NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2024 State of Reliability

June 2024

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Technical Assessment of 2023 Bulk Power System Performance

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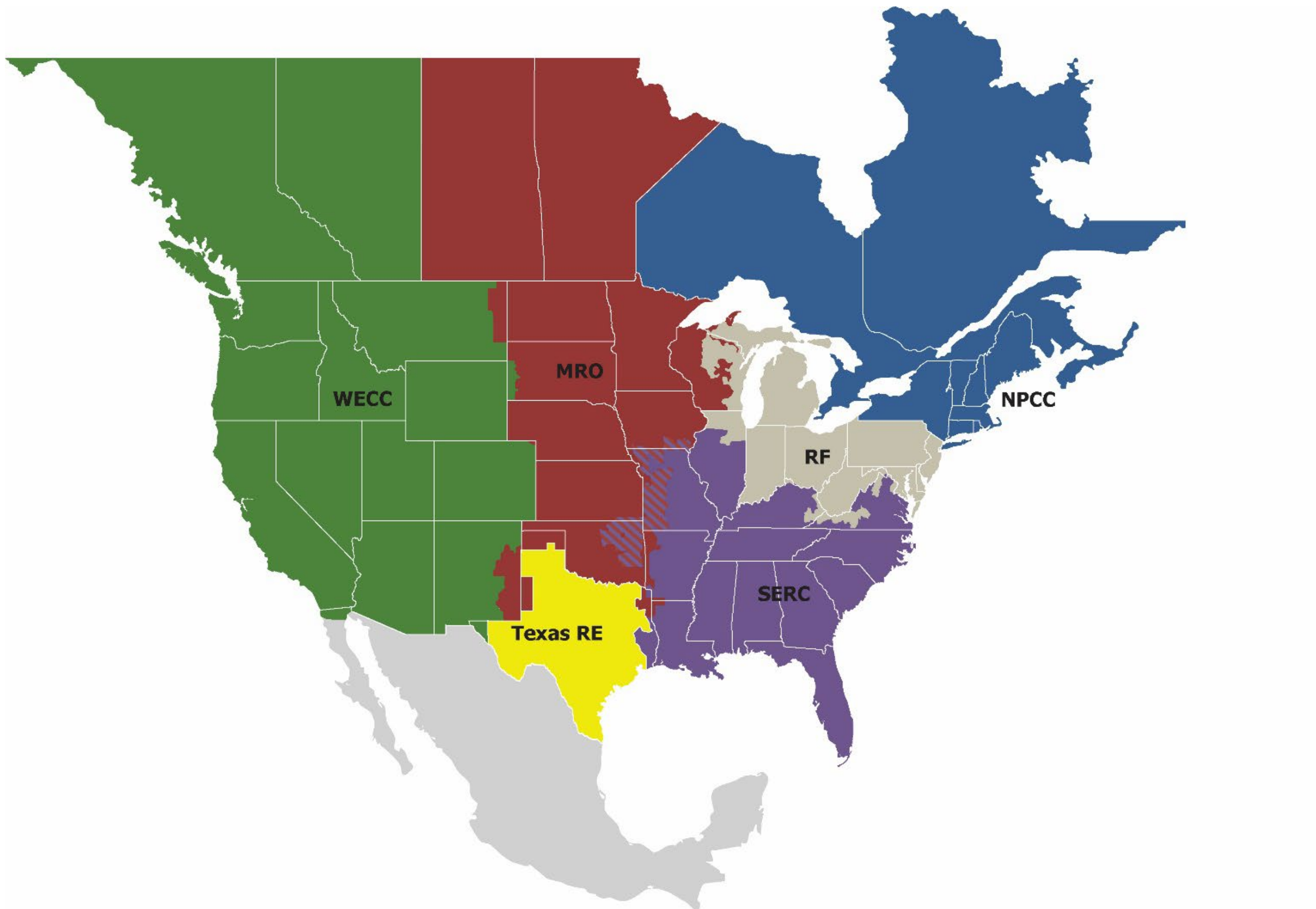
Preface

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 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/Transmission 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 *2024 SOR Technical Assessment*, which provides NERC's comprehensive annual technical review of BPS reliability for the 2023 operating (calendar) year, and the *2024 SOR Overview*,[1] which is a high-level summary of the Technical Assessment, summarized by important findings.

- The *2024 SOR Overview* replaces the key findings previously found in the Technical Assessment.

- This *2024 SOR Technical Assessment* provides key occurrences and highlights major reports released in 2023, along with 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 document identifies performance trends and provides strong technical support for those interested in the underlying data and detailed analytics.

NERC defines the reliability[2] of the interconnected BPS in terms of the following two basic and functional aspects:

- Adequacy
- Operating Reliability

The *2024 SOR* report focuses on BPS[3] 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] https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2024_Overview.pdf

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

[3] The term BPS is defined in Section 215 of the Federal Power Act to encompass the facilities, control systems, and electric energy needed to operate an interconnected electric energy transmission network and maintain transmission system reliability, excluding facilities used to locally distribute electricity. Bulk Electric System (BES) is a Federal Energy Regulatory Commission (FERC)-approved term defined in NERC's *Glossary of Terms*. The BES is, in short, the portion of the BPS to which NERC's standards apply and from which data is collected for analysis.

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*[4]

Considerations

- Data in the *SOR* report represents the performance for the January–December 2023 operating year unless otherwise noted.
- Analysis in this report is based on data from 2019–2023 that was available in Spring 2024, and it provides a basis to evaluate 2023 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 2014.
- 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.

[4] 2023 E-ISAC *End-of-Year Report*

Chapter 1: Major Occurrences and Report Releases for 2023

This chapter highlights major occurrences and reports that were issued in 2023. These occurrences and reports did not constitute a key finding but had a notable impact on the BPS.

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

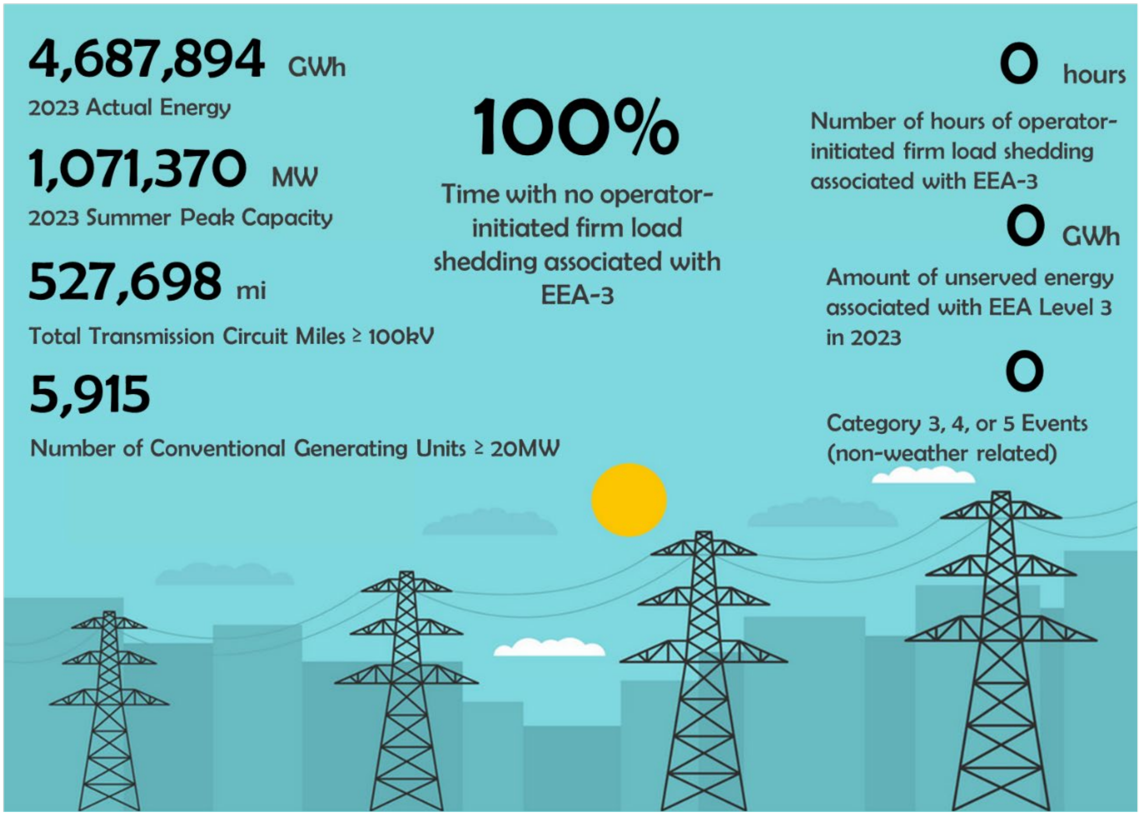

Figure 1.1: 2023 BPS Inventory and Performance Statistics

Table 1.1: Five-Year BPS Inventory and Performance Statistics

Rank	2019	2020	2021	2022	2023
Actual Energy (GWh)	4,639,653	4,588,062	4,585,939	4,674,290	4,687,894
Summer Peak Capacity (MW)	N/A	1,048,944	1,056,980	1,057,455	1,071,370
Total Transmission Circuit Miles > 100 kV miles	492,463	503,551	511,099	522,665	527,698
Number of Conventional Generating Units > 20 MW	6,064	6,009	5,966	5,910	5,915
Portion of hours in the year with no operator-initiated firm load shedding associated with EEA Level 3	99.9%	99.7%	99.2%	99.4%	100%
Category 3, 4, 5 Events (non-weather related)	0	0	0	1	0
Amount of unserved energy associated with EEA Level 3 (GWh)	5.85	828.1	1,015.5	96.2	0
Number of hours with operator-initiated load shed	>1	22	71	56.5	0

Québec Wildfires

In Québec, the 2023 wildfire season began in May when La Société de Protection des Forêts Contre le Feu (SOPFEU),[5] a nonprofit responsible for forest fire prevention in Québec, provided the provincial power grid operator, Hydro-Québec, with its first notification of a critical situation from the threat from increased wildfire activity. This wildfire season escalated to become the worst such season in Québec's history, quickly breaking records set during the 1923 wildfire season.[6] According to SOPFEU, 4,318,538.6 hectares (ha), the equivalent of 16,673.97 square miles, were burned by active fires across the province (see Figure 1.2).[7] The size of the impacted area is approximately equal to the cumulative area in the province that burned over the previous 20 years combined (equal to the area of Massachusetts and New Hampshire). The smoke from the Québec wildfires reached New York City during Summer 2023, briefly causing hazy skies and hazardous air quality.

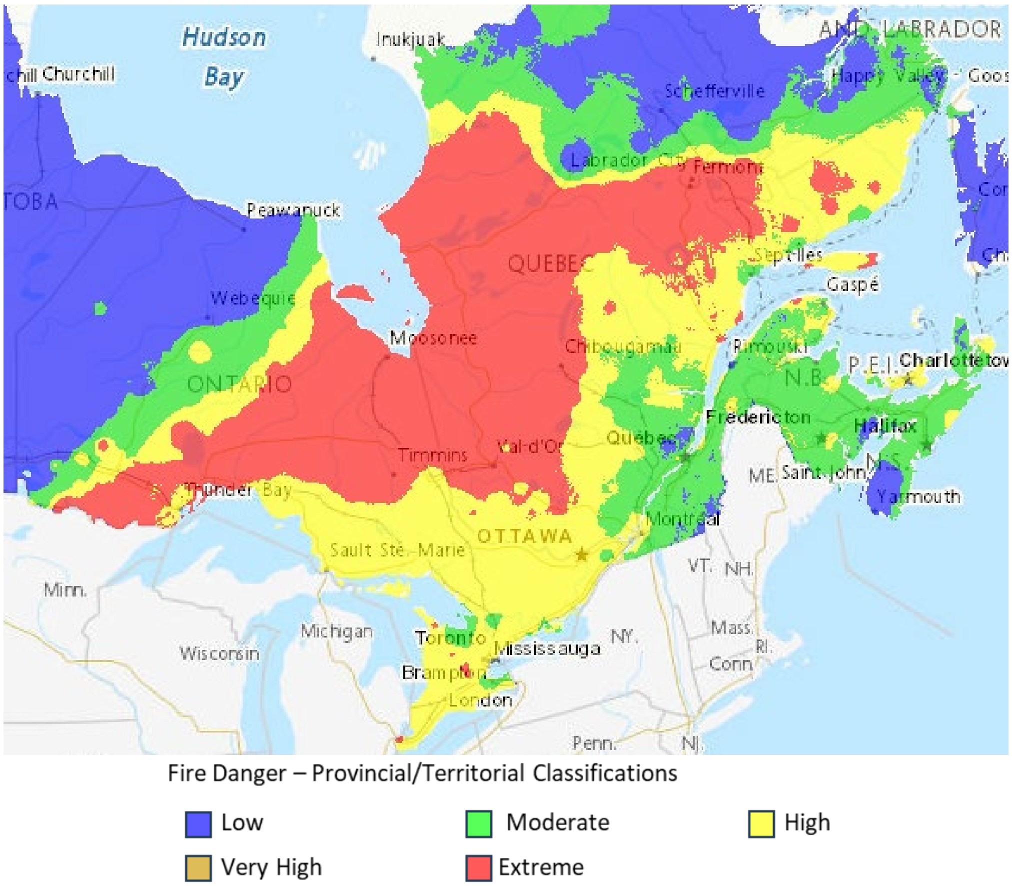

Figure 1.2: Map from Natural Resources Canada, June 20, 2023[8]

Hydro-Québec is a public corporation utility owned by the government of Québec that manages the generation, transmission, and distribution of electricity across the province. Hydro-Québec coordinates power exchanges through interconnections with three Canadian provinces (Newfoundland and Labrador, New Brunswick, and Ontario) and portions of the United States, including New York and the New England states. As a direct result of the dense smoke caused by increased wildfire activity throughout the province, Hydro-Québec experienced multiple transmission power line outages from the operation of protection systems. To address the situation, specific operating strategies were used to manage these challenging system conditions. During a period of increased intensity and proximity to wildfires in the northern portion of the province, Hydro-Québec staff and personnel had to be evacuated from critical generating and transmission facilities. The two most significant events during this period were the load-shedding

[5] SOPFEU | Organization
[6] *The 2023 wildfire season in Québec: an overview of extreme conditions, impacts, lessons learned and considerations for the future* (biorxiv.org)
[7] SOPFEU | 2023 Season Review | A record-breaking season for SOPFEU
[8] Natural Resources Canada, June 20, 2023

actions by the remedial action scheme (RAS) that operated to ensure system stability, shedding approximately 600 and 1,200 MW, respectively.[9] However, the outages were short-lived, with an average customer outage duration of less than an hour. The wildfires also impacted high-voltage direct current (HVdc) facilities and equipment exporting power from the province to the New England power grid operator, Independent System Operator New England, Inc. (ISO-NE); this subsequently caused a temporary capacity deficiency event for the ISO-NE footprint.[10]

Through enhanced coordination and real-time communication among neighboring Reliability Coordinators (RC), including New York Independent System Operator (NYISO), ISO-NE, Independent Electricity System Operator (IESO), and New Brunswick Power System Operator (NBP-SO) along with the NPCC situation awareness team, the grid across northeastern North America remained stable throughout the 2023 Québec wildfires. This collaborative effort maintained the reliability of the Québec Interconnection and the entire region.

This year's severity risk index (SRI), extreme days for transmission, and transmission outage severity (TOS) analyses all indicated that these wildfires had a disproportionately high impact on the BPS. The fires rose in prominence due to somewhat frequent and brief outages on very high-voltage transmission lines. These analyses highlighted a deficiency with the current definition of a formula that sums up transmission capacity affected by the outages started on a given day without consideration for their durations or whether repeat outages occur on the same equipment. This leads to a systematic overestimation of the contribution of much shorter outages while conversely underestimating the contribution of longer outages. The PAS is evaluating the calculations to incorporate and adequately account for outage duration.

Utah Solar Photovoltaic (PV) Performance Improvement

On April 10, 2023, at 08:51 Pacific, a single-line-to-ground fault occurred on a 345 kV transmission circuit in the southern Nevada/southwest Utah area (see Figure 1.3). The fault was normally cleared in 58 ms. While no conventional generation tripped because of the transmission line outage, supervisory control and data acquisition (SCADA) data for the area showed that aggregate solar PV output dropped significantly. The abnormal active power reduction for each facility was due to inverters tripping for a variety of causes, including loss of synchronization, ac overvoltage, and ac overcurrent.

Fifteen solar sites were connected to the system with the majority on 138 kV transmission lines. The total solar loss was approximately 929 MW, ranging anywhere from 3 MW to 234 MW per site. Most of the generation was automatically restored within 1–11 minutes and the remainder was manually restored within 120 minutes. A joint NERC, WECC, and BA investigative team recommended that the plant owners work with their inverter manufacturers to apply known improvements to ride-through settings.

[9] Remedial action schemes are designed to detect abnormal or predetermined system conditions and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. These schemes are independent of firm load shed reported through an energy emergency alert.
[10] *2023 Summer Quarterly Markets Report* (iso-ne.com)

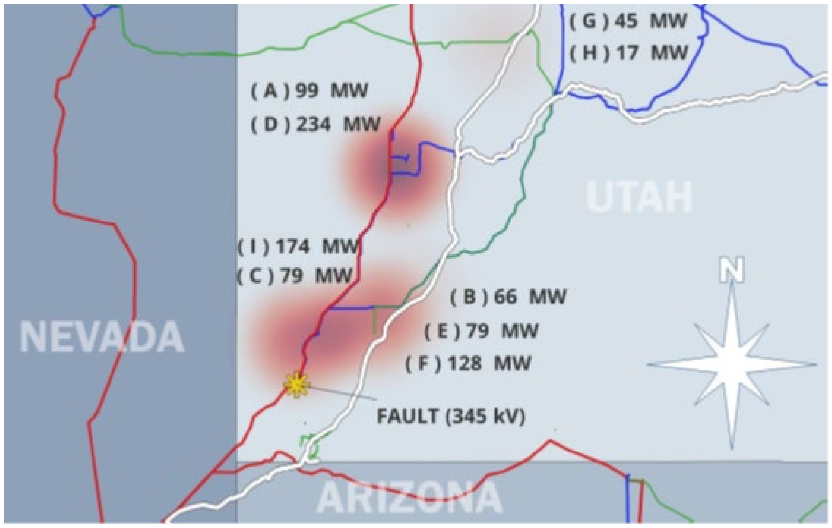

Figure 1.3: Map of Fault Location and Affected Solar PV Facilities, April 10, 2023, Event

On September 29, 2023, at 14:32:40 Pacific, a trip with no reclosing occurred on another 345 kV transmission circuit in southern Utah due to a line-to-line fault that lasted approximately 66 ms and was cleared as intended. At the same time, roughly 537 MW of solar generation (about 90% of which was from the same facilities involved in the April 10, 2023, event) experienced a sudden cessation of generation output while remaining connected to the grid. All but 5.3 MW of generation were restored within seven minutes.

After the April 10, 2023, event, the Generator Owners (GOs) of some of the larger facilities worked with their inverter manufacturers to set the inverters to not trip on the same behaviors seen during that event. These changes allowed their IBR generation to reduce active power injection but not trip, resulting in significantly improved recovery times of two to three minutes. GOs also provided updated models to the Transmission Planner for all but two of the sites.

Although these IBR facilities exhibited improved performance, recovery time still has room to improve. The investigative team is working with the inverter manufacturers and the GOs to identify the settings that need to be altered to optimize performance.

Winter Storm Elliott Report

In November 2023, FERC and the ERO Enterprise released a 167-page report on Winter Storm Elliott,[11] the late December 2022 storm that contributed to power outages for millions of electricity customers in the eastern half of the United States. During this extreme cold weather event, over 90,000 MW of coincident unplanned generation outages occurred that rendered 18% of the U.S. portion of anticipated resources in the Eastern Interconnection unavailable along with generation already on outage at that time.[12] As temperatures rapidly decreased across the event area and electricity demand correspondingly increased, balancing area operators in SERC-East and SERC-Central were faced with energy deficiencies that required 5,400 MW of firm load shed to maintain system balance, the largest controlled firm load shed recorded in the history of the Eastern Interconnection (see Figure 1.4).[13]

[11] *Winter Storm Elliott Report: Inquiry into Bulk-Power System Operations During December 2022*
[12] FERC/NERC/RE WS Elliott Report at 18.
[13] FERC/NERC/RE WS Elliott Report at 6.

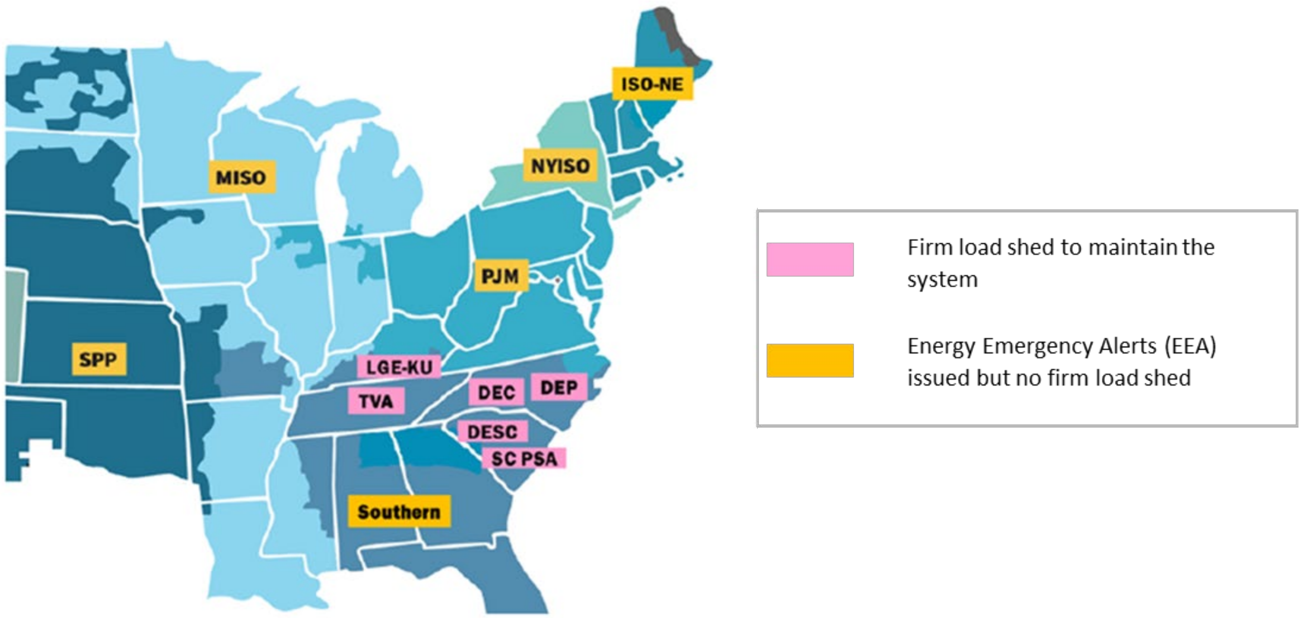

Figure 1.4: Bulk Electric System Map of Entities in the U.S. Eastern Interconnection Affected by Winter Storm Elliott

During the 2022 event, domestic U.S. natural gas production experienced its greatest decline since 2021's Winter Storm Uri. In the Marcellus and Utica shale regions, production dropped by 23–54%. Wellhead freeze-offs, the freezing of other natural gas supply chain equipment, and weather-related poor road conditions that prevented necessary maintenance were reported as the top causes.[14] The combination of reduced natural gas production and record consumption[15] forced some pipelines in the event area to declare force majeure and curtail deliveries even to firm gas transportation customers. While natural gas availability and delivery issues accounted for 20% of unplanned generating unit MW outages, mechanical/electrical issues comprised 41% and freezing issues comprised 31%[16] (see Figure 1.5).[17]

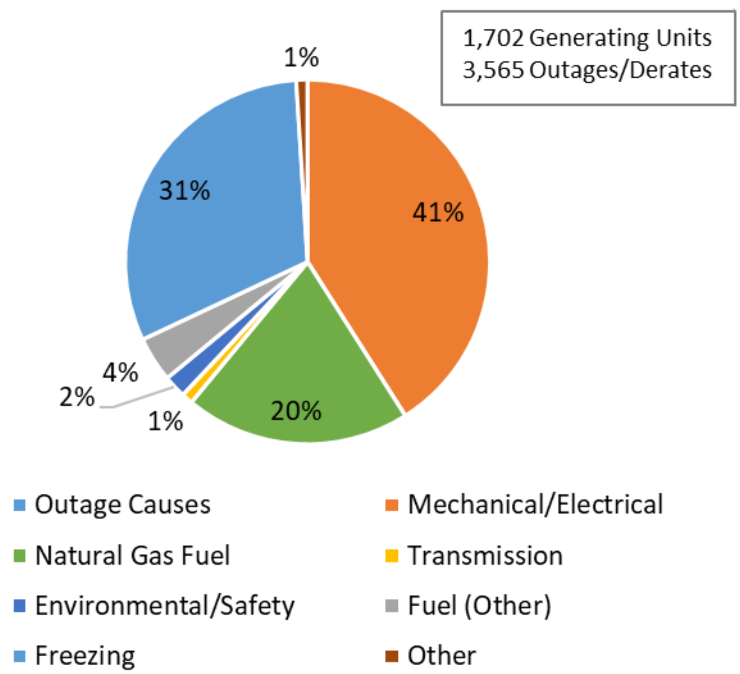

Figure 1.5: Incremental Unplanned Generating Unit MW Outages, Derates, and Failures to Start; Winter Storm Elliott Event Area by Cause

[14] FERC/NERC/RE WS Elliott Report at 19.

[15] FERC/NERC/RE WS Elliott Report at 112.

[16] "Natural Gas Fuel Issues include the combined effects of decreased natural gas production; cold weather impacts and mechanical problems at production, gathering, processing and pipeline facilities resulting in gas quality issues and low pipeline pressure; supply and transportation interruptions; curtailments and failure to comply with contractual obligations. Additionally, it includes shippers' inability to procure natural gas due to tight supply, prohibitive, scarcity-induced market prices, or mismatches between the timing of the natural gas and energy markets." (Footnote 58 of FERC/NERC/RE WS Elliott Report)

17 FERC/NERC/RE WS Elliott Report Fig 7.

CAISO Battery Energy Storage System (BESS) Disturbance Report[18]

On March 9 (Figure 1.6) and April 6, 2022 (Figure 1.7), the Southern California area experienced normally cleared transmission faults of less than 5 cycles, resulting in solar PV and BESS generation losses. The March 9 fault was due to a circuit breaker failure on a 694 MW natural gas unit; it cleared in 4.5 cycles and led to 1,102 MW of generation loss: a 694 MW natural gas unit, initiating the loss of 124 MW BESS and 284 MW of other IBRs. The second fault cleared in about 4 cycles on April 6 and led to about 500 MW of generation loss and all IBRs.

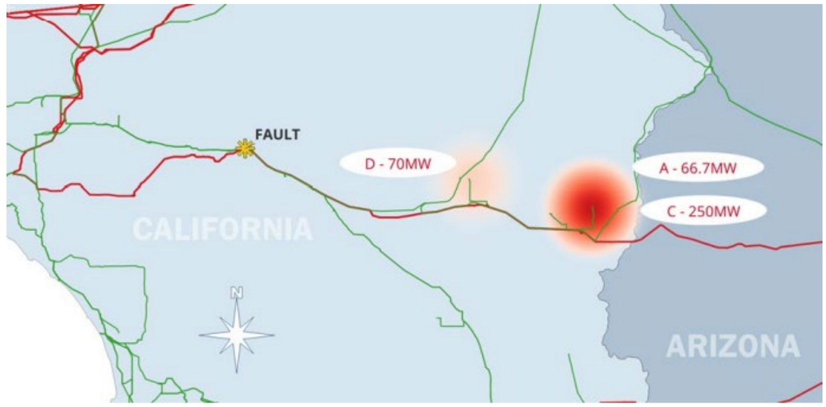

Figure 1.6: Map of the Fault Location and Affected IBR Facilities, March 9, 2022

The March 9 event is unique in that it occurred after sunset with no solar resources on-line. It was noted that, in this event, "most of the affected BESS facilities were located in the vicinity of solar PV facilities." Of the 1,102 MW of generation lost in this event, 124 MW was attributed to BESS and the remainder to synchronous generation.

A single phase-to-ground fault on a 220 kV bus caused the April 6 event at 15:06 Pacific. In this event, 498 MW of IBRs were lost. Because of poor or no metering at the BESS facilities, the report was not able to indicate the exact MW impact of the BESS lost. None of the facilities involved in these two events met CAISO's 10 ms data resolution requirement, making it difficult or impossible to verify the behavior of the plants during the disturbance.

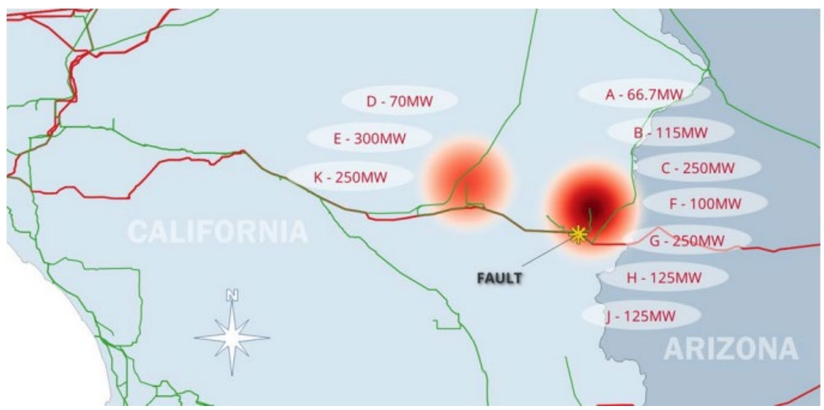

Figure 1.7: Map of the Fault Location and Affected IBR Facilities, April 6, 2022

The causes and problems that have been traditionally seen in IBR events within the Western Interconnection were seen in these events as well. Key observations and recommendations from the report are as follows:

- BESS may have the same system performance problems as solar PV resources.
- BESS ride-through performance is not adequately assessed during the interconnection process.
- Poor commissioning practices are a significant contributor to the unreliable performance of IBRs.
- NERC will be conducting a model quality assessment of this event and subsequently issue an alert as needed.
- Inadequate monitoring hinders performance and event analysis.

Based on the analysis of the events, including a finding that the affected entities did not meet the performance requirements of the Generator Interconnection Agreement, CAISO worked with affected GOs to develop and implement mitigation plans to eliminate the unexpected causes of tripping and make changes to recording capabilities to meet the Interconnection agreement requirements.

[18] *2022 California Battery Energy Storage System Disturbances*

Chapter 2: Severe Risks, Impact, and Resilience

This chapter identifies and examines the highest-stress days on the BPS in 2023 using established measures.

Severity Risk Index[19]

The SRI provides a quantitative measure that assesses 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 2023, 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. Three of these cumulative measures for 2023 were the lowest in the past five years (Cumulative Weighted Load Loss, Annual Cumulative SRI, and Average Daily SRI) and Cumulative Weighted Generation was the second lowest.

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 2019–2023.

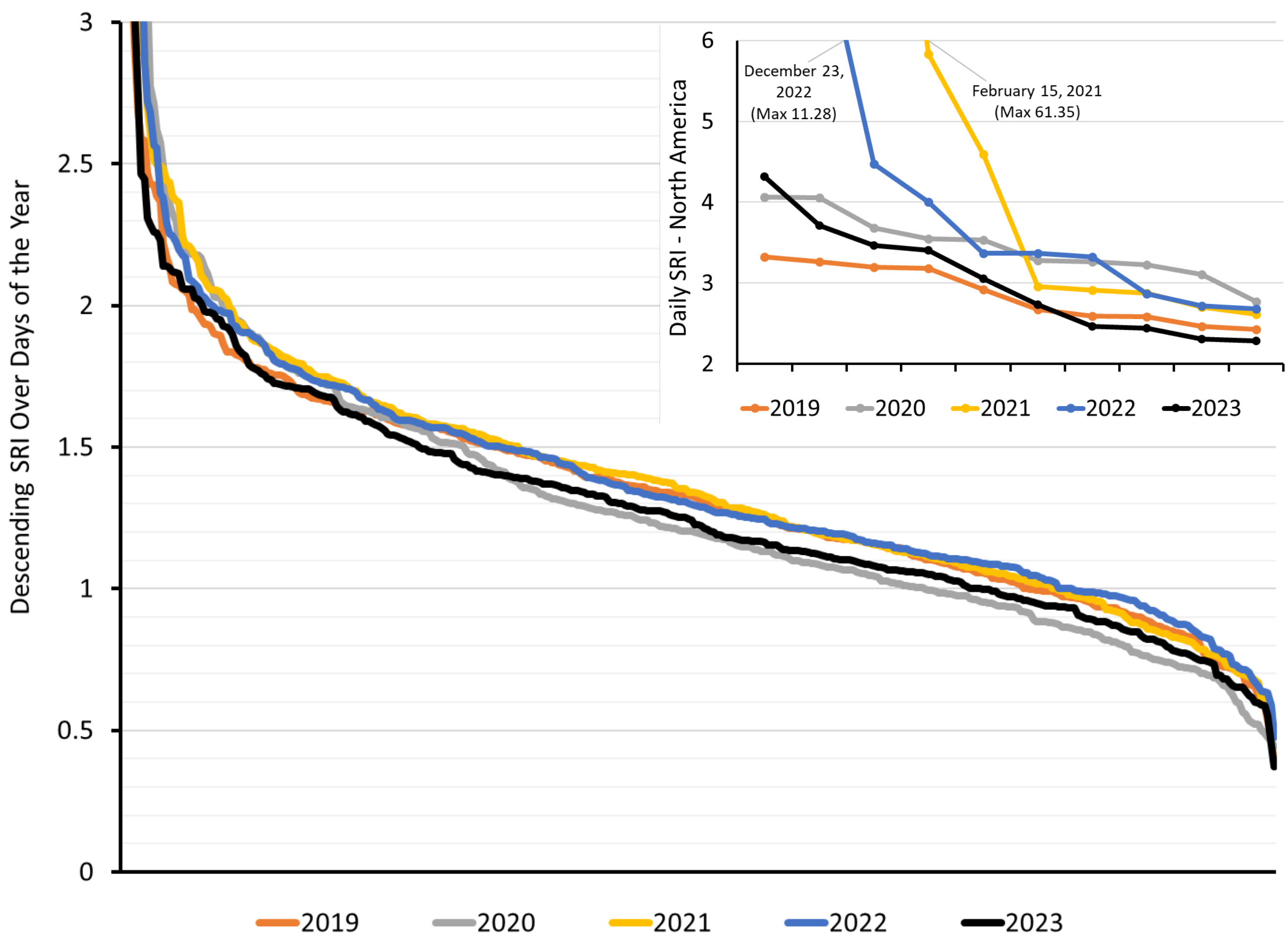

Figure 2.1: NERC Descending SRI by Day of the Year

[19] Severity Risk Index

Table 2.1: Annual Cumulative SRI					
Year	Cumulative Weighted Generation	Cumulative Weighted Transmission	Cumulative Weighted Load Loss	Annual Cumulative SRI	Average Daily SRI
2019	368.9	67.4	57.0	493.3	1.35
2020	339.0	67.7	72.5	479.2	1.31
2021	375.8	65.3	152.1	593.2	1.63
2022	404.2	61.1	55.2	520.4	1.43
2023	356.8	65.9	53.2	475.9	1.30

Figure 2.2 plots the daily SRI scores for 2023 against control limits that were calculated by using 2019–2022 seasonal daily performance and identifies the 10 highest SRI days. A general normal range of performance is represented by the gray-colored band, showing the daily seasonal 90% control limits.[20] 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.

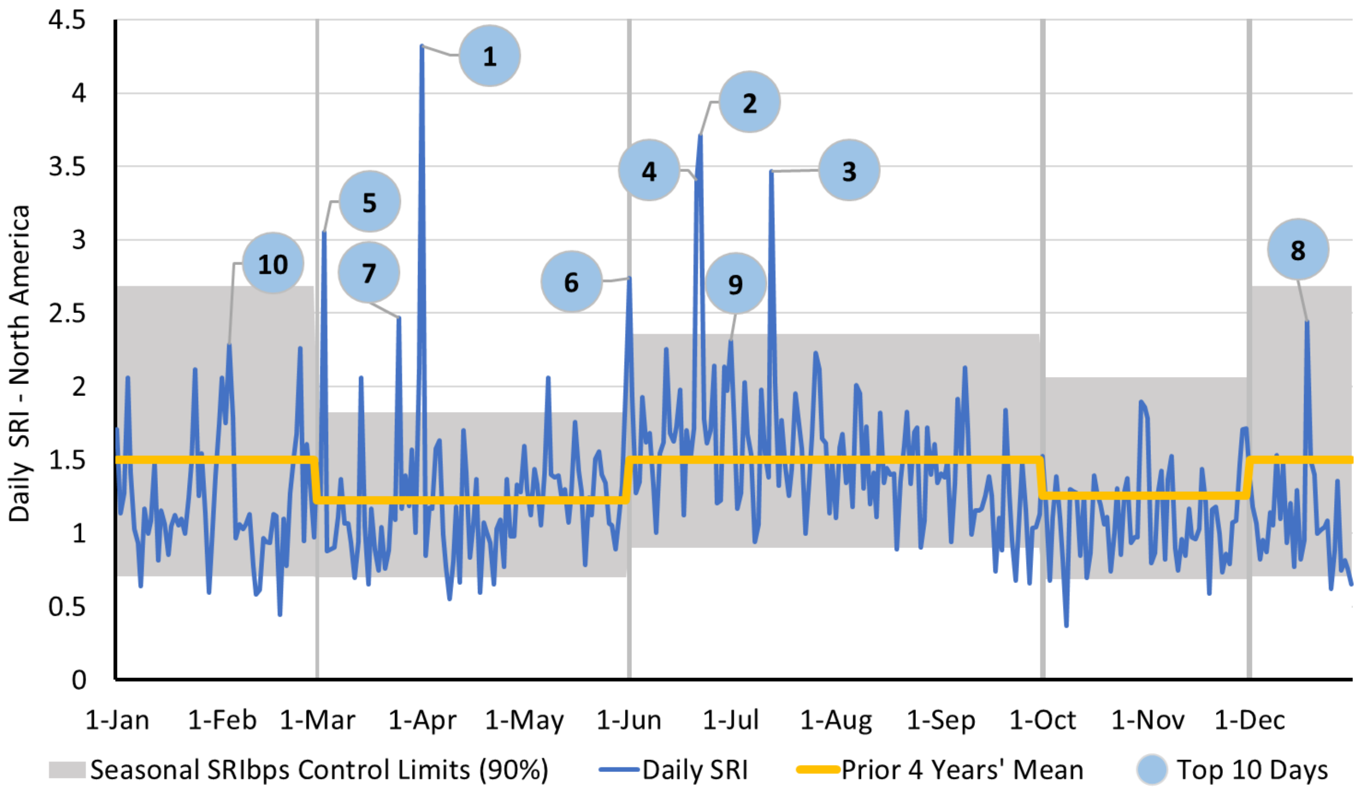

Figure 2.2: 2023 Daily SRI with Top 10 Days Labeled, 90% Confidence Interval

Table 2.2 details the scores for the top 10 SRI days during 2023. The table identifies where atypical weather conditions were ongoing during the day and the general location by Regional Entity. Four of the top 10 SRI days in 2023 were driven by relatively short high-voltage transmission outages resulting from the wildfires in Québec. As noted in other areas of this report, although the wildfires did have some impact on reliability, they have disproportionately increased transmission indicators. Five of the six remaining top days were coincident with major thunderstorms, leading to higher load loss than usual. Due to the relatively calm weather in 2023, the final remaining day was a result of several coincident large fossil generator outages.

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

Table 2.2: 2023 Top 10 SRI Days							
Rank	Date	SRI and Weighted Components 2023				Atypical Weather Conditions	Regional Entities
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss		
1	1-Apr	4.32	1.10	0.45	2.77	Widespread storms and tornadoes	MRO, RF, SERC
2	22-Jun	3.71	1.39	2.18	0.14	Québec Wildfires	NPCC
3	13-Jul	3.47	1.01	2.18	0.28	Québec Wildfires	NPCC
4	21-Jun	3.40	1.36	1.80	0.24	Québec Wildfires	NPCC
5	3-Mar	3.05	1.40	0.57	1.08	Severe Storms	RF, SERC, Texas RE
6	1-Jun	2.74	1.78	0.77	0.19	Québec Wildfires	NPCC
7	25-Mar	2.46	0.71	0.30	1.46	Widespread storms	RF, SERC
8	18-Dec	2.45	1.26	0.15	1.04	East Coast thunderstorms and coincident generation outages	NPCC, SERC
9	1-Jul	2.31	1.68	0.51	0.12	Three high-voltage lines out < 30 minutes due to lightning	NPCC
10	3-Feb	2.28	2.00	0.14	0.15	Coincident large coal and gas generator outages	N/A

SRI Performance Trends

To put the severity of days in 2023 into context with historic BPS performance, the top 10 days over the five-year period are updated annually. Table 2.3 identifies the top 10 SRI days occurring for 2019–2023 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. Only April 1, 2023, was severe enough to be added to the top 10 SRI days of the past five years.

Table 2.3: 2019–2023 Top 10 SRI Days							
Rank	Date	SRI and Weighted Components				Atypical Weather Conditions	Regional Entity
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss		
1	February 15, 2021	61.35	5.54	0.79	55.02	Cold Weather Event	MRO, RF, SERC, TRE
2	February 16, 2021	18.34	5.02	0.54	12.78	Cold Weather Event	MRO, RF, SERC, TRE
3	February 17, 2021	12.04	2.49	0.29	9.26	Cold Weather Event	MRO, RF, SERC, TRE
4	December 23, 2022	11.28	8.17	0.86	2.26	Winter Storm Elliott	All
5	December 24, 2022	7.46	6.44	0.97	0.05	Winter Storm Elliott	All

Table 2.3: 2019–2023 Top 10 SRI Days							
Rank	Date	SRI and Weighted Components				Atypical Weather Conditions	Regional Entity
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss		
6	February 18, 2021	5.83	2.20	0.33	3.30	Cold Weather Event	MRO, RF, SERC, TRE
7	February 14, 2021	4.59	1.91	0.86	1.83	Cold Weather Event	MRO, RF, SERC, TRE
8	June 14, 2022	4.47	1.52	0.39	2.57	High Temperatures and Derecho	MRO, NPCC, RF, SERC, TRE
9	April 1, 2023	4.32	1.10	0.45	2.77	Hurricane Florence	SERC
10	August 27, 2020	4.06	1.52	0.94	1.60	Winter Storm Riley	NPCC

Major Weather Events

The typical major weather systems that have been analyzed for 2023, such as severe thunderstorms, hurricanes, tornadoes, and winter storms, had less of an impact on the BPS than seen in the past. Six of the 28 events highlighted in Figure 2.3[21] were identified as large transmission events in the resilience analysis. By far the largest natural disaster event that impacted the BPS transmission metrics was the Québec wildfires; however, the impact of this event does not align with the metrics (see **Major Occurrences**, **Resilience Curves,** and **TADS Reliability Indicators** sections).

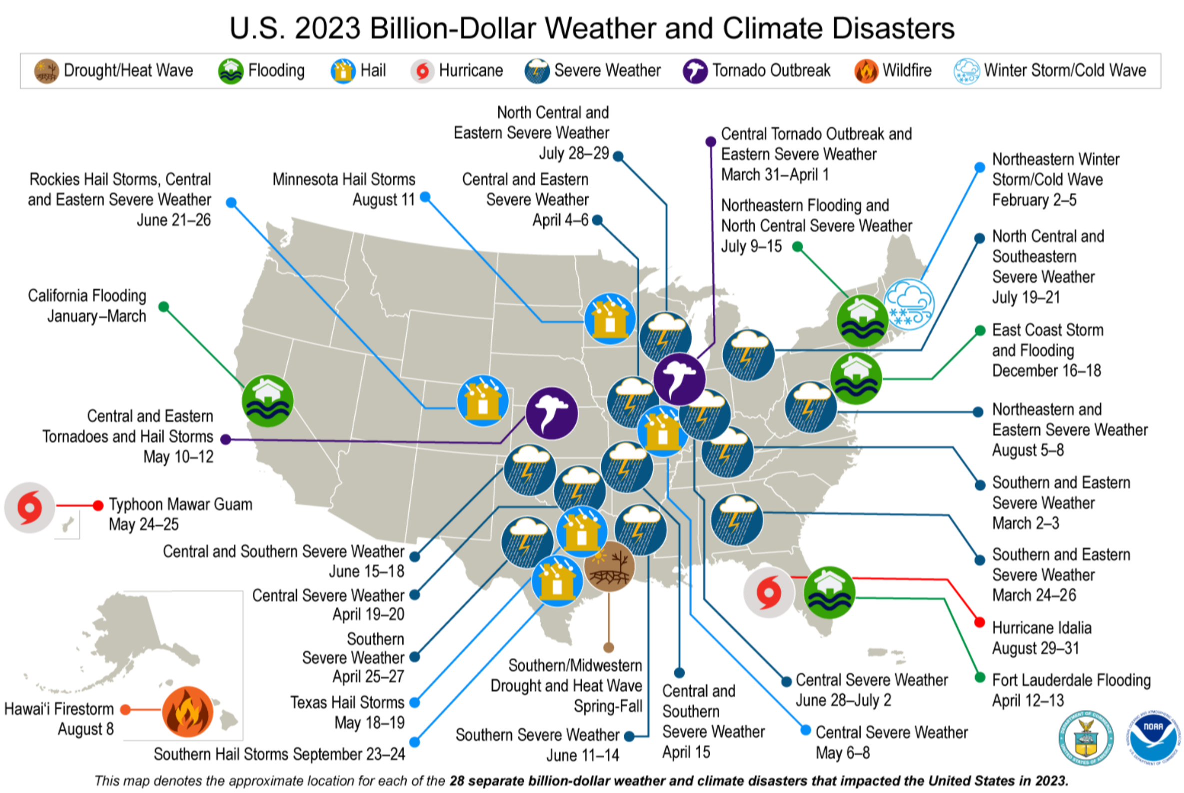

Figure 2.3: 2023 U.S. Billion-Dollar Weather and Climate Disasters[22]

[21] 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

[22] 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

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.[23] The analysis provided in the following subsections is reported separately for transmission and generation. The total estimated MVA transfer capacity[24] 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 2023, 22 days met the criteria of extreme transmission days for the BPS as compared to 11 in 2022. Of the 22 extreme days in 2023, 14 were associated with the Québec wildfires. The most extreme transmission-impacting day was June 22, primarily due to the Québec wildfires (see Figure 2.4), followed closely by July 13, also due to the Québec wildfires. On these days, the potential MVA capacity impacted due to automatic transmission outages was 10.4 times as high as the associated season's average.

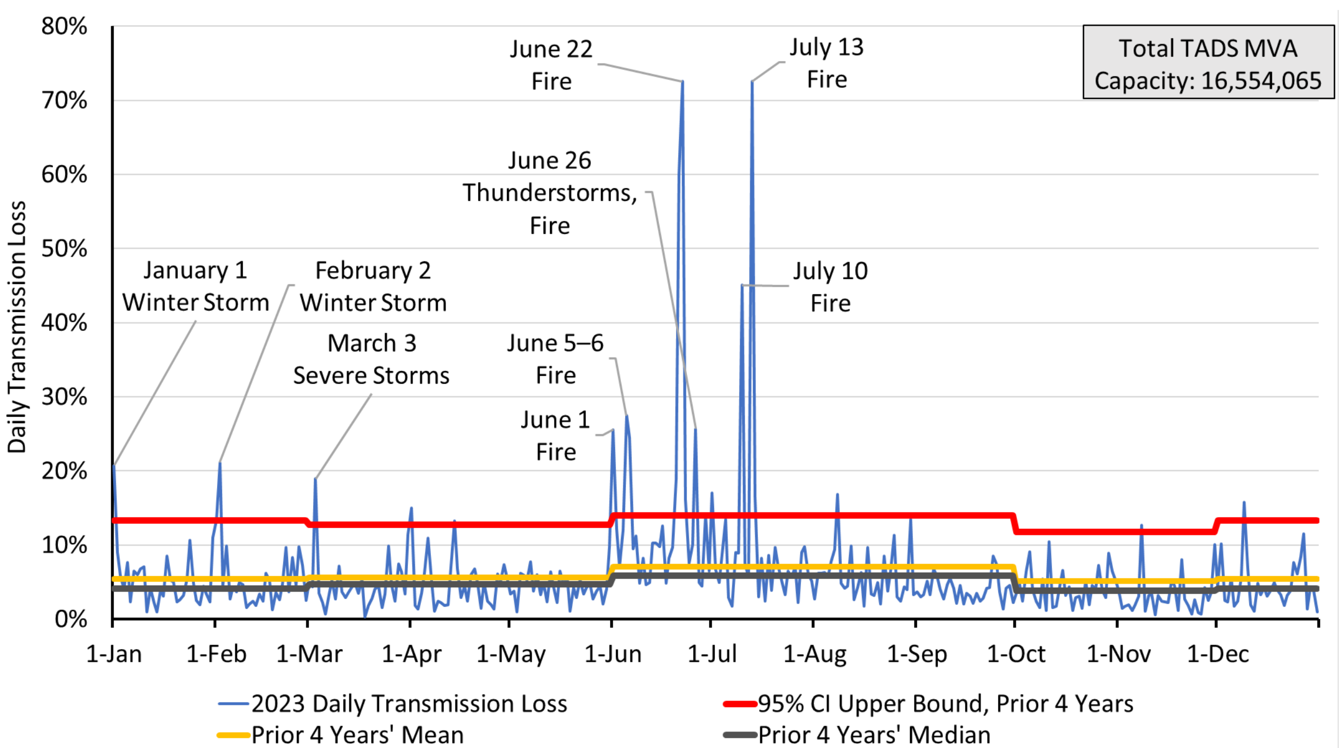

Figure 2.4: 2023 Transmission Outages during Extreme Days

[23] For extreme day Interconnection-level analysis, the Québec Interconnection is included in the analysis labeled as Eastern Interconnection–Québec Interconnection.
[24] 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).

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	Fire (568,311)	Weather (Excluding Lightning) (112,908)	Lightning (59,365)	Failed AC Circuit Equipment (32,329)	Unknown (31,075)
Eastern–Québec Interconnections	Fire (568,392)	Weather (Excluding Lightning) (91,274)	Lightning (49,745)	Failed AC Circuit Equipment (31,732)	Failed Protection System Equipment (29,606)
Texas Interconnection	Weather (Excluding Lightning) (55,125)	Lightning (27,487)	Failed AC Circuit Equipment (18,963)	Unknown (6,895)	Other (5,952)
Western Interconnection	Weather (Excluding Lightning) (24,675)	Unknown (16,615)	Power System Condition (8,739)	Lightning (8,475)	Human Error (6,668)

Conventional Generation Impacted

Based on analysis of GADS data, a total of 14 days in 2023 qualified as extreme for North America's BPS (see Figure 2.5) compared to 22 in 2022. The two highest-impact days for generation loss were July 27 (severe storms) and February 3 (winter storm). On these days, conventional generating units experienced outages that were 1.8–1.9 times as severe as the associated season's average. Two of the extreme generation loss days coincided with extreme days identified for transmission (early February winter storms and June 1). The days on which generation outages were slightly above the seasonal bounds (**red** line) do not have a specific cause listed and have been investigated; they either coincided with severe thunderstorms (i.e., May 8, June 1, June 12, and July 27) or saw many coincident outages that were not a result of adverse weather conditions.

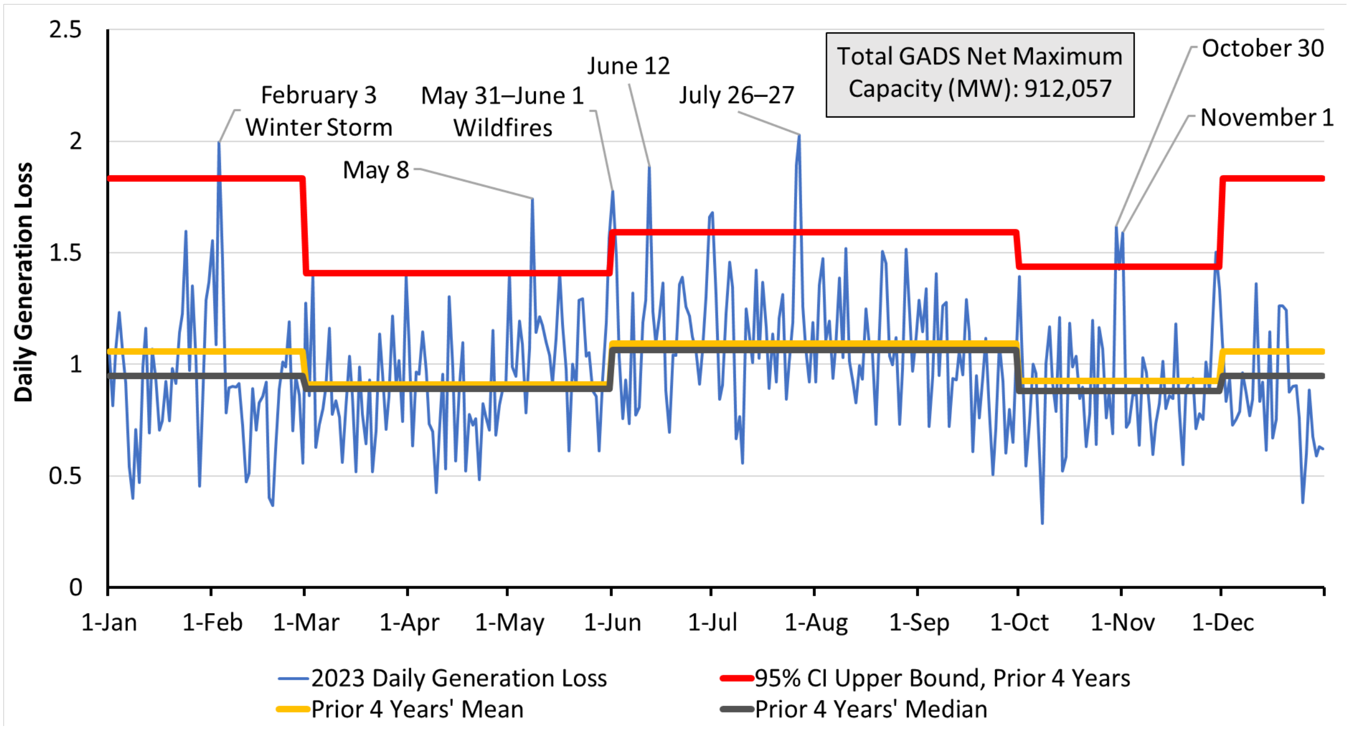

Figure 2.5: 2023 Generation Impacted during Extreme Days

The top causes reported for outages that occurred on extreme days are shown in rank order for North America and each Interconnection (Table 2.5).

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	Electrical (17,851)	Fuel, Ignition, and Combustion Systems (14,130)	Auxiliary Systems (13,876)	Boiler Tube Leaks (13,008)	Controls (11,341)
Eastern–Québec Interconnections	Fuel, Ignition, and Combustion Systems (11,086)	Boiler Tube Leaks (10,758)	Electrical (9,073)	Auxiliary Systems (7,126)	Lack of Fuel (Hydro, gas, coal) (6,746)
Texas Interconnection	Electrical (5,784)	Controls (4,933)	Boiler Tube Leaks (4,868)	Fuel, Ignition, and Combustion Systems (4,471)	Boiler Piping System (4,444)
Western Interconnection	Feedwater System (2,136)	Electrical (1,579)	Fuel, Ignition, and Combustion Systems (1,470)	Controls (1,397)	Condensing System (1,373)

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 2023 transmission outages identified 11 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.[25]

This section provides a detailed description of the March 31 winter storm and tornado event as the largest outage event on the transmission system in 2023 and the Québec wildfires as a composite event due to the impact on other transmission metrics. 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: 2018–2022 and 2019–2023.

TADS Outage Grouping and 2023 Large Weather Events

The outage grouping algorithm[26] 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 National Oceanic and Atmosphere Administration (NOAA) and Ventusky were used to visualize the weather events. Matching the data from these sources provides a much clearer picture of outages within the event. This combination of automatic and manual procedures results in a set of transmission events that can cross boundaries of different utilities and Regional Entities to capture significant events caused by major weather occurrences, such as hurricanes and severe winter storms.

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 2023, the largest event was the Québec wildfire composite event with 180 outages between June 20 and July 16, which consisted of 101 small non-overlapping events and as such was not captured by the algorithm as one single event. The combination of all events affected 600,635 of MVA capacity. This composite event is shown in **blue** in Table 2.6.

The second largest event, the March 31 winter storm/tornado event (with 119 transmission outages reported), occurred in the Eastern Interconnection, shown in **red** in Table 2.6. In terms of impact to the overall system, the February 1 ERCOT winter storm event had the highest transmission capacity affected (48,761 MVA out) for any single event in 2023. The two events taking place on June 25 were reported as two separate events due to the large time gap and geographical distance between them.

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

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

Table 2.6: 2023 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)	Element-Days[27] Lost	Most Simultaneous Unavailable Capacity (MVA)
	All Automatic	Sustained Automatic	Momentary Auto.							
February 1	66	61	5	Texas	Winter Storm, Ice	48,105	1,270	61.5	115	35,593
March 3	88	75	13	Eastern	Severe / High Winds	39,100	2,609	5.6	50	13,676
March 25	29	23	6	Eastern	Thunderstorm	16,401	920	2.3	15	4,706
March 31	**119**	**99**	**20**	**Eastern**	**Winter Storm, Tornadoes**	**47,097**	**3,091**	**22.8**	**164**	**16,788**
June 15	85	72	13	Eastern	Thunderstorm, Tornadoes	26,747	2,034	11.3	127	14,388
June 18	32	29	3	Eastern	Thunderstorm, Tornadoes	9,406	859	9	60	6,620
June 20-July 14	**180**	**143**	**37**	**Québec**	**Wildfires (composite event)**	**600,635**	**25,710**	**N/A**	**9**	**17,482**
June 25	22	19	3	Eastern	South Central Thunderstorm, Tornadoes	5,038	587	6.9	29	3,121
June 25	21	19	2	Eastern	Thunderstorms	6,472	503	2.2	10	3,686
June 29	58	50	8	Eastern	Derecho, Thunderstorms	23,781	1,520	11.7	51	10,983
July 20	52	42	10	Eastern	Thunderstorm, High Winds	18,147	1,365	4.9	33	7,055
August 30	58	56	2	Eastern	Hurricane Idalia	15,170	1,439	9.2	106	11,132

[27] 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 he events unfolded.[28] Figure 2.6 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.

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.

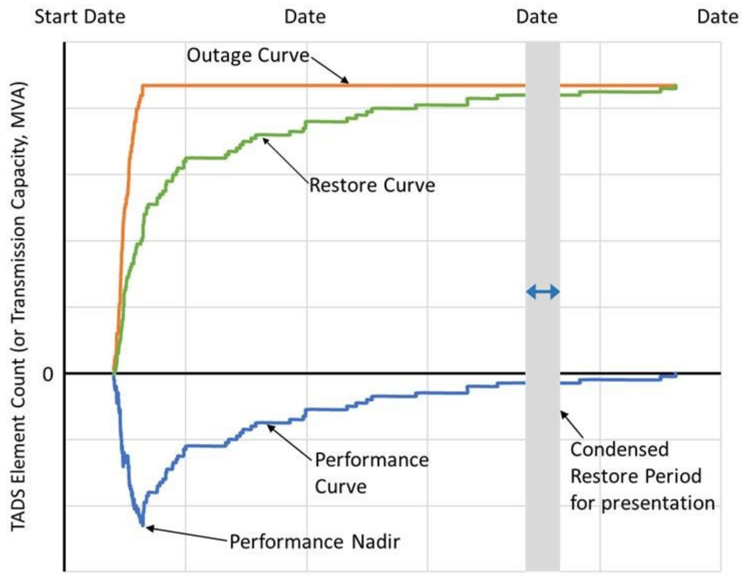

Figure 2.6: Example of Outage, Restore, and Performance Curves for a Large Transmission Outage Event

Lastly, 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.[29] 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 (event duration, time to first restore, time to substantial restoration, instantaneous restore rate).

Resilience Curves and Statistics for Two Largest Transmission Events in 2023

Québec Wildfires (June 20–July 14, 2023)

The Québec wildfire outages were combined into one composite event that consisted of 101 non-overlapping small outage events that are grouped together to better assess the overall impact between June 20 and July 26, 2023. These small events together contained 180 automatic outages. It should be noted that the creation of this composite event is only possible due to the specificity of the “Fire” cause code. With current data, it would be impossible to perform a similar, accurate methodology for other types of weather, making for limited comparability.

Out of the 180 outages, 37 were momentary (< 1 minute) and the remaining were sustained. The event included 11 dc circuit outages and 169 ac circuit outages. A total of 180 automatic outages occurred on 2 distinct dc circuits and 26 distinct ac circuits. The affected dc circuits were from the 400–499 kV voltage class and the ac circuits from the 300–399 kV and 600–799 kV voltage classes. Because of the high voltages and large estimated MVA capacity of the dc and ac circuits and because the wildfires were considered as one composite event, the total affected transmission capacity summed up to 600,635 MVA. Outage durations were short (1.2 hours on average) and generally not overlapping, reducing the simultaneous stress on the transmission system. The total duration analyzed from the first outage to final restoration was 26.1 days. The element- and MVA-based performance curves for the Québec wildfires

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

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

composite event are shown in Figure 2.7 and Figure 2.8, respectively. The outage and restore curves for the composite event are not shown because they do not provide valuable information since regular resilience statistics cannot be properly applied.

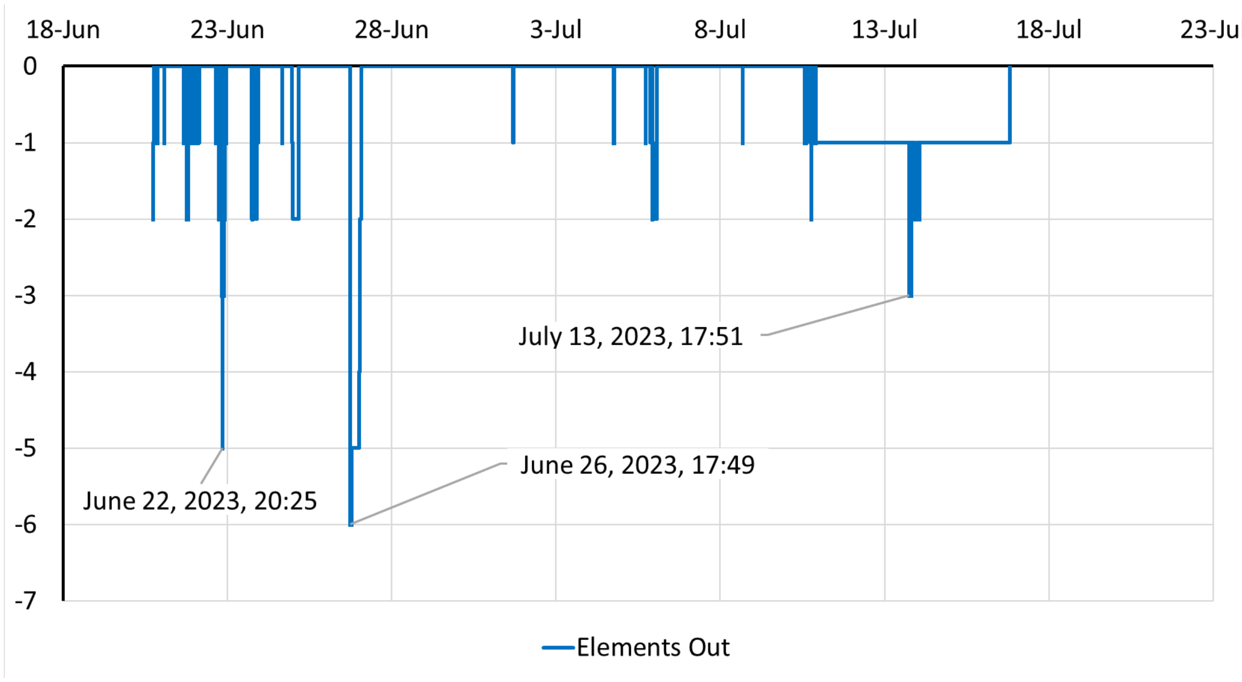

Figure 2.7: Transmission Element-Based Performance Curve for Québec Wildfire Event, June 20–July 14, 2023

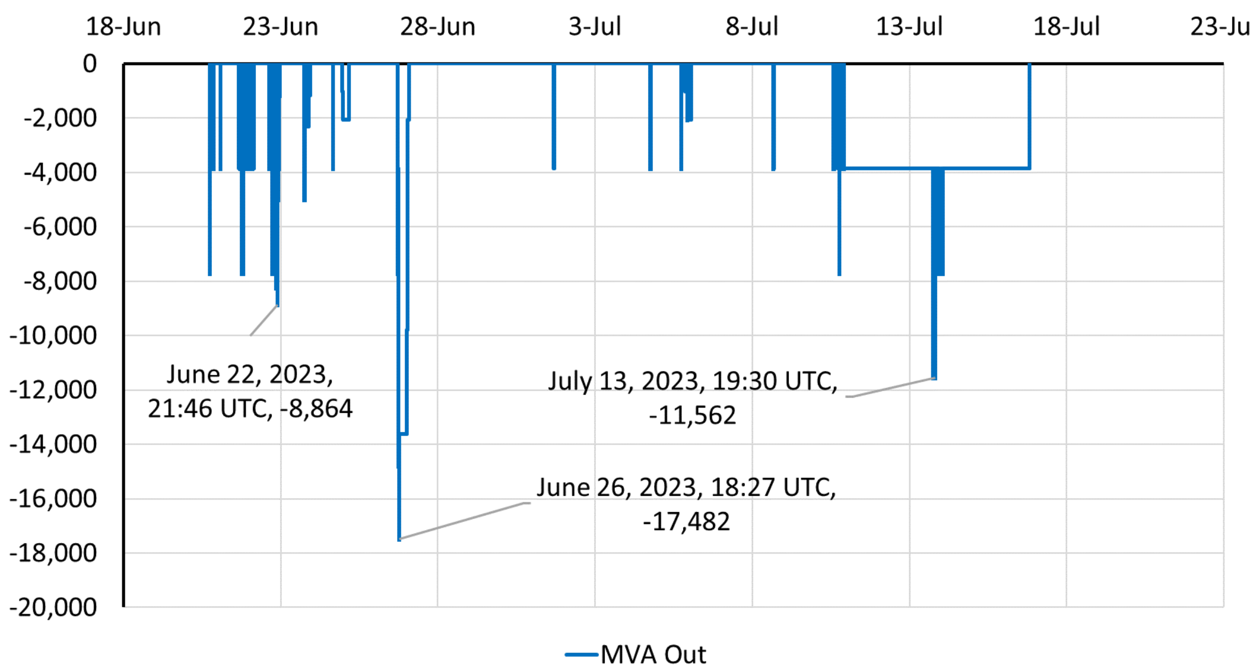

Figure 2.8: Transmission Capacity (MVA-Based) Performance Curve for Québec Wildfire Event, June 20–July 14, 2023

The maximum simultaneous loss of potential transmission capacity was greater than that of the Eastern Interconnection winter storm and tornado event, 17,482 MVA vs. 16,788 MVA, respectively. The elements' high voltages resulted in a significant total loss of 29,492 MVA-days compared to only nine element-days lost. This ratio of 3,276:1 is roughly nine times the average ratio of 363:1, clearly demonstrating how these outages disproportionately impact transmission calculations that do not account for duration.

Winter Storm and Tornado Event (March 31–April 23, 2023)

Table 2.6 indicates that the events with a combination of weather types significantly impacted the transmission system in 2023. The largest non-composite transmission outage event in 2023 was the winter storm and tornado event that started in the Eastern Interconnection on March 31, 2023, in terms of the number of element outages. This weather event was also recorded by NOAA as one of the billion-dollar weather disasters of 2023 (see Figure 2.3). It involved a series of strong storms containing high winds, heavy rain, and multiple tornadoes across the Mississippi, Tennessee, and Ohio Valleys and into the Mid-Atlantic and Northeast on Friday and Saturday, March 31, and April 1. At the storm's peak, EAGLE-I[30] indicated approximately 1.1 million distribution outages between Arkansas and New York; 268,000 in Pennsylvania; 237,000 in Ohio; and 99,000 in Tennessee.

The event caused 119 automatic transmission outages reported by 36 Transmission Owners; 20 out of the 119 outages were momentary (< 1 minute), and the remaining were sustained. The event included five transformer outages and 114 ac circuit outages with more than 3,090 ac circuit miles affected, totaling 47,097 MVA capacity. The event had a duration of 22.8 days, second only to the ERCOT winter transmission outage event that lasted 61.5 days. The element- and MVA-based curves for the winter storm are shown in Figure 2.9 and Figure 2.10, respectively. The curves are condensed with the gray area representing the time between April 11, 2023, 15:55 UTC and April 22, 2023, 0:00 UTC.

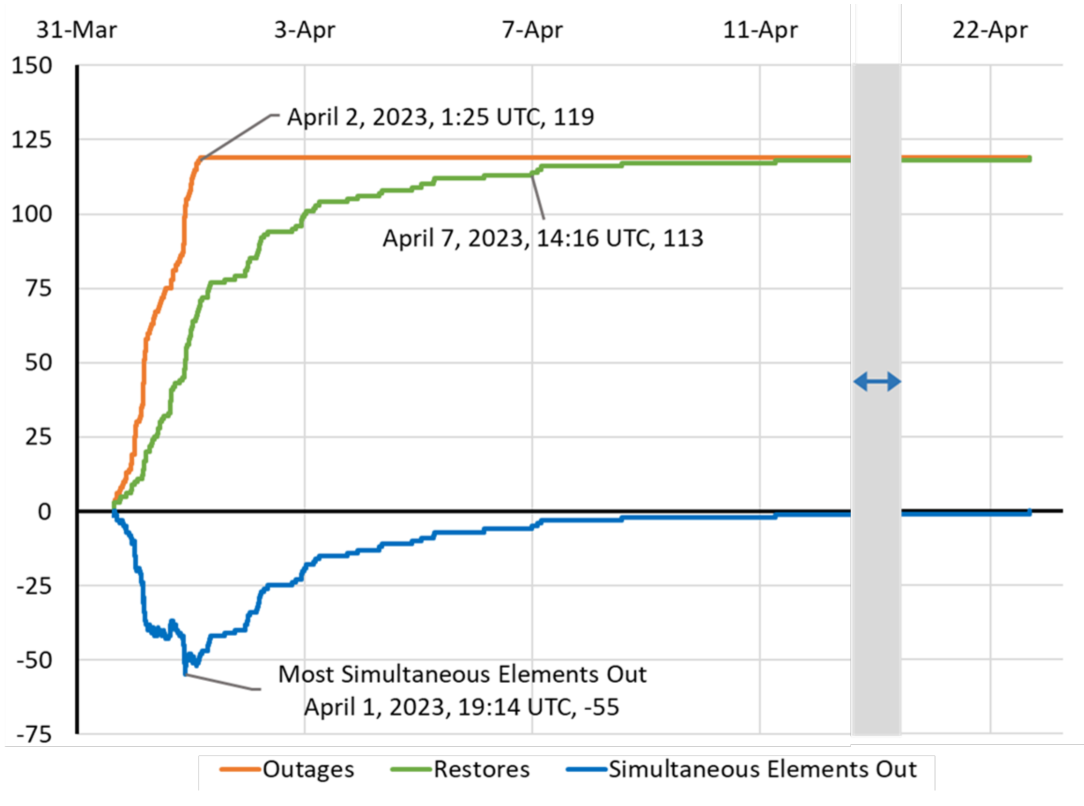

Figure 2.9: Transmission Element Outage, Restore, and Performance Curves for Winter Storm/Tornado Event, March 31–April 23, 2023

[30] EAGLE-I is an interactive geographic information system (GIS) that allows users to view and map the nation's energy infrastructure and obtain near real-time informational updates concerning the electricity, petroleum, and natural gas sectors within one visualization platform.

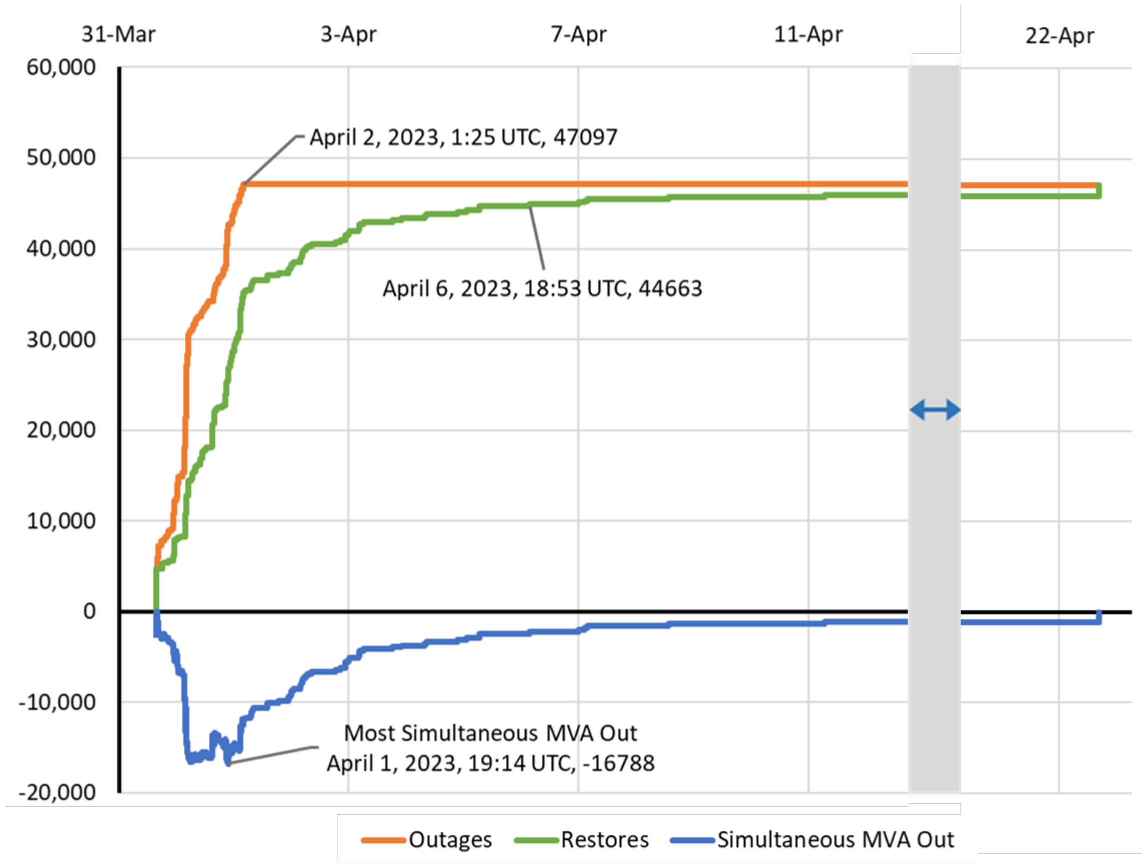

Figure 2.10: Transmission Capacity (MVA-Based) Outage, Restore, and Performance Curves for Winter Storm/Tornado Event, March 31–April 23, 2023

The large transmission outage event started with a series of ac circuit momentary outages due to galloping caused by the winter storm. During this transmission event, four distinct ac circuits followed the same scenario: a line had several momentary outages in close succession due to galloping followed by a sustained outage with a multiday duration. Due to the multiple outages of the same ac circuit, a total of 119 automatic outages occurred on 111 distinct transmission elements. The **orange** outage curves in Figure 2.9 and Figure 2.10 show that an outage process lasted 35 hours with the outages accumulating at the average rate of 3.4 outages per hour (1,359 MVA capacity per hour).

The restore process, shown in Figure 2.9 and Figure 2.10 by **green** curves, started immediately due to a momentary outage with the earliest sustained restore occurring in 10 minutes. It then followed the usual pattern for most large events.[31] The maximum number of elements (55) and MVA capacity (16,788) simultaneously out, shown by the nadir of the respective blue performance curves, was reached approximately 28 hours into the event, and the system remained in this most degraded state for six 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,[32] the maximum instantaneous restore rate was 1.8 restores per hour, which was reached 13.7 hours into the event. At the time point when half of sustained outages were restored, the rate was 1.3 restores per hour, and it was only 0.07 restores per hour at the 95% element restoration level. The substantial restoration level when 95% of outages were restored was reached in 167.5 hours, or 31% of the event duration. The substantial restoration for transmission capacity (MVA) happened faster, 148.1 hours, or 27% of the event duration. The total loss for the event, calculated as the area between a blue performance curve and the time axis, was 164 element-days lost (Figure 2.9) and 62,675 MVA-days lost (Figure 2.10).

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[31] 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.

[32] S. Ekisheva, D. K. Pratt, M. Kachadurian, W. G. Martin, J. Norris, and I. Dobson, "Grid Restoration after Extreme Weather Events," 2023 IEEE PES Innovative Smart Grid Technologies Europe (ISGT) Conference.

The last unrestored outage in the event was 22.4 days, likely due to extensive damage of the 300–399 kV ac circuit. This is typical for large transmission events when few remaining elements are out either due to the inaccessibility of a portion of the line or a damaged structure or equipment. In some cases, this is attributable to a utility postponing the restoration of a single remaining element (or a few elements) after all other outages in the large event are restored because this outaged element is considered not critical for grid reliability.[33]

Transmission System Resilience Statistics by Associated Weather Type: 2019–2023

Weather Types

The outage grouping procedure identified 59 large transmission events in the years 2019–2023, only one of which was not weather-related (a 2023 contamination event).[34] The 58 large weather-related events were caused by the weather types listed in Figure 2.11. 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.

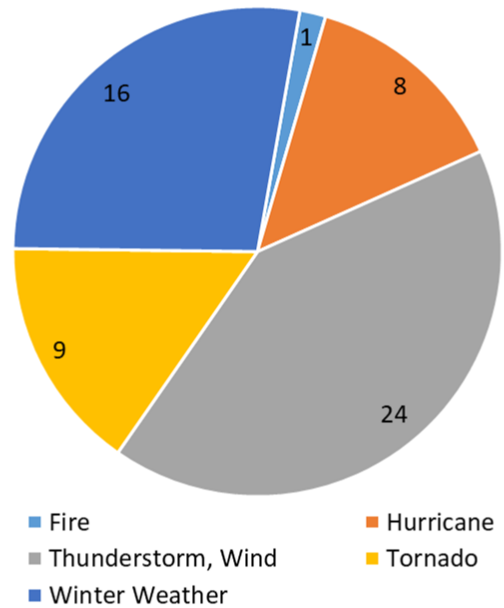


Figure 2.11: Weather Types of Large Transmission Events, 2019–2023

Figure 2.12 shows selected resilience statistics for the 2019–2023 events by weather type. Hurricanes caused the largest transmission events with an average size of 154 outages while other groups had average sizes that ranged from 40–59 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.

[33] 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.

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

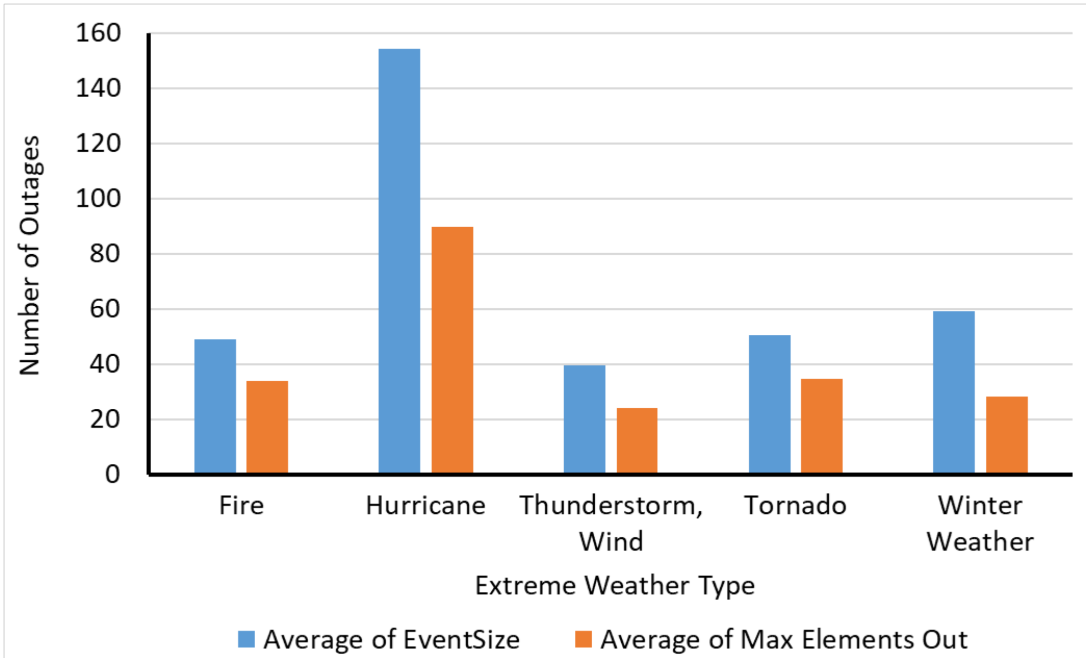


Figure 2.12: Resilience Statistics for 2019–2023 Large Weather-Related Events

Figure 2.13 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. The one fire event (2020 WECC wildfires) had a duration of 87 days, thus having a greater impact on this statistic due to the small group size. For other groups, the event duration is positively correlated with the event size. For all weather types, the time to restore 95% of outages (the substantial restoration level) is much shorter than the total event duration (on average, from 35% of the event duration for hurricanes to 52% of the event duration for tornadoes and thunderstorm, wind). The time to reach a restoration level of 95% MVA ranges from 29% of an event's duration for hurricanes to 63% for tornadoes. The first restore typically occurs inside one hour from the event start; hurricane events have the shortest average time to the first restore (34 minutes) among all groups. This indicates effective advanced preparation by utilities for these forecasted events. This is down two minutes from the 2017–2022 statistic calculated in the *2022 SOR* report, indicating that fast response to hurricanes is consistent.

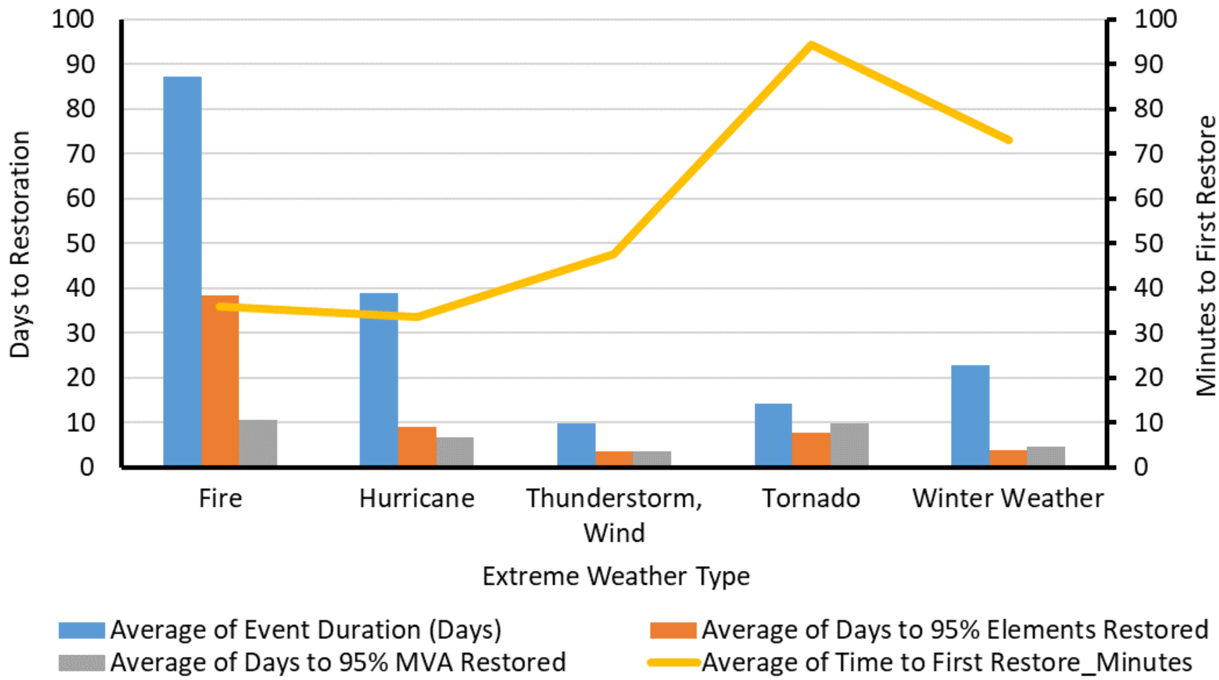


Figure 2.13: Average Event Duration vs. Average Sustained Restoration Duration

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.[35] 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: 2019–2023 Events vs. 2018–2022 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 2018–2022 and 2019–2023, 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 2.14 shows the groups of large weather-related transmission events by weather type; the five patterned bubbles correspond to the groups for combined 2018–2022 data, and the five solid-colored bubbles show the same groups for combined 2019–2023 data. The size of a bubble represents the group size. The X-axis of a bubble center shows the average time to restore 95% of outages for the events in this group; the Y-axis shows the average number of outages for the events. 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 2.14 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 2.14. The average MVA-day loss increased for all weather types due to some of the smaller events falling off from 2018, which is highlighted by the change of color for Fire and Winter Weather. The average event size of Hurricanes

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

increased due to the removal of several small hurricanes from 2018. The average MVA-day loss for the Fire category increased when a short 2018 fire (with approximately 6,000 MVA-day loss) dropped off.

The time to substantial restoration for all extreme weather types combined in 2023 decreased compared with the previous five years (from 5.3 to 4.3 days for element recovery and from 4.9 to 4.5 days for MVA recovery). Possible explanations could be improvements in transmission resilience and less severe weather events. Additional years of the outage data as well as incorporation in the analysis of more detailed weather data are needed for more reliable inferences.

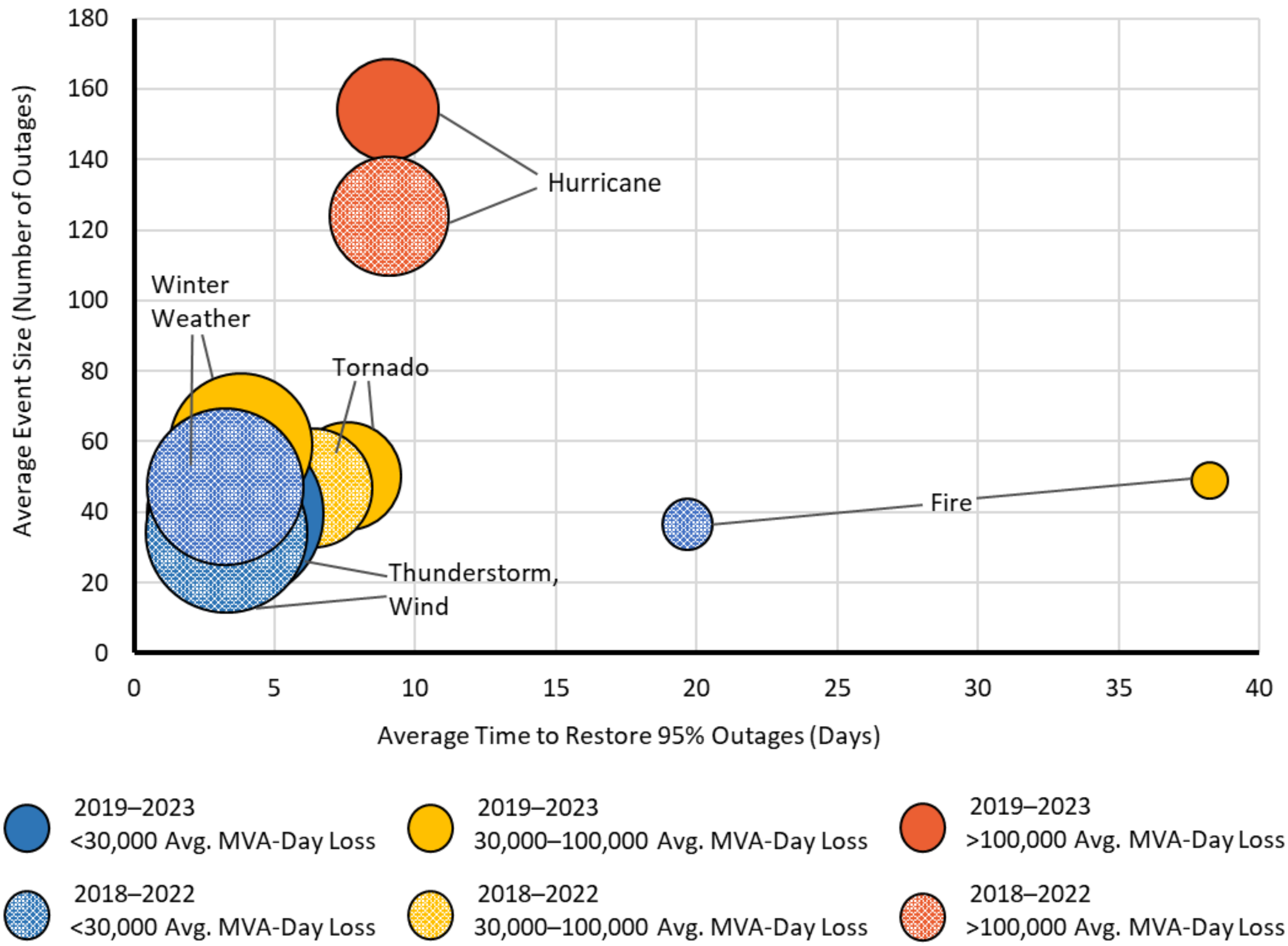


Figure 2.14: Statistics for Large Transmission Events by Weather Type for 2018–2022 vs. 2019–2023

Resource Adequacy

For this report, two measures of resource adequacy are examined for the **Energy Emergency Alerts** (EEA) section. 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.

2023 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.[36] It is calculated as the difference in anticipated resources and net internal demand divided by net internal demand and shown as a percentage.[37] Each assessment area's ARM is compared against its Reference Margin Level (RML)—the threshold margin established by the state, provincial authority, ISO/regional transmission organization (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 2023, all assessment areas 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 2023 to meet established resource adequacy targets. However, risks of electricity supply shortfalls arising from extreme weather, insufficient generator fuel supplies, or other energy limitations in the resource mix are not generally addressed by this traditional resource adequacy criteria.

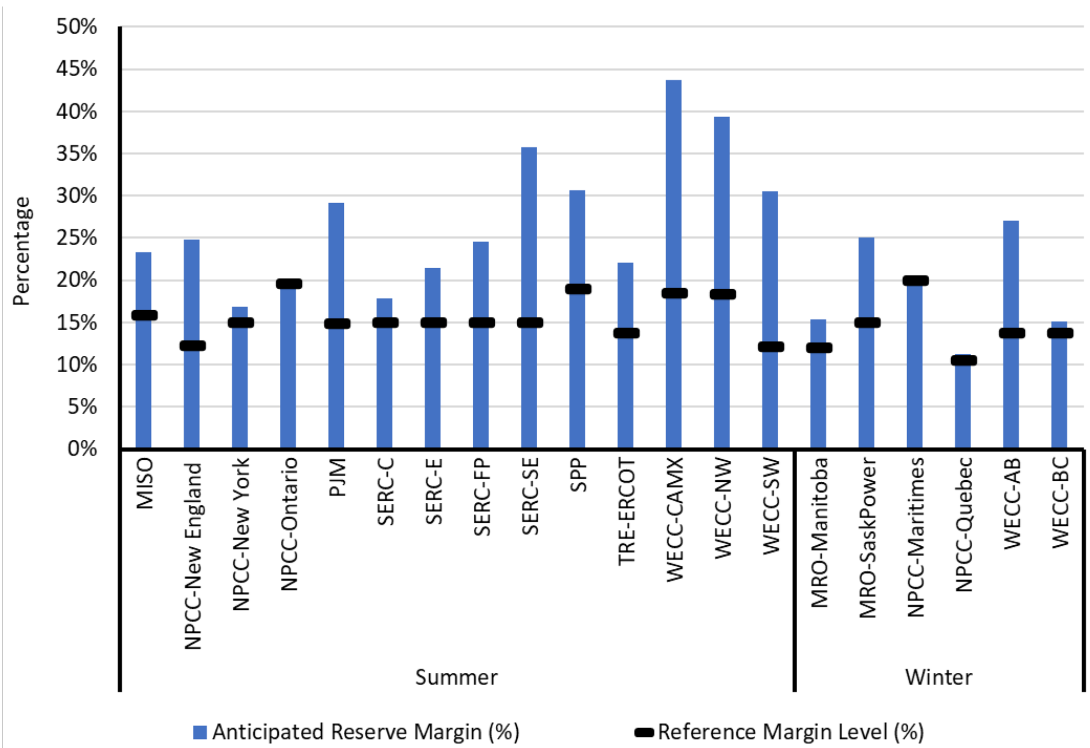


Figure 3.1: 2023 Peak Season Planning Reserve Margins and Reference Margin Levels[38]

[36] The peak demand season for an assessment area generally occurs when peak demand is highest or when planning reserves are lowest. For example, if an assessment area is summer peaking, that area experiences its highest demand levels during the summer months.

[37] Anticipated resources include all generating capacity and firm capacity transfers for the assessed summer and winter season. See the *2023 Long-Term Reliability Assessment* (*LTRA*) pp. 126–132 for complete definitions.

[38] M-1, Reserve Margin

2023 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. 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 2023[39] and Winter 2023–2024[40] seasons as at risk for resource deficiencies.

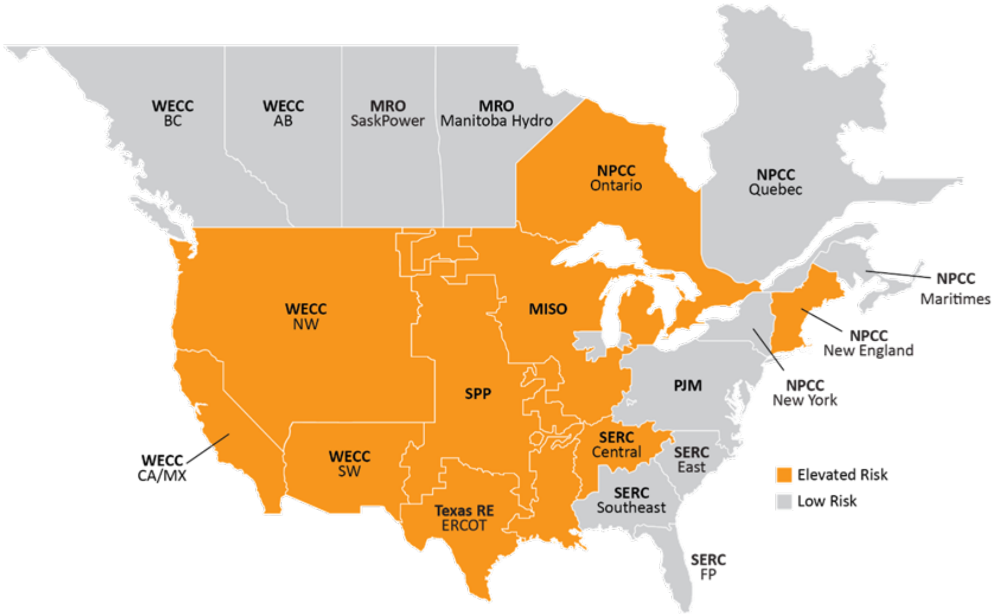


Figure 3.2: 2023 Summer Reliability Assessment Risk Area Map

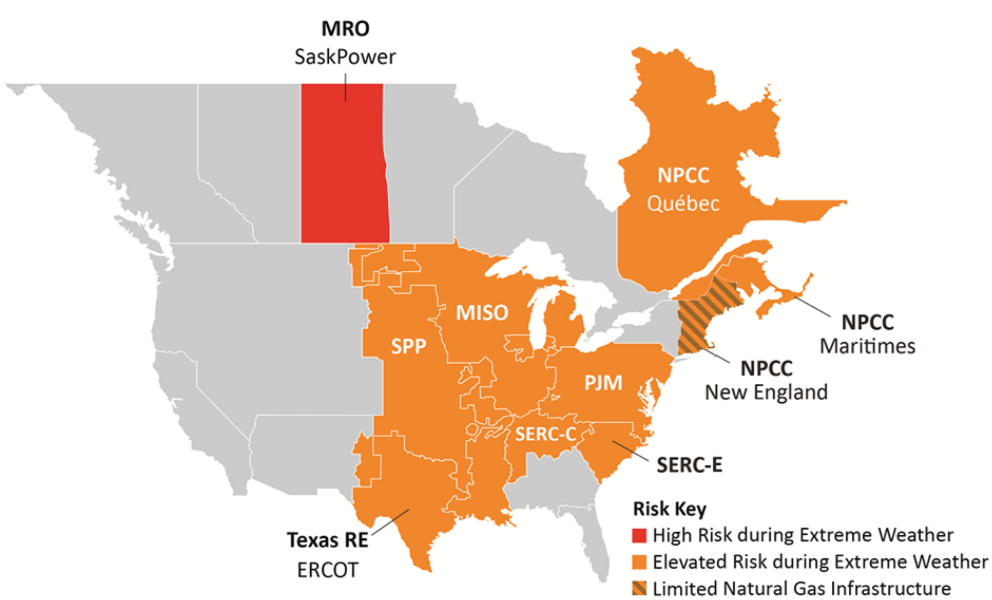


Figure 3.3: 2023–2024 Winter Reliability Assessment Risk Area Map

[39] NERC *2023 Summer Reliability Assessment*
[40] NERC *2023/2024 Winter Reliability Assessment*

2023 Capacity and Energy Performance

Actual operating conditions in 2023 stressed energy supplies to meet demand. In summer, high temperatures, wildfires, and weather conditions challenged electric grid operators in many parts of North America to maintain a reliable supply of electricity. It is noteworthy that, after a summer of soaring temperatures, extended heat waves, and new electricity demand records, few high-level EEAs were issued, and no disruptions occurred because of inadequate resources. Nonetheless, operators at BAs, TOPs, and RCs faced significant challenges and drew upon procedures and protocols to obtain all available resources, manage system demand, and ensure the flow of electricity over the transmission network. Additionally, load-serving entities and state and local officials in many parts of North America used mechanisms and public appeals to lower customer demand during periods of strained supplies. Table 3.1 and the following section describe actual demand and resource levels in comparison with NERC's *2023 SRA* and summarize 2023 resource adequacy events.

Eastern Interconnection–Canada and Québec Interconnection

Systems in parts of Canada experienced challenging conditions early in the summer from high electricity demand and wildfires over large areas. Electricity transfers from Québec to the neighboring Maritimes and New England were curtailed or disrupted during periods in May and June, when wildfires affected transmission facilities. Peak electricity demand in Ontario occurred in early September at a level near the 90/10 demand forecast. Additional imports helped the area meet the extreme demand.

Manitoba Hydro and SaskPower both experienced peak electricity demand in excess of 90/10 summer forecasts. Manitoba Hydro's peak occurred at the start of summer in June. Operators had sufficient reserves and were able to export supplies during the peak period to neighboring areas.

SaskPower peak electricity demand occurred in late July. A forced outage at a large thermal generator early in the summer contributed to operating challenges over much of the summer period. At the time of peak demand, forced outages were significantly higher than typical for summer peak periods.

Eastern Interconnection–United States

In Southwest Power Pool (SPP), summer electricity demand peaked in August and exceeded 90/10 forecasts. At the hour of peak demand, SPP experienced normal levels of forced thermal generation outages. Wind resource performance at the time of peak demand exceeded seasonal peak forecasts, helping to alleviate the strain on supplies. However, during periods in June and July, operators at SPP issued resource advisories during periods of forecasted high demand and low or uncertain wind resource output.

Midcontinent Independent System Operator (MISO) also experienced peak electricity demand during the same period in August; however, demand was between the normal and 90/10 summer peak forecast levels. Wind and solar resource output at the time of peak demand were below expectations for summer on-peak contributions. However, forced outages of thermal units were lower than expected. A Level 2 EEA was issued in August due to high forecasted loads and wind uncertainty. MISO used operating procedures to ensure that sufficient reserves were maintained during periods of high electricity demand and high forced generator outages at times throughout the summer.

PJM experienced peak electricity demand in late July at a level between normal summer peak and the 90/10 forecast. Wind and solar resource output were below seasonal peak expectations while low thermal generator outages were reported.

Peak electricity demand at NYISO and ISO-NE occurred in early September and fell below average summer peak forecasts.

Systems in the U.S. Southeast experienced peak demand above the 90/10 forecasts in mid to late August. Solar resource output exceeded the expected contributions for the peak demand period. Electricity imports into resource-constrained areas helped BAs maintain reserves during high-demand periods.

ERCOT

Extended heat waves led to record-setting system electricity demand in the ERCOT system throughout Summer 2023. Peak electricity demand occurred in mid-August at a level exceeding the 90/10 demand forecast. Simultaneous with peak demand, wind and solar generation were slightly below expected levels for peak demand periods, and thermal generator outages were also slightly higher than normal for peak periods. Nonetheless, operators were able to maintain sufficient reserves. At various times throughout the summer, ERCOT issued public appeals for conservation to help manage high-demand periods and periods when output from the solar resources is diminished (e.g., evenings). On September 6, ERCOT declared a Level 2 EEA to address a low-frequency condition on the system during a period of unusually high demand, declining solar output, and low wind output. Transmission system constraints led to the curtailment of some generation from wind resources in southern parts of the system. No load was shed during the event.

Western Interconnection–Canada

At the start of summer, the province of Alberta was in a state of emergency because of active wildfires and the threat of spreading from hot and dry conditions. A period of high demand from heat and humidity that coincided with generator forced outages and low wind conditions triggered an EEA. Alberta's system peak demand occurred in late July at a level above normal summer peak demand forecasts but below the 90/10 level. Wind and solar resource outputs were above seasonal forecast levels for peak demand periods. High temperatures in late August led to high demand at a time of planned transmission system maintenance. A Level 3 EEA was triggered when low wind conditions and insufficient imports resulted in reserve shortage.

The BC-Hydro system also experienced peak electricity demand in early August at a level near the 90/10 summer peak forecast.

Western Interconnection–United States

The California-Mexico assessment area, which consists of the CAISO, Northern California, and CENACE BAs, experienced system peak electricity demand in mid-August between the average summer peak demand forecast and the 90/10 peak demand forecast. Public appeals to shift electricity use to off-peak hours were used during some high-demand periods. The Mexico portion of the assessment area faced reserve shortages during periods in July and August because of high demand, generator outages, and unavailability of imports.

System peak electricity demand in the U.S. Northwest also occurred in mid-August and was below normal summer peak demand forecasts.

The U.S. Southwest experienced extended heat conditions and demand levels that exceeded normal summer peak demand forecasts. Wind and solar output also exceeded the expected levels for peak demand periods.

Table 3.1: 2023 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	120,781	116,825 123,871	8,598	5,488	2,096	3,750	6,638
MRO-Manitoba Hydro	3,529	3,060 3,390	83	47	-		95
MRO-SaskPower	3,669	3,489 3,633	381	203	15		737
MRO-SPP	56,048	52,626 55,126	8,278	4,500	130	378	6,533

Table 3.1: 2023 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)**
NPCC-Maritimes	3,544	3,284 3,625	131	255	40	-	1,690*
NPCC-New England	23,475	24,664 26,479	186	186	145	1,163	1,969
NPCC-New York	30,206	30,823 32,657	223	331	-	84	9,716
NPCC-Ontario	23,713	21,752 23,731	786	771	200	126	3,419*
NPCC-Québec	22,531	22,859 22,859	496	-	8		12,287*
PJM	147,605	141,771 162,666	1,278	1,688	1,826	2,984	8,020
SERC-C	44,011	40,313 42,967	15	564	673	511	1,225
SERC-E	43,307	42,881 45,606	-	-	3,032	1,473	2,129
SERC-FP	54,139	49,297 52,416	-	-	4,590	4,534	1,610
SERC-SE	45,558	44,117 44,834	-	-	2,781	4,647	2,334
TRE-ERCOT	85,432	78,927 82,316	9,557	10,293	10,431	12,509	6,699
WECC-AB	11,522	11,206 11,596	906	309	894	763	-
WECC-BC	9,157	8,636 9,234	373	137	0	1	-
WECC-CA/MX	54,130	55,494 67,344	1,074	1,111	6,930	14,489	2,444
WECC-NW	57,417	65,328 71,956	2,137	593	3,821	1,411	4,855
WECC-SW	31,689	25,612 27,992	835	3,968	1,731	5,062	2,507

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. 14–33). Values represent the normal summer peak demand forecast and an extreme peak demand forecast that represents a 90/10, or once-per-decade, peak demand. Some areas use other basis for extreme peak demand.

[3] Expected values of wind and solar resources from the *2023 SRA*.

[4] Values from NERC Generator Availability Data System or provided by NERC entities for the 2023 summer hour of peak demand in each assessment area. Values marked with * include both planned and forced outages.

Operators issued Level 3 EEAs over five periods during the summer months because of projected reserve deficiencies from insufficient electricity supplies to meet forecasted demand. Table 3.2 provides an overview of resource and energy adequacy EEAs. This count of EEAs excludes events that resulted from transmission outages or storm damage to transmission.

Table 3.2: 2023 Resource and Energy EEA-3 Summary			
Date (2023)	**Regional Entity**	**EEA Description**	**NERC Seasonal Assessment Indication**
June 7 and 12	MRO WECC (Canada Assessment Areas)	Heat and humidity contributed to high demand and thermal generator outages and derates. Low wind conditions caused wind resource output to be below seasonal norms. Some interruptible load was affected, but no firm load was shed.	**Low Risk**
July 26	WECC (Mexico Area)	High electricity demand, generator outages within the area, and transmission system congestion resulted in a reserve shortage. No load shed.	**Elevated Risk**
July 31–August 4, and August 14	MRO (Canadian Assessment Area)	Thermal generator outages and low wind conditions resulted in insufficient reserves during forecasted peak demand; periods of interruptible load shed were required to maintain reserves. No firm load was shed.	**Low Risk**
August 16	WECC (Mexico Area)	The Mexico assessment area experienced reserve deficiency when all BA resources were committed and imports from neighboring areas were curtailed during early evening hours. No firm load was shed.	**Elevated Risk**
August 28–29	WECC (Canada Assessment Area)	High temperatures caused high demand during periods when planned maintenance on a major transmission line reduced imports. Low wind conditions reduced wind generator output. No firm load was shed.	**Low Risk**

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 over 122 GW and reduced its capacity of nuclear generation by 9 GW. During this time, the BPS added on-peak generation capacity: 73 GW of natural gas, 21 GW of wind, and 57 GW of solar PV.[41]

Table 3.3: Generation Resource Capacity by Fuel Type				
Generation Fuel Type	**2013 On-Peak**		**2023 On-Peak**	
	GW	**Percent**	**GW**	**Percent**
Coal	318.0	30.1%	195.3	18.4%
Natural Gas	412.0	39.0%	485.3	45.8%
Hydro	138.9	13.2%	124.5	11.7%
Nuclear	115.2	10.9%	106.2	10.0%
Oil	48.9	4.6%	32.1	3.0%
Wind	11.6	1.1%	32.8	3.1%
Solar PV	2.0	0.2%	59.7	5.6%
Other	8.5	0.8%	24.4	2.3%
Total:	**1055.0**	**100.0%**	**1,060.2**	**100.0%**

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

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 2013.

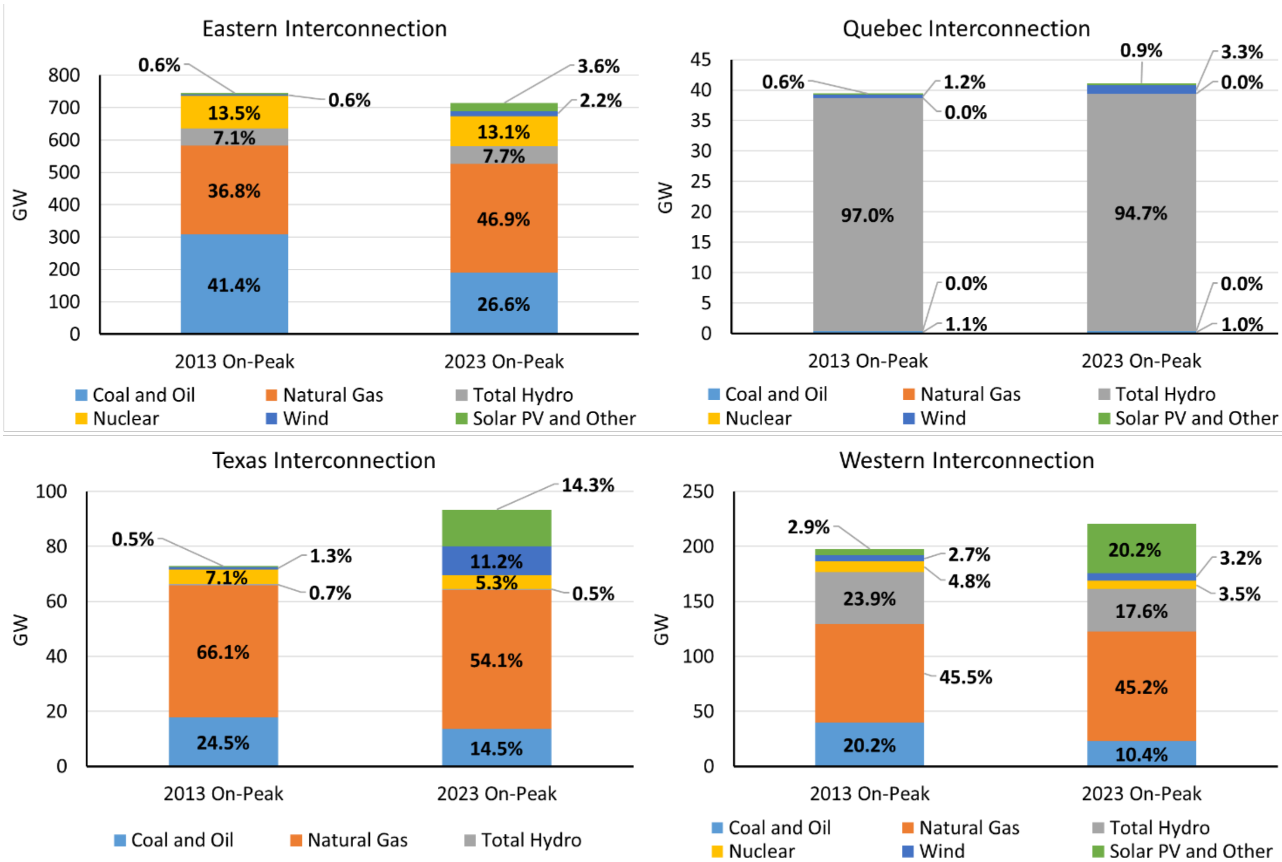


Figure 3.4: 2013 and 2023 Capacity Resource Mix by Interconnection

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 *2023 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 have a deliverable electricity supply from new resources to changing types of loads and the ability to withstand system contingencies.

Critical Infrastructure Interdependencies

In addition to an increased reliance on weather-dependent fuels, such as wind and solar, today's generation resource mix includes more natural gas-fueled generation than ever before. Figure 3.5,[42] prepared by the Energy Information Agency (EIA), shows the average natural gas generation by dispatch hour for the years 2021–2023.

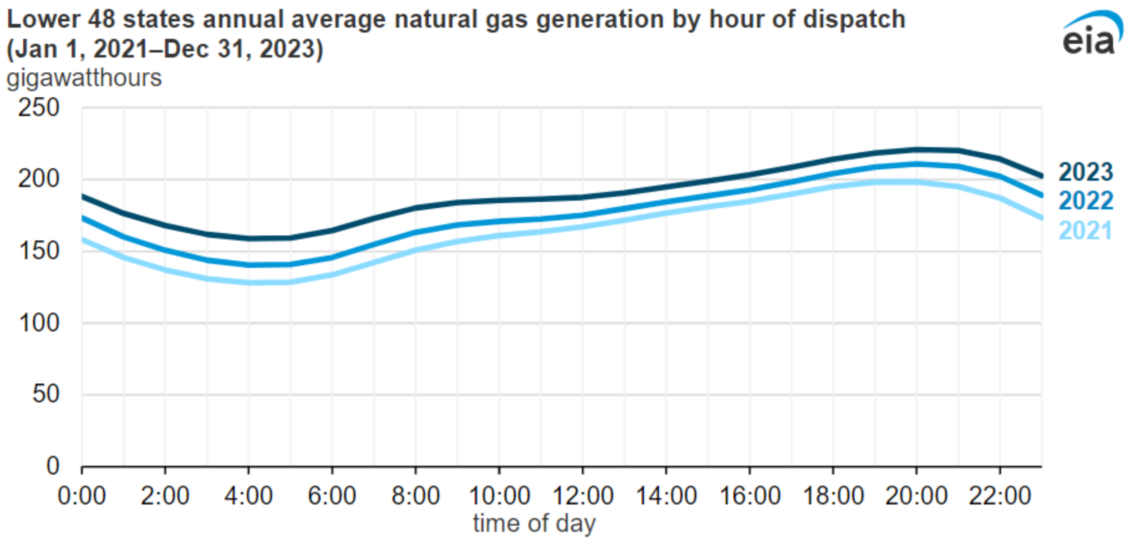


Figure 3.5: Lower 48 States Annual Average Natural Gas Generation by Hour of Dispatch

The supply and delivery of natural gas to power plants depends on the reliable operation of natural gas production, gathering, processing, and delivery facilities that in turn often rely on electricity as a prime mover. The same is true of the water supply, whether it will be used to directly generate electricity or to cool another generator, it is often managed and controlled by third-party infrastructure powered by electricity. Figure 3.6 and Figure 3.7 show generation outages over the past five years that have been attributed to a lack of natural gas fuel or water supply availability issues.

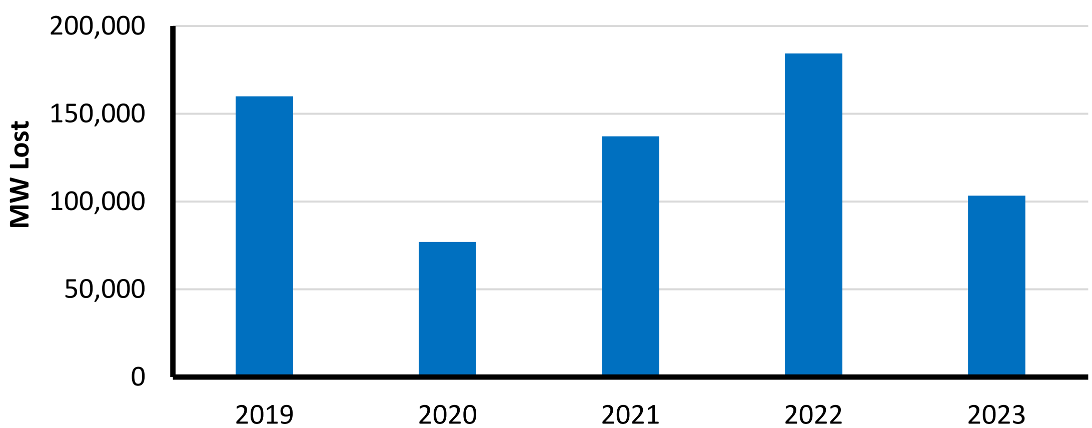


Figure 3.6: Natural-Gas-Fired Outages Due to Lack of Fuel

[42] U.S. natural gas-fired electricity generation consistently increased in 2022 and 2023 - U.S. Energy Information Administration (EIA)

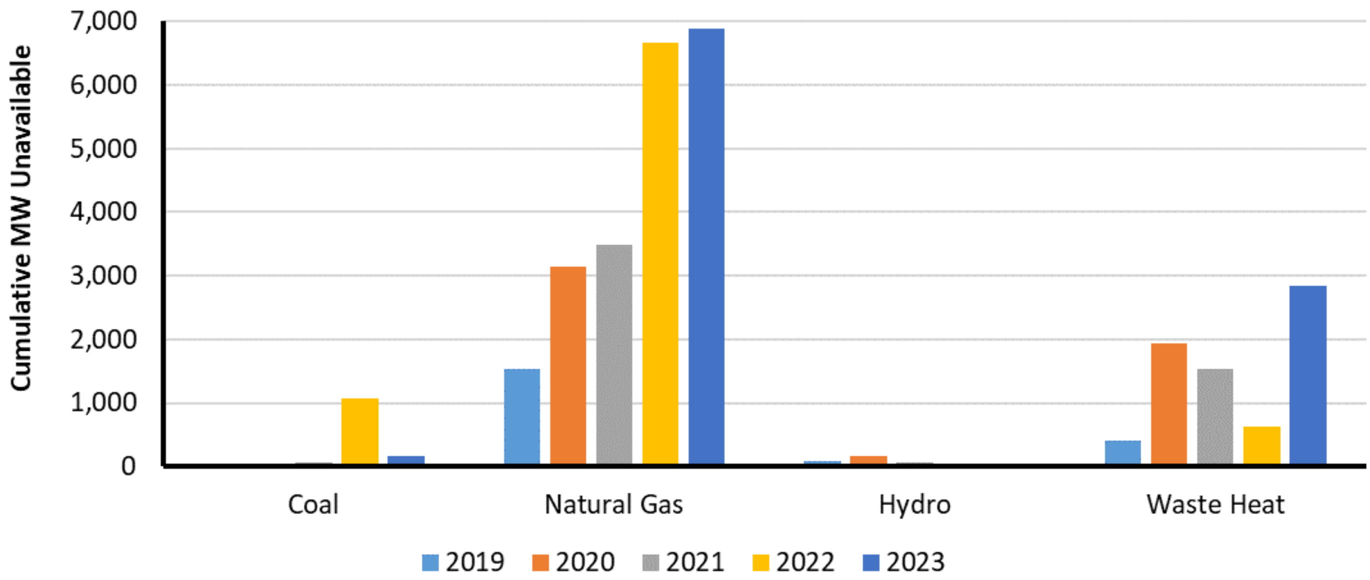


Figure 3.7: Cumulative MW–Water Supply Issues by Year

As natural gas continues to fuel more base and intermediate loaded generation, extreme weather events have highlighted the risks of the natural gas and electric industries' mutual reliance. The risk is particularly acute in winter when natural gas demand for home and commercial space heating coincides with high electricity demand. This risk was realized in February 2021 when extreme cold weather descended upon the U.S. central southwest. The resulting gas production declines, pipeline force majeures, and generator outages led to electrical energy deficiencies and load shedding, which in turn exacerbated gas unavailability issues. Since that time, efforts to maintain gas production and pipeline availability during cold weather, notably in Texas, as well as NERC and industry actions to improve cold weather generator availability, have been developed and many have been implemented.[43,44,45,46]

In October 2023, FERC and the ERO Enterprise published the official report on Winter Storm Elliott. Previously identified electric–gas interdependencies were less of a contributing factor to the electrical energy deficiencies than what occurred during the February 2021 winter storm. Energy-deficient balancing areas shed much less load than in February 2021, and gas production facilities were not impacted. The report identifies the degree to which facilities essential to the production and delivery of natural gas have still not been identified to balancing area operators as critical electrical loads, which remains a risk for future cold weather events.[47] Risks emanating from the interconnected electric–gas energy delivery system were also highlighted.[48]

[43] Fuel Assurance and Fuel-Related Reliability Risk Analysis Guideline
[44] Considerations for Performing an Energy Reliability Assessment
[45] Project 2022-03 Energy Assurance with Energy-Constrained Resources
[46] Project 2023-07 Transmission System Planning Performance Requirements for Extreme Weather
[47] WS Elliott Report Recommendation 4(c) addresses this risk.
[48] See, generally, WS Elliott Report, pp 76-88.

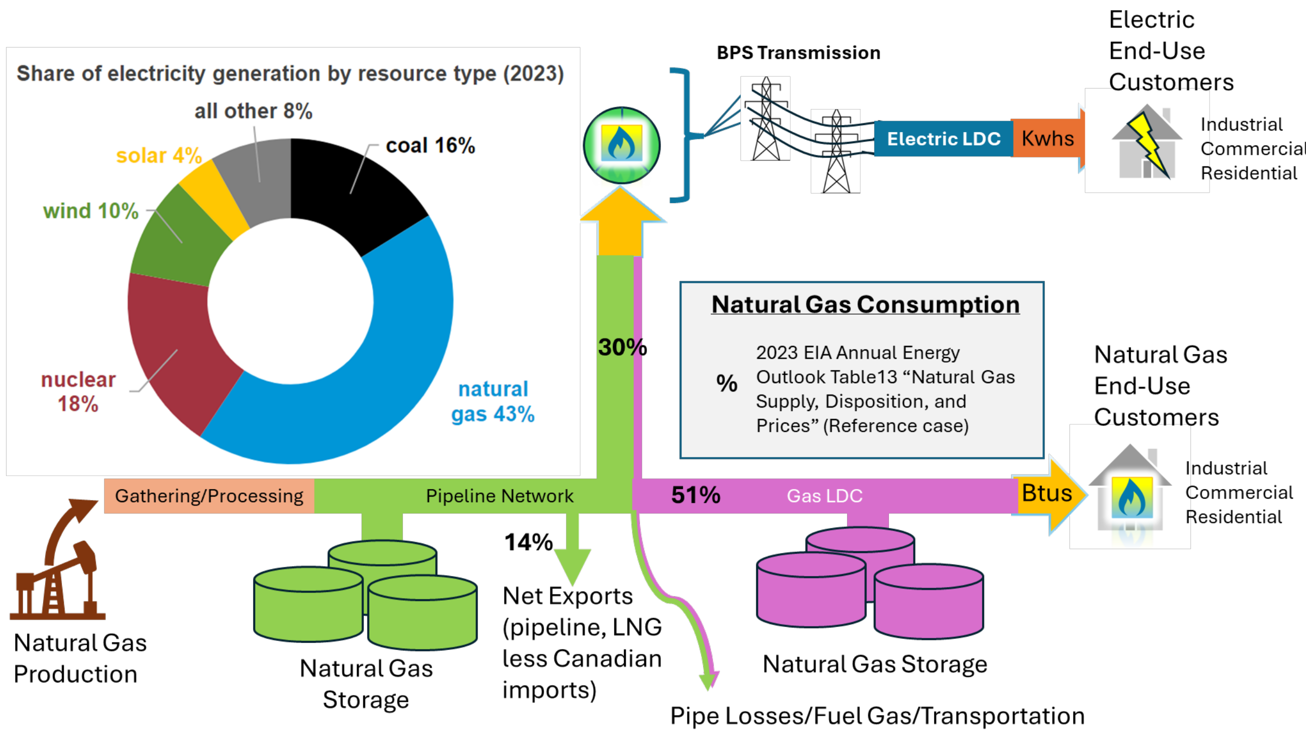


Figure 3.8: The Interconnected Gas and Electric Energy Delivery System[49,50]

Utilizing data from the EIA's 2023 Annual Energy Outlook, Figure 3.8 shows the annual generation by fuel type and natural gas consumption by end-use sector percentages. Industrial, commercial, and residential end users account for 51% of all natural gas use in the United States. Power generators use 30% of all natural gas to produce electricity, representing 37% of all electrical energy delivered. Extreme cold weather can significantly increase demand for natural gas by power generators and residential/commercial end-use customers well above these annual averages. For example, during the December 2022 event, the U.S. Northeast/Midwest/Southeast regions' natural gas consumption51 by electric generators temporarily increased by roughly 15% while consumption of natural gas by residential and commercial end-use gas customers increased by nearly 50% (shown in Table 3.4).[52]

Table 3.4: Overall and Relative Increase in Natural Gas Consumption for the Northeast, Midwest, and Southeast Regions during Winter Storm Elliott Billion Cubic Feet per Day (Bcf/day)[53]

	Dec. 15–20, 2022 Average	Dec. 21–26, 2022 Average	Percent Change
Northeast/Midwest/Southeast Natural Gas Demand	82.3	100.5	22.1%
Power Burn	21.2	24.6	15.8%
Residential/Commercial	31.4	46.0	46.5%
Industrial	15.3	16.5	7.9%
LNG Feedgas	10.6	8.5	-19.8%
Pipe Loss	3.9	5.0	29.2%

49 Annual gas consumption percentages EIA 2023 Annual Energy Outlook
50 Annual electric energy from fuel type EIA 2023
51 Consumption does not include demand unmet due to fuel unavailability.
52 WS Elliott Report, Fig. 92.
53 WS Elliott Report, Fig. 92

This increased consumption, in combination with natural gas supply interruptions during extreme cold weather periods, challenges both grid operators and gas controllers to maintain energy deliveries to end-use customers when conditions can be life threatening. While the gas industry has long relied upon natural gas storage to manage spikes in consumption and mitigate the risk of supply interruption, electric generators typically do not store natural gas, and electric energy storage at utility scale is not currently available to overcome this risk.

Winter Storm Elliott Report Recommendation 5 addresses situational awareness issues by urging grid operators and gas controllers from across the interconnected natural gas–electric production and energy delivery system to quickly develop and formalize protocols to communicate operational issues leading up to and during extreme weather events.[54] Longer term, Recommendation 4 of the Winter Storm Elliott report calls for the creation of a natural gas reliability organization to develop rules that would require natural gas wellhead, gathering, processing, and transportation infrastructure cold weather preparations to maintain natural gas availability and energy deliveries to end-use customers when needed most.[55]

6 GHz Frequency Communications

In April 2020, the Federal Communications Commission (FCC) opened usage of the 6 GHz[56] spectrum to new users to promote spectrum sharing. Sharing this spectrum will likely impact the energy industry (specifically critical infrastructure) and BPS reliability. The industry and incumbent users continue to conduct testing on potential harmful interference for BPS communications.

In support of industry awareness and strengthening reliability, the 6 GHz Task Force published its *6 GHz Microwave Link Interference Preparedness*[57] white paper in December 2023. This white paper provides valuable background information on the current state of the FCC processes, current spectrum usage, and recommendations for the industry to assist with baseline understanding, the identification of potential harmful interference, and mitigation options to offset impacts from harmful interference. Additionally, the 6 GHz Task Force plans to conduct an awareness webinar in the second quarter of 2024.

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 IBRs 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 proliferate, it is imperative to cultivate agile, adaptive solutions.

Protection System Misoperation Trends

Figure 3.9 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 Texas RE. No statistically significant trend is observed for any other Regional Entity, nor within the overall MIDAS data. The overall count of misoperations in 2023 was the lowest over the past five years (see Table 3.5).

[54] WS Elliott Report, p. 143.
[55] WS Elliott Report, p. 137.
[56] *6 GHz Communication Penetration in the Electric Industry*, April 23, 2024
[57] *6 GHz Microwave Link Interference Preparedness*

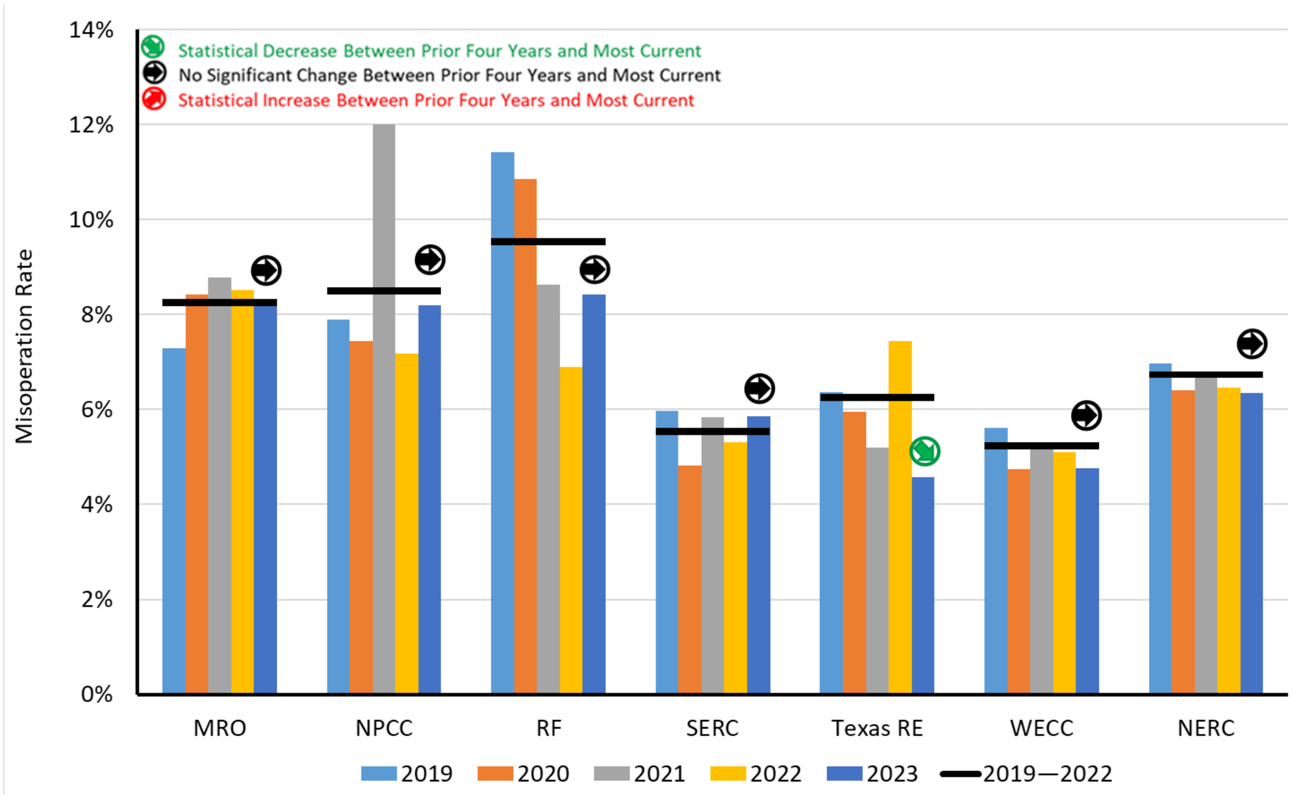


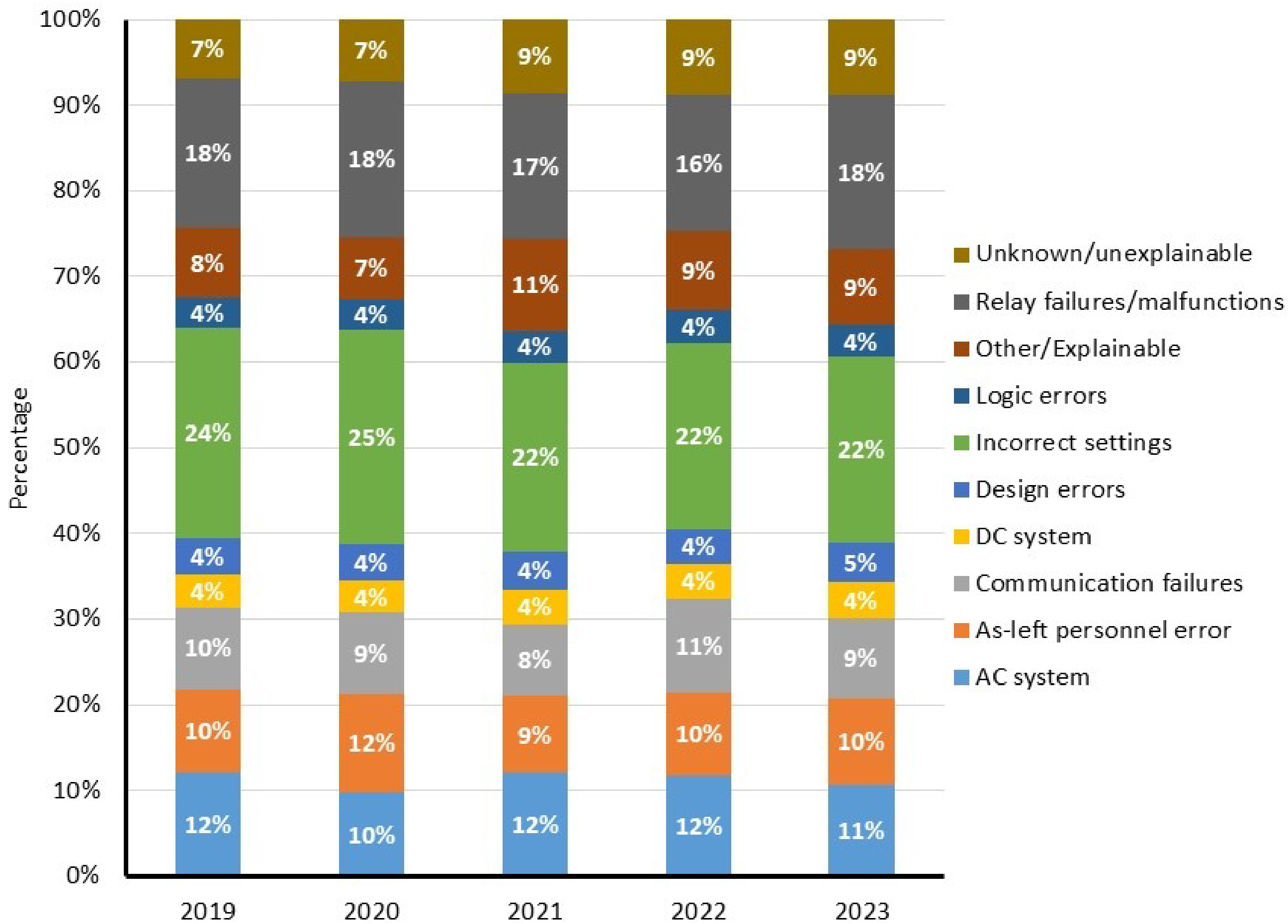
Figure 3.9: Changes and Trends in the Annual Misoperations Rate by Regional Entity[58]

Table 3.5: Five-Year Protection System Operations and Misoperations Counts 2019–2023										
Area	Protection System Operations					Misoperations				
	2019	2020	2021	2022	2023	2019	2020	2021	2022	2023
North America	19,283	18,306	17,460	18,012	17,821	13,44	1,172	1,187	1,163	1,131
MRO	3,734	3,054	2,617	3,299	2,999	272	257	230	281	247
NPCC	1,658	1,774	1,365	1,811	1,744	131	132	164	130	143
RF	2,146	1,888	1,867	2,061	1,865	245	205	161	142	157
SERC	4,736	5,267	4,622	4,775	4,894	283	254	270	254	287
Texas RE	2,640	2,000	2,599	1,991	2,182	168	119	135	148	100
WECC	4,369	4,323	4,390	4,075	4,137	245	205	227	208	197

Leading Causes of Misoperations

Figure 3.10 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 2022 to 2023.

[58] M-9, Protection System Misoperations Rate



Year	2019	2020	2021	2022	2023
Misoperation Count	1,344	1,172	1,187	1,163	1,131

Figure 3.10: Percentage of Misoperations by Cause Code (2019–2023)

Misoperation Impact Score

The misoperation impact score provides an 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 (shown in the equation and Table 3.6 below). Note that this calculation can be scaled down to an individual misoperation. In this report, the results are aggregated and then plotted in a box and whisker plot to identify potential trends.

$$[Misoperation\ Impact\ Score] = [Voltage\ Class\ Factor] * 0.3 + [Equipment\ Type\ Factor] * 0.2 + [Cause\ Factor] * 0.1 + [Category\ Factor] * 0.4$$

Table 3.6: Generation Resource Capacity by Fuel Type Misoperation Impact Factors

Field	Value	Factor
Voltage Class	0–99 kV	0.4
	100–199 kV	0.5
	200–299 kV	0.65
	300–499 kV	0.85
	500–765 kV	1
Equipment Type	BES UFLS, BES UVLS	0.333
	Shunt Capacitor, Shunt Reactor/Inductor	0.5
	HVdc, Line, Series Capacitor, Series Reactor/Inductor, Transformer, Breaker	0.667

Table 3.6: Generation Resource Capacity by Fuel Type Misoperation Impact Factors		
Field	**Value**	**Factor**
	Bus, Other	0.833
	Dynamic VAR Systems, Generator	1
Cause	Equipment Errors (and Other)	0.5
	Human Errors	0.85
	Unknown	1
Category	Slow Trip–Other than Fault	0.167
	Unnecessary Trip–Other than Fault	0.333
	Failure to Trip–Other than Fault, Unnecessary Trip–During Fault	0.667
	Failure to Trip–During Fault, Slow Trip–During Fault	1

The median and inner quartiles of all misoperations' impact scores (see Figure 3.**11**) have remained largely unchanged over the past five years, while the number of outliers has decreased. The Duncan's grouping test[59] confirms that the mean impact score for 2023 was statistically similar to 2021 and 2022 but statistically lower than in 2019 and 2020. These factors (in combination with the slowly decreasing but statistically stable misoperation rate, number of misoperations, and cause distribution) indicate that work being done to reduce misoperations is continuing. The ERO and industry should continue to monitor and coordinate to identify any common issues to further drive down misoperations and their severity.

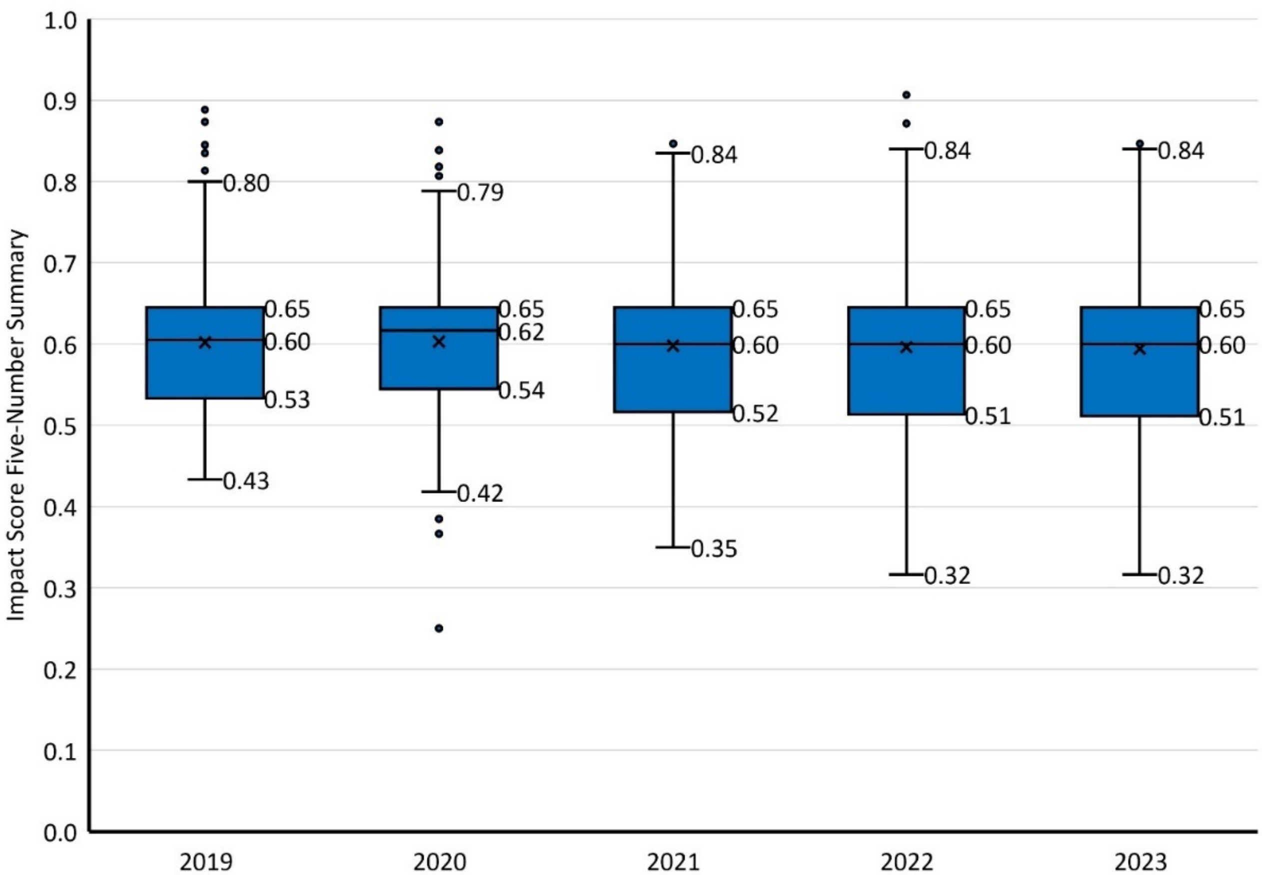


Figure 3.11: Misoperations Impact Score Distribution (2019–2023)

Year	2019	2020	2021	2022	2023
Total Impact Score	808.98	706.88	709.91	693.41	671.50

[59] Duncan, David B. "Multiple Range and Multiple F Tests." *Biometrics* 11, No. 1 (1955): 1–42. https://doi.org/10.2307/3001478.

Protection System Failures Leading to Transmission Outages

AC circuits and transformers saw a decrease in the number of outages per element in 2023, resulting in the number of outages per ac circuit being statistically significantly lower than the prior four years (see Figure 3.12).

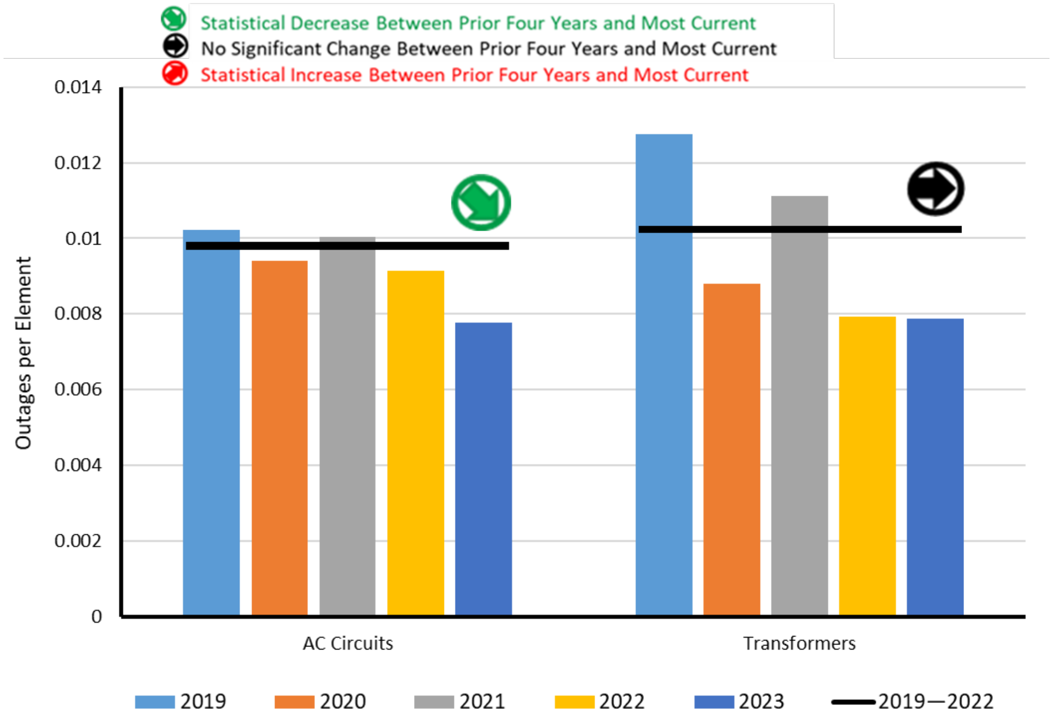


Figure 3.12: Failed Protection System Equipment Outages[60]

Event-Related Misoperations

An analysis of qualified events reported through the ERO Event Analysis Process (EAP) found that there were 72 transmission-related qualified events in 2023, 36 of which (50%) involved misoperations (see Figure 3.13). In comparison, 2019 saw 76 transmission-related qualified events, of which 41 (54%) had associated misoperations. This reduction is attributed to the ERO and industry stakeholder efforts to reduce protection system misoperations through initiatives such as various task forces, workshops, and more granular root-cause analysis.

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

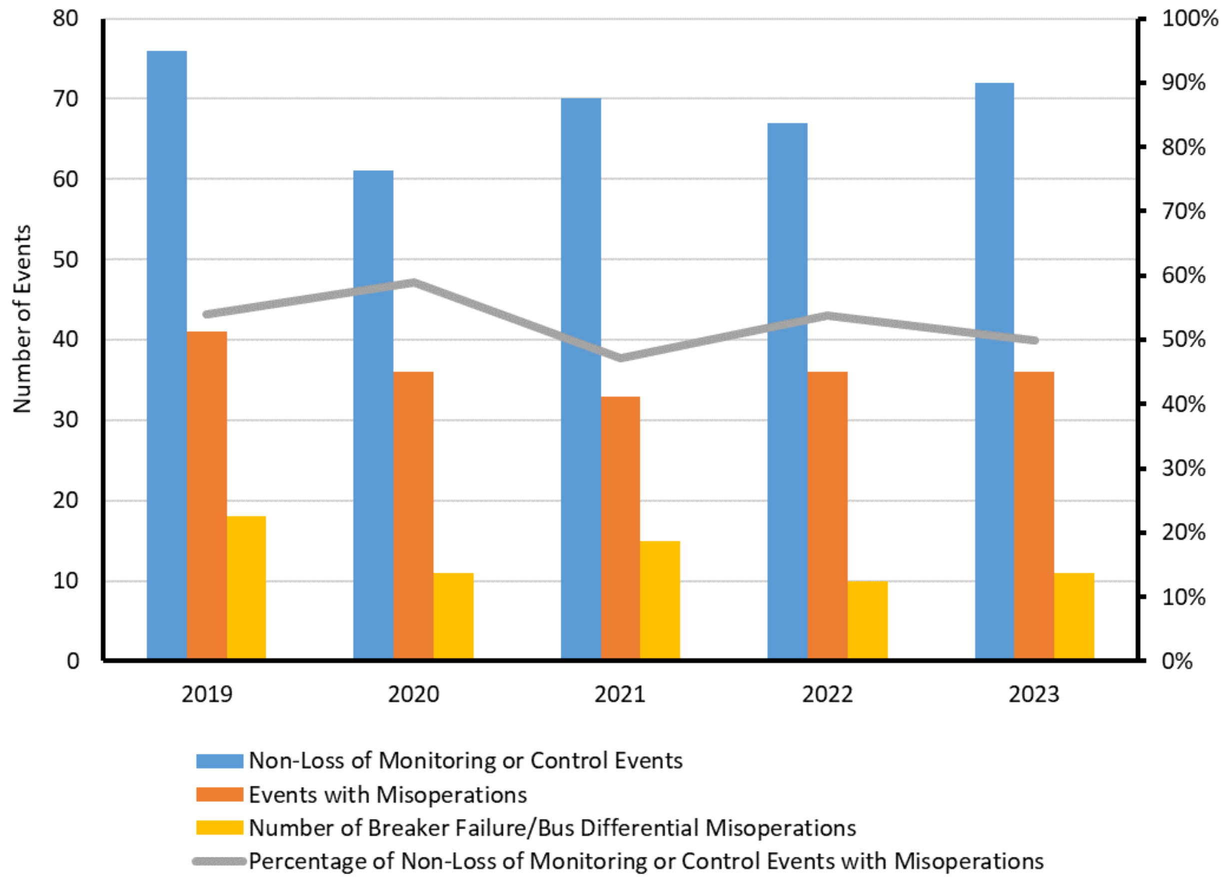


Figure 3.13: Events with Misoperations

Loss of Situational Awareness

The BPS operates in a dynamic environment with physical properties that are constantly changing. Situational awareness is necessary to maintain reliability, anticipate events, and respond appropriately when or before events occur. To maintain the reliability of the BPS, entities use various situational awareness tools, including energy management systems (EMS), transmission outage planning, load forecasting, geomagnetic disturbance/weather forecasting, data from neighboring entities' operations, and interpersonal communication within their own companies and with neighboring systems.

Without the appropriate tools and up-to-date data, system operators may have degraded situational awareness that impacts their ability to make informed decisions regarding BPS reliability. Unexpected outages of systems needed for communications or monitoring and control of equipment, as well as planned outages without appropriate coordination or oversight, can leave system operators with reduced visibility. For system operators, the EMS is a critical component of situational awareness.

At the same time, security risks have implications for industry that require a broadened perspective from what was traditionally addressed in conventional engineering practices, such as planning, design, and operations. The *2023 ERO Reliability Risk Priorities Report*[61] continued to highlight security risks as one of the four top risks for the electricity 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-aided set of tools used by system operators as a primary means to monitor, control, and optimize the performance of the generation and/or transmission system. The EMS allows system operators to monitor and control frequency, the status (open or closed) of switching devices plus real and reactive power flows

[61] *2023 ERO Risk Priorities Report*, August 2023

on BPS tie-lines and transmission facilities within the respective control area, and the status of critical applicable EMS applications (e.g., state estimator (SE), real-time contingency analysis (RTCA), automatic generation control, alarm management).

There were 32 categorized events associated with an EMS in 2023; there were no reported EMS-related events that caused loss of generation, transmission lines, or customer load. Figure 3.14 shows a trend of the reported EMS events by loss of EMS functions over the 2019–2023 period.

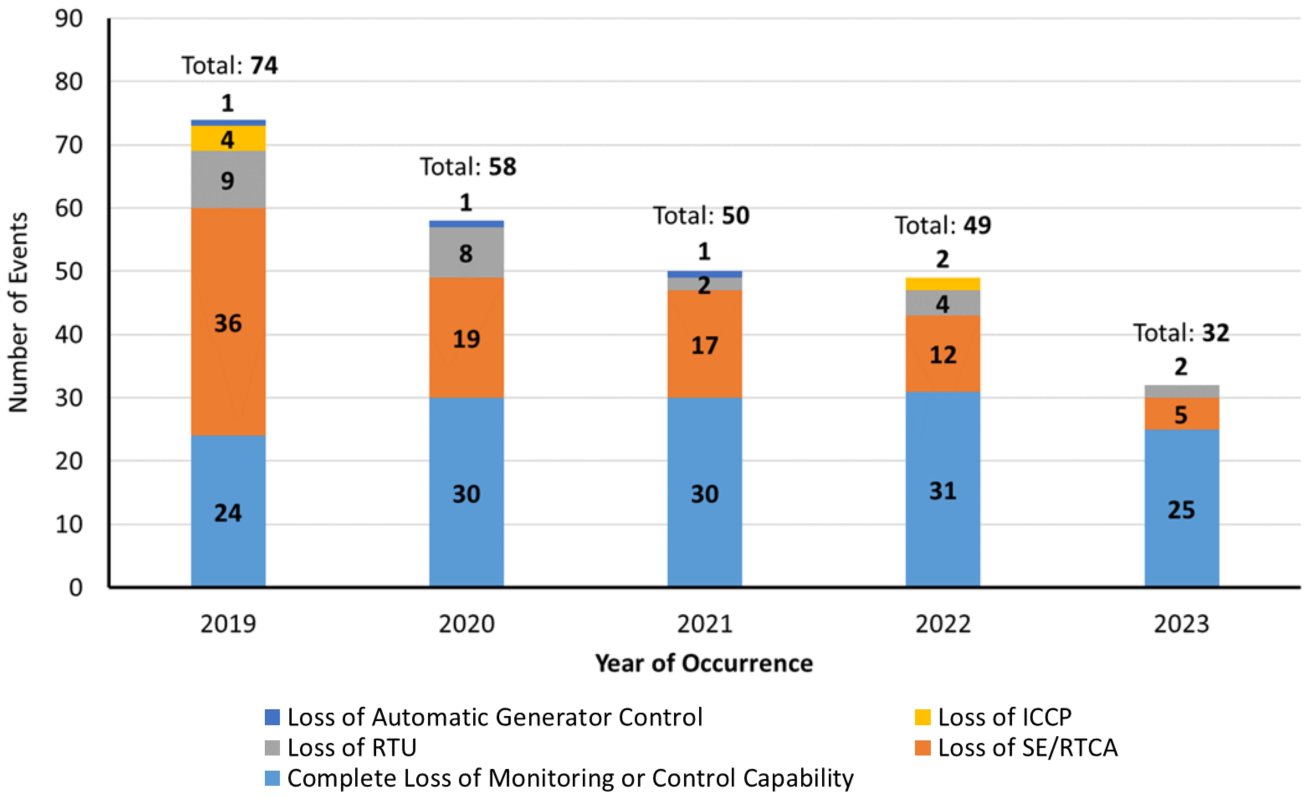


Figure 3.14: Number of EMS-Related Events (2019–2023)

There are two main reasons for the declining trend of the loss of SE/RTCA and Inter-Control Center Protocol (ICCP) events since 2019:

- **Changes to Work Environment**
  The industry has made major efforts to enhance EMS reliability and resilience. For example, many entities built a 24x7 onsite team that works with system operators and provides dedicated support to SE and RTCA. This action has reduced the outage duration, resulting in many SE/RTCA issues not being reportable.

- **Changes to Reporting**
  Partial loss events (i.e., loss of SE/RTCA, loss of ICCP, loss of remote terminal units (RTU), and loss of automatic generation control) are no longer captured as part of EOP-004-4[62] mandatory reporting (effective April 1, 2019). However, the ERO encourages partial-loss EMS reporting through the ERO EAP for trending of potential reliability risks/impacts to the BPS as some entities continue to do.

There were 25 complete loss of monitoring[63] or control[64] capability events in 2023. The following two major contributors to the events were observed:

[62] Emergency Operating Procedure, Event Reporting, EOP-004-4

[63] 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.

[64] 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.

- **Network Communications Configuration**
  EMS-related communications networks are moving from point-to-point serial communication infrastructures to packet-based networks. The main advantage of a packet-based network is to transmit data from one node to another node while avoiding a communications system failure caused by the breakdown of a single (or few) intermediate link(s). Consequently, the correct configuration is critical to ensure that the communications network functions as designed.

- **Power Supply**
  Stable and secure power supplies are critical to control rooms, data centers, and substations. It is essential that routines be established for monthly testing and maintenance of the backup generator, uninterruptible power supply, and associated power switches.

Database and system configuration/settings were improved in 2023, contributing to the decrease in the complete loss of monitoring or control capability events.

- **Settings**
  Periodic review of system parameters and settings with vendor support has been shown to reduce settings errors. Different flags and weighting levels may need to be adjusted as models are expanded or system conditions change.

- **Skill Development**
  More skilled in-house personnel who can troubleshoot and correct these issues can lead to shorter outage durations, including additional knowledge transfer from the vendor to the in-house staff.

Over the five-year period (2019–2023), the average partial or full function EMS outage time (see Figure 3.15) was 73 minutes, making the calculated EMS availability 99.994% during the term.

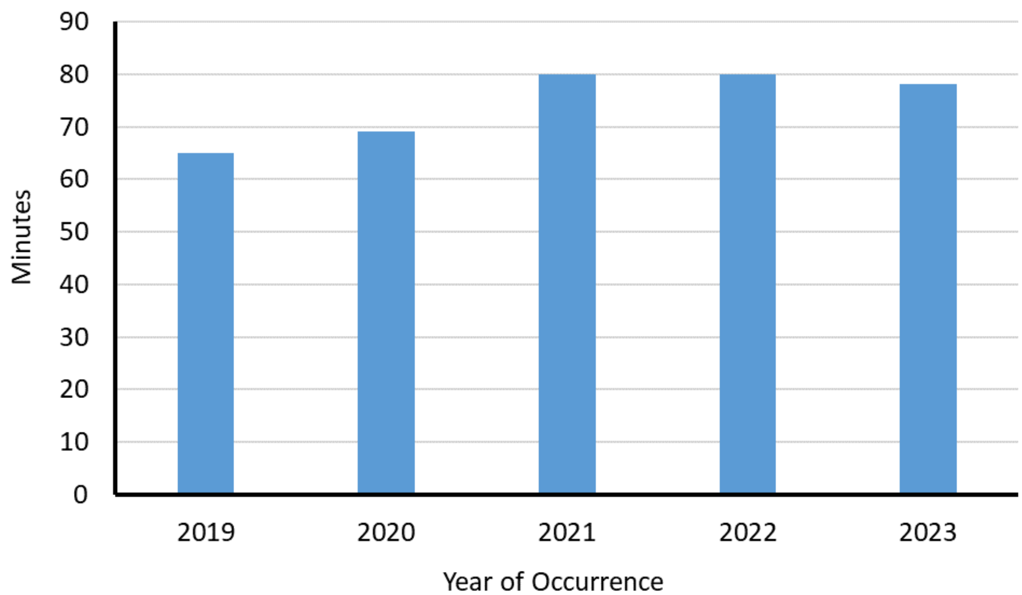


Figure 3.15: Average EMS Outage Time (2019–2023)

Largest Contributor to Loss of EMS

Reported EMS events can be grouped by the following attributes:

- **Software**: Software defects, modeling issues, database corruption, memory issues, etc.
- **Communications**: Device issues, less-than-adequate system interactions, etc.
- **Facility:** Loss of power to the control center or data center, fire alarm, ac failure, etc.

- **Maintenance:** System upgrades, job scoping, change management, software configuration, settings failure, etc.

Figure 3.16 shows that, over the evaluation period of 2019–2023, outages associated with software challenges were the leading contributors to EMS outages followed by outages associated with communications and maintenance challenges.

Software failure was usually caused by bugs, either in a vendor application or in an in-house implementation. A software testing process is always recommended to meet requirements. Systems and software assurance require a process model for formal testing based on the development framework the software was created with. The scope of the test should provide an assurance case for operation of the software under test for both known and unknown operating conditions with the inclusion of a data integrity check of the module. In general, the process is considered to have four components:

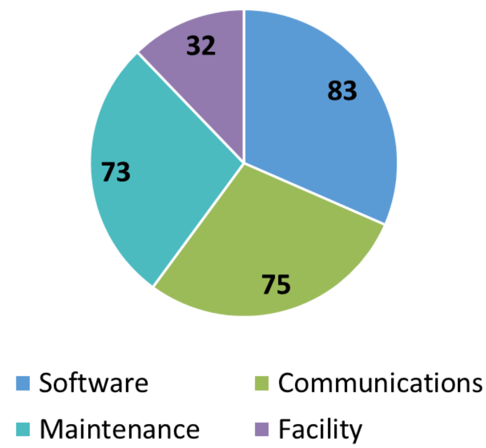


Figure 3.16: Contributors to Loss of EMS Functions (2019–2023)

- **Test Scope:** Define the requirements and setup of the test environment, features and functions that need to be tested, documentation to refer to and produce as output, approval workflows, etc.
- **Test Design:** Design the test cases that are necessary to validate the system, functions, and features being built compared to its design requirements. Typically, regression testing, and incremental testing are necessary.
- **Test Execution:** Execute tests in many different ways.
- **Test Closure:** Consider the exit criteria for signaling completion of the test cycle and readiness for release.

Communications failure means that data exchange was degraded between substations and control rooms or between the entity and its RC/neighboring entities. Internal network configuration error and hardware failure are two major contributors to this cause. Entities should maintain network devices on a schedule in accordance with the latest vendor information, security bulletins, technical bulletins, and other recommended updates. Entities must also consider redesigning communications systems such that the most critical BPS substations communicate simultaneously over entirely separate physical paths to control centers.

Maintenance failure usually occurs when system configuration/settings are not updated according to changes in the latest system operation. These EMS system configuration/settings are often uniquely programmed for the entity to meet the individual needs based on the entity's configuration, topology, contingencies, and external model. When the entity expands or modifies its model, the configuration/settings need to be tuned or calibrated based on subsequent topology changes. Periodic reviews of the settings and configuration with the vendor's help may be necessary to ensure that the EMS functions continue to converge and produce a quality solution. The frequency of these reviews will vary, but consideration of reviewing the settings and configuration following model changes, generation retirements, software upgrades, and any other significant changes made to the EMS system or model is necessary.

A review of ERO EAP data shows that a total of 5.7%, or 15 out of the 263 reportable loss of EMS events between 2019 and 2023 that were greater than 30 minutes, were related to external communication provider issues. External communication provider related issues are not currently influencing EMS outages in a major way.

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*[65] 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.”

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*.[66] Weaknesses in human performance hamper an organization’s ability to identify and address precursor conditions that degrade effective mitigation and behavior management. Effective human performance will help mitigate the active and latent errors that negatively affect reliability.

Statistical significance testing compared the average outage rate of 2023 to that of the prior four years. For ac circuits, all forced outages caused by human error saw a statistically significant decrease in frequency (see Figure 3.17). Transformers saw a statistically significant decrease in operational outages and an apparent increase in automatic outages caused by human error; however, this was not statistically significant (see Figure 3.18).

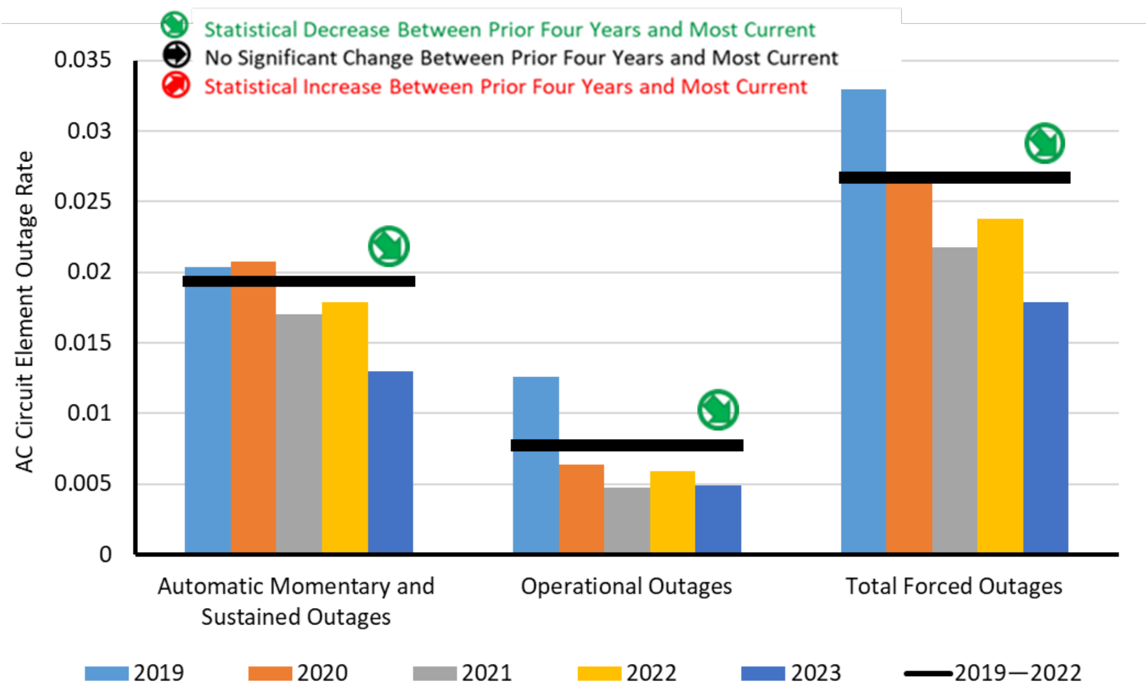


Figure 3.17: AC Circuit Outages per Circuit Initiated by Human Error[67]

[65] [2023 ERO Reliability Risk Reliabilities Priority Report]

[66] 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.

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

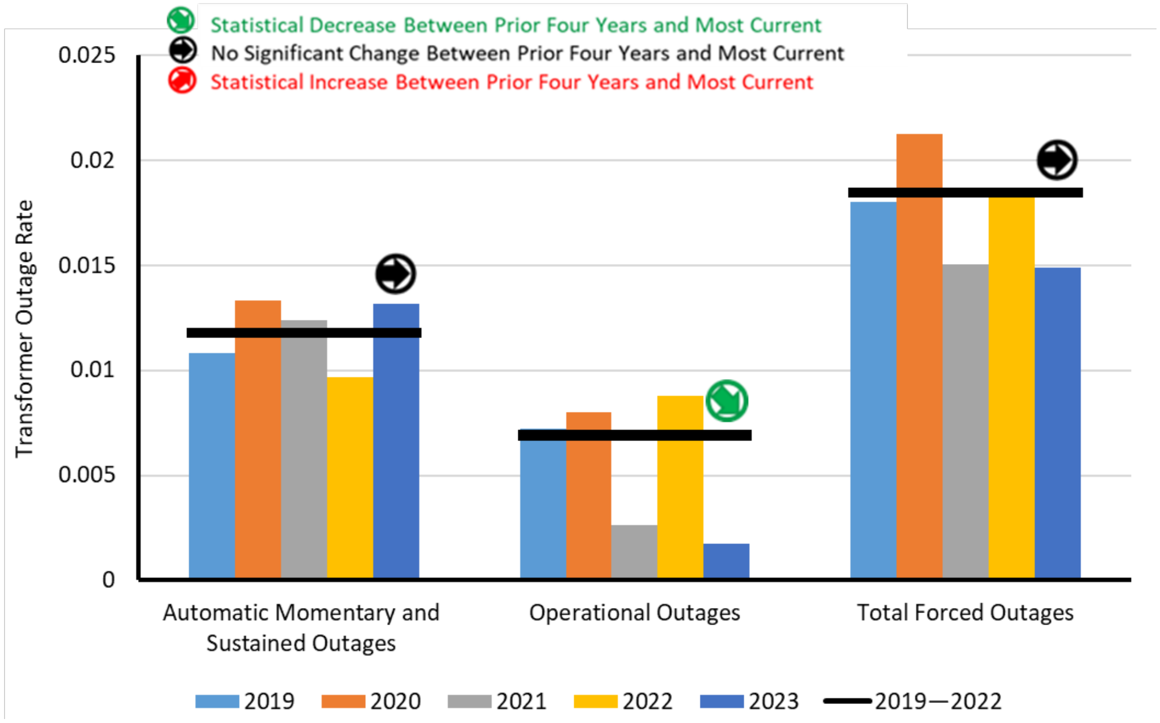


Figure 3.18: Transformer Outages per Element Initiated by Human Error[68]

Generation Outages

NERC's GADS collects generation availability data, including on outages associated with human error. While NERC continues tracking these outages, they have historically represented approximately 1% of all forced-outage events, and no systemic increase warranting presentation was observed in 2023.

Trends of Event Root Causes

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 2023, organization/human performance was identified as the root cause for 20 processed events (see Figure 3.19). This may not fully project the final number as just more than half of the 2023 events have been assigned a final root cause. For the same period, the top five detailed root causes, listed in priority order below, are members of the management and organization performance categories or the design and engineering category:

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

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

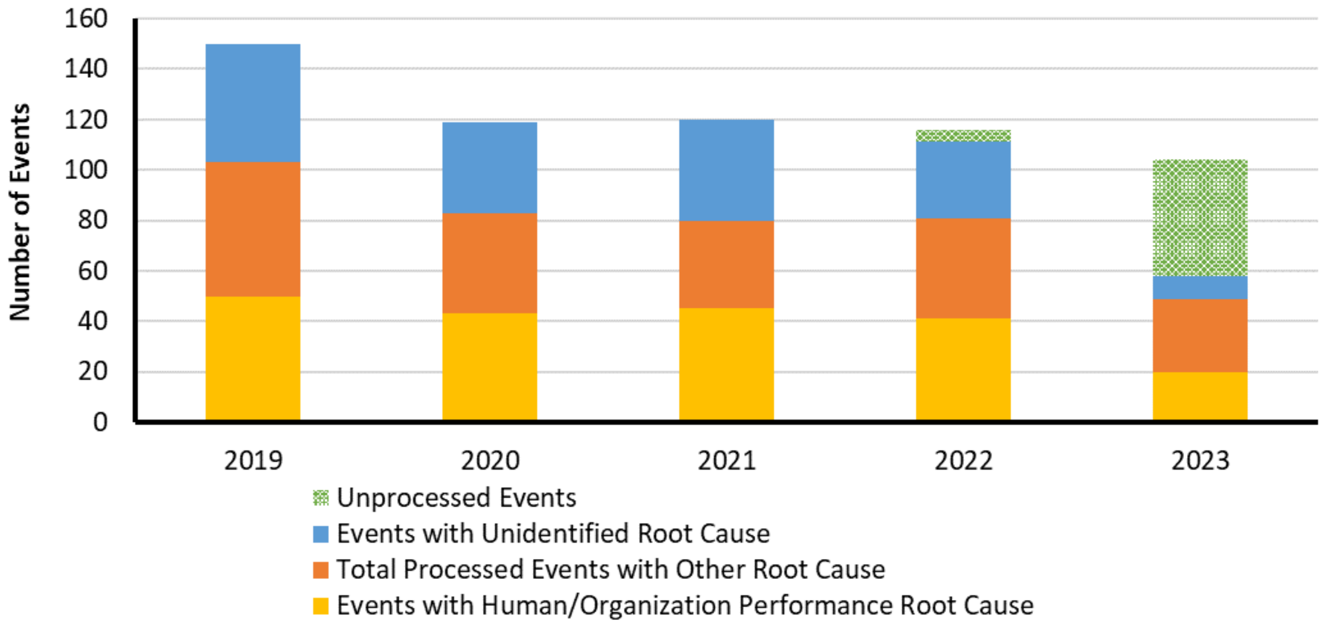


Figure 3.19: ERO EAP Organization/Human Performance Root Cause Identification by Year

Events processed between 2019 and 2023 saw three of the same top five root causes identified in the 2018–2022 time period. The causes “Design Output Scope Not Correct” and “Previous Industry or In-House Experience Was not Effectively Used To Prevent Recurrence” were replaced with “Management Policy Guidance or Expectations Are not Well-Defined, Understood, or Enforced” and “System Interactions not Considered or Identified,” respectively.

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. One way to improve human and organization performance would be to establish robust internal control mechanisms to ensure that processes and procedures are in place to ensure that project leaders consider the potential impacts and dependencies that may exist elsewhere on the system.

Protection System Misoperations

Human performance-related misoperations remain common, representing 41% of misoperations in 2023; consisting of 10% As-Left Personnel Error, 5% Design Errors, 22% Incorrect Settings, and 4% Logic Errors (see Figure 3.10). Figure 3.20 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 SERC, are either improving or remaining consistent.

To improve the frequency of misoperations potentially due to human error, SERC formed a task force last year to develop sub-cause categories to better identify what areas to target for improvement. Starting in 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.

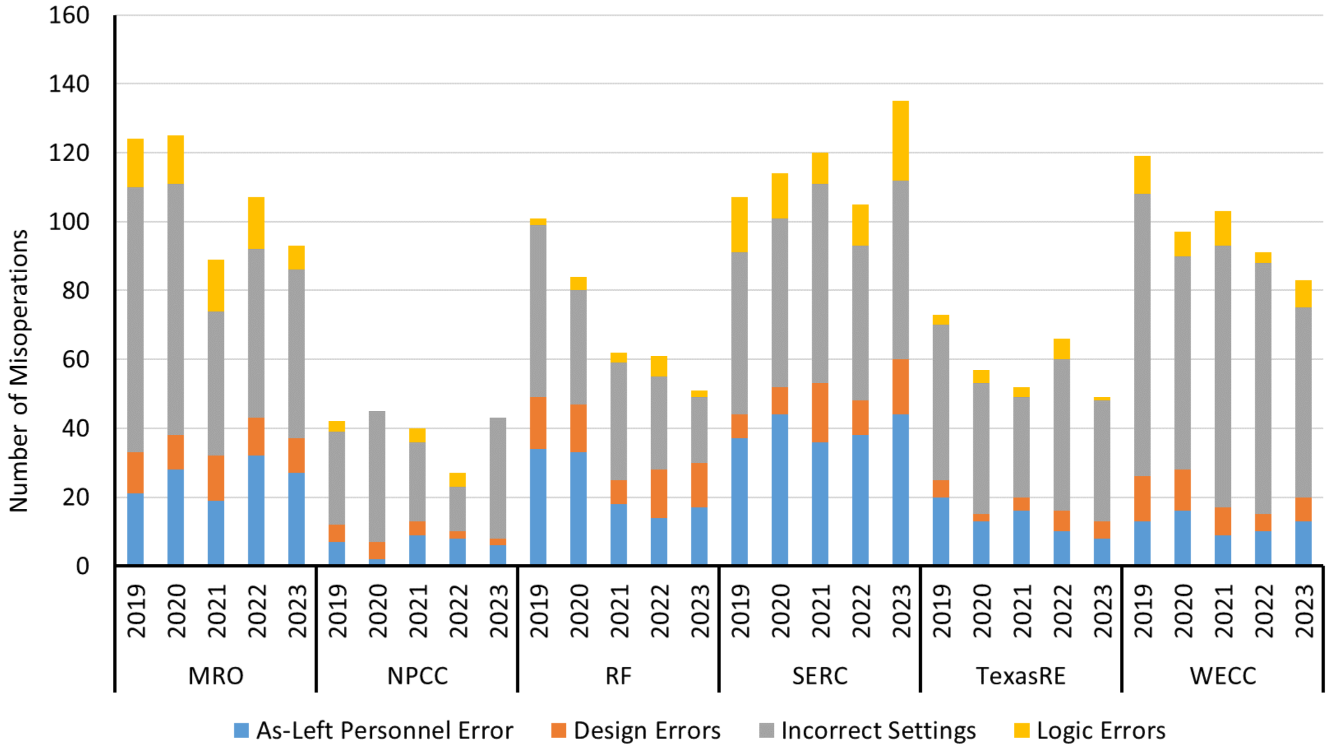


Figure 3.20: MIDAS Protection System Misoperations Due to Human Error by Regional Entity

Energy Emergency Alerts[69]

The purpose of an EEA is to provide 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 3.21 shows that 16 EEA-3s were declared in 2023, a decrease of 10 EEA-3 declarations over 2022. None of the EEA-3 declarations in 2023 included shedding of firm load (92.6 GWh in 2022 vs 0 GWh in 2023.)

All EEA-3 declarations in 2023 were associated with periods of reduced generation or import capability combined with a heavy load day. While none of these days would be considered extreme weather days, 11 of the EEA-3 reports did indicate that higher temperatures or loads were involved.

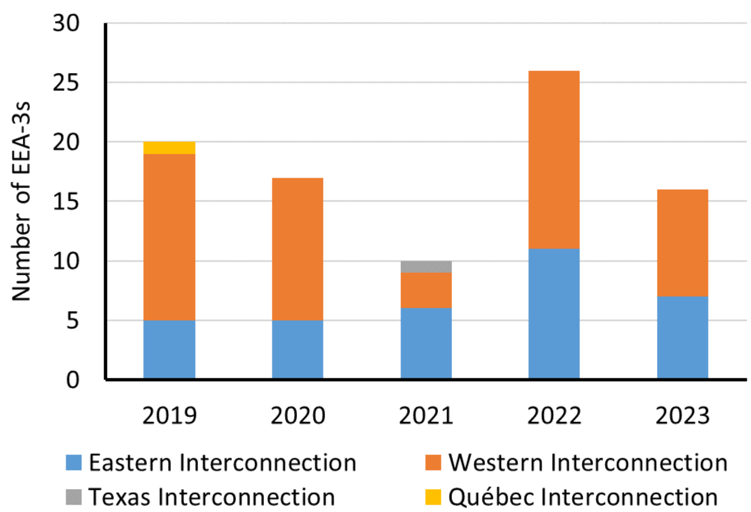


Figure 3.21: EEA-3 by Year and Interconnection

Figure 3.22 shows the number of hours when operator-initiated firm load shed was deployed during each of the past five years. In 2023, zero hours occurred, while 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.

[69] M-11, Energy Emergency Alerts

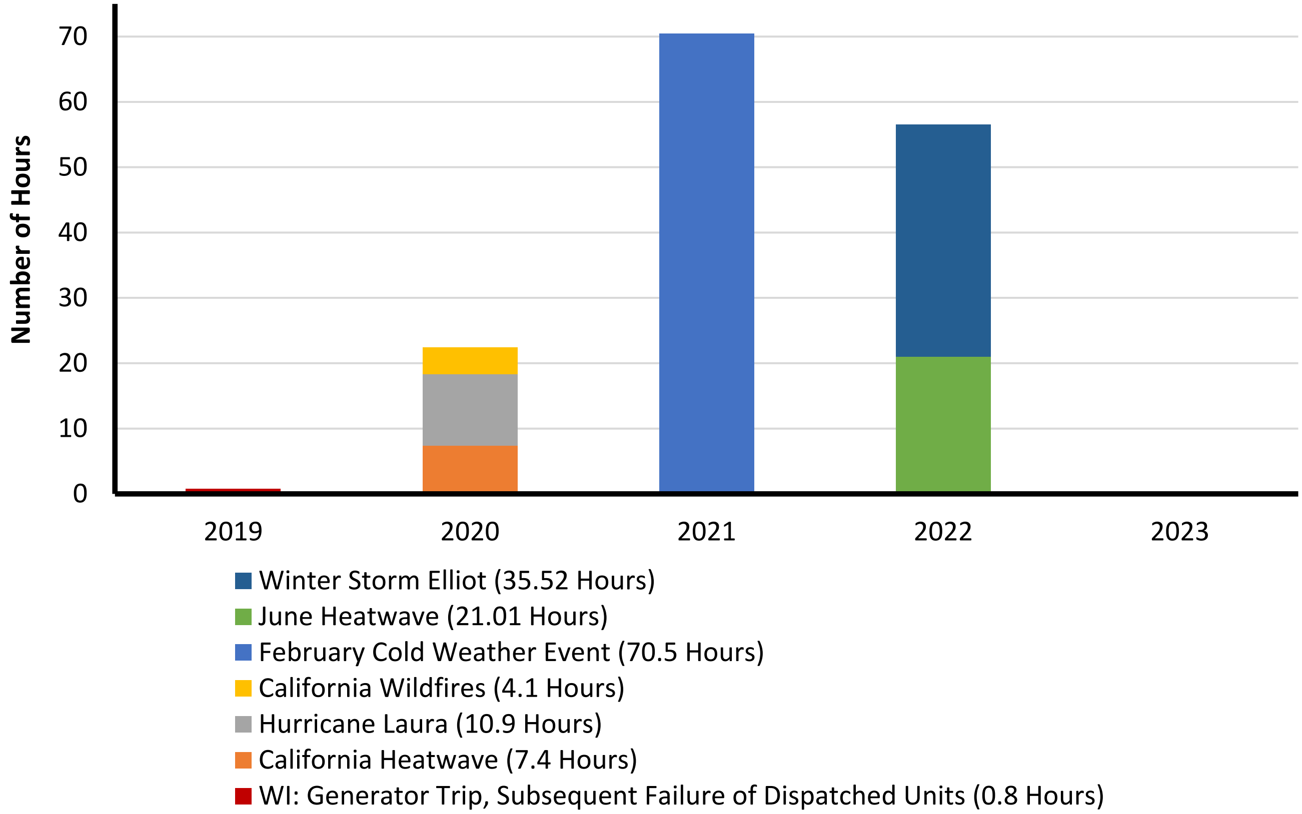


Figure 3.22: Hours with Operator-Initiated Firm Load Shed (Hours/Year)

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 2023 reliability metrics[70] 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	Actionable		
M-2: Transmission-Related Events Resulting in Loss of Load (Excluding Weather)	Improving		
M-3: System Voltage Performance	Retired		
M-4: Interconnection Frequency Response	Improving: Texas Interconnection	Stable: Eastern and Western Interconnections	Monitor: Québec Interconnection
M-4.1: Inertia and Rate-of-Change-of-Frequency	Improving: Texas Interconnection	Stable: Eastern and Western Interconnections	Monitor: Québec Interconnection
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: Texas and Western Interconnections		Monitor: Eastern and Québec Interconnections
M-9: Protection System Misoperations Rate	Stable		
M-10: Transmission Constraint Mitigation	Retired		
M-11: Energy Emergency Alerts	Improving		
M-12: Automatic AC Transmission Outages Initiated by Failed Protection System Equipment	Improving		
M-13: Automatic AC Transmission Outages Initiated by Human Error	Improving		
M-14: Automatic AC Transmission Outages Initiated by Failed AC Substation Equipment	Improving		

[70] 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-15: Automatic AC Transmission Outages Initiated by Failed AC Circuit Equipment	**Improving**
M-16: Transmission Element Availability Percentage and Unavailability Percentage	**Stable**
M-17: Transmission Outage Severity	**Stable**

Frequency Response Performance

Frequency response arrests and stabilizes frequency during system disturbances. NERC closely monitors the frequency response of each of the four Interconnections and measures the margin at which under-frequency load shedding (UFLS) would be activated. UFLS provides a vital safety net for preserving Interconnection reliability. Measuring the margin allows NERC and the industry to ensure that there is adequate frequency response on the system.

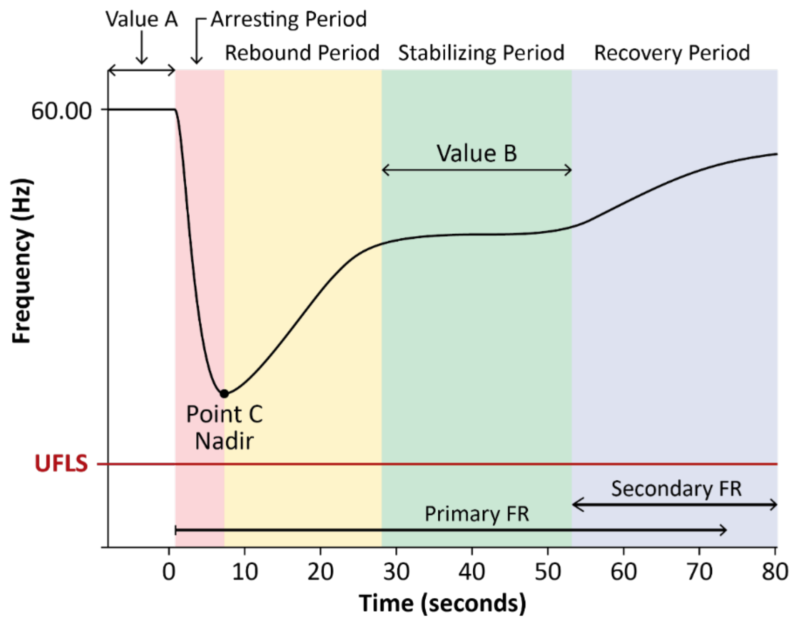


Figure 4.1: Frequency Response Methodology

During the arresting period, the goal is to arrest the frequency decline for credible contingencies before the activation of UFLS. The calculation for Interconnection frequency response obligation (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)[71] for the Interconnection. Measuring and tracking the margin between the first-step UFLS set point and the Point C nadir is an important indicator of risk for each Interconnection. Figure 4.1 indicates the measurement periods used for analysis of the arresting period of events by looking at the frequency response between Value A and Point C as well as at the margin between Point C and the first-step UFLS set point.

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.

2023 Interconnection Frequency Response

2023 performance and trends frequency response analysis indicate an adequate level of reliability.

- For the stabilizing period, the Interconnection frequency response,[72] the Eastern Interconnection, the Québec Interconnection, and the Western Interconnection showed no statistically significant changes from 2019 through 2023. The Texas Interconnection showed a statistically significant improvement for the stabilizing period from 2019 through 2023.
- For the arresting period, the inertia and rate-of-change-of-frequency (ROCOF),[73] the Eastern and Western Interconnections showed no statistically significant changes from 2019 through 2023. The Texas

[71] BAL-003-2 specifies that the RLPC be based on the two largest potential resource losses in an Interconnection or the largest resource loss due to an N-2 RAS. This value is updated annually through the BAL-003-2 data collection process.
[72] Interconnection Frequency Response, M-4
[73] Inertia and Rate-of-Change-of-Frequency, M-4.1

Interconnection showed a statistically significant improvement. The Québec Interconnection showed a statistically significant decreasing trend.

Of note in 2023, as shown in Table 4.2, the Western Interconnection had two events within the five-year period in which the measured frequency response was less than the IFRO. Both events had a starting frequency well above 60.00 Hz and had a confirmed MW loss under 500 MW. These two factors combined alleviate concerns that the Western Interconnection frequency response is insufficient. Also, of note in 2023 was the decreasing trend in the inertia and ROCOF for the Québec Interconnection. The Québec Interconnection confirmed an overrepresentation of summer events in 2023 compared to other years (2019–2022). Twenty percent of all events in the past five years occurred between May and October 2023 (months that typically have lower inertia), in part due to the wildfire events in the region. The Eastern Interconnection, Québec Interconnection, and Texas Interconnection did not have any events within the five-year period in which the measured frequency response was less than the IFRO for the respective Interconnection.

Table 4.2: 5-Year Statistical Trend

Interconnection	M-4 Interconnection Frequency Response	M4.1 Inertia and Rate-of-Change-of-Frequency	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
Québec	neither decreasing nor increasing	decreasing	neither decreasing nor increasing	No M4 events with FR below IFRO
Western	neither decreasing nor increasing	neither decreasing nor increasing	neither decreasing nor increasing	Two M4 events with FR below IFRO

Of note, the Western Interconnection has had the least number of valid events since frequency response evaluation started. This trend in reduction of valid frequency response events is suspected to be due to the retirement of large generating facilities in the Interconnection over the evaluation period and is a positive indicator when considering impacts to Interconnection reliability.

Frequency response for all Interconnections indicates stable and improving performance for the stabilizing period and arresting period as shown in Table 4.3 and Table 4.4.[74]

Table 4.3: 2023 Frequency Response Performance Statistics for Stabilizing Period

	2023 Operating Year Stabilizing Period Performance					
	Number of Events	Mean Frequency Response	Median	Minimum	Maximum	Number of events with FR below the IFRO
Eastern	47	2,685	2,459	1,138	5,176	0
Texas	38	1,410	1,241	682	2,788	0
Québec	65	762	693	260	1,682	0
Western	28	2,049	1,682	912	5,050	2

[74] Frequency Response Performance Statistics

Table 4.4: 2023 Frequency Response Performance Statistics for Arresting Period								
	Operating Year (OY)							
	Number of Events	Mean Frequency Response	Median	Minimum	Maximum	Mean UFLS Margin	Median UFLS Margin	Min. UFLS Margin
Eastern	47	2,151	1,969	1,059	3,550	0.454	0.453	0.441
Texas	38	727	738	283	1,604	0.611	0.606	0.579
Québec	65	124	120	48	233	1.022	1.065	0.118
Western	28	868	829	544	1,554	0.415	0.421	0.332

Figure 4.2 represents an analysis of the arresting period of frequency response events. The Y-axis shows the percent UFLS margin from 100% (60 Hz) to 0% (first UFLS set point for the Interconnection). The X-axis represents the MW loss for the event, expressed as a percentage of the RLPC for the Interconnection. The Québec Interconnection had two events at or greater than 100% of the RLPC and maintained sufficient UFLS margin. The largest events for the Eastern Interconnection and Texas Interconnection were 45% and 50%, respectively, as measured by percentage of RLPC.

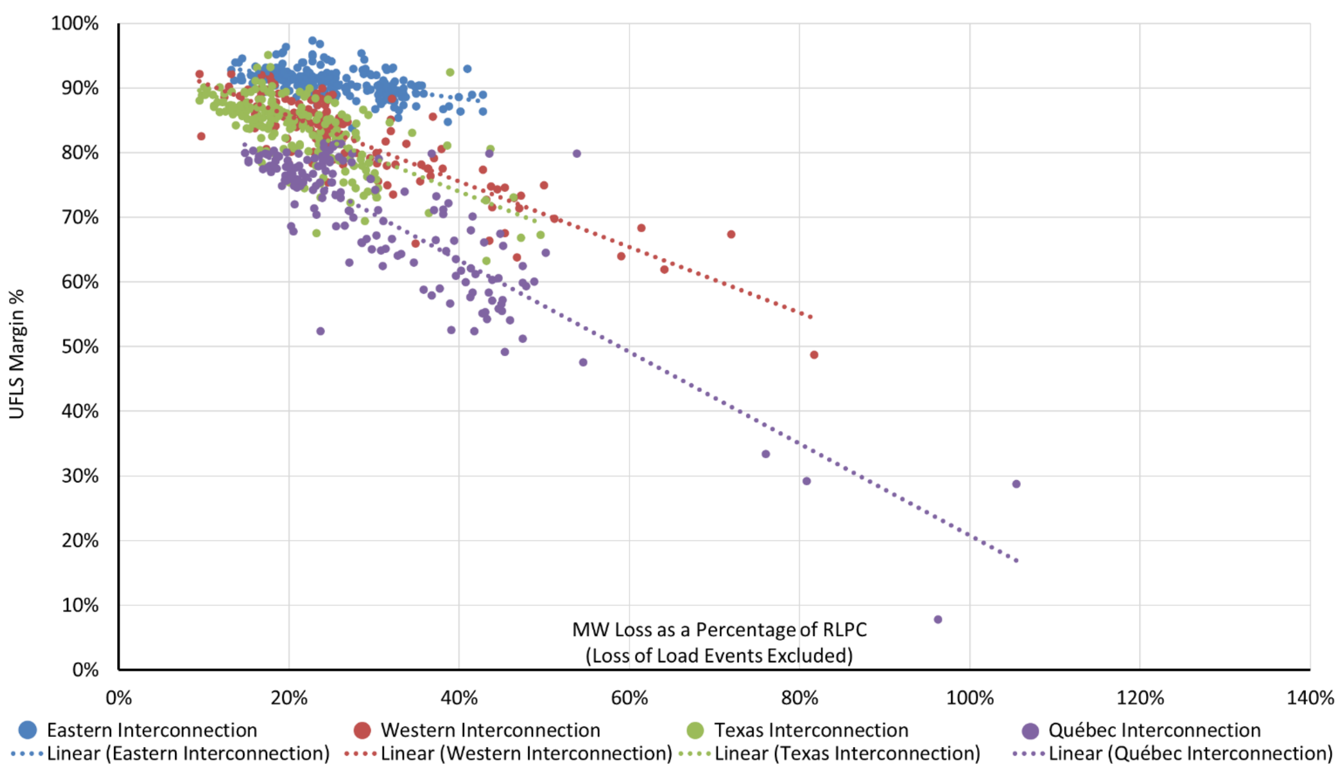


Figure 4.2: Operating Year 2019–2023 Qualified Frequency Disturbances and Remaining UFLS Margin

Interconnection Reliability Operating Limit Exceedances

2023 Performance and Trends

Each RC has a different methodology for determining Interconnection reliability operating limits (IROL)[75] 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:

[75] M-8, IROL Exceedance

- **Eastern–Québec Interconnections:** In 2023, there were eight exceedances that lasted more than 10 minutes, less than the five-year average of 19.4 exceedances as shown in Figure 4.3. The 10- to 20-minute range continued to decline from its all-time peak in 2019 with zero exceedances greater than 20 minutes.
- **Western Interconnection:** The trend has been stable with no IROL exceedances reported in 2023.
- **Texas Interconnection:** The trend has been stable with no IROL exceedances reported in 2023.

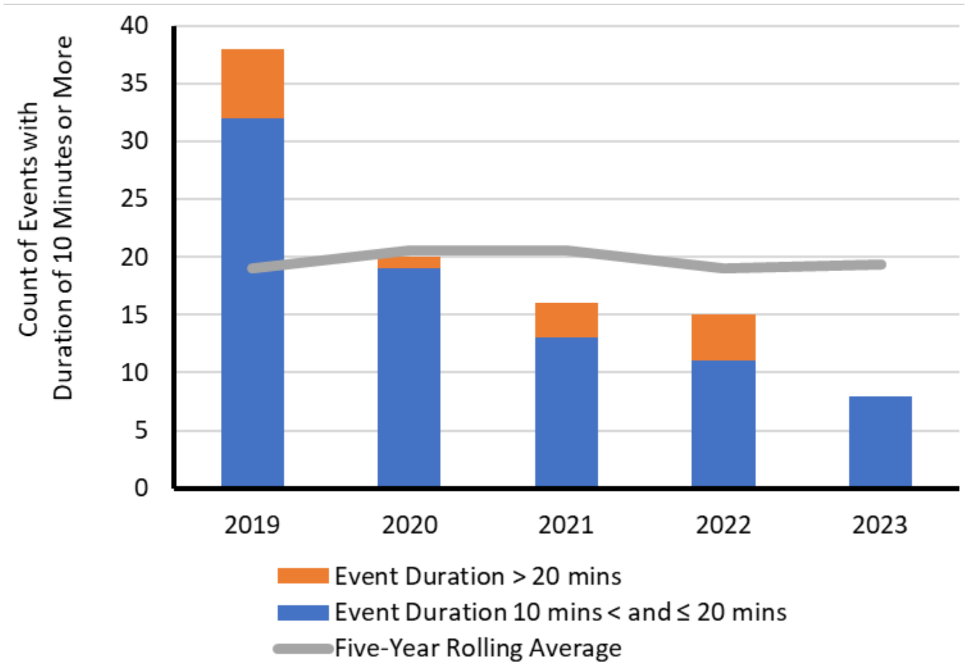


Figure 4.3: IROL Exceedance Counts[76]

Generation Performance and Availability

GADS contains information that can be used to compute reliability measures, such as WEFOR. GADS collects and stores unit operating information by pooling individual unit information, overall generating unit availability, performance, and calculated metrics.

Conventional Generation WEFOR

The horizontal lines in Figure 4.4 show the annual WEFOR compared to the monthly WEFOR columns; the solid horizontal bar shows the WEFOR for all years in the analysis period of 7.4%. While noticeably lower than the two preceding years, the annual WEFOR of 7.8% for 2023 is the third highest since NERC began digitally collecting GADS data in 2013, despite no major outlying winter weather event.

[76] M-8, IROL Exceedance

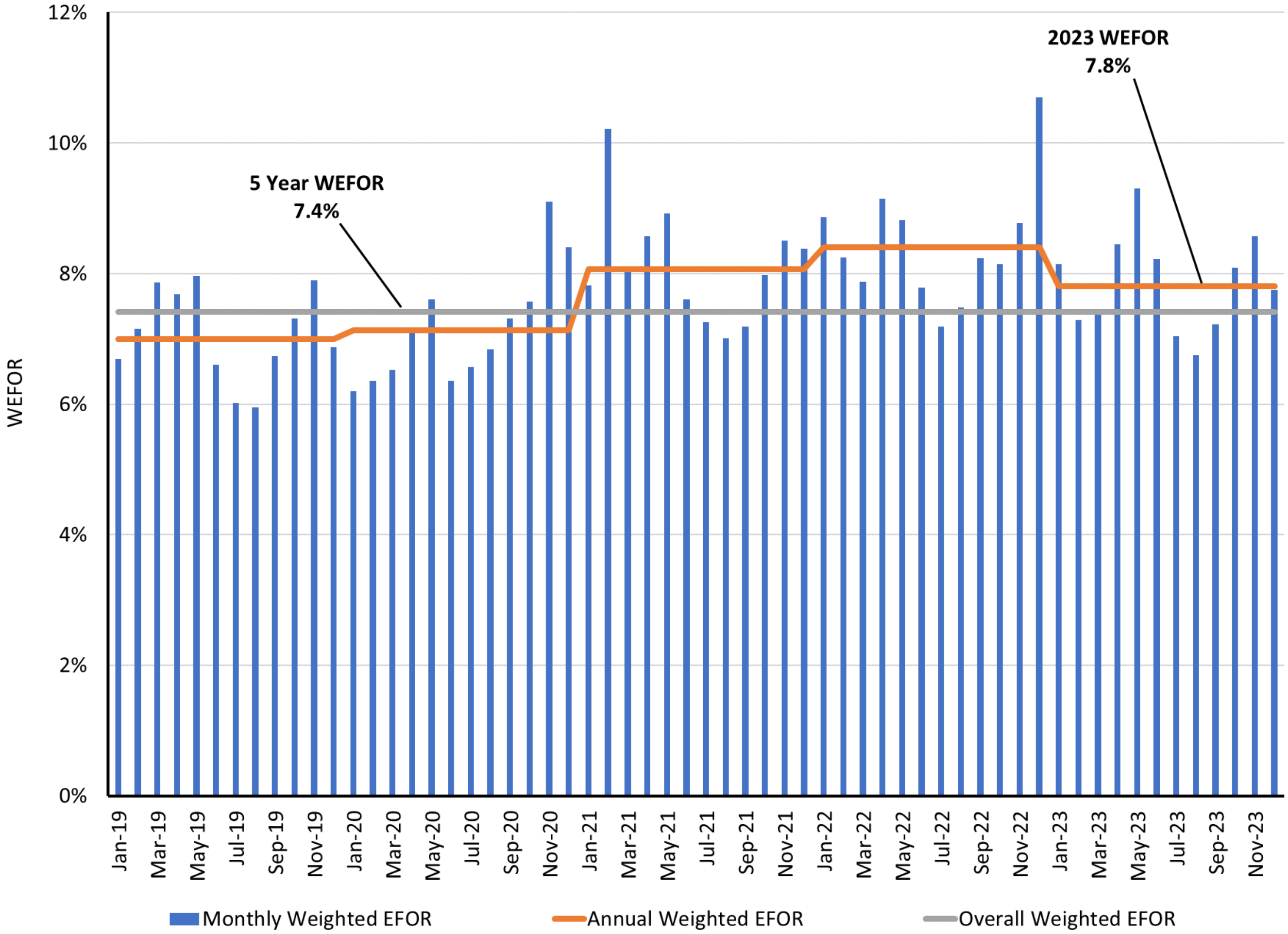


Figure 4.4: Monthly, Annual, and Five-Year WEFOR

To better illustrate 2023's high WEFOR relative to historical norms, Figure 4.5 shows the annual WEFOR by fuel type for the past 10 years. This extended analysis period is presented to illustrate how the abnormally high WEFORs in 2021 and 2022 caused by extreme cold weather conditions obfuscate long-term trends.

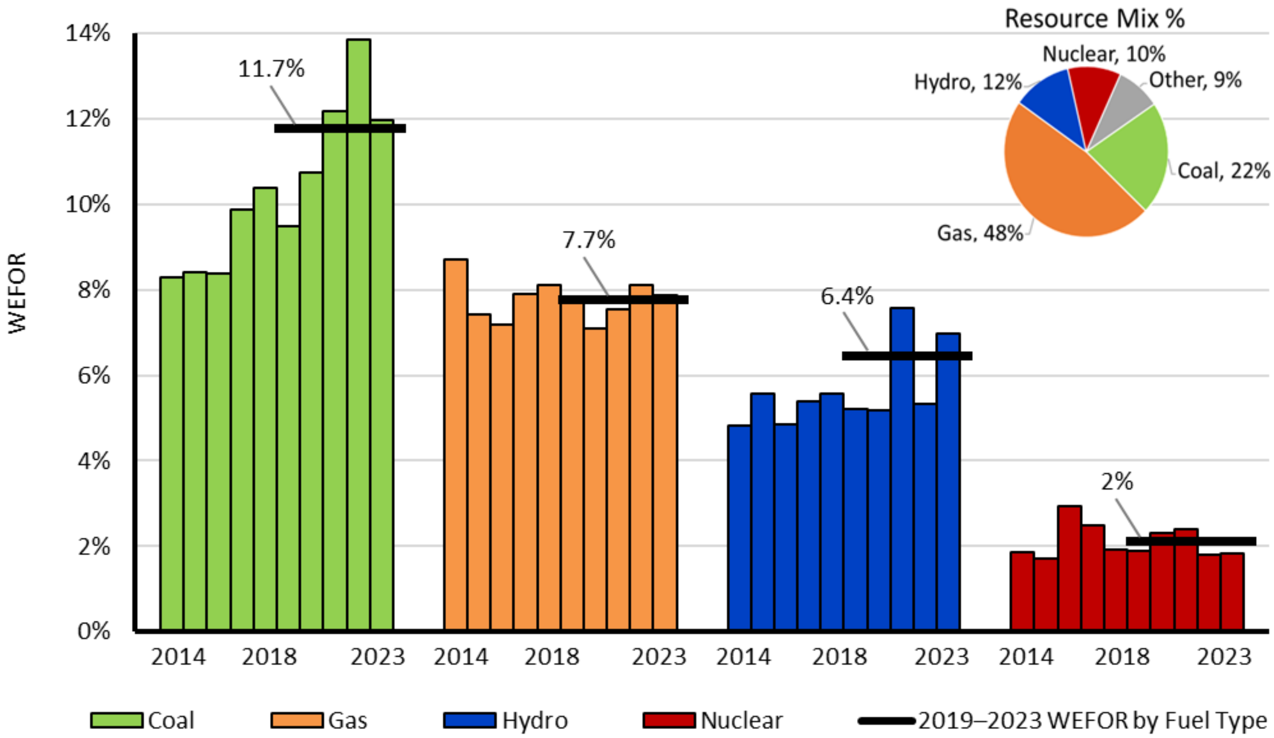


Figure 4.5: 10-Year Annual WEFOR by Fuel Type and 2023 Resource Mix by Net Maximum Capacity

Although coal-fired generation experienced a large decrease in WEFOR in 2023 (12.0% in 2023 versus 13.9% in 2022), it remains above pre-2021 rates. Due to year-over-year variability, coal generation is the primary driver of change in the overall WEFOR despite more energy being produced by both natural gas and nuclear power in 2023 (see Figure 4.6). Further investigation into baseload coal generation indicates that a unit's WEFOR negatively correlates most strongly to capacity factor.[77] Notably, once capacity factor falls below approximately 60%, unweighted average EFORs of units begin increasing more rapidly than those between 60% and 100%. Although forced-outage hours are a definite contributor to lower capacity factor units' increased WEFOR, the disproportionate change appears to be driven more by maintenance/planned outage hours and decreased service hours. This aligns with industry statements indicating that reduced investment in maintenance and abnormal cycling that are being adopted primarily in response to rapid changes in the resource mix are negatively impacting baseload coal unit performance.

Hydro units also experienced an unusually high annual WEFOR (6.9%) for the second time following one in 2021 (7.6%). However, these two relatively high years were both still lower than the associated years' overall WEFOR and do not indicate a trend at this point but warrant continued awareness.

[77] The correlation factor between capacity factor and WEFOR for baseload coal in 2023 was -0.41. While not mathematically indicative of a strong correlation (generally +/-0.7), it is notably stronger than any other aspect that is not a direct component of the WEFOR with the next highest being age (0.18) and planned outage hours (-0.16) given the relatively small sample size and amount of variation between coal units.

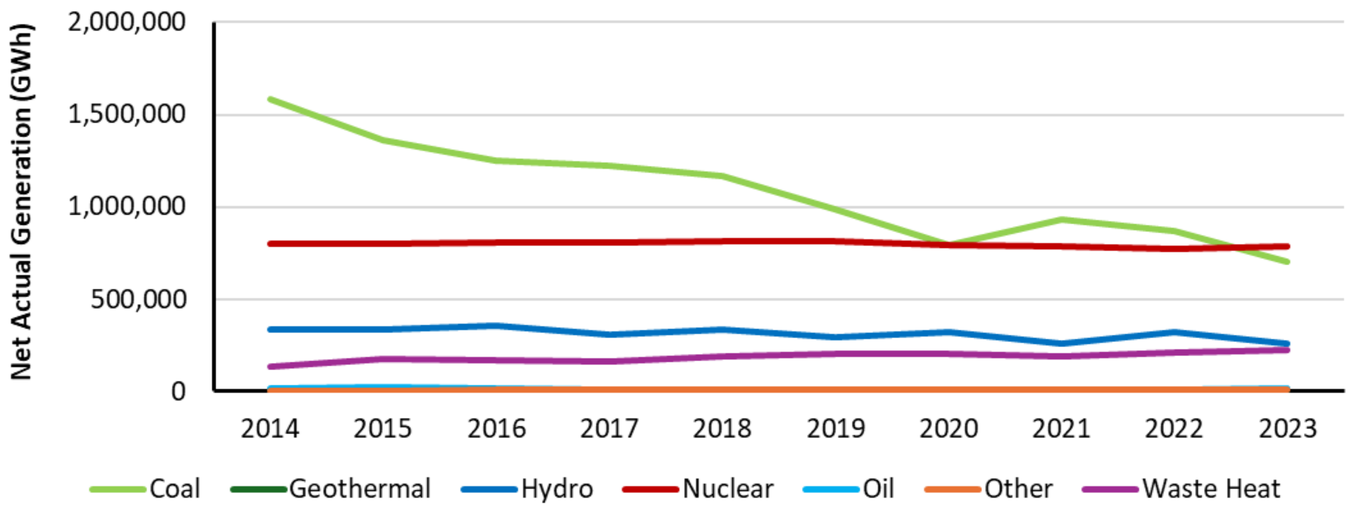


Figure 4.6: 10-Year Annual Conventional Net Actual Generation (GWh) by Fuel Type

Wind Generation Weighted Resource Forced-Outage Rate

NERC began collecting wind performance data with a phased-in approach based on plant size starting with a total installed capacity of 200 MW or greater in 2018 followed by plants with a total installed capacity of 100–199 MW in 2019 and plants with a total installed capacity of 75–99 MW in 2020 (see Figure 4.7). By the end of 2023, data from 137,737 MW of installed capacity, representing 703 wind plants across North America and 13% of nameplate generation, was reported to NERC. Data will continue to be reported separately for the reporting phase groups until sufficient history is available to analyze trends for a five-year rolling period across all wind plants comparable to the analysis for conventional generation. Specific event data collection for wind and solar began in 2024 and will allow for further analysis.

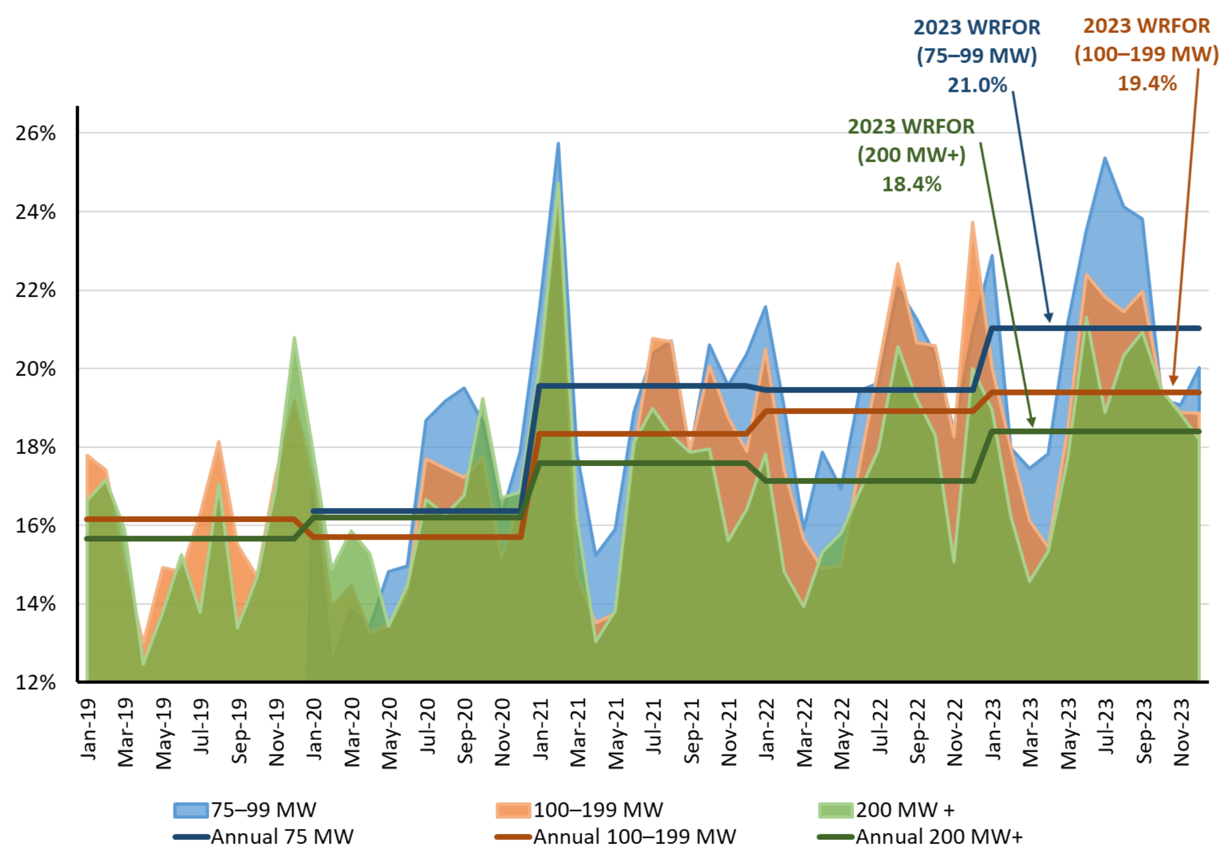


Figure 4.7: Monthly Capacity and Annual Average WRFOR Wind Plant Reporting Group

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 2023, a total of nine distinct non-weather-related transmission events resulted in a loss of firm load that met the ERO EAP reporting criteria (see Figure 4.8). The median firm load loss over the past five years was 97 MW, which is a decrease from 2018–2022's 101 MW. Although, notably, the median load loss was 113 MW in 2023, which is above the five-year median value, no discernible trend in the number of events or amount of loss is identifiable.

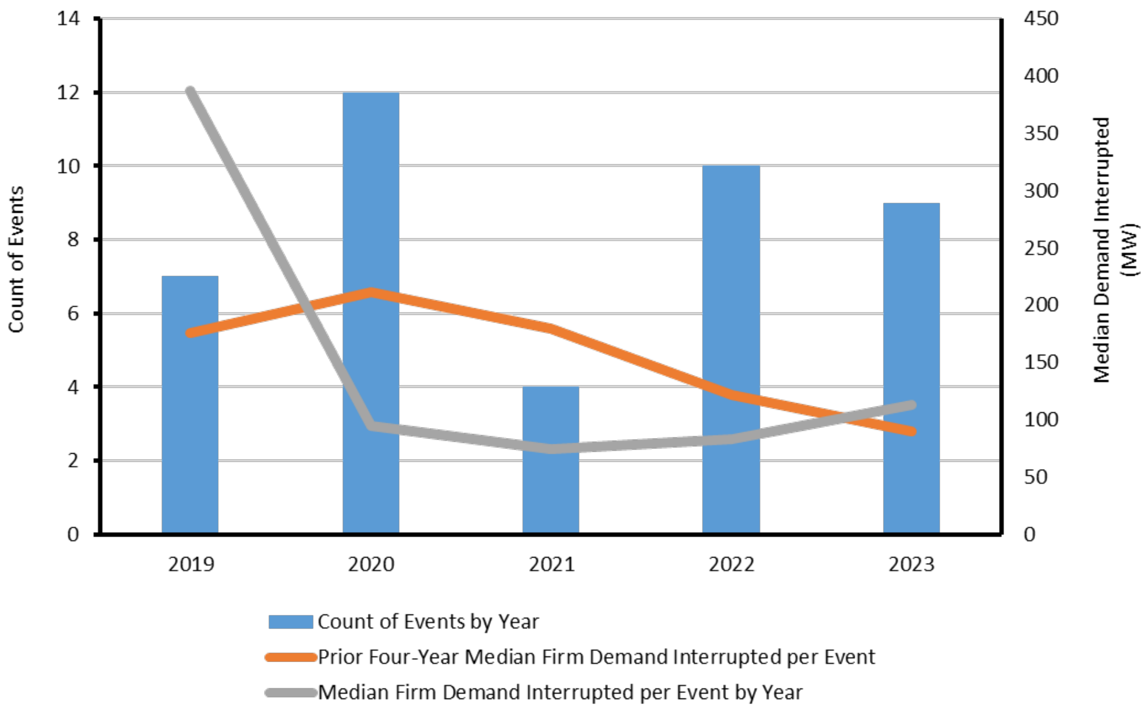


Figure 4.8: Transmission-Related Events Resulting in Loss of Firm Load and Median Amount of Firm Load Loss Excluding Weather-Related Events[78]

TADS Reliability Indicators

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

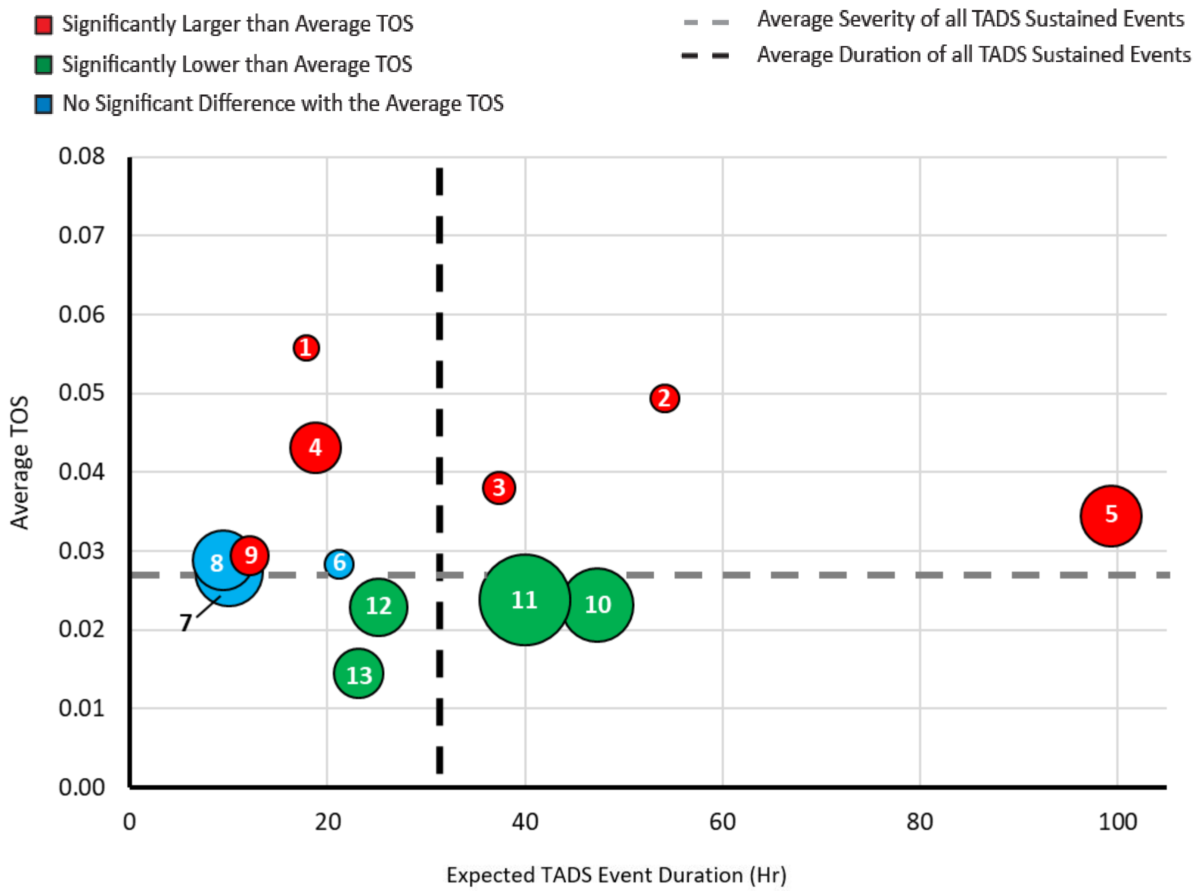
- Transmission Outage Severity
- Automatic AC Transmission Outages
- Transmission Element Unavailability

Transmission Outage Severity

The impact of a TADS event on BPS reliability is called the TOS of the event, which is defined by the number of 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.

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

By examining the average TOS, duration, and frequency of occurrence for events with different ICCs (see Figure 4.9), it is possible to determine which ICCs contribute most to reliability performance for the considered period. The average TOS for events with a specific ICC is displayed on the Y-axis. A higher TOS for an ICC indicates that more 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. Change in size or position of a bubble with the same number (identifying ICC) may indicate improved or declined performance. 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.



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

Figure 4.9: TOS vs. Expected TADS Event Duration

Table 4.5: TOS vs. Expected TADS Event Duration			
TADS Event	**Events per Hour**	**Average TOS**	**Average Event Duration**
Power System Condition	.012	.056	17.9
Fire	.014	.049	54.2
Combined Smaller ICC Groups	.019	.038	37.4
Misoperation	.046	.043	18.8
Failed AC Substation Equipment	.068	.034	99.4
Other	.015	.028	21.2
Unknown	.085	.027	10.0
Lightning	.067	.029	9.5
Human Error	.026	.029	12.2
Failed AC Circuit Equipment	.098	.023	47.3
Weather, Excluding Lightning	.153	.024	40.0
Foreign Interference	.061	.023	25.2
Vegetation	.045	.014	23.2

An analysis of the total TOS by year indicates that 2023 was an outlier from the statistically improving trend identified over the previous five years. Figure 4.10 shows the annual TOS, which is the third highest over the last five years; the shaded area shows the effect of the Québec wildfires on the 2023 TOS.

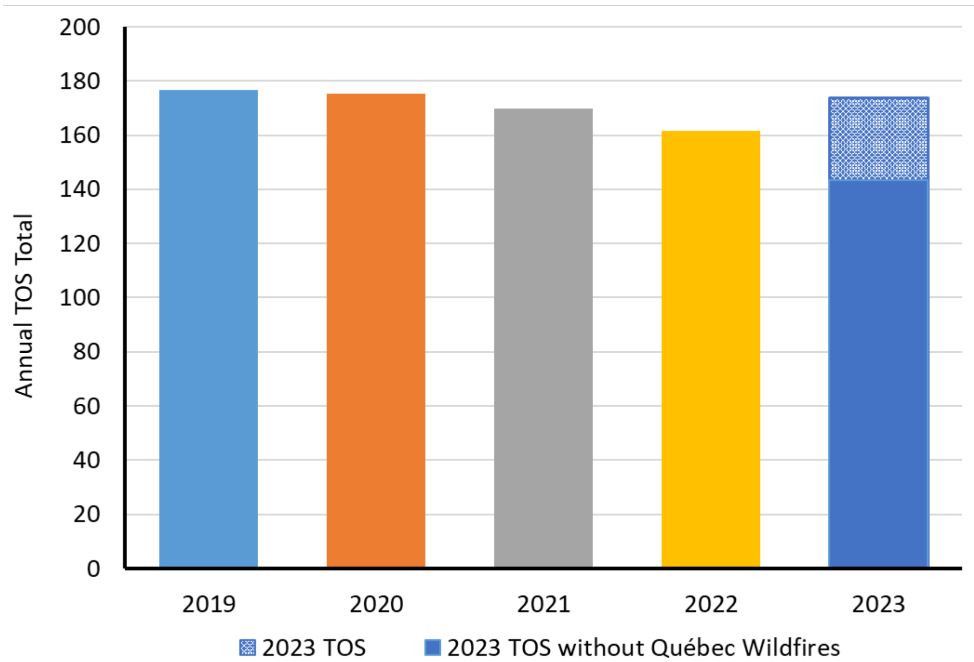


Figure 4.10: TOS of TADS Sustained Events of 100 kV+ AC Circuits and Transformers by Year[79]

Automatic AC Transmission Outages

The average number of outages per circuit due to failed ac substation equipment has continued to improve consistently over the last four years, showing a statistically significant decrease in 2023 compared to 2019–2022 (see Figure 4.11 The number of sustained outages due to failed ac circuit equipment per 100 miles saw a decrease in 2023 (see Figure 4.12).

[79] M-17, Transmission Outage Severity

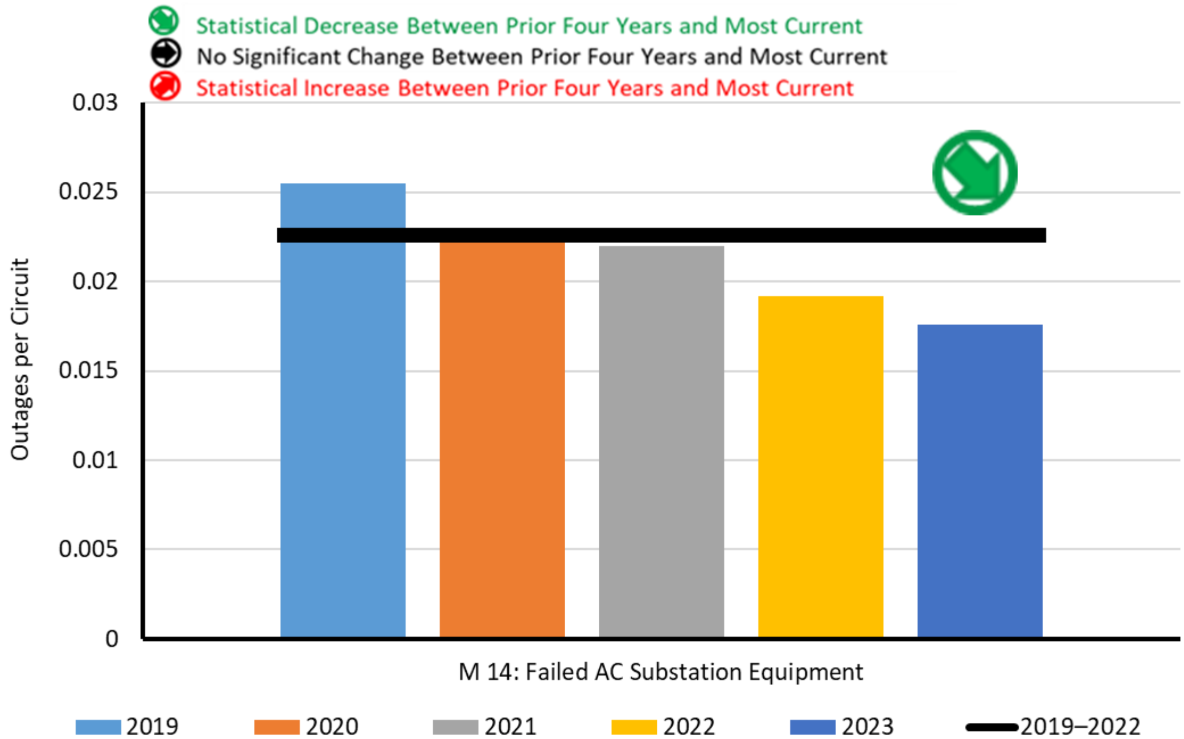


Figure 4.11: Number of Outages per AC Circuit Due to Failed AC Substation Equipment[80]

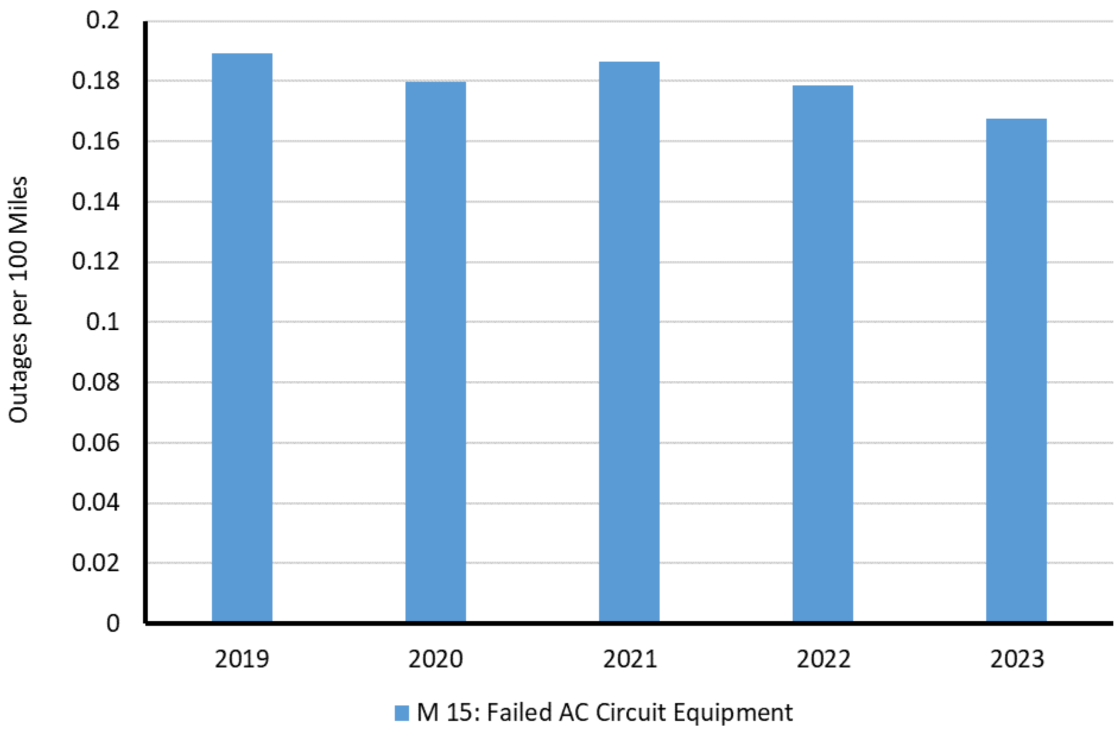


Figure 4.12: Number of Outages per 100 Miles Due to Failed AC Circuit Equipment[81]

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

Automatic AC Transformer Outages

In 2023, the number of automatic ac transformer outages per element caused by failed ac substation equipment was statistically equal to 2019–2022 (see Figure 4.13); the overall average remains stable.

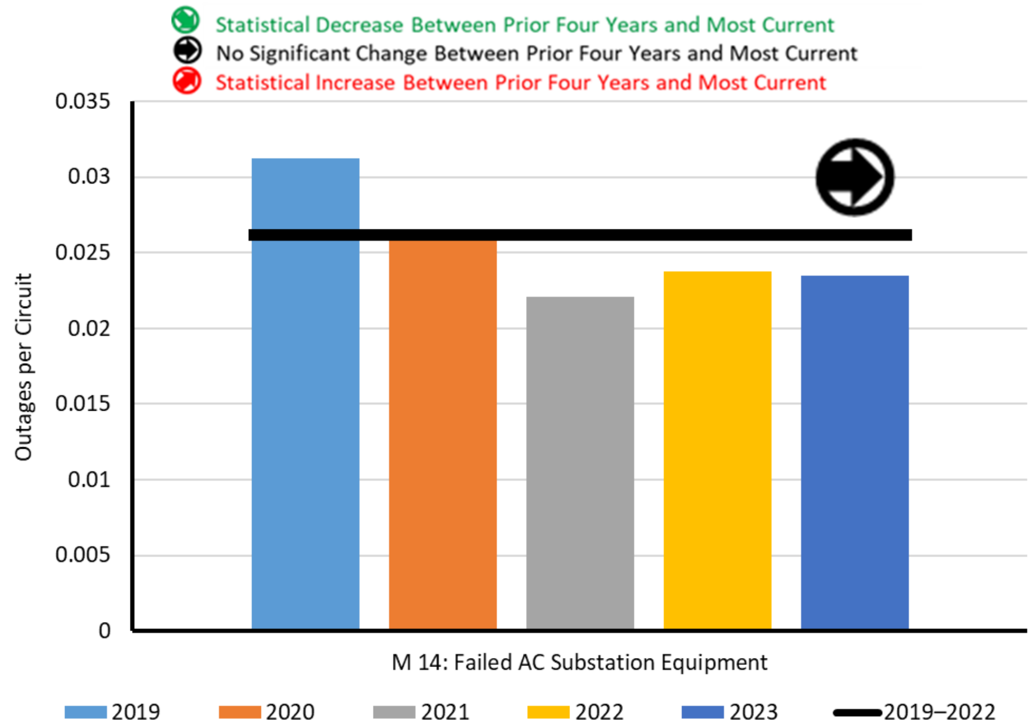


Figure 4.13: Number of Outages per Transformer Due to Failed AC Substation Equipment[82]

Transmission Element Unavailability

In 2023, ac circuits over 200 kV across North America had an unavailability rate of 0.24%, meaning that there is a 0.24% chance that a specific transmission circuit is unavailable due to sustained automatic and operational outages at any given time. Transformers had an unavailability rate of 0.25% in 2023. Figure 4.14 shows that 2023 was the lowest year for ac circuit unavailability of the five-year analysis period. Figure 4.15 shows that 2023 was the second-highest year for transformer unavailability of the five-year analysis period.

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

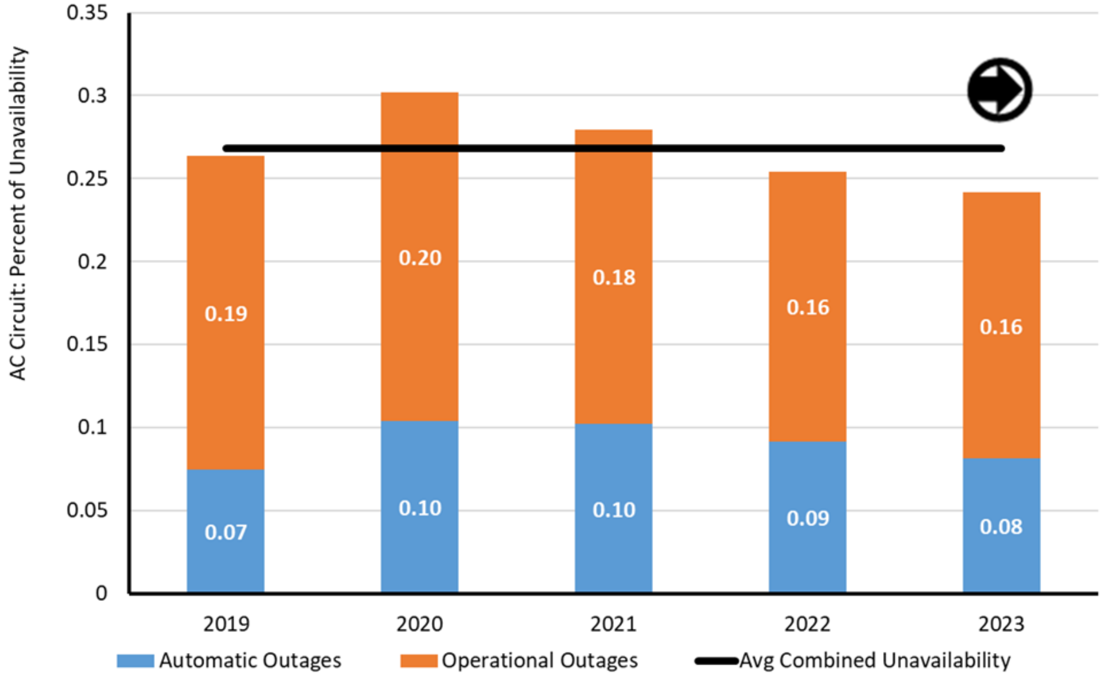


Figure 4.14: AC Circuit Unavailability > 200 kV[83]

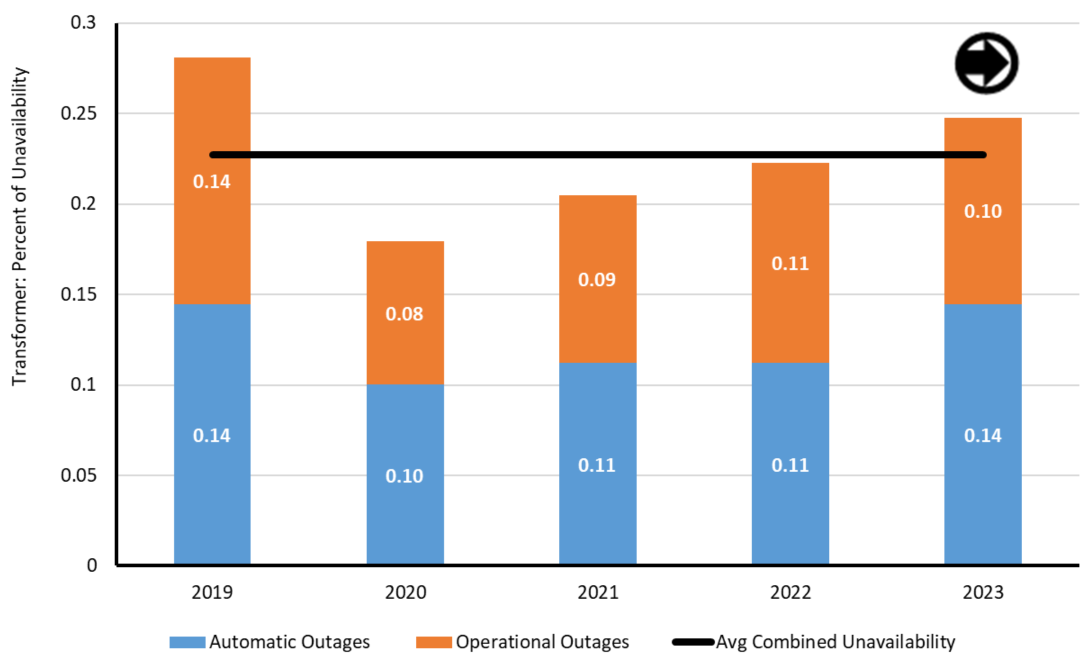


Figure 4.15: Transformer Unavailability[84]

[83] M-16, Element Availability Percentage (APC) & Unavailability Percentage
[84] Ibid.

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 5% decrease compared to the average of the four-year period of 2019–2022.

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
2019	345.9	59.3	51.3	456.4	1.25
2020	315.3	58.4	67.4	441.0	1.21
2021	346.2	54.5	64.1	464.8	1.27
2022	385.3	53.0	53.0	491.2	1.35
2023	**324.7**	**65.4**	**48.5**	**438.6**	**1.20**

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 8 of the top 10 days that occurred in the Eastern and Québec Interconnections align with the top 10 SRI days reported for North America.

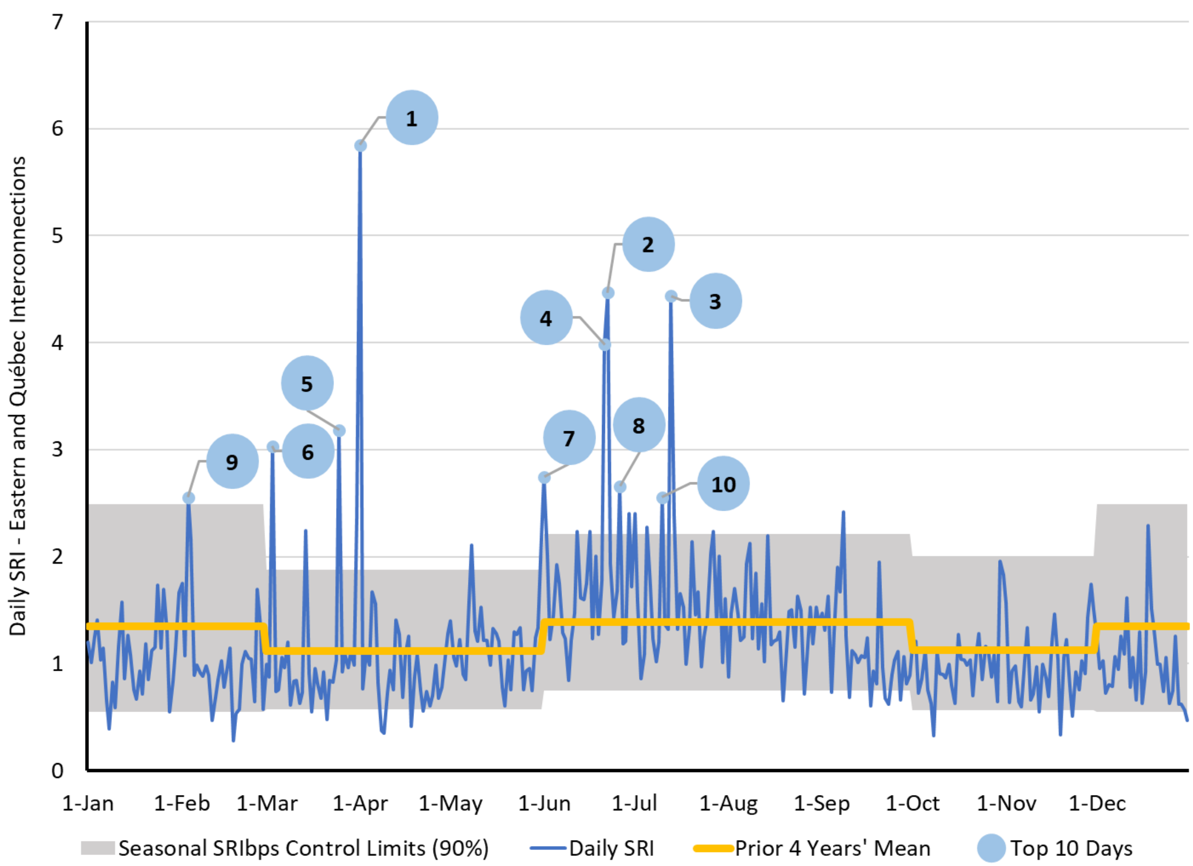


Figure A.1: 2023 Eastern and Québec Interconnections Daily SRI with Top 10 Days Labeled, 90% Confidence Interval

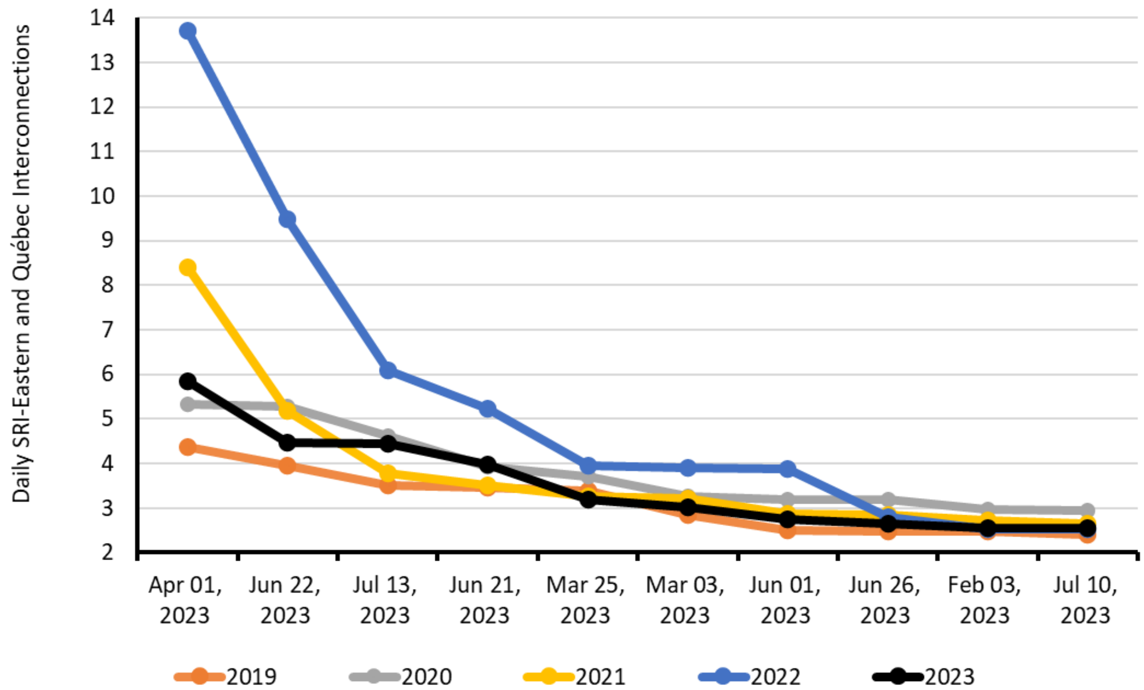


Figure A.2: Eastern and Québec Interconnections Top Annual Daily SRI Days, Sorted Descending

Table A.2 provides details on each component's contribution to the top 10 SRI days for the Eastern and Québec Interconnections.

Table A.2: 2023 Top 10 SRI Days Eastern and Québec Interconnections							
Rank	Date	SRI and Weighted Components 2022				Atypical Weather Conditions	Regional Entities within the Interconnection
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss		
1	1-Apr	5.85	0.74	0.64	4.46	Widespread Storms and Tornadoes	MRO, RF, SERC
2	22-Jun	4.47	1.34	2.99	0.14	Québec Wildfires	NPCC
3	13-Jul	4.44	0.89	3.19	0.36	Québec Wildfires	NPCC
4	21-Jun	3.98	1.15	2.60	0.23	Québec Wildfires	NPCC
5	25-Mar	3.18	0.60	0.42	2.17	Widespread Storms	NPCC, RF, SERC
6	3-Mar	3.03	1.22	0.65	1.16	Severe Storms	MRO, NPCC, RF, SERC
7	1-Jun	2.75	1.62	1.07	0.05	Québec Wildfires	NPCC
8	26-Jun	2.66	1.16	1.12	0.39	Thunderstorms	MRO, NPCC, RF, SERC
9	3-Feb	2.55	2.28	0.10	0.18	Coincident Large Coal and	N/A

Table A.2: 2023 Top 10 SRI Days Eastern and Québec Interconnections							
Rank	Date	SRI and Weighted Components 2022				Atypical Weather Conditions	Regional Entities within the Interconnection
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss		
						Gas Generator Outages	
10	10-Jul	2.55	0.56	1.89	0.10	Québec Wildfires	NPCC

Table A.3 shows the top 10 SRI days for the Eastern and Québec interconnection over the last five years with the only date in 2023 highlighted in red.

Table A.3: 2019–2023 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	13.72	8.88	0.91	3.92	Winter Storm Elliott	All
2	December 24, 2022	9.49	8.13	1.29	0.07	Winter Storm Elliott	All
3	February 16, 2021	8.32	4.11	0.59	3.63	Cold Weather Event	MRO, RF, SERC
4	June 14, 2022	6.10	1.71	0.49	3.90	High Temperatures and Derecho	MRO, NPCC, RF, SERC, TRE
5	April 1, 2023	5.85	0.74	0.64	4.46	Widespread Storms and Tornadoes	MRO, RF, SERC
6	August 4, 2020	5.33	1.38	1.02	2.93	Hurricane Isaias	NPCC, RF, SERC
7	August 27, 2020	5.28	1.42	1.33	2.52	Unnamed Tropical Storm	RF, SERC
8	June 15, 2022	5.23	1.63	0.24	3.36	High Temperatures and Derecho	MRO, NPCC, RF, SERC, TRE
9	February 15, 2021	5.16	3.63	0.55	0.99	Cold Weather Event	MRO, RF, SERC
10	October 29, 2020	4.62	1.03	1.42	2.17	Hurricane Zeta	MRO, RF, SERC

Western Interconnection

The 2023 cumulative SRI for the Western Interconnection (see Table A.4) shows a 4% decrease over the prior four-year period of 2019–2022. The 2023 cumulative SRI was the second 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
2019	421.7	104.4	73.9	599.9	1.64
2020	390.8	100.6	73.0	564.4	1.54
2021	426.8	104.0	96.9	627.7	1.72
2022	423.7	93.4	61.6	578.7	1.59
2023	**423.2**	**74.3**	**68.8**	**566.3**	**1.55**

The top 10 SRI days of the Western Interconnection for 2023 were distributed throughout the year as shown in Figure A.3. None of the top 10 days that occurred in the Western Interconnection align with the top 10 SRI days reported for North America. All days were driven by either generation or load loss.

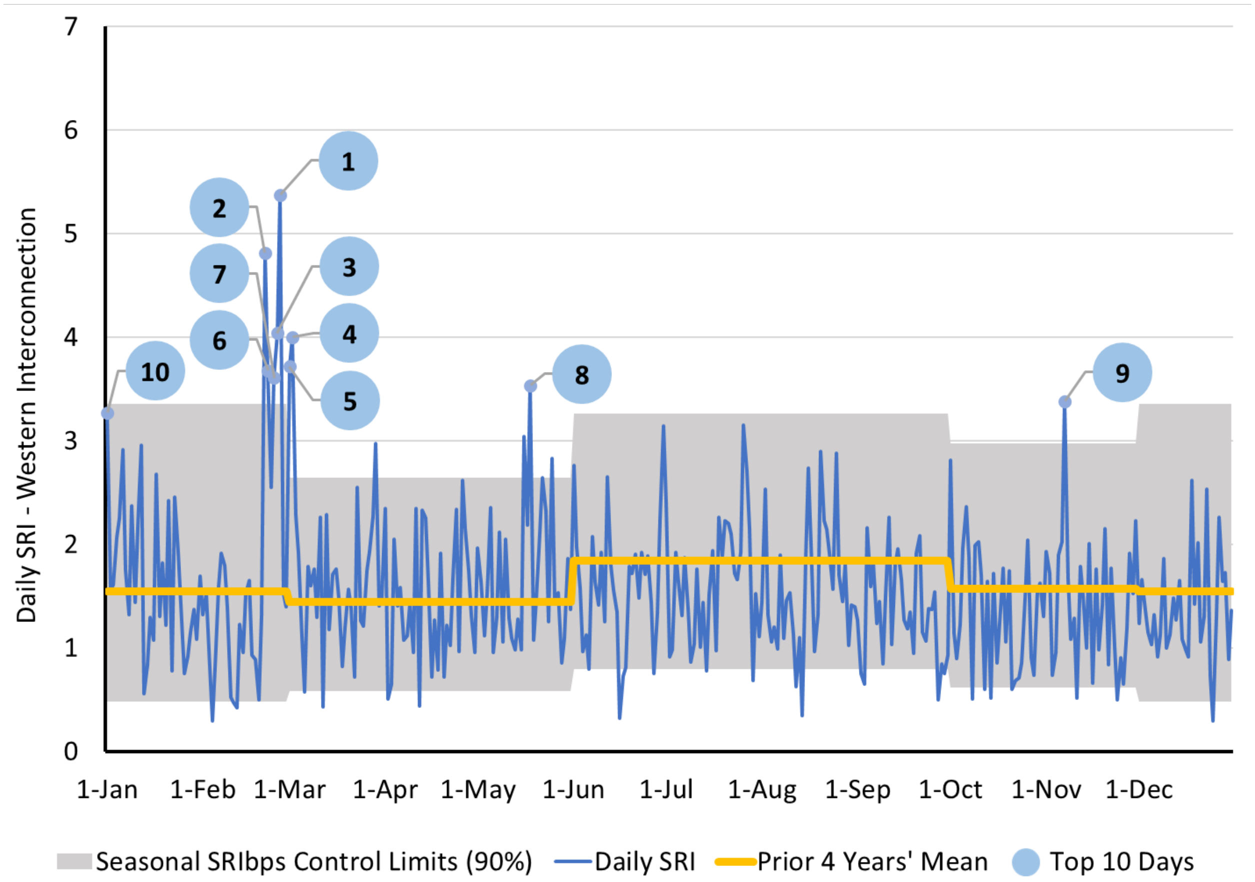


Figure A.3: 2023 Western Interconnection Daily SRI with Top 10 Days Labeled, 90% Confidence Interval

Figure A.4 shows the Western Interconnection's top ten SRI days in 2023 relative to the four prior years.

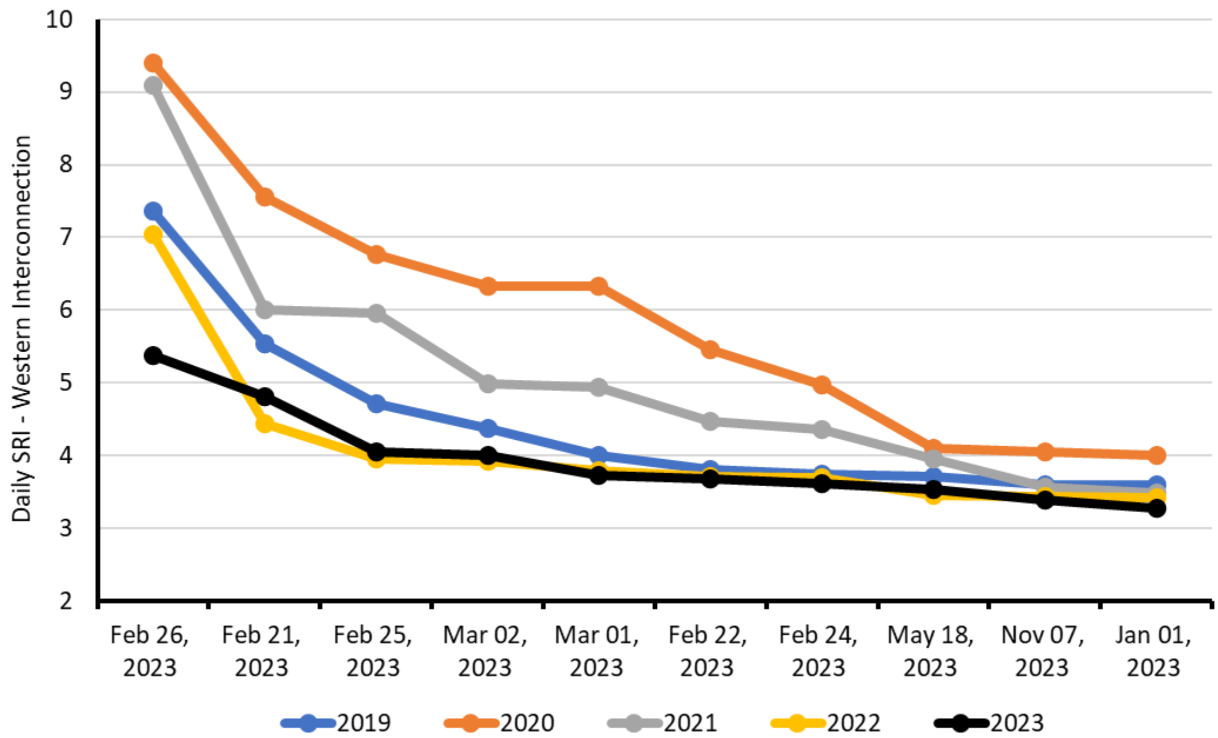


Figure A.4: Western Interconnection Top Annual Daily SRI Days Sorted Descending

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.

Table A.5: 2023 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	26-Feb	5.38	1.30	0.17	3.91	Winter Storm
2	21-Feb	4.82	1.63	0.04	3.14	Winter Storm
3	25-Feb	4.04	1.20	0.64	2.20	Flooding
4	2-Mar	4.00	1.96	0.21	1.83	Winter Storm
5	1-Mar	3.72	2.66	0.44	0.62	Winter Storm
6	22-Feb	3.68	2.22	1.23	0.22	Winter Storm
7	24-Feb	3.61	2.61	0.96	0.05	Winter Storm
8	18-May	3.53	2.80	0.48	0.25	No discernible atypical weather conditions
9	7-Nov	3.38	1.54	0.03	1.81	No discernible atypical weather conditions
10	1-Jan	3.27	1.92	1.32	0.02	Severe Storms

Table A.6 shows the top 10 SRI days for the Western interconnection over the last five years.

Table A.6: 2019–2023 Top 10 SRI Days Western Interconnection[85]

Rank	Date	SRI and Weighted Components				Atypical Weather Conditions
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss	
1	August 16, 2020	9.40	2.05	0.92	6.43	Extreme Heat
2	November 17, 2021	9.09	0.62	0.06	8.41	High winds and Special Protection System Operation
3	August 17, 2020	7.55	2.13	0.87	4.55	Extreme Heat
4	October 11, 2019	7.36	0.75	5.72	0.88	Saddle Ridge Fire
5	December 22, 2022	7.03	2.40	0.71	3.93	No discernible atypical weather conditions
6	September 8, 2020	6.76	3.38	3.14	0.25	Wildfires
7	September 9, 2020	6.33	1.44	1.11	3.78	Wildfires
8	August 19, 2020	6.33	1.63	2.12	2.58	Extreme Heat
9	January 13, 2021	6.00	1.86	4.05	0.09	Northwest Winter Weather
10	January 15, 2021	5.96	1.36	0.12	4.48	Winter Storm

Extreme Day Analysis by Interconnection

The extreme-day analyses for transmission and generation for 2023 are presented by Interconnection. The maximum TADS reported MVA capacity or GADS reported net maximum capacity for 2023 is shown in the upper-right 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 weather conditions are not identified. All dates are shown in UTC.

[85] 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.

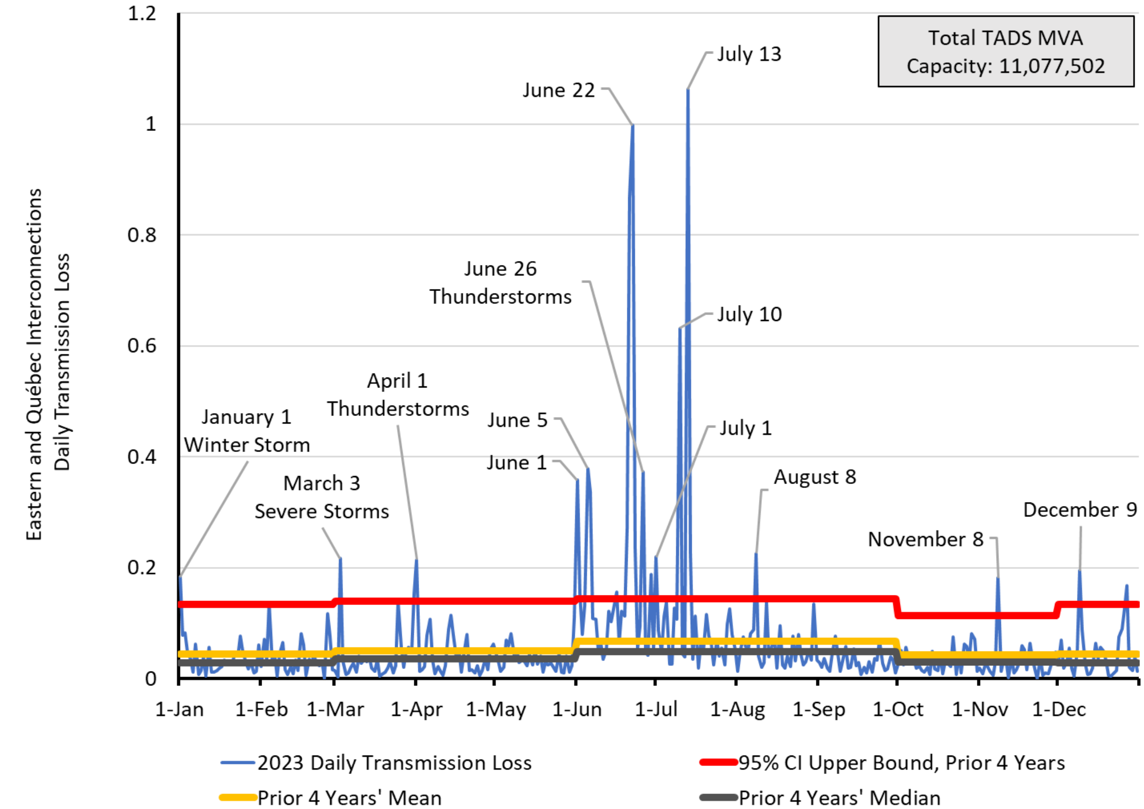


Figure A.5: Eastern and Québec Interconnections—Transmission Impacts during Extreme Days of 2023

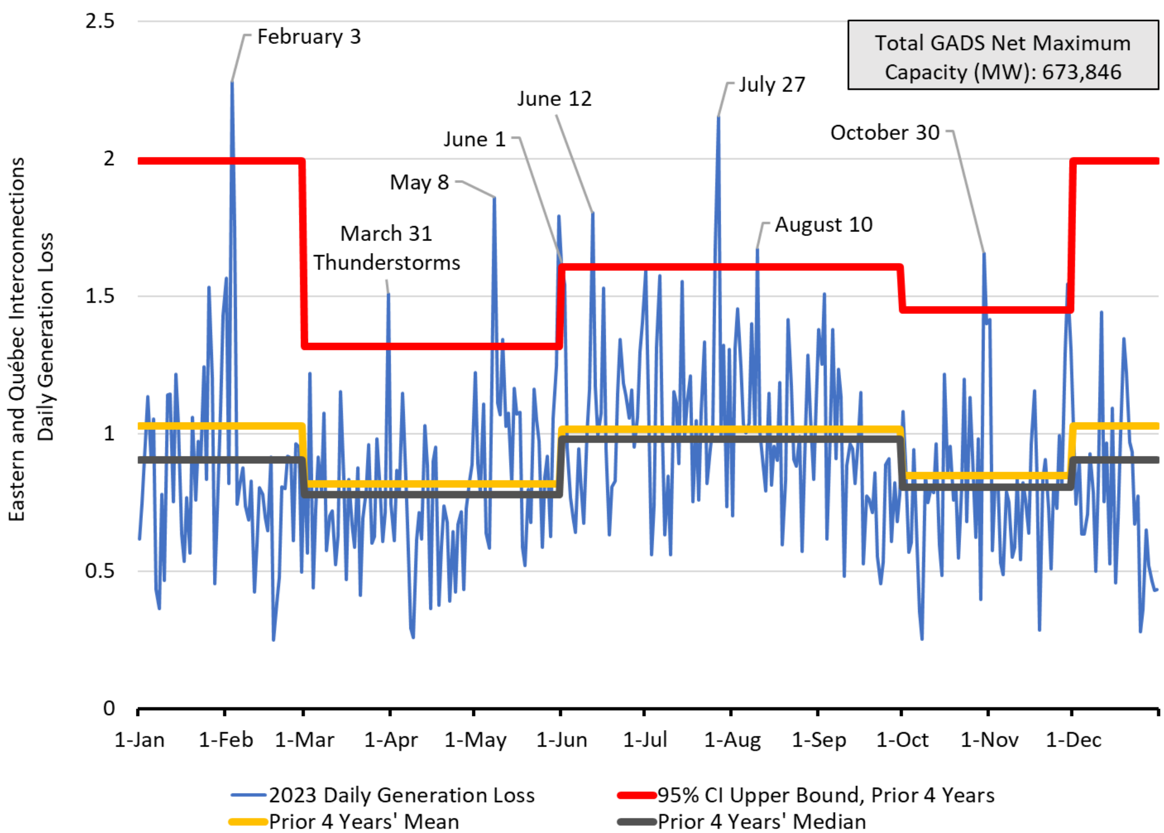


Figure A.6: Eastern and Québec Interconnections—Generation Impacts during Extreme Days of 2023

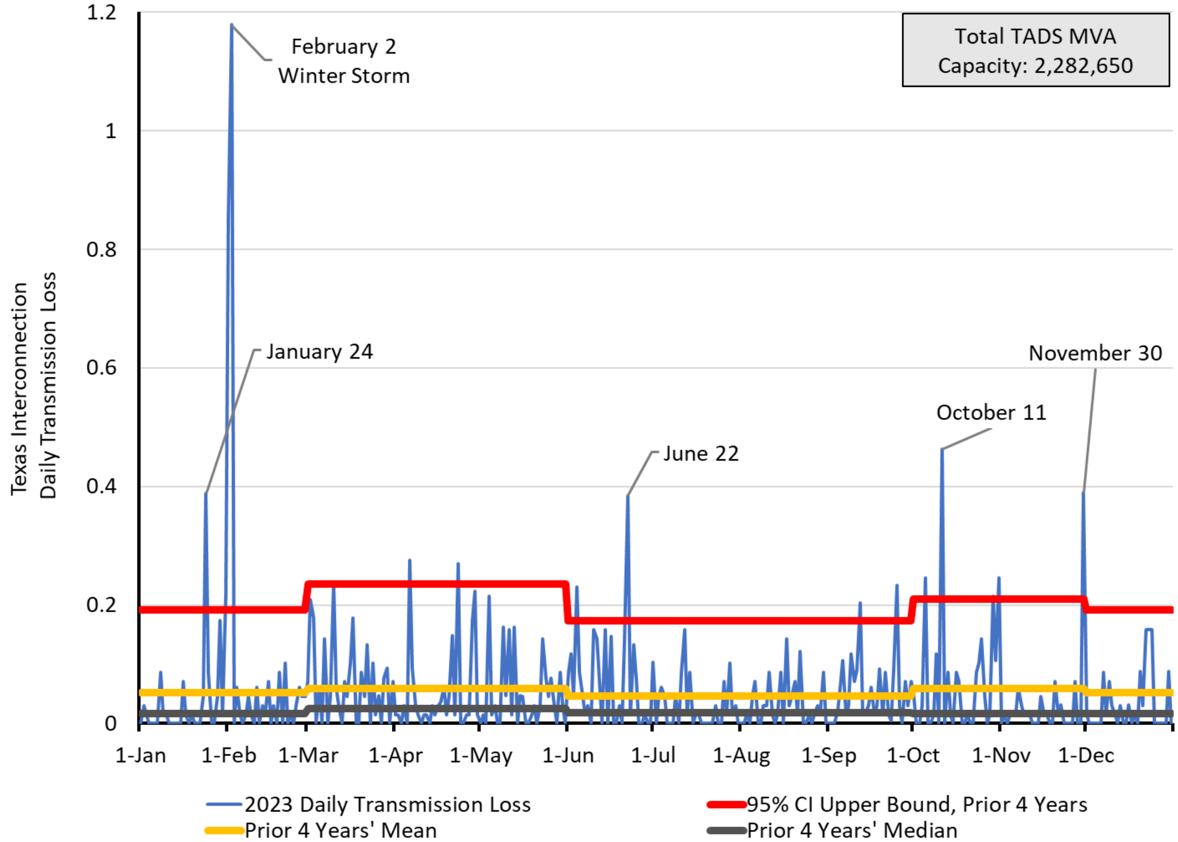


Figure A.7: Texas Interconnection—Transmission Impacts during Extreme Days of 2023

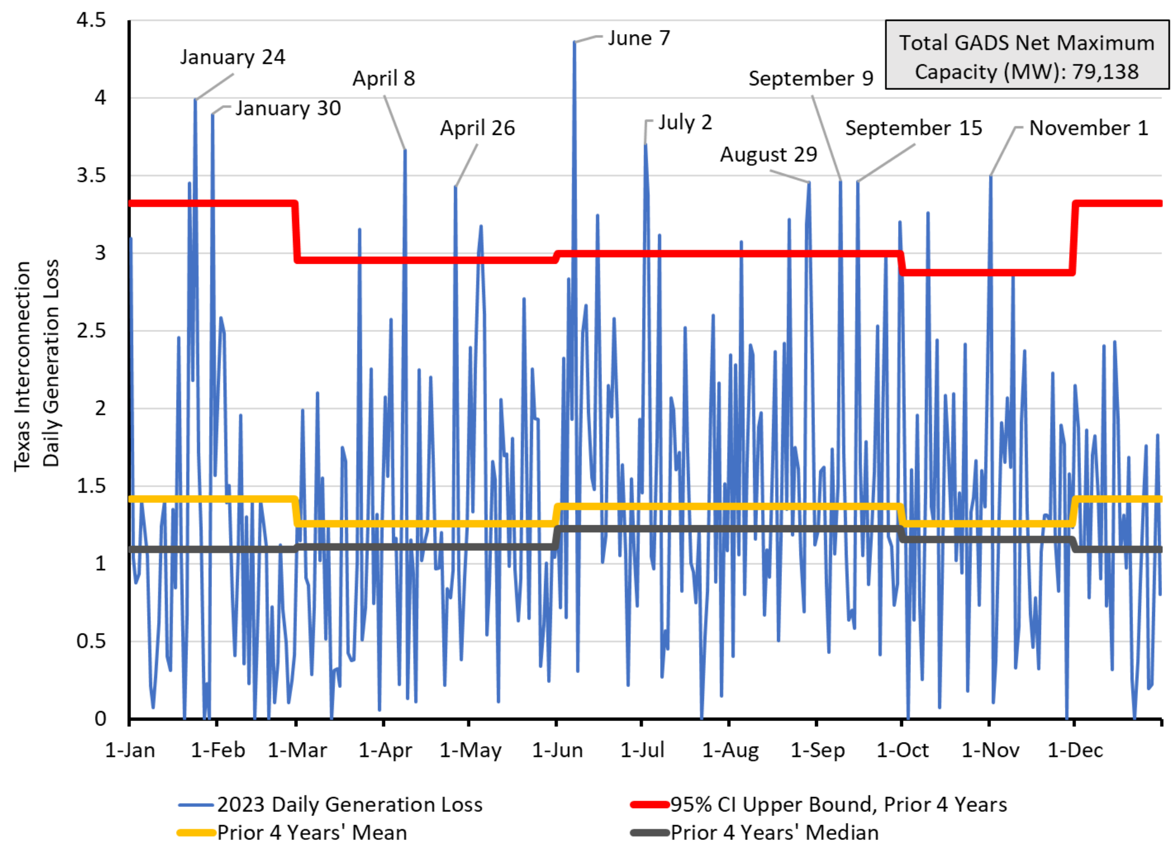


Figure A.8: Texas Interconnection—Generation Impacts during Extreme Days of 2023

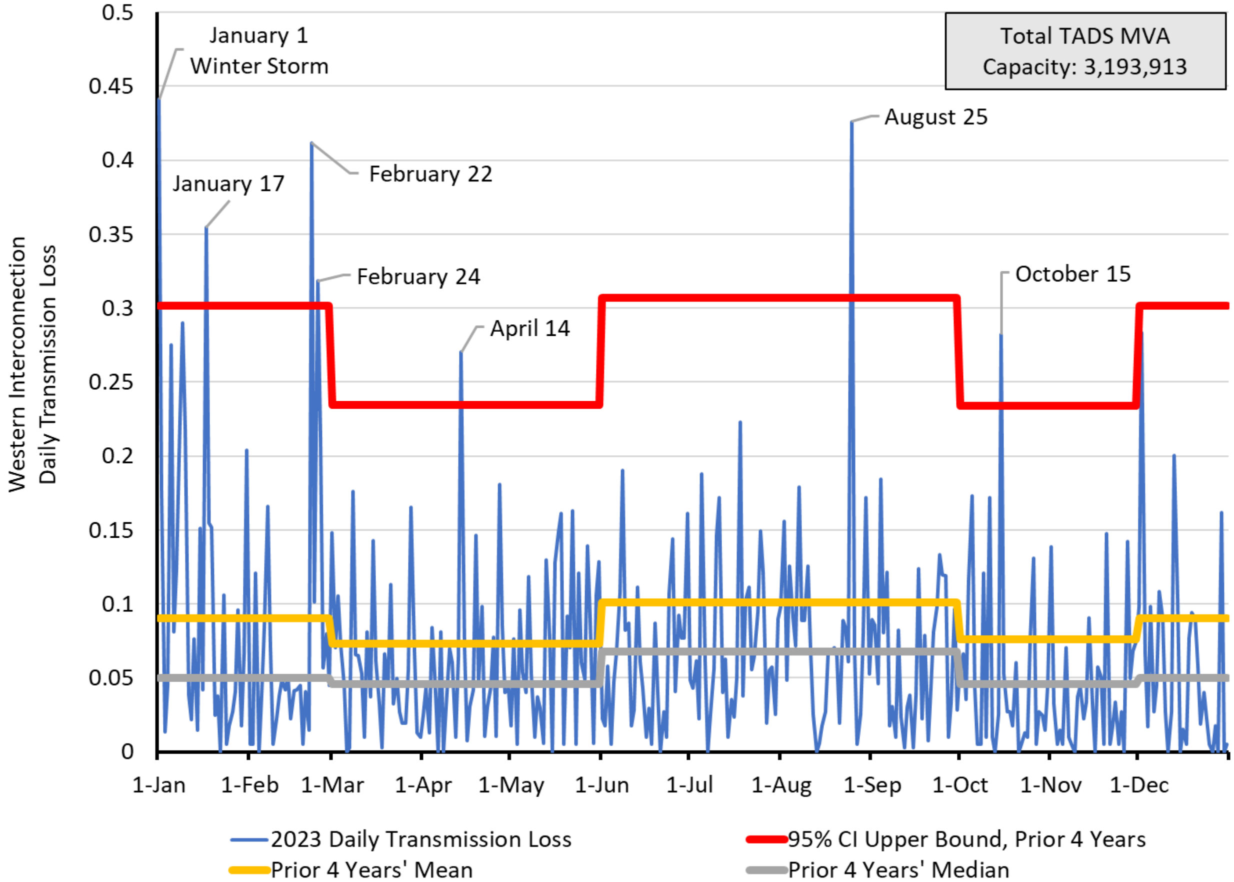


Figure A.9: Western Interconnection—Transmission Impacts during Extreme Days of 2023

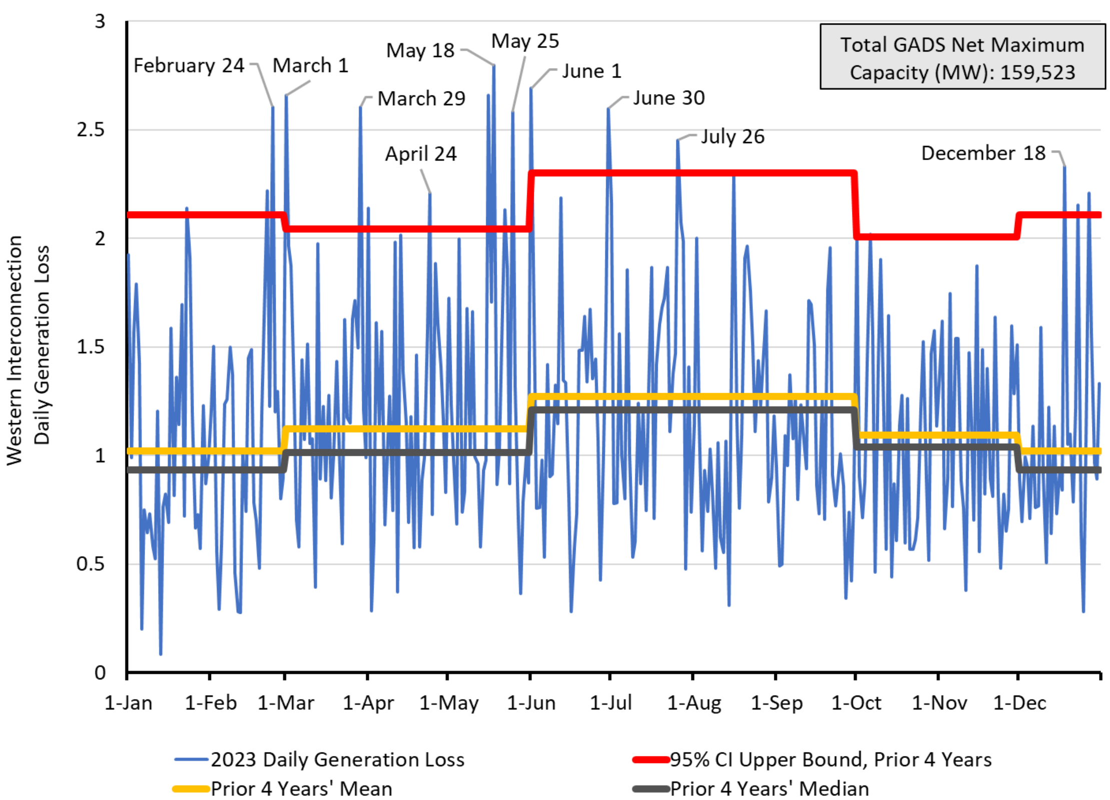


Figure A.10: Western Interconnection—Generation Impacts during Extreme Days of 2023

Appendix B: Acknowledgements

NERC would like to express its appreciation to the many people who provided direct technical support and identified areas for improvement to this document as well as all the people across the industry who work tirelessly to keep the lights on every day.

NERC Industry Group Acknowledgements	
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