NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2022 State of Reliability

July 2022

An Assessment of 2021 Bulk Power System Performance

Table of Contents

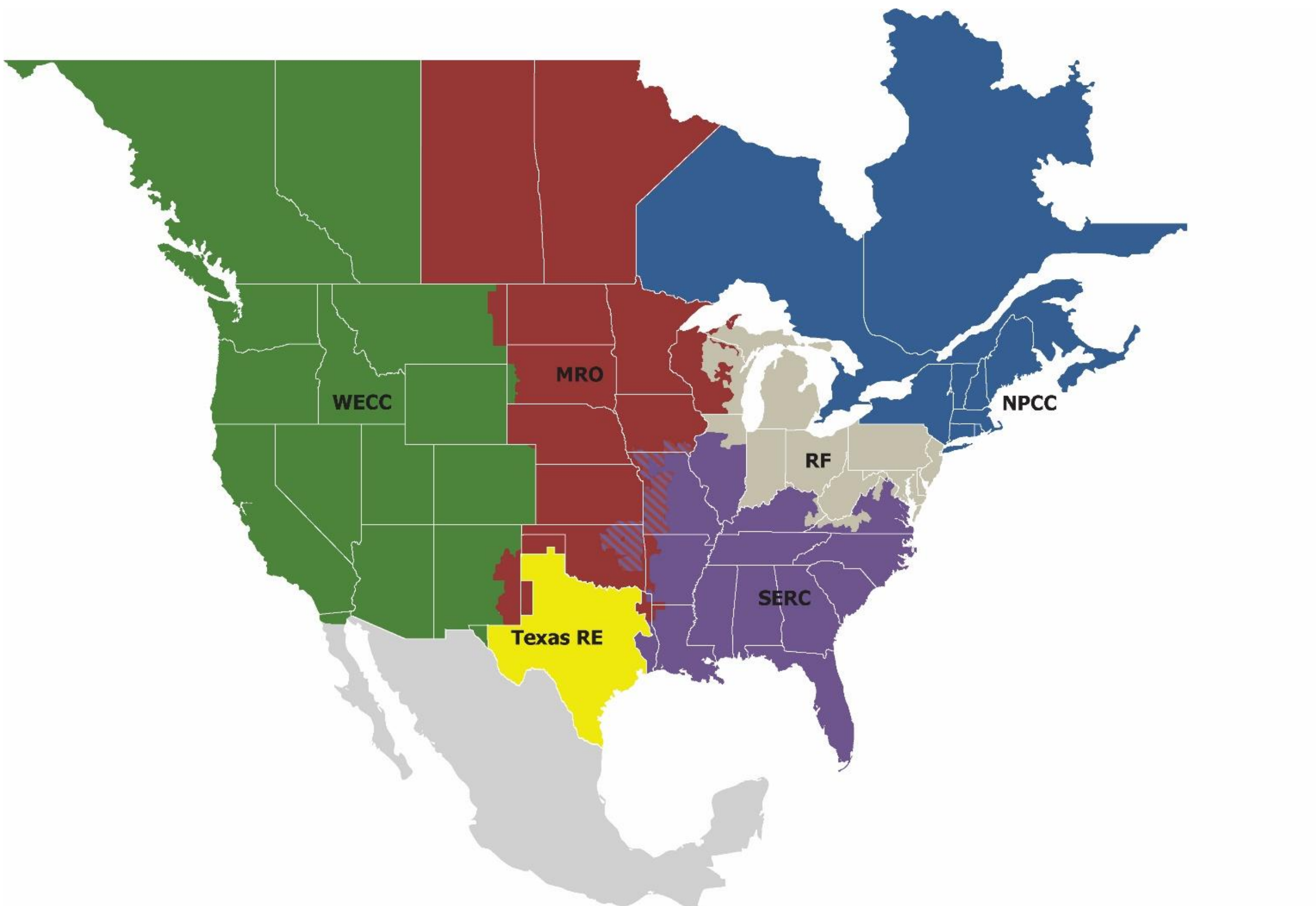
Preface

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 the North American Electric Reliability Corporation (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 Entity boundaries as shown in the map and 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 Report

The purpose of this yearly report is to provide objective and concise information to policymakers, industry leaders, and regulators on issues that affect the reliability and resilience of the North American BPS. Specifically, the report does the following:

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

NERC, as the ERO of North America, works to assure the effective and efficient reduction of reliability risks as well as the security risks of 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. Additionally, analyses of past BPS performance serve to document BPS adequacy and to identify positive or negative performance trends; the annual State of Reliability report is one such analysis of past performance that informs regulators, policymakers, and industry leaders while providing strong technical support for those interested in the underlying data and detailed analytics.

Development Process

ERO staff developed this independent assessment with support from the Performance Analysis Subcommittee. This *2022 State of Reliability* report focuses on Bulk Electric System (BES)[1] performance during the prior complete year as measured by a predetermined set of reliability indicators and more detailed analysis performed by ERO staff and technical committee participants. This report has been endorsed by the Reliability and Security Technical Committee (RSTC) and accepted by the NERC Board.

Primary Data Sources

In addition to a variety of information-sharing mechanisms—including (but not limited to) the NERC RSTC and the Electricity Information Sharing and Analysis Center (E-ISAC)—the ERO administers and maintains the information systems described in **Figure AR.1**.

[1] The term bulk power system (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 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.

Transmission Availability Data System (TADS)

TADS inventory and outage data are used to study the initiating cause codes and sustained cause codes of transmission outages. Metrics are developed that analyze outage frequency, duration, causes, and many other factors related to transmission outages. This analysis can shed light on prominent and underlying causes that affect the overall performance of the BPS.

Transmission
100 kV and greater

Generation Availability Data System (GADS)

GADS contains information that can be used to compute generation-related reliability measures, such as the weighted-equivalent forced outage rate, which is a metric for measuring the probability that a unit will not be available to deliver its full capacity at any given time due to forced outages and derates. NERC's GADS maintains operating histories on more than 5,000 generating units in the North America.

Conventional Generators
20 MW and larger
Wind Plants
75 MW and greater

Misoperation Info Data Analysis System (MIDAS)

MIDAS collects protection system relay operations and misoperations. Metrics are developed to assess protection system performance. Trends are evaluated and can be used to identify remediation techniques to reduce the rate of occurrence and the severity of misoperations. Misoperations exacerbate event impacts on the BPS. The data collection is granular and allows NERC to identify specific trends associated with certain geographies, technologies, human performance, and management.

Transmission Owners,
Generator Owners,
Distribution Providers

The Event Analysis Management System (TEAMS)

TEAMS is used to track and process records originating from the EOP-004 reporting, OE-417 reporting, Event Analysis Process and the ERO Cause Code Assignment Process. Relevant reports are recorded, uploaded, and tied together into a single event. The data in TEAMS is used to support event cause coding, general system performance analysis, and key performance indicators for the bulk power system.

Balancing Authorities,
Reliability Coordinators,
Transmission
Owner/Operators,
Generation
Owner/Operators

Figure AR.1: Information Systems Administered and Maintained by the ERO

Considerations

- The data in this report represents the performance for the January–December 2021 operating year unless otherwise noted.
- Analysis in this report is based on data from 2017–2021 that was available at the time of this report and provides a basis to evaluate 2021 performance relative to performance over the last five years. Any updates to data that occur after the report is published will be reflected in a subsequent report.
- This report is a review of industry-wide trends and not a review of the performance of individual entities. Accordingly, information presented in this report is always aggregated at the Interconnection level or the Regional Entity level in order to maintain the anonymity of individual reporting organizations.
- The background on approaches, method, statistical tests, and procedures are available by request.
- When analysis is presented by Interconnection, the Québec Interconnection (QI) is combined with the Eastern Interconnection (EI) for confidentiality unless specific analysis for the QI is shown.

Executive Summary

This *2022 State of Reliability* report is NERC's review of BES reliability during 2021. It is prepared to inform regulators, policymakers, and industry leaders of major reliability risks and performance trends, actions that are being taken to address them, and the effectiveness of past actions.

There were unprecedented challenges to BES reliability in 2021. Despite these challenges, grid operators were able to maintain reliability with one notable exception: The extreme and sustained cold weather in February 2021,[2] especially in the Texas and South Central parts of the United States, led grid operators in the impacted areas to order the largest controlled load shed event in U.S. history.[3] The event was also the third largest in the quantity of outaged megawatts of load—following the August 2003 Northeast and the August 1996 Western Interconnection (WI) blackouts.[4] While these emergency operating measures were necessary in order to prevent more prolonged blackouts, firm load shed and weather-related unplanned outages imposed enormous hardships on millions of electricity customers. At least 210 deaths resulted from the outages and cold weather in Texas.[5] In November 2021, the Federal Energy Regulatory Commission (FERC), NERC, and the affected Regional Entities issued a report that thoroughly analyzed the event. The analysis confirmed that industry had not sufficiently implemented voluntary recommendations from similar events that were first identified in 2011.[6] Based on these related findings, this *2022 State of Reliability* report considers the 28 recommendations from the *FERC, NERC and Regional Entity Staff Report,*[7] including several mandatory cold weather preparedness Reliability Standards.

In March 2021, the NERC Board acted to expedite completion of revisions to Reliability Standards EOP-011-2, IRO-010-2, and TOP-003-5 under Project 2019-06 Cold Weather. The NERC Board adopted the three revised standards in June; FERC subsequently approved all three in August, and they become effective on April 1, 2023. EOP-011-2 includes new cold weather preparedness planning requirements for Generator Owners and Generation Operators. IRO-010-2 and TOP-003-5 establish new cold weather generating unit operating limitation data specifications as well as collection and reporting requirements for Reliability Coordinators, Balancing Authorities (BA), Generator Owners, Generation Operators, Transmission Operators, Transmission Owners, and Distribution Providers.

In addition to the aforementioned development of cold weather winterization standards, the ERO Enterprise has ramped up mitigating activities, including implementation of a fuel assurance guideline that addresses extreme weather scenarios in long-term reliability assessments and the development of additional standards for energy resource adequacy. Among other things, the February 2021 cold weather event and other past related severe weather events confirm that interdependencies between the electricity and natural gas industries are a major new reliability risk that must be explicitly managed.

Throughout 2021, the North American electricity industry continued to weather cyber and physical attacks of varying degrees of sophistication and severity. Although the reliability of the BES was maintained, nation-state adversaries and organized cyber criminals have demonstrated that they have the ability and willingness to disrupt critical infrastructure. Notably, cyber-attacks routinely targeted the digital supply chain. In addition, reports of suspicious cyber incidents (including vulnerability exposure, phishing, malware, denial of service, and other cyber-related reports) increased significantly. While 2021 saw a moderate increase in the overall number of physical security incidents, the most serious types of incidents declined.

---

[2] February 2021 was the 19th coldest out of the 127 year record: https://www.ncei.noaa.gov/news/national-climate-202102

[3] Federal Energy Regulatory Commission (2021, November) *FERC, NERC and Regional Entity Staff Report: The February 2021 Cold Weather Outages in Texas and the South Central United States* p.9, fn. 6: https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and

[4] Id.

[5] Id. at 9.

[6] Id. at 17, fn 26.

[7] Id. at 240–41.

Going forward, industry must continue to integrate cyber and physical security considerations with conventional power system planning, operations, design, and restoration practices. The E-ISAC is contributing to these efforts with a two-pronged approach: active response to specific events and specialized trend analysis to suit the operational and information technology environments of member and partner organizations.

In 2021, as in past years, there were several widespread solar photovoltaic (PV) loss events: two in Texas[8] and four in California.[9] While reliability was maintained, the fact that these events continue to take place highlights the importance and urgency of expanding and accelerating ERO Enterprise and industry efforts to address them. It is imperative that the industry reliably integrate the rapidly growing fleet of inverter-based resources (IBRs), including solar PV and energy storage.

To address systemic issues with IBRs, NERC continues to urge industry's adoption of the recommended practices set forth in NERC guidelines even as NERC begins the process of developing mandatory Reliability Standards based on those guidelines (See **Key Findings and Actions in Progress** section). Recommended practices include a renewed focus on establishing and improving interconnection requirements, improved interconnection and reliability studies that mitigate systemic modeling errors, and development of a comprehensive inverter ride-through standard.

The impact of wide-area and long-duration extreme weather events, like the February 2021 South Central U.S. cold weather event and the August 2020 Western U.S. wide-area heat event, have underscored the need to consider extreme scenarios in resource adequacy and energy sufficiency planning. Diminished levels of flexible generation (i.e., fuel-assured, weatherized, and dispatchable resources) are occurring in many areas as the resource mix evolves, increasing the risk of energy shortfalls. No longer is the peak demand period the only clear risk period; instead, risks can emerge when weather-dependent generation is impacted by abnormal atmospheric conditions or when extreme conditions disrupt fuel supplies. Accordingly, the ERO's methods for analyzing and tracking the effects of these events are evolving. Although margins in 2021 were all assessed as adequate for traditional reliability criteria, the NERC analysis used for seasonal reliability assessments in 2021 accounted for more extreme conditions and warned of potential seasonal shortfalls in 8 of the 20 assessment areas, accounting for nearly half of the geographic area that comprises the North American BPS.

In addition, the events of the past year have led the ERO Enterprise to begin reassessing how best to measure the overall reliability performance objectives for the industry as reflected in the definition of "Adequate Level of Reliability (ALR)."[10] As far back as 2015, the Performance Analysis Subcommittee highlighted the need for metrics to evaluate the resilience of the BPS to the changing resource mix, and industry's efforts have advanced that work forward. This report introduces methods for evaluating restoration events as a first step toward developing formal resilience metrics.

The year 2021 saw improvement in both the year-over-year and the five-year average in automatic outages, both for transmission and transformers as initiated by failed substation equipment and human performance. Transmission outage severity (TOS), transmission events resulting in loss of load, and the ERO Enterprise-wide planning reserve margin also improved. The frequency response remained stable or improved across all Interconnections, and the number of energy emergency alert (EEA) Level 3s improved in the QI and WI.

As a result of the February 2021 cold weather event, the EEA Level 3 metric for the Texas Interconnection (TI) and EI is now being monitored. Other reliability indicators being monitored are automatic transmission and transformer outages due to ac circuit unavailability and failed protection systems, the generation weighted-equivalent forced outage rate (WEFOR), and the disturbance control standard.

[8] https://www.nerc.com/pa/rrm/ea/Pages/May-June-2021-Odessa-Disturbance.aspx
[9] https://www.nerc.com/pa/rrm/ea/Pages/CAISO-2021-Disturbance-Report.aspx
[10] Informational Filing on Definition: *Adequate Level of Reliability for the Bulk Electric System*, May 10, 2013.

Key Findings and Actions in Progress

Based on data and information collected for this assessment of BES reliability performance in 2021, NERC identified six key findings and is taking actions to address them. The impact of extreme weather upon BES reliability is a consistent theme underlying four of the key findings.

Key Finding 1

The February cold weather event demonstrated that a significant portion of the generation fleet in the impacted areas was unable to supply electrical energy during extreme cold weather.

In February, BES operators were confronted with unplanned and uncontrolled generator outages that required reliance on an extraordinary amount of necessary emergency actions to avoid instability, uncontrolled separation, cascading, or voltage collapse. As a result of February's cold weather event, the amount of unserved energy due to operator-initiated load shedding reported through the EEA process was the highest amount since the ERO Enterprise began reporting this metric and almost one-hundred times higher than the prior year (1,015 GWh in 2021 vs. 13 GWh in 2020). Refer to the **Energy Emergency Alerts** section of Chapter 3 for more information on this topic.

Actions in Progress

The ERO Enterprise is quickly implementing the recommendations in the *FERC, NERC and Regional Entity Staff Report: The February 2021 Cold Weather Outages in Texas and the South Central United States*.[11] Once implemented, these corrective actions will provide BES planners and operators with additional tools to avoid a recurrence of BES reliability threats arising from extreme cold weather events and address energy availability standards development for long-term planning and operational planning/operations time frames.

Key Finding 2

Electricity and natural gas interdependencies are no longer emerging risks but require immediate attention, including implementation of mitigating approaches.

Over the past several years, the electricity and natural gas industries' interdependencies have been identified as emerging risks to BES reliability. It is now evident that these risks are no longer emerging; they are certain and expected to increase. Natural-gas-fired generators are now necessary balancing resources for reliable integration of the growing fleet of variable renewable energy resources and can be expected to remain so until new storage technologies are fully developed and deployed at scale to provide balancing. At the same time, reliable electric power supply is often required to ensure uninterrupted delivery of natural gas to these balancing resources, particularly in areas where penetration levels of renewable generation resources are highest. Refer to the **Planning Reserve Margin** of Chapter 3 and the **Critical Infrastructure Interdependencies** of Chapter 4 for more information.

Actions in Progress

NERC's forward-looking Reliability Assessment Program continues to emphasize the risk of increased reliance on natural gas generation. The ERO Enterprise is actively encouraging registered entities to conduct studies to model plausible and extreme natural gas disruptions set forth in NERC's March 2020 reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risks Analysis for the Bulk Power System*.[12] Furthermore, the ERO Enterprise and industry are prioritizing two standards authorization requests that are currently being drafted to require registered entities to conduct studies for both planning and operations to ensure energy resource adequacy.

---

[11] Federal Energy Regulatory Commission (2021, November) *FERC, NERC and Regional Entity Staff Report: The February 2021 Cold Weather Outages in Texas and the South Central United States*: https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and

[12] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Fuel_Assurance_and_Fuel-Related_Reliability_Risk_Analysis_for_the_Bulk_Power_System.pdf

Key Finding 3

As climate change increases extreme weather event intensity and frequency,[13] severe weather again challenged the BPS putting grid resilience (the ability to withstand and recover from extreme events) into focus.

NERC began analyzing the largest transmission events caused by severe weather in 2020 and introduced new quantitative measures to assess the severity of these events and the ensuing restoration processes. Resilience and restoration analysis in **Chapter 2** provides additional insights into BES performance during and after extreme weather events. The ERO Enterprise continues to examine outage and restoration processes for large weather-related transmission events to develop resilience statistics that measure and track the BES's ability to withstand, adapt, protect against, and recover from the impacts of extreme weather events.

Actions in Progress

The ERO Enterprise is expanding and further refining resilience and restoration analysis by examining generation and load loss as well as improving linkage between equipment outages and weather. The resulting analysis can help target certain risk areas, benchmark the performance the system impacted by varying weather events, and serve as key data for industry investment and mitigation.

Key Finding 4

Geopolitical events, new vulnerabilities, new and changing technologies, and increasingly bold cyber criminals and hacktivists presented serious challenges to the reliability of the BES.

The North American electricity industry weathered a series of attacks on the digital supply chain. In addition, reports of suspicious cyber incidents (including vulnerabilities, phishing, malware, denial of service, and other cyber-related reports) increased significantly. Vulnerabilities and risks to reliability are serious and unavoidable in an internet-enabled environment. The **Cyber and Physical Security** section of Chapter 4 provides more information on this topic.

Actions in Progress

Industry is developing security-informed institutional practices that leverage security frameworks and activities to protect and secure the operational and organizational environment in order to mitigate and prepare for the security risks that threaten reliability. Supply chain requirements and guidance are being drafted by NERC and the technical committees to reduce vulnerabilities and better protect industry systems and infrastructure.

Key Finding 5

Large assessment areas have become dependent upon renewable resources to meet peak loads, but multiple loss of solar events in Texas and California in 2021 confirm that unaddressed inverter issues increased reliability risk.

Multiple loss of solar events in Texas and CAISO as detailed in the *Odessa Disturbance Report*[14] and the *2021 CAISO Solar PV Disturbance Report*[15] highlight that there are continued BES reliability risks associated with inadequately interconnected IBRs. At the same time, assessment data from several areas revealed that peak demand could not be met without renewable generation.[16] Failing to address remaining solar PV inverter issues increased reliability risk. More information on this topic can be found in the **Resource Adequacy** section in Chapter 3.

Actions in Progress

The ERO Enterprise and industry are implementing the recommendations set forth in the *Odessa Disturbance Report* and the *2021 CAISO Solar PV Disturbance Report* with high priority and a focused strategy. High priority items include incorporating Electromagnetic Transient Modeling into the NERC Reliability Standards and developing a comprehensive ride-through requirement that focuses specifically on generator protections and controls.

---

[13] https://www.nationalacademies.org/based-on-science/climate-change-global-warming-is-contributing-to-extreme-weather-events
[14] https://www.nerc.com/pa/rrm/ea/Pages/May-June-2021-Odessa-Disturbance.aspx
[15] https://www.nerc.com/pa/rrm/ea/Pages/CAISO-2021-Disturbance-Report.aspx
[16] *NERC 2021 Long-Term Reliability Assessment*

Key Finding 6

Additional data types are needed to enable more complete analysis of adequate level of reliability performance objectives.

Two of the five ALR performance objectives do not have performance measures in place because data to support them is not collected. Data to measure performance of IBRs, voltage performance, energy resource adequacy, and load loss and restoration are needed to improve analysis and trending of BES reliability performance. While the BES restoration and resiliency analyses have begun, quantifying and trending the efficiency with which resources and load are restored during these events require new analyses that depend on additional data. **Chapter 5** provides more information on this topic.

Actions in Progress

NERC is identifying appropriate approaches for measuring ALR performance objectives where gaps have been identified.

Chapter 1: The North American BPS—By the Numbers

Figure 1.1 highlights a few key numbers and facts about the North American BPS. How NERC defines BPS reliability is outlined on the next page.

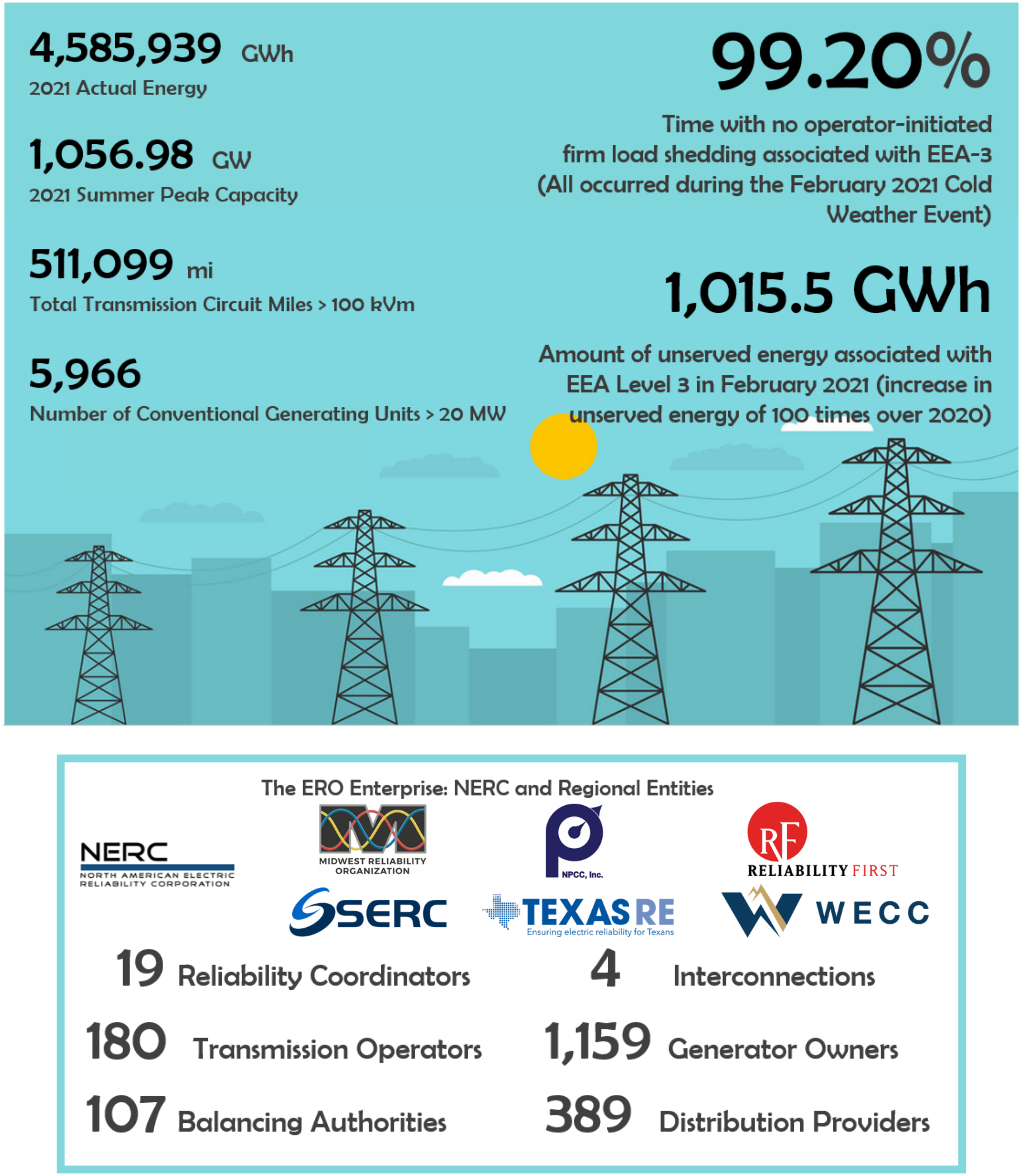


Figure 1.1: 2021 BPS Inventory, Performance Statistics, and Key Functional Organizations

How NERC Defines BPS Reliability*

NERC defines the reliability of the interconnected BPS in terms of three basic and functional aspects as follows:

Adequacy: The ability of the electric system to supply the aggregate electric power and energy requirements of electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components

Operating Reliability: The ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system components

Regarding adequacy, system operators can and should take controlled actions or introduce procedures to maintain a continual balance between supply and demand within a balancing area (formerly known as a control area). Emergency actions in a capacity deficit condition include public appeals and the following:

- Interruptible demand that the end-use customer makes available to its load-serving entity via contract or agreement for curtailment
- Voltage reductions (often referred to as “brownouts” because incandescent lights will dim as voltage is lowered, sometimes as much as 5%)
- Rotating interruptions/outages where a preplanned set of distribution feeders is interrupted for a limited time and put back in service and another set is interrupted, thus, “rotating” the outages

Under the heading of operating reliability are all other system disturbances that result in the unplanned and/or uncontrolled interruption of customer demand, regardless of cause. When these interruptions are contained within a localized area, they are considered unplanned interruptions or disturbances. When these interruptions spread over a wide area of the grid, they are referred to as “cascading blackouts” (uncontrolled successive loss of system elements triggered by protective systems).

The intent of the set of NERC Reliability Standards is to deliver an ALR.

Adequate Level of Reliability: The state that the design, planning, and operation of the BES will achieve when the following reliability performance objectives are met with the following considerations:

- The BES does not experience instability, uncontrolled separation, cascading, and/or voltage collapse under normal operating conditions when subject to predefined disturbances.
- BES frequency is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.
- BES voltage is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.

Adverse reliability impacts on the BES following low-probability disturbances (e.g., multiple contingencies, unplanned and uncontrolled equipment outages, cyber security events, or malicious acts) are managed.

Restoration of the BES after major system disturbances that result in blackouts and widespread outages of BES elements is performed in a coordinated and controlled manner.

For less probable severe events (i.e., losing an entire right of way due to a tornado, simultaneous or near simultaneous multiple transmission facilities outages due to a hurricane, sizeable disruptions to natural gas infrastructure impacting multiple generation resources, or other severe phenomena), BES owners and operators may not be able to apply economically justifiable or practical measures to prevent or mitigate an adverse reliability impact on the BES even if these events can result in cascading, uncontrolled separation or voltage collapse.

*Definition of BES:
https://www.nerc.com/pa/RAPA/BES%20DL/BES%20Definition%20Approved%20by%20FERC%203-20-14.pdf

2021 Key Occurrences

Extreme weather, recurring systemic issues with solar IBRs, and cyber security threats contributed to a number of events that impacted adversely upon BES reliability and produced a dramatic increase year-to-year in the amount of unserved energy in 2021. In February 2021, for example, resource unavailability that resulted from a lack of cold weather preparedness and natural gas supply interruptions contributed to an historic loss of firm load in Texas and the South Central United States. Extreme weather events in 2021 also included the June Northwest heat dome, Hurricane Ida, and tornadoes that ran a destructive and deadly path through eight South Central and Midwestern states in early December. 2021 also saw recurrences of systemic issues with solar IBRs' inability to ride through momentary events on the transmission system, resulting in hundreds of MWs of supply from smaller, individual solar generation facilities coming off-line at the same time. Through all of this, BES planners and operators continued to manage risks from the Covid-19 pandemic, cyber security threats, and supply chain issues.

2021 Extreme Weather Events

As emphasized in NERC's comments for the Climate Change, Extreme Weather, and Electric System Reliability Technical Conference15 and in the *FERC, NERC and Regional Entity Staff Report: The February 2021 Cold Weather Outages in Texas and the South Central United States*, 16 extreme events are having greater impacts on BPS reliability, and these impacts are largely attributable to the effect of extreme weather on the rapidly transforming grid. NERC's most recent planning assessments have warned of the potential for the loss of large amounts of generating resources due to severe weather in winter and summer as well as the potential need for grid operators to employ operating mitigations or EEAs to meet energy demand. In what can only be described as extraordinary, 2021 saw the manifestation of each of these risks. This subsection covers the **February Cold Weather Event**, **Northwest Heat Dome**, **Texas and California Loss of Solar Events**, **Western U.S. and Canadian Wildfires**, **Hurricane Ida**, and **Thunderstorms and Tornadoes.**

February Cold Weather Event

As shown in **Figure 1.2**, the February 2021 winter weather event was the fourth cold-weather-related event in the last 10 years to jeopardize BES reliability.

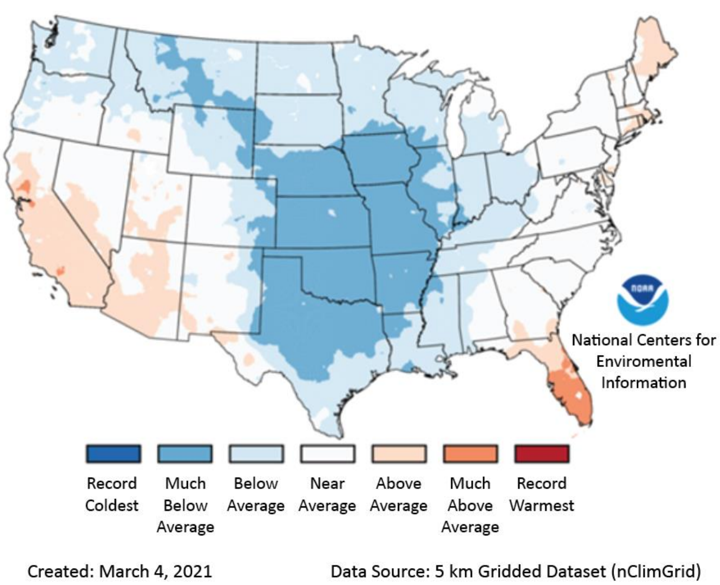


Figure 1.2: Average February Temperatures across North America—February 2021

Between February 8 and 20, extreme cold temperatures and freezing precipitation led 1,045 individual BES generating units with a combined 192,818 MW of nameplate capacity in Texas and the South Central United States to experience 4,124 outages, derates, or failures to start. Unplanned generation outages escalated over the duration of the February 2021 winter weather event and accumulated to over four times the amount that had occurred during the previous largest cold weather event in 2011 (65,622 MW vs. 14,702 MW). Between 7:00 a.m. Central, February 15 and 1:00 p.m. Central, February 17, ERCOT alone averaged 34,000 MW of unavailable generation, nearly half of ERCOT's all-time winter peak electricity load of 69,871 MW. As the coldest weather took hold during the week of February 14 and electricity demand increased, ERCOT, Southwest Power Pool (SPP), and MISO simultaneously faced emergency conditions.[17] In response to these emergency conditions and to avoid more damaging cascading outages and system-wide blackouts, ERCOT system operators issued firm load shed orders that totaled 20,000 MW at the worst point. In the EI, SPP, and MISO system operators also shed a combined total of 3,418 MW of firm load on February 15 and 16. The combined 23,418 MW of manual firm load shed was the largest controlled firm load shed event in U.S. history.[18]

In Texas, temperatures were below freezing for over six days. More than 4.5 million people in Texas were without power during the period, some for as long as four days. As documented in the comprehensive November 2021 *FERC, NERC and Regional Entity Staff Report* analyzing the event, at least 210 deaths were directly or indirectly connected to the February 2021 cold weather outages along with an estimated loss to just the Texas economy of between $80 and $130 billion.

The *FERC, NERC and Regional Entity Staff Report* identifies a confluence of two causes, which are part of a recurring pattern observed over the last decade, that led to sharp increases in generation unavailability and ultimately loss of firm load:

- Generating units that were unprepared for cold weather failed in large numbers.
- In the wake of massive cold weather-induced natural gas production declines and declines in natural gas processing to a lesser extent, the natural gas fuel supply struggled to meet both residential heating load and generating unit demand for natural gas.

Additionally, the generation fleet's increasing reliance on natural gas worsened the impacts of reductions in natural gas fuel supply.

The report identifies 28 recommendations, including revisions to mandatory Reliability Standards. These recommendations address generation cold weather reliability, natural gas infrastructure cold weather reliability and joint preparedness with BES winter peak operations, grid emergency operations preparedness, and grid seasonal cold weather preparedness. The ERO Enterprise is currently implementing many of these recommendations.

Northwest Heat Dome

The heat wave that enveloped the Pacific Northwest from late June through early July 2021 delivered unprecedented temperatures to the normally cool region—108°F (42°C) in Seattle, 116°F (47°C) in Portland—and claimed over 1,000 lives, mostly in British Columbia.[19] As shown in **Figure 1.3**, some of the most populated areas of the Pacific Northwest recorded the highest average mean temperatures on record. These unprecedented temperatures resulted in utilities across the region setting new all-time summer peak demand records. During the Heat Dome, several substation distribution transformers reached internal hotspot levels causing outages in some areas. In combination with the Bootleg Fire, the event resulted in Reliability Coordinators issuing three EEA Level 3s due to transmission impacts that produced energy-constrained load pockets.

[17] https://www.ncei.noaa.gov/access/monitoring/us-maps/1/202102

[18] FERC, NERC, and Regional Entity Staff Report

[19] Neal, E., Huang, C. S. Y., & Nakamura, N. (2022). The 2021 Pacific Northwest heat wave and associated blocking: Meteorology and the role of an upstream cyclone as a diabatic source of wave activity. Geophysical Research Letters, 49, e2021GL097699: https://doi.org/10.1029/2021GL097699

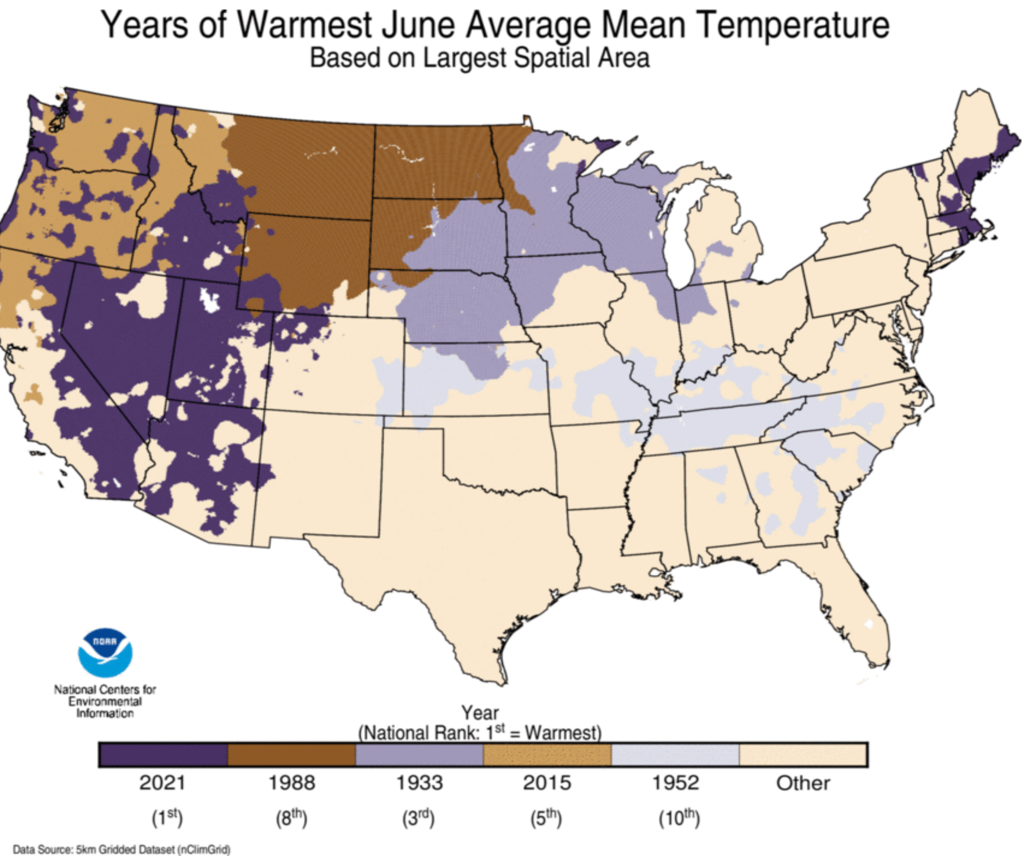


Figure 1.3: Average June Temperatures across the United States—June 2021[20]

Texas and California Loss of Solar Events

Grid disturbances on the BPS continue to result in unreliable operation of BPS-connected solar PV resources, particularly an inability to "ride through" these disturbances. On May 9 and June 26, 2021, widespread reductions of solar PV resource power output occurred in the TI, the first events of this type that have occurred outside California. The May 9 "Odessa Disturbance," the subject of the September 2021 *Joint NERC Texas RE Staff Report*,[21] involved over 1,100 MW of reduced output from solar PV facilities up to 200 miles away from the location of the initiating event and a single-line-to-ground fault that occurred on a generator step-up transformer near Odessa, Texas. Like the California events that preceded them, the May and June events in Texas were mainly attributed to abnormal performance of the inverter controls, plant controls, and protections within the facility. Four additional widespread solar PV loss events occurred in California between June and August of 2021, caused primarily by the legacy facilities that had been interconnected with minimal performance requirements. The April 2022 *Joint NERC and WECC Staff Report - Multiple Solar PV Disturbances in CAISO Disturbances between June and August 2021*[22] provides detailed analyses of these four California disturbances. Across these events, widespread loss of solar PV resources was also coupled with the loss of synchronous generation, unintended interactions with remedial action schemes, and some tripping of distributed energy resources (DERs).

The Texas and California events continue to highlight the criticality of ensuring a reliable resource mix that is able to support the BPS by providing essential reliability services, including during contingency events. The previously mentioned disturbance reports highlights three notable areas for improvement moving forward:

---

[20] NOAA National Centers for Environmental Information, State of the Climate: Monthly National Climate Report for June 2021, published online July 2021, retrieved on May 19, 2022: https://www.ncei.noaa.gov/access/monitoring/monthly-report/national/202106/supplemental/page-7.

[21] September 2021 Joint NERC Texas RE Staff Report

[22] https://www.nerc.com/pa/rrm/ea/Documents/NERC_2021_California_Solar_PV_Disturbances_Report.pdf

- Industry adoption of NERC guidelines focused on establishing and improving interconnection requirements to ensure reliable operation of IBRs with performance validation to confirm resources are providing essential reliability services that meet those requirements as well as improving modeling and study practices to mitigate systemic modeling errors and challenges that the industry faces.
- Significant updates to the NERC Reliability Standards to address systemic performance issues, particularly in the areas of inverter-specific performance-based resources, the establishment of a performance validation standard, developing a comprehensive ride-through standard, and significantly enhancing modeling and study standards to ensure accurate and verified/validated models are used when making reliability decisions.
- Modernization of the generator interconnection process and FERC generator interconnection procedures and agreements to ensure that adequate steps are taken so that the reliability of newly interconnection IBRs and overall reliability of the BPS are considered when rapidly interconnecting more IBRs.

To understand the operational performance of IBRs, a Section 1600 Data Request for the collection of GADS data for solar PV facilities and an expansion of wind reporting is underway in 2022.

Western U.S. and Canadian Wildfires

While most wildfire impacts on the electricity system are at the distribution level, wildfires also pose a risk to the reliable operation of the BPS. These risks arise through damage to transmission infrastructure and through pre-emptive public safety power shutoffs.

At least one wildfire in the third quarter of 2021 had a significant effect on the BES: the Bootleg Fire resulted in a BPS event that began on July 6 when three 500 kV lines tripped over a seven-minute period. The BPS impacts lasted just over five hours when the second of the three lines was returned to service. While no firm load was shed, one entity did use their demand response program to lower their load by 1,748 MW prior to escalating to an EEA-3. Two other EEA-3s were declared when entities fell short of their reserve requirements.

In 2021, the number and size of wildfires in the WI were slightly below the 2020 totals, but wildfires remained a threat. Almost 26,000 fires consumed 8.1 million acres in 2021, year-over-year reductions of 3% and 14%, respectively. Most states suffered fewer acres lost to wildfires than in the year before, but Idaho, Montana, and New Mexico were exceptions. The number of acres burned in Alberta and British Columbia were 15 and 57 times greater, respectively, than that of the year before; this highlights the extreme variability of state- and province-level statistics from one year to the next rather than a trend.

Wildfires correlate with drought and persist in the Western United States, particularly in Oregon, California, Nevada, Utah, New Mexico, and Montana. The fraction of the entire area facing severe to exceptional drought conditions was slightly greater in March 2022 than it was in March 2021. To better understand the relationship between wildfires and transmission outages, WECC has launched a Geographic Information System-based research project by using detailed information about fires and transmission outages. While the results of this inquiry will not be public for some time, preliminary results have not revealed any obvious trends.

Hurricane Ida

According to the National Oceanographic and Atmospheric Administration, 2021 was the third most active year on record in terms of named storms, marking the sixth consecutive above-normal Atlantic hurricane season and the first time on record that two consecutive hurricane seasons exhausted the list of 21 storm names.

One of the most damaging storms of 2021 was Hurricane Ida, which made landfall in Louisiana on August 29, 2021, on the 16 year anniversary of Hurricane Katrina. Hurricane Ida was a deadly and destructive Category 4 hurricane that became the second most damaging hurricane on record to strike the state of Louisiana (only behind Hurricane Katrina). As the hurricane cut across Southeastern Louisiana, it maintained hurricane strength, primarily affecting entities in Louisiana and Mississippi. Hurricane force winds were predominately isolated to Louisiana, resulting in 210 transmission lines out of service and approximately 1.2 million customers out of power in SERC, including the greater New Orleans area. Over 30,000 workers from 41 states worked to restore power throughout the affected areas. **Figure 1.4** shows Hurricane Ida's path, **Table 1.1** and **Table 1.2** summarize its BES impacts.

Map plotting the track and intensity of the storm, according to the Saffir-Simpson Scale

Table 1.1: Transmission Line Outages by Voltage Class[23]	
500 kV	5
230 kV	93
138 kV	10
115 kV	70
69 kV	33
Total	211

Table 1.2: Initial Customer Outages by State Where Hurricane Ida Made Landfall	
Louisiana	1,041 k
Mississippi	123 k
Alabama	20 k
Total:	> 1.2 Million

Figure 1.4: Path of Hurricane Ida[24]

Thunderstorms and Tornadoes

A major storm system formed the afternoon of December 10, 2021, with long-lived thunderstorms (see **Figure 1.5**) that consolidated into a line that reached from Arkansas into Missouri, Tennessee, Kentucky, and Illinois. Eight states reported tornadoes during this time, including two long-tracked EF-4 tornadoes. The longest tornado track associated with this event was nearly 166 miles across Kentucky and a small portion of Tennessee. There were over 800 total miles of tornado path length associated with this storm system with wind speeds of 190 mph at peak intensity. At its height, the storm damage caused outages that affected more than 270,000 customers in SERC.

The December 2021 tornado event resulted in extensive transmission system damage, including the outages of 67 transmission lines or line segments. One tornado followed the path of the right-of-way along a 500 kV transmission corridor, resulting in extensive damage to a large number of transmission structures, including foundation damage. The miles of damage to the 500 kV circuit complicated restoration efforts.

[23] A resilience analysis in **Chapter 2**, which is based on TADS data, shows 225 outages on the transmission system that were caused by Hurricane Ida. This count, in contrast with **Table 1.2,** includes both momentary and sustained outages that occurred on BES elements reportable in TADS and reported in all areas affected by Ida.
[24] File:Ida 2021 track.png - Wikimedia Commons

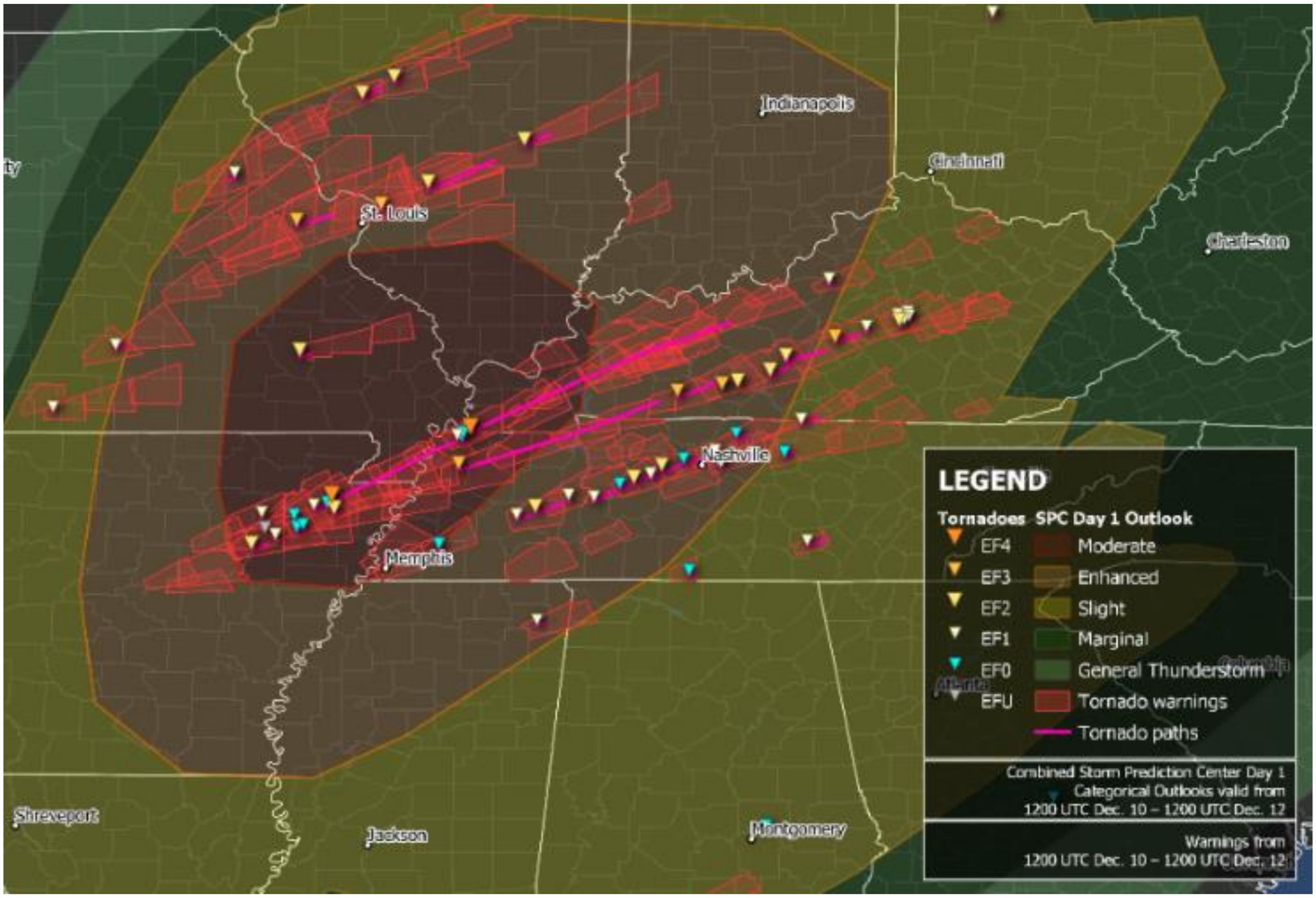


Figure 1.5: Widespread December 2021 Tornadoes[25]

25 https://en.wikipedia.org/wiki/Tornado_outbreak_of_December_10%E2%80%9311,_2021#/media/File:December_10%E2%80%9311,_2021_tornado_outbreak_warnings_and_reports.png

Chapter 2: Severe Risks, Impact, and Resilience

This chapter covers three areas: **Severity Risk Index**, **Bulk Electric System Impact of Extreme Event Days**, and **Bulk Electric System Resilience against Extreme Weather**.

Severity Risk Index

The severity risk index (SRI) measures the severity of daily conditions based on the combined impact of load loss, loss of generation, and loss of transmission on the BPS. The SRI provides a quantitative measure that assesses the relative severity of these events on a daily basis, and it provides a comprehensive picture of the performance of the BPS and allows NERC to assess year-on-year trends of its reliability. For 2021 load loss data available from the Institute of Electrical and Electronics Engineers (IEEE) Distribution Reliability Working Group, the TI was inadequately representative. In the past, NERC has recognized the incomplete coverage experienced in load loss representation in the TI; however, due to the intense manner in which BPS load shedding was required during the extreme conditions experienced in February 2021 and its impact to distribution customer reliability, proxy inputs have been used to perform estimates of the impacts of these actions. Proxy inputs utilized data obtained from the PowerOutage website[26] as well as customers served by using information reported to Department of Energy (DOE) Energy Information Administration (EIA).

Figure 2.1 plots the daily SRI scores for 2021 against control limits that were calculated by using 2017–2020 seasonal daily performance. On a daily basis, a general normal range of performance exists, visible by the gray-colored band or within the daily seasonal 90% control limits.[27] Days of stress on the system are identified by those that extend above the seasonal daily control limits. The top 10 days of 2021 are labeled with the rank of severity. **Figure 2.2** provides the full-scale version of **Figure 2.1** to show the magnitude of the daily SRI scores during the February cold weather event as compared with other daily SRI scores (see **Table 2.1**).

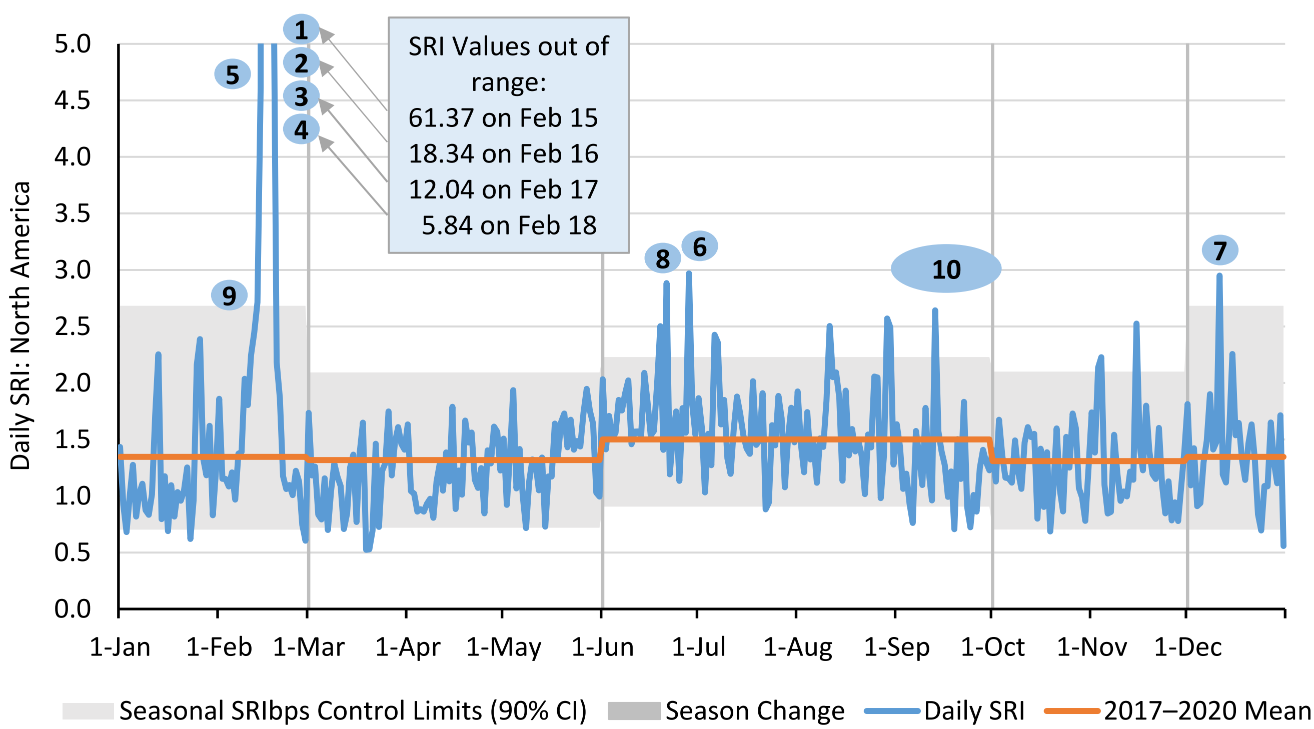


Figure 2.1: 2021 Daily SRI with Top 10 Days Labeled, 90% Confidence Interval

[26] PowerOutage.US

[27] The 90% confidence interval (CI) of the historic values is between 5th percentile and 95th percentile.

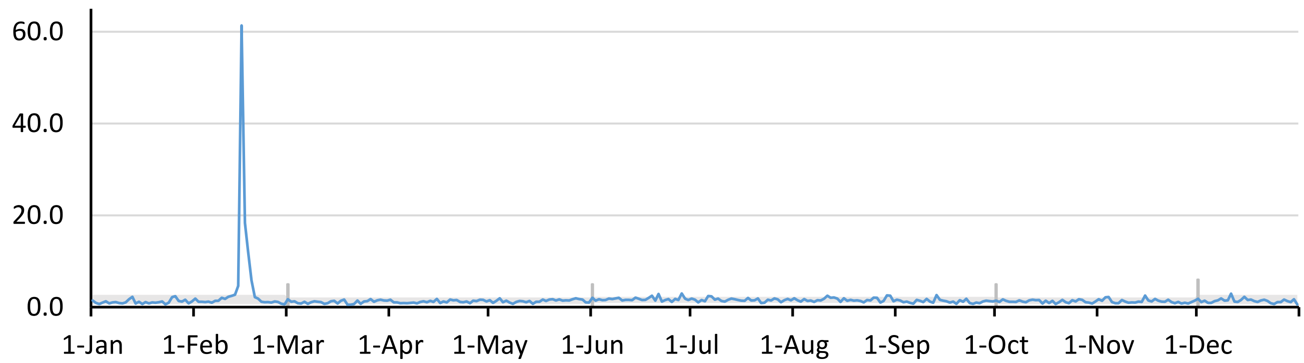


Figure 2.2: 2021 Full-Scale Daily SRI

Table 2.1 provides details of the scores for the top 10 SRI days during 2021. The table includes whether a specific event was a contributing factor, the type of event that occurred, and its general location by Regional Entity. All of the top 10 SRI days in 2021 were primarily attributed to some type of weather occurrence: six occurred as result of the February cold weather event, two were related to thunderstorms, one was due to high winds and tornadoes, and one was due to a hurricane and a special protection system misoperation that resulted in generation loss.

Table 2.1: 2021 Top 10 SRI Days

Rank	Date	SRI and Weighted Components 2021				Event Type	Regional Entities
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss		
1	February 15	61.37	5.54	0.81	55.02	Cold weather event	MRO, RF, SERC, TRE
2	February 16	18.34	5.02	0.55	12.78	Cold weather event	MRO, RF, SERC, TRE
3	February 17	12.04	2.49	0.28	9.26	Cold weather event	MRO, RF, SERC, TRE
4	February 18	5.84	2.21	0.32	3.30	Cold weather event	MRO, RF, SERC, TRE
5	February 14	4.61	1.91	0.88	1.83	Cold weather event	MRO, RF, SERC, TRE
6	June 28	2.97	1.78	0.29	0.90	Heat Dome and major thunderstorms	WECC
7	December 11	2.95	1.03	0.73	1.19	December windstorm and tornadoes	NPCC, RF, SERC
8	June 21	2.88	1.47	0.34	1.08	Major thunderstorms	RF, SERC
9	February 13	2.71	1.71	0.44	0.57	Cold weather event	MRO, RF, SERC, TRE
10	September 13	2.64	1.19	0.42	1.03	Hurricane Nicholas and special protection system misoperation dropping generation	TRE, WECC

SRI Performance Trends

Performance trends can be recognized by comparing the last year's top SRI days to those of prior years. **Figure 2.3** shows the top 10 SRI days for each of the past five years in descending rank order. The top five SRI days in 2021 greatly exceeded all top 10 days of all five prior years with the remaining five days being more similar to historic trends.

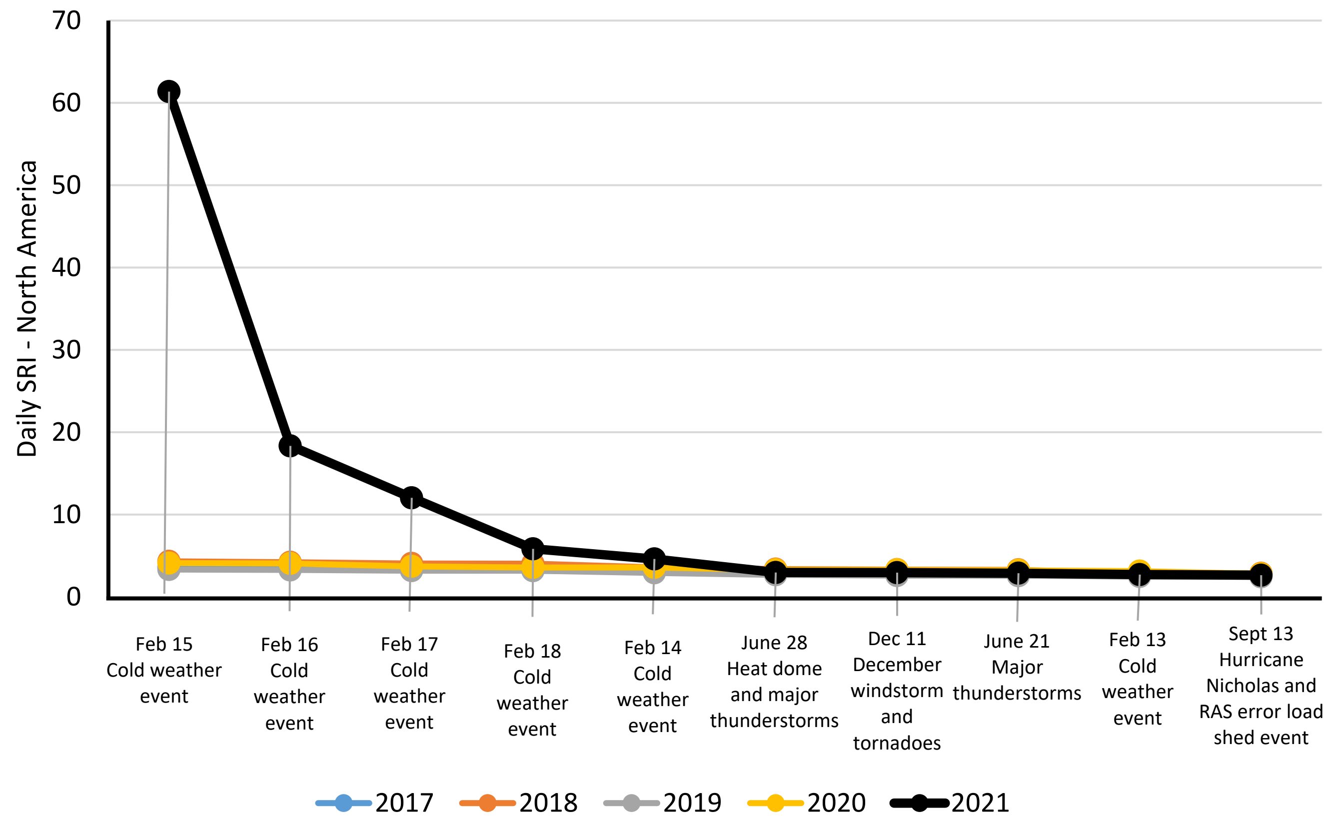


Figure 2.3: Top Annual Daily SRI Days Sorted Descending

To put the severity of days in 2021 into context with historic BPS performance, the top 10 days over the five-year period are updated annually. **Table 2.2** identifies the top 10 SRI days occurring between 2017–2021 with the contribution of the generation, transmission, and load loss components to the SRI for each day as well as contributing event information and the Regional Entities impacted by the event. The top five SRI days for 2021, shown in red, have replaced all earlier top SRI days, indicating the severity of these days not just for 2021 but also over the past five years. All five of these days were due to the February cold weather event.

Table 2.2: 2017–2021 Top 10 SRI Days

Rank	Date	SRI and Weighted Components				Event Type	Regional Entity
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss		
1	February 15, 2021	61.37	5.54	0.81	55.02	Cold weather event	MRO, RF, SERC, TRE
2	February 16, 2021	18.34	5.02	0.55	12.78	Cold weather event	MRO, RF, SERC, TRE
3	February 17, 2021	12.04	2.49	0.28	9.26	Cold weather event	MRO, RF, SERC, TRE
4	February 18, 2021	5.84	2.21	0.32	3.30	Cold weather event	MRO, RF, SERC, TRE

Table 2.2: 2017–2021 Top 10 SRI Days							
Rank	Date	SRI and Weighted Components				Event Type	Regional Entity
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss		
5	February 14, 2021	4.61	1.91	0.88	1.83	Cold weather event	MRO, RF, SERC, TRE
6	September 14, 2018	4.33	1.34	0.46	2.53	Hurricane Florence	SERC
7	March 2, 2018	4.22	0.90	0.41	2.90	Winter Storm Riley	NPCC
8	January 2, 2018	4.06	3.81	0.15	0.10	Winter Storm Grayson	SERC, RF, MRO, NPCC, Texas RE
9	November 15, 2018	4.05	1.85	0.25	1.95	Winter Storm Avery	RF, NPCC
10	October 28, 2020	3.98	1.22	2.06	0.71	Ice Storm and Hurricane Zeta	Texas RE, MRO, SERC

The cumulative performance of the BPS is calculated by summing each day's SRI for the year. **Table 2.3** shows the annual cumulative SRI for the five-year period of 2017–2021. For this period, 2021 had the highest annual cumulative SRI and is statistically significantly higher than 2019 and 2020. The year of 2021 saw similar performance from the transmission system to previous years with the increase in the annual cumulative SRI being driven by increases in generation and load loss.

Table 2.3: Annual Cumulative SRI					
Year	Cumulative Weighted Generation	Cumulative Weighted Transmission	Cumulative Weighted Load Loss	Annual Cumulative SRI	Average Daily SRI
2017	370.7	79.5	66.7	516.0	1.41
2018	389.9	73.5	68.4	530.8	1.46
2019	368.7	69.9	57.0	494.7	1.36
2020	337.2	65.4	72.5	481.0	1.30
2021	**377.6**	**66.8**	**152.1**	**596.5**	**1.63**

Bulk Electric System Impact of Extreme Event Days

Extreme Event Days

Extreme event days are identified as events that fall above the 95th percentile upper bound relative to historical severity measures for any season within North America or a specified Interconnection.[28] 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 response to the impacts of extreme days on BES resources is characterized by the amount of transmission or generation reporting immediate forced outages or derates 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 BES. 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.

[28] The 90% confidence interval of the historic values is between 5th percentile and 95th percentile.

Extreme day outages for transmission and generation by Interconnection are presented for North America in **Appendix A**, Supplemental Analysis by Interconnection.[29] The analysis listed in the following subsections is reported separately for transmission and generation. The total estimated megavolt-amperes (MVA) capacity reported in the Transmission Availability Data System (TADS) or net maximum capacity reported to GADS for 2021 for North America or by Interconnection is shown in the upper right corner of each figure in this chapter.

Transmission Impacted: North America

In 2021, 17 days qualified as extreme transmission days for the BPS as compared to 14 in 2020. On these days, the aggregated potential MVA capacity impacted due to automatic transmission outages was 2.2–7.6 times as high as the average day, which is 0.061% of total MVA capacity across North America. Weather (Excluding Lightning) and Failed Protection System Equipment were the primary initiating cause codes reported for events on these extreme days. In 2021, the most extreme transmission-impacting day was on August 30, primarily due to Hurricane Ida (see **Figure 2.4**). Days where transmission outages were slightly above the seasonal bounds (red line) and do not have a specific cause listed have been investigated; they were due to coincidental outages or smaller unnamed weather events.

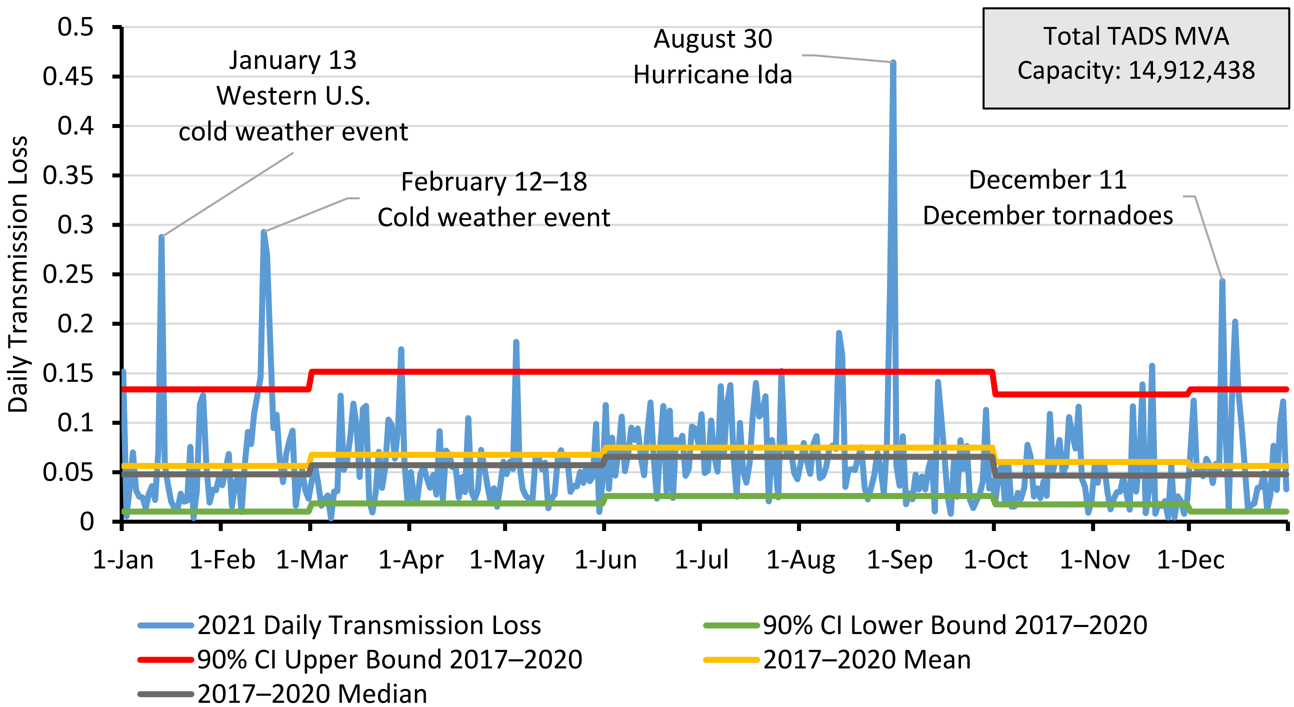


Figure 2.4: 2021 Transmission Outages during Extreme Days—North America

Conventional Generation Impacted: North America

Based on analysis of GADS data, a total of 17 days in 2021 qualified as extreme for North America's BES (see **Figure 2.5**), eight of which coincided with extreme days identified for transmission (February 12 and 18, and August 30). On these days, the generation portion of the BES experienced outages that were 1.4–5.4 times as severe as the average day, which is 1.035% of total generating capacity. Five of the days can be attributed to the February cold weather event that primarily impacted the South Central United States. Other points of note include major thunderstorms damaging substation and transmission equipment on June 28 and a large number of unrelated forced outages beginning on November 4. The days where generation outages were slightly above the seasonal bounds (red line) do not have a specific cause listed and have been investigated; they were due to coincidental outages on large units.

[29] For extreme day Interconnection-level analysis, the QI is included in the analysis labeled as EI–QI.

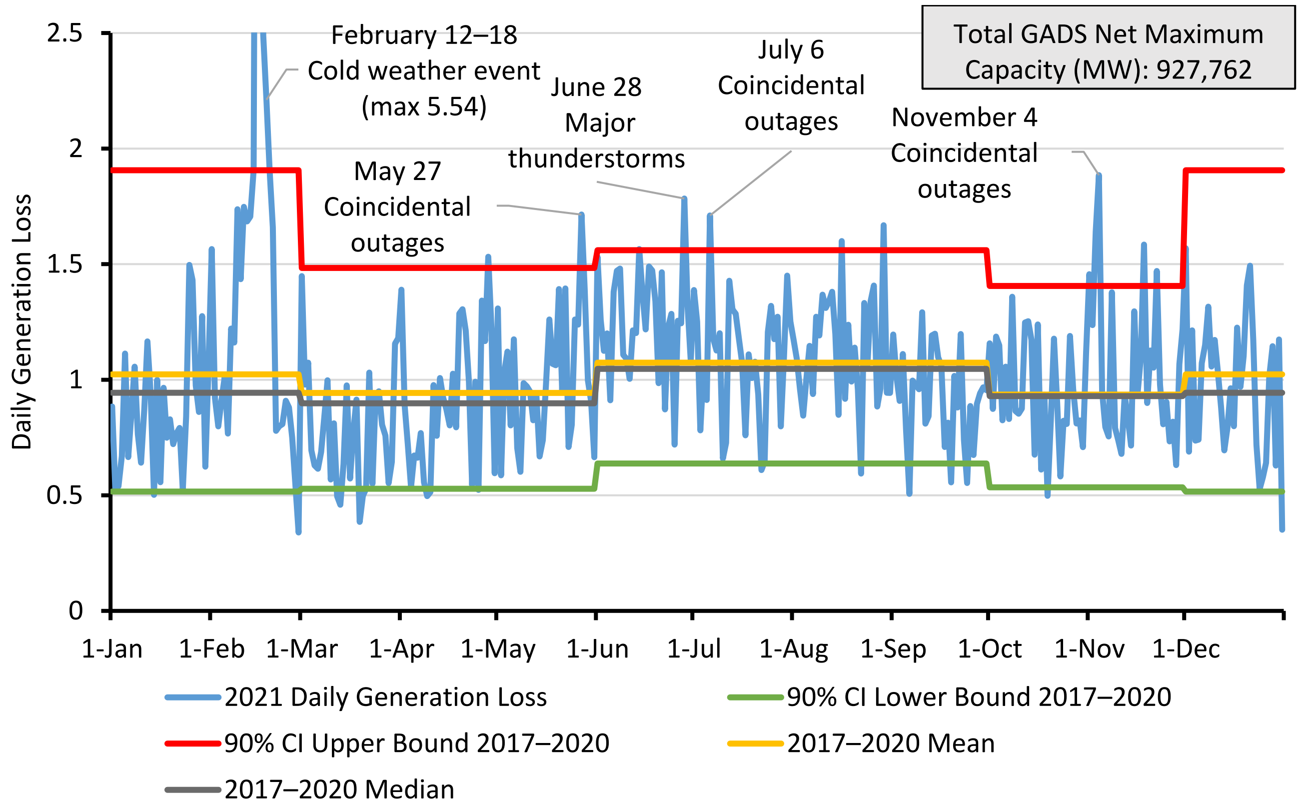


Figure 2.5: 2021 Generation Impacted during Extreme Days—North America

Top Causes of Outages on Extreme Days

The top causes reported for outages that occurred on extreme days are shown below in rank order for North America as a whole and each Interconnection. Weather (Excluding Lightning), Fire, and Failed Protection System Equipment were the top three causes for transmission systems (**Table 2.4**).

Table 2.4: Top Transmission Outage Causes on Extreme Days

Area	Cause #1	Cause #2	Cause #3	Cause #4	Cause #5
North America	Weather (Excluding Lightning)	Failed Protection System Equipment	Failed AC Substation Equipment	Failed AC Circuit Equipment	Unknown
Eastern–Québec Interconnections	Weather (Excluding Lightning)	Failed Protection System Equipment	Failed AC Circuit Equipment	Failed AC Substation Equipment	Lightning
Texas Interconnection	Weather (Excluding Lightning)	Failed AC Circuit Equipment	Lightning	Unknown	Failed AC Substation Equipment
Western Interconnection	Weather (Excluding Lightning)	Fire	Unknown	Power System Conditions	Failed AC Circuit Equipment

The primary causes of generation outages reported on extreme days were equipment-related to Fuel/Ignition/Combustion Systems and Economic reasons, both of which are attributable to cold weather events (**Table 2.5**).

Table 2.5: Top Generation Outage Causes on Extreme Days					
Area	Cause #1	Cause #2	Cause #3	Cause #4	Cause #5
North America	Fuel, Ignition, and Combustion Systems	Economic	Catastrophe	Electrical	Boiler Tube Leaks
Eastern–Québec Interconnections	Economic	Fuel, Ignition, and Combustion Systems	Boiler Tube Leaks	Electrical	Catastrophe
Texas Interconnection	Catastrophe	Fuel, Ignition, and Combustion Systems	Economic	Auxiliary Systems	Boiler Control Systems
Western Interconnection	Electrical	Controls	Boiler Tube Leaks	Auxiliary Systems	Miscellaneous (Natural Gas Turbine)

Bulk Electric System Resilience against Extreme Weather

In the 2021 SOR,[30] NERC introduced a new analysis of 2020 large transmission events caused by extreme weather that quantified some aspects of restoration and recovery activities. Restoration and recovery actions can mitigate those conditions identified as posing the highest risk to the BES on extreme event days. This analysis was based on outage and restoration processes for transmission elements, not on disruption and restoration of customer load. Restoration of the transmission system to serve customer load is always the priority, and restoration of load generally takes place long before all transmission elements are returned to service.

This year's SOR focuses on the 2021 large transmission weather-related events and extends the resilience analysis to assess Hurricane Ida as a major transmission and generation event. Additionally, **Appendix B** includes detailed analyses and statistics for large transmission events caused by extreme weather, such as hurricanes and tornadoes. These statistics enable the measurement and tracking of the transmission system ability to withstand, adapt, protect against, and recover during and after extreme weather events. Changes in the transmission system resilience statistics from 2016–2020 to 2017–2021 for each extreme weather type are identified by the analysis.

Weather-Related Transmission Outage Events

TADS Outage Grouping and 2021 Large Weather Events

An algorithm group's automatic outages reported in TADS are based on Interconnection and associated start and end times.[31] 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. This combination of automatic and manual procedures results in a set of transmission events that can cross boundaries of different utilities and Regional Entities as well as allows for the capture of significant events caused by extreme weather, such as hurricanes.

The outage grouping procedure produced eight large transmission events (events with the event size of 20 or more outages) that occurred in the year 2021. **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 system. All of the large

[30] Report (nerc.com)

[31] S. Ekisheva, R. Rieder, J. Norris, M. Lauby, and I. Dobson, "Impact of extreme weather on North American transmission system outages," 2021 IEEE Power & Energy Society General Meeting.

transmission events identified as part of the restoration analysis have also been identified as extreme in the TOS extreme weather analysis, indicating consistency between the methodologies.

In 2021, the largest number of outages in a single event occurred in the EI with Hurricane Ida, which started on August 29 (225 transmission outages reported); this is shown in red in **Table 2.6**. Note that the February cold weather event, which was the largest event on the generation system, also resulted in a large transmission event in the TI. The definitions of element-days lost and the MVA-days lost are provided in **Appendix B.**

Table 2.6: 2021 Large Transmission Weather-Related Events

Event Start	Event Outage Count	Inter-connection	Extreme/Severe Weather Event	MVA Affected	Miles Affected	Duration (Days)	Element-Days Lost	MVA-Days lost
January 13	144	Western	Strong winter storms, high winds, landslides	41,592	5,439	13	146	32,592
January 26	21	Eastern	Storm system with high winds, snow, sleet, and ice	10,835	354	3	8	3,923
February 15	28	Texas	February 2021 Cold Weather	16,695	902	1.4	12	4,115
April 10	25	Eastern	Tornadoes	7,970	508	11	39	35,118
May 4	24	Eastern	Tornadoes and thunderstorms	9,666	624	4	21	7,035
August 29	225	Eastern	Hurricane Ida	101,058	2,876	124	1,300	641,506
December 11	53	Eastern	Tornadoes and thunderstorms	17,653	1,691	21	230	114,393
December 15	87	Eastern	Strong storms with high winds	36,529	2,849	16	123	63,693

Outage, Restore, and Performance Curves

Table 2.6 illustrates the variability in event sizes and event duration. However, these statistics do not completely explain what happened during the events; the outage, restore, and performance curves of the events provide more details on how the events unfolded.[32] As shown in **Figure 2.6** to describe transmission outages during an event, these curves track the number of elements out or the MVA impact on the vertical axis vs. time on the horizontal axis. Similarly, to describe generation outages during the event, these curves track generation out on the vertical axis vs. time on the horizontal axis.

[32] 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

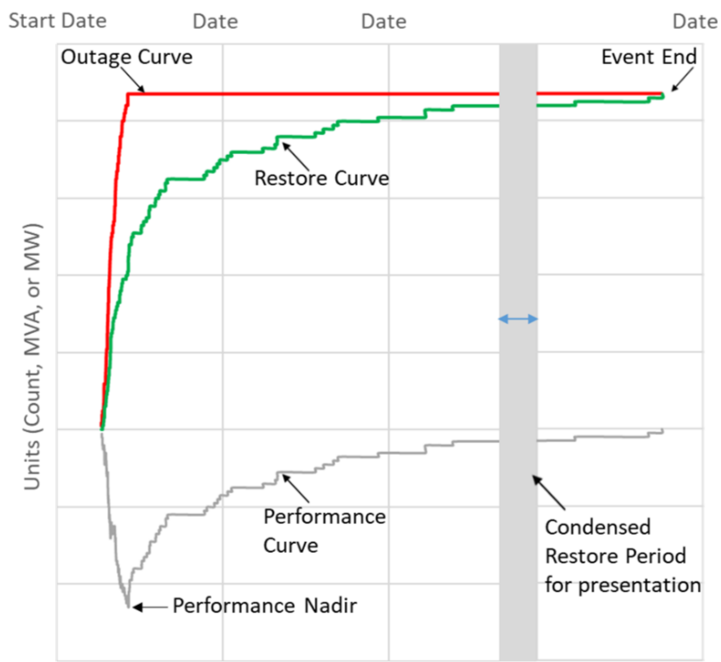


Figure 2.6: Outage, Restore, and Performance Curves for a Large Transmission or Generation Event

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

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

Lastly, the performance curve is the number of elements out, equivalent MVA impact out, or generation out at the time shown on the horizontal axis. The value is equal to elements, MVA, or MW restored minus the elements, MVA, or MW out (i.e., the performance curve is the restore curve minus the outage curve). The performance curve illustrates the degradation and restoration phases of the event. All the curves enable the calculation of several important event statistics defined in **Appendix B**, some of which are also included in **Figure 2.6**.

Resilience Analysis of Hurricane Ida as a Large Transmission and Generation Event

Transmission Curves and Statistics[33] for Hurricane Ida

Hurricanes cause the largest, longest, and most impactful events on the transmission system (as measured by element- and MVA-days lost). Hurricane Ida was the largest and longest event in 2021 and the most impactful for 2016–2021. The 225 automatic transmission outages grouped in this event were reported by 12 Transmission Owners. These outages included 4 transformer outages and 221 ac circuit outages; 24 out of the 221 ac circuit outages were momentary, and the remaining were sustained. It was also the longest event in 2021 with a duration of 124 days, including a few very long unrestored outages before the event end, so the element and MVA-based curves for Hurricane Ida in **Figure 2.7** and **Figure 2.8** are truncated at the 95% restoration level to better show significant changes in outage, restore, and performance curves.

The transmission outage curves show that outages accumulated very fast relative to the duration of the event (for about 13.2 hours) at the outage rate of 17 outages per hour, or 7,656 MVA per hour. The maximum number of elements out (171) and MVA out (78,122), shown by the nadir of the respective performance functions, was reached in about 13 hours into the event, and the system remained in the most degraded state for one minute. The restore process started 47 minutes from the event start and progressed steadily to recover 214 (95%) of the elements and 96,012 (95%) of MVA affected by the hurricane after 19 days (or only 15% of the total event duration). The total event losses, calculated for the complete (not truncated) performance curves, were 1,300 element-days and 641,506 MVA-days.

[33] Resilience statistics are defined in **Appendix A**.

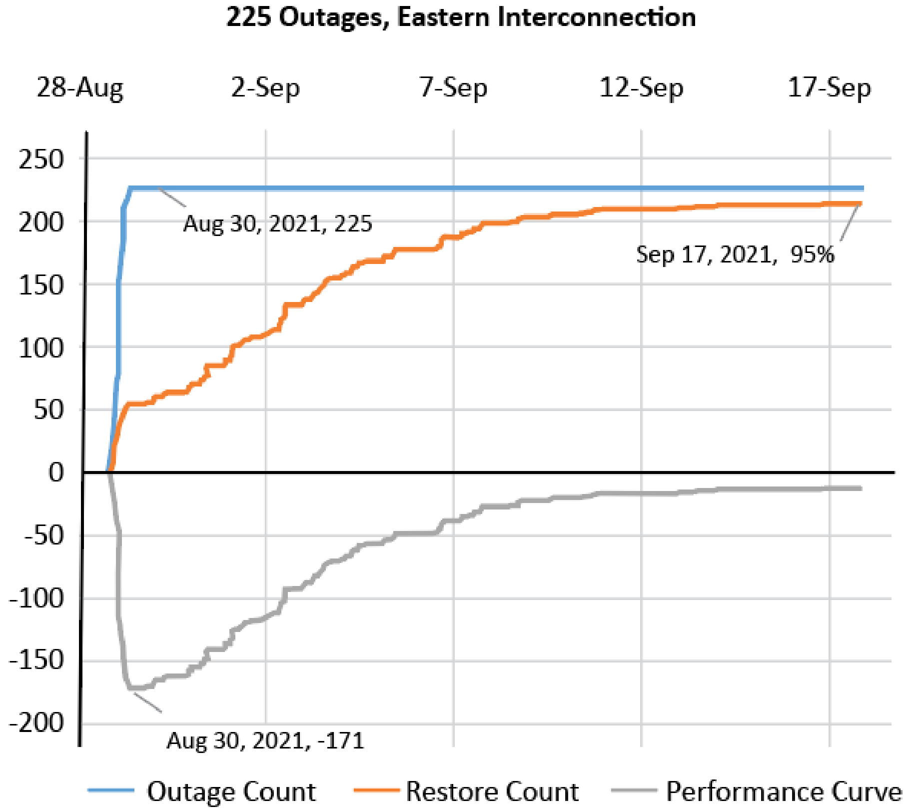


Figure 2.7: Transmission Element Outage, Restore, and Performance Curves for Hurricane Ida (Truncated at the 95% restoration level)

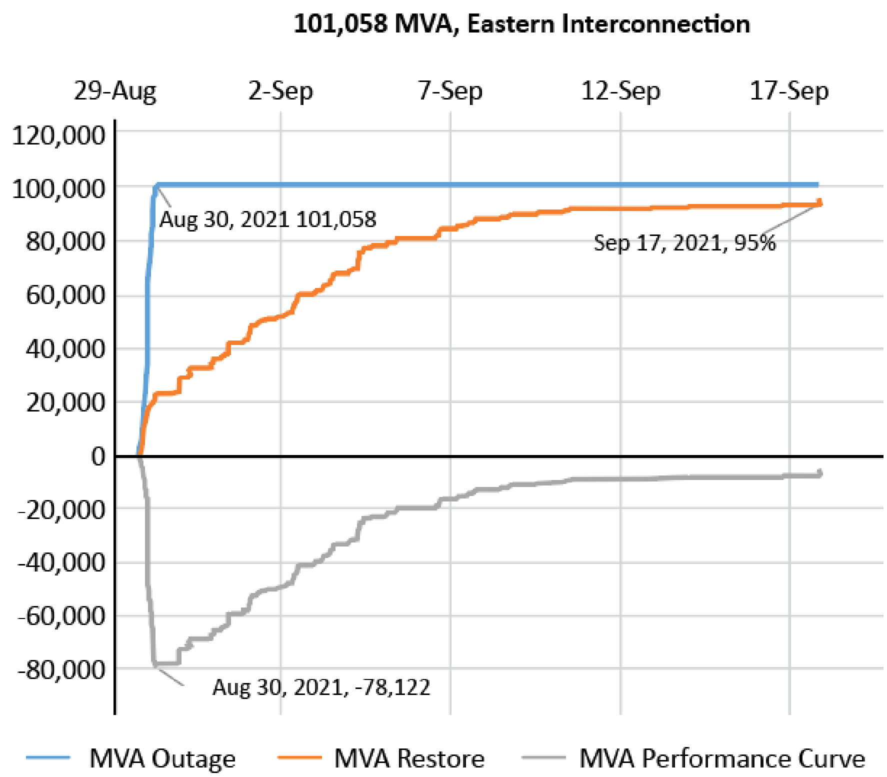


Figure 2.8: Transmission MVA-based Outage, Restore, and Performance Curves for Hurricane Ida (Truncated at the 95% restoration level)

Generation System Curves and Statistics for Hurricane Ida

This year, NERC is extending the restoration analysis to demonstrate how event and performance data reported to NERC from conventional generating units that are 20 MW and larger can be used to provide analysis of large generation events comparable to the methodology used for large transmission events.

The path of the storm, as determined by the National Oceanic and Atmospheric Administration,[34] was used to identify units that were likely impacted by the hurricane as the storm progressed. The impact of Hurricane Ida on generating units was evaluated based on time and location of the direct impact of the hurricane: forced outages and derates for generation in Louisiana and Texas that started between August 28, 2021, at 12:00 a.m. Central time and September 1, 2021, at 11:59 p.m. Central time. Although additional states in the Northeast and Southeast were impacted by the remnants of the hurricane, the primary impact occurred in these two areas. While only 56 GADS events explicitly reported the hurricane as the primary cause, approximately 75% of which were reported during Hurricane Ida; other water-related cause codes (e.g., Wet Coal, Flood) were also observed in the affected footprint during the storm.

Differences between Transmission and Generation

A comparison of transmission restoration performance with generation restoration performance during the same large event is not meaningful due to the fundamental differences in function, characteristics, and properties. Doing so could introduce assumptions and hypotheses that do not have a sound foundation.

The transmission system is functionally always on when available and operates largely in an N+X state with N being the minimum elements required to deliver sufficient power and X being the number of alternative elements available to deliver power to the same point, generally a single-digit amount. Generation operates on a reserve-based model and is effectively interchangeable as long as a transmission path exists within certain less stringent parameters. The reserve-based model means that an amount of excess generation is available in case of an event and can be brought on-line rapidly to replace nearly any other loss of generation of the same magnitude. Because of this, until a critical point where reserves run out, the impact from generation loss is generally less severe. The generation analysis performed does not include information about whether transmission outages were related to the outage of the generator, available reserves, or load loss; the critical point at which reserves run out was not identified.

Additionally, due to the transmission system being located primarily outdoors and above ground, it is generally more susceptible to weather and quick-succession outages. In comparison, conventional generation is protected by more robust structures, leading to fewer unit outages but making it susceptible to more lingering effects, such as flooding. This causes transmission to often have a relatively steeper outage curve than the generation for the same event.

Figure 2.9 shows the outage, restore, and performance curves for generation for Hurricane Ida with the same methodology as for transmission.

[34] https://www.nhc.noaa.gov/archive/2021/IDA_graphics.php?product=5day_cone_with_line

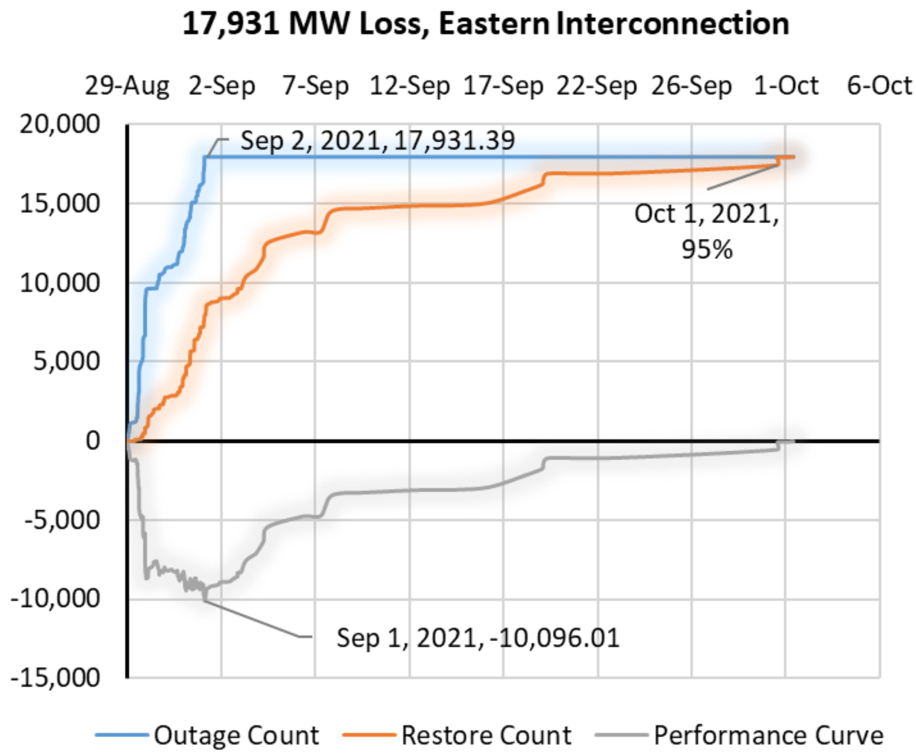


Figure 2.9: Generating MW-based Outage, Restore, and Performance Curves for Hurricane Ida

Table 2.7 provides measures of the resilience analysis with observations highlighting the differences between how transmission and generation were impacted by Hurricane Ida.

Table 2.7: 2021 Comparison of Resilience Analysis Statistics for Hurricane Ida Transmission and Generation			
Measure	**Transmission**	**Conventional Generation**	**Observation**
Outage process duration[35]	13 hours	96 hours	Generation outages occurred at a slower rate and may have been impacted by transmission outages in addition to extensive flooding during this event.
Number of distinct elements/units out	197 elements	73 units	
Outage rate	17 per hour (225 outages over 13.2 hours)	1.32 per hour (127 outages over 96 hours)	Generator outages occurred at a much slower rate due to the geographical distribution of generating units.
Rate of loss	7,656 MVA per hour	186.79 MW per hour	
Time to first restore	47 minutes	9.5 hours	Flooding likely delayed ability to restore generating units. Additionally, transmission restoration efforts benefit from assistance from volunteer utility crews that are in place in advance of the storm to support recovery efforts.

[35] Outage process duration is defined as the time between the start of the first outage and the start of the last outage of the event.

Table 2.7: 2021 Comparison of Resilience Analysis Statistics for Hurricane Ida Transmission and Generation			
Measure	**Transmission**	**Conventional Generation**	**Observation**
Most degraded state (nadir)	Occurred after 13 hours Duration: 1 minute	First inflection point occurred after 72 hours 35 minutes (3.02 days) Duration: 32 minutes Maximum degradation occurred after 94 hours 27 minutes (3.94 days) Duration: 19 minutes	The distributed locations of generation delayed the time of the most degraded state. By comparison, during Hurricane Harvey (2017), the transmission system remained in a degraded state for 7.2 hours.
Duration of outages within 95% of nadir	24 hours 41 minutes (1.03 days)	2 hours 48 minutes	The long time when the transmission system experienced 162 (95% of the nadir) or more simultaneous outages is due to a very low restore rate on August 30 when in over 12.5 hours only four ac circuits were restored to service.
Maximum number of simultaneous outages	171 unique elements	49 unique units	
95% of outages restored	459 hours (15% of transmission event duration)	792 hours (97% of generation event duration)	
Restoration complete	124 days	34 days	The last transmission outage lasted 72 days after all other outages were restored. This is typical for large transmission events when few remaining elements are outaged either due to inaccessibility of a portion of the line, damaged structure or equipment or, in some cases, a utility postpones a restoration of a single remaining element (or few elements) after all other outages in the large event are restored because this outaged element is considered not critical for reliability of the grid. [36]

This introductory analysis provides an example of how the method developed for transmission resilience against extreme weather serves as a foundation for development of a restoration analysis methodology that recognizes the differences applicable to large generator outage events. Analysis to define the criteria, measures, and historical trends will continue and updates will be provided in future reports.

[36] 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

Chapter 3: Grid Transformation

Resource Adequacy

For this chapter, two measures have been selected to indicate the status of resource adequacy for the BES: **Planning Reserve Margin** and **Energy Emergency Alerts**. Planning Reserve Margins present a forward-looking perspective on whether sufficient resources are expected to be available to meet demand. The EEAs provide a real-time indication of potential and actual energy emergencies within an Interconnection.

Planning Reserve Margin

Planning Reserve Margins are a long-term resource adequacy indicator, defined as the difference in resources (anticipated or prospective[37]) and net internal demand then divided by net internal demand and shown as a percentage.

Anticipated resources remove confirmed retirements and consist of existing resources, capacity that is under construction or has received approved planning requirements, and firm capacity transfers. Prospective resources remove unconfirmed retirements and include all anticipated resources plus the following: capacity that has been requested but not received approval for planning requirements and expected nonfirm capacity transfers.

The Planning Reserve Margins (Anticipated Reserve Margin (ARM) or Prospective Reserve Margin) are compared against the Reference Margin Level (RML) to measure resource adequacy for the planning period. **Figure 3.1** shows the 2021 summer peak Planning Reserve Margin by assessment area, and **Figure 3.2** shows the 2021–2022 winter peak Planning Reserve Margin by assessment area.

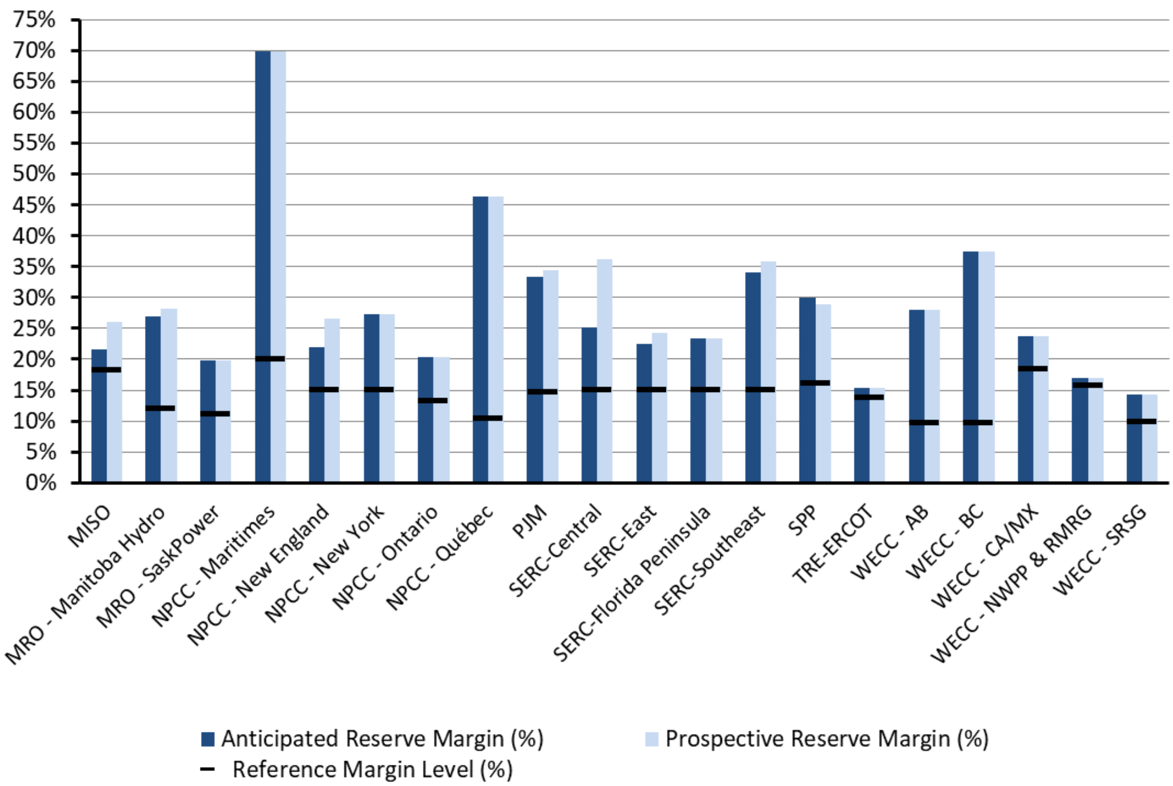


Figure 3.1: 2021 Summer Peak Planning Reserve Margins (Anticipated and Prospective Reserve Margins)

[37] Anticipated and prospective resources and all Reserve Margins are defined in detail on pages 123–125 in the ***2021 Long-Term Reliability Assessment***

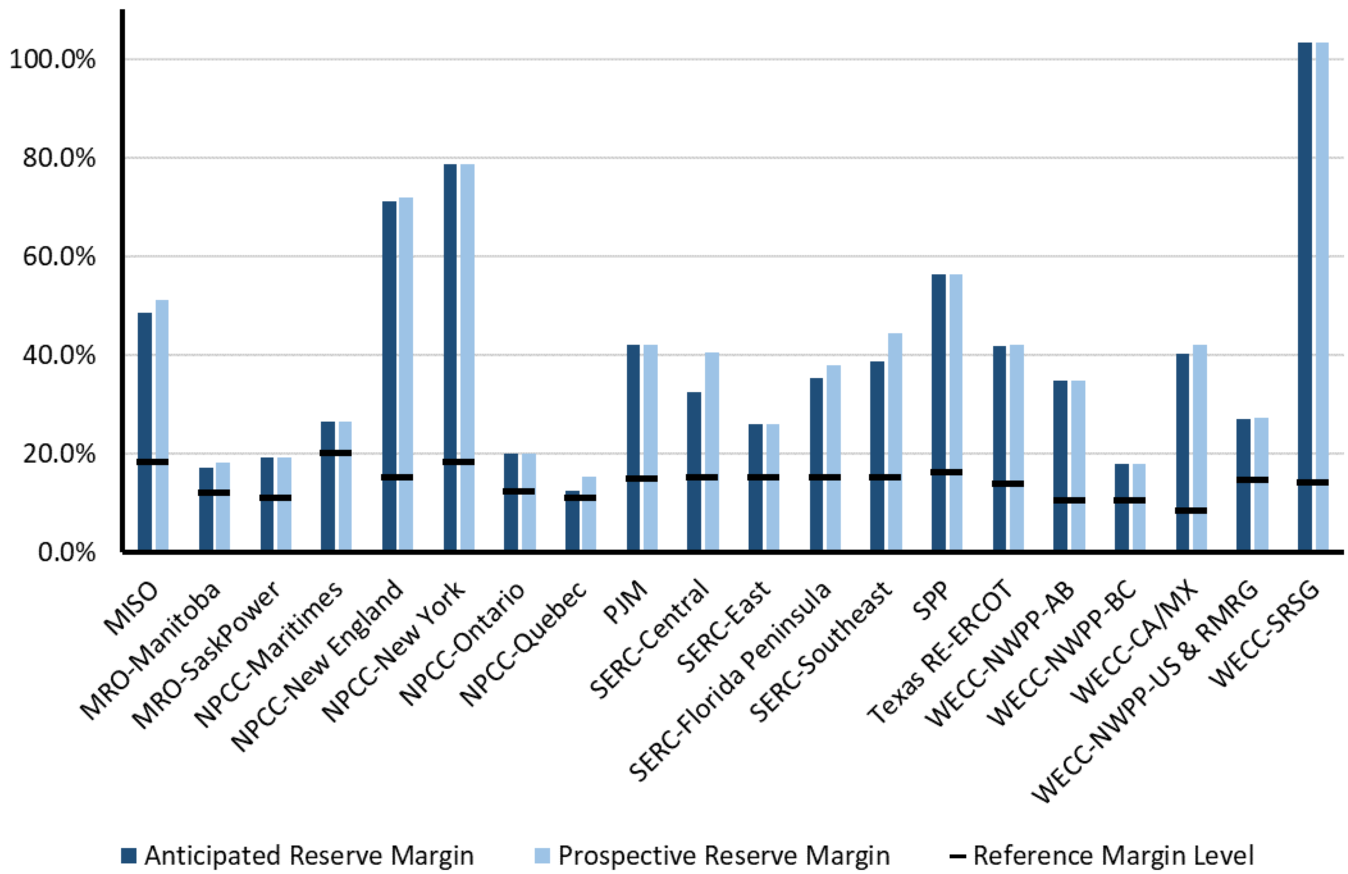


Figure 3.2: 2021–2022 Winter Peak Planning Reserve Margins (Anticipated and Prospective Reserve Margins)

2021 Performance and Trends

The Planning Reserve Margins exceeded the RML for all assessment areas ahead of both the 2021 summer and 2021–2022 winter periods. This is an improvement from last year's report where Texas RE ERCOT's ARM fell short of the RML for the 2020 summer season.

Although ARMs exceeded RMLs in all assessment areas, shown in **Figure 3.1** and **Figure 3.2**, some assessment areas raised concerns about analyzing the impact of typical outages and extreme operating conditions. Increased demand caused by extreme temperatures and higher-than-anticipated generator forced outages and derates can create conditions that lead system operators to take emergency operating actions. **Table 3.1** highlights the effects typical outages and extreme operating conditions can have on the ARMs in addition to the ARMs for Summer 2021 and Winter 2021–2022, respectively. Green boxes indicate that the reserve margin is above the assessment area's seasonal RML, orange boxes indicate available resources satisfy demand but do not satisfy the RML, and red boxes indicate resources fall below the demand for the studied conditions. The maps in **Figure 3.3** and **Figure 3.4** highlight the assessment areas that were identified ahead of the Summer 2021[38] and Winter 2021–2022[39] seasons as at risk for resource deficiencies based on the information in **Table 3.1**.

[38] *NERC 2021 Summer Reliability Assessment*
[39] *NERC 2021–2022 Winter Reliability Assessment*

Table 3.1: Seasonal Risk Scenario Margins						
	Summer 2021			Winter 2021–2022		
Assessment Area	Anticipated Reserve Margin	Typical Outages	Extreme Conditions	Anticipated Reserve Margin	Typical Outages	Extreme Conditions
MISO	21.60%	4.60%	-4.20%	48.50%	20.50%	-1.20%
MRO-Manitoba	26.90%	21.20%	8.40%	17.20%	14.20%	4.20%
MRO-SaskPower	19.80%	16.40%	5.70%	19.30%	16.10%	11.60%
NPCC-Maritimes	69.80%	58.80%	27.60%	26.50%	19.90%	-2.10%
NPCC-New England	22.00%	9.50%	-0.70%	71.10%	55.30%	25.90%
NPCC-New York	27.30%	17.00%	18.30%	78.60%	58.40%	33.50%
NPCC-Ontario	20.30%	20.30%	8.50%	20.00%	20.00%	21.30%
NPCC-Québec	46.40%	40.80%	37.90%	12.40%	8.30%	-0.80%
PJM	33.50%	25.60%	12.10%	42.00%	29.10%	11.30%
SERC-Central	25.20%	25.20%	10.20%	32.50%	24.40%	9.30%
SERC-East	22.50%	22.50%	12.70%	25.90%	20.60%	4.30%
SERC-Florida Peninsula	23.40%	23.40%	15.40%	35.40%	29.70%	23.20%
SERC-South East	34.10%	34.10%	15.60%	38.70%	31.60%	21.10%
SPP	29.90%	10.80%	-3.90%	56.40%	30.90%	0.80%
Texas RE-ERCOT	15.30%	10.50%	-13.30%	41.90%	26.80%	-37.10%
WECC-AB	34.70%	25.00%	14.50%	34.70%	28.60%	8.30%
WECC-BC	37.50%	37.30%	9.30%	17.90%	17.80%	-0.60%
WECC-CAMX	23.80%	16.70%	-19.30%	40.30%	33.30%	12.30%
WECC-NWPP-US & RMRG	16.90%	15.10%	-10.10%	27.10%	26.60%	-1.50%
WECC-SRSG	20.60%	3.90%	-13.80%	103.30%	93.30%	56.50%

Note: The extreme conditions in **Table 3.1** represent higher than average derates of resource capacity and demand.

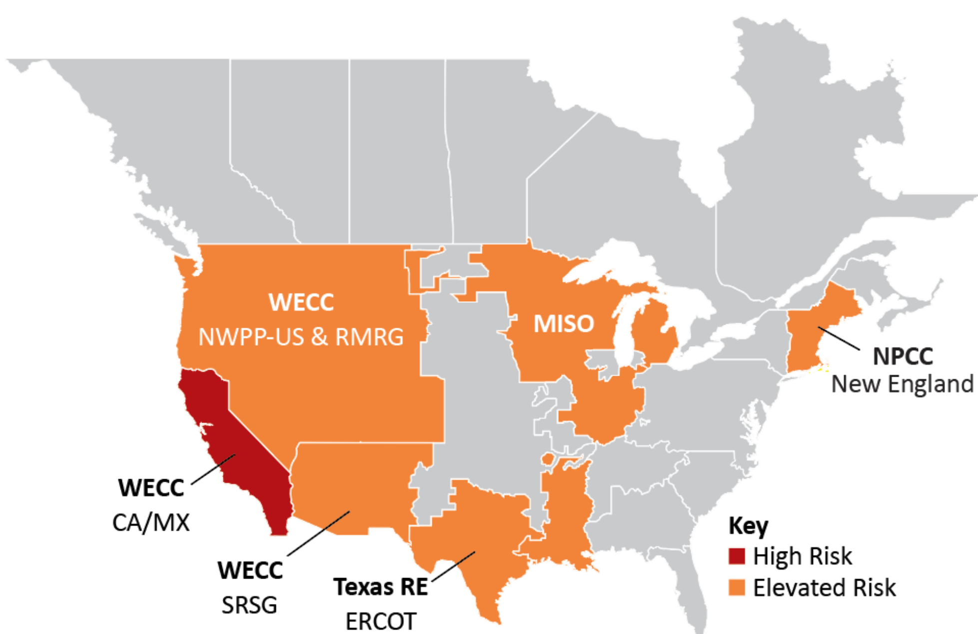


Figure 3.3: 2021 Summer Reliability Assessment Risk Area Map

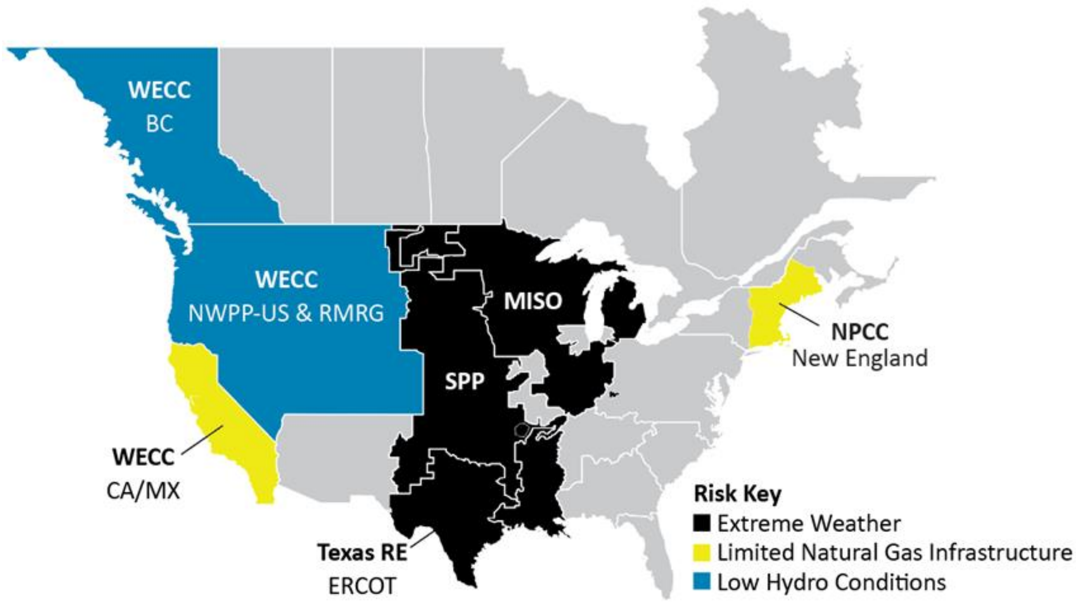


Figure 3.4: 2021–2022 Winter Reliability Assessment Risk Area Map

Changes in the Peak Resource Mix over the Past 10 Years

Over the past 10 years, the BPS has reduced its on-peak capacity of coal by 98.7 GW. During this time, the BPS added 77 GW of natural gas, 11.7 GW of wind, and 25.2 GW of solar PV generation on-peak capacity.[40] Variable generation from renewable wind and solar PV resources contribute to resource adequacy, but because their output depends on the environment and local weather conditions, they often do not provide the same contribution to capacity at the peak demand hour (i.e., on-peak) as conventional generation resources. **Table 3.2** shows the changing on-peak capacity composition of generating resources in North America over the past 10 years. Although the installed nameplate capacity for wind and solar PV resources has grown considerably over the past decade (wind installed capacity has grown from 44.7 GW to 137.7 GW, and solar PV has risen from less than 1 GW to over 40.5 GW in the 10-year period), their contribution to on-peak capacity is 5% of total generation in 2021.

Table 3.2: Generation Resource Capacity by Fuel Type

Generation Fuel Type	2011 On-Peak		2021 On-Peak	
	GW	Percent	GW	Percent
Coal	318.5	30.5%	219.8	21.4%
Natural Gas	385.9	36.9%	462.9	45.0%
Hydro	153.9	14.7%	132.6	12.9%
Nuclear	111.6	10.7%	107.7	10.5%
Oil	50.3	4.8%	39.6	3.8%
Wind	13.7	1.3%	25.4	2.5%
Solar PV	0.5	0.1%	25.7	2.5%
Other	10.0	1.0%	15.0	1.5%
Total:	**1,044.5**	**100.0%**	**1,028.7**	**100.0%**

The resource mix and the speed it changes vary considerably across different parts of the North American BPS. **Figure 3.5** provides an Interconnection-level view of the generation resource mix since 2011. NERC's Long-Term Reliability

[40] Data obtained from EIA and NERC Long-Term Reliability Assessments.

Assessment 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.

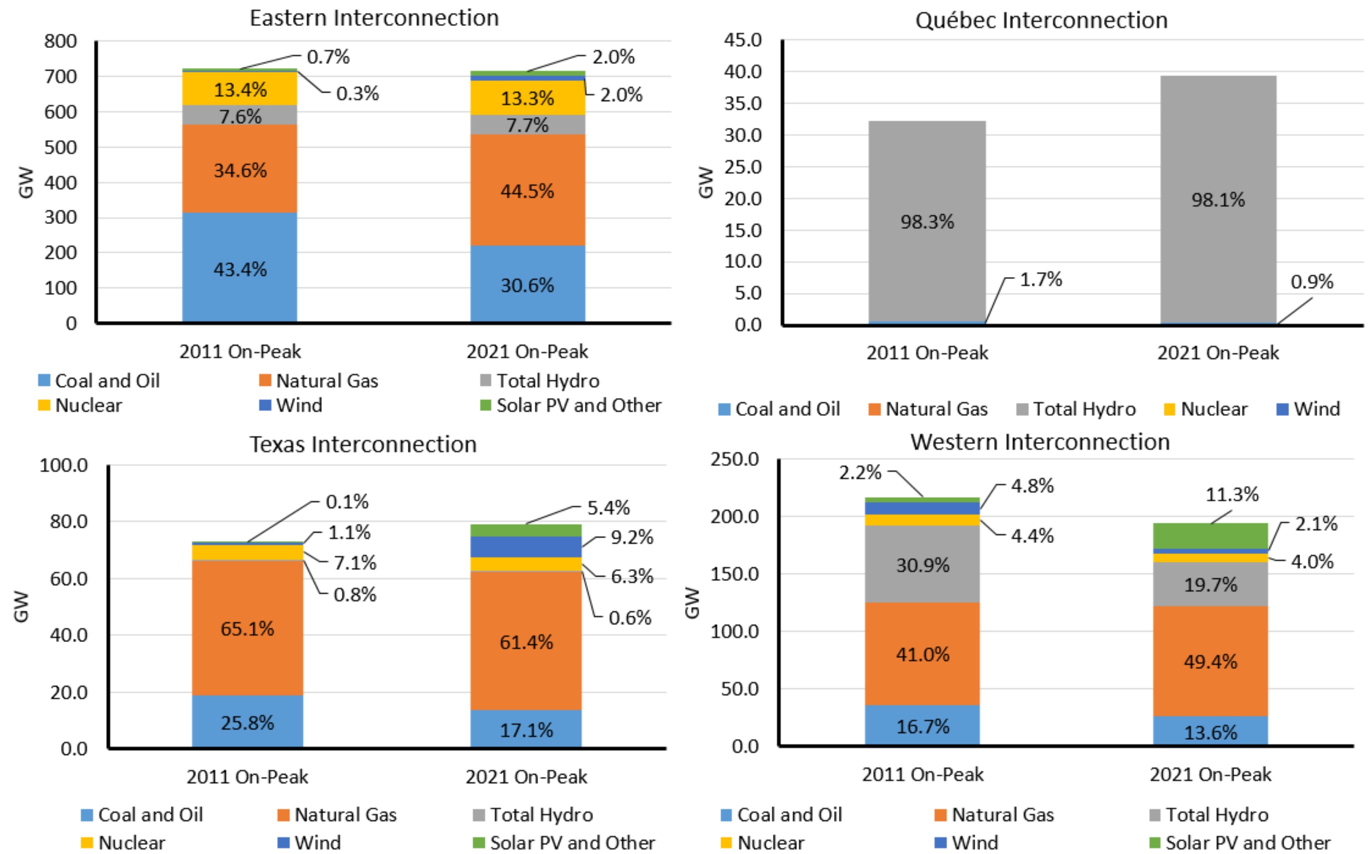


Figure 3.5: 2011 and 2021 Capacity Resource Mix by Interconnection

Managing Risks as the Resource Mix Evolves

The addition of variable energy resources (VER), primarily wind and solar PV as well as the retirement of conventional generation, are fundamentally changing how the BPS is planned and operated. Planning and operating the grid must increasingly account for energy limitations and variability across the resource fleet. At the same time, many areas are seeing increasing volatility in forecasted electricity demand as variable demand-side resources grow. Energy assessments that consider variability in resources and demand across all hours of the assessment period are increasingly important to maintaining resource adequacy of the BPS.[41] Ensuring sufficient flexible resources, maintaining fuel assurance, and planning and operating the BPS with IBRs are all key reliability elements to managing the changing resource mix.

Ensuring Sufficient Flexible Resources

As **Figure 3.6** shows, flexible resources are playing an increasing role in addressing net internal demand. Texas RE-ERCOT, for example, relies on solar PV and wind resources to serve 4.6% of its net internal demand.[42] Sufficient flexible resources are needed to ensure resource adequacy and energy sufficiency as the grid transforms and to reduce the exposure to energy shortfalls in extreme weather. Until storage technology is fully developed and deployed at scale, natural-gas-fired generation will remain a necessary balancing resource to provide increasing

[41] For more information on energy assessments, see the *2021 LTRA* and the included 2020 ERO probabilistic assessment, which accounts for all hours in selected study years of 2022 and 2024.

[42] Net internal demand is the total internal demand reduced by the amount of controllable and dispatchable DR projected to be available during the peak hour. Net internal demand is used in all reserve margin calculations. See: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf at p. 122.

flexibility needs. Resource planning and policy decisions must ensure that sufficient balancing resources are developed and maintained for reliability. As IBRs and DERs continue to transform the grid, sufficient flexible resources are needed to ensure a reliable grid transformation given the variable energy nature of IBRs and DERs. IBRs and DERs increase variability and uncertainty in demand, so they require careful attention in planning for resource adequacy and energy availability. Reliably integrating IBRs requires owners and operators to pay attention to modeling and coordination needs so that planning studies and operating models accurately account for new resource types. Furthermore, improvements to NERC Reliability Standards to address IBR performance issues are needed.

Extreme weather is another consideration for maintaining flexible resources in resource planning. A comprehensive resource planning construct must focus attention on energy available with the understanding that capacity alone does not provide for reliability unless the fuel behind it is assured in extreme weather. Figure 3.6 shows the on-peak resource contributions to meeting net internal demand. Maintaining flexible resources, such as natural gas, helps to ensure demand can be met in the absence of energy production from VERs.

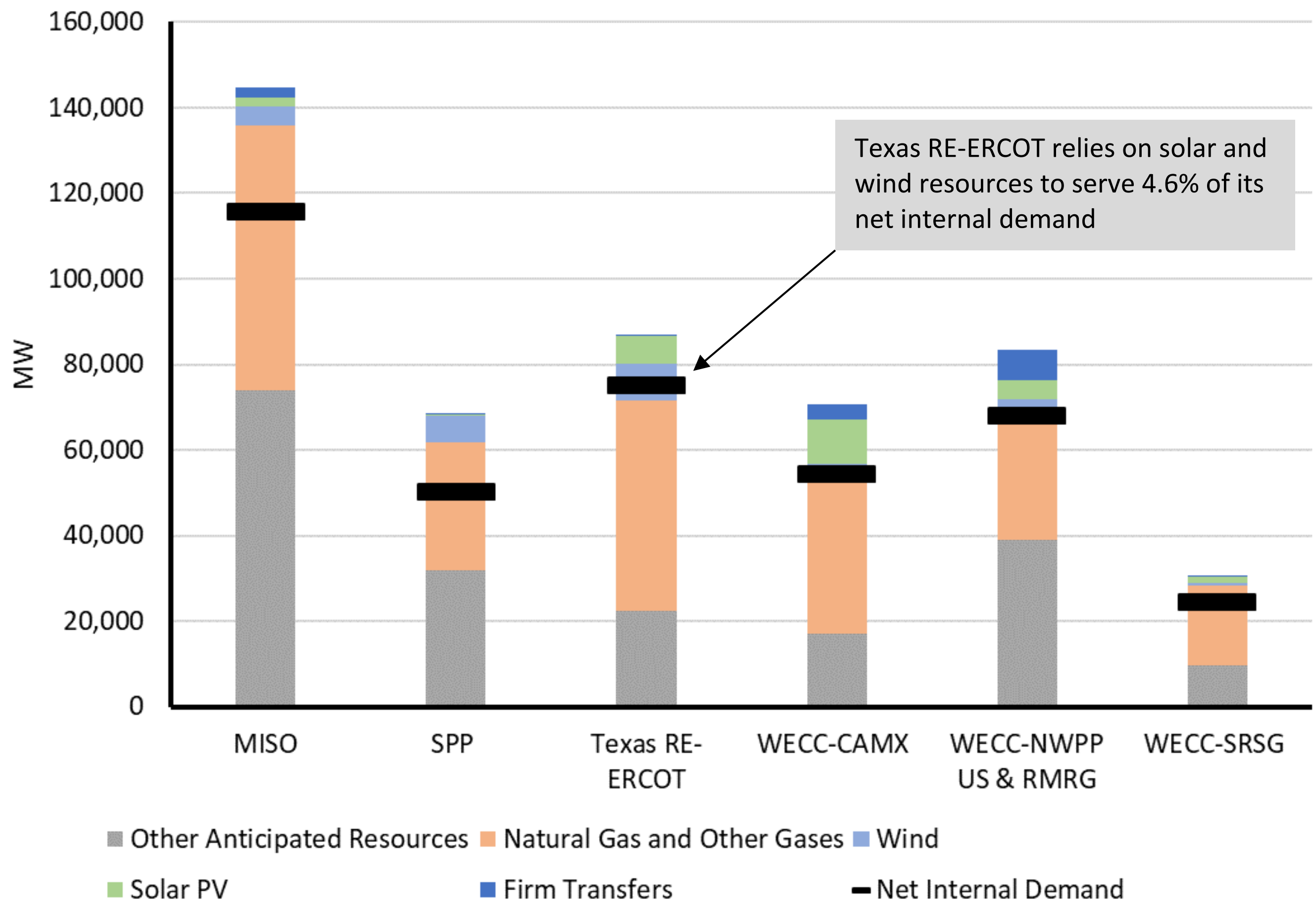


Figure 3.6: Resource Contributions to Meeting Net Internal Demand

Resource Mix Examined in Hourly Generation Data

While the growing contribution of wind and solar PV generation is noticeable in the 10-year on-peak capacity, greater contributions can be seen when examining hourly generator data over the full year. BAs in the United States provide hourly historical demand and generation data that can be analyzed to provide an even clearer understanding of VER's contribution to total generation. Figure 3.7 shows monthly maximum, minimum, and average contributions of grid-connected wind and solar PV generation for some BAs from 2021 data reported to the U.S. Energy Information

Administration (EIA).[43] The depictions give additional details about how the mix of generation in the BA areas was used to serve electricity demand in 2021.

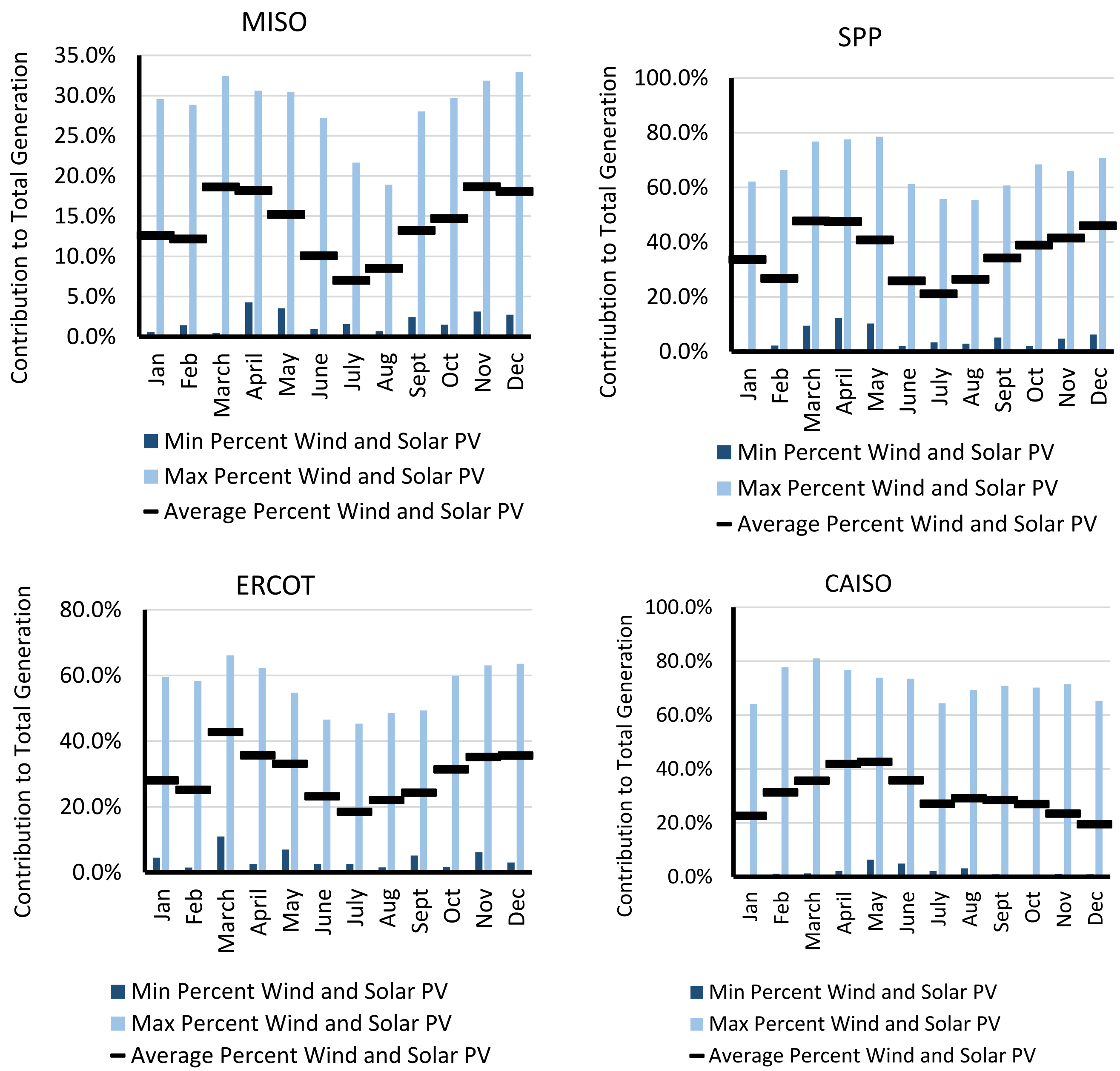


Figure 3.7: 2021 Monthly Maximum, Minimum, and Average Contributions of Grid-Connected Wind and Solar PV Generation

The growth in VERs adds complexity to operational planning and real-time operations and shown in **Figure 3.7** by the large difference in penetration levels between maximum percentages versus the average percentages. Seasonal, day-ahead, and real-time forecasts are used to ensure system operators have resources to balance electricity demand and supply in real-time. Sufficient dispatchable resources that can be called on by system operators in a flexible and timely manner are needed to balance changes in output from variable generation and cover forecast uncertainty. Furthermore, the output of variable generation can differ significantly from day-to-day. Shown in **Figure 3.8** and **Table 3.3** are minimum and maximum daily range of variation in combined wind and solar PV output (MW) for each month of 2021 in several BA areas.

[43] Data from U.S. EIA, EIA-930 Hourly Electric Grid Monitor: https://www.eia.gov/electricity/gridmonitor/about

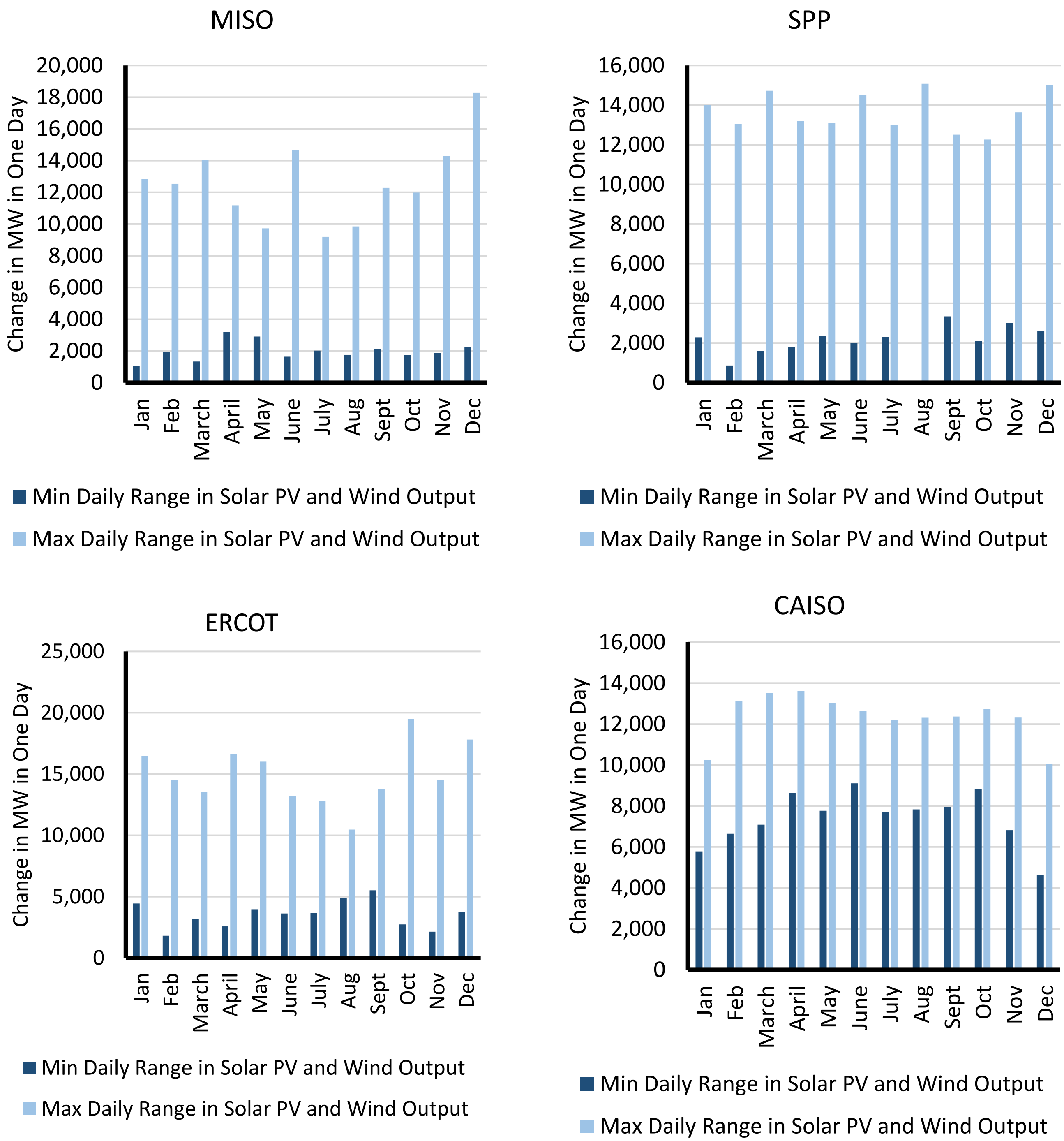


Figure 3.8: 2021 Minimum and Maximum Daily Range of Variation in Combined Wind and Solar PV Output (MW)

Table 3.3: Maximum and Minimum Daily Range of Variation in Wind and Solar PV Generation			
Assessment Area	**Extrema in Daily Range of Solar PV and Wind Output**	**Change in MW in One Day**	**Month Occurring (2021)**
MISO	Minimum	1,070	January
	Maximum	18,300	December
SPP	Minimum*	865	February
	Maximum	15,079	August
	* SPP’s minimum was determined from all months except August. Due to a data issue, the minimum for August cannot be accurately determined from the data set.		
ERCOT	Minimum	1,810	February
	Maximum	19,514	October
CAISO	Minimum	4,636	December
	Maximum	13,608	April

In MISO, the lowest daily change in combined wind and solar PV output was 1,070 MW (January) while the greatest daily change for these two resources was 18,300 MW (December). This high degree of daily variability can be contrasted with CAISO, where the lowest daily change in combined wind and solar PV output was 4,636 MW (December) and the greatest daily change was 13,608 MW (April). Large daily range of combined solar PV and wind generation, unlike a more granular measure of one-hour or three-hour ramps, give an indication of the extent that the area has a need for maintaining flexible resources to balance the system as other generation resources load and unload. A large difference between combined solar PV and wind generation’s minimum daily range and maximum daily range over the year indicates that the amount of flexible resources needed for balancing varies by a large degree.

Actions in Progress within the ERO Enterprise

- Assess resource adequacy, operating reliability, and emerging reliability issues through NERC’s long-term, seasonal, and probabilistic reliability assessments
- Perform seasonal risk scenarios in seasonal assessments to assess low-likelihood extreme scenarios
- Conduct technical analysis and develop guidelines and recommendations as specified in the work plans for the Inverter-Based Resource Performance Subcommittee, System Planning Impacts from Distributed Energy Resources Working Group, and the Resources Subcommittee
- Develop requirements to collect GADS data for solar PV, wind, and energy storage installations

Energy Emergency Alerts

2021 Performance and Trends

In 2021, a total of 10 EEA Level 3 alerts were declared, including four that resulted in the shedding of firm load. This is seven fewer EEA Level 3s and one less EEA Level 3 with load shedding than the previous year (**Figure 3.9**). While the number of EEA Level 3s decreased, the amount of load shed during these EEA Level 3s was almost two orders of magnitude larger (a factor of 100 times) than the previous year—1,015 GWh in 2021 vs. 13.8 GWh in 2020 (**Figure 3.10**). All load shedding occurred during the February cold weather event that primarily impacted Texas and the South Central United States. The EEA Level 3s with load shed occurred between February 15 and February 19, 2021.

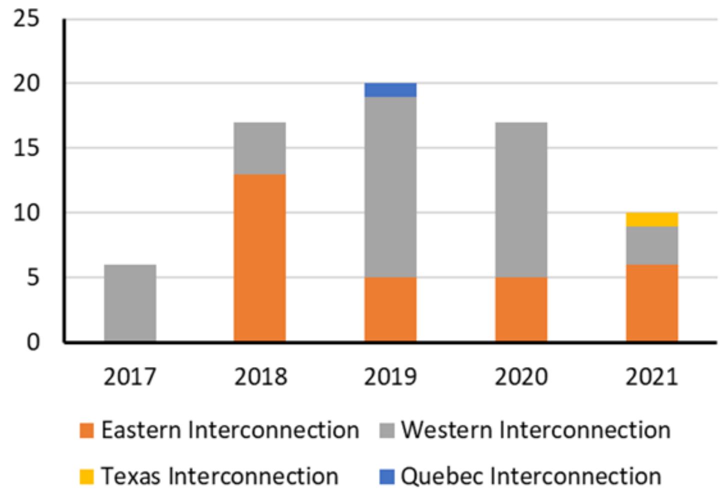


Figure 3.9: EEA 3 by Year and Interconnection

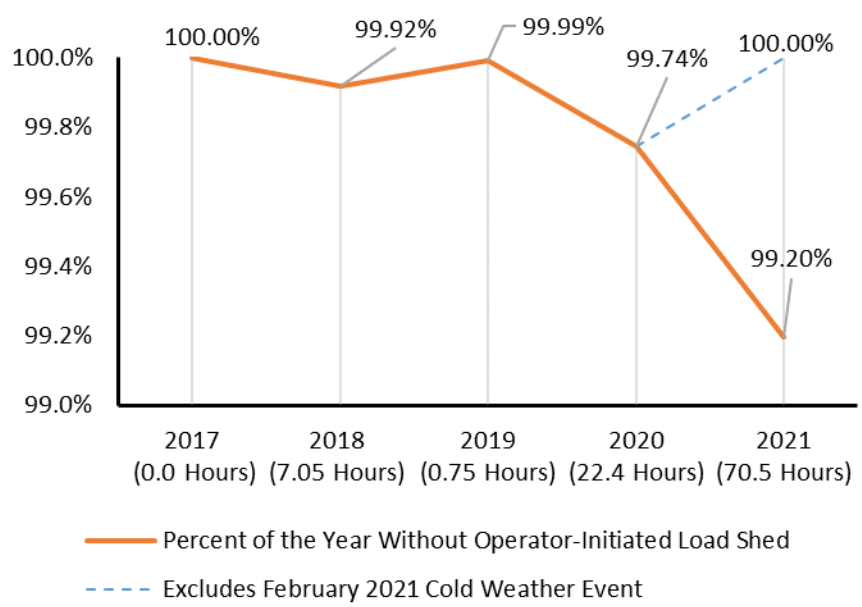


Figure 3.10: Hours without Operator-Initiated Firm Load Shed (%/year)

Over the course of the EEA events, extreme cold temperatures and freezing precipitation led 1,045 individual BES generating units in Texas and the South Central United States to experience 4,124 outages, derates, or failures to start. Texas was the largest contributor with total unserved energy of 1,002 GWh. However, the EI could not serve 13.1 GWh of energy, which comes close to equaling all unserved energy in 2020.

Heading into the 2020–2021 Winter season, ERCOT, SPP, and MISO anticipated winter reserve margins[44] of 49.8%, 59.1%, and 48.8%,[45] respectively, in the *2020–2021 NERC Winter Reliability Assessment*.[46] ERCOT's most extreme scenario, adjusting for extreme peak demand and extreme outages (but not including low wind conditions), indicated

[44] Planning reserve margins are designed to assess the overall capacity supply of the system and do not necessarily predict how the system will perform on a given day.

[45] This winter reserve margin is for the entire MISO footprint. MISO does not calculate a separate winter reserve margin for MISO South.

[46] See NERC *2020–2021 Winter Reliability Assessment*: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2020_2021.pdf

that ERCOT would have only 1,352 MW of operating reserve capacity if those conditions materialized.[47] Like ERCOT, MISO projected that adequate resources would likely be available to meet the expected winter demand forecast but recognized that winter scenarios with high generation outages and high demand could drive operational challenges.[48] In its seasonal assessment for Winter 2020–2021, SPP stated that "the operating capacity for the 2020-21 winter season is expected to be sufficient for normal operating conditions; however, under severe conditions, localized or brief capacity constraints may occur…"[49]

With VERs and just-in-time natural-gas-fired generation comprising an increasingly greater percentage of the generation fleet, the Winter 2021 planning reserve assessments for these areas illustrate how incomplete a picture capacity reserve margin by itself provides.

[47] Federal Energy Regulatory Commission (2021, November): *FERC, NERC and Regional Entity Staff Report: The February 2021 Cold Weather Outages in Texas and the South Central United States* p.34.

[48] Id. at 36; *see also* 2020-2021 MISO Winter Readiness Forum, (Oct. 27, 2020), 42: https://cdn.misoenergy.org/20201027%20Winter%20Readiness%20Workshop%20Presentation486841.pdf

[49] Federal Energy Regulatory Commission (2021, November): *FERC, NERC and Regional Entity Staff Report: The February 2021 Cold Weather Outages in Texas and the South Central United States* p.37.

Chapter 4: Grid Performance

Performance trends in terms of generation, transmission, and protection and control metrics are reviewed in this chapter. Included are the following sections: **System Protection and Disturbance Performance, Disturbance Control Standard Metric, Interconnection Reliability Operating Limit Exceedances, Generation Performance and Availability, Transmission Performance and Unavailability, Critical Infrastructure Interdependencies, Loss of Situational Awareness, Increasing Complexity of Protection and Control Systems, Protection System Failures Leading to Transmission Outages, Human Performance,** and **Cyber and Physical Security**.

By calculating 2021 reliability metrics 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 BES in this manner supports the goal of encompassing NERC's responsibility to ensure the reliable planning and operation of the BES and NERC's obligation to assess the capability of the BES.

System Protection and Disturbance Performance

2021 Performance and Trends

Frequency response analysis indicates Stable or Improving performance for all Interconnections in both the arresting period and stabilizing period:

- **For the arresting period**, the EI, QI, and WI showed no statistically significant changes from 2017 through 2021. The TI showed a statistically significant improvement for the arresting period from 2017 through 2021. Improvement in ERCOT's arresting period frequency response coincides with ERCOT's actions to increase reserves of primary frequency control capabilities selectively during times of low system inertia.
- **For the stabilizing period**, the QI, WI, and TI exhibited statistically significant improvement from 2017 through 2021 while the EI showed no statistically significant changes.

Of note in 2021, the EI frequency response mean and median values for the arresting and stabilizing periods are the lowest over the past five years. Also in 2021, the QI had one analyzed event where the measured frequency response during the stabilizing period was less than the Interconnection frequency response obligation for the Interconnection.

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 under BAL-003, frequency response and frequency bias settings, 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)[50] 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** represents an 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. Analysis for each of the Interconnections indicates an ALR. Within the five-year period, the WI had three events at or greater than 100% of the RLPC and maintained a sufficient UFLS margin. The largest events as measured by percentage of RLPC for the EI and TI were 45% and 50%, respectively.

[50] The RLPC is the predetermined contingency in each Interconnection used to determine the respective Interconnection frequency response obligation.

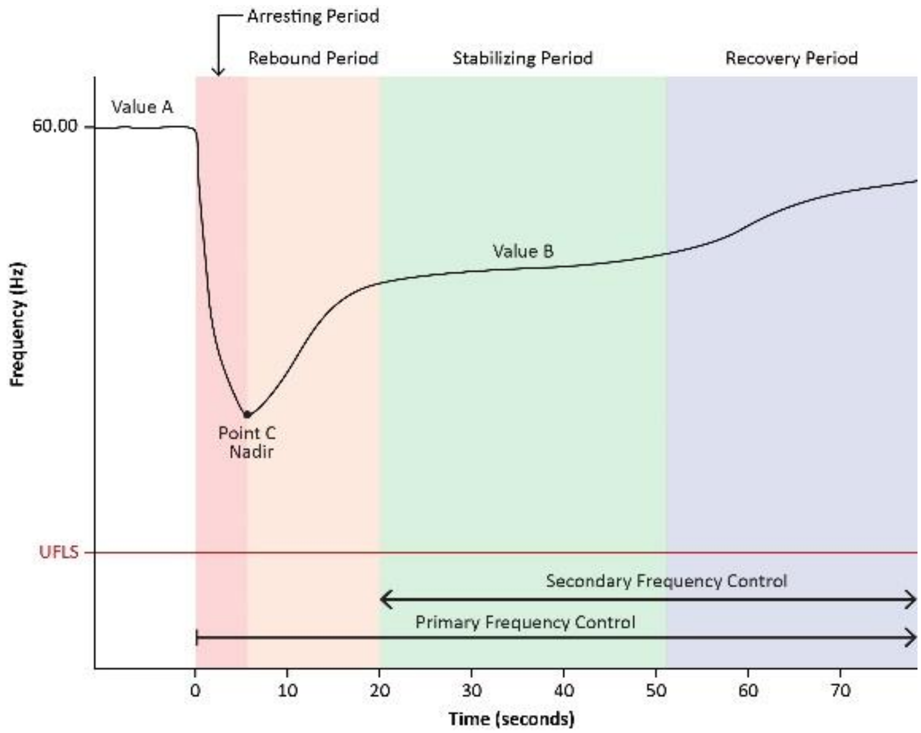


Figure 4.1: Frequency Response Methodology

Frequency response for all of the Interconnections indicates Stable and Improving performance for the stabilizing period as shown in **Table 4.1**. Frequency response for all of the Interconnections indicates Stable and Improving performance for the arresting period as shown in **Table 4.2**.

Table 4.1: 2021 Frequency Response Performance Statistics for Stabilizing Period

Interconnection	2021 OY Stabilizing Period Performance					
	Mean $IFRM_{A-B}$ (MW/0.1 Hz)	Median $IFRM_{A-B}$ (MW/0.1 Hz)	Lowest $IFRM_{A-B}$ (MW/0.1 Hz)	Maximum $IFRM_{A-B}$ (MW/0.1 Hz)	Number of Events	2017–2021 OY Trend
Eastern	2,202	2,065	1,385	3,594	29	Stable
Texas	1,010	912	559	2,083	44	Improving
Québec	1,581	732	156	12,433	44	Improving
Western	2,109	1,742	1,011	7,814	43	Improving

Table 4.2: 2021 Frequency Response Performance Statistics for Arresting Period

Interconnection	2021 OY Arresting Period Performance					
	Mean $IFRM_{A-C}$ (MW/0.1 Hz)	Median $IFRM_{A-c}$ (MW/0.1 Hz)	Lowest $IFRM_{A-c}$ (MW/0.1 Hz)	Mean UFLS Margin (Hz)	Lowest UFLS Margin (Hz)	2017–2021 $IFRM_{A-C}$ OY Trend
Eastern	1,814	1,727	1,154	0.454	0.424	Stable
Texas	517	440	309	0.576	0.468	Improving
Québec	132	131	46	1.083	0.801	Stable
Western	846	842	549	0.408	0.319	Stable

Disturbance Control Standard Metric

2021 Performance and Trends

In 2021, the total number of reportable balancing contingency events (RBCE) was slightly less than 2020 and significantly less than the years 2017 and 2018.[51] Over the last five years, the average percent recovery was 99.5%. In 2021, there was one event where the BA did not restore its system to pre-disturbance levels within the contingency event recovery period. See **Figure 4.2** and **Figure 4.3**.

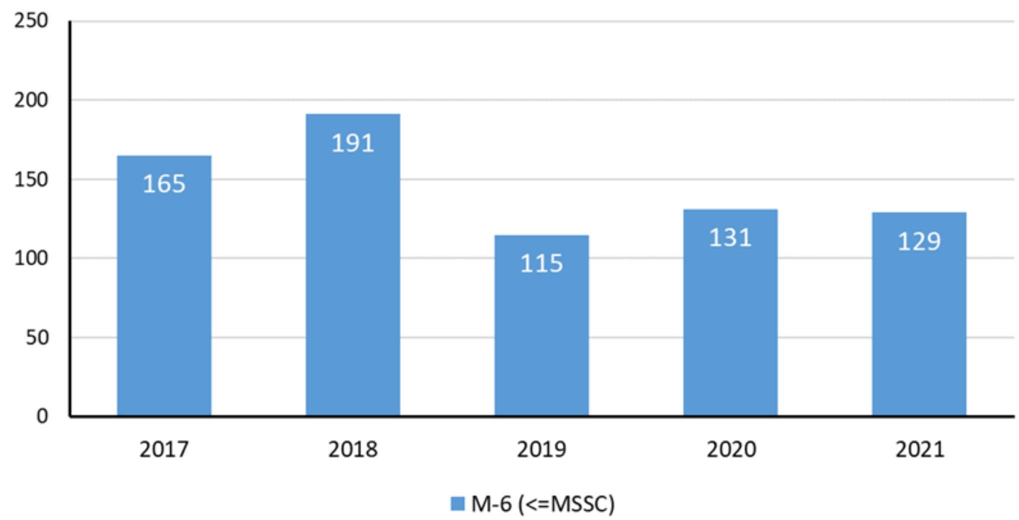


Figure 4.2: Total Number of RBCEs

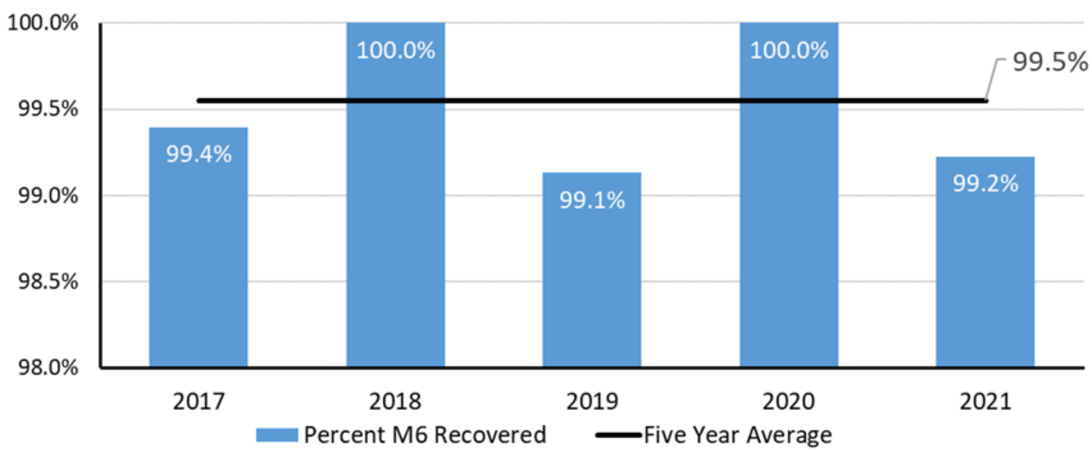


Figure 4.3: Percent of RBCEs with 100% Recovery[1]

[51] Prior to December 31, 2017, NERC Reliability Standard BAL-002-1 required that a BA or reserve sharing group (RSG) report all disturbance control standard events and non-recoveries to NERC. On January 1, 2018, NERC Reliability Standard BAL-002-2 became effective and no longer requires all RBCES to be reported to NERC. The disturbance control standard data used for 2018–2021 is from voluntary submissions from the BAs and RSGs.

Interconnection Reliability Operating Limit Exceedances

2021 Performance and Trends

Each Reliability Coordinator has a different methodology to determine Interconnection reliability operating limits (IROL) based on the make-up 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 for comparison:

- **Eastern–Québec Interconnections:** In 2021, there were exceedances in all four ranges of the metric as shown in **Figure 4.4**. The largest number of exceedances was below 10 minutes (range not shown). The 10-minute to 20-minute range continued to decline from its all-time peak in 2019 and remained near historical levels with 15 minutes in 2021. There were 3 exceedances greater than 20 minutes. The total of 18 exceedances that lasted more than 10 minutes in 2021 places it just below the five-year average of 21 exceedances.
- **Western Interconnection:** Prior to 2014, only system operating limits were reported. Since 2014, the trend has been Stable with no IROL exceedances reported.
- **Texas Interconnection:** ERCOT had zero IROL exceedances from 2016 Q1 through 2020 Q3. In October 2020, ERCOT made a change to its system operating limit methodology that increased the number of IROLs for the Interconnection from one to five. In 2021, there were six exceedances; all were less than 10 minutes.

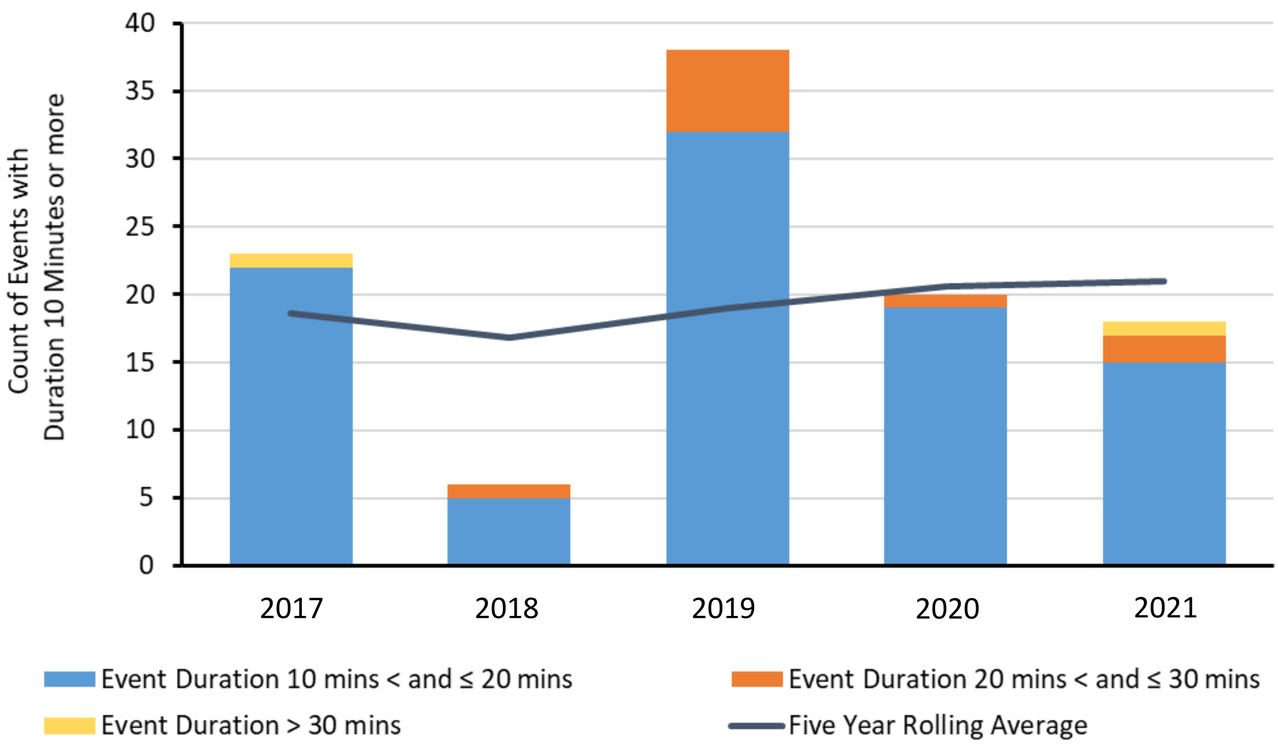


Figure 4.4: IROL Exceedance Counts

Generation Performance and Availability

GADS contains information that can be used to compute reliability measures, such as megawatt-WEFOR. GADS collects and stores unit operating information; by pooling individual unit information, overall generating unit availability, performance, and metrics are calculated. The information supports equipment reliability, availability analyses, and risk-informed decision making to industry. Industry uses reports and information from the data collected through GADS for benchmarking and analyzing electricity power plants.

Conventional Generation WEFOR

2021 Performance and Trends

The horizontal lines in **Figure 4.5** show the annual WEFOR compared to the monthly WEFOR columns; the solid horizontal bar shows the WEFOR for all years in the analysis period of 7.25%, notably lower than the 2021 WEFOR of 8.27%. The WEFOR has been fairly consistent and has a statistical distribution that is nearly an exact standard distribution. The 2021 annual WEFOR is the highest of the last five years. The increase compared to prior years is primarily attributable to the February cold weather event and several independent long-duration outages of large units.

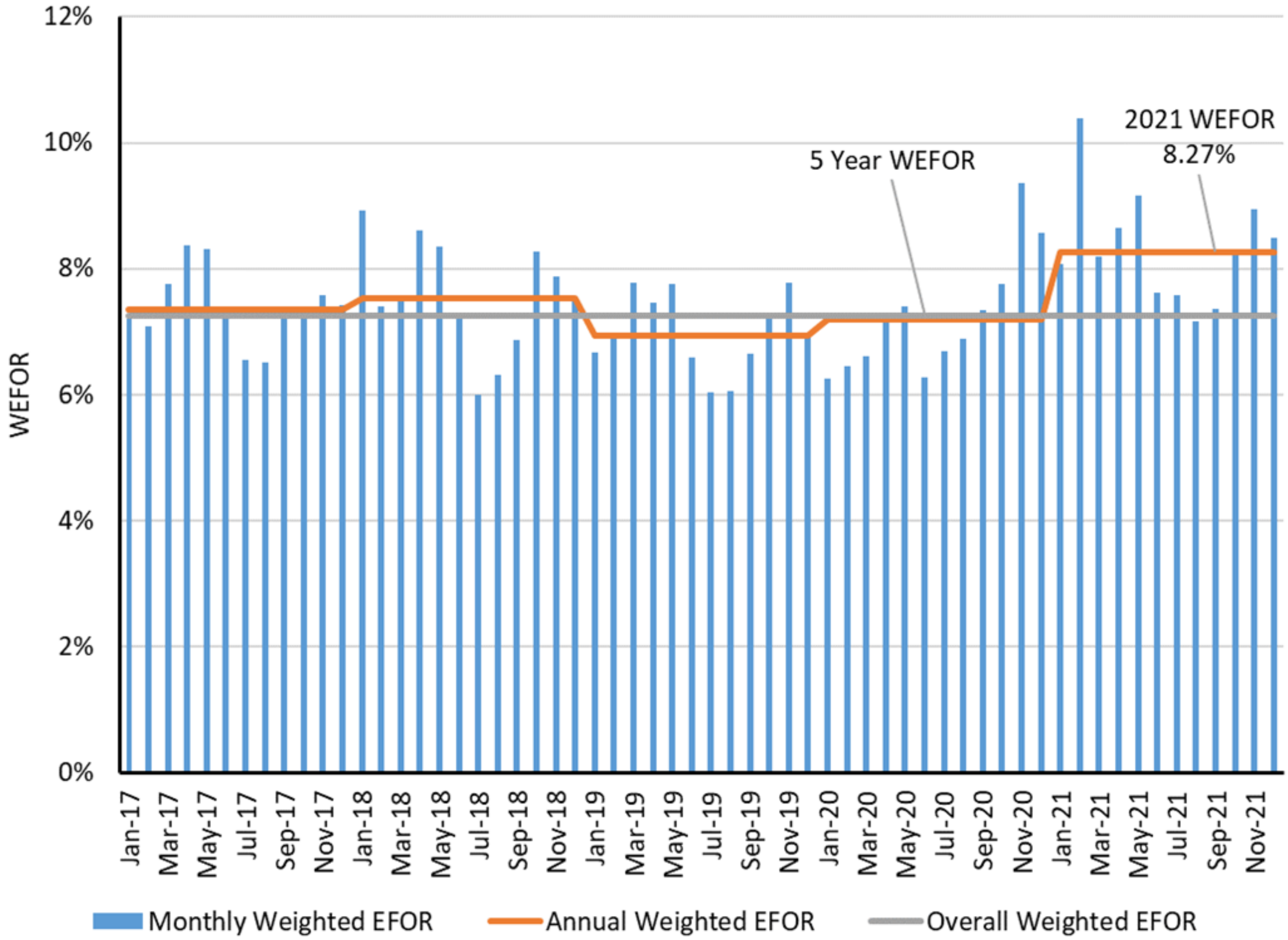


Figure 4.5: Monthly, Annual, and Five-Year WEFOR

The monthly WEFOR for select fuel types is shown as a layered area chart in **Figure 4.6**. The dashed line shows the monthly WEFOR of all fuel types reported to NERC, and the yellow line shows the mean outage rate of all fuel types reported to NERC over the five years in the analysis period. Coal-fired generation continues to show a slightly increasing trend over the five-year period and represents the highest forced outage rate of all conventional fuels except during extreme winter weather when natural-gas-fired generation outages generally spike above coal. Additionally, hydro units experienced uncharacteristically high outage rates during the spring and in November of 2021.

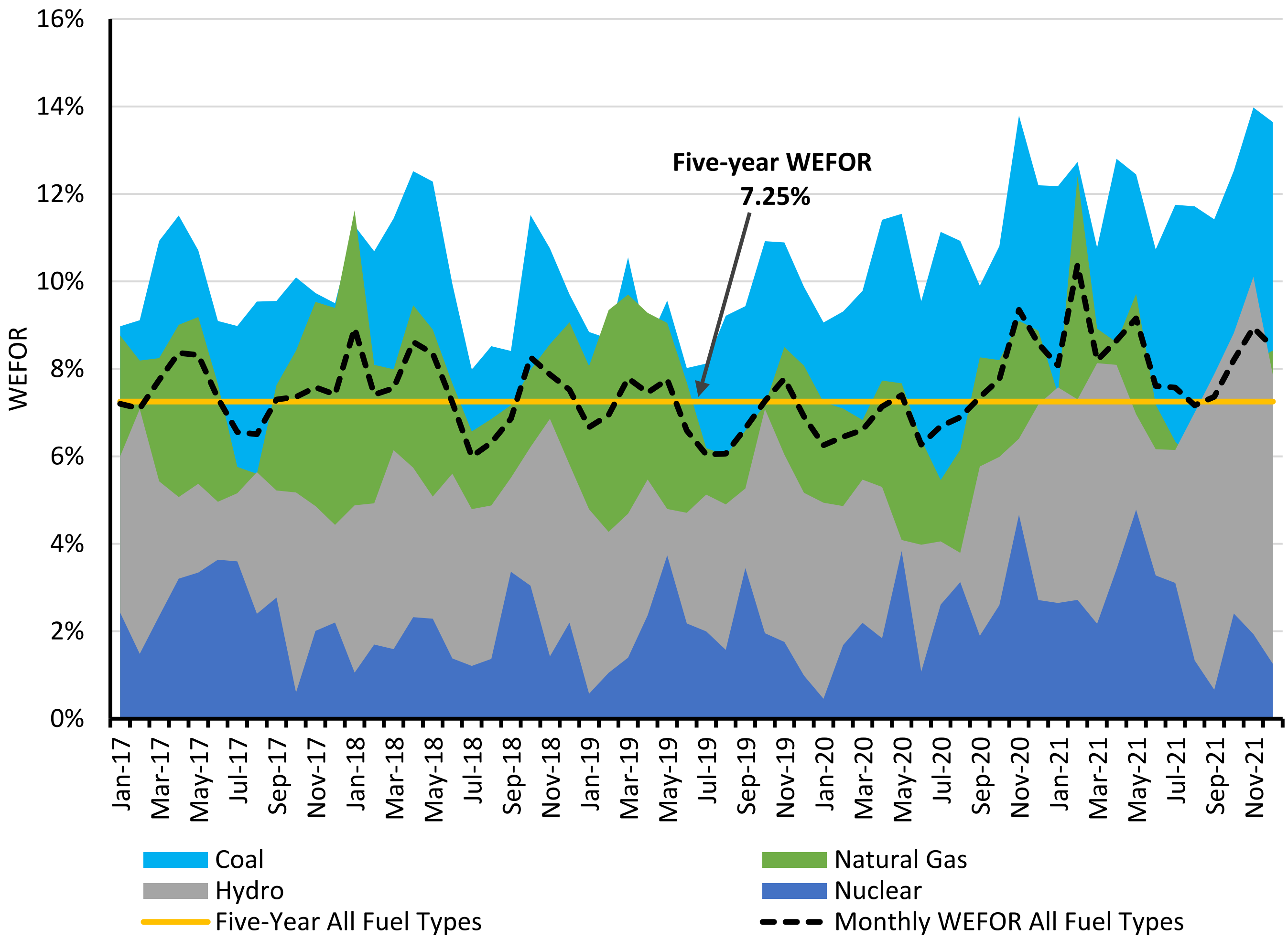


Figure 4.6: 2021 Overlaid Monthly Capacity WEFOR by Fuel Type

Wind Generation Weighted Resource Equivalent 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. By the end of 2021, data from 120,100 MW of installed capacity, representing 640 wind plants across North America, 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.

The Weighted Resource Equivalent Forced Outage Rate (WREFOR) for wind generation, which is equivalent to WEFOR for conventional generation, is shown in **Figure 4.7**. The horizontal lines show the annual WREFOR compared to the monthly WREFOR columns based on the data provided during phased-in reporting periods according to plant size. Seasonal trends, such as the increased outage rates during summer months and lower forced outage rates in spring, are evident. The aggregate annual rates for 2021 show better performance as the size of the wind plants increase; February 2021 reported the highest monthly WREFOR, 25% for all wind plant sizes since reporting began.

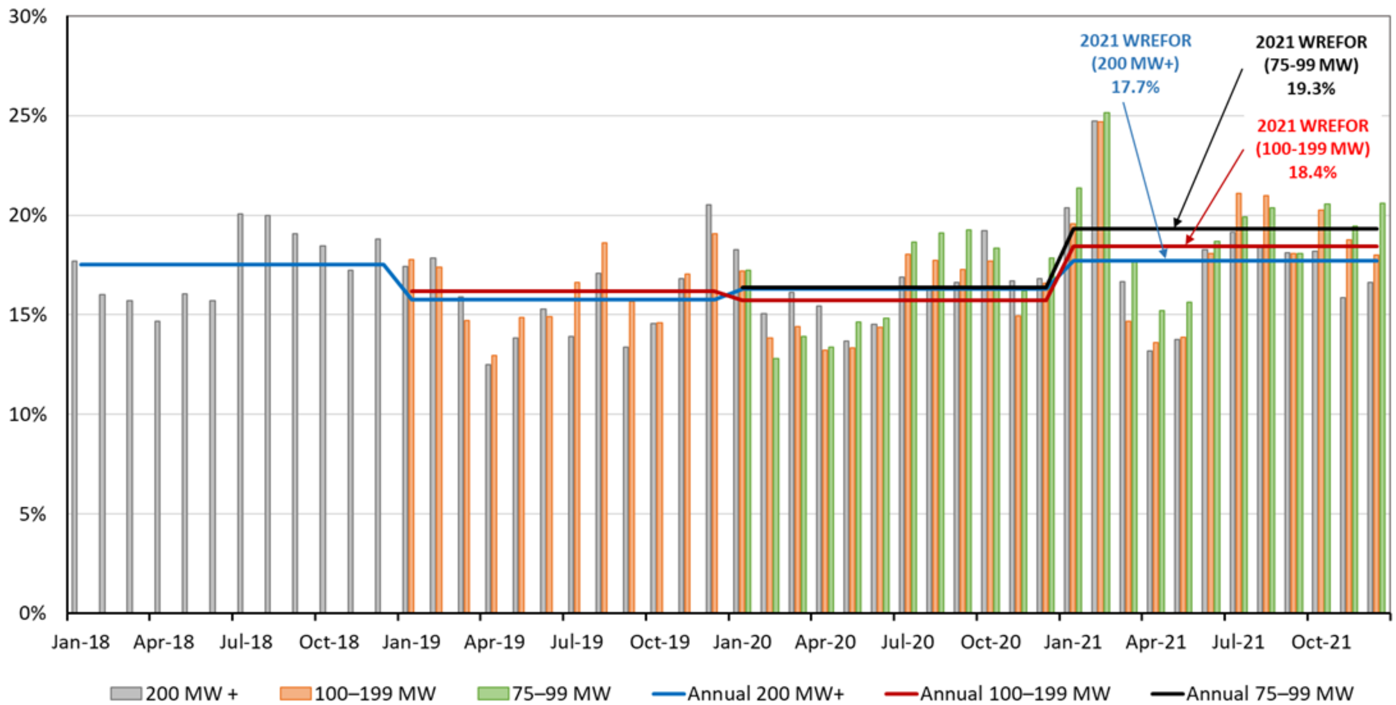


Figure 4.7: Monthly Capacity WREFOR and Annual Average Wind Plant Reporting Group

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

2021 Performance and Trends

In 2021, four distinct non-weather-related transmission events resulted in loss of firm load meeting the Event Analysis Process (EAP) reporting criteria (see **Figure 4.8**). Analysis indicates no discernable trend in the number of annual events. The median firm load loss over the past five years was 131 MW, which is a significant decrease from 2016–2020's 183 MW. In 2021, the median was 74.7 MW, and this represents a decrease in both the number of events and median load loss in 2021 with 2021's median load loss remaining below the five-year median value.

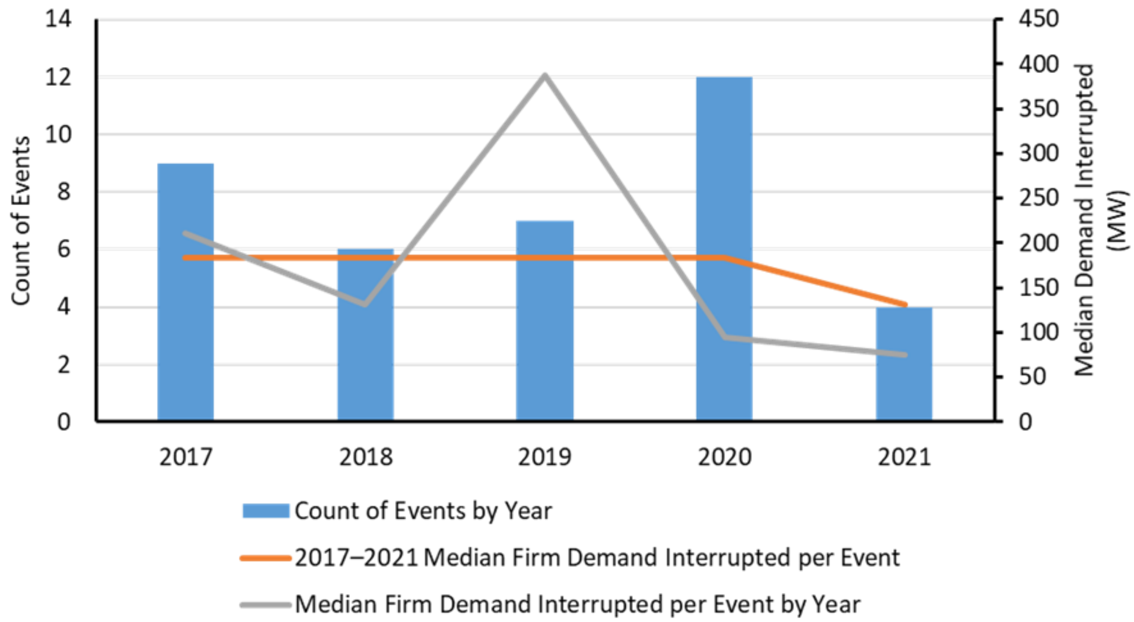


Figure 4.8: Transmission-Related Events Resulting in Loss of Firm Load and Median Amount of Firm Load Loss Excluding Weather-Related Events

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
- Automatic AC Transformer Outages
- Transmission Element Unavailability

Transmission Outage Severity

2021 Performance and Trends

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 (ICCs). These ICCs facilitate the study of cause-effect relationships between each event's ICC and event severity.

By examining the average TOS, duration, and frequency of occurrence for events with different ICCs (see **Figure 4.9**), it is possible to determine which ICCs contribute most to reliability performance for the time period considered. The average TOS for an ICC's events is displayed on the Y-axis. A higher TOS for an ICC indicates more outages or higher voltage elements were involved in an event. The average duration for a given ICC's events is displayed on the X-axis; events with a longer duration generally pose a greater risk to the BPS. The number of ICC occurrences is represented by the bubble size; larger bubbles indicate 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.

There was a statistically significant reduction in the average event TOS and duration from 2016–2020 to 2017–2021 (past five-year period to the current five-year period) that indicates an improvement in the TOS and duration sub-metrics.

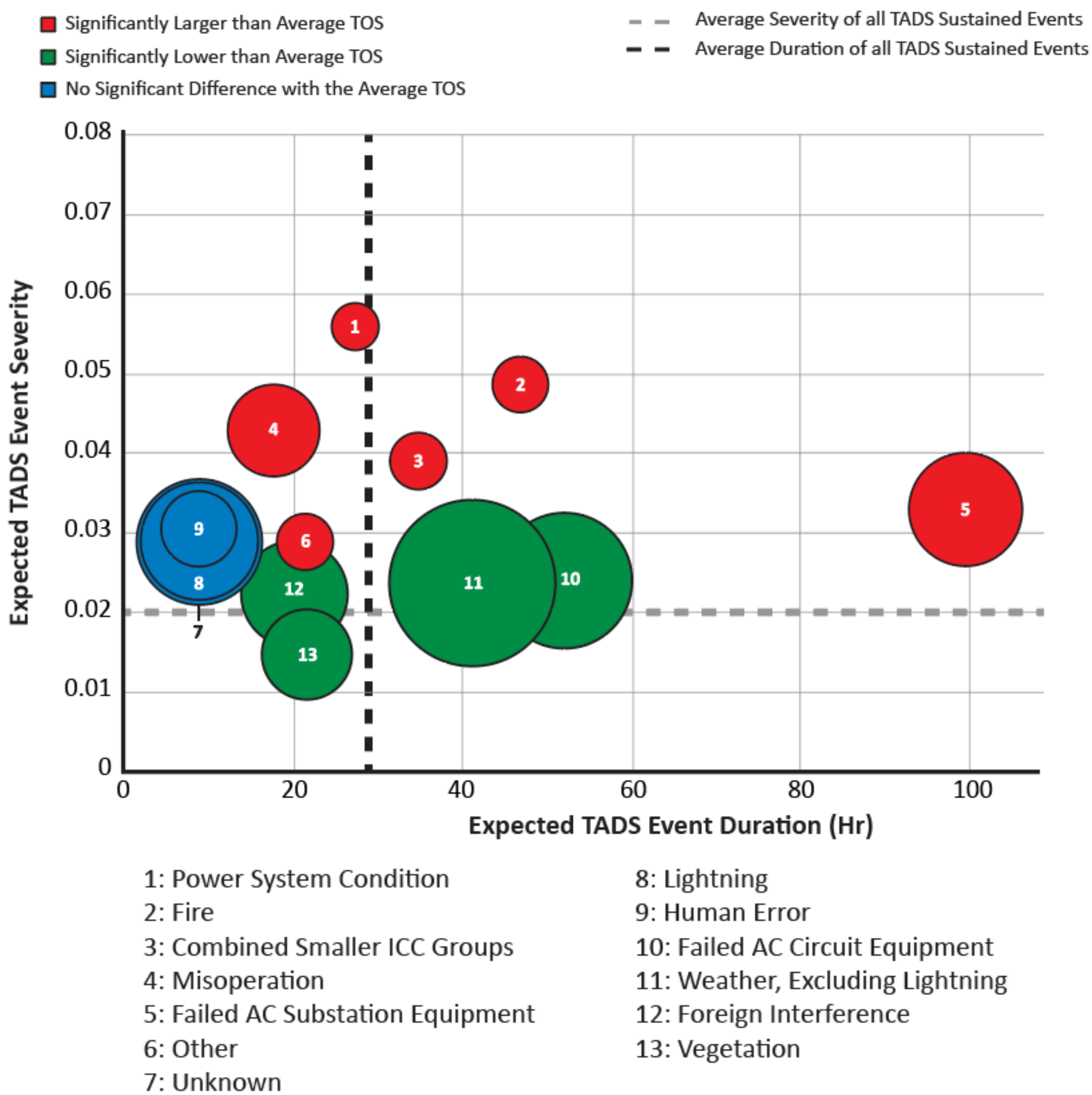


Figure 4.9: TOS vs. Expected TADS Event Duration

An analysis of the total TOS by year indicates a statistically significantly improving trend for the last five years (see Figure 4.10); this is a positive indication that transmission outages are leading to less severe reliability impacts.

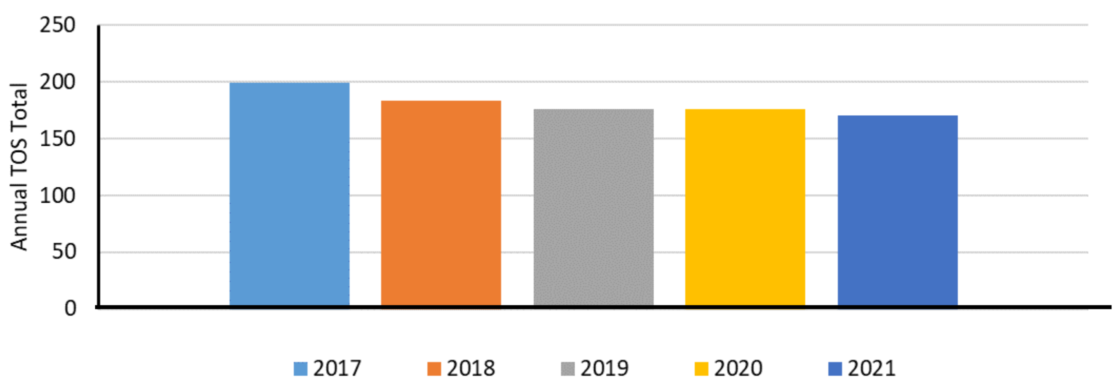


Figure 4.10: TOS of TADS Sustained Events of 100 kV+ AC Circuits and Transformers by Year Automatic AC Transmission Outages

2021 Performance and Trends

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 2021 compared to 2017–2020 (See **Figure 4.11**). The number of sustained outages due to Failed AC Circuit Equipment per 100 miles saw a slight increase, bringing it above the five-year average; however, it remains Stable overall (See **Figure 4.12**).

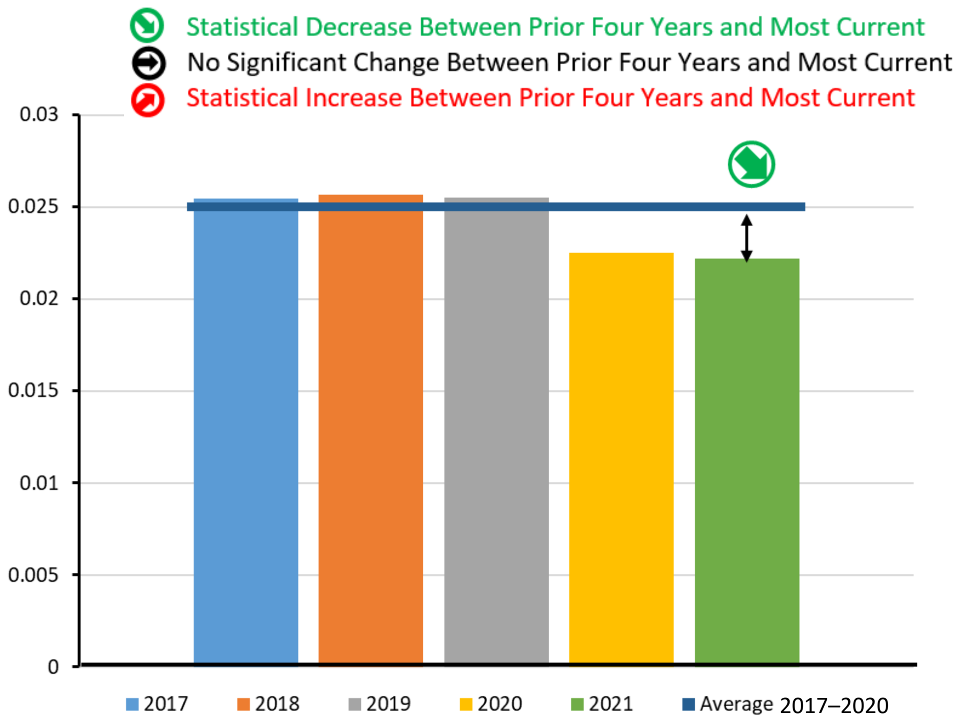


Figure 4.11: Number of Outages per AC Circuit due to Failed AC Substation Equipment

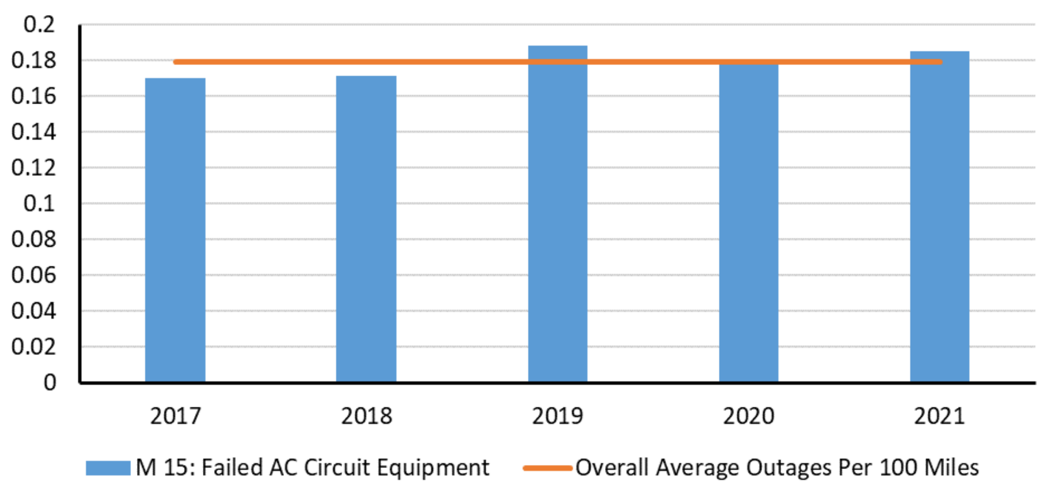


Figure 4.12: Number of Outages per Hundred Miles due to Failed AC Circuit Equipment

Automatic AC Transformer Outages

2021 Performance and Trends

From 2017 through 2021, the trend of automatic ac transformer outages caused by Failed AC Substation Equipment is showing a statistically significant decrease in the number of outages per element.

See **Figure 4.13** for the number of outages per transformer due to various initiating causes.

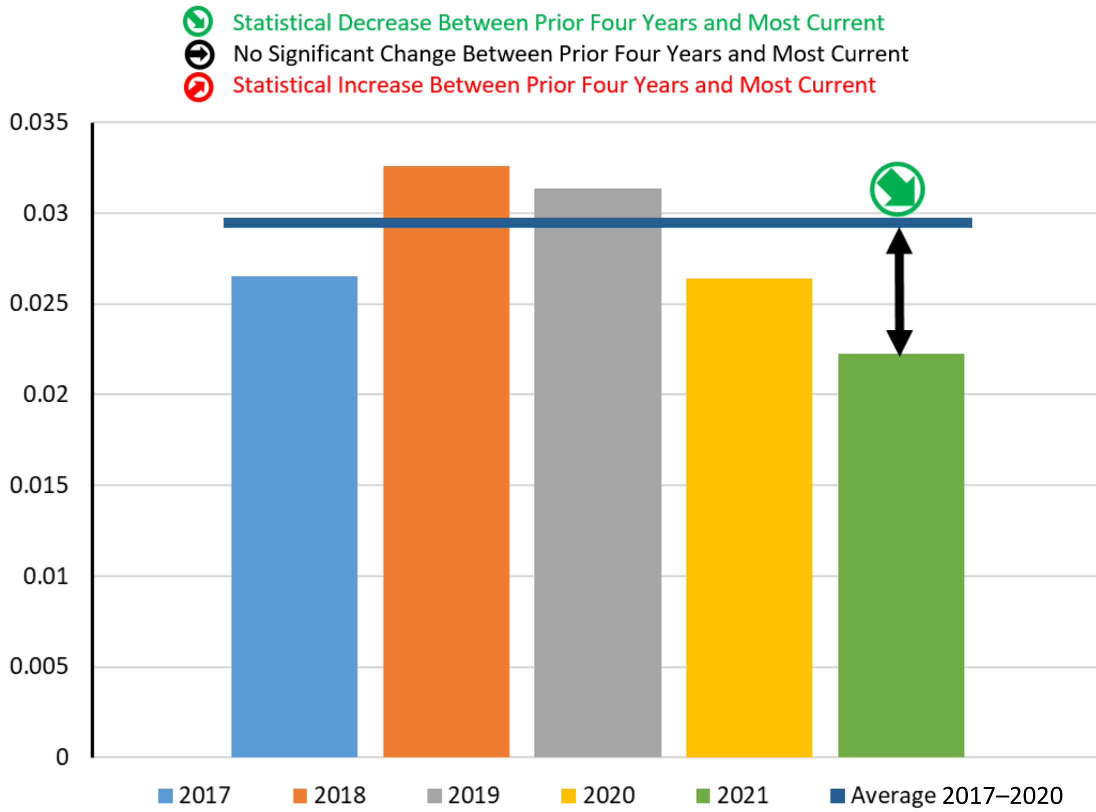


Figure 4.13: Number of Outages per Transformer Due to Failed AC Substation Equipment

Transmission Element Unavailability

2021 Performance and Trends

In 2021, ac circuits over 200 kV across North America had an unavailability rate of 0.275%, meaning that there is a 0.275% chance that a transmission circuit is unavailable due to sustained automatic and operational outages at any given time. Transformers had an unavailability rate of 0.20% in 2021. **Figure 4.14** shows 2021 was the second highest year for ac circuit unavailability of the five-year analysis period behind 2020. **Figure 4.15** shows 2021 was the second lowest year for transformer unavailability behind 2020.

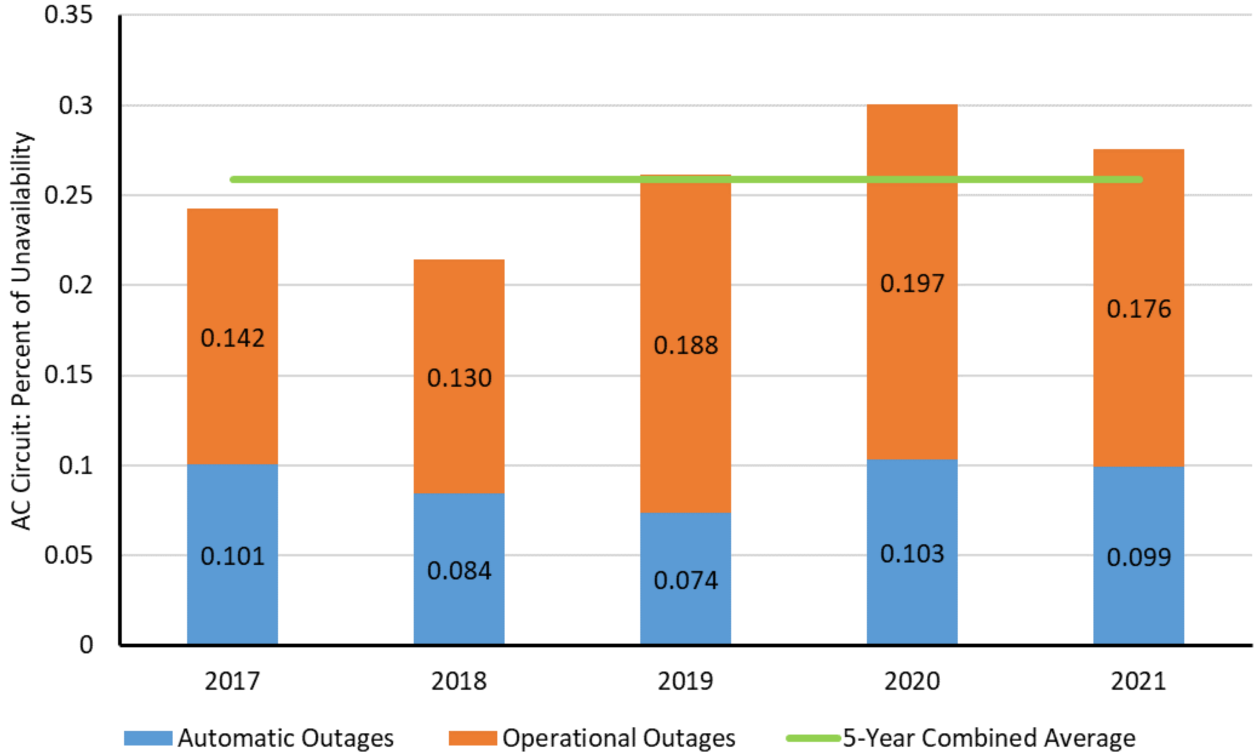


Figure 4.14: AC Circuit Unavailability

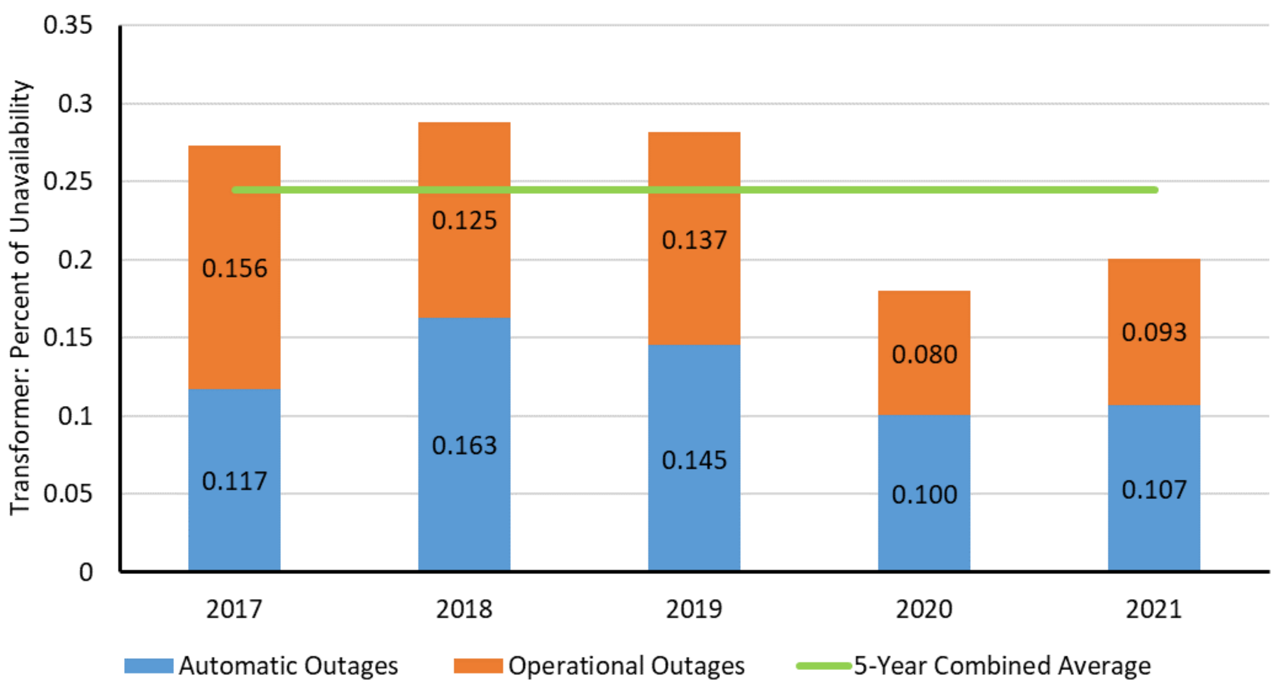


Figure 4.15: Transformer Unavailability

Critical Infrastructure Interdependencies

With the continued retirement of coal and nuclear units and a growing reliance on natural-gas-fired generation, the interdependency of the electricity and natural gas industries has become more pronounced. As shown in **Figure 4.16**, over the last decade natural-gas-fired on-peak generation has increased from 385 GWs in 2011 to over 460 GWs today, an increase of over 20%. Another 47 GWs of natural-gas-fired generation is expected to be added in the coming decade. Since 2011, on-peak wind capacity has doubled while on-peak solar PV capacity has increased by a factor of 25. In addition to serving as base and intermediate-load plants, natural-gas-fired generation has become a necessary balancing resource to reliably integrate VERs into the dispatch. Until storage technology is fully developed and deployed at scale, natural-gas-fired generation will remain essential to providing the grid's rapidly increasing flexibility needs. Improvements in the mutual understanding of electricity and natural gas interdependencies enable operators in both industries to enhance reliability across energy delivery systems and reduce end-use customer exposure to energy shortfalls during extreme weather events.

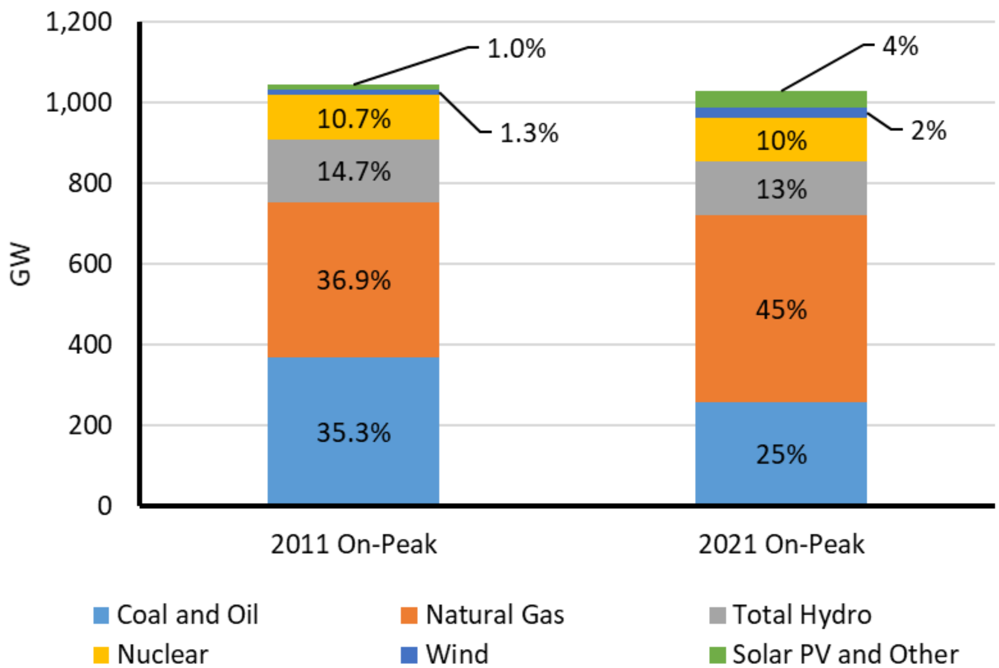


Figure 4.16: 2011 and 2021 Capacity Resource Mix across North America

Growing reliance on natural gas as an electricity generation fuel source increases the potential for common-mode failures that have widespread reliability impacts. Natural gas can generally be considered a "just-in-time" fuel source as natural gas is typically delivered to the generation facility through the natural gas pipeline system and not stored on-site. For example, high demand, decreased natural gas production, and decreased processing volumes occasioned by prolonged freezing temperatures and power outages resulted in a number of pipelines in the impacted areas issuing operational flow orders during the February 2021 cold weather event. These, along with critical notices, indicate potential delivery and reliability concerns on the natural gas pipeline system, translating into potential fuel supply disruptions for interconnected natural-gas-fired generation. This risk of fuel delivery curtailment is elevated for the many natural gas generators that do not contract for firm natural gas transportation.

Figure 4.17 and **Figure 4.18** are courtesy of Argonne National Laboratory through DOE Office of Electricity North American Energy Resilience Model program. They show the number of critical notices and operational flow orders during the February 2021 winter weather event compared to the same time period a year earlier.

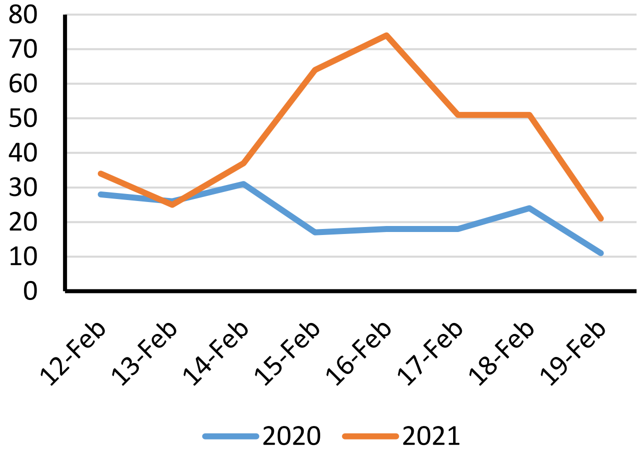


Figure 4.17: Number of Critical Notices

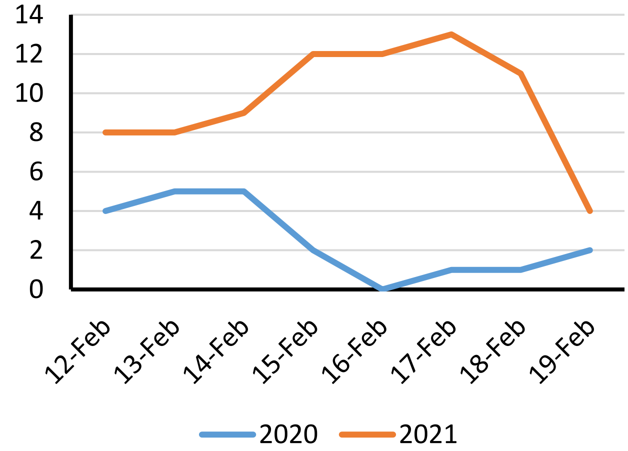


Figure 4.18: Number of Operational Flow Orders

As described elsewhere in this *2022 State of Reliability Report* and far more comprehensively in the November 2021 *FERC, NERC and Regional Entity Staff Report*, natural gas fuel supply issues caused 27.3% of all generator outages, derates, and failures to start during the February 2021 cold weather event.[52] **Table 4.3** displays the amount of natural-gas-fired generation that experienced outages over the course of the February 2021 event in the states of Texas, Oklahoma, Kansas, Louisiana, and Arkansas.

Table 4.3: Natural Gas—Outages over the Course of the February 2021 event				
	in the states of Texas, Oklahoma, Kansas, Louisiana, and Arkansas			
State	Number of Natural Gas Pipelines	Number of Plants Impacted	Cumulative Nameplate Capacity (MW)	Cumulative Outage Duration (hours)
Arkansas	4	8	1,717.4	108
Kansas	3	4	373.1	133
Louisiana	9	19	4,290.7	517
Oklahoma	6	21	4,004.9	451
Texas	22	160	25,167.7	4,919

Over the duration of the February 2021 cold weather event, loss of power supply to natural gas infrastructure caused 23.5% of the decline in natural gas production. However, power outages at natural gas infrastructure facilities were caused by both weather and manual firm load shedding. Because many natural gas infrastructure loads had not been identified as critical loads to be protected from manual firm load shedding, and power outages caused by weather and firm load shed were coincident, the exact extent of firm load shed-caused power outages to critical natural gas infrastructure loads is unknown. While the percentage of production declines caused by power outages varied little over the entire event, firm load shed did not begin until the early morning of February 15. Natural gas production declines from power outages that occurred before then would necessarily have been weather initiated.[53]

NERC continues to recommend that registered entities conduct studies to model plausible and extreme natural gas supply disruptions. These recommendations are set forth in NERC's March 2020 guideline, *Fuel Assurance and Fuel-*

[52] Federal Energy Regulatory Commission (2021, November) *FERC, NERC and Regional Entity Staff Report: The February 2021 Cold Weather Outages in Texas and the South Central United States* p.16: https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and

[53] Id. at 175.

Related Reliability Risk Analysis for the Bulk Power System.[54] Additionally, two standard authorization requests have been introduced to mandate that registered entities conduct requisite studies for both planning and operations to ensure energy resource and supply adequacy. An industry team is currently drafting these proposed standards.

While natural gas deliveries and the reliance on natural gas for electricity generation are where much of the impactful risks of critical infrastructure interdependencies (CII) have been experienced, it is important to note that other CIIs have been identified by the NERC Reliability Issues Steering Committee (RISC) committee with associated risk mitigating activities; these CII are discussed in more detail in the *2021 ERO Reliability Risk Priorities Report*, which is developed by NERC's RISC committee.[55] Communication systems, water and waste water, and oil also have dependent structures on BPS reliability and effective operations; the RISC committee has identified mitigating activities to address these risks that are also defined and described in detail in the *2021 ERO Reliability Risk Priorities Report*.

Loss of Situational Awareness

The BES 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. In order to maintain the reliability of the BES, entities use various situational awareness tools that include but are not limited to energy management systems (EMS), transmission outage planning, load forecasting, geomagnetic disturbance/weather forecasting, data from neighboring entities' operations, and interpersonal communication within their own company 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 that ensure reliability for the given state of the BES. Unexpected outages of systems needed for communications, monitoring and control of equipment, or planned outages without appropriate coordination or oversight can leave system operators with impaired 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 ERO *Reliability Risk Priorities Reports*[56] of 2019 and 2021 both highlighted 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.

The ERO is focused on working collaboratively with industry stakeholders to develop recommended practices for integrating security with engineering practices, particularly related to developing cyber engineering capability that integrate these practice more holistically.

Impacts from the Loss of EMS

An EMS is a computer-aided environment 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 the frequency, the status (open or closed) of switching devices plus real and reactive power flows on the BES tie-lines and transmission facilities within the control area, and the status of applicable EMS applications (e.g., state estimator (SE), real-time contingency analysis (RTCA), automatic generation control (AGC), alarm management).

[54] *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System:* https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Fuel_Assurance_and_Fuel_Related_Reliability_Risk_Analysis_for_the_Bulk_Power_System.pdf

[55] https://www.nerc.com/comm/RISC/Documents/RISC%20ERO%20Priorities%20Report_Final_RISC_Approved_July_8_2021_Board_Submitted_Copy.pdf

[56] *2019 ERO Risk Priorities Report*, November 2019: https://www.nerc.com/comm/RISC/Related%20Files%20DL/RISC%20ERO%20Priorities%20Report_Board_Accpeted_November_5_2019.pdf

There were 50 EMS-related events reported in 2021. In total, 371 EMS-related event reports were submitted between 2017 and 2021; there were no reported EMS-related events that caused loss of generation, transmission lines, or customer load. **Figure 4.19** shows a trend of the reported EMS events by loss of EMS functions over the 2017–2021 period. Both loss of SE/RTCA and Inter-Control Center Protocol (ICCP) events have been declining since 2018. The complete loss of monitoring or control capability events was Stable from 2017–2019 but increased in 2020 and was Stable in 2021. There are two reasons for the declining trend of loss of SE/RTCA and ICCP:

- Partial loss events (e.g., loss of SE/RTCA, loss of ICCP, loss of remote terminal units, and loss of AGC) are no longer captured as part of EOP-004-4 mandatory reporting. NERC Reliability Standard EOP-004-4 was modified to require the complete loss of monitoring or control capability at a BES control center for 30 continuous minutes or more. The modified NERC Reliability Standard went into effect on April 1, 2019, in the United States and some Canadian provinces. However, the ERO encourages partial loss EMS reporting through the EAP for trending of potential reliability risks/impacts to the BES as some entities continue to do.
- The industry has made significant effort to enhance EMS reliability and resilience. For example, many entities built a 24x7 onsite team that works along with system operators and provides dedicated support to SE and RTCA. This action has significantly reduced the outage duration resulting in many SE/RTCA issues not being reportable.

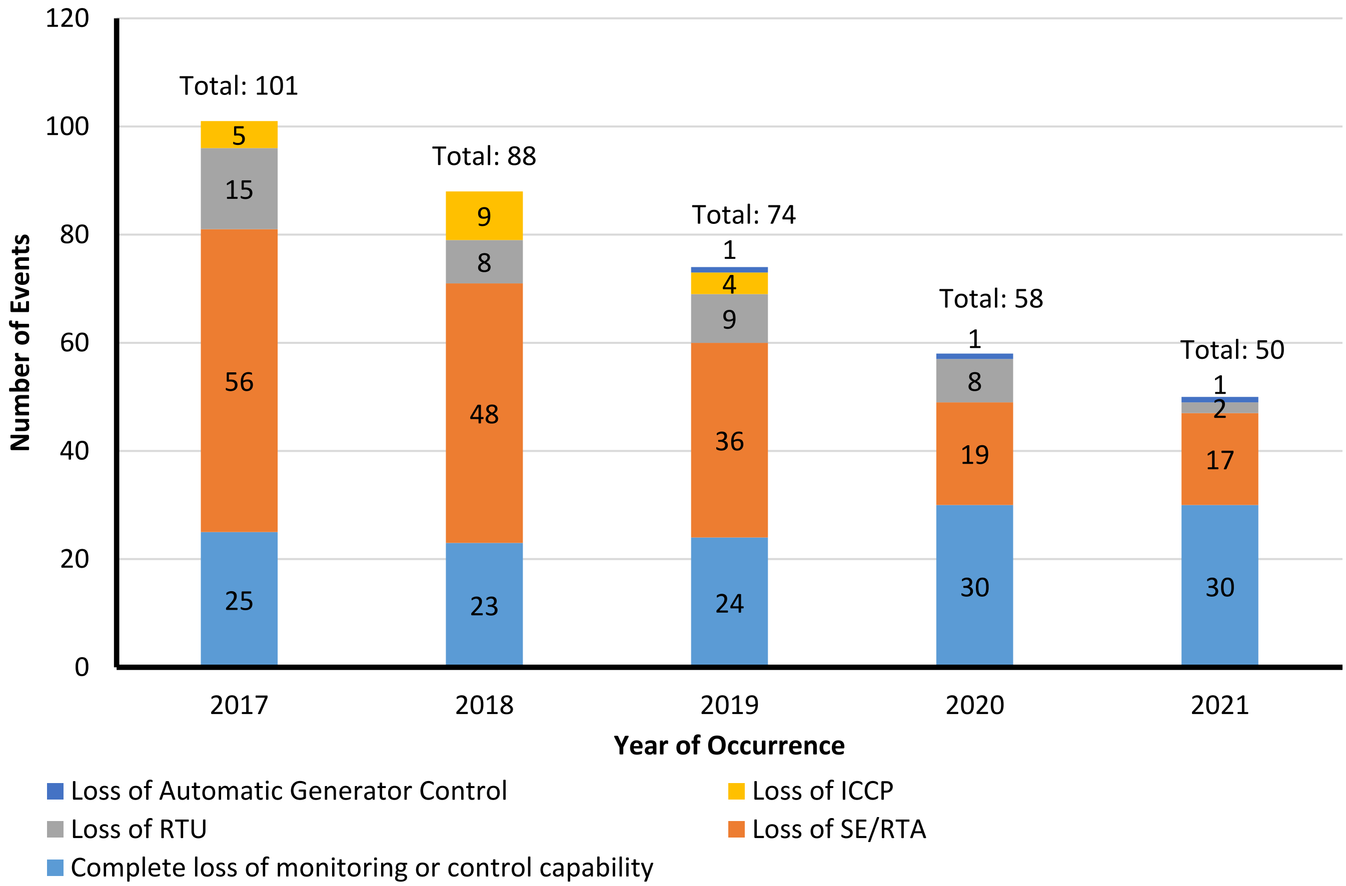


Figure 4.19: Number of EMS-Related Events (2017–2021)

Over the five-year period, the average partial or full function EMS outage time (see **Figure 4.20**) was 70 minutes, making the calculated reported EMS availability 99.99%.

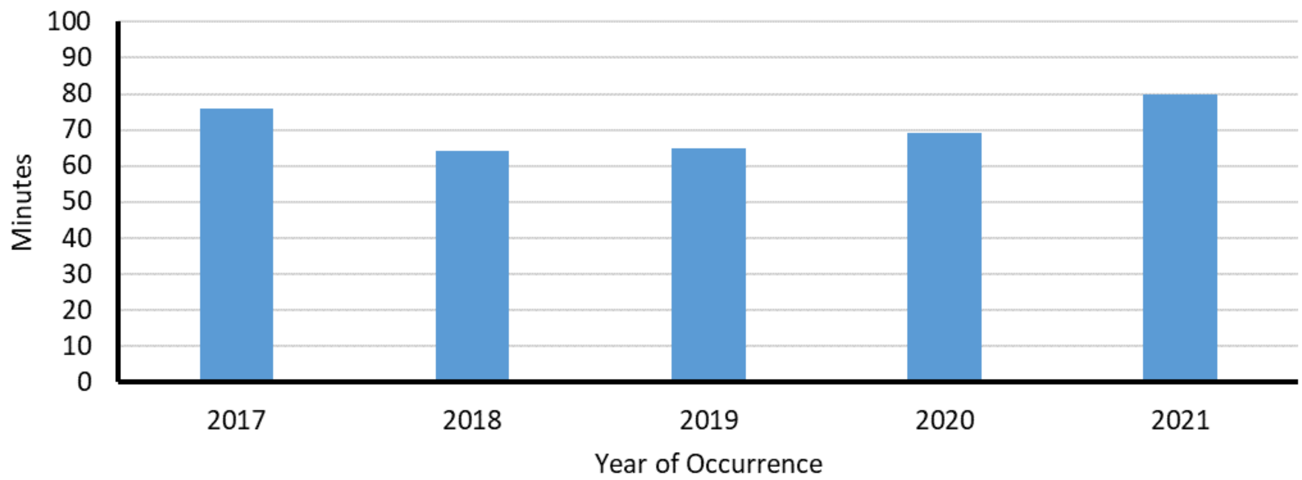


Figure 4.20: Average EMS Outage Time (2017–2021)

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**: Devices 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, or settings failure, etc.

Figure 4.21 shows that, over the evaluation period from 2017–2021, outages associated with software and communications challenges were the leading contributors to EMS outages.

A review of ERO EAP data shows that between 2017 and 2021, only 24 out of the 361 events, or 6.5%, that lasted over 30 minutes were related to external communication provider issues. At this time, external communication provider issues have not been a major issue related to EMS outages.

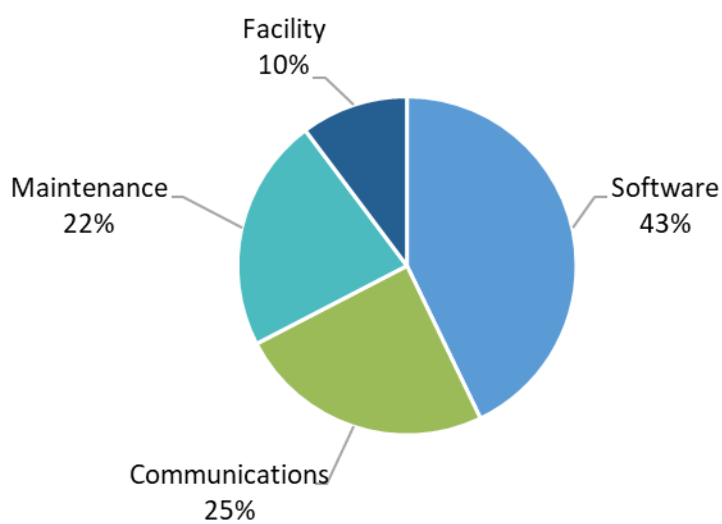


Figure 4.21: Contributors to Loss of EMS Functions (2017–2021)

Assessment

Software and communications failure are major contributors to the loss of EMS. The complete loss of monitoring or control capability has been the most prevalent event failure since 2020, but the loss of SE/RTCA is the most prevalent one over the evaluation period from 2017–2021. Both loss of SE/RTCA events and loss of ICCP events have been declining since 2018 due to the EOP-004-4 impact on partial loss of EMS functions reporting and the industry effort to enhance EMS reliability and resilience.

While failure of a decision-support tool has not directly led to the loss of generation, transmission lines, or customer load, EMS failures may hinder the decision-making capabilities of the system operators during normal operations or more importantly during a disturbance. The ERO has analyzed data and identified that short-term outages of tools and monitoring systems are not uncommon and that the industry is committed to reducing the frequency and duration of these types of events.

Increasing Complexity of Protection and Control Systems

Protection and Control Systems

As the system of interconnected power generation, transmission, and distribution assets has evolved, so too has the numbers and types of automated tools and systems that use digital information and microprocessor-driven devices to manage the electricity grid. This technologically diverse environment allows an operator to manage specified controls from virtually anywhere and at a cost far lower than what would have been possible otherwise. When designed and implemented properly, automated tools can enhance the reliable and secure use of new technologies and concepts that become available. On the other hand, maintaining, prudently replacing, and upgrading BPS control system assets can lead to protection and control system misoperations. Misoperations can initiate more frequent and/or more widespread outages. Resource mix changes that involve growth in inverter-based generation sources can also impact wide-area protection and increase the need to coordinate protection with the distribution system.

By evaluating the annual misoperation rates across North America and separately for each Regional Entity over the last five years and comparing the average of the first four years with the most recent year (see **Figure 4.22**), a statistically significant decreasing trend can be observed in the misoperation rates for RF and Texas-RE. No statistically significant trend is observed for MRO, SERC, WECC, or the overall MIDAS data reported to NERC.

A statistically significant increase in the misoperation rate for NPCC occurred in 2021. Looking at the components of the misoperation rate in **Table 4.4** indicates that this increase is driven primarily by a sharp decrease in the number of protection system operations and a slight increase in the count of misoperations. Historically, substantial changes in the misoperations rate have occurred when large changes in the protection system operations counts occur. The increase in the number of misoperations for NPCC was due to an increase in misoperations that occurred during non-fault conditions. This category of misoperation made up 65% of NPCC's misoperations reported in 2021, compared with 57% of NPCC's misoperations over the prior four years. This finding suggests that additional information is needed to further analyze the impact of misoperations.

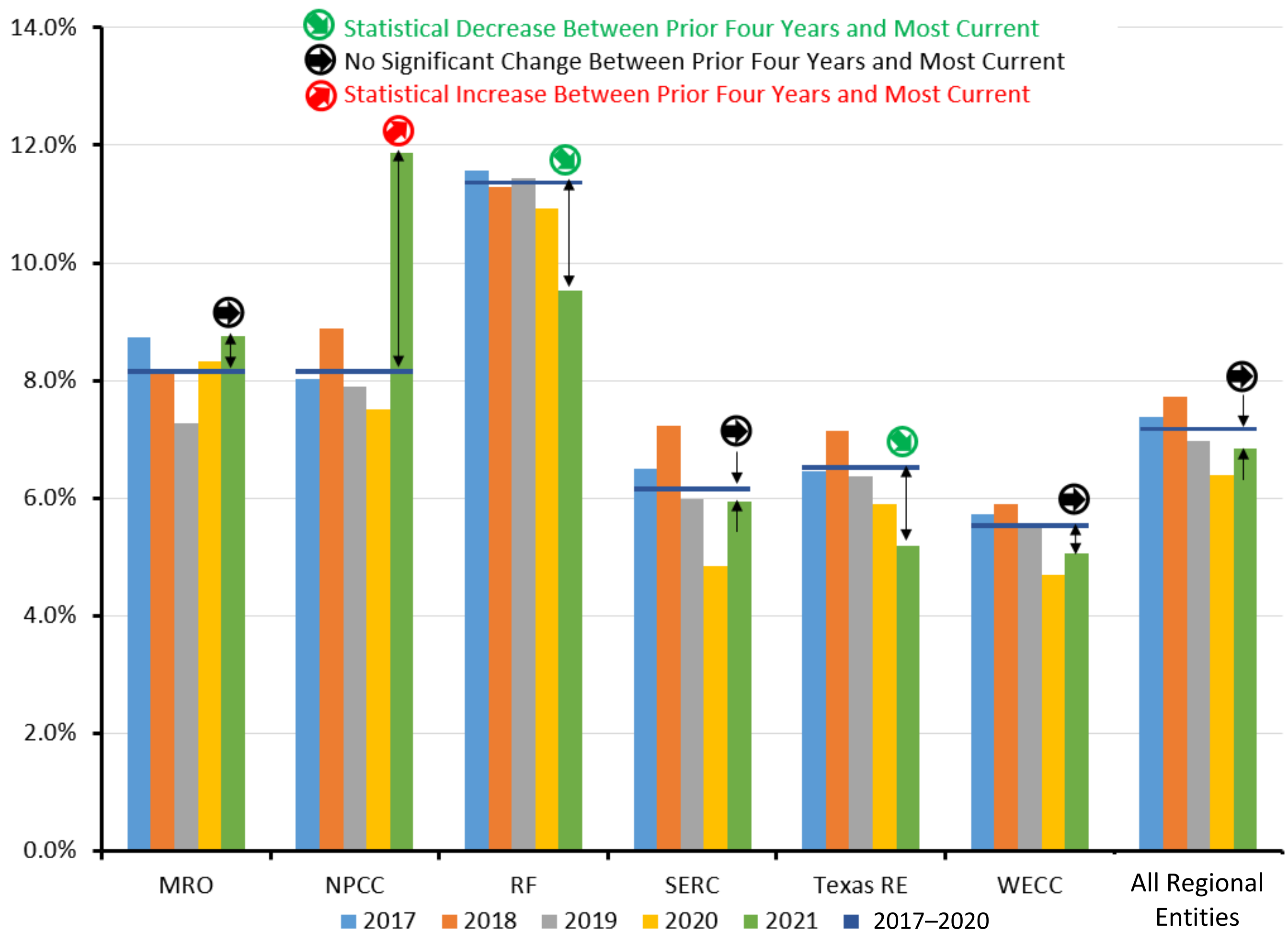


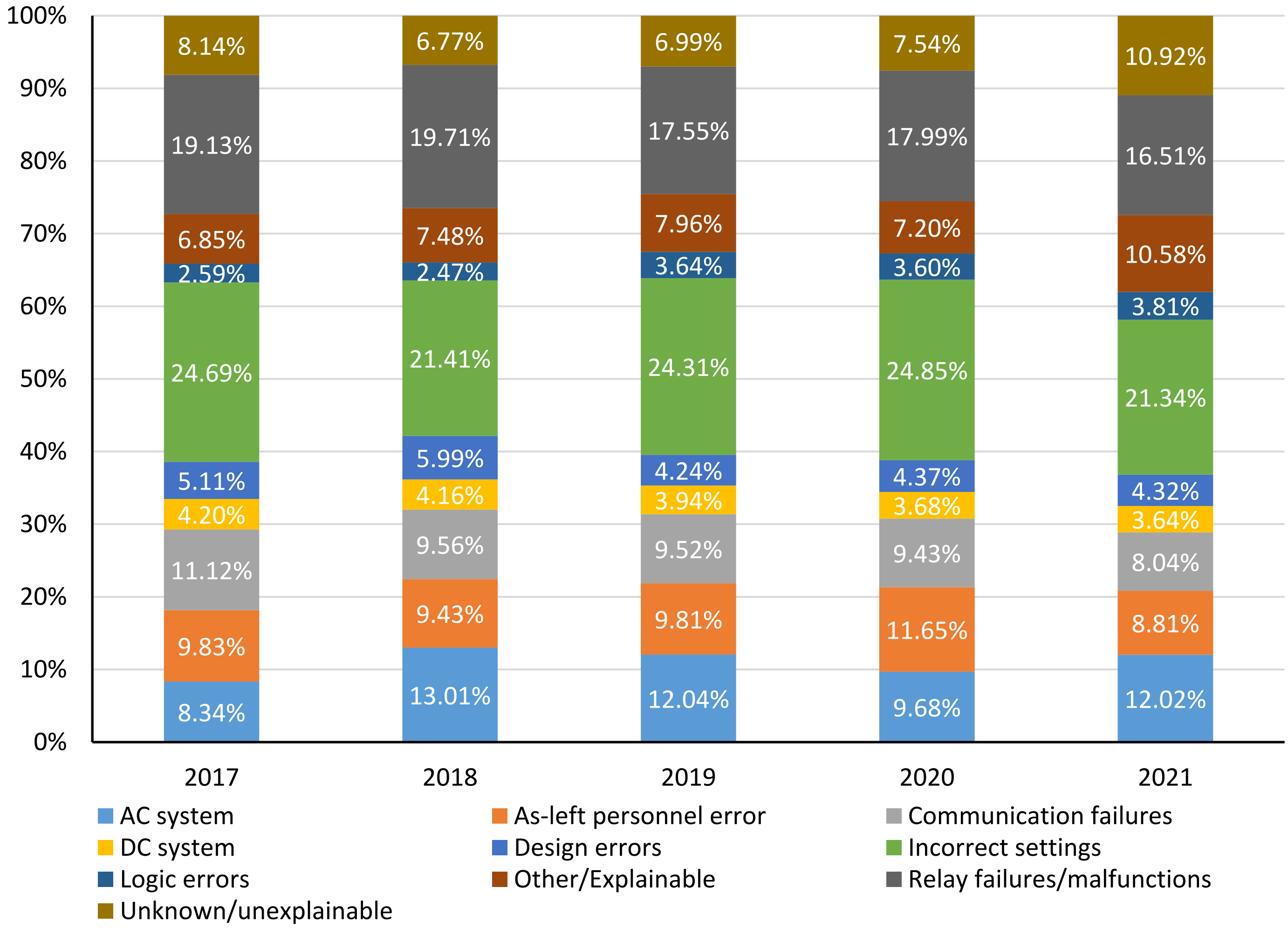
Figure 4.22: Changes and Trends in the Annual Misoperations Rate by Regional Entity

Table 4.4: Five-Year Protection System Operations and Misoperations Counts 2017 through 2021

Area	Protection System Operations					Misoperations				
	2017	2018	2019	2020	2021	2017	2018	2019	2020	2021
All Regional Entities	20,971	19,905	19,305	18,279	17,239	1,550	1,539	1,345	1,167	1,180
MRO	3,678	3,740	3,734	3,054	2,617	321	306	272	254	229
NPCC	2,031	2,117	1,661	1,760	1,365	163	188	131	132	162
RF	2,264	2,275	2,149	1,875	1,658	262	257	246	205	158
SERC	5,411	4,873	4,753	5,267	4,616	352	352	284	255	274
Texas RE	2,385	2,279	2,639	2,000	2,599	154	163	168	118	135
WECC	5,202	4,621	4,369	4,323	4,384	298	273	244	203	222

Leading Causes of Misoperations

The top causes of misoperations over the past five years have consistently been Incorrect Settings and Relay Failures/Malfunctions (see Figure 4.23), and the relative frequency of these two causes has been slowly decreasing. 2021 also saw the first increase in the number of misoperations coded as Unknown/Unexplainable in the past five years, up to 129 from 88 in 2020.



Year	2017	2018	2019	2020	2021
Misoperation Count	1,550	1,539	1,345	1,167	1,180

Figure 4.23: Misoperations by Cause Code (2017–2021)

Protection System Failures Leading to Transmission Outages

AC circuits and transformers both saw a slight increase in the number of outages per element in 2021, but neither was statistically significant (see **Figure 4.24**).

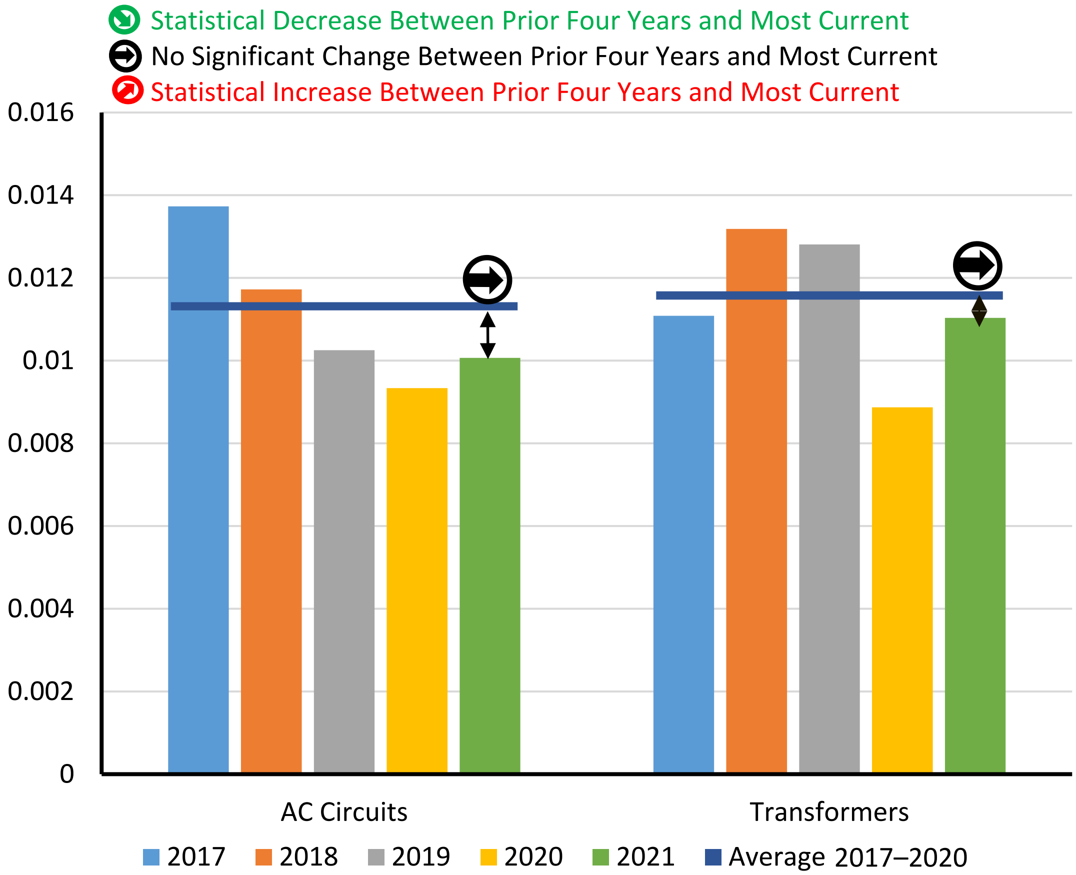


Figure 4.24: Failed Protection System Equipment

Event-Related Misoperations

An analysis of qualified events reported through the ERO EAP found that there were 75 transmission-related system disturbances in 2017. Of those 75 events, a total of 47 events (63%) had associated misoperations. Since 2017, the ERO and industry stakeholders have continued efforts to reduce protection system misoperations through initiatives that included formation and participation in various task forces, workshops, and conducting more granular root cause analysis. In 2021, there were 69 transmission-related qualified events. Of those 69 events, 31 events (45%) involved misoperations (see **Figure 4.25**). The efforts made by the ERO and industry have resulted in a declining trend in the number of events with misoperations over the last five years.

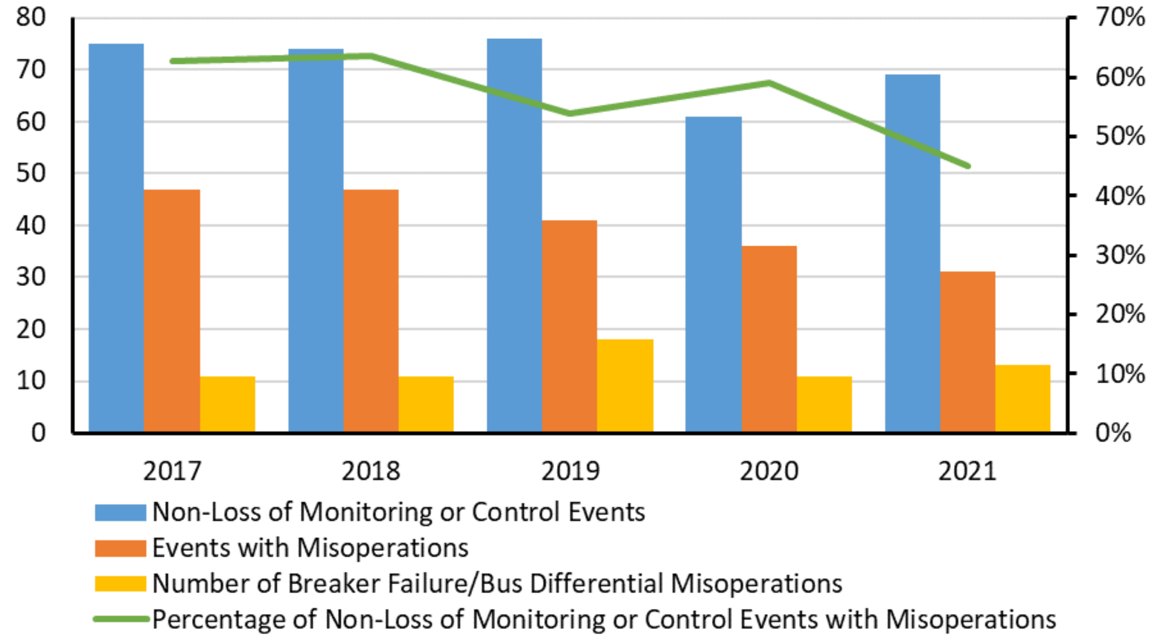


Figure 4.25: Events with Misoperations

Actions in Progress

- NERC, Regional Entities, and stakeholders continue to conduct industry webinars on protection systems and document success stories on how Generator Owners and Transmission Owners are achieving high levels of protection system performance.
- The Misoperation Information Data Analysis System (MIDAS) User Group (MIDASUG) continues to collect and analyze protection system misoperations data and information through MIDAS and provide training to ensure consistency of operations and misoperations reporting.

Human Performance

Transmission Outages Related to Human Performance

NERC TADS collects transmission outage data with a variety of causes that include Human Error. The definition of Human Error as a cause of transmission outage is defined in the *TADS Data Reporting Instructions*.[57] The effective use of human performance will help mitigate the active and latent errors that negatively affect reliability. Weaknesses in human performance hamper an organization's ability to identify and address precursor conditions that degrade effective mitigation and behavior management.

Statistical significance testing was done that compared 2021 to the average outage rate of the prior four years. For ac circuits, all forced outages caused by Human Error have seen a statistically significant decrease in frequency (see **Figure 4.26**). For transformers, operational outages caused by Human Error have seen a statistically significant decrease; however, automatic and all forced outages caused by Human Error have seen no statistically significant change in frequency (see **Figure 4.27**).

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

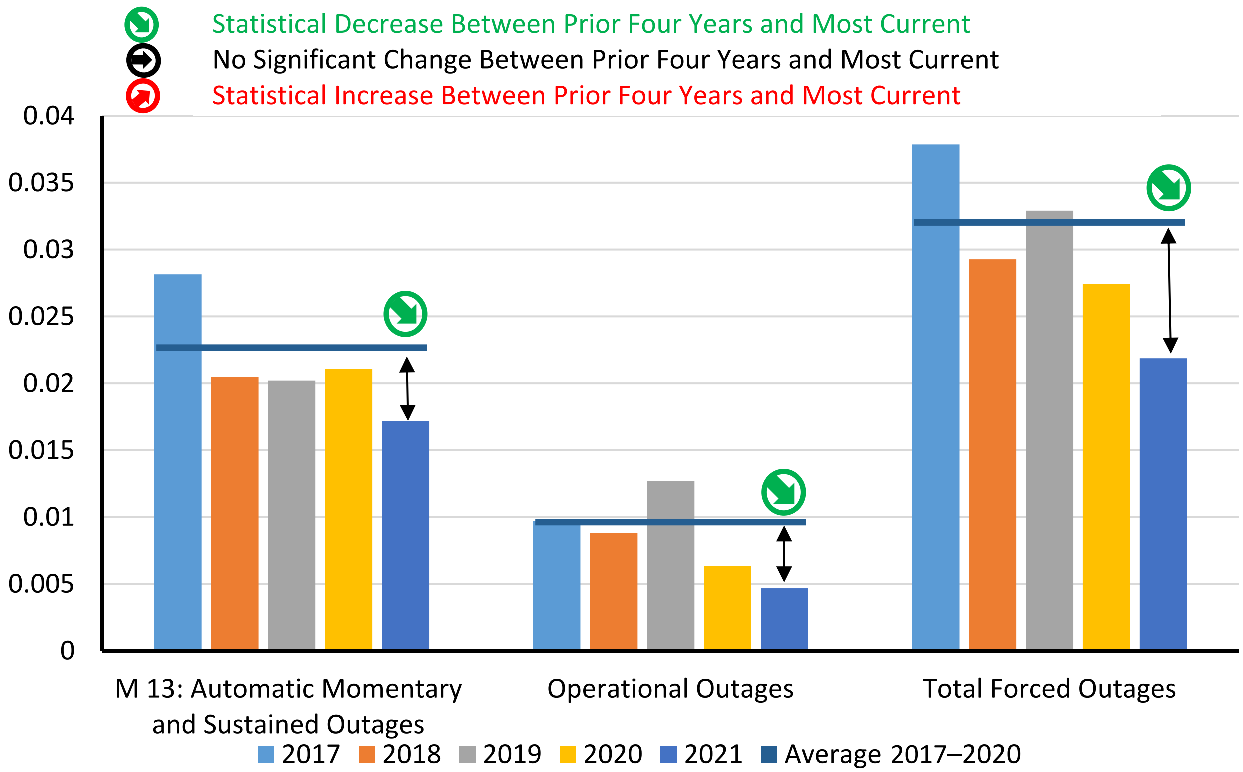


Figure 4.26: AC Circuit Outages Initiated by Human Error

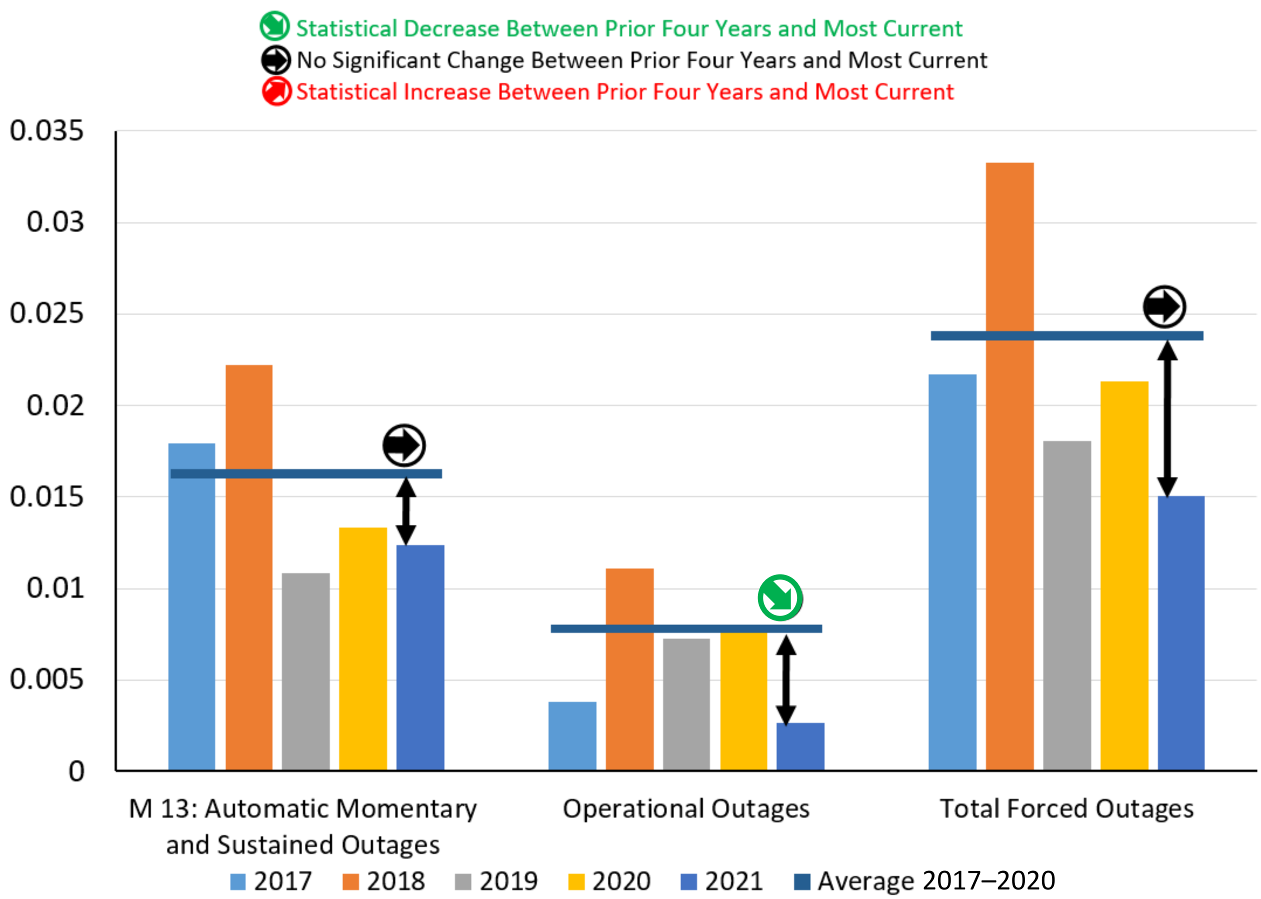


Figure 4.27: Transformer Outages Initiated by Human Error

Human Performance and Generation Outages

NERC GADS collects generation outage data associated with a variety of causes that include Human Error. Over the past five years, forced outages attributed to Human Error have averaged around 1% of all forced generator outage events, and no fuel type showed a notable increase in 2021.

Trends of Events Involving Human/Organization Performance as a Root Cause

In the ERO EAP, the cause sets of individual human performance and management/organization identify events or conditions that are directly traceable to individual or management actions or organization methods (or lack thereof) that caused or contributed to the reported event. In 2021, human/organization performance was identified as the root cause for 46% of processed events (see **Figure 4.28**). This is higher than for the previous years but may not fully project the final percentage as more than half of the 2021 events have not yet had a final root cause assigned to them. For the same period, the top five detailed root causes, listed in priority order, below are members of the management or organization performance categories:

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

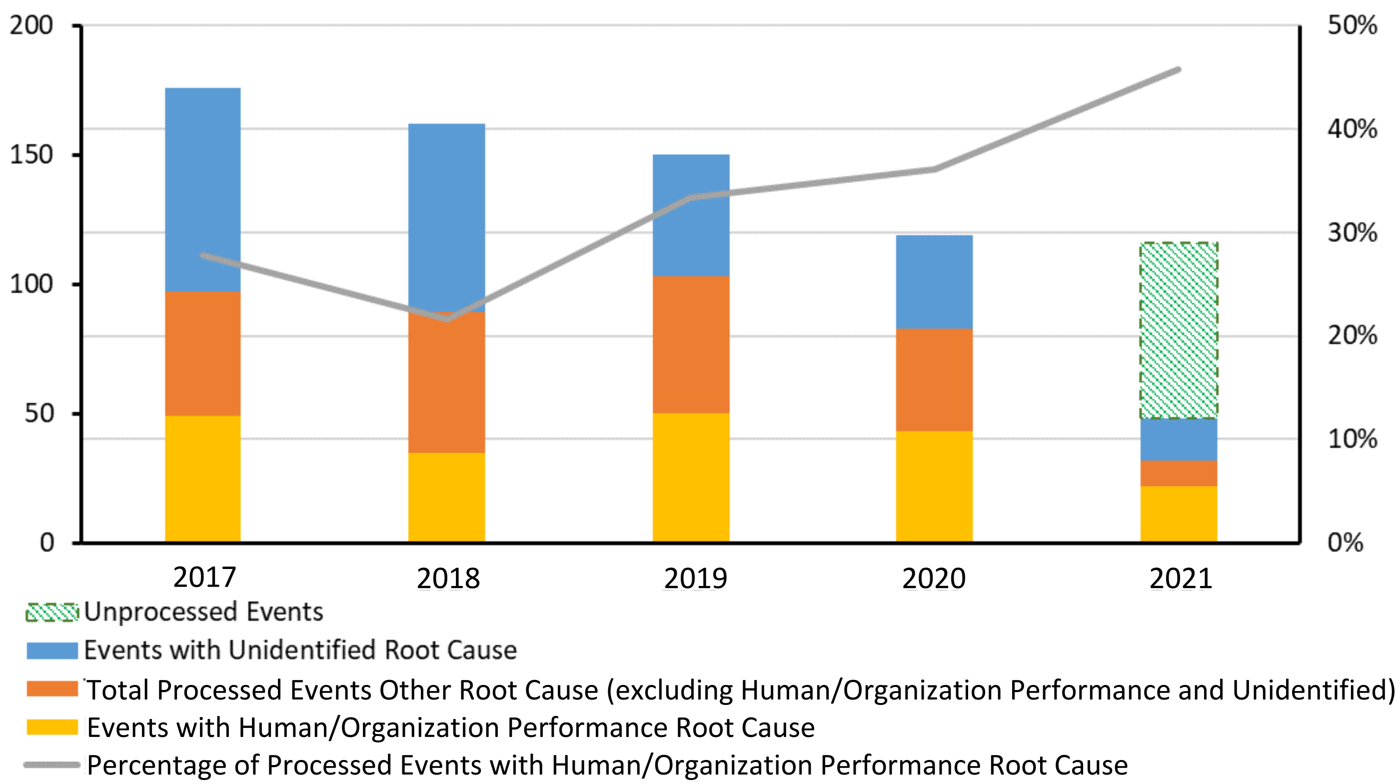


Figure 4.28: Human/Organization Performance Root Cause by Year

Events processed during 2021 saw three of the same top five root causes identified in 2020. Two causes—"Inadequate work package preparation" and "risks/consequences associated with change not adequately reviewed/assessed"—were replaced with "corrective action responses to a known or repetitive problem was untimely," and the "design output scope was less than adequate."

The top five detailed root causes coupled with the apparent underlying increase suggests that an opportunity exists for industry to improve BPS reliability through increased focus in the area of management and organization performance and engineering design. Possible contributing and root causes in the area of management and organization performance include subcategories where methods, actions, and/or practices are less than adequate, such as management methods, resource management, work organization and planning, supervisory methods, and change management. Possible contributing and root causes in the area of engineering and design include ensuring that the engineering group has a robust peer review process to identify procedural errors and all the considerations a design needs to be accountable to contain.

Human Error and Protection System Misoperations

Protection system misoperations remain an important indicator of the reliability of the BPS; Human Error is one of the potential causes for misoperations to occur. **Figure 4.29** shows the number of misoperations due to Human Error by Regional Entity for the past five years. There are two different causes of Human Error misoperations reported in MIDAS: As-left Personnel Errors and Incorrect Settings/Logic/Design Errors. Together, these account for roughly 40% of misoperations over the last five years, described in more detail as follows:

- **As-left Personnel Errors:** These misoperations are due to the as-left condition of the composite protection system following maintenance or construction procedures. These include test switches left open, wiring errors not associated with incorrect drawings, carrier grounds left in place, settings placed in the wrong relay, or settings left in the relay that do not match engineering intended and approved settings. This includes personnel activation of an incorrect settings group.
- **Incorrect Settings/Logic/Design Errors:** These are misoperations due to errors in the following:
  - **Incorrect Settings:** These are errors in issued settings associated with electromechanical or solid-state relays, the protection element settings in microprocessor-based relays, and setting errors caused by inaccurate modeling. It excludes logic errors discussed in the Logic Error cause code.
  - **Logic:** This includes errors in issued logic settings and errors associated with programming microprocessor relay inputs, outputs, custom user logic, or protection function mapping to communication or physical output points.
  - **Design:** This involves incorrect physical design. Examples include incorrect configuration on ac or dc schematics or wiring drawings or incorrectly applied protective equipment.

Figure 4.29 indicates the number of misoperations varying among Regional Entities. The five-year trends generally show a stable or downward trend in misoperations with causes attributed to Human Error.

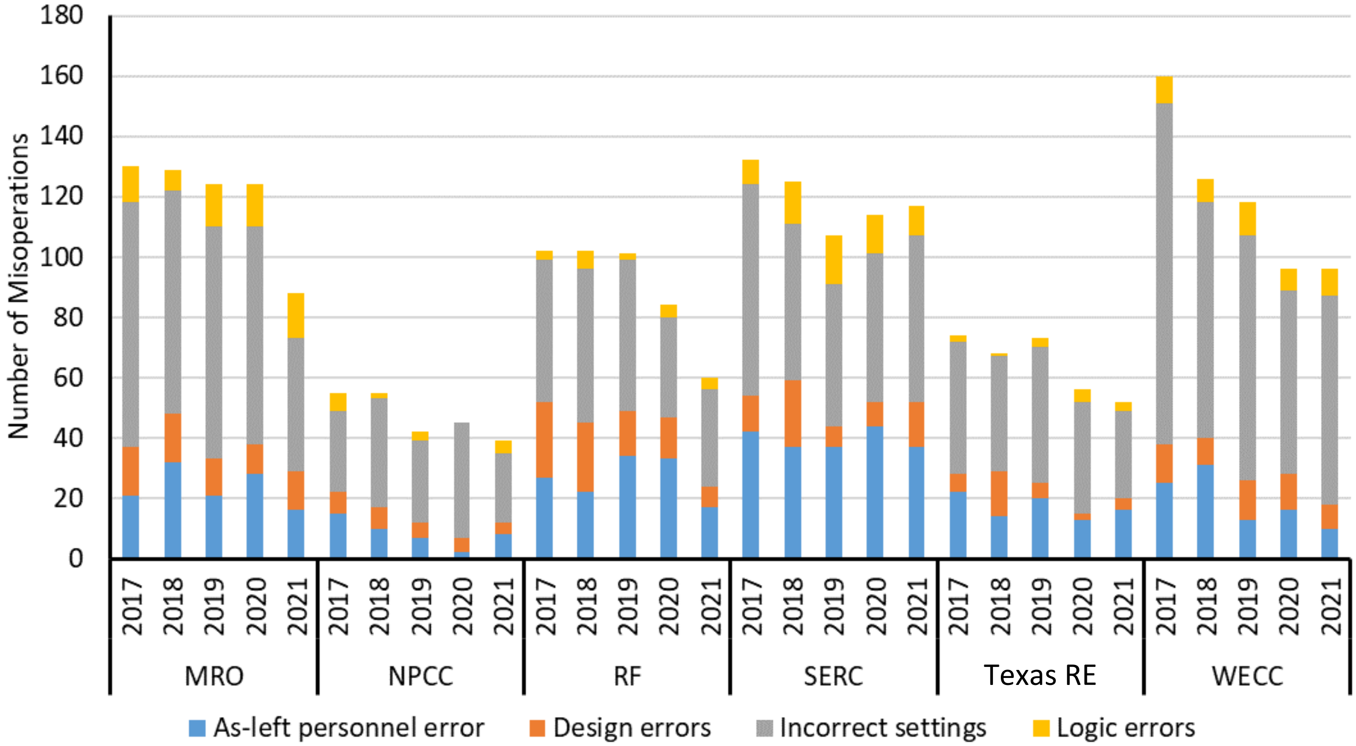


Figure 4.29: Protection System Misoperations Due to Human Error by Regional Entity[58]

Actions and Mitigations in Progress

- The ERO has identified work force capability and Human Error as possible threats to the reliability of the BPS. These broad topics are categorized for analysis by the ERO under management, organization, and individual contributions. The data suggests a need for focus on both individual actions and organizational processes/procedures pertaining to protective systems.
- The ERO Enterprise provides educational opportunities annually to help industry understand and focus on reducing Human Error through human performance concepts, methods, techniques, and procedures.
- The Regional Entities have been working with local industry working groups to review and aid in addressing reported misoperations and other human performance issues.
- The ERO Event Analysis Program continues.
- Regional-Entity-specific activities related to human performance continue to occur.

[58] Protection System Operation data collection for WECC began in Q2 2016.

Cyber and Physical Security

In 2021, NERC's E-ISAC and the electricity industry faced a security threat landscape (see below graphic) that was both unprecedented and relentless.

The above topics were but some of the substantial challenges that threatened the North American grid. The E-ISAC provided its members and partners with the resources, insights, and leadership to keep their cyber and physical infrastructure secure.

Cyber Security Threats

The cyber security threat landscape presented serious challenges to the electricity industry in 2021: geopolitical events, new vulnerabilities, changes in technologies, and increasingly bold cyber criminals and hacktivists. The E-ISAC countered these threats with a two-pronged approach: active response to specific events and specialized trend analysis to suit the operational and information technology environments of member and partner organizations.

Throughout 2021, the North American electricity industry weathered a series of attacks on the digital supply chain that involved now familiar names: SolarWinds, Microsoft Exchange, Pulse Secure, and Kaseya. While the reliability of the BPS remained intact, the sophistication and boldness of these attacks demonstrate that nation-state adversaries and organized cyber criminals with demonstrated capability have the ability and increasing willingness to disrupt critical infrastructure.

The E-ISAC took an industry-leading role in the response to the SolarWinds supply chain compromise that carried over from 2020 into 2021 and kept members and partners informed of the evolving situation. E-ISAC analysts posted SolarWinds-related bulletins in January and February. The E-ISAC created a dedicated page on its secure Portal, the organization's secure online information hub, for members and partners to easily access updates in a "one-stop shop." The E-ISAC took advantage of its website[59] to share industry resources for the general public. The E-ISAC also co-led the Electricity Subsector Coordinating Council's Tiger Team made up of government and industry partners that coordinated a united response to the crisis.

In addition to the attacks on the supply chain, reports of suspicious cyber incidents (including vulnerabilities), phishing, malware, denial of service, and other cyber-related reports increased significantly.

Recognizing that proactive trend analysis and early warnings are essential to collective defense, the E-ISAC also developed resources throughout the year to help members and partners identify cyber trends and threats and began conducting threat hunts through available data sets, including the Cybersecurity Risk Information Sharing Program.

[59] eisac.com

The E-ISAC again demonstrated its capabilities in December 2021 during the emergence of the Log4j Java remote code execution vulnerability, also known as “Log4Shell.” The E-ISAC highlighted the criticality of this vulnerability found in billions of devices by rolling out an all-points bulletin with mitigation information followed by regular updates.

Throughout 2021, the E-ISAC observed potential threats to critical infrastructure across North America from sophisticated adversaries, such as China, Iran, North Korea, and Russia.

In 2021, the Biden administration launched a 100-day plan to safeguard U.S. critical infrastructure and improve visibility of persistent and strategic threats to operational technology environments. In recognition of the importance of this effort, the E-ISAC leveraged its advanced analytical tools—including the Cybersecurity Risk Information Sharing Program and its access to Neighborhood Keeper—to support the 100-day plan by increasing the visibility on critical industrial control systems in the electricity industry. The E-ISAC also communicated the necessity of securing these systems to its members and partners, encouraging them to share what they detected on their own networks.

The E-ISAC Portal served as a vital hub to keep members and partners current on geopolitical events. This was illustrated during the period of growing tension between Russia and NATO over threats to Ukraine in the latter part of the year. Among the chief concerns for the electricity industry was the potential for escalatory cyber attacks on North American critical infrastructure by Russia-linked adversaries in the event of a conflict. Throughout December, E-ISAC analysts actively shared on its Portal the possible implications of a conflict as well as tradecraft and mitigations for previous Russia-linked activity. A webinar with DOE and the downstream natural gas and oil and natural gas ISACs was also conducted in mid-December to raise vigilance and further increase industry preparedness.

The E-ISAC also created a new information page on its Portal that features a compendium of E-ISAC analysis, news, and other information on threats from nation-state adversaries.

The escalation of cyber attacks perpetrated by ransomware-as-a-service gangs represented a significant threat to critical infrastructure in 2021. Electricity utilities saw an increase of ransomware attacks on utility corporate systems. However, this did not lead to power outages even as the attacks grew in sophistication and boldness throughout the year.

The high-profile ransomware attack on the Colonial Pipeline in May 2021 brought national attention to the potential for cyber attacks on critical infrastructure to disrupt daily life as it forced the six-day closure of a major 5,500-mile East Coast gasoline pipeline. Although this incident did not impact the electricity industry directly, the E-ISAC provided additional information and context by highlighting adversary tradecraft in a special report to members and partners.

The E-ISAC leveraged its cyber tools and partnerships to monitor ransomware attacks and to inform members and partners of specific threats to utilities. For instance, the E-ISAC released an all-points bulletin in December that offered an overview of utilities affected by Conti ransomware activity. Working with the impacted utilities, the E-ISAC developed valuable data on the characteristics of ransomware attacks, such as the fact that attacks largely occur on Friday evening or Saturday morning.

Automated tools and systems that use digital information and microprocessor-driven devices to manage the electricity grid are proliferating, and it is essential that new technology is implemented in a manner that is reliable, timely, and secure. NERC’s BPS Security and Grid Transformation department has actively engaged partners from industry to address the implementation of new technologies and practices that leverage tools, such as cloud technology, DERs, DER Aggregators, zero-trust network architectures, etc.

Physical Security Threats

While the electricity industry experienced a moderate increase in the overall number of physical security incidents in 2021, the most serious types of incidents declined overall. However, the ongoing threat of domestic extremist groups to the electricity industry persisted as did the use of unauthorized aircraft, or drones.

Domestic Extremists

The E-ISAC kept a close watch on the various activities of domestic extremist groups throughout 2021 and added to the knowledge base for members and partners to help them protect their infrastructure from damage. The E-ISAC's physical security analysts compiled and shared information on threats against the grid. Member and partner organizations also contributed to overall awareness with timely posts on the E-ISAC Portal. This reinforced the value of bidirectional information sharing for both the E-ISAC and industry.

Drones

The use of unauthorized and unmanned aircraft, or drones, provided another potential security concern for critical infrastructure, such as power lines and power generation facilities. The E-ISAC kept members and partners apprised of unauthorized drone activity around critical infrastructure and offered guidance for mitigation.

COVID-19

Finally, the COVID-19 pandemic continued through 2021 as the extended remote operating environment presented an extra layer of cyber security concerns. The E-ISAC innovated along with the rest of industry to what has become a "new normal" operating environment with additional virtual product offerings and flexibility in the remote work environment.

Chapter 5: Adequate Level of Reliability Performance Objectives

An ALR is that state of BES reliability that the design, planning, and operation of the BES attains when the reliability performance objectives (RPO) set forth in the ALR definition are met.[60] The ALR's RPOs articulate what system planners and operators are expected to do on a day-to-day basis to ensure that the BES is reliable. These represent the bottom-line performance objectives that the NERC Performance Analysis Subcommittee and NERC reliability assessment staff have sought to report on throughout this *State of Reliability* report.

This chapter reorganizes the individual findings presented in the preceding chapters to provide a final integrated summary of BES reliability that is directly aligned with each of the five ALR RPO (see **Table 5.1**) so that they can be tracked consistently over time. Reliability metrics M4, 6, 8, 9, 11-15 and M-17 are calculated annually and employed in **Table 5.1** for this purpose. Where appropriate, the year-over-year and rolling five-year trend for each metric is color coded for each of the Eastern, Québec, Texas, and Western Interconnections (EI, QI, TI, and WI) as well as the relevant transmission element (ac circuits and transformers). Except to identify gaps in data that must be addressed in future SORs, this chapter does not seek to add to the narratives presented earlier but instead simply summarizes overall findings with respect to the ALR RPOs.

In reviewing **Table 5.1**, it is important to bear in mind that RPO 1–3 are defined with respect to more probable predefined disturbances, which are the ones the BES is planned, designed, and operated to withstand. In contrast, RPO 4 and 5 cannot be defined with respect to more probable disturbances.

For these less probable, yet routinely extremely severe events, BES owners and operators may not be able to apply any economically justifiable or practical measures to prevent or mitigate their adverse reliability impacts (ARI)[61] on the BES despite the fact that these events can result in cascading, uncontrolled separation, or voltage collapse. For this reason, these events generally fall outside of the design and operating criteria for BES owners and operators. Less probable severe events would include, for example, losing an entire right of way due to a tornado or simultaneous or near simultaneous multiple transmission facility outages due to a hurricane or other severe natural phenomena.

[60] Informational Filing on Definition of "Adequate Level of Reliability," May 10, 2013.

[61] The impact of an event that results in frequency-related instability, unplanned tripping of load or generation, or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection: https://www.nerc.com/files/glossary_of_terms.pdf

Table 5.1: Adequate Level of Reliability Performance Objectives				
Normal operations and predefined disturbances (i.e., more probable disturbances to which the power system is planned, designed, and operated)			Less probable severe events that generally fall outside of BES owner and operator design and operating criteria	
1. The BES does not experience instability, uncontrolled separation, cascading, or voltage collapse.	**2. BES frequency is maintained within defined parameters.**	**3. BES voltage is maintained within defined parameters.**	**4. Adverse Reliability Impacts on the BES following low probability disturbances are managed.**	**5. Restoration of the BES after major system disturbances is performed in a coordinated and controlled manner.**
Disturbance control standard (M-6)	Interconnection frequency response A to B (M-4) EI QI TI WI		Disturbance control standard (M-6)	BES restoration analysis
IROL exceedances (M-8) EI QI TI WI	Interconnection frequency response A to C (M-4.1) EI QI TI WI		IROL exceedances (M-8) EI QI TI WI	
Automatic ac outages initiated by Failed ac Substation Equipment (M-14) ac circuits, Transformers			Protection system misoperations (M-9)	
Automatic ac transmission outages initiated by Failed ac Circuit Equipment (M-15)			Energy emergency alerts (M-11) EI QI TI WI	
Transmission outage severity (M-17)			Automatic ac outages initiated by Failed Protection System Equipment (M-12) ac circuits, Transformer	
			Automatic ac outages initiated by Human Error (M-13) ac circuits, Transformer	

IMPROVING	STABLE	MONITOR	ACTIONABLE

Under normal operating conditions and during the occurrence of predefined disturbances (i.e., more probable disturbances to which the power system is planned, designed, and operated), the BES in 2021 experienced no instability, uncontrolled separation, cascading, or voltage collapse. Moreover, BES frequency and voltage were maintained within defined parameters during these operating states in 2021. Frequency response analysis in both the arresting period and stabilizing period indicates Stable or Improving performance for all of the Interconnections as metrics M-4, Interconnection frequency response A to B, and M-4.1, Interconnection frequency response A to C, in **Table 5.1** attest. Specific metrics to assess BES voltage performance have not yet been developed; however, a review of the ERO Events Analysis data revealed no under or overvoltage qualified events in 2021.

In last year's *State of Reliability* report, NERC introduced a new analysis of the prior year's large transmission events caused by extreme weather that quantifies some aspects of restoration and recovery activities but not restoration of customer load. This new analysis provides critical insights into the efficiency with which the BES is restored to a stable interconnected state after the BES experiences extreme weather events. However, quantifying the efficiency with which resources and load are restored during these events requires additional new analyses and measures.

In 2021, the BES was subjected to a number of less probable and severe events as evidenced by the extreme day SRI discussed in **Chapter 2** and further expanded upon in **Appendix A**. In every instance, ARI[62] were avoided and ALR maintained through operator actions as documented through actions taken pursuant to EEA Level 3. Furthermore, restoration of the BES was conducted in a controlled and coordinated manner as seen, for example, in the **Chapter 2** BES element restoration curves developed for Hurricane Ida. While ALR was maintained in 2021, the reliability indicators shown in **Table 5.1** that fall within the Monitor category highlight areas of continuing concern that underlie many of the recommendations provided in this report. Improvement in these metrics and measures would likely reflect a decreased severity of low probability disturbances as well as enhanced BES resiliency during and accelerated BES restoration after major system disturbances.

In addition to refining and developing restoration and resiliency metrics to include load restoration, annual evaluation of the past year's BES performance in providing an ALR would be significantly enhanced with the addition of energy resource adequacy and voltage metrics. Filling in the current gaps in **Table 5.1** will require NERC's Performance Analysis Subcommittee, ERO Enterprise reliability assessment staff, and industry to undertake development of load restoration definition and analysis as well as energy resource adequacy and voltage metrics.

[62] The impact of an event that results in frequency-related instability, unplanned tripping of load or generation, or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection: https://www.nerc.com/files/glossary_of_terms.pdf

Appendix A: Supplemental Analysis at Interconnection Level

Severity Risk Index by Interconnection

While the averages of daily SRIs for the entirety of North America, EI–QI, and the WI are somewhat similar (with the average 2017–2021 daily SRI of 1.43, 1.31, and 1.63, respectively), the variability of daily SRI differs considerably between North America and each of the two Interconnections.[63] The standard deviation of the North America SRI is statistically significantly lower compared to the EI–QI and the WI for the years 2017–2020 and statistically significantly higher for 2021. The NERC standard deviation in 2021 increased six times compared with the average four-day 2017–2020 daily SRI due to February 2021 cold weather impact to the load loss component of the SRI calculated with imputed data for the TI.

The following section presents a review of trends over the past five years, the top 10 days for the current year, and the top 10 days for the prior five years for the EI–QI and WI.

Eastern–Québec Interconnection

The cumulative SRI for the EI–QI in **Table A.1** shows a 3% decrease compared to the average of the four-year period of 2017–2020. In the EI–QI, the 2021 cumulative SRI is the median among the five years (2017–2021); it is statistically significantly lower than 2018 but not statistically lower or higher than other years.

Table A.1: Annual Cumulative SRI EI–QI

Year	Cumulative Weighted Generation	Cumulative Weighted Transmission	Cumulative Weighted Load Loss	Annual Cumulative SRI	Average Daily SRI
2017	350.7	68.3	68.8	487.8	1.34
2018	383.4	65.7	96.4	545.5	1.49
2019	345.8	62.4	51.3	459.5	1.26
2020	314.2	53.8	67.4	435.4	1.19
2021	**347.8**	**55.7**	**64.1**	**467.7**	**1.28**

The top 10 SRI days of the EI–QI were distributed throughout the year as shown in **Figure A.1** (numbered circles)**.** A total of 6 of the top 10 days that occurred in the EI–QI contributed to the top 10 SRI days reported for North America. The February cold weather event was the biggest single factor in the EI-QI, causing 3 of the top 10 days, followed by **Hurricane Ida** and **Thunderstorms and Tornadoes**.

[63] As noted in **Chapter 2**, sufficient load loss data were not available to calculate the SRI analysis for the Texas interconnection.

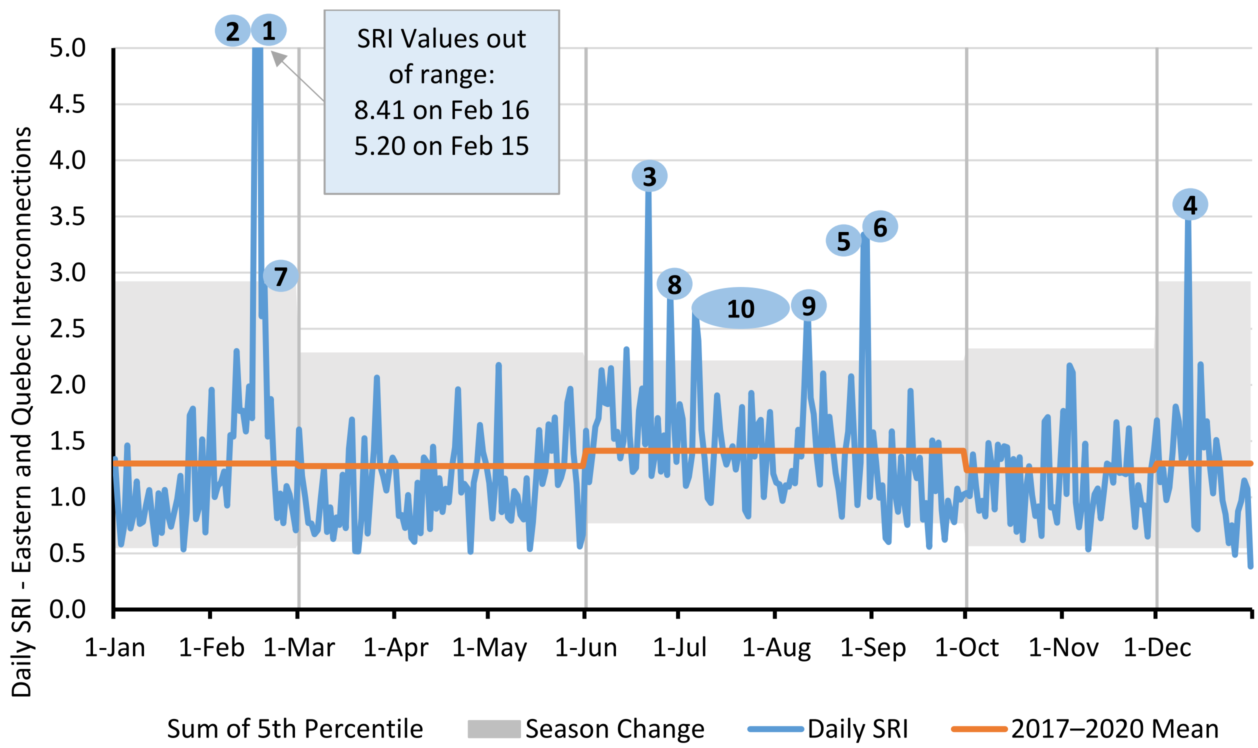


Figure A.1: 2021 EI–QI Daily SRI with Top 10 Days Labeled, 90% Confidence Interval

When comparing the top 10 days in 2021 to each of the previous four years shown in **Figure A.2**, 2021 had the highest daily SRI values for the worst day and was slightly better than average for the remaining 8.

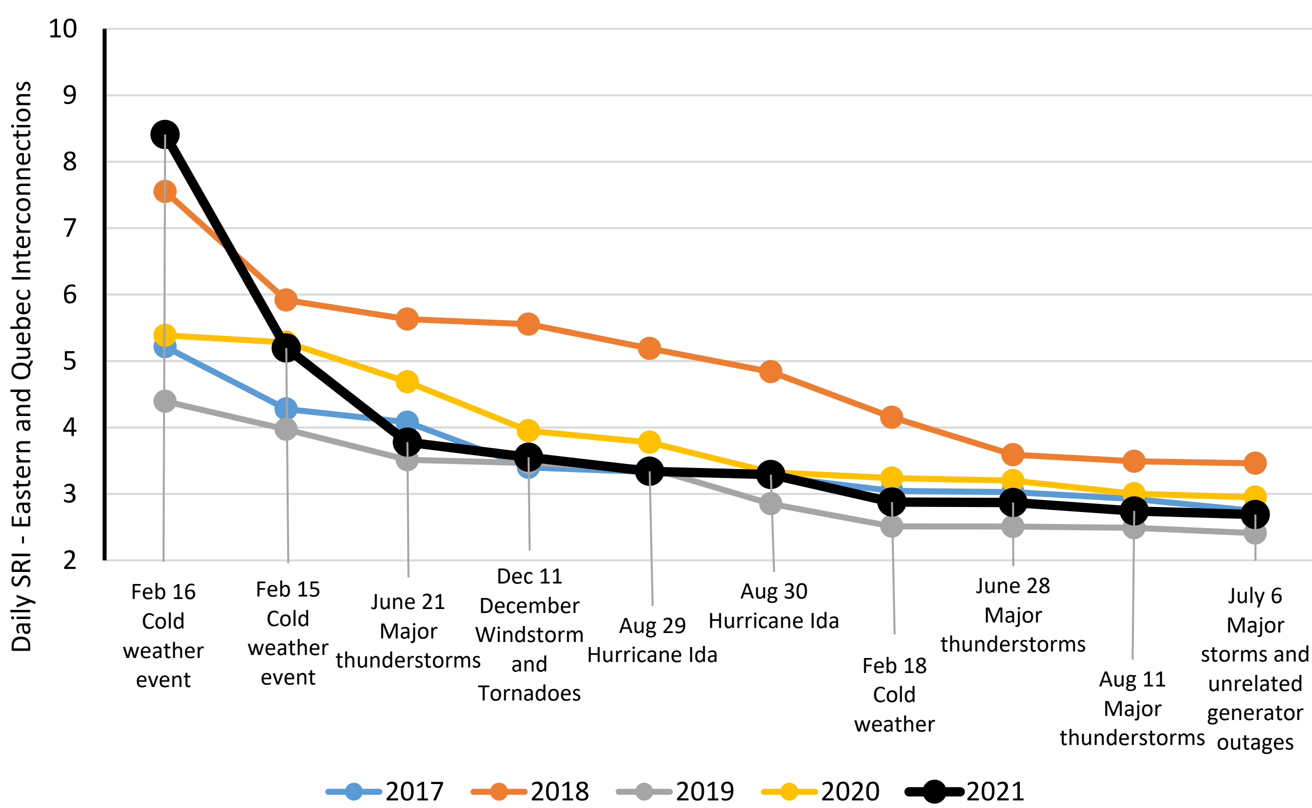


Figure A.2: EI–QI Top Annual Daily SRI Days, Sorted Descending

Table A.2 provides details on each component's contribution to the top 10 SRI days for the EI–QI. Generation loss was the primary contributor to 8 of the top 10 days.

Table A.2: 2021 Top 10 SRI Days EI–QI

Rank	Date	SRI and Weighted Components 2021				Event Type	Regional Entities within the Interconnection
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss		
1	February 16	8.41	4.11	0.60	3.70	Cold weather event	MRO, RF, SERC
2	February 15	5.20	3.63	0.56	1.01	Cold weather event	MRO, RF, SERC
3	June 21	3.78	1.64	0.43	1.71	Major thunderstorms	SERC
4	December 11	3.55	0.94	0.96	1.65	Windstorm and tornadoes	SERC
5	August 29	3.34	2.03	1.03	0.28	Hurricane Ida	SERC
6	August 30	3.29	1.08	1.98	0.23	Hurricane Ida	SERC
7	February 18	2.88	2.22	0.39	0.27	Cold weather event	MRO, RF, SERC
8	June 28	2.87	1.97	0.26	0.64	Major thunderstorms	NPCC, RF
9	August 11	2.74	1.13	0.12	1.49	Major thunderstorms	RF
10	July 6	2.69	1.67	0.19	0.83	Major storms and coincidental generator outages	RF

Two of the top 10 SRI days in 2021, shown in red in **Table A.3,** are both related to the cold weather event and are included as historically high SRI days for the EI–QI.

Table A.3: 2017–2021 Top 10 SRI Days EI–QI

Rank	Date	SRI and Weighted Components				Event Type	Regional Entities within the Interconnection
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss		
1	February 16, 2021	8.41	4.11	0.60	3.70	Cold weather event	MRO, RF, SERC
2	September 14, 2018	7.56	1.62	0.58	5.37	Hurricane Florence	SERC
3	October 11, 2018	6.06	0.76	0.73	4.56	Hurricane Michael	SERC
4	April 15, 2018	5.64	0.93	0.52	4.19	Thunderstorms and winter storms	NPCC, SERC
5	November 15, 2018	5.56	1.82	0.22	3.52	Winter Storm Avery	RF, NPCC
6	August 4, 2020	5.40	1.37	1.09	2.93	Hurricane Isaias	SERC, RF, NPCC

Table A.3: 2017–2021 Top 10 SRI Days EI–QI							
Rank	Date	SRI and Weighted Components				Event Type	Regional Entities within the Interconnection
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss		
7	March 8, 2017	5.23	0.88	0.51	3.83	Winter storm	MRO
9	February 15, 2021	5.20	3.63	0.56	1.01	Cold weather event	MRO, RF, SERC
8	January 2, 2018	5.19	4.80	0.23	0.16	Winter Storm Grayson	SERC, RF, MRO, NPCC
10	March 2, 2018	4.85	0.92	0.49	3.45	Winter Storm Riley	NPCC

Western Interconnection

The 2021 cumulative SRI for the WI (see **Table A.4**) shows a 9% increase over the prior four-year period of 2017–2020. The 2020 cumulative SRI was the highest among the five years analyzed and statistically significantly higher than 2018 and 2020. All three SRI cumulative components (**Table A.4**) saw increases when compared to prior years except for generation and transmission in 2017.

Table A.4: Annual Cumulative SRI WI					
Year	Cumulative Weighted Generation	Cumulative Weighted Transmission	Cumulative Weighted Load Loss	Annual Cumulative SRI	Average Daily SRI
2017	433.8	123.1	75.2	632.2	1.73
2018	395.9	105.7	41.0	542.5	1.49
2019	421.0	105.4	74.9	601.3	1.65
2020	385.2	103.3	72.1	560.6	1.53
2021	**430.1**	**106.8**	**100.2**	**637.1**	**1.75**

The top 10 SRI days of the WI for 2021 were primarily clustered in the winter months, with a number of days outside of the control limits occurring throughout the summer, as shown in **Figure A.3**. The three top SRI days (numbered circles) are related to winter weather and three partially related to high wind conditions. Higher values for all three SRI components contributed to the top 10 days for 2021.

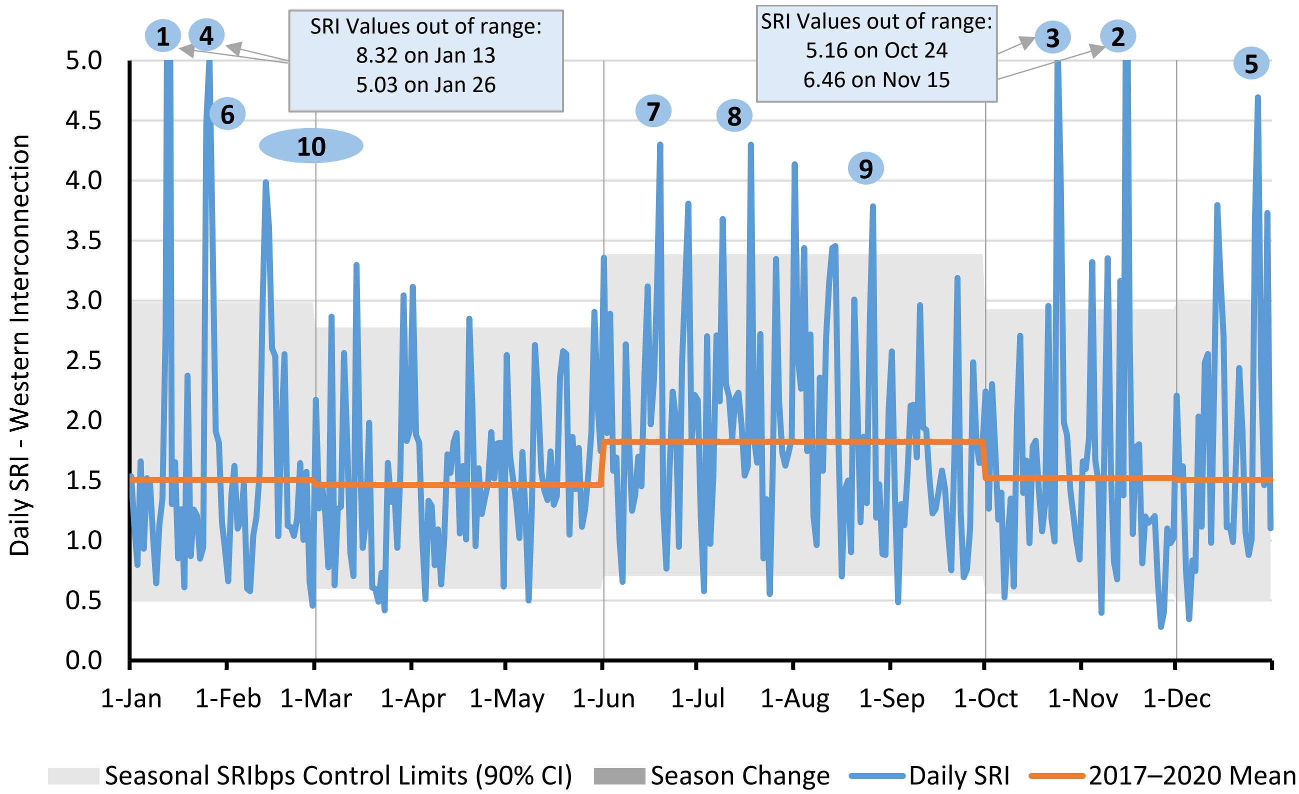


Figure A.3: 2021 WI Daily SRI with Top 10 Days Labeled, 90% Confidence Interval

When comparing the top 10 days in 2021 to each of the previous four years as shown in **Figure A.4**, 2021 had the most severe days were about average, however, the less severe days we above historical years.

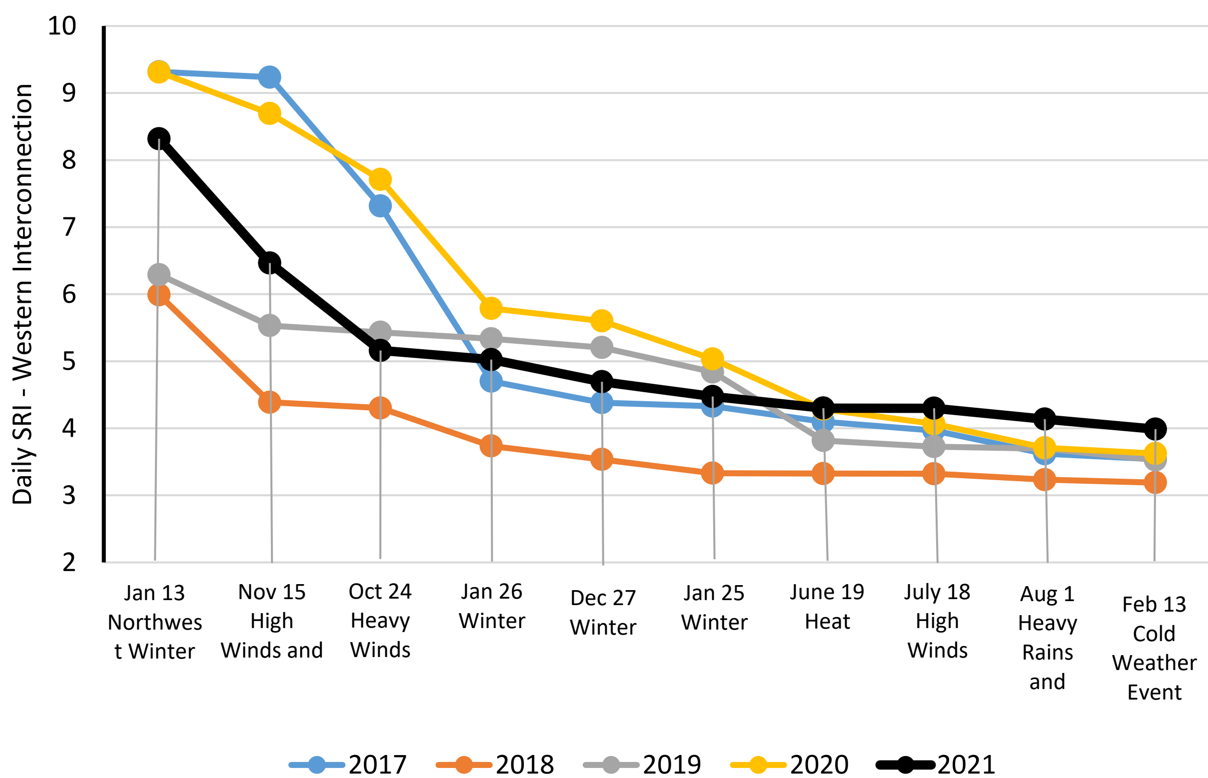


Figure A.4: WI Top Annual Daily SRI Days Sorted Descending

Table A.5 provides details on each component's contribution to the top 10 SRI days for the WI; WECC is the only Regional Entity in the WI.

Table A.5: 2021 Top 10 SRI Days WI						
Rank	Date	SRI and Weighted Components 2020				Event Type
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss	
1	January 13	8.32	1.86	4.22	2.24	Northwest winter weather
2	November 15	6.46	1.47	0.44	4.56	High winds and special protection system misoperation
3	October 24	5.16	1.52	1.03	2.61	Heavy winds and rain
4	January 26	5.03	1.71	0.26	3.06	Winter storm
5	December 27	4.69	2.32	0.94	1.44	Winter storm
6	January 25	4.47	2.19	0.76	1.52	Winter storm
7	June 19	4.30	1.74	0.54	2.02	Heat Dome
8	July 18	4.30	1.17	1.31	1.81	High winds and fires
9	August 1	4.14	1.35	0.31	2.47	Heavy rains and flooding
10	February 13	3.99	1.14	1.39	1.46	Cold weather event

Two of the top 10 SRI days in 2021, shown in red in Table A.6, are included as historically high SRI days for the WI.

Table A.6: 2016–2020 Top 10 SRI Days WI						
Rank	Date	SRI and Weighted Components				Event Type
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss	
1	April 7, 2017	9.32	3.16	1.86	4.29	Wind storm
2	September 8, 2020	9.31	3.38	3.21	2.73	Wild fires
3	December 4, 2017	9.24	1.05	0.07	8.12	Thomas fire
4	September 7, 2020	8.69	2.51	2.41	3.78	Wild fires
5	January 13, 2021	8.32	1.86	4.22	2.24	Northwest winter weather
6	August 14, 2020	7.71	1.29	0.00	6.43	Extreme heat and demand with load shed-California
7	December 10, 2017	7.32	0.99	2.16	4.16	Thomas fire
8	November 15, 2021	6.46	1.47	0.44	4.56	High winds* and special protection system misoperation
9	October 11, 2019	6.29	0.75	5.51	0.02	Saddle Ridge fire
10	August 11, 2018	5.99	1.63	2.42	1.93	Natchez fire

Extreme Day Analysis by Interconnection

The extreme day analysis for transmission and generation for 2021 are presented by Interconnection. The maximum TADS reported MVA or GADS reported net maximum capacity for 2021 is shown in the upper right corner of Figure A.5–Figure A.10. Lower-impact transmission days without a distinctly listed cause have been investigated and were either due to coincidental outages or smaller unnamed weather events. Lower-impacting generation days without a distinctly listed cause have been investigated and were elevated above the threshold to coincidental outages on large units.

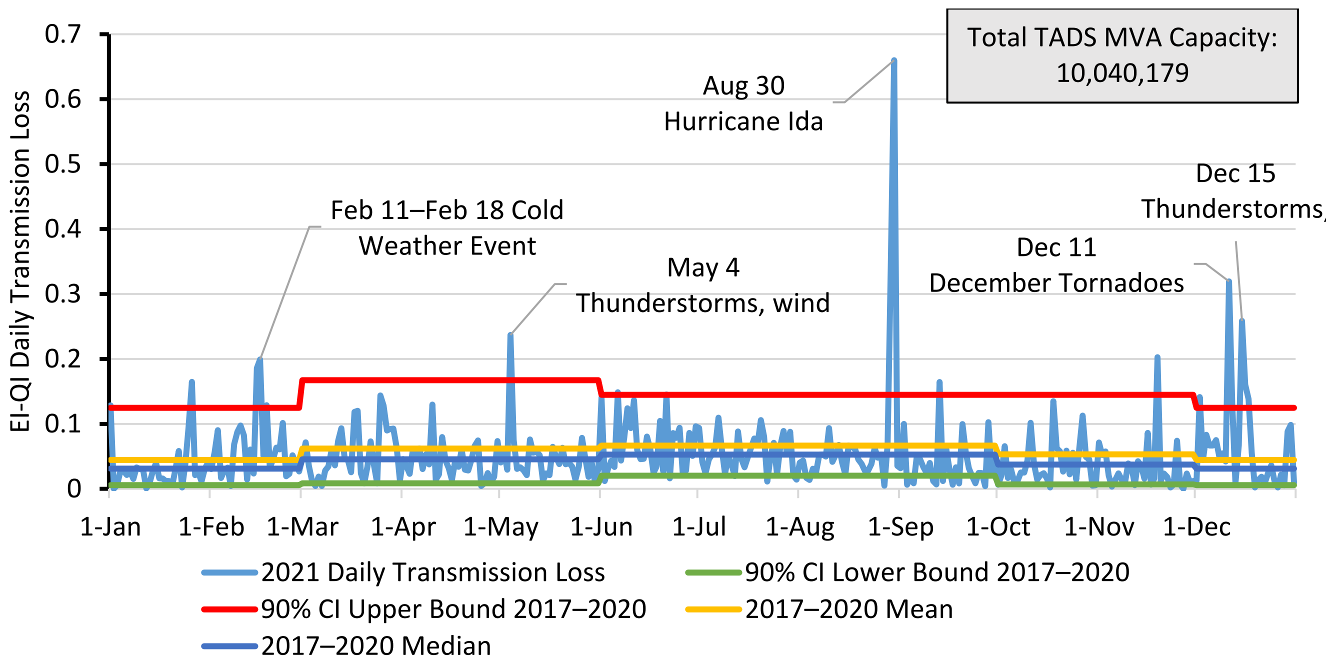


Figure A.5: EI–QI—Transmission Impacts during Extreme Days of 2021

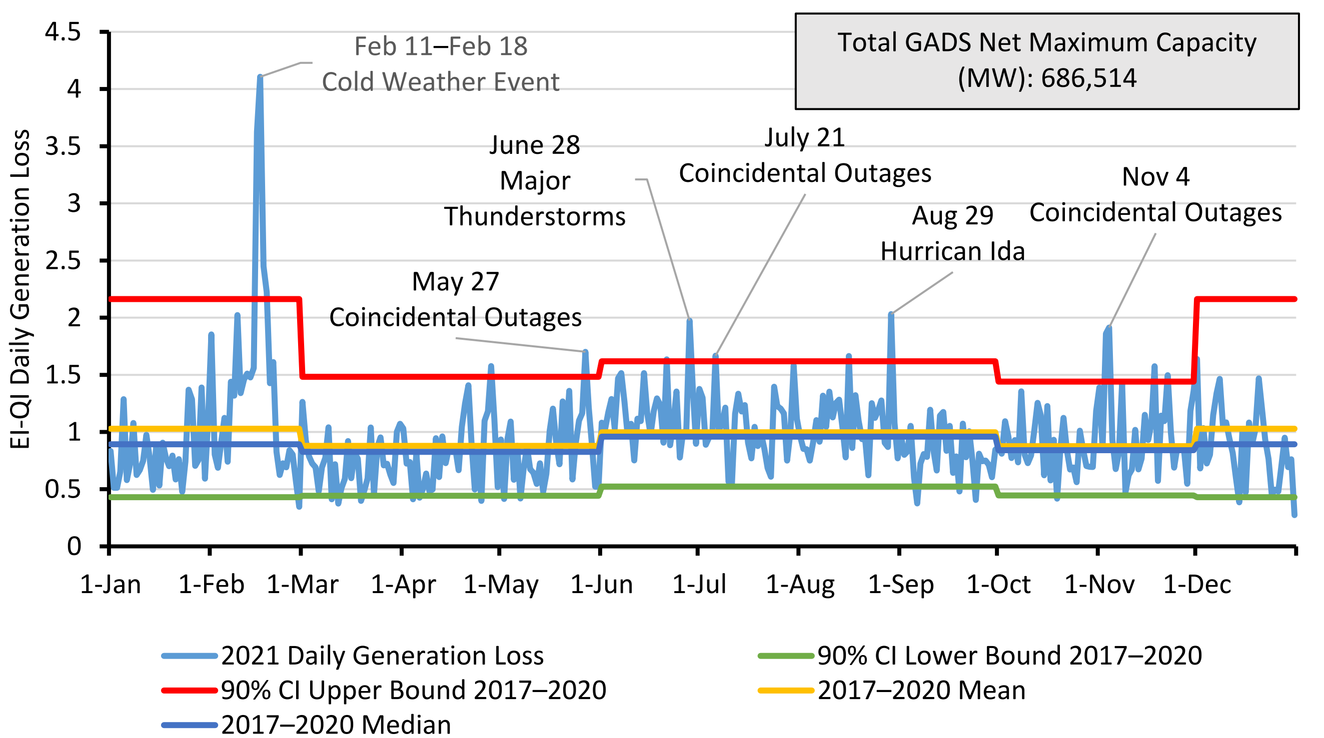


Figure A.6: EI–QI—Generation Impacts during Extreme Days of 2021

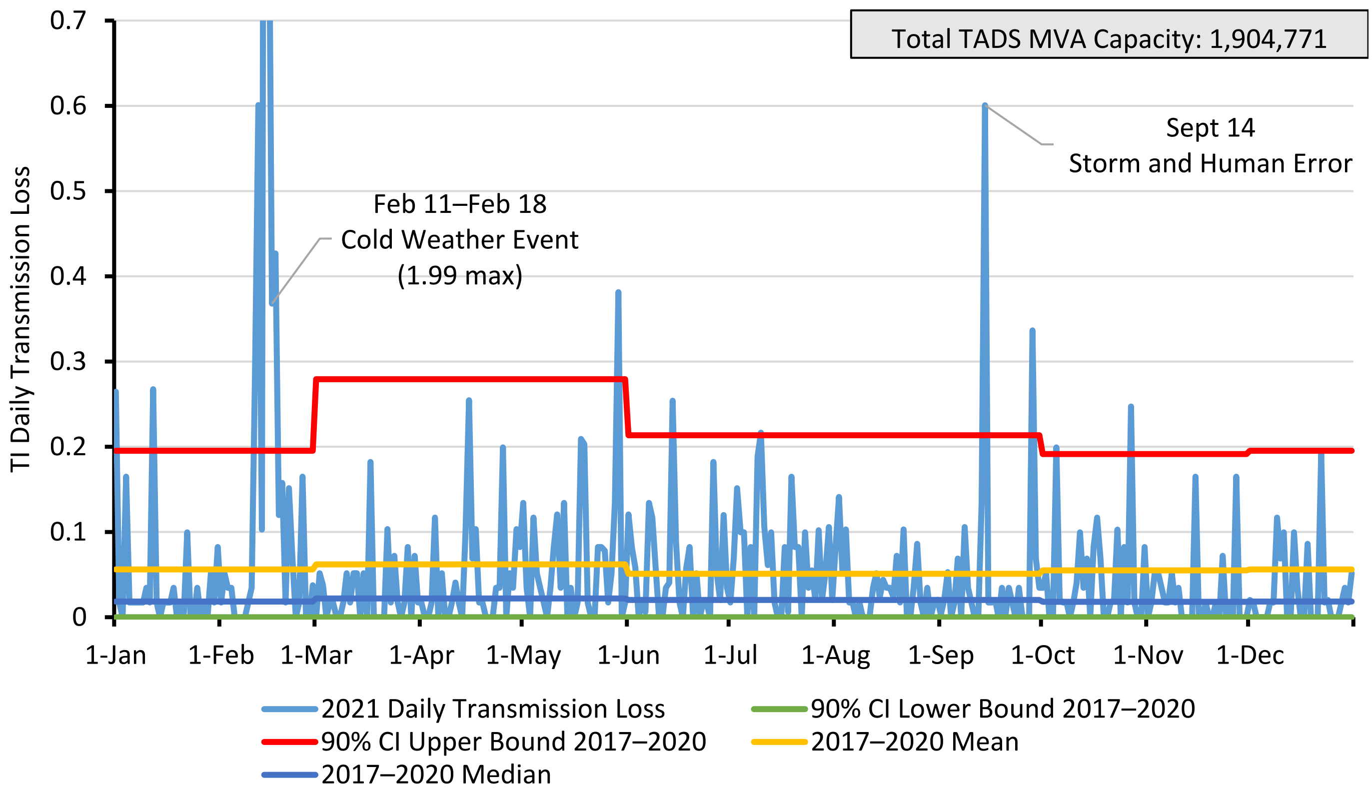


Figure A.7: TI—Transmission Impacts during Extreme Days of 2021

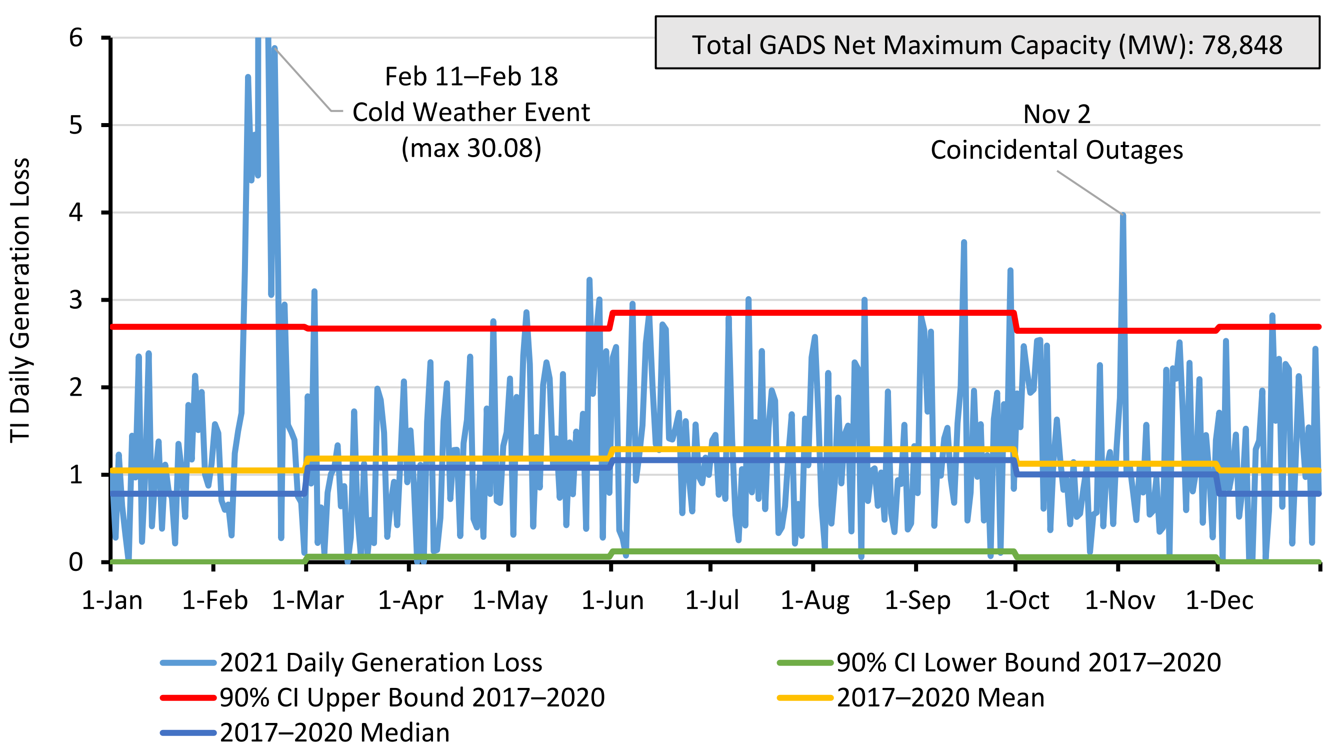


Figure A.8: TI—Generation Impacts during Extreme Days of 2021

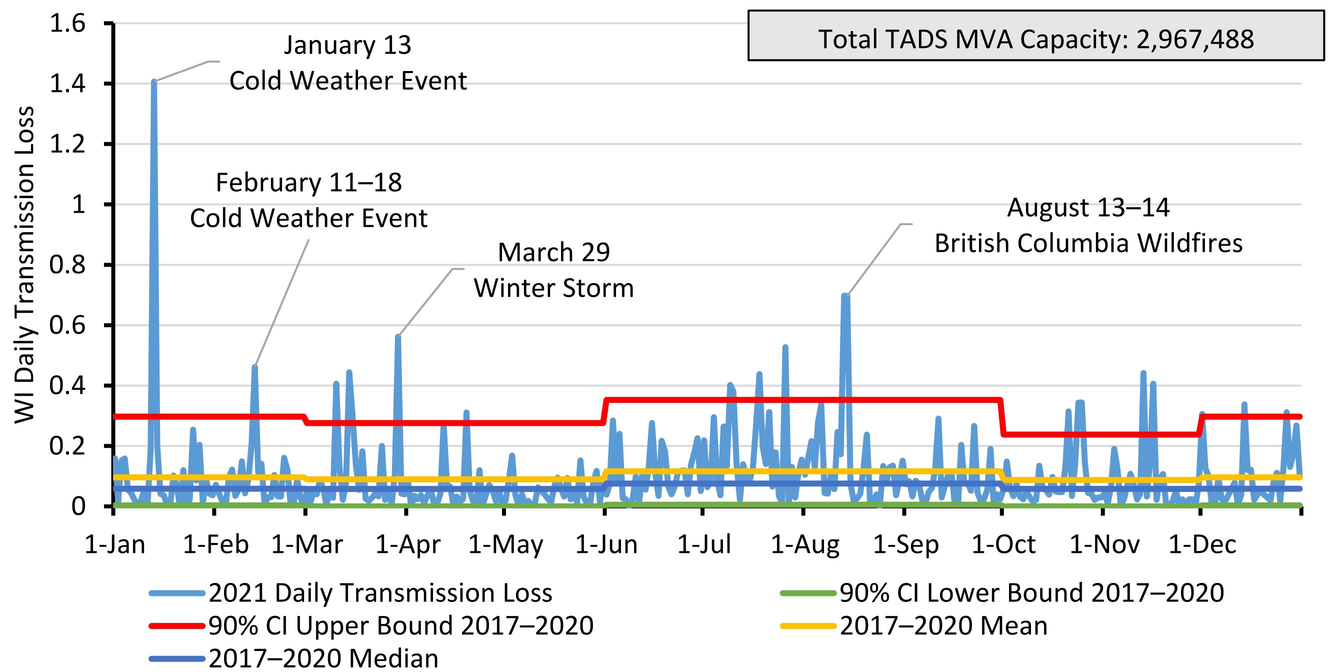


Figure A.9: WI—Transmission Impacts during Extreme Days of 2021

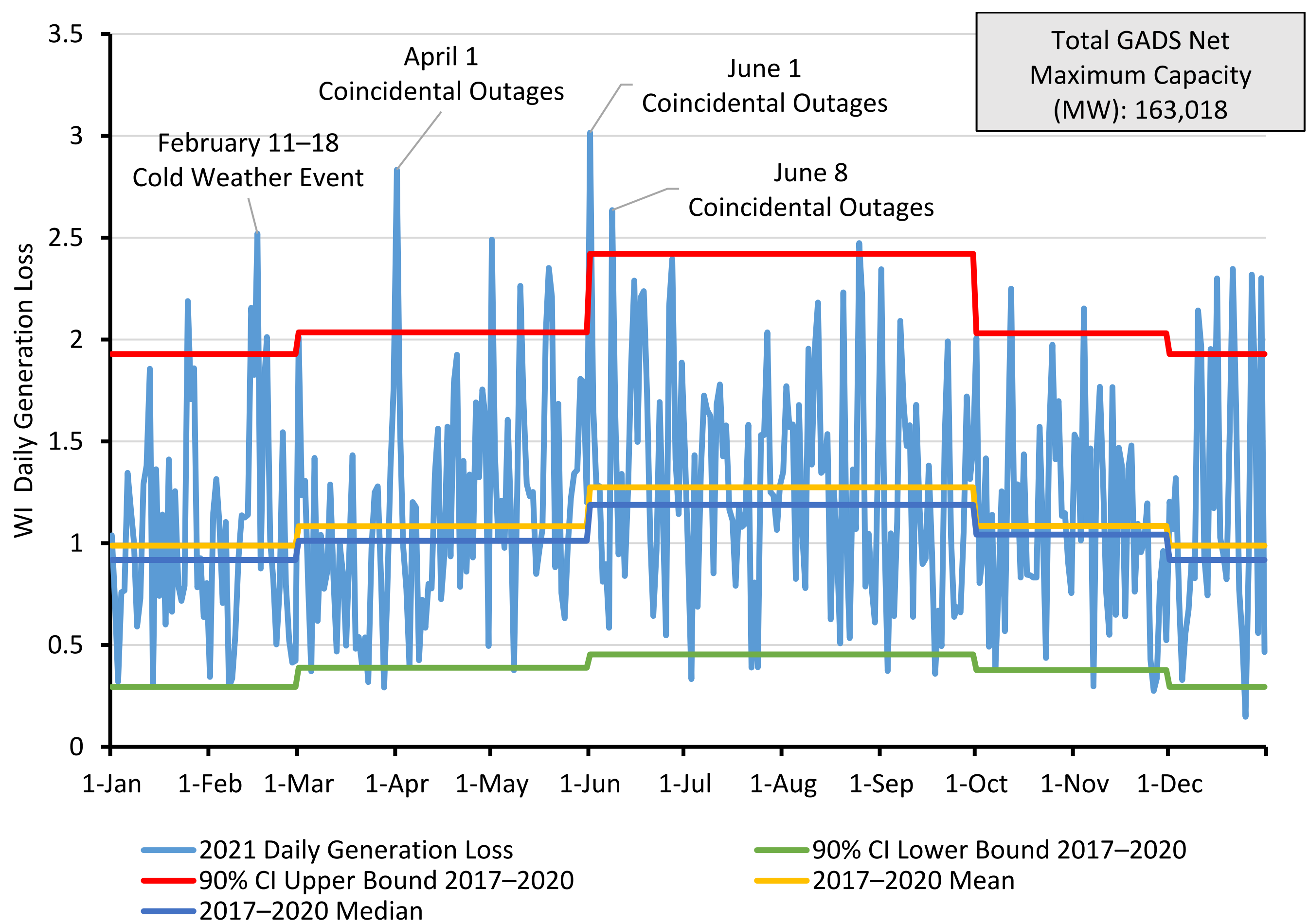


Figure A.10: WI—Generation Impacts during Extreme Days of 2021

Appendix B: Transmission System Resilience and Statistics

Resilience Statistics Calculated from Outage, Restore, and Performance Curves

The 2018 NERC RISC Report on Resilience[64] and the 2020 IEEE technical report, *PES-TR83 Resilience Framework, Methods, and Metrics for Electricity Sector*[65] include definitions of resilience developed by NERC, FERC, DOE, the North American Transmission Forum, and IEEE. These definitions list several key attributes/abilities of a resilient power system that can be summarized as follows: anticipate or plan, absorb or withstand, adapt or protect against, and recover or reduce the duration of extreme events on the system. The IEEE technical report also identifies severe weather as the most common disruptions that test modern power systems' resilience.

This section of the SOR describes several metrics that quantify different abilities/attributes of resilient power systems with calculations and discussions of them for selected 2021 large events (See **2016–2021 Transmission System Resilience Statistics by Extreme Weather Type** section of this Appendix B). These resilience metrics[66] may also depend on the characteristics of the extreme weather that is causing these transmission events (e.g., weather type, magnitude, duration, wind speed), so a comprehensive analysis of transmission resilience is possible only when TADS data is linked to detailed weather data and other relevant information (e.g., geographic and demographic data). Additional data may be helpful to evaluate the ability of the system to anticipate and plan for extreme events, such as the information about industry practices on cold weather preparedness, hurricane preparedness, etc.; currently, these attribute cannot be tracked with available data. Other attributes are discussed in detail in this section.

Absorb or Withstand and Adapt or Protect Against

Event size refers to the number of outages or total MVA out in the event and quantifies the total impact of the weather on the transmission system.

Outage process duration is the time between the earliest start time of an outage and the latest start time of an outage in an event. The outage process duration is relatively small compared with the event duration, and it is mainly determined by the duration of the extreme weather that caused the event.

The outage rate is the frequency at which outages occur during the outage process duration. It is approximately linear and is dependent on the system's ability to absorb the extreme weather. For the 2021 events, the outage rate ranges from 4 elements per hour for the EI April tornado to 17 elements per hour for Hurricane Ida.

Time to first restore is the time between the earliest start time of an outage and the earliest restore time. It also measures the system's ability to absorb, withstand, and protect against extreme weather. The time to first restore is very short and typically does not exceed one hour. In 2021, the shortest time to the first restore, five minutes, was for the February cold weather event in the TI and the longest (3.5 hours) for the EI April tornado.

The nadir of a performance curve indicates the negative of the maximum simultaneous number of elements out or the maximum simultaneous amount of MVA out. The maximum simultaneous number of elements out is always less than or equal to the number of outages in the event.

The total element-days lost and the total MVA-days lost are important statistics of a large event, and they are calculated from the event performance curve as the area between the time axis and the curve. These metrics quantify

---

[64] https://www.nerc.com/comm/RISC/Related%20Files%20DL/RISC%20Resilience%20Report_Approved_RISC_Committee_November_8_2018_Board_Accepted.pdf#search=RISC%20resilience%20report

[65] Resilience Framework, Methods, and Metrics for the Electricity Sector (ieee-pes.org)

[66] 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

the largest degradation levels and total losses during an event (element-based and MVA-based) respectively and also describe the system's ability to withstand and protect against extreme weather. **Figure B.1** and **Figure B.2** show the graphs for the WI January winter storm event, the second largest event of 2021, which had 144 outages. The WI winter storm also had the second lowest nadir of -79 (after Hurricane Ida) and the tornadoes event in EI December, which had the second largest loss of 114,393 MVA days. The patterned area (shaded color) illustrates the area that was used in the calculations. The latter event was also the second-longest event in 2021. Two long 500 kV ac circuit outages contributed more than half of the total MVA-day loss caused by the tornado event in December.

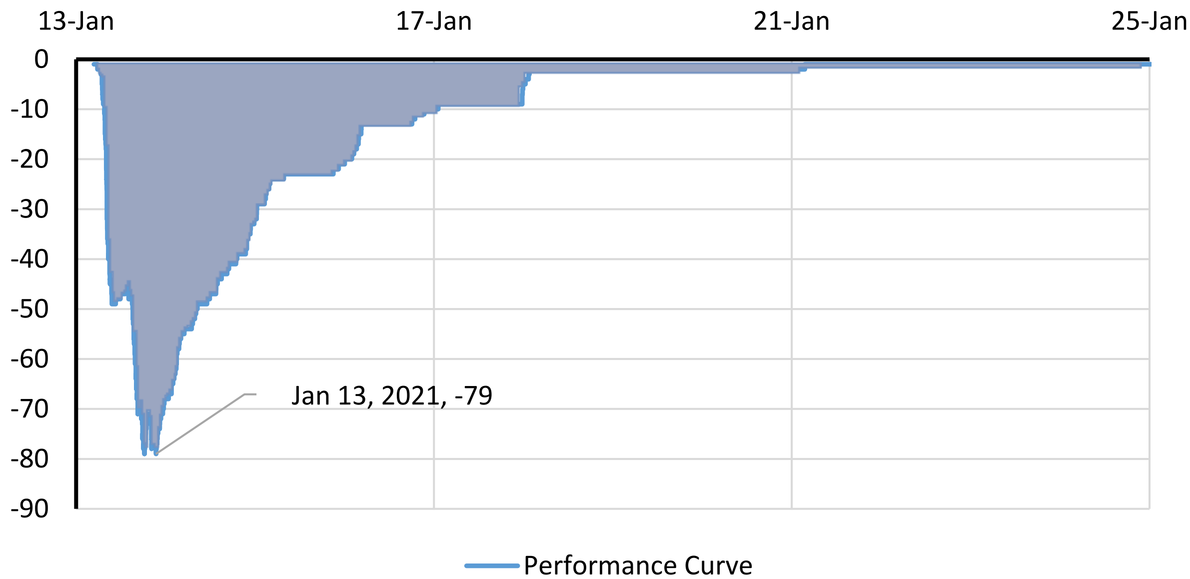


Figure B.1: January 2021 Winter Storm Event

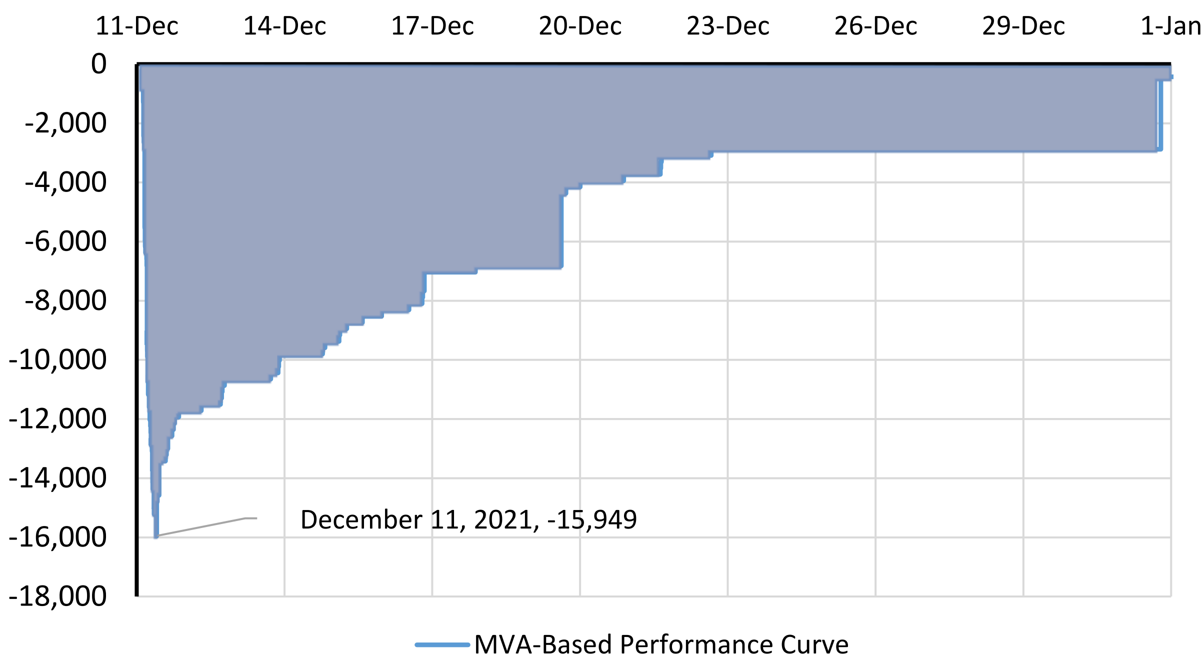


Figure B.2: December 2021 Tornadoes Event

Despite being caused by different types of extreme weather, these two events nevertheless had very similar element-based outage rates (7.95 and 7.34 elements per hour for the January winter storm event and for the December tornado event, respectively) as well as MVA-based outage rates (2,296 and 2,446 MVA per hour). The times to first restore for these events were longer than what is typically seen and similar (142 and 153 minutes, respectively).

Recover or Reduce Duration

The next set of important resilience metrics describes and tracks grid restoration during and after extreme weather.

Event duration is an indicator of the system's ability to recover. The transmission element-based curves in **Figure B.3** show the December 15, 2021, thunderstorm with wind events in the EI with a duration of 16.4 days. **Figure B.4** shows the February 2021 cold weather event in Texas with a duration of 34 hours, which was the shortest large transmission event in 2021. Both curves show the same time scale of 20 days, and a restore process started almost immediately for both cases (within 5 minutes for the TI event and within 31 minutes for the EI event from the event start). While all outages were restored quickly at a nearly linear rate of 0.8 restores per hour for the February cold weather event, the EI event the restore process was typical for large events: it progressed rapidly, then slowed down until almost all elements were restored except a few that remained out for many days.

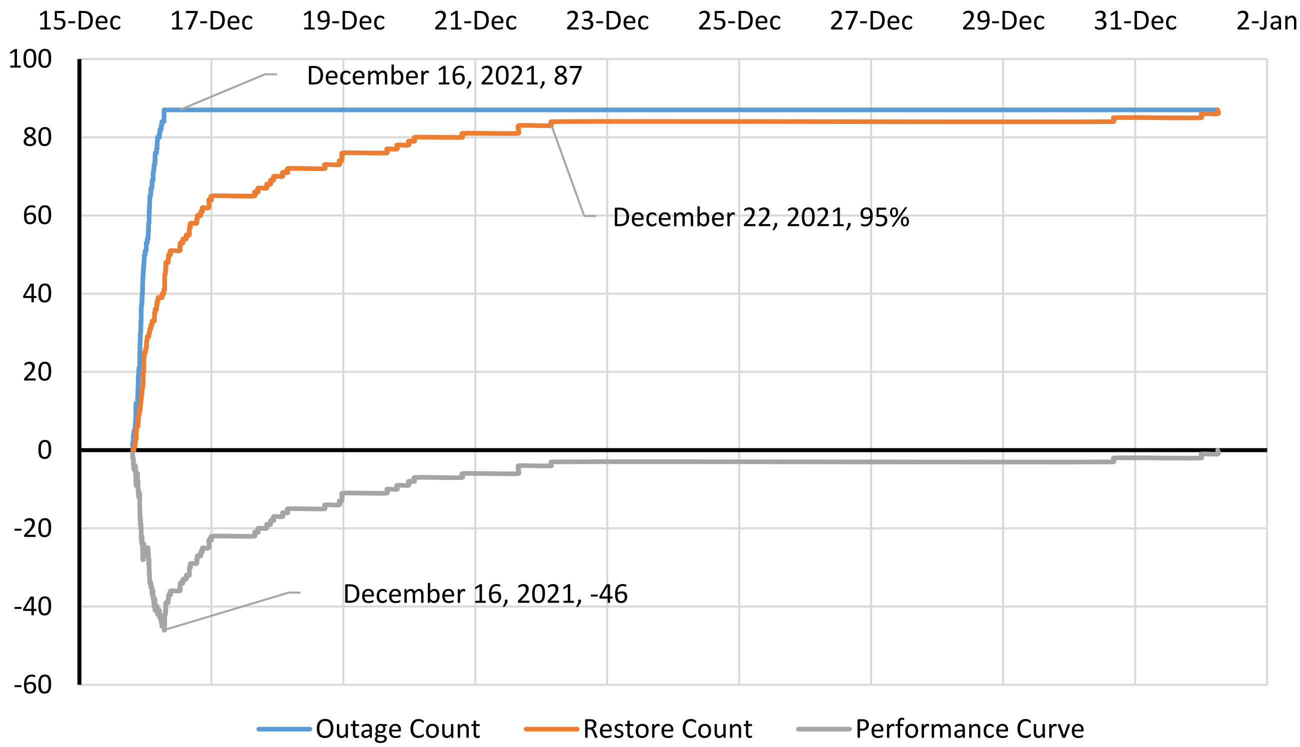


Figure B.3: December 2021 Thunderstorm with Winds Event

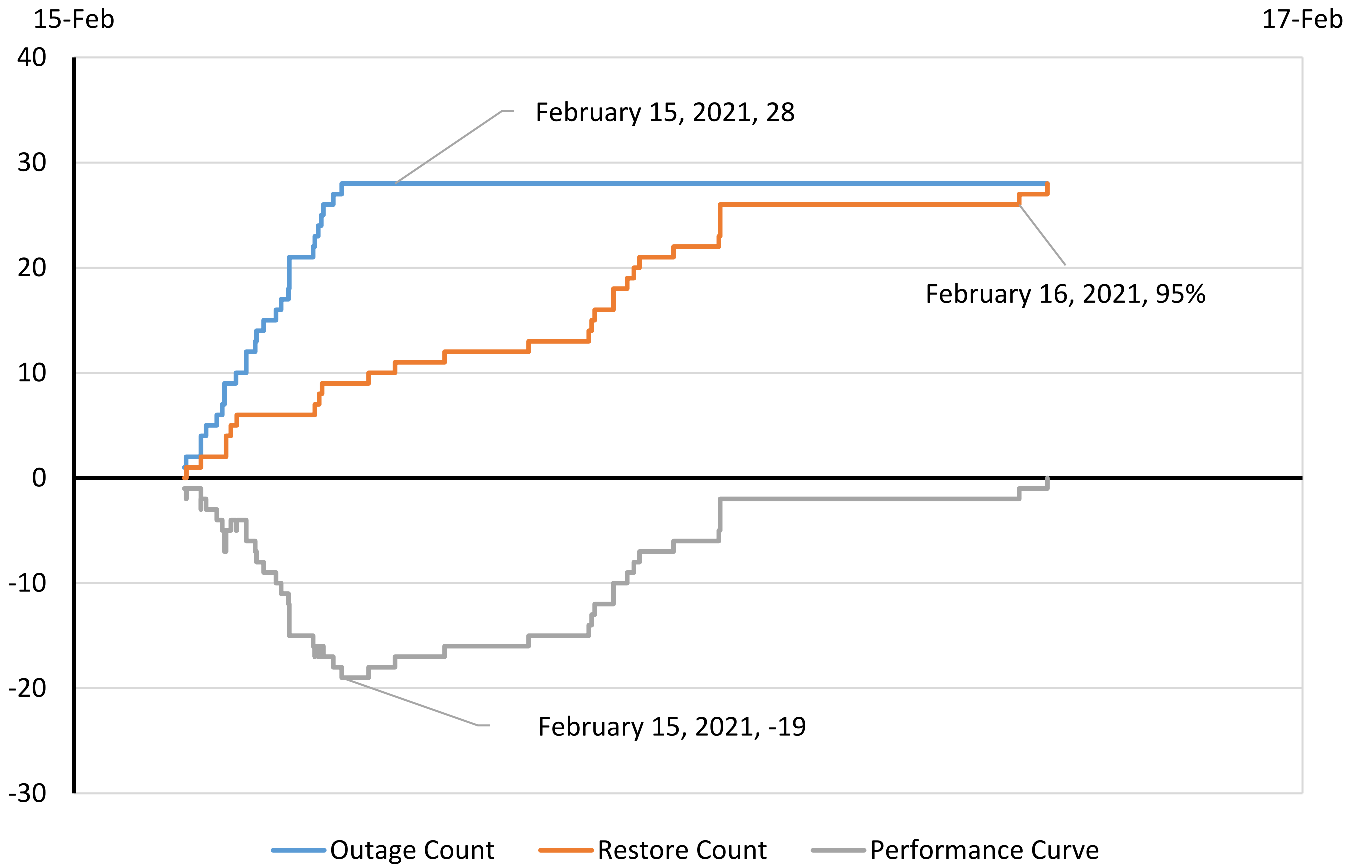


Figure B.4: February 2021 Cold Weather Event

The analysis of large events confirms that complete restoration of outaged elements, especially following large events, can take many days—long after all customers loads have been restored. To measure and track the partial critical restoration, two additional metrics are defined: the time to restore 95% of outages and the time to restore 95% of MVA affected by an event.[67]

Figure B.3 and **Figure B.4** show the 95% restoration level for the events: in the EI event, the 83 outages were restored in 5.9 days after the event start (or 36% of the total event duration); in the TI event, the 26 outages were restored in 32.6 hours (or 97% of the total event duration). On average, for 2021 large events, the time to restore 95% of outages comprised 58% of the event duration and the time to restore 95% of MVA was 59% of the event duration.

[67] Industry is evaluating the level of restoration at 95% of outaged equipment based on the industry practice for identifying the end of an event.

2016–2021 Transmission System Resilience Statistics by Extreme Weather Type

Extreme Weather Types

The outage grouping procedure identified 70 large transmission events in the years 2016–2021, and only one was not weather-related (the latter was caused by incorrect field modification and RAS operation that led to partial system collapse).[68] The 69 large weather-related events were caused by the extreme weather types listed in **Figure B.5**. If several weather factors were observed together (e.g., hurricane and wind, tornado and wind), the dominant cause of the transmission outage was determined to be the extreme weather type. Multiple sources were used to determine an extreme weather event associated with each large transmission event (e.g., NERC's daily BPS awareness reports, NERC's The Event Analysis Management System (TEAMS), National Oceanic and Atmospheric Administration data, public media reports)

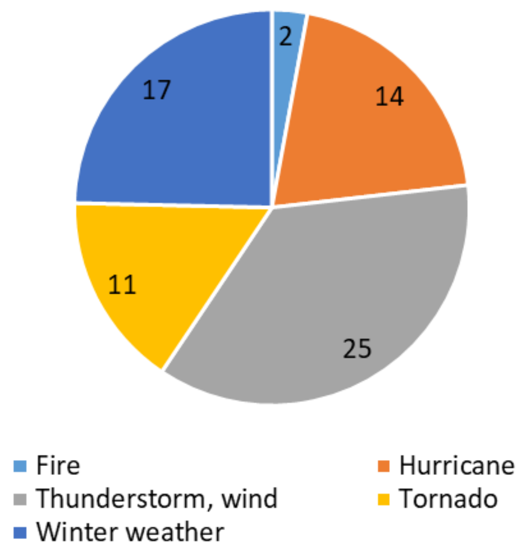
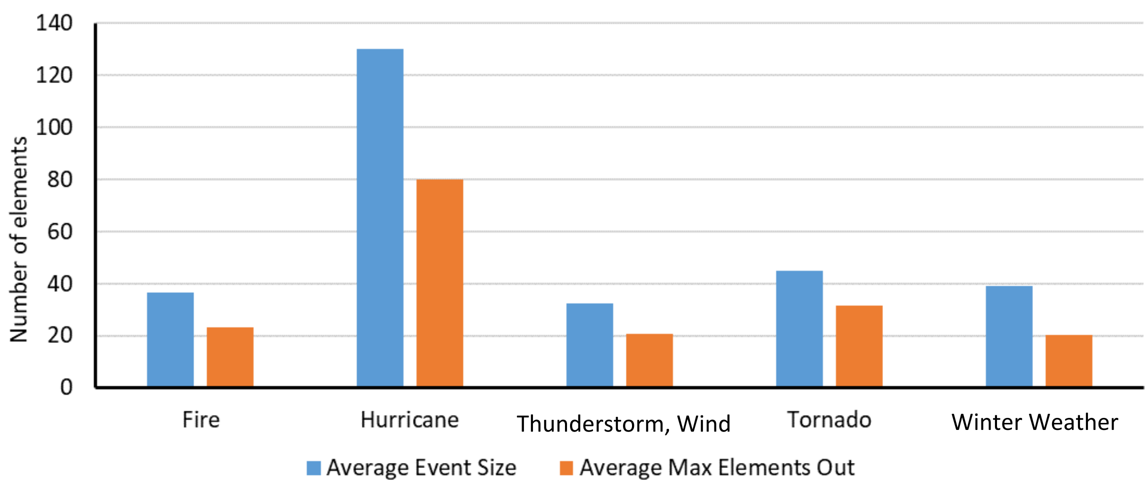


Figure B.5: Extreme Weather Types

Figure B.6 shows selected resilience statistics for the 2016–2021 events by extreme weather type. Hurricanes caused the largest transmission events with an average size of 130 outages while other groups had similar average sizes that ranged from 32 to 45 outages. The maximum number of elements simultaneously out (the most degraded state in an event as indicated by the nadir of the performance curve) is determined by both outage rate and restore rate, equaling 62% of the event size on average. The average percentage is the smallest for winter events (52%) and the highest for tornado events (71%). Since the outage rates for winter weather events and tornado events are similar, this difference indicates slower restorations during and after tornados than during and after extreme winter weather.

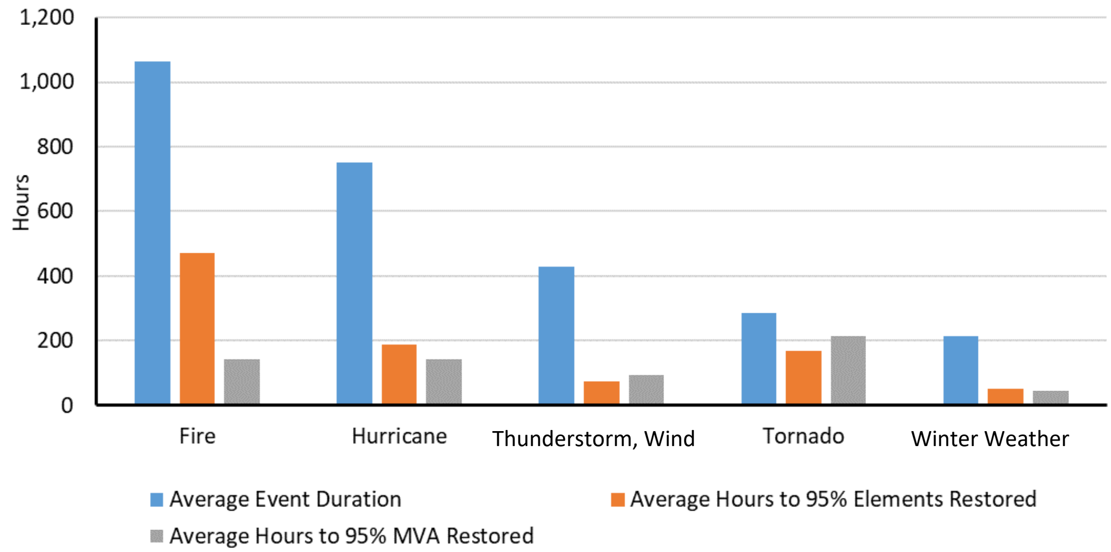


Figures B.6: Resilience Statistics for 2016–2021 Large Weather-Related Events by Extreme Weather Type

Figure B.7 compares the average event duration with the average critical restoration duration (the times to restore 95% of outages and 95% of MVA). One of two fire events (the 2020 WECC wildfires) had a duration of 87 days and strongly affected the average duration for the group. For other groups, the event duration is positively correlated

[68] LL20181002_Incorrect_Field_Modification_and_RAS_Operation_Lead_to_Partial_System_Collapse.pdf (nerc.com)

with the event size. For all weather types, the time to restore 95% of outages is much shorter than the total event duration (on average, from 40% of the event duration for hurricanes to 67% of the event duration for winter weather). For the time to restore 95% MVA, these percentages range from 33% of the event duration for fire to 73% for tornado).



Figures B.7: Average Event Duration vs. the Average Critical Restoration Duration

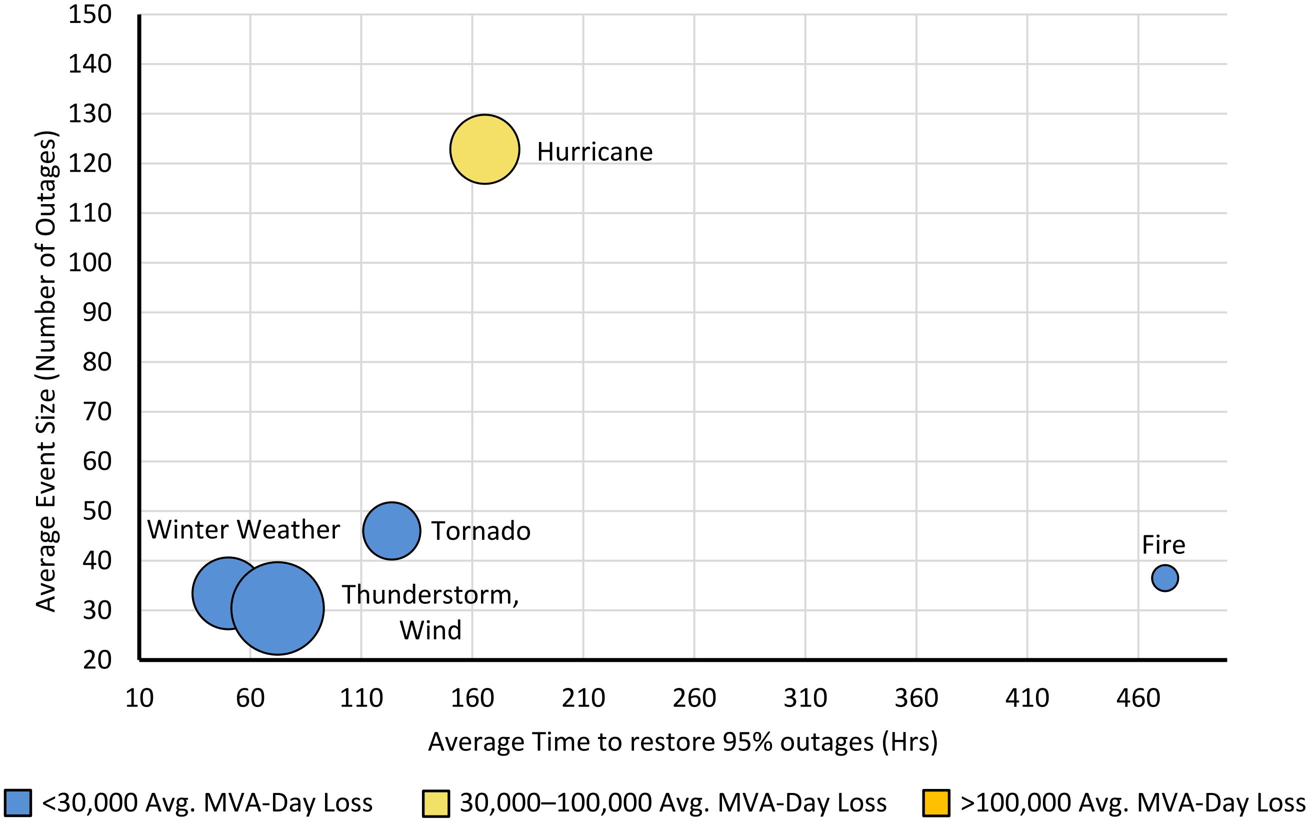
Overall, the event duration had very high variability. For the 2016–2021 large weather events, the 90% confidence interval (the interval between 5th and 95th percentile of all event durations) ranged from 17 hours to 2,073 hours compared with the confidence interval for the time to restore 95% outages ranging from 13 to 549 hours, and the confidence interval for the time to restore 95% MVA ranging from 8 to 485 hours. This makes critical restoration duration the preferable metric to measure and track the ability of transmission system to recover and reduce the duration of outage events caused by extreme weather.

Changes in Resilience Statistics: 2017–2021 Events vs. 2016–2020 Events

The resilience statistics are calculated for large weather-related events for the years 2017–2021 and for the years 2016–2020, and changes in the metrics by extreme weather types were analyzed. The five-year time period is selected due to a small annual number of events in some groups (e.g., fire).

The bubble charts in **Figure B.8** and **Figure B.9** show the groups of large weather-related transmission events by extreme weather type; five bubbles in **Figure B.8** correspond to the groups for combined 2016–2020 data, and five bubbles in **Figure B.9** show the same groups for combined 2017–2021 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 extreme weather type from **Figure B.8** to **Figure B.9** may indicate improved or declined performance. While there were no significant changes in the size of the groups, there was an observable change in the position of the Hurricane group that was caused by increases in both the average event size and the average time to restore 95% of outages. These changes as well as a change in color from yellow to orange were caused by adding Hurricane Ida to the group, which was the largest, the longest, and the most impactful transmission event of 2021. Ida replaced 2016 Hurricanes Matthew and Hermione in this group, which were smaller and much shorter events. Similarly, the tornado group was affected by the 2021 December tornadoes that had the second largest MVA-days loss after Hurricane Ida.



Figures B.8: Statistics for Large Transmission Events by Weather Type for 2016–2020

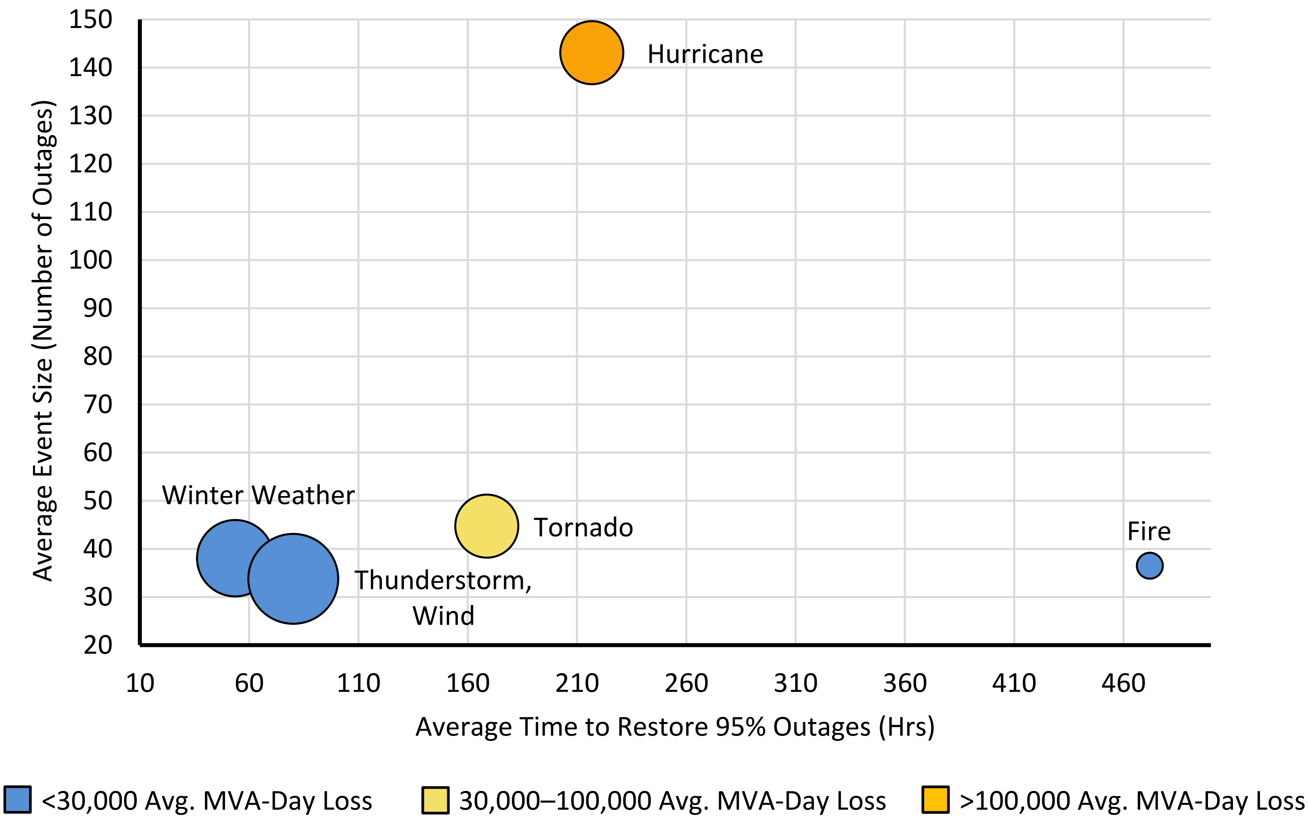


Figure B.9: Statistics for Large Transmission Events by Weather Type for 2017–2021

Conclusions

NERC staff used the outage and restore processes for the large weather-related transmission events to define several resilience statistics that measure and track the system's ability to absorb or withstand, adapt or protect, and recover and reduce the extent and duration of extreme weather events. Several conclusions and observations from this analysis are listed as the following:

- All large events identified from the 2016–2021 TADS data except one[69] were weather-related. This confirms that extreme weather is the major risk to resilience of the transmission BPS.
- Hurricanes cause the largest, longest, and most impactful events on the transmission system (as measured by element and MVA-days loss). Hurricane Ida was the largest and longest event in 2021 and the most impactful in 2016–2021.
- Typically, the most degraded state during a large transmission event (the maximum simultaneous number of elements and MVA out) occurs relatively soon after the event start, and the system remains in this state for only a few minutes. The average value of the most degraded state is about 62% of the event size.
- The restore process starts quickly after the event start (usually during the first hour), progresses quickly, and then slows down. Often a single (or few) elements remain unrestored for many days and sometimes weeks.
- The 95% restoration level is reached much faster relative to the event duration. On average, it takes about 55% of the event duration to restore 95% of outages and 53% of event duration to restore 95% of MVA.
- Hurricane Ida, which had the largest amount of MVA out and the largest MVA-days loss in the 6 years of data, caused a negative change of resilience metrics for the Hurricane group. The EI December tornadoes, the most impactful tornado event over the six years, similarly affected the Tornado group. The remaining groups of events by weather type (Winter Weather, Fire, Thunderstorms, Wind) did not have significant changes from 2016–2020 to 2017–2021.

[69] LL20181002_Incorrect_Field_Modification_and_RAS_Operation_Lead_to_Partial_System_Collapse.pdf (nerc.com)

Appendix C: Contributions

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

NERC Industry Group Acknowledgements	
Group	**Officers**
Reliability Security and Technical Committee	Chair: Greg Ford, Georgia System Operations Corporation Vice Chair: Rich Hydzik, Avista
Performance Analysis Subcommittee	RSTC Sponsor: Jeff Harrison, Associated Electric Cooperative Chair: Brantley Tillis, Duke Energy Vice Chair: David Penney, Texas RE
Events Analysis Subcommittee	Chair: Ralph Rufrano, NPCC Vice Chair: Chris Moran, PJM
Generation Availability Data System User Group	Chair: Leeth DePriest, Southern Company Vice Chair: Danny Small, City Utilities
Misoperations Information Data Analysis System User Group	Chair: Brian Kasmarzik Vice Chair: Thomas Teafatiller, ReliabilityFirst
Transmission Availability Data System User Group	Chair: John Idzior, ReliabilityFirst Vice Chair: Nick DePompei, SERC
Resources Subcommittee	Chair: Greg Park, NWPP Vice Chair: Rodney O'Bryant, Southern Company
Real-Time Operating Subcommittee	Chair: James Hartmann, Electric Reliability Council of Texas, Inc. Vice Chair: Timothy Beach, California Independent System Operator (RC West)
Frequency Working Group	Chair: Dan Baker, SPP
Reliability Assessment Subcommittee	Chair: Anna Lafoyiannis, Independent Electricity System Operator Vice Chair: Andreas Klaube, NPCC
System Protection and Control Working Group	Chair: Bill Crossland, ReliabilityFirst Vice Chair: Lynn Schroeder, Sunflower Electric

NERC Staff	
Name	**Title**
Laura Brown	Director, E-ISAC Strategy, Policy, and Programs
Tony Burt	Physical Security Analyst
Terry Campbell	Manager and Editor, Technical Publications
Alex Carlson	Senior Technical Publications Specialist
Stephen Coterillo	Engineer II
Svetlana Ekisheva	Principal Data Science Advisor
Brad Gordon	Senior Engineer
Bill Graham	Manager, Bulk Power System Awareness
Richard Hackman	Senior Event Analysis Advisor
Maria Kachadurian	Senior Analyst
Mark Lauby	Senior Vice President and Chief Engineer
Stephanie Lawrence	Program Specialist, Situational Awareness and Personnel Certification
Matthew Lewis	Manager of Event Analysis

NERC Staff	
Name	**Title**
Robert Maddox	Senior Data Analyst
Mani Mardhekar	Senior Engineer
William G. (Marty) Martin	Senior Data Analyst
John Moura	Director, Reliability Assessment and Performance Analysis
Kimberly Mielcarek	Vice President, Communications
Darrell Moore	Director, Situation Awareness
Jack Norris	Engineer II
Mark Olson	Manager, Reliability Assessments
Margaret Pate	Program Liaison
Donna Pratt	Manager, Performance Analysis
Wei Qiu	Lead Engineer
Ryan Quint	Senior Manager, BPS Security and Grid Transformation
Darrel Richardson	Principal Technical Advisor
Ed Ruck	Senior Engineer
Janet Sena	Senior Vice President, Policy and External Affairs
Sandy Shiflett	Senior Program Specialist
Robert Tallman	Senior Engineer
Lee Thaubald	Senior Application Specialist
David Till	Senior Manager