BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-01:
Current Energy Group Report

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Resource Adequacy in the Mountain West

An Assessment of Resource Adequacy Studies Following the Planned Retirement of Craig Station Unit 1

Prepared for Earthjustice, Sierra Club, and Environmental Defense Fund

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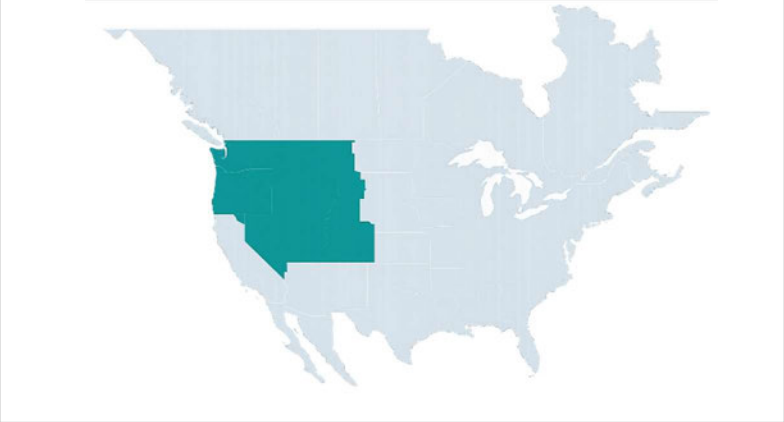
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Executive Summary

On December 30, 2025, the U.S. Department of Energy (DOE) issued Order No. 202-25-14 (DOE Order).[1] The Order prevents the planned retirement of Craig Station Unit 1 on grounds of "a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes" in the Western Electricity Coordinating Council (WECC) Northwest assessment area.[2] According to DOE, "the emergency conditions resulting from increasing demand and shortage from accelerated retirement of generation facilities will continue in the near term and are also likely to continue in subsequent years."[3]

The DOE Order contains only one definition of the WECC Northwest assessment area, stating that it "includes Colorado, Idaho, Montana, Nevada, Oregon, Utah, Washington, and Wyoming."[4] DOE's definition may derive from the 2024 Long-Term Reliability Assessment (LTRA) of the North American Electric Reliability Corporation (NERC).[5] Figure 1 shows the NERC-defined area.

Figure 1: NERC-Define WECC Northwest Assessment Area[6]



In support of its determination, DOE relies on a few sources: (1) NERC's 2024 LTRA, (2) WECC's 2024 Western Assessment of Resource Adequacy (WARA), (3) DOE's own resource adequacy study, and (4) information published by the Energy Information Administration.[7]

[1] U.S. Department of Energy (DOE). "Order No. 202-25-14," December 30, 2025. https://www.energy.gov/ceser/federal-power-act-section-202c-craig-order-no-202-25-14.
[2] DOE Order at 1.
[3] DOE Order at 3.
[4] DOE Order at 1.
[5] DOE Order at 1.
[6] 2024 Long-Term Reliability Assessment," NERC, page 127, July 2025, https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf.
[7] DOE Order at 1–3.

This report evaluates whether the sources on which DOE relies support a finding of the current existence of a resource adequacy crisis for the short-term future (*i.e.*, in 2026) or for the medium-term future (*i.e.*, in 2027–2031) in the WECC Northwest assessment area.[8] CEG did not conduct a new or independent resource adequacy model; rather, this report analyzes how, if at all, the methodology, assumptions, and conclusions in DOE's cited sources speak to the existence of any such crisis in the area. This report also explains the fundamentals of resource adequacy planning and assessments. Additionally, because the Pacific Northwest is within the area in which the Order asserts the existence of emergency conditions, our recent report on "Resource Adequacy in the Pacific Northwest" informs our opinion here and is part of this report in Appendix A.

We conclude that DOE's sources do not support the existence of a resource adequacy crisis in the WECC Northwest assessment area. The 2024 Long Term Reliability Assessment finds no elevated reliability risk across the broader WECC regions, assigning the region its lowest possible risk rating. The 2024 Western Assessment of Resource Adequacy finds no demand-at-risk hours in 2026 and almost none in 2027 in the three subregions that roughly correspond to the WECC Northwest assessment area. DOE's July 2025 study focuses on long-term scenarios and, even under highly conservative assumptions, does not find evidence of a near-term resource adequacy crisis in Colorado or the broader region. Finally, the Energy Information Administration's data on planned power plant retirements and additions show substantial net generation additions in Colorado beyond the retirements cited in DOE's Order and do not support the finding of a near-term or medium-term resource adequacy shortfall. Moreover, the retirement of Craig Station Unit 1 represents a long-planned transition that is reflected in regional planning analyses and is not identified as a driver of either near-term or medium-term reliability risk.

The potential for load-growth driven resource shortfalls identified by the studies in 2030 reflects the normal and intended function of resource adequacy planning: to identify risks with sufficient lead time for state, regional, and utility processes to respond through deliberate, coordinated action, as they have done for decades.

What is Resource Adequacy?

Introduction

Electric resource adequacy and energy system reliability are among the most important, discussed, and analyzed energy challenges among utility practitioners, regulators, and policymakers. Both resource adequacy and reliability practices and requirements have evolved over time with the growth of the electricity system, advancements in economic and regulatory theory, and in response to prominent grid failures like the Northeast blackouts of 1965 and 2003.[9] This has led to a layered

[8] This report considers the "WECC Northwest assessment area" consistent with the definition in the DOE Order at page 1. This report does not analyze the presidential executive orders discussed in the DOE Order.
[9] "Reliability Explainer," Federal Energy Regulatory Commission, accessed December 21, 2025, https://www.ferc.gov/reliability-explainer; "Resource Adequacy: History and Catalog of Metrics," Electric Power Research Institute, December 31, 2018, https://www.epri.com/research/products/000000003002013734.

planning and regulatory framework for the bulk power system involving national entities (the North American Electric Reliability Corporation and the Federal Energy Regulatory Commission), regional reliability organizations, and state regulators, each of which conducts ongoing assessments and planning studies. These layers intentionally overlap, with assessments from different organizations analyzing different geographies or using different methodologies and time horizons. Collectively, these resource adequacy and reliability planning efforts create a robust record with which to evaluate DOE's claims of a reliability and resource adequacy crisis.

Resource adequacy describes the situation in which an electric system has sufficient capacity to meet customer demand, plus a reserve margin, in most hours under most conditions, based on a chosen standard.[10,11] The National Laboratory of the Rockies (formerly National Renewable Energy Laboratory) defines a power system as being resource adequate "if it has procured sufficient resources (including supply, transmission, and responsive demand) such that it runs a sufficiently low risk of invoking emergency measures (such as involuntary load shedding) due to resource unavailability or deliverability constraint."[12] The level of risk deemed sufficient is typically defined by a resource adequacy standard (*e.g.*, the "1-in-10" standard discussed below) set by planners based on engineering judgement and acceptable cost. Because no system can ever be perfectly reliable, planners must determine how to appropriately balance incremental cost and risk reduction. Put simply, resource adequacy measures how much generation and other resources are available to meet load.

Resource adequacy and power system reliability are closely related but distinct concepts. Reliability refers to the ability of the electric system to deliver electricity to customers in real time, encompassing generation, transmission, and distribution. Even where the bulk power system is resource adequate and reliable, customers may still experience outages, primarily due to distribution-level issues, such as a downed residential line caused by a fallen tree.

How Resource Adequacy is Assessed

Resource adequacy planning is a well-established practice across the country, in which multiple entities independently produce resource adequacy assessments for each region, generally according to a centralized standard. These assessments often will complement or overlap, but may use different methodological approaches or metrics. The collection of multiple, overlapping but independently produced studies helps operators, policymakers, and the many vested stakeholders make decisions to ensure the adequacy of the bulk electric system.

[10] "Reliability Explainer," Federal Energy Regulatory Commission, accessed December 16, 2025, https://www.ferc.gov/reliability-explainer.
[11] "Resource Adequacy Basics," National Renewable Energy Laboratory, archived October 20, 2025, accessed December 16, 2025. https://web.archive.org/web/20251020042833/https://www.nrel.gov/research/resource-adequacy.
[12] "Probabilistic Resource Adequacy Suite (PRAS) v0.6 Model Documentation," National Renewable Energy Laboratory (now National Laboratory of the Rockies), May 2021, https://docs.nrel.gov/docs/fy21osti/79698.pdf.

The context of each study is important. Because each study is a product of its underlying methodology, assumptions, and goals, any reliance on a given study must be based on consideration of the study's particular context. A study's findings cannot be relied upon without due consideration of the context, including the underlying methodology, assumptions, and goals.

An essential component of each study is the metric or metrics used to measure resource adequacy. There are several metrics used across North America to capture different dimensions of resource adequacy. These metrics can be broadly categorized as deterministic or probabilistic.[13] Deterministic metrics were historically more common because they are relatively simple to calculate and rely on fixed assumptions about load, resource availability, and reserve margins. In recent years, however, many planning entities have increasingly relied on probabilistic metrics, which evaluate the distribution of possible outcomes across a wide range of system conditions. Probabilistic metrics are better suited to capturing uncertainty and risk and are generally viewed as more informative than deterministic metrics for assessing resource adequacy.

- **Loss of Load Expectation (LOLE).** This metric measures the expected number of loss-of-load event-days over the study's planning period. An event-day is usually defined as any single day in which electricity demand is not met at least once because system resources were not sufficient to meet demand, whether the event lasts 5 minutes or 5 hours. A single event that spans two days is counted as two event-days. In general, $LOLE = \frac{Number\ of\ Event-Days}{Total\ Time\ Period}$. The most common LOLE standard is "1-in-10," which refers to an expectation that there is no more than 1 event-day (resulting from insufficient resources) in a 10-year period. The 1-in-10 standard equates to a LOLE of 0.1, calculated as $0.1 = \frac{1\ event-day}{10\ years}$. LOLE is usually evaluated on a yearly timescale, but it can also be expressed at an hourly or daily timescale.
- **Loss of Load Hours (LOLH).** This metric is an expression of LOLE where an "event" is specified to be at the hourly level (*e.g.*, 15 hours in 10 years), allowing for higher resolution of the duration of potential shortfalls.
- **Loss of Load Probability (LOLP).** This metric is like LOLE, except that it measures the expected percentage of events over the planning period in which there was a loss of load. LOLP is equivalent to LOLE divided by the period chosen. For example, a 1-in-10 LOLE standard would lead to a LOLP of 0.0274% per day, calculated as:

$$LOLP = \left(\frac{1\ event-day}{10\ years}\right) * \left(\frac{1\ year}{365\ days}\right) * 100 = 0.0274\%$$

- **Expected Unserved Energy (EUE).** This metric measures the total expected amount of unserved energy, in MWh, over the planning period. Unlike LOLE and LOLP, which measure the frequency or likelihood of a loss-of-load event, EUE measures the magnitude of energy demand not served. While modeling tools would quantify actual EUE in given scenarios, a simple conceptual relationship is as follows: EUE is equal to the LOLE multiplied by the average

[13] "Metrics Explainers," Electric Power Research Institute, accessed 12/16/2025, https://msites.epri.com/resource-adequacy/metrics/metrics-explainers.

magnitude of the shortfall. For example, if a model found that the average shortfall during an event was 200MW across a 1-in-10 LOLE standard, and further assuming that the event lasts a full 24 hours, the EUE per year would be 480MWh.

- **Planning Reserve Margin (PRM).** This metric measures the difference between the total resources and the expected peak load, divided by the peak load. It is expressed as a percentage.[14] For example, if a system has 107,000 MW of resources and an expected peak load of 100,000 MW, the system has a 7% reserve margin, calculated as:

$$PRM = \left(\frac{107{,}000 - 100{,}000}{100{,}000}\right) = 7\%$$

The PRM assessment may, and typically does, "de-rate" resources based on the likelihood that a generator will be unavailable or produce less than its maximum potential output (i.e., less than its "nameplate capacity") during a peak demand period. The resulting figure is known as a generator's "accredited" capacity. For example, although the system's total nameplate capacity could be 225,000 MW, resource accreditation may result in only 107,000 MW being counted for PRM purposes. Accreditation is further discussed below.

Each metric measures a different aspect of system risk, and most regions rely on multiple metrics. PRM provides a high-level indicator of resource capacity relative to expected peak load, but it does not capture hourly or seasonal variability in resource availability. LOLE and LOLP quantify the probability and frequency of shortfall events, but do not identify the magnitude of a loss-of-load event. EUE is used to measure the total quantity of energy that cannot be served in a loss-of-load event. By using multiple metrics, planners can capture both the likelihood and the magnitude of potential shortages, which a single metric cannot do on its own. The Western Resource Adequacy Program, a voluntary regional reliability and capacity-sharing program composed of electric utilities across the Western Interconnection uses LOLE as its primary metric in its probabilistic analysis.[15]

Because these metrics evaluate system risk, the studies need a method for representing how much each resource will likely contribute to meeting demand during a period of system stress. In LOLE-, LOLH-, or EUE-based analyses, this is typically done through probabilistic assumptions about unit availability, forced outages, and load shapes rather than relying on nameplate capacity alone to reflect each resource's expected availability during peak or net-peak hours. In most of the country, these performance assumptions guide grid operators when they assign resources an accredited capacity value. The most commonly used probabilistic accreditation method is Effective Load Carrying Capability (ELCC), which measures the contribution a resource makes to reducing loss-of-load risk, typically by comparing system reliability outcomes with and without the resource relative to a benchmark "perfect capacity" resource. The purpose of applying an accredited value (via ELCC

[14] "Metrics Explainers," Electric Power Research Institute, accessed 12/16/2025, https://msites.epri.com/resource-adequacy/metrics/metrics-explainers.
[15] "Western Resource Adequacy Program Tariff of Northwest Power Pool D/B/A Western Power Pool," Western Power Pool, March 16, 2025, https://www.westernpowerpool.org/private-media/documents/WRAP_Tariff_Effective_3.16.25.pdf.

or another method) to each resource is to ensure that resources are counted based on their contribution to reducing loss-of-load risk, rather than their installed capacity.

Who Conducts Resource Adequacy Planning?

Resource adequacy planning occurs at multiple institutional layers, each producing a unique assessment based on its purview, methodology, and assumptions. States in the Western Interconnection do not have a single coordinating entity that sets resource adequacy requirements. As a result, there are several independent organizations, many with overlapping jurisdictions or footprints, that conduct and publish resource adequacy analyses. Each of these assessments provides complementary but sometimes divergent perspectives on system conditions.

At the national level, the North American Reliability Corporation, or NERC, is the entity responsible for ensuring the reliability and security of the North American bulk power system, under delegated authority from the Federal Energy Regulatory Commission (FERC).[16] NERC performs a variety of functions. It develops and enforces mandatory reliability standards. It also monitors the bulk power system. And NERC assesses system reliability through a variety of forecasts: (1) an annual 10-year forecast, (2) an annual forecast of the upcoming summer, usually issued about a month or two before summer begins, and (3) an annual forecast of the upcoming winter, also typically issued about a month or two before winter begins. Other NERC functions include "audit[ing] owners, operators, and users [of the bulk power system] for preparedness, as well as educat[ing] and train[ing] industry personnel."[17] However, NERC does not oversee, review, or approve resource adequacy studies and reliability assessments conducted by individual utilities. Instead, state regulators, such as public utility commissions, review electric resource plans and assess whether individual utilities are resource-adequate.

State regulators play an essential role in resource adequacy and reliability planning. Public Utility Commissions, such as the Colorado Public Utilities Commission, typically approve utility resource adequacy assessments, specific power plants, and capital expenditures through their review of requested Certificates of Public Convenience and Necessity (CPCNs), rate cases, and integrated resource plans. Electric utilities, both investor-owned and consumer-owned, develop integrated resource plans that identify how the utility will meet customer demand over the planning horizon, usually 20 years. Electric utilities typically develop integrated resource plans every 2 to 3 years and rely on a variety of methods for evaluating resource adequacy and accrediting resources. The utility-specific resource adequacy assessment and the resource accreditation values are important components for identifying the utility's future resource needs.

In addition to state and national entities, there are several entities in the WECC Northwest assessment area that provide regional resource adequacy assessments.

[16] "Reliability Explainer," Federal Energy Regulatory Commission, accessed December 16, 2025, https://www.ferc.gov/reliability-explainerhttps://www.ferc.gov/reliability-explainer.
[17] "Who We Are," North American Electric Reliability Corporation, accessed December 23, 2025, https://www.nerc.com/who-we-are.

1. **Western Electricity Coordinating Council (WECC)** is one of the six regional entities with delegated authority from NERC to ensure reliability and resource adequacy. As the FERC-approved regional manager for reliability for the Western Interconnection, its geographic focus spans 14 Western states, 2 Canadian provinces, and Northern Baja Mexico. [18] Its functions include setting standards, identifying threats and shortfalls, and monitoring compliance. As part of this role, WECC conducts interconnection-wide resource adequacy assessments. WECC's assessments are advisory rather than binding, but they provide one of the most comprehensive views of adequacy risks across the Western grid and can be (and are) used as inputs to utility, state, and regional resource adequacy planning processes.
2. **The Western Power Pool's Western Resource Adequacy Program (WRAP)** is a coordinated regional resource adequacy planning and compliance program in the West. Although participation is voluntary, member utilities enter into a binding agreement to meet common resource adequacy standards and comply with the program's planning and operational requirements. The program received FERC approval of its tariff in February 2023, establishing enforceable capacity sufficiency demonstrations, resource accreditation methods, and operational sharing provisions.[19] The Western Resource Adequacy Program will start binding operations in Winter 2027/2028 for the 16 participants who agreed to participate by October 31, 2025.[20] Before binding operations begin, the Western Resource Adequacy Program will release informational assessments on regional resource development, ELCCs, and calculated PRMs.[21] The Western Resource Adequacy Program will provide a consistent, region-wide framework for assessing and addressing resource adequacy needs and represents a significant step forward in strengthening reliability across the West.[22]
3. **The Southwest Power Pool (SPP)** is a Regional Transmission Organization concentrated in the Great Plains states[23] that is expanding into Colorado, Wyoming, and small portions of Utah. SPP also administers a regional day-ahead market program called Markets+. Markets+ participants will utilize WRAP standards to meet their resource adequacy obligations.[24] Public Service Company of Colorado, Tri-State Generation and Transmission Association, Inc., the Western Area Power Administration, Basin Electric Cooperative, Colorado Springs Utilities, Platte River Power Authority, and Deseret Power Electric

[18] "About WECC," Western Electricity Coordinating Council (WECC), accessed December 23, 2025. https://www.wecc.org/about/about-wecc.
[19] "History," Western Power Pool, accessed December 16, 2025, https://www.westernpowerpool.org/about/history/.
[20] "WPP Notice to WRAP Resource Adequacy Participants Committee," Western Power Pool, October 31, 2025, https://www.westernpowerpool.org/news/wpp-notice-to-wrap-resource-adequacy-participants.
[21] "Metrics," Western Power Pool, accessed December 16, 2025, https://www.westernpowerpool.org/resources/wrap_metrics/.
[22] "Tariff & Business Practice Manuals," Western Power Pool, accessed 12/16/2025, https://www.westernpowerpool.org/resources/wrap_bpms/.
[23] Most or all of Oklahoma, Kansas, Nebraska, South Dakota, North Dakota, with portions of Minnesota, Iowa, Missouri, Arkansas, Louisiana, Texas, New Mexico, Wyoming, and Montana are covered by SPP.
[24] "What is Markets+?," Markets+, accessed January 20, 2026, https://www.marketsplus.org/about.

Cooperative are all participating in the expansion of the Southwest Power Pool Regional Transmission Organization or Markets+.[25]

In addition to the regional resource adequacy organizations, at least two other entities provide input and operational data that are frequently used to develop resource adequacy assessments. These organizations are important for understanding the depth and breadth of planning in the region.

1. **WestConnect** is the FERC-jurisdictional regional transmission planning organization for much of the Intermountain West, responsible for developing long-term transmission plans under FERC Orders 890 and 1000. Its studies evaluate future load, resource additions, and system contingencies to identify needed transmission upgrades, all of which influence regional transfer capability.
2. **Western Area Power Administration (WAPA)** is a federally managed (semi-independent) Power Marketing Agency, and one of largest regional electrical planning entities in the western United States. WAPA markets power generated from 57 dams, owns and operates more than 17,000 miles of high-voltage transmission lines, and supplies electricity to approximately 700 organizations (e.g., public utility districts, investor-owned utilities, utilities) across 15 states. Although WAPA does not publish its own resource adequacy assessment, its hydrological data, operational planning studies, and transmission reliability evaluations are foundational inputs to regional resource adequacy modeling conducted by other organizations.

Summary and Interpretation

Resource adequacy planning is conducted widely across the country, and the variety of methods, geographic scopes, and modeling approaches provides a robust set of perspectives on system conditions. Resource adequacy is inherently probabilistic. It is not an end state but an ongoing evaluation of risk, and all findings include uncertainty. A projected shortfall in a given modeling approach does not ensure an outage, or even necessarily predict one, particularly where the projection is a small shortfall below a target reserve margin. Although individual studies may differ in their specific findings or the magnitude of particular metrics, consistent patterns across assessments offer meaningful signals about regional adequacy. For example, if multiple studies indicate medium-term capacity shortfalls, that alignment points to elevated medium-term risk; similarly, broad agreement on sufficient near-term resources suggests low near-term risk.

[25] "Markets+," Southwest Power Pool, accessed January 20, 2026, https://www.spp.org/marketsplus.

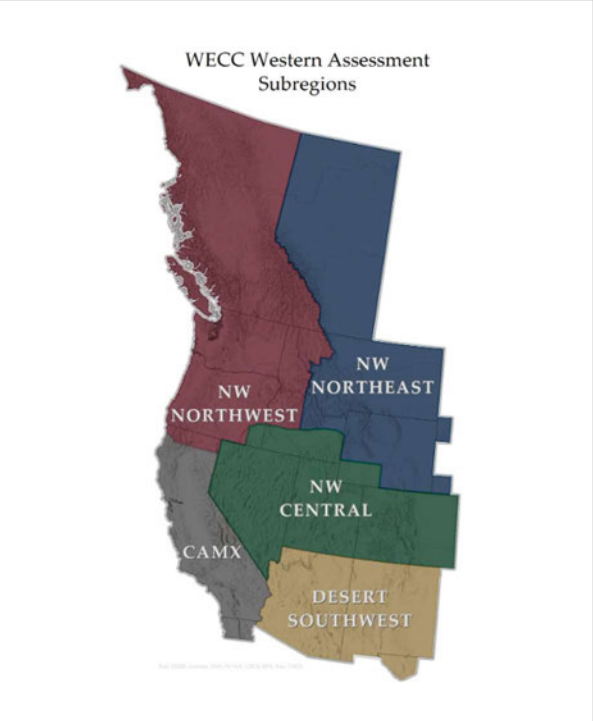
Analysis

WECC's 2024 Western Assessment of Resource Adequacy

Introduction

The Western Electricity Coordinating Council annually produces a Western Assessment of Resource Adequacy report. The most recent assessment is the 2024 publication. The 2024 Western Assessment of Resource Adequacy divides the Western Interconnection into five sub-regions shown in Figure 2 below.[26]

Figure 2: WECC subregions used for 2024 Western Assessment of Resource Adequacy



The 2024 Western Assessment of Resource Adequacy provides an hourly, 10-year, and forward-looking analysis of the WECC subregions.[27] The assessment uses an energy-based probabilistic approach that incorporates planned new resources, demand growth (and its drivers), retirements, imports, and other factors across several scenarios to estimate peak demand and potential hourly shortfalls. Moreover, to further analyze the approach's sensitivities, the Western Assessment of

[26] WECC updated its planning regions in 2025.
[27] "Western Assessment of Resource Adequacy 2024: Scenario Analysis," Western Electricity Coordinating Council (WECC), December 3, 2024, https://feature.wecc.org/wara/.

Resource Adequacy also relies on aggregated data from the regional balancing authorities in which the completion of planned resources is delayed or not completed.[28]

The 2024 Western Assessment of Resource Adequacy employs "demand-at-risk hours" to evaluate resource adequacy.[29] Under this measure, any of the 8,760 hours in a year is identified as a "demand-at-risk hour" if the probability that resources are inadequate to serve demand is less than 99.98%.[30] This 99.98% threshold is derived from the "one day in ten years" LOLE standard typical in the industry and discussed above, as modified for a more granular, hourly analysis.[31]

As WECC explains, "[d]emand-at-risk-hours are not a prediction that demand will be lost."[32] And a finding of demand at risk hours is not necessarily unusual, nor a finding of an emergency. Planners take into account both the magnitude of the finding and the trend when making planning decisions, using both to identify the amount and type of measures needed. Modest quantities of modeled demand-at-risk hours are not unusual and should be interpreted as early planning signals rather than evidence of an imminent resource adequacy shortfall. For example, the 2024 Western Assessment of Resource Adequacy identifies demand-at-risk hours in 2025 under certain scenarios. However, actual system operations during 2025 did not result in supply shortfalls.

The 2024 Western Assessment of Resource Adequacy generally examines "demand-at-risk-hours" in the context of four future scenarios. These scenarios differ based on the percentage of planned resources built on time.[33] The four scenarios are:

1. All planned resources are built on time
2. 95% of planned resources are built on time
3. 85% of planned resources are built on time
4. 55% of planned resources are built on time

Analysis of Short-Term Findings

The 2024 Western Assessment of Resource Adequacy does not find any near-term resource adequacy shortfall for the Western Interconnection or the "NW Central" subregion, specifically. The DOE Order notes that, according to the 2024 Western Assessment of Resource Adequacy, demand is forecast to grow in the NW Central region, but it does not acknowledge that the assessment finds no near-term resource adequacy shortfall in that region and identifies no demand-at-risk hours until 2031.[34] Even in the most extreme scenario (in which only 55% of planned resources are

[28] "Western Assessment of Resource Adequacy 2024: Scenario Analysis," WECC.
[29] "2024 Western Assessment of Resource Adequacy: Appendix," page 3, January 24, 2025, WECC, https://www.wecc.org/sites/default/files/documents/products/2025/2024%20WARA%20%20Appendix.pdf.
[30] 2024 Western Assessment of Resource Adequacy: Appendix," page 3, January 24, 2025, WECC, and "*One-Day-in-Ten-Year Metric Explanation*," page 2, WECC, October 25, 2022, https://www.wecc.org/sites/default/files/documents/program/2024/WECC%20One-day-in-ten-year%20metric%20explanation.pdf.
[31] "2024 Western Assessment of Resource Adequacy: Appendix," page 3, January 24, 2025, WECC.
[32] "Western Assessment of Resource Adequacy 2024: Scenario Analysis," WECC.
[33] "Western Assessment of Resource Adequacy 2024: Scenario Analysis," WECC.
[34] DOE Order at 1.

built on time), the study finds **no demand at risk hours in 2026 and almost none in 2027** in the three subregions that roughly correspond to the WECC Northwest assessment area, as depicted in Table 1.[35]WECC notes that demand-at-risk hours do not appear in the NW Central subregion in any of the buildout scenarios until 2031.[36]

Table 1: Demand-at-Risk Hours in WECC Northwest Subregions Under the Most Extreme Buildout Scenario (2026–2027)

Subregion	2026 Demand-at-Risk Hours in Most Extreme Scenario	2027 Demand-at-Risk Hours in Most Extreme Scenario
NW Central	0	0
NW Northeast	0	0
NW Northwest	0	~7

As such, for the WECC Northwest assessment area, neither the magnitude of any identified shortfalls nor the rate of increase in 2026 and 2027 indicates the existence of a resource adequacy crisis.

Notably, the 2024 Western Assessment of Resource Adequacy also anticipates 10 GW of new generation in 2026, of which more than 4 GW is firm capacity.[37] Recent EIA data for 2025 supports this conclusion. Based on Energy Information Administration 860M reports, Colorado, Utah, and Nevada added more than 2.3GW in 2025, matching expectations from 2024.[38,39] 3.6 GW is planned to be added to these three states in 2026, according to the November 2025 data. [40]

Analysis of Medium-Term Findings

The 2024 Western Assessment of Resource Adequacy finds that medium-term resource adequacy risks emerge later, particularly under scenarios in which planned generation is delayed or import capacity is constrained.[41] While modeled demand-at-risk hours increase over time in certain stress scenarios, WECC does not characterize these results as evidence of a reliability crisis. Rather, WECC frames them as a planning signal.[42]

[35] "WARA 2024 Demand at Risk by Subregion," Pages 5–8, WECC, accessed January 26, 2026, https://www.wecc.org/sites/default/files/documents/products/2024/WARA%202024%20Demand-at-Risk%20Hours%20by%20Subregion%20%281%29.pdf.
[36] "Western Assessment of Resource Adequacy 2024: Scenario Analysis," WECC.
[37] 2024 WARA: Planned Resource Additions by Subregion, figures 2 and 3
[38] "Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860)," December 2024 and November 2025 data, U.S. EIA, accessed January 21, 2026, https://www.eia.gov/electricity/data/eia860m/.
[39] "Electric Power Annual: Table 4.7.A," U.S. EIA, accessed January 21, 2026, https://www.eia.gov/electricity/annual/table.php?t=epa_04_07_a.html.
[40] "Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860)," November 2025 data, U.S. EIA.
[41] "Western Assessment of Resource Adequacy 2024: Risks to Planned Resource Additions," WECC.
[42] Western Assessment of Resource Adequacy 2024: Summary," WECC.

The 2024 Western Assessment of Resource Adequacy demonstrates that the region has been actively planning for plant retirements and load growth through increased planned resource additions, including new capacity (~15GW of new batteries and ~3GW of new natural gas by 2027), and by moderating previously-assumed retirements downward from 2022.[43] Generation additions across the WECC subregions appear to be on track with the 2024 assessment's expectations. In 2025, approximately 9.4 GW of new batteries, 6 GW of solar, 1.7 GW of gas, and 2 GW of wind were deployed across the interconnection. Of this 19GW, more than 4.7GW has been deployed in Colorado, Nevada, Utah, Idaho, Washington, Oregon, Montana, and Wyoming as of the November report, and 2.1GW in the same states is expected to be completed in December.[44]

The study does not identify retirements as a primary cause of future reliability risks. Instead, the analysis finds that the principal risks stem from insufficient new generation and constraints on imports, both of which could be exacerbated by supply chain challenges, interconnection backlogs, siting and permitting delays, and cost pressures. [45] According to the 2024 Western Assessment of Resource Adequacy, imports play a critical role in maintaining short-term reliability, and the timely completion of new generation is the key medium-term requirement for maintaining resource adequacy.[46]

Although the 55% build-out scenario is a useful planning exercise for stress-testing the system, it appears unlikely based on historical data. The assessment notes that the 2018–2023 average project completion rate was closer to 76%, a period that included significant inflation and the supply chain disruptions from the COVID pandemic.[47]

A consistent theme in the 2024 Western Assessment of Resource Adequacy is the need to continue and improve upon existing state, regional, and private planning processes. The assessment highlights recent changes to utility forecasting methodologies, new long-term transmission planning efforts (*e.g.*, efforts pursuant to FERC Order 1920), and the development of the Western Resource Adequacy Program as positive planning developments.[48] In other words, the assessment calls for incremental improvement to established planning for and proportional responses to medium-term challenges, not extraordinary measures outside of the planning process.

[43] Western Assessment of Resource Adequacy 2024: Retirements," WECC, WECC and "WARA 2024 Annual Demand by Subregion," Figure 6, WECC, accessed December 16, 2025 https://www.wecc.org/wecc-document/17061.
[44] "Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860)," December 2024 and November 2025 data, U.S. Energy Information Administration, accessed January 21, 2026, https://www.eia.gov/electricity/data/eia860m/.
[45] Western Assessment of Resource Adequacy 2024: Additional Considerations," WECC.
[46] "WARA 2024 Import Scenarios," page 6, Western Electricity Coordinating Council, December 3, 2024, https://www.wecc.org/wecc-document/17081.
[47] Western Assessment of Resource Adequacy 2024: Historical Resource Additions," WECC.
[48] Western Assessment of Resource Adequacy 2024: Resource Planning," WECC.

NERC's 2024 Long-Term Reliability Assessment

Introduction

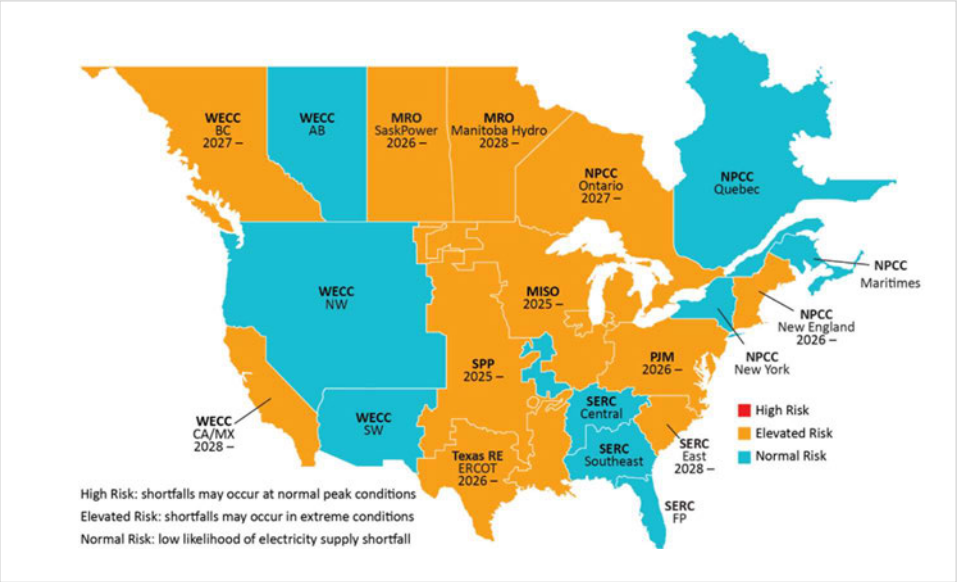
NERC releases an annual Long-Term Reliability Assessment that provides a forward-looking, regional assessment of bulk power system reliability over a 10-year period. The assessment is primarily targeted at the medium-term and long-term timeframes. Using industry data and projections, the assessment assigns a risk level to each region using a three-tiered classification system: "high risk," "elevated risk," and "normal risk."

The 2024 Long-Term Reliability Assessment covers the period from 2024 through 2034.

Analysis of Short-Term Findings

The 2024 Long-Term Reliability Assessment assigns the lowest risk ranking to the WECC Northwest assessment area. Figure 3 shows NERC's summary of risk for the 2025-2029 period.

Figure 3: NERC Risk Area Summary 2025-2029



The 2024 Long-Term Reliability Assessment provides a year-by-year breakdown of its findings. The findings do not support the proposition that the WECC Northwest assessment area faces near-term risk. The assessment reports that "negligible unserved energy and load-loss risk" are expected.[49] Table 2 below presents the detailed reliability findings for 2026 and 2028. In 2026, no reliability metrics are violated, and in 2028, the analysis identifies only a single MWh of expected unserved energy, a level well within commonly accepted reliability thresholds. [50] NERC's findings

[49] 2024 Long-Term Reliability Assessment, NERC, pages 129, July 2025, https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf.
[50] 2024 Long-Term Reliability Assessment, NERC, pages 129.

(shown in the table below) do not support an immediate or emerging reliability crisis, as the outputs from NERC's probabilistic assessment show essentially no risk to WECC Northwest in 2026 and 2028.

Table 2: Base Case Summary of NERC 2024 LTRA Results

	2026	2028
EUE (MWh)	0	1
EUE (PPM)	0	0
LOLH (hours per year)	0	0
Operable On-Peak Margin[51]	36.1%	27.8%

The 2024 Long-Term Reliability Assessment anticipates that the WECC Northwest assessment area will maintain a 37.7% and 34.1% reserve margin in 2026 and 2027, respectively, substantially higher than the reference reserve margin[52] of 15.8%.[53] The area maintains a relatively healthy reserve margin, even if short-term demand grows from 66.4 GW in 2024 to 69.7 GW in 2026.[54]

Analysis of Medium-Term Findings

As discussed above, the 2024 Long-Term Reliability Assessment finds that, in the medium term, the WECC Northwest assessment area is at the lowest risk classification available, "normal risk." And the assessment identifies no violations of reliability metrics in 2028.[55] NERC's report finds that only beginning in Summer 2031 do anticipated reserve margins in the WECC Northwest assessment area fall below the reference reserve margin, but that does not include "Tier 2 resources."[56] Tier 2 resources are generally planned resources that have made tangible progress and meet certain criteria.[57] When Tier 2 resource additions are included, the 2024 Long-Term

[51] NERC calculates the Operable Reserve Margin as the amount of anticipated resources (the sum of Existing Certain and Net Firm Transfers and Tier 1 planned additions) calculated as a percentage of total internal demand. 2024 Long Term Reliability Assessment, NERC, July 2025, https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf.

[52] NERC defines the reference margin level as the metric system planners use "...to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads," noting that the reference margin level is often established by a state or other planning / regulatory body. 2024 Long Term Reliability Assessment, NERC, July 2025, https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf.

[53] "2024 Long-Term Reliability Assessment," NERC, page 127.

[54] "2024 Long-Term Reliability Assessment," NERC, page 127.[54] "2024 Long-Term Reliability Assessment," NERC, page 127..,

[55] "2024 Long-Term Reliability Assessment," NERC, page 129.

[56] "2024 Long-Term Reliability Assessment," NERC, page 128.

[57] NERC explains that "Tier 2" refers to "[a] unit that meets at least one of the following guidelines (with consideration for an area's planning processes): Signed/approved Completion of a feasibility study[;] Signed/approved Completion of a system impact study[;] Signed/approved Completion of a facilities study[; or] Requested Interconnection Service Agreement." "2024 Long-Term Reliability Assessment," NERC, page 137. See

Reliability Assessment finds that the reserve margin in the WECC Northwest assessment area remains above reference levels throughout the planning period (*i.e.*, through 2034).[58] Further, to the extent EUE or LOLH are found over the study period, they are fully mitigated by the addition of Tier 3[59] resources.[60]

In sum, the 2024 Long-Term Reliability Assessment finds that the WECC Northwest assessment area begins from a position of strong resource adequacy. No reliability or resource adequacy challenges are expected to emerge, provided the region continues to advance planned generation, transmission, and demand-side resource additions, a proviso that the 2024 Long-Term Reliability Assessment does not doubt.

The 2024 Long-Term Reliability Assessment explicitly states that its designation of "normal risk" across the full study period (2025-2034) reflects planned retirements and the projected 18.7% demand growth in the WECC Northwest assessment area. [61] The assessment explains that the energy associated with these retirements is expected to be replaced primarily by solar, wind, and battery energy storage systems. [62] The 2024 Long-Term Reliability Assessment does not identify retirements as a reliability concern; rather, it notes that reliability challenges could emerge in later study years only if Tier 2 and 3 resources are delayed or not added (and does not include any reason to believe either will occur).[63] While the assessment notes the increased variability inherent to renewable energy and batteries (the vast majority of additions of the study period), it does not characterize this variability as a threat over the planning period.

The 2024 Long-Term Reliability Assessment does not call for delaying planned retirements. Instead, the assessment calls for building upon existing practices for analyzing and planning for retirements, continuing full participation in and support for the long-term assessment processes, and ensuring new transmission and generation can come online quickly.[64]

Together, the 2024 Long-Term Reliability Assessment finds no evidence of medium-term resource adequacy crisis in the WECC Northwest assessment area (or WECC as a whole). In fact, the assessment finds the region in a relative position of strength, particularly if planned buildout of an additional 10GW of Tier 1 resources, 7.2GW of Tier 2 resources, and 43.8GW of Tier 3 resources proceeds.[65] While noting plant retirements as one of the reasons for additional generation, the assessment does not characterize these retirements as threatening reliability over the study period.

also NERC, July 11, 2025, https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf.

[58] "2024 Long-Term Reliability Assessment," NERC, page 128.

[59] NERC defines Tier 3 resources as "units in an interconnection queue that do not meet the Tier 2 requirement." 2024 Long-Term Reliability Assessment, NERC, page 137.

[60] "2024 Long-Term Reliability Assessment," NERC, page 128.

[61] "2024 Long-Term Reliability Assessment," NERC, page 127.

[62] "2024 Long-Term Reliability Assessment," NERC, page 127.

[63] "2024 Long-Term Reliability Assessment," NERC, pages 127-129.

[64] "2024 Long-Term Reliability Assessment," NERC, page 10.

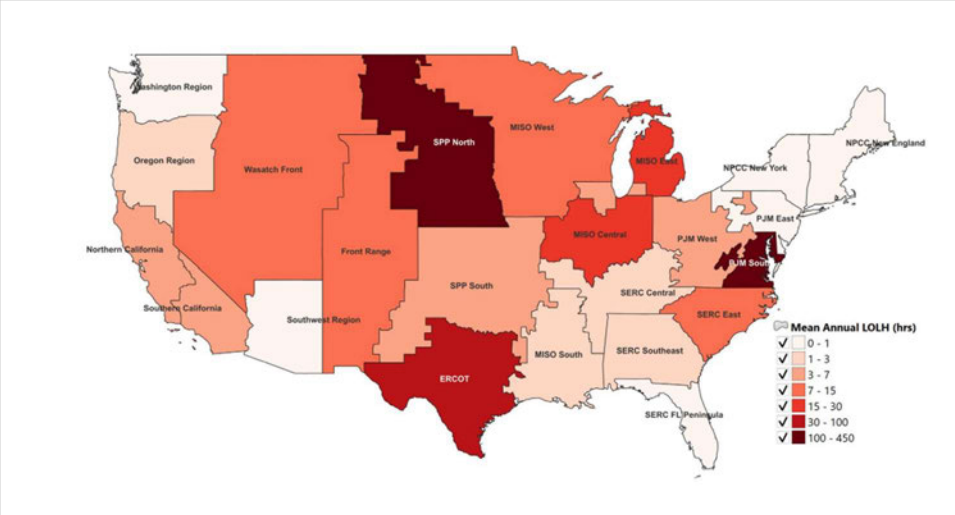
[65] "2024 Long-Term Reliability Assessment," NERC, page 127.

DOE's July Resource Adequacy Report

In July 2025, the Department of Energy released a resource adequacy report, analyzing the impacts of planned retirements on resource adequacy.[66] The July report analyzes several resource adequacy and reliability measures in 2030 nationwide, with findings for various regions and states. DOE acknowledged that its study "could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level."[67]

The DOE study found that plant retirements have only moderate impacts on the West subregions, even when relying on DOE's highly unusual assumption that no Tier 2[68] or Tier 3[69] generation resources are built by 2030.[70, 71] Figure 4 shows the loss of load hours by region in DOE's report.

Figure 42: DOE's July 2025 Report Mean Annual LOLH by Region (2030) – Plant Closures



Source: "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," page 6, U.S. Department of Energy.

[66] "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," U.S. Department of Energy, July 2025, https://www.energy.gov/topics/reliability.
[67] "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," page i, U.S. Department of Energy.
[68] NERC defines Tier 2 resources as those having made tangible progress (e.g., completion of feasibility or system impacts studies) but are less developed than Tier 1 resources. 2024 Long-Term Reliability Assessment, NERC, July 11, 2025, https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf.
[69] NERC defines Tier 3 resources as "units in an interconnection queue that do not meet the Tier 2 requirement." "2024 Long-Term Reliability Assessment," NERC.
[70] "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," page 7 and 37, U.S. Department of Energy.
[71] "Request for Rehearing Of The Clean Energy Organizations," American Clean Power Association, Advanced Energy United, American Council on Renewable Energy, August 6, 2025, https://cleanpower.org/wp-content/uploads/2025/08/2025-08-06-Resource-Adequacy-Rehearing-Request-FINAL.pdf.

DOE's scenarios can be understood as a thought exercise, testing an unlikely hypothetical scenario in which plants are retired, but where utilities do not procure additional generation per typical planning processes and requirements. DOE found that, even in this hypothetical, the non-CAISO West region had the least normalized unserved energy of all regions analyzed.[72]

DOE's July 2025 Report includes no evidence supporting the existence of a near-term resource adequacy crisis. The report does not analyze near-term conditions, and the limitations discussed above render it inadequate as a basis to evaluate, nor to conclude that there is an existing resource adequacy crisis in 2030.

Energy Information Administration Planned Additions and Retirements

The Energy Information Administration (EIA) publishes monthly and annual datasets documenting historical and planned power plant additions and retirements. Order No. 202-25-14 relies on this EIA data, asserting that 571.3 MW of coal-fired generating capacity retired in Colorado since 2019 and that "about" 3,700 MW of coal-fired generating capacity and 675.6 MW of natural-gas-fired generating capacity in Colorado are scheduled to retire by 2029.[73]

EIA data corroborates DOE's reported 571.3MW of historical coal retirements between 2019 and 2022, with no coal capacity retired in Colorado in 2023 or 2024. However, DOE appears to overstate the amount of planned retirements reflected in the EIA data. As shown in the November 2025 EIA Form 860M dataset, only 2,789.6 MW of coal-fired generation and 656.8 MW of natural gas-fired generation in Colorado are reported to have planned retirement dates. The source of the discrepancy, approximately 910MW of coal-fired generation, is unclear. Only by including Comanche Unit 3, which is currently scheduled to retire no later than January 1, 2031, but is not assigned a retirement date in EIA's data, does the coal retirement total expand to 3,646 MW, or approximately 3,700 MW. Table 3 compares the EIA data with the retirement figures cited in Order No. 202-25-14.

[72] "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," pages 8 and 37, U.S. Department of Energy.
[73] DOE Order at 2.

Table 3: Comparison of Planned Retirements in EIA Data and Order 202-25-14

	Order 202-25-14	EIA 860 M Data*	Discrepancy
Historical (2019-2024) Coal Retirements	571.3 MW	571.3 MW	None
Planned Coal Retirements by 2029	~3,700 MW[74]	2,789.6MW	~910 MW
Planned Natural Gas Retirements by 2029	656.8 MW	675.6 MW	18.8 MW

*As of November 2025 (released December 2025)

Moreover, DOE's Order cites EIA data to identify planned generation retirements but does not acknowledge that the same EIA data also show substantial new generation additions in Colorado. Significant generation has been deployed and is planned for deployment in response to both retirements and load growth. Based on November 2025 EIA data - the same dataset DOE relies on in its order - Colorado added more than 4.8 GW of additional generating capacity between 2019 and November 2025.[75] By 2029 (the latest year available in the data), nearly 5.8 GW of additional generating capacity is planned in Colorado.[76] In total, as shown in Table 4, approximately 10.6 GW has been or is planned to come online between 2019 and 2029, compared to approximately 4.3 GW that has retired or is expected to retire over the same period. This trend is illustrated by the planned 2028–2029 pipeline, which more than doubled from 1,295 MW in the December 2024 EIA data to 2,913 MW in the November 2025 EIA data.[77]

Table 4: Comparison of Planned Retirements in EIA Data and Order 202-25-14

	Retirements (MW)	Deployments (MW)
Historical (2019-2024) Retirements	845.9	4,827.6
Planned Retirements by end of 2029	3,455	5,793.5
Total (2019-2029)	**4,300.9**	**10,621.1**

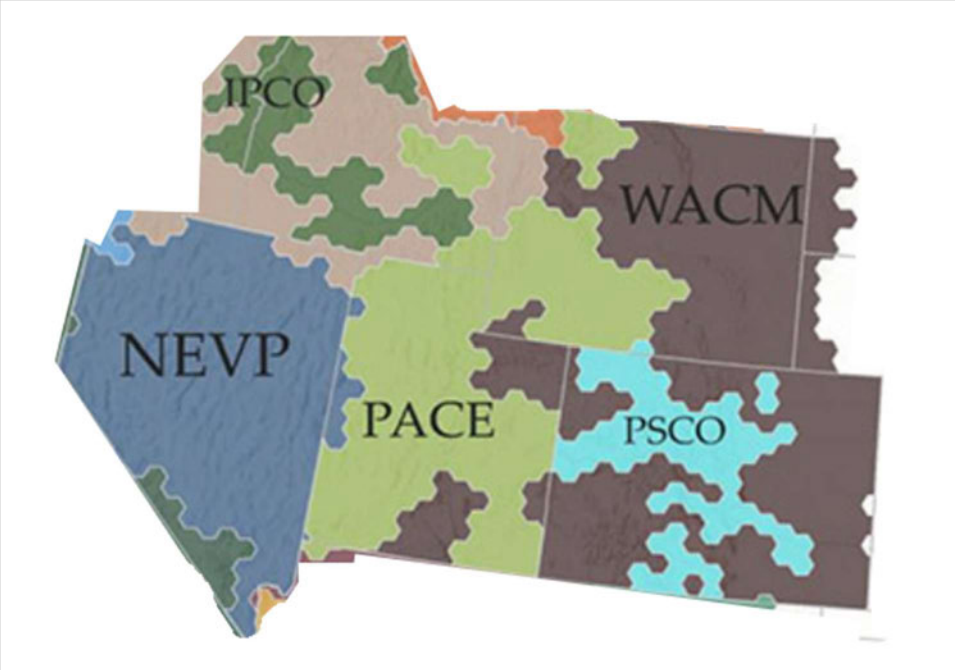
[74] DOE Order at 2.
[75] "Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860)," November 2025 data, U.S. EIA, accessed January 21, 2026, https://www.eia.gov/electricity/data/eia860m/.
[76] "Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860)," November 2025 data, U.S. EIA
[77] "Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860)," December 2024 and November 2025 data, U.S. EIA, accessed January 21, 2026, https://www.eia.gov/electricity/data/eia860m/.

Balancing Authorities and Real-Time System Operations

As previously discussed, Resource Adequacy is generally forward-looking and distinct from real-time system operations. In addition to the extensive resource adequacy planning efforts discussed above, there is also a suite of tools available to manage the power system in real time when challenged by extreme weather, load conditions, or other occurrences. Balancing Authorities are required by NERC and other entities to have extensive operational plans to respond to threats as wide-ranging as natural disasters, winter storms, or squirrels.

Balancing Authorities are the entities responsible for managing power system operations (e.g., balancing supply and demand) and ensuring the real-time reliability of the electric system within a specific geographic area. The Western Interconnection, which spans into Mexico and Canada, has 34 Balancing Authorities in the United States. Five major Balancing Authorities are located in the Mountain West region, depending on the chosen footprint, as shown in the figure below.[78]

Figure 5: Mountain West Balancing Authorities



The outputs of Resource Adequacy planning ultimately inform, but do not replace, the real-time reliability responsibilities of Balancing Authorities. A Balancing Authority maintains real-time balance by ensuring that generation, load, and transmission interchanges align at all times. Although generators may be owned and operated by different utilities, the Balancing Authority is responsible for ensuring that each resource's schedules and actual output support system balance and comply with reliability requirements. The Balancing Authority does not economically dispatch

[78] "26 Western Entities Signal Continued Support for Markets+," RTO Insider LLC, April 15, 2024, https://www.rtoinsider.com/76303-western-entities-signal-continued-support-rto-markets/.

resources it does not control. Rather, the Balancing Authority oversees scheduling and deploys its own balancing reserves to ensure the area remains in compliance with NERC reliability standards. Public Service Company of Colorado and the Western Area Power Administration – Rocky Mountain Region (shown as PSCO and WACM in the figure above, respectively) are the main Balancing Authorities for Colorado.

Balancing Authorities are responsible for developing, maintaining, and executing emergency procedures in extreme conditions. NERC Reliability Standard EOP-011 sets the requirements for Balancing Authorities and Reliability Coordinators.[79] The current NERC requirements (approved by FERC in 2024) require Balancing Authorities to have operations plans for energy and capacity-based emergencies and prescribe actions regarding record-keeping and communications for Balancing Authorities. NERC also defines Energy Emergency Alert (EEA) levels reflecting conditions in a Balancing Authority as shown in the table below. [80] The Western Electricity Coordinating Council provides further information on best practices for complying with NERC guidelines and potential actions to take in an emergency.[81]

Balancing Authorities develop plans in response to the NERC (or other) requirements. The NERC rules allow for Balancing Authorities to develop plans to flexibly and proportionally respond to challenges or crises such as unplanned outages, extreme conditions, natural disasters, or other scenarios. In other words, Balancing Authorities are required to maintain a variety of options to respond to emergencies based on localized conditions.

[79] "EOP-011-4 – Emergency Operations," NERC, accessed December 16, 2025, https://www.nerc.com/globalassets/standards/reliability-standards/eop/eop-011-4.pdf.
[80] "2025–2026 Winter Reliability Assessment," Table 4, NERC, November 2025, https://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf.
[81] "Best Practices for Energy Emergency Alerts," Western Electricity Coordinating Council, March 28, 2022, https://www.wecc.org/sites/default/files/documents/meeting/2024/07%20-%20Park%20G%20-%20Best%20Practices%20for%20EEAs_July%202024.pdf.

Table 5: NERC Energy Emergency Alert (EEA) Level Descriptions [82]

EEA Level	Description	Circumstances
EEA 1	All available generation resources in use	▪ The BA is experiencing conditions in which all available generation resources are committed to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required operating reserves. ▪ Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
EEA 2	Load management procedures in effect	▪ The BA is no longer able to provide its expected energy requirements and is an energy-deficient BA. ▪ An energy-deficient BA has implemented its operating plan(s) to mitigate emergencies. ▪ An energy-deficient BA is still able to maintain minimum operating reserve requirements.
EEA 3	Firm load interruption is imminent or in progress	▪ The energy-deficient BA is unable to meet minimum operating reserve requirements.

CEG's Assessment on Resource Adequacy in the Pacific Northwest

In January 2026, Current Energy Group conducted an assessment of several major regional planning and reliability studies in response to the DOE's order requiring the continued operation of the Centralia Power Plant Unit 2 in Washington State. That assessment, titled "Resource Adequacy in the Pacific Northwest," focused on the Pacific Northwest, which is part of the WECC Northwest assessment area defined in the DOE Order associated with Craig Station Unit 1. That assessment also examined two of the same sources discussed in this report, namely, WECC's 2024 Western Assessment of Resource Adequacy and DOE's July Resource Adequacy Report, albeit with a slightly different regional focus. That assessment informs our opinion in this report and is therefore part of this report in Appendix A.

Disclaimer

This report was prepared by Current Energy Group (CEG). It is intended to be read and used as a whole and not in parts. The report reflects the analyses and opinions of the authors using currently available information and does not necessarily reflect those of any other entity associated with this work.

[82] "2025–2026 Winter Reliability Assessment," Table 4, NERC.

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APPENDIX A



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Resource Adequacy in the Pacific Northwest

An Assessment of Resource Adequacy Studies Following the Planned Retirement of Centralia

Prepared for Earthjustice, Sierra Club, and Environmental Defense Fund

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Executive Summary

On December 16, 2025, the U.S. Department of Energy (DOE) issued Order 202-25-11 under its authority under section 202(c) of the Federal Power Act to prevent the planned retirement of Unit 2 of the Centralia Power Plant on grounds of "a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes" in the Western Electricity Coordinating Council (WECC) Northwest region.[1] In support of this determination, DOE relied heavily on findings from the North American Electric Reliability Corporation (NERC) and Energy + Environmental Economics (E3).

As of 2025, WECC-Northwest includes Washington, Oregon, Montana, and parts of northern California and northern Idaho. The following map shows the WECC subregions.[2]

Figure 1: Map of the WECC subregions



[1] U.S. Department of Energy (DOE). "Order No. 202-25-11," December 16, 2025. https://www.energy.gov/documents/order-number-202-25-11.

[2] "2025–2026 Winter Reliability Assessment Western Overview," WECC, Subregion Reliability Highlights, November 2025, https://feature.wecc.org/seasonal-assessment-western-overview/index.html.

In this report, Current Energy Group (CEG), evaluates the resource adequacy and reliability findings contained in the studies relied upon by DOE, as well as several other prominent regional resource adequacy studies, and places them in broader regional planning context. CEG did not conduct a new or independent resource adequacy model. Rather, this assessment reviews, synthesizes, and interprets the results of existing national, regional, and utility-level studies to examine:

- The extent to which RA best practices have been followed,
- The geographic scope covered by the analyses,
- How load growth has been incorporated into RA analyses,
- If/how analyses planned for Centralia's retirement (and repowering)

Based on this review, CEG assesses whether the findings support the conclusion that WECC-Northwest faces an imminent or emergency-level resource adequacy crisis. As discussed below, no study supports the conclusion that WECC-Northwest faces a resource adequacy crisis, including the studies on which DOE relied. Any risk identified in the studies is more appropriately characterized as a medium-term planning challenge of the type regularly addressed by state, regional, and utility planning processes.

Near-Term Findings (2026)

All of the planning studies—those upon which DOE relied and the ones DOE does not discuss—assume Centralia Unit 2's retirement on December 31, 2025. Across the studies most directly relied upon by DOE, particularly NERC's 2025/2026 Winter Reliability Assessment and E3's Phase 1 results, the record does not support a finding of a resource adequacy crisis in 2026 or early 2027. The same goes for the other prominent planning studies.

NERC concludes that the region has sufficient capacity to meet expected peak demand this winter. NERC also does not identify violations of key probabilistic reliability metrics under normal assumptions. NERC identifies only one type of extreme scenario presenting risk, which is characterized as "[a]bove-normal peak demand combined with high generator outages in extreme conditions."[3] But the risk presented is only whether the region will maintain its reserve margin (*i.e.*, its buffer of additional resources above that necessary to meet demand), and NERC expressly concludes that the risk is addressed through imports.[4] In fact, NERC emphasizes that "[o]perating reserve margins are expected to be met after imports in all winter scenarios."[5] NERC's classification falls short of the "high risk" designation reserved for conditions in which operating reserve requirements cannot be met under expected conditions.

E3 also recently examined resource adequacy in Washington, Oregon, Montana, Idaho, Utah, and Wyoming, a somewhat different region than WECC-Northwest. In the area it examined, E3

[3] "2025–2026 Winter Reliability Assessment," page 37, NERC, November 2025, https://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf.
[4] "2025–2026 Winter Reliability Assessment," page 37, NERC.
[5] "2025–2026 Winter Reliability Assessment," page 37, NERC.

estimates that in 2026 resources will be slightly (approximately 380 MW) below 50,737 MW, the amount E3 estimates is needed to secure a full margin above peak demand and meet obligations under an international treaty. E3 does not identify this shortfall as an emergency, nor do we consider it an emergency. E3's modeled loss-of-load expectation is approximately 0.15, which represents a small deviation from commonly used planning thresholds (0.1 loss-of-load expectation) and does not indicate a material increase in the risk of load loss in 2026. E3's analysis, moreover, relies on conservative estimates of the region's import capabilities that are lower than levels observed during recent extreme events and assumptions for hydropower that do not reflect current hydrological conditions. When accounting for in-development resources, observed regional import performance during recent extreme events, and current hydrological conditions, the identified shortfall—which is less than 1 percent—would likely evaporate.

Other regional and utility-level planning studies, including those from the Western Electricity Coordinating Council, Bonneville Power Administration (BPA), and Puget Sound Energy (PSE), do not identify a shortfall. These entities thus further reinforce the conclusion that WECC-Northwest does not face a near-term reliability crisis.

Table 1: Summary of Short-Term Resource Adequacy Findings

Organization	Study	Sufficient Resources to Meet Peak Demand with Full Reserve Margin in 2026?	Assumed Centralia Coal Retirement?	Considered Multiple Reliability Metrics?
NERC	2025/2026 Winter Reliability Assessment	Yes	Yes	Yes
Western Electricity Coordinating Council	2024 Western Assessment of Resource Adequacy	Yes	Yes	Yes
Puget Sound Energy	2023 Update to Puget IRP	Yes	Yes	Yes
Bonneville Power Administration	BPA Resource Program (2024) and White Book (2025)	Yes	Yes	Yes
E3	Phase 1 Results	No*	Yes	Yes

*As discussed below, E3's study relied on several conservative assumptions that understate the contributions of existing and expected resources, including assumptions related to import capacity, planned resource additions, and Canadian hydropower entitlements.

Medium-Term Findings (2027–2031)

The studies reviewed by CEG consistently identify growing resource adequacy gaps in the latter part of the decade, driven primarily by potential rapid load growth, particularly from potential data center development, rather than by coal or other resource retirements. E3 projects a substantial resource gap by 2030 under its modeled assumptions, and this finding should be taken seriously as an indication that additional resources, transmission, and demand-side measures will be required. Notably, E3 explains that the entire resource gap is addressed by completion of projects that utilities have identified in their Integrated Resource Plans.

The reviewed studies—including from E3, NERC, Western Electricity Coordinating Council, the Northwest Power and Conservation Council, BPA, and Puget Sound Energy—do *not* characterize these medium-term challenges as an immediate reliability crisis. Instead, they present the emerging gap as a planning signal intended to inform timely action through established state and regional resource planning, procurement, and coordination processes. The studies emphasize the importance of accelerating resource development, refining load forecasts and reliability assumptions, expanding transmission capability, and strengthening regional coordination. The studies do not support a proposition that extraordinary federal interventions into established processes are necessary to address the challenges in the latter part of the decade. Rather, federal intervention sends mixed and counterproductive signals to the market that undermine existing planning and procurement practices.

Overall Conclusions

Taken together, the body of regional and national planning evidence does not support the conclusion that the Pacific Northwest faces an imminent or emergency-level resource adequacy crisis. The retirement of Centralia Unit 2 is a long-planned transition that is fully reflected in regional planning analyses and is not identified as a driver of either near-term or medium-term reliability risk.

The emergence of larger modeled shortfalls toward 2030 is an important finding, but one that reflects the normal function of resource adequacy planning: to identify risks early enough for state, regional, and utility processes to respond through deliberate, coordinated action, as they have done for decades.

What is Resource Adequacy?

Introduction

Electric resource adequacy and energy system reliability are among the most important, discussed, and analyzed energy challenges among utility practitioners, regulators, and policymakers. Both resource adequacy and reliability practices and requirements have evolved over time with the growth of the electricity system, advancements in economic and regulatory theory, and in response

to prominent grid failures like the Northeast blackouts of 1965 and 2003.[6] This has led to a layered planning and regulatory framework for the bulk power system involving national entities (the North American Electric Reliability Corporation and the Federal Energy Regulatory Commission), regional reliability organizations, and state regulators, each of which conducts ongoing assessments and planning studies. These layers intentionally overlap, with assessments from different organizations analyzing different geographies or using different methodologies and time horizons. Collectively, these resource adequacy and reliability planning efforts create a robust record with which to evaluate DOE's claims of a reliability and resource adequacy crisis.

Resource Adequacy describes the situation where an electric system has enough capacity available to meet customer demand, plus a reserve margin on top, in most hours under most conditions based on a chosen standard.[7,8] The National Laboratory of the Rockies (formerly National Renewable Energy Laboratory) defines a power system as being resource adequate "if it has procured sufficient resources (including supply, transmission, and responsive demand) such that it runs a sufficiently low risk of invoking emergency measures (such as involuntary load shedding) due to resource unavailability or deliverability constraint."[9] The level of risk deemed sufficient is typically defined by a resource adequacy standard (*e.g.*, the "1-in-10" standard discussed below) set by planners based on engineering judgement and acceptable cost. Because no system can ever be perfectly reliable, planners must determine how to appropriately balance incremental cost and risk reduction. Put simply, resource adequacy measures how much generation and other resources are available to meet load.

Resource adequacy and power system reliability are closely related but distinct concepts. Reliability refers to the ability of the electric system to deliver electricity to customers in real time, encompassing generation, transmission, and distribution. Even where the bulk power system is resource adequate and reliable, customers may still experience outages, primarily due to distribution-level issues, such as a downed residential line caused by a fallen tree.

How Resource Adequacy is Assessed

Resource adequacy planning is a well-established practice across the country where multiple entities independently produce resource adequacy assessments for each region, generally according to a centralized standard. These assessments often will complement or overlap but may use different methodological approaches or metrics. As there is no "national standard" for resource

[6] "Reliability Explainer," Federal Energy Regulatory Commission, accessed December 21, 2025, https://www.ferc.gov/reliability-explainer; "Resource Adequacy: History and Catalog of Metrics," Electric Power Research Institute, December 31, 2018, https://www.epri.com/research/products/000000003002013734.
[7] "Reliability Explainer," Federal Energy Regulatory Commission, accessed December 16, 2025, https://www.ferc.gov/reliability-explainer.
[8] "Resource Adequacy Basics," National Renewable Energy Laboratory, archived October 20, 2025, accessed December 16, 2025. https://web.archive.org/web/20251020042833/https://www.nrel.gov/research/resource-adequacy.
[9] "Probabilistic Resource Adequacy Suite (PRAS) v0.6 Model Documentation," National Renewable Energy Laboratory (now National Laboratory of the Rockies), May 2021, https://docs.nrel.gov/docs/fy21osti/79698.pdf.

adequacy, each state and grid operator (often the local utility) establishes its own approach. The collection of multiple, overlapping but independently produced studies help operators, policymakers, and the many vested stakeholders make decisions to ensure the adequacy of the bulk electric system.

The context of each study is important. Because each study is a product of its underlying methodology, assumptions, and goals, any reliance on a given study must be based on consideration of the study's particular context. A study's findings cannot be relied upon without due consideration of the context, including the underlying methodology, assumptions, and goals.

An essential component of each study is the metric or metrics used to measure resource adequacy. There are several metrics used across North America to capture different dimensions of resource adequacy. These metrics can be broadly categorized as deterministic or probabilistic.[10] Deterministic metrics were historically more common because they are relatively simple to calculate and rely on fixed assumptions about load, resource availability, and reserve margins. In recent years, however, many planning entities have increasingly relied on probabilistic metrics, which evaluate the distribution of possible outcomes across a wide range of system conditions. Probabilistic metrics are better suited to capturing uncertainty and risk and are generally viewed as more informative than deterministic metrics for assessing resource adequacy.

- **Loss of Load Expectation (LOLE).** This metric measures the expected number of loss-of-load event-days over the study's planning period. An event-day is usually defined as any single day in which electricity demand is not met at least once because system resources were not sufficient to meet demand, whether the event lasts 5 minutes or 5 hours. A single event that spans two days is counted as two event-days. In general, $LOLE = \frac{Number\ of\ Event-Days}{Total\ Time\ Period}$. The most common LOLE standard is "1-in-10," which refers to an expectation that there is no more than 1 event-day (resulting from insufficient resources) in a 10-year period. The 1-in-10 standard equates to a LOLE of 0.1, calculated as $0.1 = \frac{1\ event-day}{10\ years}$. LOLE is usually evaluated on a yearly timescale, but it can also be expressed at an hourly or daily timescale.
- **Loss of Load Hours (LOLH).** This metric is an expression of LOLE where an "event" is specified to be at the hourly level (*e.g.*, 15 hours in 10 years), allowing for higher resolution of the duration of potential shortfalls.
- **Loss of Load Probability (LOLP).** This metric is like LOLE, except that it measures the expected percentage of events over the planning period in which there was a loss of load. LOLP is equivalent to LOLE divided by the period chosen. For example, a 1-in-10 LOLE standard would lead to a LOLP of 0.0274% per day, calculated as:

$$LOLP = \left(\frac{1\ event-day}{10\ years}\right) * \left(\frac{1\ year}{365\ days}\right) * 100 = 0.0274\%$$

[10] "Metrics Explainers," Electric Power Research Institute, accessed 12/16/2025, https://msites.epri.com/resource-adequacy/metrics/metrics-explainers.

- **Expected Unserved Energy (EUE).** This metric measures the total expected amount of unserved energy, in MWh, over the planning period. Unlike LOLE and LOLP, which measure the frequency or likelihood of a loss-of-load event, EUE measures the magnitude of energy demand not served. While modeling tools would quantify actual EUE in given scenarios, a simple conceptual relationship is as follows: EUE is equal to the LOLE multiplied by the average magnitude of the shortfall. For example, if a model found that the average shortfall during an event was 200MW across a 1-in-10 LOLE standard, and further assuming that the event lasts a full 24 hours, the EUE per year would be 480MWh.
- **Planning Reserve Margin (PRM).** This metric measures the difference between the total resources and the expected peak load, divided by the peak load. It is expressed as a percentage.[11] For example, if a system has 107,000 MW of resources and an expected peak load of 100,000 MW, the system has a 7% reserve margin, calculated as:

$$PRM = \left(\frac{107{,}000 - 100{,}000}{100{,}000}\right) = 7\%$$

  The PRM assessment may, and typically does, "de-rate" resources based on the likelihood that a generator will be unavailable or produce less than its maximum potential output (i.e., less than its "nameplate capacity") during a peak demand period. The resulting figure is known as a generator's "accredited" capacity. For example, although the system's total nameplate capacity could be 225,000 MW, resource accreditation may result in only 107,000 MW being counted for PRM purposes. Accreditation is further discussed below.

Each metric measures a different aspect of system risk, and most regions rely on multiple metrics. PRM provides a high-level indicator of resource capacity relative to expected peak load, but it does not capture hourly or seasonal variability in resource availability. LOLE and LOLP quantify the probability and frequency of shortfall events, but do not identify the magnitude of a loss of load event. EUE is used to measure the total quantity of energy that cannot be served in a loss-of-load event. By using multiple metrics, planners can capture both the likelihood and the magnitude of potential shortages, which a single metric cannot do on its own.

The Northwest Power and Conservation Council, an interstate compact agency created by Congress to conduct long-term regional planning for the region, uses several metrics that measure both the likelihood and the magnitude of events. The Western Resource Adequacy Program, a voluntary regional reliability and capacity-sharing program composed of electric utilities across the Pacific Northwest and the broader Western Interconnection, uses LOLE as its primary metric in its probabilistic analysis.[12]

[11] "Metrics Explainers," Electric Power Research Institute, accessed 12/16/2025, https://msites.epri.com/resource-adequacy/metrics/metrics-explainers.

[12] "Western Resource Adequacy Program Tariff of Northwest Power Pool D/B/A Western Power Pool," Western Power Pool, March 16, 2025, https://www.westernpowerpool.org/private-media/documents/WRAP_Tariff_Effective_3.16.25.pdf.

Because these metrics evaluate system risk, the studies need a method for representing how much each resource will likely contribute to meeting demand during period of system stress. In LOLE-, LOLH-, or EUE-based analyses, this is typically done through probabilistic assumptions about unit availability, forced outages, and load shapes rather than relying on nameplate capacity alone to reflect each resource's expected availability during peak or net-peak hours. In most of the country, these performance assumptions guide grid operators when they assign resources an accredited capacity value. The most commonly used probabilistic accreditation method is Effective Load Carrying Capability (ELCC), which measures the contribution a resource makes to reducing loss-of-load risk, typically by comparing system reliability outcomes with and without the resource relative to a benchmark "perfect capacity" resource. The purpose of applying an accredited value (via ELCC or another method) to each resource is to ensure that resources are counted based on their contribution to reducing loss-of-load risk, rather than their installed capacity.

Who Conducts Resource Adequacy Planning

Resource adequacy planning occurs at multiple institutional layers, each producing a unique assessment based on its purview, methodology, and assumptions. States in the Western Interconnection do not have a single coordinating entity that sets resource adequacy requirements. As a result, there are several independent organizations, many with overlapping jurisdictions, that conduct and publish resource adequacy analyses for the Pacific Northwest. Each of these assessments provides complementary but sometimes divergent perspectives on system conditions.

At the national level, the North American Reliability Corporation, or NERC, is the entity responsible for ensuring the reliability and security of the North American bulk power system, under delegated authority from the Federal Energy Regulatory Commission (FERC).[13] NERC performs a variety of functions. It develops and enforces mandatory reliability standards. It also monitors the bulk power system. And NERC assesses system reliability through a variety of forecasts: (1) an annual 10-year forecast, (2) an annual forecast of the upcoming summer, usually issued about a month or two before summer begins, and (3) an annual forecast of the upcoming winter, also typically issued about a month or two before winter begins. Other NERC functions include "audit[ing] owners, operators, and users [of the bulk power system] for preparedness, as well as educat[ing] and train[ing] industry personnel."[14]

State regulators play an essential role in resource adequacy and reliability planning. Public Utility Commissions, such as the Washington Utilities and Transportation Commission in Washington state, typically approve utility resource adequacy assessments, specific power plants, and capital expenditures through their review of requested Certificates of Public Convenience and Necessity (CPCNs), rate cases, and integrated resource plans. Electric utilities, both investor-owned and consumer-owned, develop integrated resource plans that identify how the utility will meet

[13] "Reliability Explainer," Federal Energy Regulatory Commission, accessed December 16, 2025, https://www.ferc.gov/reliability-explainerhttps://www.ferc.gov/reliability-explainer.
[14] "Who We Are," North American Electric Reliability Corporation, accessed December 23, 2025, https://www.nerc.com/who-we-are.

customer demand over the planning horizon, usually 20 years. Electric utilities typically develop integrated resource plans every 2 to 3 years and rely on a variety of methods for evaluating resource adequacy and accrediting resources. The utility-specific resource adequacy assessment and the resource accreditation values are important components for identifying the utility's future resource needs.

In addition to state and national entities, there are several entities in the Pacific Northwest region that provide regional resource adequacy assessments.

1. **Western Electricity Coordinating Council (WECC)** is one of the six regional entities with delegated authority from NERC to ensure reliability and resource adequacy. As the FERC-approved regional manager for reliability for the Western Interconnection, its geographic focus spans 14 Western states, 2 Canadian provinces, and Northern Baja Mexico. [15] Its functions include setting standards, identifying threats and shortfalls, and monitoring compliance. As part of this role, WECC conducts interconnection-wide resource adequacy assessments. WECC's assessments are advisory rather than binding, but they provide one of the most comprehensive views of adequacy risks across the Western grid and can be (and are) used as inputs to utility, state, and regional resource adequacy planning processes. WECC is divided into eight sub-regions as shown in Figure 1.[16]
2. **Northwest Power and Conservation Council (NWPCC)** is a regional planning body created by Congress in 1980 to ensure reliable, affordable, and environmentally responsible energy for Washington, Oregon, Idaho, and Montana (Northwest). The council develops a regional power plan that guides Bonneville Power Administration, regional utilities, and federal hydropower operations in the region. The council conducts an annual resource adequacy assessment through a collaborative approach with its Resource Adequacy Committee[17] made up of regional utilities and stakeholders.[18]
3. **The Western Power Pool's Western Resource Adequacy Program (WRAP)** is the first coordinated regional resource adequacy planning and compliance program in the Northwest. Although participation is voluntary, member utilities enter into a binding agreement to meet common resource adequacy standards and comply with the program's planning and operational requirements. The program received FERC approval of its tariff in February 2023, establishing enforceable capacity sufficiency demonstrations, resource accreditation methods, and operational sharing provisions.[19] The Western Resource Adequacy Program will start binding operations in Winter 2027/2028 for the 16

[15] "About WECC," Western Electricity Coordinating Council (WECC), accessed December 23, 2025. https://www.wecc.org/about/about-wecc.
[16] "2025–2026 Winter Reliability Assessment Western Overview," WECC, Subregion Reliability Highlights, November 2025, https://feature.wecc.org/seasonal-assessment-western-overview/index.html.
[17] "Resource Adequacy Advisory Committee," Northwest Power and Conservation Council, accessed December 16, 2025, https://www.nwcouncil.org/energy/energy-advisory-committees/resource-adequacy-advisory-committee/.
[18] "Resource Adequacy Advisory Committee – Steering Committee Members," Northwest Power and Conservation Council, June 2024, https://nwcouncil.app.box.com/s/m922hdzzk0mxsoke01l9xgcvpqj0412o.
[19] "History," Western Power Pool, accessed December 16, 2025, https://www.westernpowerpool.org/about/history/.

participants who agreed to participate by October 31, 2025.[20] These participants include a number of utilities and entities in the WECC-Northwest region: BPA, Puget Sound Energy, PUD No. 1 of Chelan County, Avista Corp., Clatskanie People's Utility District, Constellation, PUD #2 of Grant County, NorthWestern Energy, Seattle City Light, Tacoma Power, and The Energy Authority, Inc. Before binding operations begin, the Western Resource Adequacy Program will release informational assessments on regional resource development, ELCCs, and calculated PRMs.[21] The Western Resource Adequacy Program will provide a consistent, region-wide framework for assessing and addressing resource adequacy needs and represents a significant step forward in strengthening reliability across the West.[22]

4. **Bonneville Power Administration (BPA)** is a federally managed, semi-independent power marketing agency and one of the largest regional electric planning entities in the Pacific Northwest. BPA markets power from 31 federal hydroelectric dams and one nuclear plant, owns and operates roughly 75 percent of the region's high-voltage transmission system, and provides power and transmission services to approximately 148 customers, including public utility districts, cooperatives, and investor-owned utilities.[23] BPA's hydrological data, operational planning studies, and transmission reliability evaluations are foundational inputs to regional RA modeling conducted by other organizations. BPA also produces its own long-term planning documents which assess resource adequacy needs.

In addition to the regional resource adequacy organizations, there are at least two other entities that provide input and operational data that are frequently used for developing resource adequacy assessments. While we do not discuss these organizations in detail, they are important for understanding the depth and breadth of planning in the region.

1. **Pacific Northwest Utilities Conference Committee (PNUCC)** is a member organization of utilities in the West, primarily the Northwest, with the purpose of sharing information and jointly addressing issues to the membership (including resource adequacy). PNUCC annually publishes its members' energy and peak demand forecasts, which serve as inputs in resource adequacy and other analytical assessments.

2. **NorthernGrid** is the FERC-jurisdictional regional transmission planning organization for much of the Northwest, as well as the Intermountain West, responsible for developing long-term transmission plans under FERC Order 1000. Its studies evaluate future load, resource additions, and system contingencies to identify needed transmission upgrades, all of which influence regional transfer capability.

[20] "WPP Notice to WRAP Resource Adequacy Participants Committee," Western Power Pool, October 31, 2025, https://www.westernpowerpool.org/news/wpp-notice-to-wrap-resource-adequacy-participants.
[21] "Metrics," Western Power Pool, accessed December 16, 2025, https://www.westernpowerpool.org/resources/wrap_metrics/.
[22] "Tariff & Business Practice Manuals," Western Power Pool, accessed 12/16/2025, https://www.westernpowerpool.org/resources/wrap_bpms/.
[23] Corrina Ikakoula, *Bonneville Power Administration Overview*, U.S. Department of Energy, January 2016, accessed December 16, 2025, https://www.energy.gov/sites/prod/files/2016/01/f28/0911review_ikakoula.pdf.

Summary and Interpretation

Resource adequacy planning is conducted widely across the country, and the variety of methods, geographic scopes, and modeling approaches provides a robust set of perspectives on system conditions. Resource adequacy is inherently probabilistic. It is not an end state but an ongoing evaluation of risk, and all findings include uncertainty. A projected shortfall in a given modeling approach does not ensure an outage, or even necessarily predict one, particularly where the projection is a small shortfall below a target reserve margin. Although individual studies may differ in their specific findings or the magnitude of particular metrics, consistent patterns across assessments offer meaningful signals about regional adequacy. For example, if multiple studies indicate medium-term capacity shortfalls, that alignment points to elevated medium-term risk; similarly, broad agreement on sufficient near-term resources suggests low near-term risk.

Analysis of PNW Resource Adequacy Reports and Findings

Introduction to Analysis Section

In this report, we identify the key Northwest resource adequacy studies, analyze their findings, and compare their conclusions against DOE's stated rationale in the 202(c) order. We analyze studies conducted by the North American Electric Reliability Corporation, the Western Electricity Coordinating Council, the Northwest Power and Conservation Council, E3 (a consulting firm), Bonneville Power Administration, and Puget Sound Energy. These assessments use a range of deterministic and probabilistic methods that evaluate system conditions across a variety of scenarios, including extreme weather, low hydro conditions, and delayed resource development.

As noted above, we assess each study across two planning horizons: the near-term (less than 1 year) and the medium-term (1 year to 5 years) focusing on modeling outcomes, underlying assumptions, and treatment of major system changes including resource retirements. The near-term analysis evaluates resource adequacy and reliability conditions under operating conditions in which system operators generally rely on the existing resource portfolio and established emergency and operational tools, rather than new resource procurement or infrastructure development. By contrast, the medium-term analysis evaluates planning organizations' findings and identifies potential deficiencies in underlying assumptions, models, or processes.

While these analyses identify elevated risks in certain circumstances, none conclude, and none supports a conclusion, that the studied regions are at imminent risk of failing to meet demand in 2026 or in the years immediately following. Importantly, all studies incorporate planned coal retirements, including Centralia, into their modeling frameworks. The retirement of Centralia is therefore not an unaccounted-for development, but rather a long-planned transition that is fully embedded in the region's resource outlook.

Analysis of Short-Term (2026) Findings

Summary of near-term (2026) findings: Near-term resource adequacy conditions for 2026 do not indicate that the region is likely to experience a resource adequacy shortfall. NERC's Winter

Reliability Assessment and Western Electricity Coordinating Council's Western Assessment of Resource Adequacy provide high resolution short-term findings, and analyses from BPA and Puget Sound Energy provide complementary short-term insights. All studies note that extreme winter conditions or significant delays in new generation could create challenges, but none identify an imminent crisis, recommend extraordinary measures, or predict that resources will be insufficient to meet demand. While E3's assessment identifies a modeled resource adequacy shortfall in 2026, that finding is driven by a set of conservative assumptions related to the region's imports capabilities and treaty obligations. E3's assessment also does not reflect the region's current weather conditions, which points towards support to resource adequacy. Table 1 summarizes our findings.

2025/2026 NERC Winter Reliability Assessment Short-Term Findings

NERC's annual Winter Reliability Assessment is an analysis of immediate reliability and resource adequacy in the United States and Canada for the upcoming winter season. NERC's 2025/2026 assessment, released in November 2025, found all regions to be resource adequate under normal peak-load conditions.[24]

NERC concludes that, in WECC-Northwest, "there is sufficient capacity in the area for expected peak conditions,"[25] and its probabilistic analysis finds no Expected Unserved Energy or Loss of Load Hours for Winter 2025–26 when planned additions are included. NERC also finds that, based on planned resource additions, imports, and expected demand growth, that no resource adequacy metrics are violated for the region, stating, "The results of the probabilistic assessment reveal no [expected unserved energy] or [loss of load hours] for Winter 2025–2026." [26] NERC further explains that the results for a case where new resource additions are not completed for Winter 2025-26 found "some" expected unserved energy and loss of load hours, without specifying the magnitude.[27] The region's reserve margin is projected at 30.9%, nearly double typical requirements.[28] Only in the most extreme conditions (*i.e.*, higher than expected demand paired with higher than expected generation outages) does NERC assess that the region risks pre-import shortfalls—and even then, the shortfalls are only below reserve margins (not expected peak load), and the region can rely on imports to restore reserve margins "in all winter scenarios."[29]

NERC also finds that planned Tier 1 resources ("soar[ing]" from 463 MW to more than 3 GW) and increased firm imports (6.1 GW) more than offset the reduction from retiring units.[30] The region's imports are particularly valuable for maintaining resource adequacy in extreme conditions. For

[24] "2025–2026 Winter Reliability Assessment," page 5, NERC, November 2025, https://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf.
[25] "2025–2026 Winter Reliability Assessment," NERC, page 6.
[26] "2025–2026 Winter Reliability Assessment," NERC, page 15.
[27] "2025–2026 Winter Reliability Assessment," NERC, page 15.
[28] "2025–2026 Winter Reliability Assessment," NERC, page 11.
[29] "2025–2026 Winter Reliability Assessment," NERC, page 37.
[30] "2025–2026 Winter Reliability Assessment," NERC, page 37.

example, in the January 2024 Arctic storm in the region, FERC found that, in addition to better coordination and forecasting, effective use of regional import capacity helped prevent any load shedding event despite extreme winter conditions.[31] NERC explains that, during the January 2024 event, "[t]he U.S. Northwest relied heavily on imports—averaging 4,745 MW during peaks and 5,241 MW across all hours, mostly from the Southwest and Rockies."[32] The region's import capacity are also a cost effective means to better utilize excess generation in other regions during normal conditions, meaning they support normal grid operations in addition to avoiding load shedding in extreme conditions. Together, increased in-region generation and more imports explain why NERC does not issue an emergency recommendation to WECC-Northwest, instead emphasizing preparedness, monitoring, and winterization of thermal units, all of which are steps that helped avoid emergencies in extraordinary winter conditions.

NERC identifies WECC-Northwest as one of these regions facing "elevated" risk, the middle of three risk categorizations ("normal," "elevated," and "high"). NERC's elevated risk categorization provides an indicator against a crisis being present. NERC reserves its "high risk" category for situations in which the region is unable to meet operating reserve requirements in normal peak conditions. If NERC had concluded there was an imminent resource adequacy crisis, it would have assigned the highest classification. Instead, NERC selected the lower risk category. And in context with the discussion and analysis in the 2025-26 winter assessment, it is clear that NERC does not identify anything near crisis conditions in WECC-Northwest.

In summary, our analysis finds that NERC's elevated risk ranking is a finding warranting attention by state and regional authorities but falls well short of demonstrating an imminent crisis.

2024 Western Electricity Coordinating Council's Western Assessment of Resource Adequacy Short-Term Findings

The Western Electricity Coordinating Council annually produces a Western Assessment of Resource Adequacy report, which provides an hourly, 10-year, and forward looking analysis of the WECC sub-regions, one of which is WECC-Northwest.[33] The Western Assessment of Resource Adequacy uses an energy-based probabilistic approach that incorporates planned new resources, demand growth (and its drivers), retirements, imports and other factors across several scenarios to estimate peak demand and potential hourly shortfalls. Moreover, to further analyze the approach's sensitivities, the Western Assessment of Resource Adequacy also relies on aggregated data from the regional balancing authorities in which the completion of planned resources are delayed or not completed.[34] While largely overlapping with the WECC-Northwest region used by NERC in the

[31] "System Performance Review of the January 2024 Arctic Storms," page 18, 20, and 21, FERC, April 25, 2024, https://www.ferc.gov/sites/default/files/2024-04/24_System%20Performance%20Review%20of%20the%20January%202024%20Arctic%20Storms_0425.pdf.
[32] "2025–2026 Winter Reliability Assessment," NERC, page 52.
[33] "Western Assessment of Resource Adequacy 2024: Scenario Analysis," Western Electricity Coordinating Council (WECC), December 3, 2024, https://feature.wecc.org/wara/.
[34] "Western Assessment of Resource Adequacy 2024: Scenario Analysis," WECC.

Winter Reliability Assessment, the Western Assessment of Resource Adequacy divides the Western Interconnection into five sub-regions (shown in Figure 2 below) for its 2024 Assessment (which is the most recent assessment).[35]

Figure 2: WECC subregions used for 2024 Western Assessment of Resource Adequacy



The 2024 Western Assessment of Resource Adequacy did not indicate any near-term resource adequacy shortfall for the Western Interconnection or the "NW Northwest" subregion, specifically. In all but the most extreme scenario (in which only 55% of planned resources are deployed), the study finds no demand at risk hours in 2026 and a minor number (~7) in 2027 for the NW Northwest subregion. In the moderate scenario (in which 85% of planned resources come online), the Western Electricity Coordinating Council concludes that there is "minimal impact [to NW Northwest] in the short-term."[36] Importantly, the extreme 55% build scenario is less likely to materialize in the near-term than over longer forecast horizons, as project development assumptions are generally more certain and less speculative closer to the present. Recent EIA data

[35] WECC updated its planning regions in 2025. See https://feature.wecc.org/seasonal-assessment-western-overview/index.html.
[36] "Western Assessment of Resource Adequacy 2024: Scenario Analysis," WECC.

for 2025 supports this conclusion. Based on Energy Information Administration 860M reports, Washington, Oregon, Idaho, and Montana added more than 1.6GW in 2025, slightly beating the 1.53GW of additions planned for 2025 and the ~1GW of additions in 2024.[37,38] 1.68GW is planned to be added in 2026 as of the October 2025 report. [39]

Figure 3: WARA Comparison of Resource Build Out Scenarios and Demand at-Risk Hours

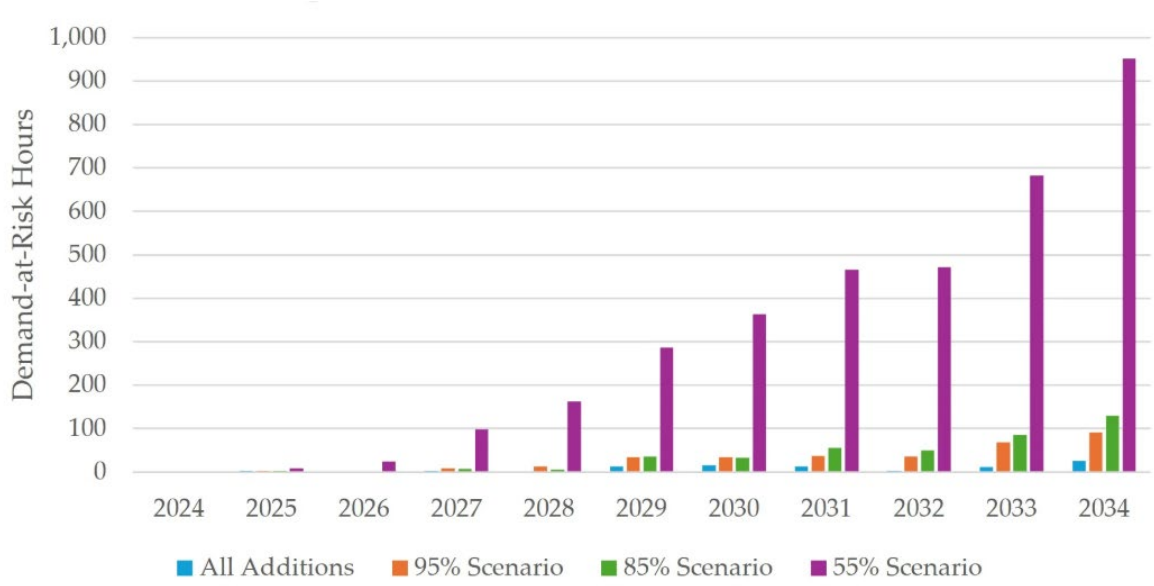


Figure 3 illustrates that the 2024 Western Assessment of Resource Adequacy results show modest delays in planned resource additions have limited impact on near-term reliability, while the extreme delays, such as the 55% build scenario, result in rapidly escalating demand-at-risk hours beginning in the late 2020s.[40] As previously discussed, a finding of demand at risk hours is not necessarily unusual nor a finding of an emergency. Planners take into account both the magnitude of the finding and the trend when making planning decisions, using both to identify the amount and type of measures needed. While any potential shortfall warrants attention, both the magnitude of any identified shortfalls and the rate of increase in 2026 and 2027 do not indicate a resource adequacy shortfall. For example, as shown in Figure 3 above, the 2024 Western Assessment of Resource Adequacy identifies demand-at-risk hours in 2025 under certain scenarios. However, actual system operations during 2025 did not result in supply shortfalls. Modest quantities of modeled demand-

[37] "Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860)," December 2024 and October 2025 data, U.S. EIA, accessed December 16, 2025, https://www.eia.gov/electricity/data/eia860m/.
[38] "Electric Power Annual: Table 4.7.A," U.S. EIA, accessed December 16, 2025, https://www.eia.gov/electricity/annual/table.php?t=epa_04_07_a.html.
[39] "Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860)," October 2025 data, U.S. EIA, accessed December 16, 2025, https://www.eia.gov/electricity/data/eia860m/.
[40] "Western Assessment of Resource Adequacy 2024: Scenario Analysis," WECC.

at-risk hours are not unusual and should be interpreted as early planning signals rather than evidence of an imminent resource adequacy shortfall.

E3 Resource Adequacy and the Energy Transition in the Pacific Northwest: Phase 1 Results, Short-Term Findings

E3 Study Overview

In September 2025, Energy + Environmental Economics (E3) presented the Phase 1 results of its "Resource Adequacy and the Energy Transition in the Pacific Northwest" analysis to the Washington Utilities and Transportation Commission and Washington State Department of Commerce Energy Division.[41] The E3 presentation is a high-level briefing of a resource adequacy assessment that E3 conducted on behalf of more than a dozen investor- and consumer-owned utilities. The E3 analysis is an examination of the "Greater Northwest" region, which appears to include most of the NERC Northwest subregion as well as parts of the WECC-Basin subregion.[42] The presentation was not accompanied by a report or other documentation of the study's inputs, assumptions, and methodologies.

In the presentation, E3 states that it found a resource gap (characterized as a "reliability position") across the Greater Northwest beginning in 2026 and growing each year through 2030. [43] Specifically, E3 states that it forecasts a resource gap of 1,321 MW in 2026. To reach this conclusion, E3 compares available resources against expected peak demand, inclusive of a planning reserve margin and estimated export obligations to Canada. However, the resulting finding of a resource gap is driven, in part, by a set of conservative underlying assumptions. First, E3 explains that its analysis does not include the contributions of 296 MW of "in-development" firm resources, nor the 645 MW of firm capacity equivalent "in-development" wind, solar, and battery projects.[44] When the projects currently being built are finalized, as is expected, the resource shortfall for 2026 declines to 380 MW (approximately 0.75% of total expected need for 2026). Second, E3 assumes that the Greater Northwest region is exporting power to Canada in all hours, even during peak conditions, to meet treaty obligations that are not mandatory. Third, E3 assumes an import level

[41] "Resource Adequacy and the Energy Transition in the Pacific Northwest: Phase 1 Results," page 2, E3, Sept. 22, 2025, https://www.utc.wa.gov/sites/default/files/2025-10/Revised%20V3%20E3%20Presentation%20RA%20Study%20September%2022%20WA%20RA%20Meeting.pdf. The two state agencies held the resource adequacy meeting as required by state legislation. Revised Code of Washington 19.280.065, https://app.leg.wa.gov/rcw/default.aspx?cite=19.280.065.

[42] According to NERC's 2025-2026 Winter Reliability Assessment, the WECC-Basin is a summer-peaking assessment area in the WECC Regional Entity that includes Utah, southern Idaho, and a portion of western Wyoming, covering Idaho Power and PacifiCorp's eastern BA area.

[43] "Resource Adequacy and the Energy Transition in the Pacific Northwest: Phase 1 Results," E3, pages 7, 8, and 10.

[44] While wind and solar are not "dispatchable" resources in the traditional sense, they do provide a reliability contribution to grid that is well understood by utility system planners. This understanding has evolved over decades of improvements in statistical weather modeling, forecasting, and actual performance observations. All generators (including wind, solar, gas, coal, etc.) have a statistical probability of being available to assist the grid during periods that are typically high-stress conditions (e.g., late afternoon in August). The contribution of each resource, after accounting for this statistical probability is often referred to as the Effective Load Carrying Capability or ELCC. This represents the "firm capacity" equivalent of the resource being considered.

that is significantly less than the level of imports experienced during the region's cold weather event in January 2024. As explained in more detail below, these three conservative assumptions contribute directly to E3's conclusion that the region has a modest "resource gap,"

Figure 4: E3 Total Resource Need Results for the Greater Northwest

Greater Northwest
Total Resource Need and Effective Capacity Contribution from Planned Resources (MW)

System Needs (MW)	2025	2026	2027	2028	2029	2030
Total Resource Need*	49,245	50,737	52,499	54,184	55,879	57,195
Existing Portfolio w/ Retirements	46,716	45,666	45,395	45,388	45,098	44,757
Firm Imports	3,750	3,750	3,750	3,750	3,750	3,750
Reliability Position Surplus (+) / Shortfall (-)	**+1,221**	**-1,321**	**-3,354**	**-5,046**	**-7,031**	**-8,689**
ELCC from "In-Development" Firm Resources	-	296	407	580	770	1,114
ELCC from "In-Development" Wind, Solar and Battery projects	-	645	1,015	1,316	1,508	1,934

** Total Resource Need includes peak load + planning reserve margin as well as obligation to serve the Columbia River Treaty Regime*

E3 Study Put into Context

E3's presentation of its Phase 1 results included a 25-page slide deck but did not provide any other documentation or explanations of the assumptions and inputs used in the model. The data underlying E3's analysis does not accompany the presentation. The lack of documentation for the E3 Study is not necessarily surprising as the work product is only Phase 1 of a consultant study meant to inform Washington state policymakers on general, high-level themes of "long-term" resource adequacy projections in the Greater Northwest. Nevertheless, the absence of summary-level information regarding key parameters, as well as the unavailability of underlying data and calculation methods, limits the ability of third parties to independently verify the study's findings. With that caveat, CEG contacted E3 to better understand how their model was designed. Where appropriate, CEG contextualized our analysis of the E3 study with supplemental information provided by E3 but not contained in the slide deck.

Total Resource Need

As an initial matter, E3's finding of a "resource gap" does not necessarily indicate an immediate or persistent shortage of electricity on the grid. Rather, it reflects that, under the study's modeling assumptions, the system's set of available resources ("Existing Portfolio w/ Retirements") is lower

than E3's estimate of Total Resource Need, resulting in modeled risk metrics that exceed the study's defined tolerance level. The identified resource gap represents the additional accredited capacity required to bring modeled system risk back into compliance with the chosen reliability standard and is contingent on the assumptions embedded in the analysis.

The presentation, as shown in the excerpt in the figure above, identifies the Total Resource Need as "peak demand + planning reserve margin as well as obligation to serve the Columbia River Treaty regime."[45] The presentation does not identify the numerical values that sum to the total need and does not provide sufficient detail to clearly understand how each of these elements contributes to the total resource need or how the resulting Total Resource Need is calibrated to a specific probabilistic reliability standard.

In probabilistic resource adequacy frameworks, the Total Resource Need is typically defined by the level of accredited capacity required to satisfy a chosen reliability metric, most commonly a loss-of-load expectation (LOLE) of 0.1 events per year (i.e., a one-in-ten-year standard). Under such frameworks, a small, modeled resource shortfall does not necessarily indicate a qualitatively different reliability outcome, but rather that the modeled system slightly exceeds the selected risk threshold. For this study, E3 did in fact use a 0.1 LOLE. And although this information is not in the slide deck, E3 also found that the LOLE with its projected 2026 shortfall is 0,15. While 0.15 exceeds the 0.1 planning target, the incremental increase is relatively small in absolute terms and should be interpreted in the context of near-term uncertainty and conservative modeling assumptions.

Consistent with other resource adequacy studies, E3 finds that reliability risk in the Greater Northwest is most pronounced during winter periods. The most immediate modeled risk arises under a combination of extreme cold temperatures and reduced hydropower availability, such as during drought conditions.[46] As detailed below, the evidence available by December 16, 2025, the day of the DOE order, suggests that the extreme scenario will not occur during Winter 2025-26.

Imports Assumption

The E3 Study assumes a firm import limit of 3,750 MW to the Greater Northwest region. [47] Recent historical evidence, however, indicates that the Northwest has been able to achieve materially higher levels of imports under stressed system conditions. During the January 2024 Cold Weather Winter event, imports reached approximately 6,000 MW,[48] averaged 4,745 MW during peak hours, and averaged 5,241 MW across all hours.[49] These import levels were achieved even while California was a net importer during the same period.[50] Had E3 modeled import capability at levels

[45] "Resource Adequacy and the Energy Transition in the Pacific Northwest: Phase 1 Results," E3, page 10.
[46] "Resource Adequacy and the Energy Transition in the Pacific Northwest: Phase 1 Results," E3, pages 11-12.
[47] "Resource Adequacy and the Energy Transition in the Pacific Northwest: Phase 1 Results," E3, page 10.
[48] "Memorandum: January 2024 Cold Weather Event," page 8, Northwest Power and Conservation Council, March 5, 2024, https://www.nwcouncil.org/fs/18649/2024_03_5.pdf.
[49] "2025–2026 Winter Reliability Assessment," NERC, page 52.
[50] "2025–2026 Winter Reliability Assessment," NERC, page 52.

consistent with the observed performance in January 2024, it would materially affect the projected reliability outcomes and would eliminate the modeled shortages through at least 2026. In its independent evaluation of E3's Phase 1 results, Sylvan Energy Analytics assumed winter import capability of up to 5,000MW, including 3,000 MW into the Pacific Northwest from non-Canadian sources, 1,000 MW from Canada, and 1,000 MW into the PacifiCorp East balancing area, based on the observed regional import levels during 2024 winter event.[51]

Canadian Hydropower Entitlements under the Columbia River Treaty

The Canadian Entitlement for the 2026 to 2029 operating years is 660 MW in hydropower generation capacity and 305 average MW (aMW) of energy.[52] E3 modeled that the region would export power 660 MW of power into Canada in all hours, even during peak periods. E3's analysis did not allow for the Greater Northwest region to rely on Canadian imports and storage during peak hours. The Columbia River Treaty does not mandate that the US export power to Canada at all hours, even during peak periods. Rather, the Treaty establishes an obligation for the US to provide Canada with an agreed share of power benefits on an annual basis but allows operational flexibility in the timing and coordination of deliveries, particularly under conditions of system stress. Sylvan Energy Analytics modeled the region exporting 660 average MW into Canada across a month but allowed Canadian imports in any given hour.[53]

Reserve Margin

As described earlier, Total Resource Need reflects a reserve margin that is intended to satisfy a probabilistic reliability criterion. In practice, small differences in the implied reserve margin associated with that criterion can determine whether a system appears to be in surplus or deficit, particularly where the modeled shortfall is relatively small, as is the case here. The E3 presentation does not disclose the reliability standard applied, such as a target loss of load expectation, nor does it provide sufficient information to infer the implied planning reserve margin embedded in the Total Resource Need or to understand how obligations associated with the Columbia River Treaty are incorporated into that calculation. As a result, it is not possible to use the slide deck to evaluate the sensitivity of the results to reasonable alternative reliability assumptions.

By way of illustration, regional resource adequacy practices commonly rely on reliability standards that result in implied planning reserve margins within a relatively narrow range. The Pacific

[51] Hart, Elaine. "Near-Term Winter Resource Adequacy Challenges in the Pacific Northwest: A Review of E3's Northwest RA Study Phase 1 and Independent Evaluation of Near-Term Winter Challenges." Sylvan Energy Analytics, January 2026. https://gridlab.org/portfolio-item/pnw_nearterm_winterra/.
[52] "Details About the Key Elements Agreed Between the United States and Canada Regarding Modernization of the Columbia River Treaty Regime" U.S. Department of State, July 26, 2024. https://www.state.gov/bureau-of-western-hemisphere-affairs/details-about-the-key-elements-agreed-between-the-united-states-and-canada-regarding-modernization-of-the-columbia-river-treaty-regime.
[53] Hart, Elaine. "Near-Term Winter Resource Adequacy Challenges in the Pacific Northwest: A Review of E3's Northwest RA Study Phase 1 and Independent Evaluation of Near-Term Winter Challenges." Sylvan Energy Analytics, January 2026. https://gridlab.org/portfolio-item/pnw_nearterm_winterra/.

Northwest Utilities Conference Committee, for example, has historically relied on a planning reserve margin of approximately 16%.[54] If the implied reserve margin resulting from E3's reliability criterion was modestly lower, such as 15%, the resulting capacity balance could differ materially. Using E3's own figures, the 2026 system shows approximately 50,357 MW of accredited capacity against a stated Total Resource Need of 50,737 MW, implying a shortfall of roughly 380 MW, a magnitude that could be affected by relatively small differences in implied reserve margin.[55]

As demonstrated earlier, regional resource adequacy frameworks differ meaningfully in their reliability standards, planning reserve margin targets, and resource accreditation methodologies. Consequently, a system configuration that satisfies adequacy criteria in one region may not be evaluated the same way in another, even under similar system conditions. For example, ERCOT applies a minimum planning reserve margin target of 13.75 percent of peak demand,[56] while the Southwest Power Pool set a planning reserve margin of 15%[57] but allows for a lower PRM (9.89%) if the system is at least 75% hydro-based generation.[58] This reflects the view that hydro-dominated systems possess distinct operational attributes that influence reliability outcomes and resource adequacy assessments.

Winter 2025-2026 Conditions

The E3 presentation is an illustrative resource adequacy analysis intended to identify potential resource adequacy risks through 2030. It is designed to be informative and to support preliminary policy consideration, rather than to serve as a near-term operational assessment of the current 2025-2026 Winter. The study establishes planning thresholds, not real-time reliability metrics, and relies on annual average assumptions. For example, the presentation's hydropower generation is modeled using historical average hydrologic conditions from 1989 through 2018.

There is good reason to believe that the actual circumstances this winter pose less risk than the assumptions used in the E3 presentation. While system planners reasonably strive to meet a 1-in-10 loss-of-load expectation (LOLE) standard over the planning horizon, short-term deviations from that benchmark do not, by themselves, indicate the likelihood of load loss in any specific operating year. Assessing near-term reliability risk requires greater reliance on contemporaneous weather, hydrological, and resource availability projections. This is particularly true in the Pacific Northwest, where hydrological conditions are a dominant driver of winter reliability outcomes. E3's Report appropriately emphasizes water-year analysis for this reason. By the date of the Department of Energy order on December 16, 2025, hydrology and temperature forecasts indicated that many of

[54] "Northwest Regional Forecast of Power Loads and Resources: August 2025 through July 2035," page 11, Pacific Northwest Utilities Conference Committee, April 2025, https://www.pnucc.org/wp-content/uploads/2025-PNUCC-Northwest-Regional-Forecast-final.pdf.
[55] "Resource Adequacy and the Energy Transition in the Pacific Northwest: Phase 1 Results," E3, pages 7, 8, 10.
[56] "Resource Adequacy," Electric Reliability Council of Texas, accessed December 16, 2025, https://www.ercot.com/gridinfo/resource.
[57] Southwest Power Pool (SPP) et al., "SPP Planning Criteria Revision 4.1A," May 12, 2023, https://www.spp.org/documents/69547/spp%20planning%20criteria%20v4.1a.pdf.
[58] Southwest Power Pool (SPP) et al., "SPP Planning Criteria Revision 4.1A."

the worst-case low-hydropower conditions reflected in the study had already been reduced to low-probability scenarios. As of December 15, 2025, Pacific Northwest snowpack and hydro reservoir forecasts indicate that regional hydrologic conditions are relatively strong.[59] NOAA's 120-day hydrologic outlook for the Columbia River Basin shows most rivers expected to experience near- or above-average conditions.[60] **Error! Reference source not found.**The figure below shows the hydrological forecast from the NOAA Northwest River Forecast Center at BPA's largest hydropower project, Grand Coulee dam (current forecast as of December 22,2025 and previous forecast in dark red as of December 15, 2025). The 120-day forecast indicates that as of December 15, 2025, hydrological conditions were expected to be at or above average through April 2026.

[59] Northwest River Forecast Center, "Northwest River Forecast Center," National Oceanic and Atmospheric Administration, accessed December 22, 2025, https://www.nwrfc.noaa.gov/rfc/
[60] Northwest River Forecast Center, "Northwest River Forecast Center," National Oceanic and Atmospheric Administration, accessed December 22, 2025, https://www.nwrfc.noaa.gov/rfc/

Figure 5: Hydrology Forecast for Grand Coulee Dam (December 22, 2025 to April 21, 2026)[61]

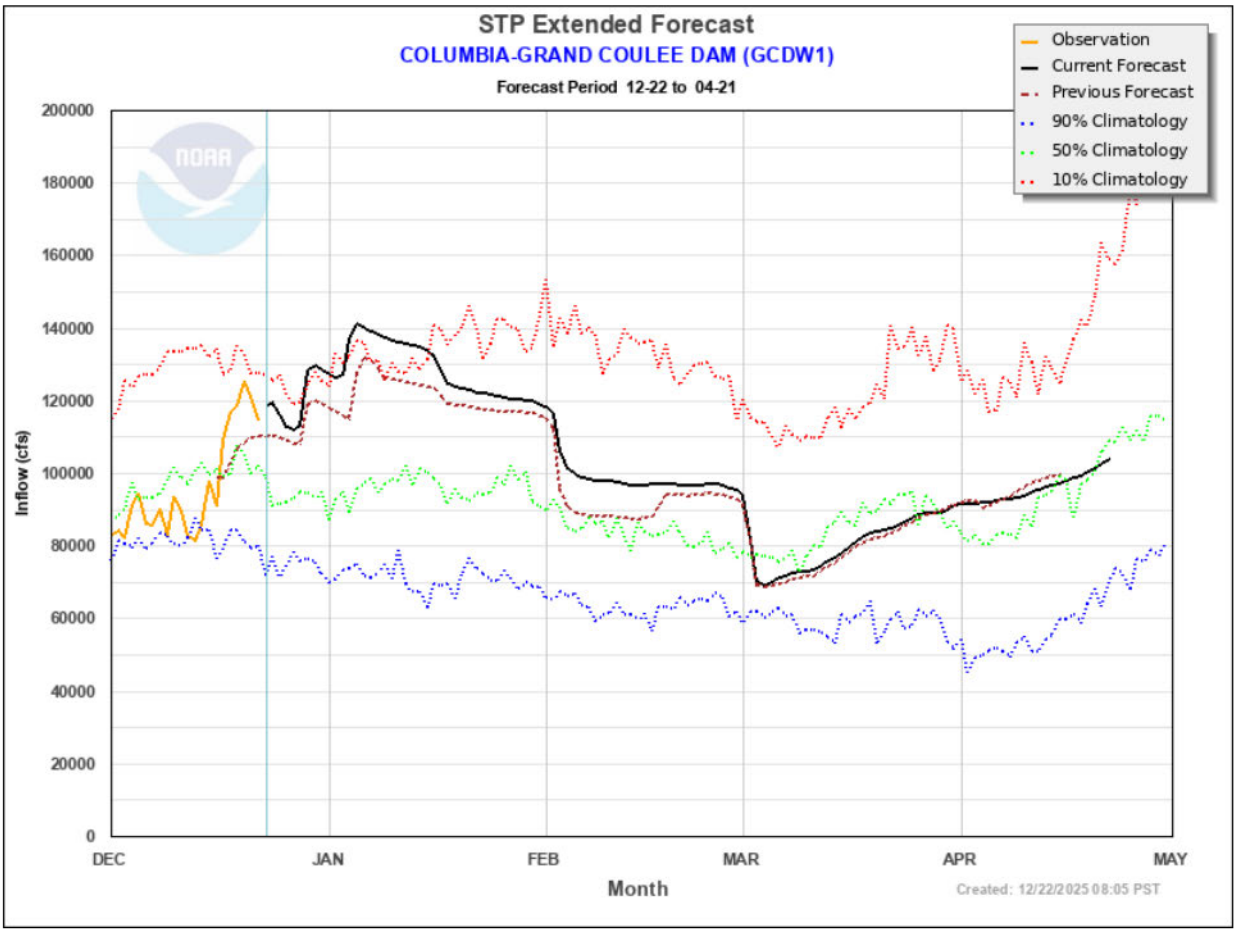


Figure 5 shows the forecasted inflows to the Columbia River at Grand Coulee Dam as compared with historical flow conditions for the same time of year. Measuring the hydropower output at Grand Coulee Dam is appropriate because it is the largest and most operationally influential facility in the Columbia River system, making its flows a reliable proxy for basin-wide hydrological conditions that drive regional winter energy availability. The black solid line represents the current forecast issued on December 22, 2025, and the red dashed line, titled "previous forecast," represents the December 15, 2025, forecast, the day before DOE issued its Order for Centralia. CEG was unable to locate an equivalent figure released on December 15, 2025. The green dotted line represents the 50 percent climatology, or median historical inflow for each day of the year. The blue and upper red dotted lines show low and high historical flow levels for the season. Together, the climatology lines provide a reference for whether forecasted inflows are below, near, or above typical historical conditions.

[61] Northwest River Forecast Center, "GCDW1 Streamflow and Snow Telemetry Plot," National Oceanic and Atmospheric Administration, accessed December 22, 2025, https://www.nwrfc.noaa.gov/stp/station/stpplot/stpplot.cgi?GCDW1

As shown, the December 15 forecast (red dashed line) is consistently above the 50 percent climatology (green dotted line) across the late December through February period. This indicates that, as of mid-December, expected inflows at Grand Coulee were forecast to be above median historical conditions, rather than indicating low-hydro or stress conditions.

E3's presentation indicates that the probability of resource shortfall is highest during winter periods associated with low hydro availability.[62] In this context, the December 15, 2025, forecast for Grand Coulee does not reflect low-hydro conditions during the critical winter months. Instead, both forecasts project inflows at or above median historical levels for much of the January–February period. As a result, the hydrologic conditions reflected in these forecasts reduce the likelihood of the most constraining near-term scenarios identified by E3, particularly during winter peak months when cold-weather events can drive elevated demand.

Bonneville Power Administration and Puget Sound Energy Planning Documents Short-Term Findings

As previously noted, the planning assessments of Puget Sound Energy (Puget) and the Bonneville Power Administration are relevant for evaluating resource adequacy in the Pacific Northwest. Puget is the largest electric and gas utility in Washington and was the largest offtaker of energy from the Centralia plant. BPA is the region's largest balancing authority and transmission owner, and Centralia is surrounded by (but not a part of) BPA's balancing authority area. Together, the planning documents produced by Puget and BPA provide the most direct insight into near-term and medium-term resource adequacy conditions relevant to Centralia, and they present no indication of a resource adequacy crisis in 2026 or early 2027.

Puget's published its most recent update to its IRP in 2023.[63] In that filing, Puget's resource adequacy analysis, conducted by E3, finds that the utility maintains a winter planning reserve margin exceeding 20 percent in 2027 under its preferred portfolio.[64] The analysis explicitly incorporates the retirement of the Centralia plant. Puget is currently developing its 2027 Integrated System Plan (formerly the Integrated Resource Plan) and has again retained E3 to perform the resource adequacy assessment. Puget presented its initial results in September 2025 and described several methodological updates, including changes to the load forecast, operating reserve requirements, resource accreditation, and market availability assumptions.[65] Neither the

[62] "Resource Adequacy and the Energy Transition in the Pacific Northwest: Phase 1 Results," slide 11, E3, Sept. 22, 2025, https://www.utc.wa.gov/sites/default/files/2025-10/Revised%20V3%20E3%20Presentation%20RA%20Study%20September%2022%20WA%20RA%20Meeting.pdf.
[63] "2023 Electric Progress Report", Puget Sound Energy, March 31, 2023, https://www.pse.com/en/IRP/Past-IRPs/2023-IRP. Puget Sound Energy will next publish a full Integrated System Plan in 2027.
[64] 2023 ERP Table 7.1 shows Puget Sound Energy's PRM is more than 20% in 2029 in preferred portfolio.
[65] "Resource Planning Advisory Group Meeting 2027 Integrated System Plan," page 38, Puget Sound Energy, September 30, 2025, https://irp.cdn-website.com/dc0dca78/files/uploaded/2025_0930_RPAGMeeting_Final-5b0bf24b.pdf.

2023 IRP nor the preliminary 2027 results identify emergency resource adequacy concerns in 2026 or 2027.

The Bonneville Power Administration's most recent long-term planning assessments are presented in its 2025 Pacific Northwest Loads and Resources Study (also known as the "White Book") and its 2024 Resource Program, which, together, evaluate the adequacy of BPA's resource portfolio under a range of hydrological and operating conditions.[66]

BPA finds that, assuming the availability of market purchases and independent power producers, the Pacific Northwest is projected (in annual energy terms) to have firm energy surpluses in the first two operating years.[67] BPA further concludes that, under median water conditions, the federal system is capable of meeting demand during extreme winter weather events.[68] To the extent that resource adequacy challenges emerge in BPA's analysis, they occur in later years and are intended to signal the need for additional resource development, consistent with standard long-term planning practice, rather than indicating near-term emergency conditions.

Consistent with long-standing practice across the region, both Puget and BPA rely on interregional transmission access and short-term market purchases to meet resource adequacy needs and minimize system costs. Puget explains that purchasing energy from the regional power market has historically been a cost-effective means of meeting demand.[69] In other words, the region's strong interregional transmission capacity and surplus generation across the West allowed for relatively efficient balancing of supply and demand, even if a particular utility had a "shortfall" in owned resources within their own portfolio.

Puget and BPA's planning assessments do not support the finding of an imminent resource adequacy or reliability emergency. The studies identify manageable planning challenges in later years, but they do not indicate near-term operational shortfalls in 2026 or early 2027, even under conservative assumptions and stress-test scenarios.

Analysis of Medium-Term (2027-2031) Findings

Summary of medium-term (2027-2031) findings: The medium-term planning horizon is the most consequential for resource adequacy assessments, as it is the period in which emerging risks can still be addressed by state, regional, and private actors through established planning and investment processes. In addition to the 2024 Western Assessment of Resource Adequacy, E3, and Puget/BPA planning documents, we also analyze the Northwest Power and Conservation Council 2029 Resource Adequacy Assessment to assess RA conditions in the medium-term (2027-2031).

[66] "2025 Pacific Northwest Loads and Resources Study," Bonneville Power Administration (BPA), May 2025, https://www.bpa.gov/-/media/Aep/power/white-book/2025-whitebook.pdf; "2024 Resource Program," page 7, Bonneville Power Administration, February 21, 2025, https://www.bpa.gov/-/media/Aep/power/resource-program/2024-rp-document.pdf.
[67] "2025 Pacific Northwest Loads and Resources Study," BPA, page 32.
[68] "2025 Pacific Northwest Loads and Resources Study," BPA, Tables 3-7.
[69] "2023 Electric Progress Report", Puget Sound Energy, page 7-1, March 31, 2023, https://www.pse.com/en/IRP/Past-IRPs/2023-IRP.

The Northwest Power and Conservation Council assessment is notable as the council is required, per Congressional mandate, "to assure the Pacific Northwest of an adequate, efficient, economical, and reliable power supply."[70]

The most significant risks CEG identify in the reviewed studies arise in the medium-term and are driven primarily by rapid load growth rather than coal retirements. Growing electrification, new industrial load, and data center development have increased peak and annual energy needs more quickly than in past years. These conditions place greater pressure on the timely development of new resources, transmission expansion, and demand-side programs. While risks increase later in the decade if new resources are not built on schedule, the current conditions do not constitute a crisis, nor do they justify suspending long-planned coal retirements, and planning entities are appropriately adjusting their expectations. The retirement of Centralia is not a primary driver of any identified shortfall, and none of the reviewed studies suggest that extending its operation would materially improve resource adequacy. Table 4 summarizes our findings for the medium-term analysis.

Western Electricity Coordinating Council's Western Assessment of Resource Adequacy Medium-Term Results

In its 2024 Western Assessment of Resource Adequacy, the Western Electricity Coordinating Council finds that medium-term resource adequacy risks are concentrated in later years, particularly under scenarios where planned generation is delayed or import capability is constrained.[71] Across all scenarios, modeled demand-at-risk hours increase over time, with the highest risk observed in a scenario in which only 55% of planned resources are deployed. While the assessment identifies emerging and increasing challenges under adverse assumptions, the Western Electricity Coordinating Council does not characterize this as evidence of a crisis. Instead, it is characterized as a signal for additional prioritization of reliability in (as well as generic improvement of) planning processes.[72]

The Western Assessment of Resource Adequacy finds that load growth is the primary driver of the increasing risk,[73] with an expected 20.4% increase in energy demand between 2025 and 2034, and a 17.2% increase in peak demand over same period[74] - approximately four times the growth rate between 2013 and 2022.[75] In the Northwest region specifically, the 2024 Western Assessment of

[70] Northwest Power and Conservation Council 2024 Annual Report to Congress
[71] "Western Assessment of Resource Adequacy 2024: Risks to Planned Resource Additions," Western Electricity Coordinating Council, December 3, 2024, https://feature.wecc.org/wara/.
[72] Western Assessment of Resource Adequacy 2024: Summary," Western Electricity Coordinating Council, December 3, 2024, https://feature.wecc.org/wara/.
[73] Western Assessment of Resource Adequacy 2024: Summary," Western Electricity Coordinating Council, December 3, 2024, https://feature.wecc.org/wara/.
[74] Western Assessment of Resource Adequacy 2024: Summary," Western Electricity Coordinating Council, December 3, 2024, https://feature.wecc.org/wara/.
[75] Western Assessment of Resource Adequacy 2024: Summary," Western Electricity Coordinating Council, December 3, 2024, https://feature.wecc.org/wara/.

Resource Adequacy projects a 20% increase in energy needs from 2025 through 2034 (250 TWh to 299 TWh).[76]

Consistent with the short-term findings, the 2024 Western Assessment of Resource Adequacy demonstrates that the region has been planning for plant retirements and load growth by increasing planned builds, adding unprecedented levels of new capacity (~15GW of new batteries and ~3GW of new natural gas by 2027)[77] and moderating previously-assumed retirements downwards as compared to 2022.[78] Generation additions across the WECC subregions (including WECC-Northwest) appear to be on track with the 2024 assessment's expectations, with ~9.5GW of new batteries, ~6GW of solar, ~1.7GW of gas, and ~2GW of wind, deployed across the interconnection in 2025, more than 1.6GW of which was deployed in Washington, Oregon, Idaho, and Montana.[79]

The study does not identify retirements as a primary cause of future reliability risks. Instead, the analysis finds that the principal risks stem from insufficient new generation and constraints on imports, both of which could be exacerbated by supply chain challenges, interconnection backlogs, siting and permitting delays, and cost pressures.

According to the Western Assessment of Resource Adequacy, imports play a critical role in maintaining short-term reliability, and the timely completion of new generation is the key medium-term requirement for maintaining resource adequacy.[80] Although the 55% build out scenario is a useful planning exercise to stress-test the system, it appears unlikely based on historical data. The assessment notes that the 2018-2023 average project completion rate was closer to 76%, a period that included significant inflation and the supply chain disruptions from the Covid pandemic.[81]

A consistent theme in the 2024 Western Assessment of Resource Adequacy is the need to continue and improve upon existing state, regional, and private planning processes. The assessment highlights recent changes to utility forecasting methodologies, new long-term transmission planning efforts (*e.g.*, efforts pursuant to FERC Order 1920), and the development of the Western Resource Adequacy Program as positive planning developments.[82] In other words, the

[76] WARA 2024 Annual Demand by Subregion (figure 6)
[77] Western Assessment of Resource Adequacy 2024: Additions," Western Electricity Coordinating Council, December 3, 2024, https://feature.wecc.org/wara/.
[78] Western Assessment of Resource Adequacy 2024: Retirements," Western Electricity Coordinating Council, December 3, 2024, https://feature.wecc.org/wara/; "WARA 2024 Annual Demand by Subregion," Figure 6, Western Electricity Coordinating Council, accessed December 16, 2025 https://www.wecc.org/wecc-document/17061.
[79] "Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860)," December 2024 and October 2025 data, U.S. Energy Information Administration, accessed December 16, 2025, https://www.eia.gov/electricity/data/eia860m/.
[80] "WARA 2024 Import Scenarios," page 6, Western Electricity Coordinating Council, December 3, 2024, https://www.wecc.org/wecc-document/17081.
[81] Western Assessment of Resource Adequacy 2024: Historical Resource Additions," Western Electricity Coordinating Council, December 3, 2024, https://feature.wecc.org/wara/.
[82] Western Assessment of Resource Adequacy 2024: Resource Planning," Western Electricity Coordinating Council, December 3, 2024, https://feature.wecc.org/wara/.

assessment calls for incremental improvement to established planning for and proportional responses to medium-term challenges, not extraordinary measures outside of the planning process.

E3 Study Medium-Term Results

By 2030, E3 finds a significant resource shortfall of ~9,000 MW for the Greater Northwest region.[83] E3 attributes the projected shortfall primarily to load growth, driven predominantly by the rapid interconnection of data centers.[84] While peak demand increases modestly due to population growth, increased air-conditioning adoption, and electric vehicle uptake, E3 finds that data center development accounts for the largest share of incremental demand in the region. E3 also identifies planned generator retirements and limited replacement capacity as contributing factors to its modeled 2030 shortfall.

The magnitude and timing of the projected medium-term shortfall is sensitive to several key assumptions. First, E3 did not consider large load flexibility, which Sylvan Energy Analytics finds could mitigate most or all the near-term winter resource needs under most laod scenarios.[85] Second, E3 treated the Centralia coal plant as retired throughout the study period, and did not include a corresponding replacement resource, as the analysis preceded TransAlta's announcement of a coal-to-gas conversion beginning in 2028. Including the announced conversion would reduce the shortfall by approximately 670 MW of accredited capacity.

As in the Short-Term 2026 analysis, E3's medium-term results remain sensitive to assumptions related to achievable import levels, rate of new resource additions, Canadian entitlement obligations, and the implied reserve margin associated with the selected reliability criterion. These factors continue to play a material role in determining whether resource shortfalls emerge in the study.

Finally, even within E3's own presentation, the identified medium-term shortfalls appear likely to be resolved by the completion of resource additions that utilities have already planned and reflected in their Integrated Resource Plans,[86] which underscores the function of the E3 presentation as a planning signal rather than evidence of an unaddressed reliability gap.

[83] "Resource Adequacy and the Energy Transition in the Pacific Northwest: Phase 1 Results," pages 9, E3, Sept. 22, 2025, https://www.utc.wa.gov/sites/default/files/2025-10/Revised%20V3%20E3%20Presentation%20RA%20Study%20September%2022%20WA%20RA%20Meeting.pdf.

[84] "Resource Adequacy and the Energy Transition in the Pacific Northwest: Phase 1 Results," pages 7, E3, Sept. 22, 2025, https://www.utc.wa.gov/sites/default/files/2025-10/Revised%20V3%20E3%20Presentation%20RA%20Study%20September%2022%20WA%20RA%20Meeting.pdf.

[85] Hart, Elaine. "Near-Term Winter Resource Adequacy Challenges in the Pacific Northwest: A Review of E3's Northwest RA Study Phase 1 and Independent Evaluation of Near-Term Winter Challenges." slide 11, Sylvan Energy Analytics, January 2026. https://gridlab.org/portfolio-item/pnw_nearterm_winterra/.

[86] "Resource Adequacy and the Energy Transition in the Pacific Northwest: Phase 1 Results," pages 21, E3, Sept. 22, 2025, https://www.utc.wa.gov/sites/default/files/2025-

Accordingly, the identification of a medium-term shortfall should be understood as a planning signal rather than an indication of an imminent or existing reliability emergency. Results of this magnitude underscore the need for continued and timely development of new resources, refinement of load and reliability assumptions, and improvements in regional coordination and transmission capability. Viewed in this context, the findings highlight the importance of sustained planning and investment through state, regional, and private processes, rather than the presence of a near-term crisis.

Northwest Power and Conservation Council's Medium-Term Results

The Northwest Power and Conservation Council's 2029 Resource Adequacy Assessment is the most comprehensive look at the Northwest region's power needs and risks in the medium-term. The Council was created by Congress with a mandate to improve electricity system planning for the Northwest and Columbia River Basin.[87] The Northwest Power and Conservation Council's annual Resource Adequacy Assessment is one of several planning efforts undertaken by the Council and provides a five-year evaluation of the region's resource adequacy. As the Council explains, the assessment "summarizes the . . . aggregate regional power supply's adequacy for the 2029 operating year (October 2028 through September 2029)."[88]

The Northwest Power and Conservation Council is one of the country's only Congressionally mandated regional coordination efforts on energy planning. The Council forecasts demand and recommends resource plans. The eight-member Council is made of two governor-appointed members from each member state (Oregon, Washington, Idaho, and Montana) who work with support staff and technical committees, and is required to consult with utilities, state and local governments, tribes, and customers "to assure the Pacific Northwest of an adequate, efficient, economical, and reliable power supply."[89]

The 2029 Assessment uses the Council's own GENESYS model to evaluate system reliability across multiple metrics, providing information about the frequency, duration, and magnitude of potential shortfall events.[90] The Assessment analyzes:

- Loss of load Events (LOLE), which measures the frequency of shortfalls.
- Duration Value at Risk, which measures shortfall duration.
- Peak Value at Risk, which measures maximum hourly shortfalls; and

10/Revised%20V3%20E3%20Presentation%20RA%20Study%20September%2022%20WA%20RA%20Meeting.pdf.

[87] "2024 Annual Report to Congress," page 3, Northwest Power and Conservation Council, accessed December 16, 2025, https://storymaps.arcgis.com/stories/3c12b13cd3a9487ab44120f5beffe128.

[88] "Pacific Northwest Power Supply Adequacy Assessment for 2029," page 5, Northwest Power and Conservation Council, August 9, 2024, https://www.nwcouncil.org/reports/2024-4/.

[89] "2024 Annual Report to Congress," page 3, Northwest Power and Conservation Council, accessed December 16, 2025, https://storymaps.arcgis.com/stories/3c12b13cd3a9487ab44120f5beffe128.

[90] "Pacific Northwest Power Supply Adequacy Assessment for 2029," page 6, Northwest Power and Conservation Council, August 9, 2024, https://www.nwcouncil.org/reports/2024-4/.

- Energy Value at Risk, which measures the annual energy shortfall.[91]

The Northwest Power and Conservation Council's model is also intentionally conservative. For example, the assessment limits the use of emergency measures that would be employed in actual emergency situations (e.g., targeted brownouts, emergency backup generation).[92]

The 2029 Assessment evaluates three scenarios: (1) a reference case (planned buildouts and demand growth), (2) a reduced energy efficiency case (1000MW vs. 1300MW), and (3) higher data center demand case (3976MW by 2029 vs. 2386 MW) to test and quantify specific reliability threats. Scenarios two and three are, in effect, assuming higher electricity demand. Scenario two does so by removing a portion of the anticipated energy demand savings due to energy efficiency programs, increasing total demand needing to be served in 2029. Scenario three does so explicitly by increasing data center loads.

The 2029 Assessment finds that there is no resource adequacy threat in the reference scenario in 2029 (the analyzed year). The Council concludes that even with substantial load growth the 2021 Power Plan strategy—achieving energy efficiency consistent with the high end of the Council's target, 6,600 MW of new renewables by 2029, and sufficient balancing resources and demand response is adequate to meet regional needs.[93] The Council's findings include modeling the full retirement of the Centralia Plant.[94]

The Northwest Power and Conservation Council's analysis finds that risks only begin to emerge in the two sensitivity scenarios tested: one where energy efficiency deployment is lower than expected (1000MW vs. 1300MW by 2029), and another where data center growth is much larger than anticipated (3976MW by 2029 vs. 2386 MW).[95,96] The table below shows the results of the reliability analysis. Unsurprisingly, significant and unplanned for additional load led to greater adequacy metric violations.[97]

[91] "Pacific Northwest Power Supply Adequacy Assessment for 2029," page 10, Northwest Power and Conservation Council, August 9, 2024, https://www.nwcouncil.org/reports/2024-4/.
[92] "Pacific Northwest Power Supply Adequacy Assessment for 2029," pages 9-14, Northwest Power and Conservation Council, August 9, 2024, https://www.nwcouncil.org/reports/2024-4/.
[93] "Pacific Northwest Power Supply Adequacy Assessment for 2029," page 26, Northwest Power and Conservation Council, August 9, 2024, https://www.nwcouncil.org/reports/2024-4/.
[94] "Pacific Northwest Power Supply Adequacy Assessment for 2029," page 19, Northwest Power and Conservation Council, August 9, 2024, https://www.nwcouncil.org/reports/2024-4/.
[95] "Pacific Northwest Power Supply Adequacy Assessment for 2029," page 6, Northwest Power and Conservation Council, August 9, 2024, https://www.nwcouncil.org/reports/2024-4/.
[96] "Pacific Northwest Power Supply Adequacy Assessment for 2029," page 26, Northwest Power and Conservation Council, August 9, 2024, https://www.nwcouncil.org/reports/2024-4/.
[97] "Pacific Northwest Power Supply Adequacy Assessment for 2029," table 7, Northwest Power and Conservation Council, August 9, 2024, https://www.nwcouncil.org/reports/2024-4/.

Table 3: Northwest Power and Conservation Council Adequacy Metric Results

Type	Metric	Threshold	Reference	Low End EE	Higher Data Center
Frequency	Winter LOLEV	0.1	0.022	0.350	1.294
Frequency	Summer LOELV	0.1	0.017	0.033	0.3
Duration	Duration VaR 97.5	8 hours	0	1.5	20.6
Magnitude	Peak VaR 97.5	1,200 MW	0	1,567	3,076
Magnitude	Energy VaR 97.5	9,600 MWh	0	4,196	196,324

Despite the risks in the sensitivity scenarios, the Northwest Power and Conservation Council does not characterize the findings as a crisis or as evidence that generator retirements threaten reliability. Rather, the reports finds that the best actions to mitigate risks are continuing development of energy efficiency, renewable energy, coal to gas conversions, and new transmission.[98] The Council frames these results as "early warnings" that reinforce the need for sustained planning, including work underway for the 2026 Power Plan.[99] The Council's decision not to characterize these results as a crisis reflects the fact that the modeled risks arise only under sensitivity scenarios and can be addressed through established planning mechanisms already contemplated in the Council's power planning process.

BPA/Puget Sound Energy Medium-Term Results

Neither Puget nor BPA present a picture of a reliability crisis in the 2027-2031 timeframe. Instead, both identify rapid load growth as the primary driver of increasing system needs and the principal source of potential reliability risk if additional resources and measures are not developed in a timely manner. BPA explains that, under firm water conditions, the Pacific Northwest is projected to have an annual energy surplus of up to 960 average megawatts in operating year 2026, declining steadily over time to an annual energy deficit of approximately 3,026 average megawatts by operating year 2034, driven primarily by increasing regional retail load.[100]

In response to these conditions, both entities emphasize the need for timely development of new generation, expanded demand-side resources, regional coordination, and transmission investment.

[98] "Pacific Northwest Power Supply Adequacy Assessment for 2029," pages 18-21 and 26, Northwest Power and Conservation Council, August 9, 2024, https://www.nwcouncil.org/reports/2024-4/.
[99] "Pacific Northwest Power Supply Adequacy Assessment for 2029," page 6, Northwest Power and Conservation Council, August 9, 2024, https://www.nwcouncil.org/reports/2024-4/.
[100] "2025 Pacific Northwest Loads and Resources Study," page v, Bonneville Power Administration, May 2025, https://www.bpa.gov/-/media/Aep/power/white-book/2025-whitebook.pdf.

BPA's least-cost portfolio relies on energy efficiency, demand response, and market purchases to meet its obligations and requires only modest resource additions over the long-term.[101] BPA's sensitivity analyses show little-or-no unserved energy in most cases, with notable shortfalls occurring only in extreme scenarios that assume the complete loss of market imports.[102]

Puget projects demand growth in its territory, reaching a median winter peak load of over 5GW by 2029.[103] Puget also identifies the total resource need based on the median peak load and a five percent LOLP target. Assuming the total resource need is met, Puget will have a PRM of 26-28% in 2029 and 2034. [104] Table 4 shows these results.

Table 4: Puget Sound Energy 2023 IRP Total Resource Need and Planning Reserve Margin (MW)

Resource(s)	2029 Winter	2034 Winter	2029 Summer	2034 Summer
Median Peak Load	5,004	5,382	4,171	4,831
Total Resource Need	6,319	6,771	5,329	6,107
Planning Reserve Margin	**26%**	**26%**	**28%**	**26%**

Puget also estimated the additional resource development needed to meet the projected total resource need. Using an updated ELCC method for existing and new resources, Puget identifies a need for additional "perfect capacity" (i.e., new resources). Table 5 shows the ELCC-adjusted capacity of existing resources and the addition "perfect capacity" required. [105] Puget's modeling shows this need will be met through wind, solar, storage, peaking capacity, demand-side, and distributed resources in its preferred, least-cost, portfolio.[106]

[101] "2024 Resource Program," page 70, Bonneville Power Administration, February 21, 2025, https://www.bpa.gov/-/media/Aep/power/resource-program/2024-rp-document.pdf.
[102] "2024 Resource Program," pages 57-58, Bonneville Power Administration, February 21, 2025, https://www.bpa.gov/-/media/Aep/power/resource-program/2024-rp-document.pdf.
[103] "2023 Electric Progress Report," Table 7.10, Puget Sound Energy, March 31, 2023, https://www.pse.com/en/IRP/Past-IRPs/2023-IRP.
[104] "2023 Electric Progress Report," Table 7.10, Puget Sound Energy, March 31, 2023, https://www.pse.com/en/IRP/Past-IRPs/2023-IRP.
[105] "2023 Electric Progress Report," Table 7.10, Puget Sound Energy, March 31, 2023, https://www.pse.com/en/IRP/Past-IRPs/2023-IRP.
[106] "2023 Electric Progress Report," Table 1.1, Puget Sound Energy, March 31, 2023, https://www.pse.com/en/IRP/Past-IRPs/2023-IRP.

Table 5: Puget Sound Energy 2023 IRP Total Resource Need by Resource Type (MW)

Resource(s)	2029 Winter	2034 Winter	2029 Summer	2034 Summer
Thermal Plants	2,050	2,050	1,688	1,688
Mid-C Hydro	560	560	560	560
Wind, Solar, Baker, Other Contracts	997	981	244	252
Market Purchases	1,440	1,434	961	751
Total Existing Resource Capacity (ELCC-adjusted)	**5,047**	**5,025**	**3,453**	**3,251**
Total Resource Need	**6,319**	**6,771**	**5,329**	**6,107**
Additional Perfect Capacity Needed	**1,272**	**1,746**	**1,875**	**2,856**

Both Puget and BPA conduct resource adequacy analyses consistent with their balancing authority responsibilities and regional requirements, including participation in the Western Resource Adequacy Program and alignment with broader Western Electricity Coordinating Council and NERC planning efforts. While each identifies similar medium-term risks—such as delays in resource development, reduced import availability, and retirements of independent power producers—neither calls for extraordinary measures or for delaying planned plant retirements, including Centralia (from which both Puget and BPA used to purchase power). Each study, and taken together, reflects manageable planning challenges rather than a medium-term reliability crisis.

Review of Recent Washington State Assessment

Our assessment that the regional resource adequacy studies do not identify an imminent emergency is supported by the two Washington state agencies charged by the state legislature to conduct annual resource adequacy meetings. The Washington State Utilities and Transportation Commission and the Washington Department of Commerce concluded their 2025 Long-term Resource Adequacy Meetings in November 2025.

On December 31, 2025, the two state agencies transmitted a letter to the Washington Legislature and the Governor summarizing the findings of the November 4, 2025 Winter Preparedness Resource Adequacy Meeting.[107] The Agencies concluded that the "[w]inter reliability assessments, presented by regional resource adequacy experts, the North American Electric Reliability Corporation and Western Electricity Coordinating Council, indicate the Northwest's electric grid

[107] Summary of the 2025 Winter Preparedness Resource Adequacy Meeting, Letter from Chair Brian J. Rybarik and Assistant Director, Energy Division, Jennifer Grove to Governor Bob Ferguson, Secretary of Senate Sarah Bannister, and Chief Cler of the House of Representatives Bernard Dean. December 31, 2025, available at https://www.utc.wa.gov/casedocket/2021/210096/docsets

meets national resource adequacy criteria under normal conditions this winter."[108] The Agencies further reported that neither the Bonneville Power Administration nor Washington utilities forecast outages during the upcoming winter season. Finally, the Agencies shared that the utilities reported they have maximized hydro and natural gas storage ahead of winter and ensured facilities are operating properly, and at least two utilities noted voluntary the availability of customer curtailment programs designed to reduce demand if system conditions were to tighten.

The near-term findings are consistent with the Agencies' broader conclusions from the 2025 Long-Term Resource Adequacy Meetings. In a November 2025 summary of the three meetings on resource adequacy to the Washington Legislature and Governor, the state agencies reported that the,

> *Reliability assessments presented...indicated that the Northwest's electric grid meets national resource adequacy criteria over the near and medium terms under a broad range of operating conditions. As a region assessed as "normal risk" the Northwest has a low likelihood of electricity supply shortfall.*[109]

The Agencies cautioned that "normal risk" is not the same as "no risk" and that the presentations emphasized that no electric system is 100% risk-free and no resource provides perfect capacity.[110] Utilities, policymakers, grid operators, and planners must balance the level of reliability risk with the added cost to achieve that level of reliability. There is no perfect reliability metric or reliability target. For example, one expert may conclude a 16% planning reserve margin is optimal, while another may conclude a lower PRM of 15% better balances risk and costs. These differences reflect professional judgment, input assumptions, and tolerance for risk—all of which are the traditional province of state, regional, and utility planners and decision-makers.

The Agencies also cautioned that if significant new electricity usage materializes and more extreme weather continues, the grid could face reliability challenges. With respect to the medium-term outlook, the Agencies wrote that the "utilities and policy makers must increase efforts to make customer energy demand more flexible, reduce delays in siting and interconnecting new clean energy projects, expand regional transmission capacity, and improve transparency and accuracy of

[108] Summary of the 2025 Winter Preparedness Resource Adequacy Meeting, Letter from Chair Brian J. Rybarik and Assistant Director, Energy Division, Jennifer Grove to Governor Bob Ferguson, Secretary of Senate Sarah Bannister, and Chief Cler of the House of Representatives Bernard Dean, page 1, December 31, 2025, available at https://www.utc.wa.gov/casedocket/2021/210096/docsets

[109] Summary of the 2025 Long-term Resource Adequacy Meeting, Letter from Chair Brian J. Rybarik and Assistant Director, Energy Division, Jennifer Grove to Governor Bob Ferguson, Secretary of Senate Sarah Bannister, and Chief Cler of the House of Representatives Bernard Dean. November 19, 2025, available at https://www.utc.wa.gov/casedocket/2021/210096/docsets.

[110] Summary of the 2025 Long-term Resource Adequacy Meeting, Letter from Chair Brian J. Rybarik and Assistant Director, Energy Division, Jennifer Grove to Governor Bob Ferguson, Secretary of Senate Sarah Bannister, and Chief Cler of the House of Representatives Bernard Dean. November 19, 2025, available at https://www.utc.wa.gov/casedocket/2021/210096/docsets.

load forecasts and planned resource additions."[111] Meanwhile, federal intervention into an established and functioning regional planning process introduces uncertainty and may complicate ongoing efforts to bring new resources online in a timely manner. Broadly, the 2024 Western Assessment of Resource Adequacy notes that resource adequacy is related to policy decisions, and that shifts in policymaking can "introduce significant risks to reliability."[112]

Continued investments to strengthen the Pacific Northwest's reliability position – while accounting for Centralia's retirement – have been planned for over many years. This activity is expected to continue and can be further aided through policy certainty (and avoidance of unneeded extraordinary interventions) at the federal level.

DOE's July Resource Adequacy Report

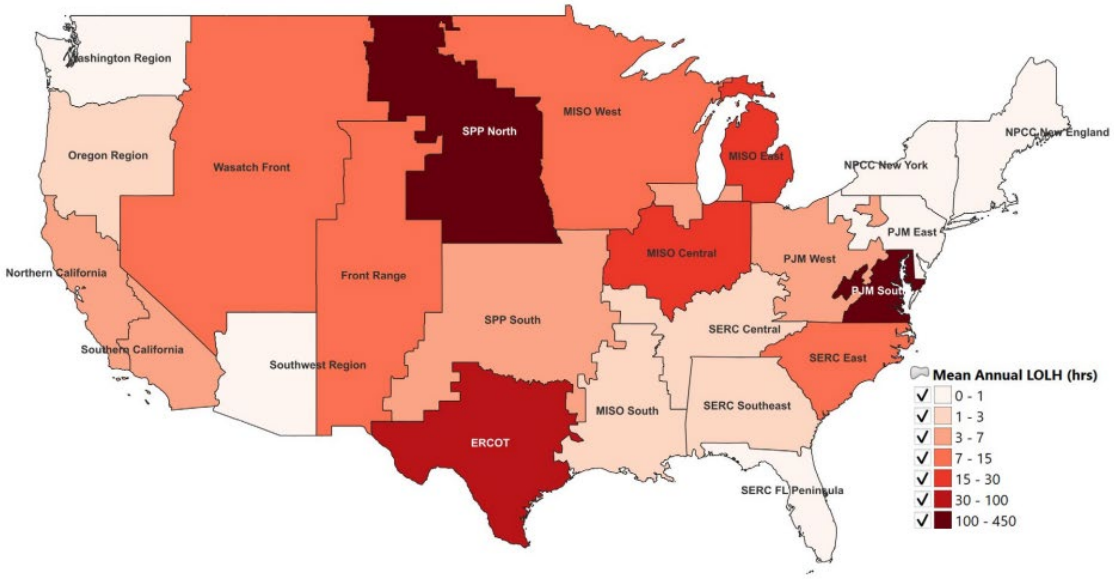
In July 2025, the Department of Energy released a resource adequacy report, analyzing the impacts of planned retirements on resource adequacy.[113] DOE references the July report in Order 202-25-11.[114] The July report analyzes several resource adequacy and reliability measures in 2030 across the nation, with findings for specific regions and states. DOE acknowledged that its study "could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level."[115]

The DOE study found that plant retirements have essentially no impact on Washington state, limited impacts on Oregon, and moderate impacts on other Western subregions, even when relying

[111] Summary of the 2025 Long-term Resource Adequacy Meeting, Letter from Chair Brian J. Rybarik and Assistant Director, Energy Division, Jennifer Grove to Governor Bob Ferguson, Secretary of Senate Sarah Bannister, and Chief Cler of the House of Representatives Bernard Dean. November 19, 2025, available at https://www.utc.wa.gov/casedocket/2021/210096/docsets.
[112] Western Assessment of Resource Adequacy 2024: Additional Considerations," Western Electricity Coordinating Council, December 3, 2024, https://feature.wecc.org/wara/.
[113] "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," U.S. Department of Energy, July 2025, https://www.energy.gov/topics/reliability.
[114] DOE Order No 202-25-9 at 6-7
[115] "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," page i, U.S. Department of Energy, July 2025, https://www.energy.gov/topics/reliability.

on DOE's highly unusual assumption that no Tier 2[116] or Tier 3[117] generation resources are built by 2030. [118, 119] Figure 6 shows loss of load hours by region in DOE's report.

Figure 61: DOE's July 2025 Report Mean Annual LOLH by Region (2030) – Plant Closures[120]



DOE's scenarios can be understood as a thought exercise, testing an unlikely hypothetical scenario in which plants are retired but where utilities do not procure additional generation per typical planning processes and requirements. Even in this hypothetical, DOE does not appear to find that Washington and Oregon violate its chosen reliability metrics.[121] DOE found that, even regionally, the non-CAISO West region had the least normalized unserved energy of all regions analyzed.[122]

[116] NERC defines Tier 2 resources as those having made tangible progress (e.g., completion of feasibility or system impacts studies) but are less developed than Tier 1 resources. 2024 Long-Term Reliability Assessment, NERC, July 11, 2025, https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf.
[117] NERC defines Tier 3 resources as "units in an interconnection queue that do not meet the Tier 2 requirement." 2024 Long-Term Reliability Assessment, NERC, July 11, 2025, https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf.
[118] "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," page 7 and 37, U.S. Department of Energy, July 2025, https://www.energy.gov/topics/reliability.
[119] "Request for Rehearing Of The Clean Energy Organizations," American Clean Power Association, Advanced Energy United, American Council on Renewable Energy, August 6, 2025, https://cleanpower.org/wp-content/uploads/2025/08/2025-08-06-Resource-Adequacy-Rehearing-Request-FINAL.pdf.
[120] "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," page 6, U.S. Department of Energy, July 2025, https://www.energy.gov/topics/reliability.
[121] "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," page 37, U.S. Department of Energy, July 2025, https://www.energy.gov/topics/reliability.
[122] "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," pages 8 and 37, U.S. Department of Energy, July 2025, https://www.energy.gov/topics/reliability.

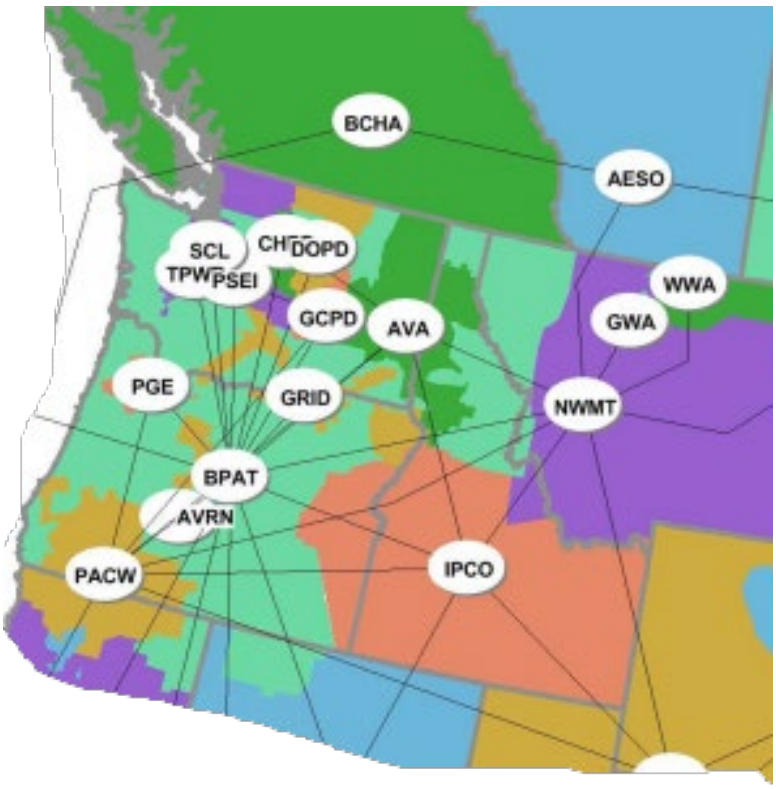
Balancing Authorities and Real-Time System Operations

As previously discussed, Resource Adequacy is generally forward-looking and distinct from real-time system operations. In addition to the extensive resource adequacy planning efforts discussed above, there is also a suite of tools available to manage the power system in real-time when challenged by extreme weather, load conditions, or other occurrences. Balancing Authorities are required by NERC and other entities to have extensive operational plans in response to threats as wide-ranging as natural disasters, winter storms, or squirrels.

Balancing Authorities are the entities responsible for managing power system operations (e.g., balancing supply and demand) and ensuring the real-time reliability of the electric system within a specific geographic area.[123] The Western Interconnection, which spans into Mexico and Canada, has 34 Balancing Authorities in the United States. Approximately 15 of those Balancing Authorities are located in the Northwest region, depending on the definition of the Northwest footprint, as shown in the figure below.

[123] "How it Works: The Role of a Balancing Authority ," U.S. Department of Energy, accessed December 16, 2025, https://www.energy.gov/sites/default/files/2023-08/Balancing%20Authority%20Backgrounder_2022-Formatted_041723_508.pdf.

Figure 7: Pacific Northwest Balancing Authorities as of October 2019[124]



The outputs of Resource Adequacy planning ultimately inform, but do not replace, the real-time reliability responsibilities of Balancing Authorities. A Balancing Authority maintains real-time balance by ensuring that generation, load and transmission interchanges align at all times. Although generators may be owned and operated by different utilities, the Balancing Authority is responsible for ensuring that each resource's schedules and actual output support system balance and comply with reliability requirements. The Balancing Authority does not economically dispatch resources it does not control. Rather, the Balancing Authority oversees scheduling and deploys its own balancing reserves to ensure the area remains in compliance with NERC reliability standards. The Bonneville Power Administration (shown as BPAT in the figure above) is the Balancing Authority for portions of Washington, Oregon, Idaho, and Montana.[125]

Balancing Authorities are responsible for developing, maintaining, and executing emergency procedures in extreme conditions. NERC Reliability Standard EOP-011 sets the requirements for

[124] "Balancing Authority Areas As of October 2019," NERC, accessed December 16, 2025, https://www.nerc.com/globalassets/programs/rapa/ra/ba-bubble-map-20191106.pdf.
[125] "Balancing Authority Area Services," Bonneville Power Administration, accessed December 16, 2025, https://www.bpa.gov/energy-and-services/transmission/interconnection/balancing-authority-area.

Balancing Authorities and Reliability Coordinators.[126] The current NERC requirements (approved by FERC in 2024) require Balancing Authorities to have operations plans for energy and capacity-based emergencies and prescribe actions regarding records keeping and communications for Balancing Authorities. NERC also defines Energy Emergency Alert (EEA) levels reflecting conditions in a Balancing Authority as shown in the table below.[127] The Western Electricity Coordinating Council provides further information on best practices for adhering to NERC guidelines and potential actions to take in an emergency situation.[128]

Table 6: NERC Energy Emergency Alert (EEA) Level Descriptions [129]

EEA Level	Description	Circumstances
EEA 1	All available generation resources in use	• The BA is experiencing conditions in which all available generation resources are committed to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required operating reserves. • Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
EEA 2	Load management procedures in effect	• The BA is no longer able to provide its expected energy requirements and is an energy-deficient BA. • An energy-deficient BA has implemented its operating plan(s) to mitigate emergencies. • An energy-deficient BA is still able to maintain minimum operating reserve requirements.
EEA 3	Firm load interruption is imminent or in progress	• The energy-deficient BA is unable to meet minimum operating reserve requirements.

Balancing Authorities develop plans in response to the NERC (or other) requirements. For example, Puget's Energy System Restoration Plan sets criteria and procedures for different types of incidents (including extreme cold) depending on severity, defining chains of command and responsibilities for

[126] "EOP-011-4 – Emergency Operations," NERC, accessed December 16, 2025, https://www.nerc.com/globalassets/standards/reliability-standards/eop/eop-011-4.pdf.
[127] "2025–2026 Winter Reliability Assessment," Table 4, NERC, November 2025, https://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf.
[128] "Best Practices for Energy Emergency Alerts," Western Electricity Coordinating Council, March 28, 2022, https://www.wecc.org/sites/default/files/documents/meeting/2024/07%20-%20Park%20G%20-%20Best%20Practices%20for%20EEAs_July%202024.pdf.
[129] "2025–2026 Winter Reliability Assessment," Table 4, NERC, November 2025, https://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf.

various entities.[130] The NERC rules allow for Balancing Authorities to develop plans to flexibly and proportionally respond to challenges or crises such as unplanned outages, extreme conditions, natural disasters, or other scenarios. In other words, Balancing Authorities are required to maintain a variety of options to respond to emergencies based on localized conditions.

Disclaimer

This report was prepared by Current Energy Group (CEG). It is intended to be read and used as a whole and not in parts. The report reflects the analyses and opinions of the authors using currently available information and does not necessarily reflect those of any other entity associated with this work.

[130] "Energy System Restoration Plan," Puget Sound Energy, August 30, 2024, https://www.pse.com/en/safety/first-responders/emergency-operations.

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-02:
Grid Strategies Resource Adequacy Report

Craig Unit 1 is Not Needed for Electric Reliability

Michael Goggin

January 2026

The U.S. Department of Energy's (DOE's) December 2025 order claims Craig Unit 1 is needed to meet a regional shortage of electric energy and a shortage of generating facilities in the WECC Northwest assessment area.[1] However, DOE does not cite any documents that make this claim or that support such a claim. In addition, after extensive planning analyses, Craig Unit 1's utility owners and their regulators have determined it is not needed for electricity reliability in either the near-term or long-term.

DOE's order does not attempt to present any evidence demonstrating there is a near-term emergency. Instead, DOE's order focuses on planned generator retirements by the end of this decade and projected load growth through 2034. By ignoring generating resource additions that will replace retiring capacity and meet load growth, DOE's order provides an incomplete picture of the West's long-term electricity supply and demand balance. Proper long-term resource assessments show that planned resources will ensure the West has adequate generation supplies for the decade time horizon covered by its analysis, with large capacity surpluses in the near-term.

A. The Utilities that Own Craig Unit 1, and Their State Regulators, Have Processes In Place for Assessing and Maintaining Reliability.

Craig 1 is owned by five utilities: Tri-State, Public Service Company of Colorado (PSCo), Platte River Power Authority (PRPA), Salt River Project (SRP), and PacifiCorp. State public utilities commissions regulate the resource planning, resource adequacy, and reliability of Tri-State's, PSCo's, and PacifiCorp's systems. Specifically, the Colorado Public Utilities Commission (CPUC) regulates electric resource planning for PSCo and Tri-State. The Washington, Oregon, California, Utah, and Wyoming commissions regulate PacifiCorp's electric resource planning process.

A recent report by Telos Energy explains how Colorado regulators and utilities conduct extensive analysis to determine that they have adequate resources to meet peak electricity demand and provide all needed electric reliability services in all hours of the year, even under extreme events.[2] As discussed in the attached report from Telos Energy, Tri-State and PSCo are required to file Electric Resource Plans (ERPs) at regular intervals with the CPUC. The report explains that each plan is reviewed and approved by the CPUC after a years-long process involving discovery, witness testimony, an evidentiary hearing, and briefing. Various Colorado statutes and CPUC regulations require utilities to develop resource plans that will meet reliability needs across

[1] DOE, *Order No. 202-25-14,* (December 2025) https://www.energy.gov/documents/federal-power-act-section-202c-craig-order-no-202-25-14

[2] D. Stenclik and A. Shwartz, *Resource Adequacy Planning in Colorado: How Colorado utilities and regulators ensure reliability*, (September 2025).

a range of scenarios.[3] A primary focus is ensuring there are enough existing and new generating resources to meet electricity demand, which is typically called "resource adequacy."

PacifiCorp is subject to similar regulatory proceedings before the commissions in the states it serves. PacifiCorp typically files Integrated Resource Plans (IRPs) every two years (Colorado's ERPs are equivalent to IRPs, which is the more common name for these planning proceedings in most states). PacifiCorp's IRP dockets in Oregon and Utah usually involve discovery, technical conferences, multiple rounds of comments, and a written Commission decision.

PRPA and SRP do not have their resource plans regulated by a state commission. However, PRPA files and submits an IRP to the Western Area Power Administration (WAPA) as a condition of receiving federal hydropower from WAPA. PRPA prepares each of its IRPs through a years-long, public process that includes multiple public meetings. PRPA's IRP contains recommendations, which PRPA's Board votes on, as the Board has the ultimate responsibility for adopting PRPA's resource plan. Like PRPA, SRP regularly prepares an IRP (which it calls an Integrated System Plan) which it submits to its Board for approval. SRP's Integrated System Plan process includes an informal stakeholder advisory group. SRP is also required to submit an annual 10-year transmission plan to the Arizona Corporation Commission.

B. Craig 1's Owners Have Determined that It is not Needed for Near-Term Reliability.

Each of the five co-owners of Craig Unit 1 has determined that the unit is neither economic nor needed for resource adequacy or other reliability reasons. As noted above, those co-owners include the regulated investor-owned utilities PacifiCorp and PSCo, and public power utilities SRP, Tri-State, and PRPA. For the utility co-owners subject to oversight by state utility regulators, the determination that Craig 1 is neither needed nor economic has been approved by their state regulators. This section reviews the planning analyses each utility has completed, which in all cases have determined that Craig 1 is not needed for resource adequacy or other reliability reasons. All of these analyses have been completed in the last several years, and in many cases this year. These analyses account for recent upward revisions in anticipated load growth, largely due to the possible interconnection of data centers and other large loads, and still find that Craig 1 is not needed.

In 2016, the co-owners announced that they would close Craig 1 at the end of 2025, after deciding that closing the unit was the most cost-effective option.[4] In the decade since 2016, the co-owners have been preparing for Craig 1 to close at the end of 2025. Each of the co-owners has acquired new generating resources and taken other steps to replace the capacity and energy from

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[3] Colorado Secretary of State, *Code of Colorado Regulations*: *Public Utilities Commission Rules Regulating Electric Utilities 4 CCR 723-3*, https://www.sos.state.co.us/CCR/GenerateRulePdf.do?ruleVersionId=8369&fileName=4%20CCR%20723-3, at 92.

[4] Shutting down Craig 1 was also found to be the most cost-effective solution for meeting Colorado's State Implementation Plan for regional haze requirements. *See* 83 Fed. Reg. 31,332 (July 5, 2018) – *Final EPA action on Colorado's regional haze first planning period SIP revision*.

Craig 1 after 2025. Because these utilities have already replaced Craig 1's capacity, it will be an unneeded and redundant resource under DOE's Order.

Tri-State

Tri-State is one of the co-owners of Craig 1 and the operator of the entire Craig plant (*i.e.*, Craig Units 1-3). Tri-State is a wholesale generation and transmission provider that serves retail electric cooperatives. In the last several years, Tri-State has experienced a significant decline in its peak load because several member cooperatives have exited Tri-State's system, including the cooperative that was the single largest member on Tri-State's system, United Power.

Tri-State's most recent resource plan proceeding concluded in 2025. At the conclusion of that case, the CPUC found that Tri-State does not need Craig 1 after 2025 in order to maintain the reliability of Tri-State's system. Specifically, the CPUC concluded that "Craig Unit 1 is not required for reliability or resource adequacy purposes based on the record in this ERP. Every portfolio that Tri-State modeled assumes that Craig Unit 1 retires at the end of 2025 and does not provide any energy or capacity after 2025. At the same time, Tri-State convincingly concludes that every portfolio meets all reliability metrics and is reliable."[5]

The Commission had noted in the regulatory proceeding for Tri State's Phase II filing for the 2023 ERP that, "Tri-State applied Level 1 and Level 2 reliability metrics to all six portfolios presented in the ERP Implementation Report, and that all of them passed those screens. No party disputes that point."[6] Level 1 reliability metrics are based on industry-standard measures of resource adequacy, while Level 2 metrics demonstrate resource adequacy in extreme winter and summer weather events.[7] Craig 1 was assumed to retire at the end of 2025 in all six of Tri-State's ERP portfolios, and "the Preferred Portfolio comprises 1,350 MW of wind, solar, and storage resources."[8] The cooperative's broader plans to expand clean energy and close coal plants are expected to save its members $422 million over 20 years.[9] Moreover, because those investments in replacement resources by Tri-State and other owners have already begun, utility customers will end up paying for redundant resources if DOE mandates that Craig 1 remain open.

In December 2025, Tri-State filed an update with the CPUC reaffirming that Craig 1 is not needed because the utility has a capacity surplus through 2035, stating: "Tri-State stated within Phase I of the 2023 [Energy Resource Plan] ERP that it did not forecast a capacity shortfall until 2029. With the updated load forecast, shown above, utilized in Phase II and Phase II preferred portfolio resources, a capacity shortfall is not forecasted to occur until 2035…," when it will need 19 MW.[10] That update also documented that Tri-State has already contracted for 500 MW of storage

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[5] CPUC, *Proceeding No. 23A-0585E, Decision No. C25-0612*, (Aug. 26, 2025) at page 40.
[6] *Id.* at 38
[7] Tri-State, *Reliable, lowest-cost, reduced emissions preferred portfolio focus of Tri-State resource plan filing*, (April 2025), *available at* **https://tristate.coop/tri-state-files-ERP-implementation-plan**.
[8] *Id.* at 9
[9] J. Spector, *This coal-heavy rural co-op utility is buying its first solar plants*, (June 2024), *available at* https://www.canarymedia.com/articles/utilities/this-coal-heavy-rural-co-op-utility-is-buying-its-first-solar-plants
[10] Tri State, *2025 Annual Progress Report: 2023 Electric Resource Plan*, (December 2025), *available at* https://s3.documentcloud.org/documents/26458023/2025-erp-annual-progress-report-dec-25.pdf at 8-10

resources and 200 MW of wind resources that will come online over the next several years, supplementing 255 MW of solar that came online in October 2025, and that Tri State is negotiating to procure other resources pursuant to its plan.[11]

PRPA

In both its 2020 and 2024 IRPs, PRPA assumed that Craig 1 would close at the end of 2025. In both the 2020 and 2024 IRPs, PRPA concluded that it could maintain a reliable electric system without Craig 1 after 2025. The 2020 and 2024 IRPs contain a plan for PRPA to acquire additional generating and storage resources to replace PRPA's share of the capacity and energy from Craig 1. PRPA's 2024 IRP also indicates that the utility has surplus capacity without Craig 1 and does not need new capacity until 2029.[12]

SRP

Salt River Project's 2023 System Resource Plan also documented that the utility has adequate resources with Craig 1's planned retirement in 2025.[13] SRP is a public power entity and, under Arizona law, its electric resource planning process is not regulated by the Arizona Corporation Commission. SRP's Board oversees planning to ensure SRP has sufficient generation to meet reliability needs. DOE's Order for Craig 1 does not claim or cite any evidence indicating SRP or the Southwest have a shortfall of electric generating capacity. SRP experiences its peak demand in the summer.[14]

PSCo

All of PSCo's electric resource plans filed after 2016 have assumed that Craig 1 would close at the end of 2025. For example, PSCo's 2021 resource plan and its pending resource plan both assume that Craig 1 closes at the end of 2025.

PSCo recently extended operations at Comanche Unit 2 to compensate for the extended unavailability of Comanche Unit 3 due to an unexpected outage. However, PSCo did not request a variance to operate Craig 1 past its scheduled retirement date of December 31, 2025. Indeed, the petition requesting a variance of the Comanche 2 retirement date expressly states that PSCo is not seeking any other changes to its approved resource plans.[15] In granting a variance for Comanche 2 because of the outage at Comanche 3, the CPUC did not indicate that there would be any need for Craig 1 to operate past 2025.[16] Moreover, in a December 5 filing, PSCo indicated that it has already made short-term purchases for both winter and summer 2026 to ensure it has adequate capacity

[11] *Id.*
[12] PRPA, *2024 IRP*, https://prpa.org/wp-content/uploads/2023/04/2024-Integrated-Resource-Plan.pdf, at 132
[13] SRP, *2023 Integrated System Plan*, https://www.srpnet.com/assets/srpnet/pdf/grid-water-management/grid-management/isp/SRP-2023-Integrated-System-Plan-Report.pdf, at 27.
[14] *Id.* at 83, 86.
[15] Colorado PUC Proceeding No. 25V-0480E, Joint Petition at 3 (Nov. 10, 2025) ("[T]he Joint Petitioners are not requesting any further modification of existing resource plans beyond the variance requested here to address recent events and associated issues discussed in this Petition.").
[16] *See* Colorado PUC Proceeding No. 25V-0480E, Decision No. C25-0892 (Dec. 10, 2025).

and energy to meet demand in 2026.Like the other four utility co-owners, PSCo's system is summer-peaking, meaning that peak demand occurs in the summer, not in the winter.[17]PacifiCorp

Finally, PacifiCorp's 2025 IRP shows it has surplus capacity without Craig 1. PacifiCorp's system is divided between an eastern and western Balancing Authority (BA), and Craig 1 is directly connected to the eastern BA.[18] Each BA maintains its own balance of electricity supply and demand in real-time, and moving power between the BAs requires scheduling flows on the transmission ties between them. As a result, the capacity position and outlook for the eastern BA is more relevant for assessing whether Craig 1 is needed.

PacifiCorp's most recent IRP, which was prepared in 2025, shows that, even without any resource additions, its eastern BA has adequate capacity supplies until 2036 in summer and until 2040 in winter.[19] System-wide, PacifiCorp does not need new summer capacity until 2028 and winter capacity until 2030.[20] PacifiCorp's 2025 IRP identifies new resource additions that will build an economically optimal generation portfolio, including large-scale additions of storage, nuclear, demand-side, and renewable resources.[21] As discussed below, PacifiCorp's large transmission ties with neighboring utilities and regions with large capacity surpluses will also help ensure resource adequacy even if it faces extreme conditions.

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All five of the utility owners of Craig 1 experience peak demand in the summer.[22] As a result, DOE's mandate to continue operating Craig 1 for 90 days through March 30, 2026[23] would not affect the ability of those utilities to meet their annual peak demand. Regardless, assessments by the North American Electric Reliability Corporation (NERC) indicate the regions served by Craig 1's owners have adequate supplies of generating capacity in both winter and summer 2026.

NERC's 2025/2026 Winter Reliability Assessment confirms that the Rocky Mountain region and other parts of the West have surplus generating capacity for this winter. Specifically, NERC's report finds that the Rocky Mountain region has a 61.7% reserve margin for winter peak periods,[24] more than 3 times greater than the target reserve margin level of 18.2%. Craig 1 is located in the

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[17] PSCO, *2021 ERP and CEP Transmission System Impact Study for the Approved Portfolio*, available at https://www.rmao.com/public/wtpp/Operating_Studies/ERP%20Phase%20II_Transmission%20Planning%20Study_10.11.24.pdf, at 37.
[18] PacifiCorp, *Corporate Realignment Report: Utah Legislature,* (November 2024) https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/about/Corporate_Realignment_Report_UT_Legislature.pdf, at 2.
[19] PacifiCorp, *2025 IRP Volume 1*, https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2025-irp/2025_IRP_Vol_1.pdf, at 132-139.
[20] *Id.*
[21] *Id.* at 227
[22] In addition to citations above demonstrating SRP and PSCo are summer peaking, see *id.* at 114; PRPA, *2024 IRP*, https://prpa.org/wp-content/uploads/2023/04/2024-Integrated-Resource-Plan.pdf, at 61; and Tri State, *FERC Form 1*, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250418-8013 at 401b.
[23] DOE, *Order No. 202-25-14,* (December 2025) https://www.energy.gov/documents/federal-power-act-section-202c-craig-order-no-202-25-14.
[24] *Id.* at 38.

Rocky Mountain region, and is used by Tri-State, Xcel, PacifiCorp, and PRPA to serve customers in the Rocky Mountain region. Most of the remaining[25]customers served by Craig 1's owners are in the Southwest region, which NERC found has an even larger capacity surplus for this winter.[26]

While NERC's winter assessment finds the Rocky Mountain and Southwest regions have "normal" risk, NERC identifies the WECC-Basin region, which is largely made up of PacifiCorp's eastern Balancing Authority, as being in a middle category of "Elevated risk during extreme weather," below the highest category of "high risk during extreme weather." This places WECC-Basin among 7 regions nationally that NERC assessed were in the "elevated" category, in addition to 10 regions categorized as having "normal" risk.

NERC explains that for WECC-Basin, "There is sufficient capacity in the area for expected peak conditions; however, Balancing Authorities (BA) are likely to require external assistance during extreme winter weather that causes thermal plant outages, adverse wind turbine conditions, and natural gas fuel supply issues for area internal resources. With an expected winter peak demand of 11.1 GW, under an extreme combination of generator derates and outages, the region could be short 1.6 GW before imports."

In other words, NERC's 2025/2026 Winter Assessment finds that for WECC-Basin, there is sufficient capacity under expected conditions, but that under "extreme" winter weather, the WECC-Basin region could need to rely on imports from neighboring regions. Neither NERC nor DOE has stated the probability that such an "extreme" situation will actually occur this winter, or that such an extreme situation is likely to actually occur. More importantly, NERC's Winter Assessment does not state that WECC-Basin would actually experience a shortfall even if this "extreme" scenario occurred. Instead, NERC states only that WECC-Basin "could be short . . . before imports." But NERC does not state that imports are likely to be unavailable. In fact, WECC-Basin has strong transmission ties to California, the Rocky Mountain region, the Southwest, and the Northwest, as summarized in the following table. As a result, external assistance would likely be available if the WECC-Basin subregion is affected by extreme winter weather.

Table 1: PacifiCorp's import limits with neighboring regions[27]

Import region	
Northwest (WECC Paths 17 and 18)	1,856 MW
California (Path 27)	1,400 MW
Southwest (Paths 32, 35, 78, 79)	1,715 MW
Rocky Mountain (Paths 30 and 36)	2,330 MW
Total	**7,301 MW**

[26] *Id.* at 11.
[27] California ISO, *PacifiCorp Transmission System Map and Path Ratings*, https://www.caiso.com/Documents/PacifiCorpTransmissionSystemMap-PathRatings.pdf

Severe winter events that cause extreme outage rates and peak load are not typically extreme across a wide footprint,[28] making it likely that imports will be available from at least one of those other regions. The expansion of regional markets in the West, as well as resource adequacy sharing and accounting mechanisms like the Western Resource Adequacy Program, are further enabling Western utilities to tap into geographic diversity in supply and demand patterns to more efficiently meet their own needs with less generating capacity.

Table 2: Reserve margin levels by Western region with zero, normal, and extreme outage rates[29]

Region	Target	Zero outages	Normal outages	Extreme Outages
Rocky Mountain	18.2%	61.7%	53.2%	10.0%
California	12.5%	82.3%	73.7%	57.9%
Southwest	16.0%	104.4%	90.1%	50.1%

NERC's outlook for the Western U.S.'s ability to reliably meet summer peak demand is even sunnier. NERC's 2025 Summer Reliability Assessment found all parts of the Western U.S. had normal risk, with no regions categorized as elevated or high risk.[30]

C. NERC and Others Show There is No Long-term Need for Craig 1, Either.

Looking even further into the future, IRPs for all five utility co-owners of Craig 1 continue to show the unit is not needed for reliability. As noted above, these IRPs show these utilities have adequate resources for at least the next several years without Craig 1.

Other assessments confirm that outlook. NERC's 2024 Long-Term Reliability Assessment (LTRA) found all regions of the Western U.S., except California/Mexico, have normal risk for the 2025-2029 period, and California/Mexico was rated "elevated risk."[31] The California/Mexico region is not included in the footprint of DOE's claimed emergency, and none of the utility owners of Craig 1 serve customers in the California/Mexico region (PacifiCorp serves a very small number of customers in northern California, though NERC's map appears to group that part of the state into the Northwest subregion). The discussion of the LTRA in DOE's order for Craig 1 focuses on the Northwest region. However, NERC's LTRA shows the Northwest region has adequate supplies through summer 2031, and that "with the addition of Tier 2 capacity, the PRM [Planning Reserve Margin] stays above the RML [Reference Margin Level or target reserve margin] for all years in the LTRA time horizon." In other words, if planned resources come online as expected, the Northwest

[28] M. Goggin *et al.*, *Quantifying a Minimum Interregional Transfer Capability Requirement*, (May 2023) https://gridstrategiesllc.com/wp-content/uploads/2023/05/GS_Interregional-Transfer-Requirement-Analysis-final54.pdf, at 3-4.
[29] NERC, *2025/2026 Winter Reliability Assessment*, (November 2025) https://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf, at 11, 48-49.
[30] NERC, *2025 Summer Reliability Assessment,* (May 2025) https://www.nerc.com/globalassets/programs/rapa/ra/nerc_sra_2025.pdf.
[31] NERC, 2024 *Long-Term Reliability Assessment,* (initially issued December 2024, corrected July 2025) https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf.

region has a large capacity surplus for the study's horizon through the year 2034.[32] Notably, the Northwest's planning reserve margins through 2029 are expected to be 30% or higher, more than twice the region's target reserve margin in those years.

Since the LTRA was issued, NERC has sometimes broken the WECC Northwest region into three smaller regions, called Front Range, Basin, and Northwest. As discussed in the previous section, NERC assessed that the Front Range region that includes Colorado has "normal" risk in both winter and summer. Most of Craig 1's co-owners' customers are in the Front Range or the Southwest region, which also has "normal" risk in both summer and winter. Only PacifiCorp, which has a 19% stake in Craig 1, is in the WECC-Basin region. As discussed in the preceding section, while NERC assessed that the Basin region has "elevated" winter risk, NERC did not state that the Basin region has a shortfall of energy or capacity right now—only that under an "extreme" situation, the Basin region might need to rely on some amount of imports (and NERC does not state that such imports would be unavailable).

DOE's order for Craig 1 does not address the LTRA's finding that the Northwest region has adequate supplies into the 2030s. Instead, it takes out of context a quote focused on variability in wind and solar output, which relates to a separate reliability issue of flexibility. In fact, wind and solar contribute significantly to meeting peak demand, and utilities, other grid operators, and regulators use sophisticated methods to account for their contributions. Utilities in the West precisely quantify the capacity value contributions of wind and solar resources using proven methods that utilities and their regulators have relied on for decades. For example, in 2011 NERC released a white paper documenting these capacity accreditation methods.[33]

The DOE order's focus on flexibility is perplexing because, compared to newer resources, most coal plants have far less flexibility for accommodating variability in electricity supply and demand. Coal plants can only slowly change their level of output, can only turn down to high minimum output levels, and can take a dozen or more hours to start up, which also incurs significant costs. Regardless, the Northwest region has a substantial amount of flexible resources due to highly flexible hydropower resources and increasing penetrations of new flexible resources (described below). As a result, retaining inflexible older resources like Craig 1 will not help power system flexibility, and could hurt flexibility by impeding the transition to new more flexible resources.

DOE's order also focuses on thermal resource retirements across the West and in Colorado. Focusing on retirements of one resource type paints an incomplete picture of the overall supply and demand balance. Utilities across the West and in Colorado are rapidly building new resources, including new resources that offer large capacity value and are highly flexible. DOE's Energy Information Administration tallies nearly 5,800 MW of planned resource additions through 2029 in Colorado alone, including 860 MW of gas generation and more than 1,300 MW of battery

[32] *Id.* at 127

[33] N. Am. Elec. Reliability Corp., *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning* (Mar. 2011), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/IVGTF1-2.pdf.

capacity.[34] Across the West, DOE tallies more than 78,000 MW of planned resources through 2031 (with most of those resources expected to be online by 2030), including more than 34,000 MW of storage and thermal resources.[35] For the WECC Northwest states of Colorado, Idaho, Montana, Oregon, Utah, Washington, and Wyoming, the planned total is more than 39,000 MW through 2031 (with most of those resource additions occurring by 2030), of which nearly 16,000 MW are storage and thermal resources, many times greater than the 5,000 MW of planned retirements that DOE cites in those states.

DOE's order also cites a projection from the Western Electricity Coordinating Council's 2024 Western Assessment of Resource Adequacy that peak demand in the Northwest-Central region will grow by 8.5%, or 3 GW over the next 10 years. A growth rate of less than 1% per year is manageable, and a 3 GW increase in demand is far less than the planned resource additions in that region, even after accounting for retirements. Moreover, IRPs already account for demand growth and the need for flexibility, and planning the optimal resource mix to meet all of those needs at lowest cost. As documented above, the IRPs for all Craig 1 co-owners show they can meet all reliability needs without the unit, even in light of expected demand growth.

DOE also cites its own July 2025 report[36] to claim there is a long-term risk of a nationwide resource adequacy shortfall. DOE's report has been widely criticized[37] for vastly overstating the need for resources by using assumptions for nationwide generator retirements, capacity additions, and load growth that are far more pessimistic than other data and projections from EIA and others. As summarized in Table 3 below, DOE's report overstates the nationwide need for resources by around 200 GW relative to other DOE sources. If the inputs to DOE's July 2025 report were corrected, the report would not have found a 2030 need because 109 GW of resource additions would more than meet the 92 GW of need created by 40 GW of load growth plus 52 GW of retirements nationwide. As noted above, NERC's LTRA uses more reasonable assumptions for generator retirements, capacity additions, and load growth than DOE's July 2025 report. NERC's LTRA finds the Northwest region that includes Colorado has large capacity surpluses through 2031, and that with planned resource additions the region has surpluses throughout the assessment's 2034 planning horizon.

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[34] DOE Energy Information Administration, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860) November 2025*, (December 2025) https://www.eia.gov/electricity/data/eia860m/xls/november_generator2025.xlsx

[35] *Id.*

[36] DOE, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, (July 2025), https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf

[37] For example, *see* Ric O'Connell, *GridLab Analysis: Department of Energy Resource Adequacy Report* (July 11, 2025), *available at* https://gridlab.org/gridlab-analysis-department-of-energy-resource-adequacy-report/; *see also* Jennifer Danis, et al., *Enough Energy: A Review of DOE's Resource Adequacy Methodology* (July 2025), *available at* https://policyintegrity.org/files/publications/IPI_EnoughEnergy_FinalReport.pdf.

Table 3: Assumptions in DOE's July 2025 report vs other DOE data, nationwide GW by 2030

	DOE July 2025 report	Other DOE data/projections	Overstatement of need for resources
Capacity retirements	104 GW firm	52 GW nameplate[38]	52 GW
Resource additions	22 GW firm	109 GW[39]	87 GW
Load growth	101 GW	40 GW in high growth case[40]	61 GW
Total overstatement of need for resources nationwide			**200 GW**

D. DOE Has Not Explained Whether and How Craig Unit 1 Can Address any Shortfalls in the Pacific Northwest and WECC Basin

As explained above, DOE has not shown that there is an emergency on either a short-term or long-term basis. And the regions that most of Craig Unit 1's output serves—the Rocky Mountain and Southwest regions—have the lowest level of risk in NERC's assessment for this winter, as noted above. Even if DOE were correct that there is a short-term emergency in the Pacific Northwest or WECC Basin regions (which is not the case), the Order does not explain how Craig Unit 1 could address that emergency.

Craig Unit 1 is located in western Colorado. Most of the unit's output goes to four of the five co-owners: Tri-State, PRPA, PSCo, and SRP. Collectively, those utilities own around 81% of Craig Unit 1, while PacifiCorp owns the remaining 19%. PRPA's and PSCo's service territories are solely in Colorado, and SRP's service territory is solely in Arizona. Most of Tri-State's members are located in Colorado, with the remainder in New Mexico and Wyoming (members in Nebraska are not served by Craig Unit 1, and are instead served through a separate, all-requirements contract with Basin Electric Cooperative). PacifiCorp is the only one of the owners of Craig Unit 1 that serves customers outside of the Rocky Mountain and Southwest regions.

The primary purpose of the Yampa project (consisting of Craig Units 1 and 2) was not to serve customers in the Pacific Northwest or the WECC Basin; it was to serve customers in Colorado (and secondarily in Arizona), which is where most of the customers of most of the co-owners are located. DOE has not explained why Craig Unit 1 is even a reasonable solution to any concerns it may have about other parts of the WECC region, let alone the best one.

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[38] EIA, *EIA-860M* (June 2025), (data for May 2025), https://www.eia.gov/electricity/data/eia860m/.

[39] *Id.* To be conservative, the tally of 109 GW of planned resource additions includes only thermal and battery resources and does not account for the significant resource adequacy contributions from planned wind and solar resources. The 22 GW figure for the July 2025 DOE report is based on the statement on page 1 that for capacity additions by 2030, "only 22 GW would come from firm baseload generation sources."

[40] EIA Annual Energy Outlook high growth case assumes 6% growth through 2030, versus 15% assumed in DOE's July 2025 report.

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-03:
Powers Decl.

CRAIG UNIT 1 DECLARATION OF BILL POWERS, P.E.

January 2026

I, Bill Powers, P.E., declare as follows:

1. I am the principal of Powers Engineering, an engineering firm that consults on issues related to the operation of, and control of pollution from, power plants, including coal-fired power plants. My office is located in San Diego, California. My professional and educational experience is summarized in the curriculum vitae attached to this declaration (Attachment A).

2. I received a Bachelor of Science degree from Duke University in Mechanical Engineering and a Master of Public Health degree in Environmental Sciences from the University of North Carolina. I am a registered engineer in the state of California.

3. I have been an independent engineering consultant with a focus on power systems since 1994. In prior employment, I received "Engineer of the Year" awards from ENSR Consulting and Engineering in 1991 (before ENSR merged with AECOM) and from the Naval Energy and Environmental Support Activity ("NEESA") office within the U.S. Navy in 1986 (before NEESA was subsumed by the Naval Facilities Engineering Service Center). I also received a "Productivity Award of Excellence" from the U.S. Department of Defense in 1985. I worked extensively on Navy and Marine Corps coal-fired power plants in the 1980s as a Navy civilian engineer.

4. I have over 40 years of experience in the fields of power plant operations and environmental engineering. My technical specialties include, among others: combustion

equipment permitting, testing, and monitoring; air emission control assessments; air pollution control equipment retrofit design/performance; and power plant cooling system conversion.

5. I have served as an engineering expert for a wide array of clients, including private companies, non-profits, and government entities, including the cities of Carlsbad, California and Houston and Dallas, Texas. In this role, I have provided expert testimony, conducted feasibility studies, and consulted on power plant engineering issues in a number of states, including Arkansas, California, Connecticut, Florida, Georgia, Kentucky, Maryland, Missouri, Nevada, North Carolina, New York, and Tennessee.

6. I have extensive experience with coal-fired power plants. In 2022, I provided expert testimony before the North Carolina Public Utility Commission regarding Duke Energy's proposed plan to maintain coal-fired units in its electric supply portfolio — a proposal the company advanced in part based on its belief that those units were necessary to meet winter peak demand. Throughout my career, I have consulted on the control of pollution from coal-fired power plants. Examples include serving as the lead engineer on a system and performance audit of continuous emissions monitoring systems at a coal-fired power plant in Nevada, and on a project to assess and address the root causes of opacity exceedances at Ameren Missouri's Labadie, Meramec, and Rush Island coal-fired power plants. I have also frequently provided expert testimony on coal-fired power plants. For example, I testified on air pollution controls at a coal-fired power plant in Massachusetts, and on the correlation between a Georgia coal-fired power plant's particulate matter emissions and opacity excursions, among other issues. I also served as a testifying expert on an evaluation of the air emissions limits and control technologies for a proposed coal-fired power plant in Arkansas. Finally, I submitted an expert declaration in the J.H. Campbell Generating Complex 202(c) case (Michigan) in June and September 2025, and

in the Schahfer and Culley 202(c) cases (Indiana) in January 2026. In those declarations, I documented the dramatic reduction in ongoing capital and major maintenance investments by the plant owners in the years prior to the planned permanent retirement, the impact of that lack of investment on the reliability of the plants, and the environmental issues associated with the plants' availability and operation.

7. I am also very familiar with "peaking" units, which are intended to ramp up and provide electricity during times of peak demand, such as during hot summer months. For example, in 2001, I prepared all aspects of the air permit applications for five 50 MW simple-cycle gas turbine installations in response to an emergency request by the California state government for additional peaking power.

8. I am familiar with the U.S. Department of Energy's ("DOE") December 30, 2025 order regarding the Craig Station coal-fired power plant (Order No. 202-25-14) ("Order").

9. The Craig Station coal-fired power plant ("Craig Station") consists of three coal-fired generating units. Craig Station Units 1, 2, and 3 have net generating capacities of 427 MW, 410 MW, and 448 MW, respectively.[1]

10. Tri-State Generation and Transmission Association ("Tri-State") is the operator of Craig Station. Tri-State has provided key filings concerning the operations of Craig Unit 1 across state and federal regulatory bodies.

11. Craig is owned by the following entities: Tri-State, Platte River Power Authority, PacifiCorp, Public Service Company of Colorado, and Salt River Project. Tri-State owns 24% interest in Unit 1 (equating to 102 MW) and 24% of Unit 2 (equating to 92 MW).[2] Tri-State is

[1] Colorado PUC Proceeding No. 23A-0585, Hearing Exhibit 105, *Barry Insgold Direct Testimony*, pg. 6 (December 1, 2023).
[2] *Id.* The other entities' ownership shares are as follows: PacifiCorp, 19.28%, Platte River Power Authority, 18%; Public Service Company of Colorado, 9.72%; Salt River Project, 29%. Pacificorp, *FERC Form 1* (April 14, 2025);

the sole owner of Craig 3, and it holds a 49% interest in the common facilities serving all three units.[3]

12. The in-service dates for Craig Units 1, 2, and 3 are 1980, 1979, and 1984, respectively.[4]

13. In accordance with the current Colorado Regional Haze State Implementation Plan, the owners of Craig Unit 1 must retire Unit 1 by December 31, 2025.[5] The Tri-State plan for Craig Station as a whole is to retire Craig Unit 1 by December 31, 2025, Craig Unit 3 by January 1, 2028, and Craig Unit 2 by September 30, 2028.[6]

14. I was asked by Earthjustice to develop an opinion on: (A) the extent to which Craig 1 can operate reliably after December 31, 2025; (B) whether Craig 1 can operate effectively as a peaking unit; (C) the environmental impact of continued operation of Craig 1; and (D) easily attainable steps DOE can require to ensure Craig 1 operates in a manner consistent with environmental requirements and that minimizes adverse environmental impacts. A list of materials I reviewed in developing my opinion is attached (Attachment B).

Platte River Power Authority, *Coal Energy*, https://prpa.org/generation/coal/; Public Service Company of Colorado, *FERC Form 1* (April 4, 2025); Salt River Project, *SRP Power Generation Sources*, https://www.srpnet.com/grid-water-management/grid-management/power-generation-stations.

[3] Colorado PUC Proceeding No. 23A-0585E, Hearing Exhibit 101, Attachment LKT-1, Attachment C-3, *Assessment of Existing Resources*, pg. 4 (December 1, 2023).

[4] Docket No. EPA-R08-OAR-2011-0770, Colorado Department of Public Health and Environment, Air Pollution Control Division, *Best Available Retrofit Technology (BART) Analysis – Tri-State Craig Station Units 1&2*, pg. 1 (March 26, 2012).

[5] Specifically, Colorado's federally-approved Regional Haze State Implementation Plan provides two scenarios for Craig Unit 1: (1) retirement by December 31, 2025, or (2) conversion to natural-gas firing by 2023. Docket No. EPA-R08-OAR-2018-0015, Environmental Protection Agency, *SIP Element Adopted,* pp. 7-8 (April 26, 2018); Colorado Department of Public Health and Environment, Colorado APCD, *Regulation No. 3, Part F, Sec. VI.D* (adopted December 15, 2016). However, as described below, converting Craig Unit 1 to natural gas by 2023 is an impossibility, and the owners committed to a retirement date of December 31, 2025.
Colorado PUC Proceeding No. 20A-0528E, Hearing Exhibit 102, *Lisa Tiffin Direct Testimony,* pg. 47 (December 1, 2020).

[6] Colorado PUC Proceeding No. 23A-0585E, *2025 Annual Progress Report - 2023 Electric Resource Plan,* pg. 5 (December 1, 2025).

15. While there may be alternatives to the continued operation of Craig 1 that are available to DOE to address the circumstances DOE describes in the Order, my analysis does not focus on these alternatives. I also do not opine on the claimed energy emergency described in the Order.

A. The extent to which Craig 1 can operate reliably beyond December 2025

16. In my professional opinion, it is unlikely that Craig 1 can be depended upon to operate reliably beyond December 2025 as an emergency generation resource. Craig 1 experienced a sharp increase in forced outages in 2023, the last year publicly accessible forced outage rate data is available for Unit 1. Tri-State also phased-out capital investment in Unit 1 in 2023. These facts point to degraded Unit 1 reliability. Craig 1 will be especially unreliable if the plant is required to run for extended periods of time, is required to stop and start numerous times, or attempts to start up at an accelerated rate in response to extreme demand conditions.

17. Craig 1 has been operating for 45 years. A typical coal unit has an economic design life of 30 to 40 years and a typical operational lifetime of 40 to 50 years.[7,8] As a power plant ages, the equipment degrades even though it is maintained and inspected, and it is unable to perform as well as brand new equipment. It becomes necessary to upgrade or replace degraded equipment to a new condition. Maintenance is necessary to minimize the effect of equipment degradation with age and operating regime.[9]

[7] M. Hafner, G. Luciani, *The Palgrave Handbook of International Energy Economics*, pg. 127 (2022).
[8] International Energy Agency, *The role of CCUS in low-carbon power systems*, pg. 18 (2020).
[9] Intertek, *Update of Reliability and Cost Impacts of Flexible Generation on Fossil-fueled Generators*, pg. 7 (May 12, 2020).

18. Tri-State provides its capital investment strategy for early retirement resources in its 2020 ERP. Tri-State indicates that it "proactively works to reduce and eliminate capital expenses" related to plants set to retire.[10]

19. Tri-State has substantially reduced capital and operations and maintenance ("O&M") spending on the Craig coal units in recent years in anticipation of an impending permanent shutdown. In the Tri-State 2023 Electric Resource Plan ("ERP") proceeding, in response to the question "What approach is Tri-State taking to capital and operational investments for Craig Station over the remaining life of the plant?," Tri-State witness Ingold testified that "Tri-State's investments in Craig Station are being appropriately limited to only actions necessary for ensuring safe operations and regulatory compliance, given the impending retirement of these units."[11] While this strategy is appropriate for units approaching retirement, it is not a viable strategy for units that may continue to operate indefinitely into the future and will be expected to provide grid reliability support. And because Tri-State implemented this strategy a number of years ago, the reliability of Craig Unit 1 to continue operating beyond 2025 is jeopardized.

20. In my professional opinion, Tri-State has taken a reactive, "fix it if it breaks" approach to the maintenance of Craig Unit 1. In his testimony, witness Ingold describes Craig Station's transition away from a preventative capital investment and maintenance structure, which was intended to maintain the Craig units' long-term reliability.[12] In other words, Tri-State's objective has shifted from maintaining long-term reliability to simply keeping the units operating—to the extent possible with little or no spending—*up until their scheduled retirement*

[10] Colorado PUC Proceeding No. 20A-0528E, Hearing Exhibit 101, Attachment BN-2, *2020 Integrated Resource Plan/Electric Resource Plan Volume I*, pg. 187 (Dec. 1, 2020).
[11] Colorado PUC Proceeding No. 23A-0585E, Hearing Exhibit 105, *Barry Insgold Direct Testimony*, pg. 10.
[12] *Ibid.*

dates and no longer. In the case of Craig 1, Tri-State's stated objective was to keep the unit operating until December 31, 2025 and shut it down at that time. The objective was *not* to maintain a high level of reliability beyond December 31, 2025. A high level of reliability would be necessary for Craig 1 to ramp up and work reliably under emergency demand conditions.

21. Tri-State confirmed its "fix it if it breaks" approach for Craig Unit 1 in its December 31, 2025 press release. Tri-State stated that "[s]ince 2016, Unit 1 has been scheduled for retirement by Dec. 31, 2025, for economic reasons, and to comply with numerous state and federal requirements. This retirement decision has informed operational and maintenance decisions."[13]

22. And Craig 1 did not even make it to its scheduled retirement date without breaking. When the 202(c) Order was issued, Craig Unit 1 had a forced outage that began on December 19, 2025 due to a mechanical failure of a valve.[14] Craig Unit 1's mechanical failure and resulting forced outage are characteristic of an older plant at the end of its operational life. The December 2025 forced outage reinforces my conclusion that Craig Unit 1's co-owners and operator have underspent on capital and O&M, and that Craig 1 is at risk of even more future forced outages.

23. This reality is also reflected in the Craig Station forced outage rate trends. The forced outage rates for Craig Station Unit 1 for the eight-year period from 2016 to 2023 are shown in Table 1. The 2023 forced outage rate for Unit 1 was 9.53 percent, and it was the highest forced outage rate in the eight-year period. Craig 1 experienced the sharpest year-over-year forced outage rate increase between 2022 and 2023, increasing from 1.75 percent to 9.53

[13] Tri-State, *U.S. DOE orders Tri-State to keep Craig Generating Station operating for next 90 days* (December 31, 2025).
[14] *Ibid*.

percent. A 9.53 percent forced outage rate translates into 835 hours that Craig 1 could not operate in 2023, or approximately five weeks of forced unavailability.[15]

Table 1. Craig Station Unit 1 Forced Outage Rates, 2016–2023[16]

	2016	2017	2018	2019	2020	2021	2022	2023
Forced Outage Rate	1.59	2.11	5.53	1.21	3.35	8.18	1.75	**9.53**

24. Craig 1's sharp increase in year-over-year forced outage rate from 2022 to 2023 is alarming, especially if Craig 1 is expected to operate past the December 31, 2025 retirement date. Maintenance is necessary to minimize the effect of equipment degradation with age and changing operating regimes. Plants, such as Craig Station, that have underspent on capital and/or O&M are at greater risk of future forced outages.[17]

25. In my professional opinion, it is unlikely that Craig 1 can reliably dispatch. As described above, Tri-State has deferred capital and major maintenance spending, which is reflected in the plant's forced outage rate and an outage as recently as December 2025.

B. Whether Craig 1 can operate effectively as a peaking unit

26. In my professional opinion, Craig 1 cannot operate effectively as a peaking unit.

27. Coal units generally, including Craig 1, cannot serve as peaking units that respond to extreme peak demand on short notice. Coal units are designed for baseload, around-the-clock operation.[18] Coal units started "cold" (room temperature) usually require 12 or more hours to

[15] 0.0953 x 8,760 hr/yr = 834.8 hr/yr. 835 hr ÷168 hr/week = 4.97 weeks.
[16] Colorado PUC Proceeding No. 20A-0528E, Tri-State 2020 ERP, Volume I, Table 21, pg. 187 (December 1, 2020); Colorado PUC Proceeding No. 23A-0585E, Phase II Implementation Report, Attachment B, *Modeling Assumptions*, Table 7, pg. 14 (April 11, 2025). 2024 and 2025 forced outage rate data is not publicly available for Craig Unit 1.
[17] *Ibid*.
[18] RMI, *Reality Check: We Have What's Needed to Reliably Power the Data Center Boom*, *and It's Not Coal Plants* (August 12, 2025).

reach full load operation.[19] The ramp rate is slow to avoid excessive thermal stress on components exposed to heat. In contrast, utility-scale battery storage can dispatch from a cold start to full power in a matter of seconds.[20] Similarly, combustion gas turbines, designed for fast-response peaking duty, can go from a cold start to full power in 5 to 10 minutes.[21]

28. Coal units cannot respond to extreme demand events unless they are fully online several hours before the high demand situation occurs. In other words, coal units need substantial lead time to be fully operational at or before an extreme peak demand is reached. They cannot be dispatched from an offline "cold" status to address extreme emergency demand if an emergency is declared only a few hours before the demand must be met.

29. Bringing Craig 1 from a cold start condition to full output to meet extreme demand would also be expensive. According to the National Association of Regulatory Utility Commissioners, the estimated cost to "cold start" a coal-fired power plant is $417 per MW of capacity.[22] The net capacity of Craig 1 is 427 MW. Therefore, the estimated cost to start up Craig 1 from a cold start condition would be approximately $180,000. (427 MW × $417 per MW = $178,059).

30. Alternatively, instead of starting cold, Tri-State could be forced to run Craig 1 unnecessarily. That approach would be even more expensive and, as discussed below, highly polluting.

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[19] IEA, *Increasing the flexibility of coal-fired power plants*, pg. 26 (September 2014); Proceeding No. 23A-0585E, Phase II Implementation Report, Attachment B, *Modeling Assumptions*, pg. 12.
[20] NERC, *Energy Storage: Overview of Electrochemical Storage*, pg. 1 (February 2021), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Master_ESAT_Report.pdf ("BESS are a well suited technology to provide short-term grid contingency support (tens of seconds)…").
[21] General Electric, *Get to know the LM6000* (2025), https://www.gevernova.com/gas-power/products/gas-turbines/lm6000. ("With around five minutes to ramp up from start-up to full power . . . .").
[22] NARUC, *Recent Changes to U.S. Coal Plant Operations and Current Compensation Practices*, p. 16 (January 2020).

C. Environmental impact of continued operation of Craig 1

31. The Craig Station units' closure dates are identified in state law. In 2016, Colorado revised its regional haze regulations to provide two compliance pathways for Craig Unit 1: closure by December 31, 2025, or conversion to natural gas (with more stringent emission limits) by August 31, 2023.[23] Colorado also required the facility to comply with additional nitrogen oxide ("NOx") limits between January 2017 and closure or conversion.[24] Colorado included these regulatory provisions in a revision to its Clean Air Act Regional Haze State Implementation Plan ("SIP"), which EPA approved in 2018.[25] The facility owners chose to retire Craig Unit 1 instead of converting it to natural gas. Colorado subsequently established firm closure dates for Units 1, 2, and 3 (and removed the natural gas conversion option for Unit 1), which were adopted by the Colorado Air Quality Control Commission ("AQCC") and made effective by publication in the Colorado Register on February 14, 2021.[26]

32. Burning coal emits air pollutants and greenhouse gases. These pollutants include NO_x, sulfur dioxide ("SO^2"), particulate matter ("PM"), volatile organic compounds ("VOC"), mercury ("Hg"), and carbon dioxide ("CO_2"), among others. NO_x is a lung irritant and a precursor to ozone formation.[27] SO_2 can harm the respiratory system and contribute to the formation of acid rain.[28] PM emissions can cause decreased lung function and increased respiratory symptoms.[29] In addition, NO_x, SO_2, and PM_{10} contribute to the formation of

[23] Colorado Department of Public Health and Environment, Colorado APCD, *Regulation No. 3, Part F, Sec. VI.D* (adopted December 15, 2016).
[24] *Ibid*.
[25] 83 Fed. Reg. 31332 (July 5, 2018).
[26] Colorado PUC Proceeding No. 23A-0585E, Hearing Exhibit 105, *Barry Insgold Direct Testimony*, pp. 8-9.
[27] U.S. EPA, *Basic Information about NO_2*, https://www.epa.gov/no2-pollution/basic-information-about-no2.
[28] U.S. EPA, *Sulfur Dioxide Basics*, https://www.epa.gov/so2-pollution/sulfur-dioxide-basics.
[29] U.S. EPA, *Health and Environmental Effects of Particulate Matter (PM)*, https://www.epa.gov/pm-pollution/health-and-environmental-effects-particulate-matter-pm.

atmospheric haze, which reduces visibility.[30] Colorado has determined that air pollution from Craig Station is a major contributor to visibility impairment in several national parks and wilderness areas, including Eagles Nest Wilderness Area, Flat Tops Wilderness Area, Rocky Mountain National Park, Rawah Wilderness Area, and Mount Zirkel Wilderness Area.[31] CO_2 emissions are the primary cause of global warming.[32]

33. Large quantities of these pollutants and greenhouse gases will enter the atmosphere if uncontrolled. Craig Station's Title V air permit sets out the emission limits and other requirements the facility must comply with to reduce air pollution from coal combustion and related operations.[33]

34. Coal-burning power plants must include air emission control equipment to reduce the pollutants in the coal boiler exhaust gas stream. The equipment still allows some level of pollution to be emitted, but it reduces the amount of pollutants entering the atmosphere.

35. Some of that air cleaning equipment at Craig Unit 1 includes pulse jet fabric filters, wet limestone scrubbers, and low-NO_x burners with over-fire air.[34] Pulse jet fabric filters remove PM from the boiler exhaust gas. Wet limestone scrubbers (also known as flue gas desulfurization) remove SO_2. The low-NO_x burner system is intended to limit the amount of NO_x generated at the point of combustion in the boiler.

[30] Docket No. EPA-R08-OAR-2018-0015, Colorado APCD, *Best Available Retrofit Technology (BART) Analysis – Tri-State Craig Station Units 1 and 2*, pg. 2 (April 26, 2018).
[31] Colorado Department of Public Health and Environment, *BART CALPUFF Class I Federal Area Individual Source Attribution Visibility Impairment Modeling Analysis for Tri-State Generation & Transmission Association Craig Station Units 1 and 2 (Revised)*, pp. 47-48 (Mar. 3, 2006).
[32] U.S. EPA, *Carbon Dioxide Emissions*, https://www.epa.gov/ghgemissions/carbon-dioxide-emissions.
[33] Colorado Department of Public Health and Environment, Craig Station Operating Permit, section II(I) (July 1, 2021).
[34] Docket No. EPA-R08-OAR-2018-0015, Colorado APCD, *Best Available Retrofit Technology (BART) Analysis – Tri-State Craig Station Units 1 and 2*, pg. 1.

36. Unit 1 became operational in 1980 and was originally equipped with a hot-side electrostatic precipitator ("ESP") to control PM emissions and a wet limestone scrubber to control SO_2 emissions. In October 2003, the Unit 1 ESP was replaced with a fabric filter, the wet scrubber was changed, and ultra-low NO_x burners with over-fire air were added to the boiler.[35] The wet-limestone scrubber and the ultra-low NO_x burner system were required to be installed as a result of a consent decree with the Sierra Club.[36]

37. Additional Unit 1 activities permitted to emit air pollution include an evaporative cooling tower, coal handling system, ash handling system, limestone and lime handling system, a waste ash staging area, and landfilling operations.[37]

38. Tables 2a and 2b summarize the projected CO_2, SO_2, NO_x, PM, VOC, and Hg emissions from Craig 1 for the 90-day period from January 1, 2026 to March 31, 2026, assuming the same level of Craig 1 electricity generation as recorded in January, February, and March of 2025. As shown in Table 2a, more than 1.1 billion pounds of CO_2, nearly 270,000 pounds of SO_2, and more than 1.2 million pounds of NO_x would be emitted. As shown in Table 2b, nearly 47,000 pounds of PM, more than 900 pounds of VOC, and a trace amount of Hg would be emitted. None of these emissions could occur if Craig 1 is permanently retired by December 31, 2025.

Table 2a. Projected Craig 1 CO_2, SO_2, and NO_x Emissions,[38] 90-Day Order

Month	Production,[39] MWh	CO_2 emissions, lbs	SO_2 emissions, lbs	NO_x emissions, lbs
January 2026	174,089	438,258,940	102,016	479,093
February 2026	124,764	306,919,440	73,112	343,351
March 2026	161,356	396,935,760	94,555	444,052
90-day total:	460,209	1,142,114,140	269,683	1,266,496

[35] Colorado APCD, *Field Inspection Report – Craig Generating Station*, pg. 2 (March 25, 2025).
[36] Docket No. EPA-R08-OAR-2018-0015, Colorado APCD, *Best Available Retrofit Technology (BART) Analysis – Tri-State Craig Station Units 1 and 2*, pg. 2.
[37] *Ibid.*
[38] Colorado PUC Proceeding No. 23A-0585E, *ERP Phase II Implementation Report, Attachment B: Modeling Assumptions*, Table 10, pg. 19 (April 11, 2025). CO2 = 2,460 lb/MWh; SO2 = 0.586 lb/MWh; NO_x = 2.752 lb/MWh. Denominator is "net MWh".
[39] U.S. Department of Energy, *EIA Form 923*, *Page 4 Generator Data* (2025).

Table 2b. Projected Craig 1 PM, VOC, Hg,[40] 90-Day Order

Month	Production,[41] MWh	PM emissions, lbs	VOC emissions, lbs	Hg emissions, lbs
January 2026	174,089	17,757	348	1.04
February 2026	124,764	12,726	250	0.75
March 2026	161,356	16,458	323	0.97
90-day total:	460,209	46,941	921	2.76

D. Easily attainable steps DOE can require to ensure Craig 1 operations are consistent with environmental requirements and minimize adverse environmental impacts

39. Tri-State has a very robust forecasted 2026 planning reserve margin ("PRM") of 46 percent, without operation of Craig 1, to meet peak demand conditions.[42] The Tri-State PRM target to assure sufficient resources to meet peak demand is 22 percent.[43]

40. Craig Station's Title V permit requires that the facility "maintain control equipment or operational practices" to comply with emission limits and "establish procedures to ensure that such equipment or operational practices are properly operated and maintained."[44] It further provides that "[a]t all times, including periods of startup, shutdown, and malfunction, the Source shall maintain and operate Unit 1 in a manner consistent with good air pollution control practices for minimizing emissions."[45] As described above, Tri-State has been limiting its operational expenditures in light of Unit 1's expected retirement. In my opinion, for DOE's order to be consistent with environmental requirements, Tri-State must demonstrate, prior to

[40] Colorado PUC Proceeding No. 23A-0585E, *2023 ERP Phase II Implementation Report, Attachment B: Modeling Assumptions*, Table 10, pg. 19 (April 11, 2025). PM = 0.102 lb/MWh; VOC = 0.0020 lb/MWh; Hg = 0.0000060 lb/MWh. Denominator is "gross MWh".
[41] U.S. Department of Energy, *EIA Form 923*, *Page 4 Generator Data* (2025).
[42] Colorado PUC Proceeding No. 23A-0585E, Hearing Exhibit 101, Attachment LKT-1, *Tri-State 2023 Electric Resource Plan Phase I*, Table 11, pg. 22 and Table 24, pg. 29 (April 22, 2024).
[43] Colorado PUC Proceeding No. 23A-0585E, *2025 Annual Progress Report - 2023 Electric Resource Plan*, pg. 8 (December 1, 2025).
[44] Colorado Department of Public Health and Environment, *Tri-State Craig Station Operating Permit* #96OPMF155, pg. 23 (July 1, 2021).
[45] *Ibid*., pg. 22.

restarting Unit 1, that the (1) fabric filter bags are in sound, leak-free condition, and (2) that wet limestone scrubber and ultra-low NO_x burners are in good working order.

41. Fabric filter bags are degraded over time by fly ash erosion and plugging, resulting in particulate "bleed through" and potentially bag rupture, which would result in increased PM emissions.[46] Regular replacement of fabric filter bags is necessary to ensure good performance of the fabric filter. Typical operational problems with wet limestone scrubbers include: scale formation in the scrubber vessels, poor utilization of the limestone reagent, and inadequate spray nozzle efficiency.[47] Regular maintenance of (1) spray nozzles to address plugging and wear, and (2) limestone grinding mills to assure an optimum limestone particle size, is essential to maintaining the control efficiency of the wet scrubber. Ultra-low NO_x burners are subject to degradation from (1) erosion wear at the burner tip and (2) less than optimum pulverized coal combustion efficiency due to wear in the coal pulverizers.[48] Regular maintenance of the ultra-low NO_x burners and the associated coal pulverizers is essential to minimize NO_x formation in the boiler.

42. There is no information in the public record on (1) the age or condition of the fabric filter bags in the Unit 1 fabric filter, (2) the operational history and current condition of the Unit 1 wet limestone scrubber, or (3) the Unit 1 ultra-low NO_x burners and overfire air system. Up to 50 percent of the Unit 1 fabric filter bags may require replacement on an annual basis to address wear-and-tear.[49] Major fabric filter bag replacements are generally classified as capital

[46] Power Engineering, *Real World Performance Results of Fabric Filters on Utility Coal-Fired Boilers* (August 1, 2012) https://www.power-eng.com/environmental-emissions/real-world-performance-results/.
[47] Power Engineering, *Wet-Limestone Scrubbing Fundamentals*, https://www.power-eng.com/operations-maintenance/wet-limestone-scrubbing-fundamentals/ (August 1, 2006).
[48] Power Magazine, *To optimize performance, begin at the pulverizers* (February 2007); Riley Power, *Advanced Erosion Protection Technology Provides Sustained Low NOx Burner Performance* (April 2004).
[49] Neundorfer, *Lesson 5 - Fabric Filter Design Review*, pg. 5-4 (April 2016).

expenses by utilities.[50] As noted earlier, it is Tri-State's established procedure to zero-out capital investments on early retirement units several years before the actual retirement date, and to limit maintenance expenses to "only actions necessary for ensuring safe operations and regulatory compliance" (through December 2025 for Unit 1). Therefore, based on the fabric filter bag replacement example, it cannot be assumed that Unit 1's pollution control equipment is in good working order and will operate reliably to control the facility's emissions beyond December 2025.

43. It is my opinion that DOE should require verification of the good working order of the Unit 1 air emission control systems before authorizing Craig 1 to operate under extreme demand conditions. DOE should also require that if air permit limits for opacity, NO_x, or SO_2 are exceeded during operation of Unit 1, as registered on the continuous opacity, NO_x, or SO_2 monitors installed on Unit 1, then Unit 1 will be shut down.

44. It is also my opinion that there are alternatives to running Craig 1 to meet an extreme peak demand that would produce far less environmental harm. As previously noted, battery storage and (natural gas and oil-fired) combustion gas turbines are examples of resources that are ideally suited to addressing rapidly varying, peak demand conditions. Hydropower can also respond quickly to changing demand conditions. In 2026, Tri-State will have at its disposal 717 MW of gas and oil-fired generation, 516 MW of hydropower, and 134 MW of demand response to address fast-changing demand on its system.[51] Tri-State anticipates having excess capacity in 2026 and will continue to have excess resources for nearly a decade, until 2035.[52]

[50] *See* Michigan PSC Case No. U-21090, Revised Direct Testimony of Norman J. Kapala, pp. 12-16 (October 2021) (listing fabric filter bag replacements as a projected capital expenditure).
[51] Colorado PUC Proceeding No. 23A-0585E, *2025 Annual Progress Report - 2023 Electric Resource Plan*, Table 2, pg. 10.
[52] *Ibid.*

45. Any air emissions that result from running Craig 1 would not occur if the plant is retired. Additionally, Craig 1 consumes approximately 250,000 gallons of water per hour of operation at its net capacity of 427 MW.[53] Finally, any coal burned will produce coal ash that will have to be stored/disposed of onsite. That is an additional impact that would not occur if Craig 1 is retired.

46. In my opinion, a coal unit would be the last alternative to consider for a peaking power application due to its slow ramp time and high environmental impact.

I declare under penalty of perjury under the laws of the United States, pursuant to 28 U.S.C. § 1746, that the foregoing is true and correct to the best of my knowledge.

Executed on this 24 day of January 2026, in San Diego, California.

Bill Powers, P.E.

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53 Colorado PUC Proceeding No. 23A-0585E, *2023 ERP Phase II Implementation Report, Attachment B: Modeling Assumptions,* Table 10, pg. 19 (April 11, 2025).

Attachment A

BILL POWERS, P.E.

PROFESSIONAL HISTORY

Powers Engineering, San Diego, CA 1994-
ENSR Consulting and Engineering, Camarillo, CA 1989-93
Naval Energy and Environmental Support Activity, Port Hueneme, CA 1982-87
U.S. Environmental Protection Agency, Research Triangle Park, NC 1980-81

EDUCATION

Bachelor of Science – Mechanical Engineering, Duke University
Master of Public Health – Environmental Sciences, University of North Carolina

PROFESSIONAL AFFILIATIONS

Registered Professional Mechanical Engineer, California (Certificate M24518)
Registered Professional Engineer, Missouri (Certificate 2018039156)
American Society of Mechanical Engineers
Institute of Electrical and Electronics Engineers

TECHNICAL SPECIALTIES

Forty years of experience in:

- Air quality and utility commission proceedings - expert witness
- Distributed solar photovoltaics (PV) siting and regional renewable energy planning
- Power plant cooling system conversion and air emission control assessments
- Combustion equipment permitting, testing and monitoring
- Air pollution control equipment retrofit design/performance testing
- Petroleum refinery air engineering and testing
- Latin America environmental project experience

RECENT AIR QUALITY AND UTILITY COMMISSION PROCEEDINGS

Compressor Station Gas Turbine Air Emission Controls. Assessed the air emission controls and siting issues related to two proposed pipeline compressor station projects in the vicinity of Nashville, Tennessee utilizing Solar Turbines, Inc Titan gas turbines. The result, based on application of a Reasonably Available Control Technology (RACT) requirement, was the reduction of the proposed air permit nitrogen oxides (NOx) emission limit from 25 parts per million (ppm) to 9 ppm.

Combined Heat and Power Plant Gas Turbine Air Emission Controls. Evaluated the air emission controls proposed for a combined heat and power (CHP) plant at Duke University that would utilize Solar Turbines, Inc Titan gas turbine. Applicant proposed a 25 ppm NO_x limit using dry low-NO_x combustion as Best Available Control Technology (BACT) in its Certificate of Public Convenience and Necessity (CPCN) application to the North Carolina Utilities Commission. Argued that NO_x BACT for the CHP plant should be use of selective catalytic reduction (SCR) to achieve a 2 ppm NO_x emission limit. Applicant withdrew its CPCN application.

SDG&E 36-Inch Transmission Pipeline. Expert witness for non-profit client advocating that existing 16-inch pipeline did not require replacement with new $600 million 36-inch pipeline. Underscored in testimony that SDG&E had recently completed extensive inline inspection of existing 16-inch pipeline and found that pipeline was in good condition for long-term operation at 512 psig transmission pressure. Demonstrated that reduction of pressure to 320 psig would not increase safety of existing pipeline, as ILI could no longer be done periodically at lower pressure. Commission accepted this reasoning and denied SDG&E's application.

Cove Point LNG Export Terminal. Expert witness in two separate administrative proceedings before the Maryland Public Service Commission, in 2014 and 2017, regarding air permit conditions for the proposed Cove Point LNG export. The plant site is located in a non-attainment area for ozone. Testimony addressed deficiencies in the proposed air emission limits and proposed control technology for combustion equipment – including gas turbines, auxiliary boilers, and flares, fugitive emission sources, and marine loading vapor recovery systems.

Corpus Christi LNG Expert Terminal. Expert witness in Texas Commission on Environmental Quality contested air permit proceeding in 2013 before the State Office of Administrative Hearings. Testimony addressed deficiencies in the proposed control technology for compressor-drive gas turbines, flares, and fugitive emission sources, and marine loading vapor recovery systems.

DISTRIBUTED SOLAR PV SITING AND REGIONAL RENEWABLE ENERGY PLANNING

Roadmap to 100 Percent Local Solar by 2030 in the City of San Diego. Author of the May 2020 *Roadmap to 100 Percent Local Solar Build-Out by 2030 in the City of San Diego* strategic energy plan for San Diego. The *Roadmap* outlines a strategy to maximize the use of solar energy and battery storage in the City of San Diego (City) to provide 100 percent clean electricity to all San Diegans by 2030. The City's Climate Action Plan sets a mandatory target of 100 percent clean electricity by 2035. The *Roadmap* describes how the City can best deliver lower-cost electricity and provide local job growth by choosing local solar power paired with battery storage, complemented by smart energy efficiency and demand response programs, to reach 100 percent clean energy.

North Carolina Clean Path 2025 Plan. Author of the August 2017 *North Carolina Clean Path 2025* strategic energy plan for North Carolina. *NC Clean Path 2025* implements local solar power, battery storage, and energy efficiency measures to rapidly replace fossil fuel-generated electricity in the state. The plan is substantially less costly than the $40 billion expansion of natural gas infrastructure, nuclear power, and transmission infrastructure being planned for North Carolina. Implementation of *NC Clean Path 2025* would reduce power generated by coal- and natural gas-fired plants by about 60 percent by 2025, and 100 percent by 2030. All in-state coal-fired plants would be closed and gas-fired plants would be used only for backup supply. Existing transmission and distribution infrastructure would be maintained and not expanded.

Bay Area Smart Energy 2020 Plan. Author of the March 2012 *Bay Area Smart Energy 2020* strategic energy plan for the nine-county region surrounding San Francisco Bay. This plan uses the zero net energy building targets in the *California Energy Efficiency Strategic Plan* as a framework to achieve a 60 percent reduction in GHG emissions from Bay Area electricity usage, and a 50 percent reduction in peak demand for grid electricity, by 2020. The 2020 targets in the plan include: 25 percent of detached homes and 20 percent of commercial buildings achieving zero net energy, adding 200 MW of community-scale microgrid battery storage and 400 MW of utility-scale battery storage, reduction in air conditioner loads by 50 percent through air conditioner cycling and targeted incentive funds to assure highest efficiency replacement units, and cooling system modifications to increase power output from The Geysers geothermal production zone in Sonoma County.

Solar PV technology selection and siting for SDG&E Solar San Diego project. Served as PV technology expert in California Public Utilities Commission proceeding to define PV technology and sites to be used in San Diego Gas & Electric (SDG&E) $250 million "Solar San Diego" project. Recommendations included: 1) prioritize use of roof-mounted thin-film PV arrays similar to the SCE urban PV program to maximize the installed PV capacity, 2) avoid tracking ground-mounted PV arrays due to high cost and relative lack of available land in the urban/suburban core, 3) and incorporate limited storage in fixed rooftop PV arrays to maximizing output during peak demand periods. Suitable land next to SDG&E substations capable of supporting 5 to 40 MW of PV (each) was also identified by Powers Engineering as a component of this project.

Rooftop PV alternative to natural gas-fired peaking gas turbines, Chula Vista. Served as PV technology expert in California Energy Commission (CEC) proceeding regarding the application of MMC Energy to build a 100 MW peaking gas turbine power plant in Chula Vista. Presented testimony that 100 MW of PV arrays in the Chula Vista area could provide the same level of electrical reliability on hot summer days as an equivalent amount of peaking gas turbine capacity at approximately the same cost of energy. The final decision issued by the CEC in the case denied the application in part due to failure of the applicant or CEC staff to thoroughly evaluate the PV alternative to the proposed turbines.

San Diego Smart Energy 2020 Plan. Author of October 2007 *San Diego Smart Energy 2020*, an energy plan that focuses on meeting the San Diego region's electric energy needs through accelerated integration of renewable and non-renewable distributed generation, in the form of combined heat and power (CHP) systems and solar photovoltaic (PV) systems. PV would meet approximately 28 percent of the San Diego region's electric energy demand in 2020. Annual energy demand would drop 20 percent in 2020 relative to 2003 through use all cost-effective energy efficiency measures. Existing utility-scale gas-fired generation would continue to be utilized to provide power at night, during cloudy weather, and for grid reliability support.

COOLING SYSTEM CONVERSION AND POWER PLANT EMISSION CONTROL ASSESSMENTS

Closed-Cycle Cooling Alternative at California Nuclear Plant.
Lead engineer on review of Bechtel assessment of wedgewire screens and closed-cycle cooling for Diablo Canyon nuclear plant. Demonstrated that wedgewire screens were not likely to be effective in substantially reducing entrainment at the site, and that lower cost closed-cycle retrofit alternatives could be utilized to allow a "cost reasonable" cooling tower retrofit. Plume-abated back-to-back cooling towers located in secondary parking lots to the southeast of the turbine building were identified as the most cost-effective alternative.

Closed-Cycle Cooling Alternative at Florida Nuclear Plant.
Evaluated closed cycle cooling tower feasibility assessment for Turkey Point Nuclear Units 3 and 4. Closed-cycle cooling would replace the existing closed-cycle cooling canals. Wet cooling towers for Units 3 and 4 are feasible and could be operational within four years of submittal of applications for the necessary permits.

Utility Boilers – Conversion of Existing Once-Through Cooled Boilers to Wet Towers, Parallel Wet-Dry Cooling, or Dry Cooling. Provided expert testimony and preliminary design for the conversion of four natural gas and/or coal-fired utility boilers (Unit 4, 235 MW; Unit 3, 135 MW; Unit 2, 65 MW; and Unit 1,65 MW) from once-through river water cooling to wet cooling towers, parallel wet-dry cooling, and dry cooling. Major design constraints were available land for location of retrofit cooling systems and need to maintain maximum steam turbine backpressure at or below 5.5 inches mercury to match performance capabilities of existing equipment. Approach temperatures of 12 ^{o}F and 13 ^{o}F were used for the wet towers. SPX Cooling Technologies F-488 plume-abated wet cells with six feet of packing were used to achieve approach temperatures of 12 ^{o}F and 13 ^{o}F. Annual energy penalty of wet tower retrofit designs is approximately 1 percent. Parallel wet-dry or dry cooling was determined to be technically feasible for Unit 3 based on straightforward access to the Unit 3 surface condenser and available land adjacent to the boiler.

Utility Boiler – Assessment of Air Cooling and Integrated Gasification/Combined Cycle for Proposed 500 MW Coal-Fired Plant. Provided expert testimony on the performance of air-cooling and IGCC relative to the conventional closed-cycle wet cooled, supercritical pulverized coal boiler proposed by the applicant. Steam Pro™ coal-fired power plant design software was used to model the proposed plant and evaluate the impacts on performance of air cooling and plume-abated wet cooling. Results indicated that a conservatively designed air-cooled condenser could maintain rated power output at the design ambient temperature of 90 ^{o}F. The IGCC comparative analysis indicated that unit reliability comparable to a conventional pulverized coal unit could be achieved by including a spare gasifier in the IGCC design, and that the slightly higher capital cost of IGCC was offset by greater thermal efficiency and reduced water demand and air emissions.

Utility Boiler – Assessment of Closed-Cycle Cooling Retrofit Cost for 1,200 MW Oil-Fired Plant. Prepared an assessment of the cost and feasibility of a closed-cycle wet tower retrofit for the 1,200 MW Roseton Generating Station. Determined that the cost to retrofit the Roseton plant with plume-abated closed-cycle wet cooling was well established based on cooling tower retrofit studies performed by the original owner (Central Hudson Gas & Electric Corp.) and subsequent regulatory agency critique of the cost estimate. Also determined that elimination of redundant and/or excessive budgetary line items in owners cost estimate brings the closed-cycle retrofit in line with expected costs for comparable new or retrofit plume-abated cooling tower applications.

Nuclear Power Plant – Assessment of Closed-Cycle Cooling Retrofit Cost for 2,000 MW Plant. Prepared an assessment of the cost and feasibility of a closed-cycle wet tower retrofit for the 2,000 MW Indian Point Generating Station. Determined that the most appropriate arrangement for the hilly site would be an inline plume-abated wet tower instead of the round tower configuration analyzed by the owner. Use of the inline configuration would allow placement of the towers at numerous sites on the property with little or need for blasting of bedrock, greatly reducing the cost of the retrofit. Also proposed an alternative circulating cooling water piping configuration to avoid the extensive downtime projected by the owner for modifications to the existing discharge channel.

Power Plant Dry Cooling Symposium – Chair and Organizer. Chair and organizer of the first symposium held in the U.S. (May 2002) that focused exclusively on dry cooling technology for power plants. Sessions included basic principles of wet and dry cooling systems, performance capabilities of dry cooling systems, case studies of specific installations, and reasons why dry cooling is the predominant form of cooling specified in certain regions of North America (Massachusetts, Nevada, northern Mexico).

Ameren Missouri Coal Units – Causes of Opacity and Opacity Reduction Alternatives. Lead engineer to assess the root causes of opacity exceedances and evaluate potential alternatives to eliminate opacity violations from the Labadie, Meramec, and Rush Island power plants.

Utility Boilers – Evaluation of Correlation Between Opacity and PM_{10} Emissions at Coal-Fired Plant. Provided expert testimony on whether correlation existed between mass PM_{10} emissions and opacity during opacity excursions at large coal-fired boiler in Georgia. EPA and EPRI technical studies were reviewed to assess the correlation of opacity and mass emissions during opacity levels below and above 20 percent. A strong correlation between opacity and mass emissions was apparent at a sister plant at opacities less than 20 percent. The correlation suggests that the opacity monitor correlation underestimates mass emissions at opacities greater than 20 percent, but may continue to exhibit a good correlation for the component of mass emissions in the PM_{10} size range.

IGCC as BACT for Air Emissions from Proposed 960 MW Coal Plant. Presented testimony on IGCC as BACT for air emissions reduction from 960 MW coal plant. Applicant received air permit for a pulverized coal plant to be equipped with a baghouse, wet scrubber, and wet ESP for air emissions control. Use of IGCC technology at the emission rates permitted for two recently proposed U.S. IGCC projects, and demonstrated in practice at a Japanese IGCC plant firing Chinese bituminous coal, would substantially reduce potential emissions of NO_x, SO_2, and PM. The estimated control cost-effectiveness of substituting IGCC for pulverized coal technology in this case was approximately $3,000/ton.

Analysis of Proposed Air Emission Limits for 600 MW Pulverized Coal Plant. Project engineer tasked with evaluating sufficiency of air emissions limits and control technologies for proposed 600 MW coal plant Arkansas. Determined that the applicant had: 1) not properly identified SO_2, sulfuric acid mist, and PM BACT control levels for the plant, and 2) improperly utilized an incremental cost effectiveness analysis to justify air emission control levels that did not represent BACT.

Eight Pulverized Coal Fired 900 MW Boilers – IGCC Alternative with Air Cooling. Provided testimony on integrated gasification combined cycle (IGCC) as a fully commercial coal-burning alternative to the pulverized coal (PC) technology proposed by TXU for eight 900 MW boilers in East Texas, and East Texas as an ideal location for CO2 sequestration due to presence of mature oilfield CO2 enhanced oil recovery opportunities and a deep saline aquifer underlying the entire region. Also presented testimony on the major increase in regional consumptive water use that would be caused by the evaporative cooling towers proposed for use in the PC plants, and that consumptive water use could be lowered by using IGCC with evaporative cooling towers or by using air-cooled condensers with PC or IGCC technology. TXU ultimately dropped plans to build the eight PC plants as a condition of a corporate buy-out.

Utility Boilers – Retrofit of SCR and FGD to Existing Coal-Fired Units.
Expert witness in successful effort to compel an existing coal-fired power plant located in Massachusetts to meet an accelerated NO_x and SO_2 emission control system retrofit schedule. Plant owner argued the installation of advanced NO_x and SO_2 control systems would generate > 1 ton/year of ancillary emissions, such as sulfuric acid mist, and that under Massachusetts Dept. of Environmental Protection regulation ancillary emissions > 1 ton/year would require a BACT evaluation and a two-year extension to retrofit schedule. Successfully demonstrated that no ancillary emissions would be generated if the retrofit NO_x and SO_2 control systems were properly sized and optimized. Plant owner committed to accelerated compliance schedule in settlement agreement.

Utility Boilers – Retrofit of SCR to Existing Natural Gas-Fired Units.
Lead engineer in successful representation of interests of California coastal city to prevent weakening of an existing countywide utility boiler NO_x rule. Weakening of NO_x rule would have allowed a merchant utility boiler plant located in the city to operate without installing selective catalytic reduction (SCR) NO_x control systems. This project required numerous appearances before the county air pollution control hearing board to successfully defend the existing utility boiler NO_x rule.

Biomass Plant NO_x and CO Air Emissions Control Evaluation. Lead engineer for evaluation of available nitrogen oxide (NO_x) and carbon monoxide (CO) controls for a 45 MW Aspen Power biomass plant in Texas where proponent had identified selective non-catalytic reduction (SNCR) for NO_x and good combustion practices for CO as BACT. Identified the use of tail-end SCR for NO_x control at several operational U.S. biomass plants, and oxidation catalyst in use at two of these plants for CO and VOC control, as BACT for the proposed biomass plant. Administrative law judge concurred in decision that SCR and oxidation catalyst is BACT. Developer added SCR and oxidation catalyst to project in subsequent settlement agreement.

Biomass Plant Air Emissions Control Consulting. Lead expert on biomass air emissions control systems for landowners that will be impacted by a proposed 50 MW biomass to be built by the local East Texas power cooperative. Public utility agreed to meet current BACT for biomass plants in Texas, SCR for NO_x and oxidation catalyst for CO, in settlement agreement with local landowners.

Combined-Cycle Power Plant Startup and Shutdown Emissions. Lead engineer for analysis of air permit startup and shutdown emissions minimization for combined-cycle power plant proposed for the San Francisco Bay Area. Original equipment was specified for baseload operation prior to suspension of project in early 2000s. Operational profile described in revised air permit was load following with potential for daily start/stop. Recommended that either fast start turbine technology be employed to minimize start/stop emissions or that "demonstrated in practice" operational and control software modifications be employed to minimize startup/shutdown emissions.

NON-WIRES ALTERNATIVES TO TRANSMISSION LINES

Ameren Missouri Mark Twain 345 kV Transmission Line. Responsible for evaluating: 1) the expected peak load growth of Ameren Missouri (MO) in general and in Northeast MO specifically over the next decade, 2) the likelihood of wind projects moving forward in the Northeast MO over the next decade, 3) the feasibility and cost of reconductoring with high capacity composite conductors the three 161 kV line segments that would experience NERC violations if 450 to 500 MW of wind power was constructed in Northeast MO, and 4) the feasibility and cost-effectiveness of substituting local solar for wind power to allow Ameren MO to meet its 2021 Renewable Portfolio Standard (RPS) obligation without building the proposed 345 kV transmission line or upgrading the three existing 161 kV lines interconnecting at the Adair Substation.

American Transmission Corporation Badger-Coulee 345 kV Line. Responsible for evaluating: 1) the expected peak load growth of Wisconsin utilities over the next decade, and 2) the feasibility and cost-effectiveness of alternatives including load management, energy efficiency, local solar, biogas, and energy storage as viable no-wires alternatives to the proposed ATC Badger-Coulee 345 kV transmission line.

San Diego Gas & Electric Wood Pole to Steel Pole Replacement Project.
Lead engineer assessing need and alternatives to replacement of existing wooden 69 kV poles with larger steel 69 kV poles as a response to the fire hazard potential of wooden poles in rural, high fire risk areas. Wooden poles in good condition and not a source of fire ignition. Utility would continue to shut off power to customers during low humidity, high wind conditions. Prepared alternative, solar with batteries for the ~10,000 affected customer meters, to allow customers to ride-through high fire hazard preventive grid power shut-offs at far less cost than replacing wood poles with steel poles.

San Diego Gas & Electric 500 kV Sunrise Transmission Line.
Lead engineer assessing the validity of load growth forecasts used by the utility to justify the need for the 500 kV line, and for developing a no-wires alternative, net-metered solar power with some battery support, to meet the identified reliability need at little or no net cost to the utility customer base.

COMBUSTION EQUIPMENT PERMITTING, TESTING AND MONITORING

EPRI Gas Turbine Power Plant Permitting Documents – Co-Author.
Co-authored two Electric Power Research Institute (EPRI) gas turbine power plant siting documents. Responsibilities included chapter on state-of-the-art air emission control systems for simple-cycle and combined-cycle gas turbines, and authorship of sections on dry cooling and zero liquid discharge systems.

Air Permits for 50 MW Peaker Gas Turbines – Six Sites Throughout California.
Responsible for preparing all aspects of air permit applications for five 50 MW FT-8 simple-cycle turbine installations at sites around California in response to emergency request by California state government for additional peaking power. Units were designed to meet 2.0 ppm NO_x using standard temperature SCR and innovative dilution air system to maintain exhaust gas temperature within acceptable SCR range. Oxidation catalyst is also used to maintain CO below 6.0 ppm.

Kauai 27 MW Cogeneration Plant – Air Emission Control System Analysis. Project manager to evaluate technical feasibility of SCR for 27 MW naphtha-fired turbine with once-through heat recovery steam generator. Permit action was stalled due to questions of SCR feasibility. Extensive analysis of the performance of existing oil-fired turbines equipped with SCR, and bench-scale tests of SCR applied to naphtha-fired turbines, indicated that SCR would perform adequately. Urea was selected as the SCR reagent given the local availability of urea. Unit is first known application of urea-injected SCR on a naphtha-fired turbine.

Microturbines – Ronald Reagan Library, Ventura County, California.
Project manager and lead engineer or preparation of air permit applications for microturbines and standby boilers. The microturbines drive the heating and cooling system for the library. The microturbines are certified by the manufacturer to meet the 9 ppm NO_x emission limit for this equipment. Low-NO_x burners are BACT for the standby boilers.

Hospital Cogeneration Microturbines – South Coast Air Quality Management District.
Project manager and lead engineer for preparation of air permit application for three microturbines at hospital cogeneration plant installation. The draft Authority To Construct (ATC) for this project was obtained two weeks after submittal of the ATC application. 30-day public notification was required due to the proximity of the facility to nearby schools. The final ATC was issued two months after the application was submitted, including the 30-day public notification period.

Gas Turbine Cogeneration – South Coast Air Quality Management District. Project manager and lead engineer for preparation of air permit application for two 5.5 MW gas turbines in cogeneration configuration for county government center. The turbines are equipped with selective catalytic reduction (SCR) and oxidation catalyst to comply with SCAQMD BACT requirements. Aqueous urea is used as the SCR reagent to avoid trigger hazardous material storage requirements. The NO_x and CO continuous emissions monitoring systems are covered by a separate permit.

Peaker Gas Turbines – Evaluation of NO_x Control Options for Installations in San Diego County.
Lead engineer for evaluation of NO_x control options available for 1970s vintage simple-cycle gas turbines proposed for peaker sites in San Diego County. Dry low-NO_x (DLN) combustors, catalytic combustors, high-temperature SCR, and NO_x absorption/conversion ($SCONO_x$) were evaluated for each candidate turbine make/model. High-temperature SCR was selected as the NOx control option to meet a 5 ppm NO_x emission requirement.

Hospital Cogeneration Plant Gas Turbines – San Joaquin Valley Unified Air Pollution Control District.
Project manager and lead engineer for preparation of air permit application and Best Available Control Technology (BACT) evaluation for hospital cogeneration plant installation. The BACT included the review of DLN combustors, catalytic combustors, high-temperature SCR and $SCONO_x$. DLN combustion followed by high temperature SCR was selected as the NO_x control system for this installation. The high temperature SCR is located upstream of the heat recovery steam generator (HRSG) to allow the diversion of exhaust gas around the HRSG without compromising the effectiveness of the NO_x control system.

1,000 MW Coastal Combined-Cycle Power Plant – Feasibility of Dry Cooling.
Expert witness in on-going effort to require use of dry cooling on proposed 1,000 MW combined-cycle "repower" project at site of an existing 1,000 MW utility boiler plant. Project proponent argued that site was two small for properly sized air-cooled condenser (ACC) and that use of ACC would cause 12-month construction delay. Demonstrated that ACC could easily be located on the site by splitting total of up to 80 cells between two available locations at the site. Also demonstrated that an ACC optimized for low height and low noise would minimize or eliminate proponent claims of negative visual and noise impacts.

Industrial Cogeneration Plant Gas Turbines – Upgrade of Turbine Power Output.
Project manager and lead engineer for preparation of Best Available Control Technology (BACT) evaluation for proposed gas turbine upgrade. The BACT included the review of DLN combustors, catalytic combustors, high-, standard-, and low-temperature SCR, and $SCONO_x$. Successfully negotiated air permit that allowed facility to initially install DLN combustors and operate under a NO_x plantwide "cap." Within two major turbine overhauls, or approximately eight years, the NO_x emissions per turbine must be at or below the equivalent of 5 ppm. The 5 ppm NO_x target will be achieved through technological in-combustor NO_x control such as catalytic combustion, or SCR or SCR equivalent end-of-pipe NO_x control technologies if catalytic combustion is not available.

Gas Turbines – Modification of RATA Procedures for Time-Share CEM.
Project manager and lead engineer for the development of alternate CO continuous emission monitor (CEM) Relative Accuracy Test Audit (RATA) procedures for time-share CEM system serving three 7.9 MW turbines located in San Diego. Close interaction with San Diego APCD and EPA Region 9 engineers was required to

receive approval for the alternate CO RATA standard. The time-share CEM then passed the annual RATA without problems as a result of changes to some CEM hardware and the more flexible CO RATA standard.

Gas Turbines – Evaluation of NO_x Control Technology Performance. Lead engineer for performance review of dry low-NO_x combustors, catalytic combustors, high-, standard-, and low-temperature selective catalytic reduction (SCR), and NO_x absorption/conversion ($SCONO_x$). Major turbine manufacturers and major manufacturers of end-of-pipe NO_x control systems for gas turbines were contacted to determine current cost and performance of NO_x control systems. A comparison of 1993 to 1999 "$/kwh" and "$/ton" cost of these control systems was developed in the evaluation.

Lead engineer for evaluation for proposed combined cycle gas turbine NO_x and CO control systems. Project was in litigation over contract terms, and there was concern that the GE Frame 7FA turbine could not meet the 3 ppm NO_x permit limit using a conventional combustor with water injection followed by SCR. Operations personnel at GE Frame 7FA installatins around the country were interviewed, along with principal SCR vendors, to corroborate that the installation could continuously meet the 3 ppm NO_x limit.

Gas Turbines – Title V "Presumptively Approvable" Compliance Assurance Monitoring Protocol. Project manager and lead engineer for the development of a "presumptively approval" NO_x parametric emissions monitoring system (PEMS) protocol for industrial gas turbines. "Presumptively approvable" means that any gas turbine operator selecting this monitoring protocol can presume it is acceptable to the U.S. EPA. Close interaction with the gas turbine manufacturer's design engineering staff and the U.S. EPA Emissions Measurement Branch (Research Triangle Park, NC) was required to determine modifications necessary to the current PEMS to upgrade it to "presumptively approvable" status.

Environmental Due Diligence Review of Gas Turbine Sites – Mexico. Task leader to prepare regulatory compliance due diligence review of Mexican requirements for gas turbine power plants. Project involves eleven potential sites across Mexico, three of which are under construction. Scope involves identification of all environmental, energy sales, land use, and transportation corridor requirements for power projects in Mexico. Coordinator of Mexican environmental subcontractors gathering on-site information for each site, and translator of Spanish supporting documentation to English.

Development of Air Emission Standards for Gas Turbines - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian gas turbine power plants. All major gas turbine power plants in Peru are currently using water injection to increase turbine power output. Recommended that 42 ppm on natural gas and 65 ppm on diesel (corrected to 15% O_2) be established as the NO_x limit for existing gas turbine power plants. These limits reflect NO_x levels readily achievable using water injection at high load. Also recommended that new gas turbine sources be subject to a BACT review requirement.

Gas Turbines – Title V Permit Templates. Lead engineer for the development of standardized permit templates for approximately 100 gas turbines operated by the oil and gas industry in the San Joaquin Valley. Emissions limits and monitoring requirements were defined for units ranging from GE Frame 7 to Solar Saturn turbines. Stand-alone templates were developed based on turbine size and NO_x control equipment. NO_x utilized in the target turbine population ranged from water injection alone to water injection combined with SCR.

Gas Turbines – Evaluation of NO_x, SO_2 and PM Emission Profiles. Performed a comparative evaluation of the NO_x, SO_2 and particulate (PM) emission profiles of principal utility-scale gas turbines for an independent power producer evaluating project opportunities in Latin America. All gas turbine models in the 40 MW to 240 MW range manufactured by General Electric, Westinghouse, Siemens and ABB were included in the evaluation.

Stationary Internal Combustion Engine (ICE) RACT/BARCT Evaluation. Lead engineer for evaluation of retrofit NO_x control options available for the oil and gas production industry gas-fired ICE population in the San Joaquin Valley affected by proposed RACT and BARCT emission limits. Evaluation centered on lean-burn compressor engines under 500 bhp, and rich-burn constant and cyclically loaded (rod pump) engines under 200 bhp. The results of the evaluation indicated that rich burn cyclically-loaded rod pump engines comprised 50 percent of the affected ICE population, though these ICEs accounted for only 5 percent of the uncontrolled gas-fired stationary ICE NO_x emissions. Recommended retrofit NO_x control strategies included: air/fuel ratio adjustment for rod pump ICEs, Non-selective catalytic reduction (NSCR) for rich-burn, constant load ICEs, and "low emission" combustion modifications for lean burn ICEs.

Development of Air Emission Standards for Stationary ICEs - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian stationary ICE power plants. Draft 1997 World Bank NO_x and particulate emission limits for stationary ICE power plants served as the basis for proposed MEM emission limits. A detailed review of ICE emissions data provided in PAMAs submitted to the MEM was performed to determine the level of effort that would be required by Peruvian industry to meet the proposed NO_x and particulate emission limits. The draft 1997 WB emission limits were revised to reflect reasonably achievable NO_x and particulate emission limits for ICEs currently in operation in Peru.

Air Toxics Testing of Natural Gas-Fired ICEs. Project manager for test plan/test program to measure volatile and semi-volatile organic air toxics compounds from fourteen gas-fired ICEs used in a variety of oil and gas production applications. Test data was utilized by oil and gas production facility owners throughout California to develop accurate ICE air toxics emission inventories.

AIR ENGINEERING/AIR TESTING PROJECT EXPERIENCE – GENERAL

Reverse Air Fabric Filter Retrofit Evaluation – Coal-Fired Boiler. Lead engineer for upgrade of reverse air fabric filters serving coal-fired industrial boilers. Fluorescent dye injected to pinpoint broken bags and damper leaks. Corrosion of pneumatic actuators serving reverse air valves and inadequate insulation identified as principal causes of degraded performance.

Pulse-Jet Fabric Filter Performance Evaluation – Gold Mine. Lead engineer on upgrade of pulse-jet fabric filter and associated exhaust ventilation system serving an ore-crushing facility at a gold mine. Fluorescent dye used to identify bag collar leaks, and modifications were made to pulse air cycle time and duration. This marginal source was in compliance at 20 percent of emission limit following completion of repair work.

Pulse-Jet Fabric Filter Retrofit - Gypsum Calciner. Lead engineer on upgrade of pulse-jet fabric filter controlling particulate emissions from a gypsum calciner. Recommendations included a modified bag clamping mechanism, modified hopper evacuation valve assembly, and changes to pulse air cycle time and pulse duration.

Wet Scrubber Retrofit – Plating Shop. Project engineer on retrofit evaluation of plating shop packed-bed wet scrubbers failing to meet performance guarantees during acceptance trials, due to excessive mist carryover. Recommendations included relocation of the mist eliminator (ME), substitution of the original chevron blade ME with a mesh pad ME, and use of higher density packing material to improve exhaust gas distribution. Wet scrubbers passed acceptance trials following completion of recommended modifications.

Electrostatic Precipitator (ESP) Retrofit Evaluation – MSW Boiler. Lead engineer for retrofit evaluation of single field ESP on a municipal solid waste (MSW) boiler. Recommendations included addition of automated power controller, inlet duct turning vanes, and improved collecting plate rapping system.

ESP Electric Coil Rapper Vibration Analysis Testing - Coal-Fired Boiler. Lead engineer for evaluation of ESP rapper effectiveness test program on three field ESP equipped with "magnetically induced gravity return" (MIGR) rappers. Accelerometers were placed in a grid pattern on ESP collecting plates to determine maximum

instantaneous plate acceleration at a variety of rapper power setpoints. Testing showed that the rappers met performance specification requirements.

Aluminum Remelt Furnace Particulate Emissions Testing. Project manager and lead engineer for high temperature (1,600 ºF) particulate sampling of a natural gas-fired remelt furnace at a major aluminum rolling mill. Objectives of test program were to: 1) determine if condensable particulate was present in stack gases, and 2) to validate the accuracy of the in-stack continuous opacity monitor (COM). Designed and constructed a customized high temperature (inconel) PM_{10}/Mtd 17 sampling assembly for test program. An onsite natural gas-fired boiler was also tested to provide comparative data for the condensable particulate portion of the test program. Test results showed that no significant levels of condensable particulate in the remelt furnace exhaust gas, and indicated that the remelt furnace and boiler had similar particulate emission rates. Test results also showed that the COM was accurate.

Aluminum Remelt Furnace CO and NO_x Testing. Project manager and lead engineer for continuous week-long testing of CO and NO_x emissions from aluminum remelt furnace. Objective of test program was to characterize CO and NO_x emissions from representative remelt furnace for use in the facility's criteria pollution emissions inventory. A TECO Model 48 CO analyzer and a TECO Model 10 NO_x analyzer were utilized during the test program to provide $\pm$1 ppm measurement accuracy, and all test data was recorded by an automated data acquisition system.

PETROLEUM REFINERY AIR ENGINEERING/TESTING EXPERIENCE

Big West Refinery Expansion EIS. Lead engineer on comparative cost analysis of proposed wet cooling tower and fin-fan air cooler for process cooling water for the proposed clean fuels expansion project at the Big West Refinery in Bakersfield, California. Selection of the fin-fin air-cooler would eliminate all consumptive water use and wastewater disposal associated with the cooling tower. Air emissions of VOC and PM_{10} would be reduced with the fin-fan air-cooler even though power demand of the air-cooler is incrementally higher than that of the cooling tower. Fin-fan air-coolers with approach temperatures of 10 ºF and 20 ºF were evaluated. The annualized cost of the fin-fin air-cooler with a 20 ºF approach temperature is essentially the same as that of the cooling tower when the cost of all ancillary cooling tower systems are considered.

Criteria and Air Toxic Pollutant Emissions Inventory for Proposed Refinery Modifications. Project manager and technical lead for development of baseline and future refinery air emissions inventories for process modifications required to produce oxygenated gasoline and desulfurized diesel fuel at a California refinery. State of the art criteria and air toxic pollutant emissions inventories for refinery point, fugitive and mobile sources were developed. Point source emissions estimates were generated using onsite criteria pollutant test data, onsite air toxics test data, and the latest air toxics emission factors from the statewide refinery air toxics inventory database. The fugitive volatile organic compound (VOC) emissions inventories were developed using the refinery's most recent inspection and maintenance (I&M) monitoring program test data to develop site-specific component VOC emission rates. These VOC emission rates were combined with speciated air toxics test results for the principal refinery process streams to produce fugitive VOC air toxics emission rates. The environmental impact report (EIR) that utilized this emission inventory data was the first refinery "Clean Fuels" EIR approved in California.

Development of Air Emission Standards for Petroleum Refinery Equipment - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian petroleum refineries. The sources included in the scope of this project included: 1) SO_2 and NO_x refinery heaters and boilers, 2) desulfurization of crude oil, particulate and SO_2 controls for fluid catalytic cracking units (FCCU), 3) VOC and CO emissions from flares, 4) vapor recovery systems for marine unloading, truck loading, and crude oil/refined products storage tanks, and 5) VOC emissions from process fugitive sources such as pressure relief valves, pumps, compressors and flanges. Proposed emission limits were developed for new and existing refineries based on a thorough evaluation of the available air emission control technologies for the affected refinery sources. Leading vendors of refinery control technology, such as John Zink and Exxon Research, provided estimates of retrofit costs for the largest Peruvian refinery, La Pampilla,

located in Lima. Meetings were held in Lima with refinery operators and MEM staff to discuss the proposed emission limits and incorporate mutually agreed upon revisions to the proposed limits for existing Peruvian refineries.

Air Toxic Pollutant Emissions Inventory for Existing Refinery. Project manager and technical lead for air toxic pollutant emissions inventory at major California refinery. Emission factors were developed for refinery heaters, boilers, flares, sulfur recovery units, coker deheading, IC engines, storage tanks, process fugitives, and catalyst regeneration units. Onsite source test results were utilized to characterize emissions from refinery combustion devices. Where representative source test results were not available, AP-42 VOC emission factors were combined with available VOC air toxics speciation profiles to estimate VOC air toxic emission rates. A risk assessment based on this emissions inventory indicated a relatively low health risk associated with refinery operations. Benzene, 1,3-butadiene and PAHs were the principal health risk related pollutants emitted.

Air Toxics Testing of Refinery Combustion Sources. Project manager for comprehensive air toxics testing program at a major California refinery. Metals, Cr^{+6}, PAHs, H_2S and speciated VOC emissions were measured from refinery combustion sources. High temperature Cr^{+6} stack testing using the EPA Cr^{+6} test method was performed for the first time in California during this test program. Representatives from the California Air Resources Board source test team performed simultaneous testing using ARB Method 425 (Cr^{+6}) to compare the results of EPA and ARB Cr^{+6} test methodologies. The ARB approved the test results generated using the high temperature EPA Cr^{+6} test method.

Air Toxics Testing of Refinery Fugitive Sources. Project manager for test program to characterize air toxic fugitive VOC emissions from fifteen distinct process units at major California refinery. Gas, light liquid, and heavy liquid process streams were sampled. BTXE, 1,3-butadiene and propylene concentrations were quantified in gas samples, while BTXE, cresol and phenol concentrations were measured in liquid samples. Test results were combined with AP-42 fugitive VOC emission factors for valves, fittings, compressors, pumps and PRVs to calculate fugitive air toxics VOC emission rates.

OIL AND GAS PRODUCTION AIR ENGINEERING/TESTING EXPERIENCE

Air Toxics Testing of Oil and Gas Production Sources. Project manager and lead engineer for test plan/test program to determine VOC removal efficiency of packed tower scrubber controlling sulfur dioxide emissions from a crude oil-fired steam generator. Ratfisch 55 VOC analyzers were used to measure the packed tower scrubber VOC removal efficiency. Tedlar bag samples were collected simultaneously to correlate BTX removal efficiency to VOC removal efficiency. This test was one of hundreds of air toxics tests performed during this test program for oil and gas production facilities from 1990 to 1992. The majority of the volatile air toxics analyses were performed at in-house laboratory. Project staff developed thorough familiarity with the applications and limitations of GC/MS, GC/PID, GC/FID, GC/ECD and GC/FPD. Tedlar bags, canisters, sorbent tubes and impingers were used during sampling, along with isokinetic tests methods for multiple metals and PAHs.

Air Toxics Testing of Glycol Reboiler – Gas Processing Plant. Project manager for test program to determine emissions of BTXE from glycol reboiler vent at gas processing facility handling 12 MM/cfd of produced gas. Developed innovative test methods to accurately quantify BTXE emissions in reboiler vent gas.
Air Toxics Emissions Inventory Plan. Lead engineer for the development of generic air toxics emission estimating techniques (EETs) for oil and gas production equipment. This project was performed for the Western States Petroleum Association in response to the requirements of the California Air Toxics "Hot Spots" Act. EETs were developed for all point and fugitive oil and gas production sources of air toxics, and the specific air toxics associated with each source were identified. A pooled source emission test methodology was also developed to moderate the cost of source testing required by the Act.

Fugitive NMHC Emissions from TEOR Production Field. Project manager for the quantification of fugitive Nonmethane hydrocarbon (NMHC) emissions from a thermally enhanced oil recovery (TEOR) oil production field in Kern County, CA. This program included direct measurement of NMHC concentrations in storage tank

vapor headspace and the modification of available NMHC emission factors for NMHC-emitting devices in TEOR produced gas service, such as wellheads, vapor trunklines, heat exchangers, and compressors. Modification of the existing NMHC emission factors was necessary due to the high concentration of CO_2 and water vapor in TEOR produced gases.

Fugitive Air Emissions Testing of Oil and Gas Production Fields. Project manager for test plan/test program to determine VOC and air toxics emissions from oil storage tanks, wastewater storage tanks and produced gas lines. Test results were utilized to develop comprehensive air toxics emissions inventories for oil and gas production companies participating in the test program.

Oil and Gas Production Field – Air Emissions Inventory and Air Modeling. Project manager for oil and gas production field risk assessment. Project included review and revision of the existing air toxics emission inventory, air dispersion modeling, and calculation of the acute health risk, chronic non-carcinogenic risk and carcinogenic risk of facility operations. Results indicated that fugitive H_2S emissions from facility operations posed a potential health risk at the facility fenceline.

TITLE V PERMIT APPLICATION/MONITORING PLAN EXPERIENCE

Title V Permit Application – San Diego County Industrial Facility. Project engineer tasked with preparing streamlined Title V operating permit for U.S. Navy facilities in San Diego. Principal emission units included chrome plating, lead furnaces, IC engines, solvent usage, aerospace coating and marine coating operations. For each device category in use at the facility, federal MACT requirements were integrated with District requirements in user friendly tables that summarized permit conditions and compliance status.

Title V Permit Application Device Templates - Oil and Gas Production Industry. Project manager and lead engineer to prepare Title V permit application "templates" for the Western States Petroleum Association (WSPA). The template approach was chosen by WSPA to minimize the administrative burden associated with listing permit conditions for a large number of similar devices located at the same oil and gas production facility. Templates are being developed for device types common to oil and gas production operations. Device types include: boilers, steam generators, process heaters, gas turbines, IC engines, fixed-roof storage tanks, fugitive components, flares, and cooling towers. These templates will serve as the core of Title V permit applications prepared for oil and gas production operations in California.

Title V Permit Application - Aluminum Rolling Mill. Project manager and lead engineer for Title V permit application prepared for largest aluminum rolling mill in the western U.S. Responsible for the overall direction of the permit application project, development of a monitoring plan for significant emission units, and development of a hazardous air pollutant (HAP) emissions inventory. The project involved extensive onsite data gathering, frequent interaction with the plant's technical and operating staff, and coordination with legal counsel and subcontractors. The permit application was completed on time and in budget.

Title V Model Permit - Oil and Gas Production Industry. Project manager and lead engineer for the comparative analysis of regional and federal requirements affecting oil and gas production industry sources located in the San Joaquin Valley. Sources included gas turbines, IC engines, steam generators, storage tanks, and process fugitives. From this analysis, a model applicable requirements table was developed for a sample device type (storage tanks) that covered the entire population of storage tanks operated by the industry. The U.S. EPA has tentatively approved this model permit approach, and work is ongoing to develop comprehensive applicable requirements tables for each major category of sources operated by the oil and gas industry in the San Joaquin Valley.

Title V Enhanced Monitoring Evaluation of Oil and Gas Production Sources. Lead engineer to identify differences in proposed EPA Title V enhanced monitoring protocols and the current monitoring requirements for oil and gas production sources in the San Joaquin Valley. The device types evaluated included: steam generators, stationary ICEs, gas turbines, fugitives, fixed roof storage tanks, and thermally enhanced oil recovery (TEOR) well vents. Principal areas of difference included: more stringent Title V O&M requirements

for parameter monitors (such as temperature, fuel flow, and O_2), and more extensive Title V recordkeeping requirements.

RACT/BARCT/BACT EVALUATIONS

RACT/BARCT Reverse Jet Scrubber/Fiberbed Mist Eliminator Retrofit Evaluation. Project manager and lead engineer on project to address the inability of existing wet electrostatic precipitators (ESPs) and atomized mist scrubbers to adequately remove low concentration submicron particulate from high volume recovery boiler exhaust gas at the Alaska Pulp Corporation mill in Sitka, AK. The project involved thorough on-site inspections of existing control equipment, detailed review of maintenance and performance records, and a detailed evaluation of potential replacement technologies. These technologies included a wide variety of scrubbing technologies where manufacturers claimed high removal efficiencies on submicron particulate in high humidity exhaust gas. Packed tower scrubbers, venturi scrubbers, reverse jet scrubbers, fiberbed mist eliminators and wet ESPs were evaluated. Final recommendations included replacement of atomized mist scrubber with reverse jet scrubber and upgrading of the existing wet ESPs. The paper describing this project was published in the May 1992 TAPPI Journal.

Aluminum Smelter RACT Evaluation - Prebake. Project manager and technical lead for CO and PM_{10} RACT evaluation for prebake facility. Retrofit control options for CO emissions from the anode bake furnace, potline dry scrubbers and the potroom roof vents were evaluated. PM_{10} emissions from the coke kiln, potline dry scrubbers, potroom roof vents, and miscellaneous potroom fugitive sources were addressed. Four CO control technologies were identified as technologically feasible for potline CO emissions: potline current efficiency improvement through the addition of underhung busswork and automated puncher/feeders, catalytic incineration, recuperative incineration and regenerative incineration. Current efficiency improvement was identified as probable CO RACT if onsite test program demonstrated the effectiveness of this approach. Five PM_{10} control technologies were identified as technologically feasible: increased potline hooding efficiency through redesign of shields, the addition of a dense-phase conveying system, increased potline air evacuation rate, wet scrubbing of roof vent emissions, and fabric filter control of roof vent emissions.

RACT/BACT Testing/Evaluation of PM_{10} Mist Eliminators on Five-Stand Cold Mill. Project manager and lead engineer for fiberbed mist eliminator and mesh pad mist eliminator comparative pilot test program on mixed phase aerosol (PM_{10})/gaseous hydrocarbon emissions from aluminum high speed cold rolling mill. Utilized modified EPA Method 5 sampling train with portion of sample gas diverted (after particulate filter) to Ratfisch 55 VOC analyzer. This was done to permit simultaneous quantification of aerosol and gaseous hydrocarbon emissions in the exhaust gas. The mesh pad mist eliminator demonstrated good control of PM_{10} emissions, though test results indicated that the majority of captured PM_{10} evaporated in the mesh pad and was emitted as VOC.

Aluminum Remelt Furnace/Rolling Mill RACT Evaluations. Lead engineer for comprehensive CO and PM_{10} RACT evaluation for the largest aluminum sheet and plate rolling mill in western U.S. Significant sources of CO emissions from the facility included the remelt furnaces and the coater line. The potential CO RACT options for the remelt furnaces included: enhanced maintenance practices, preheating combustion air, installation of fully automated combustion controls, and energy efficiency modifications.

BARCT Low NO_x Burner Conversion – Industrial Boilers. Lead engineer for evaluation of low NO_x burner options for natural gas-fired industrial boilers. Also evaluated methanol and propane as stand-by fuels to replace existing diesel stand-by fuel system. Evaluated replacement of steam boilers with gas turbine co-generation system.

BACT Packed Tower Scrubber/Mist Eliminator Performance Evaluations. Project manager and lead engineer for Navy-wide plating shop air pollution control technology evaluation and emissions testing program. Mist eliminators and packed tower scrubbers controlling metal plating processes, which included hard chrome, nickel, copper, cadmium and precious metals plating, were extensively tested at three Navy plating shops.

Chemical cleaning and stripping tanks, including hydrochloric acid, sulfuric acid, chromic acid and caustic, were also tested. The final product of this program was a military design specification for plating and chemical cleaning shop air pollution control systems. The hydrochloric acid mist sampling procedure developed during this program received a protected patent.

BACT Packed Tower Scrubber/UV Oxidation System Pilot Test Program. Technical advisor for pilot test program of packed tower scrubber/ultraviolet (UV) light VOC oxidation system controlling VOC emissions from microchip manufacturing facility in Los Angeles. The testing was sponsored in part by the SCAQMD's Innovative Technology Demonstration Program, to demonstrate this innovative control technology as BACT for microchip manufacturing operations. The target compounds were acetone, methylethylketone (MEK) and 1,1,1-trichloroethane, and compound concentrations ranged from 10-100 ppmv. The single stage packed tower scrubber consistently achieved greater than 90% removal efficiency on the target compounds. The residence time required in the UV oxidation system for effective oxidation of the target compounds proved significantly longer than the residence time predicted by the manufacturer.

BACT Pilot Testing of Venturi Scrubber on Gas/Aerosol VOC Emission Source. Technical advisor for project to evaluate venturi scrubber as BACT for mixed phase aerosol/gaseous hydrocarbon emissions from deep fat fryer. Venturi scrubber demonstrated high removal efficiency on aerosol, low efficiency on VOC emissions. A number of VOC tests indicated negative removal efficiency. This anomaly was traced to a high hydrocarbon concentration in the scrubber water. The pilot unit had been shipped directly to the jobsite from another test location by the manufacturer without any cleaning or inspection of the pilot unit.

Pulp Mill Recovery Boiler BACT Evaluation. Lead engineer for BACT analysis for control of SO_2, NO_x, CO, TNMHC, TRS and particulate emissions from the proposed addition of a new recovery furnace at a kraft pulp mill in Washington. A "top down" approach was used to evaluate potential control technologies for each of the pollutants considered in the evaluation.

Air Pollution Control Equipment Design Specification Development. Lead engineer for the development of detailed Navy design specifications for wet scrubbers and mist eliminators. Design specifications were based on field performance evaluations conducted at the Long Beach Naval Shipyard, Norfolk Naval Shipyard, and Jacksonville Naval Air Station. This work was performed for the U.S. Navy to provide generic design specifications to assist naval facility engineering divisions with air pollution control equipment selection. Also served as project engineer for the development of Navy design specifications for ESPs and fabric filters.

CONTINUOUS EMISSION MONITOR (CEM) PROJECT EXPERIENCE

Process Heater CO and NO_x CEM Relative Accuracy Testing. Project manager and lead engineer for process heater CO and NO_x analyzer relative accuracy test program at petrochemical manufacturing facility. Objective of test program was to demonstrate that performance of onsite CO and NO_x CEMs was in compliance with U.S. EPA "Boiler and Industrial Furnace" hazardous waste co-firing regulations. A TECO Model 48 CO analyzer and a TECO Model 10 NO_x analyzer were utilized during the test program to provide $\pm$1 ppm measurement accuracy, and all test data was recorded by an automated data acquisition system. One of the two process heater CEM systems tested failed the initial test due to leaks in the gas conditioning system. Troubleshooting was performed using O_2 analyzers, and the leaking component was identified and replaced. This CEM system met all CEM relative accuracy requirements during the subsequent retest.

Performance Audit of NO_x and SO_2 CEMs at Coal-Fired Power Plant. Lead engineer on system audit and challenge gas performance audit of NO_x and SO_2 CEMs at a coal-fired power plant in southern Nevada. Dynamic and instrument calibration checks were performed on the CEMs. A detailed visual inspection of the CEM system, from the gas sampling probes at the stack to the CEM sample gas outlet tubing in the CEM trailer, was also conducted. The CEMs passed the dynamic and instrument calibration requirements specified in EPA's Performance Specification Test - 2 (NO_x and SO_2) alternative relative accuracy requirements.

LATIN AMERICA ENVIRONMENTAL PROJECT EXPERIENCE

Assessment of operational deficiencies of Camisa pipeline – Peru. Project leader of multi-year assessment of root causes of ruptures on Camisea 14-inch natural gas liquids pipeline for non-profit client. Determined that primary causes of hurried construction in difficult and unstable terrain, unstable right-of-way in the jungle sector due to inadequate erosion control practices, and inadequate pipe wall thickness to withstand external lateral forces. Two assessments were developed during the course of the project documenting deficiencies and recommending remedial actions.

Evaluation of U.S.-Mexico Border Region Copper Smelter Compliance with Treaty Obligations – Mexico. Project manager and lead engineer to evaluate compliance of U.S. and Mexican border region copper smelters with the SO_2 monitoring, recordkeeping and reporting requirements in Annex IV [Copper Smelters] of the La Paz Environmental Treaty. Identified potential problems with current ambient and stack monitoring practices that could result in underestimating the impact of SO_2 emissions from some of these copper smelters. Identified additional source types, including hazardous waste incinerators and power plants, that should be considered for inclusion in the La Paz Treaty process.

Development of Air Emission Limits for ICE Cogeneration Plant - Panamá. Lead engineer assisting U.S. cogeneration plant developer to permit an ICE cogeneration plant at a hotel/casino complex in Panama. Recommended the use of modified draft World Bank NO_x and PM limits for ICE power plants. The modification consisted of adding a thermal efficiency factor adjustment to the draft World Bank NO_x and PM limits. These proposed ICE emission limits are currently being reviewed by Panamanian environmental authorities.

Mercury Emissions Inventory for Stationary Sources in Northern Mexico. Project manager and lead engineer to estimate mercury emissions from stationary sources in Northern Mexico. Major potential sources of mercury emissions include solid- and liquid-fueled power plants, cement kilns co-firing hazardous waste, and non-ferrous metal smelters. Emission estimates were provided for approximately eighty of these sources located in Northern Mexico. Coordinated efforts of two Mexican subcontractors, located in Mexico City and Hermosillo, to obtain process throughput data for each source included in the inventory.

Translation of U.S. EPA Scrap Tire Combustion Emissions Estimation Document – Mexico. Evaluated the Translated a U.S. EPA scrap tire combustion emissions estimation document from English to Spanish for use by Latin American environmental professionals.

Environmental Audit of Aluminum Production Facilities – Venezuela. Evaluated the capabilities of existing air, wastewater and solid/hazardous waste control systems used by the aluminum industry in eastern Venezuela. This industry will be privatized in the near future. Estimated the cost to bring these control systems into compliance with air, wastewater and solid/hazardous waste standards recently promulgated in Venezuela. Also served as technical translator for team of U.S. environmental engineers involved in the due diligence assessment.

Assessment of Environmental Improvement Projects – Chile and Peru. Evaluated potential air, water, soil remediation and waste recycling projects in Lima, Peru and Santiago, Chile for feasibility study funding by the U.S. Trade and Development Agency. Project required onsite interaction with in-country decisionmakers (in Spanish). Projects recommended for feasibility study funding included: 1) an air quality technical support project for the Santiago, Chile region, and 2) soil remediation/metals recovery projects at two copper mine/smelter sites in Peru.

Air Pollution Control Training Course – Mexico. Conducted two-day Spanish language air quality training course for environmental managers of assembly plants in Mexicali, Mexico. Spanish-language course manual prepared by Powers Engineering. Practical laboratory included training in use of combustion gas analyzer, flame ionization detector (FID), photoionization detector (PID), and occupational sampling.

Stationary Source Emissions Inventory – Mexico. Developed a comprehensive air emissions inventory for stationary sources in Nogales, Sonora. This project requires frequent interaction with Mexican state and federal environmental authorities. The principal Powers Engineering subcontractor on this project is a Mexican firm located in Hermosillo, Sonora.

VOC Measurement Program – Mexico. Performed a comprehensive volatile organic compound (VOC) measurements program at a health products fabrication plant in Mexicali, Mexico. An FID and PID were used to quantify VOCs from five processes at the facility. Occupational exposures were also measured. Worker exposure levels were above allowable levels at several points in the main assembly area.

Fluent in Spanish. Studied at the Universidad de Michoacán in Morelia, Mexico, 1993, and at the Colegio de España in Salamanca, Spain, 1987-88. Have lectured (in Spanish) on air monitoring and control equipment at the Instituto Tecnológico de Tijuana. Maintain contact with Comisión Federal de Electricidad engineers responsible for operation of wind and geothermal power plants in Mexico, and am comfortable operating in the Mexican business environment.

PUBLICATIONS

Bill Powers, "*More Distributed Solar Means Fewer New Combustion Turbines*," Natural Gas & Electricity Journal, Vol. 29, Number 2, September 2012, pp. 17-20.

Bill Powers, "*Federal Government Betting on Wrong Solar Horse*," Natural Gas & Electricity Journal, Vol. 27, Number 5, December 2010,

Bill Powers, "*Today's California Renewable Energy Strategy—Maximize Complexity and Expense*," Natural Gas & Electricity Journal, Vol. 27, Number 2, September 2010, pp. 19-26.

Bill Powers, "*Environmental Problem Solving Itself Rapidly Through Lower Gas Costs*," Natural Gas & Electricity Journal, Vol. 26, Number 4, November 2009, pp. 9-14.

Bill Powers, "*PV Pulling Ahead, but Why Pay Transmission Costs?*" Natural Gas & Electricity Journal, Vol. 26, Number 3, October 2009, pp. 19-22.

Bill Powers, "*Unused Turbines, Ample Gas Supply, and PV to Solve RPS Issues*," Natural Gas & Electricity Journal, Vol. 26, Number 2, September 2009, pp. 1-7.

Bill Powers, "*CEC Cancels Gas-Fed Peaker, Suggesting Rooftop Photovoltaic Equally Cost-Effective*," Natural Gas & Electricity Journal, Vol. 26, Number 1, August 2009, pp. 8-13.

Bill Powers, "*San Diego Smart Energy 2020 – The 21st Century Alternative*," San Diego, October 2007.

Bill Powers, "*Energy, the Environment, and the California – Baja California Border Region*," Electricity Journal, Vol. 18, Issue 6, July 2005, pp. 77-84.

W.E. Powers, *"Peak and Annual Average Energy Efficiency Penalty of Optimized Air-Cooled Condenser on 515 MW Fossil Fuel-Fired Utility Boiler,"* presented at California Energy Commission/Electric Power Research Institute Advanced Cooling Technologies Symposium, Sacramento, California, June 2005.

W.E. Powers, R. Wydrum, P. Morris, *"Design and Performance of Optimized Air-Cooled Condenser at Crockett Cogeneration Plant,"* presented at EPA Symposium on Technologies for Protecting Aquatic Organisms from Cooling Water Intake Structures, Washington, DC, May 2003.

P. Pai, D. Niemi, W.E. Powers, *"A North American Anthropogenic Inventory of Mercury Emissions,"* presented at Air & Waste Management Association Annual Conference in Salt Lake City, UT, June 2000.

P.J. Blau and W.E. Powers, *"Control of Hazardous Air Emissions from Secondary Aluminum Casting Furnace Operations Through a Combination of: Upstream Pollution Prevention Measures, Process Modifications and End-of-Pipe Controls,"* presented at 1997 AWMA/EPA Emerging Solutions to VOC & Air Toxics Control Conference, San Diego, CA, February 1997.

W.E. Powers, et. al., *"Hazardous Air Pollutant Emission Inventory for Stationary Sources in Nogales, Sonora, Mexico ,"* presented at 1995 AWMA/EPA Emissions Inventory Specialty Conference, RTP, NC, October 1995.

W.E. Powers, *"Develop of a Parametric Emissions Monitoring System to Predict NO_x Emissions from Industrial Gas Turbines,"* presented at 1995 AWMA Golden West Chapter Air Pollution Control Specialty Conference, Ventura, California, March 1995.

W. E. Powers, et. al., *"Retrofit Control Options for Particulate Emissions from Magnesium Sulfite Recovery Boilers,"* presented at 1992 TAPPI Envr. Conference, April 1992. Published in *TAPPI Journal*, July 1992.

S. S. Parmar, M. Short, W. E. Powers, *"Determination of Total Gaseous Hydrocarbon Emissions from an Aluminum Rolling Mill Using Methods 25, 25A, and an Oxidation Technique,"* presented at U.S. EPA Measurement of Toxic and Related Air Pollutants Conference, May 1992.

N. Meeks, W. E. Powers, *"Air Toxics Emissions from Gas-Fired Internal Combustion Engines,"* presented at AIChE Summer Meeting, August 1990.

W. E. Powers, *"Air Pollution Control of Plating Shop Processes,"* presented at 7th AES/EPA Conference on Pollution Control in the Electroplating Industry, January 1986. Published in *Plating and Surface Finishing* magazine, July 1986.

H. M. Davenport, W. E. Powers, *"Affect of Low Cost Modifications on the Performance of an Undersized Electrostatic Precipitator,"* presented at 79th Air Pollution Control Association Conference, June 1986.

AWARDS

Engineer of the Year, 1991 – ENSR Consulting and Engineering, Camarillo
Engineer of the Year, 1986 – Naval Energy and Environmental Support Activity, Port Hueneme
Productivity Excellence Award, 1985 – U. S. Department of Defense

PATENTS

Sedimentation Chamber for Sizing Acid Mist, Navy Case Number 70094

Attachment B

List of reviewed materials

* The following list notes the corresponding exhibit number assigned to each document.

1. Colorado PUC Proceeding No. 23A-0585, Hearing Exhibit 105, *Barry Insgold Direct Testimony* (December 1, 2023) (Exhibit 1-50)
2. Pacificorp, *FERC Form 1* (April 14, 2025) (Exhibit 1-54)
3. Platte River Power Authority, *Coal Energy*, https://prpa.org/generation/coal/ (Exhibit 1-55)
4. Public Service Company of Colorado, *FERC Form 1* (April 4, 2025) (Exhibit 1-55)
5. Salt River Project, *SRP Power Generation Sources*, https://www.srpnet.com/grid-water-management/grid-management/power-generation-stations (Exhibit 1-60)
6. Colorado PUC Proceeding No. 23A-0585E, Hearing Exhibit 101, Attachment LKT-1, Attachment C-3, *Assessment of Existing Resources* (December 1, 2023) (Exhibit 1-49)
7. Docket No. EPA-R08-OAR-2011-0770, Colorado Department of Public Health and Environment, Air Pollution Control Division, *Best Available Retrofit Technology (BART) Analysis – Tri-State Craig Station Units 1&2* (March 26, 2012) (Exhibit 1-82)
8. Docket No. EPA-R08-OAR-2018-0015, Environmental Protection Agency, *SIP Element Adopted* (April 26, 2018) (Exhibit 1-57)
9. Colorado PUC Proceeding No. 20A-0528E, *Lisa Tiffin Direct Testimony* (December 1, 2020) (Exhibit 1-58)
10. Colorado PUC Proceeding No. 23A-0585E, *2025 Annual Progress Report - 2023 Electric Resource Plan* (December 1, 2025) (Exhibit 1-89)
11. M. Hafner, G. Luciani, *The Palgrave Handbook of International Energy Economics* (2022) (Exhibit 1-47)
12. IEA, *The role of CCUS in low-carbon power systems* (2020) (Exhibit 1-49)
13. Intertek, *Update of Reliability and Cost Impacts of Flexible Generation on Fossil-fueled Generators* (May 12, 2020) (Exhibit 1-59)
14. Colorado PUC Proceeding No. 20A-0528E, Hearing Exhibit 101, Attachment BN-2, *2020 Integrated Resource Plan/Electric Resource Plan Volume I* (Dec. 1, 2020) (Exhibit 1-51)
15. Tri-State, *U.S. DOE orders Tri-State to keep Craig Generating Station operating for next 90 days* (December 31, 2025) (Exhibit 1-6)
16. Colorado PUC Proceeding No. 20A-0528E, Tri-State 2020 ERP, Volume I (December 1, 2020) (Exhibit 1-51)
17. Colorado PUC Proceeding No. 23A-0585E, Phase II Implementation Report, Attachment B, *Modeling Assumptions* (April 11, 2025) (Exhibit 1-61)
18. RMI, *Reality Check: We Have What's Needed to Reliably Power the Data Center Boom, and It's Not Coal Plants* (August 12, 2025) (Exhibit 1-44).
19. IEA, *Increasing the flexibility of coal-fired power plants* (September 2014) (Exhibit 1-33)
20. NERC, *Energy Storage: Overview of Electrochemical Storage* (February 2021) (Exhibit 1-62)
21. General Electric, *Get to know the LM6000* (2025), https://www.gevernova.com/gas-power/products/gas-turbines/lm6000 (Exhibit 1-63)
22. Tri-State, *Benefits of SPP RTO West participation highlighted in filing with Colorado PUC* (June 17, 2025), https://tristate.coop/benefits-spp-rto-west-participation-highlighted-filing-colorado-puc (Exhibit 1-64)

23. NARUC, *Recent Changes to U.S. Coal Plant Operations and Current Compensation Practices* (January 2020) (Exhibit 1-32)
24. Colorado Department of Public Health and Environment, Air Quality Control Commission*, Regulation No. 3, Part F, Sec. VI.D* (adopted December 15, 2016) (Exhibit 1-65)
25. 83 Fed. Reg. 31332 (July 5, 2018) (Exhibit 1-66)
26. U.S. EPA, *Basic Information about NO_2*, https://www.epa.gov/no2-pollution/basic-information-about-no2 (Exhibit 1-67)
27. U.S. EPA, *Sulfur Dioxide Basics*, https://www.epa.gov/so2-pollution/sulfur-dioxide-basics (Exhibit 1-68)
28. U.S. EPA*, Health and Environmental Effects of Particulate Matter (PM)*, https://www.epa.gov/pm-pollution/health-and-environmental-effects-particulate-matter-pm (Exhibit 1-69)
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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-04:
Grid Strategies Costs Report

The Economic Cost of a DOE Mandate for the Craig Unit 1 Coal-Burning Generator to Continue Operating

December 2025

Michael Goggin

Prepared for Sierra Club

Grid Strategies



This report analyzes the cost of a U.S. Department of Energy (DOE) mandate that Unit 1 at the Craig coal-burning power plant in Colorado remain available and operate beyond its December 31, 2025, retirement date.

Our analysis predicts that a DOE order that requires Craig Unit 1 to remain available and operate for 90 days would cost at least $20 Million. That equates to approximately $85 Million per year. If DOE's order effectively requires Unit 1 to operate in must-run status, these costs would likely increase to around $150 Million per year. The costs, and similar costs associated with renewals each 90 days, would likely be passed on to ratepayers.

Our analysis also indicates that Craig Unit 1 is usually an uneconomic source of electricity. Specifically, the cost of generating electricity from Craig Unit 1 is higher than nearby power prices more than 90% of the time. Key reasons that Craig Unit 1 is uneconomic are its high fuel cost and low efficiency.

1 Introduction to Craig Unit 1.

Craig Unit 1 generates electricity by burning coal. It has a nameplate generating capacity of 446.4 megawatts (MW). Unit 1 entered service in 1980. At 45 years old, the unit is beyond the typical economic design life of a coal-burning generator (30–40 years) and near the end of the generator's typical operational life (40–50 years).[1] Craig Unit 1 is scheduled to retire on December 31, 2025.



Craig Power Plant in Colorado

CREDIT Tupungato - stock.adobe.com

2 The Costs to Comply with a DOE Mandate Are Substantial.

We calculate a likely cost of at least $20 Million for Craig Unit 1 to comply with a DOE order to remain available and operate over 90 days. Our calculation is based on the following two categories of costs:

- **Fuel Costs:** These are the costs to purchase and transport coal to Unit 1. These are variable costs, because they vary depending on how much power is generated by Unit 1.
- **Other Operations and Maintenance (O&M) Costs:** These are the non-fuel costs associated with Craig Unit 1 being available to generate power and actually generating power. These include variable costs associated with producing electricity (such as wear-and-tear and costs for resources like water that are consumed to produce electricity) and fixed costs that are incurred regardless of how much electricity the unit produces (such as regular maintenance and overhead costs).

To estimate the variable costs associated with a DOE mandate, we must assume a level of output from Craig Unit 1. To be conservative, we use Unit 1's average output from 2022 through 2024. If DOE mandates that Unit 1 be placed in a "must-run" status that requires it to operate continuously when it is available, the variable costs would roughly double, as calculated below.

Our cost estimate is primarily based on recent data collected by the Federal Energy Regulatory Commission (FERC).[2] The data show that operating Craig Unit 1 cost over $80 million in 2024 alone. Over the period 2022–2024, operating Craig Unit 1 cost nearly $85 million per year. The FERC data show fuel costs account for roughly two-thirds of this cost (67.4%), while the remainder is comprised of O&M costs, as shown in the table below.

AVERAGE ANNUAL COST OF CRAIG UNIT 1 FROM 2022–2024

	Fuel Cost	**$57.1 Million**
+	**O&M Cost**	**$27.6 Million**
=	**Total Cost**	**$84.7 Million**

The $84.7 Million annual cost translates to a 90-day cost of $20.9 Million. This is calculated as $84.7 Million × (90/365) ≈ $20.9 Million.

Craig's fuel costs are high due to its above average cost of fuel and its low efficiency. Data from the DOE Energy Information Administration (EIA) show the plant's fuel cost averaged $3.33/million British thermal units (MMBtu) over the September 2024–August 2025 timeframe,[3] significantly higher than the nationwide average for coal plants of $2.53/MMBtu in 2024.[4] EIA data also show the plant averaged an 11,676 Btu/kilowatt-hour (kWh) heat rate over the last 12 months (which corresponds to an efficiency of around 29% in converting the energy in fuel into electricity), also significantly worse than the national average for coal plants of 10,777 Btu/kWh in 2024 (which corresponds to an efficiency of around 32% in converting the energy in fuel into

electricity).[5] As a result, the Craig plant spent $38.84 on fuel for each megawatt-hour (MWh) produced over the last 12 months.

Our estimate of Craig Unit 1's O&M costs is likely conservative. Our analysis uses recent costs, which are lower than future O&M costs because the plant owners have likely been foregoing maintenance in recent years in anticipation of the unit's retirement in December 2025. The foregone maintenance would have decreased the O&M costs over the last several years.

Foregone maintenance would also mean future expenditures will be even higher than the long-term average to make up for that underinvestment and to repair or replace equipment with deferred maintenance as it fails. Foregone maintenance reduces the economic and reliability value of the unit because it makes the unit more prone to failure, and more likely to need to go on outage to fix broken parts or maintain the unit. Sargent and Lundy developed a dataset for DOE's Energy Information Administration in 2019 that estimates coal plants' need for sustaining capital expenditures and increasing O&M costs over time.[6] The Sargent and Lundy report documents a significant increase in capital expenditure as coal plants reach an age of 40–50 years, and even higher O&M and capital expenditure costs at plants like Craig that operate at a low capacity factor.

3 Craig Unit 1 Is Usually an Uneconomic Source of Electricity.

To determine the exact extent to which Craig Unit 1 is an uneconomic source of electricity, the best source would be the dispatch methodologies and parameters used by the operators of Craig Unit 1. However, much of this type of information is kept confidential.

To gauge Craig Unit 1's uneconomic nature, we evaluated market prices at the closest market location to Craig. This location, the Rangely pricing node, is part of the Western Energy Imbalance Market. It is less than 100 miles from Craig. While Craig itself does not operate in a regional electricity market, these nearby prices are a strong indicator of the marginal cost and thus marginal value of producing electricity.

A. Market Prices Are Usually Inadequate to Cover Craig Unit 1's Fuel Costs.

Prices at Rangely averaged $22.71 per MWh for all 5-minute intervals over the period September 2024–August 2025. That is significantly lower than Craig's fuel cost of $38.84 per MWh. This means that, on average, the marginal value of power from Craig Unit 1 is $16.13 per MWh *lower* than just the cost of supplying fuel to Craig Unit 1 to produce that power. The calculation is shown below.

AVERAGE MARKET PRICES AND CRAIG UNIT 1'S FUEL COSTS

	Average Market Price	$22.71 per MWh
–	Fuel Cost	$38.84 per MWh
=	**Marginal Value or Loss**	**-$16.13 per MWh**

We did not simply look at the average Rangely price. Prices at Rangely are constantly fluctuating, so we also examined the extent to which the prices were below the Craig Unit 1 fuel cost during each 5-minute interval from September 2024–August 2025. Our analysis demonstrates that prices were inadequate to cover Craig Unit 1's fuel cost alone in 84.2% of the intervals. This is depicted by the intersection of the curved line and the "Fuel" horizontal line in Figure 1 below. The curved line in the figure shows prices in all 105,120 5-minute intervals in a year, sorted from lowest to highest.[a]

B. Craig Unit 1 Is Even More Uneconomic When Considering Its Fuel Costs Along with Other Variable Costs.

Adding Craig Unit 1's other costs shows that the unit is even more uneconomic compared to the market price.

To derive Craig Unit 1's other variable costs, we need to make an assumption regarding the share of the total Operations and Maintenance costs reported to FERC that are variable costs versus the share that are fixed costs. As further discussed in the Methodological Appendix, we use data from DOE's National Energy Technology Laboratory and Wall Street investment firm Lazard. We estimate that Craig Unit 1's O&M costs are 61.125% fixed and 38.875% variable.

Our analysis indicates that Craig Unit 1's non-fuel variable costs are $5.38 per MWh. Adding that figure to Craig Unit 1's fuel cost, we derive an estimated variable cost of $44.22 per MWh. ($5.38 + $38.84 = $44.22.) This means that, compared to the Rangely market price indication of marginal value, Craig Unit 1's marginal value is even lower than when solely looking at fuel costs, as shown in the calculation below.

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a To make the chart more readable, the y-axis is truncated so 0.4% of time periods are not shown. Those outlier pricing intervals were below negative $50/MWh or above $100/MWh.

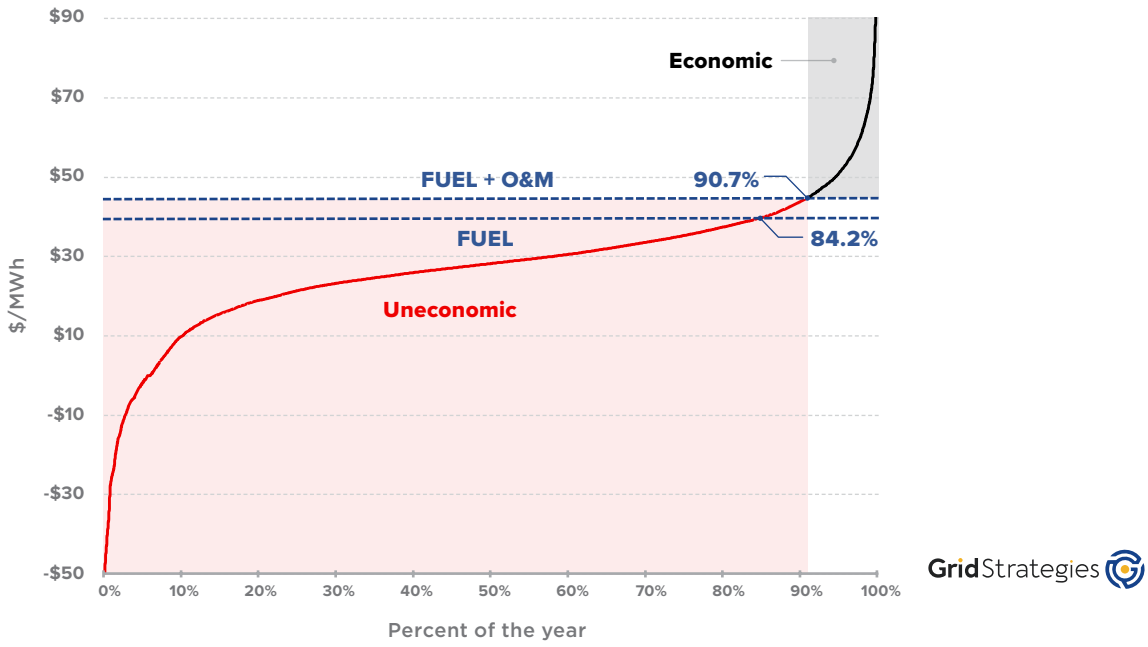


AVERAGE MARKET PRICES AND CRAIG UNIT 1'S VARIABLE COSTS

	Average Market Price	$22.71 per MWh
–	Fuel Cost	$38.84 per MWh
–	Non-Fuel Variable Cost	$5.38 per MWh
=	**Marginal Value or Loss**	**-$21.51 per MWh**

When considering the total variable cost of $44.22/MWh against the fluctuating prices at Rangely from September 2024–August 2025, we see that prices were inadequate to cover Craig Unit 1's variable costs in 90.7% of hours. In the chart below, this is depicted by the intersection of the "Fuel + O&M" horizontal line with the curved line showing market prices.

FIGURE 1. Craig Unit 1 is Almost Always Uneconomic Relative to Regional Power Prices



As noted above, electricity prices at a nearby market node are a good indicator of the marginal value of electricity from Craig. These prices indicate that Craig 1's cost of producing electricity is almost always higher than the value of that electricity, and thus it would not be economic for Craig 1 to generate electricity during those hours. Even these estimates of Craig Unit 1's poor competitiveness are conservative. To begin producing electricity, coal units typically take a day or more and incur tens of thousands of dollars in fuel and maintenance costs. Of the few price intervals in which the market price exceeded Craig Unit 1's variable cost, many lasted only a few hours or less, too short for a coal plant to profitably start up and then shut down. (New and more flexible resources like batteries could profitably generate during those periods, however.)

The preceding costs would also increase dramatically if DOE were to mandate that Craig Unit 1 run continuously when it is available. Craig 1 operated at a 41.5% capacity factor (actual generation divided by theoretical maximum generation if the plant constantly ran at full output)

over the last 12 months.[7] This is below the national average capacity factor for coal plants of 46.86% over that time period,[8] reflecting Craig 1's inability to economically compete with other generation sources. If Craig 1's capacity factor doubled due to a DOE must-run mandate, its fuel costs would similarly increase, likely going from the $57.1 Million average over the last three years to more than $100 Million per year. The variable O&M costs of around $8.7 Million would also roughly double, bringing total annual costs from around $85 Million to around $150 Million ($84.7M+$57.1M+$8.7M=$150.5M).

More fundamentally, a federal mandate overriding the economic decision to retire Craig Unit 1 made by all five co-owners of the unit, and endorsed by their state utility regulators or other governance bodies, is inherently likely to increase ratepayer costs. Those utilities and their regulators are best equipped to determine the optimal mix of generation resources to serve ratepayers, and they have the best information about the cost of operating Craig 1 going forward, including detailed non-public information regarding its condition and future maintenance and investment needs.

Conclusion

This report demonstrates that a federal mandate forcing the uneconomic Craig 1 coal unit to continue operating would impose large costs. The costs are likely to exceed $20 Million for each 90-day period of such mandates, or approximately $85 Million annually. And there is good reason to believe this is a conservative estimate, including because of the use of recent data that likely underestimates the going-forward cost of operating Craig Unit 1. The owners and operators of Craig Unit 1 decided to retire Craig Unit 1 due to its uneconomic nature.

The large costs to comply with a DOE mandate are likely to be passed on to ratepayers. The costs can be avoided by the unit retiring on schedule, according to the plan developed by the unit's owners and operators and approved by state regulators.

Methodological Appendix

Data from DOE EIA Form 923 Page 5 show Craig's quantity and price of coal expenditures per month, which indicate the plant's fuel cost averaged $3.33/million British thermal units (MMBtu) over the September 2024–August 2025 timeframe. Craig's fuel consumption and electricity generation data from Form 923 Page 1 were used to calculate the average heat rate over that time period of 11,676 Btu/kWh, which was multiplied by the average fuel cost to find the $38.84/MWh fuel cost.

FERC Form 1 total fuel cost and total O&M cost for Craig Units 1 and 2 are available for 2022–2024 for co-owners PacifiCorp, Public Service Company of Colorado, and Tri-State. Because those three utilities respectively own 19%, 9.7%, and 24% of Craig Units 1 and 2, the sum of average annual costs for those three utilities were weighted by their annual generation reported on Form 1 and then scaled up to cover the remaining plant owners. Costs were then assumed to be evenly split between Craig 1 and 2.

FERC Form 1 group cost data for Craig Units 1 and 2 together, while EIA Form 923 reports heat rates and fuel prices for the entire three-unit plant, not at the unit level. We assumed the non-fuel operations and maintenance costs reported on Form 1 were incurred evenly between Craig 1 and 2.

Because Form 1 does not break down total O&M costs into fixed and variable costs, we reviewed analyses from DOE's National Energy Technology Laboratory (NETL) and Wall Street investment firm Lazard.[9] Lazard reports variable O&M costs of $3.20–$7.20/MWh and fixed O&M costs of $21.70–$33.80/kW-year for existing coal generators, while NETL's 2015 report shows variable costs of $8.47/MWh and fixed costs of $73.62/kW-year. Averaging the NETL costs and the low and high estimates from Lazard indicates O&M costs are 61.125% fixed and 38.875% variable, which we used for our central cost estimate.

Our analysis also explored a low estimate in which fixed and variable O&M costs are evenly split 50/50, and an alternative case in which costs are 70% fixed and 30% variable. The results for these scenarios are presented in Table 2 below, and show the plant is only economic about 8–10% of the time. **In our central cost estimate, Craig Unit 1 is uneconomic 90.7% of the time.** The right-most column shows results for the case presented at the beginning of the report, in which all O&M costs are assumed to be fixed and only the $33.84/MWh fuel costs are factored into variable costs.

RATEPAYER NET COSTS OF CRAIG 1 UNDER DIFFERENT ASSUMPTIONS FOR FIXED VS. VARIABLE O&M COSTS

Fixed vs variable split	50/50	**61.125/38.875**	70/30	100/0
Profitable hours	8.0%	**9.3%**	10.4%	15.8%
Annual fixed O&M cost	$13.2 M	**$16.2 M**	$18.5 M	$26.4 M

To calculate Craig Unit 1's 45.1% capacity factor over the last 12 months, Unit 1's gross hourly generation data was downloaded from EPA. EPA reports that Craig 1 averaged 209 MW of gross generation, before accounting for parasitic losses and other plant consumption that reduce net generation provided to the power grid. EIA reports net generation by plant, but does not report unit-specific net generation. EIA net generation from all three Craig units over the last year is 88.7% of the EPA gross generation for all three units. To estimate net generation from Craig 1, the EPA gross generation was multiplied by 0.887, yielding average net generation of 185.43 MW, which corresponds to a 45.1% capacity factor for the 446.4 MW unit.

Endnotes

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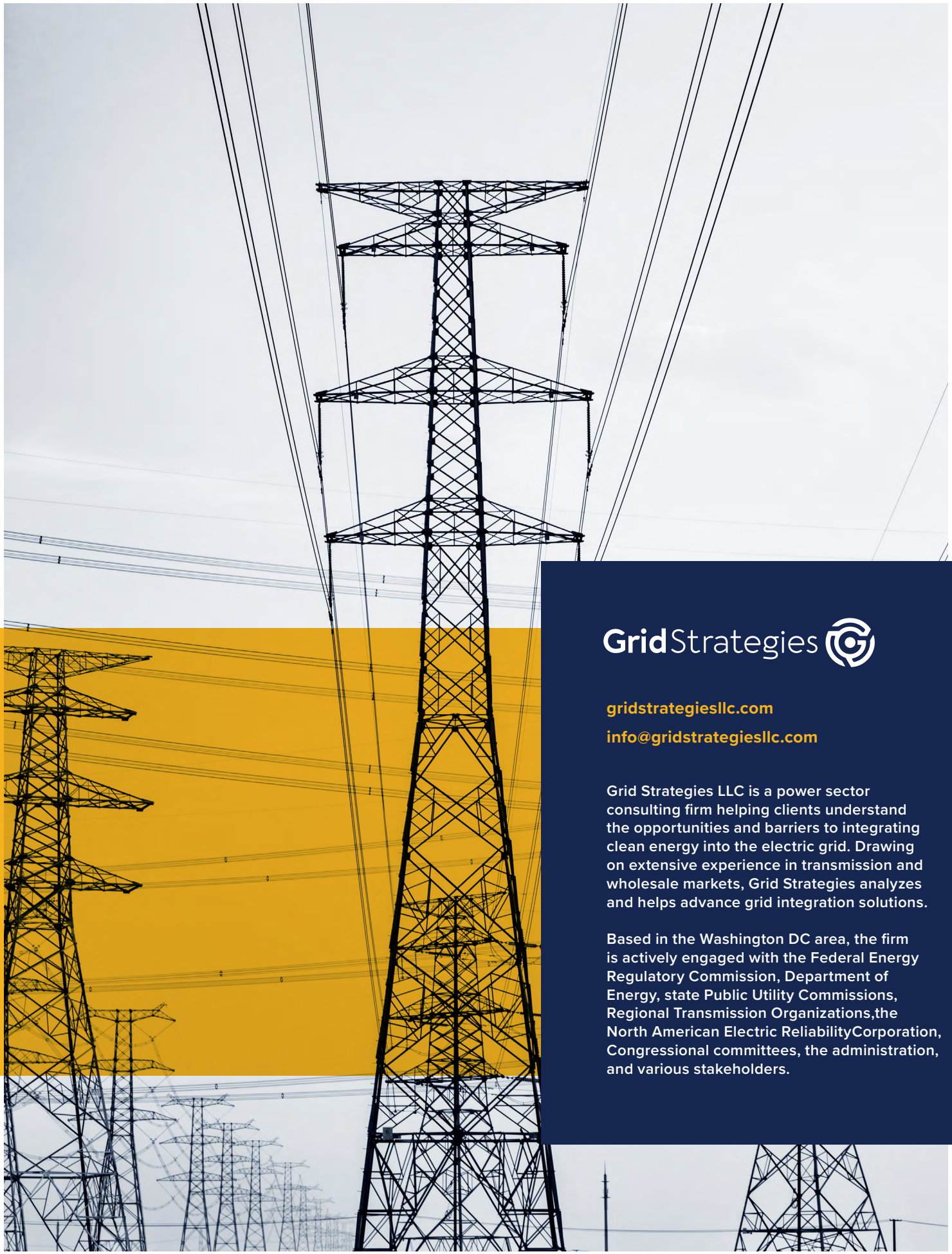
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Grid Strategies LLC is a power sector consulting firm helping clients understand the opportunities and barriers to integrating clean energy into the electric grid. Drawing on extensive experience in transmission and wholesale markets, Grid Strategies analyzes and helps advance grid integration solutions.

Based in the Washington DC area, the firm is actively engaged with the Federal Energy Regulatory Commission, Department of Energy, state Public Utility Commissions, Regional Transmission Organizations,the North American Electric ReliabilityCorporation, Congressional committees, the administration, and various stakeholders.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-05:
Telos Resource Adequacy Report

Resource Adequacy Planning in Colorado

How Colorado utilities and regulators ensure reliability

SEPTEMBER 2025

TELOS ENERGY



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TELOS ENERGY

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INTRODUCTION

This report examines how Colorado's electric utilities and state regulators plan for and ensure the reliability of their electric system. Ensuring reliability is at the center of a comprehensive, multi-year utility planning process that requires approvals by either utility boards or the Public Utilities Commission and is informed by robust stakeholder participation. This report describes the respective roles of utilities and regulatory agencies, the standards and metrics for reliability, and the analytical methods for assessing reliability.

There are many facets of a reliable power grid. Transmission reliability ensures power can flow from where it is generated to where it is consumed. Grid stability analysis ensures rapid, sub-second, disturbances on the grid do not cascade into large blackouts. And grid operators ensure the system is flexible enough to meet short term fluctuations in load. This report focuses primarily on the resource adequacy aspects of reliability—ensuring there are enough resources to serve the electricity demand given uncertainties in weather, load, and generator outages.

Portfolios of electric generation and storage resources—such as gas power plants, wind and solar farms, and batteries—are developed with modern reliability methods to ensure the future power system can serve demand across a wide range of uncertainties, including higher than expected demand growth, inclement weather, periods of low wind and solar production, and unexpected generator outages. Plans are then rechecked for operability and stress-tested against extreme weather conditions to verify performance when the grid is under the greatest strain. Ensuring a reliable power system requires an iterative and transparent process: utilities file detailed assumptions, scenarios, and sensitivity analyses; stakeholders provide feedback; regulators review those assumptions in open proceedings; and portfolios are adjusted before any plant retirement or new resource procurement is approved.

This report explains how Colorado's planning and procurement system works and why it is well suited to maintain reliability while serving new electricity demand. The report describes the structure of long-term utility planning and today's reliability toolkit, shows how system needs and resource contributions are quantified with widely accepted methods, and outlines the "reliability back-checks" and extreme-event testing that ensure new portfolios are operable in real-world conditions. Finally, the report highlights the expert-driven, stakeholder-reviewed nature of the planning process, which balances cost, risk, and reliability and adapts as facts on the ground change.

RELIABLY NAVIGATING THE NEEDS OF COLORADO'S ELECTRICITY SYSTEM

UPGRADES FOR A CHANGING RESOURCE MIX

> ***Colorado utilities have developed detailed replacement plans for retiring coal plants leveraging a diverse set of new in-state resources, designed to maintain or enhance reliability.***

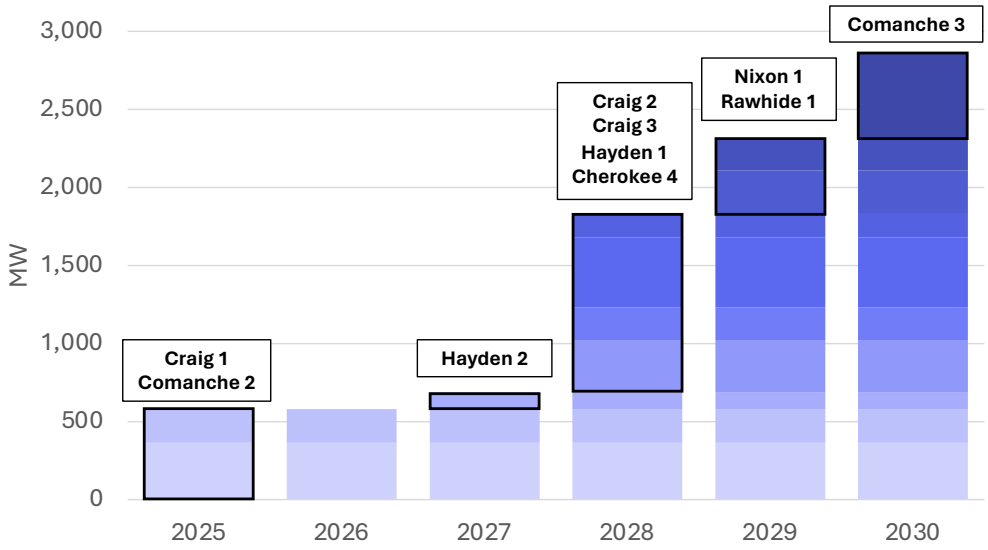
For decades, Colorado's power system has been evolving to reflect changes that include the availability of new generating and storage technologies, changes in the economics of resources, state and federal regulation, and customer preferences. The state's major load-serving entities[1] are planning and executing the phased retirement of coal plants and their replacement with balanced portfolios that include wind, solar, battery storage, transmission, and new natural-gas resources. This portfolio approach is designed to maintain reliability while meeting both existing customer demand and new demand from data centers, oil and gas operations, electric vehicle charging, and building electrification.

This transition from coal to a portfolio of new resources is driven by many factors. For example, coal has faced increased economic competition ever since hydraulic fracturing ("fracking") led to declines in the price of natural gas and thus the price of gas-fired generation. Other generating and storage technologies have also declined in cost relative to coal. Today, the costs of new wind, solar, and storage technologies continue to decline and benefit from remaining federal tax credits, making clean resources cost-competitive over a planning horizon. At the same time, because Colorado has not built a new coal unit in nearly two decades, the coal fleet in Colorado is aging and faces escalating fuel, operations, and maintenance costs and increasing outage risk.

To date, six Colorado coal and several gas plants are scheduled to retire before 2030 (Figure 1), including Craig, Hayden, Comanche, Nixon, Rawhide, Cherokee plants. These plants are owned in whole, or in part, by the following Colorado utilities: Public Service of Colorado, Tri-State Generation and Transmission, Platte River Power Authority, and Colorado Springs Utilities.

1 In this report, Colorado's load-serving entities, also referred to as "utilities", include Xcel Energy's Public Service Company of Colorado (PSCo), Tri-State Generation and Transmission Association (Tri-State), Platte River Power Authority (PRPA), Colorado Springs Utilities (CSU).

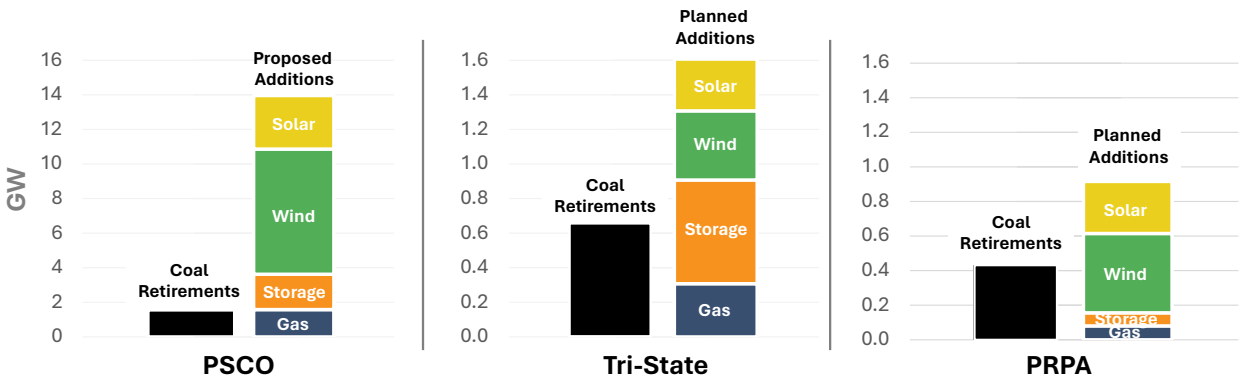
Figure 1. Planned coal retirements in Colorado, 2025-2030



Note: Capacities exclude ownership shares from non-Colorado utilities

Each of these planned retirements includes a replacement plan[2] that includes a diverse set of resources located across the state. Figure 2 provides a visual representation of generator additions and retirements across PSCO, Tri-State, and PRPA service territories.

Figure 2. Planned coal retirements and resource additions by utility, 2025-2031



Note: Colorado Springs Utilities was excluded based on limited data provided, capacities exclude ownership shares from non-Colorado utilities and based on nameplate capacity. Data regarding PSCo includes 2031 additions.

2 For Figure 2, the planned additions for Tri-State are taken from the portfolio approved by the PUC in its Phase II decision in Proceeding No. 23A-0585E; the planned additions for PRPA come from its 2024 IRP; and the proposed additions for PSCo are based on Phase I portfolios that PSCo presented in Proceeding No. 24A-0442E. The amount and type of resources that the PUC approves in 24A-0442E may differ from the amount and type of resources in PSCo's Phase I modeling.

Crucially, the retirement and replacement of these coal and gas units is the outcome of long-term, strategic utility planning. These plans are submitted either to the utility's board or in formal regulatory proceedings at the Colorado PUC. The plans are designed to meet reliability requirements (through planning reserve margins, ELCC accreditation, and seasonal risk assessments), are stress-tested against extreme weather, and refined through regulator oversight and stakeholder participation. This structure is precisely how Colorado intends to maintain and enhance reliability.

Meeting Growing Electricity Demand

> ***Demand for electricity is growing in Colorado and the rest of the nation, but its utilities have tools and strategies to carefully manage growing demand to ensure reliability and control costs.***

After a decade and a half of largely flat electricity demand (2005–2020), Colorado and the nation have begun to see demand rise again, driven by end-use electrification like electric vehicles and heat pumps, new industrial activity, and increasingly, data center development driven by advancements in artificial intelligence (AI). How much and how fast demand will grow, and how much these "large loads" will contribute to that growth, remains uncertain. Forecasts differ on the extent to which AI may drive growth in electricity demand, and parallel advances in hardware and software efficiency could slow that trajectory. Interconnection queues already include a high volume of speculative data-center requests, which can inflate near-term projections and obscure what will actually be built. Opportunities for flexible data center operations, in which they reduce or shift the power they draw from the grid, could prove to substantially reduce their contributions to peak demand.

The United States has navigated periods of growing demand before, and utilities have a suite of options to maintain reliability while accommodating new demand. For example, utilities can build new supply-side resources to maintain sufficient levels of capacity to confidently serve electricity demand throughout the year; and utilities can expand existing, or create new, demand response programs to reduce and/or flexibly manage demand, especially for new large new loads, through programs that reduce or shift consumption during the small number of hours when the system is most stressed.

Critically, large loads such as AI data centers do not simply "show up" on the grid without prior analysis and planning. Utilities conduct detailed interconnection and transmission deliverability studies to determine their reliability impacts, and utilities assess whether sufficient resources exist—or will exist on a defined schedule—before allowing them to connect to the electric grid. Across the country, utilities and grid operators are piloting flexible interconnection agreements which allow customers to agree to flexible operations or voluntary reductions in their electricity consumption in exchange for faster interconnection timelines. These types of agreements not only help ensure system reliability by aligning new loads with system capability, but can help reduce investments in new infrastructure to meet growing demand that ultimately get passed down to customers.

LONG-TERM UTILITY PLANNING IN COLORADO

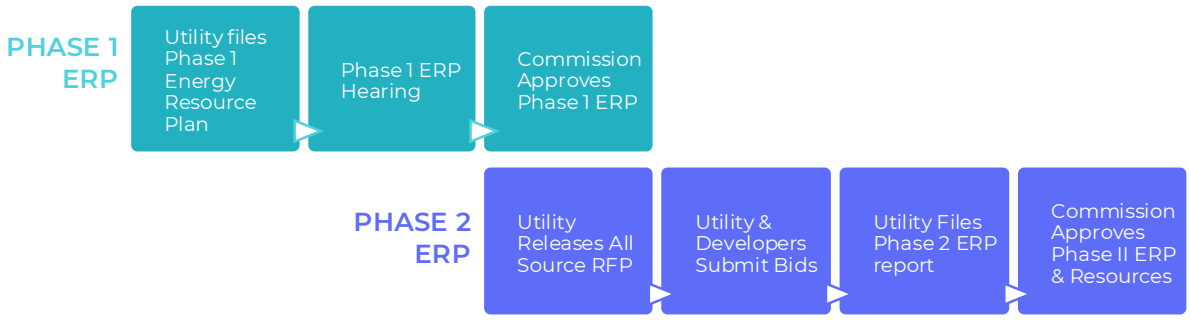
> ***Colorado has a nation-leading, two-phase resource planning process for PUC-regulated utilities and an alternative resource planning process for non-PUC-regulated utilities***

For two of the utilities discussed in this report (Public Service of Colorado (PSCo or Xcel Colorado) and Tri-State Generation and Transmission (Tri-State)), the Colorado PUC regulates their electric resource planning process. By contrast, the PUC does not regulate the resource planning of Platte River Power Authority (PRPA) and Colorado Springs Utilities (CSU), which are instead governed by internal board review processes.

For PSCo and Tri-State, Colorado law requires these utilities to file long-term Electric Resource Plans (ERPs) that demonstrate how they will serve customers reliably and affordably while complying with policy, including the state's clean-energy targets, electric vehicle incentives, and business development objectives. These plans are reviewed in a formal, litigated proceedings before the PUC, with opportunities for participation by communities, business groups, and advocacy organizations.

For the PUC-regulated utilities, Colorado's ERP process was an early example of **two-phase** integrated resource planning, a process that is being adopted by other states and often cited as a utility-planning best practice.[3] In **Phase I**, the utility files its inputs and assumptions, modeling framework, and proposed resource additions and retirements; the Commission then rules on the capacity needs, modeling parameters, and the evaluation process. During this phase the Companies address any planned plant retirements and model generic resource additions. In **Phase II,** the utility runs a competitive, technology neutral ("all-source"), solicitation for new resources and evaluates bids under the Commission-approved rules to assemble a specific resource portfolio that meets the identified needs. A detailed review of the regulatory process for the PSCO Just Transition Solicitation is provided in Appendix Table 2.

Figure 3. Colorado ERP Process for New Resources



3 Rocky Mountain Institute, *Reimagining Resource Planning*, 2023, https://rmi.org/insight/reimagining-resource-planning/, p. 47

The ERPs also look across two distinct timeframes. The Resource Acquisition Period (RAP) defines the near-term window in which specific additions are procured, while the "planning period" extends multiple decades to account for long-lived cost and reliability impacts. For example, in the most recent PSCo Just Transition Solicitation, the RAP ran through 2031 while the planning period extended to 2050. This long-term view allows utilities and regulators to balance affordability, policy compliance, and reliability by sequencing retirements, new builds, and transmission additions.

As noted above, CSU and PRPA do not conduct their electric resource planning at the PUC. Instead, PRPA and CSU undertake their own resource planning processes that have some of the same elements as the PSCo and Tri-State processes but without a litigated proceeding at the PUC and without PUC review and approval. The CSU and PRPA electric resource plans are typically developed over several years; are open to stakeholder feedback; and are based on many of the same kinds of consultant studies—including reliability and resource adequacy studies—as are used by PSCo and Tri-State. All four utilities base investment decisions and reliability on similar reliability standards and planning criteria. The staff of CSU and PRPA submit their resource plans, including a recommendation for a preferred portfolio and an action plan, to their respective utility boards, which have the ultimate say in approving the resource plan.

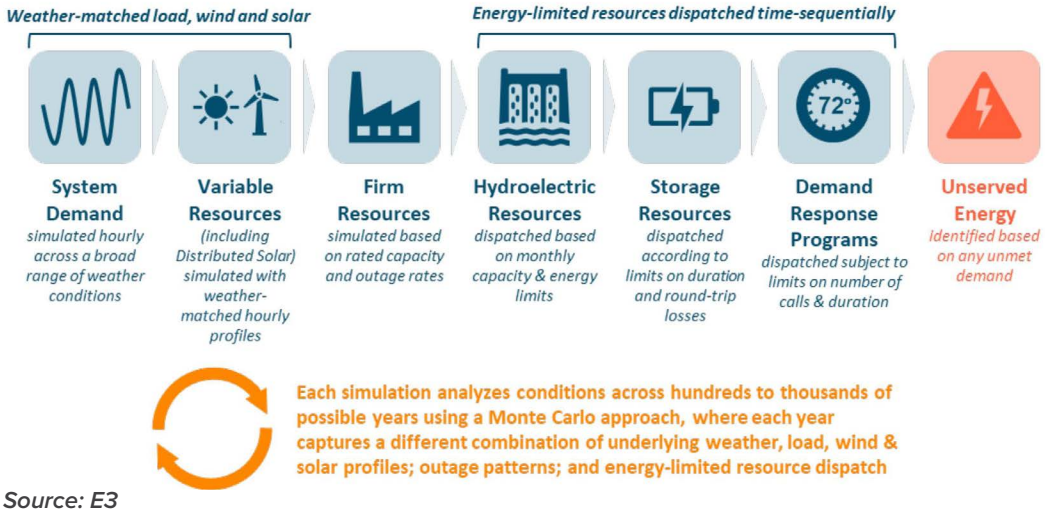
MEETING RELIABILITY TODAY AND IN THE FUTURE

> ***Proposed resource portfolios in Colorado are required to meet or exceed stringent, industry-standard reliability criteria designed to effectively balance cost and reliability.***

For both PUC and non-PUC-regulated electric utilities in Colorado, reliability is a non-negotiable outcome. The utility boards, and the PUC, approve a resource plan only if it is reliable. In order to move forward with plant retirements or procurement of new resources, PUC-regulated utilities must first propose only those future portfolios that meet or exceed stringent reliability requirements, and the Commission's review ensures that cost, risk, and operability are all addressed.

Both PUC-regulated and non-PUC-regulated electric utilities conduct detailed, industry-standard resource adequacy studies to test whether there will be sufficient resources to meet demand under a wide range of uncertainties. These uncertainties include higher-than-expected loads, extreme weather, planned and unplanned generator outages, and periods of low wind and solar availability (Figure 4). Through these studies, Colorado utilities ensure that the system meets, at a minimum, the widely used "one day in ten years" reliability criterion, (i.e., a 0.1 days/year Loss-of-Load Expectation, LOLE). This means that after evaluating the resource portfolios against thousands of potential future conditions, the portfolio is shown to meet demand for electricity in all but one day out of 10-years of analysis (or one day out of 3,650 days) and is used as the most common reliability criterion across the United States (see Appendix Table 1).

Figure 4. Illustrative Example of Resource Adequacy Modeling



Source: E3

The resource adequacy criterion is the tool that balances cost and reliability. Eliminating all risk would be prohibitively expensive and technically impractical. Setting the bar too low would expose households, businesses, and industry to unacceptable service disruptions and economic damages. At the approved standard, a rare shortfall event is not a calamitous grid-wide blackout, but rather implementation of controlled, predefined procedures. First, the state's utilities would attempt to import power from neighbors via non-contracted market purchases, then emergency operating procedures, and only as a last resort, brief, controlled rotating outages to preserve the reliability of the wider electrical grid. Designing resource portfolios to this criterion ensures Colorado's grid is prepared for credible challenges without over-building and over-charging customers.

While methods and the resource mix continue to evolve, this type of resource adequacy analysis has anchored Colorado's reliability for decades and will continue to guide prudent investment and operations in the years ahead.

LOCAL PLANNING WITH REGIONAL AND FEDERAL OVERSIGHT

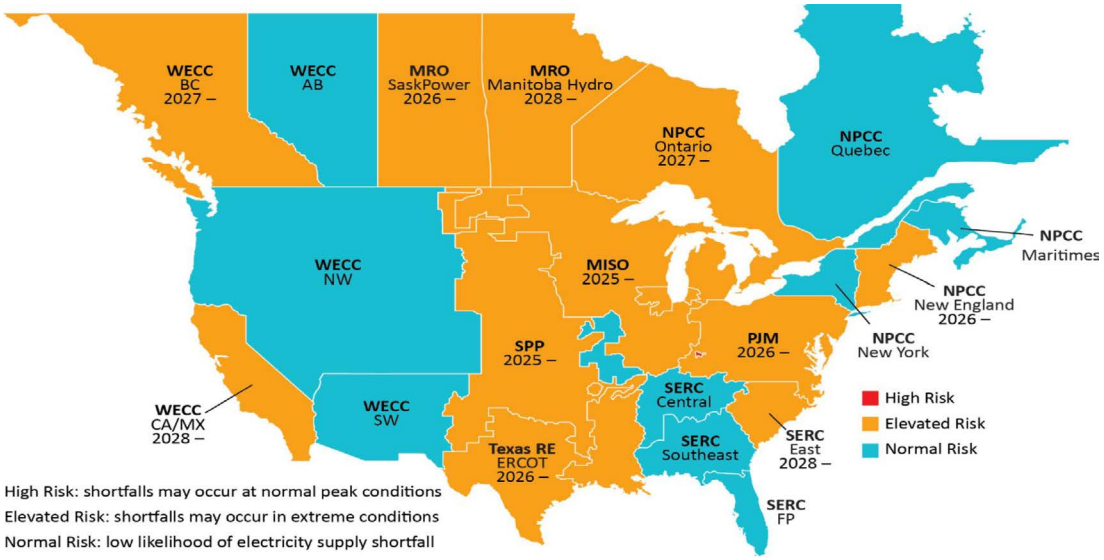
> ***Regional and national reliability assessments as well as resource adequacy frameworks administered by RTOs/ISOs provide additional checks and guidance to support reliable grid planning at the local level.***

Colorado's utility planning (by the utilities, their boards, and the PUC) is complemented by additional checks from national and regional reliability organizations. The North American Electric Reliability Corporation (NERC) and its six Regional Entities together form the Electric Reliability Organization (ERO) Enterprise—the oversight system responsible for keeping the North American

electric power system reliable and secure. The ERO Enterprise develops and enforces reliability standards, monitors compliance, and analyzes grid performance. However, the ERO Enterprise does not set standards for resource adequacy, which is ultimately the responsibility of states.

At the national level, NERC publishes seasonal Summer and Winter Reliability Assessments that evaluate near-term risks, along with an annual Long-Term Reliability Assessment that looks a decade ahead. NERC also conducts a probabilistic resource adequacy assessment to complement its deterministic long-term outlook. In the Western United States, the Western Electricity Coordinating Council (WECC), the Regional Entity with oversight over the Western United States and parts of Canada and Mexico, issues an annual regional reliability assessment of the Western Interconnect (the electrical grid that spans the Western U.S.), the Western Assessment of Resource Adequacy, offering an additional perspective of resource adequacy tailored to the unique circumstances in the West. Because these studies cover large geographies, they are necessarily coarser than a single utility's IRP or resource adequacy study.

Figure 5. Risk Area Summary for the most recent NERC Long-Term Reliability Assessment



Source: NERC LTRA[4]

Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs), where they operate, also play an important function in ensuring resource adequacy. These independent, nonprofit entities manage the high-voltage grid, run wholesale markets, coordinate regional transmission planning, and administer programs that ensure resource adequacy. Although Colorado utilities are not yet part of an ISO or RTO, state law directs transmission utilities to join an organized wholesale market by 2030, and several have announced intentions to do so on an

4 North American Electric Reliability Corporation, *2024 Long Term Reliability Assessment,* December 2024, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf



accelerated timeline, with CSU, PRPA, Tri-State planning to join the Southwest Power Pool (SPP) West RTO in 2026. Within RTO and ISO footprints, resource adequacy is maintained through a mix of market design, accreditation rules, and compliance mechanisms. For example, SPP uses a Resource Adequacy Requirement (RAR) framework under which each load-serving entity submits an annual plan; SPP reviews those plans, conducts its own assessments, and requires entities with deficiencies to procure additional accredited capacity or face penalties. ISOs and RTOs also determine planning reserve margins and establish how different resource types count toward those requirements—assumptions that utilities commonly reference in their own resource adequacy analyses.

Taken together, state-level electric resource plans, utility resource adequacy studies, and the broader checks provided by NERC, Regional Entities, and ISOs/RTOs create multiple layers of scrutiny around the resource adequacy of the electric power system. This layered approach ensures that Colorado's power plant retirements and portfolio changes proceed with clear reliability guardrails at the utility, state, and regional levels.

RESOURCE ADEQUACY METHODS

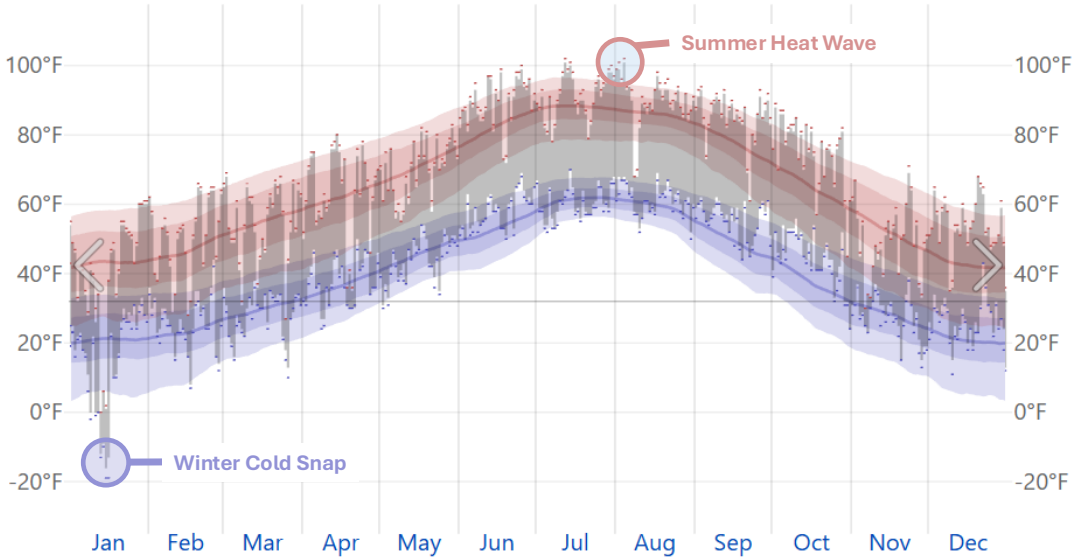
Overview of Resource Adequacy Methods

> ***Contemporary resource adequacy modeling relies on advanced, probabilistic methods that evaluate millions of operational hours reflecting diverse weather, load and outage conditions, producing a statistically robust picture of reliability risk.***

Each of the Colorado utilities use probabilistic grid modeling to test whether future portfolios maintain reliability under a wide range of real-world conditions. Rather than rely on a single "average" year of weather data, planners replay decades of historical weather, or "weather years," against a future power system to see how it would perform if those conditions occurred again. These simulations leverage detailed weather datasets from National Oceanic and Atmospheric Administration (NOAA), Department of Energy national laboratories, and in-state

measurements. This weather data is translated into power system variables; temperatures are used to estimate electricity demand arising for heating and cooling demand, reflecting the potential heat waves and cold snaps that challenge utility operations. Wind speeds and solar irradiance are used to estimate power production from renewable plants so that variability, uncertainty, and renewable "lulls" are accurately reflected.

Figure 6. 2024 temperature profile for Denver, including examples of weather events evaluated in resource adequacy analysis



The daily range of reported temperatures (gray bars) and 24-hour highs (red ticks) and lows (blue ticks), placed over the daily average high (faint red line) and low (faint blue line) temperature, with 25th to 75th and 10th to 90th percentile bands.

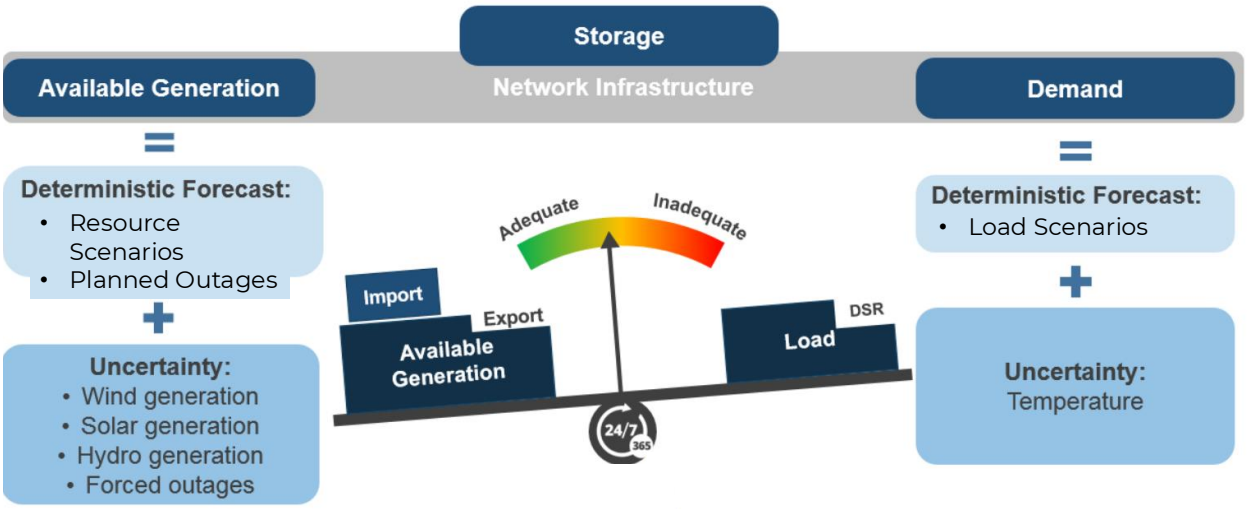
Source: WeatherSpark[5]

Reliability modeling also incorporates random sampling of generator outages, recognizing that units sometimes fail without warning. Hundreds of statistically drawn outage patterns are layered onto each weather year to reflect the chance that multiple plants are unavailable simultaneously. This is particularly important for large, aging coal and gas plants: when a single, large power plant trips offline, the sudden, unexpected loss of capacity can create much larger adequacy risk than natural variability from wind and solar.

Uncertainty in future load growth is also evaluated through higher-and lower-demand cases, and simulations include operating reserves that utilities must carry to cover grid emergencies and minute-to-minute and hour-to-hour fluctuations in electricity supply and demand.

5 WeatherSpark, *2024 Weather History in Denver,* https://weatherspark.com/h/y/3709/2024/Historical-Weather-during-2024-in-Denver-Colorado-United-States#Figures-Temperature

Figure 7. Overview of resource adequacy modeling



Source: adapted from ENTSO-E[6]

Taken together, these detailed simulations combine many weather years, hundreds of generator outage draws, and multiple load trajectories. The result is an evaluation of millions of operational hours, producing a statistically robust picture of reliability risk and the contribution of each resource type to meeting reliability needs. Utilities then use this information to develop two key assumptions for their resource plans:

1. **Planning Reserve Margin:** The total capacity needed, above and beyond the maximum forecasted demand, to serve as a reliability buffer to manage uncertainty in demand, generator outages, wind and solar variability, and drought conditions.

2. **Capacity Accreditation:** The relative reliability contribution of each generating resource and how much its "firm capacity" counts towards the planning reserve margin.

Quantifying System Needs and Resource Contributions

> ***Grid planners have developed sophisticated accounting methods to make apples-to-apples comparisons of the reliability contributions of diverse resource types, such as between thermal power plants and variable renewables like wind and solar. This allows them to confidently develop portfolios of replacement resources that meet or exceed the resource adequacy value of retiring capacity.***

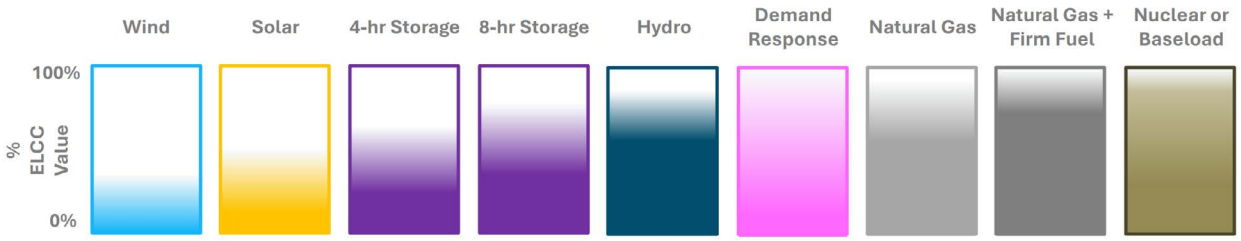
The planning reserve margin quantifies the total firm capacity the utility must have available to meet reliability targets; it is commonly expressed as a percentage above the system's forecast peak demand. For example, if a utility's peak demand is 10 GW and the Commission-approved

6 ENTSO-E, *2024 European Resource Adequacy Assessment, Annex 2: Methodology,* 2024, https://www.entsoe.eu/eraa/2024/downloads/

PRM is 15%, the utility would need 15 GW of accredited firm capacity. This surplus provides a buffer for higher-than-expected load, periods of low wind and solar output, and unexpected generator outages. In other words, all of Colorado's utilities are following industry-standard practice of procuring resources above and beyond their expected peak load to cover for challenging grid conditions and ensure reliability.

Capacity accreditation then determines how much each resource contributes toward that firm capacity requirement. Using probabilistic methods (e.g., Effective Load Carrying Capability, or ELCC), planners estimate the fraction of nameplate capacity that is likely to be available when the system is at greatest risk. For example, a 100-MW solar plant may contribute 70 MW of "firm capacity" if reliability risk hours occur in a summer afternoon, but may only contribute 5 MW of "firm capacity" if critical risk hours occur after sunset or during winter mornings with limited solar availability. Similarly, a 100-MW coal plant may only count as 70 MW of firm capacity, because planners know, at times, the plant will be offline during risk periods due to unplanned outages. Batteries, wind, hydro, demand response, and other fossil fuel plants each receive analogous accreditations that reflect their performance during reliability-critical hours.

Figure 8. Illustrative Comparison of Firm Capacity Contribution (ELCC) of Different Resource Types



Source: E3[7]

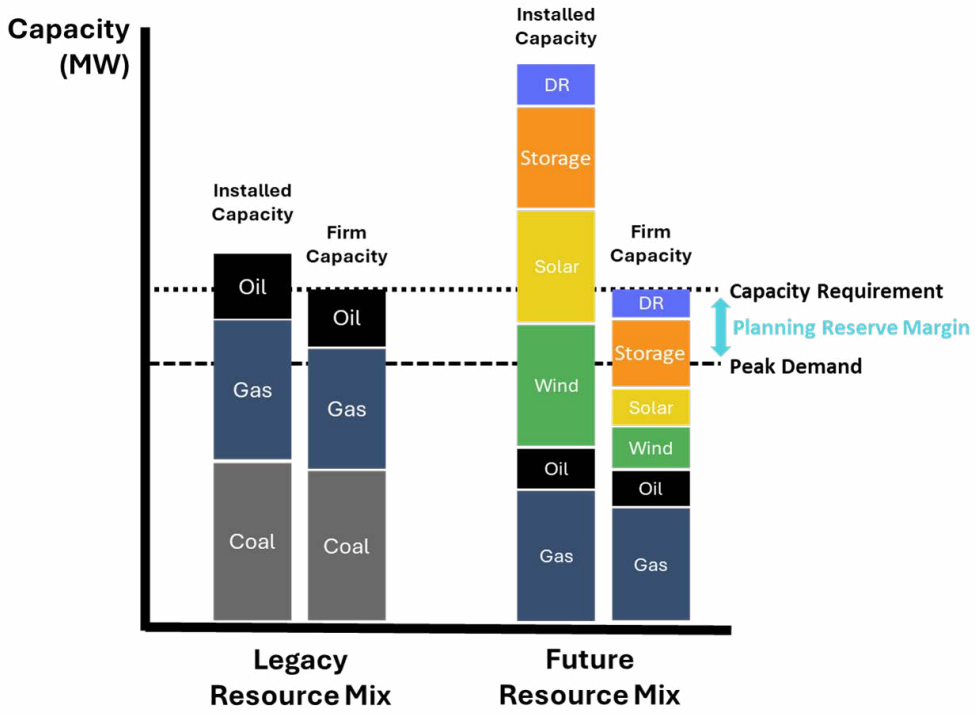
With the PRM defining the total need and accreditation defining each resource's contribution, portfolios can be compared on an apples-to-apples reliability basis. If the utility needs 100 MW of additional firm capacity, one option might be ~120 MW of new simple-cycle gas turbines that provide 100 MW of firm capacity after accounting for the possibility of unplanned outages; another could be a portfolio such as 80 MW of battery storage, 80 MW of solar, and 40 MW of wind that—after accreditation—also sums to 100 MW of firm capacity. While the operational profiles and costs differ—addressed elsewhere in the ERP through production cost modeling and rate impact analysis—capacity accreditation ensures both portfolios meet the same reliability standard.

The same framework governs retirements. If a 500-MW coal unit is slated for retirement, its accredited capacity can be replaced by a combination of resources—storage, renewables,

7 E3, Resource Adequacy for the Energy Transition: *A Critical Periods Reliability Framework and its Applications in Planning and Markets*, August 2025, https://www.ethree.com/wp-content/uploads/2025/08/E3_Critical-Periods-Reliability-Framework_White-Paper.pdf

demand response, and, where appropriate, new gas capacity—so that the sum of accredited contributions equals or exceeds the retiring unit's accredited value, preserving system adequacy.

Figure 9. Planning Reserve Margin Framework Accrediting All Resource Types



Ensuring New Portfolios are Operable

> ***Operational modeling ensures that resource portfolios don't just replace the firm capacity of retiring generation, but provide for safe and reliable grid operations in both normal and contingency conditions.***

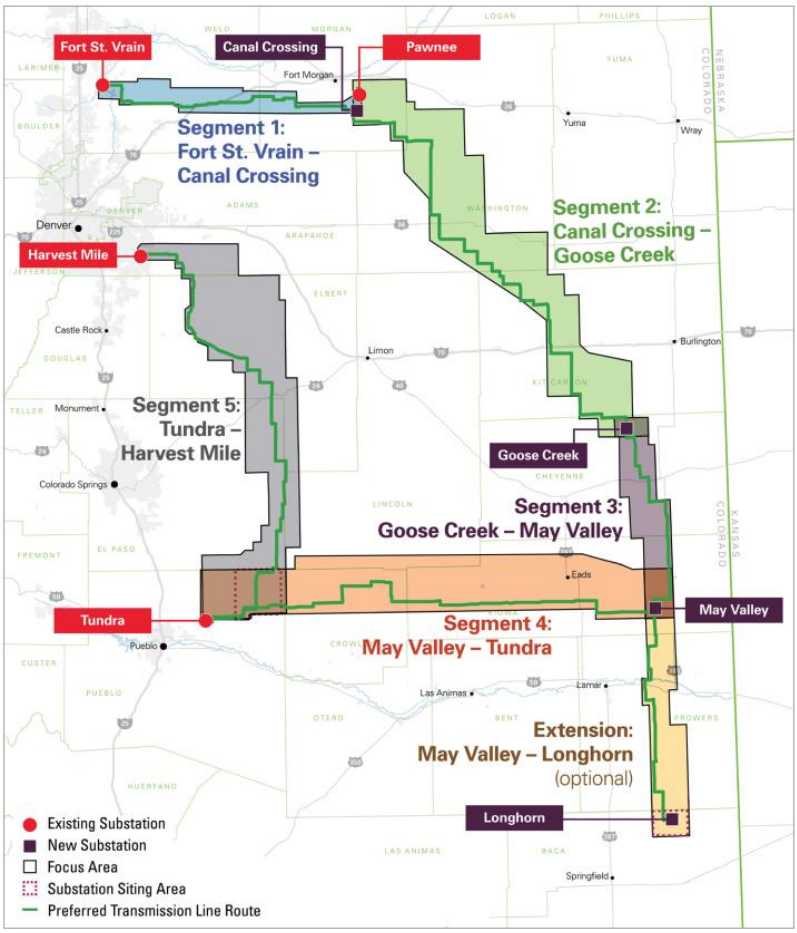
Beyond proving that future portfolios have enough accredited capacity to meet the planning reserve margin, Colorado utilities test whether those portfolios can actually operate safely and reliably by simulating the lowest-cost production of energy to meet hour-to-hour demand. These "production cost simulations" verify that the mix of resources can follow rapid increases or decreases in demand, maintain required operating reserves (e.g., regulation, spinning, non-spinning) to respond to hour-by-hour and minute-by-minute fluctuations in demand and generation availability, charge and discharge storage, and accommodate the variability and uncertainty of wind and solar. They also check that constraints such as transmission line rates, minimum up/down times, start times, fuel limits, maintenance schedules, and emissions constraints are honored so the portfolio remains operable under real-world conditions.

Operability and reliability depends on the transmission system as much as on generation. Along with the production cost simulations, utilities perform transmission reliability and security

analysis to confirm that power can be delivered from plants to loads while withstanding credible contingencies like an unexpected transmission line fault, a transformer outage, generator outage, or load disconnection. In doing so they ensure transmission line loading, voltage profiles, and stability margins are within the reliable range and identify any upgrades needed to maintain reliability. They also assess deliverability of new resources and sufficient transmission to serve new loads.

In addition to targeted reliability upgrades tied to plant retirements and new interconnections for load and generation, PSCo is also building the Colorado Power Pathway, a 345-kV, 600-mile transmission "backbone" to move new generation from the Eastern Plains to Front Range load centers. The project was approved by the Colorado PUC and is intended to improve reliability and resilience while demonstrating how coordinated generation and transmission planning can meet the state's reliability and policy goals.

Figure 10. Colorado's Power Pathway Transmission Investment



Source: Xcel Colorado[8]

8 Public Service of Colorado (Xcel Energy), *Colorado's Power Pathway,* _

As power plants retire and inverter-based resources grow, utilities increasingly assess operational attributes such as ramping headroom, inertia and frequency response, reactive power and voltage support, and black-start capability. Grid-forming inverter capabilities, synchronous condensers, and targeted upgrades are evaluated where needed to maintain stability and restore capability. Together, these operability checks ensure portfolios do not only meet the capacity requirement on paper but can be operated and delivered reliably in real time, across seasons, and under stressed system conditions.

Stress Testing of Extreme Weather Events

> ***Colorado utilities implement industry-leading approaches to stress test resource portfolios under extreme weather and operating conditions, complementing probabilistic modeling to provide further confidence of portfolio reliability even during the grid's most demanding periods.***

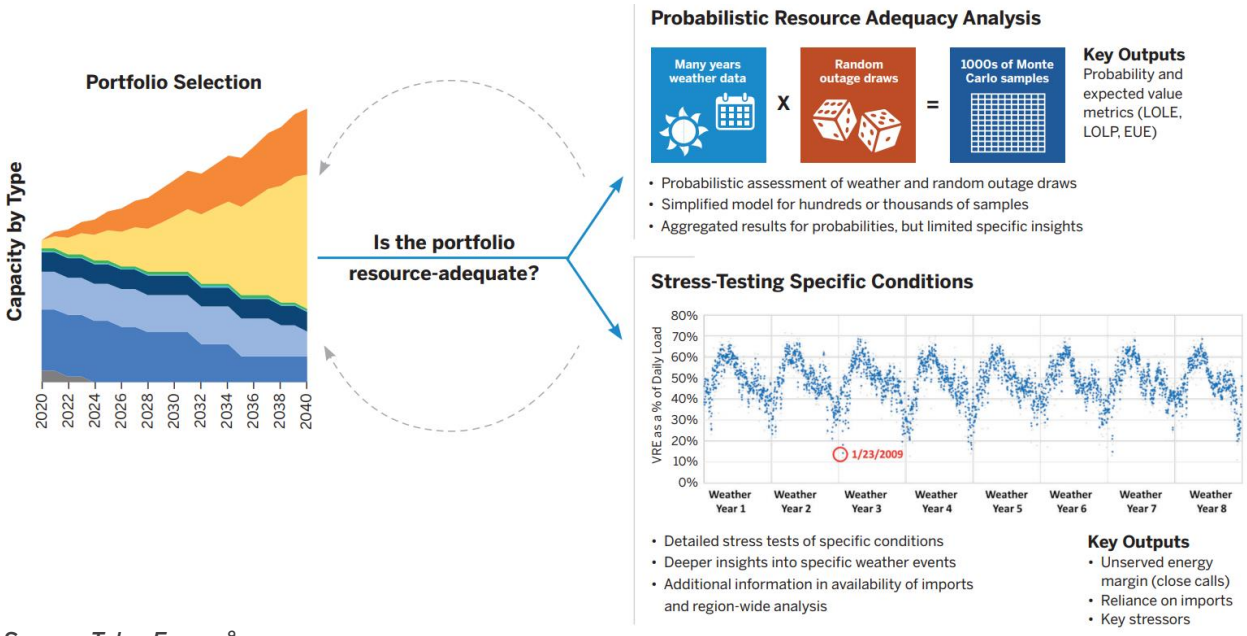
Colorado utilities are augmenting traditional probabilistic resource adequacy studies with targeted extreme weather event "stress tests." While probabilistic methods already simulate decades of historical weather to measure reliability, extreme weather stress testing zooms in on a handful of challenging episodes like multi-day cold snaps, heat waves, wildfires, and renewable lulls. This analysis answers a stricter question: can the future portfolio operate through the worst combinations of load, renewable output, and outages without unacceptable consequences?

This two-step process has been adopted in recent Colorado PUC proceedings by both PSCo and Tri-State. First, portfolios are screened to meet the standard adequacy criterion (e.g., 0.1 days/year LOLE) under many years of weather. Second, the same portfolios are "stress-tested" against selected extreme weather events in production cost simulations to probe multi-day energy



sufficiency under severe challenging conditions. Key outputs include unserved-energy hours (if any), depth of storage drawdown, reliance on market purchases, and any incremental mitigation needs. This layered approach improves confidence that portfolios are robust not only on average but also at the extremes—the very conditions that matter most to customers and system resilience. An illustrative example of this two-stage approach is provided in Figure 11, with a flow diagram of the process used in the Public Service Colorado Just Transition Solicitation provided in the Appendix Figure 12. The Tri-State ERP also includes a similar stress testing approach.

Figure 11. Two-stage approach to ensuring reliability, combining resource adequacy and stress testing



Source: Telos Energy[9]

EXPERT-DRIVEN, STAKEHOLDER REVIEWED PROCESS

> ***Resource additions and retirements are evaluated through proceedings featuring expert engagement as well as stakeholder review to safeguard reliability.***

While utilities lead the electric resource planning process, much of the resource adequacy work is performed by independent, third-party consultants with specialized expertise in probabilistic modeling and power system planning. These firms maintain state-of-the-art tools, continuously refresh weather and outage datasets, and incorporate emerging best practices from proceedings

9 Telos Energy, *Reliably Reaching California's Clean Electricity Targets: Stress Testing Accelerated 2030 Clean Portfolios,* a GridLab report, May 2022, https://gridlab.org/california-2030-study/

across the country. Their methods—spanning multi-decade weather assessment, Monte Carlo outage sampling, and ELCC-based accreditation—provide a consistent, transparent basis for comparing portfolios on reliability, cost, and risk. In general, both PUC-regulated and non-PUC-regulated make the consultant reports and technical appendices they rely on publicly available, though some portions may be redacted to protect competitively-sensitive material. A list of these reports is provided below:

- **Public Service of Colorado, 2024 Resource Adequacy Study**
- **Platte River Power Authority: Reserve Margin and ELCC Study**
- **Tri-State, Reserve Margin and Effective Load Carrying Capability (ELCC) Study**

For non-PUC-regulated utilities, any consultant studies that are made publicly available can be reviewed and commented on by stakeholders. For PUC-regulated utilities, consultant studies are reviewed in a litigated proceeding at the Public Utilities Commission. Typically, a diverse set of stakeholders—consumer advocates, environmental and community organizations, large customers, independent power producers, and local governments—intervene in electric resource plan proceedings at the PUC and often retain their own nationally-recognized experts. While these stakeholders may have different views on the types of resources that should be procured, the pace of change, or the costs that are reasonable, all of them agree on one thing: reliability is a crucial component of resource planning. These experts review datasets and model code where appropriate, run independent analyses, file testimony, and cross-examine utility witnesses, creating a robust peer-review environment that evaluates assumptions and results against national standards.[10]

Crucially, no portfolio is implemented without approval from the utility's board (for CSU and PRPA) or the PUC (for PSCo and Tri-State). For CSU and PRPA, their utility board reviews and approves a preferred portfolio after considering reliability, among other factors. For PSCo and Tri-State, the Colorado Public Utilities Commission evaluates whether proposed plans meet reliability requirements, align with statutory objectives, and prudently balance cost and risk. Commission decisions in Phase I establish modeling parameters and need; Phase II involves a competitive, all-source procurement and PUC approval of a portfolio that conforms to approved reliability criteria. This expert-driven, stakeholder-reviewed, and regulator-approved structure is designed to safeguard reliability.

10 For examples, see 23A-0585E, Hearing Exhibit 701, Public Answer Testimony of Derek Stenclik, May 2024, https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=1021320&p_session_id= and 24A-0442E, Hearing Exhibit 801, Public Answer Testimony of Derek Stenclik_Redacted, https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=1039708&p_session_id=

CONCLUSIONS

> ***Time-tested regulatory criteria, advanced modeling, and regulatory oversight come together to ensure that Colorado's electric system is reliable.***

Colorado's utilities are retiring aging power plants and new generating and storage resources (including new natural gas-fired power plants) through a planning framework that keeps reliability at the forefront. This is not planning by assertion. Utilities file detailed analyses that are scrutinized by independent experts, contested by a broad stakeholder community, and ultimately approved by either their board (for CSU and PRPA) or the Colorado Public Utilities Commission (for PSCo and Tri-State)in a transparent, two-phase proceeding. The process requires portfolios to meet stringent adequacy criteria, demonstrate hour-to-hour operability, and withstand extreme-weather stress tests before procurements move forward. And it occurs in a regional and national context where reliability is being re-assessed year after year by reliability organizations, ensuring that local planners can stay well ahead of seasonal and long-term trends that could threaten reliability.

Colorado's electric grid is evolving but the planning needs remain constant. With modern tools, rigorous accreditation of resource contributions, and regulatory oversight, the state is positioned to maintain, or even improve, the reliability of Colorado's electric grid.

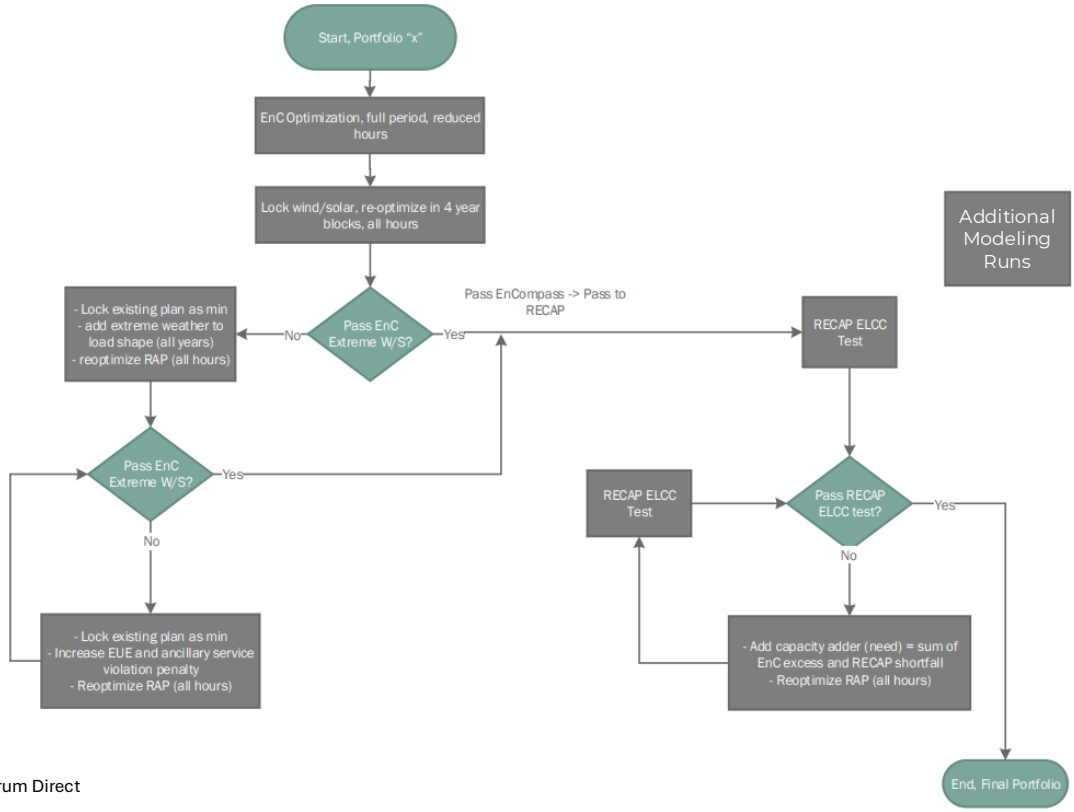
APPENDIX

Table 1. Resource Adequacy Criterion for Select Utilities & Jurisdictions

Category	Utility/Jurisdiction	Metric	Current Standard
Western Utilities	Arizona Public Service Co	LOLE	0.1 days per year
	Avista Corporation	aLOLP[1]	5% per year
	Black Hills Energy	LOLE	0.1 days per year
	El Paso Electric Co[2]	LOLE	0.2 days per year
	Idaho Power Company	LOLE	0.1 days per year
	NV Energy	LOLE	0.1 days per year
	Portland General Electric	LOLH	2.4 hours per year
	Public Service Company of Colorado	LOLE	0.1 days per year
	Public Service Company of New Mexico	LOLE	0.1 days per year
	Puget Sound Energy	aLOLP[1]	5% per year
	Salt River Project	LOLH	2.4 hours per year
	Tucson Electric Co[3]	PRM	15%
Other Utilities	Dominion Energy South Carolina	LOLE	0.1 days per year
	Duke Energy Carolinas	LOLE	0.1 days per year
	Duke Energy Progress	LOLE	0.1 days per year
	Florida Power & Light	LOLE	0.1 days per year
	Georgia Power Co	LOLE	0.1 days per year
	Nova Scotia Power, Inc.	LOLE	0.1 days per year
RTOs & Resource Adequacy Programs	California Public Utilities Commission	LOLE	0.1 days per year
	ISO New England	LOLE	0.1 days per year
	Midcontinent ISO	LOLE	0.1 days per year
	New York ISO	LOLE	0.1 days per year
	PJM	LOLE	0.1 days per year
	Southwest Power Pool	LOLE	0.1 days per year
	Western Resource Adequacy Program[5]	LOLE	0.1 days per year

Source: Public Service of Colorado 2024 Just Transition Solicitation, Direct Testimony of Zachargy Ming

Figure 12. Public Service of Colorado, Enhanced Reliability Rubric and Portfolio Backcheck



CO JTS, Landrum Direct

Source: 2025 Just Transition Solicitation, Direct Testimony of Jon T. Landrum

Table 2. Public Service Company of Colorado, 2024 Just Transition Solicitation Procedural Schedule

Milestone	Summary	Scheduled Completion Date
Application Filed	Filed date of the Application	October 15, 2024
Application Deemed Complete	Date the Commission decides the Application has all the information required by rule to support the request. This date starts the decision deadline - either 120 days or 250 days after the Application is deemed complete.	November 30, 2024
Supplemental Direct Testimony	The Commission may order supplemental direct testimony be filed by the Applicant if it believes that more information is necessary to complete the record regarding the requested action.	January 31, 2025
Public Comment Hearing	Public Comment Hearings can be virtual and/or in person hearings. The public is allowed to comment orally on the rate change and requested actions.	April 17, 2025 (in-person at Pueblo) April 28, 2025 (remote) May 1, 2025 (in-person at Hayden) June 5, 2025 (remote)
Answer Testimony	Testimony filed by parties to the proceeding to present their perspectives on the Application and requested actions.	April 18, 2025
Technical Conference	Sometimes used to better understand the Application and its impacts to customers.	March 13, 2025
Rebuttal & Cross-Answer Testimony	Testimony filed by the Applicant (Rebuttal) and parties (cross-answer) in response to the Answer Testimony.	May 23, 2025
Stipulations/Settlement Agreements	Agreements on parts or all the issues presented in the Application.	June 2, 2025
Evidentiary Hearing	Hearing held on the merits of the Application. All parties and the Applicant provide oral testimony in response to cross-examination by other parties and the Commission.	Beginning June 10, 2025
Statements of Position	Final legal statements from the Applicant and all parties.	July 17, 2025
Commission Decision	Final ruling on all issues presented in the proceeding.	Expected Fall 2025

Source: Colorado Public Utilities Commission[11]

11 Colorado Public Utilities Commission, *Electric Resource Plans,* https://puc.colorado.gov/puc-home/energy-and-water/electric-resource-plans/clean-energy-plan

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-06:
Tri-State December 2025 Press Release

12/31/25

U.S. DOE orders Tri-State to keep Craig Generating Station unit operating for next 90 days

(December 31, 2025 – Westminster, Colorado) Tri-State Generation and Transmission Association and the other utilities that co-own Craig Generating Station Unit 1 received an emergency order from the U.S. Department of Energy (DOE) under Section 202(c) of the Federal Power Act identifying an energy emergency in the Western Electricity Coordinating Council Northwest area and directing Tri-State to keep Unit 1 available to operate at the direction of either the Western Area Power Administration (WAPA)—Rocky Mountain Region Western Area Colorado Missouri (WACM) in its role as Balancing Authority or the Southwest Power Pool (SPP) West in its role as the Reliability Coordinator, for the next 90 days.

Since 2016, Unit 1 has been scheduled for retirement by Dec. 31, 2025, for economic reasons, and to comply with numerous state and federal requirements. This retirement decision has informed operational and maintenance decisions, and Tri-State has planned for adequate resources to maintain reliability on its system following the unit's retirement.

Separately, Unit 1 went into an outage on Dec. 19, 2025, due to a mechanical failure of a valve, and Tri-State and the other co-owners will need to take the necessary steps to repair the valve in a timely manner.

"Tri-State has a policy of 100% compliance, and we will work with Unit 1 co-owners, and federal and state governments to determine the most cost-effective path to that end," said Duane Highley, Tri-State CEO. "We are continuing to review the order to determine what this means for Craig Station employees and operations, and the financial impacts. As a not-for-profit cooperative, our membership will bear the costs of compliance with this order unless we can identify a method to share costs with those in the region. There is not a clear path for doing so, but we will continue to evaluate our options ´

As a result of the order, retaining Unit 1 will likely require additional investments in operations, repairs, maintenance and, potentially, fuel supply, all factors increasing costs. Tri-State is continuing to review the order to determine how best to comply while limiting the costs to its members, and the impacts to its employees and operations.

The retirement of Craig Unit 1 was specified in Colorado Air Quality Control Commission Regulation No. 23 on Regional Haze Limits, and the Regional Haze State Implementation Plan put in place in 2016. Tri-State's 2020 and 2023 Electric Resource Plan (ERP) modeling reflected the previously announced retirement date for Unit 1. The model results of the 2023 ERP showed adequate resources to maintain reliability on Tri-State's system following the retirement of Craig Station.

Craig Units 1 and 2 are part of the Yampa Project, jointly owned with multiple utility services providers including Tri-State, Platte River Power Authority, PacifiCorp, Xcel Energy and Salt River Project, with Tri-State as the operating entity. Tri-State owns 100% of Unit 3. Craig Unit 1's capacity is 427 megawatts. Unit 2, with a capacity of 410 megawatts, and Unit 3, with a capacity of 448 megawatts, are scheduled to retire in 2028.

Tri-State will share more information as appropriate when available.

About Tri-State

Tri-State is a power supply cooperative, operating on a not-for-profit basis, serving electric distribution cooperatives and public power district member-owners in four states. Together with our members, we deliver reliable, affordable and responsible power to more than a million electricity consumers across nearly 200,000 square miles of the rural West. Visit www.tristate.coop.

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-07:
NERC 2024 Long-Term Reliability Assessment

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2024 Long-Term Reliability Assessment

December 2024

Corrected July 11, 2025



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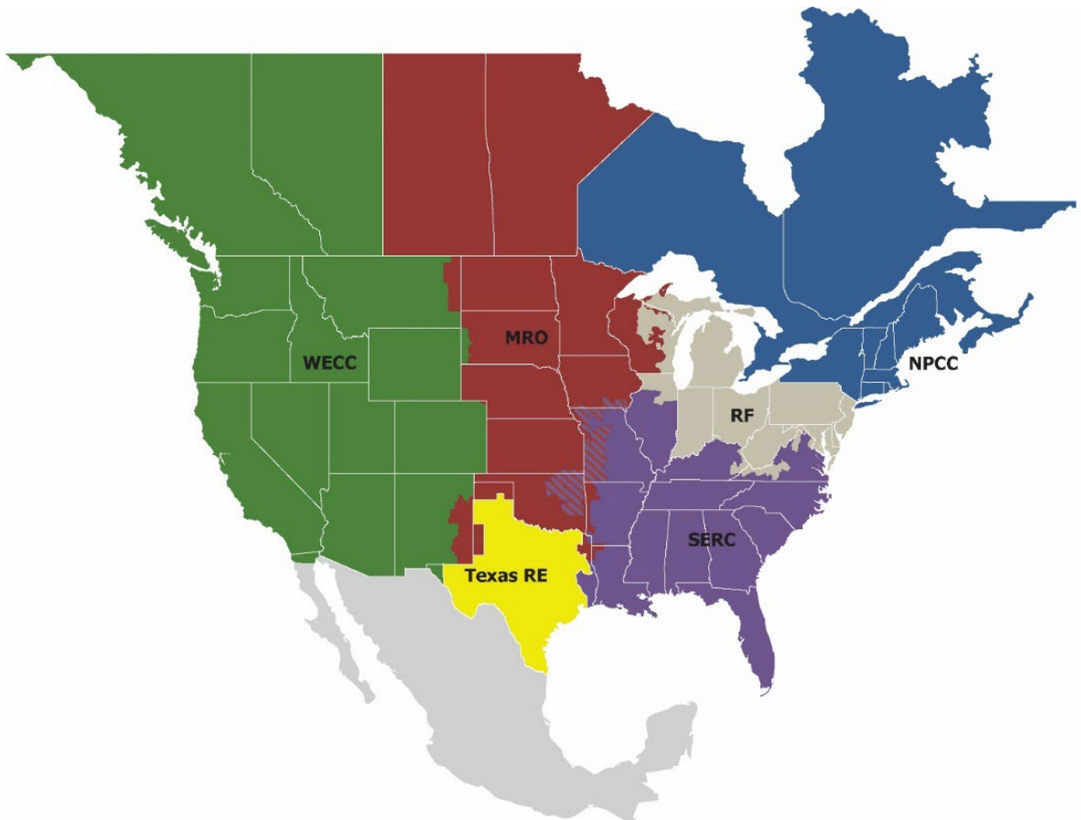
Preface

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

Reliability | Resilience | Security

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

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



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

About This Assessment

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

Development Process

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

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

Considerations

This assessment was developed by using a consistent approach for projecting future resource adequacy through the application of the ERO Reliability Assessment Process.[5] Projections in this assessment are not predictions of what will happen; they are based on information supplied in July 2024 about known system changes with updates incorporated prior to publication. This *2024 LTRA* assessment period includes projections for 2025–2034; however, some figures and tables examine data and information for the 2024 year. 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 Resource Categories** section of this report. Reliability impacts related to cyber and physical security risks are not specifically addressed in this assessment; it is primarily focused on resource adequacy and operating reliability. NERC leads a multi-faceted approach through NERC's Electricity Information Sharing and Analysis Center (E-ISAC) to promote mechanisms to address physical and cyber security risks, including exercises and information-sharing efforts with the electric industry.

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

[1] NERC Rules of Procedure - Section 803

[2] Section 39.11(b) of FERC's regulations states the following: "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

[3] Title 18, § 39.11 of the Code of Federal Regulations

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

[5] ERO Reliability Assessment Process Document

Assumptions

In this *2024 LTRA*, the baseline information on future electricity supply and demand is based on several assumptions:[6]

- Supply and demand projections are based on industry forecasts submitted and validated in July 2024. Any subsequent demand forecast or resource plan changes may not be fully represented; however, updated data submitted throughout the report drafting time frame have been included where appropriate.
- Peak demand is based on average peak weather conditions and assumed forecast economic activity at the time of submittal. Weather variability is discussed in each Regional Entity's self-assessment.
- Generation and transmission equipment will perform at historical availability levels.
- Future generation and transmission facilities are commissioned and in service as planned, planned outages take place as scheduled, and retirements take place as proposed.
- Demand reductions expected from dispatchable and controllable DR programs will yield the forecast results if they are called on.
- Other peak demand-side management programs, such as energy efficiency (EE) and price-responsive DR, are reflected in the forecasts of total internal demand.

Reading this Report

This report is compiled into two major parts:

1. **A reliability assessment of the North American BPS with the following goals:**
   a. Evaluate industry preparations that are in place to meet projections and maintain reliability
   b. Identify trends in demand, supply, reserve margins, and probabilistic resource adequacy metrics
   c. Identify emerging reliability issues
   d. Focus the industry, policymakers, and the general public's attention on BPS reliability issues
   e. Make recommendations based on an independent NERC reliability assessment process
2. **A regional reliability assessment that contains the following:**
   a. A 10-year data dashboard
   b. Summary assessments for each assessment area
   c. A focus on specific issues identified through industry data and emerging issues
   d. A description of regional planning processes and methods used to ensure reliability

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

Executive Summary

In the *2024 LTRA*, NERC finds that most of the North American BPS faces mounting resource adequacy challenges over the next 10 years as surging demand growth continues and thermal generators announce plans for retirement. New solar PV, battery, and hybrid resources continue to flood interconnection queues, but completion rates are lagging behind the need for new generation. Furthermore, the performance of these replacement resources is more variable and weather-dependent than the generators they are replacing. As a result, less overall capacity (dispatchable capacity in particular) is being added to the system than what was projected and needed to meet future demand. **The trends point to critical reliability challenges facing the industry: satisfying escalating energy growth, managing generator retirements, and accelerating resource and transmission development.**

This *2024 LTRA* is the ERO's independent assessment and comprehensive report on the adequacy of planned BPS resources to reliably meet the electricity demand across North America over the next 10 years; it also identifies reliability trends, emerging issues, and potential risks that could impact the long-term reliability, resilience, and security of the BPS. The findings presented here are vitally important to understanding the reliability risks to the North American BPS as it is currently planned and being influenced by government policies, regulations, consumer preferences, and economic factors. Summaries of the report sections are provided below.

Capacity and Energy Risk Assessment

The **Capacity and Energy Risk Assessment** section of this report identifies potential future electricity supply shortfalls under normal and extreme weather conditions. NERC's evaluation of resource adequacy in the LTRA considers both the capacity of the resources and the capability of resources to convert inputs (e.g., fuel, wind, and solar irradiance) into electrical energy. NERC used both a probabilistic assessment and a reserve margin analysis to assess the risk of future electricity supply shortfalls. Both are forward-looking snapshots of resource adequacy that are tied to industry forecasts of electricity supplies, demand, and transmission development.

Areas categorized as **High Risk** fall below established resource adequacy criteria in the next five years. High-risk areas are likely to experience a shortfall in electricity supplies at the peak of an average summer or winter season. Extreme weather, producing wide-area heat waves or deep-freeze events, poses an even greater threat to reliability. **Elevated-Risk** areas meet resource adequacy criteria, but analysis indicates that extreme weather conditions are likely to cause a shortfall in area reserves. **Normal-Risk** areas are expected to have sufficient resources under a broad range of assessed conditions. The results of the risk assessment are depicted in **Figure 1**.

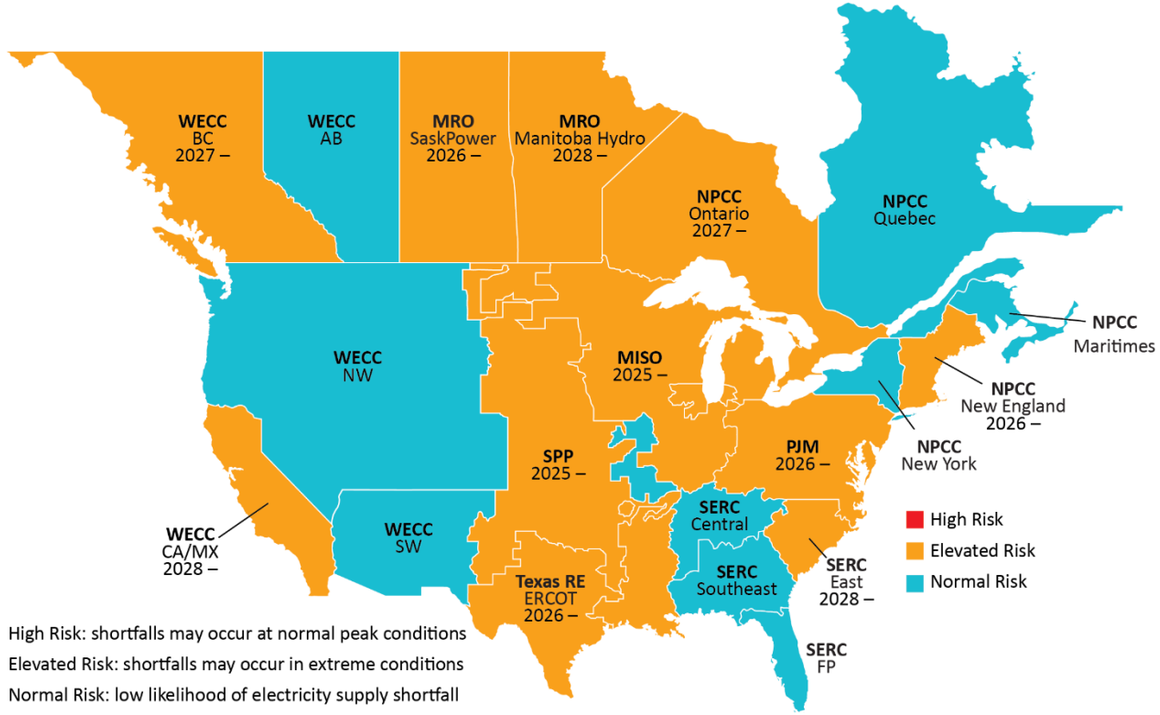


Figure 1: Risk Area Summary 2025–2029 (Corrected July 2025)

Regional Assessments Dashboards

The **Regional Assessments Dashboards** section contains dashboards and summaries for each of the 20 assessment areas, developed from data and narrative information collected by NERC from the six Regional Entities. Probabilistic Assessments (ProbA) are presented that identify energy risk periods and describe the contributing demand and resource factors.

Table 1: Capacity and Energy Risk Assessment Area Summary (Corrected June 2025)			
Area	**Risk Level**	**Years**	**Risk Summary**
MISO	Elevated	2025 -	Uncertainty around new resource additions and existing generator retirements results in resource adequacy risks. Above-normal generator outages during extreme weather can result in unserved energy or load loss.
Manitoba	Elevated	2028 -	Potential resource shortfalls in low-hydro conditions, driven by rising demand.
SaskPower	Elevated	2026 -	Risk of insufficient generation during fall and spring when more generators are off-line for maintenance.
Southwest Power Pool (SPP)	Elevated	2025 -	Potential energy shortfalls during peak summer and winter conditions arise from low wind conditions and natural gas fuel risk.
New England	Elevated	2026 -	Strong demand growth and persistent winter natural gas infrastructure limitations pose risks of supply shortfalls in extreme winter conditions.
Ontario	Elevated	2027 -	Reserve margins fall below RMLs as nuclear units undergo refurbishment and some current resource contracts expire. Demand growth is also adding to resource procurement needs.
PJM	Elevated	2026 -	Resource additions are not keeping up with generator retirements and demand growth. Winter seasons replace summer as the higher-risk periods due to generator performance and fuel supply issues.
SERC-East	Elevated	2028 -	Demand growth and planned generator retirements contribute to growing energy risks. Load is at risk in extreme winter conditions that cause demand to soar while supplies are threatened by generator performance, fuel issues, and inability to obtain emergency transfers.
ERCOT	Elevated	2026 -	Surging load growth is driving resource adequacy concerns as the share of dispatchable resources in the mix struggles to keep pace. Extreme winter weather has the potential to cause the most severe load-loss events.
California-Mexico	Elevated	2028 -	Demand growth and planned generator retirements can result in supply shortfalls during wide-area heat events that limit the supply of energy available for import.
British Columbia	Elevated	2027 -	Drought and extreme cold temperatures in winter can result in periods of insufficient operating reserves when neighboring areas are unable to provide excess energy.

Risk from Additional Generator Retirements

Plans for generator retirements continue at similar pace and scale to levels reported in the *2023 LTRA*. Confirmed generator retirements (52 GW by 2029 and 78 GW over the 10-year period) are accounted for in the Capacity and Energy Risk Assessment above. Economic, policy, and regulatory factors spur further fossil-fired generators to retire in the 10-year horizon. Announced retirements, which include many generators that have not begun formal deactivation processes with planning entities, total 115 GW over the 10-year period. The effect of all retirements on the assessment area Planning Reserve Margins (PRM) can be seen in **Figure 2**. On-peak reserve margins fall below RMLs; the levels required by jurisdictional resource adequacy requirements) in the next 10 years in almost every assessment area, signaling an accelerating need for more resources.

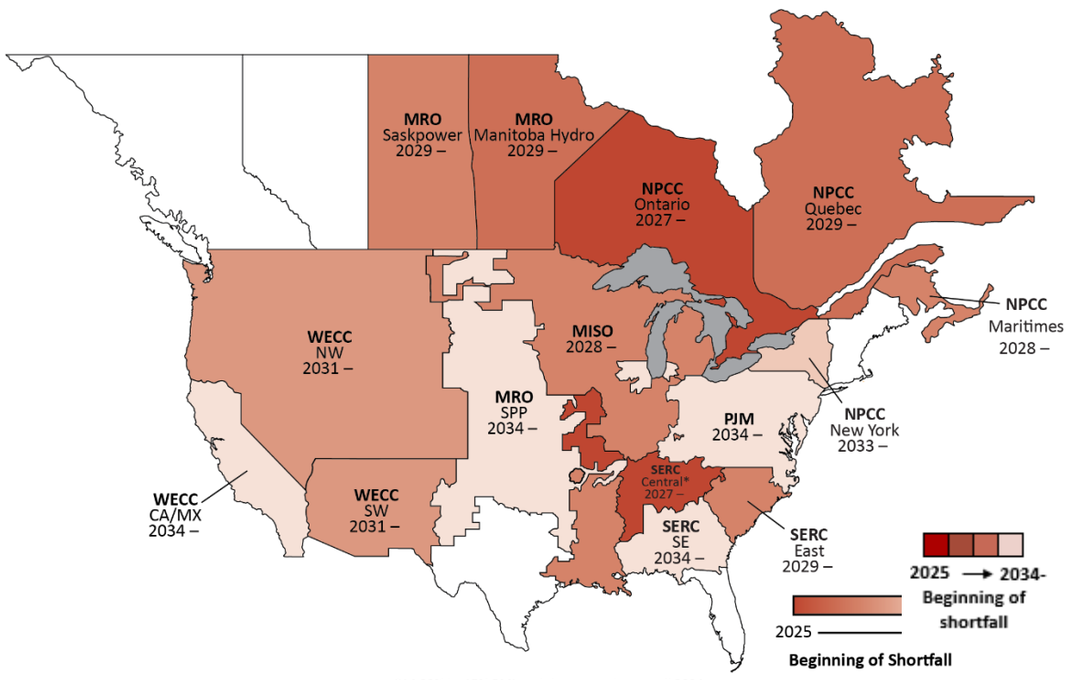


Figure 2: Projected Reserve Margin Shortfall Areas with Announced Generator Retirements (Corrected July 2025)

Changing Resource Mix and Reliability Implications

New resource additions continue at a rapid pace. Solar PV remains the overwhelmingly predominant generation type being added to the BPS followed by battery and hybrid resources, natural-gas-fired generators, and wind turbines. New resource additions fell short of industry's projections from the *2023 LTRA* with the notable exception of batteries, which added more nameplate capacity than was reported in development last year.

As older fossil-fired generators retire and are replaced by more solar PV and wind resources, the resource mix is becoming increasingly variable and weather-dependent. Solar PV, wind, and other variable energy resources (VER) contribute some fraction of their nameplate capacity output to serving demand based on the energy-producing inputs (e.g., solar irradiance, wind speed). The new resources also have different physical and operating characteristics from the generators that they are replacing, affecting the essential reliability services (ERS) that the resource mix provides. As generators are deactivated and replaced by new types of resources, ERS must still be maintained for the grid to operate reliably.

Natural-gas-fired generators are a vital BPS resource. They provide ERSs by ramping up and down to balance a more variable resource mix and are a dispatchable electricity supply for winter and times when wind and solar resources are less capable of serving demand. Natural gas pipeline capacity additions over the past seven years are trending downward, and some areas could experience insufficient pipeline capacity for electric generation during peak periods.

Trends and Reliability Implications

Demand and transmission trends affect long-term reliability and the sufficiency of electricity supplies. A summary for each is provided below and further discussed within the **Demand Trends and Implications** and **Transmission Development and Interregional Transfer Capability** sections.

Demand Trends

Electricity peak demand and energy growth forecasts over the 10-year assessment period continue to climb; demand growth is now higher than at any point in the past two decades. Increasing amounts of large commercial and industrial loads are connecting rapidly to the BPS. The size and speed with which data centers (including crypto and AI) can be constructed and connect to the grid presents unique challenges for demand forecasting and planning for system behavior. Additionally, the continued adoption of electric vehicles and heat pumps is a substantial driver for demand around North America. The aggregated BPS-wide projections for both winter and summer have increased massively over the 10-year period:

- The aggregated assessment area summer peak demand forecast is expected to rise by 15% for the 10-year period: 132 GW this LTRA up from over 80 GW in the *2023 LTRA*.
- The aggregated assessment area winter peak demand forecast is expected to rise over almost 18% for the 10-year period: 149 GW this LTRA up from almost 92 GW in the *2023 LTRA*.

Transmission Trends

For the first time in recent years, transmission projections reported for the LTRA reflect a significant increase in transmission development. This year's cumulative level of 28,275 miles of transmission (>100 kV) in various stages of development for the next 10 years is substantially higher than the *2023 LTRA* 10-year projections (18,675 miles) and is above the average of the past five years of NERC's LTRA reporting on average (18,900 miles of transmission planning projects in each 10-year period published in the last five LTRAs). Transmission in construction has yet to increase substantially; rather, the large increase in transmission projects is seen in planning stages of development.

New transmission projects are being driven to support new generation and enhance reliability. Transmission development continues to be affected by siting and permitting challenges. Of the 1,160 projects that are under construction or in planning for the next 10 years, 68 projects totaling 1,230 miles of new transmission are delayed by siting and permitting issues, according to data collected for the LTRA. Questions of cost allocation and recovery can also challenge transmission development when the benefits apply to more than one area, as often occurs with projects that enhance interregional transfer capability.

In NERC's separate Interregional Transfer Capability Study (ITCS), which was performed to meet requirements contained in the Fiscal Responsibility Act of 2023, NERC found that an additional 35 GW of transfer capability across the United States would strengthen energy adequacy under extreme conditions. Increasing transfer capability between neighboring transmission systems has the potential to alleviate energy shortfalls in some areas identified in this LTRA's **Capacity and Energy Risk Assessment**. Conversely, when resource plans are developed that address these same energy shortfalls, such as through resource additions, demand-side management initiatives, or changes to generator retirement plans, the need for increased transfer capability will also change. Planners have options for reducing energy adequacy risks from extreme weather. Selecting the best course of action will depend on weighing these options against various engineering, economic, policy, reliability, and resilience objectives.

The ITCS provides foundational insights that facilitate stakeholder analysis and actions; it is not a transmission plan. In the future, NERC will extend the study beyond the congressional mandate to include transfer capabilities from the United States to Canada and among Canadian provinces.

Emerging Issues

The **Emerging Issues** section discusses developments and trends that have the potential to substantially change future long-term demand and resource projections, resource availability, and reliable operations of the BPS. Topics include data centers and large industrial loads, battery energy storage systems, electric vehicles and load, and energy drought. NERC's RSTC has formed new task forces where needed to address emerging issues.

Recommendations

To address the energy and capacity risks identified in this LTRA, NERC recommends the following priority actions:

1. **Integrated Resource Planners, market operators, and regulators: Carefully manage generator deactivations.** Independent System Operator/Regional Transmission Organizations (ISO/RTOs) should evaluate mechanisms and process enhancements for obtaining information on expected generator retirements that would support early identification of reliability risks. State and provincial regulators and ISO/RTOs need to have mechanisms they can employ to extend the service of generators seeking to retire when they are needed for reliability, including the management of energy shortfall risks. Regulatory and policy-setting organizations must use their full suite of tools to manage the pace of retirements and ensure that replacement infrastructure can be developed and placed in service.

2. **NERC and Regional Entities: Improve the LTRA by incorporating new analysis and criteria to inform stakeholders of future reliability risks.** NERC increased the frequency of the ProbA from biennial to annual and included unserved energy and load-loss metrics as the basis for risk analysis in this year's LTRA. To be more effective in using energy criteria and outputs of probabilistic analysis, NERC must specify consistent methods and assumptions for assessment areas to follow in preparing the annual ProbA. NERC and the Regional Entities, in consultation with the RSTC, should also continue to enhance NERC's LTRA to assess ERSs in the future system and the potential impact of new and evolving electricity market practices, regulations, or legislation on resource adequacy. Finally, NERC should work with the Regional Entities to perform wide-area energy analysis with modeled interregional transfer capability. Wide-area energy analysis will support the evaluation of extreme weather and regional fuel supply issues on an interconnection level.

3. **Regulators and Policymakers: Streamline siting and permitting processes to remove barriers to resource and transmission development.** As ISO/RTOs continue looking for opportunities to speed transmission planning processes, delays from siting and permitting activities will need to be reduced. These are the most common causes for delayed transmission projects. Support from regulators and policymakers at the federal, state, and provincial levels is urgently needed.

4. **Regulators, electric industry, and gas industry member organizations: Implement a framework for addressing the operating and planning needs of the interconnected natural gas-electric energy system.** Various initiatives were launched in the past year to address the reliability needs that arise from the complexity of interconnecting natural gas and electric infrastructure. Voluntary actions taken by the natural gas industry in response to the North American Energy Standards Board (NAESB) Forum report are a positive step toward improving winter readiness. The National Association of Regulatory Utility Commissioners (NARUC) launched its Gas-Electric Alignment for Reliability (GEAR) task force this year and recently created the Natural Gas Readiness Forum. For its part, NERC continues to collaborate extensively with industry and policymakers. NERC has enhanced its Reliability Standards requiring generators to prepare for winter extremes, implement training, and establish communication protocols between generators and grid operators. Current standards projects encompass extreme weather planning and energy assurance requirements. NERC will continue to provide full support to initiatives aimed at achieving a reliable interconnected energy system and urges regulators and policymakers to support needed avenues of coordination between the two sectors.

5. **Regional transmission organizations, independent system operators, and FERC: Continue to ensure essential reliability services are maintained.** The changing composition of the North American resource mix calls for more robust planning approaches to ensure adequate ERSs.[7] Retiring conventional generation is being replaced with large amounts of wind and solar; planning considerations must adapt with more attention to ERSs. As replacement resources are interconnected, these new resources should be capable of supporting voltage, frequency, ramping, and dispatchability. Many technologies can contribute to ERSs, including variable energy resources; however, policies and market mechanisms need to reflect these requirements to ensure these services are provided and maintained. Regional transmission organizations, independent system operators, and FERC have taken steps in this direction, and these positive steps must continue.

In addition to these priorities, NERC recommends continued progress in areas identified previously in NERC's LTRA and other assessment reports. All recommendations are listed in the **Recommendations and ERO Actions Summary** section.

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

Capacity and Energy Assessment

The resource mix transformation is making traditional capacity-based adequacy criteria obsolete. Resource Planners and state and provincial policymakers use resource adequacy criteria to ensure sufficient resources are available to meet demand. In their application, current capacity-based adequacy criteria were not designed to differentiate between the scenarios, size, frequency, duration, and timing of energy shortfalls. This has become increasingly important as the resource transformation evolves from capacity-based resources with assured and stored energy supplies to energy-constrained resources that are increasingly impacted by weather and environmental conditions. Therefore, supplemental criteria must be adapted to properly assess system adequacy and help determine appropriate solutions. This year's LTRA includes probabilistic indices to measure these additional dimensions of risk and provide a more robust approach to understanding risk of inadequacy in future plans.

Assessment Approach

NERC is using two approaches in this LTRA to assess future resource capacity and energy risk; both are forward-looking snapshots of resource adequacy that are tied to industry forecasts of electricity supplies, demand, and transmission development:

- Assessing load-loss metrics determined from probability-based simulation of projected demand and resource availability over all hours. This approach identifies high-risk periods and potential energy constraints resulting in load-loss events. The 2024 ProbA is performed for each assessment area and examines the system as planned for the years 2026 and 2028. Loss-of-load hours (LOLH) and expected unserved energy (EUE) from NERC's ProbA are used to identify risk levels.
- Comparing the margin between projected resources and peak net demand, or reserve margin, to a reserve margin target (known as RML) that represents the accepted level of risk based on a probability-based loss-of-load analysis.

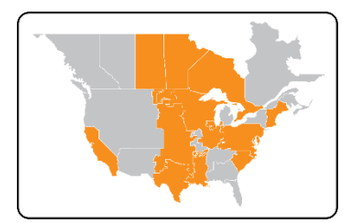
See the **Demand Assumptions and Resource Categories** for further details on these approaches. Assessment area dashboards (see **Regional Assessments Dashboards**) provide resource capacity and energy risk assessment results for all areas.

Risk Categories

An assessment area is **high risk** when established resource adequacy targets or requirements are not met during this assessment period. Regulatory authorities or market operators establish resource adequacy targets. Most targets in North America are currently based on a 1-day/event load loss in a 10-year planning requirement. See the **Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area**. Recently, regulators and policymakers in many states and market areas have begun considering or developing resource adequacy targets based on additional criteria that can better address energy risks and extreme weather-related supply disruption.[8] High-risk areas are likely to experience a shortfall in electricity supplies at the peak of an average summer or winter season. Unusual heat waves or deep-freeze events pose an even greater threat to reliability.

For the *2024 LTRA*, assessment areas are classified as high risk based on an evaluation of the following criteria for each of the first five years of the LTRA period (i.e., 2025–2029):

- Annual LOLH exceeds 2.4 hours/year for one or more years in the ProbA.
- Annual normalized EUE exceeds 0.002% (20 ppm) for one or more years in the ProbA.
- Resource adequacy target(s) established by regulatory authority or market operator are not met.

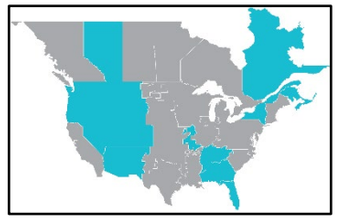


An assessment area is considered an **elevated risk** when it meets the established resource adequacy target or requirement, but probabilistic or deterministic analysis of conditions that are plausible but more extreme than normal seasonal peaks are likely to cause shortfall in area reserves. More extreme conditions can include temperatures that result in above-normal demand levels, low resource output or availability, and/or disruption of normal electricity transfers. In the analysis, elevated risk may be found by modeling above-normal demand and low resource availability. The risk can also be identified by examining output data from probabilistic analysis tools to determine the underlying conditions for load-loss events. Simply put, elevated-risk areas meet resource adequacy requirements but may face challenges meeting load under extreme conditions. For the *2024 LTRA*, assessment areas are classified as elevated risk based on an evaluation of the following criteria for each of the first five years of the LTRA period (i.e., 2025–2029):

- Annual LOLH is between 0.1 and 2.4 hours/year for one or more years in the ProbA.

[8] See the NERC-National Academy of Engineering Workshop Report *Evolving Planning Criteria for a Sustainable Power Grid*.

- Annual normalized EUE is less than 0.002% (20 ppm) but non-zero for one or more years in the ProbA.
- Resource adequacy target(s) established by regulatory authority or market operator are met, but plausible scenarios of above-normal demand and/or low-resource conditions associated with a once-per-decade event indicate risk of load loss.



NERC assesses areas as **normal risk** when resource adequacy criteria are met and there is a low likelihood of electricity supply shortfall even when demand is above forecasts or resource performance is abnormally low (e.g., above-normal forced outages or low VER performance). Although areas categorized as normal risk are expected to have sufficient resources for plausible extreme[9] conditions, they are not immune to the effects of high-impact, low-frequency weather events that affect demand and generation simultaneously. For the *2024 LTRA*, assessment areas are classified as normal risk based on an evaluation of the following criteria for each of the first five years of the LTRA period (i.e., 2025–2029):

- Annual LOLH is below 0.1 hours/year.
- Annual normalized EUE is negligible or zero.
- Resource adequacy target(s) established by regulatory authority or market operator are met and reserves are expected to be available in plausible scenarios of above normal demand and/or low resource conditions associated with a once-per-decade event indicate risk of load loss.

Application of the Risk Criteria: NERC uses industry-provided demand and resource information and the results from probabilistic assessments performed by NERC Regional Entities, ISO/RTOs, and regulated utilities to determine risk of energy and capacity shortfalls. The methods, assumptions, and approaches used by entities to perform probabilistic assessments affect the results and outputs. In this year's LTRA, NERC incorporated new probabilistic assessment criteria (LOLH and EUE) from the NERC-National Academy of Engineering Workshop Report *Evolving Planning Criteria for a Sustainable Power Grid* alongside established reserve margin criteria. In instances where an assessment area's probabilistic assessment results and reserve margins give mixed indications as to the risk category, adherence to resource adequacy targets (e.g., required RML and load-loss criteria) established by regulatory jurisdictions took precedence. Any other apparent contradictions with metrics and criteria were generally assessed according to results of all-hours probabilistic analysis.

Elevated-Risk Area Details

The below areas are projected to meet resource adequacy criteria and have energy and capacity for normal forecasted conditions but are at risk of supply shortfall in extreme conditions. Areas are listed in order of appearance in the **Regional Assessments Dashboards** section.

MISO

MISO has experienced slower resource additions due to market pressures and constraints faced by projects with signed interconnection agreements. MISO has highlighted uncertainties with a large number of new resources that have signed interconnection agreements (Tier 1 additions) and are expected to come on-line in the next several years.[10] Resource adequacy risks could grow over time absent the new capacity reflected in the Tier 1 additions and the deferral of announced retirements (see **Risk from Additional Generator Retirements**).

PRMs in MISO with resource additions are shown in **Figure 3** and **Figure 4**. MISO reports 56 GW of nameplate generating capacity, predominantly solar and batteries, with signed generation interconnection agreements (qualifying as Tier 1 and reflected in the ARM in **Figure 3** and **Figure 4**) as of July 2024 that can help meet resource adequacy needs if connection is completed. If resource additions remain at or near historically average levels (approximately 2.3 GW/year average over the last 3 years), PRMs in MISO will fall below the RML reserve margin requirements much faster. Summer PRMs with average resource additions are shown in **Figure 3** as **Reserve Margin-Avg Addition**.

[9] Plausible extreme conditions considered by NERC in this assessment are similar to those experienced during Winter Storm Elliott, Winter Storm Uri, and the 2020 Western Wide Area Heat Dome.
[10] See results from the 2024 Organization of MISO States (OMS)-MISO Survey.

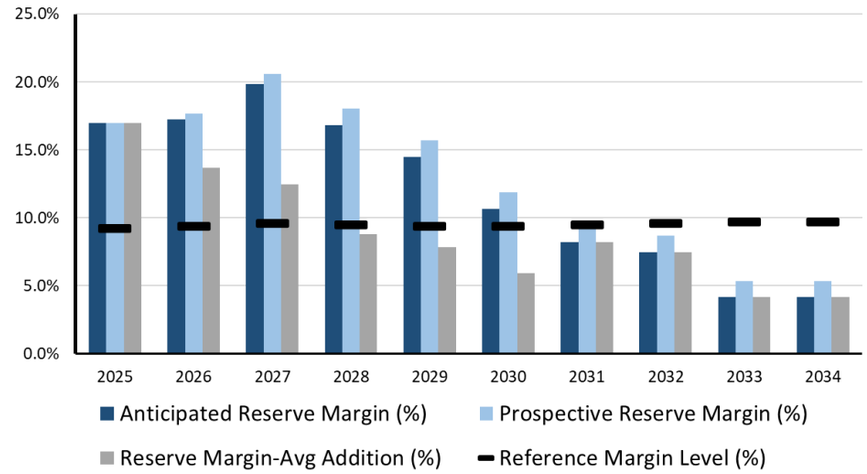


Figure 3: MISO Planning Reserve Margin–Summer

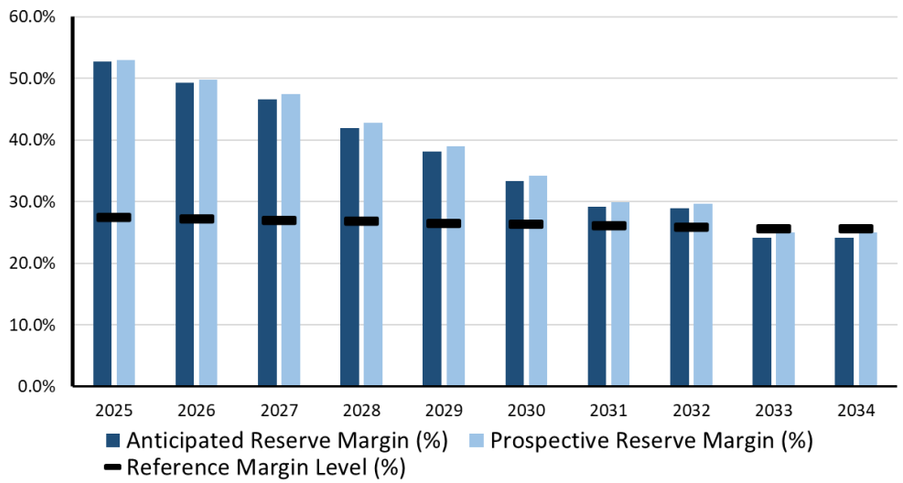


Figure 4: MISO Planning Reserve Margin–Winter

To establish the RMLs that define the minimum reserve margins for resource adequacy, MISO performs its annual probabilistic Loss-of-Load Expectation (LOLE) Study per MISO tariff. The study produces seasonal RMLs for the upcoming planning year that are used in MISO's planning resource auction. These RMLs are calculated such that they define the minimum PRM that will meet an LOLE of 1 day in 10 years. See the **MISO** assessment area pages.

MISO is an elevated risk in the *2024 LTRA* because probabilistic assessments indicate above-normal generator outages during extreme weather can result in unserved energy or load loss. With uncertainty around new resource additions and existing generator retirements, MISO is also at risk of falling below RMLs within the next five years.

MRO-Manitoba Hydro

The electricity demand forecast in the province of Manitoba has increased since the *2023 LTRA*, driven by expected economic activity and adoption of electric vehicles. Resource projections have not changed significantly.

As in prior probabilistic assessments, Manitoba Hydro's 2024 ProbA indicates that there is some risk of load loss and unserved energy associated with very low hydro conditions (see **Table 2**). Electricity demand peaks in winter, making this the higher-risk season. However, electricity supplies could fall short during either peak summer or winter conditions should an extreme and prolonged drought affect hydro production.

Table 2: MRO-Manitoba Hydro ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	7.23	**4.71**	**68.87**
EUE (PPM)	0.29	**0.18**	**2.50**
LOLH (hours per year)	0.01	**0.06**	**0.91**
Operable On-Peak Margin	13.5%	**18.8%**	**15.6%**

** Year 2026 Results from the 2022 ProbA provided for trending*

MRO-SaskPower

Resource projections for Saskatchewan over the 10-year period have increased since the *2023 LTRA*, rising to just over 1 GW and include two new 377 MW gas-fired generation facilities, expansion of existing gas-fired generation facilities, and new geothermal resources. The peak demand forecast growth rate (1.35% annually) has changed little since the *2023 LTRA*.

The ProbA for SaskPower indicates there is some risk of load loss and unserved energy that diminishes with the new resource additions that are planned for 2027 (**Table 3**). Saskatchewan is a winter-peaking system; however, the unserved energy risks are more closely associated with the planned outages of large generators that typically occur in the fall and spring shoulder periods. The months of September and October are the highest risk periods because of the potential for high temperatures to unexpectedly extend beyond summer and into the maintenance period.

Table 3: MRO-SaskPower ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	117.0	**75.64**	**8.55**
EUE (PPM)	4.4	**2.81**	**0.30**
LOLH (hours per year)	0.9	**0.54**	**0.08**
Operable On-Peak Margin	24.6%	**24.8%**	**30.8%**

** Year 2026 Results from the 2022 ProbA provided for trending*

MRO-SPP

New resource capacity in the interconnection queue—primarily solar, battery, and wind—is currently projected to keep up with rising peak demand forecasts. DR programs are also increasing over the next 10 years. Resource adequacy issues can arise, however, if generators retire earlier than anticipated or new resource additions connect more slowly. Currently, there are over 8 GW of coal and gas-fired generators that have indicated that they may retire within the next 10 years, making the resource outlook unclear. SPP's summer reserve margins, based on installed generator capacity, remain above RMLs through 2029 (see **Figure 5**).

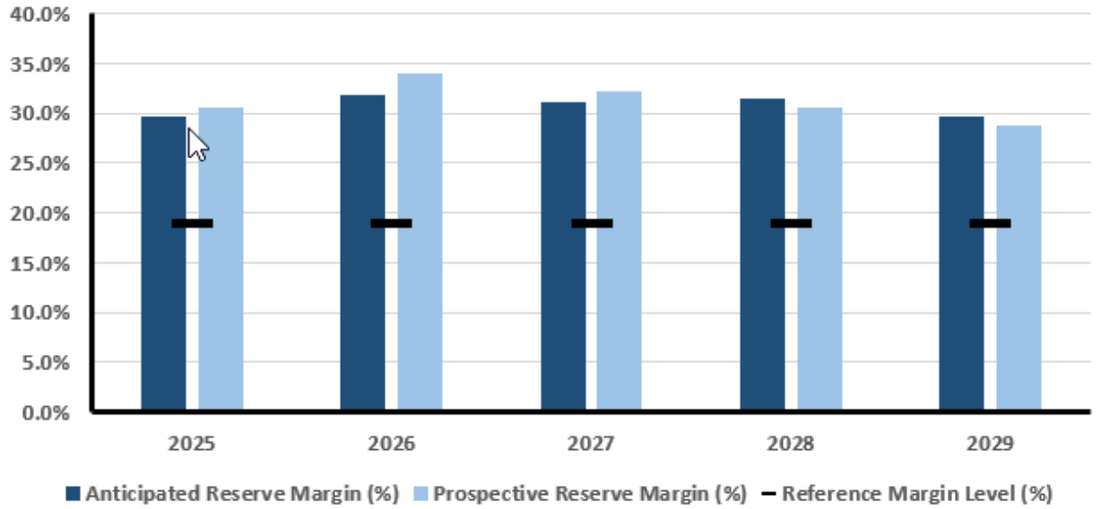


Figure 5: MRO-SPP Five-Year Planning Reserve Margin–Summer

All-hours probabilistic analysis performed by SPP shows that resource adequacy challenges are shifting from summer (when area demand is at its highest) to winter months (when the new resource mix is less capable of performing reliably). Annual results of the ProbA are in **Table 4** below. SPP's 2023 loss-of-load expectation (LOLE) study results indicate that a separate RML and seasonal resource capacity contributions are needed for the summer and winter seasons to effectively provide for resource adequacy.

Table 4: MRO-SPP ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	0.84	**0.00**	**6.61**
EUE (PPM)	0.00	**0.00**	**0.02**
LOLH (hours per year)	0.00	**0.00**	**0.01**
Operable On-Peak Margin	19.6%	**19.5%**	**16.0%**

** Year 2026 Results from the 2022 ProbA provided for trending*

NPCC-New England

New England is forecasting unprecedented demand growth driven by electrification of heating and transportation. Wind, solar, and batteries make up the projected resource additions, along with growth in distributed energy resources. Since the *2023 LTRA*, the peak demand forecast is relatively unchanged. New England has among the strongest winter demand forecast growth rates of any assessment area, rising over 7 GW in the 10-year period, or 35% from its current peak demand forecast.

The 2024 ProbA for NPCC-New England reveals increasing risk of load loss and unserved energy compared to the 2022 ProbA (see **Table 5**). Higher-demand forecast and replacement of dispatchable resources with more VERs contribute to this trend. In the ProbA modeling, supply shortfall risk is limited to the summer months and is associated with periods of above-normal demand and low resource output (e.g., low wind, solar, or high thermal outages).

Table 5: NPCC-New England ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	0.55	**10.69**	**67.40**
EUE (PPM)	0.00	**0.09**	**0.06**
LOLH (hours per year)	0.00	**0.07**	**0.03**
Operable On-Peak Margin	27.8%	**12.4%**	**13.7%**

** Year 2026 Results from the 2022 ProbA provided for trending*

While NPCC's ProbA results indicate that the risk of unserved energy in New England is concentrated in summer months, a persistent concern is whether there will be sufficient fuel available to satisfy electrical energy and operating reserve demands during an extended cold spell or a series of cold spells given the existing resource mix and regional fuel delivery infrastructure. Potential natural gas transportation constraints can affect supply to generators during extreme cold temperatures, when natural gas demand for space heating is also peaking. Most natural-gas-fired generators in the area do not have firm natural gas transportation service and can be subject to supply curtailment during peak conditions. Many natural-gas-fired generators in New England can also operate with stored oil, providing for assured electricity supply in extreme winter conditions while oil stores are procured and maintained. Scenarios of extended and extreme cold weather that affect the availability of natural gas and oil replenishments present a reliability risk but were not within the scope of the 2024 ProbA.

NPCC-Ontario

Near- and long-term resource adequacy challenges continue in the NPCC-Ontario assessment area as the Independent Electricity System Operator (IESO) manages lengthy refurbishment outages at nuclear generators and demand growth driven by agriculture and electrification. The beginning of projected shortfalls occurs in 2027 when some contracts for firm capacity are set to expire (see **Figure 6**). However, a number of resources with expiring contracts between 2026 and 2029 are anticipated to be re-committed for five-year terms through the IESO's second medium-term procurement, which is underway. As such, Ontario's Anticipated Reserve Margins (ARM) and Prospective Reserve Margins shown in **Figure 6** (which do not include this set of expiring resources) are conservative. Recommitment of these resources is expected to raise margins above the reference level in 2029 and help maintain reliability through the end of the decade. In May 2024, the IESO finalized long-term commitments for new-build battery storage facilities (1,784 MW) and new-build natural gas and biogas facilities (411 MW). Early operation incentives anticipated to bring a portion of these resources online as early as 2027 could help alleviate the reserve margin gap. The IESO also launched procurements for new capacity and energy-producing resources to be online as early as 2029. In addition, the IESO finalized an agreement with Hydro-Québec for capacity sharing in November 2024, providing 600 MW of firm imports to Ontario starting in Summer 2025 through Summer 2031. This capacity is also expected to help alleviate shortfalls indicated in 2027.

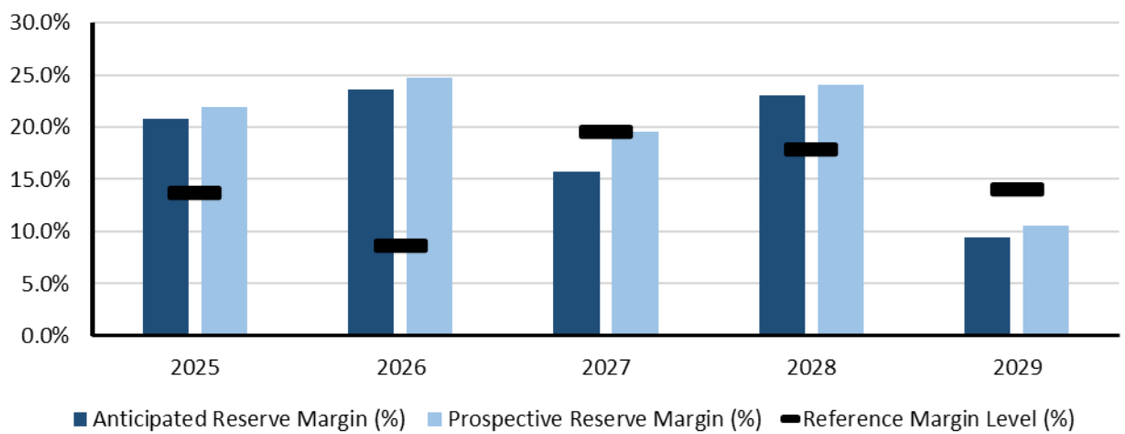


Figure 6: NPCC-Ontario Five-Year Planning Reserve Margin–Summer

The probabilistic assessment for Ontario performed by NPCC provides further insights into the potential for load loss and unserved energy. There is negligible risk of unserved energy and load loss in 2026 and earlier years; however, a small risk of load loss (< 0.01 hours) emerges after 2026 (Table 6). The 2024 ProbA study included only years 2026 and 2028, both of which have projected capacity surpluses above RMLs (see Figure 6). If 2027 and 2029 had been included in the ProbA, it can be expected that there would have been higher amounts of LOLH and unserved energy. ProbA results are also helped by the inclusion of electricity transfers from neighboring areas and modeling for some operating procedures used to manage supply shortfalls.

Table 6: NPCC-Ontario ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	72.16	**0.04**	**4.97**
EUE (PPM)	0.49	**0.00**	**0.03**
LOLH (hours per year)	0.44	**0.00**	**0.01**
Operable On-Peak Margin	-6.7%	**13.3%**	**9.5%**

** Year 2026 Results from the 2022 ProbA provided for trending*

PJM

PJM's projections for generator additions in 2025 and 2026 are scaled back dramatically from the *2023 LTRA* while demand forecasts continue to rise. As a result, ARMs for future years have fallen by as much as nine percentage points from last year. The trends in demand growth and resource additions create resource adequacy and system planning challenges for PJM as it carefully manages generator deactivation requests from the aging fossil and nuclear fleet.

PJM's ProbA results provide indication of the increasing resource adequacy risk to the system (see Table 7). EUE and LOLH are found in both ProbA assessment years (2026 and 2028) with risk concentrated in the winter months (especially January). The risk occurs on days where temperatures are very low across the entire PJM area, which results in high loads. While normal resource performance can meet these demand forecasts, resource performance from thermal resources on very cold days has historically been below normal due to freezing and fuel supply issues. Furthermore, solar resources are not likely to contribute during some of the coldest hours, resulting in very low total electricity supply and thus projections of load loss. ProbA analysis shows some summer load-loss and unserved energy risk but at much lower levels. Summer shortfall events are most likely to occur during wide-area heat events that coincide with low wind and low solar output, or very high outage and derates in the thermal generation.

Table 7: PJM ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	0.00	**537.52**	**1,043.44**
EUE (PPM)	0.00	**0.00**	**0.00**
LOLH (hours per year)	0.00	**0.12**	**0.22**
Operable On-Peak Margin	29%	**17.8%**	**17.7%**

** Year 2026 Results from the 2022 ProbA provided for trending*

SERC-East

The addition of solar resources is helping to raise summer on-peak reserve margins in the assessment area, despite rising demand forecasts and additional coal-fired generator retirements. Since the *2023 LTRA*, solar PV resources have grown from 1.5 GW to an expected 4.7 GW by the end of 2024. An additional 2 GW of solar PV resources are in the process of connecting. The summer peak demand forecast has also risen since the *2023 LTRA*, increasing by 2.8 GW (6.3%) over last year's projection. The area reserve margins have increased in the near term as a result of the solar resource additions then drop off after 2028 due to higher demand forecasts and planned generator retirements.

Despite these resource additions and higher summer reserve margins, the 2024 ProbA reveals growing resource adequacy risk in SERC-East (see Table 8). Measures of unserved energy and load-loss have increased since the 2022 ProbA as demand has risen and the resource mix has changed. SERC-East has changed from a summer-peaking area to one with peak electricity demand occurring in both the summer and winter seasons. This change is the result of added solar PV generation that shaves off summer peak demand and trends toward electrification in heating that drives up winter peak demand. The ProbA shows that the risk of unserved energy and load loss is concentrated in winter (January–February) months when wide-area extreme cold weather can affect electricity demand, generator performance, generator fuel supplies, and the availability of electricity imports. Based on current forecasts, resource adequacy risk will increase in SERC-East after 2028 due to the planned retirement of over 1,800 MW in coal-fired generation and continued load growth.

Table 8: SERC-East ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	92.49	**143.35**	**207.26**
EUE (PPM)	0.40	**0.60**	**0.81**
LOLH (hours per year)	0.08	**0.09**	**0.17**
Operable On-Peak Margin	16.1%	**14.2%**	**11.1%**

** Year 2026 Results from the 2022 ProbA provided for trending*

Texas RE-ERCOT

ERCOT is forecasting explosive demand growth, driven by data center projects, Bitcoin operations, development in oil- and natural-gas-producing areas, and industrial facilities. Over 20 GW of newly contracted large loads, in addition to other organic load growth, is projected to be added to ERCOT by 2028. Substantial amounts of solar PV and battery resources are being added to help meet rising demand, but there are significant reliability challenges to address during this period of rapid growth. Resource adequacy risks are mounting as fewer dispatchable resources comprise the resource mix. One of the strategies to address this risk is state implementation of a dispatchable resource generation loan program called the Texas Energy Fund. Furthermore, the forecasted growth in loads and resources poses significant challenges for transmission system planners.

Load growth and the characteristics of the resource mix are contributing to higher levels of unserved energy and load loss in probabilistic analysis (see **Table 9**). In the 2024 ProbA, EUE for the analyzed 2026 ERCOT system has risen to 19 ppm (0.0019 %) of the total annual supplied energy compared to the same analysis in the 2022 ProbA. The 2024 ProbA shows an improving trend in the analyzed 2028 ERCOT system, enabled by additional generation capacity from ERCOT scenarios developed to support rapid growth in large loads.[11]

A deeper analysis of the probabilistic assessment results reveals the unique characteristics of winter and summer risk. While peak winter loads can persist for 48 hours or longer, peak summer periods generally only last for a few hours. This is manifested in the duration and depth of the winter firm load-shed events that appear in the ProbA and has significant implications for the reliability contribution of energy-limited and non-dispatchable resources. The most extreme winter event modeled for 2026 was 16 hours in duration and up to 29 GW in load loss. In contrast, most summer unserved energy events were 1–2 hours in duration.

Table 9: Texas RE-ERCOT ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	1,235	**11,090**	**781**
EUE (PPM)	2.63	**18.95**	**1.12**
LOLH (hours per year)	0.30	**1.57**	**0.16**
Operable On-Peak Margin	35.9%	**28.8%**	**46.9%**

** Year 2026 Results from the 2022 ProbA provided for trending*

A key conclusion from the Texas RE-ERCOT 2024 ProbA is that matching the area's demand growth with a resource mix that is more variable and less fully dispatchable is increasing the risk of supply shortfalls that can result in load loss and unserved energy. When the seasonal characteristics of demand and resources are considered, Resource Planners can appropriately focus efforts to reduce the risk of potentially severe, long-duration winter shortfall events. The Public Utility Commission of Texas established a Reliability Standard and accompanying reliability assessment process in August 2024. The reliability standard is based on multiple probabilistic reliability measures that capture the different dimensions of loss-of-load events: average event frequency (LOLE), maximum event duration, and maximum event magnitude.

WECC-CA/MX

Resource additions continue to improve the overall resource adequacy outlook for the WECC California-Mexico assessment area. Since the 2022 ProbA, the planned extension of the Diablo Canyon nuclear plant (2.2 GW) and resource additions (over 5 GW nameplate in batteries, 3.3 GW nameplate in solar PV, and 0.2 GW in natural-gas-fired and geothermal generation) have alleviated supply shortfalls that were driving unserved energy and load-loss metrics in year 2026, as shown in the results of the 2024 ProbA performed by WECC (see **Table 10**).

Table 10: WECC-CA/MX ProbA Case Summary of Results

	2026*	2026	2028
EUE (MWh)	37,305	0	19,662
EUE (PPM)	136	0	70.07
LOLH (hours per year)	0.72	0	0.38
Operable On-Peak Margin	30.7%	43.2%	41.2%

** Year 2026 Results from the 2022 ProbA provided for trending*

Demand growth and planned generator retirements cause energy adequacy risks to re-emerge in future years. With a resource portfolio that includes a substantial amount of solar PV, the risk of supply shortfall is associated with summer evening periods when demand is high and solar output is diminished. WECC's analysis for the 2024 ProbA found only a small occurrence (<1 hour) of resources falling below margin levels for reliability in the 2028 study year. WECC further observed that load-loss and unserved energy risk was localized in the Mexico portion of the assessment area, reflecting localized resource and transmission system constraints.

[11] Due to the inclusion of an additional 20 GW of large loads based on newly signed interconnection agreements, study-year 2028 included additional generation capacity from the "High Large Load Adoption" scenario of the ERCOT 2024 Long-Term System Assessment (LTSA), which included 22 GW of combustions turbines (CT) and 4 GW of combined cycles (CC).

The CA/MX 2028 system analyzed by WECC for the 2024 ProbA reflects the continued rapid transformation of the power grid. The analysis assumes forecasted demand growth of 3.5 GW, substantial resource additions (4.6 GW of solar PV, 7.6 GW in batteries, and 0.8 GW of natural-gas-fired generation imported from repowered coal units in Utah), and the retirement of over 3 GW of gas-fired generation. As demand grows and the resource mix becomes increasingly variable, periods of supply shortfalls can emerge. Battery additions and transfers help make up for energy shortfalls that can arise during evening solar down ramps.

WECC-BC

BC has a predominantly hydroelectric generation system with vast amounts of energy storage provided by its reservoirs. Winter peak demand in the province is forecast to grow modestly over the next 10 years, from 11,966 MW this winter to 12,305 MW at the end of the 10-year period. Since the *2023 LTRA*, the winter peak demand compound annual growth rate (CAGR) has fallen from 1.0% to 0.3%. Growth rate and reserve margins are higher. While the overall resource adequacy outlook has improved, the 2024 ProbA indicates the area continues to be at an elevated risk of supply shortfall during extreme conditions. Drought and extreme cold temperatures in winter can result in periods of insufficient operating reserves when neighboring areas are unable to provide excess energy.

Western Interconnection-wide probabilistic analysis performed by WECC for the 2024 ProbA reveals that risk of reserve shortages emerges after 2026, potentially resulting in unserved energy and load-loss events during extreme weather. WECC's analysis identified over five hours in 2028 when high demand and low supply from WECC-BC's internal resources were not able to be remedied with imports from neighboring areas experiencing similar conditions (see **Table 11**). In contrast, 2026 had no unserved energy or load-loss periods. An examination of hourly results showed that imports from neighbors were more available in 2026 to cover periods of potential shortfalls in BC Hydro's internal resources.

Table 11: WECC-BC ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	24	**0**	**103,132**
EUE (PPM)	0.71	**0**	**1,456**
LOLH (hours per year)	0.00	**0**	**5.52**
Operable On-Peak Margin	12.7%	**16.9%**	**9.4%**

** Year 2026 Results from the 2022 ProbA provided for trending*

WECC's interconnection-wide analysis simulates the probabilistic performance of resource types using historic hourly output data to identify future risk periods. Operators of systems with large hydroelectric storage facilities make adjustments to generation based on the level of demand and shape the water use within the day, week, month, or between years. These actions help posture hydroelectric generation for expected conditions and can reduce energy shortfall risks.

BC's supply margins relative to demand are lowest during winter peak demand periods. Imports from neighbors in the U.S. Northwest are common during these periods, and often during the overnight hours of 23:00 to 4:00 local. WECC's analysis shows the need for imports growing year to year throughout most of the LTRA forecast horizon. A widespread, extreme cold weather event in the Northwest that limits transfer capability is thus a risk to BC. Even though WECC-BC is expecting only moderate demand growth and relatively few retirements, diminished surplus capacity in neighboring areas is negatively affecting the resource adequacy outlook.

Normal-Risk Area Details

All other assessment areas (see **Figure 1**) are assessed as normal risk. In these areas, resource adequacy criteria are met, and there is a low likelihood of electricity supply shortfall even when demand is above forecasts or resource performance is abnormally low (e.g., above-normal forced outages or low VER performance).

Resource and Demand Projections

The **Capacity and Energy Assessment** section in this LTRA is a forward-looking snapshot of resource adequacy that is tied to industry forecasts of electricity supplies, demand, and transmission development. Later sections in this report describe important trends in each of these forecast areas. The future electricity supply will come from a resource mix that is more variable, weather-dependent, and reliant on natural gas for fuel, requiring broad coordination and careful attention to manage reliability risks. Future electricity demand is being shaped by many factors that collectively influence peak demand forecast levels, peak seasons, and hourly profiles. Peak demand and energy forecasts are projected to continue rising dramatically over the *2024 LTRA* assessment period, exceeding their highest rates in recent years. Ongoing challenges with resource and transmission development and the continued pace of generator retirements raise concerns that, in the future, the risk assessment map will expand with more elevated and high-risk areas.

Risk from Additional Generator Retirements

Accelerated retirements of the existing coal, natural gas, and nuclear generators can have a profound and negative effect on the resource adequacy and reliability of the BPS in the next 10 years. In this preceding **Capacity and Energy Assessment** NERC accounted for nearly 79 GW of fossil-fired and nuclear generator retirements that are anticipated through 2034. Environmental regulations and energy policies have the potential to influence generators to seek deactivation during the 10-year assessment period.[12] An additional 43 GW of fossil-fired generators have announced plans to retire over the decade but have yet to enter deactivation processing with the planning authorities. These retirements, along with the confirmed retirements, contribute to declining reserve margins in the assessment areas over the next 10 years (see **Table 12**). As a result of demand growth and generator retirements, ARM is projected to fall below RML in 18 of the 20 assessment areas by 2034. While forecasts such as this factor into resource planning and market mechanisms to obtain resources needed for resource adequacy, it underscores the significant resource growth needed across North America. The lack of dispatchable resources and diverse generator fuel types in the interconnection processes makes the future resource mix look alarmingly unreliable. The potential for capacity and energy shortfalls and a higher-risk resource mix is heightened by economic and policy factors that place pressure on existing thermal generators.

The yearly projections of future retirements and an assessment area view are provided in the **Risk from** Additional Generator Retirements section.

[12] The Environmental Protection Agency (EPA) issued a final rule on May 9, 2024, establishing Greenhouse Gas Standards and Guidelines for Power Plants (the "GHG Rule"). This rule was released concurrently with three other EPA regulations that impact fossil-fueled power generation: Coal Combustion Residuals, Effluent Limitations Guidelines, and Mercury and Air Toxics Standards. Collectively, these four new regulations impose considerable financial and operational challenges on coal-fired generators.

Table 12: Anticipated Reserve Margins with Announced Retirements											
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
MISO[13]	17.7%	10.3%	10.3%	13.2%	8.6%	7.1%	10.6%	8.2%	7.5%	4.2%	-2.5%
MRO-Manitoba	12.5%	21.3%	18.4%	18.0%	15.0%	9.8%	0.5%	-0.6%	-1.7%	-2.9%	-4.2%
MRO-SaskPower	28.9%	27.8%	26.6%	31.1%	29.4%	7.0%	28.8%	28.0%	26.7%	26.8%	1.2%
MRO-SPP	28.3%	26.7%	26.0%	25.0%	20.8%	19.1%	26.7%	24.9%	23.5%	22.4%	8.1%
NPCC-Maritimes	18.9%	20.6+%	25.5%	25.1%	18.6%	3.9%	23.4%	20.7%	19.1%	17.7%	-1.5%
NPCC-New England	20.4%	25.0%	25.0%	26.3%	24.9%	23.5%	22.0%	20.1%	19.7%	17.1%	14.6%
NPCC-New York	18.4%	17.1%	21.4%	22.5%	22.4%	21.6%	20.7%	18.3%	16.7%	14.9%	13.6%
NPCC-Ontario	22.5%	20.8%	23.6%	15.7%	23.0%	9.5%	5.1%	-0.2%	-1.4%	-3.9%	-5.5%
NPCC-Quebec	12.5%	12.2%	13.1%	14.2%	12.6%	11.3%	9.8%	6.2%	3.5%	0.5%	-2.2%
PJM	29.8%	34.9%	35.7%	28.1%	21.4%	18.2%	23.1%	21.6%	20.1%	18.5%	10.3%
SERC-C	28.2%	18.9%	18.9%	15.0%	16.0%	15.2%	17.3%	17.1%	18.4%	21.1%	11.8%
SERC-E	30.4%	27.3%	25.8%	24.6%	20.6%	14.4%	14.3%	10.2%	6.3%	4.6%	-2.2%
SERC-FP	27.0%	25.4%	26.0%	23.2%	22.1%	20.9%	18.4%	22.0%	20.4%	18.2%	16.0%
SERC-SE	44.9%	39.9%	35.9%	31.5%	24.5%	21.4%	27.7%	25.8%	24.7%	23.7%	13.0%
TRE-ERCOT	24.3%	30.2%	32.5%	29.7%	25.6%	25.4%	27.8%	28.0%	28.4%	28.9%	24.9%
WECC-AB	36.3%	35.8%	35.7%	38.5%	41.7%	41.9%	35.4%	41.2%	33.6%	27.8%	27.0%
WECC-BC	20.9%	25.2%	25.2%	15.8%	15.9%	22.3%	22.1%	21.6%	21.2%	13.4%	19.9%
WECC-CA/MX	38.6%	45.5%	45.2%	38.4%	43.1%	28.8%	29.6%	23.3%	25.0%	15.2%	11.1%
WECC-NW	34.5%	40.3%	38.9%	35.6%	30.7%	24.5%	18.3%	12.2%	10.2%	8.1%	5.9%
WECC-SW	28.6%	37.0%	35.6%	31.6%	24.2%	17.4%	11.3%	7.7%	0.2%	-4.7%	-9.6%

Reducing Resource Capacity and Energy Risk

The risk of electricity supply shortfalls in the assessment period can be lowered through the concerted efforts of resource and system planning stakeholders. The actions taken in electricity markets and regulatory jurisdictions with the improving trends noted previously provide examples of what can work: obtaining additional firm resources to meet resource adequacy targets, delaying generation retirements when reliability needs dictate, and using capacity targets and energy risk metrics based on better resource and demand models. Specific and actionable recommendations are contained in the Executive Summary.

[13] MISO reserve margins in this table reflect MISO Seasonal Accredited Capacity for summer. Adjustments and derates are applied to account for factors affecting expected resource output, resulting in unforced capacity (UCAP) reserve margins that are lower compared to installed capacity (ICAP) values. For more information see the **MISO assessment area** page.

Resource Mix Changes

Capacity Versus Energy: Changes in the Way to Plan for Resource Adequacy

Industry's methods of planning for resource adequacy need to change. The modern power system requires the enhancement of assumptions and supplementation of risk information for a better characterization of the risk. Historically, the resource adequacy criterion has been based on the LOLE metric, which should be no more than 1 event-day in 10 years when the generating resources are less than load (commonly known as "1-day-in-10"). This has been a design basis for the U.S. electric grid for at least 70 years (with its first formal mention in a 1951 American Institute of Electrical Engineers paper by C. W. Watchorn) and has historically served the industry well. Two important related but separate discussion topics include considerations for assumptions in the calculation of LOLE and other metrics and the establishment of the resource adequacy criteria (i.e., traditionally in terms of LOLE-1-day-in-10). The 1-day-in-10 LOLE criterion is commonly converted into a minimum capacity requirement resulting in a target or RML. In doing this, planners determine the minimum PRM required to maintain a 1-day-in-10 LOLE level. Historically, systems with an actual PRM above the minimum generally have sufficient resources and provide adequate energy and ERSs that operators need to reliably operate the BPS. Issues can arise in resource adequacy planning processes when planners solely rely on the RML comparison as the system transforms from an era of certain to more uncertain fuel sources and load behavior. In recent years, NERC has documented warnings of potential energy shortages in its reliability assessments, while in many cases the RML comparison indicates no shortfall. Substantial uncertainty has been introduced into planning the system with the addition of energy-constrained resources (variable energy resources such as wind and solar, and, at times, just-in-time fuels such as natural gas) that are highly dependent on weather and environmental conditions. Uncertainty in energy sufficiency is increasing as the types of resources change, leaving fewer resources that can be dispatched (dispatchable resources) in response to the variable resource availability and greater exposure to constraints in fuel supplies, reservoir levels, or battery discharge capabilities. Historical generator reliability assumptions based on the idea of well-maintained, well-invested units with an anticipated long life are no longer adequate. This increases uncertainty as a greater proportion of fossil-fueled resources continue to be retired, often with little notice to system planners. Nameplate values of variable energy resources are not as meaningful as projected energy availability, and environmental conditions can adversely impact the simultaneous availability of thousands of megawatts.

Probabilistic analysis enhances deterministic transmission planning from an energy adequacy standpoint given the following factors:

- Considers likelihood of events: It uses historical data to estimate how often different outages and weather conditions might occur.
- Provides more information: It calculates the average impact of these events, including how often and how long power outages might last.
- Helps compare options: It enables the selection of the upgrade(s) that provide the best balance between cost and reliability over time to be chosen.

Detailed recommendations are included in a recently published NERC report:
Evolving Planning Criteria for a Sustainable Power Grid: A Workshop Report, June 2024

Changes in Existing BPS Resource Capacity

Thermal generator retirements and new resource additions continue at a rapid pace. Since the *2023 LTRA*, over 8 GW of coal-fired generation has been retired, while substantial solar and battery resources have connected to the grid (see **Table 13**). From a strictly on-peak capacity perspective, there has been little change (8,348 MW is 0.8% of the total BPS summer on-peak resource capacity.)

Table 13: Existing BPS Resource On-Peak Capacity

	2023 Capacity (MW)	2024 Capacity (MW)	Difference (MW)
Coal	188,856	180,402	-8,454
Petroleum	32,107	30,987	-1,120
Natural Gas	483,391	484,148	757
Biomass	7,273	7,381	108
Solar[14]	52,998	66,293	13,295
Wind[15]	32,320	31,370	-950
Geothermal	4,319	3,881	-438
Conventional Hydro	103,368	105,792	2,424
Run of River Hydro	1,565	2,047	482
Pumped Storage	19,463	19,422	-41
Nuclear	106,173	105,385	-788
Hybrid & Battery	5,593	9,909	4,316
Other	2,217	774	-1,443
Total	1,039,643	1,047,791	8,348

This year-on-year change in on-peak capacity continues the general trend of declining baseload and dispatchable generation—which includes coal-fired, natural gas, and nuclear generators—and rising VERs. **Figure 7** shows the trend continuing through 2034, where 20% of the generating capacity will be provided by VERs. Focusing on the relatively small change in total on-peak capacity since 2023 can mask risks to reliability that result when important attributes of the retiring generation resources are not inherent in the replacement resource mix. Thermal generation resources, such as coal-fired generators, have the capability to be dispatched when needed and provide system inertia, dynamic reactive support, and frequency response for stable grid operation. Most types of replacement resources have limited or none of these attributes. Further, retirements in the thermal generator fleet are making the resource mix less effective in meeting winter energy needs.

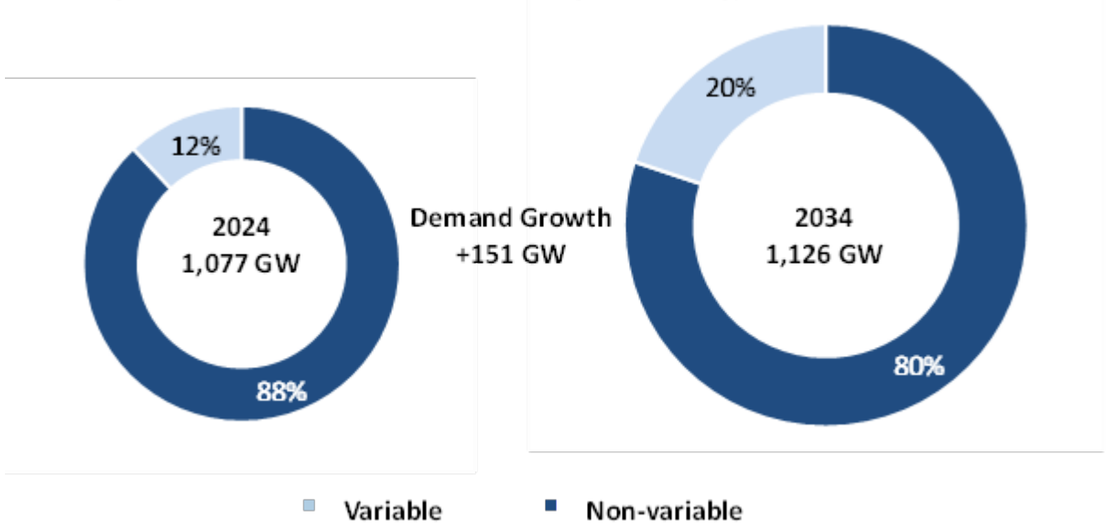


Figure 7: North America Total Generation Capacity in 2024 and 2034

Capacity Additions

New generation is added to the BPS through the area interconnection planning processes. Solar PV is the overwhelmingly predominant generation type being added to the BPS, followed by battery and natural-gas-fired generators, wind turbines, and hybrid resources. Batteries are now the second most predominant resource in the North America BPS interconnection queues. A summary of generation resources in the interconnection planning queues is shown in **Figure 8**.

Capacity in planning has grown since the *2023 LTRA* by over 44 GW (12%). In general, **Tier 1** resources are in the final stages for connection, while **Tier 2** resources are further from completion (see text box). Some projects that are in the earlier stages of the interconnection queue process will be withdrawn before completion due to supply chain issues, planning and siting challenges, and business or economic factors. While interconnection queues continue to swell, considerable uncertainty

[14] The capacity values in this table represent the on-peak contribution of solar resources. The total installed (nameplate) capacity of BPS solar in 2024 is 111,102 MW. See Table 11.
[15] The capacity values in this table represent the on-peak contribution of wind resources. The total installed (nameplate) capacity of BPS wind in 2024 is 176,636 MW. See Table 11.

surrounds the timing and amount of resource additions. (See an analysis of projected and actual additions on the next page).

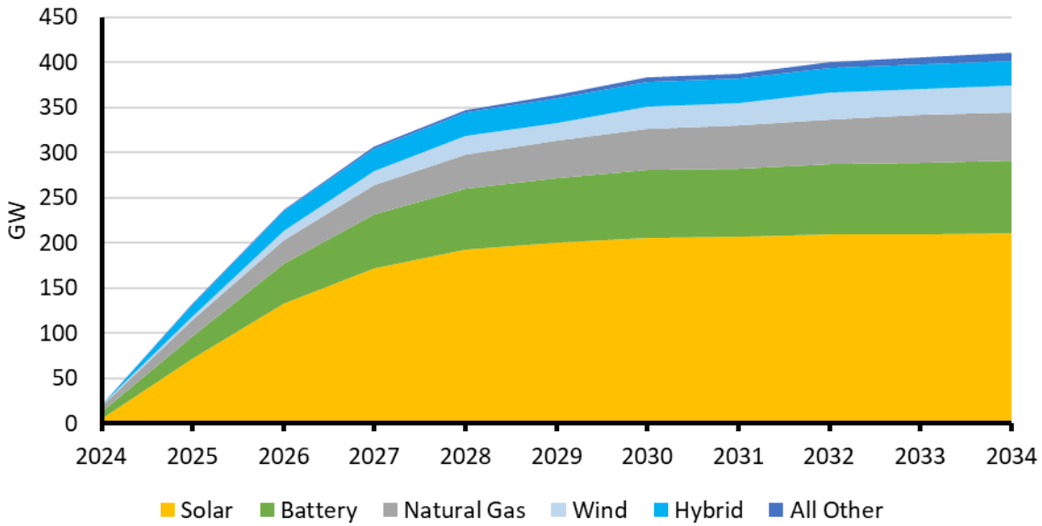


Figure 8: Tier 1 and 2 Planned Resources Projected Through 2034

Solar PV and wind nameplate capacity, both existing and planned, vary widely by area. Figure 9 and Figure 10 show current solar PV and wind installed capacities and the capacity in the planning process through 2034 for assessment areas with significant amounts. In addition, hybrid generation resources, which combine energy storage with a generating plant (i.e., a wind or solar farm), are connecting to the grid in parts of North America, and many more projects are in BPS planning processes.

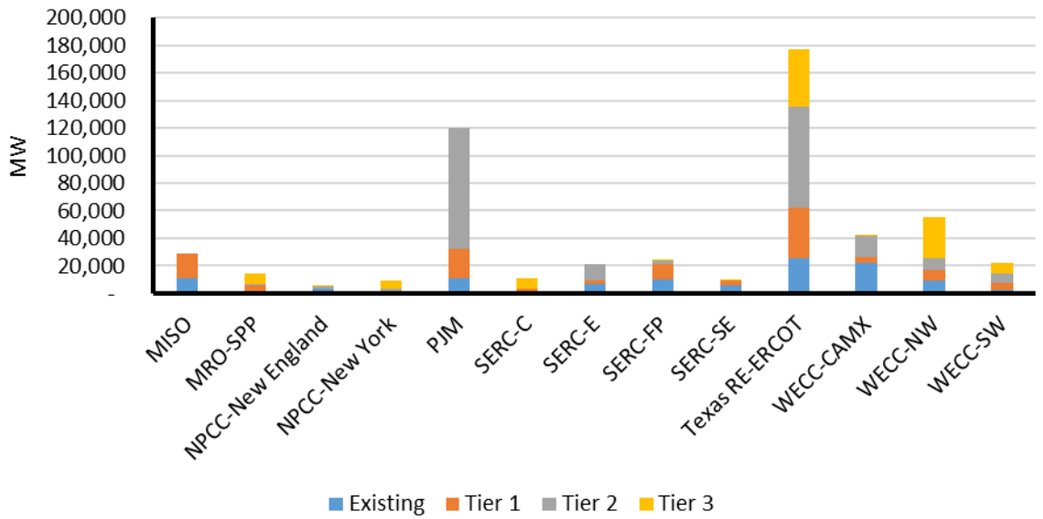


Figure 9: Solar Nameplate Capacity Existing and Planned through 2034

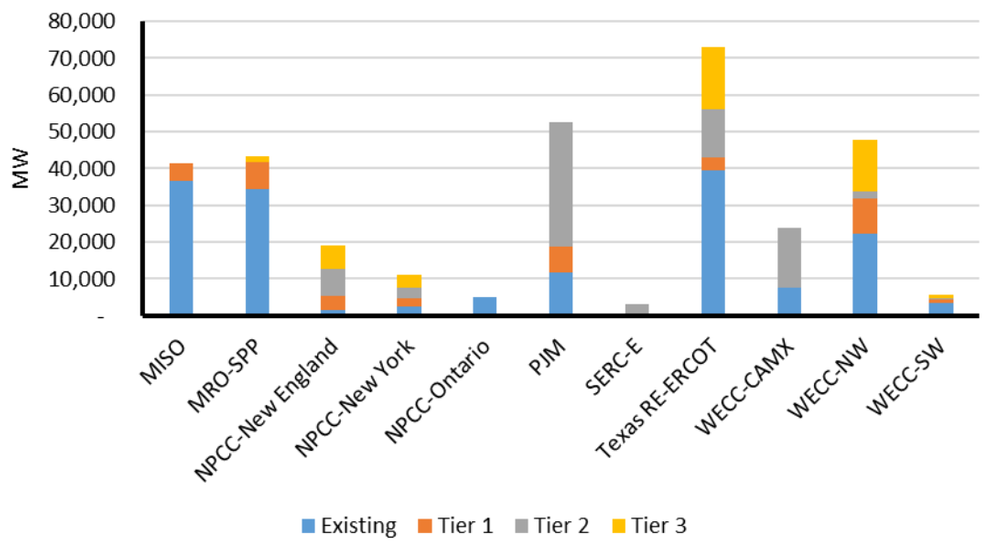
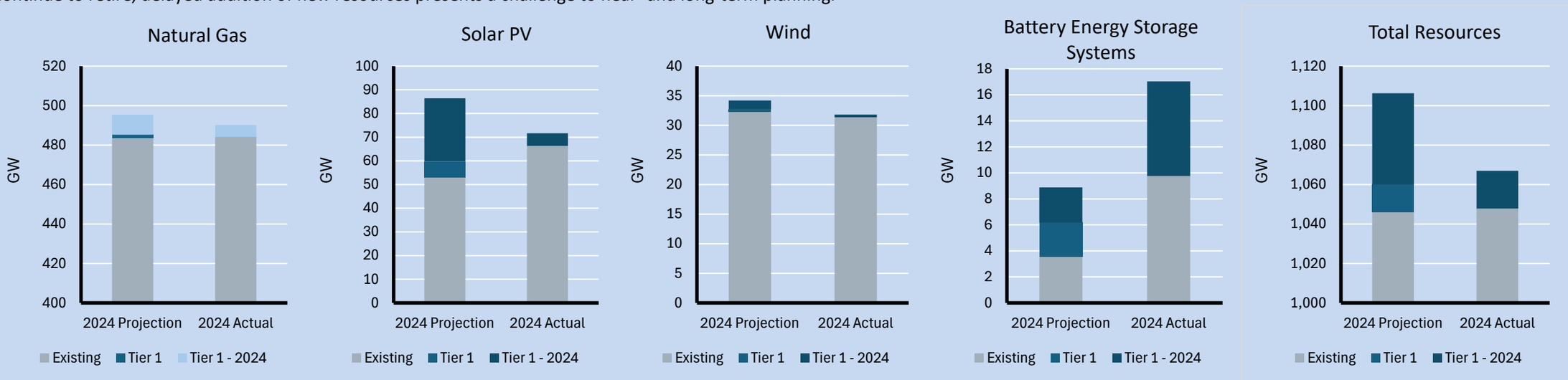


Figure 10: Wind Nameplate Capacity Existing and Planned through 2034

Resource Additions – How Much and When?

The added resource capacity on the BPS over the past year fell short of industry's projections, raising concerns that demand growth has the potential to outpace supply resources. The figures below compare the *2023 LTRA* projection of this year's installed capacity against the actual current installed capacity derived from data collected for this LTRA. Natural gas, solar PV, and wind resources were all over-projected last year. This gives evidence to industry reports of construction delays that prevented the expected interconnection of new resources. To a lesser extent, project withdrawals prior to commercial operation also contributed to lower-than-expected resource additions. One key exception—battery energy storage systems (BESS)—came in higher than last year's projections. As baseload and dispatchable generation continue to retire, delayed addition of new resources presents a challenge to near- and long-term planning.



Comparison of Projected Capacity from the 2023 LTRA to the Actual Capacity in the *2024 LTRA*

The sluggish rate at which new generation moves through the interconnection queue and begins service has been a cause for concern for long-term reliability planning. The Lawrence Berkeley National Laboratory published the results of an interconnection queue study in April 2024 assessing that less than one-fifth of generation capacity projects seeking interconnection between 2000 and 2018 actually came to fruition by the end of 2023.[16] Wait times have also been on the rise: According to the same study, the time from initiating a request for interconnection to the start of commercial operations has increased from less than two years, as was the case from 2000–2007, to more than four years from 2018–2023. The delay in bringing new generation capacity online in assessment areas that are anticipating steady or accelerated thermal capacity retirements, as well as increased demand, presents a significant reliability risk.

In recognition of the interconnection backlog risk, some regional transmission organizations have taken steps to address the lagging completion rates. MISO has assigned multiplication factors to generator requests based on the study phase and the likelihood of that resource coming on-line to more accurately gauge the likely incremental capacity in its footprint.[17] MISO also continues to advance the Joint Targeted Interconnection Queue (JTIQ) with SPP to resolve binding constraints that have delayed the interconnection process. PJM analyzed the completion rate of its interconnection queue and reported that less than 16% of resources submitted into the queue between 1999 and 2023 went into operation. The ISO has also applied a reduction to the nameplate capacity of value of Tier 1 resources to reflect the historical addition rate of new generation. PJM's interconnection process subcommittee is working on enhancements for new generation to interconnect as a capacity resource. These measures and others are examples of the broader effort to streamline generator additions and thus offset retiring capacity.

Offshore wind plants are increasingly entering interconnection queues, located around the Northeastern United States. **Figure 11** shows the current planned capacity in the planning process through 2034 by assessment area. Currently, the existing offshore wind nameplate capacities are small in comparison: a single 29 MW plant in NPCC-New England and a 12 MW plant in PJM.

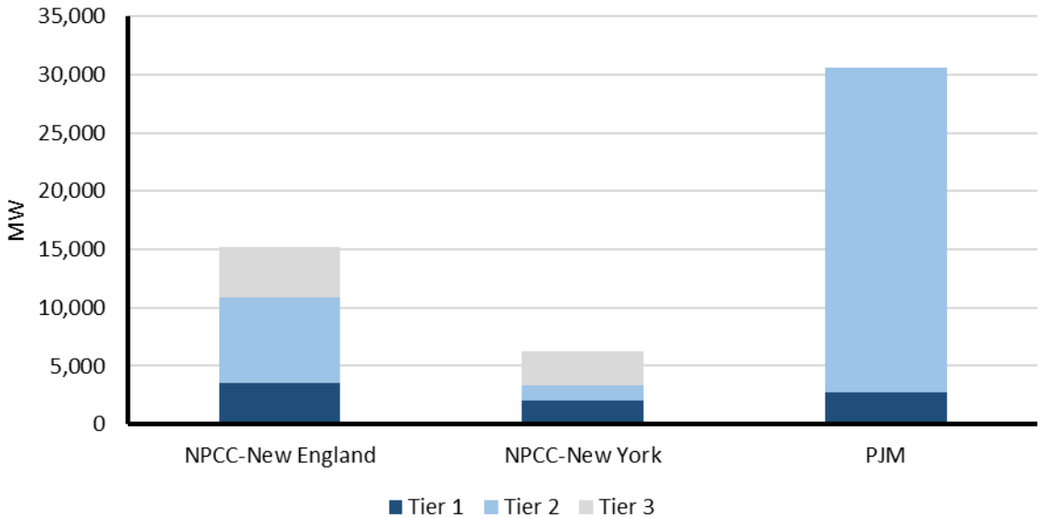


Figure 11: Offshore Wind Capacity Planned through 2034

Battery Resources

As the BPS increases the share of energy provided by VERs, the ability to provide energy by BESS or hybrid-solar PV and wind plants is increasingly important. While currently installed capacity totals just over 17 GW, an additional 306.5 GW of BESS are in planning. **Figure 12** shows the nameplate capacity of BESS resources currently in operation and in planning for connection to the BPS through 2034.

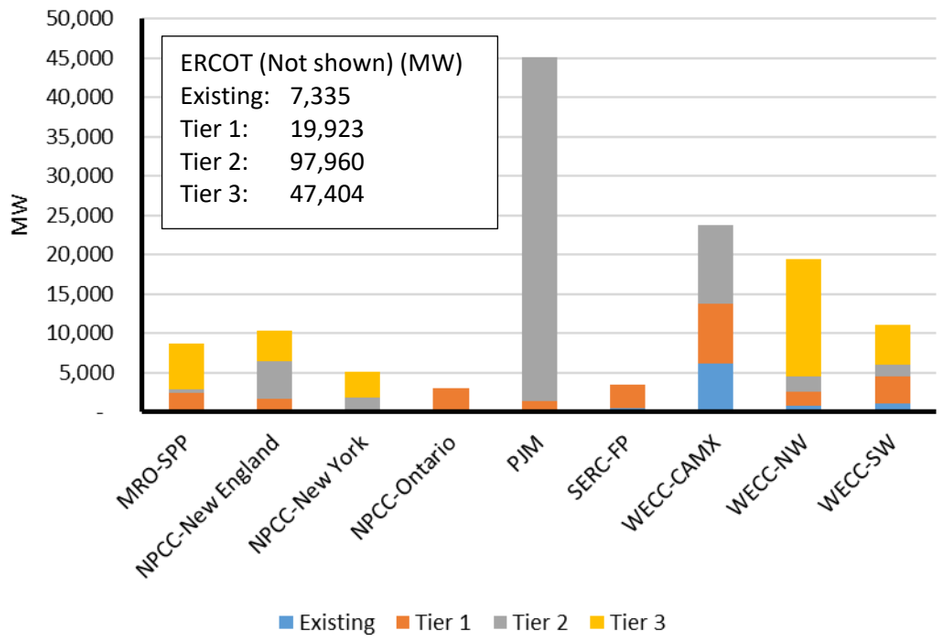


Figure 12: Battery Resource Capacity Existing and Planned through 2034

BESS are improving reliability by helping to offset the variability and uncertainty of inverter-based resources (IBR). BESS are, however, a relatively new type of grid resource with unique operating characteristics. The joint *NERC-WECC Staff Report: 2022 California Battery Energy Storage System Disturbances*[18] highlights an event when a BESS, like some other IBRs, failed to properly ride through a normal system fault. This indicates that BESS must be included in the currently underway strategies to address IBR performance issues.

Because the electrical output of variable energy resources (e.g., wind, solar PV) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. **Table 14** shows the nameplate value and the capacity contribution of existing wind, solar PV, hydro, and energy storage systems resources at the peak demand hour for each assessment area. During risk periods after peak demand (e.g., U.S. assessment areas in WECC), contributions of solar PV resources output is diminished during evening periods and additional resources are needed.

[18] NERC–WECC *2022 California Battery Energy Storage System Disturbances*

Table 14: BPS Wind, Solar, Hydro, and Battery Generation Resources by Assessment Area Year 2024												
Assessment Area	Wind			Solar			Hydro			Energy Storage Systems		
	Nameplate (MW)	Expected On-Peak Demand Hour	Expected Share of Nameplate (%)	Nameplate (MW)	Expected On-Peak Demand Hour	Expected Share of Nameplate (%)	Nameplate (MW)	Expected On-Peak Demand Hour	Expected Share of Nameplate (%)	Nameplate (MW)	Expected On-Peak Demand Hour	Expected Share of Nameplate (%)
MISO	41,349	5,715	13.8%	30,502	5,305	17.4%	2,450	1,576	64.3%	401	84	21.0%
MRO-Manitoba Hydro		52	-	-	-	-	6,434	5,704	88.7%	-	-	-
MRO-SaskPower	815	164	20.1%	30	-	-	864	862	99.8%	-	-	-
MRO-SPP	34,475	5,134	14.9%	703	275	39.1%	5,633	4,079	72.4%	2	2	100%
NPCC-Maritimes	-	261	-	-	5.1	-	1,361	1,312	96.4%	-	-	-
NPCC-New England	2,548	127	5.0%	3,361	308	9.2%	1,917	1,469	76.6%	26	9	34.9%
NPCC-New York	2,706	461	17.1%	1,039	240	23.1%	4,915	3,736	76.0%	60	30	50.2%
NPCC-Ontario	4,943	1,364	28%	478	-	0.0%	8,748	6,215	71.0%	18	-	0.0%
NPCC-Québec	3,820	1,375	36.0%	10	-	0.0%	40,907	39,354	96.2%	-	-	-
PJM	11,701	1,760	15.0%	10,735	4,808	44.8%	3,071	2,367	77.1%	222	100	44.8%
SERC-C	982	172	17.5%	2,308	771	33.4%	4,995	3,364	67.4%	100	50	50.0%
SERC-E	-	-	-	6,777	4,753	70.1%	3,170	3,016	95.1%	15	6	38.4%
SERC-FP	-	-	-	10,121	5,618	55.5%	-	-	-	538	523	97.2%
SERC-SE	-	-	-	7,267	5,414	74.5%	3,293	3,260	99.0%	115	40	34.9%
Texas RE-ERCOT	39,532	11,062	28.0%	31,058	19,098	61.5%	583	458	78.6%	10,720	-	0.0%
WECC-AB	5,559	1,867	33.6%	3,042	-	0.0%	894	285	31.9%	270	264	97.8%
WECC-BC	776	279	36.0%	2	-	0.0%	16,902	12,623	74.7%	-	-	-
WECC-CA/MX	7,694	1,158	15.0%	24,905	14,641	58.8%	10,211	3,582	35.1%	11,883	11,155	93.9%
WECC-NW	23,518	3,489	14.8%	12,787	6,877	53.8%	41,257	21,168	51.3%	1,909	1,231	64.5%
WECC-SW	3,784	628	16.6%	5,944	2,527	42.5%	1,025	721	70.3%	2,997	2,592	86.5%

Solar PV Distributed Energy Resource Growth

Behind-the-meter (BTM) solar PV generators are solar PV resources connected on the distribution system, such as residential rooftop solar systems. The rapid growth of BTM solar PV continues with cumulative levels expected to reach over 123 GW by the end of this 10-year assessment period (up from 89 GW reported in the *2023 LTRA*, an increase of 38%). There are currently 58.7 GW of installed BTM solar PV across the North American BPS.

BTM solar PV generators, like grid-connected solar PV, are also VERs. In large penetrations, their predictable change in output from the time of day contributes to steep ramps in demand. As the sun sets and output diminishes, grid resources must make up for the decrease in solar generation and increase in demand that was being served. The opposite ramp occurs during morning hours; it may be less impactful to reliability but can be challenging for grid-connected generator scheduling and dispatch. **Figure 13** shows the current and projected BTM solar PV by area through 2034.

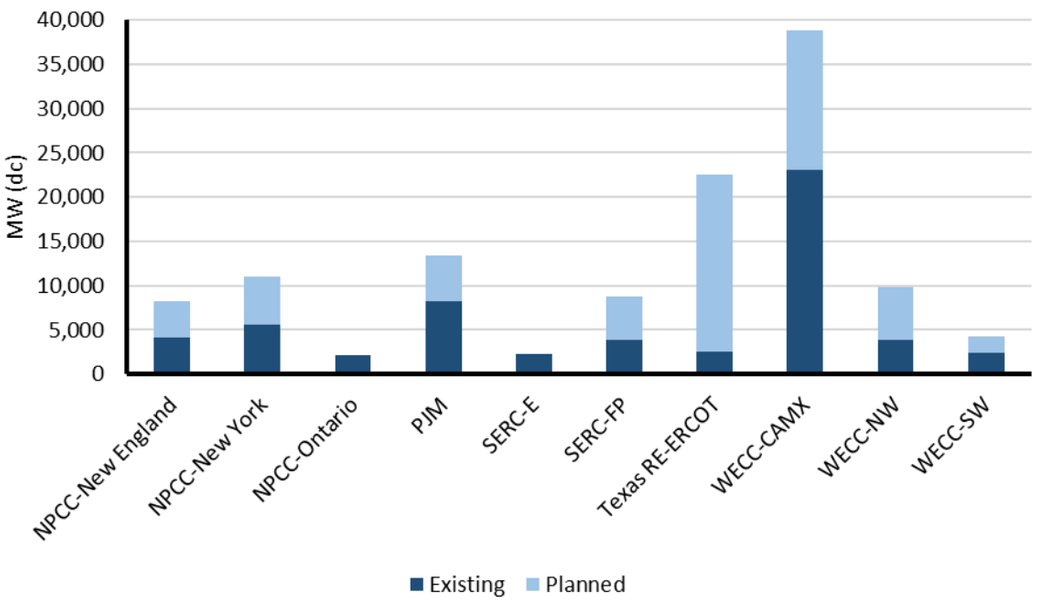


Figure 13: Solar PV DER Capacity Existing and Planned through 2034

Generation Retirements

The total capacity of traditional baseload generation fuel types will continue to decline as older generators retire. Generators become confirmed for retirement according to various processes in place in the Interconnections, such as regional planning tariffs in the wholesale electricity market areas or the integrated resource planning process in vertically integrated states. Properly designed mechanisms can prevent generators from retiring before planners can study and address reliability issues that could occur.

Currently, over 79 GW of fossil-fired and nuclear generating capacity is being retired over this assessment period (see **Figure 14**), a small decrease from the 83 GW in retirements reported in the *2023 LTRA*. This capacity includes generators that are confirmed for retirement through retirement planning processes or that have indicated plans to retire to an ISO/RTO or Planning Coordinator.

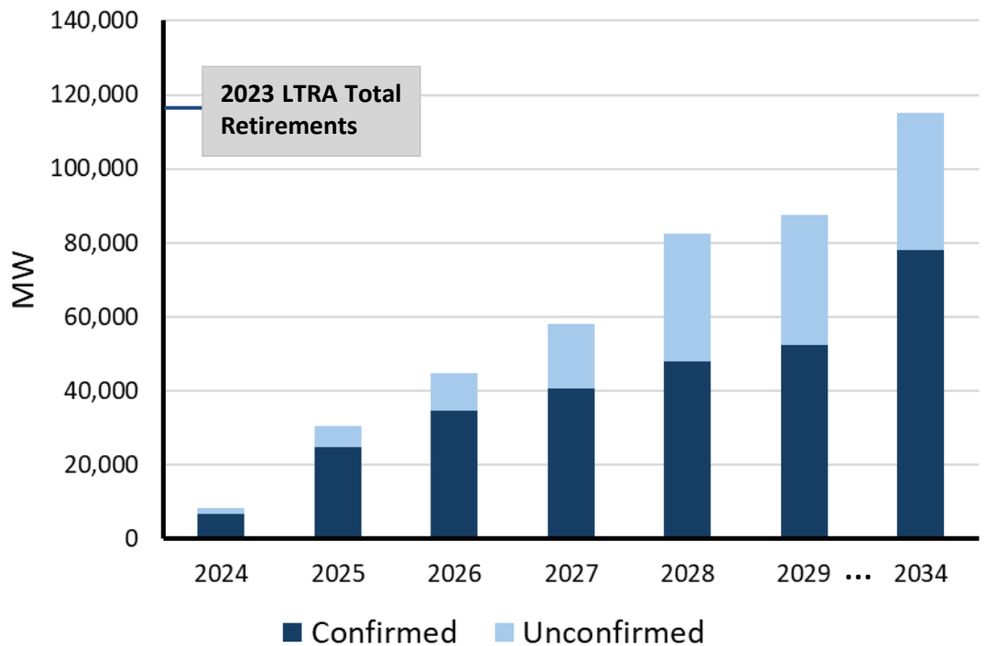


Figure 14: Projected Generation Retirement Capacity through 2034

Additional fossil-fired generator retirements are expected and would result in further loss of existing capacity. Generator Owners often announce plans to retire generator units before initiating the

interconnection planning process, and the announced plans or timing may be subject to change before the retirement is confirmed. Wholesale electricity market areas, where merchant electric generators make up a large part of the generating fleet, have more uncertainty around future generator retirements, making resource planning and adequacy assessment difficult. **Figure 15** shows the total capacity of reported retirements (i.e., reported to ISO/RTOs and planning entities) as well as owner-announced, unconfirmed retirements of fossil-fueled and nuclear generators across the BPS over the next 10 years in each assessment area.[19] This total of confirmed and announced-potential retirements over the next 10 years is over 115 GW (3 GW lower than 10-year projections in the *2023 LTRA*).

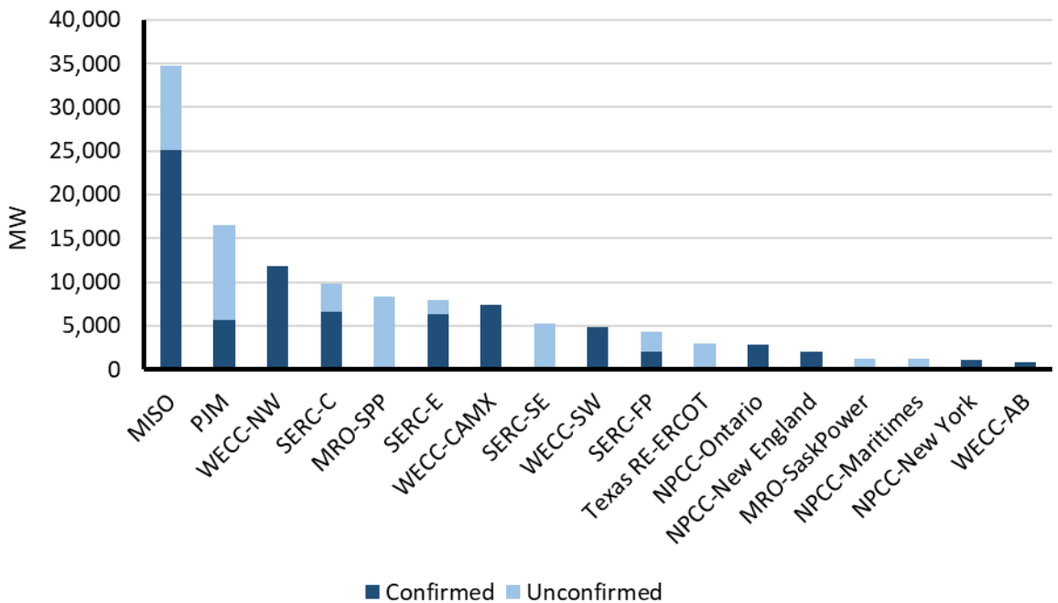


Figure 15: Projected Capacity Retirements of Nuclear and Fossil Generation 2024–2034

Natural Gas Fuel Reliance Trends

Natural-gas-fired generators are and will remain a critical resource for BPS reliability in many areas over the 10-year assessment period, especially during winter. These generators provide many necessary reliability attributes that are exiting the system as traditional generators retire and inverter-based renewable resources take their place in the resource mix. Natural-gas-fired generators are dispatchable and provide the ERSs of inertia, frequency response, and ramping flexibility. In winter, when peak demand in most areas occurs during early morning hours, natural-gas-fired generation is at its highest contribution to the resource mix in many areas. Severe winter weather events in 2021 and 2022 provided stark evidence of the critical nature of natural gas as a generator fuel and the importance of secure supplies during times of extreme electricity demand.

As the generation resource mix evolves and becomes more weather-dependent, fuel assurance becomes increasingly critical when conducting reliability assessments. Until recently, comparing seasonally available capacity to a predetermined PRM level has sufficed as a means to assess resource adequacy. However, resource adequacy is now only the first step of a meaningful reliability assessment. Energy adequacy must now be layered on top to assess the risk that available capacity may be rendered unavailable due to phenomena including low wind or solar output and/or natural gas supply and transportation issues.

This year, the Energy Information Administration (EIA) projected that more than 40% of delivered natural gas would be consumed by power generators, more than 0.6 Bcf/d higher than was consumed by power generators in 2023 and 7% higher than what the EIA had projected for 2024 in the fall of last year. Natural-gas-fired power plants generated 42% of the electrical energy consumed by end-use electricity customers in 2023 and are on track to maintain that share of generation this year. A significant percentage of natural-gas-fired power plants rely upon as-available, non-firm gas supply and transportation arrangements. Non-firm natural gas supply and transportation is generally sufficient for electric generators most of the year. However, during extreme cold weather, demand for natural gas by both generators and natural gas distribution companies (generally firm shippers) can at the same time dramatically increase. In these instances, generators that lack firm supply and transport arrangements are at risk of fuel unavailability, and when winter weather impacts gas production facilities, the resulting imbalance in pipeline injections and withdrawals can put at risk even firm pipeline customers as preparatory linepack is rapidly depleted.

[19] Confirmed generator retirements are reported to NERC by each assessment area in this *2024 LTRA* development process. NERC obtained data on announced, unconfirmed generator retirements from Energy Ventures Analysis, Inc. and from each assessment area. Some sources of information on announced generator retirements include EIA 860 data, trade press, and utility integrated resource plans.

The *2024 LTRA* projects that an additional 6,500 MW of new natural-gas-fired generation will be added in North America over the next five years. While some assessment areas project net decreases in natural-gas-fired capacity, other areas report increases ranging from 3% to over 50%.

In the United States, 8 out of 13 assessment areas are adding capacity to their fleet of natural-gas-fired power plants over the next 10 years, amounting to over 10 GW of new natural-gas-fired power capacity. Altogether, those additions translate to an increase in natural gas use for power generation of more than 84 Bcf (245 MMcf/d). Whether this increase in natural gas generation capacity is sufficient to meet the increase in net internal demand projected for these same assessment areas remains to be seen, but based on the capacity additions alone, some areas are set to see an insufficient increase in gas pipeline capacity, as per the EIA's database of nationwide U.S. gas pipeline projects. (see **Figure 16**).

PJM is one such area, projected to see a 3% increase in natural-gas-fired generation capacity (+2,500 MW). Net internal electricity demand in PJM is forecasted to rise by 25 GW over the planning horizon at the same time that non-variable resources are expected to shrink their share of the capacity mix from 96% to 88%. To the extent that variable resources are uncertain during times of peak stress on the grid, there is a risk of gas delivery capacity being insufficient for the amount of natural gas supply that could be required to meet the demand increase. SPP is another assessment area where natural-gas-fired power capacity is set to rise, by 5%, or roughly 1,500 MW. In both PJM and SPP, there is a risk of a shortfall in natural gas pipeline capacity that could facilitate delivery of the additional fuel that is necessary to meet their capacity expansion plans.

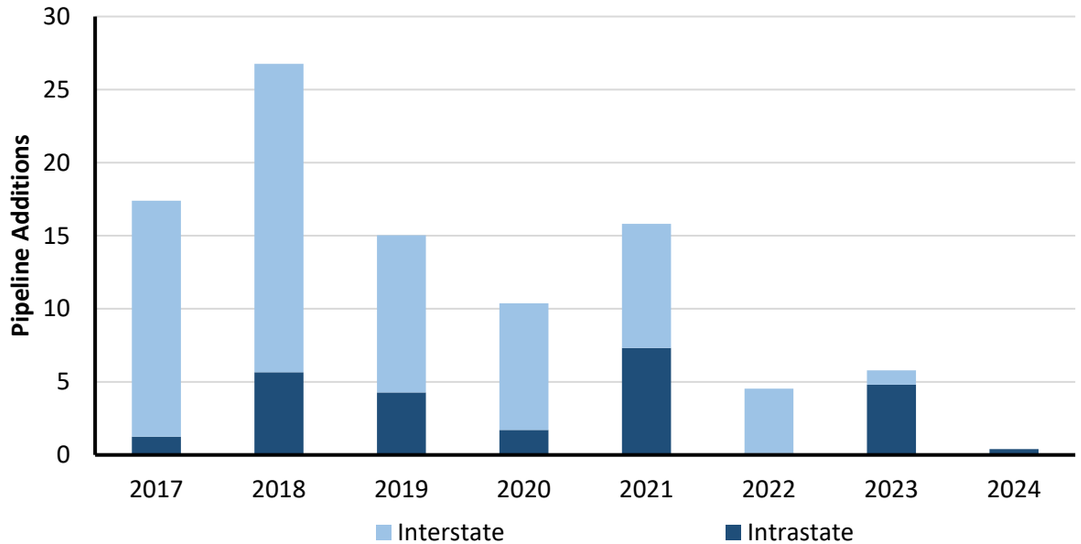


Figure 16: Annual U.S. Natural Gas Pipeline Capacity Additions by Type (2017–2024) Bcf/d (Source: U.S. Energy Information Administration)

Reliability Implications

The addition of variable resources, primarily wind and solar PV, and the retirement of conventional generation are fundamentally changing how the BPS is planned and operated. With electricity supplies coming increasingly from VERs and natural-gas-fired generators, there is a growing risk that supplies can fall short of demand during some periods. Geographically diverse wind and solar resources and loads can help reduce these risks, but they require robust transmission networks, comprehensive energy and transfer capability analysis, and effective operating procedures and market mechanisms.

Maintaining ERSs for Grid Support

For the grid to operate reliably, it needs resources that are not only sufficient for meeting demand and energy requirements but also capable of controlling voltages, maintaining stable frequency across the system, and flexibly ramping up or down to dispatch control at all times. Conventional generators, such as nuclear, coal, and natural gas-fired generators, provide much of the ERSs that support reliable operation today. New resources on the grid are almost all IBRs, which have different physical and operating characteristics that affect the level of ERSs that they can provide. Without the spinning mass or traditional excitation systems providing the voltage control of a hydroelectric or thermal generator,

most IBRs have limited capability for maintaining system voltages and stability. Batteries, with their fast response time, have some ERS capability that wind and solar do not. They are useful in regulating system frequency and are helping to balance variability from VERs in ERCOT and California where wind and solar make up a large portion of the resource mix.[20] As generators are deactivated and replaced by new types of resources, ERSs must still be maintained for the grid to operate reliably.

Accelerated generator retirements, especially unanticipated requests for deactivation, can cause ERS-related reliability issues in parts of the system due to the future loss of the generator's reliability attributes. This reduction in the level of ERSs can result in voltage violations or system instability. System planning and generator deactivation processes evaluate these changes to the system and ensure plans proceed only when reliability criteria, including ERS-related considerations, are met. For example, PJM's deactivation process identified reliability concerns to the system as a result of the requested deactivation of the Brandon Shores power plant (1,280 MW) in 2023. Until necessary system upgrades are completed to address identified system voltage and other reliability issues that would occur with the deactivation, PJM has requested that the Brandon Shores generators at the plant remain in service through the reliability-must-run process.[21]

To ensure the future system can operate reliably, market operators, system planners, regulators, and policymakers need to ensure effective mechanisms are in place to provide for the ERS needs of the future system. Long-term activities can provide incentives to generators with needed reliability attributes. Effective backstops will also be needed to prevent the loss of critical generators when analysis finds deactivation would violate reliability criteria.

Specific and actionable recommendations are contained in the **Recommendations and ERO Actions Summary** section of this report.

[20] See the *2023 Special Report on Battery Storage* from the California ISO.
[21] Information on this and other proposed deactivations in PJM are found on PJM's Generator Deactivations page.

Demand Trends and Implications

Demand and Energy Projections

Electricity peak demand and energy growth forecasts over the 10-year assessment period continue to climb higher than at any point in the past two decades. The aggregated assessment area summer peak demand forecast is expected to rise by over 132 GW, and aggregated winter peak demand forecasts are increasing by 149 GW. The growth rates of forecasted peak demand (see **Figure 17**) and energy (see **Figure 18**) continue to rise sharply since the 2022 LTRA, reversing an almost two-decade trend of falling or flat growth rates. See **Figure 17** for seasonal peak demand growth over the current and prior assessment periods and **Figure 18** for net energy growth. A map of the primary demand drivers for the North American BPS is illustrated for each assessment area in **Figure 19**.

Electrification and Demand Growth

Electrification of household appliances (e.g., heat pumps for household heating) and projections for electric vehicle growth over this assessment period are components of the demand and energy estimates provided by each assessment area. Since the *2023 LTRA*, peak season CAGR has risen in all assessment areas except two: NPCC-Maritimes' winter CAGR fell from 0.98% to 0.63% and WECC-BC's winter CAGR fell from 1.05% to 0.28%. Rising peak demand forecasts are contributing to the lower reserve margins projected for nearly all assessment areas.

Large Commercial and Industrial Loads

Increasing amounts of large commercial and industrial loads are connecting rapidly to the BPS. Emerging large loads, such as data centers (including crypto and AI) and hydrogen fuel plants, present unique challenges to forecasting and planning for increased demand. Earlier this year, NERC's RSTC established a Large Loads Task Force to better understand the reliability implications of growth in large loads and develop solutions.

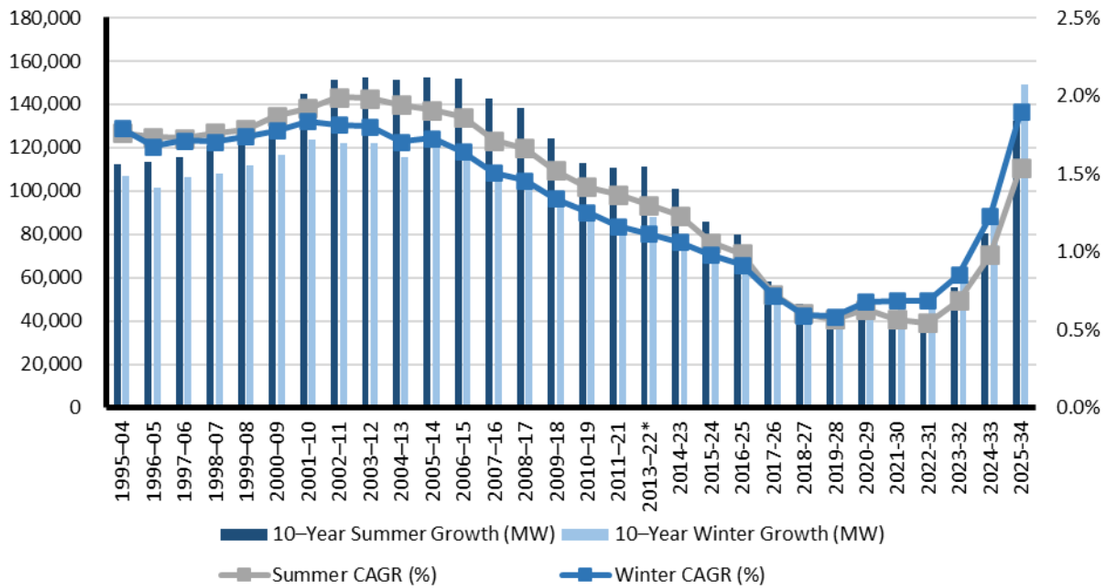


Figure 17: 10-Year Summer and Winter Peak Demand Growth and Rate Trends



Figure 18: Net Energy for Load Growth and Rate Projections

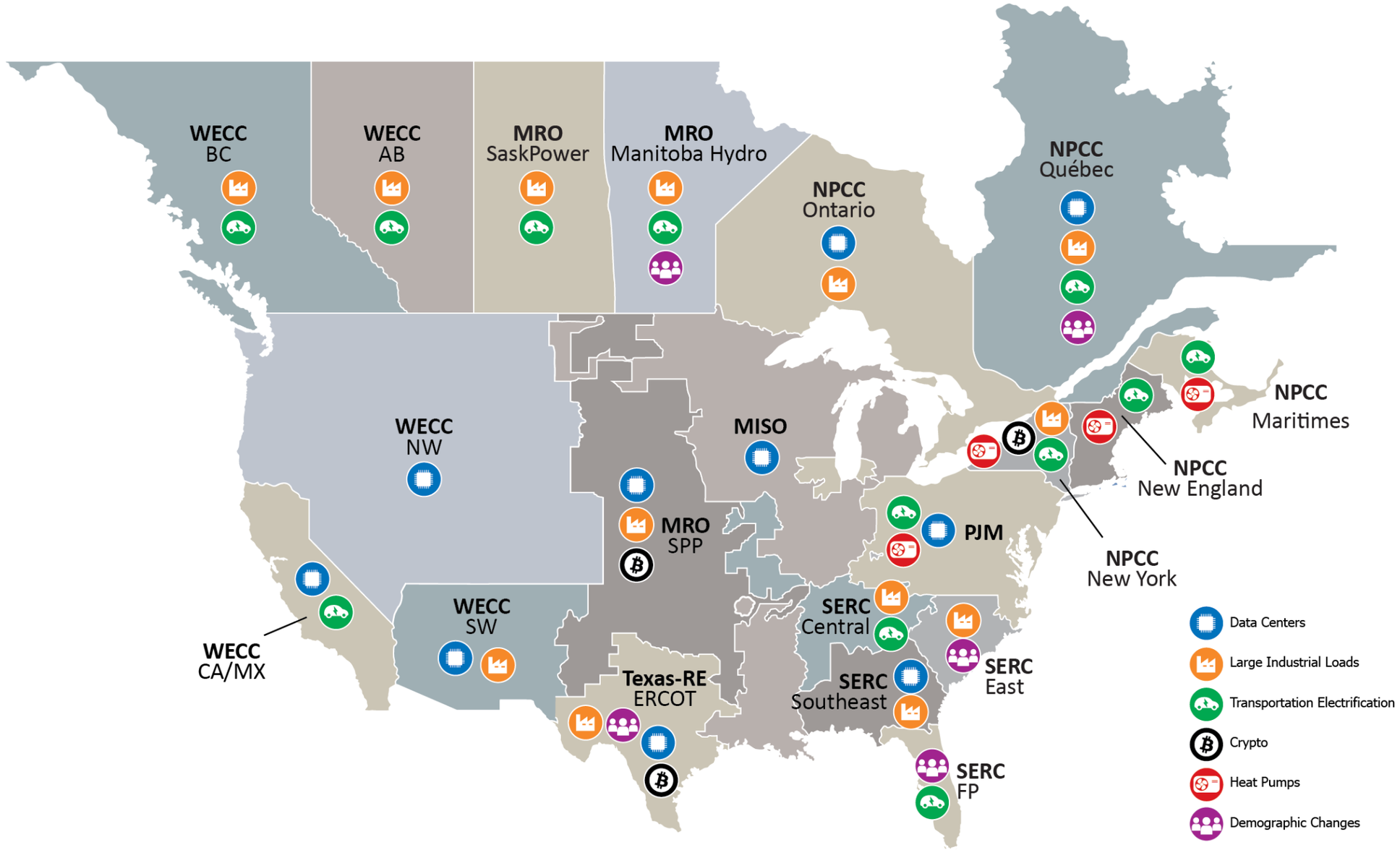


Figure 19: Primary Demand Drivers by Assessment Area

Peak Season Transition

Some of the sharpest peak demand forecast increases and growth rates can be seen in winter seasons as electrification in heating systems and transportation influence forecasts. Dual-peaking or changing from summer to winter peaking is anticipated in several areas, including the U.S. Southeast and Northeast. Electrification of heating systems and the anticipated growth of electric vehicles (which are expected to charge overnight and coincide with periods of electricity demand for heating) are driving factors. Such changes have wide-ranging implications for how the grid and resources are planned and operated. For example, resource output and fuel risks are significantly different in winter, requiring the focus of resource adequacy processes to change. The following are the areas that anticipate a change from a summer-peaking system to a winter-peaking (or dual-season peaking) system and the approximate year of the transition:

- NPCC-New England (mid-2030s)
- NPCC-New York (mid to late-2030s)
- NPCC-Ontario (2030)

In the U.S. Southeast, SERC-Central and SERC-East became dual-peaking systems in recent years. SERC-Southeast recently began experiencing slightly higher peak demand in winter compared to summer.

Reliability Implications

Demand and energy growth projections in this assessment period provide both challenges and opportunities for electric grid reliability. Planning for resource and transmission adequacy requires accurate long-term forecasting, but future demand and energy use will be influenced by many factors, including the economy, energy policies, technology development, weather, and consumer preferences. Changing patterns in electricity use, load behavior, and distributed energy resource performance affect the accuracy of operational load forecasts that are essential to grid operators. Large flexible loads and demand-side management programs hold promise for peak load management capabilities that can reduce the risk of firm load interruption.

Anticipating large commercial and industrial loads, electrification, electric vehicle adoption, and the impacts of energy transition programs on future demand and energy needs will require even more focus for planners and operators. Peak demand forecast changes in the past year had a noticeable effect on resource adequacy for many areas. A confluence of factors (economic, energy policies, technology development, and consumer preferences) has the potential to fuel continued growth.

Transmission Development and Interregional Transfer Capability

Transmission Projects

This year's cumulative level of 28,275 miles of transmission (>100 kV) in construction or stages of development for the next 10 years (see **Figure 20**) is substantially higher than the *2023 LTRA* 10-year projections (18,675 miles) and is above the average of the past five years of NERC's LTRA reporting on average (18,900 miles of transmission planning projects in each 10-year period published in the last five LTRAs). Transmission in construction has yet to increase substantially; rather, the large increase in transmission projects is seen in planning phases.

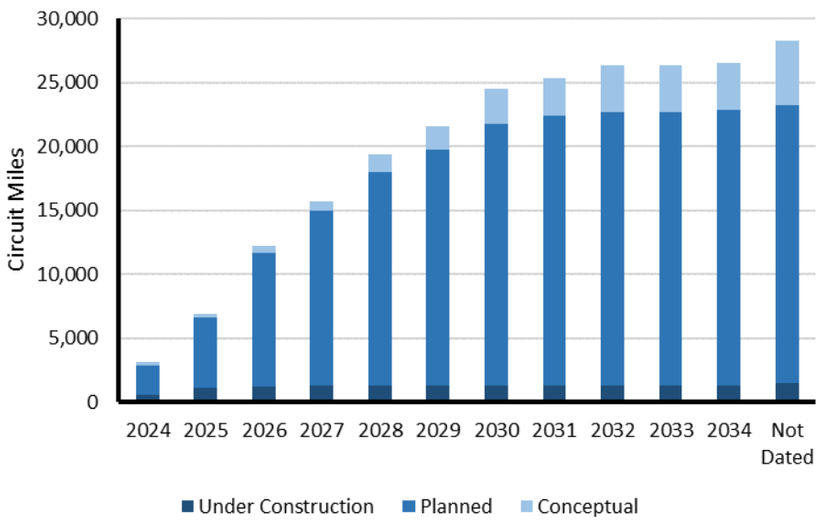


Figure 20: Future Transmission Circuit Miles >100 kV by Project Status

New transmission projects are being driven to support new generation and enhance reliability. **Figure 21** shows the percentage of future transmission circuit miles by primary driver. Most projects reported this year have been initiated for the purpose of grid reliability, which generally includes transmission projects that are needed to ensure that the BPS operates within established limits and design criteria. Some substantial new projects to integrate renewable generation are also in development or are entering planning processes. Nearly 70 of the 1,160 transmission projects in development are for tie-lines and tie-line upgrades, which support transfer capability between neighboring Balancing Authority areas. See the transmission summaries at the end of each assessment area's pages (in the **Regional Assessments Dashboards**) for current transmission development details.

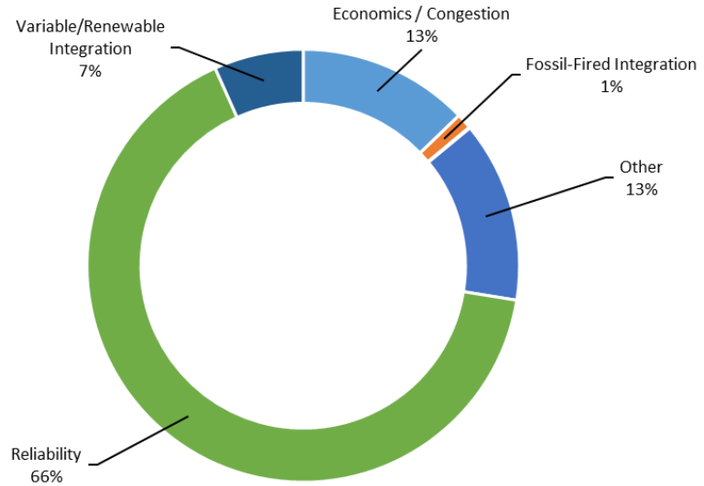


Figure 21: Future Transmission Circuit Miles by Primary Driver

Transmission development in some areas is hampered by siting and permitting challenges. Of the 1,160 projects that are under construction or in planning for the next 10 years, over 110 projects are currently delayed from their expected in-service dates. Siting and permitting issues are the most common cause for delays, affecting 68 projects (totaling 1,230 miles of new transmission). Other reasons for delays include economic impacts, planning and construction issues, or changing needs.

Interregional Transfer Capability Study (ITCS)

The Fiscal Responsibility Act of 2023[22] required NERC to conduct a comprehensive study of existing and future interregional transfer capability between each Transmission Planning Region[23] (TPR) to make recommendations for prudent additions to the amount of power that can be moved or transferred between neighboring TPRs and to make recommendations on how to meet and maintain transfer capability. In addressing this legislation, NERC identified additions to transfer capability that could support energy adequacy.[24] NERC filed the completed study report with FERC on November 19, 2024.[25]

Transfer Capability is the measure of the ability of the interconnected electric systems to reliably move or transfer electric power from one area to another area by way of all the transmission lines (or paths) between those areas under specific system conditions. The units of transfer capability are in terms of electric power, generally expressed in MW.

To provide further opportunities for stakeholder engagement and consultation, the project was divided into several stages, each with an accompanying report.

- **Overview of Study Need and Approach[26]:** Provided background and context regarding transfer capability calculations and the approach for recommending prudent additions, laying the foundation for the ITCS as a whole and its associated methods. (published in June 2024)
- **Transfer Capability Analysis (Part 1)[27]:** Addressed the first part of the congressional directive, which mandated a transfer capability analysis between each pair of neighboring TPRs, as well as the simultaneous import capability of each TPR. (published in August 2024)
- **Prudent Additions Recommendations (Part 2) and Meet/Maintain Recommendations (Part 3)**: Contained an energy margin analysis and resulting recommendations for prudent[28] additions to the transfer capability between neighboring TPRs to improve energy adequacy during, for example, extreme weather events. It also discussed how to meet and maintain transfer capability as enhanced by these prudent additions.
- **Canadian Analysis:** Due to the interconnected nature of the BPS, NERC will extend the study beyond the congressional mandate to identify and make recommendations to transfer capabilities from the United States to Canada and among Canadian provinces.[29]

Transfer Capability Analysis (Part 1)

Adequate transfer capability is fundamental to the reliable operation of the BPS. Balancing Authorities may rely on their neighbors to supply energy for various purposes, including economic or policy reasons. Transfer capability is also essential under stressed operating conditions, allowing Balancing Authorities to maintain reliability by importing needed energy from their neighbors. As the resource mix becomes increasingly dependent on just-in-time and weather-dependent fuel and energy for wind and solar, the ability to transfer electrical energy from areas of surplus to areas experiencing fuel or energy constraints has become essential to maintaining reliable delivery of electricity to end-use customers.

The ITCS is a congressionally mandated study to evaluate transfer capability and recommend additions to strengthen reliability.

A holistic view of the interconnected system and a thorough understanding of its behavior are essential when calculating or increasing transfer capability. When neighboring TPRs transfer energy over a highly interconnected system, the energy flows over many different lines based on the electrical characteristics, or impedance, of traveling each route, unless there is specific equipment used to control flows. As a result, energy typically flows not only across the tie lines that directly connect the exporting (source) TPR to the importing (sink) TPR but over many routes, some of which

[22] H.R.3746 - 118th Congress (2023–2024): Fiscal Responsibility Act of 2023 | Congress.gov | Library of Congress
[23] For the purposes of the ITCS, this term refers to the study regions as described in ITCS Overview of Study Need and Approach, Chapter 2.
[24] As evidenced during recent operational events including Western Interconnection Heatwave (2020), Winter Storm Uri (2021) and Winter Storm Elliott (2022), more needs to be done to support energy adequacy to be able to continuously meet customer demand. This is the reliability risk that the ITCS seeks to identify and mitigate through additions to transfer capability.
[25] NERC filing of the Interregional Transfer Capability Study, FERC Docket AD25-4-000.
[26] The ITCS Overview of Study Need and Approach can be found here.
[27] The ITCS Transfer Capability Analysis (Part 1) report can be found here.
[28] FERC defines prudence as the determination of whether a reasonable entity would have made the same decision in good faith under the same circumstances at the relevant point in time. See, e.g., New England Power Co., 31 FERC ¶61,047 at p. 61,084 (1985); and PotomacAppalachian Transmission Highline, LLC, 140 FERC ¶61,229 at P 82 2012 (Sept. 20, 2012).
[29] The ITCS Part 1 evaluated transfer capability from Canada into the United States.

may be running through third-party systems. The way electrical energy flows has broad implications for calculating and using transfer capability in an interconnected system, especially when traveling over long distances. For example, maintaining and increasing transfer capability may be highly dependent on the system conditions within the source and sink TPRs as well as surrounding areas. Likewise, transfer capability does not correlate one-to-one with the rating of new or upgraded transmission facilities.

Part 1 Key Findings

- Transfer capability varies seasonally and under different system conditions that limit transmission loading—it cannot be represented by a single number.
- Transfer capability varies widely across North America, with total import capability varying between 1% and 92% of peak load.
- Observed transfer capabilities are generally higher in the West Coast, Great Lakes, and Mid-Atlantic areas but relatively lower in the Mountain States, Great Plains, Southeast, and Northeast. There is limited transfer capability between interconnections

The transfer capability results in the Part 1 report reflect the conditions studied and are not an exhaustive evaluation of the potential for energy transfers. This study used a set of cases representative of stressed system conditions most relevant for the Part 2 analysis. As such, the study did not attempt to maximize transfer capability values for each interface through optimal generation re-dispatch, system topology changes, or other operational measures. Consequently, higher transfer capabilities may be available under different conditions. Changes to future resource additions, resource retirements, load forecast changes, and/or transmission expansion plans have the potential to significantly alter the study results.

Recommendations for Prudent Additions (Part 2) and to Achieve Transfer Capability (Part 3)

Part 2 of the ITCS evaluated the energy adequacy of the BPS should past weather conditions occur again in 2033. Specifically, the study applied 12 past weather years to the 2033 loads and resource mix using the current transfer capabilities as calculated in Part 1. The Part 2 study then evaluated the impact that additional transfer capability could have in mitigating the identified resource deficiencies[30] during extreme events, thereby improving energy adequacy. Using a six-step process, the ITCS developed a list of recommended additions to transfer capability. **Figure 22** shows the existing and potential new interfaces where additional transfer capability is recommended. While there are several factors that Transmission Planners consider, including reliability, economics, and policy objectives, given NERC's role as the ERO, the ITCS focused solely on reliability, specifically in terms of energy adequacy, for these recommendations.

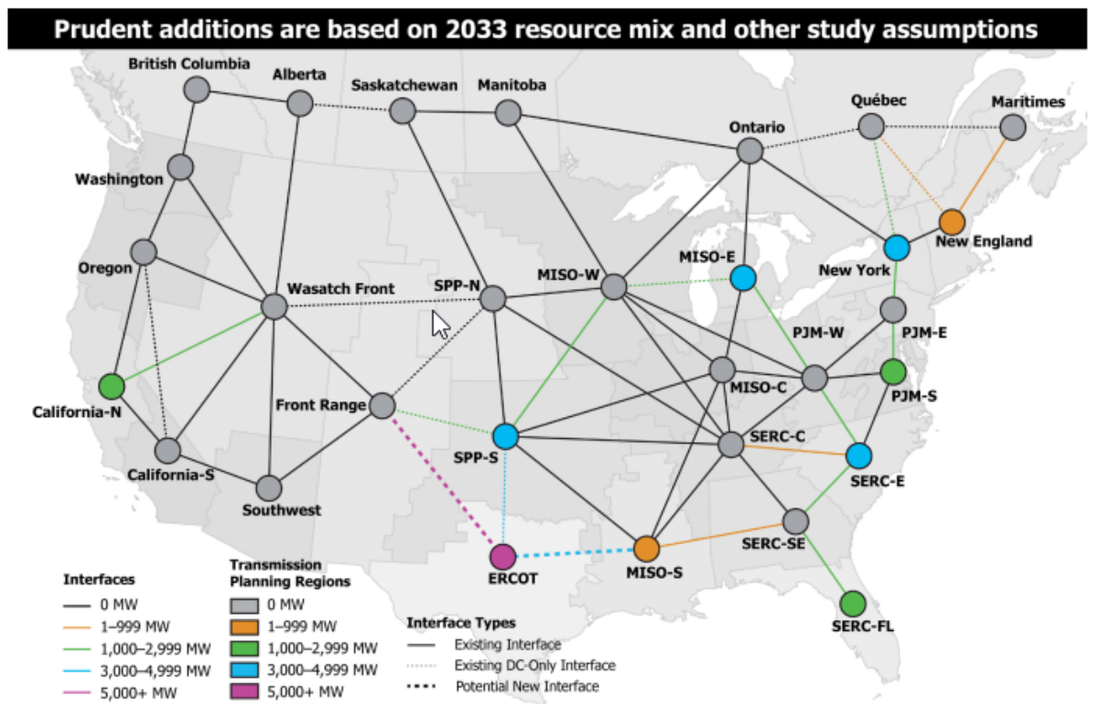


Figure 22: Prudent Additions to Transfer Capability

[30] For the purposes of this study, "resource deficiency" is used to describe instances where available resources, including energy transfers from neighbors, are insufficient to meet the projected demand plus minimum margin level.

The resulting recommendations for prudent additions to transfer capability (Part 2 study) were published in a report along with recommendations to meet and maintain transfer capability as enhanced by the prudent additions (Part 3).[31] Planners have multiple options for reducing the energy adequacy and extreme weather risks. In addition to the transmission enhancements that were in scope for the ITCS, due consideration should also be given to constructing local generation and storage, demand-side management approaches, and grid resilience projects. The ITCS recommended that planners consider all options and balance reliance on external resources vs. internal resources, noting that there may be better options than an over-reliance on one or the other.

Part 2 Key Findings

- Import capability required to reliably serve customers during extreme conditions varied significantly across the country, so a one-size-fits-all requirement would be inefficient and ineffective.
- Transmission limitations and the potential for energy inadequacy were identified in all 12 years studied.
- 35 GW of additional transfer capability is recommended across the United States to improve energy adequacy under extreme conditions.
- Some identified transmission needs could be alleviated by projects already in the planning, permitting, or construction phases. If completed, these projects could mitigate several risks highlighted by the ITCS, reinforcing their importance for grid resilience.
- The ITCS provides foundational insights for further discussion, and decisions. Transmission upgrades alone will not fully address all risks, and a broader set of solutions should be considered, emphasizing the need for local resources, energy efficiency, demand-side, and storage solutions.

See the *ITCS Final Report* for Detailed Key Findings

[31] The ITCS report *Recommendations for Prudent Additions to Transfer Capability (Part 2) and Recommendations to Meet and Maintain Transfer Capability (Part 3)* can be found here.

Emerging Issues

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

Data Centers and Large Industrial Load

Growth in large load parcels like data centers and industrial facilities pose various challenges for system planners and operators, in addition to fueling rapid demand growth discussed elsewhere in this report. **Figure 23** shows one estimate of data center growth in the United States by 2027.[32] Other types of large industrial loads include smelters, manufacturing centers, hydrogen electrolyzers, and future electrified mass transit or shipping charging stations. Adding large parcels of load on the system can add new uncertainties to peak and hourly load forecasting. For example, data centers have longer operating hours and require more heating and cooling than other commercial buildings. In Texas, crypto mining facilities have connected in recent years that scale their operations (and thus electricity demand) depending on electricity prices. The behavior of large data centers during normal grid faults is also an emerging concern because customer-initiated automatic disconnecting of sizeable load can cause operating issues. Sudden and unexpected disconnecting load during a grid fault is analogous to well-known IBR performance issues and poses similar reliability risks. Planners and operators need to consider the characteristics of these loads as they begin to proliferate and support NERC RSTC's Large Loads Task Force to share best practices.

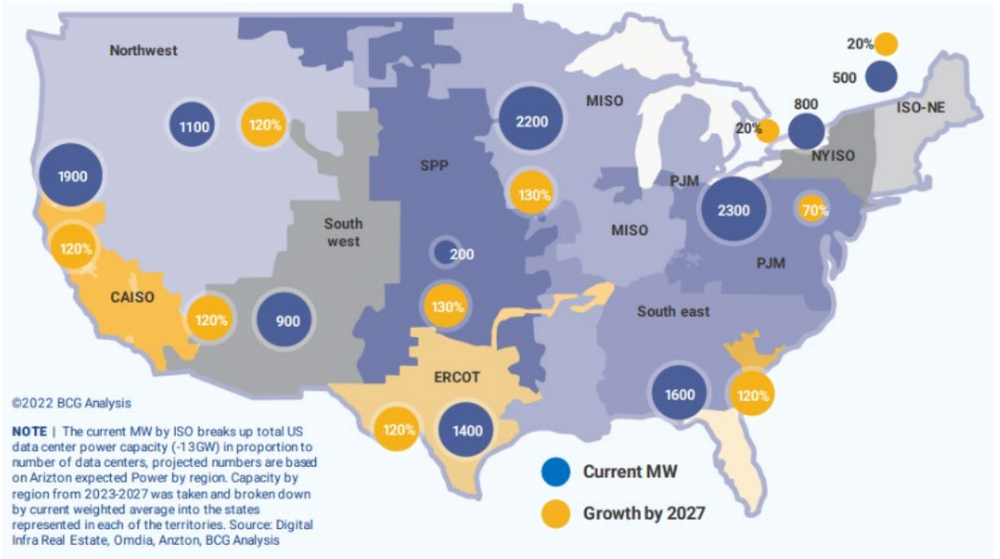


Figure 23: Projected Growth in Data Centers in the United States

Battery Energy Storage Systems

Planners and operators are focused on requirements to model, study, and operate the BPS with increased BESS and hybrid resources. BESS are increasingly being relied upon in areas with substantial amounts of solar PV resources to reduce ramping requirements on other resources by discharging in late afternoon as solar PV output rapidly declines. BESS are also often used for ancillary services, such as frequency response. Accurately accounting for BESS in operating and planning studies is a challenge because it requires assumptions and modeling capabilities for battery charging and discharging behavior. In real-time operations, system operators often do not have visibility into battery state-of-charge, a necessary condition for reliably integrating batteries into system operating plans. Without such information, operators may be surprised should battery resources fail to deliver when needed. In Texas, where battery resource growth is among the highest in North America, ERCOT uses a battery storage data collection program to obtain operational information and is pursuing market rules for state-of-charge accounting in unit commitment processes. System planners in many areas will be counting on new BESS facilities to manage variability and demand and resources. Obtaining the benefits of these resources requires careful integration into operating, planning, and market designs.

[32] *Grid Strategies: The Era of Flat Power Demand is Over*: https://gridstrategiesllc.com/wp-content/uploads/2023/12/National-Load-Growth-Report-2023.pdf

Electric Vehicles and Electric Load

With increased adoption of electric vehicles (EV), which use batteries to store energy, there is a need to understand the impact of battery charging on system performance. EV forecasting is important for resource adequacy and system planning to account for changing load and load patterns. It is also important for system studies to include EV modeling and parameterization that account for the behavior of battery charging systems on system performance. In January 2024, NERC released the *EV Charging Study*, noting that the behavior of large amounts of EV chargers in operation can affect the BPS response to common outages. The RSTC established an EV Task Force to promote collaboration among the electric power industry and automotive representatives on areas of grid reliability.

Energy Drought

More reliance on wind, solar, and hydro resources in the resource mix has the potential to expose the electric system to supply shortages under abnormal weather patterns. When two or more resource types are simultaneously affected by conditions that cause below-normal resource output, operators can face challenges in meeting demand. Analysis of U.S. historical hourly generator data indicates that there are regional patterns to energy drought that can be expressed in terms of duration, magnitude, and seasonality (See **Figure 24**). There is also a higher likelihood for energy droughts to be more likely occur during high-load periods than at other times, underscoring the importance in considering such events in planning for resource and storage needs.[33]

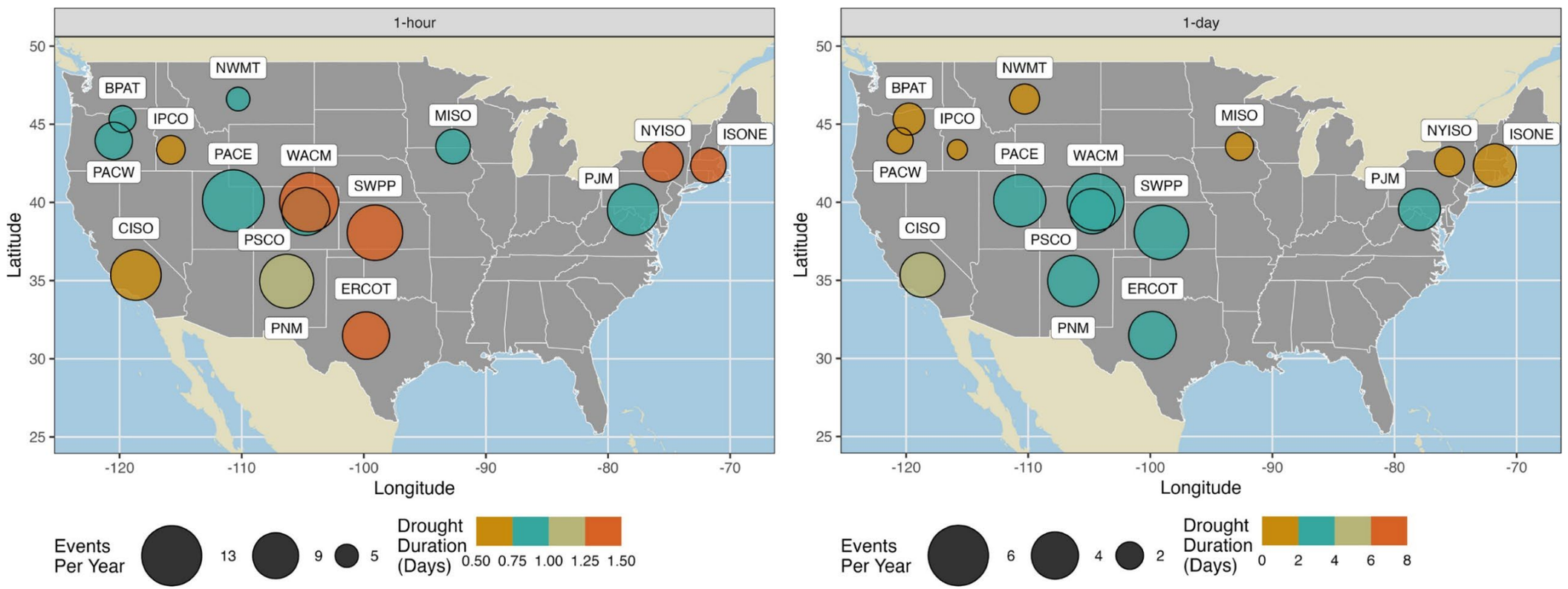
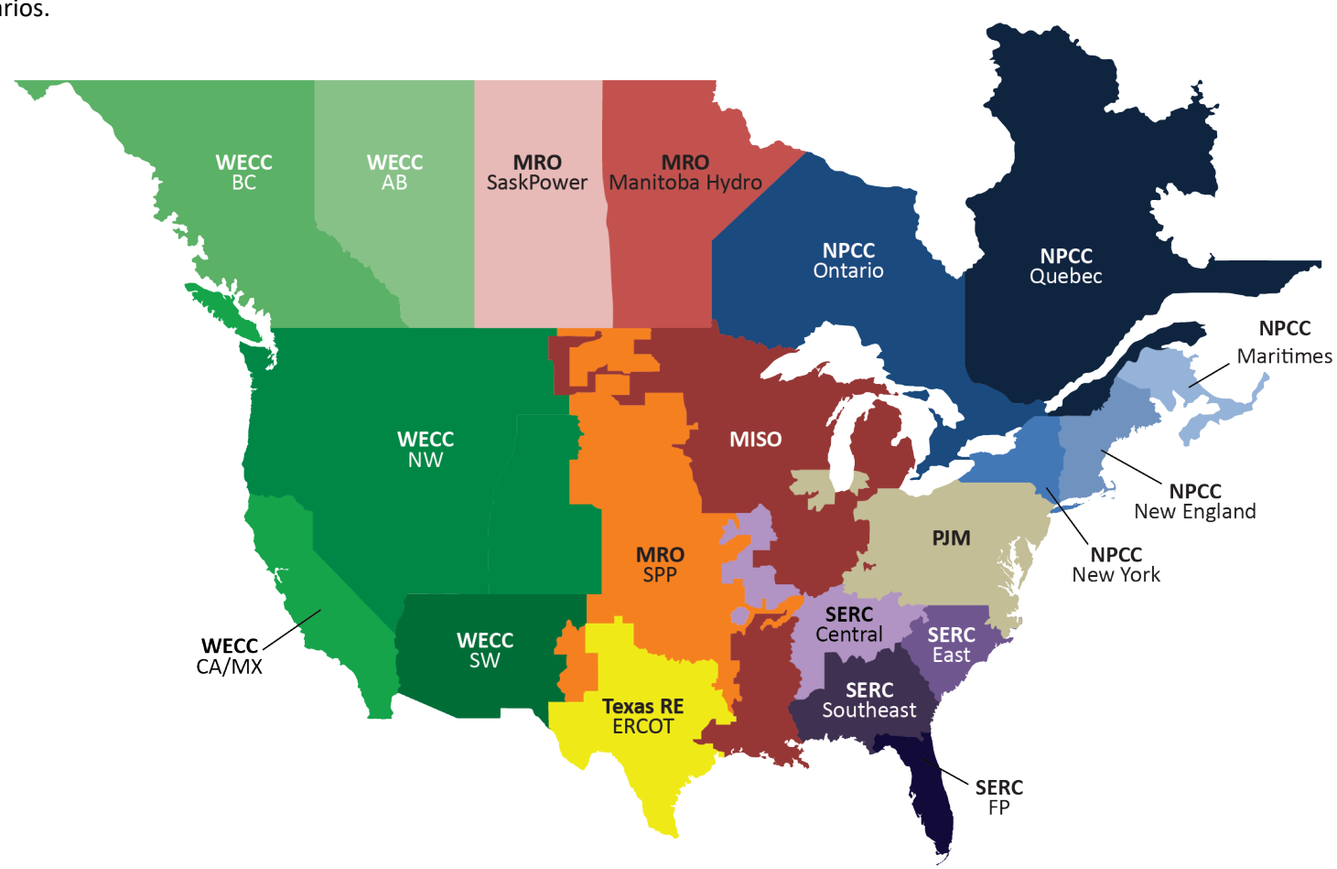


Figure 24: Frequency and Duration of Hourly (Left Panel) and Daily (Right Panel) Energy Droughts. Source: Pacific Northwest National Laboratory

[33] See Standardized benchmark of historical compound wind and solar energy droughts across the Continental United States

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. Guidelines and definitions are in the **Demand Assumptions and Resource Categories** table. On-Peak Reserve Margin bar charts show the ARM compared to the RML established for the area to meet resource adequacy criteria. Prospective Reserve Margins can give an indication of additional on-peak capacity but are not used for assessing adequacy. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left blue column shows anticipated resources (from the Demand and Resource Tables), and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand (from the Demand and Resource Tables) and the extreme winter peak demand determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources. Adjustments may include reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools (if any) that are available during scarcity conditions but have not been accounted for in the WRA reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios.



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

MRO – Midwest Reliability Organization
- MRO-Manitoba Hydro
- MRO-SaskPower
- MRO-SPP

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

SERC – SERC Reliability Corporation
- SERC-Central
- SERC-East
- SERC-Southeast
- SERC-Florida Peninsula

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

WECC
- WECC-AB *(Alberta)*
- WECC-BC *(British Colombia)*
- WECC-CA/MX *(California/Mexico)*
- WECC-NW *(Northwest)*
- WECC-SW *(Southwest)*



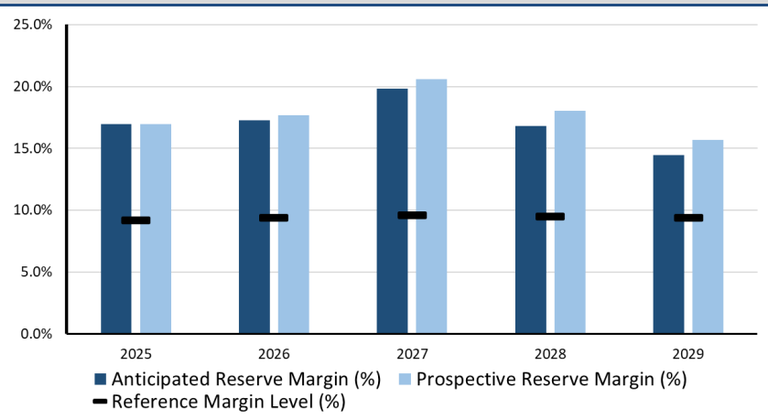
MISO

Midcontinent Independent System Operator, Inc. (MISO) is a not-for profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy, reliability, and operating reserve markets that consist of 36 local Balancing Authority and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

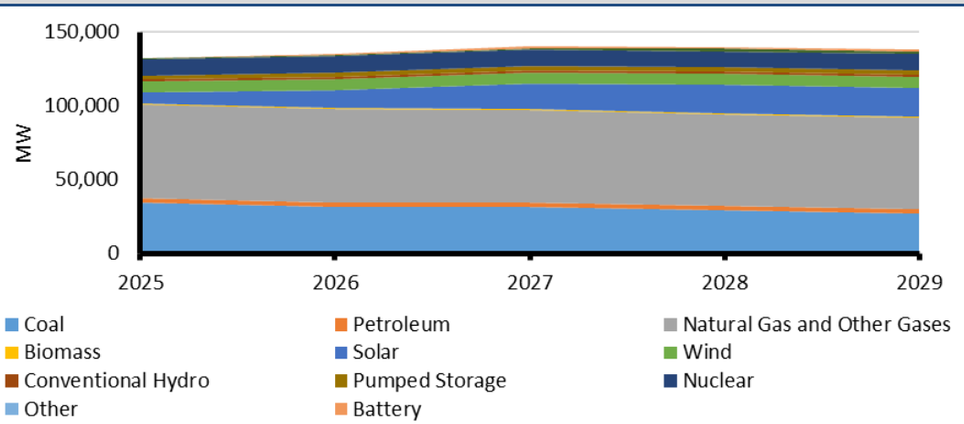
Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	122,328	124,343	126,073	128,700	129,401	130,120	130,493	131,327	131,952	131,952
Demand Response	8,205	8,221	8,058	8,065	8,074	8,077	8,079	8,075	8,075	8,075
Net Internal Demand	114,122	116,122	118,015	120,635	121,327	122,043	122,414	123,252	123,877	123,877
Additions: Tier 1	4,959	11,376	18,275	21,501	22,205	22,205	22,205	22,205	22,205	22,205
Additions: Tier 2	19	464	916	1,486	1,486	1,486	1,486	1,486	1,486	1,486
Additions: Tier 3	803	3,686	8,252	13,017	15,546	16,399	16,542	16,608	16,659	16,659
Net Firm Capacity Transfers	1,320	1,270	1,165	925	855	750	549	549	549	549
Existing-Certain and Net Firm Transfers	128,520	124,787	123,153	119,397	116,669	112,823	110,273	110,273	106,838	106,838
Anticipated Reserve Margin (%)	17.0%	17.3%	19.8%	16.8%	14.5%	10.6%	8.2%	7.5%	4.2%	4.2%
Prospective Reserve Margin (%)	17.0%	17.7%	20.6%	18.0%	15.7%	11.9%	9.4%	8.7%	5.4%	5.4%
Reference Margin Level (%) (Summer)	9.2%	9.4%	9.6%	9.5%	9.4%	9.4%	9.5%	9.6%	9.7%	9.7%

Note: See **Figure 3** for summer reserve margins with historically average resource additions in MISO based on results from the 2024 Organization of MISO States (OMS)-MISO Survey.



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- MISO's capacity resource turnover continues to occur with coal unit contributions being primarily replaced by solar, wind, and battery facilities. Furthermore, generation installation delays result in uncertainty throughout the assessment timeframe. As a result of these factors, MISO is facing capacity shortfalls in the next five years.
- MISO's reduction in capacity resources since the *2023 LTRA* has primarily been in the coal fleet with a reduction of 6,200 MW in the first year of the assessment.
- MISO has continued the seasonal capacity auction construct and has found growing evidence of risk in non-peak (e.g., spring and fall) seasons. Countering the risk during these off-peak seasons requires more resources to be available, and this can result in less opportunity for generators to pursue their maintenance needs. During peak seasons when high levels of generator availability are expected, short-notice unplanned outages and higher forced outages could occur as a result of deferred maintenance and challenge reliability.

MISO Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	**2026**	**2027**	**2028**	**2029**
Coal	34,637	31,706	31,618	29,067	26,841
Coal*	27,450	24,362	23,203	17,977	16,744
Petroleum	3,065	3,058	3,060	3,050	3,050
Petroleum*	2,992	2,990	2,992	2,992	2,992
Natural Gas	63,051	62,977	62,616	62,394	62,009
Natural Gas*	62,576	61,543	62,396	62,394	62,009
Biomass	577	571	553	481	481
Solar	8,091	12,538	17,318	19,174	19,763
Wind	6,954	7,236	7,536	7,632	7,660
Conventional Hydro	1,527	1,527	1,527	1,527	1,527
Pumped Storage	2,528	2,528	2,578	2,578	2,578
Nuclear	11,027	11,127	11,127	11,127	11,127
Other	72	72	72	72	72
Battery	208	582	1,011	1,358	1,377
Total MW	132,159	134,892	140,263	139,973	138,018
Total MW*	124,423	126,048	131,562	128,826	127,864
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to give formal notice to MISO are removed from the resource projection where marked.					

MISO Assessment

Planning Reserve Margins

The planning reserves across the MISO footprint in the summer are projected to fall below reserve margin requirements as new generation coming on-line could be insufficient to make up for generator retirements and load growth. It is important to note that there is 56 GW of generation with signed generation interconnection agreements that are yet to come on-line as of July 5, 2024, so there is an opportunity to accelerate installation speeds. However, if resource additions remain at or near historically average levels (approximately 2.3 GW/year average over the last 3 years), PRMs in MISO will fall below the RML reserve margin requirements much faster. Summer PRMs with average resource additions are shown in **Figure 3** as **Reserve Margin-Avg Addition**.

Increased coordination between MISO and its members will be critical to ensuring reliability throughout this resource transition of integrating new intermittent resources and continuing to retire conventional resources. Resource adequacy is a key function of MISO, and the MISO annual planning resource auction (PRA) provides a mechanism for capacity sellers to provide resources that meet the needs of load-serving entities for each of the four seasons in the upcoming year. MISO's resource adequacy construct complements the jurisdiction that regulatory authorities have in determining the necessary level of adequacy.

Note: Capacity values for existing resources in tables on p. 41–42 reported by MISO reflect the Seasonal Accredited Capacity (SAC) for Summer. Adjustments and derates are applied to account for factors affecting expected resource output. The RML in the Demand, Resources, and Reserve Margins table on p. 41 is the Unforced Capacity (UCAP) RML, consistent with the reported capacity values.

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

The introduction of the seasonal PRA and inputs to the process provide more granularity and reliability planning for non-peak hour times during the year. In addition to that change, MISO conducts seasonal resource assessments evaluating generation availability, outage rates, and forecasted load variation across all four seasons. Refer to MISO's Resource Adequacy page.

Probabilistic Assessments

To establish RMLs that define the minimum reserve margins for resource adequacy, MISO performs its annual probabilistic Loss-of-Load Expectation (LOLE) Study per MISO tariff. In recent years, MISO improved its LOLE study modeling by including seasonal outage rates, correlated cold weather outage adder profiles, a probabilistic distribution of non-firm support, and 30 years of hourly wind and solar profiles. The LOLE study produces seasonal RMLs for the upcoming planning year that are used in MISO's planning resource auction. These RMLs are calculated such that they prescribe the minimum PRM that will meet an LOLE of 1 day in 10 years. For more information on the seasonal LOLE Study, visit: https://cdn.misoenergy.org/LOLE%20Study%20Report%20PY%202024-2025631112.pdf.

MISO also performed a probabilistic analysis for the 2024 ProbA. Because MISO used the same model for both the ProbA and the LOLE study, transmission limitations were not included explicitly in the simulations. It is appropriate for MISO to make this assumption for the LOLE study and for determining capacity needs in the MISO system because MISO accounts for transmission limitations elsewhere in the resource adequacy process. However, for an adequacy assessment like the ProbA, the assumption can overvalue resource performance by not accounting for transmission constraints on the deliverability of energy resources. The resulting 2024 ProbA metrics in the table below can understate the risk of unserved energy and load loss.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	68.8	**0.000**	**0.000**
EUE (PPM)	0.108	**0.000**	**0.000**
LOLH (hours per year)	0.393	**0.000**	**0.000**
Operable On-Peak Margin	13.9%	**11.3%**	**11.3%**

* Provides the 2022 ProbA Results for Comparison

MISO is an elevated risk in the *2024 LTRA* because probabilistic assessments indicate above-normal generator outages during extreme weather can result in unserved energy or load loss. All-hours probabilistic studies of the MISO system performed apart from the 2024 ProbA show that shortfall risks can also occur during spring and fall in months that are not peak demand seasons for MISO. The 2022 NERC ProbA Regional Risk Scenario Sensitivity Case included seasonal forced-outage rates and correlated cold weather outages instead of annual average outage rates. MISO found that not only did EUE increase in this sensitivity, but it was also spread throughout the year. Since this study, MISO implemented enhancements to its LOLE study and PRA to address seasonal resource needs.

Demand

The peak demand forecast has increased from the *2023 LTRA* by close to 3 GW (~2.5%), and, while the load forecasts still vary across year to year, the load at the end of the study horizon is ~5 GW higher (~4%). Load-serving entities do not include DR resources in the load forecast, and MISO does not have much insight into the amount of electrification built into the load forecasts. There are other studies at MISO investigating electrification and transportation industry impacts to load forecasts

through the MTEP report. MISO contracted with Applied Energy Group (AEG) to evaluate the MISO footprint's electrification potential. This is documented in the report and has been utilized to update the MISO Futures Report.

Demand-Side Management

DR programs continue to play a significant role in providing capacity to MISO. DR is steady around 8 GW in the summer and 6.5 GW in the winter and is projected to remain constant during the study horizon. MISO's transition to seasonal auctions highlights accreditation of DR and availability during non-summer seasons.

Distributed Energy Resources

Behind-the-meter generation (BTMG) resources contribute about 4.2 GW of capacity across the study horizon, of which ~1.2 GW are distributed PV. MISO's transition to seasonal auctions highlights the availability of DERs across the four seasons, and MISO is working with stakeholders to derive adequate methods of aggregating, reporting, and allowing DER participation in MISO markets.

Generation

The departure of MISO's coal fleet has continued with a reduction in capacity of around 6 GW in the past year, and a projected reduction of a further 12 GW over the next five years. Solar continues to rise in capacity contributions with a growth of 1,200 MW since the *2023 LTRA* and growth of 3,200 MW in the first year of the study.

There are ~56 GW installed capacity (ICAP) of generation (predominantly solar and battery) with signed generation interconnection agreements in MISO that are projected to come on-line over the next few years. There have been some supply chain and tariff issues that have delayed the commercial operation of these resources.

Due to the large size in the MISO interconnection queue, in the 2022 LTRA (similarly to the OMS-MISO Survey), prospective generation in the queue gets multiplied by a factor based on the study phase and likelihood of that resource coming on-line and gets added into the footprint over time. This reduction is utilized to minimize the impact of prospective generation projects that will not come to fruition through the queue cycle. MISO continues to pursue queue reform efforts to expedite the process by ensuring projects being studied are of adequate certainty.

Transmission

The MISO Transmission Expansion Plan (MTEP) 2021 included the Long-Range Transmission Plan (LRTP) tranche 1 projects totaling $10.3 billion in investment for reliability and economic benefits estimated at $23–52 billion across the MISO footprint while also facilitating the integration of ~53 GW of new resources. In MTEP22, $4.3 billion in transmission projects were approved with $550 million going toward integrating new resources, $550 million going toward baseline reliability projects, and the age and condition category for the rest. MTEP23 includes a further $9 billion investment into the MISO footprint to address the local needs of the region. MISO is also pursuing LRTP tranche 2 with an expected investment of $18-23 billion to implement a 765 kV backbone into the northern portion of the footprint. These projects are expected to be included as part of MISO's MTEP24 project portfolio. In MTEP24, $6.7 billion in transmission projects have been submitted for board approval. MISO is also pursuing LRTP tranche 2.1 with an expected investment of $21.8 billion to implement a 765 kV backbone into the midwestern portion of the footprint. Tranche 2.1 brings reliability and economic benefits estimated at $51.7–101 billion across the MISO Midwest footprint, facilitating integration of ~115.7 GW of new resources.

Energy Storage

MISO's energy storage resources are still primarily in the future with only 84 MW of on-line storage. The MISO interconnection queue does have a significant amount of energy storage upcoming, but these are primarily Tier 3 resources at present.

Capacity Transfers

MISO benefits from significant transfer capacity with neighboring assessment areas due to the geographic location. MISO and SPP continue to finalize the Joint Targeted Interconnection Queue (JTIQ) portfolio to resolve the binding constraints that have traditionally delayed the interconnection process. MISO's utilization of capacity transfers is identified in the LOLE report and memorialized through the MISO PRA.

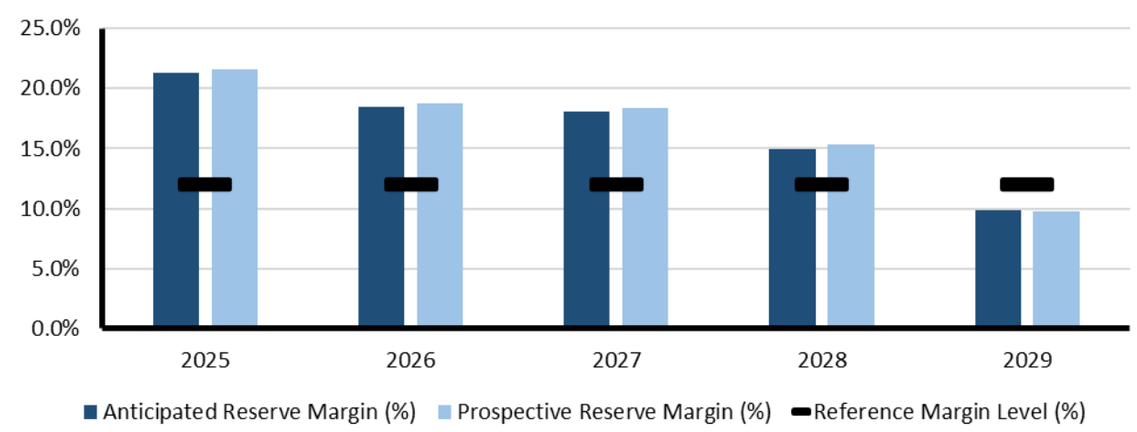


MRO-Manitoba Hydro

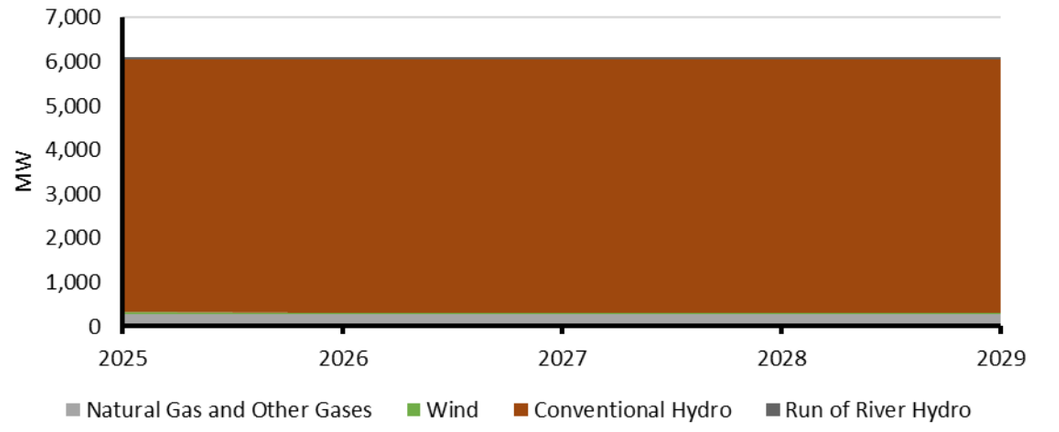
Manitoba Hydro is a provincial Crown Corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro provides electricity to approximately 616,000 electric customers in Manitoba and provides approximately 296,000 customers with natural gas in southern Manitoba. The service area is the province of Manitoba, which is 251,000 square miles. Manitoba Hydro is winter-peaking. Manitoba Hydro is its own Planning Coordinator and Balancing Authority. Manitoba Hydro is a coordinating member of MISO. MISO is the Reliability Coordinator for Manitoba Hydro.

Demand, Resources, and Reserve Margins

Quantity	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035
Total Internal Demand	4,797	4,923	4,968	5,037	5,268	5,366	5,427	5,486	5,556	5,629
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	4,797	4,923	4,968	5,037	5,268	5,366	5,427	5,486	5,556	5,629
Additions: Tier 1	30	51	64	64	64	64	64	64	64	64
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	-113	-113	-93	-167	-172	-565	-565	-565	-565	-565
Existing-Certain and Net Firm Transfers	5,786	5,780	5,800	5,726	5,721	5,328	5,328	5,328	5,328	5,328
Anticipated Reserve Margin (%)	21.3%	18.4%	18.0%	15.0%	9.8%	0.5%	-0.6%	-1.7%	-2.9%	-4.2%
Prospective Reserve Margin (%)	21.6%	18.8%	18.4%	15.3%	9.8%	0.5%	-0.6%	-1.7%	-3.0%	-4.2%
Reference Margin Level (%)	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The electricity demand forecast in the province of Manitoba has increased since the *2023 LTRA*, driven by expected economic activity and adoption of EVs. Resource projections have not changed significantly.
- The ARM falls below the RML of 12% beginning in Winter 2029–2030 due to load growth and the reduction of winter import capacity transfers. Manitoba Hydro is performing analysis to inform its integrated resource plan and support future decisions for resources.

MRO-Manitoba Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025–2026	**2026–2027**	**2027–2028**	**2028–2029**	**2029–2030**
Natural Gas	278	278	278	278	278
Wind	52	31	31	31	31
Conventional Hydro	5,705	5,726	5,739	5,739	5,739
Conventional Hydro*	5,705	5,726	5,739	5,739	5,721
Run of River Hydro	856	856	856	856	856
Total MW	6,094	6,094	6,107	6,107	6,107
Total MW*	6,094	6,094	6,107	6,107	6,089
*** Capacity with additional generator retirements.** Generators that are being considered for retirement but have not been confirmed are removed from the resource projection where marked.					

MRO-Manitoba Hydro Assessment

Planning Reserve Margins

The winter ARM falls below the Reference Margin Level of 12% in 2029–2030. No resource adequacy issues are anticipated until Winter 2029–2030. A Tier 1 project to replace eight older and smaller hydro units is being planned for the Pointe du Bois Generating Station. The Pointe du Bois Renewable Energy Project (PREP), approximately 50 MW, replaces the original hydro units that were mothballed or retired based on economics/end of life after about 100 years of operation. No Tier 2 or Tier 3 resources have been assumed to come into service during the assessment period.

The ARM falls below the Reference Margin Level of 12% beginning in Winter 2029–2030 due to net load growth and the reduction of winter import capacity transfers. Manitoba Hydro's Integrated Resource Plan was published in Summer 2023. Further analysis is underway and will help inform Manitoba Hydro's future resource decisions for resources in the 2029 timeframe.

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

Under normal water conditions, over 95% of the generation in Manitoba Hydro's system is from renewable energy—primarily hydro generation and wind generation. As the operator of a predominantly hydro system, Manitoba Hydro frequently performs an all-hours energy adequacy analysis of the near-term through seasonal time periods to manage reservoir energy storage and meet system demand. Additionally, Manitoba Hydro conducts specific analyses to determine short-term storage and minimum flow requirements for maintaining Manitoba and extra-provincial resource adequacy obligations. As there are modest levels of wind and solar on the Manitoba Hydro system, the resource adequacy risk on the Manitoba Hydro system over the next five years and under normal water conditions is expected to coincide with peak demand hours**.**

There are a number of influencing factors associated with Manitoba Hydro's resource adequacy performance, such as the water resource conditions, energy and capacity exchanges with neighboring jurisdictions, forecast load level, uncertainties in load forecast and load variation profiles, demand responses, wind penetration, and generation fleet availability. Most of Manitoba Hydro's generating facilities are use-limited or energy-limited hydro units. The annual energy output of these facilities is mostly dependent on the availability of the water resource. In the 2024 ProbA, Manitoba Hydro examines the impact of the most significant factor over the long run—variations in water conditions.

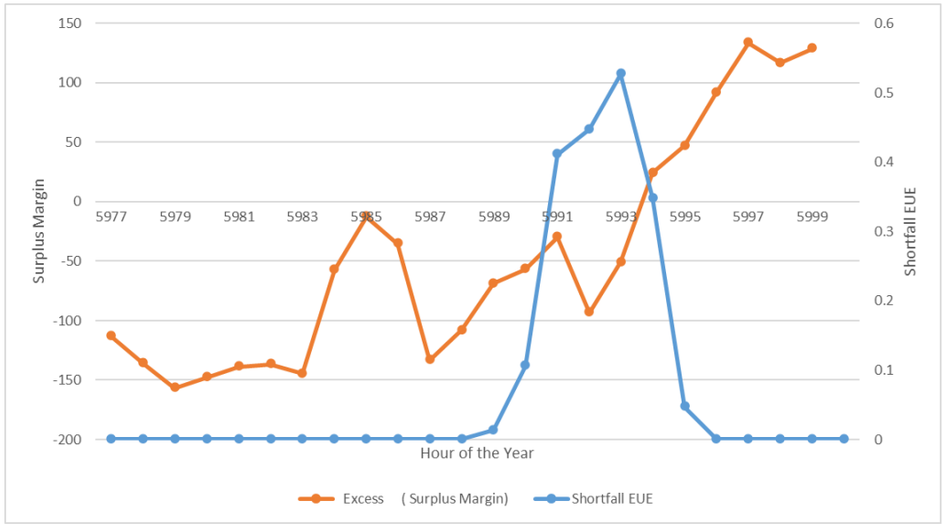
Nonzero LOLH and EUE are observed for both reporting years of 2026 and 2028 and shown in the table below. The LOLH and EUE indices are higher compared to the 2022 assessment mainly due to the increase in the forecast peak demand. Water flow conditions of 10th percentile or lower tend to increase the LOLH and EUE. As a small winter-peaking system on the northern edge of a large summer peaking system (MISO), there generally is assistance available, particularly in MISO's off-peak hours, to provide energy to supplement hydro generation in low-flow conditions in winter. Management of energy in reservoir storage in accordance with good utility practice provides risk mitigation under low water flow conditions.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	7.23	**4.711**	**68.870**
EUE (PPM)	0.29	**0.176**	**2.504**
LOLH (hours per year)	0.01	**0.059**	**0.914**
Operable On-Peak Margin	13.5%	**18.8%**	**15.6%**

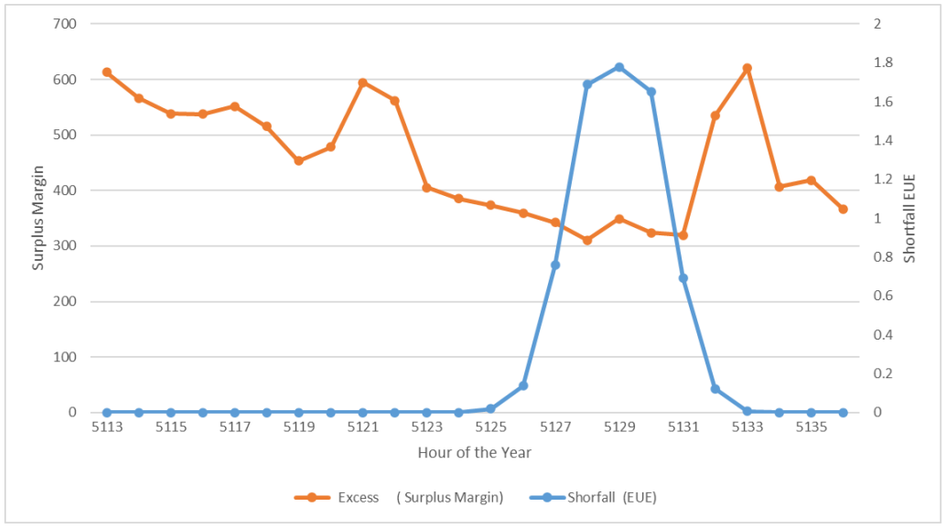
* Provides the 2022 ProbA Results for Comparison

The Monthly EUE and LOLH for 2026 and 2028 show that the highest LOLH and EUE contribution are from July and November, respectively, for 2026 and 2028.

The two graphs below show the hourly energy availability on the Manitoba Hydro system during the ProbA's highest risk days in 2026 and 2028. Surplus energy and shortfall EUE are plotted for the day when the highest loss of load event happens in the ProbA analysis. The Probability Weighted Average (PWA) surplus margin is negative, which indicates possible loss of loads for 2026. However, the PWA surplus energy is higher for 2028 during the day when the highest loss of load event is observed. This is because the surplus is an average for different water year data and the average surplus may not represent the event when loss of load occurs.

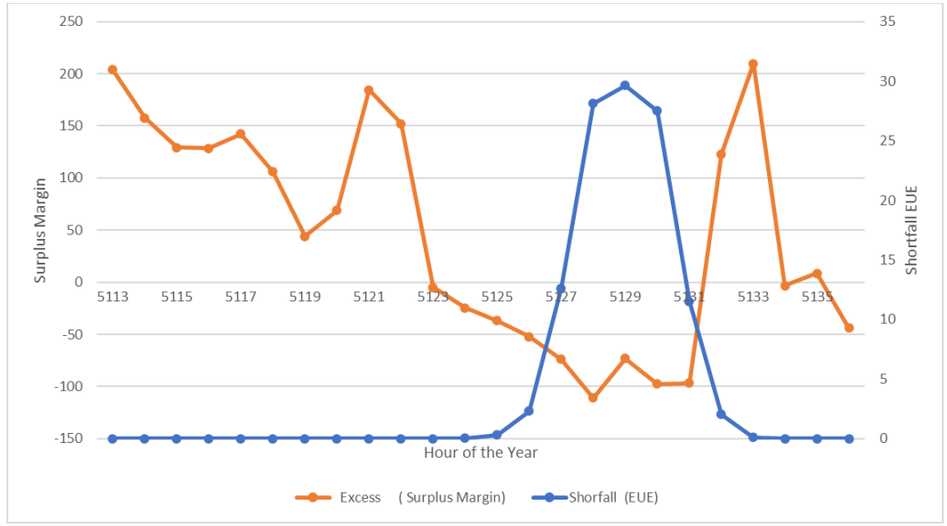


Hourly PWA Surplus Margin and Shortfall EUE for 2026 Representative Risk Day (Summer)



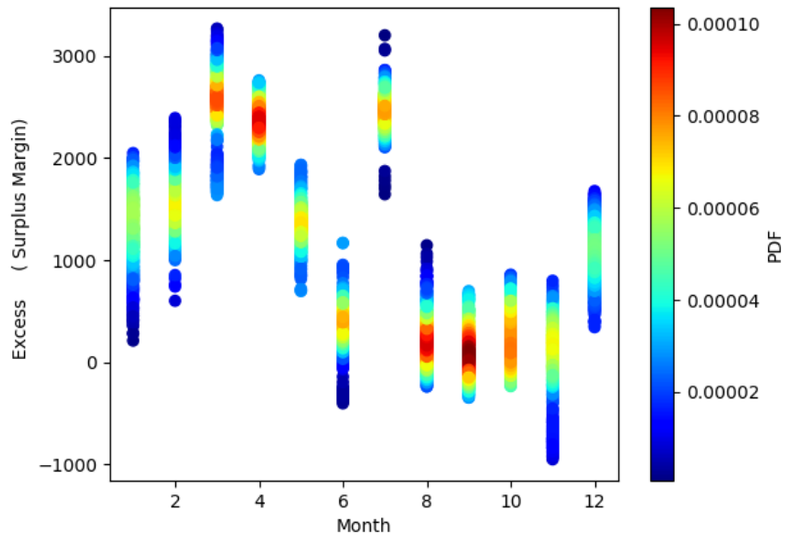
Hourly PWA Surplus Margin and Shortfall EUE for 2028 Representative Risk Day (Summer)

The figure below shows the surplus margin and shortfall EUE for 2028 under extreme drought conditions. It can be seen that the loss-of-load event occurs when the surplus margin becomes negative. This surplus energy shown in the figure is the average value for this hour for the entire simulation. It may not represent each individual loss-of-load event during simulation. By plotting the hourly surplus and unserved energy for the low-water years, it is possible to see what risk periods are likely to emerge during extreme drought.



Hourly PWA Surplus Margin and Shortfall EUE for 2028 Representative Risk Day (Summer) During Extreme Drought Condition

The scatter plots of surplus energy vs. month for 2026 and 2028 are shown in the figures below. In the months of June and August to November, the PWA surplus energy is relatively lower compared to the other months due to less import from MISO. The PWA surplus energy in July 2026 is high due to higher hydro energy availability for July. However, since PWA is the result of averaging, positive surplus energy does not mean that there will be no loss-of-load events.



PWA Surplus Energy Versus Month for 2026

Demand

Manitoba Hydro's load-growth forecast is up around 3.2% over the assessment period in comparison with the forecast used for the *2023 LTRA*. Factors considered in load-growth projections include economic activity, EV adoption, and demand-side management programs in Manitoba operated by Efficiency Manitoba. EV adoption in Manitoba is being driven in part by proposed federal regulations that are expected to require that at least 20 percent of new vehicles sold in Canada will be zero-emission by 2026, at least 60 percent by 2030, and 100 percent by 2035.

Manitoba Hydro is anticipating load growth of 1.3% over the last half of the assessment period. Limited surplus firm generation resources (resource adequacy) have the potential to slow the connection of very large new industrial loads. In order to limit load growth, Manitoba Hydro has been directed by the Province of Manitoba to suspend processing of cryptocurrency load connections until 2026.

Demand-Side Management

Manitoba Hydro currently does not have any form of directly controllable and dispatchable DR programs. Manitoba Hydro does have an indirectly controllable and dispatchable DR program called the Curtailable Rate Program.

The Curtailable Rate Program provides approximately 160 MW of load reduction through up to 16 load curtailments of 4¼ hours each on five minutes notice. The program is intended for peak load management. In addition, one product provides 50 MW of contingency reserves, also on five minutes' notice.

The terms and conditions of the Curtailable Rate Program were updated in August 2023 to require an annual curtailment test, increase the number of possible curtailments, extend the notice period for conversion to firm service, and make minor editorial changes.

Distributed Energy Resources

Manitoba is not currently experiencing large additions of wind and solar resources being seen in other regions; hence, emerging reliability issues arising from such large wind and solar resource additions are not anticipated in the next five years. Additions of energy storage resources in the next 10 years are not anticipated at this time. There is a potential for significant solar DER resources in the latter half of the assessment period, and plans are being developed to study the impacts on the Manitoba Hydro system. The potential for future solar DER may be dependent on solar PV subsidies and/or incentives.

Generation

Manitoba Hydro is monitoring federal and provincial policy/strategies/regulations related to electricity/energy. The Canadian federal government is considering significant carbon emission regulations. Through Environment and Climate Change Canada, it is taking multiple steps to develop clean electricity regulations that aim for Canadian electricity generation to achieve net-zero greenhouse gas emissions by 2035 by requiring generating units to meet a stringent emissions intensity standard (measured in tons CO2 equivalent per GWh) and pay a price for any remaining emissions. The proposed regulations are still in development and not proposed to be fully implemented until 2035, so it is too early to determine any potential impacts. The Province of Manitoba is developing a provincial energy strategy/policy which may be released in Fall 2024. As details are not yet available, it is too early to determine any potential impacts.

Energy Storage

Manitoba Hydro currently has no energy storage resources, and none have been committed to over the next 10-year period.

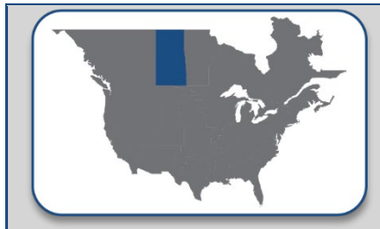
The hydro generation resources, while not storing electricity directly, do store water in a reservoir for conversion to electricity and have been in use for over 100 years. For most hours of the year, the only dispatchable resources online are hydro generation resources which therefore serve most operational, reliability, and economic functions.

Capacity Transfers

Manitoba Hydro has coordination and tie-line agreements with neighboring assessment areas, such as MISO, SaskPower, and the IESO. In accordance with these agreements, planning- and operating-related issues are discussed and coordinated through respective committees. In addition to this planning and operating committee work, Manitoba Hydro engages with the neighboring utilities of Minnesota Power, Xcel Energy, Otter Tail Power, Minnkota Power Cooperative, SaskPower, and Hydro One regularly to share information, discuss issues, and coordinate activities. Manitoba Hydro also coordinates planning studies (for example, transmission service request studies and requests for generation interconnections) with its neighboring assessment areas. In addition, capacity transfers are verified from a resource adequacy perspective with adjacent regions/entities. Significant capacity transfer limitations from MISO into Manitoba may have the potential to cause reliability impacts but only in extreme conditions occurring simultaneously.

Transmission

Manitoba Hydro has identified aging components of its HVdc system as a potential reliability issue that is unique to the assessment area. The concern is that the oldest HVdc system components could be approaching end of life. Studies have been initiated to study/evaluate modernization options and alternatives. The studies and procurement of replacement equipment could take up to 10 years to implement based on the current HVdc market capability. There is currently spare capacity on the HVdc system, and the end-of-life failure of a single pole would not create reliability issues. The further end-of-life failure of a second pole, while believed to be a very low probability, has the potential to create reliability concerns under peak winter loads if mitigation measures are not implemented. Mitigation measures to minimize the likelihood of experiencing this quantity of long-term outages are being actively pursued.

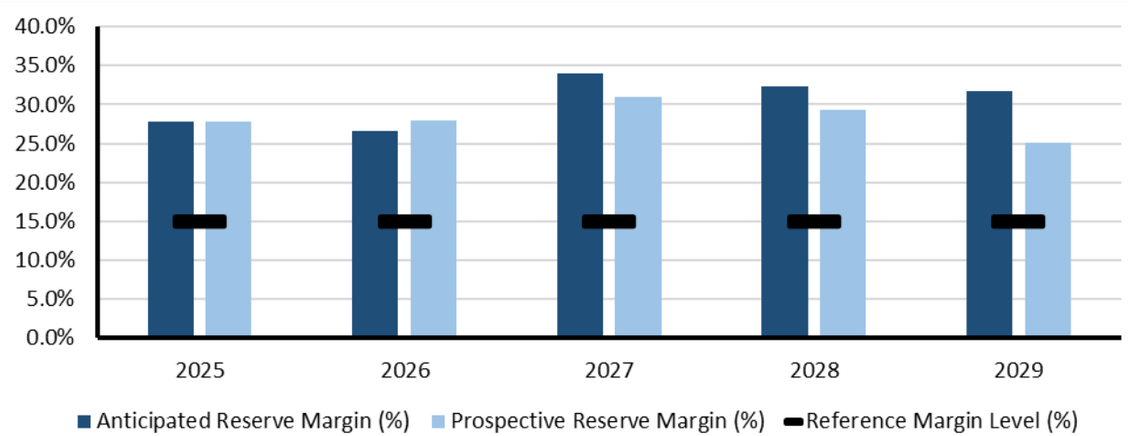


MRO-SaskPower

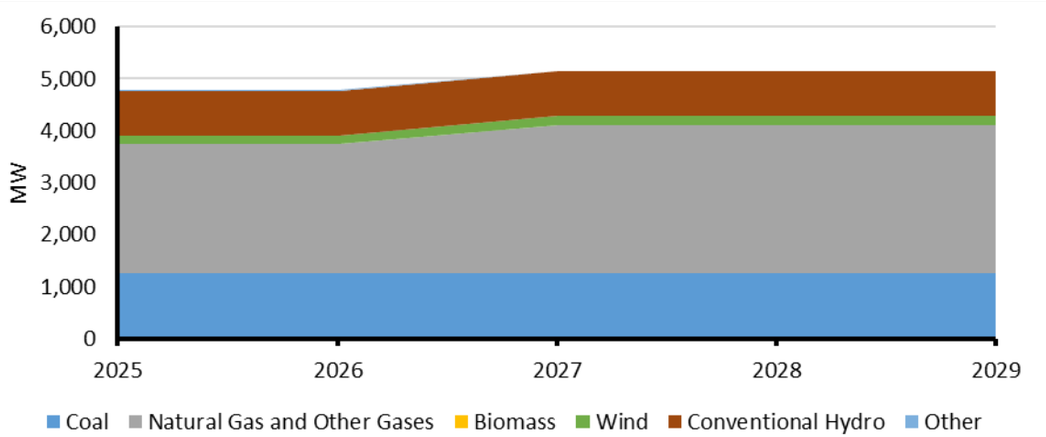
MRO-SaskPower is an assessment area in the Saskatchewan province of Canada. The province has a geographic area of 651,900 square kilometers (251,700 square miles), with a population of 1.2 million and approximately 550,000 customers. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the Planning Coordinator and Reliability Coordinator for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial Crown Corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan Bulk Electric System (BES) and its interconnections.

Demand, Resources, and Reserve Margins

Quantity	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035
Total Internal Demand	3,917	4,025	4,149	4,189	4,210	4,242	4,271	4,315	4,359	4,408
Demand Response	72	72	72	72	72	72	72	72	72	72
Net Internal Demand	3,845	3,953	4,077	4,117	4,138	4,170	4,199	4,243	4,287	4,336
Additions: Tier 1	507	507	883	883	883	883	883	883	883	883
Additions: Tier 2	0	55	175	175	928	928	928	928	928	928
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	290	290	315	315	315	315	315	315	315	315
Existing-Certain and Net Firm Transfers	4,407	4,497	4,582	4,566	4,566	4,489	4,490	4,490	4,552	4,566
Anticipated Reserve Margin (%)	27.8%	26.6%	34.0%	32.4%	31.7%	28.8%	28.0%	26.6%	26.8%	25.7%
Prospective Reserve Margin (%)	27.8%	28%	31.0%	29.3%	25.1%	22.3%	20.8%	19.5%	19.8%	18.7%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- SaskPower's ARM is above the RML throughout the assessment period. No resource adequacy issues are anticipated.
- Saskatchewan is adding approximately 1,064 MW of generation under Tier 1 within the next five years. This includes a 200 MW wind generation facility, two new 377 MW gas generation facilities, and the expansion of two existing natural gas facilities totaling 90 MW. The remaining capacity addition comes from geothermal and flare gas.

MRO-SaskPower Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030
Coal	1,249	1,249	1,249	1,249	1,249
Coal*	1,249	1,249	1,088	1,088	188
Natural Gas	2,487	2,487	2,863	2,863	2,863
Biomass	3	3	3	3	3
Wind	164	164	162	162	162
Conventional Hydro	856	856	856	856	856
Other	22	17	17	1	1
Total MW	4,781	4,775	5,150	5,134	5,134
Total MW*	4,781	4,775	4,989	4,973	4,073
*** Capacity with additional generator retirements.** Generators that are being considered for retirement but have not been confirmed are removed from the resource projection where marked.					

MRO-SaskPower Assessment

Planning Reserve Margins

Saskatchewan uses a criterion of 15% as the reference reserve margin and has assessed its PRM for the upcoming 10 years considering the summer and winter peak hour loads, available existing and anticipated generation resources, firm capacity transfers, and available demand response for each year. Saskatchewan's ARM ranges from approximately 19% to 34% and does not fall below the Reference Margin Level.

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

Saskatchewan performs energy assessments using probabilistic methods to inform the area's resource adequacy requirements. Saskatchewan evaluates non-peak hour risks and diminishing capacity credits associated with higher penetration levels of VERs as part of the long-term planning process.

Results of the 2024 ProbA are provided in the table below. Based on the deterministic calculations within this assessment, Saskatchewan's ARM is 27.8% and 34.0% for years 2026 and 2028, respectively. Since the 2022 ProbA, the reported forecast reserve margin for 2026 has remained consistent. The minor variation in the reserve margin is due to a slight change in the schedule of generator outages. EUE is also comparable to the 2022 ProbA, with some variation attributed to updated hydro energy dispatch, which is able to reduce the EUE in the months where it was highest in the prior ProbA.

Base Case Summary of Results			
	2026*	2026	2026
EUE (MWh)	117.0	**75.641**	**8.553**
EUE (PPM)	4.4	**2.807**	**0.300**
LOLH (hours per year)	0.9	**0.547**	**0.078**
Operable On-Peak Margin	24.6	**24.4%**	**30.5%**

* Provides the 2022 ProbA Results for Comparison

Saskatchewan does not anticipate resource adequacy issues during its off-peak hours. Currently, its resource mix consists of baseload and fast ramping generation resources, with little penetration of VERs. The main factor contributing to EUE is the amount of planned generator outages. When these short-term reliability issues are identified in advance, they can be mitigated by rescheduling the maintenance. The hourly EUE heat maps in the following figures show that risk of unserved energy is at its highest in the summer months. Risk can also be found in months before or after summer and be driven by unseasonable temperatures driving above-normal demand that coincides with generator maintenance periods. Winter risks of shortfall are associated with extreme cold weather and unexpected generator outages.

Hourly EUE Heat Map : 2026																								
EUE	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Jan-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Feb-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mar-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Apr-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
May-26	1.2	1.2	1.1	1.2	1.2	1.3	1.3	1.3	1.4	1.5	1.6	1.8	1.8	1.7	1.7	1.6	1.6	1.6	1.5	1.5	1.5	1.6	1.5	1.3
Jun-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Jul-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.2	0.2	0.1	0.0	0.0	0.0	0.0	0.0
Aug-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.0
Sep-26	0.5	0.6	0.6	0.6	0.6	0.5	0.6	0.7	0.7	0.8	0.9	1.2	1.2	1.3	1.4	1.5	1.5	1.6	1.4	1.5	1.7	1.3	1.0	0.7
Oct-26	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.6	0.6	0.4	0.3	0.3
Nov-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0
Dec-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.1	0.1

Hourly EUE Heat Map : 2028																								
EUE	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Jan-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Feb-28	0.0	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mar-28	0.0	0.0	0.0	-	-	-	-	0.0	-	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Apr-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
May-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Jun-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0
Jul-28	0.0	-	-	-	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.2	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
Aug-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Sep-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oct-28	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.1	0.1	0.1	0.1
Nov-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.0	0.0	0.0
Dec-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.0

Hourly EUE Heat Maps (in MWh)

Demand

Saskatchewan experiences its peak-season in the winter. Saskatchewan's system peak load forecast is based on econometric variables, weather normalization, and individual level forecasts for large industrial customers. The average annual summer and winter peak demand growth is expected to be approximately 1.35% throughout the assessment period.

Demand-Side Management
Saskatchewan's EE and energy conservation programs include incentive-based and education programs focusing on installed measures and products that provide verifiable, measurable, and permanent reductions in electrical energy, and demand reductions during peak hours.

Saskatchewan's DR consists of contracts with industrial customers for interruptible load based under conditions specified in demand response programs. The first of these programs provides a curtailable load, currently up to 72 MW, with a 12-minute event response time. Other programs are in place providing access to additional curtailable load requiring up to two hours notification time.

Distributed Energy Resources
The current BTM DER installed capacity in Saskatchewan is approximately 50 MW, which includes approximately 48 MW of solar PV and the remaining approximately 2 MW of distributed wind projects. An additional 25 MW of DER solar PV are expected to be added in the next five years. BTM DER installations are incorporated into the load forecast models, which are used in supply and transmission planning study models.

Small power producers contribute an additional 5 MW installed DER capacity (non-BTM) in Saskatchewan. There is currently an existing 8 MW and a potential for up to 20 MW of DERs being added in the next 2 years based on the currently approved Power Generation Partner program. These projects are included as generation additions, but currently their capacity is not considered in reliability planning.

Generation
Saskatchewan is adding approximately 1,064 MW into its resource mix of generation under the Tier 1 category within the next five years. The includes a 200 MW wind generation facility, expansion of two existing natural gas facilities totaling 90 MW, two new natural gas facilities totaling 754 MW, 15 MW of flare gas generation, and 5 MW of geothermal generation.

Under Tier 2, over 1,717 MW of new generation is projected in the assessment period. This includes 754 MW of natural gas, 600 MW of wind generation, 300 MW of utility-scale solar generation, and 63 MW of co-generation.

Generating resources being planned as Tier 2 and Tier 3 will replace generators planned for retirement prior to deactivation. Therefore, Saskatchewan is not expecting any long-term reliability impacts due to generation retirements.

Energy Storage
SaskPower currently has its first battery storage system, a 20 MW/20 MWh unit, under commissioning. There are plans to expand this site by an additional 60 MW/60MWh capacity. The prevalent use for the planned energy storage is to provide regulating reserve, peak capacity and energy reduction, net demand ramping control, reactive power/voltage control, primary frequency control, and blackstart.

Capacity Transfers
SaskPower has three interfaces with its neighboring areas. The interface with Manitoba is the largest of the three interfaces and is the only interface with long-term firm contracts. Capacity transfers from Manitoba would be limited in the event of a prior outage of tie lines between SaskPower and Manitoba Hydro, as well as nearby transmission facilities supporting the interface. This could only impact reliability if it is coincident with the extreme winter or summer peak demand and a prior outage of one or more larger generating units in Saskatchewan. Risk mitigation is in place through SaskPower's emergency operating procedure that will allow one or more measures such as short-term imports from other available interfaces (for example Alberta or SPP), initiating demand response and short-term load shedding.

Transmission
SaskPower's major transmission projects in the first five years of the assessment period are related to the interconnection expansion with SPP and the 650 MW of new transmission service. This includes two new international power lines between Saskatchewan and North Dakota. Within Saskatchewan, a total of approximately 180 kilometers of new 230 kV lines, a new 230 kV transmission station, expansion of several existing transmission stations, and installation of two phase-shifting transformer interfaces and two static var systems are being added.

The remaining other transmission projects (approximately 460 circuit kilometers) are under the planning and conceptual phase in the 5-to-10-year planning horizon. These projects are driven by load growth, new generation additions, and reliability needs.

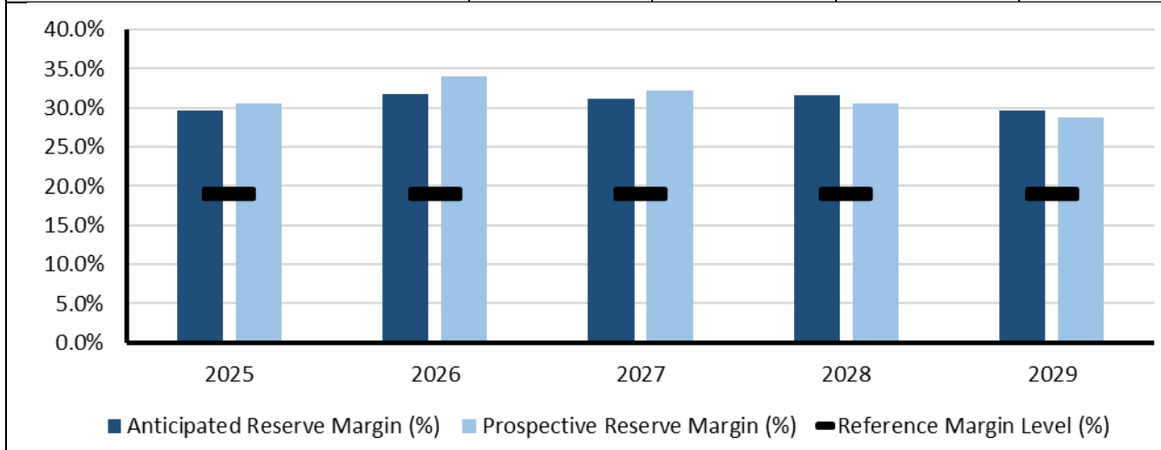


MRO-SPP

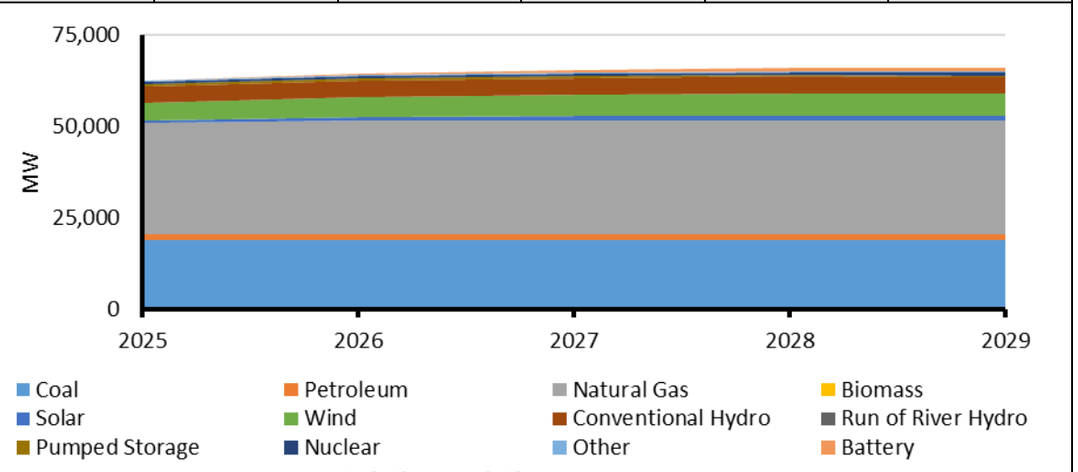
The Southwest Power Pool (SPP) Planning Coordinator footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported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

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	55,669	57,171	59,031	59,764	60,596	61,963	62,490	63,287	63,764	64,172
Demand Response	1,463	1,771	2,057	2,124	2,172	2,222	2,259	2,465	2,467	2,472
Net Internal Demand	54,206	55,400	56,975	57,640	58,424	59,741	60,231	60,822	61,297	61,700
Additions: Tier 1	2,123	4,966	6,750	7,843	7,957	7,957	7,957	7,957	7,957	7,957
Additions: Tier 2	1,239	2,454	2,756	2,756	2,756	2,756	2,756	2,756	2,756	2,756
Additions: Tier 3	6,823	16,770	22,655	28,948	28,948	28,948	28,948	28,948	28,948	28,948
Net Firm Capacity Transfers	-1,097	-1,077	-1,136	-1,131	-1,131	-1,131	-1,131	-1,133	-1,133	-1,133
Existing-Certain and Net Firm Transfers	68,157	68,039	67,981	67,984	67,799	67,749	67,253	67,175	67,055	67,094
Anticipated Reserve Margin (%)	29.7%	31.8%	31.2%	31.6%	29.7%	26.7%	24.9%	23.5%	22.4%	21.6%
Prospective Reserve Margin (%)	30.6%	34.1%	32.2%	30.6%	28.7%	25.2%	23.3%	22.0%	20.6%	19.6%
Reference Margin Level (%)	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- There are over 8 GW of coal and gas-fired generators that have indicated they plan to retire over the next 10 years in SPP. Without sufficient dispatchable generation, SPP can experience energy shortages when output from wind resources is low.

MRO-SPP Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	**2026**	**2027**	**2028**	**2029**
Coal	18,952	18,952	18,919	18,919	18,919
Coal*	17,934	16,647	16,614	14,062	14,062
Petroleum	1,629	1,629	1,631	1,631	1,631
Petroleum*	1,629	1,629	1,575	1,575	1,575
Natural Gas	30,471	31,098	31,098	31,098	31,098
Natural Gas*	29,896	30,220	29,924	29,812	29,812
Biomass	20	20	20	20	20
Solar	495	864	1,149	1,283	1,283
Wind	4,974	5,456	5,928	6,117	5,909
Conventional Hydro	4,526	4,541	4,573	4,605	4,628
Pumped Storage	472	472	472	472	472
Nuclear	769	769	769	769	769
Other	281	281	281	281	281
Battery	41	290	555	930	1,044
Total MW	62,630	64,370	65,392	66,124	66,053
Total MW*	61,037	61,188	61,858	59,925	59,855
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to give formal notice to SPP are removed from the resource projection where marked.					

MRO-SPP Assessment

Planning Reserve Margins

The Existing-Certain and Net Firm Transfers Reserve Margin for the SPP assessment area is projected to fall below the current coincident summer season RML of 19% in 2027. The current summer season reserve margin target for SPP is 15%, but that is based on the non-coincident peak demand of load-responsible entities (LRE) in the SPP assessment area. For purposes of NERC assessments, the 15% target is converted, along with forecasted demand values, to an SPP coincident peak representation based on the latest calculated diversity factor. This results in an RML of 19%. Based on resources submitted in the ARM calculation, including the impact of retirements, SPP is forecasted to be above the 19% RML for the 10-year horizon.

Like the generation unavailability scenario in NERC's *2024 Summer Reliability Assessment*, SPP shows the potential to utilize all the current projected capacity and there could be times of capacity shortfall based on performance impacts during high-load periods. While the potential to all available capacity has a lower probability, the assumptions and projections are based around historical unavailability during peak periods. Current LTRA projections are based on the latest resource adequacy data submittals, which are provided by the LREs and Generator Owners in SPP.

SPP performs a biennial LOLE study to establish a reserve margin target such that the LOLE for the applicable planning year (3- and 6-year study) does not exceed 1 day in 10 years, or 0.1 day per year. The target is determined using probabilistic methods by altering capacity through the application of generator forced outages and forecasted demand with load uncertainty to ensure that the LOLE does not exceed 0.1 day per year.

SPP's 2023 LOLE study results indicate that separate PRMs and capacity requirements are needed for the summer and winter seasons to recognize the seasonal balance of risk. Also, as colder temperature outages increase with the incorporation of additional wind and solar resources, the loss-of-load risk shifts to the winter season. Due to the shift in seasonal risk, it would be appropriate to consider a maximum LOLE threshold for the winter season or incorporation of an EUE reliability metric to complement the LOLE metric.

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

As the resource mix continues to change from a standard base load conventional thermal and hydro resources to VERs and short-term energy storage resources (ESR), SPP is incorporating energy adequacy metrics (i.e., EUE) in the determination of PRMs, RMLs, additional reliability policies, and resource accreditation enhancements.

SPP will begin performing a yearly energy adequacy assessment and assessment of reliability attributes (inertia, primary frequency response, ramp, regulation, contingency reserves, voltage and reactive support capability, fuel assurance, flexibility, and blackstart capability). Results of the analysis will be presented annually to SPP stakeholders. The results will also be used to identify needs for new market products, changes to market functionality, or changes to resource adequacy policies and requirements.

The 2024 ProbA performed for the NERC LTRA used assumptions and methods that reflect SPP's Loss of LOLE studies. Results are shown in the following table.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0.84	0.00	6.61
EUE (PPM)	0.00	0.00	0.02
LOLH (hours per year)	0.00	0.00	0.01
Operable On-Peak Margin	19.6%	19.5%	16.0%

*Provides the 2022 ProbA Results for Comparison

With the current SPP fleet, there was no loss of load for the 2026 study that included Tier 1 resource additions and 600 MW in generator retirements. The 2028 analysis included both Tier 1 and Tier 2 resource additions and 2,700 MW in generator retirements. The result was a small amount of EUE (6.61MWh) and LOLH (0.01hr/year). The loss of load/hour occurred mostly during the summer season (0.007hr/yr), while the winter season had 0.0004hr/yr. SPP is a summer-peaking region, and the results also supported that. The demand was highest in the afternoons between 13:00 and 19:00 during July and August.

Study improvements for 2024 from the previous NERC ProbAs include additional weather years, seasonal forced-outage modeling, and incremental cold weather outages.

SPP uses the Strategic Energy & Risk Valuation Model (SERVM) for the ProbA. It is a production-cost modeling tool that uses the Monte Carlo method to solve LOLE. Each weather year was simulated 300 times to simulate a multitude of random forced outage draws. Taking 300 draws for each weather year (43) and multiplying by 8,760 hours gets to a total of over 113 million simulated hours, from 1980 to 2022. Each iteration was performed on an 8,760-hour basis.

The study input model consisted of multiple modeling assumptions including multiple historical weather years (1980–2022); hourly load, solar, and wind profiles; load forecast uncertainty; random forced outages draws and variability; physical and economic resource parameters; resource retirements; future resource additions; zonal transmission limitations; and incremental conventional resource forced outages due to extreme cold temperature.

The generating resources modeled in the Probabilistic Assessment reflect the data supplied in the *2024 LTRA*. Existing and projected resources were included in the Probabilistic Assessment along with reported confirmed retirements. As mentioned previously, wind and solar resources, as well as historical weather years, were modeled at historical hourly values using 2012 to 2022 weather years. There were six study zones, and SPP modeled a projected 8,760 hourly demand profile for each area to provide load variability and volatility for chronological hours during simulation. Each local resource zone was modeled with an import and export limit based on a separate power flow transfer analysis. SPP used unit-specific outage rates within the analysis based on NERC Generation Availability Data System (GADS) data from 2015 to 2022. External assistance only included firm contracts from external entities with firm transmission service.

Demand

SPP peak load occurs during the summer season; the 2024 net internal demand forecast is projected to peak at 53,094 MW, which is projected to increase compared to the previous year's LTRA forecast for the 2022 summer season. The diversity factor used to convert the non-coincident peak demand forecast to an SPP coincident peak demand forecast was consistent with the ~3.5% applied in the *2023 LTRA*. SPP forecasts the coincident annual peak growth based on member submitted data over the 10-year assessment timeframe. One risk that SPP has noted is that the aggregated noncoincident demand forecast submitted by members in recent years, which is based on a 50/50 forecast and is weather normalized, is tracking at a lower demand level than what the BA has observed.

Demand-Side Management

SPP's energy efficiency (EE) and conservation programs are incorporated into the reporting entities' demand forecasts. There are no known impacts to the SPP assessment area's long-term reliability related to the forecasted increase in EE and DR across the assessment area. In addition, SPP is constructing a new policy to more appropriately categorize DR based on the flexibility of the program, which will ultimately be reflected in the accreditation process.

Distributed Energy Resources

The SPP Model Development, Economic Studies, and Supply Adequacy working groups are developing policies and procedures around DERs. SPP resource adequacy implemented policies for DERs that mandate certain testing, reporting, and document requirements for resources and programs not registered in the SPP Integrated Market. Accreditation methodology policies are being constructed and are planned to be approved in late 2024.

Generation

SPP currently has approximately 900 MW of installed solar generating facilities. In the ARM calculation, SPP is reporting nameplate capacity of approximately 11 GW of Tier 1, 2, and 3 wind resources, approximately 18 GW of Tier 1, 2, and 3 solar resources, approximately 9.8 GW of Tier 1, 2, and 3 battery resources and approximately 2.7 GW of Tier 1, 2, and 3 gas resources.

In 2024, SPP filed conventional based performance accreditation and effective load carrying capability (ELCC) methodology for wind and solar resources. The goal is for these policies to become effective in the 2026/2027 timeframe for both the summer and winter seasons.

There are concerns of drought conditions impacting the Missouri River and other water sources for generation resources that rely on once-through cooling processes. Low water can impact the generation's capacity output and reduce its ability to support congestion management and serve load. An additional concern could be the impact of river conditions on coal shipments, which could cause generators to run at a derated level to conserve supplies.

Energy Storage

Currently, SPP is studying approximately 17,000 MWs of energy storage and hybrid resource projects in the generator interconnection queue process. There are approximately 50 MWs of energy storage under contract by SPP members. These resources are being modeled as generation in the planning assumptions both near and long term.

Capacity Transfers

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

SPP and ERCOT executed a Coordination Plan that superseded the prior coordination agreement. The Coordination Plan addresses operational issues for coordination of the dc ties between the Texas Interconnection and Eastern Interconnection, block load transfers (BLT), and switchable generation resources (SWGR). Under the terms of the Coordination Plan, SPP has priority to recall the capacity of any SWGRs that have been committed to satisfying the resource adequacy requirements contained in Attachment AA of the SPP Open Access Transmission Tariff. Annually, SPP and ERCOT update the

Coordination Plan based on the latest discussions and business decisions, and it was updated in June 2024.

Transmission

In the 2023 ITP Assessment, SPP approved 44 transmission projects, including 150 miles of new transmission. Additionally, the study calls for 93 miles of transmission to be rebuilt.

SPP is observing a number of transmission projects that are currently delayed. SPP is actively tracking these projects and discussing them throughout its stakeholder process. Many delays are driven by supply chain issues or increasing length of construction times. The delays of these transmission projects do not currently seem to be driving reliability issues.

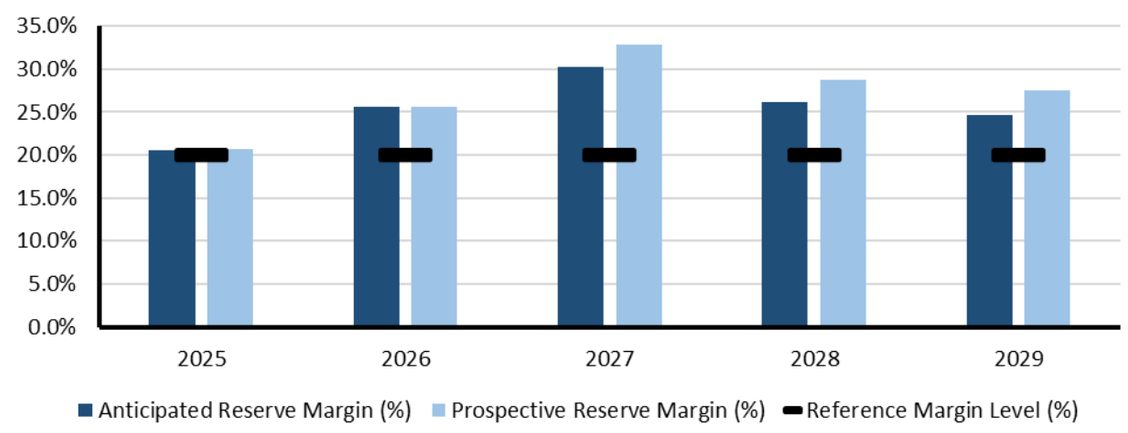


NPCC-Maritimes

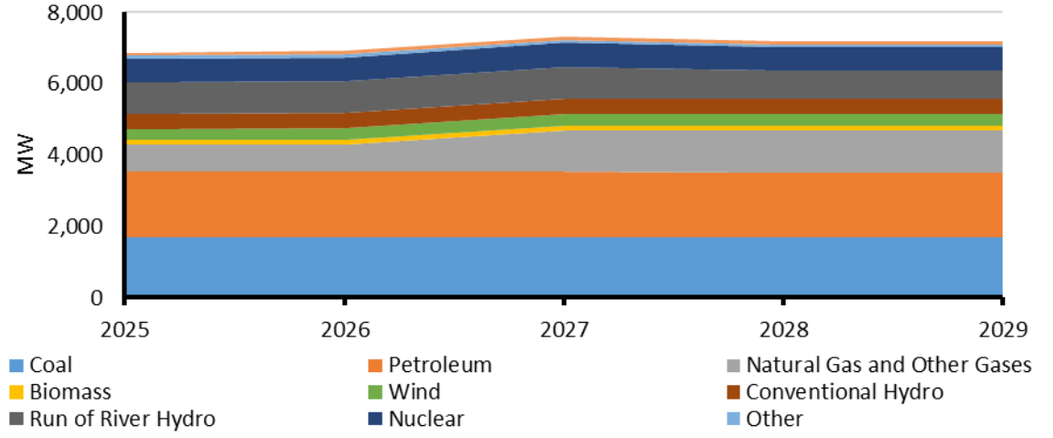
The Maritimes assessment area is a winter peaking NPCC sub-region with a single Reliability Coordinator and two Balancing Authority Areas (New Brunswick and Nova Scotia). It is comprised of the Canadian provinces of New Brunswick (NB), Nova Scotia (NS), and Prince Edward Island (PEI) and the northern portion of Maine (NM), which is radially connected to NB. The area covers 58,000 square miles with a total population of 2 million people.

Demand, Resources, and Reserve Margins

Quantity	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035
Total Internal Demand	6,201	6,056	6,095	6,141	6,216	6,272	6,331	6,398	6,474	6,560
Demand Response	274	293	309	317	317	317	317	317	317	318
Net Internal Demand	5,927	5,763	5,786	5,825	5,899	5,954	6,014	6,081	6,157	6,242
Additions: Tier 1	108	171	579	579	579	579	579	579	579	579
Additions: Tier 2	6	4	447	600	1,398	1,398	1,398	1,398	1,398	1,398
Additions: Tier 3	0	13	80	127	197	255	267	279	291	291
Net Firm Capacity Transfers	289	322	215	145	145	145	145	145	145	145
Existing-Certain and Net Firm Transfers	7,038	7,063	6,959	6,771	6,771	6,771	6,679	6,665	6,665	6,752
Anticipated Reserve Margin (%)	20.6%	25.5%	30.3%	26.2%	24.6%	23.4%	20.7%	19.1%	17.7%	17.4%
Prospective Reserve Margin (%)	20.7%	25.6%	32.8%	28.8%	27.5%	26.3%	23.5%	21.9%	20.4%	20.1%
Reference Margin Level (%)	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- Since the *2023 LTRA*, the overall resource outlook has improved with expected new natural-gas-fired generators coming into service in 2027. Winter peak demand forecasts for this assessment area have risen through 2030; however, ARMs are currently projected to remain above the RML of 20% until 2031 when the ARM dips to 19.7%.

NPCC-Maritimes Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025–2026	**2026–2027**	**2027–2028**	**2028–2029**	**2029–2030**
Coal	1,696	1,696	1,696	1,696	1,696
Coal*	1,696	1,696	1,396	1,248	467
Petroleum	1,831	1,831	1,825	1,819	1,819
Natural Gas	757	757	1,157	1,157	1,157
Biomass	148	148	148	148	148
Solar	5	5	5	5	5
Wind	293	321	329	329	329
Conventional Hydro	412	412	412	412	412
Run of River Hydro	902	902	902	791	791
Nuclear	663	663	671	671	671
Other	77	77	77	77	77
Battery	72	99	99	99	99
Total MW	6,856	6,911	7,321	7,204	7,204
Total MW*	6,856	6,911	7,021	6,756	5,975
*** Capacity with additional generator retirements.** Generators that are being considered for retirement but have not been confirmed are removed from the resource projection where marked.					

NPCC-Maritimes Assessment

Planning Reserve Margins

The NPCC-Maritimes assessment area is comprised of NB, NS, PEI, and NM. The RML for the assessment area is 20%; however, this reserve margin is not mandated. The ARM over the study period for the Maritimes area ranges between 17% and 30% during the winter period and between 88% and 93% during the summer period.

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

During off-peak hours, the Maritimes area has surplus generation and no constraints with converting the capacity to energy.

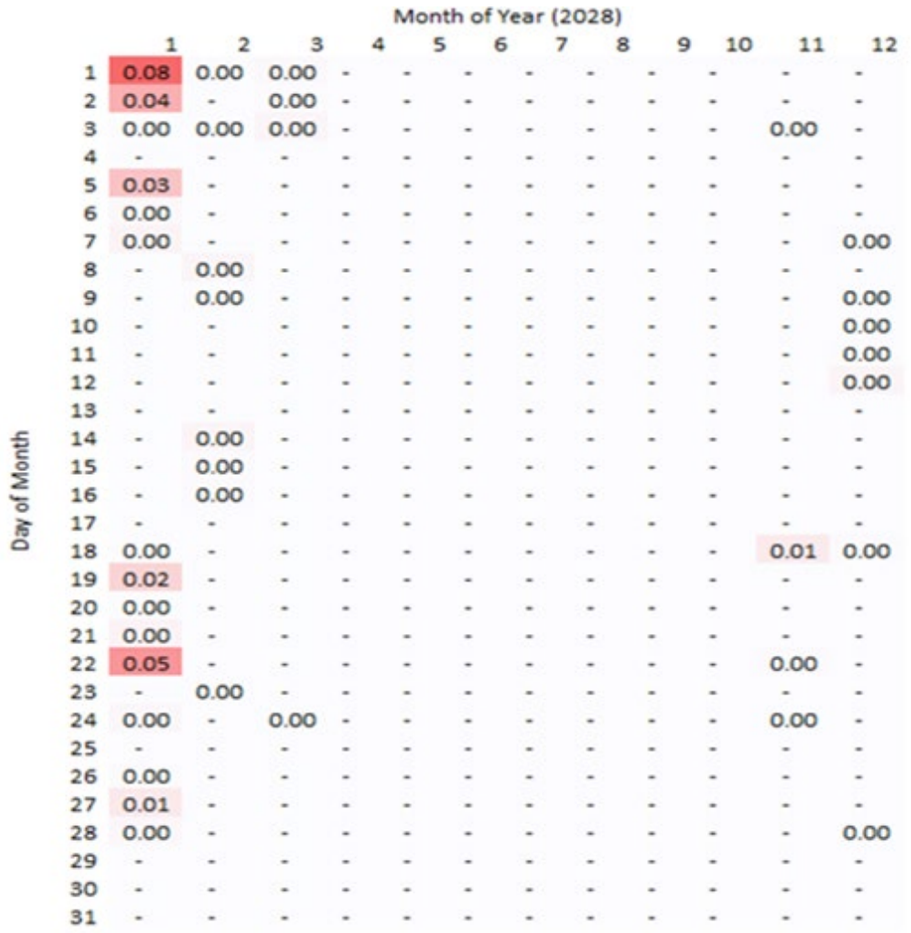
Probabilistic Assessments

Two Balancing Authorities within the Maritimes area are members of NPCC and jointly prepare annual probabilistic assessments that cover three- to five-year forward-looking periods and evaluate the adequacy of the Maritimes' transmission system and resources. In addition, the Maritimes area also supports NERC's annual seasonal ProbAs, which provides an evaluation of generation resource and transmission system adequacy that will be necessary to meet projected seasonal peak demands and operating reserves. Results of the 2024 ProbA are in the table below.

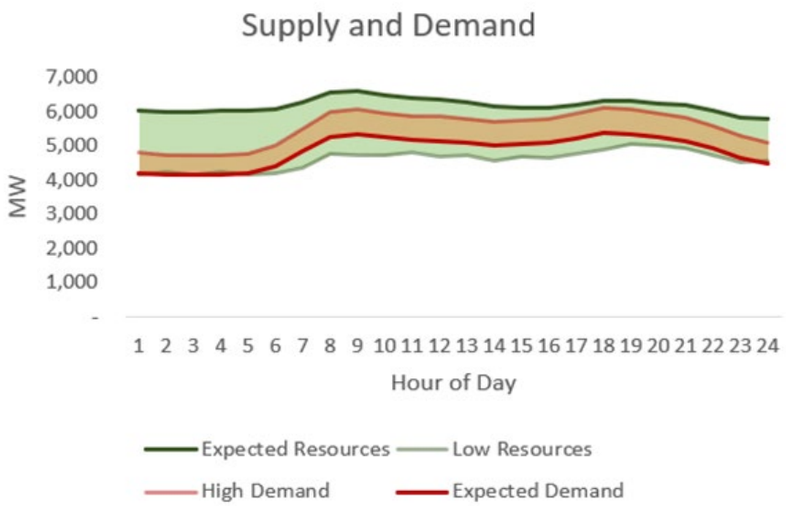
Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	3.87	**5.02**	**0.28**
EUE (PPM)	0.14	**0.17**	**0.01**
LOLH (hours per year)	0.07	**0.09**	**0.02**
Operable On-Peak Margin	22.9%	**17.9%**	**29.0%**

* Provides the 2022 ProbA Results for Comparison

The following table of LOLH for 2028 provides a depiction of risks across the calendar year and highlights the concentration of risk in winter. Most load-loss risk occurs in winter months of December–February, with some additional risk occurring in shoulder months. 2026 has a similar risk distribution.



Hourly demand and resource projections for a typical risk-day in 2026 are shown in the figure below. Expected resource contributions are observed to cover expected demand on the risk day. However, the greatest risk for this assessment area is in the form of lower-than-expected resource contributions. If this were to occur, expected demand for all hours would not be met. This risk would be exaggerated by the addition of a higher-than-expected demand event. Reliance on external assistance may be necessary in these events. A risk day in 2028 has a similar profile.



Hourly Probabilistic Assessment Results | Representative Summer Risk Day 2026

Demand

There is no regulatory requirement for a single authority to produce a forecast for the whole Maritimes area. The peak area demand occurs in winter and is highly reliant on the forecasts of the two largest sub-areas of NB and NS, which are historically highly coincidental. Demand for the Maritimes area is determined to be the non-coincident sum of the peak loads forecasted by the individual sub-areas. The aggregated growth of both demand and energy for the combined sub-areas see an upward trend over summer and winter seasonal periods of the LTRA assessment period. The area peak loads are expected to increase by 4.2% during summer and by 6.4% during winter seasons over the 10-year assessment period. This translates to compound average growth rates of 0.4% in summer and 0.6% in winter. The Maritimes Area annual energy forecasts are expected to increase by a total of 5.9% during the 10-year assessment period for an average growth of 0.6% per year.

Demand-Side Management

Plans to develop up to 100 MW by 2030/2031 of controllable direct load control programs using smart grid technology to selectively interrupt space and/or water heater systems in residential and commercial facilities are underway but no specific annual demand and energy saving targets currently exist. During the 10-year LTRA assessment period in the Maritimes area, annual amounts for summer peak demand reductions associated with EE and conservation programs rise from 20 MW to 169 MW while the annual amounts for winter peak demand reductions rise from 168 MW to 629 MW.[34]

Distributed Energy Resources

The DER installed capacity in NS is approximately 245 MW at present, including distribution-connected wind projects under purchase power agreements, small community wind projects under a feed-in tariff, and BTM solar.

LTRA wind capacity for NB, NS, and PEI is derated between 18% and 33% using probabilistic methods to calculate equivalent perfect capacities for each sub-area excluding NM, which uses seasonal capacity factors. BTM solar is assumed to have an ELCC of 0% during winter period. The Maritimes area has shown embedded BTM solar PV projections of 149 MW in 2024 rising to 881 MW by 2034. These projects include distributed small-scale solar (mainly rooftop) that fall under the net metering program and serve as a reduction in load mainly in the residential class. The forecasted increase in solar installations in the coming years is a result of initiatives including municipal and provincial incentive programs. There is no capacity contribution from solar generation due to the timing of the area's system peak, which occurs either before sunrise or after sunset in the winter period.

Generation

NB assumes extending 28 MW of diesel-fired generator starting in 2025 and recently upgraded 290 MW of natural-gas-fueled resource completed in 2023. There are 25.2 MW of wind power purchase agreements (PPA) also slated to start in 2025. An anticipated replacement PPA contract, a long-term firm energy contract from a neighboring jurisdiction, and opportunities to buy in day-ahead and real-time markets will be utilized to maintain the overall resource adequacy.

NB Tier 1 resources include 71 MW of wind and 400 MW of combustion turbines. Tier 2 resources include 200 MW of wind resources and Tier 3 includes 400 MW of wind.

In NS, Tier 1 resources include wind projects with a total nameplate capacity of 473 MW phased in from 2024–2027 with an ELCC of 10%, 150 MW battery storage, 4 MW tidal power, 2 MW biomass unit, and a small 0.14 MW solar farm. Tier 2 resources in NS include 250 MW of battery storage (2026–2032), 600 MW of combustion turbines (2027–2033), a 150 MW conversion of a coal-fired unit to natural gas (2028), 450 MW in conversion of coal-fire units to oil (2030), 220 MW of solar generation,

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

and 416 MW of wind generation. Tier 3 resources in NS include natural gas additions (combustion turbines) of 50 MW in 2029 and new wind generation with a nameplate capacity of 850 MW phased in from 2026–2033. These Tier 3 resource additions are anticipated to facilitate the retirement of additional coal-fired generation by 2030. However, these retirements have not been included in the assessment due to their uncertainty.

Small amounts of new solar generation capacity (Tier 1) of up to 21 MW were being installed in PEI in 2024, along with 10 MW of new hybrid energy storage (Tier 1). PEI also has 30 MW of Tier 2 wind, 111 MW Tier 3 wind, and 140 MW of Tier 3 petroleum-based generation and 10 MW of Tier 3 batteries.

NB derates its wind capacity using a calculated year-round equivalent capacity of 22%. NS and PEI derate wind capacity to 18% and 17%, respectively, of nameplate based on year-round calculated equivalent load carrying capabilities for their respective individual sub areas. The peak capacity contribution of grid-based solar is estimated at zero since the Maritimes area peak occurs in the winter either before sunrise or after sunset.

Energy Storage

NS Power includes a 150 MW (4-hour duration) nameplate standalone battery resource as a Tier 1 resource and a 250 MW (4-hour duration) nameplate capacity standalone battery resource added as a Tier 2 resource phased in from 2026 through 2032. This grid-scale project will support the integration of new renewable generation, provide energy arbitrage and resiliency services, and provide firm capacity and fuel savings.

PEI includes a 10 MW nameplate capacity hybrid energy storage as a Tier 1 resource starting summer of 2024 and another 10 MW nameplate capacity energy storage system as a Tier 3 resource. This project will provide a storage option for the output from the 10 MW solar facility that is planned to come online during the same time frame. This project will provide fuel savings and may assist in providing additional reliability if a generation outage occurs.

NB Power has not included any energy storage resources in the *2024 LTRA* submission; however, the value of energy storage options is expected to increase as the technology improves and as NB's smart grid network develops. NB Power issued a request for expressions of interest for new renewable generation sources including 200 MW of wind, 15 MW of solar, 5 MW of tidal, and 50 MW of 4-hour duration battery storage in February 2023. Under this program, NB Power expects uptake in new energy storage projects in the coming years. Internal pilot projects and studies are underway to understand the economics, application, and performance of battery storage resources. Ongoing internal analyses are conducted by NB Power to determine the cost and benefit associated with battery storage options and dispatching these resources to reduce/shift peaks and/or balance intermittent resources, such as wind, to provide additional flexibility to the system.

Capacity Transfers

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

Transmission

NS has multiple new transmission line projects compared to the *2023 LTRA*; most being shorter runs to enable the connection of renewable resources, with one major project of 165 miles designed to improve the reliability of the existing tie between NS and NB.

Reliability Issues

The Maritimes area has a diversified mix of capacity resources fueled by oil, coal, hydro, nuclear, natural gas, wind (derated), dual fuel oil/gas, tie benefits, and biomass with no single one type feeding more than about 27% of the total capacity in the area. The Maritimes area does not anticipate fuel disruptions that pose significant challenges for resources during this assessment period.



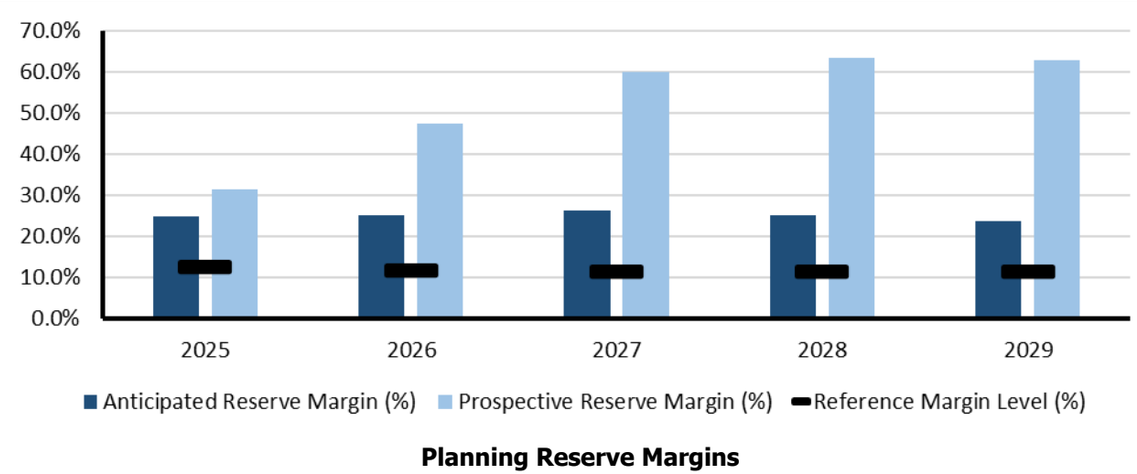
NPCC-New England

NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont served by ISO New England Inc. (ISO-NE). ISO-NE is a regional transmission organization responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS. Note: Northern Maine is not directly connected to the transmission system administered by ISO-NE.

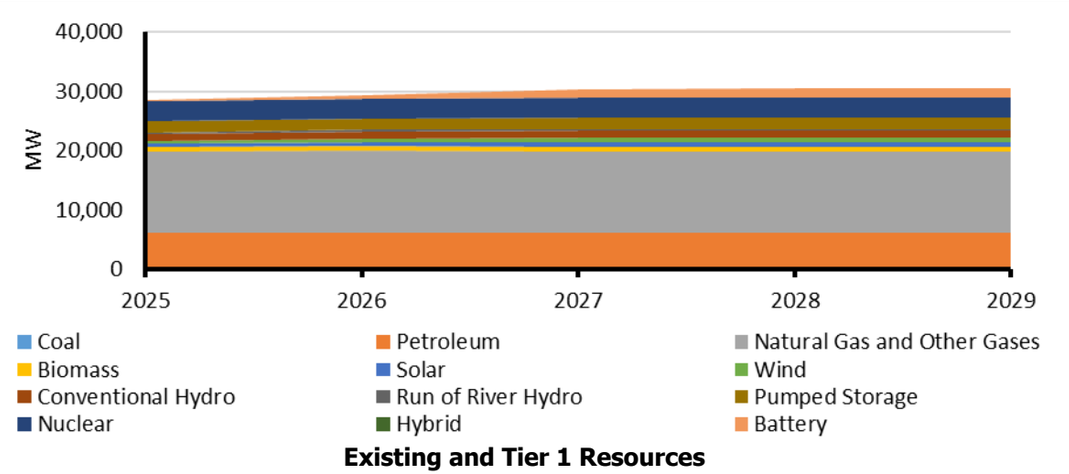
The New England BPS serves approximately 15.1 million customers over 68,000 square miles.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	24,579	24,702	24,845	25,076	25,364	25,706	26,100	26,547	27,052	27,567
Demand Response	566	588	544	544	544	544	544	544	544	544
Net Internal Demand	24,013	24,114	24,301	24,532	24,820	25,162	25,556	26,003	26,508	27,023
Additions: Tier 1	660	1,492	2,374	2,748	2,748	2,748	2,748	3,168	3,168	3,168
Additions: Tier 2	337	3,089	5,911	7,084	7,425	7,766	7,766	7,766	7,766	7,766
Additions: Tier 3	1,404	1,765	5,106	7,906	9,221	9,355	9,721	10,432	10,432	10,432
Net Firm Capacity Transfers	1,248	567	465	84	84	84	84	84	0	0
Existing-Certain and Net Firm Transfers	29,354	28,658	28,327	27,946	27,946	27,946	27,946	27,946	27,862	27,862
Anticipated Reserve Margin (%)	25.0%	25.0%	26.3%	25.1%	23.7%	22.0%	20.1%	19.7%	17.1%	14.8%
Prospective Reserve Margin (%)	31.4%	47.3%	60.1%	63.3%	62.8%	62.0%	59.5%	58.3%	55.0%	52.0%
Reference Margin Level (%)	12.7%	11.8%	11.3%	11.3%	11.3%	11.3%	11.3%	11.3%	11.3%	11.3%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- New England is forecast to have sufficient ARMs to meet consumer demand for electric energy for the first five years (2025–2029) of the assessment period and not require any Tier 2 resources.
- ISO-NE is addressing the issues brought on by grid transformation through several planning, operational, and market measures. A significant project is the redesign of the capacity market from a forward, annual auction to a prompt, seasonal auction with resource accreditation. The Capacity Auction Reforms (CAR) project began in Q2 2024 and is expected to be in place for the 19th Capacity Commitment Period (CCP 19) beginning on June 1, 2028. Additionally, New England has made tariff modifications to its Longer-Term Transmission Planning process to facilitate the New England states' achievement of their policy-based goals by enabling the development of transmission infrastructure. ISO-NE is also working with regional stakeholders to develop a regional energy shortfall threshold (REST) that defines the region's tolerance for energy shortfalls during low-probability extreme weather conditions.

NPCC-New England Projected Generating Capacity by Energy Source in Megawatts (MW)[35]					
	2025	**2026**	**2027**	**2028**	**2029**
Coal	541	541	541	541	541
Coal*	445	445	445	7	7
Petroleum	5,703	5,703	5,687	5,687	5,687
Natural Gas	13,651	13,724	13,708	13,708	13,708
Biomass	780	780	780	780	780
Solar	533	663	663	663	663
Wind	391	594	819	819	819
Conventional Hydro	1,209	1,209	1,209	1,209	1,209
Run of River Hydro	289	289	289	289	289
Pumped Storage	1,860	1,860	1,860	1,860	1,860
Nuclear	3,331	3,331	3,331	3,331	3,331
Hybrid	34	35	35	35	35
Other	74	74	74	74	74
Battery	159	584	1,242	1,616	1,616
Total MW	28,553	29,385	30,237	30,611	30,611
Total MW*	28,458	29,290	30,141	30,077	30,077
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to give formal notice to ISO-NE are removed from the resource projection where marked.					

[35] MW totals reflect Existing and Tier 1 generation. Generator retirements in this timeframe would be captured if a resource submits a retirement request through the ISO-NE capacity market.

NPCC-New England Assessment

Planning Reserve Margins

ISO-NE's installed capacity requirement (ICR) is based on the capacity needed to meet the ISO-NE and NPCC resource adequacy reliability criterion of an LOLE of 0.1 day/year. The ICR varies from year to year depending on projected system conditions. The ICR is calculated on an annual basis, in advance of the capacity auctions for each Capacity Commitment Period. The latest ICR calculations result in an annual RML of 12.70% in 2025, 11.82% in 2026, and 11.33% in 2027, expressed in terms of the annual 50/50 peak demand forecast published in the *2024 Capacity, Energy, Loads, and Transmission (CELT) Report*. For the years 2028 through 2034, which are beyond the current forward capacity market timeframe, ISO-NE continued to use the last available RML value of 11.33%. The ISO-NE RML is relatively low compared to other regions due to the impact of reflecting external assistance from neighboring control areas and the continued increase in BTM solar facilities.

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

ISO-NE routinely prepares 21-day energy forecasts. These forecasts incorporate weather, transmission topology, resource capability and availability, fuel inventories and constraints, and projected imports/exports. If the forecasted regional supply/demand balance is negative, projected energy deficiencies can trigger energy alerts or energy emergencies that are then disseminated to market participants and federal and state regulators. This early notification of potential energy shortfalls is expected to inform market participants such that actions can be taken to increase the expected availability of generating resources as needed.

ISO-NE recently completed work with the Electric Power Research Institute (EPRI) to develop the Probabilistic Energy Adequacy Tool (PEAT) framework. This tool is a framework that has three major steps (weather modeling, risk screening/scenario generation, and 21-day energy assessment), which were subsequently applied to assess the summers and winters of 2027 and 2032.

Probabilistic Assessments

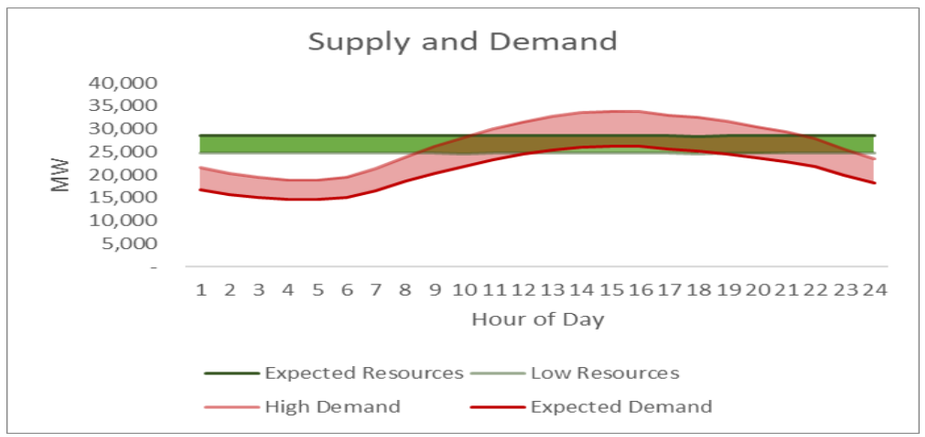
ISO-NE conducts probabilistic resource adequacy assessments annually in conjunction with NPCC to identify regional capacity resource needs and to comply with NPCC/NERC reliability requirements. In the transmission assessment domain, revisions to ISO-NE planning processes reflect the changing resource characteristics, probabilistic study assumptions, and changes to national and regional criteria. Coordinated planning activities with neighboring systems will continue and help support the New England states' policy objectives of providing access to a greater diversity of clean resources to meet environmental compliance obligations. Results from the 2024 ProbA, shown in the table below, reveal a slight increase in load-loss and unserved energy risk from the 2022 analysis, but values remain small. ISO-NE is considered to have sufficient resources for the planning horizon to meet NPCC resource adequacy criteria.

Base Case Summary 2024 ProbA of Results			
	2026*	2026	2028
EUE (MWh)	0.551	**10.69**	**7.40**
EUE (PPM)	0.004	**0.09**	**0.06**
LOLH (hours per year)	0.002	**0.07**	**0.03**
Operable On-Peak Margin	27.8%	**12.4%**	**13.7%**

* Provides the 2022 ProbA Results for Comparison

NPCC's ProbA results indicate that the risk of unserved energy in New England is concentrated in summer months (June–August).

Hourly demand and resource projections for a typical summer risk day in 2026 are shown in the figure below. Although expected resource contributions meet expected demand, there is risk that above-normal peak demand could exceed resources. Demand could be 25–30% higher than expected, which could cause strain on the system from the hours beginning 10:00 a.m. through 10:00 p.m. Also, below-normal resource performance from unexpected generator outages or low solar output could also cause supply shortfalls. If resource contributions are less than expected, strain on the system could be seen from the hour beginning 12:00 p.m. through 7:00 p.m. on a typical peak day. Reliance on external assistance may be necessary in these extreme conditions. A risk day in 2028 has a similar profile.



Hourly Probabilistic Assessment Results | Representative Summer Risk Day 2026

Fuel availability during extreme winter conditions is a persistent reliability concern in New England that is not modeled in detail in the ProbA. Potential natural gas transportation constraints can affect supply to generators during extreme cold temperatures, when natural gas demand for space heating is also peaking. Most natural-gas-fired generators in the area do not have firm natural gas transportation service and can be subject to supply curtailment during peak conditions. Many natural-gas-fired generators in New England can also operate with stored oil, providing for assured electricity supply in extreme winter conditions while oil stores are procured and maintained. Scenarios of extended and extreme cold weather that affect the availability of natural gas and oil replenishments present a reliability risk and were not modeled in the 2024 ProbA.

Demand

Over the 10-year LTRA planning horizon, the forecast net internal summer peak demand increases by 2,988 MW from 24,579 MW in 2025 to 27,567 MW in 2034 (roughly 2% decrease from the 2023 forecast in the later years). The corresponding net internal winter peak demand increases by 7,342 MW from 20,639 MW in 2025–2026 to 27,981 MW in 2034–2035 (roughly a 2.5% decrease from the 2023 forecast). Net energy for load is forecast to grow by 24,701 GWh from 119,285 GWh in 2025 to 143,986 GWh in 2034 (roughly 10% decrease from the 2023 forecast). The changes from the 2023 forecast were in part due to continued enhancements of the heating and transportation electrification forecasts.

The higher winter peak growth rate due to anticipated electrification results in significant convergence with summer peak projections by the end of the 10-year period, such that New England's transition to a winter-peaking system is currently anticipated by the mid-2030s. It is also expected that the timing of the peaks will likely occur in the morning by this time, with heating electrification in particular inducing a greater tendency for morning peaks due to electrified residential and commercial heating.

Demand-Side Management

For the summer of 2025, ISO-NE forecasts 566 MW of controllable and dispatchable demand-side management (DSM) resources, and that amount is projected to decrease by 22 MW to 544 MW by 2034. For the summer of 2025, ISO-NE forecasts 1,873 MW of passive DSM resources (EE and conservation). Demand-side resources are projected to peak in 2030 at 2,117 MW and then begin to decrease to 1,978 MW by 2034. This decrease in the later years is due to expiring EE measures outpacing new passive DSM additions.

Distributed Energy Resources

For summer months, the BTM PV forecast is incorporated as estimated reductions to the ISO-NE gross demand forecast. In 2025, New England forecasts 1,141 MW of peak load reduction (4,533 MW nameplate) of BTM PV. BTM PV is forecast to grow to 1,299 MW of peak load reduction (8,217 MW nameplate) by 2034. The BTM PV peak load reduction values are calculated as a percentage of ac nameplate. The percentages include the effect of diminishing PV production at the time of the system peak as increasing PV penetrations shift the timing of peaks later in the day. The BTM peak load reduction decreases from 25.2% of nameplate in 2025 to 15.8% in 2034.

ISO-NE recently adopted a new planning procedure (PP12) to formalize and standardize data collection for DERs. Under this procedure, distribution providers would be responsible for providing installation-level data on DERs connected to their system. Additionally, transmission providers would be responsible for providing basic data to translate feeder IDs into substation names and other useful identifying information. Among the other benefits that this procedure will lead to is "*proper accounting for the location, size, and type of DER which will lead to more accurate study outcomes.*"

Generation

The largest change that will impact New England's generation fleet is ISO-NE's CARs.

Specifically, to better ensure power system reliability and cost efficiency as New England's resource mix evolves, ISO-NE is proposing a CAR that would transition the capacity market from a forward/annual market to a prompt/seasonal market with accreditation reforms. This initiative has three primary components that would be in place for the Capacity Commitment Period (CCP) scheduled to start on June 1, 2028.

- Prompt auction: Instead of taking place three years in advance, the capacity auction would take place shortly before the CCP, reflecting more accurate information about projected electricity supply and demand.
- Seasonal CCP: The CCP changes from annual to sub-annual (seasonal) commitment periods to better address the distinct reliability challenges of winter and summer, as well as variations in resource performance from season to season.
- Accreditation reforms: Work began in 2022 via the former "Resource Capacity Accreditation in the Forward Capacity Market" project to identify and implement methodologies that will more accurately reflect resource contributions to resource adequacy in the capacity market. It is critical to the reliable and efficient clean-energy transition that the accreditation methodologies are updated to reflect resources' capabilities and how those capabilities contribute to resource adequacy. This work continues through CAR in the context of the proposed market constructs.

Energy Storage

New England currently has a total of 1,899 MW of energy storage capacity. This number includes about 39 MW of battery storage (BESS) and hybrid solar/battery storage. The largest energy storage resource(s) in New England are three pumped-storage hydro-electric facilities that can supply a combined 1,860 MW of quick-start 10-minute operating reserve capability, and with full reservoirs, and can deliver over 11,800 MWh of energy to the BPS.

Over the next five years (2025–2029), the nameplate capacity of energy storage devices (BESS, integrated-hybrid, and co-located-hybrid) are projected to increase significantly (Tier #1 [1,607 MW], Tier #2 [5,047 MW], and Tier #3 [4,955 MW]). No new pumped-storage facilities are planned for the region. Over the next 10 years, those total Tier 1–3 capacities do not increase from the five-year projection. All the above capacity totals reflect summer seasonal claimed capability ratings.

Capacity Transfers

New England is interconnected with the three BAs of Québec, the Maritimes, and New York. ISO-NE considers the tie benefits associated with these BAs within its capacity market methodology to reduce the installed capacity requirement to meet the regional resource adequacy criterion. Assumed assistance from tie benefits ranges from 1,830 MW in 2025 to 2,115 MW in 2027. Aside from such assistance, ISO-NE's firm capacity imports are projected to range from a maximum of 1,248 MW in the summer of 2025 down to 465 MW in the summer of 2027. There is one long-term firm import contract of 84 MW that extends through the summers of 2028 through 2032. There are currently no firm imports projected for the summers of 2033 and 2034. In addition, there are no firm exports identified over the 10-year assessment.

Transmission

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

The future reliable and economic performance of the BPS is expected to be maintained as a result of approximately $1.5 billion of planned transmission upgrades over the next 10 years. Generator retirements, the integration of many DERs and VERs, the use of IBR technologies, and issues rising from minimum load assessments and high-voltage conditions are changing the needs for reliability-based transmission upgrades. Interregional import capability will also increase with the completion of the 1,200 MW HVdc New England Clean Energy Connect (NECEC) tie line between Québec and Maine, scheduled to be in service by the beginning of 2026.

In addition, transmission improvements will also be needed to support state policies to access remotely located sources of clean energy and serve increased load as transportation and heating are electrified. Transmission assessments and resultant plans are being developed throughout the region to meet these future system needs.

Reliability Issues

New England's BPS is transitioning to a system with unprecedented demand growth, due to electrification of heating and transportation, and a growing number of renewables, clean energy resources, VERs, and DERs. ISO-NE is engaged in the implementation of revised interconnection standards for VERs and DERs that will ensure overall BPS reliability and facilitate the economic development of IBRs.

ISO-NE has observed some delays in projected in service dates for system upgrades due to supply chain issues. In these cases, ISO-NE develops operating plans to work around any issues caused by these delays. Additionally, the New England Transmission Owners have indicated that supply chain issues are causing a notable increase in project costs.

New England has already experienced constraints on electric energy production due to constraints on fuel infrastructure that have an impact on the power sector during winter. In response, ISO-NE has been a key player at the national level in promoting BPS reliability through sharing of lessons learned, best practices, and, more recently, through the performance of more detailed and in-depth BPS energy assessments. Additionally, to address winter energy security challenges, ISO-NE and regional stakeholders developed and put in place a two-year program to compensate certain resources that provide energy security during the winters of 2023–2024 and 2024–2025 (from December to February). ISO-NE's Inventoried Energy Program (IEP) is a voluntary program designed to provide incremental, winter-period compensation for participants that maintain inventoried energy for their assets during extreme cold periods when energy security is most stressed.

The just-in-time delivery of a generator's fuel supply, whether natural gas, wind, or solar, is creating the need for the electric sector to quickly develop ways to retain access to flexible, stored energy—either through long-term energy storage solutions that can capture and store renewable power or through the use of dispatchable resources.

ISO-NE is actively working on numerous major projects to prepare for the clean energy transition and ensure continued reliability. The following is a short list of major projects in which ISO-NE has engaged:

- **CAR Project**
- **Operational Impacts of Extreme Weather Events**
- **Regional Energy Shortfall Threshold**
- **Day-Ahead Ancillary Services Initiative**
- **Economic Planning for the Clean Energy Transition (EPCET)**
- **Extended-Term Transmission Planning Tariff Changes**
- **Longer-Term Transmission Studies**
- **Storage As Transmission Only Asset (SATOA)**
- **FERC Order No. 1920 Project**
- **FERC Order No. 2023 & 2023-A Project**
- **FERC Order No. 2222 Project**
- **FERC Order No. 881 Project**

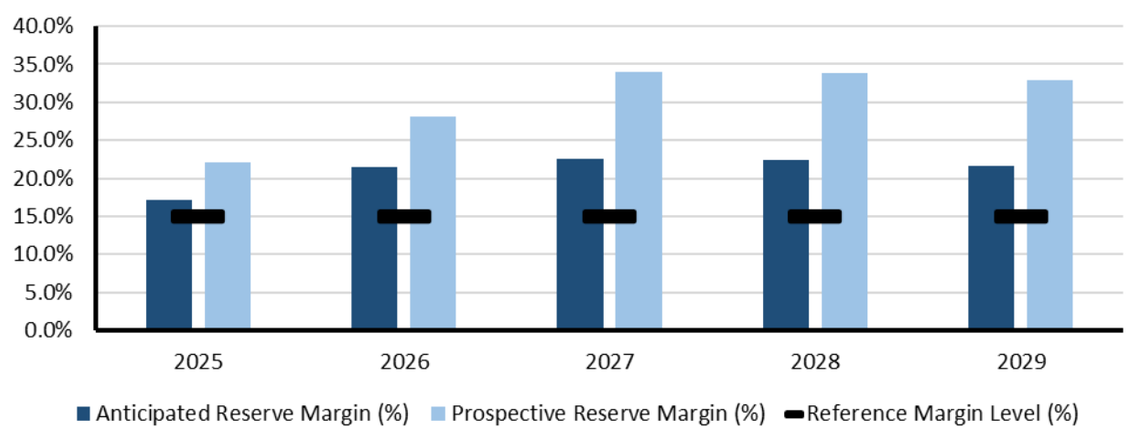


NPCC-New York

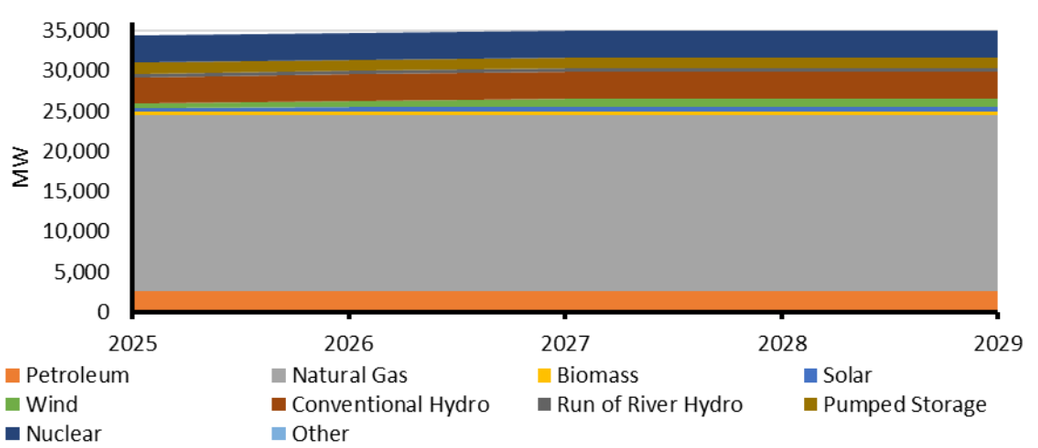
NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only Balancing Authority within the state of New York. The BPS encompasses over 11,000 miles of transmission lines and 760 power generation units and serves 20.2 million customers. For this LTRA, the established RML 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). The NYSRC approved the 2025–2026 IRM at 24.4%.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	31,650	31,900	32,110	32,130	32,340	32,580	32,880	33,320	33,830	34,210
Demand Response	897	897	897	897	897	897	897	897	897	897
Net Internal Demand	30,754	31,004	31,214	31,234	31,444	31,684	31,984	32,424	32,934	33,314
Additions: Tier 1	495	858	1,144	1,144	1,144	1,144	1,144	1,144	1,144	1,144
Additions: Tier 2	1,558	2,090	3,572	3,572	3,572	3,572	3,572	3,572	3,572	3,572
Additions: Tier 3	1,381	4,384	6,384	7,928	8,383	8,383	8,383	8,383	8,383	8,383
Net Firm Capacity Transfers	1,600	2,880	3,186	3,186	3,186	3,186	3,186	3,186	3,186	3,186
Existing-Certain and Net Firm Transfers	35,511	36,790	37,096	37,097	37,097	37,097	36,687	36,687	36,687	36,687
Anticipated Reserve Margin (%)	17.1%	21.4%	22.5%	22.4%	21.6%	20.7%	18.3%	16.7%	14.9%	13.6%
Prospective Reserve Margin (%)	22.1%	28.2%	34.0%	33.9%	33.0%	32.0%	29.5%	27.7%	25.7%	24.3%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- Public policies, such as New York state's 2019 Climate Leadership and Community Protection Act (CLCPA), are driving rapid changes in New York's electric system, impacting how electricity is produced, transmitted, and consumed. The transition to a cleaner grid in New York is leading to an electric system that will be increasingly dynamic, decentralized, and reliant on weather-dependent renewable generation.
- Recent assessments reveal that reliability margins are shrinking. Electrification programs are increasing the demand for electricity and placing New York on a trajectory to be a winter-peaking system in the future. Largely in response to public policies, fossil fuel generators are retiring at a faster pace than new renewable supply is entering service. The potential for delays in construction of new supply and transmission, higher than forecasted demand, and extreme weather could threaten reliability and resilience of the New York grid.
- NYISO's reliability studies identified actionable reliability needs starting 2025 in New York City. The reliability need is primarily driven by a combination of forecasted increases in peak demand and the assumed unavailability of certain generation in New York City affected by state legislation and regulations promulgated by the New York State Department of Environmental Conversation, commonly known as the Peaker Rule,[36] to limit emissions. Following a solicitation for proposed solutions to the reliability need, NYISO retained several plants in New York City that would have otherwise been deactivated to comply with the Peaker Rule. NYISO's 2024 Reliability Needs Assessment (RNA), targeting completion in the fourth quarter of 2024, identifies transmission security violations of reliability criteria primarily driven by a combination of forecasted increases in peak demand, limited additional supply, and the assumed retirement of generation in New York City in response to state law and regulations.
- Driven by public polices, new supply, large loads, and transmission projects are seeking to interconnect to the grid at record levels. NYISO's interconnection process balances developer needs with grid reliability. Efforts are underway to make this process more efficient while protecting grid reliability. New transmission is being built, but more investment is necessary to support the delivery of offshore wind energy and to connect new resources upstate to downstate load centers where demand is greatest. Planning for new transmission to support offshore wind is underway in NYISO's Public Policy Transmission Planning Process.
- To achieve the mandates of the CLCPA, new dispatchable emission-free resources (DEFR) with the necessary reliability services will be needed to replace the capabilities and attributes of today's generation. These types of resources, which can achieve the necessary attributes by a combination of solutions, must be significant in capacity and have attributes similar to traditional generation plants, such as the ability to come on-line quickly, stay on-line for as long as needed, maintain the system's balance and stability, provide ERSs, and adapt to meet rapid, steep ramping needs. Such new emission-free supply is not yet available on a commercial scale.
- New wholesale electricity market rules are supporting the grid in transition. These markets are critical for a reliable transition. Wholesale electricity markets are open to significant investment in wind, solar, and battery storage as well as distributed energy resources. Demand management programs are also under development as a measure to facilitate achievement of CLCPA targets. By lowering the peak load and avoiding system buildout to serve the highest demand hour, fewer DEFRs will be needed and fewer fossil fuel-fired plants will be needed to meet lower peaks during the transition.

[36] Subpart 227-3 of Title 6 of the New York Codes, Rules an3,323d Regulations.

NPCC-New York Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Petroleum	2,631	2,631	2,631	2,631	2,631
Petroleum*	2,628	2,628	2,628	2,628	2,628
Natural Gas	21,907	21,907	21,907	21,907	21,907
Biomass	334	334	334	334	334
Solar	545	586	586	586	586
Wind	461	785	1,070	1,070	1,070
Conventional Hydro	3,323	3,323	3,323	3,323	3,323
Run of River Hydro	413	413	413	413	413
Pumped Storage	1,410	1,410	1,410	1,410	1,410
Nuclear	3,330	3,330	3,330	3,330	3,330
Battery	50	50	50	50	50
Total MW	34,405	34,769	35,054	35,054	35,054
Total MW*	34,401	34,765	35,051	35,051	35,051
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to give formal notice to NYISO are removed from the resource projection where marked.					

NPCC-New York Assessment

Planning Reserve Margins

The LTRA anticipated and prospective margins are above 15% with the exception of year 9 (2033) and year 10 (2034). However, the system margins are narrowing throughout the assessment period. Wind, grid-connected solar, and run-of-river totals were derated for the LTRA calculation. Under its reliability planning processes, NYISO uses probabilistic assessments to evaluate its system's resource adequacy against the LOLE resource adequacy criterion of no greater than 0.1 event-days/year probability of unplanned load loss. NYISO's 2024 Reliability Needs Assessment, which is underway and targets completion in Q4 2024, will likely identify reliability criteria violations.

NYISO also provides support to the NYSRC in conducting an annual IRM study. This study determines the IRM for the upcoming capability year (May 1 through April 30). The IRM is used to quantify the capacity required to meet the NPCC and NYSRC resource adequacy criterion of "1 day in 10 years." The current IRM for the 2024–2025 capability year is 22% of the forecasted NYCA peak load. All values in the IRM calculation are based upon full installed capacity values of resources. The IRM has varied historically from 15% to 22%. Additionally, the NYISO performs an annual study to identify the locational minimum installed capacity requirements (LCR) for the upcoming capability year.

Energy Assessment, Including Non-Peak Hour Risk

New York State's CLCPA mandates to decarbonize span over all major industries and are a main driver for the electric system changes. NYISO staff in system operations, planning, and markets will continue to assess the system changes to prepare for the grid's transformation.

With high penetration of renewable intermittent resources, the system will need dispatchable emission-free resources (DEFR) and long-duration resources to balance intermittent supply with demand. These types of resources must be significant in capacity and have attributes such as the ability to come on-line quickly, stay on-line for as long as needed, maintain the system's balance and stability, and adapt to meet rapid, steep ramping needs. Additionally, although new transmission is being built, more investment is necessary to support the delivery of future offshore wind energy and to connect new resources upstate to downstate load centers where demand is greatest.

NYISO performs long-range assessments (10-year and beyond planning horizon), and certain energy aspects are accounted for in the hourly modeling and simulations performed under the resource adequacy studies through NYISO's reliability planning processes along with the production cost simulations performed under its System and Resource Outlook.

NYISO performs and supports energy assessments, including a fuel and energy security study, a study assessing potential impacts related to climate change, and weekly analysis of fuel and energy security based on load profiles and fuel inventories reported through NYISO's Generator and Fuel Emissions Reporting (GFER) data portal. These assessments are based on data and information provided by resources on an annual, weekly, and as-needed basis considering system operating conditions. These assessments have the capability to analyze the impact of changes in stored fuel inventory, resource outages, fuel supply disruptions, transmission constraints, and other relevant conditions that may adversely impact fuel and energy security. Additionally, the New York City and Long Island areas have a loss of gas supply dual-fuel requirement and certain combined cycle gas units participate in a "Minimum Oil Burn" program. While oil accounts for a relatively small percentage of the total energy production in New York, it is often called during critical periods, such as when severe cold weather limits access to natural gas.

Probabilistic Assessments (NERC ProbA and Other Studies)

NYISO performs probabilistic assessments using GE's Multi-Area Reliability Simulation (MARS) as part of its reliability planning processes as well as to determine annual IRM LCRs. NYISO also pursued capacity accreditation market rules to more accurately reflect capacity market suppliers' contributions to resource adequacy. These new market rules align compensation for capacity suppliers with an individual resource's expected reliability benefit to consumers and uses the probabilistic models from the LCR process to define capacity accreditation factors (CAF) for various capacity accreditation resource classes. The groundbreaking proposal was accepted by FERC in May 2022. The CAFs will reflect the marginal reliability contribution of the ICAP Suppliers within each Capacity Accreditation Resource Class toward meeting NYSRC resource adequacy requirements for the upcoming capability year, starting with the capability year that began in May 2024.

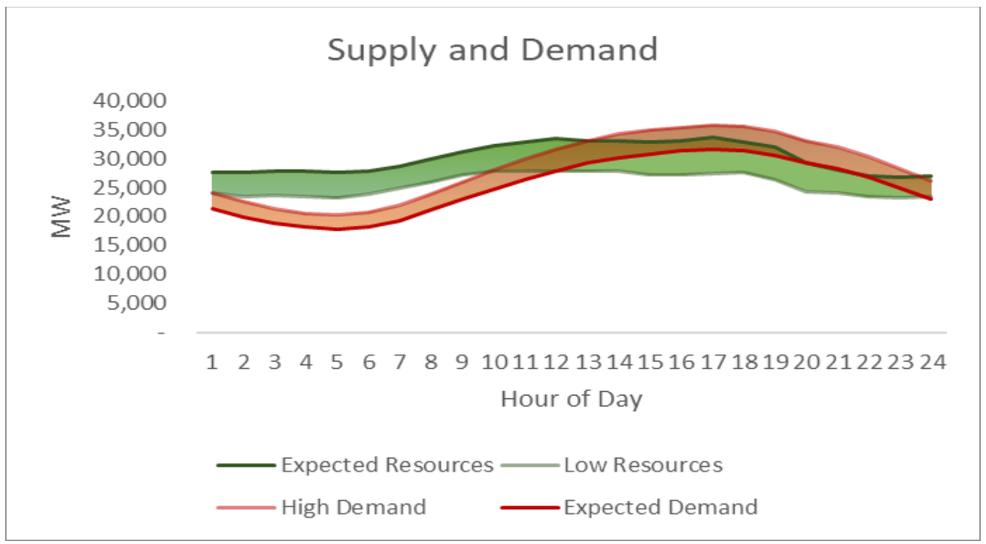
Additionally, NPCC provides results into NERC's ProbA process under the LTRA. The results from the ProbA performed in 2024 by NPCC are shown below.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0.06	1.91	1.30
EUE (PPM)	0.00	0.01	0.01
LOLH (hours per year)	0.00	0.01	0.01
Operable On-Peak Margin	16.7%	14.0%	15.0%

* Provides the 2022 ProbA Results for Comparison

Most load-loss and unserved energy risk is in the summer months of late June through August.

Hourly demand and resource projections for a typical summer risk day in 2026 are shown in the figure below. Although expected resource contribution is enough to meet expected demand, there is risk that above-normal peak demand could exceed resources. Demand could be 10–13% higher than expected, which could cause strain on the system from the hours beginning 2:00 p.m. through 11:00 p.m. Also, below-normal resource performance from unexpected generator outages or low-solar output could also cause supply shortfalls. If resource contributions are less than expected, strain on the system could be seen from hour beginning 12:00 p.m. through 12:00 a.m. on a typical peak day. Reliance on external assistance may be necessary in these events. A risk day in 2028 has a similar profile.



Hourly Probabilistic Assessment Results | Representative Summer Risk Day 2026

NPCC's Directory 1 defines a compliance obligation for the NYISO, as a Resource Planner and Planning Coordinator, to perform a resource adequacy study evaluating a five-year planning horizon. NYISO delivers a report every year under this study process to verify the system against the 1-day-in-10-years LOLE criterion, which is usually based on NYISO's latest available reliability assessment results and assumptions. NYSRC Reliability Rules have recently included a requirement defining NYISO's obligation to deliver a Long-Term Resource Adequacy Assessment Report every year during which the NYISO publishes a Reliability Needs Assessment (RNA) and an annual update in the intervening year between RNAs.

Demand

NYISO employs a multi-stage process to develop load forecasts for each of the 11 zones within the New York Control Area (NYCA). The impacts of net electricity consumption of energy storage resources due to charging and discharging are added to the energy forecasts, while the peak-reducing impacts of BTM energy storage resources are deducted from the peak forecasts.

Currently, the NYCA summer peak typically occurs in late afternoon. The NYCA summer peak is projected to shift into the evening as additional BTM solar is added to the system and as EV charging impacts increase during the evening hours. Because the hour of the summer peak shifts into the evening over the course of the forecast horizon, BTM solar generation becomes less coincident with the NYCA peak hour, and BTM solar coincident peak reductions are forecasted to decrease in later years. The forecast of solar PV-related reductions to the winter peak is zero because the system typically peaks after sunset.

Trended weather conditions from the Climate Impact Study Phase I report are included in NYISO's end-use models and are reflected in the baseline, policy scenario, and percentile forecasts. NYISO develops 90th and 99th percentile forecasts to account for the impacts of extreme weather on seasonal peak demand and calculates 10th percentile forecasts to represent milder seasonal peak conditions.

The 10-year annual average energy (+1.7%) and summer peak demand (+0.8%) growth rates are higher than last year's forecast. Increases in growth rates relative to the prior forecast are primarily attributed to the significant impacts of interconnecting large load projects. Baseline energy and coincident peak demand increase significantly throughout the 30-year forecast period, driven largely by large load project growth in the early forecast years and electrification of space heating, non-weather sensitive appliances, and EV charging in the outer forecast years. New York is projected to become winter-peaking in future decades due to space heating electrification and EV penetration. To account for forecast uncertainty during winter due to electrification and large loads, NYISO implemented a winter dynamic load forecast uncertainty in the resource adequacy models for its 2024 RNA.

Demand-Side Management

NYISO is working on developing market concepts to encourage the participation of flexible load, which will become increasingly important as the levels of weather-dependent intermittent resources on New York's grid increase in response to the state's climate and clean energy policies. Many of New

York's utilities are piloting several load management programs (e.g., smart EV charging, home-thermostat use, and integration of BTM storage for local peak demand modulation). As part of NYISO's annual long-term forecasting process, the impacts of these programs are discussed and significant impacts on demand are included in the load forecast.

DR participation for the summer capability period has increased slightly from 1,234 MW to 1,281 MW since the *2023 LTRA*. There are currently 425 MW of DR participating in ancillary services programs and providing either 10-minute spinning reserves or 30-minute non-synchronous reserves.

Distributed Energy Resources

NYISO has implemented in 2024 a plan to integrate DERs, including DR resources, into the markets it administers. The DER Participation Model project aims to enhance participation of DERs in the competitive wholesale markets. These measures closely align the bidding and performance measurements for DERs with the rules for generators. The measures establish a state-of-the-art model that is largely consistent with the market design envisioned by FERC in its Order 2222. This project, which began in 2017, provides a single participation model for DER DR resources to provide energy, ancillary services, and installed capacity through an aggregation. The market rules for the DER and aggregation participation model were accepted by FERC in January 2020. NYISO filed additional proposed tariff revisions with FERC in June 2023 to clarify and enhance these market rules. NYISO deployed its DER participation model in 2024.

Generation

The pace of renewable project development and existing generation retirement is unprecedented and driving a need to increase the pace of transmission expansion, clean dispatchable generation, and demand management programs development. In general, resource and transmission expansion take many years from development to deployment. Coordination of project additions and retirements is essential to maintaining reliability and achieving policy. Significant new resource development will be required to achieve energy targets under the CLCPA. The total installed generation capacity to meet policy objectives within New York is projected to range between 111 GW and 124 GW by 2040. At least 95 GW of this capacity will consist of new generation projects and/or modifications to existing plants. Even with these additions, New York still may not be sufficient to maintain the reliable electricity supply. The sheer scale of resources needed to satisfy system reliability and policy requirements within the next 20 years is unparalleled.

Currently, NYISO's interconnection process contains a significant number of proposed projects in various stages of development with only a fraction in more advanced stages included in the reliability planning models. However, the grid will evolve to achieve the policy mandates, and those changes will affect the nature and amount of resources.

For the 2024 RNA, gas availability is derated during winter to further account for cold weather risks.

To achieve the CLCPA mandate of an emission-free grid by 2040, DEFRs must be developed and deployed throughout New York. DEFRs that provide sustained on-demand power and system stability will be essential to meeting policy objectives while maintaining a reliable electric grid. While essential to the grid of the future, such DEFR technologies are not commercially available today.

ERSs usually provided to the system by synchronous fossil generation will continue to be necessary. New technology is being developed to allow for a reliable transition to a clean grid. Grid-forming inverter capabilities, as well as DEFRs, will likely be part of this transformation. In May 2023, the New York State Public Service Commission (PSC) initiated a process to examine the need for resources to ensure the reliability of the CLCPA mandate for a zero-emissions electric grid by 2040. The PSC seeks to identify innovative technologies to ensure the reliability of a zero-emissions electric grid. Numerous other initiatives at both state and federal levels are in progress and may impact the grid of the future.

Energy Storage

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

Capacity Transfers

The models used for NYISO's reliability planning studies include firm capacity transactions (purchases and sales) with the neighboring systems as a base-case assumption. Proposed projects that are in a more advanced stage are included. One such project is the 1,250 MW HVdc line from Québec to New York City, which is reflected in the LTRA summer total transfers starting in 2026. Additionally, the probabilistic model that NYISO uses to assess the adequacy of resources in the reliability planning processes employs several methods aimed at preventing overreliance on the external systems support. For example, NYISO employs limiting emergency assistance from neighbors by modeling a total limit of 3,500 MW, modeling five simultaneous peak days, modeling the long-term purchases and sales with neighboring control areas, and not modeling emergency operating procedure steps for the neighbors.

New York is fortunate to have strong interconnections with neighboring regions and has enjoyed reliability and economic benefits from such connections. As the energy policies in neighboring regions evolve, New York's imports and exports of energy could vary significantly due to the resulting changes in neighboring grids. The availability of energy for interchange is predicted to shift fundamentally as policy achievement progresses. As New York's and other regions' grids evolve, continuous monitoring and collaboration with our neighboring states will be required.

Transmission

Significant new transmission is being built across New York, but more investment is necessary to support, among other things, the delivery of offshore wind energy to connect new resources upstate to downstate load centers where demand is greatest.

Key transmission projects under development and accounted for in the reliability models include the following:

- The Northern New York Priority Transmission Project upgrading the transmission corridors from the renewable generation pocket in the north country to central New York
- The 1,250 MW Champlain-Hudson Power Express HVdc line from Hydro-Québec to New York City
- The AC Public Policy Transmission Projects that consist of upgrading transmission corridors in central New York and the lower Hudson Valley, which projects target completion of the majority of the components by December 2023
- The transmission project selected to address the Long Island Offshore Wind Expert Public Policy Transmission Need and that adds three new dc tie lines and a 345 kV backbone across western/central Long Island with an in-service date in 2030

Additionally, there are significant transmission projects either recently selected or under study that have not yet met the criteria to be in the reliability model. For instance, the PSC recently identified a new public policy transmission planning need for NYISO to solicit proposed solutions and that is intended to support the integration of 4.7 GW of wind resources in New York City.

Furthermore, in 2020, the PSC ordered the New York utilities to undertake planning assessments and make investment proposals to facilitate the cost-effective development of renewable and emissions-free resources while maintaining the reliability of New York's electric grid. The Coordinated Grid Planning Process (CGPP) was approved by the PSC in August 2023. The process is designed to assess the state's electric grid using a 20-year planning horizon. The CGPP is intended to identify electric grid expansions that can aid in unlocking renewable generation capacity and provide energy headroom for the purpose of meeting New York's clean energy goals while providing value to customers. Moreover, the CGPP is designed to identify opportunities for expansion of the bulk transmission system to advance the mandates of CLCPA. This provides another opportunity to inform the PSC's consideration of whether to establish a public policy transmission need for NYISO to solicit and evaluate proposed solutions.

Reliability Issues

The 2024 RNA, targeting completion in the fourth quarter of 2024, identifies transmission security violations of reliability criteria primarily driven by a combination of forecasted increases in peak demand, limited additional supply, and the assumed retirement of generation in New York City in response to state law and regulations. Accounting for these factors, the planned bulk power transmission system will not be able to securely and reliability serve the forecasted demand in New York City. When accounting for forecasted economic growth and policy-driven increases in demand, the New York City (Zone J) will be deficient starting in summer 2033 by as much as 17 MW for 1 hour and increasing to 97 MW for 3 hours in summer 2034 on the peak day during expected weather conditions. The Reliability Need occurs within the transmission district owned by Consolidated Edison Company of New York, Inc. ("Con Edison"). Con Edison is designated as the Responsible Transmission Owner in the NYISO's transmission planning process and required to submit a regulated backstop solution to address the need, which may be triggered if sufficient market-based solutions do not materialize.

Prior to the 2024 RNA, the NYISO completed the 2023 Q2 STAR on July 14, 2023. This assessment found a reliability need beginning in summer 2025 in New York City primarily driven by a combination of forecasted increases in peak demand and the assumed unavailability of certain generation in New York City affected by the New York Department of Environmental Conservation (DEC) Peaker Rule. The reliability need is a deficiency in the transmission security margin. Specifically, the New York City zone is deficient by as much as 446 MW for a duration of nine hours on the peak day during expected weather conditions (95 degrees Fahrenheit) when accounting for forecasted economic growth and policy-driven increases in demand. To ensure the continued reliability of electric service in New York City, NYISO designated the generators on the Gowanus 2 & 3 and Narrows 1 & 2 barges as necessary for reliability to temporarily remain in operation after the Peaker Rule compliance date until permanent solutions to the need are in place, for an initial period of up to two years (May 1, 2027).

The transition to a cleaner grid in New York is leading to an electric system that is increasingly dynamic, decentralized, and reliant on weather-dependent renewable generation and may lead to increasing reliability issues on the New York system. Reliability margins are shrinking. Generators needed for ERSs are planning to retire. Delays in the construction of new supply and transmission, higher-than-expected demand, and extreme weather could threaten reliability and resilience in the future. The

system is projected to become winter-peaking in the next decade due to electrification and decarbonization policies. Large loads are being proposed to interconnect to the system. New York's current reliance on neighboring systems is expected to continue through the next 10 years. A successful transition of the electric system requires replacing the reliability attributes of existing fossil-fueled generation with clean resources with similar capabilities. Such resources must be significant in capacity and have attributes such as the ability to come on-line quickly, stay on-line for as long as needed, maintain the system's balance and stability, and adapt to meet rapid, steep ramping needs. New transmission is being built but more investment is necessary to support the delivery of offshore wind energy to connect new resources located in upstate to downstate load centers where demand is greatest.

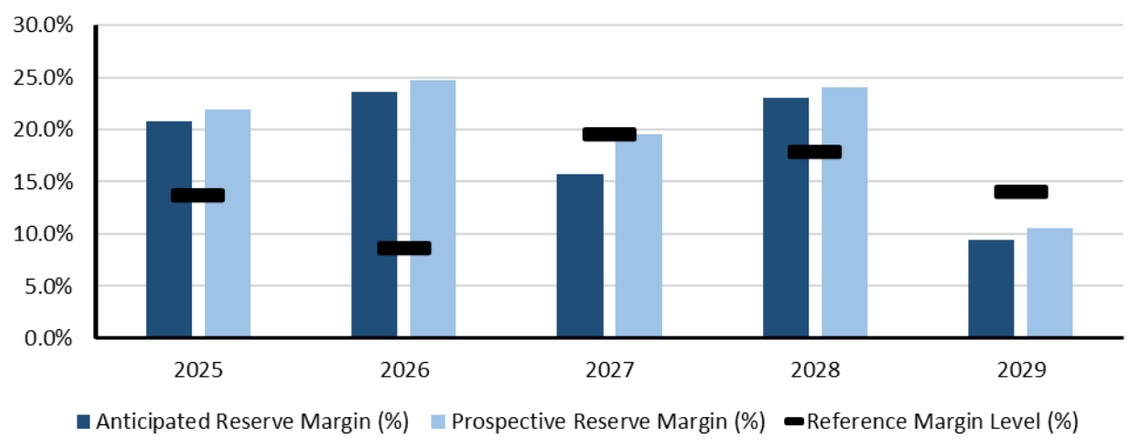


NPCC-Ontario

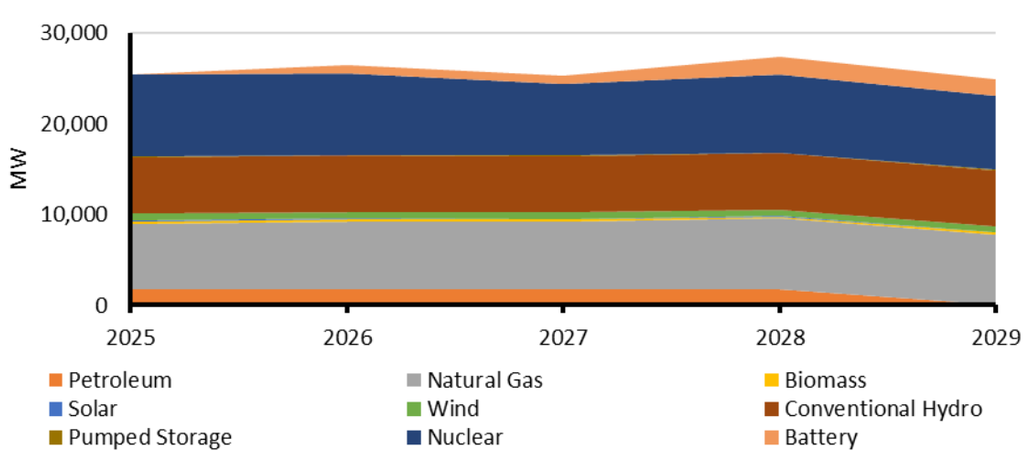
NPCC-Ontario is an assessment area in the Ontario province of Canada. The IESO is the Balancing Authority for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of more than 16 million. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	23,385	23,860	24,264	24,627	25,248	26,038	26,473	27,373	27,974	28,789
Demand Response	1,791	1,914	1,914	1,914	1,914	1,914	1,914	1,914	1,914	1,914
Net Internal Demand	21,594	21,946	22,350	22,713	23,333	24,123	24,559	25,458	26,060	26,875
Additions: Tier 1	617	1,737	1,735	3,012	3,302	3,300	3,843	4,385	4,384	5,128
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	600	600	500	600	600	600	600	0	0	0
Existing-Certain and Net Firm Transfers	25,470	25,394	24,133	24,924	22,242	22,051	20,660	20,705	20,671	20,257
Anticipated Reserve Margin (%)	20.8%	23.6%	15.7%	23.0%	9.5%	5.1%	-0.2%	-1.4%	-3.9%	-5.5%
Prospective Reserve Margin (%)	22.0%	24.8%	19.5%	24.1%	10.5%	6.1%	0.8%	-0.5%	-2.9%	-4.6%
Reference Margin Level (%)	13.7%	8.6%	19.5%	17.8%	14.1%	9.4%	17.2%	8.1%	6.8%	8.5%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- While potential reserve margin shortfalls are forecast for 2027 and 2029, they are mainly driven by changes in the IESO's resource adequacy assessment methodology since the *2023 LTRA*. Last year, reserve margin calculations included the continuation of existing resources (following contract expiry) for the entire outlook period. For this LTRA, reserve margins reflect the contribution of existing resources only until the end of their contract or commitment period. This change to the methodology is more conservative and helps to better identify system needs in the IESO's planning assessments to establish resource acquisition targets and address anticipated needs.
- The IESO has two capacity sharing agreements with Hydro-Québec providing firm summer capacity, which will help to address future shortfalls this decade.
- The IESO has completed a broad set of actions to secure new capacity for this decade to ensure that Ontario's power system needs are met during a period of nuclear retirements and refurbishments and economy-wide demand growth. This includes securing long-term commitments amounting to 2,195 MW of new capacity to be on-line by 2028, with early operation incentives anticipated to bring a portion on-line as early as 2027 to help alleviate the reserve margin gap.
- The annual capacity auction, which helps to meet needs in the short term by securing capacity for up to one year at a time, has historically secured more capacity than targeted. Trends suggest that this should continue, as the November 2024 auction (which will help to ensure reliability through summer 2025 and winter 2025–2026) also secured more capacity than targeted.
- The IESO is taking steps that will address future shortfalls around the end of this decade and heading into the 2030s. The next round of medium- and long-term procurements was recently launched to ensure that capacity and energy needs continue to be met. The second medium-term procurement aims to re-commit existing resources with contracts expiring over the 2026–2029 period, while the second long-term procurement aims to secure capacity and energy from new resources (to be online as early as 2029), to meet needs emerging in the early 2030s.
- The IESO is also responsible for implementing new provincial policy as outlined in the Ontario government's July 2023 Powering Ontario's Growth report, which includes developing new nuclear projects, transmission expansions, and expanded conservation and demand management programs. The IESO will also incorporate changes stemming from the federal release of the final Clean Electricity Regulations, anticipated toward the end of 2024.

NPCC-Ontario Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	**2026**	**2027**	**2028**	**2029**
Petroleum	1,695	1,695	1,695	1,695	5
Natural Gas	7,275	7,465	7,465	7,847	7,761
Biomass	297	294	257	209	209
Solar	100	100	100	100	100
Wind	743	722	711	711	602
Conventional Hydro	6,215	6,212	6,212	6,212	6,202
Pumped Storage	38	38	38	38	38
Nuclear	9,008	9,008	7,895	8,639	8,142
Battery	118	998	996	1,886	1,885
Total MW	25,487	26,531	25,368	27,336	24,944

Planning Reserve Margins

The ARM falls below the RML starting in 2027. While expected nuclear retirements, the ongoing nuclear refurbishment program, and demand growth are resulting in increased needs this decade, the reserve margin shortfalls indicated in 2027 and 2029 are primarily driven by the change in the IESO's resource adequacy assessment methodology described above.

Mid-decade capacity needs that were identified in the 2022 *Annual Acquisition Report* have been met through a series of competitive procurements. Since May 2023, the IESO has secured over 3,600 MW of new capacity from battery storage, natural gas, and biogas facilities, expected to come on-line between 2025 and 2028. In addition, the 2023 capacity auction secured 1,867 MW of summer capacity and 1,311 MW of winter capacity above targets of 1,400 and 850 MW, respectively. The IESO continues to actively procure existing and new resources to meet longer-term needs, using the mechanisms in the Resource Adequacy Framework.

Ongoing refurbishments at Bruce Nuclear Generating Station (NGS) and Darlington NGS will see between one and three reactors concurrently off-line through Summer 2033. Refurbishments remain on or ahead of schedule and outages continue to be managed to limit impacts to the grid. Following the return to service of refurbished units at Bruce, each unit is expected to be uprated, with the additional capacity anticipated to be available in the early 2030s.

The Ontario government has also announced a plan to deliver three additional small modular reactors in addition to the 300 MW unit already underway (anticipated on-line in 2029). The provincial government's July 2023 Powering Ontario's Growth plan directed the IESO to conduct an impact assessment on potentially adding 4,800 MW of large-scale nuclear capacity to Bruce NGS. Approval was granted from the federal nuclear regulator in October 2024 to extend operation of four units at Pickering NGS (previously scheduled for decommissioning in 2025) through September 2026. The government is also supporting the refurbishment of the four units at Pickering, with refurbishment of the first unit anticipated to be completed in 2031.

To address resource adequacy needs emerging mid-decade due to the combined effect of nuclear retirements and refurbishments, as well as expiring generation contracts, the IESO has employed competitive acquisition mechanisms from the Resource Adequacy Framework in part via the capacity auction referenced above. The IESO's first long-term procurement concluded in May 2024 and secured long-term commitments from 10 battery storage facilities for 1,784 MW of new capacity and three natural gas/biogas facilities for 411 MW of new capacity. Facilities are anticipated to be in service as early as May 2027.

The IESO calculates the reserve margin requirement on an annual basis and publishes this in the Annual Planning Outlook (APO). The requirement is calculated for each year for net demand at the time of the annual demand peak to provide an LOLE that is at or below 0.1 days per year. The reserve margin requirement in the *2024 LTRA* is derived from the capacity requirement in the 2024 APO, plus any material changes to demand and supply following APO publication.

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

Energy adequacy assessments are conducted annually for the APO by using a deterministic approach in the IESO's economic dispatch model. In addition, the IESO's capacity adequacy assessments consider the system's ability to serve load in all hours of the year (i.e., during peak hours as well as non-peak load hours).

As demand requirements increase, nuclear refurbishments continue, and some units at the Pickering NGS retire in 2024, Ontario's energy needs are expected to be met this decade by the resources secured through the IESO's recently completed procurements. The second medium-term procurement, which was recently launched, aims to secure capacity and energy from existing resources reaching contract end; this is expected to help alleviate energy risks in the latter half of this decade. The second long-term procurement that is underway aims to acquire new capacity and energy-producing resources and is anticipated to alleviate energy risks in the early 2030s.

Factors that could increase energy adequacy risks include aging resources and the potential for decreased performance, market exit of resources reaching contract end, extreme weather, and decarbonization policies and risks presented by new resources, including in-service delays or a high risk of forced outages during the initial period of operation. Deliverability challenges for new resources and long lead times required to build new transmission may also increase energy adequacy risks. Demand-side factors include materialization of data centers, increased industrial automobile production and EV supply chain loads, and climate change impacts on weather-sensitive load.

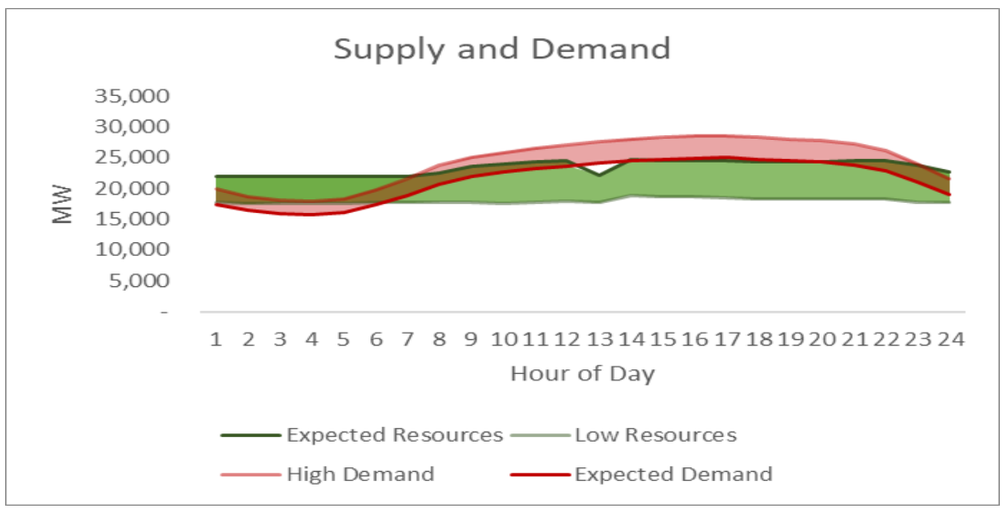
Looking forward, with the federal government's proposed Clean Electricity Regulations to decarbonize Canada's electric system by 2050, the IESO is assessing the role of natural gas generation as a flexible resource in the interim as new sources of non-emitting supply are added to the system.

The IESO conducts probabilistic resource adequacy assessments annually in conjunction with NPCC to identify regional capacity resource needs and to comply with NPCC and NERC reliability requirements. Results from the 2024 ProbA are shown in the table on the next page. The low risk of unserved energy is concentrated in the summer peak period, which typically occurs in late August.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	72.16	**0.04**	**4.97**
EUE (PPM)	0.49	**0.00**	**0.03**
LOLH (hours per year)	0.44	**0.00**	**0.01**
Operable On-Peak Margin	-6.7%	**13.3%**	**9.5%**

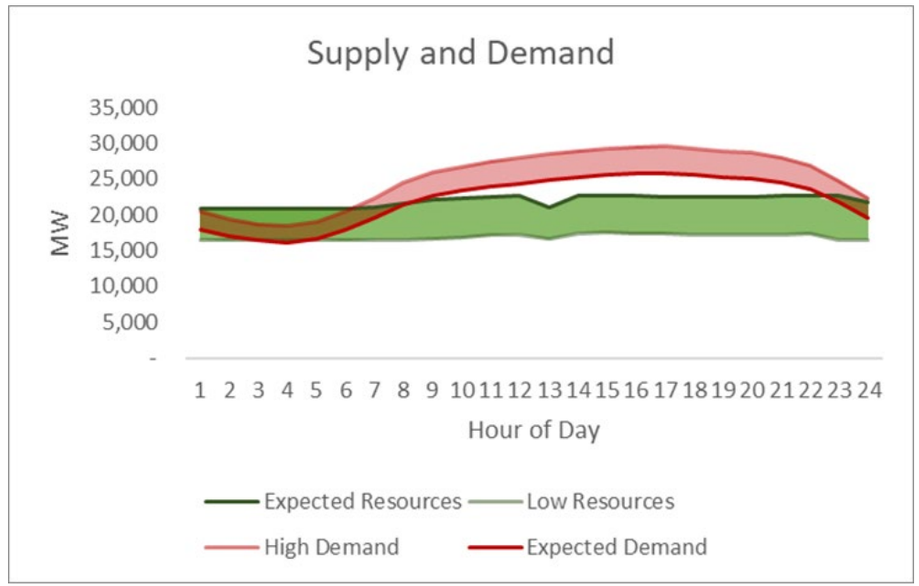
* Provides the 2022 ProbA Results for Comparison

Hourly demand and resource projections for a representative summer risk-day in 2026 are shown in the figure below. Expected resource contributions are not sufficient to meet expected demand on the risk day. The risk could be exacerbated by either a lower-than-expected resource contribution event or a higher-than-expected demand event, with greater risk being due to a larger variability in resource contribution. There is expected strain on the system from the hours beginning 12:00 p.m. through 8:00 p.m. If resource contributions are less than expected, strain on the system at expected demand conditions could be seen for almost all hours of the day beginning at 7:00 a.m. Reliance on external assistance may be necessary during peak conditions.



Hourly Probabilistic Assessment Results | Representative Summer Risk Day 2026

In 2028, the EUE and LOLH are higher than 2026. Risk occurs during the same summer peak period but also during winter peak conditions in December. Demand growth that is forecasted to occur between 2026 and 2028 contributes to higher loss-of-load risk compared to the 2026 result. The risk day in 2028 has the same drivers as the 2026 result noted above.



Hourly Probabilistic Assessment Results | Representative Summer Risk Day 2028

Demand

Forecasted demand for this *2024 LTRA* outlook period (relative to the *2023 LTRA* outlook period) indicates 10% higher annual energy demand, 8% higher summer peak demand, and 9% higher winter peak demand.

With an expanding agricultural and greenhouse sector, along with increasing electricity use for home heating and transportation, summer and winter peaks are anticipated to converge over the forecast period, leading Ontario to be dual-peaking by 2030. In the near term, the peak magnitude is expected to increase slightly as the province exits the remnants of the post-pandemic inflationary cycle, and new industrial projects supporting decarbonization begin commercial operation. Over this assessment period, the IESO projects total internal demand growth to increase at a compound annual growth rate of 2.34% for summer and 2.75% for winter. Offsetting the growth in demand are reductions from conservation, including savings from EE programs and codes and standards regulations, electricity price responsiveness and increased output by embedded generation.

Ontario's Industrial Conservation Initiative (ICI) acts as a critical peak pricing program leading to reductions in demand at peak and is expected to reduce around 1,500 MW if the hour of annual system peak demand occurs in the summer or around 1,000 MW if it occurs in the winter. It is expected to scale based on increased industrial growth in future years, with reductions in 2034 of 2,000 MW for a summer peak demand hour and over 1,400 MW for a winter peak demand hour.

Demand-Side Management

DR capacity, from both dispatchable loads and hourly DR resources (e.g., residential or commercial and industrial load), is procured through the IESO's annual capacity auction. Starting with the 2023 capacity auction, the IESO implemented a capacity qualification process for all resource types eligible to participate, which applies resource-specific calculation methodologies to determine the amount of unforced capacity (UCAP) each resource is eligible to offer into the auction.

In June 2023, the IESO launched Peak Perks, a residential DR program where participants help reduce demand by up to 150 MW through brief, time-limited thermostat adjustments during periods of peak electricity demand in the summer months.

In July 2023, the IESO launched an interruptible rate pilot to provide large-load customers with an interruptible rate in exchange for agreeing to temporarily reduce demand when directed by the IESO. The pilot spans a three-year period and up to 15 events of up to four-hour duration can be called, primarily in the day-ahead timeframe but also on shorter notice.

Forecast savings from the IESO's 2021–2024 Conservation and Demand Management Framework were included in the forecast and resulted in a decrease in demand. Savings from the 2021–2024 CDM framework are expected to persist beyond the end of 2024. In February 2024, Ontario's minister of energy asked the IESO to examine options and analysis for a post-2024 EE framework and programs.

Distributed Energy Resources

The IESO estimates that contracted DERs contributed more than 3,400 MW of capacity and 5.3 TWh of energy in 2023, more than half of which is solar PV, one-third wind, and modest contributions from hydroelectric and biomass resources. While the IESO has little insight into uncontracted DERs, it has observed energy contributions of approximately 2 TWh in 2023.

Generation

Recent generation procurements are provided in the PRM section.

The transmission-connected supply mix in Ontario has shifted over the past decade from having only synchronous generation facilities to one with more IBRs including wind, solar, and storage. Previous assessments performed by the IESO indicate that Ontario is expected to have sufficient inertia and frequency response to ensure stable operation up to 2025.

Going forward, the addition of over 2,900 MW of new battery storage resources in the next few years will increase the proportion of IBRs on the system. With the shift toward a higher proportion of IBRs, further areas that will be explored include the sufficiency of the resource mix to provide system inertia, primary frequency response, operating reserve, ramping capability, reactive support, and voltage control. If needs are identified, the IESO's procurements may be used as one avenue to acquire resources that can provide the required services.

The IESO has also been taking a proactive approach to dealing with challenges posed by IBRs. This includes working to optimize the location of IBR resources acquired through the IESO's procurements to minimize performance issues and initiating a review of the IESO's Market Rules to align with the latest IEEE 2800 standard, which aims to establish uniform technical minimum requirements for interconnection, capability, and lifetime performance of IBRs.

Energy Storage

By May 2028, over 2,900 MW of new battery storage resources are expected to come on-line, including the 250 MW/1,000 MWh Oneida battery storage facility (expected to be operational in June 2025), and 2,714 MW of battery storage resources secured through the IESO's first set of long-term procurements. Of this, 930 MW is expected to reach commercial operation by May 2026 and the remaining 1,784 MW by May 2028. These standalone battery storage resources (with a minimum four-hour duration) are expected to support the reliable operation of Ontario's electric system through the ability to be dispatched by the IESO and ramp up and down quickly. The resources are also located in areas of Ontario where transmission security or resource adequacy needs were identified.

Newly acquired energy storage facilities through the IESO's first set of long-term procurements will be required to be available during peak hours.

Capacity Transfers

Firm capacity imports and exports with neighboring jurisdictions are included in the IESO's planning studies. For non-firm imports, the IESO assumes a limited amount for the purposes of its reliability assessments. Non-firm imports are assumed to be 250 MW for summer and 240 MW for winter, an amount considered likely to flow throughout the year, including under tight supply conditions and prices.

In November 2024, the IESO and Hydro-Québec finalized a new capacity sharing agreement for a swap of a minimum of 600 MW of capacity per season. Under this agreement, the IESO will deliver capacity

to Québec during the winter period and Hydro-Québec will deliver capacity to Ontario during the summer period. The agreement commences in the Winter 2024–2025 season and runs to October 2031, with an option for an extension for an additional three years. Other terms of the agreement are expected to include the option for the IESO to increase the minimum amount provided to Québec each year and to bank any amount of the 600 MW from Québec for use in a future summer period over the term of the agreement.

The 2023 capacity auction secured 300 MW of system-backed imports from Québec for the Summer 2024 obligation period. As part of the 2016 capacity sharing agreement between Ontario and Québec, the IESO may call on a total of 500 MW of firm imports from Hydro-Québec, which may be requested all in one summer or in smaller amounts over multiple summers. The IESO's recent assessments indicate the intention to utilize the 500 MW of firm imports from June to September 2027 to help meet resource adequacy needs. However, depending on the outcomes of the ongoing procurements and changes to Ontario's resource adequacy outlook, the IESO may choose to utilize this capacity in another year.

Transmission

The existing transmission system in northeastern Ontario has insufficient capability to reliably supply forecasted load growth; as such, the IESO has recommended several new transmission reinforcements in the region to address this need. Several of the recommended reinforcements are in the early project development stage and one is undergoing a transmitter selection process.

The IESO recently recommended additional transmission reinforcements in southwest Ontario to support the area's medium-term needs, including a double circuit, 230 kV line from Lambton transmission station to Chatham substation, expected in-service by 2028, and a new 500 kV transmission line connecting Longwood and Lakeshore transmission stations, to be in-service by 2030. These projects will ensure that transfer capability continues to be sufficient as additional load continues to connect in the area.

Reliability Issues

Nuclear refurbishment over the next decade is a major resource risk that requires additional attention. The IESO has regular meetings with nuclear operators to assess probable delays and take appropriate mitigation actions.

For long-term planning purposes, the IESO carries an additional level of nuclear refurbishment reserve to account for the risk of refurbishment delays and increased forced outage rates pre- and post-refurbishment. In addition, advanced outage approvals are provided solely when Ontario is adequate under extreme weather.

Other factors that may pose reliability risks include supply chain issues, conditions in neighboring jurisdictions, extreme weather, decarbonization-driven changes to supply and demand, policy and regulatory uncertainty, asset health, and potential market exit of existing resources.

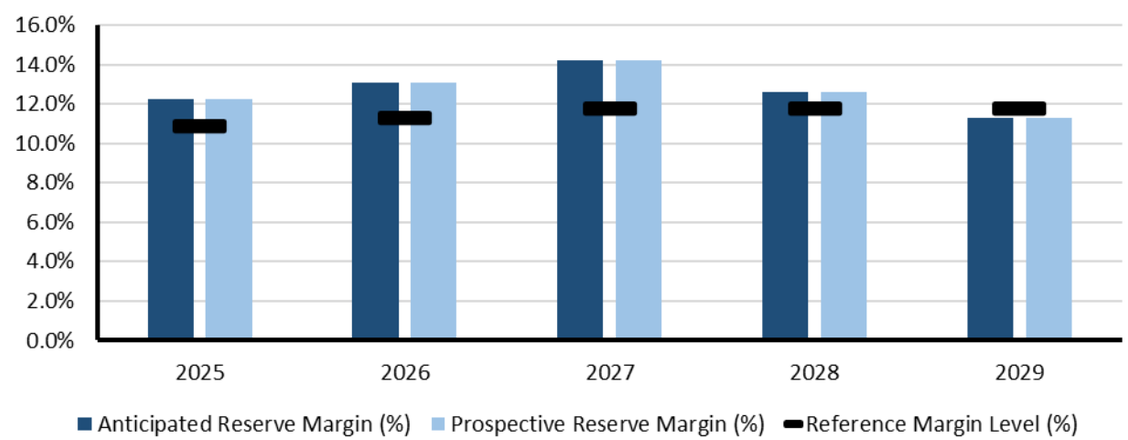


NPCC-Québec

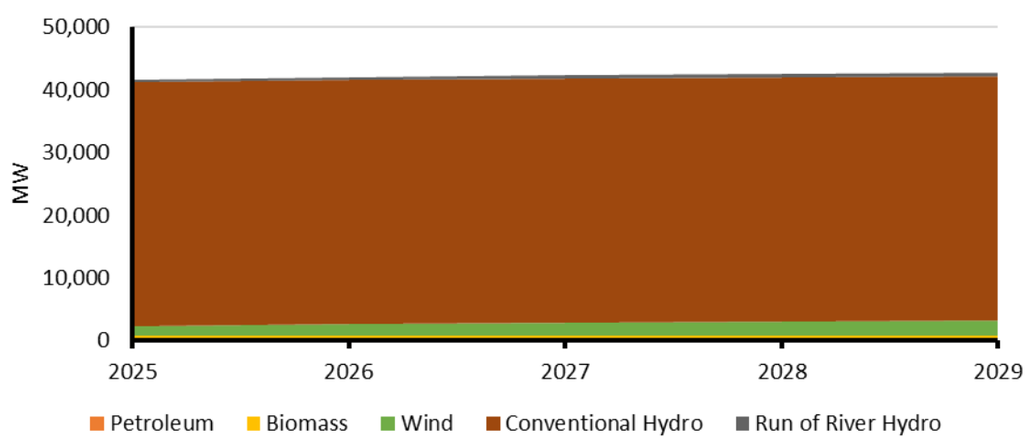
The Québec assessment area (Province of Québec) is a winter-peaking NPCC subregion that covers 595,391 square miles with a population of 8.5 million. Québec is one of the four NERC Interconnections in North America with ties to Ontario, New York, New England, and the Maritimes. These ties consist of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

Demand, Resources, and Reserve Margins

Quantity	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035
Total Internal Demand	41,497	41,954	42,476	43,385	44,070	44,784	45,577	46,635	47,828	49,041
Demand Response	4,732	4,896	5,068	5,258	5,322	5,377	5,388	5,388	5,388	5,388
Net Internal Demand	36,765	37,058	37,408	38,127	38,748	39,408	40,189	41,247	42,440	43,652
Additions: Tier 1	73	469	665	835	1,016	1,016	1,016	1,016	1,016	1,016
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	-390	-145	455	455	455	600	0	0	0	0
Existing-Certain and Net Firm Transfers	41,185	41,429	42,066	42,103	42,103	42,256	41,656	41,656	41,656	41,656
Anticipated Reserve Margin (%)	12.2%	13.1%	14.2%	12.6%	11.3%	9.8%	6.2%	3.5%	0.5%	-2.2%
Prospective Reserve Margin (%)	12.2%	13.1%	14.2%	12.6%	11.3%	9.8%	6.2%	3.5%	0.5%	-2.2%
Reference Margin Level (%)	10.9%	11.3%	11.8%	11.8%	11.8%	11.8%	11.8%	11.8%	11.8%	11.8%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM and PRM remain above the RML until 2029 (winter 2029–3030).
- A total of 4,048 MW wind generation capacity (1,016 MW capacity value at peak time) is expected to be in service by 2030.
- Two new transmission projects connecting Québec with New England and New York are expected to be in service by the end of 2025 and May 2026, respectively.

NPCC-Québec Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030
Petroleum	429	429	429	429	429
Biomass	400	400	400	400	400
Wind	1,449	1,807	2,002	2,173	2,354
Conventional Hydro	38,925	38,962	38,999	39,036	39,036
Run of River Hydro	446	446	446	446	446
Total MW	41,648	42,043	42,276	42,483	42,664

NPCC-Québec Assessment

Planning Reserve Margins

The ARM is based on existing and anticipated generating capacity and firm capacity transfers. The Québec area projects an ARM above the RML over the first five winters of the assessment period (2024–2025 to 2028–2029). The ARM is under the RML for the winters 2029–2030 to 2034–2035 mainly due to the demand growth.

The RML is derived from the NPCC 2023 Québec Balancing Authority Area Comprehensive Review of Resource Adequacy, which was approved by NPCC's Reliability Coordinating Committee on December 5, 2023. The demand uncertainty captured in the reserve ratio reflects both weather and economic uncertainty. The methods and assumptions can be found in the *Comprehensive Review* report available on the NPCC website.

The assumptions used for this assessment, including demand forecast and resources, are consistent with the Hydro-Québec 2023 Supply Plan update, which was filed with the Régie de l'énergie on November 1, 2023.

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

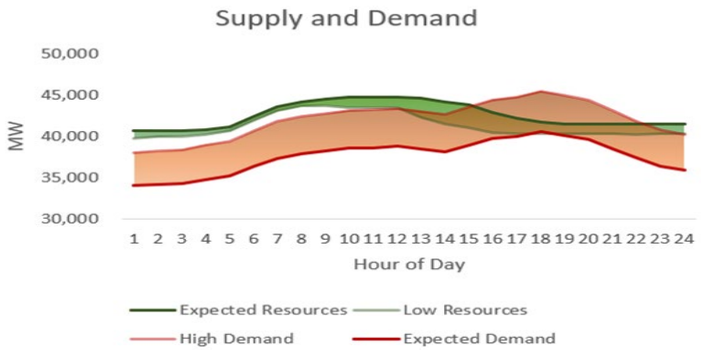
The main energy risk for the Québec area is associated with a series of dry years, hence the energy reliability criterion established by the Régie de l'énergie. This risk surpasses the energy risk associated with the other renewable resources over the horizon of this study. The potential impact of climate change on the water inflows could be an issue for energy reliability and is therefore the subject of various ongoing internal studies.

Hydro-Québec conducts probabilistic resource adequacy assessments annually in conjunction with NPCC to identify regional capacity resource needs and comply with NPCC and NERC reliability requirements. Results from the 2024 ProbA are shown in the table below. The low risk of unserved energy is concentrated in the winter peak period, which typically occurs in late January to early February.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0.00	**8.21**	**4.97**
EUE (PPM)	0.00	**0.04**	**0.03**
LOLH (hours per year)	0.00	**0.01**	**0.01**
Operable On-Peak Margin	-2.3%	**9.8%**	**11.9%**

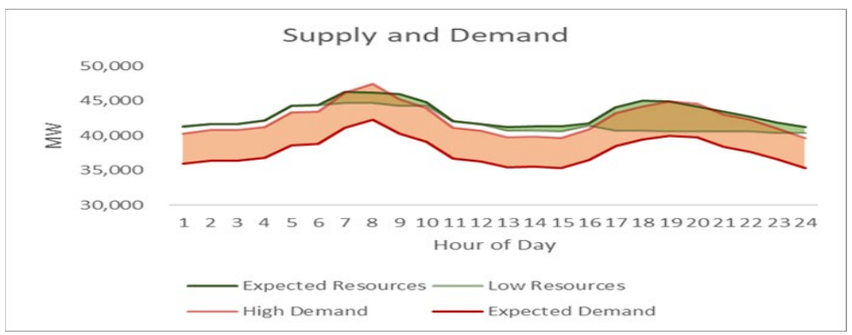
* Provides the 2022 ProbA Results for Comparison

Hourly demand and resource projections for a typical winter risk day in 2026 are shown in the figure below. Although expected resource contribution is expected to be enough to meet expected demand, there is risk that above-normal demand could exceed resources. Demand could be 10–15% higher than expected, which could strain the system from the hours beginning 3:00 p.m. through 10:00 p.m. Also, if resource contributions are less than expected, the peak hour beginning at 6:00 p.m. could lead to a loss-of-load situation. Reliance on external assistance may be necessary in these events.



Hourly Probabilistic Assessment Results | Representative Winter Risk Day 2026

Hourly demand and resource projections for a typical winter risk day in 2028 are shown in the figure below.



Hourly Probabilistic Assessment Results | Representative Winter Risk Day 2026

Demand

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

Demand-Side Management

The Québec area has various types of DR resources specifically designed for peak shaving during winter operating periods. The first type of DR resource is the interruptible load program that is mainly designed for large industrial customers; it has an impact of 2,784 MW on winter 2024–2025 peak demand. The area is also expanding its existing interruptible load program for commercial buildings, which will grow from 611 MW in 2024–2025 to 889 MW by the end of the period study. Another similar program for residential customers is in operation and should gradually rise from 166 MW for Winter 2024–2025 to 621 MW for Winter 2028–2029.

New dynamic rate options for residential and small commercial or institutional customers will also contribute to reducing peak load during winter periods by 371 MW for Winter 2024–2025 and 445 MW for Winter 2034–2035. Moreover, data centers specializing in blockchain applications are required to reduce their demand during peak hours at Hydro-Québec's request. Their contribution as a resource is expected to be around 269 MW over the study period. Finally, another DR resource consists in a voltage reduction scheme allowing for a 250 MW peak demand reduction. EE and conservation programs are integrated in the assessment area's demand forecasts.

Distributed Energy Resources

Total installed BTM capacity (solar PV) is expected to increase to 862 MW in 2035. Solar PV is accounted for in the load forecast. Nevertheless, since Québec is a winter-peaking area, DERs' on-peak contribution ranges from 2 MW for Winter 2024–2025 to 5 MW for the last winter period. No potential operational impacts of DERs are expected in the Québec area considering their low contribution.

Generation

Four wind projects with a total installed capacity of 4,000 MW are expected to be commissioned during the assessment period. The first project, Apuiat (204 MW), is expected to be commissioned in 2024–2025. The second project (1,144 MW divided into 6 wind farms) is expected to be commissioned in December 2026. The third project is Des Neiges (1,200 MW) and is divided into three phases (400 MW each). The first phase is expected to be operational in the winter of 2026–2027. The second and third phases are expected to be in service for the 2027–2028 and 2028–2029 winters, respectively. The fourth project is made of 1,500 MW divided into 8 wind farms, which are expected to be operational in the winters of 2027–2028, 2028–2029 and 2029–2030, depending on the location.

In addition to wind projects, unit replacement projects at existing hydroelectric facilities are being studied. Up to 2,000 MW of capacity could be added by replacing generating units with most recent models, as outlined in Hydro-Québec's Action Plan 2035.

Energy Storage

No energy storage facilities are planned to be commissioned during the assessment period.

Capacity Transfers

The governments of Québec and Ontario have signed an MOU of an agreement that allows a seasonal capacity exchange between the two areas for the next seven years except for the year 2027 (no exchange is allowed). The technical details of the agreement will be completed by Fall 2024 and will be in place from Winter 2024–2025 to winter 2030–2031. This agreement will be firm and allow Québec to import 600 MW from November to April. In summer, Québec will export 600 MW of firm capacity to Ontario from May to October.

Transmission

Appalaches-Maine Interconnection

This project, expected to increase transfer capability between Québec and Maine by 1,200 MW, has resumed construction. The project will connect to the New England Clean Energy Connect project (NECEC) in Maine. It involves the construction of a ±320 kV dc transmission line about 100 kilometers (62 miles) long from the Des Appalaches 735/230 kV substation to the Canada-United States. border. From the international border crossing, the dc transmission line will be extended 145 miles to a substation in Lewiston, ME, where the power will be converted from dc to ac. The project in Québec also includes the construction of an dc to dc converter at the Des Appalaches substation and triggers the need of thermally upgrade two 735 kV lines in the south of the system. The project is expected to be in service in December 2025.

Hertel-New York Interconnection (CHPE)

This project, expected to increase transfer capability between Québec and New York by 1,250 MW, is under construction. It involves the construction of a ±400 kV dc underground transmission line about 60 kilometers (37 miles) long from the Hertel 735/315 kV substation just south of Montréal to the Canada-United States border. The project will connect to the Champlain Hudson Power Express project (CHPE) in New York state. From the international border crossing, the dc transmission line will be extended 339 miles to a substation in Astoria, NY, where the power will be converted from dc to ac. The project in Québec also includes the construction of an ac to dc converter at the Hertel substation. The project is expected to be in service in May 2026.

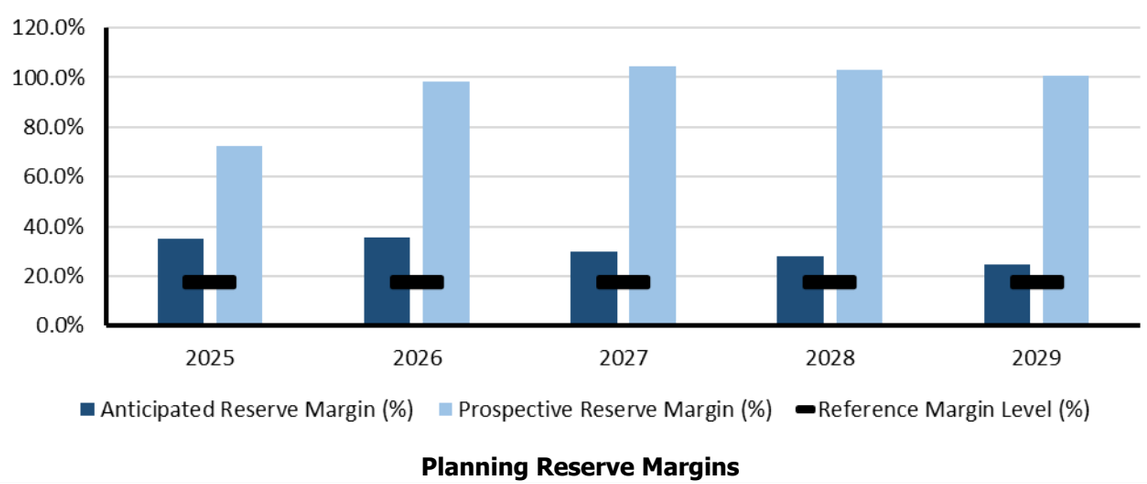


PJM

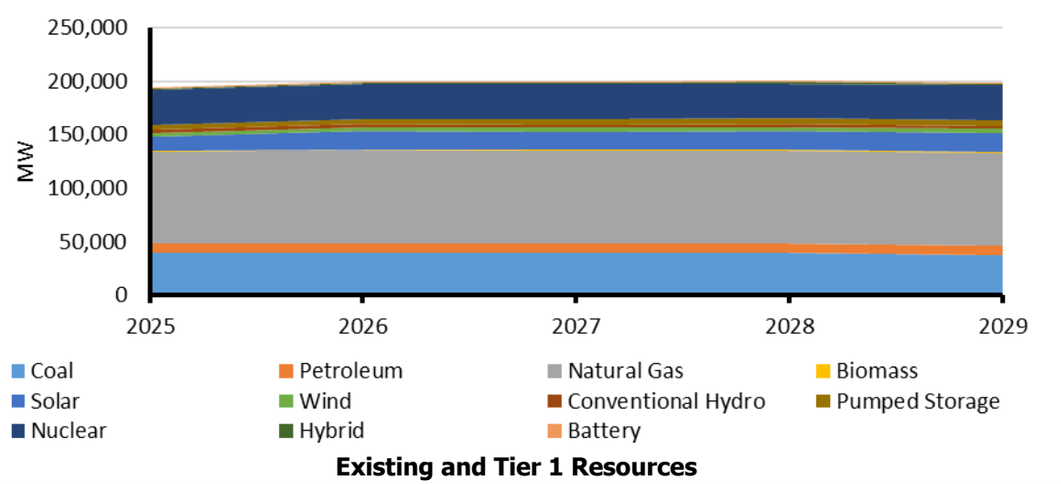
PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM serves 65 million customers and covers 369,089 square miles. PJM is a Balancing Authority, Planning Coordinator, Transmission Planner, Resource Planner, Interchange Authority, Transmission Operator, Transmission Service Provider, and Reliability Coordinator.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	153,493	156,803	159,859	162,972	165,681	167,873	170,008	172,109	174,366	176,822
Demand Response	7,554	7,693	7,808	7,913	8,000	8,083	8,162	8,230	8,312	8,400
Net Internal Demand	145,939	149,110	152,051	155,059	157,681	159,790	161,846	163,879	166,054	168,422
Additions: Tier 1	11,056	17,047	17,139	17,784	17,911	18,155	18,155	18,155	18,155	18,155
Additions: Tier 2	55,112	93,845	112,827	122,781	127,059	131,113	131,287	133,652	133,652	133,652
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	4,502	4,347	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	185,828	185,270	180,552	180,552	178,577	178,577	178,577	178,577	178,577	178,577
Anticipated Reserve Margin (%)	34.9%	35.7%	30.0%	27.9%	24.6%	23.1%	21.6%	20.0%	18.5%	16.8%
Prospective Reserve Margin (%)	72.4%	98.3%	104.7%	103.3%	100.5%	96.5%	94.1%	92.9%	82.1%	79.5%
Reference Margin Level (%)	17.7%	17.7%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM remains above the RML until 2034 when it falls below the 17.6% RML level.
- PJM implemented a number of changes to the 2023 load forecasting process to improve model accuracy, switching from an annual to monthly end-use model for PJM's sector models to better determine heating, cooling, and other non-weather-sensitive load and moving to an hourly model to better capture new technologies and peak shifting. Additionally, higher expectations for data center loads now incorporate 15-year forecasts from impacted electric distribution companies (EDC).
- PJM's review of recent policies (e.g., state laws and federal environmental initiatives) indicates over 32 GWs of potential deactivations through 2034. The pace of retirements is being driven in large part by these state laws and federal environmental initiatives that create a clear near-term, date-certain requirement for generation to comply or retire. Conversely, there are multiple mandates with renewable portfolio standards (RPS) that account for the majority of over 150 GWs submitted projects.

PJM Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	39,735	39,735	39,325	39,325	37,747
Coal*	39,394	39,394	33,313	28,240	25,124
Petroleum	8,810	8,514	8,514	8,514	8,117
Natural Gas	85,541	87,245	87,245	87,245	87,245
Natural Gas*	85,541	87,245	87,228	87,228	87,228
Biomass	928	928	928	928	928
Solar	13,349	16,770	16,908	17,621	17,754
Wind	3,017	3,512	3,507	3,507	3,507
Conventional Hydro	2,934	2,922	2,934	2,934	2,944
Pumped Storage	5,189	5,189	5,189	5,189	5,189
Nuclear	32,535	32,535	32,535	32,535	32,535
Hybrid	1,315	1,742	1,739	1,739	1,739
Battery	393	982	982	994	994
Total MW	193,747	200,074	199,807	200,532	198,699
Total MW*	193,406	199,733	193,779	189,430	186,060
*** Capacity with additional generator retirements.** Generators that are forecasted to retire by PJM are removed from the resource projection where marked.					

PJM Assessment

Planning Reserve Margins

The ARM does not fall below the RML in PJM until 2034. PJM's growing demand profile and a change in resource mix that favors VERs, however, present a new level of risk.

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

PJM is forecasting around 30% installed reserves (including expected committed demand resources), which is well above the target installed reserve margin of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion. Due to the current low penetration of energy-limited and VERs in PJM relative to PJM's peak load, the hour with most loss of load risk remains the hour with highest forecasted demand. To address future reliability concerns due to growing VER penetration and limitations associated with the performance of those resources, PJM's Effective Load Carrying Capability methodology calculates the reliability and energy contribution of limited and variable resources.

Some of PJM's assumptions for determining the resource mix to use in the ProbA differ from those used in developing the LTRA. Only a portion of the Tier 1 resource additions are used in the ProbA to more accurately reflect historical rates of development. Additionally, more generator retirements are used in the ProbA based on PJM's generator forecasting. These assumptions are more consistent with the assumptions included in official studies performed by PJM to support its capacity market. In addition, the information in the ProbA for winter seasons refers to the Winter 2026–2027 and Winter 2028–2029 because PJM's studies are based on "delivery years," which start on June 1 of a year and end on May 31 of the subsequent year.

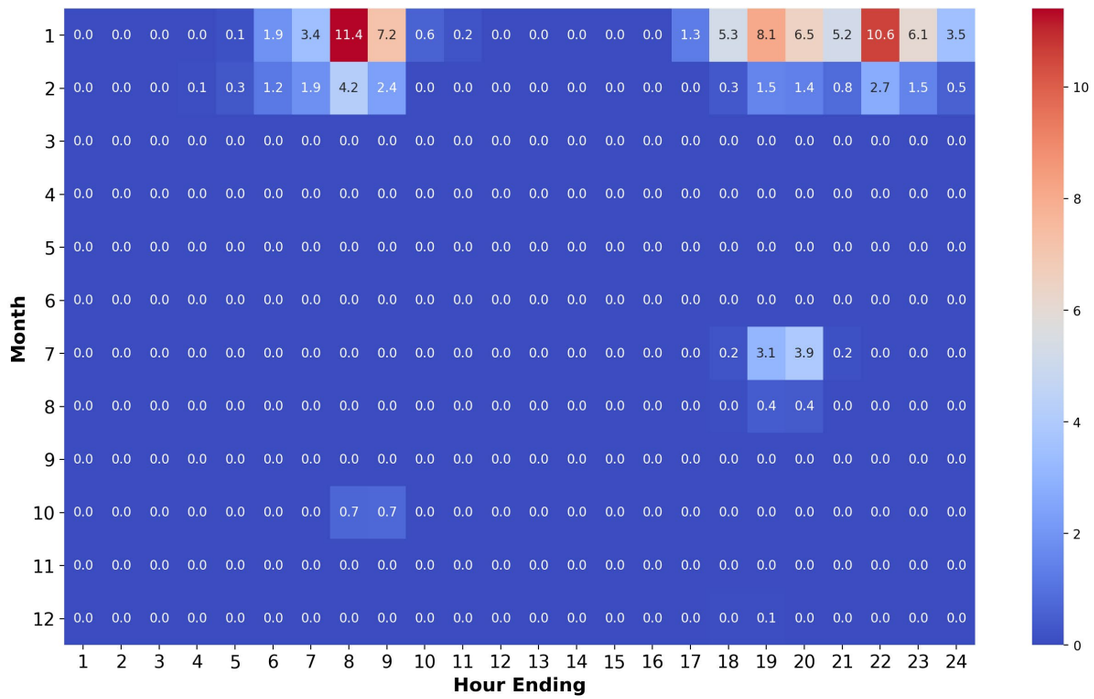
Results of the 2024 ProbA are provided in the table below.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0.00	**537.52**	**1043.44**
EUE (PPM)	0.00	**0.00**	**0.00**
LOLH (hours per year)	0.00	**0.11**	**0.22**
Operable On-Peak Margin	29.0%	**17.8%**	**17.7%**

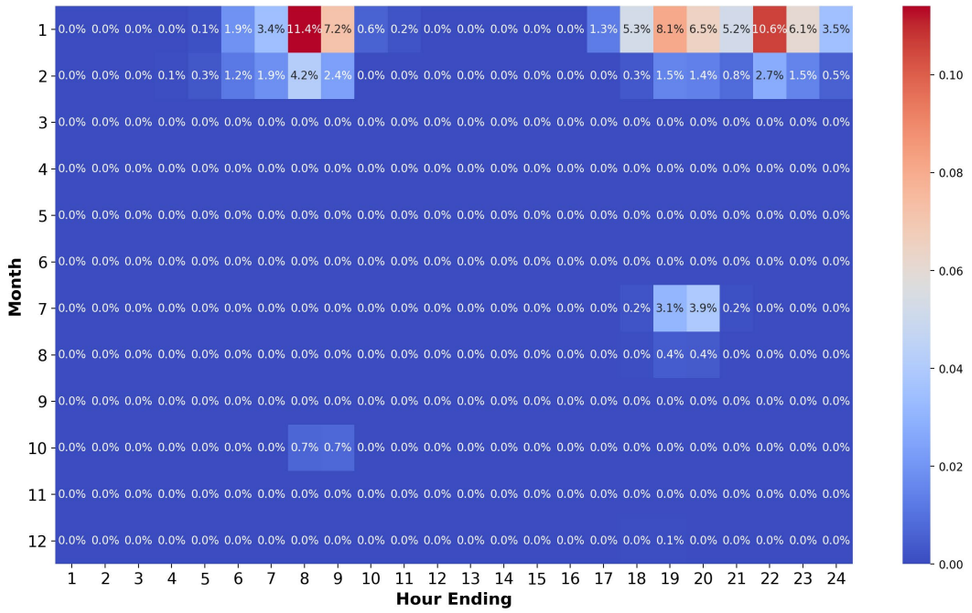
* Provides the 2022 ProbA Results for Comparison

In both 2026 and 2028, most EUE and LOLH are concentrated in the winter months (especially January), as shown in the following EUE heat maps. The risk occurs in days when temperatures are very low, which results in high loads across the assessment area. If resource performance were to occur at the levels expected during average winter days, the system should be able to serve these high loads. However, resource performance from thermal resources on very cold days, especially natural gas resources, is more likely to be poor. This, coupled with poor performance from solar resources, results in very low total electricity supply and causes loss-of-load events in the ProbA analysis. The winter load-loss events tend to occur during morning and evening demand peaks and coincide with poor thermal performance and poor solar performance.

The smaller shares of EUE and LOLH observed in the summer period for 2026 and 2028 are associated with high temperatures and high loads across the assessment area that drive load-loss events in the evening (hours ending 19 and 20) as grid-connected and BTM solar resource output declines. Low performance of wind resources and, to a lesser extent, slightly worse performance of thermal resources, also contribute to the load-loss events in the analysis.



2026 EUE Heat Map (Share of Annual EUE in %)



2028 EUE Heat Map (Share of Annual EUE in %)

PJM implemented capacity reforms (approved by FERC) at the start of 2024, which include using the loss-of-load model employed to perform the ProbA, as well as accreditation reforms based on the risk patterns identified by said model, for the capacity auctions starting with delivery year 2025–2026.

Demand

PJM is experiencing large growth in data centers that are in turn driving higher demand forecasts. Loudoun County, Virginia, in the PJM assessment area, is home to "Data Center Alley," the largest concentration of data centers in the world. Electrification in transportation, heating, and industrial sectors is also spurring demand growth.

The PJM Interconnection produces an independent peak load forecast of total internal demand using econometric regression models with daily load as the dependent variable and independent variables including calendar effects, weather, economics, and end-use characteristics. PJM annually reviews its load forecast methodology and implements changes when improvements are identified.
Summer peak load growth in PJM is projected to average 1.6% per year over the next 10-year period and 1.6% over the next 15 years. The PJM summer peak is forecasted to be 176,822 MW in 2034, a 10-year increase of 25,575 MW, and reaches 190,752 MW in 2039, a 15-year increase of 39,505 MW. Annualized 10-year growth rates for individual zones range from 0% to 5.5% with a median of 0.5%.

Winter peak load growth for PJM is projected to average 1.9% per year over the next 10-year period and 1.8% over the next 15 years. The PJM regional transmission organization winter peak load in 2033–2034 is forecasted to be 163,069 MW, a 10-year increase of 28,410 MW, and reaches 176,195 MW in 2038–2039, a 15-year increase of 41,536 MW. Annualized 10-year growth rates for individual zones range from 0% to 5.0% with a median of 0.7%.

Net energy for load growth for PJM is projected to average 2.3% per year over the next 10-year period and 2.2% over the next 15 years. Total PJM energy is forecasted to be 1,021,955 GWh in 2034, a 10-year increase of 208,627 GWh, and reaches 1,120,928 GWh in 2039, a 15-year increase of 307,600 GWh. Annualized 10-year growth rates for individual zones range from 0.1% to 7.3% with a median of 0.7%.

Demand-Side Management

DR resources can participate in all PJM markets—capacity, energy, and ancillary services. DR is forecast to grow during summer peak season from 7,550 MW in 2025 to 8,400 MW in 2034.

Distributed Energy Resources

PJM expects 4,470 MW of solar DERs at the time of the peak in 2029 and 5,103 MW in 2034. The effects of solar DERs are included in the load forecast for PJM. No effect of solar DERs is incorporated in the winter load forecast since winter expected peak occurs after sundown.

Generation

Overall, new generation is coming on-line slower than anticipated. Generator retirements are outpacing the new generation replacing them. As a result, PJM could face future resource adequacy challenges, impacting system reliability and PJM's ability to serve load. PJM could be at risk of facing resource adequacy challenges if these trends continue. PJM has applied an 11% reduction to the nameplate value of Tier 1 resources to reflect the historical rate of slower-than-anticipated addition of new generation.

PJM reviews the progression of generation interconnection to understand overall developer trends more fully and their impact on the interconnection process. Of new and expanded generation resources submitted in Queue A (1999) through December 31, 2023, 74,294 MW (or 15.8%) reached commercial operation, 33,166 MW (or 7%) were withdrawn from the interconnection process after Interconnection Service Agreement (ISA) execution, and 1,560 MW (or 0.3%) were withdrawn after wholesale market participant agreement (WMPA) execution but before construction. Overall, 20.4% of projects that requested uprates to existing capacity reached commercial operation.

Stakeholders at the June 6, 2023, Interconnection Process Subcommittee meeting approved an issue charge to examine how to enhance transfer of CIRs, which allow new generation to interconnect as a capacity resource, from deactivating resources to new generation. The goal is to develop a solution that both improves the efficiency of the process and clarifies that it applies to all energy-injecting capacity resource types. The existing provisions in the PJM Tariff, and related defined terms included in the Reliability Assurance Agreement (RAA), governing the CIR transfer process will be clarified to reduce confusion as to which capacity resource types the transfer process applies.

PJM's existing installed capacity reflects a fuel mix consisting of approximately 48% natural gas, 22% coal, and 18% nuclear. Hydro, wind, solar, oil, and waste fuels constitute the remaining 12%. A diverse generation portfolio reduces the system risk associated with fuel availability and reduces dispatch price volatility. Totaling nearly 125,000 MW of CIRs, renewable and hybrid fuels are changing the landscape of PJM's interconnection process. Solar energy makes up 40% of the new service requests in PJM's generation interconnection queue. State policies encouraging renewable generation are contributing to the rise in solar generation interconnection requests.

PJM's review of recent policies indicates over 32 GWs of potential deactivations through 2034. The pace of retirements is being driven in large part by state laws and federal environmental initiatives that create a clear near-term, date-certain requirement for generators to comply or retire. See *Energy Transition in PJM: Resource Retirements, Replacements, and Risks* (February 2023). Conversely, there are multiple mandates with RPS that account for the majority of over 150 GWs in submitted projects. Growing levels of intermittent and limited duration resources, such as wind, solar, and battery storage, do not replace conventional large-scale generation installations megawatt-for-megawatt but rather require multiple megawatts to replace one megawatt of dispatchable generation due to their limited availability in certain hours of the day and seasons of the year. Many megawatts from a range of generation technologies, available at different times, are required to replace a megawatt of thermal generating capacity. Looking out over the next 8 to 10 years of the energy resource transition, maintaining an adequate level of generation resources with operational and physical characteristics that support reliability will be crucial for PJM's ability to serve electrical demand reliably.

Energy Storage

Energy storage development continues in PJM. As solar generation increases in PJM, growth of storage is expected to follow since storage devices are frequently co-located with solar projects. Efficient grid operations in an era of rapid renewable energy resource growth will require greater system flexibility. Energy storage can offer grid operators another tool to maintain stable power supply under varying wind and solar power output driven by weather conditions or unit outages. Storage can also improve grid efficiency by increasing utilization of existing transmission lines. PJM continues to work with members, Department of Energy (DOE) national laboratories, and other industry entities to advance the use of energy storage and, in particular, enable its participation in PJM markets.

Today, there are approximately 177 GWs of solar, wind, battery, and hybrid in the PJM interconnection queue. Hybrid resources make up approximately 26 GWs and standalone storage makes up approximately 28 GWs.

Some developers are pairing storage with variable, renewable generation, such as solar or wind, to create opportunistic revenue streams. The pairing is either co-located (in which the storage facility and the generator facility are sited on the same parcel of land but each has its own connection to the grid) or hybrid (in which the storage facility and generator share a common connection to the grid).

Capacity Transfers

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

Transmission

PJM's Regional Transmission Expansion Plan (RTEP) continues to manage an unprecedented capacity shift driven by federal and state public policy and broader fuel economics. This shift is characterized by new wind and solar generating units driven by federal and state renewable incentives, generating plant deactivations, and market impacts introduced by DR and EE programs. As of December 31, 2023, renewable resources continue to represent a significant portion of PJM's new services requests.

The PJM board approved 48 new baseline projects during 2023 at an estimated $6.6 billion to ensure that fundamental system reliability criteria across the grid are met. The board also approved the inclusion of 93 new network transmission projects at an estimated $180 million into the RTEP.

Reliability Issues

PJM's 2023 *Load Forecast Report* addressed the impact of industry changes that are reshaping system hourly loads. As a result, the level and timing of coincident peak and non-coincident peak demands across PJM have begun to shift. Solar-power penetration, expected impacts of EVs, state electrification programs, home battery storage, and a significant increase in data center loads are markedly increasing the complexity of PJM's load forecasting process. Driven by discrete and localized load growth, like Data Center Alley in Loudoun County, Virginia, in 2022, PJM and stakeholders conducted a review of data center load growth and identified growth rates of over 300% in some instances. As a result, the 2023 PJM *Load Forecast Report* incorporates adjustments to specific zones for data center load growth.

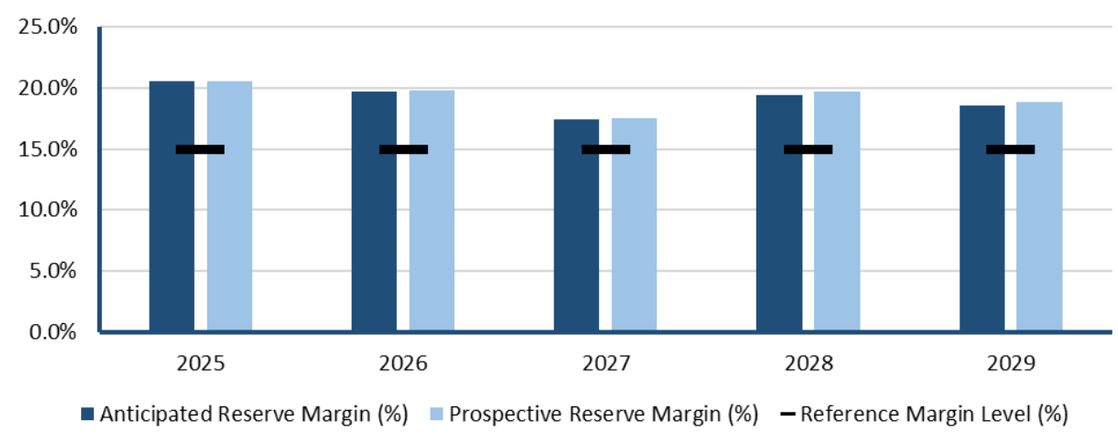


SERC-Central

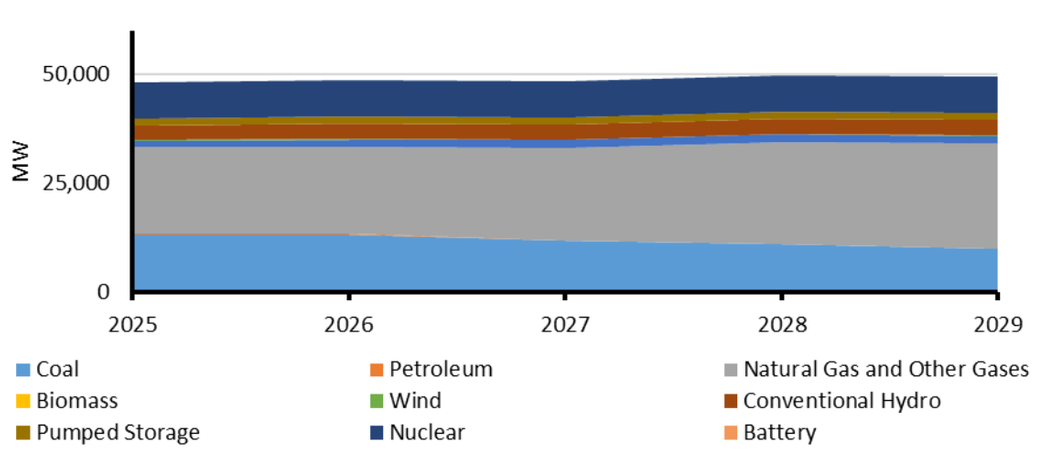
SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	42,983	43,202	43,399	43,384	43,440	43,636	43,725	43,913	44,077	44,316
Demand Response	1,859	1,856	1,852	1,849	1,847	1,844	1,842	1,840	1,839	1,837
Net Internal Demand	41,124	41,346	41,547	41,535	41,593	41,792	41,883	42,074	42,239	42,479
Additions: Tier 1	1,123	1,540	2,970	4,983	5,841	5,841	5,841	7,609	8,935	9,598
Additions: Tier 2	20	20	20	120	120	120	120	120	120	120
Additions: Tier 3	135	263	415	1,118	3,395	4,198	4,965	5,368	5,745	6,198
Net Firm Capacity Transfers	1,240	765	190	-288	-288	-288	-288	-287	-287	-287
Existing-Certain and Net Firm Transfers	48,437	47,962	45,813	44,608	43,478	43,191	43,191	42,224	42,224	41,153
Anticipated Reserve Margin (%)	20.5%	19.7%	17.4%	19.4%	18.6%	17.3%	17.1%	18.4%	21.1%	19.5%
Prospective Reserve Margin (%)	20.8%	20.0%	17.7%	19.7%	18.9%	17.6%	17.4%	18.8%	21.4%	19.8%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM remains above the 15% target RML for the assessment period.
- Projected coal generation retirements total 4,399 MW in the next 10 years. Resource additions include 6,838 MW of natural gas, 75 MW of BESS, and 760 MW of solar generation over the next 10 years.
- New transmission line additions total 209 miles through 2028. The entities also plan to upgrade 185 miles of transmission lines through 2031 to enhance system reliability by supporting voltage and relieving challenging flows.

SERC-Central Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	13,348	13,348	11,774	11,047	9,917
Coal*	13,048	13,348	11,146	10,013	8,883
Petroleum	148	148	148	148	148
Natural Gas	19,857	19,857	21,287	23,300	24,158
Natural Gas*	19,476	19,476	20,906	22,919	23,777
Biomass	36	36	36	36	36
Solar	1,338	1,706	1,706	1,706	1,706
Wind	172	172	172	172	172
Conventional Hydro	3,393	3,393	3,393	3,393	3,393
Pumped Storage	1,673	1,673	1,673	1,673	1,673
Nuclear	8,280	8,280	8,280	8,280	8,280
Battery	75	125	125	125	125
Total MW	48,319	48,737	48,593	49,879	49,607
Total MW*	47,639	48,356	47,584	48,464	48,192
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

SERC-Central Assessment

Planning Reserve Margins
The future reserve margins are above the RML for SERC-Central.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments
The 2024 ProbA results shown in the table below indicate negligible unserved energy and load-loss. Analysis of detailed ProbA outputs shows that that this negligible risk occurring in 2026 is associated with hot summer conditions and upper levels of economic load forecast models.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0.00	**0.10**	**0.00**
EUE (PPM)	0.00	**0.00**	**0.00**
LOLH (hours per year)	0.00	**0.00**	**0.00**
Operable On-Peak Margin	18.4%	**13.2%**	**14.9%**

* Provides the 2022 ProbA Results for Comparison

Demand
Drivers of load growth are commercial expansion, electrification of heating and transportation, and growth in residential load. Entities expect to continue to have increased economic growth that will drive both population and employment to the SERC-Central assessment area, but these gains in employment are slightly offset by improvements in efficiency.

Distributed Energy Resources
SERC entities continue to monitor DER penetration levels, assess the impacts of DERs, and incorporate these impacts in system studies. Unlike directly modeled transmission-connected resources, DERs (e.g., rooftop solar, plug-in EVs) are netted against load in the Energy Management System and transmission planning models. Some entities are beginning to use software to develop DER projections of rooftop solar. DER resource output is modeled at various levels to account for load scenarios. The overall amount of rooftop solar is small compared to the utility-scale projects.

Generation
Projected coal generation retirements total 4,399 MW in the next 10 years. Resource additions include 6,838 MW of natural gas, 75 MW of BESS, and 760 MW of solar generation over the next 10 years.

Generator retirements are carefully managed by entities in the SERC-Central assessment area. Entities perform studies to determine the impacts of confirmed or unconfirmed retirements. Entities incorporate these studies into resource plans that highlight the significance of future generation projects. Additionally, there are no significant retirement plans that will affect reliability.

Capacity Transfers
Entities participate in the SERC committees and study groups to perform power transfer studies of the system within the SERC geographic area. These studies include evaluating transfer limitations between all assessment areas within the Region for the existing or planned system configuration and with normal (pre-contingency) operating procedures in effect, such that all facility loading is within normal ratings and all voltages are within normal limits.

Transmission
The entities reported a total addition of 209 miles of new transmission lines until 2028. The entities are also planning to upgrade 185 miles of transmission lines in the next 10 years to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include adding new transformers, upgrading existing transmission lines, storm hardening, and other system reconfigurations/additions to support transmission system reliability. Entities do not anticipate any transmission limitations or constraints with significant impacts on reliability.

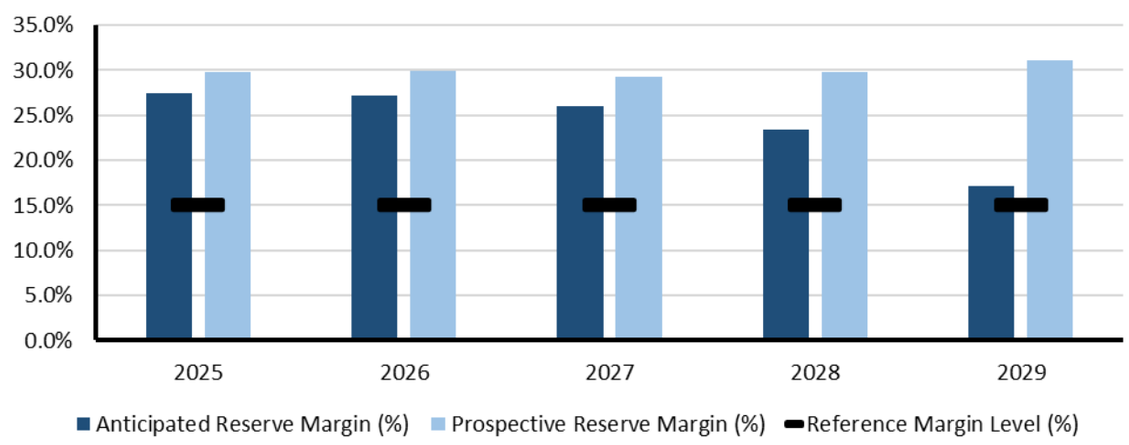


SERC-East

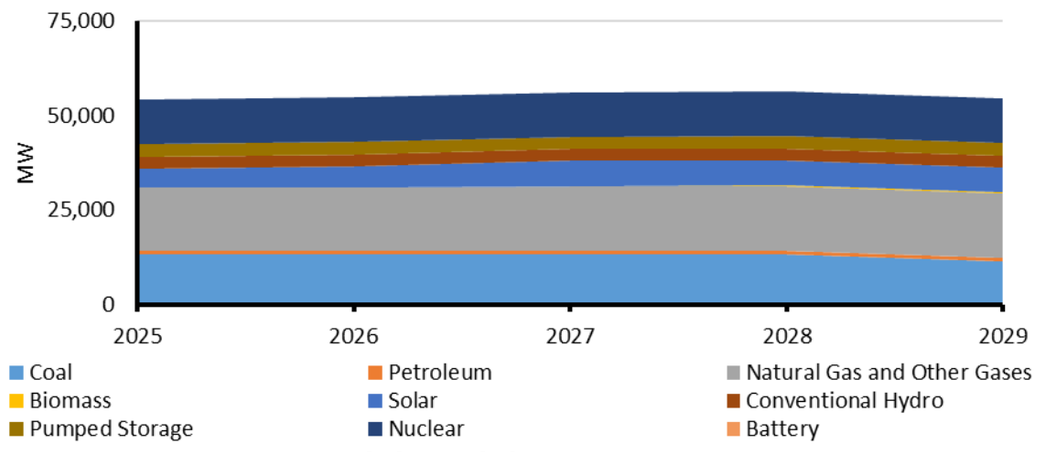
SERC-East is an assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina. Historically a summer-peaking area, SERC-East is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	44,099	44,789	46,308	47,378	48,286	49,533	50,349	50,896	51,741	52,155
Demand Response	1,092	1,186	1,214	1,225	1,228	1,229	1,230	1,231	1,232	1,233
Net Internal Demand	43,007	43,603	45,094	46,153	47,058	48,304	49,119	49,665	50,509	50,922
Additions: Tier 1	772	1,330	2,777	2,818	2,818	2,818	2,818	2,818	2,818	2,818
Additions: Tier 2	38	217	506	1,975	5,577	8,032	9,766	11,595	13,978	16,767
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	593	593	593	593	593	593	593	593	593	593
Existing-Certain and Net Firm Transfers	54,039	54,129	54,045	54,118	52,301	52,395	51,316	49,998	49,998	48,636
Anticipated Reserve Margin (%)	27.4%	27.2%	26.0%	23.4%	17.1%	14.3%	10.2%	6.3%	4.6%	1.0%
Prospective Reserve Margin (%)	29.8%	30.0%	29.3%	29.8%	31.1%	33.0%	32.1%	31.7%	34.2%	35.9%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM remains above the RML until 2030 when it falls below the 15.0% RML level.
- Since the *2023 LTRA*, solar PV resources have grown from 1.5 GW to an expected 4.7 GW by the end of 2024.

SERC-East Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	13,150	13,150	13,150	13,150	11,333
Coal*	13,108	12,564	12,564	11,910	10,093
Petroleum	1,044	1,044	992	992	992
Petroleum*	1,044	1,044	868	868	868
Natural Gas	16,627	16,717	17,061	17,121	17,121
Natural Gas*	16,601	16,691	17,061	17,121	17,121
Biomass	176	176	176	176	176
Solar	4,995	5,553	6,624	6,665	6,665
Conventional Hydro	3,102	3,102	3,102	3,102	3,102
Pumped Storage	3,324	3,324	3,324	3,324	3,324
Nuclear	11,795	11,795	11,795	11,808	11,808
Battery	6	6	6	6	6
Total MW	54,218	54,866	56,229	56,343	54,526
Total MW*	54,150	54,254	55,519	54,979	53,162
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

SERC-East Assessment

Planning Reserve Margins
The ARM falls below the RML starting in 2030 for SERC-East. Projected demand is expected to increase around 8.75% from 2024 to 2028 in the footprint.

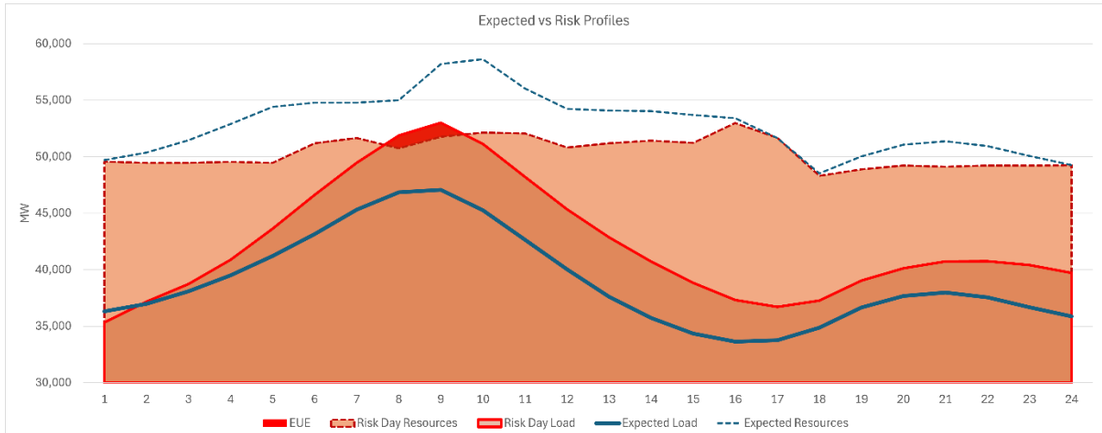
Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments
SERC-East has an elevated risk of energy shortages based on results of the 2024 ProbA shown in the table below.

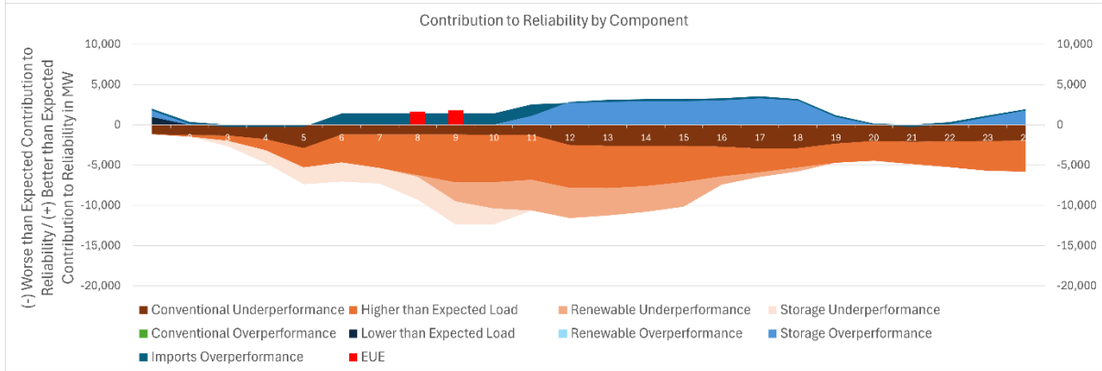
Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	92.49	**143.35**	**207.26**
EUE (PPM)	0.39	**0.60**	**0.81**
LOLH (hours per year)	0.08	**0.09**	**0.17**
Operable On-Peak Margin	16.1%	**14.2%**	**11.1%**

* Provides the 2022 ProbA Results for Comparison

SERC-East has changed from a summer-peaking assessment area to a dual-peaking assessment area, with both a summer and winter peak. The addition of solar PV generation shaves off summer peak demand, and a trend toward electrification of heating drives up winter peak demand. The ProbA results for 2026 indicate some risk for SERC-East in the winter months of January and February. The annual EUE is 143.35 MWh but for a very short, expected duration of 0.09 hours. The risk occurs during winter morning hours around 8:00 a.m. due to a combination of higher loads and solar resources not yet ramped up. For extreme cold weather events that might impact a wide geographical footprint, there is also a limit on imports from neighboring areas.

For 2028, SERC-East continues to show winter risk with 207.26 MWh of EUE and 0.17 hours of LOLH. The load is expected to grow by over 2%. The load-loss events in the analysis are for very few hours and short duration, occur around 8:00 a.m., and are tied to extreme weather, higher forecasted load levels, and lower resource performance. This can be seen in the following figures showing the risk profile and resource performance for a likely event-day.





Demand
Population growth is driving demand forecast increases in SERC-East. Entities expect faster-than-average growth in the urban areas and overall increasing energy and demand in the 10-year forecast. While the economic indicators used in the forecast have growth rates that vary during each year, the economic outlook will contribute to increased energy and demand over the 10-year forecast. Some entities project their EE adoption to impact roughly 1% of annual retail sales (after opt-outs) during the 10-year forecast.

There are also many large commercial/industrial loads accounted for in the forecast that have been announced or in discussions with the entities to locate in the service territory. If the large sites come to fruition, it will drive significant increases in energy and demand during the later part of the 10-year forecast.

The projected EV adoptions are driving energy and demand increases during the later part of the 10-year forecast window. EVs are currently the most significant contributor of all electrification sources (e.g., heating, industrial) in the 10-year forecast.

Distributed Energy Resources

SERC entities continue to monitor DER penetration levels, assess the impacts of DERs, and incorporate these impacts in system studies. Unlike directly modeled transmission-connected resources, DERs (e.g., rooftop solar, plug-in EVs) are netted against load in the Energy Management System and transmission planning models. Some entities are beginning to use software to develop DER projections of rooftop solar. DER resource output is modeled at various levels to account for load scenarios. The overall amount of rooftop solar is small compared to the utility-scale projects.

Capacity Transfers

Entities participate in the SERC committees and study groups to perform power transfer studies of the system within the SERC geographic area. These studies include evaluating transfer limitations between all assessment areas for the existing or planned system configuration and with normal (pre-contingency) operating procedures in effect, such that all facility loading is within normal ratings and all voltages are within normal limits.

Transmission

The entities reported a total addition of 286 miles of new transmission lines through 2028. The entities are also planning to upgrade 515 miles of transmission lines through 2031 to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include adding new transformers, upgrading existing transmission lines, storm hardening, and other system reconfigurations/additions to support transmission system reliability. Entities do not anticipate any transmission limitations or constraints with significant impacts on reliability.

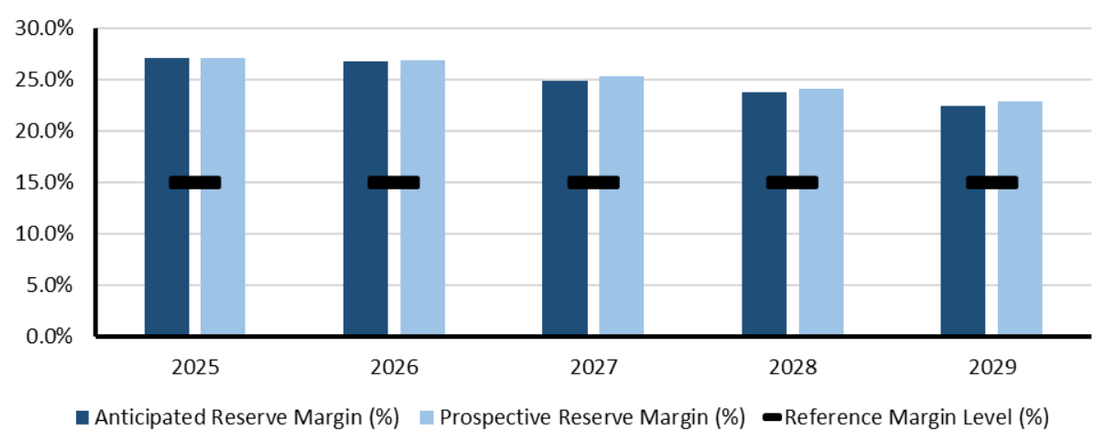


SERC-Florida Peninsula

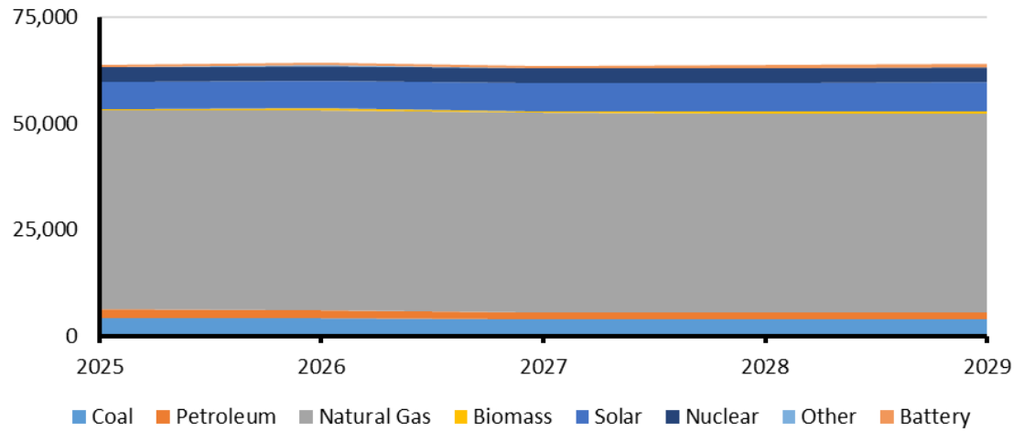
SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	53,509	53,795	54,015	54,551	55,250	55,879	56,593	57,612	58,631	59,679
Demand Response	2,840	2,834	2,837	2,820	2,806	2,795	2,783	2,771	2,761	2,748
Net Internal Demand	50,669	50,961	51,178	51,731	52,444	53,084	53,810	54,841	55,870	56,931
Additions: Tier 1	871	1,497	1,573	1,785	2,018	3,421	3,927	4,545	4,547	4,549
Additions: Tier 2	0	40	200	200	200	200	200	200	200	200
Additions: Tier 3	0	39	39	39	39	39	39	39	39	39
Net Firm Capacity Transfers	494	293	293	200	200	200	200	200	200	200
Existing-Certain and Net Firm Transfers	63,521	63,121	62,366	62,230	62,230	61,725	61,725	61,493	61,493	61,493
Anticipated Reserve Margin (%)	27.1%	26.8%	24.9%	23.7%	22.5%	22.7%	22.0%	20.4%	18.2%	16.0%
Prospective Reserve Margin (%)	27.1%	26.9%	25.3%	24.1%	22.9%	23.1%	22.4%	20.8%	18.6%	16.4%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM remains above the 15% target RML for the assessment period.
- Projected coal generation retirements total 459 MW in the next 10 years. Tier 1 additions include 484 MW of natural gas, 1,560 MW of BESS, and 1,792 MW of solar generation over the next 10 years.
- New transmission line additions total 668 miles through 2030. The entities also plan to upgrade 256 miles of transmission lines through 2031 to enhance system reliability by supporting voltage and relieving challenging flows.

SERC-Florida Peninsula Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	4,367	4,367	3,908	3,908	3,908
Coal*	3,341	3,779	2,851	2,851	2,851
Petroleum	1,957	1,852	1,724	1,724	1,724
Petroleum*	1,892	1,786	1,477	1,477	1,477
Natural Gas	46,860	47,012	46,844	46,801	46,801
Biomass	310	310	310	310	310
Solar	6,255	6,635	6,711	6,853	6,997
Nuclear	3,502	3,502	3,502	3,502	3,502
Other	9	9	9	9	9
Battery	638	638	638	708	797
Total MW	63,898	64,324	63,646	63,815	64,048
Total MW*	62,807	63,671	62,343	62,512	62,745
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

SERC-Florida Peninsula Assessment

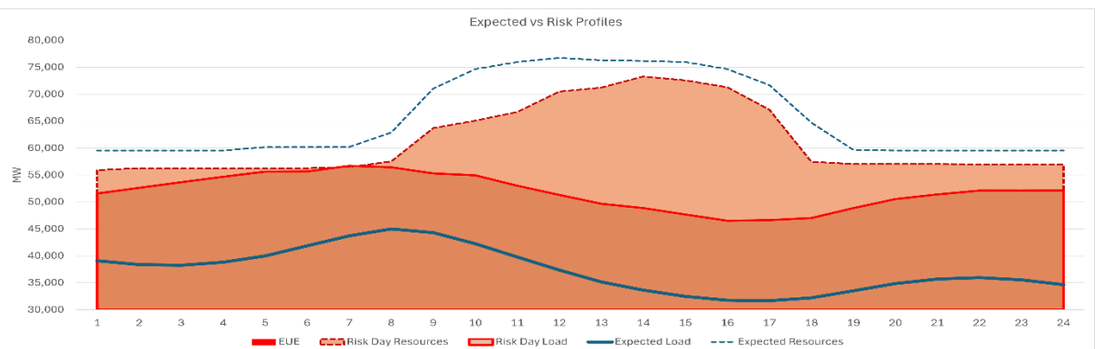
Planning Reserve Margins
The ARM is not expected to fall below the RML for any period of the assessment period.

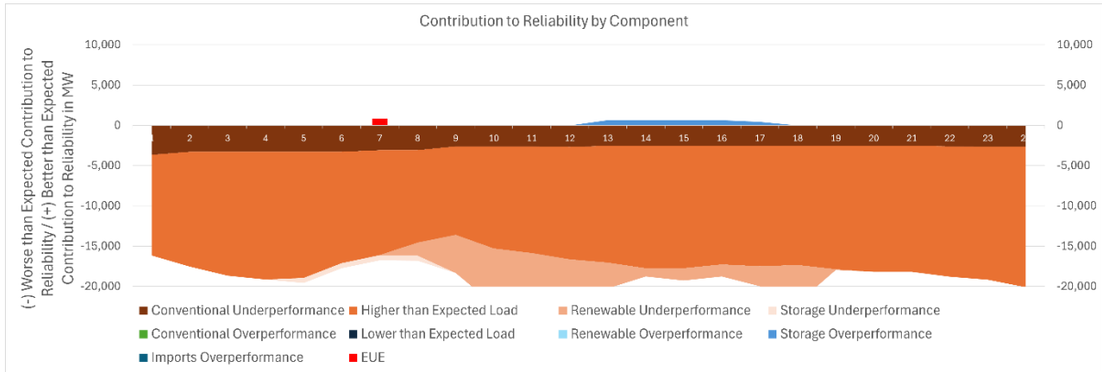
Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments
The 2024 ProbA results shown in the table below indicate negligible unserved energy and load loss. Analysis of detailed ProbA outputs shows that that the negligible risk in year 2026 is associated with hot late-summer or early fall conditions, high generator forced outages, and upper levels of economic load forecast models. The risk occurs in evening hours around 7:00 p.m. when contribution from solar generation is limited.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	1.13	**2.18**	**16.28**
EUE (PPM)	0.00	**0.01**	**0.06**
LOLH (hours per year)	0.00	**0.01**	**0.02**
Operable On-Peak Margin	18.6%	**19.2%**	**16.3**

* Provides the 2022 ProbA Results for Comparison

For study year 2028, the ProbA results shows very low risk with 16.28 MWh of EUE and 0.02 LOLH hours. The driver of the risk is mainly extreme winter weather, similar to conditions from 1989, when Florida experienced one of the worst winter freezes on record. With higher load levels and lower resources in 2028, the low risk shifts to late December, occurring in morning hours when contribution from solar generation is limited, and is associated with winter freeze events that limit imports.





Demand
The individual entities within the FL-Peninsula Subregion develop their load forecasts and the Florida Reliability Coordinating Council (FRCC) then aggregates these forecasts to calculate a non-coincident seasonal peak for the subregion. Each entity adjusts their forecasts annually to account for their actual peak demands, updated economic outlooks, population growth, weather patterns, conservation and energy efficiency efforts, and electric appliances usage patterns. Based on the data reported in the 2023 FRCC Regional Load and Resource Plan, the net energy for load (NEL) and summer peak demands are forecasted to grow when compared to previous forecasts. The current average annual growth rate for the NEL is 0.97% per year. Firm summer and winter peak demand growth are expected to increase to 1.19% and 1.17%, respectively.

Demand-Side Management
Controllable DR from interruptible and dispatchable load management programs within the FL-Peninsula Subregion is treated as a load-modifier, and it is projected to be constant at approximately 6% of the summer and winter total peak demands for all years of the assessment period.

Distributed Energy Resources
SERC entities continue to monitor DER penetration levels, assess the impacts of DERs, and incorporate these impacts in system studies. Unlike directly modeled transmission-connected resources, DERs (e.g., rooftop solar, plug-in EVs) are netted against load in the Energy Management System and transmission planning models. Some entities are beginning to use software to develop DER projections of rooftop solar. DER resource output is modeled at various levels to account for load scenarios. The overall amount of rooftop solar is small compared to the utility-scale projects.

Generation

Generator retirements are carefully managed by entities in the SERC-Florida Peninsula assessment area. Entities perform studies to determine the impacts of confirmed or unconfirmed retirements. Entities incorporate these studies into resource plans that highlight the significance of future generation projects. Additionally, there are no significant retirement plans that will affect reliability.

Energy Storage

Electricity storage (ES) is still a growing capacity contributor in the assessment area. Over the next 10 years, a total of approximately 2,900 MW of ES generation is projected to be in service by 2032 and is included in the utilities' 10-year site plans (approximately 775 MW by 2029).

Individual entities in the assessment area that have installed or are projecting the installation of ES are developing operating protocols on the use and dispatch of these facilities. ES units are studied as part of the normal generation interconnection process and included in other FRCC studies and processes with members providing individual dispatch profiles and study levels in order to identify potential operational impacts.

Capacity Transfers

Entities participate in the SERC committees and study groups to perform power transfer studies of the system within the SERC geographic area. These studies include evaluating transfer limitations between all assessment areas for the existing or planned system configuration and with normal (pre-contingency) operating procedures in effect, such that all facility loading is within normal ratings and all voltages are within normal limits.

Transmission

The entities reported a total addition of 668 miles of new transmission lines through 2030. The entities are also planning to upgrade 256 miles of transmission lines through 2031 to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include adding new transformers, upgrading existing transmission lines, storm hardening, and other system reconfigurations/additions to support transmission system reliability.

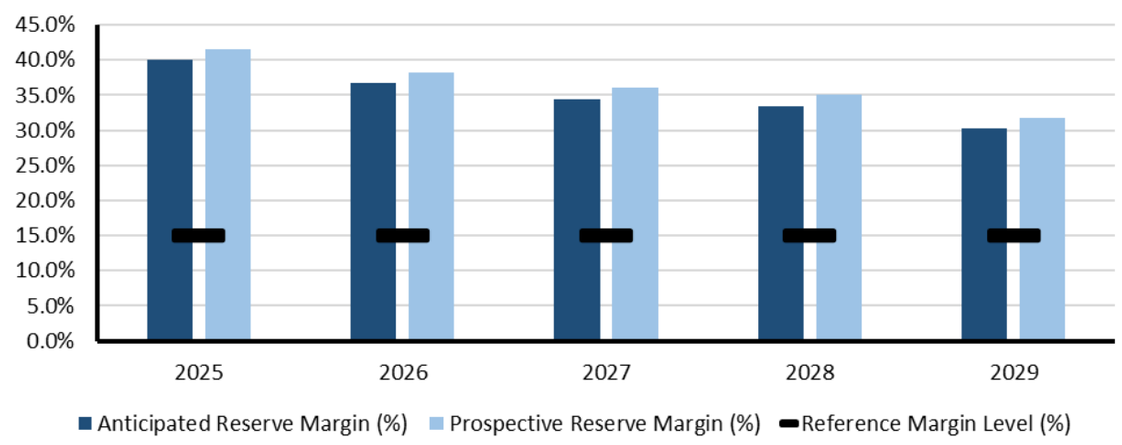


SERC-Southeast

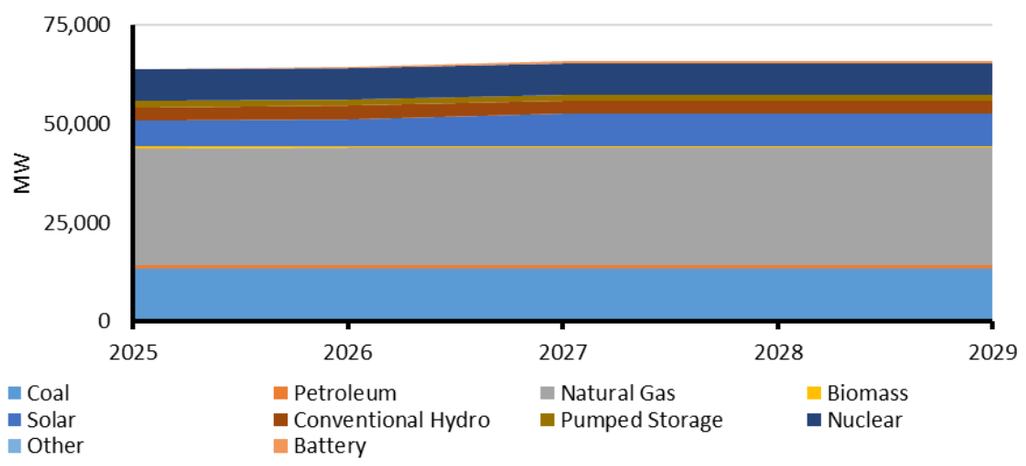
SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the southeastern and central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	46,984	48,384	50,467	50,852	51,974	53,031	53,794	54,233	54,677	55,078
Demand Response	1,633	1,666	1,723	1,755	1,875	1,876	1,875	1,875	1,876	1,876
Net Internal Demand	45,351	46,718	48,744	49,097	50,099	51,155	51,919	52,358	52,801	53,202
Additions: Tier 1	1,248	1,486	3,050	3,050	3,050	3,129	3,129	3,129	3,129	3,129
Additions: Tier 2	105	105	218	218	218	218	218	218	218	218
Additions: Tier 3	366	366	366	366	366	366	366	366	366	366
Net Firm Capacity Transfers	-392	-392	-392	-392	-684	-684	-684	-684	-684	-684
Existing-Certain and Net Firm Transfers	62,257	62,413	62,472	62,472	62,180	62,180	62,180	62,180	62,180	62,180
Anticipated Reserve Margin (%)	40.0%	36.8%	34.4%	33.5%	30.2%	27.7%	25.8%	24.7%	23.7%	22.8%
Prospective Reserve Margin (%)	41.5%	38.2%	36.0%	35.0%	31.7%	29.2%	27.3%	26.2%	25.1%	24.2%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM remains above the 15% target RML for the assessment period.

SERC-Southeast Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	13,275	13,275	13,275	13,275	13,275
Coal*	13,275	13,275	12,271	10,321	10,321
Petroleum	915	915	915	915	915
Petroleum*	915	915	915	899	899
Natural Gas	29,639	29,795	29,854	29,854	29,854
Natural Gas*	29,564	29,387	29,446	28,426	28,426
Biomass	424	424	424	424	424
Solar	6,597	6,835	8,021	8,021	8,021
Conventional Hydro	3,293	3,293	3,293	3,293	3,293
Pumped Storage	1,632	1,632	1,632	1,632	1,632
Nuclear	8,018	8,018	8,018	8,018	8,018
Battery	105	105	483	483	483
Total MW	63,897	64,291	65,914	65,914	65,914
Total MW*	63,822	63,883	64,502	61,516	61,516
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

SERC-Southeast Assessment

Planning Reserve Margins

The future reserve margins are above the RMLs for SERC-Southeast.

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

The 2024 ProbA results shown in the table below indicate negligible unserved energy and load loss.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0.00	**0.00**	**0.00**
EUE (PPM)	0.00	**0.00**	**0.00**
LOLH (hours per year)	0.00	**0.00**	**0.00**
Operable On-Peak Margin	30.8%	**29.6%**	**25.6%**

* Provides the 2022 ProbA Results for Comparison

Demand

Data centers, cryptocurrency facilities, and large commercial and industrial load are driving demand forecast growth in the assessment area. Metro areas are experiencing a higher growth rate compared to rural areas.

Demand-Side Management

Entities within the SERC-Southeast assessment area use a variety of controllable and dispatchable DR programs to reduce peak demand. One entity manages a voluntary DSM water heater program designed to allow system operators to control the appliances' usage during peak demand periods. Another entity monitors and dispatches DR programs commensurate with contract terms. Annual ELCC simulations are performed to determine the capacity value for each unique and active DR program. An adjustment to that capacity value is then made based on predicted customer response when the program is called or dispatched.

Distributed Energy Resources

SERC entities continue to monitor DER penetration levels, assess the impacts of DERs, and incorporate these impacts in system studies. Unlike directly modeled transmission-connected resources, DERs (e.g., rooftop solar, plug-in EVs) are netted against load in the Energy Management System and transmission planning models. Some entities are beginning to use software to develop DER projections of rooftop solar. DER resource output is modeled at various levels to account for load scenarios. The overall amount of rooftop solar is small compared to the utility-scale projects.

Generation

Generator retirements are carefully managed by entities in the SERC-Southeast assessment area. Entities perform studies to determine the impacts of confirmed or unconfirmed retirements. Entities incorporate these studies into resource plans that highlight the significance of future generation projects. Additionally, there are no significant retirement plans that will affect reliability.

Capacity Transfers

Entities participate in the SERC committees and study groups to perform power transfer studies of the system within the SERC geographic area. These studies include evaluating transfer limitations between all assessment areas within the Region for the existing or planned system configuration and with normal (pre-contingency) operating procedures in effect, such that all facility loading is within normal ratings and all voltages are within normal limits.

Transmission

The entities reported a total addition of 1,078 miles of new transmission lines in the next 10 years. The entities are also planning to upgrade 694 miles of transmission lines during this time to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include adding new transformers, upgrading existing transmission lines, storm hardening, and other system reconfigurations/additions to support transmission system reliability.

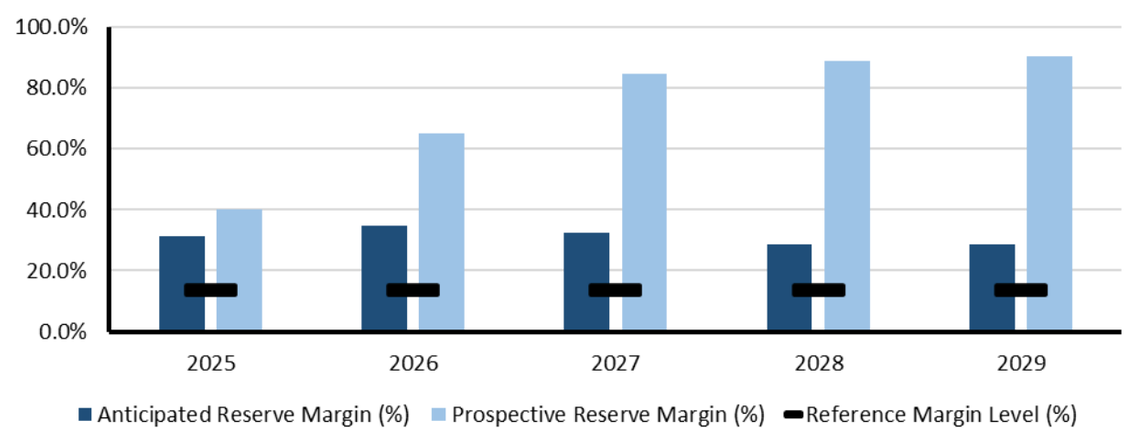


Texas RE-ERCOT

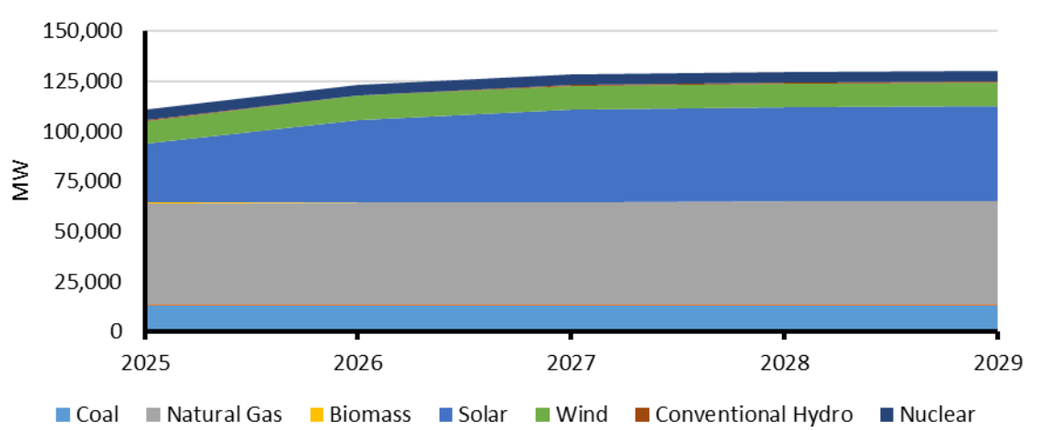
The Electric Reliability Council of Texas (ERCOT) is the ISO for the Texas Interconnection and is located entirely in the state of Texas; it operates as a single BAand performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is summer-peaking and covers approximately 200,000 square miles, connects over 54,100 miles of transmission lines, has over 1,250 generation units, and serves more than 27 million people. Texas RE is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	88,873	95,721	101,405	105,417	106,365	106,951	106,772	106,463	106,062	106,961
Demand Response	2,652	2,652	2,652	2,652	2,652	2,652	2,652	2,652	2,652	2,652
Net Internal Demand	86,220	93,069	98,753	102,765	103,713	104,298	104,119	103,811	103,410	104,309
Additions: Tier 1	11,187	23,684	28,725	29,226	29,903	29,903	29,903	29,903	29,903	29,903
Additions: Tier 2	7,281	27,876	51,414	62,225	65,786	65,939	65,939	65,939	65,939	65,939
Additions: Tier 3	7,252	17,627	29,082	41,174	45,318	47,062	47,062	47,062	47,062	47,062
Net Firm Capacity Transfers	20	20	20	20	20	20	20	20	20	20
Existing-Certain and Net Firm Transfers	101,906	101,645	102,003	103,088	103,338	103,338	103,338	103,338	103,338	103,338
Anticipated Reserve Margin (%)	31.2%	34.7%	32.4%	28.8%	28.5%	27.8%	28.0%	28.3%	28.8%	27.7%
Prospective Reserve Margin (%)	40.3%	65.2%	84.6%	88.8%	90.3%	88.8%	89.1%	89.7%	90.4%	88.8%
Reference Margin Level (%)	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- Generation resources, primarily solar PV, continue to be added to the grid in Texas in large quantities, increasing ARMs but also elevating concerns of energy risks that result from the variability of these resources and the potential for delays in implementation. The summer ARM is above the RML (13.75%) for all 10 years of this assessment period (2025–2034). The ARM peaks at 34.7% by Summer 2026, reflecting the expected addition of about 23,680 MW of Tier 1 capacity, most of which is solar PV.

- The Public Utility Commission of Texas (PUCT) established a reliability standard and accompanying reliability assessment process in August 2024. The reliability standard is based on multiple probabilistic reliability measures that capture the different dimensions of loss-of-load events: average event frequency (LOLE), maximum event duration, and maximum event magnitude. ERCOT will begin performing reliability assessments required by the new standard in 2026.

- ERCOT's summer peak demand is forecast to increase by 4.6% per year from 2025 through 2029. In comparison, the five-year summer peak demand growth projection for the *2023 LTRA* was 1.1%. This high growth level is driven by a large amount of newly contracted loads planned for interconnection during this period. These contracted loads are mainly comprised of Permian Basin oil and gas production facilities, data centers, crypto-mining operations, and industrial facilities.

Texas RE-ERCOT Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	**2026**	**2027**	**2028**	**2029**
Coal	13,568	13,568	13,568	13,568	13,568
Coal*	13,568	13,568	12,913	12,353	12,353
Petroleum	10	10	10	10	10
Natural Gas	50,568	50,694	50,845	51,458	51,458
Natural Gas*	49,709	49,928	48,823	49,436	49,436
Biomass	163	163	163	163	163
Solar	29,557	41,201	45,984	46,485	47,163
Wind	11,332	11,908	12,166	12,166	12,166
Conventional Hydro	458	458	458	458	458
Nuclear	4,973	4,973	4,973	4,973	4,973
Total MW	110,628	122,975	128,167	129,281	129,958
Total MW*	109,769	122,208	125,490	126,044	126,721
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

Texas RE-ERCOT Assessment

Planning Reserve Margins

The summer ARM is above the RML (13.75%) for all 10 years of this assessment period (2025–2034). The ARM peaks at 34.7% by Summer 2026, reflecting the expected addition of about 23,680 MW of Tier 1 capacity, most of which is solar PV. However, the high reserve margin belies concerns over the continuing trend toward less fully dispatchable resources and more IBRs like solar PV and wind. While thermal resource availability and adequate gas supplies are still concerns during extreme winter weather events, the fleet performed well during Winter Storm Heather in January 2024, indicating that new weatherization standards, fully implemented in 2023, are effective.

Non-Peak Hour Risk and Energy Assurance

The PUCT established a reliability standard and accompanying reliability assessment process in August 2024. The reliability standard is based on multiple probabilistic reliability measures that capture the different dimensions of loss-of-load events: average event frequency (LOLE), maximum event duration, and maximum event magnitude. The latter two measures have an "exceedance tolerance," which is the maximum acceptable percentage frequency of loss-of load events that exceed the permissible thresholds based on a probabilistic simulation.

For non-winter months, ERCOT continues to experience the highest reserve scarcity risk during the early evening hours—peaking at hour ending (HE) 9:00 p.m.—based on probabilistic modeling of monthly peak load days. The elevated risk is due to the drop-off in solar generation and continued higher loads during those hours. The summer peak load hour continues to be 5:00 p.m. For winter, the peak load hour is HE 8:00 a.m. Risk modeling indicates elevated reserve scarcity risk for the morning hours (HE 7:00 a.m. to 9:00 a.m.) as well as the early evening hours.

ERCOT is experiencing transmission limitations as a result of load growth and resource development that affect energy delivery. On March 1, 2024, ERCOT introduced four new Interconnection reliability operating limits (IROL) in the South Texas region. This consists of two South Texas import constraints and two South Texas export constraints, which, if violated, could result in a thermal cascading condition. This is the first thermal IROL that could lead to a cascading condition in the Texas RE-ERCOT Region and has been attributed to the increase in generation capacity in South Texas and the rapid load growth in central Texas. To manage the South Texas export constraint, generation in South Texas must be curtailed to maintain transmission line flows below 100% of the impacted lines' thermal ratings. The risk of such curtailments, which is highest for the hours with the highest net peak loads (early evening), is included in the monthly probabilistic reserve risk assessments. ERCOT has approved two San Antonio Reliability projects that are expected to be completed in 2027 and should help alleviate some of risk drivers associated with these IROLs.

Probabilistic Assessment

Results of the 2024 ProbA are shown in the table below.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	1,235	**11,090**	**781**
EUE (PPM)	2.63	**18.95**	**1.12**
LOLH (hours per year)	0.30	**1.57**	**0.16**
Operable On-Peak Margin	35.9%	**28.8%**	**46.9%**

* Provides the 2022 ProbA Results for Comparison

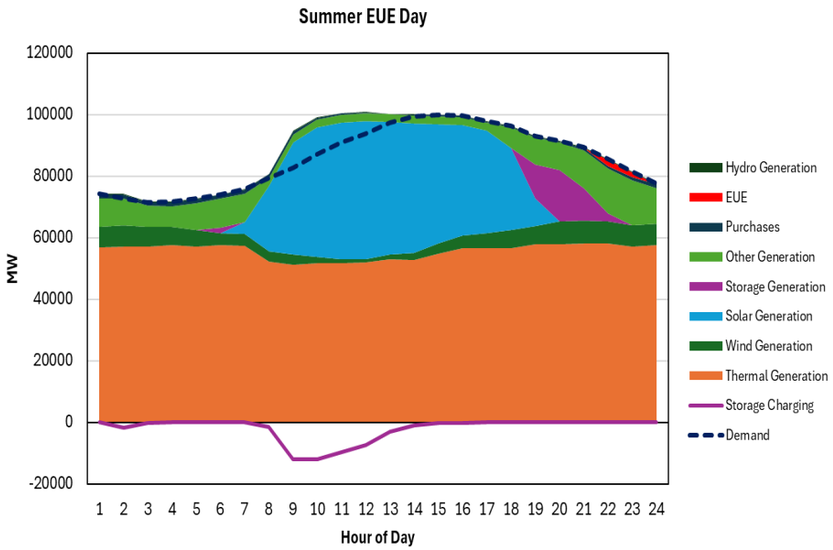
Increasing reliability risk in ERCOT is primarily driven by increasing large load demand anticipated from data centers, Bitcoin operations, continued load growth in oil and gas-producing areas (such as the Permian Basin), and growth in industrial facilities. Over 20 GW of newly contracted large loads, in addition to other organic load growth, is projected to be added to ERCOT by 2028. ERCOT also anticipates 1,860 MW of fossil-fueled plant capacity to be retired by Summer 2028. New planned units are primarily renewable and storage, which exhibit declining marginal reliability contributions. The reliability forecasts provided by this ProbA assessment for 2028 include resource capacity contributions from expansion planning analysis conducted for ERCOT's 2024 *Long-Term System Assessment*. While there is uncertainty around the deployment of these resources, the large load demand growth is also uncertain and large loads are subject to various requirements for being integrated into the grid.

All SERVM simulations for ERCOT and surrounding regions impose all relevant generator temporal constraints, including operating limitations on conventional units as well as state-of-charge on batteries, so this assessment accounts for energy adequacy. However, this assessment does assume fuel for conventional units will be available when needed.[37]

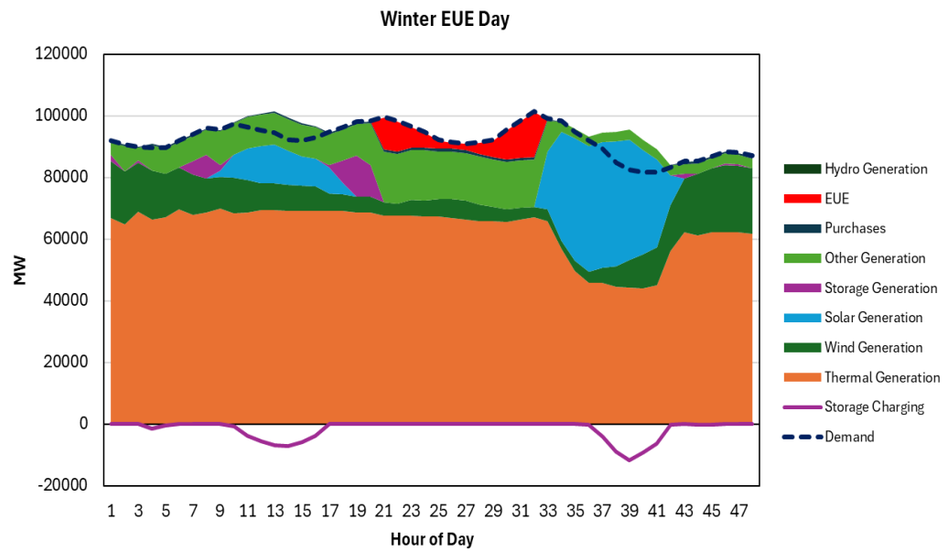
The unique characteristics of winter risk vs. summer risk can be seen in the following charts of a representative risk day. While peak winter loads can persist for 48 hours or longer, peak summer

[37] ERCOT and several other entities used SERVM software tool to perform the ProbA. Information about SERVM can be found at the company's website.

periods generally only last for a few hours. This has significant implications for the duration and depth of firm load-shed events in the winter as well as for the reliability contribution of energy limited and non-dispatchable resources. The most extreme winter event modeled for 2026 was 16 hours in duration and 29 GW in depth. The illustration below indicates a winter EUE event with duration >12 hours while most summer events were 1–2 hours in duration.



Metric	2026 Summer	2026 Winter	2028 Summer	2028 Winter
LOLE (days/year)	0.38	0.51	0.05	0.04
LOLH (hours/year)	1.41	1.57	0.18	0.16
EUE (MWh)	10,985	11,090	857	781
Max Hourly EUE (MWh)	29,124	29,266	17,762	16,851
Max EUE Duration (Hr)	15	16	12	11



From the hourly event data, ERCOT provided a multi-metric summary of the largest event showing the highest magnitude and longest-duration, as shown in the following figure.

Demand

ERCOT's long-term load forecast consists of the following individual components: (1) a base forecast that uses an econometric model with estimation data comprising 15 historical weather years, economic drivers, calendar information, and historical loads, (2) a roof-top PV forecast, (3) an EV forecast, a large flexible load forecast (crypto-mining facilities), and new "large loads" with a signed interconnection contract with their transmission or distribution service provider. Forecasts are provided for eight weather zones as well as system coincidental and non-coincidental demands. ERCOT's summer peak demand is forecast to increase by 4.6% per year from 2025 through 2029. In

comparison, the five-year summer peak demand growth projection for the *2023 LTRA* was 1.1%. This high growth level is driven by a large amount of newly contracted loads planned for interconnection during this period. These contracted loads are mainly comprised of Permian Basin oil and gas production facilities, data centers, crypto-mining operations, and industrial facilities. (A negligible amount of new contracted loads reported by transmission service providers occur past 2029). The base peak load, which excludes these new contracted loads as well as load reductions due to rooftop solar installations, grows at a more modest 1.4%.

A major load forecasting change from last year is a new Texas Legislature requirement to include non-contracted loads in transmission planning studies. Non-contracted loads lack a signed Interconnection or facility expansion agreement. ERCOT's previous practice had been to exclude these more speculative loads from the load forecast. The non-contracted loads total about 3.6 GW for summer 2025 and reach about 31.7 GW by 2029. The non-contracted loads are not included in the LTRA's peak load forecast. ERCOT is evaluating how these non-contracted forecasted loads will be handled for future resource adequacy and other planning activities.

Demand-Side Management

Most of the demand-side resources available to ERCOT are dispatchable in the form of noncontrollable load resources providing responsive reserve service and ERCOT's Emergency Response Service. The ERCOT Emergency Response Service consists of 10- and 30-minute ramping DRs and distributed generation that can first be deployed when physical responsive reserves drop to 3,000 MW and are not projected to be recovered above 3,000 MW within 30 minutes following the deployment of non-spin reserves. Responsive reserve is provided by industrial loads and is procured on an hourly basis in the day-ahead market. During 2023, load resources started to participate in two other ancillary services, the Non-Spinning Reserve Service and ERCOT Contingency Reserve Service (ECRS), which are used to help balance the system during periods when there may be net-load ramps that cannot be met with conventional supply-side resources.

The remaining dispatchable DR available to ERCOT is from the transmission and distribution service providers' (TDSP) load management programs. These programs provide price incentives for voluntary load reductions from commercial, industrial, and residential loads during energy emergency alert events.

Distributed Energy Resources

DERs that register with ERCOT to participate in wholesale energy and/or ancillary services markets are modeled and dispatched in ERCOT transmission planning studies similarly to transmission-connected resources participating in those markets. For DERs not participating in those markets, ERCOT relies on member TDSPs to provide information about individual DERs on their systems for shorter-term reliability and economic impact studies, typically a one-to-six-year timeframe.

A bill was approved in the 88th Texas Legislature (HB 3390) that outlines new DER reporting responsibilities. The bill authorizes ERCOT to require TDSPs to provide unregistered DER information that ERCOT deems necessary for grid reliability assessment. ERCOT is now developing annual data collection and maintenance processes.

A multi-phase aggregated DER (ADER) pilot program was implemented in 2022. As of May 2024, there were two ADERs with 13 MW of dispatchable capability actively participating in the pilot project with another nine ADERs in various stages of registration/qualification.

Generation

Natural-gas-fired generation makes up approximately 45% of the available generation inside the ERCOT footprint. Approximately 6% of the natural-gas-fired generation demonstrates firm fuel capabilities as part of ERCOT's Firm Fuel Supply Service required by the PUCT.

ERCOT has established formal working relationships with grid generators' fuel suppliers to gather operational and delivery information useful for its control room operators. ERCOT has focused the efforts on two fronts: (1) obtaining real-time (or near real-time) information on the health of the natural gas systems that serve the generators and (2) maintaining communication with pipelines to notify ERCOT of any planned or unplanned events that could impact deliveries to generators.

After the 2021 Odessa event, ERCOT intensified its efforts to find corrective measures to enhance the ride-through performance of IBRs and improve overall system resilience. The study, which recommended installing synchronous condensers at six locations in West Texas, has been completed, and the ERCOT board of directors endorsed the project in December 2023. The project is expected to be in service in 2027.

ERCOT has proposed new grid code requirements for IBRs to improve voltage ride-through (VRT) performance to align with IEEE Standard 2800. The proposed grid code requirements are continuing to go through ERCOT's stakeholder approval process. Until new rules go into effect, IBRs will be expected to maximize VRT capability and address existing performance failures (such as by reducing maximum output).

To provide an incentive to build new dispatchable resources, the PUCT adopted a new rule to establish a generation loan program, one of four incentive programs under the recently established Texas Energy Fund (TEF). The other three programs within the TEF include completion bonus grants for new dispatchable generation projects that consistently provide power generation over a 10-year period, grants for companies to establish or secure backup power resources, and grants to improve the resiliency and availability of electric utility service outside the ERCOT region. The TEF has $5 billion

available for all four programs. These loans and grants have thus far resulted in 72 applications seeking funding under the TEF loan program. The PUCT staff-recommended portfolio represents 9,781 MW in potential new generation if all recommended applicants were to execute a loan agreement at the requested loan amounts.

Energy Storage

The current installed BESS capacity is 9,149 MW. These systems participate in ERCOT's Energy and Ancillary Service markets. Most have durations in the one-to-two-hour range. ERCOT is seeing an increase in longer-duration systems (three to four hours) to take advantage of energy-shifting and capacity-firming opportunities arising from continued high renewable generation penetration. For the first half of 2024, energy storage provided 87% of ERCOT's regulation up and 91% of responsive reserve service from primary frequency response (RRS-PFR). In June 2023, ERCOT implemented a new ancillary service, the ERCOT Contingency Reserve Service (ECRS), which, in part, is designed to address the ramping needs of the system. This ancillary service product provides additional opportunities for BESS ancillary service participation. To support larger BESS penetration levels, ERCOT submitted new proposed rules for state-of-charge accounting in energy dispatch and reliability unit commitment that are planned for implementation this year.

Based on the latest developer information for projects that are in the interconnection queue, ERCOT expects about 10,500 MW of additional battery energy storage capacity to be operational by year-end 2025. This capacity constitutes projects for which developers have posted financial security to build the interconnection facilities. By year-end 2029, the additional cumulative Tier 1 planned capacity reaches about 20,000 MW.

ERCOT currently assigns a 0% on-peak contribution for battery energy storage. ERCOT has changed its rule to adopt an ELCC methodology for battery storage of various durations. Extending the proposed ELCC methodology for BESS to current and forecasted resources in ERCOT would improve the anticipated reserve margins in the future.

Capacity Transfers

ERCOT has coordination plans in place with neighboring grids. These plans cover dc tie emergency operations, procedures for generators that can switch between grids, and temporary block load transfers.

Transmission

In September, the PUCT approved ERCOT's Permian Basin Reliability Plan. The plan consists of new and upgraded local transmission projects as well as building new import paths to load centers in other areas of the Texas RE-ERCOT region, including options for extra high voltage (EHV) infrastructure operating at 345 kW or 765 kV. The plan supports Permian Basin load growth that is currently expected to reach 24 GW by 2030 and over 26 GW by 2038.

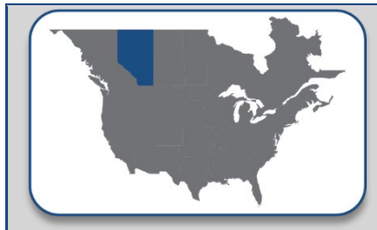
ERCOT's 2023 Regional Transmission Plan (RTP) identified 173 reliability projects, with the majority consisting of 138 kV and 345 kV system upgrades. The 2023 RTP also included an economic assessment of the ERCOT transmission system for years 2025 and 2028 using production cost savings and generator revenue reduction tests.

The substantial increase in new loads from a year ago is expected to present challenges for transmission planning. The forecasted pace of the load growth could exceed the pace at which transmission capacity can be built to support it. ERCOT is working on major changes to its transmission planning process to address these challenges. For example, ERCOT is investigating a "generation hub" concept to indicate optimal generation location to address regional load growth and optimize transmission investments.

A new biennial report on grid resiliency—the Grid Reliability and Resiliency Assessment—evaluates extreme weather scenarios considering different levels of thermal and renewable generation availability and the potential outages caused by extreme weather conditions. The assessment also includes proposed transmission projects that may mitigate regional resiliency risks. The first report will be released by December 31, 2024.

New minimum deliverability criteria were included in ERCOT's 2023 RTP to ensure the deliverability of 100% of generation resource capacity and energy storage resources with a duration greater than or equal to two hours. For storage systems with a duration less than two hours, a prorated deliverability was ensured. Corrective action plans (CAP) were proposed to address any reliability violations under the contingencies defined for the minimum deliverability criteria.

ERCOT has also started implementing the PUCT's amended rules relating to certification criteria and is in the process of integrating a new congestion cost savings test for economic projects evaluation.

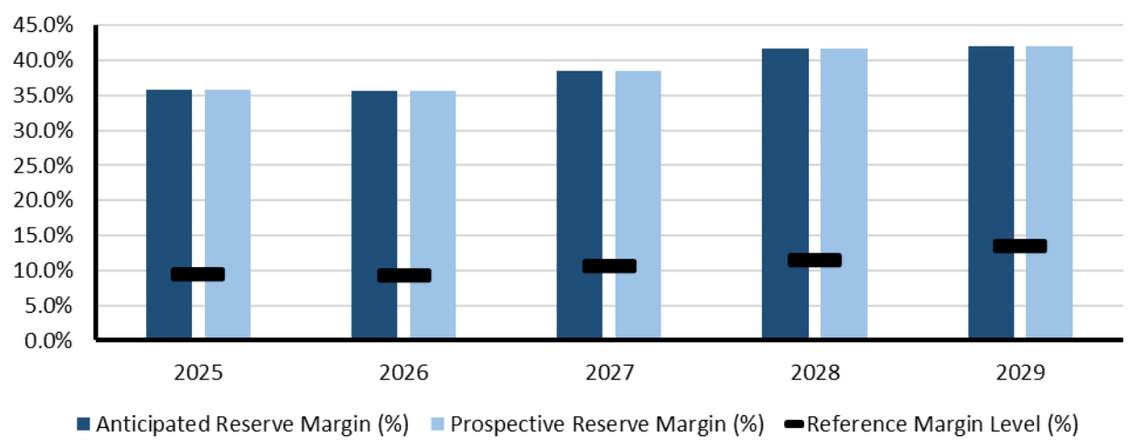


WECC-AB

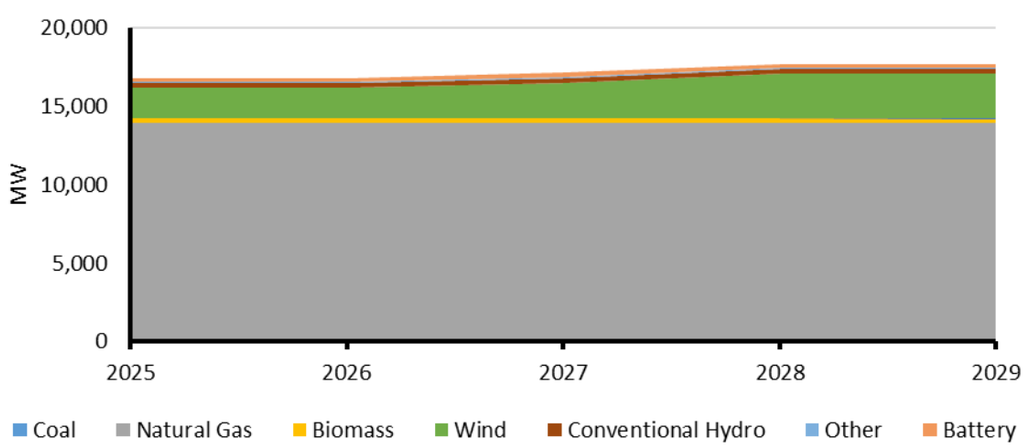
WECC-AB (Alberta) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of Alberta, Canada. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and BC in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 western U.S. states in between.

Demand, Resources, and Reserve Margins

Quantity	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035
Total Internal Demand	12,411	12,463	12,434	12,510	12,528	12,759	12,831	12,956	12,992	13,076
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	12,411	12,463	12,434	12,510	12,528	12,759	12,831	12,956	12,992	13,076
Additions: Tier 1	3,275	3,275	3,405	3,541	3,537	3,342	3,537	3,441	3,273	3,273
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	1,031	1,680	1,824	2,247	2,700	2,502	3,068	3,096	2,744	2,744
Net Firm Capacity Transfers	43	96	69	0	68	396	409	0	0	0
Existing-Certain and Net Firm Transfers	13,578	13,631	13,822	14,182	14,244	13,931	14,585	13,867	13,330	13,330
Anticipated Reserve Margin (%)	35.8%	35.6%	38.5%	41.7%	41.9%	35.4%	41.2%	33.6%	27.8%	27.0%
Prospective Reserve Margin (%)	35.8%	35.6%	38.5%	41.7%	41.9%	35.4%	41.2%	33.6%	27.8%	27.0%
Reference Margin Level (%)	9.4%	9.4%	10.6%	11.5%	13.6%	9.2%	13.2%	11.3%	9.0%	9.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM does not fall below the RML during the 2024–2034 timeframe.
- The peak hour of demand for Alberta occurs in the winter. The peak hour for total internal demand is expected to grow from about 12.3 GW in 2024 to 13.1 GW in 2034, a 6.5% load growth over the forecast horizon. The average year-to-year growth rate is 0.62%. There is a slight increase in the load forecast for this year's LTRA versus last year's.
- Despite low resource adequacy risk, operational risk is still present. Ensuring sufficient frequency response capability has been identified as the region's highest priority. Frequency response has been declining in the region due to the increasing share of IBR resources and declining baseload resources. This under frequency load shedding risk is exacerbated in islanded or near-islanded situations.
- Alberta's two remaining coal-fired generators completed their conversion to natural gas this year.

WECC-AB Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030
Natural Gas	13,932	13,932	13,941	13,930	13,920
Biomass	336	336	336	336	336
Wind	1,912	1,912	2,232	2,811	2,799
Conventional Hydro	285	285	303	302	312
Other	81	81	81	81	81
Battery	264	264	264	264	263
Total MW	16,810	16,810	17,157	17,723	17,713

WECC-AB Assessment

Planning Reserve Margins

The ARM does not fall below the RML during the 2024–2034 timeframe. From the 2032–2033 winter onward, Alberta shows a shortfall of existing-certain and net firm transfers. This indicates that imports may be necessary during this timeframe if new resources were to be significantly delayed.

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

WECC performs a probabilistic analysis to evaluate the probability distribution curves of demand and resource availability together. The area where those curves overlap represents the possibility that there will not be enough resources available to serve the demand, or the "demand at risk." The greater the overlap area, the greater the likelihood that this will be the case. For this analysis, WECC sets the risk tolerance threshold to the one-day-in-ten-year (ODITY) level, meaning that 99.98% of the demand for each hour is covered by available resources (i.e., the area of overlap is equal to no more than .02% of the total area of the demand curve for any given hour). The overlap—the demand at risk—increases when one or both curves move due to increases to expected demand or decreases to expected resource availability, or a combination of these (the curves maintain their original shape but move closer together, increasing the overlap). The overlap is also increased through variability. When rare events occur more regularly than predicted, the probability curve changes shape.

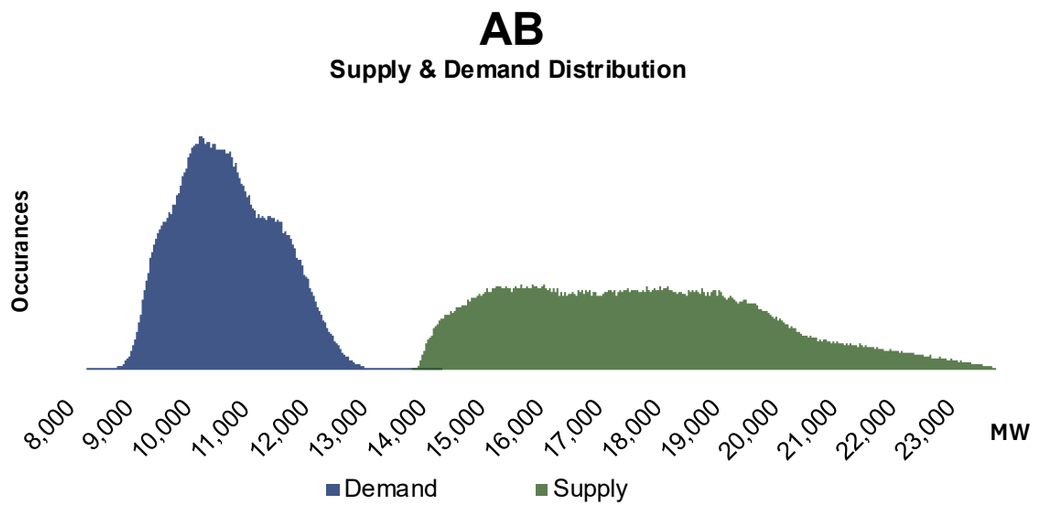
Results of the 2024 ProbA shown in the table below indicate negligible unserved energy and load-loss risk.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0	0	0
EUE (PPM)	0	0	0
LOLH (hours per year)	0	0	0
Operable On-Peak Margin	26.1%	41.6%	42.4%

* Provides the 2022 ProbA Results for Comparison

The resource adequacy work performed at WECC uses the Multi-Area Variable Resource Integration Convolution (MAVRIC) model. The MAVRIC model is a convolution-based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour. In the resource adequacy environment, the reports produced support NERC's seasonal assessments, LTRA, and Probabilistic Assessment. WECC also produces an annual reliability assessment called the *Western Assessment of Resource Adequacy* (WARA).[38]

The availability and demand distributions in the ProbA simulations do not overlap, indicating an extremely low probability of Alberta not being resource adequate over the next four years. For 2026 and 2028, the peak hour occurs in December at HE 18:00. Alberta does not show LOLH nor EUE in the LTRA forecast horizon. The gap between the demand distribution and the supply distribution shown in the figure below emphasizes that there is minimal resource adequacy risk in Alberta. The ARM appears to further validate this, as it is far above the RML for 2026 and 2028.



Demand

Peak demand for Alberta occurs in the winter. The peak hour for total internal demand is expected to grow from about 12.3 GW in 2024 to 13.1 GW in 2034, a 6.5% load growth over the forecast horizon. The average year-to-year growth rate is 0.62%. There is a slight increase in the load forecast for this year's LTRA versus last year's. Near-term load growth is driven by industrial loads, such as oil sands production, pulp and paper mills, and gas and oil processing. Long-term demand growth is driven by electrification of transportation and buildings as well as potential growth in emerging industries, such as hydrogen production.

[38] See WECC Reliability Assessments.

Distributed Energy Resources
BTM DERs are difficult to measure due to data gathering barriers. AESO released its updated 2022 Plan for DER Roadmap Integration Activities.

Generation
Over 6 GW of nameplate capacity are being added in Alberta through the end of 2028. There is significantly more solar, wind, and energy storage in this year's planned capacity additions than in the last LTRA. Additionally, several states and provinces in the region as well as cities and utilities are implementing renewable or carbon-free electricity targets. Retirements tend to be concentrated across three resource types: coal, nuclear, and natural gas. Coal and natural gas units are being retired due to age and emissions. Alberta's two remaining coal units have been converted to natural gas this year.

Energy Storage
Energy storage is being relied on to help mitigate ramping risk from afternoon net demand due to increasing penetrations of solar. Many additions are being co-located into hybrid PV + storage, but there is also increased standalone battery storage. Learning curves for potential operational challenges to mitigate energy storage risks include further real-world testing under extreme weather conditions, especially extended high temperatures such as during heat waves, and exploring solutions to mitigate the risks of fire.

Capacity Transfers
In WECC's analysis, Alberta is not showing significant changes to capacity transfers. There is a slight increase in exports between 5:00 p.m. and 10:00 p.m. and in the later years of the assessment period.

Reliability Issues
WECC notes that supply chain issues impacting transformers, circuit breakers, transmission cables, switchgears, and insulators continue to be a risk to generation and transmission development and are an ongoing reliability concern.

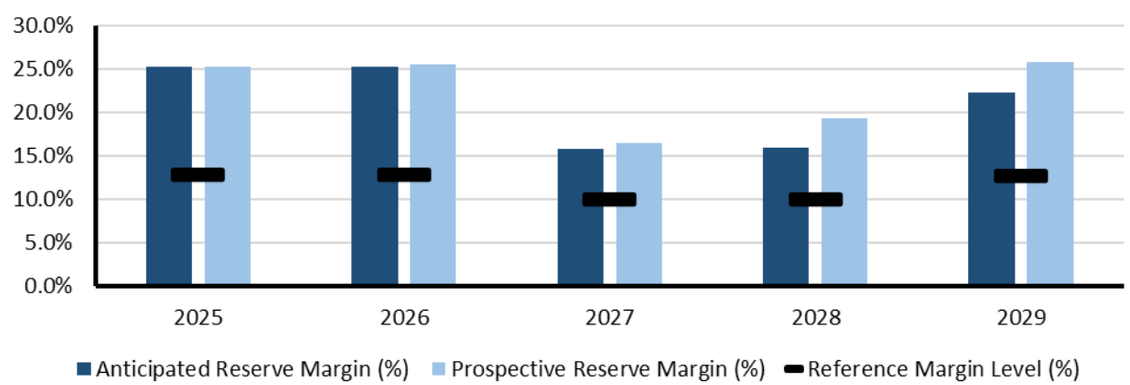


WECC-BC

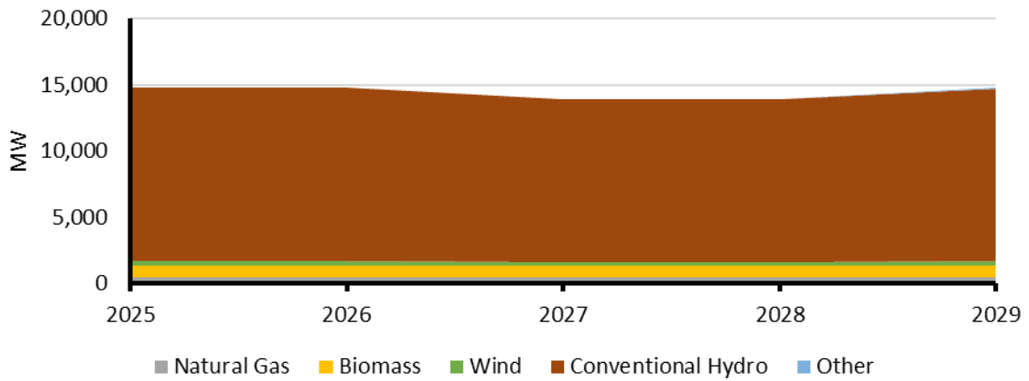
WECC-BC (British Columbia) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of BC, Canada. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and BC in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 western U.S. states in between.

Demand, Resources, and Reserve Margins

Quantity	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035
Total Internal Demand	11,986	11,959	12,015	11,983	12,075	12,082	12,130	12,174	12,237	12,305
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	11,986	11,959	12,015	11,983	12,075	12,082	12,130	12,174	12,237	12,305
Additions: Tier 1	956	956	893	893	956	956	956	956	893	956
Additions: Tier 2	0	41	79	398	419	748	1,077	1,077	1,012	1,405
Additions: Tier 3	0	5	5	5	6	6	59	59	56	59
Net Firm Capacity Transfers	184	188	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	14,054	14,022	13,019	12,998	13,812	13,795	13,795	13,795	12,982	13,795
Anticipated Reserve Margin (%)	25.2%	25.2%	15.8%	15.9%	22.3%	22.1%	21.6%	21.2%	13.4%	19.9%
Prospective Reserve Margin (%)	25.2%	25.6%	16.5%	19.2%	25.8%	28.3%	30.5%	30.0%	21.7%	31.3%
Reference Margin Level (%)	12.8%	12.8%	10.0%	10.0%	12.7%	12.7%	12.6%	12.6%	9.8%	12.5%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM does not fall below the RML during the 2024–2034 timeframe.
- BC shows a shortfall of existing-certain and net firm transfers for the 2027–2028 winter and the 2028–2029 winter. Shortfalls are also projected from the winter of 2033–2034 onward. This indicates that imports may be necessary during these periods if new resources were to be significantly delayed.
- The peak hour of demand for BC occurs in the winter. BC shows the lowest demand growth rate in the west. The peak demand is expected to grow from about 12.0 GW in 2024 to 12.3 GW in 2034, slightly less than in the previous LTRA forecast. This is an average annual growth rate of 0.28%, and a 2.8% load growth over the forecast horizon.
- BC is showing hours of demand at risk that are not fully mitigated by the addition of Tier 3 resources. Supply chain performance will play a significant role in BC's ability to reliably meet energy needs. Seasonal and daily fluctuations of hydro resource availability is also a risk. LOLH and EUE correlate with periods when river flows are at their lowest.

WECC-BC Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030
Natural Gas	459	459	456	456	459
Biomass	920	920	914	914	920
Wind	279	279	268	268	279
Conventional Hydro	13,145	13,110	12,253	12,232	13,087
Other	22	22	22	22	22
Total MW	14,825	14,790	13,912	13,891	14,768

WECC-BC Assessment

Planning Reserve Margins

The ARM does not fall below the RML during the 2024–2034 timeframe. BC shows a shortfall of existing-certain and net firm transfers for the 2027–2028 winter and the 2028–2029 winter. Shortfalls are also projected from winter of 2033–2034 onward. This indicates that imports may be necessary during these periods if new resources were to be significantly delayed.

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

WECC performs a probabilistic analysis to evaluate the probability distribution curves of demand and resource availability together. The area where those curves overlap represents the possibility that there will not be enough resources available to serve the demand, or the "demand at risk." The greater the overlap area, the greater the likelihood that this will be the case. For this analysis, WECC sets the risk tolerance threshold to the ODITY level, meaning that 99.98% of the demand for each hour is covered by available resources (i.e., the area of overlap is equal to no more than .02% of the total area of the demand curve for any given hour). The overlap—the demand at risk—increases when one or both curves move due to increases to expected demand or decreases to expected resource availability, or a combination of these (the curves maintain their original shape but move closer together, increasing the overlap). The overlap is also increased through variability. When rare events occur more regularly than predicted, the probability curve changes shape.

Results of the 2024 ProbA shown in the table below indicate negligible unserved energy and load-loss risk in 2026. In 2028, however, WECC's analysis identified over five hours where resources, including imports from neighbors, fall below margins for system reliability.

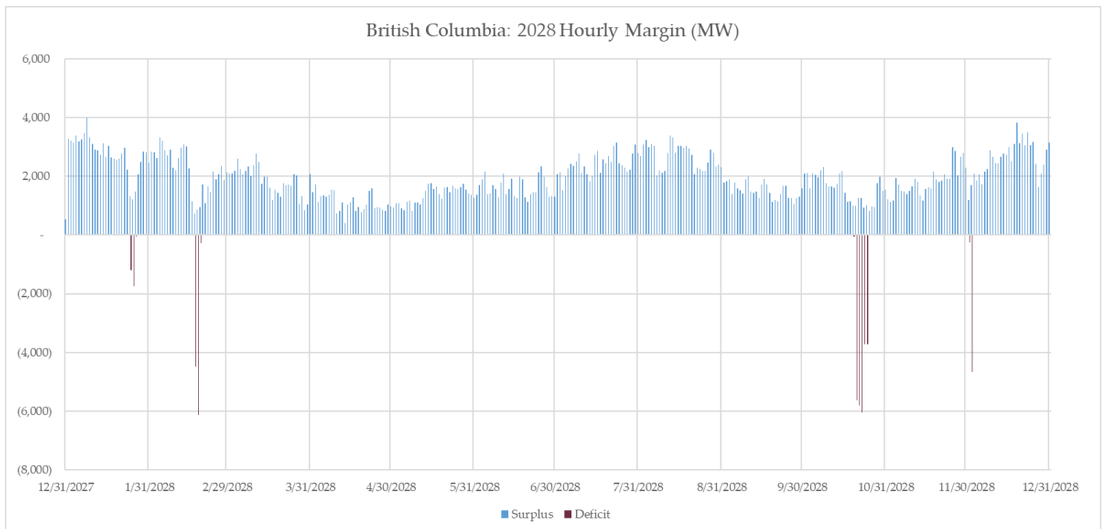
Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	24	0	103,132
EUE (PPM)	0.71	0	1,457
LOLH (hours per year)	0.002	0	5.52
Operable On-Peak Margin	12.7%	16.9%	9.4%

* Provides the 2022 ProbA Results for Comparison

The resource adequacy work performed at WECC uses the MAVRIC model. The MAVRIC model is a convolution based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour. In the resource adequacy environment, the reports produced support NERC's seasonal assessments, LTRA, and Probabilistic Assessment, as well as WECC's WARA.

For both 2026 and 2028, the peak hour occurs in December at HE 19:00. LOLH and EUE are not forecast in 2026 but do appear in 2028. No LOLH or EUE occurs at the peak hour. 88% of the EUE in 2028 occurs overnight between the hours of 23:00 and 4:00.

In 2026, the peak summer hour is HE 17:00 in September, and in 2028 the peak hour is HE 17:00 in August. There is no LOLH projected for 2026 or during peak hours. LOLH occurs in 2028 between the hours of 17:00 and 20:00.



Icicle Plot with Hourly Surplus and Deficits for British Columbia in 2028

WECC's interconnection-wide analysis simulates the probabilistic performance of resource types using historic hourly output data to identify future risk periods. Operators of systems with large hydroelectric storage facilities make adjustments to generation based on the level of demand and shape the water use within the day, week, month, or between years. These actions help posture hydroelectric generation for expected conditions and can reduce energy shortfall risks.

	1	2	3	4	5	6	7	8	9	10	11	12
0	(0)	(5)	-	-	-	-	-	-	-	(10)	-	-
1	(1)	(5)	-	-	-	-	-	-	-	(12)	-	-
2	(1)	(6)	-	-	-	-	-	-	-	(20)	-	-
3	(3)	(5)	-	-	-	-	-	-	-	(14)	(0)	-
4	(0)	(1)	-	-	-	-	-	-	-	(0)	(0)	-
5	-	(0)	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-	-	-	(0)	-	-
8	-	(0)	-	-	-	-	-	-	-	(0)	-	(0)
9	(0)	(0)	-	-	-	-	-	-	-	-	-	(0)
10	-	(0)	-	-	-	-	-	-	-	-	-	(0)
11	-	-	-	-	-	-	-	-	-	-	-	(1)
12	-	-	-	-	-	-	-	-	-	-	-	(3)
13	-	(0)	-	-	-	-	-	-	-	-	-	(5)
14	-	-	-	-	-	-	-	-	-	-	-	(1)
15	-	(0)	-	-	-	-	-	-	-	-	-	(0)
16	-	-	-	-	-	-	-	-	-	-	-	-
17	-	-	-	-	-	-	-	-	-	-	-	-
18	-	-	-	-	-	-	-	-	-	-	-	-
19	-	-	-	-	-	-	-	-	-	-	-	-
20	-	(0)	-	-	-	-	-	-	-	-	-	-
21	-	(0)	-	-	-	-	-	-	-	-	-	-
22	-	(0)	-	-	-	-	-	-	-	(0)	-	(0)
23	-	(2)	-	-	-	-	-	-	-	(5)	-	-

2028 Heat Map EUE (GW) - British Columbia

Demand

BC's average annual load growth in its forecast has fallen to a rate below Alberta's. The peak hour total internal demand for BC occurs in the winter. The peak demand is expected to grow from about 12.0 GW in 2024 to 12.3 GW in 2034, slightly less than in the last forecast. This is an average annual growth rate of 0.28% and a 2.8% load growth over the forecast horizon. BC's load growth is lower due to updated monthly profiles that reflect current trends and aggressive DSM which it includes as a demand reduction in the demand forecasts provided to WECC. Load growth in BC is primarily driven by EV and gas sector load growth and is partially offset by a decline in demand from the forestry sector.

Distributed Energy Resources

BTM DERs are difficult to measure due to data-gathering barriers. BC Hydro has net metering. Net metering for residential and commercial customer projects are up to 100 kW. The net metering program has no annual energy volume target.

Generation

Across WECC, several states and provinces as well as cities and utilities are implementing renewable or carbon-free electricity targets. Retirements tend to be concentrated across three resource types: coal, nuclear, and natural gas. Coal and natural gas units are being retired due to age and emissions.

In BC, hydro and wind resources are being added to the system. The BC Hydro Authority (BCHA) is taking steps to mitigate risks associated with climate change by improving coastal watershed inflow forecasting to an hourly level and increasing investment in capital projects to increase the resiliency of its hydro-dominant portfolio. Drought conditions in BC have led to water conservation measures, such as encouraging generation at facilities located in less drought-impacted areas, revising discharge plans at storage capable sites, and importing power when available to reduce water consumption.

Capacity Transfers

WECC's probabilistic analysis indicates that BC's need for imports is increasing during the assessment period.

Transmission

Three transmission projects with voltage design of 500 kV and higher are planned in the BC region.

Reliability Issues

WECC notes that supply chain issues impacting transformers, circuit breakers, transmission cables, switchgears, and insulators continue to be a risk to generation and transmission development and are an ongoing reliability concern.

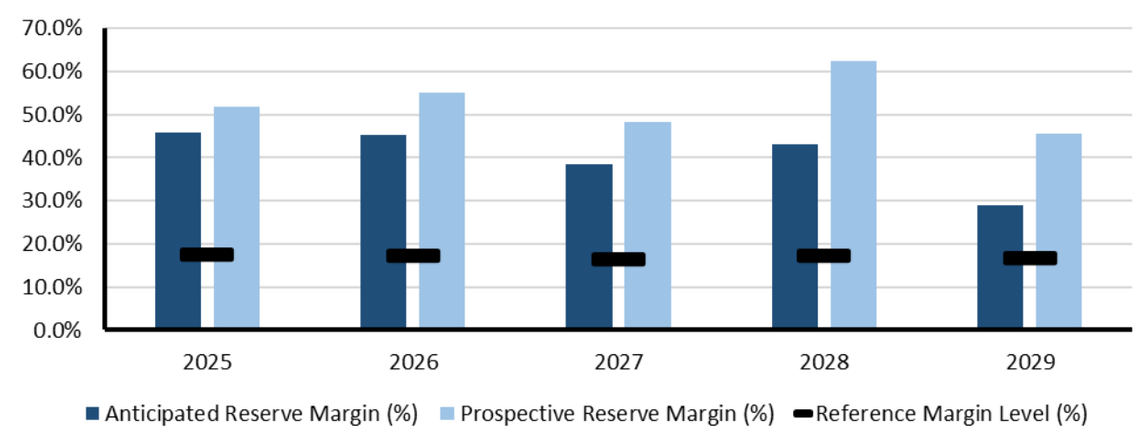


WECC-CA/MX

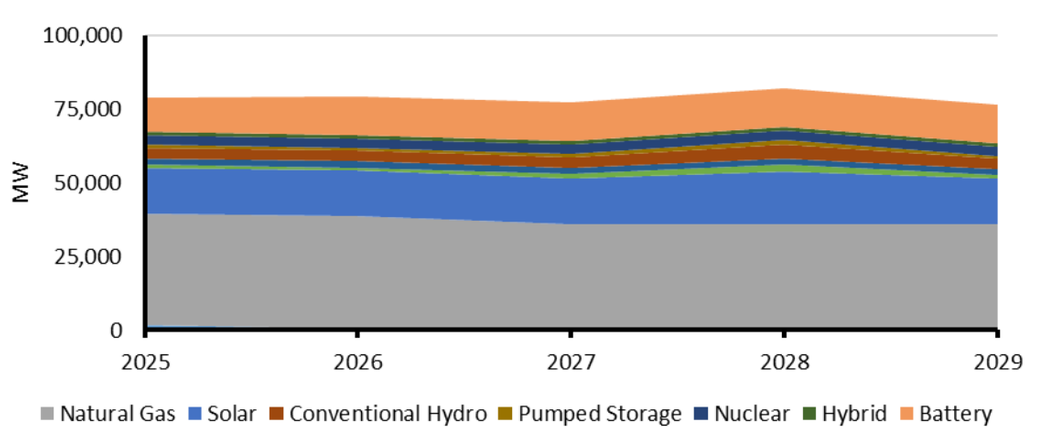
WECC-CA/MX (California/Mexico) is a summer-peaking assessment area in the WECC Regional Entity that includes parts of California, Nevada, and Baja California, Mexico. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 western U.S. states in between.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	56,619	57,274	59,291	60,131	61,289	61,067	62,336	65,876	67,251	69,064
Demand Response	795	797	793	793	793	794	794	794	794	794
Net Internal Demand	55,824	56,477	58,499	59,338	60,496	60,273	61,542	65,082	66,457	68,269
Additions: Tier 1	9,700	11,074	11,128	11,546	11,074	11,990	11,990	12,437	12,047	11,990
Additions: Tier 2	3,349	5,628	5,727	11,483	10,121	17,017	17,017	22,135	23,212	24,650
Additions: Tier 3	9	19	19	22	19	321	321	326	322	321
Net Firm Capacity Transfers	1,509	1,828	2,760	1,953	448	357	342	898	317	314
Existing-Certain and Net Firm Transfers	71,707	70,921	69,827	73,373	66,866	66,142	63,916	68,939	64,533	63,888
Anticipated Reserve Margin (%)	45.8%	45.2%	38.4%	43.1%	28.8%	29.6%	23.3%	25.0%	15.2%	11.1%
Prospective Reserve Margin (%)	51.8%	55.1%	48.2%	62.5%	45.6%	57.9%	51.0%	59.0%	50.2%	47.3%
Reference Margin Level (%)	17.4%	17.4%	16.4%	17.4%	16.6%	16.4%	16.1%	16.3%	14.9%	15.3%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM falls below the RML in Summer 2034, but the RML is covered by the PRM, which includes Tier 2 resource additions.
- Starting in Summer 2029 onward, CA/MX shows a shortfall of existing-certain and net firm transfers. However, with planned generation resource additions the shortfalls are eliminated. Imports may be necessary if the new resources were to be significantly delayed. LOLH and EUE are mitigated over the assessment horizon with the addition of Tier 2 resources and primarily correspond with the evening down ramp of solar and lingering demand after peak.
- The peak hour of demand for CA/MX occurs in the summer. Total internal demand at peak hour is expected to grow from about 56.4 GW in 2024 to 69.1 GW in 2034, a 22.5% load growth over the forecast horizon. The average annual growth rate is 2.07%.
- Diablo Canyon, a 2.2 GW nuclear site, will no longer be retired by 2025 and is now slated to be retired in 2030.

WECC-CA/MX Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	1,572	466	466	465	466
Coal*	1,122	16	16	15	16
Petroleum	185	185	185	184	185
Natural Gas	38,180	38,180	35,565	35,504	35,506
Biomass	726	726	727	726	726
Solar	15,464	15,464	15,501	17,990	15,464
Wind	1,158	1,158	1,428	2,144	1,158
Geothermal	2,004	2,059	2,061	2,056	2,059
Conventional Hydro	3,582	3,582	3,838	4,727	3,582
Pumped Storage	889	889	951	1,710	889
Nuclear	3,282	3,282	3,287	3,283	3,282
Hybrid	32	32	34	39	32
Other	32	32	32	32	32
Battery	12,792	14,111	14,119	14,106	14,111
Total MW	79,898	80,166	78,194	82,967	77,492
Total MW*	79,448	79,716	77,744	82,517	77,042
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

Planning Reserve Margins

The ARM falls below the RML in the summer of 2034. With the addition of Tier 2 resources, reserve margins remain above RML. Starting in Summer 2029 onward, CA/MX shows a shortfall of existing-certain and net firm transfers, meaning that imports may be necessary if new resources were to be significantly delayed.

The California Independent System Operator (CAISO) is responsible for much of the BPS that is in CA/MX. CAISO manages the transmission system, oversees transmission planning, and operates the wholesale electricity market for its territory. Other entities in CA/MX include the Balancing Authority of Northern California (BANC), the Imperial Irrigation District (IID), and Mexico's National Center for Energy Control (CENACE), which operates the connected Baja California system.

CAISO Only: The ARM falling below the RML in Summer 2034 and the shortfall of existing-certain and net firm transfers in Summer 2029 is consistent when looking at CA/MX or solely at CAISO. The RML of CAISO averages 0.7% higher than the CA/MX region RML over the LTRA horizon. This is due to the exclusion of natural gas and coal resource energy contributions from CA/MX entities outside of CAISO. Decreasing baseload generators results in increased variability, which in turn requires a greater RML to maintain the ODITY threshold. However, the gap between the anticipated, prospective, and existing reserve margins and the RML for CAISO are greater than the broader CA/MX region. The proportion of energy availability to anticipated net internal demand is larger for CAISO, accounting for this increase.

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

The resource adequacy work performed at WECC uses the MAVRIC model. The MAVRIC model is a convolution-based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour. In the resource adequacy environment, the reports produced support NERC's seasonal assessments, LTRA, and Probabilistic Assessment, as well as WECC's WARA.

WECC performs a probabilistic analysis to evaluate the probability distribution curves of demand and resource availability together. The area where those curves overlap represents the possibility that there will not be enough resources available to serve the demand, or the "demand at risk." The greater the overlap area, the greater the likelihood that this will be the case. For this analysis, WECC sets the risk tolerance threshold to the ODITY level, meaning that 99.98% of the demand for each hour is covered by available resources (i.e., the area of overlap is equal to no more than .02% of the total area of the demand curve for any given hour). The overlap—the demand at risk—increases when one or both curves move due to increases to expected demand or decreases to expected resource availability, or a combination of these (the curves maintain their original shape but move closer together, increasing the overlap). The overlap is also increased through variability. When rare events occur more regularly than predicted, the probability curve changes shape.

Results of the 2024 ProbA shown in the table below indicate negligible unserved energy and load-loss risk in 2026. After 2026, however, WECC's analysis identified periods of unserved energy and load loss in CA/MX during June through October. Of note, this risk is limited to the Mexico portion of CA/MX (i.e., ProbA results for the CAISO do not indicate LOLH or EUE) until 2029, when the risk extends across the entire assessment area.

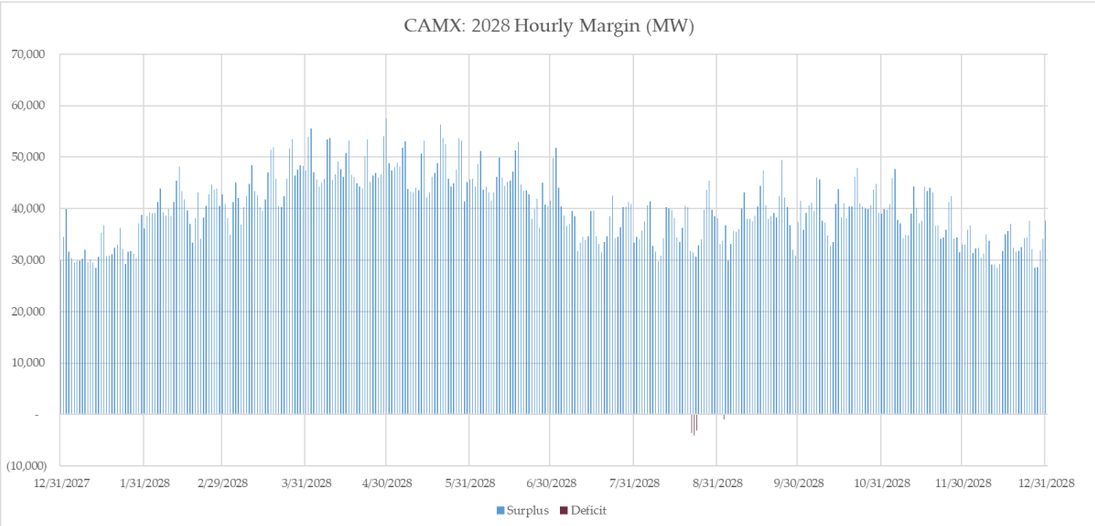
Base Case Summary of Results

	2026*	2026	2028
EUE (MWh)	37,305	0	19,662
EUE (PPM)	136	0	70.07
LOLH (hours per year)	0.721	0	0.38
Operable On-Peak Margin	30.7%	43.2%	41.2%

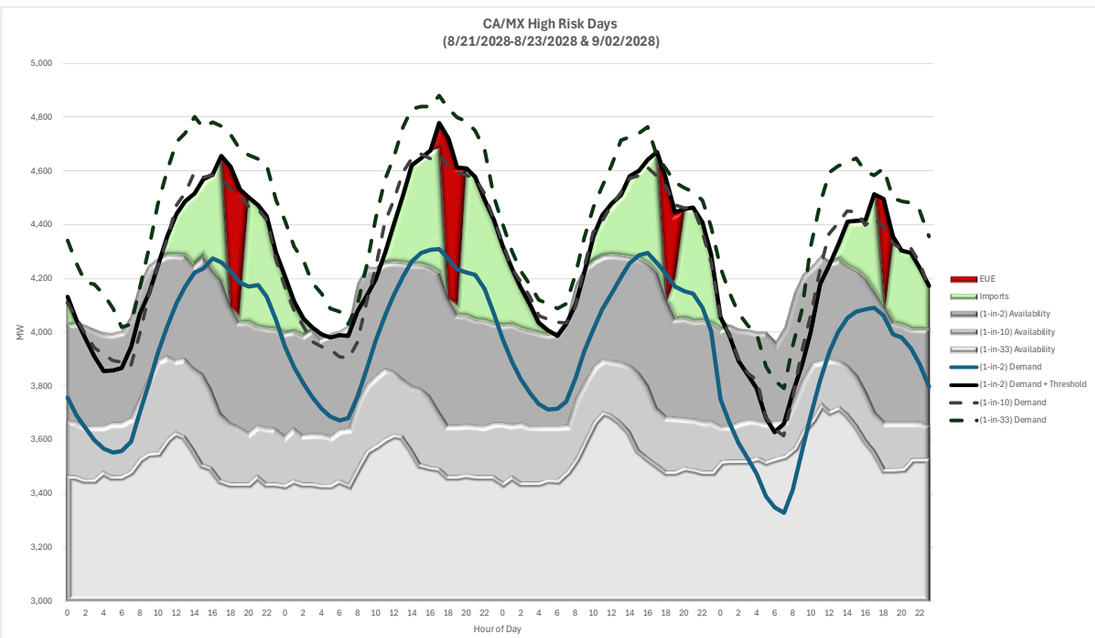
* Provides the 2022 ProbA Results for Comparison

Though the hour and month of peak demand are the same for both CAISO and the broader CA/MX region, CAISO shows the greatest amount of EUE and LOLH in September, whereas CA/MX shows the greatest amount of EUE and LOLH in August. This coincides with the seasonal reduction of solar irradiance in the fall and CAISO having a proportionally larger share of solar resources than the CA/MX region. Excluding regions external to CAISO results in a 96% reduction in LOLH events and EUE over the LTRA horizon.

The hour of peak demand in summer occurs at 5:00 p.m. The hours of highest risk, however, occur during periods after the peak demand hour as solar PV resource output diminishes. There is no LOLH projected for 2026; however in 2028, the ProbA reveals some LOLH between the hours of 5:00 and 8:00 p.m.



Icicle Plot with Hourly Surplus and Deficits for CA/MX in 2028



Demand

The peak demand for CA/MX occurs in the summer. The peak hour for total internal demand is expected to grow from about 56.4 GW in 2024 to 69.1 GW in 2034, a 22.5% load growth over the forecast horizon. The average annual growth rate is 2.07%. Transportation and building electrification are the primary drivers of demand growth.

CAISO Only: The demand forecast for CAISO grows at a slightly higher rate than the broader CA/MX region, with a load growth of 25.2% over the LTRA forecast horizon, and an average annual rate of 2.1%.

Demand-Side Management

A portion of the near-term decline in controllable and dispatchable DR for Summer 2024 is partly driven by regulatory changes in the CA/MX region. This includes making resource adequacy DR crediting adjustments based on historical performance and increasing DR availability requirements. The California Public Utilities Commission (CPUC) determined resource adequacy values of utility DR were overestimated during high load days. In response, the CPUC removed transmission gross-ups and some credits from utility DR resource adequacy values starting in 2024. The CPUC also directed that DR resource adequacy capacity must be available during all days the ISO calls a flex alert or issues a grid warning or on which the governor's office has issued an emergency notice, representing a significant increase in required availability. In addition, the CPUC now requires all DR capacity to be available a minimum of three days per week for at least four hours per day.

For CAISO, energy efficiency and conservation drops significantly when excluding non-CAISO entities from the CA/MX region. The entities outside of CAISO account for an average of 70% of the energy efficiency and conservation DSM for the CA/MX region for the LTRA timeframe.

Distributed Energy Resources

BTM DERs are difficult to measure due to data-gathering barriers. CAISO allows seven DER aggregators as market participants for energy and ancillary services. Additionally, PG&E's Partnership Pilot includes new or existing solar, storage, energy efficiency and demand response used via third party DER providers, vendors, or aggregators.

Generation

There is significantly more solar, wind, and energy storage in planned capacity additions than in the last LTRA. Additionally, several states in the region as well as cities and utilities are implementing renewable or carbon-free electricity targets. Retirements tend to be concentrated across three resource types: coal, nuclear, and natural gas. Coal and natural gas units are being retired due to age and emissions.

Energy Storage
Energy storage is being relied on to help mitigate ramping risk from afternoon net demand caused by increasing penetrations of solar. Many additions are being co-located into hybrid PV + storage but there is also increased standalone battery storage. Learning curves for potential operational challenges to mitigate energy storage risks include further real-world testing under extreme weather conditions, especially extended high temperatures such as during heat waves, and exploring solutions to mitigate the risks of fire.

Capacity Transfers
CA/MX is showing increasing amounts of exports to the northwest, especially during winter months.

Transmission
Seventeen transmission projects with 500 kV and higher are planned.

Reliability Issues
WECC notes that supply chain issues impacting transformers, circuit breakers, transmission cables, switchgears, and insulators continue to be a risk to generation and transmission development and are an ongoing reliability concern.

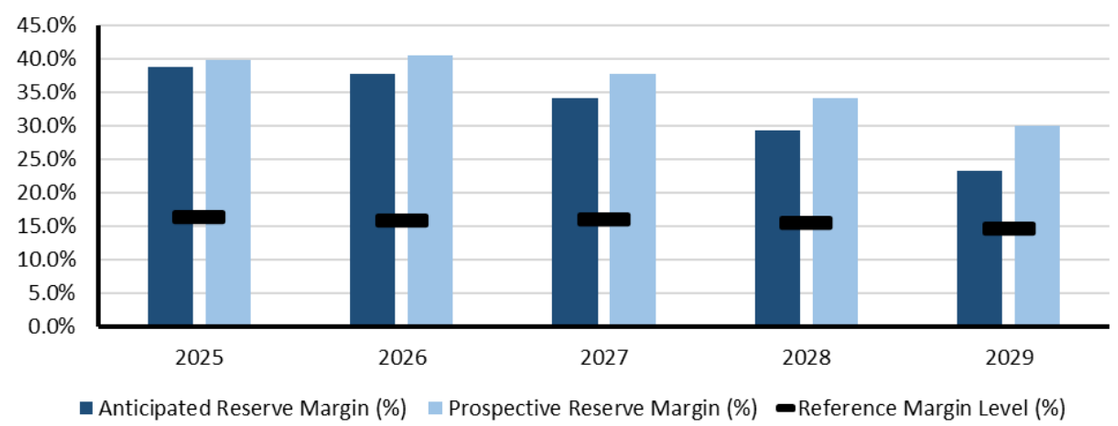


WECC-NW

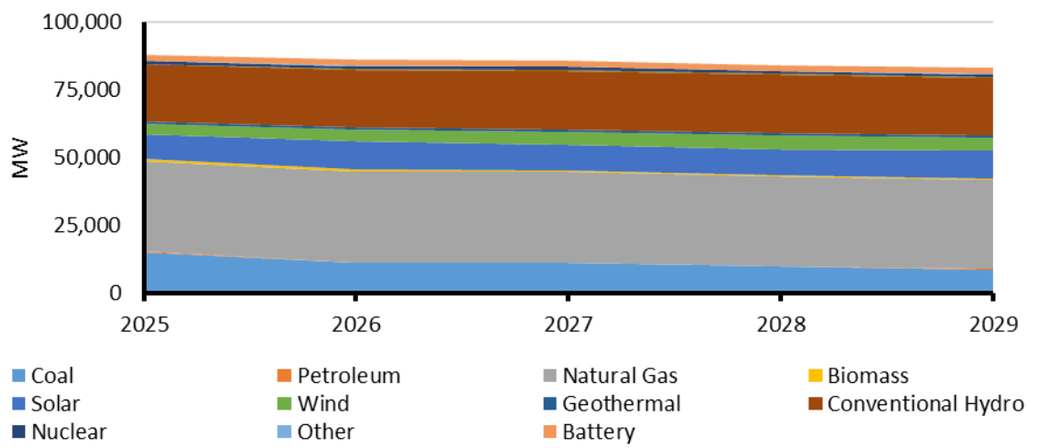
WECC-NW (Northwest) is a summer-peaking assessment area in the WECC Regional Entity. The area includes Colorado, Idaho, Montana, Oregon, Utah, Washington, and Wyoming and parts of California, Nebraska, Nevada, and South Dakota. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 western U.S. states in between.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	68,274	69,745	71,580	73,626	75,079	75,917	76,736	77,462	78,316	78,835
Demand Response	806	808	811	814	806	809	812	814	817	820
Net Internal Demand	67,469	68,936	70,768	72,811	74,273	75,108	75,925	76,647	77,499	78,016
Additions: Tier 1	7,000	9,386	9,295	9,489	9,752	9,752	10,141	10,141	9,915	10,141
Additions: Tier 2	788	1,955	2,628	3,595	5,046	6,593	7,258	7,273	6,935	7,253
Additions: Tier 3	2,945	8,874	14,008	21,247	28,296	33,802	40,239	42,260	41,876	43,809
Net Firm Capacity Transfers	5,627	8,796	9,087	9,863	8,462	6,037	2,783	2,423	2,370	2,140
Existing-Certain and Net Firm Transfers	86,609	85,564	85,605	84,618	81,788	78,094	74,003	73,297	72,810	71,446
Anticipated Reserve Margin (%)	38.7%	37.7%	34.1%	29.3%	23.3%	17.0%	10.8%	8.9%	6.7%	4.6%
Prospective Reserve Margin (%)	39.9%	40.6%	37.8%	34.2%	30.0%	25.7%	20.4%	18.4%	15.7%	13.9%
Reference Margin Level (%)	16.3%	15.8%	15.9%	15.4%	14.7%	14.5%	14.3%	14.2%	14.4%	13.8%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM falls below the RML starting in Summer 2031. With the addition of Tier 2 capacity, the PRM stays above the RML for all years in the LTRA time horizon.
- Starting in Summer 2029 onward, the Northwest shows a shortfall of existing-certain and net firm transfers, meaning that imports may be necessary if new resources were to be significantly delayed. Five GW of baseload resource retirements are anticipated between 2024 and 2028. The energy needs are to be replaced by solar and wind, supported by BESS. Supply chain issues preventing the construction of BESS resources are a concern as they assist in meeting demand during shoulder periods where solar availability is dropping but loads remain high. LOLH and EUE are mitigated over the assessment horizon with the addition of Tier 3 resources.
- The Northwest is dual peaking, so the peak hour can occur in either the summer or the winter. Probabilistic modeling efforts show a peak in the summer for this LTRA. The summer peak for the total internal demand is expected to grow from about 66.4 GW in 2024 to 78.8 GW in 2034, which is lower than in the previous LTRA. This represents a nearly 18.7% load growth over the forecast horizon, with an average growth rate of 1.73%.

WECC-NW Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	**2026**	**2027**	**2028**	**2029**
Coal	14,965	11,031	11,021	9,667	8,761
Coal*	14,661	10,223	10,607	9,349	8,060
Petroleum	321	321	319	319	316
Natural Gas	33,452	33,636	33,304	32,954	32,749
Biomass	729	723	683	683	604
Solar	9,086	10,191	9,350	9,431	10,379
Wind	3,924	4,566	4,939	4,939	4,561
Geothermal	884	934	933	1,007	997
Conventional Hydro	21,003	21,000	21,542	21,522	20,958
Pumped Storage	373	373	375	375	373
Nuclear	1,096	1,096	1,096	1,096	1,096
Other	64	64	64	64	64
Battery	2,084	2,219	2,188	2,188	2,219
Total MW	87,981	86,154	85,814	84,245	83,077
Total MW*	87,679	85,346	85,398	83,926	82,377
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

WECC-NW Assessment

Planning Reserve Margins

The ARM falls below the RML starting in Summer 2031. With the addition of Tier 2 capacity, the PRM stays above the Reference Margin for all years in the LTRA time horizon. Starting in Summer 2029 onward, the Northwest shows a shortfall of existing-certain and net firm transfers, meaning that imports may be necessary if new resources were to be significantly delayed.

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

WECC performs a probabilistic analysis to evaluate the probability distribution curves of demand and resource availability together. The area where those curves overlap represents the possibility that there will not be enough resources available to serve the demand, or the "demand at risk." The greater the overlap area, the greater the likelihood that this will be the case. For this analysis, WECC sets the risk tolerance threshold to the ODITY level, meaning that 99.98% of the demand for each hour is covered by available resources (i.e., the area of overlap is equal to no more than .02% of the total area of the demand curve for any given hour). The overlap—the demand at risk—increases when one or both curves move due to increases to expected demand or decreases to expected resource availability, or a combination of these (the curves maintain their original shape but move closer together, increasing the overlap). The overlap is also increased through variability. When rare events occur more regularly than predicted, the probability curve changes shape.

Results of the 2024 ProbA shown in the table below indicate negligible unserved energy and load-loss risk.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	1,722	0	1
EUE (PPM)	4	0	0
LOLH (hours per year)	0.04	0	0
Operable On-Peak Margin	37.6%	36.1%	27.8%

* Provides the 2022 ProbA Results for Comparison

The resource adequacy work performed at WECC uses the MAVRIC model. The MAVRIC model is a convolution based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour. In the resource adequacy environment, the reports produced support NERC's seasonal assessments, LTRA, and Probabilistic Assessment, as well as WECC's WARA.

Imports to the Northwest from the CA/MX region grow throughout the LTRA forecast horizon. A calm, cloudy, extreme heat event occurring in the Northwest and CA/MX regions simultaneously poses a risk to the Northwest by limiting surplus energy in CA/MX to send northward.

Energy variability is greater in the Northwest than other WECC regions due to the large share of wind and hydro in the portfolio. More variability in energy output requires a greater reserve margin to maintain resource adequacy.

For 2026 and 2028, the peak hour occurs in August at HE 17:00. LOLH and EUE are not forecast in 2026 and only occur for a single hour in 2028. The LOLH occurred in August at HE 19:00, slightly after peak. The LOLH corresponds with the declining solar availability in the evening while demand remains high.

Demand

The Northwest is dual peaking, so the peak hour can occur in either the summer or the winter. Probabilistic modeling efforts show a peak in the summer for this LTRA. The summer peak for the total internal demand is expected to grow from about 66.4 GW in 2024 to 78.8 GW in 2034, which is lower than in the previous plan. This represents a nearly 18.7% load growth over the forecast horizon, with an average growth rate of 1.73%. There are significant differences between balancing areas, with some showing large load growth impacts while others showing a slight decrease in demand. Entities reporting large load growth cite new data centers as a primary driver.

Demand-Side Management

In the Northwest, Idaho Power implements a substantial dispatchable DR program focused on the agricultural sector with its Irrigation Peak Rewards Programs. This allows Idaho Power to remotely turn off specific irrigation pumps a minimum of four times during the summer. Participation varies year to year based on factors such as the availability of water and program parameters. In 2022, the utility lengthened the season and included additional evening hours, which drove some reduction in participation that carried over to the Summer 2024 availability.

PacifiCorp states in its most recent Integrated Resource Plan (IRP) that it hopes to reach 1,123 MW of demand response by 2042 in its preferred portfolio plan, which is a 21% increase by 2042 from its previous plan. PacifiCorp's dispatchable DR programs include residential, small commercial air-conditioner load control, irrigation load management, and 203 MW of interruptible contracts.

The Public Service Company of Colorado (PSCo) also offers a wide array of DR programs, such as Saver's Switch, which is a program where the air-conditioning unit of a customer may be controlled

remotely and cycled during extreme heat events. Peak Day Partners allows for the direct load control and reduction of customers 0.5 MW or greater in size when system peaking conditions are met. The Interruptible Service Credit Option (ISOC) is a program where customers agree to reduce consumption in return for a rate discount with non-compliance being met with a fee.

Distributed Energy Resources
BTM DERs are difficult to measure due to data-gathering barriers. One example is Idaho Power's filing of annual DER Resources Status Reports by customer class and resource type, such as in 2023.

Generation
Five GW of baseload resource retirements are anticipated between 2024 and 2028. The energy needs are to be replaced by solar, wind, and BESS, further increasing variability in the portfolio. Given the retiring of baseload resources, supply chain issues preventing the construction of BESS resources are a concern as they assist in meeting demand during shoulder periods where solar availability is dropping but loads remain high.

There is significantly more solar, wind, and energy storage in planned capacity additions than in the last LTRA. Additionally, several states in the region as well as cities and utilities are implementing renewable or carbon-free electricity targets. Retirements tend to be concentrated across three resource types: coal, nuclear, and natural gas. Coal and natural gas units are being retired due to age and emissions.

Energy Storage
Energy storage is being relied on to help mitigate ramping risk from afternoon net demand due to increasing penetrations of solar. Many additions are being co-located into hybrid PV + storage, but there is also increased standalone battery storage. Learning curves for potential operational challenges to mitigate energy storage risks include further real-world testing under extreme weather conditions, especially extended high temperatures such as during heat waves, and exploring solutions to mitigate the risks of fire.

Capacity Transfers
The Northwest is showing greatly increasing import needs over the 10-year time horizon, especially in the winter months. Most of the imports in the model simulations come from CA/MX, with a smaller portion coming from BC**.**

Transmission
Twelve transmission projects with 500 kV and higher are planned.

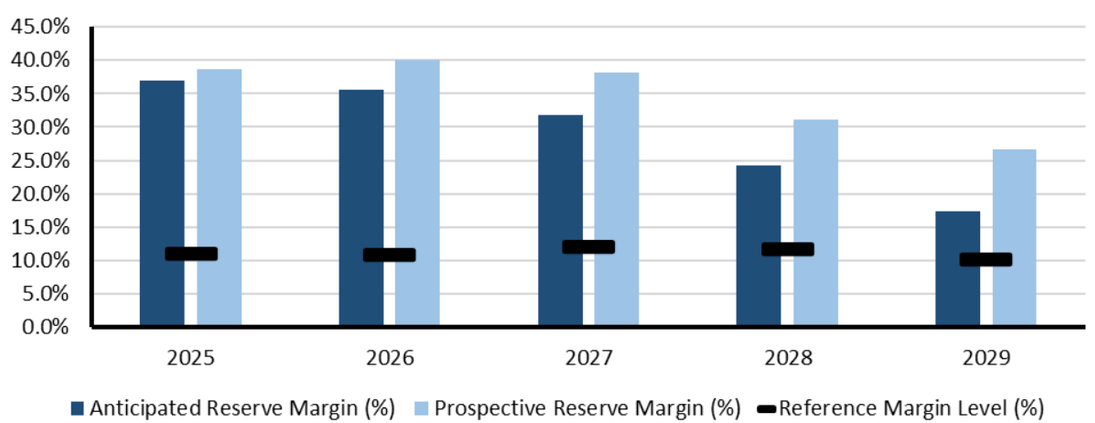


WECC-SW

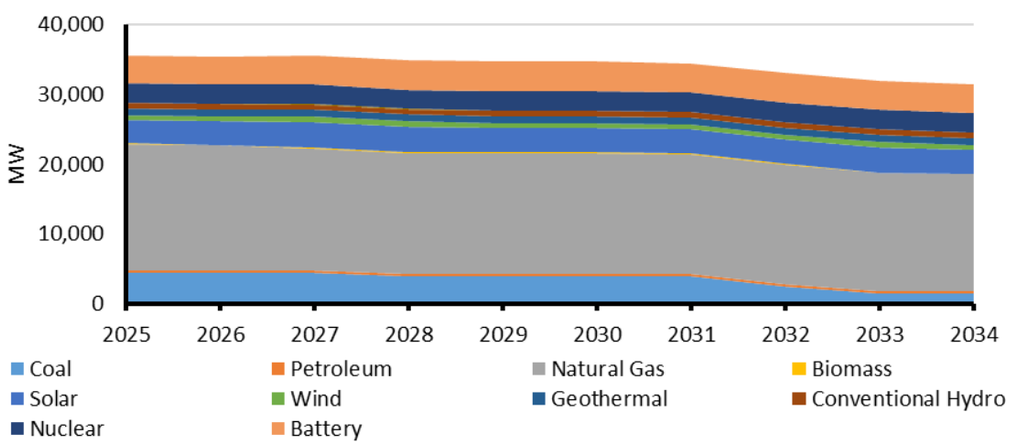
WECC-SW (Southwest) is a summer-peaking assessment area in the WECC Regional Entity. It includes Arizona, New Mexico, and part of California and Texas. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada as well as the northern portion of Baja California in Mexico and all or portions of the 14 Western U.S. states in between.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	28,347	29,184	30,098	30,905	31,684	32,401	33,082	33,676	34,301	34,886
Demand Response	417	392	396	424	373	389	392	396	424	373
Net Internal Demand	27,930	28,792	29,702	30,481	31,311	32,012	32,690	33,279	33,876	34,512
Additions: Tier 1	5,140	5,251	5,656	5,656	5,557	5,557	5,557	5,557	5,656	5,557
Additions: Tier 2	475	1,305	1,899	2,079	2,932	2,932	2,966	2,984	3,221	2,984
Additions: Tier 3	40	677	1,148	2,589	3,113	4,438	5,734	7,479	8,960	10,027
Net Firm Capacity Transfers	2,651	3,556	3,554	2,966	2,045	928	716	320	322	0
Existing-Certain and Net Firm Transfers	33,110	33,784	33,491	32,212	31,187	30,070	29,644	27,787	26,645	25,956
Anticipated Reserve Margin (%)	36.9%	35.6%	31.8%	24.2%	17.4%	11.3%	7.7%	0.2%	-4.7%	-8.7%
Prospective Reserve Margin (%)	38.6%	40.1%	38.2%	31.1%	26.7%	20.4%	16.8%	9.2%	4.9%	0.0%
Reference Margin Level (%)	11.0%	10.8%	12.0%	11.7%	10.2%	10.1%	9.9%	9.7%	10.8%	9.4%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM does not fall below the RML until Summer 2031, and the PRM falls below the RML in Summer 2032.
- Starting in Summer 2028 onward, the Southwest shows a shortfall of existing-certain and net firm transfers, meaning that imports may be necessary if new resources were to be significantly delayed. LOLH and EUE are mitigated over the assessment horizon with the addition of Tier 3 resources. Both supply chain and zoning issues have been cited as inhibiting project completion.
- The Southwest's peak demand in summer is forecast to grow at an average of 2.49%. Over the LTRA horizon, the forecast grows by a total of 27.8%, which is the highest forecasted growth in the WECC region. The Southwest's total internal demand forecast is nearly the same as last year's over the near and medium term, with a slight drop from last year's in the longer term, growing from a summer peak of 27.3 GW in 2024 to 34.9 GW by 2034.
- Natural gas derates during extreme heat events are a risk for the Southwest as these resources make up a large share of the resource portfolio in the area.

WECC-SW Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	4,436	4,436	4,432	3,939	3,941
Coal*	4,432	4,432	4,148	3,655	3,657
Petroleum	323	323	322	322	323
Natural Gas	18,165	17,933	17,520	17,323	17,343
Biomass	82	82	82	82	82
Solar	3,354	3,354	3,628	3,628	3,479
Wind	628	695	799	799	695
Geothermal	1,047	1,047	1,047	1,047	1,047
Conventional Hydro	721	721	721	721	721
Pumped Storage	104	104	104	104	104
Nuclear	2,724	2,724	2,711	2,711	2,724
Battery	4,016	4,061	4,226	4,226	4,240
Total MW	35,599	35,479	35,593	34,902	34,698
Total MW*	35,595	35,475	35,309	34,618	34,414
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

WECC-SW Assessment

Planning Reserve Margins

The ARM does not fall below the RML until Summer 2031, and the PRM falls below the RML in Summer 2032. This indicates that imports may be necessary if new resources were to be significantly delayed, as Tier 3 resources will be required for reserve margins to meet the RML. Starting in Summer 2028 onward, the Southwest shows a shortfall of existing-certain and net firm transfers, meaning that imports may be necessary if new resources were to be significantly delayed.

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

WECC performs a probabilistic analysis to evaluate the probability distribution curves of demand and resource availability together. The area where those curves overlap represents the possibility that there will not be enough resources available to serve the demand, or the "demand at risk." The greater the overlap area, the greater the likelihood that this will be the case. For this analysis, WECC sets the risk tolerance threshold to the ODITY level, meaning that 99.98% of the demand for each hour is covered by available resources (i.e., the area of overlap is equal to no more than .02% of the total area of the demand curve for any given hour). The overlap—the demand at risk—increases when one or both curves move due to increases to expected demand or decreases to expected resource availability, or a combination of these (the curves maintain their original shape but move closer together, increasing the overlap). The overlap is also increased through variability. When rare events occur more regularly than predicted, the probability curve changes shape.

Results of the 2024 ProbA shown in the table below indicate negligible unserved energy and load-loss risk.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	84	0	19
EUE (PPM)	1	0	0.13
LOLH (hours per year)	0.003	0	0.00
Operable On-Peak Margin	18.3%	33.8%	22.5%

* Provides the 2022 ProbA Results for Comparison

The resource adequacy work performed at WECC uses the MAVRIC model. The MAVRIC model is a convolution based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour. In the resource adequacy environment, the reports produced support NERC's seasonal assessments, LTRA, and Probabilistic Assessment. Another report produced is a WECC report called the WARA.

For 2026 and 2028, the peak hour occurs in July at HE 17:00. LOLH and EUE are not anticipated in 2026 and are minimal in 2028. LOLH was only observed in August at HE 19:00. The LOLH corresponds with the evening down ramp of solar and lingering demand after peak.

Due to the significant share of natural gas resources in the Southwest portfolio, a concern for the Southwest is natural gas derates during extreme heat events. A strategy to assist with resource planning is to construct derate curves for natural gas resources as a function of temperature. Resource procurement practices have also changed to focus on adding resources that have no dependence on temperature.

Demand

The Southwest has the highest rate of load growth in the Western Interconnection for the LTRA horizon. Large industrial and commercial load additions, such as data centers, have been cited as the reason for this growth.

The Southwest's peak demand in summer is forecast to grow at an average of 2.49%. Over the LTRA horizon, the forecast grows by a total of 27.8%. The Southwest's total internal demand forecast is nearly the same as last year's over the near and medium term, with a slight drop from last year's in the longer term, growing from a summer peak of 27.3 GW in 2024 to 34.9 GW by 2034.

Demand-Side Management

Arizona Public Service (AZPS) has numerous DSM pilots and programs, such as the Residential Energy Storage Pilot and Commercial Advanced Rooftop Controls. In the Residential Energy Storage Pilot, residents may install a small BESS at their residence and enable it to be dispatched by AZPS in response to grid needs 100 times a year, but not below 20% of its capacity. AZPS is projecting an almost 50 MW increase in available DR from 2024 to 2025.

In 2023, the Salt River Project (SRP) subscribed 87 MW of DR capability through the installation of 76,143 smart thermostats and enrolled over 500 businesses as interruptible customers providing 41 MW of controllable DR capacity. The SRP aims to achieve 300 MW of dispatchable DR capability by 2035.

The Public Service Company of New Mexico (PNM) operates the Peak Saver and Power Saver programs. Peak Saver reduces demand from commercial customers greater than 50 kW in size during peak demand periods, and the Power Saver program cycles the compressor of air conditioners to reduce peak demand in the summer. One hundred hours of curtailment are available for both

programs with a four-hour limit per curtailment, and it was found that both programs combined reduce peak demand by an average of 45 MW per curtailment event.

El Paso Electric (EPE) operates a smart thermostat program to cycle air conditioners with the potential to achieve 50 MW of relief by 2040.

Additionally, AZPS, SRP, PNM, and EPE all offer time of use (TOU) rate structures for their customers.

Distributed Energy Resources
BTM DERs are difficult to measure due to data gathering barriers. In the Southwest, NV Energy has added DER plans to its triennial IRPs.

Generation
Southwest entities have slightly under 10 GW of nameplate capacity Tier 1 solar resources planned between 2024 and 2028. Supply chain issues resulting in project delays or failure of completion are a concern for the Southwest. Zoning issues prohibiting the construction of new solar assets are also an issue.

There is significantly more solar, wind, and energy storage in planned capacity additions than in the last LTRA. Additionally, several states in the region as well as cities and utilities are implementing renewable or carbon-free electricity targets. Retirements tend to be concentrated across three resource types: coal, nuclear, and natural gas. Coal and natural gas units are being retired due to age and emissions.

Energy Storage
Energy storage is being relied on to help mitigate ramping risk from afternoon net demand caused by increasing penetrations of solar. Many additions are being co-located into hybrid PV + storage, but there is also increased standalone battery storage. Learning curves for potential operational challenges to mitigate energy storage risks include further real-world testing under extreme weather conditions, especially extended high temperatures such as during heat waves, and exploring solutions to mitigate the risks of fire.

Capacity Transfers
The Southwest is not showing a significant increase in reliance on imports in the model, with peak exports occurring between 5:00 p.m. and 10:00 p.m.

Transmission
Twelve transmission projects with 500 kV and higher are planned.

Reliability Issues
WECC notes that supply chain issues impacting transformers, circuit breakers, transmission cables, switchgears, and insulators continue to be a risk to generation and transmission development and are an ongoing reliability concern.

Demand Assumptions and Resource Categories

Demand (Load Forecast)	
Total Internal Demand	This is the peak hourly load[39] for the summer and winter of each year.[40] Projected total internal demand is based on normal weather (50/50 distribution)[41] and includes the impacts of distributed resources, EE, and conservation programs.
Net Internal Demand	This is the total internal demand reduced by the amount of controllable and dispatchable DR projected to be available during the peak hour. Net internal demand is used in all reserve margin calculations.

Load Forecasting Assumptions by Assessment Area			
Assessment Area	**Peak Season**	**Coincident / Noncoincident[42]**	**Load Forecasting Entity**
MISO	Summer	Coincident	MISO LSEs
MRO-Manitoba Hydro	Winter	Coincident	Manitoba Hydro
MRO-SaskPower	Winter	Coincident	SaskPower
MRO-SPP	Summer	Noncoincident	SPP LSEs
NPCC-Maritimes	Winter	Noncoincident	Maritimes sub-areas
NPCC-New England	Summer	Coincident	ISO-NE
NPCC-New York	Summer	Coincident	NYISO
NPCC-Ontario	Summer	Coincident	IESO
NPCC-Québec	Winter	Coincident	Hydro-Québec
PJM	Summer	Coincident	PJM
SERC-East	Summer	Noncoincident	SERC LSEs
SERC-Florida Peninsula	Summer	Noncoincident	
SERC-Central	Summer	Noncoincident	
SERC-Southeast	Summer	Noncoincident	
Texas RE-ERCOT	Summer	Coincident	ERCOT
WECC-AB	Winter	Noncoincident	WECC BAs, aggregated by WECC
WECC-BC	Winter	Noncoincident	
WECC-CA/MX	Summer	Noncoincident	
WECC-NW	Summer	Noncoincident	

[39] Glossary of Terms Used in NERC Reliability Standards.

[40] The summer season represents June–September and the winter season represents December–February. In this assessment, the year of a winter period is referred to by the year of the month of December (e.g., Winter 2025 is December 2025 – February 2026).

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

[42] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval. This is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year.

Load Forecasting Assumptions by Assessment Area			
Assessment Area	**Peak Season**	**Coincident / Noncoincident[42]**	**Load Forecasting Entity**
WECC-SW	Summer	Noncoincident	

Resource Categories

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

Anticipated Resources[43]

- Existing-certain generating capacity: includes capacity to serve load during period of peak demand from commercially operable generating units with firm transmission or other qualifying provisions specified in the market construct.
- Tier 1 capacity additions: includes capacity that is either under construction or has received approved planning requirements
- Firm capacity transfers (Imports minus Exports): transfers with firm contracts
- Less confirmed retirements[44]

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

- Existing-other capacity: includes capacity to serve load during period of peak demand from commercially operable generating units without firm transmission or other qualifying provision specified in the market construct. Existing-other capacity could be unavailable during the peak for a number of reasons.
- Tier 2 capacity additions: includes capacity that has been requested but not received approval for planning requirements
- Expected (non-firm) capacity transfers (imports minus exports): transfers without firm contracts but a high probability of future implementation.
- Less unconfirmed retirements.[45]

[43] Projected capacities are inputs to reserve margin calculations and probabilistic assessments. Projections are dependent on official retirement notices to system operators. If no notice is given, capacity projections assume no retirements, even if established trends for resource retirements show declines over past years

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

[45] Capacity that is expected to retire based on the result of an assessment area generator survey or analysis. This capacity is aggregated by fuel type.

Resource Categories

Generating Unit Status: Status at time of reporting:

- Existing: It is in commercial operation.
- Retired: It is permanently removed from commercial operation.
- Mothballed: It is currently inactive or on standby but capable for return to commercial operation. Units that meet this status must have a definite plan to return to service before changing the status to "Existing" with capacity contributions entered in "Expected-Other." Once a "mothballed" unit is confirmed to be capable for commercial operation, capacity contributions should be entered in "Expected-Certain."
- Cancelled: planned unit (previously reported as Tier 1, 2, or 3) that has been cancelled/removed from an interconnection queue.
- Tier 1: A unit that meets at least one of the following guidelines (with consideration for an area's planning processes):[46]
  - Construction complete (not in commercial operation)
  - Under construction
  - Signed/approved Interconnection Service Agreement (ISA)
  - Signed/approved Power Purchase Agreement (PPA) has been approved
  - Signed/approved Interconnection Construction Service Agreement (CSA)
  - Signed/approved Wholesale Market Participant Agreement (WMPA)
  - Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to Vertically Integrated Entities)
- Tier 2: A unit that meets at least one of the following guidelines (with consideration for an area's planning processes):[47]
  - Signed/approved Completion of a feasibility study
  - Signed/approved Completion of a system impact study
  - Signed/approved Completion of a facilities study
  - Requested Interconnection Service Agreement
  - Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to RTOs/ISOs)
- Tier 3: A units in an interconnection queue that do not meet the Tier 2 requirement.

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

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

Methods and Assumptions

How NERC Defines BPS Reliability

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

- **Adequacy:** The ability of the 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

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

- Public appeals
- Interruptible demand that the end-use customer makes available to its LSEs via contract or agreement for curtailment[48]
- Voltage reductions (sometimes referred to as "brownouts" because incandescent lights will dim as voltage is lowered, sometimes as much as 5%)
- Rotating blackouts (The term "rotating" is used because each set of distribution feeders is interrupted for a limited time, typically 20–30 minutes, and then those feeders are put back in service and another set is interrupted, rotating the outages among individual feeders.)

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

The BES is a defined subset of the BPS that includes all facilities necessary for the reliable operation and planning of the BPS.[49] NERC Reliability Standards are intended to establish requirements for BPS owners and operators so that the BES delivers an adequate level of reliability (ALR),[50] which is defined by the following characteristics.

- **Adequate Level of Reliability:** It is the state that the design, planning, and operation of the BES will achieve when the following reliability performance objectives are met:
  - The BES does not experience instability, uncontrolled separation, cascading,[51] and/or voltage collapse under normal operating conditions or when subject to predefined disturbances.[52]
  - BES frequency is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.
  - BES voltage is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.
  - Adverse reliability impacts on the BES following low-probability disturbances (e.g., multiple BES contingences, unplanned/uncontrolled equipment outages, cyber security events, malicious acts) are managed.

[48] Interruptible demand (or interruptible load) is a term used in NERC Reliability Standards. See Glossary of Terms used in Reliability Standards: NERC Glossary of Terms
[49] BES Definition
[50] NERC Informational Filing (to FERC) on the Definition of Adequate Level of Reliability, Docket Number RR06-1, May 10, 2013.
[51] 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."
[52] 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."

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

How NERC Evaluates Reserve Margins in Assessing Resource Adequacy

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

NERC assesses resource adequacy by evaluating each assessment area's PRMs 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-peak resource capacity reflects expected output at the hour of peak demand. Because the electrical output of VERs (e.g., wind and solar) depend on weather conditions, on-peak capacity contributions are less than nameplate capacity. Based on the five-year projected reserves compared to the established RMLs, NERC determines the risk associated with the projected level of reserve and concludes in terms of the following:

Adequate: The ARM is greater than RML.

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

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

Metrics for Probabilistic Evaluation Used in this Assessment

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

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

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

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

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

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

NERC is not aware of any planning criteria in North America based on EUE; however, in Australia, the Australian Energy Market Operator is responsible for planning using 0.002% (20 ppm) EUE as their energy adequacy requirement.[53] This requirement incorporates economic factors based on the risk of load shedding and the value of load loss along with the load-loss reliability component.

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

Normal Risk: Negligible amounts of LOLH and EUE.

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

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

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 its forecasts on an annual basis or as its resource planning requires. In recent years, the difference between forecast and actual peak demands have decreased, reflecting a trend toward improving forecasting accuracy.

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

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

Future Transmission Project Categories

- **Under Construction:** Construction of the line has begun.
- **Planned** (any of the following):
  - Permits have been approved to proceed
  - Design is complete
  - Needed in order to meet a regulatory requirement

- **Conceptual** (any of the following):
  - A line projected in the transmission plan
  - A line that is required to meet a NERC TPL standard or 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”

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

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

Reference Margin Levels for Each Assessment Area (2025–2029)					
Assessment Area	**Reference Margin Level**	**Assessment Area Terminology**	**Requirement?**	**Methodology**	**Reviewing or Approving Body**
MISO	2024-2025 Summer: 9.0% Fall: 14.2% Winter: 27.4% Spring (2025): 26.7%	Planning Reserve Margin	Yes: Established Annually[54]	0.1 day/Year Loss of Load Expectation (LOLE)	MISO
MRO-Manitoba Hydro	12.0%	Reference Margin Level	No	0.1 day/Year LOLE	Reviewed by the Manitoba Public Utilities Board
MRO-SaskPower	15.0%	Reference Margin Level	No	EUE and Deterministic Criteria	SaskPower
MRO-SPP	19.0%	Resource Adequacy Requirement	Yes: studied on Biennial Basis	0.1 day/Year LOLE	SPP Staff, Stakeholders, SPP Regional State Committee.
NPCC-Maritimes	20.0%[55]	Reference Margin Level	No	0.1 day/Year LOLE	Maritimes Sub-areas; NPCC
NPCC-New England	11.3–12.7%	Installed Capacity Requirement	Yes: three year requirement established annually	0.1 day/Year LOLE	ISO-NE, NPCC Criteria
NPCC-New York	15.0%[56]	Installed Reserve Margin	Yes: one year requirement, established annually by NYSRC based on full installed capacity values of resources	0.1 day/Year LOLE	NYSRC, NPCC Criteria
NPCC-Ontario	8.6–19.5%	Reserve Margin Requirement	Yes: established annually for all years	0.1 day/Year LOLE	IESO, NPCC Criteria
NPCC-Québec	10.9–11.8%	Reference Margin Level	No: established Annually	0.1 day/Year LOLE	Hydro-Québec, NPCC Reliability Coordinating Committee
PJM	17.6–17.7%	Installed Reserve Margin	Yes: established Annually for each of three future years	0.1 day/Year LOLE	PJM Board of Managers, ReliabilityFirst BAL-502-RFC-02 Standard
SERC-Central	15.0%[57]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities

[54] In MISO, the states can override the MISO PRM.

[55] The 20% RML is used by the individual jurisdictions in the Maritimes area with the exception of Prince Edward Island, which uses a margin of 15%. Accordingly, 20% is applied for the entire area.

[56] The NERC LTRA RML for NY is 15%; however, there is no PRM criteria in New York. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. Additionally, the NYISO uses probabilistic assessments to evaluate its system's resource adequacy against the LOLE resource adequacy criterion of 0.1 days/year. However, New York requires LSEs to procure capacity for their loads equal to their peak demand plus an IRM. The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). NYSRC approved the 2025/2026 IRM at 24.4%. All values in the IRM calculation are based upon full installed capacity (ICAP) MW values of resources, and it is identified based on annual probabilistic assessments and models for the upcoming capability year.

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

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

Reference Margin Levels for Each Assessment Area (2025–2029)					
Assessment Area	**Reference Margin Level**	**Assessment Area Terminology**	**Requirement?**	**Methodology**	**Reviewing or Approving Body**
SERC-East	15.0%[58]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities
SERC-Florida Peninsula	15.0%[59]	Reliability Criterion	No: Guideline	0.1 day/Year LOLP	Florida Public Service Commission
SERC-Southeast	15.0%[60]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities
Texas RE-ERCOT	13.75%	Target Reserve Margin	No	0.1 day/Year LOLE plus adjustment for non-modeled market considerations	ERCOT Board of Directors
WECC-AB	9.0–13.6%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[61]
WECC-BC	9.8–12.8%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[53]
WECC-CA/MX[62]	14.9–17.4%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[53]
WECC-NW	13.8–16.3%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[53]
WECC-SW	9.4–12.0%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[53]

[58] SERC does not provide RMLs or resource requirements for its sub-areas. However, SERC members perform individual assessments to comply with any state requirements.
[59] 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.
[60] SERC does not provide RMLs or resource requirements for its sub-areas. However, SERC members perform individual assessments to comply with any state requirements.
[61] WECC's RML in this table is for the hour of peak demand. Some hours in the year require a higher reserve margin to meet the 0.02% reliability criteria due to the variability in resource availability and resource performance characteristics.
[62] California is the only state in the Western Interconnection that has a wide-area RML, currently 17.5%: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage,

Recommendations and ERO Actions Summary

In addition to the recommendations in the Executive Summary, NERC recommends continued progress in areas identified previously in NERC's LTRA and other assessment reports. The ERO, industry, vendors/manufacturers, and stakeholders should continue acting on the following recommendations to inform system and operations planning, develop the transmission network, and address resource performance issues attributed to IBR characteristics, cold weather, and fuel supply limitations. The ERO has a range of activities underway to monitor, assess, and reduce long-term BPS reliability risks. The selected ERO activities summarized below will result in new or enhanced Reliability Standards requirements, reliability guidelines, resources, or significant findings and actionable steps for stakeholders to address reliability risks.

LTRA Recommendations and Ongoing ERO Actions

Add new resources with needed reliability attributes and make existing resources more dependable.

1. **Use enhanced resource adequacy and energy risk assessments for determining resource needs:** PRMs are not sufficient for measuring resource adequacy for most areas because VERs and generator fuel supply issues expose additional energy risks. Resource Planners and wholesale markets need to use enhanced modeling that accounts for energy risks, such as all-hours probabilistic assessments. Multi-metric criteria applied to results from probabilistic studies that include load loss, unserved energy, event magnitude, and event duration will support achieving the levels of reliability that are required for modern society.
2. **Address performance deficiencies with existing and future inverter-based resources:** Reliably integrating IBRs onto the grid is paramount, and evidence indicates that the risk of grid vulnerabilities from interconnection practices and IBR performance issues are growing. IBRs include most solar and wind generation as well as new BESS or hybrid generation and account for 85% of the new generation in development for connecting to the BPS. IBRs respond to disturbances and dynamic conditions based on programmed logic and inverter controls. The tripping of BPS-connected solar PV generating units and other control system behavior during grid faults has caused sudden loss of generation resources (over wide areas in some cases). Industry experience with unexpected tripping of BPS-connected solar PV generation units can be traced back to the 2016 Blue Cut fire in California, and similar events have occurred in new geographic areas as recently as the summer of 2023.[63] A common thread with these events is the lack of IBR ride-through capability that causes a minor system disturbance to become a major disturbance. Based on the findings of a recent NERC alert, more ride-through and ERS capabilities can be enabled within existing solar PV resources to improve performance and support the reliable operation of the BPS.[64] Industry adoption of the recommended practices set forth in NERC reliability guidelines and the NERC alert will reduce risks from IBR performance issues to the grid as NERC also develops mandatory Reliability Standards based on those reliability guidelines. It is also critically important for interconnection processes to include accurate modeling and studies requirements.[65] Guided by NERC's comprehensive Inverter-Based Resources Strategy and in response to FERC Order No. 901, the ERO, industry, and manufacturers should take additional steps to ensure that IBRs operate reliably and that the system is planned with due consideration for their characteristics.[66,67]
3. **Improve the performance of the generating fleet in extreme cold temperatures:** The ERO and industry need to complete enhanced requirements for generator cold-weather performance to address reliability related findings from the FERC, NERC, and Regional Entity joint staff inquiry into the February 2021 cold weather grid outages.[68] Revisions to Reliability Standard EOP-012-2 will improve the effectiveness of the standard and speed the implementation of corrective actions necessary to address unacceptable freezing issues. Findings of the inquiry into Winter Storm Elliott (December 2022) reinforce the urgency of this effort.[69]

[63] See the ERO's extensive IBR event reporting here: NERC Major Event Reports
[64] The NERC Level 2 alert to gather data from solar PV resource owners and issue recommendations can be found here: *Industry Recommendation: Inverter-Based Resource Performance Issues*.
[65] NERC's comprehensive initiatives to reduce IBR risks are detailed here: IBR Quick Reference Guide
[66] NERC IBR Activities
[67] Order No. 901 Work Plan
[68] *The February 2021 Cold Weather Outages in Texas and the South Central United States | FERC, NERC and Regional Entity Staff Report*
[69] *Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott*

LTRA Recommendations and Ongoing ERO Actions

4. **Mitigate fuel-related risks to electricity generation (fuel assurance):** In addition to serving as base and intermediate-load plants, natural-gas-fired generation has become a necessary balancing resource that enables reliable integration of VERs into the dispatch. As a result, the BES has never been more dependent upon the round-the-clock continuity of just-in-time natural gas delivery. The past two winters have seen interruptions of natural gas delivery to generators that resulted in energy deficiencies. Collaborative assessments involving NERC, the Regional Entities, the National Labs, and natural gas and electric power industry participants are needed to identify natural gas fuel supply needs for reliable operation of the BPS. NERC strongly endorses actions to establish reliability rules for the natural gas infrastructure necessary to support the grid as recommended in the Winter Storm Elliott report. Additionally, as part of future transmission and resource planning studies, planning entities will need to more fully understand how impacts to the natural gas transportation system can impact electricity reliability. The NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System,* provides planning guidance.[70]

Initiative	Description	Product/Reliability Solution
Cold Weather Reliability Standards and Activities	New cold weather Reliability Standards adopted by the NERC Board of Trustees in June 2021 went into effect in the United States in 2023. Generator Owners and Generator Operators are required to implement plans for cold weather preparedness and provide cold weather operating parameters to their Reliability Coordinators, Transmission Operators, and Balancing Authorities for use in operating plans. Additional Reliability Standard requirements have been developed by NERC and industry to address further recommendations of the *FERC-NERC-Regional Entity staff report—The February 2021 Cold Weather Outages in Texas and Southcentral United States.* The NERC Board adopted these requirements in October 2023 and directed NERC to file them with regulatory authorities for approval and industry implementation. NERC and the industry are currently developing the remaining Reliability Standard enhancements to address the staff report. Refer to *Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination* on NERC's standards development page.[71]	Reliability Standards NERC Alerts Event Analysis Reports Lessons Learned
Inverter-Based Resources Strategy	NERC's IBR strategy includes four key focus areas: Risk Analysis, Interconnection Process Improvements, Sharing Best Practices and Industry Education, and Regulatory Enhancements. The statuses of NERC's extensive activities in each area are described in detail in the *IBR Activities Reference Guide*.[72] NERC has investigated and analyzed IBR performance issues during grid disturbances dating back to 2016. Since that time, NERC and its technical groups have published a range of reliability guidelines for studying, modeling, controlling, and interconnecting IBRs. In partnership with many experts from across the industry, NERC maintains an active campaign of education, awareness, and outreach to support its strategy and reduce IBR performance risks. NERC and the RSTC recognized that Reliability Standard requirements would be needed as part of a comprehensive approach to reliability and undertook a full review of existing standards to identify gaps. Several reliability standards projects were initiated following this review. In October 2023, FERC issued Order No. 991, which provided clear direction for the industry to develop requirements that address reliability gaps related to IBR in data sharing, model validation, planning and operational studies, and performance requirements.	Reliability Standards NERC Alerts Reliability Guidelines Event Analysis Reports Lessons Learned Educational Webinars

[70] Informed by severe weather events of the past two winters, the 2023 triennial review of the NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System*, incorporated the *Design Basis for Natural Gas Study* developed by the ERO in 2022. The revised Guideline also identifies as fuel risks requiring evaluation many of the scenarios industry has encountered during recent periods of extreme cold weather and high demand for natural gas. The revised guideline is under review with the Reliability and Security Technical Committee. The approved and revised draft guideline can be found on the RSTC website: NERC Reliability and Security Guidelines

[71] Project 2021-07

[72] IBR Activities

LTRA Recommendations and Ongoing ERO Actions		
	FERC issued an order in 2022 directing NERC to identify and register owners and operators of currently unregistered bulk power system-connected IBRs.[73] Working closely with industry and stakeholders, NERC is executing a FERC-approved work plan to achieve the identification and registration directive by 2026. Resources are also posted on the Registration page of the NERC website.	
Natural Gas-Electric Interdependence Initiatives	Informed by severe weather events of the past two winters, the 2023 triennial review of the NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System*, incorporated the *Design Basis for Natural Gas Study* developed by the ERO in 2022. The revised guideline also identifies the fuel risks encountered by industry during recent periods of extreme cold weather and high demand for natural gas. These natural gas supply risks can inform industry's development of planning scenarios. The revised guideline is under review with the RSTC. Refer to the RSTC-Approved Documents page.[74]	Reliability Guideline
Expand the transmission network to deliver supplies from new resources and locations to serve changing loads. 5. **Develop the transmission network:** ISOs and RTOs should continue looking for opportunities to streamline transmission planning processes and reduce the time required for transmission development. However, addressing the siting and permitting challenges that are the most common cause for delayed transmission projects will require regulators and policymakers at the federal, state, and provincial levels to focus attention and provide support.		
Initiative	**Description**	**Product/Reliability Solution**
Interregional Transfer Capability Study (ITCS)	NERC completed the ITCS required by the Fiscal Responsibility Act of 2023 and filed the final report with FERC on November 19, 2024. The ITCS is the first-of-its-kind assessment of transmission transfer capability under a common set of assumptions. However, the ITCS is not a transmission plan or blueprint. Transmission expansion analysis, resource plans, and other inputs must be considered in effective system planning. The ITCS is designed to provide foundational insights that facilitate stakeholder analysis and actions. Due to the interconnected nature of the BPS, NERC will extend the study beyond the congressional mandate to identify and make recommendations for transfer capabilities from the United States to Canada and among Canadian provinces. The Canadian analysis will be published in 2025. See **Interregional Transfer Capability Study (**ITCS).	ERO Study and Recommendations

[73] FERC Order Issued November 17, 2022
[74] RSTC Approved Documents

LTRA Recommendations and Ongoing ERO Actions

Adapt BPS planning, operations, and resource procurement markets and processes to the realities of a more complex power system.

6. **Use enhanced resource adequacy and energy risk assessments for determining resource needs:** PRMs are not sufficient for measuring resource adequacy for most areas because VERs and generator fuel supply issues expose additional energy risks. Resource Planners and wholesale markets need to use enhanced modeling that accounts for energy risks, such as all-hours probabilistic assessments. Multi-metric approaches to resource adequacy using load loss, unserved energy, and event magnitude and duration criteria and results from probabilistic studies will support achieving the levels of reliability that are required for modern society.

7. **Resource contributions must be accurately represented in resource planning, wholesale electricity markets, and operating models:** Resource Planners and wholesale market designers must use appropriate methods for determining the contribution of resources to meeting demand. Weather-dependent resources, fuel supplies, and demand profiles result in seasonal risks. This can be seen in the increasing winter resource adequacy risks observed in the 2024 ProbA for many traditionally summer-peaking areas. ISO/RTOs can help reduce seasonal risks by implementing seasonal resource adequacy procurement (e.g., spring, summer, fall, winter) based on reserve requirements and resource performance that are tailored to each season. The explosive growth of BESS and hybrid resources seen in most areas requires additional details to be incorporated into operating and planning models, such as state of charge, BESS duration, and BESS operating mode.

8. **Maintain sufficient amounts of flexible resources and essential reliability services:** To maintain load-and-supply balance in real-time with higher penetrations of variable supply and less-predictable demand, dispatchable generators must be available and capable of following changing electricity demand. Retirements of fossil-fired generators are reducing the amounts of dispatchable generation in many areas. As more solar PV 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. Natural-gas-fired generators and hydro generators have traditionally provided this ERS. Battery resources can provide flexibility during short durations, while new wind and solar PV have minimal assured flexibility. Maintaining ERSs is critically important. Resource Planners and wholesale electricity market operators should ensure resources are procured and made available in the long-range resource portfolio as part of the planning process; markets and other mechanisms need to be in place to deliver weather-ready resources with sufficient energy and ERS capabilities to the operators. [75]

9. **Include energy risks and extreme weather scenarios in resource and system planning:** Industry and regulators need to conduct all-hours analyses for evaluating and establishing resource adequacy and include extreme conditions in integrated resource planning and wholesale market designs. While more sophisticated capabilities for assessing extreme event risk are being developed, scenario planning can be more readily incorporated in resource and system planning. Scenarios should consider the potential effects of wide-area, long-duration extreme weather events, including the impact they can have on natural gas fuel supplies and on the interconnected energy system. NERC and the industry should continue to prioritize completion of new reliability standards supporting energy assurance in operating and planning time horizons, and for the assessment of extreme heat and cold weather events in transmission system planning.

10. **Accommodate the growth of DERs:** Preparing the grid to operate with increasing levels of distributed resources is a priority for most areas. Data sharing, models, and information protocols are needed to support BPS planners and operators. Industry must continue to evaluate potential reliability concerns associated with increasing DER penetration and DER performance and, when necessary, develop reliability standards requirements to address identified gaps. DER aggregators will also play an increasingly important role for BPS reliability in the coming years. ISO/RTOs must consider how the implementation of DER aggregators in the wholesale market will affect BPS planning and operations. [76]

[75] NERC ERS Measure 6 Forward Tech Brief

[76] A comprehensive guide to ERO activities on DERs can be found here: DER Activities

LTRA Recommendations and Ongoing ERO Actions		
Initiative	**Description**	**Product/Reliability Solution**
Energy Assessments Initiatives	NERC conducts seasonal long-term and probabilistic reliability assessments and issues reports like this *2024 LTRA* to advise industry and stakeholders of findings on BPS adequacy, including energy adequacy. In recent years, NERC has enhanced the energy risk analysis in seasonal assessments by incorporating deterministic energy risk scenarios and introducing probability-based assessments. NERC's ProbA uses hourly simulations to examine the ability of resources to meet demand over the entire study year, helping to identify energy risks that could otherwise go unaddressed by peak hour reserve margin resource adequacy analysis. NERC reliability assessments continue to evolve as more sophisticated energy assessment tools, models, and capabilities are developed. The RSTC created the Energy Reliability Assessment Working Group (ERAWG) to support wide adoption of technically sound approaches to energy assessments by BPS planners and operators. Working group projects and activities are described on the ERAWG page.[77] The working group is developing a technical reference document to inform registered entities on approaches and considerations for assessing and reducing the risk of energy shortfalls. New and revised Reliability Standards requirements for BPS planners and operators to address energy risks are in development in Project 2022-03 *Energy Assurance with Energy Constrained Resources.*[78] In other Reliability Standard development work, Project 2023-07 *Transmission System Planning Performance Requirements for Extreme Weather* requirements are being developed that will ensure entities consider extreme heat and cold weather scenarios in BPS planning, including the expected availability of the future resource mix.[79]	Reliability Assessments Reliability Standards
Distributed Energy Resources Strategy	NERC has proactively worked with industry stakeholders to identify BPS reliability risks associated with the increasing DER levels and has initiated actions to support broad awareness and education as well as to provide guidance for industry and enhance Reliability Standards where gaps exist. The status of NERC's extensive activities in each area are described in detail in the *DER Activities Reference Guide*.[80]	Reliability Standards Reliability Guidelines Educational Webinars
4: Strengthen relationships among reliability stakeholders.		
Initiative	**Description**	**Product/Reliability Solution**
Ongoing Strategic Engagements	NERC and the Regional Entities engage in frequent dialogue and conduct outreach with regulators and policymakers at the state/provincial, regional, and federal/national levels.	Constructive Partnerships

[77] ERAWG
[78] Project 2022-03
[79] Project 2023-07
[80] DER Activities

Errata

In June 2025, NERC, MRO, and MISO determined that incorrect RMLs were used in the 2024 LTRA for MISO.[81] After applying the correct RMLs, the following changes have been made:

- Figure 1 Risk Area Summary 2025–2029 (p. 6) | MISO changed from High Risk to Elevated Risk
- Table 1: Capacity and Energy Risk Assessment Summary (p. 7)| MISO changed from High Risk to Elevated Risk and Risk Summary updated
- Figure 2: Projected Reserve Margin Shortfall Areas with Announced Generator Retirements (p. 8) | MISO year of shortfall changed from 2025 to 2028 and caption updated
- High Risk Area Details and Elevated Risk Area Details (p. 12) | Removed the description of High Risk, moved relevant discussion of MISO risks to Elevated Risk Area Details, and updated text.
- Figures 3 and 4: MISO Planning Reserve Margins for Summer and Winter (p.13)| Updated with correct RMLs
- Table 12: Anticipated Reserve Margins with Announced Retirements (p. 40) | Footnote added to identify use of UCAP reserve margins for MISO
- MISO Demand, Resources and Reserve Margins (p. 41) | Updated the Reference Margin Level (%) row in the table and updated the Planning Reserve Margins bar graph with correct RMLs; added a note and reference to OMS-MISO Survey
- MISO Highlights (p. 42) | Changed MISO projected capacity shortfall from *2025* to *within the next five years* in the first bullet
- MISO Assessment (p. 43) | Removed the shortfall capacity value in the Planning Reserve Margins section and added a note on the capacity values for existing resources in the MISO tables; removed the statement of ARM falling below RML in the Probabilistic Assessments section

[81] See the *Statement on NERC's 2024 Long-Term Reliability Assessment* issued on June 17, 2025.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-08:
NERC 2025-26 Winter Assessment

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2025–2026 Winter Reliability Assessment

November 2025



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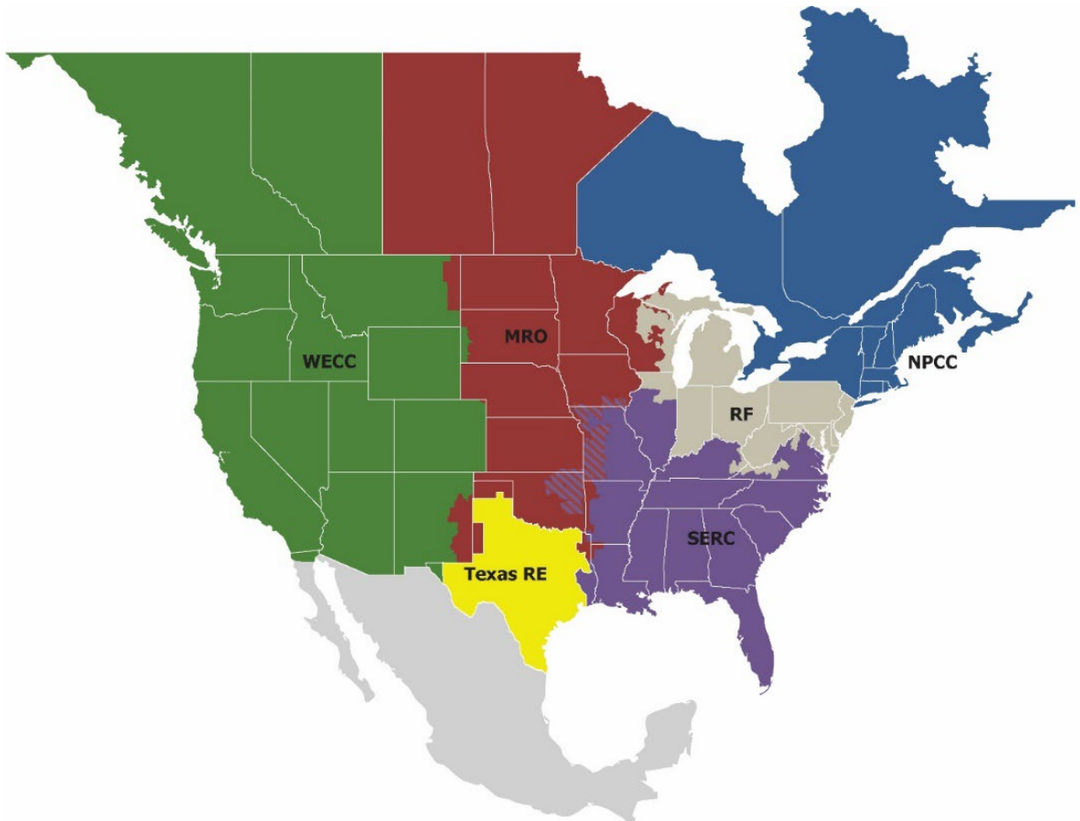
Preface

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

Reliability | Resilience | Security

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

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



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

About this Assessment

NERC's *2025–2026 Winter Reliability Assessment* (WRA) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming winter season. In addition, the WRA presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might affect the reliability of the BPS.

The reliability assessment process is a coordinated evaluation between the Reliability Assessment Subcommittee, the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas.

This report reflects an independent assessment by the ERO Enterprise (i.e., NERC and the six Regional Entities) and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to ensure BPS reliability. This report also provides an opportunity for industry to discuss plans and preparations to ensure reliability for the upcoming winter period.

Key Findings

This WRA covers the upcoming three-month (December–February) winter period, providing an evaluation of the generation resource and transmission system adequacy necessary to meet projected winter peak demands and operating reserves. This assessment identifies potential reliability issues of interest and regional risks. The following findings are the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as the potential operational concerns that may need to be addressed for the upcoming winter.

Two trends affecting resource adequacy across the BPS for the upcoming winter are rising electricity demand forecasts and a continued shift in the resource mix characterized by the retirement of thermal generators and growth in battery resources. After years of flat or low (~1%) peak demand growth, the aggregate peak demand for all NERC assessment areas has risen by 20 GW (2.5%) since the previous winter. Nearly all assessment areas are reporting year-on-year demand growth; some are forecasting increases near 10%. Total BPS resources have also increased since last winter, but by a smaller amount of 9.4 GW. This number includes the net change in generating capacity as well as additional demand response. These demand and resource changes are described in **Escalating Winter Demand** and **Resource Trends** sections.

The following findings are derived from NERC and the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as potential operating concerns that should receive attention for Winter 2025–2026:

1. **All areas are assessed as having adequate resources for normal winter peak-load conditions (i.e., the area's 50-50 peak forecast). However, more extreme winter conditions extending over a wide area could result in electricity supply shortfalls.** Prolonged, wide-area cold snaps can drive sharp increases in electricity demand and threaten reliable BPS generation and the availability of fuel supplies for natural-gas-fired generation. Four severe arctic storms have descended to cover much of North America since 2021, causing regional demand for electricity and heating fuel to soar and exposing generation and fuel infrastructure in temperate areas to freezing conditions.[1] The following areas face risks of electricity supply shortfalls during periods of more extreme conditions this winter (see **Figure 1**):

    - **NPCC-Maritimes**: The peak demand forecast has fallen slightly (-1.6%) in the NPCC-Maritimes assessment area, contributing to higher reserves compared to the 2024–2025 winter. Maritimes is projected to have an Anticipated Reserve Margin (ARM) of 16.9%, which is 270 MW below the area's Reference Margin Level of 20% . New Brunswick has long-term energy contracts that can be used to mitigate resource adequacy challenges through the purchase of energy on a day-ahead basis. NPCC's all-hours probabilistic assessment for the NPCC Region included the simulation of both a base case (i.e., normal 50/50 demand) and highest peak load scenario (having an approximate 7% chance of occurring), for both an expected and a low-likelihood, reduced-resource condition. The preliminary results of this assessment indicate that operators in Maritimes are likely to require emergency operating mitigations and/or energy emergency alerts (EEA) during above-normal demand or low-resource output conditions.
    - **NPCC-New England**: A lower peak demand forecast and additional resources from demand response and firm imports offset recent generator retirements, resulting in little change to the NPCC-New England ARM for this winter. New England continues to closely monitor regional energy adequacy, particularly during extended cold snaps where constrained natural gas pipelines contribute to rapid depletion of stored fuel supplies. ISO-NE's deterministic winter scenario analysis shows limited exposure to energy shortfalls this winter. In New England, winter energy concerns are highest in scenarios when stored fuels are rapidly depleted; during these periods, timely replenishment is critical to minimizing the potential for energy shortfalls.
    - **SERC-East**: The winter peak demand forecast has increased by 700 MW (1.6%) since last winter, while winter firm capacity has declined, resulting in lower reserves. SERC-East has changed from a summer-peaking area to potentially peaking during both summer and winter. This is due to the continued addition of solar photovoltaic (PV) generation that shaves off summer peak demand and a trend toward electrification of heating that drives up winter peak demand. All-hours probabilistic analysis from SERC found some load-loss hours (<0.1 hrs) and small amounts of expected unserved energy, with the highest risk occurring during above-normal peak demand and early morning hours when solar output is absent.
    - **SERC-Central:** Additional demand response and flat load growth since last winter is offsetting declining resource capacity (down 1,120 MW), resulting in little change to the ARM at 30.5%. There are adequate resources for normal winter peak demand; however, higher levels of demand that can occur during extreme cold temperatures can result in insufficient reserves that operators would need to manage with non-firm imports and potential energy emergencies.
    - **Texas RE-ERCOT:** Strong load growth from new data centers and other large industrial end users is driving higher winter electricity demand forecasts and contributing to continued risk of supply shortfalls. For the upcoming winter season, Texas RE-ERCOT is expected to continue facing reserve shortage risks during the peak load hour and high-

[1] See detailed reports on the January 2024 and January 2025 Arctic Storms, Winter Storm Elliott, and Winter Storm Uri.

net-load hours, particularly under extreme load conditions that accompany freezing temperatures. Elevated forced outage of thermal resources and reduced output from intermittent resources during these conditions exacerbates the risk of supply shortfalls. In winter, peak demands typically occur before sunrise and after sunset coinciding with the unavailability of solar generation making the system dependent on wind generation and dispatchable resources. Data centers are altering the daily load shape due to their round-the-clock operating pattern, lengthening peak demand periods. Additional battery storage and demand-response resources since last winter help mitigate shortfall risks. However, with the continued flattening of the load curve, maintaining sufficient battery state of charge will become increasingly challenging for extended periods of high loads, such as a severe multi-day storm like Winter Storm Uri.

- **WECC-Basin**: There is sufficient capacity in the area for expected peak conditions; however, Balancing Authorities (BA) are likely to require external assistance during extreme winter weather that causes thermal plant outages, adverse wind turbine conditions, and natural gas fuel supply issues for area internal resources. External assistance may not be available during region-wide extreme winter conditions. With an expected winter peak demand of 11.1 GW, under an extreme combination of generator derates and outages, the region could be short 1.6 GW before imports. Forecasted net internal demand has increased 1% since last year, with little change in winter capacity. Note that the WECC-Basin assessment area includes Utah, southern Idaho, and a portion of western Wyoming. In prior WRA reports, this part of the BPS was included as part of the WECC-NW assessment area. The *2025–2026 WRA* includes a new assessment area map for the Western Interconnection. The new assessment area boundaries provide reliability risk information in more geographic detail for the United States and Mexico.
- **WECC-NW**: Like WECC-Basin, there is sufficient capacity in the area for expected peak conditions; however, BAs are likely to require external assistance during extreme winter weather that causes thermal plant outages and adverse wind turbine conditions for area internal resources. External assistance may not be available during region-wide extreme winter conditions. Winter peak demand for the area is forecast to be 2.9 GW higher (9.3%) compared to last year. Over 3 GW of new resources have been in development for the assessment area this year, primarily battery storage, solar PV, and wind resources. Delays that threaten timely completion of these resource additions will make the area more reliant on imports to meet peak demand.

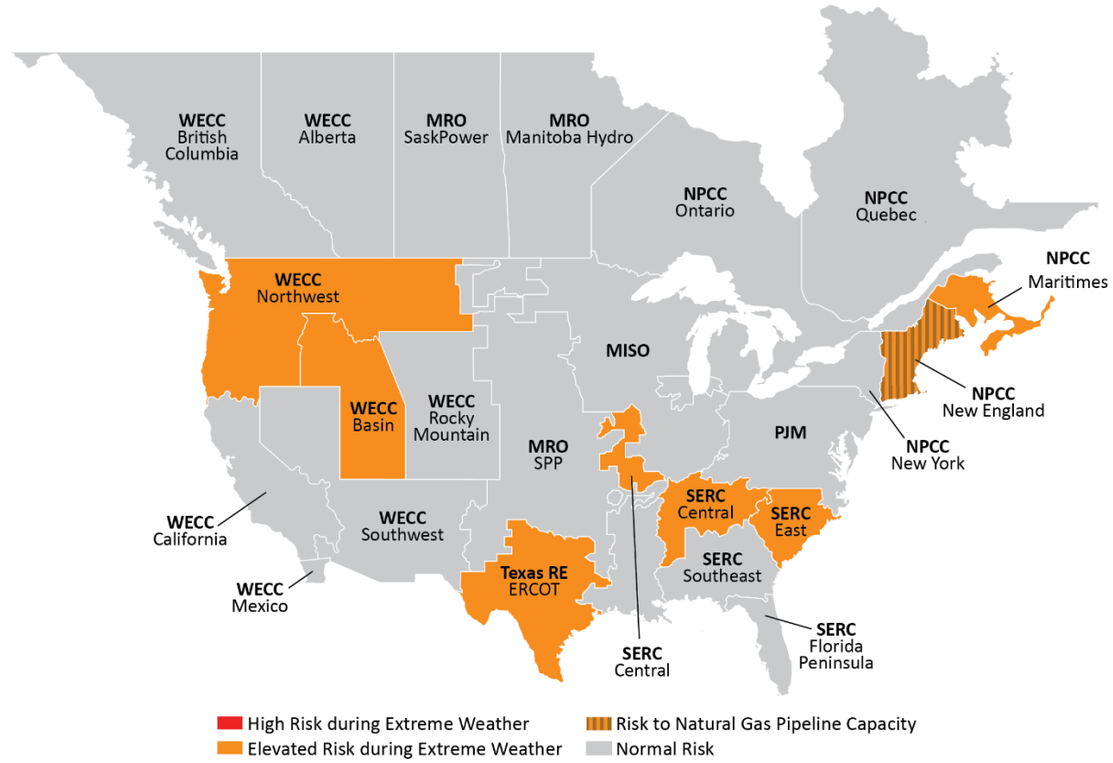


Figure 1: Winter Reliability Risk Area Summary

2. **The performance of natural gas production and supply infrastructure during peak winter conditions will again have a significant effect on BPS reliability.** Natural gas is an essential fuel for electricity generation in winter. Winter fuel supplies for thermal generators must be readily available during the periods of high electricity and natural gas demand that accompany extreme cold weather. Yet these periods are the most challenging for natural-gas-fired Generator Operators to obtain sufficient fuel and delivery. Natural gas production often falls off in extreme winter temperatures as supply infrastructure is affected by freezing issues, and Generator Operators that fail to secure firm fuel delivery are frequently unable to access fully subscribed pipelines. Evidence from the past two winters indicates notable improvement in the delivery of natural gas to BPS generators since winter storms Elliott and Uri with overall less natural gas production decline during cold weather and fewer natural gas infrastructure

force majeures.[2] Still, natural gas infrastructure freeze protection mitigations are voluntary for the natural gas industry in most of North America, resulting in uneven application of protections and continued supply risks during extreme conditions. Furthermore, timing misalignments between the natural gas and electric markets continue to challenge generator fuel procurement in advance of severe winter conditions that occur over winter holiday weekends. As winter approaches, NERC encourages all entities across the gas-electric value chain—from production to the burner tip—to take all necessary preparations for extreme cold and keep natural gas flowing and the lights on.

3. **Cold weather Reliability Standards first introduced in 2023 have been improved prior to the upcoming winter and address recommendations from winter storms Elliott and Uri.** In September 2025, the Federal Energy Regulatory Commission (FERC) approved EOP-012-3 with an effective date of October 1, 2025, concluding the development of Reliability Standards for generator cold weather preparedness.[3] The EOP-012 Reliability Standard contains requirements for generator freeze protection measures, cold weather preparedness plans, and operator training. Among the improvements in the new version are enhanced and expanded requirements to ensure that Generator Owners (GO) are implementing corrective actions to address known issues affecting their ability to operate in cold weather in a timely manner. NERC collects data on the winterization of generating units, which, in conjunction with NERC's monitoring of BPS performance and analysis of cold weather events, helps determine the effectiveness of Reliability Standards. NERC submitted to FERC its first annual *Cold Weather Data and Analysis* informational filing in October 2025.[4] Based on the data reported this year, 96% of the total net winter capacity reported extreme cold weather temperatures (ECWT) at or below 32 degrees Fahrenheit, triggering winter preparedness measures under the Cold Weather Preparedness Standard, and 99% of total net winter capacity in the continental US reporting the ability to operate at the calculated ECWT. As the first such report, this *Cold Weather Data and Analysis* filing provides a benchmark for future analysis.

Recommendations

To reduce the risks of energy shortfalls on the BPS this winter, NERC recommends the following:

- Reliability Coordinators (RC), BAs, and Transmission Operators (TOP) in the elevated risk areas identified in the key findings should review seasonal operating plans and the protocols for communicating and resolving potential supply shortfalls in anticipation of potentially high generator outages and extreme demand levels. Operators should review NERC's Resources on Cold Weather Preparations.
- GOs should complete winter readiness plans and checklists prior to December, deploy weatherization packages well in advance of approaching winter storms, and frequently check and maintain cold weather mitigations while conditions persist.
- BAs should be cognizant of the potential for short-term load forecasts to underestimate load in extreme cold weather events and be prepared to take early action to implement protocols and procedures for managing potential reserve deficiencies. Proactive issuance of winter advisories and other steps directed at generator availability contributed to improved reliability during cold weather events of the past two winters.
- RCs and BAs should implement generator fuel surveys to monitor the adequacy of fuel supplies. They should prepare their operating plans to manage potential supply shortfalls and take proactive steps for generator readiness, fuel availability, load curtailment, and sustained operations in extreme conditions.
- Generator Owners/Operators of natural-gas-fired units should maintain awareness of potential extreme cold weather developing over holiday weekends and the implications for fuel planning and procurement that may result given the natural gas purchase close dates that precede long holiday weekends.
- State and provincial regulators can assist grid owners and operators in advance of and during extreme cold weather by maintaining awareness of BA, natural gas pipeline, and gas local distribution company (LDC) operational public announcements and notices, amplifying public appeals for electricity and natural gas conservation, and supporting requested environmental and transportation waivers.

[2] See *January 2025 Arctic Events | A System Performance Review*, April 2025
[3] See NERC's Statement on FERC September Open Meeting for summary and link to FERC's order.
[4] See 2025 Cold Weather Data Collection and Analysis Informational Filing

Risk Highlights

Escalating Winter Demand

Winter electricity demand is rising at the fastest rate in recent years, particularly in areas where data center development is occurring. After several years of low (~1%) growth, total internal demand for the BPS is forecast to increase by 20.2 GW (2.5%) over last winter's forecast. The changes in forecasted net internal demand for each assessment area are shown in **Figure 2** below.[5] Assessment areas develop these forecasts based on historical load and weather information as well as future projections. Most assessment areas are projecting an increase in peak demand. SaskPower, PJM, the U.S. Southeast, and parts of the U.S. West have the largest increase in peak demand forecasts.

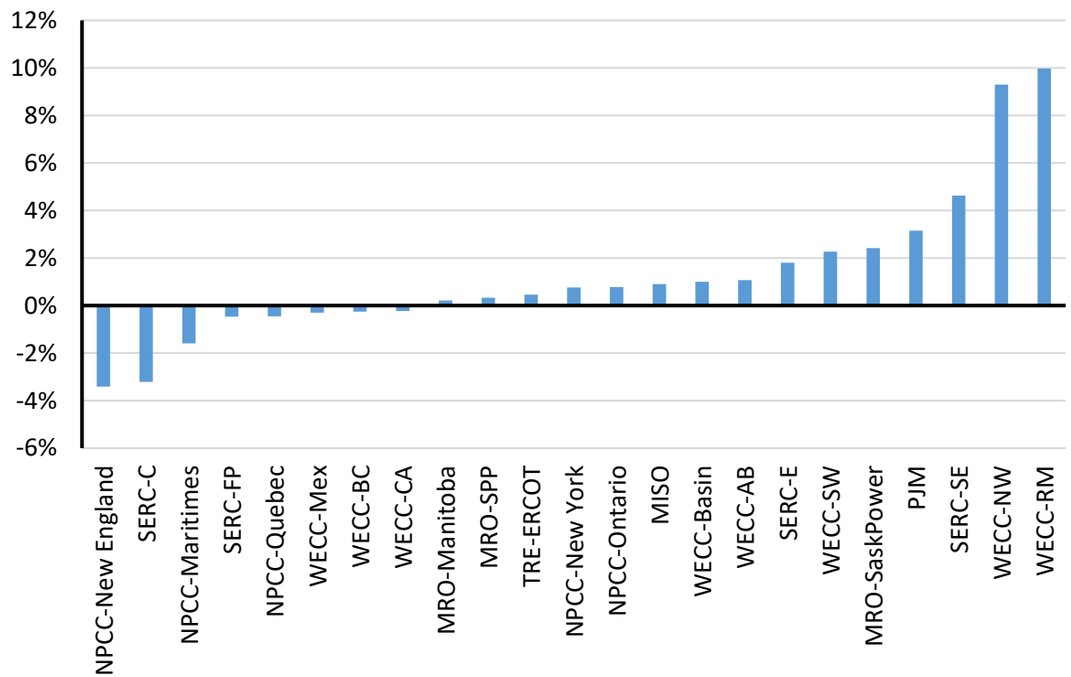


Figure 2: Change in Net Internal Demand—Winter 2025–2026 Forecast Compared to Winter 2024–2025 Forecast

[5] See **Data Concepts and Assumptions** section for demand definitions.

Resource Trends

BPS resources are growing, but at a slower rate than demand is rising. Battery and solar facilities were the leading resource types added to the BPS since last winter. Solar resources, however, often do not supply output during hours of peak winter demand. Growth in demand response is also contributing to BPS resources for the upcoming winter. **Table 1** shows the total change in BPS resources since last winter. For battery, solar, and wind resources, the table includes change in both nameplate (installed) capacity as well as the change in on-peak demand capacity, which is the capacity that resources are expected to provide in their area during the time of peak demand. For assessment-area specific information see **Variable Energy Resource Contributions** section.

Table 1: BPS Resource Change from Winter 2024–2025 to Winter 2025–2026

Resource	Net Change Nameplate Capacity (MW)	Net Change Peak Demand Capacity (MW)
Total Generator Capacity		1,335
Battery	19,659	11,121
Solar	11,097	1,176
Wind	-562	-14,238
Thermal and Hydro		3,276
Demand Response		8,112
Total Resources		9,447

Total BPS resources for serving winter peak demand, including generating capacity and demand response, have increased since last winter by 9,447 MW. Sizeable additions in battery resources and some new natural gas-fired generators contribute to the increase in resource capacity. However, the increase is offset by lower on-peak capacity values for wind resources, which are the result of revised valuations of wind resource capability at peak demand hours in some areas.[6] As a result, BPS generator capacity for winter peak demand makes up only a small portion of the total BPS increase. Generation accounts for 1,335 MW of the total 9,445 MW increase, while the larger share comes from demand response programs. Area specific information on demand response is provided in the **Demand and Resource Tables**.

The recent trend in resource additions is contributing to higher risk of electricity supply shortfalls in winter. BA operators are likely to face higher winter demand without a comparable increase in supply resources. Furthermore, the types of resources that are growing the most-- battery resources and

[6] Since last winter, ERCOT and MISO have implemented new methods for determining capacity contributions that result in lower wind and solar resources contributions at peak demand. See ERCOT's Resource Adequacy page and MISO's *Planning Year 2025-2026 Wind and Solar Capacity Credit Report*.

demand response—have unique characteristics that operators will need to account for and could limit the use of these resources in extreme winter conditions. Battery energy is reliable when it can be dispatched and has sufficient charge for the period it is needed, yet little time to recharge can be expected during extreme winter weather. System operators will need good visibility on battery state of charge and should anticipate that some extreme winter events will cause these resources to become depleted when needed. Demand response is limited by contract terms, which typically specify how often and for how long the resource may be used. Other resource types are also challenged in winter (see **Thermal Generator Fuel Adequacy and Security**). As BAs grapple with higher demand in most parts of the BPS, they will do so with resources that are becoming increasingly complex to dispatch especially in winter.

Thermal Generator Fuel Adequacy and Security

The performance of the thermal generator fleet remains critical to winter BPS operations. Winter fuel supplies for thermal generators must be readily available during periods of high demand and extreme cold weather. Generally, fuel adequacy for the thermal generating fleet is bolstered through strategic infrastructure investments and fuel stockpiling that increases the certainty of having fuel on hand that can be converted to electricity when needed. Because of this, winter performance of thermal generators is inextricably linked to extraction, processing, storage, and delivery infrastructure for a variety of fuels. Fuel supply risks have been noted in recent years' WRAs related to coal and natural gas availability and illustrate the interconnected nature of these critical energy infrastructure systems.

BPS stakeholders across North America note multiple fuel-related issues that are being monitored entering the winter season. For example, while coal represents a waning share of the overall resource mix, it continues to play an important role in meeting demand during extreme winter weather events, and oil inventories at dual-fuel gas-oil generators lessen risks related to natural gas deliverability in infrastructure-constrained regions, especially during the winter. Notably, it is infeasible or prohibitively costly to stockpile natural gas locally at power plants, and this exposes the BPS to the risk profile of the constituent systems that comprise the supply and delivery of this just-in-time fuel.

Natural Gas Generator Fuel Supplies

Natural gas generators remain a crucial part of on-peak resources meant to meet winter electricity demand across much of North America. While many Generator Owners and Operators secure backup fuel supplies at critical gas-fired generators, particularly in the northeastern United States and Florida, large contributions to the on-peak winter resource mix by single-fuel natural-gas-fired generators remain across North America (see **Figure 3**).

Natural gas generator performance can be threatened when natural gas supplies are insufficient or when natural gas infrastructure is unable to maintain the flow of fuel to critical generators. Grid operators continue to acknowledge and enhance their winter planning processes to firm up their fuel supplies and guard against natural gas disruptions, but winter storms Uri and Elliott demonstrated that combinations of natural gas flow restrictions and supply insufficiency can occur regardless of whether cold temperatures are common or uncommon in the region and can affect more than one BA area concurrently.

Many BPS areas that regularly experience cold weather events, like New England, have adopted mitigating technologies to lessen the impact of natural gas shortages through generator dual-fuel capability and stored backup fuel. In those areas, prolonged cold weather events present a risk of rapid depletion of stored backup fuel. Robust regional and distributed storage investments and winter planning for timely fuel replenishment are critical to minimizing potential energy shortfalls in the operational time frame in these areas.

Natural gas and electricity infrastructures have the added complexity of interdependence. Electricity is used to power some facilities, such as compressor stations and processing plants that make up natural gas infrastructure. These interdependencies mean that reliability events that originate on one system have the potential to affect the other and worsen the overall event magnitude or duration.

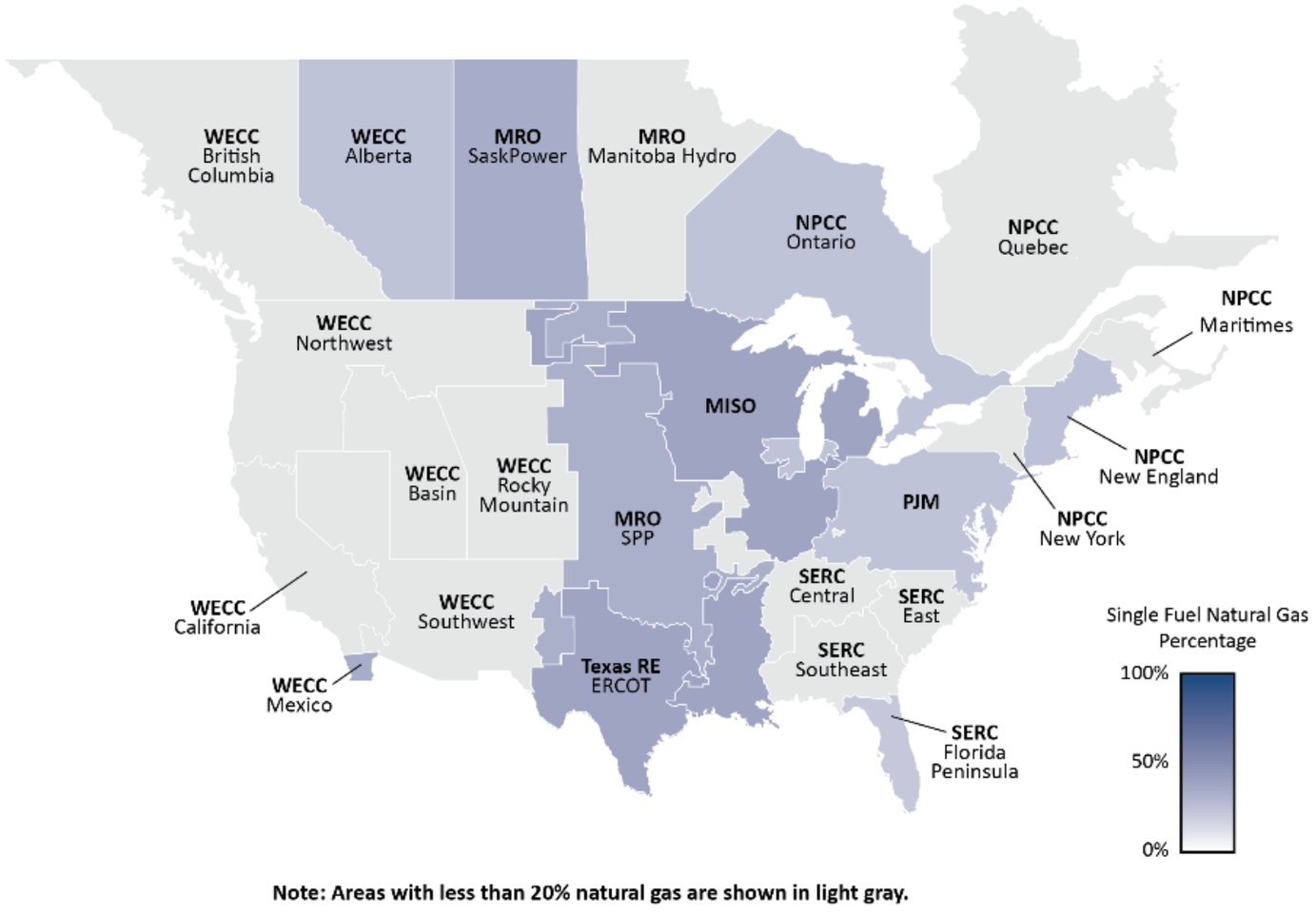
Natural gas infrastructure freeze protection mitigations are voluntary for the natural gas industry in most of North America. Texas is an exception, where the Railroad Commission of Texas adopted rules to require critical natural gas facilities to implement weather-related emergency preparation measures.[7] Lack of consistent standards for natural gas infrastructure protections will result in uneven application of freeze protections and continued supply risks during extreme conditions in many areas.

These considerations have driven higher levels of coordination to ensure sustained reliable operation of the natural gas and electricity systems. While a FERC and ERO staff review of system performance during the January 2025 arctic events[8] details improvements in electric and natural gas coordination since winter storms Uri and Elliott, the review also identifies continuing gaps between the electricity and natural gas industries that remain entering the 2025–2026 Winter season. These include natural gas scheduling challenges during winter holiday weekends, market time frame and process incompatibility, and electric power entities' lack of visibility into operational impact data from natural gas producers and suppliers.

[7] See Railroad Commission of Texas weatherization rule.

[8] FERC, NERC Issue Report on System Performance During the January 2025 Arctic Weather | Federal Energy Regulatory Commission

The U.S. Energy Information Administration (EIA)[9] anticipates a slightly milder winter than last year across much of the United States, especially in the Northeast, leading to a projection that households will consume approximately 2% less natural gas than last winter. Working natural gas storage inventories are about 5% above the previous five-year average in the United States heading into the winter season. The EIA attributes this relative surplus in part to robust production this summer and lower-than-expected natural gas consumption by power generators.



Single-Fuel Natural-Gas-Fired Generation

	Winter Capacity (GW)	Contribution to Total Winter Resource Mix
MISO	63.9	38%
TRE-ERCOT	53.0	38%
WECC-MX	2.2	34%
MRO-SaskPower	2.5	34%
SPP	33.4	32%
NPCC-New England	12.1	24%
PJM	60.9	23%
WECC-AB	13.9	23%
NPCC-Ontario	8.0	23%
SERC-FP	45.6	21%
WECC-CA	35.9	18%
WECC-SW	21.5	17%
WECC-Basin	4.9	16%
WECC-RM	6.2	14%
SERC-C	17.0	13%
SERC-SE	21.5	13%
WECC-NW	8.7	12%
SERC-E	11.3	9%
NPCC-New York	5.0	8%
NPCC-Maritimes	0.5	7%
MRO-Manitoba	0.3	4%
WECC-BC	0.1	1%
NPCC-Quebec	0.0	0%

Figure 3: Single-Fuel Natural-Gas-Fired Generation Capacity Contribution to the 2025–2026 Winter Generation Mix

[9] See the U.S. Energy Information Administration's Winter Fuels Outlook 2025–26

Risk Assessment Discussion

NERC assesses the risk of electricity supply shortfall in each assessment area for the upcoming season by considering Planning Reserve Margins, seasonal risk scenarios, probability-based risk assessments, and other available risk information. NERC provides an independent assessment of the potential for each assessment area to have sufficient operating reserves under normal conditions as well as above-normal demand and low-resource output conditions selected for the assessment. A summary of the assessment approach is provided in Table 2.

Table 2: Seasonal Risk Assessment Summary

Category	Criteria[1]
High Potential for insufficient operating reserves in normal peak conditions	• Planning Reserve Margins do not meet Reference Margin Levels (RML); or • Probabilistic indices exceed benchmarks, e.g., loss of load hours (LOLH) of 2.4 hours over the season; or • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **normal peak-day demand and outage scenarios**[2]
Elevated Potential for insufficient operating reserves in above-normal conditions	• Probabilistic indices are low but not negligible (e.g., LOLH above 0.1 hours over the season); or • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **extreme peak-day demand with normal resource scenarios** (i.e., typical or expected outage and derate scenarios for conditions);[2] or • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **normal peak-day demand with reduced resources** (i.e., extreme outage and derate scenarios)[3]
Normal Sufficient operating reserves expected	• Probabilistic indices are negligible • Analysis of the risk hour(s) indicates resources will be sufficient to meet operating reserves under normal and extreme peak-day demand and outage scenarios[4]

Table Notes:
[1]The table provides general criteria. Other factors may influence a higher or lower risk assessment.
[2]**Normal resource scenarios** include planned and typical forced outages as well as outages and derates that are closely correlated to the extreme peak demand.
[3]**Reduced resource scenarios** include planned and typical forced outages and low-likelihood resource scenarios, such as extreme low-wind scenarios, low-hydro scenarios during drought years, or high thermal outages when such a scenario is warranted.
[4]Even in normal risk assessment areas, extreme demand and extreme outage scenarios that are not closely linked may indicate risk of operating reserve shortfall.

Assessment of Planning Reserve Margins and Operational Risk Analysis

Anticipated Reserve Margins (ARM), which provide the Planning Reserve Margins for normal peak conditions, as well as reserve margins with typical forced outage levels and for the most extreme seasonal risk scenarios are provided in Table 3.

Table 3: Seasonal Risk Scenario On-Peak Reserve Margins

Assessment Area	Anticipated Reserve Margin	Reserve Margin with Typical Outages	Reserve Margin with Higher Demand, Outages, Derates in Extreme Conditions
MISO	49.5%	22.3%	3.7%
MRO-Manitoba	13.7%	11.4%	6.1%
MRO-SaskPower	35.1%	29.0%	16.1%
MRO-SPP	56.5%	29.4%	16.9%
NPCC-Maritimes	16.9%	12.5%	-4.7%
NPCC-New England	58.9%	45.4%	8.7%
NPCC-New York	78.2%	52.4%	16.2%
NPCC-Ontario	28.6%	21.8%	13.2%
NPCC-Québec	15.2%	15.1%	5.0%
PJM	35.6%	24.8%	15.6%
SERC-C	30.5%	22.4%	-0.9%
SERC-E	21.9%	17.5%	3.0%
SERC-FP	41.7%	28.3%	25.6%
SERC-SE	39.7%	24.7%	17.7%
TRE-ERCOT	36.0%	25.2%	-20.0%
WECC-AB	35.2%	32.4%	10.0%
WECC-Basin	29.6%	19.7%	-21.1%
WECC-BC	25.9%	25.8%	15.4%
WECC-CA	82.3%	73.7%	57.9%
WECC-Mex	83.1%	79.4%	52.9%
WECC-NW	30.9%	29.5%	-8.5%
WECC-RM	61.7%	53.2%	10.0%
WECC-SW	104.4%	90.1%	50.1%

Seasonal risk scenarios for each assessment area are presented in the **Regional Assessments Dashboards** section. The on-peak reserve margin and seasonal risk scenario charts in each dashboard provide potential winter peak demand and resource condition information. The reserve margins on the right side of the dashboard pages provide a comparison to the previous year's assessment. The seasonal risk scenario charts present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. The assessment areas determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized in the seasonal risk scenario charts; more information about these dashboard charts is provided in the **Data Concepts and Assumptions** section.

The seasonal risk scenario charts can be expressed in terms of reserve margins: In **Table 3**, each assessment area's ARMs are shown alongside the reserve margins for a typical generation outage scenario (where applicable) and the extreme demand and resource conditions in their seasonal risk scenario.

Areas highlighted in orange in **Figure 1** above have been identified as having resource adequacy or energy risks for the winter and are included in the **Key Findings** section's discussion that follows. The typical outage reserve margin includes anticipated resources minus the capacity that is likely to be in maintenance or forced outage at peak demand. If the typical maintenance or forced-outage margin is the same as the ARM, it is because an assessment area has already factored typical outages into the anticipated resources. The extreme conditions margin includes all components of the scenario and represents the most severe operating conditions of an area's scenario. Note that any reserve margin below zero indicates that the resources fall below demand in the scenario.

In addition to the peak demand and seasonal risk hour scenario charts, the assessment areas provided a resource adequacy risk assessment that was probability-based for the winter season. Results are summarized in **Table 5**. The risk assessments account for the hour(s) of greatest risk of resource shortfall. For most areas, the hour(s) of risk coincides with the time of forecasted peak demand; however, some areas incur the greatest risk at other times based on the varying demand and resource profiles. Various risk metrics are provided and include loss of load expectation (LOLE), loss of load hours (LOLH), expected unserved energy (EUE), and the probabilities of energy emergency alert (EEA) declarations (see **Table 4** for a description of EEA levels).

Table 4: Energy Emergency Alert Levels

EEA Level	Description	Circumstances
EEA 1	All available generation resources in use	• The BA is experiencing conditions in which all available generation resources are committed to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required operating reserves. • Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
EEA 2	Load management procedures in effect	• The BA is no longer able to provide its expected energy requirements and is an energy-deficient BA. • An energy-deficient BA has implemented its operating plan(s) to mitigate emergencies. • An energy-deficient BA is still able to maintain minimum operating reserve requirements.
EEA 3	Firm load interruption is imminent or in progress	• The energy-deficient BA is unable to meet minimum operating reserve requirements.

Energy Emergency Alerts

The combination of above-normal generation outages, low resource output, and peak loads as occurred during the extreme cold weather events of Winter Storm Uri in 2021 and Winter Storm Elliott in 2022 are ongoing winter reliability risks. When supply resources in an area fall below expected demand and operating reserve requirements, BAs may need to employ EEAs to maintain balance between available capacity and energy and real-time demand. A description of each EEA level is provided above.

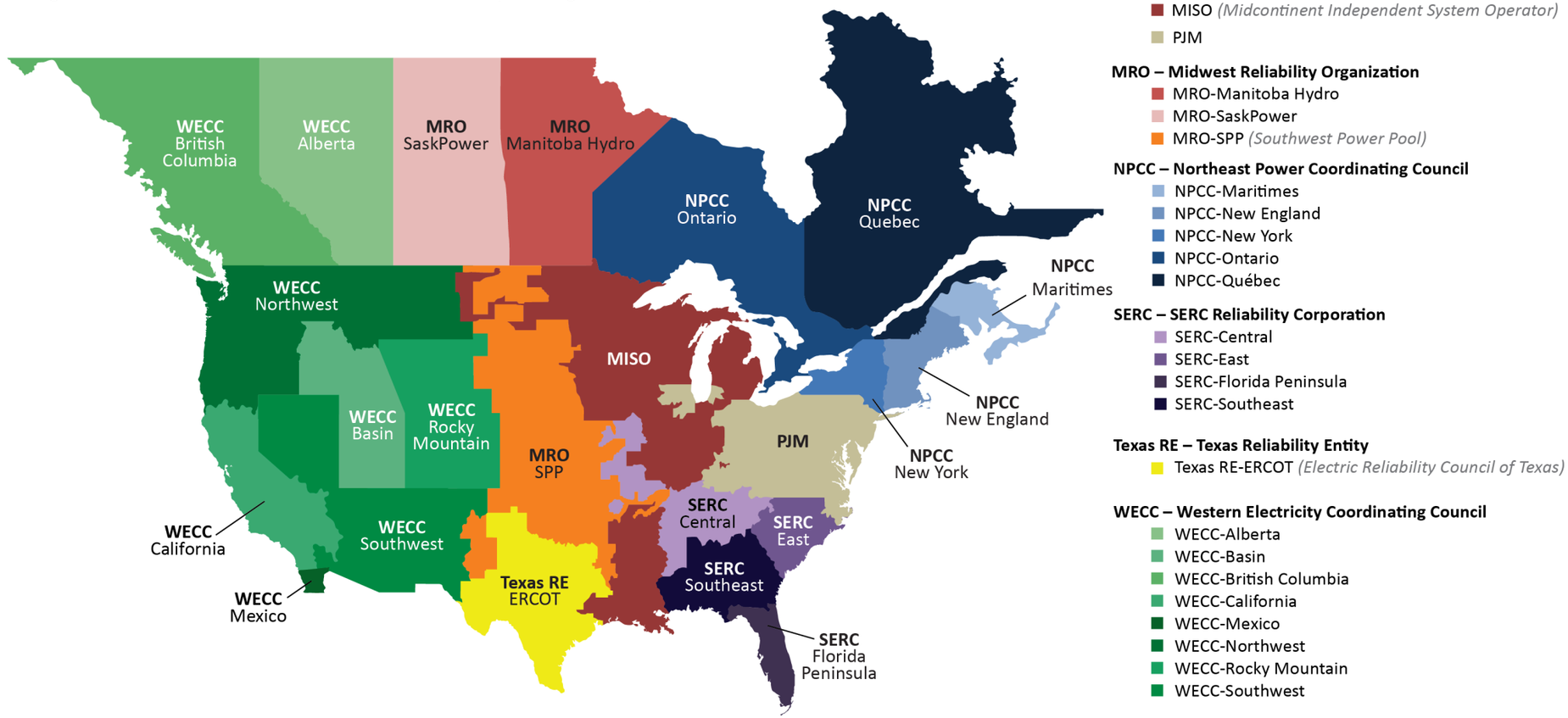
Table 5: Probability-Based Risk Assessment		
Area	**Type of Assessment**	**Results and Insight from Assessment**
MISO	Deterministic	MISO does not provide a probabilistic assessment for the WRA. MISO applies a deterministic look at expected system conditions, looking at generation availability under typical and extreme outages and looking at a typical 50/50 load forecast and an extreme 90/10 load forecast. For the upcoming winter season, under an extreme outage and extreme 90/10 load forecast, this is the riskiest scenario for the MISO footprint. This scenario produces the shortest actual reserve margin for January.
MRO-Manitoba	Probabilistic study for the NERC Probabilistic Assessment (ProbA)	Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 *Long-Term Reliability Assessment* (LTRA) found no load-loss or unserved energy hours for 2026.
MRO-SaskPower	Probability-based capacity adequacy assessment	SaskPower's probabilistic assessment for the 2025–2026 Winter indicates that risk of shortfalls is lower than the previous winter. LOLH for an elevated risk scenario for the 2025–2026 Winter season is 0.08 hours. The month with the highest LOLH is December (0.05 hours).
MRO-SPP	NERC 2024 ProbA	Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 LTRA found no load-loss or unserved energy hours for 2026.
NPCC	NPCC conducted an all-hour probabilistic reliability assessment that included detailed neighbor modeling and consisted of a base case and severe case examining low resources, reduced imports, and higher loads. The assessment evaluates the probabilistic indices of LOLE, LOLH, and EUE. The highest peak load scenario has an approximately 7% probability of occurring.	
NPCC-Maritimes	The Maritimes Area low-likelihood resource case assumed: wind derated by 50% for every hour in December through February and a 50% natural gas capacity curtailment for December through February (dual-fuel units assumed reverting to oil) and reduced transfer capabilities.	The preliminary assessment indicates that established operating procedures are not sufficient to maintain a balance between electricity supply and demand. Under highest peak load levels, the Maritimes Area shows a notable likelihood of utilizing its operating procedures such as reducing 30-minute reserves, initiating interruptible loads, and reducing 10-minute reserves to maintain system reliability during the upcoming winter period.
NPCC-New England	The New England Area low-likelihood resource case assumed: 500 MW of additional maintenance outages, ~4,513 MW of gas-fired generation unavailable due to fuel supply constraints, and 50% reduced import capabilities of external ties.	The preliminary results of this assessment indicate that operating procedures were not needed to maintain a balance between electricity supply and demand
NPCC-New York	The New York Area low-likelihood resource case assumed: ~500 MW of extended maintenance in southeastern New York, 600 MW of cable transmission reduction across HVdc facilities, and ~5,000 MW of generation unavailable due to fuel delivery issues.	The preliminary results of this assessment indicate that operating procedures were not needed to maintain a balance between electricity supply and demand. No cumulative LOLE, LOLH or EUE risks were indicated over the December–February winter period, for all the scenarios modeled.
NPCC-Ontario	An energy assessment for the Ontario Assessment Area was conducted for two scenarios: firm resources and firm demand with expected weather, and planned resources with planned demand with expected weather.	No cumulative LOLH or EUE risks were identified over the entire November-to-April winter season for both scenarios modeled.

Table 5: Probability-Based Risk Assessment		
Area	**Type of Assessment**	**Results and Insight from Assessment**
NPCC-Québec	The Québec Area low-likelihood resource case assumed 1,000 MW of generation reductions.	The preliminary results of this assessment indicate that established operating procedures are sufficient to maintain a balance between electricity supply and demand if needed. No cumulative LOLE, LOLH or EUE risks were indicated over the December–February winter period for all the scenarios modeled
PJM	Probabilistic study for the NERC Probabilistic Assessment (ProbA)	Probabilistic study for 2025–2026 Winter is not provided for the WRA. PJM performed probabilistic analysis for 2026-2027 winter as part of the 2024 ProbA summarized in NERC's 2024 LTRA. The results of this study indicate risk of load loss (<0.1 hours) and unserved energy during winter months. For the upcoming winter, load-loss hours are expected to be less than this value because forecasted load is lower and anticipated resource capacity is higher than the case studied for the 2024 ProbA.
SERC	Based on the 2024 NERC Probabilistic Assessment (ProbA) base-case result. SERC's assessment used 38 years of historical load shapes to assess the resource adequacy of years 2026 and 2028, primarily based on data from the 2024 Long Term Reliability Assessment (LTRA).	
SERC-Central		Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 LTRA found no load-loss or unserved energy hours for 2026.
SERC-East		Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 LTRA found a small number of load-loss hours (<0.1) and EUE (61 MWh / 1 ppm) for 2026.
SERC-Florida Peninsula		Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 LTRA found negligible load-loss hours and EUE.
SERC-Southeast		Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 LTRA found no load-loss or unserved energy hours for 2026.
Texas RE-ERCOT	ERCOT Probabilistic Reserve Risk Model	ERCOT's probabilistic risk assessment indicates a 2% probability of having to declare EEAs during the January forecasted winter peak day (which coincides with the highest reserve shortage risk) and a controlled load shed probability of 1.8%. ERCOT defines low-risk hours as when the probability of an EEA is less than 10%.
WECC	The resource adequacy work performed at WECC used the Multi-Area Variable Resource Integration Convolution (MAVRIC) model for the 2025 LTRA. The MAVRIC model is a convolution-based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour. In the resource adequacy environment, the reports produced support NERC's seasonal assessments, LTRA, and ProbA.	
WECC-AB		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-Basin		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-BC		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.

Table 5: Probability-Based Risk Assessment		
Area	**Type of Assessment**	**Results and Insight from Assessment**
WECC-CA		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-Mexico		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-Rocky Mountain		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-NW		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026. Results for a case where new resource additions are not completed for the upcoming winter found some EUE and LOLH.
WECC-SW		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. Guidelines and definitions are in the **Data Concepts and Assumptions** table. On-Peak Reserve Margin bar charts show the ARM compared to a reference margin level (RML) that is established for each area to meet resource adequacy criteria. Prospective Reserve Margins can give an indication of additional on-peak capacity but are not used for assessing adequacy. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left blue column shows anticipated resources (from the **Demand and Resource Tables**), and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand (from the **Demand and Resource Tables**) and the extreme winter peak demand determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources. Adjustments may include reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools (if any) that are available during scarcity conditions but have not been accounted for in the WRA reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios. In addition, results from a probability-based resource adequacy assessment are shown in the Highlights section of each dashboard. Methods vary by assessment area and provide further insights into the risk conditions forecasted for this upcoming winter period.



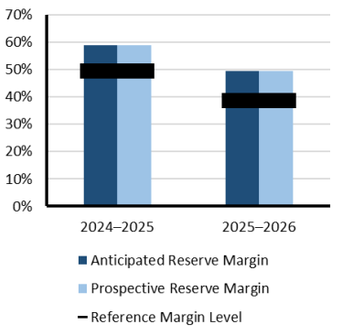


MISO

The Midcontinent Independent System Operator, Inc. (MISO) is an independent, not-for-profit organization responsible for operating the bulk electric power system and administering wholesale electricity markets across 15 U.S. states and the Canadian province of Manitoba. MISO ensures the reliable delivery of electricity to approximately 45 million people by managing regional transmission operations as well as energy and ancillary services markets and advising on long-term resource planning. The MISO footprint includes 39 Local BAs and more than 550 market participants. MISO operates one of the world's largest organized electricity markets, with its members operating a system that consists of over 77,000 miles of transmission lines and approximately 1,888 generating units. The peak electricity demand on the MISO system currently occurs during the summer season. MISO's footprint lies across three regional entities (MRO, RF, and SERC), but MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

- MISO expects limited risk in the 2025–26 Winter season as MISO was able to procure 6.1% more resources through the annual planning reserve auction than required by its minimum resource adequacy target. A further 3.3 GW of resources were available but not chosen to be committed for the winter season.
- Some risk has been identified for this upcoming winter season. In a high generation outage and high winter load scenario reliability is expected to be maintained by reliance upon operational mitigations that include non-firm energy transfers into the system, energy-only resources not subject to a must-offer requirement that may still offer into the energy markets, load-modifying resources, and internal transfers that exceed the Sub-Regional Import/Export Constraint (SRIC/SREC) between the MISO North/Central and South areas.
- MISO continues to coordinate with neighboring RCs and BAs to improve situational awareness and vet any needs for energy transfers to address extreme system conditions.
- MISO continues to survey and coordinate with its members on winter preparedness and fuel sufficiency.
- MISO has implemented a seasonal resource adequacy construct and seasonal unit accreditation to better affirm adequate supply in all seasons.

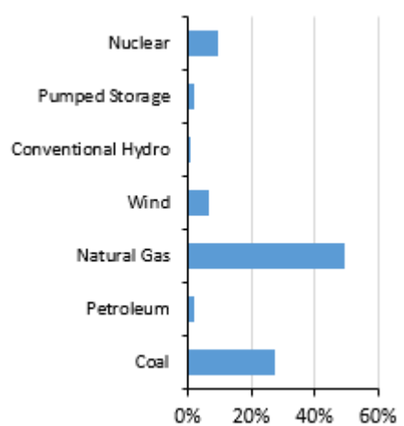
On-Peak Reserve Margin[10]



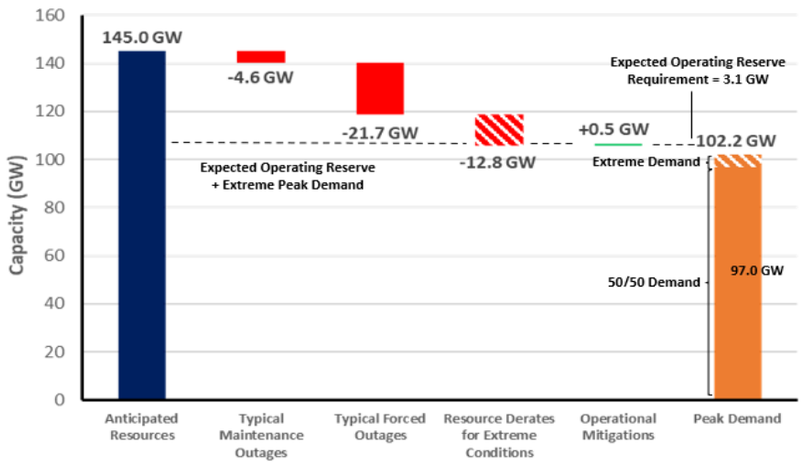
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed demand scenarios. Above-normal winter peak load combined with generator outages from freezing or fuel supply issues and low wind output result in the need to employ operating mitigations (i.e., demand response and transfers).

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: 50/50 net internal demand and additional demand during extreme weather conditions (e.g., Winter Storm Enzo) using member submitted data and historical load data

Typical Maintenance Outages: Rolling three-year winter average of peak-day maintenance and planned outages

Typical Forced Outages: Three-year average of all peak-day outages that were not planned

Resource Derates for Extreme Conditions: Represents derates aligning with the most extreme hour of each of the past 3 years,

Operational Mitigations: Non-firm energy transfers into the system, energy-only resources that do not have a must-offer requirement, or internal transfers that exceed the SRIC/SREC between the MISO North/Central and South regions

[10] The MISO Risk Scenario Assessment for the 2025-26 Winter Season is not directly comparable to that for the 2024-25 Winter Season as methodology improvements have been implemented.



MRO-Manitoba Hydro

Manitoba Hydro is a provincial Crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro is a leader in providing renewable energy and clean-burning natural gas. Manitoba Hydro provides electricity to approximately 608,500 electric customers in Manitoba and natural gas to approximately 293,000 customers in southern Manitoba. Its service area is the province of Manitoba, which is 251,000 square miles. Manitoba Hydro is winter-peaking. Manitoba Hydro is its own Planning Coordinator (PC) and Balancing Authority (BA). Manitoba Hydro is a coordinating member of MISO, which is the RC for Manitoba Hydro.

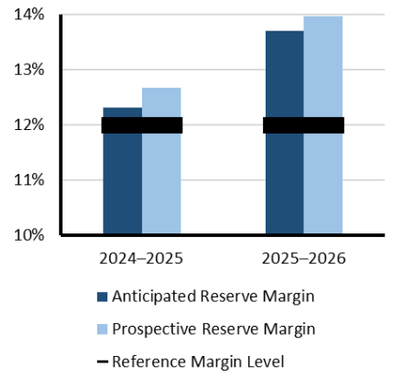
Highlights

- Manitoba Hydro is not anticipating any operational challenges and/or emerging reliability issues in its assessment area for Winter 2025–2026.
- Manitoba Hydro expects to reliably supply its internal demand and export obligations even under continued drought conditions.
- Manitoba Hydro is experiencing well below-average water supply conditions; however, the Manitoba Hydro system is designed and operated such that reliable operations can be maintained under extreme drought.
- The ARM for Winter 2025–26 exceeds the 12% RML.

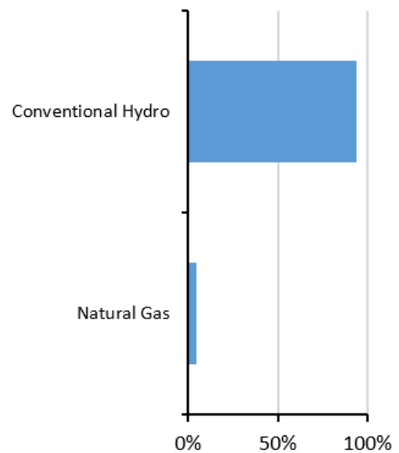
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

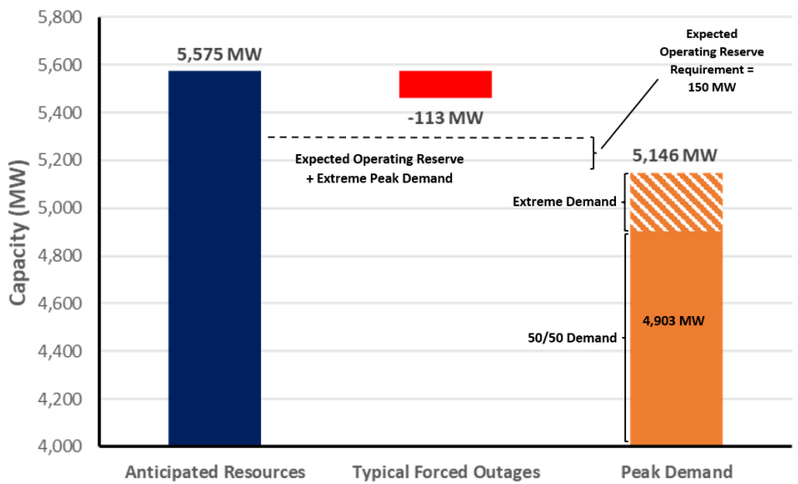
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of weather data

Typical Forced Outages: Accounts for average forced outages



MRO-SaskPower

MRO-SaskPower is an assessment area that covers the Canadian province of Saskatchewan. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and a population of just over 1.1 million people. The Saskatchewan Power Corporation (SaskPower) is the PC and RC for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial Crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan Bulk Electric System (BES) and its interconnections. Overall, SaskPower operates nearly 14,816 circuit-km of transmission lines, 65 high-voltage switching stations, and 191 distribution substations. Peak electricity demand on the SaskPower system currently occurs during the winter season.

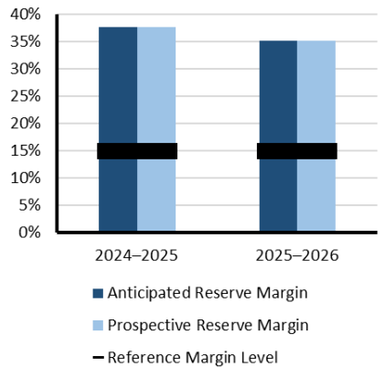
Highlights

- Saskatchewan experiences its peak load during the winter months due to extreme cold weather.
- Based on the planned maintenance, typical forced outages from historical data, and expected renewable generation under the normal and extreme demand conditions, SaskPower does not anticipate any reliability issues during the 2025–2026 Winter.
- During extreme winter conditions, SaskPower would utilize available demand-response programs, short-term power transfers from neighboring utilities, maintenance rescheduling, and/or short-term load interruptions to manage the situation.

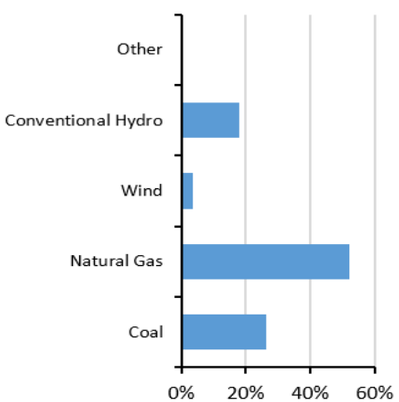
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

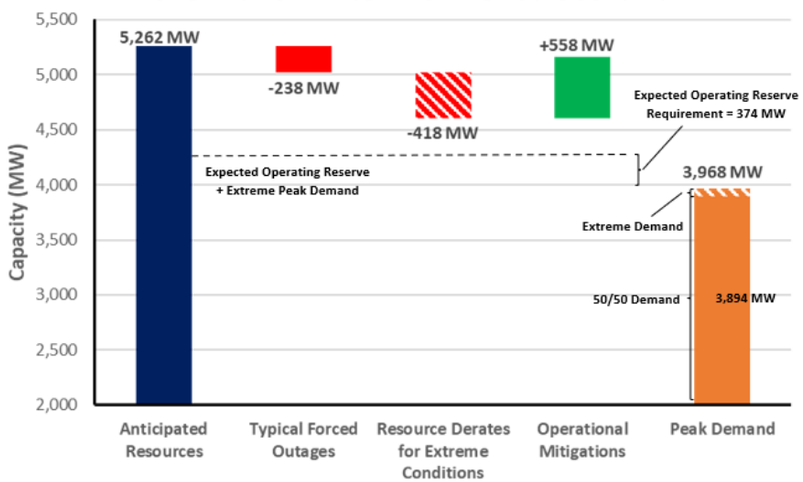
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Based on the historical load variability, SaskPower calculates a probability density function for load to simulate various scenarios that include extreme conditions.

Typical Forced Outages: Estimated using SaskPower forced outage model

Resource Derates for Extreme Conditions: Wind capacity is derated by 96% due to the cut-out of most wind farms below -30°C. Solar generation is expected to be fully unavailable under extreme conditions.

Operational Mitigations: Includes the non-firm import capability (360 MW) and generators in layup status (167 MW) that can be brought online with one to five days' notice; additional demand-side resources are estimated based on other demand response programs and non-firm loads that require 15 minutes to 2 hours of notification



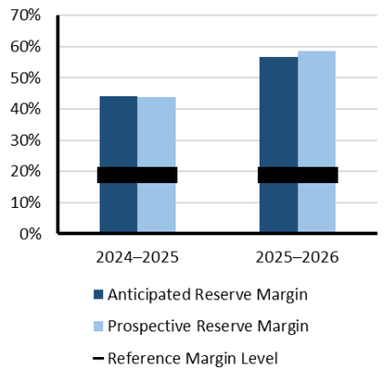
MRO-SPP

SPP's footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the PC footprint, which touches parts of the MRO Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.

Highlights

- SPP anticipates that planning reserves are adequate for the upcoming winter season even as SPP continues to set new winter season load records.
- SPP does not anticipate any emerging reliability issues impacting the area for the 2025–2026 Winter season but realizes that interruptions to fuel supply combined with higher penetration of variable energy resources could create unique operation challenges.
- SPP continues to work at enhancing communications and operator preparedness with neighboring regions to address potential electric deliverability issues associated with extreme weather events.
- To minimize conservative operations, EEAs, and mid-range forecast error uncertainty response in wind forecasts, SPP implemented several new operational mitigation processes and procedures to deal with high-impact real-time areas of reliability concern.
- SPP has proposed numerous resource adequacy initiatives, including addressing EUE standards, fuel assurance, winter planning reserve margins, outage policies, demand response, and accreditation; all were recently approved by FERC.

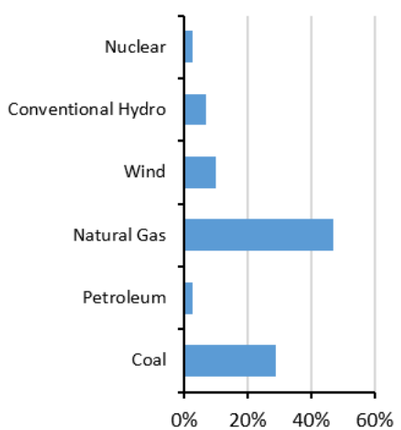
On-Peak Reserve Margin



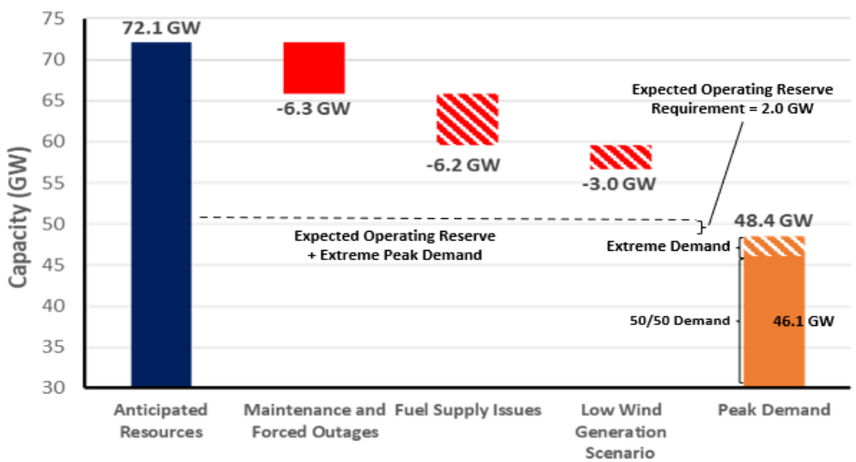
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast using historical data

Maintenance and Forced Outages: A capacity derate of 6.3 GW for maintenance outages, forced outages, and performance in extreme weather based on historical data

Fuel Supply Issues: BA derate of 6.2 GW based on MW capacity of gas-fired generators experiencing fuel supply issues in winter storm Elliott.

Low Wind Generation Scenario: 3 GW of wind potentially off-line when temperatures fall below their cold weather performance packages



NPCC-Maritimes

NPCC-Maritimes is an assessment area that covers the Canadian Maritime provinces—New Brunswick, Nova Scotia, and Prince Edward Island—and the northernmost portion of the U.S. state of Maine. The area covers approximately 150,000 square kilometers (58,000 square miles) and has a total population of nearly 1.9 million people. The New Brunswick Power Corporation (NB Power) is the balancing authority for New Brunswick, Prince Edward Island, and the northern portion of Maine. Nova Scotia Power Inc. (NSPI) is the balancing authority for Nova Scotia. NB Power's system is electrically interconnected with NPCC-Québec and NPCC-New England, and the electric systems in the provinces of Nova Scotia and Prince Edward Island have ties with New Brunswick but no direct ties with other assessment areas. Peak electricity demand in NPCC-Maritimes occurs during the winter season.

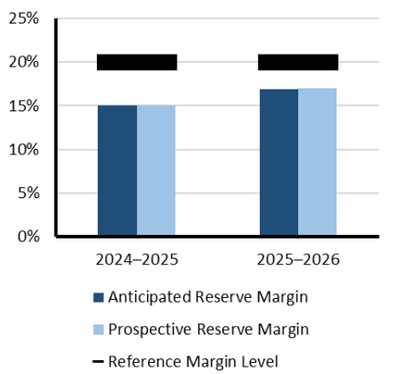
Highlights

- The Maritimes has a diversified mix of capacity resources fueled by oil, coal, hydro, nuclear, natural gas, wind, dual-fuel oil/gas, tie benefits, and biomass with no one type making up more than about 27% of the total capacity in the area.
- The Maritimes has long-term energy contracts in place for its winter supply and can purchase additional energy in the day-ahead and in real time as required.
- As part of the winter planning and preparation process, dual-fueled units will have sufficient supplies of heavy fuel oil stored on site to enable sustained operation in the event of natural gas supply interruptions.

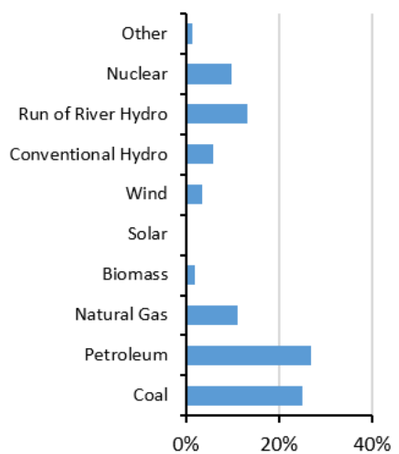
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand scenarios. Normal winter peak load and outage conditions could result in the need for operating mitigations (i.e., demand response, transfers, appeals) and EEAs. NPCC probabilistic analysis indicates some risk of unserved energy and LOLH under high demand or low resource scenarios.

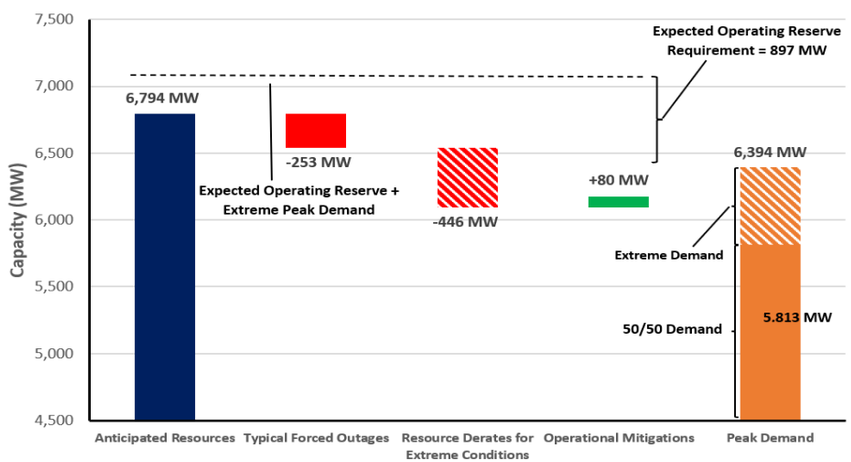
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Scenario peak load with adjustment calculated by adding a 10% margin of error to the peak internal demand forecast taken from the *Long-Term Reliability Assessment* (LTRA) for the 2025–2026 Winter period (aligns with the all-time winter peak, which occurred on February 4, 2024)

Typical Forced Outages: Based on historical operating experience

Resource Derates for Extreme Conditions: Based on ambient temperature thermal derates, wind derated to zero, as well as natural gas capacity derated by 50% due to supply issues

Operational Mitigations: Based on emergency operations and planning procedures in place including fuel switching



NPCC-New England

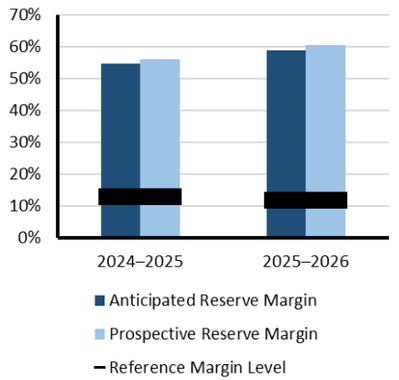
NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont that is served by ISO New England (ISO-NE) Inc. ISO-NE is a regional transmission organization that is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS.

The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

Highlights

- ISO-NE expects to meet its regional resource adequacy requirements this 2025–2026 Winter operating period without calling upon operating procedures to maintain a balance between electricity supply and demand.
- A standing concern is whether there will be sufficient energy available to satisfy electricity demand during an extended cold spell given the existing resource mix, fuel delivery infrastructure, and expected fuel arrangements without considerable effort to replenish stored fuels (i.e., fuel oil and liquefied natural gas (LNG)).
- ISO-NE expects to have sufficient capacity resources to meet the 2025–2026 50/50 and 90/10 winter peak demand forecast of 19,616 MW and 21,125 MW, respectively, for the weeks beginning January 10, January 17, and January 24.
- ISO-NE has recently developed the Regional Energy Shortfall Threshold (REST) as an effort to quantify the tolerable risk of energy shortfall during extreme events. Within the 0.25% highest-risk scenarios, the REST thresholds are 3.0% normalized EUE over 72-hour periods and 18.0 hours over 21-day periods.
    - ISO-NE does not anticipate exceeding the REST criteria for Winter 2025–2026.

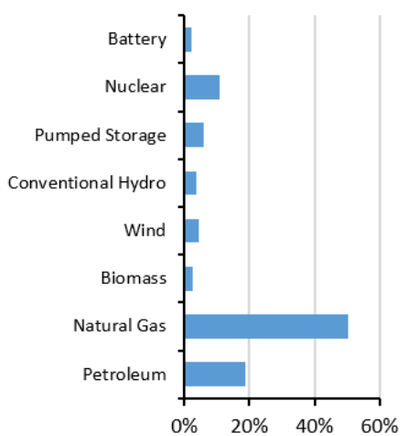
On-Peak Reserve Margin



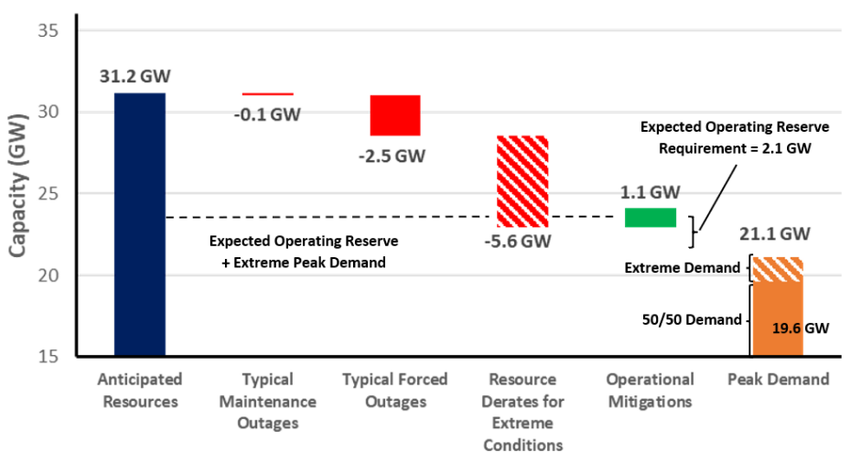
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed demand scenarios. Above-normal winter peak load combined with high generator outages could result in the need for operating mitigations (i.e., demand response and transfers). Prolonged extreme cold weather events that result in depletion of stored fuels can lead to resource shortfalls.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Peak net internal demand (50/50) and (90/10) extreme demand forecast capturing the region's coldest day in the last 30 years using current and future load models

Typical Maintenance Outages: Based on historical weekly averages

Typical Forced Outages: Based on seasonal capacity of each resource as determined by ISO-NE

Resource Derates for Extreme Conditions: Represent a case that is beyond the (90/10) conditions based on historical observation of force outages and additional reductions for generation at risk due to natural gas supply and cold weather-related outages

Operational Mitigations: Based on load and capacity relief assumed available from invocation of ISO-NE operating procedures



NPCC-New York

NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only BA within the state of New York. The BPS in New York encompasses over 11,000 miles of transmission lines and 760 power generation units and serves 20.2 million customers. For this WRA, the established RML is 15%. Wind, grid-connected solar PV, 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. The council approved the 2025–2026 IRM at 24.4%.

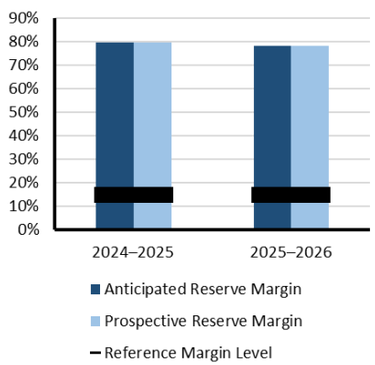
Highlights

- New York is presently a summer-peaking area, and no emerging reliability issues are anticipated during the 2025–26 Winter assessment period.
- Expected resources meet operating reserve requirements under the assessed demand and resource scenarios. A scenario involving an extended cold snap that causes above-normal demand and diminished natural gas supplies would result in low but sufficient reserves.
- The preliminary results of the NPPCC winter probabilistic assessment indicate that operating procedures are not needed to maintain a balance between electricity supply and demand. No cumulative LOLE, LOL,H or EUE risks were indicated over the December–February winter period for all the scenarios modeled.

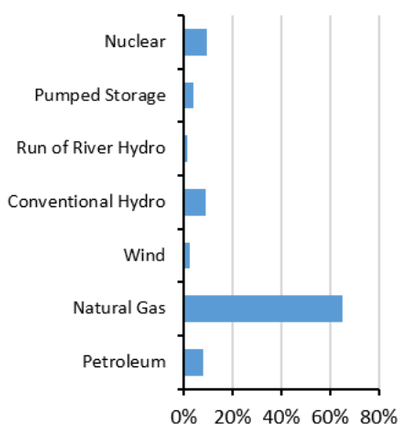
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed demand and resource scenarios.

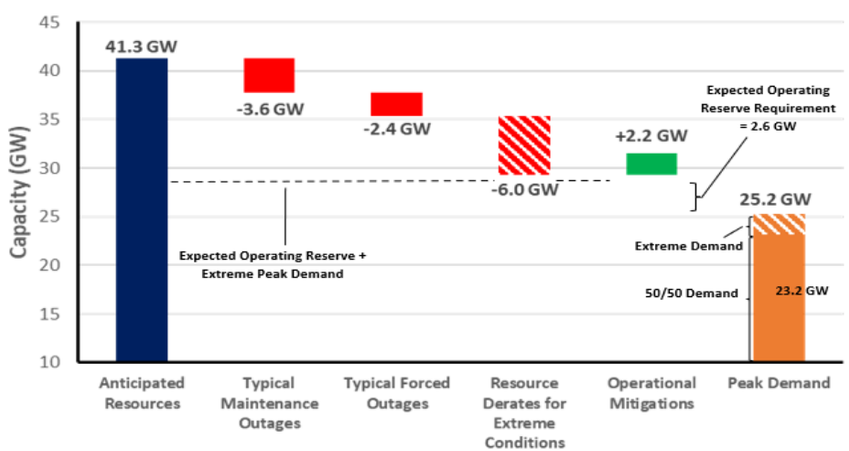
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Typical Maintenance Outages: Based on planned scheduled maintenance

Typical Forced Outages: Based on 5–year averages from GADS data.

Resource Derates for Extreme Conditions: Potential natural gas generation at risk if non-firm supply is unavailable in a period of extended cold weather. Based on a 2025 analysis, approximately 6,307 MW of gas generation with non-firm fuel supplies could be unavailable.

Operational Mitigations: Based on NYISO operating procedures



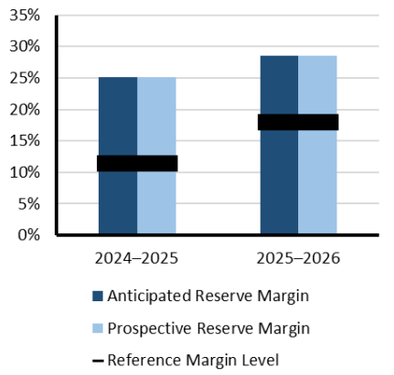
NPCC-Ontario

NPCC-Ontario is an assessment area that covers the Canadian province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of almost 16 million people. The Independent Electricity System Operator (IESO) is the balancing authority for the province of Ontario. NPCC-Ontario is electrically interconnected with NPCC-Québec, MRO-Manitoba, MISO, and NPCC-New York. Peak electricity demand in NPCC-Ontario occurs during the summer season.

Highlights

- As Ontario is a summer-peaking province, there is typically a lower risk of reliability issues during the winter than the summer. However, Ontario regularly experiences extreme cold weather in the winter.
- NPCC-Ontario is well prepared for Winter 2025–2026, and IESO expects that the electric system will remain reliable with reserve margins well above required levels.
- Operators and forecasters in Ontario work closely with neighboring jurisdictions to manage extreme weather events.
- Natural-gas-fired generators in Ontario are supplied by pipelines with access to the Enbridge Gas Dawn Hub and its associated storage facilities, which significantly reduces natural gas deliverability and reliability concerns by connecting those systems to several major gas transportation corridors, enabling access to multiple supply basins.

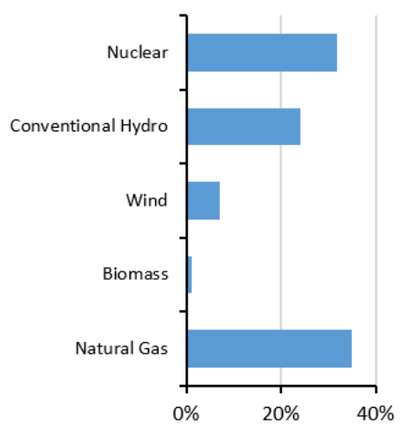
On-Peak Reserve Margin



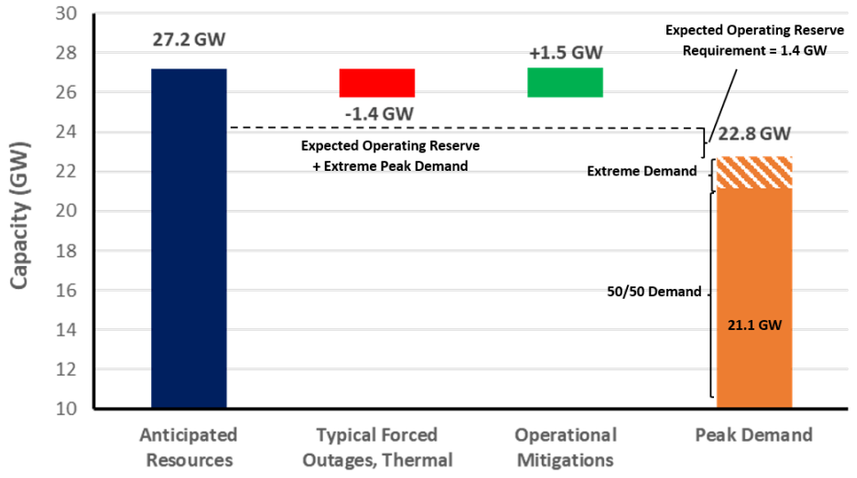
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50 forecast) and highest weather-adjusted daily demand from 31 years of winter demand history

Typical Forced Outages, Thermal: Based on analysis of a rolling five-year history of actual forced outage data.

Operational Mitigations: Imports anticipated from **neighbors** during emergencies



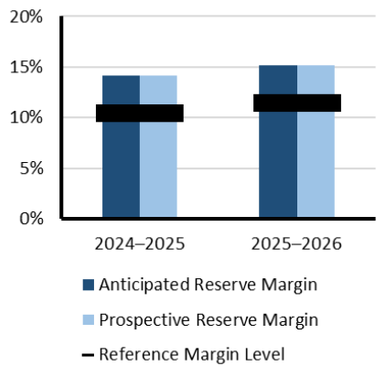
NPCC-Québec

NPCC-Québec is an assessment area that covers the Canadian province of Québec. The province of Québec covers over 1.5 million square kilometers (nearly 600,000 square miles) and has a population of 9 million people. Hydro-Québec is the BA for the province of Québec. The Québec BPS is one of the four electric Interconnections in North America. It is a predominately hydroelectric-generation-based system that is electrically interconnected with NPCC-Ontario, NPCC-New York, NPCC-New England, and NPCC-Maritimes. Peak electricity demand in NPCC-Québec occurs during the winter season.

Highlights

- NPCC-Québec projects adequate capacity margins above its reference reserve requirements and that system resource adequacy will be maintained for the province for the 2025–26 Winter assessment period.
- No hydropower performance issues are expected during extreme cold because of design criteria for cold weather.
- No fuel supply or transportation issues are anticipated for the upcoming winter season.
- While a slight decrease in net firm transfers has occurred since last winter (-89 MW), significant increases in demand-side management programs (+450 MW year-over-year) have been realized over the same period and are expected to compensate for this winter's modest expected load growth.

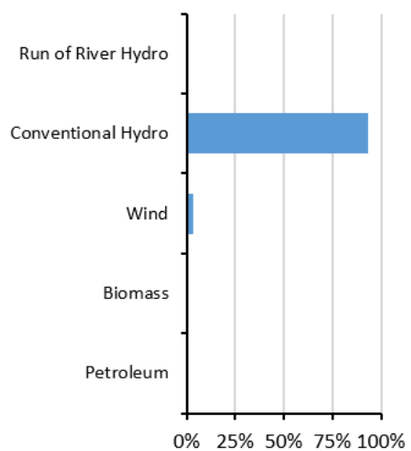
On-Peak Reserve Margin



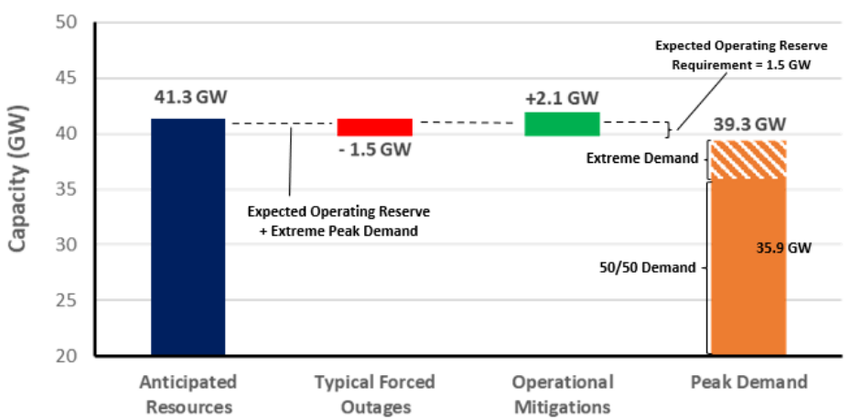
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at hour ending 8:00 a.m.

Demand Scenarios: Demand forecasts include demand-side resources. The demand side resources are the same for the 50/50 and extreme demand scenarios. The extreme load forecast is determined at two standard deviations higher than the mean, which has a 6.06% probability of occurrence.

Extreme Derates: Maintenance outages and other deratings are already included in existing-certain capacity calculation. Wind capacity is 64% derated

Typical Forced Outages: Unplanned outages are 1,500 MW.

Operational Mitigations: Operational mitigations include imports from neighboring areas and reduction of reserves



PJM

PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM's footprint covers approximately 369,054 square miles and with an approximate population of 67 million people. PJM is the area's BA, Transmission and Resource Planner, interchange authority, TOP, transmission service provider, and RC. PJM is electrically interconnected with MISO, NPCC-New York, SERC-Central, and SERC-East. Peak electricity demand in PJM occurs during the summer season.

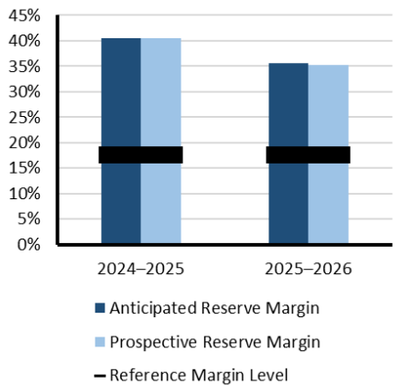
Highlights

- Due to the low penetration of limited and variable resources in PJM relative to PJM's peak load, the hour with highest loss-of-load risk remains the hour with highest forecasted demand.
- PJM is expecting little capacity adequacy risk during Winter 2025–2026 and expects around 35% installed reserves, which is above the target IRM of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion.
- Last winter, PJM hit a new all-time winter peak, but generator preparations anticipating congestion and tight capacity projections led to sufficient reserves throughout the demand event and PJM's transmission system performed well.
- The decrease in reserves from Winter 2024–2025 is due to load increases and retirement of generation without like (non-solar dispatchable) replacement generation.

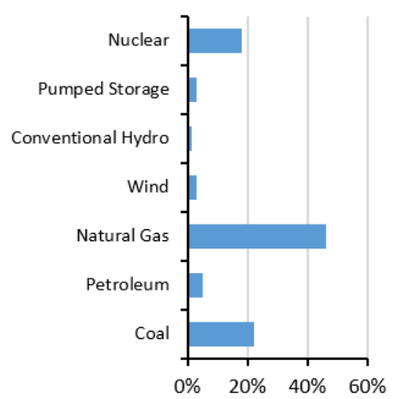
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

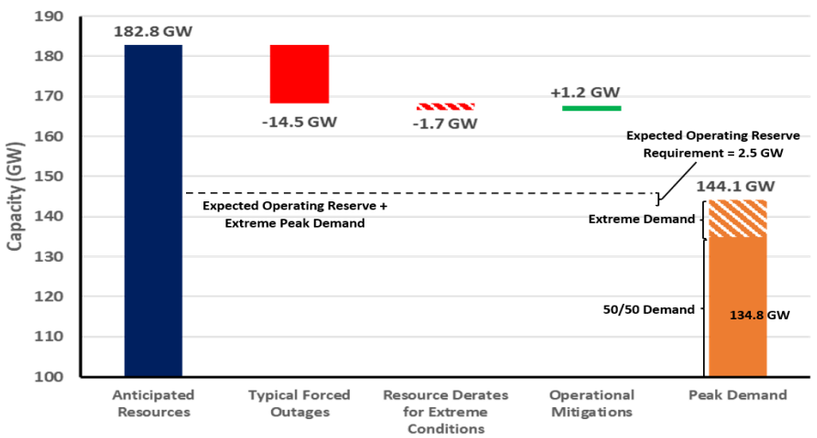
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Typical Forced Outages: Based on historical data and trending

Resource Derates for Extreme Conditions: Reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: accounts for an estimated value based on operational / emergency procedures



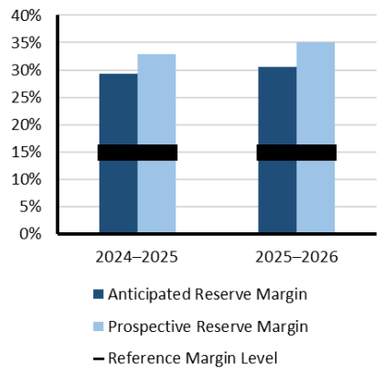
SERC-Central

SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC-Central is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

- SERC-Central is transitioning from a summer-peaking area to a dual-peaking system.
- For the 2025–2026 Winter, SERC-Central projects a sufficient level of resources to serve the expected load under median weather and typical system operating conditions, based on the 2024 NERC ProbA base-case results.
- Most entities across SERC-Central report that fuel security is strong since it is supported by firm natural gas contracts, storage resources, and reliable pipeline capacity. Coal inventories are projected to remain within operational ranges necessary to meet winter demand.
- Following lessons from Winter Storm Elliott, one SERC-Central entity raised its winter Planning Reserve Margin target to 26% and updated preparedness programs with improved heat trace capabilities.

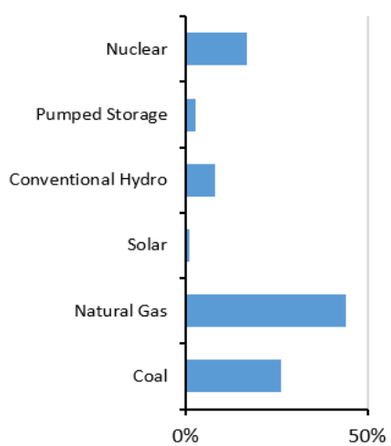
On-Peak Reserve Margin



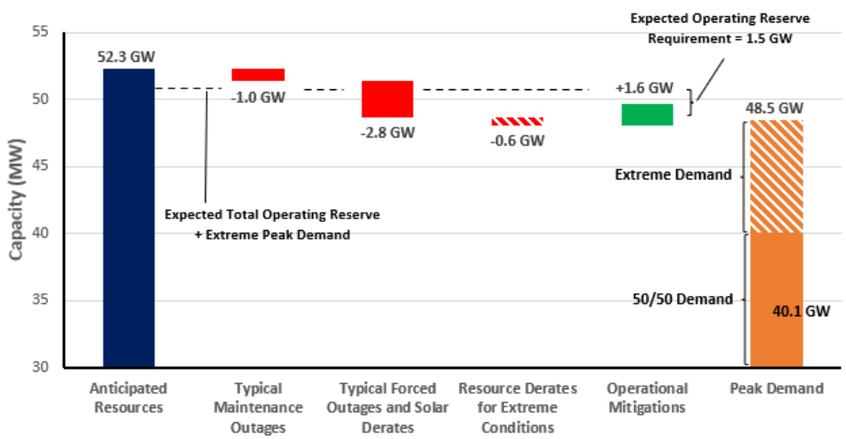
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand. A severe cold weather event that extends to the south could lead to energy emergencies as operators face sharp increases in generator forced outages and electricity demand. Above-normal winter peak load and outage conditions could result in the need for operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Typical Maintenance Outages: Data collected through a survey of members for expected outages during December through February

Typical Forced Outages and Solar Derate: Includes any weighted average forced-outage rates on-peak that are not factored into the anticipated resources calculation . Also, solar resources are derated to account for peak demand occurrence during darkness.

Resource Derates for Extreme Conditions: Entity-provided values for low likelihood extreme conditions

Operational Mitigations: A total of over 1.6 GW based on operational/emergency procedures



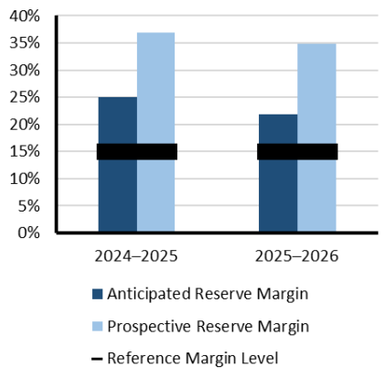
SERC-East

SERC-East is an assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina. Historically a summer-peaking area, SERC-East is beginning to have higher peak demand forecasts in winter. SERC is one of the six Regional Entities across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central United States. The SERC Regional Entity covers approximately 630,000 square miles with a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities (PA), and 6 RCs.

Highlights

- SERC-East is transitioning from a summer-peaking area to potentially peaking during both summer and winter. This shift is attributed to the continued addition of solar PV generation, which reduces summer peak demand, and a trend toward electrification of heating, which drives up winter peak demand.
- For the 2025–2026 Winter, the SERC-East region projects a sufficient level of resources to serve the expected load under median weather and typical system operating conditions, based on the 2024 NERC ProbA base-case results.
- Fuel supplies and transportation remain stable, and entities anticipate maintaining adequate coal and oil inventories with no reported changes to fuel procurement or operator plans for the upcoming winter.
- Probabilistic Base Case Results (Median Weather): EUE is 61.95 MWh and LOLH is 0.06 hours/year. EUE values are likely due to higher winter peaks and/or lower supply of capacity that can meet early winter morning demand.
- Mitigation measures for extreme conditions include voltage reduction (25–50 MW) and load-shedding programs that cover up to 30% of system load.

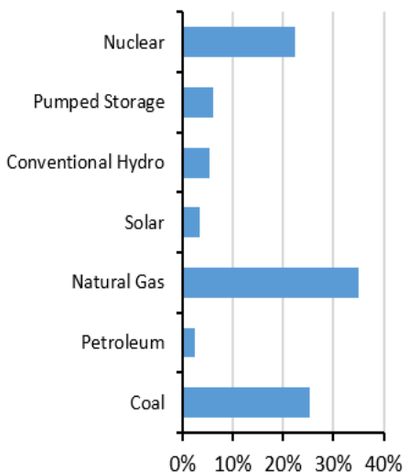
On-Peak Reserve Margin



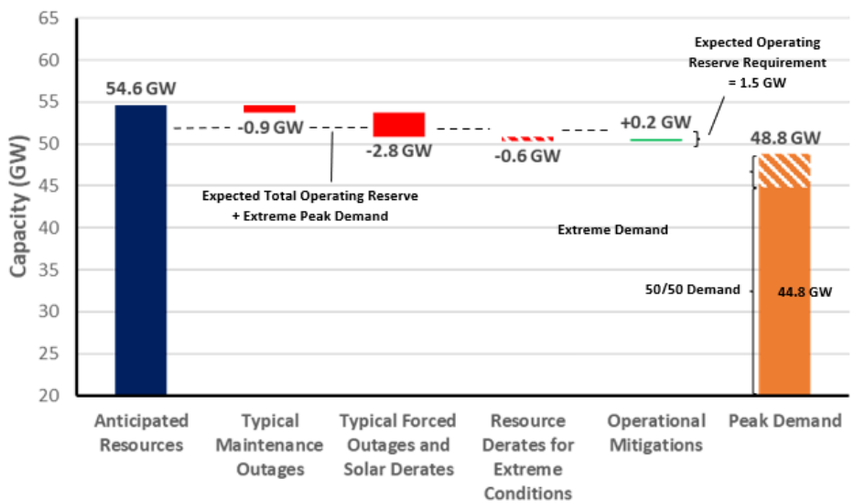
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal demand scenarios. A severe cold weather event extending to the south could lead to energy emergencies as operators face sharp increases in generator forced outages and electricity demand. Above-normal winter peak load and outage conditions could result in the need for operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Typical Maintenance Outages: Data collected through a survey of members for outages during December through February

Typical Forced Outages and Solar Derate: Weighted average forced-outage rates on-peak are factored into the anticipated resources calculation. Also, solar resources are derated to account for peak demand occurrence during darkness.

Resource Derates for Extreme Conditions: Maximum historical generation outages (excluding 2022–2025)

Operational Mitigations: A total of 0.2 GW based on operational/emergency procedures



SERC-Florida Peninsula

SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six Regional Entities across North America that is responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central United States. The SERC Regional Entity area covers approximately 630,000 square miles with a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 PAs, and 6 RCs.

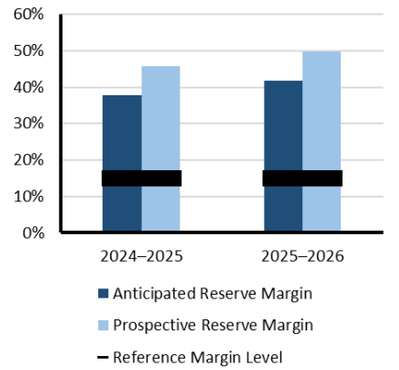
Highlights

- SERC-Florida Peninsula is a summer-peaking assessment area.
- Florida Peninsula entities have not identified any emerging reliability issues for the upcoming 2025–26 Winter season with an ARM projected at 39%, well above the RML, while the 2024 NERC ProbA base-case results project a sufficient level of resources to serve the expected load under median weather and typical system operating conditions (EUE is 1.09 MWh and LOLH is 0.00 hours/year).
- Many entities report strong fuel security, supported by firm natural gas contracts, storage resources, reliable pipeline capacity, and actively managed coal and oil inventories, which are projected to remain within operational ranges to meet winter demand.
- Florida Peninsula entities do not assume non-firm external assistance from neighboring areas during extreme conditions.

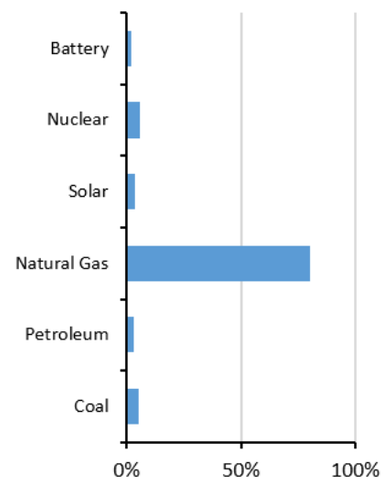
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

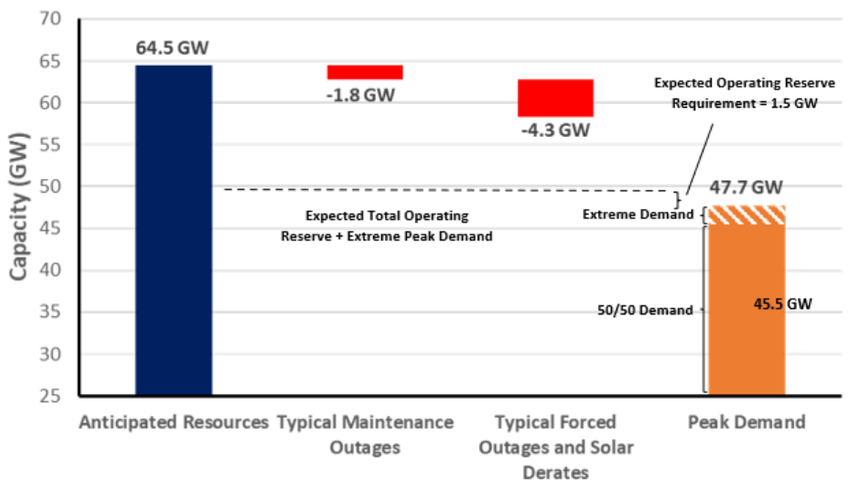
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Typical Maintenance Outages: Data collected through a survey of members for outages during December through February

Typical Forced Outages and Solar Derate: Weighted average forced-outage rates on-peak are factored into the anticipated resources calculation. Also, solar resources are derated to account for peak demand occurrence during darkness.

Resource Derates for Extreme Conditions: Entity-provided values for low likelihood extreme conditions



SERC-Southeast

SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six Regional Entities across North America that is responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central United States. The SERC Regional Entity covers approximately 630,000 square miles with a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 PAs, and 6 RCs.

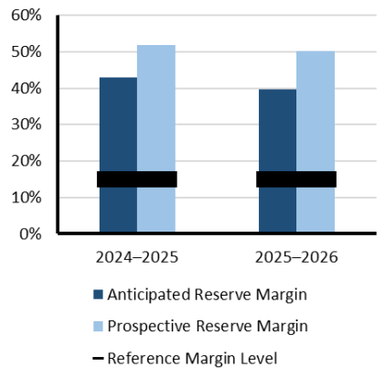
Highlights

- SERC-Southeast is trending towards becoming slightly winter-peaking.
- For the 2025–2026 Winter, SERC-Southeast entities report no emerging reliability concerns and expect to have adequate resources, supported by firm natural gas transportation contracts, diverse fuel portfolios, and sufficient on-site coal inventories to serve the expected load under typical system operating conditions. The 2024 NERC ProbA base-case results in EUE and LOLH are both 0.00.
- While most SERC-Southeast BAs expect to have adequate resources, supported by firm natural gas transportation contracts, diverse fuel portfolios, and sufficient on-site coal inventories, one BA highlights potential risks related to natural gas transportation capacity, citing high pipeline utilization, competition for delivered gas, and ratable flow requirements. Mitigation strategies include securing third-party gas supply, adding dual-fuel capability, and implementing coal inventory management.
- Entities have made refinements such as replacing specific 230 kV circuit breakers and increasing monitoring frequencies for critical plant systems after January 2025 winter events.

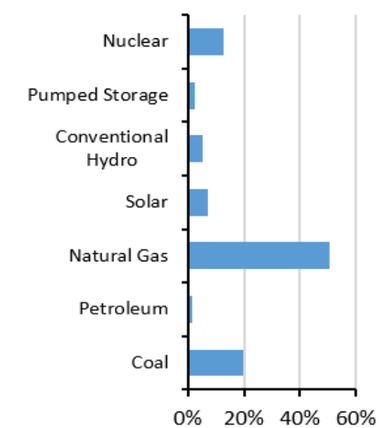
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

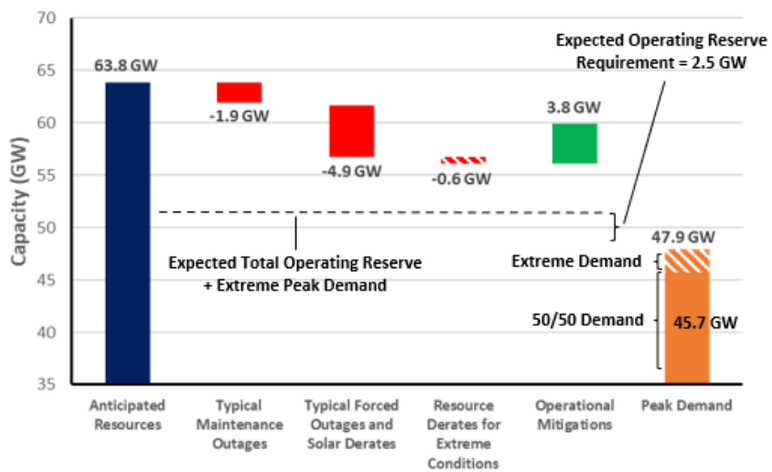
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Typical Maintenance Outages: Data collected through a survey of members for outages during December through February

Typical Forced Outages and Solar Derate: Weighted average forced-outage rates on-peak are factored into the anticipated resources calculation. Also, solar resources are derated to account for peak demand occurrence during darkness.

Resource Derates for Extreme Conditions: Maximum historical generation outages

Operational Mitigations: A total of 3.8 GW based on operational/emergency procedures



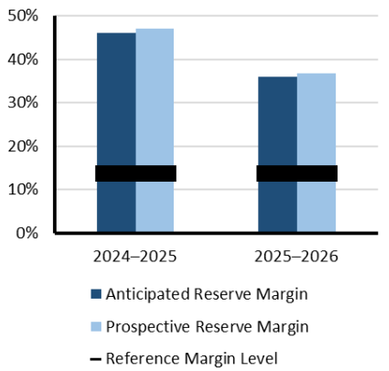
Texas RE-ERCOT

ERCOT is the ISO for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is summer-peaking and covers approximately 200,000 square miles, connects over 54,100 miles of transmission lines, has over 1,250 generation units, and serves more than 27 million customers. Texas RE is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT. On November 3, 2022, the Public Utility Commission of Texas issued an order directing ERCOT to assume the duties and responsibilities of the reliability monitor for the Texas power grid.

Highlights

- Given expected system conditions, an ARM of 36% and RML of 13.75%, ERCOT expects to have sufficient operating reserves for the peak hour ending 8:00 a.m.
- ERCOT does not expect any significant fuel supply issues for the winter.
- ERCOT has conducted 2,028 generation resource and transmission service provider (TSP) winter weatherization inspections since Winter 2021–2022.
- Winter peak demands typically occur before sunrise and after sunset when solar generation is not available. Significant battery storage mitigates these risks.
- ERCOT's probabilistic risk assessment indicates a 2% probability of having to declare EEAs during the January forecasted winter peak day (which coincides with the highest reserve shortage risk) and a controlled load shed probability of 1.8%. ERCOT defines low-risk hours as when the probability of an EEA is less than 10%.
- Increased load growth in west Texas combined with "no solar" and low wind conditions can cause transmission lines into this area to become heavily loaded. ERCOT has introduced improved dynamic line ratings that allow for greater transfers at colder temperatures and periods of low irradiance.

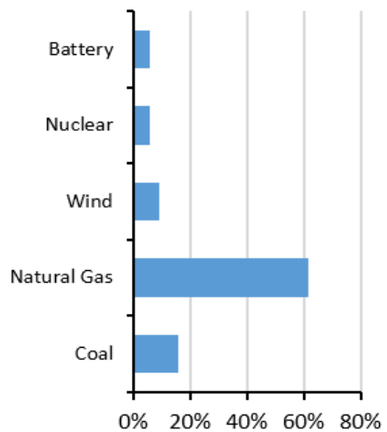
On-Peak Reserve Margin



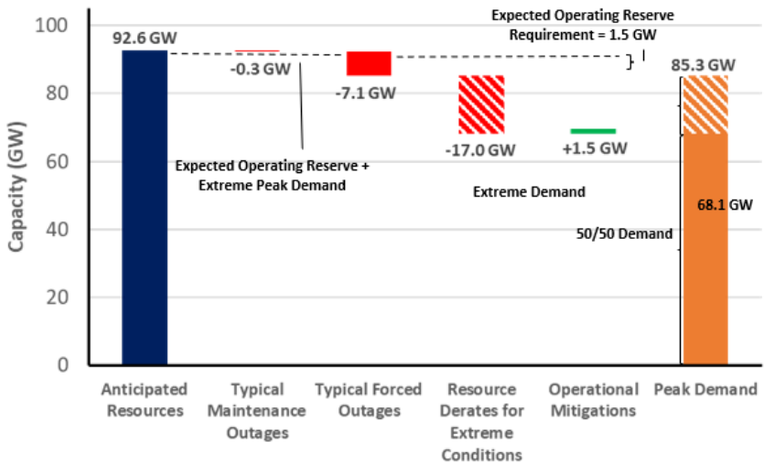
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need for operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Presumes weather conditions comparable to Winter Storm Uri. The adjustment is calculated as the difference between the 100th percentile and 50th percentile values from ERCOT's Probabilistic Reserve Risk Model (PRRM) simulated load outcome distribution for hour ending 8:00 a.m.

Typical Maintenance Outages: Based on historical winter data and consideration of ERCOT's allowed maximum system daily planned outage capacity

Typical Forced Outages: Based on a probability distribution created using historical ERCOT Outage Scheduler data for the last three Januarys.

Resource Derates for Extreme Conditions: Weather-related thermal and wind outages based on Winter Storm Uri levels, adjusted for reductions due to weatherization standards. Also includes high non-weather-related outages.

Operational Mitigations: Additional potential capacity from switchable generation and imports



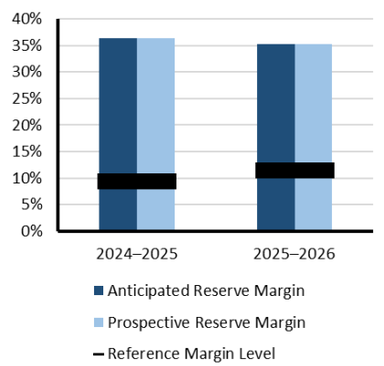
WECC-Alberta

WECC-Alberta is an assessment area that covers the Canadian province of Alberta. The province has a geographic area of 661,848 square kilometers (255,541 square miles) and a population of almost 5 million people. The Alberta Electric System Operator (AESO) is the province's Planning Entity and RC responsible for safe, reliable, and economic operation of the Alberta Interconnected Electric System. AESO is a non-profit corporation that operates a system that includes approximately 26,000 kilometers of transmission lines and connects approximately 426 qualified generating units and nearly 250 market participants through a wholesale market. Alberta's transmission system has three interties with neighboring areas: Saskatchewan (see MRO-SaskPower), British Columbia (see WECC-British Columbia), and Montana (see WECC-Northwest). Peak electricity demand on the AESO system currently occurs during the winter season.

Highlights

- At an extreme winter peak of 12,982 MW, with extreme forced outages at 530 MW and derates for extreme conditions bringing wind energy availability down by 1,800 MW and hydroelectricity by 88 MW, the required reserves are 759 MW and are sufficiently met, even with low availability.
- Demand is expected to increase 1.1% from last winter with the existing-certain installed capacity having increased 23%.
- Solar availability is down because 1,000 MW of PV moved from originally expecting to come on-line in 2024 as Tier 1 resources to Tier 2s mostly anticipated to come on-line in 2025, but with less certainty.

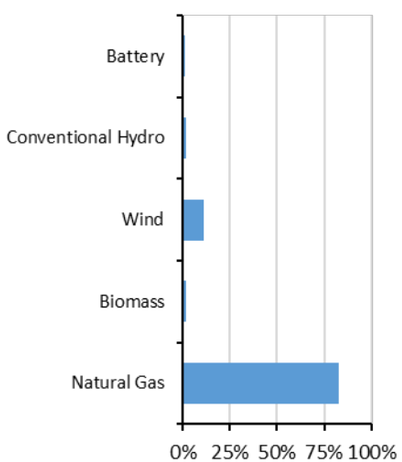
On-Peak Reserve Margin



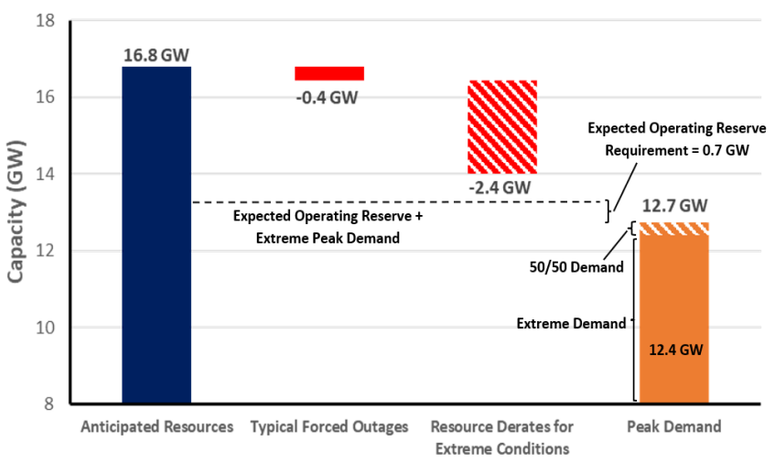
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS data

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period



WECC-Basin

WECC-Basin is a summer-peaking assessment area in the WECC Regional Entity that includes Utah, southern Idaho, and a portion of western Wyoming, covering Idaho Power and PacifiCorp's eastern BA area. The population of this area is approximately 5.4 million. It has 15,910 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025-26 WRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024–25 WRA*.

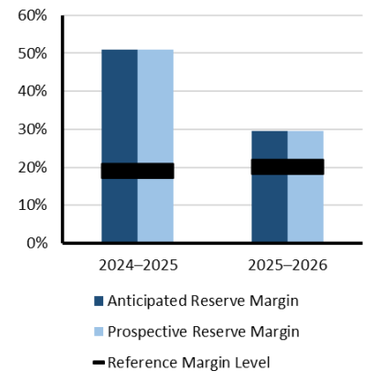
Highlights

- At an extreme winter peak of 11.1 GW under an extreme combination of derates and outages, the region could be short 1.0 GW before imports and is expected to need to rely on transfers.
- Net internal demand is expected to increase 1% since last year, with total internal demand up 1.8% being offset by a doubling of controllable and dispatchable demand response.
- Tier 1 resources have declined and do not appear to be offset by increases in existing-certain generation resource capacity. Nameplate wind has increased by almost 18% and solar by almost 30%. Hydro is also up over 7% in total installed capacity.
- Reliance on imports is expected to be required to maintain resource adequacy during extreme peak demand and extreme derate conditions.

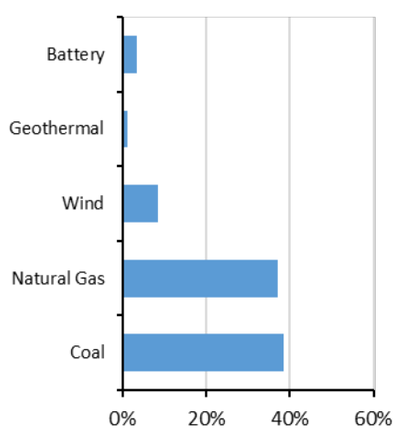
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand scenarios. Above-normal peak demand combined with high generator outages in extreme conditions results in the need for external assistance to maintain reserves.

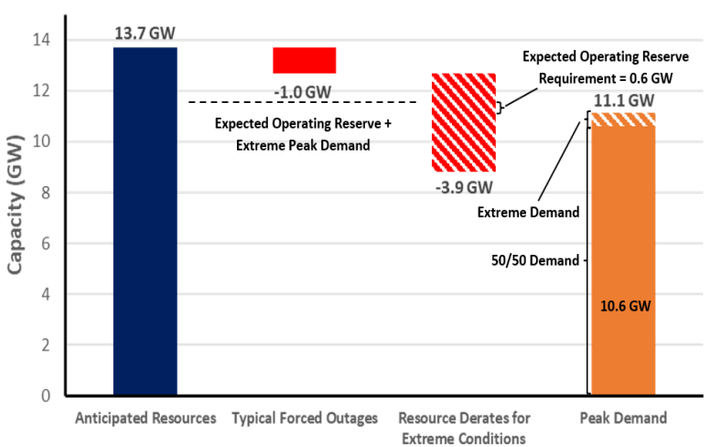
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Extreme Derates: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period



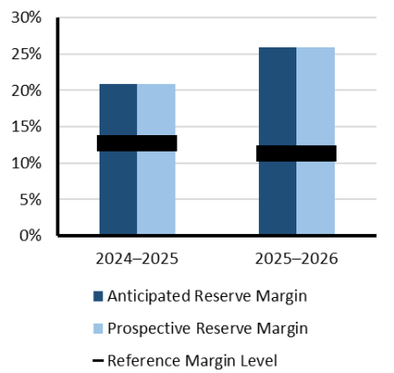
WECC-British Columbia

WECC-British Columbia is an assessment area that covers the Canadian province of British Columbia. The province has a geographic area of 944,735 square kilometers (364,764 square miles) and a population of just over 5 million people. BC Hydro is the Planning Entity and RC for the province of British Columbia and is the principal supplier of electricity for the province. BC Hydro is a provincial Crown corporation and, under provincial legislation, is responsible for the oversight of the British Columbia BES and its interconnections. BC Hydro operates an integrated system supported by 30 hydroelectric plants, approximately 80,000 kilometers of transmission and distribution lines, and 125 contracts with independent power producers. BC Hydro's transmission system has two interties with neighboring areas: the U.S. state of Washington (see WECC-Northwest) and Alberta (see WECC-Alberta). Peak electricity demand on the BC Hydro system currently occurs during winter.

Highlights

- Peak demand is expected to remain about the same as last winter.
- There are about 200 MW more (47%) planned Tier 1 resources for this winter than last.
- Solar nameplate capacity has increased from 2 MW to 17 MW since last winter and hydroelectric nameplate capacity is up more than 5%, or 1,366 MW.

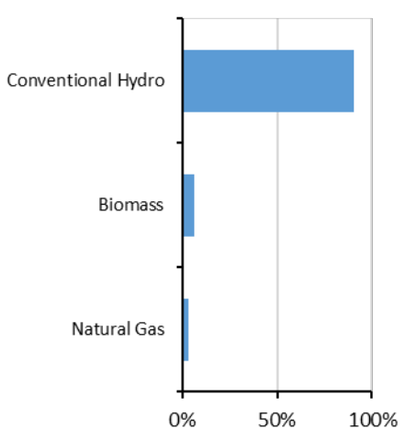
On-Peak Reserve Margin



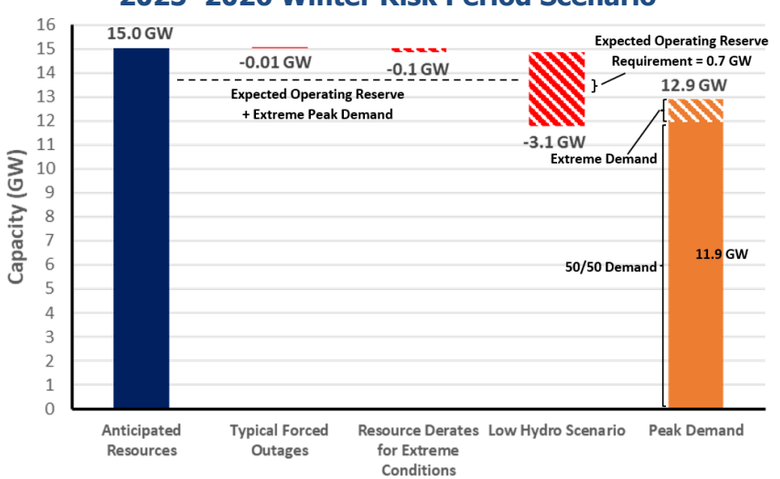
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal and extreme demand scenarios.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period

Low Hydro Scenario: Estimated derate for lower hydro output



WECC-California

WECC-California is a summer-peaking assessment area in the Western Interconnection that includes most of California and a small section of Nevada. The assessment area has a population of over 42.5 million people. The area includes the California ISO, the Los Angeles Department of Water and Power, the Turlock Irrigation District, and the Balancing Area of Northern California. It has 32,712 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025–26 WRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024–25 WRA.*

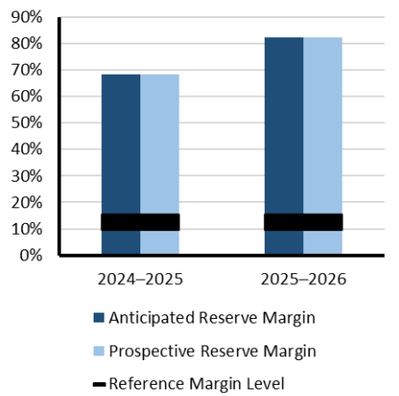
Highlights

- Operating reserve margins are met before imports in all winter resource availability scenarios.
- On-peak demand is expected to remain about the same as last winter. Demand-side management is down about 10%.
- Existing-certain capacity is up almost 5%, while planned Tier 1 resources are up more than 2 GW. The total wind nameplate capacity is up almost 27% and solar almost 13%. Hydro is down 4%.
- No reliance on imports is expected to be required to maintain resource adequacy for Winter 2025–2026.

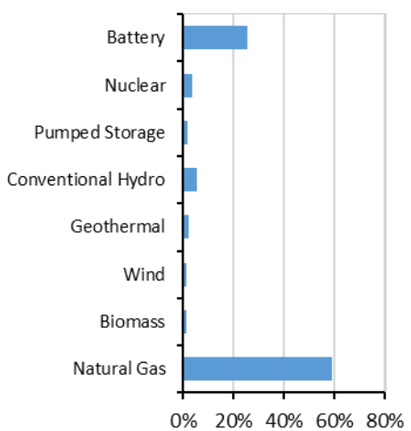
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

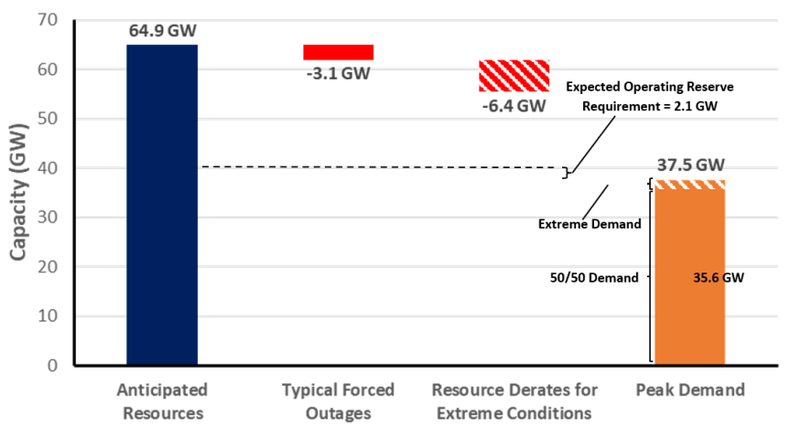
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period



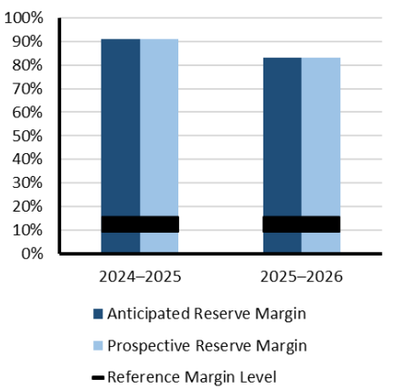
WECC-Mexico

WECC-Mexico is a summer-peaking assessment area in the Western Interconnection that includes the northern portion of the Mexican state of Baja California, which has a population of 3.8 million people and includes CENACE. It has 1,568 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025–26 WRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024–25 WRA.*

Highlights

- As a summer-peaking region, operating reserve margins are met before imports in all scenarios.
- Planned Tier 1 resources are down 100% to zero as expected resources have either been brought on-line to move into existing or, in the case of some natural gas, have been delayed until 2026 and moved into Tier 2.
- The existing-certain on peak reserve margin is down by 5.2%, and the anticipated and prospective reserve margins are down by 7.8%; however, since Mexico is heavily summer-peaking, the 83% reserve margin still exceeds the RML of 12.5%, which remains unchanged.

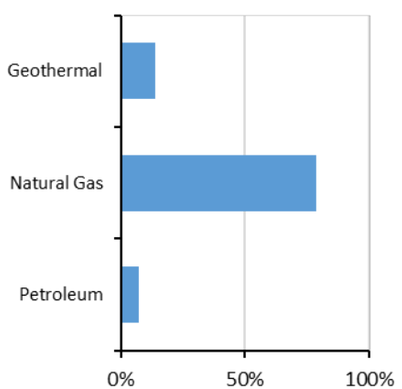
On-Peak Reserve Margin



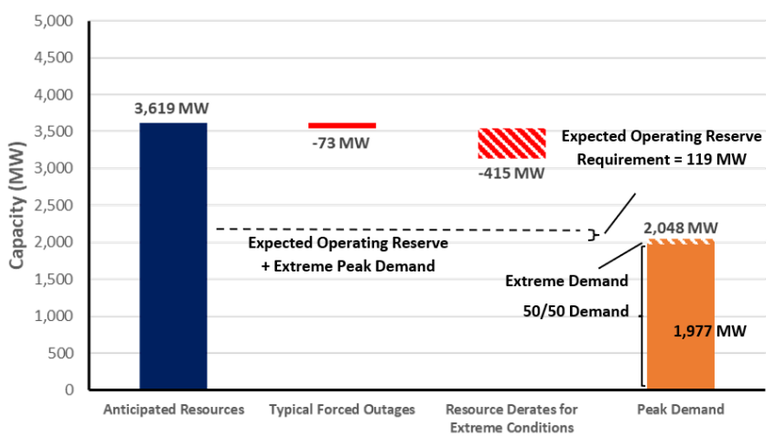
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period



WECC-Northwest

WECC-Northwest is a winter-peaking assessment area in the WECC Regional Entity. The area includes Montana, Oregon, and Washington and parts of northern California and northern Idaho. The population of the area is approximately 13.6 million. It has 32,751 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025–26 WRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024–25 WRA.*

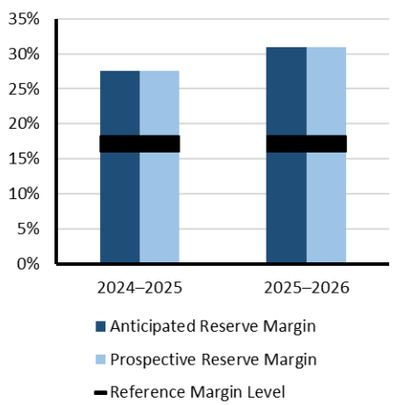
Highlights

- The Northwest has historically been a mixed season-peaking region.
- Operating reserve margins are expected to be met after imports in all winter scenarios.
- Total and net internal demand are up 9.3% with the primary drivers being data centers, residential electrification, transportation electrification, and semiconductor manufacturing.
- Large coal unit retirements and conventional hydro unit retirements are attributable to the reduction in existing certain capacity of 10.5%; however, planned Tier 1 resources have soared over 580%, from 463 MW to over 3 GW.
- Nameplate wind capacity is up over 3 GW (26%) and solar nameplate capacity is up nearly 2,690 MW (134%), which has also increased the solar availability on the peak hour.
- An increase in firm imports is seen in the model, 6.1 GW, absorbing the reduction in existing certain capacity of 4 GW.

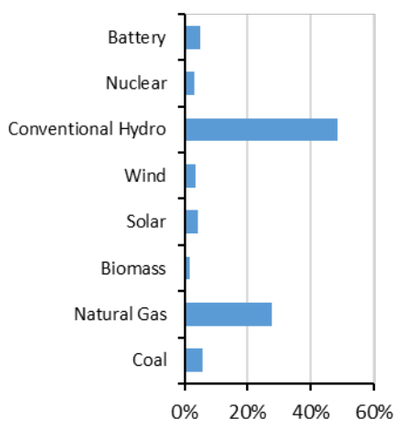
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand scenarios. Above-normal peak demand combined with high generator outages in extreme conditions results in the need for external assistance to maintain reserves.

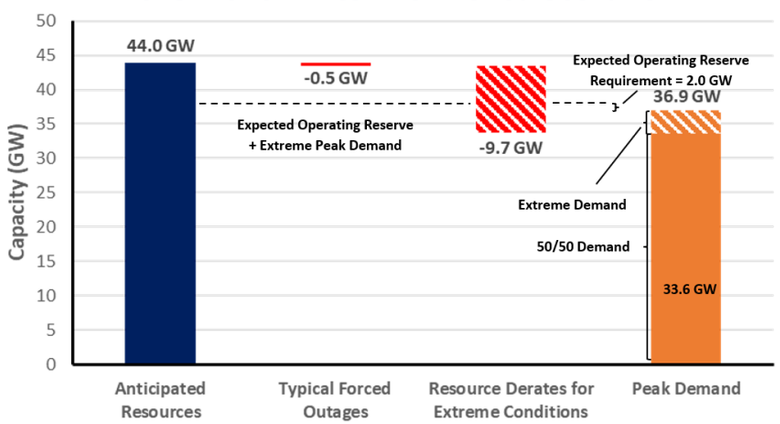
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period. This value includes 6.8 GW of hydro derates.



WECC-Rocky Mountain

WECC-Rocky Mountain is a summer-peaking assessment area in the Western Interconnection that includes Colorado, most of Wyoming, and parts of Nebraska and South Dakota. The population of the area is approximately 6.7 million. It covers the balancing areas of the Public Service Company of Colorado and the Western Area Power Administration's Rocky Mountain Region. It has 18,797 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note The 2025–26 WRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024–25 WRA.*

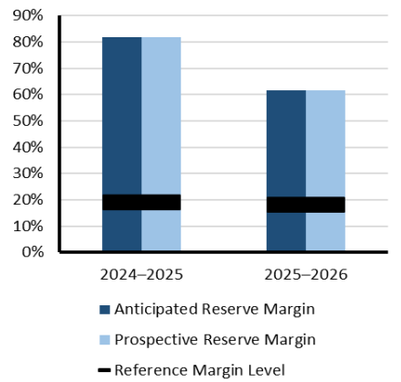
Highlights

- In Rocky Mountain, operating reserve margins are expected to be met before imports in all winter scenarios.
- Total and net internal demand are up almost 1%. The primary drivers are data centers and commercial and industrial customer growth.
- Planned Tier 1 resources are up over 84%, from almost 200 MW to over 365 MW. Solar nameplate capacity is up 27%; however, on-peak solar energy availability is down 100% due to the shift to after sunset. Expected hydro on peak energy availability is also down by around a quarter on the peak hour. Existing-Certain, Anticipated, and Prospective Reserve Margins are all down by over 20% on the peak hour; however, the region still maintains resource adequacy with margins hovering around 60% compared to the RML of 18%.
- No reliance on imports is expected to be required to maintain resource adequacy under combined extreme peak and extreme derated conditions.

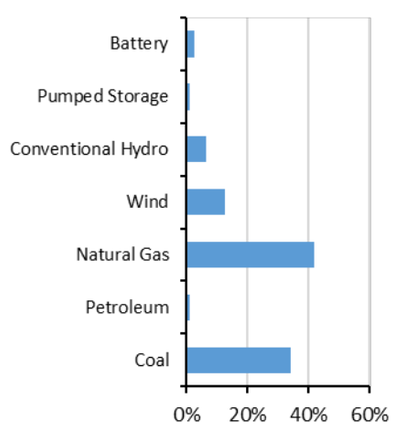
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

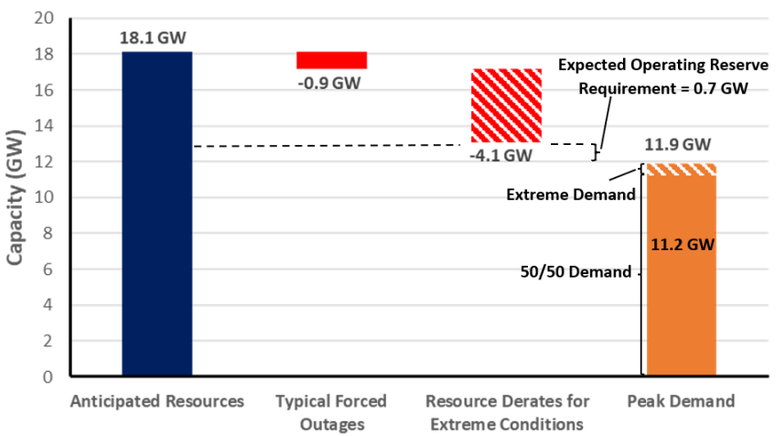
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period



WECC-Southwest

WECC-Southwest is a summer-peaking assessment area in the Western Interconnection that includes all of Arizona and New Mexico, most of Nevada, and small parts of California and Texas. The area has a population of approximately 13.6 million. It has 23,084 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note The 2025–26 WRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024–25 WRA.*

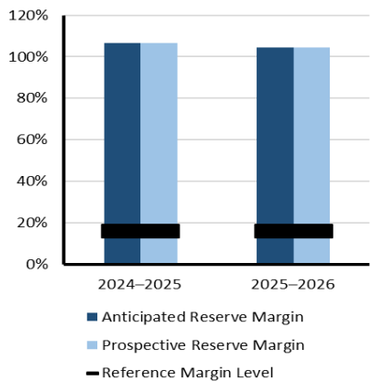
Highlights

- The Southwest is anticipated to be resource adequate under all winter expected and extreme energy availability and demand scenarios before imports.
- Total internal demand is expected to be up 1.5% and net internal demand up 2.3% since last winter. The primary drivers for load growth are data centers and industrial and residential electrification. Controllable and dispatchable demand response is down nearly half, by 163 MW.
- Planned Tier 1 resources are down over 19% as some have moved into existing certain, which is up almost 3%, over 1 GW, and other projects have experienced delays.
- Wind nameplate is up 12%, 470 MW, correlating to on-peak energy availability from wind increasing almost 11%, by 114 MW, while solar nameplate is up 27% or over 2.5 GW.

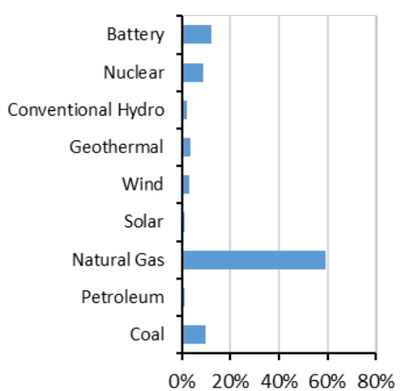
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

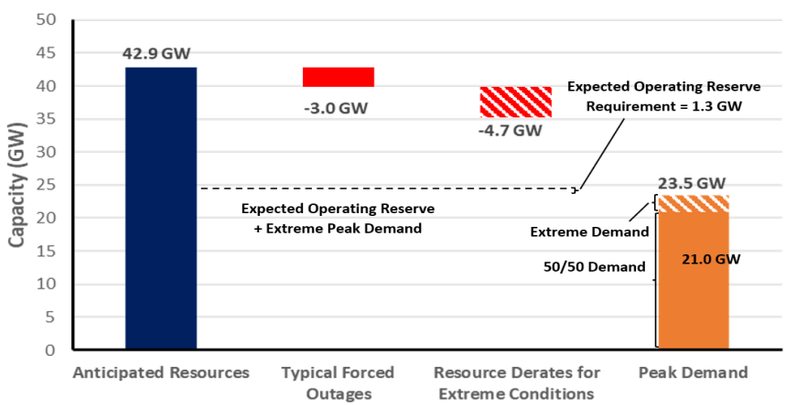
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period

Data Concepts and Assumptions

The table below explains data concepts and important assumptions used throughout this assessment.

General Assumptions
• Reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
▪ Adequacy is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
▪ Operating reliability is the ability of the electric system to withstand sudden disturbances, such as electric short-circuits or unanticipated loss of system components.
• The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
• All data in this assessment is based on existing federal, state, and provincial laws and regulations.
• Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
• A positive net transfer capability would indicate a net importing assessment area; a negative value would indicate a net exporter.
Demand Assumptions
• Electricity demand projections, or load forecasts, are provided by each assessment area.
• Load forecasts include peak hourly load[11] or total internal demand for the summer and winter of each year.[12]
• Total internal demand projections are based on normal weather (50/50 distribution)[13] and are provided on a coincident[14] basis for most assessment areas.
• Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.
Resource Assumptions
Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. Because the electrical output of variable energy resources (VER) (e.g., wind, solar PV) depends on weather conditions, their contribution to reserve margins and other on-peak resource adequacy analysis is less than their nameplate capacity.
Anticipated Resources: • **Existing-Certain Capacity**: Included in this category are commercially operable generating units or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the summer season: unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or, where energy-only markets exist, unit must be a designated market resource eligible to bid into the market. • **Tier 1 Capacity Additions**: This category includes capacity that either is under construction or has received approved planning requirements. • **Net Firm Capacity Transfers (Imports minus Exports)**: This category includes transfers with firm contracts.
Prospective Resources: Includes all anticipated resources plus the following: **Existing-Other Capacity**: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.

[11] https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf used in NERC Reliability Standards

[12] The summer season represents June–September and the winter season represents December–February.

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

[14] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval; this is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC calculates total internal demand on a noncoincidental basis.

Reserve Margin Descriptions

Planning Reserve Margin: This is the primary metric used to measure resource adequacy; it is defined as the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage.

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

Seasonal Risk Scenario Chart Description

Each assessment area performed an operational risk analysis that was used to produce the seasonal risk scenario charts in the **Regional Assessments Dashboards**. The chart presents deterministic scenarios for further analysis of different resource and demand levels: The left blue column shows anticipated resources, and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand and the extreme summer peak demand—both determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources, such as the following:

- Reductions for typical generation outages (i.e., maintenance and forced outages that are not already accounted for in anticipated resources)
- Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions that result in reduced thermal generation output)
- Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions

Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable.

The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Furthermore, the effects from extreme events can also be examined by comparing resource levels after applying extreme scenario derates and/or extreme summer peak demand.

Resource Adequacy

The ARM, which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecast peak demand.[15] Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. NPCC-Maritimes marginally does not meet its RML for the upcoming winter. Other than NPCC-Maritimes, all assessment areas have sufficient ARMs to meet or exceed their RML for the 2025 winter as shown in **Figure 4**.

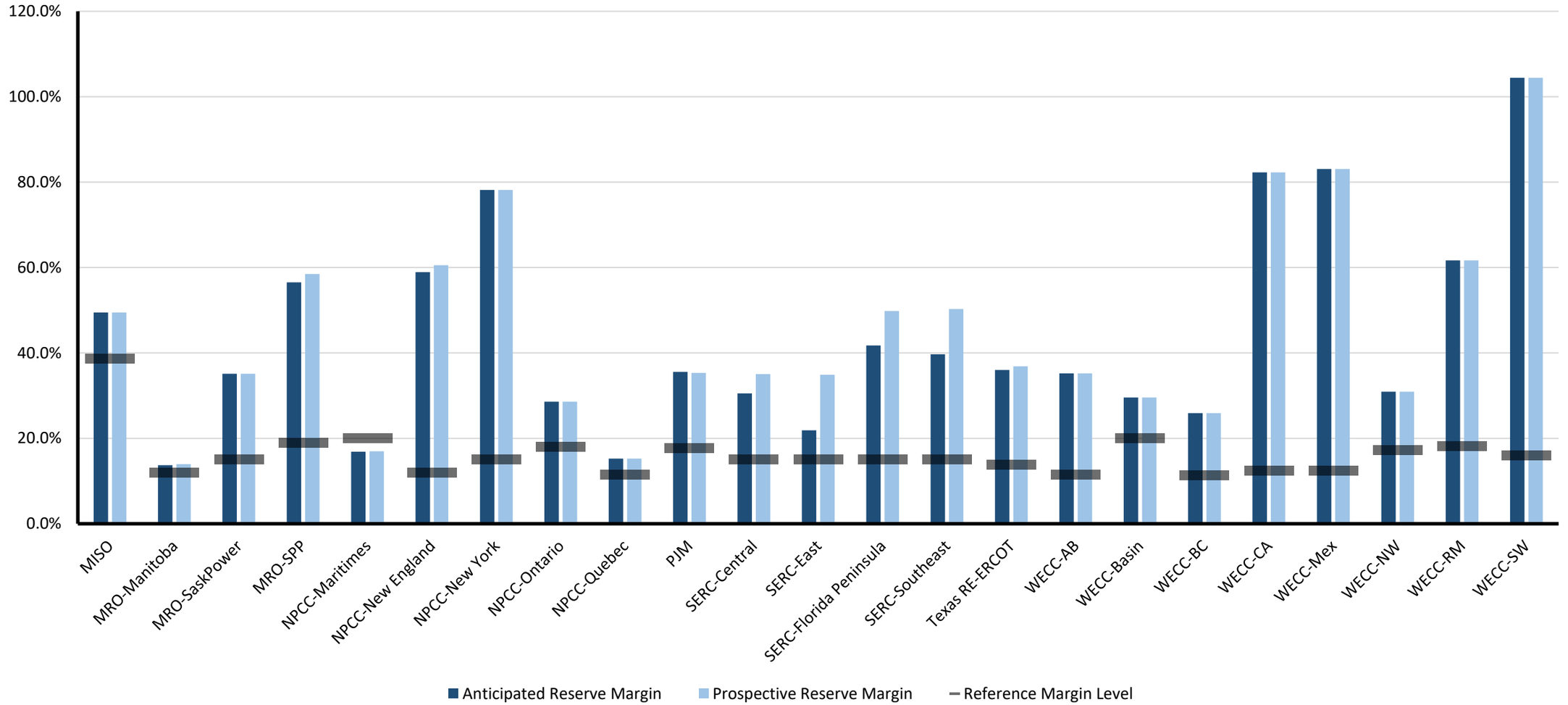


Figure 4: Winter 2025–2026 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[15] Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during electrical peak loads for the season. Prospective resources are those that could be available but do not meet criteria to be counted as anticipated resources. Refer to the **Data Concepts and Assumptions** section for additional information on Anticipated/Prospective Reserve Margins, anticipated/prospective resources, and RMLs.

Changes from Year-to-Year

Figure 5 provides the relative change in the forecast ARMs from the 2024–2025 Winter to the 2025–2026 Winter. All areas except NPCC-Maritimes remain above their RMLs for 2025–2026 Winter. The Canadian winter-peaking systems, which include MRO-Manitoba, MRO-SaskPower, NPCC-Maritimes, NPCC-Québec, WECC-Alberta, and WECC-British Columbia, may have reserve margins that are near RMLs but are unlikely to experience high outage rates from their winterized generators. Additional details are provided in the Data Concepts and Assumptions section.

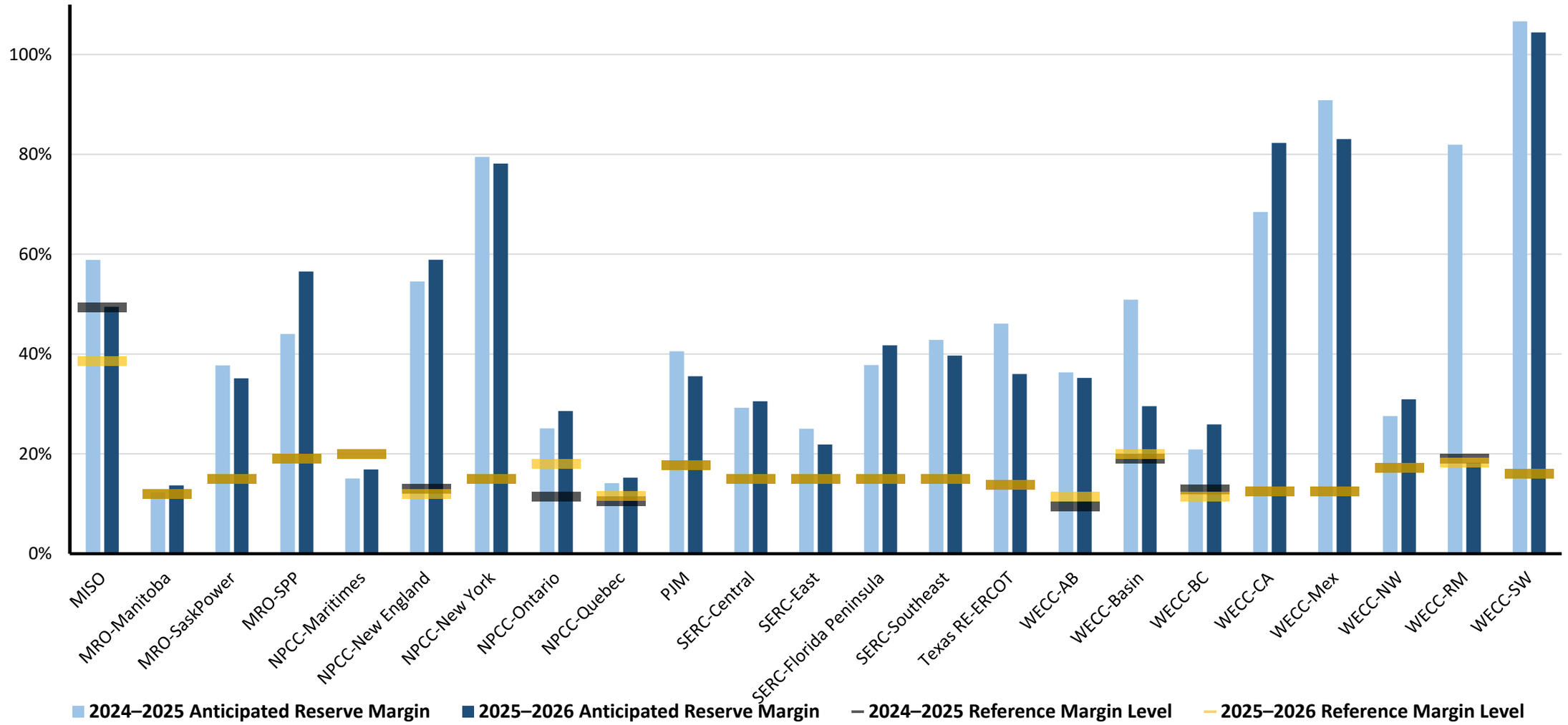


Figure 5: Winter 2024–2025 and Winter 2025–2026 Anticipated Reserve Margins Year-to-Year Change

Demand and Resource Tables

Peak demand and supply capacity data (i.e., resource adequacy data) for each assessment area are as follows in each table.

MISO			
Demand, Resource, and Reserve Margins	**2024–2025 WRA[16]**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	102,353	105,249	2.8%
Demand Response: Available	6,219	8,250	32.7%
Net Internal Demand	96,134	96,999	0.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	150,407	142,880	-5.0%
Tier 1 Planned Capacity	122	0	0.0%
Net Firm Capacity Transfers	2,310	2,113	-8.5%
Anticipated Resources	152,717	144,993	-5.1%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	152,839	144,993	-5.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	58.9%	49.5%	-9.4
Prospective Reserve Margin	59.0%	49.5%	-9.5
Reference Margin Level	49.4%	38.6%	-10.8

MRO-SPP			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	45,788	47,168	3.0%
Demand Response: Available	1,128	1,091	-3.3%
Net Internal Demand	45,926	46,077	0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	67,252	71,074	5.7%
Tier 1 Planned Capacity	0	1087	0.0%
Net Firm Capacity Transfers	-1,116	-32	-97.1%
Anticipated Resources	66,136	72,129	9.1%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	66,090	73,029	10.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.0%	56.5%	12.5
Prospective Reserve Margin	43.9%	58.5%	14.6
Reference Margin Level	19.0%	19.0%	0.0

MRO-SaskPower			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,852	3,944	2.4%
Demand Response: Available	50	50	0.0%
Net Internal Demand	3,802	3,894	2.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,946	4,972	0.5%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	290	290	0.0%
Anticipated Resources	5,236	5,262	0.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	5,236	5,262	0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	37.7%	35.1%	-2.6
Prospective Reserve Margin	37.7%	35.1%	-2.6
Reference Margin Level	15.0%	15.0%	0.0

MRO-Manitoba Hydro			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	4,814	4,903	1.8%
Demand Response: Available	0	0	0.0%
Net Internal Demand	4,814	4,903	1.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,924	5,688	-4.0%
Tier 1 Planned Capacity	10	0	-100.0%
Net Firm Capacity Transfers	-527	-113	-78.5%
Anticipated Resources	5,407	5,575	3.1%
Existing-Other Capacity	18	13	-26.8%
Prospective Resources	5,425	5,588	3.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	12.3%	13.7%	1.4
Prospective Reserve Margin	12.7%	14.0%	1.3
Reference Margin Level	12.0%	12.0%	0.0

[16] MISO-provided updated data post 2024-25 WRA publication.

NPCC-Maritimes			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	6,167	6,061	-1.7%
Demand Response: Available	259	248	-4.4%
Net Internal Demand	5,907	5,813	-1.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	6,647	6,704	0.9%
Tier 1 Planned Capacity	6	88	0.0%
Net Firm Capacity Transfers	145	1	-99.0%
Anticipated Resources	6,798	6,794	-0.1%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	6,798	6,800	0.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	15.1%	16.9%	1.8
Prospective Reserve Margin	15.1%	17.0%	1.9
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New England			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	20,651	20,056	-2.9%
Demand Response: Available	343	440	28.2%
Net Internal Demand	20,308	19,616	-3.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	30,030	29,935	-0.3%
Tier 1 Planned Capacity	194	0	-100.0%
Net Firm Capacity Transfers	1,161	1,235	6.4%
Anticipated Resources	31,385	31,170	-0.7%
Existing-Other Capacity	306	322	5.2%
Prospective Resources	31,691	31,492	-0.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	54.5%	58.9%	4.4
Prospective Reserve Margin	56.1%	60.5%	4.5
Reference Margin Level	13.0%	12.0%	-1.0

NPCC-New York			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	23,800	24,200	1.7%
Demand Response: Available	802	1,027	28.1%
Net Internal Demand	22,998	23,173	0.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	40,522	40,080	-1.1%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	759	1,203	58.5%
Anticipated Resources	41,281	41,283	0.0%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	41,281	41,283	0.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	79.5%	78.2%	-1.3
Prospective Reserve Margin	79.5%	78.2%	-1.3
Reference Margin Level	15.0%	15.0%	0.0

NPCC-Ontario			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	21,898	22,013	0.7%
Demand Response: Available	915	868	-5.2%
Net Internal Demand	20,982	21,146	0.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	26,652	27,319	2.5%
Tier 1 Planned Capacity	0	294	#DIV/0!
Net Firm Capacity Transfers	-450	-420	-6.7%
Anticipated Resources	26,202	27,193	3.8%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	26,202	27,193	3.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.1%	28.6%	3.5
Prospective Reserve Margin	25.1%	28.6%	3.5
Reference Margin Level	11.5%	18.0%	6.5

NPCC-Québec			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	40,512	40,799	0.8%
Demand Response: Available	4,451	4,902	10.9%
Net Internal Demand	36,061	35,897	-0.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	41,560	41,698	0.3%
Tier 1 Planned Capacity	73	61	0.0%
Net Firm Capacity Transfers	-479	-390	-18.6%
Anticipated Resources	41,154	41,368	0.5%
Existing-Other Capacity	-479	0	0.0%
Prospective Resources	41,154	41,368	0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	14.1%	15.2%	1.1
Prospective Reserve Margin	14.1%	15.2%	1.1
Reference Margin Level	10.5%	11.5%	1.0

PJM			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	136,328	140,827	3.3%
Demand Response: Available	5,616	5,998	6.8%
Net Internal Demand	130,712	134,829	3.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	179,216	178,335	-0.5%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	4,502	4,448	-1.2%
Anticipated Resources	183,718	182,783	-0.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	183,718	182,452	-0.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	40.6%	35.6%	-5.0
Prospective Reserve Margin	40.6%	35.3%	-5.2
Reference Margin Level	17.7%	17.7%	-12.3

SERC-Central			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	42,895	42,875	0.0%
Demand Response: Available	1,497	2,809	87.6%
Net Internal Demand	41,397	40,067	-3.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	51,578	50,454	-2.2%
Tier 1 Planned Capacity	0	0	0%
Net Firm Capacity Transfers	1,922	1,847	-3.9%
Anticipated Resources	53,500	52,301	-2.2%
Existing-Other Capacity	1,498	1,810	20.8%
Prospective Resources	54,998	54,111	-1.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	29.2%	30.5%	1.3
Prospective Reserve Margin	32.9%	35.1%	2.2
Reference Margin Level	15.0%	15.0%	0.0

SERC-East			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	45,005	45,703	1.6%
Demand Response: Available	982	888	-9.6%
Net Internal Demand	44,023	44,815	1.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	54,379	54,460	0.1%
Tier 1 Planned Capacity	72	11	-84.3%
Net Firm Capacity Transfers	593	150	-74.7%
Anticipated Resources	55,045	54,622	-0.8%
Existing-Other Capacity	5,209	5,832	12.0%
Prospective Resources	60,254	60,453	0.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.0%	21.9%	-3.2
Prospective Reserve Margin	36.9%	34.9%	-2.0
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	48,494	48,628	0.3%
Demand Response: Available	2,780	3,127	12.5%
Net Internal Demand	45,714	45,501	-0.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	62,579	63,502	1.5%
Tier 1 Planned Capacity	15	692	4510.0%
Net Firm Capacity Transfers	400	300	-25.0%
Anticipated Resources	62,994	64,494	2.4%
Existing-Other Capacity	3,673	3,671	0.0%
Prospective Resources	66,667	68,165	2.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	37.8%	41.7%	3.9
Prospective Reserve Margin	45.8%	49.8%	4.0
Reference Margin Level	15.0%	15.0%	0.0

SERC-Southeast			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	45,308	47,056	3.9%
Demand Response: Available	1,638	1,365	-16.7%
Net Internal Demand	43,670	45,691	4.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	62,805	63,339	0.9%
Tier 1 Planned Capacity	765	0	-100.0%
Net Firm Capacity Transfers	-1,192	489	-141.0%
Anticipated Resources	62,378	63,828	2.3%
Existing-Other Capacity	3,920	4,847	23.7%
Prospective Resources	66,298	68,675	3.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	42.8%	39.7%	-3.1
Prospective Reserve Margin	51.8%	50.3%	-1.5
Reference Margin Level	15.0%	15.0%	0.0

Texas RE-ERCOT			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	73,193	77,387	5.7%
Demand Response: Available	5,447	9,330	71.3%
Net Internal Demand	67,746	68,057	0.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	98,712	89,977	-8.8%
Tier 1 Planned Capacity	239	1351	464.9%
Net Firm Capacity Transfers	20	1,235	6075.0%
Anticipated Resources	98,971	92,562	-6.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	99,691	93,137	-6.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	46.1%	36.0%	-10.1
Prospective Reserve Margin	47.2%	36.9%	-10.3
Reference Margin Level	13.75%	13.8%	0.0

WECC-AB			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	12,280	12,411	1.1%
Demand Response: Available	0	0	0.0%
Net Internal Demand	12,280	12,411	1.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,535	16,658	23.1%
Tier 1 Planned Capacity	3206	124	-96.1%
Net Firm Capacity Transfers	0	0	0.0%
Anticipated Resources	16,740	16,782	0.3%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	16,740	16,782	0.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	36.3%	35.2%	-1.1
Prospective Reserve Margin	36.3%	35.2%	-1.1
Reference Margin Level	9.5%	11.5%	2.0

WECC-Basin			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	10,568	10,758	1.8%
Demand Response: Available	85	170	100.0%
Net Internal Demand	10,483	10,588	1.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,213	13,183	-0.2%
Tier 1 Planned Capacity	2,605	533	-79.5%
Net Firm Capacity Transfers	0	0	0%
Anticipated Resources	15,817	13,717	-13.3%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	15,817	13,717	-13.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	50.9%	29.6%	-21.3
Prospective Reserve Margin	50.9%	29.6%	-21.3
Reference Margin Level	19.0%	20.0%	1.0

WECC-CA			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	36,441	36,281	-0.4%
Demand Response: Available	743	666	-10.4%
Net Internal Demand	35,698	35,615	-0.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	55,380	57,923	4.6%
Tier 1 Planned Capacity	4,757	6,997	47.1%
Net Firm Capacity Transfers	0	0	0.0%
Anticipated Resources	60,138	64,920	8.0%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	60,138	65,920	8.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	68.5%	82.3%	13.8
Prospective Reserve Margin	68.5%	82.3%	13.8
Reference Margin Level	12.5%	12.5%	0.0

WECC-BC			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,966	11,936	-0.3%
Demand Response: Available	0	0	0.0%
Net Internal Demand	11,966	11,936	-0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,870	14,389	3.7%
Tier 1 Planned Capacity	433	637	47.0%
Net Firm Capacity Transfers	164	0	-100.0%
Anticipated Resources	14,467	15,026	3.9%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	14,467	15,026	3.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.9%	25.9%	5.0
Prospective Reserve Margin	20.9%	25.9%	5.0
Reference Margin Level	12.8%	11.4%	-1.5

WECC-Mexico			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	1,983	1,977	-0.3%
Demand Response: Available	0	0	0%
Net Internal Demand	1,983	1,977	-0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	3,733	3,619	-3.0%
Tier 1 Planned Capacity	52	0	-100.0%
Net Firm Capacity Transfers	0	0	0%!
Anticipated Resources	3,784	3,619	-4.4%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	3,784	3,619	-4.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	90.8%	83.1%	-7.8
Prospective Reserve Margin	90.8%	83.1%	-7.8
Reference Margin Level	12.5%	12.5%	0

WECC-Northwest			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–25 vs. 2025–26**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	30,748	33,604	9.3%
Demand Response: Available	30	30	0.0%
Net Internal Demand	30,718	33,574	9.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	38,729	34,671	-10.5%
Tier 1 Planned Capacity	463	3,152	581.5%
Net Firm Capacity Transfers	0	6,136	100%!
Anticipated Resources	39,192	43,959	12.2%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	39,192	43,959	12.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.6%	30.9%	3.3
Prospective Reserve Margin	27.6%	30.9%	3.3
Reference Margin Level	17.2%	17.2%	0.0

WECC-Rocky Mountain			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–25 vs. 2025–26**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	10,481	11,501	9.7%
Demand Response: Available	282	285	1.1%
Net Internal Demand	10,199	11,216	10.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	18,356	17,768	-3.2%
Tier 1 Planned Capacity	199	366	84.3%
Net Firm Capacity Transfers	0	0	0%
Anticipated Resources	18,555	18,134	-2.3%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	18,555	18,134	-2.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	81.9%	61.7%	-20.3
Prospective Reserve Margin	81.9%	61.7%	-20.3
Reference Margin Level	19.0%	18.2%	-0.8

WECC-Southwest			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–25 vs. 2025–26**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	20,844	21,147	1.5%
Demand Response: Available	340	177	-47.9%
Net Internal Demand	20,504	20,970	2.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	38,991	40,135	2.9%
Tier 1 Planned Capacity	3,381	2,733	-19.2%
Net Firm Capacity Transfers	0	0	0.0%
Anticipated Resources	42,372	42,868	1.2%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	42,372	42,868	1.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	106.6%	104.4%	-2.2
Prospective Reserve Margin	106.6%	104.4%	-2.2
Reference Margin Level	16.0%	16.0%	0.0

Variable Energy Resource Contributions

Because the electrical output of VERs (e.g., wind, solar PV) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity and may vary widely year to year based on the identified risk hour. In many areas, winter demand peaks in the early morning hours or early evening resulting in little or no electrical resource output from solar PV resources and wide variability in wind availability. The following table shows the capacity contribution of existing wind and solar PV resources at the identified risk hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS.

BPS Variable Energy Resources On-Peak Capacity Contributions by Assessment Area

	Wind			Solar			Run of River Hydro		
Assessment Area/Interconnection (* - includes all hydro)	Nameplate Wind (MW)	Expected Wind (MW)	Expected Share of Nameplate (%)	Nameplate Solar PV (MW)	Expected Solar (MW)	Expected Share of Nameplate (%)	Nameplate Hydro (MW)	Expected Hydro (MW)	Expected Share of Nameplate (%)
MISO	30,247	8,772	29%	13,726	686	5%	2,351	1,404	60%
MRO-Manitoba Hydro	259	52	20%	0	0	0%	202	0	0%
MRO-SaskPower	816	433	53%	30	0	13%	884	703	80%
MRO-SPP	35,714	7,198	20%	1,197	457	38%	114	72	63%
NPCC-Maritimes	1,635	241	15%	155	10	6%	1,357	1,283	95%
NPCC-New England	2,675	455	17%	3,620	0	0%	3,742	1,453	39%
NPCC-New York	2,586	737	29%	627	0	0%	974	596	61%
NPCC-Ontario	4,943	1,971	40%	478	0	0%	0	0	0%
NPCC-Québec	4,024	1,426	35%	10	0	0%	445	445	100%
PJM*	13,318	5,463	41%	15,732	1	0%	8,134	7,900	97%
SERC-Central	1,324	370	28%	1,576	455	29%	4,991	4,027	81%
SERC-East	0	0	0%	7,068	1,792	25%	3,010	2,951	98%
SERC-Florida Peninsula	0	0	0%	12,058	2,151	18%	0	0	0%
SERC-Southeast	0	0	0%	8,670	4,461	51%	3,258	3,258	100%
Texas RE-ERCOT	40,629	7,833	19%	35,609	660	2%	579	566	98%
WECC-AB*	5,712	1,919	34%	2,206	0	0%	894	285	32%
WECC-Basin*	5,932	1,148	19%	3,853	62	2%	2,667	1,473	55%
WECC-BC*	747	85	11%	17	0	0%	17,752	13,560	76%
WECC-CA*	9,382	682	7%	28,328	0	0%	15,740	4,572	29%
WECC-Mex	40	4	11%	350	0	0%	0	0	0%
WECC-NW*	14,744	1,319	9%	4,695	1,556	33%	32,915	18,502	56%
WECC-RM*	5,681	2,265	40%	3,521	0	0%	3,251	1,327	41%
WECC-SW*	4,303	1,182	27%	12,139	391	3%	3,117	948	30%
EASTERN INTERCONNECTION	93,517	25,692	27%	64,937	10,013	15%	29,017	23,647	81%
QUÉBEC INTERCONNECTION	4,024	1,426	35%	10	0	0%	445	445	100%
TEXAS INTERCONNECTION	40,629	7,833	19%	35,609	660	2%	579	566	98%
WECC INTERCONNECTION	46,541	8,605	19%	55,108	2,008	4%	76336	40667	53%
INTERCONNECTION TOTAL:	**184,711**	**43,556**	**23%**	**155,664**	**12,685**	**8%**	106,377	65,325	61%

Review of Winter 2024–2025 Capacity and Energy Performance

The meteorological winter across the contiguous United States had an average temperature of 34.1 degrees F—1.9 degrees above average—ranking in the warmest third of NOAA's historical record. Total winter precipitation in the US was 5.87 inches, 0.92 of an inch below average, ranking in the driest third of the December–February climate record.[17] Most of Canada experienced temperatures at least 2°C above the baseline average with the Maritime provinces, southern Ontario, and the Canadian west coast recording temperature departures nearer the baseline average while a small region in southern Saskatchewan recorded temperatures just slightly below the baseline average.[18]

In February 2025, FERC and NERC and its Regional Entities launched a joint review of the BPS' performance during the January 2025 arctic events, which comprised Winter Storms Blair, Cora, Demi, and Enzo.[19] The week of January 19–25, 2025 was the third coldest winter week (spanning Sunday through Saturday) across the United States since 2000. Between January 21 and 22, 2025, natural gas demand peaked at 150 Bcf/day, electric demand peaked at 683 GW, and unplanned outages peaked at 71,022 MW. Nevertheless, during the January 2025 arctic events, manual load shed was not required. The January 2025 arctic events had lower observed hourly wind chill temperatures in pockets of the Northeast, the Louisiana Gulf, California, and the Southwest compared to Winter Storms Uri, Elliott, Gerri, and Heather. During the January 2025 arctic events, the most extreme storm relative to typical weather was Winter Storm Enzo—a Gulf and Southern storm. On January 20, 2025, a burst of snow, sleet, and freezing rain developed across Texas and Louisiana late in the day. A mixture of sleet and freezing rain fell from Austin to San Antonio and to the southernmost point of Texas. By the early morning hours of January 21, 2025, for the first time in history, a blizzard warning was issued for southwest Louisiana and the southeastern-most point of Texas. Snow fell in Gulf cities in Texas, southern Mississippi, southern Alabama, and western Florida. On January 21, 2025, Baton Rouge recorded 7.6 inches of snowfall, making it the city's snowiest day since recordkeeping began in 1892, while New Orleans saw its snowiest day on record, with a total of 8.0 inches. Temperatures plunged to single digits in Louisiana. Temperatures in some parts of the state fell to levels not seen in more than 125 years.

The review team engaged with 10 electric entities across the Eastern and Texas Interconnections to gather the information necessary to provide a high-level overview of the BPS' performance during the cold weather events. Based on the data and interviews that the team reviewed, electric generators appear to have performed better during the January 2025 arctic events because of additional generator commitments, improved preparedness, increased situational awareness, and the implementation of lessons learned from previous extreme cold weather events and prior report recommendations. The natural gas system also performed better overall, serving record levels of natural gas demand and experiencing only minor production declines and short-duration force majeure events.

On October 1, 2025, NERC submitted to the Federal Energy Regulatory Commission its first *Cold Weather Data Annual Report*. This report includes a review of forced outage data from GADS for the winter 2024–2025 period indicating performance consistent with historical performance as reported in NERC's annual *State of Reliability* report. This is within the normal range of capacity that occurs across the fleet. During the Winter 2024–2025 period, the highest amount of capacity in a forced outage state for all reasons occurred on January 20, 2025, with 68,519 MW across all regions. The outages occurring over January 20, 2025, were analyzed as part of the joint FERC, NERC, and Regional Entity *2025 System Performance Review*. The joint FERC, NERC, and Regional Entity *2025 System Performance Review* found a reduction in peak coincident unplanned generator outages for the four 2025 winter storms reviewed compared to past winter storms; however, this review also noted that it was not an exact comparison due to prior winter storms having different characteristics.

Eastern Interconnection–Canada and Québec Interconnection

No EEAs were needed during the previous winter season. One entity plans to make a slight increase to the demand-response program based on last winter's operations.

[17] Despite Arctic air outbreaks, U.S. had warm, dry winter on average | National Oceanic and Atmospheric Administration
[18] Climate Trends and Variations Bulletin – Winter 2024/2025 - Canada.ca
[19] https://www.ferc.gov/media/report-january-2025-arctic-events-system-performance-review-ferc-nerc-and-its-regional

Eastern Interconnection–United States

Several entities indicated that generators performed better during the January 2025 arctic events than in previous winter storms. For example, TVA stated that generator performance within its footprint was stable, with minimal natural gas delivery issues. Southeastern RC detailed that no major fuel-related outages occurred. FRCC noted that generator performance was strong during this period. The significant characteristics of Winter Storm Enzo in the Southern and Gulf states were freezing precipitation and snow accumulation, especially in regions where those conditions rarely occur. In FRCC, only the northern portion of Florida experienced severe arctic weather including freezing precipitation and snowfall (record-setting, in some cities) that were abnormal for the region even though certain northern cities have faced cold temperatures in the past. In Florida, entities experienced energy emergencies caused by extended generation outages from hurricanes Milton and Helene, compounded by unusually high loads from cold weather. Entities were able to serve native load and firm delivery obligations, though non-firm sales were curtailed during certain events. ISO-NE, NYISO, and PJM all generally described the January 2025 arctic events as having cold temperatures but overall weather conditions that were similar to a winter without a major storm.

MISO emerged from Winter 2024–2025 without turning to emergency procedures despite the wide-ranging winter storms from January 6 to 9 and again from January 20 to 22. Generators continue to prioritize scheduling planned or maintenance outages to the shoulder seasons of fall and spring to maximize unit availability for the winter season. Also, extreme cold weather outage adders were added to the LOLE model to make sure that winter storm risks are included in planning. In PJM, demand reached a new all-time winter peak on January 22, 2025, of 143,714 MW with sufficient reserves. PJM did call an EEA1 on January 22, 2025, however reserves remained adequate. PJM had less than 3% load forecast error over the peak days of the January cold weather events. Reliability cases were conducted, and units with extended start times were evaluated and started early to ensure units were on-line before extreme cold weather settled in. PJM had a 9.24% forced outage rate on the peak day, a relatively low forced outage rate for the weather experienced. There were also very few gas production problems; however, market issues prevented proper scheduling because of the four-day holiday weekend.

In SERC-Central, entities reported only limited impacts from Winter 2024–2025 coldest weather and made minor adjustments. One entity declared conservative operations ahead of peak conditions but experienced no emergencies. One entity raised its winter Planning Reserve Margin target to 26% following lessons learned from Winter Storm Elliott. Corrective actions were implemented due to isolated equipment issues, including improved heat trace capabilities and adding heat trace equipment to the cold weather critical component list. During the previous winter season, some SERC-Florida Peninsula entities experienced energy emergencies caused by extended generation outages from hurricanes Milton and Helene, compounded by unusually high loads from cold weather. Despite these challenges, entities were able to serve native load and firm delivery obligations, though non-firm sales were curtailed during certain events.

Texas Interconnection–ERCOT

There were no energy emergencies for the Texas RE-ERCOT region last winter and no conditions that prompted changes in operating procedures. Winter Storm Kingston, which occurred in February 2025, was the only storm where ERCOT utilized firm fuel supply service resources (FFSS), a firm-fuel product that provides additional grid reliability and resiliency during extreme cold weather and compensates generation resources that meet a higher resiliency standard. A maximum FFSS deployment of 470 MW occurred on February 19 between the hours 13:10 and 17:02. Two other storms, Enzo and Cora, impacted ERCOT in January 2025, but these storms did not cause any system reliability issues.

Western Interconnection

Between January 11 and 17, 2024, a prolonged Arctic outbreak impacted British Columbia, Alberta, and the U.S. Pacific Northwest, driving record electricity demand and widespread reliability challenges. Four U.S. Northwest BAs and one Canadian BA declared energy emergencies, underscoring two core vulnerabilities: Inadequate capacity during evening peak hours (4 to 8 p.m.) and Insufficient fuel supply (limited hydro availability) across multiple days.

Although temperatures were comparable to the December 2022 cold snap, WECC-Northwest peak demand rose two percentage points to 6% over then, with BC Hydro and AESO both setting new all-time records. The U.S. Northwest relied heavily on imports—averaging 4,745 MW during peaks and 5,241 MW across all hours, mostly from the Southwest and Rockies. California remained a net importer, providing little relief. Market prices in the Northwest reached or neared caps across most hours, indicating persistent scarcity rather than short-term peaks. Overall, the January 2024 event illustrated capacity alone does not ensure resilience. Sustained energy availability with interregional flexibility (both physical and market-based) will be key to maintaining reliability through the 2025–2026 and future winter seasons.

2024–2025 Winter Demand and Generation Summary at Peak Demand											
Assessment Area	**Peak Demand Date**	**Peak Demand Hour**	**Demand[1] (MW)**	**WRA Peak Demand Scenarios[2] (MW)**	**Generation[1] (MWh)**	**Transfers[1] (MW)**	**Wind – Actual[1] (MWh)**	**Wind – Expected[3] (MW)**	**Solar – Actual[1] (MWh)**	**Solar – Expected[3] (MW)**	**Forced Outages Summary[4] (MW)**
MISO	Jan. 21	18:00	108,888*	96,134 100,395	101,655	-977	18,468	16,761	0	519	17,010
MRO-Manitoba Hydro	Jan. 20	08:00	5,132	4,814 5,060	5,292	-277	142	52	N/A	0	146
MRO-SaskPower	Dec. 18	18:00	3,785	3,802 3,897	3,641	-231	664	368	0	3	0
MRO-SPP	Feb. 20	08:00	47,981	45,926 47,054	40,898	-1,424	4,886	4,783	255	36	9,272
NPCC-Maritimes	Jan. 22	07:00	5,810	5,907 6,498	4,266	-1,174	368	261	3	5	*
NPCC-New England	Jan. 21	18:00	19,607	20,308 21,814	17,686	-1,896	285	329	4	23	624
NPCC-New York	Jan. 22	19:00	23,521	22,998 24,023	18,932	-4,589	654	728	0	0	4,835

2024–2025 Winter Demand and Generation Summary at Peak Demand											
Assessment Area	**Peak Demand Date**	**Peak Demand Hour**	**Demand[1] (MW)**	**WRA Peak Demand Scenarios[2] (MW)**	**Generation[1] (MWh)**	**Transfers[1] (MW)**	**Wind – Actual[1] (MWh)**	**Wind – Expected[3] (MW)**	**Solar – Actual[1] (MWh)**	**Solar – Expected[3] (MW)**	**Forced Outages Summary[4] (MW)**
NPCC-Ontario	Jan. 22	18:00	21,940	20,951 22,179	24,250	2,990	3,693	1,914	0	0	*
NPCC-Québec	Jan. 22	08:00	37,178	36,061 39,545	39,514	-766	1,463	1,449	0	0	*
PJM	Jan. 22	09:00	144,420	130,712 144,939	152,142	7,731	3,704	3,620	3,076	1	8,663
SERC-C	Jan. 22	08:00	47,815	41,397 47,062	40,898	-6,921	563	176	214	455	1,538
SERC-E	Jan. 23	08:00	47,130	44,023 47,662	41,810	-5,323	0	0	145	2,526	1,830
SERC-FP	Jan. 25	08:00	43,974	45,714 54,239	41,702	-557	0	0	362	1,684	2,824
SERC-SE	Jan. 22	08:00	46,490	43,670 45,116	48,227	1,741	0	0	592	3,861	2,210

2024–2025 Winter Demand and Generation Summary at Peak Demand											
Assessment Area	**Peak Demand Date**	**Peak Demand Hour**	**Demand[1] (MW)**	**WRA Peak Demand Scenarios[2] (MW)**	**Generation[1] (MWh)**	**Transfers[1] (MW)**	**Wind – Actual[1] (MWh)**	**Wind – Expected[3] (MW)**	**Solar – Actual[1] (MWh)**	**Solar – Expected[3] (MW)**	**Forced Outages Summary[4] (MW)**
TRE-ERCOT	Feb. 20	08:00	80,560	73,193[5] 90,405[5]	79,960	-191	9,397	15,697	1,586	15	5,742
WECC-AB	Dec. 18	17:00	12,241	12,280 12,635	12,711	-470	3,175	1,867	4	0	*
WECC-BC	Feb 3	18:00	11,359	11,996 12,749	11,415	44	70	279	0	0	839
WECC-CA/MX	Dec. 12	15:00	35,555	35,359 36,823	31,925	-4,669	4,021	569	11,547	0	1,627
WECC-NW	Feb. 12	08:00	54,278	58,001 62,230	48,437	-920	2,607	7,876	1,494	2,198	3,281
WECC-SW	Feb. 13	16:00	22,969	16,177 17,777	25,087	2,117	2,741	1,065	1,599	182	1,496
Highlighting Notes:			Actual peak demand in the highlighted areas met or exceeded extreme scenario levels				Actual wind output in highlighted areas was significantly below seasonal forecast.		Actual solar output in highlighted areas was significantly below seasonal forecast.		Actual forced outages above or below forecast by factor of two

2024–2025 Winter Demand and Generation Summary at Peak Demand											
Assessment Area	**Peak Demand Date**	**Peak Demand Hour**	**Demand[1] (MW)**	**WRA Peak Demand Scenarios[2] (MW)**	**Generation[1] (MWh)**	**Transfers[1] (MW)**	**Wind – Actual[1] (MWh)**	**Wind – Expected[3] (MW)**	**Solar – Actual[1] (MWh)**	**Solar – Expected[3] (MW)**	**Forced Outages Summary[4] (MW)**
Table Notes: [1] Actual demand, wind, and solar values for the hour of peak demand in U.S. areas were obtained from EIA From 930 data. For areas in Canada, this data was provided to NERC by system operators and utilities. [2] See NERC *2024–2025* WRA demand scenarios for each assessment area. Values are the normal winter peak demand forecast and an extreme peak demand forecast that represents a 90/10, or once-per-decade, peak demand. Some areas use other basis for extreme peak demand. [3] Expected values of wind and solar resources from the *2024–2025 WRA*. [4] Values from NERC Generator Availability Data System for the 2024–2025 winter hour of peak demand in each assessment area. Highlighted areas had actual forced outages that were more than twice the value for typical forced outage rates used in the 2024–2025 winter risk period scenarios in the *2024–2025 WRA*. [5] Texas RE-ERCOT peak demand scenarios are obtained by adding expected demand response (5.4 GW for winter 2024-2025) to the demand scenarios found on p. 29 of the 2024-2025 WRA. *Canadian assessment areas report to the NERC Generator Availability Data System on a voluntary basis, which can contribute to the absence of some values in certain assessment areas.										

Errata

December 2025

- Corrections made to the VER Table (page 50): Hydro values for WECC NW, Western Interconnection Total, and Total

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

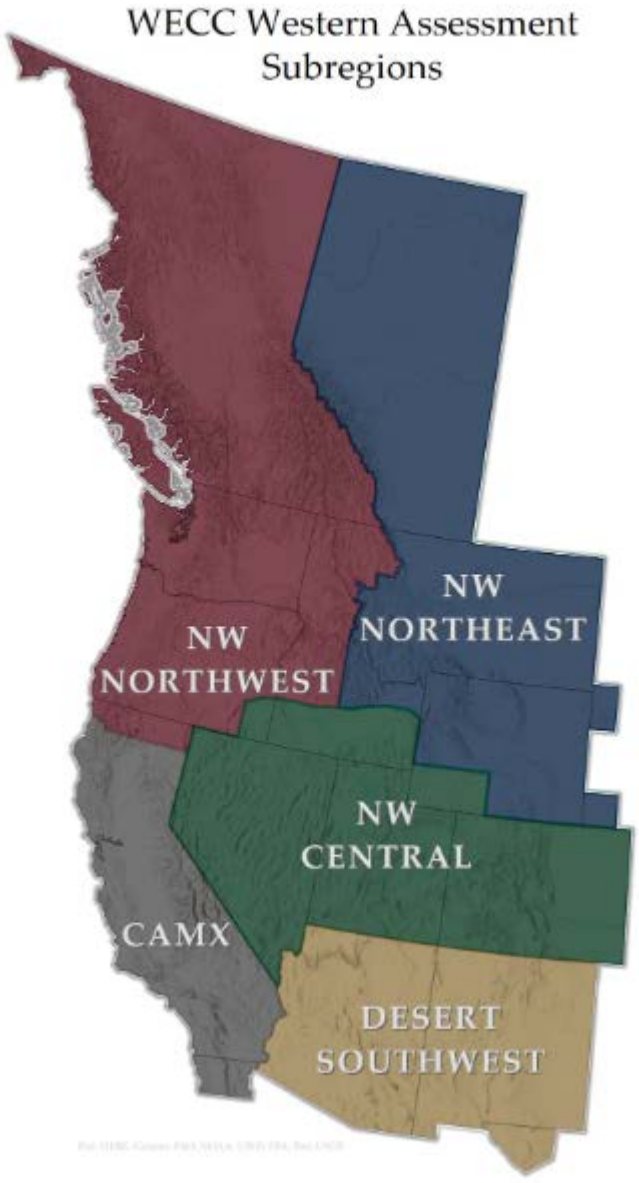
Exhibit 1-09
2024 Western Assessment of Resource Adequacy

(This is a best efforts reproduction of the material on this website cited in footnote 8 of Order No. 202-25-14: https://feature.wecc.org/wara/.)


WESTERN ASSESSMENT
OF RESOURCE ADEQUACY
2024

The pace of change is increasing the risks to reliability across North America. The supply of electricity is not growing fast enough to keep up with demand growth. What was once a simple problem of supply and demand has become complicated by rapid change and increasing variability. Unless we prioritize reliability as the resource mix evolves and becomes more variable, we are at risk for serious and more frequent disruptions. The West must move quickly and more decisively to ensure resource adequacy over the next decade.

WECC's annual Western Assessment of Resource Adequacy (Western Assessment) examines resource-adequacy-related risks concerning the reliability of the Western Interconnection over the next 10 years. Through an energy-based probabilistic approach, WECC looks at the risks throughout the interconnection and five subregions. This work is meant to help stakeholders target specific areas and topics for deeper evaluation and mitigation.



The forecast rate of demand growth over the next decade is double what was forecast just two years ago.

Current resource plans forecast staggering demand growth over the next decade. For the Western Interconnection, annual demand is forecast to grow 20.4%, from 942 TWh in 2025, to 1,134 TWh in 2034. That growth rate is more than double the 9.6% growth forecast in resource plans filed in 2022, and over four times the historical growth rate of 4.5% between 2013 and 2022.

New large loads create reliability challenges that must be addressed immediately.

A major driver for the increase in demand over the next 10 years is the expansion of large loads like data centers, manufacturing facilities, and cryptocurrency mining operations. These loads consume immense amounts of energy, can be constructed quickly, have different consumption patterns, and require changes or additions to infrastructure. In some cases, large loads require a steady supply of power at all times, while in other cases, their demand can fluctuate, creating a need for large ramping capability. There can be challenges with the way large loads behave during grid disturbances, including their ride-through capability. According to current plans, the effects of large-load growth are greatest in the next three to five years; however, more large loads will likely be added to future forecasts.

To meet growing demand, entities plan to build unprecedented amounts of new resources over the next decade. Never has generation been built in the West at the rate called for in current resource plans. These plans could be unattainable given past struggles to build planned resources on time.

Current resource plans include 172 GW of new generation resources to be built in the next decade. This is more than double the generation capacity added in the last 10 years and will require an exceptional effort to carry out. Between 2014 and 2023, entities added 74 GW of new generation. Demand growth and resource retirements are driving up the number of new resources needed in the next 10 years.

If demand grows as expected and industry experiences delays and cancellations in building new resources over the next decade, the West will face potentially severe resource adequacy challenges.

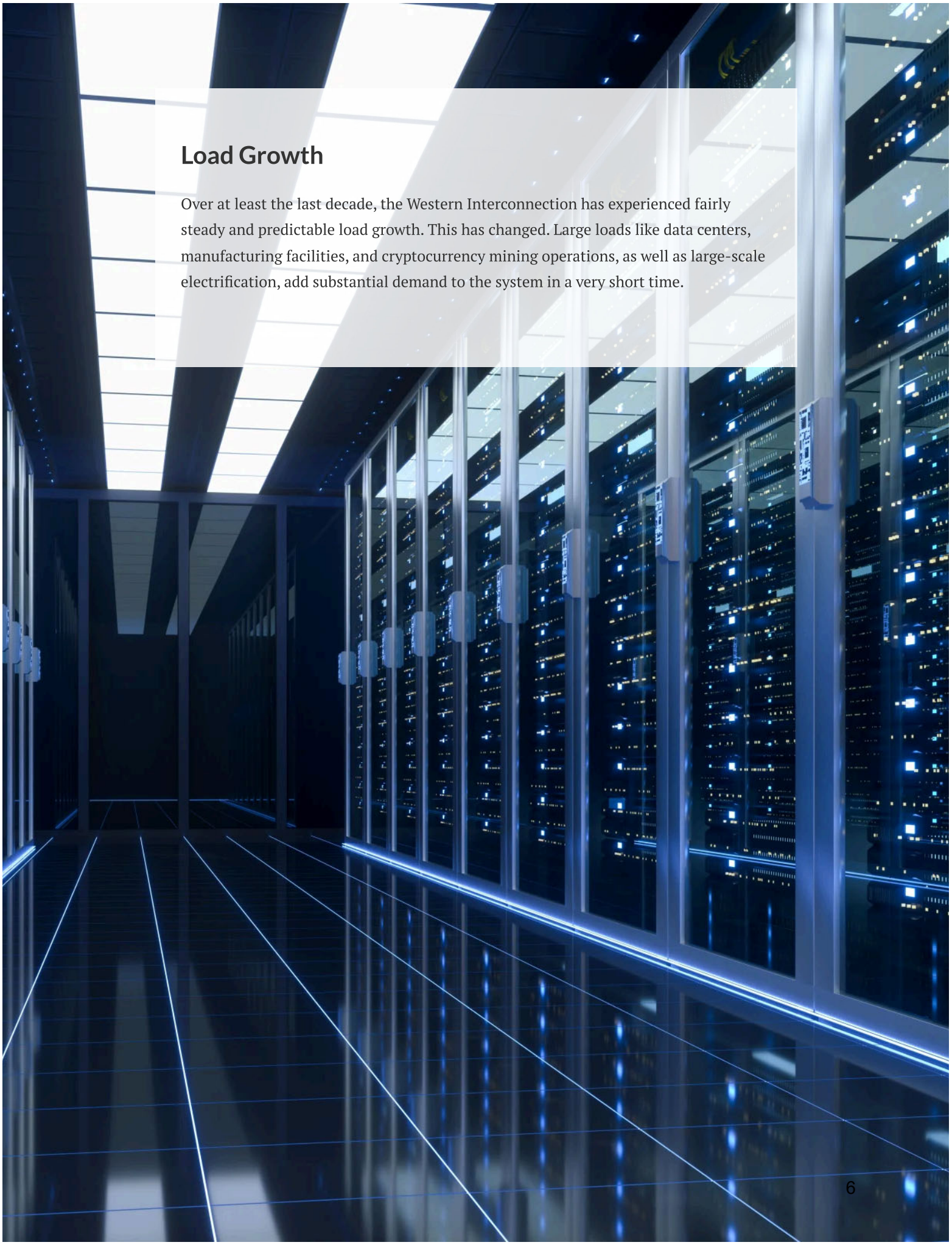
Over the last six years, only 76% of planned resource additions came online in the year scheduled, and in 2023, that number was 53%. Resource margins are shrinking, leaving less buffer for cancelled and delayed projects. If the resource build-out over the next 10 years mimics the last five years, by 2034, the West will have hundreds of hours each year when demand is at risk.

Variability will continue to increase, exacerbating the risk of having inadequate dispatchable energy.

Over 85% of the 172 GW of planned resource additions in the next decade are variable resources (wind and solar), battery storage, or a hybrid. The addition of so many energy-limited resources, along with decreases in baseload resources and changes in load patterns, is creating more variability in the system. This increases uncertainty as to when and how much energy is needed and available. As uncertainty increases, risk increases.

Is the current resource planning structure adequate?

Entity resource plans seem overly optimistic. While planning entities provide specific information about the resources they plan to add in the next one to five years, in many cases, they provide generic, non-specific "placeholder" resources in long-term planning five to ten years out. Traditional resource planning and review practices do not have a mechanism to ensure that resources will actually be built.



Load Growth

Over at least the last decade, the Western Interconnection has experienced fairly steady and predictable load growth. This has changed. Large loads like data centers, manufacturing facilities, and cryptocurrency mining operations, as well as large-scale electrification, add substantial demand to the system in a very short time.

Load Changes

Annual Demand

Demand for electricity across the Western Interconnection is expected to grow 20.4% over the next 10 years. That is more than double the 9.6% growth projected in resource plans filed in 2022. Much of this increase is attributed to plans for large load facilities across many areas in the West. The greatest area of load growth is the Desert Southwest (DSW), which is forecasting almost 35% load growth over the next decade.

The issue is not confined to the 10-year future. Large-load growth affects every year over the next decade, with greater effect in the next few years. For example, in 2023, the load projections for the NW-Central subregion showed a change from 128 TWh in 2025 to 139 TWh in 2034. This year's projections show an alarming increase in both the near and long-term: from 167 TWh in 2025 to 190 TWh in 2034. Data centers, manufacturing facilities, and to a lesser extent electrification, are driving this increase.

Peak Demand

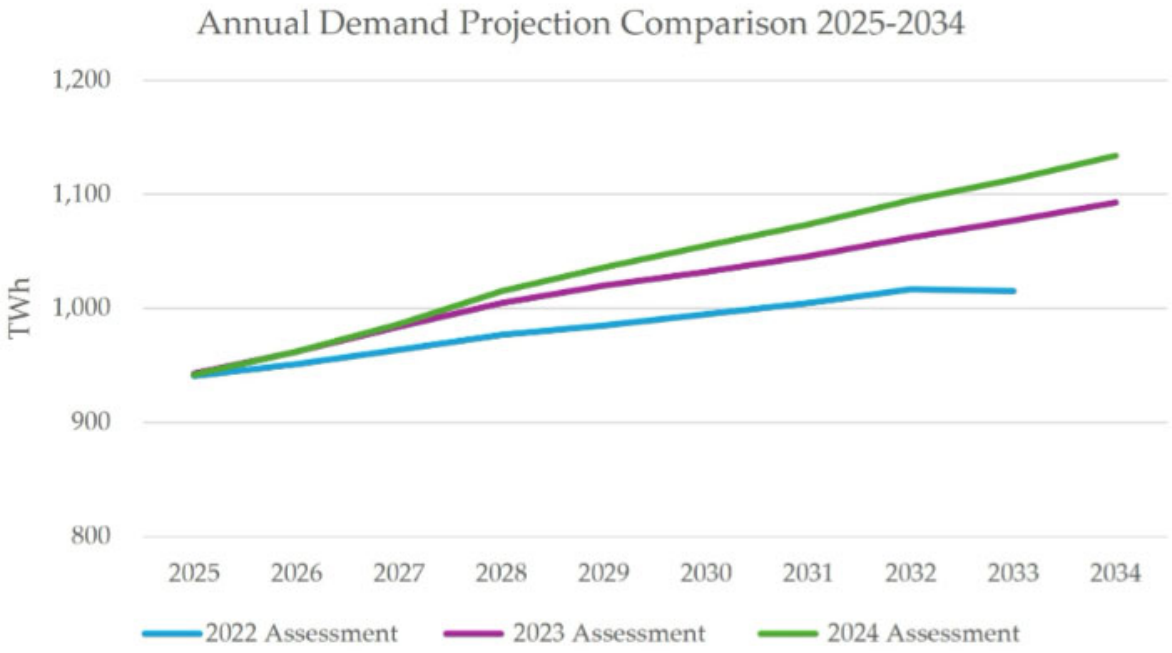
Peak demand in the Western Interconnection occurs in the summer. Based on plans submitted by the BAs, the expected peak demand for the Western Interconnection will grow from 164 GW in 2025 to 193 GW in 2034, an increase of 17.2%. This represents a slight increase from 2023 resource plans.

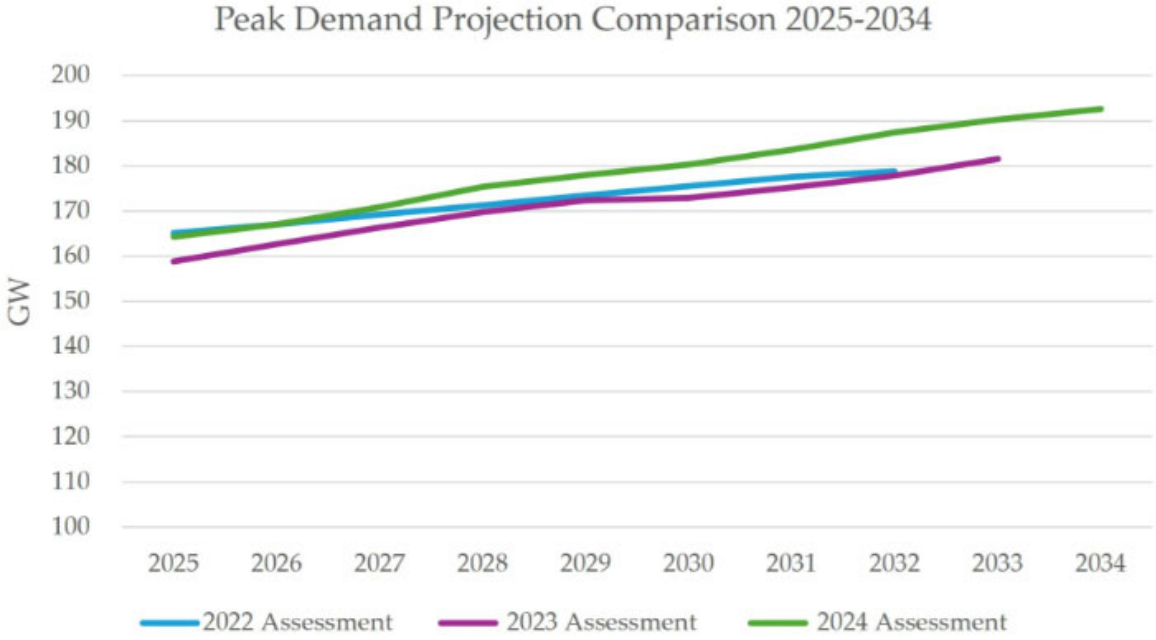
According to 2024 resource plans, the projected peak is slightly lower for NW-Central than it was in 2023 plans, while it is slightly higher for the DSW subregion. For the California-Mexico (CAMX) subregion, the peak reflected in 2024 plans is also slightly lower each year until 2034, when the projected peak demand is identical (66 GW) to the projections made in 2023. The projections for NW-Northeast have not changed much between 2023 and 2024 resource plans, while the 2024 projections are slightly lower for the NW-Northwest subregion.

In addition, although the peak demand in the Western Interconnection overall occurs in the summer, many entities see their peak demand in the winter. As the climate changes, some of these entities are becoming dual-peaking. This introduces challenges to resource planning for entities that have historically seen one predominant peak.

See the appendix for more information about the drivers of load growth.




Annual Demand Projection Comparison 2025-2034
TWh
1,200
1,100
1,000
900
800
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2022 Assessment
2023 Assessment
2024 Assessment

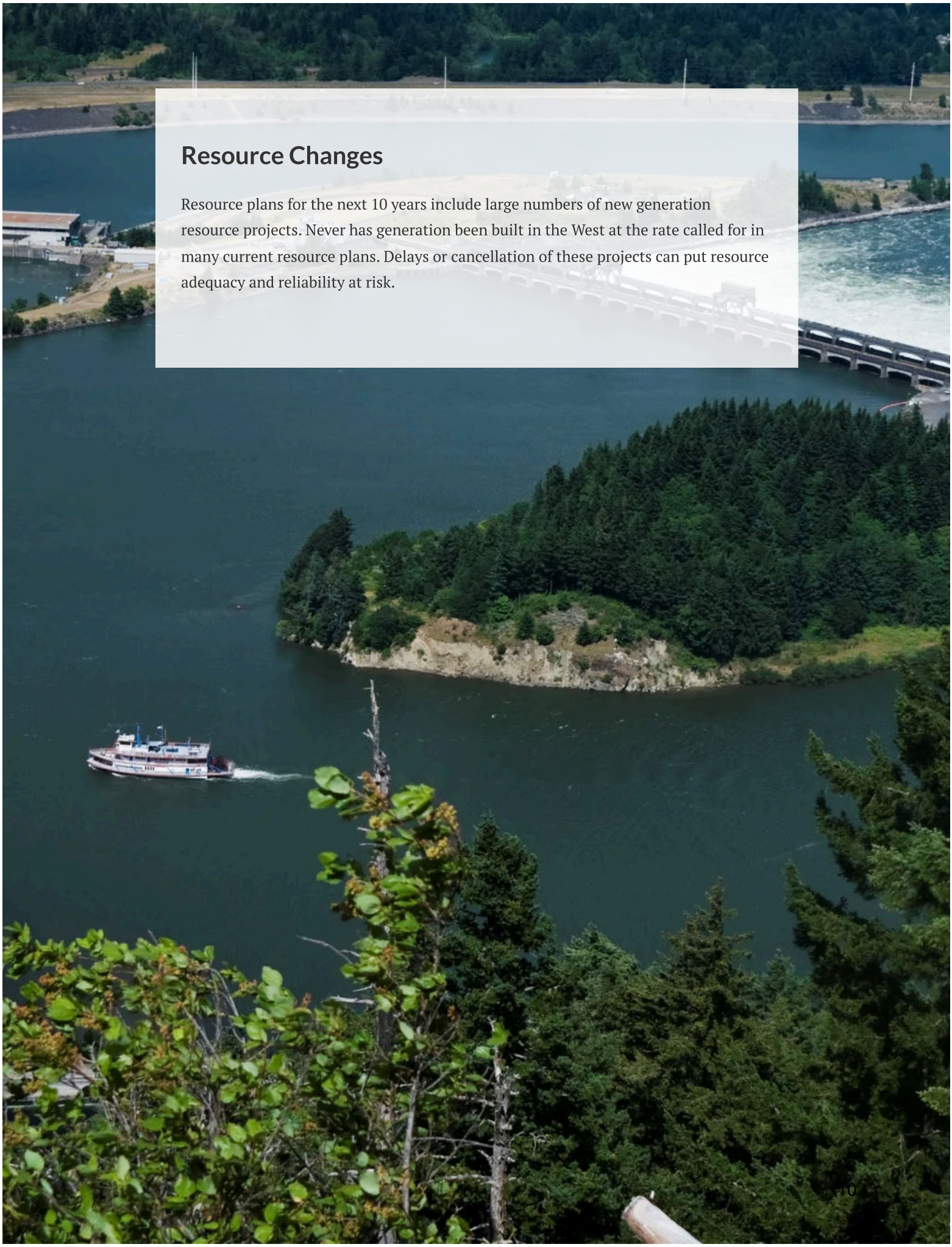

Peak Demand Projection Comparison 2025-2034
GW
200
190
180
170
160
150
140
130
120
110
100
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2022 Assessment
2023 Assessment
2024 Assessment



Impact of Large Loads

Large loads like data centers, manufacturing facilities, and cryptocurrency mining operations add a large amount of concentrated load to the system. In some cases, new large loads inundate a service area, overwhelming existing infrastructure. Some new large-load consumption patterns are different than traditional load patterns, requiring around-the-clock energy. Others have a significant amount of variability.

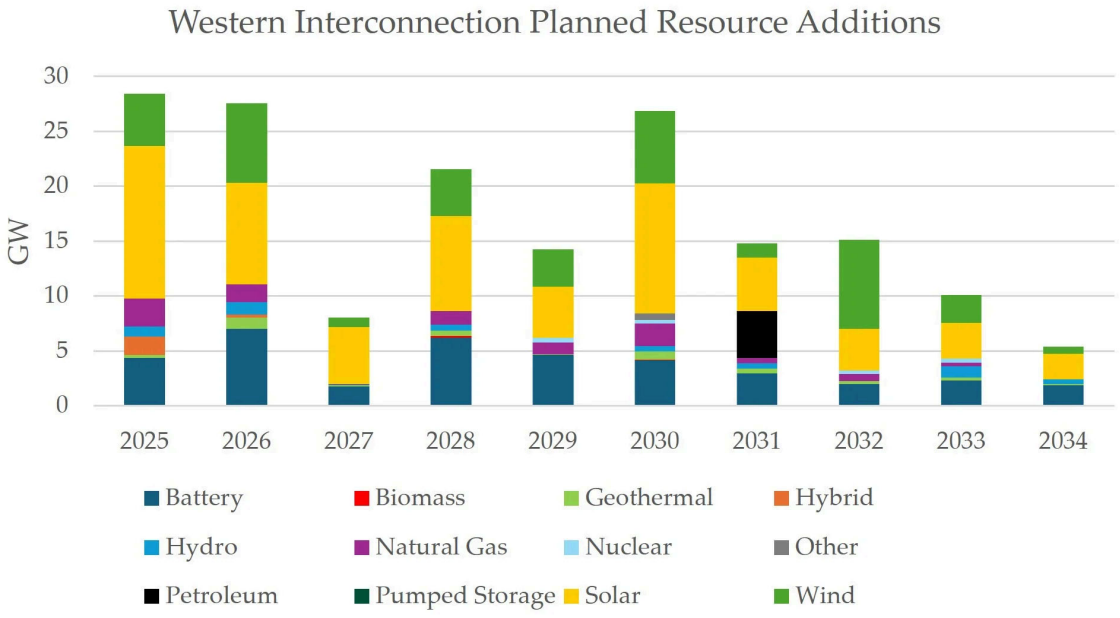
Integrating large loads often requires changes or additions to power system infrastructure. Large-load facilities can be built relatively quickly, as fast as 18 months, while building new generation resources and transmission infrastructure can take years. In addition, the question of cost allocation can complicate the construction of new infrastructure.



Resource Changes

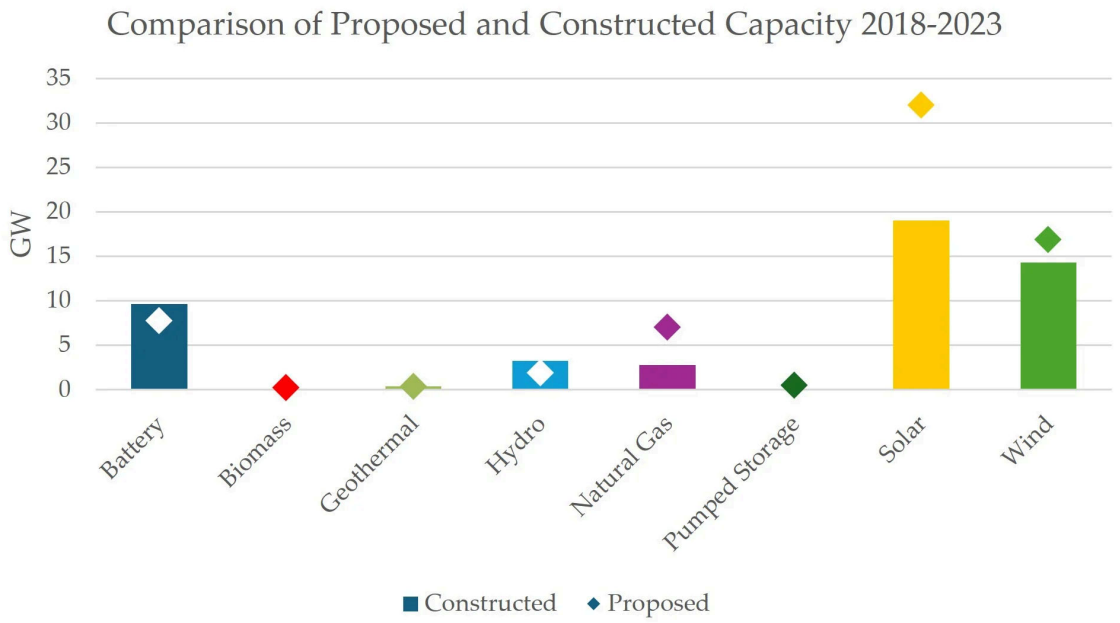
Resource plans for the next 10 years include large numbers of new generation resource projects. Never has generation been built in the West at the rate called for in many current resource plans. Delays or cancellation of these projects can put resource adequacy and reliability at risk.

Planned Additions



Planned Resource Additions

Over the next decade, entities in the Western Interconnection plan to add more than 172 GW of new generation capacity—almost 145 GW in battery storage, solar, and wind, according to resource plans filed in 2024. i That is up from 121 GW of resources in 2023 10-year plans i and is more than double the amount of generating capacity added in the last 10 years (73.7 GW). The existing generating capacity in the Western Interconnection as of 2023 was 299.5 GW.



Historical Resource Additions

Between 2018 and 2023, approximately 76% of the proposed resource additions came online in the year scheduled. In 2023, only 53% of the new generation resources i scheduled to come online that year actually came online; the rest were delayed or cancelled.

Go here for a breakdown of the planned resource additions by subregion over the next decade.

according to resource plans filed in 2024. That is up from 121 GW of resources in 2023 10-year plans and is more than double the amount of generating capacity added in the last 10 years (73.7 GW). The existing generating capacity in the Western Interconnection as of 2023 was 299.5 GW.

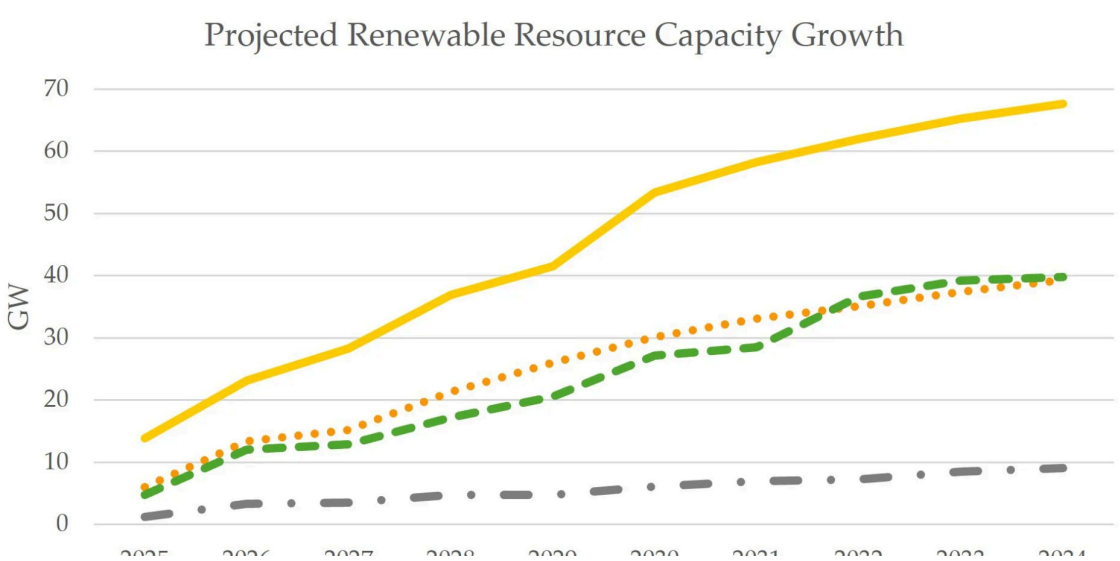
The Western Assessment relies on data submitted by the Balancing Authorities (BA) that describes projected hourly demand and resource projections over the next 10 years.

according to resource plans filed in 2024. That is up from 121 GW of resources in 2023 10-year plans and is more than double the amount of generating capacity added in the last 10 years (73.7 GW). The existing generating capacity in the Western Interconnection as of 2023 was 299.5 GW.

Historical Resource Additions

Other refers to generation types such as wood, oil, and non-gas biomass.

Between 2018 and 2023, approximately 76% of the proposed resource additions came online in the year scheduled. In 2023, only 53% of the new generation resources scheduled to come online that year actually came online; the rest were delayed or cancelled.

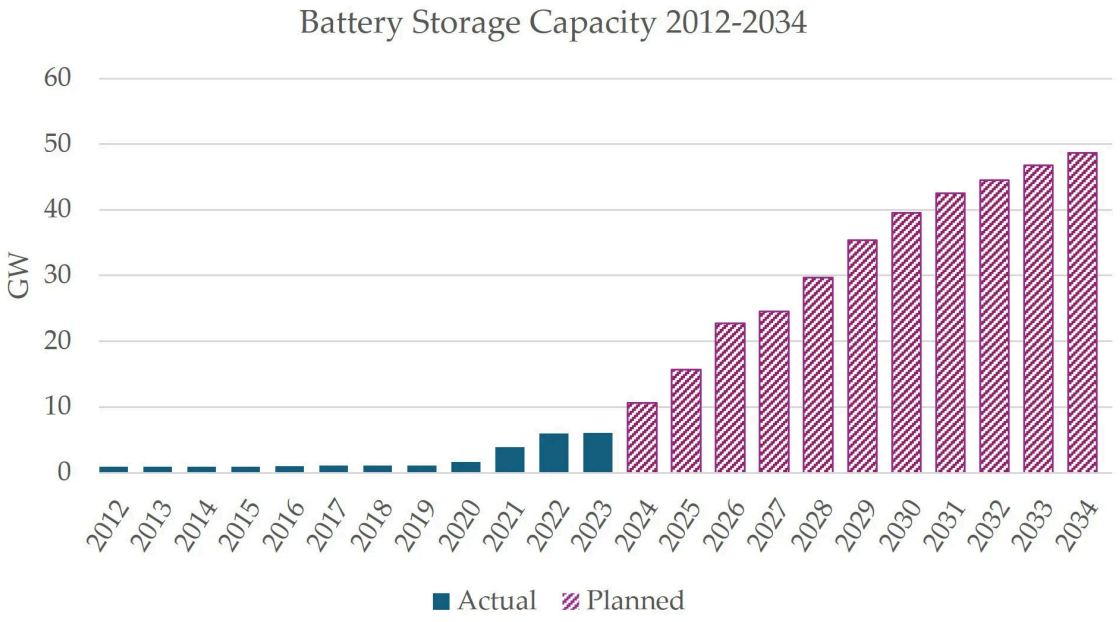


Solar

Entities plan to add nearly 68 GW of solar capacity over the next decade, more than any other resource. This will almost triple the amount of solar capacity that was in operation in 2023 (35 GW).

Wind

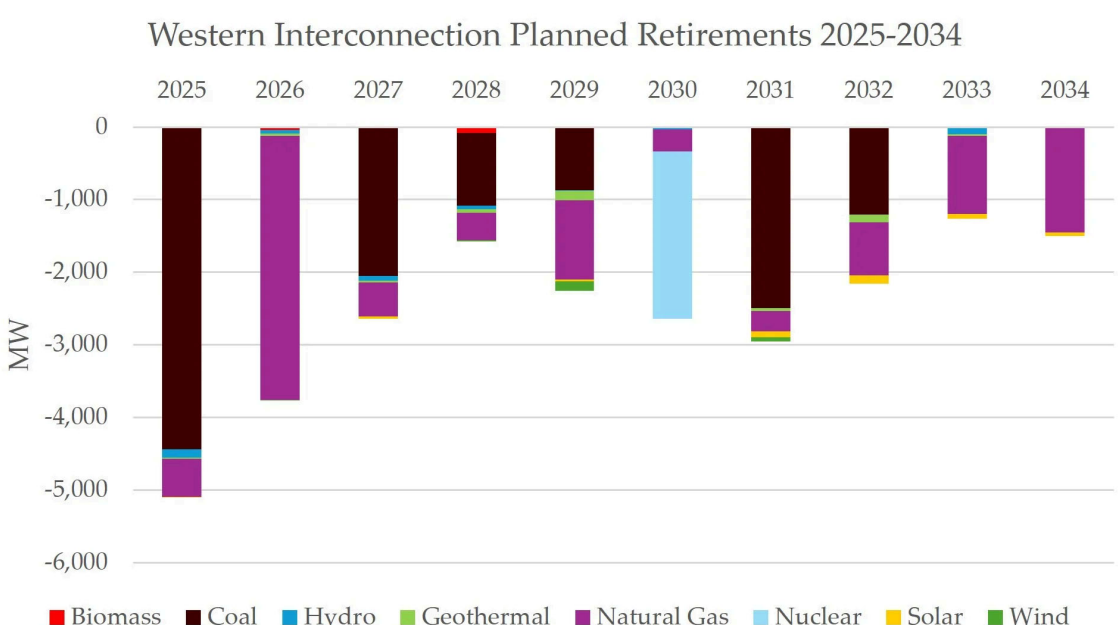
Wind capacity is projected to grow by nearly 40 GW from now until 2034. This increase will more than double the 37 GW in operation in 2023.



Battery Storage

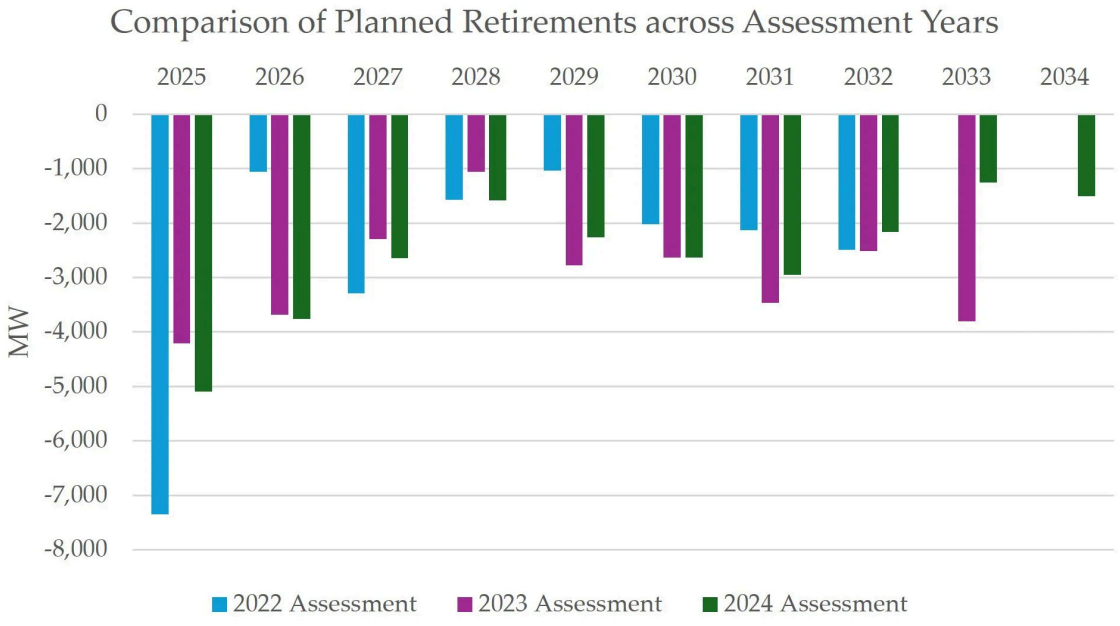
According to 2024 resource plans, battery storage will grow by more than 37 GW by 2034. In 2022, resource plans projected a total of 23 GW of storage by 2032, and that was 14 times more than what was operational in 2021 (1.6 GW). As of 2023, there was more than 10 GW of energy storage (battery and other forms of storage) installed in the Western Interconnection, primarily batteries but also pumped hydro. One major driver of new storage is the extension of the investment tax credit (ITC) for storage-solar projects and creation of a 30% ITC for standalone storage.

Retirements



Planned Retirements

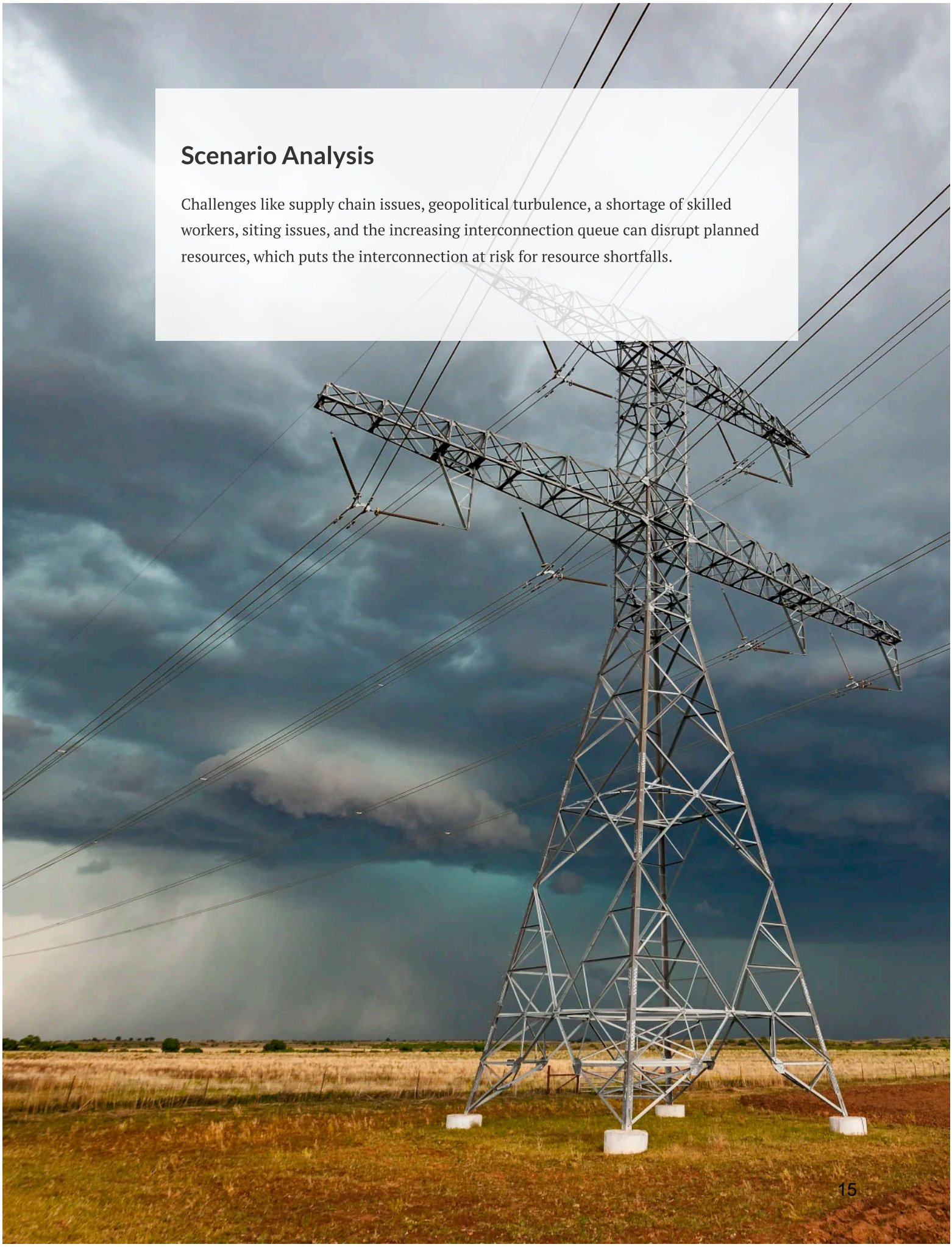
Entities plan to retire 25.85 GW of generation over the next 10 years. This is down slightly from resource plans filed in 2023, in which entities planned to retire 27 GW over the next decade, but is up considerably over the last 10 years. Retirement dates over the coming decade varied slightly compared to resource plans filed a year ago, but did not vary as much compared to the retirement delays we saw in 2023 resource plans. In 2025, for example, current resource plans call for 5.1 GW to retire, up from 4.2 GW in 2023 resource plans (but still down considerably from 2022 plans, when 7.4 GW were slated for retirement in 2025). Current plans also show a significant change in retirements in 2033. A year ago, 3.8 GW was set for retirement in 2033; in 2024, that dropped to 1.3 GW.



Changes in Planned Retirements

Most of these planned retirements (more than 24 GW) are baseload generation, such as coal, natural gas, and nuclear. In 2025, more than 4.4 GW of coal is set for retirement, and more than 3.6 GW of gas is slated for retirement in 2026.

In December 2023, California regulators voted to allow Diablo Canyon nuclear plant to remain open an additional five years—until 2030; it had been set to close in 2025. Diablo Canyon's two reactors have a combined generating capacity of more than 2.2 GW and accounted for 7% of California's in-state electricity generation in 2023.



Scenario Analysis

Challenges like supply chain issues, geopolitical turbulence, a shortage of skilled workers, siting issues, and the increasing interconnection queue can disrupt planned resources, which puts the interconnection at risk for resource shortfalls.

Scenario Analysis

One way WECC measures resource adequacy risk is by analyzing the number of hours in a year when there is a risk for potential load loss (demand-at-risk hour). A demand-at-risk hour is one in which the risk for potential load loss exceeds a risk tolerance threshold. WECC uses the one-day-in-ten-years (ODITY) or 99.98% reliability threshold. If the probability of load shed for any given hour is greater than the ODITY threshold, it is counted as a demand-at-risk hour. Demand-at-risk hours are not a prediction that demand will be lost; they indicate times when load is at risk of being lost because under certain conditions the interconnection does not have enough energy to meet demand.

Historically, the number of new resources that were built according to plan and on time has varied. In 2023, only 53% of planned resources were successfully built and brought online as scheduled. In other years the success rate was better. Between 2018 and 2023, only 76% of planned resource additions came online as scheduled.

If the past is a model for building planned resources over the next 10 years, resource adequacy will be at risk. To examine this, WECC evaluated four resource build-out scenarios:

- All planned resources are built on time
- 95% of planned resources are built on time
- 85% of planned resources are built on time
- 55% of planned resources are built on time

All Additions Scenario

If all planned additions are completed and operational on time, there are 89 demand-at-risk hours over the next decade.

95% Scenario

In this scenario, there is demand at risk in every year except 2024 and 2026. In 2025, there are three hours of demand at risk, all in the NW-Northwest subregion. By 2034, that number increases to 91 demand-at-risk hours across the NW-Northwest and NW-Northeast subregions.

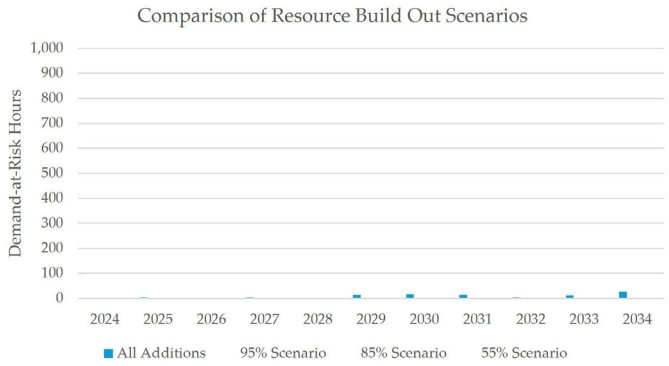
- NW-Northwest: Most of the demand at risk is in this subregion, including all three hours in 2025 and 82 hours in 2034.
- NW-Northeast: A total of 46 hours of demand is at risk over the next 10 years.

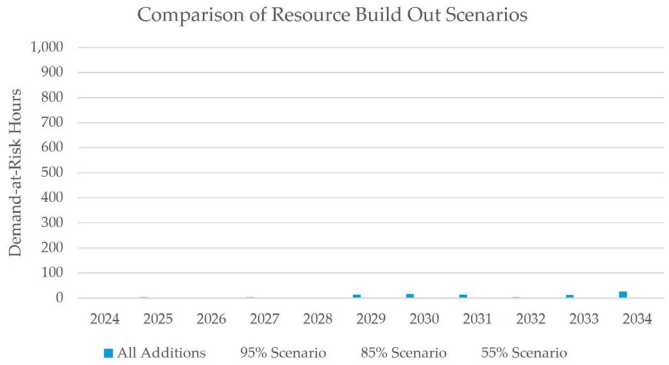
85% Scenario

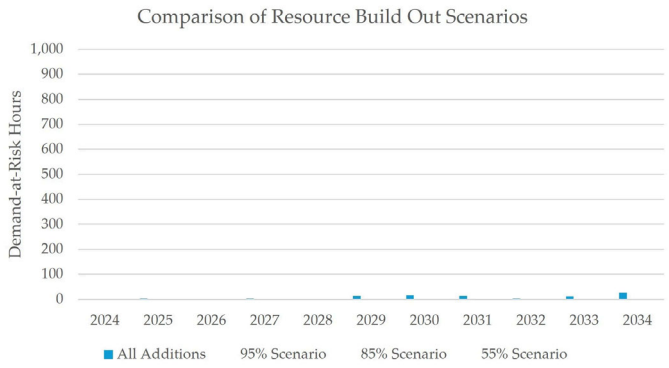
If only 85% of resources are built on time, demand at risk begins to increase significantly in 2029, when 36 hours are at risk. This increases nearly every year until 2034, when 129 hours of demand is at risk. The vast majority of the demand at risk is in the NW-Northwest subregion.

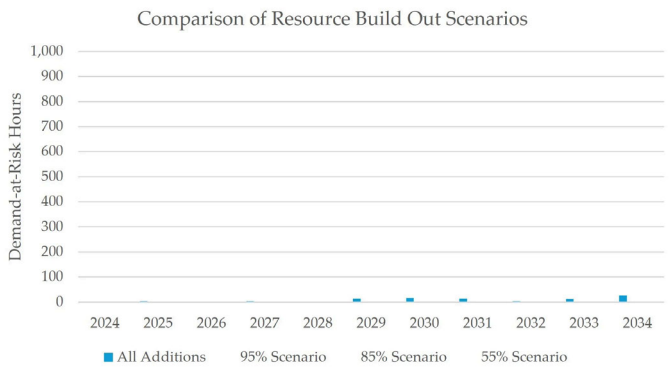
- NW-Northwest: There is minimal impact in the short-term—a total of 16 hours of demand at risk through 2028. That increases nearly every year through the end of the 10-year period, peaking at 87 demand-at-risk hours in 2034.
- NW-Central: Demand-at-risk hours appear in 2031, with a total of 16 hours, and increase to 41 hours in 2034.

55% Scenario





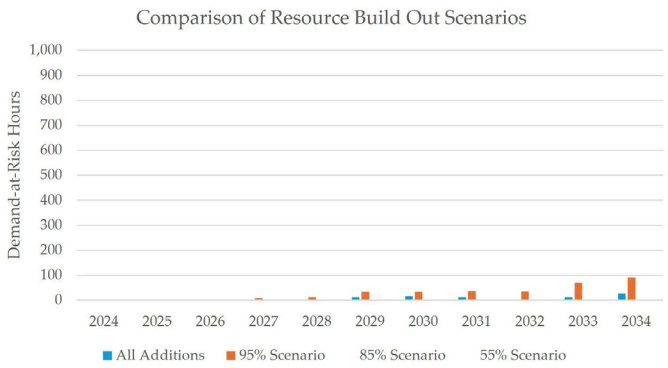


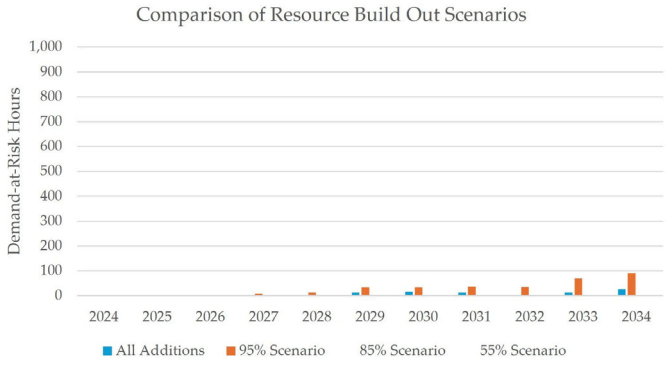


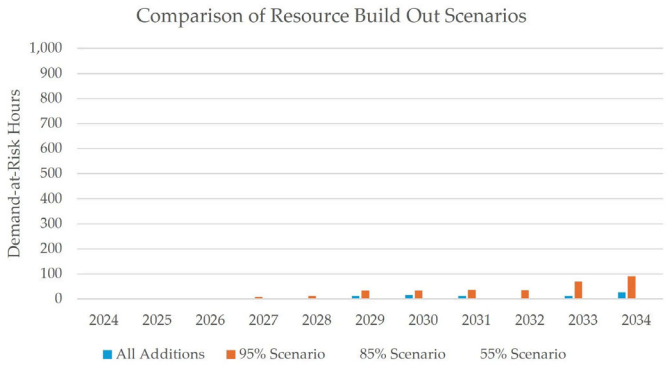
In this scenario, there are a total of eight demand-at-risk hours in 2025 growing to 952 hours by 2034.

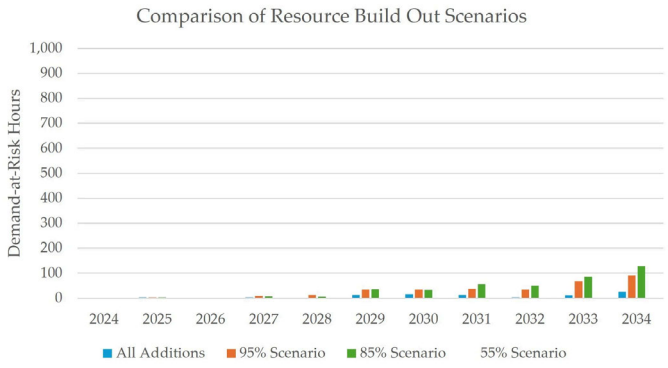
- CAMX: CAMX relies heavily on imports, resulting in no demand-at-risk hours in this scenario.
- DSW: Demand is at risk starting in 2028 (one hour) and increases to 69 hours in 2034.
- NW-Northwest: Demand is at risk every year over the 10-year period, starting with 8 hours in 2025 and climbing to 787 hours in 2034
- NW-Northeast: Demand is at risk every year starting in 2029 with two hours and increasing to 31 hours in 2034
- NW-Central: Demand is at risk after 2031, with a maximum of 65 hours in 2034

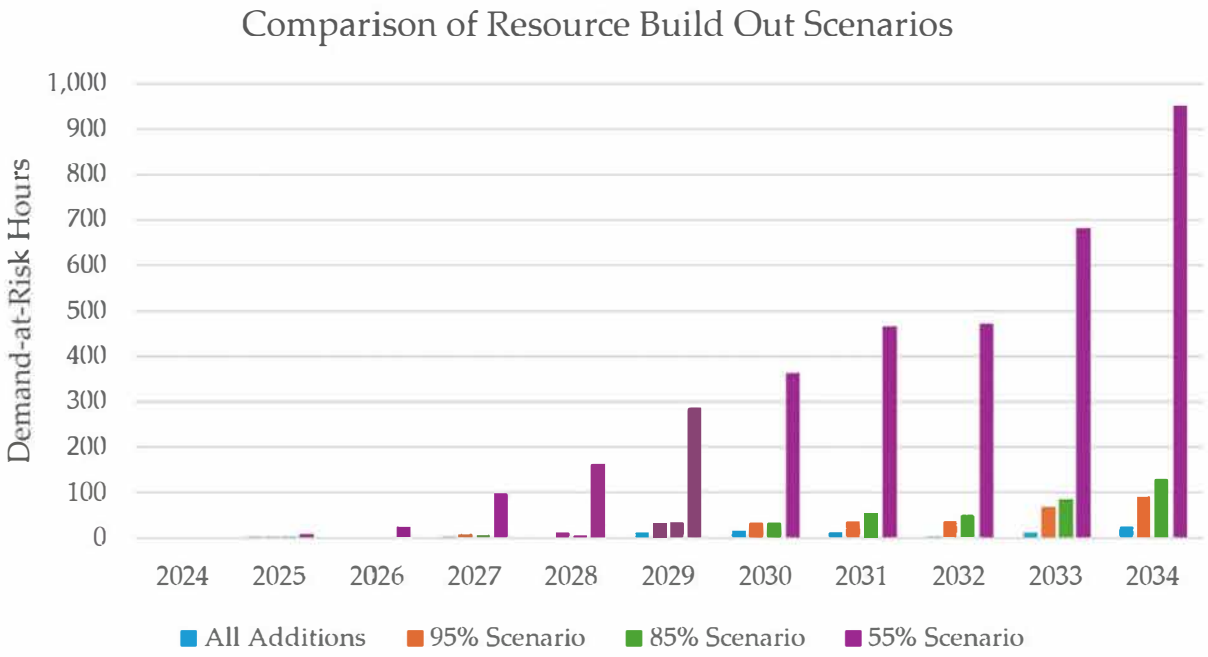
See the appendix for information on how demand at risk was calculated.










Comparison of Resource Build Out Scenarios
Demand-at-Risk Hours
1,000
900
800
700
600
500
400
300
200
100
0
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
All Additions
95% Scenario
85% Scenario
55% Scenario

If significant numbers of new resources are delayed or cancelled, much of the Western Interconnection may not be resource adequate over the next decade.

Risks to Planned Resource Additions



Supply Chain Disruptions

Supply chain issues that surfaced during the pandemic in 2020 continue to affect the industry, particularly the construction of new projects and the interconnection of new generating resources. A recent survey found that supply chain issues remain a significant problem in 2024.



Interconnection Queue

The interconnection queue nationwide grew more than 30% in 2023 and has increased eightfold in the last decade. The planned additions over the next 10 years will exacerbate this issue, although FERC Order 2023 calls for reforms to reduce the backlog and address uncertainty in the interconnection process.



Siting Delays

There has been increasing resistance to building new energy facilities, particularly wind, solar, and battery projects. These projects have encountered opposition in at least 45 states, according to a recent report that found that local opposition to new energy facilities is widespread and growing.

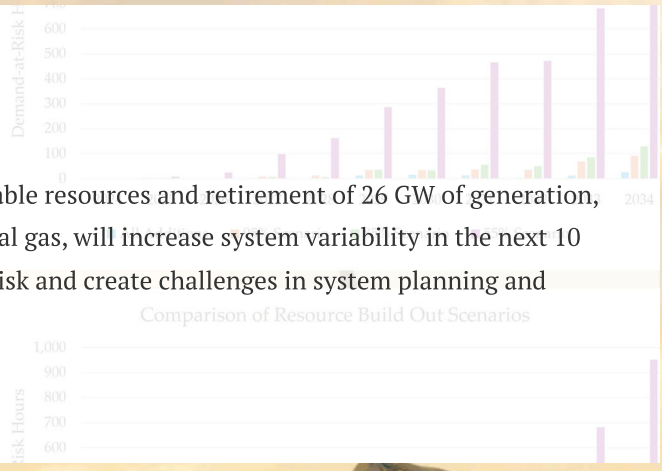


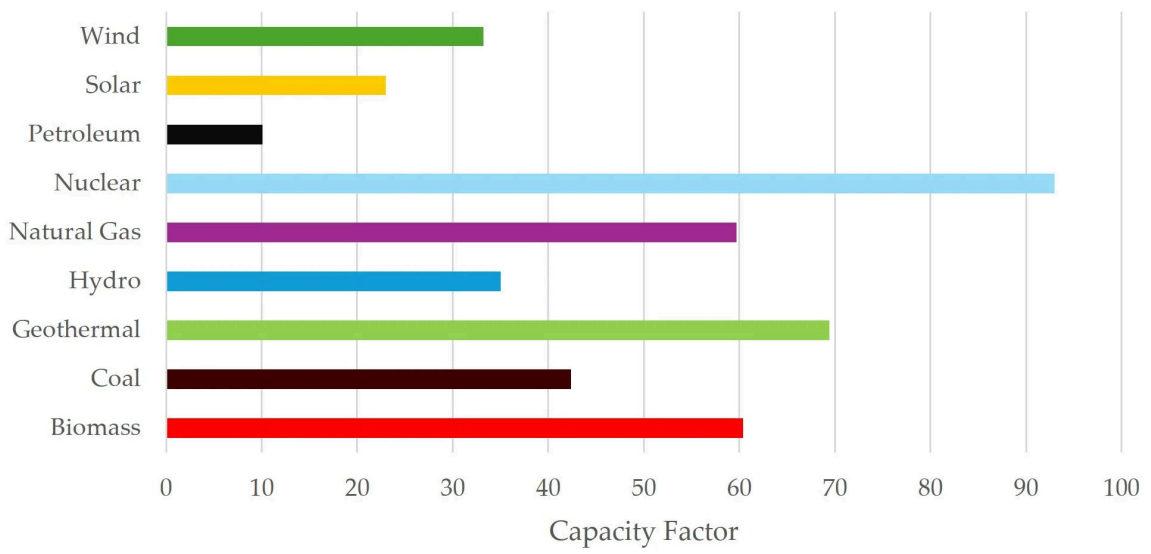
Increased Costs

Increased costs of materials for new wind and solar construction, transmission expansion, and replacement of plant equipment have caused project delays and maintenance deferrals. The rise in interest rates in recent years has also substantially increased the cost of capital for all energy projects.

Variability

The addition of 107 GW of variable resources and retirement of 26 GW of generation, most of which is coal and natural gas, will increase system variability in the next 10 years. These changes increase risk and create challenges in system planning and operation.





Replacing Generation Resources

Over the next decade, the addition of 107 GW of wind, solar, and battery hybrid generation must cover load increases and replace 26 GW of retired resources, of which almost 25 GW are coal, natural gas, and nuclear resources. The capacity factor of variable resources is lower than baseload resources like coal, natural gas, and nuclear. Replacing the 25 GW of retired baseload resources will require much more installed capacity of wind, solar, and storage resources.

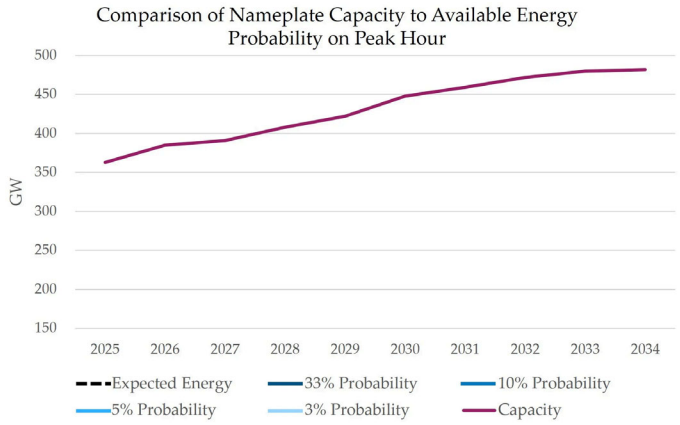
The capacity factor is the ratio of energy produced by a generating unit over a period of time to the amount of energy the unit could have produced at full power (or nameplate capacity). The chart shows average capacity factors by resource type across the U.S. (Source: EIA Electric Power Monthly)

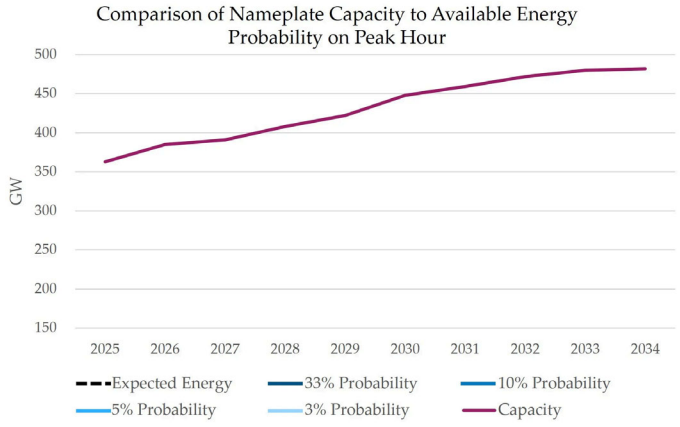


Traditionally, resource planning has been based on capacity and focused on ensuring there is enough capacity to meet peak demand. This has been based on the assumption that resources are available as expected (accounting for forced outages). However, with increasing variability, looking only at resource capacity is no longer enough. An examination of energy availability is crucial to ensuring the West has enough energy to meet demand at all hours of the year.

WECC receives nameplate capacity and historical generation information from Balancing Authorities. From this, WECC calculates the expected energy output of each resource and aggregates that number to get the expected energy for the entire resource fleet. The expected energy is lower than the nameplate capacity because resources do not produce at full capacity all the time. An increase in energy-limited resources widens the gap.

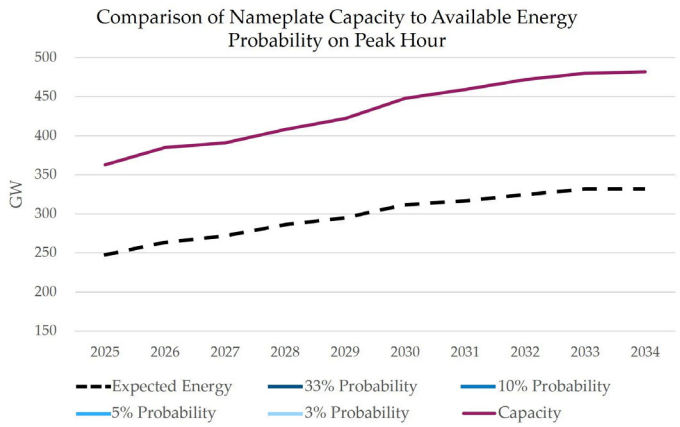
As the variability of the resource mix increases, so does the range of possible generation output at any given time. Depending on system and resource fleet conditions, more or less than the expected energy may be available. Instances when less energy is available can create risk, particularly when load is high. This can be the case during extreme weather events that cause simultaneous load increases and reductions in wind and solar output.

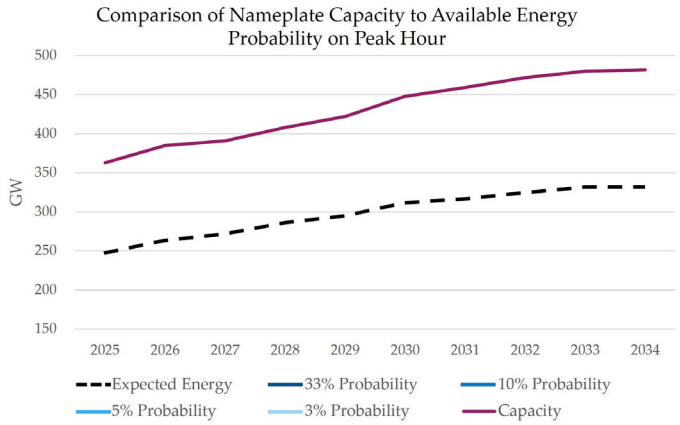


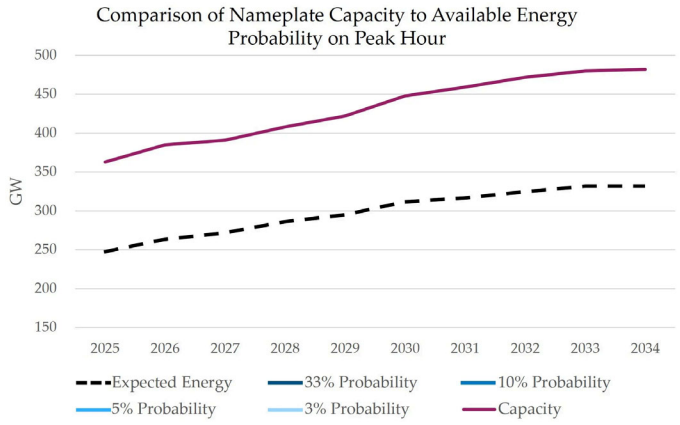


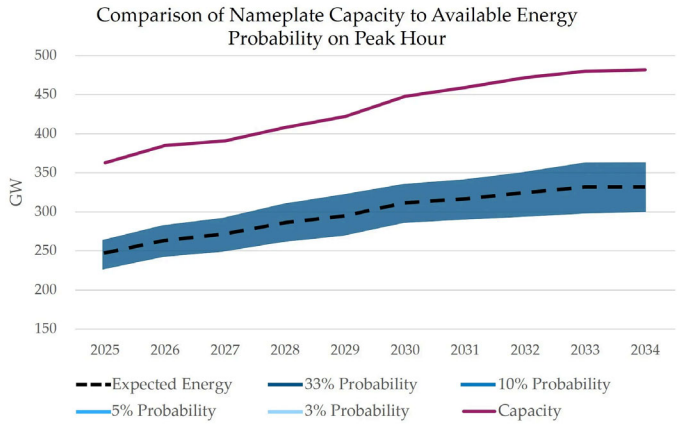
To address this, WECC calculates the probability distributions for each resource in the fleet. These distributions show the probability that a resource will generate at levels other than the expected level. The probabilities form a band of variability where the most likely output is in the middle and the least likely outputs are at the edge. The wider the band, the higher the variability on the system and the more possibilities planners and operators need to account for.

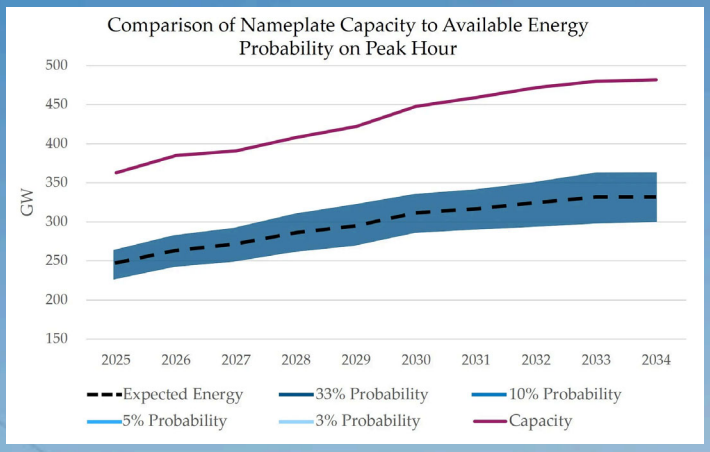
The size of the variability band increases over the next decade, indicating that while the West is building large amounts of new resources, the overall variability of the resource fleet is increasing.

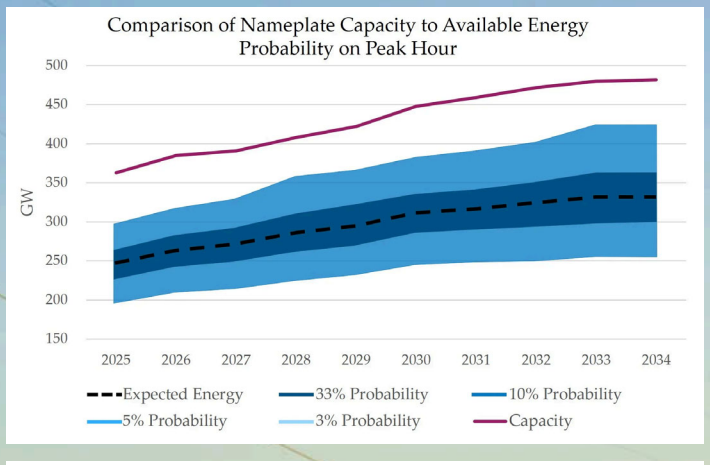


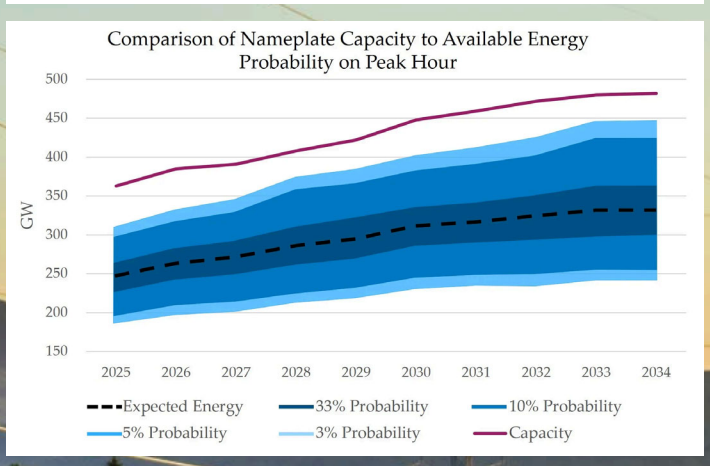


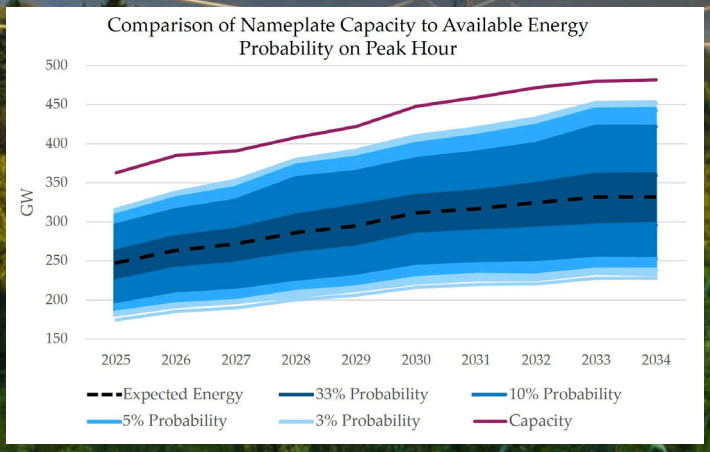






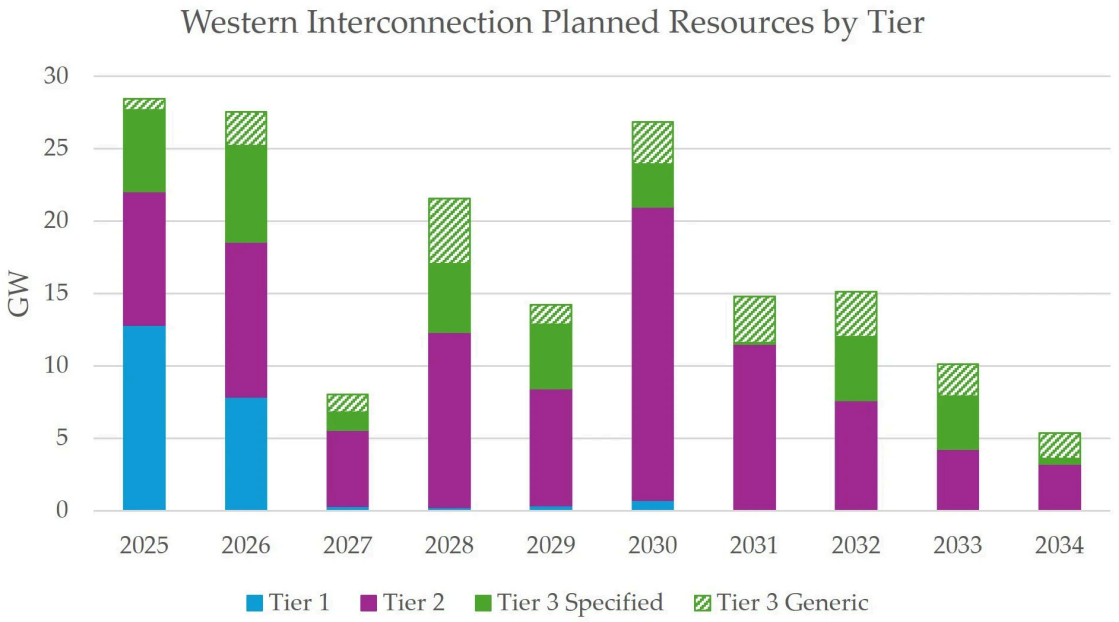






Resource Planning

Existing resource planning practices allow a lack of specificity about the resources entities need to meet demand, particularly in the long term. The resulting uncertainty about future resource additions puts the resource adequacy of the interconnection at risk.



Planning Resource Additions

Planning entities provide WECC with information about new resources they will need to meet demand over the next 10 years. In the near term, this information includes specific resource additions for the next one to five years. Typically, entities have a higher level of certainty about these resources because they are in some state of development. (Tier 1 or Tier 2 resources) Entities also include resources that are not yet under development (Tier 3 resources). When Tier 3 resources are included in near-term plans, they often reflect specific resources the entity can add relatively quickly (Tier 3 Specified). When they are included in later years of a resource plan, they are usually generic placeholder resources (Tier 3 Generic). In these cases, there is less certainty about whether the resource will be built. These resources often lack unit characteristics and may be grouped together instead of listed as individual plants or units.

In the past, when there was steady, predictable load growth and a generation surplus, entities could grossly estimate the resources needed 5 to 10 years in the future and hone those plans later. There was enough surplus generation in the interconnection to cover situations where new resources were built late, cancelled, undersized, or when demand increased unexpectedly. However, given the level of change in the West, the large amounts of new generation needed over the next decade, and obstacles to building it, delaying long-term resource decisions may put the resource adequacy of the interconnection at risk. This leaves the industry in a difficult position, because it needs more clarity about the future in a world that is becoming increasingly hard to predict. Resource plans that include large amounts of Tier 3 resources likely overestimate the ability to build generation.

Recently, there have been efforts to conduct longer-term planning on a 20-year horizon to meet needs identified by industry and the Federal Energy Regulatory Commission (FERC). In its Order 1920, FERC requires 20-year transmission planning to ensure the industry is preparing for the long-term future of the electric grid. While planning further out may allow the industry to see potential risks sooner, that work is only as good as the information on which it relies. Planning entities struggle to specify new resources in their 10-year resource plans; hypothesizing a resource mix in the 20-year future to study transmission may be incredibly challenging. To be successful, requirements for 20-year—and longer—planning horizons will spur advances in long-term resource planning.

Balancing Authorities provide WECC with information on planned resources classified into three tiers:
- Tier 1: resources that are under construction and expected to be complete and available for the year being studied
- Tier 2: resources that are under contract but have yet to begin construction. These resources may be operational by the year being studied.
- Tier 3 Generic: Generic placeholder resources that an entity has less certainty about.
- Tier 3 Specified: These Tier 3 resources may include capacity, type, and location information, but other unit characteristics and specific commission date are not known, and the project hasn't been started.

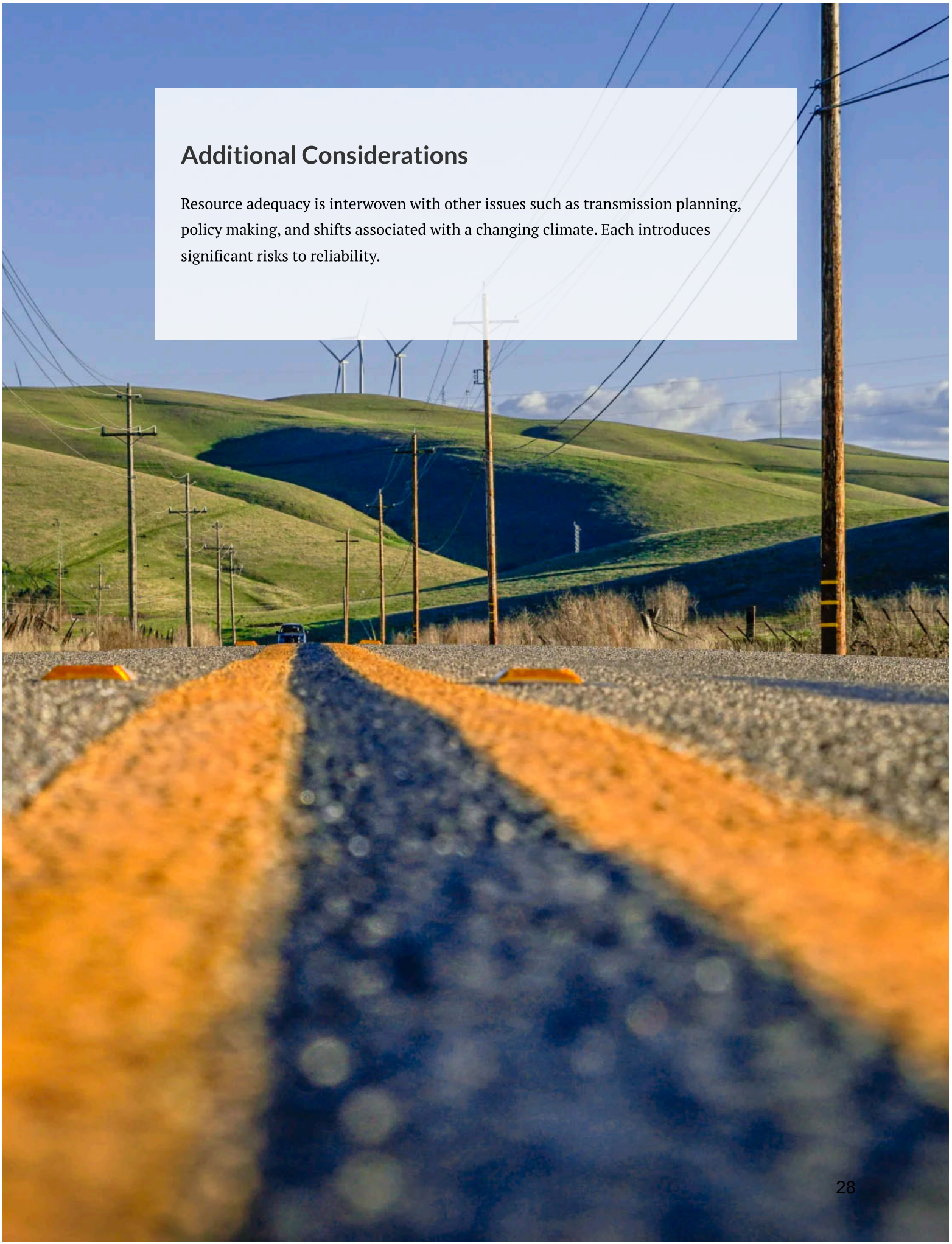
Resource Adequacy Programs

Resource adequacy programs can help manage resource adequacy by taking advantage of operating efficiencies and diversity across the entities in their footprint. The California ISO's reliability requirements program sets resource adequacy requirements for load serving entities in the ISO. The CAISO program has functioned for years and is integrated with its other functions.

The Western Resource Adequacy Program (WRAP) is a developing program with the goal of providing a region-wide, collaborative approach to resource adequacy. The WRAP is administered through a FERC-approved tariff that allows participants to phase into full, binding participation, including being subject to non-compliance charges for failing to meet the requirements of the program. Efforts to launch the binding program have encountered several obstacles. In April 2024, WRAP participants indicated they lacked critical mass to be able to move to the binding phase by Summer 2026. Participants cited challenges that include procuring sufficient firm capacity to meet program requirements and avoid charges. In an effort to move toward a binding program by Summer 2027, WRAP will file tariff changes with FERC that include a temporary reduction of non-compliance charges so participants can fully participate in the program and have access to WRAP capacity reserves on the worst of operating days.

To commit to a resource adequacy program, entities must know what resources they will have to offer. Resource plans that contain large numbers of Tier 2 and Tier 3 resources provide little certainty about future resource capacity, meaning entities cannot be confident in what resources they will have to offer. This may create reticence and, ultimately, delays on the part of entities in joining these programs.





Additional Considerations

Resource adequacy is interwoven with other issues such as transmission planning, policy making, and shifts associated with a changing climate. Each introduces significant risks to reliability.



Transmission Considerations

The modeling tool WECC uses for the Western Assessment transfers electricity between entities when one has a shortfall and the other has sufficient available energy to meet that shortfall.

The analysis in this report differs from that in the Interregional Transfer Capability Study (ITCS), an assessment on which WECC collaborated with NERC and the other Regional Entities to gauge the ability to transfer electricity between regions in the U. S. and Canada, and to determine prudent additions to transfer capability to support reliability. Congress mandated the ITCS in the Fiscal Responsibility Act of 2023. The ability to transfer power between regions could be a key to maintaining reliability amid the changing resource mix and as climate change brings more extreme weather.



Imports

WECC's analysis includes imports, or the ability for entities to transfer electricity between subregions. Studying the ability to import electricity is important because the Western Interconnection was designed to take advantage of its geographic and resource diversity. Imports are critical to reliability, particularly as the variability of the system increases. However, under some extreme conditions, either the resources or the transmission capacity may be reduced or eliminated altogether. Looking at different import scenarios helps WECC better understand the interplay between resource adequacy and transmission availability.

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Go here to see how resource adequacy is impacted in each of the five subregions based on the ability to import electricity.

The analysis shows that every subregion relies on the ability to import or transfer electricity, although the impact is much less significant in the DSW and CAMX subregions. The NW-Northwest and NW-Northeast subregions were the most affected in terms of demand at risk, with more than 1,900 hours of demand at risk every year.

For more information about how transfer capability was handled in this assessment, see the appendix.

The analysis shows that every subregion relies on the ability to import or transfer electricity, although the impact is much less significant in the DSW and CAMX subregions. The NW-Northwest and NW-Northeast subregions were the most affected in terms of demand at risk, with more than 1,900 hours of demand at risk every year.

For more information about how transfer capability was handled in this assessment, see the appendix.



Energy Policy

Federal and state policies are driving changes in the electric system. Several states in the West have ambitious clean energy goals, for example, and federal legislation has steered unprecedented amounts of funding to the energy sector.

Together with the Bipartisan Infrastructure Law (BIL), the Inflation Reduction Act (IRA) has accelerated the transformation of the electric grid by making funding available for the development and deployment of clean energy manufacturing facilities and research in the form of tax credits, loans, investments, and other programs.

Batteries and electric vehicles have drawn the most investment—since the IRA's passage, $114 billion in new projects in those industries have been announced, a recent analysis indicates. Also, according to the White House, the U.S. was projected to build more new electric generation capacity in 2024 than has been built in the last two decades, with 96% of that being renewable energy.

At the state level, Washington's Clean Energy Transformation Act requires utilities to supply the state's customers with electricity that is 100% renewable or free of greenhouse gas emissions by 2045. California also has a goal of 100% of its electricity coming from renewable energy and zero-carbon resources by 2045. And Oregon's Clean Energy Targets bill requires the state's electricity providers to significantly reduce the greenhouse gas emissions levels of the electricity sold in the state: 80% below baseline emissions levels by 2030, 90% below baseline emissions levels by 2035, and emissions-free by 2040.

The impact of the IRA was initially expected to be approximately $370 billion in spending and tax credits for clean energy projects over 10 years. That estimate appears low. It could be as high as $1.2 trillion. Since 2022, the IRA has driven approximately $332 billion in new investments in clean energy and transportation technologies nationwide. Nearly all of that was private investment, not government spending, that was sparked by an estimated $48 billion in federal tax credits. Batteries and electric vehicles have drawn the most investments – since the IRA's passage, $114 billion in new projects in those industries have been announced, recent analysis indicates.

Weather

Extreme weather events are increasing in frequency and intensity, in some cases becoming more extreme, unpredictable, widespread, and longer-lasting. These events affect generation, particularly as the resource mix and the demand for electricity becomes more variable. As weather becomes more extreme, what used to be considered extreme is becoming more normal. This is changing how we manage the system.

FERC has approved several new weather-related standards in recent years, to help close reliability gaps, and utilities and planning entities continue to adapt their projections to account for climate change.

Through its 10-year and 20-year assessments, WECC examines the impact of severe weather on resource adequacy by assessing how the subregions in the Western Interconnection rely on imports to remain resource adequate during events that trigger high demand for electricity. As the climate changes and events become more widespread, it is important to understand how to use the diversity of the interconnection and its evolving resource mix to ensure resource adequacy.

Three new winter reliability standards took effect in April 2023. EOP-011-2 requires generator owners and operators to have cold weather preparedness plans subject to annual inspection. TOP-003-5 and IRO-010-4 direct the creation of databases with information about the operational limitations of generation resources during cold weather conditions.

FERC also approved two new reliability standards in February 2023: EOP-011-3 and EOP-012-1. The standards, which have not taken effect, include new and modified requirements to enhance grid reliability during extreme cold.

And NERC is working on TPL-008-1, which addresses a lack of a long-term planning requirement for extreme heat and cold weather events.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-10:
Cooke Email to Alle-Murphy

-----Original Message-----
From: Alle-Murphy, Linda
Sent: Wednesday, December 28, 2005 9:05 AM
To: Mansueti, Lawrence
Subject: Re: Order No. 202-05-3

Dear Mr. Mansueti,

I am an associate at Schnader Harrison Segal and Lewis, working together with John Britton, who represents the City of Alexandria in the Mirant Power Plant matter. I have a few procedural questions regarding the application for rehearing.

According to Section VI.H. of Order No. 202-05-3, applications for rehearing in this matter should be addressed to you. Section VI.H. cites to 16 U.S.C. Section 825(l), which refers to the "Commission" (FERC). I am just seeking to confirm that Section 825(l) also applies to this DOE proceeding.

Also, are 10 CFR Section 1003.1 et seq., Office of Hearings and Appeals Procedural Regulations applicable to this proceeding (e.g. re service requirements, etc.) If not, are there other procedural rules that apply to this proceeding?

Thank you very much for your assistance! You may respond by return e-mail or, if that is not convenient for you, by telephone or fax.

Linda Alle-Murphy
Linda B. Alle-Murphy
Schnader Harrison Segal & Lewis LLP
1600 Market Street, Suite 3600
Philadelphia, PA 19103-7286

From: Cooke, Lot
Sent: Friday, December 30, 2005 8:51 AM
To: 'LAlle-Murphy@Schnader.com'
Subject: Rehearing procedures for DOE Order No. 202-05-3

Dear Ms. Alle-Murphy:

In response to your emailed question to Mr. Mansueti--

The DOE Organization Act transferred the authority of the Federal Power Commission to the Secretary, except for authority over rates and charges for the transmission and sale of electric energy, which was transferred to FERC. Federal Power Act (FPA) Section 202(c) emergency authority was generally and specifically given to the Secretary.

An order issued under the FPA is only reviewable pursuant to the rehearing provisions contained in section 313 of the FPA, so that is the applicable provision under which to seek rehearing of the December 20,
2005 order.

The DOE regulations on emergency orders, 10 CFR section 205.370, et seq., do not a have specific rehearing section, but a party seeking rehearing can look for procedural guidance to FERC's Rules of Practice and Procedure, 18 CFR Part 385. In particular the rehearing regulations contained at 18 CFR section 385.713 and the service requirement contained at 18 CFR section 385.2010. The Office of Hearings and Appeals procedures are not applicable as the Secretary will make the rehearing decision pursuant to FPA section 313.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-11:
Department Rehearing Procedures

An official website of the United States government Here's how you know

U.S. DEPARTMENT of ENERGY

DOE 202(c) Order Rehearing Procedures

DOE may revise these procedures through advance written notification to the parties and posting here.

Intervention. Any person seeking to intervene to become a party must file a written motion to intervene by emailing AskCR@hq.doe.gov. A motion to intervene must state the movant's interest in sufficient factual detail to demonstrate that the movant has or represents an interest which may be directly and substantially affected by the outcome of the proceeding. A motion to intervene must be filed within 30 days after the

issuance of a section 202(c) order, which includes an original order or a renewal order. No grant of late intervention is permitted unless DOE finds good cause. The grant of party status will be expressly stated by DOE order within thirty days of filing. A motion to intervene may be combined with a motion for rehearing, answer, or other motion.

Rehearing. Pursuant to 16 U.S. Code § 825*l*, any party applying for rehearing must file a written motion for rehearing by emailing AskCR@hq.doe.gov within 30 days after the issuance of a section 202(c) order. The motion for rehearing must set forth specifically the ground or grounds upon which such motion is based and must contain a clear and concise statement of the facts and law which support the motion and the specific relief or ruling requested. Any grounds not specifically identified in such motion shall be waived. All motions for rehearing will be addressed in a consolidated proceeding and order on rehearing. Unless DOE acts upon the motion for rehearing within 30 days of filing, such motion may be deemed to have been denied.

Answers. Any party may file an answer to another party's motion by emailing AskCR@hq.doe.gov within 7 days after the motion is filed. An answer must contain a clear and concise statement of any disputed factual allegations and any law upon which the answer relies. An answer to an answer is not permitted.

Timing and Service. DOE will use best efforts to post filings here within 24 hours of receipt. Such posting constitutes service to all parties. Filing or posting due dates that fall on a federal holiday or weekend shall be extended to the next business day. Documents received after 4:30 p.m. Eastern Time are deemed filed on the next business day.

Confidentiality. DOE strongly encourages that all filings be limited to information suitable for public release. If procedures to maintain confidentiality are requested, DOE will provide them as needed at the discretion of DOE.

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-12:
Department 202(c) Webpage

An official website of the United States government Here's how you know

U.S. DEPARTMENT of ENERGY

DOE's Use of Federal Power Act Emergency Authority

Under Federal Power Act (FPA) section 202(c), during the continuance of a war in which the United States is engaged or when an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy, or of facilities for the generation or transmission of electric energy, or of the fuel or water for generating facilities, or other causes, the Secretary of Energy may require by order temporary connections of facilities, and generation, delivery, interchange, or transmission of electricity as the Secretary determines will best meet the emergency and serve the public interest. 16 U.S.C. § 824a(c).

All public comments and requests related to FPA section 202(c) should be sent via email to AskCR@hq.doe.gov. Information that the sender deems sensitive and not eligible for public release should be marked accordingly, and both a public (redacted) and non-public version of such materials should be submitted. Additional information about 202(c) procedures, if necessary, will be announced on this page.

The provision of this process for submission of correspondence or comments on any pending application is for purposes of ensuring the receipt by the appropriate office and personnel within the Department. Establishment of this

email address does not establish a “docket,” and those submitting correspondence do not constitute parties or intervenors to any proceeding. Further, submission of correspondence to the Department does not in any way limit or prevent the ability of the Secretary to act on any application, or pursuant to section 202(c) without application, in any way and at any time as he or she deems appropriate.

202(c) Orders Issued to Date

2025 DOE 202(c) Orders

202(c) orders issued from Jan. 1, 2025 to Dec. 31, 2025

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2024 DOE 202(c) Orders

202(c) orders issued from Jan. 1, 2024 to Dec. 31, 2024

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2023 DOE 202(c) Orders

202(c) orders issued from Jan. 1, 2023 to Dec. 31, 2023

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2022 DOE 202(c) Orders

202(c) orders issued from Jan. 1, 2022 to Dec. 31, 2022

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2021 DOE 202(c) Orders

202(c) orders issued from Jan. 1, 2021 to Dec. 31, 2021

2020 DOE 202(c) Orders

202(c) orders issued from Jan. 1, 2020 to Dec. 31, 2020

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DOE 202(c) Orders Issued Prior to 2020

DOE 202(c) orders issued prior to 2020

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Numbering Scheme Information

Beginning in 2022, the Department modified the numbering scheme associated with its section 202(c) emergency orders. Prior to 2022, emergency orders followed a fiscal year timeline, whereas since the beginning of 2022, emergency orders have aligned with the calendar year. For example, a 202(c) emergency order issued in November 2017 is identified as Order No. 202-18-1 and an order issued in December 2022 is identified as Order No. 202-22-3.

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-13:
Department Order No. 202-22-4

Department of Energy
Washington, DC 20585

Order No. 202-22-4

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and delegated by email correspondence (Dec. 23, 2022), and for the reasons set forth below, I hereby determine that an emergency exists in the electricity grid operated by PJM Interconnection, LLC (PJM) due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

On December 24, 2022, PJM, the Regional Transmission Operator (RTO) for 65 million people in thirteen states and the District of Columbia (the PJM Region), filed a *Request for Emergency Order Under Section 202(c) of the Federal Power Act* (Application) with the United States Department of Energy (Department) "to preserve the reliability of the bulk electric power system."

The PJM Region, like many regions across the country, is currently being affected by a severe winter weather system. PJM states that this weather system caused a significant drop in temperatures across the PJM Region on December 23, 2022, accompanied by high winds in excess of 40 mph. As a consequence of the impact of wind and decreasing temperatures, the demand for electricity in the PJM Region rose to an unusually high peak load on the evening of December 23, 2022, in excess of 135,000 MW. This severely cold weather is expected to last through Sunday morning.

While the vast majority of generating units in the PJM Region continue to function adequately under these stressed conditions, some units have experienced operating difficulties due to cold weather or fuel limitations, primarily gas. Specifically, approximately 45,000 MW of generating units (the majority of which are thermal) are currently outaged or derated. PJM has expressed its concern that these units will be unable to return to service over at least the next 48 hours, which coincides with the time period for which PJM is requesting this Order. Since these units may not promptly return to service, and in the event PJM experiences additional generating unit outages, PJM states that it may need to curtail some amount of firm load on December 24, December 25, or December 26, 2022 in order to maintain the security and reliability of the PJM system.

Description of Mitigation Measures

In its Application, PJM identifies the measures it is taking to ensure the supply of generation will continue to be sufficient to meet system demand and reserve requirements. On December 20, 2022, PJM issued a cold weather advisory in the PJM Region in anticipation of the forecasted weather conditions. Then on December 23, 2022, PJM issued

a PJM Region-wide cold weather alert which further highlighted PJM's expected need to call higher-than-normal generation resources in light of the anticipated weather.

On December 23, 2022, generating reserves diminished to a level that required PJM to declare an Energy Emergency Alert (EEA) Level 2 and take other emergency actions. PJM states that after having exhausted economic operation, PJM triggered a Maximum Generation Emergency Action to increase the PJM Region generation above the maximum economic level. Further, PJM triggered its load management reduction actions to provide additional load relief by using PJM-controllable load management programs. PJM called on demand response providers and curtailment service providers to reduce load. PJM also issued public appeals for consumers to reduce usage. PJM has continued to employ these emergency actions through December 24, 2022, and anticipates needing to continue them through the order end date that it has requested.

Since December 23, 2022, PJM has also taken additional measures to provide additional reserves, including:

- Reducing exports to neighboring regions and requested shared reserves for neighboring regions; consistent with joint operating agreements and other regulatory requirements, PJM has continued to communicate and collaborate with its interconnected neighboring systems when the demand on the PJM system has exceeded expected energy and reserve requirements and when emergency transfers were required to support PJM's interconnected neighboring systems;
- Issuing additional public conservation appeals;
- Running uneconomic generation during lower load periods to ensure their availability during peak conditions;
- Utilizing its Emergency Procedures to assist in maximizing the pumped storage hydro generation levels;
- Communicating and preparing transmission and distribution service providers to implement distribution voltage reduction measures; and
- Communicating and preparing transmission and distribution service providers to implement firm load shed.

In its Application, PJM committed to continue to take such actions, including utilizing other supply resources before calling upon any generators to operate in excess of permitting levels. According to PJM, it is nevertheless possible that the measures it has and will take may not be sufficient to avoid the need to curtail firm load in order to ensure system reliability.

Request for Order

PJM requests that the Secretary issue an order immediately, effective today, December 24, 2022, through 12:00 p.m. Eastern Time on Monday, December 26, 2022, authorizing the electric generating units identified in Exhibit A, as well as any other

generating units subject to emissions or other permit limitations in the PJM Region to operate up to their maximum generation output levels under the limited circumstances described in this Order, notwithstanding air quality or other permit limitations. The generating units (Specified Resources) that this Order pertains to are listed on the Order 202-22-4 Resources List, as described below.

ORDER

Given the emergency nature of the expected load stress, the responsibility of PJM to ensure maximum reliability on its system, and the ability of PJM to identify and dispatch generation necessary to meet the additional load, I have determined that, under the conditions specified below, additional dispatch of the Specified Resources is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on, among other things:

- The emergency nature of the expected load stress caused by the current cold weather event threatens to cause loss of power to homes and local businesses in the areas that may be affected by curtailments, presenting a risk to public health and safety.
- The expected shortage of electric energy, shortage of facilities for the generation of electric energy, and other causes in the PJM Region demonstrate the need for the Specified Resources to contribute to the reliability of the PJM Region.
- PJM is responsible to ensure maximum reliability on its system, and, with the authority granted in this Order, its ability to identify and dispatch generation, including the Specified Resources, necessary to meet the additional load resulting from the cold weather event is enhanced.

In line with the anticipated circumstances precipitated by the cold weather event, this Order is limited to the period beginning with the issuance of this Order on December 24, 2022 through 12:00 pm Eastern Time on December 26, 2022. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation on the conditions contained in this Order, with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts. PJM anticipates that this Order may result in exceedance of emissions of sulfur dioxide, nitrogen oxide, mercury, and carbon monoxide emissions, as well as wastewater release limits. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes.

Based on my determination of an emergency set forth above, I hereby order:

A. From the time this Order is issued on December 24, 2022, to 12:00 pm Eastern Time on December 26, 2022, in the event that PJM determines that generation from the Specified Resources is necessary to meet the electricity demand that PJM anticipates in the PJM Region during this event, I direct PJM to dispatch such unit or units and to order their operation only as needed to maintain the reliability of the power grid in the PJM Region when the demand on the PJM system exceeds expected energy and reserve requirements. Specified Resources are those generating units set forth on the Order 202-22-4 Resource List, subject to updates directed here and as described in paragraph D, which the Department shall post on www.energy.gov.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes. Consistent with good utility practice, PJM shall exhaust all reasonably and practically available resources, including available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions, to the extent that such resources provide support to maintain grid reliability, prior to dispatching the Specified Resources. PJM shall provide a daily notification to the Department reporting each generating unit that has been designated to use the allowance and operated in reliance on the allowances contained in this Order.

In furtherance of the foregoing and, in each case, subject to the exhaustion of all available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions available to support grid reliability:

(i) For any generation resource whose operator notifies PJM that the unit is unable, or expected to be unable, to produce at its maximum output due to an emissions or other limit in any federal environmental permit, and during the pendency of a PJM-triggered Maximum Generation Emergency Action, at any point before 12:00 Eastern Time on Monday, December 26, 2022, the unit will be allowed to exceed any such limit only during any period for which PJM has declared an Energy Emergency Alert (EEA) Level 2 or Level 3 (during which time PJM will have triggered a Maximum Generation Emergency Action), except as described in item (iii) below in certain limited circumstances in anticipation of an EEA Level 2. Once PJM declares that the EEA Level 2 event has ended, the unit would be required to immediately return to operation within its permitted limits. And at all other times, the unit would be required to operate within its permitted limits, except for the limited exceptions provided herein for operations in anticipation of an EEA Level 2 to prevent the cycling of units or facilitate the charging or pumping of other resources necessary for the EEA Level 2.

(ii) For any generation resource whose operator notifies PJM that the unit is offline or would need to go offline at any point before 12:00 Eastern Time on Monday, December 26, 2022, due to an emissions or other limit in any

federal environmental permit, PJM may direct the unit operator to bring the unit online, or to keep the unit online, and to operate at the level consistent with its permits but subject to the exceptions set forth in this Order. In this circumstance, the operator is allowed to make all of the unit's capacity available to PJM for dispatch during any period for which PJM has declared an EEA Level 2 or 3 (during which time PJM has triggered a Maximum Generation Emergency Action), except as described in item (iii) below in certain limited circumstances in anticipation of an EEA Level 2. Once PJM declares that such an EEA Level 2 event has ended and the Maximum Generation Emergency Action is discontinued, the unit would be required to immediately return to operating at a level below the higher of its minimum operating level or the maximum output allowable under the permitted limit.

(iii) PJM is hereby granted authority to operate the Specified Units that are combined cycle generating units in certain limited circumstances in advance of declaring an EEA Level 2, Maximum Generation Emergency, or in between such events, where such operation or continued operation of the Specified Resource is reasonably necessary to avoid shutting down and restarting the Specified Unit. PJM has represented that such cycling of units can cause reliability issues regarding restarting, delays, and increased emissions during start up. PJM is further authorized to operate the Specified Units in certain limited circumstances in advance of the declaring an EEA Level 2, Maximum Generation Emergency where such operation or continued operation of the Specified Resource is reasonably necessary to facilitate charging storage resources or pumping for pumped storage facilities that will needed during an anticipated EEA Level 2. PJM is required to take measures to dispatch units for which cycling would otherwise be required in a manner reasonably intended to limit the duration and operating level of those units in such a way as to minimize exceedance of permit limitations consistent with the security and reliability of the PJM Region.

(iv) To minimize adverse environmental impacts as set forth herein, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes. Consistent with good utility practice, and notwithstanding standard merit order dispatch, PJM shall exhaust all reasonably and practically available resources, including available imports, demand response and identified behind-the-meter generation resources selected to minimize an increase in emissions to the extent that such resources provide support to maintain grid reliability prior to dispatching the Specified Resources at levels above their permitted emissions levels. PJM shall provide a daily notification to the Department reporting each generating unit that has been designated to use the allowance and operated in reliance on the allowances contained in this Order.

C. All operation of the Specified Resource must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. In the event that PJM identifies additional generation units that it deems necessary to operate in excess of federal environmental permitting limits in order to maintain the reliability of the power grid in the PJM Region when the demand on the PJM system exceeds expected energy and reserve requirements, PJM shall provide prompt written notice to the Department of Energy at AskCR@hq.doe.gov with the name and location of those units that PJM has identified, as well as additional notice by the same means through updating Exhibit A to its Application with such additional generation units, the fuel type of such unit, and the anticipated category of environmental impact, at 09:00 Eastern Time or 21:00 Eastern Time, whichever follows closest in time to the unit identification by PJM to the greatest extent feasible. Such additional generation unit shall be deemed a Specified Resource for the purpose of this Order for the hours prior to the required written notice to the Department updating Exhibit A, and PJM may dispatch such additional generation units, provided that if the Department of Energy notifies PJM that it does not approve of such generation unit being designated as a Specified Resource, such generation unit shall not constitute a Specified Resource upon notification from the Department. The Department shall post an updated Order 202-22-4 Resource List as soon as practicable following notification from PJM under this paragraph.

E. PJM shall provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time. By January 26, 2023, PJM shall report all dates between December 24, 2022, and December 26, 2022, inclusive, on which the Specified Resources were operated, the hours of operation, and exceedance of permitting limits, including sulfur dioxide, nitrogen oxide, mercury, carbon monoxide, and other air pollutants, as well as exceedances of wastewater release limits. PJM shall submit a final report by February 27, 2023, with any revisions to the information reported on January 26, 2023. The environmental information submitted in the final report shall also include the following information:

(i) Emissions data in pounds per hour for each Specified Resource unit, for each hour of the operational scenario, for CO, NOx, PM10, VOC, and SO2;

(ii) Emissions data must include emissions (lbs/hr) calculated consistent with reporting obligations pursuant to operating permits, permitted operating/emission limits, and the actual incremental emissions above the permit limits;

(iii) The number and actual hours each day that each Specified Resource unit operated in excess of permit limits or conditions, e.g., "Generator #1; December 25, 2022; 4 hours; 04:00-08:00 CT";

(iv) Amount, type and formulation of any fuel used by each Specified Resource;

(v) All reporting provided under the Specified Resource's operating permit requirements over the last three years to the United States Environmental Protection Agency or local Air Quality Management District for the location of a Specified Resource that operates pursuant to this Order;

(vi) Additional information requested by DOE as it performs any environmental review relating to the issuance of this Order; and

(vii) Information provided by the Specified Resource describing how the requirements in paragraph C above were met by the Specified Resource while operating under the provisions of this Order.

In addition, PJM shall provide information to the Department quantifying the net revenue in aggregate associated with generation in excess of environmental limits in connection with orders issued by the Department pursuant to Section 202(c) of the Federal Power Act.

F. PJM shall take reasonable measures to inform affected communities where all Specified Resources operate that PJM has been issued this Order, in a manner that ensures that as many members of the community as possible are aware of the Order, and explains clearly what the Order allows PJM to do. At a minimum, PJM shall post a description of this Order on its website (with a link to this Order) and identify the name, municipality or other political subdivision, and zip code of Specified Resources covered by this Order, as the Specified Resources may be updated pursuant to paragraph D above. In addition, in the event that a Specified Resource operates pursuant to this Order, a general description of the action authorized by this Order will be included in any press release issued by PJM with respect to the cold weather event and will include a reference to the website posting required by the preceding sentence for further information. PJM shall describe the actions taken to comply with this paragraph in the reports delivered to the Department pursuant to paragraph E above.

G. This Order shall not preclude the need for the Specified Resource to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

H. PJM shall be responsible for the reasonable third-party costs of performing analysis of the environmental and environmental justice impacts of this Order, including any analysis conducted pursuant to the National Environmental Policy Act.

I. This Order shall be effective upon its issuance, and shall expire at 12:00 Eastern Time on Monday, December 26, 2022, with the exception of the reporting requirements in

paragraph E. Renewal of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. at 5:30 PM Eastern Standard Time on this 24th day of December 2022.

Kathleen B. Hogan

Digitally signed by Kathleen B. Hogan
Date: 2022.12.24 17:38:01 -05'00'

Undersecretary of Energy for Infrastructure

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-14:
Department Order No. 202-17-4 Summary of Findings

Summary of Findings
Department of Energy Order No. 202-17-4

September 14, 2017

Section 202(c) of the Federal Power Act (FPA) (codified at 16 U.S.C. § 824a(c)), through section 301(b) of the Department of Energy Organization Act (codified at 42 U.S.C. § 7151(b)), authorizes the Secretary of Energy, upon finding "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes," to issue an order "requir[ing] . . . such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in [the Secretary's] judgment will best meet the emergency and serve the public interest." 16 U.S.C. § 824a(c)(1). If the order "may result in a conflict with [an] environmental law or regulation," then the Secretary must "ensure that such order requires generation, delivery, interchange, or transmission of electric energy only during hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable, is consistent with any applicable . . . environmental law or regulation and minimizes any adverse environmental impacts." *Id.* § 824a(c)(2). Orders issued under FPA section 202(c) "that may result in a conflict with [an] environmental law or regulation" expire 90 days after they are issued, but the Secretary "may renew or reissue such order[s] . . . for subsequent periods, not to exceed 90 days for each period, as [the Secretary] determines necessary to meet the emergency and serve the public interest." *Id.* § 824a(c)(4)(A).

The Department's regulations implementing FPA section 202(c) define the term "emergency" to mean, among other situations, "a specific inadequate power supply situation." 10 C.F.R. § 205.371. The regulations do not exhaustively list what qualifies as an emergency, but they note specifically that "[e]xtended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities can result in an emergency as contemplated in these regulations." *Id.*

On June 13, 2017, PJM filed a *Request for Emergency Order Pursuant to Section 202(c) of the Federal Power Act* (Order Application) (included in the docket[1] of this Order) with the Department "to preserve the reliability of [the] bulk power transmission system in the North Hampton Roads area." Virginia Electric and Power Company[2] (Dominion), the electric utility serving the area, owns the coal-fired, power generating Units 1 and 2 at the Yorktown Power Station in Yorktown, Virginia. In November 2011 and October 2012, Dominion notified PJM of its plan to deactivate Units 1 and 2, respectively, effective December 31, 2014, because the units were not equipped to

[1] The docket of this Order is available at https://www.energy.gov/oe/downloads/federal-power-act-section-202c-dominion-energy-virginia-june-2017.
[2] *See* Dominion Energy, Inc., Form 10-Q filing, at 1 (Aug. 3, 2017), included in the docket of this Order.

comply with the Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards (MATS), 40 C.F.R. part 63 subpart UUUUU. On June 24, 2014, pursuant to 40 C.F.R. § 63.6(i)(4)(i)(A), the Virginia Department of Environmental Quality granted Dominion a one-year MATS compliance extension for Yorktown Units 1 and 2.

On April 16, 2016, pursuant to section 113(a) of the Clean Air Act, 42 U.S.C. § 7413(a)(3) and (4), the EPA issued an Administrative Compliance Order (ACO) through April 15, 2017. The ACO implemented a 2011 MATS Enforcement Policy regarding issuance of section 113(a) administrative orders to sources that are unable to comply with the MATS but that may need to operate for up to a year to address a specific and documented reliability concern. The 2011 MATS Enforcement Policy was limited in application to units critical for reliability purposes. The EPA found that operation of Yorktown Units 1 and 2 met the policy criteria, as verified by the Federal Energy Regulatory Commission (FERC). Dominion has not achieved full compliance with the MATS for Yorktown Units 1 or 2 since the ACO expired, and section 113(a) of the Clean Air Act bars further compliance extensions.

Since Dominion's decision to retire the coal-fired Yorktown units, PJM has planned for their permanent deactivation by including required transmission upgrades in its own Regional Transmission Expansion Planning Process. PJM is subject to federal reliability standards enforced by the North American Electric Reliability Corporation (NERC), the Electric Reliability Organization designated by FERC. PJM holds the highest-level reliability responsibilities for the system it manages as a certified Reliability Coordinator, Balancing Authority, and Transmission Operator. PJM is also registered with NERC as a Planning Coordinator and Transmission Planner, among other functions. NERC Compliance Registry Active Entities List (updated Sept. 7, 2017), included in the docket of this Order. PJM applies reliability criteria to evaluate transmission system conditions and then develops the transmission solutions needed to ensure compliance with the reliability standards. The PJM Board of Managers approves those solutions in a Regional Transmission Expansion Plan (RTEP). Through its Transmission Expansion Advisory Committee (TEAC) and Sub-Regional RTEP Committees, PJM works with stakeholders throughout the RTEP's development. PJM Manual 14B, "Regional Planning Process," included in the docket of this Order. The PJM Board of Managers approved the transmission upgrades necessitated by the retirement of Yorktown Units 1 and 2 on May 17, 2012. TEAC Recommendations to the PJM Board (PJM Staff Whitepaper), May 2012, at 12, included in the docket of this Order.

PJM's approved solution was the Skiffes Creek Transmission Project, which consists of three components: a 500kV line, a 230kV line rebuild, and a new switching station. United States Army Corps of Engineers (Army Corps), Memorandum for the Record re: Department of the Army Environmental Assessment and Statement of Findings for the Above-Referenced Standard Individual Permit Application, CENAO-WR-RS (NAO-2012-00080 / 13-V0408), at 1, included in the docket of this Order. A

number of issues in the North Hampton Roads area, many of which are interrelated, needed to be addressed to avoid overloading transmission lines with too much power, as detailed in PJM's Deactivation Study. Yorktown Units 1 and 2 Generator Deactivation Notification: Deactivation Study Results – updated June 26, 2017 (PJM Deactivation Study), included in the docket of this Order. *See also Va. Elec. & Power Co.*, Commission Comments on Requests for EPA Administrative Orders, Docket No. AD16-11-000, 153 FERC ¶ 61,265 at PP 14-16 (2015).

PJM completed a series of analyses consistent with RTEP procedures, finding that only the Skiffes Creek Transmission Project—and none of the stakeholder-proposed alternatives—addressed the full range of potential reliability violations. Order Application, app. I, at 16. For example, reliance on operation of the oil-fired Yorktown Unit 3 generator would not address thermal overload and voltage violations on the 230kV and 115kV bulk electric system that PJM identified because of significant environmental operating restrictions and other plant operation constraints associated with that unit, including an 8 percent capacity factor limitation. *See id.*, app. II, at 18. As a result, PJM did not recommend reliance on Yorktown Unit 3 as a sustainable alternative solution to the identified reliability criteria violations. *Id.*

As part of PJM's analyses, Dominion transmission staff provided PJM with an analysis of system needs as well as potential solutions to the retirement of generating units at Yorktown and elsewhere. Dominion Update to Retirement Study Results (Mar. 10, 2012), included in the docket of this Order. Dominion's analysis, which was based on PJM's initial determination of reliability criteria violations that needed to be addressed, was independently validated by PJM and publicly vetted through the PJM stakeholder process before PJM staff recommended that the Board of Managers approve the Skiffes Creek Transmission Project. PJM Staff Whitepaper at 12, included in the docket of this Order.

PJM, as the Regional Transmission Organization (RTO) responsible for transmission system operation across multiple states, including Virginia, maintains its expert determination that the Skiffes Creek Transmission Project is the most effective and efficient solution to address the identified reliability criteria violations. Order Application, app. I, at 16. As recently as March 1, 2017, PJM provided the Army Corps with an analysis of proposed alternatives and found that none of them sufficiently resolved the identified violations. Letter to Col. Jason E. Kelly, U.S. Army Corps of Engineers (Mar. 1, 2017), included in the docket of this Order. PJM's subsequent RTEP materials reaffirm the need for the Skiffes Creek Transmission Project, even considering the updated, steadily rising load forecasts in the recently released 2017 PJM Load Forecast Report (included in the docket of this Order). *See* PJM Interconnection, L.L.C., 2017 RTEP Process Scope & Input Assumptions, rev. 1, at 25-27 (Aug. 3, 2017), included in the docket of this Order.

Construction of the Skiffes Creek Transmission Project began in July 2017 and is expected to take approximately 18-20 months. *Order No. 202-17-2 Renewal Application Filing* (Renewal Application) at 3. Until the Project is completed, a plan known as the North Hampton Remedial Action Scheme (RAS) remains in effect. According to NERC's Glossary of Terms, a RAS is "[a] scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation ([megawatts] and [megavolt amperes (reactive)]), tripping load, or reconfiguring a System(s)." Glossary of Terms Used in NERC Reliability Standards (updated Aug. 1, 2017), at 24, included in the docket of this Order.

To preserve the grid's reliability, the North Hampton RAS would allow PJM, the grid operator, to drop load—that is, shut off power to certain customers—to prevent voltage collapse. Dominion presented this RAS to PJM in January 2017, and the SERC Reliability Corporation, the NERC-delegated regional reliability enforcement entity, approved it that same month. *See* Dave Rees, *Dominion Virginia Power Sets Plan for Emergency Blackouts*, Daily Press, Jan. 13, 2017, included in the docket of this Order. If Yorktown Units 1 and 2 were unavailable, many N-1-1 contingencies could result in voltage collapse and thermal overloads. New Remedial Action Scheme, North Hampton RAS (Presentation to PJM), at 4, included in the docket of this Order; PJM Deactivation Study, included in the docket of this Order. According to FERC, "An N-1-1 contingency is a sequence of events consisting of an initial loss of a single generator or transmission element, followed by system adjustment, followed by another loss of a single generator or transmission element." *Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators*, Docket No. AD14-14-000, 153 FERC ¶ 61,221 at P 30 n.61 (2015).

The North Hampton RAS is on standby for use at PJM's discretion. If PJM detects the loss of certain facilities, it could trip the remaining feeds to the Yorktown area and drop service to approximately 150,000 customers, preventing voltage collapse. Rotating outages would follow until the system returns to normal operating parameters. New Remedial Action Scheme, North Hampton RAS (Presentation to PJM), at 6, included in the docket of this Order. According to U.S. Census estimates, the region PJM identifies as the North Hampton Roads load area in its Order Application had a population of more than 660,000 as of July 2016. At a minimum, rotating outages under the RAS would therefore impact, directly or indirectly, several hundred thousand people. United States Census Bureau, QuickFacts database, available at https://www.census.gov/quickfacts/fact/table/US/PST045216.

On July 3, 2017, the Army Corps issued a permit to Dominion for the Skiffes Creek Transmission Project pursuant to section 10 of the Rivers and Harbors Act of 1899 (33 U.S.C. § 403) and section 404 of the Clean Water Act (33 U.S.C. § 1344). On July

10, 2017, Dominion commenced construction of the Skiffes Creek Transmission Project. Renewal Application at 3.

On August 24, 2017, PJM filed its Renewal Application with DOE. The filing included all reports required by Order No. 202-17-2 (included in the docket of this Order). PJM said that construction of the Project was still expected to take 18-20 months, and that periodic transmission outages would be necessary to proceed apace with the Project. The same day, Dominion wrote to the Department that it "agrees with the Renewal Application and will operate in accordance with its provisions." Further, Dominion acknowledged that a 202(c) order "is not a long term solution to the reliability issues in the North Hampton Roads area on the Virginia Peninsula." The Skiffes Creek Transmission Project, underway as of July 2017, is the long-term solution.

On September 7, 2017, the Department received comments from Sierra Club opposing PJM's renewal request. On September 13, 2017, the Department received an answer to Sierra Club's comments from PJM. Both documents are included in the docket of this Order.

Discussion

Order No. 202-17-2 directs operation of Yorktown Units 1 and 2 as needed to address reliability issues, subject to a dispatch methodology submitted to the Department for review. The reliability issues noted in Order No. 202-17-2 were described as Scenario One, increased load due to weather-related temperature extremes, and Scenario Two, decreased transmission capacity required by the RTEP upgrade. Scenario Two was contemplated but not yet applicable when Order No. 202-17-2 was issued because the Army Corps permit application for the Skiffes Creek Transmission Project was still pending. On July 3, the Army Corps issued Permit No. NAO-2012-00080, resulting in the potential need to operate Yorktown Units 1 and 2 to address both Scenario One and Two reliability issues. To date, in accordance with Order No. 202-17-2, PJM has directed operation of Yorktown Units 1 and/or 2 for all or part of 13 days. PJM Interconnection, L.L.C., Report on Yorktown Units 1 and 2 Operations Pursuant to Order No. 202-17-2, Attachment 1, included in the docket of this Order; Telephone call to Steven Pincus, Associate General Counsel, PJM, Sept. 11, 2017.

Scenario One applies when load conditions exceed a certain threshold due to local transmission issues that would cause PJM to operate the system outside its normal operating parameters.[3] Weather-related temperature extremes are one example of such a local transmission issue. Scenario Two is also triggered when load conditions exceed a certain threshold, but the threshold is lowered depending on the particular construction-related transmission outages in effect as the Skiffes Creek Transmission Project is built.

[3] Exact load thresholds were submitted as critical electric infrastructure information and are thus not described here so as not to provide vulnerability information on critical infrastructure.

Because the Project minimizes environmental impacts by utilizing existing transmission line rights-of-way to the extent possible, portions of existing transmission lines must be taken offline for upgrades. Under either scenario, when the relevant thresholds are exceeded, to prevent system overload and uncontrolled power disruptions, PJM must implement the North Hampton RAS. The only sufficient alternative to the RAS and its resulting outages for up to approximately 150,000 customers is the emergency operation of Yorktown Units 1 and 2. The demand response available to PJM is a small fraction of the load threshold and is "not sufficient to ensure reliable service." Order Application, app. II, at 18. Likewise, Dominion has limited demand-side management and curtailment capabilities, insufficient for reliability purposes even when fully deployed. *See id.*, app. III, at 21.

Activating the RAS would immediately interrupt service to load in the North Hampton Roads area. PJM asserts that, according to the RAS, during certain high load conditions, this "load shedding" could result in the loss of roughly 950 MW of electric power—that is, the loss of service to over 150,000 North Hampton Roads area customers. Order Application at 9. This service interruption could last hours or even days. *See* North Hampton RAS Presentation to PJM, at 8, included in the docket of this Order. Activating the RAS is not a gradual approach that presents a wide range of likely impacts; it is an extreme measure with immediate consequences to 150,000 customers. While the RAS is designed to prevent more catastrophic, uncontrolled grid impacts from occurring, load shedding of this magnitude is significant, and would trigger mandatory reporting both to DOE and FERC. DOE Form OE-417 requires reporting within one hour for "[l]oad shedding of 100 Megawatts or more implemented under emergency operational policy," and within six hours for "[l]oss of electric service to more than 50,000 customers for 1 hour or more." This is the same level of reporting triggered by a cyber or other hostile attack on grid resources. Form OE-417, Electric Emergency Incident and Disturbance Report, https://www.oe.netl.doe.gov/docs/OE417_Form_03312018.pdf. Similarly, FERC and NERC mandate notification for a variety of serious events including when a bulk electric system emergency triggers automatic load shedding of 100 MW or more, as in the RAS. *See* North American Electric Reliability Corporation, Reliability Standard EOP-004-3 (Event Reporting), http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-004-3&title=Event%20Reporting.

To underscore the potential impact of RAS activation, the estimated 150,000 impacted customers are counted by meter, not individual. One or more meters could translate to large household or commercial or industrial facilities, including those critical to health and safety systems. Whether counted as 150,000 or that amount multiplied several times over, the anticipated impact of this emergency situation is on par with or exceeds the impacts described in prior 202(c) orders. *Crisp Cnty. Power Comm'n v. Ga. Power Co.*, 35 FPC 629, 630-31 (1966) (ordering interconnection to prevent, in part,

outages lasting more than an hour and affecting 500 to 2,000 customers on Crisp County, Georgia's system). *City of Cleveland, Ohio v. Cleveland Elec. Illuminating Co.*, 47 FPC 747, 749 (1972) (ensuring reliable service was provided to the approximately 20% of the city's consumers). Cleveland's 1970 Census-reported population was 750,903, suggesting that just over 150,000 individuals were affected by the 1972 202(c) order. *See* https://www.census.gov/population/www/documentation/twps0027/tab20.txt. As described earlier, the U.S. Census estimated the population of the North Hampton Roads load area at nearly 661,000 people just over a year ago.

A benefit of the planning efforts mandated by federal reliability standards is that entities such as PJM can accurately forecast the impacts to the bulk power system in steady-state and various contingency event situations. Thus, as reliability planning continues to mature, there should be fewer electric energy shortages that take bulk power system owners, operators, and regulators by surprise. That planners can identify conditions under which shortages may occur, however, does not rule out electric energy shortages constituting emergencies under FPA section 202(c) and the Department's implementing regulations. It is impossible to plan for every contingency, and challenges may arise even when implementing the most prudent plans. FPA section 202(c) affords the Secretary of Energy discretion in finding when an emergency exists and how best to meet the emergency and serve the public interest.

Here, an emergency exists due to the imminent possibility of implementing the North Hampton RAS under a range of both steady-state and contingency events, including potential transmission congestion preventing the delivery of available generation to the North Hampton Roads area. PJM Deactivation Study at 1-2, included in the docket of this Order. The RAS would leave approximately 150,000 customers without power, including residential, industrial, commercial, health and safety facilities, major national defense, and educational institutions. *See* Order Application, app. IV, at 30-31. That creates serious health and safety issues. Issuance of today's Order meets the emergency and serves the public interest.

In these circumstances, transmission outages, like those contemplated for or otherwise in connection with the construction of the Skiffes Creek Transmission Project, constitute an emergency for purposes of a section 202(c) order. As stated earlier, the Department's implementing regulations, in their current form since 1981, contemplate that "[e]xtended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities [may create] an emergency." 10 C.F.R. § 205.371. The regulations add that "[i]n such cases, the impacted 'entity' will be expected to make firm arrangements to resolve the problem until new facilities become available, so that a continuing emergency order is not needed." *Id.* PJM, the impacted entity in this case, requested today's Order. Through the RTEP, PJM made firm arrangements to resolve the problem through the Skiffes Creek Transmission Project, which is now permitted and under construction. That construction was delayed due to events beyond

PJM's control has no bearing on the likelihood of power outages for 150,000 customers. Such a power loss event would also constitute an emergency as contemplated by FERC in its Public Utility Regulatory Policies Act of 1978 regulations, which define "system emergency" as "a condition on a utility's system which is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property." 18 C.F.R. § 292.101(b)(4). The risk faced by 150,000 customers will continue, assuming the Skiffes Creek Transmission Project construction schedule is met, for approximately another 18 months. Today's Order is limited in time and specifically tailored to address an emergency contemplated both in the authorizing statute and the Department's implementing regulations.

Between 2005 and 2007, DOE issued orders under similar circumstances, directing the Mirant Potomac River Generation Station to operate until two new 230kV transmission lines could be built to ensure reliability to a portion of the District of Columbia. *See* Order No. 202-5-3 (relying on DOE regulatory definition of emergency as including extended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities). In a series of orders under FPA section 202(c), the Secretary ordered operation of the generation units while the two existing 230kV lines that supplied the central District of Columbia area were temporarily and sequentially removed from service to connect the new lines. Neither the problems leading up to the closure of the generating units nor the need for a particular transmission solution were unexpected. Nevertheless, the Department found that imminent power shortages, faced if contingency events occurred, constituted an emergency under the Federal Power Act. Order Nos. 202-5-3, 202-6-1, 202-6-2, 202-7-1, and 202-7-2.

In this matter, the likelihood of RAS activation is not theoretical. While Order No. 202-17-2 was in effect, PJM had to call upon Yorktown Units 1 and/or 2 on 13 days over three months. Absent Order No. 202-17-2, the RAS would have been activated instead. The alternatives available to PJM and Dominion are not sufficient to ensure reliability without available capacity from Yorktown Units 1 and 2. As described, PJM and Dominion cannot mobilize adequate alternatives to counter the loss of transmission during construction of the Skiffes Creek Transmission Project. For example, demand response resources, while potentially helpful at the margin, are insufficient to address either Scenario One or Scenario Two. *See* Order Application, app. II, at 18. Further, PJM's recent RTEP Input Assumptions and Scope Whitepaper indicates that Dominion theoretically has up to 130 MW of distributed solar generation available during the summer. 2017 RTEP Process Scope and Input Assumptions, rev. 1, tbl.3.2, at 18 (Aug. 3, 2017), included in the docket of this Order. Outside of ramp-up and ramp-down times, each Yorktown Unit typically ran at 100 MW output or higher, day or night, when operational while Order No. 202-17-2 was in effect. PJM Interconnection, L.L.C., Report on Yorktown Units 1 and 2 Operations Pursuant to Order No. 202-17-2, Attachment 1. Distributed generation is an intermittent resource; even under ideal conditions, with full-capacity, daytime generation and load reduction at the height of the

summer, distributed generation generally would still not have offset the baseload generating capacity needed to ensure reliability on the North Hampton Roads area grid. And any flexibility for scheduling the Skiffes Creek Transmission Project's construction during historically low-load periods ended when the EPA ACO expired, as expeditious completion of the Project is now the priority. Therefore, even if PJM and Dominion made full use of available alternatives, capacity from Yorktown Unit 1, 2, or both would still be necessary to meet the emergency and serve the public interest.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law or regulation be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable, [be] consistent with any applicable . . . environmental law or regulation and minimize[] any adverse environmental impacts." Certain load conditions may necessitate operation of Yorktown Units 1 and 2.

To minimize the hours of operation and adverse environmental impacts, the Order contains certain limitations. First, DOE maintains consistency with EPA's approach in the 2016 ACO by authorizing operation of Yorktown Units 1 and 2 only when called upon by PJM for reliability purposes. The Department consulted with EPA and has reviewed data provided by PJM and Dominion on operations, air emissions, and water usage. This Order will continue the operational limitations described in EPA's above-referenced ACO, AED-CAA-113(a)-2016-0005. Second, DOE requires that PJM and Dominion, consistent with good utility practice, first exhaust all reasonably and practically available resources, including demand response and behind-the-meter generation resources, before operating Yorktown Units 1 and 2. Third, DOE requires continued compliance with the June 27 dispatch methodology, which was reviewed by the Department, and which remains subject to continuing oversight by the Department. In particular, the dispatch methodology establishes Yorktown Units 1 and 2 commitment procedures, describes the utilization and trip conditions of the North Hampton RAS for mitigating congestion on the Virginia Peninsula or North Hampton Roads area, and describes Dominion's mitigation options for the existing James River tower contingency. The dispatch methodology is an operating protocol that limits the ability of PJM to dispatch Yorktown Units 1 and 2 only when needed to mitigate reliability issues associated with scheduled and emergency transmission outages directly related to the Skiffes Creek Transmission Project and other local transmission issues. The EPA ACO recognized that such a dispatch methodology, under which PJM determines when the Yorktown units are needed for reliability issues, serves the objective of minimizing emissions. ACO at 8-9, included in the docket of this Order. Fourth, to track when Yorktown Units 1 and 2 are operated to maintain grid reliability and to monitor associated air emissions and water usage, reports will be required every two weeks going forward. If the Department becomes concerned with PJM or Dominion's compliance with this Order, enforcement actions are available, up to and including termination of the underlying order.

While DOE has constrained PJM's operations with regard to Yorktown Units 1 and 2, it is necessary to preserve reasonable discretion for PJM, as a Transmission Operator, to address the second-to-second operational challenges of grid management. This follows DOE's practice in earlier orders issued under FPA section 202(c), which prioritized reliability concerns as identified and assessed by the operator. For example, Order No. 202-02-1 (Aug. 16, 2002) ordered Cross-Sound Cable Company, LLC to operate a cable across Long Island Sound, limiting "transmission and delivery of . . . electric capacity and/or energy [to that] necessary in the judgment of the New York Independent System Operator [ISO] to meet the supply and essential reserve margin needs of the Long Island Power Authority [LIPA]," but only "in order for LIPA to serve its firm retail customers after it has implemented all available load reduction measures consistent with good utility practice." Order No. 202-03-1 (Aug. 14, 2003) directed operation of the same cable, but specifically ordered the New York ISO and ISO New England to require Cross-Sound Cable Company to operate the cable. That order also required both RTOs to "consult with each other and with appropriate reliability organizations." Today's Order similarly requires PJM to identify and mitigate reliability issues in accordance with DOE's specified operational limitations.

In considering renewal or reissuance of an order under FPA section 202(c) that may conflict with an environmental law or regulation, DOE is required to "consult with the primary Federal agency with expertise in the environmental interest protected by such law or regulation" and to include "conditions as such Federal agency determines necessary . . . to the extent practicable." 16 U.S.C. § 824a(c)(4). The EPA is the primary federal agency in this case with expertise in the protected environmental interest, specifically MATS and section 316(b) of the Clean Water Act, and the Department consulted with EPA after receiving the Renewal Application. Email from Acting Assistant Administrator Starfield, Office of Enforcement and Compliance Assurance, to Acting Under Secretary for Science and Energy Hoffman (Sept. 11, 2017), included in the docket of this Order. After consulting with EPA, and consistent with that consultation, the Department found that the only appropriate short-term emissions limitation on Yorktown Units 1 and 2 would be to curtail operating hours to the maximum extent practical for reliability purposes.

Pursuant to the National Environmental Policy Act of 1969, the Department has determined that issuance of this Order fits within the category of actions included in Categorical Exclusion (CX) B4.4 and otherwise meets the requirements for application of a CX. The Order fits within the category of actions because it authorizes "[p]ower marketing services and power management activities (including, but not limited to, storage, load shaping and balancing, seasonal exchanges, and other similar activities), provided that the operations of generating projects would remain within normal operating limits." Records of Categorical Exclusion Determination, Order No. 202-17-4, Sept. 11, 2017, included in the docket of this Order.

For the reasons stated above, the Secretary of Energy finds that an emergency exists threatening imminent electric energy shortages, and that this Order is necessary to address the emergency and serve the public interest in the North Hampton Roads area. The limitations on operation set forth in Order No. 202-17-4 and outlined above are, to the maximum extent practicable, consistent with applicable environmental laws or regulation and minimize any adverse environmental impacts, and the reporting requirements for operations and estimated emissions ensure transparency of implementation.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	)	Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-15:
Department Order No. 202-02-1

Department of Energy
Washington, DC 20585

Order No. 202-02-1

Pursuant to the authority vested in me by section 202(c) of the Federal Power Act, 16 U.S.C. 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. 7151(b), I hereby determine that an emergency exists on Long Island in the State of New York due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, a shortage of facilities for the transmission of electric energy and other causes, and that issuance of this order will alleviate the emergency and serve the public interest. Based on this determination, I hereby order:

From the effective date and time of this order until 12:01 a.m. Eastern Daylight Time, October 1, 2002, Cross-Sound Cable Company, LLC is directed to operate the Cross-Sound Cable and related facilities connecting substations in New Haven, Connecticut and Shoreham, Long Island, New York, to transmit and deliver electric capacity and/or energy when, as and in such amounts as may be scheduled and purchased by the Long Island Power Authority (LIPA), and to take such actions as are necessary in order to enable it to do so, including but not limited to energizing and continuing to energize the facilities of Cross-Sound Cable Company, LLC; *provided*, that this order otherwise shall be limited to requiring the transmission and delivery of such electric capacity and/or energy as is necessary in the judgment of the New York Independent System Operator to meet the supply and essential reserve margin needs of LIPA, in order for LIPA to serve its firm retail customers after it has implemented all available load reduction measures consistent with good utility practice, including curtailing and/or terminating service to interruptible customers, public appeals for conservation, reducing 30 minute reserves to zero, and implementing voltage reductions; *and provided further*, that prior to exercising its judgment as required by this order, the New York Independent System Operator must consult with ISO New England, Inc. to ensure that the scheduling of such electric capacity and/or energy will not violate system operating criteria, and the New York Independent System Operator should, as practicable, consult with appropriate reliability organizations. If necessary, just and reasonable terms for the transmission and delivery of electric capacity and/or energy pursuant to this order, including the compensation therefor, shall be established by a supplemental order issued pursuant to Federal Power Act section 202(c).

Nothing in this order shall preclude use of the energized Cross-Sound Cable and its related facilities connecting substations in New Haven, Connecticut and Shoreham, Long Island, New York, to transmit and deliver electric capacity and/or energy from Long Island to Connecticut or from Connecticut to Long Island in accordance with the operating and scheduling protocols and decisions of the New York Independent System Operator and ISO New England, Inc.

This order shall be effective upon its issuance.

Issued in Washington, D.C. at 2:38PM this 16th day of August, 2002.

Spencer Abraham
Secretary of Energy

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