NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2025 State of Reliability

Technical Assessment of 2024 Bulk Power System Performance

June 2025

[2025 SOR Infographic]

[2025 SOR Overview]

[2025 SOR Video]

RELIABILITY | RESILIENCE | SECURITY




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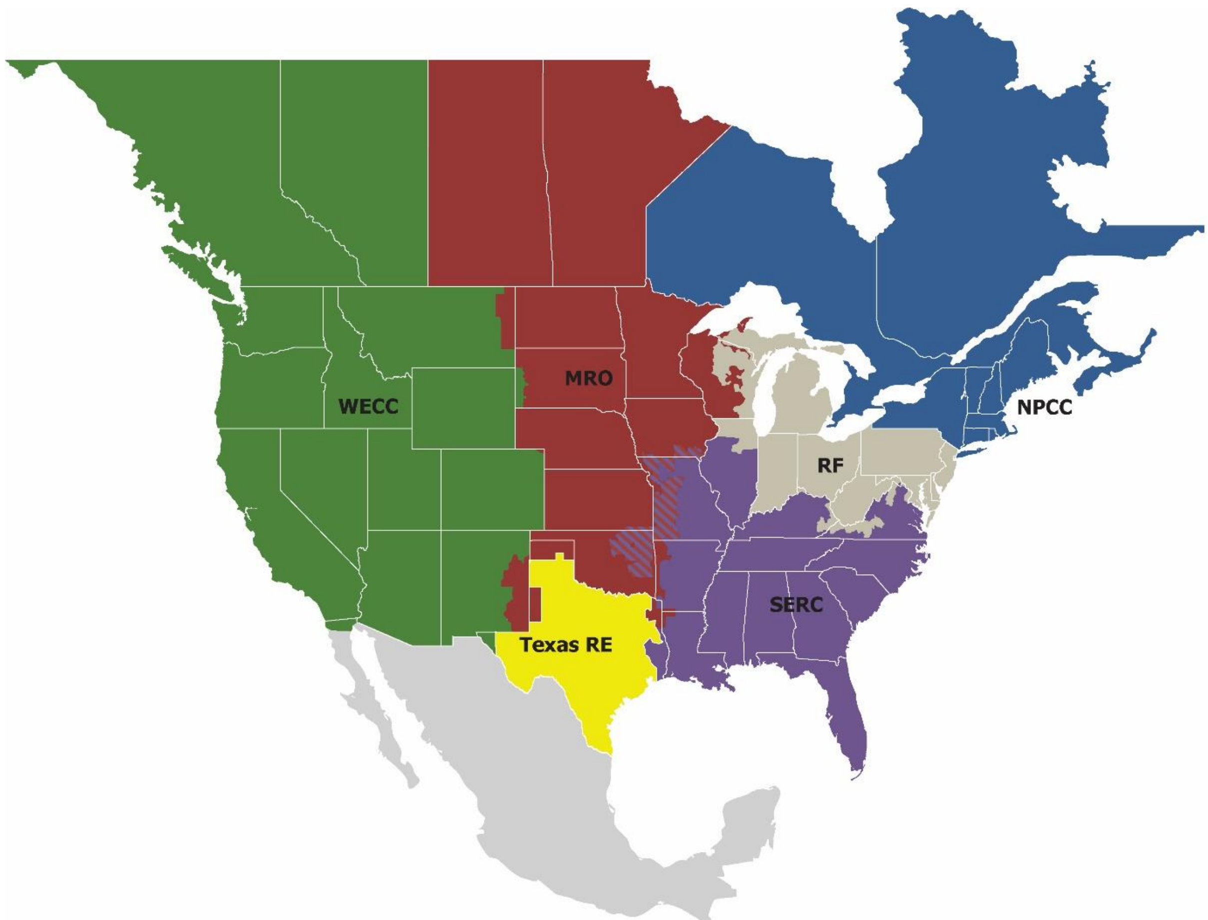
Preface

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

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

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



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

About This 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 *2025 SOR Technical Assessment*, which provides NERC's comprehensive annual technical review of BPS reliability for the 2024 operating (calendar) year, and the *2025 SOR Overview*, which is a high-level summary of the Technical Assessment with the following details:

- The *2025 SOR Overview* replaces the key findings previously found in the Technical Assessment.
- This *2025 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 based on past performance
- Reports on the relative health of the interconnected system
- Measures the success of mitigation activities deployed

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 underlying data and detailed analytics.

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

The *2025 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).

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[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 2024 operating year unless otherwise noted.
- Analysis in this report is based on data from 2020–2024 that was available in Spring 2025, and it provides a basis to evaluate 2024 performance relative to performance over the last five years. All dates and times shown are in Coordinated Universal Time (UTC).
- To properly demonstrate key trending information, this year's report evaluates generation data dating back to 2015.
- 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 is combined with the Eastern Interconnection unless specific analysis for the Québec Interconnection is shown.

Chapter 1: Major Occurrences for 2024

This chapter highlights major occurrences and reports that were issued in 2024. These occurrences and reports did not constitute a key finding but had a notable impact on the BPS.

By the Numbers

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

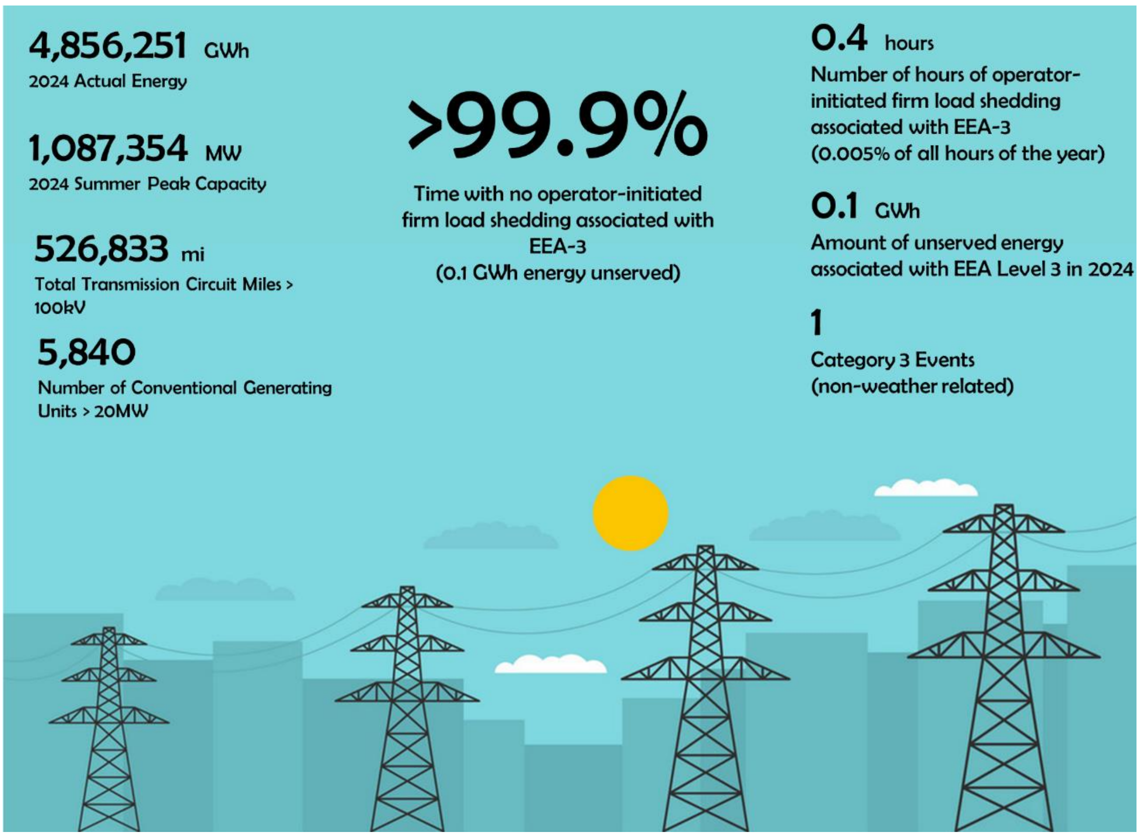

Figure 1.1: 2024 BPS Inventory and Performance Statistics

Table 1.1: Five-Year BPS Inventory and Performance Statistics					
Rank	**2020**	**2021**	**2022**	**2023**	**2024**
Actual Energy (GWh)	4,588,062	4,585,939	4,674,290	4,687,894	4,856,251
Summer Peak Capacity (MW)	1,048,944	1,056,980	1,057,455	1,071,370	1,087,354
Total Transmission Circuit Miles >100 kV miles	506,734	508,766	522,433	529,344	526,853
Count of Transmission Circuits >100 kV	28,018	28,411	29,165	29,932	30,014
Count of Transformers with a Low Side Voltage >100 kV	5,634	5,715	5,773	5,805	5,832
Number of Conventional Generating Units >20 MW	6,009	5,966	5,910	5,915	5,840[3]

[3] Decrease in generator counts is partially attributable to a 2024 change in GADS reporting that corrects the number of combined cycle units' reporting.

Table 1.1: Five-Year BPS Inventory and Performance Statistics					
Rank	**2020**	**2021**	**2022**	**2023**	**2024**
Reported MW of Installed Conventional Generation[4]	974,511	964,967	965,578	936,747	929,055
Reported MW of Installed Wind Generation[5]	96,048	112,811	124,039	129,963	135,866
Reported MW of Installed Solar Generation[6]	N/A	N/A	N/A	N/A	38,004
Portion of Hours in the Year with No Operator-Initiated Firm Load Shedding Associated with EEA Level 3	99.7%	99.2%	99.4%	100%	>99.9%
Category 3 Events (non-weather related)	0	0	1	0	1
Amount of Unserved Energy Associated with EEA Level 3 (GWh)	828.1	1,015.5	96.2	0	0.1
Number of Hours with Operator-Initiated Load Shed	22	71	56.5	0	0.4

Major Weather Events

Overall, the BPS was reliable[7] throughout 2024. Major weather events continue to pose 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 are evolving risks to reliability. Major weather events in 2024, including severe winter storms, hurricanes, thunderstorms, and tornadoes, were analyzed and collectively found to have had less of an impact on the BPS than in previous years. Nine of the 27 events highlighted in **Figure 1.2**[9] were identified as large transmission events as seen in the **Analysis of Transmission System Resilience** section. Although numerous economically impactful events also occurred in Canada in 2024 (**Figure 1.3**), none were considered to have had a major impact on the BPS based on data used in the SRI and transmission system resilience analysis. By far the largest natural disaster event that impacted BPS transmission metrics was Hurricane Helene. There were four other hurricanes that made landfall throughout the year and two major winter storms, one of which affected all the contiguous United States.

[4] MW of installed conventional generation is calculated based on highest Net Maximum 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.
[5] Includes plants with a total installed capacity >75 MW.
[6] As 2024 is the first reporting year, some plants have been excluded due to data errors. Only plants >100 MW were required to report. Please see here for more details.
[7] Learn About NERC provides background information about NERC, the definition of reliability, and understanding the grid.
[8] NERC's ERO Reliability Risk Priorities Report
[9] NOAA National Centers for Environmental Information (NCEI) U.S. Billion-Dollar Weather and Climate Disasters

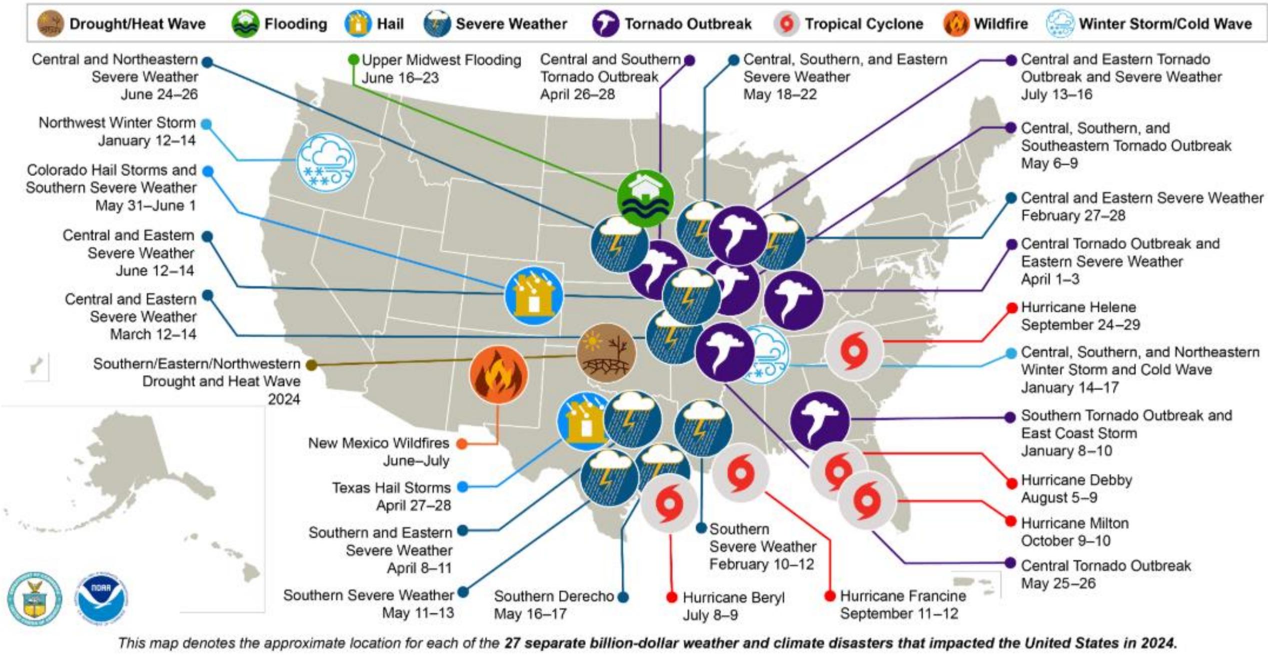

Figure 1.2: 2024 U.S. Billion-Dollar Weather and Climate Disasters10

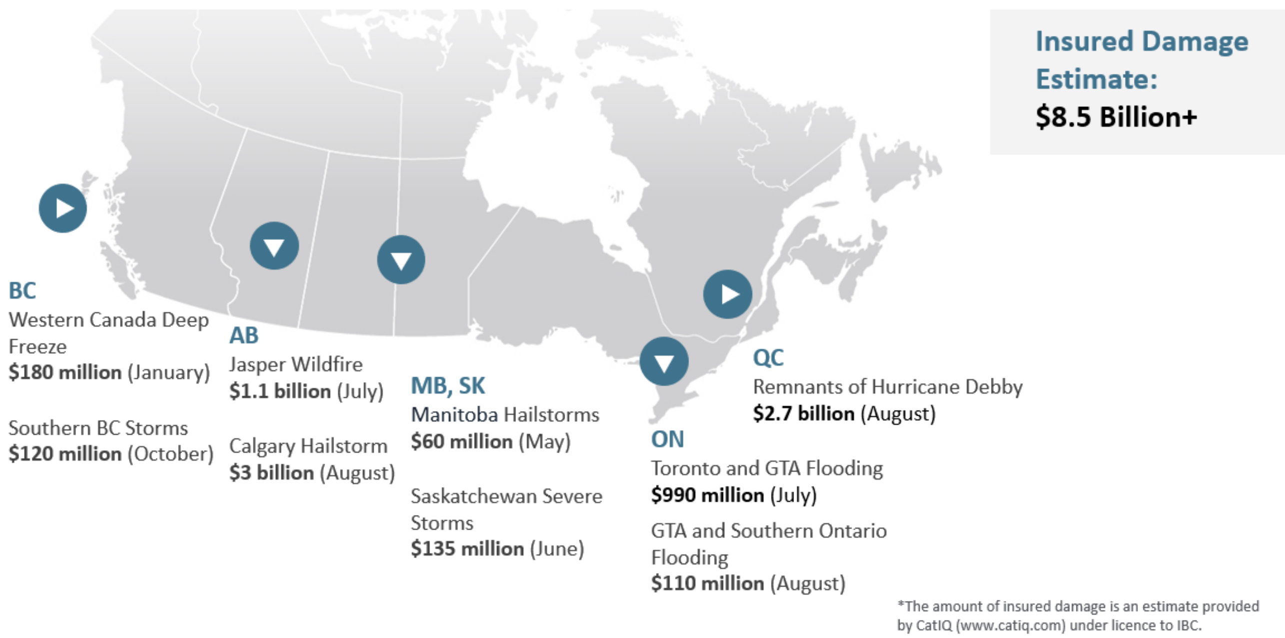

Figure 1.3: 2024 Canadian Insured Catastrophic Losses[11]

[10] NOAA National Centers for Environmental Information (NCEI) U.S. Billion-Dollar Weather and Climate Disasters (2023). https://https://www.ncei.noaa.gov/access/billions/, DOI: 10.25921/stkw-7w73

[11] 2024 shatters record for costliest year for severe weather-related losses in Canadian history at $8.5 billion

2024 Hurricanes

The prediction of an active hurricane season for 2024 proved accurate with 18 named storms, five of which were major hurricanes that made landfall. According to analysis performed by climatecentral.org, weather-related power outages are rising in both their frequency and intensity.[12] These events stressed the BPS and are among the leading causes of major power outages in the United States. This became clear as new records were set during the 2024 hurricane season.

Hurricane Helene, a Category 4 storm, was the deadliest inland hurricane on record with the storm path moving inland from Florida through Georgia, South Carolina, Kentucky, and Tennessee and into the North Carolina mountains. This deadly hurricane was followed less than two weeks later by Hurricane Milton, which made landfall as a Category 3 storm, impacting some of the same areas in Florida as Hurricane Helene. Both storms caused widespread damage to infrastructure, including over 400 transmission element outages. More than 4.7 million utility customers were left without power due to a combination of transmission and distribution outages.[13] While both hurricanes Milton and Helene were catastrophic and caused widespread damage, the storm restoration was relatively quick as further described in the **Analysis of Transmission System Resilience** section. In both restoration efforts, mutual assistance from nearly 50,000 personnel from at least 34 states were utilized.

Hurricane Beryl also had a large impact on the BPS, making landfall as a Category 1 storm in the Texas Gulf Coast area near Houston. Nearly 100 transmission elements were removed from service. More than 2 million Texas utility customers were left without power due to a combination of transmission and distribution outages. It moved rapidly northeast and spawned a tornado outbreak that impacted the south-central United States, Mississippi Valley, and Northeastern United States.

Florida may have seen restoration times improve in recent storms due to system hardening efforts[14] as well as significant support from mutual assistance personnel. The ERO Enterprise studies significant weather events, performs inquiries and event analyses, and produces recommendations and revisions to Reliability Standards, NERC alerts, and data collection efforts to supplement performance information.

Arctic Blast

Winter arctic blasts impacted most of the United States from January 8–16, 2024.[15] Winter Storm Gerri started in the northwestern part of the country and moved to the Midwest Reliability Organization (MRO) region. Winter Storm Heather started in the Texas RE region and moved into the SERC Reliability Corporation (SERC), ReliabilityFirst (RF), and Northeast Power Coordinating Council (NPCC) areas. Even though record-low temperatures caused high system demand and some parts of the system were stressed, no operator-initiated load shed was required. However, there were five EEA-3 events declared that were directly attributed to the widespread cold weather.

While the implemented recommendations from winter storms Uri and Elliott have been shown to be effective, the 2024 winter storms did expose planning operating challenges that still need to be addressed and highlight the importance of energy transfer capabilities, such as those being examined by the *NERC Interregional Transfer Capability Study*.[16] The implementation of several of the recommendations from Winter Storm Elliott is still in progress.

The Western Power Pool analysis of Winter Storm Gerri identified that the Northwest area, including British Columbia, Washington, Oregon, Idaho, and western Montana, experienced sustained temperatures at or near record lows for the five-day period from January 12 to 16, 2024, resulting in high system demand. The Pacific Northwest

[12] Weather Related Power Outages Rising
[13] Impact of Hurricanes Helene and Milton on the BPS, SERC
[14] NERC Lesson Learned, Weathering the Storm – System Hardening
[15] System Performance Review of January 2024 Arctic Storms
[16] Interregional Transfer Capability Transfer Study Final Report

averaged 4,900 MW of imports during the duration of the storm. Since the storm's impact was concentrated in the north of the Western Interconnection, surplus energy from the south was able to assist throughout the storm (see Figure 1.4). The Northwest was a net importer of an average of 4,900 MW per hour during the five days from January 12 to 16, 2024.[17]

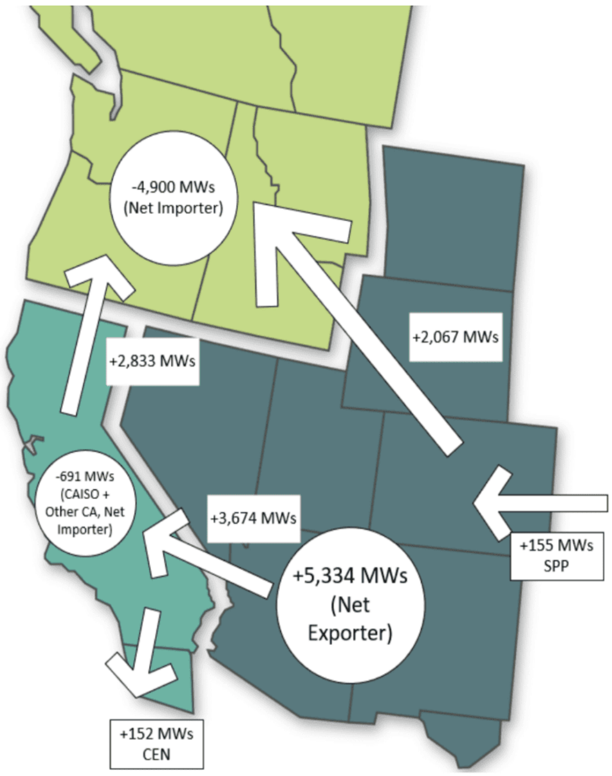

Figure 1.4: Average Net Regional Imports into the Northwest January 12–16, 2024

Geomagnetic Disturbance Event

Multiple coronal mass ejections (CME) collided with Earth's magnetosphere on May 10–12, 2024, resulting in the largest geomagnetic disturbance (GMD) event in over two decades. The BPS remained stable throughout the event as GMD conditions varied between Strong (G3) and Extreme (G5) over the three-day period. BPS operators received early notification from the U.S. National Oceanic and Atmospheric Administration (NOAA) Space Weather Prediction Center (SWPC) through existing protocols, and Reliability Coordinators (RC), Transmission Operators (TOP), and other registered entities implemented GMD Operating Procedures. Operators observed isolated impacts to BPS transformers, voltage support equipment, transmission line breakers, and harmonic filters. High levels of geomagnetically induced currents (GIC) and harmonics were reported by operators and the Electric Power Research Institute's (EPRI) SUNBURST monitoring network.

Historically, these storms can be much larger, such as the March 1989 solar storm that caused the Hydro Québec blackout as well as transformer outages in the United States. As such, the 2024 storm provides an important opportunity to deepen understanding of GMD events and their effects on the BPS and continue industry and NERC's activities to reduce the risk that extreme GMD events pose to grid reliability. NERC's data sources, which include the GMD Data System and various equipment data systems, provide information to complement industry observations and insights to provide expanded understanding. An after-action review is underway with a goal of better informing industry operating procedures and practices and technical guidelines used for planning and operating the BPS. The results will also support better understanding of GMD events and their impact on electric infrastructure by the broader space weather community. This report will be published in Summer 2025.

[17] Western Power Pool Assessment of January 2024 Cold Weather Event

Chapter 2: Severity Risks, Impact, and Resilience

This chapter identifies and examines the highest-stress days on the BPS in 2024 using established measures.

Severity Risk Index

The severity risk index (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 2024, 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 (see **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** and **Figure 2.1** show the annual cumulative SRI for the five-year period of 2020–2024.

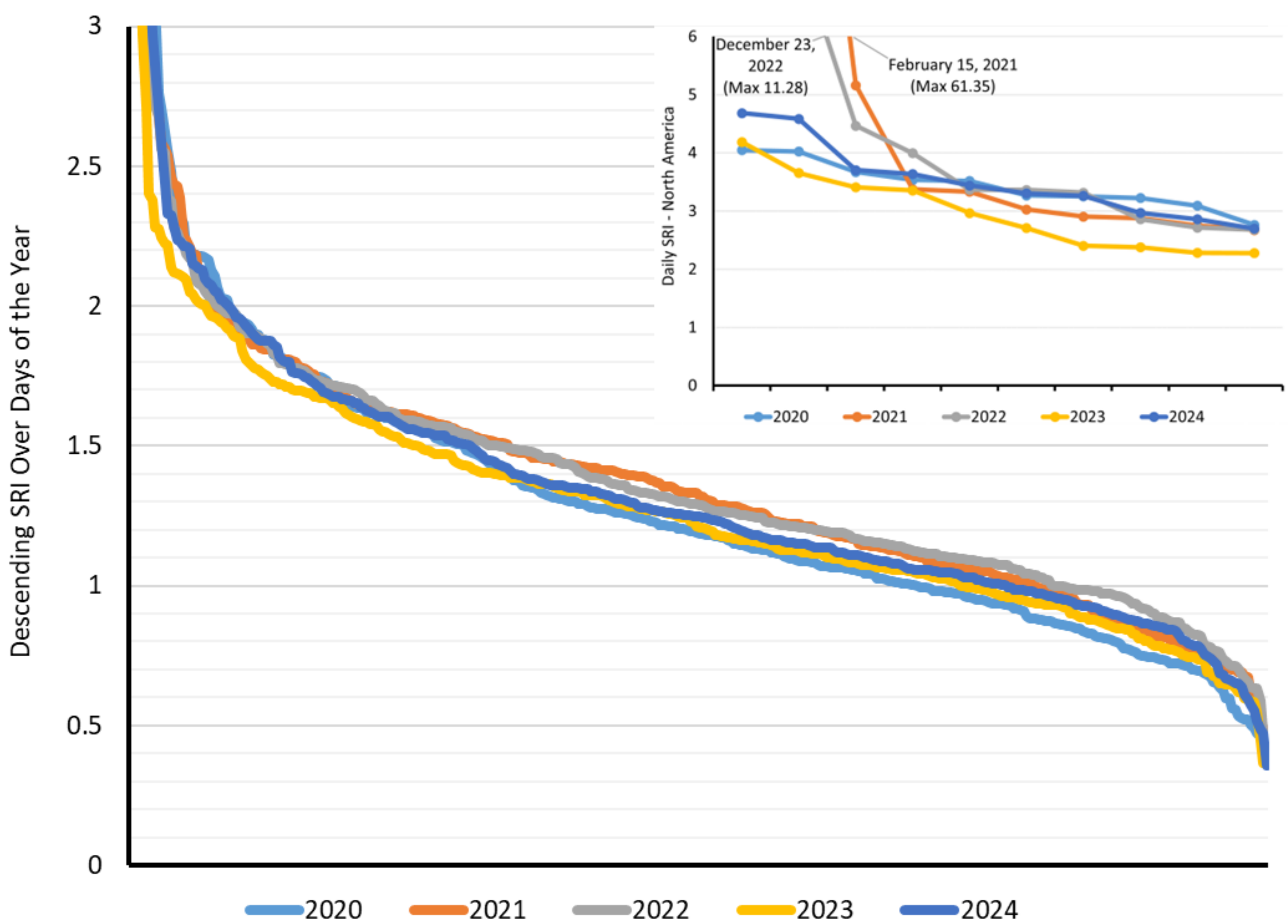

Figure 2.1: NERC Descending SRI by Day of the Year

Table 2.1: Annual Cumulative SRI					
Year	Cumulative Weighted Generation	Cumulative Weighted Transmission	Cumulative Weighted Load Loss	Annual Cumulative SRI	Average Daily SRI
2020	338.8	66.6	72.5	477.9	1.31
2021	375.8	64.2	96.6	536.6	1.47
2022	404.2	59.9	55.2	519.3	1.42
2023	356.8	64.4	50.5	471.7	1.29
2024	380.2	61.1	51.8	493.0	1.35

Figure 2.2 plots the 10 highest SRI days daily and the SRI scores for 2024 against control limits that were calculated by using 2020–2023 seasonal daily performance. A general normal range of performance is represented by the gray-colored band, showing the daily seasonal 90% control limits.[18] 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.

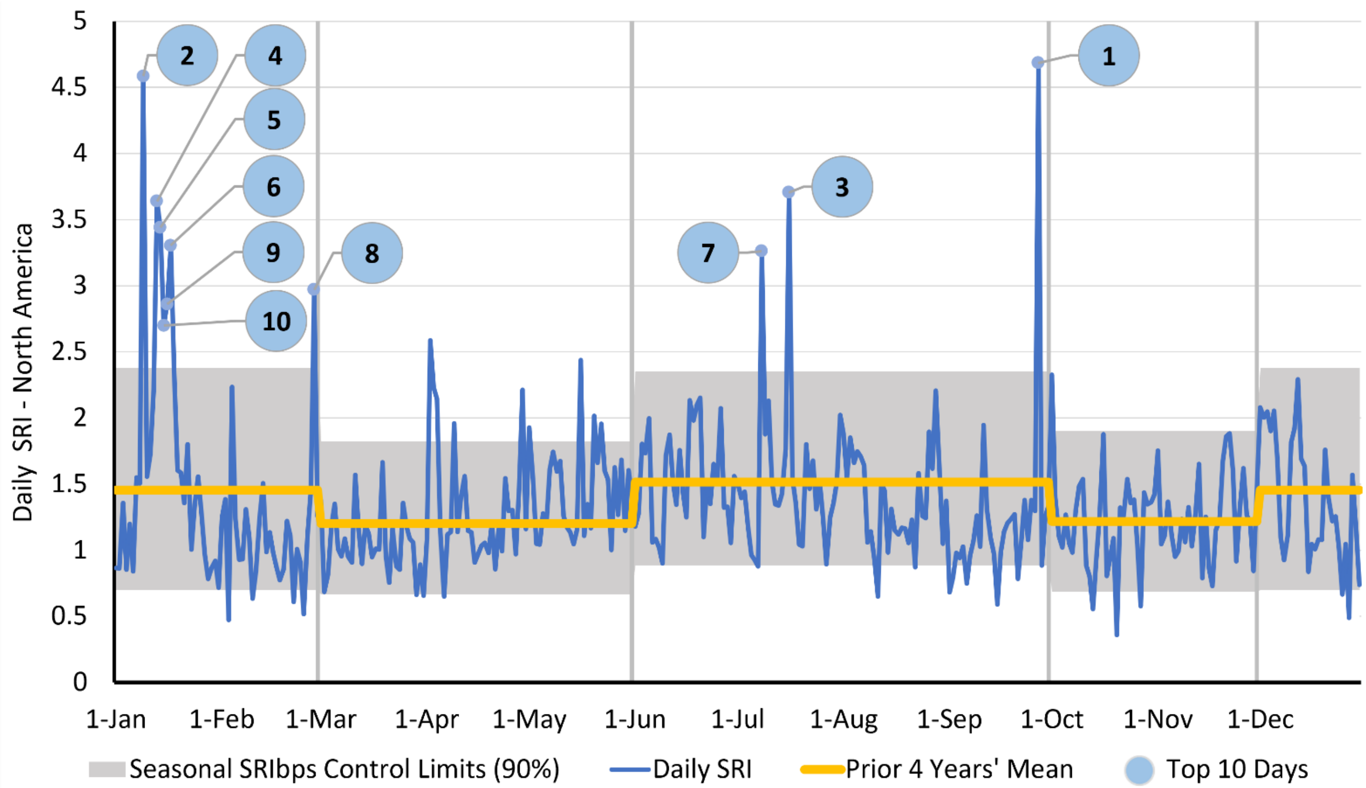

Figure 2.2: 2024 Daily SRI with Top 10 Days Labeled, 90% Confidence Interval

Table 2.2 details the scores for the top 10 SRI days during 2024. The table identifies where atypical weather conditions were ongoing during the day and the general location by Regional Entity. Five of the top 10 SRI days in 2024 were driven by generator outages during a winter storm from January 13–17 that impacted a large portion of North America. When the size and severity of the storm is taken into account as well as the geographical spread of generator outages, the impact to the BES was much less severe than similar events in previous years.

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

Table 2.2: 2024 Top 10 SRI Days							
Rank	Date	SRI and Weighted Components 2024				Atypical Weather Conditions	Regional Entities
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss		
1	27-Sep	4.68	1.42	2.41	0.85	Hurricane Helene	RF, SERC
2	9-Jan	4.58	1.56	0.68	2.35	Northwestern Winter Storm, Eastern Tornadoes & Severe Storms	RF, SERC, Texas RE, WECC
3	16-Jul	3.71	1.80	0.38	1.52	Central & Eastern Tornadoes & Severe Weather	NPCC, RF, SERC
4	13-Jan	3.64	2.47	0.48	0.68	Winter Storm	MRO, RF, SERC, WECC
5	14-Jan	3.44	3.09	0.27	0.08	Winter Storm	MRO, RF, SERC, Texas RE
6	17-Jan	3.30	2.87	0.29	0.14	Winter Storm	MRO, RF, SERC
7	8-Jul	3.26	2.04	0.92	0.30	Hurricane Beryl	MRO, SERC
8	28-Feb	2.97	1.46	0.37	1.13	Central & Eastern Severe Storms	NPCC, RF WECC
9	16-Jan	2.86	2.41	0.38	0.07	Winter Storm	MRO, SERC, Texas RE, WECC
10	15-Jan	2.70	2.27	0.37	0.06	Winter Storm	MRO, RF, SERC, Texas RE, WECC

SRI Performance Trends

To put the severity of days in 2024 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 2020–2024 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 2024, only January 9 and September 27 were severe enough to be added to the top 10 SRI days of the past five years.

Table 2.3: 2020–2024 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	26.09	5.54	0.78	19.77	Cold Weather Event	MRO, RF, SERC, Texas RE, WECC

Table 2.3: 2020–2024 Top 10 SRI Days							
Rank	Date	SRI and Weighted Components				Atypical Weather Conditions	Regional Entities
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss		
2	February 16, 2021	13.03	5.02	0.53	7.48	Cold Weather Event	MRO, RF, SERC, Texas RE, WECC
3	December 23, 2022	11.26	8.17	0.84	2.26	Winter Storm Elliott	All
4	December 24, 2022	7.45	6.44	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	4.68	1.42	2.41	0.85	Hurricane Helene	SERC
7	January 9, 2024	4.58	1.56	0.68	2.35	Northwestern Winter Storm, Eastern Tornadoes & Severe Storms	RF, SERC, Texas RE, WECC
8	June 14, 2022	4.47	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	August 27, 2020	4.05	1.52	0.93	1.60	Hurricane Laura	MRO, 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 **Appendix A: Supplemental Analysis by Interconnection**.[19] The analysis provided in the following subsections is reported separately for transmission and generation. The total estimated MVA transfer capacity[20] reported in TADS or 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 2024, 19 days met the criteria of extreme transmission days for the BPS as compared to 22 in 2023. The most extreme transmission-impacting day was September 27, primarily due to Hurricane Helene (see **Figure 2.3**), where the MVA capacity impacted due to automatic transmission outages was 11.8 times as high as the associated season's average. This is also the highest transmission loss for any single day in the past five years. Other extreme days include July 8, also due to a hurricane (Hurricane Beryl), April 2 (tornado outbreak), and January 9 (winter storms).

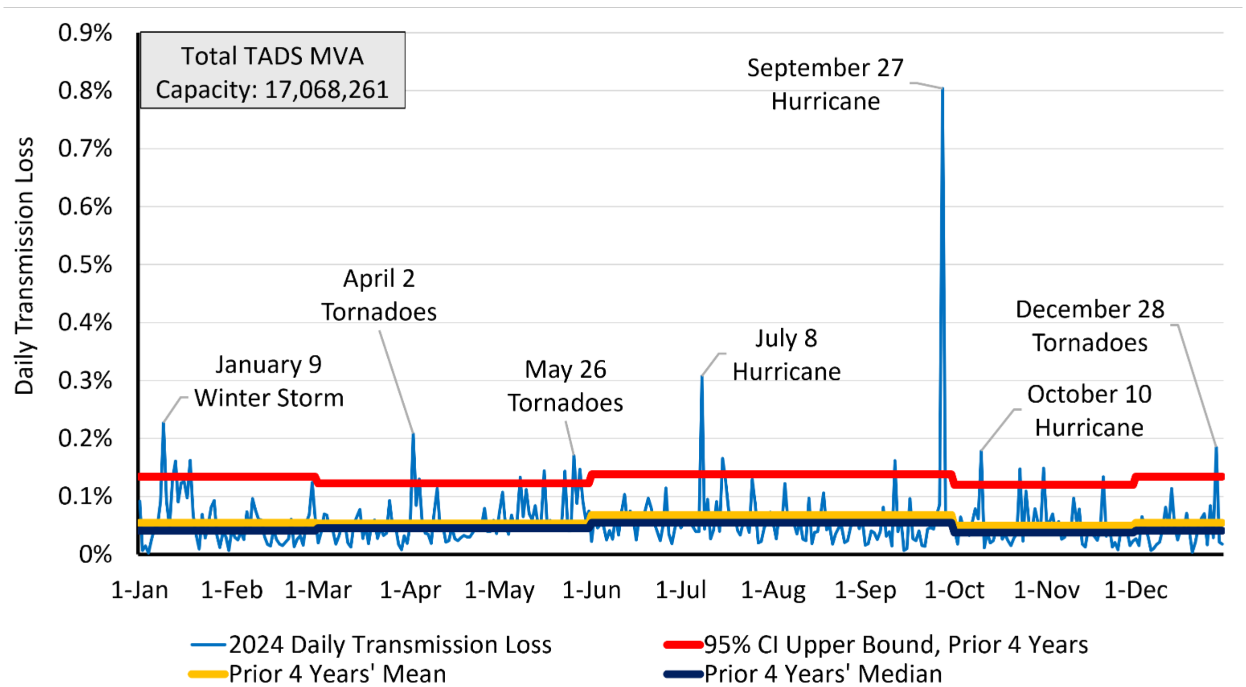

Figure 2.3: 2024 Transmission Outages during Extreme Days

[19] For extreme-day Interconnection-level analysis, the Québec Interconnection is included in the analysis labeled as Eastern Interconnection–Québec Interconnection.

[20] Severity Risk Index

The top causes reported for outages that occurred on extreme days are shown in rank order for North America and each Interconnection (**Table 2.4**). Causes for Interconnections are based on those interconnections' extreme days, shown in **Appendix A: Supplemental Analysis at Interconnection Level**. The number one outage cause for 2024 was Weather (Excluding Lightning), which affected over six times more MVA capacity than any of the other top causes for the year across the 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) (320,136)	Vegetation (51,685)	Failed ac Substation Equipment (51,573)	Lightning (41,942)	Foreign Interference (32,673)
Eastern–Québec Interconnections	Weather (Excluding Lightning) (270,137)	Vegetation (42,031)	Failed ac Substation Equipment (32,497)	Lightning (28,764)	Failed ac Circuit Equipment (28,183)
Texas Interconnection	Weather (Excluding Lightning) (45,455)	Lightning (13,802)	Failed ac Substation Equipment (12,153)	Unknown (8,034)	Failed ac Circuit Equipment (7,687)
Western Interconnection	Weather (Excluding Lightning) (38,150)	Fire (37,708)	Failed ac Substation Equipment (13,860)	Power System Condition (11,393)	Unknown (11,217)

Conventional Generation Impacted

Based on analysis of GADS data, a total of 26 days in 2024 qualified as extreme for North America's BPS (see **Figure 2.4**) compared to 14 in 2023. The five highest-impact days for generation loss were the January 13–17 winter storms. On these days, conventional generating units experienced outages that were 2.1–2.9 times as severe as the associated season's average. Two of the extreme generation loss days coincided with extreme days identified for transmission (January 13 winter storms and the July 8 hurricane). The days on which generation outages were slightly above the seasonal bounds (**red** line) that do not have a specific cause listed have been investigated and were either found to coincide with severe thunderstorms, high temperatures, or saw many coincidental outages that were not a result of adverse weather conditions.

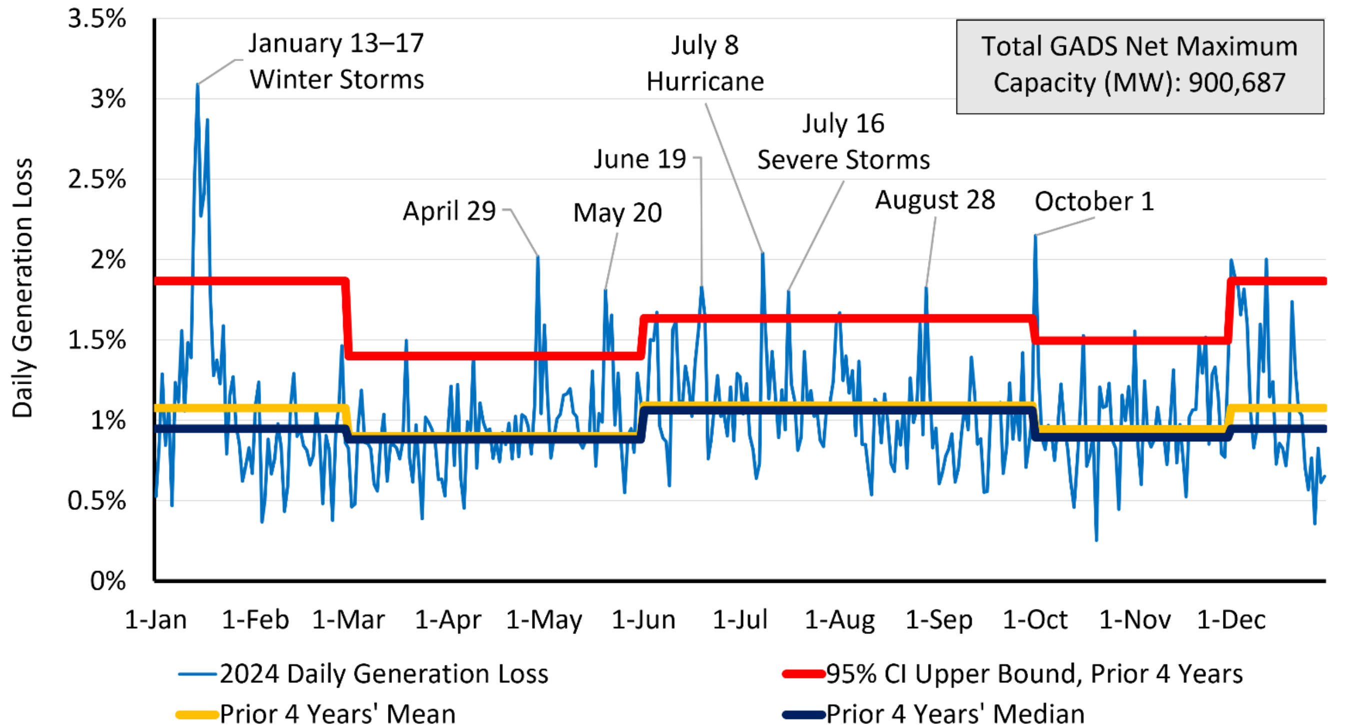

Figure 2.4: 2024 Generation Impacted during Extreme Days

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 interconnection's extreme days, shown in **Appendix A: Supplemental Analysis at Interconnection Level**.

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 Regional Entities	Fuel, Ignition, and Combustion Systems (38,022)	Electrical (36,975)	Auxiliary Systems (31,591)	Boiler Tube Leaks (28,358)	Economic (28,168)
Eastern–Québec Interconnections	Economic (27,012)	Electrical (25,813)	Fuel, Ignition, and Combustion Systems (25,740)	Boiler Tube Leaks (23,424)	Auxiliary Systems (20,362)
Texas Interconnection	Electrical (9,189)	Auxiliary Systems (7,382)	Fuel, Ignition, and Combustion Systems (5,196)	Feedwater System (2,843)	Controls (2,722)
Western Interconnection	Electrical (5,910)	Controls (5,066)	Auxiliary Systems (3,895)	Miscellaneous (Gas Turbine) (3,821)	Miscellaneous (Steam Turbine) (2,841)

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 2024 transmission outages identified 14 large transmission events that were caused by weather 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.[21]

This section provides a detailed description of the Hurricane Helene event as the largest outage event on the transmission system in 2024. 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: 2019–2023 and 2020–2024.

TADS Outage Grouping and 2024 Large Weather Events

The outage grouping algorithm[22] 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 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 2024, the grouping algorithm identified 14 large weather events. **Table 2.6** lists these events in chronological order and shows the severe weather type for each event with statistics that quantify the impact of the event on the transmission system. In 2024, the largest event was Hurricane Helene with 431 outages between September 27 and October 30, affecting 9,138 miles, and 127,687 MVA of capacity, making it the highest-impact storm of the year on the transmission system. This event is shown in **blue** in **Table 2.6**.

The second largest event, as identified by the grouping algorithm, is Hurricane Milton (with 80 transmission outages reported), which occurred in the Eastern Interconnection (shown in **red** in **Table 2.6**). Though it was the second largest event in terms of the number of outages, it had the longest duration of any event in 2024 with 71.8 days until final restoration. It is also worth noting that Hurricane Beryl, though identified by the grouping algorithm as two separate events in two different Interconnections, is also listed as a combined event in **Table 2.6** (shown in **purple**), to show the overall impact this hurricane had on the system. When combined, this storm had an even larger impact on the system than Hurricane Milton, with 97 outages, affecting 35,441 MVA of capacity and 1,536 miles.

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

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

Table 2.6: 2024 Large Transmission Weather-Related 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[23] Lost	Most Simultaneous Unavailable Capacity (MVA)
	All Automatic	Sustained Automatic	Momentary Auto.								
8-Jan	22	14	8	Eastern	Winter Storm	4,707	707	1.3	1.2	5	1,998
9-Jan	72	65	7	Eastern	Winter Storm	21,798	1,748	6.7	3.0	47	11,207
15-Jan	24	22	2	Eastern	Winter Storm	9,548	374	2.6	0.9	7	3,773
3-Apr	20	17	3	Eastern	Thunderstorm	4,564	472	3.0	1.5	7	2,884
10-Apr	39	34	5	Eastern	Thunderstorm	10,706	600	7.3	5.3	37	6,014
10-May	34	34	0	Eastern	Thunderstorm, Tornado	8,048	567	5.5	3.3	30	6,488
13-May	33	29	4	Eastern	Thunderstorm	6,398	488	6.2	6.1	39	3,787
16-May	30	25	5	Eastern	Derecho	6,071	436	9.7	4.2	33	4,069
8-Jul	50	47	3	ERCOT	Hurricane Beryl	24,686	810	5.7	4.4	66	20,217
8-Jul	47	43	4	Eastern	Hurricane Beryl	10,755	726	3.5	3.3	54	7,472
8-Jul	**97**	**90**	**7**	**Eastern /ERCOT**	**Hurricane Beryl**	**35,441**	**1,536**	**5.7**	**3.8**	**120**	**27,342**
11-Sep	37	30	7	Eastern	Hurricane Francine	15,702	528	2.1	2.0	16	5,340
27-Sep	**431**	**407**	**24**	**Eastern**	**Hurricane Helene**	**127,687**	**9,138**	**33.4**	**7.6**	**1,140**	**91,557**
9-Oct	**80**	**57**	**23**	**Eastern**	**Hurricane Milton**	**35,099**	**1,070**	**71.8**	**3.9**	**137**	**19,069**
20-Nov	61	57	4	Western	Extratropical Cyclone	15,961	1,322	6.1	4.3	106	13,108

[23] 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.[24] **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.

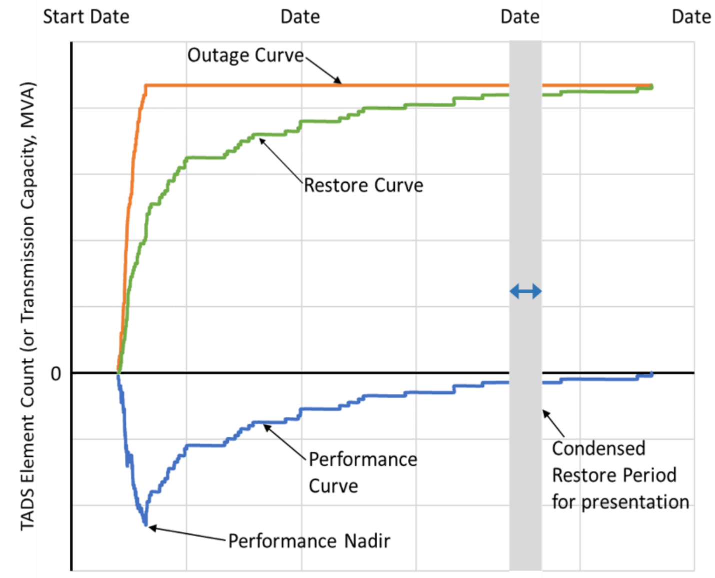

Figure 2.5: Example of Outage, Restore, and Performance Curves for a Large Transmission Outage Event

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.[25] 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).

[24] 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

[25] Resilience statistics are defined in Appendix B in the [2022 SOR](#).

Resilience Curves and Statistics for Largest Transmission Event in 2024

Hurricane Helene caused a huge transmission outage event in the Eastern Interconnection that impacted 20 Transmission Owners in 10 states across the Tennessee Valley, Ohio Valley, Appalachians, and Mid-Atlantic (see **Figure 2.6**). With 431 automatic outages, this event was the largest transmission event not only in 2024 but for the years 2015–2024, representing the full range of the transmission resilience analysis performed by NERC. The previous largest transmission outage event with 352 automatic outages was caused by Hurricane Irma in 2017.

Out of the 431 outages caused by Helene, 422 were ac circuit outages (24 momentary and 398 sustained) and 9 were transformer outages (all sustained). The total affected mileage was 9,138 ac circuit-miles, and the total transmission capacity affected was 127,687 MVA. It was a long event with a total duration of 33.5 days, but not the longest one even in 2024 (which was Hurricane Milton with a duration of 71.8 days). The element- and MVA-based curves for Hurricane Helene are shown in **Figure 2.7** and **Figure 2.8**, respectively. The curves are condensed with the gray area representing the time between 10/15/2024 0:00 UTC and 10/30/2024 0:00 UTC.

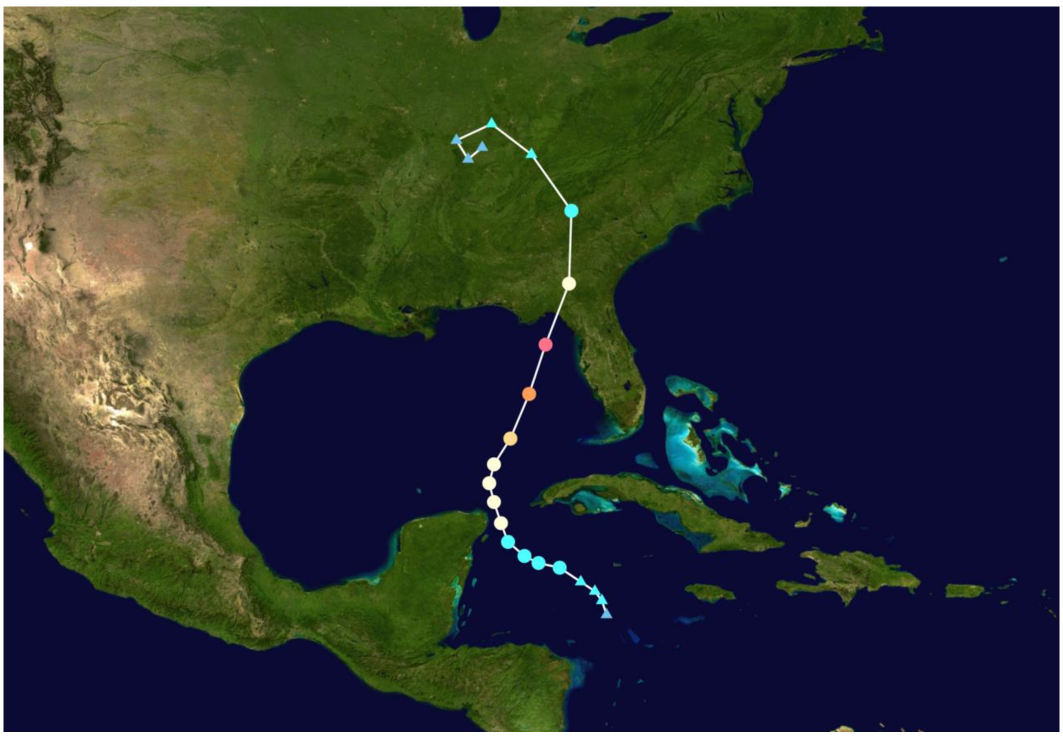

Figure 2.6: Path of Hurricane Helene, September 27–28, 2024[26]

[26] https://upload.wikimedia.org/wikipedia/commons/thumb/5/55/Helene_2024_path.png/1280px-Helene_2024_path.png

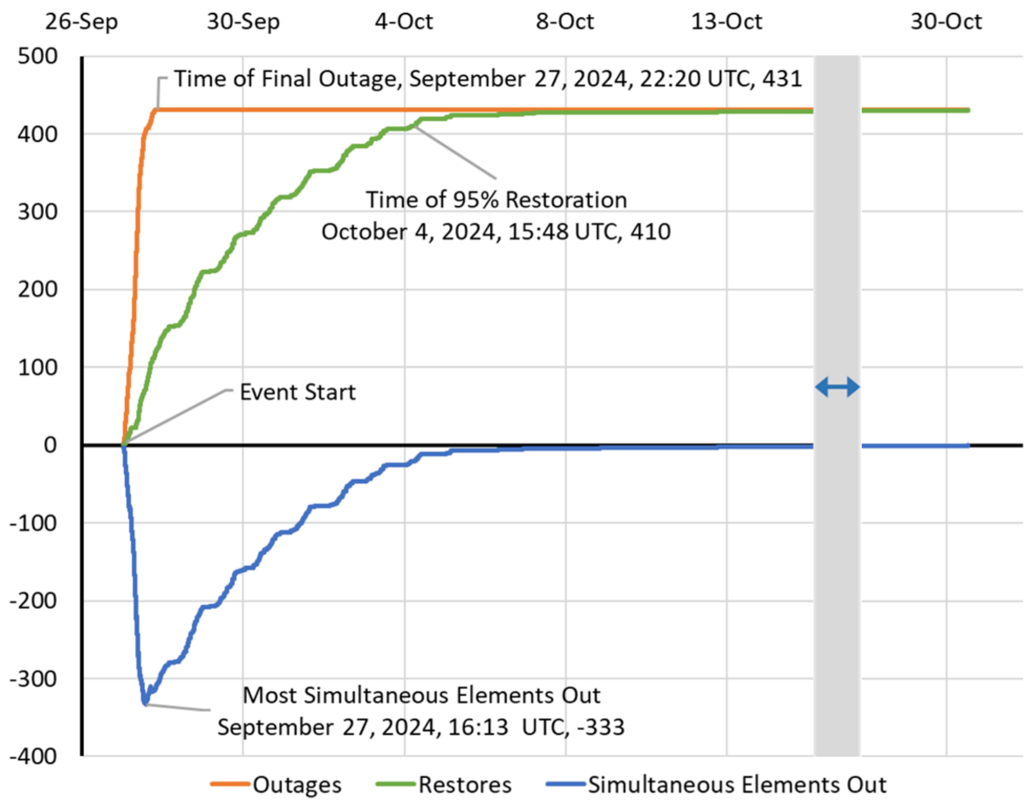

Figure 2.7: Transmission Element Outage, Restore, and Performance Curves for Hurricane Helene, September 27–October 30, 2024

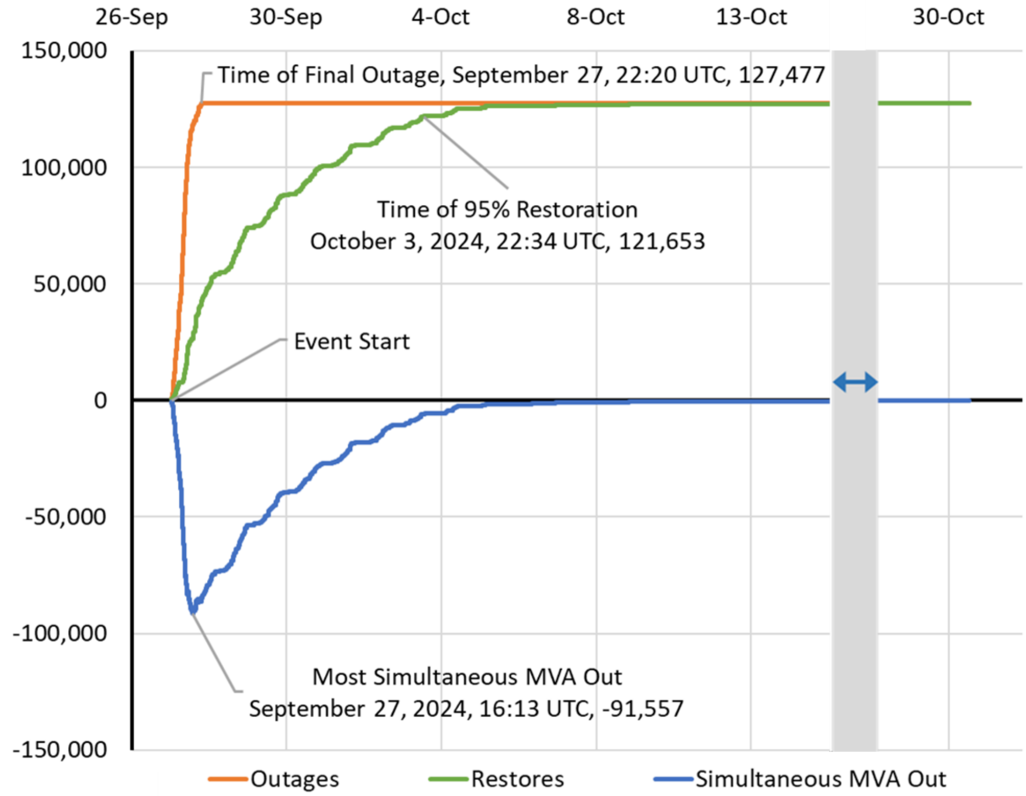

Figure 2.8: Transmission Capacity (MVA-Based) Outage, Restore, and Performance Curve for Hurricane Helene, September 27–October 30, 2024

The outage process shown in **Figure 2.7** and **Figure 2.8** by orange curves started with 8 outages caused by trees or limbs on lines and continued for 20 hours with an average outage rate of 21 outages per hour (6,346 MVA per hour). Due to multiple outages of the same ac circuit, a total of 431 outages occurred on 413 distinct TADS elements. The restore process shown in **Figure 2.7** and **Figure 2.8** by green curves started in 18 minutes after the event start and first progressed steadily and then slowed—a typical pattern for most large events.[27] The most degraded state in the event, with maximum number of elements (333) and MVA capacity (91,557) simultaneously out shown by the nadir of the respective blue performance curves, was reached 14 hours into the event, and the system stayed at the nadir for seven minutes. Unlike the outage process, the restore process did not occur at a constant rate; rather, its rate decreased over the event duration. Using a log-normal fitted curve for the restore process,[28] it is estimated that the maximum instantaneous restore rate of 6.8 restores per hour was reached in 11.6 hours into the event; the rate was 3.1 restores per hour at the time when half of outages were restored, and only 0.37 restores per hour at the 95% element restoration level. The substantial restoration level when 95% of outages were restored was reached after 182 hours or 23% of the event duration. The substantial restoration for transmission capacity (MVA) occurred even faster, 164 hours or 20% of the event duration. The total loss for the event, calculated as the area between a blue performance curve and the time axis, was 1,140 element-days lost (**Figure 2.7**) and 288,329 MVA-days lost (**Figure 2.8**).

The longest outage of a 100–199 kV ac circuit had a duration of almost 33 days (which was also the last restored outage in the event) and was caused by a fallen tree that likely caused extensive damage to the structure. This is typical for large transmission events when few remaining elements are outaged, stemming from either inaccessibility

[27] 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.

[28] 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.

of a portion of the line or damaged structure or equipment; in some cases, a utility postpones the restoration of a single remaining element (or a few elements) until after all other outages in the large event are restored because this outaged element is not considered critical for the reliability of the grid.[29]

It is noteworthy that the time to substantial restoration level (i.e., duration to restore 95% of outages (7 days 14 hours) and duration to restore 95% of MVA (6 days 21 hours)) was remarkably short for the historic outage event. This was a result of a massive coordinating effort of the industry: Nearly 50,000 personnel from at least 36 states, the District of Columbia, and Canada aided in assessment and restoration work.

Transmission System Resilience Statistics by Associated Weather Type: 2020–2024

Weather Types

The outage grouping procedure identified 62 large transmission events in the years 2020–2024, only one of which was not weather-related (a 2023 contamination event).[30] The 61 large weather-related events were caused by the weather types listed in **Figure 2.9**. 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 to determine if a weather event was associated with each large transmission event.

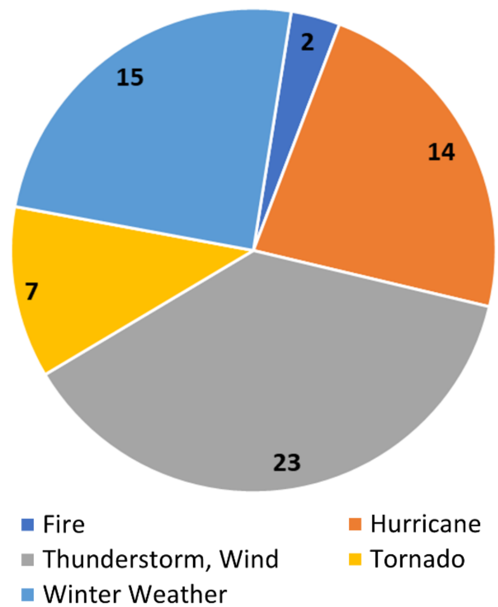

Figure 2.9: Weather Types of Large Transmission Events, 2020–2024

Figure 2.10 shows selected resilience statistics for the 2020–2024 events by weather type. Hurricanes caused the largest transmission events with an average size of 139 outages, while other groups had average sizes that ranged from 41–115 outages. The maximum number of elements simultaneously out (the most degraded state in an event as indicated by the nadir of the performance curve) equals 60% of the event size on average.

[29] 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.

[30] A 2023 large event in SERC with 30 outages caused by bird contamination; the event duration was 2.5 days.

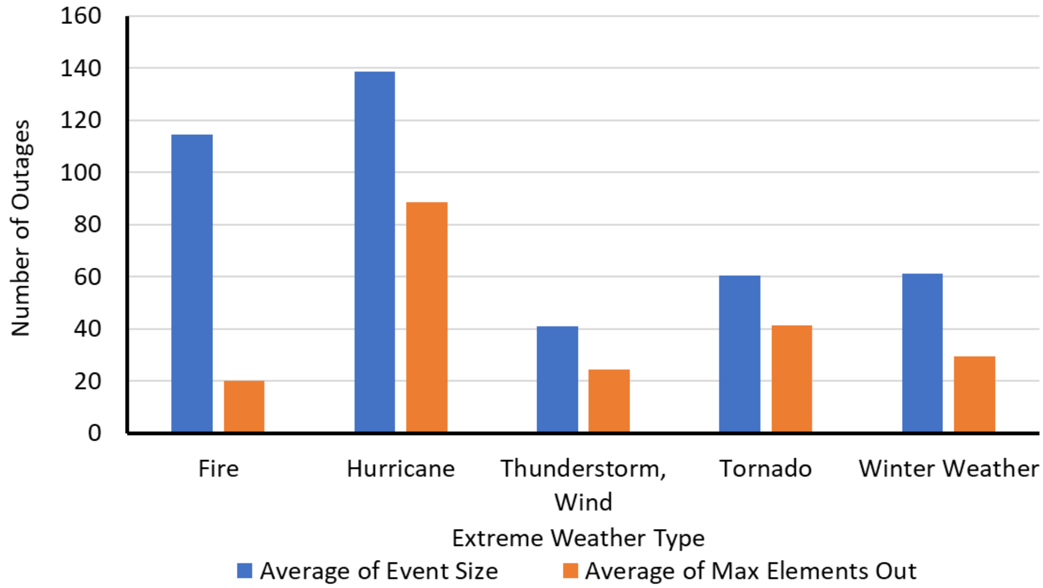

Figure 2.10: Resilience Statistics for 2020–2024 Large Weather-Related Events

Figure 2.11 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.

Fire was highest in average event duration and average substantial restoration time (both outages and MVA capacity) but was lowest in time until first restoration. The two fire events in this year range did vary greatly in resilience statistics. The 2020 Fire was much longer in duration but had a lower ratio of time until substantial restoration and event size, while the 2023 Fire was less than a third of the length, but the ratio until substantial restoration was approximately 90% of the event. Tornado and Winter Weather had the highest time until first restoration.

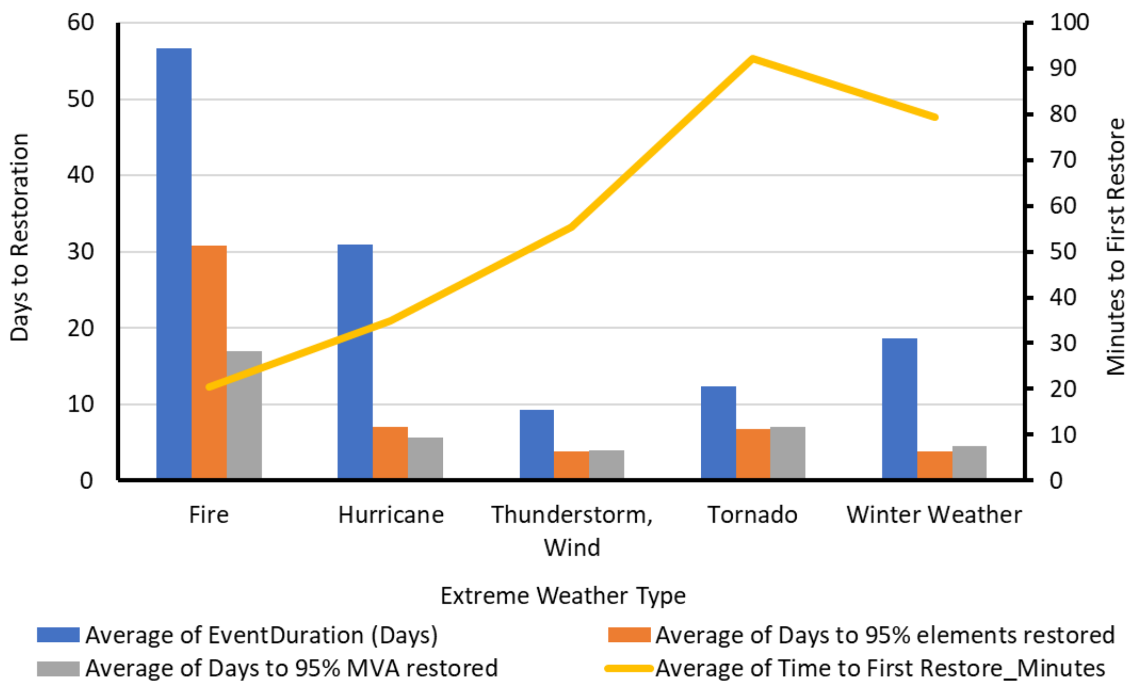

Figure 2.11: Average Event Duration vs. Average Sustained Restoration Duration

Event duration is a straightforward metric but is too highly variable to be a reliable estimate. Moreover, it depends strongly on the last few restores, making the event duration relate poorly to transmission performance because these last restores may be unimportant for customers or may be excessively delayed by factors out of the utility's control, such as the difficulty of repairing transmission lines in the mountains in the winter or structural damage caused by hurricane or tornado.[31] The substantial restoration duration is a preferable metric to measure and track the ability of the transmission system to recover from outage events caused by major weather systems.

Changes in Resilience Statistics: 2020–2024 Events vs. 2019–2023 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 2019–2023 and 2020–2024, 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 (e.g., Fire).

The bubble chart in **Figure 2.12** shows the groups of large weather-related transmission events by weather type; the five patterned bubbles correspond to the groups for combined 2019–2023 data, and the five solid-colored bubbles show the same groups for combined 2020–2024 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 **orange**.

Change in size or position of a bubble for the same weather type in **Figure 2.12** 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 as reflected by the bubble sizes in **Figure 2.12**.

Comparing 2019–2023 vs. 2020–2024, Fire remains unchanged. Hurricanes experienced a slight drop in average number of outages and an increase in the number of events but an improvement in substantial restoration time (9 to 7 days). Tornado, Winter Weather, and Thunderstorms all experienced fewer numbers of events but had a slight increase in average event size. Tornado substantial restoration time improved from 7.6 to 6.8, Thunderstorm substantial restoration time increased from 3.6 to 3.8, and Winter Weather remains unchanged.

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

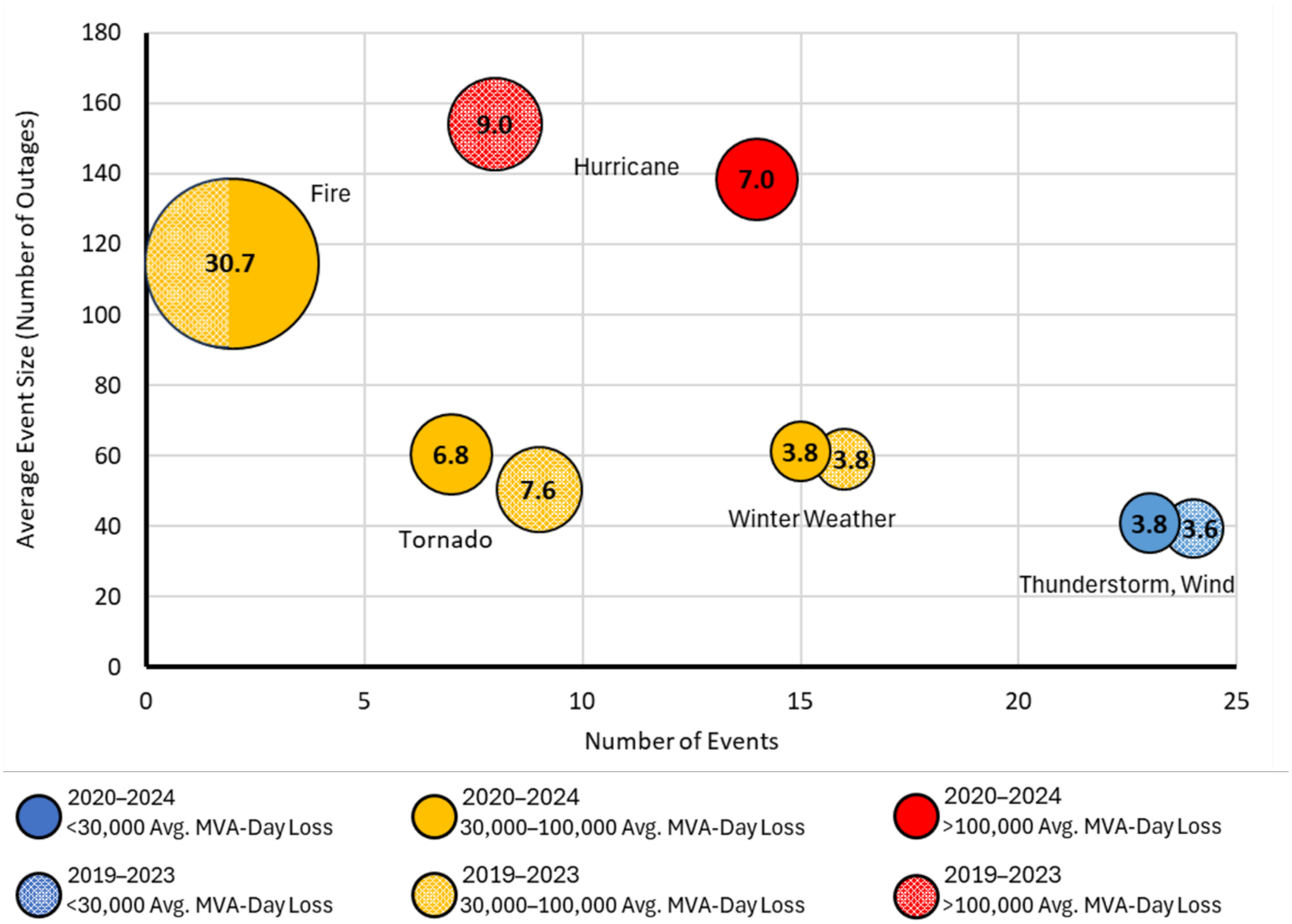

Figure 2.12: Statistics for Large Transmission Events by Weather Type for 2019–2023 vs. 2020–2024

Chapter 3: Grid Transformation

Resource Adequacy

Planning Reserve Margins present a forward-looking perspective on whether sufficient resources are expected to be available to meet demand. The EEAs provide details of actual energy emergencies within an Interconnection.

2024 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 Reference Margin Level (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).

In 2024, all assessment areas except NPCC-Maritimes (winter) had adequate ARMs compared to their RMLs (see **Figure 3.1**; assessment areas are grouped together based on their peak demand season). This indicates that sufficient resource capacity was planned for 2024 to meet established resource adequacy targets in most areas. In NPCC-Maritimes, the 2024–2025 winter reserve margins had fallen by 4.6% from the winter of 2023–2024 as forecasted peak demand had grown by more than 5.5% (300 MW). Future *LTRA* projections indicate that NPCC-Maritimes will be above its RML starting in the 2025–2026 Winter. However, electricity supply shortfalls can still arise from extreme weather, insufficient generator fuel supplies, or other energy limitations in the resource mix despite meeting this traditional resource adequacy criteria.

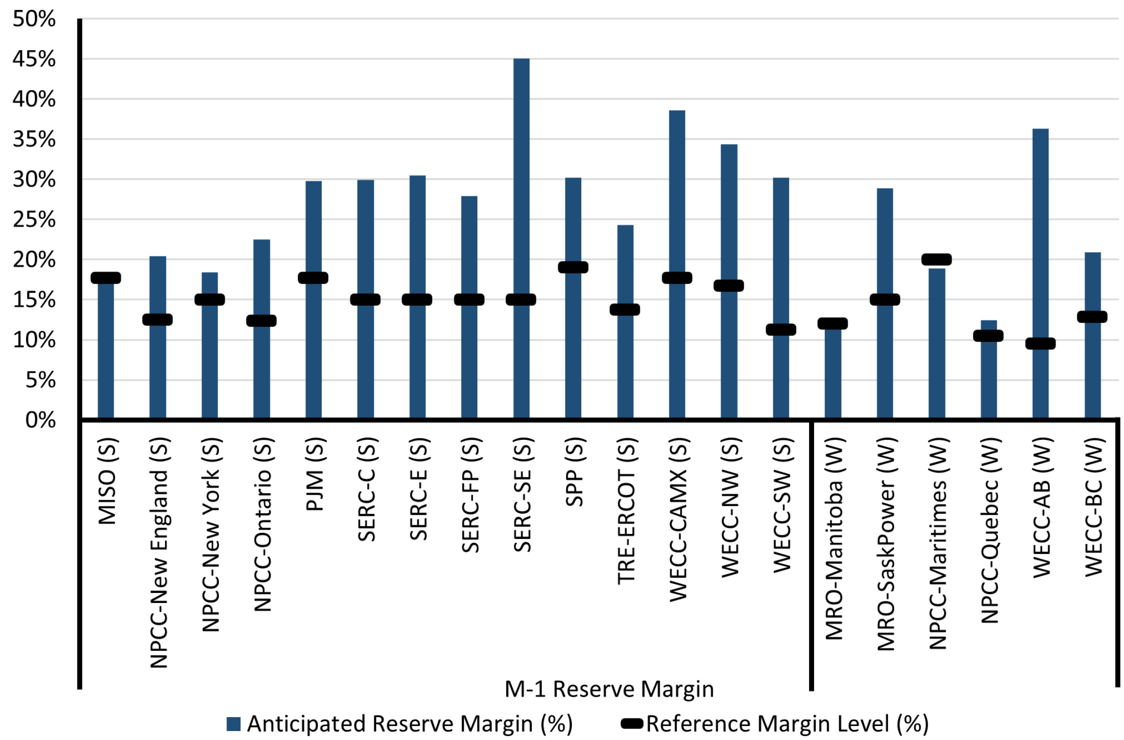

Figure 3.1: 2024 Peak Season Planning Reserve Margins and Reference Margin Levels[32]

[32] M-1, Reserve Margin

2024 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 3.2** and **Figure 3.3** highlight the assessment areas that NERC identified ahead of the Summer 2024[33] and Winter 2024–2025[34] seasons as at risk for resource deficiencies.

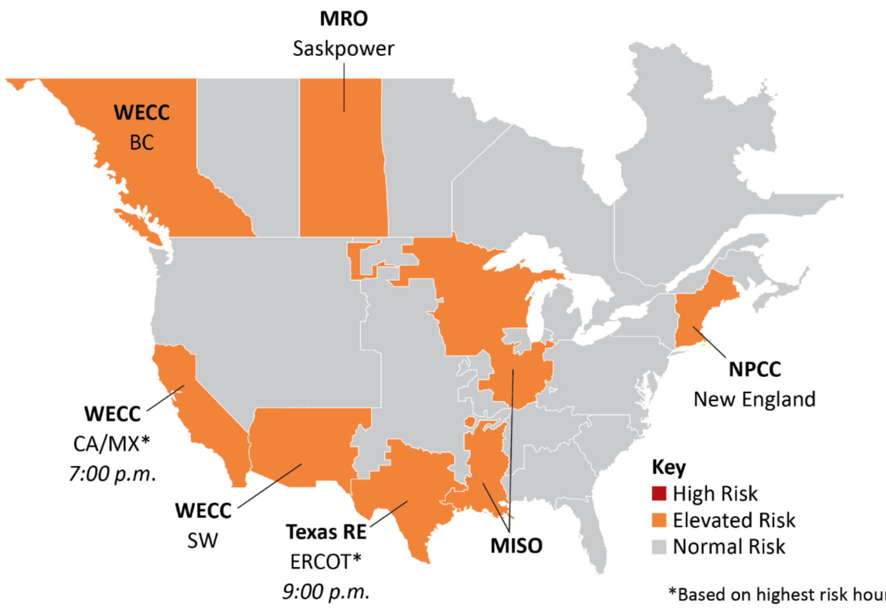

Figure 3.2: 2024 Summer Reliability Assessment Risk Area Map

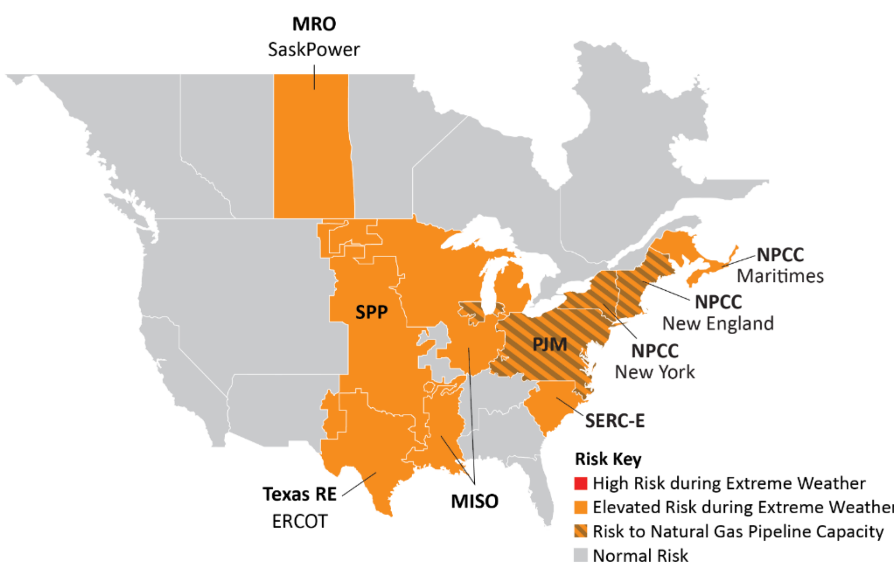

Figure 3.3: 2024–2025 Winter Reliability Assessment Risk Area Map

33 NERC 2024 Summer Reliability Assessment
34 NERC 2024/2025 Winter Reliability Assessment

2024 Capacity and Energy Performance

Summer 2024 was the fourth hottest on record for both the contiguous United States[35] and Canada[36] with some areas experiencing their hottest summer ever. The result was record electricity demand in the United States as well as in Canada, which was particularly pronounced in the Western Interconnection. While peak demand exceeded normal summer forecasts in most areas, only one area experienced demand that met or exceeded a 90/10 demand scenario as defined in the prior year's *Summer Reliability Assessment (SRA)* (See **Table 3.1**). To manage the challenging grid conditions brought about by heat domes and other extreme weather events, grid operators across North America used various operating mitigations up to and including the issuance of energy emergency alerts (EEA). No disruptions to the BPS occurred due to inadequate resources. The following section describes actual demand and resource levels in comparison with NERC's *2024 SRA* and summarizes 2024 resource adequacy events.

Eastern Interconnection–Canada and Québec Interconnection

During the June heat wave that extended across the eastern half of the United States and Canada, system operators in the Ontario and Maritimes provinces followed conservative operating protocols and issued energy emergencies. A late-summer heat wave resulted in an energy emergency in Maritimes.

Eastern Interconnection–United States

Midcontinent Independent System Operator (MISO) experienced peak electricity demand during late August. Demand was between the normal and 90/10 summer peak forecast levels. Wind and solar resource output at the time of peak demand was near expectations for summer on-peak contributions. Forced outages of thermal units, however, were lower than expected. On the day prior to MISO's peak demand, operators issued advisories to maximize generation. Similar advisories were issued earlier in the summer, coinciding with above-normal temperatures and periods of high generator forced outages.

In Southwest Power Pool (SPP), summer electricity demand peaked in mid-July at a level below normal 50/50 forecasts. Above-normal wind performance and sufficient generator availability contributed to sufficient electricity supplies during peak conditions. In late August, however, SPP operators issued an EEA (EEA Level 1) due to high load forecasts, generator outages, and forecasts for low wind output. The period coincided with MISO's peak demand period, making excess supplies for import uncertain. Also, in August during a period of high demand and low resource availability, operators issued public appeals for conservation when a 345 kV line outage caused a transmission emergency. At various other periods during the summer, SPP operators responded to forecasts for high-demand and low-resource conditions with resource advisories intended to maximize available generators.

Like SPP, PJM Interconnection (PJM) also experienced peak electricity demand in mid-July and issued an EEA in August.[37] Peak demand in July was near 90/10 forecast levels. Generator outages were below normal at the time of peak demand. In late August, PJM operators issued an EEA-1 in expectation of extreme demand.

A period of unseasonably high demand in early summer brought on by high temperatures in the Northeast contributed to an EEA-1 in NPCC-New England when a large thermal generator encountered a forced outage. Peak demand in New England occurred in mid-July at a near-normal summer peak demand level. At the time of peak demand, generator outages were below historical averages.

Peak demand in the NPCC-New York area occurred in early July at a level below the normal summer peak demand forecast. Generator outages were below historical levels for peak summer conditions.

Systems in the U.S. Southeast saw successive heat waves beginning prior to the official start of summer and extending to early fall. Operators in SERC used conservative operations and resource advisories to maximize generation and

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[35] US sweltered through its 4th-hottest summer on record – National Oceanic and Atmospheric Administration

[36] Climate Trends and Variations Bulletin – Summer 2024 – Government of Canada

[37] PJM Cold Weather Operations

transmission network availability and issued EEAs when warranted by conditions. In some instances, EEAs were issued when generator outages threatened supplies needed for high demand (See **Table 3.2**). Peak demand in all assessment areas within SERC exceeded normal summer peak demand levels and approached 90/10 demand forecasts.

ERCOT

Peak demand in ERCOT was at or near record levels last summer as load growth and extreme temperatures contributed to escalating summer electricity needs. Demand peaked in August well above the 90/10 demand forecast. At the time of peak demand, wind generation was below expected levels for peak demand periods while output from solar generation was near forecasted levels. Forced generator outages were well below historical average levels for peak demand, helping to meet the extreme electricity demand. Unlike the prior summer, ERCOT did not issue any conservation appeals to customers to reduce demand during high-demand periods. New solar generation, battery resources, and some thermal generation additions since Summer 2023 boosted electricity supplies, enabling operators to meet demand records without demand-side management.

Western Interconnection–Canada

In the province of Alberta, the electric system operator issued an EEA-3 in early July as high temperatures contributed to elevated demand that coincided with a forced generator outage. A new summer peak demand record was set in Alberta later in July at 12.2 MW (up from 11.5 GW in summer 2023). Alberta's demand peak was slightly higher than the normal demand peak scenario projected in the spring of last year.

In British Columbia, peak demand reached 9.4 GW (up from 9.2 GW the previous year), also slightly above the normal peak demand that was projected last year.

In both Alberta and British Columbia, peak demand was still below the extreme peak demand scenarios previously projected, which lowered the risk profile of those provinces over Summer 2024.

Western Interconnection–United States

Demand peaked in July in the U.S. Northwest at a level below the normal summer peak demand. During a period of high demand In July, operators at a Balancing Authority (BA) in the U.S. Northwest issued an EEA-1 to address forecasted conditions.

The California-Mexico assessment area, which consists of the California Independent System Operator (CAISO), Northern California, and Centro Nacional de Control de Energía (CENACE) BAs, experienced system peak electricity demand in early September at a level nearing the 90/10 peak demand forecast. The extreme demand contributed to localized supply concerns and led CAISO to declare a transmission emergency and use conservative operations protocols to posture the system. Despite the extreme demand, operators were able to maintain a sufficient supply without resorting to public appeals, as was required in prior summers. New battery resources were instrumental in providing energy to meet high demand during late afternoon and early evenings. Gas-fired generators also performed well and were important to meet high demand during these same periods. Dry conditions from early summer prompted operators in CA/MX to frequently employ public safety power shutoff (PSPS) procedures beginning in June. Active wildfires led transmission operators to de-energize transmission lines in Northern California and declare transmission emergencies that affected operations across CAISO.

The U.S. Southwest experienced extended heat conditions and demand levels that exceeded 90/10 peak summer forecasts, with peak occurring in early August. Higher-than-expected wind and solar output and low generator outages helped maintain sufficient supplies.

Table 3.1: 2024 Summer Demand and Generation Summary at Peak Demand							
Assessment Area	Actual Peak Demand[1] (MW)	SRA Peak Demand Scenario[2] (MW)	Wind – Actual[1] (MW)	Wind – Expected[3] (MW)	Solar – Actual[1] (MW)	Solar – Expected[3] (MW)	Forced Outages Summer[4] (MW)
MISO	118,600	116,100 125,800	4,565	5,599	5,858	4,981	4,412
MRO-Manitoba Hydro	3,631	3,100 3,300	50	48	0	-	290
MRO-SaskPower	3,669	3,500 3,700	170	208	22	6	0
MRO-SPP	54,279	55,300 57,500	10,869	5,876	442	486	6,046
NPCC-Maritimes	3,500	3,300 3,600	428	262	21	-	777
NPCC-New England	24,300	24,600 26,500	174	122	167	1,111	1,496
NPCC-New York	29,000	30,300 32,000	130	340	0	53	1,451
NPCC-Ontario	23,900	21,800 23,700	915	720	260	66	1,268
NPCC-Québec	23,000	22,900 24,000	2,270	-	0	-	10,500*
PJM	153,100	143,500 156,900	3,366	1,703	2,709	5,694	6,402
SERC-C	42,300	40,700 43,900	312	172	813	996	959
SERC-E	44,000	42,600 44,700	0	-	3,009	2,405	1,878
SERC-FP	52,400	50,500 53,600	0	-	5,376	5,643	94.8
SERC-SE	44,900	44,400 45,300	0	-	3,507	7,217	1,007
TRE-ERCOT	85,500	81,300 82,300	6,286	9,070	17,566	17,797	3,622
WECC-AB	12,221	12,200 12,700	1,091	666	1,114	786	**
WECC-BC	9,430	9,300 9,800	257	140	0.94	0	**

Table 3.1: 2024 Summer Demand and Generation Summary at Peak Demand

Assessment Area	Actual Peak Demand[1] (MW)	SRA Peak Demand Scenario[2] (MW)	Wind – Actual[1] (MW)	Wind – Expected[3] (MW)	Solar – Actual[1] (MW)	Solar – Expected[3] (MW)	Forced Outages Summer[4] (MW)
WECC-CA/MX	58,900	53,200 61,600	1,633	1,124	10,112	13,147	921
WECC-NW	59,700	63,000 69,700	4,694	2,964	6,339	2,595	3,655
WECC-SW	30,800	26,400 28,800	1,179	542	3,357	1,294	2,042

Table Notes:

[1] Actual demand, wind, and solar values for the hour of peak demand in U.S. areas were obtained from Energy Information Agency (EIA) Form 930 data. For areas in Canada, this data was provided to NERC by system operators and utilities.

[2] See NERC *2024 SRA* demand scenarios for each assessment area (pp. 18–37). 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 *2024 SRA*.

[4] Values from NERC Generator Availability Data System or provided by NERC entities for the 2024 summer hour of peak demand in each assessment area.

*Values include both maintenance and forced outages.

**Canadian assessment areas report to the NERC Generator Availability Data System on a voluntary basis, which can contribute to the absence of some values in certain assessment areas.

Table 3.2: 2024 Resource and Energy EEA-3 Summary

Date (2024)	Regional Entity	EEA Description	NERC Seasonal Assessment Indication
January 9–15	WECC (American and Canadian Assessment Areas)	Canadian and U.S. systems in the Western Interconnection experienced cold temperatures during winter storms Heather and Gerri,[38] which contributed to higher demand. Concurrently, energy emergencies were issued as generation loss in the same assessment areas led to reduced resources. No firm load was shed during this event.	**Normal Risk**
July 8	WECC	In the province of Alberta, the electric system operator issued an EEA-3 in early July as high temperatures contributed to elevated demand that coincided with a forced generator outage. A new summer peak demand record was set in Alberta later in July.	**Normal Risk**

[38] FERC-WECC Presentation on Winter Storms Heather and Gerri

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 (see **Table 3.3**). Over the past 10 years, the BPS has reduced its on-peak capacity of coal-fired generation by almost 132 GW and reduced its capacity of nuclear generation by 10.1 GW. During this time, the BPS added on-peak generation capacity: 71 GW of natural gas, 17.9 GW of wind, and 65 GW of solar PV.[39]

Table 3.3: Generation Resource Capacity by Fuel Type

Generation Fuel Type	2014 On-Peak		2024 On-Peak	
	GW	Percent	GW	Percent
Coal	309.6	28.5%	180.4	16.9%
Natural Gas	442.7	40.8%	490.2	46.0%
Hydro	141.1	13.0%	127.3	11.9%
Nuclear	115.5	10.6%	105.4	9.9%
Oil	48.2	4.4%	31.0	2.9%
Wind	14.0	1.3%	31.9	3.0%
Solar PV	5.4	0.5%	71.6	6.7%
Other	9.8	0.9%	28.7	2.7%
Total:	1,087	100.0%	1,066	100.0%

The resource mix and the pace at which it is changing varies considerably across different parts of the North American BPS. **Figure 3.4** provides an Interconnection-level view of the generation resource mix since 2014.

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

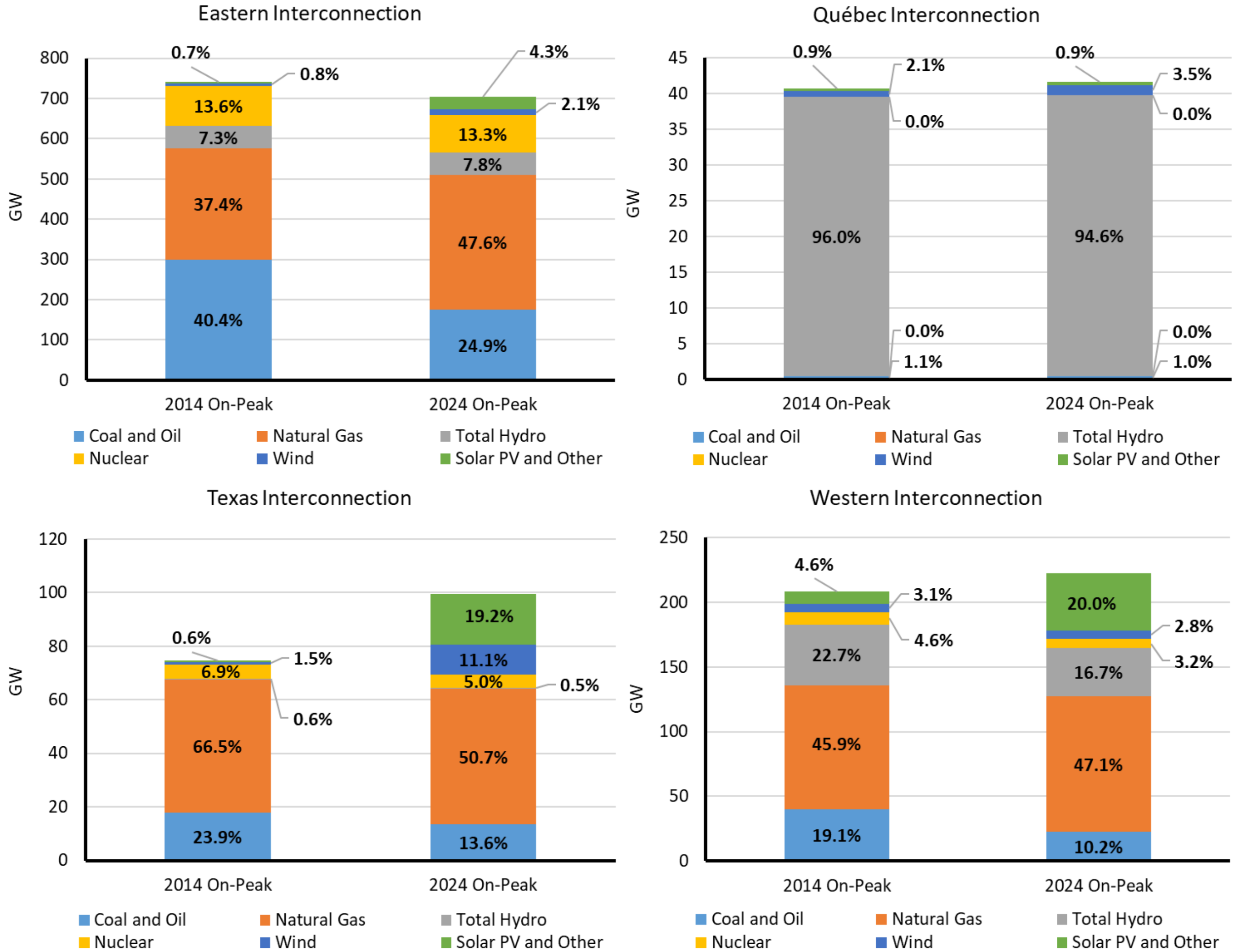

Figure 3.4: 2014 and 2024 Capacity Resource Mix by Interconnection

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. NERC's *2024 LTRA* shows that wind, solar PV, and hybrid (battery storage combined with another type of generator) resources are projected to be the primary additions to the resource mix over the 10-year assessment period; this leads the continued energy transition as older thermal generators continue to retire. Maintaining a reliable BPS throughout the transition requires unwavering attention to ensure that the resource mix satisfies capacity, energy, and essential reliability service (ERS) needs under designed conditions. It will also require significant planning and development of the interconnected transmission system to maintain a deliverable electricity supply from new resources, serve changing types of loads, and maintain the ability to withstand system contingencies.

Critical Infrastructure Interdependencies

2024 saw the intensification of reliability risks related to interdependent critical infrastructure that corresponded both to typical seasonal weather patterns and extreme weather events and natural disasters.

The electric sector's dependence on natural gas grew in both the United States and Canada.

In the United States, natural gas consumption averaged a record 90.3 billion cubic feet per day (Bcf/d), a 1% increase from 2023.[40] U.S. natural gas consumption also set new winter and summer monthly records in January and July. The new record consumption was driven entirely by natural gas consumed for electricity generation, which saw a 4% year-on-year rise in gas demand (see **Figure 3.5**). Annual natural gas consumption declined in the commercial and residential sectors (despite reaching a monthly record in January) and held steady in the industrial sector. Natural gas consumption reached a record high, also topping the US Energy Information Administration's (EIA) forecast for natural gas consumption in its April 2024 *Short-Term Energy Outlook*,[41] despite last summer only being the fourth hottest on record.

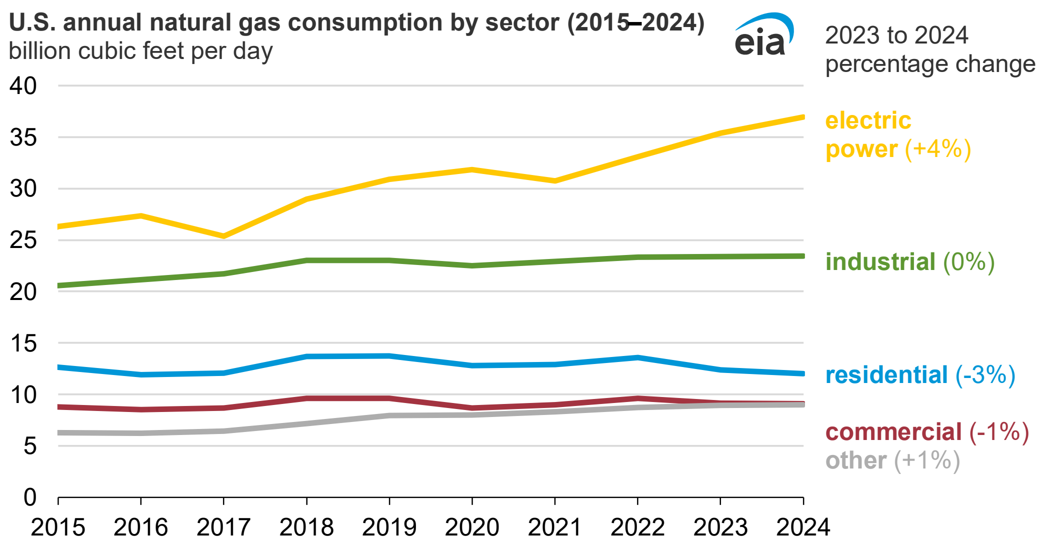

Figure 3.5: Lower 48 States Annual Average Natural Gas Consumption by Sector

In Canada, a record 89.7 TWh of electricity was generated using natural gas.[42]

The trend points to natural gas consumption being increasingly fueled not only by weather patterns but also by the continued expansion of the natural gas fleet to meet large loads, to which data centers are a major contributor. The rise in natural gas consumption, driven by the need for power generation fuel, increases pressure on a largely static natural gas pipeline grid, keeping the question of fuel assurance elevated in reliability risk assessment.

As the EIA under-forecasted natural gas consumption in early 2024, it over-forecasted the availability of hydroelectricity, pointing to another point of interdependent-infrastructure risk and stress. Hydro-power generation fell to a 23-year low in 2024 due to extreme drought, particularly in the Pacific Northwest.[43] Hydroelectric power generation in 2024 totaled 242 TWh, underperforming the EIA's early 2024 forecast of 250 TWh. In Canada, hydroelectric power generation totaled 341.8 TWh, the lowest level in at least 10 years.[44]

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[40] U.S. natural gas consumption set new winter and summer monthly records in 2024 - U.S. Energy Information Administration (EIA)
[41] *Short-Term Energy Outlook April 2024*
[42] Electricity Data Explorer | Ember
[43] Drought conditions reduce hydropower generation, particularly in the Pacific Northwest - U.S. Energy Information Administration (EIA)
[44] Electricity Data Explorer | Ember

Receding reservoirs and low snowpack levels may continue to stress North American conventional hydroelectricity infrastructure, particularly in the Western Interconnection.

Extreme weather events also played a role in stressing critical infrastructure. Hurricanes Helene and Milton resulted in the need to rebuild electricity distribution systems, exacerbating an already strained supply chain for various kinds of transformers. Duke Energy noted in its November earnings report[45] that it would need to replace 16,000 transformers, adding to the growing need to replace transformers across the continent as the National Renewable Energy Laboratory estimates that 55% of residential transformers are near the end of their lives.[46]

6 GHz Frequency Communications

In April 2020, the Federal Communications Commission (FCC) opened usage of the 6 GHz spectrum to new users to promote spectrum sharing. The industry and incumbent users continue to conduct testing on potential communication interference that can impact critical infrastructure and BPS reliability.

In support of industry awareness and strengthening reliability, the 6 GHz Task Force published a white paper titled *6 GHz Microwave Link Interference Preparedness*.[47] The white paper provides background on the current state of the FCC processes, current spectrum usage, and recommendations for industry to assist with baseline understanding, the identification of potential harmful interference, and mitigation options to offset impacts from harmful interference.

In April 2024, NERC issued a Level 2 alert for 6 GHz Communication Penetration in the Electric Industry[48] to establish the extent of condition in the electric sector. An interference awareness webinar[49] was held in May 2024, which provided an overview of the federal actions, interference impacts, and a panel discussion. Additionally, an overview of the Level 2 alert as well as the interference reporting process were reviewed. As per Section 810 of the Rules of Procedure (ROP), a report was submitted to the Federal Energy Regulatory Commission (FERC) summarizing the alert.

At present, NERC has not identified any impact to BPS reliability. Existing processes and procedures are in place to continue monitoring this potential reliability risk.

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 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.

[45] Q3-2024-Earnings-Presentation_vF-w-Reg-G.pdf
[46] What Is Driving the Demand for Distribution Transformers? | News | NREL
[47] 6 GHz Communication Network Extent of Condition White Paper, November 2023
[48] Level 2 Alert, 6 GHz Communication Penetration in the Electric Industry, April 2024
[49] 6 GHz Communication Webinar, May 2024

Protection System Misoperation Trends

Figure 3.6 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, SERC, Texas RE, and within the overall MIDAS data (NERC), while there was a statistically significant increasing trend for NPCC. No statistically significant trend is observed for RF or WECC. The overall count of misoperations in 2024 was the lowest over the past five years (see Table 3.4).

Further analysis of the NPCC misoperation rate indicates that the increased rate is due to both a significant increase in misoperations compared to historical norms (increasing the numerator) and a significant decrease in operations (decreasing the denominator). The decrease in operations is likely attributable to more favorable system and environmental conditions, improvement in vegetation management, or capital investment on infrastructure, all of which are beneficial to the system. Additionally, NPCC historically has a very high percentage of misoperations that are "other than fault," around 50%, which do not correlate to changes in operations counts. The increase in misoperations can be partially attributed to four factors: flooding causing an abnormally high number of misoperations, repeat misoperations on the same equipment before corrective action plan completion, an increase in generator owner misoperations, and a change in one entity's reporting criteria.

NPCC, through its Protection System Misoperation working group (SP7), actively reviews and monitors trends related to misoperations. This includes a quarterly review of reported misoperations, analysis of misoperations data and trends, and the internal "Misoperation Report Card" for its members. In addition, NPCC is working with its members on producing a document to share information (e.g., lessons learned, best practices) regarding short- and long-term corrective action plans aimed at reducing misoperations.

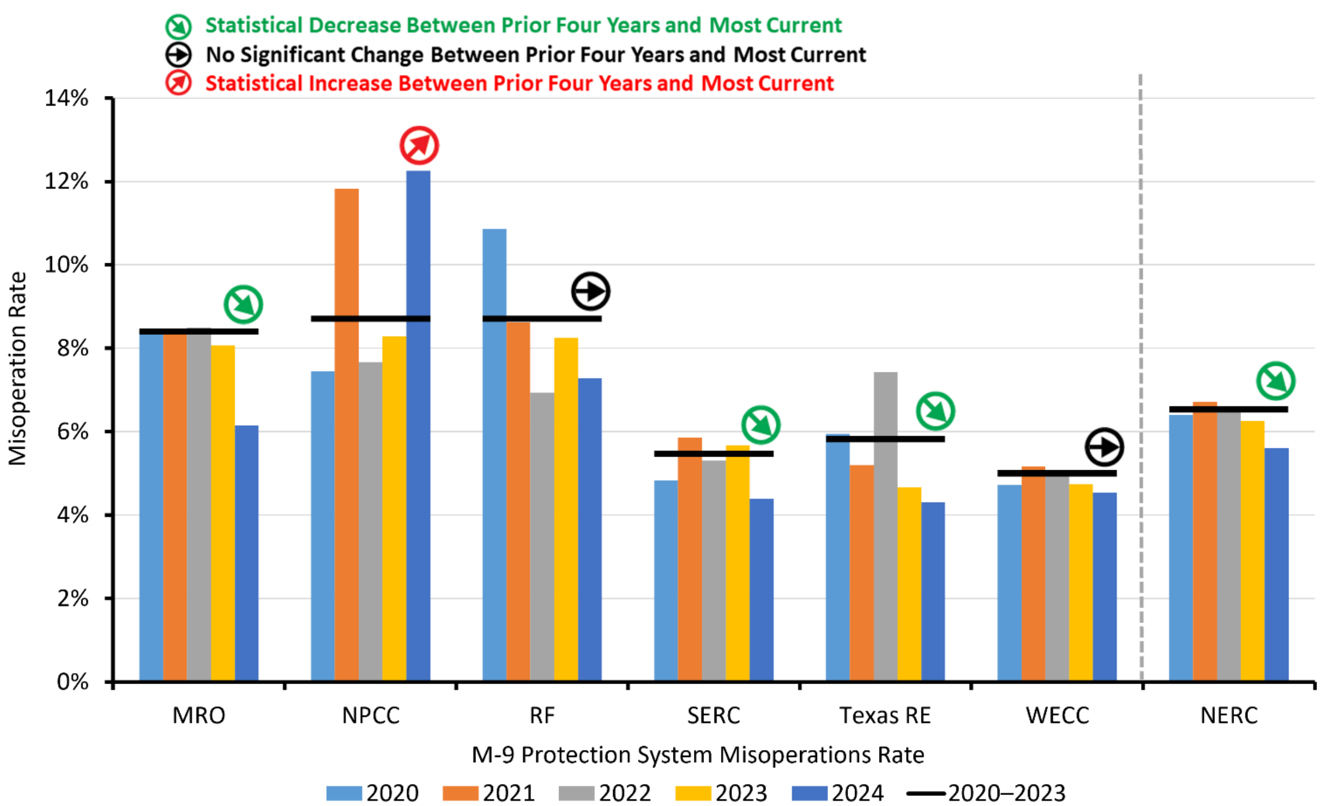

Figure 3.6: Changes and Trends in the Annual Misoperations Rate by Regional Entity[50]

[50] M-9, Protection System Misoperations Rate

Table 3.4: Five-Year Protection System Operations and Misoperations Counts 2020–2024										
Area	Protection System Operations					Misoperations				
	2020	2021	2022	2023	2024[51]	2020	2021	2022	2023	2024[51]
All Regional Entities	18,296	17,454	17,809	17,871	19,370	1,170	1,172	1,154	1,118	1,085
MRO	3,054	2,618	3,238	2,977	3,107	257	218	275	240	191
NPCC	1,774	1,362	1,669	1,752	1,559	132	161	128	145	191
RF	1,878	1,867	2,061	1,867	1,843	204	161	143	154	134
SERC	5,267	4,617	4,775	4,954	5,703	254	270	253	281	250
Texas RE	2,000	2,599	1,991	2,183	2,460	119	135	148	102	106
WECC	4,323	4,391	4,075	4,138	4,698	204	227	207	196	213

Leading Causes of Misoperations

Figure 3.7 shows the distribution of misoperation causes over the past five years. Incorrect settings and relay failures/malfunctions remain the most common causes of misoperations. There was minimal change in the relative frequency of causes from 2023 to 2024.

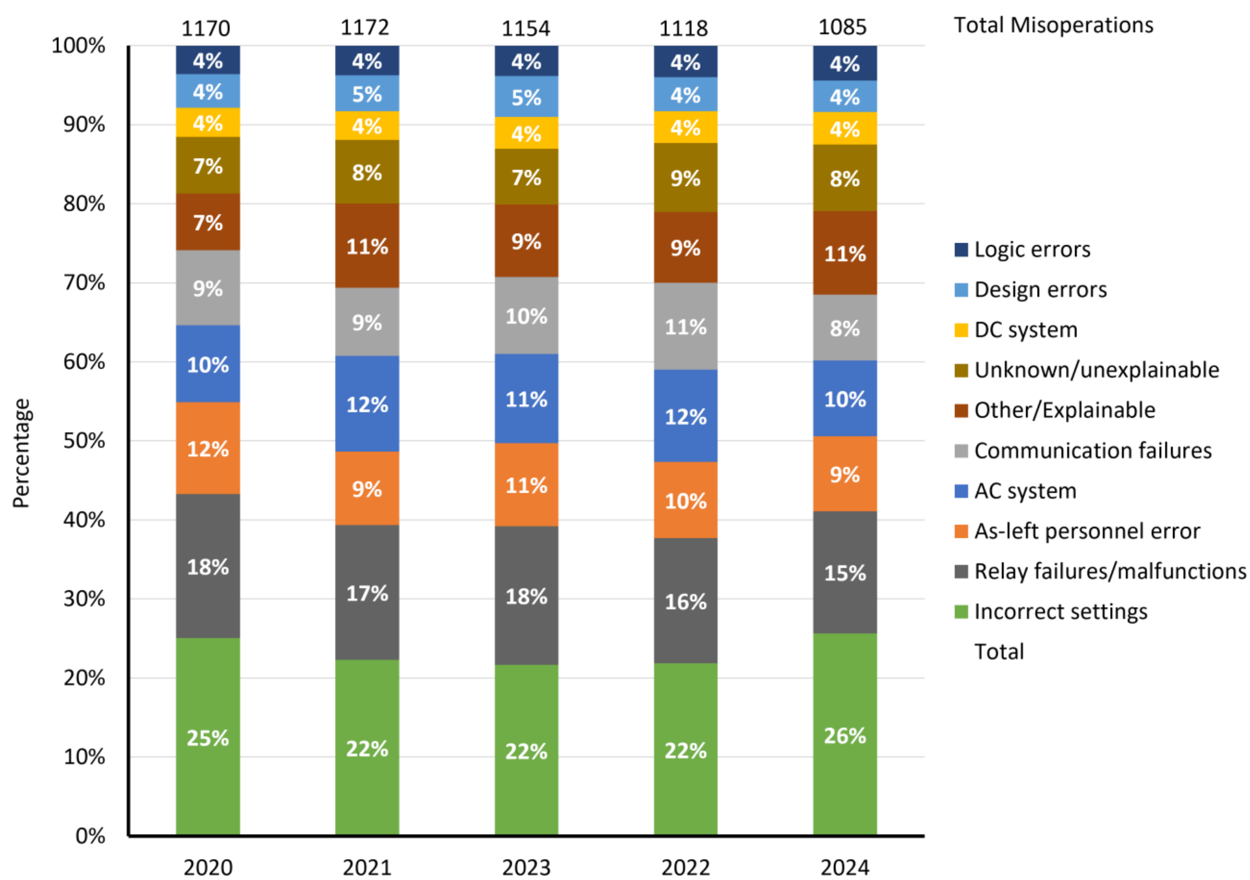

Figure 3.7: Percentage of Misoperations by Cause Code (2020–2024)

[51] The number of operations and misoperations from 2020–2024 was analyzed using a Poisson Regression model designed for count data. An indicator variable for 2024 was used to measure whether there was a significant increase (orange), decrease (green), or no meaningful change (gray) in 2024 compared to previous years' count data.

Misoperation Impact Score

The misoperation impact score measures the estimated impact of each misoperation on the BPS. 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.[52] The criteria that determine the event score are voltage class, equipment type, cause code,[53] and category. 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.

The median and inner quartiles of all misoperations' impact scores have remained largely unchanged over the past five years. The Duncan's grouping test[54] confirms that although the mean impact score for 2024 was the second highest score over the past five years, it was not statistically significant when compared to the other years. These factors (in combination with the slowly decreasing but statistically stable misoperation rate, number of misoperations, and cause distribution) indicate that ongoing work being done to reduce misoperations is effective. The ERO and industry should continue to monitor and coordinate to identify any common issues to further drive down misoperations and their severity.

Protection System Failures Leading to Transmission Outages

AC circuits saw a statistically significant decrease in the number of outages per element in 2024 when compared to the prior four years. Transformers saw a slight increase in the number of outages for 2024, but this increase was not statistically significant (see **Figure 3.8**).

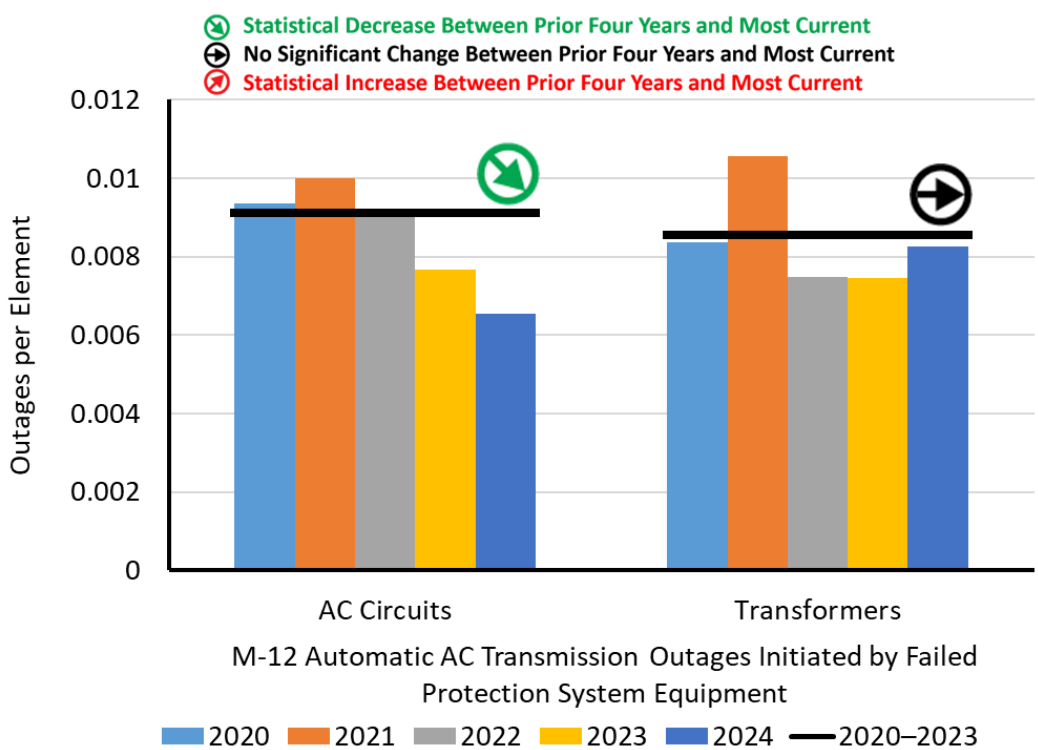

Figure 3.8: Failed Protection System Equipment Outages[55]

[52] Misoperations Impact Score
[53] Not knowing the cause increases the risk of recurrence, increasing the impact score.
[54] Duncan, David B. "Multiple Range and Multiple F Tests." *Biometrics* 11, No. 1 (1955): 1–42. https://doi.org/10.2307/3001478.
[55] M-12, Automatic AC Transmission Outages Initiated by Failed Protection System Equipment

Event-Related Misoperations

An analysis of events meeting published criteria[56] reported through the ERO Event Analysis Process (EAP) found that there were 60 transmission-related events in 2024, 34 of which (57%) involved misoperations (see **Figure 3.9**). In comparison, 2023 saw 70 transmission-related events, of which 46 (66%) had associated misoperations. 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.

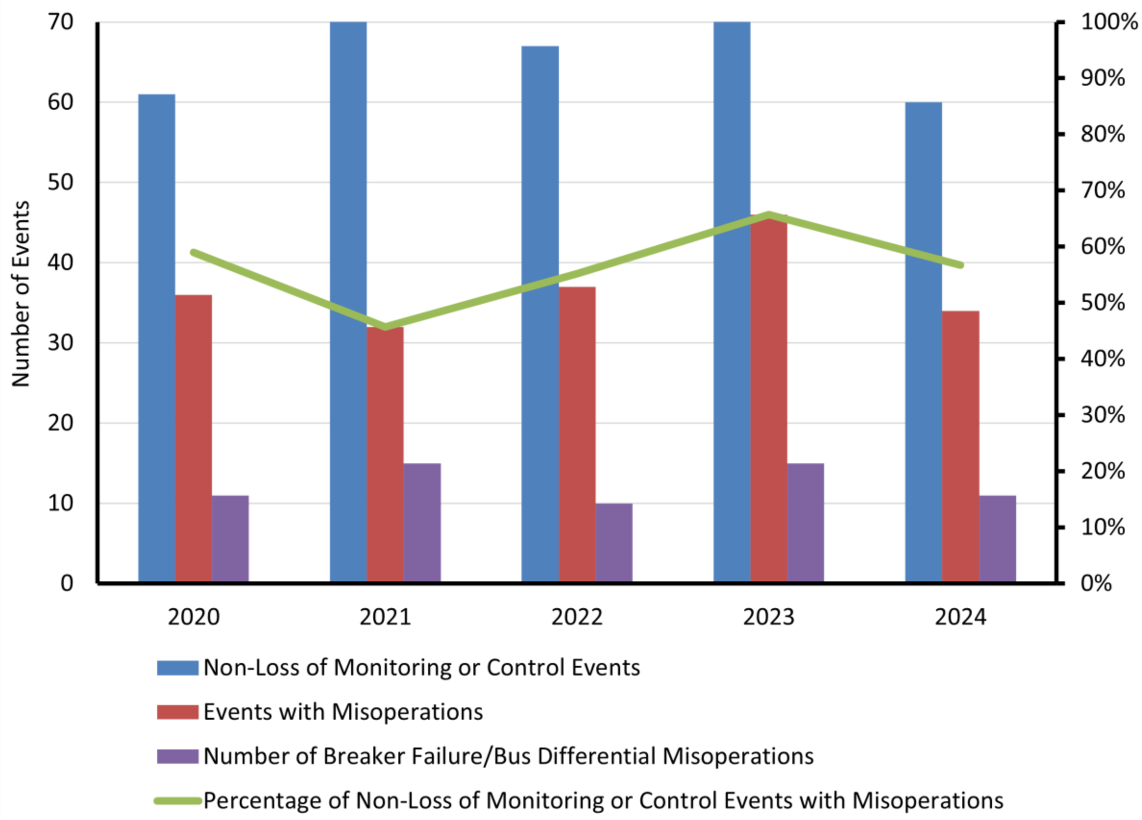

Figure 3.9: Events with Misoperations

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 the reliability of the BPS. 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.

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

Security risks have significant implications for industry, necessitating a broader perspective than what has traditionally been addressed in conventional engineering practices, such as planning, design, and operations. The *2023 ERO Reliability Risk Priorities Report*[57] highlighted security risks as one of the four main risks facing the electric sector, with cyber security risks identified as the most likely to impact the industry.

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 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 BPS tie-lines and transmission facilities within their control area. Additionally, it provides oversight of critical EMS applications, such as state estimation (SE), real-time contingency analysis (RTCA), automatic generation control, and alarm management.

There were 42 categorized[58] events associated with an EMS in 2024; there were no categorized EMS-related events that caused loss of generation, transmission lines, or customer load. **Figure 3.10** illustrates a trend of the categorized EMS events by loss of EMS functions over the 2020–2024 period.

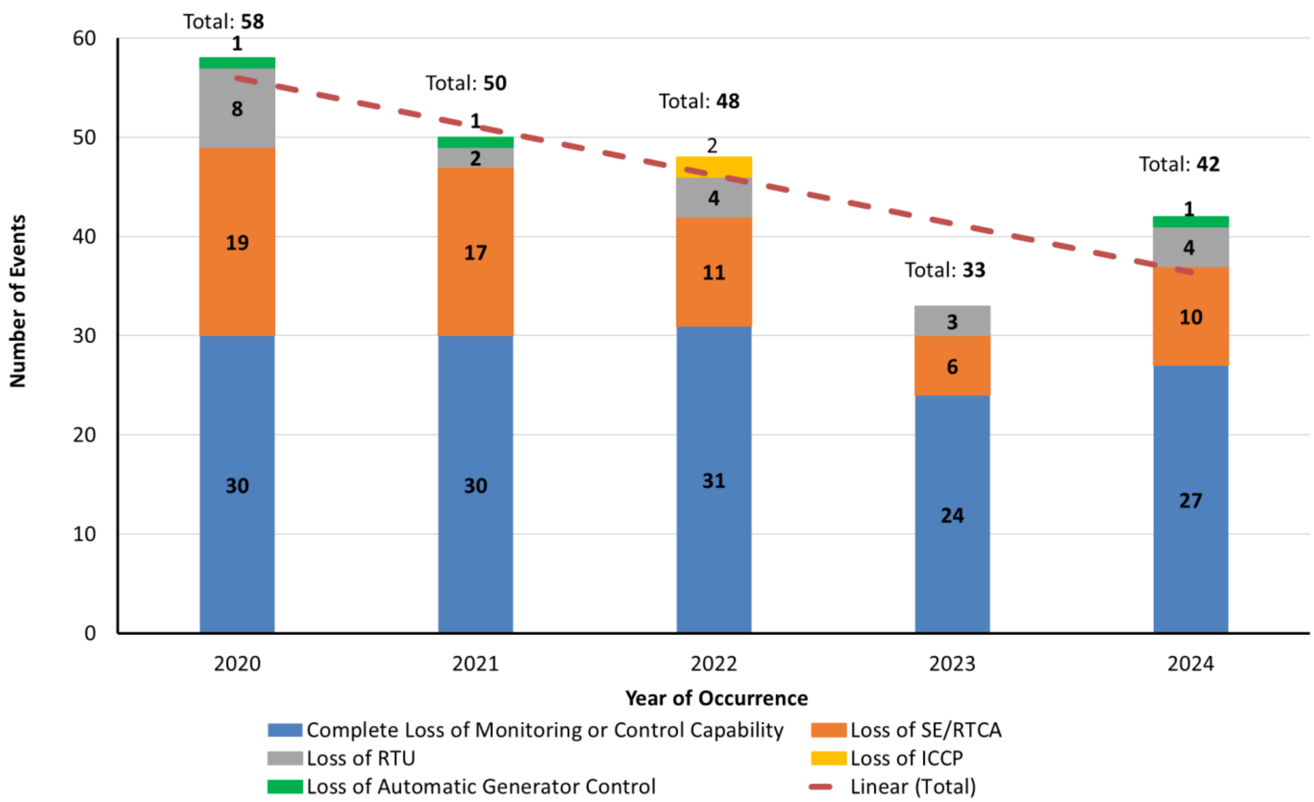

Figure 3.10: Number of EMS-Related Events (2020–2024)

Although the number of categorized EMS events in 2024 rose compared to 2023 (42 events in 2024 vs. 33 in 2023), the overall trend continued to decline over the 2020–2024 period.

The loss of the categorized SE/RTCA increased from 6 in 2023 to 10 in 2024. External modeling was the primary contributor to these events. 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

[57] *2023 ERO Reliability Risk Priorities Report*, August 2023

[58] Category 1h. See Electric Reliability Organization Event Analysis Process Version 5.0

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, new facilities, and the removal of existing facilities, to neighboring entities well in advance.[59] 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.

In 2024, there were 27 categorized events involving a complete loss of monitoring[60] or control[61] capability. Two new themes to these events were identified:

- **Loss of communication between control centers**

  In some complete loss events, the EMS production systems were primarily operated at one control center, while system operators managed them from a different control center. However, system operators lost both monitoring and control when communication between the two centers was interrupted. This disruption was caused by one of the following issues: the collapse of a VPN tunnel, the expiration of a VPN license, or firewall problems related to address resolution protocol routing.

  To prevent communication failures, it is crucial to design and implement redundant and diverse communication paths/tunnels/firewall configurations, as well as associated power supplies, between control centers. Additionally, network devices should be maintained on a scheduled basis, using the latest vendor information, security bulletins, technical updates, and other recommendations. Furthermore, developing an asset management system that tracks software license expiration dates is essential for overseeing the entire lifecycle of assets, which allows for effective risk identification and management.

- **Incorrect configuration of the network time protocol (NTP)[62]**

  When replacing a failed Global Positioning System (GPS) clock, an entity experienced a complete loss of monitoring and control due to an incorrect NTP configuration. To prevent the issue in the future, it is essential to establish operating procedures that verify the accuracy of both the *date* and *time* whenever NTP time sources are modified, changed, or replaced. System operators and support staff must understand the consequences of introducing an incorrect NTP configuration into the supervisory control and data acquisition (SCADA) network. Additionally, it is important to conduct dependency testing on the NTP design to ensure that there are no single points of failure within the time synchronization system.

Over the five-year period (2020–2024), the average partial or full function categorized EMS outage time (see **Figure 3.11**) was 77 minutes, making the calculated EMS availability 99.992% during the term.

[59] Risks and Mitigations for Losing EMS Functions Reference Document Version 4

[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.

[62] Lessons Learned: Loss of SCADA/EMS Monitoring and Control – GPS Clock Failure

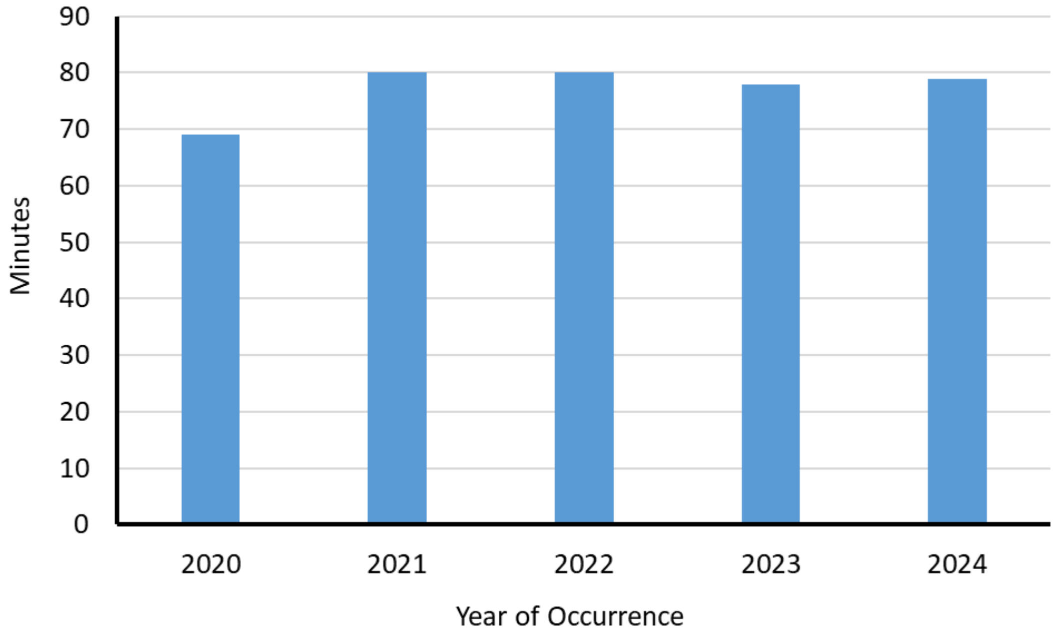

Figure 3.11: Average EMS Outage Time (2020–2024)

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.

During the evaluation period from 2020 to 2024, Figure 3.12 illustrates that software was the primary contributor to EMS outages. This was followed by communication and maintenance challenges.

Figure 3.13 shows a trend in reported EMS events by the contributors of EMS function loss throughout the same period. In 2024, the main contributors were identified as software and maintenance challenges. Although there was an increase in these areas compared to 2023, the analysis indicates that the overall trend remained consistent over the five-year period from 2020 to 2024.

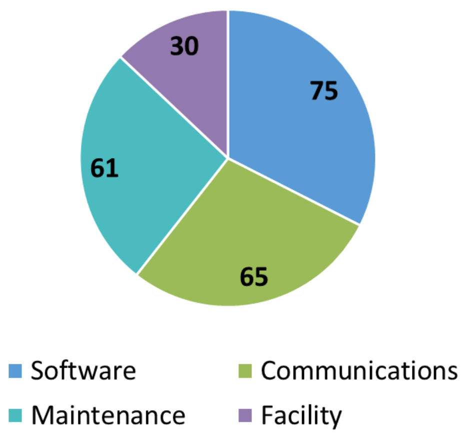

Figure 3.12: Overview of Contributors to Loss of EMS Functions (2020–2024)

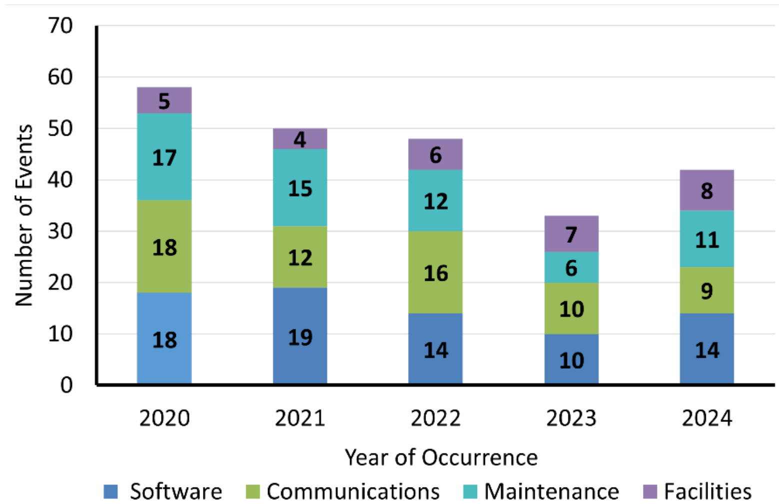

Figure 3.13: Trend of Contributors to Loss of EMS Functions (2020–2024)

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.

Maintenance failures typically occur when the system configurations and settings are not updated to reflect changes in the latest system operations. These configurations and settings for an EMS are often specially programmed to meet the unique needs of an entity, considering its configuration, topology, contingencies, and external factors. When the entity expands or modifies its model, these configurations and settings must be adjusted according to the resulting changes in topology. It is often necessary to periodically review the settings and configurations, possibly with assistance from the vendor, to ensure that the EMS continues to function effectively and produces high-quality results. The frequency of these reviews may vary, but it is important to consider reviewing the settings and configurations after model changes, generation retirements, software upgrades, and any other significant modifications to the EMS system or model.

An analysis of the ERO EAP data reveals that 5.6%, or 13 out of 231 reportable EMS events lasting more than 30 minutes from 2020–2024, were linked to issues with external communication providers. However, these external communication provider-related problems are not currently significantly impacting EMS outages.

Human Performance

As human error can adversely impact the performance of BPS 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 *2023 ERO Reliability Risk Reliabilities Priority Report*[63] states, "The BPS is becoming more complex, and the industry will have difficulty staffing and maintaining necessary skilled workers as it faces turnover in technical expertise."

[63] *2023 ERO Reliability Risk Reliabilities Priority Report*

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*.[64]

Statistical significance testing compared the average outage rate of 2024 to that of the prior four years. For ac circuit outages caused by human error, automatic momentary and sustained outages and total forced outages saw no significant change in occurrence (see **Figure 3.14**), while operational outages saw a statistically significant increase. Transformers saw a statistically significant increase in both automatic momentary and sustained outages and total forced outages caused by human error, while operational outages saw no significant change (see **Figure 3.15**). Further investigation into the transformer outages due to human error identified a decrease in the number of events; however, two events involved three different transformers, and one event involved six different transformers. For comparison, no more than two transformers were involved in any events during the prior four years.

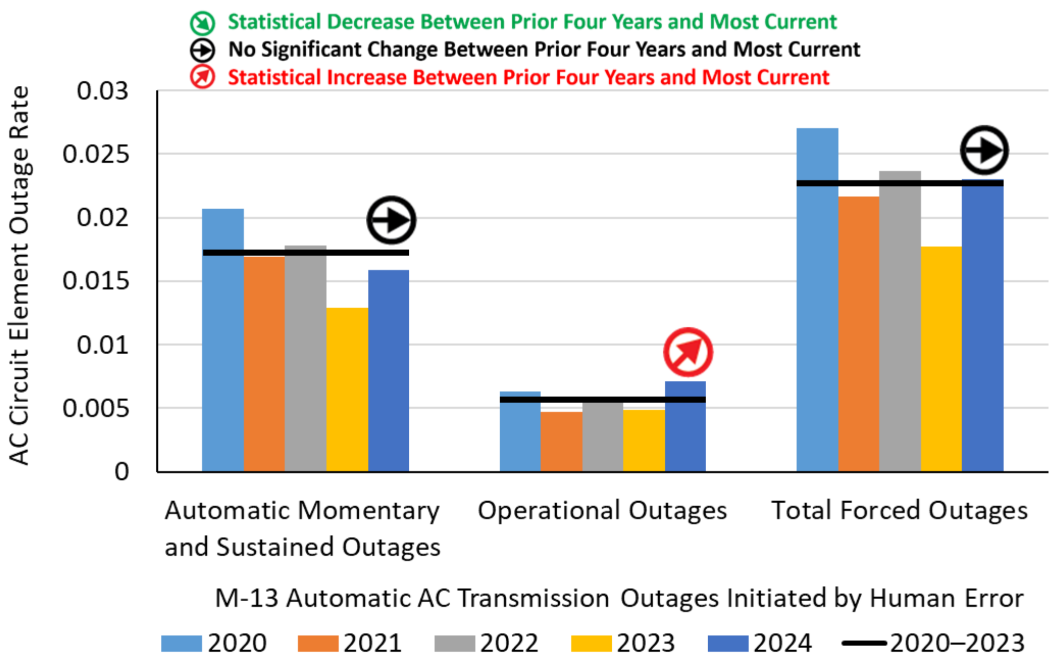

Figure 3.14: AC Circuit Outages Per Circuit Initiated by Human Error[65]

[64] 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.

[65] M-13, Automatic AC Transmission Outages Initiated by Human Error

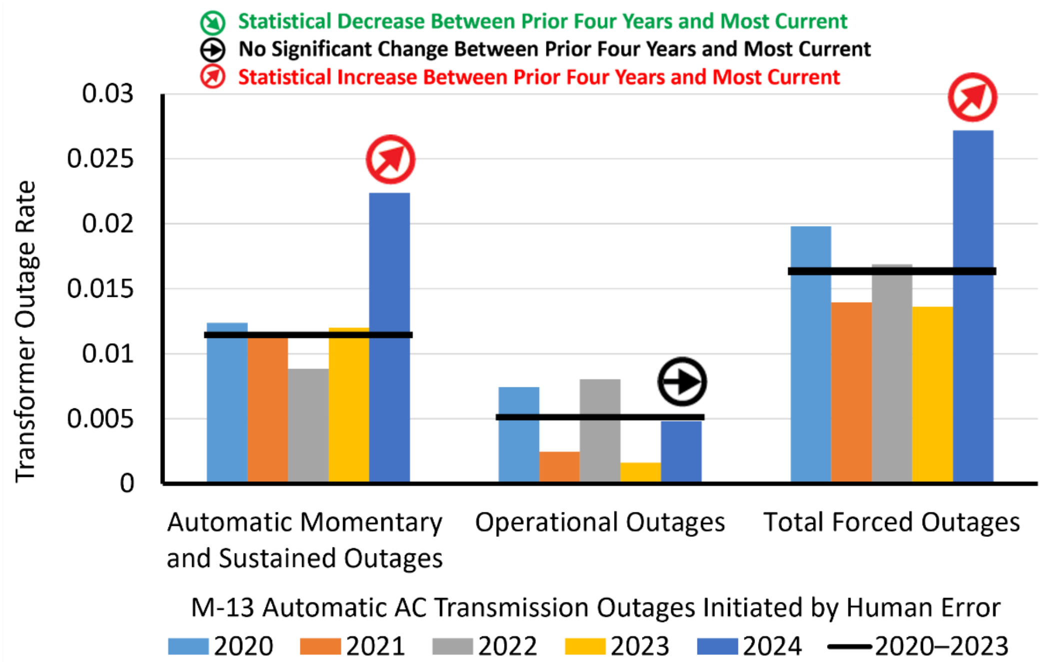

Figure 3.15: Transformer Outages Per Element Initiated by Human Error[66]

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 events. Though there was a slight decrease observed in 2024, it was not significant enough of a variance to warrant presentation.

Trends of Human and Organizational Root Causes[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 2024, organization/human performance was identified as the root cause for 38 processed events (see **Figure 3.16**). This does not fully project the final 2024 number, as just more than half of the 2024 events have been assigned a final root cause. The top five human and organizational performance root causes for the 2020–2024 period are listed in priority order 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 processed between 2020 and 2024 saw the same top five human and organizational performance root causes identified in the 2019 and 2023 time period.

[66] M-13, Automatic AC Transmission Outages Initiated by Human Error
[67] Cause Code Assignment Process (Updated January 2025)

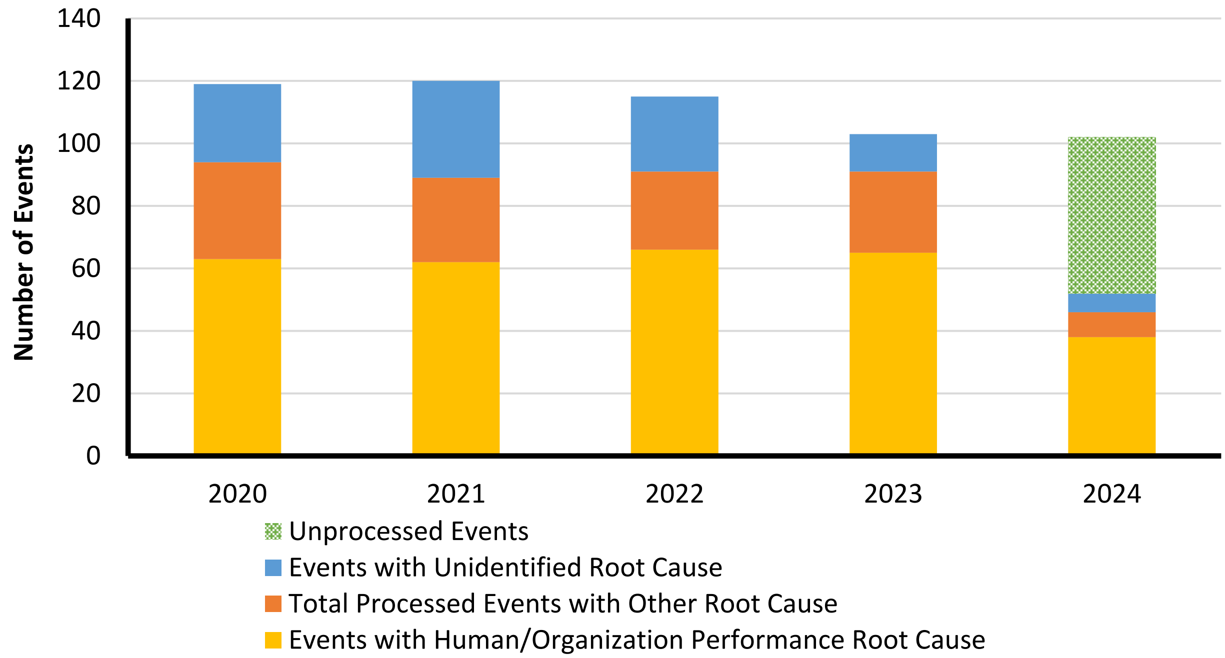

Figure 3.16: ERO EAP Organization/Human Performance Root Cause Identification by Year

In mid-2024, the vendor's corrective actions were reassigned from the "unidentified causes" category to another cause category. Additionally, a second change involved incorporating design/engineering codes into human/organization performance analysis.

An opportunity exists for industry to improve BPS reliability through increased focus in the areas of management and organization performance and engineering and design. Management and organization 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 43% of misoperations in 2024 and consisting of 9% As-Left Personnel Error, 4% Design Errors, 26% Incorrect Settings, and 4% Logic Errors (see **Figure 3.7**). **Figure 3.17** additionally shows the number of misoperations related to human error by Regional Entity for the past five years. The five-year trends for all Regional Entities, except NPCC and WECC, are either improving or remaining consistent.

To reduce the frequency of misoperations potentially due to human error, SERC formed a task force two years ago to develop sub-cause categories to better identify what areas to target for improvement. Since 2024, the SERC Protection and Control Working Group (PCWG) has documented these subcategories to develop mitigation strategies. It is also focusing on reducing incorrect settings by having members summarize their relay settings processes to identify improvement opportunities and incorporate them into stakeholder setting processes. While it is too soon to draw a correlation between these efforts and the results shown in **Figure 3.17**, the data shows a decrease in human error misoperations for SERC (34%), the largest decrease among all the Regional Entities this year.

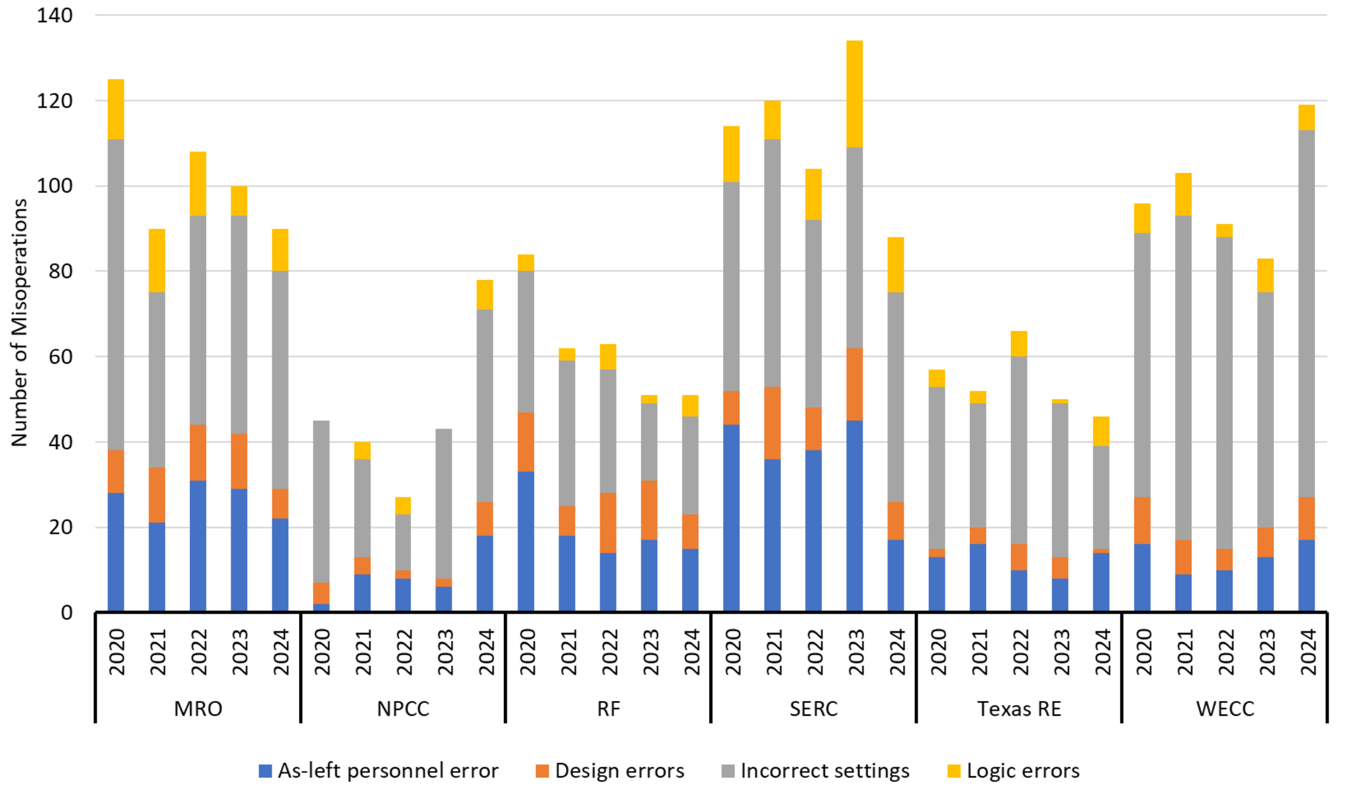

Figure 3.17: MIDAS Protection System Misoperations Due to Human Error by Regional Entity

Energy Emergency Alerts[68]

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.

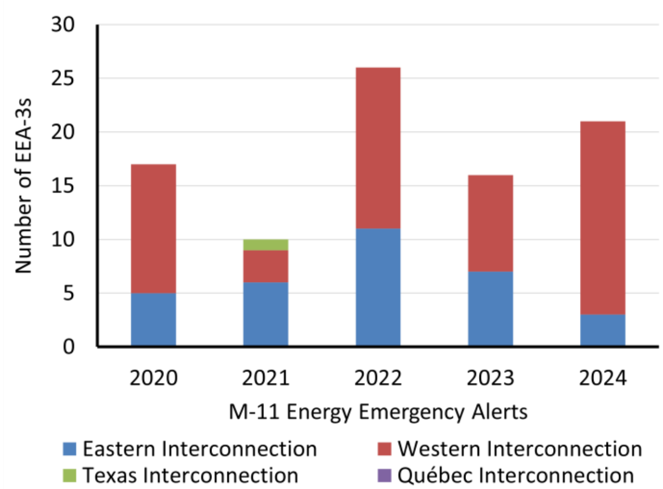

Figure 3.18: EEA-3 by Year and Interconnection

Figure 3.18 shows that 21 EEA-3s were declared in 2024, an increase of 5 EEA-3 declarations over 2023. Only one of the EEA-3 declarations in 2024 included 0.108 GWh of firm load shed vs 92.6 GWh in 2022 and 0 GWh in 2023.

Nineteen of the EEA declarations in 2024 were associated with periods of reduced generation or import capability combined with heavy load days, and two were associated with severe cold weather. Seventeen EEA-3s were associated with two non-U.S. entities, both of which have weak connections to their neighbors. Of these 17, 9 are associated with a balancing area that has processes requiring the declaration of an EEA-3 prior to requesting assistance from neighbors. Table 3.5 shows the number of hours when operator-initiated firm load shed was deployed during each of the past five years. In 2024, 0.43 hours occurred, while in 2023 0 hours occurred. In 2022, 21 hours occurred in June during excessive heat and 35.5 hours occurred during Winter Storm Elliott for a total of 56.5 hours.

[68] M-11, Energy Emergency Alerts

Table 3.5: Hours with Operator-Initiated Firm Load Shed (Hours/Year)			
Year	**Event**	**Event Hours**	**Total Annual Hours**
2020	California Heatwave	7.4	22.4
	California Wildfires	4.1	
	Hurricane Laura	10.9	
2021	February Cold Weather Event	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

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 2024 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 chapter can be categorized as either Improving, Stable, Monitor, or Actionable. Measuring and trending the relative state of the BPS 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)		**Stable**
M-3: System Voltage Performance		**Retired**
M-4: Interconnection Frequency Response	Eastern	**Stable**
	Texas	**Improving**
	Western	**Improving**
	Québec	**Stable**
M-4.1: Inertia and Rate-of-Change-of-Frequency	Eastern	**Stable**
	Texas	**Improving**
	Western	**Stable**
	Québec	**Monitor**
M-5: Activation of Under Frequency Load Shedding		**Retired**
M-6: Disturbance Control Standard Failures		**Metric is Under Review**
M-7: Disturbance Control Events Greater than Most Severe Single Contingency		**Metric is Under Review**
M-8: Interconnection Reliability Operating Limit (IROL) Exceedance		**Improving**
M-9: Protection System Misoperations Rate		**Improving**
M-10: Transmission Constraint Mitigation		**Retired**
M-11: Energy Emergency Alerts		**Monitor**
M-12: Automatic AC Transmission Outages Initiated by Failed Protection System Equipment	AC Circuits	**Improving**
	Transformers	**Stable**
	AC Circuits	**Stable**

[69] Current Approved Reliability Metrics; Metrics M-3, M-5, and M-10 are retired.

Table 4.1: Reliability Indicators		
Metric Name		**Metric Performance Status**
M-13: Automatic AC Transmission Outages Initiated by Human Error (AC Circuits and Transformers)	Transformers	**Actionable**
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)		**Stable**
M-16: Transmission Element Availability Percentage and Unavailability Percentage	AC Circuits	**Stable**
	Transformers	**Stable**
M-17: Transmission Outage Severity		**Monitor**
M-18: TADS Physical Security Metric		**Stable**

Frequency Response Performance

2024 Interconnection Frequency Response

2024 analysis of frequency response performance and trends indicates an adequate level of reliability.

- For the stabilizing period (M4 metric), the Eastern and Québec Interconnections showed no statistically significant changes from 2020 through 2024. The Western and Texas Interconnections showed a statistically significant improvement for the stabilizing period from 2020 through 2024.
- For the arresting period (M-4.1 metric), the Western and Eastern Interconnections showed no statistically significant changes from 2020 through 2024, while the Texas Interconnection showed a statistically significant improvement. However, the QI showed a statistically significant decreasing trend.
- Of note in 2024, the number of valid events for the Western and Texas Interconnections continued to decline (see **Figure 4.1**). This trend in the reduction of valid M-4 events could 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 a positive indicator when considering impacts to Interconnection reliability.
- Also of note in 2024, there were several extreme outlier events in the Western Interconnection. All the Western Interconnection events were confirmed to be valid. These events demonstrate the frequency response support that a large battery energy storage system (BESS) availability can provide in the Western Interconnection when a large resource loss occurs.

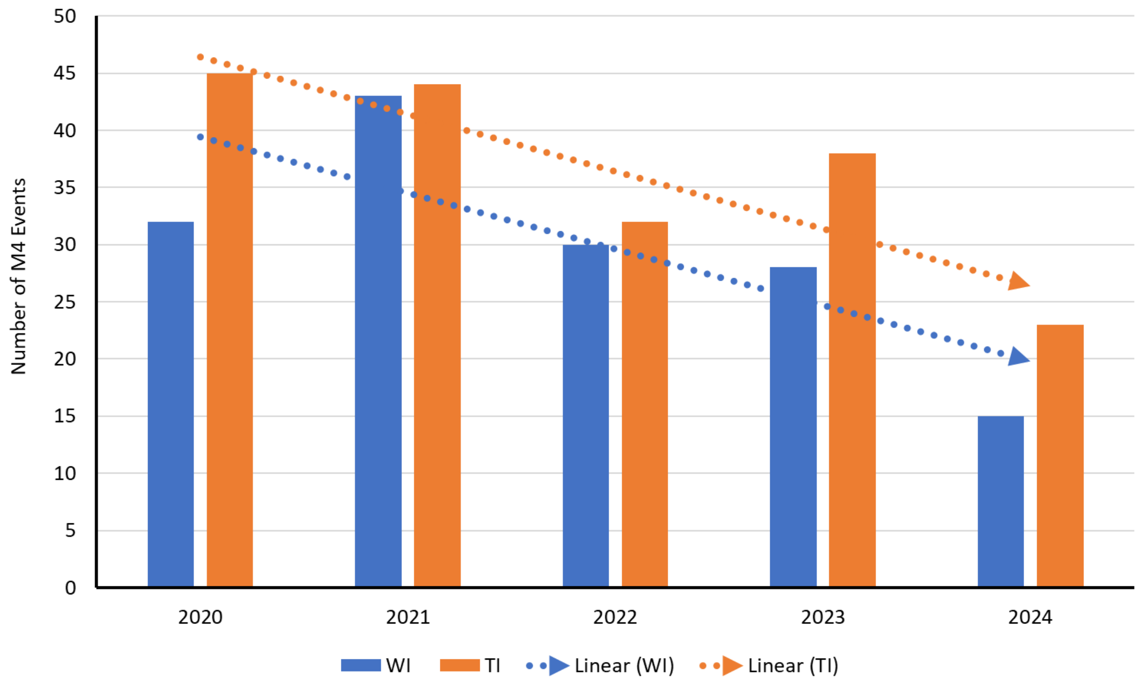

Figure 4.1: Declining Event Count in Western and Texas Interconnections

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

The decreasing trend in the arresting period metric for the Québec Interconnection was due to an overrepresentation of events in Summer 2023 compared to other years. An abnormally high number of events occurred between May and October 2023 (months that typically have lower inertia), in part due to the wildfire events in the region. This was also noted in the *2024 SOR* report.

The Eastern, Québec, and Texas Interconnections 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: 5-Year Statistical Trend

Interconnection	M4 Stabilizing Period	M4.1 Arresting Period	Margin-C-UFLS	Comment
Eastern	Neither decreasing nor increasing	Neither decreasing nor increasing	Neither decreasing nor increasing	No M4 events with FR below IFRO
Texas	Increasing	Increasing	Increasing	No M4 events with FR below IFRO
Western	Increasing	Neither decreasing nor increasing	Neither decreasing nor increasing	Two M4 events from 2023 with FR below IFRO

Table 4.2: 5-Year Statistical Trend				
Interconnection	M4 Stabilizing Period	M4.1 Arresting Period	Margin-C-UFLS	Comment
Québec	Neither decreasing nor increasing	Decreasing	Neither decreasing nor increasing	No M4 events with FR below IFRO

Frequency response for all Interconnections' stabilizing period is stable or improving (see **Table 4.3**).

Table 4.3: 2024 Frequency Response Performance Statistics for Stabilizing Period										
2024 Operating Year Stabilizing Period Performance										
	Number of Events					Mean Frequency Response	Median	Minimum	Maximum	Number of events with FR below the IFRO
	2020	2021	2022	2023	2024					
Eastern	35	29	46	47	44	2,673	2,321	1,227	6,457	0
Texas	45	44	33	39	23	1,658	1,440	869	3,141	0
Québec	50	42	22	65	63	927	713	283	4,073	0
Western	32	43	30	28	15	4,566	2,220	1,279	20,920	0

During the arresting period, the goal is to arrest the frequency decline for credible contingencies before the activation of under-frequency load shedding (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)[70] 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 4.2** 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 4.2** 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 all Interconnections indicates stable and improving performance for the arresting period for 2024 as shown in **Table 4.4** below.

Table 4.4: 2024 Frequency Response Performance Statistics for Arresting Period												
2024 Operating Year Arresting Performance												
	Number of Events					Mean Frequency Response	Median	Min	Max	Mean UFLS Margin	Median UFLS Margin	Min. UFLS Margin
	2020	2021	2022	2023	2024							
Eastern	35	29	46	47	44	2,104	1,980	1,036	3,400	0.452	0.451	0.439
Texas	45	44	33	39	23	786	764	504	1,382	0.608	0.610	0.544
Québec	50	42	22	65	63	119	123	51	196	1.078	1.149	0.649
Western	32	43	30	28	15	979	918	755	1,506	0.416	0.425	0.334

[70] BAL-003-2 specifies that the resource loss protection criteria (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.

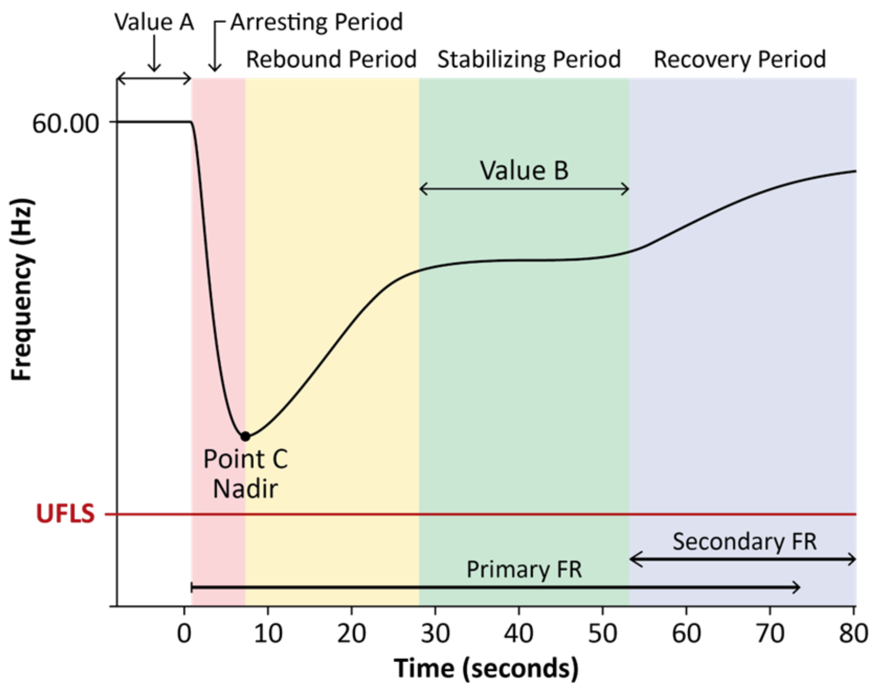

Figure 4.2: Frequency Response Methodology

Figure 4.3 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 Eastern and Texas Interconnections were 50% as measured by percentage of RLPC. The largest events for the Western and Quebec Interconnections were 88% and 96%, respectively, as measured by percentage of RLPC.

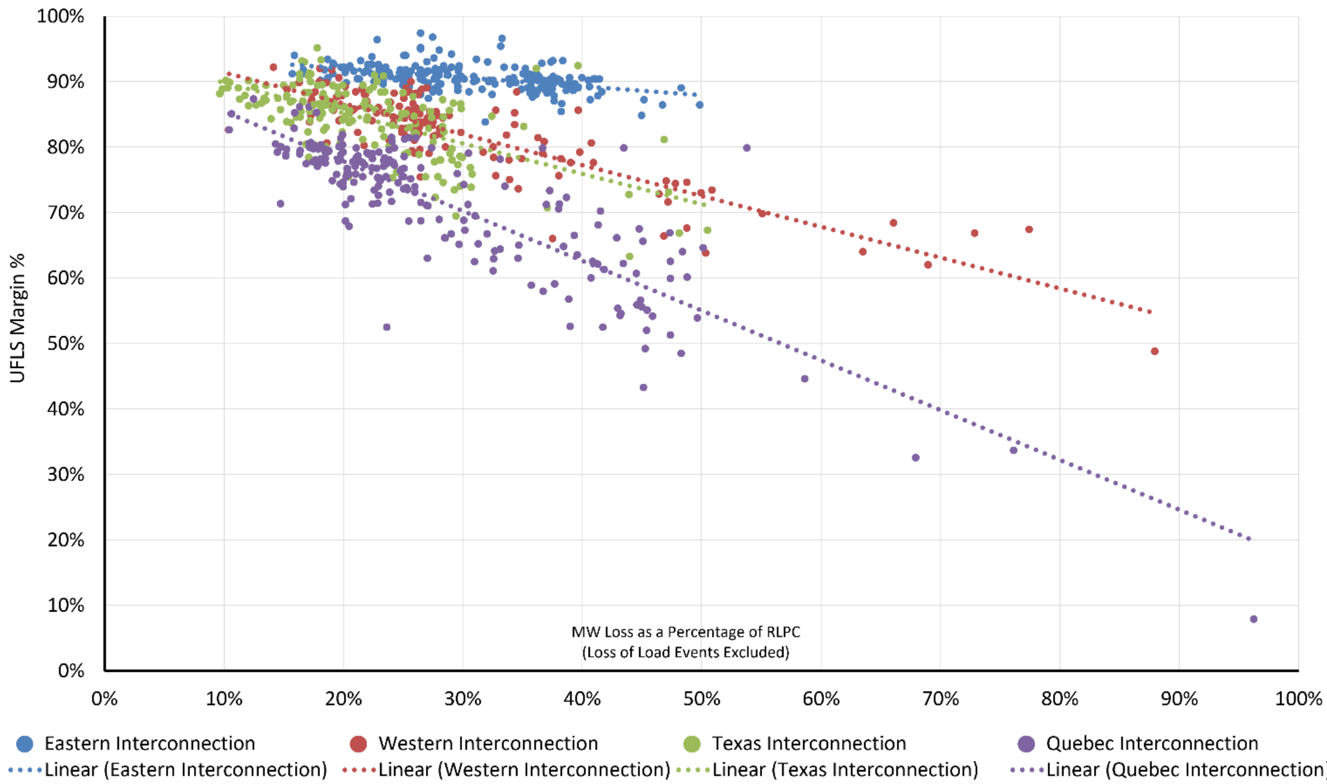

Figure 4.3: Operating Year 2020–2024 Qualified Frequency Disturbances and Remaining UFLS Margin

Interconnection Reliability Operating Limit Exceedances

2024 Performance and Trends

Each RC has a different methodology for determining Interconnection reliability operating limits (IROL)[71] based on the makeup of their area and what constitutes an operating condition that is less than desirable. The following discussion of performance on an Interconnection basis is for clarity, not comparison:

- **Eastern–Québec Interconnections:** In 2024, there was one exceedance that lasted more than 10 minutes, which is less than the five-year average of 12.0 exceedances as shown in **Figure 4.4**. The 10- to 20-minute range continued to decline with zero exceedances greater than 20 minutes. The sharp decline in the five-year rolling average is due to the all-time peak of 38 exceedances experienced in 2019 falling off the five-year average, along with the continued decline of events over 10 minutes.
  - In late 2018, one entity performed a review where it determined there was a need to update how it tracked and identified IROLs exceedances in real time. The entity found that it was not clear to the operators when something was flagged as an IROL for certain equipment-related thermal exceedances. The entity then upgraded its systems and tools to address the identified issues. The new system provided automatic identification and tracking of IROL exceedances.
  - As a result of these changes, there was a significant increase in the number of reported IROL exceedances by this entity in 2019. Since that time, that entity has and continues to work diligently to reduce the number of IROL exceedances experienced by its system. The result of that work is a major contributing factor to the overall reduction in IROLs experienced over the past five years.

[71] M-8, IROL Exceedance

- **Western Interconnection:** The trend has been stable with no IROL exceedances reported in 2024.
- **Texas Interconnection:** The trend has been stable with no IROL exceedances reported in 2024.

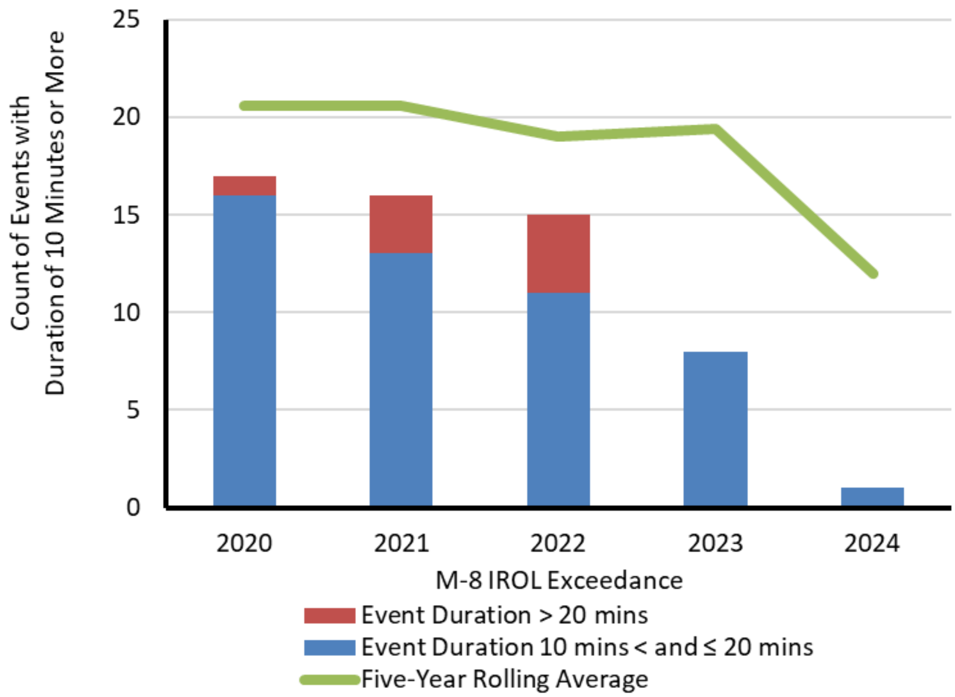

Figure 4.4: IROL Exceedance Counts[72]

Generation Performance and Availability

GADS contains information that can be used to compute reliability measures, such as 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 4.5** 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 7.4%. While the 2024 WEFOR rate of 7.7% is only a slight decrease over 2023 (7.8%), it is the second lowest WEFOR in the five-year analysis period.

[72] M-8, IROL Exceedance

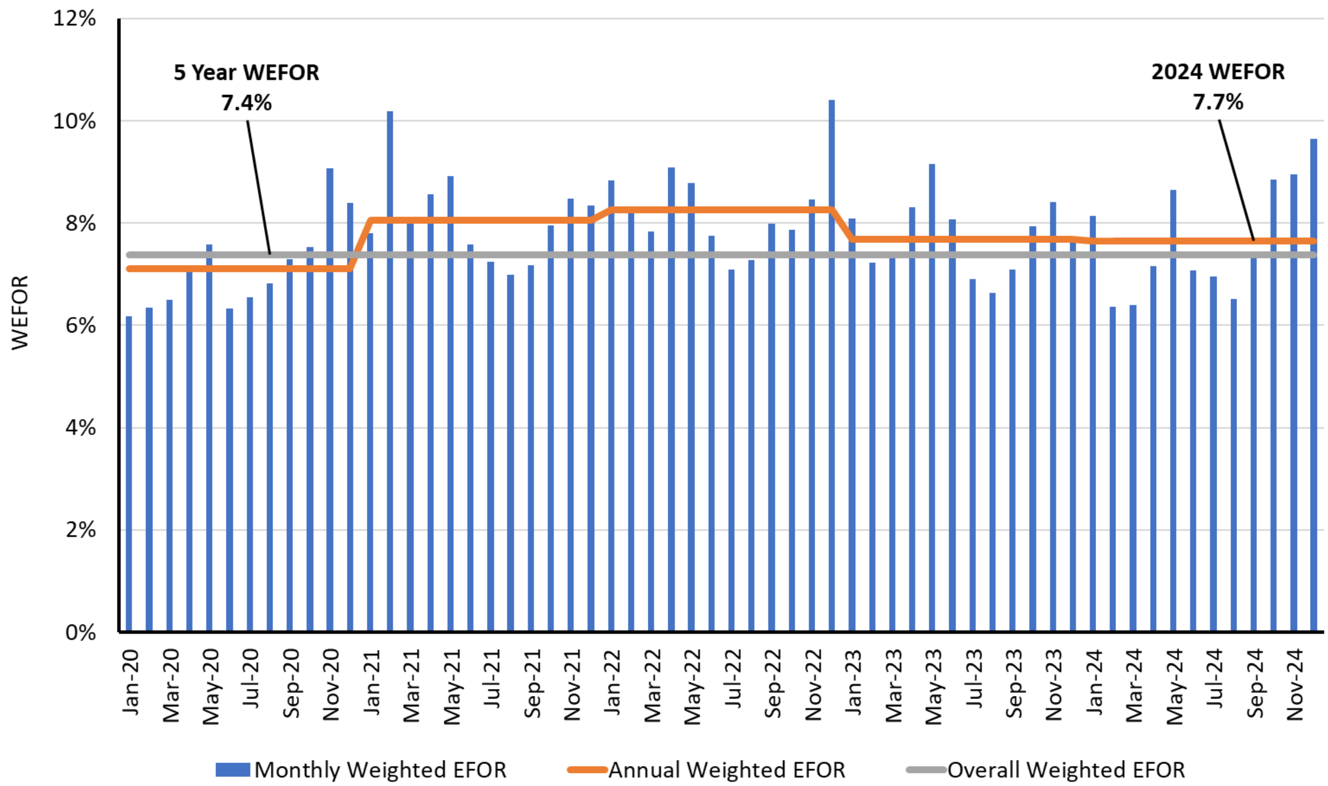

Figure 4.5: Monthly, Annual, and Five-Year WEFOR

The monthly WEFOR for select fuel types is shown as a layered area chart in **Figure 4.6**. 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. While the overall WEFOR remains effectively unchanged from 2023 to 2024 (both round to 7.7%), an increase was observed in hydro units with a 2024 WEFOR of 8.5%. This is an increase of 22% over 2023 and is the highest WEFOR for hydro in the last five years, despite the decrease in annual net actual generation as observed in **Figure 4.7**. Further investigation did not indicate a common systemic issue, and NERC will continue to monitor. **Figure 4.7** also shows that coal generation is the primary driver of the year-over-year variability in the overall WEFOR despite more energy being produced by both natural gas and nuclear power in 2024.

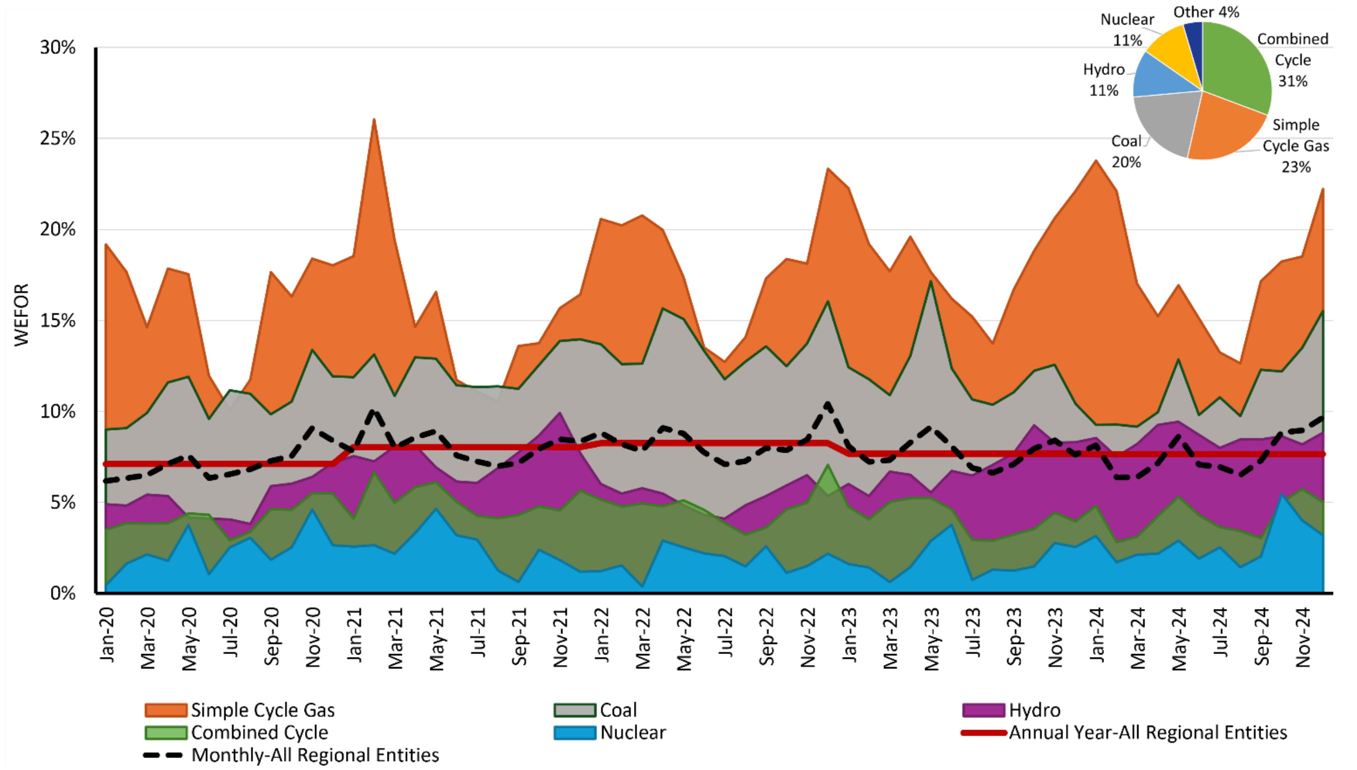

Figure 4.6: Five-Year WEFOR by Fuel Type and 2024 Resource Mix by Net Maximum Capacity

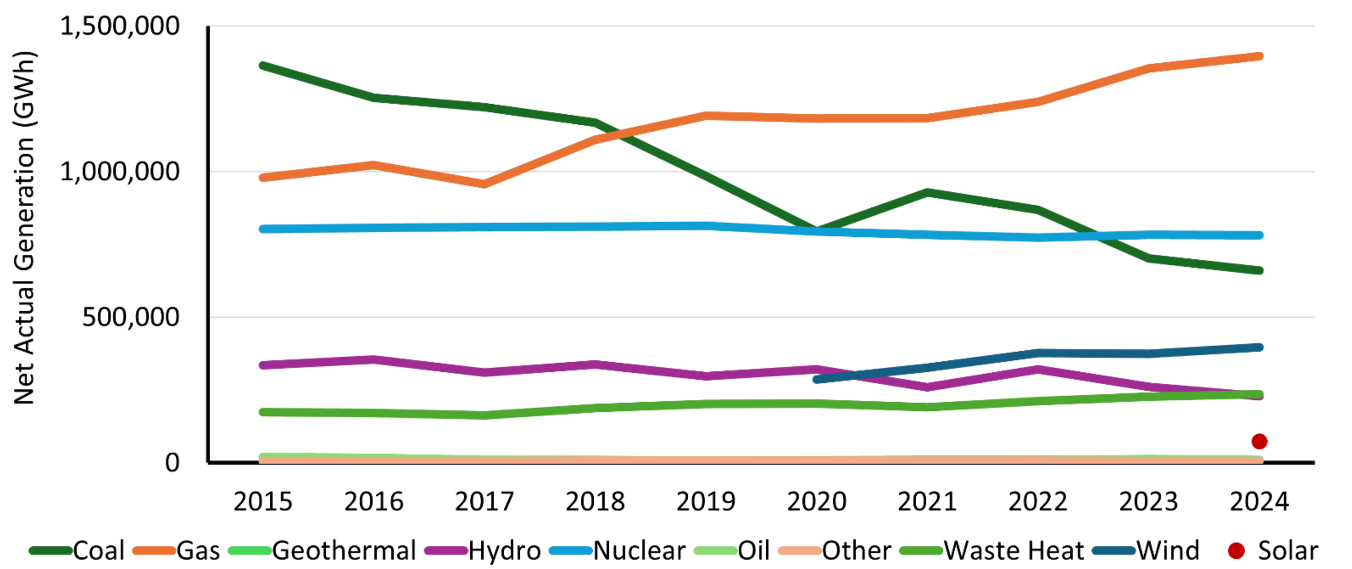

Figure 4.7: Five-Year Annual Net Actual Generation (GWh) by Fuel Type

Wind and Solar Generation Weighted Factors

Figure 4.8–Figure 4.12 present various weighted factors for wind[73] and solar[74] 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

[73] 2025_GADS_Wind_DRI
[74] 2025_GADS_Solar_DRI

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 a new equation. It is calculated the same way as other factors, with reserve shutdown as the numerator.
- Generation losses due to sub-optimal resource conditions is a new equation. It is 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%.
- As 2024 was the first year in which solar data was collected, data reporting errors are expected. Egregious, obviously erroneous data has been excluded. These errors represented a small portion of the records, but due to their nature they could greatly alter analysis. Some examples of these errors included generation above a plant's capacity, listing the plant's capacity for each inverter group while reporting each inverter as its own inverter group, reporting values in kW instead of MW, and producing above 95% of the plant's capacity, including during night, for months at a time. NERC will continue to work with these entities to fix existing issues and improve data reporting going forward.

Wind data is presented in **Figure 4.8**–**Figure 4.10**, with each figure showing a different stage of data collection: plants >200 MW, 100–199 MW, and 75–99 MW. Solar data is presented with **Figure 4.11** showing factors only during daylight hours,[75] and **Figure 4.12** showing factors over the entire 24-hour day.

[75] Daylight hours are defined in the GADS Solar DRI as being from the times between sunrise and sunset that produce energy in the inverter.

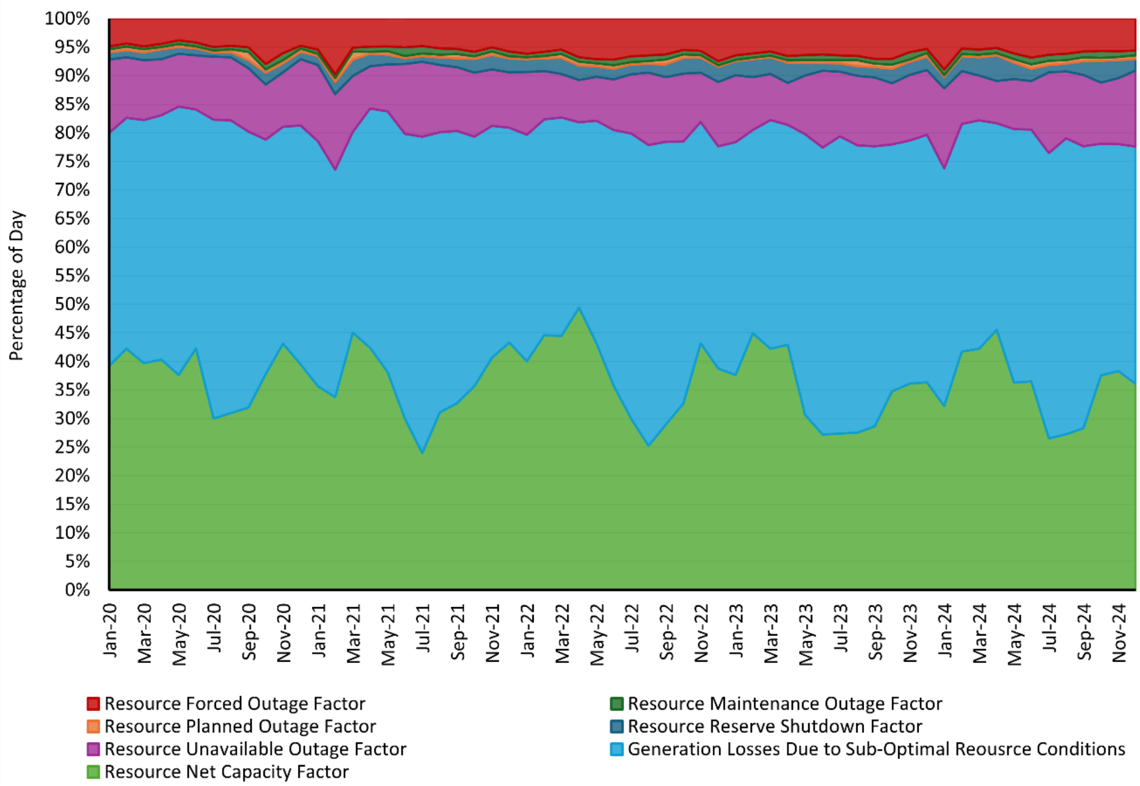

Figure 4.8: Monthly Net Output Factor and Weighted Resource Forced Outage Rate (WRFOR) Wind Plant Reporting Group 200 MW+

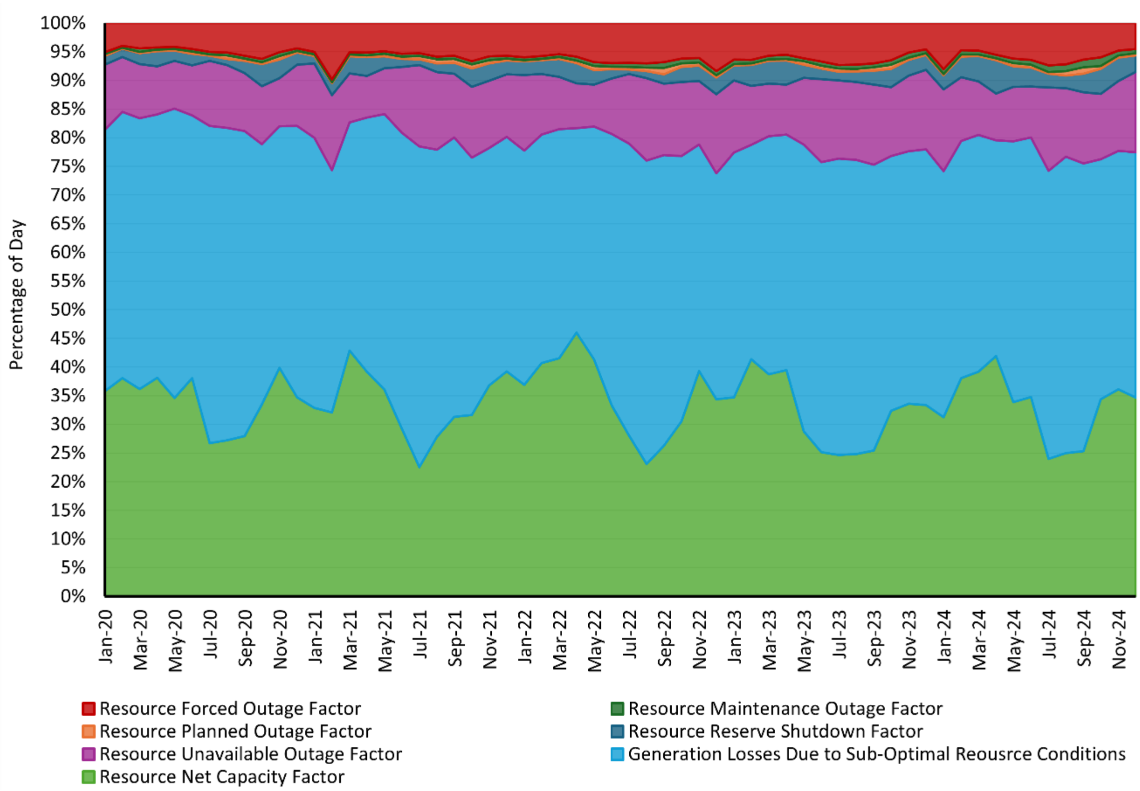

Figure 4.9: Monthly Net Output Factor and WRFOR Wind Plant Reporting Group 100–199 MW

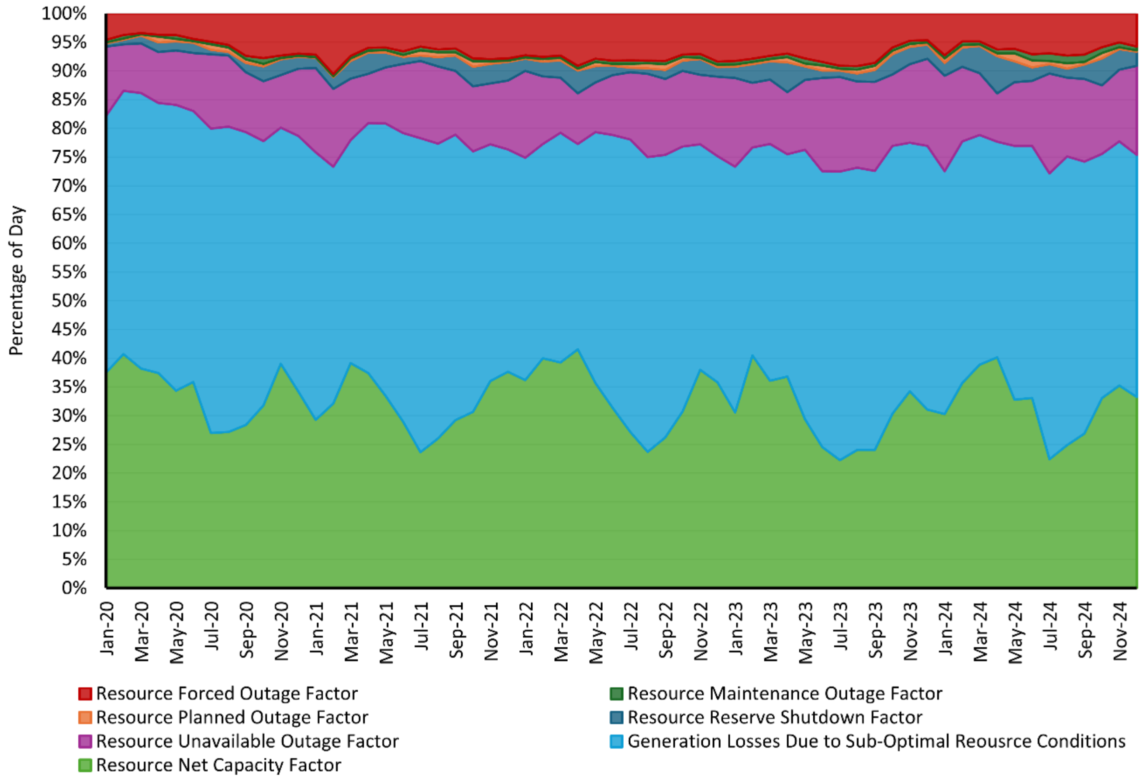

Figure 4.10: Monthly Net Output Factor and WRFOR Wind Plant Reporting Group 75–99 MW

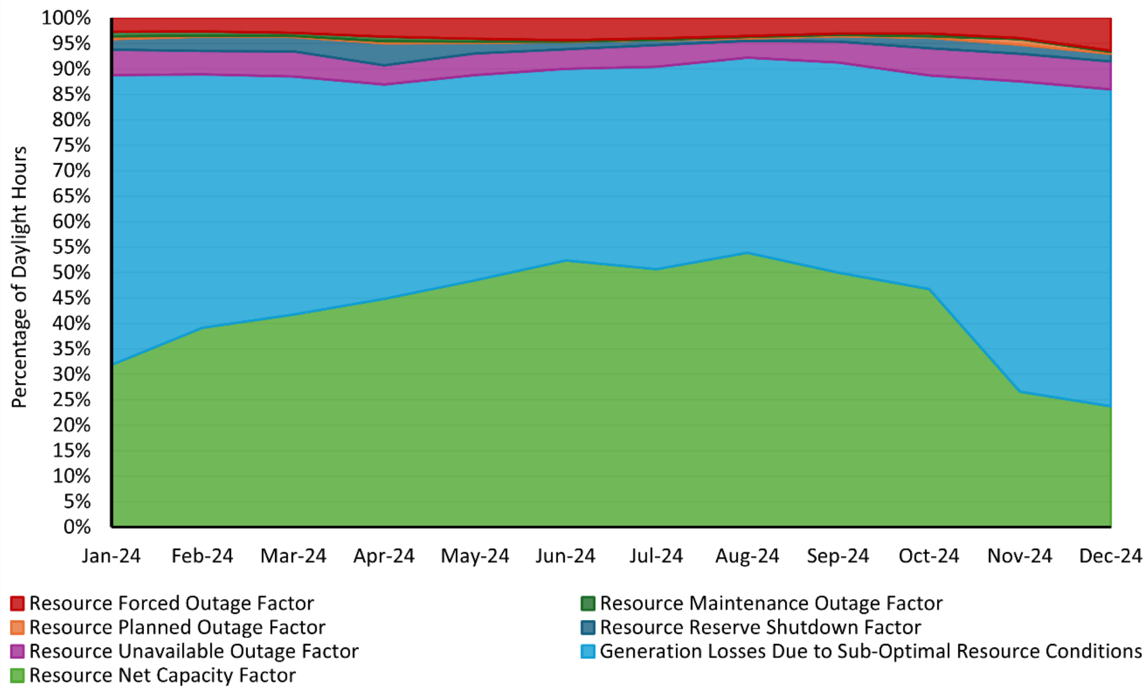

Figure 4.11: Monthly Factors for Solar Plants >100 MW, Daylight Hours

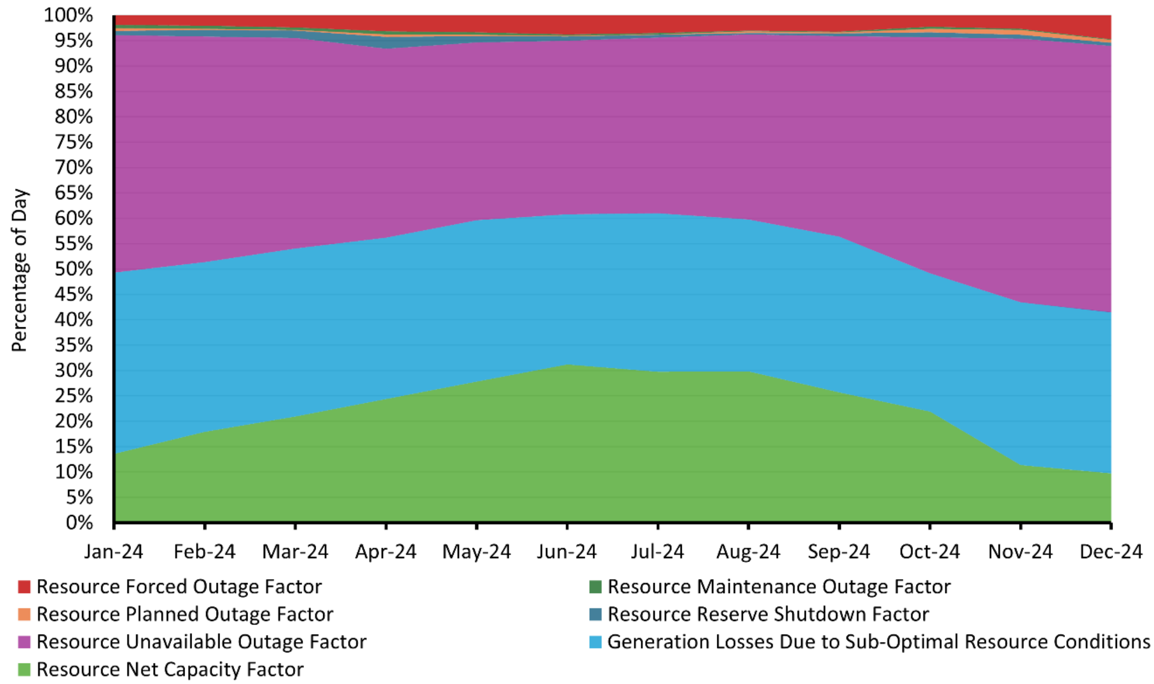

Figure 4.12: Monthly Factors for Solar Plants >100 MW, Full Day

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. The number of qualified events that include transmission outages that resulted in firm load loss not related to weather is provided in the following subsection.

Transmission-Related Events Resulting in Loss of Load

In 2024, a total of six distinct non-weather-related transmission events resulted in a loss of firm load that met the ERO EAP reporting criteria (see **Figure 4.13**). The median firm load loss over the past five years was 90 MW, which is a decrease from 2019–2023's 97 MW. While in 2023 the median load loss was 113 MW or 16 MW above the 2019–2022 median, 2024 saw the median fall to 86 MW, which is 4 MW below the 2020–2024 median.

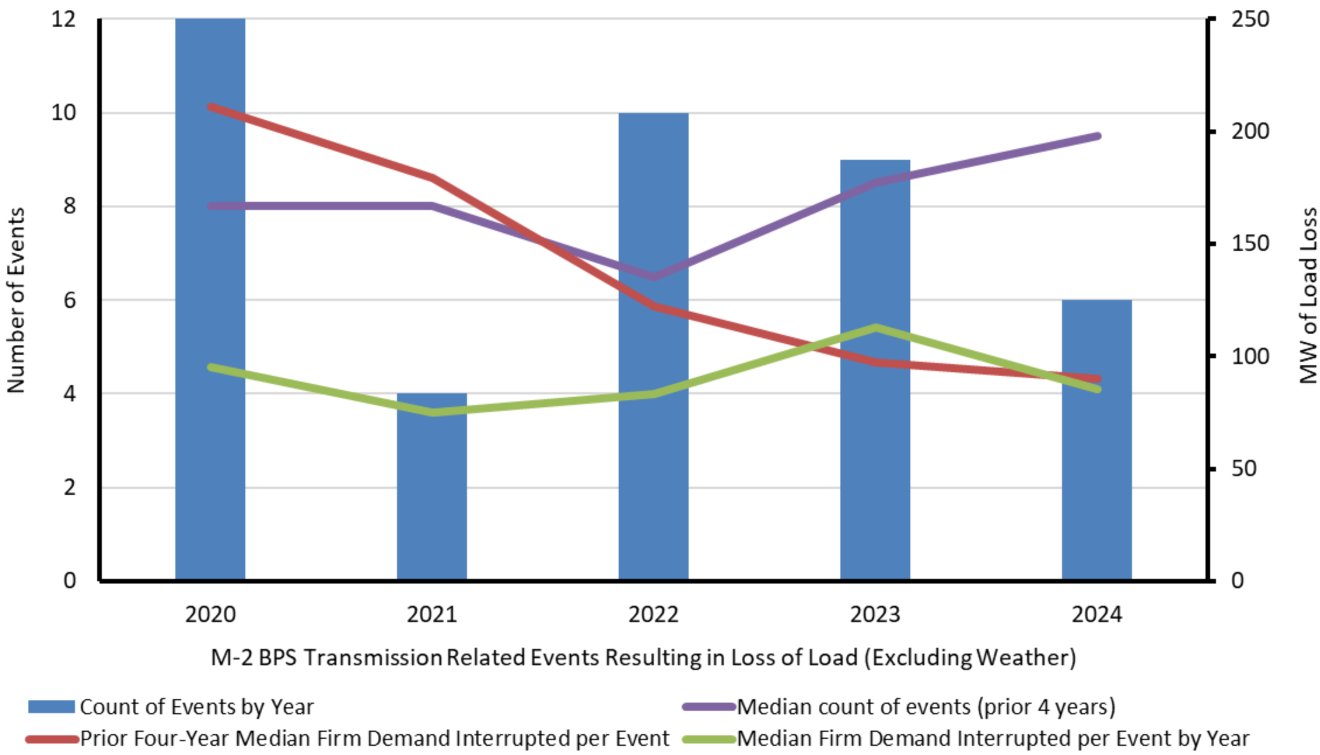

Figure 4.13: Transmission-Related Events Resulting in Loss of Firm Load and Median Amount of Firm Load Loss Excluding Weather-Related Events[76]

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 (TOS)**
- **Automatic AC Transmission Outages**
- **Transmission Element Unavailability**

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

Transmission Outage Severity

The impact of a TADS event on BPS reliability is called the 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.

By examining the average TOS, duration, and frequency of occurrence for events with different ICCs (see **Figure 4.14**) 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. The number of events per hour, average event duration, and average TOS for each ICC group are shown in **Table 4.5**.

Table 4.5: 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	0.320	40.2
Failed AC Circuit Equipment	0.099	0.022	0.393	48.1
Failed AC Substation Equipment	0.065	0.033	0.544	99.0
Fire	0.016	0.074	0.656	44.7
Foreign Interference	0.061	0.021	0.739	24.7
Human Error	0.026	0.028	0.379	12.3
Lightning	0.067	0.027	0.522	12.0
Misoperation	0.042	0.040	0.474	20.8
Other	0.015	0.027	0.329	22.2
Power System Condition	0.010	0.054	1.003	13.1
Unknown	0.085	0.026	0.367	11.0
Vegetation	0.046	0.013	0.138	23.3
Weather, Excluding Lightning	0.151	0.023	0.657	39.8

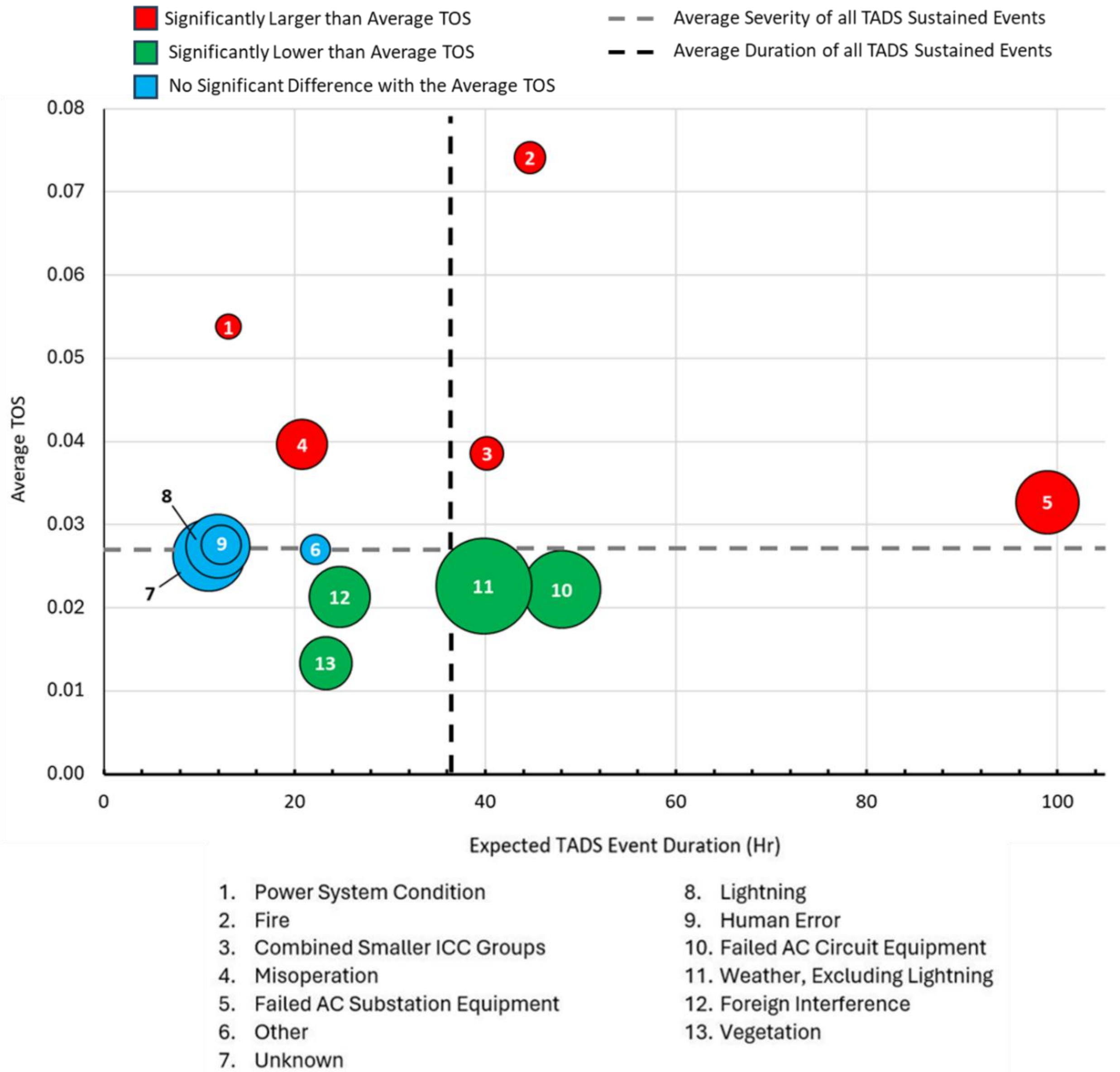

Figure 4.14: TOS vs. Expected TADS Event Duration

An analysis of the total TOS by year indicates that 2024 shows an improving trend compared to 2023, where the TOS was impacted by the 2023 Québec wildfires. Figure 4.15 shows the annual TOS, which is the second lowest over the last five years. This would seem to suggest a positive indication that transmission outages are leading to less severe reliability impacts.

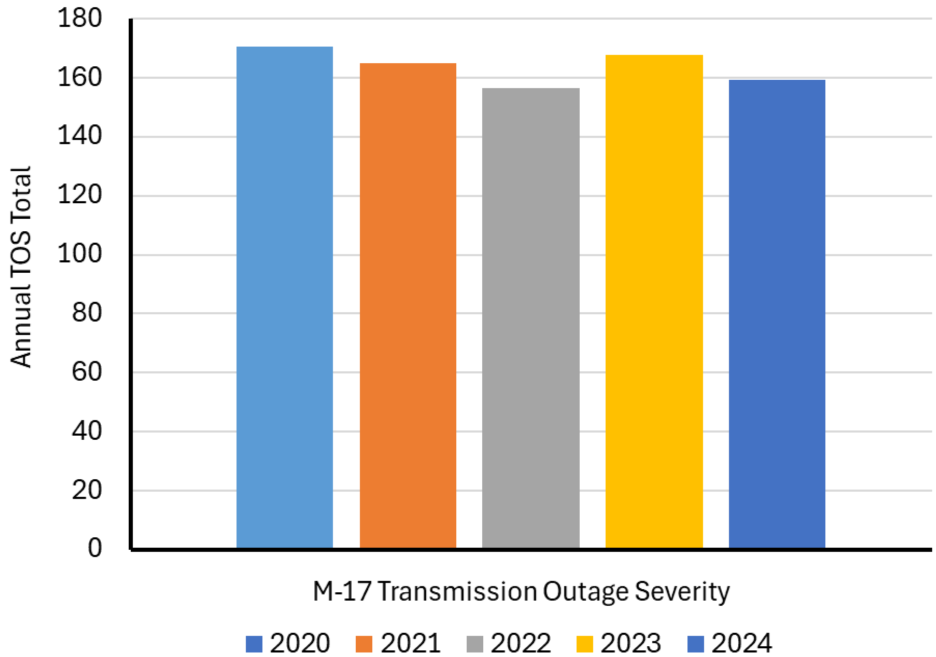

Figure 4.15: TOS of TADS Sustained Events of 100 kV+ AC Circuits and Transformers by Year[77]

Automatic AC Transmission Outages

The average number of outages per circuit due to failed ac substation equipment saw an increase compared to the previous two years but is still below the average number of outages for 2020–2023 (see **Figure 4.16**) and is not a statistically significant increase. The number of sustained outages due to failed ac circuit equipment per 100 miles saw an increase in 2024 but is still the second lowest number for the past five years (see **Figure 4.17**).

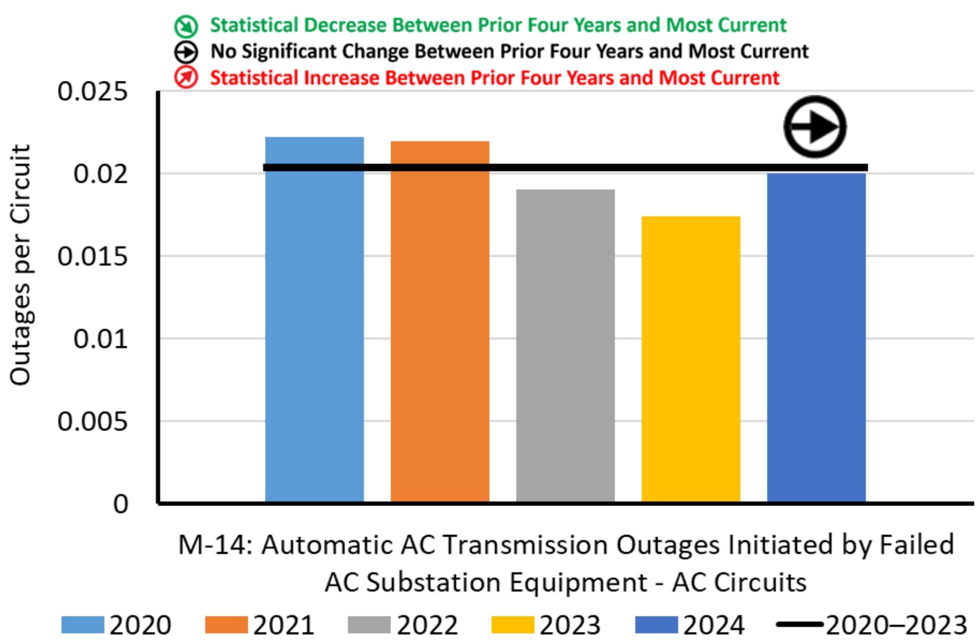

Figure 4.16: Number of Outages Per AC Circuit Due to Failed AC Substation Equipment[78]

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

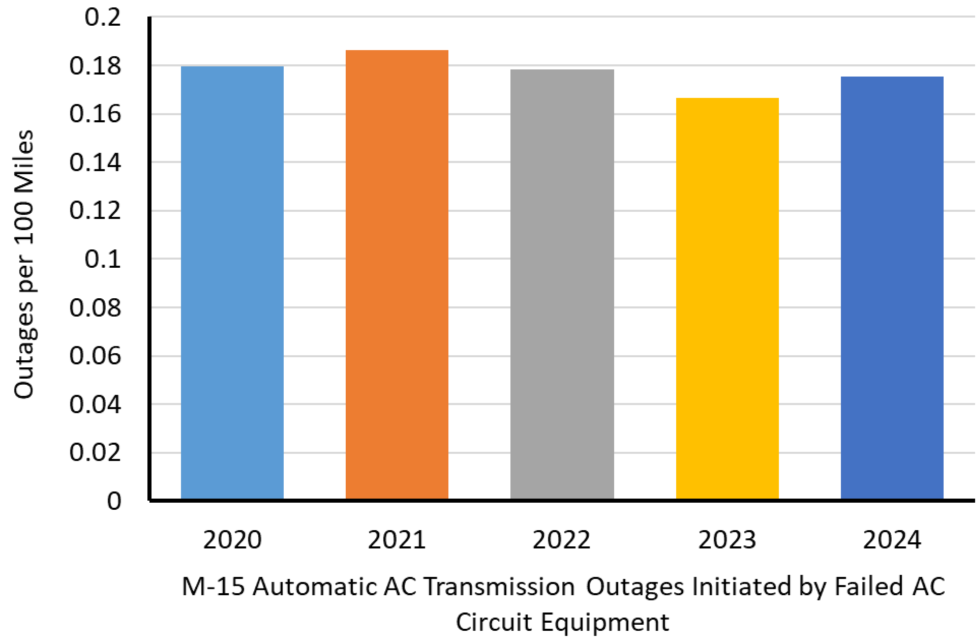

Figure 4.17: Number of Outages Per 100 Miles Due to Failed AC Circuit Equipment[79]

Automatic AC Transformer Outages

In 2024, there was an increase in the number of automatic ac transformer outages per element caused by failed ac substation equipment, but there was no significant change between 2020–2023 and 2024. Though the increase in outages is not statistically significant, as can be seen in **Figure 4.18**, this number is the second highest over the past five years.

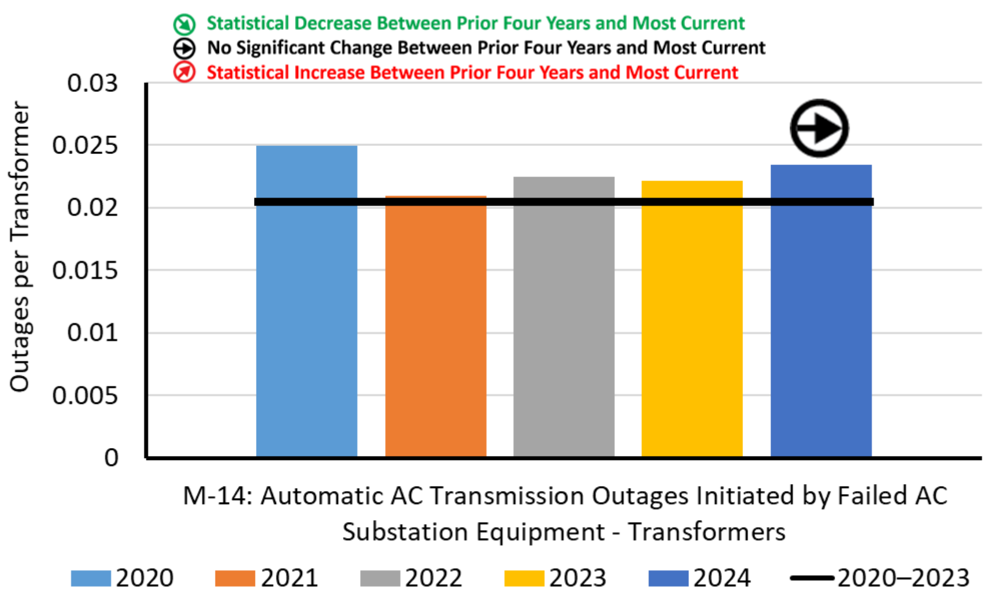

Figure 4.18: Number of Outages Per Transformer Due to Failed AC Substation Equipment[80]

Transmission Element Unavailability

In 2024, ac circuits over 200 kV across North America had an unavailability rate of 0.28%, meaning that there is a 0.28% chance that a specific transmission circuit is unavailable due to sustained automatic and operational outages

[79] M-15, Automatic AC Transmission Outages Initiated by Failed AC Circuit Equipment

[80] M-14, Automatic AC Transmission Outages Initiated by Failed AC Substation Equipment

at any given time. Transformers also had an unavailability rate of 0.28% in 2024. Figure 4.19 shows that while there was an increase in ac circuit availability in 2024 (due primarily to an increase in automatic outages), the increase was not statistically significant when compared to the prior four years. Figure 4.20 shows that 2024 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. Despite the fact that the transformer unavailability rate has been steadily increasing year over year, the increase is not statistically significant.

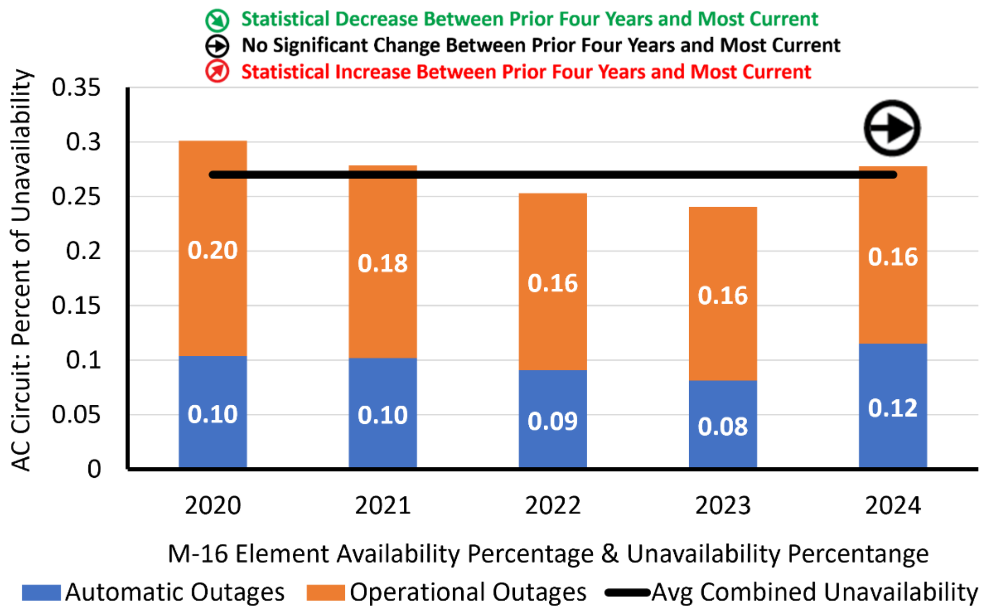

Figure 4.19: AC Circuit Unavailability >200 kV[81]

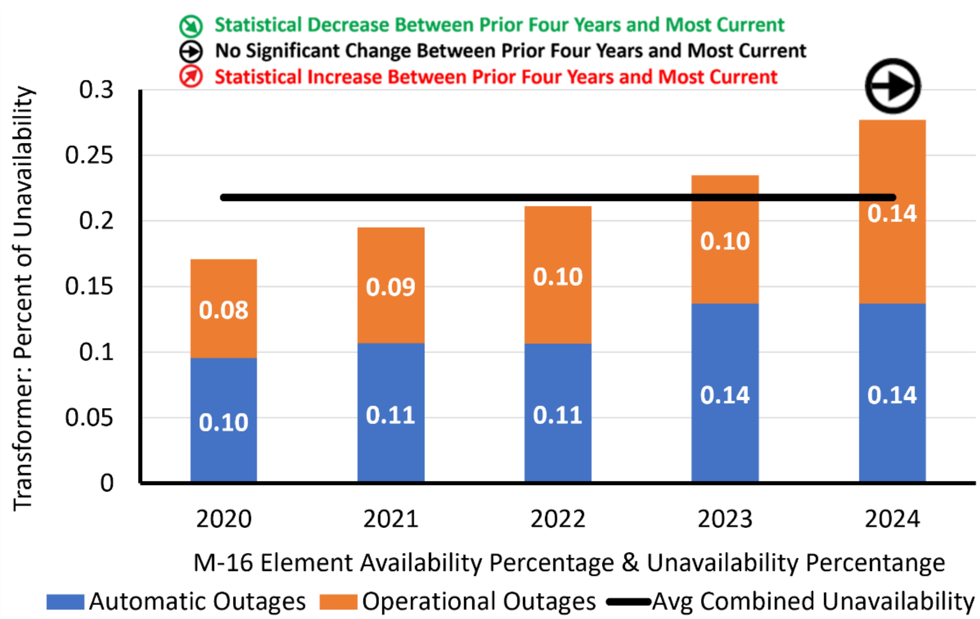

Figure 4.20: Transformer Unavailability >200 kV[82]

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

TADS Physical Security Metric

Over the past several years, there has been an increase in physical attacks on the bulk power system. 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 4.21** compares the TADS Physical Security metric for 2019–2023 and 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.

Figure 4.21 shows a decreasing trend in both the total number of physical security outages (from 85 to 78) and average duration of the outages (from 83 hours to 80 hours) and an increase in the average MVA capacity for those outages (from 292 MVA to 308 MVA). Based on the rating criteria for this metric, the assessment rating for this metric is Stable.

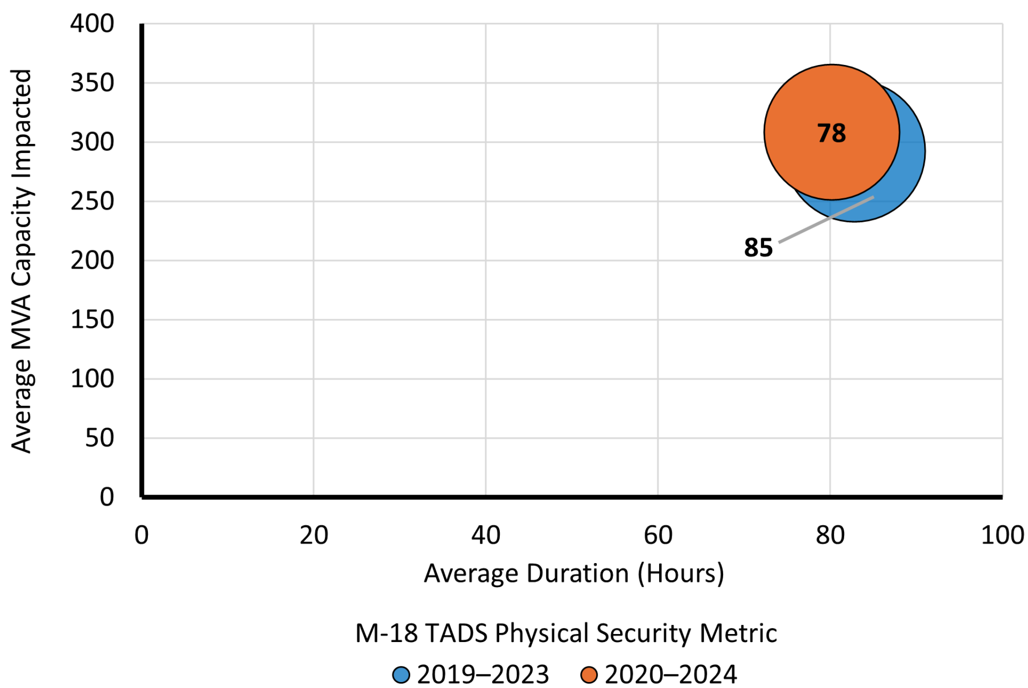

Figure 4.21: Comparison of TADS Physical Security Metric for 2019–2023 vs. 2020–2024

Table 4.6: 2024 M-18 TADS Physical Security Metric		
	2019–2023	**2020–2024**
Outage Count	85	78
Average MVA	292.4	308.5
AvgDurationHr	82.8	80.2

Appendix A: Supplemental Analysis at Interconnection Level

Severity Risk Index by Interconnection

Eastern and Québec Interconnections

The cumulative SRI for the Eastern and Québec Interconnections in **Table A.1** shows a 3% increase compared to the average of the four-year period of 2020–2023. The 2024 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
2020	315.1	57.8	67.4	440.3	1.20
2021	346.2	53.9	65.8	465.9	1.28
2022	385.3	52.5	53.0	490.7	1.34
2023	324.7	64.6	47.2	436.6	1.20
2024	**359.2**	**59.7**	**52.0**	**471.0**	**1.29**

The top 10 SRI days of the Eastern and Québec Interconnections were distributed throughout the year as shown in **Figure A.1** (numbered circles). A total of 9 of the top 10 days that occurred in the Eastern and Québec Interconnections aligned with the top 10 SRI days reported for North America.

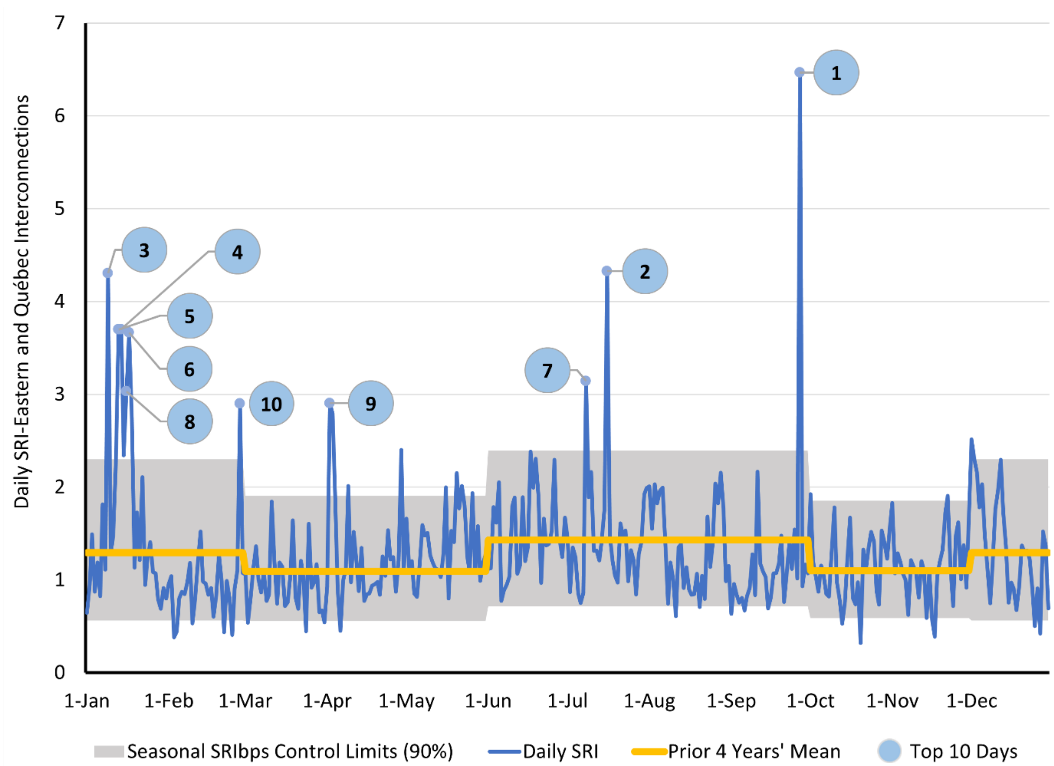

Figure A.1: 2024 Eastern and Québec Interconnections Daily SRI with Top 10 Days Labeled, 90% Confidence Interval

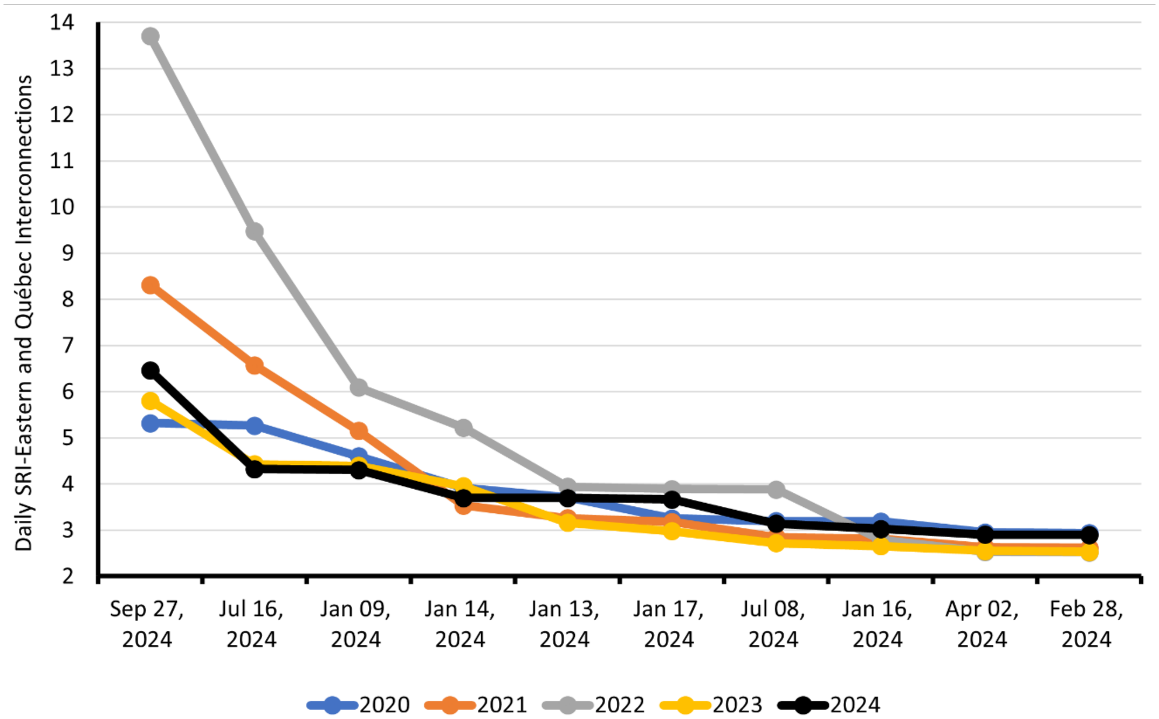

Figure A.2: Eastern and Québec Interconnections Top Annual Daily SRI Days, Sorted Descending

Figure A.2 shows the Eastern and Québec Interconnections' top 10 SRI days in 2024 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 EQI, one was driven by load loss, one was driven by transmission, one was driven by a combination of generation and load loss, and the rest were predominantly driven by generation.

Table A.2: 2024 Top 10 SRI Days Eastern and Québec Interconnections

Rank	Date	SRI and Weighted Components 2024				Atypical Weather Conditions	Regional Entities within the Interconnection
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss		
1	27-Sep	6.47	1.61	3.63	1.23	Hurricane Helene	SERC
2	16-Jul	4.33	2.09	0.47	1.77	Central & Eastern Tornadoes & Severe Weather	NPCC, RF, SERC
3	9-Jan	4.30	1.16	0.72	2.42	Tornadoes & Severe Storms	RF, SERC
4	14-Jan	3.70	3.47	0.12	0.11	Winter Storm	MRO, RF, SERC,
5	13-Jan	3.70	2.79	0.41	0.50	Winter Storm	
6	17-Jan	3.66	3.37	0.28	0.01	Winter Storm	MRO, RF, SERC
7	8-Jul	3.14	2.21	0.56	0.37	Hurricane Beryl	MRO, SERC
8	16-Jan	3.03	2.44	0.51	0.09	Winter Storm	MRO, SERC
9	2-Apr	2.90	1.23	0.85	0.83	Derecho	MRO, RF, SERC
10	28-Feb	2.90	1.34	0.53	1.03	Central & Eastern Severe Storms	NPCC

Table A.3 shows the top 10 SRI days for the Eastern and Québec Interconnections over the last five years with the only date in 2024 highlighted in red.

Table A.3: 2020–2024 Top 10 SRI Days Eastern and Québec Interconnections							
Rank	Date	SRI and Weighted Components				Atypical Weather Conditions	Regional Entities within the Interconnection
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss		
1	December 23, 2022	13.71	8.88	0.90	3.92	Winter Storm Elliott	All
2	December 24, 2022	9.48	8.13	1.28	0.07	Winter Storm Elliott	All
3	February 16, 2021	8.32	4.11	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	6.47	1.61	3.63	1.23	Hurricane Helene	SERC
6	June 14, 2022	6.10	1.71	0.49	3.90	High Temperatures and Derecho	All
7	April 1, 2023	5.81	0.74	0.64	4.43	Widespread Storms and Tornadoes	MRO, RF, SERC
8	August 4, 2020	5.32	1.38	1.01	2.93	Hurricane Isaias	NPCC, RF, SERC
9	August 27, 2020	5.27	1.42	1.32	2.52	Unnamed Tropical Storm	RF, SERC
10	June 15, 2022	5.22	1.63	0.24	3.36	High Temperatures and Derecho	All

Western Interconnection

The 2024 cumulative SRI for the Western Interconnection (see Table A.4) shows a 6.5% decrease over the prior four-year period of 2020–2023. The 2024 cumulative SRI was the lowest among the five years analyzed.

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
2020	390.79	96.20	71.92	558.91	1.53
2021	426.76	99.35	97.80	623.91	1.71
2022	423.78	88.36	60.12	572.26	1.57
2023	423.10	69.48	59.59	552.17	1.51
2024	**413.29**	**75.28**	**50.12**	**538.69**	**1.47**

The top 10 SRI days of the Western Interconnection 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 Western Interconnection aligned with the top 10 SRI days reported for North America.

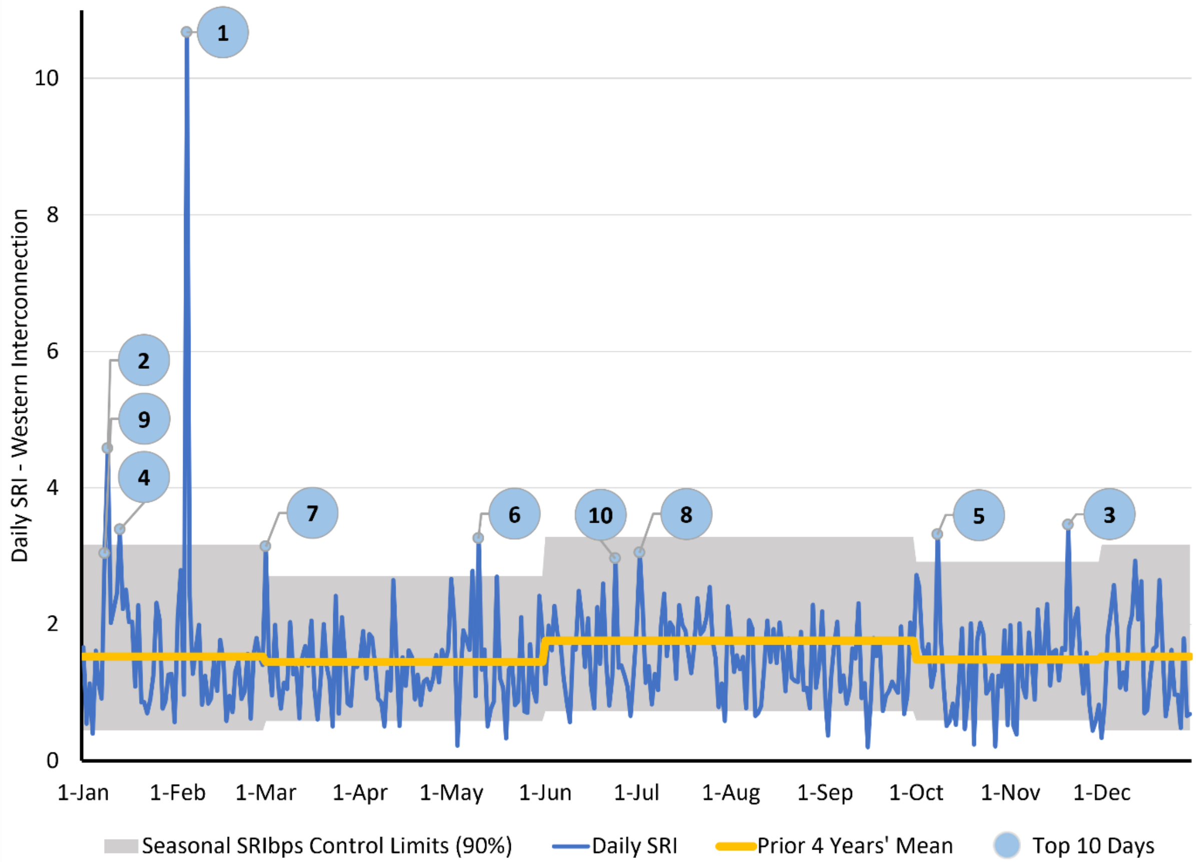

Figure A.3: 2024 Western Interconnection Daily SRI with Top 10 Days Labeled, 90% Confidence Interval

Figure A.4 shows the Western Interconnection's top 10 SRI days in 2024 relative to the four prior years.

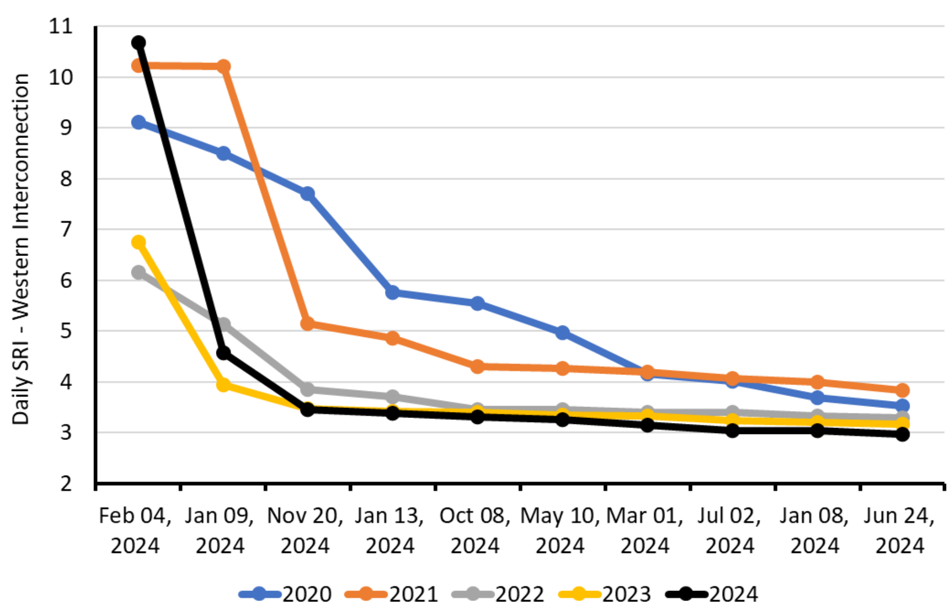

Figure A.4: Western Interconnection Top Annual Daily SRI Days Sorted Descending

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

Table A.5: 2024 Top 10 SRI Days Western Interconnection

Rank	Date	SRI and Weighted Components 2022				Atypical Weather Conditions
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss	
1	4-Feb	10.68	0.35	0.31	10.02	Atmospheric River
2	9-Jan	4.58	1.90	0.98	1.69	Northwestern Winter Storm
3	20-Nov	3.46	1.61	1.62	0.23	Atmospheric River
4	13-Jan	3.39	1.99	1.07	0.32	Winter Storm
5	8-Oct	3.32	2.16	0.74	0.41	Extreme Heat
6	10-May	3.26	1.82	0.16	1.28	Severe Storms
7	1-Mar	3.14	0.69	0.22	2.23	Severe Storms
8	2-Jul	3.05	2.29	0.31	0.44	Extreme Heat
9	8-Jan	3.04	2.62	0.42	0.00	Wildfires
10	4-Jun	2.96	2.63	0.16	0.17	Atmospheric River & High Temperatures

Table A.6 shows the top 10 SRI days for the Western Interconnection over the last five years, with the only date in 2024 highlighted in red.

Table A.6: 2020–2024 Top 10 SRI Days Western Interconnection[83]

Rank	Date	SRI and Weighted Components				Atypical Weather Conditions
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss	
1	February 4, 2024	10.68	0.35	0.31	10.02	Atmospheric River
2	November 15, 2021	10.23	1.42	0.40	8.41	Atmospheric River
3	January 13, 2021	10.21	1.86	3.87	4.48	Northwest Winter Weather
4	September 8, 2020	9.11	3.38	3.00	2.73	Wildfires
5	September 7, 2020	8.51	2.51	2.22	3.78	Wildfires
6	August 14, 2020	7.71	1.29	0.00	6.43	Extreme Heat
7	February 24, 2023	6.76	2.61	0.89	3.26	Winter Storm
8	November 5, 2022	6.15	1.75	1.79	2.61	Severe Weather
9	August 15, 2020	5.76	0.99	0.22	4.55	Extreme Heat
10	August 17, 2020	5.54	2.13	.83	2.58	Extreme Heat

Extreme-Day Analysis by Interconnection

The extreme-day analyses for transmission and generation for 2024 are presented by Interconnection. The maximum TADS reported MVA capacity or GADS reported net maximum capacity for 2024 is shown in the upper right or left

[83] Values in this table do not align with prior years' *SOR* reports due to a database error causing load-loss values to be shifted by two days.

corners of Figures A.5–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. All dates are shown in UTC.

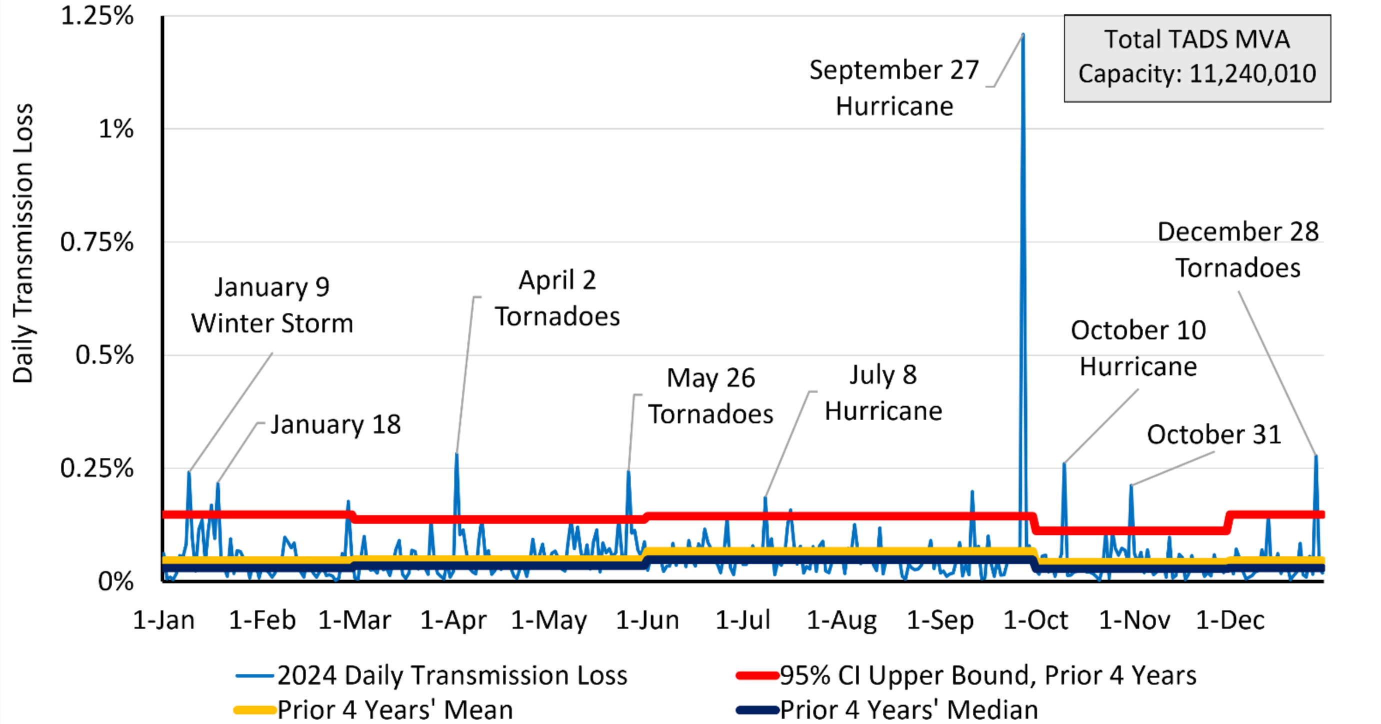

Figure A.5: Eastern and Québec Interconnections—Transmission Impacts during Extreme Days of 2024

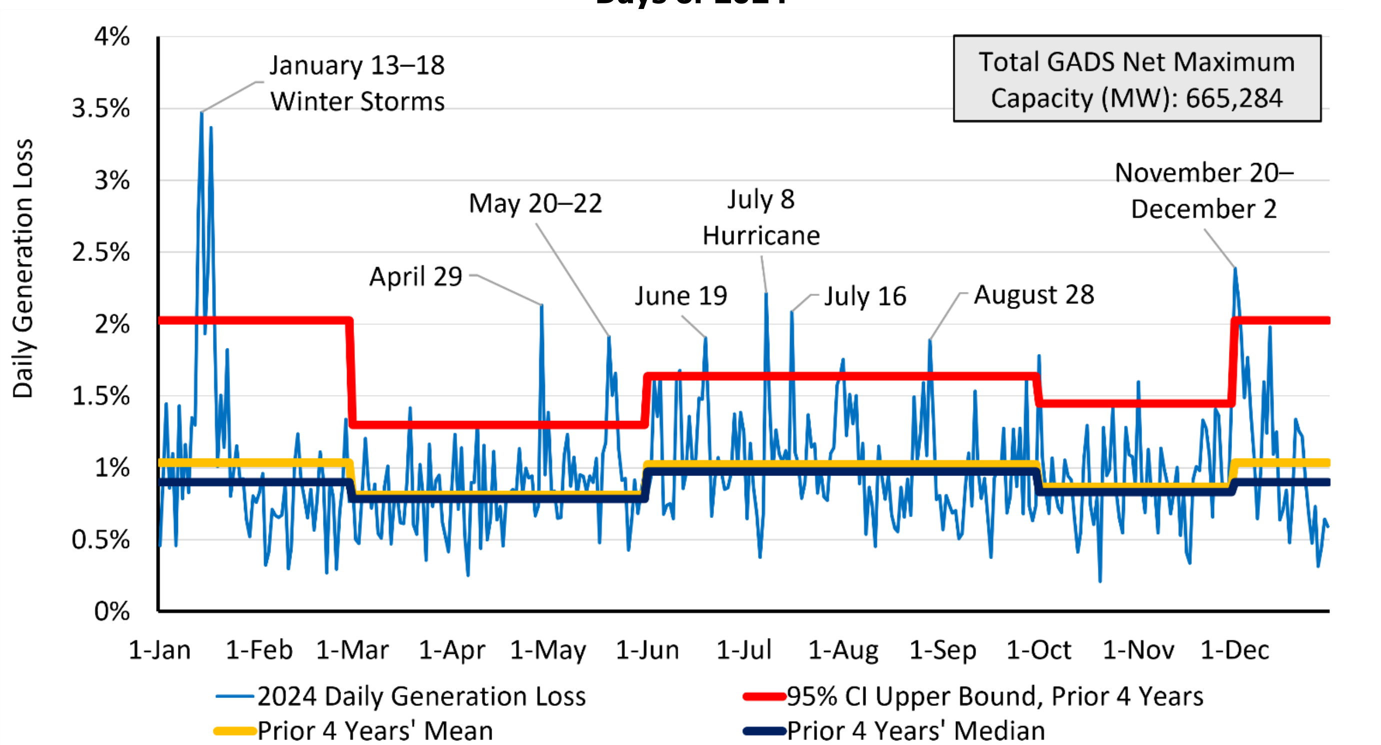

Figure A.6: Eastern and Québec Interconnections—Generation Impacts during Extreme Days of 2024

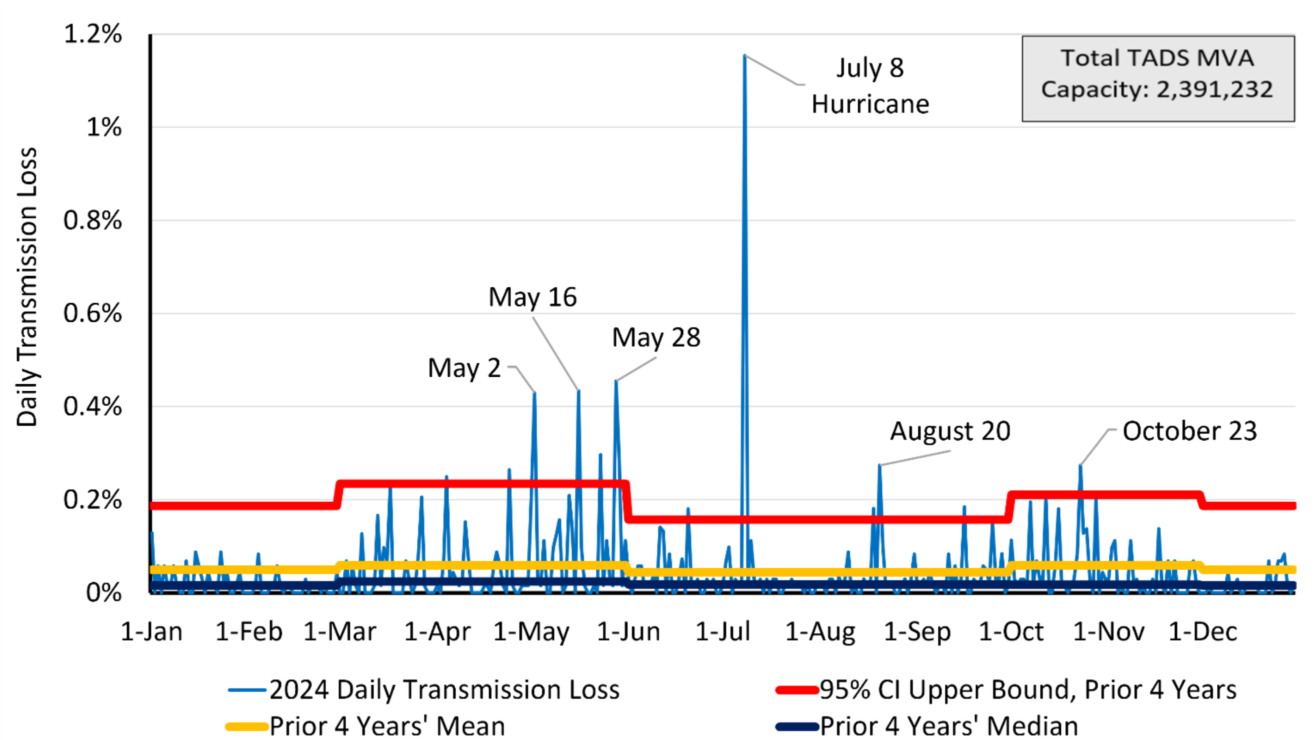

Figure A.7: Texas Interconnection—Transmission Impacts during Extreme Days of 2024

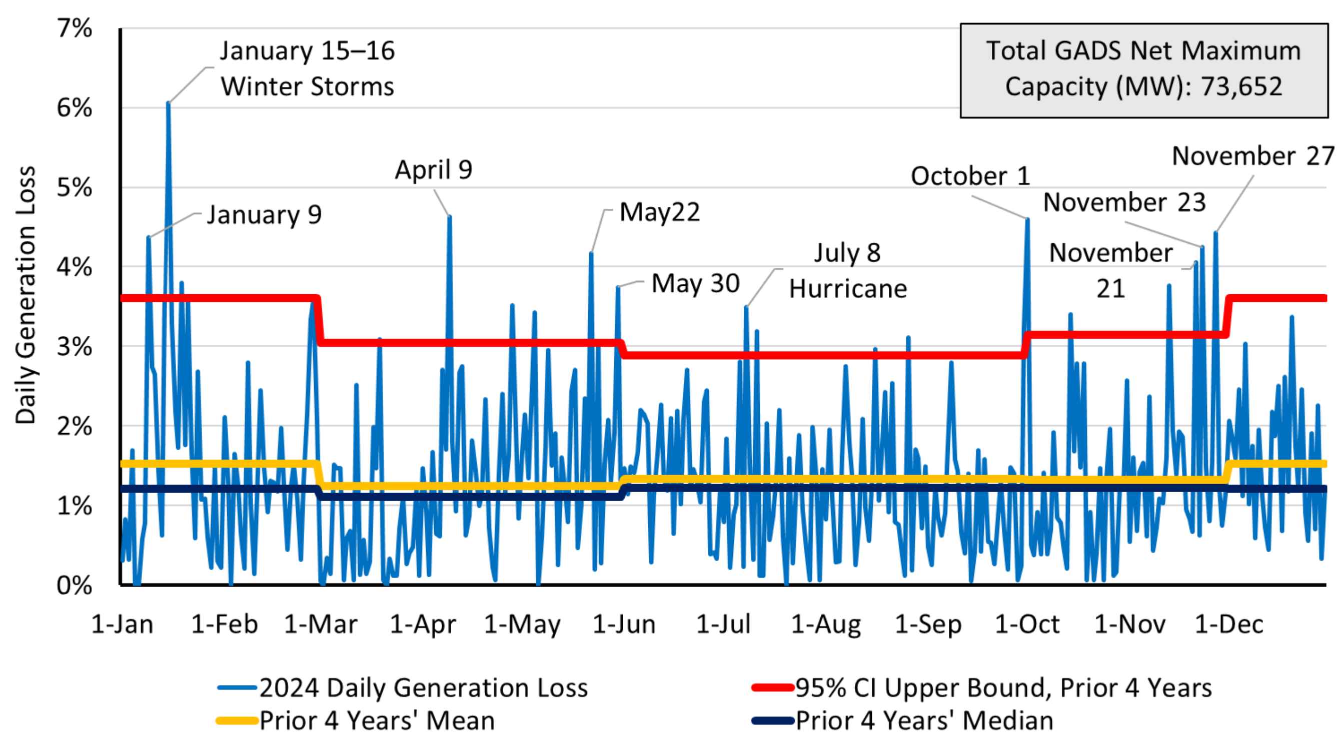

Figure A.8: Texas Interconnection—Generation Impacts during Extreme Days of 2024

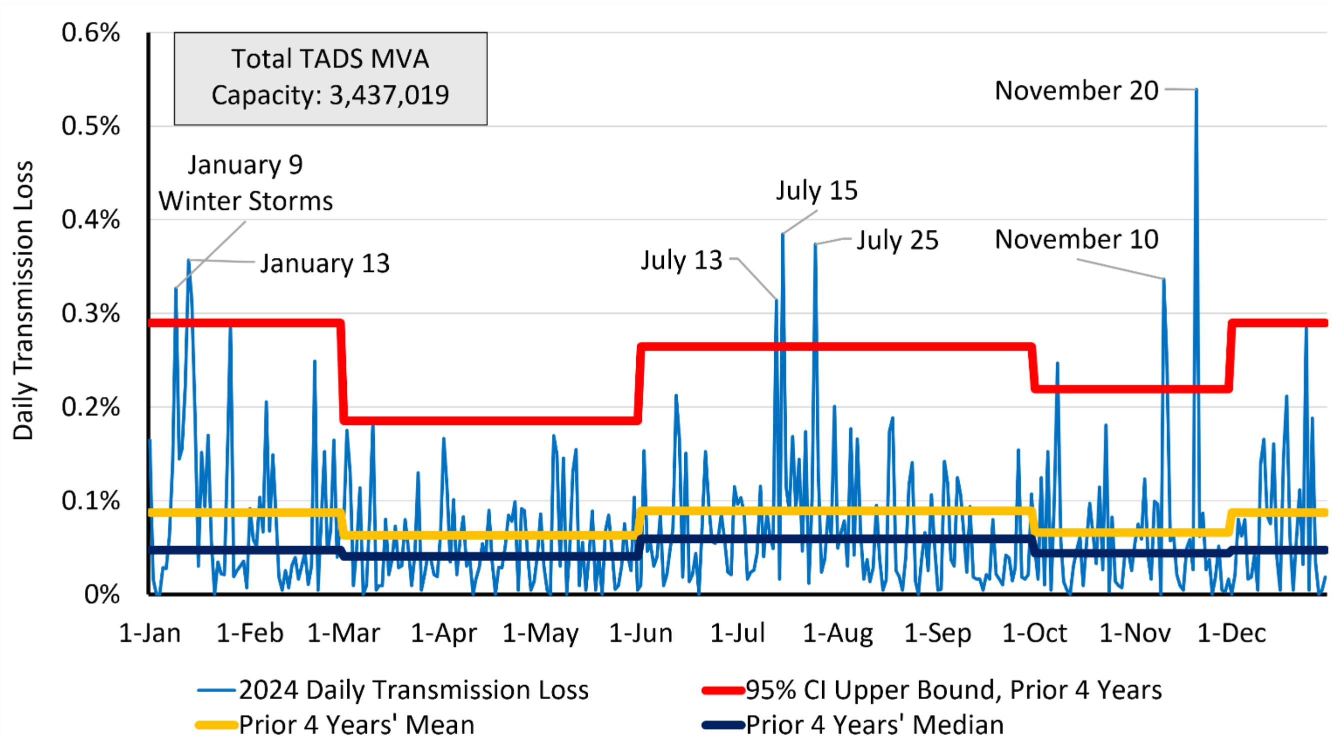

Figure A.9: Western Interconnection—Transmission Impacts during Extreme Days of 2024

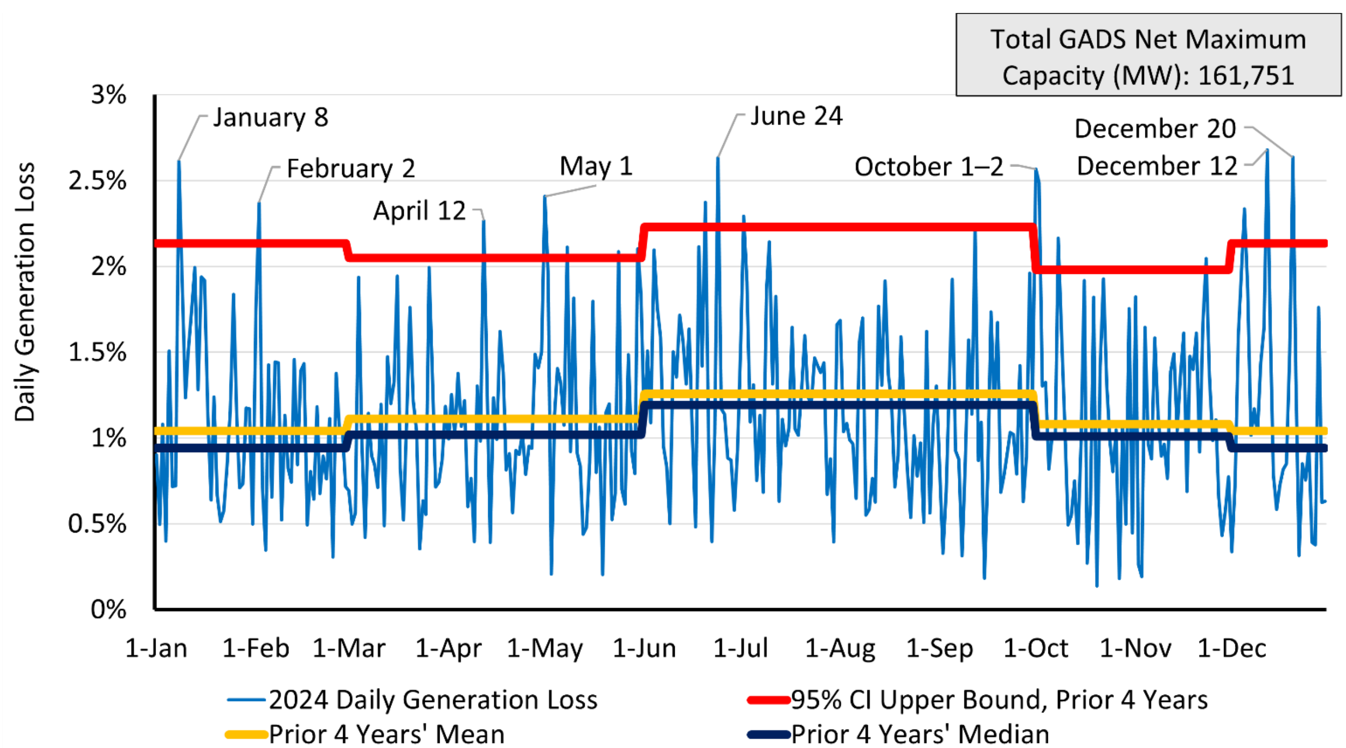

Figure A.10: Western Interconnection—Generation Impacts during Extreme Days of 2024

Appendix B: Preliminary Exploratory Analysis

This appendix covers exploratory analysis performed during the development of this year's *SOR* report. The goal of this analysis is to better define and quantify the impacts of transmission and generation outages on the BPS. While this analysis has the potential to provide value in this regard in the future, it should be viewed as preliminary at this time, as some aspects, such as measure of success, have not been finalized.

The **Analysis of Transmission System Resilience** in its current form is a valuable tool that looks at TADS transmission outages to measure the impact of extreme weather on the transmission system by quantifying resilience and restoration statistics. However, to get a more accurate measure of the impact of these events on the BPS, the customer impact should be considered as well. In accordance with the ROP, NERC does not collect customer outage data from distribution providers; however, a publicly available data set, Eagle-I, provides this data and is widely used among industry to conduct time-series analyses.

Figure B.1 shows an example of how Eagle-I data may be incorporated with TADS data to compare transmission element restorations to customer restorations. This example uses TADS element outage data during Hurricane Helene and compares it to Eagle-I customer outage data during the same time frame. By comparing the restoration rate for both components and performing a more detailed analysis (that has not yet been developed), it may be possible to identify useful trends, comparisons, or correlations.

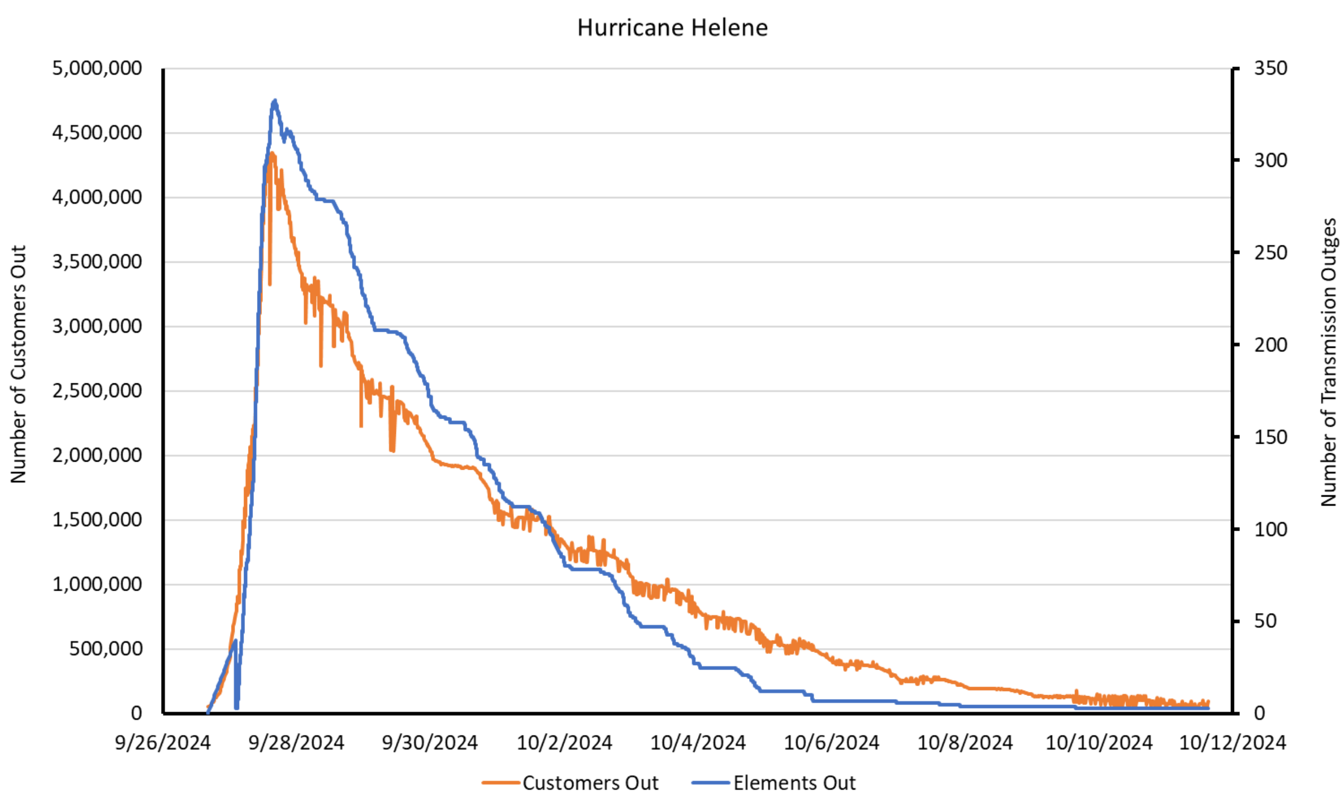

Figure B.1: Hurricane Helene, Transmission Element and Customer Outage Restoration

Generation data can also be looked at in a continuous time-series format. **Figure B.2** shows outages and restorations that occur on a day-by-day basis. Days shown with a white bar, or "candle," indicate an increase in overall generation from the start to the end of the day, while days with a blue bar indicate a decrease. The bottoms of the white candles show the MWs of generation values at the start of the day and the tops of the white candles represent the end of the day, with the reverse applying to the blue (the top is the start, bottom is the end). The outer lines, or "wicks," indicate the most and least MWs outaged throughout the day. By looking at generation data in this way and using various types of outage data (such as forced, maintenance, or planned outages), a variety of events, such as outages accumulating over the course of a storm, can be evaluated.

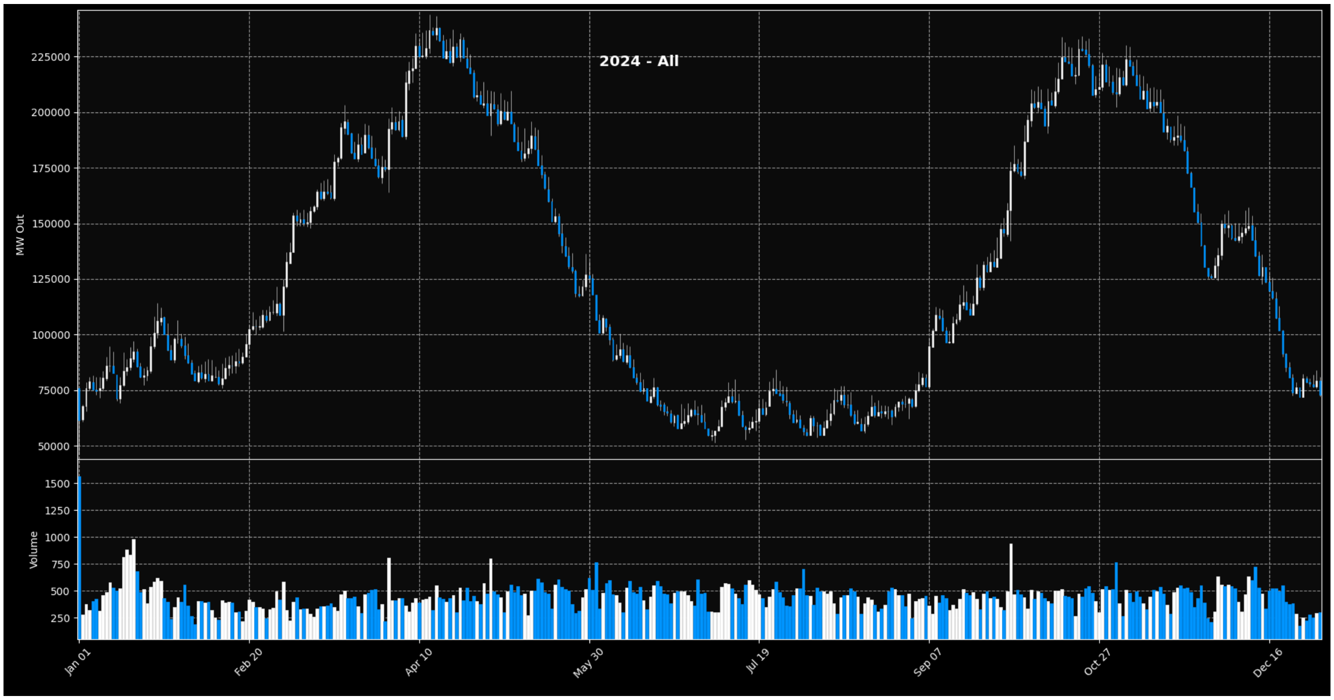

Figure B.2: 2024 Generation Outages and Restorations, Day by Day

Figure B.3 shows generation outages' accumulation and restoration during the first 10 days after major winter storm events. In addition to developing a clear evaluation methodology, further study is necessary to determine the period over which outages vs. restorations should be evaluated. This data could also prove valuable in calculating the SRI.

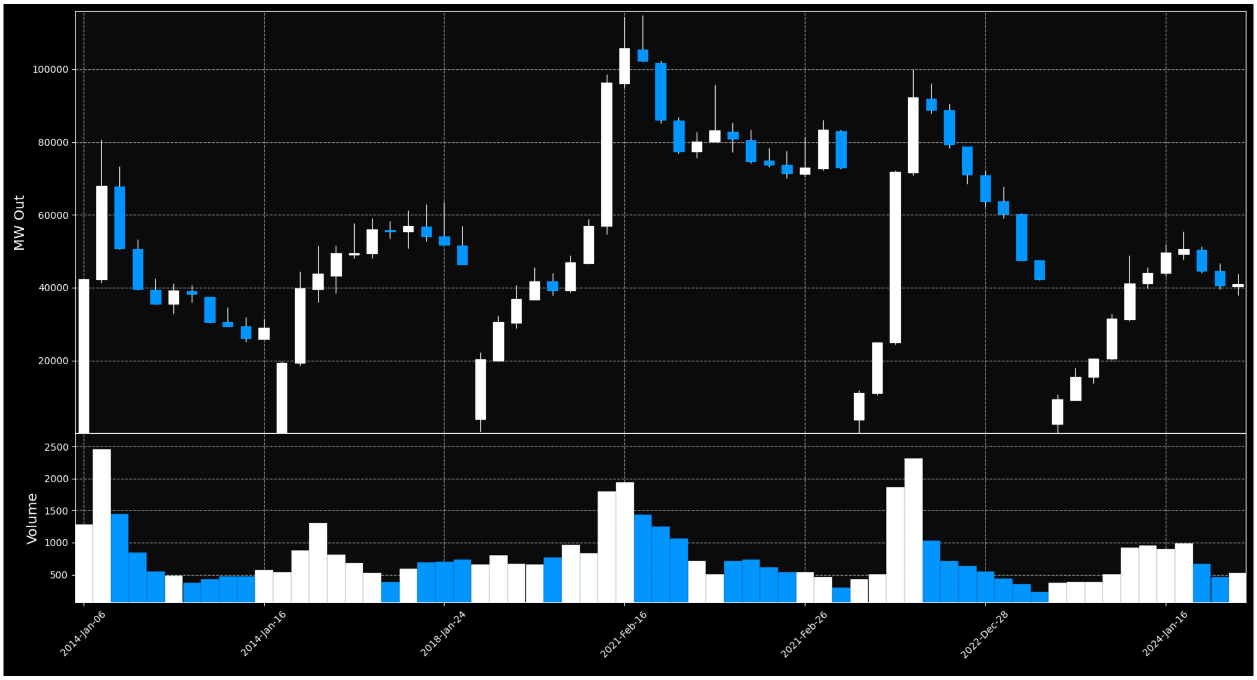

Figure B.3: Comparison of Generation Outages during Major Winter Storms

Appendix C: Acknowledgements

NERC Industry Group Acknowledgements	
Group	**Officers**
Reliability and Security Technical Committee	Chair: Rich Hydzik, Avista Vice Chair: John Stephens, City Utilities of Springfield
Performance Analysis Subcommittee	RSTC Sponsor: Brett Kruse, Calpine Corporation Chair: Heide Caswell, Oregon Public Utilities Commission Vice Chair: Peter Ashcroft, WECC
Transmission Availability Data System User Group	Chair: Nick DePompei, SERC Vice Chair: Rodolfo Lozano, ITC Transmission
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