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U.S. House Committee on Energy and Commerce
Subcommittee on Energy

"Winter Storm Fern Lessons: Supplying Reliable Power to Meet Peak Demand"

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Summary and About NERC

Reliability risk in North America continues to rise. The continent is at risk of more frequent and more serious long duration reliability disruptions, including the possibility of national consequence events. A supply and demand problem remains the central challenge for reliability of the bulk power system (BPS). Electricity demand is growing faster than electricity supply. Even as many operational grid metrics show strong performance trends, the prevalence of observed and close call reliability events such as Winter Storm Fern signals the need to prioritize reliability requirements as the resource mix and operating characteristics of the BPS undergo dramatic changes.

The North American Electric Reliability Corporation (NERC) is a not-for-profit, international regulatory authority dedicated to effectively and efficiently reducing risks to the reliability and security of the BPS. To accomplish that, we work with owners, operators, consumers as well as federal, state, and provincial regulators across North America to develop and enforce mandatory Reliability Standards, monitor the grid, train personnel, and assess risks to ensure that the grid remains reliable and secure today and in the future. NERC also works with six Regional Entities on Reliability Standards compliance and risk management. Overseen by the Federal Energy Regulatory Commisserion (FERC) and designated by FERC at the Electric Reliability Organization (ERO) for the United States, NERC's statutory jurisdiction is prescribed by Section 215 of the Federal Power Act.

Introduction

NERC's *Long-Term Reliability Assessment* (*LTRA*) provides a ten-year forward look at the most salient trends shaping the future of reliability, informing risks and mitigation actions by industry stakeholders, regulators, and policymakers. The recently-released *2025 LTRA* finds that most of North America is at risk of energy shortfalls over the next five years, and the risk is growing. Key drivers include a confluence of interrelated issues, including unprecedented growth in electricity demand, a generation resource base that is becoming more variable and weather-dependent, and a pace of resource additions that is not keeping up with demand projections.

Winter Storm Fern was a near-miss event closely tracking many risks identified in the *2025 LTRA*. A wide-area, multi-day extreme weather event, Fern significantly stressed the bulk electric grid and local distribution systems across the Midwest, Northeast, and South, resulting in distribution system power outages for approximately one million people. While the BPS performed with resilience, without the need for operator-initiated load shedding, affected regions experienced near record demand and significant operating challenges. These conditions underscore the need for maintaining generation resources in sufficient quantities and types to sustain reliability. Winter preparations, cold weather operating procedures, and communication were essential elements to effectively navigating the storm. Energy Emergency Alerts (EEA) were among the tools employed to maintain system reliability, including EEA3s, the highest alert level. These outcomes should be no cause for complacency. The wide array of actions to manage Fern may have had far different results with a larger, longer, colder storm.

With a highly reliable and secure BPS at the core of NERC's mission as the nation's ERO, NERC is focused on proactively addressing the reliability risks of the transforming grid. To be clear, NERC believes that a reliable future can be navigated effectively, but time is growing shorter. To do so, reliability must be anchored as our north star guiding the journey, with flexibility for any needed course corrections. The challenge is not whether we have the resources and technical ability. Rather, the central challenge is calibrating the pace of change with the reliability needs of a transforming system that must remain reliable and resilient at all times and under all conditions. As it exists today, this balance is out of calibration and must be corrected.

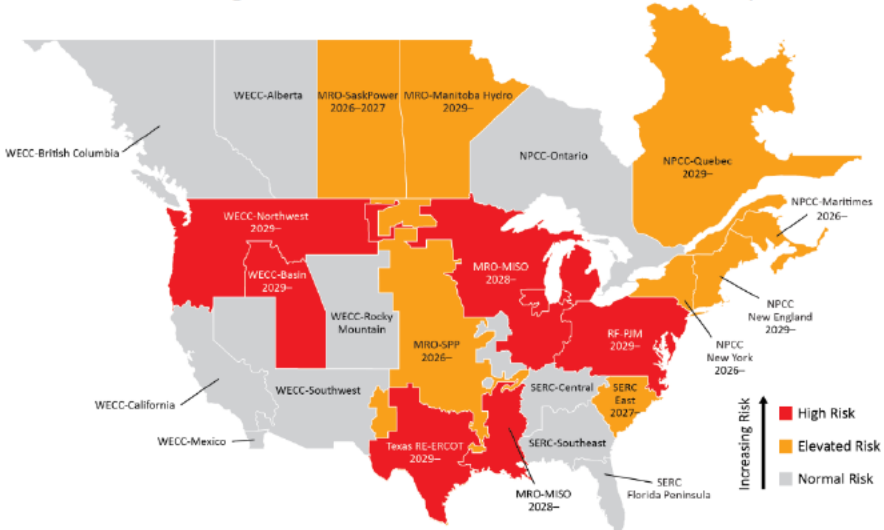
Overview of *2025 Long-Term Reliability Assessment*

NERC's *2025 LTRA* finds that the overall resource adequacy outlook for the North American BPS is worsening. The *2025 LTRA* finds that 13 of 23 assessment areas face resource adequacy challenges over the next decade. Projections for resource and transmission growth lag what is needed to support new data centers and other large loads that drive escalating demand forecasts. Most new resources in development to come on-line in the next five years consist of battery storage and solar photovoltaic (PV), which are inverter-based and weather-dependent resources that increase the complexity of planning and operating a reliable grid. Meanwhile, more fossil-fired generator retirements loom in the next five years, reducing the amount of generation that has fuel on site and impacting the system's ability to respond to spikes in demand. The continuing shift in the resource mix toward weather-dependent resources and less fuel diversity increases risks of supply shortfalls during winter months. As resource planners, market operators, and regulators grapple with steep increases in demand and swelling resource queues, they face more uncertainty, adding to the already-complex endeavor of planning for resource adequacy during this period of rapid grid transformation. To ensure there are sufficient resources for supplying electricity in the future and to reliably meet the growing electricity needs for North Americans, industry, regulators, and policymakers need to be vigilant for shifting projections, keep plans for deactivating existing generators flexible, expedite system development, and perform robust adequacy assessments of future scenarios. In addition, careful planning and broad cross-sector coordination will be needed to navigate a period of potentially strained electricity resources.

Much of North America is at Risk of Energy Shortfalls During the Next Five Years

2025 LTRA **Risk Area Summary 2026–2030**

Shows highest risk classification that occurs in the first 5 years and initial year of occurrence



<u>High Risk</u>: Shortfalls may occur at normal peak conditions.

<u>Elevated Risk</u>: Shortfalls may occur in extreme conditions.

<u>Normal Risk</u>: Low likelihood of electricity supply shortfall.

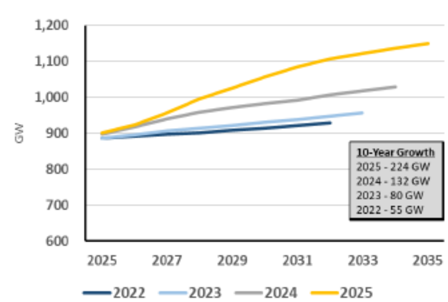
Since 2018, the LTRA documents a concerning and increasing risk trend. The 2025 assessment finds that approximately two-thirds of the United States is at risk of energy shortages over the next five years. Areas in orange are at risk of energy shortfalls during above-normal extreme conditions, and the red areas risk shortfalls even during normal peak conditions. The gray areas meet reliability criteria, however the risk is not zero, as evidenced by BPS disruption in parts of the Southeast caused by Winter Storm Elliott in 2022. It is important to stress that the *LTRA* is not a prediction of outages. Instead, it is a risk assessment – a forward-looking view of where the system is exposed, based on what we know today. The following discussion reviews the key drivers behind the current risk scenario.

Electricity Demand is Growing at an Unprecedented Rate

Electricity peak demand and energy growth forecasts over the next ten years continue to climb higher than at any point in the past two decades. These trends are driven by widespread electrification, the proliferation of large industrial loads – particularly data centers and artificial intelligence computing facilities – and expanding use of electric heating and electric vehicles. Over the 10-year period, aggregated summer peak demand is forecast to rise by over 224 gigawatts (GW). This is 69% higher than last year's 10-year growth projection of 132 GW. Winter peak demand is expected to grow by 245 GW, continuing to outpace summer and exceed prior-year projections.

10-year BPS Summer Peak Demand Growth

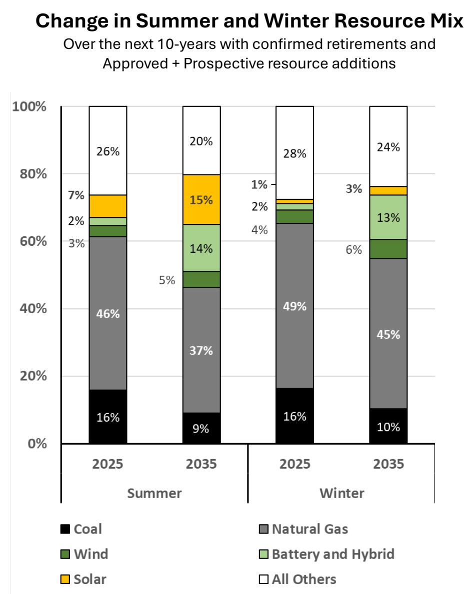
With 10-Year Growth from Previous LTRAs



The Changing Resource Mix is Increasingly Weather Dependent, and the Supply of Essential Reliability Services is at Risk

Current trends show that the proportion of variable generation coming onto the system is rising, while the proportion of dispatchable or "firm" resources is declining. As older fossil-fired generators retire and are replaced by more battery and solar PV resources, the resource mix is becoming increasingly variable and weather-dependent. This trend also affects the supply of essential reliability services (ERS) needed for grid stability. These factors present a critical challenge that must be well understood and planned for.

Reliability risk is generally greatest during summer and winter due to seasonal extremes that affect generator and transmission system performance, fuel availability, and high electricity demand conditions that can limit regional energy sharing. This chart compares the current and projected resource mix into 2035 during summer and winter peak-demand hours. General findings show a diminishing share of electricity from dispatchable resources and significantly greater reliance on variable resources. During summer, the LTRA projects that coal and natural gas-fired generation's share in peak generating capacity will decline from 62% of the resource mix today to 48% by 2035. Resources for meeting peak demand will be more variable, as wind, solar, battery, and hybrid generation's portion of the resource mix climbs from 12% today to 34% in 2035. A similar trend in the resource mix is projected for winter on-peak capacity, but the implications for electric reliability are more alarming. While there are substantial amounts of wind, solar, and battery resource installed capacity on the grid currently, their contribution to on-peak winter capacity is limited at just 7% of the resource mix. Winter demand often peaks during periods of darkness and during weather conditions that are not favorable for renewable generation. As a result, the winter peak resource mix leans heavily on coal and gas-fired generation, combined at 65%, and another 28% of nuclear, hydro, and other resource types. While we project substantial amounts of new solar and battery installed capacity over the next ten years, these resources will have a diminished contribution to future winter on-peak capacity. Meeting rising demand will require more winter-capable resources.



The risk of diminishing ERS is also rising. Non-variable generation – including coal, petroleum, natural gas, biomass, geothermal, conventional hydro, nuclear, hybrid or storage systems – can ramp up or down in response to demand. Non-variable resources can also provide other ERS like system inertia, dynamic reactive support, and frequency response needed for stable grid operation. Many of the variable resources that are being added to the grid to replace non-variable resources cannot provide the same ERS in their current configuration. This deficiency is amplified in the winter when on-peak contributions from variable resources are diminished by changing weather and environmental conditions.

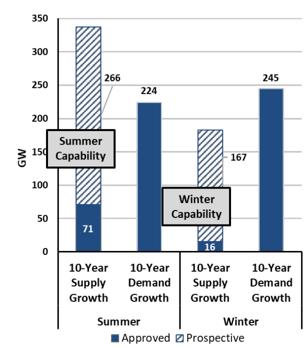
Even resources considered “firm” – like natural gas – can become constrained under certain conditions. Solar, wind, and battery storage each have duration or output limitations. These are not flaws; they are characteristics that must be planned for and managed. And importantly, that means their performance should not be overly relied on during winter peak conditions. Texas is a great example where solar and battery have provided significant benefits to prop up summer resource adequacy during the last five years. However, these resources are not very effective during winter conditions when risk is most concentrated.

NERC is seeing a slowing of retirements to some degree. Projected retirements have shrunk from the 2024 LTRA. Growing demand, market signals, and resource plans have highlighted the potential need to keep resources online longer than previously anticipated. Though the confirmed and announced potential retirements over the next decade remain high and total over 105 GW in peak seasonal capacity, this is roughly 10 GW lower than the 10-year retirement projections last year.

Energy Supply is Not Keeping Up with Demand

The system also faces a timing problem – resources are not coming online fast enough to keep up with demand, and the pace of needed resource additions is subject to uncertainty. This figure depicts expected growth in electricity supply and demand during summer and winter in 2035. The electricity supply numbers represent expected energy delivery, which varies by season. The winter season shows a deficit of 62 megawatts (MW). Both seasons show the vast majority of planned resource additions are still in the planning stages, without interconnection agreements and regulatory approvals. Experience shows that major energy infrastructure projects can encounter permitting delays, public opposition, and supply chain delays. Projects to increase electricity supply resources often have associated transmission upgrades and natural gas fuel infrastructure needs that further complicate development timelines. These challenges are validated by a recent report from Lawrence Berkley National Laboratory which finds the median duration from interconnection agreement to commercial operations date has increased over time, with the median being about 33 months.[1]

Demand and Resource Growth



Approved: Resources with Interconnection Agreements or regulatory approval
Prospective: Resources in earlier planning

These findings underscore the imperative of initiatives and reforms to accelerate deployment of energy infrastructure. Expedited resource programs that were approved by FERC in late Summer 2025 for the organized markets of MISO, PJM, and SPP have resulted in acceleration and prioritization for resources that can address identified reliability risks. Due to the timing of market changes that followed the LTRA data collection window, most new resources brought in through

[1] See “Queued Up: 2025 Edition, Characteristics of Power Plants Seeking Interconnection as of the End of 2024,” Lawrence Berkley National Laboratory, December 12, 2025.

recently approved expedited resource programs are not included in the 2025 LTRA risk assessment. Legislative measures such as permitting reform could also make a meaningful contribution to addressing the nation's energy needs.

Winter Storm Fern

Winter Storm Fern was a major North American weather event that occurred from January 23-27, 2026. The system brought long-duration extreme cold, widespread snow, sleet, and freezing rain across the eastern two-thirds of the United States and parts of eastern Canada. These conditions drove high electricity demand and required the activation of established industry operating procedures designed to manage reliability risk.

Throughout the cold weather event, while there were significant generation outages, observed or reported impacts on the BPS were minimal. This outcome reflects years of sustained and ongoing winterization efforts following Winter Storms Uri and Elliott, industry preparation and collaboration, and extensive outreach by NERC and its Regional Entities. Nevertheless, widespread use of emergency procedures and extraordinary governmental actions are powerful warnings that should not be ignored. Each event has unique characteristics. A larger, colder, longer storm could have had far more extensive consequences.

Joint Performance Review – NERC, FERC and the Regional Entities are preparing to conduct a comprehensive review of Winter Storm Fern, assessing generation outages, derates and forced outages, system performance, electric-gas interdependence, and other matters. This joint review will provide deeper insights into the strategies employed by industry to manage Fern, including newly implemented cold weather reliability standards, industry practices, and potential recommendations to inform winter readiness. This analysis will inform more complex analysis, however information collected during the event does provide valuable insight, as discussed below.

Distribution System Impacts – Even while noting strong performance of the BPS, severe winter storms typically have significant impacts on the electricity distribution system – the facilities that deliver power to local homes and businesses. Fern's impacts of the distribution system were most acute in the Southeast – particularly in Louisiana, Mississippi, Arkansas, and central Tennessee – where approximately one million people lost power due to ice accumulation that toppled trees and knocked out power lines. Tragically, the storm did result in loss of lives.

NERC Coordination – NERC's Bulk Power System Awareness (BPSA) group and the ERO Situation Awareness teams serve as the organization's continuous monitoring and situational awareness function – our eyes and ears on the system. BPSA maintains real-time visibility across all twelve U.S. Reliability Coordinator areas and works closely with the six Regional Entities to collect, analyze, and disseminate information on disturbances, operational concerns, and emerging threats.

During Winter Storm Fern, BPSA operated under an elevated posture. The team conducted multiple daily coordination calls with Regional Entities focused on fuel levels, natural gas availability, storage and replenishment plans, system conditions, and dual-fuel capabilities.

BPSA also issued daily situational awareness updates to NERC and the six Regional Entities, U.S. Department of Energy (DOE), and FERC, and conducted historical assessments of temperature deviations and past generator performance under similar conditions. This coordinated approach ensured that federal partners, industry, and NERC leadership had a shared, near-real-time understanding of risks and system conditions throughout the event.

Operational Measures to Maintain Reliability – The BPS remained stable and reliable during Fern, even given the generation outages discussed below. Despite elevated load demand from high customer heating demands and challenging grid operating conditions, there was no reported or observed thermal, voltage stability, or cascading failures; no uncontrolled separation events; and no load shed.

To manage reliability during Fern, operators implemented the following operational measures:

- Conservative operations – Declaration in which a registered entity is undergoing, or has the potential to face, adverse impacts from weather, environmental, physical or cyber security events. The declaration may include additional actions, including recalling or cancelling non-critical maintenance outages, reductions in transfers into, across or through the system, increased reserves, or additional requests placed upon grid operators.
- Cold weather advisories and alerts – Notice which prepares personnel and facilities for expected cold weather conditions.
- Public appeals – Voluntary requests for customers to reduce the use of electricity for purposes of maintaining the continuity of the Bulk Electric System.
- Generating capacity advisories – Notice which provides an early alert that system conditions may require generation to be loaded above or below the normal levels.
- Transmission emergency – Declaration for any event threatening or limiting transmission grid capability, including line or equipment overloads or outages.
- Demand response – Programs to reduce electricity consumption.
- Fuel optimization strategies – Procedures for maximizing fuel inventories.
- Energy Emergency Alerts (EEAs) – A formal notification of actual or forecast energy deficiencies, classified into three levels, calling for conservation, reserves, or load shedding to maintain grid stability.

These actions, combined with increased situational awareness and proactive operator decision-making, ensured that the system remained stable and reliable throughout the event.

Electricity providers postured their systems appropriately, and Reliability Coordinators maintained continuous communication to manage the impact of the extreme, long-duration cold.

High demand and decreasing reserves in the Carolinas during the cold weather event highlighted the need for continued vigilance regarding reserve margins.

Significant generation outages, including an accumulative loss of 2.8 GW overnight Friday, January 30. These outages were far below the scale observed during Winter Storms Elliott and Uri. Natural gas, coal, and nuclear resources provided most of the generation during the event, while renewable resources contributed modestly. In New England, fuel oil and natural gas kept the lights on, underscoring the criticality of the Everett LNG terminal in Massachusetts. The storm was not as cold as initially forecast, and widespread closures of schools and businesses reduced demand, relieving pressure on the system.

Between January 24 and February 3, 26 EEAs were declared, including two EEA3s, the highest level alert. Importantly, no load shed was associated with the EEA3 declarations.

During the event, DOE issued twenty 202(c) emergency orders; seven in Florida, four in the Southeast, four in the Mid-Atlantic, one in New York, two in New England, and two in Texas. PJM and other grid operators indicated that 202(c) facilities made material contributions. Additionally, DOE encouraged grid operators to coordinate with data centers and other large facilities to leverage backup generation when necessary.

Gas/Electric Coordination – Natural gas system performance, and supply of natural gas to electric generators, are perennial issues during extreme winter events. The natural gas system performed significantly better during Winter Storm Fern than in previous major winter events. While production declines were observed and massive storage withdrawals were made, production in the Marcellus and Utica regions remained strong. This performance highlights the critical role that natural gas storage plays in supporting electric reliability and demonstrates that many previously observed production challenges can be mitigated by natural gas producers. It also stresses the growing need for assuring sustained winter operations across the natural gas value chain as reliance on natural gas continues to rise.

Cross-Sector and Government Coordination – The Electricity Subsector Coordinating Council (ESCC) is a CEO-led collaboration serving as the principal liaison between the federal government and the electric power industry on efforts to prepare for, and respond to, national-level disasters or threats to critical infrastructure. Winter Storm Fern marked the first time the ESCC convened calls in advance of a winter storm. This milestone reflects a heightened level of preparedness and collaboration across the electric and natural gas sectors and with federal partners.

Continued vigilance, collaboration, and winter preparedness remain essential as extreme weather events become more frequent, longer duration, and more severe.

Recommendations

The *2025 LTRA* and the Winter Storm Fern experience stress the urgent needs to build needed energy infrastructure quickly, better manage the pace of generator retirements, integrate new loads reliably, securing natural gas system operation, and maintaining essential grid services.

Accordingly, NERC makes the following recommendations for Congress, regulators at the federal, state, and provincial levels, and industry stakeholders:

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, many states are also taking steps to expedite siting and permitting. Siting and permitting issues are among the most common causes for delayed transmission projects. Support from regulators and policymakers at the federal, state, and provincial levels is urgently needed.

Expedite resource additions to meet growing demand and carefully manage generator deactivations. BPS planners should develop, implement, or enhance mechanisms to expedite resource additions to the grid that provide the services needed to address anticipated reliability issues related to each area's needs. Independent System Operator/Regional Transmission Organizations (ISO/RTO) 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. Regulators must support resource development and manage the pace of retirements such that replacement infrastructure can be developed and placed in service to support reliability needs.

Understand and manage reliability risks accompanying large load growth and leverage potential capabilities in new types of loads to provide flexibility to operators during times of grid stress. An increasing number of large commercial and industrial loads is rapidly connecting to the BPS. Emerging large loads—such as data centers (including cryptocurrency and artificial intelligence applications) and hydrogen fuel plants—present unique challenges in BPS planning and operations. Stakeholders should support NERC's Large Loads Action Plan10 and collaborate through NERC's Large Loads Task Force. ISO/RTOs should collectively work to create more uniform requirements to address the emerging reliability issues associated with large data center loads.

Continue identifying and implementing solutions for addressing the operating and planning needs of the interconnected natural gas-electric energy system. As various initiatives launched in past years roll out recommendations for addressing reliability needs, stakeholders should act with urgency on implementation. Continued collaboration through readiness forums and working groups remains a priority. While new regulatory and oversight mechanisms of the natural gas industry have yet to solidify, voluntary actions for managing natural gas production, processing, and delivery risks are needed. NERC, gas and electric industry, and research partners should continue studies and assessments of regional fuel supply risks to BPS generation.

The National Petroleum Council released a study in December 2025, "Reliable Energy: Delivering on the Promise of Gas-Electric Coordination." The report analyzes misalignment between electric power and natural gas markets and the associated risks. Actionable recommendations include integrating resource adequacy and fuel assurance across sectors through comprehensive long-term planning, permitting reform, and aligning market incentivizes to ensure generators are securing reliable fuel supply.

Maintain essential reliability services. The changing composition of the North American resource mix calls for more robust planning approaches to ensure adequate ERSs. 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 that these services are provided and maintained. ISO/RTOs and FERC have taken steps in this direction, and these positive steps must continue.

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