RELIABILITY FIRST

April 28, 2026

PA Senate Environmental Resources and Energy Committee
Energy Innovation Center, 1435 Bedford Ave,
Pittsburgh, PA

Re: PA Senate Environmental Resources and Energy Committee Meeting

As requested, RF respectfully provides written comments on technical considerations related to resource adequacy.

RF is one of the six North American Electric Reliability Corporation[1] (NERC) Regional Entities responsible for preserving and enhancing the reliability, resilience, and security of the bulk power system (BPS, or "system"). [2] Collectively, NERC and the Regional Entities comprise the ERO Enterprise. With specific authorities under the Federal Power Act and through a delegation agreement with NERC, RF's mission serves the public good by assuring BPS reliability for over 73 million customers in 13 states including the District of Columbia. We audit and enforce the NERC Reliability Standards for more than 300 registered entities. We also provide outreach and education to registered entities in our footprint, and technical expertise to state public utility commissions, legislators, and other stakeholders.

RF's role with the states is to serve as an objective technical resource concerning reliability risks. While energy policy should appropriately prioritize BPS reliability, our statements are not intended and should not be interpreted as advocating for a specific policy or market outcome.

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[1] NERC is a not-for-profit international regulatory authority designated by the Federal Energy Regulatory Commission (FERC) to assure the effective and efficient reduction of risks to the reliability and security of the grid. Through delegation agreements and with oversight from FERC, NERC works with six Regional Entities (including RF) on compliance monitoring and enforcement activities.

[2] RF does not have jurisdiction over the local distribution of electricity, which is a state responsibility.

The Energy Trilemma

The latest *2025 ERO Reliability Risk Priorities Report* recommends that policymakers adopt a three-pronged principles-based approach to decision making regarding energy policy.[3] Energy policy that is volatile or misaligned can be a risk to reliability. RF refers to this as the "energy trilemma," *i.e.,* the need to balance electric reliability, affordability, and environmental sustainability. Often, prioritizing one leg of the energy trilemma has tradeoffs or detrimental impacts on one or both other legs. For example, rebuilding aging infrastructure and adding new lines and substations may benefit reliability, but at a cost to the ratepayer. Preserving an aging fossil fuel generator may be a detriment to state renewable goals. Integrating new Inverter-Based Resources (IBRs) may result in the need for new transmission, tools, training, and technology to maintain reliability, adding additional costs to the system.

As another example, in an effort to prioritize the least cost generation coming onto the system, a state may compromise the diversity of resources needed to maintain a reliable and secure grid. Caps to market prices may remove entry of resources that can benefit reliability and/or environmental sustainability. Rate freezes may defer needed maintenance and modernization to aging infrastructure. These factors all need to be balanced to maintain a reliable grid and avoid energy poverty (i.e., the inability of consumers to afford electricity). The cost/affordability conversation also includes job creation, economic development, and the impact on the economy. Large load growth may negatively impact energy prices when adding new resources, however there may be long term economic benefits to increasing the overall supply. Every factor of the energy trilemma contains nuance.

RF's focus throughout this testimony will be on reliability (our area of expertise), although we are mindful that policymakers and commissioners make difficult decisions regarding the tradeoffs of cost (and cost allocation) along with compliance with federal and state environmental regulations. While states may have preferences and priorities regarding affordability, economic development, and/or environmental targets, reliability (*e.g*., meeting resource adequacy requirements and maintaining essential reliability services) remains essential to prevent blackouts. The *2025 ERO Reliability Risk Priorities Report* recommends a durable "all of the above" approach that considers energy sufficiency and the full spectrum of resource options and services required to keep the BPS reliable, including solutions such as Grid-Enhancing Technologies and load flexibility.

Energy Trilemma: Affordability

While this testimony focuses on reliability, affordability has become a central focus in recent state discussions, and consistent with the energy trilemma, decisions affecting affordability are closely tied to reliability outcomes. Affordability considerations can be shaped by a wide range of factors including underlying system costs, market design, and broader structural decisions such as participation in an RTO.

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[3] 2025 ERO Reliability Risk Priorities Report, page 45

For example, the overall cost of electricity to consumers is a combination of several factors, including distribution and transmission costs, market design, and state regulated investments in enhancing and maintaining the reliability and security of the grid. Affordability can also hinge on factors such as geography, access to natural resources, load growth, and the interconnectedness of transmission systems (*i.e.,* the ability to move power both intra-regionally and inter-regionally). Both the EIA and FERC track energy prices by state to maintain transparency to consumers.[4]

In terms of market design, we've seen PJM's continued focus on affordability, particularly as data centers and other large loads show increasing interest in connecting to the grid. The PJM Board of Managers released an outline of steps for PJM and its stakeholders to maintain affordability and reliability for ratepayers while integrating large-load customers. The plan includes reviewing and reassessing PJM markets, improving load forecasting, expanding state roles, creating pathways for "bring your own new generation" (BYONG) for large-load customers, establishing an accelerated interconnection track for state-sponsored generation projects, and initiating a rapid backstop generation procurement process.[5] These actions, under PJM's Resource Adequacy Schedule,[6] will be filed with FERC and will modify PJM's policies and procedures. Many of the measures are intended for interim use as the region works to rebalance supply and demand. PJM will also publish a white paper around midyear after their holistic review of the wholesale power markets, after which PJM will begin stakeholder collaboration. This is in addition to ongoing stakeholder engagement as PJM advances development plans focused on affordability and reliability.

Finally, affordability has also been discussed in the context of participation in an RTO. Regional Transmission Organizations (RTOs), such as PJM, aim to improve efficiency and reduce costs by coordinating participating utilities and power providers for generation and transmission across the region. If a state considers leaving PJM, it would likely pursue either a Fixed Resource Requirement (FRR) or a Vertically Integrated Utility (VIU) model to secure power. Both options can offer state regulators greater control, but some believe this may lead to higher electricity prices.[7] Alternatively, PJM estimates that its operations save consumers in the region between $3.2 and $4 billion annually.[8]

In addition to potentially higher electricity prices, states leaving PJM would need to consider the cost of higher Reserve Margin requirements, which are generally lower when part of a larger RTO. This means Pennsylvania would have to self-supply peak demand plus reserves. While Pennsylvania is currently a majority-exporting state, future load forecasts, unconfirmed retirements, proposed new large loads, and supply chain challenges may change this trend.

[4] See How Much Is the Average Electric Bill in November 2025? and FERC How Affordable and Reliable is Your Power.
[5] PJM Board Decisional Letter on Critical Issue Fast Path - Large Load Additions.
[6] See PJM's Resource Adequacy Schedule, https://insidelines.pjm.com/pjm-stakeholders-advance-initiatives-to-reliably-integrate-data-centers/
[7] See PJM's Securing Resources Through the Fixed Resource Requirement and What Happens if States Leave PJM - EPSA.
[8] See PJM Fact Sheet for Policymakers 2024, p. 2.

Beyond seeking to suppress price volatility, states outside the RTO framework have more control over generation (e.g., renewable targets, building generation typically outside of least-cost such as nuclear) while protecting consumers and placing the risk on generators, especially with the uncertainty of load forecasts. For example, Dominion in Virginia followed an FRR model in 2021 while PJM still operated the capacity market under previous MOPR. This was largely due to state incentivized renewables goals, which were not being met while under the PJM market structure at the time. Three years later in 2024, due to financial pressure with larger reliability margin requirements, and the emergence of large loads and growing demand coupled with the market changes PJM had made, Dominion returned to the PJM capacity markets.[9]

Leaving an RTO would require collaboration with utilities in the existing framework, tie-line agreements, Independent Power Producers, as well as permission from FERC while establishing and training the new entity that takes on the Reliability Coordinator (RC), Balancing Authority (BA), Transmission Operator (TOP), and Planning Coordinator (PC) required functions currently performed by PJM.

Reliability Backstop

These affordability considerations are closely linked to underlying resource adequacy conditions, which PJM is also addressing through a focus on resource adequacy and the need for new generation. New generation faces several barriers to final commercial operation, from global supply chain friction, siting and permitting delays, extended resource development timelines, and as noted by PJM, the overall queue transition, and the inability for developers to respond timely to pricing signals.[10] This year, for the first time in its history, PJM cleared short of the Reliability Requirement in their 2027/2028 Base Residual Auction (BRA). PJM noted this shortfall is projected to continuously grow over the next decade as new large loads come on to the system.[11] While PJM is looking to instate the Reliability Backstop Procurement (RBP),[12] they have noted this initiative will be companioned with a broader review of investment incentives within PJM to meet resource adequacy needs.

Resource Adequacy Reliability Considerations

These near-term actions reflect broader trends in resource adequacy that are also identified in NERC's independent reliability assessments. NERC annually assesses and reports on the adequacy of the Bulk Electric System in the United States and Canada over a 10-year period. This report, the Long-Term Reliability Assessment (LTRA),[13] projects electricity supply and demand and discusses key issues and trends that could affect reliability. It is important to note

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[9] See, Petition of Virginia Electric and Power Company for authority to defer incremental electric generation capacity expenses.

[10] https://www.pjm.com/pjmfiles/directory/etariff/FercDockets/9248/20251107-er25-455-000.pdf

[11] See PJM's Reliability Backstop Design Working Paper, https://www.pjm.com/-/media/DotCom/committees-groups/workshops/rbpw/2026/20260218/20260218-item-03---pjm-reliability-backstop-design-working-paper.pdf

[12] The Reliability Backstop Procurement is a one-time, transitional procurement of capacity. See https://www.pjm.com/-/media/DotCom/committees-groups/cifp-rbp/2026/20260416/20260416-item-05---pjm-reliability-backstop-procurement-design---pjm-presentation.pdf.

[13] The LTRA is an annual reliability and adequacy study of the BPS, mandated by Section 215(g) of the Federal Power Act. Background information about the LTRA process including the process, assumptions, and definitions of technical terms used can be found here. The latest LTRA was published in January 2026.

that the LTRA reports are not predictions of what will happen; but rather are projections based on information supplied through a transparent stake-holder process collecting data about resources, load forecasts, transmission system changes, and generation retirements. LTRA reports also include recommendations to address risks, such as enhanced communication, coordination, and collaboration between federal and state policymakers, regulators, owners, and operators of the BPS as well as with the needed critical infrastructure sectors.

The LTRA is unique because it is the only study of this type by an independent group solely dedicated to reliability, just as Congress intended when it created the ERO model. Over the past 14 years, LTRA findings show a clear deterioration in reliability margins and have identified resource adequacy risks. As early as 2012, the LTRA anticipated significant fossil-fired generator retirements over the five-year period (2012-2017) and noted that generator developers would need to make up for the shortfall in future years.[14] Although the region has experienced high levels of reliability, severe weather events such as the Polar Vortex (2014) and Winter Storm Elliott (2022) have underscored the trend and risks associated with shrinking reserve margins.

The 2018 LTRA was the first assessment to identify projected resource shortfalls in the RF footprint, specifically impacting the Midcontinent Independent System Operator (MISO) region adjacent to PJM.[15] This projection was based on challenges balancing supply and demand due to the changing generation mix and retirement of baseload resources, well before the emerging large load increases primarily driven by data centers. Market response to higher capacity prices resulted in new generation resources that pushed the risk out several years in subsequent LTRA assessments.

The 2019 LTRA revealed an emerging risk of energy deficiencies during off-peak periods in the MISO region. Historically, meeting summer peak load requirements was seen as sufficient for year-round reliability, but by 2019, this was no longer the case, marking a trend toward greater vulnerability and underscoring that resource adequacy could no longer be measured solely by summer peak conditions.[16] The report also called for increased coordination, communication, and outreach with state policy makers to discuss the changing resource mix (which included more local generation resources added to the distribution system, commonly referred to as Distributed Energy Resources (DERs)).

The 2020-2022 LTRA reports continued to show increasing resource adequacy risks across the country in the five-year horizon due to the changing generation mix and retirements of baseload units. In the 2022 LTRA, NERC introduced its first Risk Area Summary map.[17] This map was used in Congressional hearings to highlight NERC's warning that two-thirds of the country was at elevated or high risk of resource adequacy shortfalls.[18] Even if a region was at normal risk

[14] See 2012 LTRA, page 200.
[15] See 2018 LTRA, page 12.
[16] See 2019 LTRA, page 8.
[17] See 2022 LTRA, page 7.
[18] "The Reliability and Resilience of Electric Service in the United States in Light of Recent Reliability Assessments and Alerts," June 1, 2023, before the Committee on Energy and Natural Resources of the United States Senate. James Robb, President and CEO of NERC, provided testimony concerned about the pace of change overtaking the reliability needs of the system.

(gray area), it was often adjacent to an elevated or high risk region, indicating that the region may be relied upon for energy transfers during emergency conditions. The 2022 LTRA indicated a trend of projected load growth rates for the first time due to electrification, electric vehicles, and cryptocurrency. This was still before the recent upward demand of data center load growth that has accelerated these resource adequacy risks.

Although the PJM region remained in the normal risk category for the 2023 LTRA, the report highlighted that electricity peak demands and energy growth forecasts over the 10-year assessment period were higher than any point in the past decade, due to large industrial loads such as data centers, smelters, manufacturing centers, hydrogen electrolyzers, and charging stations. The PJM section of the report warned of increasing reliability risks "due to the potential for the timing of generator retirements to be misaligned with load growth and the arrival of new generation on the system. Trends toward higher demand, faster generation retirements, and slower resource entry could expose PJM to decreasing Planning Reserve Margins and reliability challenges from imbalanced resource composition and resource performance characteristics."[19] Around this time, PJM and MISO expressed similar concerns through the release of the PJM *Resource Retirements, Replacements and Risks* (4R) Report and the MISO *Reliability Imperative*.[20]

The LTRA published in December 2024 moved both the MISO and PJM regions into the elevated risk category, largely due to resource additions not keeping pace with generator retirements with over 79 GW of national fossil-fired and nuclear generator retirements planned through 2034[21] and rapid demand growth.[22] Uncertainty around new resource additions and existing generation retirements indicated that above-normal generator outages during extreme weather could result in unserved energy or load loss. The 2024 LTRA recommended carefully managing generator deactivations, streamlining siting and permitting processes to remove barriers to resource and transmission development, and continuing to ensure essential reliability services are maintained on the grid. It also cited the need for enhanced analyses, and the importance of implementing a framework to address the operating and planning needs of the interconnected natural gas-electric energy system.[23]

In January 2025, President Trump issued Executive Order 14262 declaring a national energy emergency impacting the United States' ability to remain at the forefront of technological innovation. In July 2025, the Department of Energy released its own resource adequacy report, *Evaluating the Reliability and Security of the United States Electric Grid,*[24] which cites to resource adequacy projections found in the NERC LTRA. This led to several 202c orders in the RF footprint blocking the retirements of power plants in Pennsylvania, Michigan, and Indiana.[25] The 202c orders are 90-day orders that can be renewed by the administration; as such it is uncertain how long these resources will remain on the system available to be dispatched.

[19] See 2023 LTRA, page 76.
[20] See PJM 4R Report and MISO Reliability Imperative.
[21] See 2024 LTRA page 28. These risks may be escalated during the winter peak in the PJM region due to weather-dependent resources and fuel supply issues.
[22] See 2024 LTRA page 8.
[23] See 2024 LTRA page 10.
[24] See Evaluating the Reliability and Security of the Electric Grid report.
[25] See list of DOE 202c Orders and timeline.

In the latest 2025 LTRA, results show increased risk in the RF footprint (seen in Figure 1), due to a combination of factors (*e.g.,* continued escalating demand forecasts from new data center loads, the pace of resource additions and uncertainty due to supply chain issues and other headwinds to development, the future resource mix capabilities for serving load over the range of seasons and hours, and mounting fuel supply issues for current and future winter generation needs such as gas pipeline constraints).[26]

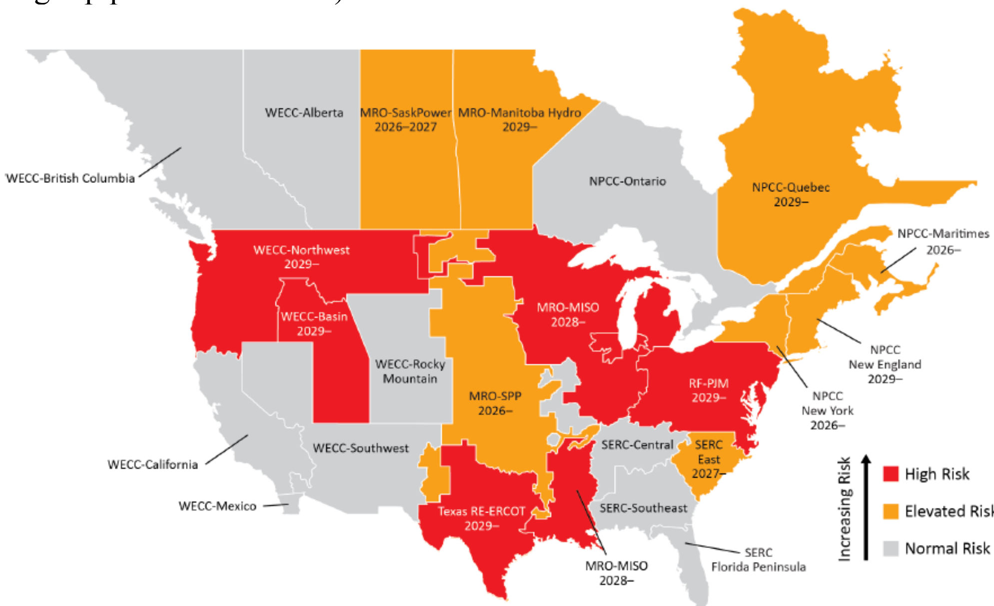

Figure 1: Risk Area Summary 2026-2030

The series of LTRA reports project significant resource shortfalls in the RF footprint as we approach the end of the decade, beginning with the changing resource mix and accelerated by data center load forecasts.

Similarly, RF recently released a Resource Adequacy Report focusing on the RF footprint,[27] which evaluates projected future grid reliability, load growth, changes in the generation mix, and key risks including generation retirements, policy volatility, permitting delays, and supply chain constraints. It uses data collected annually as part of NERC's LTRA process. The report, released in February 2026, underscores the need for proactive, coordinated action among policymakers, utilities, and stakeholders to ensure infrastructure development keeps pace with reliability requirements and avoids shortfalls that could jeopardize grid stability and affordability.

The Resource Adequacy Report analyzes the adequacy of generation resources to serve anticipated load demand for the next 10-year period under a range of different scenarios and assumptions including:

1. Reserve margin projections with existing and planned resources. This includes resources that are operational and those that are under construction or have received approved planning requirements.

[26] See 2025 LTRA.
[27] Read the report here: https://feature.rfirst.org/resource-adequacy-report-2026/index.html.

2. Reserve margin projections with existing, planned, and 30% potential resources with unconfirmed retirements. This includes 30% of the capacity that has been requested but has not yet received approval, and retirements that are likely to be announced.
3. Reserve margins with existing, planned, and 100% potential resources with unconfirmed retirements. This includes resources that are operational, those under construction and 100% of those remaining in the queue. It also includes existing resources that are likely to retire but have not announced a retirement date.
4. Reserve margins with existing, planned, and 100% potential resources. This includes resources that are operational, those under construction and 100% of those remaining in the queue. [28]

From the resulting scenarios, Figure 2 shows the surplus or deficit of resources identified for each scenario and the estimate of additional potential resources needed to close the gap and meet the reserve margin.

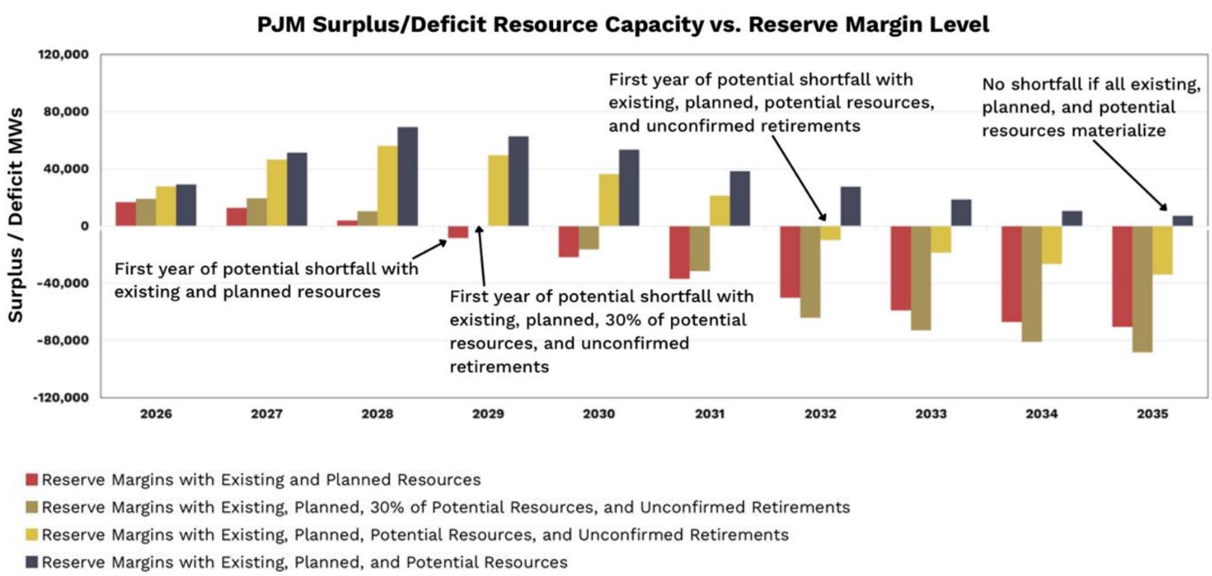

Figure 2: PJM Resource Capacity vs. Reserve Margin Level by studied scenario

As shown in Figure 2, PJM is projected to face resource adequacy challenges beginning as early as 2029, with outcomes dependent on whether anticipated resources are developed and retirements occur as expected. Even under more optimistic assumptions, maintaining reserve margins later in the decade requires substantial amounts of new capacity, much of which remains uncertain. By 2035, PJM would need between approximately 71 GW and 88 GW of additional capacity depending on resource realization and retirement assumptions.

The latest NERC LTRA recommends expediting new resources to meet growing demand and carefully managing generator deactivations. Within the RF footprint, this is done through collaboration between the states and their RTOs. In Pennsylvania, PJM operates a capacity

[28] The four scenarios are as shown in the RF Resource Adequacy Report one-page infographic. The full report includes an additional fifth scenario analyzed: Reserve Margins w/ Existing, Planned, and 30% of Potential Resources (Figure 5 of the RF Resource Adequacy Report).

market to ensure resource adequacy and oversees the Regional Transmission Expansion Plan (RTEP) process to plan and facilitate new transmission infrastructure, including substations and transmission lines. However, many factors impact the amount and type of resources that each state gets. These factors include state policy (e.g., clean energy goals, flexibility, incentives, tariffs), permitting and siting, population growth, geography, natural resources, supply chain, and more.

Emergency Procedures

The NERC LTRA reports reveal a consistent trend that reliability margins have been shrinking over the past several years, especially in the RF footprint. While not explicitly linked to Resource Adequacy, a leading indicator that we are entering high-risk times may be reviewing the trend of grid operator emergency procedures, one being the occurrences of Energy Emergency Alerts (EEA).

An EEA is a formal real-time notification issued by a regional grid operator (e.g., PJM) when operating reserves are tightening and there is an increased risk to electric reliability. This can be precipitated by an extreme weather event, or any combination of unplanned outages to the system. EEAs are issued in escalating levels (EEA-1, EEA-2, and EEA-3) with EEA-1 indicating reserve shortages, EEA-2 notifying stakeholders that emergency actions are required, and EEA-3 representing imminent controlled load shedding and outages.[29] The NERC State of Reliability Reports[30] publish EEA-3 occurrences, as seen in Figure 3. The graph shows the overall trend of increasing EEA-3s across the country over the past decade.

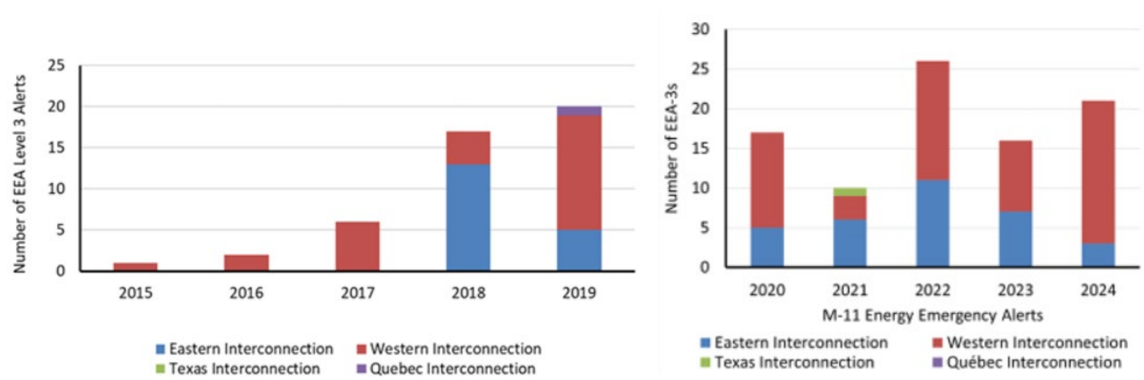

Figure 3: Number of EEA Level 3 Alerts by Interconnection 2015-2024

The charts below in Figure 4 reflect PJM-issued emergency procedures as published on their website[31] from 2015 through the end of 2025. On the left, EEA instances (including all three

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[29] As described in Attachment 1 of NERC Standard EOP-011-4, there are three levels of EEAs, though the Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially. Each level refers to the actions being taken by the grid operator, with EEA-1 meaning all available generation is in use, EEA-2 is when load management procedures are in effect, and EEA-3 entails firm load interruption in progress or is imminent (https://www.nerc.com/globalassets/standards/reliability-standards/eop/eop-011-4.pdf, PDF p. 13-15).

[30] See the 2025 NERC State of Reliability report (page 49) and 2022 report (page 27)

[31] See all PJM Emergency Procedures at https://emergencyprocedures.pjm.com/ep/pages/dashboard.jsf; note the charts include rounding, concurrent issuances for EEA1 and EEA2, and exclude PJM Drills

levels of EEA Alert) rose to over 240 hours in 2025 alone. On the right, PJM issues Cold Weather and Hot Weather alerts with expected actions from their members for the realized or forecast conditions. The weather emergency conditions, while not necessarily constituting grid emergencies, are an indicator of reliability risks to the PJM footprint due to extreme weather (both hot and cold) compounding the reliability challenges discussed in the LTRA and the RF Resource Adequacy Report.

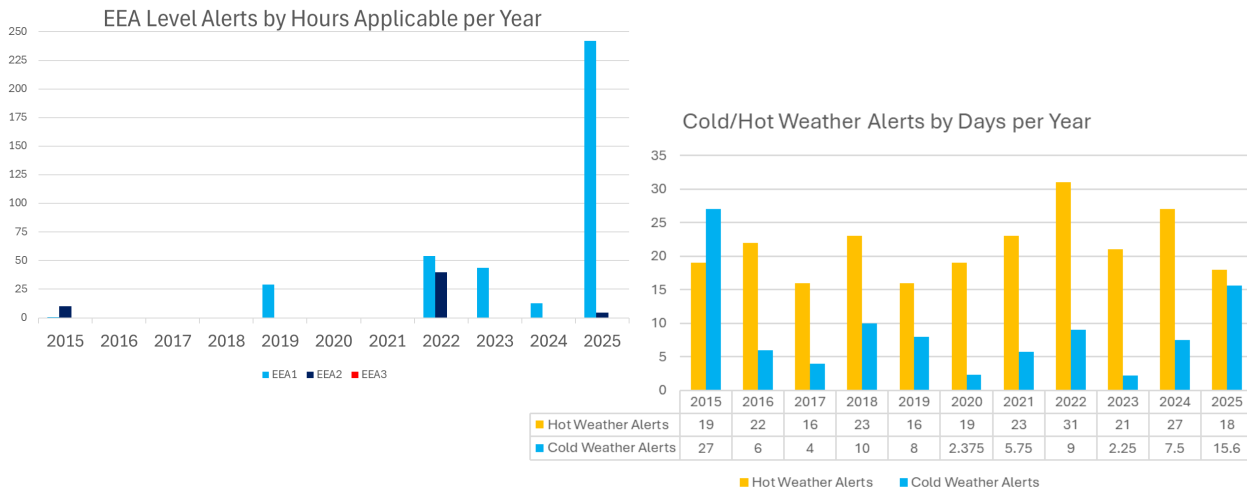

Figure 4: PJM issued Emergency Procedures 2015-2025

<u>Responding to Resource Adequacy Challenges</u>

A key recommendation from the 2025 LTRA is for Integrated Resource Planners, market operators, and regulators to expedite new resources to meet growing demand and carefully manage generator deactivations.[32] Under Section 215(i) of the Federal Power Act, the ERO Enterprise (NERC and the regions including RF) do not have the authority to set or enforce mandatory standards for adequacy or safety of electric facilities or services. This means that although the LTRA and the RF Resource Adequacy Report show potential shortcomings, the ERO does not have the authority to require the construction of generation or transmission assets. This responsibility is left to the states, and in the case of Pennsylvania, working with its Regional Transmission Operator (RTO) PJM.

Generation mix and infrastructure build-out is dependent on many factors (not just the RTO markets). It also depends on state policy preferences, load forecasts, natural resources, geography, supply chain, and various other socio-economic factors. One thing a state can do is to look at data from other states in its RTO to determine which states have built new lines, installed new generators (and which types), or implemented load flexibility measures. Comparing states is not apples-to-apples, as each state has its own unique profile regarding population, topology, and resources; however a state may want to look at an adjacent state with similar priorities to determine if there are policies (e.g., permitting and siting requirements) that are impacting new or modified infrastructure. The graphs and charts below provide some reference points for

[32] 2025 NERC LTRA, recommendation 1, page 10.

comparison and are not an indication of which states are doing better or worse, but instead share data that may be useful when looking at comparisons for having state-to-state discussions.

In Figure 5, a snapshot is provided of baseline and supplemental projects by state in the PJM footprint.[33] Baseline projects are transmission upgrades identified through PJM's RTEP process to resolve identified reliability or market efficiency needs. Supplemental projects are transmission-owner initiated upgrades that address local system needs, asset management, or company-specific planning criteria. While the number and instances of projects vary by state and transmission zone, states that have incurred a high number of projects may have helpful advice and lessons learned regarding removing barriers to adding transmission infrastructure to support reliability.

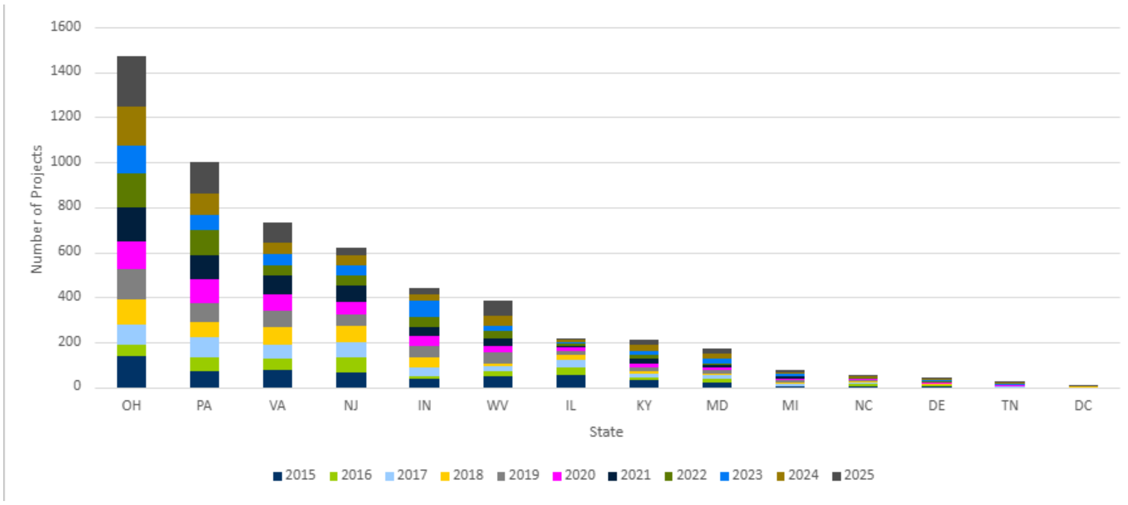

Figure 5: The number of baseline and supplemental projects built from 2015-2025 within the PJM region by state

Another tool used to help balance supply and demand and reduce reliability risk is load flexibility, which includes demand response. Figure 6 below displays which transmission zones in PJM plan to add demand response resources in upcoming years.

33 PJM Project Status Website

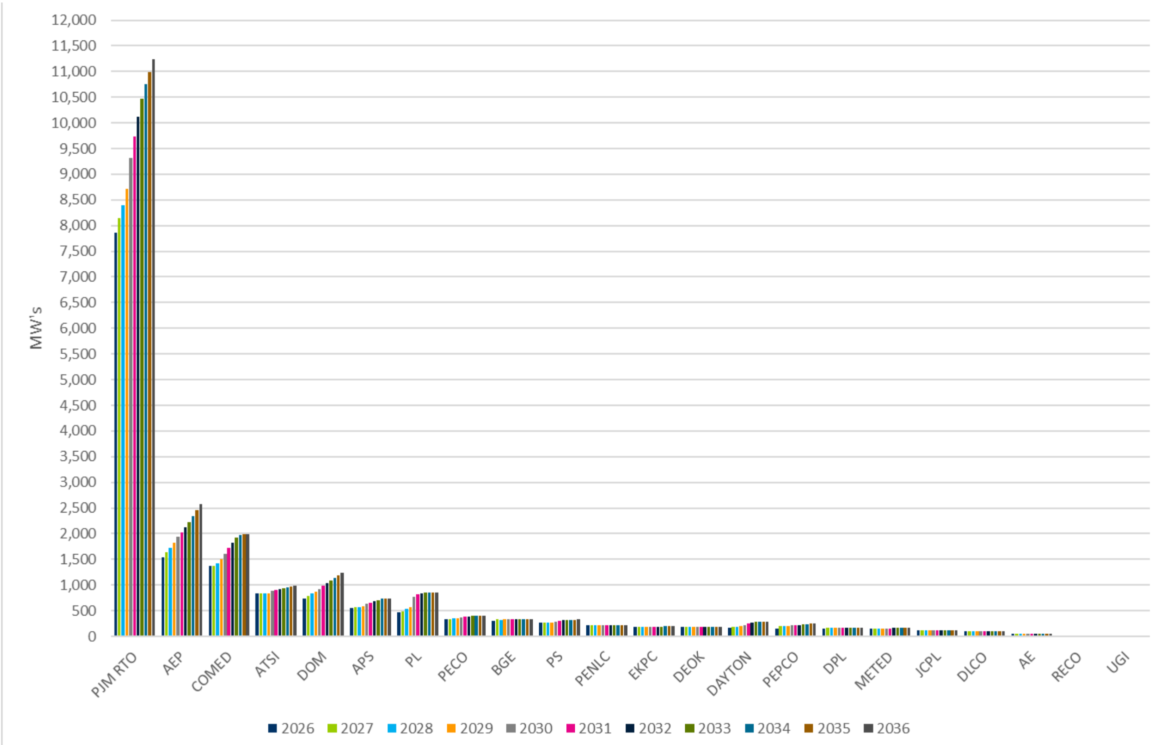

Figure 6: The amount of demand response in Megawatts projected for 2026-2036 by transmission zone

Demand response can be a useful tool for operators to quickly mitigate emergency conditions, whether it be resource adequacy challenges or any operational challenges (thermal overloads, voltage instability*, etc*.). There are certain technical considerations that states should keep in mind when they prioritize demand response as an option. While it may be an agile, cost-effective option to manage grid challenges, demand response (*i.e*., the absence or reduction of a megawatt (MW) on the grid) is not synonymous with adding a MW on the system. The removal of a demand response MW through voluntary load shedding does not provide essential reliability services to the grid (*e.g.,* ramping, volage, frequency). Secondly, demand response needs to be tested in advance so that grid operators have certainty that these resources will respond when asked upon.[34] And finally, there are economic and environmental considerations related to demand response. Economically, more frequent curtailments of (large) loads can have an impact on jobs, production, and the economy. Environmentally, if the demand response resource is reducing load by using backup generation (for example, utilizing diesel generators), this could impact environmental goals.

As stated above, it may be helpful for states to engage with adjacent states with similar goals to discuss the planning, development, and commissioning of additional and existing resources. Continued collaboration with the RTO will remain important in addressing these resource

[34] See FERC All Civil Penalty Actions – 2024, with one example being the 'Ketchup Caddy' incident detailing how Ketchup Caddy and Mango engaged in a scheme to register demand response resources within MISO without those resources' knowledge or consent.

adequacy challenges. The next section of this testimony will outline one of the primary drivers of resource adequacy risk, large load forecasts driven by data center growth in the PJM footprint.

<u>Data Centers, Demand Growth and Operational Risks</u>

There has been a rapid increase in demand, due to the recent rise in data centers, electric vehicles, and the overall electrification of society. For example, in 2024 PJM forecasted an average 2.3% net energy load growth per year over the next 10-year period,[35] and in 2025 forecasted 4.8% growth (over double the previous year's estimate).[36]

In the 2024 LTRA, NERC states that "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."[37] In the 2025 LTRA, shown in Figure 7, projected retirements continue to be high while peak demand growth for both summer and winter also increases, with winter becoming the new peak season in the 2020-2029 10-year analysis.

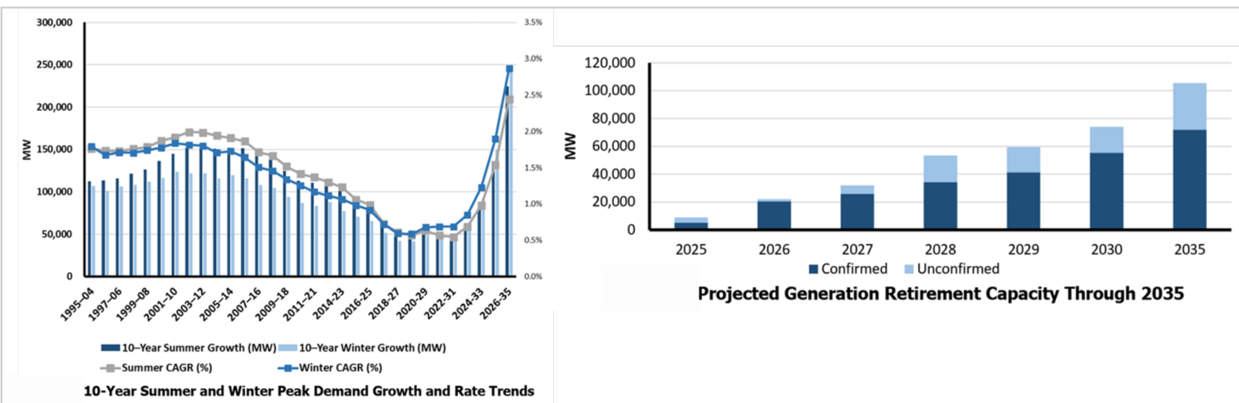

Figure 37: NERC 2025 LTRA Peak Demand Growth and Rate Trends and Projected Generation Retirement Capacity (PDF p. 25 and 23, respectively)

In its 2024 United States Data Center Energy Usage Report,[38] the Lawrence Berkeley National Laboratory analyzed a range of future demand scenarios. The findings suggest that data centers could consume up to 12% of the total U.S. electricity consumption by 2028 - nearly triple their 2023 share of 4.4%, as seen in Figure 8 below.

[35] https://www.pjm.com/-/media/library/reports-notices/load-forecast/2024-load-report.ashx, page 2.
[36] https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2025-load-report.pdf, page 6.
[37] See 2024 LTRA page 8.
[38] See Lawrence Berkeley National Laboratory's 2024 United States Data Center Energy Usage Report.

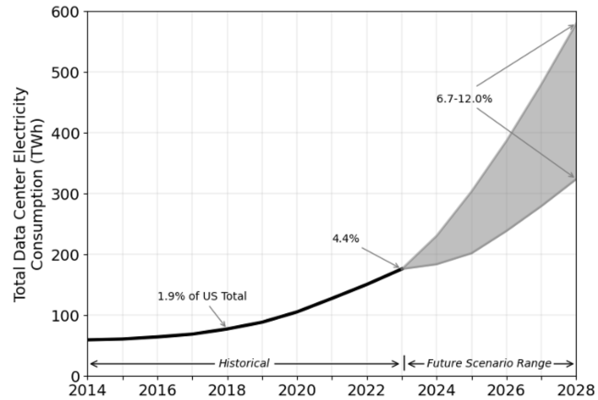

Figure 5.5. Total data center electricity use from 2014 through 2028.

Figure 8: Data center electricity use from 2014-2028, from Lawrence Berkeley National Laboratory[39]

This rapid growth in demand is not solely due to data centers, however, there are unique reliability challenges associated with the data center load growth. Perhaps the largest reason for the focus area is the high load density for data centers compared to other sources. While the impact of electrification and electric vehicles (EVs) is more dispersed, data centers can sit in a small area and require upwards of 300 MW. This makes data center load growth more challenging. As noted in the 2025 LTRA, "beginning in 2023, PJM began to identify trends encompassing large load increases in specific areas, driven primarily by the construction of new data centers […] the large load increases are driving heavier, increased regional transfers and the consequent need for significant system reinforcement."[40]

The map in Figure 9 from the National Renewable Energy Laboratory (now known as the National Laboratory of the Rockies) shows data center infrastructure in the US, including transmission lines, natural gas pipeline infrastructure (in blue), and some of the data centers by size and whether they are currently operating, under construction, or proposed. Many existing and planned data centers are sited where infrastructure can already support them, typically in areas with large existing loads or near major generation sources with established transmission lines. This concentration can further amplify demand in these already high-demand regions.

[39] *Id*. at p. 52.
[40] 2025 LTRA at p. 94.

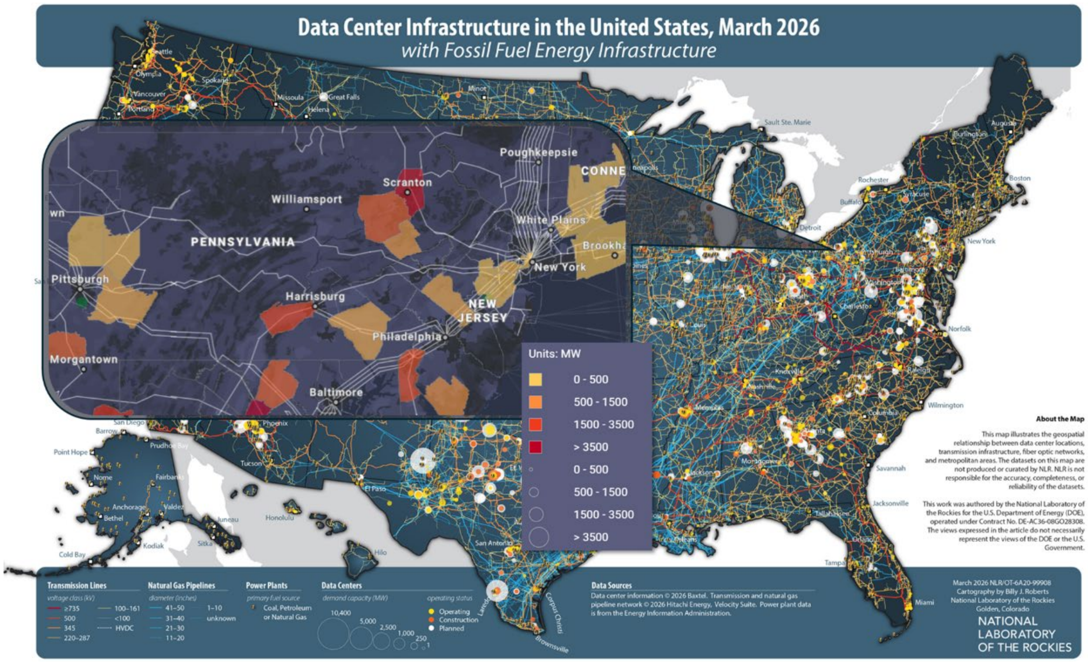

Figure 9: NLR map of data center infrastructure, released March 2026[41] with cutaway showing Pennsylvania as of April 2026[42]

To meet growing electricity demand from data centers, significant transmission and generation expansion will be needed to transport energy. However, the timelines for building transmission infrastructure (often a decade or more) and new generation do not align with the much shorter timelines for data center development. For example, the average time to construct a nuclear power plant is five years or more, not including siting and permitting.[43] Natural gas-fired power plants and IBRs have shorter construction periods, but predicted labor shortages, supply chain constraints, and required transmission expansion may lengthen their overall development.[44] In contrast, the average time to build a 1 GW data center facility ranges from 1 to 3.6 years,[45] creating a clear mismatch between the pace of load growth and the timelines for developing new generation and transmission needed to serve it.

This underscores a broader challenge: while projections to 2030 or 2040 carry considerable uncertainty, long-term planning is essential. FERC Order 1920 requires transmission providers to conduct long-term planning for regional transmission facilities over a 20-year time horizon to anticipate future needs.[46] To ensure reliability, efforts to ensure infrastructure is timely built and coordinated is key.

Recent events have shown that data center loads are unique, which we will discuss further below. Current dynamic models face challenges in capturing the unique characteristics of emerging

[41] Updates can be found on the National Laboratory of the Rockies website.
[42] Updated Pennsylvania map is from National Laboratory of the Rockies website, retrieved April 14, 2026 from https://maps.nrel.gov/speed-to-power/data-viewer.
[43] U.S. nuclear industry - U.S. Energy Information Administration (EIA)
[44] Why 2026 will be the Year of Flexibility - RTO Insider
[45] Build times for gigawatt-scale data centers | Epoch AI
[46] https://www.ferc.gov/news-events/news/ferc-strengthens-order-no-1920-expanded-state-provisions

large loads, and accurately modeling the behavior of such loads becomes increasingly critical amidst rapid development.[47] NERC's Large Loads Working Group (LLWG)[48] discusses and has started publishing documents on how data centers interact with the grid and the associated operational risks, including that many operators lack experience managing such substantial and dynamic loads.

For example, there was an incident in July 2024, where data centers tripped themselves offline during a grid-side fault as shown in Figure 10 – described as a "customer-initiated simultaneous loss of approximately 1,500 MW of voltage-sensitive load that was not anticipated by the BES [Bulk Electric System] operators."[49]

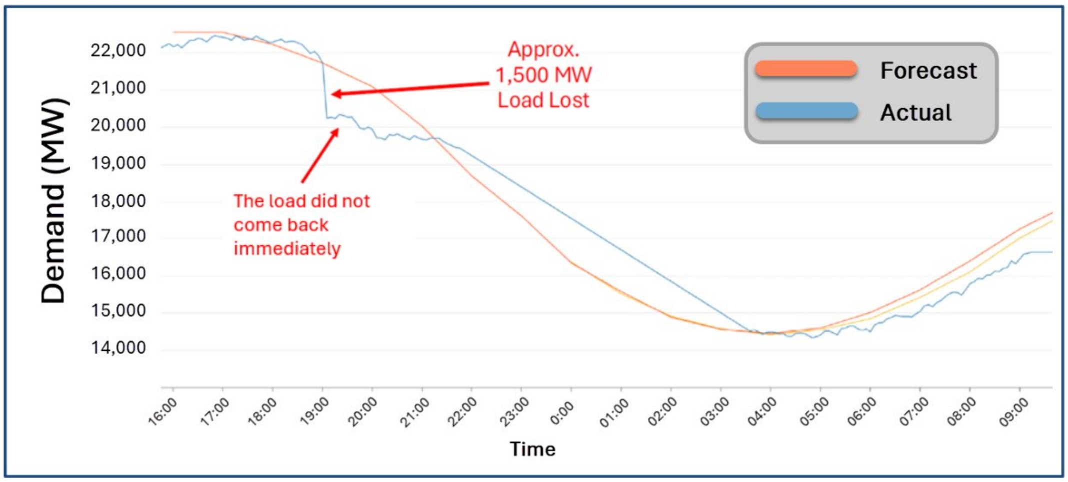

Figure 10: Demand curve showing 1,500 MW load loss event over time, from NERC Large Load Working Group

In a report on the incident published in January 2025, NERC noted that depending on vendor supplied protection/control scheme settings, "if a certain number of voltage disturbances are seen within a certain time, the data center will transfer its load to their backup system, and it will remain there until it is manually reconnected to the grid."[50] Historically, the grid has been planned for large generation losses but not for such significant simultaneous load losses.

The heightened voltage sensitivity of data centers, coupled with rapid fluctuations in their energy consumption, present unique challenges in forecasting, operating, and planning for increased demand.[51] To raise awareness of these challenges, NERC has drafted several white papers on the characteristics and risks of emerging large loads (such as data centers), the first of which was released July 2025.[52]

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[47] See Large Loads FAQs.pdf for additional information.
[48] Information on the NERC Large Loads Working Group can be found at https://www.nerc.com/who-we-are/committees/reliability-and-security-technical-committee-rstc/subcommittees-working-groups-and-task-forces/large-loads-working-group-llwg
[49] NERC Incident Review - Considering Simultaneous Voltage-Sensitive Load Reductions, at p.1.
[50] *Id.* at p. 7.
[51] NERC Large Loads Frequently Asked Questions
[52] See Characteristics and Risks of Emerging Large Loads: Large Loads Task Force White Paper.

Another risk to consider during this period of energy transition and increased demand is the strain on supply chains. This risk is discussed in the most recent RF Regional Risk Assessment,[53] and the rapid growth of data centers can add complexity to this risk. For instance, when a utility seeks to install infrastructure to support a new data center, it is often competing with other utilities doing the same. At the same time, data center developers are often sourcing from the same limited pool of suppliers for critical equipment like backup diesel generators, battery systems, and switchgear.[54]

Forecasting data center growth remains a significant challenge. Non-Disclosure Agreements (NDAs) are commonly used between developers and utilities, which can restrict information sharing with neighboring utilities. Developers may also enter into NDAs with public officials and landowners to keep locational and development details confidential. While these agreements protect sensitive information, they can impede accurate forecasting by restricting access to information on load size and energy demand necessary for effective planning.

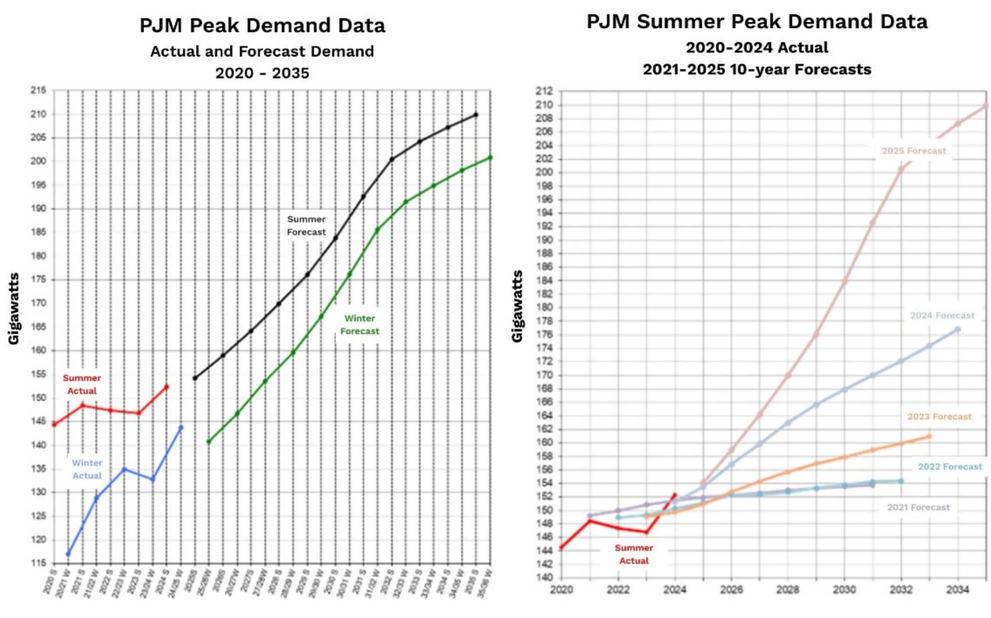

Figure 411: PJM demand forecasts from the ReliabilityFirst Resource Adequacy Report 2026[55]

Regardless of whether demand comes from data centers or other sources, the need for additional generation to meet the demand is clear, as highlighted in Figure 11 showing PJM's increasing load forecasts. Matching this accelerating demand with new generation and transmission capacity is increasingly difficult, even with efforts to bring previously retired generation assets back online to support data center loads. Figure 12 from the RF Resource Adequacy Report shows the past 10 years' actual peak compared to PJM's peak load forecasts. Notably, PJM's 2024 summer peak forecast was lower than the actual peak, departing from prior trends and

[53] See RF Regional Risk Assessment 2023-2024, at p. 7.
[54] See Tackling operational challenges in modern data centers - DCD
[55] See https://feature.rfirst.org/resource-adequacy-report-2026/index.html

indicating that resource adequacy planning studies may have underestimated the need for new resources in that planning year.

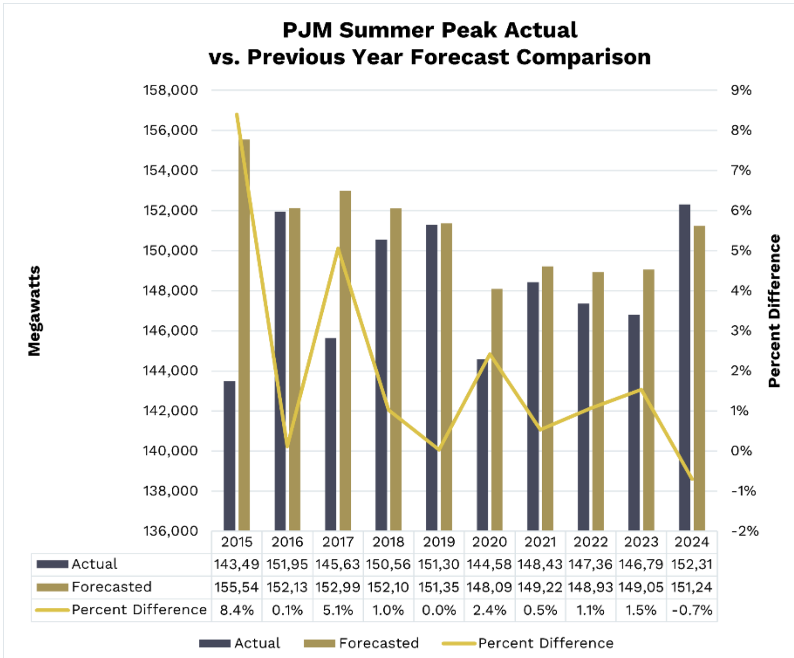

Figure 512: Comparison between actual summer peak vs. forecasted peak from one year prior, as reported in the RF 2026 Resource Adequacy Report

To address resource adequacy challenges, the industry will need to be flexible and plan far ahead to remain reliable.

Load Flexibility and Backup Generation

One concept being explored is that resource adequacy challenges associated with the pace of change (primarily the long lead times required to build generation and transmission infrastructure to support load growth) can be mitigated in part through load flexibility.[56] This invokes the idea of using the load as a balancing resource when generation or transmission deliverability cannot provide power in the time frames data centers are seeking. Load flexibility is often raised as an opportunity to help reduce customer costs, deliver speed to data centers, and meet state environmental targets regarding reducing emissions. Load flexibility can refer to load management demand response (often referred to as peak shaving during times of high load or other emergency conditions) or economic demand response (*e.g.,* time-of-use rates or otherwise curtailing power during expensive time periods).[57] The NERC LLWG whitepaper contains a

[56] T. Norris, T. Profeta, D. Patino-Echeverri, and A. Cowie-Haskell, "Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems," Nicholas Institute of Energy, Environment, & Sustainability, 2025. Accessed: May 30, 2025. [Online]. Available: https://nicholasinstitute.duke.edu/sites/default/files/publications/rethinking-load-growth.pdf
[57] See PJM Demand Response Fact sheet.

section exploring the concept of flexible loads, and how it can allow operators to maintain reliability during times of high demand and/or other emergency conditions.[58]

For reliability, flexibility helps if it is available when and where you need it, in those moments the grid needs it most. Some things to consider about flexibility: First, is the flexibility voluntary or guaranteed? For example, a customer may be able to choose between curtailing load or paying a higher cost to stay online. If flexibility is not assured during stressed grid conditions, reliability may not be assured either. In addition, operators need visibility and verification of the flexibility. They need to know where the large loads are located and understand how they will behave. One final note is that the length of the flexibility commitment matters and needs to be understood. If the grid will continue to rely on large-load flexibility for years to come, we'll need to know how long those flexibility contracts will last, how they are operationalized, and how they are incorporated into planning.

Understanding the type and configuration of large loads is essential when assessing load flexibility opportunities. For many data centers, uptime is paramount, and their load factors are typically between 70% and 90%, which reflects a consistent demand throughout the day.[59] This consistency at all hours of the day, combined with the critical need for uninterrupted operations, limits their ability to curtail load during grid stress as most demand response programs require, unless they can switch to full load backup generation. Adding this flexibility often hinges on the facility's ability to purchase and install the necessary equipment and ensure fuel availability to support on-site backup generation when called upon.

While backup generation may provide load flexibility, it is important to study the reliability impacts of these arrangements. The 2024 data center event referenced above was an event where approximately 1,500 MW of data center load switched to backup power, covering approximately 25-30 substations and 60 data centers.[60] This unplanned shift (what could be termed 'accidental load flexibility') highlights the potential challenges that grid operators encounter in managing sudden, unpredictable shifts in system conditions. There are two important technical considerations to keep in mind related to the use of backup generation.

1. **Impact of losing the load or the generator**
   There are times when the generation or the load is unavailable (tripped, unavailable for maintenance, etc.) and often it is one of the two scenarios, but not both at the same time. For example, there will inevitably be times when the generation is unavailable and the load may be supported 100% by the transmission network; or conversely there may be times where the load is unavailable (e.g., trips off due to a voltage or frequency sensitivity) and the full output of the generator(s) is delivered to the grid.

   While this may not be as impactful for smaller distributed energy resources, the size and magnitude of these large loads and their associated generation may cause thermal, voltage, or stability impacts to the grid at large. While there may be relaying or other protection systems that isolate both the load and generation together, each circumstance

[58] Characteristics and Risks of Emerging Large Loads white paper, page 21
[59] Load factor approximations can vary depending on the assumptions used by the publication, but an often cited number is 86% from the Energy and Environmental Economics (E3) whitepaper.
[60] An Assessment of Large Load Interconnection Risks in the Western Interconnection

and location must be modeled and studied. Operators need visibility of how these configurations may react, and what operational flexibility is available at each location.[61]

2. **Backup generation challenges**
   The generation brought by the large load may be backup generation (*i.e.,* used for load flexibility, and/or emergency backup power) or it may run continuously to offset power demanded from the grid. Regardless of how often it is needed, or the type or magnitude of the generation behind the meter, it is still subject to the same risks as traditional front-of-the-meter generation (such as supply chain issues, vulnerabilities, and emission limits). Data centers that want to bring their own generation are competing for materials from the same supply chain, which impacts supply and demand for turbines across the region. If they are using natural gas, they are competing for the same fuel supply chain. Even if the generator is not subject to NERC reliability standards (based on configuration, voltage, and magnitude), these generators still require the same maintenance (e.g., winterization, relay testing) to remain reliable. They are also subject to the same risks related to weather, security, natural disasters, and human factors such as staffing, testing, and maintenance.

These technical considerations are not meant to discourage load flexibility and other creative options to manage the pace of change when generation and/or transmission infrastructure is not available. Rather, they are shared to emphasize the importance of reliability analysis when considering these configurations.

Reliability Risks Related to Extreme Weather

Extreme weather events can put strain on the grid, as demonstrated during Winter Storm Elliott, when unprecedented generation outages coincided with winter peak demands, resulting in about 5,000 MW of load shed as rolling blackouts. FERC, NERC, and the Regions released a Joint Inquiry Report on Winter Storm Elliott with lessons learned and recommendations (which led to the creation of revised cold weather reliability standards and numerous other actions by FERC, NERC, and the industry).[62] More recently, Winter Storm Fern in January provided another real-world example of the grid under stressed winter conditions. While the industry demonstrated measurable progress in cold weather performance, the system again operated with little margin for error. Operators relied on a broad set of emergency procedures and extraordinary governmental actions also played a critical role in maintaining reliability. This reliance on extraordinary measures could be indicative of tightening reserve margins during periods of system stress. Decreased reserve margins can create additional risk during extreme weather events, when power is needed the most.

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[61] Characteristics and Risks of Emerging Large Loads white paper, pages 19-21

[62] See https://www.ferc.gov/media/winter-storm-elliott-report-inquiry-bulk-power-system-operations-during-december-2022. FERC also released a summary of actions taken in response to the Winter Storm Elliott Joint Inquiry Report: https://www.ferc.gov/ReliabilitySpotlight#:~:text=FERC%20and%20the%20North%20American,FERC%2DNERC%20winter%20storm%20analyses.

Retirements can also exacerbate winter performance risks, as shown in the August 2025 whitepaper[63] that used LTRA data to forecast the resource gap if events from the January 2025 cold snap repeated in the year 2029, given the projected retirements, approximate solar, wind, and battery performance, and the forced outages observed on January 22, 2025. The result was an over 18 GW resource gap, as shown in Figure 13.

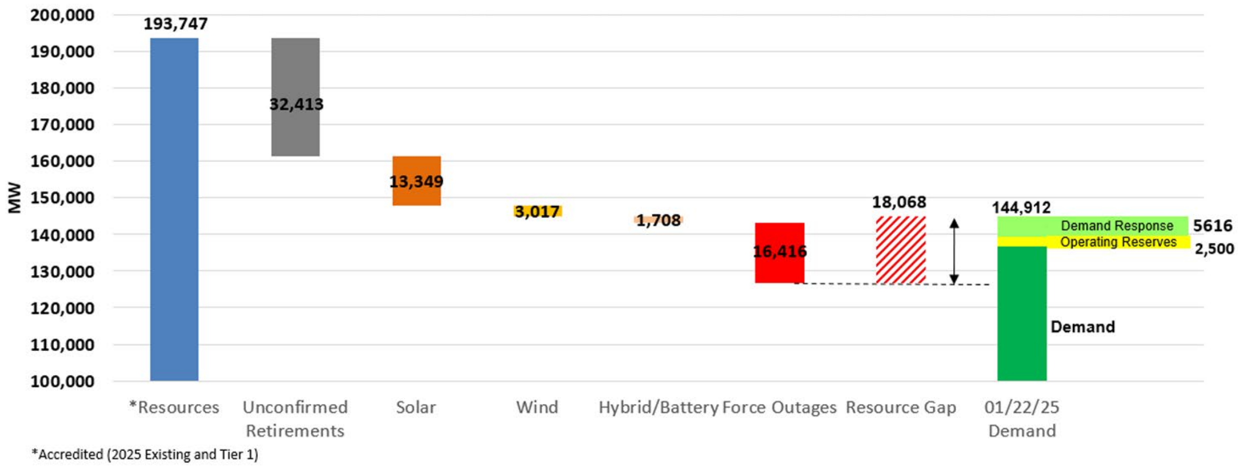

Figure 13: PJM 2029/30 Winter Risk Scenario (using Jan. 2025 Peak Conditions)

Post-weather event storm damage, such as from the tornado that damaged a 500 kV line in Louisiana in March of 2025, can combine with other factors to result in emergency load shed, like the event on May 25, 2025, in Southeast Louisiana. The outage of the damaged 500 kV line, which was not yet restored, coupled with spring outage season (when many generators are out of service for maintenance and repairs, preparing for the summer season), lack of import capability, and unseasonably high temperatures, required MISO to order 600 MW of load shed to prevent broader system failure.[64]

Another reliability risk associated with extreme weather is overdependence on a limited range of energy sources. This can be seen during extreme winter weather when natural gas is a key component of the resource mix. A significant percentage of natural-gas fired power plants rely on as-available, non-firm gas supply alongside solid transportation arrangements. However, this supply can be interrupted during extreme cold weather events when demand by both generators and natural gas distribution companies is high. The 2024 LTRA finds that natural gas fired power plants generated over 40% of electrical energy consumed by end use electricity customers over the last two years, with an additional 6,500 MW of new generation expected over the next five years.[65] Given the expanding role of this fuel source, it is important to continue to address natural gas supply risks.

Intermittent resources also pose concerns during extreme weather conditions, and when two or more resource types simultaneously experience below-normal resource output from weather

[63] See published Reliability Insights article https://www.nerc.com/globalassets/who-we-are/news/2025/06/reliability-insights---new-approaches-needed-to-ensure-system-adequacy.pdf
[64] See MISO May 25 Load Shed Event Report.
[65] 2024 LTRA at p. 28-29.

conditions, meeting demand can be difficult.[66] These times, called "energy droughts" as seen in Figure 14 below, are more likely to occur during high-demand periods and highlight a need for robust resource adequacy planning.

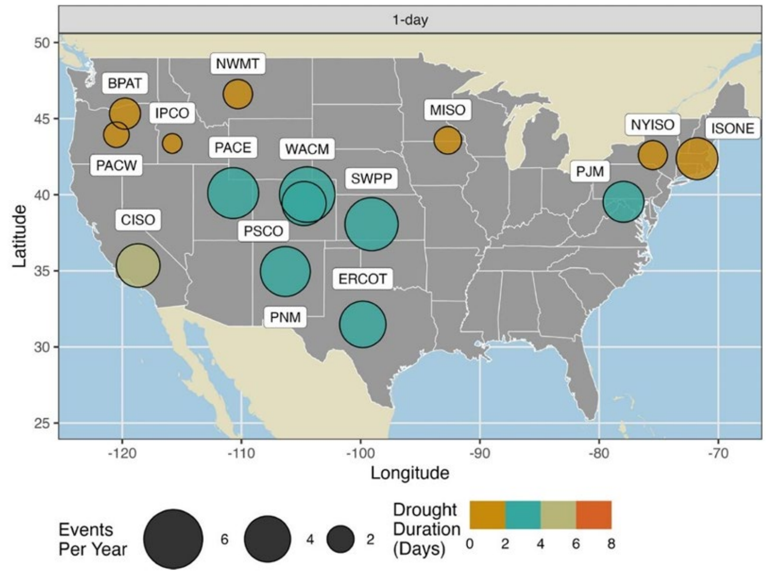

Figure 14: Daily energy droughts from the 2024 LTRA (Source: Pacific Northwest National Laboratory)

<u>**Additional System Events**</u>

RF analyzes events in our region to identify new risks and share lessons learned. Any of these events may be a precursor to future events if the causes are not identified and mitigated. Last year, RF analyzed an event that resulted in load shed in Maryland. Beyond extreme or unseasonable weather, the grid faces strain due to general resource availability issues (existing generation and transmission constraints). For example, the Baltimore disturbance in August 2025[67] stemmed from an unplanned outage at Brandon Shores substation (eight miles southeast of Baltimore). The loss of the single 230 kV substation cut off all transmission paths from the station to the grid in an already resource constrained area and ultimately culminated in emergency load shed.

RF also studies events across North America and from other countries to gather insights from energy transitions in other regions and internationally. In one example, a voltage instability issue outside our region triggered a load-shedding event. During the event, severe weather (tornados and thunderstorms) resulted in line outages, combined with a large generator unexpectedly operating at lower capability, a large load forecast error, wind generation coming in lower than expected, and solar ramping off for the evening.[68]

[66] As a recent example, the SPP footprint had to declare Conservative Operations throughout multiple days in October based on forecasts of high peak loads due to unseasonably warm temperatures combined with low expected output from wind and other intermittent resources.
[67] See August 2025 Baltimore Load Shed Event After Action Analysis.
[68] See NERC Lesson Learned - Load Shed for Voltage Instability.

On the global stage, the 2025 Iberian Peninsula Blackout impacted approximately 50 million people in Spain, Portugal, and a section of France when a combination of generation outages created voltage and frequency swings. The final report highlights how developments at the local level (such as the non-regulated, local generation networks in Spain not aligning with larger system needs) can have systemwide impacts.[69] Additionally, a lesser-known power outage in Sri Lanka impacted 22 million people when a transformer outage resulted in system-wide imbalances and cascading outages. During the time of the outage, a substantial portion of generation was supplied by solar PV systems.[70] This event is still under investigation, but an initial report states that with a high penetration of IBRs, system inertia was reduced and the system was more susceptible to disturbance.[71] These three events are concerning because they did not occur during extreme hot or extreme cold weather conditions. These examples further validate the importance of NERC's work regarding implementing FERC Order 901 aimed at protecting grid reliability as intermittent power generation technologies increase penetration on the U.S. grid.[72] New and revised Standards implement and reinforce requirements regarding studies, model and data sharing, and ride-through requirements.

<u>ERO Enterprise Efforts</u>

Given the rapidly changing resource mix, increasing demand, and the associated reliability risks, FERC and the ERO Enterprise are working to help mitigate these emerging concerns. The *ERO Reliability Risk Priorities Report* outlines the work of the NERC Reliability Issues Steering Committee (RISC) to define and prioritize risks to the BPS.[73] The report found that, in no particular order, the top risks include grid transformation, resilience to extreme events, critical infrastructure interdependencies, security, and energy policy. Energy policy first appeared in the 2023 RISC report and remains a concern because it can amplify each of the other risks and has wide reaching impacts. The primary challenges stem from policy volatility and misalignment, as policies can shift quickly, conflict with one another, and create market uncertainty. Additionally, policies that do not align with the operational capabilities of the electric grid can create reliability risks. Policy decisions can significantly influence the resilience of the BPS, as well as capital investment strategies and market dynamics. Policy and implementation plans require careful consideration to avoid potential reliability issues from emerging.

The ERO Enterprise and industry are creating new and revised standards to enhance reliability, such as Project 2022-03: Energy Assurance with Energy-Constrained Resources[74] (revising several standards to require energy reliability assessments to evaluate energy assurance and Corrective Action Plans to address identified risks), and Project 2023-07: Transmission System Planning Performance Requirements for Extreme Weather.[75] There are also several ERO Enterprise working groups working on these risks.

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[69] See final report by ENTSO-E, Root Cause Tree, p. 23, 331-334
[70] Ceylon Electricity Board Report on February 2025 Sri Lanka Event, p.23.
[71] Id. at p. 45.
[72] FERC Order 901
[73] See 2025 ERO Reliability Risk Priorities Report.
[74] See project page on NERC's website
[75] See project page on NERC's website

NERC and the Regions partnered to perform the Interregional Transfer Capability Study (ITCS),[76] which analyzed total transfer capability (the amount of power that can be transferred between transmission planning regions to improve energy adequacy). It recommends prudent additions to total transfer capability that could strengthen reliability. The complete ITCS was filed with FERC in late 2024.[77]

Additional ERO efforts specific to data center load growth include the creation of the Large Load Working Group (LLWG), plus the Emerging Large Loads Technical Conference that convened in February.[78] The Large Load Working Group issued their white paper (referenced above) in 2025 and will issue a Reliability Guideline scheduled for later this year.[79] The latest Q1 update from the Large Load Working group included a timeline of upcoming activities, plus details on NERC's three-pronged approach to mitigating reliability challenges associated with large loads:[80]

1. **Technical Justification**: An Essential Action Level 3 alert will be issued to recommend near-term mitigation actions that current registered entities can take to address critical reliability risks, expected May 2026. This also includes the upcoming Reliability Guideline mentioned above.
2. **Registration Criteria for Computational Loads:** NERC will define which entities (i.e., which large loads), based on specific physical and electrical criteria, would be required to register with NERC and comply with its Reliability Standards. A Standards Authorization Request and Proposed Rules of Procedure Revisions summary have both been submitted and NERC is accepting comments.[81]
3. **Reliability Standards:** NERC will revise and adopt new Reliability Standards to define computational loads and establish measurable requirements for newly registered entities, with an initial Reliability Standard completed, expected by the end of 2026.

Conclusion

There are additional risk topics and case studies that we are available to discuss at future hearings and testimonies – for example, there are cyber and physical security risks as we plan, build, operate, and defend the grid of the future. We touched on environmental factors associated with weather-dependent resources, and we can expand this discussion with case studies from Winter Storms Uri, Elliot, Gerri, Heather, Enzo, and Fern. Finally, while reliability is our area of expertise and is of key importance during the energy transition, there are socio-economic considerations such as electricity costs, availability and supply of critical minerals, land usage, impacts on the economy (job growth and economic development), and environmental factors

[76] See Interregional Transfer Capability Study Final Report at https://www.nerc.com/pa/RAPA/Documents/ITCS_Final_Report.pdf.
[77] https://www.ferc.gov/sites/default/files/2024-11/20241125-3020_AD25-4-000-NERC%20ITCS%20Notice.pdf, see also FERC Docket AD25-4.
[78] Emerging Large Loads Technical Conference
[79] See the preliminary draft of the Reliability Guideline for Rist Mitigation for Emerging Large Loads.
[80] Large Loads Action Plan Q1 2026 Update.
[81] Large Loads Standard Authorization Request and Computational Load Entity Proposed Rules of Procedure Revisions Summary.

including recycling, emissions, pollution, and water usage. We can discuss case studies and events that have impacted other regions of the country, and other parts of the world.

To successfully address the complex reliability challenges emerging as the grid is transformed, NERC, the Regional Entities, and state and federal policymakers will need continued collaboration, coordination, and thoughtful action. Robust resource adequacy planning that acknowledges the benefits of a diverse resource mix and the threat of extreme weather will also help fortify the grid and electricity consumers. As states craft policies for a more sustainable grid, we are pleased to serve as an independent and reputable resource to help you remain well informed regarding key reliability topics.