414 Nicollet Mall
Minneapolis, MN 55401

January 6, 2020

**—Via Electronic Filing—**

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: NERC 2019 LONG-TERM RELIABILITY ASSESSMENT
2019 BIENNIAL TRANSMISSION PROJECTS REPORT
DOCKET NO. E999/M-19-205

Dear Mr. Wolf:

On November 21, 2019, in response to a request by the Department of Commerce, the Minnesota Transmission Owners (MTO) submitted the pertinent sections for the MRO-MAPP load and capability report from the most current NERC Long-Term Reliability Assessment, which was for 2018.

On December 19, 2019, the 2019 NERC Long-Term Reliability Assessment became available electronically. Accordingly, the MTO is filing the latest MRO-MAPP load and capability report which can be found in the attached sections of the 2019 Assessment. The full report is available at the following link: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2019.pdf

With this submission of the 2019 data, the MTO has provided the best available load and capability information from the regional reliability council, as required under Minn. R. 7848.1300 (B), and the 2019 Biennial Transmission Projects Report is complete.

We plan to reply to the January 2, 2020 Comments of the Department of Commerce, Division of Energy Resources during the reply period. If you have any questions about this filing, please contact me at bria.e.shea@xcelenergy.com or (612) 330-6064.

Sincerely,

/s/

BRIA E. SHEA
DIRECTOR, REGULATORY AND STRATEGIC ANALYSIS

Enclosure
c: Service List

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

# 2019 Long-Term Reliability Assessment

# Contents

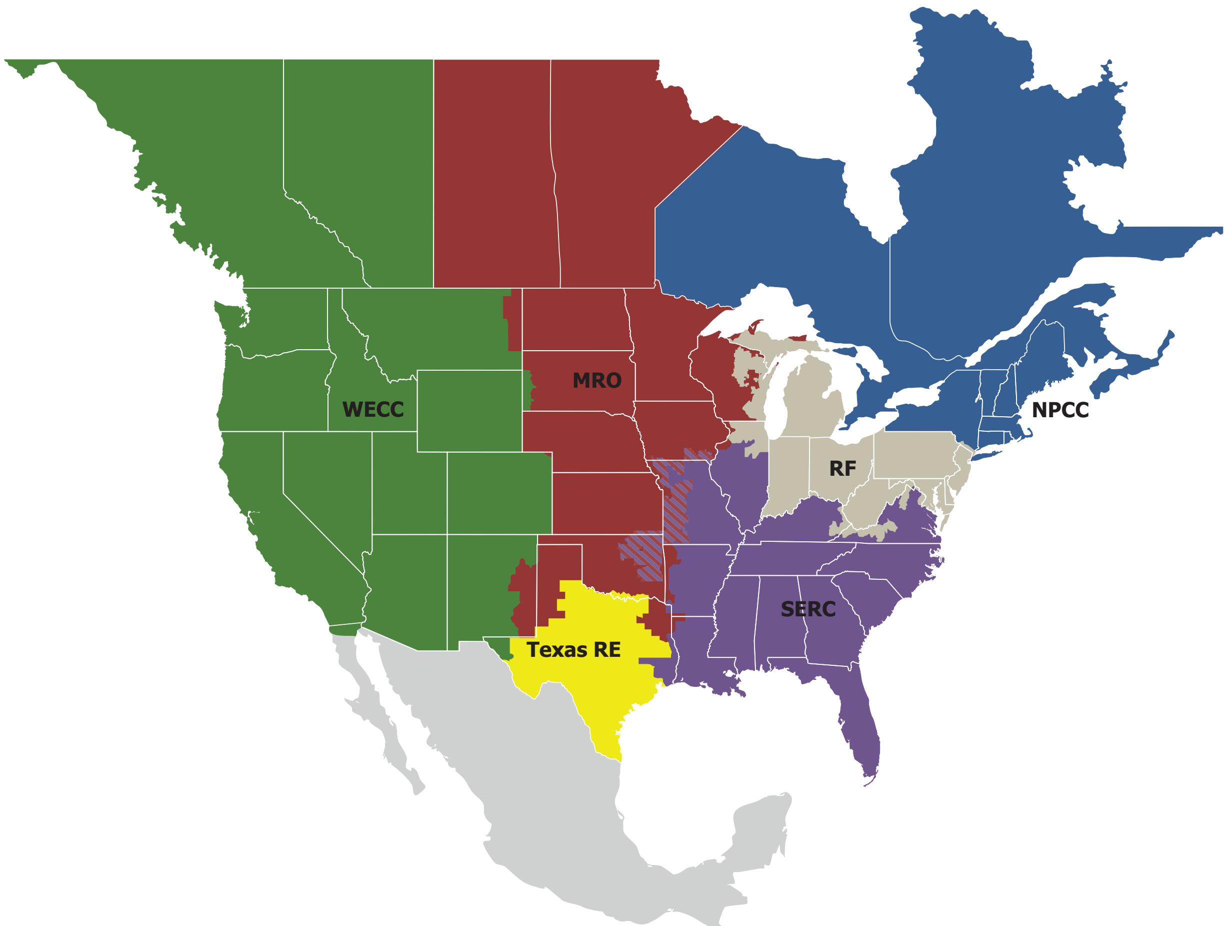
# Preface

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). The ERO Enterprise's 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 divided into six RE boundaries as shown in the map below. The multicolored area denotes overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another.



# About This Assessment

## 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 10-year assessment period. The Reliability Assessment Subcommittee (RAS) supports the development of this assessment at the direction of NERC's Planning Committee (PC) 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 PC, 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, also referred to as Section 215 of the Federal Power Act, which instructs NERC to conduct periodic assessments of the North American BPS.[3]

## Considerations

Projections in this assessment are not predictions of what will happen but are based on information supplied in July 2019 about known system changes with updates incorporated prior to publication. The assessment period for the *2019 LTRA* includes projections for 2020–2029; however, some figures and tables examine data and information for the 2019 year. The assessment was developed using a consistent approach for projecting future resource adequacy through the application of NERC's assumptions and assessment methods. 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 **Demand Assumptions and Supply Categories** section.

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 BPS reliability, as defined in the **How NERC Defines BPS Reliability** section of this report, does not include the reliability of the lower-voltage distribution systems that account for 80% of all electricity supply interruptions to end-use customers.

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 multi-faceted approach through the Electricity-Information Sharing and Analysis Center to promote mechanisms to address these risks, including exercises and information-sharing efforts with the electric industry.

The LTRA data used for this assessment creates a reference case dataset that includes projected on-peak demand and energy, demand response (DR), resource capacity, and transmission projects. Data and information from each NERC Region 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, policymakers, and regulators and to aid NERC in achieving its mission to ensure the reliability of the North American BPS.

In this LTRA, the baseline information on future electricity supply and demand is based on several assumptions:[4]

- Supply and demand projections are based on industry forecasts submitted and validated in July 2019. Any subsequent demand forecast or resource plan changes may not be fully represented; however, updated data may be submitted throughout the drafting time frame and included if appropriate (May–November).
- 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 Region's self-assessment.
- Generating and transmission equipment will perform at historical availability levels.

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

- Future generation and transmission facilities are commissioned and in-service as planned, that planned outages take place as scheduled, and retirements are scheduled as proposed.
- Demand reductions expected from dispatchable and controllable demand response (DR) programs will yield the forecast results if they are called on.
- Other peak demand-side management programs, such as energy efficiency (EE) and price-responsive DR, are reflected in the forecasts of total internal demand.

## Reading this Report

This report is compiled into two major parts:

- **ERO-Wide Reliability Assessment**
  - Evaluate industry preparations in place to meet projections and maintain reliability
  - Identify trends in demand, supply, and reserve margins
  - Identify emerging reliability issues
  - Focus the industry, policymakers, 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 Region-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 and rapid change that presents new challenges and opportunities for reliability. With appropriate insight, careful planning, and continued support, the electricity sector will continue to navigate the associated challenges in a manner that maintains reliability and resilience.

As NERC has identified in recent assessments, retirements of conventional generation and the rapid addition of variable resources, primarily wind and solar, are altering the operating characteristics of the grid in some areas. Natural gas generation is providing the system with increasing flexibility; however, if an area's fuel delivery infrastructure is constrained, a significant influx of natural gas generation raises questions about how disruptions on the natural gas pipeline systems impact electric system reliability.

Distributed energy resources (DERs) and storage are increasingly offering electricity customers an option to reduce energy costs and create additional resilience. By their nature, DERs are increasingly being implemented at the electric distribution level, resulting in a possible net source of power injected into the BPS instead of being load. This change will require a strong transmission system with good links to the distri¬bution system to maintain an appropriate balance between load, variable energy resources (VERs), and energy storage devices.

While risks and corresponding mitigations may be unique to each area, industry stakeholders and policymakers should continue to respond with policies and plans that support a reliable BPS and a strong linkage to the distribution system to enhance the vision of the interactions between the distribution and transmission systems.

This *2019 LTRA* serves as a comprehensive, reliability-focused perspective on the 10-year outlook for the North American BPS and identifies potential risks to inform industry planners and operators, regulators, and policymakers.

## Key Findings

Based on data and information collected for this assessment, NERC has identified four key findings:

**Resource Adequacy: Projected reserves fall below the Reference Margin Level in TRE-ERCOT and NPCC-Ontario; there is sufficient generation supply in all other areas:**

- The Anticipated Reserve Margin (ARM) in TRE-ERCOT is projected below the Reference Margin Level (RML) in most of the first five-year period, but if additional Tier 2 resources in development come into service, they are more than sufficient to exceed the RML.
- NPCC-Ontario projects a shortfall beginning in 2023 that is driven by nuclear retirements and refurbishments; however, market mechanisms that secure incremental capacity are expected to begin addressing the shortfall in future capacity auctions.
- The emerging risk of energy deficiencies is being identified during off-peak conditions in the Midcontinent Independent System Operator (MISO) area and the Western Electricity Coordinating Council (WECC) Region.
- Sufficient resources are planned to be available throughout the assessment period in all other areas.

**Resource Mix Changes: Resource mix changes are driven by the addition of large amounts of new wind, solar, and natural gas resources:**

- Some areas of North America have and continue to see more rapid resource mix changes with North America as a whole having a diverse fuel mix.
- Over 330 GW of installed capacity from solar and wind are planned through 2029.
- To accommodate large amounts of solar and wind generation, additional flexible resources are needed to offset ramping and variability.
- Solutions to inverter-based resource interconnection challenges are being implemented to reliably accommodate more resources.
- The growth in natural gas generation requires continued and coordinated planning to maintain appropriate fuel assurance; guidance is currently being developed by the Electric Gas Working Group (EGWG).

**Storage and Distributed Energy Resources: Large amounts of storage and distributed energy resources require coordinated interconnection and a robust transmission system:**

- A total of 8 GW of BPS-connected electric storage is expected by 2024.
- A total of 35 GW of distributed solar PV is expected by 2024.
- Increasing installations of DERs modify how distribution and transmission systems interact with each other.
- Transmission Planners and Operators may not have complete visibility and control of DERs, but information and data is needed for system planning, forecasting, and modeling as growth becomes considerable.

**Transmission Infrastructure: Transmission planning and infrastructure development need to keep pace with an increasing amount of utility scale wind and solar resources:**

- Under 15,000 circuit miles of new transmission is expected over the next 6 years; this is considerably less than the nearly 40,000 circuit miles planned earlier this decade.
- Many new VERs will be located in areas remote from demand centers and existing transmission infrastructure. In some areas, such as SPP and ERCOT, the level of VERs are reaching full subscription of the transmission network and exhaust current as well as planned transmission capacity.

## Recommendations

Based on the identified key findings, the grid is transforming with the interconnection of new resources with different characteristics and requirements. NERC has formulated the following recommendations, some of which will require the development, validation, and application of new methods, designs, devices, and simulation models:

**The ERO should enhance the reliability assessment process by incorporating energy adequacy metrics and evaluating scenarios posing the greatest risk.**
The ERO recognizes that the changing resource mix, shifting demands, and other factors can have a significant effect on resource adequacy. As a result, the ERO is incorporating more probabilistic methods and other analysis approaches to provide vital and rich insights to effectively assess reliability of the evolving systems with energy-limited and uncertain resources. While the ERO has historically gauged resource adequacy by using solely planning reserve margins focused at peak demand hour, the ERO will expand its use of probabilistic approaches in the 2020 LTRA to support assessment of resource and energy adequacy across all hours.

**The ERO should increase its communication and outreach with state and provincial policymakers on resource adequacy risks and challenges.**
As more resources are located on the distribution system, it is important that the ERO effectively communicates resource adequacy risk to its state and provincial stakeholders. The ERO's independent and objective assessment is a valuable resource to regulatory and policy making stakeholders that are ultimately responsible for their jurisdictions' resource adequacy and distribution systems. The changing resource mix creates new technical challenges that are complex and complicated, requiring even greater engagement and outreach. The ERO Enterprise, strengthened by NERC and RE engagement at the state and provincial levels, will amplify and enhance outreach toward providing guidance and information to support continued reliable operation of the BPS.

**The ERO should publish reliability guidelines, develop requisite tools, and validate models to establish common industry practices for planning and operating the BPS with increasing energy limitations and disruption risks.**
Given the increased reliance on resources that have a higher level of fuel uncertainty than the previous fleet, system planners should identify potential system risks that could occur under extreme but realistic contingencies and under various future supply portfolios. Proper software applications and modeling are required to support system planners performing these studies.

**Industry should identify, design, and commit flexible resources needed to meet increasing ramping and variability requirements.**
Presently, concerns associated with ramping are largely confined to California. However, as solar generation increases in California and various parts of North America, system planners will need to ensure that sufficient flexibility is available to operators to offset variability and fuel uncertainty.

**The ERO and industry need to work together to ensure system studies incorporate DER impacts.**
As the penetration of DERs continues to increase across the North American BPS, it is necessary to account for DERs in the planning, operation, and design of the BPS. System operators and planners should gather data as early as possible about the aggregate technical specifications of DERs connected to local distribution grids to ensure accurate and valid system planning device and simulation models, load forecasting, coordinated system protection, and real-time situation awareness. In areas with large or emerging DER penetrations, current operational models and system studies do not properly account for DERs. These models and studies will need to be improved to accurately represent the system's behavior.

**The ERO should assess the implications of electricity storage on BPS planning and operations.**
Electricity storage has the potential to offer much needed capabilities to the grid of the future. Based on data received in the resource information collected to support this assessment, there will be an increase of BPS-connected storage in the future; this may even be accelerated if the conditions are right. Before this storage is built and integrated into the BPS, the ERO should identify, assess, and report on the risks and potential mitigation approaches to accommodate large amounts of energy storage on BPS reliability.

**In future assessments, the ERO should review challenges in transmission development and reliability risks due to the changing resource mix.**
To accommodate large amounts of variable generation and to meet policy objectives associated with renewables in a reliable and economic manner, more transmission may be needed. For example, to meet the renewable energy requirements, transmission may be required to ensure that transfer of large amounts of energy can be supported when it becomes available. The ERO should assess and evaluate if the decreasing amount of transmission projects presents any future reliability risks or concerns.

See the Recommendations Tracking Matrix for more information.

## 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 electric 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 electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system components

For adequacy, system operators can and should take controlled actions or introduce 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[5]
- 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.)

Operating reliability disturbances result in the unplanned and/or uncontrolled interruption of customer demand regardless of cause. When these interruptions are contained within a localized area, the interruptions are considered unplanned interruptions or disturbances. When the interruptions spread over a wide area of the grid, they are referred to as "cascading blackouts," the uncontrolled successive loss of system elements triggered by an incident at any location. The intent of NERC Reliability Standards is to deliver an adequate level of reliability,[6] 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,[7] and collapse under normal operating conditions and/or voltage when subject to predefined disturbances.[8]
- 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, and 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.
- For rare severe events, BES owners and operators may not be able to apply economically justifiable or practical measures to prevent or mitigate an adverse reliability impact on the BES even if these events can result in cascading, uncontrolled separation, or voltage collapse. Rare severe events include losing an entire right of way due to a tornado, multiple transmission facilities outages due to a hurricane, sizeable disruptions to natural gas infrastructure impacting multiple generation resources, or other severe phenomena.

5 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

6 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

7 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."

8 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 Continue to Fall below the Reference Margin Level in TRE-ERCOT, NPCC-Ontario Falls below the RML in 2023, and there Is Sufficient Generation Supply in all other Areas.

**Key Points**

- The ARM in TRE-ERCOT is projected below the RML) in most of the first five-year period, but if additional Tier 2 resources in development come into service, they are more than sufficient to exceed the RML.
- NPCC-Ontario projects a shortfall beginning in 2023 that is driven by nuclear retirements and refurbishments; however, market mechanisms that secure incremental capacity are expected to begin addressing the shortfall.
- Emerging energy deficiency risks are being identified during off-peak conditions in MISO and WECC.
- Sufficient resources are planned to be available throughout the assessment period in all other areas.

For the majority of the BPS, PRMs appear sufficient to maintain reliability during the long-term, ten-year horizon. However, there are challenges facing the electric industry that may shift industry projections and cause NERC's assessment to change. Where markets exist, signals for new capacity must be effective for planning purposes and reflect the lead times necessary to construct new generation, any requisite natural gas infrastructure, and any associated transmission. Although generating plant construction lead times have been significantly reduced, environmental permitting and pipeline and transmission planning and approval still require significant lead times.[9]

### How NERC Evaluates Resource Adequacy

PRMs are calculated by finding the difference between the amount of projected on-peak capacity and the normal projected peak demand and then dividing this difference by the normal projected 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 RML, as shown in Figure 1, NERC determines the risk associated with the projected level of reserve and concludes in terms of the following:

**Adequate:** The ARM is greater than RML.

**Marginal:** The ARM is lower than RML, and the Prospective Reserve Margin is higher than RML.

**Inadequate:** The Anticipated and Prospective Reserve Margins are less than the RML, and Tier 3 resources are unlikely to advance.

9 Capacity supply and Planning Reserve Margin 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**, all assessment areas remain above the Anticipated RML through 2024 with the exception of TRE-ERCOT and NPCC-Ontario.

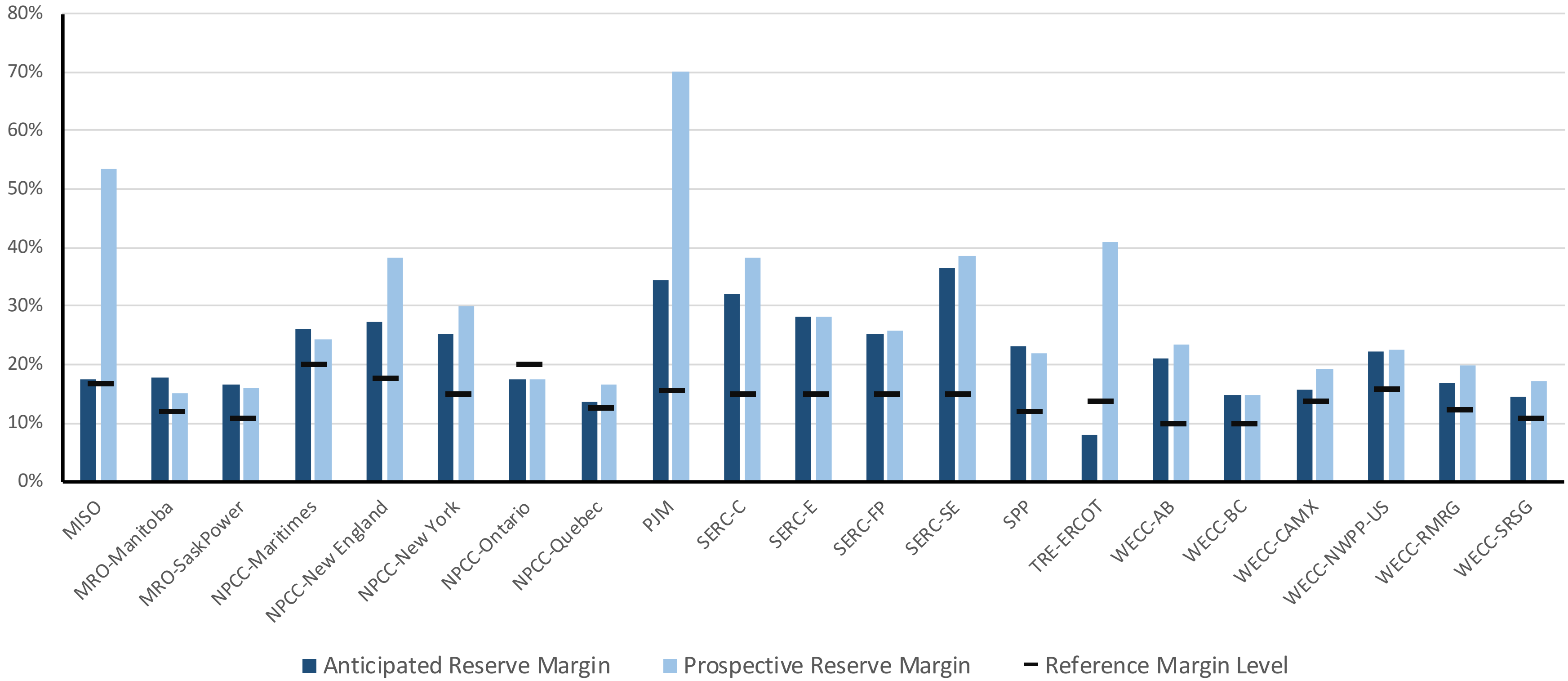



**Figure 1: Anticipated and Prospective Reserve Margins for 2024 Peak Season by Assessment Area**

The results of NERC's risk determination for all assessment areas is shown in **Table 1**. NPCC-Ontario and TRE-ERCOT are identified as "Marginal" with all other areas identified as "Adequate" through 2024. While NPCC-Ontario shows only a very small shortfall, TRE-ERCOT shows a shortfall of over 4,000 MW.

| Table 1: NERC's Risk Determination of All Assessment Areas<br>5-Year Projected Reserve Margins | | | | |
|---|---|---|---|---|
| **Assessment Area** | 2024 Peak Anticipated Reserve Margin | 2024 Reference Margin Level | Expected Capacity Surplus or Shortfall (MW) | Assessment Result Through 2024 |
| MISO | 17.5% | 16.8% | 877 | Adequate |
| MRO-Manitoba | 17.6% | 12.0% | 269 | Adequate |
| MRO-SaskPower | 16.6% | 11.0% | 219 | Adequate |
| NPCC-Maritimes | 26.0% | 20.0% | 320 | Adequate |
| NPCC-New England | 27.3% | 17.8% | 2,261 | Adequate |
| NPCC-New York | 25.3% | 15.0% | 3,152 | Adequate |
| NPCC-Ontario | 17.3% | 20.1% | -615 | Marginal |
| NPCC-Quebec | 13.7% | 12.8% | 324 | Adequate |
| PJM | 34.3% | 15.7% | 26,779 | Adequate |
| SERC-C | 32.0% | 15.0% | 3,862 | Adequate |
| SERC-E | 28.1% | 15.0% | 6,828 | Adequate |
| SERC-FP | 25.3% | 15.0% | 4,827 | Adequate |
| SERC-SE | 36.5% | 15.0% | 9,875 | Adequate |
| SPP | 23.0% | 12.0% | 5,966 | Adequate |
| TRE-ERCOT | 7.8% | 13.75% | -4,859 | Marginal |
| WECC-AB | 20.9% | 10.1% | 1,326 | Adequate |
| WECC-BC | 14.8% | 10.1% | 577 | Adequate |
| WECC-CAMX | 15.7% | 13.9% | 958 | Adequate |
| WECC-NWPP-US | 22.1% | 15.8% | 3,288 | Adequate |
| WECC-RMRG | 16.7% | 12.4% | 590 | Adequate |
| WECC-SRSG | 14.5% | 11.0% | 916 | Adequate |

## NERC Planning Reserve Margin Categories

### Anticipated Resources

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

### Prospective Resources

- **Anticipated Resources:** as described above
- **Existing-Other Capacity:** includes operable capacity that could be available to serve load during the peak hour but lacks firm transmission and could be unavailable during the peak for a number of reasons
- **Tier 2 Capacity Additions:** includes 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:** capacity that is expected to retire based on the result of an assessment area generator survey or analysis (This capacity is aggregated by fuel type.)

**Planning Reserve Margins in TRE-ERCOT**

The projected 5-year ahead ARMs falls below the RML of 13.75% in the first year—Summer 2020, increasing above the RML in 2021 and falling below the RML for the remainder of the LTRA forecast period (**Figure 2**). The 2020 ARM is projected to be 10.2% and 7.8% by 2024. This is consistent with the findings of the past two LTRAs. The near-term deficiency in the ARM is mainly due to the following:[10]

- An increase in the forecasted summer peak demands, averaging about a 1,300 MW increase from 2019 through 2023
- The mothballing and subsequent retirement of the 470 MW Gibbons Creek coal-fired plant, beginning in October 2018
- Cancellation of two planned natural-gas-fired generation projects with projected 2020 and 2021 in-service dates (combined 1,439 MW summer rating) along with the cancellation of the planned Bethel Compressed Air Energy Storage project (324 MW, projected 2020 in-service date)
- Cancellations of several planned wind projects, totaling over 2,100 MW of installed capacity

ERCOT has a variety of operational tools to help manage tight reserves and maintain system reliability. For example, control room operators can release ancillary services (including load resources that can provide various types of operating reserves depending on meeting certain qualification criteria), deploy contracted emergency response service resources, instruct investor-owned utilities to call on their load management and distribution voltage reduction programs, request emergency power across the dc ties, and request support from available switchable generators currently serving non-ERCOT grids. ERCOT estimates that 2,000–3,000 MW of additional resources will become available when an energy emergency alert is declared.

To respond to such cyclical resource investment and retirement trends, the ERCOT market is designed to incentivize increases in supply along with temporary reductions in demand to maintain the reliability of the system. For

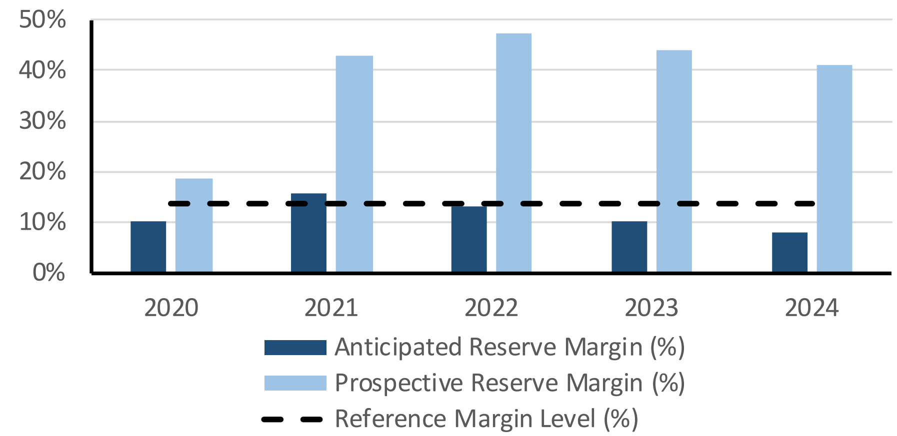



**Figure 2: TRE-ERCOT 5-year Projected Reserves (ARM and PRM)**

example, there are programs operated by ERCOT, retail electric providers, and distribution utilities that compensate customers for reducing their demand or operating their own generation in response to market prices and anticipated capacity scarcity conditions. ERCOT also has operational tools available to maintain system reliability, such as calling upon demand response (DR) resources that are qualified to provide ancillary services, requesting emergency power across the dc ties to neighboring grids, and requesting emergency support from available switchable generators currently serving non-ERCOT grids. However, insufficient reserves during peak hours could lead to an increased risk of entering emergency operating conditions, including the possibility of rotating firm load outages.

Since 2010, a downward trend in ERCOT's reserve margins has led to scarce resources during the peak and less operating flexibility (**Figure 3**). To some extent, this is an expected outcome of managing resource adequacy through an energy-only market construct.[11] 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

10 Generation interconnection queues in the ERCOT area are continually changing and the pace of queue entry has increased since tight conditions in late Summer 2019. Data used in ERCOT ISO's December 5, 2019, *Capacity, Demand and Reserves Report* shows a higher future peak reserve range of 18%–13% versus 15%–8% in the LTRA for the years 2021 to 2024. Primary differences between this *2019 LTRA* and the *Capacity, Demand, and Reserves Report* reflect a downward revision to the ERCOT load forecast of approximately 1%–1.5% with a marked increase in utility-scale solar expected in Summer 2021.

11 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, in addition to energy payments.

operations to be successful with no load shedding events despite setting a new system-wide peak demand record of 73,308 MW on July 19, 2018, and another record of 74,666 MW on August 12, 2019.

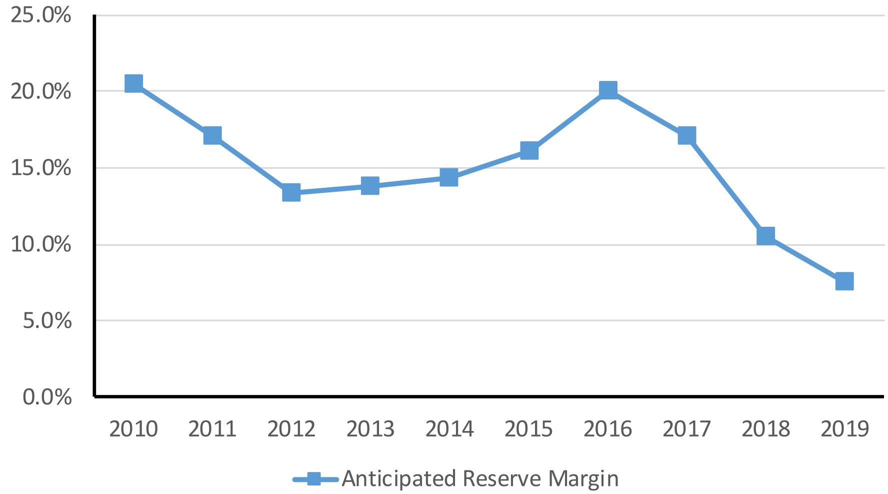



**Figure 3: TRE-ERCOT Historical Projected Reserve Margins***

*Projections are Year-1 projections from prior LTRAs. For example, the 2010 value is based on the *2009 LTRA's* 2010 projection.

**Planning Reserve Margins in NPCC-Ontario**

The ARM falls below the RML to 15% starting in 2023 and 17% in 2024 (**Figure 4**). This is driven primarily by nuclear retirements and the nuclear refurbishment program. The RML for the summer peak varies over the 10-year period from 19%–26%. Additional reserves are required in 2020 to account for the risk that nuclear refurbishments are not completed on schedule. This risk varies from year-to-year. More reserves are needed when nuclear resources are off-line due to nuclear's high availability compared to the other resources that will need to replace it. The Independent Electricity System Operator's (IESO's) long-term planning forecast anticipates there will be sufficient energy to meet demand and a limited need for new domestic capacity if existing Ontario resources are reacquired when their contracts expire.

The IESO is evolving its capacity market from the existing demand response (DR) auction to a capacity auction. Over the coming years, this auction will allow additional resources to participate, such as off-contract generators. imports, storage, and enhancements of current facilities.

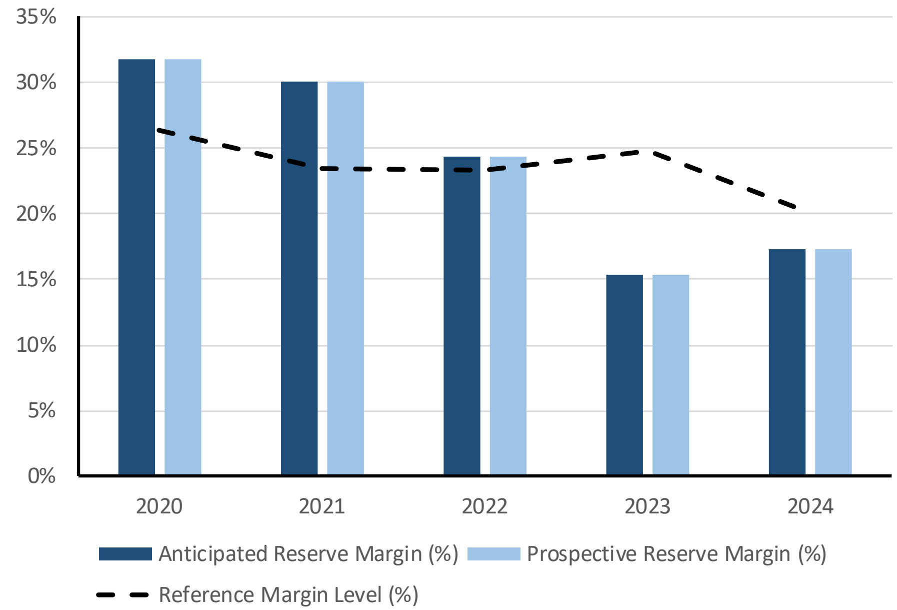



**Figure 4: NPCC-Ontario 5-year Projected Reserves (ARM and PRM)**

**Emerging Reliability Considerations**

- **Seasonality of Loss-of-Load Risk**: As the resource mix continues to change, the increase in energy-limited resources and other factors influence resource adequacy. The MISO and WECC-CAMX assessment areas are beginning to see signs of potential energy deficits in the next five years. While traditionally the risk is observed during the summer and winter peak conditions, potential risk is being observed during shoulder and off-peak periods when solar and/or wind output is low.[12] Through periodical probabilistic assessments, the ERO is monitoring the potential for energy deficiencies for all hours.

12 *2018 Long-Term Reliability Assessment*: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2018_12202018.pdf

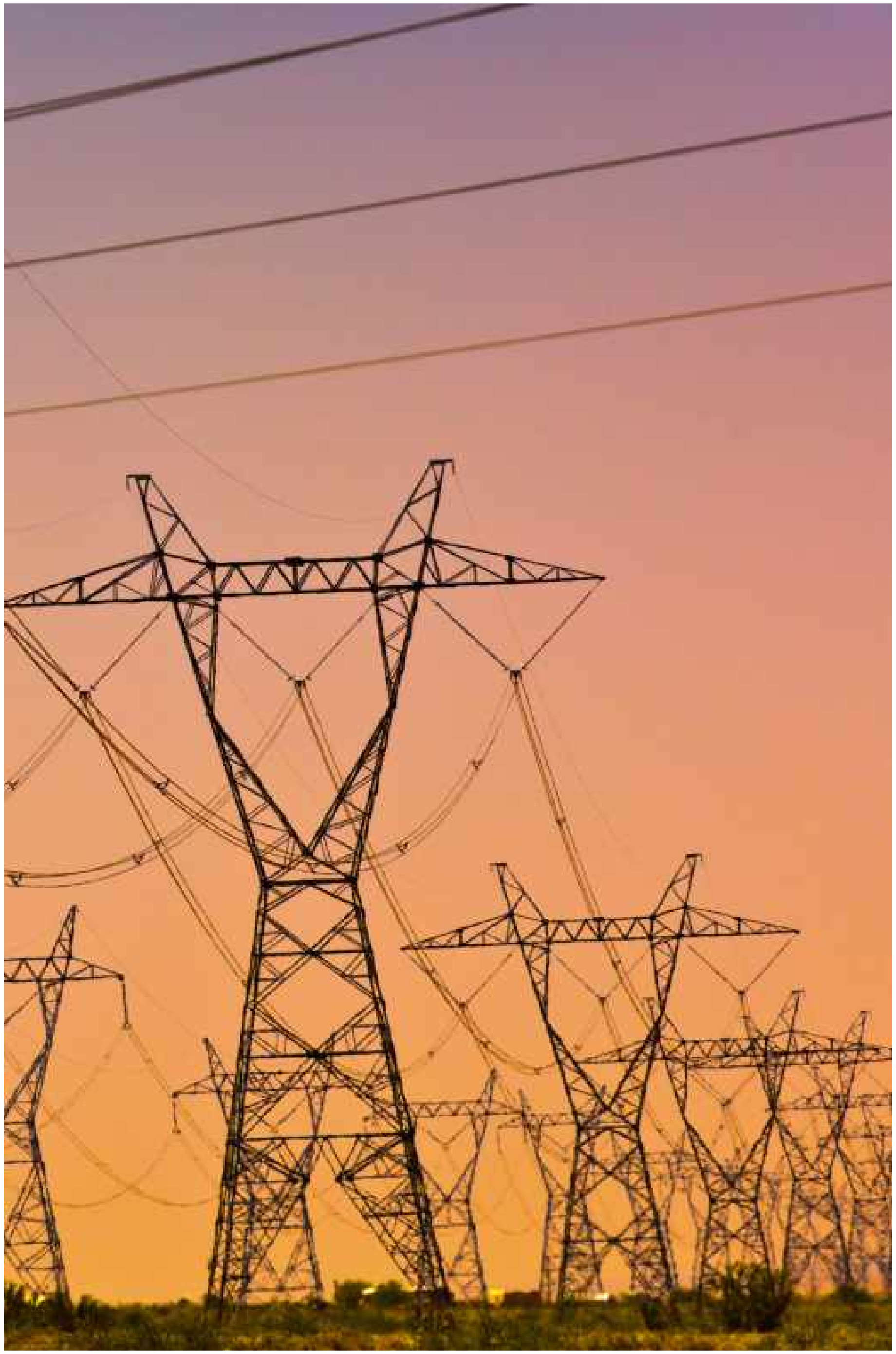
- **Potential Implications of Significant Unanticipated Electricity Demand Growth:** A rapid onset of transportation-related or industrial demand could create unexpected load growth. Automobiles are now increasingly battery-powered. Electric heating is also driving efficiency increases as heat pumps replace other forms of heating, including natural gas, oil, and direct electric heating on broader scales.

  Plug-in electric vehicles are projected to account for as much as half of all United States new car sales by 2030. The electricity required to charge these vehicles will increase demand on BPS. Scenario analysis is the best method to understand these potential risks. For example, how might a three-fold increase in electric vehicle penetration by 2028 affect the reliability of the BPS? Would there be a change in planning and/or operating reserve requirements? Would charging patterns affect ramping needs?

## Recommendations

**The ERO should enhance the reliability assessment process by incorporating energy adequacy metrics and evaluating scenarios posing the greatest risk.** The ERO recognizes that the changing resource mix, shifting demands, and other factors can have a significant effect on resource adequacy. As a result, the ERO is incorporating more probabilistic methods and other analysis approaches to provide vital and rich insights to effectively assess reliability of the evolving systems with energy-limited and uncertain resources. While the ERO has historically gauged resource adequacy by using solely planning reserve margins focused at peak demand hour, the ERO will expand its use of probabilistic approaches in the 2020 LTRA to support assessment of resource and energy adequacy across all hours.

**The ERO should increase its communication and outreach with state and provincial policymakers on resource adequacy risks and challenges.** As more resources are located on the distribution system, it is important that the ERO effectively communicates resource adequacy risk to its state and provincial stakeholders. The ERO's independent and objective assessment is a valuable resource to regulatory and policy making stakeholders that are ultimately responsible for their jurisdictions' resource adequacy and distribution systems. The changing resource mix creates new technical challenges that are complex and complicated, requiring even greater engagement and outreach. The ERO Enterprise, strengthened by NERC and RE engagement at the state and provincial levels, will amplify and enhance outreach toward providing guidance and information to support continued reliable operation of the BPS.



## Key Finding 2: Resource Mix Changes Driven by the Addition of Large Amounts of New Wind, Solar, and Natural Gas Resources.

**Key Points**

- While some areas of North America have and continue to see more rapid resource mix changes, North America has a diverse fuel mix and modest changes are currently planned over the 10-year period as a whole.
- Over 330 GW of installed capacity from solar and wind are planned through 2029.
- To accommodate large amounts of solar and wind generation, additional flexible resources are needed to offset ramping and variability.
- Solutions to inverter and protection challenges are being implemented to reliably accommodate more resources.
- The growth in natural gas generation requires continued and coordinated planning to maintain appropriate fuel assurance; guidance is currently being developed by the EGWG.

**Fuel Mix Changes**

Figure 5 identifies the components of the fuel mix for the United States and Canada as a whole. From an installed capacity perspective, wind and solar resources have the largest impact to the North American generation fleet with a combined increase from 15% in 2019 to 26% by 2029. Coal and nuclear are projected to decrease from 20% and 9%–16% and 7%, respectively. Included in the "Other" category is battery storage, among other forms of generation.

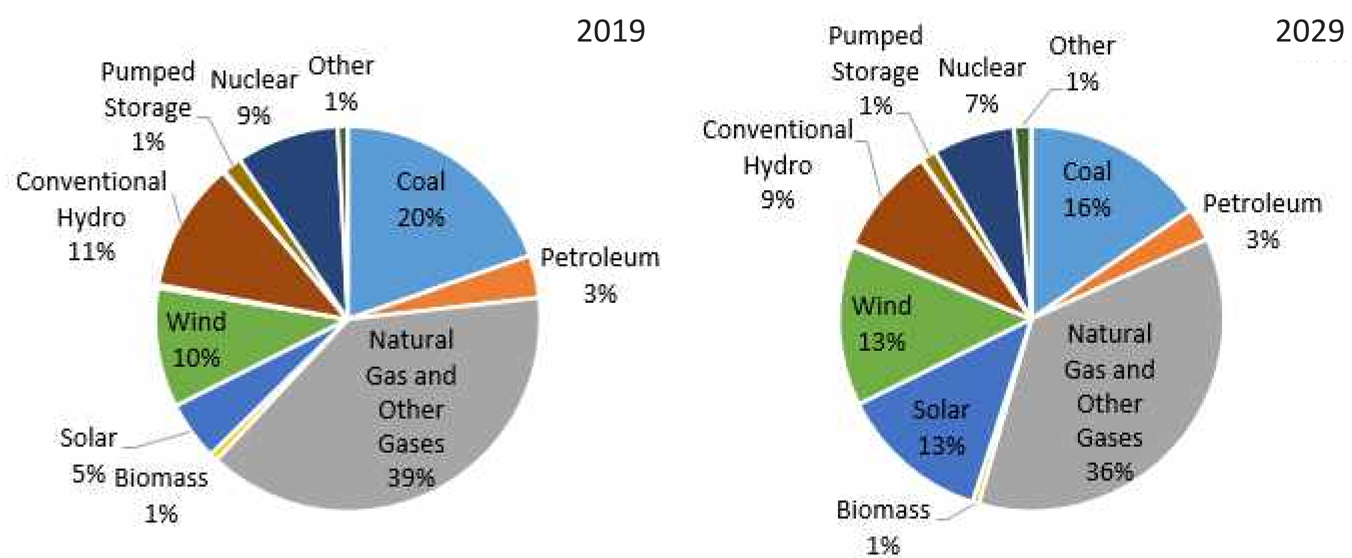



**Figure 5: Installed Nameplate Capacity by Fuel Mix Trend (Includes Future Tier 1 Resources)**

**Figure 6** shows the installed capacity composition of generating resources NERC-wide as of July 2019 compared to the projected installed capacity composition of 2029 (includes Tier 1 additions). Installed nameplate capacity suggests what resource is capable of producing at its maximum potential output. Notably, wind and solar increase from a combined 10–a combined 16%.

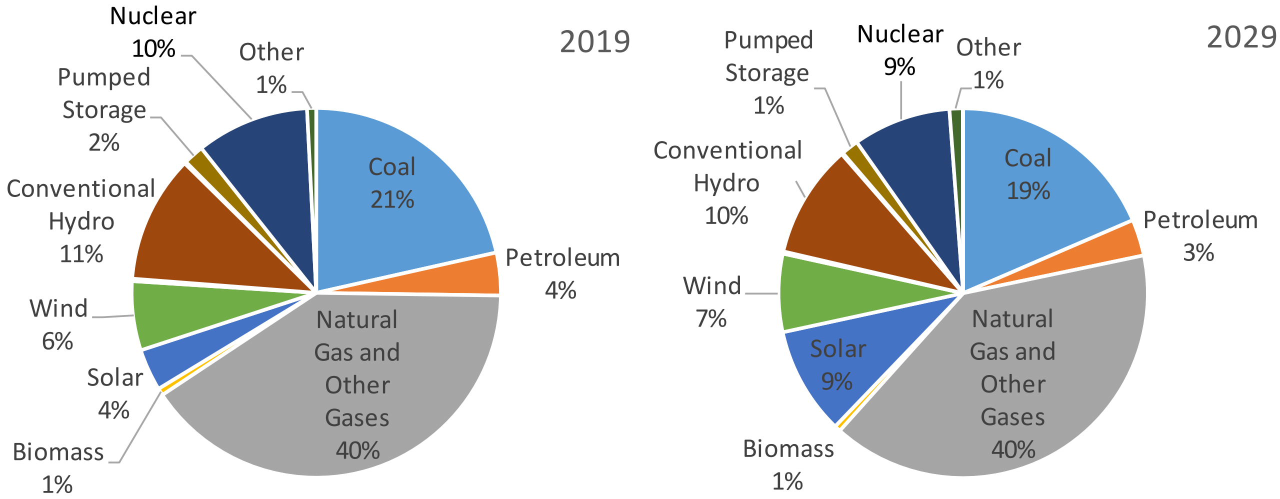



**Figure 6: Installed On-Peak Anticipated Capacity Trend by Fuel Mix**

## 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)/ISOs)

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

**Figure 7** shows the on peak capacity composition of generating resources NERC-wide as of July 2019 compared to the projected on peak capacity composition of 2029 (includes Tier 1 additions). On-peak capacity gives an idea of what a resource is capable of producing at peak demand. Notably, wind and solar increase from a combined 10–a combined 16%.

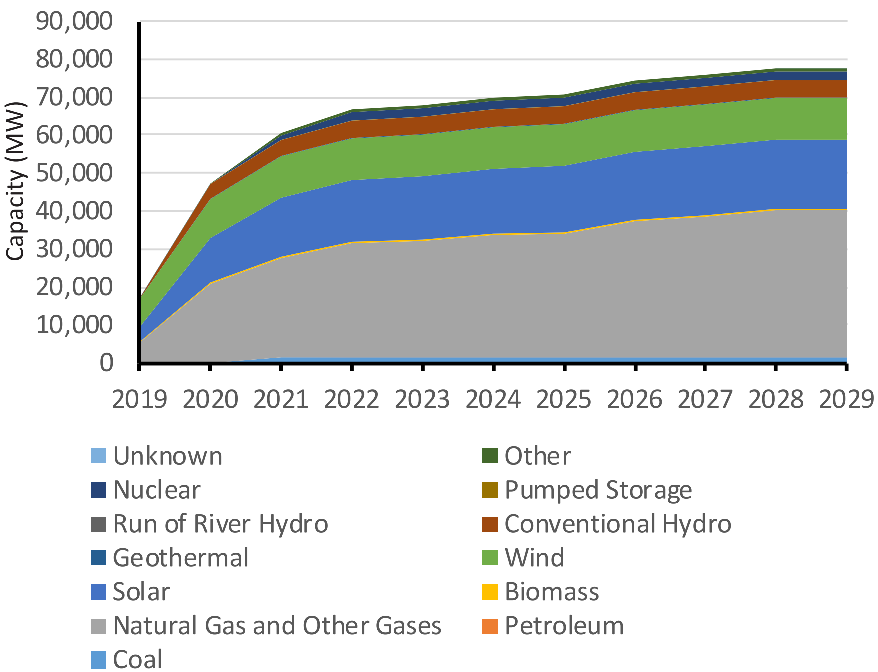



**Figure 7: Tier 1 Planned Resources Projected Through 2029**

In addition to natural-gas-fired generation, solar additions provide the second most additions to capacity to the overall North American fuel mix with approximately 18 GW of Tier 1 capacity (**Figure 7**). Tier 1 wind additions total to almost 11 GW of capacity. When considering Tier 2 resources, up to 88 GW of solar and 27 GW of wind are projected (**Figure 8**). These projections are used for peak reserve margin purposes and are different than the solar resource nameplate capacity.[13]

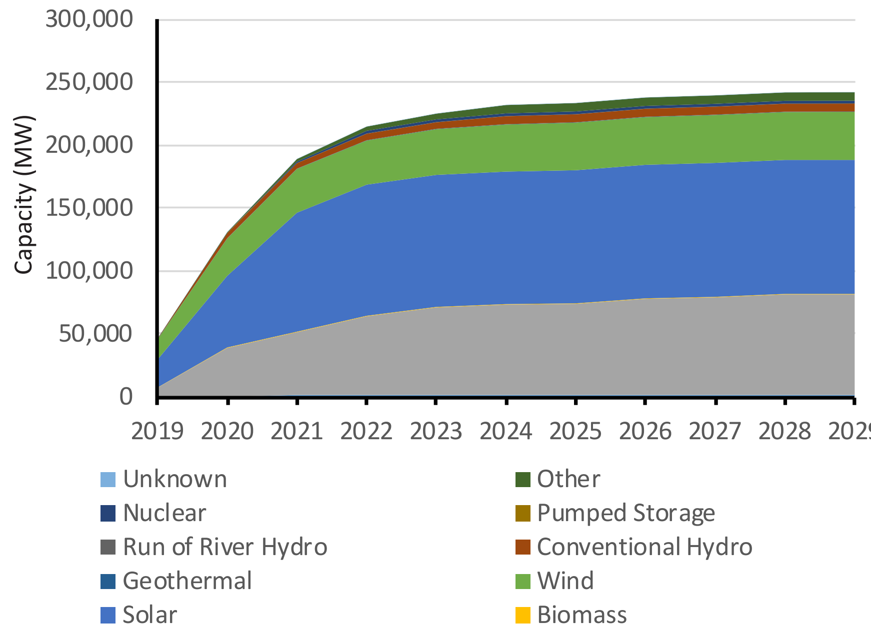



**Figure 8: Tier 1 and 2 Planned Resources Projected Through 2029**

While some areas of North America have and continue to see more rapid resource mix changes, North America has a diverse fuel mix and modest changes are currently planned over the 10-year period as a whole. A 10-year projection of North America peak capacity is shown in **Figure 9**. The changes level off around 2024 as the majority of planning occurs five years in advance.

**Figure 10** 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, an indication that coal and petroleum are being phased out in favor of other resources. The capacity of coal and petroleum is reduced by 35 GW and almost 4 GW, respectively, since 2012. During the same period, natural gas increased by almost 130 GW.

13 The nameplate capacity additions for 2028 are 18 GW of Tier 1 capacity and 86 GW of Tier 2 capacity.

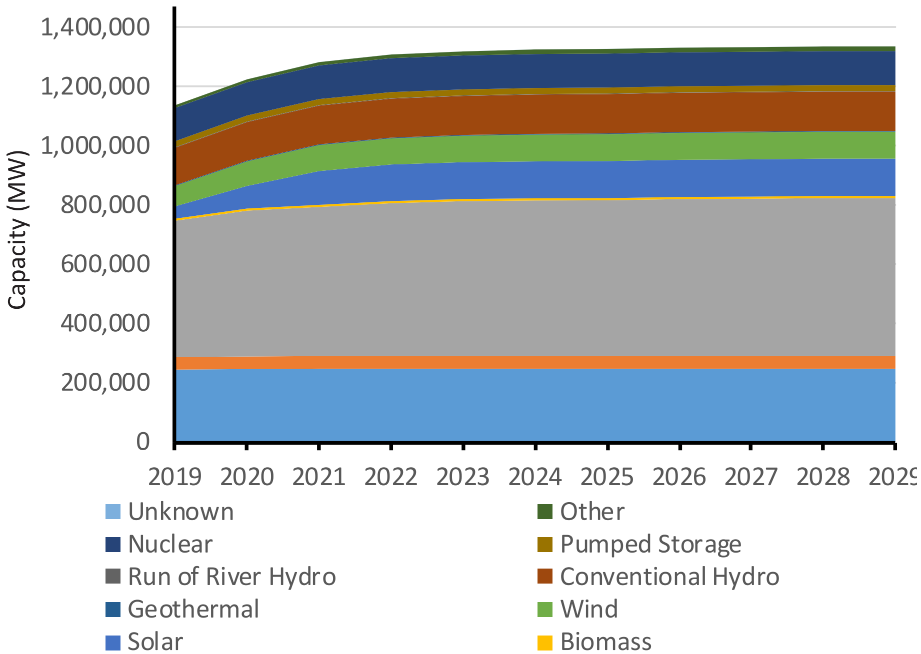



**Figure 9: Existing, Tier 1, and 2 Planned Resources Projected through 2029**

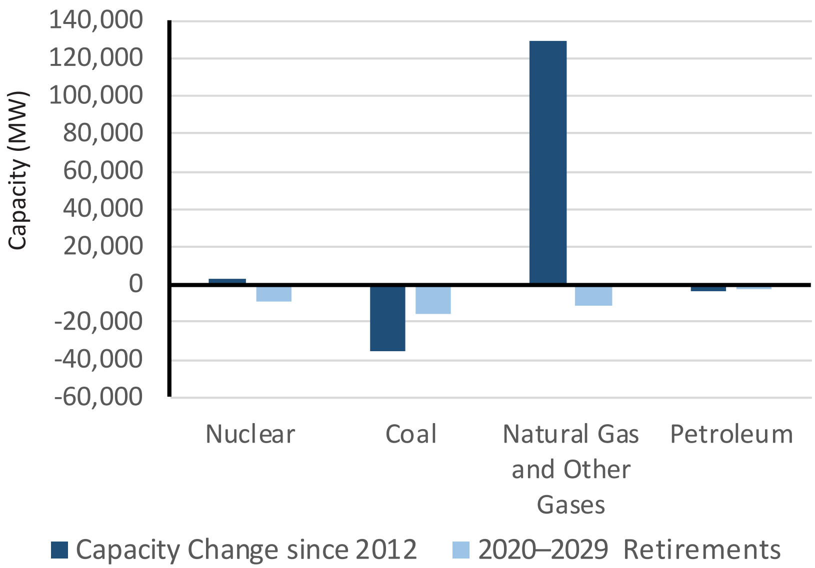



**Figure 10: Capacity Changes since 2012 and Retirements Projected through 2029**

## 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.[14] If the transmission links between an area and generation sources are relatively weak, voltage instability can be the 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, 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 that often require additional actions or investments (e.g., transformers, shunt capacitors) in equipment to maintain voltage stability.

Figure 11 displays the capacity retirements for the previous 7-year period as well as the 10-year projected cumulative retirements through 2029. Between the years 2012 and 2018, over 32 GW of coal generation and over 7 GW of natural gas generation were retired among the almost 43 GW retired in that period of time. The cumulative projected retirements for the 10-year period of 2019–2029 are forecasted to exceed 46 GW in capacity. All of the projected nuclear retirements for the 10-year period occur by 2024, totaling over 10 GW of capacity. The other projected retirements mostly consist of 19 GW of coal and 13.5 GW of natural gas. The 10-year projected retirements are based on committed retirements known to date and is expected to increase as the time horizon progresses.

14 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

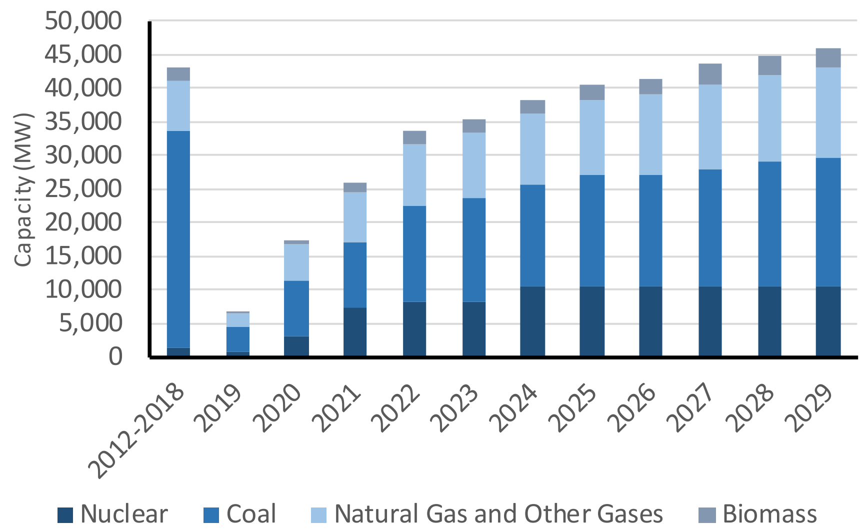



**Figure 11: Nameplate Capacity Retirements since 2012 and Projected Cumulative Retirements through 2029**

**Solar and Wind Capacity Additions**

Significant solar and wind capacity additions are expected over the next 10 years. **Table 2** identifies solar and wind installed capacity additions by assessment area. From an installed capacity perspective, over 335 GW of new solar and wind are planned through 2029, including Tier 1, 2, and 3 resources. Of all generation resources, future solar capacity is expected to be the largest contribution at 160 GW when considering Tier 1 and 2 resources and 206 GW when considering Tier 3 resources. Wind capacity is expected to more than double by 2029, and over 100 GW are planned when considering Tier 1 and 2 resources.

| Table 2: Solar and Wind Installed Capacity, Existing and Planned Additions through 2029 | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Nameplate Capacity of Solar (MW) | | | | | Nameplate Capacity of Wind (MW) | | | | |
| Assessment Area | Existing | Tier 1 | Tier 2 | Tier 3 | Total | Existing | Tier 1 | Tier 2 | Tier 3 | Total |
| **MISO** | 280 | 2,040 | 60,125 | 640 | **63,084** | 19,172 | 7,598 | 27,468 | 5,714 | **59,953** |
| **MRO-Manitoba** | 0 | 0 | 0 | 0 | **0** | 259 | 0 | 0 | 0 | **259** |
| **MRO-SaskPower** | 0 | 10 | 20 | 50 | **80** | 242 | 377 | 0 | 400 | **1,019** |
| **NPCC-Maritimes** | 1 | 3 | 0 | 0 | **4** | 1,146 | 80 | 0 | 30 | **1,256** |
| **NPCC-New England** | 1,206 | 126 | 509 | 2,555 | **4,396** | 1,390 | 111 | 4,884 | 5,963 | **12,348** |
| **NPCC-New York** | 32 | 20 | 0 | 686 | **738** | 1,898 | 226 | 1,091 | 3,350 | **6,565** |
| **NPCC-Ontario** | 424 | 54 | 0 | 0 | **478** | 4,431 | 460 | 0 | 0 | **4,891** |
| **NPCC-Quebec** | 0 | 0 | 0 | 0 | **0** | 3,776 | 54 | 0 | 0 | **3,830** |
| **PJM** | 1,549 | 3,915 | 41,754 | 0 | **47,219** | 8,012 | 3,419 | 22,538 | 0 | **33,969** |
| **SERC-C** | 10 | 268 | 597 | 3,758 | **4,633** | 486 | 0 | 0 | 0 | **486** |
| **SERC-E** | 491 | 0 | 0 | 0 | **491** | 0 | 0 | 0 | 0 | **0** |
| **SERC-FP** | 1,121 | 8,855 | 0 | 0 | **9,976** | 0 | 0 | 0 | 0 | **0** |
| **SERC-SE** | 1,248 | 893 | 705 | 2,188 | **5,034** | 0 | 0 | 0 | 0 | **0** |
| **SPP** | 276 | 0 | 650 | 25,307 | **26,233** | 20,486 | 300 | 2,500 | 31,905 | **55,191** |
| **TRE-ERCOT** | 1,857 | 7,699 | 27,376 | 26,155 | **63,087** | 22,090 | 14,457 | 15,191 | 5,864 | **57,602** |
| **WECC-AB** | 0 | 0 | 0 | 900 | **900** | 0 | 0 | 0 | 4,400 | **4,400** |
| **WECC-BC** | 1 | 1 | 21 | 79 | **102** | 702 | 26 | 0 | 184 | **912** |
| **WECC-CAMX** | 11,784 | 0 | 475 | 6,051 | **18,310** | 6,191 | 0 | 469 | 1,144 | **7,804** |
| **WECC-NWPP-US** | 2,479 | 3,352 | 39 | 0 | **5,869** | 9,764 | 1,134 | 504 | 0 | **11,402** |
| **WECC-RMRG** | 464 | 292 | 720 | 45 | **1,521** | 3,792 | 59 | 969 | 354 | **5,175** |
| **WECC-SRSG** | 1,399 | 301 | 167 | 2,807 | **4,673** | 1,162 | 165 | 99 | 776 | **2,202** |
| **Total** | **24,620** | **27,828** | **132,508** | **45,914** | **230,870** | **104,998** | **27,789** | **73,213** | **28,179** | **234,179** |

**Figure 12** shows the planned solar capacity for assessment areas through 2029. MISO, PJM, and TRE-ERCOT have the most total planned, mostly Tier 2 resources. SPP contains almost 26 GW of planned solar capacity, mostly Tier 3 resources. WECC-CAMX leads the way with over 11 GW of current solar capacity, the most currently installed.

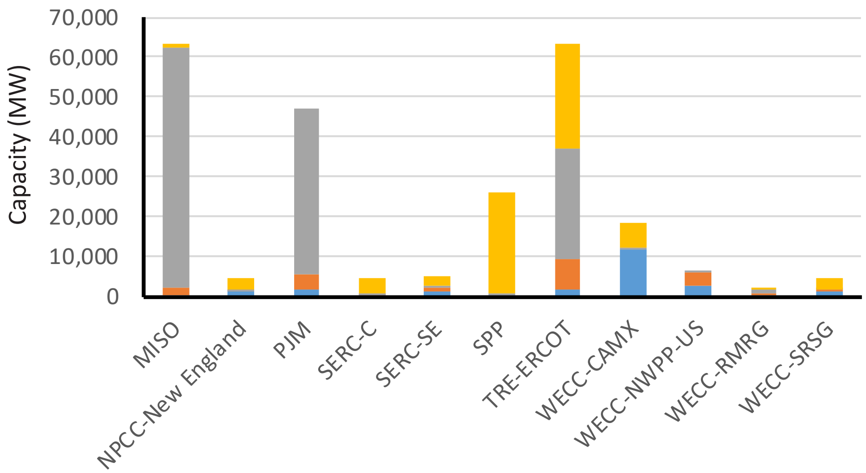



**Figure 12: Solar Nameplate Capacity Planned and Existing**

**Figure 13** shows the planned wind capacity for assessment areas through 2029. As with solar, the larger footprint assessment areas of MISO, PJM, SPP, and TRE-ERCOT have the most total planned. MISO, SPP, and TRE-ERCOT are all about 20 GW of currently installed wind capacity, the only assessment areas with above 10 GW of installed wind capacity thus far.

### Natural Gas Capacity Additions

NERC-wide natural-gas-fired on-peak generation has increased from 280 GW in 2009 to 460 GW today with an additional 43 GW planned during the next decade—88 GW when considering Tier 2 additions as shown in **Figure 14**.

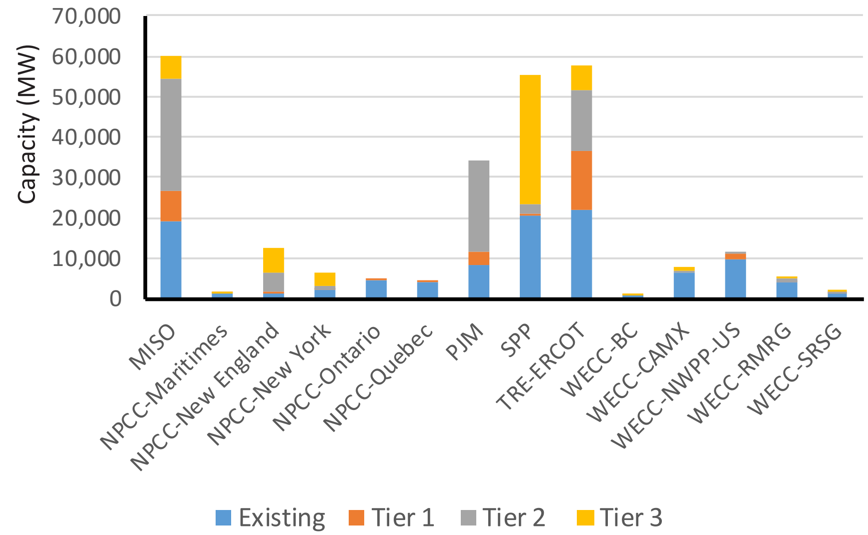



**Figure 13: Wind Nameplate Capacity Planned and Existing**

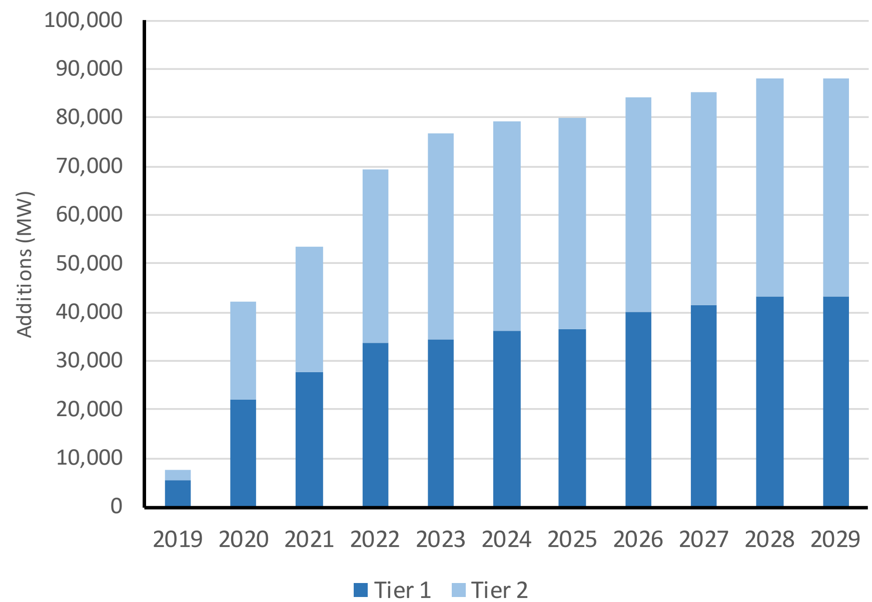



**Figure 14: Natural Gas Capacity Planned Additions through 2029, Tier 1 and 2**

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 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, and arrangements for alternative fuels should be considered. Some plants no longer have the option of burning a liquid fuel. Further, 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*.[15] 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 EGWG[16] was created to gather industry experts and drive the development of tools and other resources to better educate and inform the electric industry about how to reduce risks related to the disruption of fuel supplies.

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

16 https://www.nerc.com/comm/PC/ElectricGas%20Working%20Group%20EGWG/EGWG%20Scope%20Document%20-%20May%202019.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. 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 electric generation to fuel supply and delivery vulnerabilities.

| Mechanisms that Promote 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 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 prices. |
| **Pipeline Expansions** | • Areas that have an increasing amount of transportation capacity being added may be reducing their risk.<br>• Pipeline expansion into constrained areas significantly promotes fuel assurance. |

New England is currently fuel constrained; 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 and LNG and the now-declining nuclear, coal, and oil-fired generators. Although new, incremental 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 ever 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. **Figure 15** shows that natural gas demand will continue to increase with no pipeline additions projected in the near future.

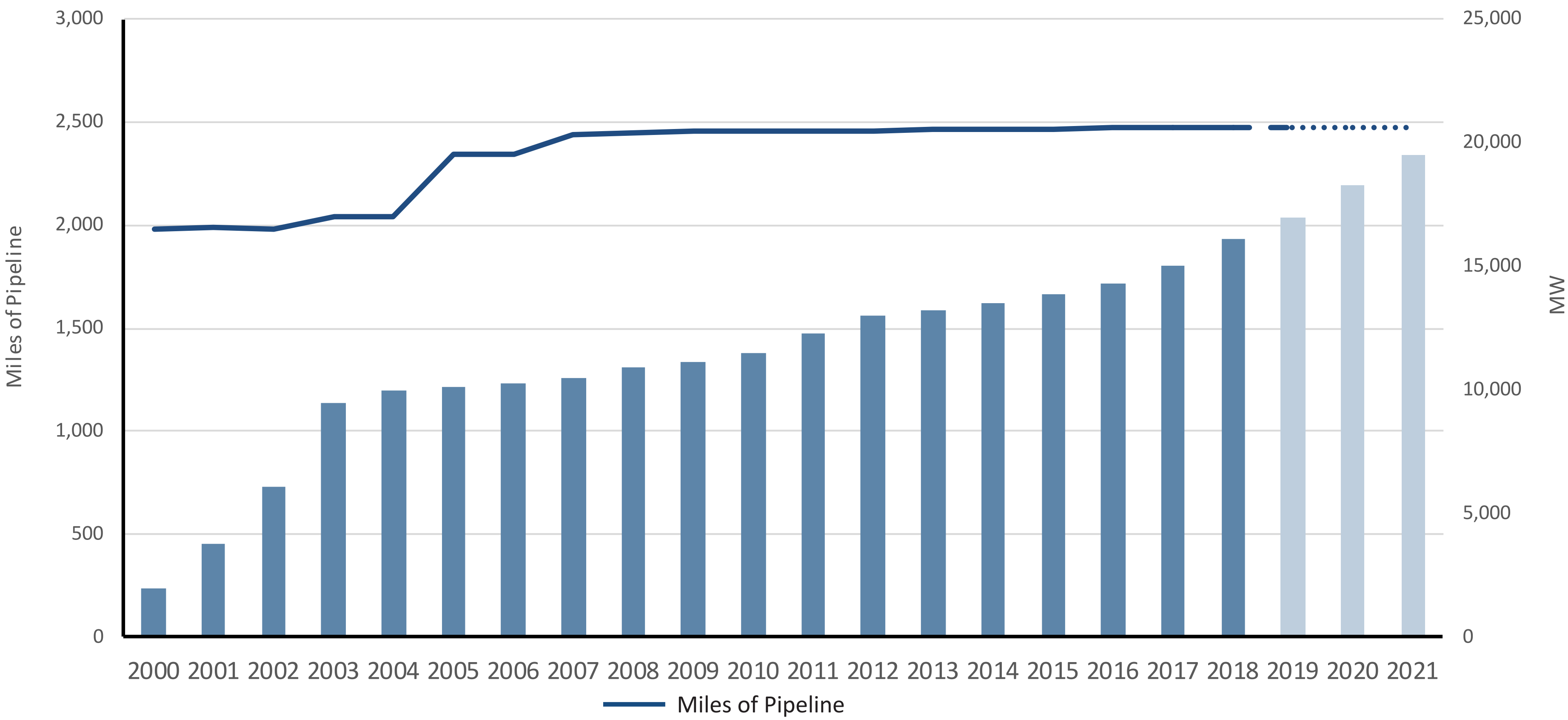



**Figure 15: Natural Gas Generation Expansion in New England Compared to Interstate Pipeline Miles**

Giving heightened priority to the regional energy security issue, the Federal Energy Regulatory Commission (FERC) directed ISO New England to submit "Tariff revisions reflecting improvements to its market design to better address regional fuel security concerns" in 2018.[17] That directive arose amidst a contentious regulatory process involving shorter-term, out-of-market actions to bolster the area's (winter) fuel supplies by delaying the retirement of the large Mystic Generating Station in Everett, Massachusetts. This station is fueled solely by vaporized LNG from the Distrigas LNG Import Terminal located on the Mystic River, also in Everett, MA.

**Figure 16** shows the assessment areas with solar and wind resources over 5% of their peak demand for the years 2019, 2024, or both. The percentages located beside each bar indicate that two assessment areas have to rely on these resources to meet peak demand as their peak demand exceeds the total capacity of conventional resources. WECC-CAMX and TRE-ERCOT are becoming increasingly reliant on solar and wind resources to meet peak demand. In the event solar and wind output is below expectations, CAMX and TRE-ERCOT may need to rely on additional and/or external resources to cover the shortfall.

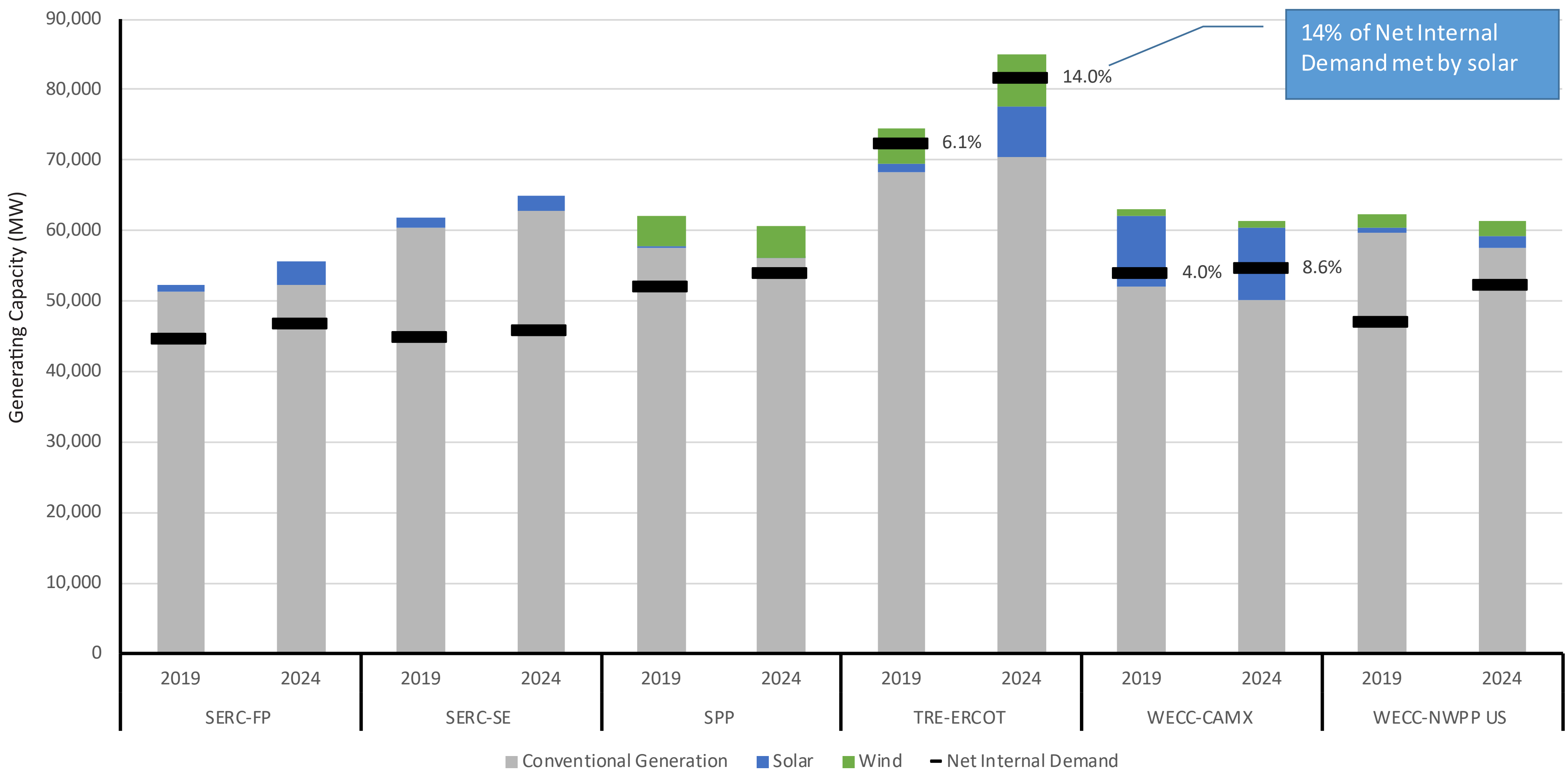



**Figure 16**: Assessment Areas with Solar and Wind Capacity Greater than 5% of On-Peak Demand

17 ISO New England Inc., 164 FERC ¶ 61,003 at PP 2, 5 (2018).

### Emerging Reliability Considerations

Replacing coal and nuclear generation with nonsynchronous and natural-gas-fired generation introduces new considerations for reliability planning, such as 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. This data shows that ERCOT's frequency response is highest when wind output is high.[18] Specific emerging reliability considerations include the following:

- **Planning for Increased Natural Gas Dependency:** During the past decade, several assessment areas have significantly increased dependence on natural-gas-fired generation. As natural-gas-fired generation continues to increase, vulnerabilities associated with the natural gas pipeline system can potentially result in greater electric generation 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 electric reliability. 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 electric system (e.g., loss of electric motor-driven compressors) that are compounded when multiple plants are connected through the same pipeline or storage facility. Although the ability to use alternate fuel provides a key mitigation effect, only 27% of natural-gas-fired capacity added in the United States since 1997 is dual fuel capable.
- **Increasing Need for System Flexibility**: 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.[19] In particular, the following areas are currently impacted the most:
  - **California:** Increasing solar generation increases the need for flexible resources. CAISO's 2020 solar generation projection increases the three-hour ramp requirement to over 18,500 MW, approximately 8% greater than the amount projected for 2019. The requirement further increases to over 20,000 MW by 2022.[20]
  - **Texas:** Changing ramping requirements induced by increasing amounts of wind is largely managed with improved forecasting. Ramp forecasts allow ERCOT operators to curtail wind production and/or reconfigure the system in response to large changes in wind output.

## Recommendations

**The ERO should publish reliability guidelines, develop requisite tools, and validate models to establish common industry practices for planning and operating the BPS with increasing energy limitations and disruption risks.**
Given the increased reliance on resources that have a higher level of fuel uncertainty than the previous fleet, system planners should identify potential system risks that could occur under extreme but realistic contingencies and under various future supply portfolios. Proper software applications and modeling are required to support system planners performing these studies.

**Industry should identify, design, and commit flexible resources needed to meet increasing ramping and variability requirements.**
Presently, concerns associated with ramping are largely confined to California. However, as solar generation increases in California and various parts of North America, system planners will need to ensure that sufficient flexibility is available to operators to offset variability and fuel uncertainty.

18 *2019 State of Reliability Report*: https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2019.pdf

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

20 https://www.caiso.com/Documents/2019FinalFlexibleCapacityNeedsAssessment.pdf

## Key Finding 3: Large Amounts of Storage and Distributed Energy Resources Require Coordinated Interconnection and Robust Transmission System.

**Key Points**

- A total of 8 GW of BPS-connected electric storage is expected by 2024.
- A total of 35 GW of distributed solar photovoltaic (PV) is expected by 2024.
- Increasing installations of DERs modify how distribution and transmission systems interact with each other.
- Transmission Planners and Operators may not have complete visibility and control of DERs, but information and data is needed for system planning, forecasting, and modeling as growth becomes considerable.

The generation mix is undergoing a transition from large, synchronously connected generators to smaller natural-gas-fired generators, renewable energy, and DR. The growing interest in a more decentralized electric grid and new types of distributed resources further increases the variety of market stakeholders and technologies, including a variety of electric storage. Both new and conventional stakeholders are building or planning to build distributed solar PV systems, energy management systems, microgrids, demand services, aggregated generation behind the retail meter, and many other types of distributed generation. Many of these stakeholders have considerable experience with installing such systems on the distribution network for the benefit of industrial or residential customers but may have less familiarity with the BPS and the coordinated activities that ensure system reliability during both normal operation and in response to disturbances.

At low penetration levels, the effects of DERs may not present a risk to BPS reliability. However, as penetrations increase, the effect of these resources can present certain reliability challenges that require attention. 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. A recent NERC report, *Distributed Energy Resources: Connection, Modeling, and Reliability Considerations*,[21] provides a detailed assessment of DERs and their potential impact on BPS reliability.

**Projection of Distributed Energy Resources**

Figure 17 shows the amount of DERs NERC-wide through 2029. The amount of DERs is projected to more than double by 2029, surpassing 45 GW total capacity.

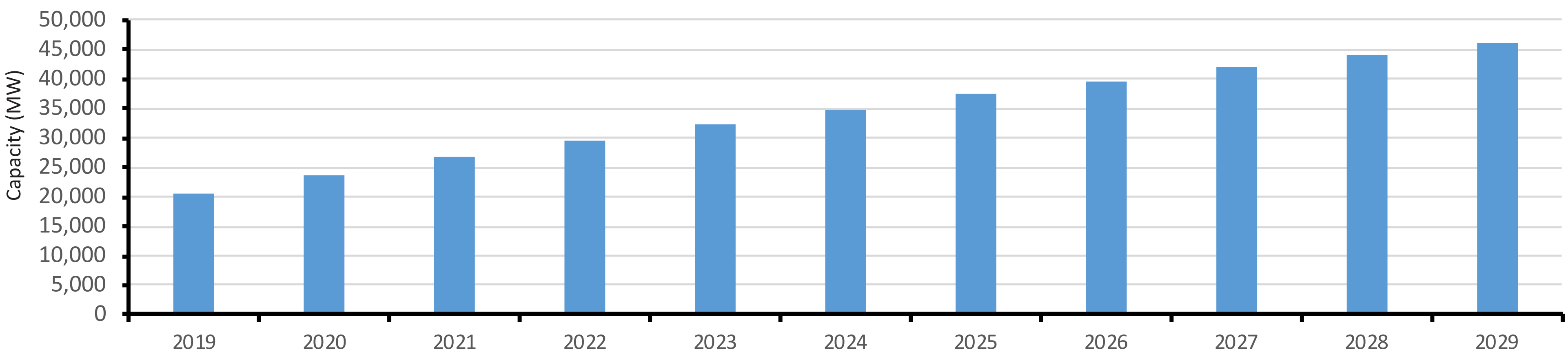



**Figure 17: NERC-Wide Cumulative Distributed Solar PV Capacity—2019 through 2029**

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

Figure 18 shows the amount of DERs by assessment area by 2029. The amount of DERs being installed in WECC-CAMX is far beyond other assessment areas, totaling near 18,000 MW of solar DERs by 2029.

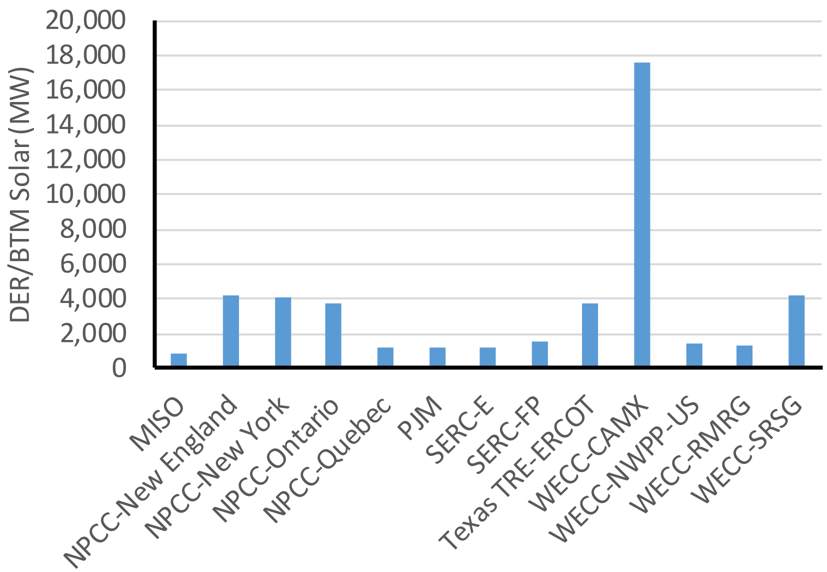



**Figure 18: Solar DER by Assessment Area by 2029**

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

- **NPCC-New England:** To understand the possible impact of a large penetration of renewable and DERs in New England, the Region has conducted studies to simulate hypothetical resource scenarios for the years 2025 and 2030. These studies investigate the challenges of integrating renewable resources and transitioning New England to a hybrid system with decreasing amounts of traditional resources (e.g., coal, oil, and nuclear) and increasing amounts of renewable resources.
- **NPCC-New York:** Currently, DERs may participate in certain New York Independent System Operator (NYISO) energy, ancillary services, and capacity markets. In February 2017, the NYISO published a report providing a roadmap that the NYISO will use over the next three to five years as a framework to develop the market design elements, functional requirements, and tariff language necessary to implement the NYISO's vision to integrate DERs.
- **NPCC-Ontario:** The IESO is working, through the Grid-LDC Interoperability Standing Committee, to increase coordination between the grid operator and embedded resources directly or through integrated operations with local distribution companies with the aim to improve visibility of DERs and identify opportunities for a more coordinated operation of Ontario's electricity system.
- **Texas TRE-ERCOT:** ERCOT initiated several DER programs that have been approved by stakeholders, which were originally identified in the March 2017 ERCOT whitepaper[22] on DER reliability impacts. For example, all existing registered DERs (>1 MW that export to the ERCOT grid) are being mapped in the common information model (CIM) at their load point so that the DER locations will be visible to operators in the ERCOT control room and can be incorporated into the power flow, state estimator, and load forecast programs.
- **WECC:** The impacts of DERs on the individual LSEs are well understood and are in included in local assessments. For example, CAISO has approximately 11,800 MW 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, which reduces the expectations of widespread generation disruptions due to localized weather conditions (overcast skies in Northern California with clear skies in Southern California).[23]

22 March 2017 ERCOT whitepaper on DER reliability impacts: http://www.ercot.com/content/wcm/lists/121384/DERs_Reliability_Impacts_FINAL.pdf

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

**Projection of Electric Storage Capacity**

Energy storage has the potential to offer much needed 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 re-sell the energy during high peak, high cost periods. Storage may also provide ancillary services such as regulation, load following, contingency reserves, and capacity. This is true for both bulk storage, which acts in many ways like a central power plant, and distributed storage technologies.

At the end of 2017, approximately 708 MW of utility-scale storage of differing types,[24] such as batteries, flywheels, and compressed air, was in operation. In California alone, legislation requires investor owned utilities to procure 1,325 MW of energy storage by 2020.[25] A total of 84 different projects across the United States are currently "planned," according to the U.S. Energy Information Administration. Based on the *2019 LTRA*, over 8 GW are currently planned (see **Figure 19**).

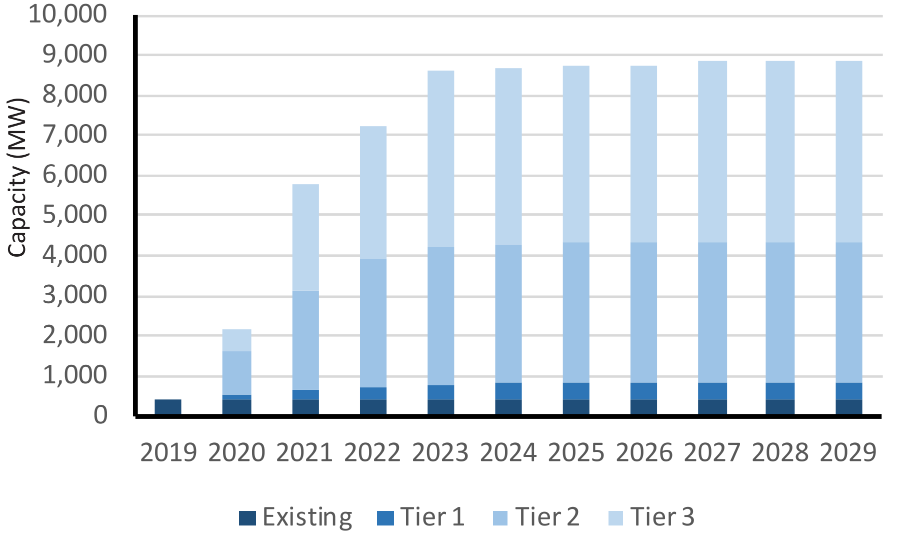



**Figure 19: Total Existing and Planned Nameplate Energy Storage Capacity**

24 This does not include pumped hydro storage.

25 https://www.eia.gov/analysis/studies/electricity/batterystorage/

An illustrative example of the impacts of large amounts of solar on ramping can be found in Figure 20 that 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 (i.e., sun, wind) are not available.

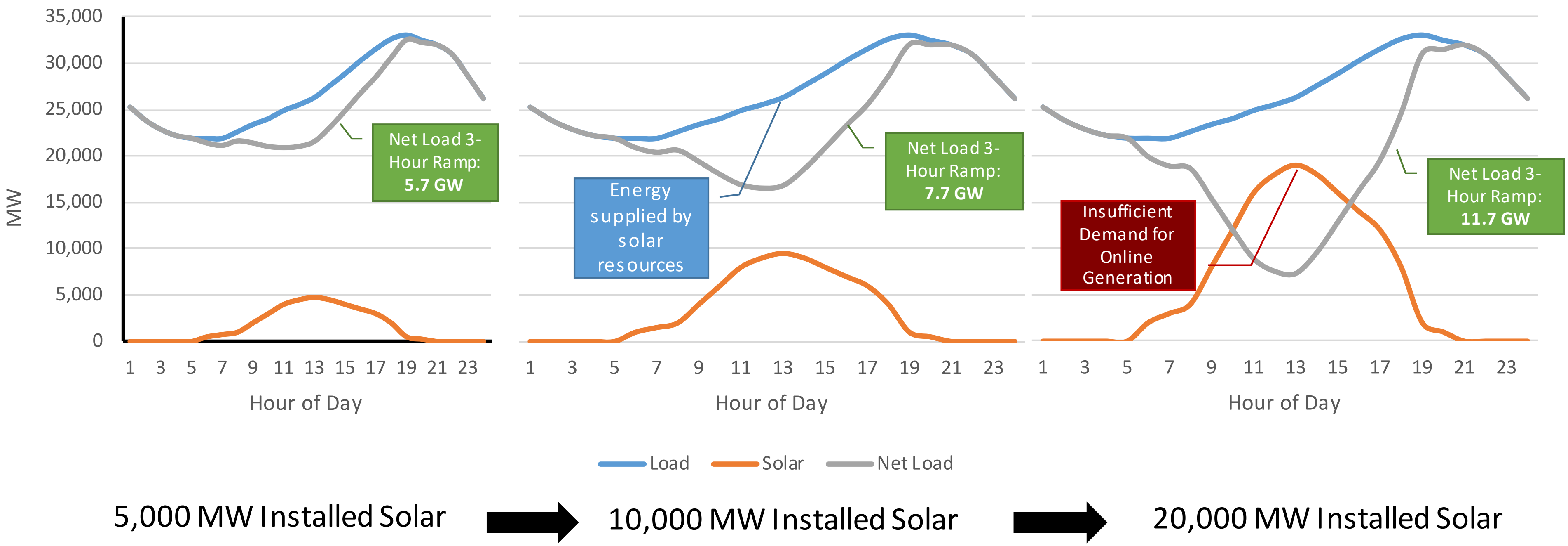



**Figure 20: Example of Increasing Solar Resources Leading to Increased Ramping Requirements**

## Ramping

Ramping is a term used to describe the loading or unloading of generation resources in an effort to balance total generation and load 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, which can be attributed to an increased integration of solar PV DER generation across its footprint. For example, CAISO has approximately 11,800 MW 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, which reduces 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 14 GW. Based on current projections, maximum three-hour upward net-load ramps are projected to exceed 17,000 MW in March by 2021, which is approximately 20% greater than the amount projected for 2018 (see **Figure 21** on the next page). 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 balancing authorities would have to provide the necessary support to balance supply and demand.

Surpassing projections reinforces CAISO's near-term need for access to more flexible resources in their footprint:

- Currently, there are more than 13.3 GW of utility-scale and 8.2 GW of behind-the-meter (BTM) solar PV resources in WECC-CAMX's footprint, which has the most concentrated area of solar PV in North America.
- In March 2018, CAISO set a new ramping record with actual three hour upward net-load ramps reaching 14,777 MW. The maximum one hour net-load upward ramp was 7,545 MW. This record coincided with utility-scale solar PV, serving nearly 50% of the CAISO demand during the same time period.
- BTM solar PV has continued to grow in WECC-CAMX, and the projected BTM solar PV is expected to be 17.5 GW by 2029.


| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2017 (Actual) | 12,378 | 12,659 | 12,733 | 10,939 | 10,591 | 11,774 | 8,403 | 8,706 | 12,108 | 11,949 | 12,591 | 12,981 |
| 2018 (Actual) | 13,326 | 14,440 | 14,777 | 12,553 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2018_Forecast | 13,310 | 13,668 | 13,669 | 12,380 | 10,832 | 11,618 | 8,836 | 9,093 | 12,355 | 12,437 | 13,184 | 14,197 |
| 2019_Forecast | 14,506 | 14,889 | 14,971 | 13,509 | 11,808 | 12,524 | 9,967 | 10,393 | 13,511 | 13,510 | 13,898 | 15,129 |
| 2020_Forecast | 15,784 | 15,877 | 16,110 | 14,664 | 12,762 | 13,404 | 11,187 | 11,823 | 15,024 | 14,791 | 14,993 | 16,057 |
| 2021_Forecast | 16,674 | 16,677 | 17,048 | 15,450 | 13,546 | 13,864 | 11,817 | 12,536 | 15,575 | 15,679 | 15,507 | 16,296 |

**Figure 21: Maximum Three-Hour Ramps in CAISO (Actual and Projected) through 2021**

**Emerging Reliability Considerations**

Increasing amounts of DERs can change how the distribution system interacts with the BPS and will transform the distribution system into an active source for energy and essential reliability services. In certain areas, DERs are being connected on the distribution system at a rapid pace, sometimes with limited coordination between DER installation and BPS planning activities. With the rapid rate of DER installations on distribution systems, it will be necessary for the BPS planning functions to incorporate future DER projections in BPS models. These changes will affect not just the flow of power but also the behavior of the system during disturbances. As more DERs are added, system planners may needed to adapt their protection schemes to account for the changing system characteristics. There are at least two major events that have occurred on the European power system where the disconnection of DERs played a role in system collapse.[26] It is important to coordinate the planning, installation, and operation of DERs in relation to the BPS as transition to a new resource mix occurs. Specific emerging reliability considerations include the following:

- **Accommodating Large Amounts of DERs:** Today, the effect of aggregated DERs is not fully represented in BPS models and operating tools. This could result in unanticipated power flows and increased demand forecast errors. An unexpected loss of aggregated DERs could also cause frequency and voltage instability at sufficient DER penetrations. The system operator typically cannot observe or control DERs, so variable output from DERs can contribute to ramping and system balancing challenges. Overall, reliability risks concerning larger penetrations of DERs can be summarized by three major aspects:
  - Difficulty in obtaining and managing the amount of data concerning DERs, including their size, location, and operational characteristics
  - A current inability to observe and control most DERs in real time
  - A need to better understand the impacts on system operations of the increasing amounts of DERs, including ramping, reserve, frequency response, and regulation requirements
- **Accommodating Large Amounts of Bulk Electric Storage Systems (BESSs):** In addition to the potential safety issues of the devices themselves, BESSs introduce unique characteristics into the operation of the BPS. As BESSs do not convert fuel into electricity, it requires electricity for its charging that later is injected into the system. This appears as a demand on the rest of the system. In large penetrations, the energy for charging may not be available, and the state of charge for these resources may not be sufficient to perform when called upon. Coupled with the increasing penetrations of DERs and VERs, planning and operations need to enhance visibility and probabilistic forecasting and modelling.

## Recommendations

**The ERO and industry need to work together to ensure system studies incorporate DER impacts.**

As the penetration of DERs continues to increase across the North American BPS, it is necessary to account for DERs in the planning, operation, and design of the BPS. System operators and planners should gather data as early as possible about the aggregate technical specifications of DERs connected to local distribution grids to ensure accurate and valid system planning device and simulation models, load forecasting, coordinated system protection, and real-time situation awareness. In areas with large or emerging DER penetrations, current operational models and system studies do not properly account for DERs. These models and studies will need to be improved to accurately represent the system's behavior.

**The ERO should assess the implications of electricity storage on BPS planning and operations.**

Electricity storage has the potential to offer much needed capabilities to the grid of the future. Based on data received in the resource information collected to support this assessment, there will be an increase of BPS-connected storage in the future; this may even be accelerated if the conditions are right. Before this storage is built and integrated into the BPS, the ERO should identify, assess, and report on the risks and potential mitigation approaches to accommodate large amounts of energy storage on BPS reliability.

26 See **Italy Blackout 2003** and **European Blackout 2006** for more information.

## Key Finding 4: Transmission Planning and Infrastructure Ddevelopment Need to Keep Pace with an Increasing Amount of Utility Scale Wind and Solar Resources.

### Key Points

- Under 15,000 circuit miles of new transmission is expected over the next 6 years, considerably less than the nearly 40,000 circuit miles earlier this decade.
- Many new VERs will be located in areas remote from demand centers and existing transmission infrastructure.

The existing electric transmission systems and planned additions over the next 10 years appear adequate to reliably meet customer electricity requirements. However, less and shorter lines are being constructed at a time when more and longer transmission is needed to accommodate large amounts of wind and solar resources. While a lack of future transmission projects does not currently pose a reliability concern, the importance of a secure transmission system is amplified when considering the significant addition of variable generation resources, continuing retirement of conventional and nuclear generation, and increased demand projections throughout North America in the assessment's 10-year horizon.

### Transmission Projects

Figure 22 shows the historical 10-year transmission projections for the past 10 years, each year being a 10-year projection. Between the years 2010 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 18,000 circuit miles of planned transmission for the next 10 years. Whether the planned transmission lines were actually constructed was not determined.

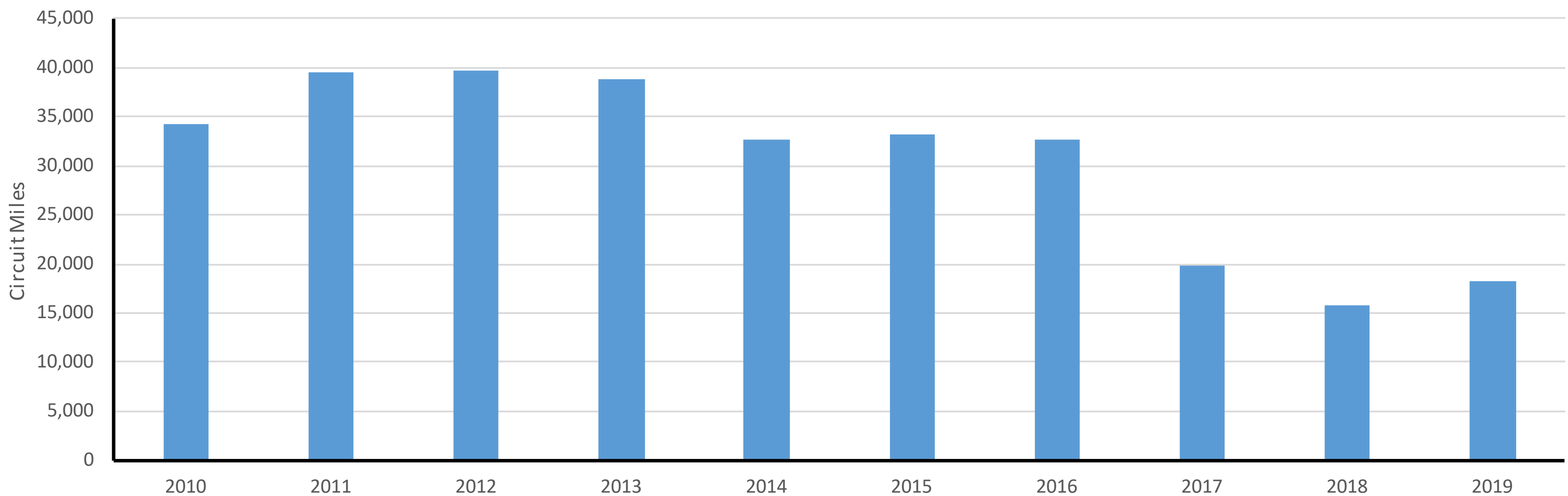



**Figure 22: Historical 10-Year Transmission Projections**

### 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 power-flow model and cannot be categorized as "Under Construction" or "Planned"
- Other projected lines that do not meet requirements of "Under Construction" or "Planned"

As part of the ERO assessment, information about future transmission projects is evaluated. **Figure 23** highlights the transmission additions during the 10-year period include plans for over 18,000 circuit miles, including conceptual projects. 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 2010–2016 (see **Figure 22** on previous page).

**Figure 24** 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.

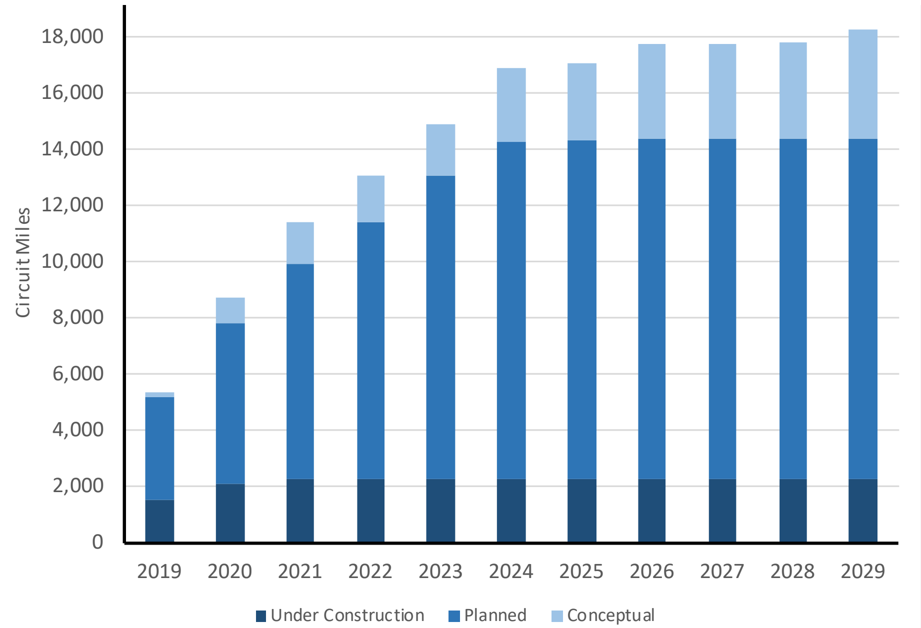



**Figure 23: Cumulative 10-Year Projection of Planned Transmission**

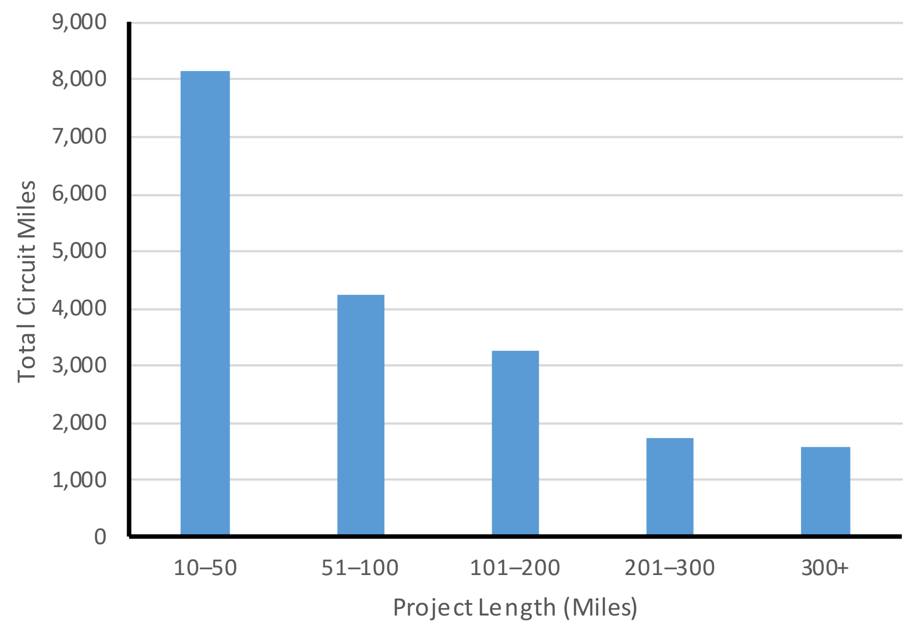



**Figure 24: Line Miles Projected through 2029**

**Emerging Reliability Considerations**

Additional transmission infrastructure is therefore vital to reliably accommodating large amounts of wind and solar resources, specifically in order to interconnect VERs planned in remote areas as well as to smooth the variable generation output across a broad geographical area and resource portfolio and deliver ramping capability and ancillary services from inside and outside a balancing area to equalize supply and demand.

## Recommendation

**In future assessments, the ERO should review challenges in transmission development and reliability risks due to the changing resource mix.**

To accommodate large amounts of variable generation and to meet policy objectives associated with renewables in a reliable and economic manner, more transmission may be needed. For example, to meet the renewable energy requirements, transmission may be required to ensure that transfer of large amounts of energy can be supported when it becomes available. The ERO should assess and evaluate if the decreasing amount of transmission projects presents any future reliability risks or concerns.

# Demand, Resources, Reserve Margins, and Transmission

## Demand Projections

NERC-wide electricity peak demand and energy growth rates are up for the first in nearly 20 years, reaching its peak decline last year. The 2019 through 2029 aggregated projections of summer peak demand NERC-wide are slightly higher than last year's projection. A comparison of this year's 10-year forecasted growth to last year's 10-year forecasted growth indicates that peak demand is roughly flat for North America as a whole.

Figure 25 identifies the 10-year compound annual growth rate (CAGR) of peak demand that is increasing this year from the prior year—the lowest year on record. The projected 10-year energy growth rate is 0.60% per year compared to more than 1.48% just a decade earlier (Figure 26).

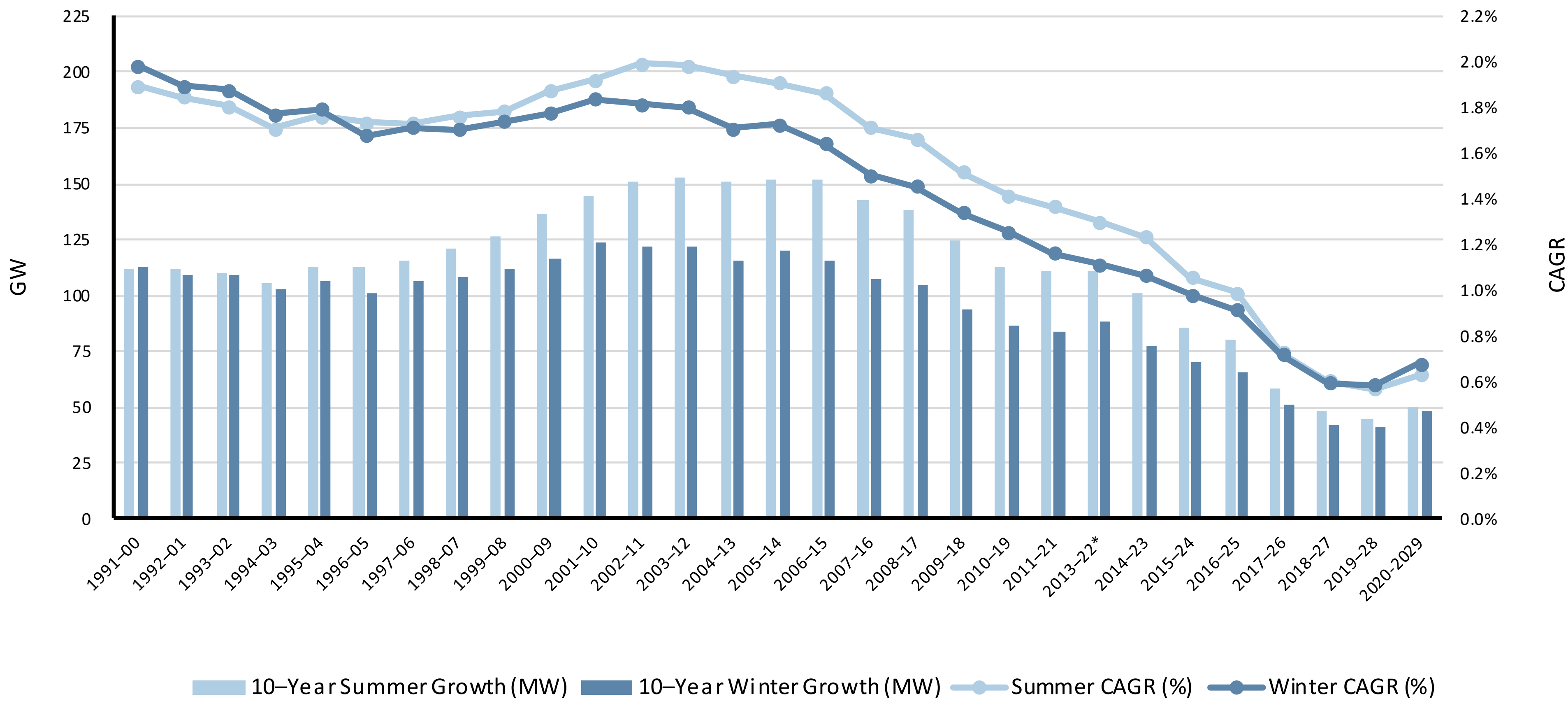



**Figure 25: 10-Year Summer and Winter Peak Demand Growth and Rate Trends**

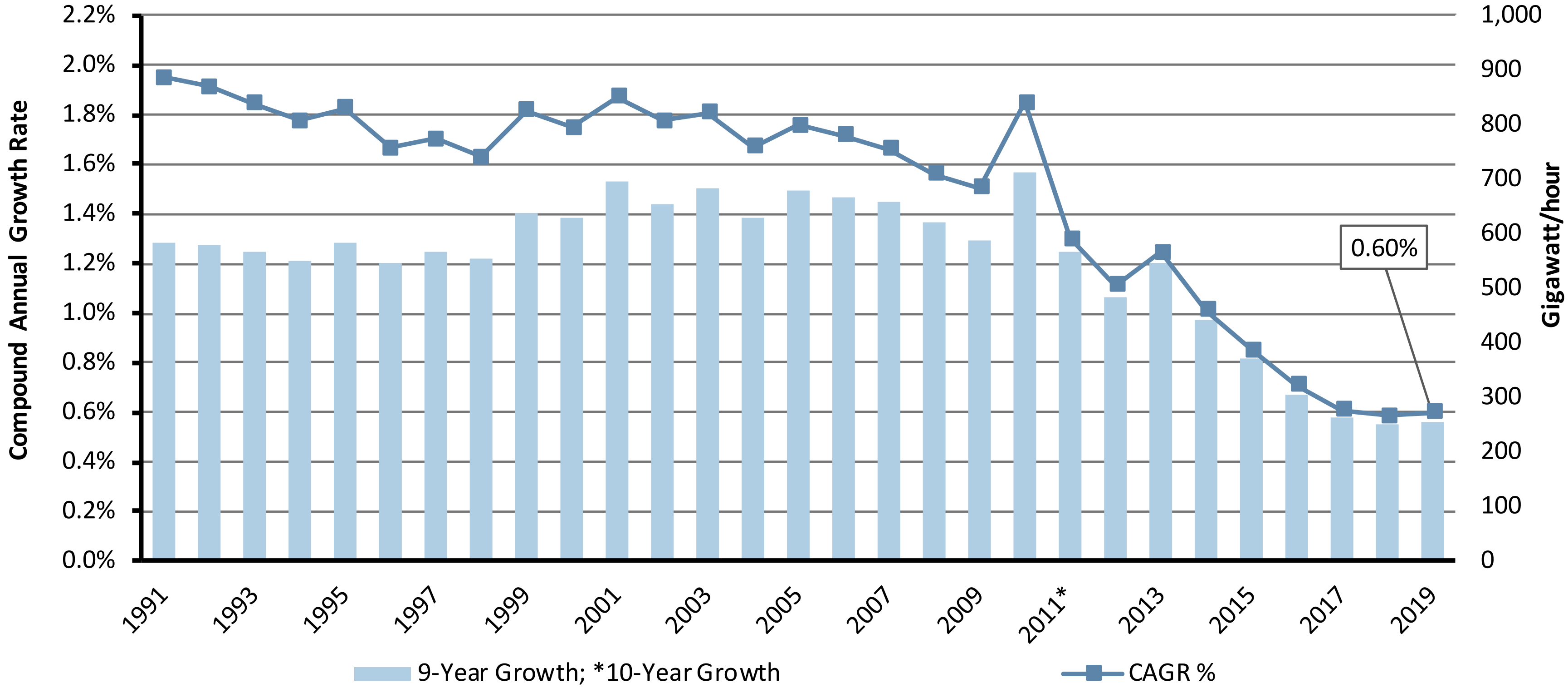



**Figure 26: 10-Year Net Energy to Load Growth and Rate Trends**

**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 electric 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 forecasts 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 internal electricity demands that have already been reduced to reflect the effects of demand-side management 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. 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, dispatchable and controllable DRs are included in net internal demand.

The 10-year demand growth rate in all assessment areas is 2% or less per year with three assessment areas projecting reductions in peak demand (**Figure 27**).

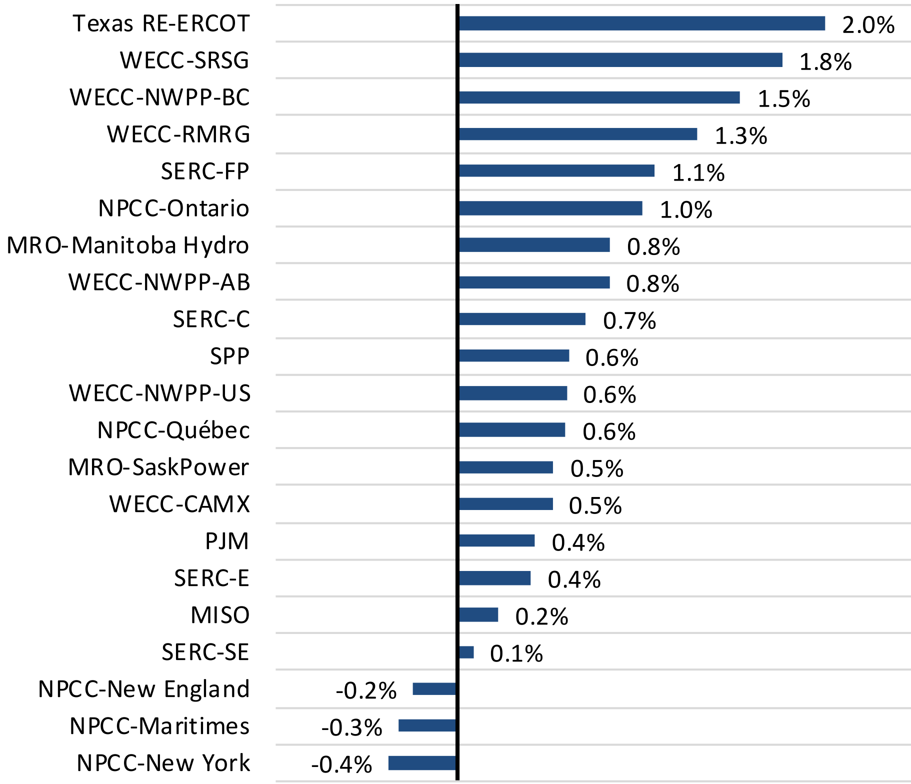
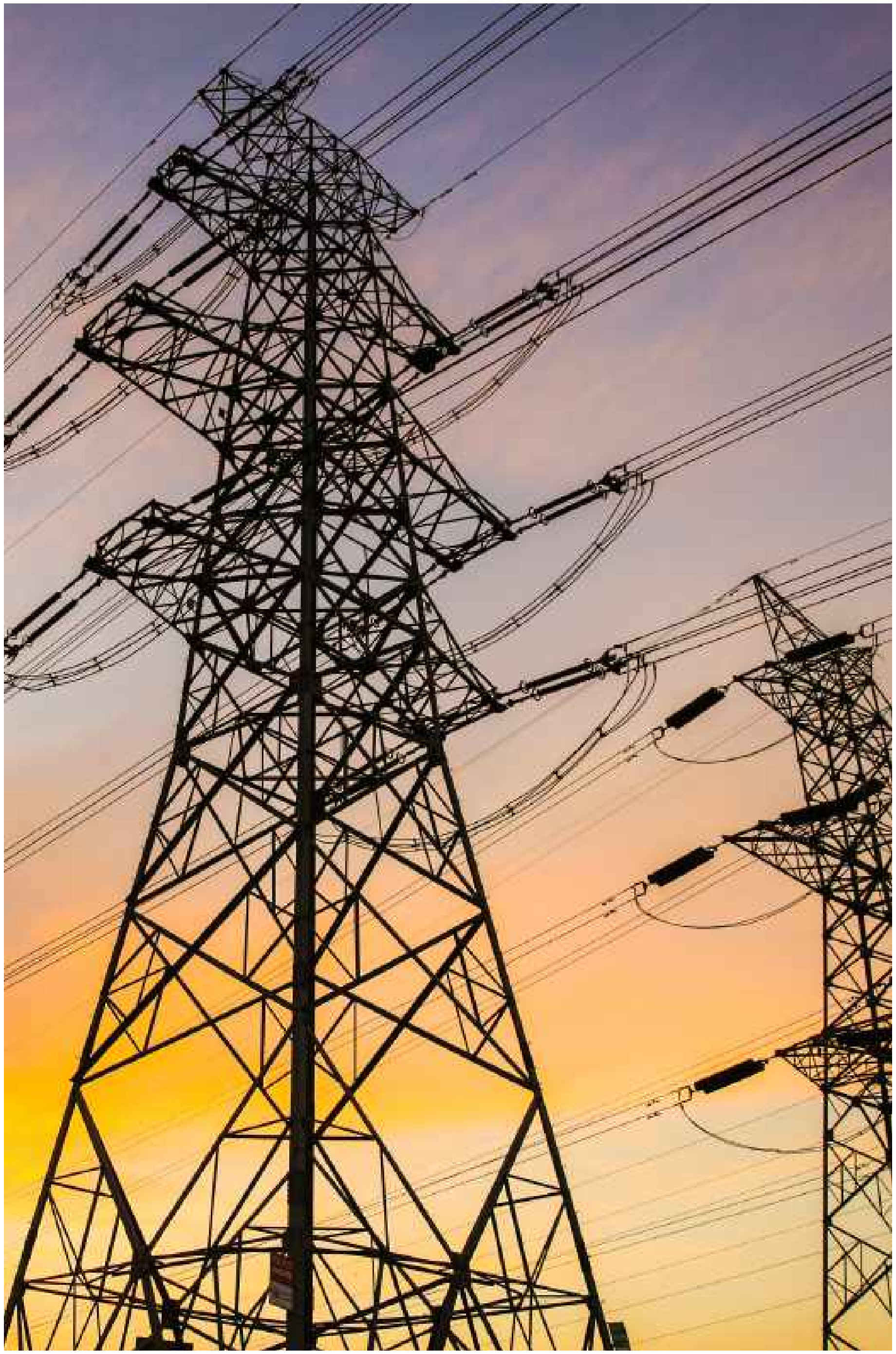



**Figure 27: Annual Peak Demand Growth Rate for 10-Year Period by Assessment Area**

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. Thirty states in the United States have adopted EE policies that are contributing to reduced peak demand and overall energy use.[27] Additionally, DERs and other behind-the meter resources continue to increase and reduce the net demand for the BPS even further.

The PRMs for the years 2020–2024 are shown in **Table 3**. **Table 4** shows the Reference Margin Levels for each assessment area.



27 EIA - Today in Energy: Many states have adopted policies to encourage energy efficiency.

## Reserve Margin Projections

**Table 3: Planning Reserve Margin Years 2020–2024**

| Assessment Area | Reserve Margins (%) | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|
| MISO | Anticipated Reserve Margin | 22.5% | 19.8% | 18.7% | 18.1% | 17.5% |
| | Prospective Reserve Margin | 20.8% | 20.0% | 26.3% | 45.5% | 53.5% |
| | Reference Margin Level | 16.8% | 16.8% | 16.8% | 16.8% | 16.8% |
| MRO-Manitoba | Anticipated Reserve Margin | 12.7% | 15.8% | 24.8% | 22.6% | 17.6% |
| | Prospective Reserve Margin | 14.0% | 17.1% | 22.0% | 19.8% | 15.0% |
| | Reference Margin Level | 12.0% | 12.0% | 12.0% | 12.0% | 12.0% |
| MRO-SaskPower | Anticipated Reserve Margin | 23.3% | 23.1% | 19.8% | 15.8% | 16.6% |
| | Prospective Reserve Margin | 23.3% | 23.1% | 21.1% | 15.1% | 16.0% |
| | Reference Margin Level | 11.0% | 11.0% | 11.0% | 11.0% | 11.0% |
| NPCC-Maritimes | Anticipated Reserve Margin | 22.4% | 22.2% | 21.3% | 25.3% | 26.0% |
| | Prospective Reserve Margin | 25.3% | 22.3% | 21.4% | 25.4% | 24.3% |
| | Reference Margin Level | 20.0% | 20.0% | 20.0% | 20.0% | 20.0% |
| NPCC-New England | Anticipated Reserve Margin | 32.2% | 31.7% | 30.5% | 26.7% | 27.3% |
| | Prospective Reserve Margin | 34.7% | 35.6% | 37.3% | 36.7% | 38.3% |
| | Reference Margin Level | 18.5% | 18.0% | 17.8% | 17.8% | 17.8% |
| NPCC-New York | Anticipated Reserve Margin | 25.3% | 22.7% | 23.0% | 24.6% | 25.3% |
| | Prospective Reserve Margin | 26.2% | 25.6% | 26.0% | 29.2% | 30.0% |
| | Reference Margin Level | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% |
| NPCC-Ontario | Anticipated Reserve Margin | 31.8% | 30.1% | 24.4% | 15.3% | 17.3% |
| | Prospective Reserve Margin | 31.8% | 30.1% | 24.4% | 15.3% | 17.3% |
| | Reference Margin Level | 26.4% | 23.4% | 23.3% | 24.7% | 20.1% |
| NPCC-Quebec | Anticipated Reserve Margin | 13.1% | 13.5% | 13.3% | 14.3% | 13.7% |
| | Prospective Reserve Margin | 16.0% | 16.5% | 16.3% | 17.3% | 16.7% |
| | Reference Margin Level | 12.8% | 12.8% | 12.8% | 12.8% | 12.8% |
| PJM | Anticipated Reserve Margin | 39.4% | 39.3% | 35.3% | 34.8% | 34.3% |
| | Prospective Reserve Margin | 50.2% | 55.9% | 64.9% | 68.1% | 70.0% |
| | Reference Margin Level | 15.9% | 15.8% | 15.7% | 15.7% | 15.7% |
| SERC-C | Anticipated Reserve Margin | 39.8% | 36.2% | 35.1% | 34.7% | 32.0% |
| | Prospective Reserve Margin | 46.3% | 42.6% | 41.5% | 41.1% | 38.4% |
| | Reference Margin Level | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% |
| SERC-E | Anticipated Reserve Margin | 24.1% | 24.6% | 25.6% | 24.9% | 28.1% |
| | Prospective Reserve Margin | 24.2% | 24.7% | 25.7% | 25.0% | 28.2% |
| | Reference Margin Level | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% |
| SERC-FP | Anticipated Reserve Margin | 25.3% | 24.3% | 24.9% | 26.2% | 25.3% |
| | Prospective Reserve Margin | 25.9% | 24.9% | 25.5% | 26.7% | 25.8% |
| | Reference Margin Level | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% |
| SERC-SE | Anticipated Reserve Margin | 34.3% | 33.9% | 35.5% | 37.3% | 36.5% |
| | Prospective Reserve Margin | 35.0% | 35.9% | 37.7% | 39.4% | 38.7% |
| | Reference Margin Level | 15.0% | 15.0% | 15.0% | 15.0% | 15.0% |
| SPP | Anticipated Reserve Margin | 28.7% | 26.5% | 25.9% | 24.5% | 23.0% |
| | Prospective Reserve Margin | 27.7% | 25.4% | 24.9% | 23.5% | 22.0% |
| | Reference Margin Level | 12.0% | 12.0% | 12.0% | 12.0% | 12.0% |
| TRE-ERCOT | Anticipated Reserve Margin | 10.2% | 15.5% | 13.0% | 10.3% | 7.8% |
| | Prospective Reserve Margin | 18.7% | 42.9% | 47.2% | 44.2% | 41.0% |
| | Reference Margin Level | 13.8% | 13.8% | 13.8% | 13.8% | 13.8% |
| WECC-AB | Anticipated Reserve Margin | 23.9% | 27.2% | 22.7% | 21.5% | 20.9% |
| | Prospective Reserve Margin | 26.6% | 30.0% | 25.3% | 24.1% | 23.5% |
| | Reference Margin Level | 10.4% | 10.4% | 10.3% | 10.2% | 10.1% |
| WECC-BC | Anticipated Reserve Margin | 16.2% | 15.9% | 14.7% | 14.6% | 14.8% |
| | Prospective Reserve Margin | 16.2% | 15.9% | 14.7% | 14.6% | 14.8% |
| | Reference Margin Level | 10.4% | 10.4% | 10.3% | 10.2% | 10.1% |
| WECC-CAMX | Anticipated Reserve Margin | 17.2% | 17.0% | 15.6% | 15.4% | 15.7% |
| | Prospective Reserve Margin | 21.0% | 20.8% | 19.4% | 19.1% | 19.4% |
| | Reference Margin Level | 13.7% | 13.9% | 13.9% | 13.8% | 13.9% |
| WECC-NWPP-US | Anticipated Reserve Margin | 23.2% | 23.1% | 22.1% | 22.2% | 22.1% |
| | Prospective Reserve Margin | 23.4% | 23.3% | 22.3% | 22.5% | 22.4% |
| | Reference Margin Level | 15.7% | 15.7% | 16.0% | 15.9% | 15.8% |
| WECC-RMRG | Anticipated Reserve Margin | 25.8% | 23.8% | 22.4% | 18.3% | 16.7% |
| | Prospective Reserve Margin | 25.8% | 25.4% | 23.9% | 21.4% | 19.8% |
| | Reference Margin Level | 13.0% | 12.0% | 12.3% | 12.5% | 12.4% |
| WECC-SRSG | Anticipated Reserve Margin | 20.5% | 17.7% | 17.1% | 16.8% | 14.5% |
| | Prospective Reserve Margin | 21.3% | 18.8% | 18.2% | 19.6% | 17.2% |
| | Reference Margin Level | 10.0% | 11.0% | 11.0% | 11.0% | 11.0% |

| Table 4: Reference Margin Levels for Each Assessment Area (2020–2024) | | | | | |
|---|---|---|---|---|---|
| Assessment Area | Reference Margin Level | Assessment Area Terminology | Requirement? | Methodology | Reviewing or Approving Body |
| **MISO** | 17.1% | Planning Reserve Margin | Yes: Established Annually[28] | 0.1/Year LOLE | MISO |
| **MRO-Manitoba Hydro** | 12% | Reference Margin Level | No | 0.1/Year LOLE/LOEE/ LOLH/EUE | Reviewed by the Manitoba Public Utilities Board |
| **MRO-SaskPower** | 11% | Reference Margin Level | No | EUE and Deterministic Criteria | SaskPower |
| **NPCC-Maritimes** | 20%[29] | Reference Margin Level | No | 0.1/Year LOLE | Maritimes Subareas; NPCC |
| **NPCC-New England** | 17.8–18.5% | Installed Capacity Requirement | Yes: three year requirement established annually | 0.1/Year LOLE | ISO-NE; NPCC Criteria |
| **NPCC-New York** | 15%[30] | Installed Reserve Margin | Yes: one year requirement; established annually by NYSRC based on full installed capacity values of resources | 0.1/Year LOLE | NYSRC; NPCC Criteria |
| **NPCC-Ontario** | 18%–25% | Ontario Reserve Margin Requirement | Yes: established annually for all years | 0.1/Year LOLE | IESO; NPCC Criteria |
| **NPCC-Québec** | 12.9% | Reference Margin Level | No: established Annually | 0.1/Year LOLE | Hydro Québec; NPCC Criteria |
| **PJM** | 16.6%–16.7% | Installed Reserve Margin | Yes: established Annually for each of three future years | 0.1/Year LOLE | PJM Board of Managers; Reliability*First* BAL-502-RFC-02 Standard |
| **SERC-E** | 15% | Reference Margin Level | No: NERC-Applied 15% | SERC Performs 0.1/Year LOLE | Reviewed by Member Utilities |
| **SERC-FP** | 15%[31] | Reliability Criterion | No: Guideline | 0.1/Year LOLP | Florida Public Service Commission |
| **SERC-C** | 15% | Reference Margin Level | No: NERC-Applied 15% | SERC Performs 0.1/Year LOLE | Reviewed by Member Utilities |
| **SERC-SE** | 15%[32] | Reference Margin Level | No: NERC-Applied 15% | SERC Performs 0.1/Year LOLE | Reviewed by Member Utilities |

28 In MISO, the states can override the MISO Planning Reserve Margin.

29 The 20% Reference Margin Level 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.

30 The NERC Reference Margin Level for NY is 15%. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. However, New York requires load serving entities to procure capacity for their loads equal to their peak demand plus an 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 approved the 2019–2020 IRM at 17.0%.

31 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.

32 SERC does not provide Reference Margin Levels or resource requirements for its subregions. However, SERC members perform individual assessments to comply with any state requirements.

| Table 4: Reference Margin Levels for Each Assessment Area (2020–2024) | | | | | |
|---|---|---|---|---|---|
| Assessment Area | Reference Margin Level | Assessment Area Terminology | Requirement? | Methodology | Reviewing or Approving Body |
| **SPP** | 12% | Resource Adequacy Requirement | Yes: studied on Biennial Basis | 0.1/Year LOLE | SPP RTO Staff and Stakeholders |
| **TRE-ERCOT** | 13.75% | Target Reserve Margin | No | 0.1/Year LOLE plus adjustment for non-modeled market considerations | ERCOT Board of Directors |
| **WECC-AB** | 11.03%–11.22% | Reference Margin Level | No: Guideline | Based on a conservative .02% threshold | WECC |
| **WECC-BC** | 10.60%–12.10% | Reference Margin Level | No: Guideline | Based on a conservative .02% threshold | WECC |
| **WECC-CAMX**[33] | 14.76%–16.14% | Reference Margin Level | No: Guideline | Based on a conservative .02% threshold | WECC |
| **WECC-NWPP-US** | 16.38%–17.46% | Reference Margin Level | No: Guideline | Based on a conservative .02% threshold | WECC |
| **WECC-RMRG** | 11.65%–14.17% | Reference Margin Level | No: Guideline | Based on a conservative .02% threshold | WECC |
| **WECC-SRSG** | 12.02%–15.83% | Reference Margin Level | No: Guideline | Based on a conservative .02% threshold | WECC |

33 California is the only state in the Western Interconnection that has a wide-area Planning Reserve Margin, currently 15%.

## Transmission

Figure 28 highlights that ERO-wide transmission additions during the 10-year period include plans for over 18,000 circuit miles. NERC continues to monitor the progress of transmission projects across North America.

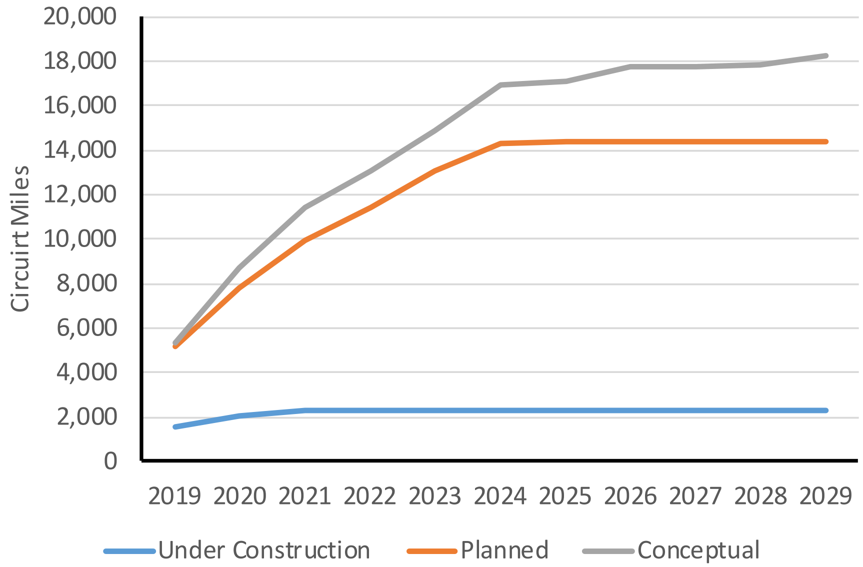



**Figure 28: Future Transmission Circuit Miles >100 kV by Project Status**

Figure 29 shows the future transmission circuit miles by voltage class.

Figure 30 shows the percentage of future transmission circuit miles by primary driver. According to industry, new transmission projects are being driven primarily to enhance reliability. Other reasons include congestion alleviation and integration of renewables. The breakdown of reasons for future transmission projects through 2029 are shown in Figure 30. As expected, most of the lines are coming in to address reliability, approximately 60%. Renewable integration will account for 1,400 miles of planned transmission.

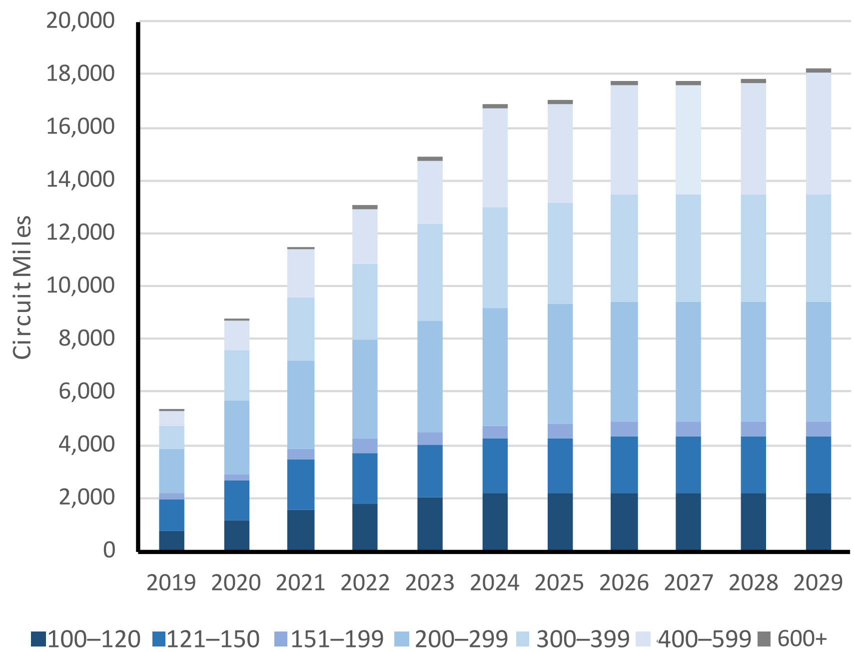



**Figure 29: Future Transmission Circuit Miles >100 kV by Voltage Class**

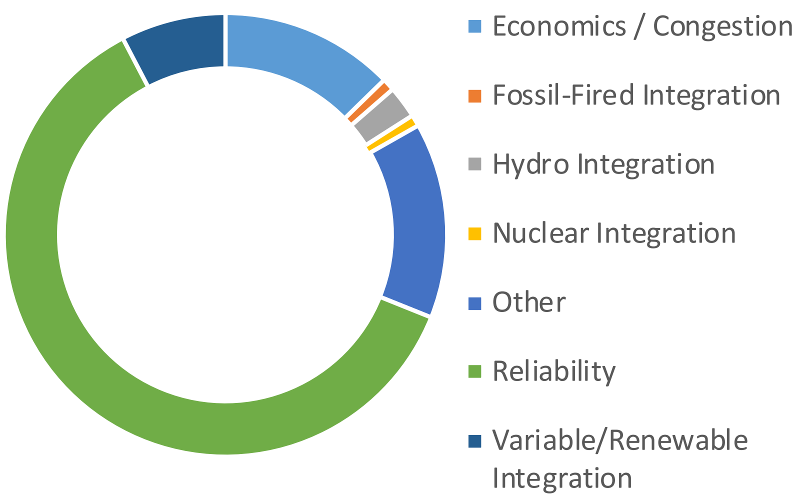



**Figure 30: Future Transmission Circuit Miles by Primary Driver**

**Figure 31** shows the assessment areas as net importers or exporters for the year 2020 at the time of their seasonal peak. Net importers are shown in gold and net exporters are shown in blue. The grey assessment areas are below 100 MW of capacity imported or exported for 2020.

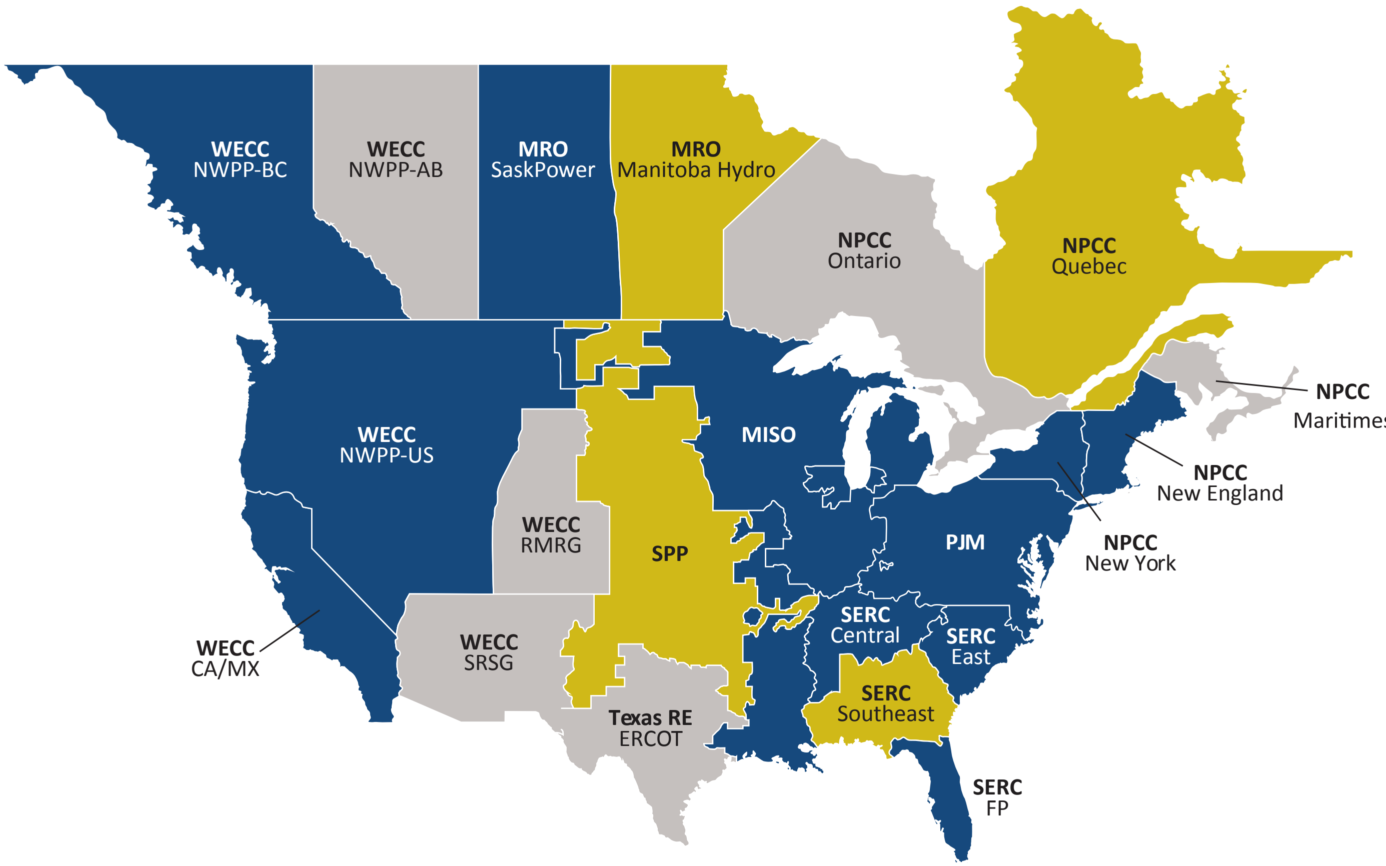



**Figure 31: Net Transfers**

**Table 5** shows the percent of the reserve margin that is supported by net transfers. If an assessment area has a negative percentage, it is a net exporter. Conversely, if an assessment area has a positive percentage, it is a net importer.

| Table 5: Net Transfers by Assessment Area | | | | | |
|---|---|---|---|---|---|
| **Assessment Area** | **Peak Demand (MW)** | **Firm Net Transfers (MW)** | **Reserve Margin (MW)** | **Percent of Reserve Margin** | **ACR** |
| **MISO** | 120,107 | 575 | 21,055 | 2.73% | 141,162 |
| **MRO-Manitoba Hydro** | 4,757 | (488) | 839 | -58.15% | 5,597 |
| **MRO-SaskPower** | 3,883 | 100 | 646 | 15.48% | 4,529 |
| **NPCC-Maritimes** | 5,300 | - | 1,380 | 0.00% | 6,680 |
| **NPCC-New England** | 23,697 | 81 | 6,479 | 1.25% | 30,176 |
| **NPCC-New York** | 30,618 | 1,939 | 7,745 | 25.04% | 38,363 |
| **NPCC-Ontario** | 22,333 | - | 3,868 | 0.00% | 26,202 |
| **NPCC-Quebec** | 37,081 | (145) | 5,082 | -2.85% | 42,163 |
| **PJM** | 144,192 | - | 49,417 | 0.00% | 193,609 |
| **SERC-C** | 40,053 | 361 | 12,836 | 2.81% | 52,889 |
| **SERC-E** | 45,083 | 530 | 12,681 | 4.18% | 57,764 |
| **SERC-FP** | 47,015 | 1,132 | 20,555 | 5.51% | 67,570 |
| **SERC-SE** | 45,909 | (2,237) | 16,762 | -13.34% | 62,671 |
| **SPP** | 54,011 | (96) | 12,448 | -0.77% | 66,458 |
| **TRE-ERCOT** | 81,891 | 50 | 6,401 | 0.78% | 88,292 |
| **WECC-AB** | 12,321 | - | 2,575 | 0.00% | 14,896 |
| **WECC-BC** | 12,430 | 410 | 1,837 | 22.32% | 14,267 |
| **WECC-CAMX** | 54,835 | 2,020 | 8,586 | 23.53% | 63,421 |
| **WECC-NWPP US** | 52,315 | 2,496 | 11,575 | 21.56% | 63,890 |
| **WECC-RMRG** | 13,413 | - | 2,246 | 0.00% | 15,659 |
| **WECC-SRSG** | 26,371 | 1,480 | 3,817 | 38.78% | 30,187 |

## Regional Assessments

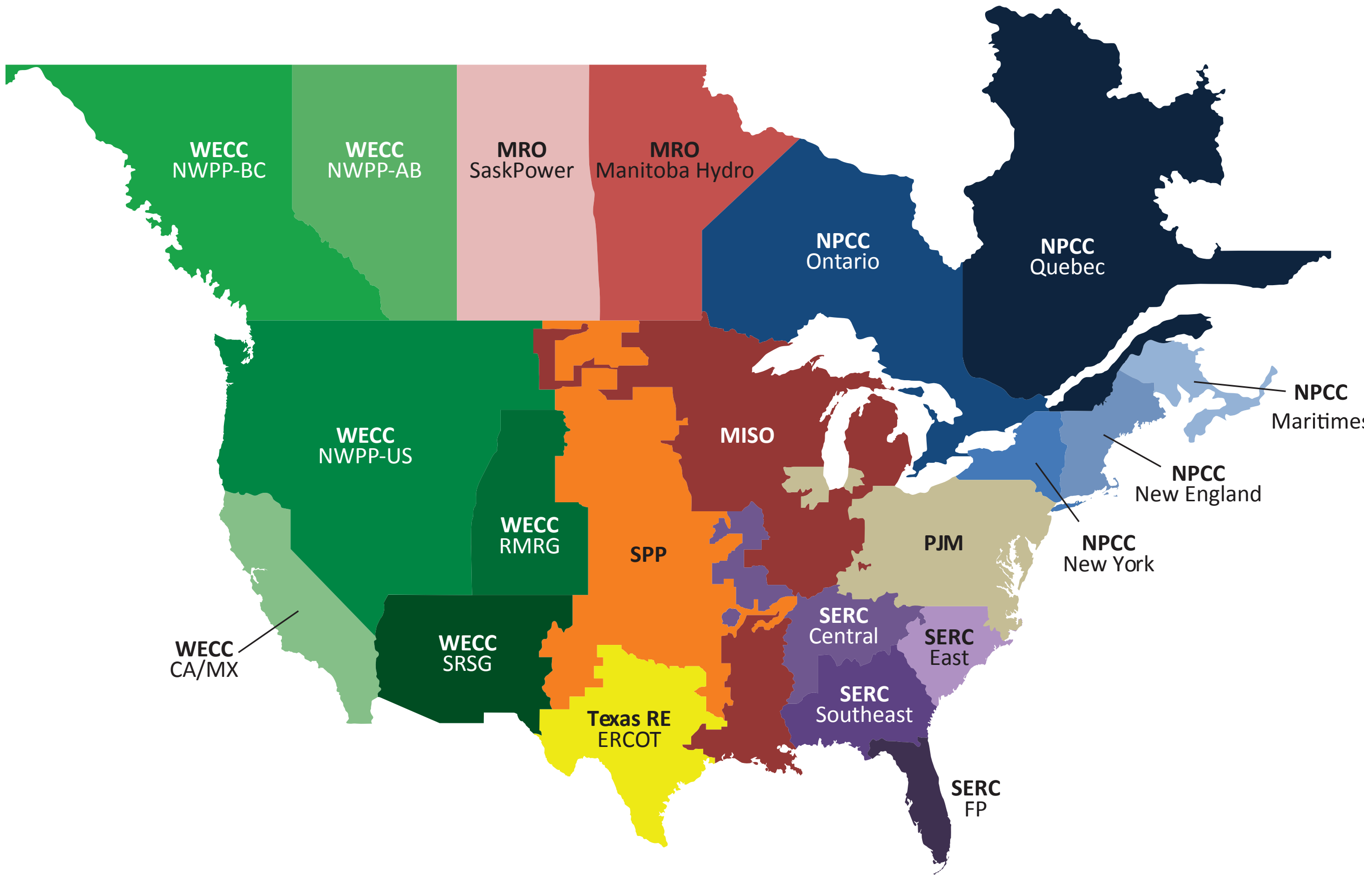
The following regional assessments were developed based on data and narrative information collected by NERC from the REs on an assessment area basis. The RAS, at the direction of NERC's PC, supported the development of this assessment through a comprehensive and transparent peer review process that leveraged 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 6**.

**Table 6: Summary of 2024 Peak Projections by Assessment Area and Interconnection**

| | Net Internal Demand (MW) | Annual Net Energy for Load (GWh) | Net Transfers (MW) | Anticipated Capacity Resources | Anticipated Reserve Margin |
|---|---|---|---|---|---|
| MISO | 120,107 | 647,218 | 575 | 141,162 | 17.5% |
| MRO-Manitoba | 4,757 | 26,219 | -488 | 5,597 | 17.6% |
| MRO-Sask | 3,883 | 27,142 | 100 | 4,529 | 16.6% |
| NPCC-Maritimes | 5,300 | 27,853 | 0 | 6,680 | 26.0% |
| NPCC-New England | 23,697 | 120,544 | 81 | 30,176 | 27.3% |
| NPCC-New York | 30,618 | 153,386 | 1,939 | 38,363 | 25.3% |
| NPCC-Ontario | 22,333 | 139,912 | 0 | 26,202 | 17.3% |
| PJM | 144,192 | 818,958 | 0 | 193,609 | 34.3% |
| SERC-C | 40,053 | 219,670 | 361 | 52,889 | 32.0% |
| SERC-E | 45,083 | 220,329 | 530 | 57,764 | 28.1% |
| SERC-FP | 47,015 | 242,808 | 1,132 | 67,570 | 43.7% |
| SERC-SE | 45,909 | 250,604 | -2,237 | 62,671 | 36.5% |
| SPP | 54,011 | 284,631 | -96 | 66,458 | 23.0% |
| WECC-AB | 12,321 | 89,223 | 0 | 14,896 | 20.9% |
| WECC-BC | 12,430 | 68,275 | 410 | 14,267 | 14.8% |
| WECC-CAMX | 54,835 | 273,162 | 2,020 | 63,421 | 15.7% |
| WECC-NWPP US | 52,315 | 311,394 | 2,496 | 63,890 | 22.1% |
| WECC-RMRG | 13,413 | 76,710 | 0 | 15,659 | 16.7% |
| WECC-SRSG | 26,371 | 123,140 | 1,480 | 30,187 | 14.5% |
| EASTERN INTERCONNECTION | 586,960 | 3,179,273 | 1,897 | 753,671 | N/A |
| QUEBEC INTERCONNECTION | 37,081 | 200,604 | -145 | 42,163 | 13.7% |
| TEXAS INTERCONNECTION | 81,891 | 450,426 | 50 | 88,292 | 7.8% |
| WESTERN INTERCONNECTION | 171,685 | 941,904 | 6,406 | 202,320 | N/A |

## NERC Assessment Areas

In order to conduct NERC reliability assessments, NERC further divides the Regional Entities into 21 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.




**MRO—Midwest Reliability Organization**
- MRO-SaskPower
- MRO-Manitoba Hydro
- MISO

**SPP—Southwest Power Pool**
- SPP

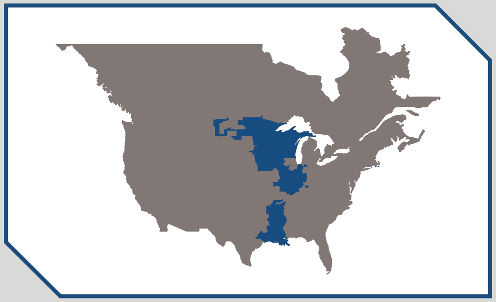
**Texas RE—Texas Reliability Entity**
- ERCOT

**NPCC—Northeast Power Coordinating Council**
- NPCC-New England
- NPCC-Maritimes
- NPCC-New York
- NPCC-Ontario
- NPCC-Québec

**RF—ReliabilityFirst**
- PJM

**WECC—Western Electricity Coordinating Council**
- WECC-BC
- WECC-AB
- WECC-RMRG
- WECC-CA/MX
- WECC-SRSG
- WECC-NWPP-US

**SERC—SERC Reliability Corporation**
- SERC-East
- SERC-Central
- SERC-Southeast
- SERC-FP

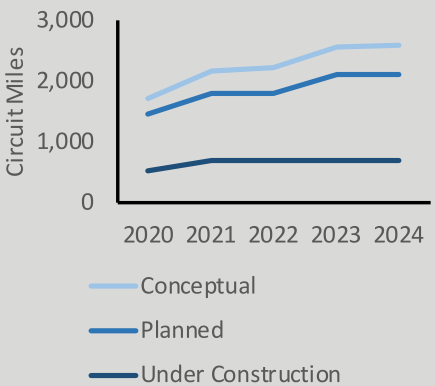


## MISO

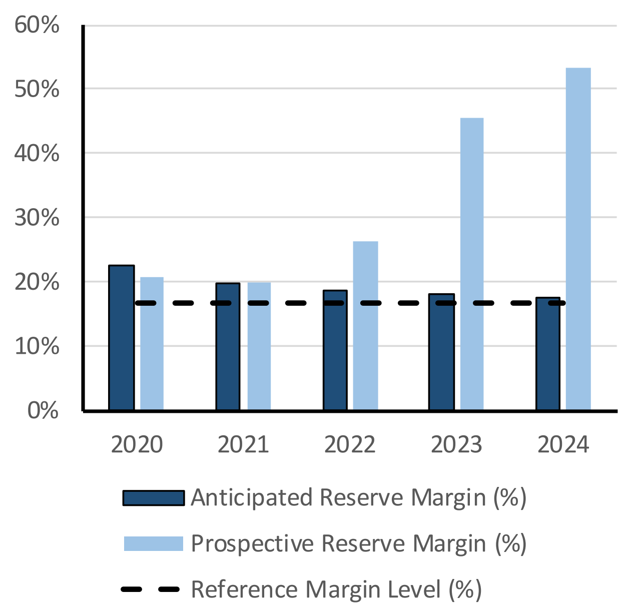
MISO is a not-for-profit, member-based organization that administers the wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages 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 Regions, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

**Demand, Resources, and Reserve Margins (MW)**

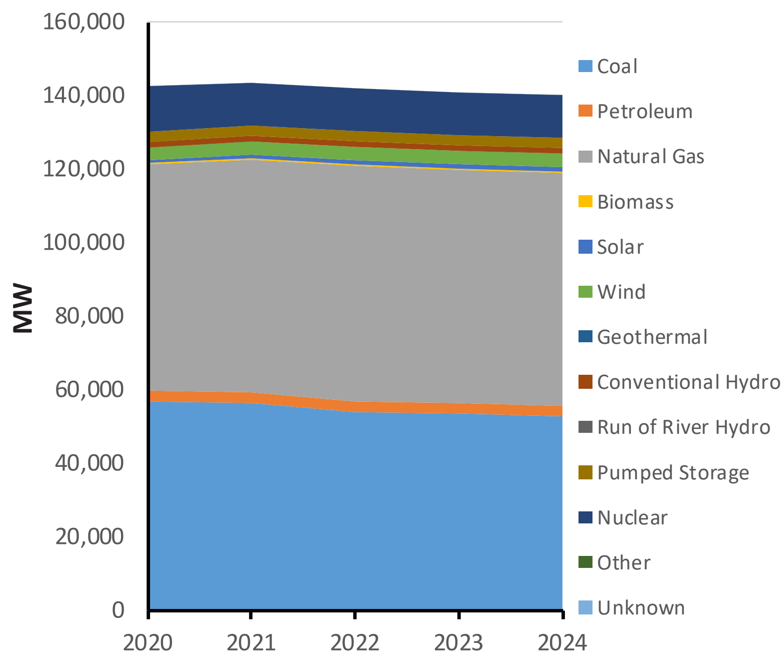
| Quantity | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|---|---|---|---|
| Total Internal Demand | 124,809 | 125,664 | 125,818 | 125,984 | 126,122 | 126,307 | 126,322 | 126,658 | 127,013 | 127,316 |
| Demand Response | 5,959 | 5,986 | 5,985 | 5,989 | 6,014 | 6,017 | 6,019 | 6,023 | 5,992 | 5,992 |
| Net Internal Demand | 118,849 | 119,678 | 119,833 | 119,995 | 120,107 | 120,290 | 120,304 | 120,635 | 121,020 | 121,323 |
| Additions: Tier 1 | 2,343 | 5,370 | 6,659 | 6,759 | 6,879 | 6,879 | 6,879 | 6,879 | 6,879 | 6,879 |
| Additions: Tier 2 | 600 | 2,811 | 10,097 | 36,283 | 47,275 | 47,800 | 47,800 | 47,800 | 47,800 | 47,800 |
| Additions: Tier 3 | 1,456 | 3,524 | 5,117 | 6,332 | 8,429 | 8,504 | 9,784 | 10,256 | 11,028 | 11,028 |
| Net Firm Capacity Transfers | 1,426 | 579 | 578 | 577 | 575 | -287 | -278 | -279 | -281 | -283 |
| Existing-Certain and Net Firm Transfers | 143,235 | 137,949 | 135,637 | 134,965 | 134,283 | 132,973 | 132,863 | 132,005 | 131,670 | 131,753 |
| Anticipated Reserve Margin (%) | 22.49% | 19.75% | 18.74% | 18.11% | 17.53% | 16.26% | 16.16% | 15.13% | 14.48% | 14.27% |
| Prospective Reserve Margin (%) | 20.84% | 20.02% | 26.30% | 45.46% | 53.46% | 52.00% | 51.60% | 50.03% | 48.36% | 48.06% |
| Reference Margin Level (%) | 16.80% | 16.80% | 16.80% | 16.80% | 16.80% | 16.80% | 16.80% | 16.80% | 16.80% | 16.80% |




**Projected Transmission Circuit Miles**




**Planning Reserve Margins**




**Existing and Tier 1 Resources**

## Highlights

- The MISO area is projected to have resources in excess of the regional requirement. Through 2022, regional surpluses and potential resources are sufficient for all zones to serve their deficits although there are two resource zones that are operating near local resource adequacy requirements. Affected MISO members and regulatory bodies are working to address in their respective resource plans.
- Continued focus on load growth variations and resource mix changes will allow for transparency around future resource adequacy risk.
- As MISO continues to operate near the PRM, it is important to ensure efficient conversion of committed capacity to energy that is able to serve near term load and not just on-peak but for all hours of the year. MISO has embarked on an initiative called resource availability and need (RAN) to review gaps in this conversion. Highlights of this initiative are as follows:
  - The RAN effort aims to address resources availability, visibility, and flexibility in several stages over the coming year.
  - The near-term focus has been improved outage scheduling and load modifying resource requirements.
  - The longer-term focus is capacity accreditation, seasonal resource adequacy, improved visibility, and market incentives in the operating horizon.
- To ensure visibility into fuel assurance to support system reliability, MISO utilizes data from the annual winter generator fuel survey for all natural gas generators to create fuel assurance ratings for generators based on transportation type, number of natural gas system connections, back-up fuel capability, and access to flexible services. In addition, MISO continues to make steady progress on incorporating major natural gas pipeline disruptions in planning studies to assess potential reliability risks.
- MISO is working with its members and regulators through the Organization of MISO States (OMS) and their DER survey to determine the current state of DERs at MISO and to strategize how to plan for increasing DERs into the future.
- MISO continues to work with policymakers and stakeholders to understand overall system needs and explore long range planning efforts that provide insights to inform decisions. MISO has begun a series of planning futures workshops to develop a broad set of future scenarios, providing long-term views of future resource portfolios.

**MISO Fuel Composition**

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|---|---|---|---|
| Coal | 56,795 | 56,406 | 53,932 | 53,560 | 52,770 | 52,710 | 52,513 | 51,839 | 51,839 | 51,839 |
| Petroleum | 2,982 | 2,900 | 2,880 | 2,832 | 2,832 | 2,668 | 2,668 | 2,668 | 2,668 | 2,668 |
| Natural Gas | 61,526 | 63,241 | 64,077 | 63,364 | 63,362 | 63,018 | 62,096 | 61,851 | 61,564 | 61,564 |
| Biomass | 403 | 389 | 389 | 366 | 341 | 336 | 336 | 263 | 263 | 263 |
| Solar | 714 | 1,002 | 1,127 | 1,227 | 1,227 | 1,227 | 1,227 | 1,227 | 1,227 | 1,227 |
| Wind | 3,418 | 3,565 | 3,624 | 3,607 | 3,724 | 3,718 | 3,688 | 3,684 | 3,665 | 3,665 |
| Conventional Hydro | 1,531 | 1,560 | 1,560 | 1,486 | 1,486 | 1,358 | 1,358 | 1,358 | 1,352 | 1,352 |
| Pumped Storage | 2,761 | 2,762 | 2,762 | 2,762 | 2,762 | 2,733 | 2,733 | 2,733 | 2,733 | 2,733 |
| Nuclear | 12,433 | 11,620 | 11,620 | 11,620 | 11,620 | 11,620 | 11,620 | 11,620 | 11,620 | 11,620 |
| Other | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| **Total MW** | 142,583 | 143,464 | 141,990 | 140,844 | 140,144 | 139,407 | 138,257 | 137,263 | 136,951 | 136,951 |

## MISO Assessment

**Planning Reserve Margins**: As directed under Module E-1 of the MISO Tariff, MISO coordinates with stakeholders to determine the appropriate PRM for the applicable planning year based upon the probabilistic analysis of the ability to reliably serve MISO coincident peak demand for that planning year. The probabilistic analysis uses a loss of load expectation (LOLE) study that assumes no internal transmission limitations within the MISO Region. MISO calculates the PRM such that the LOLE for the next planning year is 1 day in 10 years, or 0.1 days per year. The minimum amount of capacity above coincident peak demand in the MISO area required to meet the reliability criteria is used to establish the PRM. The PRM is established as an unforced capacity (PRM UCAP) requirement based upon the weighted average forced outage rate of all planning resources in the MISO Region. The PRM decreased from the *2018 LTRA* of 17.1%–16.8% on an installed capacity basis in this *2019 LTRA*. Changes from 2018–2019 planning year values are due to changes in load profiles and changes in the resource mix—retirements, additions, and suspensions.

**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 non-coincident load projections for the next 10 years, monthly for the first 2 years and seasonally for the remaining 8 years. MISO projects the summer coincident peak demand is expected to grow at an average annual rate of 0.2% for the 10-year period. This is down a tenth of a percentage point from the 2018 assessment.

**Demand-Side Management**: MISO currently separates demand response resources into two categories: direct control load management and interruptible load.[34] 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 demand-side management that is procured and cleared through the annual planning resource auction. MISO forecasts 5,959–5,992 MW of direct control load management and interruptible load to be available for the assessment period. MISO also forecasts at least 4,582 MW of BTM generation to be available for assessment period. EE is not explicitly forecasted at MISO; the majority of EE programs are reflected within the demand and energy forecasts; however, 312 MW were offered in the 2019–2020 planning resource auction.

34 See BPM 011 section 4.3 of the MISO Resource Adequacy Business Practice Manual: https://www.misoenergy.org/legal/business-practice-manuals/

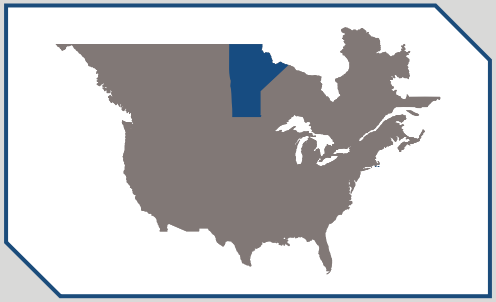
**Distributed Energy Resources**: As part of the MISO Transmission Expansion Plan (MTEP) study, there was an attempt to collect information on DERs. The forecast provides an estimate of DER programs and their impact on peak demand and annual energy savings. This forecast positions MISO to understand emerging technologies and the role they play in transmission planning as there is a specific case on DERs both at a base case level and an increased penetration level. MISO has not experienced any operational challenges as of yet but expects to as programs grow in the future. Soliciting current DER levels and methods of forecasting at MISO are an ongoing effort. To-date, the best source of existing DERs is a survey conducted annually by the Organization of MISO States, or Outage Management System (OMS). The 2019 OMS DER survey showed about 4.5 GW of DERs in the MISO footprint, 850 MW of which is BTM solar PV.

**Generation**: MISO projects approximately 3.1 GW of generation capacity to retire in 2019. Through the generator interconnection queue (GIQ) and the OMS MISO survey process, MISO anticipates 11.7 GW of future potential capacity additions to be in-service and expected on-peak during the assessment period. This is based on a snapshot of the GIQ and the *2019 OMS–MISO Survey* as of June 2019, including the aggregation of active projects.

**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 authorities 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. In the *MTEP 2018,*[35] two interregional projects with PJM were recommended for approval.

**Transmission**: The annual MTEP establishes the recommended regional plan that integrates expansion based on reliability, transmission access, market efficiency, and public policy needs across all planning horizons with the goal of maintaining a reliable electric grid and delivering the lowest-cost energy to customers in MISO. Major categories of planned transmission in *MTEP 2018* include the following: a total of 81 baseline reliability projects required to meet NERC Reliability Standards; 16 generator interconnection projects required to reliably connect new generation to the transmission grid, 2 interregional targeted market efficiency projects with PJM; and 346 other projects primarily driven by local reliability, load interconnection, age condition, and other local needs.

35 The full 2018 report is available at the following link: https://cdn.misoenergy.org/MTEP18%20Full%20Report264900.pdf

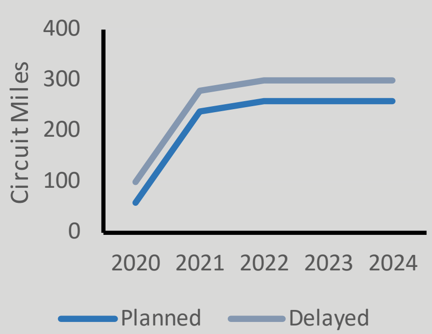


## MRO-Manitoba Hydro

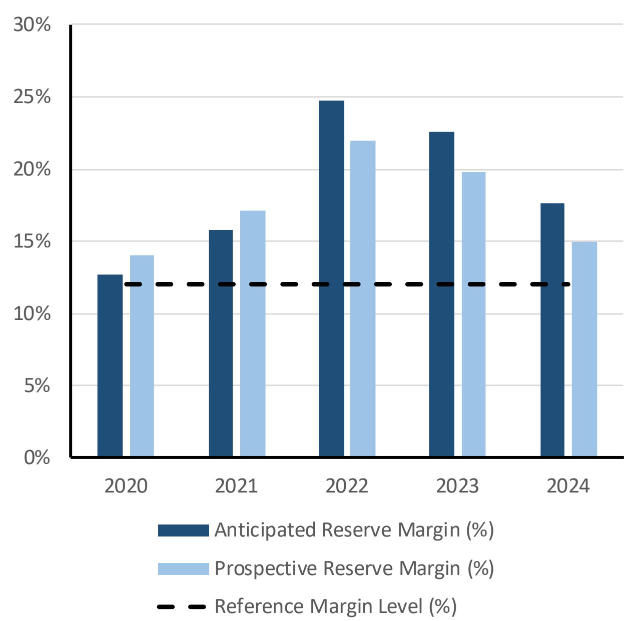
Manitoba Hydro is a provincial crown corporation providing electricity to about 580,000 electric customers in Manitoba and about 282,000 natural gas customers in Southern Manitoba. The service area is the province of Manitoba that is 250,946 square miles. Manitoba Hydro is winter-peaking. No change in the footprint area is expected during the assessment period. Manitoba Hydro is its own Planning Coordinator and BA. Manitoba Hydro is a coordinating member of the MISO. MISO is the Reliability Coordinator for Manitoba Hydro.

**Demand, Resources, and Reserve Margins (MW)**

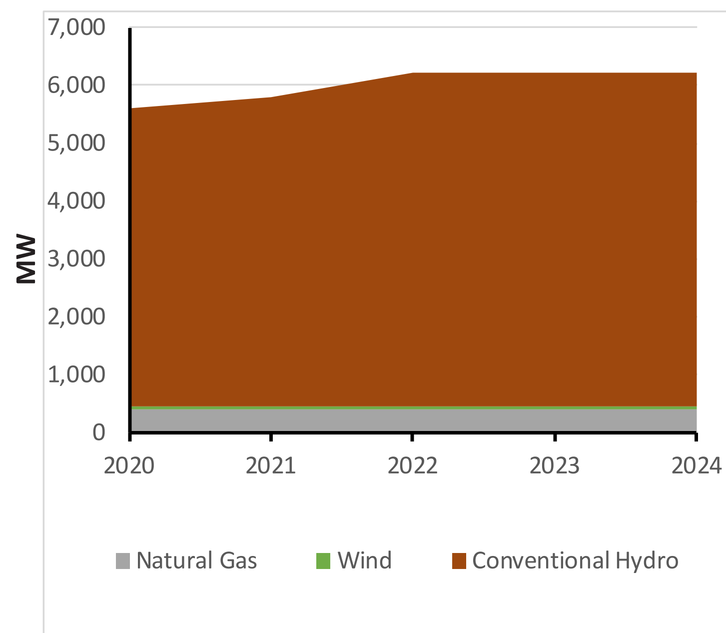
| Quantity | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|---|---|---|---|
| Total Internal Demand | 4,518 | 4,503 | 4,535 | 4,569 | 4,757 | 4,776 | 4,804 | 4,817 | 4,838 | 4,868 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Net Internal Demand | 4,518 | 4,503 | 4,535 | 4,569 | 4,757 | 4,776 | 4,804 | 4,817 | 4,838 | 4,868 |
| Additions: Tier 1 | 0 | 193 | 645 | 645 | 645 | 645 | 645 | 645 | 645 | 645 |
| Additions: Tier 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Additions: Tier 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Net Firm Capacity Transfers | -376 | -447 | -427 | -483 | -488 | -424 | -424 | -329 | -252 | -257 |
| Existing-Certain and Net Firm Transfers | 5,093 | 5,022 | 5,013 | 4,957 | 4,952 | 5,016 | 4,995 | 5,090 | 5,167 | 5,151 |
| Anticipated Reserve Margin (%) | 12.74% | 15.82% | 24.78% | 22.61% | 17.64% | 18.53% | 17.41% | 19.07% | 20.14% | 19.05% |
| Prospective Reserve Margin (%) | 14.03% | 17.11% | 21.96% | 19.81% | 14.96% | 15.85% | 14.75% | 16.41% | 17.50% | 16.30% |
| Reference Margin Level (%) | 12.00% | 12.00% | 12.00% | 12.00% | 12.00% | 12.00% | 12.00% | 12.00% | 12.00% | 12.00% |




**Projected Transmission Circuit Miles**




**Planning Reserve Margins**




**Existing and Tier 1 Resources**

## Highlights

- The ARM does not fall below the Reference Margin Level of 12% in any year during the assessment period. The 630 MW (net summer addition) Keeyask Hydro Station is expected to come into service beginning in the winter of 2021–2022, helping to ensure resource adequacy in the latter half and after the end of the current assessment period. No resource adequacy issues are expected.
- Demand is flattening over the LTRA horizon as a result of reduced load growth and EE/conservation efforts.
- Since the *2018 LTRA*, Manitoba Hydro experienced 115 MW (nameplate) of confirmed retirements, consisting of 100 MW of coal generation and 15 MW of hydro generation.

| Manitoba Hydro Fuel Composition | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 |
| **Natural Gas** | 404 | 404 | 404 | 404 | 404 | 404 | 404 | 404 | 404 | 404 |
| **Wind** | 52 | 52 | 52 | 52 | 52 | 52 | 31 | 31 | 31 | 31 |
| **Conventional Hydro** | 5,148 | 5,341 | 5,764 | 5,764 | 5,764 | 5,764 | 5,764 | 5,764 | 5,764 | 5,753 |
| **Total MW** | 5,604 | 5,797 | 6,220 | 6,220 | 6,220 | 6,220 | 6,199 | 6,199 | 6,199 | 6,188 |

## MRO-Manitoba Hydro Assessment

**Planning Reserve Margins**: The ARM does not fall below the Reference Margin Level of 12% in any year during the assessment period. The Reference Margin Level is based on both system historical adequacy performance analysis and reference to probabilistic resource adequacy studies using the index of loss of load expectation LOLE and loss of energy expectation (LOEE).

**Demand**: Manitoba Hydro's load peaks in the winter, typically in the months of January, February, or December. The primary driver of energy load growth in Manitoba is population with the secondary driver being the economy. Manitoba Hydro's system energy/energy forecasting methodology is primarily based on three market segments: residential, general service mass market, and top consumers (Manitoba Hydro's largest industrial customers) with a small amount remaining for miscellaneous groups composing of street lighting and seasonal customers. Manitoba Hydro uses econometric regression modeling by sector to determine projected energy usage. There have been no footprint changes and no significant changes to the forecast methodology since the *2018 LTRA*.

**Demand-Side Management**: Manitoba Hydro does not have any demand-side management resources that are considered controllable and dispatchable demand response. Manitoba Hydro does have EE and conservation initiatives used to reduce overall demand in the assessment area, and the impact of the reductions are included in the load forecast.

**Distributed Energy Resources**: There are approximately 19 MW dc of solar DERs in Manitoba as of the end of March 2019. Most of the solar distributed resources were installed in the last two years under an incentive program that has ended. Even with high growth rates, Manitoba Hydro is not anticipating that the quantity of solar DERs in Manitoba would increase to a level that would cause potential operation impacts in the next five years.

**Generation**: The 630 MW (net summer addition) Keeyask Hydro Generating Station is scheduled to come into service beginning in the winter of 2021–2022. The Keeyask hydro station has been under construction for several years and the major concrete work is now almost 90% complete. The completion of the Keeyask hydro station will help ensure resource adequacy in the latter half and after the end of the current assessment period. The additional hydro generation will support a related 250 MW capacity transfer into the MISO Region and an expected capacity transfer of 190 MW to SaskPower.

Brandon Unit 5 (100 MW nameplate), a coal-fired generator, was a confirmed retirement effective August 2018. The driver of the retirement of Brandon Unit 5 was both environmental and end of lifespan. Pointe du Bois Units 3, 5, 7, and 11 (total of 15 MW nameplate) were confirmed retirements effective August 2018 due to age and economic reasons. The retirement of these units did not result in adverse reliability impacts as the Reference Margin Level was maintained.

**Capacity Transfers**: The Manitoba Hydro system is winter peaking and is interconnected to the MISO Zone 1 local resource zone, which includes Minnesota and North Dakota and is summer-peaking as a whole. Significant capacity transfer limitations from MISO into Manitoba may have the potential to cause reliability impacts but only if the following conditions simultaneously occur: extreme Manitoba winter loads, unusually high forced generation/transmission outages, and a simultaneous emergency in the northern MISO footprint.

The additional hydro generation from Keeyask and the related 250 MW capacity transfer into the MISO area will tend to increase north to south flows on the Manitoba-MISO interface. A 100 MW capacity transfer from Manitoba to Saskatchewan will tend to increase east to west flow on the Manitoba–Saskatchewan interface once the 230 kV Birtle to Tantallon line is in-service in 2021. An expected capacity transfer of 190 MW from Manitoba to Saskatchewan that begins in 2022 will also tend to increase east to west flow on the Manitoba–Saskatchewan interface.

Manitoba Hydro has coordination and tie-line agreements with neighboring assessment areas, such as MISO, SaskPower, and IESO. In accordance with these agreements, planning and operating related issues are discussed and coordinated through respective committees.

**Transmission**: There are several transmission projects projected to come on-line during the assessment period. Most of the projects are dictated by the need to expand the transmission system to reliably serve growing loads: transmit power to the export market, improve safety, improve import capability, increase efficiency, and connect new generation. The major system enhancement projects include the addition of a new 500 kV interconnection from Dorsey to Iron Range (Duluth, Minnesota) to come into service in 2020, and the addition of a new 230 kV line from Birtle to Tantallon to come into service in 2021. Some transmission projects have been delayed a few years due to lower than expected load growth in the local area.

## Certificate of Service

I, Paget Pengelly, hereby certify that I have this day served copies of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota

xx electronic filing

**Docket No. E999/M-19-205**

Dated this 6th day of January 2020

/s/

______________________________

Paget Pengelly
Regulatory Administrator

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| Pam | Marshall | pam@energycents.org | Energy CENTS Coalition | 823 7th St E<br><br>St. Paul,<br>MN<br>55106 | Electronic Service | No | OFF_SL_19-205_Official |
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| Generic Notice | Residential Utilities Division | residential.utilities@ag.state.mn.us | Office of the Attorney General-RUD | 1400 BRM Tower<br>445 Minnesota St<br>St. Paul,<br>MN<br>551012131 | Electronic Service | No | OFF_SL_19-205_Official |
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| Jesse | Tomford | jtomford@otpco.com | Otter Tail Power Company | 215 S Cascade St<br>PO Box 496<br>Fergus Falls,<br>MN<br>56538-0496 | Electronic Service | No | OFF_SL_19-205_Official |
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