NERC

2026 State of Reliability

Technical Assessment of 2025 Bulk Power System Performance

June 24, 2026

2026 SOR Snapshot

2026 SOR Overview

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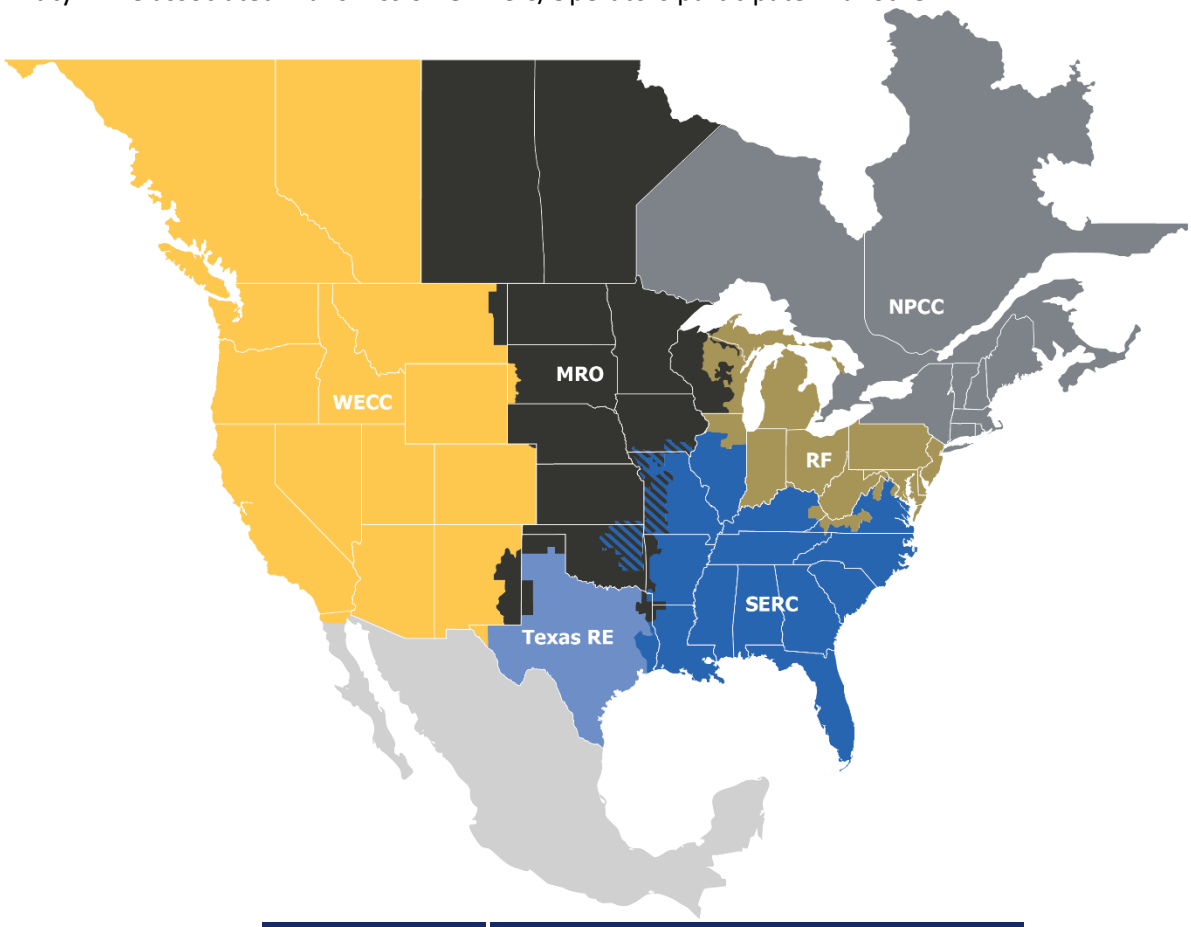
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Preface

Electricity powers our modern life and is the bedrock of our economic wellbeing. The Electric Reliability Organization (ERO) Enterprise—comprised of NERC and the six Regional Entities—is firmly committed to assuring a highly reliable, resilient, and secure bulk power system (BPS) in North America. The ERO Enterprise enables collaborative engagement with industry, regulators, and stakeholders, embracing innovation and supporting the needs of nearly 400 million people.

RELIABILITY | RESILIENCE | SECURITY
POWERING TODAY. PROTECTING TOMORROW.

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



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

About This Technical Assessment

Introduction

The *State of Reliability* (SOR) report seeks to inform regulators, policymakers, and industry leaders on the most significant reliability risks facing the BPS and describe the actions that the ERO Enterprise has taken and will take to address them. This year's SOR report is comprised of two publications: this *2026 SOR Technical Assessment*, which provides NERC's comprehensive annual technical review of BPS reliability for the 2025 operating (calendar) year, and the *2026 SOR Overview*, which is a high-level summary of the Technical Assessment with the following details:

- The *2026 SOR Overview* replaces the key findings previously found in the Technical Assessment.
- This *2026 SOR Technical Assessment* details major occurrences and provides in-depth analysis of risks and resilience, grid transformation and performance, and related performance metrics.

Purpose of the SOR

Both the Overview and the Technical Assessment provide objective and concise information for policymakers, industry leaders, and regulators on issues that affect the reliability and resilience of the North American BPS. Specifically, the SOR report does the following:

- Analyzes performance trends and emerging reliability risks
- Reports on the relative health of the interconnected system
- Measures the success of mitigation activities

NERC, as the ERO, works to assure the effective and efficient reduction of reliability and security risks to the North American BPS. Annual and seasonal risk assessments look to the future, and special reports on emergent risks serve to identify and mitigate potential risks. This assessment identifies performance trends and provides strong technical support for those interested in the detailed analytics.

NERC defines the reliability[1] of the interconnected BPS in terms of two basic and functional aspects: adequacy and operating reliability.

The *2026 SOR* report focuses on BPS[2] performance during the prior calendar year as measured by an established set of performance metrics, other reliability indicators, and more detailed analysis performed by ERO staff and technical committee participants. Data used in the analysis comes from the Transmission Availability Data System (TADS), the Generating Availability Data System (GADS), the Misoperation Information Data Analysis System (MIDAS), voluntary reporting into the Event Analysis Management System (TEAMS), Bulk Power System Awareness monitoring and processes, and the Institute of Electrical and Electronics Engineers (IEEE) Distribution Reliability Working Group. ERO staff developed this independent assessment with support from the Performance Analysis Subcommittee (PAS).

[1] **Learn About NERC** provides background information about NERC, the definition of reliability, and the electric grid.

[2] The term BPS is defined in Section 215 of the Federal Power Act as facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and electric energy from generating facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy. 16 U.S.C. § 824o(a)(1). Bulk Electric System (BES) is a subset of the BPS and is a defined term under the NERC Glossary as approved by the Federal Energy Regulatory Commission (FERC). As the Electric Reliability Organization, NERC is responsible for developing and enforcing Reliability Standards to ensure an adequate level of reliability of the BPS and assessing reliability of the BPS. NERC's regulatory model is designed to ensure that entities capable of affecting the reliability of the BPS are registered and subject to Reliability Standards. North Am. Elec. Reliability Corp., 187 FERC ¶ 61,196, P 53 (2024).

NERC also produces the following regular assessments to evaluate BPS security as well as present and future BPS reliability:

- *Long-Term Reliability Assessment* (LTRA)
- Summer and Winter Assessments
- Electricity Information Sharing and Analysis Center (E-ISAC) *End-of-Year Report*

Considerations

- Data in the SOR report represents the performance for the January–December 2025 operating year unless otherwise noted.
- Unless specified otherwise, analysis in this report is based on data from 2021–2025 that was available in Spring 2026, and it provides a basis to evaluate 2025 performance relative to performance over the last five years. All dates and times shown are in Coordinated Universal Time (UTC).
- The SOR report is a review of industry-wide trends and not the performance of individual entities.
- When analysis is presented by Interconnection, the Québec Interconnection (QI) is combined with the Eastern Interconnection (EI) unless specific analysis for the QI is shown.

Chapter 1: Major Occurrences for 2025

Overall, the BPS was reliable[3] throughout 2025. This chapter highlights major occurrences and reports that were issued in 2025. These occurrences and reports did not constitute a key finding but had a notable impact on the BPS.

Figure 1.1 highlights important numbers and facts about the North American BPS. **Table 1.1** shows the five-year trend of these numbers.

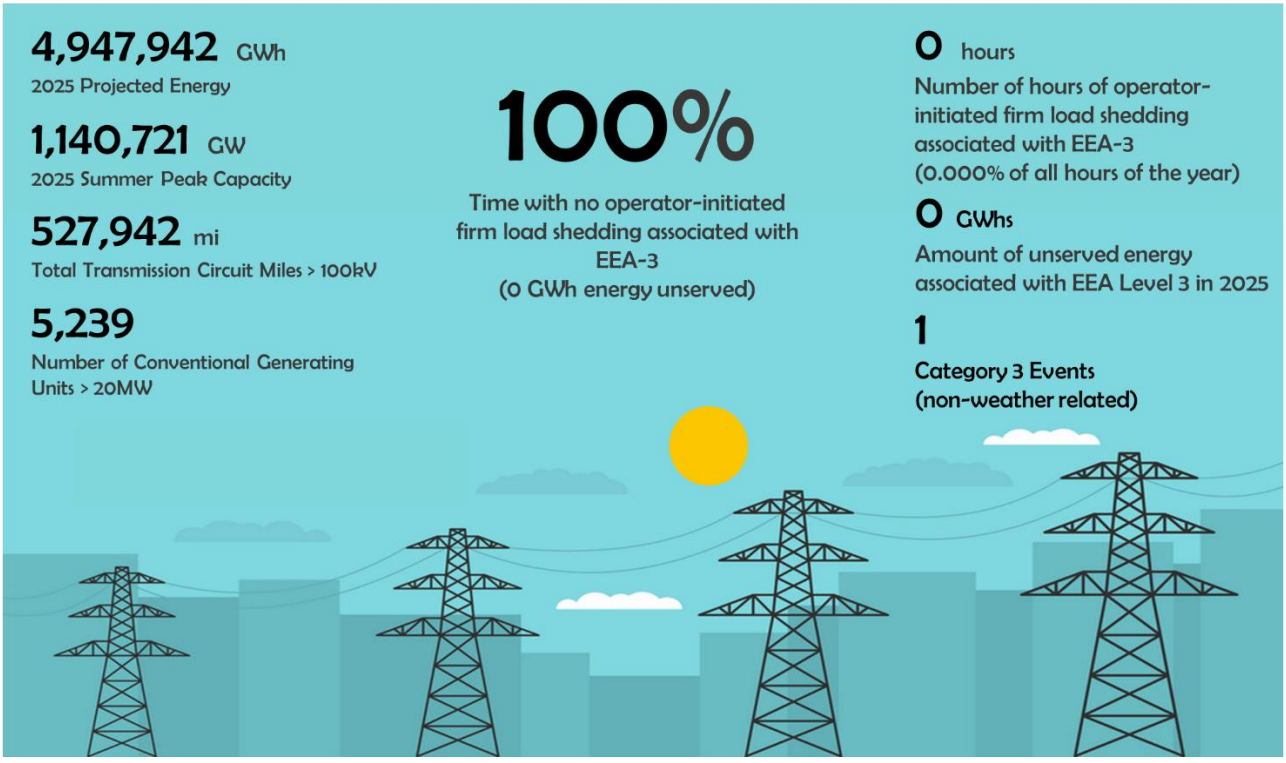


Figure 1.1: 2025 BPS Inventory and Performance Statistics

Table 1.1: Five-Year BPS Inventory and Performance Statistics

Rank	2021	2022	2023	2024	2025
Projected Energy (GWh)	4,585,939	4,674,290	4,687,894	4,856,251	4,947,942
Actual Energy (GWh)	4,626,790	4,695,921	4,663,574	4,787,277	N/A
Summer Peak Capacity (MW)	1,056,980	1,057,455	1,071,370	1,087,354	1,140,721
Total Transmission Circuit Miles >100 kV miles	508,766	522,433	529,344	526,853	527,942
Count of Transmission Circuits >100 kV	28,411	29,165	29,932	30,014	30,666
Count of Transformers with a Low-Side Voltage >100 kV	5,715	5,773	5,805	5,832	5,866
Number of Conventional Generating Units >20 MW[4]	5,375	5,453	5,290	5,243	5,239

[3] Learn About NERC provides background information about NERC, the definition of reliability, and understanding the grid.
[4] 2025 methodology was updated to only include mandatorily reported units that submitted at least one performance record.

Table 1.1: Five-Year BPS Inventory and Performance Statistics					
Rank	2021	2022	2023	2024	2025
Reported MW of Installed Conventional Generation[5]	913,103	926,302	902,018	896,430	876,982
Reported MW of Installed Wind Generation[6]	112,811	124,039	129,963	135,866	138,190
Reported MW of Installed Solar Generation[7]	N/A	N/A	N/A	N/A	N/A
Portion of Hours in the Year with No Operator-Initiated Firm Load Shedding Associated with Energy Emergency Alert Level 3 (EEA 3)	99.2%	99.4%	100%	>99.9%	100%
Category 3 Events (Non-Weather Related)	0	1	0	1	1
Amount of Unserved Energy Associated with EEA 3 (GWh)	1,015.5	96.2	0	0.1	0
Number of Hours with Operator-Initiated Load Shed	71	56.5	0	0.4	0

Major Weather Events

Although 2025 was generally temperate, major weather events continue to be considered the greatest risk to reliability due to the increase in frequency, footprint, and duration; NERC's *ERO Reliability Risk Priorities Report*[8] identified resilience to extreme events, including extreme natural weather events, as one of the five risk groupings that represent evolving risks to reliability. Major weather events in 2025, including severe winter storms, thunderstorms, and tornadoes, were analyzed and collectively found to have had less of an impact on the BPS than in previous years. Of the 23 billion-dollar events highlighted in **Figure**,[9] only three appeared in the **Severity Risk Index** and six in the **Analysis of Transmission System Resilience** section. Although numerous economically impactful events also occurred in Canada in 2025 (**Figure**), none were considered to have had a major impact on the BPS based on data used in the severity risk index (SRI) and transmission system resilience analysis.

[5] MW of installed conventional generation is calculated based on highest net dependable capacity reported in GADS performance for the given year. Only units >20 MW are required to report for GADS. Units that did not complete performance reporting are excluded from this total.

[6] Includes plants with a total installed capacity >75 MW.

[7] During this year's data analysis, NERC identified significant GADS solar data reporting errors and numerous missing plants compared to EIA 860 data. NERC will be coordinating with Regional Entity staff to perform industry outreach and resolve these errors in 2026.

[8] NERC's ERO Reliability Risk Priorities Report

[9] In alignment with evolving priorities, NOAA's National Centers for Environmental Information (NCEI) will no longer be updating the Billion Dollar Weather and Climate Disasters product. Climate Central, a policy-neutral 501(c)(3) nonprofit now generates a similar product.

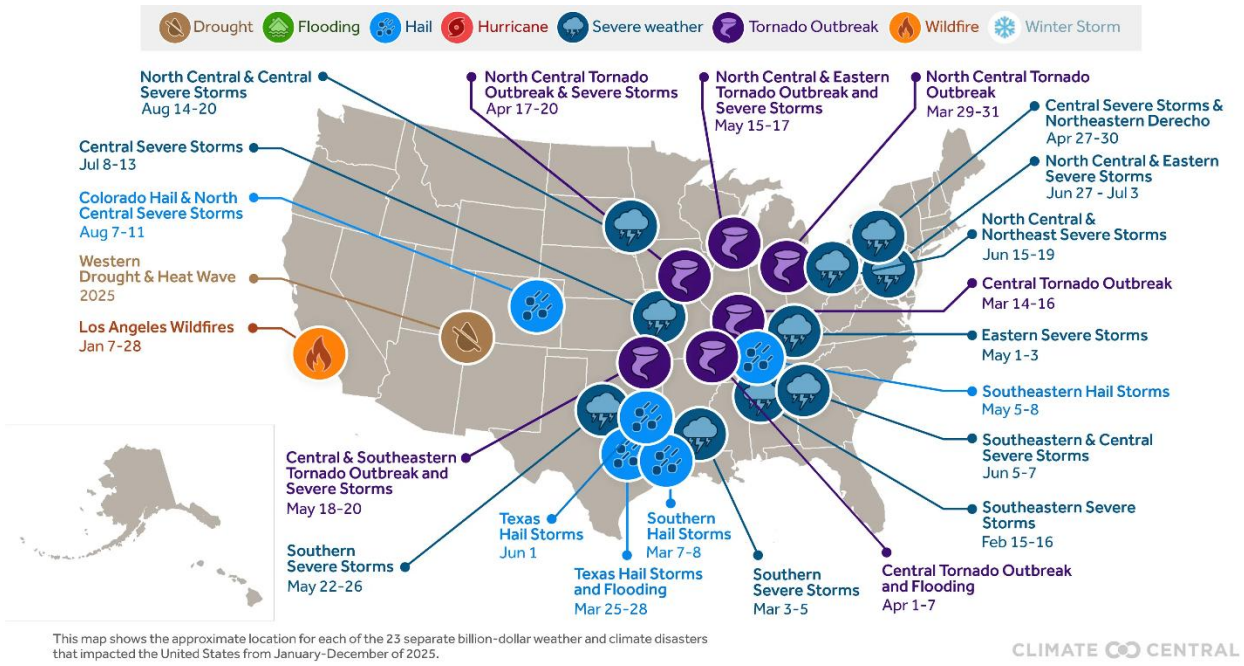


Figure 1.2: 2025 U.S. Billion-Dollar Weather and Climate Disasters[10]



Figure 1.3: 2025 Canadian Insured Catastrophic Losses[11]

[10] The peer-reviewed methodologies behind this dataset remain unchanged at Climate Central, where the project will continue to be led by Adam Smith, who served as the lead scientist for the project at NOAA from 2010 to 2025. U.S. Billion-Dollar Weather and Climate Disasters | Climate Central

[11] Severe weather-related insured losses in Canada exceed $2.4 billion in 2025

Major System Events and Observations

The following sections highlight major system events and observations that occurred last year. While these events were notable and may have impacted many customers, NERC has determined that they do not belong in the SOR Overview as no industry-wide or policy action is being proposed.

Wyoming System Event

As further detailed in the WECC and NERC joint disturbance report,[12] in the early afternoon of November 13, 2025, the northeast portion of the Western Interconnection (WI) experienced a system disturbance that triggered cascading outages affecting about 250,000 customers for up to nine hours. The event impacted parts of several states, including Montana, South Dakota, Wyoming, and Nebraska, with one Transmission Operator (TOP) experiencing a complete blackout across facilities located on the seam between two Reliability Coordinators (RC). This is a low-load, generation-rich portion of the Interconnection.

The disturbance began with a planned outage of a 500 kV transmission line, part of a critical path necessary to deliver wind and thermal generation to distant load centers in the WI. The outage was scheduled for 8:00 a.m. Mountain but postponed until 12:00 p.m. Mountain due to delays in field personnel availability at remote stations. During this delay, wind generation increased more than 50% above the day-ahead operational planning analysis (OPA) studied flows.

A remedial action scheme (RAS) is in place to automatically trip wind generation for unplanned outages to ensure system balance. Prior to switching, the TOP raised the RAS arming setpoint, effectively disabling its tripping function. Operators relied on real-time contingency analysis (RTCA) tools but were unaware of disabled alarms in their RTCA contingency modeling and the inaccurate megavolt-ampere reactive (Mvar) generation parameters that masked the issues that would occur for opening the 500 kV line.

With real-time tools showing no issues, the TOP removed the line from service. Power shifted to an adjacent 500 kV line, causing a rapid voltage collapse to approximately .30 per unit. Protective relays correctly tripped the line within 0.4 seconds, and, with the RAS disabled, there was no action to reduce wind generation.

Most of the western grid remained intact as power flows shifted across the area; however, the system experienced a rapid loss of more than 4,800 MW of coal, natural gas, solar photovoltaic (PV), and wind generation within six seconds. The sudden imbalance caused frequency to dip to 59.758 Hz, after which it gradually recovered and stabilized over the next six minutes. Underfrequency load shedding mechanisms were appropriately triggered in the region before the blackout occurred. Total load loss was just over 1,100 MW.

Coordinated restoration was delayed due to limited RC visibility and competing mitigation priorities. High voltages and seam coordination challenges slowed progress, including instances where equipment was energized across TOP boundaries without prior notification. Most load was restored within nine hours. The entity performing the initial line switching returned most of its generation within eight hours, but one thermal plant required more than four days, and one thermal unit experienced catastrophic damage.

Opportunities for Improvement

Personnel

- Communications during system events should be clear and concise and ensure that mutual understanding has been achieved prior to actions being taken.

[12] WECC and NERC Joint Wyoming Disturbance Report

- System restoration training should be re-evaluated for effectiveness with respect to the RCs and TOPs to improve the effectiveness of restoration, focusing on their system status by thorough assessments, and communication and coordination among the entities.

Processes

- RCs should verify how far to model across seams to provide overlapping visibility of potential contingencies and operating limits.
- Entities should use conservative decision making in verifying any discrepancies between RTCA results.
- RCs/TOPs should evaluate the variability of the generation resources in their OPA and set appropriate max/min parameters within system operating limits (SOL) to prompt additional operator actions.

Tools

- Entities should investigate the use of additional offline tools to confirm/evaluate online tool results.
- To ensure mutual understanding, RCs and TOPs should clearly define the information needed and the means of communication to be used.
- Entities should ensure consistent modeling of system parameters such as RAS status.

Load-Pocket Shoulder Season Challenges

In recent years, shoulder seasons have become increasingly challenging for BPS operators to manage, resulting in several recent instances of pre-contingent load shedding.[13] In all these cases, RTCA indicated that significant issues, such as cascading outages or widespread voltage instability, would likely occur following the next loss of a transmission element.

Shoulder seasons are the spring and fall periods between summer and winter peak load periods and have historically been used for planned maintenance. Because of this common industry practice, fewer generators and transmission lines are available for operators to utilize during these periods, which has historically been offset by the lower peak loads. Spring in particular also coincides with more frequent thunderstorms. In recent years, tightening reserve margins and an increasing baseline load have compounded with a rapid increase in variable energy resources (VER), which present an inherent level of uncertainty, to significantly increase operating challenges during these periods.

Instances where these challenges align in specific small areas within a Balancing Authority's (BA) footprint that have limited transmission lines connecting them to the remainder of the system, also known as load pockets, have been the catalyst of several recent instances of pre-contingent load shedding.[14]

Opportunities for Improvement

As the Interconnections are changing in both resource mix and load characteristics coupled with weather variability during shoulder seasons, a different approach may be needed when coordinating facility outages. Entities should consider the following:

- Planning a higher level of operating margin and committing additional generation in load pockets to account for larger real-time variabilities in generation, load, and weather
- Including demand-side management in the mitigation plans for insufficient capacity in load pockets

[13] *Incident Review: Load-Pocket Shoulder Season Challenges*

- Considering more extreme scenarios when determining which outage requests to approve
- Considering PRC-023 loadability requirements when determining contingent overload thresholds that trigger cascading analysis
- Periodically revisiting planned outages and considering updated and expected system conditions to determine whether such outages should be postponed
- In market areas, reviewing processes to ensure that reliability studies (OPA) are using accurate generation dispatch and availability as determined from the latest day-ahead market analysis (coordinating processes that eliminate discrepancies between the day-ahead market unit commitment plan and the OPA studies)

Chapter 2: Severity Risks, Impact, and Resilience

This chapter identifies and examines the highest-stress days on the BPS in 2025 using established measures.

Severity Risk Index (SRI)

The SRI provides a quantitative measure of the relative severity of the combined impact of load, generation, and transmission loss on the BPS daily and offers a comprehensive picture of the performance of the BPS, allowing NERC to assess year-on-year reliability trends. For 2025, load-loss data voluntarily reported to the IEEE Distribution Reliability Working Group was used to estimate the daily load-loss component; generation and transmission components are calculated from data collected by NERC.

By comparing the daily SRI scores in descending order for each of the past five years, the overall performance of the BPS can be evaluated (**Figure 2.1**). The inset chart in the upper right of **Figure 2.1.** provides a detailed comparison of the top 10 SRI days for each year. The annual cumulative SRI shown in **Table 2.1** sums each day's SRI for the year by component.

The cumulative performance of the BPS is calculated by summing each day's SRI for the year. **Table 2.1** shows the annual cumulative SRI for the five-year period of 2021–2025.

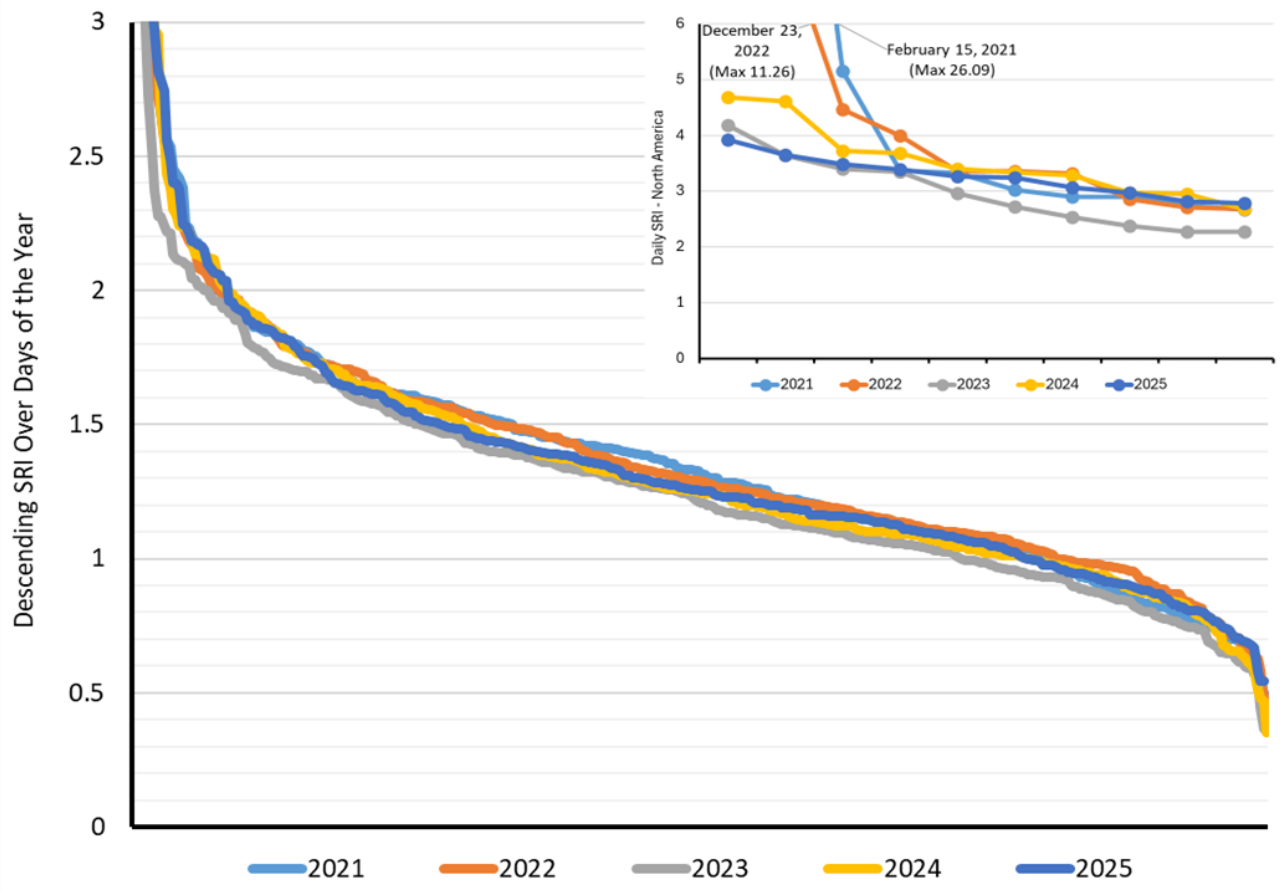


Figure 2.1: NERC Descending SRI by Day of the Year

Table 2.1: Annual Cumulative SRI					
Year	Cumulative Weighted Generation	Cumulative Weighted Transmission	Cumulative Weighted Load Loss	Annual Cumulative SRI	Average Daily SRI
2021	375.9	63.9	96.6	536.4	1.47
2022	404.1	59.7	55.2	518.9	1.42
2023	356.9	64.1	50.5	471.5	1.29
2024	383.7	60.6	51.8	496.1	1.36
2025	395.0	55.7	45.3	496.0	1.36

Figure 2.2 plots the 10 highest SRI days daily and the SRI scores for 2025 against control limits that were calculated by using the seasonal daily performance of the prior four years. A general normal range of performance is represented by the gray-colored band, showing the daily seasonal 90% control limits.[14] Days that extend above the seasonal control limit indicate irregularities for the season but may not have a high enough SRI to rank in the top 10.

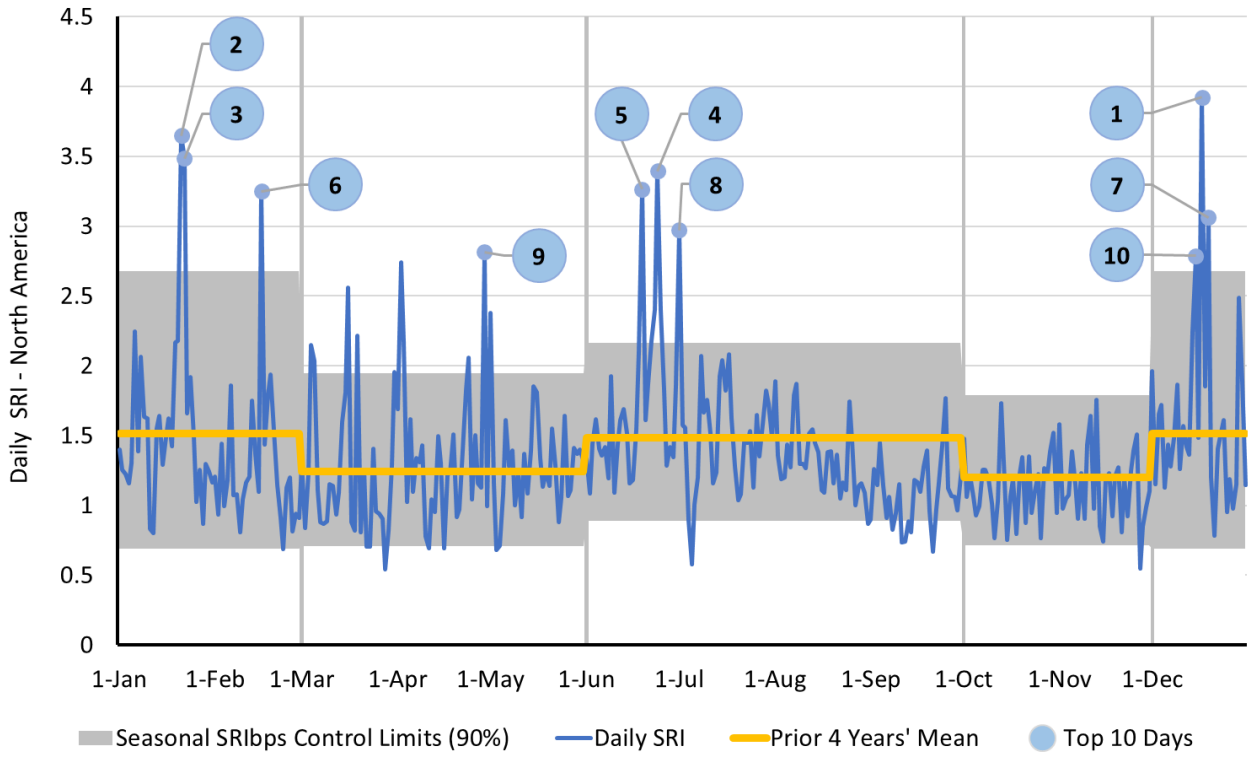


Figure 2.2: 2025 Daily SRI with Top 10 Days Labeled, 90% Confidence Interval

Table 2.2 details the scores for the top 10 SRI days during 2025. The table identifies where atypical weather conditions were ongoing during the day and the general location by Regional Entity. Weather conditions in 2025 were fairly temperate with no hurricanes making landfall and only a few large, major winter storms and thunderstorms. The most impacted day was the result of an atmospheric river, a phenomenon that resulted in high winds and heavy rainfall in the Northwestern United States.

[14] The shaded area reflects the 90% confidence interval (CI) of the historic values between the 5th and 95th percentiles.

Table 2.2: 2025 Top 10 SRI Days							
Rank	Date	SRI and Weighted Components 2025				Atypical Weather Conditions	Regional Entities
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss		
1	17-Dec	3.92	2.34	0.95	0.64	Northwestern Atmospheric River	WECC
2	21-Jan	3.65	3.24	0.32	0.09	Winter Storm Enzo	RF, SERC
3	22-Jan	3.49	3.27	0.14	0.07	Winter Storm Enzo	RF, SERC
4	24-Jun	3.39	2.75	0.24	0.40	Thunderstorms	NPCC, RF, SERC
5	19-Jun	3.27	1.35	0.26	1.65	Thunderstorms, Tornadoes	MRO, RF, SERC
6	16-Feb	3.25	1.91	0.21	1.13	Severe Storm in Southeast	SERC
7	19-Dec	3.06	1.56	0.31	1.19	Northwestern Atmospheric River	WECC
8	1-Jul	2.97	2.75	0.16	0.06	Coincidental Generator Outages	All Regions
9	29-Apr	2.81	1.03	0.28	1.51	Thunderstorms	MRO, NPCC, RF
10	15-Dec	2.79	2.47	0.10	0.22	Winter Storm	RF, SERC, Texas RE

SRI Performance Trends

To put the severity of days in 2025 into context with historic BPS performance, the top 10 days over the five-year period are updated annually. Historically, the PAS has identified days with an SRI below 5 to generally be low impact to the BPS. **Table 2.3** identifies the top 10 SRI days occurring for 2021–2025 with the contribution of the generation, transmission, and load-loss components to the SRI for each day; contributing event information; and the Regional Entities impacted by the event. For 2025, there were no days severe enough to be added to the top 10 SRI days of the past five years, with all days having an SRI under 4, which has historically been considered a very good year.

Table 2.3: 2021–2025 Top 10 SRI Days							
Rank	Date	SRI and Weighted Components				Atypical Weather Conditions	Regional Entities
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss		
1	February 15, 2021	61.35[15]	5.54	0.78	55.02[16]	Winter Storm Uri	MRO, RF, SERC, Texas RE, WECC
2	February 16, 2021	18.31[17]	5.01	0.53	12.78[18]	Winter Storm Uri	MRO, RF, SERC, Texas RE, WECC

[15] IEEE DRWG data supplemented with Eagle-I information.
[16] Ibid.
[17] Ibid.
[18] Ibid.

Table 2.3: 2021–2025 Top 10 SRI Days							
Rank	Date	SRI and Weighted Components				Atypical Weather Conditions	Regional Entities
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss		
3	December 23, 2022	11.25	8.16	0.84	2.26	Winter Storm Elliott	All
4	December 24, 2022	7.44	6.43	0.95	0.05	Winter Storm Elliott	All
5	December 11, 2021	5.16	1.01	0.70	3.45	Severe Storms	MRO, NPCC, RF, SERC, WECC
6	September 27, 2024	4.69	1.44	2.40	0.85	Hurricane Helene	SERC
7	January 9, 2024	4.61	1.59	0.68	2.35	Northwestern Winter Storm, Eastern Tornadoes and Severe Storms	RF, SERC, Texas RE, WECC
8	June 14, 2022	4.46	1.52	0.38	2.57	High Temperatures and Derecho	MRO, NPCC, RF, SERC, Texas RE
9	April 1, 2023	4.19	1.10	0.44	2.65	Hurricane Florence	MRO, NPCC, RF, SERC
10	June 15, 2022	3.99	1.59	0.19	2.21	High Temperatures and Derecho	MRO, NPCC, RF, SERC, Texas RE

Impact of Extreme Event Days

Extreme Event Days

Extreme event days are identified as event days above the 95th percentile upper bound relative to the past four years' severity measures for any season within North America or a specified Interconnection. This analysis expands on the transmission and generation components that contribute to the SRI reported in the previous **SRI Performance Trends** section to explore the causes of the extreme days.

The impacts of extreme days on BPS resources are characterized by the amount of transmission or generation reporting immediate forced outages or derates starting on a given day. By analyzing the impact and causes of extreme event days, it is possible to identify which conditions pose the highest risk to the BPS. While this analysis does not address every potential scenario, learning from performance during extreme events helps provide insight into how the system may respond to a range of conditions and events.

- Extreme-day outages for transmission and generation by Interconnection are presented in **0**. The analysis provided in the following subsections is reported separately for transmission and generation. The total estimated megavolt-amperes (MVA) transfer capacity[19] reported in TADS or

[19] Severity Risk Index

net maximum capacity reported to GADS for all Regional Entities or by Interconnection is shown at the top of each figure in this chapter.

Transmission Impacted

In 2025, 12 days met the criteria of extreme transmission days for the BPS as compared to 19 in 2024. The most extreme transmission-impacting day was December 17, primarily due to a combination of storms throughout the Northwestern United States as part of an atmospheric river phenomenon, affecting a total of 16 states (**Figure 2.3**), where the MVA capacity impacted due to automatic transmission outages was 5.8 times as high as the associated season's average. Other extreme days include March 14–15 due to a widespread winter storm, March 9 due to a series of severe thunderstorms, and the November 13 **Wyoming System Event**.

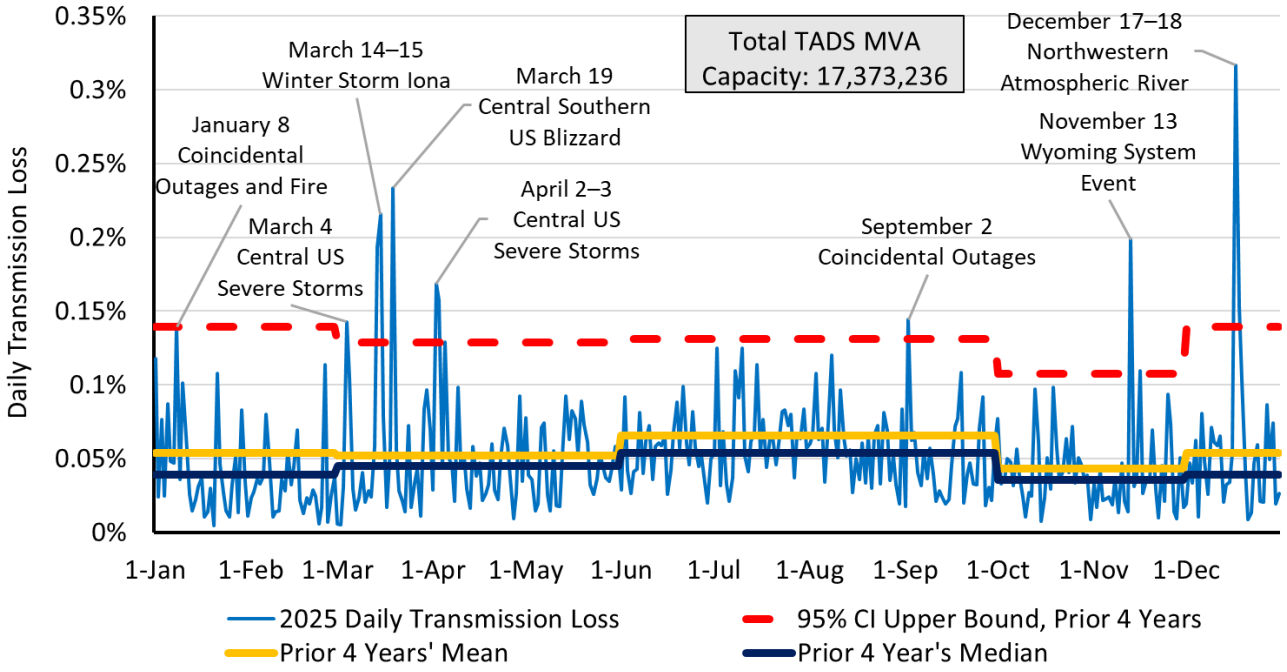


Figure 2.3: 2025 Sustained Transmission Outages During Extreme Days

The top causes reported for outages that occurred on extreme days are shown in rank order of MVA loss for North America and each Interconnection (**Table 2.4**). Causes for outages are based on those Interconnections' extreme days, shown in **Appendix A**. The number one outage cause for 2025 was Weather (Excluding Lightning), which affected almost five times more MVA capacity than any of the other top causes for the year across the Bulk Electric System (BES) and within each Interconnection.

Table 2.4: Top Transmission Initiating Outage Causes on Extreme Days Ranked by MVA Capacity					
Area	**Cause #1**	**Cause #2**	**Cause #3**	**Cause #4**	**Cause #5**
All NERC Regional Entities	Weather (Excluding Lightning) 156,789	Failed AC Substation Equipment 31,586	Unknown 31,515	Power System Condition 28,585	Contamination 23,963
Eastern–Québec Interconnections	Weather (Excluding Lightning) 142,446	Failed AC Substation Equipment 35,696	Lightning 24,057	Human Error 19,268	Failed AC Circuit Equipment 15,094
Texas Interconnection	Weather (Excluding Lightning) 18,052	Failed AC Substation Equipment 10,536	Lightning 6,993	Power System Condition 4,911	Unknown 4,315
Western Interconnection	Weather (Excluding Lightning) 49,701	Unknown 39,187	Fire 37,074	Power System Condition 30,008	Other 20,165

Conventional Generation Impacted

Based on analysis of GADS data, a total of 20 days in 2025 qualified as extreme for North America's BPS (**Figure 2.4**) compared to 26 in 2024. The four highest-impact days for generation loss were the January 19–22 winter storms. On these days, conventional generating units experienced outages that were 1.8–2.9 times as severe as the associated season's average. One of the extreme generation loss days coincided with extreme days identified for transmission (December 17 Atmospheric River Event). The days on which generation outages were slightly above the seasonal bounds that do not have a specific cause listed have been investigated and were either found to coincide with severe thunderstorms or high temperatures or saw many coincidental outages that were not a result of adverse weather conditions.

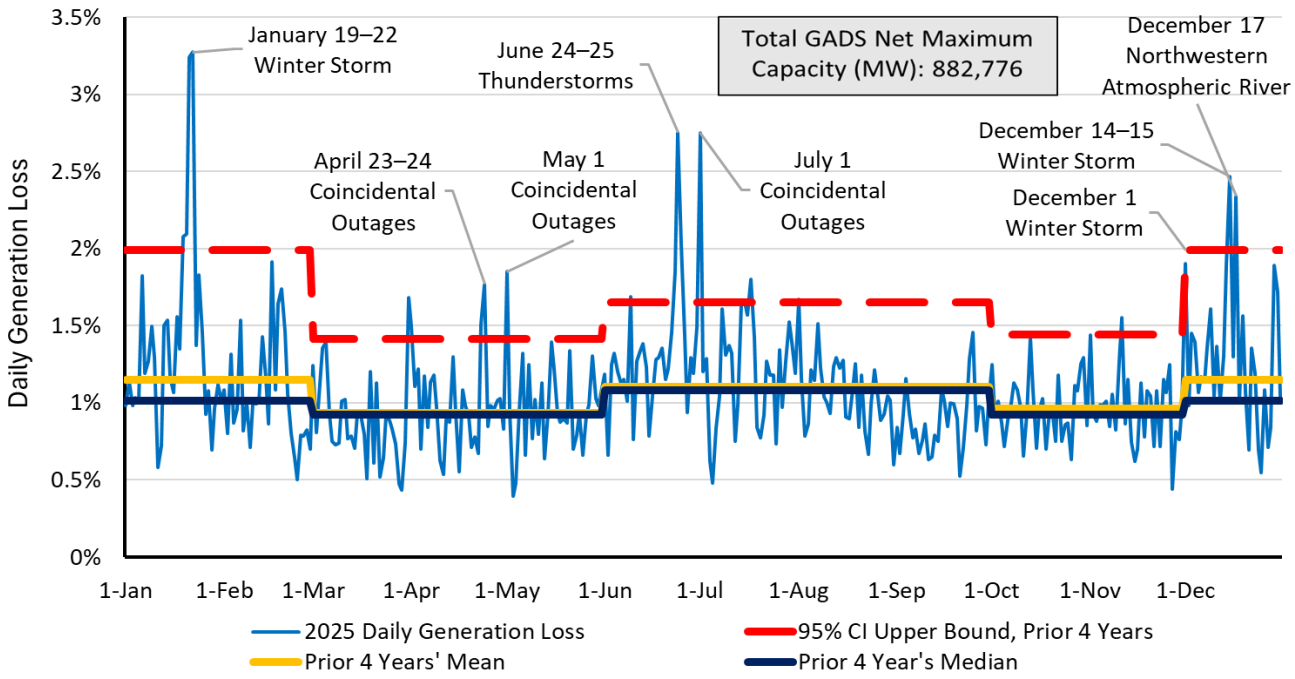


Figure 2.4: 2025 Generation Impacted During Extreme Days

The top causes reported for outages that occurred on extreme days are shown in ranked order by Interconnection (**Table 2.5**). Causes for Interconnections are based on those Interconnections' extreme days, shown in **Appendix A.**

Table 2.5: Top Generation Outage Causes on Extreme Days Ranked by Unavailable Net Maximum Capacity

Area	Cause #1	Cause #2	Cause #3	Cause #4	Cause #5
All NERC Regional Entities	Fuel, Ignition, and Combustion Systems (32,263)	Electrical (25,877)	Boiler Tube Leaks (21,524)	Controls (20,850)	Auxiliary Systems (20,596)
Eastern–Québec Interconnections	Fuel, Ignition, and Combustion Systems (29,278)	Electrical (22,638)	Boiler Tube Leaks (19,109)	Auxiliary Systems (17,338)	Miscellaneous (Gas Turbine) (14,908)
Texas Interconnection	Electrical (11,433)	Controls (9,391)	Boiler Control System (9,094)	Boiler Tube Leaks (7,432)	Feedwater System (5,504)
Western Interconnection	Controls (6,951)	Electrical (6,565)	Auxiliary Systems (5,941)	Turbine (5,740)	Miscellaneous (External) (5,529)

Analysis of Transmission System Resilience

The analysis of large transmission events evaluates transmission outages related to severe weather events that involve 20 or more automatic outages. Outage and restoration processes for transmission elements are analyzed, not the disruption and restoration of distribution customer load. Restoration of the transmission system to serve customer load is always the priority.

The analysis of the 2025 transmission outages identified 13 large transmission events, 12 of which were caused by weather and one non-weather event (**Wyoming System Event**) and quantified the resilience and restoration statistics for them. The resilience statistics enable the measurement and tracking of some abilities of the transmission system to withstand, adapt, protect against, and recover during and after major weather events.[20]

This section provides a detailed description of the December 17 Atmospheric River Event as the largest outage event on the transmission system in 2025. Multiyear statistics by associated weather type and changes in the severity and duration of these events as measured by the number of transmission outages reported for each cause are compared for two five-year periods: 2020–2024 and 2021–2025.

TADS Outage Grouping and 2025 Large Weather Events

The outage grouping algorithm[21] considers automatic outages reported in TADS based on Interconnection and associated start and end times. The resulting transmission outage events are determined to be weather-related if at least one outage in the event is initiated or sustained by one of the following TADS cause codes: Weather (Excluding Lighting), Lightning, Fire, or Environmental. The procedure produces groupings of outages that are further reviewed and compared with the weather information from external sources to confirm or refine the events. The TADS data was supplemented by Velocity Suite as a source to identify utility company footprints, and weather sources like the National Oceanic and Atmospheric Administration (NOAA) and Ventusky were used to visualize the weather events. Matching the data from these sources provides a much clearer picture of outages within the event. This combination of automatic and manual procedures results in a set of transmission events that can cross boundaries of different utilities and Regional Entities to capture significant events caused by major weather occurrences, such as hurricanes and severe winter storms.

In 2025, the grouping algorithm identified 13 large events; 12 of the 13 were weather-related events, in addition to the **Wyoming System Event** that started on November 13. **Table 2.6** lists these events in chronological order and shows the severe weather/event type for each event with statistics that quantify the impact of the event on the transmission system.

In 2025, the largest event was the December 17 Atmospheric River in the WI with 137 outages, affecting 5,343 miles and 48,418 MVA of capacity, making it the highest-impact storm of the year on the transmission system (shown in **blue** in **Table 2.6)**.

The second largest event, as identified by the grouping algorithm, was the March 14 severe storm event, which saw everything from blizzards in the north to tornadoes in the south (with 124 transmission outages reported) and occurred in the EI (shown in **red** in **Table 2.6**). Though it was the second largest event in terms of the number of outages, it had the largest amount of transmission capacity affected (MVA) and the highest number of element-days lost of any event in 2025 with 52,678 MVA affected and 359 element-days lost.

[20] *Resilience Framework, Methods, and Metrics for the Electricity Sector* | IEEE Power & Energy Society Resource Center (ieee-pes.org)

[21] *Impact of Extreme Weather on North American Transmission System Outages* | IEEE Conference Publication | IEEE Xplore

It is also worth noting that the **Wyoming System Event**, though not weather-related, had enough outages to be considered a large transmission event. This event (shown in **purple** in **Table 2.6**) had the quickest recovery of all large transmission events in 2025, with a time to 95% element restoration of just 0.1 days and a final restoration duration of 1 day.

Table 2.6: 2025 Large Transmission Outage Events

Event Start	Event Outage Count			Interconnection	Extreme/Severe Weather Event	Transmission Capacity Affected (MVA)	Miles Affected	Final Restoration Duration (Days)	Time to 95% Restoration, Elements (Days)	Element-Days[22] Lost	Most Simultaneous Unavailable Capacity (MVA)
	All Automatic	Sustained Automatic	Momentary Auto.								
21-Jan	22	19	3	ERCOT	Blizzard	11,714	581	.8	.6	5	5,899
16-Feb	31	23	8	Eastern	Thunderstorms	13,391	1,023	2.9	1.8	13	5,855
25-Feb	29	24	5	Western	Winter Storm	13,931	940	6.1	6.	30	5,541
4-Mar	31	23	8	Eastern	Blizzard	8,745	867	3.3	2.9	18	4,934
14-Mar	**124**	**104**	**20**	**Eastern**	**Tornadoes, Blizzard**	**52,678**	**4,510**	**54.2**	**12.3**	**359**	**27,011**
19-Mar	79	70	9	Eastern	Tornadoes, Blizzard	30,617	1,899	13.5	7.5	92	18,915
24-Mar	28	15	13	Eastern	Blizzard	9,487	507	44.5	3.7	52	4,741
2-Apr	39	29	10	Eastern	Thunderstorms Tornadoes	15,361	1,550	58.1	9.2	96	7,424
5-Apr	35	32	3	Eastern	Thunderstorms	11,545	1,332	6.5	4.9	37	5,835
29-Apr	51	47	4	Eastern	Thunderstorms	16,352	1,056	5.5	4.4	53	8,567
21-Jun	22	17	5	Eastern	Derecho	7,948	2,098	68.7	17.7	118	6,429
13-Nov	**46**	**46**	**0**	**Western**	**Wyoming System Event**	**25,357**	**1,924**	**1.0**	**0.1**	**2**	**12,320**
17-Dec	**137**	**129**	**8**	**Western**	**Northwestern Atmospheric River**	**48,418**	**5,343**	**36.7**	**6.1**	**235**	**27,190**

[22]The definition for element-days is provided in Appendix B of the NERC *2022 SOR*.

Outage, Restore, and Performance Curves

Table 2.6 illustrates the variability in event sizes and duration. However, these statistics do not completely explain what happened during the events; the outage, restore, and performance curves of the events provide more details on how the events unfolded.[23] **Figure 2.5** serves as an example to describe transmission outages during an event. These curves track the number of elements out or the MVA transmission capacity impact on the vertical axis versus time on the horizontal axis.

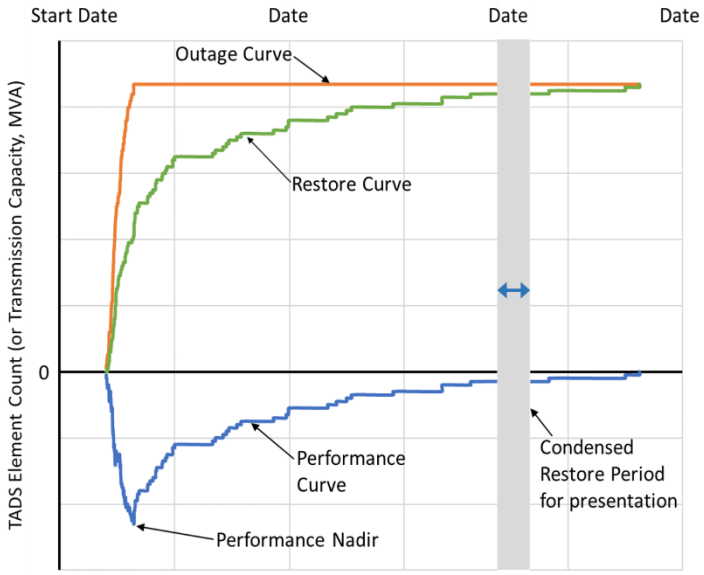


Figure 2.5: Example of Outage, Restore, and Performance Curves for a Large Transmission Outage Event

The outage curve is the cumulative number of elements or cumulative equivalent MVA capacity impact at the time shown on the horizontal axis.

The restore curve is the cumulative number of elements restored or cumulative equivalent MVA restored at the time shown on the horizontal axis.

The performance curve is the number of elements or equivalent MVA capacity impact out simultaneously at the time shown on the horizontal axis. The value is equal to elements or MVA capacity restored minus the elements or MVA capacity (i.e., the performance curve is the restore curve minus the outage curve). The performance curve combines information on degradation and recovery during the event.

The curves enable the calculation of several resilience metrics.[24] These metrics help quantify the abilities of a resilient power system to effectively absorb, withstand, adapt, protect against major weather events (event size, outage process duration and outage rate, time to first restore, the most degraded state in the event, the total element-days and MVA capacity days lost), and recover from and reduce the durations and impacts of major weather events (i.e., event duration, time to first restore, time to substantial restoration, instantaneous restore rate).

[23] S. Ekisheva, I. Dobson, R. Rieder, and J. Norris, "Assessing transmission resilience during extreme weather with outage and restore processes," 2022 17th International Conference on Probabilistic Methods Applied to Power Systems

[24] Resilience statistics are defined in Appendix B in the *2022 SOR*.

Resilience Curves and Statistics for the WI Atmospheric River, the Largest Transmission Outage Event in 2025

The atmospheric river that made landfall along the U.S. Pacific Northwest coastline on December 17, 2025, brought heavy snow and rain as well as high winds in the area before moving into British Columbia and the northern Midwestern United States. At the storm's peak, there were about 950,000 customer outages across British Columbia, Washington, Oregon, Colorado, and Montana.[25]

The atmospheric river also caused a large transmission outage event in the WI that impacted 18 Transmission Owners. With 137 automatic outages, this event was the largest transmission event in 2025 but less impactful than top historic hurricane events, such as the 2024 Hurricane Helene (431 outages) and the 2017 Hurricane Irma (352 outages).

Out of the 137 automatic outages caused by extreme weather, 133 were ac circuit outages (8 momentary and 125 sustained), two were transformer outages (both sustained), and two were ac/dc back-to-back converter outages (both sustained). The total affected mileage was 5,343 ac circuit-miles, and the total transmission capacity affected was 48,418 MVA. The reported event duration was 36.7 days, with a single 230 kV ac circuit outage continuing until January 22, 2026. The element- and MVA-based curves for the atmospheric river event are shown in **Figure 2.6** and **Figure 2.7**, respectively. The curves are truncated at 01/01/2026 0:00 UTC with one ac circuit outage still unrestored.

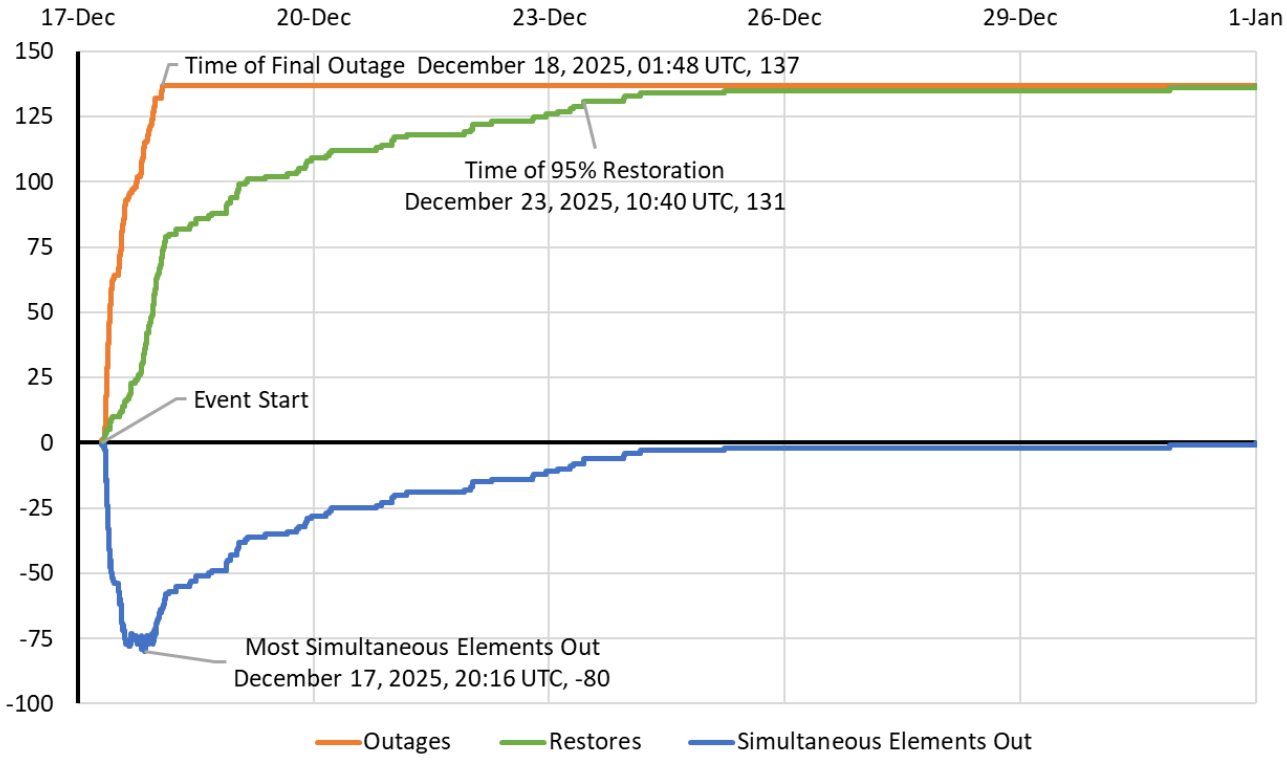


Figure 2.6: Transmission Element Outage, Restore, and Performance Curves for Atmospheric River Event in the Western Interconnection, December 17, 2025–January 22, 2026

[25] Customer outage data sourced from Eagle-I.

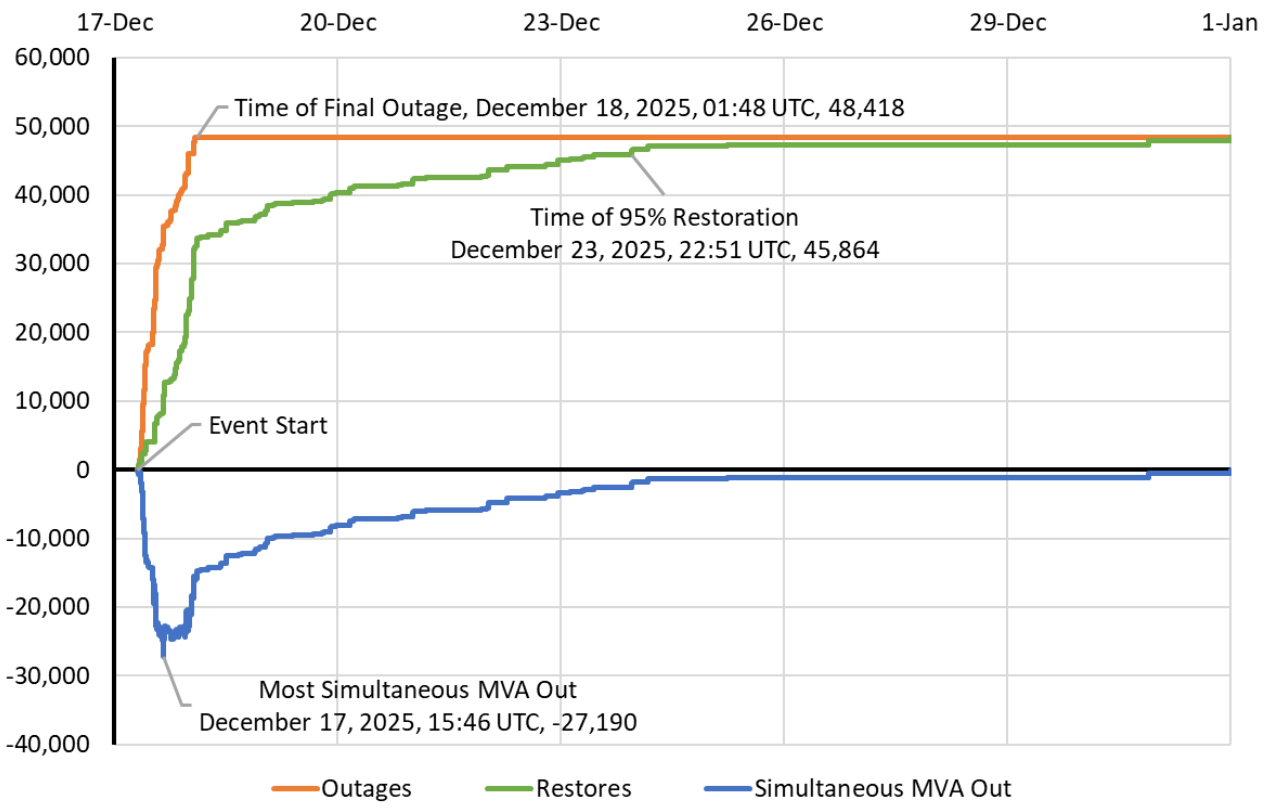


Figure 2.7: Transmission Capacity (MVA-Based) Outage, Restore, and Performance Curves for Atmospheric River Event in the Western Interconnection, December 17, 2025–January 22, 2026

The outage process shown in **Figure 2.6** and **Figure 2.7** by **orange** curves started as a cluster of quickly accumulating outages and continued for 18 hours with an average outage rate of 7.4 outages per hour (2,631 MVA per hour). Due to multiple outages of the same ac circuit, a total of 137 outages occurred on 123 distinct ac circuits.

The restoration process shown in **Figure 2.6** and **Figure 2.7** by **green** curves started with a momentary restoration 28 minutes after the first outage began, with the first sustained outage restoration 50 minutes after the event started. As is typical for large events, the restoration process progressed rapidly;[26] however, restoration times slowed with a larger percentage of equipment still out than usual. By applying a fitted curve for the restore process[27] to **Figure 2.6** it can be estimated that the maximum instantaneous restore rate of 4.3 restores per hour was reached 4 hours and 16 minutes into the event. The restoration rate was 2.4 elements per hour at the time half of the outages were restored (about 19 hours into the event), and only 0.1 elements per hour at the 95% element restoration level. The maximum number of transmission elements simultaneously out was 80 and was observed twice: a momentary nadir occurred about 13 hours after the event started, followed by another 13 minutes later, which lasted 2 minutes. The maximum amount of transmission capacity simultaneously out (27,190 MVA), represented by the nadir of the MVA-based performance curve in **Figure 2.7**, was observed only once and more than 4 hours earlier than the element-based nadirs. It occurred when a 500 kV ac circuit went out and ended 4 minutes later, when a different 500 kV ac circuit was restored. When the 80 elements were out simultaneously for the element-based nadirs,

[26] S. Ekisheva, I. Dobson, R. Rieder, and J. Norris, "Assessing transmission resilience during extreme weather with outage and restore processes," 2022 17th International Conference on Probabilistic Methods Applied to Power Systems.
[27] S. Ekisheva, D. K. Pratt, M. Kachadurian, W. G. Martin, J. Norris, and I. Dobson, "Grid Restoration after Extreme Weather Events", 2023 IEEE PES Innovative Smart Grid Technologies Europe (ISGT) Conference.

the total value of transmission capacity unavailable was about 24,000 MVA—notably lower than the MVA out at the MVA-based nadir.

A substantial 95% restoration was reached after 147 hours (17% of the event duration). The substantial 95% restoration for transmission capacity (MVA) took longer, 159 hours or 18% of the event duration. The total loss for the event, calculated as the area between a **blue** performance curve and the time axis, was 235 element-days lost (**Figure 2.6**) and 77,097 MVA-days lost (**Figure 2.7**).

The longest outage was 36.6 days on a 230 kV ac circuit that sustained tower damage. A small number of disproportionately long outages is common in large transmission events. These very large outage durations are often caused by inaccessibility of a portion of the line, damaged structure or equipment or, in some cases, a utility postponing the restoration of a single remaining element because this element is considered not critical for reliability of the grid.[28]

Transmission System Resilience Statistics by Associated Weather Type: 2021–2025

Weather Types

The outage grouping procedure identified 59 large transmission events in the years 2021–2025, two of which were not weather-related (a 2023 contamination event and a 2025 frequency event).[29,30] The 57 large weather-related events were caused by the weather types listed in **Figure 2.8**. If several weather factors were observed together (e.g., hurricane, tornado, and wind), the dominant cause of transmission outages was determined to be the weather type. Multiple sources (i.e., NERC's daily BPS awareness reports, Velocity Suite, NOAA, Ventusky, public media reports) were used in conjunction with cause codes to determine if a weather event was associated with each large transmission event.

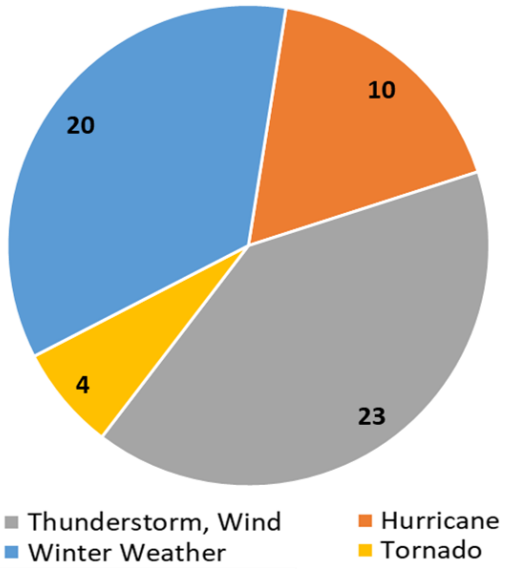


Figure 2.8: Weather Types of Large Transmission Events, 2021–2025

[28] S. Ekisheva, I. Dobson, R. Rieder, and J. Norris, "Assessing transmission resilience during extreme weather with outage and restore processes," 2022 17th International Conference on Probabilistic Methods Applied to Power Systems.
[29] A 2023 large event in SERC with 30 outages caused by Bird Contamination; the event duration was 2.5 days.
[30] A 2025 large event in WECC with 46 outages caused by Power System Condition; the event duration was a day.

Figure 2.9 shows selected resilience statistics for the 2021–2025 events by weather type. Hurricanes caused the largest transmission events, with the average one having 123 outages, while other groups had average outage counts that ranged from 43–64 outages. The maximum number of elements simultaneously out (the most degraded state in an event as indicated by the nadir of the performance curve) fell between 51–67% of the event size on average.

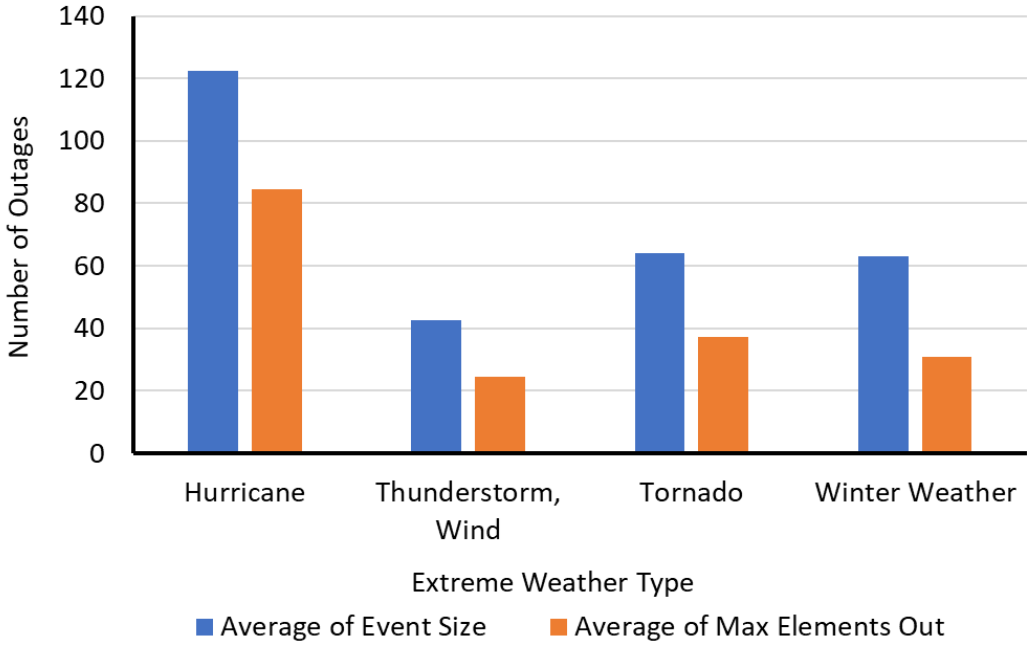


Figure 2.9: Resilience Statistics for 2021–2025 Large Weather-Related Events

Figure 2.10 compares the average event duration with the average substantial restoration duration (the time to restore 95% of outages and 95% of MVA capacity) and shows the time to first restore.

Hurricanes were the highest in average event duration, second for 95% outage restoration duration, and lowest for 95% MVA restoration duration. Tornadoes were the second highest in event duration with the highest average 95% restoration duration for both outages and MVA capacity. While some value can be extracted from evaluating the average event duration, the time to 95% restoration is typically more indicative of overall performance.[31]

[31] *How Long is a Resilience Event in a Transmission System?: Metrics and Models Driven by Utility Data* | IEEE Journals & Magazine | IEEE Xplore

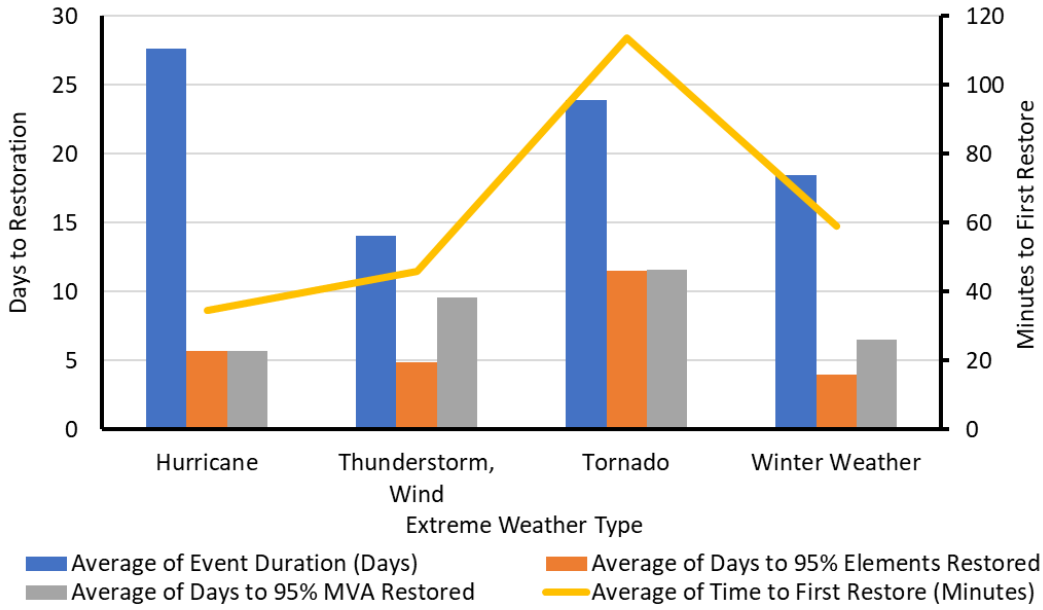


Figure 2.10: Average Event Duration vs. Average Sustained Restoration Duration

Changes in Resilience Statistics: 2021–2025 Events vs. 2020–2024 Events

To draw conclusions about improving, stable, or declining transmission resilience against weather, the analysis focuses on capturing changes in the several metrics that quantify resilience over years. The resilience statistics are calculated for large weather-related events for the years 2020–2024 and 2021–2025, and changes in the metrics by weather types were analyzed. The five-year period is selected due to the small annual number of events in some groups.

The bubble chart in **Figure 2.11** shows the groups of large weather-related transmission events by weather type; the five patterned bubbles correspond to the groups for combined 2020–2024 data, and the five solid-colored bubbles show the same groups for combined 2021–2025 data. The size of a bubble represents the average time (in days) to restore 95% of outages for the events in this group (displayed in the center of each bubble). The X-axis of a bubble shows the number of events, and the Y-axis shows the average event size. The bubble color indicates the average MVA-day loss for each group: Below 30,000 MVA-days is shown in **blue**, between 30,000 and 100,000 MVA-days is shown in **yellow**, and above 100,000 MVA-days is shown in **red**.

Change in size or position of a bubble for the same weather type in **Figure 2.11** indicates changes in the impact of that weather resulting from a combination of the weather frequency and severity and improved or declined resilience performance. There was a decrease in the number of events in all categories except for winter weather as reflected by the bubble position change along the X-axis in **Figure 2.11**.

Comparing 2020–2024 vs. 2021–2025, the number of Hurricane; Tornado; and Thunderstorm, Wind events decreased while Winter Weather increased. No weather type changed category for MVA-days lost as reflected by the color of the bubbles (shaded for previous range and solid for new). A comparison of the values for the average number of days to 95% element restoration between the year ranges indicates that the average increased by about one day. Tornado is an exception, which increased by 4.2 days because of some smaller tornadoes dropping out of the year range. Most categories had a similar average event size, except for Hurricanes. This decrease was because 2020, which is outside the most recent five-year window, had record-setting hurricanes and no hurricanes made landfall in 2025.

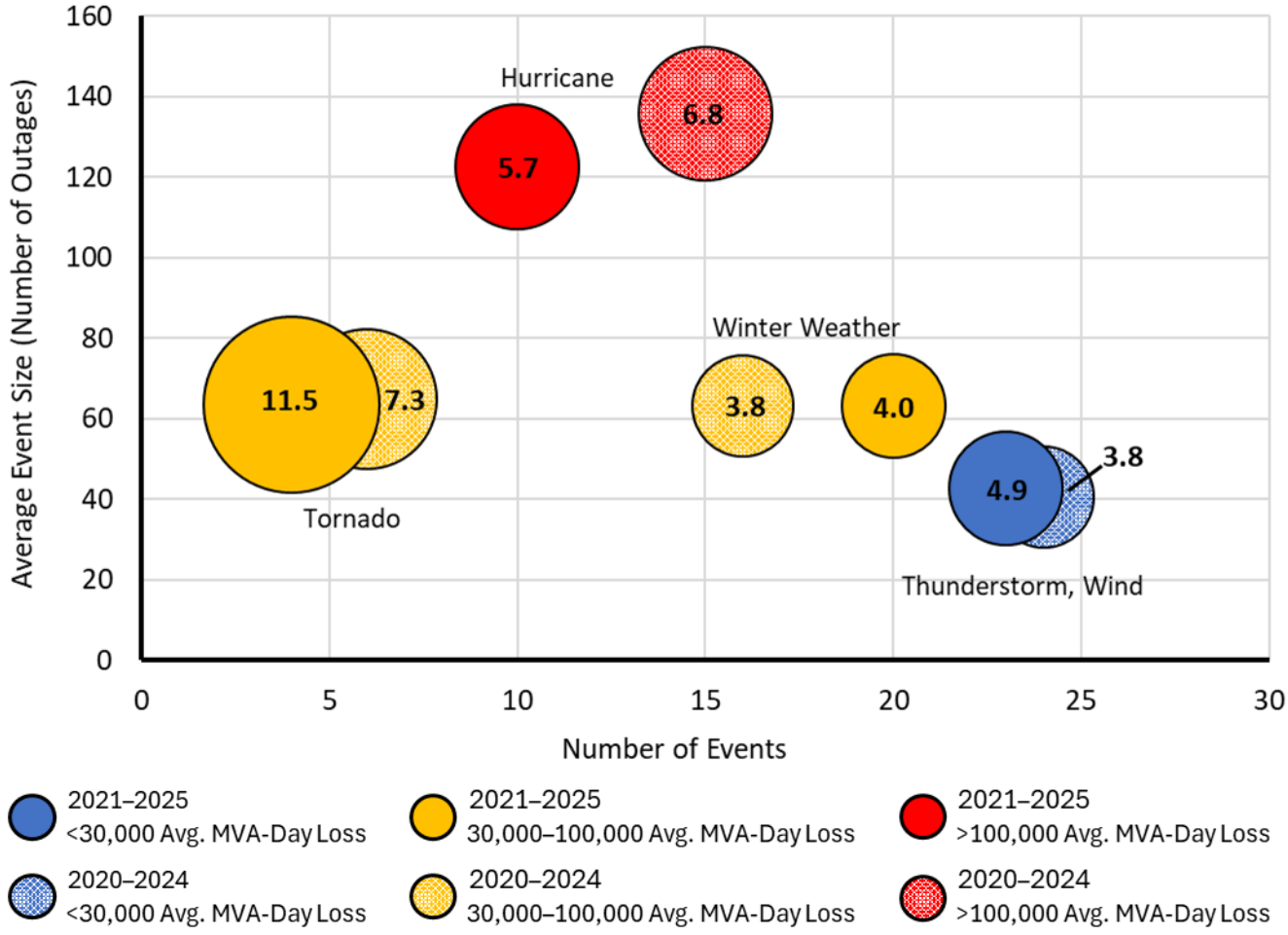


Figure 2.11: Statistics for Large Transmission Events by Weather Type for 2020–2024 vs. 2021–2025

Chapter 3: Grid Transformation

Resource Adequacy

Highlights

- In comparison to five years prior, 2025 saw tightening reserve margins across most notably Manitoba, New England and PJM with MISO, SaskPower and especially ERCOT seeing improvements in the level of anticipated reserve margins heading into last year's peak season.
- In 2025, anticipated resources exceeded Reference Margin Levels (RML) across all assessment areas.
- Improved performance of the thermal generation fleet and delivery of natural gas supplies to generators during arctic events of Winter 2024–2025 compared to prior extreme cold events.
- As of the 2025 LTRA, solar photovoltaic (PV) is no longer the sole, predominant generation type planned over the next 10 years as new battery resource projects have grown to match solar projections.

2025 Planning Reserve Margins

Planning Reserve Margins are a long-term resource adequacy indicator. Anticipated Reserve Margin (ARM) expresses the level of additional resource capacity that an area has above its peak summer (June–September) and winter (December–February) seasonal demand. It is calculated as the difference in anticipated resources and net internal demand divided by net internal demand and shown as a percentage. Each assessment area's ARM is compared against its RML—the threshold margin established by the state, provincial authority, Independent System Operator/Regional Transmission Organization (ISO/RTO), or other regulatory body to provide the level of resources needed to meet reliability criteria (e.g., maintain loss-of-load expectation below 1-day-in-10 years).

Figure 3.1 shows the ARM percent difference from the area-specific RML as calculated using data from the 2021 and 2025 seasonal assessments for each area's peak season. In 2025, all assessment areas except for NPCC-Maritimes had ARMs in excess of the area RML. Assessment areas with improved reserve margins relative to 2021 include MISO, SaskPower, New York, Québec, the eastern and southeastern SERC regions, British Columbia, and—most notably—ERCOT. A realignment of the WECC United States assessment areas in 2025 precludes comparison with 2021 values.[32]

The notable improvement in ERCOT is attributable to a 29% (7,010 MW) increase in solar capacity, continuing a trend of robust solar penetration, and a 94% (7,414 MW) increase in energy storage installed capacity. The large increase in available capacity reflects (1) new rules for managing state of charge (SoC), including a requirement to maintain a certain SoC to participate in ancillary services, (2) installation of systems with longer durations, and (3) improvements in battery operational practices.

The five-year comparisons also reveal tighter reserve margins across Manitoba, Ontario, SPP, Florida, and SERC-Central relative to 2021. In addition to having the most precipitous drops in reserve levels relative to 2021, NPCC-Maritimes, NPCC-New England, and PJM, where generator retirements and significant load growth continue to present challenges, also display discernible year-over-year trends of tightening reserve levels across the 2021–2025 period.

[32] 2025 Western Assessment, 2025–2026 Winter Reliability Assessment Western Overview

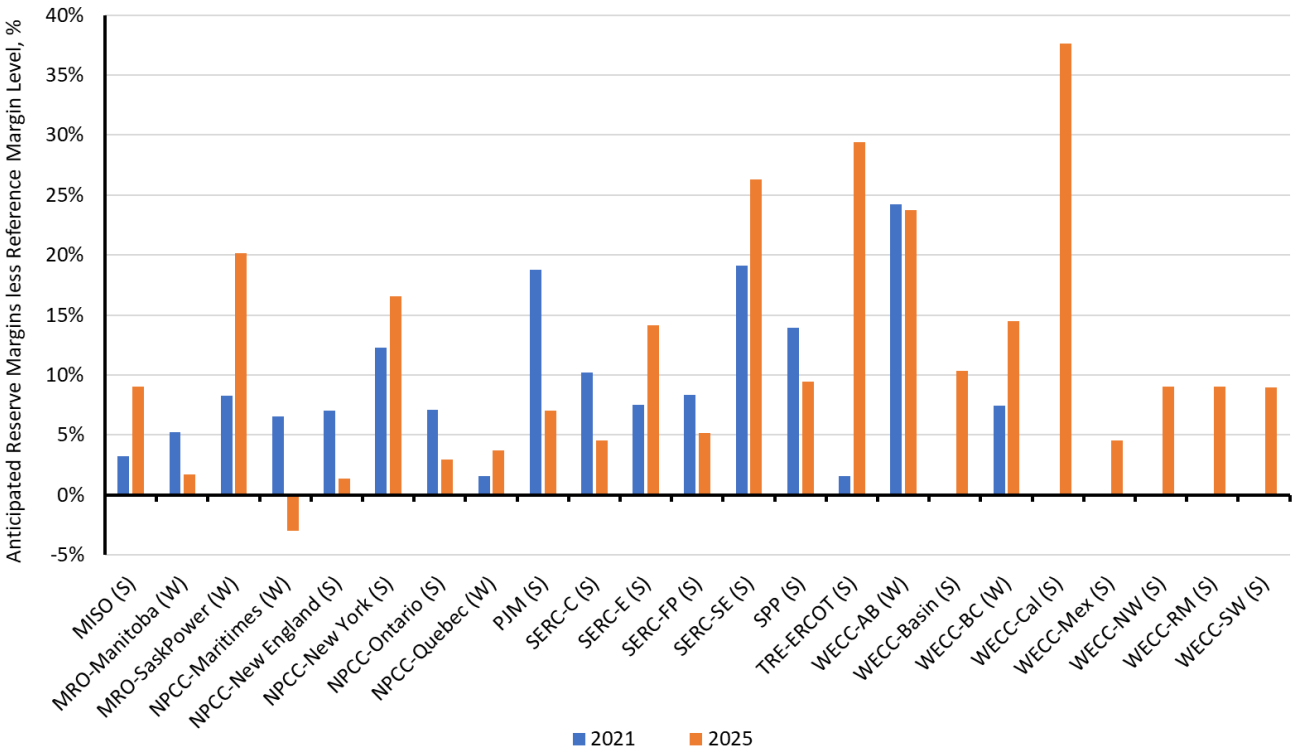


Figure 3.1: 2021 and 2025 Peak Season Planning Reserve Margins Less Reference Margin Levels[33]

Energy Emergency Alerts (EEA)[34]

The purpose of an EEA is to provide a real-time indication of potential and actual energy emergencies within an Interconnection. An EEA 3 is reported when firm load interruption is imminent or in progress. EEA trends may provide an indication of BPS capacity, energy, and transmission insufficiency.

Figure 3.2 shows that 10 EEA 3s were declared in 2025, a reduction of 11 EEA 3 declarations over 2024. None of the EEA 3 declarations in 2025 included load shed, versus 0.108 GWh of firm load shed in 2024.

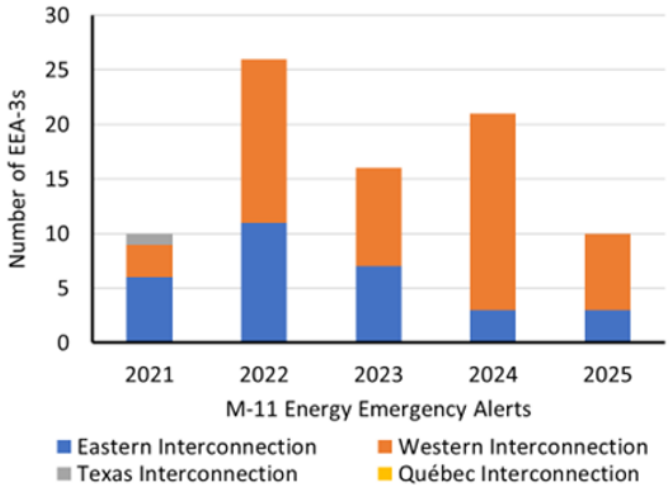


Figure 3.2: EEA 3 by Year and Interconnection

[33] M-1, Reserve Margin displayed as the difference between ARM and area's RML.
[34] M-11, Energy Emergency Alerts

All 10 of the EEA declarations in 2025 were associated with periods of reduced generation or import capability combined with heavy load days. Seven EEA 3s were associated with two non-U.S. entities, both of which have weak connections to their neighbors. Of these seven, six are associated with a balancing area that has processes requiring the declaration of an EEA 3 prior to requesting assistance from neighbors. **Table 3.1** shows the number of hours when operator-initiated firm load shed was deployed during each of the past five years.

Table 3.1: Hours with Operator-Initiated Firm Load Shed (Hours/Year)

Year	Event	Event Hours	Total Annual Hours
2021	Winter Storm Uri	70.5	70.5
2022	June Heatwave	21.0	56.5
	Winter Storm Elliot	35.5	
2023	N/A	0.0	0.0
2024	WI: Generator Trip, Subsequent Failure of Dispatched Units	0.43	0.43
2025	N/A	0.0	0.0

2025 Seasonal Energy and Capacity Risk Analysis

The ERO assesses the risk of electricity supply shortfall in seasonal reliability assessments by considering Planning Reserve Margins, seasonal risk scenarios, and probability-based risk assessments. The expected impact of generator outages and extreme operating conditions on electricity supply and demand are also considered in NERC's seasonal reliability assessments. NERC evaluates the availability of supplies to meet normal seasonal peak demand as well as higher demand that may occur only once per decade, referred to as an extreme or 90/10 demand scenario. In the case of Texas RE-ERCOT and WECC CA/MX in the summer, the highest risk hour period is analyzed. The highest risk hour typically occurs after the peak demand hour when the sun has set, and solar PV resources are not contributing. Increased demand, which can be caused by extreme temperatures, higher-than-anticipated generator forced outages, and derates, can create conditions that lead system operators to take emergency operating actions. The maps in **Figure 3.3** and **Figure 3.4** highlight the assessment areas that NERC identified ahead of the Winter 2024–2025[35] and Summer 2025[36] seasons as at risk for resource deficiencies.

[35] NERC 2024-2025 Winter Reliability Assessment
[36] NERC 2025 Summer Reliability Assessment

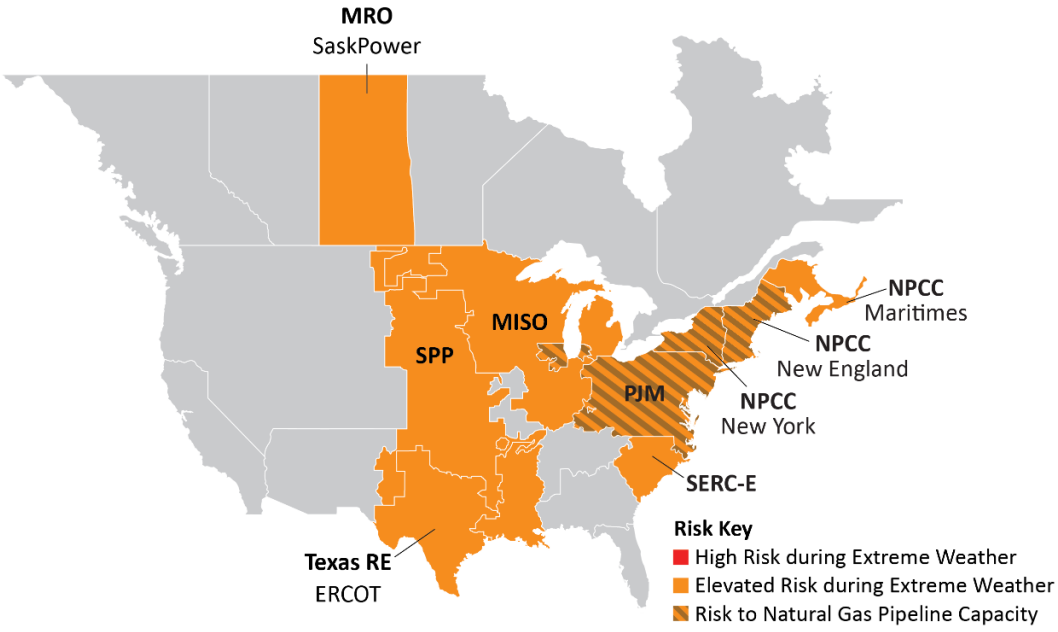


Figure 3.3: 2024–2025 Winter Reliability Assessment Risk Area Map

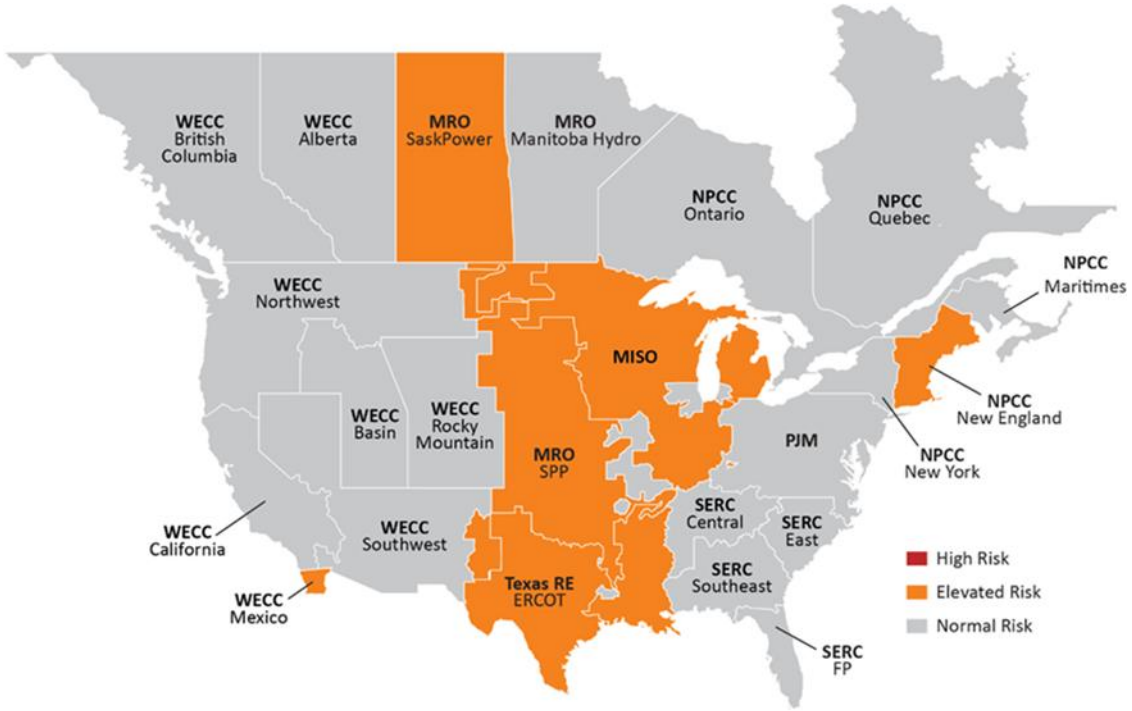


Figure 3.4: 2025 Summer Reliability Assessment Risk Area Map

Review of 2025 Capacity and Energy Performance

Periods of extreme temperatures in the summer and winter of 2025 challenged grid operators to maintain sufficient electricity supplies for demand in many parts of North America. Electricity demand is closely linked to temperature as electric load for space and equipment cooling varies with temperature. Seasonal weather extremes also affect electricity supply because generators of all types have weather-related limitations in some form. **Table 3.2** and **Table 3.3** provide demand and resource performance information for the peak demand hour of the summer and winter seasons in each assessment area. The tables include observed peak demand and resource output along with expected values from risk scenarios used in NERC's summer and

winter reliability assessments. Most assessment areas experienced peak demand that exceeded their normal 50/50 demand forecasts, and several areas exceeded their 90/10 (extreme) demand forecasts. As discussed below, winter arctic air events and summer heat domes contributed to generally high peak demand in North America.

Winter Operating Conditions

Meteorological winter (December 2024–February 2025) temperatures averaged 34.1 degrees Fahrenheit across the contiguous United States, 1.9 degrees above average, placing it in the warmest third of winters tracked by the National Oceanic and Atmospheric Administration. Total winter precipitation in the United States was nearly an inch below average, putting it in the driest third of recorded winters.[37] Canada experienced its fifth-warmest winter on record, with temperatures averaging 3.7 degrees Celsius above average.[38] Although the 2024–2025 Winter was warmer than average overall, a series of arctic events in January 2025 produced an extended deep freeze and harsh winter conditions over much of North America. As in past extreme winter storms, electricity demand surged while generator outages rose from freezing equipment and fuel supply issues. Nevertheless, during the January 2025 arctic events, operators did not require the use of manual load shedding and were able to maintain system balance using conservative operations, resource advisories, and other operational mitigations without resorting to EEA 3s.[39] A report of system performance prepared by the Federal Energy Regulatory Commission (FERC), NERC, and the NERC Regional Entities found that generators performed better during the January 2025 arctic events than in prior winter storms and attributed some improvements to additional generator commitments, improved preparedness, increased situational awareness, and the implementation of lessons learned from previous extreme cold weather events and prior report recommendations.[40] During the Winter 2024–2025 period, the highest amount of capacity in a forced outage state for all reasons occurred on January 20, 2025, with 68,519 MW across all regions. The natural gas system also performed better overall, delivering record levels of natural gas and experiencing only minor production declines and short-duration force majeure events.

A comparison of projected and actual Winter 2024–2025 peak/risk hour is provided in **Table 3.2**.

[37] Despite Arctic air outbreaks, U.S. had warm, dry winter on average | National Oceanic and Atmospheric Administration

[38] Climate Trends and Variations Bulletin – Winter 2024/2025 - Canada.ca

[39] See NERC's *2025–2026 Winter Reliability Assessment* for capacity and energy performance and operating narratives for each Interconnection (p. 51–52).

[40] *January 2025 Arctic Events | A System Performance Review by FERC, NERC, and its Regional Entities*, April 2025

Table 3.2: 2024–2025 Winter Demand and Generation Summary at Peak Demand

Assessment Area	2025 Values Winter Reliability Assessment Scenarios										
	Peak Demand			Generation[1] (MWh)	Transfers[1] (MW)	Wind Actual[1] (MWh)	Solar Actual[1] (MWh)	Forced Outages Summary[4] (MW)	Peak Demand[2] (MW)	Wind Expected[3] (MW)	Solar Expected[3] (MW)
	Date	Time	MW								
MISO	Jan. 21	18:00	108,888*	101,655	-977	18,468	0	17,010	96,134 100,395	16,761	519
MRO-Manitoba Hydro	Jan. 20	8:00	5,132	5,292	-277	142	N/A	146	4,814 5,060	52	0
MRO-SaskPower	Dec. 18	18:00	3,785	3,641	-231	664	0	0	3,802 3,897	368	3
MRO-SPP	Feb. 20	8:00	47,981	40,898	-1,424	4,886	255	9,272	45,926 47,054	4,783	36
NPCC-Maritimes	Jan. 22	7:00	5,810	4,266	-1,174	368	3	*	5,907 6,498	261	5
NPCC-New England	Jan. 21	18:00	19,607	17,686	-1,896	285	4	624	20,308 21,814	329	23
NPCC-New York	Jan. 22	19:00	23,521	18,932	-4,589	654	0	4,835	22,998 24,023	728	0
NPCC-Ontario	Jan. 22	18:00	21,940	24,250	2,990	3,693	0	*	20,951 22,179	1,914	0
NPCC-Québec	Jan. 22	8:00	37,178	39,514	-766	1,463	0	*	36,061 39,545	1,449	0
PJM	Jan. 22	9:00	144,420	152,142	7,731	3,704	3,076	8,663	130,712 144,939	3,620	1
SERC-C	Jan. 22	8:00	47,815	40,898	-6,921	563	214	1,538	41,397 47,062	176	455
SERC-E	Jan. 23	8:00	47,130	41,810	-5,323	0	145	1,830	44,023 47,662	0	2,526
SERC-FP	Jan. 25	8:00	43,974	41,702	-557	0	362	2,824	45,714 54,239	0	1,684
SERC-SE	Jan. 22	8:00	46,490	48,227	1,741	0	592	2,210	43,670 45,116	0	3,861
TRE-ERCOT	Feb. 20	8:00	80,560	79,960	-191	9,397	1,586	5,742	731,935 904,055	15,697	15
WECC-AB	Dec. 18	17:00	12,241	12,711	-470	3,175	4	*	12,280 12,635	1,867	0

Table 3.2: 2024–2025 Winter Demand and Generation Summary at Peak Demand

Assessment Area	2025 Values Winter Reliability Assessment Scenarios										
	Peak Demand			Generation[1] (MWh)	Transfers[1] (MW)	Wind Actual[1] (MWh)	Solar Actual[1] (MWh)	Forced Outages Summary[4] (MW)	Peak Demand[2] (MW)	Wind Expected[3] (MW)	Solar Expected[3] (MW)
	Date	Time	MW								
WECC-BC	Feb. 3	18:00	11,359	11,415	44	70	0	839	11,996 12,749	279	0
WECC-CA/MX	Dec. 12	15:00	35,555	31,925	-4,669	4,021	11,547	1,627	35,359 36,823	569	0
WECC-NW	Feb. 12	8:00	54,278	48,437	-920	2,607	1,494	3,281	58,001 62,230	7,876	2,198
WECC-SW	Feb. 13	16:00	22,969	25,087	2,117	2,741	1,599	1,496	16,177 17,777	1,065	182

Highlighting Notes:

Actual peak demand in the highlighted areas met or exceeded extreme scenario levels

Actual wind output in highlighted areas was significantly below seasonal forecast

Actual solar output in highlighted areas was significantly below seasonal forecast.

Actual forced outages above or below forecast by factor of two.

Table Notes:

1 Actual demand, wind, and solar values for the hour of peak demand in U.S. areas were obtained from EIA From 930 data. For areas in Canada, this data was provided to NERC by system operators and utilities.

2 See NERC 2024–2025 WRA demand scenarios for each assessment area. Values are the normal winter peak demand forecast and an extreme peak demand forecast that represents a 90/10, or once-per-decade, peak demand. Some areas use other basis for extreme peak demand.

3 Expected values of wind and solar resources from the 2024–2025 WRA for the projected peak hour; actual peak hour can impact solar contribution

4 Values from NERC GADS for the 2024–2025 winter hour of peak demand in each assessment area. Highlighted areas had actual forced outages that were more than twice the value for typical forced outage rates used in the 2024–2025 winter risk period scenarios in the 2024–2025 WRA.

5 Texas RE-ERCOT peak demand scenarios are obtained by adding expected demand response (5.4 GW for winter 2024-2025) to the demand

scenarios found on p. 29 of the 2024–2025 WRA.

*Canadian assessment areas report to GADS on a voluntary basis, which can contribute to the absence of some values in certain assessment areas.

Summer Operating Conditions

The summer of 2025 was the 12th-hottest on record for the contiguous United States[41] during the meteorological summer period (June–August) and the 11th-warmest summer in Canada.[42] Actual peak demand exceeded normal demand forecasts across most assessment areas and exceeded extreme demand projections from the *2025 SRA* in three assessment areas. A summer heat wave developed in early June for most of the eastern half of the continent, triggering system operators to issue resource advisories and other operating mitigations. The east experienced only brief periods of relief from high temperatures through the end of July. Twenty energy emergency alerts were declared during the June and July heat events, but operators were able to manage high loading without resorting to load shedding.[43]

Summer conditions were generally less severe in other parts of the North American BPS. Peak demand in the Western Interconnection was 168,206 MW, slightly below Summer 2024. Western Canada experienced a heat wave from late August and through early September, exacerbating the ongoing drought in western Canada and triggering some energy shortfall events that were managed without shedding load. Wildfire activity also increased due to heat and dry conditions. The western United States overall navigated last summer with the BPS experiencing relatively few emergency events. Demand in WECC U.S. assessment areas never reached or exceeded the projections for extreme demand from the *2025 SRA.* Texas experienced a relatively mild summer in 2025, yet, due to significant load growth, the Summer 2025 load levels were comparable to the far hotter 2023 summer load levels.[44]

A comparison of projected and actual Summer 2025 peak/risk hour is provided in **Table 3.3**.

Table 3.3: 2025 Summer Demand and Generation Summary at Peak Demand

Assessment Area	Actual Peak Demand[1]			SRA Peak Demand Scenarios[2] (GW)	Wind Actual[1] (MW)	Wind Expected[3] (MW)	Solar Actual[1] (MW)	Solar Expected[3] (MW)	Forced Outages Summary[4] (MW)
	Date	Time	GW						
MISO	Jul. 29	17:00	121.6	116.3 121.6	1,105	6,039	12,323	9,123	8,779
MRO-Manitoba Hydro	Aug. 29	17:00	3.5	3.4 3.6	0	48	0	0	252
MRO-SaskPower	Sep. 7	17:30	3.6	3.6 3.8	232	310	26	9	0
MRO-SPP	Jul. 29	16:00	54.5	54.8 57.5	8,130	5,556	810	492	4,370
NPCC-Maritimes	Aug. 11	17:00	3.6	3.3 3.5	151	314	69	0	33
NPCC-New England	Jun. 24	19:00	26.6	24.7 26.4	566	142	180	1,412	1,963
NPCC-New York	Jun. 24	19:00	32	30.0 31.7	1,256	446	164	243	1,372
NPCC-Ontario	Jun. 24	19:00	24.9	21.0 24.5	607	742	39	66	1,532
NPCC-Québec	Aug. 11	18:00	22.7	22.3 23.3	790	885	0	0	5,029
PJM	Jun. 23	18:00	160.7	146.2 158.7	4,515	1,855	7,730	6,244	15,945

[41] Assessing the U.S. Temperature and Precipitation Analysis in August 2025 | News | National Centers for Environmental Information (NCEI)

[42] Rapid Extreme Weather Attribution system: Top heat events of summer 2025 – ClimateData.ca

[43] See NERC Bulk Power Systems Awareness update to the Reliability and Security Technical Committee on September 10, 2025.

[44] See NERC's *2026 Summer Reliability Assessment* for capacity and energy performance and operating narratives for each Interconnection (p. 52–56).

Table 3.3: 2025 Summer Demand and Generation Summary at Peak Demand

Assessment Area	Actual Peak Demand[1]			SRA Peak Demand Scenarios[2] (GW)	Wind Actual[1] (MW)	Wind Expected[3] (MW)	Solar Actual[1] (MW)	Solar Expected[3] (MW)	Forced Outages Summary[4] (MW)
	Date	Time	GW						
SERC-C	Jul. 28	18:00	43.2	41.9 45.7	84	370	714	1,053	701
SERC-E	Jun. 24	17:00	44.8	42.5 45.7	0	0	3,200	5,022	2,407
SERC-FP	Jul, 28	17:00	54.6	49.8 50.8	0	0	8,035	5,749	1,599
SERC-SE	Jul. 28	16:00	46.4	45.7 55.9	0	0	3,366	7,728	1,380
TRE-ERCOT	Aug. 8	18:00	83.7	81.9 88.1	14,509	9,396	16,961	22,962	11,095
WECC-AB	Aug. 27	0:00 UTC	12.0	12.2 12.7	2,870	796	32	1,480	N/A
WECC-BC	Aug. 13	01:00 UTC	9.8	9.3 10.0	293	149	4.8	0	N/A
WECC-CA	Aug. 22	02:00 UTC	54	54.1 64.3	1,744	1,207	5,064	14,756	1,063
WECC-MX	Aug. 7	0:00 UTC	3.5	3.8 4.1	2.5	50	296	227	N/A
WECC-NW	Aug. 13	01:00 UTC	29.8	29.1 32.7	1,054	3,107	1,398	666	1,825
WECC-RM	Jul. 9	00:00 UTC	13.4	13.8 15.0	2,313	1,359	1,571	1,669	1,954
WECC-Basin	Jul. 9	01:00 UTC	13.8	13.6 15.0	931	911	2,660	2,231	0
WECC-SW	Aug. 8	01:00 UTC	36.9	35.1 39.0	1,230	1,091	4,472	4,293	2,323

Highlighting Notes

Actual peak demand in the highlighted areas met or exceeded extreme scenario levels.

Actual wind output in highlighted areas was significantly below seasonal forecast.

Actual solar output in highlighted areas was significantly below seasonal forecast.

Actual forced outages above or below forecast by factor of two.

Table Notes:

[1] Actual demand, wind, and solar values for the hour of peak demand in U.S. areas were obtained from the assessment areas.

[2] See NERC *2025 SRA* demand scenarios for each assessment area (pp. 14–33). Values represent the normal summer peak demand forecast and an extreme peak demand forecast that represents a 90/10, or once-per-decade, peak demand. Some areas use other basis for extreme peak demand.

[3] Expected values of wind and solar resources from the *2025 SRA* for the projected peak hour, actual peak hour can impact solar contribution[4] Values from NERC GADS for the 2025 summer hour of peak demand in each assessment area. Highlighted areas had actual forced outages that were more than twice the value for typical forced outage rates used in the 2024 summer risk period scenarios in the *2025 SRA*.

*Values include both maintenance and forced outages.

**Canadian assessment areas report to GADS on a voluntary basis, which can contribute to the absence of some values in certain assessment areas.

Changes in the Peak Resource Mix Over the Past 10 Years

The generation resource mix is changing as older nuclear and fossil-fired generators retire and natural-gas-fired generators and wind and solar PV resources are built (**Table 3.4**). Over the past 10 years, the BPS has reduced its on-peak[45] capacity of coal-fired generation by almost 118 GW and reduced its capacity of nuclear generation by 6.6 GW. During this time, the BPS added on-peak generation capacity: 57.6 GW of natural gas, 20.5 GW of wind, and 65 GW of solar PV.[46] **Table 3.4** shows the resource contribution to meeting the seasonal peaks for years 2015 and 2025. The lower solar contribution to meeting the Winter 2025 peak is offset by increased gas generation and lower peak demand.

Table 3.4: Generation Resource Capacity by Fuel Type

Generation Fuel Type	Summer				Winter			
	2015 On-Peak		2025 On-Peak		2015 On-Peak		2025 On-Peak	
	GW	Percent	GW	Percent	GW	Percent	GW	Percent
Coal	289.2	28.0%	172.1	15.8%	286.6	27.4%	172.7	16.2%
Natural Gas	418.1	40.5%	489.0	44.9%	437.2	41.8%	512.9	48.2%
Hydro	128.9	12.5%	135.3	12.4%	128.9	12.3%	137.9	13.0%
Nuclear	112.2	10.9%	105.4	9.7%	112.2	10.7%	107.1	10.1%
Oil	48.1	4.7%	28.2	2.6%	51.2	4.9%	30.2	2.8%
Wind	13.0	1.3%	37.4	3.4%	13.6	1.3%	44.0	4.1%
Solar PV	3.9	0.4%	77.8	7.1%	0.6	0.1%	13.5	1.3%
Other	19.8	1.9%	44.2	4.1%	16.8	1.6%	45.3	4.3%
Total:	**1,033.3**	**100.0%**	**1,089.4**	**100.0%**	**1,047.0**	**100.0%**	**1,063.7**	**100.0%**

The resource mix and the pace at which it is changing varies considerably across different parts of the North American BPS. **Figure 3.5** provides an Interconnection-level view of the generation resource mix since 2015.

[45] Individual assessment areas may peak in either the Winter or Summer season and thus on-peak in this context is the sum of the individual areas' non-coincident seasonal peak.

[46] Data obtained from NERC long-term reliability assessments

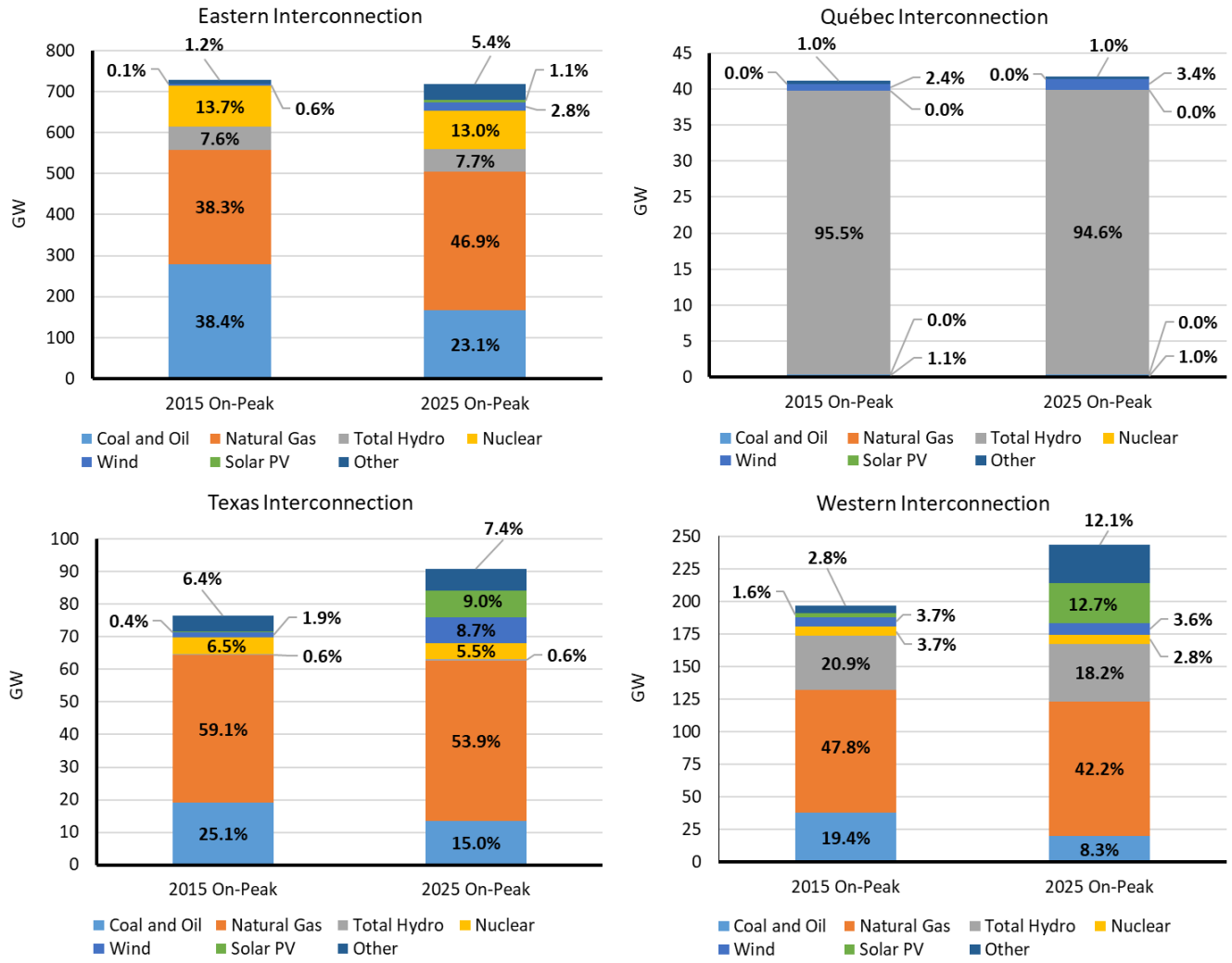


Figure 3.5: 2015 and 2025 Capacity Resource Mix by Interconnection

The growth of battery energy storage systems (BESS) arrived at an inflection point in 2025. **Figure 3.6** below shows the recent growth in both nameplate and on-peak capacity for battery storage across all Interconnections. NERC's LTRA reports on both the current generation resource mix and projections for the next 10 years for each of the 20 assessment areas within the four Interconnections that encompass the North American BPS. As the *2025 LTRA*[47] notes, the shift toward a more variable resource mix continues. One key insight from the *2025 LTRA* is that solar PV is no longer the sole, predominant generation type planned over the next 10 years. New battery resource projects have grown to match solar projections, and, together, solar and battery capacity additions represent two-thirds of the Tier 1 and Tier 2 resources over the 10-year LTRA study period.

[47] *Long-Term Reliability Assessment*, 2025

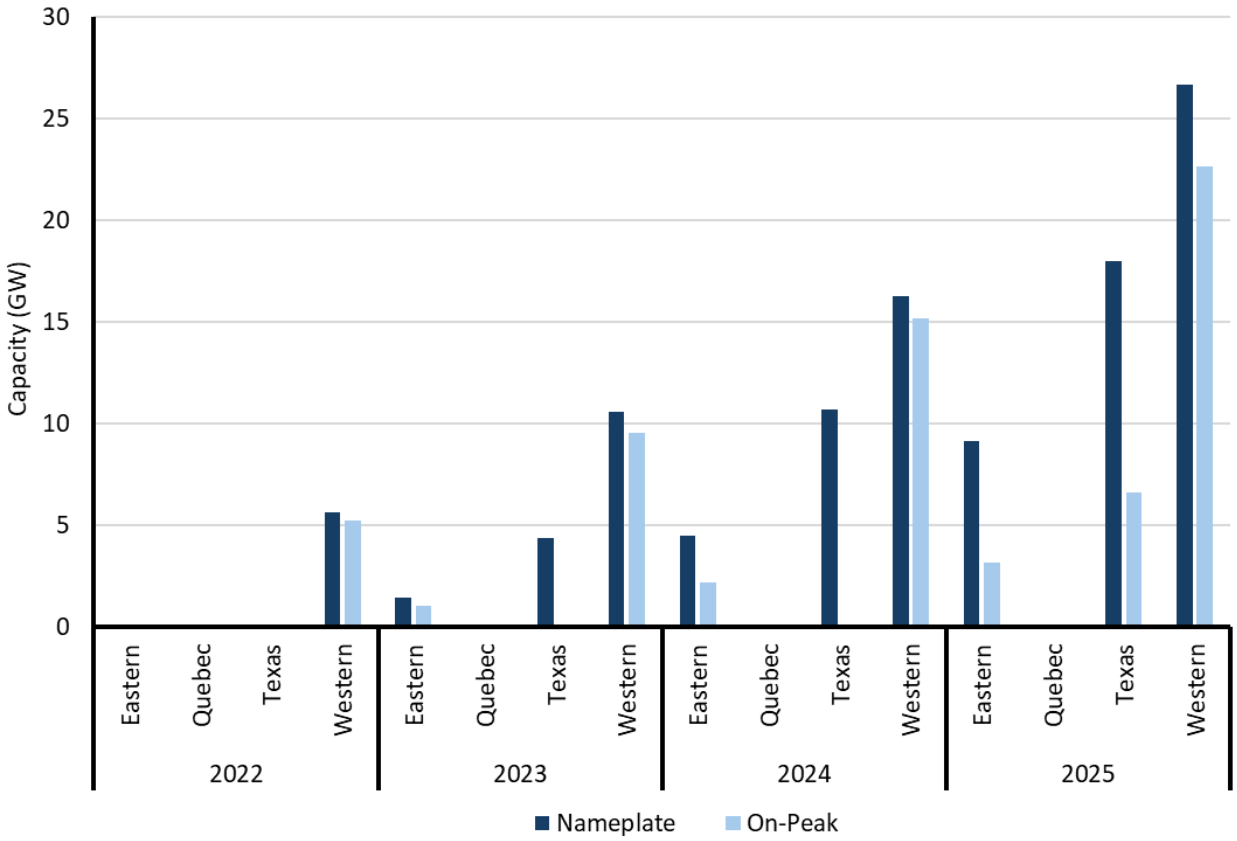
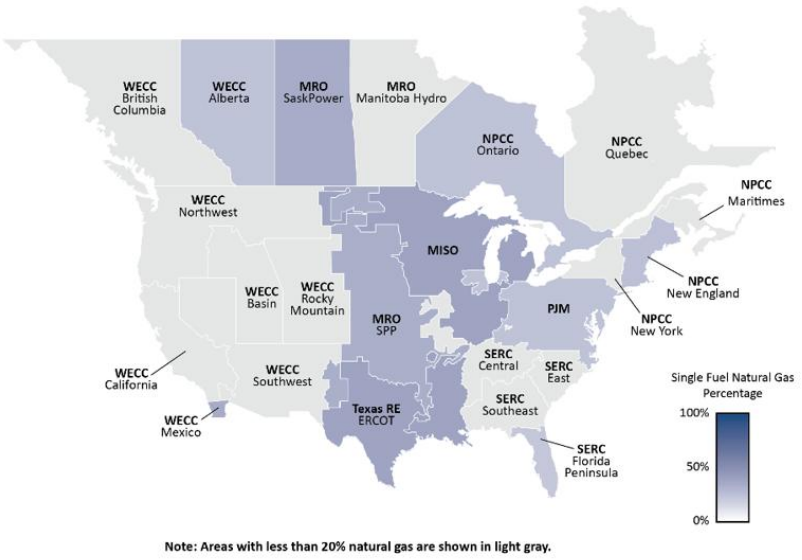


Figure 3.6: 2022–2025 Battery and Hybrid Capacity by Interconnection[48]

Critical Infrastructure Interdependencies

The natural gas and electric systems are constituent parts of an interconnected energy delivery system in North America. While natural-gas-fired generation is important in all seasons, it is especially vital to meet electricity demand in winter when solar and battery resources have less capability than in other seasons. Natural gas-fired generators can be exposed to risk of fuel supply curtailments in winter for a variety of reasons. One mitigation strategy used by generators in some areas is to have dual-fuel capability and maintain supplies of backup fuels. Single-fueled generators currently make up a large portion of the winter peak generating capacity in many parts of the BPS (**Figure 3.7**). These generators are at risk of outages or derates when fuel supplies are limited.

[48] Includes hybrid generation



Single-Fuel Natural-Gas-Fired Generation

	Winter Capacity (GW)	Contribution to Total Winter Resource Mix
MISO	63.9	38%
TRE-ERCOT	53.0	38%
WECC-MX	2.2	34%
MRO-SaskPower	2.5	34%
SPP	33.4	32%
NPCC-New England	12.1	24%
PJM	60.9	23%
WECC-AB	13.9	23%
NPCC-Ontario	8.0	23%
SERC-FP	45.6	21%
WECC-CA	35.9	18%
WECC-SW	21.5	17%
WECC-Basin	4.9	16%
WECC-RM	6.2	14%
SERC-C	17.0	13%
SERC-SE	21.5	13%
WECC-NW	8.7	12%
SERC-E	11.3	9%
NPCC-New York	5.0	8%
NPCC-Maritimes	0.5	7%
MRO-Manitoba	0.3	4%
WECC-BC	0.1	1%
NPCC-Quebec	0.0	0%

Figure 3.7: Single-Fuel Natural-Gas-Fired Generation Capacity Contribution to the Winter Generation Mix in 2025[49]

January 2025 Gas-Electric System Performance

The arctic events in January 2025 presented challenging conditions for the natural gas and electric systems, requiring close coordination between operators. A review of BPS and natural gas system performance following the January winter storms found notable improvement in the delivery of natural gas to BPS generators since winter storms Elliott and Uri with overall less natural gas production decline during cold weather and fewer natural gas infrastructure force majeures.[50] BPS generator outages climbed during the extreme cold due to equipment freezing issues and some gas supply issues.[51] The January 2025 arctic events demonstrated again how closely linked the reliability of the BPS is to natural gas supplies and infrastructure. Because natural gas infrastructure freeze protection mitigations are voluntary for the natural gas industry in most of North America, protections can be unevenly applied, resulting in continued supply risks during extreme conditions. Furthermore, timing misalignments between the natural gas and electric markets continue to challenge generator fuel procurement in advance of severe winter conditions that occur over winter holiday weekends.

Call to Action

NERC developed an Electricity-Natural Gas Strategy[52] to identify, assess, and facilitate ongoing and future treatment of the risks that arise from the growing reliance on natural gas for electricity generation. More information on NERC's response to the risks associated with gas-electric interdependence is provided on the NERC Reliability Initiatives[53] page.

Increasing Complexity of Protection and Control Systems

Together with the progression of interconnected power generation, transmission, and distribution assets, the landscape of automated tools and systems has transformed. This evolution spans an array of digital information platforms and microprocessor-driven devices, fostering a technologically diverse environment wherein operators can wield unprecedented control from virtually any location at a fraction of the historical

[49] *2025–2026 Winter Reliability Assessment*
[50] See *January 2025 Arctic Events | A System Performance Review*, April 2025
[51] PJM January 2025 Cold Weather Operations Presentation
[52] Electricity-Natural Gas Strategy
[53] Reliability Initiatives

cost. When meticulously designed and executed, these automated tools offer a means to enhance the reliable and secure use of the technologies and concepts in the BPS. However, the proliferation of these systems introduces an increasing web of rules, algorithms, and interdependencies that amplify the intricacy of operation. The swift decision-making capabilities of modern relays, tripping circuits, or initiating alternative actions within milliseconds epitomize the accelerated pace at which these systems must navigate intricate operational scenarios. The increasing integration of inverter-based resources (IBR) also expands this complexity, requiring the deployment of additional automated tools and systems. Navigating this expanding labyrinth demands not only vigilant maintenance, prudent asset replacement, and strategic upgrades but also a nuanced understanding of the dynamic interplay between diverse system components. As the scope and scale of these challenges continue to increase, it is imperative to cultivate agile, adaptive solutions.

Protection System Misoperation Trends

Figure 3.8 presents the annual misoperation rates across all Regional Entities and separately for each Regional Entity over the last five years. The comparison of the misoperation rate of the first four years to the most recent year shows a statistically significant decreasing trend for MRO. There is no statistically significant trend for other Regional Entities nor for the ERO as a whole. The overall count of misoperations in 2025 was the lowest over the past five years (**Table 3.4**).

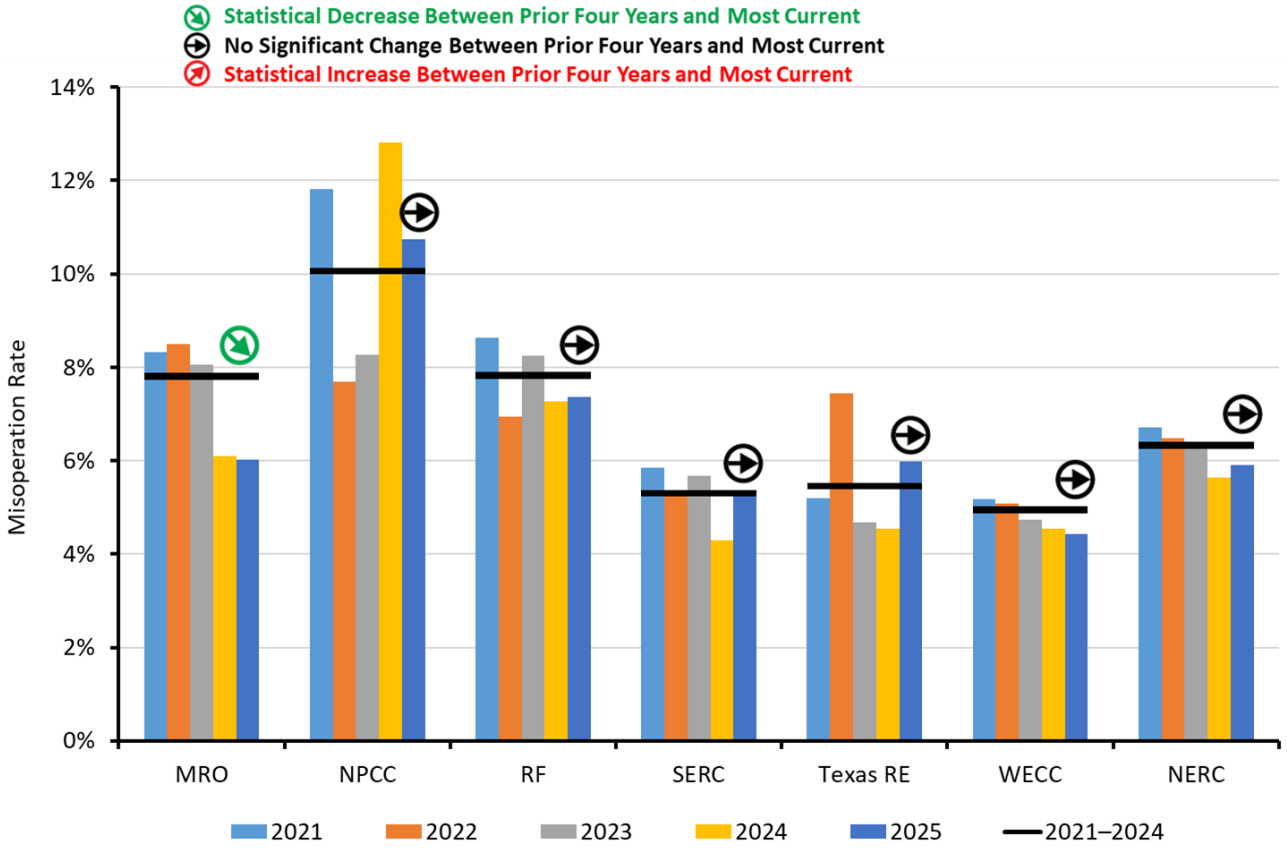


Figure 3.8: Changes and Trends in the Annual Misoperations Rate by Regional Entity[54]

[54] M-9, Protection System Misoperations Rate

Table 3.5: Five-Year Protection System Operations and Misoperations 2021–2025										
Area	Protection System Operations					Misoperations				
	2021	2022	2023	2024	2025	2021	2022	2023	2024	2025
All Regional Entities	17,454	17,804	17,871	19,325	18,397	1,172	1,153	1,118	1,089	1,087
MRO	2,618	3,238	2,977	3,097	3,267	218	275	240	189	197
NPCC	1,362	1,664	1,752	1,521	1,275	161	128	145	195	137
RF	1,867	2,061	1,867	1,843	2,010	161	143	154	134	148
SERC	4,617	4,775	4,954	5,701	5,058	270	252	281	245	265
Texas RE	2,599	1,991	2,183	2,461	2,542	135	148	102	112	152
WECC	4,391	4,075	4,138	4,702	4,245	227	207	196	214	188

Leading Causes of Misoperations

Figure 3.9 shows the distribution of misoperation causes over the past five years. Incorrect settings and relay failures/malfunctions remain the most common causes of misoperations. While a relative increase in Unknown/Unexplainable occurred from 2024 to 2025, historically the misoperation rate for this cause code decreases as ongoing investigations reveal additional information and corrective action plans (CAP) remedy the situations causing the misoperations. There were minimal changes in the relative frequency of other causes from 2024 to 2025.

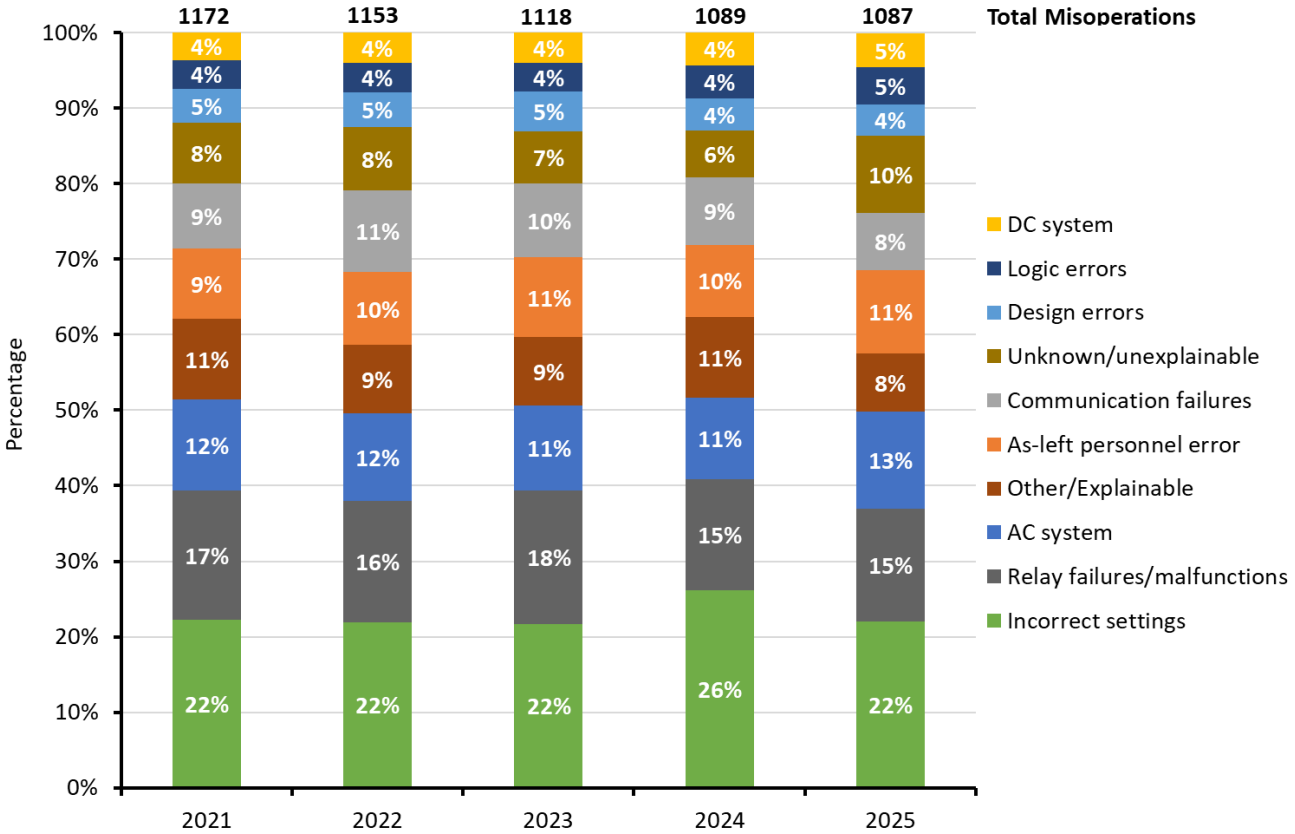


Figure 3.9: Percentage of Misoperations by Cause Code (2021–2025)

Misoperation Impact Score

The misoperation impact score measures the estimated impact of each misoperation on the BES, which is then aggregated to assess overall performance. This is done by summing weighted values for the facility voltage class, equipment type, cause, and category to determine the event's impact to BES reliability.[55] The maximum score of 1.0 implies the worst impact an event is projected to have on the BES, while a minimum score of 0.3034 reflects the least impact an event is projected to have on the BES.

In 2025, there was a statistically significant increase in the average misoperation impact score compared to the prior four years for Texas RE and NERC-wide (**Figure 3.10**). No statistically significant change occurred for any other Regional Entity. Further analysis identified that the Texas RE increase was primarily driven by an increase in misoperations reported by new Generator Owners (GO), increasing misoperations on 345 kV equipment (the highest voltage in the region) and the use of the "unknown" cause code.

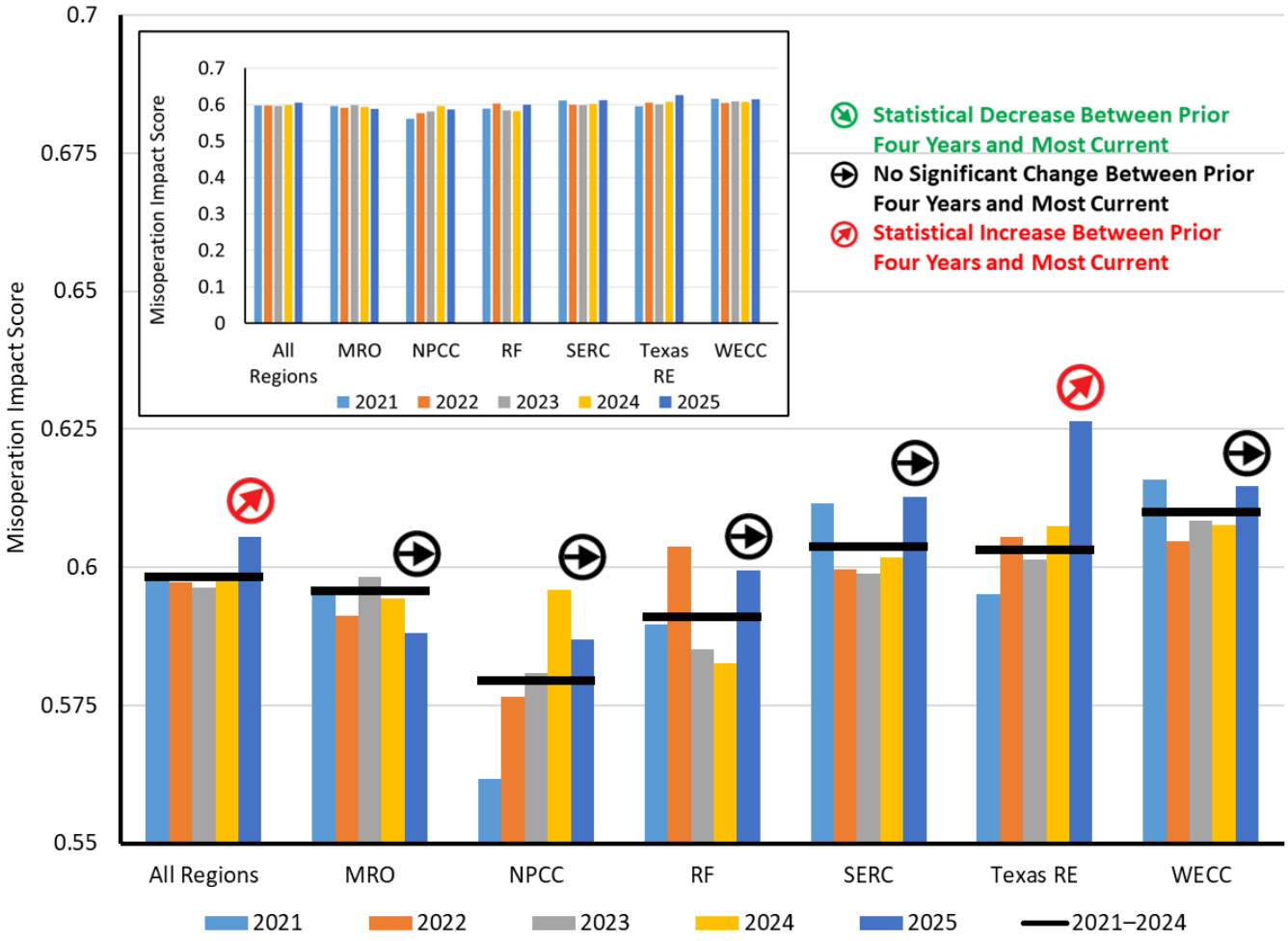


Figure 3.10: Misoperation Impact Score

Protection System Failures Leading to Transmission Outages

Protection system failures may result from or be the cause of transmission circuit outages, unnecessarily removing equipment from service. AC circuits saw a slight decrease in the number of outages due to protection system failures in 2025, but this decrease was not statistically significant. Transformers saw a statistically significant decrease in the number of outages for 2025 (**Figure 3.11**).

[55] Misoperations Impact Score

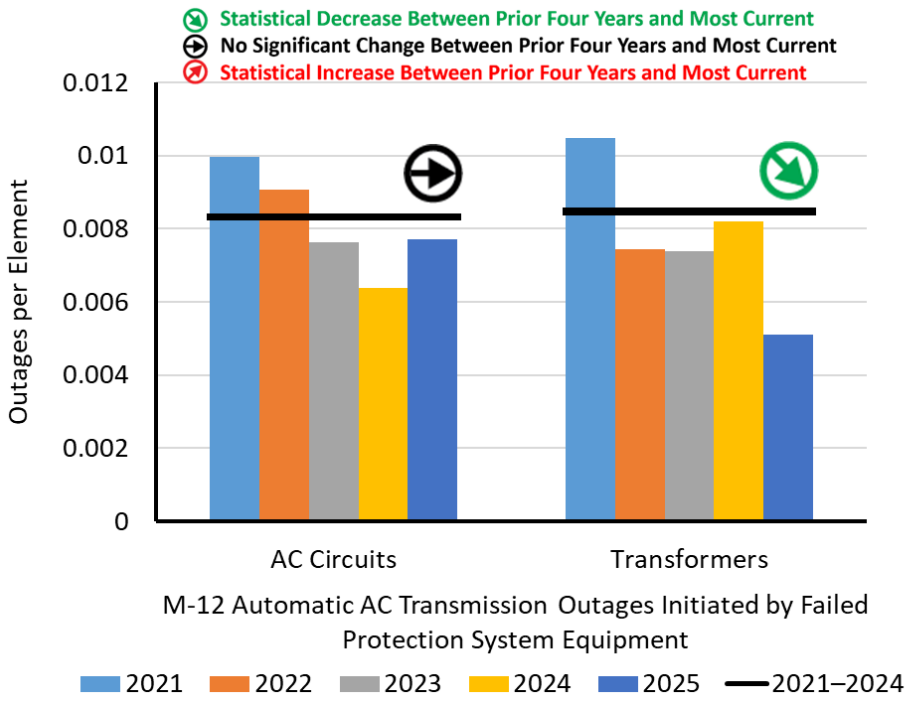


Figure 3.11: Failed Protection System Equipment Outages[56]

Event-Related Misoperations[57]

An analysis of events meeting published criteria[58] reported through the ERO Event Analysis Process (EAP) found that there were 51 transmission-related events in 2025, 32 of which (63%) involved misoperations (**Figure 3.12**). In comparison, 2024 saw 60 transmission-related events, of which 34 (57%) had associated misoperations. While the percentage of events with misoperations increased, the overall numbers for events and misoperations continue to decrease. This reduction is likely attributable in part to the ERO Enterprise and industry stakeholder efforts to reduce protection system misoperations through initiatives such as various task forces, workshops, and analytical efforts.

[56] M-12, Automatic AC Transmission Outages Initiated by Failed Protection System Equipment

[57] When reviewing ERO Event Analysis misoperations data, it is important to differentiate between it and analysis of MIDAS. These are different datasets and processes. This results in datasets that both relate to protection system misoperations and have overlap but often have significantly different sources, intents, and results.

[58] ERO Event Analysis Process - Version 5.0 (Effective January 1, 2024)

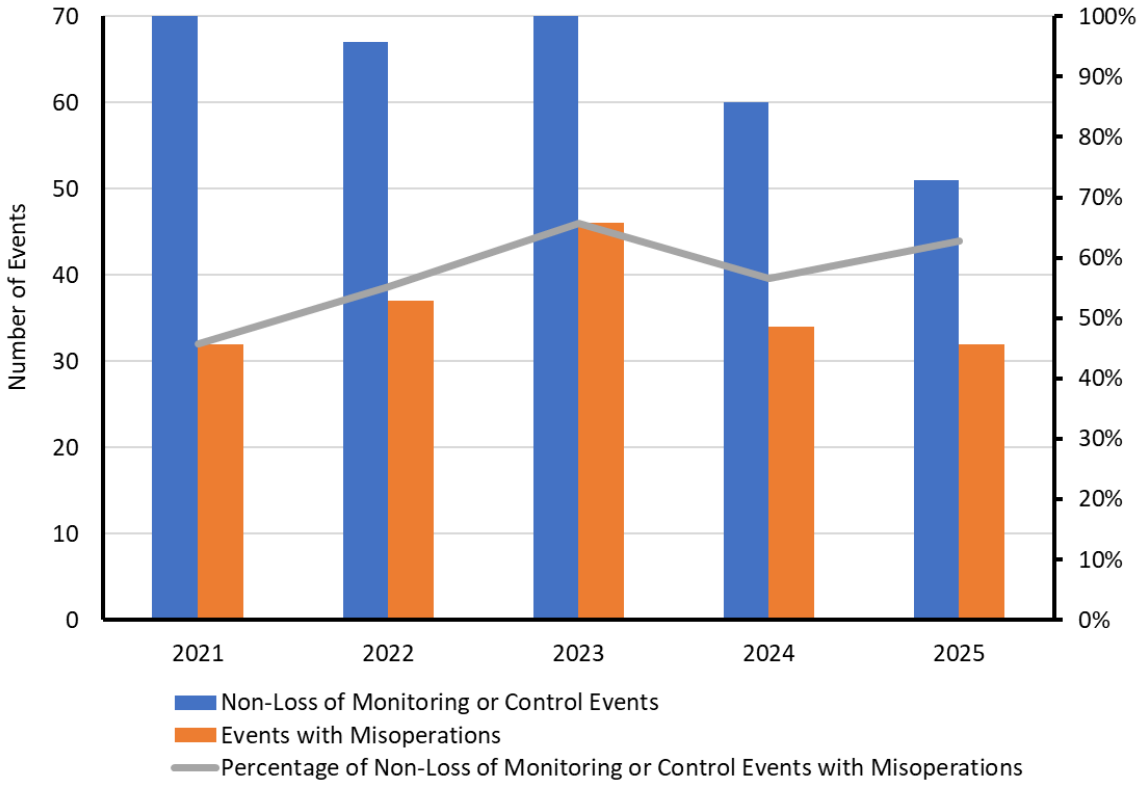


Figure 3.12: Events with Misoperations

Loss of Situational Awareness

The BPS operates in a dynamic environment where physical properties are constantly changing. To ensure reliability, it is essential to maintain situational awareness to anticipate events and respond effectively before or as they occur. Various tools are employed to support situational awareness and uphold BPS reliability. These tools include energy management systems (EMS), transmission outage planning, load forecasting, forecasting for geomagnetic disturbances and weather, data sharing with neighboring entities, and effective communication both within organizations and with adjacent systems.

Without the appropriate tools and up-to-date data, system operators may experience degraded situational awareness, which can affect their ability to make informed decisions about BPS reliability. Unexpected outages of communication systems or monitoring and control equipment, along with planned outages that lack proper coordination or oversight, can result in diminished visibility for operators. For system operators, the EMS is essential for maintaining situational awareness.

Impacts from the Loss of EMS

An EMS is a computer-based set of tools that system operators use to monitor, control, and optimize the performance of both the generation and transmission systems. The EMS enables operators to oversee and manage various factors, including frequency, the status (open or closed) of switching devices, and the real and reactive power flows on BES tie-lines and transmission facilities within their control area. Additionally, it provides oversight of critical EMS applications, such as state estimation (SE), RTCA, automatic generation control, and alarm management.

There were 36 categorized[59] events associated with an EMS in 2025; there were no categorized EMS-related events that caused loss of generation, transmission lines, or customer load. **Figure 3.13** illustrates a trend of the categorized EMS events by loss of EMS functions over the 2021–2025 period.

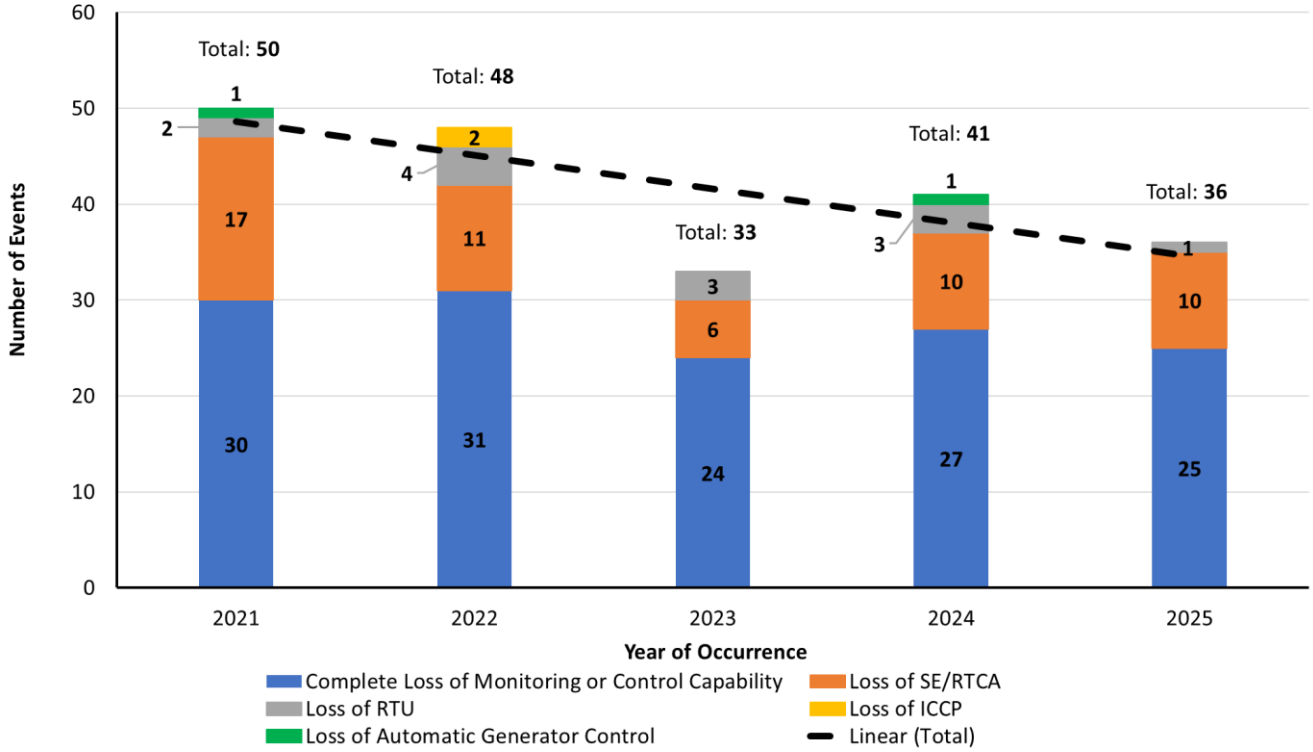


Figure 3.13: Number of EMS-Related Events (2021–2025)

In 2025, there were 25 categorized events involving a complete loss of monitoring[60] or control[61] capability. Two new themes to these events were identified:

- **Lack of effective communication between working departments**

  Maintenance typically involves the collaboration of various working departments, each playing a vital role in ensuring the efficiency and reliability of systems. Effective communication between these teams is crucial, especially when they handle the same equipment or systems that are interdependent. Prioritizing the clear exchange of work and maintenance schedules among departments will significantly reduce the likelihood of overlapping tasks that could negatively affect the utility's equipment and overall operations.

  To address the issues that have arisen from insufficient communication between working groups, a series of recommendations were developed during the analysis of the EMS events. These recommendations aim to foster a more cohesive approach to maintenance and ensure that all teams are informed and coordinated, ultimately enhancing operational safety and efficiency:

  - **Pre-Maintenance:** Planning and risk mitigation before the work starts.

[59] Category 1h. See Electric Reliability Organization Event Analysis Process Version 5.0
[60] The ability to accurately receive relevant information about the BPS in real time and evaluate system conditions using real-time data to assess existing (pre-contingency) and potential (post-contingency) operating conditions to maintain reliability of the BPS.
[61] The ability to take and/or direct actions to maintain the reliability of the BPS in real time via entity actions or by issuing operating instructions.

- Establish Communication Channels: Set up a bridge call with all stakeholders during the work to enable quick communication and coordination between groups.
- Move Active Server to Hot Standby: Move the active server to the hot standby site before work begins to reduce potential impact.
- Transfer Operational Activities: Shift all operational activities to an alternate location until the telecom work is finished.
- Verify Equipment Status: Perform a status check on all equipment prior to beginning any work.

- **During Maintenance:** Real-time monitoring and active communication
  - Monitor Progress: Supervision should actively monitor scheduled work to ensure no conflicts occur between groups.
  - Ensure Real-Time Status Updates: Communicate work status continuously between shifts and work groups, especially when multiple groups share the same equipment.
  - Implement Immediate Escalation: If schedules cannot be met, the group performing the work must immediately notify supervision and other scheduled teams.
- **Post-Maintenance:** Post-activity verification and closure
  - Ensure Final Status Handoff: Ensure the final equipment status is communicated to the next shift or work group before closing the bridge.
  - Verify System Reversion: Verify the system before moving traffic back to the primary servers.

- **Inadequate monitoring of operational support system resource usage**

  Operational support systems are vital for ensuring situational awareness and facilitating real-time decision-making across various operations. Unfortunately, several EMS events have arisen due to overwhelming demands for computer resources and the depletion of disk space. A recurring issue revealed through these incidents is the lack of a proactive framework for managing resource margins. This framework is essential for maintaining operating reserves akin to those established for ensuring BES reliability.

  To enhance the effectiveness of infrastructure monitoring, it is important to:

  - Incorporate a multi-tiered system of alert thresholds,
    - Perform a thorough trend analysis and detection of rate-of-change.
    - Enable early interventions to address issues before they escalate into emergencies.
  - Manage temporary file lifecycles and govern system logs as they are integral components of reliability controls.
    - Validate mechanism for cleanup in both normal operating conditions and potential failure scenarios.
    - Avoid unnecessary buildup of digital artifacts that could compromise system performance and reliability.

The loss of the categorized SE/RTCA was stable in 2025 (10 in both 2024 and 2025). External modeling was still the primary contributor to these events in 2025. Many entities have expanded their EMS models to monitor the impact of events and outages that occur beyond their own footprint. This expansion has raised

the risk of encountering inaccurate data points, faulty topology modeling, and communication issues that could lead to EMS events. Entities were encouraged to communicate changes to the BES, including the addition of new substations and new facilities and the removal of existing facilities, to neighboring entities well in advance. This proactive communication will allow neighboring entities to update their external EMS models promptly, ensuring that the data received through integrated communications control panel (ICCP) links is accurately aligned with the corresponding data points in their models.

Over the five-year period (2021–2025), the average partial or full function categorized EMS outage time (**Figure 3.14**) was 78 minutes, making the calculated EMS availability 99.994% during the term.

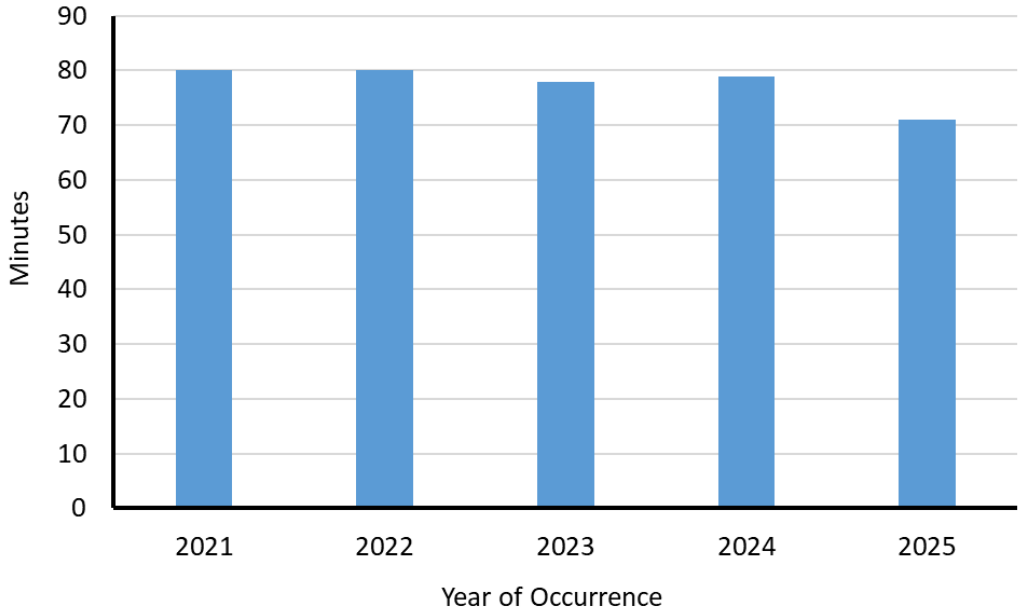


Figure 3.14: Average EMS Outage Time (2021–2025)

Largest Contributor to Loss of EMS

Reported EMS events can be grouped by the following attributes:

- **Software:** Software defects, modeling issues, database corruption, memory issues, etc.
- **Communications:** Device issues, less-than-adequate system interactions, etc.
- **Facility:** Loss of power to the control center or data center, fire alarm, ac failure, etc.
- **Maintenance:** System upgrades, job scoping, change management, software configuration, settings failure, etc.

Figure 3.15 illustrates that software was the primary contributor to EMS outages during the evaluation period from 2021 to 2025. This was followed by communication and maintenance challenges.

Figure 3.16 shows a trend in reported EMS events by the contributors of EMS function loss throughout the same period. In 2025, the main contributors were software and communications challenges, indicating a consistent overall trend from 2021 to 2025.

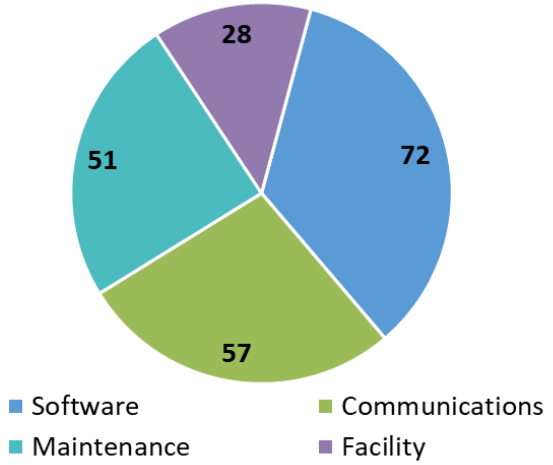


Figure 3.15: Overview of Contributors to Loss of EMS Functions (2021–2025)

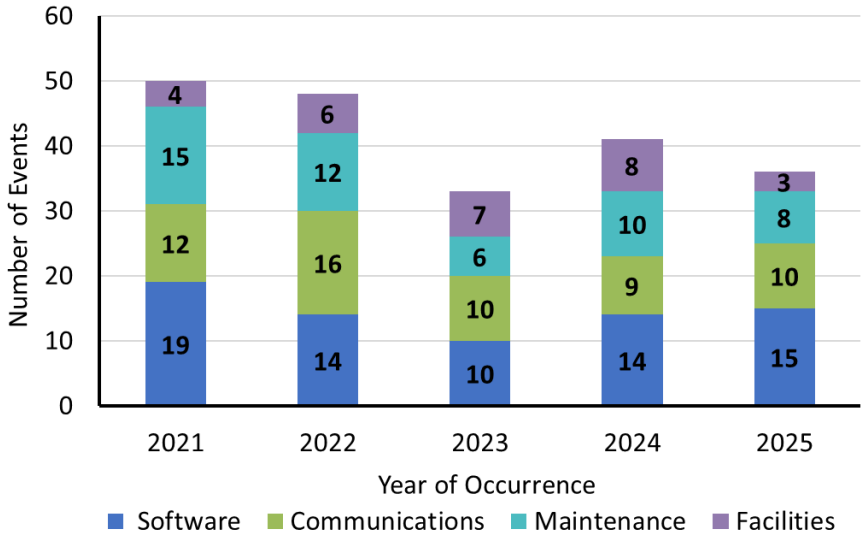


Figure 3.16: Trend of Contributors to Loss of EMS Functions (2021–2025)

Bugs often cause software failures, whether in vendor applications or in-house implementations. A software testing process should be in place to ensure that requirements are met. For effective systems and software assurance, a formal testing process model should be based on the development framework used to create the software. The testing scope should provide an assurance case for the software's operation under both known and unknown conditions and should include a data integrity check of the module. It is important to develop a team of dedicated and skilled in-house personnel who can troubleshoot and resolve issues. Providing in-house staff with real-time tools and training will enhance their knowledge and facilitate better knowledge transfer from software vendors.

Communications failure was typically related to device issues or less-than-adequate system interactions. The failure indicates that data exchange was degraded between substations and control rooms or between the entity and its RC/neighboring entities. An example is a spanning-tree protocol implementation in a network switch, causing a loop that generated an exceptionally high volume of traffic. The result was to shut down the communication network supporting the EMS. Another example is that the entity lost remote terminal unit (RTU) data from major substations as the telecom company's staff cut the fiber between the substations and the data center. Entities should maintain network devices on a schedule in accordance with

the latest vendor information, security bulletins, technical bulletins, and other recommended updates. Entities must also consider redesigning communications systems such that the most critical BES substations communicate simultaneously over entirely separate physical paths (and possibly separate vendors) to both control centers, eliminating the need for telecom company communication structure.

An analysis of the ERO EAP data reveals that 4.8% (or 10 out of 208) of the reportable EMS events lasting more than 30 minutes from 2021 to 2025 were linked to issues with external communication providers. This indicates that external communication provider-related problems are not a significant cause of EMS outages.

Human Causes

As human error can adversely impact the performance of the BPS and BES equipment, it is important to establish and adhere to robust processes to minimize the risks. In-depth analysis often identifies that primary human error causal factors are a result of latent errors as well as organizational and programmatic weaknesses. As the 2025 ERO *Reliability Risk Priorities Report*[62] states, "The BPS continues to evolve in complexity. The industry faces significant risk in staffing skilled workers due to new complexities, advanced technologies, the convergence of engineering and IT skillsets, and competition from other industries."

Transmission Outages

NERC's TADS collects transmission outage data, including on human error; human error as a cause of transmission outage is defined in the *TADS Data Reporting Instructions*.[63]

Statistical significance testing for automatic outages compared the event frequency of 2025 to the average event frequency of the prior four years. Statistical significance testing for operational outages was performed by outage frequency because they are not grouped into events. Automatic outage events involving human error improved a statistically significant amount, while operational outages did not change a significant amount for either ac circuits (**Figure 3.17**) or transformers (**Figure 3.18**).

[62] 2025 ERO Reliability Risk Priorities Report

[63] Human Error: relative human factor performance including any incorrect action traceable to employees and/or contractors of companies operating, maintaining, and/or assisting the Transmission Owner.

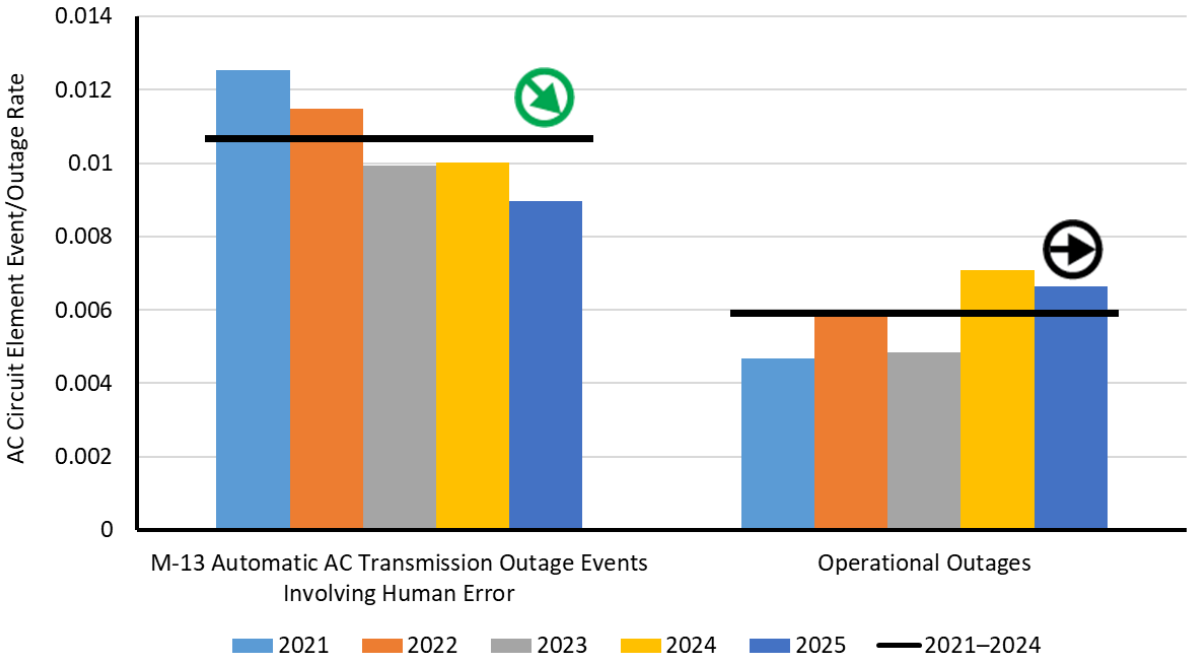


Figure 3.17: Automatic AC Transmission Outage Events and Operational Outages Involving Human Error[64]

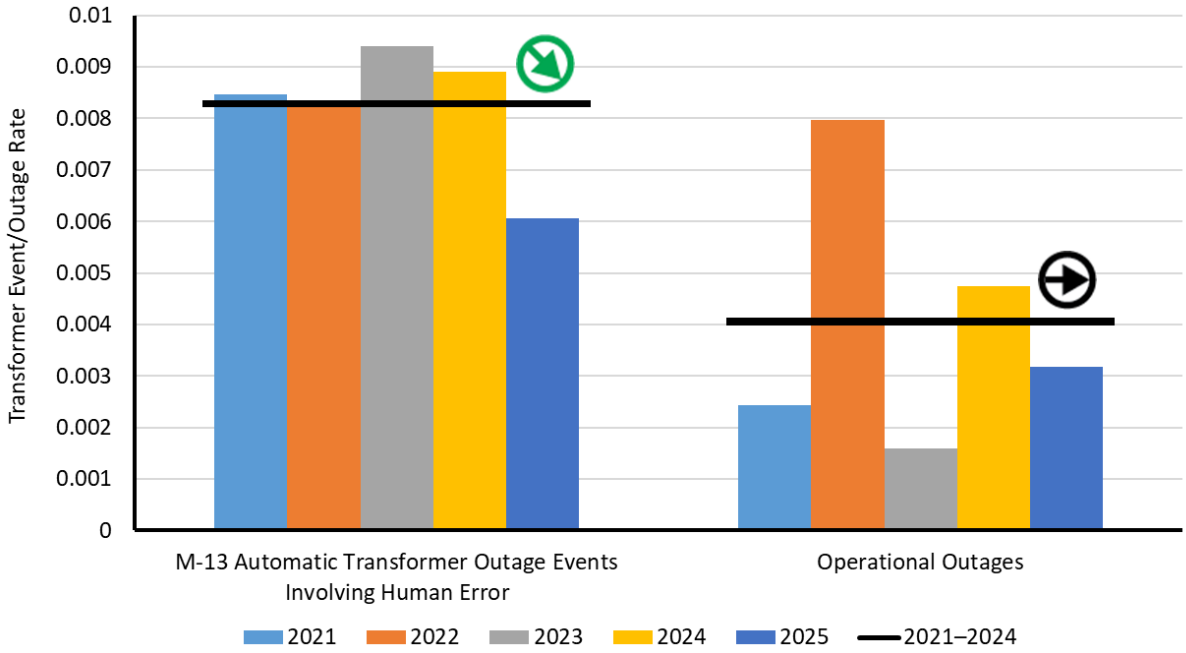


Figure 3.18: Automatic Transformer Outage Events and Operational Outages Involving Human Error[65]

Generation Outages

NERC's GADS collects generation availability data, including on outages associated with human error. While NERC continues tracking these outages, they historically represent approximately 1% of all forced outage

[64] M-13, Automatic AC Transmission Outage Events Involving Human Error
[65] Ibid.

events. Though there was a slight increase observed in 2025, it was not significant enough of a variance to warrant presentation.

Trends of Human and Organizational Root Causes[66,67]

In the ERO EAP, the cause sets of individual human performance and management/organization identify events or conditions that caused or contributed to the reported event. In 2025, organization/human performance was identified as the root cause for 41 processed events (**Figure 3.19**). This does not fully project the final 2025 number, as 66% of the 2025 events have been assigned a final root cause. The top five human and organizational performance root causes for the 2021–2025 period are listed in order of frequency below. These include the individual human error category, the management and organization performance category, and/or the design and engineering category:

- Design output scope less than adequate
- Job scoping did not identify special circumstances and/or conditions
- Management policy guidance or expectations are not well-defined, understood, or enforced
- Corrective action responses to a known or repetitive problem were untimely
- System interactions not considered or identified

Events from 2021 to 2025[68] saw the same top five human and organizational performance root cause identified events from 2020 to 2024.

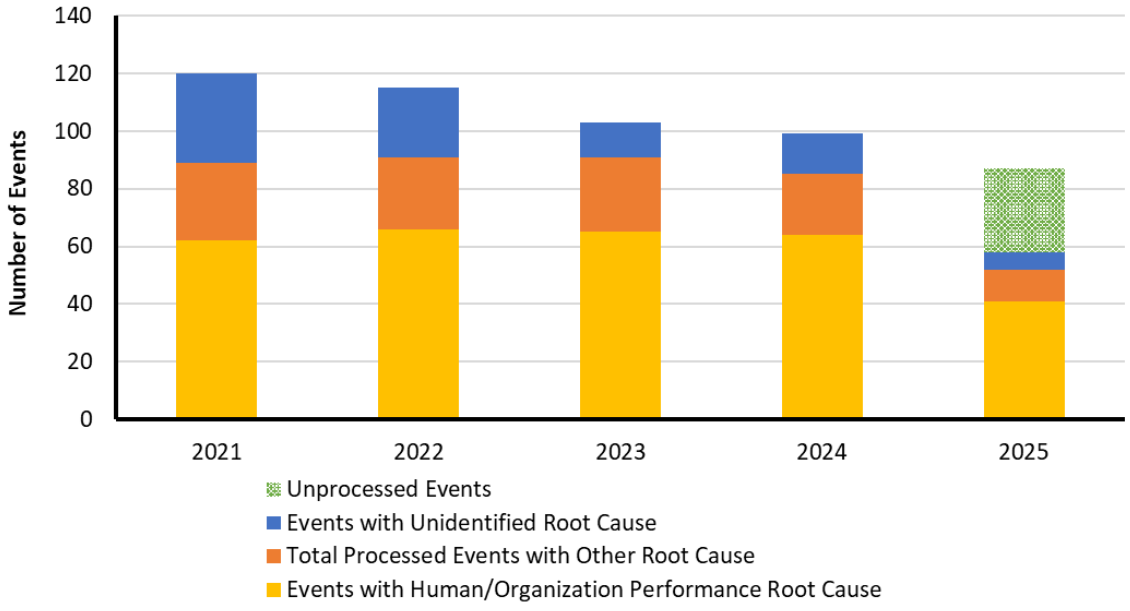


Figure 3.19: ERO EAP Organization/Human Performance Root Cause Identification by Year

Improvement opportunities exist for industry to increase BPS reliability through increased focus in the areas of management and organization performance and engineering and design. Management and organization

[66] Cause Code Assignment Process (Updated January 2026)

[67] When reviewing ERO Event Analysis Human and Organization Performance data, it is important to differentiate between it and GADS and TADS values. These are different datasets and processes. GADS and TADS are primarily focused on wholistic equipment availability and often not analyzed through the same methods nor depth used for the ERO event analysis (EA) process.

[68] Only includes 2025 events that have been processed as of data pull.

performance includes subcategories in which methods, actions, and/or practices are less than adequate. The engineering and design category includes ensuring that the engineering group employs a robust peer-review process to identify procedural errors and all considerations a design needs to be accountable. Some ways to improve human and organization performance would be to establish robust internal control mechanisms to ensure that processes and procedures such as peer reviews are in place to assist project leaders when considering the potential impacts and dependencies that may exist elsewhere on the system and to implement causal analysis when appropriate.

Protection System Misoperations

Human performance-related misoperations remain common, representing 42% of misoperations in 2025 and consisting of 11% As-Left Personnel Error, 4% Design Errors, 22% Incorrect Settings, and 5% Logic Errors (**Figure 3.9**). **Figure 3.20** additionally shows the number of misoperations related to human error by Regional Entity for the past five years.

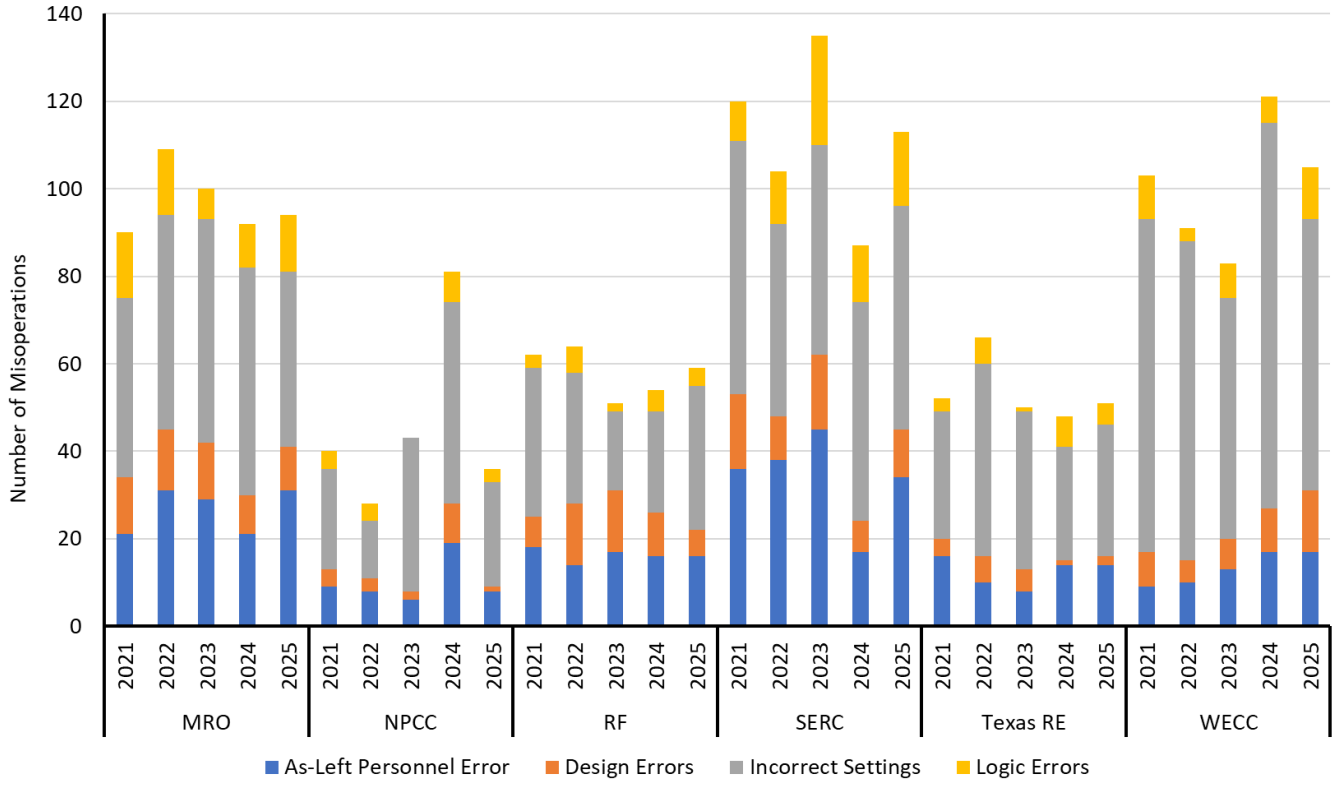


Figure 3.20: MIDAS Protection System Misoperations Due to Human Error by Regional Entity

Chapter 4: Grid Performance

Grid performance is evaluated through established reliability metrics and more in-depth analysis of specific aspects of the BPS:

- Reliability Metrics
- Frequency Response Performance
- Generation Performance and Availability
- Transmission Performance and Unavailability

Reliability Metrics

By calculating 2025 reliability metrics[69] and comparing the results to the previous years as well as the five-year average values, the reliability metrics discussed in this report can be categorized as either Improving, Stable, Monitor, or Actionable. Measuring and trending the relative state of the BPS and BES in this manner supports NERC's obligation to assess the capability of the BPS. **Table 4.1** shows the status of the reliability metrics and includes a reference to the specific metric.

Table 4.1: Reliability Indicators

Metric Name		Metric Performance Status
M-1: Reserve Margin		**Monitor: NPCC-Maritimes (Winter)**
M-2: Transmission-Related Events Resulting in Loss of Load (Excluding Weather)		**Monitor[70]**
M-3: System Voltage Performance		**Retired**
M-4: Interconnection Frequency Response	Eastern	**Improving**
	Texas	**Improving**
	Western	**Improving**
	Québec	**Stable**
M-4.1: Inertia and Rate-of-Change-of-Frequency	Eastern	**Improving**
	Texas	**Improving**
	Western	**Improving**
	Québec	**Actionable[71]**
M-5: Activation of Under Frequency Load Shedding		**Retired**
M-6: Disturbance Control Standard Failures		**Proposed Retirement**
M-7: Disturbance Control Events Greater than Most Severe Single Contingency		**Proposed Retirement**
M-8: Interconnection Reliability Operating Limit (IROL) Exceedance		**Monitor**
M-9: Protection System Misoperations Rate		**Stable**
M-10: Transmission Constraint Mitigation		**Retired**
M-11: Energy Emergency Alerts		**Improving**
M-12: Automatic AC Transmission Outages Initiated by Failed Protection System Equipment	AC Circuits	**Stable**

[69] Current Approved Reliability Metrics; Metrics M-3, M-5, and M-10 are retired.
[70] Average lost load increased, but number of events decreased.
[71] See 2025 Interconnection Frequency Response section for details.

Table 4.1: Reliability Indicators		
Metric Name		**Metric Performance Status**
	Transformers	**Improving**
M-13 Automatic AC Transmission Events Involving Human Error[72]	AC Circuits	**Improving**
	Transformers	**Improving**
M-14: Automatic AC Transmission Outages Initiated by Failed AC Substation Equipment	AC Circuits	**Stable**
	Transformers	**Monitor**
M-15: Automatic AC Transmission Outages Initiated by Failed AC Circuit Equipment (Number of Outages per 100 miles)		**Improving**
M-16: Transmission Element Availability Percentage and Unavailability Percentage	AC Circuits	**Stable**
	Transformers	**Monitor**
M-17: Transmission Outage Severity		**Stable**
M-18: TADS Physical Security Metric		**Stable**

Frequency Response Performance

2025 Interconnection Frequency Response

2025 analysis of frequency response performance and trends below indicates an adequate level of reliability. Further analysis is provided in NERC's *Frequency Response Annual Analysis* (FRAA).[73]

- For the stabilizing period (M4 metric), the EI, WI, and Texas Interconnection (TI) showed statistically significant improvements from 2021 through 2025, while the QI showed no statistically significant changes for the stabilizing period.
- For the arresting period (M4.1 metric), the EI, WI, and TI showed statistically significant improvements from 2021 through 2025, while the QI showed a statistically significant decline. It was noted in the 2024 SOR report that the decreasing trend in the arresting period metric for the QI was due to an overrepresentation of events in Summer 2023 (months that typically have lower inertia) compared to other years, in part due to the wildfire events in the region. A large number of events were also recorded in Summer 2025, which contributed to the declining trend. The QI has been experiencing low hydraulicity conditions since 2023. In 2025, this resulted in reduced energy exports and increased energy imports. Therefore, fewer hydro generating units were synchronized within the QI, particularly under summer light-load conditions, leading to lower system inertia during this period.
- For the underfrequency load shedding (UFLS) margin metric, the EI showed a statistically significant decline from 2021 through 2025. Although the decline is statistically significant, the magnitude of the decline, while measurable, is a very small magnitude. The year-over-year reduction in the mean and median UFLS margin values was only .003 Hz. During the five-year period, there have been changes to both the interconnection frequency response obligations (IFRO) and the minimum frequency bias settings, which will all have an impact on the UFLS margin metric. With UFLS starting

[72] Metric was revised in 2025 to evaluate the number of TADS events instead of outages. The change was made because a small number of events had resulted in a large number of outages. By tracking the frequency of human error events, the metric now tracks how often human error occurs instead of how many outages each instance happens to cause.

[73] 2025 FRAA Report

at .5 Hz off of nominal, the reduction is de minimis to reliability when the remaining margin to UFLS is taken into account.

- The number of valid events for the TI continues to decline. This was also noted in the 2024 SOR report. It was also noted in the 2024 SOR report that there was a declining trend for the number of events in the WI; however, the number of events measured in 2025 was back to within historical norms. This trend in the reduction of valid M4 events is suspected to be due to the retirement of large conventional generation as well as the ongoing integration of battery energy storage facilities in both Interconnections and is considered to be a positive indicator when considering impacts to Interconnection reliability.
- In both 2024 and 2025, there were multiple outlier events in the WI. The WI outlier events were reviewed and were not considered to be anomalous. This was also noted in the 2024 SOR report. These events represent the frequency response performance of the WI when a BA with a large battery energy storage system (BESS) fleet experiences a large resource loss. These events are becoming common place in both the WI and TI.

During the five-year period (**Table 4.2**), the WI had two events within the five-year period where the measured frequency response was less than the IFRO for the Interconnection. This was noted in the *2024 SOR*. Both events occurred in 2023 and had a starting frequency well above 60.00Hz and had a confirmed MW loss under 500 MW. These two factors combined eliminate any concerns that the WI frequency response is insufficient. The EI, TI, and QI did not have any events within the five-year period where the measured frequency response was less than the IFRO for the respective Interconnection.

Table 4.2: Five-Year Statistical Time Trend

Interconnection	M4 Stabilizing Period	M4.1 Arresting Period	Margin-C-UFLS	Comment
Eastern	Increasing	Increasing	Decreasing	No M4 events with FRM below IFRO
Texas	Increasing	Increasing	Increasing	No M4 events with FRM below IFRO
Western	Increasing	Increasing	Neither Increasing nor Decreasing	Two M4 events with FRM below IFRO in 2023
Québec	Neither Increasing nor Decreasing	Decreasing	Neither Increasing nor Decreasing	No M4 events with FRM below IFRO

Frequency response for all Interconnections indicates stable and improving performance for the stabilizing period as shown in **Table 4.3** below.

Table 4.3: 2025 Frequency Response Performance Statistics for Stabilizing Period										
2025 Operating Year Stabilizing Period Performance										
	Number of Events					Mean Frequency Response	Median	Minimum	Maximum	Number of events with FRM below the IFRO
	2021	2022	2023	2024	2025	MW per 0.1 Hz				
Eastern	29	46	47	44	37	2,824	2,443	1,107	6,784	0
Texas	44	33	39	23	22	1,634	1,376	961	3,509	0
Québec	42	22	65	61[74]	63	1,319	644	225	23,800	0
Western	43	30	28	15	29	2,953	2,600	1,256	7,650	0

During the arresting period, the goal is to arrest the frequency decline for credible contingencies before the activation of UFLS. The calculation for IFRO under BAL-003 is based on arresting the point C nadir before the first step of UFLS for resource contingencies at or above the resource loss protection criteria (RLPC)[75] for the Interconnection. Measuring and tracking the margin between the first step UFLS setpoint and the Point C nadir is an important indicator of risk for each Interconnection. **Figure 4.1** indicates the measurement periods used for analysis of the arresting period of events by looking at the frequency response between Value A and Point C as well as at the margin between Point C and the first step UFLS setpoint.

During the stabilizing period, the goal is to stabilize system frequency following a disturbance primarily due to generator governor action. **Figure 4.1** indicates the measurement periods used for analysis of the stabilizing period of events by looking at the frequency response between Value A and Value B.

Frequency response for the EI, WI, and TI indicates stable and improving performance for the arresting period for 2025. Frequency response for the QI indicates a declining trend for the arresting period for 2025 as shown in **Table 4.4** below.

Table 4.4: 2025 Frequency Response Performance Statistics for Arresting Period												
2025 Operating Year Arresting Performance												
	Number of Events					Mean Frequency Response	Median	Min	Max	Mean UFLS Margin	Median UFLS Margin	Min. UFLS Margin
	2021	2022	2023	2024	2025					For Loss of Generation M4 Events Only		
						MW per 0.1 Hz				Hz		
Eastern	29	46	47	44	37	2,104	1,980	1,036	3,400	0.452	0.451	0.439
Texas	44	33	39	23	22	786	764	504	1,382	0.608	0.610	0.544
Québec	42	22	65	63	63	119	123	51	196	1.078	1.149	0.649
Western	43	30	28	15	29	979	918	755	1,506	0.416	0.425	0.334

[74] GADS Events for 2024 has been updated

[75] BAL-003-2 specifies that the RLPC be based on the two largest potential resource losses in an Interconnection or the largest resource loss due to an N-2 RAS. This value is updated annually through the BAL-003-2 data collection process.

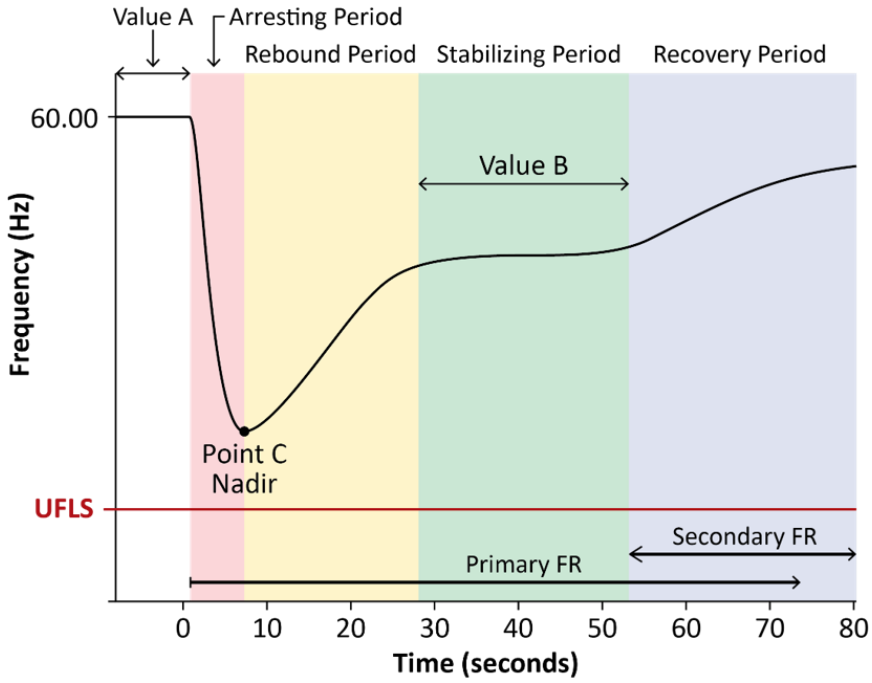


Figure 4.1: Frequency Response Methodology

Figure 4.2 represents an analysis of the arresting period of frequency response events. The Y-axis shows the percent UFLS margin from 100% (60 Hz) to 0% (first UFLS set point for the Interconnection). The X-axis represents the MW loss for the event, expressed as a percentage of the RLPC for the Interconnection. There were no events within the five-year period larger than the RLPC for any of the Interconnections. The largest events for the EI and TI were 50% as measured by percentage of RLPC. The largest events for the WI and QI were 88% and 96%, respectively, as measured by percentage of RLPC.

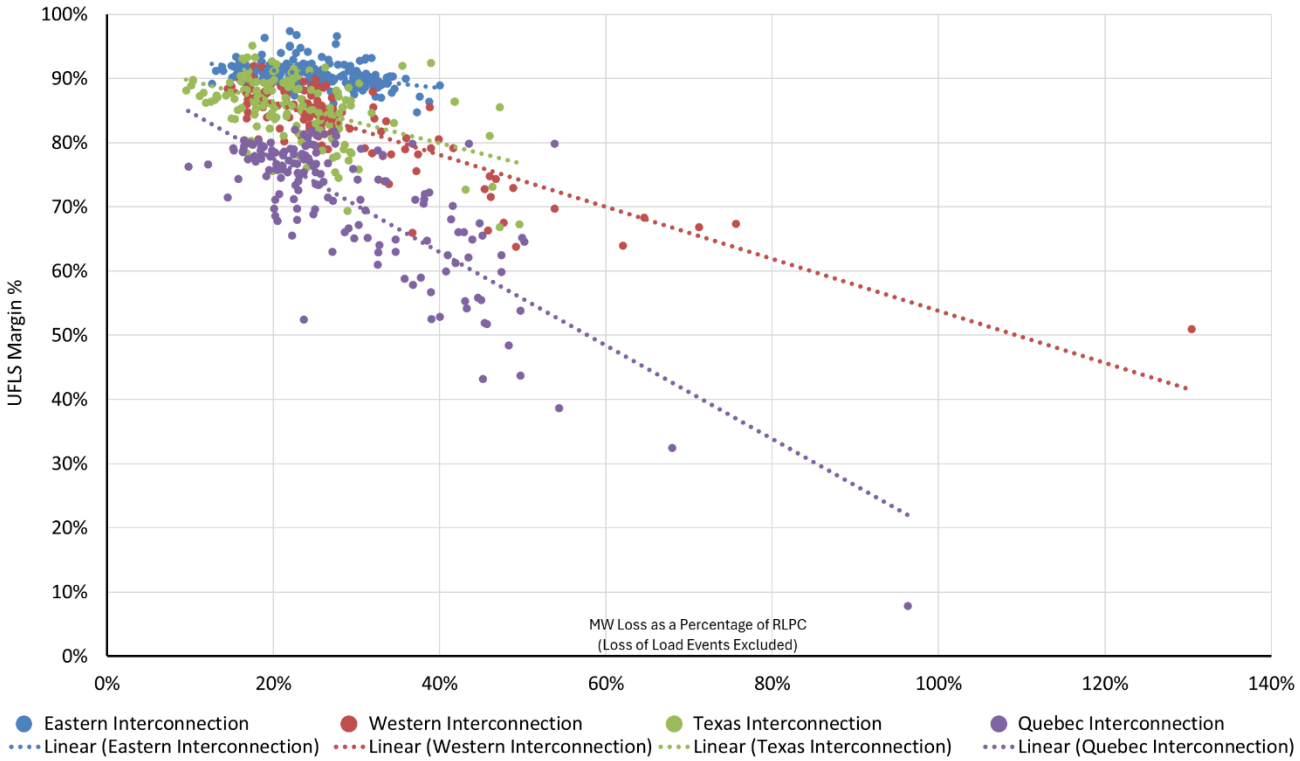


Figure 4.2: Operating Year 2021–2025 Qualified Frequency Disturbances and Remaining UFLS Margin

Interconnection Reliability Operating Limit Exceedances

2025 Performance and Trends

An IROL[76] is an SOL that, if exceeded, could lead to system instability, uncontrolled separation, or cascading that may adversely impact the reliability of the BES. The maximum time that an IROL can be exceeded is the IROL Tv. The IROL Tv must be less than or equal to 30 minutes. Each RC has a different methodology for determining IROLs based on the makeup of their area and what constitutes an operating condition that is less than desirable.

IROLs are established to ensure that corrective actions are taken to prevent and mitigate the exceedance of limits to either return to the Normal state or stay within the Alert state for certain conditions and contingencies that could otherwise cause the BPS to enter the extreme state, being at high risk of system instability, cascading, and uncontrolled separation.

The Texas and Western Interconnections both maintained stable trends with no IROL exceedances reported in 2025. In the Eastern–Québec Interconnections, there were 19 exceedances that lasted more than 10 minutes in 2025, more than the five-year rolling average of 11.8 exceedances as shown in **Figure 4.3**. The 10- to 20-minute range increased from a single exceedance in 2024 to 18 exceedances in 2025, while one exceedance lasted more than 20 minutes. The five-year average still declined slightly as year 2020 rolled off with 20 total exceedances.

[76] M-8, IROL Exceedance

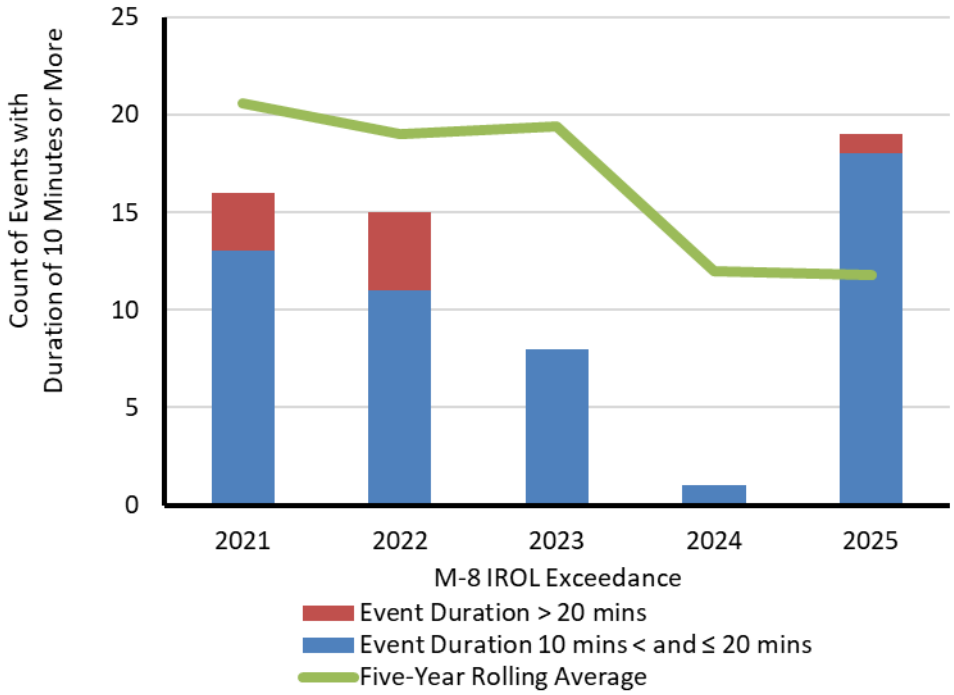


Figure 4.3: IROL Exceedance Counts

Generation Performance and Availability

GADS contains information that can be used to compute reliability measures, such as the weighted equivalent forced outage rate (WEFOR). GADS collects and stores unit operating information by pooling individual unit information, generating unit availability, performance, and calculated metrics.

Conventional Generation WEFOR

The horizontal lines in **Figure 4.4** show the annual WEFOR compared to the monthly WEFOR columns; the solid horizontal bar shows the WEFOR for all years in the analysis period of 8.1%. The 2025 WEFOR rate of 9.2% is a notable increase over 2024 (7.6%) and above recent historical norms in the 7–8% range.

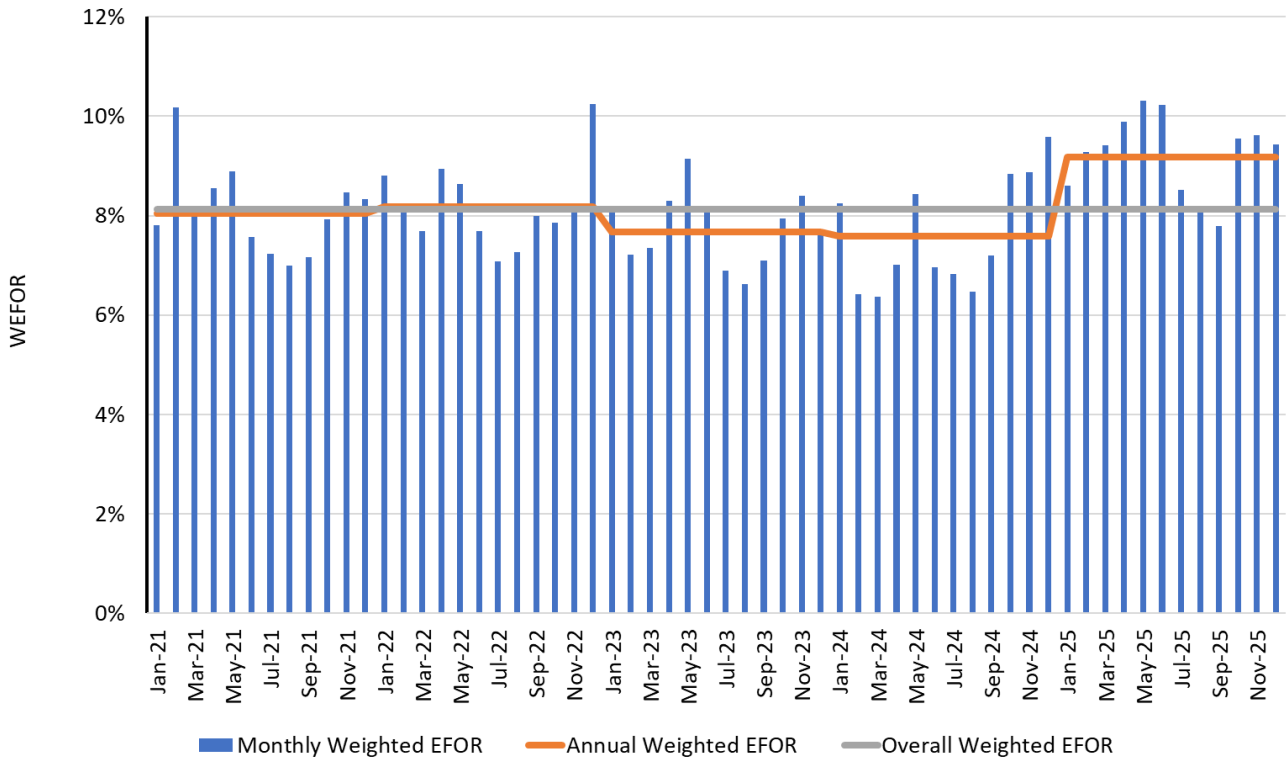


Figure 4.4: Monthly, Annual, and Five-Year WEFOR

Additional analysis identified that the increase is driven by combustion-based generators as shown in **Table 4.5**; further details are provided in the *2026 SOR Overview* report.

Table 4.5: Primary Fuel Type Year-Over-Year Change in MWh

Primary Fuel Type	2024 vs 2025 Year-Over-Year Change in GWh[77]	2024 WEFOR	2025 WEFOR
Gas - Steam Turbine	8,772	19.2%	22.4%
Gas - Simple Cycle Combustion Turbine	5,938	20.7%	22.8%
Gas – Simple Cycle w/Heat Recovery Steam Generator (HRSG)	-203	7.7%	7.0%
Combined Cycle	19,154	4.2%	5.7%
Coal	39,835	11.2%	14.1%
Oil - Steam Turbine	1,857	24.6%	25.6%
Oil - Combustion Turbine	2,427	48.2%	69.4%
Hydro	-3,171	8.4%	7.7%
Nuclear	-3,862	2.7%	2.2%
Other	-2,308	11.1%	8.4%
Total	68,440	7.6%	9.2%

[77] Measured by WEFOR numerator:
$\sum(([Forced\ Outage\ Hours] + [Equivalent\ Forced\ Derate\ Hours]) * [Net\ Maximum\ Capacity])$

The monthly WEFOR for major contributing fuel types is shown as a layered area chart with a relative capacity breakdown pie chart in **Figure 4.5**. The dashed line shows the monthly WEFOR of all fuel types reported to NERC, and the red line shows the mean outage rate of all fuel types reported to NERC over the five years in the analysis period. As stated above, in 2025, the annual WEFOR increased to 9.2%. Observing individual fuel types, coal experienced a fairly consistent increase in WEFOR throughout the year, simple cycle gas turbines experienced normal peak outage rates but with prolonged recovery, and combined cycle experienced both a baseline increase as well as two abnormal peak outage periods in early summer and early winter. These trends can be further contextualized by comparing the change in MWh of lost production due to forced unavailability from 2024 to 2025 in **Table 4.5**, examining each fuel's capacity percentage (**Figure 4.5**), and annual net actual generation (**Figure 4.6**).

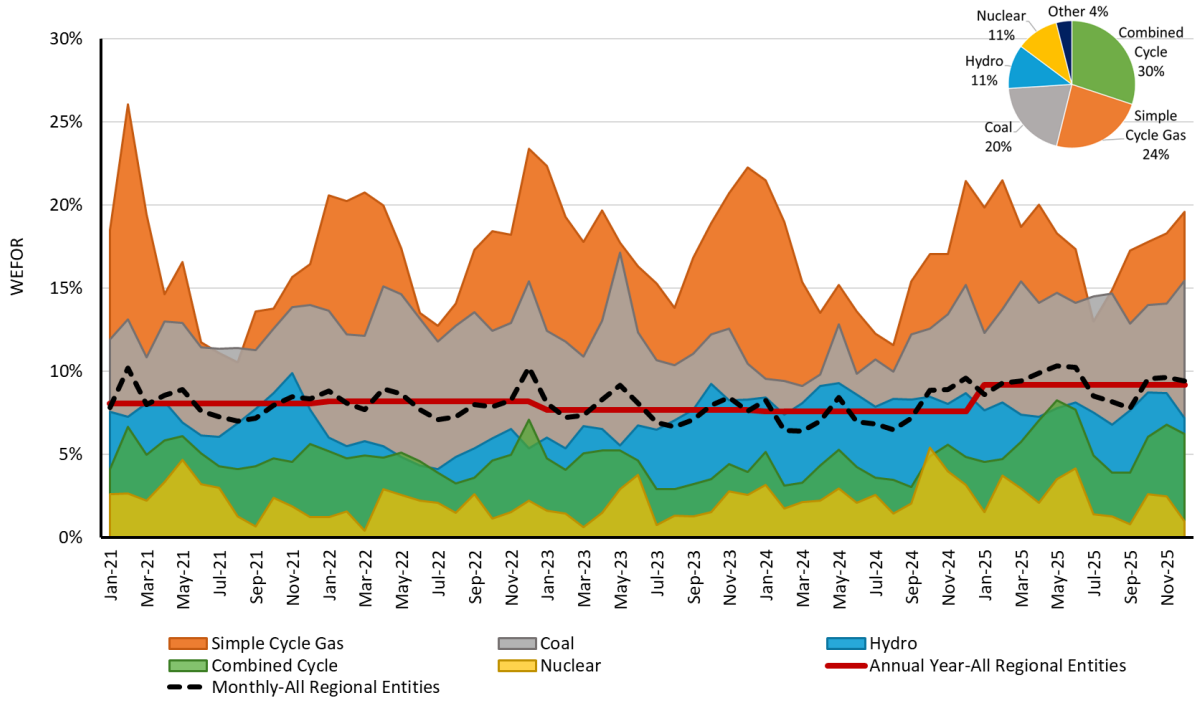


Figure 4.5: Five-Year WEFOR by Fuel Type and 2025 Resource Mix by Net Maximum Capacity

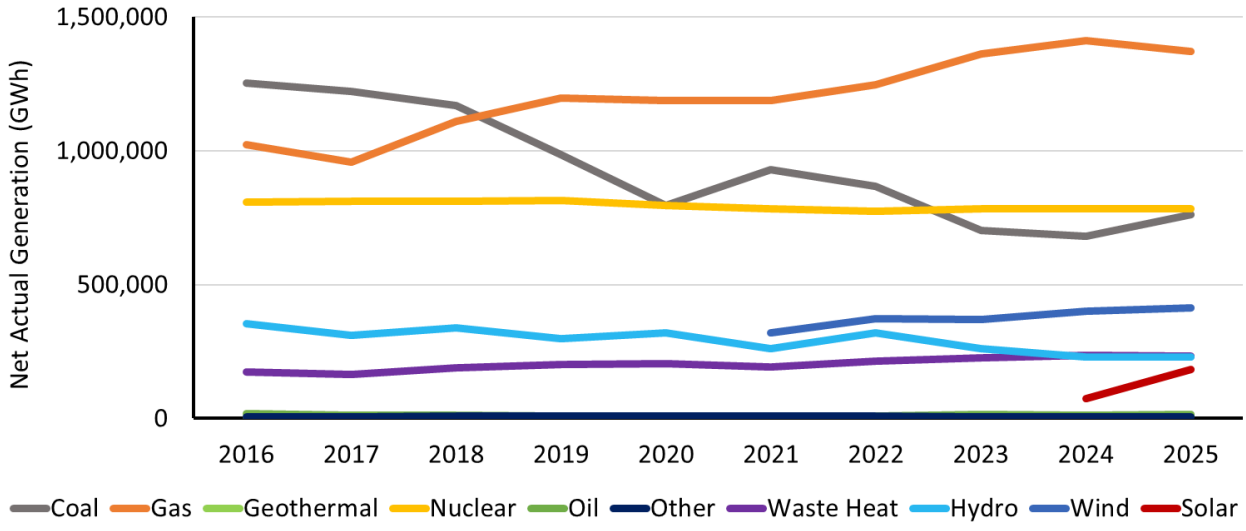


Figure 4.6: 10-Year Annual Net Actual Generation (GWh) by Fuel Type

Wind and Solar[78] Generation Weighted Factors

Figure 4.7–**Figure 4.9** present various weighted factors for wind[79] plant data collected in GADS. Because no exact analog to conventional generation's WEFOR calculation exists, the data is broken down into different factors representing what percentage of the month the plants were in each state and presented as a stacked area chart representing the entire duration of the month. For the purposes of this report, the following calculation and data modifications have been made:

- Resource forced outage factor has been separated into resource forced outage factor (representing forced equipment outages) and resource unavailable outage factor (representing forced outages due to a lack of generating resource).
- Resource reserve shutdown factor is calculated the same way as other factors, with reserve shutdown as the numerator.
- Generation losses due to sub-optimal resource conditions are calculated by subtracting the resource net capacity factor from the resource generating factor. The value represents the portion of the month in which the plant was producing at less than full capacity. For example, if a wind plant has 100 MW of installed capacity but due to wind speed is only producing 60 MW and has no other constraints, this value would be 40%.

Wind data is presented in **Figure 4.7**–**Figure 4.9**, with each figure showing a different stage of data collection: plants >200 MW, 100–199 MW, and 75–99 MW.

NERC is continuing to develop unbiased, representative analysis for wind and solar analysis to best understand trends in the data and draw comparisons to more conventional resources. In 2025, equipment performances across all wind plant sizes were comparable to one another and would not be considered problematic compared to conventional generation, with a resource forced outage factor (RFOF) most like hydro generation's WEFOR. Energy generation at plants >200 MW declined in 2025, warranting further investigation.

[78] During this year's data analysis, NERC identified significant GADS solar data reporting errors and numerous missing plants compared to EIA 860 data. NERC will be coordinating with Regional Entity staff to perform industry outreach and resolve these errors in 2026.

[79] 2025_GADS_Wind_DRI

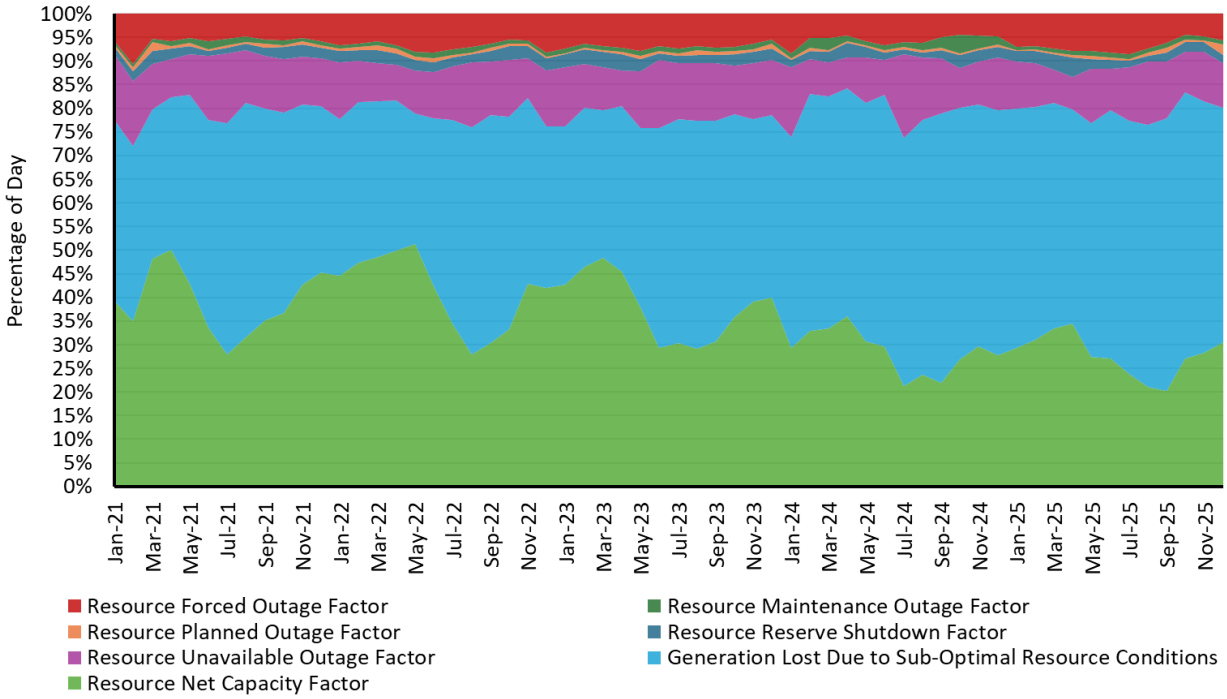


Figure 4.7: Monthly Net Output Factor and Weighted Resource Forced Outage Rate (WRFOR) Wind Plant Reporting Group 200 MW+

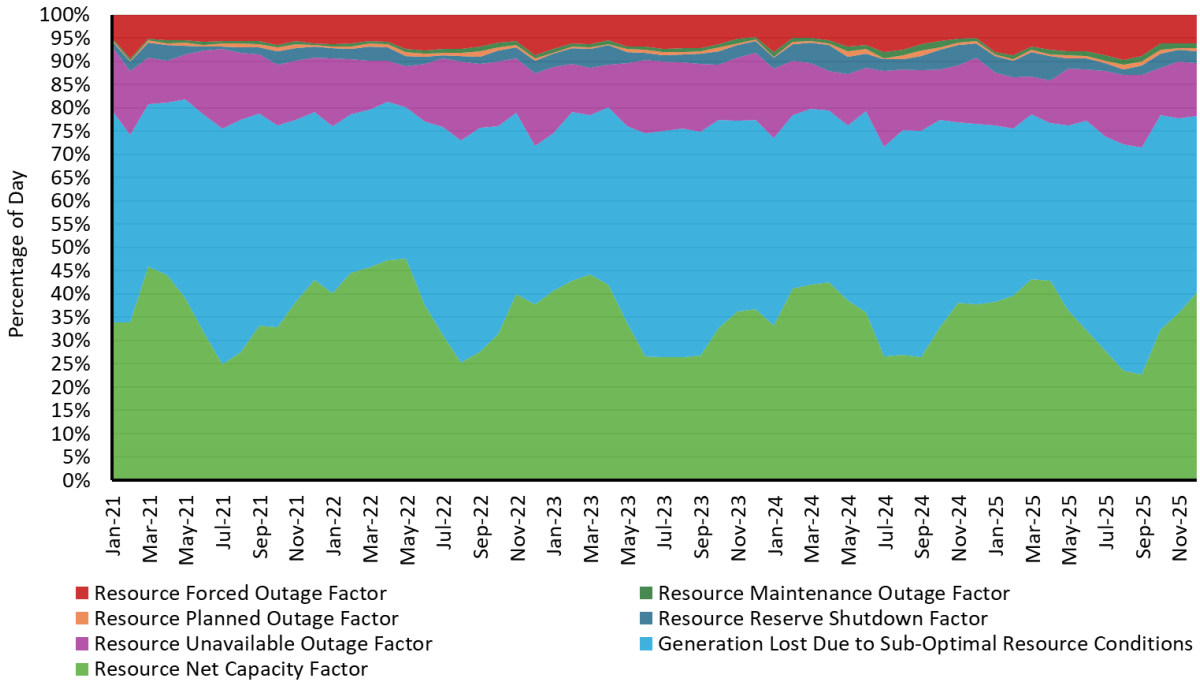


Figure 4.8: Monthly Net Output Factor and WRFOR Wind Plant Reporting Group 100–199 MW

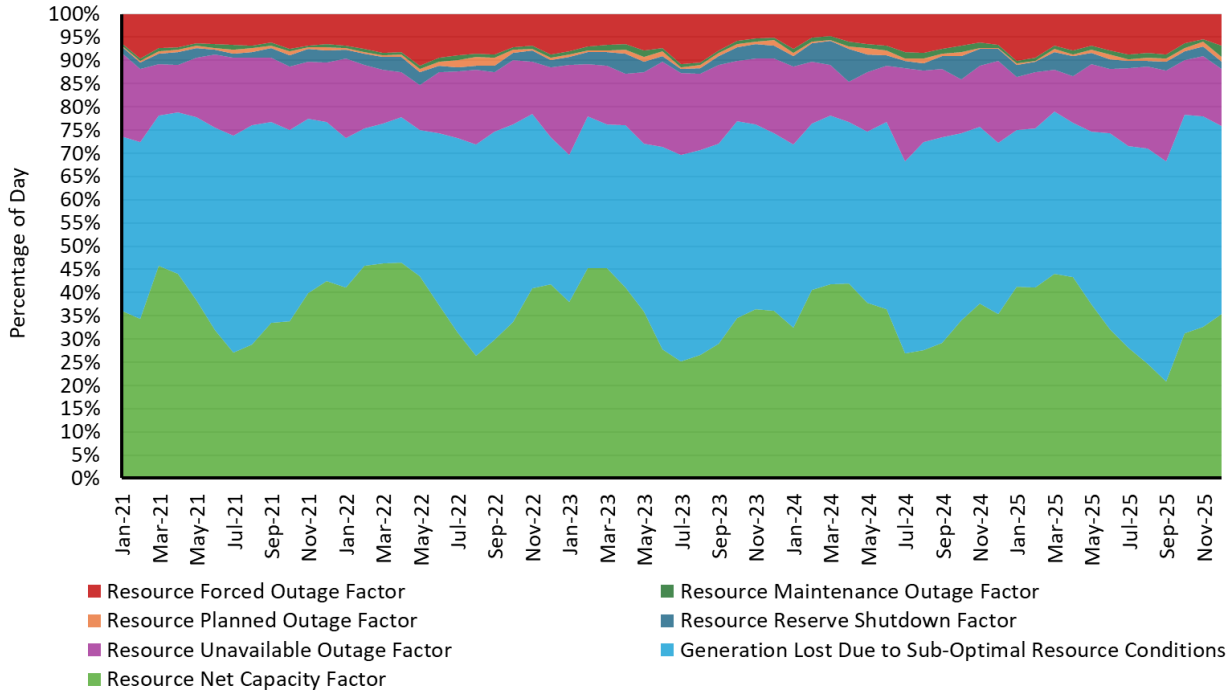


Figure 4.9: Monthly Net Output Factor and WRFOR Wind Plant Reporting Group 75–99 MW

Transmission Performance and Unavailability

When evaluating transmission reliability, an important concept is that transmission line outages have different impacts on BPS reliability. Some impacts can be very severe, such as those that affect other transmission lines and load loss. Additionally, some outages are longer than others, leaving the transmission system at risk for extended periods of time. Reliability indicators for the transmission system are measured by using qualified event analysis reporting not related to weather and outages reported to TADS.

Transmission-Related Events Resulting in Loss of Load

In 2025, a total of six distinct non-weather-related transmission events resulted in a loss of firm load that met the ERO EAP reporting criteria (**Figure 4.10**). The median firm load loss over the past five years was 88.0 MW, which is a decrease from 2020–2024's 90 MW. In 2024 the median load loss was 85.5 MW or 47.0 MW below the 2020–2023 median, and 2025 saw the median increase to 132.5 MW, which is 44.5 MW above the 2021–2024 median.

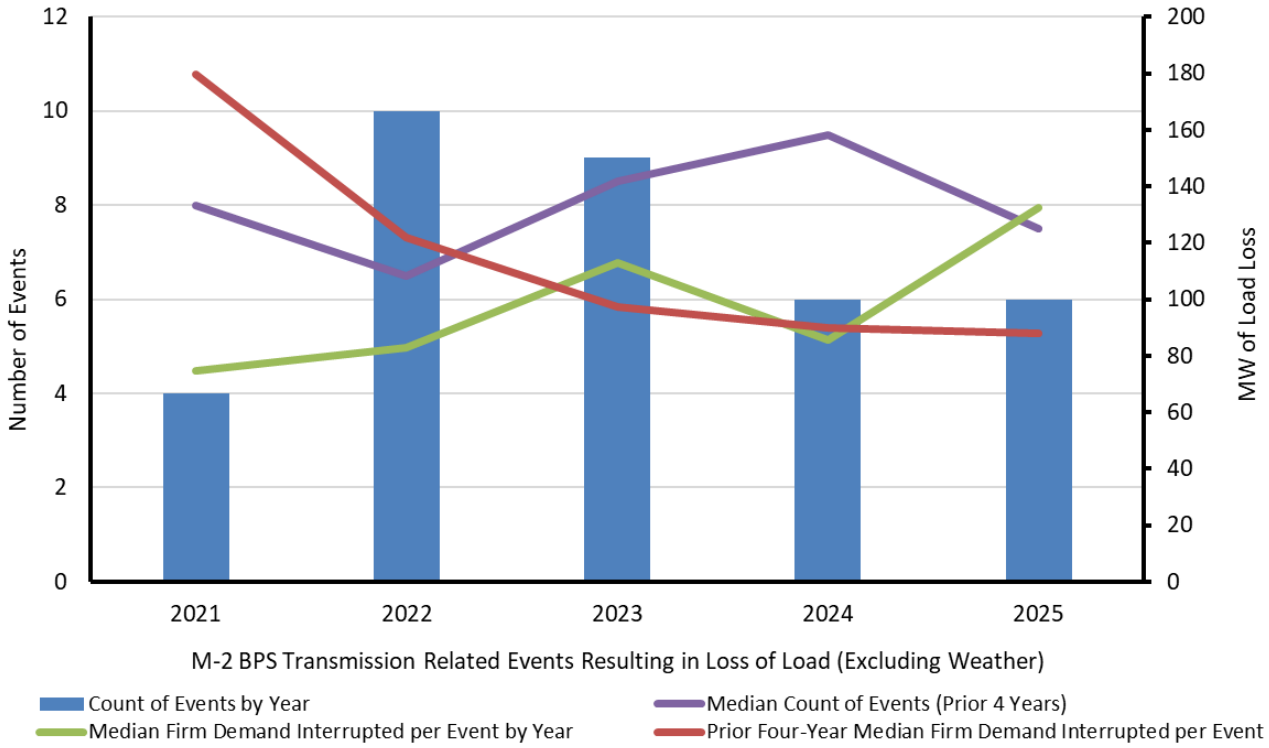


Figure 4.10: Transmission-Related Events Resulting in Loss of Firm Load and Median Amount of Firm Load Loss Excluding Weather-Related Events[80]

TADS Reliability Indicators

A TADS event is an unplanned transmission incident that results in the automatic outage (sustained or momentary) of one or more elements. TADS event information was analyzed for the following indicators in this section:

- **Transmission Outage Severity**
- **Automatic AC Transmission Outages**
- **Transmission Element Unavailability**

Transmission Outage Severity

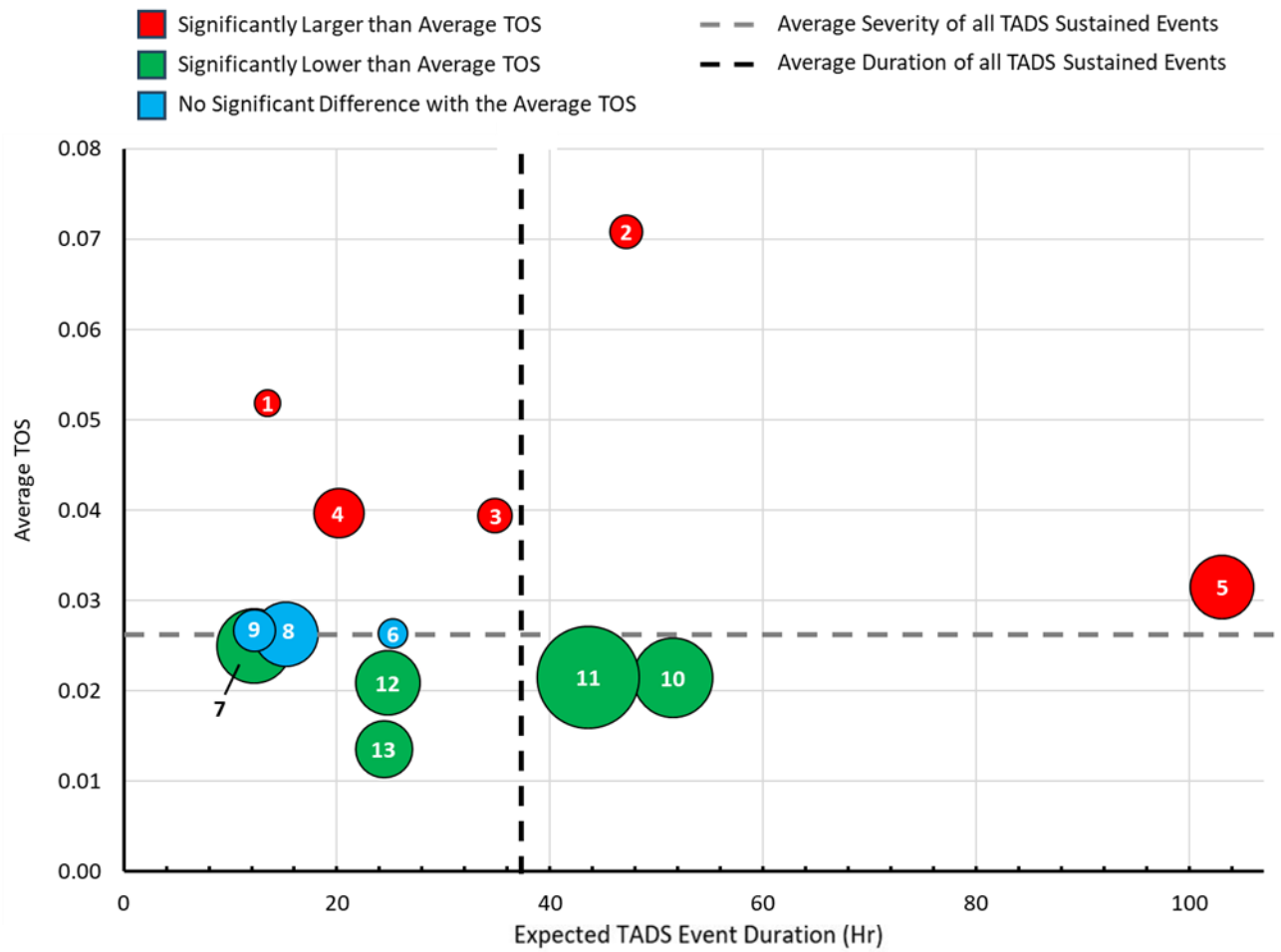
The impact of a TADS event on BPS reliability is called the transmission outage severity (TOS) of the event, which is defined by the number of sustained outages in the event and by the type and voltage class of transmission elements involved in the event. TADS events are categorized by initiating cause codes (ICC). These ICCs facilitate the study of cause-effect relationships between each event's ICC and event severity.

The number of events per hour, average event duration, and average TOS for each ICC group are shown in **Table 4.6**.

[80] M-2, BPS Transmission Related Events Resulting in Loss of Load (Excluding Weather)

Table 4.6: TOS vs. Expected TADS Event Duration				
TADS Event	Events per Hour	TOS		Average Event Duration (Hours)
		Average	Maximum	
Combined Smaller ICC Groups	0.018	0.039	0.318	34.9
Failed AC Circuit Equipment	0.099	0.021	0.249	51.5
Failed AC Substation Equipment	0.063	0.032	0.414	103.1
Fire	0.017	0.071	0.652	47.2
Foreign Interference	0.064	0.021	0.196	24.8
Human Error	0.027	0.027	0.377	12.3
Lightning	0.064	0.026	0.519	15.2
Misoperation	0.038	0.040	0.732	20.2
Other	0.013	0.026	0.327	25.2
Power System Condition	0.011	0.052	0.998	13.5
Unknown	0.086	0.025	0.365	12.2
Vegetation	0.050	0.014	0.494	24.4
Weather, Excluding Lightning	0.163	0.022	0.654	43.6

By examining the average TOS, duration, and frequency of occurrence for events with different ICCs (**Figure 4.11**) it is possible to determine which ICCs contribute most to reliability performance for the period under consideration. The average TOS for events with a specific ICC is displayed on the Y-axis. A higher TOS for an ICC indicates that more sustained outages or higher voltage elements were involved in an event. The average duration for events with a specific ICC is displayed on the X-axis; generally, events with a longer duration pose a greater risk to the BPS. The number of ICC occurrences is represented by the bubble size; larger bubbles indicate that an ICC occurs more often. Lastly, the bubble colors indicate a statistical significance of a difference in the average TOS of this group and the events from other groups.



1. Power System Condition
2. Fire
3. Combined Smaller ICC Groups
4. Misoperation
5. Failed AC Substation Equipment
6. Other
7. Unknown
8. Lightning
9. Human Error
10. Failed AC Circuit Equipment
11. Weather, Excluding Lightning
12. Foreign Interference
13. Vegetation

Figure 4.11: TOS vs. Expected TADS Event Duration

An analysis of the total TOS by year indicates that 2025 shows an improving trend compared to 2024, with the Unknown category improving to the point that it went from the No Significant Difference category (blue) in 2024 to the Significantly Lower than Average TOS category (green) in 2025. All other categories remained the same. **Figure 4.12** shows the annual TOS, which is the lowest since TADS data collection began.

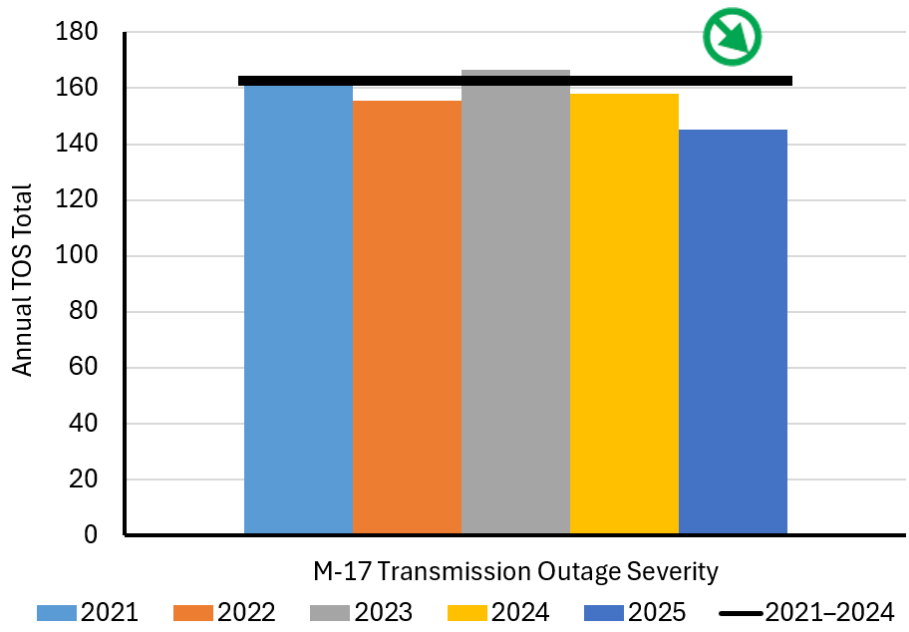


Figure 4.12: TOS of TADS Sustained Events of 100 kV+ AC Circuits and Transformers by Year[81]

Automatic AC Transmission Outages

The average number of outages per circuit due to failed ac substation equipment slightly decreased from 2024 to 2025 and is effectively equal to the previous four-year average (**Figure 4.13**). The number of sustained outages due to failed ac circuit equipment per 100 miles decreased in 2025 to the lowest of the past five years (**Figure 4.14**).

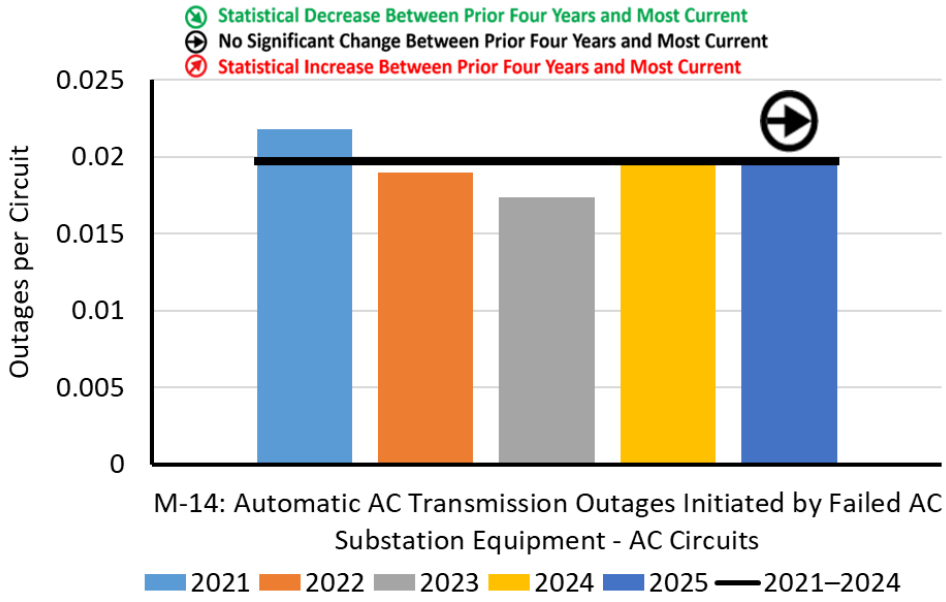


Figure 4.13: Number of Outages Per AC Circuit Due to Failed AC Substation Equipment[82]

[81] M-17, Transmission Outage Severity
[82] M-14, Automatic AC Transmission Outages Initiated by Failed AC Substation Equipment

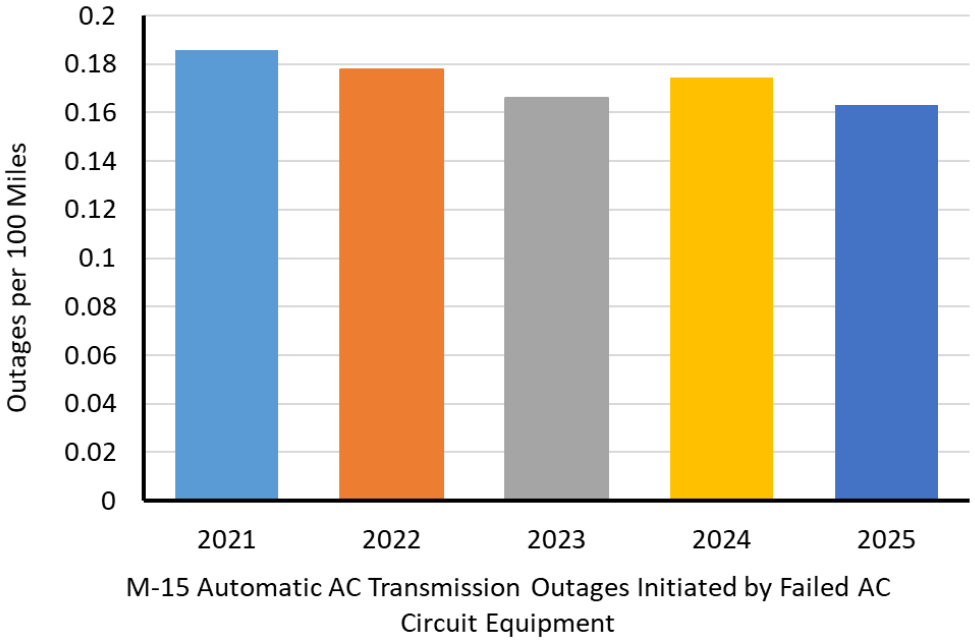


Figure 4.14: Number of Outages Per 100 Miles Due to Failed AC Circuit Equipment[83]

Automatic AC Transformer Outages

In 2025, there was a slight decrease in the number of automatic ac transformer outages per element caused by failed ac substation equipment, but there was no significant change compared to the prior four years. Though the decrease in outages is not statistically significant, as can be seen in **Figure 4.15**, this number remains the second highest over the past five years.

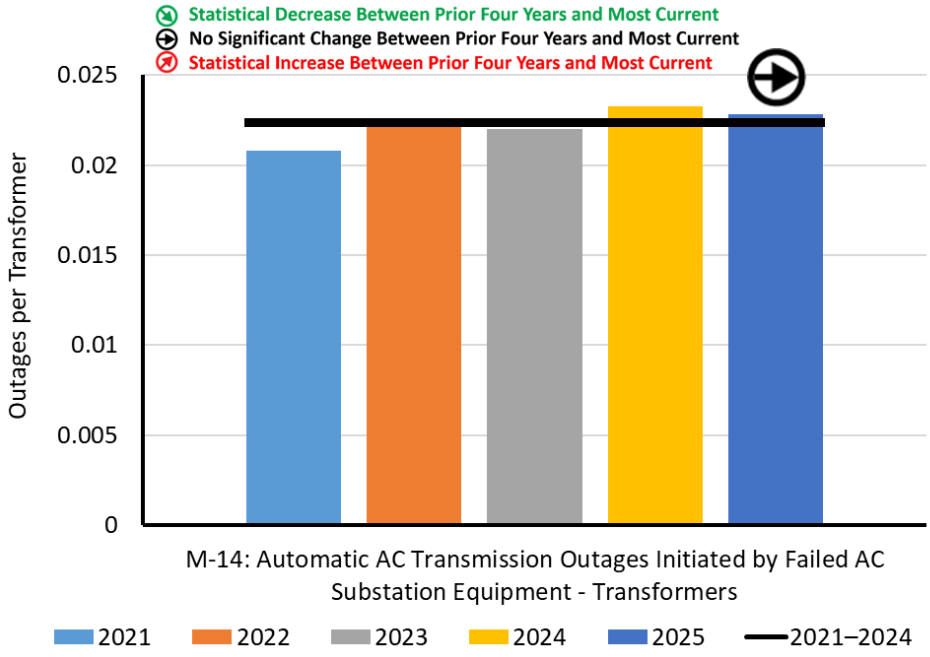


Figure 4.15: Number of Outages Per Transformer Due to Failed AC Substation Equipment[84]

[83] M-15, Automatic AC Transmission Outages Initiated by Failed AC Circuit Equipment
[84] M-14, Automatic AC Transmission Outages Initiated by Failed AC Substation Equipment

Transmission Element Unavailability

In 2025, ac circuits over 200 kV across North America had an unavailability rate of 0.22%, representing the chance that a specific transmission circuit is unavailable due to sustained automatic and operational outages at any given time. Transformers also had an unavailability rate of 0.35% in 2025. **Figure 4.16** shows that while there was a decrease in ac circuit availability in 2025, it was not statistically significant when compared to the prior four years.

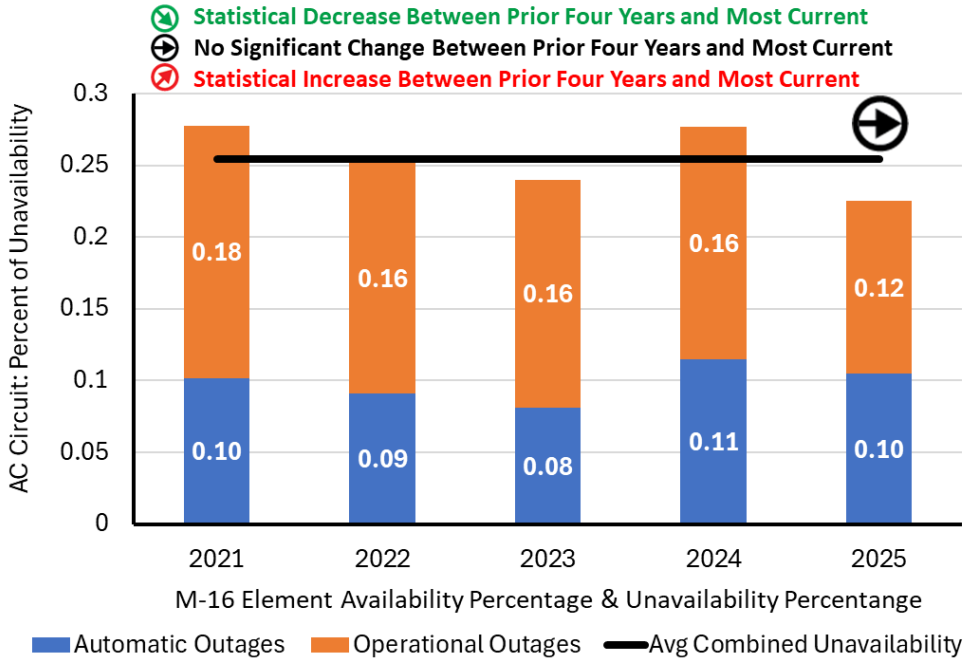


Figure 4.16: AC Circuit Unavailability >200 kV[85]

Figure 4.17 shows that 2025 is the highest year for transformer unavailability of the five-year analysis period, in large part due to an increase in the number of operational outages. Responses from voluntary outreach to utilities with the longest operational transformer outages in 2025 aligned with historically provided reasons for prolonged outages and did not indicate the need for immediate action. In addition to several one-off scenarios, common themes included removing transformers temporarily multiple times to maintain system reliability, system redundancy reducing restoration urgency, and two instances where supply chain constraints in the form of known long lead times prolonged outages.

[85] M-16, Element Availability Percentage (APC) & Unavailability Percentage

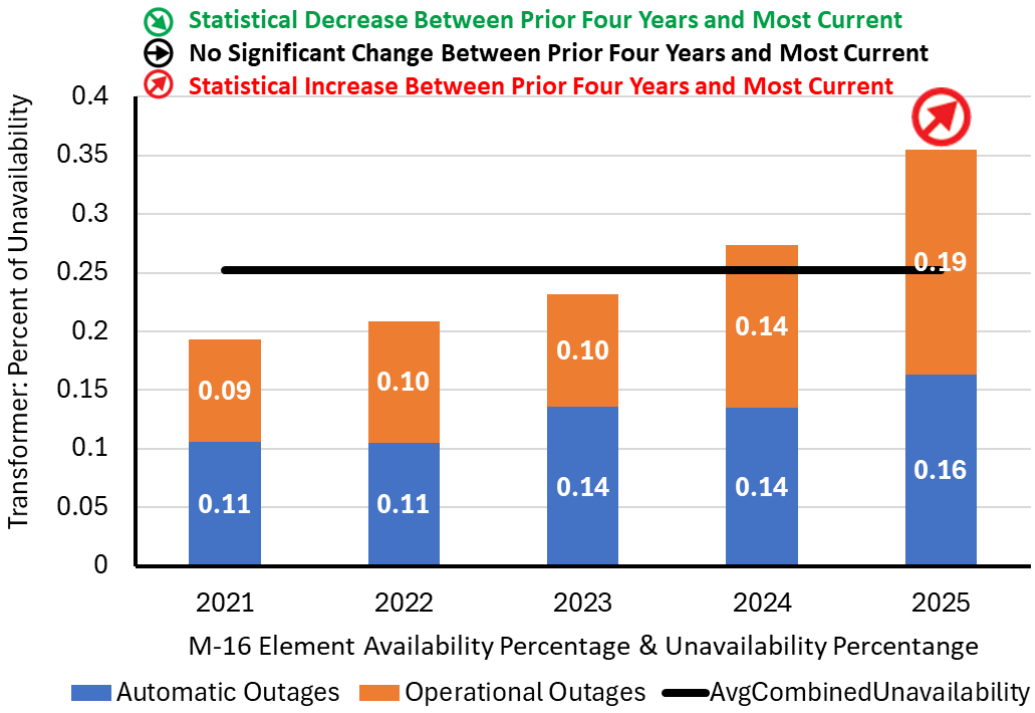


Figure 4.17: Transformer Unavailability >200 kV [86]

TADS Physical Security Metric

Over the past several years, there has been an increase in physical attacks on the BPS. To help measure the impact of these transmission physical security events on the BES and identify trends, a new metric was introduced, the TADS Physical Security Metric (M18), described as follows.

- The TADS Physical Security metric uses the data from TADS sustained physical security-related outages for transmission elements reportable in TADS with a voltage of 100 kV and above. Prior to 2024, these outages were reported using the initiating or sustained cause code labeled Vandalism, Terrorism, or Malicious Acts. Since 2024, these outages have been reported using the initiating or sustained cause code labeled Physical Security Incident. The metric is calculated by adding the number of outages, their average equivalent MVA, and their average duration, for a rolling five-year period that is then statistically compared to identify trends.
- The bubble chart in **Figure 4.18** shows a rolling comparison of the TADS Physical Security metric of 2021–2025 to 2020–2024. The size of a bubble represents the total number of physical security outages (displayed in the center of each bubble). The X-axis of a bubble shows the average duration of the outages (in hours), and the Y-axis shows the average MVA capacity impacted for those outages.

[86] M-16, Element Availability Percentage (APC) & Unavailability Percentage

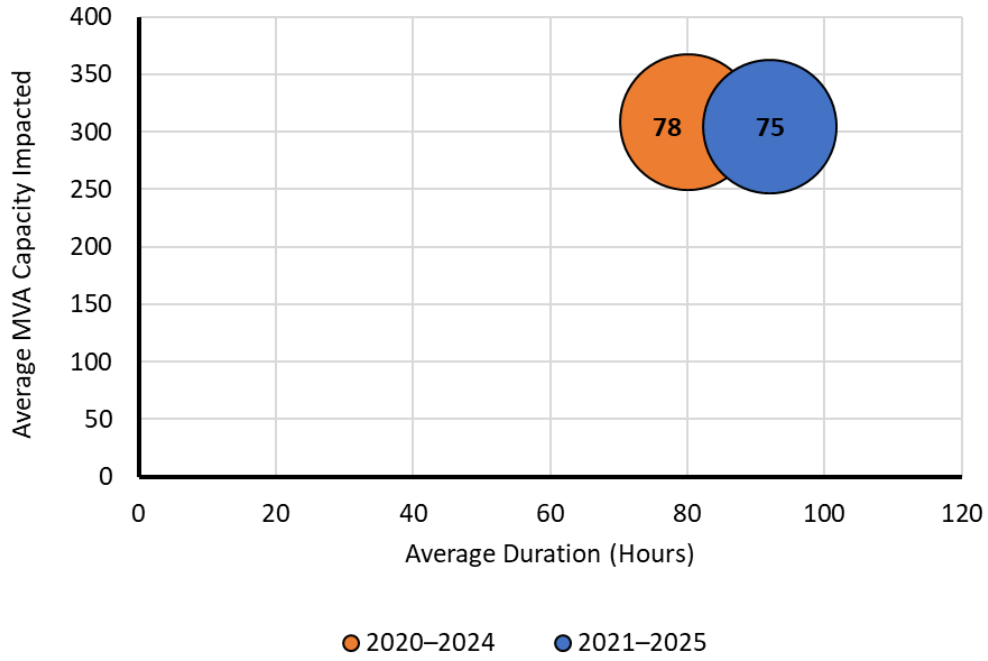


Figure 4.18: Comparison of TADS Physical Security Metric for 2020–2024 vs. 2021–2025[87]

Figure 4.18 shows a decreasing trend in both the total number of physical security outages (from 78 to 75) and average MVA capacity (from 308.5 MVA to 304.6 MVA) and an increase in the average duration for those outages (from 80 hours to 92 hours). Based on the rating criteria for this metric, the assessment rating for this metric is Stable.

Table 4.7: 2025 M-18 TADS Physical Security Metric		
	2020–2024	2021–2025
Outage Count	78	75
Average MVA	308.5	304.57
Average Duration (Hours)	80.15	92.03

Incident Tracking Context/Background

The E-ISAC tracks physical security incidents shared by asset owners across North America to reduce physical security risks to the sector by monitoring and reporting on relevant trends such as the criminal threat environment and the tactics, techniques, and procedures that result in operational impacts to the North American grid. In addition to physical security incidents reported to the ERO through mandatory mechanisms such as the DOE-417 and EOP-004 forms, the E-ISAC tracks incidents shared voluntarily by members on the E-ISAC Portal or shared directly with the E-ISAC through the Bulk Data Program. Approximately 91% of incidents tracked by the E-ISAC since 2021 were received through voluntary methods. Since 2021, the E-ISAC has tracked over 17,000 physical security incidents within the following categories: Assault, Ballistic Damage, Intrusion, Theft, Threat, Surveillance, Suspicious Activity, and Other. Of these 17,000, less than 3% have resulted in operational impacts since 2021 (**Table 4.8**), though the proportion typically fluctuates within shorter time periods between 2% and 4%.

[87] M-18, TADS Physical Security

Table 4.8: E-ISAC Severity Level Definitions and Data Summary (2021–2025)[88]		
Severity Level	**Definition**	**% of incidents**
Level 0	Non-criminal, potential security nexus	11%
Level 1	Likely criminal activity with no operational impacts; only monetary.	86%
Level 2	Some operational impacts; including limited customer outages, generation unavailability, or partial loss of control and monitoring.	2%
Level 3	Significant operational impacts; including extensive customer outages, generation unavailability or loss of control and monitoring.	<1%

Operational Impacts Increasing

Since 2021, Level 2 and Level 3 incidents shared with the E-ISAC have increased (**Figure 4.19**). While 2023 saw an increase in Ballistic Damage incidents resulting in operational impacts, the primary tactics that increased throughout 2024 and 2025 involved Theft or Vandalism. The change in tactics reflects the changing risk environment and can be attributed to copper market spikes and supply chain constraints, leading to increased targeting of copper through Theft and Vandalism. In 2025, the E-ISAC observed sustained levels of Vandalism and Ballistic Damage compared to historic norms, paired with an increase in operational impacts from Theft and continued targeting of fiber infrastructure.

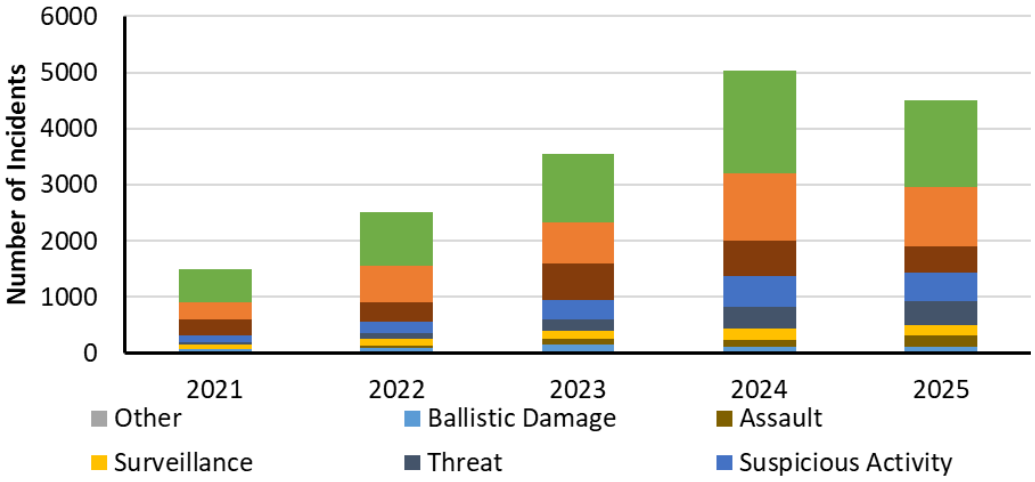


Figure 4.19: Incidents Resulting in Operational Impacts (Severity Level 2 and Level 3) by Tactic (2021–2025)

Unlike Operational Impacts, Overall Incidents Decreased

In 2025, overall incidents shared with the E-ISAC decreased by 11% compared with 2024 (**Figure 4.19**); this decline was relatively consistent between mandatory/voluntarily shared incidents for all severity levels. This is in contrast to incidents discussed above resulting in operational impacts. The differing volume trend observed between all incidents versus those resulting in operational impacts can be attributed to a shifting tactical focus by adversaries, with copper thefts increasingly affecting energized distribution (non-substation) assets, resulting in customer outages.

For more insight into the risks to industry related to physical security incidents that result in operational impacts, see the E-ISAC's annual Grid-Impacting Report (available to E-ISAC members on the Portal).

[88] https://www.eisac.com/portal/article/124886-Physical-Security-Incident-Severity-Level-Categorization

Appendix A: Supplemental Analysis at Interconnection Level

Severity Risk Index by Interconnection

Eastern and Québec Interconnections

The cumulative SRI for the EI and QI in **Table A.1** shows a 3% increase compared to the average of the four-year period of 2021–2024. The 2025 cumulative SRI was the second highest among the five years analyzed.

Table A.1: Annual Cumulative SRI, Eastern and Québec Interconnections

Year	Cumulative Weighted Generation	Cumulative Weighted Transmission	Cumulative Weighted Load Loss	Annual Cumulative SRI	Average Daily SRI
2021	346.3	53.7	65.8	465.9	1.28
2022	385.1	52.3	53.0	490.4	1.34
2023	324.5	64.4	47.2	436.1	1.19
2024	358.7	59.5	52.0	470.2	1.28
2025	**367.5**	**52.7**	**46.8**	**467.0**	**1.28**

The top 10 SRI days of the EI and QI were distributed throughout the year as shown in **Figure A.1** (numbered circles). A total of 7 of the top 10 days that occurred in the EI and QI aligned with the top 10 SRI days reported for North America.

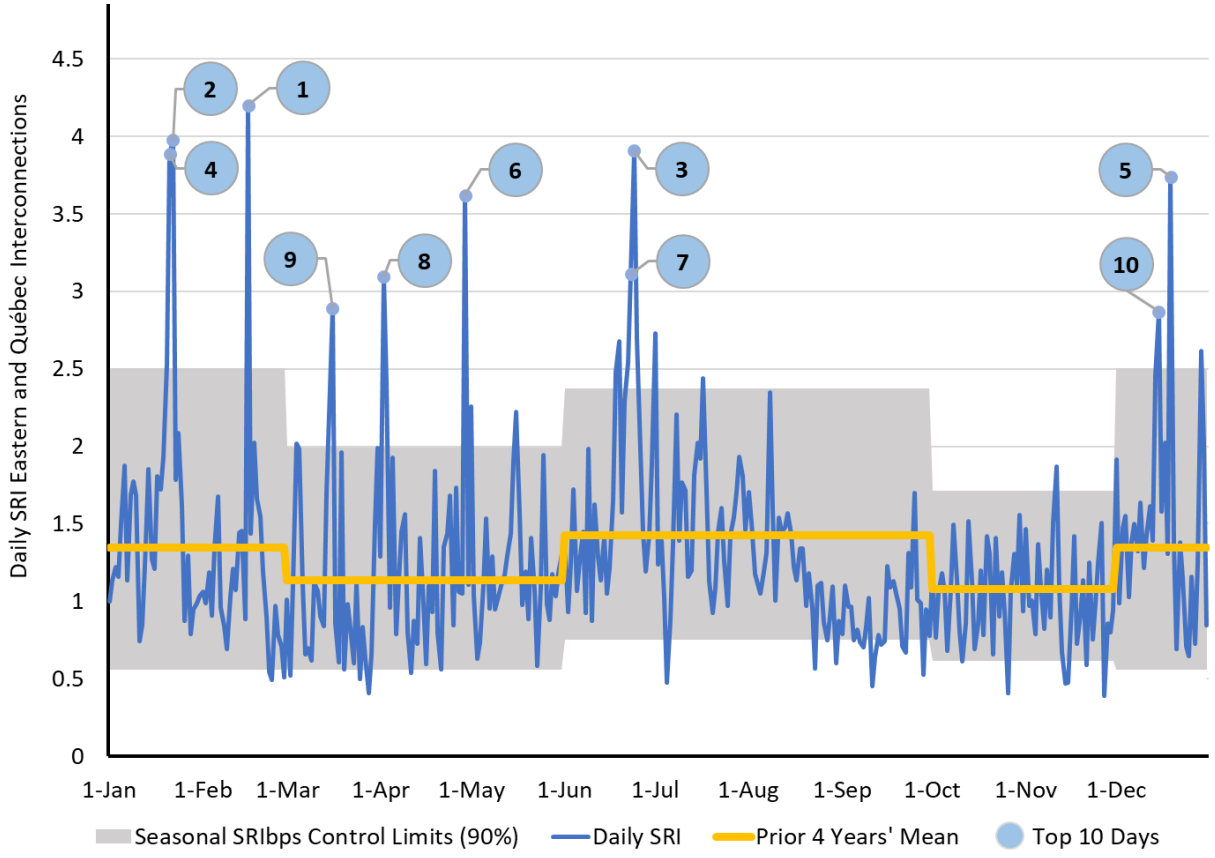


Figure A.1: 2025 Eastern and Québec Interconnections Daily SRI with Top 10 Days Labeled, 90% Confidence Interval

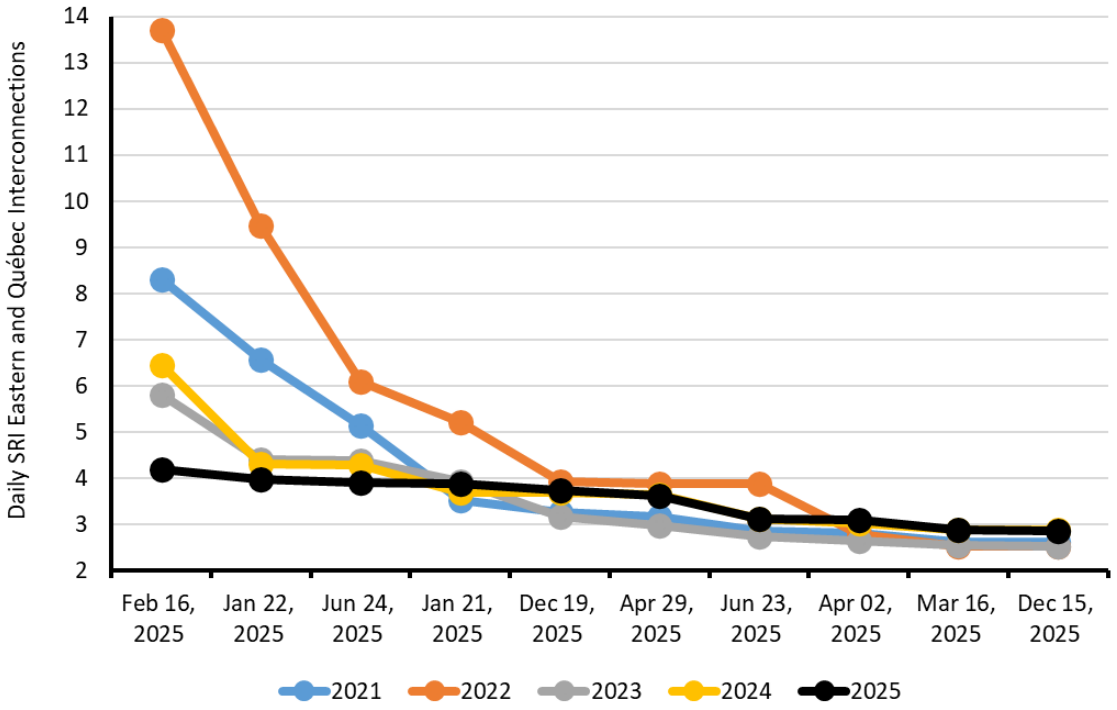


Figure A.2: Eastern and Québec Interconnections Top Annual Daily SRI Days, Sorted Descending

Figure A.2 shows the EI and QI's top 10 SRI days in 2025 relative to the four prior years, while **Table A.2** provides details on each component's contribution to the top 10 SRI days. Out of the top 10 SRI days for the EI and QI, three were driven by load loss, one was driven by a combination of generation and load loss, none were driven by transmission, and the rest were predominantly driven by generation.

Table A.2: 2025 Top 10 SRI Days, Eastern and Québec Interconnections

Rank	Date	SRI and Weighted Components 2025				Atypical Weather Conditions	Regional Entities
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss		
1	February 16, 2025	4.20	2.20	0.31	1.68	Northwestern Atmospheric River	WECC
2	January 22, 2025	3.98	3.74	0.15	0.08	Winter Storm Enzo	RF, SERC
3	June 24, 2025	3.91	3.09	0.26	0.55	Thunderstorms	NPCC, RF, SERC
4	January 21, 2025	3.89	3.71	0.10	0.07	Winter Storm Enzo	RF, SERC
5	December 19, 2025	3.74	1.70	0.29	1.76	Northwestern Atmospheric River	WECC
6	April 29, 2025	3.62	1.06	0.37	2.19	Thunderstorms	MRO, NPCC, RF
7	June 23, 2025	3.11	2.13	0.16	0.82	Thunderstorms	NPCC, RF, SERC
8	April 2, 2025	3.09	0.99	0.55	1.56	Tornadoes & Severe Storms	MRO, RF, SERC
9	March 16, 2025	2.89	0.50	0.34	2.05	Tornadoes	MRO, RF, SERC
10	December 15, 2025	2.87	2.51	0.07	0.29	Winter Storm	RF, SERC, Texas RE

Table A.3 shows the top 10 SRI days for the EI and QI over the last five years with no dates in 2025.

Table A.3: 2021–2025 Top 10 SRI Days, Eastern and Québec Interconnections

Rank	Date	SRI and Weighted Components 2025				Atypical Weather Conditions	Regional Entities
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss		
1	December 23, 2022	13.70	8.88	0.90	3.92	Winter Storm Elliott	All
2	December 24, 2022	9.46	8.12	1.27	0.07	Winter Storm Elliott	All
3	February 16, 2021	8.31	4.10	0.58	3.63	Cold Weather Event	MRO, RF, SERC
4	December 11, 2021	6.57	0.92	0.92	4.73	Severe Storms	NPCC, RF, SERC
5	September 27, 2024	6.45	1.62	3.61	1.23	Hurricane Helene	SERC
6	June 14, 2022	6.09	1.70	0.49	3.90	High Temperatures and Derecho	All
7	April 1, 2023	5.80	0.74	0.63	4.43	Widespread Storms and Tornadoes	MRO, RF, SERC
8	June 15, 2022	5.22	1.63	0.24	3.36	Hurricane Isaias	NPCC, RF, SERC
9	February 15, 2021	5.15	3.62	0.54	0.99	Unnamed Tropical Storm	RF, SERC
10	June 22, 2023	4.42	1.34	2.95	0.13	High Temperatures and Derecho	All

Western Interconnection

The 2025 cumulative SRI for the WI shows an 9% decrease over the prior four-year period of 2021–2024. The 2025 cumulative SRI was the lowest among the five years analyzed (**Table A.4**).

Table A.4: Annual Cumulative SRI, Western Interconnection

Year	Cumulative Weighted Generation	Cumulative Weighted Transmission	Cumulative Weighted Load Loss	Annual Cumulative SRI	Average Daily SRI
2021	426.8	98.2	97.8	622.7	1.71
2022	423.8	87.3	60.1	571.2	1.57
2023	423.1	68.6	59.6	551.3	1.51
2024	418.0	74.3	50.1	542.4	1.48
2025	**402.5**	**76.2**	**42.2**	**521.0**	**1.43**

The top 10 SRI days of the WI for 2024 were distributed throughout the year as shown in **Figure A.3**. A total of 2 of the top 10 days that occurred in the WI aligned with the top 10 SRI days reported for North America.

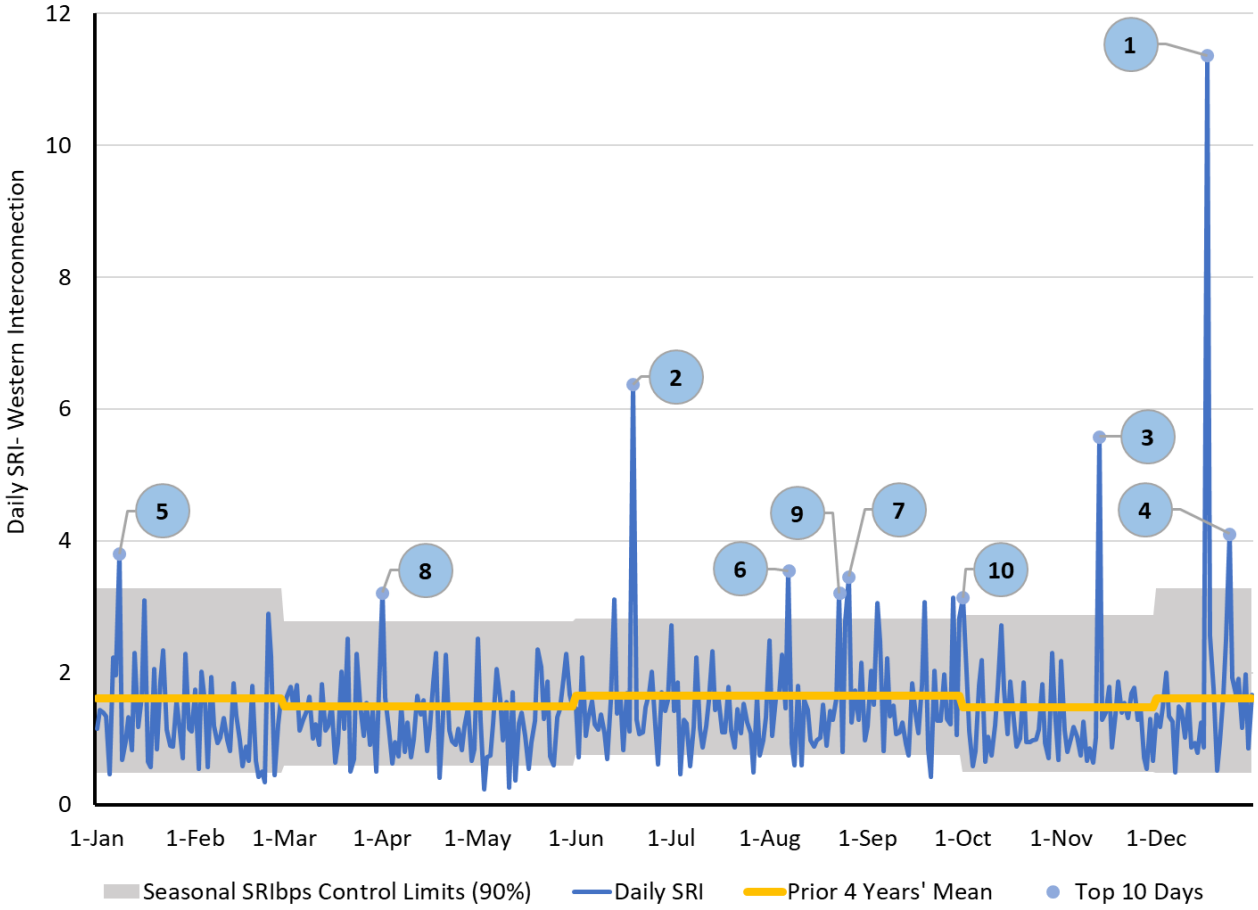


Figure A.3: 2025 Western Interconnection Daily SRI with Top 10 Days Labeled, 90% Confidence Interval

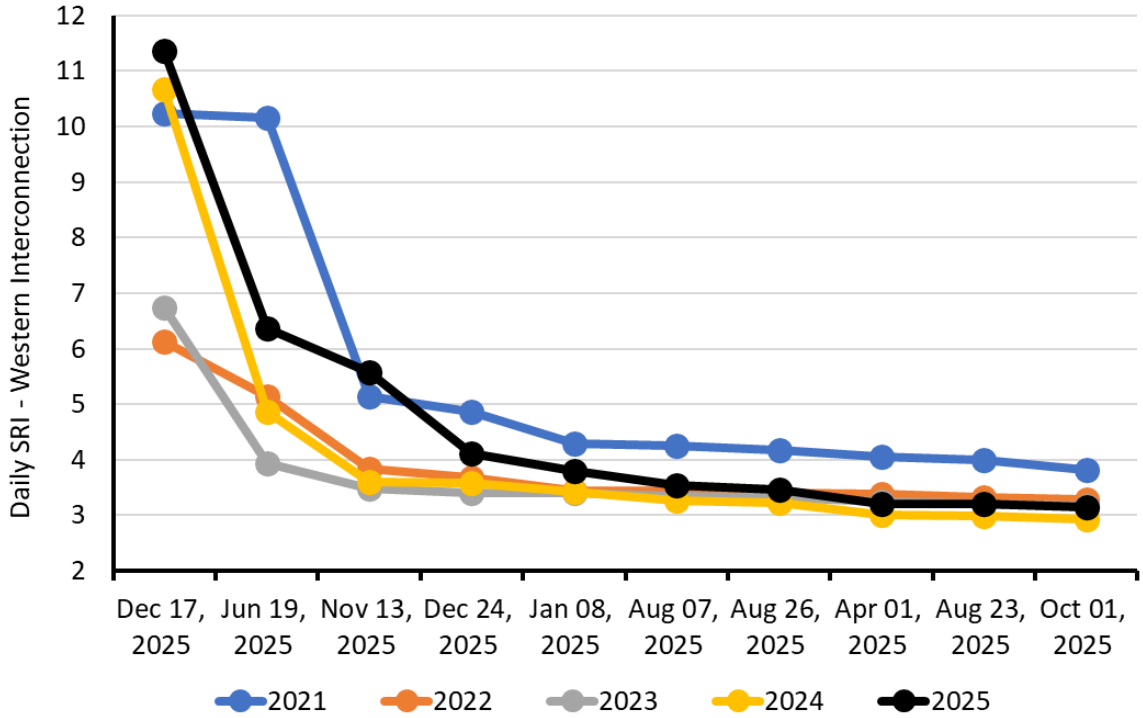


Figure A.4: Western Interconnection Top Annual Daily SRI Days Sorted Descending

Table A.5 details each component's contribution to the top 10 SRI days for the WI; WECC is the only Regional Entity in the WI. Out of the top 10 SRI days for the WI, one was driven by load loss, two were driven by a combination of transmission and generation, and the rest were predominantly driven by generation.

Table A.5: 2025 Top 10 SRI Days, Western Interconnection

Rank	Date	SRI and Weighted Components 2025				Atypical Weather Conditions Regional Entities
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss	
1	December 17, 2025	11.36	4.54	4.02	2.80	Northwestern Atmospheric River
2	June 19, 2025	6.38	0.87	0.44	5.07	Thunderstorms, Tornadoes
3	November 13, 2025	5.58	3.23	2.35	0.00	Wyoming System Event
4	December 24, 2025	4.11	1.07	0.87	2.16	Winter Storm
5	January 8, 2025	3.81	1.54	1.73	0.53	High Wind Conditions
6	August 7, 2025	3.55	2.73	0.67	0.14	Extreme Heat
7	August 26, 2025	3.46	1.99	0.57	0.90	Extreme Heat
8	April 1, 2025	3.21	2.80	0.18	0.23	Thunderstorms, Tornadoes
9	August 23, 2025	3.21	1.26	0.80	1.15	Extreme Heat
10	October 1, 2025	3.14	2.76	0.38	0.00	Thunderstorms

Table A.6 shows the top 10 SRI days for the WI over the last five years, with three days in 2025 highlighted in red.

Table A.6: 2021–2025 Top 10 SRI Days, Western Interconnection

Rank	Date	SRI and Weighted Components 2025				Atypical Weather Conditions
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss	
1	December 17, 2025	11.36	4.54	4.02	2.80	Northwestern Atmospheric River
2	February 4, 2024	10.67	0.34	0.31	10.02	Atmospheric River
3	November 15, 2021	10.23	1.42	0.40	8.41	Atmospheric River
4	January 13, 2021	10.16	1.86	3.83	4.48	Northwest Winter Weather
5	February 24, 2023	6.75	2.61	0.88	3.26	Winter Storm
6	June 19, 2025	6.38	0.87	0.44	5.07	Tornadoes, High Winds
7	November 5, 2022	6.13	1.75	1.77	2.61	Severe Weather

Table A.6: 2021–2025 Top 10 SRI Days, Western Interconnection						
Rank	Date	SRI and Weighted Components 2025				Atypical Weather Conditions
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss	
8	November 13, 2025	5.58	3.23	2.35	0.00	Wyoming System Event
9	December 20, 2022	5.14	1.05	0.15	3.93	Winter Storm
10	February 13, 2021	5.14	1.14	1.30	2.70	Winter Storm Uri

Extreme-Day Analysis by Interconnection

The extreme-day analyses for transmission and generation for 2025 are presented by Interconnection. The maximum TADS reported MVA capacity or GADS reported net maximum capacity for 2025 is shown in the upper right or left corners of **Figure A.5**–**Figure A.10**. The largest outliers and extreme days correlating with NERC-wide extreme days have been labeled with any atypical weather conditions during those days. Interconnection extreme days that do not align with NERC-wide extreme days are dated, but the underlying conditions are not identified. The number of customers interrupted (CI) due to transmission or generation sources for the day is obtained from the IEEE PES Distribution Reliability Working Group (DRWG) benchmark data. All dates are shown in UTC.

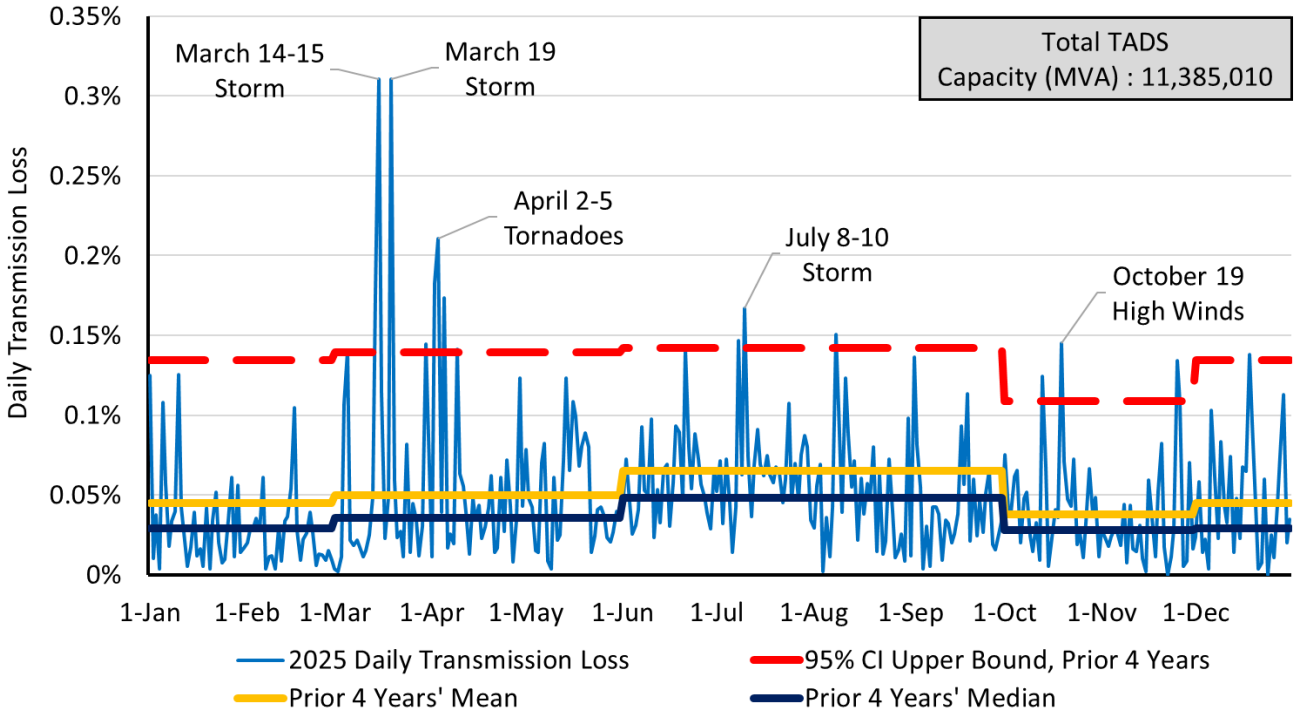


Figure A.5: Eastern and Québec Interconnections—Transmission Impacts During Extreme Days of 2025

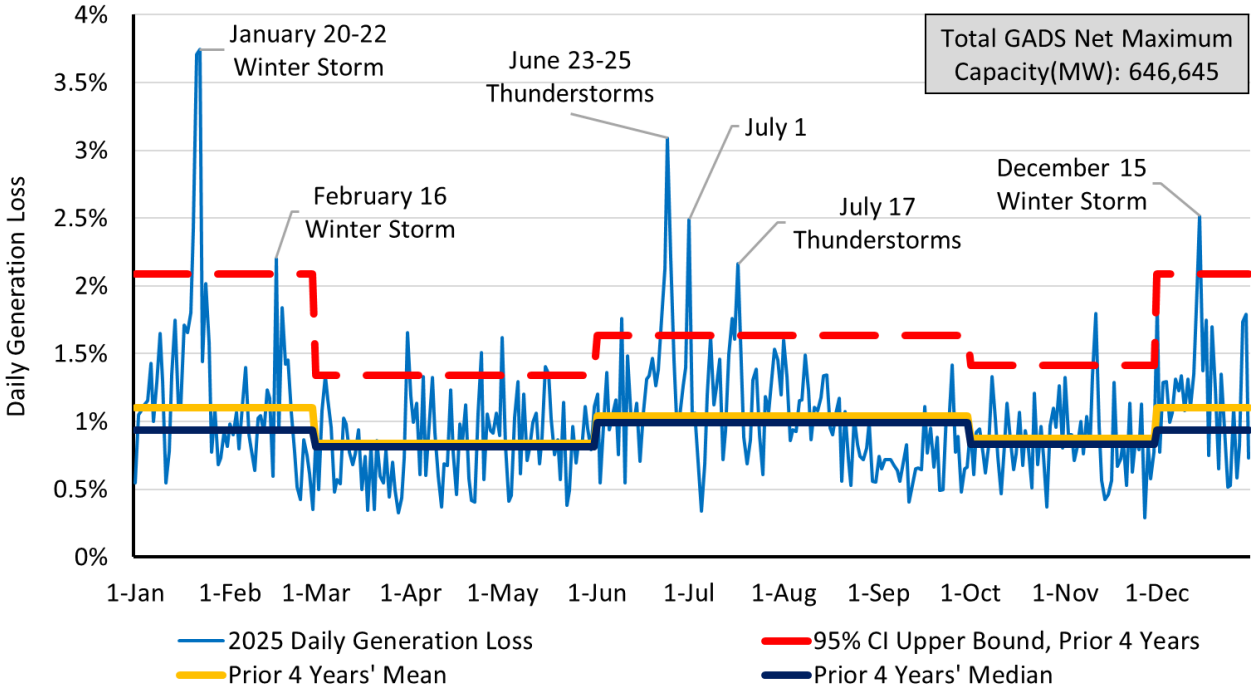


Figure A.6: Eastern and Québec Interconnections—Generation Impacts During Extreme Days of 2025

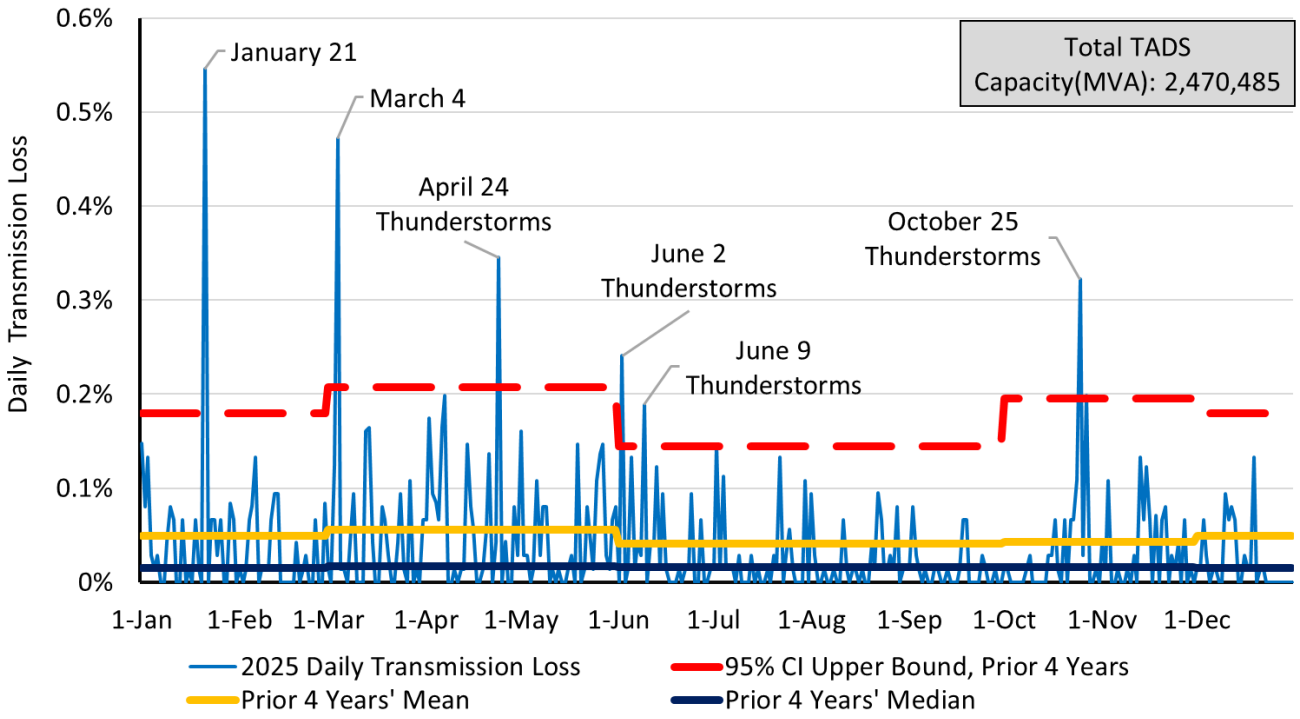


Figure A.7: Texas Interconnection—Transmission Impacts During Extreme Days of 2025

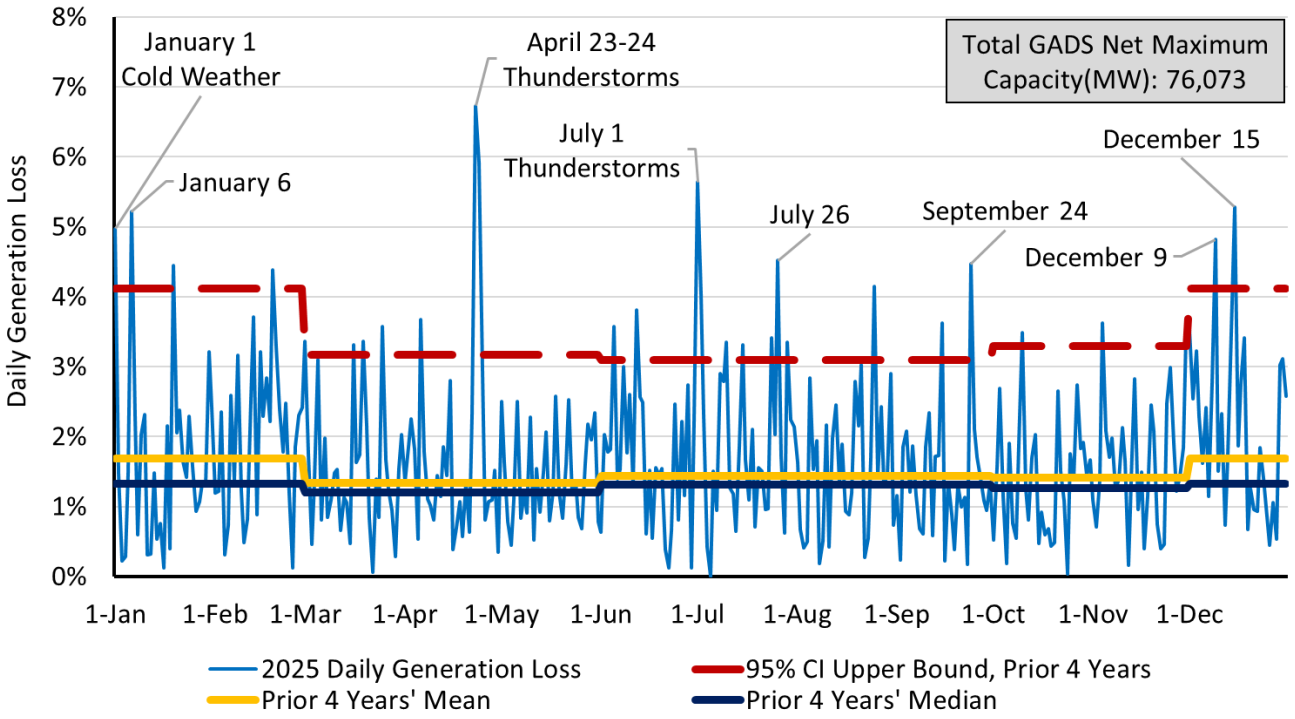


Figure A.8: Texas Interconnection—Generation Impacts During Extreme Days of 2025

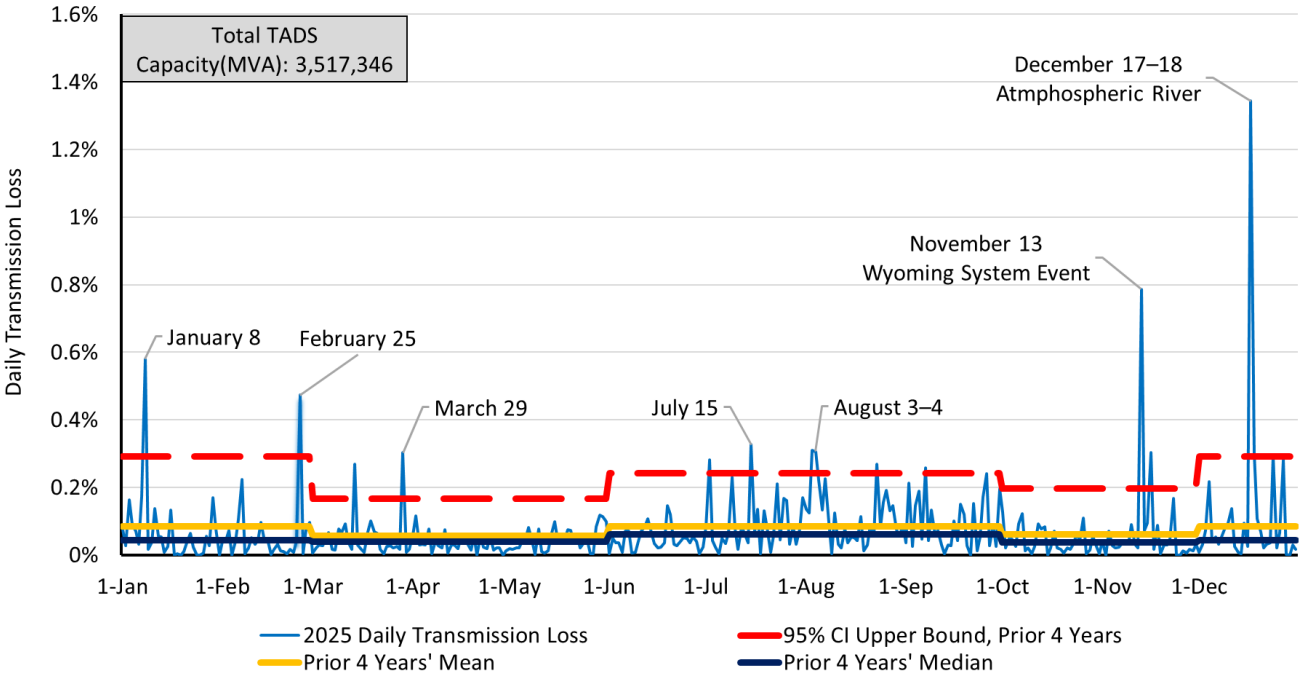


Figure A.9: Western Interconnection—Transmission Impacts During Extreme Days of 2025

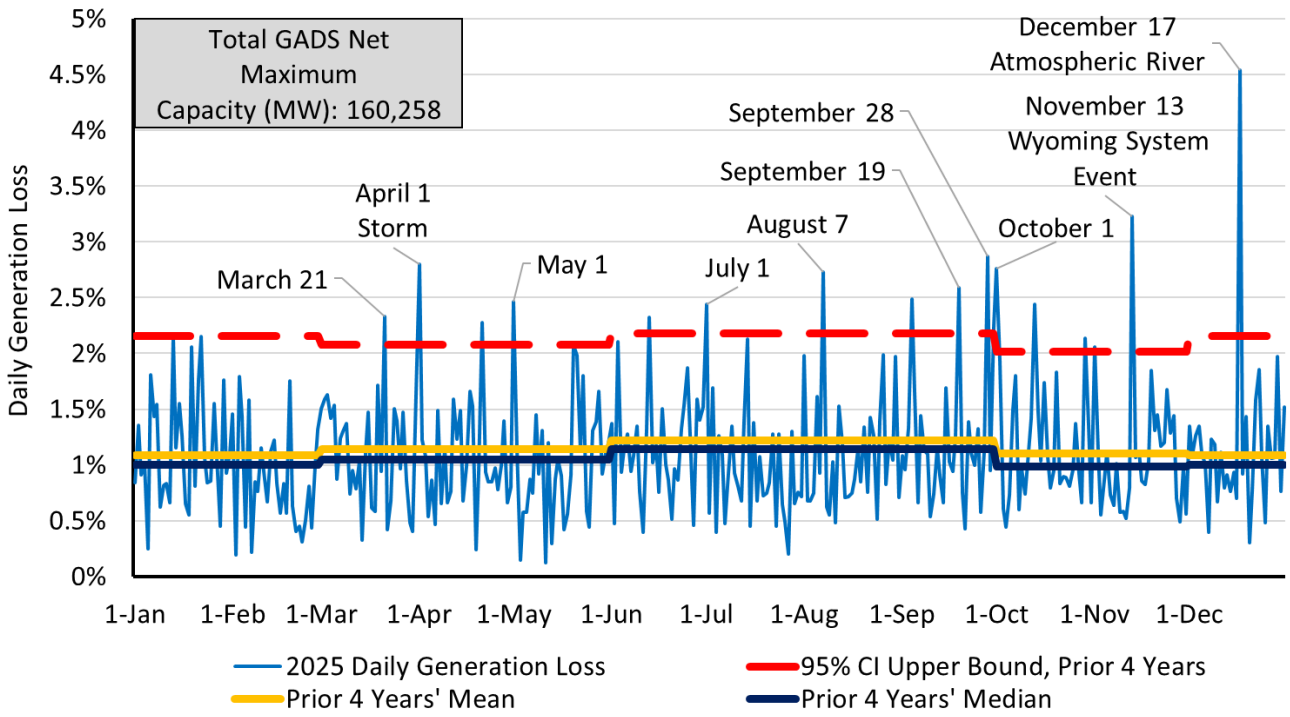


Figure A.10: Western Interconnection—Generation Impacts During Extreme Weather Days

Appendix B: Acknowledgements

NERC Industry Group Acknowledgements	
Group	**Officers**
Reliability and Security Technical Committee	Chair: John Stephens, City Utilities of Springfield Vice Chair: Srinivas Kappagantula, Arevon Energy
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Reliability Assessment Subcommittee	Chair: Amanda Sargent, WECC Vice Chair: Evan Shuvo, Texas RE
Resources Subcommittee	Chair: Daniel Baker, Southwest Power Pool Vice Chair: Jose Luis Hinojosa, ERCOT
Electromagnetic Transient Modeling Working Group	Co-Chair: Adam Sparacino, Mitsubishi Electric Power Products, Inc. Co-Chair: Miguel Angel Cova Acosta, Vestas Americas
Frequency Working Group	Chair: Joseph Marcrum, Southern Company
Inverter-Based Resources Performance Subcommittee	Chair: Julia Matevosyan, Entergy Vice Chair: Rajat Majumder, Invenergy
Large Loads Working Group	Chair: Eric Meier, ERCOT Vice Chair: Sudip Manandhar, Southern Company
Real-Time Operating Subcommittee	Chair: Derek Hawkins, Southwest Power Pool Vice Chair: Raja Thappetaobula, CAISO
System Planning Impacts from Distributed Energy Resources Working Group	Chair: Shayan Rizvi, NPCC Vice Chair: John Schmall, ERCOT
System Protection and Control Working Group	Chair: Lynn Schroeder, Sunflower Vice Chair: Manish Patel, Silicon Ranch Corporation

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