NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2020 Long-Term Reliability Assessment

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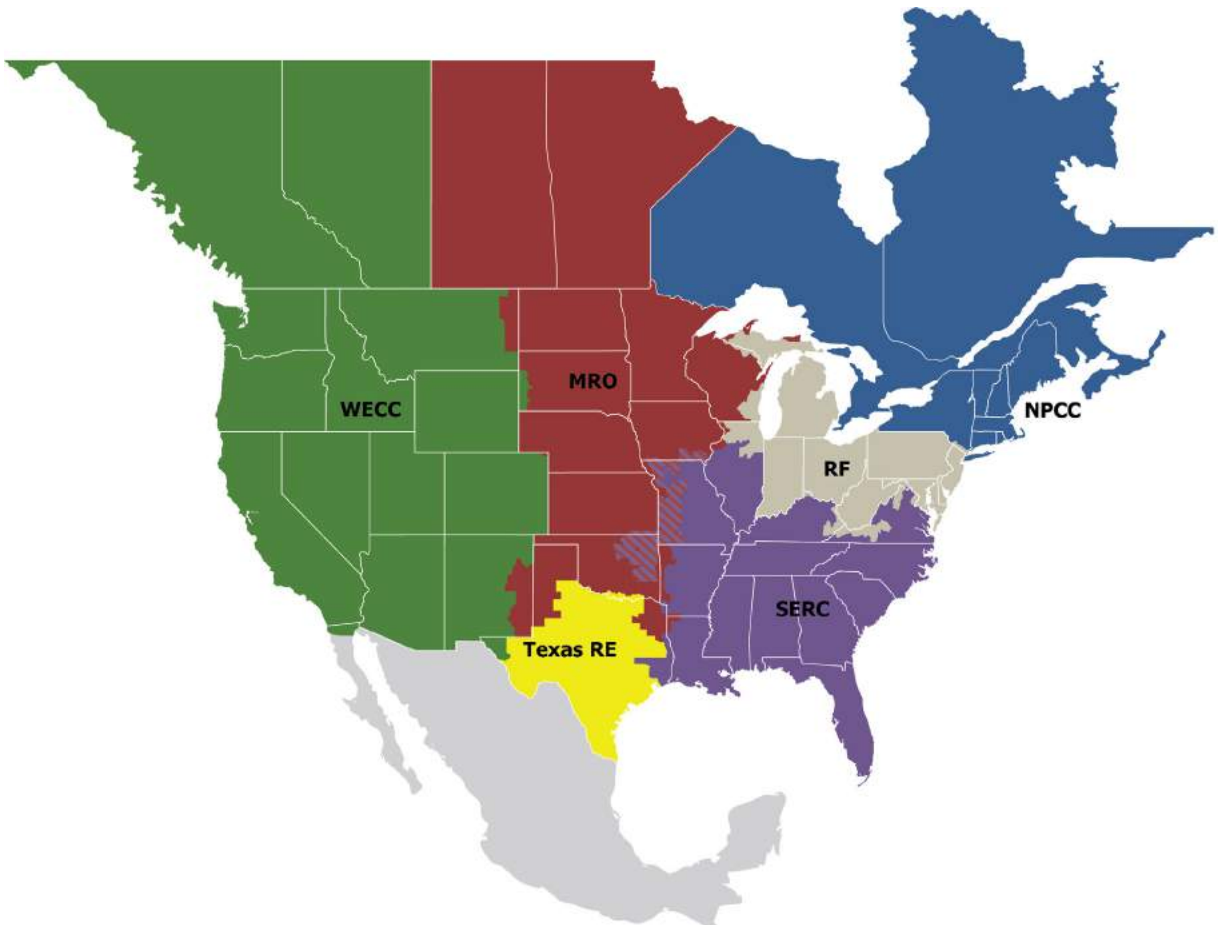
Preface

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 (REs), 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 RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one RE while associated Transmission Owners/Operators participate in another.



About This Assessment

NERC is a not-for-profit international regulatory authority whose mission is 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, subject to oversight by the Federal Energy Regulatory Commission (FERC, Commission) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, serving more than 334 million people. Section 39.11(b) of the U.S. FERC's regulations provide 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 collected by NERC from the six REs on an assessment area basis to independently assess 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 (RAS), 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, RAS 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.

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

Considerations

Projections in this assessment are not predictions of what will happen, rather they are based on information supplied in July 2020 about known system changes with updates incorporated prior to publication. The assessment period for this *2020 LTRA* includes projections for years 2021–2030; however, some figures and tables examine data and information for the 2020 year. The 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 the **Regional Assessments** section of this report. Reliability impacts related to physical and cyber security risks are not specifically addressed in this assessment; this assessment is primarily focused on resource adequacy and operating reliability. NERC leads a multifaceted approach through the 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 create a reference case dataset that includes projected on-peak demand and system energy needs, demand response (DR), resource capacity, and transmission projects. Data and information from each NERC RE are 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 portion of Baja California Norte, Mexico. NERC's reliability assessments are developed to inform industry, policy makers, and regulators and 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 RE, 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 **Demand Assumptions and Resource Categories** 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

In this *2020 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 2020. Any subsequent demand forecast or resource plan changes may not be fully represented; however, updated data submitted throughout the report drafting time frame has been and included where appropriate.
- Peak demand and Planning Reserve Margins (PRMs) are based on average weather conditions and assumed forecast economic activity at the time of submittal. Weather variability is discussed in each RE's self-assessment.
- Generating 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.

In April 2020, NERC published its *Special Report Pandemic Preparedness and Operational Assessment: Spring 2020* to advise electricity stakeholders about elevated risk to electric reliability as a result of the global health crisis.[7] NERC continues to assess risks to the reliability and security of the BPS from the global health crisis and reports on industry actions and preparedness in this *LTRA*.

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 electricity 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).

7 https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC_Pandemic_Preparedness_and_Op_Assessment_Spring_2020.pdf

Reading this Report

This report is compiled into two major parts:

ERO-Wide Reliability Assessment

- Evaluate industry preparations 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

Regional Reliability Assessment

- 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

Executive Summary

The electricity sector is undergoing significant changes that are unprecedented in both transformational nature and rapid pace. Such extraordinary evolution presents new challenges and opportunities for reliability, resilience, and security. Advances in technology, customer preferences, policies, and market forces are altering the generation resource mix and challenging the conventional understanding of the reliability role of baseload power that was traditionally provided by large, centralized generating units. While efforts are underway to address these risks, the management of reliability, resilience, and security will require increased focus by all.

The addition of variable energy resources, primarily wind and solar, and the retirement of conventional generation is fundamentally changing how the BPS is planned and operated. Resource planners must consider greater uncertainty across the resource fleet as well as uncertainty in electricity demand that is increasingly being effected by demand-side resources. As a result, reserve margins and capacity-based estimates can give a false sense of comfort and need to be supplemented with energy adequacy assessments. Energy assessments are key to understanding the reliability needs of a future BPS and are presented in this report.

This *2020 LTRA* is the ERO's independent assessment and comprehensive report on the adequacy of planned BPS resources to meet electricity demand across North America over the next ten years. It also identifies area trends and emerging issues that affect the long-term reliability and security of the BPS.

A summary of the key findings is as follows:

Most areas are projecting to have adequate resource capacity to meet annual peak demands. However, measures of energy adequacy from the ERO's probabilistic assessment (ProbA), which accounts for all hours in selected study years of 2022 and 2024, are cause for concern in several areas. The following explains these concerns in detail:

- Nearly all parts of the Western Interconnection (WI), with the exception of Alberta, face heightened loss of load risk. The WECC-CAMX assessment area (primarily California), which was a subject of concern when the prior ProbA was conducted in 2018, could face periods where resources are insufficient for area energy needs, potentially resulting in up to 22 hours of load-loss in 2022. The recent experience during the wide-area heat wave in August 2020 provides evidence of the challenges faced in the WI to reliably serve the changing demand profile with the evolving resource mix. In the Northwestern United States and Rocky Mountain areas, probabilistic studies are beginning to show potential for loss of load as well. Like California, the risk is concentrated during the summer months and occurs in the late afternoon or early evening hours after demand has peaked but as solar resource output diminishes. Across the WI, an increased reliance on transfers from neighboring areas is an emerging risk, particularly during western-wide weather events.
- In Texas, a large amount of new wind and solar generation has recently been added, providing on-peak capacity to lift reserve margins for summer peak demand. However, there is increasing risk of tight operating reserves during other periods as thermal generation capacity has declined. Although recent probabilistic studies do not reveal unserved energy, ERCOT studies show reduced availability of operating reserves over a range of several hours around the time of peak demand in summer. They also show the amount of available reserves in nonpeak months, such as March and October, to be declining to become months that see the lowest peak-day reserves during the year.

- In the Midcontinent Independent System Operator (MISO) area, most risk remains concentrated during summer peak periods. Reserve margin projections of on-peak capacity are falling and are projected to be below Reference Margin Level targets beginning in 2025. However, the ProbA is identifying the emergence of risk during times when demand is not at peak levels (e.g., during spring or fall seasons when planned generator outages for maintenance could coincide with unseasonably high load). MISO's probabilistic study shows 27.3 MWh of unserved energy and the potential for 0.2 hours of load shed in 2022.

To ensure reliability during the transition to greater reliance on wind and solar resources, emerging resource and energy adequacy issues must be addressed. Planning for long-term resource adequacy is becoming increasingly complex with a resource mix that is more unpredictable and less energy-assured. Furthermore, tomorrow's grid operators will use a resource mix that is delivered by the long-term planning decisions of today and must be equipped with models, technology, and strategies to ensure they can do so effectively. These are challenges that need to be overcome but are not insurmountable. The emerging reliability challenges are characterized as follows:

- The capacity that variable resources contribute to serving peak electricity demand differs from thermal generation because output depends on the environment, climate, and local weather conditions. As a result, variable resources typically contribute less on-peak capacity than the rated nameplate value. To assess reserve margins, variable energy resources are "derated" to reflect estimated energy production during peak hours. In the operating time frame, grid operators face the risk of forecast inaccuracy from unanticipated weather or environment conditions. Forecast errors can affect reliability in two ways: there is the potential for energy production from wind and solar resources to be less than anticipated as well as the potential for demand forecasts to be inaccurate in areas with increasingly embedded solar PV generation from the distribution network. As a result, operators must increasingly balance uncertain loads with uncertain generation.
- As more solar and wind generation is added, additional flexible resources are needed to offset these resources' variability. This is placing more operating pressure on those (typically natural gas) resources and makes them the key to securing BPS reliability. Insufficient flexible resources was a contributing cause to the load shed event in California during the wide-area heat wave in August 2020.
- Natural-gas-fired generation provides 40% of the aggregate on-peak electricity supply capacity in North America, and 41 GW of that capacity is in late-stage planning for addition over the next 10 years. As natural-gas-fired generation continues to increase, vulnerabilities associated with natural gas delivery to generators can potentially result in generator outages due to both insufficient natural gas infrastructure or alternate fuel delivery and/or disruption to natural gas or alternate fuel deliveries. These risks are most heightened in New England, the desert Southwest, and California, where there is increased reliance on natural gas generation and limited back-up fuel.

The latest industry projections included in this *2020 LTRA* provide further evidence of the rapid growth of inverter based resources on the BPS and distribution networks; these include most solar and wind as well as new battery or hybrid generation. These resources respond to disturbances and dynamic conditions based on programmed logic and inverter controls as opposed to physics and mechanical characteristics. Some inverter-based resource performance issues have been significant enough to result in grid disturbances that affect BPS reliability, such as the tripping of a number of BPS-connected solar PV generation units that occurred during the 2016 Blue Cut Fire, the 2017 Canyon 2 Fire, and 2020 San Fernando Disturbance in California. Several findings and recommendations in this report are aimed at promoting the reliable integration of these resources by addressing modeling and coordination needs. In addition to ensuring planning studies and operating models accurately account for new resource types, heightened cyber security awareness and risk-reduction engineering should be pursued to reduce the attack surface and mitigate reliability and security concerns.

To address these emerging risks and prevent similar issues from happening in other areas, NERC has developed the following recommendations for the industry and policy makers:

- Regulators and policymakers in risk areas should coordinate with electric industry planning and operating entities to develop policies that prioritize reliability, such as promoting the development and use of additional flexible resources, energy-assured generation, and resource diversity.
- Regulators and policy makers should consider revising their resource adequacy requirements to consider new risks that emerge during non-peak hours, limitations from neighboring systems during system-wide events, and the reduced resource diversity and/or increased reliance on a single fuel source or delivery mode.

- Industry should identify and commit flexible resources to meet increasing ramping and load-following requirements that result from increased variable energy resources and not solely to meet peak load capacity requirements.

Furthermore, to ensure the ERO and industry are developing solutions in advance of these emerging risks, NERC has developed the following recommendations for the ERO and the industry:

- The ERO should enhance the reliability assessment process by evaluating energy adequacy risks in seasonal reliability assessments to help inform stakeholders of reliability needs and potential solutions in the short-term.
- To better identify fuel supply risks during planning, the ERO should collaborate with industry to identify design-basis fuel supply scenarios of normal and extreme events for use by BPS and resource planners. Design-basis criteria should then be considered in planning-related Reliability Standards, such as TPL-001.
- The ERO should increase communication and outreach with state and provincial policymakers on resource adequacy risks and challenges to ensure the risks being presenting in all ERO reliability assessments are well known and understood.
- The ERO should advance the efforts to modify existing Reliability Standards to account for inverter-based resource performance and characteristics. In particular, protection and control, data sharing, and modeling-related standards all need to consider the new risks imposed by inverter-based resources connected to both distribution systems and the BPS.
- The industry should verify that inverter-based resource models used for steady state and dynamic power systems analysis agree with the as-built, plant-specific settings, controls, and behaviors of the facility. Generator Owners/Operators should engage with equipment manufacturers and coordinate with their Transmission Planner/Planning Coordinators to understand the modeling challenges and proactively address deficiencies identified in several ERO event reports and power system modeling assessments. Industry has achieved success by using ERO guidelines to support system-specific interconnection and control design requirements.
- REs and model-building designees should enhance their reviews of steady-state power flow and dynamics base case models for model deficiencies associated with existing and newly-interconnecting BPS-connected inverter-based resources.
- The ERO and industry should address aggregate DER data needs for transmission planning and operational studies and develop guidance for BPS planning with increasing DERs.

NERC Reliability Standards

BPS reliability encompasses two priorities that must be addressed simultaneously. The first is operating reliability, supporting the operational needs of the grid to maintain stability and withstand sudden disturbances. The second is adequacy, the ability of the electricity system to produce and deliver energy to end-use customers at all times.

NERC Reliability Standards are the planning and operating rules that electric utilities follow to support and maintain a reliable electricity system. These standards are developed by the industry by using a balanced, open, fair and inclusive process accredited by the American National Standards Institute (ANSI). While NERC does not have authority to set Reliability Standards for resource adequacy (e.g., reserve margin criteria) or to order the construction of resources or transmission,* NERC independently evaluates where reliability issues may arise as well as identifies emerging risks through reliability assessment. This information, along with NERC recommendations, is then available to policy makers and federal, state, and provincial regulators to support decision making within the electric sector.

* NERC is prohibited by Section 215 of the 2005 Federal Power Act from adopting standards that require adequate resources be in place or order construction of generation or transmission. Resource adequacy and the contruction of bulk power facilities is fully within state and/or provincial jurisdiction and authority.

Key Findings

Resource Adequacy—PRMs: Projected reserves fall below the Reference Margin Level (RML) in NPCC-Ontario beginning in 2022 and in MISO in 2025. There is sufficient electricity resource capacity in all other areas. Details include the following:

- Throughout this assessment period and particularly in the first five years, there is heightened uncertainty in demand projections stemming from the progression of the coronavirus (COVID-19) pandemic and the response of governments, society, and the electricity industry. Reserve margins are sensitive to demand forecast uncertainty. The uncertainty in demand forecast projections could exacerbate planning reserve shortfalls in areas that are below or near RMLs.
- Ontario's Anticipated Reserve Margins (ARMs) fall below the RML during the first five years of the assessment period, driven largely by the nuclear refurbishments, demand forecast uncertainty, and expiration of a number of generation contracts. The Independent Electric System Operator (IESO), the system operator for the area, expects to acquire the required electricity resources through capacity auctions or other acquisition tools.
- The MISO area will have adequate, but tighter, reserve margins for 2021. MISO and participating stakeholder action is needed to ensure future resource adequacy by achieving certainty of prospective resources beginning in 2025 when their ARM falls below the RML.
- NPCC Maritimes is at or near RML throughout the assessment period. Utilities can address near-term shortfalls through electricity import contracts.
- Sufficient resources are planned to be available throughout the assessment period in all other areas.

Assessment of Resource Adequacy across All Hours (Energy Adequacy): While the ERO's biennial ProbA indicates that resource adequacy meets or exceeds resource adequacy benchmarks, there is increasing risk of resource shortfalls during nonpeak hours in parts of the WI, MISO, and Texas. Details include the following:

- This *2020 LTRA* includes the ERO's biennial ProbA that provides insights into the ability of the future resource mix to meet the projected demand at all times. While the deterministic PRM assessment findings above indicated sufficient resources are planned to be available throughout this assessment period for most areas, except MISO and Ontario, the findings provide evidence that the deterministic PRM metric, especially in areas with higher penetrations of resources with energy limitations and uncertainty (i.e., wind, solar, natural gas, hydro), may not be a completely accurate way to measure an area's resource adequacy during all hours of the year.
- WECC's 2020 ProbA continues to note several hours that pose a potential risk for loss of load for almost all WI areas over studied years. The CAMX area was the only concern in the 2018 ProbA, but now all areas except Alberta (AESO) are seeing hours of potential loss of load. Exacerbated by the recent western area heat wave event that saw load shed over the summer, all areas are reviewing the level of resource adequacy considering forecast variability.
- The traditional methods of assessing resource adequacy at peak load times may not accurately or fully reflect the ability of the new resource mix to supply energy and reserves for all hours. Energy limitations can exist, requiring probabilistic analysis methods to identify risks to reliability that result from shortfalls in the conversion of capacity to energy (energy adequacy). The new resource mix includes natural-gas-fired generation; unprecedented proportions of nonsynchronous resources, including renewables and battery storage; DR; smart- and micro-grids; and other emerging technologies. Collectively, the new resources are more susceptible to energy sufficiency uncertainty.

Resource Mix Changes: Variable energy resources continue to grow, and thermal resource capacity declines in most areas throughout this assessment period; as a result, increased attention is required to the planning and operating of a more complex resource mix. Details include the following:

- In many areas, variable energy resources are increasingly important to meet electricity demand. Texas and California rely on variable energy resources to meet peak hour demand; this can lead to operational risk during unanticipated conditions that reduce the resource output. Other areas are trending toward increasing reliance on variable energy resources over this assessment period. Sufficient flexible resources are needed in areas with high levels of variable generation to avoid shortfalls when variable resource output is insufficient to meet demand.
- Inverter based resources, 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. Maintaining a reliable system as the penetration of inverter-based resources increases requires planners and operators to be cognizant of potential disturbance-related performance issues.
- Recently the ERO conducted a review of base case models used in transmission planning within the WI and identified modeling issues with wind and solar photo voltaic (PV) generators. Invalid or inaccurate generator models can contribute to steady-state or dynamic study result errors, affecting the reliability of the interconnected transmission system.[8]
- Additional fossil-fueled generator retirements could occur as a result of economic uncertainty and environmental goals.

DER Growth: DER growth continues, prompting the ERO, planners, and operators in areas where penetrations have reached or are approaching impactful levels to take actions to ensure planning processes and operating measures are in place to ensure reliability. Details include the following:

- Texas, Ontario, and areas in the Northeast United States are approaching impactful DER levels presently seen in the WI, leading to the implementation of more sophisticated planning and operating measures. Other areas are closely monitoring DER growth and incorporating DER projections in long-term planning.

8 See NERC-WECC Joint Report—*WECC Base Case Review: Inverter-Based Resources*, August, 2020.

Pandemic Impacts: The ongoing pandemic is not presenting specific threats or degradation to the reliable operation of the BPS for this assessment period. However, it is producing increased uncertainty in future electricity demand projections and presents cyber security and operating risks. Details include the following:

- Most assessment areas did not adjust long-term forecasts for pandemic impacts in this *2020 LTRA* because the effects on peak demand levels were unclear and duration of the pandemic is unpredictable. Summer operating experience in many areas showed increased residential demand that altered hourly load profiles and made up for decreased commercial/industrial load to match prepandemic peak demand levels.
- Reduced industrial load can affect the availability of DR programs that rely on curtailment of industrial customers during periods of high demand.
- Personnel protections for operators and field crews, mitigating heightened cyber risks, and systems operations planning will be persistent areas for risk management throughout the pandemic.

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 shortfalls, 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 load serving entities (LSEs) via contract or agreement for curtailment[9]
- 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.

NERC Reliability Standards are intended to provide guidance so that an adequate level of reliability (ALR) can occur,[10] which is defined by the following characteristics:

> **Adequate Level of Reliability:** It is the state that the design, planning, and operation of the Bulk Electric System (BES) will achieve when the following reliability performance objectives are met:
>
> - The BES does not experience instability, uncontrolled separation, cascading,[11] and/or voltage collapse under normal operating conditions or when subject to predefined disturbances.[12]
> - 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.
> - 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.

9 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

10 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

11 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.”

12 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.”

Detailed Key Findings

Key Finding 1: Projected reserves fall below the RML in NPCC-Ontario beginning in 2022 and in MISO in 2025. Projected electricity resources are sufficient in all other areas.

Key Points

- Throughout this assessment period and particularly in the first five years, there is heightened uncertainty in demand projections stemming from the progression of the COVID-19 pandemic and the response of governments, society, and the electricity industry. Reserve margins are sensitive to demand forecast uncertainty. The uncertainty in demand forecast projections could exacerbate planning reserve shortfalls in areas that are below or near RMLs.
- Ontario's ARMs fall below the RML during the first five years of this assessment period, driven largely by the nuclear refurbishments, demand forecast uncertainty, and expiration of a number of generation contracts. IESO, the system operator for the area, expects to acquire the required capacity through capacity auctions or other acquisition tools.
- The MISO area will have adequate but tighter reserve margins for 2021. MISO and participating stakeholder action is needed to ensure future resource adequacy by achieving certainty of prospective resources beginning in 2025 when their ARM falls below the RML.
- NPCC-Maritimes is at or near the RML throughout this assessment period. Utilities can address near-term shortfalls through electricity import contracts.
- Sufficient resources are planned to be available throughout this assessment period in all other areas.

For the majority of the BPS, PRMs appear sufficient to maintain reliability during the long-term, 10-year horizon. However, there are challenges facing the electricity industry that may shift current industry projections, constrain resources from delivering expected energy and capacity, or otherwise and cause NERC's assessment to change (for example, see **Variable Energy Resource** findings, conventional **Generation Retirements**, and **Maintaining Fuel Assurance**). Where markets exist, signals for new capacity must be effective for planning purposes and reflect the lead times necessary to construct new generation, associated transmission, and natural gas infrastructure if needed. Although generating plant construction lead times have been significantly reduced, environmental permitting for energy infrastructure and transmission planning and approval still require significant lead times.[13]

How NERC Evaluates 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. 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. 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 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: ARM is greater than RML.

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

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

13 Capacity supply and PRM projections in this assessment do not necessarily take into account all generator retirements that may occur over the next 10 years or account for all replacement resources explicitly linked with potential retiring resources. While some generation plants have already announced and planned for retirement, there are still many economically vulnerable generation resources that have not determined and/or announced their plans for retirement.

As shown in **Figure 1**, the ARM in all assessment areas is above the RML in 2025 with the exception of MISO and NPCC-Ontario.

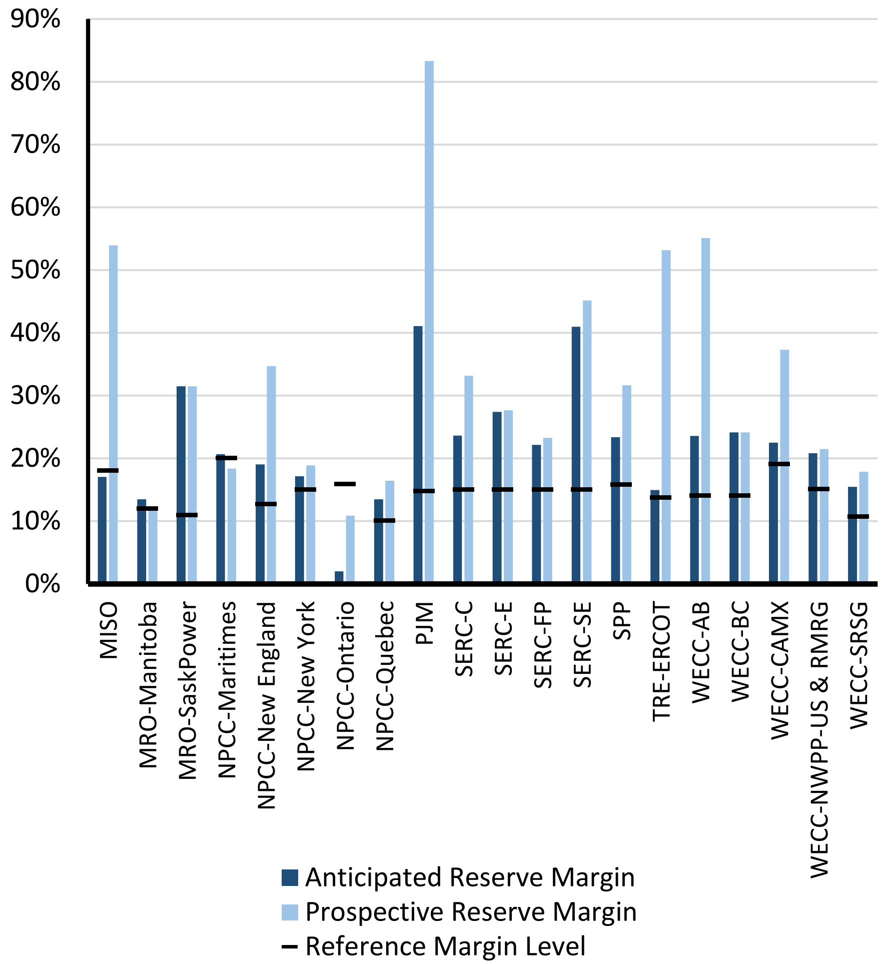


Figure 1: Anticipated and Prospective Reserve Margins for 2025 Peak Season by Assessment Area

The arrival of COVID-19 in North America in 2020 has introduced uncertainty into future electricity demand forecasts and PRM projections. Prior to Summer 2020, when government stay-at-home orders and societal response were at their highest, some areas reported as much as 15% drop in peak demand. However, these observed demand impacts varied across North America and in some areas were negligible. Electricity demand forecasts used in resource adequacy planning account for long-term trends in electricity usage based on inputs, such as weather patterns, economic growth projections, and EE initiatives and trends. Pandemic impacts can affect the accuracy of demand projections in the near term and have the potential to either exacerbate or alleviate planning reserve shortfalls in areas that are below or near RMLs. Over time, demand forecast models can be expected to better account for economic and customer behavior changes that are occurring as a result of the pandemic.

NERC PRM Categories

Anticipated Resources:

- **Existing-Certain Generating Capacity**: operable capacity expected to be available to serve load during the peak hour with firm transmission
- **Tier 1 Capacity Additions:** capacity that is either under construction or has received approved planning requirements
- **Firm Capacity Transfers (Imports minus Exports):** transfers with firm contracts
- **Confirmed Retirements:** capacity with formalized and approved plans to retire

Prospective Resources:

- **Anticipated Resources:** as described above
- **Existing-other Capacity:** operable capacity that could be available to serve load during the peak hour but lacks firm transmission and could be unavailable during the peak or a number of reasons
- **Tier 2 Capacity Additions:** capacity that has been requested but approval for planning requirements not received
- **Expected (nonfirm) Capacity Transfers (imports minus exports):** transfers without firm contracts but a high probability of future implementation
- **Unconfirmed Retirements:** expected to retire based on the result of an assessment area generator survey or analysis (capacity aggregated by fuel type)

The results of NERC's risk determination for all assessment areas is shown in **Table 1**. NPCC-Ontario is identified as "Inadequate," MISO and Maritimes as "Marginal," and all other areas identified as "Adequate" through 2025.[14] See the **NERC Assessment Areas** section for demand and supply trends through 2030.

Table 1: NERC's Risk Determination of All Assessment Areas 5-Year Projected Reserve Margins

Assessment Area	2025 Peak Anticipated Reserve Margin	2025 Reference Margin Level	Expected Capacity Surplus or Shortfall (MW)	Assessment Results Though 2025
MISO	17.0%	18.0%	-1,161	Marginal
MRO-Manitoba	13.5%	12.0%	70	Adequate
MRO-SaskPower	31.5%	11.0%	742	Adequate
NPCC-Maritimes	20.7%	20.0%	36	Marginal (2022, 2023)
NPCC-New England	19.0%	12.7%	1,522	Adequate
NPCC-New York	17.1%	15.0%	661	Adequate
NPCC-Ontario	2.0%	15.9%	-3,236	Inadequate
NPCC-Quebec	13.5%	10.1%	1,264	Adequate
PJM	41.1%	14.8%	37,856	Adequate
SERC-C	23.6%	15.0%	3,469	Adequate
SERC-E	27.4%	15.0%	5,667	Adequate
SERC-FP	22.2%	15.0%	3,439	Adequate
SERC-SE	40.9%	15.0%	11,907	Adequate
SPP	23.4%	15.8%	4,124	Adequate
TRE-ERCOT	14.3%	13.8%	412	Adequate
WECC-AB	23.6%	14.1%	1,211	Adequate
WECC-BC	24.1%	14.1%	1,163	Adequate
WECC-CAMX	22.5%	19.1%	1,852	Adequate
WECC-NWPP-US and RMRG	20.8%	15.0%	3,764	Adequate
WECC-SRSG	15.5%	10.7%	1,315	Adequate

14 *Note about NPCC-NY: While the total resources calculation is above the LTRA reference margin of 15%, there is no PRM criteria in New York. *The 2020 NYISO Reliability Needs Assessment* (RNA) preliminary results and other assessments identified potential reliability needs (*i.e.*, transmission security issues starting 2023, and resource adequacy issues starting 2027). The resource adequacy LOLE criterion used to identify reliability violations is based on a probabilistic assessment in accordance with New York State Reliability Council Reliability Rules. The RNA will be completed in 2020 and will be followed in 2021 by the Comprehensive System Plan (CRP), under which solutions for the final reliability needs will be identified.

PRMs in NPCC-Ontario

The projected five-year ahead ARMs are below the RML over the five-year period. (**Figure 2**). The ARMs fall below the RML for the first five years of this assessment period and are driven by the nuclear refurbishment program, demand forecast uncertainty, and the assumption that certain generation resources are not available once their generation contracts have expired. Planned nuclear outages are a significant contributor of the reserve margin. A period of elevated planned nuclear outages in 2021 and 2022 could lead to adequacy risks throughout the summer season. More planned reserves are needed when nuclear resources are off-line due to the high availability and capacity factor of nuclear generators compared to the other resources that may replace them.

The IESO has stated their intention to address resource adequacy needs in short-, mid-, and long-term time frames that will facilitate competition and provide business planning certainty. The IESO will work with stakeholders through a resource adequacy engagement to further develop a long-term competitive strategy to meet Ontario's resource adequacy needs reliably and cost-effectively while recognizing the unique needs of different resources. Resources, including DR, eligible to participate in a capacity auction are not included in the PRM until they have received a firm commitment in an auction. Consequently, prospective resources tend to be conservative. The IESO's capacity auction for the Summer 2021 commitment period will replace the existing DR auction and enable off-contract generators, system-backed capacity imports, and storage resources to participate and compete alongside DR. The IESO also expects to address adequacy risks from elevated planned outages through outage management.

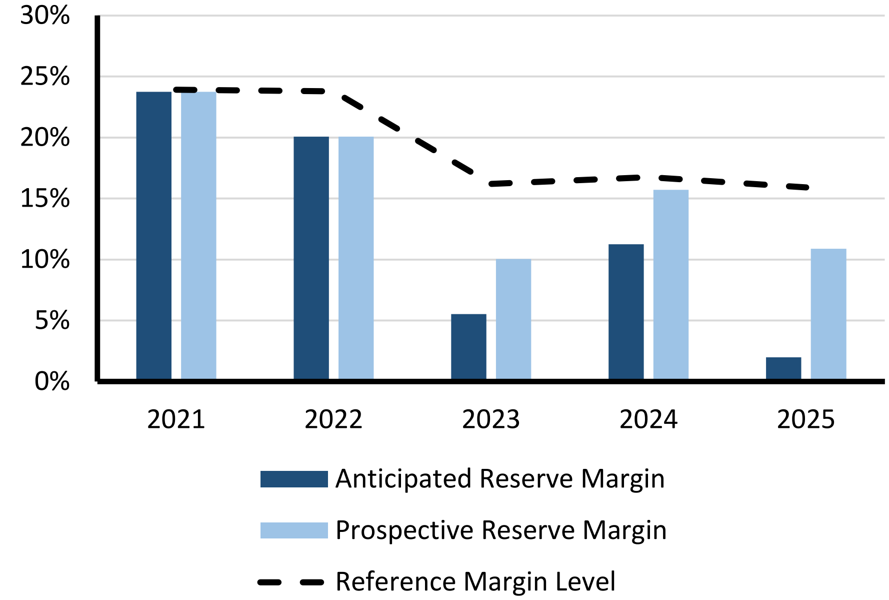


Figure 2: NPCC-Ontario 5-year Projected Reserves (ARM and PRM)

PRMs in MRO-MISO

The projected five-year ahead ARMs indicate a regional surplus through 2023 before falling near or below the RML in 2024 and beyond (**Figure 3**). The *2019 LTRA* also showed that MISO would fall below the RML beginning in 2025. The RML in MISO has increased from 16.8% to 18% as the resource mix and load shape has changed. Consequently MISO continues to have potential shortfall in the latter half of the assessment period even though anticipated resources have increased.

MISO anticipates that each zone within the MISO will have sufficient resources to meet their local requirements for serving load within their boundaries. However, the zone for lower Michigan (Zone 7) is close to the local requirement for the near term. New unit additions and possible transmission builds may help to address local needs in the future.

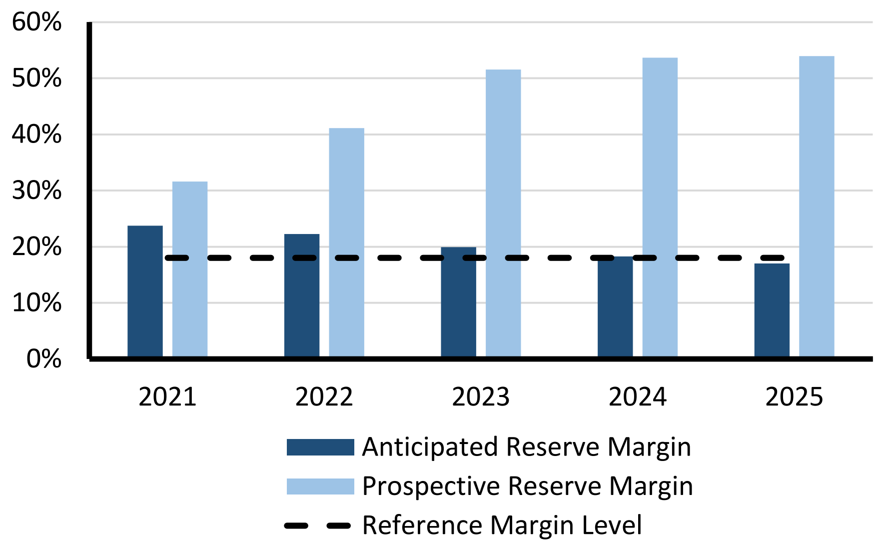


Figure 3: MISO Five-Year Projected Reserves (ARM and PRM)

Over the past several years, the near-term ARMs have been consistently above the current RML of 18% as shown in **Figure 3**. Note: Projections are Year 1 projections from prior LTRAs (see **Figure 4**). For example, the 2011 value is based on the *2010 LTRA's* 2011 projection.

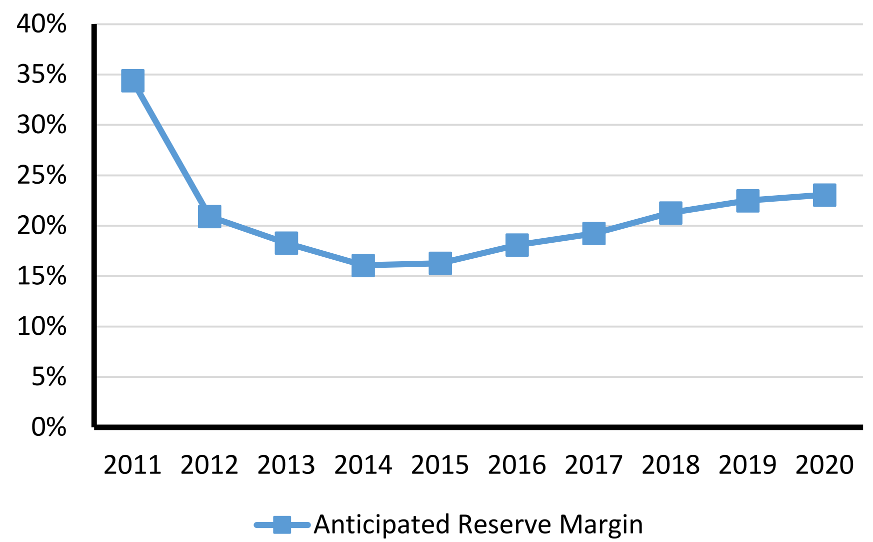


Figure 4: MISO Historical Projected Reserves Margins

PRMs in NPCC-Maritimes

The ARMs in NPCC-Maritimes fall slightly below the RML during the winter periods, beginning in the winter of 2022–2023 (**Figure 5**). An increase in the winter peak hour demand forecast, reduction in the achievable EE and conservation forecast, and planned retirement of two units at an oil-fired thermal generating station of 40 MW in year 2022 in Prince Edward Island collectively contribute to the reserve margins falling below the reference level. Contributions from Tier 2 resources help in reducing the gap but still fail to meet the 20% RML.

A long-term firm energy contract is in place with a neighboring jurisdiction to buy a minimum of 2 TWh/year until 2030 and then 2.5 TWh/year until 2040. This, along with the ability to purchase energy in day ahead and real time markets, will assist in meeting the RML for the first five years.

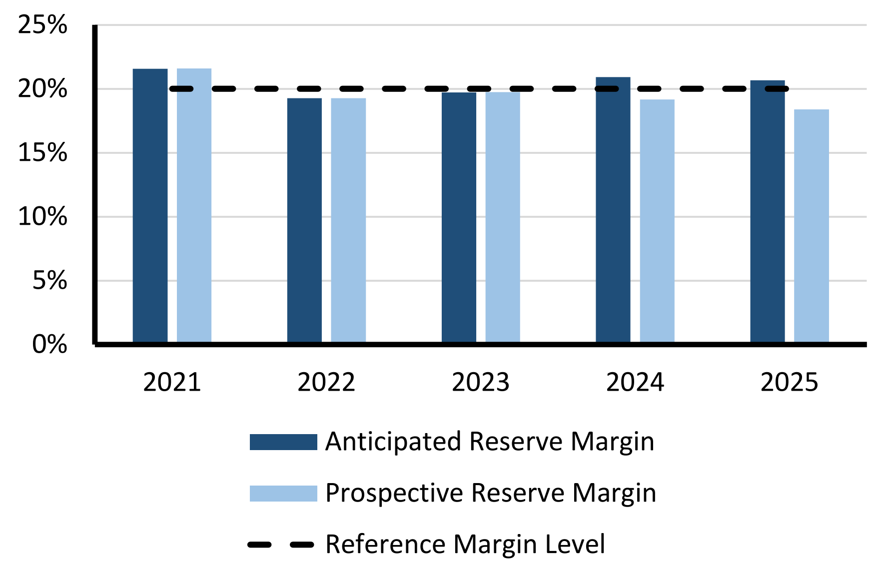


Figure 5: NPCC-Maritimes Five-Year Projected Reserves (ARM and PRM)

PRMs in TRE-ERCOT

NERC's *2019 LTRA* and previous reports have identified reliability concerns with PRMs in Texas. Beginning in 2010, a downward trend in ERCOT's reserve margins led to scarce resources during the peak and less operating flexibility (**Figure 6**). To some extent, this is an expected outcome of managing resource adequacy through an energy-only market construct.[15] However, over the past year, generation resources have been added and more are in development for connection over this assessment period, helping to reduce concerns of resource shortfalls.

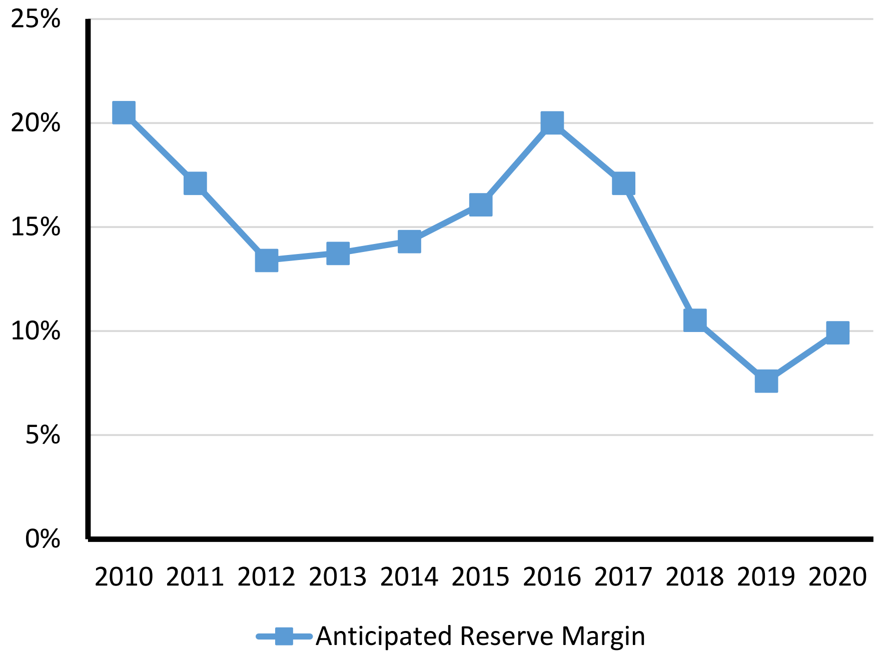


Figure 6: TRE-ERCOT Historical Projected Reserve Margins

15 Energy-only markets pay resources only when they provide energy on a day-to-day basis. Conversely, capacity markets aim to ensure resource adequacy by paying resources to commit capacity for delivery years into the future also.

The projected five-year ahead ARMs stays above the RML of 13.75% over the five-year period (**Figure 7**). This improvement since the *2019 LTRA* results from Tier 1 resources expected to come into service over the five-year period, totaling almost 14,000 MW. Nearly 9,500 MW of these additions are solar generation.

In Texas, regulators ensure reliability through a mechanism called scarcity pricing, allowing real-time electricity prices to reach as high as $9,000/megawatt hour (MWh) in response to capacity shortage conditions. Instead of guaranteeing revenue to capacity resources through a capacity market, the opportunity of high prices is intended to incentivize generators to build new plants and keep them ready to operate. Recent performance over the last several years has proven the ERCOT market and system operations to be successful with no load shedding events despite setting system-wide peak demand records.

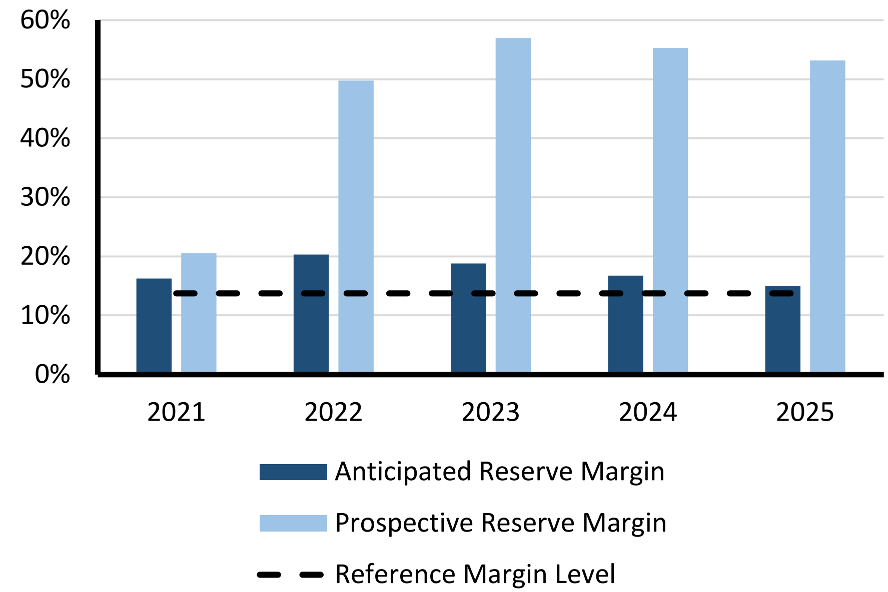


Figure 7: TRE-ERCOT Five-Year Projected Reserves (ARM and PRM)

Key Finding 2: While the ERO's biennial ProbA indicates that resource adequacy meets or exceeds resource adequacy benchmarks, there is increasing risk of resource shortfalls during nonpeak hours in parts of the WI, MISO, and Texas.

Key Points

- This *2020 LTRA* includes the ERO's biennial ProbA that provides insights into the ability of the future resource mix to meet the projected demand at all times. While the deterministic PRM assessment findings above indicated sufficient resources are planned to be available throughout this assessment period for most areas, except MISO and Ontario, the findings provide evidence that the deterministic PRM metric, especially in areas with higher penetrations of resources with energy limitations and uncertainty (i.e., wind, solar, natural gas, hydro), may not be a completely accurate way to measure an area's resource adequacy during all hours of the year.
- WECC's 2020 ProbA continues to note several hours that pose a potential risk for loss of load for almost all WI areas over studied years. The CAMX area was the only concern in the 2018 probabilistic assessment, but now all areas except Alberta (AESO) are seeing hours of potential loss of load. Exacerbated by the recent western area heat wave event, which saw load shed over the summer, all areas are reviewing the level of resource adequacy considering forecast variability.
- The traditional methods of assessing resource adequacy at peak load times may not accurately or fully reflect the ability of the new resource mix to supply energy and reserves for all hours. Energy limitations can exist, requiring probabilistic analysis methods to identify risks to reliability resulting from shortfalls in the conversion of capacity to energy (energy adequacy). The new resource mix includes natural-gas-fired generation; unprecedented proportions of nonsynchronous resources, including renewables and battery storage; DR; smart- and micro-grids; and other emerging technologies. Collectively, the new resources are more susceptible to energy sufficiency uncertainty.

Probabilistic evaluations identify resource adequacy risks during nonpeak conditions

The analytical processes used by resource planners range from relatively simple calculations of PRMs to rigorous reliability simulations that calculate system loss of load expectation (LOLE) or loss of load probability (LOLP) values.[16] The 1-event-in-10-year (0.1 events per year) LOLE is produced from this type of probabilistic analysis. This planning criterion requires an electricity system to maintain sufficient capacity such that system peak load is not likely to exceed available supply more than once in a 10-year period. Utilities, system operators, and regulators across North America rely on variations of the 1-event-in-10 year criterion for ensuring and maintaining resource adequacy.[17] Assessment area on-peak reserve margins determined from NERC's biennial ProbA are provided in **Table 2**.[18] The forecast operable reserve margin is defined as the ratio of anticipated resources derated by forced outage rates less on peak demand.

ProbA Results Summary

As part of a biannual process, this *2020 LTRA* includes a probabilistic evaluation for each assessment area and calculates LOLH and EUE for the third and fifth years of the LTRA. This year's analysis calculates the probabilistic resource measures for 2022 and 2024. A summary of the indices are show **Table 3**.

The color shading in **Table 3** is used to identify relative risk for loss-of-load hours. Green shading indicates that the risk is low (calculated LOLH is less than 0.1 hours per study year). Yellow shading indicates greater risk, with a threshold of between 0.1 and 2.4 hours per year. Instances where ProbA results are greater than 2.4 hours per year are shaded with orange. When calculated LOLH exceeds 2.4 hours per year, the study is indicating that the area may have a loss-of-load expectation that is greater than 1-day-in-10 years; this is a criterion used in many areas for determining Reference Margin Levels (see link to **Table 10**).

16 A traditional planning criterion used by some resource planners or load-serving entities is maintaining system LOLE below 1-day-in-10 years. LOLE is generally defined as the expected number of days per year for which the available generation capacity is insufficient to serve the daily peak demand. This is the original metric that is calculated using only the peak load of the day (or the daily peak variation curve). However, this metric is not being reported as part of this assessment. Currently, some assessment areas also calculate the LOLE as the expected number of days per year when the available generation capacity is insufficient to serve the daily demand (instead of the daily peak load) at least once during that day.

17 https://www.nerc.com/comm/PC/Probabilistic%20Assessment%20Working%20Group%20PAWG%20%20Relat/Probabilistic%20Adequacy%20and%20Measures%20Report.pdf

18 The *2022 marker in **Table 2** and **Table 3** denotes the results from the 2018 ProbA's 2022 projection. The ProbA from the prior iteration is used for comparison because the first year (in this case 2022) is the same study year in both the prior and current ProbA.

Table 2: 2022 and 2024 Projected Peak Reserve Margins									
	Reserve Margin (RM) Percent								
	LTRA Anticipated			LTRA Reference			ProbA Forecast Operable		
Assessment Area	**2022***	**2022**	**2024**	**2022***	**2022**	**2024**	**2022***	**2022**	**2024**
WECC-CAMX	21.3%	27.8%	26.8%	22.8%	15.8%	19.1%	22.7%	17.4%	15.3%
MRO-SaskPower	17.7%	34.7%	37.0%	11.0%	11.0%	11.0%	11.7%	27.3%	22.8%
WECC-NWPP-US and RMRG	30.3%	24.6%	21.6%	16.5%	16.1%	15.1%	21.3%	28.0%	24.9%
MISO	18.9%	22.3%	18.3%	17.1%	18.0%	18.0%	13.7%	17.9%	17.8%
SERC-FP	24.4%	21.1%	22.3%	15.0%	15.0%	15.0%	20.2%	10.2%	11.4%
NPCC-New England	28.5%	29.4%	18.9%	16.4%	13.2%	12.7%	13.2%	20.0%	9.8%
NPCC-Maritimes	25.4%	19.3%	20.9%	20.0%	20.0%	20.0%	27.6%	18.5%	16.7%
MRO-Manitoba	31.6%	17.7%	15.8%	12.0%	12.0%	12.0%	31.0%	14.0%	10.2%
NPCC-New York	22.5%	19.8%	18.6%	15.0%	15.0%	15.0%	13.7%	12.2%	11.3%
WECC-BC	56.8%	20.6%	21.2%	13.0%	12.3%	14.1%	22.2%	20.5%	21.1%
SERC-E	22.3%	22.8%	23.9%	15.0%	15.0%	15.0%	18.0%	14.9%	15.9%
Texas RE-ERCOT	10.6%	19.6%	16.0%	13.8%	13.8%	13.8%	4.6%	13.7%	10.3%
WECC-SRSG	11.7%	17.3%	14.7%	14.6%	11.9%	10.8%	15.6%	8.0%	5.5%
SERC-SE	32.4%	35.8%	39.1%	14.4%	15.0%	15.0%	24.7%	26.9%	30.2%
NPCC-Ontario	23.6%	20.1%	11.3%	18.5%	23.8%	16.7%	11.5%	12.6%	4.4%
SERC-C	25.2%	26.4%	27.0%	15.0%	15.0%	15.0%	17.7%	17.9%	18.4%
NPCC-Québec	13.6%	13.8%	14.1%	12.6%	10.1%	10.1%	7.1%	11.0%	7.1%
PJM	35.2%	38.4%	41.9%	15.8%	14.9%	14.8%	22.5%	25.6%	29.0%
SPP	25.0%	26.5%	24.2%	12.0%	15.8%	15.8%	17.1%	13.6%	13.3%
WECC-AB	28.2%	26.3%	24.0%	10.0%	12.3%	14.1%	19.9%	14.3%	20.2%

Table 3: 2022 and 2024 Probabilistic Indices by Assessment Area									
	EUE (MWh)			EUE (ppm)			LOLH (hours/year)		
Assessment Area	**2022***	**2022**	**2024**	**2022***	**2022**	**2024**	**2022***	**2022**	**2024**
WECC-CAMX	207,344	1,005,716	2,402,976	769.00	3,721.39	8,817.86	2.30	22.06	55.61
MRO-SaskPower	4,495	80	26	167.00	3.34	1.07	39.02	0.96	0.28
WECC-NWPP-US and RMRG	2,553	12,779	248,573	8.58	32.69	621.80	0.58	0.25	4.39
MISO	32	27	14	0.04	0.04	0.02	0.21	0.20	0.09
SERC-FP	0	23	2	0.00	0.00	0.00	0.00	0.03	0.00
NPCC-New England	3	3	59	0.02	0.02	0.47	0.01	0.01	0.10
NPCC-Maritimes	0	1	1	0.00	0.02	0.04	0.00	0.01	0.02
MRO-Manitoba	0	3	3	0.00	0.11	0.13	0.00	0.00	0.00
NPCC-New York	0	1	7	0.00	0.00	0.05	0.00	0.00	0.03
WECC-BC	0	19	8	0.00	0.32	0.14	0.00	0.00	0.00
SERC-E	0	1	5	0.00	0.00	0.02	0.00	0.00	0.01
Texas RE-ERCOT	1,089	0	13	2.64	0.00	0.03	0.87	0.00	0.03
WECC-SRSG	0	11	81	0.00	0.11	0.75	0.00	0.00	0.00
SERC-SE	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00
NPCC-Ontario	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00
SERC-C	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00
NPCC-Québec	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00
PJM	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00
SPP	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00
WECC-AB	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00

Figures 8 and 9 show the 2022 and 2024 projected peak reserve margins compared to the LOLH index. The graphics are sorted from left to right by the areas with the highest calculated LOLH.

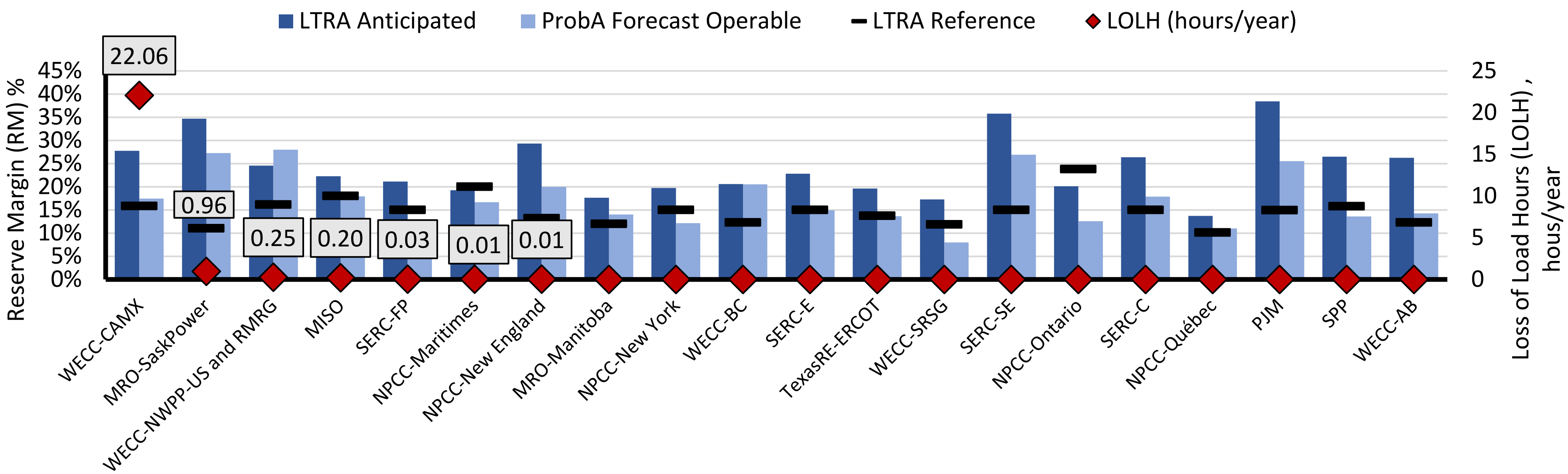


Figure 8: 2022 Assessment Area Reserve Margins and LOLH

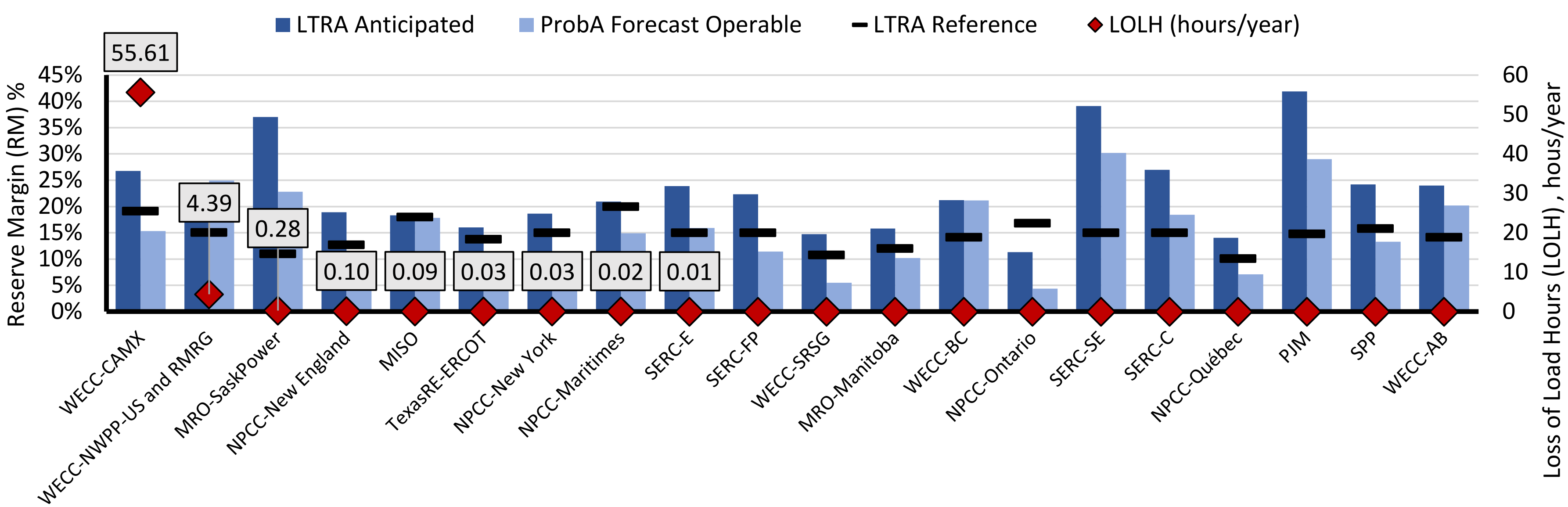


Figure 9: 2024 Assessment Area Reserve Margins and LOLH

In its probabilistic analysis, WECC found reserve margins for the WECC-CAMX area are over 27% for 2022 and over 26% for 2024, but levels of LOLH of 22 and 56 hours and levels of EUE of ~1m and ~2.4m, respectively, are due in part to the changing resource mix. It should be noted that almost all of the LOLH and EUE are associated with the Mexico portion of CAMX. The California portion has improved since the 2018 ProbA. Results with the California portion split out are shown in **Table 4**.

Table 4: Probabilistic Base Case Summary Results for WECC-CAMX

Reserve Margin (RM) %			
	2022*	2022	2024
Anticipated	21.3%	27.8%	26.8%
Reference	22.8%	15.84%	19.14%
ProbA Forecast Operable	22.7%	17.4%	15.3%
Annual Probabilistic Indices			
	2022*	2022	2024
EUE (MWh)	41,468	1,005,716	2,402,976
EUE (ppm)	513.8	3721	8818
LOLH (hours/year)	2.3	22	56
Annual Probabilistic Indices (CA Only)			
	2022*	2022	2024
EUE (MWh)	40,357	36,930	6,886
EUE (ppm)	157.35	146.05	27.15
LOLH (hours/year)	2.0	0.8	0.15

*Represents the 2018 ProbA results for 2022.

In **Figure 10**, a comparison of LOLH is provided that shows a general decrease in the LOLH metric. **Figure 11** shows that there is a general increase in the LOLH metric from the study year 2022 to 2024.

In addition to the annual metrics, the NERC 2020 ProbA provided monthly LOLE metrics and specific sensitivities to stress the forecasted system to provide more information on potential risks occurring for all hours, not only for the peak hour. Results are available for the ProbA Base Case while the results for the sensitivity case will be available early next year.

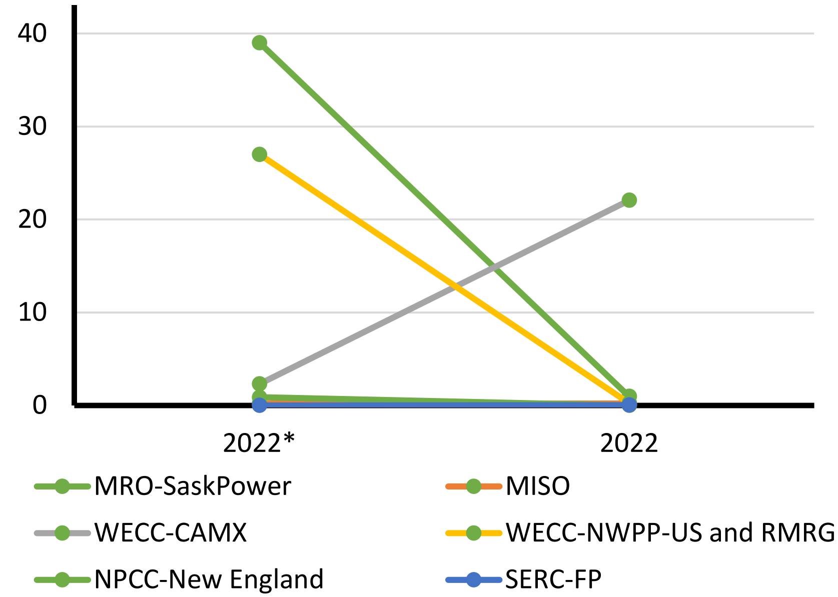


Figure 10: Comparison of the 2018 vs. the 2020 Probabilistic Analysis, LOLH Notable Trends for the 2022 Study Year

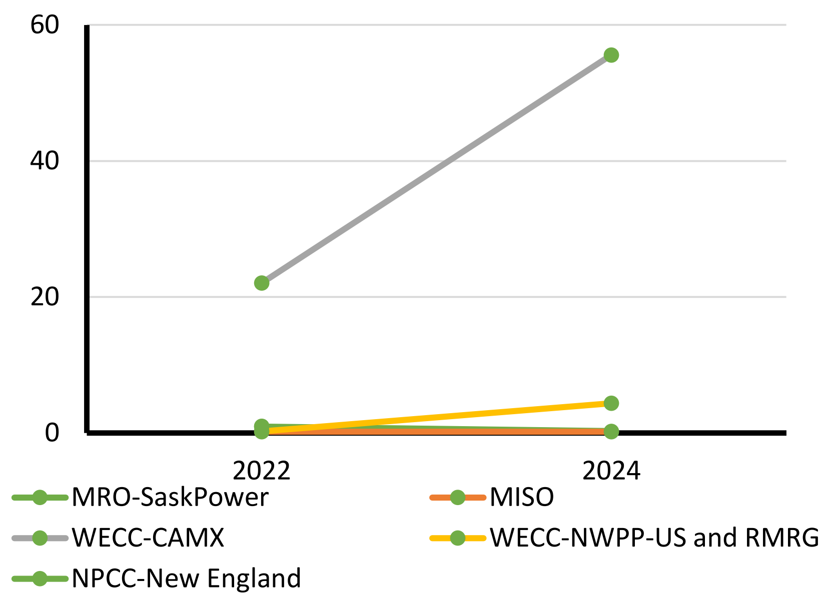


Figure 11: Comparison of 2020 Probabilistic Analysis, LOLH Notable Trends for the 2022 to 2024 Study Year

Figure 12 is an example of the MISO monthly indices, indicating LOLH in the nonpeak months.

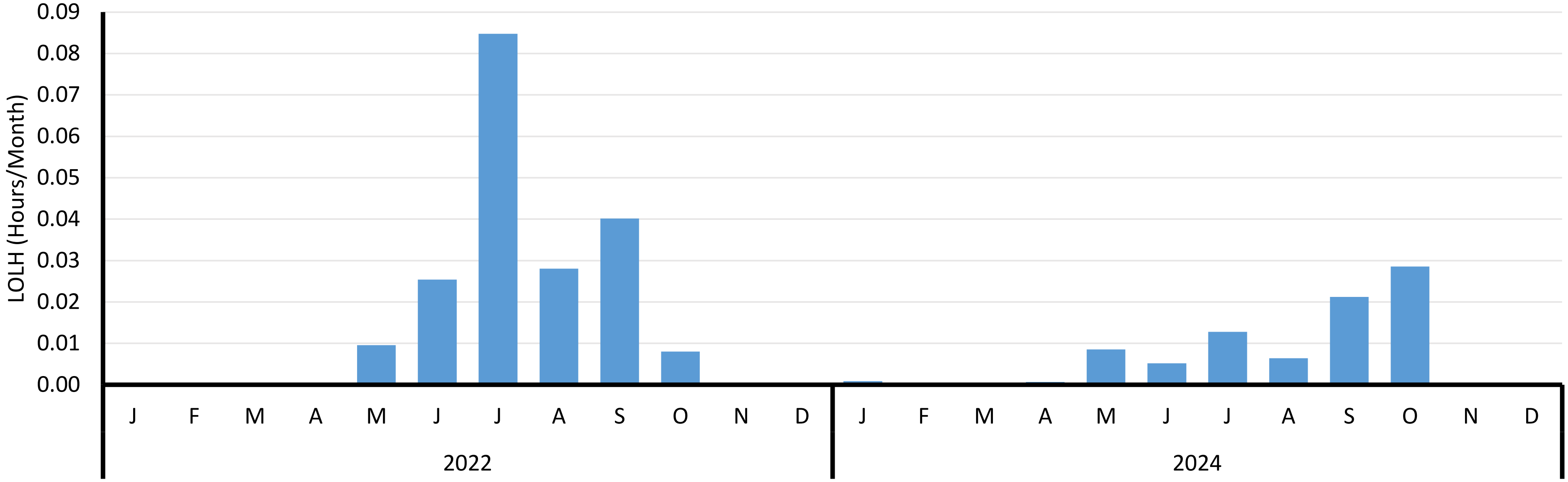


Figure 12: MISO LOLH Indices for Study Year 2022 and 2024

Additionally, the LTRA narrative questions and ProbA narrative questions were enhanced to provide further information on the emerging energy adequacy risks away from the on-peak net demand hour. Responses indicated that many assessment areas have shown off-peak energy risks in the ProbA Base Case results and other internal studies. **Table 5** provides a summary of these results, while more detailed information is contained in the **NERC Assessment Areas**.

The findings provide evidence that the deterministic PRM metric, especially in areas with higher penetration of resources with energy limitations and uncertainty (i.e., wind, solar, natural gas, hydro), may not be a completely accurate way to measure an area's resource adequacy during all hours of the year; additionally, as reserve surpluses diminishes towards the RML, this can become more pronounced. Namely, energy limitations can exist, requiring more advanced probabilistic analysis methods to identify risks to reliability that result from shortfalls in the conversion of capacity to energy (energy adequacy).

Table 5: Summary of Assessment Area ProbA Results for Energy Assurance and Off-Peak Hour Risk	
Assessment Area	**Summary**
MISO	ProbA results show some EUE in all months with the majority occurring in the summer during the afternoon peak hours. The average duration of EUE events is around two hours. EUE during the summer is driven primarily by high load and high forced outages. There are instances where EUE occurs during nonpeak hours in the assessment, when high planned outages overlap with unseasonably high load. This is magnified in zones that are transmission constrained when the zone is unable to import enough energy to meet peak demand.
MRO Manitoba	ProbA Base Case indices indicate low energy adequacy risk (near-zero EUE and LOLH values). Manitoba Hydro system is a winter-peaking system and the vast majority of its generating facilities are use-limited or energy-limited hydro units. A regional risk probabilistic scenario is being conducted that will examine water flow conditions of the tenth percentile or lower, which tend to increase the LOL probability.
NPCC Ontario	The ProbA Base Case indices indicate low energy adequacy risk (near-zero EUE and no LOLH). This indication is somewhat unexpected given the reserve shortfall shown in the PRM deterministic assessment. It results from the resources being modeled in the ProbA, including emergency operating procedures and significant amounts of emergency assistance. Demand forecasters at the IESO in Ontario have observed that summer peaks have moved later in the day; they attribute this to the increased penetration of embedded solar generation and the critical peak pricing program. Peaks are expected to increase over time due to policy changes that could reduce conservation program spending and the IESO's assessment that DERs are plateauing in the area.
TRE-ERCOT	An increase in wind and solar capacity is contributing to growing reliability risk in off-peak periods. In ProbA study years, the months of March and October (typically nonpeak periods) have the lowest monthly available reserves on the peak day. Although currently EUE and LOLH indices are negligible, ERCOT and resource planning stakeholders must manage the risk that further increases in renewable penetration could potentially result in the risk of firm load shed in shoulder months when planned outages are scheduled. To further assess risks from their increasingly-variable resource portfolio, ERCOT is performing a probabilistic scenario to evaluate risks from a low-wind event. Simulated LOL events in ERCOT are largely driven by high load with low wind output conditions. These conditions occur rarely, however, a small change in their frequency could have significant impact on the expected reliability of the ERCOT system. The risk scenario for ERCOT was designed to stress test the impact of a difference in the realized frequency of high load and low wind events from that in the synthetic profiles used for the Base Case simulations.
WECC-BC	In the 2020 ProbA, LOLH and EUE are increasing over the 2018 analysis with occurrences in the month of March, October, and November for study year 2022 and the months of February and October for study year 2024. The hours of risk are at 6:00 a.m., one hour before the peak demand for the day. Overall the LOLH and EUE values remain very low and do not indicate a reliability risk.
WECC-CAMX	The 2020 ProbA shows overall increasing risk of load loss and unserved energy in this area, though risk is more concentrated in the Baja California (Mexico) portion. The Mexico portion of the CAMX area has seen a significant increase in their demand forecast since the 2018 ProbA. This new demand forecast, coupled with the absence of energy transfers coming from California after the peak hours as the California system is itself constrained, has led to a significant increase in EUE for this area. Looking at the California portion of this area, the LOLH and EUE have improved since last ProbA with large improvements by 2024. Typical peak months of July and August are when most LOL occurrences are expected. However, the hours of greatest risk occur at 6:00 p.m., one hour past the peak demand for the day in California. These hours are also when the greatest EUE occurs.
WECC-NWPP-RMRG	The 2020 ProbA indicates the greatest risk of load loss occurs in the summer months during the one to three hours after peak demand for the day. The magnitudes of EUE during these periods range from less than a MW to 2,000 MWh in one hour.
WECC-SRSG	The 2020 ProbA indicates the greatest risk of load loss occurs in the summer months of July and August. The greatest risk occurrence during these months is during the hour ending at 6:00 p.m., one hour past the peak demand for the day. The magnitudes of EUE during these periods are low, ranging from from less than 1 MWh to 35 MWh in one hour.

Key Finding 3: Variable energy resources continue to grow, and thermal resource capacity declines in most areas throughout the assessment period. As a result, increased attention is required for planning and operating a more complex resource mix.

Key Points

- In many areas, variable energy resources are increasingly important to meet electricity demand. Texas and California rely on variable energy resources to meet peak hour demand; this can lead to operational risk during unanticipated conditions that reduce the resource output. Other areas are trending toward increasing reliance on variable energy resources over the assessment period. Sufficient flexible resources are needed in areas with high levels of variable generation to avoid shortfalls when variable resource output is insufficient to meet demand.[19]
- Inverter based resources, 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. Maintaining a reliable system as the penetration of inverter-based resources increases requires planners and operators to be cognizant of potential disturbance-related performance issues.
- Recently the ERO conducted a review of base case models used in transmission planning within the WI and identified modeling issues with wind and solar PV generators. Invalid or inaccurate generator models can contribute to steady state or dynamic study result errors, affecting the planned reliability of the interconnected transmission system.[20]
- Additional fossil-fueled generator retirements could occur as a result of economic uncertainty and environmental policies.

Variable Energy Resources

Variable energy resources include wind, solar, and run-of-river hydroelectric plants for which electric output can change according to the primary diver (e.g., wind, sunlight, moving water), resulting in plant output fluctuations on all time scales. Planners and operators must address and prepare for the uncertainty associated with these resources because the magnitude and timing of variable generation output is less predictable than for conventional generation.

19 Flexible resources refer to dispatchable conventional as well as dispatchable variable resources, energy storage devices, and dispatchable loads.

20 See NERC-WECC Joint Report–*WECC Base Case Review: Inverter-Based Resources*, August, 2020.

Figure 13 shows the assessment areas with solar and wind resources over 5% of their peak demand for the years 2020, 2025, or both. Year 2025 projections include the expected on-peak capacity contribution of anticipated resources. The percentages located beside the bars indicate that WECC-CAMX and TRE-ERCOT rely on these variable resources to meet peak demand as their peak demand exceeds the total capacity of conventional resources. Several other assessment areas are becoming increasingly reliant on solar and wind resources to meet peak demand. In the event that solar and wind output are below expectations, CAMX and TRE-ERCOT may need to rely on additional internal resources and/or external resources to cover the shortfall.

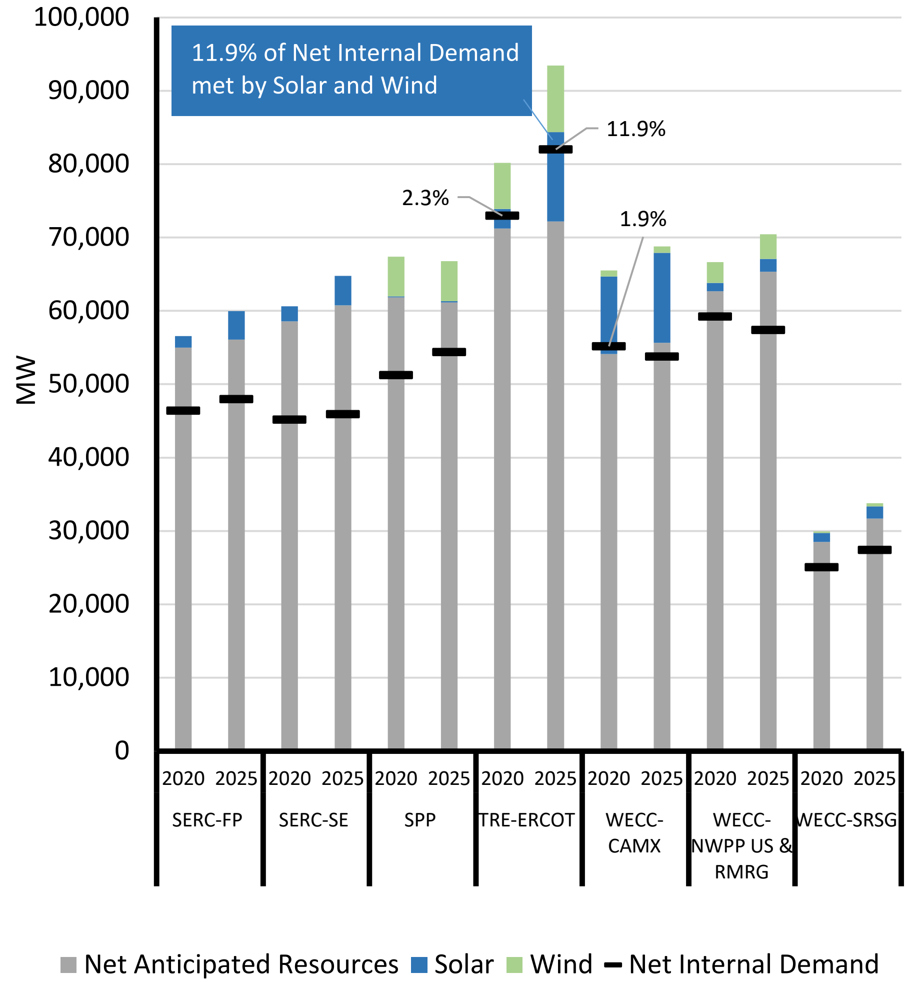


Figure 13: Assessment Areas with Solar and Wind Capacity Greater than 5% of On-Peak Demand

Capacity Additions

Wind, solar, and natural-gas-fired generation are the overwhelmingly predominant generation types in the planning horizon for addition to the BPS. The generation resources for all fuel types are shown in **Figure 14** (for Tier 1 planning) and in **Figure 15** (for Tier 1 and 2 planning).

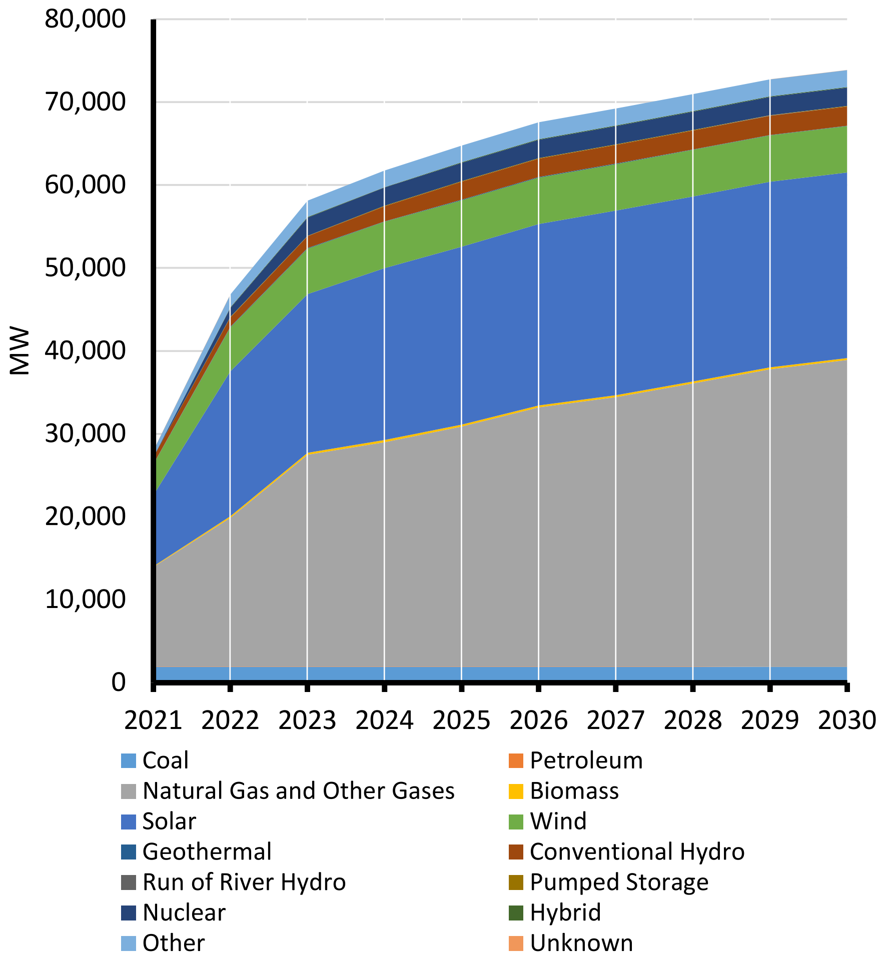


Figure 14: Tier 1 Planned Resources Projected Through 2030

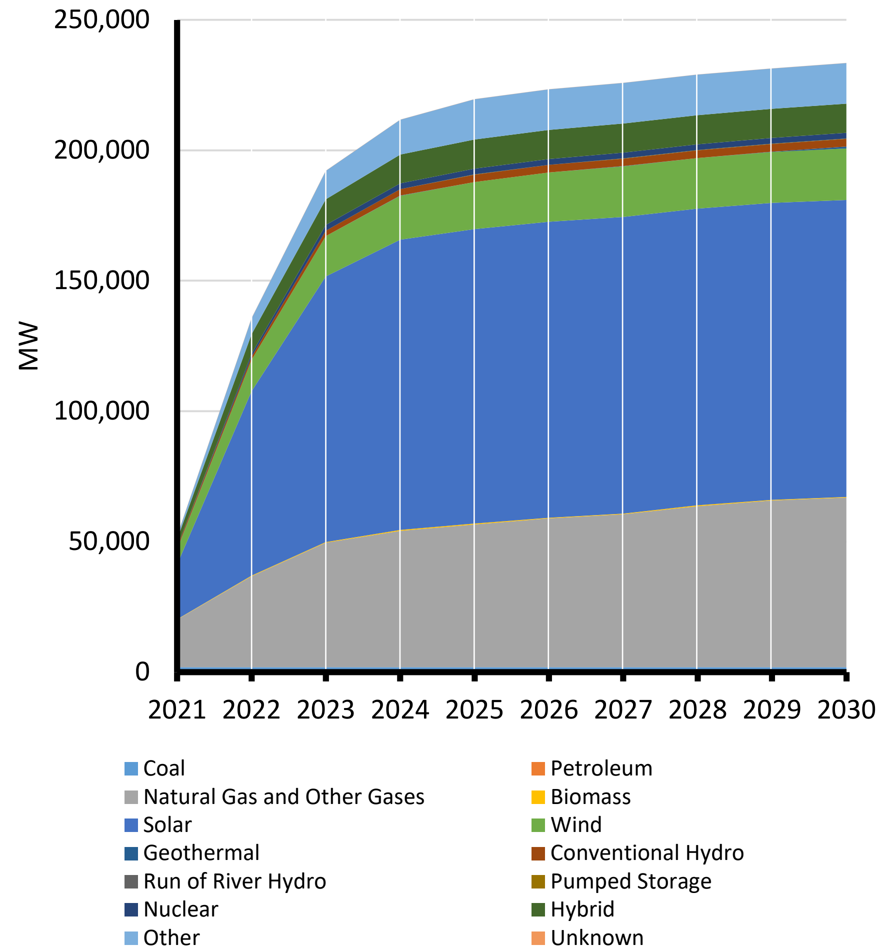


Figure 15: Tier 1 and 2 Planned Resources Projected Through 2030

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 are 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 are included as prospective resources:

- 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 regional transmission organizations (RTOs)/independent system operators (ISOs))

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

Significant solar and wind capacity additions are expected over the next 10 years. **Table 6** identifies solar and wind installed capacity additions by assessment area. From an installed capacity perspective, over 390 GW of new solar and wind are planned through 2030, including Tier 1, 2, and 3 resources. Of all generation resource additions, future solar capacity is expected to be the largest contributor at 197 GW when considering Tier 1 and 2 resources and 248 GW when considering Tier 3 resources. Wind capacity is expected to nearly double by 2030 when considering Tier 1 and Tier 2 resources.

Table 6: Solar and Wind Nameplate Capacity, Existing and Planned Additions through 2030										
	Nameplate MW of Solar					Nameplate MW of Wind				
	Existing	Tier 1	Tier 2	Tier 3	Total	Existing	Tier 1	Tier 2	Tier 3	Total
MISO	204	1,718	49,292	7,025	58,240	22,062	4,119	19,281	2,921	48,383
MRO-Manitoba	-	-	-	-	-	259	-	-	-	259
MRO-SaskPower	-	11	10	57	79	242	385	-	400	1,027
NPCC-Maritimes	1	3	-	-	4	1,146	78	-	30	1,254
NPCC-New England	1,371	197	1,064	2,742	5,374	1,419	88	7,835	4,382	13,724
NPCC-New York	32	23	-	2,350	2,404	1,739	646	500	4,850	7,736
NPCC-Ontario	478	-	-	-	478	4,486	460	-	-	4,946
NPCC-Quebec	-	-	-	-	-	3,772	54	-	-	3,827
PJM	2,067	6,125	52,522	-	60,714	8,787	3,029	25,820	-	37,636
SERC-C	10	674	175	5,060	5,919	480	-	-	-	480
SERC-E	555	94	-	-	649	-	-	-	-	-
SERC-FP	3,418	6,955	-	-	10,374	-	-	-	-	-
SERC-SE	2,005	2,042	1,665	5,837	11,549	-	-	-	-	-
SPP	273	284	11,103	-	11,659	21,892	2,646	15,641	5,253	45,432
TRE-ERCOT	3,249	12,738	37,031	20,990	74,008	24,895	12,426	10,772	8,361	56,453
WECC-AB	15	245	-	100	360	1,781	1,129	-	1,050	3,960
WECC-BC	1	1	21	-	23	717	-	-	45	762
WECC-CAMX	14,592	2,879	5,916	-	23,387	7,692	541	2,245	-	10,477
WECC-NWPP-US and RMRG	3,880	2,044	1,448	5,197	12,568	13,028	2,554	10	3,975	19,567
WECC-SRSG	1,630	580	279	2,349	4,838	1,162	1,452	-	-	2,615
Total	33,781	36,614	160,526	51,705	282,626	115,558	29,607	82,104	31,267	258,536

Figure 16 shows the planned solar capacity for selected assessment areas through 2030. Texas, PJM, and MISO have the most solar capacity in planning.

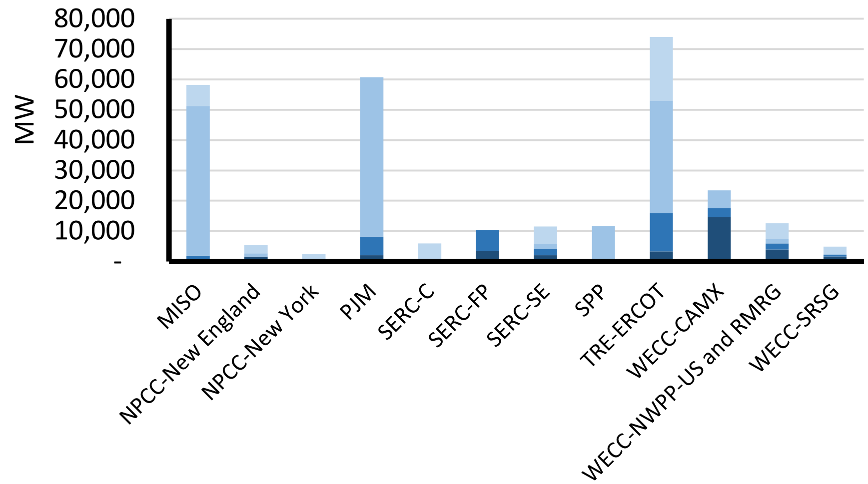


Figure 16: Solar Capacity Planned and Existing

Figure 17 shows the planned wind capacity for selectedassessment areas through 2030. MISO, PJM, SPP, and Texas RE-ERCOT have the most wind capacity in planning.

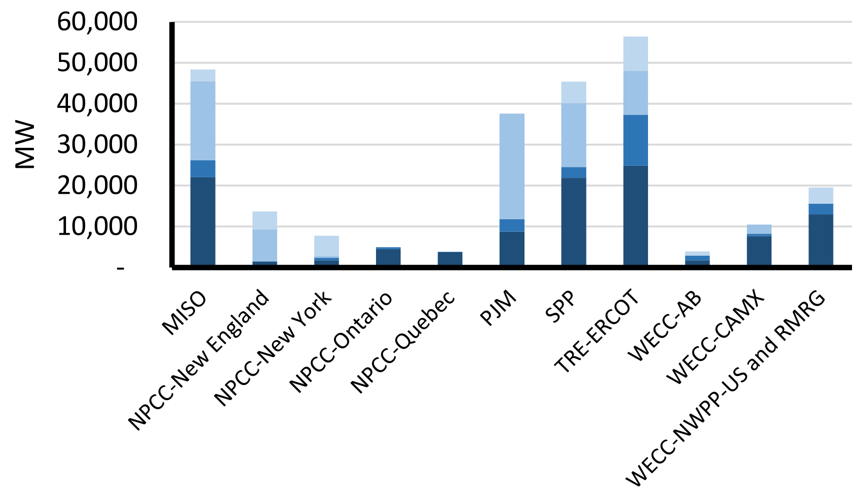


Figure 17: Wind Capacity Planned and Existing

The nameplate capacities shown in **Table 6, Figure 16,** and **Figure 17** are based on the design ratings of the generators and in general do not indicate the capacity that resource types will deliver to serve demand. On-peak resource capacity, in contrast, reflects the expected capacity that the resource type will provide at the hour of peak demand. Because the electrical output of variable energy resources (e.g., wind, solar) depend on weather conditions, on-peak capacity contributions are less than nameplate capacity. **Table 7** (on the next page) shows the capacity contribution of existing wind and solar resources for each assessment area.

While some areas of North America have and continue to see more rapid resource mix changes, overall North America has a diverse fuel mix. A 10-year projection of North America peak capacity is shown in **Figure 18**. The changes level off around 2024 as planning for wind, solar, and natural-gas-fired generation can typically take place within five-year time horizons.

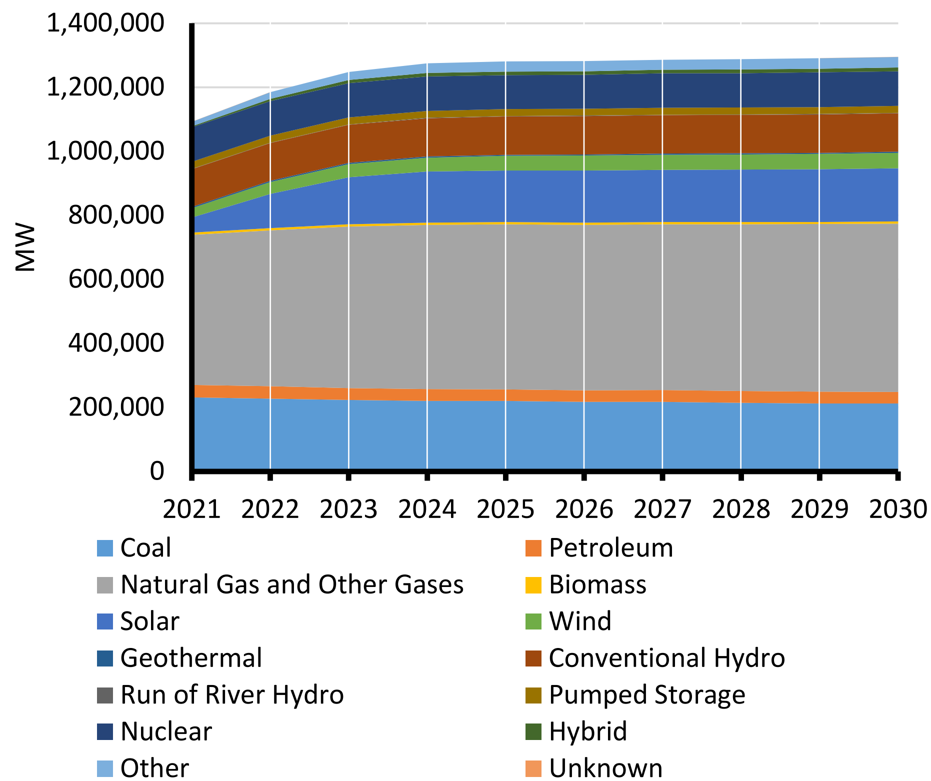


Figure 18: Existing, Tier 1, and Tier 2 Planned Resources Projected Through 2030

Table 7: BPS Wind and Solar Generation Resources by Assessment Area						
Nameplate (MW)	Wind			Solar		
	Nameplate (MW)	Available Peak Demand Hour Capacity (MW)	Available/ Nameplate (%)	Nameplate (MW)	Available Peak Demand Hour Capacity (MW)	Available/ Nameplate (%)
MISO	22,062	4,072	18.5%	204	119	58.0%
MRO-Manitoba Hydro	259	43	16.6%	-	-	-
MRO-SaskPower	242	25	10.4%	-	-	-
NPCC-Maritimes	1,146	221	19.3%	1	-	0.0%
NPCC-New England	1,419	174	12.3%	1,371	110	8.0%
NPCC-New York	1,739	297	17.1%	32	16	50.2%
NPCC-Ontario	4,486	633	14.1%	478	64	13.4%
NPCC-Quebec	3,772	104	2.8%	-	-	-
PJM	8,787	1,339	15.2%	2,067	997	48.2%
SERC-C	480	456	95.0%	10	8	80.0%
SERC-E	-	-	-	555	546	98.5%
SERC-FP	-	-	-	3,418	1,582	46.3%
SERC-SE	-	-	-	2,005	1,504	75.0%
SPP	21,892	5,157	23.6%	273	162	59.5%
Texas RE-ERCOT	24,895	6,182	24.8%	3,249	2,480	76.3%
WECC-AB	1,781	175	9.8%	15	5	30.0%
WECC-BC	717	144	20.1%	1	0	30.0%
WECC-CAMX	7,692	825	10.7%	14,592	10,602	72.7%
WECC-NWPP-US and RMRG	13,028	2,805	21.5%	3,880	1,164	30.0%
WECC-SRSG	1,162	203	17.5%	1,630	1,221	74.9%

Generation Retirements

Figure 19 shows the net change of generating capacity since 2012 and the planned retirements for the forward looking 10-year period. Coal and petroleum both have negative net changes; this is an indication that coal and petroleum are being phased out in favor of other resources. The capacity of coal and petroleum is reduced by nearly 50 GW and nearly 7 GW, respectively, since 2012. During the same period, natural-gas-fired capacity increased by almost 130 GW.

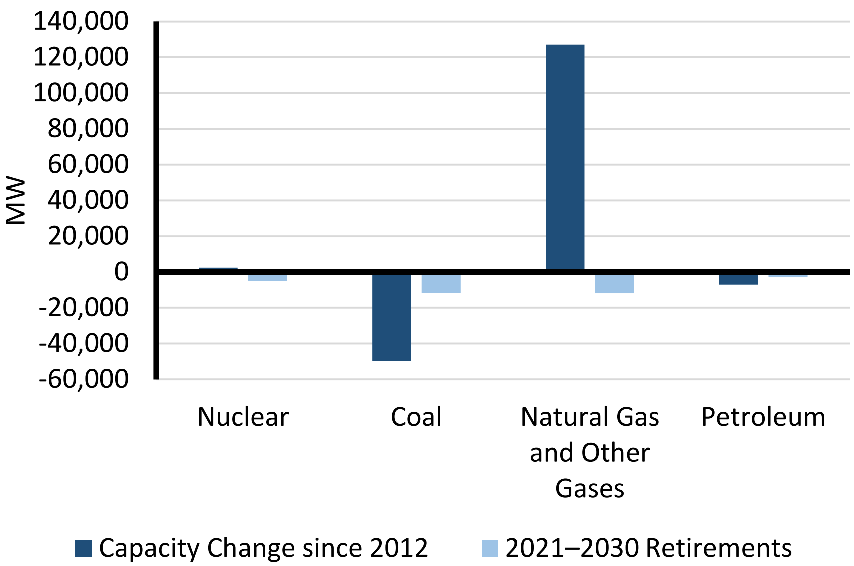


Figure 19: Capacity Changes since 2012 and Retirements Projected through 2030

Operating Reliability Risks Due to Conventional Generation Retirements

Capacity retirements located near metropolitan areas or large load centers that have limited transmission import capability present the greatest potential risk to reliability. Unless these retirements are replaced with plants in the same vicinity, these load centers will require increased power imports and dynamic reactive resource replacement.[21] If the transmission links between an area and generation sources are relatively weak, voltage instability can result; dynamic reactive power must be provided to prevent voltage collapse. Solutions to preventing voltage instability could range from extensive transmission improvements to optimal placement of static VAR compensators, synchronous condensers, and/or locating new generation in the load pocket or local energy storage. Retiring generation units in a generation "pocket" might cause the remaining units to become "reliability must run" units, and additional action or investment in equipment to maintain voltage stability could be required.

21 Dynamic reactive support is measured as the difference between its present VAR output and its maximum VAR output. Dynamic reactive support is used to support system state transients occurring post-contingency. NERC's *Reactive Power Planning Reliability Guideline* provides strategies and recommended practices for reactive power planning and voltage control and accounts for operational aspects of maintaining reliable voltages and sufficient reactive power capability on the BPS:

https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability%20Guideline%20-%20Reactive%20Power%20Planning.pdf

Figure 20 displays the capacity retirements for the previous 7-year period as well as the 10-year projected cumulative retirements through 2030. The 10-year projected retirements are based on committed retirements known to date and is expected to increase as the time horizon progresses.

This *2020 LTRA* does not predict future generator retirements, but instead reports on confirmed retirements. Additional retirements beyond what is reported as confirmed in this *LTRA* are to be expected and will continue to alter the resource mix. Because generator retirement announcements can be made as late as 90 days prior to planned deactivation in some areas, long-range retirement projections based on confirmed retirements could be significantly understated. **Table 8** shows a comparison of the projected coal-fired and nuclear generation capacity in selected assessment areas for peak seasons in 2022 based on the *2018 LTRA* and current (*2020 LTRA*) data to illustrate how projections based on confirmed retirements can differ over assessment years.

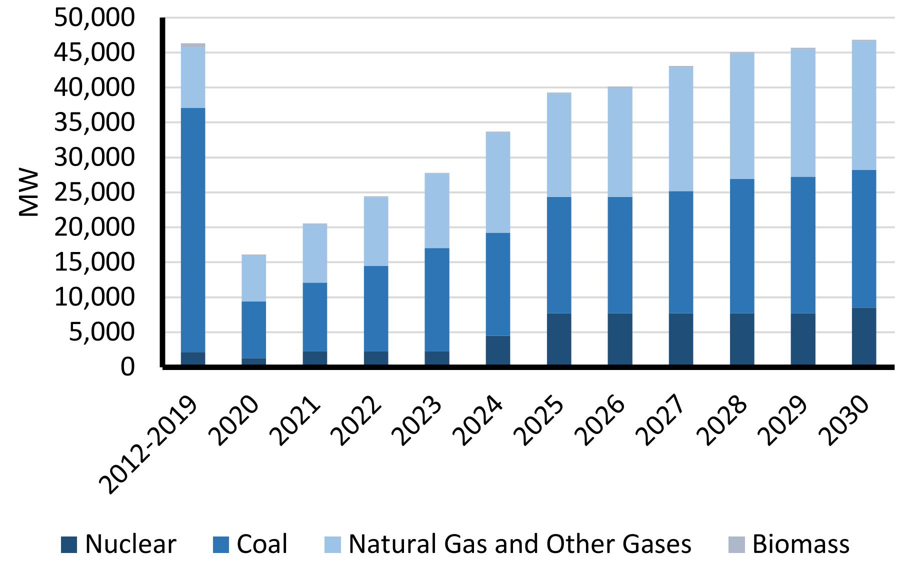


Figure 20: Capacity Retirements since 2012 and Projected Cumulative Retirements through 2030

Table 8: Generation Resource Projections of Year 2022

	2022 Capacity Projected in 2018		2022 Capacity Projected in 2020		2022 Capacity Based On 2018 Stress Test	
Area	**Coal (MW)**	**Nuclear (MW)**	**Coal (MW)**	**Nuclear (MW)**	**Coal (MW)**	**Nuclear (MW)**
MISO	57,792	11,955	51,948	12,169	40,454	6,575
NPCC New England	917	3,331	533	3,321	644	3,331
NPCC New York	1,011	3,334	-	3,343	707	3,334
PJM	54,432	28,620	52,405	32,626	38,103	15,602
SERC-E	17,384	8,653	15,552	12,104	12,169	4,759
SERC-SE	18,979	8,018	16,935	6,918	13,286	5,818
SPP	23,439	1,943	23,172	1,944	16,407	1,173
TRE-ERCOT	14,696	4,981	13,995	4,973	10,287	4,981
WECC-SRSG	8,964	3,937	5,616	2,856	6,275	2,624

In many cases, coal-fired resource capacity falls as the time-horizon to operating year draws closer; nuclear capacity is less volatile and on some occasions the projected retirements did not materialize. The set of capacity values at the right side of **Table 8** shaded in grey came from the 2018 *NERC Generation Retirements Scenario Special Reliability Assessment* report, which was developed to be a stress-test case for coal-fired and nuclear retirements.[22] With few exceptions, this *2020 LTRA* is projecting that coal-fired and nuclear capacity for the year 2022 will be above the levels that were used for the stress-test scenario, indicating that the 2018 scenario still represents a bound for informing risk insights.

Figure 21 shows the proportion of existing coal-fired generation capacity in each assessment area that is currently committed or planned for retirement.

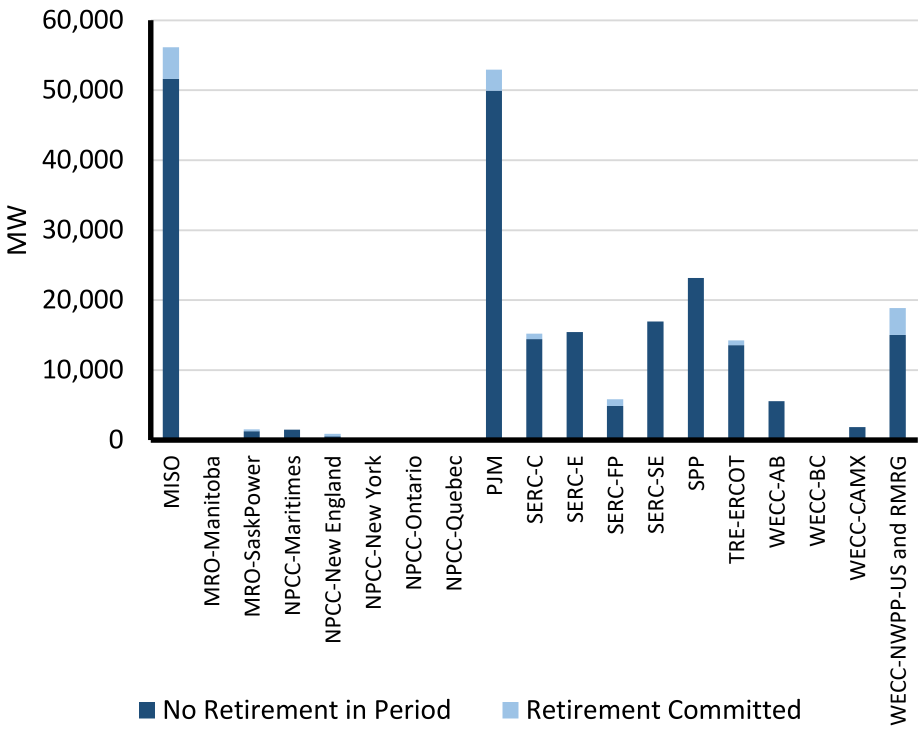


Figure 21: Portion of Existing Coal-fired Generation Capacity with Retirement Commitments through 2026

22 *Generation Retirement Scenario Special Reliability Assessment*, December 2018: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Retirements_Report_2018_Final.pdf

Maintaining Fuel Assurance

Fuel assurance mechanisms offer important reliability benefits, particularly in areas with high levels of natural gas and limited pipeline infrastructure. Fuel assurance, while not explicitly defined, refers to the confidence system planners have in a given resource's availability based on its fuel limitations. In some areas, natural gas delivery pipelines were built and sized to serve customers of natural gas utilities—not specifically to serve electricity generators. Firm contracts for natural gas can drive development of new pipelines. Higher reliance on natural gas can lead to fuel-security issues, particularly during extreme cold weather periods when demand on the natural gas delivery system can be stressed, exposing electricity generation to fuel supply and delivery vulnerabilities.

Mechanisms Promoting Fuel Assurance	Planning Considerations
Fuel Service Agreements	• Service-level arrangements should be considered in resource adequacy planning. • In areas with constrained natural gas pipeline infrastructure, generators with firm fuel service are likely to be available more often than those with interruptible service. • Generators that have procured firm service on a secondary market may also be interrupted prematurely. • Firm service does not guarantee delivery if a *force majeure* is in effect.
Alternative Fuel Capabilities	• Dual-fuel firing capability and seasonal inventories should be considered in capacity and energy adequacy planning. • Generators with dual fuel capabilities are likely to have greater availability than those without. • Backup fuel inventory must be maintained in order for dual fuel capabilities to promote fuel assurance.
Pipeline Connections	• More pipeline connections from different sources can increase the resilience of a plant's fuel supply. • Greater fuel assurance can be reached if multiple fuel supply sources and transportation paths are used to supply a given generator.
Market and Regulatory Rules	• Market and other state, federal, and provincial rules, incentives, and penalties can be used to compel Generator Owners to perform in a manner that promotes reliability, resilience, and fuel assurance. • Regulatory policies can help attract greater access and installation of fuel supplies, including resilience in pipeline transportation.
Vulnerability to Disruptions	• Geography and access to natural resources can impact a given area's vulnerability to disruption. • Areas at the "end of the line" will likely have an overall greater risk profile than those in close proximity to fuel supply sources. • Areas relying on liquefied natural gas (LNG) are vulnerable to fuel supply and delivery disruptions that are very different to pipeline vulnerabilities, including political unrest and global commodity prices.
Pipeline Expansions	• Areas that have an increasing amount of pipeline transportation capacity being added may be reducing their fuel-supply risks. • Pipeline expansion into constrained areas significantly promotes BPS fuel assurance.

Replacing coal-fired and nuclear generation with nonsynchronous and natural-gas-fired generation requires careful attention. Planning considerations include ensuring there is adequate inertia, ramping capability, frequency response, and fuel assurance on the system. NERC data and analysis indicate that inertia and frequency response are adequate for all Interconnections and generally trending in a positive direction.[23] As the resource mix continues to evolve, industry must be watchful not only for resource adequacy criteria but also for the essential reliability services that that must be maintained.

Natural Gas Capacity Additions

ERO-wide natural-gas-fired on-peak generation has increased from 280 GW in 2009 to 446 GW today. Another 41 GW of Tier 1 planned capacity can be expected over the next decade as shown in **Figure 22**. Compared to the *2019 LTRA*, the total natural-gas-fired generation in Tier 1 and Tier 2 planning for this 10-year assessment horizon has fallen from 88 GW reported in 2019 to just over 70 GW in 2020.

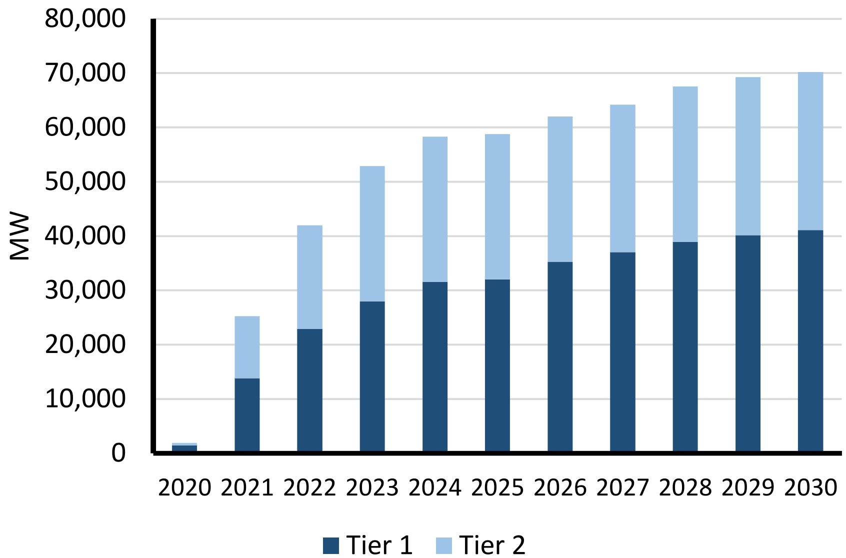


Figure 22: Natural Gas Capacity Planned Additions through 2029, Tier 1 and 2

Unlike other conventional generation with on-site storage, natural gas generation uses the natural gas pipeline system to receive just-in-time fuel to burn for its electricity production. Pipeline transportation service is subject to interruption and curtailment depending on the generator's level of service. In constrained natural gas markets, generation without firm transportation may not be served during peak pipeline conditions (more prevalent in winter), and arrangements for alternative fuels should be considered. Some plants no longer have the option of burning a liquid fuel. Furthermore, regardless of fuel service arrangements, natural gas generation is subject to curtailment during a *force majeure* event.

In November 2017, NERC published the *Special Reliability Assessment: Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System*.[24] In the report, NERC made numerous recommendations for assessing disruptions to natural gas infrastructure and related impacts to the reliable operation of the BPS in planning studies. The Electric-Gas Working Group (EGWG)[25] was created to gather industry experts and drive the development of tools and other resources to better educate and inform the electricity industry about how to reduce risks related to the disruption of fuel supplies.

23 Key Finding 3 in *2018 LTRA*: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2018_12202018.pdf

24 https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SPOD_11142017_Final.pdf

25 https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SPOD_11142017_Final.pdf

New England is currently fuel constrained in winter; this has been identified as one of the most significant risks to the area. Output restrictions at dual-fuel plants due to air emission regulations also contribute to this risk. With its existing fuel infrastructure, New England has faced challenging operating conditions, particularly in extreme cold weather. Given the shift in the current resource mix, these challenges are likely to extend beyond the winter season. During extreme cold periods, electricity needs have been met through a combination of generators using natural gas from pipelines, LNG, and the now-declining nuclear, coal, and oil-fired generators. Although new natural-gas-fired generation is being added to the fuel mix, the regional natural gas pipelines continue to have limited fuel deliverability for any power generators without firm natural gas transportation contracts. Additionally, LNG deliveries to New England that are influenced by global economics and logistics can also be uncertain without firm supply contracts. Environmental permitting for new dual-fuel capability (typically, natural gas and fuel oil) is becoming more difficult under tightening state and federal air emissions regulations. Even when these units are granted permits, their run times for burning fuel oil are usually restricted to limit their ozone season (i.e., May 1–September 30) air emissions.

Energy Storage

Energy storage provides important capabilities to maintain grid reliability and stability. With the exception of pumped hydro storage facilities, only a limited number of large-scale energy storage demonstration projects have been built. With increasing requirements for system flexibility as variable generation levels increase and energy storage technology costs decrease, bulk system and distributed stationary energy storage applications may become more viable and prevalent. Storage may be used for load shifting and energy arbitrage—the ability to purchase low-cost, off-peak energy and resell the energy during on-peak, high cost periods. Storage may also provide ancillary services, such as regulation, load following, contingency reserves, and peaking capacity. This is true for both bulk storage, which acts in many ways like a central power plant, and distributed storage technologies.

Battery storage and hybrid generation resource projects, which combine energy storage with a generating plant, such as a wind or solar farm, are now in BPS planning processes for development and connection within the first years of the assessment period (**Figure 23**). Grid planners and operators need to address modeling, study, and operating issues in the near term for reliable integration. Inverter based resources continue to grow providing battery storage with the opportunity to complement renewable projects in the form of hybrid facilities, which typically incorporate a battery storage component as part of a utility-scale solar or wind development. Additionally, battery storage has the capability to provide essential reliability services (ERSs) to the BPS, such as voltage support, frequency response, and system inertia allowing for battery storage to compete with synchronous resources that provide those same necessary characteristics to the grid. Further analysis should be conducted by system planners to model a system with significant battery storage and hybrid power plants. System planners must conduct adequate studies to determine the transmission system stability impacts on battery energy storage system interconnection, the capability to provide capacity to meet reserve margin requirements, and the ability to provide ERSs. **Figure 23** shows the current and future installations of both battery and hybrid storage through 2024.

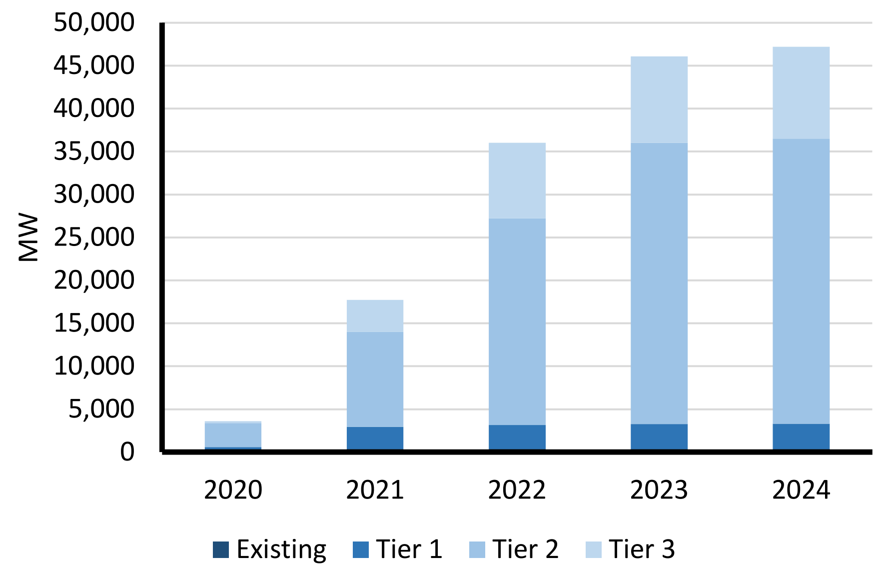


Figure 23: NERC-Wide Grid Battery and Hybrid Generation–Existing and Planning

Managing Risks as the Resource Mix Evolves

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:

- **Ensuring sufficient flexible resources:** In order to maintain load-and-supply balance in real time with higher penetrations of variable supply and less-predictable demand, 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 their committed portfolios or by removing system constraints to flexibility.[26] Variable energy resources can provide ramping and other ERSs, and procurement mechanisms can be used to obtain flexible resources for operator needs. The following highlight activities that are underway in areas where variable energy resources make up a large share of the resource mix:

    - **California:** Increasing solar generation increases the need for flexible resources. California Independent System Operator's (CAISO's) *2020 Flexible Capacity Needs Assessment* continues to show monthly maximum three-hour ramp requirements increase each year over the assessment period.[27] **See the CAISO section of the text box on page 41.**

    - **Texas:** ERCOT has managed ramping needs from increasing amounts of wind generation through forecasting tools that give operators the ability to curtail wind production and/or reconfigure the system in response to wind output changes. To support reliable operations with growth in solar capacity, ERCOT is developing a short-term solar forecasting tool that can be integrated in generation dispatching to aid in meeting flexible needs for solar up and down ramps.

26 https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERS_Measure_6_Forward_Tech_Brief_03292018_Final.pdf

27 See CAISO 2021 Flexible Capacity Needs Assessments: http://www.caiso.com/Documents/Final2021FlexibleCapacityNeedsAssessment.pdf

Planning and Operating with Inverter-Based Resources: Inverter based resources, 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. Some inverter-based resource performance issues have been significant enough to result in grid disturbances that affect the reliability of the BPS, such as the tripping of a number of BPS-connected solar PV generation units that occurred during the 2016 Blue Cut fire and 2017 Canyon 2 fire disturbances in California. More recently, fault events on the BPS occurred in the Southern California area causing around 1,000 MW of BPS-connected solar PV resources to reduce power output and likely some DER tripped off-line.[28] Planning studies and operating models must accurately account for these newer resource types. In 2020, the NERC Inverter-Based Resource Performance Working Group (IRPWG) submitted requests that will begin the process for improving NERC Reliability Standards to include verifications of inverter-based resource parameters used in BPS planning and operating models.[29] The ERO continues to focus resources on addressing potential reliability issues associated with the ever-increasing penetration of inverter-based resources.[30]

28 July 2020 San Fernando Solar PV Reduction Disturbance Report: https://www.nerc.com/pa/rrm/ea/Pages/July_2020_San_Fernando_Disturbance_Report.aspx

29 Information about the standards authorization requests for Reliability Standards MOD-026-1 and MOD-027-1 can be found in the IRPWG White Paper: https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Review_of_NERC_Reliability_Standards_White_Paper.pdf

30 In 2019, NERC published a summary of ERO activities to maintain reliability of the BPS through the growth of inverter-based resources in the resource mix. A discussion of significant grid disturbances, NERC alerts, and mitigating activities is included in the summary: https://www.nerc.com/comm/PC/Documents/Summary_of_Activities_BPS-Connected_IBR_and_DER.pdf

- **Managing fuel-related risks to electricity generation (fuel assurance):** Natural gas for electricity generation is an essential fuel bridging the rapid development of variable energy resources. 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.[31] Disruptions to the fuel delivery results from adverse events that may occur, such as line breaks, well freeze-offs, or storage facility outages. The pipeline system can be impacted by events that occur on the electricity 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 load.

31 https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Fuel_Assurance_and_Fuel-Related_Reliability_Risk_Analysis_for_the_Bulk_Power_System.pdf

Key Finding 4: DER growth continues, prompting the ERO, planners, and operators in areas where penetrations have reached or are approaching impactful levels to take actions to ensure planning processes and operating measures are in place to ensure reliability.

Key Point

- Texas, Ontario, and areas in Northeast United States are approaching impactful DER levels presently seen in the WI, leading to the implementation of more sophisticated planning and operating measures. Other areas are closely monitoring DER growth and incorporating DER projections in long-term planning.

Projection of Solar DERs

Behind the meter (BTM) solar PV is an increasingly prevalent DER seen across NERC's footprint. BTM solar PV is defined as the solar PV resources connected directly to the distribution system. Residential rooftop solar PV comprises most of the BTM solar PV installed.

Figure 24 shows the amount of DER NERC-wide through 2030. The amount of DERs is projected to more than double by 2026 and surpass 60 GW total capacity over this 10-year period.

Figure 25 shows the amount of solar DER by assessment area by 2030. Increasing DER levels in New York, New England, Ontario, and Texas are approaching levels that can impact grid reliability in some conditions, leading entities in those areas to take steps for reliable planning and operations. California and parts of the WI have planning and operating measures in place that continue to evolve with growing DER levels.

At low penetration levels, the effects of DERs may not present a risk to BPS reliability; however, the effect of these resources can present certain reliability challenges that require attention, particularly as penetrations increase. This leads to areas where further consideration is needed to better understand the impacts and how those effects can be included in planning and operations of the BPS. The NERC report, *Distributed Energy Resources: Connection, Modeling, and Reliability Considerations*, provides a detailed assessment of DERs and their potential impact on BPS reliability.[32]

32 *NERC Distributed Energy Resources: Connection, Modeling, and Reliability Considerations*: https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf

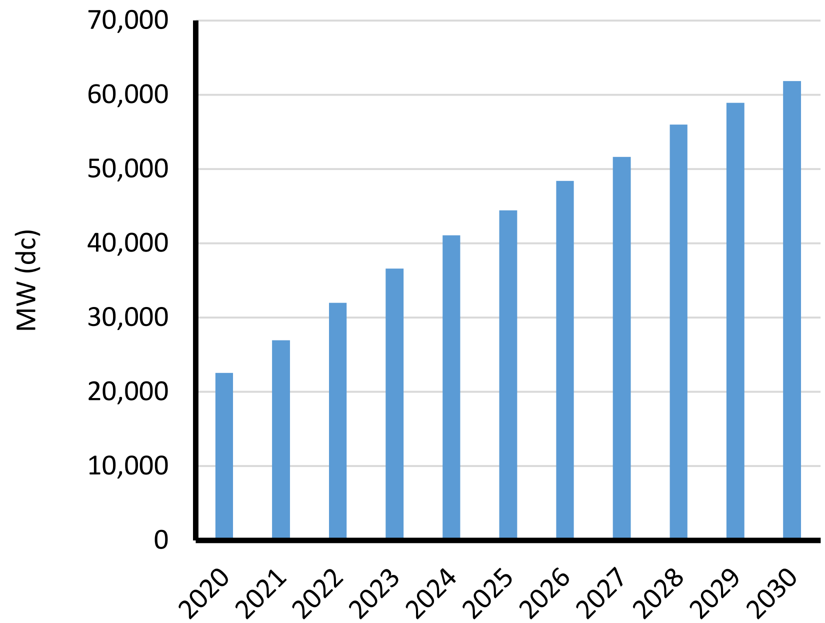


Figure 24: NERC-Wide Cumulative Distributed Solar PV Capacity—2020 through 2030

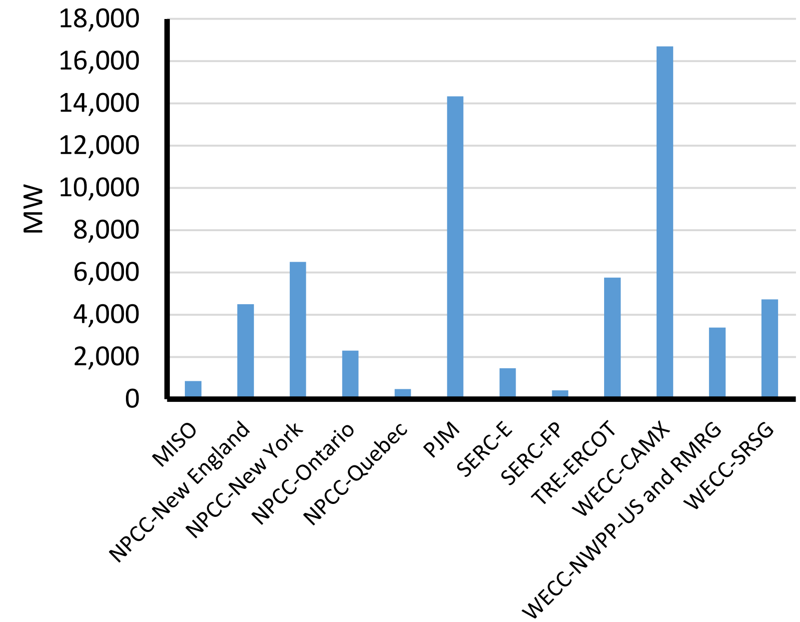


Figure 25: Solar DER by Assessment Area by 2030

An illustrative example of this can be found in **Figure 26**, which shows that as solar PV is added to a particular system, increased ramping capability is needed to support the increased ramping requirements. This is not a completely new concern for operators as some resources and imports have a long history of nondispatchability due to physical or contractual limitations. However, variable resources (particularly solar generation due to its daily production patterns) are the primary driver leading to increased ramping requirements. Other dispatchable resources are needed in reserve to offset the lack of electricity production when variable fuels (e.g., sun, wind) are not available.

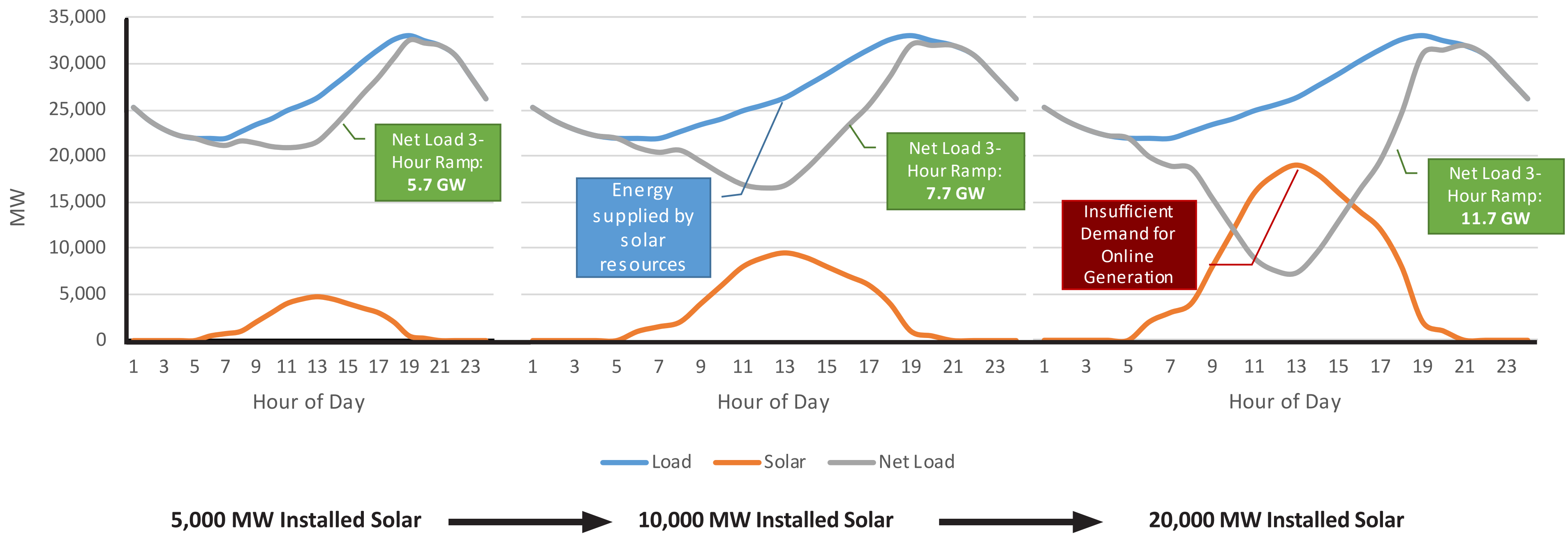


Figure 26: Example of Increasing Solar Resources Leading to Increased Ramping Requirements

Ramping

Ramping is a term used to describe the loading or unloading of generation resources in an effort to balance total demand with supply during daily system operations. Changes in the amount of nondispatchable resources, system constraints, load behaviors, and the generation mix can impact the needed ramp capability and amount of flexible resources needed to keep the system balanced in real-time. For areas with an increasing penetration of nondispatchable resources, the consideration of system ramping capability is an important component of planning and operations. Therefore, a measure to track and project the maximum one-hour and three-hour ramps for each assessment area can help understand the significant need for flexible resources.

CAISO Photovoltaic Generation and Ramping

Predominant drivers for increasing ramps have been due to changes in California's load patterns and can be attributed to an increased integration of PV DER generation across its footprint. For example, CAISO has over 11 GW of solar supply and must proportionally increase reserves to respond to a sudden increase in demand associated with cloud cover, rain, or inverter-related issues. Solar, rooftop or otherwise, is well dispersed throughout the state, reducing the expectations of widespread generation disruptions due to localized weather conditions (overcast skies in Northern California with clear skies in Southern California).

With continued rapid growth of distributed solar, CAISO's three-hour net-load ramping needs have already exceeded 15 GW. Based on current projections, maximum three-hour upward net-load ramps are projected to exceed 18,680 MW in March by 2021, an increase of just under 10% compared to the March 2021 projection from 2019 (see **Figure 27**). Upward ramping shortages are most prevalent in late afternoon when solar generation output decreases while system demand is still high. Without sufficient upward ramping capability within the balancing area to offset the loss of solar output during these times, neighboring BAs would have to provide the necessary support to balance supply and demand.

Continued increases in projected maximum three-hour ramps reinforces CAISO's near-term need for access to more flexible resources in their footprint.

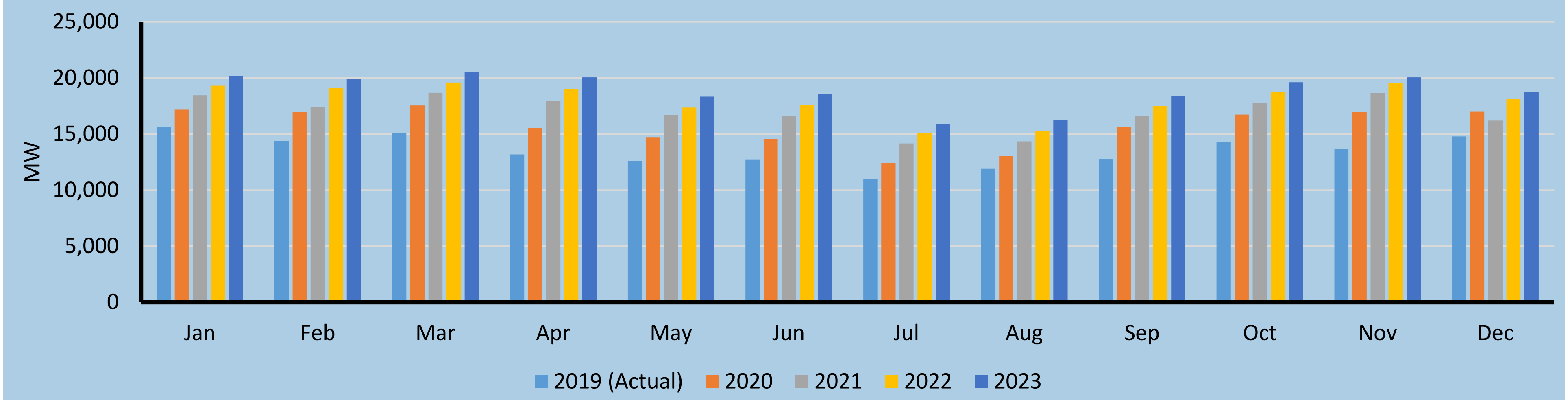


Figure 27: Maximum Three-Hour Ramps in CAISO (Actual and Projected) through 2023

Industry is already adapting by planning for the impacts of DERs. Some areas are already adapting in the following ways:

- **NPCC-New England:** ISO-NE has conducted studies regarding the higher penetration of DER (mostly solar resources) in the system and results conclude that the growth in DER still presents some concerns for system operators and planners. Concerns for ISO-NE include the following:
  - Difficulty in obtaining and managing the amount of data concerning DG/DER resources, including their size, location, and operational characteristics
  - A current inability to observe and control most DG/DER resources in real time
  - A need to better understand the impacts on system operations of the increasing amounts of DG/DERs, including ramping, reserve, and regulation requirements for both utility-based and BTM distributed generation

  To address these concerns, ISO-NE has developed various solar forecasting tools to help successfully integrate these burgeoning resources into planning and operations
- **NPCC-New York:** The historical solar PV data used to develop the demand forecast were obtained from the New York State Energy Research and Development Authority (NYSERDA),[33] which compiles information about expected solar installations. For the resource adequacy probabilistic planning assessments, the projected BTM PV is discretely modeled as an hourly (8,760 hours) shape. Nonsolar DER historical values reflect information from Transmission Owners and from NYSERDA’s DER Integrated Data System database.
- **NPCC-Ontario:** The IESO is working 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 electricity system.
- **PJM:** The Generation Attribute Tracking System collects distributed solar generation that is BTM. Utilizing this collection of data, PJM estimates the amount of distributed solar generation in terms of dc nameplate capacity.

33 https://der.nyserda.ny.gov/

- **Texas TRE-ERCOT:** ERCOT has developed a modified s-curve methodology for projecting growth for solar PV less than one MW with an underlying set of assumptions for three different scenarios (conservative, moderate, and aggressive) based on studies done for ERCOT. DER quantities in ERCOT are reported to the ERCOT Supply Analysis Working Group. One of the improvements in DER reporting over prior years was a result of NPRR891.[34] DER information from all available sources in Texas can be found in summary at the ERCOT website.[35]
- **WECC:** DER impacts on the individual LSEs are well understood and are in included in local assessments. For example, CAISO has approximately 5,132 MW of BTM solar supply and must proportionally increase reserves to respond to a sudden increase in demand associated with cloud cover, rain, or inverter-related issues. Solar, rooftop or otherwise, is well dispersed throughout the state, reducing the expectations of widespread generation disruptions due to localized weather conditions (overcast skies in Northern California with clear skies in Southern California).[36]

34 NPRR891

35 http://www.ercot.com/content/wcm/key_documents_lists/195745/2015_to_2019_DER_data_v1_pdf.pdf

36 In addition to local assessments, operating states are continuously monitored: http://www.caiso.com/TodaysOutlook/Pages/supply.aspx

The NERC Planning Committee (a predecessor of the RSTC) formed the NERC System Planning Impacts of Distributed Energy Resources Working Group (SPIDERWG), which focusing on the BPS impacts of DER from a transmission planning and system analysis perspective. NERC's SPIDERWG focuses on four key aspects of DER impacts to the BPS:

- **Modeling:** Representing aggregate DERs in BPS reliability studies, advancing industry capabilities and expertise with representing DERs in these reliability studies, and developing robust and reasonable data sets for power flow and dynamic simulations
- **Verification:** Ensuring that the models used in studies provide a reasonable and suitable representation of the actual aggregate performance of these resources, benchmarking software platforms to ensure uniformity in tools, and recommending analysis techniques for accounting for aggregate DERs during large BPS disturbances
- **Studies:** Improving study techniques and methods to ensure the most stressed operating conditions are chosen for BPS reliability studies, identifying key operating conditions and sensitivities to perform, and improving software tools and study capabilities
- **Coordination:** Supporting coordination between transmission and distribution entities for improved data exchange and coordinating with IEEE leadership to support the application of IEEE Std. 1547- 2018 across North America

The NERC SPIDERWG will develop recommended practices and guidelines around these topics to ensure registered entities have the tools and capabilities to advance transmission planning studies in light of rapidly growing penetrations of DERs. SPIDERWG also serves as an excellent forum for distribution and transmission entities to exchange ideas and sharing needs in terms of information for modeling and situational awareness. SPIDERWG also supports the review and applicability of NERC Reliability Standards and identifies whether these standards may need to be modified to ensure reliable operation of the BES in light of the potential DER impacts.[37]

37 SPIDERWG information can be found on the NERC website: https://www.nerc.com/comm/PC/Pages/System-Planning-Impacts-from-Distributed-Energy-Resources-Subcommittee-(SPIDERWG).aspx

Key Finding 5: The ongoing pandemic is not presenting specific threats or degradation to the reliable operation of the BPS for the assessment period. However, it is producing increased uncertainty in future electricity demand projections and presents cyber security and operating risks.

Key Points

- Most assessment areas did not adjust long-term forecasts for pandemic impacts in this *2020 LTRA* because the effects on peak demand levels were unclear and duration is unpredictable. Summer operating experience in many areas showed increased residential demand that can offset decreased commercial/industrial load.
- Reduced industrial load can affect the availability of DR programs that rely on curtailment of industrial customers during periods of high demand.
- Personnel protections for operators and field crews, mitigating heightened cyber risks, and systems operations planning will be persistent areas for risk management throughout the pandemic.

The global health crisis has elevated the electricity reliability risk profile due to potential workforce disruptions, supply chain interruptions, and increased cyber security threats. In April, NERC released its *Pandemic Preparedness and Operational Assessment: Spring 2020* (special report) to advise electricity stakeholders of the reliability considerations and assess the operational preparedness of BPS owners and operators during pandemic conditions in April and May 2020. In its special report, NERC did not identify any specific threat or degradation to the reliable operation of the BPS for the spring time frame. The ERO continues to assess risks and conditions and is pursuing all available avenues to continue coordination with federal, state, and provincial regulators as well as work with industry to identify reliability implications and lessons learned.

Since the start of the widening COVID-19 infection in North America in February 2020, registered entities have taken steps from pandemic plans and industry advisories to maintain the reliability and security of the BPS. In March 2020, the Electricity Subsector Coordinating Council (ESCC) issued the first version of the *ESCC Resource Guide*[38] as a resource for electricity power industry leaders to guide informed localized decisions in response to the COVID-19 global health emergency; it is updated on a regular basis as new approaches, planning considerations, and issues develop. The guide highlights data points, stakeholders, and options to consider while making decisions about operational status while protecting the health and safety of employees, customers, and communities. Sharing experiences and expertise helps users of the guide to make independent, localized decisions aimed at reducing negative impacts to the BPS's power supply during the COVID-19 global pandemic. In addition to immediate measures designed to protect critical operations, personnel, and functions, entities are working to minimize risk to resource and BPS equipment availability, assure fuel supplies, and prepare operating personnel for peak season.

The pandemic is negatively impacting electricity demand in many parts of North America just as it has elsewhere around the world. Prior to Summer 2020, when government stay-at-home orders and societal response were at their highest, some areas reported as much as 15% decrease in peak demand. However, these observed demand impacts varied across North America and were negligible in some areas. Throughout the pandemic, ISOs and RTOs have periodically reported on demand impacts.[39] In most areas, weather continues to be the predominant factor in electricity demand.

Many areas are experiencing variations in hourly load shapes as a result of changing societal behaviors and mechanisms implemented to halt the spread of COVID-19. In general, these areas are seeing below-normal ramp in demand in morning hours and lower evening demand as can be seen in **Figure 28**. Changes to pre-pandemic patterns can affect the accuracy of day-ahead demand forecasts that are relied upon to ensure resources are available for each hour of the day. In recent years, demand and resource forecasting has become more complex and more critical as the generation resource mix has changed to include higher levels of variable generation and an altered load shape with increasing solar PV resources. When operating entities began observing discrepancies between predicted and actual demand as a result of pandemic behavior, many instituted measures designed to improve the accuracy of forecasts made available to system operators. In MISO and other ISOs, support teams have increased the frequency of short-term demand forecast simulations.

38 https://www.electricitysubsector.org/

39 For example, see reports from ERCOT and CAISO: http://www.caiso.com/Documents/COVID-19-Impacts-ISOLoadForecast-Presentation.pdf and http://www.ercot.com/content/wcm/lists/200201/ERCOT_COVID-19_Analysis_FINAL.pdf

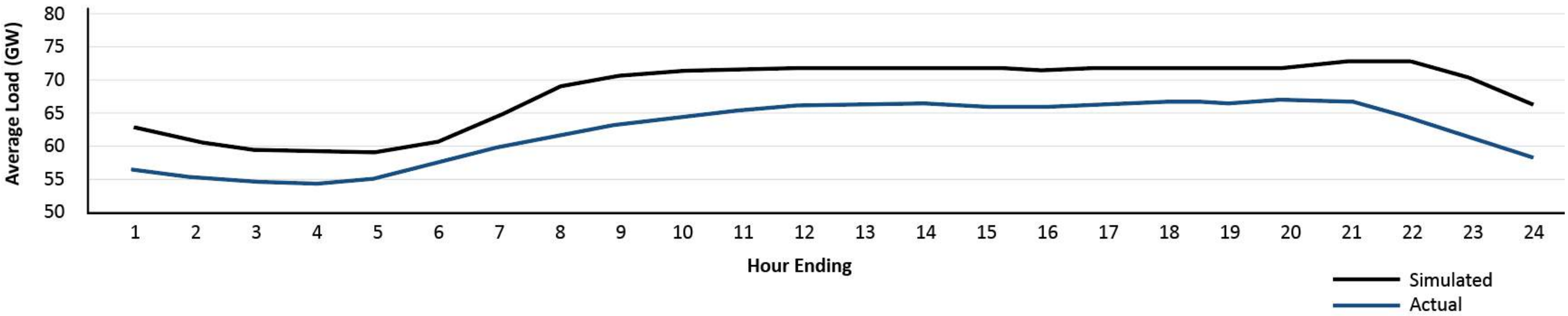


Figure 28: Average Simulated and Actual Load in MISO Area for April 4–10, 2020

Reduced industrial load has the potential to negatively affect the availability of DR resources used by operators during periods of peak demand. In assessing resource adequacy in NERC reliability assessments, entities project the MW capacity of demand that operators can modify through direct control and dispatch during the peak hour to alleviate shortages. Often DR resources are contracted industrial customers that agree to electricity curtailments during periods when operators have a shortage of operating reserves. If industrial demand is reduced already by lower industrial output and a period of extreme temperatures were to occur that drive space-heating loads, operators could find their demand-response curtailments to have little effect. Figure 29 shows the anticipated controllable and dispatchable DR contributions as a percentage of total internal demand for 2021 in selected assessment areas. In each area, DR resources are a varying mix of commercial, industrial, and residential loads.

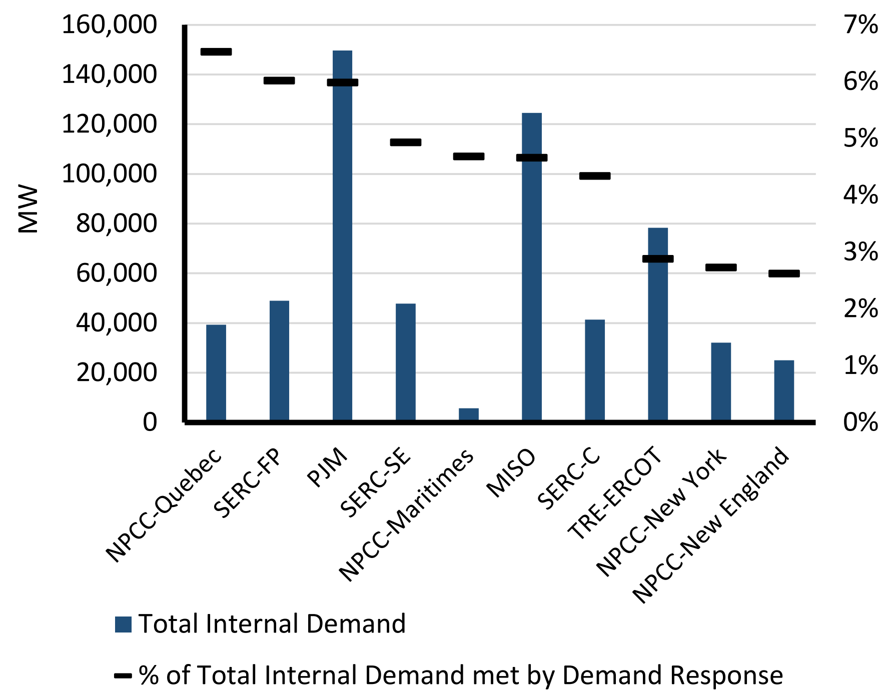


Figure 29: Projected 2021 Peak Season DR–Assessment Areas with Highest DR Contribution to Meeting Total Peak Demand

Potential Demand and Resource Challenges for System Operators

As noted in previous ERO assessments of pandemic impacts, system operators could encounter difficult system characteristics, such as increased impact of DERs on load profiles, reverse power flows on distribution circuits, higher than usual operating voltages, and minimum demands at all-time lows; operating challenges like these need to be addressed in real-time, often by using complex tools for studying these dynamic system conditions.

The effect of DERs on system performance is becoming more pronounced as synchronous generation is replaced, particularly during periods of lower minimum demand; operators could face challenges in maintaining sufficient amounts of frequency-responsive reserves necessary to regulate or arrest frequency deviations. Typically, DER effects on the system are more pronounced in the spring when milder temperatures reduce air conditioning load and increase efficiency in solar PV modules. In areas with higher DER penetrations (e.g., California, North Carolina), minimum loads and reverse power flows from the distribution system can cause challenges for system operators.

The potential lack of industrial and commercial load could alter underfrequency or undervoltage load shedding plans that rely on tripping these dispatchable loads as well as DR programs that may be relied on to support emergency operations.

Utility Crews and Operators Must Stay Postured for Reliability, Security, and Resilience

As the COVID-19 crisis unfolded, the industry prepared to operate with a significantly smaller workforce, an encumbered supply chain, and limited support services for an extended and unknown period of time. Vigilance to cyber security threats intensified as risks are elevated due to a greater reliance on remote working arrangements. The business continuity and pandemic plans developed by the different operating entities are designed to protect the people working for them and to ensure critical electricity operations and infrastructure are supported properly throughout an emergency.

Protecting the critical electricity industry workforce during the COVID-19 pandemic remains a priority for reliability and resilience. System and Generator Operators have implemented operating postures and personnel restrictions prescribed by their pandemic plans in order to protect essential personnel and support reliable operations. Many of these measures will need to be maintained or be reinstituted during periods of resurgence. There is a continuing risk that control centers or plants could be temporarily shut down if a significant number of operators or plant employees test positive for COVID-19 despite preparedness efforts, including employee sequestration. While entities have developed return to work plans, the majority are expected to maintain protective protocols for operating personnel into 2021. When relaxations can be implemented, operators will likely need to stay postured to return to heightened protections if warranted by changing public health conditions.

Operating Reliability Considerations

- Increased uncertainty in demand projections and daily use
- Potential for increased forced outages due to deferred maintenance, staff unavailability, or limited supplies and/or fuel
- Higher than usual operating voltages
- Light load conditions
- Reverse power flow and increased DER penetration levels
- Potential for reduced effectiveness in underfrequency/voltage load shedding schemes as industrial and commercial load may not be on-line

An important component of BPS resilience and recovery from hurricanes and major storms is the effective mutual assistance rendered by organizations from outside the storm-affected areas. Over the past summer, industry cooperation played a significant factor in the effective response and restoration of the power system from multiple hurricanes and tropical storms that battered areas along the U.S. Gulf of Mexico area. The comprehensive plans in place to rapidly deploy support teams and equipment take on even greater complexity due to the need to safeguard personnel from COVID-19. In April, the ESCC updated its *Resource Guide* to provide lessons learned from the experience of the utilities, electricity cooperatives, and investor-owned electricity companies affected by a series of storms in late March and early April of this year.[40] Lessons learned include considerations for maintaining social distancing at all times, planning for personnel protection equipment needs, and the increased need for local logistical and coordination personnel to support a decentralized response.

Cyber Security Risk and Information Sharing

Electricity and other critical infrastructure sectors face elevated cyber security risks arising from the COVID-19 pandemic in addition to ongoing risks. Opportunistic actors are attempting to find and exploit new vulnerabilities that arise as entities shift work processes and locations to maintain business continuity. The E-ISAC exchanges information with its members, including communications and guidance from the ESCC and from government partners as well as advisories about emerging cyber threats.

40 See *ESCC Resource Guide*, Version 7, April 27, 2020, p. 47–48.

Demand, Resources, Reserve Margins, and Transmission

Demand Projections

In 2020, there is heightened uncertainty in demand projections that stems from the progression of the COVID-19 pandemic and the response of governments, society, and the electricity industry. NERC-wide electricity peak demand and energy growth rates have leveled off, or even declined, after the increasing growth rates reported in the *2019 LTRA*.

Figure 30 identifies the 10-year compound annual growth rate (CAGR) of peak demand that is declining for summer but increasing slightly for winter when compared to the prior year. The projected 10-year energy growth rate is 0.43%, which is down from 0.6% reported in the *2019 LTRA* (**Figure 31**).

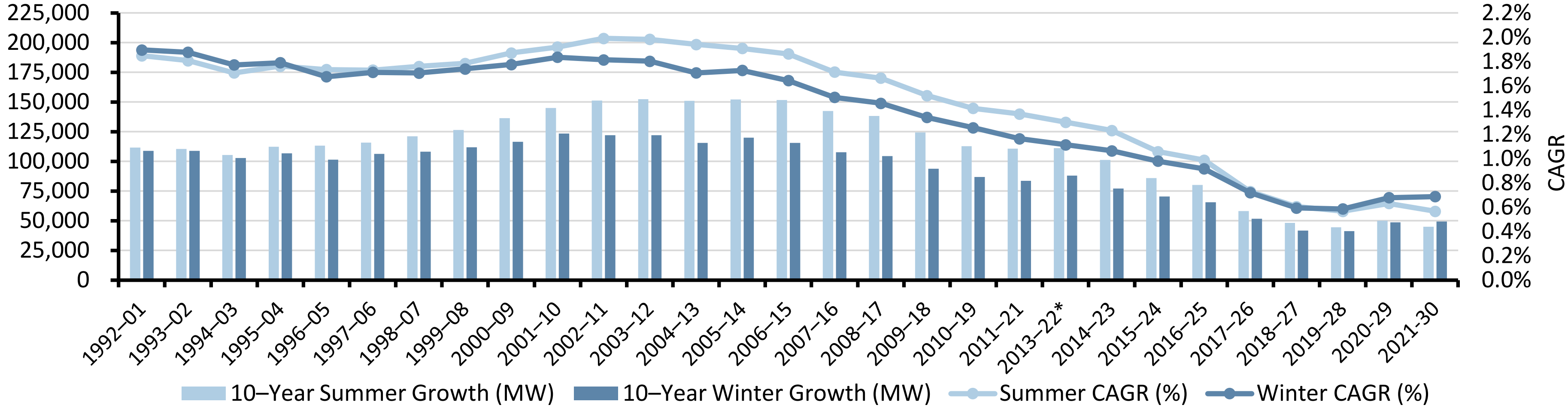


Figure 30: 10-Year Summer and Winter Peak Demand Growth and Rate Trends

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 their forecasts on an annual basis or as their 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 demand side management (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.

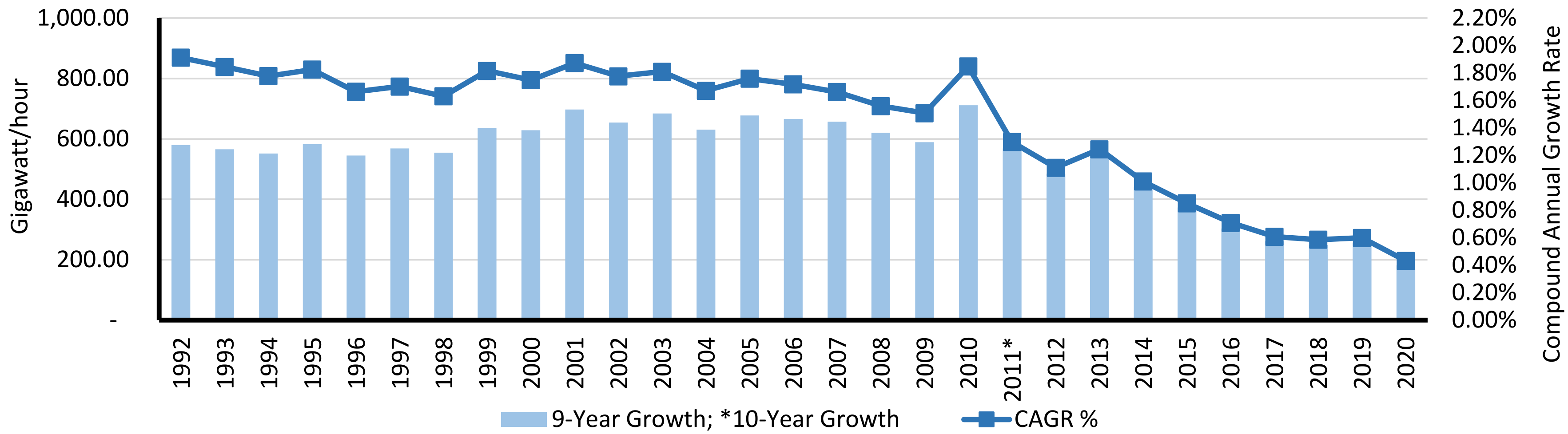


Figure 31: 10-Year Net Energy to Load Growth and Rate Projection Trends

The 10-year demand growth rate in all assessment areas is 1.7% or less per year with three assessment areas projecting reductions in peak demand (**Figure 32**). Note NPCC NY, NPCC Ontario, and NPCC Quebec have adjusted demand forecasts to account for anticipated impacts from the ongoing COVID pandemic.

Continued advancements of EE programs combined with a general shift in North America to less energy-intensive economic growth are contributing factors to slower electricity demand growth. There are 30 states in the United States that have adopted EE policies that are contributing to reduced peak demand and overall energy use.[41] Additionally, DERs and other BTM resources continue to increase in number and reduce the net demand for the BPS even further.

Fuel Mix Changes

Figures 33 and 34 identify the components of the fuel mix for the North American BPS. **Figure 33** shows the installed capacity composition of generating resources NERC-wide as of July 2020 compared to the projected installed capacity composition of 2030 (includes Tier 1 additions).

Figure 34 shows the on peak capacity composition of generating resources NERC-wide as of July 2020 compared to the projected on peak capacity composition of 2030 (includes Tier 1 additions). On-peak capacity gives an idea of what a resource is capable of producing at peak demand.

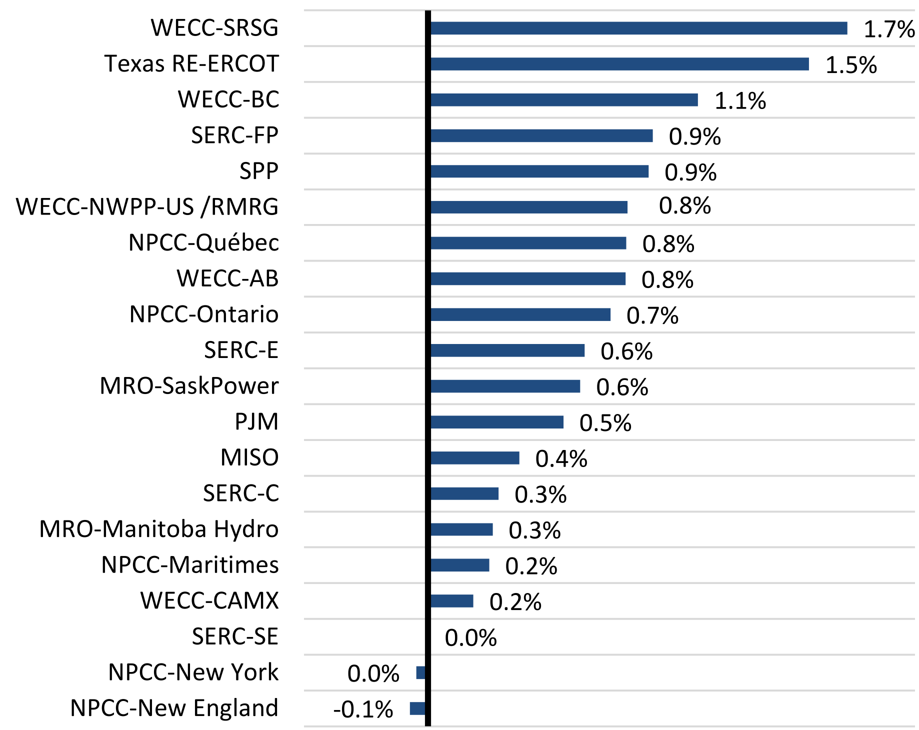


Figure 32: Annual Peak Demand Growth Rate for 10-Year Period by Assessment Area

41 EIA - Today in Energy: Many states have adopted policies to encourage EE.

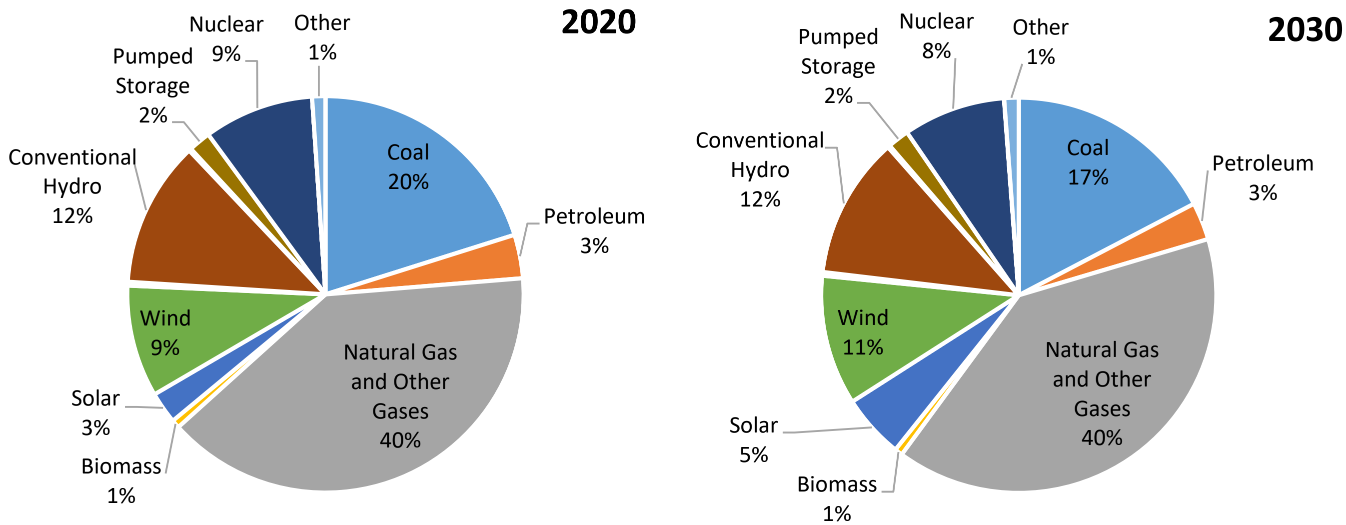


Figure 33: Installed Nameplate Capacity by Fuel Mix Trend (Includes Future Tier 1 Resources)

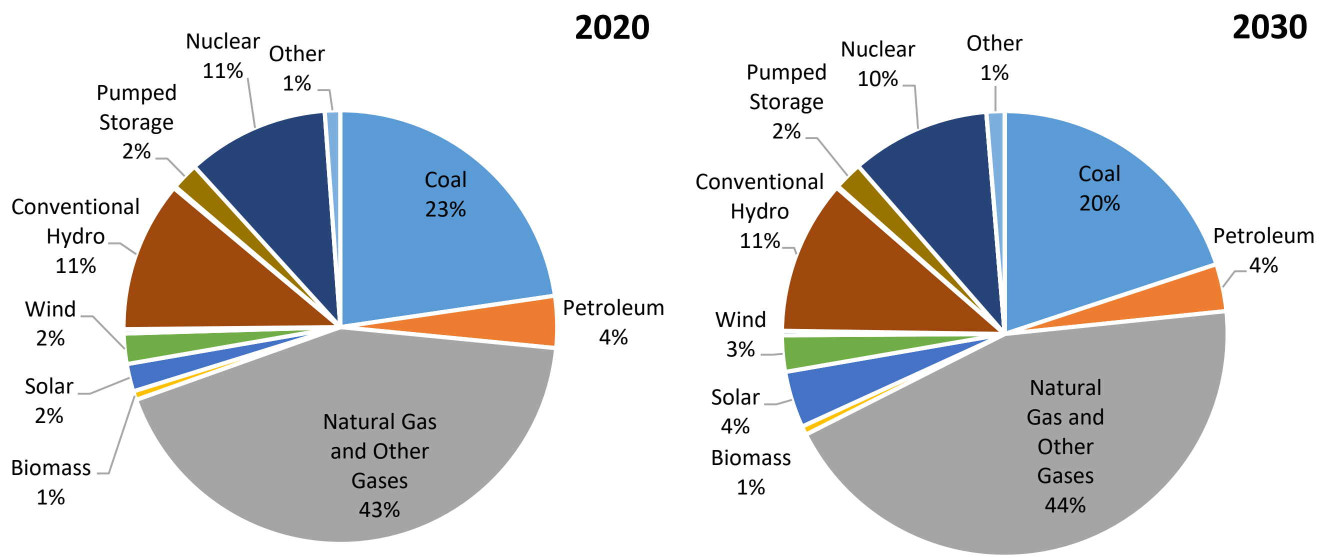


Figure 34: Installed On-Peak Anticipated Capacity Trend by Fuel Mix

The PRMs for the years 2021–2025 are shown in Table 9. Table 10 shows the RMLs for each assessment area.

Table 9: Planning Reserve Margins (2021–2025)						
Assessment Area	Reserve Margins (%)	2021	2022	2023	2024	2025
MISO	Anticipated Reserve Margin	23.8%	22.3%	19.9%	18.3%	17.0%
	Prospective Reserve Margin	31.6%	41.1%	51.6%	53.7%	53.9%
	Reference Margin Level	18.0%	18.0%	18.0%	18.0%	18.0%
MRO-Manitoba	Anticipated Reserve Margin	19.8%	17.7%	16.0%	15.8%	13.5%
	Prospective Reserve Margin	18.4%	16.2%	14.6%	14.4%	12.1%
	Reference Margin Level	12.0%	12.0%	12.0%	12.0%	12.0%
MRO-SaskPower	Anticipated Reserve Margin	34.3%	34.7%	30.0%	37.0%	31.5%
	Prospective Reserve Margin	34.3%	34.7%	30.0%	37.0%	31.5%
	Reference Margin Level	11.0%	11.0%	11.0%	11.0%	11.0%
NPCC-Maritimes	Anticipated Reserve Margin	21.6%	19.3%	19.7%	20.9%	20.7%
	Prospective Reserve Margin	21.6%	19.3%	19.7%	19.2%	18.4%
	Reference Margin Level	20.0%	20.0%	20.0%	20.0%	20.0%
NPCC-New England	Anticipated Reserve Margin	30.9%	29.4%	28.3%	18.9%	19.0%
	Prospective Reserve Margin	34.8%	34.7%	40.1%	32.2%	34.7%
	Reference Margin Level	13.1%	13.2%	12.7%	12.7%	12.7%
NPCC-New York[1]	Anticipated Reserve Margin	19.4%	19.8%	17.8%	18.6%	17.1%
	Prospective Reserve Margin	19.7%	20.1%	19.5%	20.4%	18.9%
	Reference Margin Level	15.0%	15.0%	15.0%	15.0%	15.0%
NPCC-Ontario	Anticipated Reserve Margin	23.8%	20.1%	5.5%	11.2%	2.0%
	Prospective Reserve Margin	23.8%	20.1%	10.1%	15.7%	10.9%
	Reference Margin Level	23.9%	23.8%	16.2%	16.7%	15.9%
NPCC-Quebec	Anticipated Reserve Margin	13.3%	13.5%	12.2%	14.0%	13.5%
	Prospective Reserve Margin	16.2%	16.5%	15.2%	16.9%	16.4%
	Reference Margin Level	10.1%	10.1%	10.1%	10.1%	10.1%
PJM	Anticipated Reserve Margin	39.1%	38.4%	41.5%	41.9%	41.1%
	Prospective Reserve Margin	47.1%	64.5%	77.5%	83.2%	83.3%
	Reference Margin Level	15.1%	14.9%	14.8%	14.8%	14.8%

1 The NERC RML for NY is 15%. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. 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 2020–2021 IRM at 18.9%. All values in the IRM calculation are based upon full Installed Capacity (ICAP) MW values of resources. The NYISO uses probabilistic assessments to evaluate its system's resource adequacy against the LOLE resource adequacy criterion of 0.1 days/year.

Table 9: Planning Reserve Margins (2021–2025)						
Assessment Area	Reserve Margins (%)	2021	2022	2023	2024	2025
SERC-C	Anticipated Reserve Margin	29.3%	28.7%	29.6%	25.9%	23.6%
	Prospective Reserve Margin	34.8%	34.1%	37.8%	35.4%	33.2%
	Reference Margin Level	15.0%	15.0%	15.0%	15.0%	15.0%
SERC-E	Anticipated Reserve Margin	22.7%	24.3%	23.7%	27.0%	27.4%
	Prospective Reserve Margin	22.9%	24.5%	23.9%	27.3%	27.6%
	Reference Margin Level	15.0%	15.0%	15.0%	15.0%	15.0%
SERC-FP	Anticipated Reserve Margin	22.3%	21.1%	23.7%	22.3%	22.2%
	Prospective Reserve Margin	23.5%	22.3%	24.8%	23.4%	23.3%
	Reference Margin Level	15.0%	15.0%	15.0%	15.0%	15.0%
SERC-SE	Anticipated Reserve Margin	34.2%	37.9%	39.5%	41.4%	40.9%
	Prospective Reserve Margin	36.0%	41.7%	43.6%	45.6%	45.1%
	Reference Margin Level	15.0%	15.0%	15.0%	15.0%	15.0%
SPP	Anticipated Reserve Margin	29.5%	26.5%	25.1%	24.2%	23.4%
	Prospective Reserve Margin	38.2%	35.0%	33.5%	32.5%	31.7%
	Reference Margin Level	15.8%	15.8%	15.8%	15.8%	15.8%
TRE-ERCOT	Anticipated Reserve Margin	16.2%	19.6%	18.0%	16.0%	14.3%
	Prospective Reserve Margin	20.5%	49.8%	57.0%	55.3%	53.1%
	Reference Margin Level	13.75%	13.75%	13.75%	13.75%	13.75%
WECC-AB	Anticipated Reserve Margin	22.6%	26.3%	22.8%	24.0%	23.6%
	Prospective Reserve Margin	32.2%	42.1%	50.5%	55.6%	55.1%
	Reference Margin Level	13.8%	12.3%	13.8%	14.1%	14.1%
WECC-BC	Anticipated Reserve Margin	21.4%	20.6%	19.1%	21.2%	24.1%
	Prospective Reserve Margin	21.4%	20.6%	19.1%	21.3%	24.2%
	Reference Margin Level	13.8%	12.3%	13.8%	14.1%	14.1%
WECC-CAMX	Anticipated Reserve Margin	21.4%	27.8%	27.3%	26.8%	22.5%
	Prospective Reserve Margin	21.4%	35.3%	40.8%	41.7%	37.4%
	Reference Margin Level	18.2%	15.8%	19.1%	19.1%	19.1%
WECC-NWPP-US and RMRG	Anticipated Reserve Margin	25.9%	24.6%	23.4%	21.6%	20.8%
	Prospective Reserve Margin	25.9%	24.8%	24.0%	22.2%	21.5%
	Reference Margin Level	15.4%	16.1%	15.2%	15.1%	15.0%
WECC-SRSG	Anticipated Reserve Margin	18.1%	17.3%	17.0%	14.7%	15.5%
	Prospective Reserve Margin	18.1%	18.1%	19.5%	17.2%	17.9%
	Reference Margin Level	10.9%	11.9%	11.0%	10.8%	10.7%

Table 10: Reference Margin Levels for Each Assessment Area (2021–2025)					
Assessment Area	**Reference Margin Level**	**Assessment Area Terminology**	**Requirement?**	**Methodology**	**Reviewing or Approving Body**
MISO	18.0%	PRM	Yes: Established Annually[42]	0.1 day/Year 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%[43]	Reference Margin Level	No	0.1 day/Year LOLE	Maritimes Sub-areas; NPCC
NPCC-New England	12.7–13.2%	Installed Capacity Requirement (ICR)	Yes: three year requirement established annually	0.1 day/Year LOLE	ISO-NE; NPCC Criteria
NPCC-New York	15.0%[44]	Installed Reserve Margin (IRM)	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	14.4–23.8%	Ontario Reserve Margin Requirement (ORMR)	Yes: established annually for all years	0.1 day/Year LOLE	IESO; NPCC Criteria
NPCC-Québec	10.1%	Reference Margin Level	No: established Annually	0.1 day/Year LOLE	Hydro Québec; NPCC Criteria
PJM	14.8–15.5%	IRM	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

42 In MISO, the states can override the MISO PRM

43 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.

44 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 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 2020–2021 IRM at 18.9%. 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.

Table 10: Reference Margin Levels for Each Assessment Area (2021–2025)					
Assessment Area	**Reference Margin Level**	**Assessment Area Terminology**	**Requirement?**	**Methodology**	**Reviewing or Approving Body**
SERC-C	15.0%[45]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities
SERC-E	15.0%[46]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities
SERC-FP	15.0%[47]	Reliability Criterion	No: Guideline	0.1 day/Year LOLP	Florida Public Service Commission
SERC-SE	15.0%[48]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities
SPP	15.8%	Resource Adequacy Requirement	Yes: studied on Biennial Basis	0.1 day/Year LOLE	SPP RTO Staff and Stakeholders
TRE-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	11.15–13.18%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC
WECC-BC	11.15–13.18%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC
WECC-CAMX[49]	15.65–19.14%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC
WECC-NWPP-US & RMRG	14.54–16.12%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC
WECC-SRSG	10.29–11.86%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC

45 SERC does not provide RMLs or resource requirements for its sub-regions. However, SERC members perform individual assessments to comply with any state requirements.

46 SERC does not provide RMLs resource requirements for its sub-regions. However, SERC members perform individual assessments to comply with any state requirements.

47 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.

48 SERC does not provide RMLs or resource requirements for its sub-regions. However, SERC members perform individual assessments to comply with any state requirements.

49 California is the only state in the WI that has a wide-area PRM requirement, currently 15%.

Transmission

Historical Trend

Figure 35 shows the historical 10-year transmission projections for the past 10 years, each year being a 10-year projection. Between the years 2011 and 2016, considerably more transmission was planned than more recent years. For example, in 2012, nearly 40,000 circuit miles of high voltage transmission was planned for the next 10 years. Current projections show less than 15,000 circuit miles of planned transmission for the next 10 years. NERC's transmission projection data is limited to planned projects and does not identify completed projects.

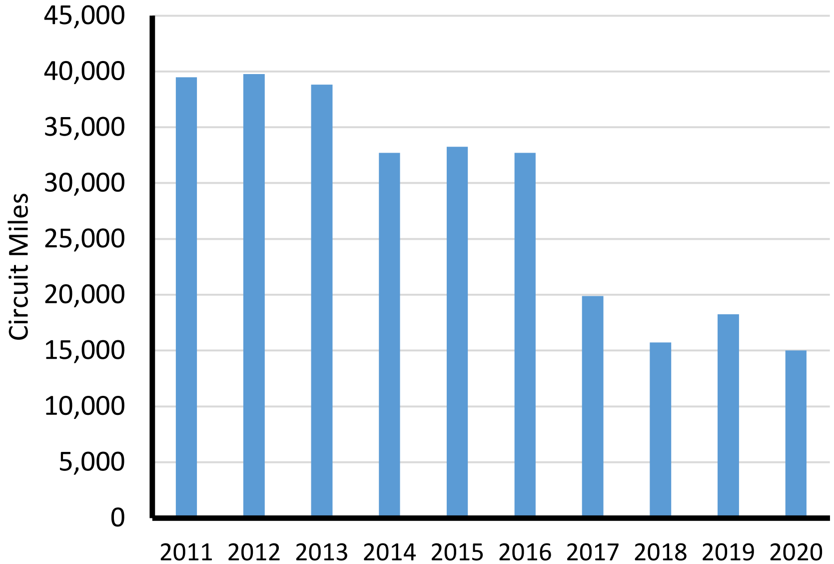


Figure 35: Historical 10-Year Transmission Projections

Future Projections

Figure 36 highlights that ERO-wide transmission additions during the 10-year period include plans for over 14,000 circuit miles, including conceptual projects. NERC continues to monitor the progress of transmission projects across North America. This amount represents a considerable reduction in the amount of transmission miles planned in nearly a decade, compared with the 30,000+ miles planned each year during the period 2011–2016 (from **Figure 35**). ISO/RTOs and utility planners must dedicate resources to planning processes that support the reliable integration of wind and solar generation into the transmission system.

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"

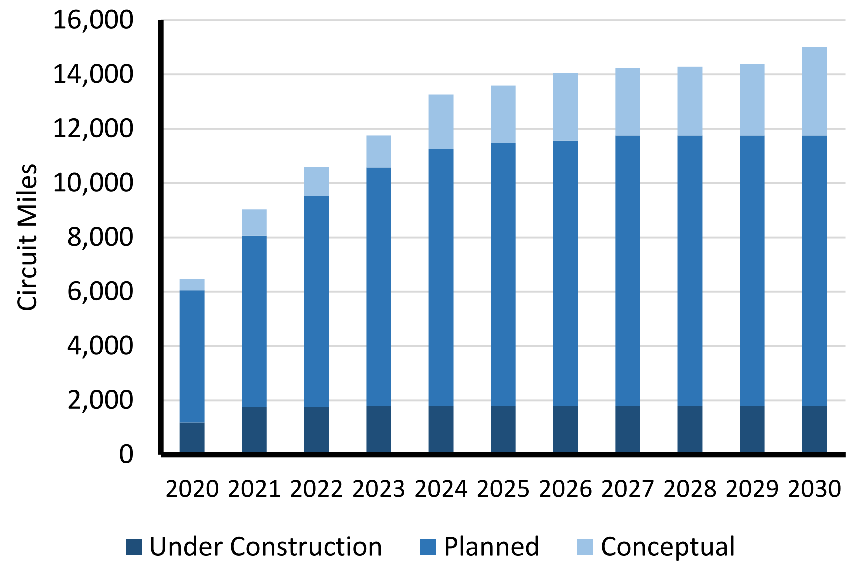


Figure 36: Future Transmission Circuit Miles >100 kV, by Project Status

Figure 37 shows the future transmission circuit miles by voltage class.

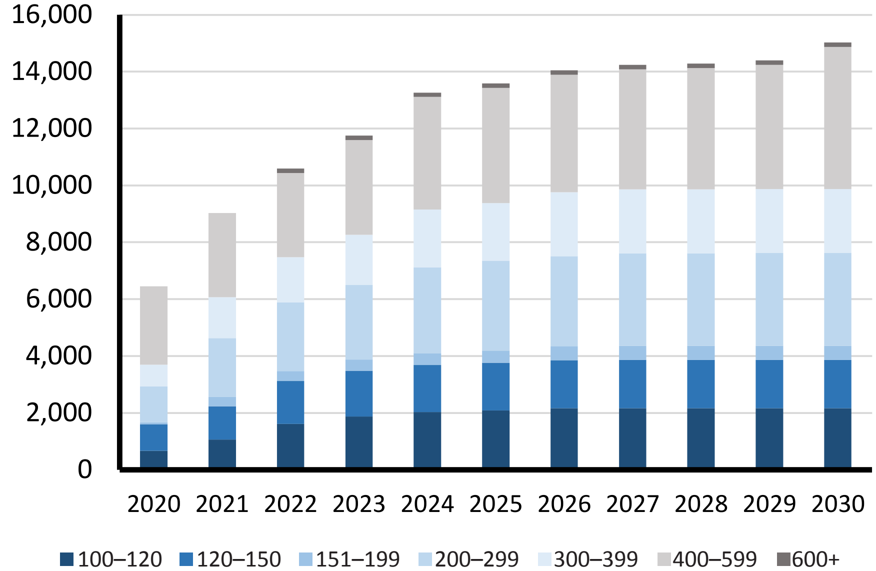


Figure 37: Future Transmission Circuit Miles >100kV, by Voltage Class

Figure 38 shows that most planned transmission projects are shorter in line length, and fewer longer length projects are being planned. However, with the amount of solar and wind coming online in the next 10 years, area planning processes may identify needs for longer length transmission projects to capture and transmit renewable energy from areas distant from load centers.

Figure 39 shows the percentage of future transmission circuit miles by primary driver over this 10-year assessment period. According to industry, new transmission projects are being driven to support new generation and enhance reliability. Other reasons include congestion alleviation and addressing aging assets and infrastructure.

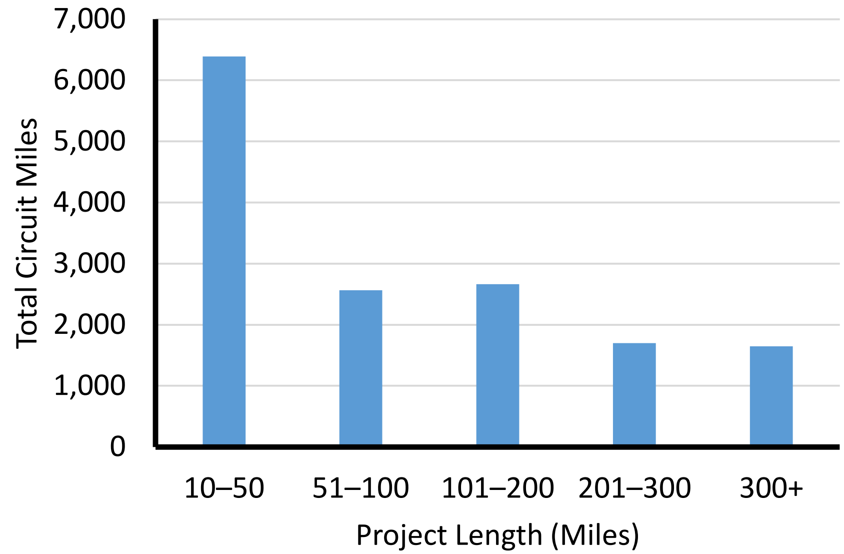


Figure 38: Line Miles Projected through 2030

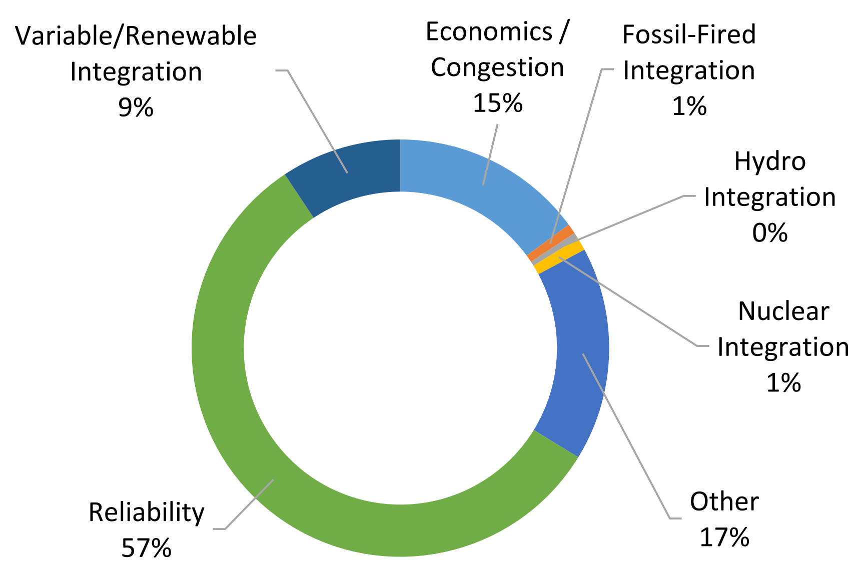


Figure 39: Future Transmission Circuit Miles by Primary Driver

Figure 40 shows the assessment areas as net capacity importers or exporters for the year 2021. Net importers are shown in yellow and net exporters are shown in blue. The grey assessment areas are below 100 MW of capacity imported or exported for 2021.

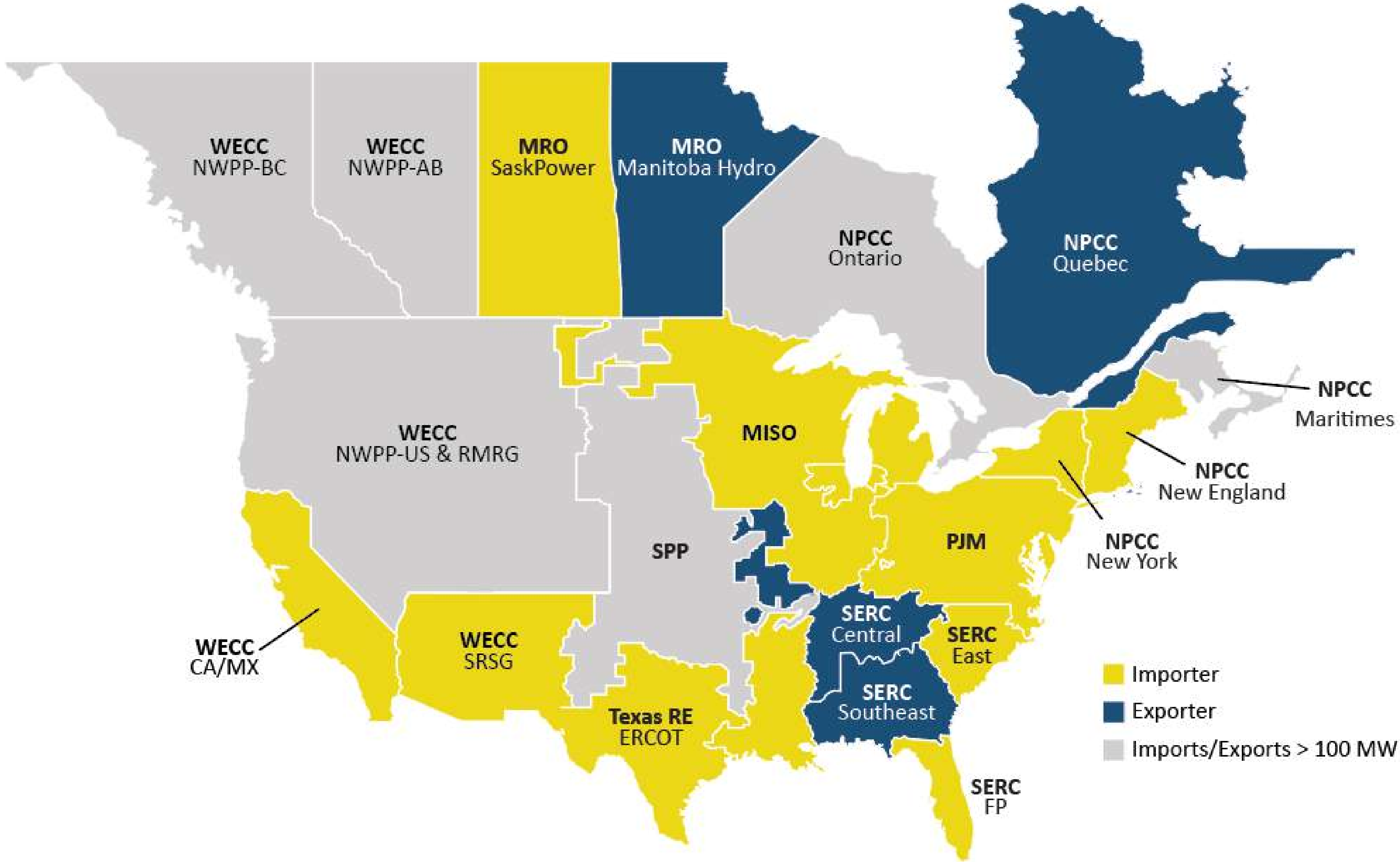


Figure 40: Net Capacity Transfers for Year 2021

Table 11 shows the percent of the reserve margin that is supported by net capacity transfers. If an assessment area has a positive percentage, it is a net importer. Conversely, if an assessment area has a negative percentage, it is a net exporter.

Table 11: Year 2021 Net Capacity Transfers by Assessment Area

Assessment Area	Peak Demand (MW)	Firm Net Transfers (MW)	Reserve Margin (MW)	Percent of Reserve Margin	Anticipated Capacity Resources
MISO	118,684	2,545	27,364	9.3%	146,048
MRO-Manitoba Hydro	4,667	-447	923	-48.4%	5,591
MRO-SaskPower	3,516	-66	1,205	-5.5%	4,721
NPCC-Maritimes	5,422	153	1,170	13.1%	6,591
NPCC-New England	24,327	1,305	7,526	17.3%	31,852
NPCC-New York	31,253	1,812	6,064	29.9%	37,317
NPCC-Ontario	21,635	0	5,139	0.0%	26,774
NPCC-Quebec	36,743	-499	4,830	-10.3%	41,610
PJM	140,661	1,460	54,988	2.7%	195,649
SERC North	39,628	-630	11,623	-5.4%	51,251
SERC-East	45,000	605	10,206	5.9%	55,206
SERC-FP	46,075	872	10,275	8.5%	56,350
SERC-Southeast	45,394	-1,016	15,506	-6.6%	60,900
SPP	51,643	-4	15,215	0.0%	66,859
TRE-ERCOT	76,045	210	12,354	1.7%	88,399
WECC-AB	12,329	0	2,784	0.0%	15,113
WECC-BC	11,077	0	2,368	0.0%	13,445
WECC-CAMX	54,713	4,224	11,704	36.1%	66,417
WECC-NWPP US and RMRG	63,096	0	16,337	0.0%	79,433
WECC-SRSG	25,590	865	4,634	18.7%	30,224

Regional Assessments

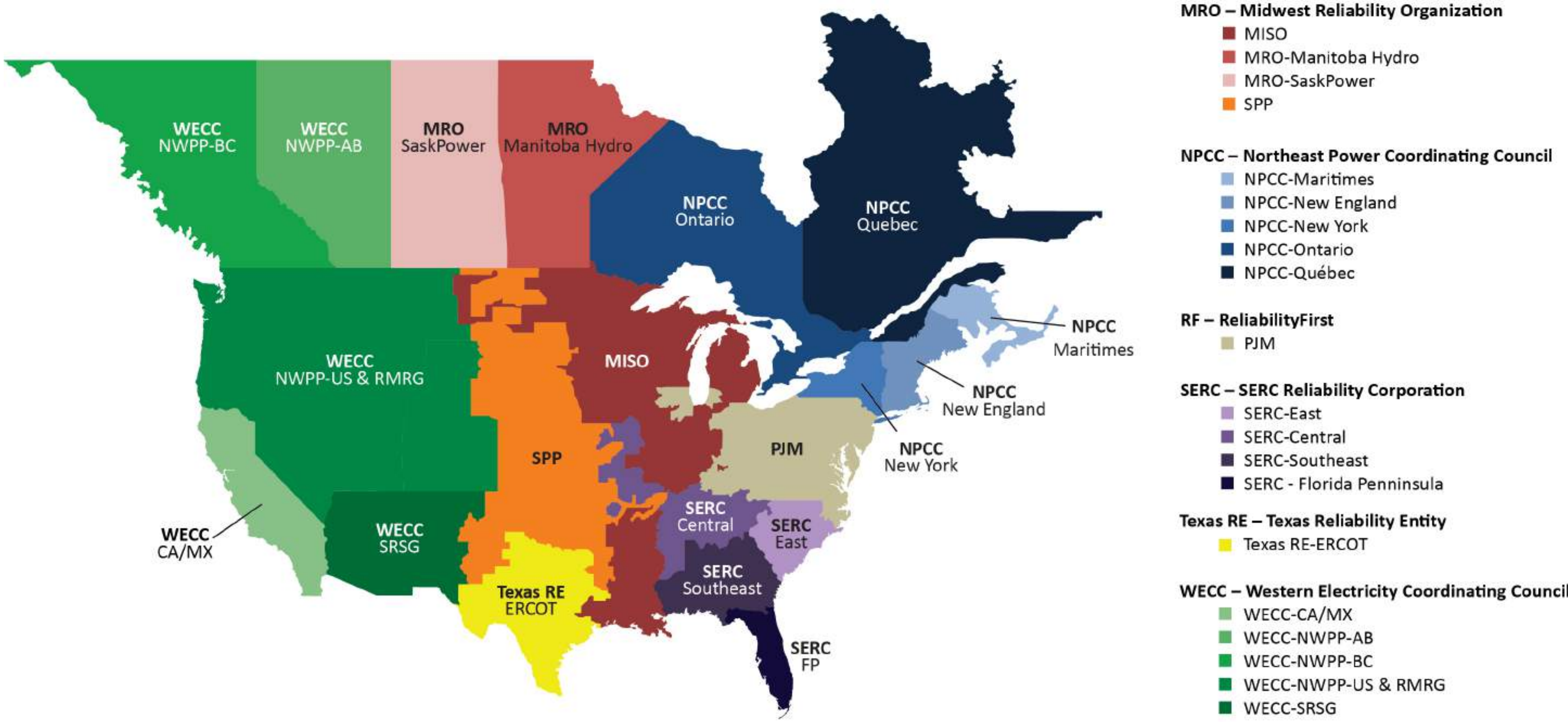
The following regional assessments were developed based on data and narrative information collected by NERC from the REs on an assessment area basis. The RAS, at the direction of NERC's RSTC, supported the development of this assessment through a comprehensive and transparent peer review process that leveraged the knowledge and experience of system planners, RAS members, NERC staff, and other subject matter experts. This peer review process promotes the accuracy and completeness of all data and information. A summary of the key data is provided in Table 12.

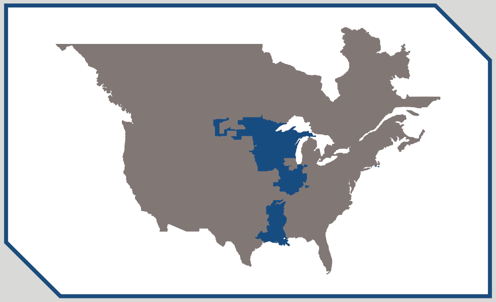
Table 12: Summary of 2025 Peak Projections by Assessment Area and Interconnection

Area	Net Internal Demand (MW)	Annual Net Energy for Load (GWh)	Net Transfers (MW)	Anticipated Capacity Resources	Anticipated Reserve Margin
MISO	121,303	743,628	1,840	141,976	17.0%
MRO-Manitoba	4,780	25,293	-614	5,423	13.5%
MRO-SaskPower	3,622	24,967	290	4,762	31.5%
NPCC-Maritimes	5,500	28,509	0	6,636	20.7%
NPCC-New England	24,065	124,678	14	30,061	19.0%
NPCC-New York	30,835	149,167	1,954	36,121	17.1%
NPCC-Ontario	23,238	137,836	0	23,703	2.0%
NPCC-Quebec	37,238	196,571	-145	42,263	13.5%
PJM	144,143	817,966	0	203,332	41.1%
SERC-C	40,202	219,331	-701	49,701	23.6%
SERC-E	45,686	221,114	605	58,206	27.4%
SERC-FP	47,961	242,993	498	58,594	22.2%
SERC-SE	45,894	253,032	-1,086	64,685	40.9%
SPP	54,399	297,456	183	67,118	23.4%
TRE-ERCOT	81,992	458,263	210	93,678	14.3%
WECC-AB	12,725	92,118	0	15,727	23.6%
WECC-BC	11,572	62,555	0	14,364	24.1%
WECC-CAMX	53,770	273,398	3,571	65,875	22.5%
WECC-NWPP US and RMRG	65,319	402,067	0	78,906	20.8%
WECC-SRSG	27,396	111,018	2,220	31,637	15.5%
EASTERN INTERCONNECTION	591,628	3,285,970	2,983	749,489	26.7%
QUEBEC INTERCONNECTION	37,238	196,571	-145	42,263	13.5%
TEXAS INTERCONNECTION	81,992	458,263	210	93,678	14.3%
WESTERN INTERCONNECTION	162,853	941,156	2,628	208,390	28.0%

NERC Assessment Areas

In order to conduct NERC reliability assessments, NERC further divides the REs into 20 assessment areas, shown below. This level of granularity allows NERC to better evaluate resource adequacy and ensure deliverability constraints between and among assessment areas are accounted for.

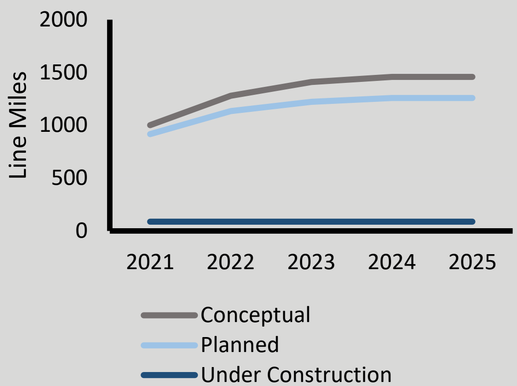




MISO

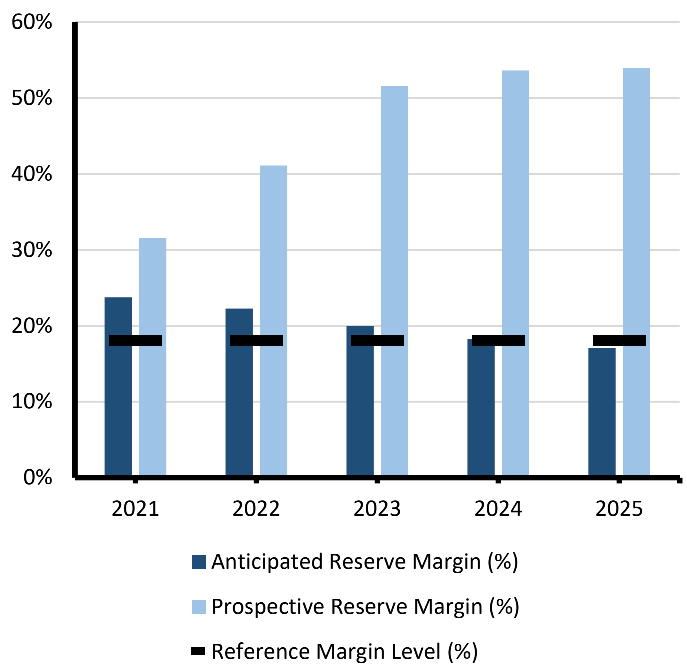
MISO is a not-for-profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency.

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

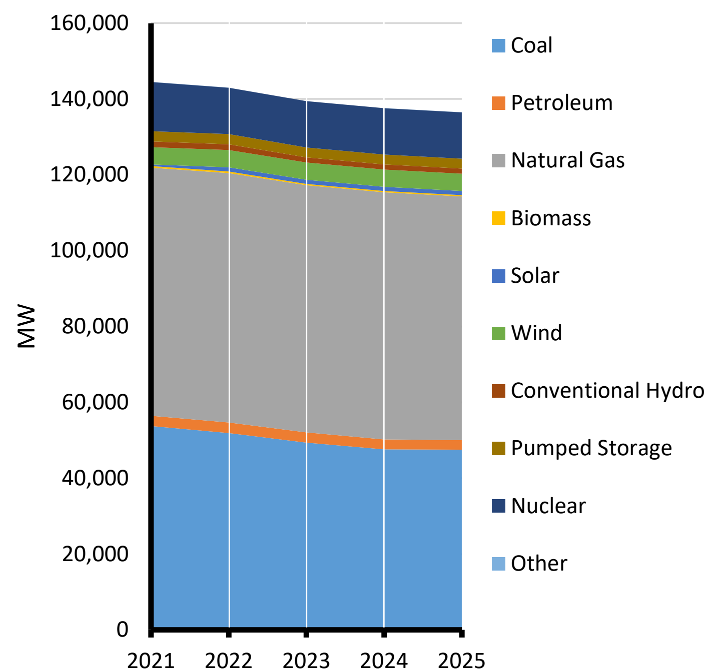


Projected Transmission Circuit Miles

Demand, Resources, and Reserve Margins (MW)										
Quantity	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Internal Demand	124,485	125,913	126,237	126,612	127,029	127,195	127,618	128,004	128,324	128,672
Demand Response	5,801	5,760	5,726	5,726	5,726	5,726	5,726	5,726	5,726	5,726
Net Internal Demand	118,684	120,152	120,511	120,886	121,303	121,469	121,892	122,277	122,598	122,946
Additions: Tier 1	2,964	4,634	4,634	4,634	4,634	4,634	4,634	4,634	4,634	4,634
Additions: Tier 2	3,214	16,615	32,360	36,993	38,993	38,993	38,993	38,993	38,993	38,993
Additions: Tier 3	1,456	3,524	5,279	6,495	8,592	8,666	9,947	10,419	11,477	11,477
Net Firm Capacity Transfers	2,545	2,550	2,555	2,560	1,840	1,840	1,745	1,750	1,755	1,755
Existing-Certain and Net Firm Transfers	143,913	142,265	139,905	138,360	137,342	136,238	136,032	135,093	133,904	134,280
Anticipated Reserve Margin (%)	23.8%	22.3%	19.9%	18.3%	17.0%	16.0%	15.4%	14.3%	13.0%	13.0%
Prospective Reserve Margin (%)	31.6%	41.1%	51.6%	53.7%	53.9%	52.7%	52.0%	50.7%	49.4%	49.2%
Reference Margin Level (%)	18.0%	18.0%	18.0%	18.0%	18.0%	18.0%	18.0%	18.0%	18.0%	18.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The MISO area will have adequate but tighter reserve margins for 2021, and continued action will be critical to ensure resource adequacy into the future. For 2021, MISO will have surplus resources to meet the regional resource requirement. In most of the MISO area, load-serving entities with oversight by the applicable state or local jurisdiction are responsible for resource adequacy. Though the 2021 peak demand forecast decreased 300 MWs from last year's survey, the five-year regional demand growth rate is up from 0.2% to just under 0.35% this year. On the supply side, the survey indicates that increasing resource adequacy risk can be avoided by firming up the commitments of additional potential resources.
- The potential for significant generation fleet transformation has prompted MISO to evaluate how system needs will change and how MISO might adapt its planning, markets, and operations to maintain reliability with aging and retiring units, higher penetration of intermittent resources, and new load consumption patterns.
- Resource adequacy planning that focuses on summer peak alone will no longer suffice. Resource adequacy analysis will likely need to reflect patterns across the year in order to capture the magnitude of risks.
- Effective dialogue amongst stakeholders will be key to this transformation; this will help identify needs and allow MISO to develop solutions that work across the footprint. MISO will leverage the forums where discussions are already underway on transmission planning, MISO's resource adequacy construct, and pricing enhancements.
- As the MISO fleet continues to evolve, ongoing comprehensive analysis is needed to detail risks; inform change in MISO's planning, markets, and operations processes; and iterate based on continued change in stakeholders' plans.

MISO Fuel Composition										
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal	53,771	51,948	49,401	47,595	47,516	46,296	46,362	45,362	43,866	43,866
Petroleum	2,737	2,737	2,652	2,652	2,507	2,507	2,507	2,507	2,507	2,507
Natural Gas	65,396	65,787	65,162	65,142	64,278	62,631	62,387	62,300	60,802	60,802
Biomass	438	420	397	372	372	372	300	300	297	297
Solar	385	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089
Wind	4,558	4,569	4,555	4,550	4,542	4,541	4,519	4,489	4,464	4,464
Conventional Hydro	1,539	1,539	1,333	1,333	1,331	1,331	1,331	1,331	1,331	1,331
Pumped Storage	2,686	2,686	2,654	2,654	2,654	2,654	2,654	2,654	2,654	2,654
Nuclear	12,982	12,169	12,169	12,169	12,169	12,169	12,169	12,169	12,169	12,169
Other	35	35	35	35	35	35	35	35	35	35
Total MW	144,527	142,978	139,446	137,591	136,492	133,624	133,352	132,235	129,213	129,213

MISO Assessment

PRM

MISO projects a regional surplus for the summer of 2021 and possibly 2022 and then falling near or below the RML in 2023–2024, sooner than the last LTRA. These results are driven by a number of factors: an increase in load forecast, an increase in reserve requirement due to changes in load shape and fleet make-up, and a decrease in load modifying resources. New resources effectively made up for retirements since 2019.

This *2020 LTRA's* results represent a point in time forecast, and MISO expects PRMs will change as future capacity plans are solidified by LSEs and states. There are enough resources in Tier 2 and 3 to mitigate any long-term resource shortfalls.

Demand

MISO does not forecast load for the seasonal resource assessments. Instead, LSEs report load projections under the Resource Adequacy Requirements section (Module E-1) of the MISO tariff. LSEs report their annual load projections on a MISO-coincident basis as well as their noncoincident load projections for the next 10 years, monthly for the first 2 years, and seasonally for the remaining 8 years. MISO LSEs have the best information of their load, so MISO relies on them for their 50/50 load forecast information.

The MISO coincident total internal demand peak forecast was 124,148 MW during the 2020 summer season, around an 850 MW decrease from last year's projection. MISO members project the summer coincident peak demand is expected to grow at an average annual rate of 0.34% over the next five-year period, up from 0.2% seen in last year's forecasts. Drivers for an increase in the annual growth rate are unknown but not surprising as 0.2% last year was very low and, compared with historical forecast growth rates, 0.34% is still very low. Electrification of transportation, heating, and other loads traditionally served by other sources are anticipated, so future growth is not unexpected. These projections were largely submitted to MISO before any observed or forecasted impacts due to COVID-19.

Demand Side Management

MISO currently separates demand response resources into two categories: Direct Control Load Management and Interruptible Load. Direct Control Load Management is the magnitude of customer service (usually residential). During times of peak conditions, or when MISO otherwise forecasts the potential for maximum generation conditions, MISO surveys local BAs to obtain the amount of their demand. For this assessment, MISO uses the registered amount of DSM that is procured and cleared through the annual planning resource auction.

MISO forecasts 7,557 MW of Direct Control Load Management and Interruptible Load to be available for the assessment period. MISO also forecasts at least 4,793 MW of BTM generation to be available for assessment period. This year's 2020 OMS-MISO survey responses indicate declining DR. The driver for this is unclear, but it may be due to respondents only entering current capacity contracts and not anticipated contract renewals.

Distributed Energy Resources

MISO has not experienced any operational challenges yet due to DERs and will continue to monitor as programs grow and visibility increases in the future. As of right now, the main method of collecting DER information is through an organization of MISO states DER survey that, to-date, has just tracked current installation levels, not future forecasts. This will be the third iteration that informs responses in the LTRA, and MISO will begin to get a better sense of future impacts to the system from DERs as this process matures or other efforts are undertaken to better assess DERs.

Generation

Though MISO does not have any authority to direct any member to construct new generation, MISO continuously seeks to improve the generator interconnection process, enabling more seamless resource integration and resource adequacy assessments; this ensures all utilities and state regulators with the authority to direct to build new generation are aware of the state of resource adequacy in MISO and its corresponding resource zones.

MISO allows units to participate in the MISO capacity auction only to the level of interconnection service they have. If a unit has transmission interconnection service less than their nameplate rating, that unit is only eligible for the level of transmission service in the capacity auction. If future projects increase the level of transmission service, that unit may then qualify for up to the rated uniformed capacity in the capacity market.

Capacity Transfers

Interregional planning is critical to maximize the overall value of the transmission system and deliver savings for customers. Interregional studies conducted jointly with MISO's neighboring planning areas are based on an annual review of transmission issues at the seams. Depending on the outcome of those reviews, studies are scoped out and performed.

MISO and SPP completed their second coordinated system plan study. The study identified one potential interregional project for further evaluation within each area whereby MISO's regional analyses determined there existed more cost-effective and efficient regional alternatives. MISO and SPP will be exploring process improvements to allow both RTOs to align more closely how each addresses future interregional system planning needs that stem from a dramatically changing future energy landscape expected to impact both RTOs.

Transmission

As a part of MISO's annual planning process, MISO performs extreme event analysis to evaluate system performance of a large variety of extreme events developed collaboratively by MISO and the Transmission Planners within the MISO footprint.

The following analyses are performed annually as part of the *MISO Transmission Expansion Plan* reliability assessment, and the results of these analyses are documented in *MISO Transmission Expansion Plan* report for future NERC compliance:[50]

- Steady State Analysis (including the simulation of documented remedial action schemes)
- Planning Horizon Transfer Analysis
- Transient Stability Analysis
- Voltage Stability Analysis

Together, these analyses address the impacts to transmission limitations, transmission constraints, dynamic and steady state reactive-power limited areas, and remedial action schemes.

50 MISO Transmission Expansion Plan information: https://www.misoenergy.org/planning/planning

Probabilistic Assessment Overview

- **General Overview:** MISO is a summer-peaking system that spans 15 states and consists of 36 Local BAs that are grouped into 10 local resource zones. For the ProbA, MISO utilized a multiarea modeling technique for the 10 local resource zones internal to MISO. Firm external imports as well as nonfirm imports are also modeled. This model and accompanying methodology has been thoroughly vetted through MISO's stakeholder process.
- **Modeling:** Each local resource zone was modeled with an import and export limit based on power flow transfer analysis. In addition to the zone-specific import and export limits, a regional directional limit was modeled, limiting the North/Central (LRZs 1–7) to South (LRZs 8–10) flow to 3,000 MWs and South to North/Central to 2,500 MWs. Specific modeling details include the following:
  - Annual peak demand in MISO varies by about ±5% of forecasted MISO demand based upon the 90/10% points of load forecast uncertainty (LFU) distributions.
  - Thermal units in MISO follow a two-state on-or-off sequence based on Monte-Carlo simulations, which utilize equivalent forced outage rate demand (EFORd). EFORd is, on average, equivalent to derating MISO thermal generating resources by ~9.36%.
  - Hydro units in MISO are modeled as resources with an EFORd except for run-of-river units. These are modeled at their individual capacity credit that is determined by the resource's historic performance during peak hours.
  - Variable energy resources (wind and solar) in MISO are load modifiers. Wind resources are modeled with varying monthly capacity values that were determined by a monthly effective load-carrying capability (ELCC) analysis. Solar resources are modeled at their individual capacity credit that is determined by the resource's historic performance during peak hours. The average capacity value is 16.6% for wind and assumed at 50% for solar initially and until enough solar exists on the system for a solar ELCC analysis to be performed.
- **Probabilistic vs. Deterministic Assessments:** The LTRA deterministic reserve margins decrement the capacity constrained within MISO south due to the 2,500 MW limit that reflects a decrease in reserve margin. The constraint was explicitly modeled for the probabilistic analysis to determine if sufficient capacity was available to transfer from south to north and vice versa. The modeling of this limitation results in a higher ProbA forecast PRM. The following describes differences and other details:
  - The ProbA utilized demand forecasts based on the average annual peak of 30 weather years developed as part of MISO's annual LOLE analysis. The 30 weather year load shapes are then scaled to match the LSE's monthly forecasted peaks. The LTRA relies on 50/50 out-year forecasts from LSE's.
  - The ProbA applies monthly ELCC values to wind resources where the LTRA counts wind at their annual capacity credit values.
  - DR is treated as a dispatchable call-limited resource in the ProbA. In the LTRA, NERC nets DR from the load.
  - The ProbA accounted for zonal transmission constraints whereas the LTRA only considers regional (north/south) constraints. The LTRA reduces the reserve margin according to capacity that is trapped behind constraints, but the ProbA does not. Instead, the constraints are modeled, and trapped capacity is probabilistically determined (this is reflected in the risk results).

Base Case Study

- The forecast operable reserve margin decreases slightly from 2022 to 2024. However, because of additional resources in import-constrained zones, the LOLH and EUE risk decreases.
- The magnitude of EUE decreased slightly from the 2018 ProbA, but EUE increased in PPM due to a reduced energy forecast. There was also a slight increase in LOLH. The increases in risk were driven by reduced import limits in some zones.

Probabilistic Base Case Results Outside of the On-Peak Hour

- Month of LOL occurrences and/or contributing factors:
  - Since MISO is a summer-peaking system, most of the LOLH occurs during the summer months (June–September) as expected. However, there are cases where LOLH occurs during off-peak periods.
- Time of day of occurrence(s) and/or contributing factors (e.g., morning, afternoon, evening, overnight):
  - LOLH typically happens in the morning during the winter and afternoon during the spring/fall. Winter LOLH is confined to MISO south where peak loads occur in the morning.
- Any reliability factors or reliability risk drivers that created additional LOL or resource adequacy risk at the nonpeak hours:
  - LOLH during nonpeak hours was the result of certain zones being import limited during shoulder seasons when seasonal planned outages are occurring or there is high seasonal load, as seen in MISO south during the winter.

Base Case Summary of Results			
Reserve Margin (RM) %			
	2022*	2022	2024
Anticipated	18.9%	21.6%	17.6%
Reference	17.1%	18.0%	18.0%
ProbA Forecast Operable	13.7%	17.9%	17.8%
Annual Probabilistic Indices			
	2022*	2022	2024
EUE (MWh)	31.6	27.3	14.3
EUE (ppm)	0.019	0.038	0.020
LOLH (hours/year)	0.108	0.196	0.085

*Represents the 2018 ProbA results for 2022.

Probabilistic Base Case results of EUE

- Month, magnitude, duration, time of day of occurrence(s) and/or contributing factors (e.g., morning, afternoon, evening, overnight):
  - EUE is observed in all months with the majority occurring in the summer during the afternoon peak hours. The average duration of EUE events is about two hours. EUE during the summer is driven primarily by high load and high forced outages.
- Any reliability factors or reliability risk drivers that created additional LOL or resource adequacy risk at the nonpeak hours:
  - There are cases where EUE occurs during nonpeak hours when high planned outages overlap with unseasonably high load. This is magnified in zones that are transmission constrained when the zone is unable to import enough energy to meet peak demand.

- Any proposed resource, system changes, or planning strategy that may help mitigate LOL or resource adequacy risks. These could be based on LTRA or ProbA Base Case results:
  - MISO's Resource Availability and Need initiative is analyzing off-peak risks and working with stakeholders on how to best address these issues. As a result of the Resource Availability and Need initiative, MISO has made changes to the annual LOLE study to better reflect unit availability, including modeling planned outages more realistically and modeling wind with monthly variation. Future improvements that are being considered include changes to resource accreditation, sub-annual resource adequacy requirements, and modeling hourly wind profiles in LOLE studies.

Key methods and assumption differences between this *2020 LTRA* and ProbA assessments

The ProbA analyzes all hours of the year while 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 nonpeak periods, and the LTRA highlights longer-term resource adequacy planning concerns.

Probabilistic resource adequacy studies conducted that address area reliability risk drivers

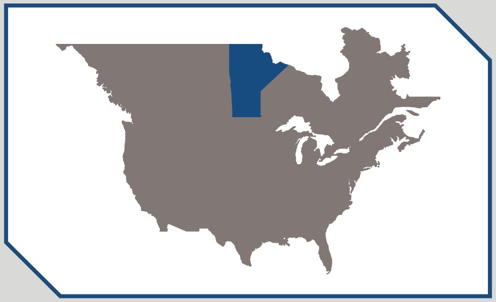
MISO conducts a LOLE analysis on an annual basis that sets the PRM and local reliability requirements for market participants. The requirements serve as inputs to MISO's annual planning resource auction, where resources are cleared in the auction up to the requirements in order to maintain an LOLE of one day-per-year. The LOLE study[51] is similar to the ProbA in that both are probabilistic Monte-Carlo simulations that analyze the entire year. However, the LOLE study does not explicitly model transmission constraints. Instead, the local resource zones (LRZs) are analyzed as though they are isolated from the rest of the system to determine local requirements while the MISO system is modeled as a "copper sheet" to determine the PRM.

51 https://www.misoenergy.org/planning/resource-adequacy/#nt=%2Fplanningdoctype%3APRA%20Document&t=10&p=0&s=&sd=

Regional Risk Scenario

For the 2020 ProbaA risk scenario sensitivity, MISO chose to investigate how the risk changes as a result of increasing DR. Over the last several years, DR in MISO has steadily increased and has made up a larger percentage of reserves. However, these resources are limited in the number of times they can be deployed each year, increasing risk as their calls are depleted. Currently in MISO, DR is required to be available at a minimum of five calls per year and four hours per call.

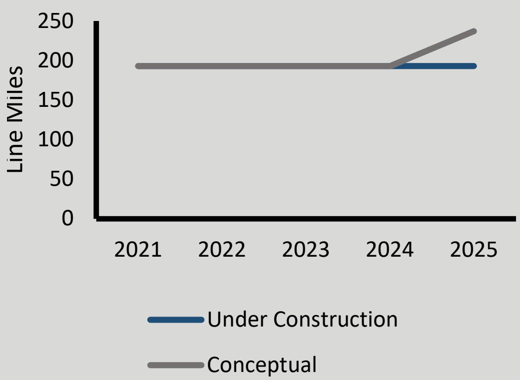
For this analysis, MISO will increase DR as a percentage of the overall resource mix in increments of 1,000 MW. This will be done by adding 100 MW DR resources to each of the 10 LRZ's as well as a 100 MW negative unit, which is equivalent to adding 100 MW of peak demand. Adding a negative unit (instead of removing units when DR is added) allows MISO to isolate the effect that increasing DR has on reliability since removing units would have its own effect on reliability depending on which units were removed. This analysis will be performed on year four. Since that year is starting from a lower LOLH value, it should be easier to see any risk that is introduced as a result of increasing DR.



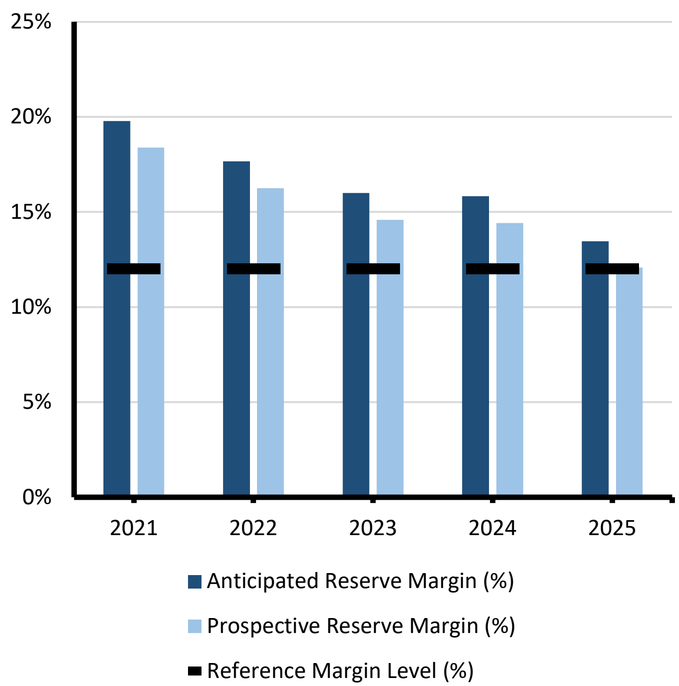
MRO-Manitoba Hydro

Manitoba Hydro is a provincial crown corporation that provides electricity to approximately 587,000 electricity customers in Manitoba and approximately 285,000 natural gas customers in southern Manitoba. The service area is the province of Manitoba, which is 250,946 square miles. Manitoba Hydro is winter peaking. No change in the footprint area is expected during the assessment period. Manitoba Hydro is its own PC and BA. Manitoba Hydro is a coordinating member of the MISO. MISO is the RC for Manitoba Hydro.

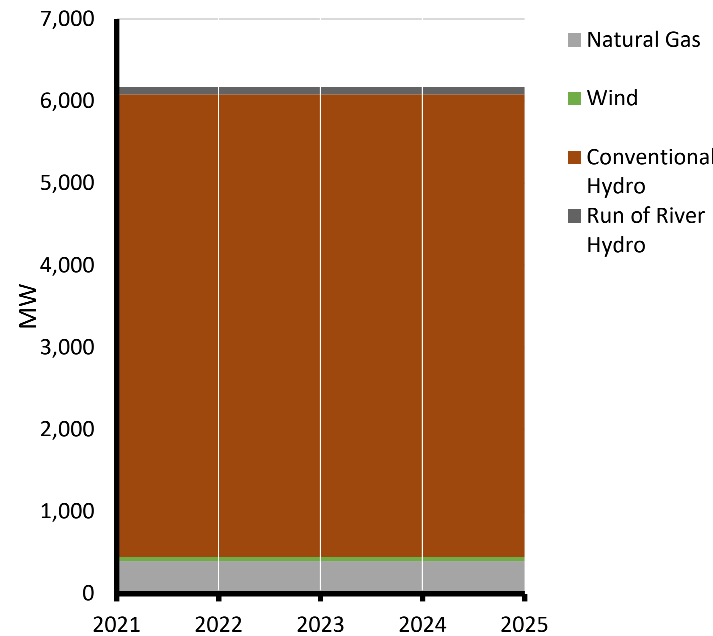
Demand, Resources, and Reserve Margins (MW)										
Quantity	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Internal Demand	4,667	4,607	4,625	4,627	4,780	4,783	4,776	4,772	4,779	4,778
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	4,667	4,607	4,625	4,627	4,780	4,783	4,776	4,772	4,779	4,778
Additions: Tier 1	630	630	630	630	630	630	630	630	630	630
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	-447	-617	-673	-678	-614	-614	-519	-442	-447	-540
Existing-Certain and Net Firm Transfers	4,961	4,790	4,734	4,729	4,793	4,772	4,867	4,944	4,931	4,838
Anticipated Reserve Margin (%)	19.8%	17.7%	16.0%	15.8%	13.5%	12.9%	15.1%	16.8%	16.4%	14.4%
Prospective Reserve Margin (%)	18.4%	16.2%	14.6%	14.4%	12.1%	11.6%	13.7%	15.4%	15.0%	13.0%
Reference Margin Level (%)	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%



Projected Transmission Circuit Miles



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM does not fall below the RML of 12% in any year during the assessment period. This ARM analysis assumes that the first two units from the Keeyask hydro station will come into service for the winter of 2020–2021. The Keeyask hydro station has been under construction for several years, and the major concrete work for the powerhouse is now complete. The completion of all seven units at the Keeyask hydro station is anticipated in 2021 and will help ensure resource adequacy in the current assessment period. When complete, the Keeyask hydro station will be a 630 MW net addition to Manitoba Hydro's system. No Tier 2 resources have been assumed to come into service during the assessment period. No resource adequacy issues are anticipated.
- Following the first units of Keeyask being placed into service, Manitoba Hydro anticipates the retirement of the 118 MW winter rating Selkirk natural gas generating station; it is considered an unconfirmed retirement for Winter 2020–2021. The Selkirk station retirement decision is based on a combination of a desire to reduce carbon emissions, high operating costs, increased transmission reliability with Bipole III, additional supply being available from the Keeyask hydro station, and additional import capability with the Manitoba to Minnesota Transmission Project (MMTP). No resource adequacy issues are anticipated as the ARM remains above the 12% reference margin.
- The completion of the MMTP, the new 500 kV interconnection that was placed into service on June 1, 2020, will provide for alternative supply from the MISO market during drought conditions and improve the resilience of Manitoba Hydro's system to extreme events, including drought.
- Manitoba is not experiencing large additions of wind and solar resources being seen in other areas, so emerging reliability issues from large wind and solar resource additions are not anticipated.

Manitoba Hydro Fuel Composition

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Natural Gas	396	396	396	396	396	396	396	396	396	396
Wind	52	52	52	52	52	31	31	31	31	31
Conventional Hydro	5,635	5,635	5,635	5,635	5,635	5,635	5,635	5,635	5,626	5,626
Run of River Hydro	90	90	90	90	90	90	90	90	90	90
Total MW	6,172	6,172	6,172	6,172	6,172	6,151	6,151	6,151	6,143	6,143

MRO-Manitoba Hydro Assessment

Planning Reserve Margins

The ARM does not fall below the RML of 12% in any year during the assessment period. The RML is based on both system historical adequacy performance analysis and reference to probabilistic resource adequacy studies by using the index of LOLE and loss of energy expectation.

Demand

Manitoba Hydro's load peaks in the winter, typically in the months of January, February, or December. The primary driver of energy load growth in Manitoba is population (1.2% anticipated population growth) with the secondary driver being the economy. Manitoba Hydro's system energy/energy forecasting methodology is primarily based on three market segments: Residential, General Service Mass Market, and Top Consumers (Manitoba Hydro's largest industrial customers) with a small amount remaining for the miscellaneous groups that consist of street lighting and seasonal customers. Manitoba Hydro uses econometric regression modeling by sector to determine projected energy usage.

Demand Side Management

Manitoba Hydro does not have any DSM resources that are considered controllable and dispatchable DR. EE and conservation programming were transitioned from Manitoba Hydro to a new crown corporation, Efficiency Manitoba, effective April 1, 2020. Efficiency Manitoba has a mandate to develop and support EE initiatives, reducing provincial consumption of energy by 1.5% annually. All of Efficiency Manitoba's DSM program evaluation efforts, including measurement and verification activities, will be undertaken by an independent third-party evaluator that will be contracted by Efficiency Manitoba. EE and conservation programming reduces overall demand in the assessment area, and the impact of the reductions is applied to the electricity load forecast.

Distributed Energy Resources

There are approximately 35 MW dc of solar DERs in Manitoba as of the end of March 2020. Most of the solar distributed resources were installed in the last three years under an incentive program that has ended. Even with high growth rates, Manitoba Hydro is not anticipating that the quantity of solar DERs in Manitoba would increase to a level that would cause potential operation impacts in the next five years.

Generation

The Keeyask hydro station has been under construction for several years, and the major concrete work for the powerhouse is now complete. The completion of all seven units at the Keeyask hydro station is anticipated in 2021 and will help ensure resource adequacy in the current assessment period. When complete, the Keeyask hydro station is a 630 MW net addition to Manitoba Hydro's system. The additional hydro generation will support a related 250 MW capacity transfer into the MISO area and a new 100 MW capacity transfer to SaskPower, both beginning in 2020.

The status of the 118 MW winter rating Selkirk natural gas generating station has been changed to an unconfirmed retirement for Winter 2020–2021. Manitoba Hydro is now considering this retirement once one or more units of the 630 MW net addition Keeyask hydro station come into service. This decision is based on a combination of a desire to reduce carbon emissions, high operating costs, increased transmission reliability with Bipole III, additional supply being available from the Keeyask hydro station, and additional import capability with the MMTP.

Capacity Transfers

The Manitoba Hydro system is winter peaking and is interconnected to the MISO Zone 1 local resource zone, which includes Minnesota and North Dakota; as a whole, the system is summer peaking. Significant capacity transfer limitations from MISO into Manitoba may have the potential to cause reliability impacts but only if the following conditions simultaneously occur: extreme Manitoba winter loads, unusually high forced generation/transmission outages, and a simultaneous emergency in the northern MISO footprint. Additional hydro generation from Keeyask and the related 250 MW capacity transfer into the MISO area will tend to increase north-to-south flows on the Manitoba-MISO interface. A 100 MW capacity transfer from Manitoba to Saskatchewan commencing in June 2020 will tend to increase east-to-west flow on the Manitoba–Saskatchewan interface. A capacity transfer of 190 MW from Manitoba to Saskatchewan beginning in 2022 will also tend to increase east-to-west flow on the Manitoba-Saskatchewan interface; this transfer will occur following the in-service of the 230 kV Birtle to Tantallon line, which is rated at 390 MVA.

All reported capacity transfers were coordinated, reviewed, and vetted by neighboring assessment areas.

Transmission

There are several transmission projects projected to come on-line during the assessment period. Most of the projects are dictated by the need to expand the transmission system to reliably serve growing loads, transmit power to the export market, improve safety, improve import capability, increase efficiency, and connect new generation. For example, the Manitoba to Minnesota Transmission Project, a new 500 kV interconnection from Dorsey to Iron Range (Duluth to Minnesota) came into service in 2020; it will provide transmission services and will improve system reliability. The addition of the new 500 kV line also reduces the total Interconnection losses. The addition of a new 230 kV line from Birtle to Tantallon line will come into service in 2021, which will provide improved transmission service capability between Manitoba and Saskatchewan. Above average load growth in Manitoba has the triggered the need for a 230 kV line between St. Vital and DeSalaberry (in service October 2020) and between DeSalaberry and Letellier (in service October 2022).

Probabilistic Assessment Overview

- **General Overview:** The 2020 Manitoba Hydro ProbA was conducted using the Multi-Area Reliability Simulation (MARS) program. The most significant model improvement for 2020 ProbA is that Manitoba Hydro modeled seven different load shapes by using actual historical data to capture the uncertainties associated with load profiles and peak load forecast. Substantial infrastructure additions are modelled in both the 2022 and 2024 Base Cases. These additions include Keeyask Generating Station (630 MW net addition), a new 500 kV tie line between Manitoba and Minnesota, and a new 230 kV tie line between Manitoba and Saskatchewan.
- **Modeling:** Manitoba Hydro and its neighboring systems are modeled as three areas that consist of Manitoba, Saskatchewan, and the northwest part of MISO. Each of the three interconnected areas is modeled as a copper sheet, and the transmission between areas is modeled with interface transfer limits. Specific modeling details include the following:
  - A hybrid method is used to model uncertainties in both peak load forecast and load profile changes. In this method, uncertainties associated with load are captured through 8,760-point hourly load shape of seven representative years and an additional ±3% of variations in each of the seven peak values by using a seven-step normal distribution.
  - A small amount of thermal units represent less than 10% of the total installed capacity in Manitoba. These thermal units follow a two-state on-or-off sequence based on Monte-Carlo simulation.
  - Manitoba Hydro system is a winter-peaking system and the vast majority of its generating facilities are use-limited or energy-limited hydro units. All hydro plants are modeled as energy limited based on the historical flow conditions of the river systems.
  - Wind resources in Manitoba are modeled as deterministic load modifiers considering the seasonal variations, which is approximately equivalent to 16% and 20% of the maximum wind generation capacity respectively for summer and winter seasons.
- **Probabilistic vs. Deterministic Assessments:** Manitoba Hydro is a winter-peaking system, and the ARM for 2022 and 2024 is taken from the LTRA 2022 and 2024 values respectively. Details include the following:
  - EE and conservation programs are modeled as a simple load modifier by reducing the peak load.
  - Contractual commitments are modeled as load modifiers that consider the hourly schedules of contractual obligations.
  - The external systems were modeled in the same detail as the Manitoba system rather than a simple equivalent model. It is assumed that potential assistances from external systems are based on their ARMs for 2022 and 2024 planning years.

Base Case Study

The Base Case LOLH values calculated in this assessment for the reporting year of 2022 and 2024 are virtually zero. Non-zero EUE values are obtained but are small. These results are mainly due to the larger forecast reserve margin, and the increase in the transfer capability between Manitoba and the United States is due to the addition of the new 500 kV tie line between Manitoba and Minnesota.

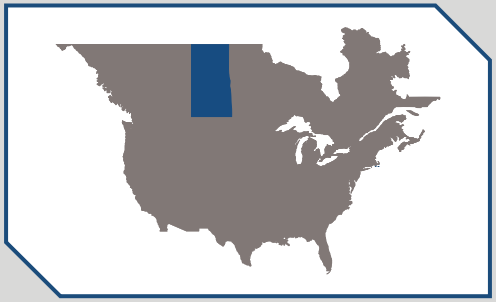
Water flow conditions of the tenth percentile or lower tend to increase the LOL probability. As a small winter-peaking system on the northern edge of a summer peaking system, assistance is generally available, particularly in off-peak hours, to provide energy to supplement hydro generation in low-flow conditions in winter. Management of energy in reservoir storage in accordance with good utility practice provides risk mitigation under low water flow conditions.

Regional Risk Scenario

There are a number of influencing factors associated with Manitoba Hydro's resource adequacy performance, such as the water resource conditions, energy and capacity exchanges with neighboring jurisdictions, forecast load level, uncertainties in load forecast and load variation profiles, DRs, wind penetration, and generation fleet availability. In the 2020 ProbA scenario analysis, Manitoba Hydro will examine the impact of the most significant factor over the long run, variations in water conditions. This will be accomplished by modeling a tenth-percentile low water conditions scenario and comparing it with the base case.

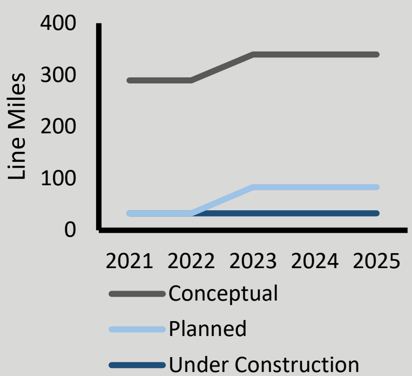
Base Case Summary of Results			
Reserve Margin (RM) %			
	2022*	**2022**	**2024**
Anticipated	N/A	16.6%	16.0%
Reference	N/A	12%	12%
ProbA Forecast Operable	N/A	20%	20%
Annual Probabilistic Indices			
	2022*	**2022**	**2024**
EUE (MWh)	0.00	2.7077	3.3831
EUE (ppm)	0.00	0.017	0.133
LOLH (hours/year)	0.00	0.0033	0.0039

*Represents the 2018 ProbA results for 2022.



MRO-SaskPower

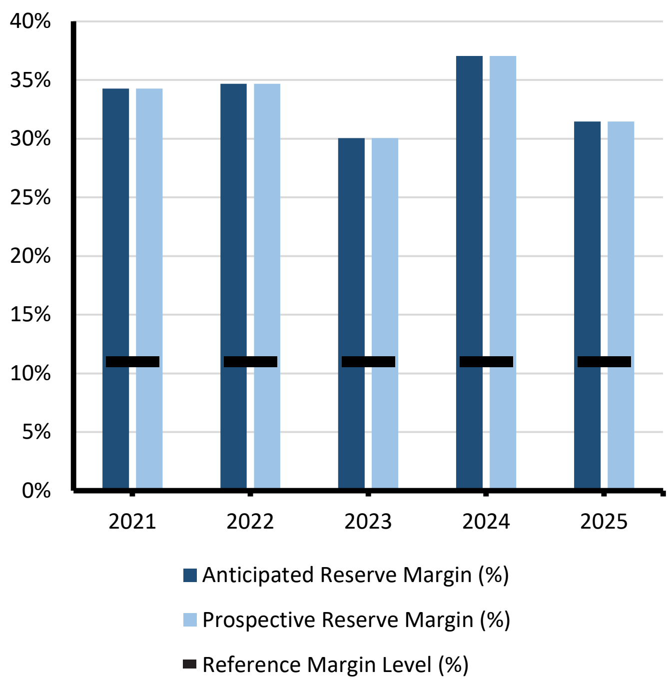
Saskatchewan is a province of Canada and comprises a geographic area of 651,900 square kilometers and approximately 1.12 million people. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the Planning Authority and RC for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial Crown corporation and under provincial legislation is responsible for the reliability oversight of the Saskatchewan BES and its interconnections.



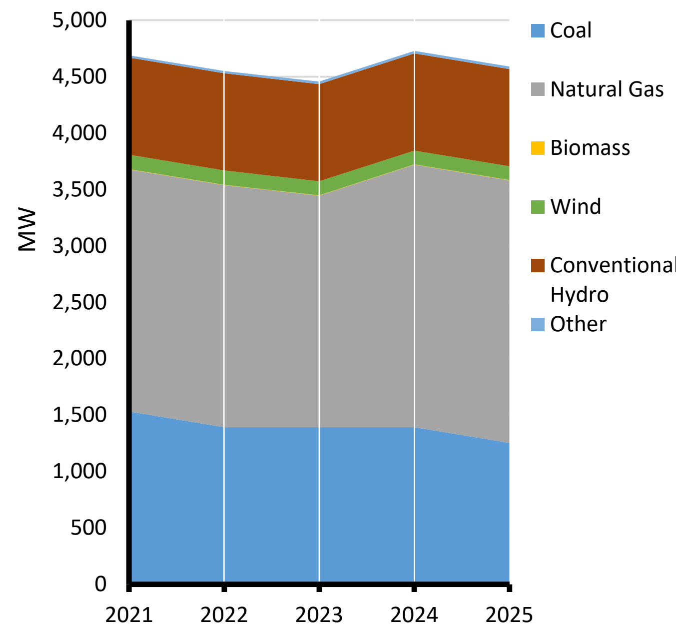
Projected Transmission Circuit Miles

Demand, Resources, and Reserve Margins (MW)

Quantity	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Internal Demand	3,576	3,597	3,631	3,648	3,682	3,704	3,686	3,689	3,707	3,728
Demand Response	60	60	60	60	60	60	60	60	60	60
Net Internal Demand	3,516	3,537	3,571	3,588	3,622	3,644	3,626	3,629	3,647	3,668
Additions: Tier 1	77	77	77	430	430	430	430	430	430	430
Additions: Tier 2	0	0	0	0	0	0	349	1,047	1,047	1,047
Additions: Tier 3	0	0	0	40	40	40	40	40	80	80
Net Firm Capacity Transfers	125	290	290	290	290	290	290	290	290	290
Existing-Certain and Net Firm Transfers	4,644	4,687	4,568	4,488	4,332	4,410	4,343	4,325	4,325	4,373
Anticipated Reserve Margin (%)	34.3%	34.7%	30.0%	37.0%	31.5%	32.8%	31.6%	31.0%	30.4%	30.9%
Prospective Reserve Margin (%)	34.3%	34.7%	30.0%	37.0%	31.5%	32.8%	41.2%	47.8%	36.6%	20.8%
Reference Margin Level (%)	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM is above the RML (11%) throughout the assessment period.
- SaskPower has added a new 350 MW natural gas facility in December 2019 and is planning to add approximately 750 MW of generation under Tier 1 category within the next five years.
- A new 230 kV tie line between Manitoba and Saskatchewan is expected to be in service in Summer 2021 to facilitate 100 MW long term capacity transfer.

SaskPower Fuel Composition										
Generation Type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal	1,531	1,392	1,392	1,392	1,253	1,253	1,253	1,253	1,253	1,253
Natural Gas	2,148	2,148	2,053	2,328	2,328	2,288	2,288	2,288	2,288	2,288
Biomass	3	3	3	3	3	3	3	3	3	3
Wind	126	126	126	124	124	124	124	122	122	122
Geothermal	0	0	0	0	0	0	0	0	0	0
Conventional Hydro	862	862	862	862	862	862	862	862	862	862
Other	22	22	22	22	22	22	17	1	1	1
Total MW	4,690	4,551	4,456	4,729	4,590	4,550	4,545	4,527	4,527	4,527

MRO-SaskPower Assessment

SaskPower uses a criterion of 11% as the reference reserve rargin and has assessed its PRM for the upcoming 10 years while 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 26–44% and does not fall below the RML.

SaskPower'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 0.5% with a range from -0.4% to 1.1% throughout the assessment period.

Saskatchewan is adding approximately 750 MW of generation under the Tier 1 category within the next five years, including two utility-scale wind generation facilities of combined 375 MW installed capacity and a 350 MW natural gas facility. Saskatchewan is adding firm capacity transfers from Manitoba with 100 MW in 2020 that includes 10 MW of seasonal firm capacity until the new tie line is in service. Saskatchewan is also adding 190 MW of firm capacity transfer, starting in 2022 and combining a total of 290 MW for the assessment period. Under Tier 2, over 1,000 MWs of new generation is projected in the assessment period, mostly in the 5–10-year horizon. This includes two utility-scale wind generation facilities and three natural gas facilities. A total of approximately 559 MW is confirmed for retirements. This includes 278 MW of coal generation, 213 MW of natural gas, 21 MW of heat recovery facility, 22 MW of wind facilities and 25 MW of hydro import contract. Unconfirmed retirements of over 1,400 MW are also expected in the assessment period. This includes approximately 1,200 MW of conventional coal generation that could 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 SaskPower is not expecting any long-term reliability impacts due to generation retirements.

SaskPower's EE and energy conservation programs include incentive-based and education programs focusing on installed measures and products that provide verifiable, measurable and permanent reductions in electrical energy, and demand reductions 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. A steady growth is expected on EE and conservation over the assessment period. SaskPower'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 60 MW with a 12-minute event response time. Other programs are in place, providing access to additional curtailable load requiring up to two hours notification time.

SaskPower has recently completed construction of the three major transmission lines with a total of approximately 270 km of 230 kV and 200 km of 138 kV transmission lines. A new 230 kV tie line with Manitoba is expected to be in service in early 2021 to enable new capacity transfers between the two areas. Approximately 20 km of 230 kV transmission line is under construction to interconnect a new wind generation facility. Approximately 80 km of 230 kV transmission line are in the planning phase, and several other transmission projects (approximately 400 circuit km) are in the conceptual phase in the 5–10-year planning horizon. These projects are driven by load growth, new generation additions, and reliability needs.

SaskPower Probabilistic Assessment Overview

- **General Overview:** Based on the deterministic calculations within this assessment, Saskatchewan's ARM is 34.2% and 30.0% for years 2022 and 2024, respectively. EUE calculated for Base Case is 80.4 MWh and 26.4 MWh for the years 2022 and 2024, respectively. LOLH follows a similar pattern to EUE.
- **Modeling:** SaskPower utilizes the MARS program for reliability planning and case runs. The software performs the Monte-Carlo simulation by stepping through the time chronologically and calculates the standard reliability indices of daily and hourly LOLE and EUE. Detailed representation of the utility system, such as load forecast, expansion sequence, unit characteristics, maintenance and outages, is included in the model. The model simultaneously considers many types of randomly occurring events, such as generating unit forced outages. The program also calculates the need for initiating emergency operating procedures (EOPs).
- This reliability study is based on the 50/50 load forecast that includes data such as annual peak, annual target energy, and load profiles. The model distributes the annual energy into hourly data based on the load shape. Saskatchewan develops energy and peak demand forecasts based on provincial econometric model, forecasted industrial load data, and weather normalization model. The forecasts also take into consideration of the Saskatchewan economic forecast, historic energy sales, customer forecasts, weather normalized sales, and system losses.
- Generating unit forced outage and partial outages are modeled in MARS by inputting a multi-state outage model that represents an Equivalent Forced Outage Rate (EFOR) for each unit represented MARS models capacity unavailability by considering the average and partial outages for each generating unit that has occurred over the most recent five-year period. Forced outages are modeled as two- or three-state models. Natural gas units are typically modeled as a two-state unit so that natural gas unit is either available to be dispatched up-to full load or is on a full forced outage with zero generation. Coal facilities are typically modeled as a three-state unit. Coal unit can be at a full load, a derated forced outage, or a full forced outage state.
- For reliability planning purposes, Saskatchewan plans for 10% of wind nameplate capacity to be available to meet summer peak and 20% of wind nameplate capacity to be available to meet winter peak demand.
- Hydro generation is modeled as energy limited resource and utilized based on deterministic scheduling on a monthly basis. Hydro units are described by specifying maximum rating, minimum rating, and monthly available energy. The first step is to dispatch the minimum rating for all the hours in the month. Remaining capacity and energy is then scheduled so as to reduce the peak loads as much as possible.
- DSM is deducted from the load forecast (both the peak load and energy forecasts). DR is modelled as an emergency operating procedure by assigning a fixed capacity value.
- **Probabilistic vs. Deterministic Assessments** Reserve margin results for ProbA is consistent with the deterministic assessment.

Base Case Study

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

The major contribution to the LOLH and EUE is in the spring and fall months due to maintenances scheduled for some of the largest units. Most of the maintenance is scheduled during off-peak periods and can be rescheduled to mitigate short-term reliability issues.

Results trending: Since the 2018 ProbA, the reported forecast reserve margin for 2022 has increased from 17.1% to 34.2%. This is mainly due to reductions in load forecast.

Probabilistic Base Case results outside of the on-peak hour

Saskatchewan doesn't anticipate resource adequacy issues during its off-peak hours. Currently, Saskatchewan doesn't have a considerable penetration level of intermittent energy resources in its resource mix. There are studies ongoing to supplement the addition of future variable resources through fast ramping capacity available from other resources.

Saskatchewan has done probabilistic analysis to look at the high loss-of-load contribution during the off-peak months that is mainly due to scheduled maintenance for the thermal units. When these short-term reliability issues are identified, they can be mitigated by rescheduling the maintenance.

Additionally, hydro units are modeled as deterministic load modifiers that are scheduled so as to reduce the peak loads as much as possible.

Probabilistic Base Case results of EUE

EUE is generally very low in the probabilistic Base Case. The major contribution to the EUE is in the spring and fall shoulder months due to maintenances scheduled for some of the largest units. The contribution to EUE in these months occurs mainly in peak hours. Most of the maintenance is scheduled during off-peak periods and can be rescheduled to mitigate short-term reliability issues.

Key methods and assumption differences between the 2020 LTRA and ProbA Assessments.

Methods and assumptions used in the ProbA assessment are consistent with those used in the LTRA.

Base Case Summary of Results			
Reserve Margin (RM) %			
	2022*	**2022**	**2024**
Anticipated	17.1%	34.2%	30.0%
Reference	11.0%	11.0%	11.0%
ProbA Forecast Operable	11.7%	27.3%	22.8%
Annual Probabilistic Indices			
	2022*	**2022**	**2024**
EUE (MWh)	4,494.9	80.4	26.4
EUE (ppm)	167	3.34	1.07
LOLH (hours/year)	39.02	0.96	0.28

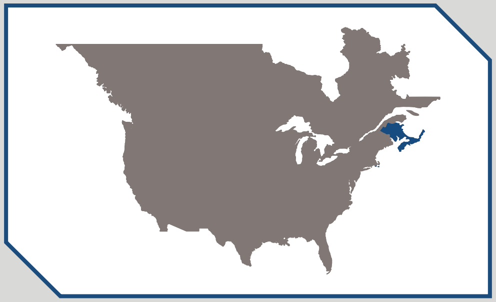
*Represents the 2018 ProbA results for 2022.

Probabilistic resource adequacy studies conducted that address area reliability risk drivers.

The main probabilistic resource adequacy study conducted is the ProbA assessment. Additionally, probabilistic studies were conducted to investigate the impact of changing generating unit maintenance schedules on EUE. The studies concluded that there was minimal effect on reliability even though there were economic impacts to changing the maintenance schedules.

Regional Risk Scenario

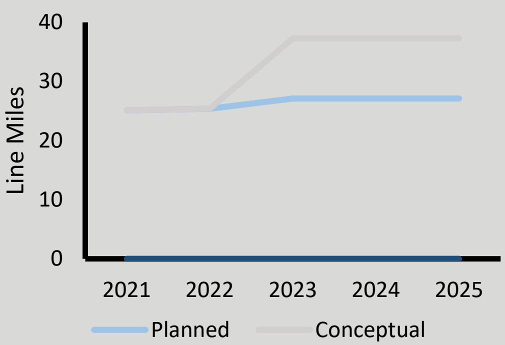
The 2020 ProbA Regional Risk Scenario selected was low hydro conditions. This scenario was selected because Saskatchewan has not experienced significantly low hydro conditions for approximately 20 years.



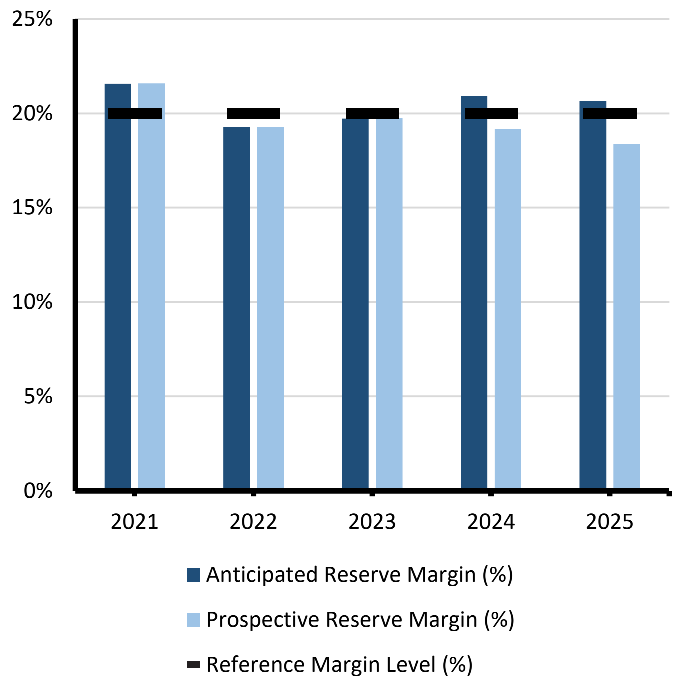
NPCC-Maritimes

The Maritimes assessment area is winter-peaking and part of NPCC with a single RC and two BA areas. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, Prince Edward Island, and the northern portion of Maine, which is radially connected to NB. The area covers 58,000 square miles with a total population of 1.9 million.

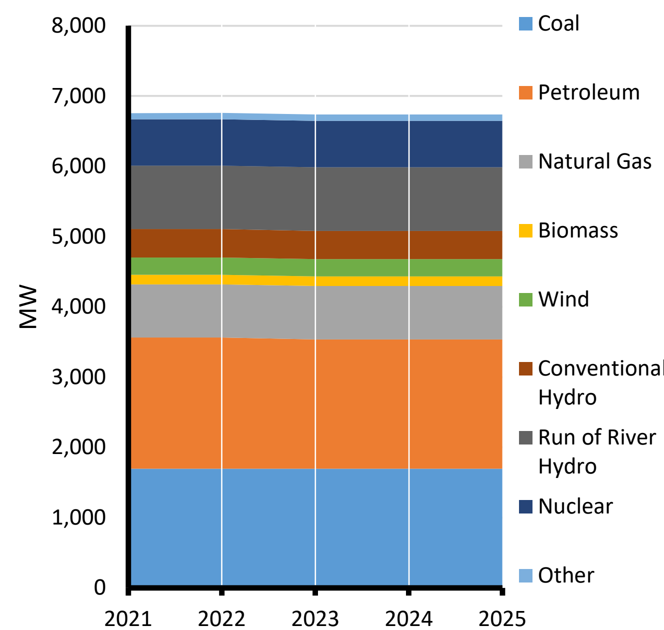
Demand, Resources, and Reserve Margins (MW)										
Quantity	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Internal Demand	5,688	5,727	5,756	5,761	5,773	5,781	5,790	5,799	5,805	5,816
Demand Response	266	268	273	273	272	272	272	272	271	271
Net Internal Demand	5,422	5,459	5,483	5,488	5,500	5,509	5,518	5,527	5,534	5,545
Additions: Tier 1	19	22	22	22	22	22	22	22	20	20
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	5	5	5	5	5	5	5	5	5	5
Net Firm Capacity Transfers	-66	-149	-72	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	6,572	6,489	6,543	6,615	6,615	6,615	6,505	6,505	6,505	6,505
Anticipated Reserve Margin (%)	21.6%	19.3%	19.7%	20.9%	20.7%	20.5%	18.3%	18.1%	17.9%	17.7%
Prospective Reserve Margin (%)	21.6%	19.3%	19.7%	19.2%	18.4%	12.9%	10.8%	10.6%	10.4%	10.2%
Reference Margin Level (%)	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%



Projected Transmission Circuit Miles



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- There is a forecast of 0.2% compound annual growth rate in demand over the duration of the LTRA analysis period and after offsets by load reductions from DSM.
- The Maritimes Link, an undersea high voltage direct current undersea cable connection to the Canadian province of Newfoundland and Labrador, began service in late 2017. This will allow for the 2021 retirement of a 150 MW coal-fired generator with an equivalent amount of firm hydro capacity imported through the cable so that the overall resource adequacy is unaffected.

Maritimes Fuel Composition										
Generation Type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal	1,695	1,695	1,695	1,695	1,695	1,695	1,695	1,695	1,695	1,695
Petroleum	1,867	1,867	1,843	1,843	1,843	1,843	1,843	1,843	1,841	1,841
Natural Gas	760	760	760	760	760	760	760	760	760	760
Biomass	134	134	134	134	134	134	134	134	134	134
Wind	246	246	246	246	246	246	246	246	246	246
Conventional Hydro	404	404	404	404	404	404	404	404	404	404
Run of River Hydro	902	904	904	904	904	904	794	794	794	794
Nuclear	660	660	660	660	660	660	660	660	660	660
Other	90	90	90	90	90	90	90	90	90	90
Total MW	6,757	6,760	6,736	6,736	6,736	6,736	6,626	6,626	6,624	6,624

NPCC-Maritimes Assessment

Planning Reserve Margins

The reference reserve margin level used for the Maritimes area is 20%. The ARM ranges from 19.3–21.6% during the first six years of the LTRA and 17.7–18.3% during the last four years of the LTRA. Renewal of supply contracts, deferral of uncertain retirements, new natural gas supply contracts, energy contracts from neighboring jurisdictions, and opportunities to buy in day ahead and real time markets will be available for use in meeting the reference reserve margin level.

Demand

There is no regulatory requirement for a single authority to produce a forecast for the whole Maritimes area. 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 that are historically highly coincidental (typically between 97% and 99%). Demand for the Maritimes area is determined to be the non-coincident sum of the peak loads forecasted by the individual sub-areas. The aggregated growth rates of both demand and energy for the combined sub-areas see an upward trend over summer and winter seasonal periods of this LTRA assessment period. Maritimes area peak loads are expected to increase by 7.5% during summer and by 1.8% during winter seasons over the 10-year assessment period. This translates to compound average growth rates of 0.7% in summer and 0.2% in winter. The Maritimes area annual energy forecasts are expected to increase by a total of 3.4% during the 10-year assessment period for an average growth of 0.3% per year. Rural to metropolitan population migration and the introduction of split-phase heat pump technology to areas traditionally heated by fossil fuels has created load growth in Prince Edward Island that has outpaced load growth in the rest of the Maritimes area in recent years. It is expected that these effects will level off in the future.

Demand Side Management

Plans to develop up to 120 MW by 2029/2030 of controllable direct load control programs by using smart grid technology to selectively interrupt space and/or water heater systems in residential and commercial facilities are underway, but no specific annual demand and energy saving targets currently exist.[1] During this 10-year LTRA assessment period in the Maritimes area, annual amounts for summer peak demand reductions associated with EE and conservation programs rise from 20 MW to 196 MW while the annual amounts for winter peak demand reductions rise from 93 MW to 465 MW.[52]

Distributed Energy Resources

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

The DER capacity in New Brunswick is currently around 1 MW. After a 1.8 MW installation 2021, New Brunswick has no future projections to report even though DERs could increase rapidly over the next 10 years and potentially impact operation of the distribution system in particular. Studies by New Brunswick Power in conjunction with Siemens are underway to determine the impact of large scale DERs installed on the system. This will include examination of the impacts of controllable solar installations and battery storage at the distribution level operating in conjunction with controllable DR to shift electric heat and electric water heater loads during peak periods. DERs are expected to form a significant portion of New Brunswick Power's DSM initiatives. Since the amounts of DERs that will be allowed to operate on the system is unknown at this time, New Brunswick Power does not forecast specific DER amounts, and all such resources are included as EE and conservation for LTRA purposes.

Prince Edward Island and Maine have not reported any DER installations.

52 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

Confirmed retirements include two units of oil-based thermal generating capacity in Prince Edward Island (totaling 17.6 MW), four small diesel fired thermal generators (totaling 7 MW), and one biomass generator (of 37 MW) in Northern Maine as they reached their end of life. Three additional units of oil-based thermal generating capacity totaling 42.8 MW are expected to retire in Prince Edward Island in the 2022–2023 time frame. In New Brunswick, unconfirmed retirements of about 390 MW of natural-gas-fired generation and an additional 28 MW petroleum-fired resources may happen as early as 2028 if load reductions programs are sufficient to reliably allow their removal. Future natural gas retirement in New Brunswick is unconfirmed and is likely to be deferred or extended. Nova Scotia will retire a 150 MW (nameplate) coal-fired generator in 2021, provided capacity from the Muskrat Falls hydro-electricity project in the Canadian province of Newfoundland and Labrador is available to completely offset its removal.

Small amounts of new generation capacity are being installed to introduce alternative renewable energy resources into the capacity mix. Except for hydro generation, renewable electricity standards (RES) have led to the development of substantially more wind generation capacity than any other renewable generation type. In Nova Scotia, the RES target for 2020 increased from 25% to 40% of energy sales from renewable resources with the expectation that the incremental renewable requirements would be met largely by the energy import from the Muskrat Falls hydro project; however, due to COVID-19 related construction delays at Muskrat Falls, the RES targets and timelines are currently being revised. Currently, RES energy is provided primarily by wind generation, hydro, and biomass. For wind capacity, the Maritimes area applies year-round calculated equivalent firm capacities of 22% (New Brunswick), 19% (Nova Scotia), 15% (Prince Edward Island), and 40% (Maine) of nameplate.

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 HVDC undersea cable link (the Maritime Link) between Newfoundland and Labrador and Nova Scotia was completed in late 2017; this cable, in conjunction with the construction of the Muskrat Falls hydro development in Labrador, is expected to facilitate the unconfirmed retirement of a 150 MW (nameplate) coal-fired unit in Nova Scotia in 2021. This unit will only be retired once a similarly sized replacement firm capacity contract from Muskrat Falls is in operation so that the overall resource adequacy is unaffected by these changes. 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.

Maritimes Probabilistic Assessment

General Overview: The Maritimes area is winter peaking with separate jurisdictions and regulators in New Brunswick, Nova Scotia, Prince Edward Island, and Northern Maine. No significant LOLH was observed. The estimated EUE is negligible. The ARMs are at or above the 20% reference margin in both years. Any contribution to the LOLH and EUE occurs during the peak (winter) monthly period.

Modeling: Assumptions are consistent with those used in *NPCC 2020 Long Range Adequacy Overview*.[53] The GE MARS model developed by the NPCC CP-8 Working Group was used to model demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures as prescribed by the NPCC resource adequacy criterion. Additional modeling information is provided below:

- Maritimes area demand is the maximum of the hourly sums of the individual sub-area load forecasts. Except for the Northern Maine sub-area that uses a simple scaling factor, all other sub-areas use a combination of some or all of efficiency trend analysis, anticipated weather conditions, econometric modeling, and end-use modeling to develop their load forecasts.
- Annual peak demand in the Maritimes area varies by +9% of forecasted Maritimes area demand based upon the 90/10 percentage points of LFU distributions.
- Maritimes area uses seasonal dependable maximum net capability to establish combustion turbine capacity for resource adequacy. During summer, these values are derated accordingly.
- Hydro capacity in the Maritimes area is predominantly run of the river, but enough storage is available for full rated capability during daily peak load periods.
- Solar capacity in the Maritimes area is BTM and netted against load forecasts. It does not currently count as capacity.
- The Maritimes area provides an hourly historical wind profile for each of its four sub-areas based on actual wind shapes for the 2012–2018 period. The wind in any particular hour is a probabilistic amount determined by selecting a random wind and load shape from the historic years. Each sub-area's actual MW wind output was normalized by the total installed capacity in the sub-area during that calendar year. These profiles, when multiplied by current sub-area total installed wind capacities, yield an annual wind forecast for each sub-area. The sum of these four sub-area forecasts represents the Maritimes area's hourly wind forecast.

Probabilistic vs. Deterministic Assessments: The following highlight significant differences between these types of assessments:

- The loads for each area were modeled on an hourly, chronological basis. It was based on the 2002 load shape for the summer period and the 2003/2004 load shape for the winter period.
- The Maritimes area modeled operating procedures that included reduced operating reserves before firm load has to be disconnected.
- DR in the Maritimes area is currently comprised of contracted interruptible loads.
- Transmission additions and retirements assumed were consistent with this NERC *2020 LTRA*.
- In the NPCC ProbA simulations, all areas received assistance on a shared basis in proportion to their deficiency. In the analysis, each step was initiated simultaneously

53 NPCC Resource Adequacy documents are posted in the NPCC library: https://www.npcc.org/library/resource-adequacy

Base Case Study

Probabilistic Base Case results outside of the on-peak hour
The Maritimes Area is winter peaking; the LOLH risk occurs during the winter months. No significant LOLH was observed.

Probabilistic Base Case results of EUE
The Maritimes Area is winter peaking; EUE risk occurs during the winter months. The estimated EUE is negligible.

Probabilistic resource adequacy studies conducted that address area reliability risk drivers.

NPCC 2019 Maritimes Area Comprehensive Review of Resource Adequacy

The 2019 Maritimes Area Comprehensive Review of Resource Adequacy, covering the period of January 2020 through December 2024, was prepared to satisfy the compliance requirements as established by the Northeast Power Coordinating Council.[54] The guidelines for this review are specified in the NPCC Regional Reliability Directory No. 1, Appendix D.

The NPCC resource adequacy criterion of an LOLE of not more than 0.1 days per year of firm load disconnections is not exceeded by the Maritimes area for all years covered by this review and varies between 0.008 to 0.010 days/year for the Base Case forecast.

The Maritimes area is also shown to adhere to its own 20% reserve criterion in all years that are covered by this review with minimum reserve levels varying between 30% and 35% for the Base Case forecast. Sensitivity analyses were performed to determine the LOLE effects of high load growth, zero wind generation, and the removal of all external tie benefits. The Maritimes area is shown to meet the NPCC resource adequacy criterion in all years for each of these sensitivities.

54 https://www.npcc.org/content/docs/public/library/resource-adequacy/2019/2019-maritimes-area-crra-rcc-approved-december-3-2019.pdf

Base Case Summary of Results			
Reserve Margin (RM) %			
	2022*	**2022**	**2024**
Anticipated	25.4%	19.3%	20.9%
Reference	20.0%	20.0%	20.0%
ProbA Forecast Operable	27.6%	18.5%	16.7%
Annual Probabilistic Indices			
	2022*	**2022**	**2024**
EUE (MWh)	0.00	0.575	1.125
EUE (ppm)	0.00	0.021	0.039
LOLH (hours/year)	0.00	0.010	0.023

*Represents the 2018 ProbA results for 2022.

The 2022 50/50 peak demand forecast is slightly higher than reported in the previous assessment; the forecast capacity resources declined slightly as compared to the previous assessment. A slight increase in estimated LOLH and EUE is observed between the two assessments. The slightly higher forecast load contributes to this result.

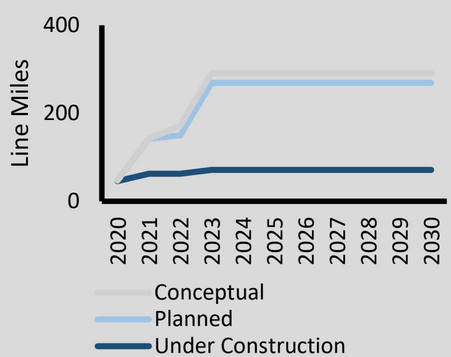
Regional Risk Scenario

For the Maritimes Risk Scenario, Tier 1 units will be removed that consisted primarily of planned wind and run-of-river hydro units. To address energy adequacy concerns, wind capacity will derated by half for every hour in the winter months (December, January, and February) to simulate icing conditions. In addition, 50% natural gas capacity curtailment will be assumed for the winter months to simulate a reduction in gas supply.

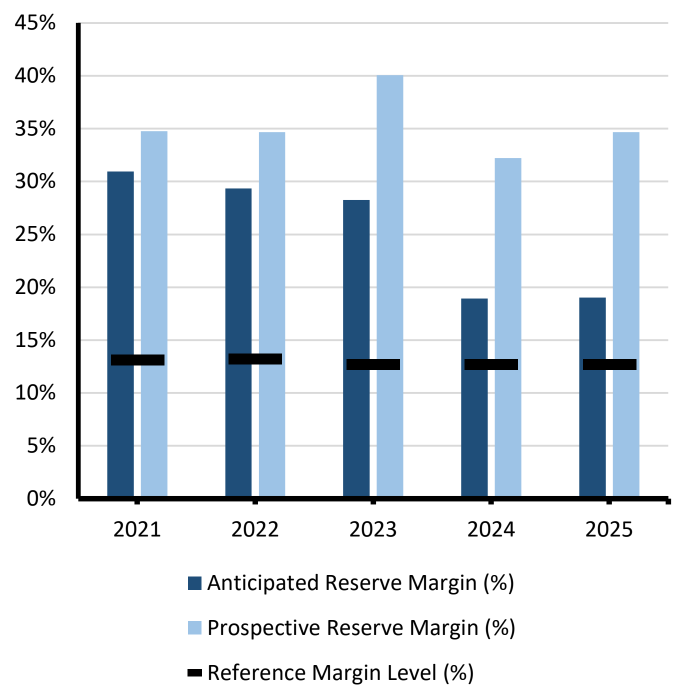
NPCC-New England

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

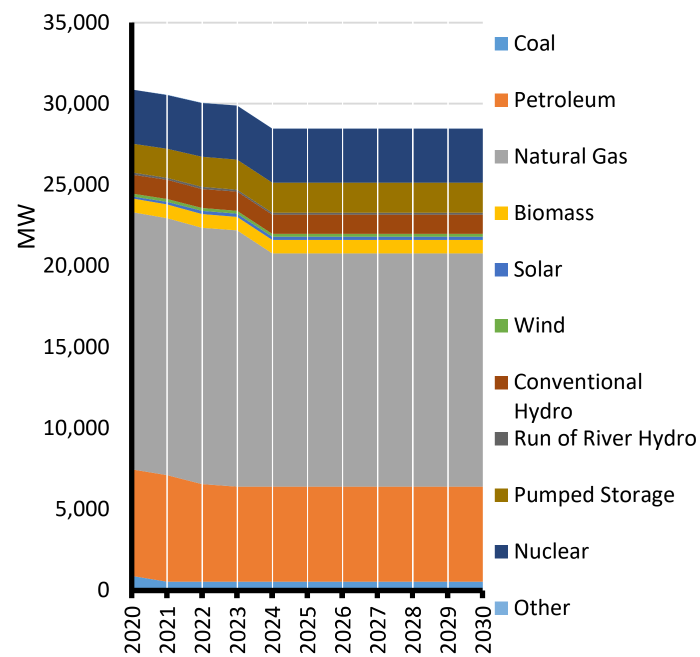
Demand, Resources, and Reserve Margins (MW)										
Quantity	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Internal Demand	24,981	24,861	24,783	24,703	24,657	24,640	24,656	24,694	24,755	24,817
Demand Response	654	681	592	592	592	592	592	592	592	592
Net Internal Demand	24,327	24,180	24,191	24,111	24,065	24,048	24,064	24,102	24,163	24,225
Additions: Tier 1	48	171	171	171	171	171	171	171	171	171
Additions: Tier 2	271	621	2,195	2,539	3,104	3,344	3,344	3,344	3,344	3,344
Additions: Tier 3	621	1,710	2,705	5,226	5,654	6,374	6,374	6,374	6,374	6,374
Net Firm Capacity Transfers	1,305	1,188	1,059	82	14	14	14	14	14	14
Existing-Certain and Net Firm Transfers	31,805	31,106	30,857	29,925	29,890	29,910	29,928	29,946	29,963	29,981
Anticipated Reserve Margin (%)	30.9%	29.4%	28.3%	19.0%	19.0%	19.2%	19.2%	19.1%	18.8%	18.6%
Prospective Reserve Margin (%)	34.8%	34.7%	40.1%	32.2%	34.7%	35.9%	35.8%	35.7%	35.4%	35.2%
Reference Margin Level (%)	13.1%	13.2%	12.7%	12.7%	12.7%	12.7%	12.7%	12.7%	12.7%	12.7%



Projected Transmission Circuit Miles



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- New England has the resource base and transmission system needed to reliably meet consumer demand for power during this assessment period.
- ISO-NE is implementing near-term market and operational changes to address the area's energy-security risks by filing market rule changes with FERC to pursue market-based solutions that should ensure sufficient firm electrical energy to maintain BPS reliability during all seasons, but primarily targeted for winter.
- New England has implemented solutions that include enhancing operating procedures for confirming natural gas availability, improving communications and coordination with natural gas pipeline operators, and implementing a 21-day energy emergency forecast to supplement near-term fuel procurement decisions by regional resource owners.
- Market-based solutions filed with FERC are designed to promote additional incentives that result in the firming of resource fuel supply chains. These incentives promote generator firm contracts with natural gas supply and transmission to improve natural gas availability for power generation, the use of existing and new dual-fuel capability when natural gas supplies are limited, and adequate on-site storage and replenishment of liquid fuels to enhance dual-fuel power plant availability and reliability.
- The development of renewable resources, EE and conservation, along with expanded power imports will help New England mitigate the identified fuel/energy security risks.

New England Fuel Mix										
Generation Type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal	533	533	533	533	533	533	533	533	533	533
Petroleum	6,567	6,017	5,859	5,859	5,859	5,859	5,859	5,859	5,859	5,859
Natural Gas	15,850	15,793	15,793	14,376	14,376	14,376	14,376	14,376	14,376	14,376
Biomass	851	848	832	832	832	832	832	832	832	832
Solar	149	200	200	200	200	200	200	200	200	200
Wind	183	185	185	185	185	185	185	185	185	185
Conventional Hydro	1,167	1,172	1,172	1,172	1,172	1,172	1,172	1,172	1,172	1,172
Run of River Hydro	131	131	131	131	131	131	131	131	131	131
Pumped Storage	1,788	1,854	1,854	1,854	1,854	1,854	1,854	1,854	1,854	1,854
Nuclear	3,321	3,321	3,321	3,321	3,321	3,321	3,321	3,321	3,321	3,321
Other	6	6	6	6	6	6	6	6	6	6
Total MW	30,547	30,059	29,886	28,469	28,469	28,469	28,469	28,469	28,469	28,469

NPCC-New England Assessment

Planning Reserve Margins: ISO-NE's RML is based on the capacity needed to meet the NPCC 1-day-in-10 years LOLE resource planning reliability criterion. The capacity needed, referred to as the Installed Capacity Requirement (ICR), varies from year-to-year depending on projected system conditions (e.g., demand, generation, transmission, capacity imports). The ICR is calculated on an annual basis, covering three years into the future. The latest calculations result in an RML of 13.6% in 2020, 13.1% in 2021, 13.2% in 2022, and 12.7% in 2023 as expressed in terms of the 50/50 peak demand forecast published in May 2020. In this assessment, the last calculated RML (12.7%) is subsequently applied for the remaining seven years of the LTRA forecast. ISO-NE's Anticipated (summer) Reserve Margin, ranging between 19–31%, is expected to stay above the RML during this assessment period. ISO-NE's Anticipated (winter) Reserve Margin, ranging between 58–78%, is also expected to stay above the RML during this assessment period.

Demand: ISO-NE develops an independent demand forecast for its BA area by using historical hourly demand data from individual member utilities. This data is used to develop the regional hourly peak demand and energy forecasts. ISO-NE then develops a forecast of both state and system hourly peak and energy demands. The regional peak and state demand forecast is considered coincident. This demand forecast is the gross demand forecast that is then decreased to a net forecast by subtracting the impacts of EE measures and BTM PV.

ISO-NE is a summer-peaking electrical power system. The reference demand forecast is based on the reference economic forecast that reflects the regional economic conditions that are expected to occur. The summer peak total internal demand (TID) is forecast to decrease by about 370 MW from 2020 to 2029 while the net energy for load is forecast to increase by about 4,597 GWh from 2020 to 2029. The TID decreases from 25,125 MW in 2020 to 24,755 MW in 2029. The net energy for load is expected to increase from 124,184 GWh in 2020 to 128,781 GWh in 2029.

Annually, ISO-NE forecasts the load reduction impact of BTM PV resources and the reductions to peak demand and energy due to passive DR programs that are comprised mostly of EE. The EE in 2020 is 3,312 MW and is forecast to grow to 3,653 MW by 2021 and increase to over 5,733 MW by 2029. Nameplate BTM PV in 2020 is 2,164 MW and is forecast to grow to 2,401 MW by 2021, and to 4,306 MW by 2029. The BTM PV and EE forecasts are seen as reductions to the gross demand forecast. This year, for the first time, ISO-NE has included an electrification forecast in the load forecast. A new electrification forecast reflects the added electricity demand associated with heat pumps (within the residential and commercial space heating sector) and electric vehicles (within the transportation sector). Heat pumps are not projected to add demand to the New England summer peak loads since they are primarily designed for winter operation. Electric vehicle demand is forecast to be 12 MW in 2020, 34 MW in 2021, and 282 MW by 2029.

Demand Side Management: On June 1, 2018, ISO-NE integrated price-responsive DR into the energy and reserve markets. Currently, approximately 584 MW of DR participates in these markets and is dispatchable (i.e. treated similar to generators). Regional DR will increase to 592 MW by 2023 and this value is assumed constant/available thru the remainder of the assessment period.

Distributed Energy Resources: New England has 174 MW (1,379 MW nameplate) of wind generation and 787 MW (2,164 MW nameplate) of BTM PV. Approximately 12,400 MW (nameplate) of wind generation projects have requested generation interconnection studies. BTM PV is forecast to grow to 1,062 MW (4,306 MW nameplate) by 2029. The BTM PV peak load reduction values are calculated as a percentage of ac nameplate. The percentages include the effect of diminishing PV production at the time of the system peak as increasing PV penetrations shift the timing of peaks later in the day, decreasing from 34.3% of nameplate in 2020 to about 23.8% in 2029.

Generation: Generating capacity that has been added since the *2019 LTRA* consists primarily of 251 MW nameplate of solar capacity. Existing certain capacity for 2021 is 30,499 MW. Approximately 40 MW of Tier 1 solar and 10 MW wind capacity is projected to be added by 2021. Tier 2 capacity additions scheduled for 2021 include 255 MW of wind and solar generation. In 2022, scheduled Tier 2 capacity additions total 605 MW of wind, solar, and natural-gas-fired generation.

Capacity Transfers: New England is interconnected with the three BAs of Quebec, the Maritimes, and New York. ISO-NE takes into account the transmission transfer capability between these BAs to assure that their limits are accounted for in regional resource adequacy. ISO-NE's Forward Capacity Market methodology limits the purchase of import capacity based on these Interconnection transfer limits. ISO-NE's capacity net imports are assumed to range from 1,059 MW to 1,305 MW during the 2021–2023 period and decrease to 82 MW by 2024 and 14 MW by 2025 through the remainder of the LTRA years.

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

Energy Security: The combination of constrained natural gas pipelines during winter, indeterminate LNG and fuel oil deliveries, and recent retirements of nuclear, coal, and oil-fired generation have resulted in fuel/energy security concerns. These concerns have prompted ISO-NE to implement solutions that include enhancing operating procedures for confirming natural gas availability, improving communications and coordination with natural gas pipeline operators, and implementing a 21-day energy emergency forecast supplement near-term fuel procurement decisions by regional resource owners. In addition, on April 15, 2020, ISO-NE filed market based solutions with FERC to promote additional firming of fuel-supply chain measures. These measures included incentives for procuring firm contracts with natural gas supply and transmission to improve natural gas availability for power generation, the continued use of existing and new dual-fuel capability when natural gas supplies are limited, and adequate on-site storage and replenishment of liquid fuels to enhance dual-fuel power plant availability and reliability.

Probabilistic Assessment Overview

General Overview: The New England area is a summer-peaking area. For 2022, the LOLH is 0.007 hours/year and the EUE is 3.292 MWh; in 2024 those values are 0.092 hours/year and 58.61 MWh, respectively; the increase is due to the retirement of Mystic Units 8 and 9. The forecast 50/50 peak demand for 2022 is lower than reported in the previous study with a lower estimated forecast PRM and a slightly increased forecast operablereserve margin. As a result, the LOLH has remained approximately the same with a negligible increase in the EUE.

Modeling: Assumptions used in this ProbA are consistent with those used in *NPCC 2020 Long Range Adequacy Overview*. The GE MARS model developed by the NPCC CP-8 Working Group was used to model demand uncertainty, scheduled outages and deratings, forced outages, assistance over interconnections with neighboring Planning Coordinator areas, transmission transfer capabilities, capacity, and/or load relief from available emergency operating procedures as prescribed by the NPCC resource adequacy criterion. The following model highlights are provided below:

- New England's long-term energy model is an annual model of ISO-NE area total energy that uses real income, the real price of electricity, economics, and weather variables as primary drivers. Income is a proxy for all economic activity. The long-term peak load model is a monthly model of the typical daily peak demand for each month and produces forecasts of weekly, monthly, and seasonal peak demands over a 10-year time period. Daily peak demands are modeled as a function of energy, weather, and a time trend on weather for the summer months to capture the increasing sensitivity of peak demand to weather due to the increasing area cooling load.

- Annual peak demand in the New England area varies by +11% of forecasted New England area demand based upon the 90/10% points of LFU distributions.

- New England generating unit availability assumptions are based upon historical performance over the prior five-year period. Modeled unit availability reflects projected scheduled maintenance and forced outages. Individual generating unit maintenance assumptions are based upon ISO-NE approved maintenance schedules. Individual generating unit forced outage assumptions were based on the unit's historical data and NERC Generator Availability Data System (GADS) average data for the same class of unit.

- The seasonal claimed capability as established through claimed capability audit is used to rate the sustainable maximum capacity of nonintermittent thermal resources. The seasonal claimed capability for intermittent thermal resources is based on their historical median net real power output during ISO-NE defined seasonal reliability hours.

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

- The majority of solar resource development in New England consists of the state-sponsored distributed BTM PV resources that do not participate in the wholesale electricity markets but reduce the real-time system load observed by ISO-NE system operators. These resources are modeled as load modifiers on an hourly basis based on the 2002 historical hourly weather profile.

- New England models wind resources use the seasonal claimed capability that is based on their historical median net real power output during seasonal reliability hours.

Probabilistic vs. Deterministic Assessments: Details regarding the differences between the probabilistic and deterministic representations can be found in the NERC 2020 Probabilistic Assessment–NPCC RE. Additional assumptions include the following:

- The loads for each area were modeled on an hourly, chronological basis. This is based on the 2002 load shape for the summer period and the 2003/2004 load shape for the winter period.
- In addition to the annual update to New England's peak demand and energy forecast, ISO NE also forecasts the anticipated growth and impact of BTM PV resources within the area that do not participate in wholesale electricity markets. This year, demand forecast also includes the impacts of transportation and heating electrifications. ISO-New England's forecast for these resources is developed with stakeholder input.

- New England also develops a forecast of long-term savings in peak and energy use for each state from state sponsored energy-efficiency programs. These programs include the use of more efficient lighting, motors, refrigeration, HVAC equipment, control systems, and industrial process equipment.
- The New England area modeled emergency operating procedures that included reduced operating reserves and voltage reduction before firm load has to be disconnected.
- Price-responsive DR resources are integrated into New England's energy and reserve markets. These resources are treated similarly to generating resources. They are dispatchable and participate as co-optimized resources within both the daily energy and reserves markets.
- Transmission additions and retirements were assumed consistent with this NERC *2020 LTRA.*
- In the NPCC ProbA simulations, all areas within NPCC received assistance on a shared basis in proportion to their capacity deficiency. In the analysis, each step was initiated simultaneously in all areas and sub-areas.

Base Case Study

The forecast 50/50 peak demand for 2022 is lower than reported in the previous study with lower estimated forecast PRM and a slightly increased forecast operable reserve margin. As a result, the LOLH remained the same with a negligible increase in the EUE. The increase in LOLH and EUE in 2024 is due to the retirement of Mystic Units 8 and 9.

Probabilistic Base Case results outside of the on-peak hour
The New England area is summer peaking; the LOLH risk occurs during the summer months. No significant LOLH was observed.

Probabilistic Base Case results of EUE
The New England Area is Summer peaking; EUE risk occurs during the summer months. The estimated EUE is negligible.

Base Case Summary of Results			
Reserve Margin (RM) %			
	2022*	**2022**	**2024**
Anticipated	28.5%	29.4%	18.95%
Reference	16.4%	13.0%	12.7%
ProbA Forecast Operable	19.0%	20.0%	9.8%
Annual Probabilistic Indices			
	2022*	**2022**	**2024**
EUE (MWh)	2.713	3.292	58.62
EUE (ppm)	0.019	0.027	0.471
LOLH (hours/year)	0.007	0.008	0.095

*Represents the 2018 ProbA results for 2022.

Probabilistic resource adequacy studies conducted that address area reliability risk drivers.

NPCC 2019 New England Interim Review of Resource Adequacy

ISO-NE's 2019 annual assessment (NPCC interim review) of its review of resource adequacy covers the time period of 2020– 2022. This interim review is conducted to comply with the Reliability Assessment Program as established by NPCC. It follows the resource adequacy review guidelines as outlined in the NPCC Regional Reliability Directory No. 1 Appendix D, Design and Operation of Bulk Power System.[55]

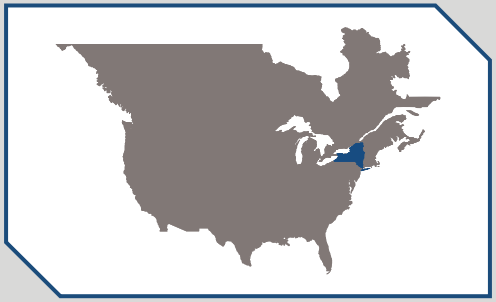
To ensure the resource adequacy for the area, ISO-NE identifies the amount and locations of resources the system needs and meets them in the short term through the forward capacity market (FCM). Forward capacity auctions have been conducted to purchase needed resources for the capacity commitment periods 2020–2021 to 2022–2023. The resources procured by ISO-NE through the FCM assume a capacity supply obligation and must be available to offer energy and reserves into New England's energy markets. Resources that do not have a capacity supply obligation can participate in the energy markets on a voluntary basis. For this interim review, resource adequacy is assessed under two sets of resource assumptions: using resources' seasonal claimed capabilities and using capacity supply obligations of resources in the FCM.

55 https://www.npcc.org/content/docs/public/library/resource-adequacy/2019/2019-new-england-interim-review-rcc-approved-december-3-2019.pdf

Results of this interim review show that New England has adequate existing and planned resources to meet the NPCC resource adequacy design criteria under both the reference and high demand forecasts for the study period 2020–2022. Capacity supply obligations acquired in the FCM auctions for 2020–2022 will also meet the area's resource adequacy needs.

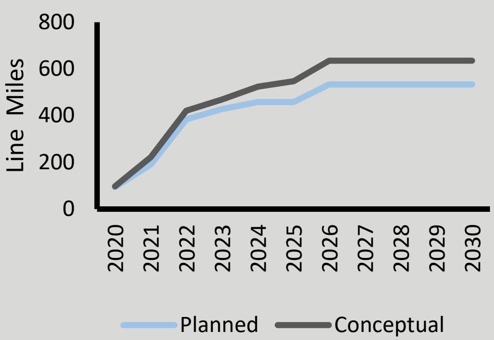
Regional Risk Scenario

- For the Risk Scenario, Tier 1 future resources that are included in the Base Case will be removed.
- In addition, the capacity ratings of wind and solar resources are assumed to reduce by 30% to reflect some uncertainty associated with their capacity contribution. Currently, these wind and solar resources are modeled using their seasonal claimed capability that are based on their historical median net real power output during reliability hours (2:00–6:00 p.m.).



NPCC-New York

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

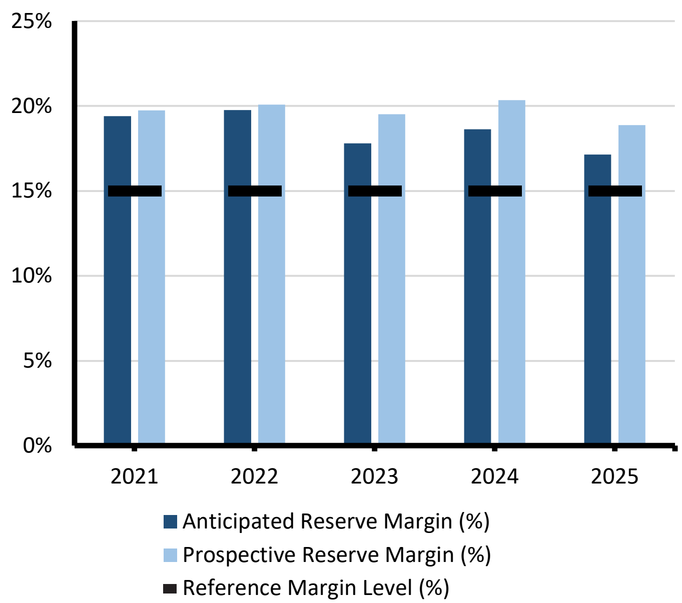


Projected Transmission Circuit Miles

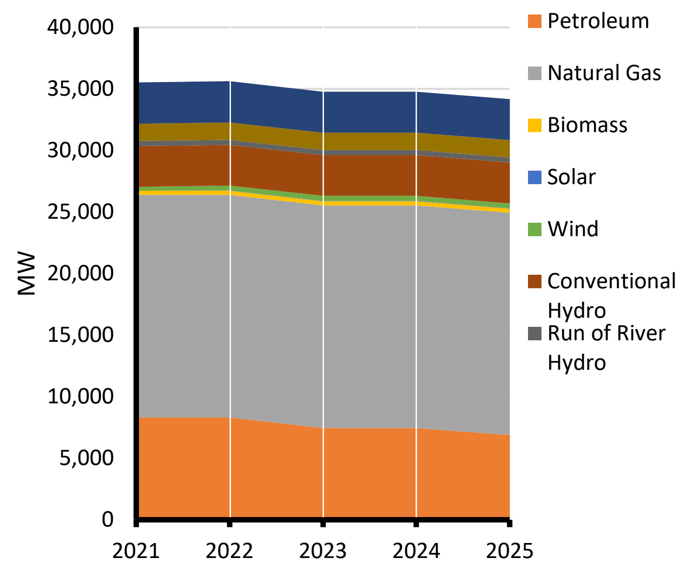
Demand, Resources, and Reserve Margins (MW)										
Quantity	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Total Internal Demand	32,129	32,128	31,918	31,838	31,711	31,670	31,673	31,756	31,865	31,992
Demand Response	877	877	877	877	877	877	877	877	877	877
Net Internal Demand	31,253	31,252	31,042	30,962	30,835	30,794	30,797	30,880	30,989	31,116
Additions: Tier 1	0	105	122	122	122	122	122	122	122	122
Additions: Tier 2	104	104	535	535	535	535	535	535	535	535
Additions: Tier 3	1,688	4,336	5,251	7,624	7,903	7,903	7,903	7,903	7,903	7,903
Net Firm Capacity Transfers	1,812	1,816	1,794	1,954	1,954	1,954	1,954	1,954	1,954	1,954
Existing-Certain and Net Firm Transfers	37,317	37,321	36,445	36,605	35,999	35,999	35,999	35,999	35,999	35,999
Anticipated Reserve Margin (%)*	19.4%	19.8%	17.8%	18.6%	17.1%	17.3%	17.3%	17.0%	16.6%	16.1%
Prospective Reserve Margin (%)	19.7%	20.1%	19.5%	20.4%	18.9%	19.0%	19.0%	18.7%	18.3%	17.8%
Reference Margin Level (%)**	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%

*Values with wind derated by 83% wind, solar by 50%, and run-of-river hydro by 56% for this summer capability period.

**The NERC LTRA RML is 15%; however, there are no PRM criteria in New York. Wind, grid-connected solar, and run-of-river totals were derated for the NERC LTRA RML calculation. Additionally, the NYISO uses ProbAs to evaluate its system's resource adequacy against the LOLE resource adequacy criterion of 0.1 days/year. 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 NYSRC. NYSRC approved the 2020–2021 IRM at 18.9%. All values in the IRM calculation are based upon full ICAP MW values of resources. IRM is based on annual ProbAs and models for the upcoming capability year.



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- Clean energy policies, such as the Climate Leadership and Community Protection Act (CLCPA) are reshaping the grid in unprecedented ways. New York's electricity industry is transforming from a grid that is powered by traditional synchronous, controllable generation to more non-emitting, weather-dependent intermittent resources and distributed generation. The increase in the intermittent and distributed generation, along with the related penetration of inverter-based technology, creates new challenges. The wholesale markets in New York are continuing to evolve to provide the price and investment signals necessary to reflect system needs and to incentivize resources capable of resolving those needs.
- The New York State Department of Environmental Conservation adopted a regulation to limit nitrogen oxides emissions from simple-cycle combustion turbines (peaking units). This is referred to as the "Peaker Rule." The Peaker Rule required all impacted plant owners to file compliance plans by March 2, 2020. The *Reliability Needs Assessment* (*RNA*) Base Case reflects generators' compliance plans in the development of the 2020 RNA Base Case.
- A new 2020–2021 Reliability Planning Process cycle started in January 2020 with its *2020 RNA*, which assesses the system for resource adequacy and transmission security out to 2030. The *2020 RNA* preliminary results and other assessments identified potential reliability needs (i.e., transmission security issues starting 2023 and resource adequacy concerns starting in 2027). The *2020 RNA* also includes a "70 by 30" scenario to simulate potential futures under which 70% renewable energy will occur by 2030.
- The NYISO is forecasting a higher growth in energy usage, which can be attributed in part to the increasing impact of EV usage and other electrification (i.e., conversion of home heating, cooking, water heating, and other end-uses from fossil-fuel based systems to electricity systems) especially in the later years of the forecast. Significant load-reducing impacts occur due to EE initiatives and the growth of distributed BTM energy resources, such as solar PV. The relative BTM solar impact on peak declines over time as the New York Balancing Area (NYBA) summer peak is expected to shift slightly further into the evening.

New York Fuel Mix

Generation Type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Petroleum	8,297	8,297	7,452	7,452	6,872	6,872	6,872	6,872	6,872	6,872
Natural Gas	18,095	18,095	18,087	18,087	18,060	18,060	18,060	18,060	18,060	18,060
Biomass	321	321	321	321	321	321	321	321	321	321
Solar	16	27	27	27	27	27	27	27	27	27
Wind	297	390	407	407	407	407	407	407	407	407
Conventional Hydro	3,317	3,317	3,317	3,317	3,317	3,317	3,317	3,317	3,317	3,317
Run of River Hydro	411	411	411	411	411	411	411	411	411	411
Pumped Storage	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407
Nuclear	3,343	3,343	3,343	3,343	3,343	3,343	3,343	3,343	3,343	3,343
Total MW	35,504	35,609	34,773	34,773	34,167	34,167	34,167	34,167	34,167	34,167

NPCC-New York Assessment

Planning Reserve Margins: The NERC LTRA RML is 15%; however, there is no PRM criteria in New York. Wind, grid-connected solar, and run-of-river totals were derated for the NERC LTRA RML calculation. NYISO uses ProbAs to evaluate its system's resource adequacy against the LOLE resource adequacy criterion of 0.1 days/year. The 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 of a LOLE of no greater than 0.1 days per year. The IRM for the 2020–2021 capability year is 18.9% 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 15–18.9%.

Demand: The energy and peak load forecasts are based upon end-use models that incorporate forecasts of economic drivers and end-use technology efficiency and saturation trends. The impacts of EE and technology trends are largely incorporated directly in the forecast model with additional adjustments for policy-driven EE impacts made where needed. The impacts of DERs, EVs, other electrification, energy storage, and BTM solar PV are made exogenous to the model. The forecast of BTM solar PV-related reductions in summer-peak time assumes that the NYBA peak currently occurs at 4:00 p.m. or 5:00 p.m. Eastern time 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 time in January. The impacts of net electricity consumption of all energy storage units are added to the baseline energy forecast while the peak-reducing impacts of BTM energy storage units are deducted from the baseline peak forecasts.
The 10-year annual average energy growth rate is higher than last year (+.05% per year in 2020 vs. -.27% in 2019). The 10-year annual average summer peak demand growth rate is also higher than last year (-0.09% per year in 2020 vs. -0.39% in 2019). Demand and consumption in the NYBA are heavily influenced by state EE and renewable energy public policy programs, such as the CLCPA. On July 18, 2019, New York's governor signed into law the CLCPA. The law also creates a Climate Action Council charged with developing a scoping plan of recommendations to meet these targets and place New York on a path toward carbon neutrality.

CLCPA targets[56] include the following: an 85% reduction in greenhouse gas emissions by 2050, 100% carbon-dioxide-free electricity by 2040, 70% renewable energy by 2030, 9,000 MW of offshore wind by 2035, 3,000 MW of energy storage by 2030, 6,000 MW of solar PV by 2025, and 22 million tons of carbon dioxide reduction through EE and electrification.

Demand Side Management: The NYISO's 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.

Distributed Energy Resources: NYISO is currently implementing a 3–5-year plan to integrate DERs, including DR resources, into its energy, capacity, and ancillary services markets. NYISO published a DER roadmap document in February 2017 that outlined NYISO's vision for DER market integration. FERC approved NYISO's proposed tariff changes in January 2020. NYISO is currently identifying the related software and procedure changes and is targeting implementation in Q4 2021.

Generation: The NYISO's *2020 RNA* includes approximately 680 MW of proposed generation, mostly wind-powered. The 680 MW CPV Valley Energy Center entered into service in 2018, and the 1,020 MW Cricket Valley Energy Center entered into service in 2020. Indian Point Unit 2 deactivated in 2020, and Indian Point Unit 3 targets deactivation in in 2021. The New York State Department of Environmental Conservation (DEC) adopted a regulation to limit nitrogen oxides (NOx) emissions from simple-cycle combustion turbines (Peaking Units) (referred to as the "Peaker Rule"). The Peaker Rule required all impacted plant owners to file compliance plans by March 2, 2020. The RNA Base Case reflects generators' compliance plans in the development of the *2020 RNA* Base Case. Based on the compliance plans, 970 MW of generation will be retired or unavailable by 2023 during the ozone season with an additional 650 MW being retired or unavailable during the ozone season by 2025. New York's electricity industry is transforming from a grid that is powered by traditional synchronous, controllable generation to more non-emitting, weather-dependent intermittent resources and distributed generation.

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

56 https://climate.ny.gov/

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

Probabilistic Assessment Overview

General Overview: The New York area is summer-peaking. The LOLH for 2022 and 2024 are 0.003 and 0.029 (hours/year), respectively, with corresponding EUE values of 0.594 and 6.837 (MWh), respectively; these values trend higher than the past ProbA results. The trend is mainly due to the decrease in the forecast PRM and operable reserve margins.

Modeling: Assumptions used in this ProbA are consistent with those used in *NPCC 2020 Long Range Adequacy Overview*. The GE MARS model developed by the NPCC CP-8 Working Group was used to model demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures as prescribed by the NPCC resource adequacy criterion. The following model highlights are provided below:

- New York employs a multi-stage process to develop load forecasts for each of the 11 zones within the New York control area. In the first stage, baseline energy and peak models are built based on projections of end-use intensities and economic variables. End-use intensities modeled include those for lighting, refrigeration, cooking, heating, cooling, and other plug loads. The considered economic variables include gross domestic product, households, population, and commercial and industrial employment. In the second stage, the incremental impacts of additional policy-based EE, BTM solar PV, and distributed generation are deducted from the forecast while the incremental impacts of EV usage and other electrification are added to the forecast. The impacts of net electricity consumption of energy storage units due to charging and discharging are added to the energy forecasts, while the peak-reducing impacts of BTM energy storage units are deducted from the peak forecasts. In the final stage, NYISO aggregates the load forecasts by zone.
- At the system level, annual peak demand forecasts range from 6% above the baseline for the ninetieth percentile forecast to 8% below the baseline for the tenth percentile forecast. These peak forecast variations due to weather are reflected in the LFU distributions applied to the load shapes within the MARS model.
- Installed capacity values for thermal units are based on the minimum of seasonal dependable maximum net capability test results and the capacity resource interconnection service MW values. Generator availability is derived from the most recent calendar five-year period forced outage data. Units are modeled using a multi-state representation that represents an EFORd. Planned and scheduled maintenance outages are modeled based upon schedules received by the New York ISO and adjusted for historical maintenance.
- Large New York hydro units are modeled as thermal units with a corresponding multistate representation that represents an EFORd. For run-of-river units, New York provides 8,760 hours of historical unit profiles for each year of the most recent five-year calendar period for each facility based on production data. Run-of-river unit seasonality is captured by randomly selecting an annual shape for each run-of-river unit in each draw. Each shape is equally weighted.
- New York provides 8,760 hours of historical solar MW profiles for each year of the most recent five-year calendar period for each solar plant based on production data. Solar seasonality is captured by randomly selecting an annual solar shape for each solar unit in each draw. Each solar shape is equally weighted.
- New York provides 8,760 hours of historical wind profiles for each year of the most recent five-year calendar period for each wind plant based on production data. Wind seasonality is captured by randomly selecting an annual wind shape for each wind unit in each draw. Each wind shape is equally weighted.

Probabilistic vs. Deterministic Assessments: The following highlight significant differences between these types of assessments:

- The loads for each area were modeled on an hourly chronological basis; this is based on the 2002 load shape for the summer period and the 2003/2004 load shape for the winter period.

- The New York area modeled operating procedures that included reduced operating reserves, voltage reduction, and implementation of DR programs before firm load has to be disconnected.
- New York's Special Case Resources Program and Emergency DR Program are modeled as operating procedure steps that are activated to minimize the probability of customer load disconnection; the programs are only activated in zones from which they are capable of being delivered.
- Transmission additions and retirements modeled were consistent with the NERC *2020 LTRA*.
- In the NPCC ProbA simulations, all areas modeled received assistance on a shared basis in proportion to their deficiency. In the analysis, each step was initiated simultaneously in all areas and sub-areas.

Base Case Study

The forecast 50/50 peak demand for 2022 is lower than reported in the previous study with lower estimated forecast reserve margins, resulting in increased LOLH and EUE for 2024.

Probabilistic Base Case results outside of the on-peak hour
The New York area is summer peaking; the LOLH risk occurs during the summer months.

Probabilistic Base Case results of EUE
The New York area is summer peaking; the EUE risk occurs during the summer months.

Describe any probabilistic resource adequacy studies conducted that address area reliability risk drivers.

NPCC 2019 Interim New York Area Review of Resource Adequacy

The NYISO conducts an annual area review of resource adequacy of New York's BPS as required by the NPCC. As described in the NPCC's Directory No. 1, a comprehensive review of resource adequacy is required every three years and analyzes a time period of five years. In the two interim years between comprehensive reviews, each Planning Coordinator conducts an annual interim review of resource adequacy that will cover, at a minimum, the remaining years of the five-year period studied in the comprehensive review of resource adequacy.

Base Case Summary of Results			
Reserve Margin (RM) %			
	2022*	**2022**	**2024**
Anticipated	22.5%	19.8%	18.6%
Reference	15.0%	15.0%	15.0%
ProbA Forecast Operable	13.7%	12.2%	11.3%
Annual Probabilistic Indices			
	2022*	**2022**	**2024**
EUE (MWh)	0.032	0.594	6.837
EUE (ppm)	0.000	0.004	0.046
LOLH (hours/year)	0.000	0.003	0.029

*Represents the 2018 ProbA results for 2022.

The purpose of this assessment is to demonstrate conformance with the applicable NPCC resource adequacy planning requirements. The *2018 Comprehensive Review of Resource Adequacy* covered the five-year study period of 2019–2023. The *2019 Interim Review of Resource Adequacy* report provides the first interim assessment of the NYISO's 2018 comprehensive review that covered the remaining four years of the study period (i.e., from 2020–2023).[57]

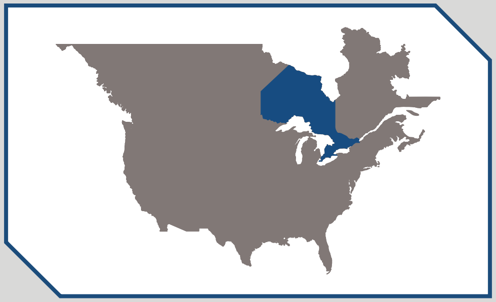
This report demonstrates that New York will meet the NPCC resource adequacy criterion that the probability of an unplanned disconnection of firm load due to resource deficiencies (i.e., LOLE) shall be, on average, no more than one occurrence in 10 years (0.1 days per year) for the baseline system covering the study period from 2020–2023.

Regional Risk Scenario

This scenario evaluates the reliability of the system under the assumption that no major Tier 1 transmission or generation projects come to fruition within this ProbA study period.

This scenario provides an indication of the potential reliability risks related with developmentally advanced projects relied upon in the NYISO's 2020–2021 reliability planning process not materializing.

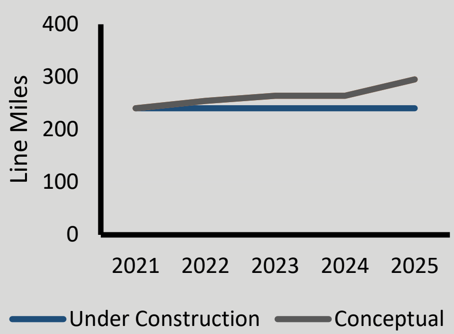
57 https://www.npcc.org/content/docs/public/library/resource-adequacy/2019/2019npcc-1stinterimnyisoreviewra-final-dec3-2019rcc-approved.pdf



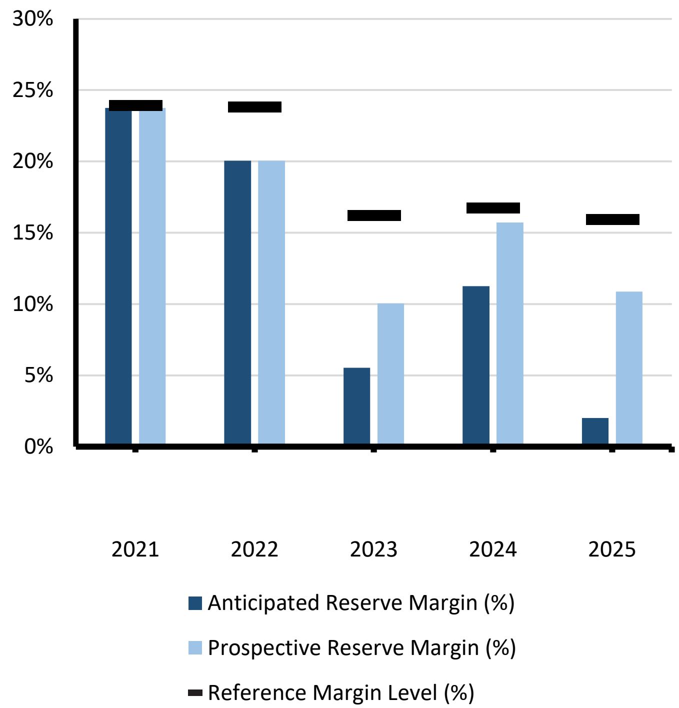
NPCC-Ontario

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

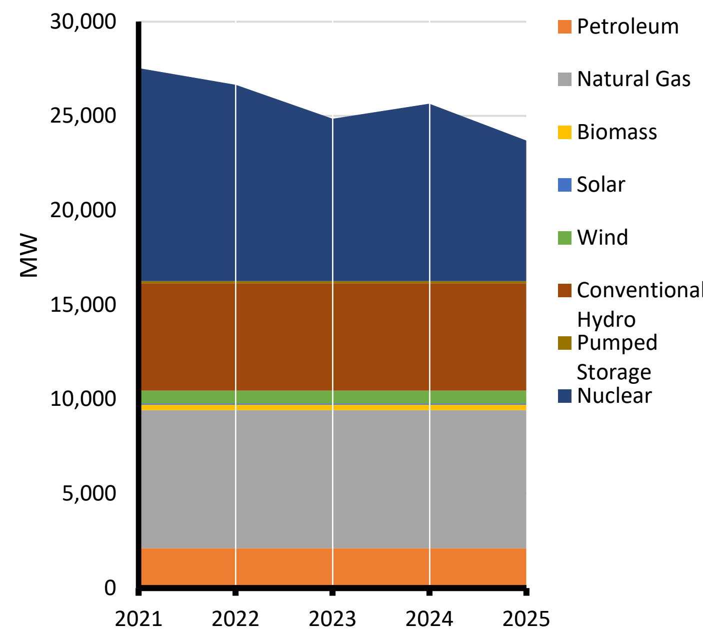
Demand, Resources, and Reserve Margins (MW)										
Quantity	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Internal Demand	22,103	22,676	23,248	23,533	23,707	23,850	24,089	24,411	24,680	24,946
Demand Response	469	469	469	469	469	469	469	469	469	469
Net Internal Demand	21,635	22,207	22,779	23,064	23,238	23,381	23,620	23,942	24,212	24,477
Additions: Tier 1	51	51	51	51	51	51	51	51	51	51
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	0	0	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	26,723	26,610	23,989	25,608	23,652	22,806	24,490	24,443	25,260	25,260
Anticipated Reserve Margin (%)	23.8%	20.1%	5.5%	11.3%	2.0%	-2.2%	3.9%	2.3%	4.5%	3.4%
Prospective Reserve Margin (%)	23.8%	20.1%	10.1%	15.7%	10.9%	-2.2%	3.9%	2.3%	4.5%	3.4%
Reference Margin Level (%)	23.9%	23.8%	16.2%	16.7%	15.9%	14.6%	15.8%	15.8%	15.8%	15.8%



Projected Transmission Circuit Miles



Planning Reserve Margins



Existing and Tier 1 Resources

Highights

- Ontario's ARMs fall below the RML for the first five years of the assessment period, driven largely by the nuclear refurbishment program, demand forecast uncertainty, and the expiry of a number of generation contracts. The IESO will acquire the required capacity through capacity auctions or other acquisition tools.
- In Q4 2020, the IESO's DR auction will be replaced by a capacity auction, which will enable resources including off-contract generators, system-backed capacity imports, and storage resources to compete alongside DR to provide capacity.
- Ontario will remain summer peaking over the forecast horizon. Summer peaks have moved later in the day due to the increased penetration of embedded solar generation and the critical peak pricing program.
- The integration of DERs and changing demand and supply patterns are creating new operating challenges in managing the BPS while providing greater customer choice and opportunity to optimize grid reliability services. The IESO collaborates with local distribution companies to ensure it has visibility of their operations and is able to forecast their output over different time frames, study their impact on reliability, and coordinate their operations to ensure reliability.
- Several transmission projects are under development to enhance the reliability of the BPS and connect growing agricultural loads in the southwest of the province.

Ontario Fuel Composition										
Generation Type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Petroleum	2,106	2,106	2,106	2,106	2,106	2,106	2,106	2,106	2,106	2,106
Natural Gas	7,323	7,323	7,323	7,323	7,323	7,323	7,323	7,323	7,323	7,323
Biomass	288	288	288	288	288	288	288	288	288	288
Solar	64	64	64	64	64	64	64	64	64	64
Wind	683	683	683	683	683	683	683	683	683	683
Conventional Hydro	5,681	5,681	5,681	5,681	5,681	5,681	5,681	5,681	5,681	5,681
Pumped Storage	112	112	112	112	112	112	112	112	112	112
Nuclear	11,282	10,404	8,596	9,402	7,446	7,406	8,284	8,237	9,054	9,054
Total MW	27,539	26,661	24,853	25,659	23,703	23,663	24,541	24,494	25,311	25,311

NPCC-Ontario Assessment

Planning Reserve Margins: The ARMs fall below the RML for the first five years of this assessment period; this is driven by the nuclear refurbishment program, demand forecast uncertainty, and the assumption that certain generation resources are not available once their generation contracts have expired. In calculating reserve margins, IESO does not consider control actions or operating procedures in its adequacy assessments. Planned nuclear outages are a significant contributor of the reserve margin. A period of elevated planned nuclear outages in 2021 and 2022 could lead to adequacy risks throughout the summer season. Future capacity auctions will be used to address supply needs. Resources, including DR, eligible to participate in a capacity auction are not included in the PRM until they have received a commitment in an auction. The IESO's capacity auction for the 2021 summer commitment period will replace the existing DR auction and enable off-contract generators, system-backed capacity imports, and storage resources to participate and compete alongside DR. The IESO also expects to address adequacy risks from elevated planned outages through outage management.

Nonpeak Hour Risks: Summer peaks have moved later in the day due to the increased penetration of embedded solar generation and the critical peak pricing program. Peaks are expected to increase over time due to reduced conservation program spending and plateauing DERs.

Demand: The increased demand for electricity is being driven by population growth, economic expansion, and the increased penetration of electric devices. Offsetting the growth are reductions from conservation, EE and codes and standards savings, electricity price responsiveness, and increased output by distributed generation. Recent policy changes have led to lower committed EE savings and the lower growth rates of renewable distributed generation, alleviating much of the downward pressure on peak demands going forward. These combined factors translate into small increases in peak demands over the forecast horizon. Energy demand is subject to the same factors as peak demands. In the near term, there is demand forecast uncertainty due to COVID-19. However, demand is expected to experience upward pressure from economic and demographic growth in the long term. Growth will also come from the electric vehicle market, the electrification of transit, and the movement away from carbon fuels to cleaner electricity. At the same time, structural changes in Ontario's economy are changing its composition from an energy–intensive industrial economy to one that is more service-oriented. These combined factors translate into an overall increase in energy demand over the forecast horizon.

Demand Side Management: Future capacity auctions will enable DR, including dispatchable loads and hourly DR resources, to compete with other resources. Resources with capacity obligations are required to be available for curtailment up to their secured capacity during times of system need. The December 2019 DR auction procured 858.6 MW for the six-month summer commitment period beginning on May 1, 2020, and 919.3 MW for the six-month winter commitment period beginning on November 1, 2020.

Distributed Energy Resources: The 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 electricity 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-quick-start resources or schedule transactions on the interties to manage supply and demand. Currently, to manage this variability, IESO initiates actions like committing dispatchable generation, curtailing intertie transactions, and scheduling additional 30-minute operating reserve to signal flexibility need.

Generation: Nuclear refurbishments at Bruce and Darlington generating stations 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/longer term. One unit at Darlington Nuclear Generating Station returned to service in May 2020 from a four-year refurbishment outage. The retirement of Pickering Nuclear Generating Station is currently proposed to be deferred to 2024/2025 from 2022/2024. Napanee Generating Station, a 994 MW natural-gas-fired plant, was added in March 2020. Contracted wind resources amounting to 360 MW are expected to be added to the grid in 2020. 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 light 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.

Energy Storage: Capacity from transmission connected storage is 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 are 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: As part of the electricity trade agreement between Ontario and Quebec, Ontario will supply 500 MW of capacity to Quebec each winter from December to March until 2023. Ontario has the option to receive 500 MW of capacity from Quebec for one summer before 2030. 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 the IESO to be above Ontario's required reserve margin levels over summer or winter season are exported. Furthermore, system-backed capacity import resources will be able to participate in the future capacity auctions.

Transmission: A new 400–450 km long 230 kV double-circuit transmission line is planned to come into service in Q4 2021 to reinforce the connection of Northwestern Ontario to the rest of the provincial grid. Planning is underway to reinforce several 230 kV transmission lines by 2023 to increase the supply capability into the Central Toronto area. 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. In the Ottawa area, IESO has requested that work proceed to upgrade circuits between Merivale TS and Hawthorne TS with a planned in-service date of Q4 2022; this project will address supply capacity constraints to West Ottawa and support the deliverability of capacity imports from Québec. In Eastern Ontario, high voltage levels have been observed due to low transfer levels across the 500 kV transmission system. To mitigate the issue, two 500 kV line-connected shunt reactors will be installed with a planned in-service date of Q4 2021.

Reliability Issues: Natural gas is delivered to Ontario from neighboring jurisdictions by mainlines and distribution utilities. Situated in Ontario is the Dawn storage 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.

Probabilistic Assessment Overview

General Overview: The Ontario area is summer-peaking. No LOLH was observed. The estimated EUE is negligible. The 50/50 peak demand forecast for 2022 increased by about 2.5% compared to the 2018 forecast.

Modeling: Assumptions used in this ProbA are consistent with those used in *NPCC 2020 Long Range Adequacy Overview.* The GE MARS model developed by the NPCC CP-8 Working Group was used to model demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures as prescribed by the NPCC resource adequacy criterion.

The Ontario demand forecast includes the impact of conservation, time-of-use rates, and other price impacts as well as the effects of embedded (distribution connected) generation. However, the demand forecast does not include the impacts of "controllable" DR programs, such as dispatchable loads and DR; the capacity from these programs is treated as resource. Modeling details include the following:

- Annual peak demand in the Ontario Area varies by +11% of forecasted Ontario area demand based upon the 90/10% points of LFU distributions.
- Ontario capacity values and planned outage schedules for thermal units are based on monthly maximum continuous ratings and planned outage information contained in market participant submissions. The available capacity states and state transition rates for each existing thermal unit are derived based on analysis of a rolling five-year history of actual forced outage data. For existing units with insufficient historical data and for new units, capacity states and the state transition rate data of existing units with similar size and technical characteristics are applied.
- Hydroelectric resources are modelled as capacity-limited and energy-limited resources. Minimum capacity, maximum capacity, and monthly energy values are determined on an aggregated basis for each zone based on historical data since market opening in 2002.
- Historical hourly profiles are used to model solar generation.
- Historical hourly load profiles are used to model wind generation.

Probabilistic vs. Deterministic Assessments: The following highlight significant differences between these types of assessments:

- The loads for each area were modeled on an hourly, chronological basis; the loads for Ontario are based on the 2002 actual weather for the summer period and the 2003/2004 actual weather for the winter period.
- The Ontario area modeled operating procedures that included reduced operating reserves, voltage reduction, public appeals, and implementation of DR programs before firm load has to be disconnected.
- In Ontario, DR is treated as a resource instead of a load modifier.
- Ontario transmission additions and retirements assumed were consistent with this *NERC 2020 LTRA*
- In the NPCC ProbA simulations, all areas received assistance on a shared basis in proportion to their deficiency. In the analysis, each step was initiated simultaneously in all areas and sub-areas.

Base Case Study

The 50/50 peak demand forecast for 2022 has increased by about 2.5% compared to the 2018 forecast. No material difference in estimated LOLH and EUE is observed between the two assessments.

Probabilistic Base Case results outside of the on-peak hour
The Ontario area is summer peaking; the LOLH risk occurs during the summer months. No LOLH was observed.

Probabilistic Base Case results of EUE
The Ontario area is summer peaking; EUE risk occurs during the summer months. The estimated EUE was is negligible.

NPCC 2019 Ontario Interim Review of Resource Adequacy

In accordance with the NPCC Regional Reliability Reference Directory #1, "Design and Operation of the Bulk Power System," the *2019 Interim Review of Resource Adequacy* covers the study period from 2020 through 2023 and identifies changes in assumptions from the 2018 comprehensive review, including changes to facilities and system conditions, generation resources' availability, demand forecast, and the impact of these changes on the overall reliability of the Ontario electricity system.[58] The results conclude that Ontario will be able to meet the NPCC resource adequacy criterion that limits the LOLE to no more than 0.1 days/year for all years within the study period (2020–2023) for both demand scenarios.

For the median demand growth scenario, the NPCC criterion is satisfied for 2020–2022 forecast years with existing and planned resources. For the 2023 forecast year, the invoking of emergency operating procedures and 501 MW of tie benefits would be required to meet the LOLE criterion.

For the high demand growth scenario, the NPCC criterion is met for 2020 and 2021 forecast years with existing and planned resources. For the 2022 and 2023 forecast years, the invoking of emergency operating procedures and the use of up to 2,707 MW of tie benefits would be required to meet the LOLE criterion.

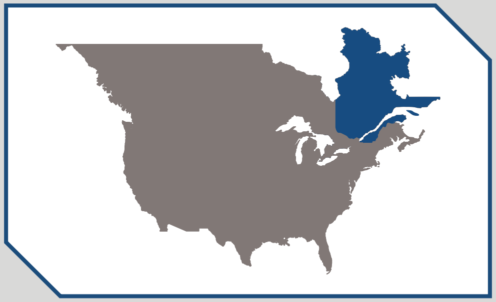
58 https://www.npcc.org/content/docs/public/library/resource-adequacy/2019/ieso-2019-interim-review-for-rcc-v3.0-for-posting-003-.pdf

Base Case Summary of Results			
Reserve Margin (RM) %			
	2022*	**2022**	**2024**
Anticipated	23.6%	20.1%	11.3%
Reference	18.5%	23.8%	16.8%
ProbA Forecast Operable	11.5%	12.6%	4.4%
Annual Probabilistic Indices			
	2022*	**2022**	**2024**
EUE (MWh)	0.00	0.000	0.049
EUE (ppm)	0.00	0.000	0.000
LOLH (hours/year)	0.00	0.000	0.000

*Represents the 2018 ProbA results for 2022.

Regional Risk Scenario

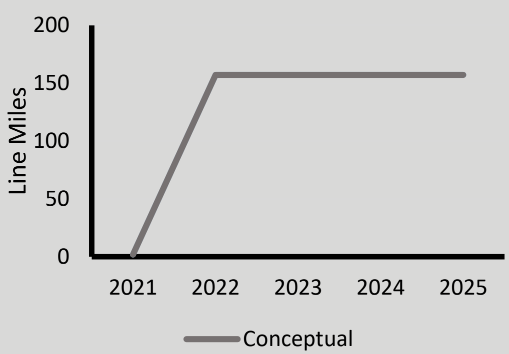
Ontario started its nuclear refurbishment program in 2016 to extend the life of 10 nuclear units. A Darlington unit is back in service after refurbishment since early 2020. The rest of the units will undergo refurbishment for the next 13 years. At times, up to 4 units may be out of service for refurbishment. There is a risk that project of this magnitude may incur delays, the reason for the IESO to pick refurbishment project delays for risk scenario; the demand forecast is increased by 5% for risk scenario.



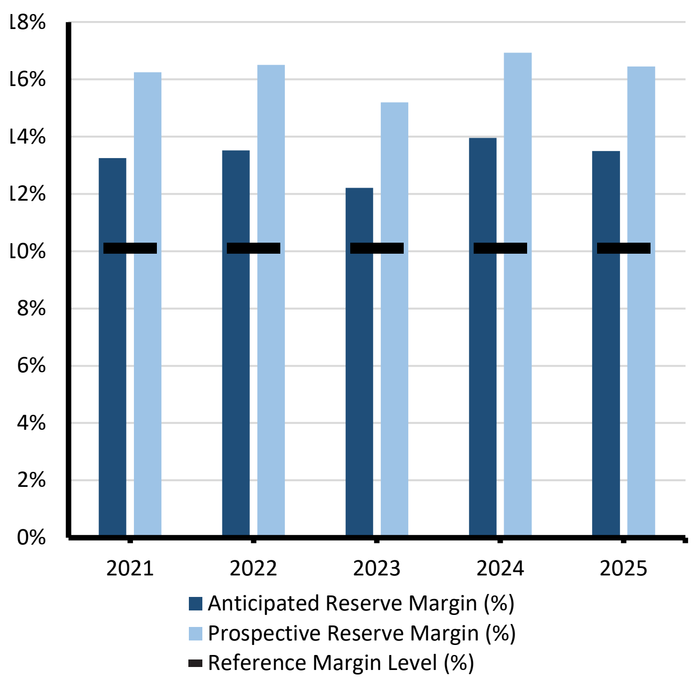
NPCC-Québec

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

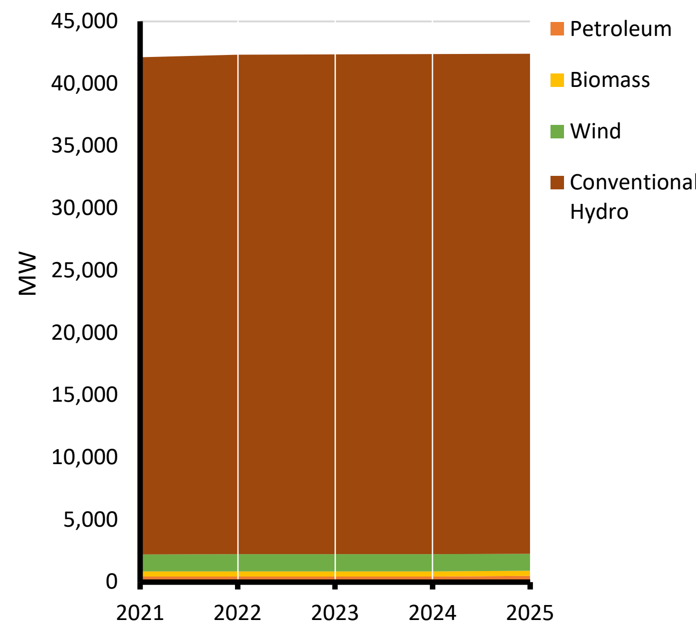
Demand, Resources, and Reserve Margins (MW)										
Quantity	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Internal Demand	39,308	39,703	40,067	40,366	40,718	41,055	41,374	41,696	41,987	42,258
Demand Response	2,565	2,780	3,117	3,309	3,480	3,553	3,564	3,580	3,581	3,582
Net Internal Demand	36,743	36,923	36,950	37,056	37,238	37,502	37,810	38,117	38,406	38,676
Additions: Tier 1	71	325	344	366	366	366	366	366	366	366
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	-499	-417	-888	-145	-145	-145	-145	-145	-145	-145
Existing-Certain and Net Firm Transfers	41,542	41,591	41,120	41,863	41,897	41,855	41,791	41,755	41,710	41,710
Anticipated Reserve Margin (%)	13.3%	13.5%	12.2%	14.0%	13.5%	12.6%	11.5%	10.5%	9.6%	8.8%
Prospective Reserve Margin (%)	16.2%	16.5%	15.2%	16.9%	16.4%	15.5%	14.4%	13.4%	12.4%	11.6%
Reference Margin Level (%)	10.1%	10.1%	10.1%	10.1%	10.1%	10.1%	10.1%	10.1%	10.1%	10.1%



Projected Transmission Circuit Miles



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM remains above the RML except for the two last winter periods of this assessment. However, the PRM is above the RML for all seasons and years during the assessment period.
- Approximately 401 MW of capacity additions are expected over this assessment period. The Romaine-4 hydro unit (245 MW) is expected to be commissioned by 2022.
- A total of 500 MW of firm import capacity from Ontario is available to Quebec each winter through Winter 2022–2023 as part of an existing trade agreement between Québec and Ontario.
- The commissioning of the second Micoua-Saguenay 735 kV line is expected in 2022.

Québec Fuel Composition										
Generation Type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Petroleum	436	436	436	436	486	490	493	497	500	500
Biomass	404	413	413	413	413	389	358	358	358	358
Wind	1,371	1,371	1,371	1,371	1,356	1,301	1,264	1,225	1,177	1,177
Conventional Hydro	39,900	40,112	40,131	40,153	40,153	40,186	40,186	40,186	40,186	40,186
Total MW	42,111	42,333	42,351	42,373	42,408	42,366	42,302	42,266	42,221	42,221

NPCC-Quebec Assessment

Planning Reserve Margins: The ARM is based on existing and anticipated generating capacity and firm capacity transfers. It is below the RML for the last two winter periods of the assessment period. However, the PRM remains above the RML for all seasons and years during the assessment period. Under the Prospective Scenario, a total of 1,100 MW of expected capacity supply are 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.

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 Quebec area demand forecast average annual growth is 0.8% during the 10-year period.

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 1,730 MW on Winter 2020–2021 peak demand. The area is also expanding its existing interruptible load program for commercial buildings, which will have an impact of 310 MW in 2020–2021, 150 MW for Winter 2021–2022, and then growing to 300 MW by 2026–2027. Another similar program for residential customers is under development and should gradually rise from 57 MW for Winter 2020–2021 to 621 MW for Winter 2030–2031.

New dynamic rate options for residential and small commercial or institutional customers will also contribute to reducing peak load during winter periods by 79 MW for Winter 2020–2021, increasing to 195 MW for Winter 2030–2031.

Moreover, data centers specialized in blockchain applications, which are part of new developments in the commercial sector, are required to reduce their demand during peak hours at Hydro-Quebec Distribution's request. Their contribution is expected to be around 160 MW over the period of this assessment.

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

Distributed Energy Resources: Total installed BTM capacity (solar PV) is expected to increase to more than 500 MW in 2031. Solar PV is accounted for in the load forecast. Nevertheless, since Quebec is a winter-peaking area, DERs on-peak contribution ranges from 1 MW for Winter 2020–2021 to 10 MW for Winter 2030–2031.

No potential operational impacts of DERs are expected in the Quebec area, considering the low DER penetration in the area.

Generation: The Romaine-4 unit (245 MW) was expected to be fully operational in 2021, but its commissioning is delayed to 2022. The refurbishment of the Rapide-Blanc generating station is expected to start next year. The integration of small hydro units also accounts for 41 MW of new capacity during the assessment period. For other renewable resources, about 371 MW (134 MW on-peak value) of wind capacity has been added to the system since 2018 and 54 MW (20 MW on-peak value) is expected to be in service by 2021. Additionally, 61 MW of new biomass is expected to be in service by 2022. Finally, 9.5 MW of solar resource will be in service by the end of this year; its impact at the peak time period is not significant.

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, where another 735 kV circuit is out-of-service on the same interface (and 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 2022. Simulations performed on the 2023–2024 and 2028–2029 systems confirm the effectiveness of this solution. Until then, this issue is monitored and addressed in real-time with a system operating limit and limited power transfer if an overload risk is detected. This new line is currently at the permitting stage and is expected to be in service in 2022.

Transmission: The Romaine River Hydro Complex Integration project is presently underway; its total capacity will be 1,550 MW. Romaine-2 (640 MW) has been commissioned in 2014, Romaine-1 (270 MW) in 2015, and Romaine-3 (395 MW) in 2017. Romaine-4 (245 MW) was planned be in service in 2020, but its commissioning is delayed to 2022. A new 735 kV line extending some 250 km (155 miles) between Micoua substation in the Côte-Nord area and Saguenay substation in Saguenay–Lac–Saint-Jean is now under construction phase and is planned to be in service in 2022. The project also includes adding equipment to both substations and expanding Saguenay substation.

Probabilistic Assessment Overview

General Overview: The Québec area is a winter-peaking area. No LOLH or EUE was observed. The ARMs are above the 10.1% RML for both 2022 and 2024.

Modeling: Assumptions used in this ProbA are consistent with those used in the *NPCC 2020 Long Range Adequacy Overview*.[59] The GE MARS model developed by the NPCC CP-8 Working Group was used to model demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnection with neighboring Planning Coordinator areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures as prescribed by the NPCC resource adequacy criterion. Modeling details are provided as follows:

- The Québec demand forecast is built on the forecast from four different consumption sectors—domestic, commercial, small and medium-size industrial, and large industrial. The model types used in the forecasting process are different for each sector and are based on end-use and/or econometric models. They consider weather variables, economic-driver forecasts, demographics, EE, and different information about large industrial customers. This forecast is normalized for weather conditions based on an historical trend weather analysis.
- Annual peak demand in the Quebec area varies by +9% of forecasted Ontario area demand based upon the 90/10% points of load forecast LFU distributions.
- For thermal units, maximum capacity in the Québec area is defined as the net output a unit can sustain over a two-consecutive hour period.
- In Québec, hydro resources maximum capacity is set equal to the power that each plant can generate at its maximum rating during two full hours while expected on-peak capacity is set equal to maximum capacity minus scheduled maintenance outages and restrictions.
- In Québec, BTM generation (solar and wind) is estimated at approximately 10 MW and doesn't affect the load monitored from a network perspective.
- In Quebec, wind capacity credit is set for the winter time as the system is winter peaking. Capacity credit of wind generation is based on a historical simulated data adjusted with actual data of all wind plants in service in 2015. For the summer period, wind power generation is derated by 100%.

Probabilistic vs. Deterministic Assessments
The following highlight significant differences between these types of assessments:

- The loads for each area were modeled on an hourly, chronological basis and based on the 2002 load shape for the summer period and the 2003/2004 load shape for the winter period.
- Québec modeled operating procedures that include reduced operating reserves, voltage reduction, and interruptible load programs before firm load has to be disconnected.
- DR programs in Québec are specifically designed for peak-load reduction during winter operating periods are mainly interruptible load programs.
- Transmission additions and retirements assumed were consistent with this NERC *2020 LTRA*.
- In the NPCC ProbA simulations, all areas received assistance on a shared basis in proportion to their deficiency. In the analysis, each step was initiated simultaneously in all areas and sub-areas.

59 NPCC Resource Adequacy documents are posted in the NPCC library: https://www.npcc.org/library/resource-adequacy

Base Case Study

The forecast 50/50 peak demand for 2022 is lower than reported in the previous study with higher estimated forecast PRM and forecast operablereserve margins. No LOLH and EUE difference is observed from the last assessment.

Probabilistic Base Case results outside of the on-peak hour
The Quebec area is winter peaking; the LOLH risk occurs during the winter months. No LOLH was observed

Probabilistic Base Case results of EUE
The Quebec area is winter peaking; EUE risk occurs during the winter months. No EUE was observed.

NPCC 2019 Québec Area Interim Review of Resource Adequacy

The Québec area's assessment of resource adequacy complies with the RAP established by the NPCC. The guidelines for the review are specified in Appendix D of the NPCC Regional Reliability Reference Directory No. 1, "Guidelines for Area Review of Resource Adequacy." This *2019 Interim Review of Resource Adequacy* is the second update from the last Comprehensive Review, and covers the study period from Winter 2019–2020 through Winter 2021–2022.[60]

Changes in assumptions since the last comprehensive review and the impact of these changes on the overall reliability of the Québec electricity system are highlighted herein. The internal demand forecast has been revised upward since the last comprehensive review is due mainly to an increase in the residential and the commercial sectors sales. Planned resources were also revised upward due mostly to new DR programs and to an increase in wind resources peak contribution. Results of this interim review show that the LOLE for the Québec area is below the NPCC reliability criterion of not more than 0.1 day per year for all years of this assessment in the Base Case and the High Case scenarios.

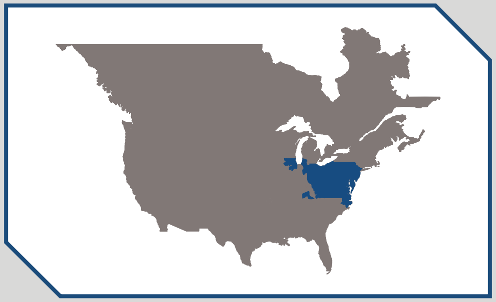
60 https://www.npcc.org/content/docs/public/library/resource-adequacy/2019/2019-quebec-interim-review-approved-by-the-rcc-on-december-3-2019.pdf

Base Case Summary of Results			
Reserve Margin (RM) %			
	2022*	**2022**	**2024**
Anticipated	15.0%	13.5%	14.0%
Reference	12.6%	10.1%	10.1%
ProbA Forecast Operable	7.1%	11.0%	7.1%
Annual Probabilistic Indices			
	2022*	**2022**	**2024**
EUE (MWh)	0.00	0.000	0.000
EUE (ppm)	0.00	0.000	0.000
LOLH (hours/year)	0.00	0.000	0.000

*Represents the 2018 ProbA results for 2022.

Regional Risk Scenario

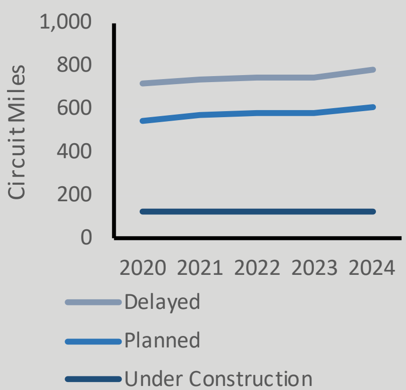
Tier 1 future resources included in the Base Case, consisting of conventional hydro, biomass, and wind units are removed in this scenario.



PJM

PJM Interconnection is an RTO that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.

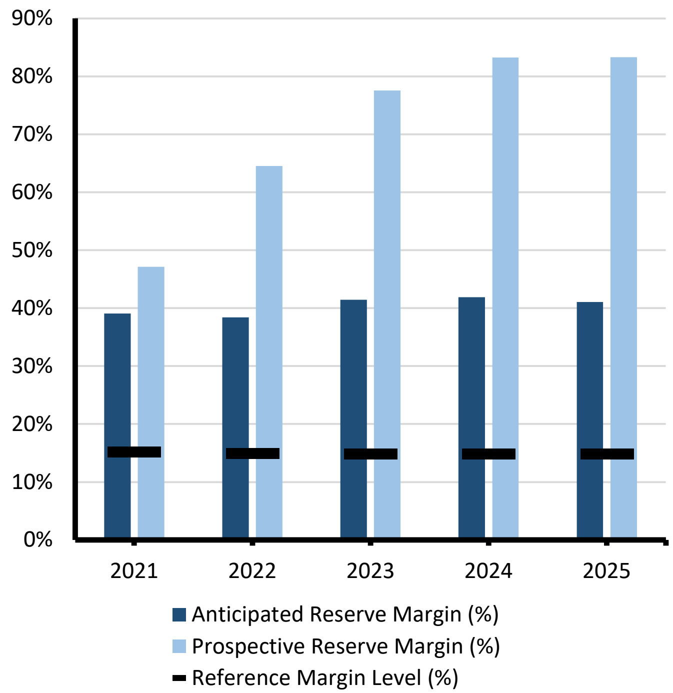
PJM serves 65 million people and covers 369,089 square miles. PJM is a BA, Planning Coordinator, Transmission Planner, Resource Planner, Interchange Authority, Transmission Operator, Transmission Service Provider, and RC.



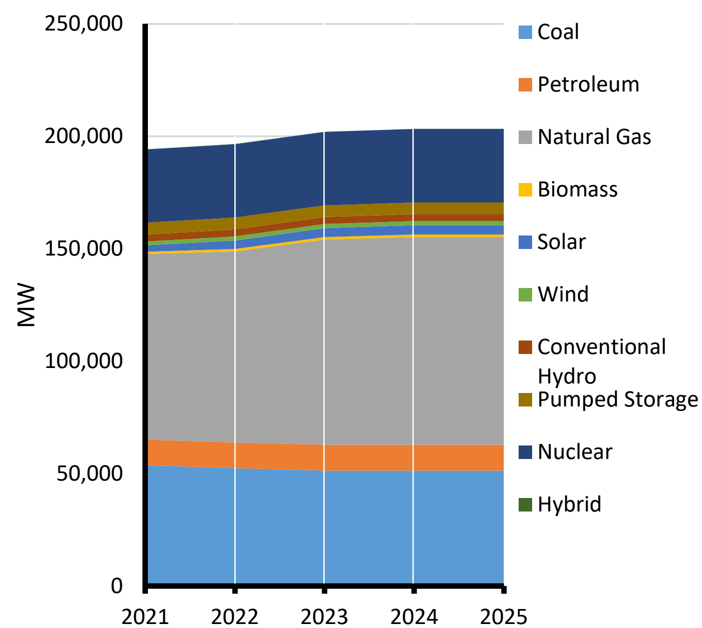
Projected Transmission Circuit Miles

Demand, Resources, and Reserve Margins (MW)

Quantity	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Internal Demand	149,616	151,051	151,898	152,443	153,315	154,499	155,441	156,014	156,556	157,132
Demand Response	8,955	9,036	9,067	9,125	9,172	9,209	9,254	9,293	9,338	9,375
Net Internal Demand	140,661	142,015	142,831	143,318	144,143	145,290	146,187	146,721	147,218	147,757
Additions: Tier 1	10,618	15,212	21,715	22,984	22,997	22,997	22,997	22,997	22,997	22,997
Additions: Tier 2	11,299	35,611	50,086	57,837	59,383	60,071	60,536	60,536	60,699	60,848
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	1,460	0	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	185,031	181,349	180,335	180,335	180,335	180,335	180,335	180,335	180,335	180,335
Anticipated Reserve Margin (%)	39.1%	38.4%	41.5%	41.9%	41.1%	40.0%	39.1%	38.6%	38.1%	37.6%
Prospective Reserve Margin (%)	47.1%	64.5%	77.6%	83.2%	83.3%	82.3%	81.5%	80.8%	80.3%	79.8%
Reference Margin Level (%)	15.1%	14.9%	14.8%	14.8%	14.8%	14.8%	14.8%	14.8%	14.8%	14.8%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

The ARMs for each year in the assessment period do not fall below the Installed Reserve Requirement in PJM.

PJM Fuel Composition										
Generation Type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal	53,683	52,405	51,391	51,391	51,391	51,391	51,391	51,391	51,391	51,391
Petroleum	11,432	11,432	11,432	11,432	11,432	11,432	11,432	11,432	11,432	11,432
Natural Gas	82,519	84,915	91,205	92,389	92,389	92,389	92,389	92,389	92,389	92,389
Biomass	1,054	1,104	1,104	1,104	1,104	1,104	1,104	1,104	1,104	1,104
Solar	2,794	3,829	4,041	4,127	4,140	4,140	4,140	4,140	4,140	4,140
Wind	1,754	1,829	1,829	1,829	1,829	1,829	1,829	1,829	1,829	1,829
Conventional Hydro	3,072	3,095	3,095	3,095	3,095	3,095	3,095	3,095	3,095	3,095
Pumped Storage	5,229	5,229	5,229	5,229	5,229	5,229	5,229	5,229	5,229	5,229
Nuclear	32,626	32,626	32,626	32,626	32,626	32,626	32,626	32,626	32,626	32,626
Hybrid	7	73	73	73	73	73	73	73	73	73
Other	20	25	25	25	25	25	25	25	25	25
Total MW	194,189	196,561	202,050	203,319	203,332	203,332	203,332	203,332	203,332	203,332

PJM Assessment

PJM performs an annual LOLE study to determine the IRM required satisfying the ReliabilityFirst BAL-502-RFC-02 standard. This reliability assurance agreement establishes the "one loss of load event in 10 years" LOLE criterion. The general requirements and obligations concerning PJM resource adequacy are defined in PJM's reliability assurance agreement among LSEs in the PJM area. The Probabilistic Reliability Index Study Model program is the principal tool used to calculate the PJM reserve requirement. The model recognizes the following factors: generation availability rates based on forced, planned and maintenance outages, LFU, and likely emergency assistance from adjacent areas. Each generator in PJM and in the external areas of NY-ISO, MISO, SERC, and TVA is modeled with unit-specific performance statistics. Wind and solar units are modeled at their average output over high load summer hours. Any project in the PJM generator interconnection queue that has executed an Interconnection service agreement is included in the model based on its expected in-service date. Energy-only resources are not included in the model. DR resources are considered generation resources. External areas are modeled at their "1-in-10" reserve levels and a single interconnection tie rated at the capacity benefit margin of 3,500 MW is assumed between PJM and its neighbors. The IRM for the delivery year beginning on June 1, 2020, is 15.5%. The IRM is expressed as a percent above the annual peak demand forecasted for Summer 2020.

Because PJM has extensive capacity resources, risk for capacity shortages during nonpeak periods are minimal. The highest risk periods are the end of the spring and fall outage seasons when numerous outages are taken to maintain generation and transmission. Some outages can take longer than planned and extend into the beginning of the peak period (June 1 through September 15 and December 1 through March 15). Careful planning and operational time frame outage denial minimize the risks of possible capacity shortages.

The PJM Interconnection produces an independent peak load forecast of TID by 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. The model is estimated over historical data back to 1998 (22 years of historical data) and is used to produce a 15-year forecast for PJM transmission zones, locational deliverability areas, and the RTO. LDA and RTO forecasts are produced using a bottom-up approach, forecasting zonal contributions and aggregating.

To develop forecasts, each econometric model is solved by moving through the year day-by-day and by using forecasted economic variables, equipment indexes, and historical weather patterns for each day. To model the most likely weather conditions, a weather rotation technique is used to simulate a distribution of daily load scenarios tied to historical weather observations, representing actual weather patterns that occurred across the PJM area. To enhance the simulation process, each yearly weather pattern is shifted by each day of the week moving forward six days and backwards six days, providing 13 different weather scenarios for each historical year. After ranking the scenario forecasts by MW value, the median value is selected as the base (or 50/50) forecast while the ninetieth percentile (or 90/10) result is used as the extreme weather forecast. These values are established for monthly and seasonal peaks.

Separately from the modeled forecast, a forecast of the peak impact of distributed solar generation is developed, using internal installed solar capacity data and a forecast of solar capacity additions obtained from a vendor. 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 forward capacity market. The load management forecast is used to develop the net internal demand forecast.

The energy and peak load models use the same specification with only the dependent variable being different.

DR resources can participate in all PJM Markets: capacity, energy, and ancillary services. PJM requires that PJM member third-party suppliers (curtailment service providers) bring these resources to PJM markets, and it is the responsibility of these curtailment service providers to acts as market operating centers that relay PJM instructions for load reductions in any of the markets to these resources.

In early 2015, recognizing the growing market of solar installations, PJM began to investigate and develop a plan to incorporate distributed solar generation into the long-term load forecast. For the purposes of the long-term load forecast, PJM defines distributed solar generation as any solar resource that is not interconnected to the PJM markets. These resources do not go through the full interconnection queue process and are not included as capacity or as energy resources in PJM's markets. Furthermore, the output of these resources is netted directly with the load. PJM does not receive metered production data from any of these resources.

There have been no current or anticipated operational impacts of DERs noted in PJM.

PJM expects[61] 3,006 MW of solar DERs at the time of the peak in 2023 and 5,445 MW in 2030. The effects of solar DERs are included in the load forecast for PJM. No effect of solar DERs is incorporated in the winter load forecast since winter expected peak occurs after sundown.

PJM's RTEP process continues to manage an unprecedented capacity shift driven by federal and state public policy and broader fuel economics. Factors affecting the RTEP process include the following:

- New generating plants powered by Marcellus and Utica shale natural gas
- New wind and solar units driven by federal and state renewable incentives
- Generating plant deactivations
- Market impacts introduced by demand resources and EE programs
- Natural-gas-fired generation capacity now exceeds coal

Variable resources are only counted partially for PJM resource adequacy studies. Both wind and solar initially utilize class average capacity factors that are 13% for wind and 38% for solar. Performance over the peak period is tracked and the class average capacity factor is supplanted with historic information. After three years of operation, only historic performance over the peak period is used to determine each unit's capacity factor. Variable energy resources are treated the same regardless of status as an existing or planned (Tier) resource. Biomass and hydro is counted at 100% of reported capacity because these resources are typically only fully utilized over the peak period of the day.

Coal retirements continue but at a fully manageable pace. New large natural gas unit development has kept pace with the retirements. Since load growth is minimal, resource adequacy is adequate and is anticipated in the future. No studies with severe retirement scenarios have been performed, but history has shown that the PJM forward capacity market will incent adequate replacement power to be built.

In PJM, a generation owner has to notify PJM no less than 90 days from the generator's intended deactivation date. Many report more in advance than the 90-day requirement. Within 30 days of the deactivation notification, PJM will notify the Generation Owner if deactivating the unit will adversely effect reliability. If there are no reliability issues, the unit can deactivate as intended. If there are reliability impacts, the notice will include the specific reliability impacts. The effected TO will provide an initial estimate of the period of time it will take to complete the transmission upgrades necessary to alleviate reliability impact. If the generator retirement needs to be delayed, the Generator Owner may file with FERC for full cost recovery associated with operating the unit until it may be deactivated. Black start resources require up to two years advanced notice to maintain the rolling two-year commitment per the PJM tariff.

PJM does not rely on significant transfers to meet resource adequacy requirements. Maximum transfer (total transmission interchange capability) into PJM would amount to less than 2% of PJM's internal generation capability. At no time within this assessment period does the anticipated capacity get anywhere near 2%. PJM reliability would not be negatively affected if transfers dropped to zero.

Since 1999, the PJM board has approved transmission system enhancements that total approximately $37.3 billion. Of this, approximately $30 billion represent baseline projects to ensure compliance with NERC, regional, and local transmission owner planning criteria and to address market efficiency congestion. An additional $6.4 billion represent network facilities to enable nearly 90,000 MW of new generation to interconnect reliably.

The $1.27 billion of baseline transmission investment approved during 2019 continues to reflect the shifting dynamics driving transmission expansion. New largescale transmission projects (345 kV and above) have become uncommon as RTO load growth has fallen below 0.5%. Aging infrastructure, grid resilience, shifting generation mix, and more localized reliability needs are now more frequently driving new system enhancements. Much of the new investment that is occurring at 500 kV is to address existing, aging transmission lines, many of which were constructed in the 1960s and 1970s.

The goal of the PJM capacity market is to provide enough capacity to meet the PJM load forecast and the PJM reserve requirement at the lowest possible cost. It is anticipated that the PJM capacity market will continue to support compliance with PJM reserve requirement in the future. The PJM Regional Transmission Expansion Plan analysis determines the transmission expansion necessary to meet the load forecast and generator development plans.

61 https://www.pjm.com/-/media/library/reports-notices/load-forecast/2020-load-report.ashx?la=en

Probabilistic Assessment Overview

- **General Overview:** LOLH and EUE are zero for both 2022 and 2024 due to the fact that the forecast operable reserve margins for those years are well above the corresponding reference reserve margin as shown in the Base Case Summary of Results table on the next page. These results are similar to the results from the 2018 ProbA. The study was performed using the same methodology as in the 2018 ProbA.

- **Modeling:** The assessment was performed in GE-MARS by using Monte-Carlo simulation. PJM was divided in five sub-areas that are interconnected with a transportation/pipeline approach. External areas were modeled using a detailed representation (NPCC) and at planned reserve margin (MISO, TVA, VACAR). Modeling details are provided as follows:

    - Internal and external load shapes were from Summer 2002 and Winter 2004 and adjusted to match monthly and annual peak forecast values from the 2020 PJM load forecast.[62] LFU was modeled on a monthly basis by using a normal distribution discretized in seven steps (90/10 forecast load values are estimated to be approximately 6% above the 50/50 forecast load values).

    - Thermal and hydro unit performance was modeled by using an on-or-off sequence based on Monte-Carlo simulation. Data on unit performance is from the period 2015–2019.

    - DSM was modeled as an emergency operating procedure as most of the DSM in PJM is emergency DSM.

    - Intermittent generators were modeled as thermal resources at their respective capacity values (average summer capacity value for wind is 13% while for solar is 38%).

    - Firm exports/imports were explicitly modeled while the limits on the transportation/pipeline interfaces were calculated based on a first contingency total transfer capability analysis.

- **Probabilistic vs. Deterministic Assessments:** For Summer 2022 and Summer 2024, the probabilistic reserve margin in slightly lower than the deterministic value due to 2,500 MW of estimated on-peak capacity derates as a result of above-average summer ambient conditions.

62 https://www.pjm.com/-/media/library/reports-notices/load-forecast/2020-load-report.ashx

Base Case Study

- LOLH and EUE are zero for both 2022 and 2024 due to large forecast operable reserve margins. The reserve margins are significantly above the reference values of 14.9% and 14.8%, respectively.
- **Results trending:** The 2022 LOLH and EUE in the 2020 ProbA are identical to the corresponding values reported in the 2018 ProbA. The 2022 LOLH and EUE values in the 2018 ProbA were zero due to a large forecast operable reserve margin. In the 2020 ProbA, the 2022 forecast operable reserve margin is even larger, explaining the zero value for LOLH and EUE.

Key methods and assumption differences between the 2020 LTRA and ProbA Assessments.
The major difference in assumptions between the *2020 LTRA* and the 2020 ProbA assessments is the consideration of 2,500 MW of estimated on-peak capacity derates due to above-average summer ambient conditions in the ProbA. These derates are not part of the forced outage data and therefore must be modeled explicitly in the study. PJM takes this approach as well in its reserve requirement study that calculates PJM's installed reserve margin.

Probabilistic resource adequacy studies that address area reliability risk drivers.
PJM performs two additional resource adequacy studies on a regular basis (annually). The reserve requirement study (RRS) and the capacity emergency transfer objective (CETO) study. The RRS has two objectives: establish a system-wide reliability requirement for PJM's capacity market and show that PJM is projected to meet the 1-day-in-10 years LOLE criterion for a period of 10 years in the future. The CETO study also has two objectives: establish zonal reliability requirements for PJM's capacity market and establish the amount of imports a zone needs in order to maintain reliability.[63]

Both studies, RRS and CETO, are similar in nature: they are probabilistic, considering load and resource performance uncertainty. The main difference between the two studies is that the RRS analyzes the entire PJM footprint assuming no transmission constraints while the CETO focuses on each one of PJM's LDAs.

63 The most recent RRS: https://pjm.com/-/media/committees-groups/committees/pc/2020/20201006/20201006-item-05b-2020-pjm-reserve-requirement-study-draft.ashx . CETO does not have its own report, however, results from recent runs can be found in the Planning Parameters sheet posted prior to a capacity market auction: https://pjm.com/markets-and-operations/rpm.aspx

Base Case Summary of Results			
Reserve Margin (RM) %			
	2022*	**2022**	**2024**
Anticipated	35.2%	38.4%	41.9%
Reference	15.8%	14.9%	14.8%
ProbA Forecast Operable	22.5%	25.6%	29.0%
Annual Probabilistic Indices			
	2022*	**2022**	**2024**
EUE (MWh)	0.000	0.000	0.000
EUE (ppm)	0.000	0.000	0.000
LOLH (hours/year)	0.000	0.000	0.000

*Indicates 2018 ProbA results for comparison.

The two studies are complementary to each other: by focusing in each of PJM's LDAs, making sure that the amount of imports needed into an LDA are deliverable by the transmission system, the CETO study provides validation of the no transmission constraints assumption in the RRS.

Considered jointly, the RRS and the CETO studies have the same objective that the ProbA has: analyzing the full resource adequacy picture in the PJM footprint. There are differences; the most notable difference is that the RRS and CETO only focus on daily peak loads. This assumption is supported by PJM peak load patterns as well as the low penetration of intermittent resources relative to system size.

Other important differences between the ProbA and the RRS/CETO:

- RRS and CETO are performed with PJM's LOLE tool.
- RRS models PJM's neighboring system but combines them into a single area.
- RRS does not explicitly model DR.
- RRS and CETO both use convolution (instead of Monte-Carlo) to derive the available capacity distribution.
- RRS and CETO assume that forced outages during winter peak week conditions are not independent.

Probabilistic Base Case results outside of the on-peak hour

PJM's ProbA shows no LOLH or EUE for 2022 and 2024 due to large forecast operable reserve margins. These large margins are the result of significant new entry in PJM's capacity market, the reliability pricing model, and retirements/ deactivations that have lagged behind new entry.

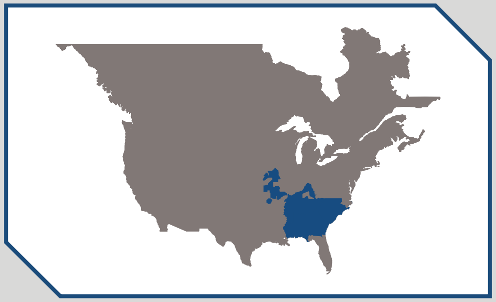
Notwithstanding the large forecast operable reserve margins, emergency actions (e.g., calling emergency DR) could occur during the summer peak period (due to high loads), shoulder period (due to planned outage scheduling), or winter peak period (due to large amount of forced outages).

Regional Risk Scenario

PJM chose the removal of Tier 1 units as its Regional Risk scenario to stress the system under a much lower reserve margin.

PJM selected Years 2 and 4 because it has not been able to run capacity market auctions for Year 2 (due to the MOPR proceedings at FERC), rendering the resource mix for 2022 uncertain.

PJM chose to also remove Tier 1 resources in neighboring NPCC for this scenario. In MISO, TVA, and VACAR the decision was to keep the same resource mix as in the Base Case due to the fact that these areas are modeled at a planned reserve margin.



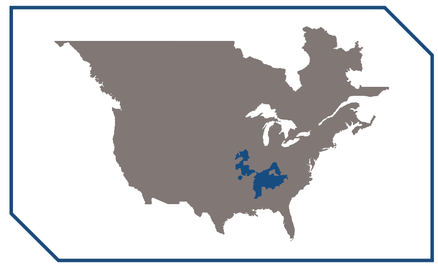
SERC

On April 30, 2019, FERC issued an order formally approving the transfer of all registered entities in the Florida Reliability Coordinating Council (FRCC) RE to SERC by July 1, 2019. The integration of FRCC entities resulted in an additional SERC sub-region and SERC assessment area for inclusion in NERC's reliability assessments.

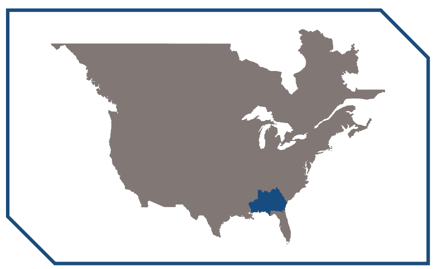
SERC is a summer-peaking assessment area that covers approximately 308,900 square miles and serves a population estimated at 39.4 million. SERC is divided into four assessment areas: SERC-E, SERC-N, SERC-SE, and SERC-FP. The SERC RE includes 36 Balancing Authorities, 21 Planning Authorities, and 4 Reliability Coordinators.

Highlights

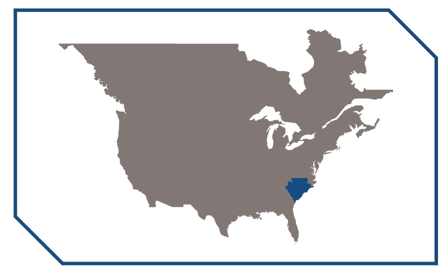
- All SERC sub-regions are near or above the 20% reserve margin for the assessment horizon.
- SERC entities continue to build new transmission lines (over 2,600 miles) over the assessment period to integrate new generation facilities and to continue to maintain a reliable interconnected power system.
- The members of SERC actively participate in the SERC Variable Energy Working Group. This working group continues to monitor the growth of variable energy in the SERC area and makes recommendations on appropriate regional studies or actions.



SERC-C

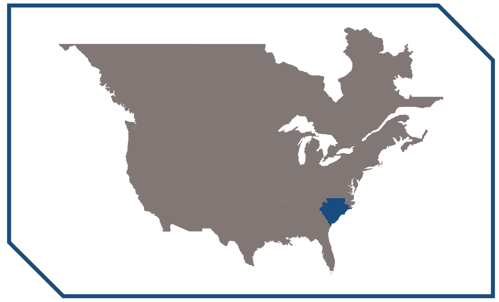


SERC-SE



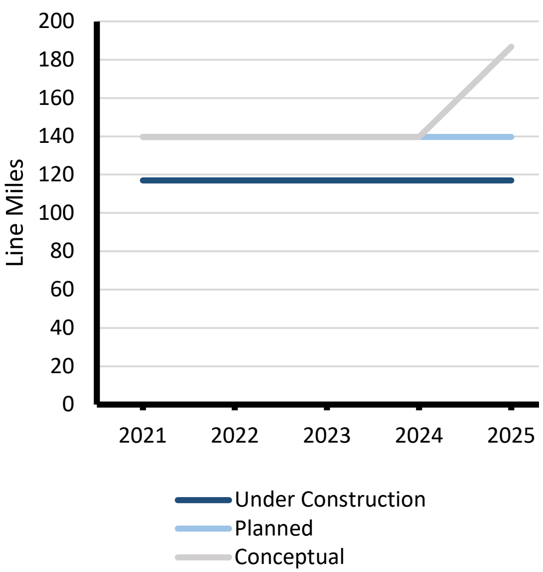
SERC-E

SERC-FP

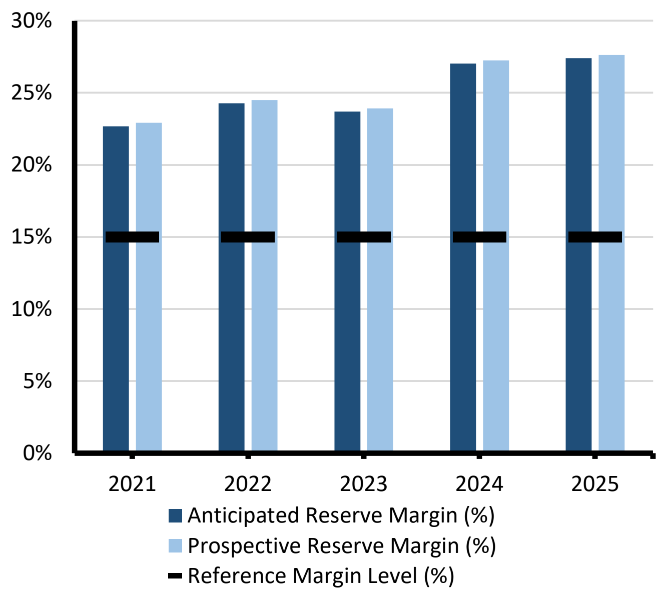


SERC-E

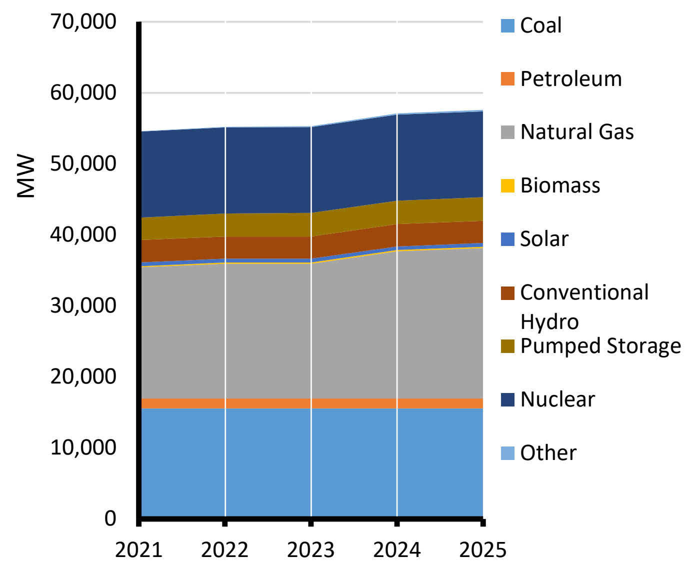
Demand, Resources, and Reserve Margins (MW)										
Quantity	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Total Internal Demand	45,887	45,811	46,108	46,332	46,596	46,979	47,328	47,733	48,103	48,562
Demand Response	887	894	901	908	910	915	925	937	951	952
Net Internal Demand	45,000	44,917	45,207	45,424	45,686	46,064	46,403	46,796	47,152	47,610
Additions: Tier 1	169	716	750	2,529	3,035	4,392	6,203	8,083	8,083	9,023
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	605	605	605	605	605	605	605	605	605	605
Existing-Certain & Net Firm Transfers	55,037	55,102	55,167	55,171	55,171	55,171	54,945	53,815	53,825	53,825
Anticipated Reserve Margin (%)	22.7%	24.3%	23.7%	27.0%	27.4%	29.3%	31.8%	32.3%	31.3%	32.0%
Prospective Reserve Margin (%)	22.9%	24.5%	23.9%	27.3%	27.6%	29.5%	32.0%	32.5%	31.5%	32.2%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Projected Transmission Circuit Miles

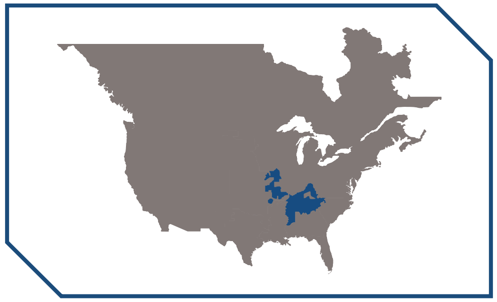


Planning Reserve Margins



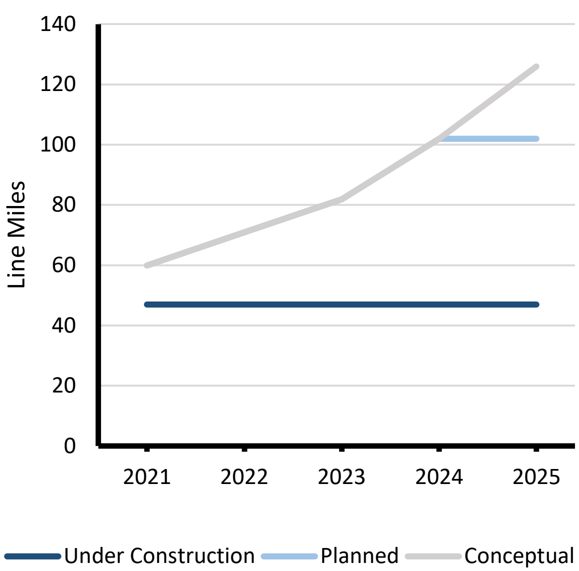
Existing and Tier 1 Resources

SERC-E Fuel Composition										
Generation Type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal	15,552	15,552	15,552	15,552	15,552	15,552	15,552	14,422	14,422	14,422
Petroleum	1,410	1,410	1,410	1,410	1,410	1,410	1,342	1,342	1,342	1,342
Natural Gas	18,467	18,980	18,980	20,723	21,193	22,534	24,181	26,061	26,061	27,001
Biomass	164	164	164	164	164	164	164	164	164	164
Solar	537	537	537	537	537	537	537	537	537	537
Conventional Hydro	3,133	3,133	3,133	3,133	3,133	3,133	3,133	3,133	3,133	3,133
Pumped Storage	3,174	3,239	3,304	3,304	3,304	3,304	3,304	3,304	3,304	3,304
Nuclear	12,104	12,104	12,104	12,108	12,108	12,108	12,114	12,114	12,124	12,124
Other	60	94	128	164	200	216	216	216	216	216
Total MW	54,601	55,213	55,312	57,095	57,601	58,958	60,543	61,293	61,303	62,243

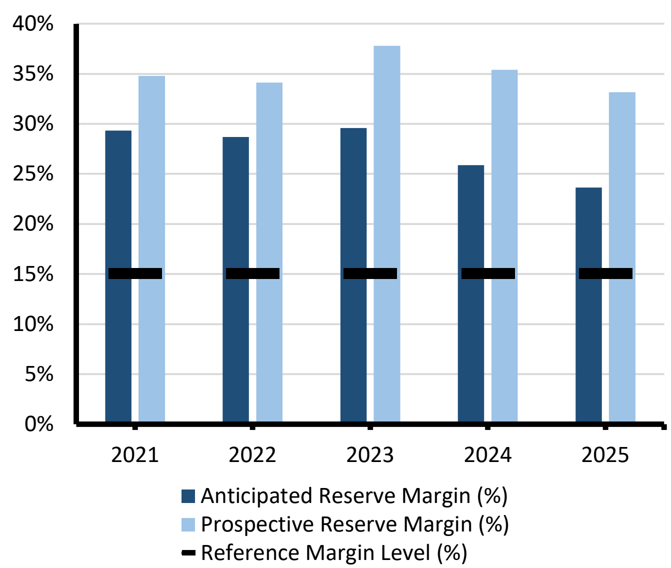


SERC-C

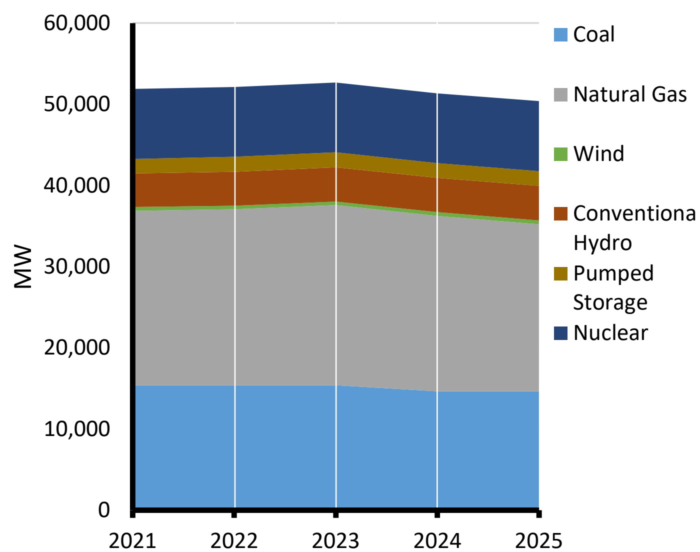
Demand, Resources, and Reserve Margins (MW)										
Quantity	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Internal Demand	41,425	41,720	41,837	41,963	41,918	42,061	42,237	42,399	42,533	42,499
Demand Response	1,797	1,749	1,716	1,716	1,716	1,716	1,716	1,716	1,716	1,616
Net Internal Demand	39,628	39,971	40,121	40,247	40,202	40,345	40,521	40,683	40,817	40,883
Additions: Tier 1	0	0	0	0	0	0	0	0	0	0
Additions: Tier 2	0	0	1,265	1,901	1,901	1,901	1,901	1,901	1,901	1,901
Additions: Tier 3	0	0	253	253	253	253	253	1,265	1,265	1,265
Net Firm Capacity Transfers	-630	-701	-701	-701	-701	-700	-700	-875	-875	-874
Existing-Certain & Net Firm Transfers	51,251	51,438	51,988	50,658	49,701	49,702	49,702	49,527	49,527	49,528
Anticipated Reserve Margin (%)	29.3%	28.7%	29.6%	25.9%	23.6%	23.2%	22.7%	21.7%	21.3%	21.1%
Prospective Reserve Margin (%)	34.8%	34.1%	37.8%	35.4%	33.2%	32.7%	32.1%	31.2%	30.7%	30.5%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Projected Transmission Circuit Miles

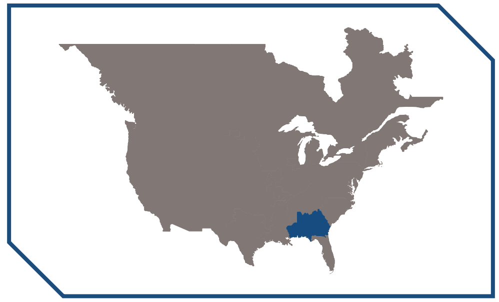


Planning Reserve Margins



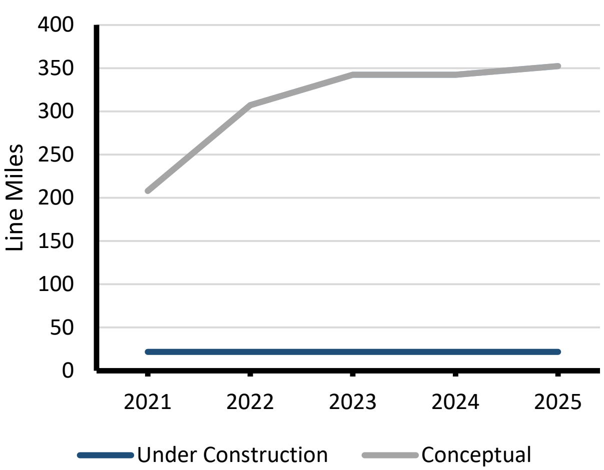
Existing and Tier 1 Resources

SERC-C Fuel Composition										
Generation Type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal	15,405	15,405	15,405	14,645	14,645	14,645	14,645	14,645	14,645	14,645
Natural Gas	21,475	21,658	22,168	21,598	20,590	20,590	20,590	20,590	20,590	20,590
Wind	460	460	460	460	460	460	460	460	460	460
Conventional Hydro	4,155	4,175	4,216	4,216	4,267	4,267	4,267	4,267	4,267	4,267
Pumped Storage	1,769	1,823	1,823	1,823	1,823	1,823	1,823	1,823	1,823	1,823
Nuclear	8,618	8,618	8,618	8,618	8,618	8,618	8,618	8,618	8,618	8,618
Total MW	51,882	52,139	52,690	51,360	50,402	50,402	50,402	50,402	50,402	50,402

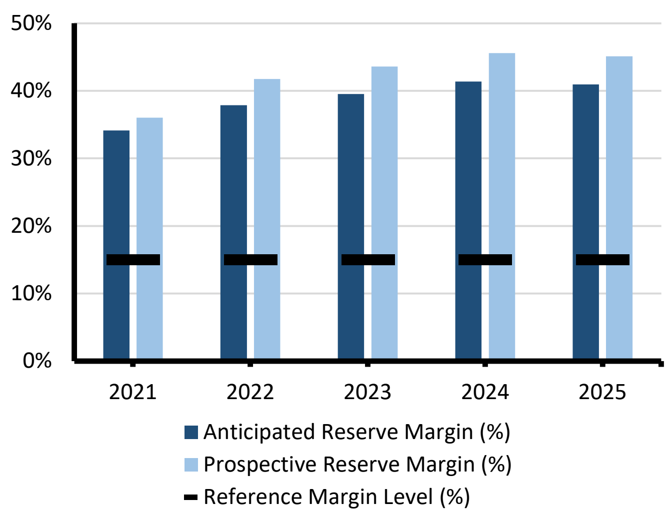


SERC-SE

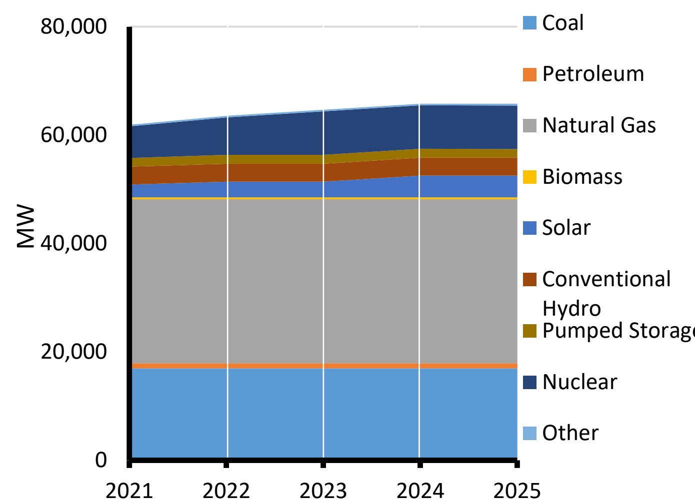
Demand, Resources, and Reserve Margins (MW)										
Quantity	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Quantity	47,748	47,882	48,057	48,289	48,450	47,923	48,208	46,970	47,342	47,762
Total Internal Demand	2,354	2,565	2,557	2,542	2,556	2,555	2,562	2,568	2,576	2,576
Demand Response	45,394	45,317	45,500	45,747	45,894	45,368	45,646	44,402	44,766	45,186
Net Internal Demand	354	2,006	3,106	4,221	4,221	4,221	4,221	4,221	4,221	4,221
Additions: Tier 1	550	1,474	1,554	1,634	1,634	1,634	1,634	1,634	1,634	1,634
Additions: Tier 2	2,750	5,183	5,663	5,743	5,743	5,743	5,743	5,743	5,743	5,743
Additions: Tier 3	-1,016	-1,098	-1,180	-1,109	-1,086	-1,083	-1,081	-1,078	-1,076	-1,073
Net Firm Capacity Transfers	60,546	60,464	60,382	60,453	60,464	60,526	60,528	60,531	60,533	60,536
Existing-Certain and Net Firm Transfers	34.16%	37.85%	39.53%	41.37%	40.94%	42.71%	41.85%	45.83%	44.65%	43.31%
Anticipated Reserve Margin (%)	36.0%	41.7%	43.6%	45.6%	45.1%	47.0%	46.1%	50.7%	49.0%	47.6%
Prospective Reserve Margin (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Projected Transmission Circuit Miles



Planning Reserve Margins

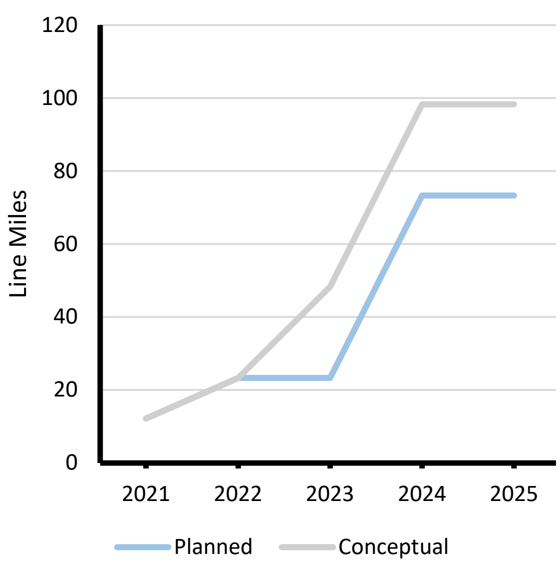


Existing and Tier 1 Resources

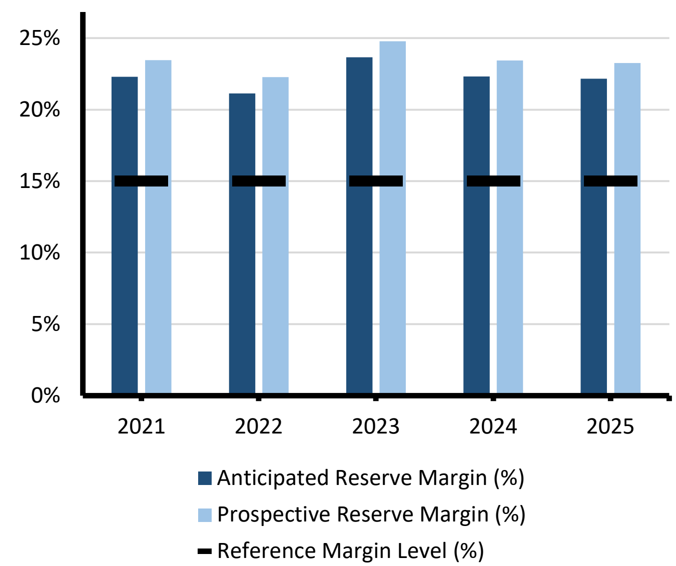
SERC-SE Fuel Composition										
Generation Type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal	16,935	16,935	16,935	16,935	16,935	16,935	16,935	16,935	16,935	16,935
Petroleum	961	961	961	961	961	961	961	961	961	961
Natural Gas	30,250	30,250	30,250	30,250	30,238	30,297	30,297	30,297	30,297	30,297
Biomass	361	361	361	361	361	361	361	361	361	361
Solar	2,356	2,908	2,908	4,023	4,023	4,023	4,023	4,023	4,023	4,023
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	5,818	6,918	8,018	8,018	8,018	8,018	8,018	8,018	8,018	8,018
Other	316	316	316	316	316	316	316	316	316	316
Total MW	61,916	63,568	64,668	65,783	65,771	65,830	65,830	65,830	65,830	65,830

SERC-FP

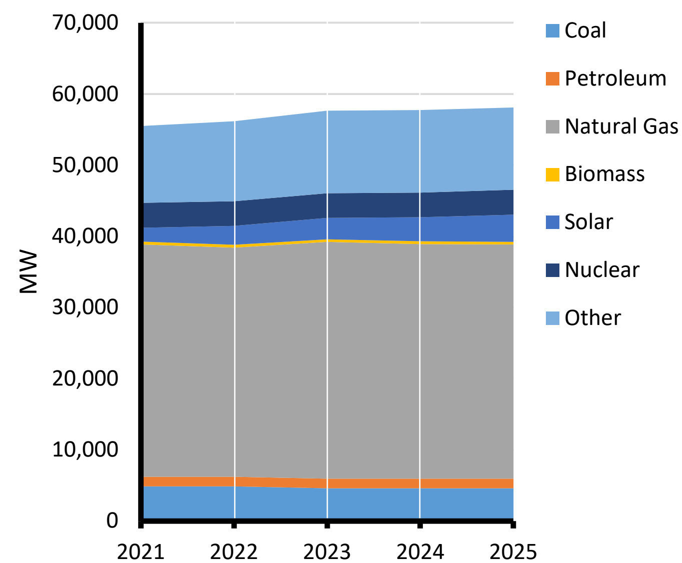
Demand, Resources, and Reserve Margins (MW)										
Quantity	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Internal Demand	49,026	49,778	50,073	50,726	51,107	51,742	52,474	53,175	53,175	53,175
Demand Response	2,951	3,008	3,053	3,099	3,146	3,193	3,238	3,285	3,285	3,285
Net Internal Demand	46,075	46,770	47,020	47,627	47,961	48,549	49,236	49,890	49,890	49,890
Additions: Tier 1	889	3,212	5,002	5,377	5,867	8,189	8,553	8,595	8,638	8,638
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	0	18	18	18
Net Firm Capacity Transfers	872	473	498	498	498	398	398	398	398	398
Existing-Certain & Net Firm Transfers	55,461	53,444	53,142	52,880	52,727	52,334	51,311	51,311	51,311	51,311
Anticipated Reserve Margin (%)	22.3%	21.1%	23.7%	22.3%	22.2%	24.7%	21.6%	20.1%	20.2%	20.2%
Prospective Reserve Margin (%)	23.5%	22.3%	24.8%	23.4%	23.3%	25.7%	22.6%	21.1%	21.2%	21.2%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Projected Transmission Circuit Miles



Planning Reserve Margins



Existing and Tier 1 Resources

SERC-FP Fuel Composition										
Generation Type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal	4,856	4,856	4,605	4,605	4,605	4,605	4,605	4,605	4,605	4,605
Petroleum	1,346	1,346	1,346	1,346	1,346	1,175	1,175	1,175	1,175	1,175
Natural Gas	32,669	32,214	33,246	32,967	32,892	34,656	33,668	33,668	33,668	33,668
Biomass	394	394	394	390	352	352	317	317	317	317
Solar	1,944	2,635	2,982	3,357	3,847	4,283	4,647	4,689	4,732	4,732
Nuclear	3,499	3,499	3,499	3,499	3,499	3,499	3,499	3,499	3,499	3,499
Other	10,771	11,240	11,575	11,596	11,556	11,556	11,556	11,556	11,556	11,556
Total MW	55,478	56,183	57,646	57,759	58,096	60,125	59,466	59,508	59,551	59,551

SERC Assessment

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 the assessment period. Additionally, all assessment areas maintain ten-year reserve margins above SERC's internally calculated reference reserve margin by using the metric of 0.1 days per year LOLE of 14.4%.

Demand: Projected demand growth within the assessment areas have remained relatively flat to less than 1% over the years with the exception of SERC-FP, which has a growth rate of slightly above 1%. 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: DR programs are minimal and vary among the assessment areas (i.e., summer load control, reserve preservation, voltage optimization, 5-minute, 60-minute, or instantaneous response). These programs are used to control peak demand. Throughout the year, entities monitor and evaluate each program's operational functionality to determine effectiveness and the ability to provide demand reduction.

Distributed Energy Resources: Most of the DER growth in the RE has been solar. To date, there are no notable reliability impacts reported to the RE; however, the RE is working within its data collection processes to collect the appropriate level of data (i.e., MWs in the queue), so these resources can be modeled and analyzed for potential impacts on the system.

Generation: SERC entities have sufficient generation to meet demand over theis assessment period. New resources are expected that include a combination of capacity purchases and new nuclear, natural gas, and combined-cycle units. Natural gas (47.4%), coal (26.5%), and nuclear (13.1%) generation are the dominant fuel types within the assessment areas. Hydro, renewables, and other fuel types (8%) are minimal. Entities within SERC will add approximately 4,000 MW of natural gas generation over the period. SERC-E will have an additional 2,200 MW of nuclear additions available to meet demand in 2021. Overall, the assessment areas will encounter 6,100 MW of net additions and retirements over within the next 10 years. Approximately 21 GW of utility-scale transmission BES-connected solar projects are expected in the interconnection queue over the next five years and are largely developing in SERC-E and SERC-FP. 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 the 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.

Transmission: Across the SERC RE, entities continue to build transmission, especially in the first five years of the assessment period, to ensure a reliable interconnected power system. SERC entities are expecting a total of ~900 miles (~300 miles of <200 kV, ~600 miles of 100–299 kV) of transmission additions over the period. These projects are in the design/construction phase and are projected to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include adding new transformers (i.e., 345/138kV and 161/500kV), reconductoring existing transmission lines, and other system reconfigurations/additions to support transmission system reliability.

Entities coordinate transmission expansion plans during the RE's annual joint model building and study efforts. These plans are also coordinated with entities external to the RE through annual joint modeling efforts within the Eastern Interconnection Reliability Assessment Group and the Multi-Regional Modeling Working Group. In addition to these forums, several entities participate in open regional transmission planning processes that are driven by FERC Order 890 and Order 1000. Transmission expansion plans by most SERC entities are dependent on regulatory support at the federal, state, and local levels since the regulatory entities can influence the siting, permitting, and cost recovery of new transmission facilities. Entities do not anticipate any transmission limitations or constraints that cause significant impacts to reliability; however, limitations exist near generation sites i and along the seams in SERC-C due to line loading and transfers on the transmission system. Constraints will be mitigated by future transmission projects (e.g., new builds, reactor), generation adjustments, system reconfiguration, and/or system power purchases.

SERC-E Probabilistic Assessment Overview

- **General Overview:** Increasing demand projections in SERC-E have marginally lowered ARMs through 2030 compared to the 2018 ProbA demand projections. Additionally, demand projections historically have shown SERC-E as a summer-peaking system; however, current demand projections now show SERC-E as a winter-peaking system. Demand projections in SERC-E increase at a rate of 0.66% per year over the 10-year period planning horizon. The ProbA study indicates anticipated resource margins that range from 23–24% and adequate reliability metrics.
- **Modeling:** SERC utilizes GE MARS software, an 8,760 hourly load, generation, and transmission sequential Monte-Carlo simulation model that consists of 15 interconnected areas, 4 of which are SERC's NERC assessment areas (SERC-E, SERC-C, SERC-SE, and SERC-FP).
    - Annual peak demand varies by approximately ±5% of forecasted SERC-E demand based upon a 3.95% standard deviation (LFU).
    - Thermal units follow a two-state on-or-off sequence based on Monte-Carlo simulation, utilizing unit class average forced outage rates and failure durations. This, on average, is equivalent to derating SERC-E thermal generating resources by approximately 6% of megawatt rating.
    - The model dispatches 20% of SERC-E traditional hydro across all hours of the year (approximately 1,449 MW; 3,031 GWH annually) while MARS schedules any remaining capacity and energy on an hourly basis as needed to serve any load that thermal generation on the system cannot meet.
    - Wind and solar are load modifiers and based on an 8,760-time series correlation to load that, based on the top ten peak load hours modeled, yield approximately 38% solar capacity credit for SERC-E.
- **Results trending:** From 2018 to 2020, the SERC-E 2022 LOLH slightly increased from 0.000 to 0.001. This is driven by a decrease in the 2022 reserve margin due to a higher net internal demand forecast.
- **Probabilistic vs. Deterministic Reserve Margin Results:** Since both assessments utilize identical capacity megawatts (existing certain and Tier 1) for thermal generation and determining exact on-peak capacity availability from the ProbA model is difficult, SERC assumes that the ARM is the same as the ProbA forecast PRM. However, the SERC-E ProbA has the following differences from the SERC-E LTRA, not already captured in the Modeling section:
    - SERC-E annual peak demand is coincident in the ProbA model since SERC conducts LFU analysis on coincident peak demands.
    - The SERC-E annual peak demand occurs in January. The summer peak is August, about 4% smaller.
    - Total controllable DR treated as a capacity resource with performance rates based on historical demand reduction realization.

Base Case Study

SERC-E resource adequacy measures are near zero in the Base Case, indicating that anticipated reserves above 22.8% result in minimal expected LOL or EUE.

Sensitivity Case Study

In recent years, SERC has seen tighter operating conditions during the shoulder months. One factor that has contributed to this trend is the amount of thermal generation resources that take planned maintenance outages during the shoulder months. For a probabilistic sensitivity scenario, SERC will incrementally increase the planned maintenance rate for thermal resources to test the reliability of the SERC system during the shoulder months.

Summary of Results			
Reserve Margin (RM) %			
	2022*	**2022**	**2024**
Anticipated	24.9%	22.8%	23.9%
Prospective	14.4%	15.0%	15.0%
Reference	18.0%	14.9%	15.9%
Annual Probabilistic Indices			
	2022*	**2022**	**2024**
EUE (MWh)	0.000	0.717	5.262
EUE (ppm)	0.000	0.003	0.024
LOLH (hours/year)	0.000	0.001	0.009

*Represents the 2018 ProbA results for 2022.

SERC-C Probabilistic Assessment Overview

- **General Overview:** The SERC-C area was referred to as SERC-N in previous assessment studies. Net internal demand projections in SERC-C increase at a rate of 0.38% per year over the 10-year period planning horizon. The ProbA study indicates adequate resources with the anticipated margins that range from 26–27%. This leads to practically zero LOLH, EUE, and LOLE, well within the target of 0.1 days/year for 2022 and 2024.
- **Modeling:** SERC utilizes GE MARS software, an 8760 hourly load, generation, and transmission sequential Monte-Carlo simulation model that consists of 14 interconnected areas, 4 of which are SERC's NERC assessment areas (SERC-E, SERC-C, SERC-SE, SERC-FP). Modeling details are provided as follows:
    - Annual peak demand varies by approximately ±5% of forecasted SERC-C demand based upon a 4.75% standard deviation (LFU).
    - Thermal units follow a two-state on-or-off sequence based on Monte Carlo simulation, which utilizes unit class average forced outage rates and failure durations. On average, this is equivalent to derating SERC-E thermal generating resources by approximately 6% of megawatt rating.
    - The model dispatches 20% of SERC-C traditional hydro across all hours of the year (approximately 2,014 MW; 8,488 GWH annually) while MARS schedules any remaining capacity and energy on an hourly basis as needed to serve any load that thermal generation on the system cannot meet.
    - Wind and solar are load modifiers and based on an 8,760 time series correlation to load that, based on the top ten peak load hours modeled, yields approximately 31% solar and 33% wind capacity credits for SERC-C.
- **Results trending:** From 2018 to 2020, the SERC-C 2022 LOLH and EUE remain zero, primarily driven by steady resources.
- **Probabilistic vs. Deterministic Reserve Margin Results:** Since both assessments utilize identical capacity megawatts (existing certain and Tier 1) for thermal generation and determining exact on-peak capacity availability from the ProbA model is difficult, SERC assumes that the ARM is the same as the ProbA Forecast PRM. However, the SERC-C ProbA has the following differences from the SERC-C LTRA, not already captured in the Modeling section above:
    - SERC-C annual peak demand is coincident in the ProbA model since SERC conducts LFU analysis on coincident peak demands.
    - The SERC-C annual peak demand occurs in January. Summer peak occurs in August and is about 4% less than the winter (January) peak demand.
    - Total controllable DR treated as a capacity resource with performance rates based on historical demand reduction realization.

Base Case Study

SERC-C resource adequacy measures EUE (ppm) and LOLH (hours/year) are zero in the Base Case. EUE (MWh) is at 0.001. This indicates that, with anticipated reserves above 26%, there is near zero EUE and LOLHs.

Sensitivity Case Study

In recent years, SERC has seen tighter operating conditions during the shoulder months. One factor that has contributed to this trend is the amount of thermal generation resources that take planned maintenance outages during the shoulder months. For a probabilistic sensitivity scenario, SERC will incrementally increase the planned maintenance rate for thermal resources to test the reliability of the SERC system during the shoulder months.

Summary of Results			
Reserve Margin (RM) %			
	2022*	2022	2024
Anticipated	24.9%	26.4%	27.0%
Prospective	14.4%	15.0%	15.0%
Reference	17.7%	17.9%	18.4%
Annual Probabilistic Indices			
	2022*	2022	2024
EUE (MWh)	0.000	0.001	0.001
EUE (ppm)	0.000	0.000	0.000
LOLH (hours/year)	0.000	0.000	0.000

*Represents the 2018 ProbA results for 2022.

SERC-SE Probabilistic Assessment Overview

- **General Overview:** Net internal demand projections in SERC-SE are flat over the 10-year period planning horizon. The ProbA study indicates high anticipated resource margins ranging from 36–39% and practically zero LOLH and EUE values.
- **Modeling:** SERC utilizes GE MARS software an 8,760 hourly load, generation, and transmission sequential Monte-Carlo simulation model that consists of fifteen interconnected areas, three of which are SERC's NERC assessment areas (SERC-E, SERC-C, SERC-SE, and SERC-FP).
  - Annual peak demand varies by approximately ±6% of forecasted SERC-SE demand based upon a 6.11% standard deviation (LFU).
  - Thermal units follow a two-state on-or-off sequence based on Monte-Carlo simulation, utilizing unit class average forced outage rates and failure durations. This, on average, is equivalent to derating SERC-SE thermal generating resources by approximately 6% of megawatt rating.
  - The model dispatches 20% of SERC-SE traditional hydro across all hours of the year (approximately 1,183 MW; 3,256 GWH annually) while MARS schedules any remaining capacity and energy on an hourly basis as needed to serve any load that thermal generation on the system cannot meet. Based upon the average over the last 10 years of generation for each hydro plant, this remaining hydro energy is limited by 23% of maximum annual output, or 29,128 GWH, for SERC-SE.
  - Wind and solar are load modifiers and based on an 8,760 time series correlation to load that, based on the top ten peak load hours modeled, yield approximately 39% solar capacity credit for SERC-SE.
- **Results trending:** From 2018 to 2020, the SERC-SE 2022 LOLH and EUE remain practically zero; this is primarily driven by lower projected demand and steady resources over the assessment timeframe, resulting in higher reserve margins.
- **Probabilistic vs. Deterministic Reserve Margin Results:** Since both assessments utilize identical capacity megawatts (existing certain and Tier 1) for thermal generation and determining exact on-peak capacity availability from the ProbA model is difficult, SERC assumes that the ARM is the same as the ProbA forecast PRM. However, the SERC-SE ProbA has the following differences from the SERC-SE LTRA, not already captured in the Modeling section above:
  - SERC-SE annual peak demand is coincident in the ProbA model since SERC conducts LFU analysis on coincident peak demands.
  - The SERC-SE annual peak demand occurs in January. The summer peak is August, 8% lower.
  - Total controllable DR treated as a capacity resource with performance rates based on historical demand reduction realization.

Base Case Study

SERC-SE resource adequacy measures are near zero in the Base Case, indicating that anticipated reserves above 35% result in minimal expected LOL or EUE.

Sensitivity Case Study

In recent years, SERC has seen tighter operating conditions during the shoulder months. One factor that has contributed to this trend is the amount of thermal generation resources that take planned maintenance outages during the shoulder months. For a probabilistic sensitivity scenario, SERC will incrementally increase the planned maintenance rate for thermal resources to test the reliability of the SERC system during the shoulder months.

Summary of Results			
Reserve Margin (RM) %			
	2022*	**2022**	**2024**
Anticipated	32.4%	35.8%	39.1%
Prospective	14.4%	15.0%	15.0%
Reference	24.7%	26.9%	30.2%
Annual Probabilistic Indices			
	2022*	**2022**	**2024**
EUE (MWh)	0.00	0.009	0.028
EUE (ppm)	0.00	0.000	0.000
LOLH (hours/year)	0.00	0.000	0.000

*Represents the 2018 ProbA results for 2022.

SERC-FP Probabilistic Assessment Overview

- **General Overview:** Sufficient generation resource additions throughout the next ten-years result in ARMs consistently above 20%. Net internal demand projections indicate 0.73% growth over the planning horizon of 10 years. On April 30, 2019, the Federal Energy Regulatory Commission issued an order formally approving the transfer of all registered entities in the Florida Reliability Coordinating Council (FRCC) area to SERC by July 1, 2019. The integration of FRCC entities resulted in an additional SERC assessment area for inclusion in NERC's reliability assessments, referred to as SERC-FP.
- **Modeling:** SERC utilizes GE MARS software an 8,760 hourly load, generation, and transmission sequential Monte-Carlo simulation model that consists of fifteen interconnected areas, four of which are SERC's NERC assessment areas (SERC-E, SERC-C, SERC-SE, SERC-FP). When comparing the 2018 and 2020 study results for the Florida peninsula, note that the 2018 results were not generated through the GE MARS software but instead were generated through the use of a modeling tool that used a recursive convolution method.
    - Annual peak demand varies by approximately ±4% of forecasted SERC-SE demand based upon a 4.04% standard deviation (LFU).
    - Thermal units follow a two-state on-or-off sequence based on Monte-Carlo simulation, which utilizes unit class average forced outage rates and failure durations. This, on average, is equivalent to derating SERC-FP thermal generating resources by approximately 10% of megawatt rating.
    - Wind and solar are load modifiers and based on an 8,760 time series correlation to load that, based on the top ten peak load hours modeled, yield approximately 50% solar capacity credit for SERC-FP.
- **Results trending:** Compared to 2018, the resource adequacy metrics show an increase in LOLH and EUE. This is at least partially driven by a lower ARM in 2022 but may also be attributable to the use of a new simulation modeling software for SERC-FP in the 2020 LTRA.
- **Probabilistic vs. Deterministic Reserve Margin Results:** Since both assessments utilize identical capacity megawatts (existing certain and Tier 1) for thermal generation and determining exact on-peak capacity availability from the ProbA model is difficult, SERC assumes that the ARM is the same as the ProbA Forecast Planning RM. However, the SERC-FP ProbA has the following differences from the SERC-FP LTRA, not already captured in the Modeling section above:
    - SERC-FP annual peak demand is coincident in the ProbA model since SERC conducts LFU analysis on coincident peak demands.
    - The SERC-FP annual peak demand occurs in August. The winter peak is January, 8% lower than summer.
    - Total controllable DR treated as a capacity resource with performance rates based on historical demand reduction realization.

Base Case Study

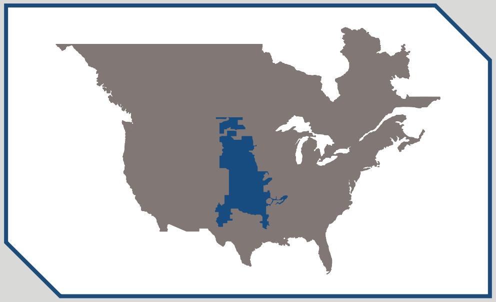
Results: Reserve Margins for the study years are expected to remain above the NERC Reference Margin of 15%. The addition of new supply resources in 2024 increases the ARM and results in resource adequacy measures that are near zero for SERC-FP.

Sensitivity Case Study

In recent years, SERC has seen tighter operating conditions during the shoulder months. One factor that has contributed to this trend is the amount of thermal generation resources that take planned maintenance outages during the shoulder months. For a probabilistic sensitivity scenario, SERC will incrementally increase the planned maintenance rate for thermal resources to test the reliability of the SERC system during the shoulder months.

Summary of Results			
Reserve Margin (RM) %			
	2022*	**2022**	**2024**
Anticipated	24.40%	21.6%	22.8%
Prospective	15.00%	15.0%	15.0%
Reference	20.20%	10.2%	11.4%
Annual Probabilistic Indices			
	2022*	**2022**	**2024**
EUE (MWh)	0	22.66	2.262
EUE (ppm)	0	0.096	0.009
LOLH (hours/year)	0	0.035	0.004

*Represents the 2018 ProbA results for 2022.

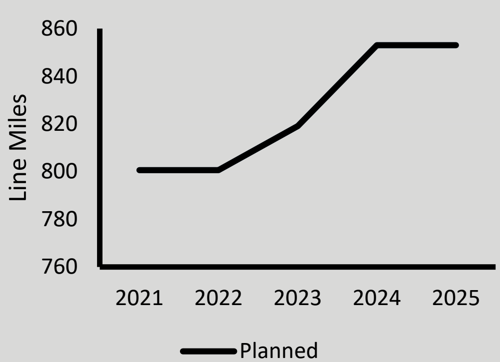


SPP

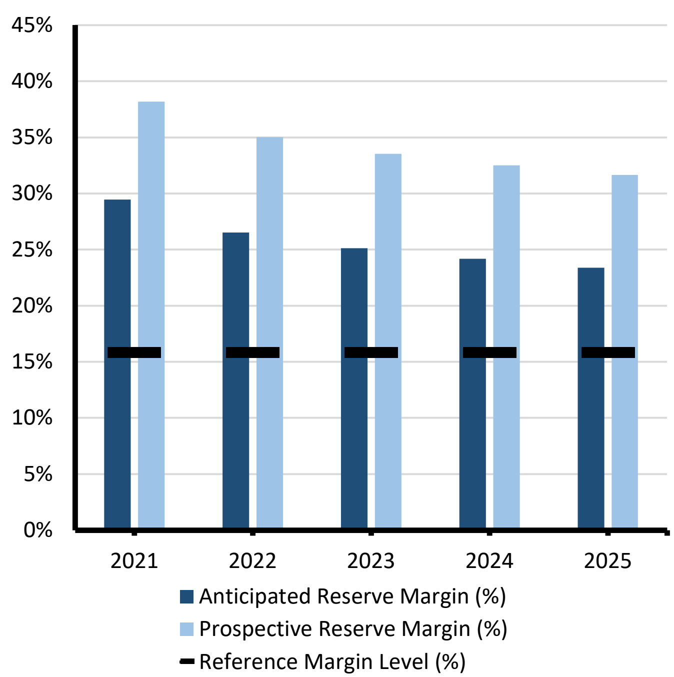
Southwest Power Pool (SPP) Planning Coordinator footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the Planning Coordinator footprint that touches parts of the Midwest Reliability Organization Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations and serves a population of more than 18 million people.

Demand, Resources, and Reserve Margins (MW)

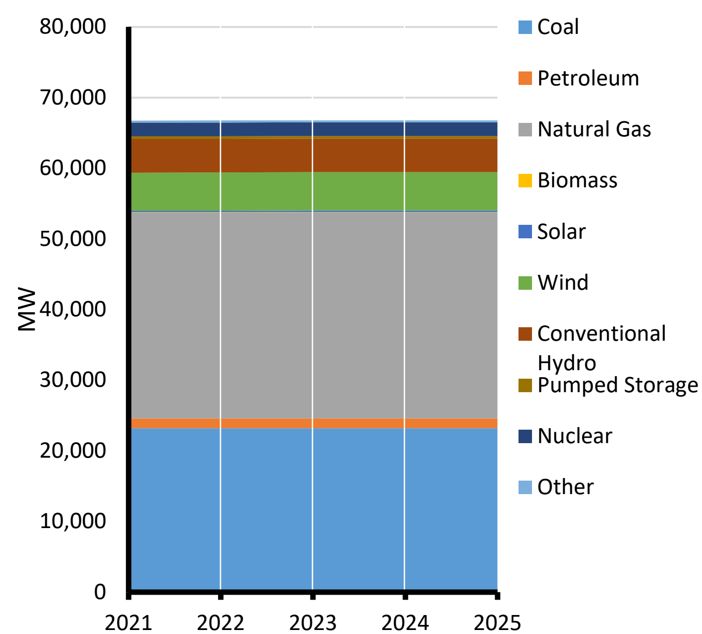
Quantity	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Internal Demand	52,249	53,524	54,242	54,689	55,082	55,480	55,738	56,046	56,375	56,584
Demand Response	606	603	633	666	684	708	732	748	756	733
Net Internal Demand	51,643	52,921	53,609	54,023	54,399	54,772	55,007	55,298	55,618	55,851
Additions: Tier 1	263	299	336	336	336	336	336	336	336	336
Additions: Tier 2	4,498	4,498	4,498	4,498	4,498	4,498	4,498	4,498	4,498	4,498
Additions: Tier 3	263	263	263	263	263	263	263	263	263	263
Net Firm Capacity Transfers	-4	55	138	138	183	158	-155	-150	-177	-176
Existing-Certain and Net Firm Transfers	66,596	66,658	66,747	66,746	66,782	66,757	66,450	66,458	66,433	66,433
Anticipated Reserve Margin (%)	29.5%	26.5%	25.1%	24.2%	23.4%	22.5%	21.4%	20.8%	20.1%	19.6%
Prospective Reserve Margin (%)	38.2%	35.0%	33.5%	32.5%	31.7%	30.7%	29.6%	28.9%	28.1%	27.6%
Reference Margin Level (%)	15.8%	15.8%	15.8%	15.8%	15.8%	15.8%	15.8%	15.8%	15.8%	15.8%



Projected Transmission Circuit Miles



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

The ARMs do not fall below the RML of 12% for the entire 10-year assessment period.

SPP Fuel Composition										
Generation Type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal	23,172	23,172	23,172	23,172	23,172	23,172	23,172	23,172	23,172	23,172
Petroleum	1,440	1,440	1,440	1,440	1,440	1,440	1,440	1,440	1,440	1,440
Natural Gas	29,148	29,148	29,148	29,148	29,148	29,148	29,148	29,148	29,148	29,148
Biomass	31	31	51	51	51	51	51	51	51	51
Solar	172	183	191	191	191	191	191	191	191	191
Wind	5,410	5,435	5,445	5,445	5,445	5,445	5,445	5,445	5,445	5,445
Conventional Hydro	4,767	4,767	4,767	4,767	4,767	4,767	4,767	4,767	4,767	4,767
Pumped Storage	363	363	363	363	363	363	363	363	363	363
Nuclear	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944
Other	280	280	280	280	280	280	280	280	280	280
Total MW	66,727	66,763	66,800	66,800	66,800	66,800	66,800	66,800	66,800	66,800

SPP Assessment

The RML is determined by a probabilistic LOLE study. The SPP assessment area performs a biennial LOLE study to establish PRM. Determination of the PRM is supported by a probabilistic LOLE study that will analyze the ability to reliably serve the SPP BA area's 50/50 forecasted peak demand by utilizing a security constrained economic dispatch. SPP, with input from the stakeholders, develops the inputs and assumptions used for the LOLE study. SPP will study the PRM such that the LOLE for the applicable planning year (2- and 5-year study) does not exceed 1-day-in-10 years, or 0.1 day per year. At a minimum, the PRM will be determined by using probabilistic methods to ensure the LOLE does not exceed 0.1 day per year. The analysis entails: altering capacity through the application of generator forced outages, and altering forecasted demand through the application of load uncertainty.

SPP load peaks during the summer season; the 2020 load forecast is projected to peak at 51,259 MW, a projected decrease compared to the previous year's LTRA forecast for the 2020 summer season. The decrease is due to SPP submitting the coincident peak for the SPP assessment area (starting in 2020), whereas the noncoincident peak was submitted in past LTRAs. SPP forecasts the coincident annual peak growth based on member submitted data over the 10-year assessment time frame. The current annual growth rate is approximately 0.85%.

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.

SPP currently has approximately 250 MW of installed solar generating facilities. SPP Model Development, Economic Studies, and the Supply Adequacy working groups are currently developing policies and procedures around DERs. These policies are planned to become effective during 2020 and will affect the SPP Resource Adequacy Process. SPP resource adequacy staff are working to create a process that notifies SPP operations and the Reliability Coordinator of new resources that are available outside of the SPP integrated marketplace mechanisms.

Since the *2019 LTRA*, more than 800 MW of nameplate capacity has been retired in SPP. The generation that has been retired over the past year has mainly been replaced with wind resources. The impact to resource adequacy in SPP is being assessed in the 2019 LOLE study. Currently, SPP is not expecting any long-term reliability impacts from generating plant retirements.

The SPP assessment area coordinates 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 dc ties between the Texas and Eastern Interconnections, 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*.[64]

SPP and ERCOT are currently going through the process to update the coordination plan based on the latest discussions and business decisions.

The SPP board of directors approved the *2020 Integrated Transmission Plan Assessment* and the *2020 SPP Transmission Expansion Plan Report*.[65] Both reports provide details for proposed transmission projects needed to maintain reliability while also providing economic benefit to the end users.

64 The SPP Tariff is available from the SPP governance web page: https://www.spp.org/governance/

65 Transmission planning reports are available at SPP's web page: https://www.spp.org/engineering/transmission-planning/integrated-transmission-planning/

Probabilistic Assessment Overview

- **General Overview:** SPP oversees the bulk electric grid and wholesale power market as one consolidated BA area on behalf of a diverse group of utilities and transmission companies in 14 states. Firm imports and exports of capacity were modeled to reflect the firm transactions reported for this *2020 LTRA*. Assumptions and the accompanying methodology have been thoroughly vetted through the SPP stakeholder process. Study improvements include unit specific limitations, multiple weather years, and modeling an economic dispatch with forced derate metrics. No events for LOL occurred in the Base Case for the ProbA.

- **Modeling:** A Monte-Carlo based software called Strategic Energy & Risk Valuation Model was used in the 2020 ProbA by randomly selecting LFU errors that were derived from historical probability of occurrence while varying the availability of thermal, hydro, and DR resources. The generating resources modeled in the ProbA reflect the data supplied in this *2020 LTRA*. Existing and projected resources were included in the ProbA along with reported confirmed retirements. Wind and solar resources as well as historical weather years were modeled at historical hourly values by using 2012–2019 weather years. Study improvements from the 2018 study include unit specific limitations (ramp rate, min up time, min down time, start-up time), multiple weather years (2012–2019), and modeling an economic dispatch with forced derate metrics.

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

- **Probabilistic vs. Deterministic Assessments:** DR and some BTM values reported in this *2020 LTRA* were modeled as generating resources available during daily on peak hours instead of reducing the TID. Another difference between the 2020 ProbA and the *2020 LTRA* was the consideration of modeling approximately 5,000 MW of additional nameplate wind capacity for planning year 2024 that was not considered in the anticipated PRM of the LTRA.

Base Case Study

No LOL events were indicated for the Base Case study due to a surplus of capacity in the SPP assessment area. Reserve margins are well above 20% in both study years, and no major impacts were observed related to resource retirements.

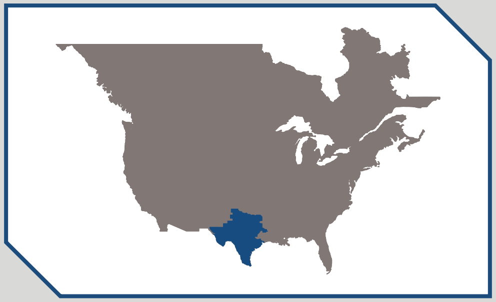
Results trending: The 2018 ProbA results for SPP indicated 0.0 EUE and 0.0 Hours/year LOLH for years 2020 and 2022. The 2018 ProbA Base Case results for 2022 were the same for the 2020 Base Case results (i.e., zero LOL).

Regional Risk Scenario

SPP has seen an increase in installed wind and slight increase in forced outage rates over the past few years. Therefore, SPP chose a low wind output scenario paired with an increase in conventional forced generation outages as the preselected 2020 ProbA Regional Risk Scenario. The low wind output consideration will be modeled as each wind generator as a percentage of its nameplate capacity when modeling each historical weather year and applied to peak hours of the simulation year. The regional risk scenario will be performed on year 2024 to reflect additional generation retirements and projected installed wind capacity. The weighted forced outage rate of the Base Case study is approximately 12.5%. This will be increased for the SPP system and the rate of increase will be applied to each resource.

Base Case Summary of Results			
Reserve Margin (RM) %			
	2022*	**2022**	**2024**
Anticipated	28.8%	27.6%	26.8%
Reference	15.8%	15.8%	15.8%
ProbA Forecast Operable	20.9%	13.6%	13.3%
Annual Probabilistic Indices			
	2022*	**2022**	**2024**
EUE (MWh)	0.00	0.00	0.00
EUE (ppm)	0.00	0.00	0.00
LOLH (hours/year)	0.00	0.00	0.00

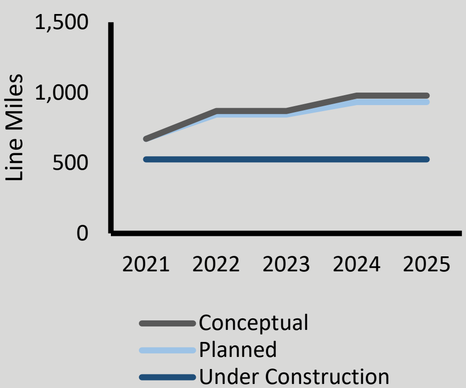
*Indicates 2018 ProbA results for comparison.



Texas RE-ERCOT

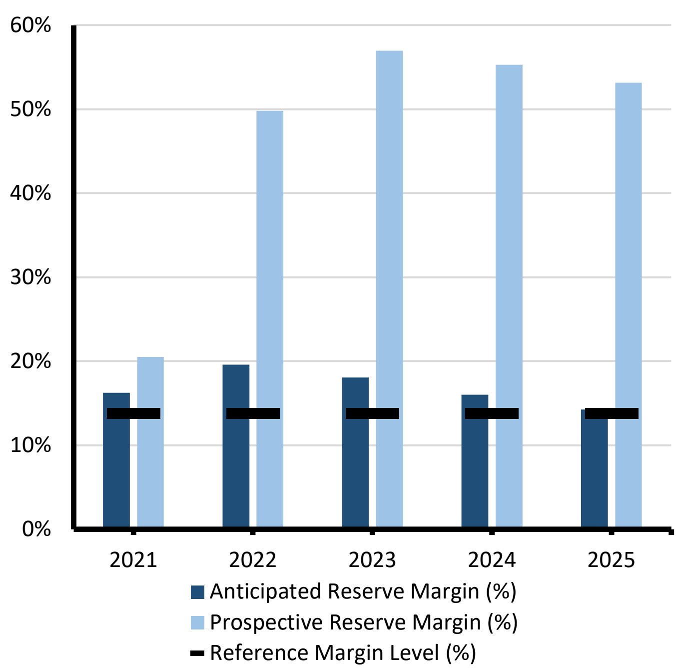
ERCOT is the ISO for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas legislature.

ERCOT is a summer-peaking RE that covers approximately 200,000 square miles, connects over 46,500 miles of transmission lines, has 650 generation units, and serves more than 25 million customers. Texas RE is responsible for the regional RE functions described in the *Energy Policy Act of 2005* for the ERCOT area.

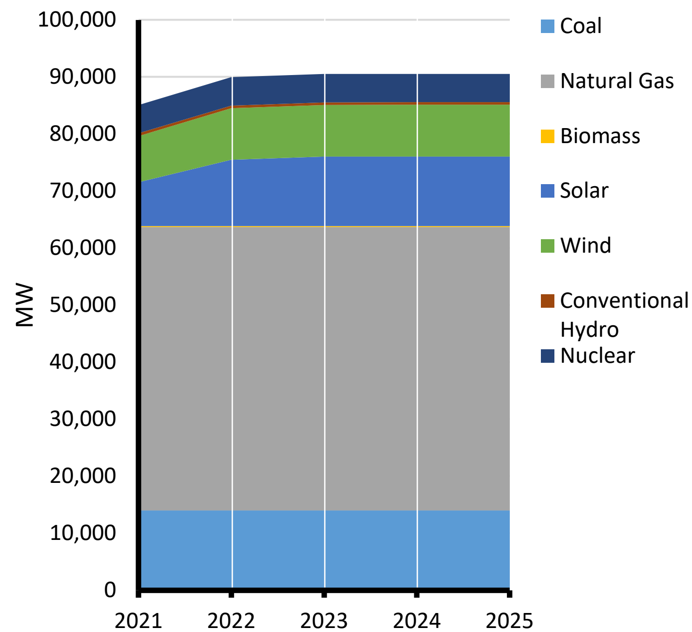


Projected Transmission Circuit Miles

Demand, Resources, and Reserve Margins (MW)										
Quantity	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Total Internal Demand	78,299	80,108	81,593	82,982	84,193	85,384	86,546	87,668	88,751	89,814
Demand Response	2,254	2,201	2,201	2,201	2,201	2,201	2,201	2,201	2,201	2,201
Net Internal Demand	76,045	77,907	79,392	80,781	81,992	83,183	84,345	85,467	86,550	87,613
Additions: Tier 1	8,538	13,406	13,954	13,995	13,995	13,995	13,995	13,995	13,995	13,995
Additions: Tier 2	3,211	23,488	30,872	31,704	31,865	31,865	31,865	31,865	31,865	31,865
Additions: Tier 3	2,632	11,263	21,187	23,345	23,345	23,345	23,345	23,345	23,345	23,345
Net Firm Capacity Transfers	210	210	210	210	210	210	210	210	210	210
Existing-Certain and Net Firm Transfers	79,861	79,774	79,769	79,724	79,684	79,469	79,469	79,464	79,464	79,464
Anticipated Reserve Margin (%)	16.25%	19.60%	18.05%	16.02%	14.25%	12.36%	10.81%	9.35%	7.98%	6.67%
Prospective Reserve Margin (%)	20.51%	49.79%	56.97%	55.30%	53.15%	50.70%	48.62%	46.67%	44.83%	43.07%
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

- The projected five-year-ahead ARMs stay above the RML of 13.75% over the five-year period. This improvement from the *2019 LTRA* is from Tier 1 resources that are expected to come into service over the five-year period that total almost 14,000 MW. Nearly 9,500 MW of these additions are solar generation.
- The increased penetration of wind in the ERCOT area, seen in trends in summer net peak load over the last few years, is increasing the risk of tight operating reserves during hours other than the daily peak load hour. Probabilistic analysis also shows indications of decreasing operating reserves during shoulder months. In particular, March and October of the study years (2022 and 2024) have the lowest monthly available reserves on the peak day even though those years did not show LOLH.
- ERCOT continues to implement enhancements to tools and processes to address increasing amounts of wind and solar generation on the ERCOT grid. These enhancements include the development of short-term solar forecasts, the implementation of grid services designed to address frequency response and flexible resource needs, and the development of DER policies and procedures.
- Over 750 MW of utility-scale battery storage capacity is in ERCOT's interconnection processes to begin service within the next two years. These new resources will add to an existing 153 MW of installed energy storage on the ERCOT system.
- Load growth continues in many parts of ERCOT (including West Texas, where oil and natural gas extraction are occurring) and industrial areas around Houston and Corpus Christi. Transmission projects in ERCOT include the addition or upgrade of 2,912 circuit miles of 138 kV and 345 kV transmission circuits and 19,246 MVA of 345/138 kV transformer capacity between 2020 and 2025.

Texas RE-ERCOT Fuel Composition

Generation Type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal	13,995	13,995	13,995	13,995	13,995	13,995	13,995	13,995	13,995	13,995
Natural Gas	49,683	49,683	49,683	49,683	49,683	49,683	49,683	49,683	49,683	49,683
Biomass	169	169	169	169	169	169	169	169	169	169
Solar	7,700	11,654	12,161	12,161	12,161	12,161	12,161	12,161	12,161	12,161
Wind	8,100	9,015	9,055	9,096	9,096	9,096	9,096	9,096	9,096	9,096
Conventional Hydro	470	470	470	470	470	470	470	470	470	470
Nuclear	4,973	4,973	4,973	4,973	4,973	4,973	4,973	4,973	4,973	4,973
Total MW	85,090	89,958	90,506	90,547	90,547	90,547	90,547	90,547	90,547	90,547

Texas RE-ERCOT Assessment

Planning Reserve Margin

The summer ARM is above the RML (13.75%) for the first five years of the assessment period (2021–2025).[66] The jump in the ARM from Summer 2020, from 11.1% to 17.2%, is mainly due to 8,237 MW of new summer-rated capacity expected to be added by Summer 2021.

A resource adequacy concern is the risk that a significant amount of planned resources expected to be in service in the next two years will be delayed or cancelled. While project delays typically happen due to market conditions and other factors, the risk is heightened due to the historically high numbers of inverter based resource projects as well as uncertainties regarding the impacts of the COVID-19 pandemic.

Reserve Scarcity Risks during Off-Peak Demand Periods

The increased penetration of wind in the ERCOT area, seen in trends in summer net peak load over the last few years, is increasing the risk of tight operating reserves during hours other than the daily peak load hour. For the operational time frame, one of the new tools available to the ERCOT control room operators is the capacity availability tool. This tool assesses whether generation capacity is sufficient to serve the forecasted load for the next 1 to 24 hours; it tracks and forecasts all available generation capacity, including all reserves, and it also monitors generation capacity that can potentially be started. To account for the variability and uncertainty of intermittent resources, the tool also allows users to evaluate the impact of different levels of load and wind forecasting uncertainties over the evaluation period. This tool improves situational awareness for possible future grid conditions and the best approaches to proactively mitigate anticipated large net-load ramp events.

For the seasonal planning time frame, ERCOT developed the Probabilistic Seasonal Assessment of Resource Adequacy model for reserves risk analysis of the Summer 2020 peak load day. The model performs Monte-Carlo simulation by using probability distributions and correlations for wind, solar, load, forced outages, and other resource supply variables. The model produces probabilistic forecasts of "Capacity available for Operating Reserves" and estimates probabilities that operating reserves will be at or below the threshold for declaring various energy emergency alert levels, including shedding load. These probabilities are estimated for hours ending 1:00 p.m. through 8:00 p.m. Central Time, not just the peak load hour. Further stakeholder discussions will take place regarding how the prototype model may be integrated as a tool for ongoing seasonal resource adequacy risk assessments.

Addressing Potential Operational Issues due to the Changing Resource Mix

ERCOT continues to implement enhancements to tools and processes to address increasing amounts of wind and solar generation on the ERCOT grid. The following are some specific actions ERCOT is taking in this regard:

- ERCOT has implemented fast frequency response as a subtype of response reserve service. Resources that provide fast frequency response automatically self-deploy and provide their obligated response within 15 cycles after frequency meets or drops below 59.85 Hz.
- In preparation to support increasing amounts of solar generation, ERCOT is partnering on a Department of Energy project to develop an intra-hour solar forecast to capture the short-term variation of solar power generation. When developed, ERCOT intends to integrate this forecast in ERCOT systems and include a five-minute solar ramp forecasts in its calculation of "Generation To Be Dispatched" as part of security-constrained economic dispatch. This change is intended to take the burden off of regulation service to cover the five-minute gain or loss of generation from variations in solar irradiance and instead dispatch this energy economically. This change will also aid in reducing frequency recovery duration following events that occur during times with significant solar up and down ramps.
- ERCOT is in the process of implementing a new ancillary service, the ERCOT contingency reserve service. With increasing wind and solar resources on the system, it will become increasingly necessary to retain some amount of capacity in reserve in real-time that can respond within 10 minutes. Solar resources will result in steeper net load ramps than what has been experienced with load and wind, and non-spinning reserve from the current ancillary service product set is not designed to meet this need.
- ERCOT is actively working with its stakeholders to develop policy, procedures and system changes to model DERs in ERCOT systems. ERCOT expects to make changes between now and sometime in 2024.

66 The area is considering alternatives for the reference reserve margin: EORM: Economically Optimal, the level at which reserves' marginal benefit equals marginal cost, and MERM: Market Equilibrium, the level at which new capacity's costs equals net revenues (including administratively-determined capacity scarcity prices). A report planned for release in late 2020 will allow comparisons of both alternatives to one based on a 1-in-10 LOLE reliability criterion.

Transmission Projects for Enhancing Grid Reliability

The recently updated ERCOT *Transmission Project and Information Tracking* list (March 2020) includes the addition or upgrade of 2,912 circuit miles of 138 kV and 345 kV transmission circuits and 19,246 MVA of 345/138 kV transformer capacity that are planned in the Texas RE-ERCOT assessment area between 2020 and 2025.[67]

Strong load growth has continued in West Texas that is primarily driven by the increase in oil and natural gas extraction-related activities. The average annual peak load growth rate, between 2010 and 2019, was over 10%. In 2017 and 2018, ERCOT recommended several large new transmission projects, including a new 345-kV loop between the Moss Switch Station and the Bakersfield Station with six new 600 MVA 345/138 kV autotransformers, two at Riverton Switch Station, two at Sand Lake Substation, and two at Solstice Switch Station. A related project will add two 250 MVAR STATCOMs in the area. The projects are expected to be in place prior to the 2021 summer peak.

The Freeport area, south of Houston and adjacent to the Gulf of Mexico, is highly industrialized. Several industrial load additions, including the Freeport LNG export facility, are either under construction or have been proposed. Transmission projects, totaling $117 million, have already been completed in 2016 and 2017. In December 2017, the Freeport Master Plan project was approved. Among other improvements, the project will add a 48-mile 345 kV double circuit transmission line from Bailey to Jones Creek.

There are over 1,000 MW of industrial load additions under construction in the Corpus Christi North Shore area that are expected to be in-service between 2021 and 2023. In June 2020, the Corpus Christi North Shore Transmission Improvement Project was approved to meet reliability needs that result from these load additions. Planned improvements include a new 345 kV Angstrom substation looped into the 345 kV transmission line from Whitepoint to STP, a new 345/138 kV Naismith substation, two new 345/138 kV transformers at Naismith, an additional 345/138 kV transformer at Whitepoint, approximately 36 total miles of new 345 kV transmission lines from Angstrom to Grissom and from Angstrom to Naismith, and approximately 28 circuit miles of 138 kV transmission line additions and upgrades.

67 List is maintained on the ERCOT planning page: http://www.ercot.com/gridinfo/planning

Mitigation Strategies for Address Gas Supply Risks

ERCOT does not foresee any adverse reliability concerns for the Texas RE-ERCOT assessment area associated with fuel supply or fuel deliverability constraints. Thus far, natural gas curtailments have not adversely affected ERCOT operations. ERCOT has formed the Gas Electric Working Group,[68] which consists of ERCOT stakeholders and natural gas supplier representatives. A main function of this group is to discuss and understand fuel supply deliverability and constraint issues. As a discussion forum, the Gas Electric Working Group allows ERCOT to develop, modify, and refine its policies, procedures, and tools to ensure reliable grid operations during both normal and extreme natural gas demand conditions. A current focus of this working group is to enhance coordination efforts around natural gas pipeline planned maintenance activities during peak electric load periods.

ERCOT also continues to receive confidential notifications of operational issues occurring on the pipelines at the same time generators are notified. ERCOT expects to enhance its existing procedures for monitoring the area's natural-gas-fired generation fleet as operational experiences dictate.

Integration of Battery Energy Storage Systems

As of May 31, there was 643 MW of battery storage capacity for which developers have requested interconnection and that have signed interconnection agreements and have posted financial security with transmission services providers for interconnection construction. These projects all have expected in-service dates of no later than September 2021 based on current developer information. There is another 109 MW of planned battery storage capacity for projects from between 1 and 10 MW with 10 MW being the threshold beyond which projects must go through ERCOT's full interconnection process. These small utility-scale projects are projected to be in service by the end of 2020 based on developer information. Currently, the main use of both existing and planned storage resources is the provision of ancillary services; however, some existing facilities are currently used for energy arbitrage (charging during lower-priced hours and discharging during higher-priced hours) and more are expected be used for this purpose in the future. ERCOT market rules allow both of these uses today, but improvements are under way to expand opportunities for participation in the ERCOT ancillary services and energy markets.

ERCOT currently has 153 MW of installed energy storage resources (transmission and/or distribution connected) that are modeled in ERCOT systems.

68 http://www.ercot.com/committee/gewg

The majority of the installed energy storage projects have limited duration energy capability. ERCOT uses a generator (injection) in combination with load (withdrawal) when modeling such energy storage resources. Since most of the current energy storage resources are very limited in duration, these resources are not considered in ERCOT's planning studies. ERCOT is currently reviewing its policies, procedures, and systems to support larger penetration levels of energy storage resources and expects to make changes between now and sometime in 2024.

Probabilistic Assessment Overview

- **General Overview:** Projected reserve margins for ERCOT have increased since the 2018 ProbA, leading to a decreased possibility of reliability issues for the study years. The 2022 projected ProbA forecast reserve margin is 19.1%. The 2024 projected reserve margin is 15.5%.
- **Modeling:** This study used Astrapé Consulting's probabilistic resource adequacy assessment model, SERVM, which simulates chronological hourly unit commitment and economic dispatch. ERCOT was modeled as a single zone connected to SPP, MISO LRZ 8,9,10, and Mexico through dc ties. SERVM captures the uncertainty of weather, economic growth, unit availability, and external assistance from neighboring areas as stochastic variables, described further as follows:
  - The simulations used 40 synthetic load, wind, solar, and hydro profiles based on historical years 1980–2019 to represent expected conditions in the study years if historical weather conditions were to take place again. Five LFU multipliers were applied to each synthetic weather year. The multipliers that ranges from -4% to +4% capture economic load growth uncertainty.
  - Thermal generator availability was based on Generation Availability Data System data for the past three years submitted by resource entities. SERVM can simulate both full and partial outages using a multi-state Monte-Carlo modeling approach.
  - Wind and solar were modeled as capacity resources with hourly profiles that are weather-correlated with the load shapes. The peak capacity contributions were 63% for coastal wind, 29% for panhandle wind, 16% for other wind, and 76% for solar.
  - Dispatch heuristics for hydro resources were developed from eight years of hourly data from ERCOT, applied to 40 years of monthly data from FERC 923 and ERCOT, and modeled with different parameters for each month, including monthly total energy output, daily maximum and minimum outputs, and monthly maximum output.

Base Case Study

The Base Case study results in minimal reliability events. As compared to the 2018 ProbA study, the reserve margin has increased substantially primarily due to an increase in solar resources. More than 12 GW of additional solar installed capacity is expected in 2022 now than was forecast when the 2018 ProbA study was published.

Results Trending: Compared to the results from the 2018 ProbA study, LOLH decreased from 0.87 to 0.001 for the first study year. The results are driven by an increase in the ARM that resulted from growth in planned solar and wind capacity.

Off-Peak Risk: With the dramatic increase in wind and solar capacity, the reliability risk in off-peak periods has grown. While no EUE was identified in the shoulder months in the Base Cases, the projected remaining reserves during shoulder months has declined significantly. In particular synthetic years, March and October have the lowest monthly available reserves on the peak day, even though those years did not show LOL. Further increases in renewable penetration could potentially result in the risk of firm load shed in shoulder months when planned outages are scheduled.

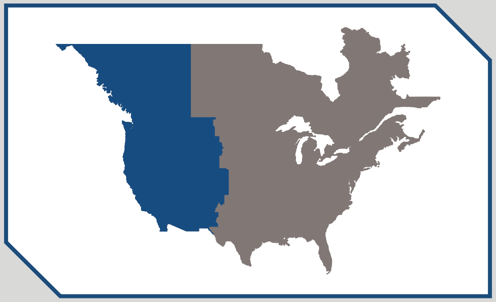
Regional Risk Scenario

Simulated LOL events in ERCOT are largely driven by high load, low wind output conditions. These conditions occur with relative rarity such that a relatively small change in their frequency could have significant impact on the expected reliability of the ERCOT system. The risk scenario for ERCOT was designed to stress-test the impact of a difference in the frequency of high load and low wind events, when compared to the Base Case.

To construct the alternate wind profiles that reflect a higher likelihood of low wind output, a filter will be performed for days in the simulated Base Case that had any firm LOL. An alternate wind profile for each day will be randomly selected from the wind profiles from this set of days. This re-shuffling of load and wind profiles will be performed 100 times. The sampled sets of profiles that represent the fifth most extreme and twenty-fifth most extreme sets of net load profiles will be selected for simulations. The criteria for most extreme will be based on the set with the highest average net loads. The 5% wind profile set represents ERCOT's expectation that future load and wind correlations have a 5% or 25% likelihood of resulting in more extreme reliability events in the future.

Base Case Summary of Results			
Reserve Margin (RM) %			
	2022*	**2022**	**2024**
Anticipated	10.6%	19.1%	15.5%
Reference	13.8%	13.8%	13.8%
ProbA Forecast Operable	4.6%	13.7%	10.3%
Annual Probabilistic Indices			
	2022*	**2022**	**2024**
EUE (MWh)	1,088.72	0.44	12.86
EUE (ppm)	2.64	0.00	0.03
LOLH (hours/year)	0.87	0.00	0.03

*Indicates 2018 ProbA results for comparison.



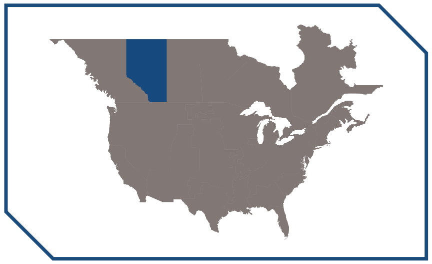
WECC

Western Electricity Coordinating Council (WECC) is responsible for coordinating and promoting Bulk Electric System (BES) reliability in the Western Interconnection. WECC's 329 members, which include 38 Balancing Authorities, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and approximately 84.6 million people. It is geographically the largest and most diverse of the NERC REs. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 western states in between. The WECC assessment area is divided into four sub-regions: California/Mexico (CA/MX); the Northwest Power Pool (NWPP), which is further divided into the NW-Canada and NW-US areas; and the Southwest Reserve Sharing Group (SRSG). The NWPP sub-region includes the previously reported RMRG sub-region. These subregional divisions are used for this assessment as they are structured around reserve sharing groups that have similar annual demand patterns and similar operating practices.

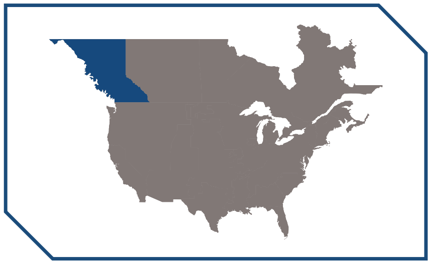
Highlights

- WECC and all the individual sub-regions are expected to have sufficient generation to meet or exceed the Reference Margin Level for the seasonal peak hours represented in the assessment period for this particular on-peak assessment. This is based on expected levels of demand and resource availability. As the probabilistic assessment reflects, when assessing the system with non-expected levels of demand and resource availability, maintaining reliability to a 1-day-in-10-year threshold of reliability for every hour is not achieved.
- WECC's 2020 ProbA continues to note several hours that pose a potential risk for loss of load for almost all regions over years 2022 and 2024. The CAMX sub-region was the only concern in the 2018 ProbA, but now all areas except AESO are seeing hours of potential loss of load. Exacerbated by the recent western area heat wave event, which saw load shed over the summer, all areas are reviewing the level of resource adequacy considering forecast variability.
- Although the Aliso Canyon Natural Gas Storage Facility has returned to operations in Southern California, there is still concern with the reduced availability of the facility. WECC continues to monitor this in conjunction with CAISO and SoCal Gas to assess the potential impacts to reliability for the Western Interconnection.

Starting on the next page are summaries of the assessment areas that make up WECC.

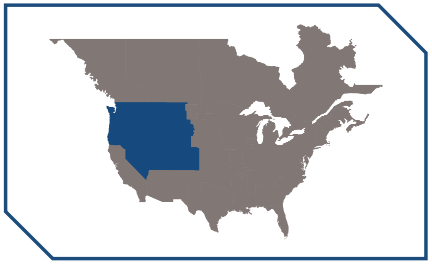


WECC-AB

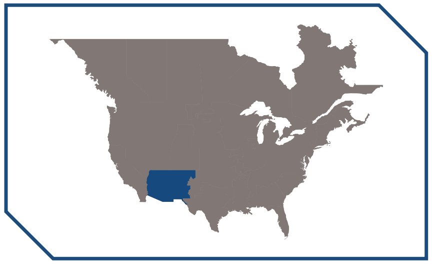


WECC-BC

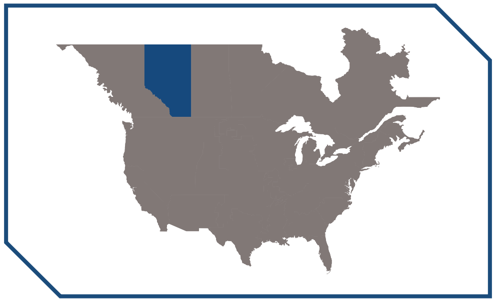
WECC-CAMX



WECC-NWPP-US and RMRG

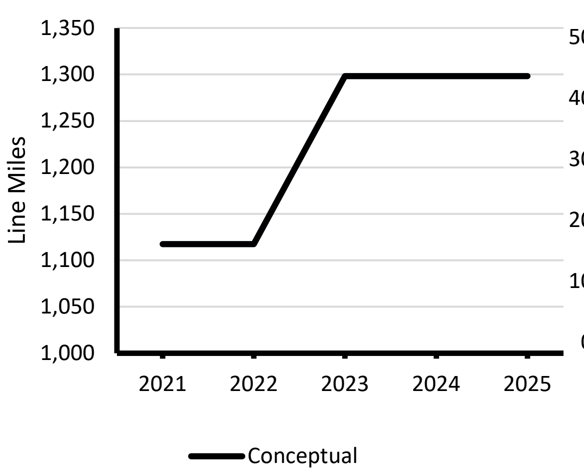


WECC-SRSG

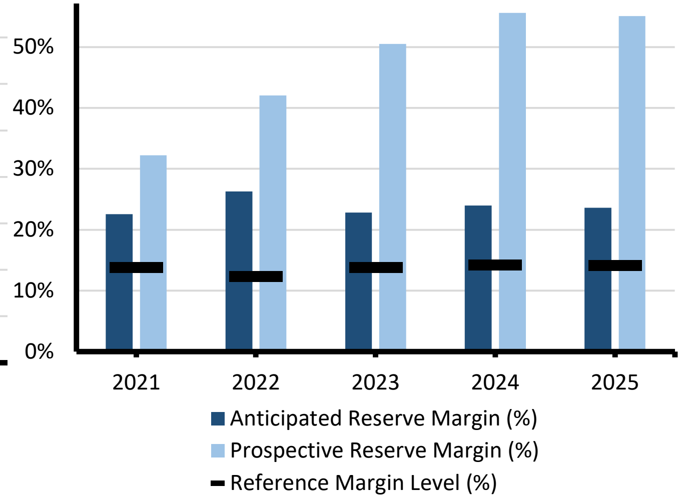


WECC-AB

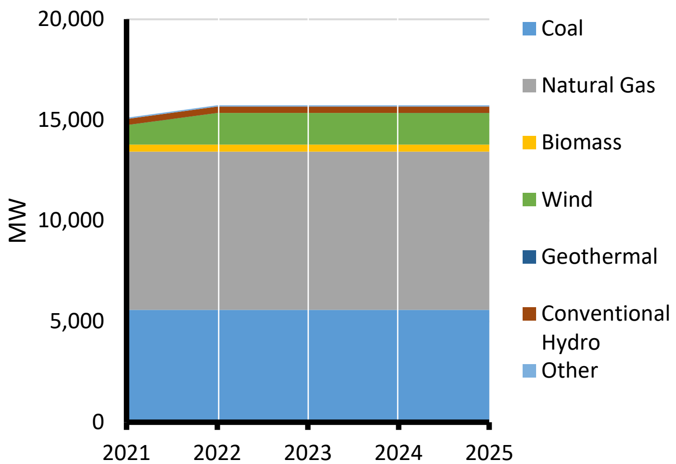
Demand, Resources, and Reserve Margins (MW)										
Quantity	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Internal Demand	12,329	12,453	12,807	12,684	12,725	12,824	12,917	13,051	13,160	13,241
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	12,329	12,453	12,807	12,684	12,725	12,824	12,917	13,051	13,160	13,241
Additions: Tier 1	139	752	752	752	752	752	752	752	752	752
Additions: Tier 2	1,192	1,966	3,546	4,009	4,009	4,009	4,009	4,809	5,275	5,275
Additions: Tier 3	0	323	323	467	799	1,140	1,185	1,320	1,553	2,339
Net Firm Capacity Transfers	0	0	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	14,974	14,974	14,974	14,974	14,974	14,974	14,974	14,974	14,974	14,974
Anticipated Reserve Margin (%)	22.6%	26.3%	22.8%	24.0%	23.6%	22.6%	21.8%	20.5%	19.5%	18.8%
Prospective Reserve Margin (%)	32.2%	42.1%	50.5%	55.6%	55.1%	53.9%	52.8%	57.3%	59.6%	58.6%
Reference Margin Level (%)	13.8%	12.3%	13.8%	14.1%	14.1%	14.0%	13.9%	12.3%	13.7%	13.5%



Projected Transmission Circuit Miles

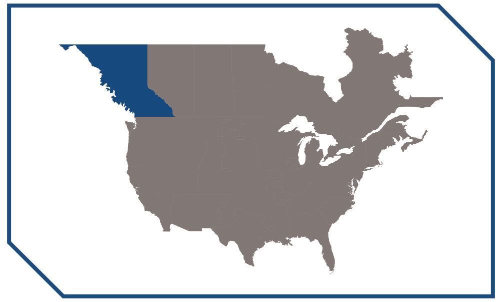


Planning Reserve Margins



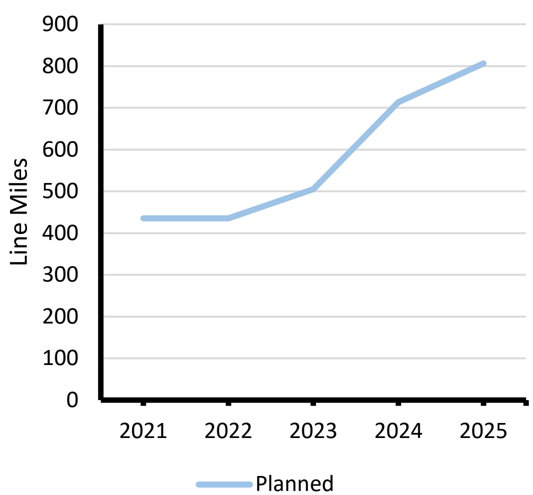
Existing and Tier 1 Resources

WECC-AB Fuel Composition										
Generation Type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal	5,578	5,578	5,578	5,578	5,578	5,578	5,578	5,578	5,578	5,578
Natural Gas	7,852	7,852	7,852	7,852	7,852	7,852	7,852	7,852	7,852	7,852
Biomass	343	343	343	343	343	343	343	343	343	343
Wind	967	1,580	1,580	1,580	1,580	1,580	1,580	1,580	1,580	1,580
Conventional Hydro	310	310	310	310	310	310	310	310	310	310
Other	63	63	63	63	63	63	63	63	63	63
Total MW	15,113	15,727	15,727	15,727	15,727	15,727	15,727	15,727	15,727	15,727

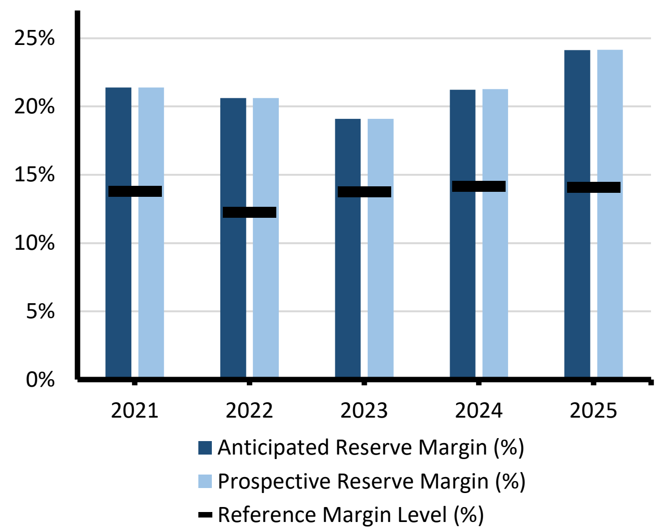


WECC-BC

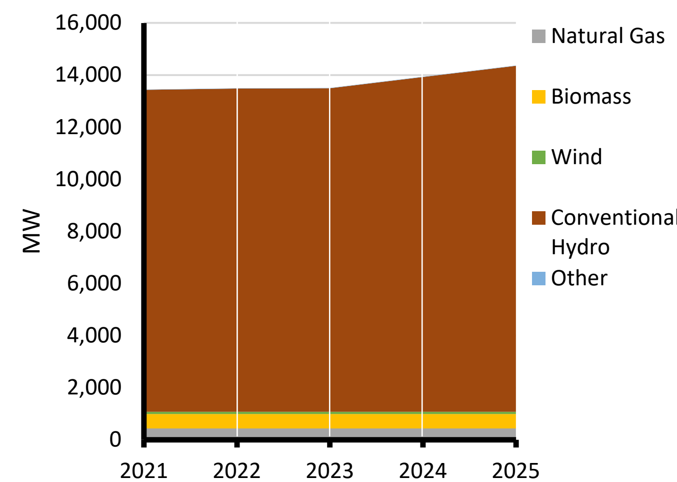
Demand, Resources, and Reserve Margins (MW)										
Quantity	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Internal Demand	11,077	11,187	11,340	11,495	11,572	11,726	11,834	11,961	12,069	12,211
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	11,077	11,187	11,340	11,495	11,572	11,726	11,834	11,961	12,069	12,211
Additions: Tier 1	124	172	184	613	1,042	1,084	1,125	1,166	1,207	1,207
Additions: Tier 2	0	0	0	4	4	4	4	4	4	4
Additions: Tier 3	2	12	55	98	142	142	176	176	176	176
Net Firm Capacity Transfers	0	0	0	0	0	108	166	130	311	397
Existing-Certain and Net Firm Transfers	13,321	13,321	13,321	13,321	13,321	13,429	13,487	13,451	13,632	13,718
Anticipated Reserve Margin (%)	21.4%	20.6%	19.1%	21.2%	24.1%	23.8%	23.5%	22.2%	22.9%	22.2%
Prospective Reserve Margin (%)	21.4%	20.6%	19.1%	21.3%	24.2%	23.8%	23.5%	22.2%	23.0%	22.3%
Reference Margin Level (%)	13.8%	12.3%	13.8%	14.1%	14.1%	14.0%	13.9%	12.3%	13.7%	13.5%



Projected Transmission Circuit Miles



Planning Reserve Margins

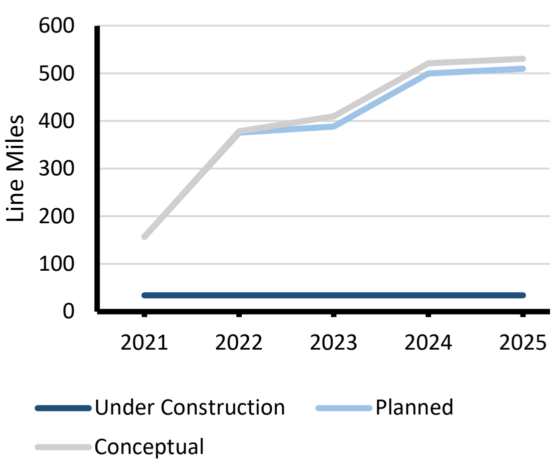


Existing and Tier 1 Resources

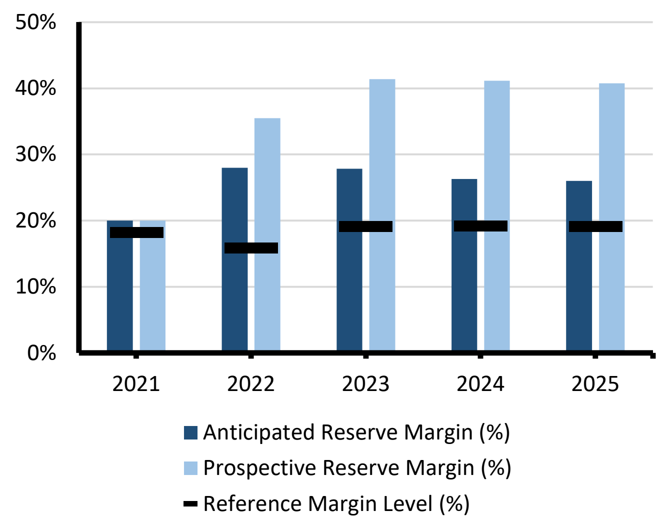
WECC-BC Fuel Composition										
Generation Type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Natural Gas	434	434	434	434	434	434	434	434	434	434
Biomass	559	559	559	559	559	559	559	559	559	559
Wind	82	82	82	82	82	82	82	82	82	82
Conventional Hydro	12,358	12,406	12,418	12,847	13,277	13,318	13,359	13,400	13,441	13,441
Other	13	13	13	13	13	13	13	13	13	13
Total MW	13,445	13,493	13,505	13,934	14,364	14,405	14,446	14,487	14,528	14,528

WECC-CAMX

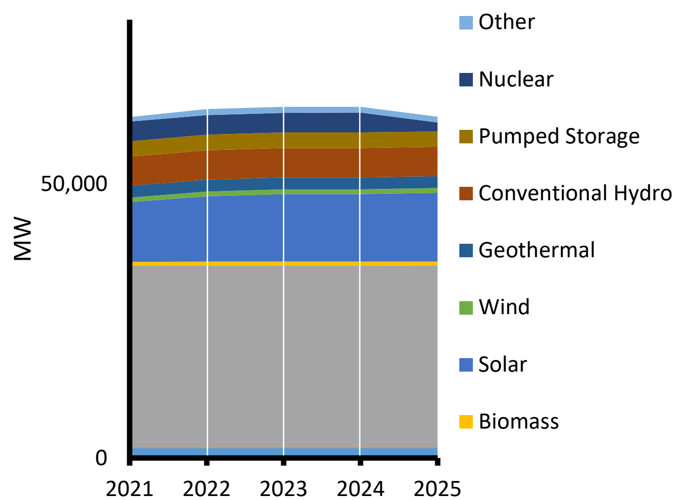
Demand, Resources, and Reserve Margins (MW)										
Quantity	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Internal Demand	55,721	53,451	53,882	54,331	54,742	55,063	55,416	55,638	56,097	56,647
Demand Response	1,008	994	972	972	972	972	972	972	972	972
Net Internal Demand	54,713	52,457	52,910	53,359	53,770	54,091	54,444	54,666	55,125	55,675
Additions: Tier 1	2,102	3,565	3,967	3,974	4,450	4,456	4,463	4,466	4,470	5,585
Additions: Tier 2	0	3,944	7,159	7,939	7,939	7,939	7,939	7,939	7,939	8,665
Additions: Tier 3	0	0	403	403	403	403	403	403	403	403
Net Firm Capacity Transfers	4,224	3,359	3,288	3,581	3,571	3,149	3,354	3,046	3,375	3,492
Existing-Certain and Net Firm Transfers	63,569	63,569	63,679	63,409	63,340	63,339	63,339	63,339	63,403	63,248
Anticipated Reserve Margin (%)	21.4%	27.8%	27.3%	26.8%	22.5%	21.0%	20.6%	19.6%	19.2%	19.2%
Prospective Reserve Margin (%)	21.4%	35.3%	40.8%	41.7%	37.3%	35.7%	35.2%	34.1%	33.6%	34.8%
Reference Margin Level (%)	18.2%	15.8%	19.1%	19.1%	19.1%	19.0%	18.9%	15.7%	18.9%	19.0%



Projected Transmission Circuit Miles

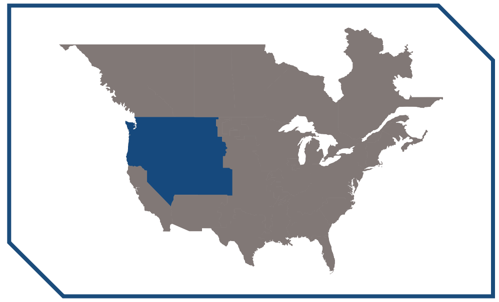


Planning Reserve Margins



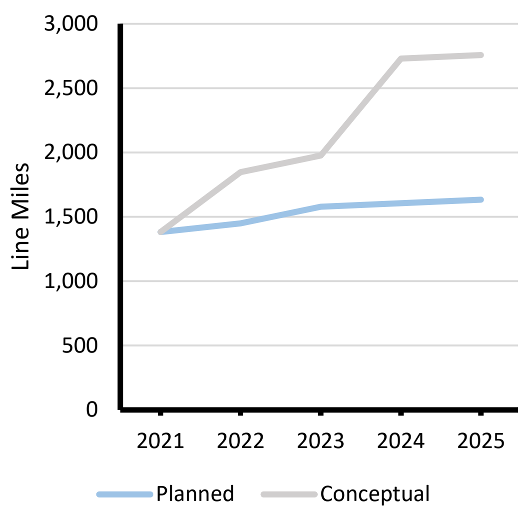
Existing and Tier 1 Resources

WECC-CAMX Fuel Composition										
Generation Type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal	1,832	1,832	1,832	1,832	1,832	1,832	1,832	1,832	1,832	1,832
Petroleum	217	217	217	217	217	217	217	217	217	217
Natural Gas	33,055	33,076	33,076	33,076	33,080	33,080	33,080	33,080	33,080	33,650
Biomass	701	745	745	745	745	745	745	745	745	745
Solar	10,888	11,889	12,291	12,298	12,504	12,510	12,517	12,520	12,524	12,528
Wind	851	897	897	897	897	897	897	897	897	897
Geothermal	2,133	2,142	2,142	2,142	2,142	2,142	2,142	2,142	2,142	2,142
Conventional Hydro	5,299	5,377	5,377	5,377	5,353	5,353	5,353	5,353	5,353	5,347
Pumped Storage	2,816	2,816	2,816	2,816	2,816	2,816	2,816	2,816	2,816	2,816
Nuclear	3,604	3,604	3,604	3,604	1,633	1,633	1,633	1,633	1,633	1,633
Other	793	1,056	1,056	1,056	1,023	1,023	1,023	1,023	1,023	1,023
Total MW	62,193	63,656	64,058	64,065	62,304	62,310	62,317	62,320	62,324	62,899

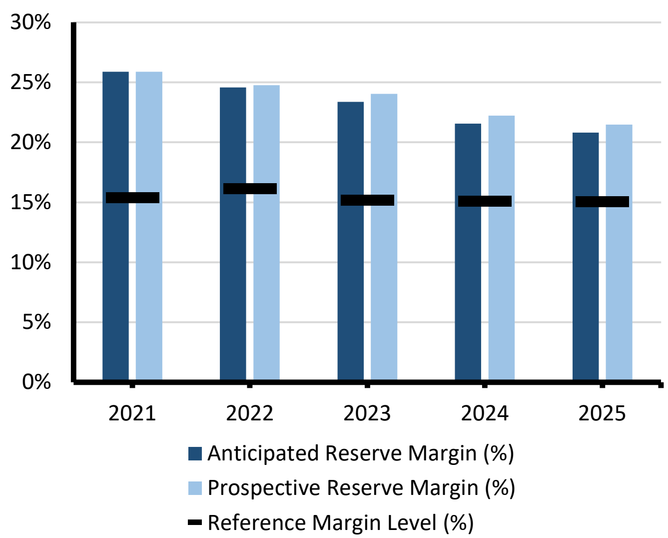


WECC-NWPP-US and RMRG

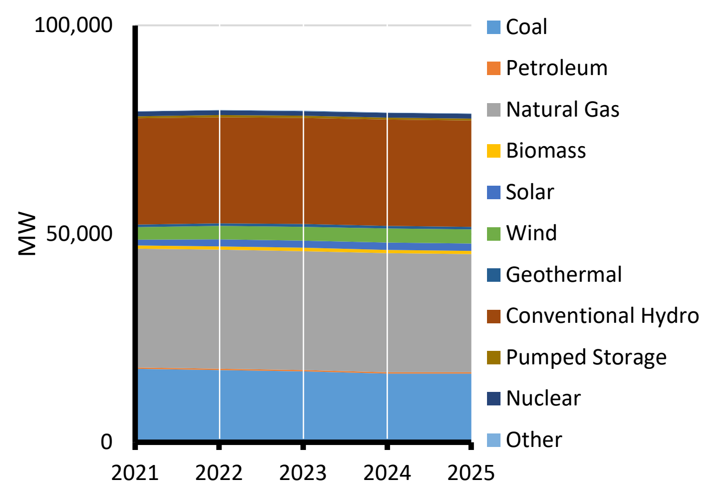
Demand, Resources, and Reserve Margins (MW)										
Quantity	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Internal Demand	64,258	65,160	65,663	66,261	66,498	66,904	67,331	68,152	68,567	69,063
Demand Response	1,162	1,169	1,174	1,178	1,180	1,182	1,183	1,179	1,179	1,172
Net Internal Demand	63,096	63,992	64,490	65,083	65,319	65,723	66,148	66,974	67,389	67,892
Additions: Tier 1	493	1,034	1,201	1,288	1,288	1,288	1,288	1,288	1,288	1,288
Additions: Tier 2	0	115	434	437	437	437	437	437	434	434
Additions: Tier 3	366	708	1,148	2,872	2,940	3,125	3,845	4,095	4,733	5,639
Net Firm Capacity Transfers	0	0	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	78,940	78,686	78,361	77,830	77,618	76,090	75,785	74,729	73,964	73,634
Anticipated Reserve Margin (%)	25.9%	24.6%	23.4%	21.6%	20.8%	17.7%	16.5%	13.5%	11.7%	10.4%
Prospective Reserve Margin (%)	25.9%	24.8%	24.0%	22.2%	21.5%	18.4%	17.2%	14.2%	12.3%	11.0%
Reference Margin Level (%)	15.4%	16.1%	15.2%	15.1%	15.0%	14.9%	14.8%	15.6%	14.7%	14.5%



Projected Transmission Circuit Miles

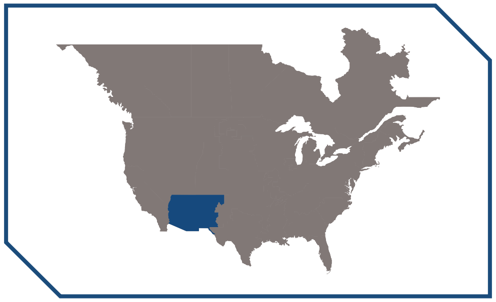


Planning Reserve Margins



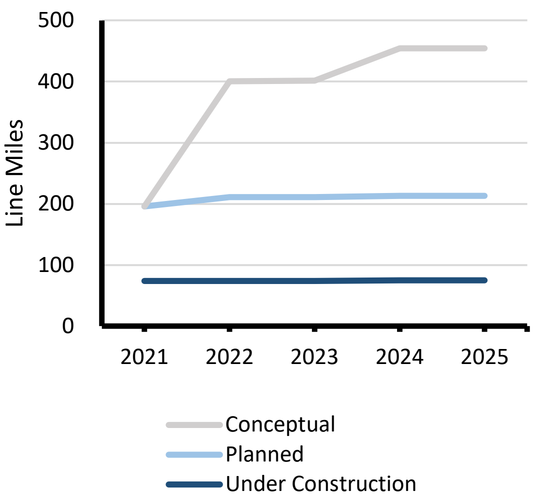
Existing and Tier 1 Resources

WECC-NWPP-US Fuel Composition										
Generation Type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal	17,599	17,345	17,020	16,489	16,489	15,033	15,033	14,288	13,749	13,469
Petroleum	303	303	303	303	303	303	303	303	303	303
Natural Gas	28,541	28,541	28,541	28,541	28,329	28,257	27,952	27,642	27,416	27,366
Biomass	793	793	793	793	793	793	793	793	793	793
Solar	1,351	1,669	1,746	1,777	1,777	1,777	1,777	1,777	1,777	1,777
Wind	2,997	3,220	3,296	3,352	3,352	3,352	3,352	3,352	3,352	3,352
Geothermal	628	628	628	628	628	628	628	628	628	628
Conventional Hydro	25,489	25,489	25,502	25,502	25,502	25,502	25,502	25,501	25,501	25,501
Pumped Storage	493	493	493	493	493	493	493	493	493	493
Nuclear	1,130	1,130	1,130	1,130	1,130	1,130	1,130	1,130	1,130	1,130
Other	109	109	109	109	109	109	109	109	109	109
Total MW	79,433	79,720	79,562	79,118	78,906	77,378	77,072	76,017	75,252	74,922

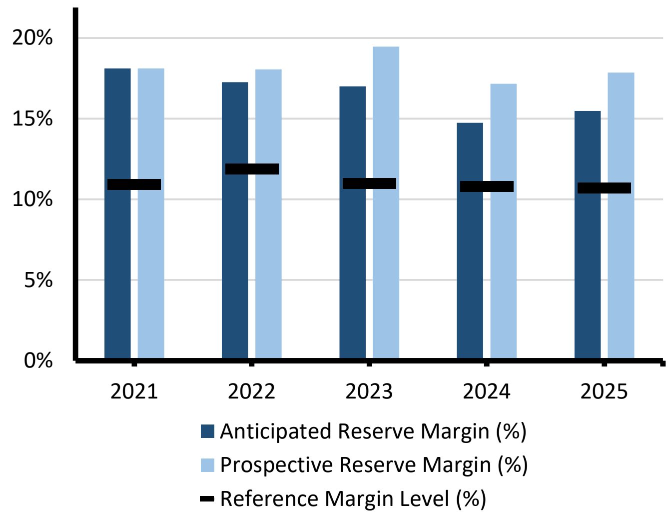


WECC-SRSG

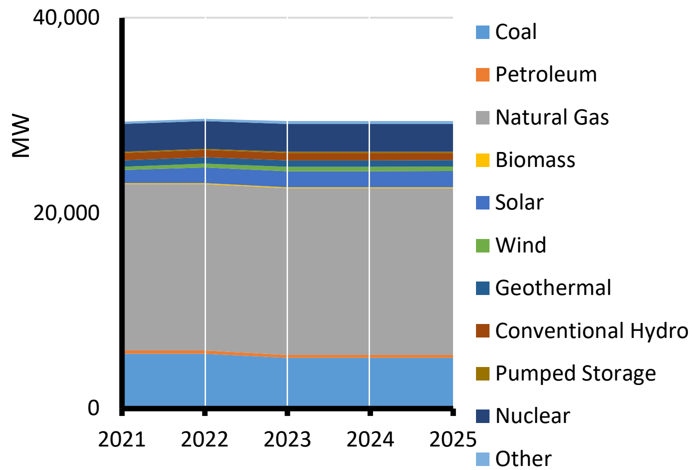
Demand, Resources, and Reserve Margins (MW)										
Quantity	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Total Internal Demand	25,652	26,128	26,570	26,991	27,458	27,902	28,374	29,051	29,358	29,830
Demand Response	62	62	62	62	62	62	62	62	62	62
Net Internal Demand	25,590	26,066	26,508	26,929	27,396	27,840	28,312	28,989	29,296	29,768
Additions: Tier 1	552	862	1,245	1,245	1,253	1,253	1,253	1,253	1,253	1,253
Additions: Tier 2	2	209	649	649	649	649	649	649	649	649
Additions: Tier 3	192	769	956	1,256	1,391	1,635	2,349	2,674	2,974	3,699
Net Firm Capacity Transfers	865	895	1,605	1,490	2,220	3,110	3,760	4,420	4,500	4,780
Existing-Certain and Net Firm Transfers	29,672	29,702	29,769	29,654	30,384	31,274	31,601	32,188	32,268	32,548
Anticipated Reserve Margin (%)	18.1%	17.3%	17.0%	14.7%	15.5%	16.8%	16.0%	15.4%	14.4%	13.6%
Prospective Reserve Margin (%)	18.1%	18.1%	19.5%	17.2%	17.9%	19.2%	18.3%	17.6%	16.6%	15.7%
Reference Margin Level (%)	10.9%	11.9%	11.0%	10.8%	10.7%	10.6%	10.5%	11.1%	10.4%	10.3%



Projected Transmission Circuit Miles



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-SRSG Fuel Composition										
Generation Type	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Coal	5,616	5,616	5,172	5,172	5,172	5,172	5,172	5,172	5,172	5,172
Petroleum	307	307	307	307	307	307	307	307	307	307
Natural Gas	17,050	17,050	17,080	17,080	17,080	17,080	16,758	16,685	16,685	16,685
Biomass	86	86	86	86	86	86	86	86	86	86
Solar	1,347	1,610	1,648	1,648	1,656	1,656	1,654	1,654	1,654	1,654
Wind	343	390	458	458	458	458	458	458	458	458
Geothermal	655	655	655	655	655	655	655	655	655	655
Conventional Hydro	747	747	747	747	747	747	747	747	747	747
Pumped Storage	120	120	120	120	120	120	120	120	120	120
Nuclear	2,856	2,856	2,856	2,856	2,856	2,856	2,856	2,856	2,856	2,856
Other	231	231	281	281	281	281	281	281	281	281
Total MW	29,359	29,669	29,409	29,409	29,417	29,417	29,094	29,021	29,021	29,021

WECC Assessment

Planning Reserve Margins: The Anticipated Reserve Margin does not fall below the Reference Margin level for any year for any of the assessment areas within WECC for the peak hours analyzed in the assessment period. However, this is based on the expected levels of demand and resource availability. WECC uses a probabilistic approach for determining Reference Margin Levels, holding a loss of load probability constant equal to 0.02% (approximately a 1-in-10 loss of load). The model determines what reserve margin must be held to maintain that fixed loss of load probability. Using this technique, WECC has a target reserve margin for every hour of the year, which we can use to assess non-peak conditions as well as peak conditions.

Demand: Load forecasts are provided to WECC annually through the Loads and Resources Data Request by their 38 individual BAs. The BAs demand and energy forecast are based on expected population growth, economic conditions, and weather patterns. Forecasted demand is reduced for rooftop solar to reflect demand expected to be served by the load serving entity (LSE). WECC's entities report their firm demand with various elements removed or modeled independently. These include behind the meter solar, energy efficiency, and DSM program totals. Electric vehicle penetration isn't explicitly reported though it is imbedded into the firm demand. The underlying assumptions in firm demand are not reported to WECC. WECC staff uses monthly peak and energy data and a historic hourly "base curve" to generate an hourly demand curve (8,760 hours) for each BA for each years 1–10.

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

Generation: The results from this assessment indicate that all assessment areas are resource adequate in the short, near, and long term with their current resource portfolio plans. It should be noted that this assessment is a peak hour deterministic view focused on the expected levels of demand and resource availability. The probabilistic results indicate potential risk for certain assessment areas during abnormal conditions. See probabilistic assessment results that start on page 156.

Variable resource capacity availabilities are based on historic on-peak generation and are aggregated into an assessment area-wide "availability curves." This process involves identifying the expected summer and winter peak hour for each assessment area and year followed by applying the availability (percentage of on peak contribution) to the summer or winter rated/reported variable resource capacities.

WECC's annual update of the base historical data leads to minor changes in availability curves, but the process itself has not changed for this *2020 LTRA*. The method for counting capacity contribution is the same for all resource tiers, but the variability in historic seasonal peak hour generation may produce different capacity contributions (availability factors) for each assessment year.

WECC studies expected future study cases that include expected generation retirements. Though it is anticipated that older coal-fired resources will retire in coming years, it is not expected that there will be unplanned retirements that cause a severe impact to reliability as these retirements would need approval from state PUCs or ISOs.

WECC is not a planning entity and does not approve or reject planned retirements. WECC does incorporate announced or reported planned retirements when creating datasets to be used in their planning models. Retirement of resources is not currently a major concern as ample generations exists in WECC based on the deterministic results, however, unexpected or accelerated retirements could pose a concern, which is why WECC decided to focus their probabilistic assessment scenario on additional retirements than what was reported.

The large geographic footprint of WECC helps mitigate generation retirements with seasonal transfers from winter-peaking areas to summer-peaking areas and vice versa. Transfers are very common in WECC.

Capacity Transfers: WECC's assessment process is based on system-wide modeling that aggregates BA-based load and resource forecasts by geographic subareas with operationally realistic power transfer capability limits between the zones. The model used for this resource adequacy assessment calculates transfers between the zones limited to the lesser of excess capacity above the margin needed in the transferring zone or the operationally realistic transmission limit. Resources that are physically located in one BA area but are owned by an entity or entities located in another BA's geographic footprint are modeled as remote resources. These resources are modeled with transmission links between the resource zone and the owner's zone that are limited to the owner's share of the resource. This treatment allows the owner of the resource, and only the owner, to count the resource for margin calculations. Remote resources are transferred first in WECC's modeling processes and reduce the capacity available for modeled transfers. Transfers with other regional councils, such as MRO and SPP, are not included in this assessment, as this would require an assumption regarding the amount of surplus or deficit generation in those councils.

Transmission: Transmission planning in WECC is coordinated by five regional planning groups that create and periodically publish transmission expansion plans: Northern Tier Transmission Group, WestConnect, ColumbiaGrid, California ISO, and Alberta Electric System Operator. Several entities have proposed major transmission projects to connect renewable resources on the eastern side of WECC to load centers on the Pacific Coast to help satisfy renewable portfolio standards, particularly in California. These projects, however, are often subject to significant development delays due to permitting and other issues. Individual LSEs and BAs perform extreme weather scenario studies to determine the potential impacts to reliability. WECC develops the Base Case Compilation Schedule that details the 11 cases to be built for the current year study cycle. Those cases include heavy and light load scenarios that are used by the TP and Planning Coordinator to study various scenarios.

WECC-AB Probabilistic Assessment Overview

- **General Overview:** Reserve margins for the WECC-AB area are 23.22% for 2022 and 23.98% in 2024, resulting in insignificant levels of LOLH and EUE.
- **Modeling:** WECC utilizes the Multiple Area Variable Resource Integration Convolution model, an 8,760-hourly load, generation, and transmission sequential convolution model consisting of 39 interconnected areas. Modeling details are as follows:
  - Annual peak demand in the WECC-AB area varies by approximately 13% below to 11% above the forecasted WECC-AB demand based upon the 90/10% points of the LFU distributions.
  - Thermal units follow a two-state on-or-off sequence based on a Monte-Carlo simulation that utilizes unit-specific average forced outage rates and failure durations.
  - Variable resources are modeled as expected hourly generation profiles with variance distributions associated with each hour.

  Results Trending: From 2018 to 2020, the WECC-AB 2020 LOLH remain unchanged at 0.000.
- **Probabilistic vs. Deterministic Reserve Margin Results:** Since both assessments utilize identical capacity megawatts (Existing Certain and Tier 1) for thermal generation and exact on-peak demand, the ARM is the same as the ProbA Forecast Planning RM.

Base Case Study

WECC-AB resource adequacy measures are zero in the Base Case, indicating that anticipated reserves above 23% lead to no expected LOL or EUE. (*Indicates 2018 ProbA results for comparison.)

Probabilistic Base Case results outside of the on-peak hour
None

Probabilistic Base Case results of EUE
None

Base Case Summary of Results			
Reserve Margin (RM) %			
	2022*	**2022**	**2024**
Anticipated	23.44%	23.22%	23.98%
Reference	10.21%	12.64%	14.15%
ProbA Forecast Operable	26.8%	14.3%	20.2%
Annual Probabilistic Indices			
	2022*	**2022**	**2024**
EUE (MWh)	**0**	**0**	**0**
EUE (ppm)	**0**	**0**	**0**
LOLH (hours/year)	**0**	**0**	**0**

*Indicates 2018 ProbA results for comparison.

Key methods and assumption differences between this 2020 LTRA and ProbA assessments
The difference between this *2020 LTRA* and ProbA results is that the ProbA captures expected the equivalent forced outage rate for baseload resources whereas this LTRA does not. The other difference is that the ProbA looks at all hours of the year and this LTRA looks at the peak hour only.

Resource adequacy studies conducted that address area reliability risk drivers

- WECC is producing a western resource adequacy assessment annually, beginning in late 2020.
- WECC produces a generation resource adequacy forecast that highlights the results of WECC's resource adequacy efforts.[69]

Regional Risk Scenario

The WECC scenario will be looking into the potential coal retirements that may occur in the WI but have not been formally announced or included in this LTRA portfolio. This scenario will provide insights into where additional risk may occur with less baseload resources.

69 https://www.wecc.org/ePubs/GenerationResourceAdequacyForecast

WECC-BC Probabilistic Assessment Overview

- **General Overview:** Reserve margins for the WECC-BC area are over 20% for 2022 and 21.23% in 2024, resulting in insignificant levels of LOLH and EUE.
- **Modeling:** WECC utilizes the MAVRIC model, an 8,760-hourly load, generation, and transmission sequential convolution model consisting of 39 interconnected areas. Modeling details are as follows:
  - Annual peak demand in the WECC-BC area varies by approximately 10% below to 10% above the forecasted WECC-BC demand based upon the 90/10% points of the LFU distributions.
  - Thermal units follow a two-state on-or-off sequence based on Monte-Carlo simulations that utilize unit-specific average forced outage rates and failure durations.
  - Variable resources are modeled as expected hourly generation profiles with variance distributions associated with each hour.
- **Results Trending:** From 2018 to 2020, the WECC-BC 2022 LOLH increased, resulting in insignificant levels of LOLH at 0.001.
- **Probabilistic vs. Deterministic Reserve Margin Results:** Since both assessments utilize identical capacity megawatts (Existing Certain and Tier 1) for thermal generation and exact on-peak demand, the ARM is the same as the ProbA Forecast PRM.

Base Case Study

WECC-BC resource adequacy measures are zero in the Base Case, indicating that anticipated reserves above 20% result in insignificant levels of expected LOL or EUE.

Probabilistic Base Case results outside of the on-peak hour

LOL occurrences are expected in the months of March, October, and November for 2022 and the months of February and October for 2024. The hours of occurrence for 2022 and 2024 are expected at 6:00 a.m. Pacific time, one hour before the peak demand for the day.

Probabilistic Base Case results of EUE

The EUE occurs in the same months and hours as the LOLH. The magnitudes range from less than 1 MW to 13 MW in 1 hour and as much as 1 to 3 hours per LOLH period.

Base Case Summary of Results			
Reserve Margin (RM) %			
	2022*	**2022**	**2024**
Anticipated	15.9%	20.62%	21.23%
Reference	13.0%	12.26%	14.15%
ProbA Forecast Operable	26.8%	14.3%	20.2%
Annual Probabilistic Indices			
	2022*	**2022**	**2024**
EUE (MWh)	0	19.137	8.452
EUE (ppm)	0	.323	.137
LOLH (hours/year)	0	.001	.001

*Indicates 2018 ProbA results for comparison.

Key methods and assumption differences between this 2020 LTRA and ProbA assessments

The difference between this LTRA and the ProbA results is that the ProbA captures expected EFOR for baseload resources whereas this LTRA does not. The other difference is that the ProbA looks at all hours of the year and this LTRA looks at the peak hour only.

Resource adequacy studies that address area reliability risk drivers

- WECC is planning on producing a Western Resource Adequacy assessment annually, beginning in 2020.
- WECC produces a generation resource adequacy forecast that highlights the results of WECC's resource adequacy efforts.[70]

Regional Risk Scenario

The WECC scenario will be looking into the potential coal retirements that may occur in the WI but have not been formally announced or included in this LTRA portfolio. This scenario will provide insights into where additional risk may occur with less baseload resources.

70 https://www.wecc.org/ePubs/GenerationResourceAdequacyForecast

WECC-CAMX Probabilistic Assessment Overview

- **General Overview:** Reserve margins for the WECC-CAMX area are over 27% for 2022 and over 26% for 2024, but levels of LOLH are 22 and 56 hours, respectively, due in part to the changing resource mix. EUE is calculated to be ~1m in 2022 and ~2.4m in 2024. It should be noted that almost all of the LOLH and EUE are associated with the Mexico portion of CAMX. The California portion has improved since the last ProbA.
- **Modeling:** WECC utilizes the MAVRIC model, an 8,760-hourly load, generation, and transmission sequential convolution model that consists of 39 interconnected areas. Modeling details are as follows:
  - Annual peak demand in the WECC-CAMX area varies by approximately 11% below to 19% above the forecasted WECC-CAMX demand based upon the 90/10% points of the LFU distributions.
  - Thermal units follow a two-state on-or-off sequence based on Monte-Carlo simulation, which utilizes unit specific average forced outage rates and failure durations.
  - Variable resources are modeled as expected hourly generation profiles with variance distributions associated with each hour.
- **Results Trending:** From 2018 to 2020, the WECC-CAMX 2022 LOLH increased to 22 hours per year.
- **Probabilistic vs. Deterministic Reserve Margin Results:** Since both assessments utilize identical capacity megawatts (existing certain and Tier 1) for thermal generation and exact on-peak demand, the ARM is the same as the ProbA forecast PRM.

Base Case Study

WECC-CAMX resource adequacy measures are showing potential LOLH in the Base Case, indicating that anticipated reserves of 17% for the peak hour are not adequate for all hours of the year.

The Mexico portion of the CAMX area has seen a significant increase in their demand forecast since the 2018 ProbA was published. The annual energy demand forecast for 2022 was expected at around 15,900 GWh when reported for the 2018 ProbA. In the 2020 ProbA, the annual energy forecast has risen to approximately 16,900 GWh, a change of approximately 6.0%. This new demand forecast, coupled with the California portion of the area's inability to transfer energy after the peak hours in the evening due to their own shortfalls, has led to a significant increase in EUE for this area. Looking at the California portion of this area, the LOLH and EUE have improved since last ProbA with large improvements by 2024.

Base Case Summary of Results			
Reserve Margin (RM) %			
	2022*	**2022**	**2024**
Anticipated	21.3%	27.8%	26.8%
Reference	22.8%	15.84%	19.14%
ProbA Forecast Operable	22.7%	17.4%	15.3%
Annual Probabilistic Indices			
	2022*	**2022**	**2024**
EUE (MWh)	41,468	1,005,716	2,402,976
EUE (ppm)	513.8	3721	8818
LOLH (hours/year)	2.3	22	56
Annual Probabilistic Indices (CA Only)			
	2022*	**2022**	**2024**
EUE (MWh)	40,357	36,930	6,886
EUE (ppm)	157.35	146.05	27.15
LOLH (hours/year)	2.0	0.8	0.15

*Indicates 2018 ProbA results for comparison.

Probabilistic Base Case results outside of the on-peak hour

LOL occurrences are expected in the month of July for 2022 and the months of July and August for 2024. The hours of occurrence for 2022 and 2024 are expected at 6:00 p.m. Pacific time, one hour past the peak demand for the day in California.

Probabilistic Base Case results of EUE

The EUE occurs in the same months and hours as the LOLH. The magnitudes range from less than 1 MW to 27 GW in one hour to most peak hours in Mexico per LOLH period.

Key methods and assumption differences between this 2020 LTRA and ProbA Assessments

The difference between this LTRA and the ProbA results is that the ProbA captures expected equivalent forced outage rate for baseload resources whereas this LTRA does not. The other difference is that the ProbA looks at all hours of the year, and this LTRA looks at the peak hour only.

Resource adequacy studies conducted that address area reliability risk drivers

- WECC is planning on producing a western resource adequacy assessment annually, beginning in 2020.
- WECC produces a generation resource adequacy forecast that highlights the results of WECC's resource adequacy efforts.[71]

Regional Risk Scenario

The WECC scenario will be looking into the potential coal retirements that may occur in the WECC but have not been formally announced or included in this LTRA portfolio. This scenario will provide insights into where additional risk may occur with less baseload resources.

71 https://www.wecc.org/ePubs/GenerationResourceAdequacyForecast

WECC-NWPP and RMRG Probabilistic Assessment Overview

- **General Overview:** Reserve margins for the WECC-NWPP and RMRG area are over 24% for 2022 and 21% for 2024, but there are levels of LOLH of 1 and 5 hours respectively due in part to the changing resource mix. EUE is calculated to be ~13k in 2022 and ~248k in 2024.
- **Modeling:** WECC utilizes the MAVRIC model, an 8,760-hourly load, generation, and transmission sequential convolution model consisting of 39 interconnected areas. Modeling details are as follows:
  - Annual peak demand in the WECC-NWUS area varies by approximately 10% below to 11% above the forecasted WECC-NWUS demand based upon the 90/10% points of the LFU distributions.
  - Thermal units follow a two-state on-or-off sequence based on a Monte-Carlo simulation that utilizes unit specific average forced outage rates and failure durations.
  - Variable resources are modeled as expected hourly generation profiles with variance distributions associated with each hour.
- **Results Trending:** From 2018 to 2020, the WECC-NWPP and RMRG 2022 LOLH has decreased to less than one hour; however, the EUE has increased to ~13k MWh.
- **Probabilistic vs. Deterministic Reserve Margin Results:** Since both assessments utilize identical capacity megawatts (existing certain and Tier 1) for thermal generation and exact on-peak demand, the ARM is the same as the ProbA forecast PRM.

Base Case Study

WECC-NWPP and RMRG resource adequacy measures are beginning to show potential LOLE in the Base Case, indicating that anticipated reserves for the peak hours are not adequate for all hours of the year.

Probabilistic Base Case results outside of the on-peak hour

The LOL occurrences is expected in the months of August and September for 2022 and the months of July thru September for 2024. The hours of occurrence for 2022 and 2024 are expected after peak hour for one to three hours past the peak demand for the day.

Base Case Summary of Results			
Reserve Margin (RM) %			
	2022*	**2022**	**2024**
Anticipated	30.3%	24.6%	21.6%
Reference	16.5%	16.12%	15.08%
ProbA Forecast Operable	15.9%	28.0%	24.9%
Annual Probabilistic Indices			
	2022*	**2022**	**2024**
EUE (MWh)	2553	12,799.289	248,573.038
EUE (ppm)	8.58	32.694	621.798
LOLH (hours/year)	0.58	0.250	4.389

*Indicates 2018 ProbA results for comparison.

Probabilistic Base Case results of EUE

The EUE occurs in the same months and hours as the LOLH. The magnitudes range from less than a MW to 2,000 MW in one hour and as much as one to three hours per LOLH period.

Key methods and assumption differences between this 2020 LTRA and ProbA assessments.

The difference between this LTRA and the ProbA results is that the ProbA captures expected equivalent forced outage rate for baseload resources whereas this LTRA does not. The other difference is that the ProbA looks at all hours of the year, and this LTRA looks at the peak hour only.

Probabilistic resource adequacy studies conducted that address area reliability risk drivers.

- WECC is planning on producing a western resource adequacy assessment annually, beginning in 2020.
- WECC produces a generation resource adequacy forecast that highlights the results of WECC's resource adequacy efforts.[72]

72 https://www.wecc.org/ePubs/GenerationResourceAdequacyForecast

Regional Risk Scenario

The WECC scenario will be looking into the potential coal retirements that may occur in WECC but have not been formally announced or included in this LTRA portfolio. This scenario will provide insights into where additional risk may occur with less baseload resources.

WECC-SRSG Probabilistic Assessment Overview

- **General Overview:** Reserve margins for the WECC-SRSG area are over 17.2% for 2022 and 14.7% in 2024, resulting in insignificant levels of LOLH and EUE.
- **Modeling:** WECC utilizes the MAVRIC model, an 8,760-hourly load, generation, and transmission sequential convolution model consisting of 39 interconnected areas. Modeling details are as follows:
  - Annual peak demand in the WECC-SW area varies by approximately 13% below to 11% above the forecasted WECC-SRSG demand based upon the 90/10% points of the LFU distributions.
  - Thermal units follow a two-state on-or-off sequence based on a Monte-Carlo simulation that utilizes unit-specific average forced outage rates and failure durations.
  - Variable resources are modeled as expected hourly generation profiles with variance distributions associated with each hour.
- **Results Trending:** From 2018 to 2020, the WECC-SRSG 2022 LOLH increased to 0.001.
- **Probabilistic vs. Deterministic Reserve Margin Results:** Since both assessments utilize identical capacity megawatts (Existing Certain and Tier 1) for thermal generation and exact on-peak demand, the ARM is the same as the ProbA forecast PRM.

Base Case Study

WECC-SW resource adequacy measures are minimal in the Base Case, indicating that the anticipated peak reserve above 14% lead to insignificant levels of expected LOL and minimal EUE.

Probabilistic Base Case results outside of the on-peak hour

The LOL occurrences is expected in the month of July for 2022 and the months of July and August for 2024. The hours of occurrence for 2022 and 2024 are expected at 6:00 p.m., one hour past the peak demand for the day.

Probabilistic Base Case of indicated EUE, please explain or describe the following, as applicable:

The EUE occurs in the same months and hours as the LOLH. The magnitudes range from less than 1 MW to 35 MW in one hour and as much as one to three hours per LOLH period.

Base Case Summary of Results			
Reserve Margin (RM) %			
	2022*	**2022**	**2024**
Anticipated	26.8%	17.25%	14.74%
Reference	16.7%	18.06%	17.16%
ProbA Forecast Operable	15.6%	8.0%	5.5%
Annual Probabilistic Indices			
	2022*	**2022**	**2024**
EUE (MWh)	0	10.951	81.337
EUE (ppm)	0	.106	.750
LOLH (hours/year)	0	.001	.004

*Indicates 2018 ProbA results for comparison.

Key methods and assumption differences between this 2020 LTRA and ProbA Assessments.

The difference between this LTRA and the ProbA results is that the ProbA captures expected equivalent forced outage rate for baseload resources whereas this LTRA does not. The other difference is that the ProbA looks at all hours of the year, and this LTRA looks at the peak hour only.

Probabilistic resource adequacy studies conducted that address area reliability risk drivers.

- WECC is planning on producing a western resource adequacy assessment annually, beginning in 2020.
- WECC produces a generation resource adequacy forecast that highlights the results of WECC's resource adequacy efforts.[5]

Regional Risk Scenario

The WECC scenario will be looking into the potential coal retirements that may occur in WECC but have not been formally announced or included in this LTRA portfolio. This scenario will provide insights into where additional risk may occur with less baseload resources.

5 https://www.wecc.org/ePubs/GenerationResourceAdequacyForecast

Demand Assumptions and Resource Categories

Demand (Load Forecast)	
Total Internal Demand	This is the peak hourly load[1] for the summer and winter of each year.[2] Projected total internal demand is based on normal weather (50/50 distribution)[3] 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[4]**	**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-E	Summer	Noncoincident	SERC LSEs
SERC-C	Summer	Noncoincident	SERC LSEs
SERC-SE	Summer	Noncoincident	SERC LSEs
SERC-FP	Summer	Noncoincident	FRCC LSEs
SPP	Summer	Noncoincident	SPP LSEs
Texas RE-ERCOT	Summer	Coincident	ERCOT
WECC-AESO	Winter	Noncoincident	Individual BAs: aggregated by WECC
WECC-BC	Winter	Noncoincident	Individual BAs: aggregated by WECC
WECC-CAMX	Summer	Noncoincident	Individual BAs: aggregated by WECC
WECC-NWPP-US and RMRG	Summer	Noncoincident	Individual BAs: aggregated by WECC
WECC-SRSG	Summer	Noncoincident	Individual BAs: aggregated by WECC

1 Glossary of Terms Used in NERC Reliability Standards.

2 The summer season represents June–September, and the winter season represents December–February.

3 Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.

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 operable capacity expected to be available to serve load during the peak hour with firm transmission • 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[1]
Prospective Resources: Includes all anticipated resources plus the following: • Existing-other capacity: includes operable capacity that could be available to serve load during the peak hour but lacks firm transmission and could be unavailable during the peak or 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[2]

1 Generators that have formally announced retirement plans. These units must have an approved generator deactivation request where applicable.

2 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): ▪ 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): ▪ 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

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

Errata

February, 2021: CAMX assessment area resources have been updated for the deactivation of Diablo Canyon Nuclear Units 1 and 2 in late 2024 and 2025, respectively. The NWPP-US and RMRG assessment area Total and Net Internal Demand projections are corrected. These revisions are reflected throughout the report.