet of thermal and wind generators. In Texas and other parts of the South that do not experience harsh winters each year, high forced outages of the thermal and wind generation fleet has been a common issue when extreme weather events have led to energy emergencies, causing generator component freezing, fuel supply disruption to natural gas and coal-fired plants, and wind generator protection cut-outs.[13] ERCOT's analysis for the 2022 ProbA included forced outage risk modeling for extreme winter conditions, and most risk of load loss occurs in winter, not summer, months. A summary of monthly energy risk is in **Figure 10**.

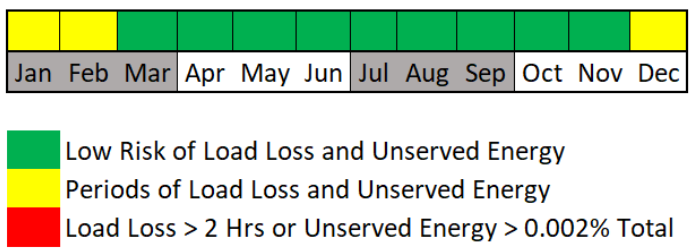


Figure 10: 2024 and 2026 Monthly Energy Risk Summary for ERCOT

These winter energy risks in the ProbA results are significantly influenced generator outage modeling like the effects from Winter Storm Uri. Since February 2021, Texas regulators, ERCOT, and Generator Owners have implemented winter preparedness programs and other reforms aimed at improving generator performance in extreme winter weather. The ProbA results do not consider these changes and are likely to be pessimistic for similar extreme weather as a result.

Energy Risks in NPCC-New England

Studies performed by NPCC and ISO New England have identified energy risks for the area. Although there is sufficient capacity to meet the resource adequacy criterion, a previously identified and persistent concern is whether there will be sufficient fuel available to satisfy electrical energy and operating reserve demands during an extended cold spell or a series of cold spells given the existing resource mix and regional fuel delivery infrastructure. See the **NPCC New England** assessment area pages.

Energy Risks in SPP

While the SPP PRM shows a significant amount of capacity, ARMs do not account for planned, forced, or maintenance generator outages. Instead, they reflect the full availability of accredited capacity. Additionally, anticipated resources do not reflect derates based on real-time operational impacts. Capacity and energy shortfalls can occur in SPP when high demand coincides with low wind or above-normal generator outages. See the **SPP** assessment area pages.

Recommendation for Reducing Resource Capacity and Energy Risk

The impact of wide-area and long-duration extreme weather events, such as the February 2021 South Central U.S. cold weather event and the August 2020 Western U.S. wide-area heat event, have underscored the need to consider extreme scenarios in resource planning. Energy risks emerge when weather-dependent generation is impacted by abnormal atmospheric conditions or when extreme conditions disrupt fuel supplies. Industry and regulators should conduct all-hours analyses for evaluating and establishing resource adequacy and include extreme condition criteria in integrated resource planning and wholesale market designs. In areas with high dependence on VERs and natural-gas-fired generation, PRMs are not sufficient for measuring resource adequacy.

The ERO and industry should prioritize the development of Reliability Standard requirements to address energy risks in operations and planning. NERC's Reliability Standards Project 2022-03 should be closely monitored, and stakeholder experts should contribute to developing effective requirements for entities to assess energy risks and implement corrective actions in all time horizons. State and provincial regulators and ISO/ RTO) should have mechanisms they can employ to prevent retirement of generators that they determine are needed for reliability, including the management of energy shortfall risks. Regulatory and policy-setting organizations should use their full suite of tools to manage the pace of retirements and ensure replacement infrastructure can be timely developed and placed in service. If needed, the Department of Energy should use its 202(c) authority as called upon by electric system operators.

[13] See the findings and recommendations of the Joint FERC/NERC/Regional Entity inquiry into the February 2021 cold weather event: https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and

Resource Mix Changes

Finding: The vast amounts of wind, solar, and now hybrid generation resources in interconnection processes will enable continued transition in the generation resource mix as traditional resources retire. VERs (resources with output dependent upon weather and hourly conditions) will increase and the fleet of thermal resources will shrink and have less fuel diversity.

The addition of VERs (primarily wind and solar) and the retirement of conventional generation are fundamentally changing how the BPS is planned and operated. Planning and operating the grid must increasingly account for different characteristics and performance in electricity resources. Maintaining reliability will require the pace of change to be carefully managed by industry and regulators and steps to be taken to ensure that essential reliability services (ERS) continue to be provided as generators retire.

Generation Resource Mix in 2022

Figure 11 shows the fuel mix composition of all generation resources connected to the North American BPS in 2022. The installed resource mix (left) is based on the design ratings of the generators. On-peak resource capacity (right), in contrast, reflects the expected capacity that the resource type will provide at the hour of peak demand. Because the electrical output of wind and solar VERs depends on weather and light conditions, on-peak capacity contributions are less than nameplate installed capacity. The wind on-peak capacity contribution ranges from a low of 10% of installed capacity in Saskatchewan to 26.2% in ERCOT. Solar on-peak contributions are 0% in most areas during winter when the peak occurs in low light. In summer, some areas, such as ERCOT and parts of the U.S. West, can expect solar contribution to reach over 80% of installed capacity at peak demand hour. High expected capacity contributions from VERs help increase Planning Reserve Margins but also increase the exposure of the system to energy risks from weather or environmental conditions that impact VER output. Supplementary tables on NERC's Reliability Assessments web page provide on-peak capacity contributions of existing wind and solar resources in each assessment area.[14]

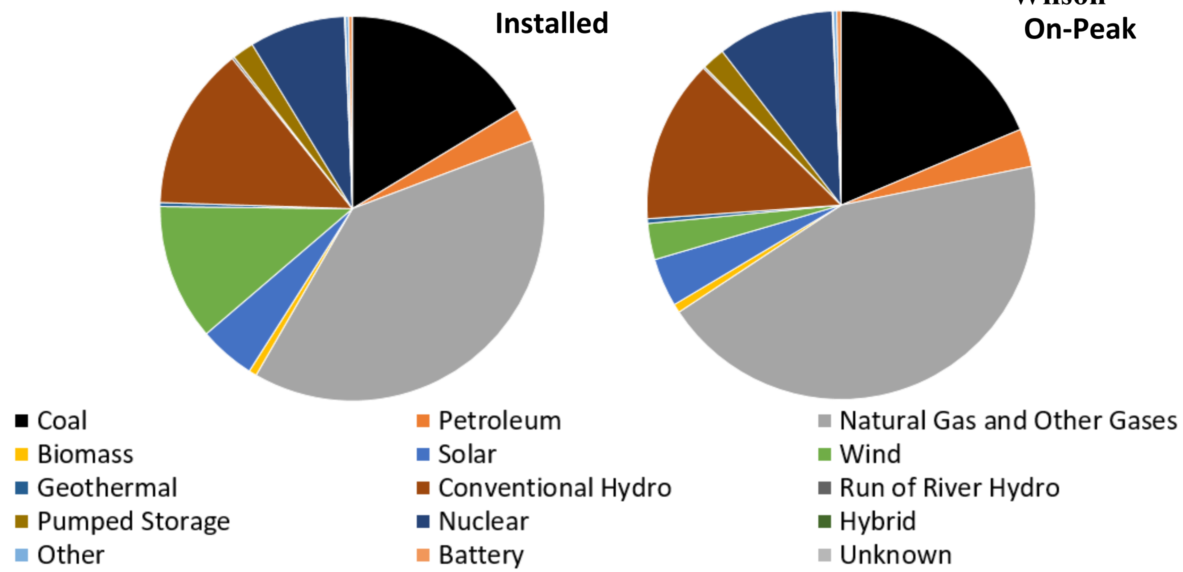


Figure 11: 2022 BPS Generation Capacity by Fuel Type

Total on-peak capacity by generation type is summarized in Table 1 below. The capacity of several traditional baseload generation fuel-types is in decline. Since the *2021 LTRA*, coal-fired generation has fallen by 17 GW and nuclear generation has fallen by 2 GW.

Table 1: 2022 Capacity at Peak Demand

Type	Capacity (GW)	Change since 2021 (GW)
Natural Gas	477	+14
Coal	202	-18
Nuclear	106	-2
Solar and Wind	70	+19
All others	189	+2
Contributions at hour of peak demand. VER (solar, wind, and some hydro) typically count less than installed nameplate capacity.		

[14] https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx

Capacity Additions

New generation is added to the BPS through area interconnection planning processes. Wind, solar, and natural-gas-fired generation are the overwhelmingly predominant generation types in the planning horizon for addition to the BPS. A summary of generation resources in the interconnection planning queues is shown in Figure 12. See supplemental tables for greater detail by fuel type.

In general, Tier 1 resources are in final stages for connection while Tier 2 resources are further from completion and some may, in fact, not be completed. Supply chain issues, planning and siting challenges, and business or economic factors can cause projects to be delayed or withdrawn.

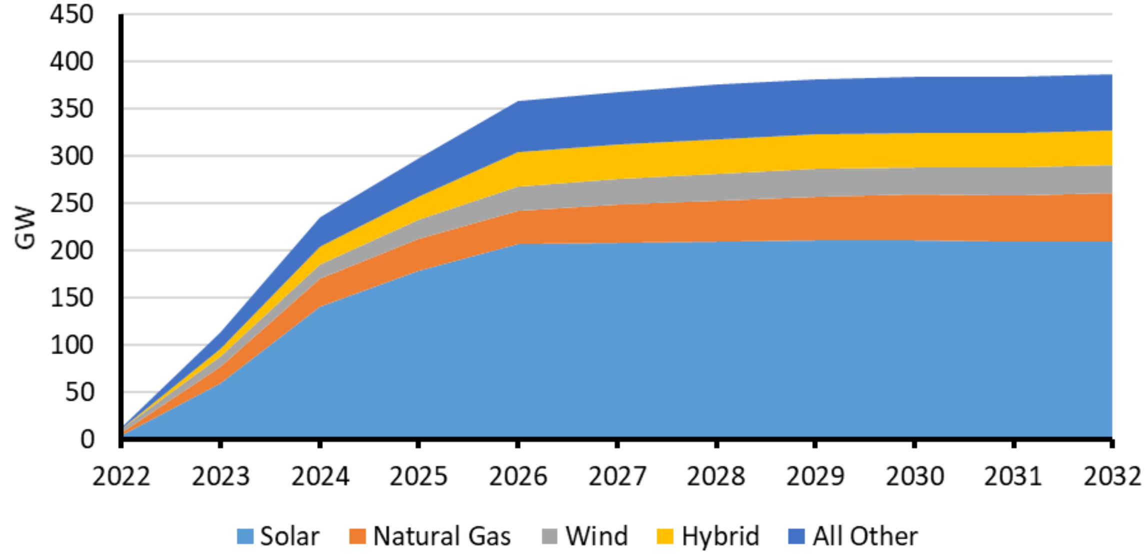


Figure 12: Tier 1 and 2 Planned Resources Projected Through 2032

Solar and wind capacity, both existing and planned, vary widely by area. Figure 13 and Figure 14 show current solar and wind installed capacities and capacity in the planning process through 2032 for assessment areas with significant amounts. In addition, hybrid generation resources, which combine energy storage with a generating plant (e.g., a wind or solar farm) are connecting to the grid in parts of North America, and many more projects are in BPS planning processes. A complete listing for all assessment areas is available in the supplemental tables.

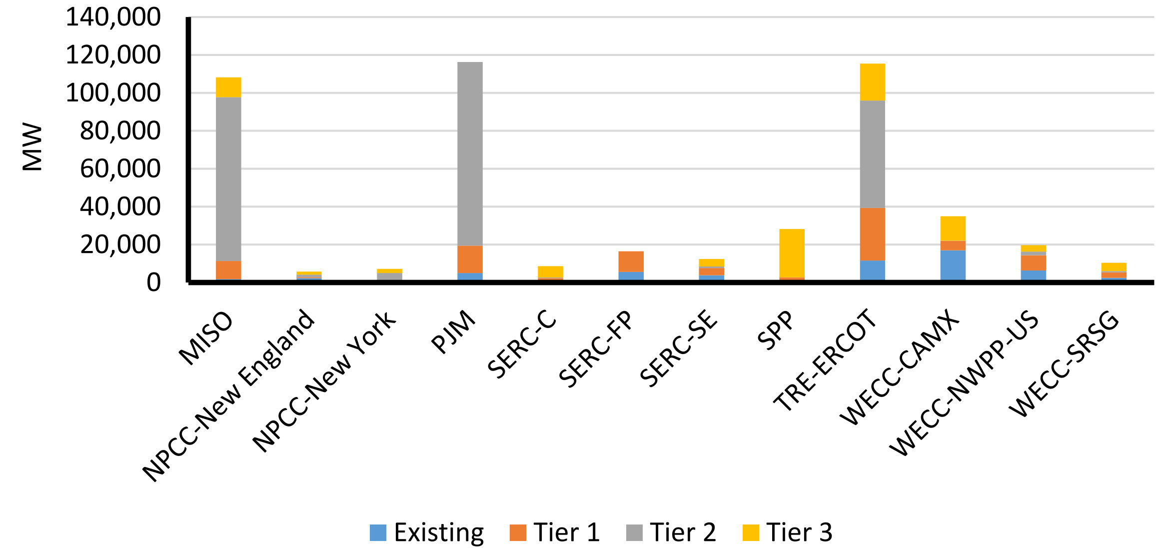


Figure 13: Solar Capacity Planned and Existing

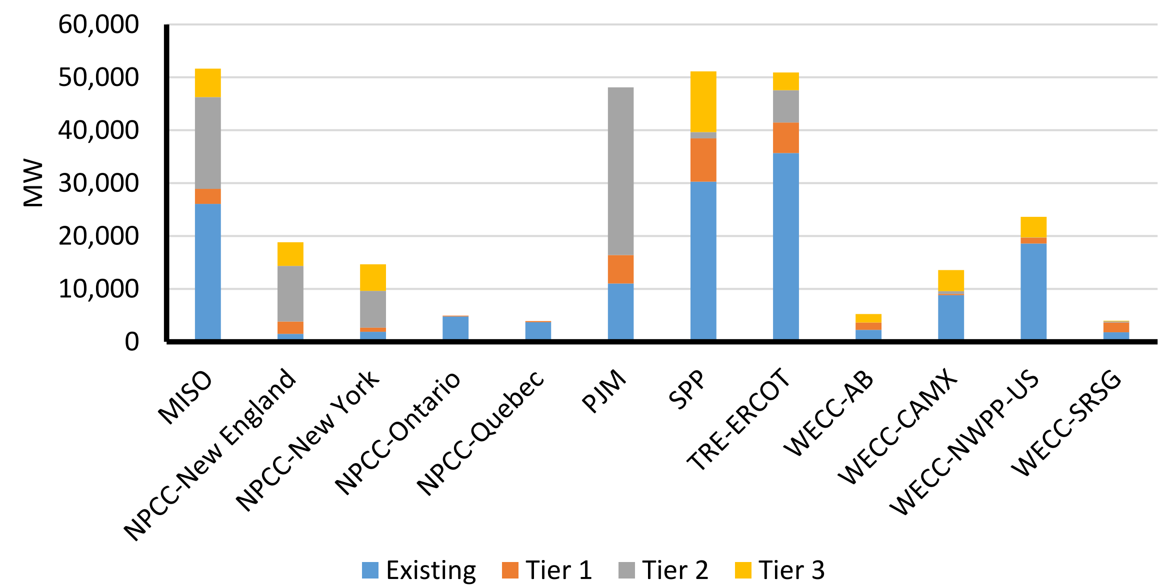


Figure 14: Wind Capacity Planned and Existing

Solar Distributed Energy Resource Growth

Behind the meter (BTM) solar PV generators are solar resources connected directly to the distribution system, such as residential rooftop solar systems. Rapid growth of BTM solar PV continues with cumulative levels expected to reach over 80 GW by the end of this 10-year assessment period (an increase of 25% since publication of the *2021 LTRA*). BTM solar PV generators, like grid-connected solar, are also VERs. In large penetrations, their predictable change in output from the time of day contributes to steep ramps in demand. As the sun sets and output diminishes, grid resources must make up for the decrease in solar generation and increase in demand that was being served. The opposite ramp occurs during morning hours and may be less impactful to reliability but can be challenging for grid-connected generator scheduling and dispatch. Supplemental tables show the current and projected BTM solar PV by area.

Generation Retirements

The total capacity of traditional baseload generation fuel-types will continue to decline as older generators retire. The resource mix changes as these retirements are coinciding with the addition of new generation of different types with different capacity characteristics. Figure 15 shows how the current resource mix (on-peak capacity) compares to the projection of the future on-peak capacity in 2032 if confirmed retirements occur and all projected Tier 1 resources are added. Across the entire BPS, the on-peak capacity contribution of solar and wind will grow modestly from the current 7% to 12%. The change in specific Interconnections varies. ERCOT and the Western Interconnection are projected to have more significant increases in the share of on-peak generation that is coming from VERs while the Eastern Interconnection and Québec Interconnection would change little in the 10-year period.

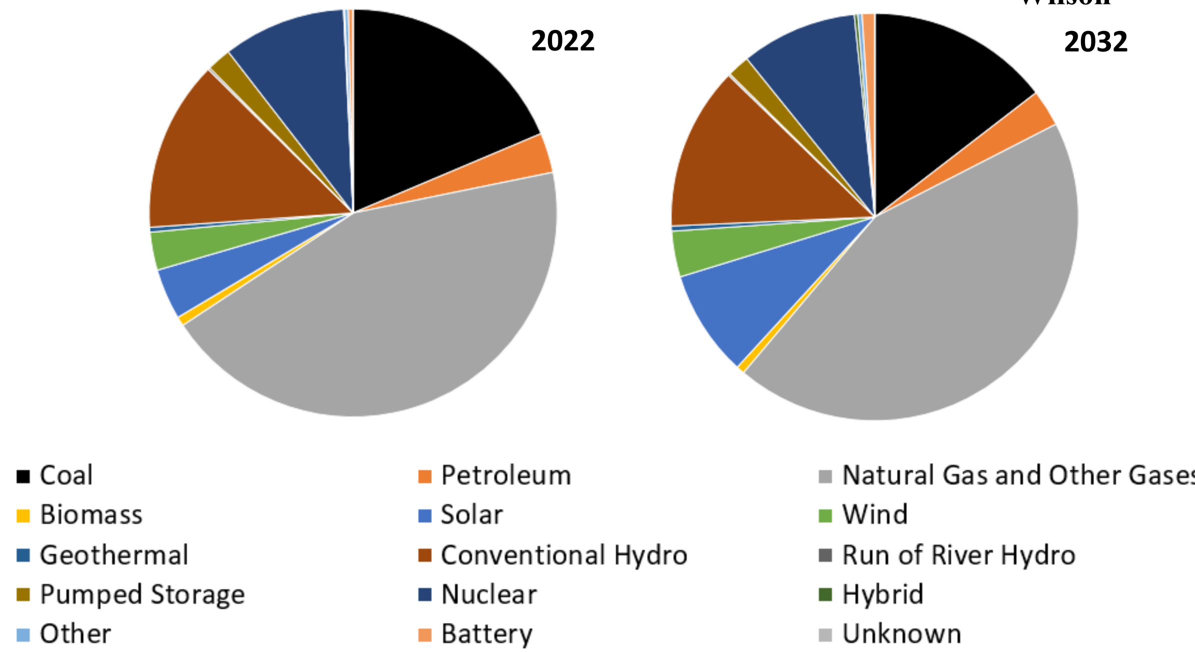


Figure 15: 2022–2032 BPS On-Peak Capacity by Fuel Type with Tier 1 Resources

Generators become confirmed for retirement according to various processes in place in the Interconnections, such as regional planning tariffs in the wholesale electricity market areas or integrated resource planning process in vertically-integrated states. Properly designed mechanisms can prevent generators from retiring before planners can study and address reliability issues that could occur.

Additional retirements beyond what is reported as confirmed in this *2022 LTRA* are expected. Often Generator Owners announce plans to retire generator units before initiating the interconnection planning process, and the announced plans or timing may be subject to change before the retirement is confirmed. Figure 16 shows the total capacity of confirmed and announced as well as unconfirmed retirements of fossil-fueled and nuclear generators across the BPS over the next five years.[15]

[15] Confirmed generator retirements are reported to NERC by each assessment area in the LTRA development process. NERC obtained data on announced, unconfirmed generator retirements from Energy Ventures Analysis, Inc. and from each assessment area. Some sources of information on announced generator retirements include EIA 860 data, trade press, and utility integrated resource plans.

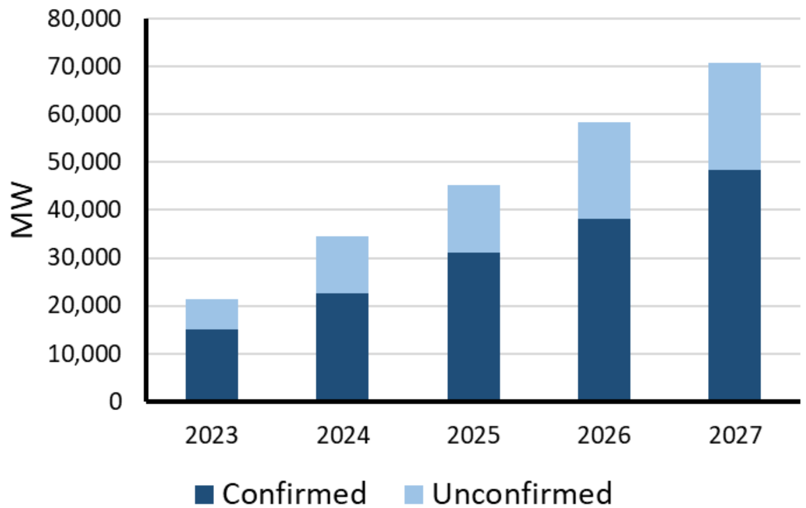


Figure 16: Projected Generation Retirement Capacity Through 2027

Throughout this *2022 LTRA*, all confirmed generation retirements have been removed from each assessment area's anticipated and prospective resources while unconfirmed, announced generator retirements have been removed from prospective resources only. In some risk areas identified in the **Resource Capacity and Energy Risk Assessment** section of this *2022 LTRA*, the announced, unconfirmed generator retirements are likely to exacerbate currently-projected energy shortfalls. **Figure 17** shows a comparison of the 2027 (Year 5) ARMs for the assessment areas at risk of shortfall as well as the potential 2027 reserve margins for a scenario with both confirmed and announced generator retirements. In MISO, where 10.2 GW of generation is expected to retire by 2027, another 5.4 GW of generation capacity is at risk of retirement based on retirement plan announcements. Loss of this additional capacity could lower the reserve margins from 6.5% in the current year to below 2% for the 2027 capacity assessment. The Maritimes provinces in Canada could also face a capacity shortfall if 550 MW of unconfirmed retirements were to exit the system without replacement resources.

In SPP, Texas RE-ERCOT, CA/MX, WPP, and SRSG, where energy limitations are contributing to projected load-loss risk in the **Resource Capacity and Energy Risk Assessment** section of this LTRA, additional thermal generator retirements could also be detrimental to reliability. Loss of these traditional baseload resources would lead to a more variable generation resource mix unless they are replaced by resources that are dispatchable, flexible, and able to counter variations in generation and demand. Consequently, the risk of insufficient energy and loss-of-load during periods of high demand and low resource output will rise.

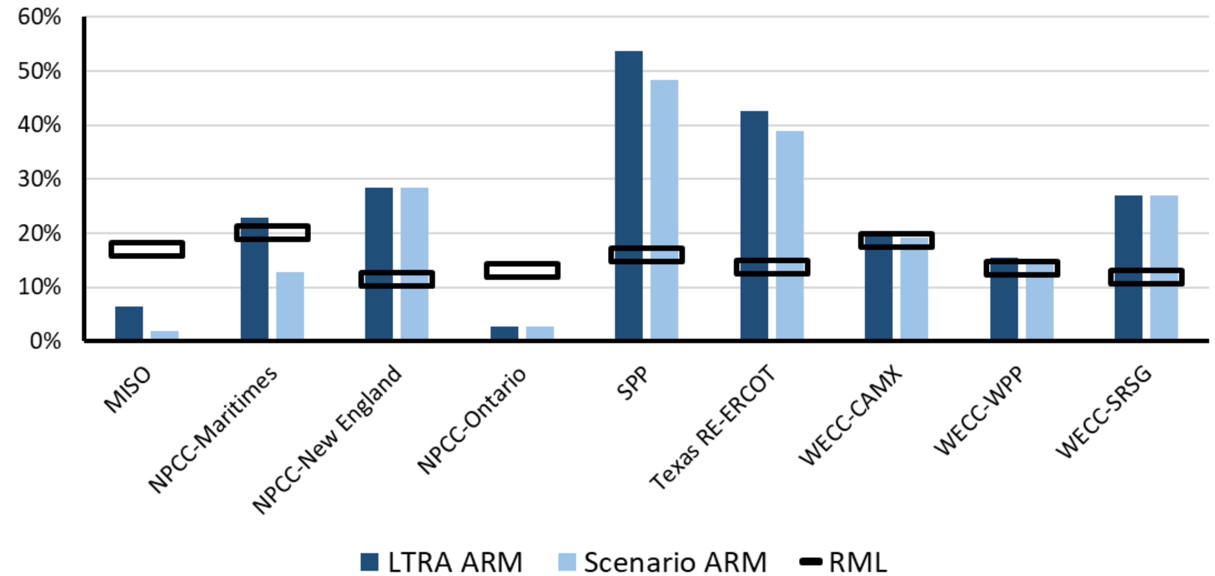


Figure 17: Year 2027 Reserve Margins Including a Scenario with Announced/Unconfirmed Retirements

These scenarios illustrate the potential impacts that significant generation retirements can have on resource adequacy, and they underscore the important role of ISO/RTO and integrated system planning processes that are necessary to maintain reliability.

Reliability Implications

The addition of variable resources, primarily wind and solar, and the retirement of conventional generation are fundamentally changing how the BPS is planned and operated. Planning and operating the grid must increasingly account for different characteristics and performance in electricity resources. Important reliability implications include the following:

- **Flexible Resources:** In order to maintain load-and-supply balance in real-time with higher penetrations of variable supply and less-predictable demand, some operators are seeing the need to have more system ramping capability. As more solar and wind generation is added, additional flexible resources are needed to offset these resources' variability, such as supporting solar down ramps when the sun goes down and complementing wind pattern changes. This can be accomplished by adding more flexible resources within committed portfolios or by removing system constraints to flexibility.[16] Maintaining ERSs is critically important, and resources must be made available in the long-range resource portfolio as part of the planning process; market and other mechanisms need to be in place to deliver resources with ERS-capabilities to the operators.

- **Fuel-related Risks to Electricity Generation (Fuel Assurance):** Natural gas for electricity generation is an essential fuel that bridges the rapid development of VERs. As natural-gas-fired generation continues to increase, vulnerabilities associated with natural gas delivery to generators can potentially result in generator outages. As part of future transmission and resource planning studies, planning entities will need to more fully understand how impacts to the natural gas transportation system can impact electricity reliability. The NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System,* provides planning guidance.[17] Disruptions to the fuel delivery can result from adverse events that may occur, such as line breaks, well freeze-offs, and/or storage facility outages. The pipeline system can be impacted by events that occur on the electric system (e.g., loss of electric motor-driven compressors) that are compounded when multiple plants are connected through the same pipeline or storage facility. Furthermore, additional pipeline infrastructure is needed to reliably serve electric load.
- **Inverter-based Resources:** IBRs, including most solar and wind as well as new battery or hybrid generation, respond to disturbances and dynamic conditions based on programmed logic and inverter controls. The tripping of BPS-connected solar PV generating units and other control system behavior during grid faults has caused sudden loss of generation resources (over wide areas in some cases). Industry experience with unexpected tripping of BPS-connected solar PV generation units can be traced back to the 2016 Blue Cut fire in California, and similar events have occurred as recently as the summer of 2022.[18] A common thread with these events is the lack of IBR ride-through capability causing a minor system disturbance to become a major disturbance. To address systemic issues with IBRs, NERC continues to urge industry's adoption of the recommended practices set forth in NERC guidelines even as NERC begins the process of developing mandatory Reliability Standards based on those guidelines. High priority items include incorporating electromagnetic transient modeling into the NERC Reliability Standards and developing a comprehensive ride-through requirement that focuses specifically on generator protections and controls.
- **BES Protective Relay Systems:** The changing resource mix presents unique risks and challenges to the vast network of protective relay systems that are critical to the safe and reliable operation of the Bulk Electric System (BES). Protection systems are meticulously planned and maintained to rapidly respond to dynamic grid conditions in a coordinated manner that isolates faults from spreading throughout the system and minimizes risks to grid equipment and personnel. With more IBRs and fewer synchronous generators on the grid, there is growing concern in the industry that protection systems will no longer function properly during system faults without redesign. Unlike synchronous generators, which produce high currents with unbalanced characteristics during faults that enable existing protections systems to function properly due to their physical properties, IBRs produce low amounts of fault currents based on control functions. Changing fault current magnitudes and characteristics in parts of the system with high penetrations of IBRs has the potential to invalidate current protection system designs, potentially leading to more protection system misoperation. Protection engineers need to have better tools to analyze periods of low synchronous generation and ensure protection systems will still function properly.
- **Tools and Models for Assessing Capacity and Energy Risks:** Planners and operators are updating processes, tools, and techniques to keep pace with the changing resource mix. The explosive growth of battery and hybrid resources seen in most areas requires additional details to be incorporated into operating and planning models, such as state of charge, battery duration, and battery operating mode. Additionally, resource planners and wholesale market designers in most areas with growing wind and solar resources are considering or developing new processes for assigning the contribution of resources to meeting demand. Some are investigating the use of effective load-carrying capacity (ELCC) methods that involve probabilistic study to assign the capacity contribution of resources. These ELCC methods should address the risks and shortcomings in present modeling described in this report. Specifically, the statistical representation of capacity that has variable and uncertain fuel can

[16] https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERS_Measure_6_Forward_Tech_Brief_03292018_Final.pdf
[17] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Fuel_Assurance_and_Fuel-Related_Reliability_Risk_Analysis_for_the_Bulk_Power_System.pdf
[18] See *May/June 2021 Odessa Disturbance Report*, *June-August 2021 CAISO Solar PV Disturbance Report*, and other relevant IBR event reports here: https://www.nerc.com/pa/rrm/ea/Pages/Major-Event-Reports.aspx

be problematic when combined in a reserve margin evaluation with capacity that has firm fuel and highly reliable. Finally, planners are finding it necessary to have improved tools and methods to study wide-area, long duration extreme weather risks and other low-likelihood, extreme events. Scenario planning is needed to ensure that the industry is ready to take actions needed to preserve the reliable operation of the BPS for many potential system conditions. Traditional models and approaches rooted in a loss-of-load expectation of 1 day-in-10-years do not account for the essential role that electricity plays in modern society, and normal demand distributions appear to be ill-suited for describing the extremes of a changing weather patterns.

- **Essential Reliability Services:** Conventional units, such as coal and nuclear power plants, provide frequency support services as a function of their large spinning mass and governor control settings, along with voltage regulation. Power system operators use these services to plan and operate reliably under a variety of system conditions, generally without the concern of having too few of these services available. The reliability of the BPS depends on the operating characteristics of the replacement resources. Merely having available generation capacity does not equate to having the necessary reliability services or ramping capability to balance generation and load. It is essential for the BPS to have resources not only with the capability to respond to frequency and voltage changes, but to actively provide those services.[19]

Recommendations for Reducing Risks as the Resource Mix Changes

In addition to the recommendations found elsewhere in the report, the following will reduce risks that can occur during the resource mix transition:

- Resource planners and policymakers must give careful attention to the pace of change in the resource mix and update capacity and energy risk studies, including all-hours probabilistic analysis, with accurate resource projections.
- The ERO and Industry should take steps to ensure IBRs operate reliably and the system is planned with due consideration for their unique attributes. NERC has developed an IBR strategy document for addressing inverter-based resource performance issues that illustrates current and future work to mitigate emerging risks in this area.[20] Regulators, industry standards-setting organizations, trade forums, and manufacturers also have a role to play addressing IBR performance issues.
- Industry should increase its focus on technical needs for reliably operating with increased amounts of DER. Growth promises both opportunity and risks for reliability. Increased DER penetrations can improve local resilience at the cost of reduced operator visibility into loads and resource availability. Data sharing, models, and information protocols are needed to support BPS planners and operators. DER aggregators will also play an increasingly important role to BPS reliability in the coming years. Increasing DER participation in wholesale markets should be considered in connection with potential impacts to BPS reliability, contingency selection, and how any reliability gaps might be mitigated.
- Industry, regulators, and energy stakeholders must urgently act to solve reliability challenges arising from interdependent natural gas and electricity infrastructure. For industry, this entails enhancing guidelines for assessing and reducing risks and developing appropriate Reliability Standards requirements to ensure corrective actions are put in place. Regulators and other energy stakeholders must also take steps. The forum convened by the North American Energy Standards Board is an example of one such important action.[21]

[19] Essential reliability services are measured periodically using evaluations developed by the Essential Reliability Service Task Force: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/ERSTF%20Framework%20Report%20-%20Final.pdf Forward-looking frequency response evaluations are conducted every three years and included in the Long-Term Reliability Assessment. Historical evaluations are reported in the State of Reliability report: https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2022.pdf

[20] https://www.nerc.com/comm/Documents/NERC_IBR_Strategy.pdf

[21] https://www.nerc.com/news/Pages/-FERC,-NERC-Encourage-NAESB-to-Convene-Gas-Electric-Forum-to-Address-Reliability-Challenges.aspx

Demand Trends and Implications

Demand and Energy Projections

Electricity peak demand and energy growth rates in North America are both increasing. The 10-year summer and winter peak demand growth projections show the largest percentage increase in recent years. Electrification and projections for growth in EV over the 10-year horizon are a component of the demand and energy estimates provided by each assessment area. Growth rate increases in winter peak demand are being influenced by electrification of space-heating systems. Summer peak demand growth rates are lower compared to winter; growth in DERs and some EE contributing to lower summer demand growth. See the **Figure 18** for seasonal peak demand growth over the current and prior assessment periods and **Figure 19** for net energy growth. Area demand growth rates are provided in the supplemental tables, and more information is available in the **Regional Assessments** pages.

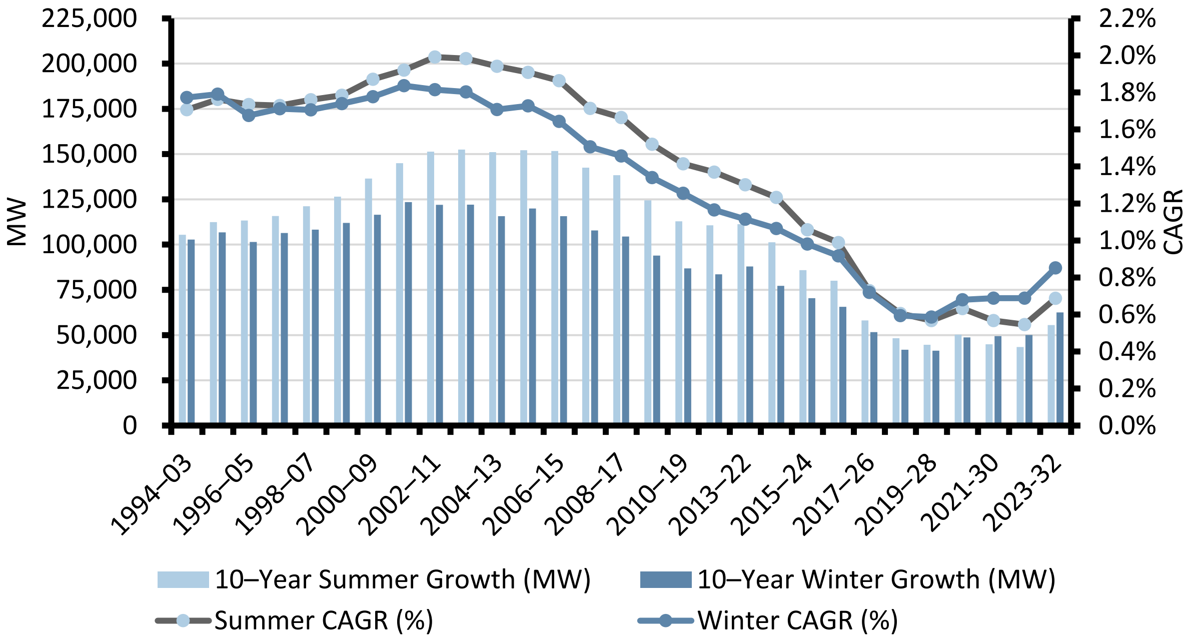


Figure 18: The 10-Year Summer and Winter Peak Demand Growth and Rate Trends

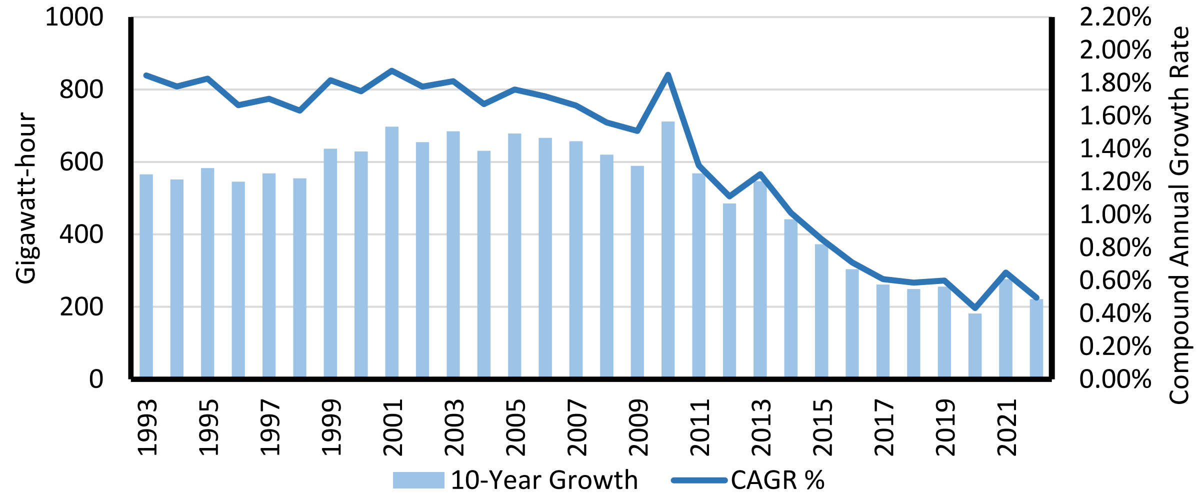


Figure 19: The 10-Year Net Energy to Load Growth and Rate Projection Trends

Demand-Side Management

Conservation, EE, and DR programs contribute to an assessment area's ability to manage load. DR describes a number of load-reducing programs that are available to system operators under specific conditions. NERC collects forecasts of the amount in MW that is expected to respond when called upon to reduce peak load for each assessment area. **Figure 20** shows the total system DR forecasted to be available for the first and fifth year's summer and winter peaks (Year 1 and Year 5) from each of the past five LTRAs.

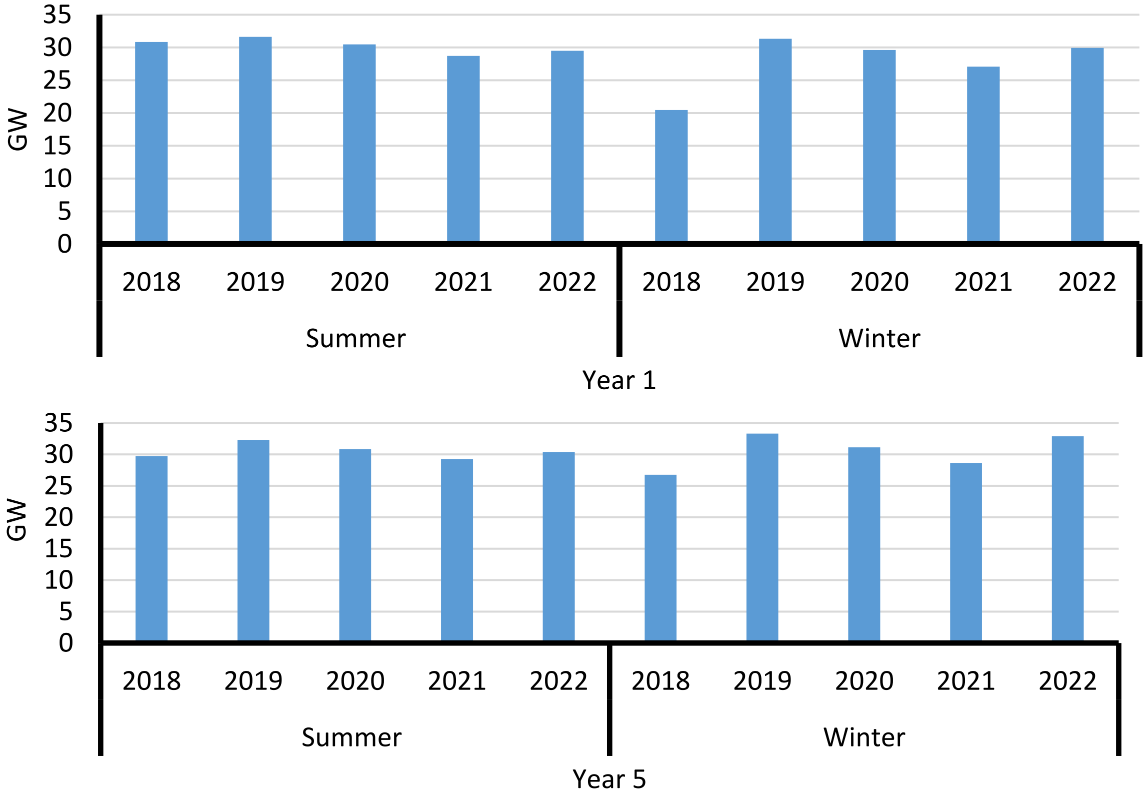


Figure 20: Demand Response Available in Year 1 and Year 5 of 2018–2022 LTRA

Reliability Implications

Demand projections are influenced by a variety of factors, including the economy, energy policies, technology development, and consumer preferences. Projections are increasing in complexity with more uncertainty in the impacts of the changing resource and demand characteristics, especially with their variability. DR, EE, BTM generation, energy storage, electrification and consumer behavior all impact the demand and energy projections. To ensure reliability, grid and resource planners must manage short- and long-term load forecasts to account for this complexity and uncertainty.

Dual-peaking or changing from summer to winter peaking is anticipated in several areas, including the U.S. Southeast and Northeast. Such changes have wide-ranging implications to how the grid and resources are planned and operated.

Transmission Development Trends and Implications

Trends

There is relatively little change in cumulative miles of BPS transmission under construction or in planning for the next 10-year horizon; however, projects for renewable integration are increasing. The current cumulative level of 15,495 miles of transmission (>100 kV) in construction or stages of development for the next 10-years (**Figure 21**) is running near averages of the past five years.

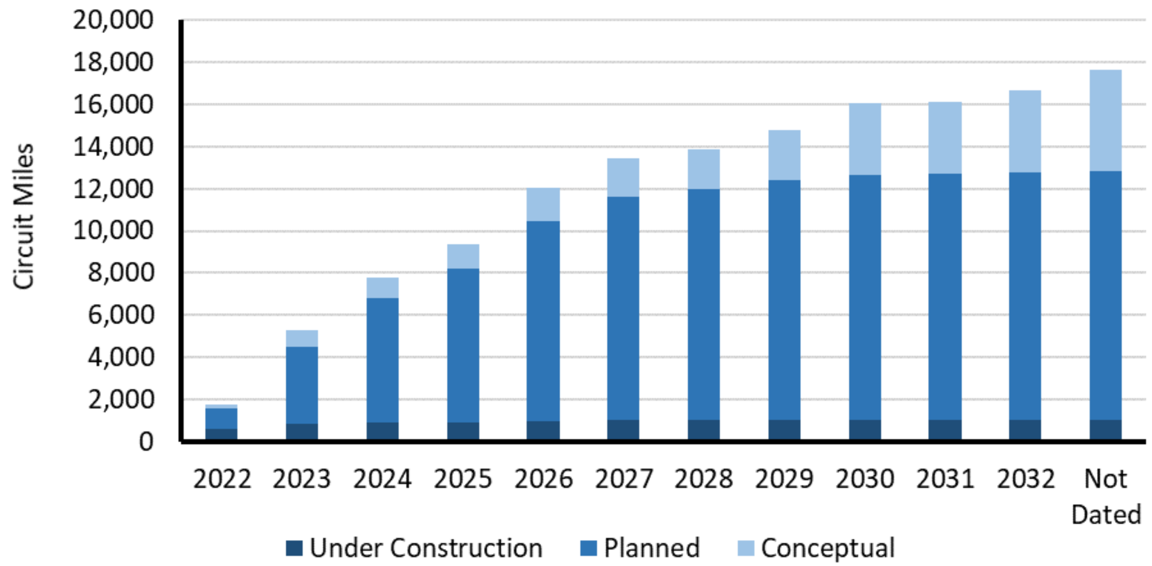


Figure 21: Future Transmission Circuit Miles >100 kV by Project Status

New transmission projects are being driven to support new generation and enhance reliability. **Figure 22** shows the percentage of future transmission circuit miles by primary driver. Most project miles are initiated to support grid reliability. Projects under construction or in planning to integrate renewables have grown from 1,589 miles reported in the *2021 LTRA* to 2,376 miles currently.

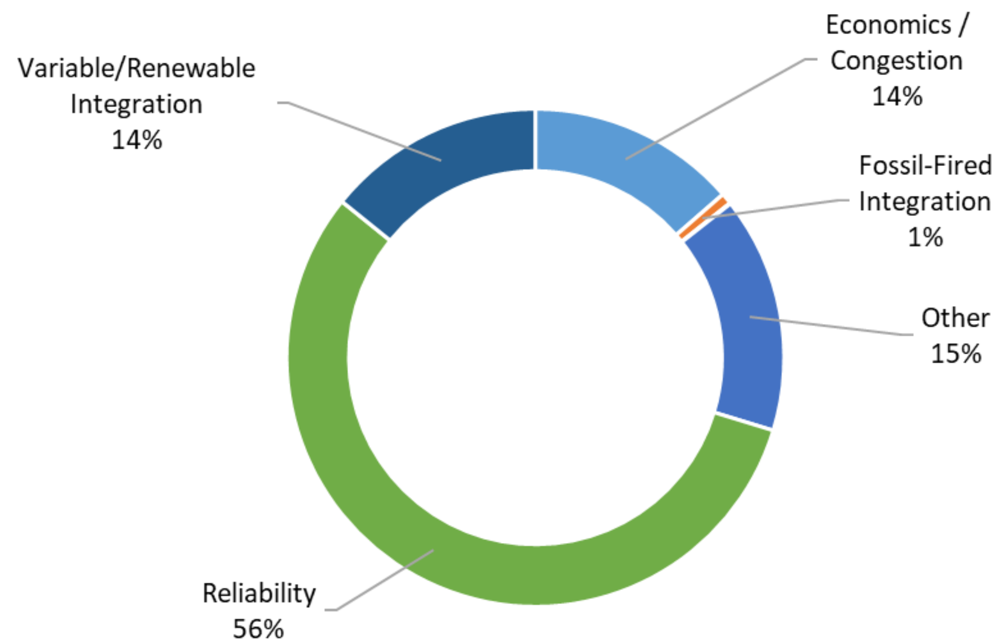


Figure 22: Future Transmission Circuit Miles by Primary Driver

Reliability Implications

Decarbonization goals must be developed with due consideration for transmission needs. Meeting the siting and grid development needs for new generation involves transmission development. Monitoring and managing transmission planning processes is a necessary part of maintaining reliability as the resource mix evolves.

Emerging Issues

In developing this *LTRA*, NERC and the industry considered trends and developments that have the potential to impact the future reliability of the BPS in the next 10-years and beyond. Discussed below are emerging issues and trends not previously covered in this report that have the potential to impact future long-term projections or resource availability and operations.

Electrification and Electric Vehicle Growth

Government policies for the adoption of EVs and other energy transition programs have the potential to significantly influence future demand and energy needs. For example, estimates from the California Energy Commission staff of the added electrical load from plug-in EV charging by 2030, under the state's zero-emission vehicle targets, indicate an additional 5,500 MW of demand at midnight and 4,600 MW of demand at 10:00 a.m. on a typical weekday. This is an increase of 25 and 20%, respectively at those times.[22] State and local policies for transitioning appliances and heating systems can also affect projections of electricity demand and daily load shapes, and these policies also have many ramifications for infrastructures other than the BPS. Industry demand forecasters have differing methods for projecting how EV adoption will impact future demand and many have not directly applied government policy targets to demand forecasts.

Cryptocurrency Impacts on Load and Resources

Due to unique characteristics of the operations associated with cryptocurrency mining, potential growth can have a significant effect on demand and resource projections. Computer operations for cryptocurrency mining are energy intensive, and mining operators can interrupt or scale operations in response to energy costs. ERCOT and their stakeholders and Texas regulators are working on resolving various policy, market, operational, and planning issues associated with interconnecting these large flexible loads and potentially using them as reliability resources.

Supply Chain and Other Factors Affecting Projections

Projections of future resources and transmission in this *LTRA* are based on industry data from the interconnection queues, representing only some of the myriad factors that will ultimately determine when and what gets completed. For resources to materialize and connect to the grid, substantial supply chain, planning, and commissioning processes must be completed. Timing is only an estimate, and some projects can be expected to be withdrawn from the interconnection process by developers. Having ample generating capacity in the interconnection queues to replace the nearly 60 GW of confirmed generation retirements projected over the 10-year assessment period (already a low indicator of future retirements) does not provide assurance that new capacity will be connected and available to meet future resource needs.

6 GHz Frequency Band Interference

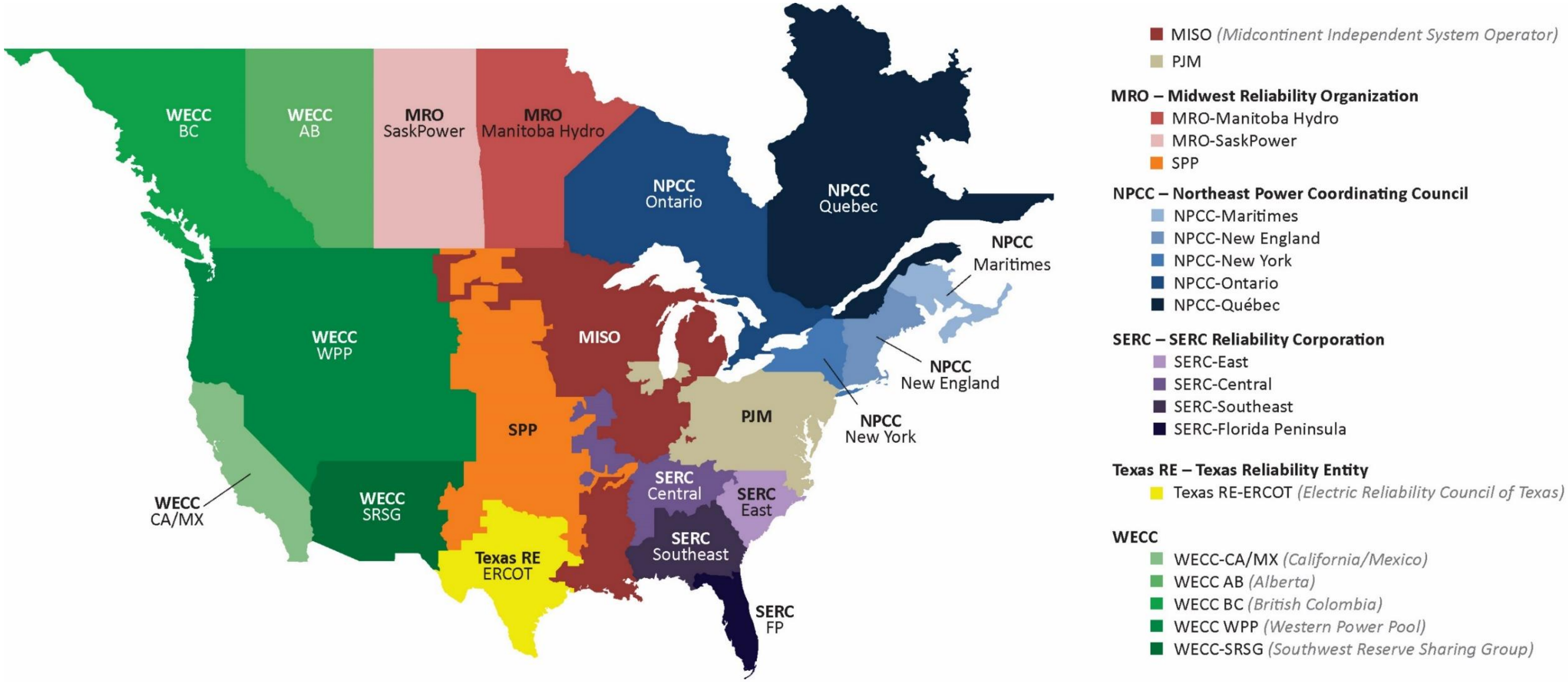
The ability of grid owners and operators to monitor and control BPS equipment and respond to grid events may impact future changes in the allocation of the frequency spectrum, constituting an emerging risk to BPS reliability. Growth in demand for wireless connectivity and the need to improve rural internet connectivity prompted the U.S. Federal Communications Commission (FCC) to issue a ruling in 2020 and propose further access changes that impact frequencies that was once restricted to licensed users, including many electric grid owners and operators.

Recent changes to U.S. communications regulations and pending future rules are increasing the risk that electric grid owners and operators will experience harmful interference on communications channels that are important for the reliable operation of the BPS. In April 2020, the FCC issued a report and order that partially opened spectrum in the 6 GHz band for unlicensed use.[23] Prior to this ruling, the 6 GHz band was restricted to use by an array of industries responsible for critical infrastructure, such as electric, natural gas and water utilities, railroads, and wireless carriers as well as by public safety and law enforcement officials. Electric utilities in the United States use communications systems operating in this frequency band as primary or alternate means for monitoring and controlling BPS equipment (via SCADA systems) and for voice communications with operators and field personnel. Subsequently, the FCC gave notice of further proposed rulemaking to fully open the 6 GHz band to unlicensed users with the removal of current restrictions on mobile device outdoor usage. Many electric grid owners and operators that use the 6 GHz band are anticipating impacts to their communications networks and are developing mitigation plans. Following an initial review and an industry survey conducted by a task force established by the NERC RSTC, NERC has identified that many grid operators continue to use the 6 GHz band for their critical communications and many have not identified remediation plans to mitigate potential interference impacts.[24] Because of the expected growth of users in the 6GHz band and potential for increased interference, NERC is taking action to determine the level of impact that the regulation changes have on BPS reliability and develop mitigation to reduce the risks.

[22] See, for example, California Energy Commission Revised Staff Report *Assembly Bill 2127 Electric Vehicle Charging Infrastructure Assessment*: https://efiling.energy.ca.gov/getdocument.aspx?tn=238032
[23] https://www.fcc.gov/document/fcc-opens-6-ghz-band-wi-fi-and-other-unlicensed-uses-0
[24] https://www.nerc.com/comm/RSTC/6GHTZF/6GHZ%20Communication%20Network%20Extent%20of%20Condition%20White%20Paper.pdf

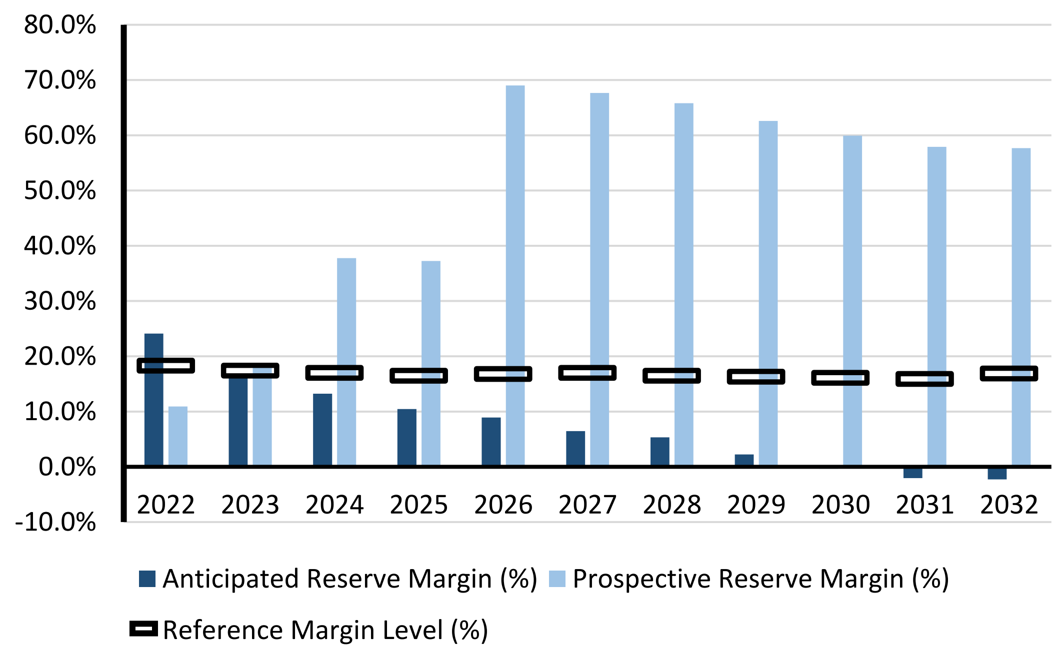
Regional Assessments

The following regional assessments were developed based on data and narrative information collected by NERC from the Regional Entities on an assessment area basis. In addition, NERC published additional *2022 LTRA* assessment area data in supplemental tables on the Reliability Assessments web page.[25] The Reliability Assessment Subcommittee, at the direction of NERC's RSTC, supported the development of this assessment through a comprehensive and transparent peer review process that leveraged the knowledge and experience of system planners, Reliability Assessment Subcommittee members, NERC staff, and other subject matter experts. This peer review process promotes the accuracy and completeness of all data and information.

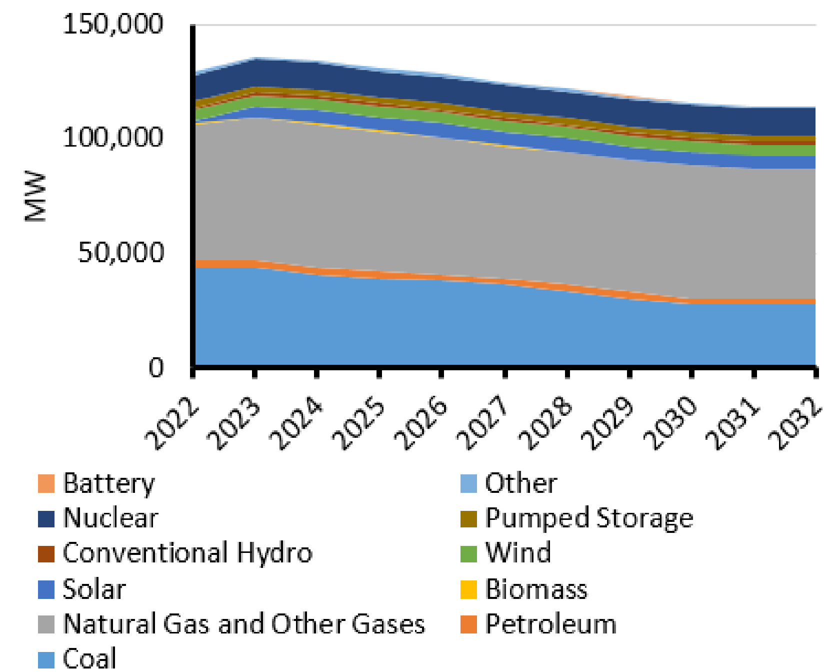


[25] See the NERC Reliability Assessments page here: https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx

Demand, Resources, and Reserve Margins (MW)										
Quantity	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Total Internal Demand	124,950	126,091	126,212	126,298	126,631	126,965	127,240	127,652	128,320	128,317
Demand Response	6,158	6,189	6,116	6,130	6,131	6,051	6,052	6,054	6,050	6,017
Net Internal Demand	118,792	119,902	120,096	120,168	120,500	120,914	121,188	121,599	122,269	122,300
Additions: Tier 1	6,605	8,253	8,311	8,311	8,311	8,311	8,311	8,311	8,311	8,311
Additions: Tier 2	2,322	30,796	35,517	76,576	78,071	78,096	78,096	78,096	78,096	78,096
Additions: Tier 3	2,193	3,504	5,501	6,055	8,581	9,331	10,538	11,621	12,226	12,409
Net Firm Capacity Transfers	1,593	1,598	767	767	663	593	598	493	493	155
Existing-Certain and Net Firm Transfers	131,538	127,506	124,353	122,572	119,986	119,034	115,593	112,865	111,440	111,204
Anticipated Reserve Margin (%)	16.3%	13.2%	10.5%	8.9%	6.5%	5.3%	2.2%	-0.3%	-2.1%	-2.3%
Prospective Reserve Margin (%)	18.2%	38.9%	40.0%	72.6%	71.3%	69.9%	66.7%	63.9%	61.8%	61.6%
Reference Margin Level (%)	17.4%	17.0%	16.5%	16.8%	17.0%	16.5%	16.3%	16.1%	15.9%	16.9%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- MISO is facing resource shortfalls across this entire assessment period. Since the *2021 LTRA*, 5,900 MW of generation has retired (mostly coal-fired generators) and 1,700 MW of new generation has been added (approximately 700 MW natural-gas-fired, 400 MW Solar, 100 MW wind, and 300 MW pumped storage. In the summer of 2023, MISO's capacity shortfall is projected to be 1,395 MW even after adding over 6.5 GW of new generation with signed interconnection agreements. More additions from the planning queue are not likely to be completed in sufficient quantity to make up for the capacity shortfall.
- MISO's Reliability Imperative Initiative is designed to lead the shared responsibility that utilities, states, and MISO have in addressing the ongoing generation fleet changes and the challenges of more frequent extreme weather events.

MISO Fuel Composition (MW)

Fuel	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Coal	44,102	40,951	39,159	38,066	36,351	33,846	30,415	28,133	28,133	28,133
Petroleum	2,800	2,800	2,707	2,707	2,697	2,697	2,697	2,524	2,451	2,451
Natural Gas	62,087	62,514	61,096	59,606	57,647	57,647	57,644	57,521	56,310	56,310
Biomass	375	375	375	375	304	273	273	240	240	240
Solar	4,753	5,852	5,829	5,828	5,828	5,827	5,827	5,826	5,826	5,826
Wind	4,645	4,689	4,741	4,739	4,730	4,682	4,670	4,660	4,654	4,654
Conventional Hydro	1,416	1,416	1,416	1,416	1,416	1,416	1,416	1,416	1,280	1,280
Pumped Storage	2,617	2,617	2,617	2,617	2,617	2,617	2,617	2,617	2,617	2,617
Nuclear	11,711	11,711	11,711	11,711	11,711	11,711	11,711	11,711	11,711	11,711
Other	1,280	1,280	1,257	1,224	1,224	1,224	1,224	1,224	1,224	1,224
Battery	20	20	20	20	20	20	20	20	20	20
Total MW	135,805	134,224	130,927	128,308	124,544	121,959	118,513	115,891	114,465	114,465

MISO Assessment

Planning Reserve Margins

MISO is projecting a decrease from last year's reserve margins with planned reserves falling below reference margin levels beginning in 2023. The reserve decline is driven mainly by lower capacity contribution from weather dependent new generation additions that are replacing retiring units with higher contributions. Increasing demand projections also contribute to lower reserve margins. Increased coordination and continued action with MISO members will be critical to ensuring resource adequacy into the future. In most of the MISO area, LSEs with oversight by the applicable state or local regulators are responsible for resource adequacy.

Non-Peak Hour Risk, Energy Assurance, Probabilistic Based Assessments

Seasonal resource assessments evaluate unit availability, outage rates, and forecasted load varies across all four seasons. MISO has also initiated a change to a seasonal capacity construct that promotes energy adequacy by evaluating how each resource and resource type helps to serve load at periods of peak risk in each season.

Probabilistic Assessment

In the Base Case results, most of the LOLHs occur in June–August, corresponding to the typical MISO peak time frame. There are some instances of LOLHs occurring in September–October when seasonal planned outages overlap with high demand. The winter also experiences a small amount LOLH when cold temperatures push demand higher than normal.

Non-peak risk drivers tend to be unique to the season. In the fall, the risk of unseasonably high demand overlapping with seasonal planned outages increases the loss of load risk. Extreme cold weather, particularly in MISO South, increases demand and causes the risk of loss of load to increase

The ProbA analyzes all hours of the year; whereas, the LTRA is only looking at 10-year summer/winter peak forecasts. As a result, the ProbA provides more insight into intra-yearly system risks that may occur during non-peak periods, and the LTRA highlights longer-term resource adequacy planning concerns.

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	14.3	193.6	68.8
EUE (ppm)	0.02	0.304	0.108
LOLH (Hours per Year)	0.085	0.808	0.393
Operable On-peak Margin	13.7%	8.1%	13.9%

* Provides the 2020 ProbA results for comparison

For the 2022 ProbA Risk Scenario, MISO is investigating how the risk changes as a result of modeling seasonal average, rather than annual average, outage rates along with correlated cold weather outages.

Demand

The peak demand forecast increased from last year by approximately 1.1 GW, largely due to a rebound from COVID-related decline. The five-year regional demand growth remained stable at a relatively flat 0.2%. It is unclear how electrification of transportation and other sectors will drive future growth, but anticipated electrification is considered in the MISO Transmission Expansion Plan (MTEP) process.

Demand Side Management

DR programs continue to play an important role in providing capacity. While DR projections are shown to be decreasing over this assessment period, this trend may change following the 2022 resource auction, OMS-Survey, and in the transition to seasonal capacity auctions.

Distributed Energy Resources

MISO estimates that there is a total of 860 MW of installed solar PV distribution resource capacity. While DERs are anticipated to play a larger role into the future, MISO is still working with stakeholders on adequate methods for aggregating, reporting, and allowing DER participation in MISO markets.

Generation

Since the *2021 LTRA*, MISO has retired 5,000 MW of generation and added 1,700 MW of new generation for a net change of 3,300 MW (on-peak capacity).

The MISO generator interconnection queue continues to show steadily increasing levels of VERs, including battery storage and hybrid resources, in the future generation fleet mix. Currently 300 MW of grid-connected batteries are installed with another 15 GW in the interconnection planning queue and 16 GW of hybrid battery-renewable generation in queue. This transition of the generation fleet, along with the observed impacts from extreme weather events, such as Hurricane Laura in 2020 and Winter Storm Uri in February 2021, continue to stress the importance of the MISO Resource Adequacy construct. Appropriate planning and operating signals must be sent to prompt investment (or system enhancements) when needed to ensure that the BPS continues to perform reliably.

Capacity Transfers

Net firm transfers with neighboring areas declined from the prior *LTRA* and continue to decline as reported in this year's *LTRA*; for the summer of 2023, firm transfer commitments have fallen by nearly 25%. Non-firm transfers have played a critical role in maintaining reliability during extreme weather events. A growing reliance on non-firm imports increases the risk of energy emergencies when external transfer assistance is not available.

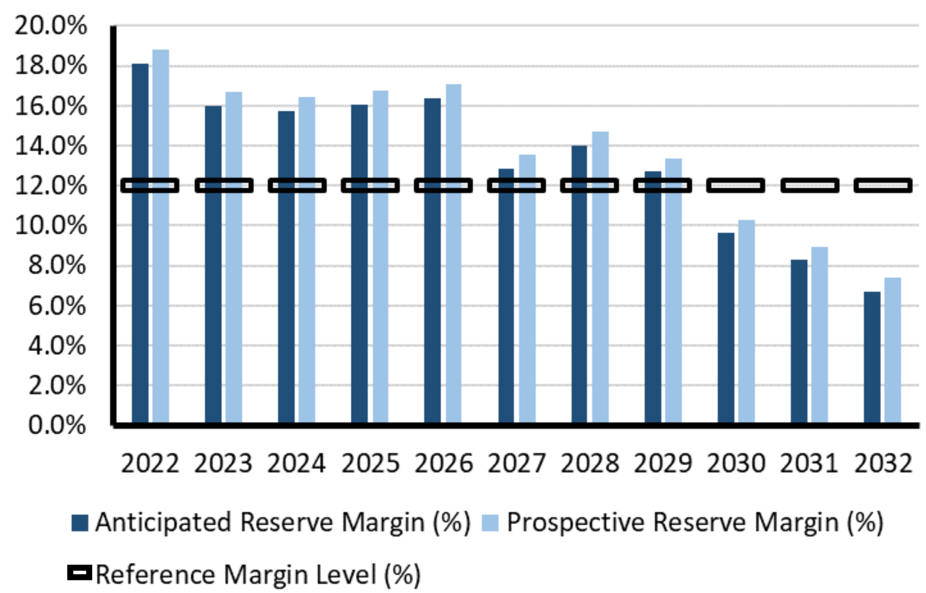
Transmission

Approved transmission projects increased since the *2021 LTRA*. In the latest MTEP (MTEP21), 33% of projects are classified as "reliability" projects that are needed to maintain system reliability in accordance with NERC Reliability Standards. Another 47% are for replacing aging equipment, and the remaining 20% are for the integration of new resources and to accommodate load growth. In addition, MISO's Long Range Transmission Plan introduced a $10.3 billion transmission project portfolio in the upper-Midwest that was appended to MTEP21 transmission projects in summer of 2022. These lines are expected to support 53 GW of renewable energy and provide $23–52 billion in benefits to MISO utilities.

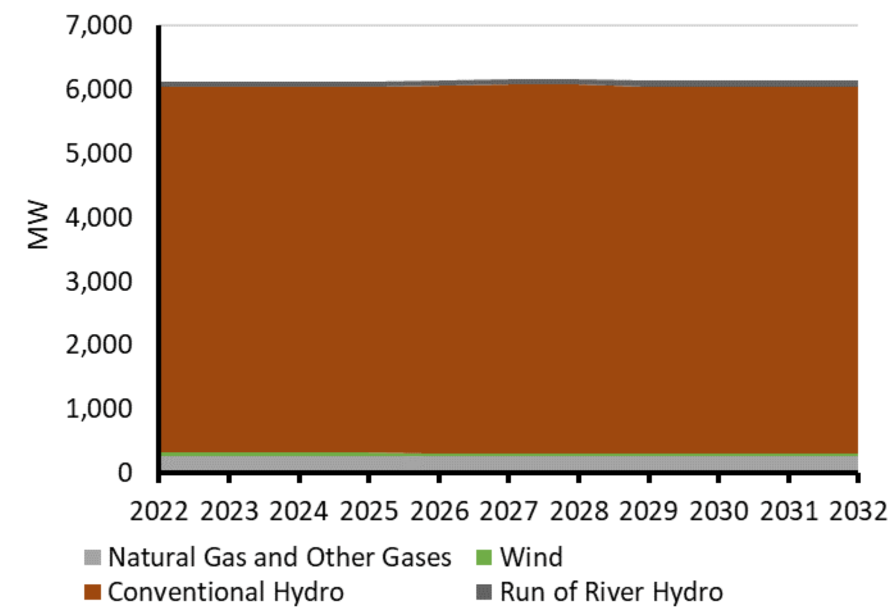
Reliability Issues

MISO's planning, markets and operations continue to evolve in response to the changing resource fleet and the increased frequency of extreme weather events. Managing the increasing uncertainty is a key component of the market redefinition effort and includes transitioning to a seasonal resource adequacy construct, reforming accreditation, and enhancing scarcity pricing to better align system needs and capabilities during tight operating conditions. The seasonal resource adequacy construct has been filed at FERC and will be effective in September 2022 ahead of the 2023/2024 Planning Resource Auction. MISO is awaiting FERC approval of the updated tariff provisions.

Demand, Resources, and Reserve Margins (MW)										
Quantity	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Total Internal Demand	4,622	4,628	4,638	4,650	4,844	4,862	4,894	4,945	5,008	5,080
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	4,622	4,628	4,638	4,650	4,844	4,862	4,894	4,945	5,008	5,080
Additions: Tier 1	279	279	279	331	340	340	337	337	337	337
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-622	-627	-587	-587	-542	-466	-471	-565	-565	-565
Existing-Certain and Net Firm Transfers	5,083	5,078	5,103	5,082	5,127	5,203	5,179	5,086	5,086	5,086
Anticipated Reserve Margin (%)	16.0%	15.8%	16.0%	16.4%	12.9%	14.0%	12.7%	9.6%	8.3%	6.7%
Prospective Reserve Margin (%)	16.7%	16.5%	16.7%	17.1%	13.5%	14.7%	13.4%	10.3%	8.9%	7.4%
Reference Margin Level (%)	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- MRO-Manitoba Hydro ARM is above the RML throughout the first five-years of this assessment period.
- All seven units at the Keeyask hydro station (630 MW net addition) are anticipated to be in commercial operation for the winter of 2022/2023.
- The Manitoba Hydro system is not currently experiencing the large additions of wind and solar generation or thermal generation retirements as seen in some other assessment areas. The predominately hydro nature of the system is not expected to change during this assessment period.

MRO-Manitoba Hydro Fuel Composition (MW)										
Fuel	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Natural Gas	278	278	278	278	278	278	278	278	278	278
Wind	52	52	52	52	31	31	31	31	31	31
Conventional Hydro	5,706	5,706	5,706	5,758	5,767	5,767	5,745	5,745	5,745	5,745
Run-of-River Hydro	83	83	83	83	83	83	83	83	83	83
Total MW	6,119	6,119	6,119	6,150	6,159	6,159	6,137	6,137	6,137	6,137

MRO-Manitoba Hydro Assessment

Planning Reserve Margins

The ARM does not fall below the RML of 12% during the first five years of this assessment period. Lower reserve margins in the second half of this assessment period compared to the *2021 LTRA* are due to demand growth. No Tier 2 resources have been assumed to come into service during this assessment period. No resource adequacy issues are anticipated during the first five years of this assessment period.

Non-Peak Hour Risk, Energy Assurance, Probabilistic Based Assessments

As the operator of a predominately hydro system, Manitoba Hydro performs an all-hours season-ahead energy adequacy analysis on an at least weekly basis as required to manage near-term to season-ahead reservoir energy storage while meeting system demands. Additionally, Manitoba Hydro conducts specific analyses to determine short-term storage and minimum flow requirements that would be required to maintain Manitoba and extra-provincial resource adequacy obligations. As there are modest levels of wind and solar on the Manitoba Hydro system, the resource adequacy risk on the Manitoba Hydro system over the next five years and under normal water conditions is expected to fall at or very near the peak demand hours.

Probabilistic Assessments

Every two years, Manitoba Hydro prepares a probabilistic assessment for the Manitoba system, most recently in 2022. The probabilistic assessment was supportive of a 12% RML for the Manitoba system being sufficient to provide a loss of load expectation of less than 1-day-in-10 years under the study assumptions.

Probabilistic Assessment

The LOLH and EUE indices calculated for 2024 increase slightly as compared to the results obtained in 2020 assessment mainly due to some improvements in the model and larger forecast reserve margins.

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	3.383	28.64	7.23
EUE (ppm)	0.133	1.141	0.287
LOLH (Hours per Year)	0.004	0.036	0.007
Operable On-peak Margin	N/A	13.5%	13.5%

* Provides the 2020 ProbA results for comparison

Demand

Manitoba Hydro is projecting modest electricity load growth over the next five years. Factors considered in load growth projections include economic activity, EV adoption, and demand side management (DSM) programs in Manitoba operated by Efficiency Manitoba. The EV load forecast in Manitoba now assumes Canadian federal targets of zero emission vehicles reaching 10% of light-duty passenger vehicles sales by 2025, 30% by 2030, and 100% by 2040. Over this assessment period, Manitoba Hydro projects the total internal demand growth to increase at a compound annual growth rate (CAGR) of 0.56% for summer and 1.06% for winter.

Demand-Side Management

Manitoba Hydro does not have any DSM resources that are considered as controllable and dispatchable DR. There have been no modifications to the methods for controllable and dispatchable DR programs since the *2021 LTRA*.

Distributed Energy Resources

There is a potential for increased solar DER resources in the latter half of this assessment period, and plans are being developed to study the impacts on the Manitoba Hydro system.

Generation

All seven hydro units at the Keeyask Generating Station (630 MW net addition) are anticipated to be in commercial operation for the winter of 2022/2023. The completion of all seven units will improve resource adequacy for the remainder of this assessment period. Manitoba is not currently experiencing large additions of wind and solar resources being seen in other areas, so emerging reliability issues arising from such large wind and solar resource additions are not anticipated in the next five years.

Energy Storage

Additions of energy storage resources in the next 10 years are not anticipated at this time.

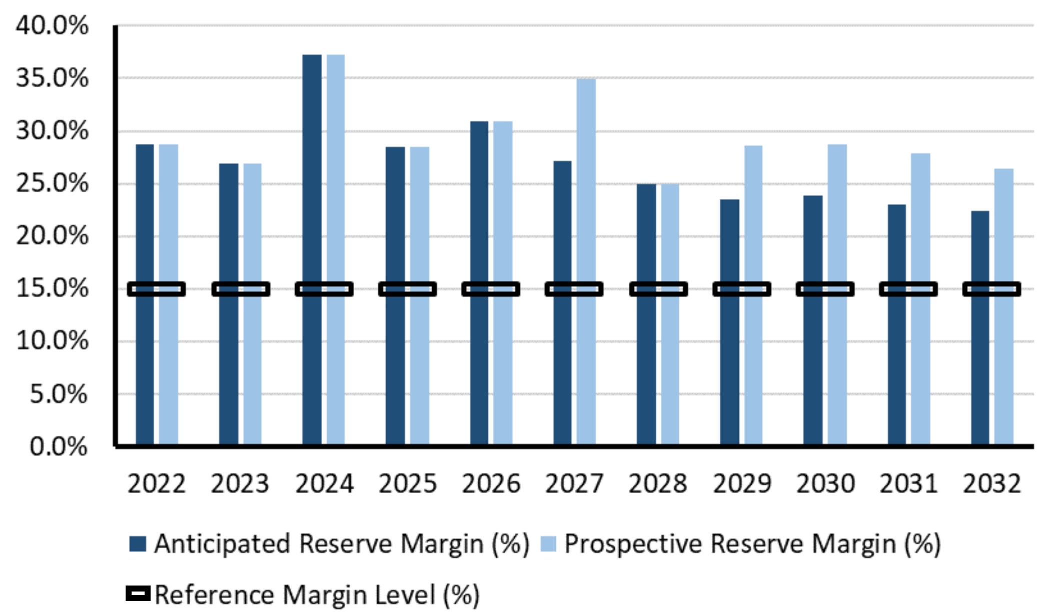
Capacity Transfers

A capacity transfer of 190/215 MW from Manitoba to Saskatchewan beginning June 1, 2022, will tend to increase east to west flow on the Manitoba–Saskatchewan interface. The 230 kV/ 390 MVA Birtle to Tantallon line, which will help facilitate this and other capacity transfers to Saskatchewan, was placed in service in March 2021.

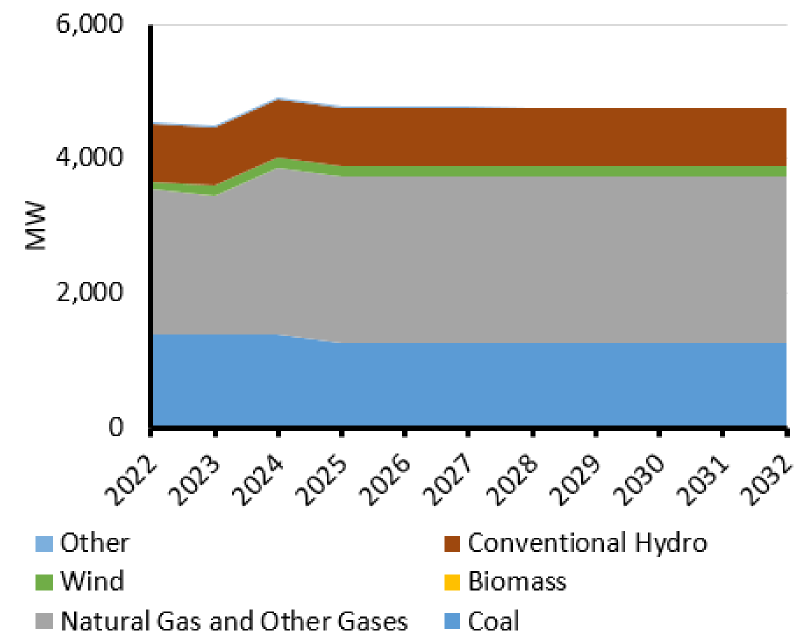
Transmission

The Manitoba to Minnesota Transmission Project, a major new 500 kV interconnection, was placed into service on June 1, 2020, and provides for alternative supply from the MISO market during drought conditions and improves the resilience of Manitoba Hydro’s system to extreme events, including drought. Manitoba Hydro currently has 86 miles of transmission under construction and 58 miles of planned transmission during the 10-year assessment period.

Demand, Resources, and Reserve Margins (MW)										
Quantity	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Total Internal Demand	3,804	3,827	3,916	3,940	3,999	4,056	4,101	4,128	4,156	4,178
Demand Response	67	67	67	67	67	67	67	67	67	67
Net Internal Demand	3,737	3,760	3,849	3,873	3,932	3,989	4,034	4,061	4,089	4,111
Additions: Tier 1	40	461	506	506	506	506	506	506	506	506
Additions: Tier 2	0	0	0	0	303	303	561	1,453	1,453	1,453
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	290	290	290	290	290	290	290	290	290	290
Existing-Certain and Net Firm Transfers	4,701	4,699	4,438	4,563	4,495	4,478	4,478	4,525	4,526	4,526
Anticipated Reserve Margin (%)	26.9%	37.2%	28.4%	30.9%	27.2%	24.9%	23.5%	23.9%	23.1%	22.4%
Prospective Reserve Margin (%)	26.9%	37.2%	28.4%	30.9%	34.9%	25.0%	28.6%	28.7%	27.8%	26.4%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- MRO-SaskPower's ARM is above the RML (15%) throughout this assessment period.
- SaskPower is adding approximately 760 MW of new generation within the next five years, including a 200 MW installed capacity wind generation facility and a 377 MW natural gas facility. Confirmed retirements in the area total approximately 340 MW.
- A long-term firm capacity transfer of 190 MW from Manitoba to Saskatchewan began in 2022.

MRO-SaskPower Fuel Composition (MW)										
Fuel	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Coal	1,390	1,390	1,251	1,251	1,251	1,251	1,251	1,251	1,251	1,251
Natural Gas	2,053	2,473	2,478	2,478	2,478	2,478	2,478	2,478	2,478	2,478
Biomass	3	3	3	3	3	3	3	3	3	3
Wind	164	164	164	164	164	162	162	162	162	162
Conventional Hydro	862	862	862	862	862	862	862	862	862	862
Other	22	22	22	22	17	1	1	1	1	1
Total MW	4,492	4,913	4,778	4,778	4,773	4,755	4,755	4,755	4,755	4,755

MRO-SaskPower Assessment

Saskatchewan uses a criterion of 15% as the Reference Reserve Margin and has assessed its PRM for the upcoming 10 years considering the summer and winter peak hour loads, available existing and anticipated generating resources, firm capacity transfers, and available DR for each year. Saskatchewan's ARM ranges from approximately 20–37% and does not fall below the RML.

Probabilistic Assessment

Saskatchewan has planned for adequate resources to meet anticipated load and reserve requirements for this assessment period. The major contribution to the EUE is due to some of the Saskatchewan's hydroelectric units requiring extended maintenances through winter peak season for the life extension and upgrade of associated components. The planned maintenance on the hydro units is segregated to minimize adverse impact on the system reliability.

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	26.5	169.5	117.0
EUE (ppm)	1.1	6.5	4.4
LOLH (Hours per Year)	0.3	1.4	0.9
Operable On-peak Margin	22.8%	23.1%	24.6%

* Provides the 2020 ProbA results for comparison

Saskatchewan's system peak forecast is contributed by econometric variables, weather normalization, and individual level forecasts for large industrial customers. Average annual summer and winter peak demand growth is expected to be approximately 1.0% with a range from 0.5–2.3% throughout this assessment period.

Saskatchewan is adding approximately 761 MW of generation under Tier 1 category within the next five years, including a 200 MW wind generation facility, two utility-scale solar projects (10 MW each), and the expansion of two existing natural gas facilities as well as two new natural gas facilities for a total of 687 MW. The remaining capacity (74 MW) is projected to be carbon neutral and waste heat recovery projects.

Under Tier 2, over 1,462 MW of new generation is projected in this assessment period. This includes six natural gas facilities. The natural gas generation is a proxy holder for any new generation needed beyond the medium-term (>5 years), but a portion of this capacity is anticipated to be covered through deploying renewables, carbon neutral, and low emission generation projects.

A total of approximately 343 MW is confirmed for retirements. This includes 139 MW of coal generation, 41 MW of natural gas, 21 MW of heat recovery facilities, 22 MW of wind facilities and 25 MW of hydro import contract. Unconfirmed retirements of approximately over 1,400 MW is also expected in this assessment period. This includes approximately 1,200 MW of coal generation that will be phased out by the end of 2029. Generating resources being planned as Tier 2 and Tier 3 will replace the retired units before retirements, so Saskatchewan is not expecting any long-term reliability impacts due to generation retirements.

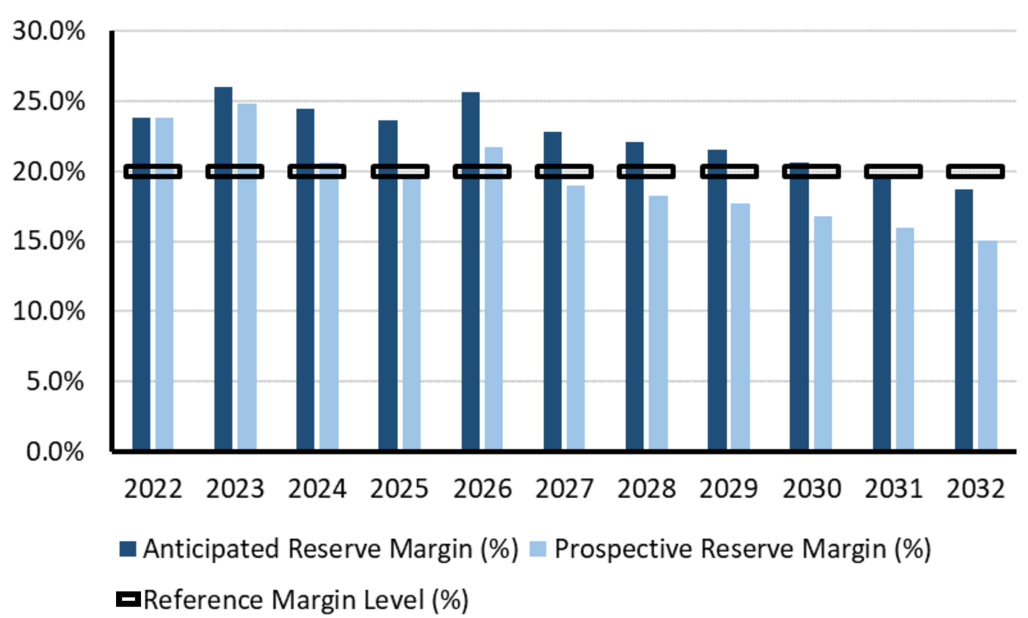
Saskatchewan's EE and energy conservation programs include incentive-based and education programs that focus on installed measures and products that provide verifiable, measurable, and permanent reductions in electrical energy and demand during peak hours. Energy provided from EE and DSM programs are modeled as load modifiers and are netted from both the peak load and energy forecasts. Saskatchewan's DR program has contracts in place with industrial customers for interruptible load based on defined DR programs. The first of these programs provides a curtailable load, currently up to 67 MW, with a 12-minute event response time. Other programs are in place that provide access to additional curtailable load that require up to two hours notification time.

Saskatchewan has interconnection agreements with Manitoba Hydro, Southwest Power Pool, and Alberta Electric System Operator. Saskatchewan currently has contracts in place for firm capacity transfers for up to 290 MW from Manitoba Hydro within this assessment period.

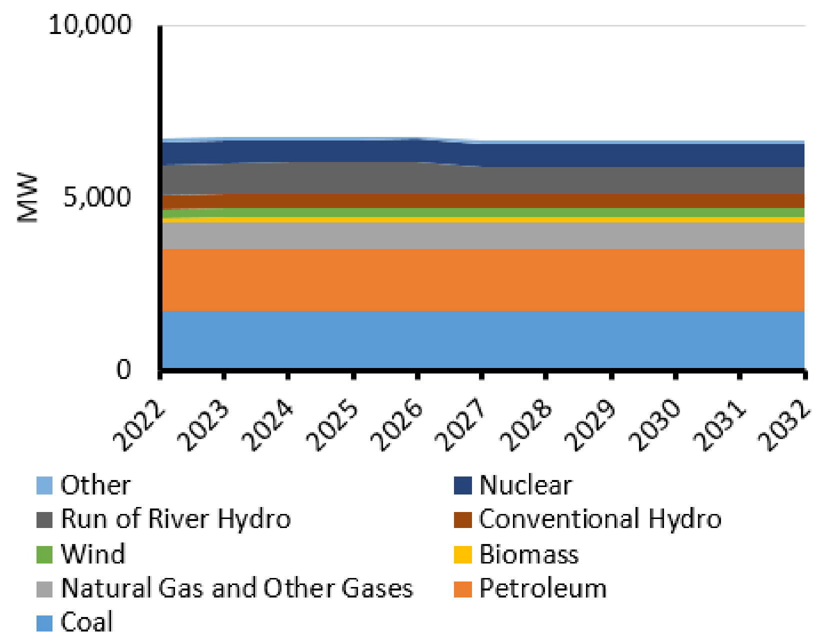
Approximately 80 km of 230 kV transmission line is under construction phase, and several other transmission projects (approximately 650 circuit km) are under the planning and conceptual phase in the 5–10-year planning horizon. These projects are driven by load growth, new generation additions and reliability needs. Saskatchewan also has its first Battery Energy Storage System, a 20 MW/20MWh facility under-construction.

SaskPower performs transmission planning studies, including the annual transmission planning assessment and other applicable periodic studies to meet NERC requirements, system impact studies for new load/generation interconnections, generation retirements, transmission service request studies, area adequacy studies, and other special studies as required to identify potential system issues. Mitigations are identified as part of these studies and included in the system development plan to ensure system performance requirements are met.

Demand, Resources, and Reserve Margins (MW)										
Quantity	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total Internal Demand	5,636	5,727	5,750	5,772	5,805	5,840	5,862	5,905	5,945	5,994
Demand Response	302	320	333	337	336	335	335	334	333	333
Net Internal Demand	5,334	5,406	5,417	5,435	5,469	5,504	5,528	5,571	5,611	5,661
Additions: Tier 1	14	39	39	39	39	39	39	39	39	39
Additions: Tier 2	0	254	254	254	254	254	254	254	254	254
Additions: Tier 3	5	21	177	237	487	554	754	804	804	804
Net Firm Capacity Transfers	81	63	31	153	153	153	153	153	153	153
Existing-Certain and Net Firm Transfers	6,709	6,691	6,659	6,789	6,679	6,679	6,679	6,679	6,679	6,682
Anticipated Reserve Margin (%)	26.1%	24.5%	23.7%	25.6%	22.8%	22.1%	21.5%	20.6%	19.7%	18.7%
Prospective Reserve Margin (%)	24.8%	20.6%	19.8%	21.7%	19.0%	18.2%	17.7%	16.8%	16.0%	15.0%
Reference Margin Level (%)	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The Maritimes Area peak loads are expected to increase by 9.7% during summer and by 6.3% during winter seasons over the 10-year assessment period. This translates to compound average growth rates of 1% in summer and 0.6% in winter. The Maritimes Area annual energy forecasts are expected to increase by a total of 1.2% during the 10-year assessment period for an average growth of 0.1% per year.
- The Maritimes Link, an undersea HVDC undersea cable connection to the Canadian province of Newfoundland and Labrador, began service in late 2017. This cable, in conjunction with the construction of the Muskrat Falls hydro development in Labrador, presently provides for a 150 MW firm capacity import to NS. 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 NS, 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 in this assessment. The Maritime Link could also potentially provide a source for imports from NS into NB that would reduce transmission loading in the southeastern NB area.

NPCC-Maritimes Fuel Composition (MW)										
Fuel	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Coal	1,695	1,695	1,695	1,695	1,695	1,695	1,695	1,695	1,695	1,695
Petroleum	1,843	1,843	1,843	1,843	1,843	1,843	1,843	1,843	1,843	1,843
Natural Gas	760	760	760	760	760	760	760	760	760	760
Biomass	129	129	129	129	129	129	129	129	129	129
Wind	250	275	275	275	275	275	275	275	275	275
Conventional Hydro	410	410	410	410	410	410	410	410	410	413
Run-of-River Hydro	902	902	902	902	792	792	792	792	792	792
Nuclear	663	663	663	671	671	671	671	671	671	671
Other	90	90	90	90	90	90	90	90	90	90
Total MW	6,743	6,768	6,768	6,776	6,666	6,666	6,666	6,666	6,666	6,669

NPCC-Maritimes Assessment

Planning Reserve Margins

The reference RML used for the Maritimes area is 20%. The ARM during the winter period ranges from 19–25% and ranges from 70–87% during the summer period for the 10-years of this *LTRA* study.

Non-Peak Hour Risk, Energy Assurance, Probabilistic Based Assessments

The ARM level during off-peak season for the Maritimes area ranges between 70–87%. During off peak hours, the Maritimes area has surplus generation available to meet the energy needs, so there are no constraints with converting the capacity to energy during these times.

Probabilistic Assessments (ProbA and Other Studies)[26]

The two Balancing Authorities (BA) within the Maritimes area, as members of NPCC, jointly prepare annual interim or comprehensive probabilistic assessment reviews that cover three- to five-year forward-looking periods for both the area's transmission system and resource adequacy evaluations. In addition, the Maritimes area also supports NERC's annual seasonal probabilistic assessments, which provides an evaluation of generation resource and transmission system adequacy; this will be necessary to meet projected seasonal peak demands and operating reserves.

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	1.125	1.838	3.869
EUE (ppm)	0.039	0.06	0.138
LOLH (Hours per Year)	0.023	0.023	0.071
Operable On-peak Margin	16.7%	25%	22.9%

* Provides the 2020 ProbA results for comparison

The Forecast 50/50 Peak Demand for year 2024 is similar in this ProbA as that reported in the previous ProbA. With the Forecast Capacity Resources declining slightly, a slight increase in estimated LOLH and EUE is observed between the two assessments. The Maritimes Area is winter peaking and EUE risk occurs during the winter months. The estimated EUE is negligible.

Demand

There is no regulatory requirement for a single authority to produce a forecast for the whole Maritimes area; thus, the peak area demand occurs in winter and is highly reliant on the forecasts of the two largest sub-areas of New Brunswick and Nova Scotia, which are historically highly coincidental (typically between 97% and 99%). Therefore, demand for the Maritimes area is determined to be the non-coincident sum of the peak loads forecasted by the individual sub-areas, and the aggregated growth of both demand and energy for the combined sub-areas see an upward trend over summer and winter seasonal periods of the LTRA assessment period. The Maritimes area peak loads are expected to increase by 9.7% during summer and by 6.3% during winter seasons over the 10-year assessment period. This translates to compound average growth rates of 1.03% in summer and 0.69% in winter. The Maritimes area annual energy forecasts are expected to increase by a total of 1.2% during the 10-year assessment period for an average growth of 0.1% per year.

Demand-Side Management

Plans to develop up to 100 MW by 2030/2031 of controllable direct load control programs with smart grid technology to selectively interrupt space and/or water heater systems in residential and commercial facilities are underway; however, no specific annual demand and energy saving targets currently exist. During the 10-year assessment period in Maritimes, annual amounts for summer peak demand reductions associated with EE and conservation programs rise from 23 MW to 186 MW while the annual amounts for winter peak demand reductions rise from 93 MW to 550 MW. [27]

Distributed Energy Resources

The DER installed capacity in Nova Scotia is approximately 235 MW at present, including distribution-connected wind projects under purchase power agreements, small community wind projects under a feed-in tariff, and BTM solar. Based on a loss of load expectation (LOLE) analysis, the existing wind resources are assumed to have an ELCC of 18% and BTM solar is assumed to have an ELCC of 0%. The Maritimes area has shown embedded BTM solar PV projections of 70 MW in 2022 rising to 327 MW by 2032. These projects include distributed small-scale solar (mainly rooftop) that fall under the net metering program and serve as a reduction in load mainly in the residential class. The forecasted increase in solar installations in the coming years is a result of initiatives that include municipal and provincial incentive programs mainly in Nova Scotia and Prince Edward Island. There is no capacity contribution from solar generation due to the timing of area's system peak (the winter period).

[26] NPCC resource adequacy documents are posted in the NPCC library: https://www.npcc.org/program-areas/rapa/resource-adequacy

[27] Current and projected EE effects based on actual and forecasted customer adoption of various DSM programs with differing levels of impact are incorporated directly into the load forecast for each of the areas but are not separately itemized in the forecasts. Since controllable space and water heaters will be interrupted via smart meters, the savings attributed to these programs will be directly and immediately measurable.

Generation
There are no new confirmed retirements in the *2022 LTRA* as compared to the *2021 LTRA*.

New Brunswick Power's 2020 Integrated Resource Plan assumes extending 28 MW of diesel-fired generation and 290 MW of natural-gas-fired generation, starting in 2025 and 2026 respectively. New Brunswick plans to add a Tier 1 community-owned wind project of 20 MW nameplate capacity in 2023. In New Brunswick, unconfirmed retirements include a hydro facility of 4 MW at the end of its service life pending regulatory approval and a 98 MW power purchase agreement contract.

In Nova Scotia, Tier 1 resources include wind projects with a total installed capacity of 350 MW phased-in from 2024/2025 with an ELCC of 10%. These projects are part of the provincial rate base procurement being undertaken by the procurement administrator appointed under the Electricity Act, assumed to represent 350 MW of additional wind. Tier 2 resources include a 200 MW battery resource and the conversion of a 150 MW coal unit to natural gas in late 2024. Tier 3 resources in Nova Scotia include natural gas additions (combustion turbines) of 150 MW in 2026 and 550 MW from 2027–2031 as well as new wind generation with a nameplate capacity of 435 MW phased in from 2025–2029. In addition, this assessment includes an expected firm import of 85 MW from the province of Newfoundland and Labrador starting in late 2023.

Small amounts of new solar generation capacity (Tier 2) of up to 31 MW are expected to be installed in Prince Edward Island in the 2022/2023 time frame. The island also plans to add (Tier 3) 50 MW of thermal capacity in 2026 as well as wind resources of 30 MW (late 2023) and 40 MW (2025–2026). Northern Main Independent System Administrator projects new solar additions (Tier 1–3) of approximately 117 MW name plate capacity during this LTRA study period.

New Brunswick derates its wind capacity using a calculated year-round equivalent capacity of 22%. Nova Scotia and Prince Edward Island derate wind capacity to 18% and 15%, respectively, of nameplate based on year-round calculated equivalent load carrying capabilities for their respective individual sub-areas. The peak capacity contribution of grid based solar is estimated at zero since the Maritimes area peak occurs in the winter either before sunrise or after sunset.

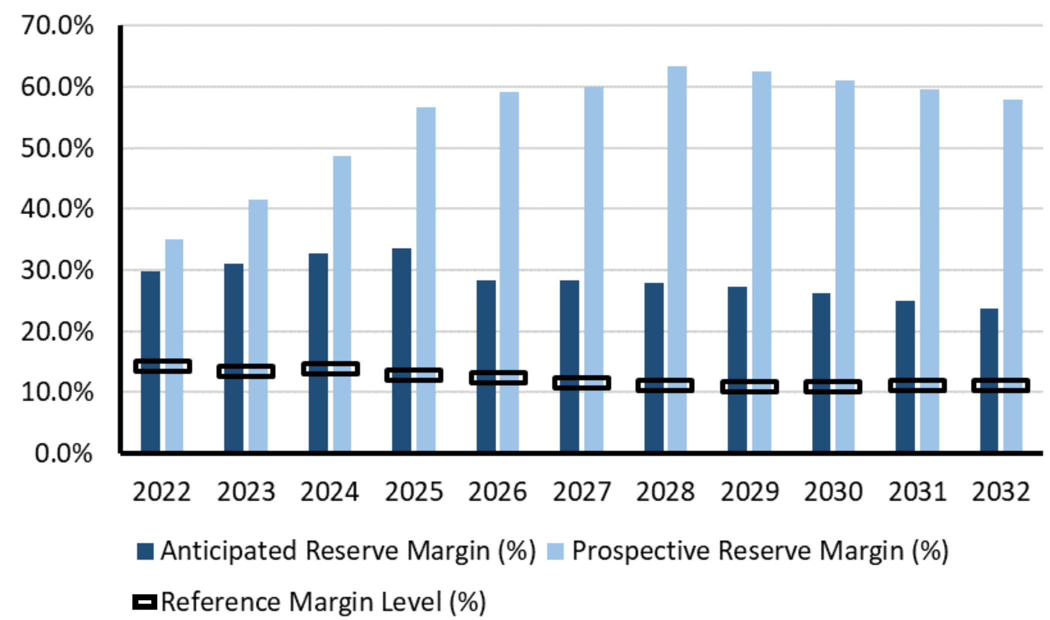
Energy Storage
Nova Scotia plans to add a 200 MW (4-hour duration) Tier 2 battery resource in late 2024. Pilot projects and internal studies are underway to further understand the economics, application, and performance of battery storage resources. Ongoing internal analyses are conducted by New Brunswick Power to determine the cost and benefit associated with battery storage options and dispatching these resources to reduce/shift peaks; these analyses are in a preliminary stage. The value of energy storage options is expected to increase as the technology improves and as New Brunswick's smart grid network develops. These studies would be evaluated further as the economics around these options become viable.

Capacity Transfers
Probabilistic studies show that the Maritimes area is not reliant on inter-area capacity transfers to meet NPCC resource adequacy criteria.

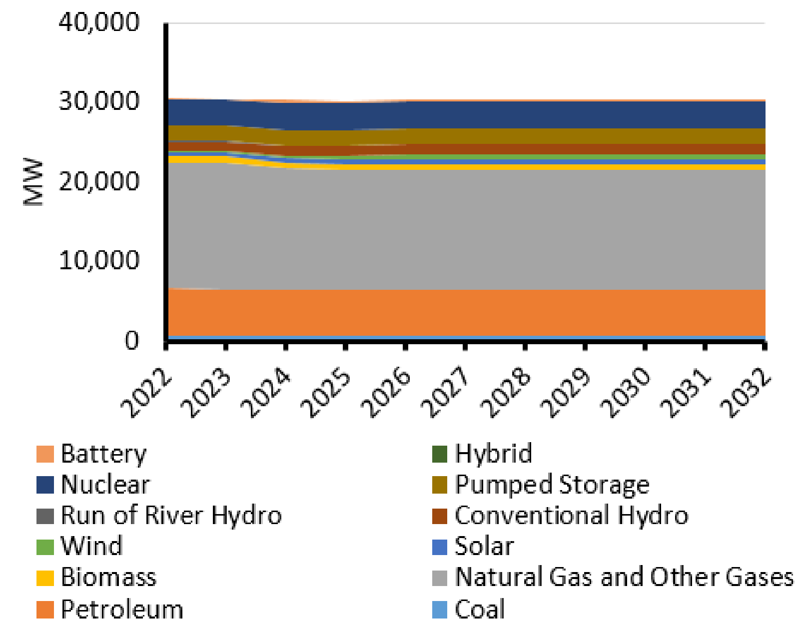
Transmission
Construction of a 475 MW +/-200 kV high voltage direct current (HVDC) undersea cable link (Maritime Link) between Newfoundland and Nova Scotia was completed in late 2017. This cable, in conjunction with the construction of the Muskrat Falls hydro development in Labrador, presently provides 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 NS, if needed, to provide firm capacity and maintain an adequate planning reserve margin for the upcoming winter of 2022/2023. The unconfirmed retirement of this coal unit is shown in 2023 in 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 the Southeastern New Brunswick area. There are currently no planned or under construction transmission projects.

Reliability Issues
There are no known resource adequacy issues that affect the Maritimes area reliability that are unique to the Maritimes area. The Maritimes area has a diversified mix of capacity resources fueled by oil, coal, hydro, nuclear, natural gas, wind (derated), dual fuel oil/natural gas, tie benefits, and biomass with no one type feeding more than about 28% of the total capacity in the area. Although there is not a high degree of reliance upon any one type or source of fuel, supply chain issues may affect fuel procurement; the situation is being monitored. The Maritimes area does not anticipate fuel disruptions that pose significant challenges to resource during this assessment period. This resource diversification also provides flexibility to respond to any future environmental issues, such as potential restrictions to greenhouse gas emissions.

Demand, Resources, and Reserve Margins (MW)										
Quantity	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Total Internal Demand	24,633	24,600	24,579	24,592	24,631	24,722	24,869	25,071	25,322	25,576
Demand Response	592	678	765	765	765	765	765	765	765	765
Net Internal Demand	24,041	23,922	23,814	23,827	23,866	23,957	24,104	24,306	24,557	24,811
Additions: Tier 1	247	1,520	1,738	1,954	1,954	1,954	1,954	1,954	1,954	1,954
Additions: Tier 2	1,666	2,941	4,601	6,451	6,720	7,634	7,634	7,634	7,634	7,634
Additions: Tier 3	776	1,976	3,468	4,528	5,240	5,612	5,984	5,984	5,984	5,984
Net Firm Capacity Transfers	1,059	1,487	1,504	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	31,249	30,245	30,087	28,640	28,679	28,697	28,711	28,721	28,728	28,735
Anticipated Reserve Margin (%)	31.0%	32.8%	33.6%	28.4%	28.4%	27.9%	27.2%	26.2%	24.9%	23.7%
Prospective Reserve Margin (%)	41.5%	48.7%	56.6%	59.1%	60.1%	63.4%	62.5%	61.1%	59.5%	57.9%
Reference Margin Level (%)	13.5%	14.0%	12.9%	12.5%	11.5%	11.2%	11.0%	11.0%	11.2%	11.2%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- New England is forecast to have adequate generating capacity and a robust bulk transmission system to meet the peak seasonal forecast demands for electricity through the 10-year LTRA assessment period; however, ISO-NE has identified energy adequacy risks for the area.
- The overall system is transitioning to lower generator emissions with the development of renewable and clean energy resources. Beyond the *2022 LTRA* assessment horizon, additional imports of Canadian hydro-electricity, offshore wind, and new technologies (e.g., longer duration energy storage) will likely continue the trend toward a cleaner, albeit more complex power system.
- ISO-NE is addressing the issues brought on by grid transformation through a number of planning, operational, and market measures.

NPCC-New England Fuel Composition (MW)

Fuel	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Coal	636	636	636	636	636	636	636	636	636	636
Petroleum	5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829
Natural Gas	15,813	15,067	15,067	15,067	15,067	15,067	15,067	15,067	15,067	15,067
Biomass	998	992	992	992	992	992	992	992	992	992
Solar	355	476	476	476	476	476	476	476	476	476
Wind	204	359	577	793	793	793	793	793	793	793
Conventional Hydro	1,168	1,168	1,168	1,168	1,168	1,168	1,168	1,168	1,168	1,168
Run-of-River Hydro	154	154	154	154	154	154	154	154	154	154
Pumped Storage	1,889	1,889	1,889	1,889	1,889	1,889	1,889	1,889	1,889	1,889
Nuclear	3,346	3,346	3,346	3,346	3,346	3,346	3,346	3,346	3,346	3,346
Hybrid	29	29	29	29	29	29	29	29	29	29
Battery	29	354	354	354	354	354	354	354	354	354
Total MW	30,450	30,300	30,518	30,734	30,734	30,734	30,734	30,734	30,734	30,734

NPCC-New England Assessment

Planning Reserve Margins

ISO-NE's annual RML is based on the capacity needed to meet the ISO-NE and NPCC 1-day-in-10 years LOLE resource planning reliability criterion. The needed capacity, referred to as the installed capacity requirement (ICR), varies from year to year depending on projected system conditions (e.g., demand, generation, transmissions, capacity imports). The ICR is calculated on an annual basis and covers four years into the future. The latest calculations result in an RML of 13.5% in 2023, 14.0% in 2024, and 12.9% in 2025 as expressed in terms of the 50/50 peak demand forecast published in May 2021. For the years beyond the forward capacity market (FCM) time frame, this assessment uses the reserve margins associated with the representative ICR calculated in 2022 for 2026 through 2031. These margins range between 11.0% (2030) to 12.5% (2026). ISO-NE assumes 11.2% reserve margin for years beyond 2031 for study purposes.

Non-Peak Hour Risk, Energy Assurance, Probabilistic Based Assessments

ISO-NE's probabilistic and deterministic study results indicate that there are sufficient capacity resources to meet forecasts of summer and winter peak as well as energy demands during this 10-year assessment period. However, a previously identified/standing concern is whether there will be sufficient fuel available to satisfy electrical energy and operating reserve demands during an extended cold spell or a series of cold spells given the existing resource mix and regional fuel delivery infrastructure.

In 2018, ISO-NE initiated its Energy Assessment process, with the development of a 21-day forecast of projected system energy availability. Forecasts of weather, transmission topology, generation capability (including intermittent renewable resources), fuel inventories, known outages, pipeline constraints, and projected imports/exports all factor into a 21-day simulation of New England's energy production capability. Depending on the severity, projected energy deficiencies can trigger energy alerts or energy emergencies that are disseminated to market participants and federal and state regulators. This early notification of potential energy shortages should initiate actions by market participants as necessary to firm up their fuel supplies or replenish inventories in order to enhance supply-side capability.

Due to the importance of these type of studies, especially as the resource mix continues to transition to rely more on renewable resources, ISO-NE has undertaken several new projects to develop more enhanced deterministic and probabilistic energy-security analyses across varying time horizons. In addition, ISO-NE, with stakeholder input, is working on near- and long-term market improvements to expand the existing suite of energy and ancillary services that will cost effectively address uncertainties in firm electric energy production due to extreme weather or supply-chain limitations. All of these activities should directly enhance overall BES energy-security.

Probabilistic Assessments (ProbA and Other Studies)[28]

ISO-NE conducts various probabilistic resource adequacy (LOLE based) assessments annually to identify regional capacity resource needs and to comply with the annual NPCC area resource adequacy review requirements. In addition, ISO-NE participates in the NPCC ProbA studies to meet the biannual LTRA assessment requirements. In the transmission assessment domain, revisions to the ISO planning processes now reflect FERC Order 1000 requirements, probabilistic study assumptions, and changes to national and regional criteria. Coordinated transmission planning activities with other neighboring systems will continue, which can help state policymakers in New England achieve their objectives of accessing a greater diversity of resources from neighboring power systems.

Base Case Summary of Results			
	2024*	**2024**	**2026**
EUE (MWh)	58.62	0.139	0.016
EUE (ppm)	0.471	0.001	0.00
LOLH (Hours per Year)	0.095	0.00	0.00
Operable On-peak Margin	9.8%	32.6%	27.8%

* Provides the 2020 ProbA results for comparison

The Forecast 50/50 Peak Demand for year 2024 is similar in this ProbA as that reported in the previous ProbA. With comparable estimated Forecast Reserve Margins, a slight decrease in LOLH and EUE for 2024 was observed. The New York area is summer peaking and the EUE risk occurs during the summer months, however the EUE values are negligible.

[28] NPCC resource adequacy documents are posted in the NPCC library: https://www.npcc.org/program-areas/rapa/resource-adequacy

Demand

Over the 10-year planning horizon, the forecast net internal summer peak demand increases by 770 MW from 24,041 MW in 2023 to 24,811 MW in 2032. The corresponding net internal winter peak demand increases by 3,233 MW from 19,498 MW in 2023/2024 to 22,731 MW in 2032/2033. Net energy for load is forecast to grow by 18,590 GWh from 125,236 GWh in 2023 to 143,826 GWh in 2032. Over this assessment period, ISO-NE projects the total internal demand growth to increase at a CAGR of 0.42% for summer and 1.95% for winter.

The forecast for EE and conservation during the forecast summer peak ranges from 2,288 MW in 2023 to 3,106 MW in 2032.

New England has 903 MW (3,146 MW nameplate) of BTM solar PV; this is forecast to grow to 1,120 MW (6,555 MW nameplate) by 2032. The BTM solar PV peak load reduction values are calculated as a percentage of ac nameplate. On-peak contributions decrease from 28.7% of nameplate in 2022 to about 17.0% in 2032. The percentages reflect diminishing solar PV production as the time of the system peak shifts later in the day, a phenomenon associated with increased BTM solar PV on the system.

Demand Side Management

New England has 592 MW of controllable and dispatchable DR resources in 2023 and the amount will grow to 765 MW by 2032. The area also has over 3,327 MW (2023) of passive demand side management resources consisting of EE and distributed generation that participate in the regional capacity market. This amount is assumed to increase to 4,226 MW by the end of the LTRA assessment period.

Distributed Energy Resources

There are approximately 1,100 MW (nameplate rating) of smaller than 5 MW each of settlement-only generating resources that do not participate in the ISO-NE capacity market.

Generation

Needed capacity and operating reserves are procured through the wholesale markets. Studies of expected system conditions show that developing new resources near load centers, particularly in NEMA/Boston and SEMA/RI, would provide the greatest reliability benefit. To the extent that new economic resources are developed that can help balance supply with demand, the system would require fewer transmission/distribution upgrades, less ancillary services, and exhibit less congestion and losses, helping the BPS perform more flexibly and reliably.

The regional reliance on natural-gas-fired generation continues and is still exposed to the lack of firm natural gas pipeline transportation entitlement and uncertain liquefied natural gas deliveries. Gas sector infrastructure contingencies can become reliability risks during any time of the year. ISO-NE and interregional organizations have assessed these risks in a number of energy-security studies, and ISO-NE has taken a number of actions, including revising OP-21 to include a 21-day energy forecast, to improve the overall reliable and efficient operation of the system. The solution includes development of renewable resources with energy storage; imports from neighboring areas; fast-start and flexible ramping resources; and continued investment in EE measures within both the electricity and gas sectors.

Future environmental regulations, public policies, and economic considerations will affect the operation of existing resources and the mix of new resources. As oil- and coal-fired generators retire, the new supply resources are expected to be predominantly renewable sources of energy, notably wind and solar. Federal and state policies and initiatives will continue to affect the planning process, such as those promoting EE, solar PV, and wind resources. Public policies restricting carbon emissions will be a limiting factor for energy production by fossil-fueled generating units.

Energy Storage

ISO-NE currently has over 1,800 MW of pumped storage hydro units and 30 MW of battery storage resources. The amount of battery storage resources is expected to grow over the next several years. There are approximately 5,600 MW of Tier 2 and 3 stand-alone battery projects currently in the queue, which are anticipated to go commercial by 2025. Another 500 MW of projects in the queue are co-located, primarily with solar PV resources.

Capacity Transfers (Reliance on Assistance)

New England is interconnected with the three BAs of Québec, the Maritimes, and New York. ISO-NE takes into account the transfer capability with these BAs to assure that their limits do not impact regional resource adequacy. ISO-NE's FCM methodology limits the purchase of import capacity based on the interconnection transfer limits. ISO-NE's capacity imports are assumed to range from 1,115 MW to 1,504 MW during the 2022–2025 summer period. Year 2025 is the end of the current FCM capacity supply obligations, and no assumptions are made regarding the availability of imports beyond it. The ISO has assigned import capacity values of zero to the remainder of the LTRA years. In addition, there are no firm exports identified over the 10-year LTRA horizon.

Transmission

Transmission expansion in New England has improved the overall level of reliability and resiliency, reduced air emissions, and lowered wholesale market costs by nearly eliminating congestion. Generator retirements, off-peak system needs, the growth of inverter-based resources, and changes to mandatory planning criteria promulgated by NERC, NPCC, and stakeholders have driven the need for longer-term transmission assessments.

The future reliable and economic performance of the power system is expected to continue to improve as a result of approximately $1.3 billion of planned transmission upgrades over the next 10 years, much of which is still in the siting process or under construction. Generator retirements, the integration of many distributed and grid-level resources, the use of inverter-based technologies, and issues rising from minimum-load assessments and high-voltage conditions are changing the needs for reliability-based transmission upgrades. In addition, transmission improvements will also be needed to support state policies to access remotely located sources of clean energy. Transmission assessments and resultant plans are currently being developed throughout the area to meet these future system needs. ISO-NE currently has 74 miles of transmission under construction and 433 miles of planned transmission during the 10-year assessment period.

Reliability Issues

New England's bulk electric power grid is transitioning to a system with a growing number of renewable and clean energy resources as well as DERs. The lack of observability and controllability of VERs and DERs is now being addressed to realize the full benefits of energy storage, micro-grids, and smart grid technologies. The rapid implementation of revised interconnection standards for distributed resources is vital for ensuring overall system reliability and facilitating the economic development of IBRs.

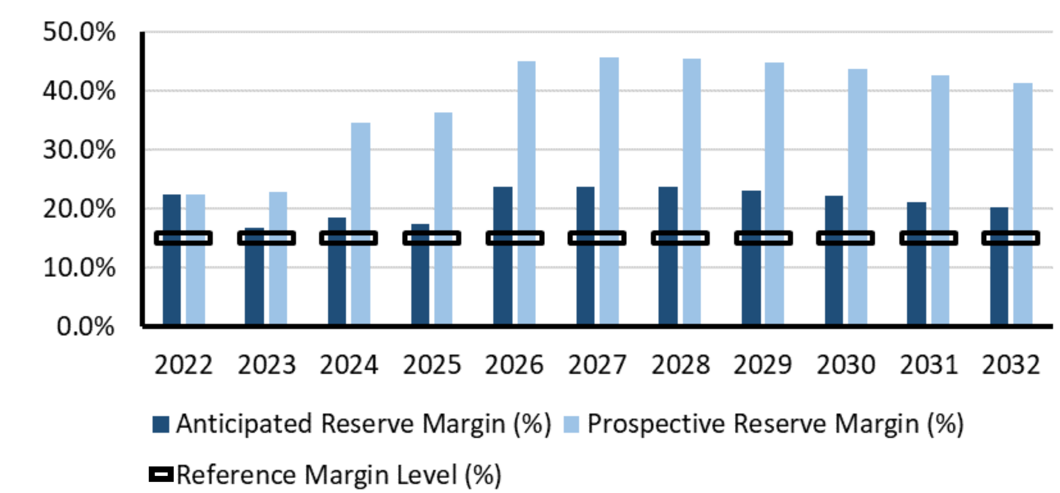
Global, regional, and local supply chains are currently impacting the residential and commercial sectors. Those same issues can have reliability impacts across the overall-interconnected energy industry. To some extent, New England has already experienced this situation in the form of fuel availability challenges during winter. ISO-NE has been a key player at the national level in promoting BES reliability through the sharing of lessons-learned and best-practices as well as initiating the performance of more detailed and in-depth BES energy assessments.

Just-in-time delivery of a generator's input fuel source—whether natural gas, wind, or solar—is creating opportunities for the electricity supply-side industry to develop long-term energy storage solutions. Energy storage has been accomplished within the oil and natural gas industries and is now the next major hurdle on the electric industry horizon.

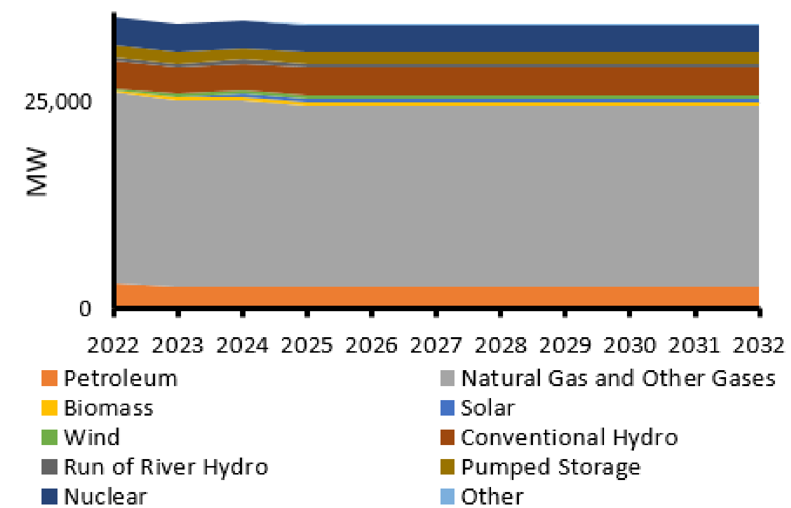
Demand, Resources, and Reserve Margins (MW)										
Quantity	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total Internal Demand	32,018	31,778	31,505	31,339	31,292	31,317	31,468	31,684	31,946	32,214
Demand Response	813	813	813	813	813	813	813	813	813	813
Net Internal Demand	31,206	30,966	30,693	30,527	30,480	30,505	30,656	30,872	31,134	31,402
Additions: Tier 1	163	648	685	685	685	685	685	685	685	685
Additions: Tier 2	1,916	4,996	5,841	6,538	6,658	6,658	6,658	6,658	6,658	6,658
Additions: Tier 3	1,369	3,060	3,968	4,870	5,046	5,046	5,046	5,046	5,046	5,046
Net Firm Capacity Transfers	1,776	1,602	1,485	3,188	3,188	3,188	3,188	3,188	3,188	3,188
Existing-Certain and Net Firm Transfers	36,212	36,038	35,321	37,024	37,024	37,024	37,024	37,024	37,024	37,024
Anticipated Reserve Margin (%)*	16.6%	18.5%	17.3%	23.5%	23.7%	23.6%	23.0%	22.1%	21.1%	20.1%
Prospective Reserve Margin (%)	22.3%	34.2%	35.9%	44.5%	45.1%	45.0%	44.3%	43.3%	42.1%	40.9%
Reference Margin Level (%)**	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%

*Wind, solar, and run-of river summer-certain capacities are derated by 85%, 58%, and 54%, respectively, for the summer period.

**The LTRA RML is 15% and it is used for the purpose of the LTRA; however, there is no planning reserve margin criteria in New York. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. Additionally, the NYISO uses probabilistic assessments to evaluate its system's resource adequacy against the LOLE resource adequacy criterion of 0.1 days/year. However, New York LSEs to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). NYSRC approved the 2022–2023 IRM at 19.6%. All values in the IRM calculation are based upon full installed capacity MW values of resources, and it is identified based on annual probabilistic assessments and models for the upcoming capability year.



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- Clean energy policies, such as the 2019 Climate Leadership and Community Protection Act, are reshaping the New York grid in unprecedented ways. NYISO has established new market rules that advance the state's clean energy policies. Wholesale electricity markets are open to significant investments in wind, solar, and battery storage.
- Reliability margins are shrinking. Generators needed for reliability are planning to retire. Delays in the construction of new supply and transmission, higher than expected demand, and extreme weather could threaten reliability and resilience in the future.
- A successful transition of the electric system requires replacing the reliability attributes of existing fossil-fueled generation with clean resources with similar capabilities. These attributes are critical to a dynamic and reliable future grid. With a high penetration of renewable intermittent resources, dispatchable and emissions-free resources as well as long-duration storage resources are needed to balance intermittent supply with demand. These types of resources must be significant in capacity and have attributes like the ability to come on-line quickly, stay on-line for as long as needed, maintain the system's balance and stability, and adapt to meet rapid and steep ramping needs.
- The transition to a cleaner grid in New York is leading to an electric system that is increasingly dynamic, decentralized, and reliant on weather-dependent renewable generation.
- Clean energy conversion is a key underlying element of electrification policies. New York is projected to become winter peaking in future decades due to electrification, primarily via heat pumps and EVs.
- New transmission is being built but more investment is necessary to support the delivery of offshore wind energy to connect new resources upstate to downstate load centers where demand is greatest. Planning for new transmission to support offshore wind is underway.

NPCC-New York Fuel Composition (MW)

Fuel	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Petroleum*	2,636	2,636	2,636	2,636	2,636	2,636	2,636	2,636	2,636	2,636
Natural Gas*	22,710	22,710	22,111	22,111	22,111	22,111	22,111	22,111	22,111	22,111
Biomass	326	326	326	326	326	326	326	326	326	326
Solar	93	513	551	551	551	551	551	551	551	551
Wind	329	394	394	394	394	394	394	394	394	394
Conventional Hydro	3,313	3,313	3,313	3,313	3,313	3,313	3,313	3,313	3,313	3,313
Run-of-River Hydro	440	440	440	440	440	440	440	440	440	440
Pumped Storage	1,409	1,409	1,409	1,409	1,409	1,409	1,409	1,409	1,409	1,409
Nuclear	3,341	3,341	3,341	3,341	3,341	3,341	3,341	3,341	3,341	3,341
Battery	40	40	40	40	40	40	40	40	40	40
Total MW	34,637	35,122	34,560	34,560	34,560	34,560	34,560	34,560	34,560	34,560

* Most petroleum and natural-gas-fired generation in the NPCC-New York assessment area is capable of operating using either fuel (i.e., dual-fueled units). For purposes of this table, generators are assigned to the category that corresponds to their primary fuel.

NPCC-New York Assessment

Planning Reserve Margins

There is no long-term reserve margin criterion in New York. For the LTRA, an RML of 15% is applied by NERC (when none is provided by an assessment area) for the purpose of evaluating on-peak capacity. The ARMs and PRMs in this LTRA are above 15% RML throughout the 10-year assessment period. Wind, grid-connected solar, and run-of-river totals were derated for the LTRA calculation. Under its reliability planning processes, NYISO uses probabilistic assessments to evaluate its system's resource adequacy against the LOLE resource adequacy criterion of no greater than 0.1 days/year probability of unplanned load loss.

NYISO also provides significant support to the NYSRC, which conducts an annual IRM study. This study determines the IRM for the upcoming capability year (May 1 through April 30). The IRM is used to quantify the capacity required to meet the NPCC and NYSRC resource adequacy criterion. The IRM for the 2022/2023 capability year is 19.6% of the forecasted NYCA peak load. All values in the IRM calculation are based upon full installed capacity values of resources. The IRM has varied historically from 15–20.7%. Additionally, NYISO performs an annual study to identify the minimum locational minimum installed capacity requirements (LCRs) for the upcoming capability year. In 2018, FERC accepted proposed revisions for determining LCRs; the new methodology uses an economic optimization algorithm to minimize the total cost of capacity for the New York balancing area. The NYISO establishes statewide and Locational ICAP requirements for the LSEs.

Energy Assessment, Including Non-Peak Hour Risk

The New York Climate Leadership and Community Protection Act (CLCPA) include the following targets for specific years:

- **2025:** 6,000 MW of distributed solar PV (10,000 MW by 2030)
- **2030:** 3,000 MW of battery storage
- **2030:** 70% renewable energy
- **2035:** 9,000 MW of offshore wind
- **2040:** 100% zero-emissions electricity
- **2050:** 85% reduction in greenhouse gas emissions

With a high penetration of renewable intermittent resources, dispatchable, emissions-free, and long-duration resources are needed to balance intermittent supply with demand. These types of resources must be significant in capacity and have attributes like the ability to come on-line quickly, stay on-line for as long as needed, maintain the system's balance and stability, and adapt to meet rapid, steep ramping needs. Additionally, although new transmission is being built, more investment is necessary to support the delivery of offshore wind energy and to connect new resources upstate to downstate load centers where demand is the greatest. Three major processes for considering energy risks are as follows:

***Energy Assessment Operations Planning* Considerations**

NPCC Grid Operations performs or assists in performing energy assessments, including, but are not limited to, a fuel and energy security study and ongoing assessments, a study assessing potential impacts related to extreme weather possibilities, and weekly analysis based on the results of reporting by generation resources through the NYISO's Generator and Fuel Emissions reporting data portal. NYISO also performs an internal energy analysis at least weekly based on data and information reported by supply resources through the NYISO Generator and Fuel Emissions reporting system. Resources provide data and information on an annual, weekly, and as-needed basis while considering system operating conditions. This analysis has the capability to analyze the impact of changes in stored fuel inventory, resource outages, fuel supply disruptions, transmission constraints, and other relevant conditions that may adversely impact fuel and energy security.

Energy Assessment Reliability Planning Process Considerations

NPCC and the NYSRC planning criteria require assessment of extreme system conditions that have a low probability of occurrence, such as peak load conditions that result from extreme weather (i.e., 90th percentile peak load forecast) and the loss of fuel (natural gas) supply under normal weather peak conditions. For the extreme system condition due to loss of fuel supply, this assessment assumes a winter peak value with all NYCA natural-gas-only units unavailable and with reductions in the capacity of dual-fuel units. These extreme system condition evaluations include both steady state and dynamics N-1 assessments.

For the resource adequacy evaluations, NYISO uses the GE Multi-Area Reliability Simulation (MARS), which employs a probabilistic method (sequential Monte Carlo) to determine reliability indices for the New York BPS and also for establishing its annual IRM. There are several types of randomly occurring events that are taken into consideration, such as the forced outages of generating units, the forced outages of transmission capacity, and deviations from forecasted loads. Once all of this analysis is completed, MARS calculates the annual reliability indices (LOLE in days/year, LOLH in hours/year, loss of energy expectation (in MWh/year) for the replication.

This analysis occurs concurrently across all load levels; MARS combines them in a weighted sum to get a single value for each replication.

The MARS simulations do not take into consideration potential reliability impacts due to unit commitment and dispatch, ramp rate constraints, and other production cost modeling techniques or impacts due to sub-zonal constraints on the transmission system.

Energy Assessment Economic Planning Process Considerations
Production cost models used by NYISO include constraint and contingency definitions that are consistent with NYISO's Reliability Planning Process. The production cost models used also incorporate market and operating criteria, such as contingency and operating reserves. While the studies performed with the model do not explicitly assess Regional Entity criteria, they do provide an outlook of future challenges that might occur while sustaining them. An example is hours/MWh of energy deficiency and reserve deficiency conditions. Additionally, because energy assessments implicitly require the evaluation of energy (MWh not MW), production cost models are useful as they model 8,760 hours per year of a multiple-year time horizon.

The currently in progress *2021–2040 System & Resource Outlook* (the Outlook), which is conducted by the NYISO in collaboration with stakeholders and state agencies, provides a comprehensive overview of the potential resource development over the next 20 years and the resultant transmission constraints throughout New York as well as highlights opportunities for transmission investment driven by economics and public policy. Together with the NYISO's publication of the *2021–2030 Comprehensive Reliability Plan* (CRP), the Outlook will provide a full power system outlook to stakeholders, developers, and policymakers.

Probabilistic Assessments (ProbA and Other Studies)[29]
NYISO performs probabilistic assessments with GE's MARS as part of its reliability planning processes as well as to determine annual IRM and LCRs. Improving capacity accreditation is in progress to value resources in the capacity market based on their duration and marginal impact upon meeting NYSRC resource adequacy requirements. NPCC's Directory 1 defines a compliance obligation for the NYISO, as a Resource Planner and Planning Coordinator, to perform a resource adequacy study evaluating a five-year planning horizon. The NYISO delivers a report every year under this study process to verify the system against the 1-day-in-10-years LOLE criterion, usually based on the latest available RNA/CRP results and assumptions. NYSRC reliability rules have recently included a requirement defining the NYISO's obligation to deliver a *Long-Term Resource Adequacy Assessment Report* every reliability needs assessment report (RNA) year as well as an annual update in the non-RNA years ("intervening year"). Results of the 2022 ProbA are tabulated below.

Base Case Summary of Results			
	2024*	**2024**	**2026**
EUE (MWh)	6.837	0.091	0.059
EUE (ppm)	0.046	0.001	0.00
LOLH (Hours per Year)	0.029	0.00	0.00
Operable On-peak Margin	11.3%	11.6%	16.7%

* Provides the 2020 ProbA results for comparison

The Forecast 50/50 Peak Demand for year 2024 is similar in this ProbA as that reported in the previous ProbA. With comparable estimated Forecast Reserve Margins, a slight decrease in LOLH and EUE for 2024 was observed. The New York area is summer peaking and the EUE risk occurs during the summer months; however, the EUE values are negligible.

Demand
The energy and peak load forecasts are based upon end-use models that incorporate projections of economic drivers as well as 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. The forecast of BTM solar PV-related reductions in summer peak assumes that the New York balancing area peak currently occurs at 4:00 p.m. or 5:00 p.m., Eastern, in July or August. The hour of the summer peak varies and is assumed to shift slightly later into the evening over the forecast horizon. The forecast of BTM solar PV-related reductions to the winter peak is zero because the sun sets before the assumed peak hour of 6:00 p.m., Eastern, in January. The baseline forecast includes upward adjustments for increased usage of EVs and other electrification as well as downward adjustments for the impacts of EE trends, DERs, and BTM solar PV. The impacts of net electricity consumption of all energy storage units are added to the baseline energy forecast and the peak-reducing impacts of BTM energy storage units are deducted from the baseline peak forecasts.

[29] NPCC resource adequacy documents are posted in the NPCC library: https://www.npcc.org/program-areas/rapa/resource-adequacy

In 2019, NYISO performed a *Climate Impact Study Phase I: Long-Term Load Impact Study* and the results of the study identified a clear upward trend in temperatures throughout the state. These trended weather conditions are incorporated within the end-use models and are reflected in the baseline and percentile forecasts. The NYISO develops 90th and 99th percentile forecasts to account for the impacts of extreme weather on seasonal peak demand and calculates 10th percentile forecasts to represent milder seasonal peak conditions.

Over this assessment period, NYISO projects the total internal demand growth to increase at a CAGR of 0.07% for summer and 2.36% for winter. The 10-year annual average energy (+0.22%) and summer peak demand (+0.39%) growth rates are higher than last year. The forecasted increase in peak demand is attributed in part to EV charging during the system peak hour and the electrification of non-weather sensitive appliances (i.e., conversion of cooking, water heating, and other end-uses from fossil-fuel based systems to electric systems). The higher forecasted growth in energy usage can be attributed primarily to the increasing impacts of EV usage, space heating electrification, and electrification of other end uses. The winter peak forecast has also increased for these same reasons. New York is projected to become winter peaking in future decades due to electrification primarily via heat pumps and EVs.

Over the course of the forecast horizon, significant load-reducing impacts occur due to EE initiatives and the growth of distributed behind-the-meter energy resources, such as solar PV. These impacts result primarily from New York State's energy policies and programs. The relative BTM solar impact on peak load declines over time as the New York balancing area summer peak is expected to shift further into the evening.

The economic and behavioral changes stemming from the COVID-19 pandemic changed 2020 and 2021 load levels and load shapes relative to a typical year. The impact on total energy consumption in 2020 was significant. In 2021, impacts on total load were much smaller than in 2020. Throughout the pandemic, the largest load reductions have consistently been in New York City (Zone J), being an urban area with a large share of commercial load. With the exception of New York City, which continues to see somewhat lower than expected energy and peak levels, the load recovery from the COVID-19 pandemic is largely complete throughout the state.

Demand-Side Management

The NYISO's resource planning process accounts for DR resources that participate in the NYISO's reliability-based DR programs based on the enrolled MW derated by historical performance. The NYISO will develop market concepts to encourage the participation of flexible load, which will become increasingly important as the levels of weather-dependent intermittent resources on New York's grid increases in response to the state's climate and clean energy policies. Many of New York utilities are piloting several load management programs (e.g., smart EV charging, home-thermostat use, integration of BTM storage for local peak demand modulation). As part of NYISO's annual long-term forecasting process, the impacts of these programs are discussed, and significant impacts on demand are included in the load forecast. There were no major changes in the DR accounting methods or assumptions since the *2021 LTRA.* The *2021 LTRA* reported 1,199.1 MW of DR participating in NYISO's DR programs for the summer capability period. For the *2022 LTRA*, the DR participation for the summer capability period has decreased slightly to 1,169.8 MW. There are currently 200 MW of DR participating in ancillary services programs that provide either 10-minute spinning reserves or 30-minute non-synchronous reserves.

Distributed Energy Resources

NYISO is currently implementing a three- to five-year plan to integrate DERs, including DR resources, into its energy, capacity, and ancillary services markets. On the markets side, the DER Participation Model project aims to enhance participation of DERs in the competitive wholesale markets. These measures closely align the bidding and performance measurements for DERs with the rules for generators. The measures establish a state-of-the-art model that is largely consistent with the market design envisioned by FERC in its Order 2222. As a next step, the NYISO will develop market concepts to encourage the participation of flexible load that will become increasingly important as the levels of weather-dependent intermittent resources on New York's grid increase in response to the state's climate and clean energy policies. These efforts will add new means by which resources can participate in NYISO's markets as well as enhance existing participation models. On a similar theme, NYISO is developing market participation rules for wholesale market generation resources co-located with storage. As part of this effort, NYISO has identified two potential participation models for such resources: the Co-Located Storage Model and the Hybrid Storage Model.

Generation
The most recent Reliability Planning Process (2022/2023 RPP) started with its *2022 RNA* and targets 2022 Q4 for completion. The study period for the RNA is 2026–2032. The 2022 RNA Base Cases future system assumptions reflect the following information:

- Approximately 2,100 MW (nameplate) proposed projects were included, mostly wind and solar.
- Approximately 1,800 MW generation assumed deactivated, including those impacted by the Peaker Rule. The generators are also reflected in the LTRA spreadsheet as either confirmed deactivations (for those units indicating plans to deactivate in order to comply with the rule), or with zero capacity during the ozone season (May–September) and with applicable capacity value during non-ozone period.

Additionally, the NYISO's interconnection process contains an unprecedented number of proposed projects in various stages of development.

Energy Storage
Storage resources help to fill in voids created by reduced output from renewable resources; however, sustained periods of reduced renewable generation can rapidly deplete storage capabilities. The Hybrid Co-Located Model is now implemented to allow wind or solar resources that are interconnected with an energy storage resource the ability to participate in the markets while respecting a shared interconnection limitation. The Hybrid Storage Resources model is in development to allow multiple technologies at the same point of interconnection participate in the market as a single resource. Additionally, the resource adequacy simulation tools (e.g., GE's MARS) used in planning and for setting the IRMs were enhanced to include energy-limited resources models that allow for charging and discharging as well as temporal constraints (e.g., hours/days or hours/month).

Capacity Transfers
The models used for the NYISO reliability planning studies include firm capacity transactions (purchases and sales) with the neighboring systems as a Base Case assumption.

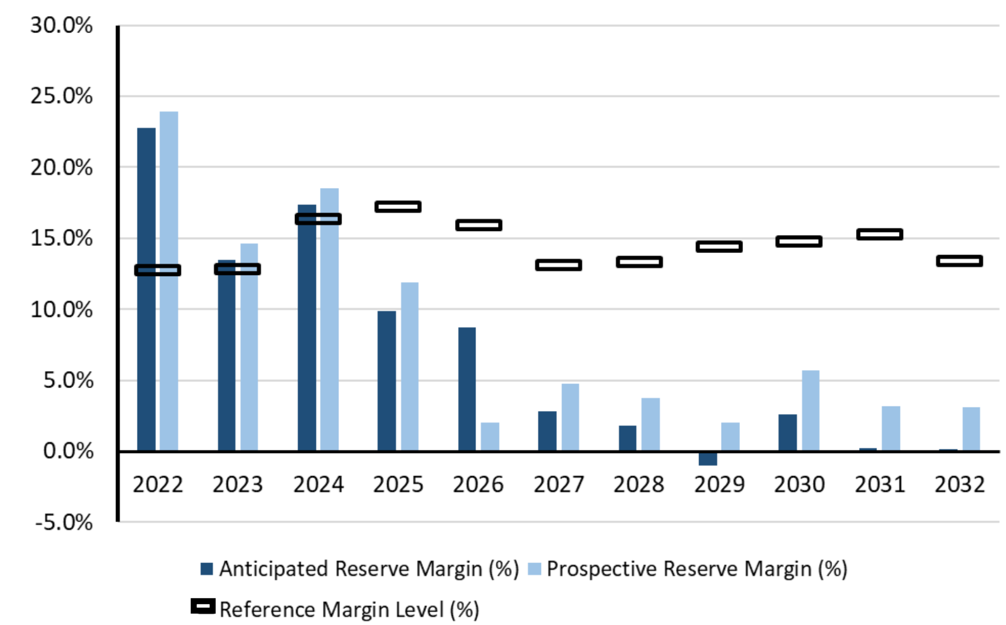
Transmission
New transmission is being built but more investment is necessary to support the delivery of offshore wind energy to connect new resources from upstate to downstate load centers where demand is greatest. Currently, 1,635 miles of transmission line projects are planned over the 10-year assessment period total.

The *2022 RNA* (targeting 2022 Q4 for completion) includes the following:

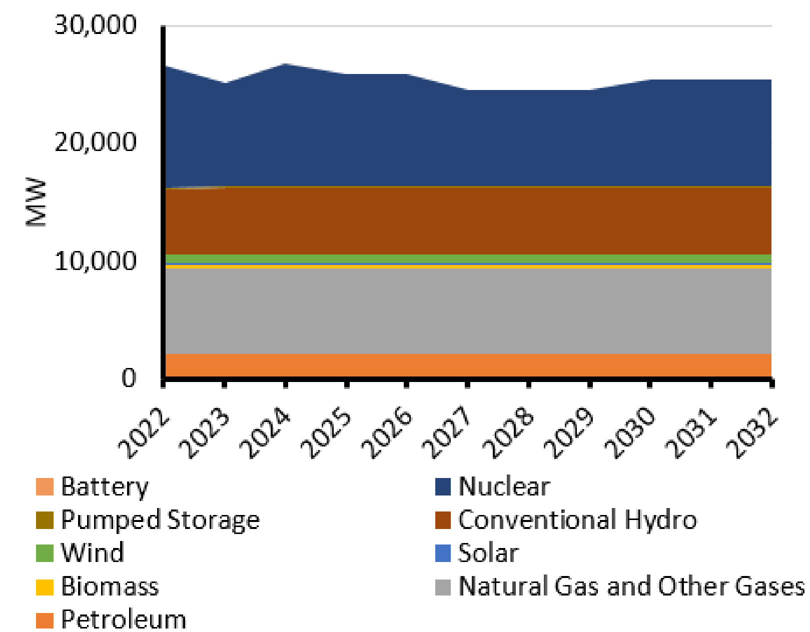
- Local Transmission Owner plans designated as firm in the applicable *NYISO Gold Book*
- The NYPA/National Grid's Northern New York Priority Transmission Project (under the New York State Accelerated Renewable Energy Growth and Community Benefit Act, which seeks to accelerate siting and construction of large-scale clean energy projects
- The 1,250 MW Champlain-Hudson Power Express HVDC Line from Hydro Québec to New York City
- The Western NY Public Policy Transmission Project (the Empire State Line Proposal), which is being developed by NextEra Energy Transmission New York, Inc.
- The AC Public Policy Transmission Project (ACPPTP) consisting of two transmission projects in the Mohawk and Hudson Valleys selected by the NYISO Board of Directors in 2019

Planning for new transmission to support offshore wind is underway. A new Public Policy Transmission Planning Process is in progress (not yet included in the reliability planning models) that will include projects to support offshore wind development.

Demand, Resources, and Reserve Margins (MW)										
Quantity	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Total Internal Demand	22,930	23,490	23,856	24,104	24,288	24,477	25,166	25,081	25,678	25,694
Demand Response	850	712	367	367	367	367	367	367	367	367
Net Internal Demand	22,080	22,777	23,488	23,737	23,921	24,110	24,799	24,714	25,311	25,326
Additions: Tier 1	99	99	99	99	99	99	99	99	99	99
Additions: Tier 2	0	0	223	223	223	223	508	508	508	508
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	0	0	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	24,959	26,640	25,715	25,715	24,489	24,442	24,442	25,260	25,262	25,262
Anticipated Reserve Margin (%)	13.5%	17.4%	9.9%	8.7%	2.8%	1.8%	-1.0%	2.6%	0.2%	0.1%
Prospective Reserve Margin (%)	14.6%	18.5%	11.9%	2.0%	4.8%	3.7%	2.0%	5.7%	3.2%	3.1%
Reference Margin Level (%)	12.8%	16.3%	17.2%	16.0%	13.1%	13.3%	14.4%	14.8%	15.3%	13.4%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- Ontario's ARMs fall below the RML beginning in 2025—driven primarily by the nuclear refurbishment program, the retirement of Pickering Nuclear Generating Station, and demand growth. ARMs and fuel composition information in this 2022 LTRA assume Pickering units will retire in late 2026, however they could retire as early as 2025.
- 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*.
- IESO expects both energy and peak demand to grow steadily over the outlook period, driven primarily by economic and demographic growth. Ontario will remain summer peaking over the forecast horizon.
- A number of transmission projects are underway to address bulk system reliability concerns, reinforce connection in the northwest, and connect new loads in the southwest area of the province.

NPCC-Ontario Fuel Composition (MW)										
Fuel	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Petroleum	2,106	2,106	2,106	2,106	2,106	2,106	2,106	2,106	2,106	2,106
Natural Gas	7,332	7,332	7,332	7,332	7,332	7,332	7,332	7,332	7,332	7,332
Biomass	300	300	300	300	300	300	300	300	300	300
Solar	123	123	123	123	123	123	123	123	123	123
Wind	771	771	771	771	771	771	771	771	771	771
Conventional Hydro	5,564	5,564	5,564	5,564	5,564	5,564	5,564	5,564	5,564	5,564
Pumped Storage	110	110	110	110	110	110	110	110	110	110
Nuclear[30]	8,745	10,426	9,501	9,501	8,275	8,228	8,228	9,046	9,048	9,048
Battery	7	7	7	7	7	7	7	7	7	7
Total MW	25,058	26,739	25,8148	23,750	24,588	24,541	24,541	25,359	25,361	25,361

[30] Nuclear outages as a result of the nuclear refurbishment program are reflected in this table.

NPCC-Ontario Assessment

Planning Reserve Margins

The ARMs fall below the RML beginning in 2025, driven primarily by the nuclear refurbishment program, the retirement of Pickering Nuclear Generating Station, and demand growth. Anticipated Shortfalls of about 1,700 MW are forecast for 2025 and 2026. In September 2022, Ontario's Ministry of Energy announced that it was supporting a plan by Ontario Power Generation to extend the operation of the Pickering Nuclear Generating Station beyond its planned retirement in 2025 through September 2026. If approval is received from the Canadian Nuclear Safety Commission, this extension would reduce the potential capacity shortfall in 2026 described in the *2021 LTRA*. The ARM in the *2022 LTRA* is calculated with an assumed retirement of Pickering units in late 2026.

In order to address emerging resource adequacy needs, the IESO established a Resource Adequacy Framework[31] in 2021 to provide a flexible and cost-effective approach for competitively securing the resources necessary to meet Ontario's needs. The Resource Adequacy Framework sets out a multi-pronged approach to cumulatively address needs over varying time frames with the Annual Acquisition Report specifying the mechanisms and targets that are used to meet the needs, including expanded targets for IESO's annual capacity auction and a set of procurements aimed at acquiring capacity from both new and existing resources. In September 2022, Ontario's Ministry of Energy directed the IESO to obtain 4,000 MW of new capacity through three separate procurements. The targets of these procurements are not reflected in this report. The IESO completes a probabilistic assessment of its resource adequacy needs annually and publishes the results in the *2021 Annual Planning Outlook* (APO).[32] This LTRA is consistent with the *2021 Annual Planning Outlook*.

Energy Assessment

Energy adequacy assessments are conducted annually for the 20-year *2021 Annual Planning Outlook* study period. Currently, the energy modelling is deterministic and performed for median conditions. NPCC-Ontario examines the production of each resource, imports, exports, unserved energy, surplus baseload generation, and marginal cost to identify risks. Ontario is expected to experience increased energy adequacy risk when Pickering NGS retires in 2024–2025. In addition, unserved energy is expected to increase should some of Ontario's resources retire after contract expiry. The IESO is developing an RFP for new-build resources (the design of which was informed) in part, by energy assessments; and as a result, it includes incentives for resources that are able to meet energy needs as they emerge.

[31] https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Resource-Adequacy-Framework
[32] https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook

Probabilistic Assessment[33]

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	0.049	0.00	72.164
EUE (ppm)	0.00	0.00	0.492
LOLH (Hours per Year)	0.001	0.00	0.442
Operable On-peak Margin	4.4%	7.9%	-6.7%

* Provides the 2020 ProbA results for comparison

The Forecast 50/50 Peak Demand for year 2024 is slightly lower in this ProbA than reported in the previous ProbA. As a result, the estimated LOLH and EUE for year 2024 decreased slightly to approximately zero. With the reported drop in capacity resources for the year 2026, there is an increase in the LOLH to 0,442 hours per year and EUE to approximately 72 MWh (0.492ppm). The Ontario area is summer peaking; the low LOLH risk occurs during the summer months.

Demand

Ontario will remain summer peaking over the forecast horizon. Peak demand is expected to grow over the outlook period, driven primarily by demographic and economic growth. Later in the forecast, decarbonization and electrification, including rapidly growing penetration of EVs, should continue to drive growth in peaks that will be partially offset by EE.

Energy demand is subject to the same factors as peak demands. In the near term, demand forecast uncertainty remains greater than usual although the source of uncertainty is shifting from the COVID-19 pandemic to the broader macroeconomic outlook. However, demand is expected to experience upward pressure from economic and demographic growth in the long term. Growth will also come from electrification of the transportation sector and significant growth in the resource sector (primarily mining and agriculture). Over this assessment period, IESO projects the total internal demand growth to increase at a CAGR of 1.27% for summer and 1.32% for winter. Overall, IESO expects to see an increase in energy demand over the forecast horizon.

Demand Side Management

As of the December 2020 capacity auction, DR (including dispatchable loads and hourly DR resources) has been enabled to compete with other resources to provide capacity. Resources with capacity obligations are required to be available for curtailment up to their secured capacity during times of system need. The December 2021 capacity auction procured 1,286 MW for the six-month summer obligation period beginning on May 1, 2022. This is an increase of nearly 300 MW over the prior year's capacity auction. Of this capacity, more than 900 MW is from DR.

Distributed Energy Resources

IESO estimates that total DERs in Ontario exceed 4,300 MW, including about 4,000 MW of contracted renewable resources. The IESO continues to collaborate with the DER community to increase coordination between the grid operator and embedded resources directly or through integrated operations with local distribution companies with the aim to improve DER visibility and identify opportunities for a more coordinated operation of Ontario's electric system. Although the output from DERs has plateaued, the need for more flexible generation to manage variability remains. Given that DERs are challenging to forecast, it can be difficult to efficiently commit non flexible resources or schedule transactions on the interties to manage supply and demand. To manage this variability, IESO initiates actions, such as committing dispatchable generation, curtailing intertie transactions, and scheduling additional 30-minute operating reserve to signal flexibility need.

Generation

Nuclear refurbishments at Bruce Nuclear Generating Station and the Darlington Nuclear Generating Station are expected to reduce the generation capacity availability in the coming years. During the refurbishment period, one to four units 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- and long-term. In addition to the 1,286 MW secured at the annual IESO Capacity Auction for the summer of 2022 obligation period with contracted wind capacity of 160 MW from the Romney Wind Project (60 MW) and Nation Rise Wind Farm (100 MW). Additional wind farms are expected to be added in late 2022. Substantial resource turnover is anticipated in the coming years that is driven by nuclear retirements, nuclear refurbishments, and by the expiry of contracted resources. The availability of the nuclear fleet is a major resource turnover risk that requires additional attention. The transmission-connected supply mix has shifted from only synchronous generation facilities to more inverter-based generation facilities (e.g., wind, solar). There are very few natural-gas-fired generation facilities producing power under low demand conditions. As a result, the IESO-controlled grid relies primarily on baseload (run-of-the-river) hydroelectric generation facilities to provide most of the primary frequency response.

[33] NPCC resource adequacy documents are posted in the NPCC library: https://www.npcc.org/program-areas/rapa/resource-adequacy

Energy Storage

The IESO views electricity storage as an important emerging resource and is actively working to enable its deployment. IESO has released a series of reports that outline the barriers to fair competition and detail a path for enduring participation of electricity storage resources in IESO's markets. Nonetheless, capacity from transmission connected storage remains relatively small in Ontario. There is a considerable amount of energy storage resources connected on the distribution system for peak shaving. Additional energy storage projects are expected and at different stages of development from feasibility studies to permitting. Energy storage uses in Ontario include regulation services, reactive support and voltage control, energy market participation, and BTM peak shaving.

Capacity Transfers

IESO has operating agreements with Hydro Québec and Manitoba Hydro to enable system backed imports from these jurisdictions that may be acquired as part of the IESO Capacity Auction. As part of the electricity trade agreement between Ontario and Québec, Ontario will supply 500 MW of capacity to Québec each winter from December to March until 2023. Ontario has the option to receive 500 MW of capacity from Québec for one summer before 2030 and expects to call on that option in the summer of 2026. The IESO and NYISO facilitates trading of capacity from Ontario to New York. To ensure that reliability in Ontario is maintained, only capacity that is determined by IESO to be above Ontario's required reserve margin levels over summer or winter season are exported.

Transmission

A new 400–450 km long 230 kV double-circuit transmission line is planned to come into service in Q3 2022 to reinforce the connection of Northwestern Ontario to the rest of the provincial grid. There is a double-circuit 230 kV line that is operated as one electrical circuit in the Sudbury District that poses risks should a contingency event occur. The IESO has requested that Hydro One Limited initiate the work required to terminate the two physical circuits on their own terminal positions so they function as two separate circuits, addressing this risk. In the Windsor-Essex area, two projects have been initiated: development of a new switching station (expected in-service in Q3 2022) and a new double-circuit approximately 50-km 230 kV transmission line to bring additional supply to the area (by Q4 2025). The IESO has also recommended further transmission reinforcement to support the area's medium-term needs, identifying an additional double circuit 230 kV line (expected in-service by 2028) and a new 500 kV line (expected in service by 2030). In the Ottawa area, IESO has requested that work proceed to upgrade circuits between Merivale Transmission Station (TS) and Hawthorne TS with a planned in-service date of Q4 2023; this project will address supply capacity constraints to West Ottawa and support the deliverability of capacity imports from Québec. The IESO has recommended the upgrade of four limiting 230 kV circuits between Richview TS and Trafalgar TS in the Toronto area, resulting in an increase in the Flow East Towards Toronto (FETT) interface capability, by spring 2026. IESO currently has 71 miles of transmission lines under construction and 499 miles of planned transmission lines during the 10-year assessment period.

Reliability Issues

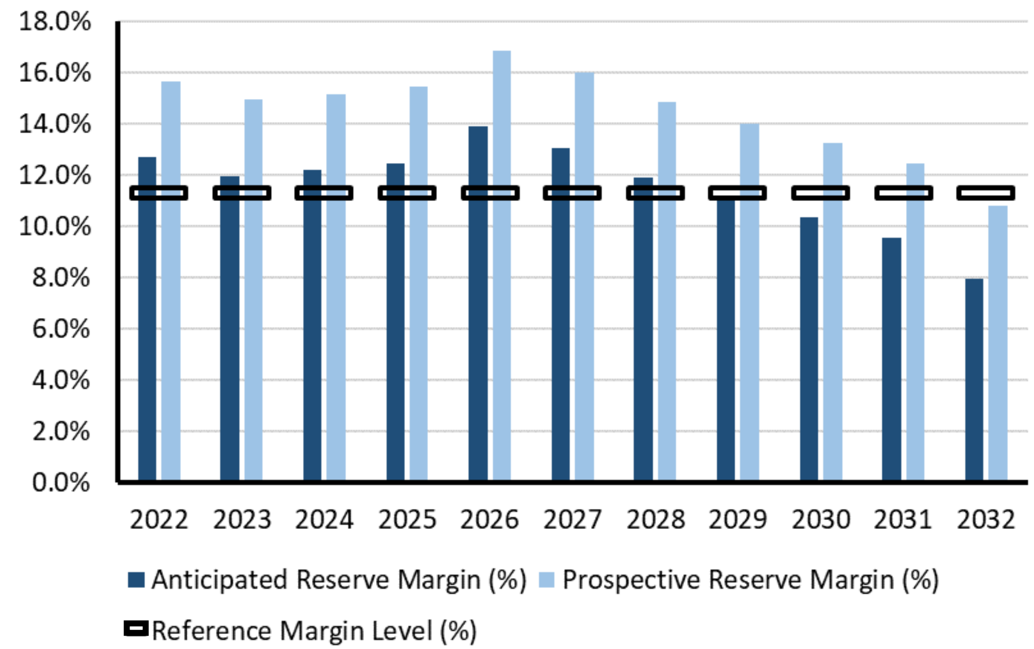
The ongoing nuclear refurbishment program that spans the next 12 years is a major resource risk that requires additional attention. IESO has regular meetings with nuclear operators to assess probable delays and to take appropriate mitigation actions.

Natural gas is delivered to Ontario from neighboring jurisdictions by mainlines and distribution utilities. Situated in Ontario is the Enbridge Gas Dawn Hub, Canada's largest integrated underground natural gas storage facility. The risk of fuel unavailability under extreme winter conditions in Ontario is reduced with a large portion of the natural gas fleet located in close proximity to the Dawn hub. Supply to Ontario's natural gas fleet is robust and supported by significant firm supply and transportation contracts.

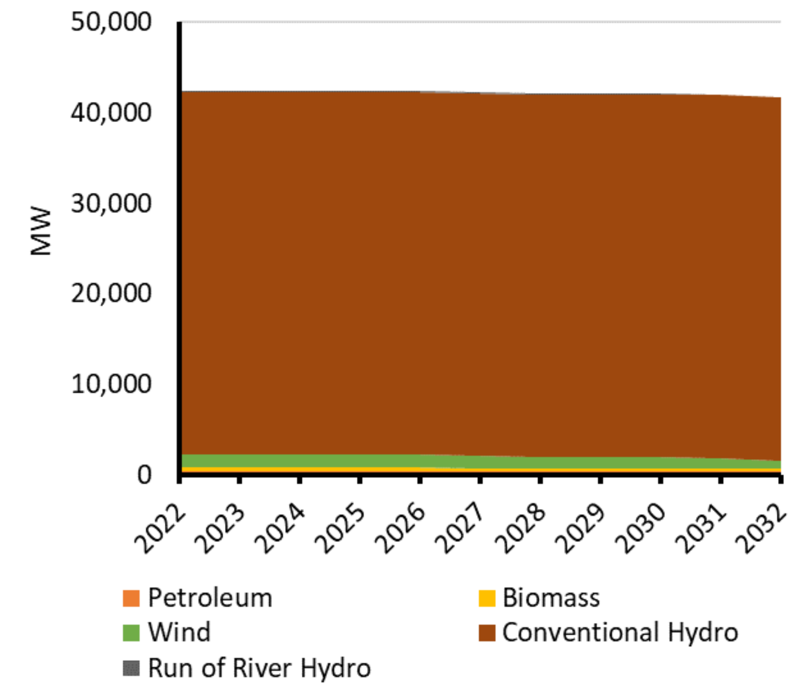
Changes to demand and resource mix in response to potential decarbonization could have significant reliability implications. The IESO is currently studying decarbonization, both of the electricity system and the economy in general (including impacts on reliability) in its *Pathways to Decarbonization* study.[34]

[34] https://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/Pathways-to-Decarbonization

Demand, Resources, and Reserve Margins (MW)										
Quantity	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Total Internal Demand	40,390	40,554	40,769	41,102	41,445	41,822	42,090	42,333	42,547	42,864
Demand Response	3,348	3,650	3,883	3,989	4,181	4,209	4,241	4,241	4,241	4,241
Net Internal Demand	37,042	36,904	36,886	37,113	37,264	37,614	37,849	38,092	38,306	38,623
Additions: Tier 1	255	369	369	369	369	369	369	369	369	369
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-888	-1,079	-990	-145	-145	-145	-145	-145	-145	-145
Existing-Certain and Net Firm Transfers	41,226	41,040	41,116	41,909	41,765	41,727	41,682	41,674	41,606	41,331
Anticipated Reserve Margin (%)	12.0%	12.2%	12.5%	13.9%	13.1%	11.9%	11.1%	10.4%	9.6%	8.0%
Prospective Reserve Margin (%)	15.0%	15.2%	15.5%	16.9%	16.0%	14.8%	14.0%	13.3%	12.4%	10.8%
Reference Margin Level (%)	11.3%	11.3%	11.3%	11.3%	11.3%	11.3%	11.3%	11.3%	11.3%	11.3%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM remains above the RML except for last four winter periods of this assessment. However, the PRM is above the RML for all the years of this assessment except for the last winter peak period.
- Approximately 490 MW of capacity additions are expected over this assessment period. The Romaine-4 hydro unit (245 MW) is expected to be fully operational by the end of 2022. A 204 MW of wind generation is expected to be in service in 2024–2025. Finally, 41 MW of biomass are expected to be in service in 2024.
- A total of 500 MW of firm import capacity from Ontario is available to Québec each winter through 2022/2023 as part of an existing trade agreement between Québec and Ontario.
- The commissioning of the second Micoua-Saguenay 735 kV transmission line is expected by the end of 2022.

NPCC-Québec Fuel Composition (MW)										
Fuel	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Petroleum	436	436	436	436	436	436	436	436	436	436
Biomass	405	405	405	405	295	228	228	228	228	220
Wind	1,375	1,449	1,430	1,372	1,336	1,296	1,248	1,248	1,191	946
Conventional Hydro	40,048	40,054	40,060	40,065	40,068	40,071	40,073	40,076	40,078	40,081
Run-of-River Hydro	103	144	144	144	144	144	144	134	121	96
Total MW	42,368	42,488	42,475	42,422	42,279	42,174	42,129	42,122	42,054	41,779

NPCC-Québec Assessment

Planning Reserve Margins

The ARM is based on existing and anticipated generating capacity and firm capacity transfers. It is above the area's RML over this study period assessment except for the last three winter periods of 2030–2033. However, the PRM remains above the RML for almost all years of this assessment. Under the prospective scenario, a total of 1,100 MW of expected capacity supply is planned by the Québec area; this capacity could either be supplied by resources within the area or by imports. This capacity has not yet been backed by firm long-term contracts. However, based on its annual capacity needs, the Québec area proceeds with short-term capacity contracts in order to meet its capacity requirements.

Non-Peak Hour Risk, Energy Assurance, Probabilistic Based Assessments

In its distribution service functions, Hydro-Québec performs an energy adequacy assessment in its supply plan and files results with the Régie de l'énergie (Québec Energy Board) in November of each year. Unserved energy and the generation surplus are metrics used to identify risks. Furthermore, an energy criterion accepted and approved by the Régie de l'énergie is also used to identify risks. The Québec area has adequate energy to meet its energy demand over the entire horizon of the analysis. The installed capacity in the Québec area is mainly composed of large reservoir hydro complexes (more than 90%) that can react quickly to adjust their generation output and meet the sharp changes in the net demand

Probabilistic Assessment[35]

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	0.00	0.00	0.00
EUE (ppm)	0.00	0.00	0.00
LOLH (Hours per Year)	0.00	0.00	0.00
Operable On-peak Margin	7.1%	-1.6%	-2.3%

* Provides the 2020 ProbA results for comparison

The Forecast 50/50 Peak Demand for the year of 2024 is higher in this ProbA than reported in the previous ProbA. Even with a smaller estimated Forecast Planning and Forecast Operable Reserve Margin, no LOLH and EUE is observed. 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.

Demand

The 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. The Québec area demand forecast average annual growth is 0.7% during the 10-year period, comparable to the last year's forecast.

Demand-Side Management

The Québec area has various types of DR resources specifically designed for peak 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 2022/2023 winter peak demand. The area is also expanding its existing interruptible load program for commercial buildings that will grow from 424 MW in 2022/2023 winter to 505 MW in 2024/2025 winter. Another similar program for residential customers is in operation and should gradually rise from 47 MW for 2022/2023 winter to 621 MW for 2028/2029 winter. Enhancing interruptible programs for large industrial customers can add potential capacity that varies from 330 MW in the 2023/2024 winter period to 512 MW at the end of the assessment 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 2021/2022 winter, increasing to 371 MW for 2024/2025 winter.

Moreover, data centers specialized in blockchain application participants (new developments in the commercial sector) are required to reduce their demand during peak hours at Hydro-Québec's request. Their contribution as a resource is expected to be around 261 MW for 2022/2023 winter and around 230 MW at the end of the study period.

EE and conservation programs are integrated in this assessment area's demand forecasts.

[35] NPCC resource adequacy documents are posted in the NPCC library: https://www.npcc.org/program-areas/rapa/resource-adequacy

Distributed Energy Resources
Total installed BTM capacity (solar PV) is expected to increase to more than 622 MW in 2033. Solar PV is accounted for in the load forecast. Nevertheless, since Québec is a winter peaking area, solar PV on-peak contribution is minimal (less than 15 MW).

No potential operational DER impacts are expected in the Québec area due to the low DER penetration in the area.

Generation
The Romaine-4 unit (245 MW) is expected to be fully operational by the end of 2022. The integration of small hydro unit accounts for 41 MW new capacity during this assessment period. For other renewable resources, 204 MW of wind generation (73 MW on-peak value) is expected to be in service for the winter period 2024/2025. A total of 10 MW of biomass is expected to be in place by the end of 2022.

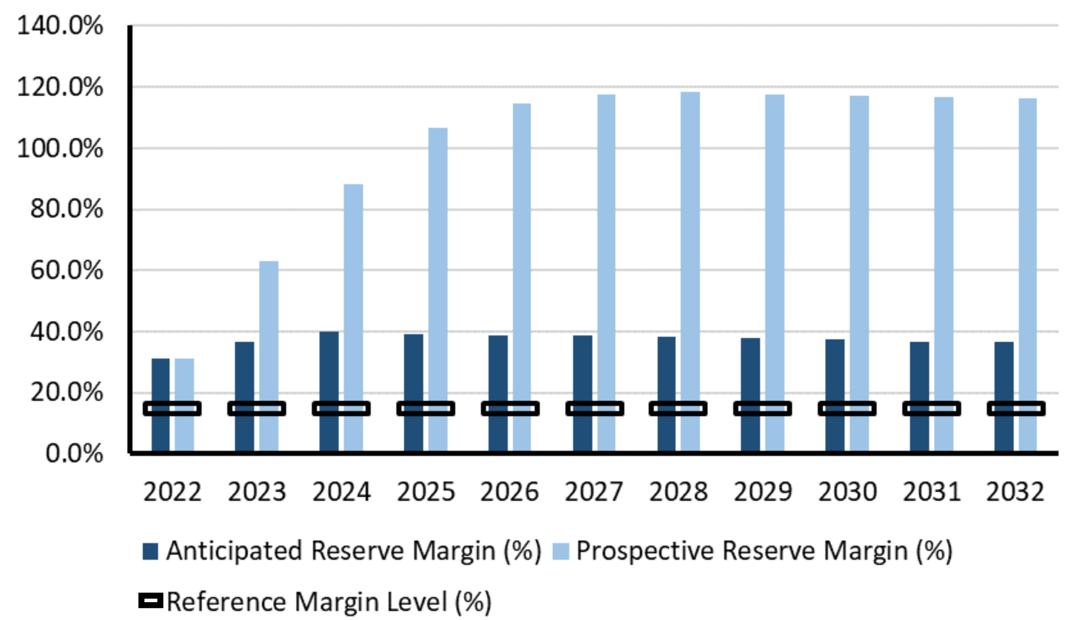
Capacity Transfers
In 2019, Hydro-Québec TransÉnergie conducted a transmission system planning assessment to fulfill NERC TPL-001-4 requirements. The loss of a 735 kV circuit on the Manic-Québec interface on a system where a 735 kV is out-of-service on the same interface (system adjustments are applied) caused the overload of the Saguenay series capacitor banks even after considering their overload capacity. The commissioning of the second Micoua-Saguenay 735 kV line is planned for 2023. Simulations performed on the 2023/2024 and 2028/2029 systems have confirmed the effectiveness of this solution. Until this second line is operational, this issue is monitored and addressed in real-time with a system operating limit (SOL), and power transfer is limited if an overload risk is detected. This new line is now under construction and is expected to be in service in 2023.

Transmission
The Romaine River Hydro Complex Integration Construction is in its final phase; its capacity will be 1,550 MW. Romaine-2 (640 MW), Romaine-1 (270 MW), and Romaine-3 (395 MW) have been commissioned. Romaine-4 (245 MW) is expected to be in service by the end of 2022. Hydro-Québec has identified the need to build a new 735 kV line that extends some 250 km (155 miles) between Micoua substation in the Côte-Nord area and Saguenay substation in Saguenay–Lac–Saint-Jean. The project also includes adding equipment to both substations and expanding Saguenay substation. This project is now under construction and is expected to be in service in 2023.

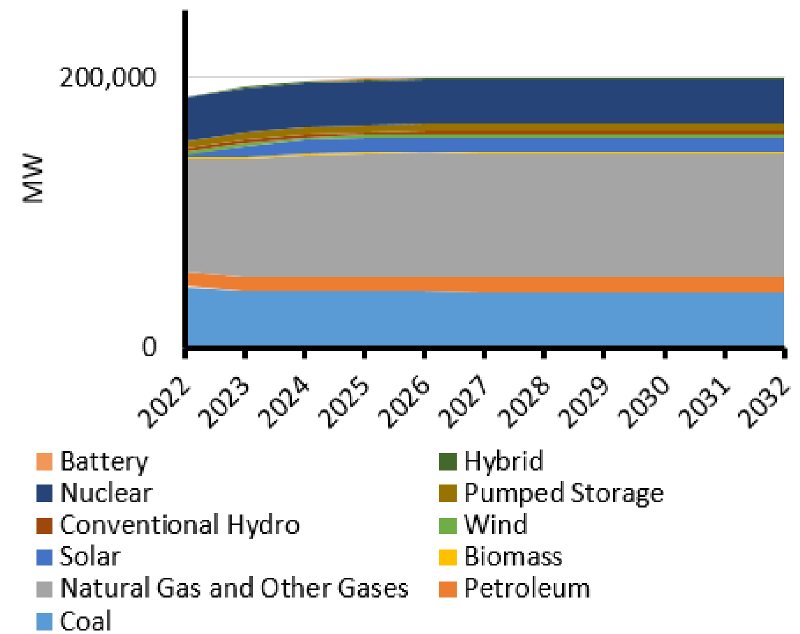
The Hertel-New York Interconnection (Champlain Hudson Power Express) project to increase transfer capability between Québec and New York by 1,250 MW is currently in the permitting phase. It involves the construction of a ±400-kV dc underground transmission line about 60 km (37 miles) long from Hertel 735/315-kV substation just south of Montréal to the Canada–United States border. The project will connect to the CHPE in New York State. From the international border crossing, the dc transmission line will be extended 339 miles to a substation in Astoria, New York, where the power will be converted from dc to ac. The project in Québec also includes the construction of an ac to dc converter at Hertel substation. The project is expected to be in service in December 2025.

Hydro Québec currently has no transmission under construction and 280 miles of planned transmission lines during this 10-year assessment period.

Demand, Resources, and Reserve Margins (MW)										
Quantity	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Total Internal Demand	149,351	150,309	151,165	152,259	152,322	152,689	153,334	153,775	154,275	154,381
Demand Response	7,065	7,104	7,133	7,161	7,167	7,176	7,200	7,219	7,235	7,240
Net Internal Demand	142,286	143,205	144,032	145,098	145,155	145,513	146,134	146,556	147,040	147,141
Additions: Tier 1	12,171	16,780	18,330	19,227	19,495	19,495	19,495	19,495	19,495	19,495
Additions: Tier 2	37,416	70,337	97,046	109,748	113,942	116,123	116,448	116,825	116,825	116,825
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	82	1,302	-321	-95	-299	-299	-299	-299	-299	-299
Existing-Certain and Net Firm Transfers	180,982	182,204	180,581	180,807	180,191	180,191	180,191	180,191	180,191	180,191
Anticipated Reserve Margin (%)	35.7%	39.0%	38.1%	37.9%	37.6%	37.2%	36.6%	36.3%	35.8%	35.7%
Prospective Reserve Margin (%)	60.2%	84.3%	102.9%	109.0%	110.8%	111.3%	110.6%	110.3%	109.6%	109.5%
Reference Margin Level (%)	14.8%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARMs for each year in this assessment period do not fall below the PJM installed reserve requirement (the RML).

PJM Fuel Composition (MW)										
Fuel	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Coal	43,401	43,401	43,401	43,401	42,989	42,989	42,989	42,989	42,989	42,989
Petroleum	10,986	10,986	10,986	10,986	10,986	10,986	10,986	10,986	10,986	10,986
Natural Gas	87,312	90,038	91,064	91,694	91,694	91,694	91,694	91,694	91,694	91,694
Biomass	964	964	964	964	964	964	964	964	964	964
Solar	8,470	10,183	10,299	10,299	10,299	10,299	10,299	10,299	10,299	10,299
Wind	1,949	1,979	2,375	2,642	2,910	2,910	2,910	2,910	2,910	2,910
Conventional Hydro	2,438	2,444	2,456	2,456	2,456	2,456	2,456	2,456	2,456	2,456
Pumped Storage	5,131	5,131	5,131	5,131	5,131	5,131	5,131	5,131	5,131	5,131
Nuclear	32,656	32,656	32,656	32,656	32,656	32,656	32,656	32,656	32,656	32,656
Hybrid	1,250	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,334
Battery	4	57	57	57	57	57	57	57	57	57
Total MW	194,560	199,172	200,722	201,619	201,475	201,475	201,475	201,475	201,475	201,475

PJM Assessment

Planning Reserve Margins

The ARMs for each year in this assessment period do not fall below the PJM installed reserve requirement (RML). Because PJM has extensive capacity resources, the risk for capacity shortages during non-peak periods is minimal.

Non-Peak Hour Risk, Energy Assurance, Probabilistic Based Assessments

PJM is expecting a low risk of experiencing periods of resources falling below required operating reserves during upcoming peak periods. PJM is forecasting around 30% installed reserves (including expected committed demand resources), well above the target installed reserve margin of 14.7% necessary to meet the 1-day-in-10 years LOLE criterion. PJM analyzed a wide range of load scenarios (low, regular, and extreme) as well as multiple scenarios for system-wide unavailable capacity due to forced outages, maintenance outages, and ambient derations. Due to the rather low penetration of limited and variable resources in PJM relative to PJM's peak load, the hour with most loss of load risk remains the hour with highest forecasted demand. To address potential future reliability concerns due to limitations associated with the performance of limited and variable resources, PJM has filed an effective load carrying capability methodology with FERC to properly calculate the reliability and capacity contribution of limited and variable resources.

Probabilistic Assessment

LOLH and EUE are zero for both 2024 and 2026 due to large forecast operable reserve margins. The reserve margins are significantly above the reference values of 14.7%.

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	0.00	0.00	0.00
EUE (ppm)	0.00	0.00	0.00
LOLH (Hours per Year)	0.00	0.00	0.00
Operable On-peak Margin	29.0%	29.0%	28.0%

* Provides the 2020 ProbA results for comparison

Demand

PJM produces an independent peak load forecast of total internal demand using econometric regression models with daily load as the dependent variable and independent variables, including calendar effects, weather, economics, and end-use characteristics. Daily unrestricted peak load is defined as metered load plus estimated load drops and estimated distributed solar generation.
Separately from the modeled forecast, a forecast of the peak impact of distributed solar generation is developed with internal installed solar capacity data and a forecast of solar capacity additions obtained from a vendor. The impact on peak is estimated by applying a historical capacity factor to installed capacity. Additionally, a separate forecast of load management is developed based on the amount of resources that have historically committed though PJM's FCM. The load management forecast is used to develop the net internal demand forecast.

PJM annually reviews its load forecast methodology and implements changes when improvements are identified. For the 2021 load forecast, the major changes encompassed refinements to sector models and non-weather-sensitive load, both of which were first introduced with the 2020 load forecast. With respect to sector models, the commercial component of the load model was improved with the addition of service sector employment to more accurately reflect evolving economic conditions. Improvements to non-weather-sensitive models were also made to better align with underlying drivers and historical trends, reducing expected load impacts. Each year, PJM measures the accuracy of the long-term load forecast model by running it with up-to-date inputs, solving with actual weather, and comparing to actual load. This measure of accuracy is meant to show how well the model would have performed with the most recent forecast inputs. PJM reviews model accuracy results on the 10 highest coincident peak days for each season for a number of forecast horizons with the Load Analysis Subcommittee. Over this assessment period, PJM projects the total internal demand growth to increase at a CAGR of 0.37% for summer and 0.64% for winter.

Demand Side Management

DR resources can participate in all PJM markets: capacity, energy, and ancillary services:

Capacity: Capacity service providers have the ability to participate in PJM's reliability pricing model auctions up to three years in advance of the delivery year (PJM delivery year is June–May).

Energy: DR resources may register for and bid into PJM day-ahead and real-time energy (economic) markets.

Ancillary Services: DR resources may register for and must be certified for participation in PJM ancillary service markets as per the requirements for each ancillary service type as found in PJM manuals.

Distributed Energy Resources

PJM expects[36] 3,176 MW of solar DERs at the time of the peak in 2024 and 5,828 MW in 2031. The effects of solar DERs are included in the load forecast for PJM. No solar DER effects are incorporated in the winter load forecast since winter expected peak occurs after sundown.

Generation

PJM processed 1,028 requests to interconnect new generation, totaling 70,375 MW, nameplate capability and 44,179 MW of capacity interconnection rights. Wind, solar, and storage requests now total over 120,000 MW (nameplate) in PJM's interconnection queue. Solar has more than doubled over 2019, it now comprising 56% of PJM's queue.

PJM's existing installed capacity reflects a fuel mix comprising approximately 43% natural gas, 27% coal, and 18% nuclear. Hydro, wind, solar, oil, and waste fuels constitute the remaining 12%. A diverse generation portfolio reduces the system risk associated with fuel availability and reduces dispatch price volatility. Totaling over 76,000 MW (nameplate), renewable fuels are changing the landscape of PJM's interconnection queue. Solar energy comprises 56% of the generation in PJM's interconnection queue.

Prior to 2021, the variable resource capacity value was set at a resource's average output over a defined number of summer peak load hours. This approach has two limitations: it weights the output over all hours equally regardless of an individual hour's actual contribution to the annual loss of load risk, and it fails to recognize the saturation effect as the amount of intermittent resources in PJM increases. To address these two limitations, PJM performed analysis to assess the reliability value of intermittent resources by using an ELCC methodology. This more robust methodology recognizes the full value of a resource's output over high-load risk hours and also accounts for the saturation effect. As part of the process to implement the ELCC, a proposal was developed. PJM now requires generation owners of ELCC resources to provide specific information about their resources. This information is used by PJM as an input to its resource adequacy model. Pending FERC approval, the ELCC methodology will be applied to variable, limited-duration and hybrid resources beginning with the 2023/2024 delivery year.

Energy Storage

Energy storage continues to grow in PJM. Efficient grid operations in an era experiencing rapid growth of VERs will require increased electric system flexibility. Energy storage provides grid operators with the ability to meet load requirements when wind, solar, and other variable resources must alter power output because of weather conditions or because those units simply are unavailable. Energy storage resources can also improve transmission system efficiency by increasing network utilization factors. PJM has worked with several industry entities, including Department of Energy national laboratories, to advance the use of energy storage and ensure that PJM's wholesale market is capable of allowing all forms of energy storage technology to participate competitively.

Transmission

A 15-year long-term planning horizon allows PJM to consider the aggregate effects of many drivers. Initially, with its inception in 1997, PJM's Regional Transmission Expansion Plan (RTEP) consisted of system enhancements that were mainly driven by load growth and generating resource interconnection requests. Today, PJM's RTEP process studies the interaction of many drivers, including those that arise out of reliability, aging infrastructure, operational performance, market efficiency, public policy, and demand-side trends. Importantly though, RTEP development considers all drivers through a reliability criteria and resilience lens. PJM's RTEP process encompasses a comprehensive assessment of system compliance with the thermal, reactive, stability, and short-circuit NERC Reliability Standard TPL-001-4.

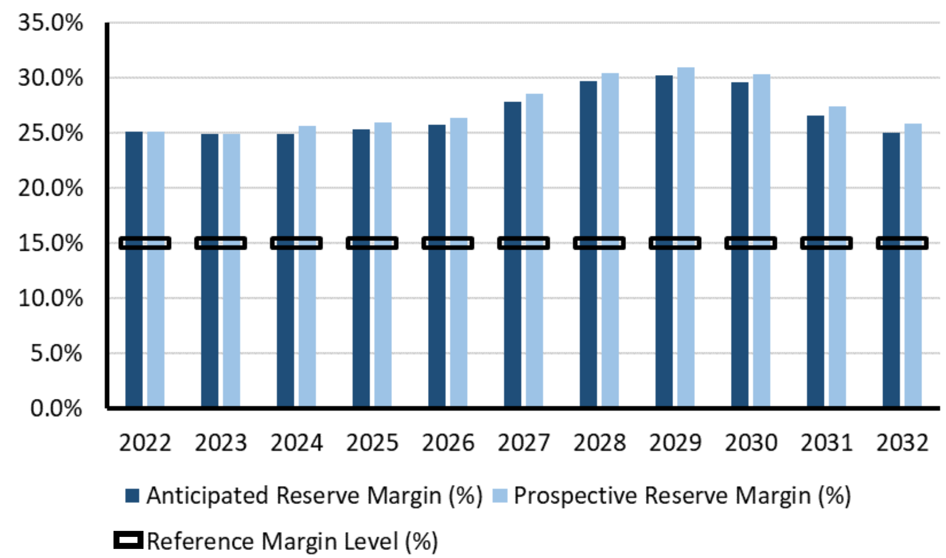
Historically, baseline transmission projects have been driven by reliability criteria, market efficiency needs, and Transmission Owner criteria requirements. PJM's state agreement approach, authorized by FERC, expands the planning process to enable a state or group of states to propose a project to advance public policy requirements as long as the states involved agree to pay all costs of any related build-out included in the RTEP. The state agreement approach was developed seven years ago after extensive consultation with the Organization of PJM States as part of implementing FERC's Order 1000. In that order, FERC required regional grid operators to "provide for the consideration of transmission needs driven by public policy requirements in the local and regional transmission planning processes." PJM currently has 35 miles of transmission lines under construction and 949 miles of planned transmission lines during this 10-year assessment period.

[36] https://www.pjm.com/-/media/library/reports-notices/load-forecast/2021-load-report.ashx

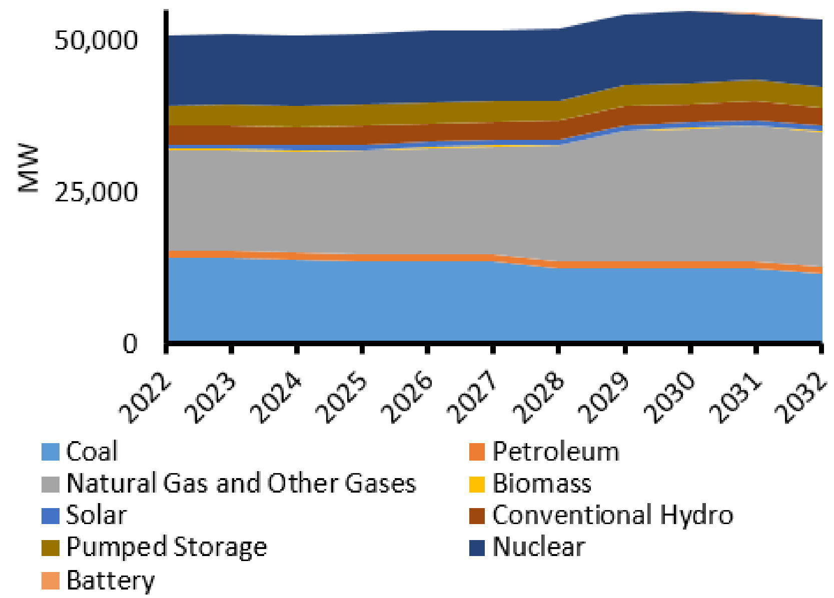
Demand, Resources, and Reserve Margins (MW)

Quantity	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total Internal Demand	44,878	44,996	45,091	45,320	45,490	45,953	46,135	46,706	47,164	47,636
Demand Response	1,130	1,131	1,136	1,141	1,142	1,143	1,144	1,145	1,146	1,147
Net Internal Demand	43,748	43,865	43,955	44,179	44,348	44,810	44,991	45,561	46,018	46,489
Additions: Tier 1	643	1,045	1,502	1,959	3,330	5,924	6,381	6,838	6,838	7,752
Additions: Tier 2	0	298	303	310	320	329	338	347	356	361
Additions: Tier 3	102	234	3,198	5,525	5,573	6,495	6,505	6,538	6,610	6,639
Net Firm Capacity Transfers	513	513	513	513	513	513	513	513	513	513
Existing-Certain and Net Firm Transfers	53,995	53,751	53,584	53,584	53,352	52,202	52,202	52,202	51,430	50,377
Anticipated Reserve Margin (%)	24.9%	24.9%	25.3%	25.7%	27.8%	29.7%	30.2%	29.6%	26.6%	25.0%
Prospective Reserve Margin (%)	24.9%	25.6%	26.0%	25.2%	27.3%	29.2%	29.8%	29.2%	26.2%	24.7%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%

*Table contains summer data. Although SERC-East forecasts higher peak demand in some years during winter, the winter resource capacity and reserve margins are also higher.



Planning Reserve Margins

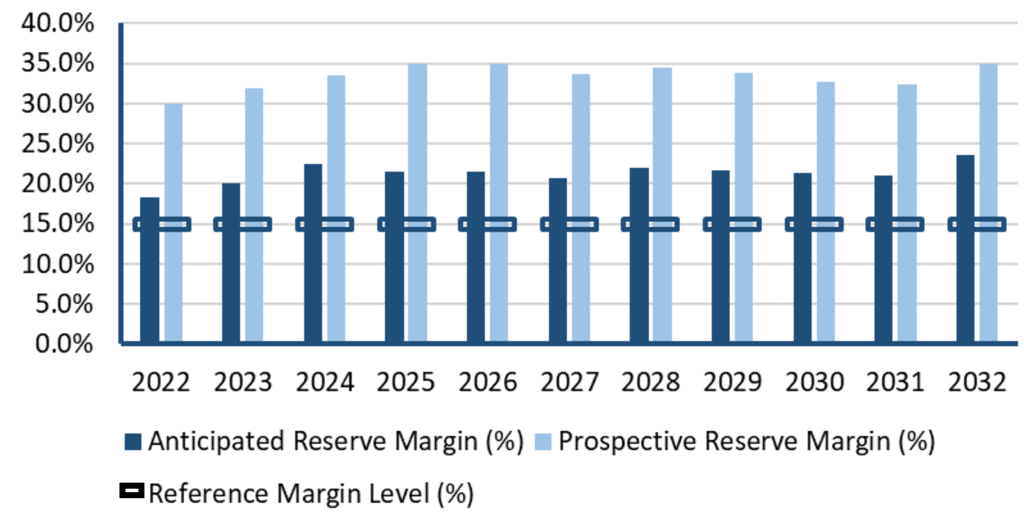


Existing and Tier 1 Resources

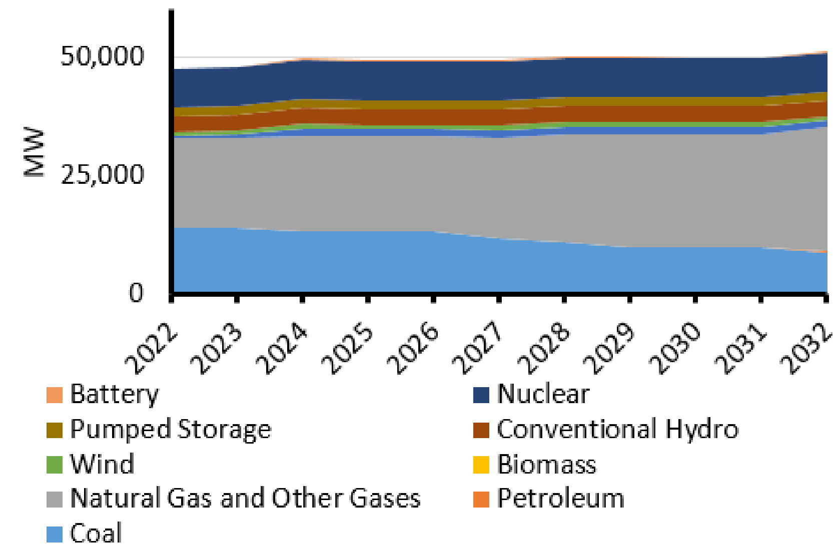
SERC-East Fuel Composition (MW)										
Fuel	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Coal	14,124	13,865	13,703	13,703	13,703	12,573	12,573	12,573	12,573	11,526
Petroleum	1,174	1,174	1,174	1,174	1,122	1,122	1,122	1,122	1,141	1,141
Natural Gas	16,726	16,726	17,091	17,510	17,805	19,062	21,470	21,889	22,308	22,308
Biomass	158	158	158	158	158	158	158	158	158	158
Solar	793	848	848	848	848	848	848	848	848	848
Conventional Hydro	3,104	3,104	3,104	3,104	3,104	3,104	3,104	3,104	3,104	3,104
Pumped Storage	3,364	3,364	3,364	3,364	3,364	3,364	3,364	3,364	3,364	3,364
Nuclear	11,774	11,789	11,789	11,789	11,789	11,789	11,789	11,789	11,030	11,030
Battery	11	11	11	11	11	11	11	11	11	11
Total MW	51,227	51,038	51,241	51,660	51,903	52,030	54,438	54,857	54,536	53,489

Demand, Resources, and Reserve Margins (MW)										
Quantity	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Total Internal Demand	41,343	41,791	41,787	41,794	41,825	41,978	42,052	42,145	42,235	42,452
Demand Response	1,786	1,751	1,754	1,758	1,762	1,761	1,759	1,758	1,757	1,756
Net Internal Demand	39,557	40,040	40,033	40,036	40,063	40,217	40,293	40,387	40,478	40,696
Additions: Tier 1	446	2,690	3,304	3,304	4,757	6,210	7,306	7,306	7,306	9,604
Additions: Tier 2	90	244	1,310	1,310	1,310	1,310	1,310	1,310	1,310	1,310
Additions: Tier 3	50	100	930	1,640	2,505	3,215	3,925	4,111	4,297	4,755
Net Firm Capacity Transfers	-491	-491	-691	-691	-866	-866	-866	-866	-866	-866
Existing-Certain and Net Firm Transfers	47,063	46,323	45,323	45,323	43,568	42,840	41,710	41,680	41,680	40,712
Anticipated Reserve Margin (%)	20.1%	22.4%	21.5%	21.5%	20.6%	22.0%	21.7%	21.3%	21.0%	23.6%
Prospective Reserve Margin (%)	31.9%	33.5%	34.9%	34.9%	33.6%	34.5%	33.9%	32.7%	32.4%	34.9%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%

*Table contains summer data. Although SERC-Central forecasts higher peak demand in some years during winter, the winter resource capacity and reserve margins are also higher.



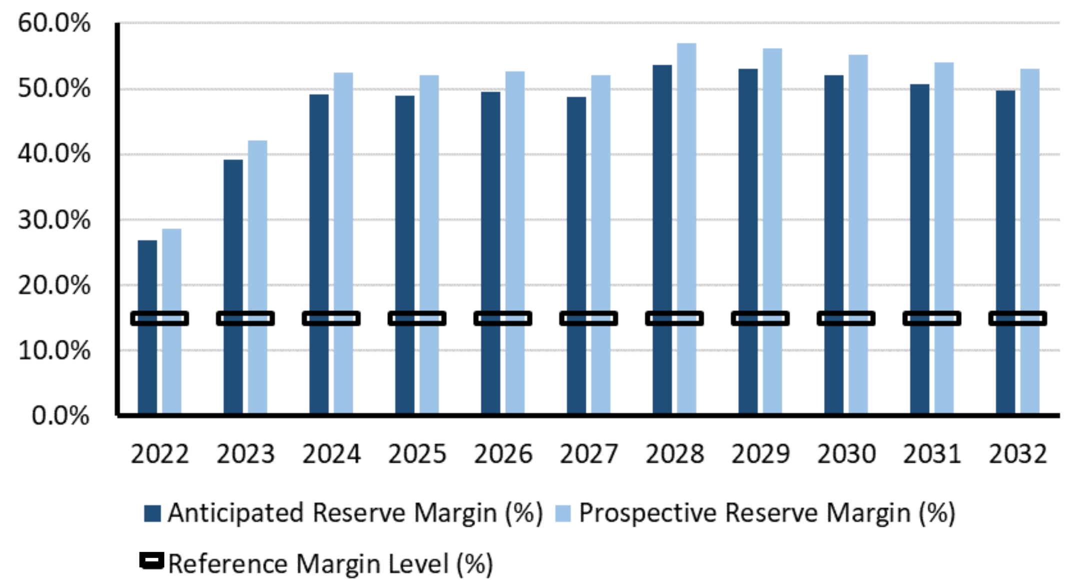
Planning Reserve Margins



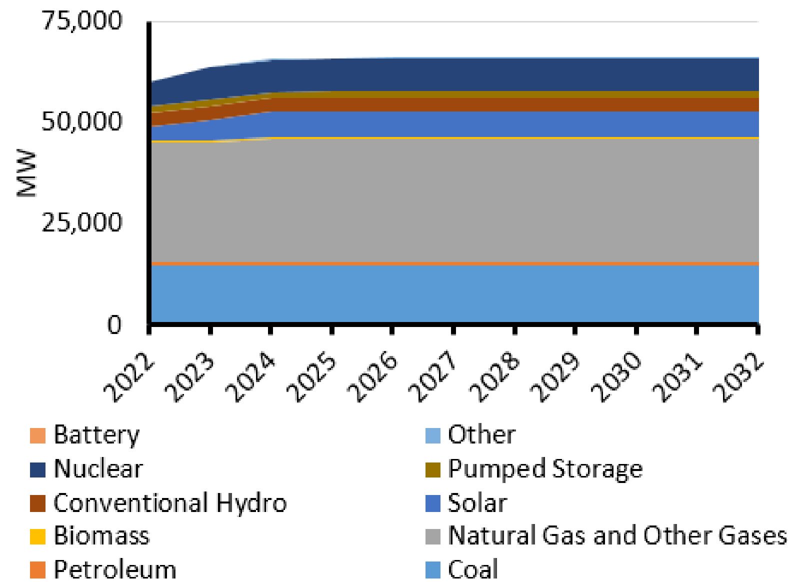
Existing and Tier 1 Resources

SERC-Central Fuel Composition (MW)										
Fuel	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Coal	14,002	13,242	13,242	13,242	11,662	10,934	9,804	9,804	9,804	8,836
Petroleum	64	64	64	64	64	64	64	64	64	64
Natural Gas	18,750	20,064	19,812	19,812	21,265	22,718	23,814	23,784	23,784	26,082
Biomass	44	44	44	44	44	44	44	44	44	44
Solar	683	1,485	1,530	1,530	1,530	1,530	1,530	1,530	1,530	1,530
Wind	958	958	958	958	958	958	958	958	958	958
Conventional Hydro	3,413	3,413	3,413	3,413	3,413	3,413	3,413	3,413	3,413	3,413
Pumped Storage	1,755	1,775	1,775	1,775	1,775	1,775	1,775	1,775	1,775	1,775
Nuclear	8,282	8,282	8,282	8,282	8,282	8,282	8,282	8,282	8,282	8,282
Battery	50	178	199	199	199	199	199	199	199	199
Total MW	48,000	49,504	49,318	49,318	49,191	49,916	49,882	49,852	49,852	51,182

Demand, Resources, and Reserve Margins (MW)										
Quantity	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total Internal Demand	46,082	45,630	45,826	45,814	46,022	44,638	44,826	44,938	45,290	45,586
Demand Response	1,197	2,118	2,129	2,223	2,222	2,222	2,213	2,090	2,091	2,091
Net Internal Demand	44,885	43,512	43,697	43,591	43,800	42,416	42,613	42,848	43,199	43,495
Additions: Tier 1	3,843	5,172	5,314	5,314	5,314	5,314	5,314	5,314	5,314	5,314
Additions: Tier 2	473	593	593	593	593	593	593	593	593	593
Additions: Tier 3	2,742	3,010	3,010	3,010	3,010	3,010	3,010	3,010	3,010	3,010
Net Firm Capacity Transfers	-1,308	-892	-871	-821	-821	-821	-820	-862	-866	-866
Existing-Certain and Net Firm Transfers	58,618	59,738	59,759	59,868	59,868	59,868	59,869	59,827	59,823	59,823
Anticipated Reserve Margin (%)	39.2%	49.2%	48.9%	49.5%	48.8%	53.7%	53.0%	52.0%	50.8%	49.8%
Prospective Reserve Margin (%)	42.0%	52.4%	52.1%	52.7%	52.0%	57.0%	56.2%	55.3%	54.0%	53.0%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



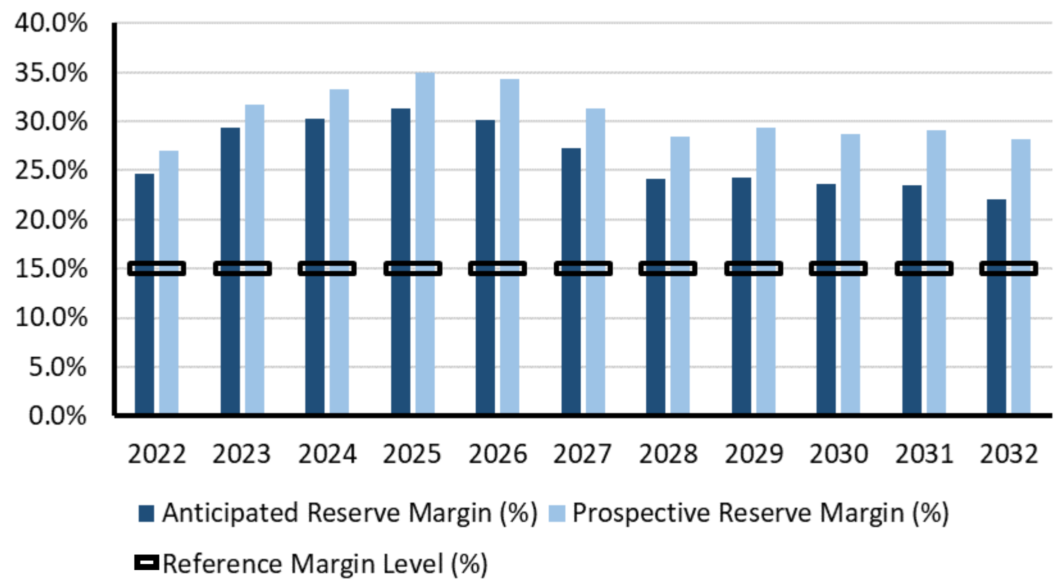
Planning Reserve Margins



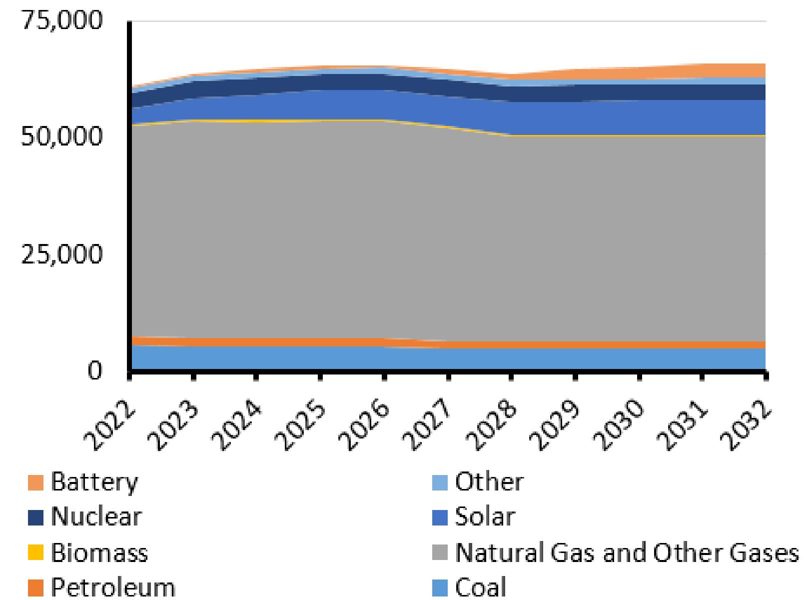
Existing and Tier 1 Resources

SERC-Southeast Fuel Composition (MW)										
Fuel	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Coal	14,642	14,642	14,642	14,642	14,642	14,642	14,642	14,642	14,642	14,642
Petroleum	929	929	929	929	929	929	929	929	929	929
Natural Gas	29,572	30,276	30,276	30,335	30,335	30,335	30,335	30,335	30,335	30,335
Biomass	449	449	449	449	449	449	449	449	449	449
Solar	4,925	6,254	6,395	6,395	6,395	6,395	6,395	6,395	6,395	6,395
Conventional Hydro	3,288	3,288	3,288	3,288	3,288	3,288	3,288	3,288	3,288	3,288
Pumped Storage	1,632	1,632	1,632	1,632	1,632	1,632	1,632	1,632	1,632	1,632
Nuclear	6,918	8,018	8,018	8,018	8,018	8,018	8,018	8,018	8,018	8,018
Other	313	313	313	313	313	313	313	313	313	313
Battery	2	2	2	2	2	2	2	2	2	2
Total MW	63,769	65,802	65,943	66,002	66,002	66,002	66,002	66,002	66,002	66,002

Demand, Resources, and Reserve Margins (MW)										
Quantity	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total Internal Demand	52,427	52,857	53,140	53,654	54,128	54,605	55,322	56,010	56,600	57,313
Demand Response	2,949	2,965	2,990	3,024	3,064	3,107	3,154	3,197	3,205	3,214
Net Internal Demand	49,478	49,892	50,150	50,630	51,064	51,498	52,168	52,813	53,395	54,099
Additions: Tier 1	4,295	5,528	6,126	6,512	7,060	7,694	8,613	9,084	9,739	9,781
Additions: Tier 2	0	374	674	973	973	1,123	1,487	1,562	1,851	2,226
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	303	406	406	306	306	306	306	306	306	306
Existing-Certain and Net Firm Transfers	59,704	59,446	59,727	59,376	57,916	56,222	56,222	56,222	56,222	56,222
Anticipated Reserve Margin (%)	29.3%	30.2%	31.3%	30.1%	27.2%	24.1%	24.3%	23.7%	23.5%	22.0%
Prospective Reserve Margin (%)	31.7%	33.3%	34.9%	34.3%	31.4%	28.5%	29.3%	28.8%	29.1%	28.2%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

SERC-Florida Peninsula Fuel Composition (MW)										
Fuel	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Coal	5,184	5,184	5,184	5,184	4,725	4,725	4,725	4,725	4,725	4,725
Petroleum	2,017	2,017	2,017	1,846	1,718	1,718	1,718	1,718	1,718	1,718
Natural Gas	46,322	46,085	46,440	46,342	45,503	43,846	43,846	43,846	43,846	43,846
Biomass	491	487	449	449	414	414	414	414	414	414
Solar	4,407	5,419	5,981	6,367	6,564	6,801	7,033	7,133	7,238	7,279
Nuclear	3,502	3,502	3,502	3,502	3,502	3,502	3,502	3,502	3,502	3,502
Other	1,255	1,255	1,255	1,274	1,274	1,274	1,274	1,274	1,274	1,274
Battery	519	619	619	619	969	1,329	2,016	2,388	2,938	2,938
Total MW	63,696	64,568	65,447	65,582	64,670	63,610	64,529	65,000	65,655	65,697

SERC Assessment

Highlights

- This narrative summary/highlight does not include parts of PJM and MISO areas that are within SERC boundaries.
- All SERC assessment areas are projected to maintain sufficient capacity to meet the reliability planning reserve margin during this assessment time frame.
- The load within three SERC assessment areas is projected to peak in winter.
- The SERC assessment areas continue to see growth in natural-gas-fired generation. Natural-gas-fired generation capacity is projected to make up over 50% of the generating capacity, approximately 118,621 MW by 2031.

Planning Reserve Margins

ARMs are at or above 20% in all assessment areas and do not fall below the NERC 15% target reference margin at any point during this assessment period.

The SERC Resource Adequacy Working Group is beginning to explore developing a SERC subregional reliability reference margin to determine resource adequacy with the changes to the resource mix and the growth of IBRs. In this *2022 LTRA*, SERC continues to use the default target reference margin of 15% .

Non-Peak Hour Risk, Energy Assurance, Probabilistic Based Assessments

SERC is made up of many members that perform their own internal studies and participate in studies under the direction of the SERC Engineering Committee. Some entities have performed studies to evaluate the fuel resiliency of all generating assets in their portfolio, including fuel supply, fuel delivery, inventory, and backup contingencies to determine the potential impact fuel diversity has on the Planning Reserve Margin. These studies suggest that SERC's overall fuel supply position is among the most resilient in the United States due to a well diverse generation portfolio, advantageous location with respect to major natural gas pipelines, access to multiple coal supply and transport options, and a strong and resilient program to secure nuclear fuel.

Reserve margin studies performed by SERC members consider a wide range of peaking conditions, including extreme weather conditions and historical water conditions. Low water conditions impact plant cooling and can have an associated reduction in plant output. This impact is modeled in reserve margin studies by increasing equivalent forced outage rates of affected plants and can lead to the identification of additional supply shortfall risk. VERs are assigned monthly net dependable capacities based on reviews of historical performance and/or historical irradiance in the geographic area.

Probabilistic Assessment

The 2022 ProbA indicates slightly tighter reserve margin results for year 2024 as compared to the 2020 ProbA. Probabilistic annual indices indicate a small loss of load risk during the morning hours of winter peak as solar resources continue to increase.

SERC-East is transitioning from a summer-peaking area to a winter peaking one. This change in peaking is mainly driven by two factors: continued electrification as well as growing solar resources that shave off the summer peak. Probabilistic Base Case results indicate a trend of growing risk during winter morning hours when solar resource capacity is low. The results for year 2026 indicate that the reliability metrics during January morning hours degrade as solar resources grow. As SERC-East transitions to peaking in winter, the growth in solar capacity projected for 2026 helps reduce loss of load risk during summer hours.

SERC East Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	5.26	64.33	92.49
EUE (ppm)	0.024	0.272	0.389
LOLH (Hours per Year)	0.01	0.06	0.081
Operable On-peak Margin	15.9%	15.0%	16.1%

* Provides the 2020 ProbA results for comparison

Anticipated Reserve Margins are in the 25–30% range over the 10-year period and are above the 15% reference margin in 2024 and 2026, 24.9% and 25.7% respectively, resulting in negligible LOLH and EUE.

SERC Central Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	0.00	0.00	0.00
EUE (ppm)	0.00	0.00	0.00
LOLH (Hours per Year)	0.00	0.00	0.00
Operable On-peak Margin	18.4%	18.6%	17.1%

Anticipated Reserve Margins are in the 20–24% range over the 10-year period and are above the 15% reference margin if 2024 and 2026, 22.4% and 21.5% respectively, resulting in negligible LOLH and EUE.

SERC Florida Peninsula Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	2.26	1.09	1.13
EUE (ppm)	0.009	0.004	0.004
LOLH (Hours per Year)	0.004	0.002	0.002
Operable On-peak Margin	11.4%	18.3%	18.6%

* Provides the 2020 ProbA results for comparison

Anticipated Reserve Margins are in the 22–31% range over the 10-year period and are above the 15% reference margin in 2024 and 2026, 30.2% and 30.1% respectively, resulting in negligible LOLH and EUE.

SERC Southeast Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	0.03	0.00	0.00
EUE (ppm)	0.00	0.00	0.00
LOLH (Hours per Year)	0.00	0.00	0.00
Operable On-peak Margin	30.2%	26.8%	30.8%

* Provides the 2020 ProbA results for comparison

Anticipated Reserve Margins are in the 39–54% range over the 10-year period and are above the 15% reference margin in 2024 and 2026, 49.2% and 49.5% respectively, resulting in negligible LOLH and EUE.

SERC will focus on extreme weather as a risk and is looking to assess the impact of severe cold weather on their system. SERC plans to pick a specific case of cold weather, assume outage rates on their resource mix, and then look at differing load levels for the given cold weather case. Recent reports have identified the need to quantify cold weather across SERC as some of the SERC subregions were impacted in the recent cold weather events.

Demand

Methods to develop total internal demand projections vary amongst the entities in each assessment area. Utilities constantly monitor load projections, weather patterns, economic patterns, emerging technology (like EVs), and customer growth to determine forecast models and other factors. The assessment areas also use statistical models to calculate naturally occurring trends. The following text provides an overview of forecasting methodologies within each assessment area.

Projected demand growth within the assessment areas is relatively flat, about 0.7% over the years. SERC-Florida Peninsula has the highest growth rate of about 1% while SERC-Southeast is forecasting a growth rate of -0.2%. Although some metro areas are experiencing higher growth rates compared to rural areas, entities report load reductions due to BTM distributed generation and appliance standards. These factors will continue suppressing load in the future.

Demand Side Management

Entities within the SERC Region use a variety of controllable and dispatchable DR programs to reduce peak demand. Larger commercial and industrial customers may participate in incentive programs to reduce exposure to high power prices. The electrical load of these customers is often referred to as interruptible load. Generally, DR programs require a minimum lead-time to implement and may or may not have a limited number of implementations in order to mitigate reliability impacts on the BES.

Entities may also directly control residential switches and devices (referred to as direct control load management) to reduce peak demand dispatched for up to a certain amount of hours annually. Dispatchable Voltage Regulation programs that reduce peak demand by optimizing distribution-level voltage are another tool at entities' disposal.

These programs historically mitigate local reliability issues; however, recent pilot programs in SERC aggregate multiple states' DR programs to provide subregional DR similar to the Interruptible Load programs dispatched up to a certain amount of times annually to mitigate high power prices and with unlimited implementation for reliability events.

The capacity available on peak of these types of programs depends on contractual obligations and historical performance derates, which are largely weather dependent. Throughout the year, entities monitor and evaluate each program's operational functionality to determine effectiveness and ability to provide demand reduction.

Distributed Energy Resources

Entities continue to monitor DER penetration levels, assess the impacts from DER, and incorporate these impacts in system studies. Unlike directly modeled transmission-connected resources, DERs (e.g., rooftop solar, plug-in EVs) are netted against load in the energy management system and transmission planning models. Some entities are beginning to use software to develop DER projections of rooftop solar.

To date, there are no notable reliability impacts reported to the Regional Entity. Development of a SERC-wide estimated penetration forecast is not available at this time for BTM. The SERC VER Working Group continues to evaluate the appropriate methods for determining growth of solar in the SERC Region.

Generation

SERC entities have sufficient generation to meet demand over the period. New resources are expected, which include a combination of capacity purchases, new nuclear, natural gas, and combined-cycle units. Natural gas (51%), coal (18%), and nuclear (13%) generation are the dominant fuel types within the assessment areas. Hydro, renewables, and other fuel types (18%) are minimal. Entities within SERC will add approximately 10,633 MW of natural gas generation over the period. Overall, the assessment areas will encounter 15,310 MW of net additions and retirements over within the next 10 years. Approximately 16 GW of utility-scale transmission BES-connected Tier 1 solar projects are expected in the interconnection queue over the next five years and are largely developing in SERC-East and SERC-Florida Peninsula. No reliability issues are expected within the assessment areas, but entities are continuing to monitor the impacts of solar generators as they are added to the interconnection queue. Entities are studying winter season impact of additional solar to the resource mix and load forecast. As more BTM solar generation is added, some entities anticipate becoming winter-peaking systems, providing additional motivation to enforce winter reserve margins.

Energy Storage

Entities in SERC are starting to see an increase in the number of request of energy storage systems in their queues. Energy storage solutions, particularly batteries, continue to be viewed as an increasing necessity for support of grid services, including frequency regulation, solar smoothing, and/or energy shifting from localized renewable energy sources with a high incidence of intermittency (i.e., solar and wind). Many energy storage sites are reported as being paired with solar generation and are discharged into the system to meet customer demand. In the next 10 years, over 3700 MW of nameplate capacity Tier 1 energy storage facilities are being projected in the SERC footprint, over 93% in SERC-Florida Peninsula and 7% in SERC-Central assessment areas.

Capacity Transfers (Reliance on Assistance)

SERC members participate in the committee and study group structure to perform First Contingency Incremental Transfer Capability studies for the Region. These studies include evaluating transfer limitations between all assessment areas within the Region for the existing or planned system configuration and with normal (pre-contingency) operating procedures in effect, such that all facility loading is within normal ratings and all voltages are within normal limits.
Annually, the SERC Long-Term Working Group performs a study to evaluate transfer capability for a summer peak condition in the planning period that covers year one through year five. In addition, the SERC Near-Term Working Group performs two studies annually, prior to each upcoming seasonal peak (summer and winter). For a SERC study, SERC members apply a selection of transfers in pairs of varying magnitudes and directions non-simultaneously to a model with expected base transfers. The study's objective is to identify transmission system weaknesses, and not necessarily to evaluate whether the transfer itself could actually happen. The model is coordinated through the SERC and Multi-regional Modeling Working Group model building processes, and the model includes projections for generation dispatch, transmission system topology, system demand, and approved transmission uses. For each transfer, N-1 events for the entity and its neighbors are evaluated and monitored.

Transmission

SERC entities in the SERC assessment area are expecting more than 2,500 miles of overhead ac transmission lines throughout the assessment period (400–599 kV: over 20 miles, 300–399 kV: over 300 miles, 200–299 kV: over 600 miles, 151–199 kV: over 500 miles, 121–150 kV: over 400 miles, 100–120 kV: around 300 miles, and <100 kV: over 40 miles). These projects are in the planning/construction phase, and they are projected to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include adding new transformers (345/138kV, 161/500kV), upgrading existing transmission lines, storm hardening, and other system reconfigurations/additions to support transmission system reliability.

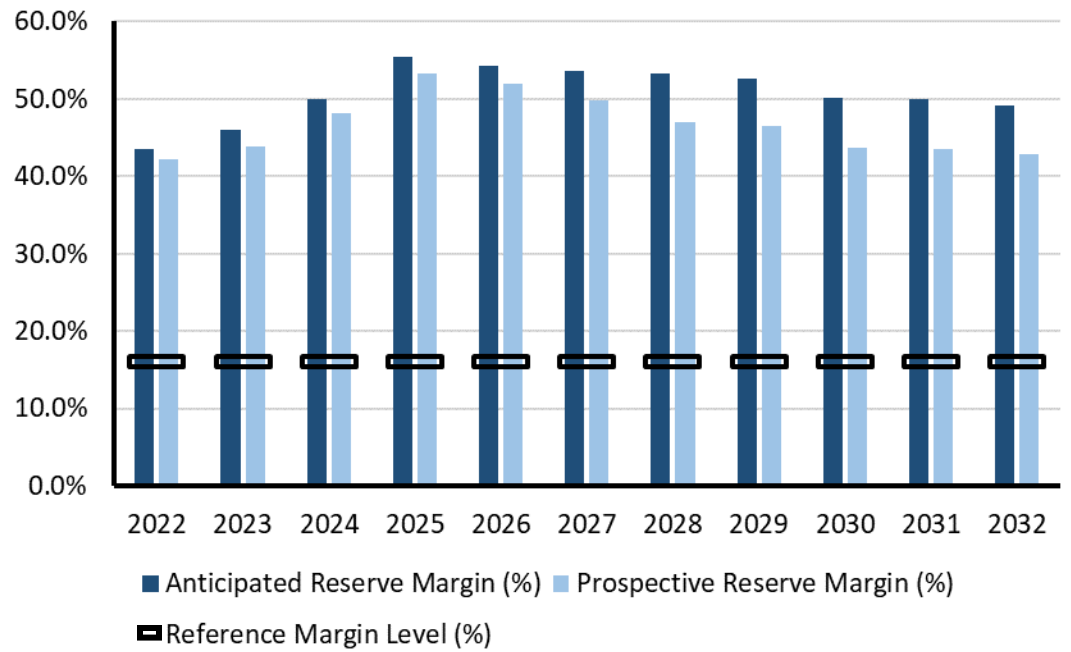
Entities do not anticipate any transmission limitations or constraints with significant impacts to reliability. However, there are some localized constraints exist under certain contingency situations in SERC-East and SERC-Central, where existing operating guides are coordinated to mitigate the potential overload and remain reliable.

Transmission and operational limitations exist near multiple generation sites in SERC-Central due to line loading and transfers on the 161 kV transmission system. To maintain reliability and mitigate around these constraints, must run units will operate during specific load levels or re-dispatching generation to reduce line loading and transfer issues.

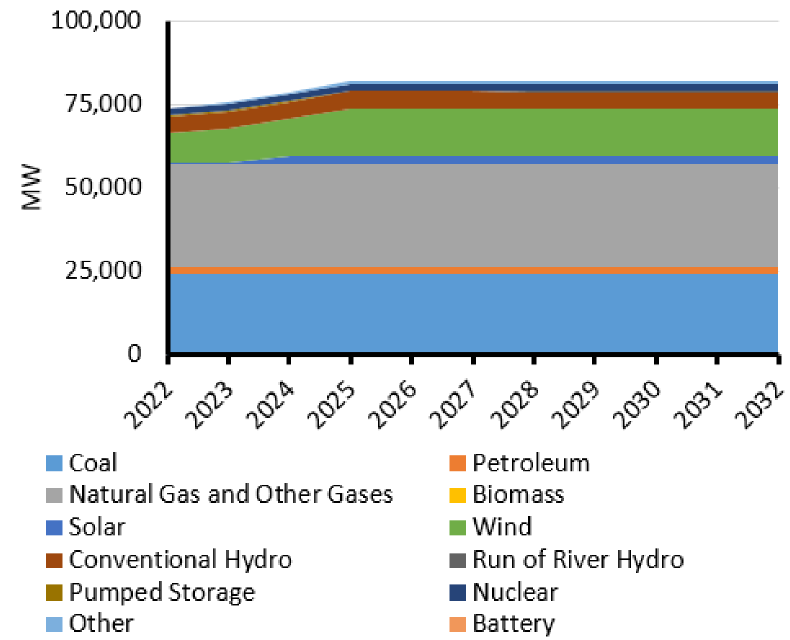
Reliability Issues

SERC and its members have not identified any other emerging reliability issues that do not have existing solutions. However, entities continue to monitor the possible impacts on the long-term reliability of the BES from the supply chain issues, changing resource mix, transmission projects and temporary mitigations, summer and dual peaking scenarios, extreme weather events, and critical infrastructure sector interdependency.

Demand, Resources, and Reserve Margins (MW)										
Quantity	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total Internal Demand	52,398	52,999	53,383	53,998	54,220	54,452	54,697	55,641	55,873	56,161
Demand Response	730	776	823	901	943	990	1,029	1,040	1,254	1,263
Net Internal Demand	51,668	52,224	52,561	53,097	53,277	53,462	53,668	54,601	54,619	54,898
Additions: Tier 1	4,902	7,630	10,880	10,880	10,880	10,880	10,880	10,880	10,880	10,880
Additions: Tier 2	575	1,175	1,175	1,175	1,175	1,175	1,175	1,175	1,175	1,175
Additions: Tier 3	17,985	25,658	44,484	48,088	50,588	50,588	50,588	50,588	50,588	50,588
Net Firm Capacity Transfers	-238	-213	-193	-173	-231	-156	-157	-157	-157	-157
Existing-Certain and Net Firm Transfers	70,527	70,665	70,822	71,057	70,998	71,068	71,066	71,055	71,044	71,035
Anticipated Reserve Margin (%)	46.0%	49.9%	55.4%	54.3%	53.7%	53.3%	52.7%	50.1%	50.0%	49.2%
Prospective Reserve Margin (%)	44.6%	47.8%	53.1%	51.3%	49.5%	48.8%	48.2%	45.7%	45.6%	44.9%
Reference Margin Level (%)	16.0%	16.0%	16.0%	16.0%	16.0%	16.0%	16.0%	16.0%	16.0%	16.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- ARMs do not fall below the RML for this assessment period.
- In 2022, the SPP Board approved an increase in PRMs for load responsible units from 12% to 15%. The Board also approved performance-based capacity accreditation rules for conventional resources. The two actions are aimed at ensuring sufficient resources are procured and available to meet peak demand as the resource mix evolves. Changes will go into effect in 2023.

SPP Fuel Composition (MW)										
Fuel	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Coal	24,226	24,226	24,226	24,226	24,226	24,226	24,226	24,226	24,226	24,226
Petroleum	1,849	1,849	1,849	1,849	1,849	1,849	1,849	1,849	1,849	1,849
Natural Gas	30,938	30,938	30,938	30,938	30,938	30,938	30,938	30,938	30,938	30,938
Biomass	43	43	43	43	43	43	43	43	43	43
Solar	631	2,506	2,506	2,486	2,482	2,478	2,477	2,473	2,468	2,468
Wind	10,188	11,038	14,288	14,291	14,289	14,288	14,286	14,284	14,284	14,282
Conventional Hydro	4,941	4,941	4,941	4,941	4,941	4,941	4,941	4,941	4,941	4,941
Run-of-River Hydro	18	18	18	18	18	18	18	18	18	18
Pumped Storage	444	444	444	444	444	444	444	444	444	444
Nuclear	1,949	1,949	1,949	1,949	1,949	1,949	1,949	1,949	1,949	1,949
Other	601	661	661	661	661	661	661	661	661	661
Total MW	75,827	78,613	81,862	81,845	81,840	81,835	81,831	81,826	81,821	81,818

SPP Assessment

Planning Reserve Margins

ARMs do not fall below the RML of 16% (SPP coincident) for the entire 10-year assessment period. The RML is determined by a probabilistic LOLE study. While the SPP PRM shows a robust amount of excess capacity, these margins do not account for planned, forced, or maintenance generator outages. Instead, they reflect the full availability of accredited capacity. Additionally, anticipated resources do not reflect derates based on real-time operational impacts. There is potential to still experience times of capacity shortfall based on performance impacts during high load periods despite the current projected LTRA PRM capacity. The *2022 Summer Reliability Assessment* provides an illustration of an extreme demand and low resource risk period in the SPP Seasonal Risk Scenario.[37]

Non-Peak Hour Risk, Energy Assurance, Probabilistic Based Assessments

SPP performs a biennial LOLE study to establish PRMs. SPP (with input from the stakeholders) develops the inputs and assumptions used for the LOLE study to analyze the ability to reliably serve the SPP BA area 50/50 forecasted peak demand while utilizing a security-constrained economic dispatch. SPP will study the PRM such that the LOLE for the applicable planning year (2- and 5-year studies) does not exceed 1-day-in-10 years. At a minimum, the PRM will be determined with probabilistic methods by altering capacity through the application of generator forced outages and forecasted demand through the application of load uncertainty to ensure that the LOLE does not exceed 1-day-in-10 years. In the 2021 LOLE study, other than the application of projected resource retirements, a future resource mix was not applied when analyzing Year 5 (2026) to establish the minimum PRM to maintain an LOLE 1-day-in-10 years. SPP performed a future generation sensitivity based on a future resource mix from the 2022 Integrated Transmission Planning (ITP) process.

The assumptions applied for planning year 2026 are shown as follows:

- 38,000 MW nameplate wind (additional 7,444 MW from the Base Case)
- 9,000 MW nameplate solar (additional 8,762 MW from the Base Case)
  - 125% overbuild (10,952 MW nameplate with overbuild)
- 3,700 MW four-hour duration battery

To effectively model the generation portfolio for analysis, existing wind facility capabilities were increased by 24% to simulate 38,000 MW of nameplate wind generation and replicate the historical wind profiles for each weather year. Since the SPP system currently has less than 300 MW of nameplate solar resources, a different methodology was used to reflect the future growth of solar installations. Locations that were developed in the 2022 ITP Future 2, Year 5 scenario were used for the analysis, resulting in 55 new solar locations. Additional information and conclusions are outlined in the *2021 LOLE Study Report*.[38]

Probabilistic Assessment

The 2020 Probabilistic Assessment results for SPP indicated 0.0 EUE and 0.0 Hours/year LOLH for years 2022 and 2024. The 2022 Probabilistic Assessment Base Case results indicate minimal LOLH and EUE for both years 2024 and 2026. The slight increase of the EUE is due to thermal retirements, increased VER penetration, and higher forecasted demand.

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	0.00	0.27	0.84
EUE (ppm)	0.00	0.00	0.00
LOLH (Hours per Year)	0.00	0.00	0.00
Operable On-peak Margin	13.3%	19.7%	19.6%

* Provides the 2020 ProbA results for comparison

Demand

SPP load peaks during the summer season; the 2022 load forecast is projected to peak at 51,058 MW, which is lower than the previous year's LTRA forecast for the 2022 summer season. A diversity factor is used to convert the non-coincident peak demand forecast to an SPP coincident peak demand forecast. SPP forecasts the coincident annual peak growth based on member submitted data over the 10-year assessment time frame. Over this assessment period, SPP projects the total internal demand growth to increase at a CAGR of 0.77% for summer and 0.91% for winter.

SPP's EE and conservation programs are incorporated into the reporting entities' demand forecasts. There are no known impacts to the SPP assessment area's long-term reliability related to the forecasted increase in EE and DR across the assessment area.

[37] See NERC's 2022 Summer Reliability Assessment, page 28:
https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2022.pdf

[38] https://www.spp.org/Documents/67465/2021%20SPP%20LOLE%20Study%20Report.pdf

Demand Side Management

As an additional sensitivity to the 2021 LOLE study, SPP modeled high level constraints applied to the current DR programs to understand the possible reliability impacts when constraining the programs to a limited number of calls per year and limited number of hours per day. The parameters were applied to each DR program, resulting in a PRM increase of approximately 0.5%. With the footprint's projected DR growth over the next few years, it will be important to model these programs accurately to better depict the reliability implications for the SPP system. The potential growth expansion in the DR and electrification will introduce a new level of uncertainty and reliability risk.

Distributed Energy Resources

The SPP assessment area has less than 50 MW of installed BTM solar currently, but it is forecasting between 700–750 MW of DERs in the 5–10-year planning horizon. The SPP Model Development, Economic Studies, and the Supply Adequacy working groups develop policies and procedures around DERs.

Generation

Since the *2021 LTRA*, SPP members have reported approximately 300 MW of conventional resources being retired. Reliability impacts of generator retirements are assessed throughout the planning process, and no impacts from these confirmed retirements are anticipated. Additionally, the impact of confirmed retirements on resource adequacy was analyzed in the 2021 LOLE study, and the impacts that retired generation have on the transmission system are analyzed in the annual ITP.

Energy Storage

There are approximately 17,000 MW of energy storage and hybrid resources in generator interconnection queue with 500 MW of that generation under contract by members across the SPP assessment area. These resources are being modeled as generation in the planning assumptions both near- and long-term.

Starting with the 2023 summer season, the ELCC methodology will be implemented for standalone energy storage resources. This will be the first set of policies for accreditation implemented by SPP for energy storage resources. By applying ELCC methodology, energy storage resources will be more properly accredited, which becomes critical as more conventional generators near retirement and cause SPP historical planning reserve margin levels to decline.

Capacity Transfers (Reliance on Assistance)

Planning entities in the SPP assessment area coordinate with neighboring areas to ensure that adequate transfer capabilities will be available for capacity transfers. On an annual basis, during the model build season, SPP staff coordinates the modeling of transfers between Planning Coordinator footprints. The modeled transactions are fed into the models created for the SPP planning process.

In April 2019, SPP and ERCOT executed a coordination plan that superseded the prior coordination agreement. The coordination plan addressed operational issues for the dc ties between the Texas Interconnection and Eastern Interconnection, block load transfers, and switchable generation resources. Under the terms of the coordination plan, SPP has priority to recall the capacity of any switchable generation resources that have been committed to satisfy the resource adequacy requirements contained in Attachment AA of the SPP Open Access Transmission Tariff.

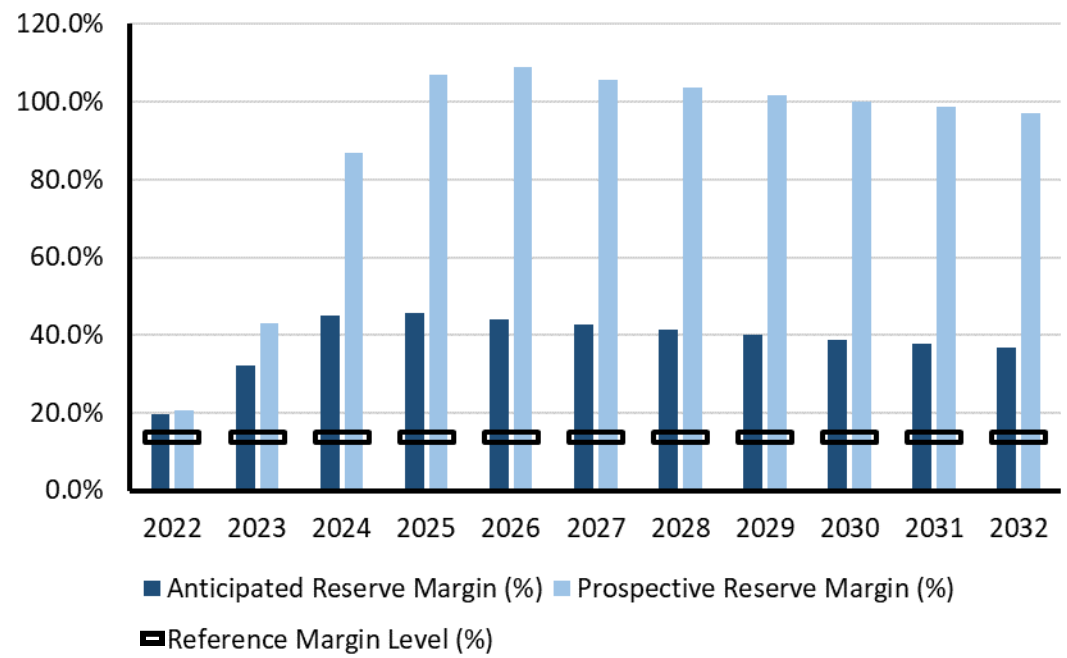
Transmission

The SPP 2021 ITP Assessment and the 2022 SPP Transmission Expansion Plan Report are both posted on the SPP website. Both reports provide details for proposed transmission projects needed to maintain reliability while also providing economic benefit to the end users. SPP currently has no transmission under construction and 58 miles of planned transmission lines during this 10-year assessment period.

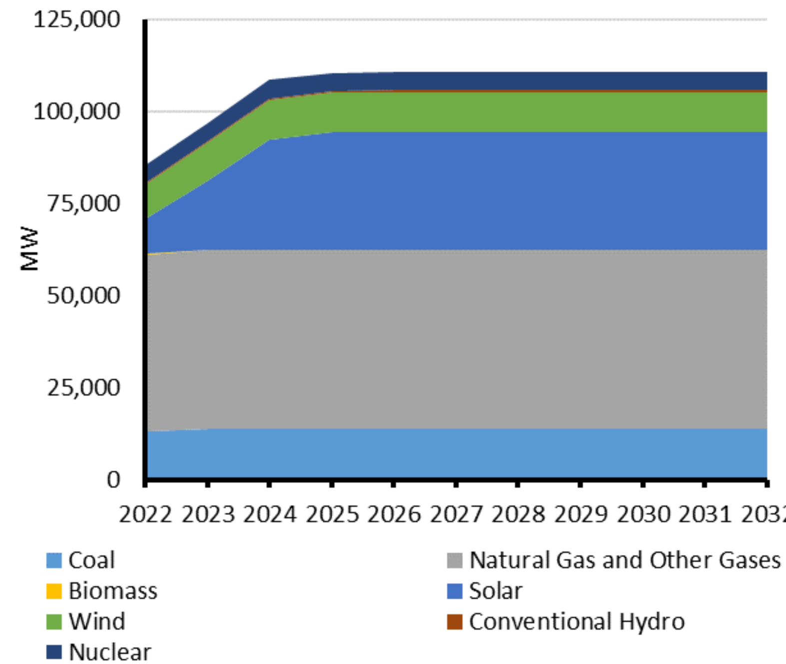
Reliability Issues

There are concerns of drought conditions impacting the Missouri River and other water sources for generation resources that rely on once-through cooling processes. A lack of water can impact the generator's capacity output and reduce its ability to serve load or ease congestion on the system. An additional concern could be the impact on coal availability that might cause units to run at a derated level to conserve supplies. These extreme conditions are studied in SPP's seasonal assessment process to identify mitigations prior to peak conditions. Additional analysis is performed with updated information as part of operations planning.

Demand, Resources, and Reserve Margins (MW)										
Quantity	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Total Internal Demand	79,329	80,554	81,581	82,606	83,398	84,146	84,878	85,569	86,233	86,863
Demand Response	2,750	2,750	2,750	2,750	2,750	2,750	2,750	2,750	2,750	2,750
Net Internal Demand	76,579	77,804	78,832	79,856	80,648	81,396	82,128	82,820	83,483	84,114
Additions: Tier 1	10,730	22,307	24,323	24,485	24,485	24,485	24,485	24,485	24,485	24,485
Additions: Tier 2	7,703	31,833	48,480	52,081	52,081	52,081	52,081	52,081	52,081	52,081
Additions: Tier 3	1,348	11,760	17,779	21,499	22,520	23,191	23,191	23,191	23,191	23,191
Net Firm Capacity Transfers	20	20	20	20	20	20	20	20	20	20
Existing-Certain and Net Firm Transfers	90,559	90,559	90,559	90,559	90,554	90,554	90,554	90,554	90,554	90,554
Anticipated Reserve Margin (%)	32.3%	45.1%	45.7%	44.1%	42.6%	41.3%	40.1%	38.9%	37.8%	36.8%
Prospective Reserve Margin (%)	43.1%	86.7%	106.9%	108.9%	104.2%	102.3%	100.5%	98.8%	97.2%	95.8%
Reference Margin Level (%)	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- Texas RE-ERCOT’s ARM is above the RML (13.75%) throughout this assessment period. The ARM continues on its increasing trend of recent prior years with the expected addition of nearly 25,000 MW of new capacity, most of which is solar generation.
- The continuing penetration of wind and solar is increasing the risk of tight operating reserves during hours other than the daily peak load hour. This issue is most acute for the summer season, but the spring can also be impacted since it is the peak unit maintenance season when planned outages are at their highest for the year.
- In addition to transmission and generator weatherization requirements in Texas, energy adequacy concerns that result from the impacts of severe winter storms have been addressed by the Public Utility Commission of Texas (PUCT), ERCOT, and market participants with market design changes for improving price signals, expanding ancillary service products (e.g., firm fuel supply service) as well as other operational reliability initiatives, such as improved reliability unit commitment and load resource deployment. Proposals for additional improvements are currently being considered.
- The Railroad Commission of Texas has adopted a weatherization rule for natural gas facilities (e.g., natural gas processing plants, natural gas pipelines directly serving electricity generators) to contribute to the reduction of power outages that occur during weather emergencies.

Texas RE-ERCOT Fuel Composition (MW)										
Fuel	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Coal	13,568	13,568	13,568	13,568	13,568	13,568	13,568	13,568	13,568	13,568
Natural Gas	48,843	48,854	48,854	48,854	48,854	48,854	48,854	48,854	48,854	48,854
Biomass	163	163	163	163	163	163	163	163	163	163
Solar	18,786	29,766	31,703	31,865	31,865	31,865	31,865	31,865	31,865	31,865
Wind	10,199	10,784	10,864	10,864	10,864	10,864	10,864	10,864	10,864	10,864
Conventional Hydro	475	475	475	475	475	475	475	475	475	475
Nuclear	4,973	4,973	4,973	4,973	4,973	4,973	4,973	4,973	4,973	4,973
Total MW	97,007	108,584	110,600	110,762	110,762	110,762	110,762	110,762	110,762	110,762

Texas RE-ERCOT Assessment

Planning Reserve Margins

The summer ARM is above the RML (13.75%) for all 10 years of this assessment period (2023–2032). The ARM increases significantly for the summers of 2023 and 2024 due to the expected addition of 22,306 MW of summer Tier 1 capacity, most of which is solar. Nevertheless, there are energy adequacy concerns due to the net load impacts of high solar capacity growth as well as extreme winter and summer weather events that have impacts on generator availability that can extend into the subsequent spring and fall seasons.

To address these energy adequacy concerns, the PUCT opened a rulemaking docket to reform the ERCOT wholesale market (Docket No. 52373); an initial outcome is the Commission's Wholesale Market Design Blueprint.[39] For Phase I of the Blueprint, the PUCT worked with ERCOT and market participants to institute short-term market design changes for improving price signals, improving and expanding ancillary service products (e.g., firm fuel supply service), and enhancing operational reliability through improved reliability unit commitment and load resource deployment among other initiatives. The Commission is now considering proposals for implementing long-term market structure changes (Phase 2). The proposals include a load-side reliability mechanism, a dispatchable energy credit program, a backstop reliability service, and/or a hybrid model that consists of various combinations of these proposals. A consulting company was hired to evaluate the market design proposals.

As part of the docket, the PUCT is also determining what aspects of resource adequacy assessment should be enshrined in the PUCT rules instead of being placed under the purview of ERCOT and market participants. At the Commission's June sixteenth open meeting, the commissioners agreed that establishing multiple metrics and associated standards appropriate for gauging success to meet system reliability needs is important as is increasing the frequency of resource adequacy reporting. These elements will be addressed as part of the Phase 2 rule-making proceedings. The PUCT further instructed ERCOT to continue collaborating with the Commission and market participants on other resource adequacy assessment reform efforts.

Non-Peak Hour Risk, Energy Assurance, Probabilistic Based Assessments

The continuing penetration of solar in the Texas RE-ERCOT area is increasing the risk of tight operating reserves during hours other than the daily peak load hour. This issue is most acute for the summer season when solar generation ramps down during the early evening hours while load is still relatively high. ERCOT developed a probabilistic Operating Reserve Risk Model designed for analysis of the hours with the highest risk of reserve shortages. The model simulates 10,000 reserve outcomes for a day during the summer and winter peak demand months. The models report the probability that ERCOT will need to declare energy emergency alerts (EEA) for those highest-risk hours based on reserve capacity reaching various EEA risk thresholds, including the point where firm load shed is required. For example, the summer of 2022 model indicates a progression of increasing hourly EEA risk probabilities from the early afternoon through the early evening hours with the peak EEA probability occurring for hour-ending 7:00 p.m. (see Figure 23).

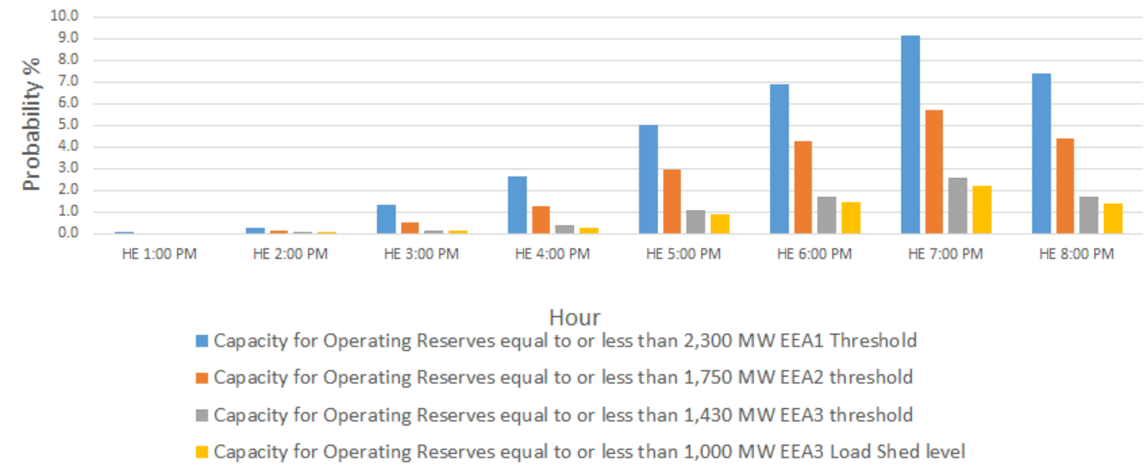


Figure 23: Likelihood of Energy Emergency Alerts in Summer [Source: ERCOT]

Probabilistic Assessment

The Base Case study shows much more risk than what was indicated in the 2020 ProbA Study. Essentially all of the risk is in the winter, largely driven by the incorporation of additional forced outage risk. 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 does 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 above current levels.

[39] http://interchange.puc.texas.gov/Documents/52373_372_1210865.PDF

Base Case Summary of Study Year Results			
	2024*	**2024**	**2026**
EUE (MWh)	12.86	492.03	1,235.40
EUE (ppm)	0.03	1.09	2.63
LOLH (Hours per Year)	0.01	0.15	0.30
Operable On-peak Margin	10.2%	36.7%	35.9%

* Provides the 2020 ProbA results for comparison

For the ProbA risk scenario study to be concluded in 2023, ERCOT is assessing the impact of transmission limits on reliability indices for the 2026 study year. The scenario focuses on the ability for IBRs concentrated in the western part of the state to serve load in the central and eastern side of the state using the transmission network. It is desirable to include transmission limits in the reliability assessment in order to reflect the dependence of IBRs on transmission to deliver to load.

Demand

ERCOT's summer peak demand is forecasted to increase by 1.2% per year from 2022–2032. This rate is the same as for the forecast used in the *2021 LTRA*. Annual energy is forecasted to increase by 1.9% per year for the same period. Summer peak demand in the far west area (which encompasses the metropolitan area of Odessa and Midland) is forecasted to grow by 4.0% per year for 2022–2032. The growth rate was 3.1% as forecasted for the *2021 LTRA*. The primary driver of this incremental growth is the future addition of cryptocurrency-based business in this part of the state. Demand growth from oil and natural gas production activities is not a material driver for the increased growth rate in the far west area.

An emerging load forecasting issue is large loads associated with interruptible computer operations—principally crypto miners. Developing a forecast of these large flexible loads is a challenge due to different metering/telemetry configurations; specifically, whether they are standalone or co-located (i.e., behind the meter) at generation sites.

Currently there are no adjustments for EVs or battery storage devices in the ERCOT long-term forecast used for the LTRA. ERCOT is in the early stages of working with a vendor to create an EV forecast.

An outcome of Winter Storm Uri in February 2021 was an increased emphasis on energy conservation/energy reduction initiatives. The impact that these initiatives may have on the load forecast is unknown at this time.

Demand Side Management

Most of the demand-side resources available to ERCOT are dispatchable in the form of non-controllable load resources providing responsive reserve service and deployable emergency resources, referred in this section as ERCOT Emergency Response Service (ERS) or ERCOT ERS. Responsive reserves make up an ancillary service for controlling system frequency. These reserves are provided by industrial loads and are procured on an hourly basis in the day-ahead market. Reserves are dispatched by automatic tripping based on under frequency relay settings (59.7 Hz) or manual dispatch instruction within 10 minutes. ERCOT ERS consists of 10-minute and 30-minute ramp DRs and DERs that can first be deployed when physical responsive reserves drop to 3,000 MW and are not projected to be recovered above 3,000 MW within 30 minutes following the deployment of non-spinning reserves.

ERCOT ERS is procured for 4-month periods during the year. ERCOT initiates the notification to reduce load; this is sent to the designated qualified scheduling entity (QSE) managing the load resources in the program, and then it is forwarded by the QSE to the load resource obligated to reduce its load. ERCOT ERS loads must meet qualification criteria and undergo a load curtailment test once every 365 days. Winter Storm Uri triggered multiple rounds of programmatic reforms. For example, the Commission recently proposed increasing the ERCOT ERS program budget from $50 to $75 million as well as allowing ERCOT the flexibility to contract ERCOT ERS for up to 24 hours in a contract term rather than four hours as currently specified in the PUCT rules.

The remaining dispatchable DR available to ERCOT is from the transmission and distribution service provider's (TDSP) load management programs. These programs provide price incentives for voluntary load reductions from commercial and industrial as well as (and most recently) residential loads during EEA events. These programs are available for the months of June through September from 1:00–7:00 p.m. weekdays (except holidays), and they are deployed concurrently with ERCOT ERS via ERCOT instruction pursuant to agreements between ERCOT and the TDSPs. The TDSP load management programs were also provided as pilots for most of the 2021/2022 winter season (Mid-December 2021 through February 2022).

On the horizon is potential treatment of crypto miners and other similar loads as controllable load resources that can be deployed to maintain grid reliability when needed. The PUCT, ERCOT, and market participants are working on resolving various policy, market, operational and planning issues associated with interconnecting these loads and potentially using them as reliability resources.

Distributed Energy Resources
ERCOT's formal definition of distributed generation is as follows: An electrical generating facility located at a customer's point of delivery (point of common coupling) 10 MW or less and connected at a voltage less than or equal to 60 kilovolts (kV), which may be connected in parallel operation to the utility system. Distributed generators (DG) include energy storage resources as well. Over the last few years, ERCOT has instituted a new generation resource taxonomy. DGs are now distinguished by whether they are transmission or distribution-connected, whether they fully participate in the ERCOT market or just get paid for exported energy (settlement-only generators), and whether they are registered or not registered with ERCOT.

DGs that register with ERCOT are modelled and dispatched in ERCOT transmission planning studies similarly to transmission-connected resources. For DERs not participating in those markets, ERCOT relies on member TDSPs to provide information about individual DERs on their systems for shorter-term reliability and economic impact studies, typically a one-to-six-year time frame.

Generation
Solar capacity continues to be rapidly added to Texas RE-ERCOT, and ERCOT is seeing a greater magnitude of five-minute solar ramps as a result. In addition to instituting an intra-hour solar forecast in 2021, ERCOT is in the process of implementing a new ancillary service called ERCOT Contingency Reserve Service (ECRS). As the wind and solar generation fleet continues to grow, ECRS will give the ERCOT control room the capability of deploying resources that can respond within 10 minutes in anticipation of net demand ramps. ERCOT is currently targeting to implement this service by mid-2023.

Also, in early 2022, ERCOT made methodology changes it its non-spinning reserve service, which is used to address large net load ramps among other uses. For example, the definition of the net load uncertainty is now the difference between the highest five-minute net load within the hour and the forecasted net load. Previously, the uncertainty was defined as the difference between the hourly net load and the forecasted net load. Another change was to switch from using the four-hours-ahead net load forecast to the six-hours-ahead net load forecast.

ERCOT completed its *South Texas Stability Assessment*, which evaluated the stability-related needs for the Lower Rio Grande Valley (LRGV) area, which is subject to both import constraints under peak load conditions and export constraints under high IBR output conditions. The outcome of the study was the LRGV System Enhancement Project, consisting of system improvements to improve stability constraints, sub-synchronous resonance vulnerability, operational flexibility, future load and generation integration, and grid resiliency considering hurricane risk. The project was endorsed by the ERCOT Board of Directors in December 2021.

ERCOT also completed its *Long-Term West Texas Export Special Study* in January 2022. The purpose of the study was to evaluate potential transmission improvements to increase transfer capability from renewable-rich areas in West Texas to urban demand centers further east. Transfers from West Texas are currently limited by both voltage and dynamic stability constraints as well as thermal constraints closer to demand centers. ERCOT presented two alternative short-listed options lists based on a 2030 study case. One of the lists included a HVDC line to move power to the Houston area. ERCOT will continue to evaluate system improvement options that consider emerging trends in generation capacity development and demand growth.

ERCOT considers natural gas limitations for natural-gas-fired generators in its Regional Transmission Plan through the inclusion of extreme events that represent the loss of multiple natural-gas generators following the loss of any single gas pipeline. These events are identified by evaluating the natural-gas-pipeline network topology and survey responses from natural gas generators.

The Texas regulators and ERCOT have enacted several mitigation strategies to address natural gas curtailment risks. For example, pursuant to PUCT guidance, ERCOT developed a Nodal Protocol Revision Request (NPRR) to create a firm fuel supply service. This service is intended to help maintain system reliability in the event of a natural gas curtailment or other fuel supply disruption. As another example, ERCOT's Black Start Working Group reviewed black start resource availability during Winter Storm Uri, and they subsequently developed an NPRR to require black start units to have on-site fuel specifically reserved for black start operations. The NPRR is waiting for approval by the ERCOT Board and PUCT. In 2021, the Texas Legislature passed Senate Bill 3, which, among other things, created the Texas Electricity Supply Chain Security and Mapping Committee. This committee recently completed a map of Texas' state electricity supply chain with critical infrastructure identified, including natural gas facilities. This map can be used in future assessments to ensure reliability of the grid, especially under extreme weather conditions. Finally, the PUCT opened a docket on electric-gas coordination to address natural gas supply and infrastructure issues.

Energy Storage
Based on the latest developer information for projects that are in the interconnection queue, ERCOT expects about 7,400 MW of battery energy storage capacity to be operational in the Texas RE-ERCOT area within the next five years. This capacity represents projects with signed interconnection agreements and proof of financial commitments to build the interconnecting transmission facilities.

The majority of the installed energy storage projects have limited duration energy capability. ERCOT uses a generator with a negative minimum power to represent withdrawal and a generator with a positive maximum power to represent injection when modeling energy storage resources in transmission planning studies. That said, ERCOT is moving to a single "combination" generator within a few years once system changes have been put into production. The discharging behavior of energy storage resources with duration of at least four hours is considered for peak cases in transmission planning studies. The charging behavior for all energy storage resources is considered for minimum load cases in transmission planning studies. Energy storage resources need to have the reactive power capability to be available at all MW levels when charging or discharging if they are required to provide voltage support and to meet the voltage ride-through requirements to remain connected to the system. ERCOT is currently reviewing its policies, procedures, and systems to support larger penetration levels of energy storage resources, and ERCOT expects to make changes between now and the end of 2024.

Capacity Transfers (Reliance on Assistance)

ERCOT coordinates with neighboring grids through coordination plans (last updated in May 2022) that cover dc tie emergency operations, procedures for generators that can switch between grids, and block load transfers (groups of loads that are transferred to a neighboring grid for service on a temporary basis).

Transmission

ERCOT completed its 2021 Regional Transmission Plan in December 2021.[40] The plan constitutes 67 projects with 33 projects designated as needed by 2023. There are currently 73 miles of transmission lines under construction and 238 miles of planned transmission lines during the 10-year assessment period. Many of the Regional Transmission Plan projects were identified as preferred projects in the ERCOT Permian Basin Load Interconnection Study and Delaware Basin Load Integration Study. Most of the planned improvements identified in the 2021 Regional Transmission Plan are 138 kV and 345 kV upgrades. The projects identified as 345 kV upgrades consist of new substations, line additions, line upgrades, new 345/138 kV transformers, 345/138 kV transformer upgrades, and reactor additions.

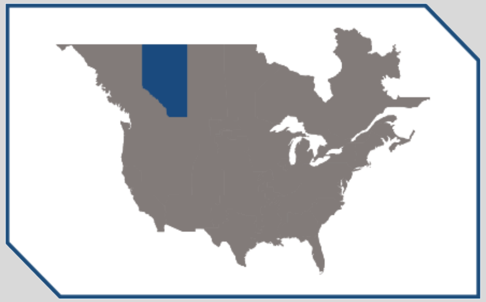
The recently updated ERCOT Transmission Project and Information Tracking list (February 2022) includes the addition or upgrade of 3,634 circuit miles of 138 kV and 345 kV transmission circuits and 12,174 MVA of 345/138 kV transformer capacity that are planned in Texas RE-ERCOT for 2022–2028.

Finally, the ERCOT Board-approved LRGV System Enhancement Project, which includes an estimated 351 right-of-way miles of new 345 kV transmission lines; it is expected to be in service by 2027.

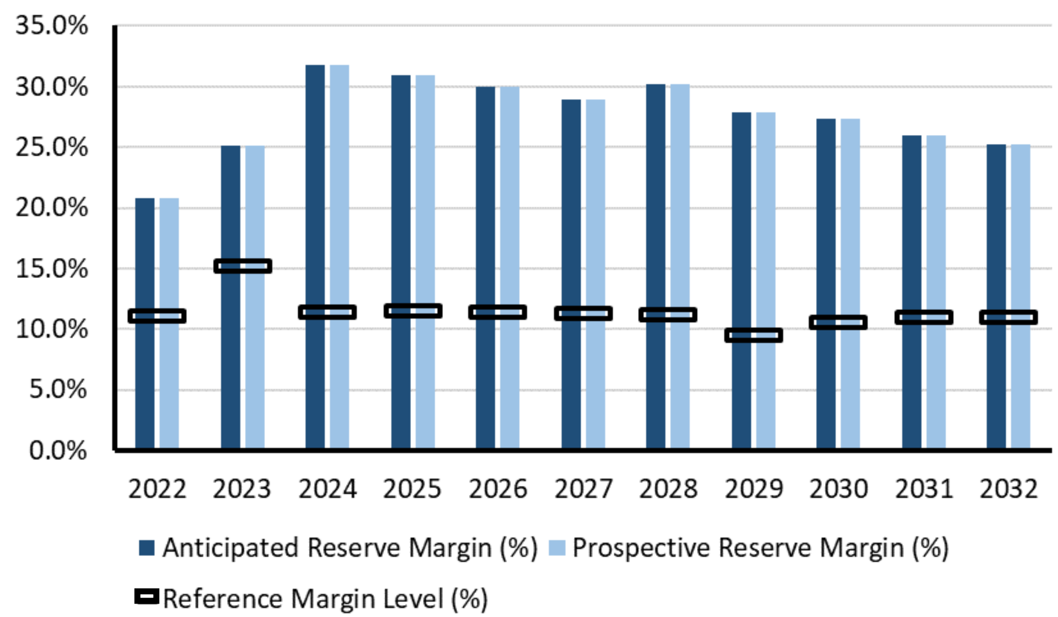
Reliability Issues

An emerging issue is that large loads associated with interruptible computer operations—principally cryptocurrency miners—are requesting accelerated interconnection of their loads to the grid. Such loads could reach up to 25,000 MW by 2026 based on current interconnection plans. ERCOT implemented an interim interconnection process in March 2022 to ensure that large loads with accelerated interconnection time lines are interconnected reliably and that NERC Reliability Standards are met. ERCOT also created a Large Flexible Load Task Force to consider a host of interconnection, operational, market, and grid planning topics. One of the key issues is the extent to which these loads can become controllable load resources that can be dispatched as needed for maintaining grid reliability.

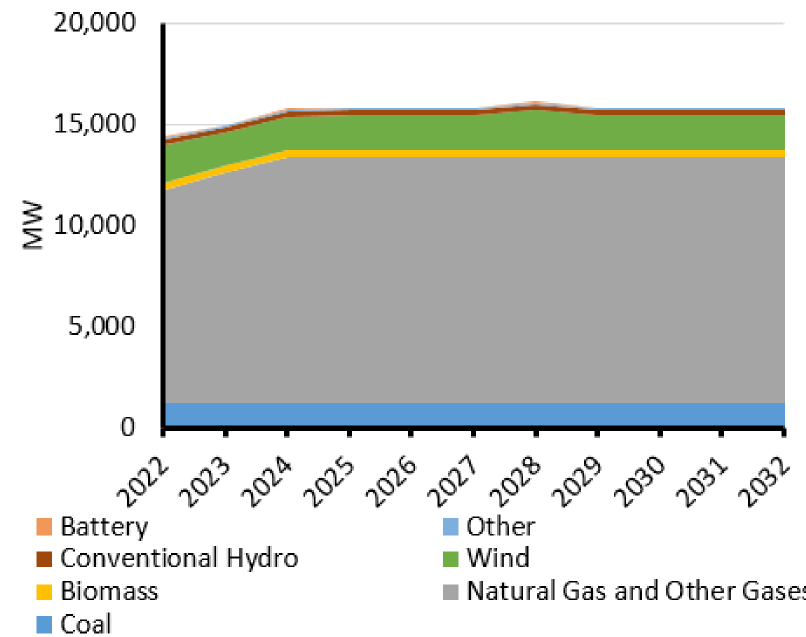
[40] https://www.ercot.com/gridinfo/planning



WECC-AB Demand, Resources, and Reserve Margins (MW)										
Quantity	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total Internal Demand	11,961	11,961	12,065	12,154	12,257	12,373	12,362	12,413	12,548	12,622
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	11,961	11,961	12,065	12,154	12,257	12,373	12,362	12,413	12,548	12,622
Additions: Tier 1	2,044	2,830	2,852	2,852	2,852	2,962	2,852	2,852	2,852	2,852
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	968	1,846	2,216	2,532	2,648	2,701	3,241	4,033	4,103	4,103
Net Firm Capacity Transfers	0	0	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	12,925	12,925	12,948	12,948	12,948	13,148	12,949	12,949	12,949	12,949
Anticipated Reserve Margin (%)	25.1%	31.7%	31.0%	30.0%	28.9%	30.2%	27.8%	27.3%	25.9%	25.2%
Prospective Reserve Margin (%)	25.1%	31.7%	31.0%	30.0%	28.9%	30.2%	27.8%	27.3%	25.9%	25.2%
Reference Margin Level (%)	15.2%	11.4%	11.5%	11.4%	11.3%	11.2%	9.5%	10.6%	11.0%	10.9%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- Alberta is expecting continued seasonal demand growth at a rate below the average of the other areas.
- ARMs do not fall below the RML for this assessment period.
- With the majority of Alberta's portfolio being baseload resources, natural gas resources in particular, WECC is not concerned with reliability risk from variability in demand or resources.

WECC-AB Composition (MW)										
Fuel	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Coal	1,235	1,235	1,236	1,236	1,236	1,236	1,236	1,236	1,236	1,236
Natural Gas	11,354	12,141	12,147	12,147	12,147	12,147	12,148	12,148	12,148	12,148
Biomass	336	336	336	336	336	336	336	336	336	336
Wind	1,642	1,642	1,697	1,697	1,697	1,990	1,697	1,697	1,697	1,697
Conventional Hydro	291	291	274	274	274	291	274	274	274	274
Other	61	61	62	62	62	62	62	62	62	62
Battery	49	49	49	49	49	49	49	49	49	49
Total MW	14,969	15,755	15,799	15,799	15,799	16,110	15,801	15,801	15,801	15,801

WECC-AB Assessment

Planning Reserve Margins
The ARM does not fall below the RML throughout the 10-year assessment period. Starting in Winter 2022/2023, Alberta shows a shortfall of reserve margins when only existing-certain and net-firm transfers are considered, meaning imports may be necessary if new wind, solar, or natural gas resources were to be delayed.

WECC continues to use a probabilistic approach for determining RMLs, holding a loss of load probability (LOLP) less than or equal to 0.02% (approximately a 1-day-in-10 years loss of load). The model determines what reserve margin must be held to maintain a fixed LOLP. Using this technique, a target reserve margin is evaluated for every hour of every year of the full forecast period. The LOLP is determined by comparing the distributions of potential load and resource states and calculating the probability that load exceeds generation. The LOLP can also be visualized by the area where the demand and supply distributions overlap.

Non-Peak Hour Risk, Energy Assurance, Probabilistic Based Assessments
Alberta'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.

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	0	0	0
EUE (ppm)	0	0	0
LOLH (Hours per Year)	0	0	0
Operable On-peak Margin	20.2%	22.4%	33.5%

* Provides the 2020 ProbA results for comparison

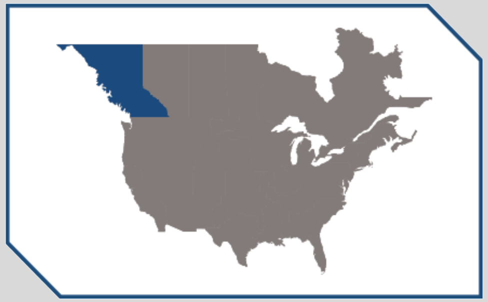
Demand
Alberta's peak demand (winter) compound annual growth rate for the 10-year period is 0.6. It is below the average of the other areas with a seasonal peak growth typically at around 0.67%.

Demand Side Management
DR is not a significant resource in the AB assessment area.

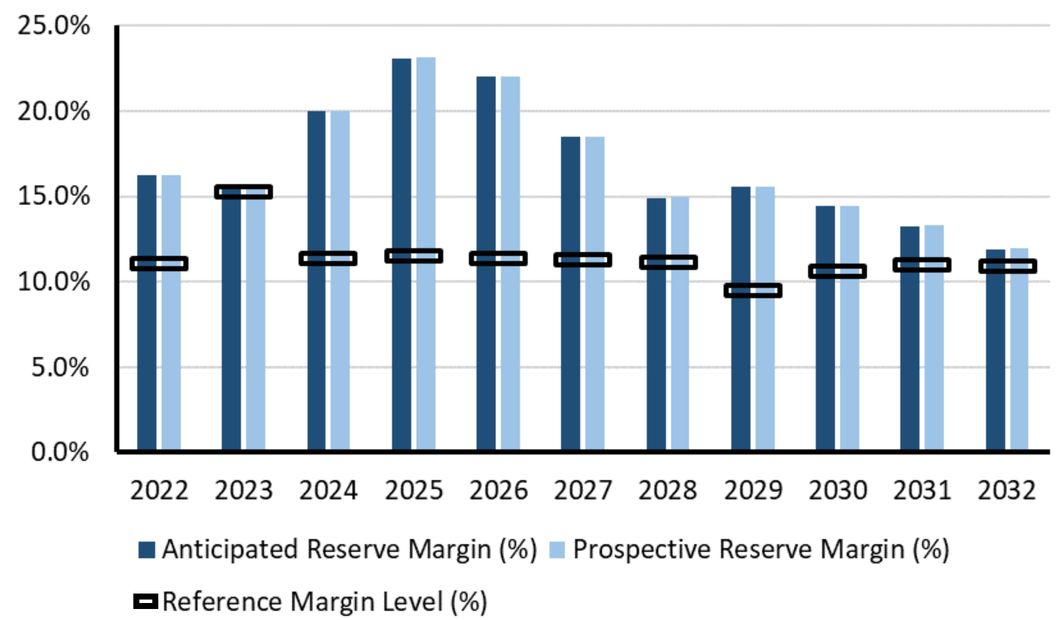
Distributed Energy Resources
Alberta Electric System Operator (AESO) is expecting a nearly 15% average annual growth rate over the time horizon.

Generation
Nearly 800 MW of new natural-gas-fired generation (Tier 1) is being added during this assessment period in Alberta. Some BPS-level solar PV (730 MW nameplate) and wind (1,370 MW nameplate) is also in development over the 10-year period. For purposes of this assessment, solar does not contribute to winter on-peak resource capacity while new wind contributes about half of its nameplate capacity. There are no confirmed retirements on the horizon in the assessment area. Consequently, little change to the resource mix is expected.

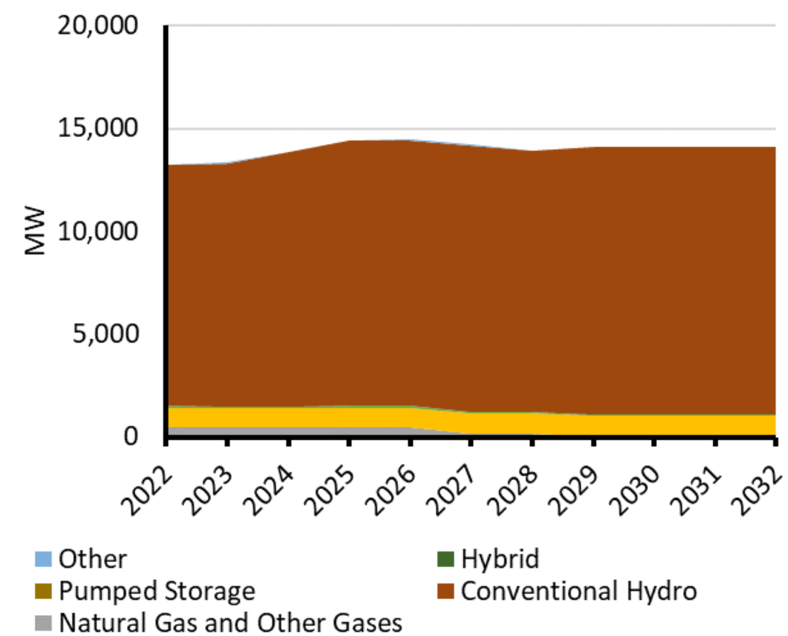
Transmission
There are 335 miles of transmission lines in planning for construction during this assessment period.



WECC-BC Demand, Resources, and Reserve Margins (MW)										
Quantity	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Total Internal Demand	11,552	11,572	11,711	11,850	11,992	12,122	12,236	12,357	12,483	12,635
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	11,552	11,572	11,711	11,850	11,992	12,122	12,236	12,357	12,483	12,635
Additions: Tier 1	289	827	899	939	980	994	1,020	1,020	1,020	1,020
Additions: Tier 2	0	0	4	4	4	4	4	4	4	4
Additions: Tier 3	0	0	0	39	39	38	39	92	92	92
Net Firm Capacity Transfers	0	0	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	13,056	13,056	13,518	13,518	13,231	12,934	13,119	13,119	13,119	13,119
Anticipated Reserve Margin (%)	15.5%	20.0%	23.1%	22.0%	18.5%	14.9%	15.6%	14.4%	13.3%	11.9%
Prospective Reserve Margin (%)	15.5%	20.0%	23.1%	22.0%	18.5%	14.9%	15.6%	14.5%	13.3%	11.9%
Reference Margin Level (%)	15.2%	11.4%	11.5%	11.4%	11.3%	11.2%	9.5%	10.6%	11.0%	10.9%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- ARMs do not fall below the RML for this assessment period.
- With the majority of their portfolio being baseload resources, conventional hydro in particular, WECC is not concerned with reliability risk from variability in demand or resources.

WECC-BC Composition (MW)										
Fuel	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Natural Gas	451	451	450	450	163	163	54	54	54	54
Biomass	974	974	971	971	971	971	968	968	968	968
Wind	62	62	84	84	84	86	84	84	84	84
Conventional Hydro	11,836	12,375	12,890	12,930	12,971	12,686	13,011	13,011	13,011	13,011
Other	22	22	22	22	22	22	22	22	22	22
Total MW	13,345	13,883	14,417	14,457	14,211	13,929	14,139	14,139	14,139	14,139

WECC-BC Assessment

Planning Reserve Margins

The ARM does not fall below the RML throughout the 10-year assessment period. Starting in Winter 2023/2024 and then 2027/2028 onwards, British Columbia shows a shortfall of existing-certain and net-firm transfers, meaning imports may be necessary if new solar or conventional hydrogeneration resources were to be delayed.

WECC continues to use a probabilistic approach for determining RMLs, holding a LOLP less than or equal to 0.02% (approximately a 1-day-in-10 years loss of load). The model determines what reserve margin must be held to maintain a fixed LOLP. Using this technique, a target reserve margin is evaluated for every hour of every year of the full forecast period. The LOLP is determined by comparing the distributions of potential load and resource states and calculating the probability that load exceeds generation. The LOLP can also be visualized by the area where the demand and supply distributions overlap.

Non-Peak Hour Risk, Energy Assurance, Probabilistic Based Assessments

British Columbia's probabilistic assessment results continue to indicate little risk of energy or capacity shortfall though load-loss hours and unserved energy metrics are slightly higher than found in the previous ProbA. The highest risk generally occurs in winter months and coincides with the hour of peak demand though the study year 2026 results indicate some risk in the shoulder months of October and November.

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	8.452	24.229	281.047
EUE (ppm)	0.137	0.37	4.13
LOLH (Hours per Year)	0.001	0.002	0.034
Operable On-peak Margin	20.2%	22.4%	33.5%

* Provides the 2020 ProbA results for comparison

Demand

British Columbia's peak demand (winter) compound annual growth rate for the 10-year period is 1.0.

Demand Side Management

DR is not a significant resource in the British Columbia assessment area.

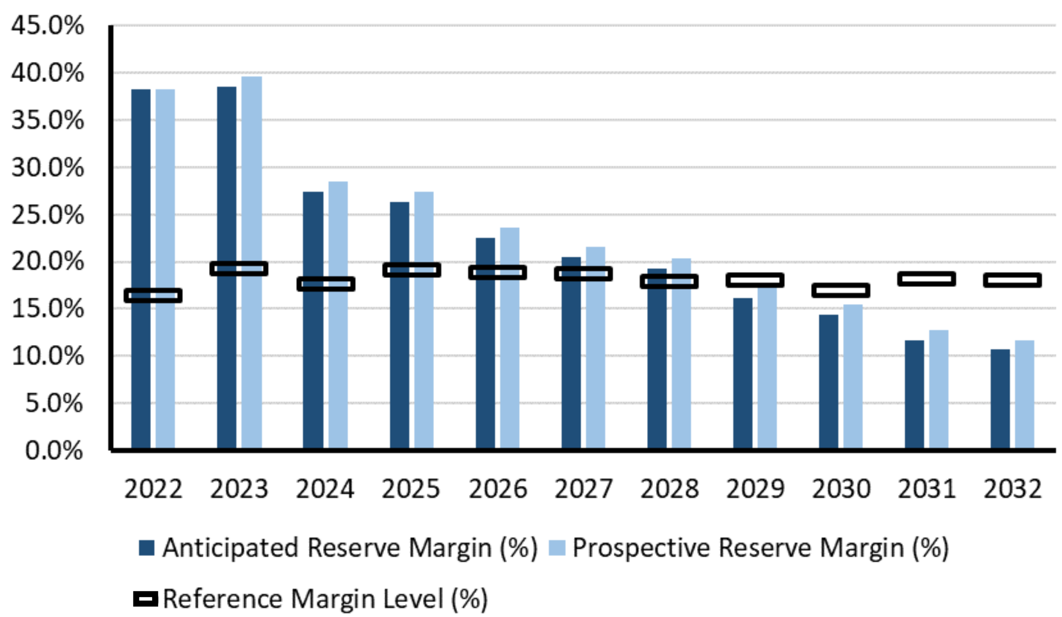
Generation

The planned retirement of 101 MW of natural-gas-fired generation in 2025, followed by another 210 MW of natural-gas-fired capacity in 2026, contributes to the reduction in existing resources. However, plans are in place to increase hydro capacity over the next five years, helping to meet expected demand growth. Because of hydro's storage capabilities, WECC is not concerned with this area's ability to meet variability in demand and/or resources. The only potential issue would be an expansion of the U.S. West's drought conditions causing less fuel availability for the hydro resources; however, this has not had a significant impact to date. WECC will continue monitoring the drought conditions for fuel availability.

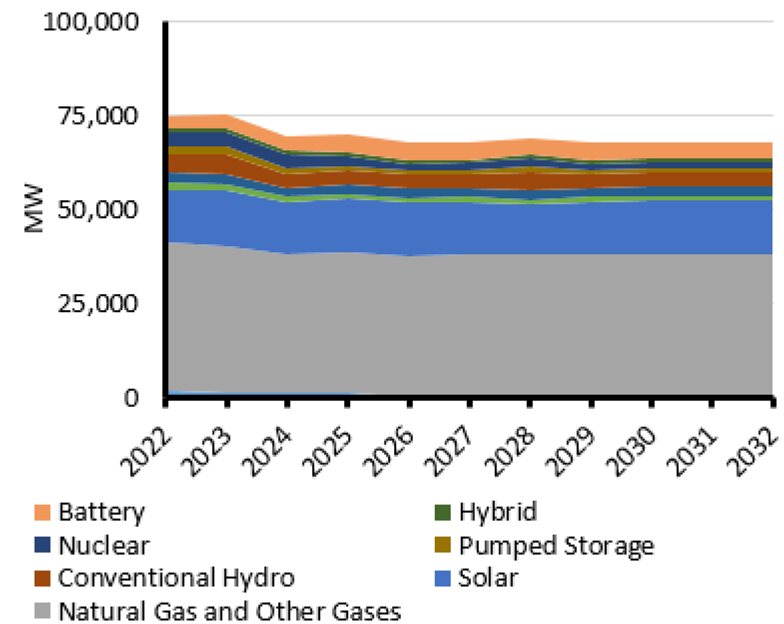
Transmission

There are 775 miles of transmission lines in planning for construction during this assessment period.

WECC-CA/MX Demand, Resources, and Reserve Margins (MW)										
Quantity	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total Internal Demand	57,091	57,759	58,609	59,184	60,028	60,652	61,423	62,164	62,967	63,526
Demand Response	862	881	897	913	928	943	959	974	989	989
Net Internal Demand	56,229	56,879	57,712	58,271	59,100	59,709	60,465	61,190	61,978	62,537
Additions: Tier 1	5,673	6,203	7,839	7,850	8,051	7,890	8,056	8,333	8,333	8,333
Additions: Tier 2	639	595	647	647	647	649	647	647	647	647
Additions: Tier 3	868	1,575	1,575	1,575	1,575	1,577	1,561	1,863	20,540	20,540
Net Transfers	1,559	2,019	1,925	2,585	2,191	1,130	1,252	753	0	0
Existing-Certain and Net Transfers	72,192	66,271	65,072	63,515	63,121	63,327	62,151	61,652	60,899	60,899
Anticipated Reserve Margin (%)	38.5%	27.4%	26.3%	22.5%	20.4%	19.3%	16.1%	14.4%	11.7%	10.7%
Prospective Reserve Margin (%)	39.6%	28.5%	26.9%	23.1%	20.2%	19.1%	15.9%	14.2%	11.5%	10.5%
Reference Margin Level (%)	19.2%	17.7%	19.1%	18.9%	18.7%	17.9%	18.0%	16.9%	18.2%	18.1%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- CA/MX's probabilistic assessment results continue to indicate a high risk of energy or capacity shortfall. The highest risk for loss of load is in the months of July through September during the hours of 4:00–7:00 p.m. This time period corresponds to the three hours after forecasted demand peaks each day in in California.
- Load-loss hours and unserved energy metrics are improved from the previous ProbA. Actions taken by regulators and industry to accelerate resource acquisition and delay retirements has helped provide the needed capacity.

WECC-CA/MX Composition (MW)										
Fuel	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Coal	1,592	1,598	1,598	487	487	487	487	487	487	487
Petroleum	184	185	185	185	185	185	184	184	184	184
Natural Gas	38,737	36,468	37,231	37,231	37,425	37,425	37,389	37,659	37,659	37,659
Biomass	779	778	778	778	778	778	779	779	779	779
Solar	14,561	14,101	14,166	14,177	14,183	13,412	14,197	14,204	14,204	14,204
Wind	1,972	1,229	1,229	1,229	1,229	1,318	1,229	1,229	1,229	1,229
Geothermal	2,487	2,490	2,490	2,490	2,490	2,490	2,485	2,485	2,485	2,485
Conventional Hydro	5,214	3,657	3,657	3,657	3,657	4,716	3,657	3,657	3,657	3,657
Pumped Storage	1,983	1,159	1,159	1,159	1,159	1,889	1,159	1,159	1,159	1,159
Nuclear	3,880	3,877	2,772	1,667	1,667	1,667	1,667	1,667	1,667	1,667
Hybrid	1,030	1,029	1,029	1,029	1,029	1,029	1,030	1,030	1,030	1,030
Other	152	152	152	152	152	152	152	152	152	152
Battery	3,734	3,731	4,540	4,540	4,540	4,540	4,541	4,541	4,541	4,541
Total MW	76,306	70,455	70,986	68,780	68,981	70,087	68,956	69,232	69,232	69,232

WECC-CA/MX Assessment

Planning Reserve Margins
The ARM falls below the RML in the summer of 2029. Starting in the summer of 2024 onwards, CA/MX shows a shortfall of existing-certain and net-firm transfers, meaning imports may be necessary if new resources were to be significantly delayed.

WECC continues to use a probabilistic approach for determining RMLs, holding a LOLP less than or equal to 0.02% (approximately a 1-day-in-10 years loss of load). The model determines what reserve margin is needed to maintain a fixed LOLP. Using this technique, a target reserve margin is evaluated for every hour of the full forecast period. The LOLP is determined by comparing the distributions of potential load and resources and calculating the probability that load exceeds generation. The LOLP can also be visualized by the area where the demand and supply distributions overlap.

California LSEs are the only ones with a state-regulated target for PRMs. This was recently increased to 17.5%.

Non-Peak Hour Risk, Energy Assurance, Probabilistic Based Assessments
Both demand and resource availability variability are increasing, and the challenges they present are accelerating. CA/MX, SRSG, and WPP show hours at risk of load loss over the next five years. In 2021, WECC studied the ramping risks of net demand from increasing penetrations of renewables in response to the August 2020 heatwave event. Four of 39 BAs, specifically those in the sunniest southwestern territory, were identified as exhibiting or expected to develop ramping risk over the planning horizon.

CA/MX's probabilistic assessment results continue to indicate a high risk of energy or capacity shortfall. Load-loss hours and unserved energy metrics are improved from the previous ProbA due to actions taken by regulators and industry to accelerate resource acquisition and delay retirements. The highest risk for loss of load is in the months of July through September during the hours of 4:00–7:00 p.m. This time period corresponds to the three hours after forecasted demand peaks each day in in California. The magnitude of unserved energy in any one hour of load loss ranges from less than a MW to 16,000 MW.

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	2,402,976	37,305	498,885
EUE (ppm)	8,818	136	1,785
LOLH (Hours per Year)	56	0.721	9.792
Operable On-peak Margin	15.3%	30.3%	25.7%

* Provides the 2020 ProbA results for comparison

Demand
CA/MX's peak demand (summer) compound annual growth rate for the 10-year period is 1.19.

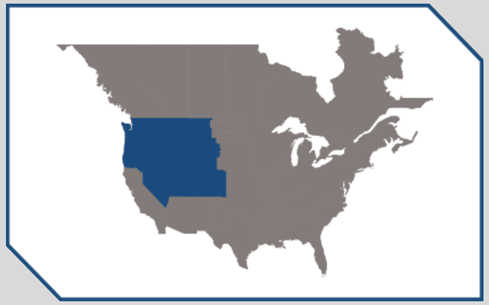
Demand Side Management
Demand side management has played an important role in preventing energy shortfalls during extreme heat events in the area. Additionally, CA/MX anticipates quintupling summer efficiency reductions to peak demand along with six–fold increase in winter EE.

Distributed Energy Resources
Although BTM solar PV resources continue to be added to the CA/MX system, their contribution at the hour of system peak demand in summer has fallen 7.4% as that hour has shifted to later in the day. In winter, the contribution of BTM solar PV at the peak hour has increased by 7.4%.

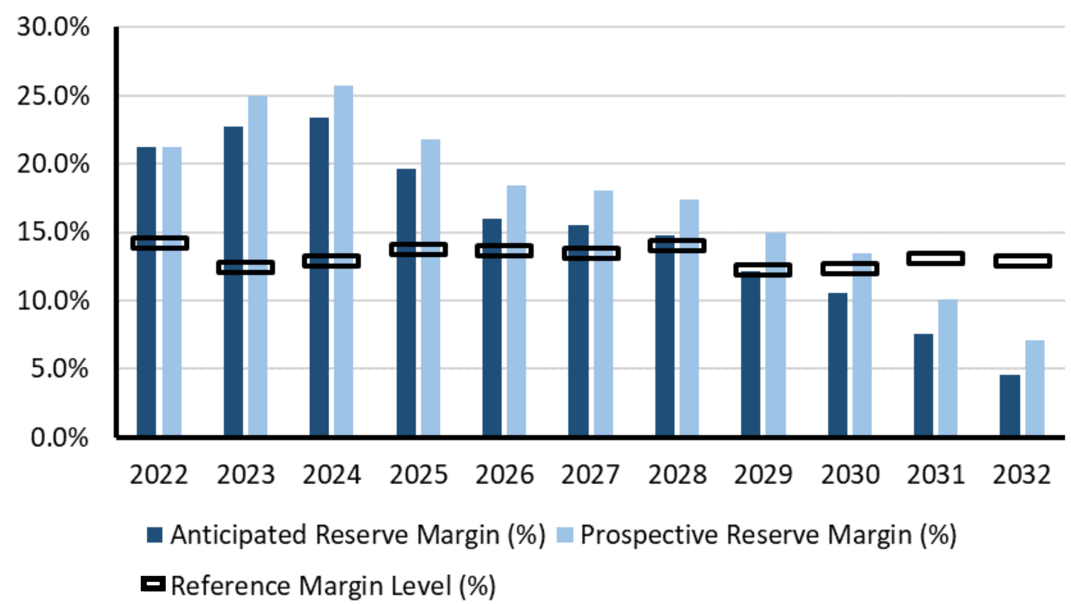
Energy Storage
Significant amounts of energy storage additions are planned. Energy storage in the West may be able to help mitigate ramping risk from afternoon net demand due to increasing penetrations of solar. Many of the additions are being co-located into hybrid solar PV and storage. Of the 24.5 GW of new energy storage in the Western Interconnection, over 15.2 GW is being developed in California

Energy Transfers (Reliance on Assistance)
The energy and capacity risk analysis performed by WECC for this LTRA uses WECC's energy transfer modeling; complete firm transfer information is not available. Imports are expected to increase in CA/MX for much of the assessment horizon.

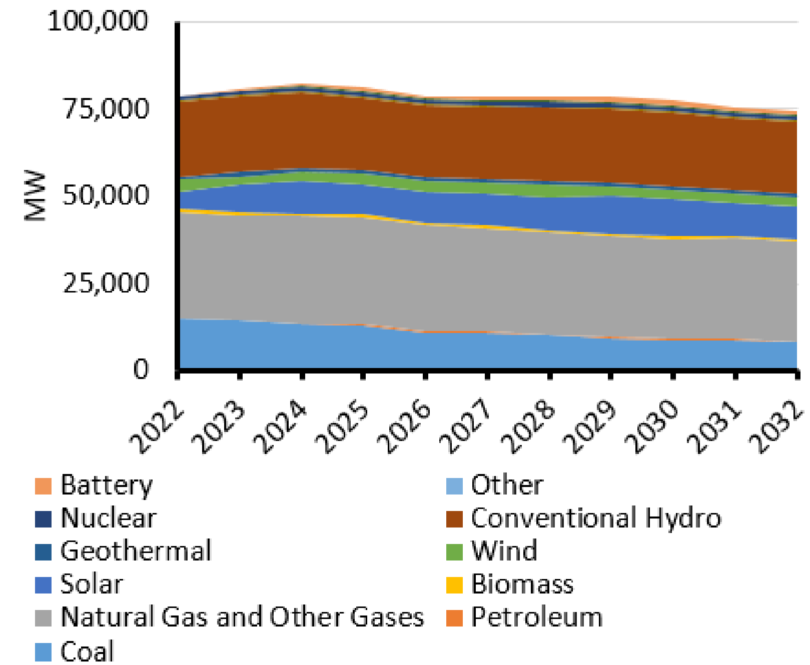
Transmission
There are 1,050 miles of transmission lines under construction or in planning for construction during this assessment period.



WECC-WPP Demand, Resources, and Reserve Margins (MW)										
Quantity	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Total Internal Demand	67,258	68,559	69,475	69,636	70,389	71,095	71,715	72,229	72,827	73,613
Demand Response	1,603	1,618	1,658	1,670	1,685	1,689	1,705	1,712	1,724	1,475
Net Internal Demand	65,655	66,941	67,817	67,965	68,703	69,406	70,009	70,516	71,103	72,138
Additions: Tier 1	3,906	7,228	7,422	7,565	8,085	8,695	9,207	9,207	8,694	8,694
Additions: Tier 2	1,469	1,469	1,354	1,550	1,557	1,591	1,712	1,731	1,572	1,588
Additions: Tier 3	42	1,113	2,284	2,943	2,943	3,512	4,182	5,925	6,926	6,951
Net Transfers	0	0	0	0	800	957	0	450	800	800
Existing-Certain and Net Transfers	76,655	75,343	73,734	71,282	71,262	70,968	69,284	68,777	67,816	66,716
Anticipated Reserve Margin (%)	22.7%	23.4%	19.7%	16.0%	15.5%	14.8%	12.1%	10.6%	7.6%	4.5%
Prospective Reserve Margin (%)	24.9%	25.7%	21.8%	17.9%	17.6%	16.9%	14.5%	13.4%	10.1%	7.1%
Reference Margin Level (%)	12.5%	12.9%	13.8%	13.7%	13.5%	14.0%	12.3%	12.4%	13.1%	12.9%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The Western Resource Adequacy Program (WRAP), which is being implemented by WPP, is a regional reliability planning and compliance program with the intent to deliver an assessment-area-wide approach for assessing and addressing resource adequacy.
- WECC's probabilistic assessment results for the WPP assessment area continue to indicate a risk of energy or capacity shortfall. Load-loss hours and unserved energy metrics are improved from the previous ProbA due to actions taken by regulators and industry to accelerate resource acquisition and delay retirements. The highest risk for loss of load is in the months of June through September during the five hours after demand peaks for the day.

WECC-WPP Composition (MW)										
Fuel	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Coal	14,304	13,311	13,046	10,876	10,876	10,028	9,318	8,729	8,736	7,968
Petroleum	307	307	309	309	309	309	307	307	307	307
Natural Gas	30,057	30,798	30,755	30,588	29,837	29,286	29,144	28,802	28,846	28,642
Biomass	778	775	773	767	737	737	670	670	669	667
Solar	7,795	9,371	8,624	8,762	9,245	9,547	10,718	10,718	9,369	9,301
Wind	2,497	2,575	3,093	3,067	3,067	3,264	2,452	2,427	2,880	2,822
Geothermal	1,151	1,151	1,154	1,138	1,138	1,138	1,114	1,114	1,123	1,123
Conventional Hydro	22,016	21,876	20,896	20,829	20,822	21,406	21,780	21,780	20,798	20,798
Nuclear	1,094	1,094	1,093	1,093	1,093	1,093	1,088	1,088	1,082	1,082
Hybrid	91	505	504	504	504	504	505	505	506	506
Other	77	77	78	78	78	78	77	77	78	78
Battery	486	1,237	1,335	1,340	1,345	1,820	1,823	1,823	1,822	1,822
Total MW	80,562	82,572	81,157	78,848	78,548	78,707	78,493	77,536	75,711	74,611

WECC-WPP Assessment

Planning Reserve Margins
The ARM falls below the RML in the summer of 2029 and the winter of 2031/2032. Starting in the summer of 2024 onwards, WPP shows a shortfall of existing-certain and net transfers, meaning imports may be necessary if new resources were to be significantly delayed.

WECC continues to use a probabilistic approach for determining RMLs, holding a LOLP less than or equal to 0.02% (approximately a 1-day-in-10 years loss of load). The model determines what reserve margin must be held to maintain a fixed LOLP. Using this technique, a target reserve margin is evaluated for every hour of every year of the full forecast period. The LOLP is determined by comparing the distributions of potential load and resource states and calculating the probability that load exceeds generation. The LOLP can also be visualized by the area where the demand and supply distributions overlap.

With the formation of the new WRAP, the WPP is working towards defining what an adequate reserve margin for their footprint will be. WECC is monitoring the WRAP's endeavors.

Non-Peak Hour Risk, Energy Assurance, Probabilistic Based Assessments
Both demand and resource availability variability are increasing, and the challenges they present are accelerating. CA/MX, SRSG, and WPP show hours at risk of load loss over the next five years. In 2021, WECC studied the ramping risks of net demand from increasing penetrations of renewables in response to the August 2020 heatwave event. Four of 39 BAs, those in the sunniest, southwestern territory, were identified as exhibiting or expected to develop ramping risk over the planning horizon.

WPP's probabilistic assessment results continue to indicate risk of energy or capacity shortfall. Load-loss hours and unserved energy metrics are improved from the previous ProbA due to actions taken by regulators and industry to accelerate resource acquisition and delay retirements. The highest risk for loss of load is in the months of June through September, during the five hours after demand peaks for the day. The magnitude of unserved energy in any one hour of load-loss range from less than a MW to 13k MW.

Base Case Summary of Results

	2024*	2024	2026
EUE (MWh)	248,573	1,722	11,280
EUE (ppm)	621.8	4.22	27.18
LOLH (Hours per Year)	4.389	0.036	0.233
Operable On-peak Margin	24.9%	25.8%	21.0%

* Provides the 2020 ProbA results for comparison

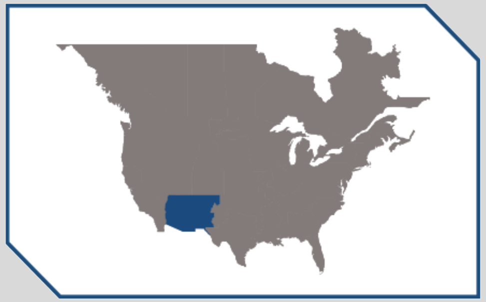
Demand
WPP's peak demand (summer) compound annual growth rate for the 10-year period is 1.0.

Distributed Energy Resources
WPP is seeing a 13% average annual growth rate in BTM solar PV on-peak capacity.

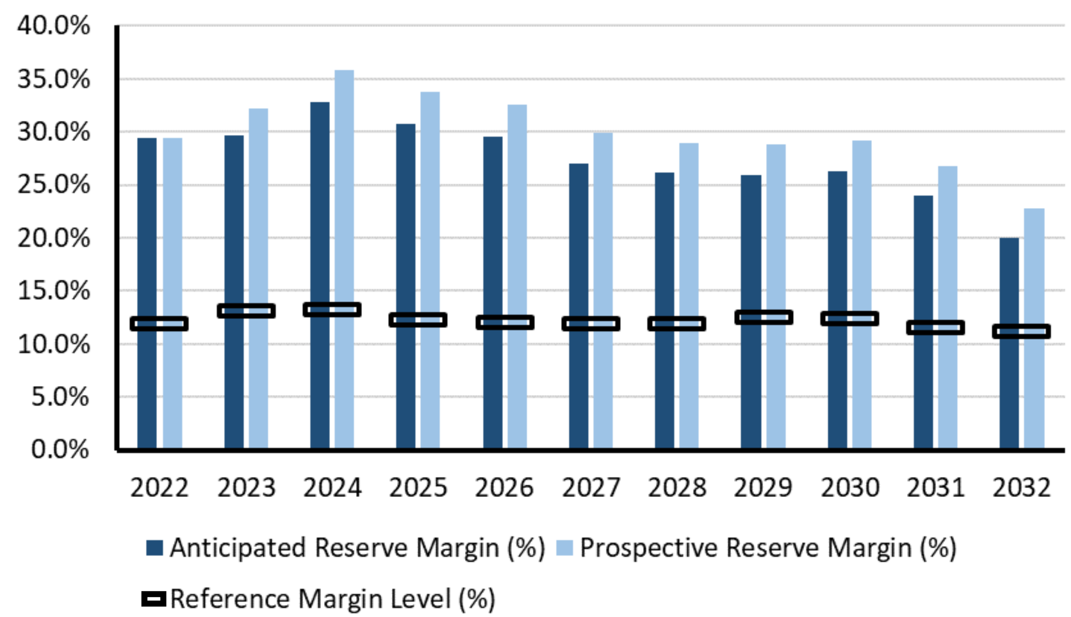
Energy Storage
Significant amounts of energy storage additions are planned. Energy storage in the west may be able to help mitigate ramping risk from afternoon net demand due to increasing penetrations of solar. Many of the additions are being co-located into hybrid solar PV and storage. Of the 24.5 GW of new energy storage in the Western Interconnection, 6 GW are being developed in WPP.

Energy Transfers (Reliance on Assistance)
Energy and capacity risk analysis performed by WECC for this *LTRA* use WECC's modeling of energy transfers. Complete firm transfer information is not available. Imports are expected to increase into WPP area in the summer of 2027.

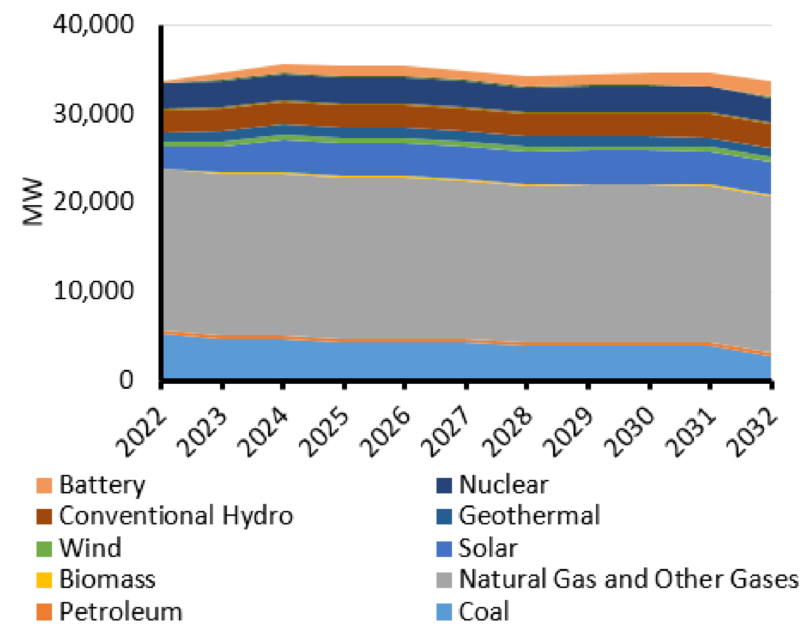
Transmission
There are over 3,400 miles of transmission lines under construction or in planning for construction during this assessment period.



WECC-SRSG Demand, Resources, and Reserve Margins (MW)										
Quantity	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Total Internal Demand	27,039	27,154	27,864	28,516	29,186	29,634	30,049	30,513	30,935	31,441
Demand Response	421	399	437	402	409	416	394	399	402	409
Net Internal Demand	26,618	26,755	27,426	28,114	28,777	29,218	29,655	30,114	30,533	31,032
Additions: Tier 1	2,834	3,833	3,954	3,954	3,954	3,939	3,955	4,224	4,224	4,586
Additions: Tier 2	670	812	847	847	847	841	849	849	849	849
Additions: Tier 3	538	683	1,277	1,902	1,902	2,031	2,328	2,859	3,352	4,378
Net Transfers	0	0	573	1,142	1,658	2,652	3,016	3,437	3,348	3,561
Existing-Certain and Net Transfers	31,694	31,694	31,896	32,465	32,591	32,912	33,393	33,813	33,639	32,663
Anticipated Reserve Margin (%)	29.7%	32.8%	30.7%	29.5%	27.0%	26.1%	25.9%	26.3%	24.0%	20.0%
Prospective Reserve Margin (%)	32.2%	35.8%	33.8%	32.6%	29.9%	29.0%	28.8%	29.1%	26.8%	22.8%
Reference Margin Level (%)	13.1%	13.3%	12.2%	12.1%	11.9%	11.9%	12.6%	12.3%	11.5%	11.2%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The SRSG assessment area continues to be summer peaking. Summer demand peaks beginning at 4:00 p.m. Winter demand peaks in the mornings before 8:00 a.m.
- Seasonal demand rates of growth continue to be roughly twice the other areas' averages.
- SRSG's probabilistic assessment results indicate that the risk of energy shortfall is increasing from the 2024 to 2026 study years. The highest risk for loss of load is in the months of July through September during the 6:00 p.m. hour (after demand peaks for the day).

WECC-SRSG Composition (MW)										
Fuel	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Coal	4,713	4,713	4,342	4,342	4,342	3,848	3,848	3,848	3,848	2,712
Petroleum	318	318	318	318	318	318	319	319	319	319
Natural Gas	18,234	18,234	18,234	18,234	17,843	17,773	17,779	17,779	17,697	17,697
Biomass	94	94	94	94	94	94	94	94	94	94
Solar	3,004	3,782	3,782	3,782	3,782	3,735	3,782	3,782	3,781	3,738
Wind	559	562	562	562	562	588	562	561	560	549
Geothermal	1,031	1,031	1,031	1,031	1,031	1,031	1,033	1,033	1,033	1,033
Conventional Hydro	2,825	2,825	2,825	2,825	2,825	2,722	2,825	2,825	2,825	2,825
Nuclear	2,821	2,821	2,821	2,821	2,821	2,821	2,821	2,821	2,821	2,821
Hybrid	145	145	145	145	145	145	145	145	145	145
Battery	785	1,003	1,124	1,124	1,124	1,124	1,125	1,394	1,394	1,756
Total MW	34,528	35,527	35,277	35,277	34,886	34,198	34,332	34,600	34,515	33,688

WECC-SRSG Assessment

Planning Reserve Margins

The ARM is above the RML throughout this assessment period. Starting in the summer of 2030, the Southwest shows a shortfall of existing-certain and net firm transfers, meaning imports may be necessary if new capacity were to be delayed.

WECC continues to use a probabilistic approach for determining RMLs, holding a LOLP of less than or equal to 0.02% (approximately a 1-day-in-10 years loss of load). The model determines what reserve margin must be held to maintain a fixed LOLP. Using this technique, a target reserve margin is evaluated for every hour of every year of the full forecast period. The LOLP is determined by comparing the distributions of potential load and resource states and calculating the probability that load exceeds generation. The LOLP can also be visualized by the area where the demand and supply distributions overlap.

Non-Peak Hour Risk, Energy Assurance, Probabilistic Based Assessments

Both demand and resource availability variability are increasing, and the challenges they present are accelerating. CA/MX, SRSG, and WPP show hours at risk of load loss over the next five years. In 2021, WECC studied the ramping risks of net demand from increasing penetrations of renewables in response to the August 2020 heatwave event. Four of 39 BAs, specifically those in the sunniest Southwestern territory, were identified as exhibiting or expected to develop ramping risk over the planning horizon.

SRSG's probabilistic assessment results indicate that the risk of energy shortfall is increasing from the 2024 to 2026 study years. The highest risk for loss of load is in the months of July through September during the 6:00 p.m. hour (one hour after demand peaks for the day). The magnitude of unserved energy in any one hour of load-loss ranges from less than 1 MW to 9,000 MW.

Base Case Summary of Results

	2024*	2024	2026
EUE (MWh)	81.33	83.58	9352.15
EUE (ppm)	0.750	0.68	71.17
LOLH (Hours per Year)	0.004	0.003	0.368
Operable On-peak Margin	5.50%	28.08%	24.85%

***** Provides the 2020 ProbA results for comparison

Demand

The SRSG's 10-year peak demand compound annual growth rates are among the highest of all assessments areas. The winter 1-year CAGR is over 2% while the summer peak demand 10-year CAGR is 1.7%.

Demand Side Management

Demand forecasters in the Southwest anticipate that EE and conservation programs will help to reduce demand growth. In summer, EE programs are estimated to offset peak demand by 315 MW currently and are projected to account for 1,315 MW of reduction in peak demand by 2032.

Distributed Energy Resources

SRSG is seeing a 13% average annual growth rate in BTM solar PV on-peak capacity.

Energy Storage

Significant amounts of energy storage additions are planned. Energy storage in the west may be able to help mitigate ramping risk from afternoon net demand due to increasing penetrations of solar. Many of the additions are being co-located into hybrid solar PV + storage. Of the 24.5 GW of new energy storage in the Western Interconnection, 2.4 GW are being developed in SRSG.

Energy Transfers (Reliance on Assistance)

Energy and capacity risk analysis performed by WECC for this LTRA use WECC's modeling of energy transfers. Complete firm transfer information is not available. Imports are expected to increase across the Southwest for summers starting in 2025.

Transmission

There are over 581 miles of transmission lines under construction or in planning for construction during this assessment period.

Demand Assumptions and Resource Categories

Demand (Load Forecast)	
Total Internal Demand	This is the peak hourly load[41] for the summer and winter of each year.[42] Projected total internal demand is based on normal weather (50/50 distribution)[43] and includes the impacts of distributed resources, EE, and conservation programs.
Net Internal Demand	This is the total internal demand reduced by the amount of controllable and dispatchable DR projected to be available during the peak hour. Net internal demand is used in all reserve margin calculations.

Load Forecasting Assumptions by Assessment Area			
Assessment Area	**Peak Season**	**Coincident / Noncoincident[44]**	**Load Forecasting Entity**
MISO	Summer	Coincident	MISO LSEs
MRO-Manitoba Hydro	Winter	Coincident	Manitoba Hydro
MRO-SaskPower	Winter	Coincident	SaskPower
NPCC-Maritimes	Winter	Noncoincident	Maritimes sub-areas
NPCC-New England	Summer	Coincident	ISO-NE
NPCC-New York	Summer	Coincident	NYISO
NPCC-Ontario	Summer	Coincident	IESO
NPCC-Québec	Winter	Coincident	Hydro Québec
PJM	Summer	Coincident	PJM
SERC-East	Summer	Noncoincident	SERC LSEs
SERC-Florida Peninsula	Summer	Noncoincident	
SERC-Central	Summer	Noncoincident	
SERC-Southeast	Summer	Noncoincident	
SPP	Summer	Noncoincident	SPP LSEs
Texas RE-ERCOT	Summer	Coincident	ERCOT
WECC-AB	Winter	Noncoincident	WECC BAs, aggregated by WECC
WECC-BC	Winter	Noncoincident	
WECC-CA/MX	Summer	Noncoincident	
WECC-US	Summer	Noncoincident	
WECC-RMRG	Summer	Noncoincident	

[41] Glossary of Terms Used in NERC Reliability Standards.
[42] The summer season represents June–September and the winter season represents December–February.
[43] Essentially, this means that there is a 50% probability that actual peak demand will be higher and a 50% probability that actual peak demand will be lower than the value provided for a given season/year.
[44] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval. This is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year.

Load Forecasting Assumptions by Assessment Area			
Assessment Area	**Peak Season**	**Coincident / Noncoincident[44]**	**Load Forecasting Entity**
WECC-SRSG	Summer	Noncoincident	

Resource Categories

NERC collects projections for the amount of existing and planned capacity and net capacity transfers (between assessment areas) that will be available during the forecast hour of peak demand for the summer and winter seasons of each year. Resource planning methods vary throughout the North American BPS. NERC uses the following categories to provide a consistent approach for collecting and presenting resource adequacy.

Anticipated Resources

- Existing-certain generating capacity: includes capacity to serve load during period of peak demand from commercially operable generating units with firm transmission or other qualifying provisions specified in the market construct.
- Tier 1 capacity additions: includes capacity that is either under construction or has received approved planning requirements
- Firm capacity transfers (Imports minus Exports): transfers with firm contracts
- Less confirmed retirements[45]

Prospective Resources: Includes all "anticipated resources" plus the following:

- Existing-other capacity: includes capacity to serve load during period of peak demand from commercially operable generating units without firm transmission or other qualifying provision specified in the market construct. Existing-other capacity could be unavailable during the peak for a number of reasons.
- Tier 2 capacity additions: includes capacity that has been requested but not received approval for planning requirements
- Expected (nonfirm) capacity transfers (imports minus exports): transfers without firm contracts but a high probability of future implementation.
- Less unconfirmed retirements.[46]

[45] Generators that have formally announced retirement plans. These units must have an approved generator deactivation request where applicable.
[46] Capacity that is expected to retire based on the result of an assessment area generator survey or analysis. This capacity is aggregated by fuel type.

Resource Categories

Generating Unit Status: Status at time of reporting:

- **Existing:** It is in commercial operation.
- **Retired:** It is permanently removed from commercial operation.
- **Mothballed**: It is currently inactive or on standby but capable for return to commercial operation. Units that meet this status must have a definite plan to return to service before changing the status to "Existing" with capacity contributions entered in "Expected-Other." Once a "mothballed" unit is confirmed to be capable for commercial operation, capacity contributions should be entered in "Expected-Certain."
- **Cancelled**: planned unit (previously reported as Tier 1, 2, or 3) that has been cancelled/removed from an interconnection queue.
- **Tier 1**: A unit that meets at least one of the following guidelines (with consideration for an area's planning processes):[47]
  - Construction complete (not in commercial operation)
  - Under construction
  - Signed/approved Interconnection Service Agreement (ISA)
  - Signed/approved Power Purchase Agreement (PPA) has been approved
  - Signed/approved Interconnection Construction Service Agreement (CSA)
  - Signed/approved Wholesale Market Participant Agreement (WMPA)
  - Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to Vertically Integrated Entities)
- **Tier 2: A unit that meets at least one of the following guidelines (with consideration for an area's planning processes):**[48]
  - Signed/approved Completion of a feasibility study
  - Signed/approved Completion of a system impact study
  - Signed/approved Completion of a facilities study
  - Requested Interconnection Service Agreement
  - Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to RTOs/ISOs)
- **Tier 3**: A units in an interconnection queue that do not meet the Tier 2 requirement.

[47] AESO: Project has completed Stage 4: the Alberta Utilities Commission (AUC) has issued a Permit and License (AESO-specific)
[48] AESO: Project has completed Stage 4: the Alberta Utilities Commission (AUC) has issued a Permit and License (AESO-specific)

Reserve Margin Descriptions
Planning Reserve Margins: The primary metric used to measure resource adequacy defined as the difference in resources (anticipated or prospective) and net internal demand divided by net internal demand, shown as a percentile
Anticipated Reserve Margin: The amount of anticipated resources less net internal demand calculated as a percentage of net internal demand
Prospective Reserve Margin: The amount of prospective resources less net internal demand calculated as a percentage of net internal demand
Reference Margin Level: The assumptions and naming convention of this metric vary by assessment area. The RML can be determined using both deterministic and probabilistic (based on a 0.1/year loss of load study) approaches. In both cases, system planners use this metric is to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing an RML is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increased demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, an RML is established by a state, provincial authority, ISO/RTO, or other regulatory body. In some cases, the RML is a requirement. RMLs can fluctuate over the duration of this assessment period or may be different for the summer and winter seasons. If an RML is not provided by a given assessment area, NERC applies 15% for predominately thermal systems and 10% for predominately hydro systems.

Methods and Assumptions

How NERC Defines BPS Reliability

NERC defines the reliability of the interconnected BPS in terms of two basic and functional aspects:

Adequacy: The ability of the electricity system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and expected unscheduled outages of system components

Operating Reliability: The ability of the electricity system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system components

When extreme or otherwise unanticipated conditions result in a resource shortfall, system operators can and should take controlling actions or implement procedures to maintain a continual balance between supply and demand within a balancing area (formerly control area); these actions include the following:

- Public appeals
- Interruptible demand that the end-use customer makes available to its LSEs via contract or agreement for curtailment[49]
- Voltage reductions (sometimes referred to as "brownouts" because incandescent lights will dim as voltage is lowered, sometimes as much as 5%)
- Rotating blackouts (The term "rotating" is used because each set of distribution feeders is interrupted for a limited time, typically 20–30 minutes, and then those feeders are put back in service and another set is interrupted, rotating the outages among individual feeders.)

System disturbances affect operating reliability when they cause the unplanned and/or uncontrolled interruption of customer demand. When these interruptions are contained within a localized area, they are considered unplanned interruptions or disturbances. When interruptions spread over a wide area of the grid, they are referred to as "cascading blackouts," the uncontrolled successive loss of system elements triggered by an incident at any location.

The BES is a defined subset of the BPS that includes all facilities necessary for the reliable operation and planning of the BPS.[50] NERC Reliability Standards are intended to establish requirements for BPS owners and operators so that the BES delivers an adequate level of reliability (ALR),[51] which is defined by the following characteristics.

Adequate Level of Reliability: It is the state that the design, planning, and operation of the BES will achieve when the following reliability performance objectives are met:

- The BES does not experience instability, uncontrolled separation, cascading,[52] and/or voltage collapse under normal operating conditions or when subject to predefined disturbances.[53]
- BES frequency is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.
- BES voltage is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.

[49] Interruptible demand (or interruptible load) is a term used in NERC Reliability Standards. See Glossary of Terms used in Reliability Standards: https://www.nerc.com/files/glossary_of_terms.pdf
[50] https://www.nerc.com/pa/RAPA/Pages/BES.aspx
[51] https://www.nerc.com/comm/Other/Adequate%20Level%20of%20Reliability%20Task%20Force%20%20ALRTF%20DL/Final%20Documents%20Posted%20for%20Stakeholders%20and%20Board%20of%20Trustee%20Review/2013_03_26_Technical_Report_clean.pdf
[52] NERC's Glossary of Terms defines Cascading: "Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies."
[53] NERC's Glossary of Terms defines Disturbance: "1. An unplanned event that produces an abnormal system condition. 2. Any perturbation to the electric system. 3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load."

- Adverse reliability impacts on the BES following low-probability disturbances (e.g., multiple BES contingences, unplanned/uncontrolled equipment outages, cyber security events, malicious acts) are managed.

Restoration of the BES after major system disturbances that result in blackouts and widespread outages of BES elements is performed in a coordinated and controlled manner.

How NERC Evaluates Reserve Margins in Assessing Resource Adequacy

PRMs are calculated by finding the difference between the amount of projected on-peak capacity and the forecasted peak demand and then dividing this difference by the forecasted peak demand. Each assessment area has a peak season, summer or winter, for which its peak demand is higher. PRMs used throughout this *LTRA* are for each assessment area's peak season listed in the load forecasting table of the **Demand Assumptions and Resource Categories**.

NERC assesses resource adequacy by evaluating each assessment area's PRM relative to its RML—a "target" or requirement based on traditional capacity planning criteria. For a description of each assessment area's RMLs refer to the **Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area** table. The projected resource capacity used in the evaluations is reduced by known operating limitations (e.g., fuel availability, transmission limitations, environmental limitations) and compared to the RML, which represents the desired level of risk based on a probability-based loss of load analysis. On-peak resource capacity reflects expected output at the hour of peak demand. Because the electrical output of VERs (e.g., wind and solar) depend on weather conditions, on-peak capacity contributions are less than nameplate capacity. Refer to supplementary tables posted on NERC's Reliability Assessments web page to see the on-peak capacity contribution of existing wind and solar resources for each assessment area).[54]

On the basis of the five-year projected reserves compared to the established RMLs, NERC determines the risk associated with the projected level of reserve and concludes in terms of the following:

Adequate: The ARM is greater than RML.

Marginal: The ARM is lower than the RML and the PRM is higher than RML.

Inadequate: The ARM and PRMs are less than the RML and Tier 3 resources are unlikely to advance.

Metrics for Probabilistic Evaluation Used in this Assessment

Probabilistic Assessment: Biennially, NERC conducts a probabilistic evaluation as part of its resource adequacy assessment and publishes results in the LTRA.

Loss of Load Hours: LOLH is generally defined as the expected number of hours per time period (often one year) when a system's hourly demand is projected to exceed the generating capacity. This metric is calculated by using each hourly load in the given period (or the load duration curve).

LOLH should be evaluated using all hours rather than just peak periods. It can be evaluated over seasonal, monthly, or weekly study horizons. LOLH does not inform of the magnitude or the frequency of loss of load events, but it is used as a measure of their combined duration. LOLH is applicable to both small and large systems and is relevant for assessments covering all hours (compared to only the peak demand hour of each season). LOLH provides insight to the impact of energy limited resources on a system's reliability, particularly in systems with growing penetration of such resources. Examples of such energy limited resources include the following:

- DR programs that can be modeled as resources with specific contract limits, including hours per year, days per week, and hours per day constraints
- EE programs that can be modeled as reductions to load with an hourly load shape impact
- Distributed resources (e.g., BTM solar PV) that can be modeled as reductions to load with an hourly load shape impact

[54] https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx

- VERs can be modeled probabilistically with multiple hourly profiles

Expected Unserved Energy: EUE is the summation of the expected number of megawatt hours of demand that will not be served in a given time period as a result of demand exceeding the available capacity across all hours. EUE is an energy-centric metric that considers the magnitude and duration for all hours of the time period and is calculated in MWhs. This measure can be normalized based on various components of an assessment area (e.g., total of peak demand, net energy for load). Normalizing the EUE provides a measure relative to the size of a given assessment area (generally in terms of parts per million or ppm).

EUE is the only metric that considers magnitude of loss of load events. With the changing generation mix, to make EUE a more effective metric, hourly EUE for each month provides insights on potential adequacy risk during shoulder and nonpeak hours. EUE is useful for estimating the size of loss of load events so the planners can estimate the cost and impact. EUE can be used as a basis for reference reserve margin to determine capacity credits for VERs. In addition, EUE can be used to quantify the impacts of extreme weather, common mode failure, etc.

NERC is not aware of any planning criteria in North America based on EUE; however, in Australia, the Australian Energy Market Operator is responsible for planning using 0.002% (20 ppm) EUE as their energy adequacy requirement.[55] This requirement incorporates economic factors based on the risk of load shedding and the value of load loss along with the load-loss reliability component.

On the basis of the two years of the ProbA results, NERC determines the risk in terms of the following:

Low Risk: Negligible amounts of LOLH and EUE.

Periods of Risk: LOLH < 2 Hrs and EUE < 0.002% of total annual net energy.

Significant Risk: LOLH > 2 Hrs and EUE > 0.002% of total annual net energy.

NERC Capacity Supply Categories

Future capacity additions are reported in three categories:

Tier 1: Planned capacity that meets at least one of the following requirements is included as anticipated resources:

- Construction complete (not in commercial operation)
- Under construction
- Signed/approved Interconnection service agreement
- Signed/approved power purchase agreement
- Signed/approved Interconnection construction service agreement
- Signed/approved wholesale market participant agreement
- Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (applies to vertically integrated entities)

Tier 2: Planned capacity that meets at least one of the following requirements is included as prospective resources:

- Signed/approved completion of a feasibility study
- Signed/approved completion of a system impact study

[55] https://wa.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2018/2018-Electricity-Statement-of-Opportunities.pdf

- Signed/approved completion of a facilities study
- Requested Interconnection service agreement
- Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (applies to RTO/ ISOs)

Tier 3: Tier 3 is other planned capacity that does not meet any of the above requirements.

Understanding Demand Forecasts

Future electricity requirements cannot be predicted precisely. Peak demand and annual energy use are reflections of the ways in which customers use electricity in their domestic, commercial, and industrial activities. Therefore, the electricity industry continues to monitor electricity use and generally revise its forecasts on an annual basis or as its resource planning requires. In recent years, the difference between forecast and actual peak demands have decreased, reflecting a trend toward improving forecasting accuracy.

The peak demand and annual net energy for load projections are aggregates of the forecasts of the individual planning entities and LSEs. These resulting forecasts reported in this LTRA are typically “equal probability” forecasts. That is, there is a 50% chance that the forecast will be exceeded and a 50% chance that the forecast will not be reached.

Forecast peak demands, or total internal demand, are electricity demands that have already been reduced to reflect the effects of DSM programs, such as conservation, EE, and time-of-use rates; it is equal to the sum of metered (net) power outputs of all generators within a system and the metered line flows into the system less the metered line flows out of the system. Thus, total internal demand is the maximum (hourly integrated) demand of all customer demands plus losses. The effects of DR resources that are dispatchable and controllable by the system operator, such as utility-controlled water heaters and contractually interruptible customers, are not included in total internal demand. Rather, the effects of dispatchable and controllable DR are included in net internal demand.

Future Transmission Project Categories

Under Construction: Construction of the line has begun.

Planned (any of the following):

- Permits have been approved to proceed
- Design is complete
- Needed in order to meet a regulatory requirement

Conceptual (any of the following):

- A line projected in the transmission plan
- A line that is required to meet a NERC TPL standard or powerflow model and cannot be categorized as “Under Construction” or “Planned”
- Other projected lines that do not meet requirements of “Under Construction” or “Planned”

Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area

Reference Margin Levels for Each Assessment Area (2023–2027)					
Assessment Area	**Reference Margin Level**	**Assessment Area Terminology**	**Requirement?**	**Methodology**	**Reviewing or Approving Body**
MISO	18.3%	PRM	Yes: Established Annually[56]	0.1 day/Year Loss of Load Expectation (LOLE)	MISO
MRO-Manitoba Hydro	12.0%	Reference Margin Level	No	0.1 day/Year LOLE	Reviewed by the Manitoba Public Utilities Board
MRO-SaskPower	11.0%	Reference Margin Level	No	EUE and Deterministic Criteria	SaskPower
NPCC-Maritimes	20.0%[57]	Reference Margin Level	No	0.1 day/Year LOLE	Maritimes Sub-areas; NPCC
NPCC-New England	13.4–13.6%	Installed Capacity Requirement	Yes: three year requirement established annually	0.1 day/Year LOLE	ISO-NE, NPCC Criteria
NPCC-New York	15.0%[58]	Installed Reserve Margin	Yes: one year requirement, established annually by NYSRC based on full installed capacity values of resources	0.1 day/Year LOLE	NYSRC, NPCC Criteria
NPCC-Ontario	18.9–23.1%	Reserve Margin Requirement	Yes: established annually for all years	0.1 day/Year LOLE	IESO, NPCC Criteria
NPCC-Québec	10.8%	Reference Margin Level	No: established Annually	0.1 day/Year LOLE	Hydro Québec, NPCC Criteria
PJM	14.4–14.8%	Installed Reserve Margin	Yes: established Annually for each of three future years	0.1 day/Year LOLE	PJM Board of Managers, Reliability*First* BAL-502-RFC-02 Standard
SERC-Central	15.0%[59]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities
SERC-East	15.0%[60]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities

[56] In MISO, the states can override the MISO PRM.
[57] The 20% RML is used by the individual jurisdictions in the Maritimes area with the exception of Prince Edward Island, which uses a margin of 15%. Accordingly, 20% is applied for the entire area.
[58] The NERC LTRA RML for NY is 15%; however, there is no planning reserve margin criteria in New York. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. Additionally, the NYISO uses probabilistic assessments to evaluate its system's resource adequacy against the LOLE resource adequacy criterion of 0.1 days/year. However, New York requires LSEs to procure capacity for their loads equal to their peak demand plus an IRM. The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). NYSRC approved the 2021/2022 IRM at 20.7%. All values in the IRM calculation are based upon full installed capacity (ICAP) MW values of resources, and it is identified based on annual probabilistic assessments and models for the upcoming capability year.
[59] SERC does not provide RMLs or resource requirements for its sub-areas. However, SERC members perform individual assessments to comply with any state requirements.
[60] SERC does not provide RMLs or resource requirements for its sub-areas. However, SERC members perform individual assessments to comply with any state requirements.

Reference Margin Levels for Each Assessment Area (2023–2027)					
Assessment Area	**Reference Margin Level**	**Assessment Area Terminology**	**Requirement?**	**Methodology**	**Reviewing or Approving Body**
SERC-Florida Peninsula	15.0%[61]	Reliability Criterion	No: Guideline	0.1 day/Year LOLP	Florida Public Service Commission
SERC-Southeast	15.0%[62]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities
SPP	16.0%	Resource Adequacy Requirement	Yes: studied on Biennial Basis	0.1 day/Year LOLE	SPP RTO Staff and Stakeholders
Texas RE-ERCOT	13.75%	Target Reserve Margin	No	0.1 day/Year LOLE plus adjustment for non-modeled market considerations	ERCOT Board of Directors
WECC-AB	13.2–14.1%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[63]
WECC-BC	13.2–14.1%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[53]
WECC-CA/MX[64]	17.4–19.0%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[53]
WECC-WPP	13.5–15.2%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[53]
WECC-SRSG	10.7–12.4%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[53]

[61] SERC-FP uses a 15% reference reserve margin as approved by the Florida Public Service Commission for non-IOUs and recognized as a voluntary 20% reserve margin criteria for IOUs; individual utilities may also use additional reliability criteria.
[62] SERC does not provide RMLs or resource requirements for its sub-areas. However, SERC members perform individual assessments to comply with any state requirements.
[63] WECC's Reference Margin Level in this table is for the hour of peak demand. Some hours in the year require a higher reserve margin to meet the 0.02% reliability criteria due to the variability in resource availability and resource performance characteristics.
[64] California is the only state in the WI that has a wide-area PRM, currently 17.5%: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage,