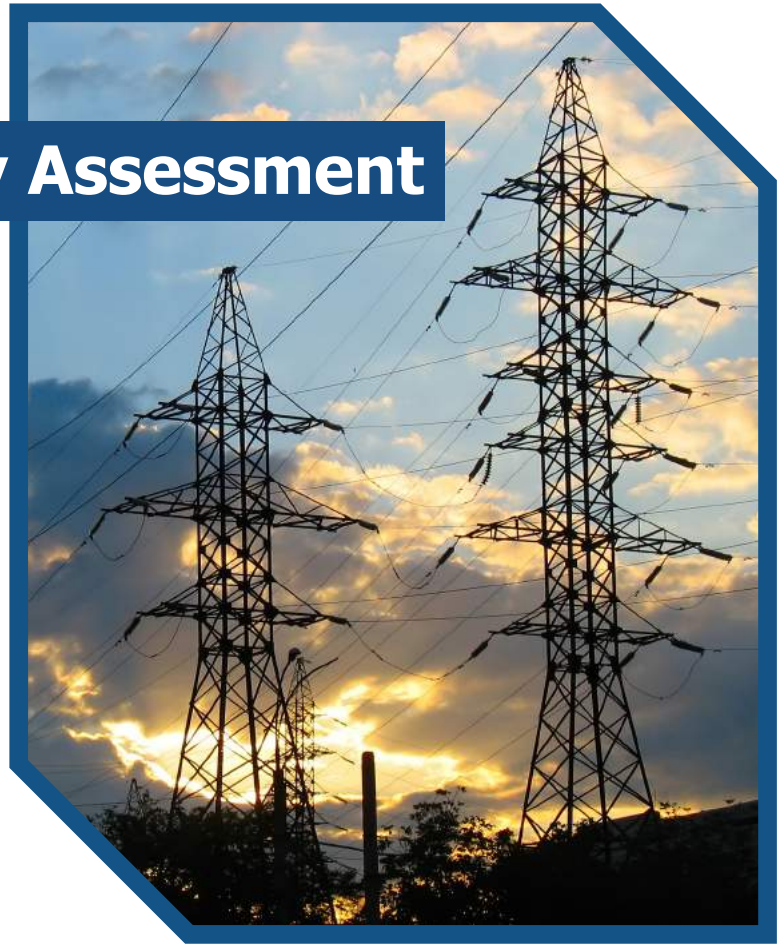
NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

# 2020 Long-Term Reliability Assessment

## December 2020



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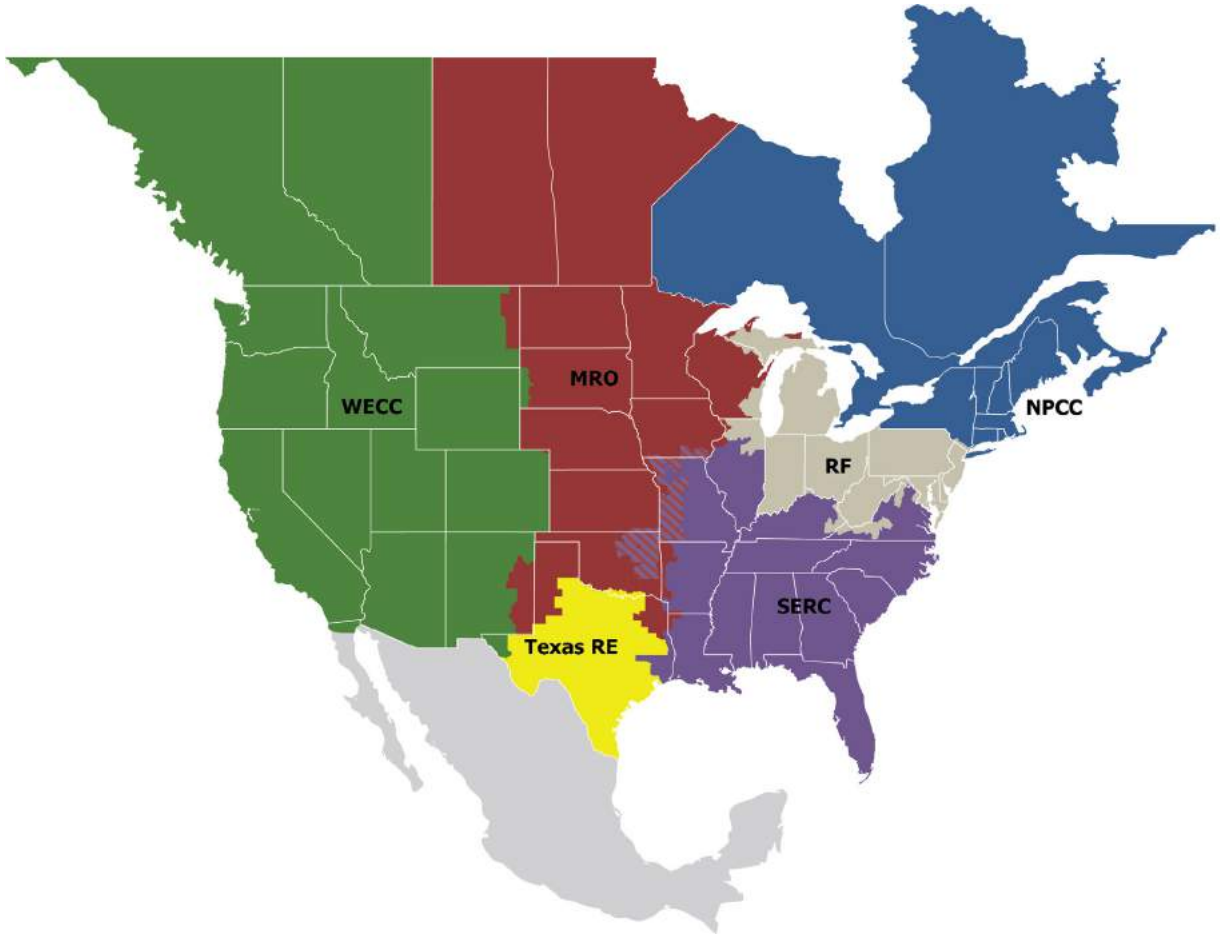
# Preface

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.

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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.

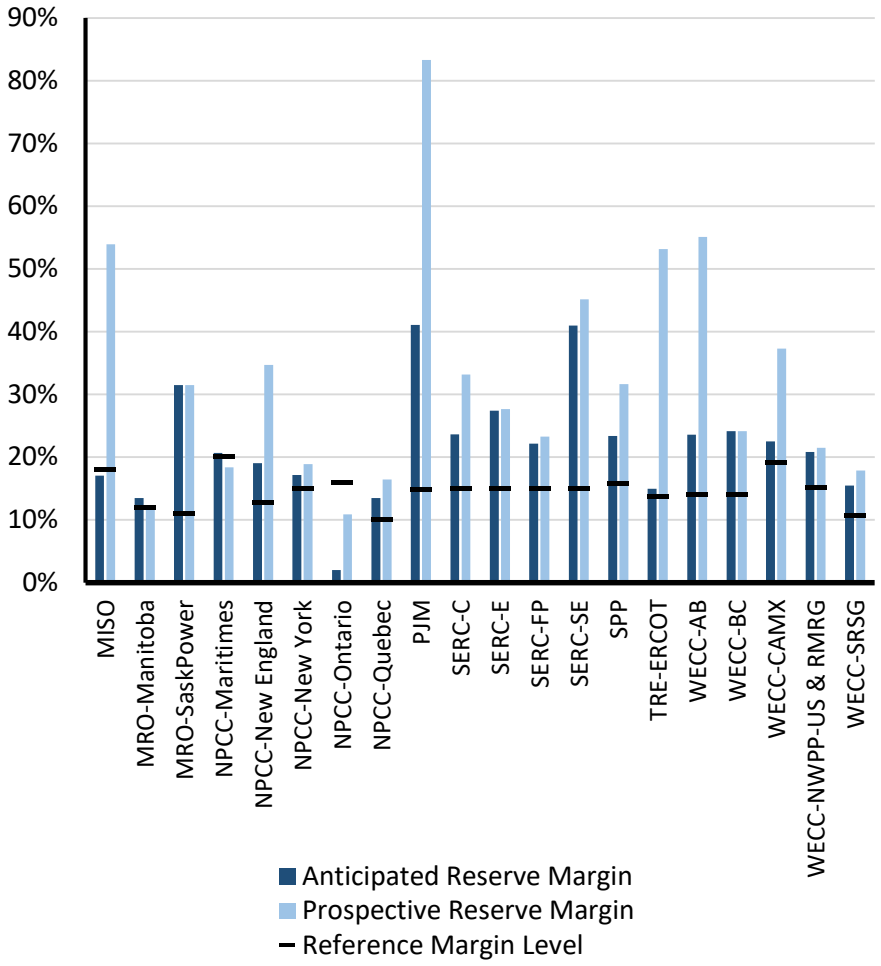



**Figure 1: Anticipated and Prospective Reserve Margins for 2025 Peak Season by Assessment Area**

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.

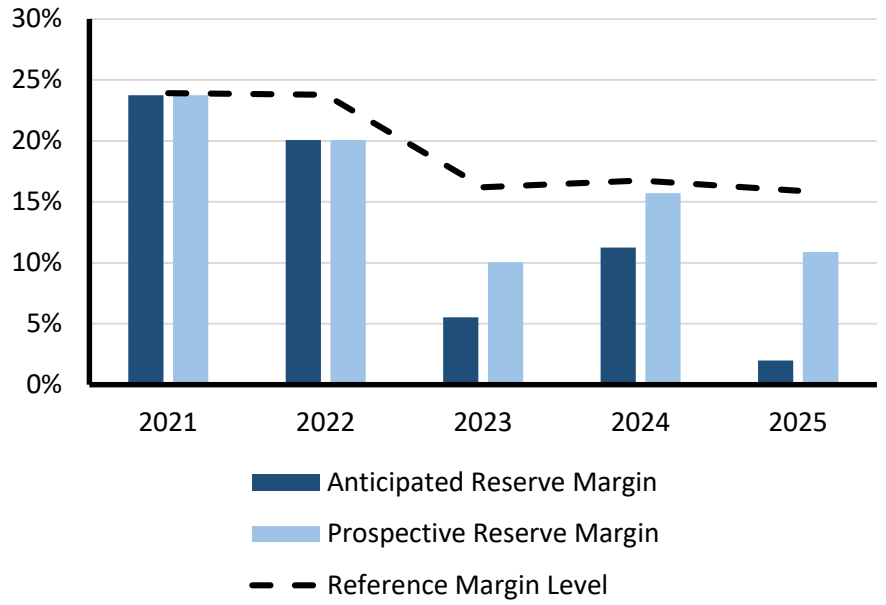



**Figure 2: NPCC-Ontario 5-year Projected Reserves (ARM and PRM)**

**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.

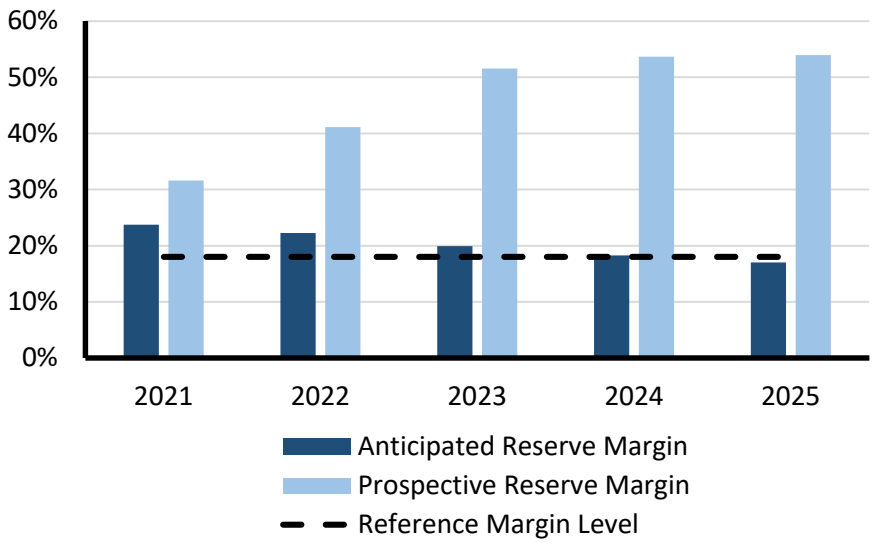



**Figure 3: MISO Five-Year Projected Reserves (ARM and PRM)**

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.

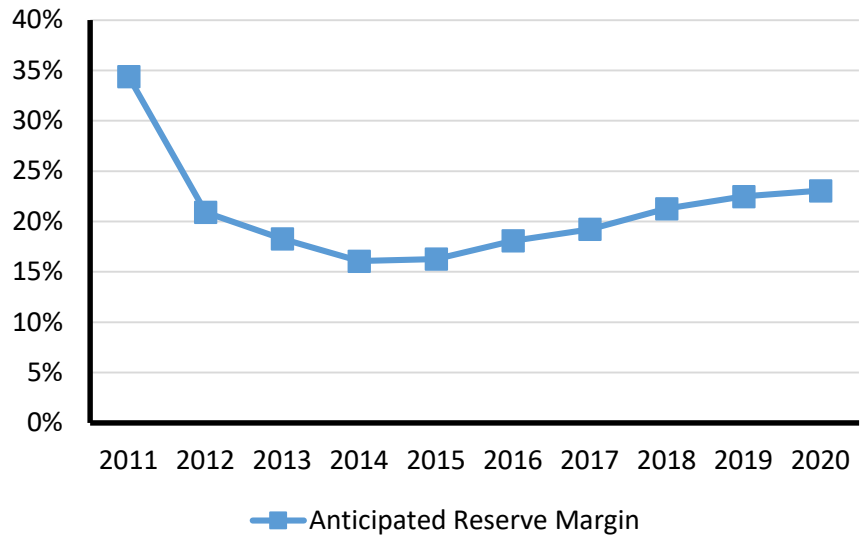



**Figure 4: MISO Historical Projected Reserves Margins**

**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.

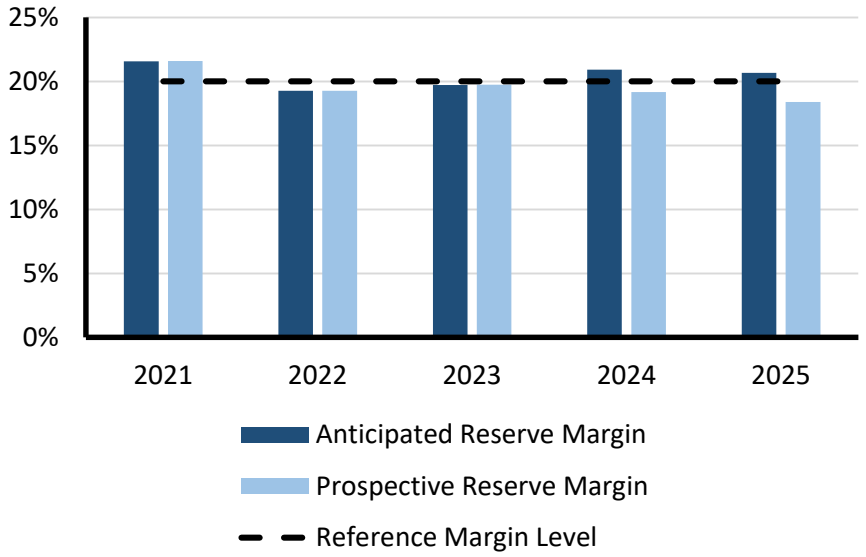



**Figure 5: NPCC-Maritimes Five-Year Projected Reserves (ARM and PRM)**

**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.

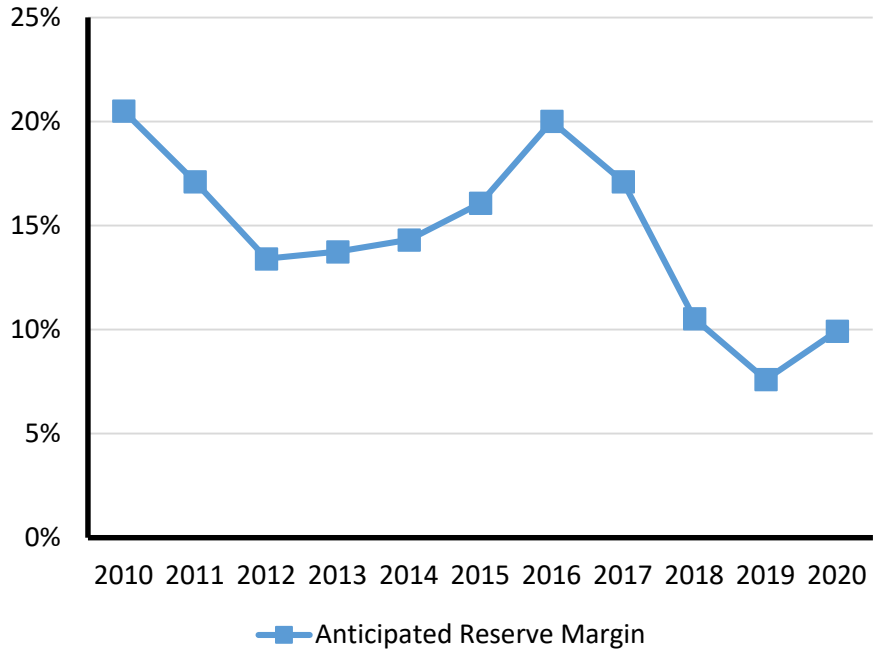



**Figure 6: TRE-ERCOT Historical Projected Reserve Margins**

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.

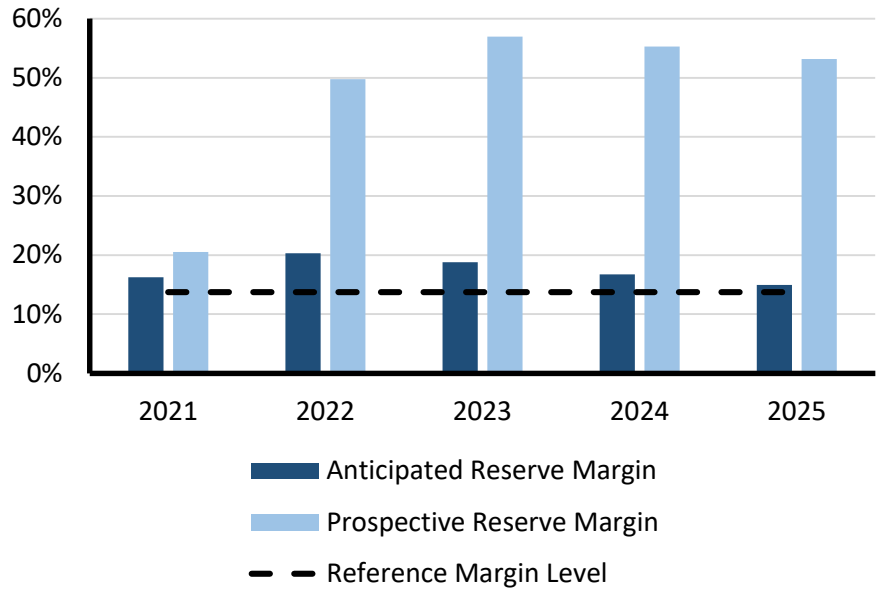



**Figure 7: TRE-ERCOT Five-Year Projected Reserves (ARM and PRM)**

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.

## 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 non-peak 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.

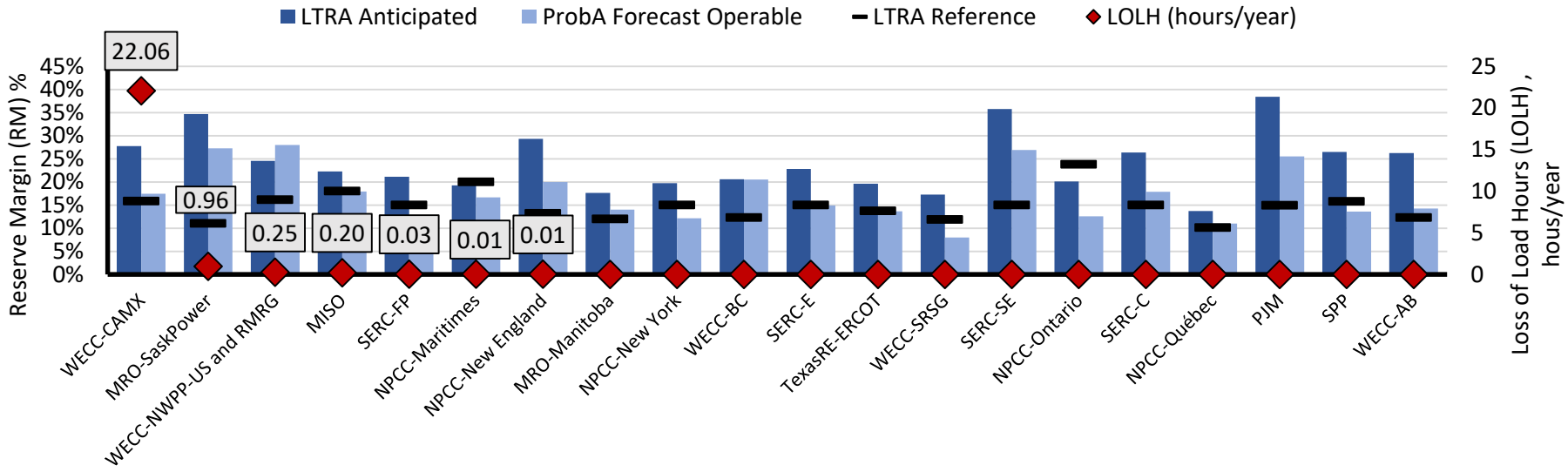



**Figure 8: 2022 Assessment Area Reserve Margins and LOLH**

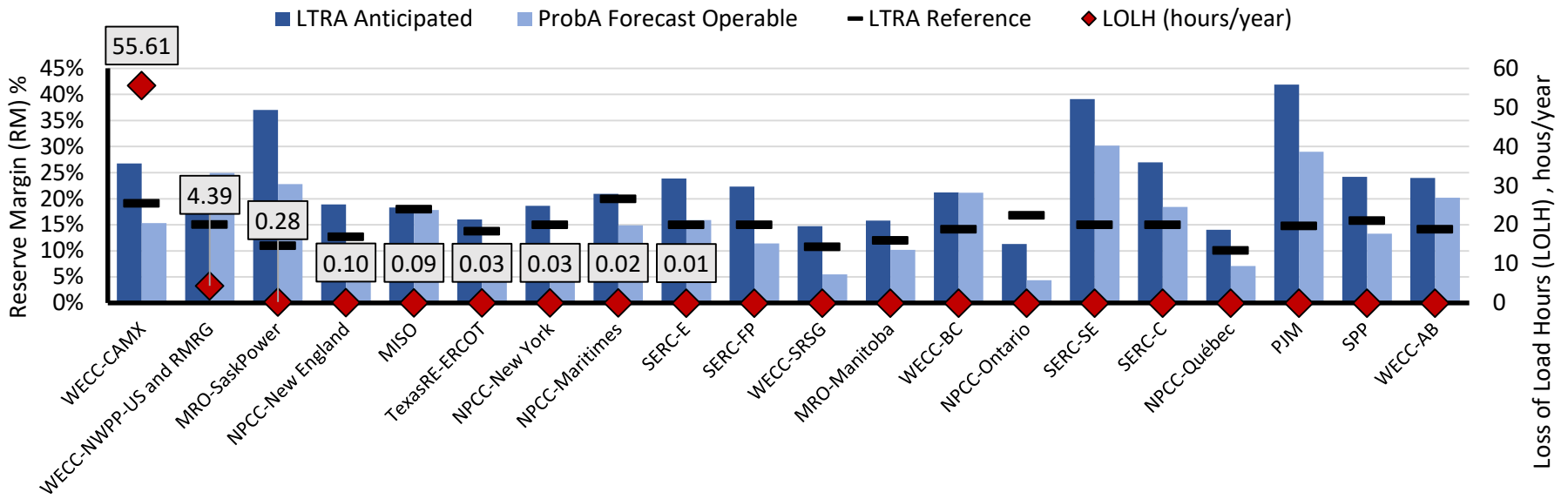



**Figure 9: 2024 Assessment Area Reserve Margins and LOLH**

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.

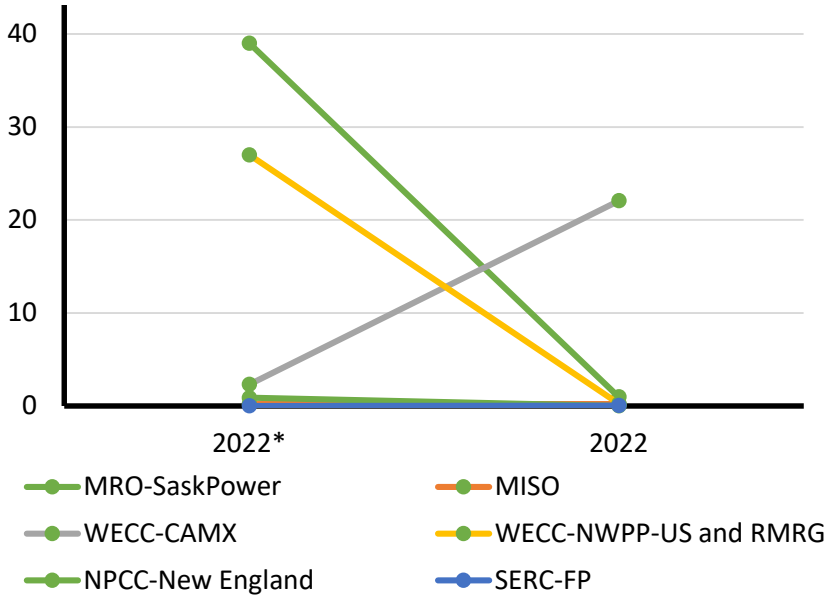



**Figure 10: Comparison of the 2018 vs. the 2020 Probabilistic Analysis, LOLH Notable Trends for the 2022 Study Year**

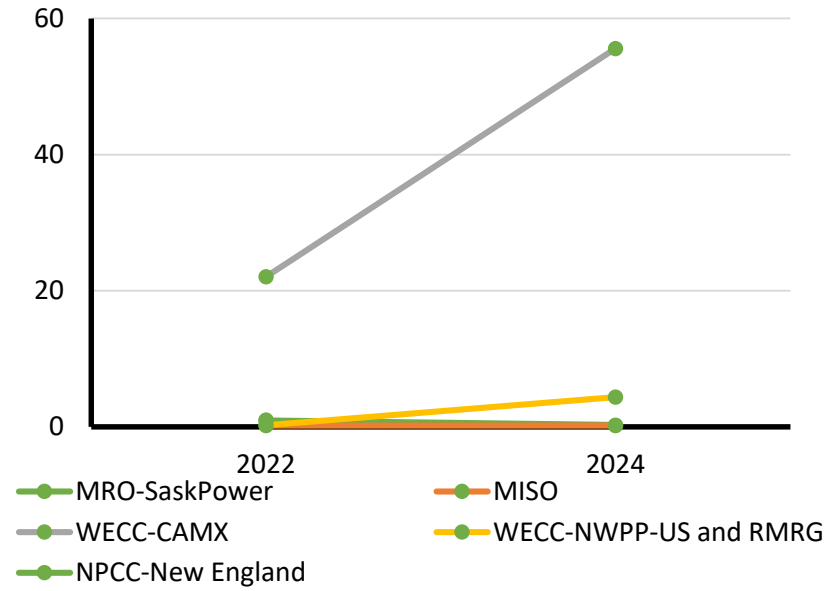



**Figure 11: Comparison of 2020 Probabilistic Analysis, LOLH Notable Trends for the 2022 to 2024 Study Year**

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

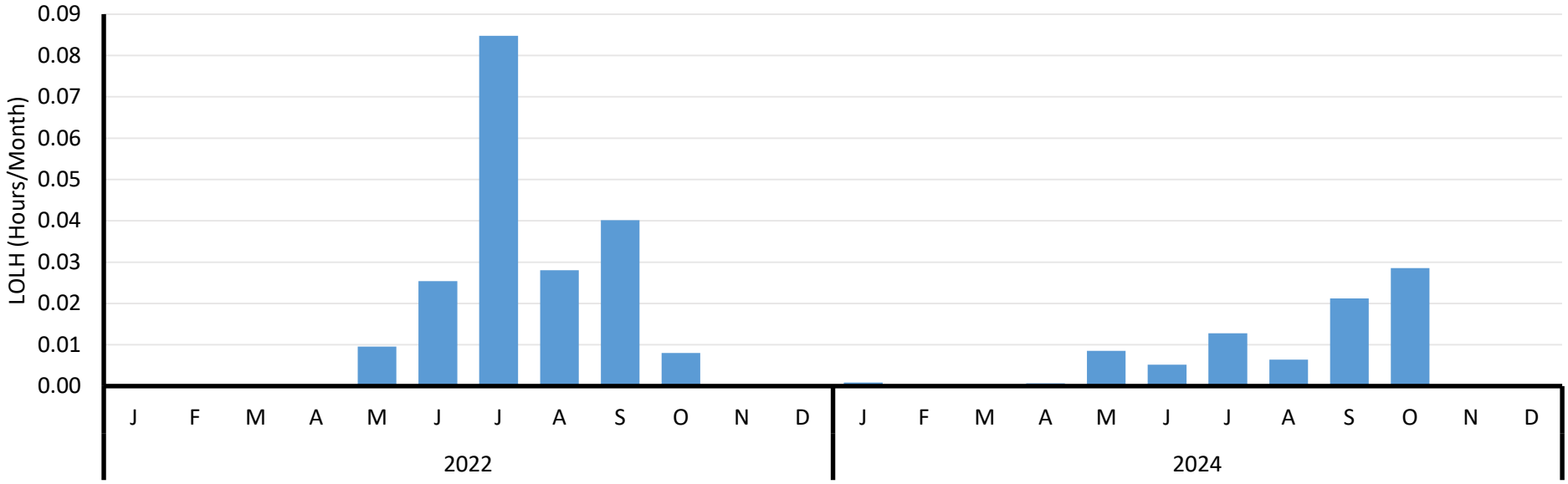



**Figure 12: MISO LOLH Indices for Study Year 2022 and 2024**

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.

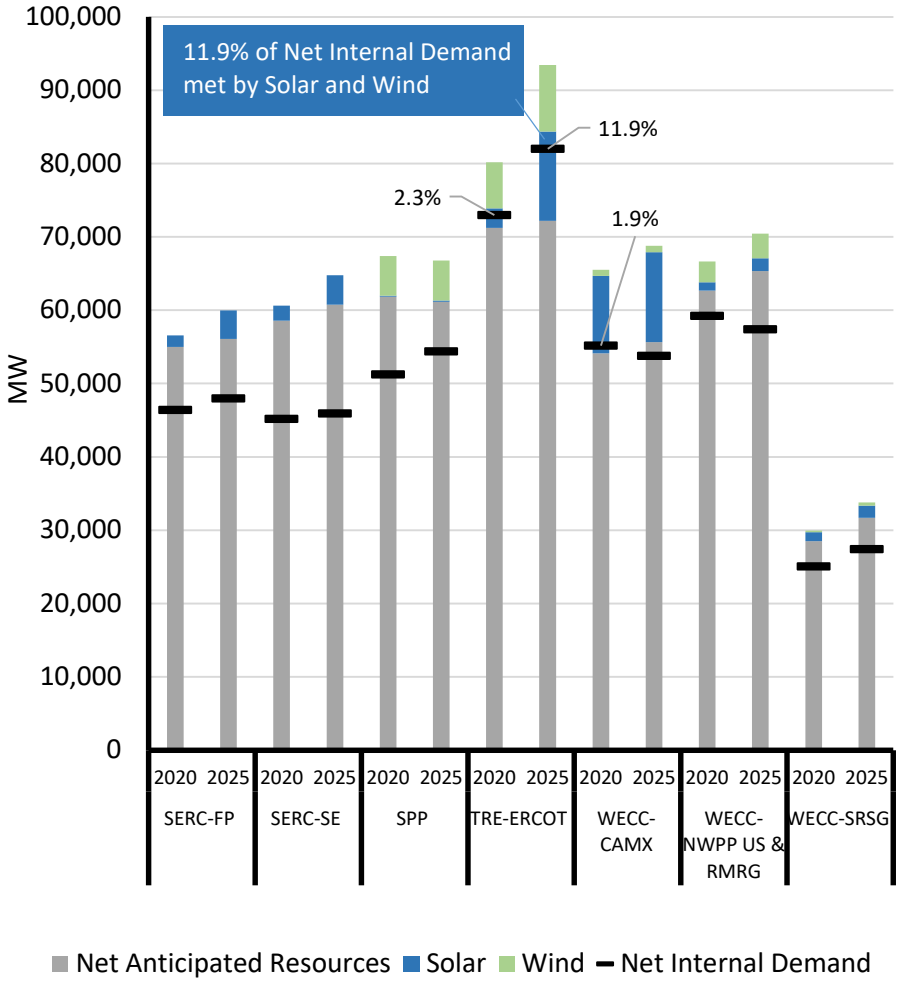



**Figure 13: Assessment Areas with Solar and Wind Capacity Greater than 5% of On-Peak Demand**

**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).

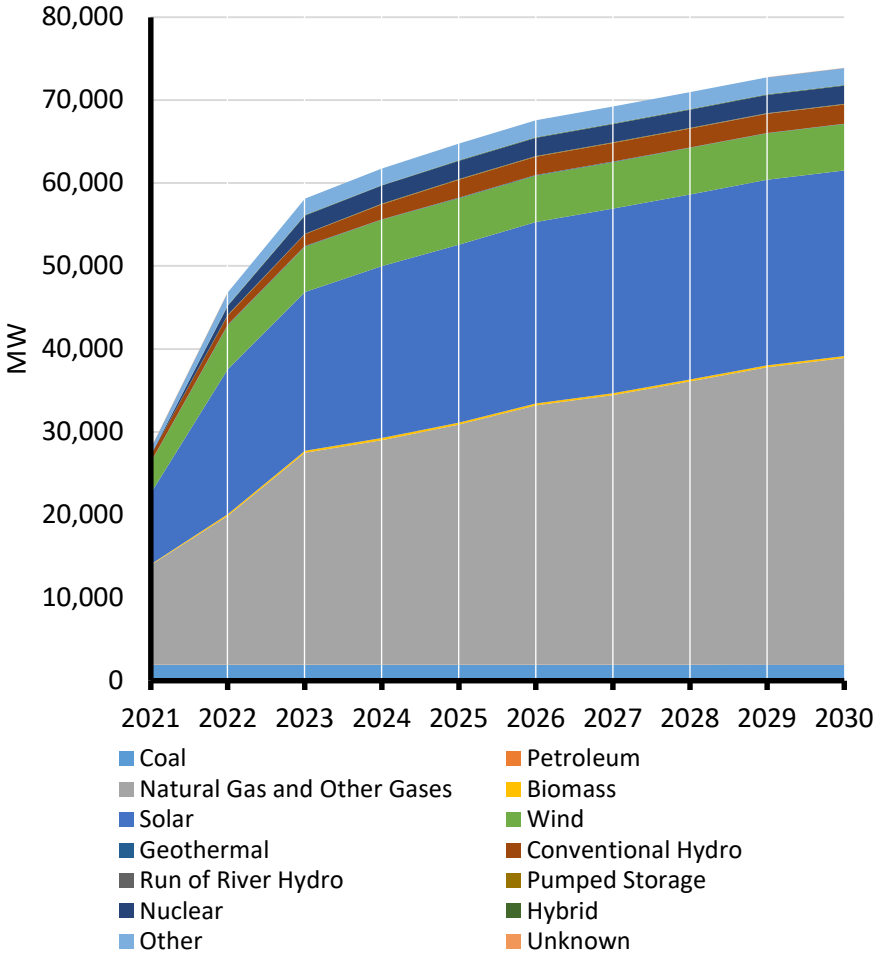



**Figure 14: Tier 1 Planned Resources Projected Through 2030**

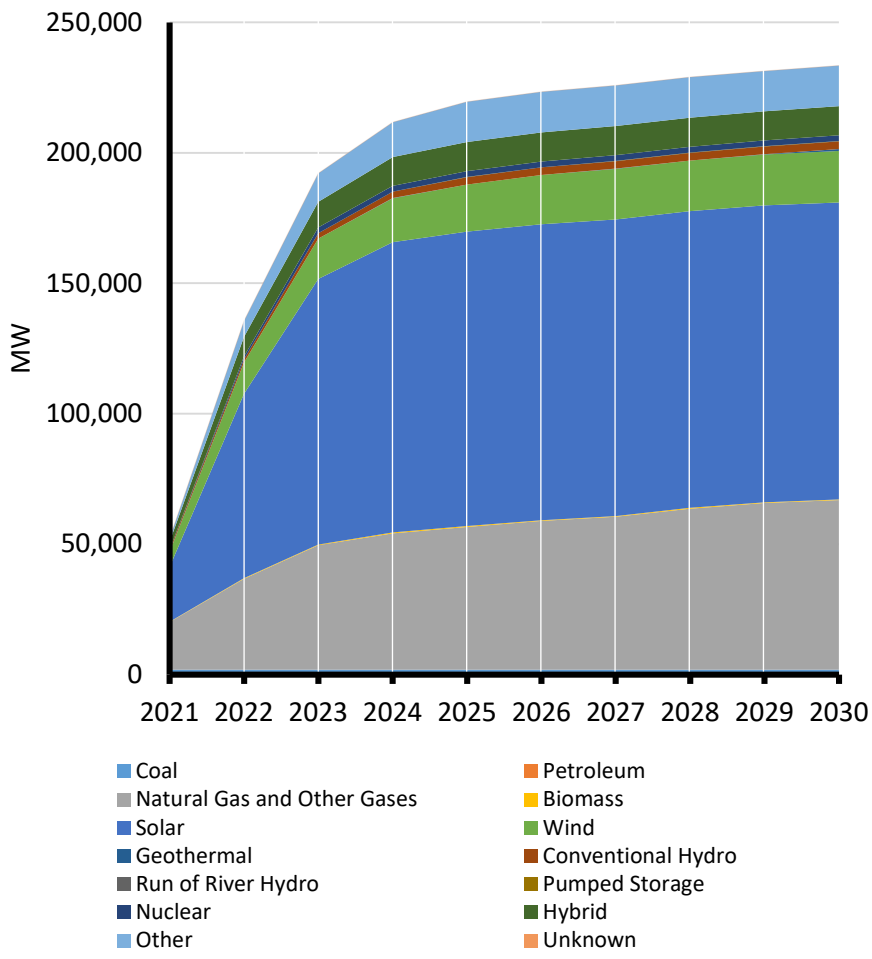



**Figure 15: Tier 1 and 2 Planned Resources Projected Through 2030**

### 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.

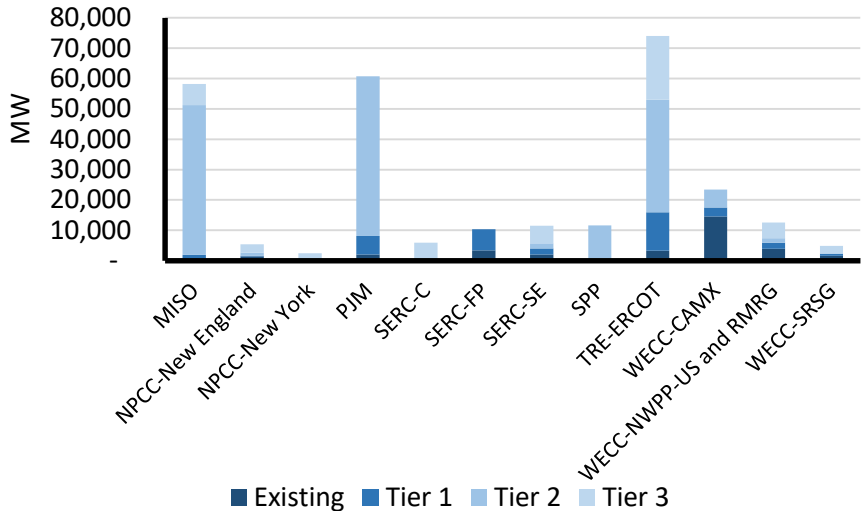



**Figure 16: Solar Capacity Planned and Existing**

**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.

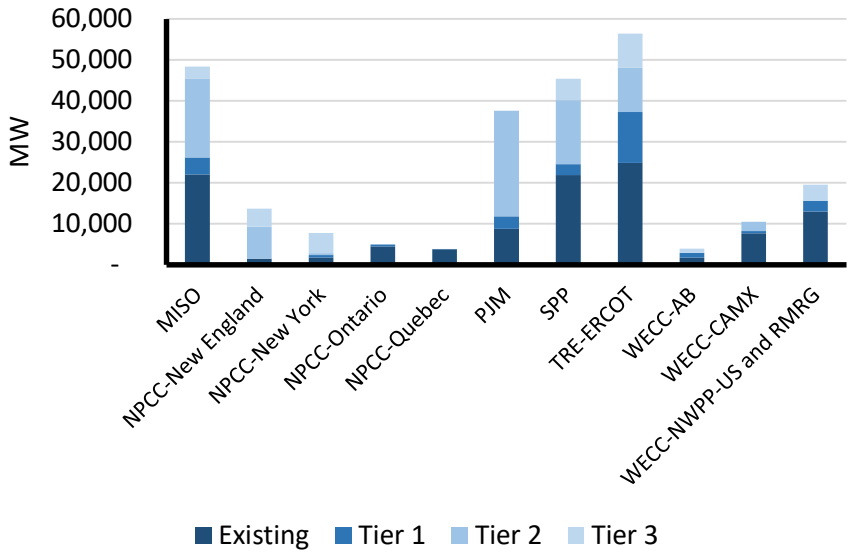



**Figure 17: Wind Capacity Planned and Existing**

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.

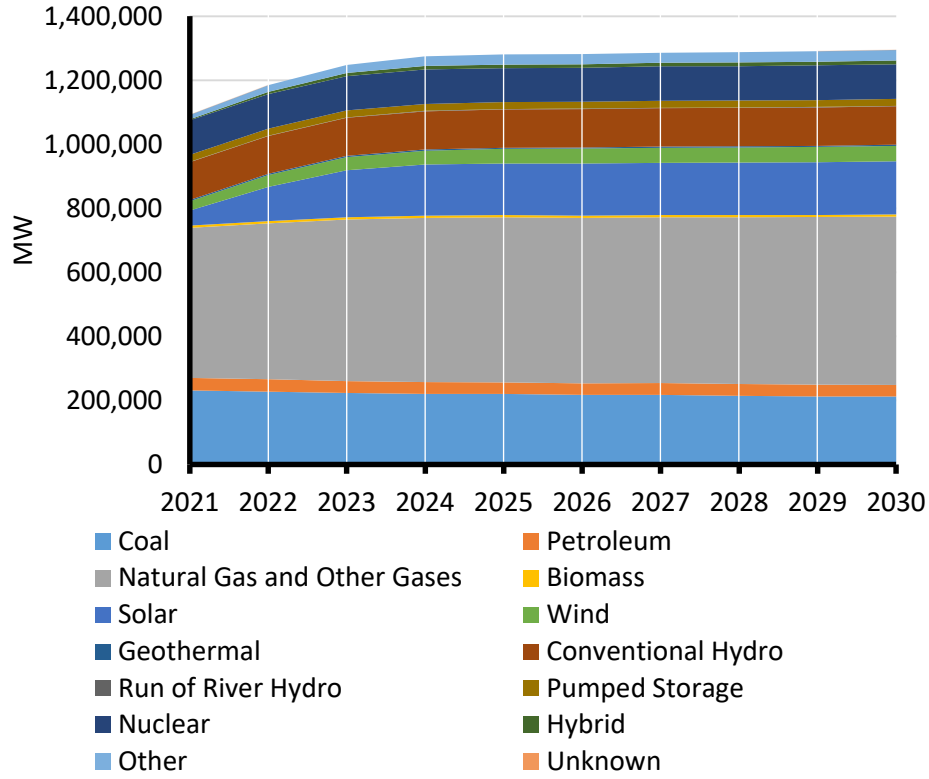



**Figure 18: Existing, Tier 1, and Tier 2 Planned Resources Projected Through 2030**

| 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.

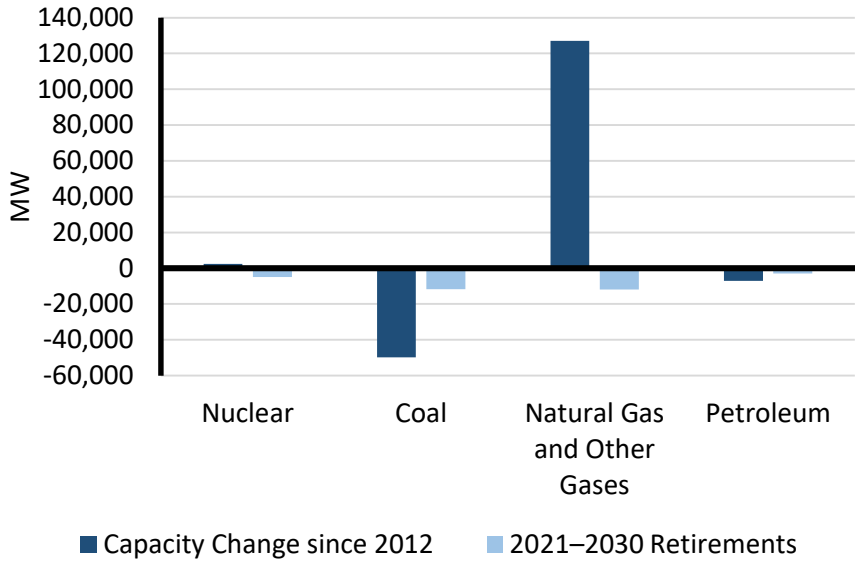



**Figure 19: Capacity Changes since 2012 and Retirements Projected through 2030**

### 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.

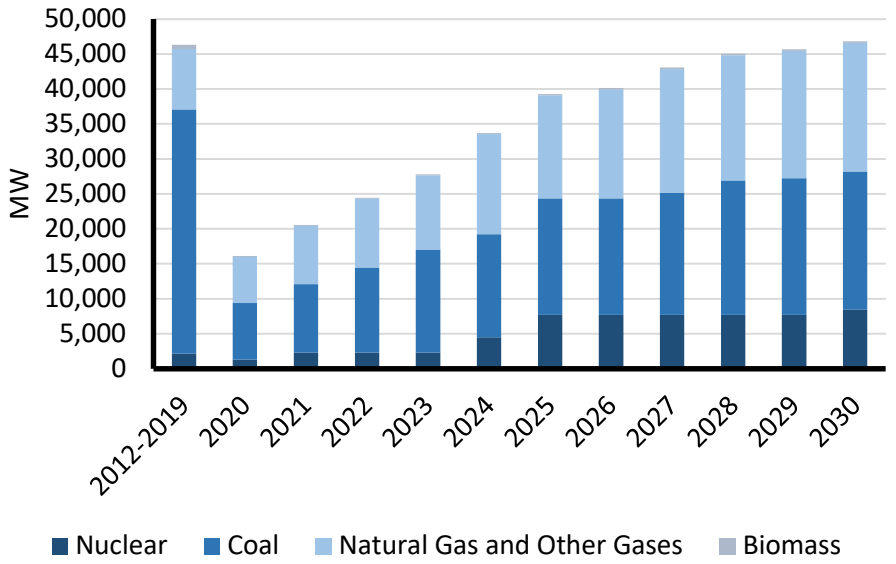



**Figure 20: Capacity Retirements since 2012 and Projected Cumulative Retirements through 2030**

**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.

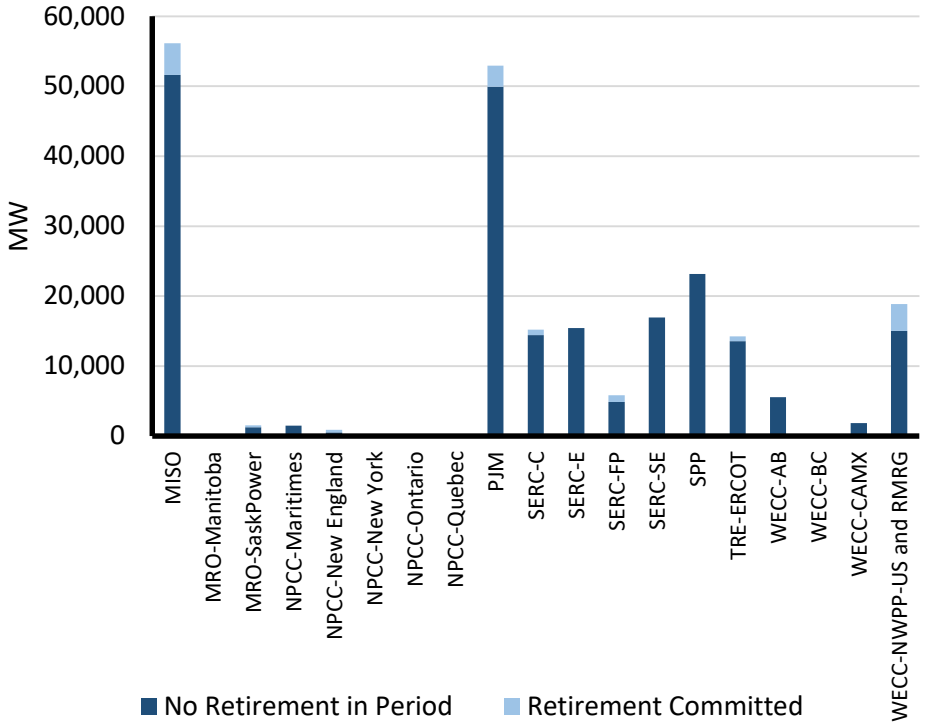



**Figure 21: Portion of Existing Coal-fired Generation Capacity with Retirement Commitments through 2026**

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.<br>• 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.<br>• Generators that have procured firm service on a secondary market may also be interrupted prematurely.<br>• 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.<br>• Generators with dual fuel capabilities are likely to have greater availability than those without.<br>• 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.<br>• 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.<br>• 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.<br>• Areas at the "end of the line" will likely have an overall greater risk profile than those in close proximity to fuel supply sources.<br>• 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.<br>• 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.

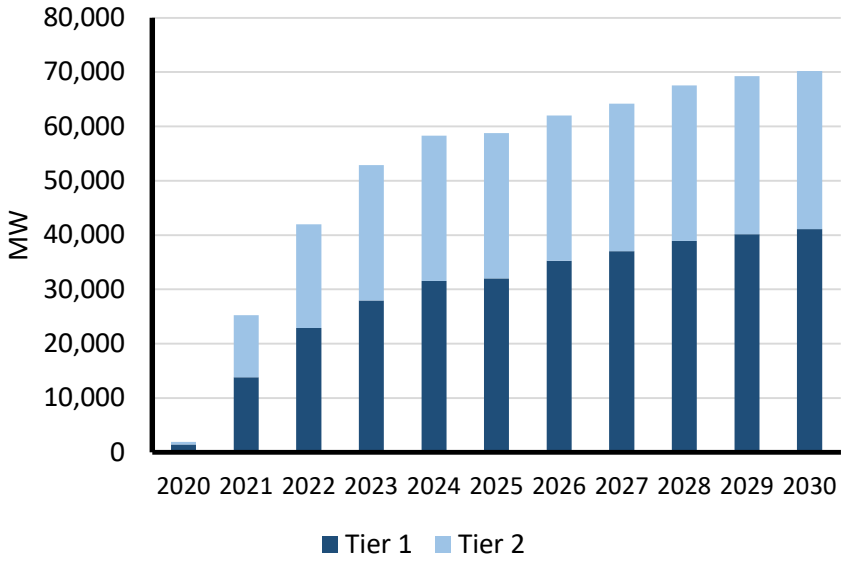



**Figure 22: Natural Gas Capacity Planned Additions through 2029, Tier 1 and 2**

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.

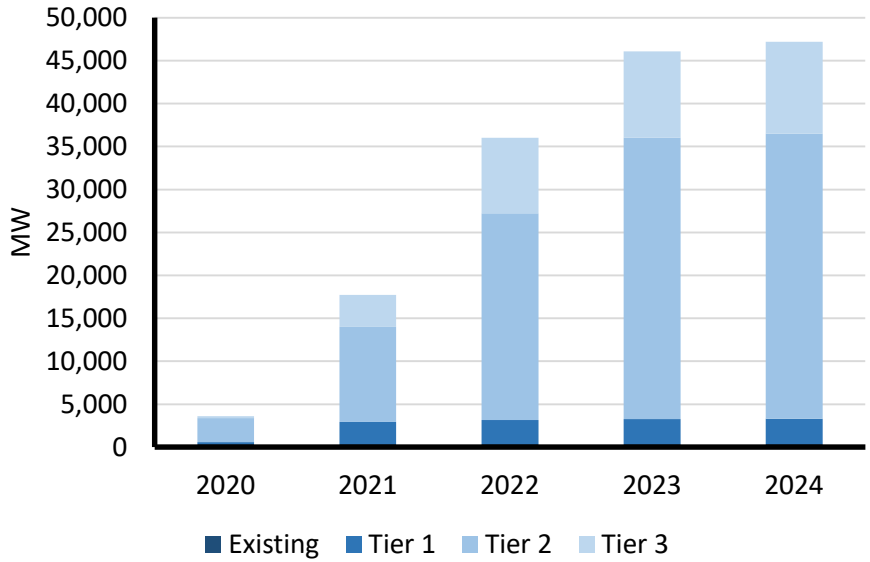



**Figure 23: NERC-Wide Grid Battery and Hybrid Generation–Existing and Planning**

**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.

**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 offline.[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]

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

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

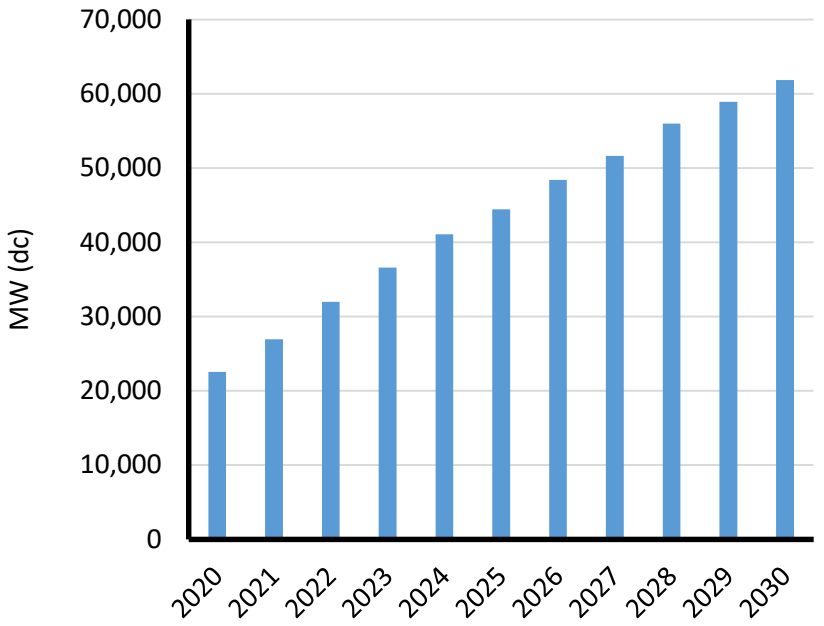



**Figure 24: NERC-Wide Cumulative Distributed Solar PV Capacity—2020 through 2030**

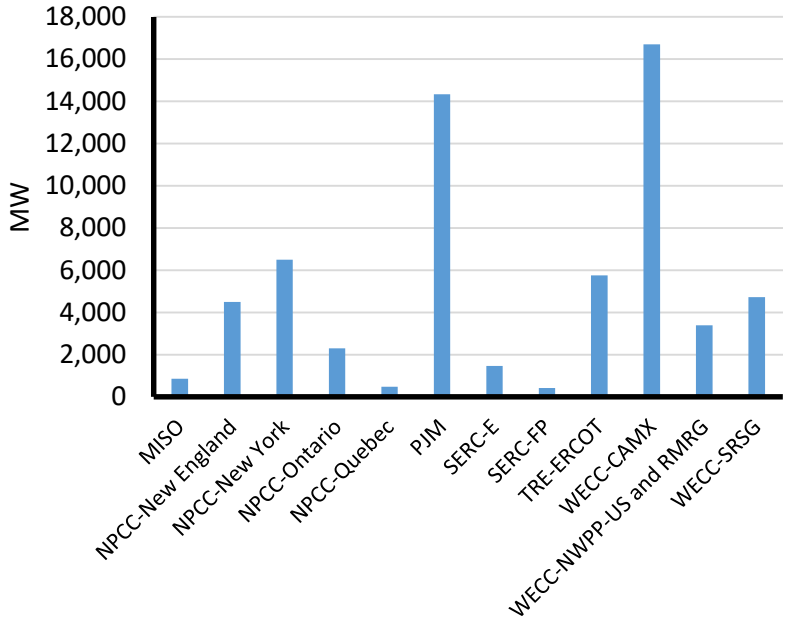



**Figure 25: Solar DER by Assessment Area by 2030**

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.

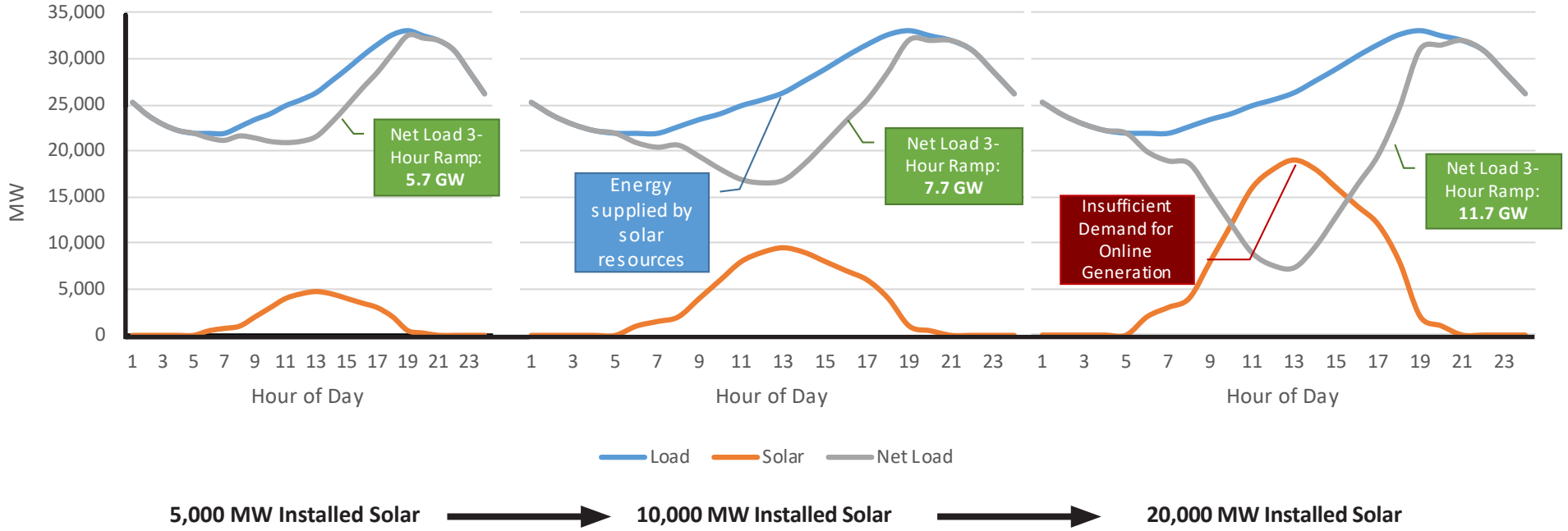



**Figure 26: Example of Increasing Solar Resources Leading to Increased Ramping Requirements**

## 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.

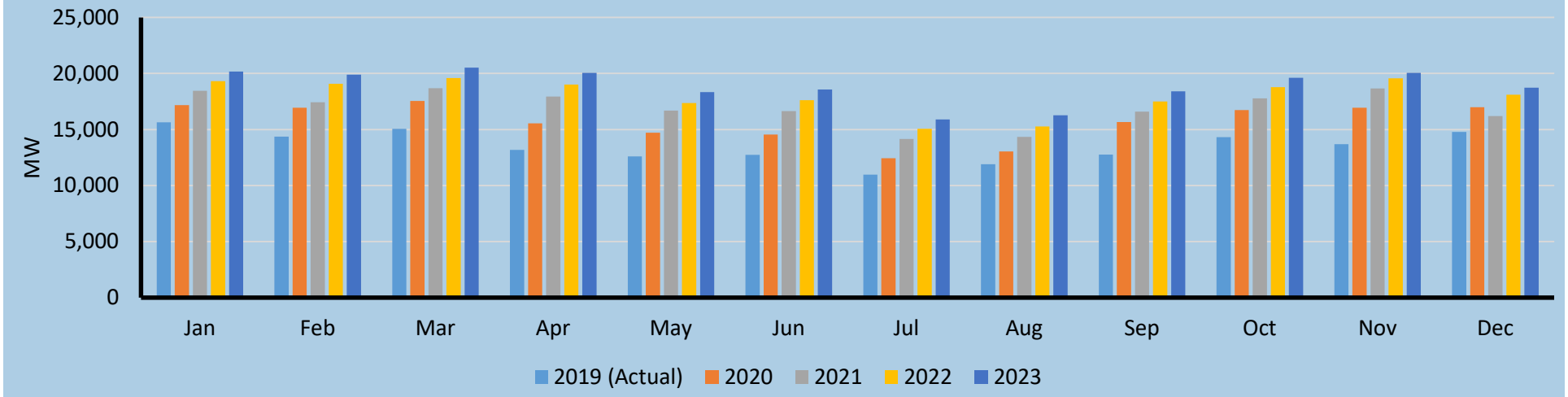



**Figure 27: Maximum Three-Hour Ramps in CAISO (Actual and Projected) through 2023**

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.
- **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]

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

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

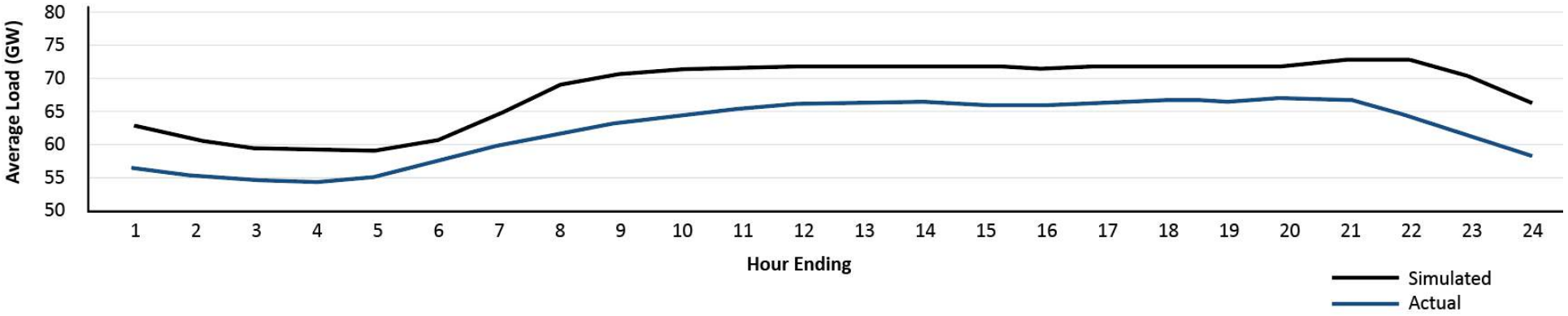



**Figure 28: Average Simulated and Actual Load in MISO Area for April 4–10, 2020**

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.

### 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 fre-

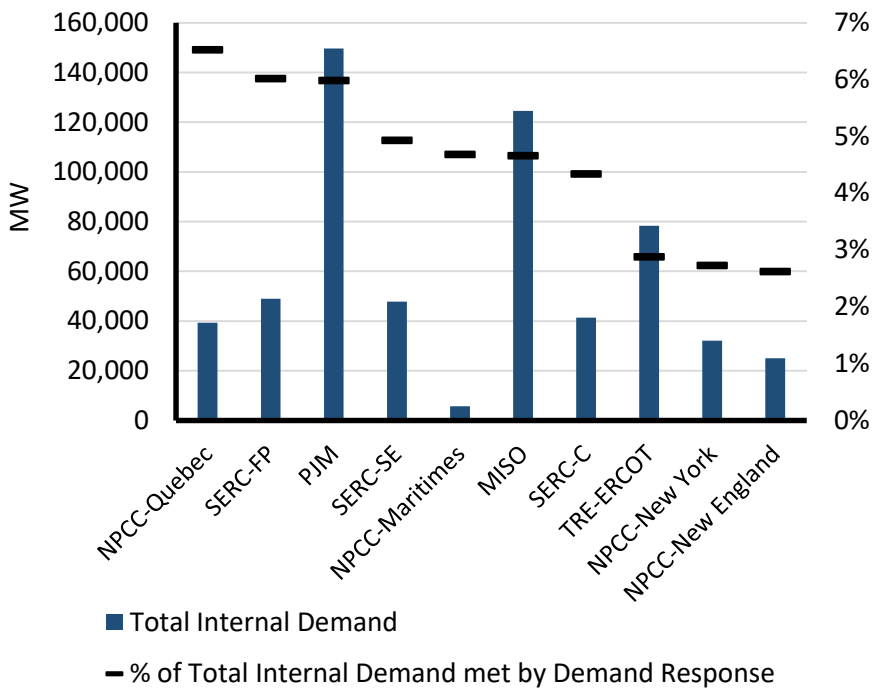



**Figure 29: Projected 2021 Peak Season DR–Assessment Areas with Highest DR Contribution to Meeting Total Peak Demand**

quency 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**).

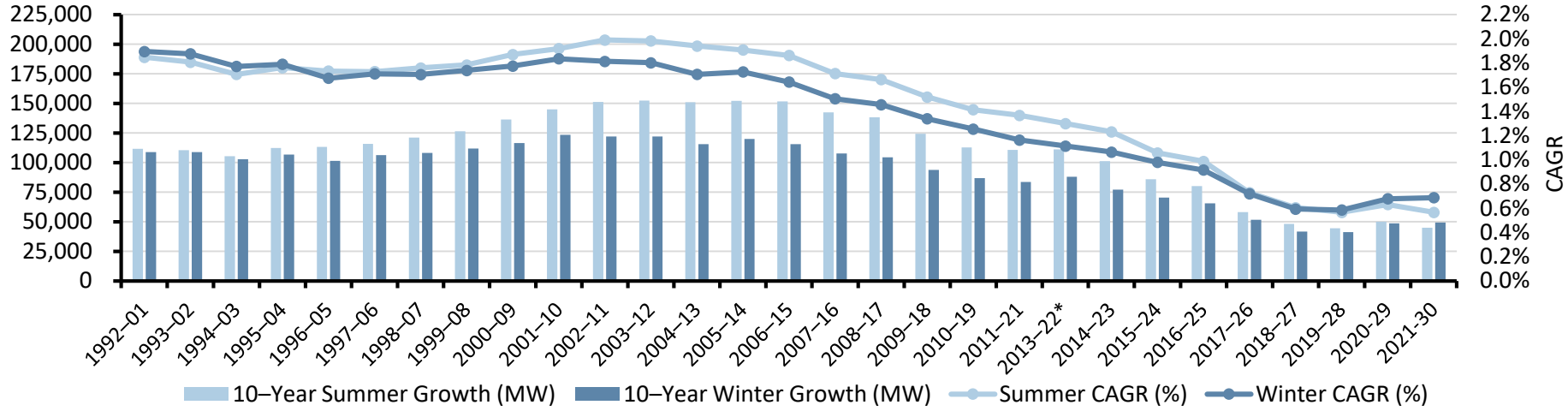



**Figure 30: 10-Year Summer and Winter Peak Demand Growth and Rate Trends**

**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.

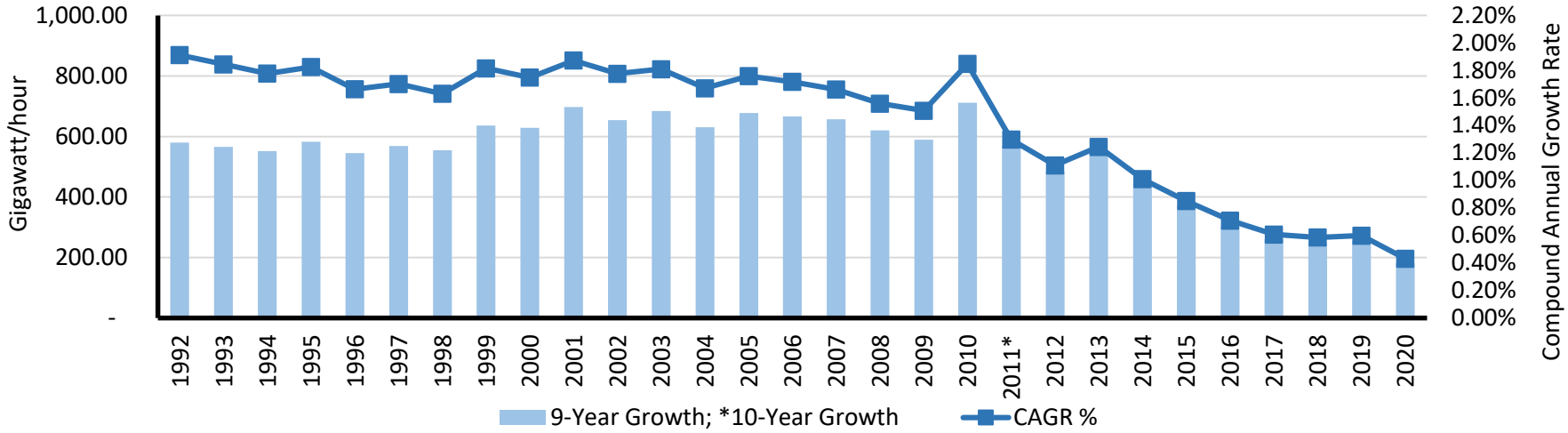



**Figure 31: 10-Year Net Energy to Load Growth and Rate Projection Trends**

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.

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

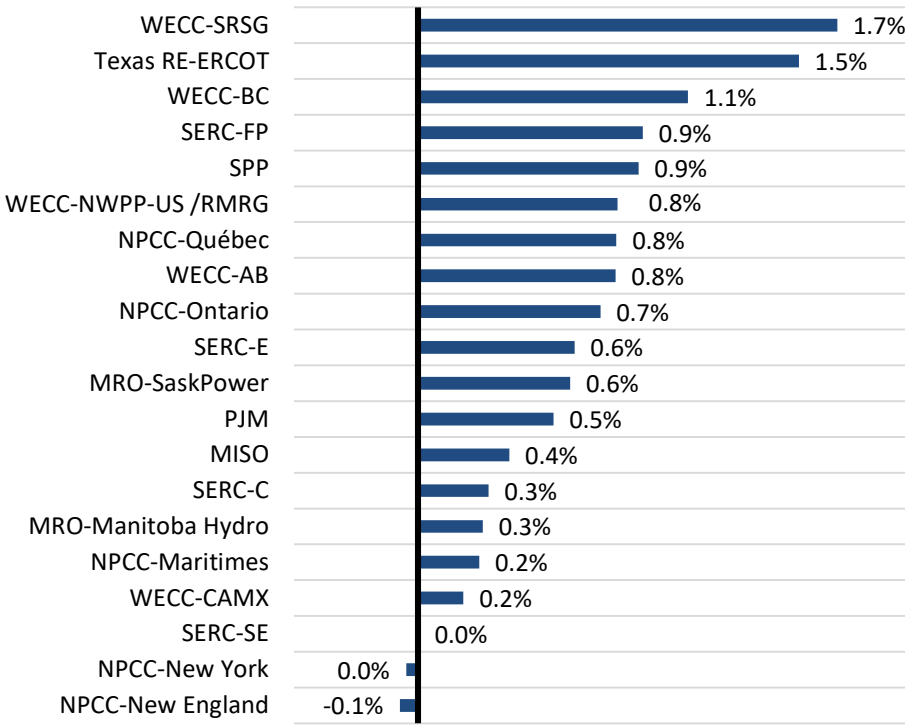



**Figure 32: Annual Peak Demand Growth Rate for 10-Year Period by Assessment Area**

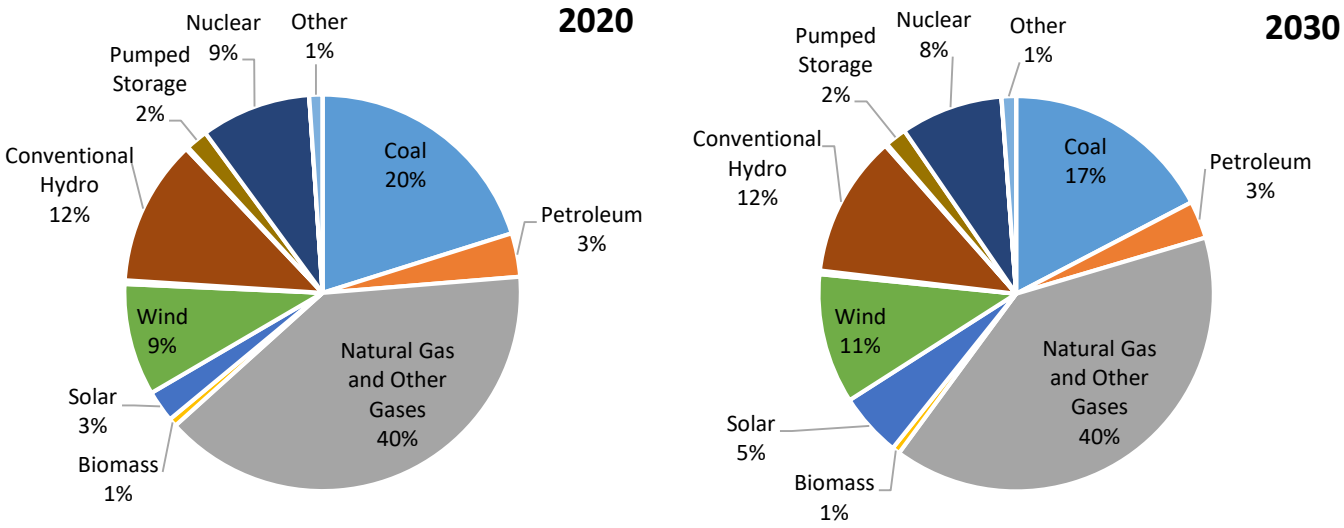



**Figure 33: Installed Nameplate Capacity by Fuel Mix Trend (Includes Future Tier 1 Resources)**

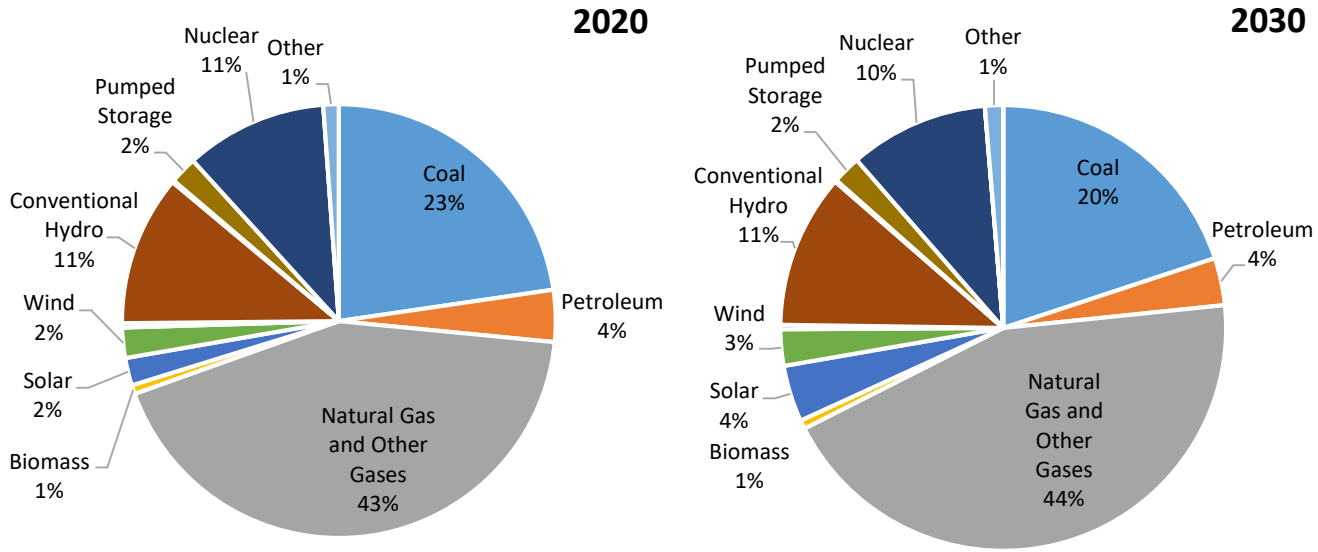



**Figure 34: Installed On-Peak Anticipated Capacity Trend by Fuel Mix**

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.

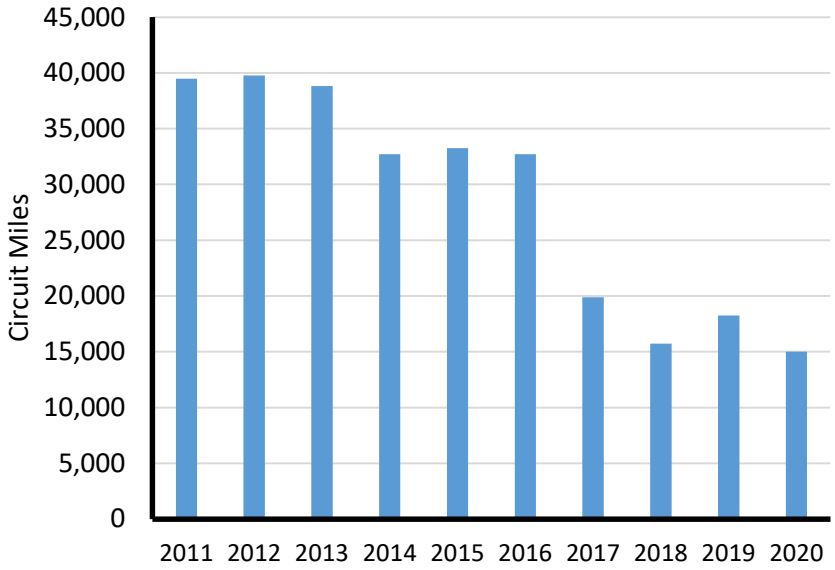



**Figure 35: Historical 10-Year Transmission Projections**

### 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"

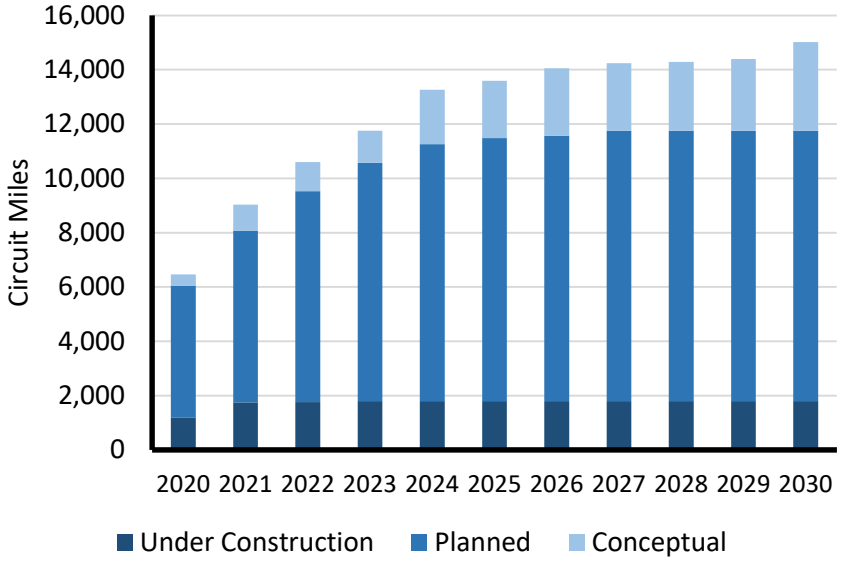



**Figure 36: Future Transmission Circuit Miles >100 kV, by Project Status**

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

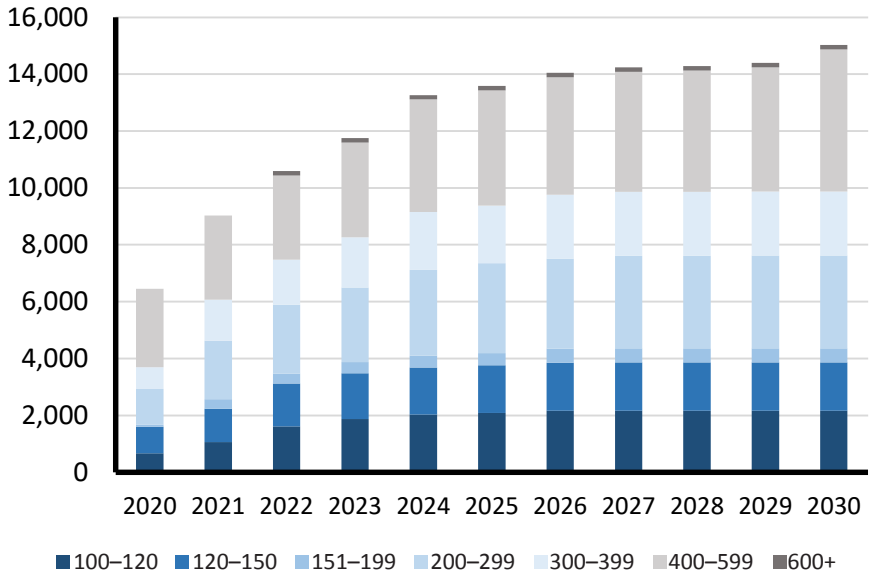



**Figure 37: Future Transmission Circuit Miles >100kV, by Voltage Class**

**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.

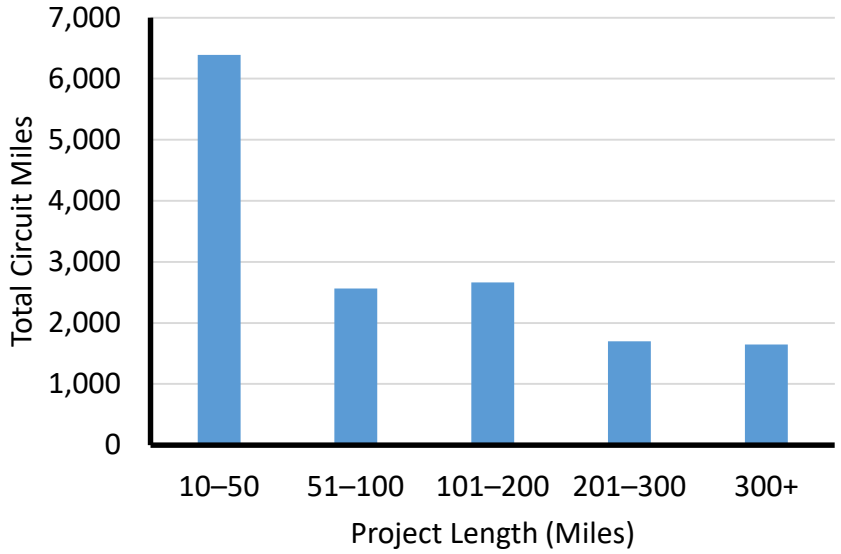



**Figure 38: Line Miles Projected through 2030**

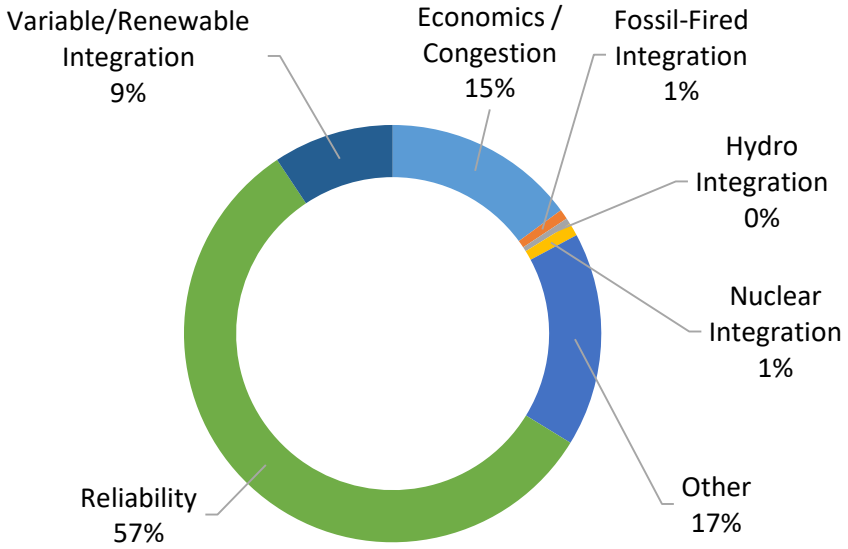



**Figure 39: Future Transmission Circuit Miles by Primary Driver**

**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.

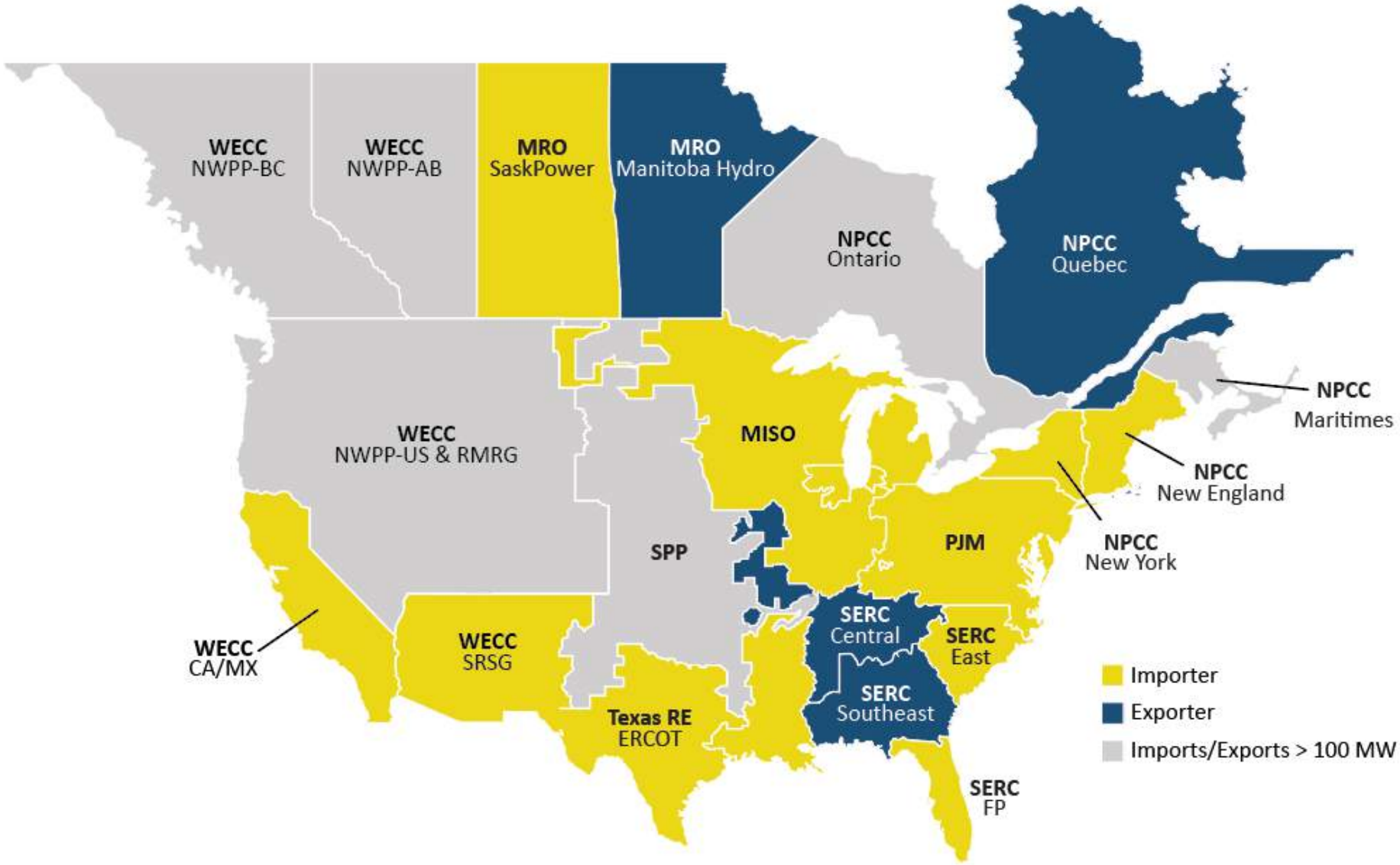



**Figure 40: Net Capacity Transfers for Year 2021**

**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

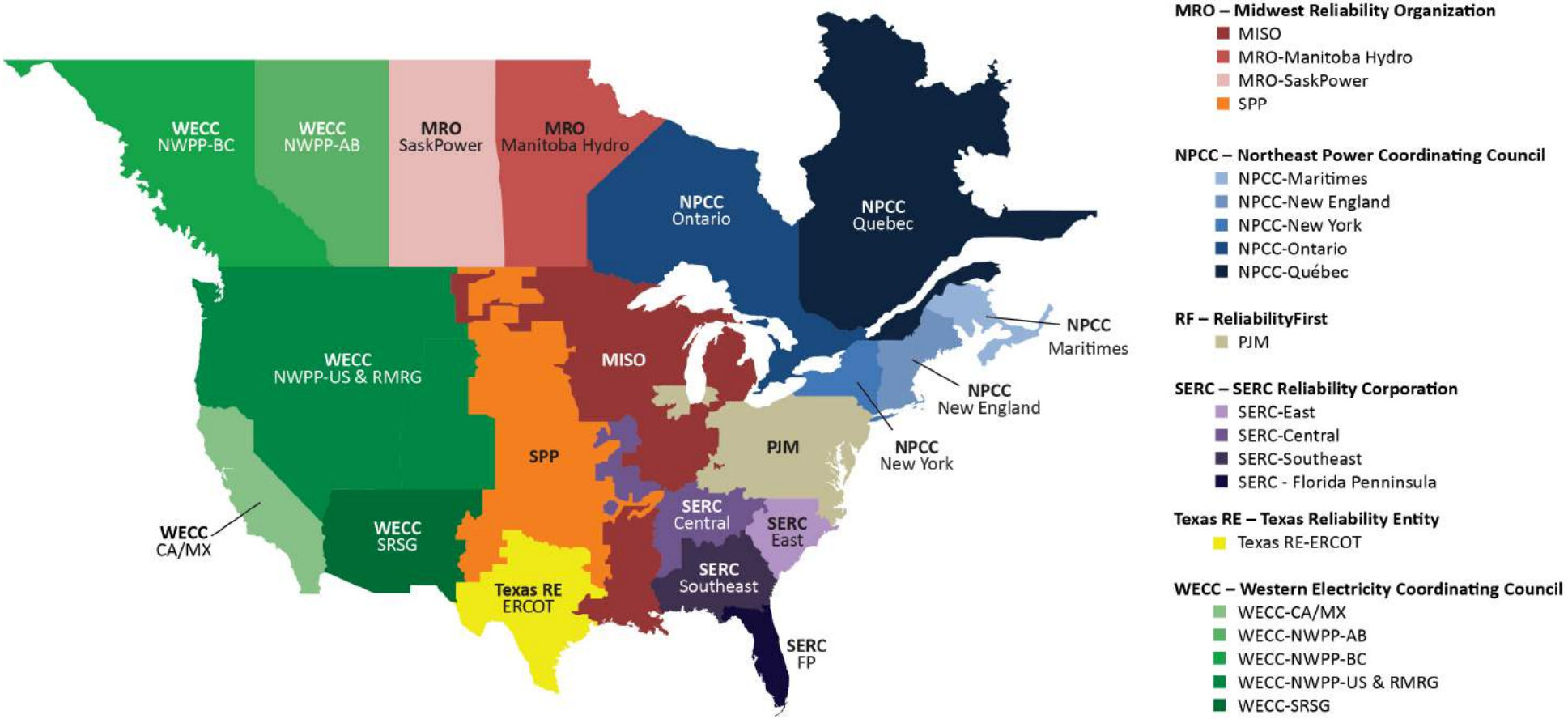
The following regional assessments were developed based on data and narrative information collected by NERC from the REs on an assessment area basis. The RAS, at the direction of NERC's RSTC, supported the development of this assessment through a comprehensive and transparent peer review process that 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**.

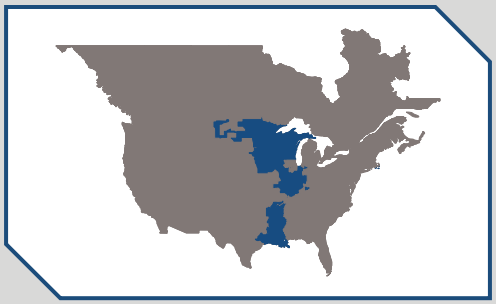
**Table 12: Summary of 2025 Peak Projections by Assessment Area and Interconnection**

| 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.

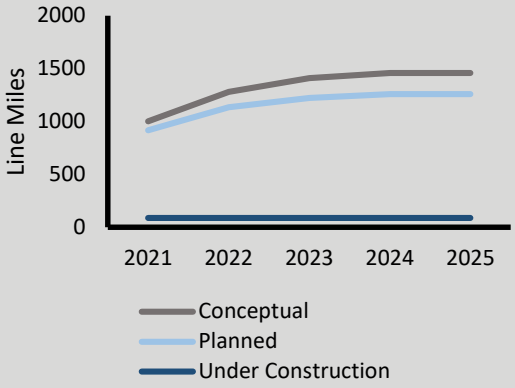




# MISO

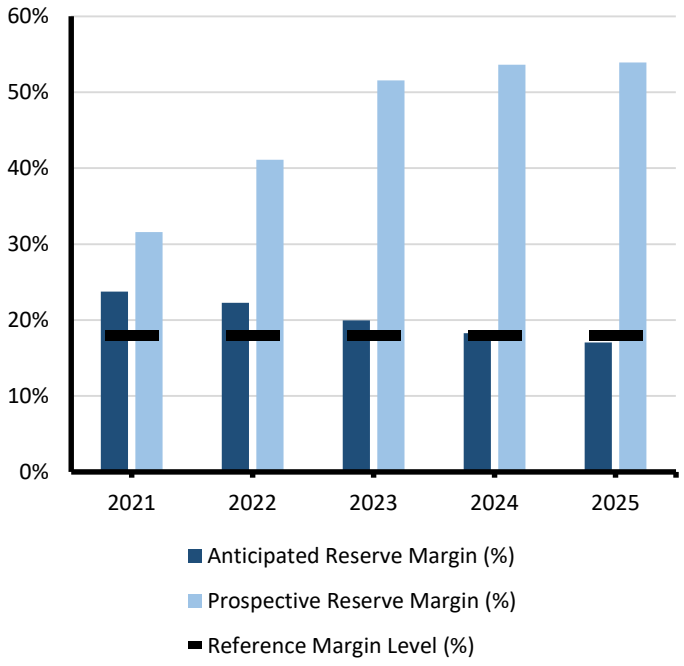
MISO is a not-for-profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency.

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.

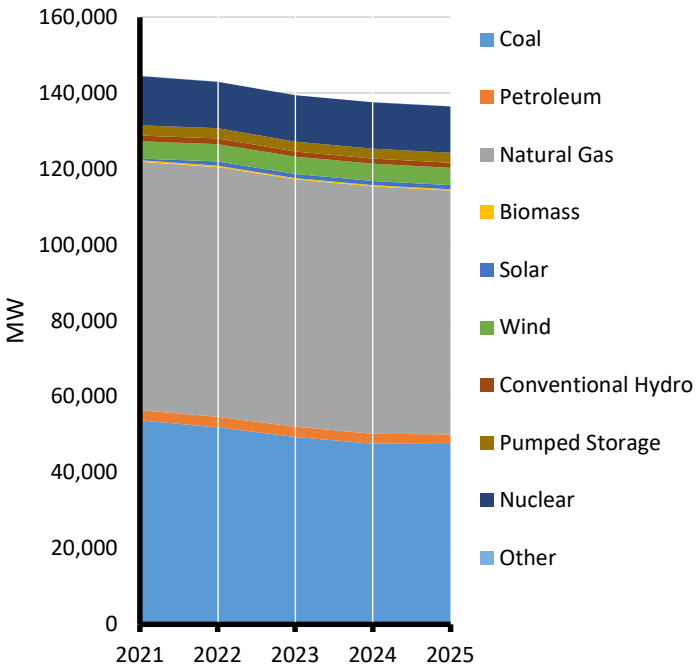



**Projected Transmission Circuit Miles**

| 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.