Public

2024 REGIONAL SUMMER ASSESSMENT

June 6, 2024

MIDWEST RELIABILITY ORGANIZATION

380 St. Peter St, Suite 800
Saint Paul, MN 55102

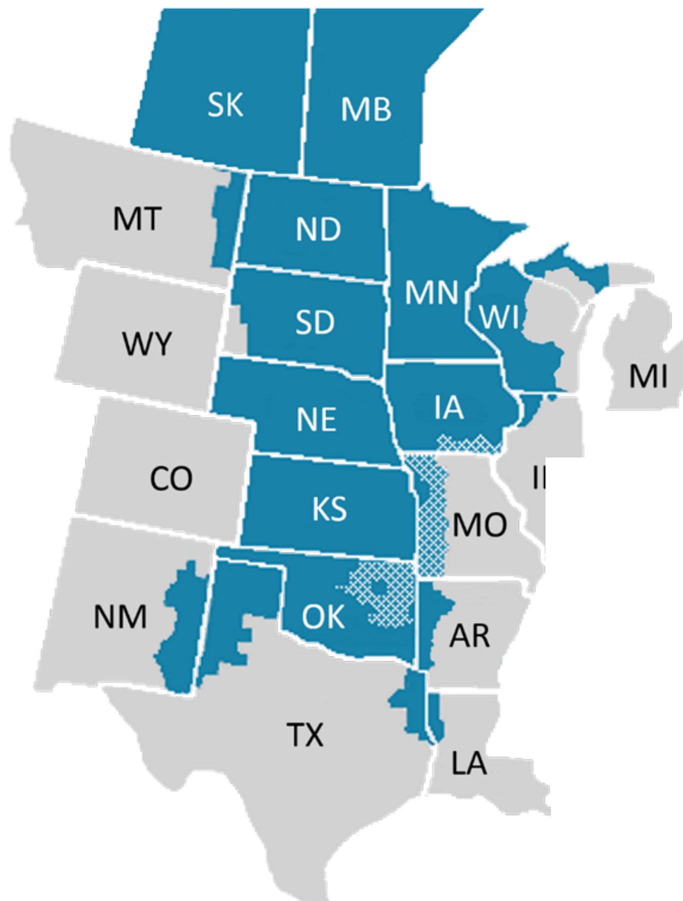
651-855-1760

MRO.net

PREFACE

Midwest Reliability Organization (MRO) is dedicated to its vision of ***a highly reliable and secure North American bulk power system***. To ensure reliability of the bulk power system in the United States, Congress passed the Energy Policy Act of 2005, creating a new regulatory organization called the Electric Reliability Organization (ERO) to establish mandatory Reliability Standards and monitor and enforce compliance with those standards on those who own, operate, or use the interconnected power grid.

In 2006, the Federal Energy Regulatory Commission (FERC) approved the North American Electric Reliability Corporation (NERC) as the ERO under section 215(e)(4) of the Federal Power Act. NERC delegates its authority to monitor and enforce compliance to six Regional Entities established across North America, of which MRO is one. Recognizing the international nature of the grid, NERC as the ERO, along with MRO, established similar arrangements with provincial authorities in Canada.



The MRO region spans the provinces of Saskatchewan and Manitoba, and all or parts of the states of Arkansas, Illinois, Iowa, Kansas, Louisiana, Michigan, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wisconsin. The region includes more than 245 organizations that are involved in the production and delivery of electric power, including municipal utilities, cooperatives, investor-owned utilities, transmission system operators, federal power marketing agencies, Canadian Crown Corporations, and independent power producers.

MRO's primary responsibilities are to ensure compliance with mandatory Reliability Standards by entities who own, operate, or use the North American bulk power system; conduct assessments of the grid's ability to meet electric power demand in the region; and analyze regional system events. Additionally, MRO creates an open forum for stakeholder experts in the region to discuss important topics related to addressing risk and improving reliable operations of the bulk power system.

EXECUTIVE SUMMARY

The 2024 Regional Summer Assessment (RSA) helps inform key stakeholders of projected reliability challenges for the bulk power system in MRO's region for the upcoming summer season. This assessment complements NERC's Summer Reliability Assessment by taking a more granular look at continent-wide reliability concerns that present a greater risk within MRO's regional footprint. MRO's RSA is unique in that it includes a review of regional bulk power system performance during the 2023 summer season to identify trends that might impact future system reliability.

This assessment focuses on the summer months of June through September and provides an evaluation of resource and transmission system adequacy needed to meet projected summer peak demands. The data collected and assessed by MRO staff on resource and transmission system adequacy is provided by the four Planning Coordinators (PCs) that operate within MRO's regional footprint: Manitoba Hydro (MH), Midcontinent Independent System Operator (MISO), Saskatchewan Power Corporation (SPC), and Southwest Power Pool (SPP).

The data used to assess historical performance of the regional bulk power system is collected from more than 245 registered entities (users, owners, and operators of the bulk power system) within MRO's region each quarter. More information on the registration and certification of companies whose data is used in this report can be found in Appendix A.

Key Findings and Trends

- MISO and SPC are at risk of implementing Energy Emergency Alerts (EEAs) for above-normal summer peak load with unplanned outage conditions like those observed last summer. Unanticipated generator outages that coincide with peak demand can result in insufficient capacity and would likely require use of available demand response programs to cover anticipated extreme summer peak demands.
- Extreme summer peak conditions in SPP's footprint with historic high outage rates and low wind conditions could result in insufficient capacity to cover anticipated extreme summer peak demands. These scenarios would result in SPP implementing available demand response programs and short-term power transfers from neighboring utilities.
- MH is projecting sufficient capacity available to meet normal and extreme forecasted seasonal peak load with typical outages this summer.
- Conventional generation Weighted Equivalent Forced Outage Rates (WEFOR) for 2023 were higher than the five-year moving average. Long-term trends continue to indicate increasing generation forced outage rates due to component fatigue from frequent ramping in response to uncertainty output of intermittent resources.
- Protection system misoperation continues to be the top event cause in the MRO region. Human error-related misoperations accounted for nearly half of last summer's total misoperations, and nearly a quarter of this was attributable to incorrect relay settings. While none of these events contributed to any significant events in terms of generation or load lost, it is still an area MRO is monitoring closely.

Recommendations

To reduce risks of energy shortfalls on the bulk power system this summer, MRO recommends the following:

- Reliability Coordinators (RCs), Balancing Authorities (BAs), Transmission Operators (TOPs) and Generator Operators (GOPs) should maintain situational awareness of unplanned generation and transmission outages, abnormal and extreme weather conditions, and low wind forecast periods.

These organizations should employ operating procedures as needed to ensure adequate resource availability.

- RCs, BAs, and Generator Owners (GOs) should have safeguard protocols in place to ensure adequate generation resources are available prior to the summer season high demand period.

- State and provincial regulators should have plans in place at the start of summer for managing emergency requests from grid operators. State and provincial regulators should be prepared to assist grid operators prior to, and during, the summer season by supporting requested environmental and transportation waivers, as well as public appeals for demand reduction.

- PCs, Resource Planners (RPs) and Transmission Planners (TPs) need to develop new and improved methods to assess and evaluate energy adequacy, especially when a significant amount of generation capacity has an intermittent fuel source that can have significant forecast error.

CHAPTER 1: ASSESSMENT OVERVIEW

Purpose

The purpose of this report is to provide information on, and raise awareness of, reliability challenges, and trends to assist industry stakeholders and key decision-makers with reducing risk to the regional bulk power system.

Process

MRO Reliability Assessment staff independently review, assess, and report on the overall reliability of the electricity supply and demand, transmission system adequacy, and key issues and trends that could affect bulk power system reliability in the region. This work is conducted in conformance with the MRO Regional Delegation Agreement and in accordance with the NERC Rules of Procedure Section 800 and the ERO Reliability Assessment Process document.

MRO staff annually assesses data collected from regional Reliability Coordinators (RCs) and Planning Coordinator (PCs) to identify key reliability issues and the risks and uncertainties affecting adequacy of the bulk power system in the region. PCs are responsible for integrating transmission facilities, service plans, resource plans, and protection systems to ensure reliable power within their respective footprints. These entities collaborate with Transmission Planners to assess resource and transmission impacts within an interconnected area. RCs—the entities responsible for real-time, reliable operation of the bulk power system—have a wide-area view of the system and are the highest level of operating authority within a designated footprint. In addition to the four PCs in MRO (MH, MISO, SPC, and SPP), there are three RCs: MISO (who is also the RC for MH), SPC, and SPP.

NERC's reliability assessment process, which covers all of North America, is a coordinated reliability evaluation effort between the NERC Reliability Assessment Subcommittee (RAS), NERC staff, and the six Regional Entities.[1] MRO's 2024 RSA is an independent staff assessment that utilizes some of the same data as NERC's 2024 Summer Reliability Assessment (SRA), with a more targeted focus on MRO's regional footprint. The evaluation of previous seasonal performance helps to identify reliability concerns, trends and emerging risks that are region-specific.

Area Studied

The area assessed in MRO's 2024 RSA includes two Canadian provinces and all or parts of 16 states. It is important to note that the MISO footprint spans three Regional Entities: MRO, Reliability First (RF), and SERC Reliability Corporation (SERC). MRO is responsible for collecting resource and transmission system adequacy data for the entire MISO area and reviews it jointly with RF and SERC when performing NERC reliability assessments. In contrast, the review of MISO's historical performance data includes only the portion of the MISO footprint within the MRO region. MRO collects and reviews both performance data and NERC reliability assessment information for the entire MH, SPC, and SPP Planning Coordinator footprints.

Sources of information used in this assessment include NERC's 2024 SRA, as well as MRO Performance Analysis (PA) data from the ERO Generating Availability Data System (GADS), Transmission Availability Data System (TADS), Misoperation Information Data Analysis System (MIDAS), and Event Analysis (EA).

Figure 1.1 illustrates the North American assessment areas and Figure 1.2 shows the North American

[1] https://www.nerc.com/AboutNERC/keyplayers/Pages/default.aspx

Regional Entity footprints, which are separate from, and do not precisely align with, the assessment areas.

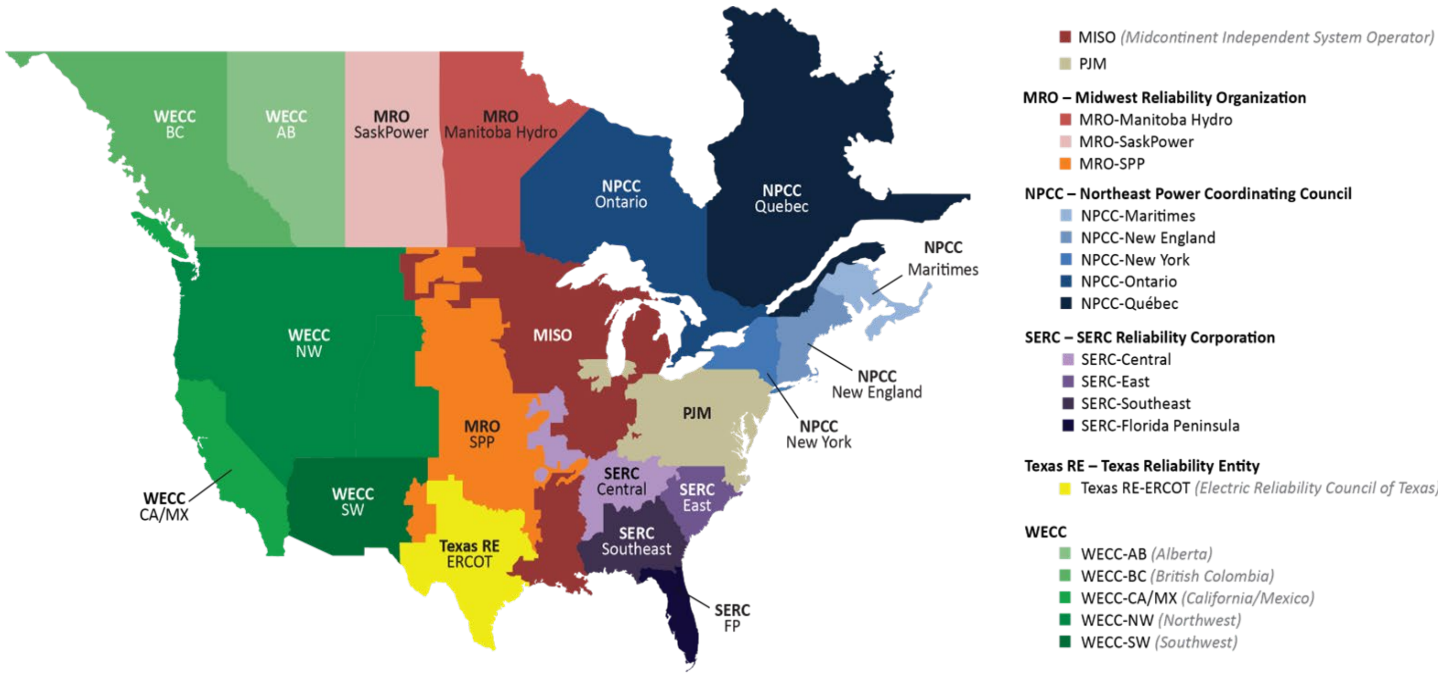


Figure 1.1: NERC Assessment Areas

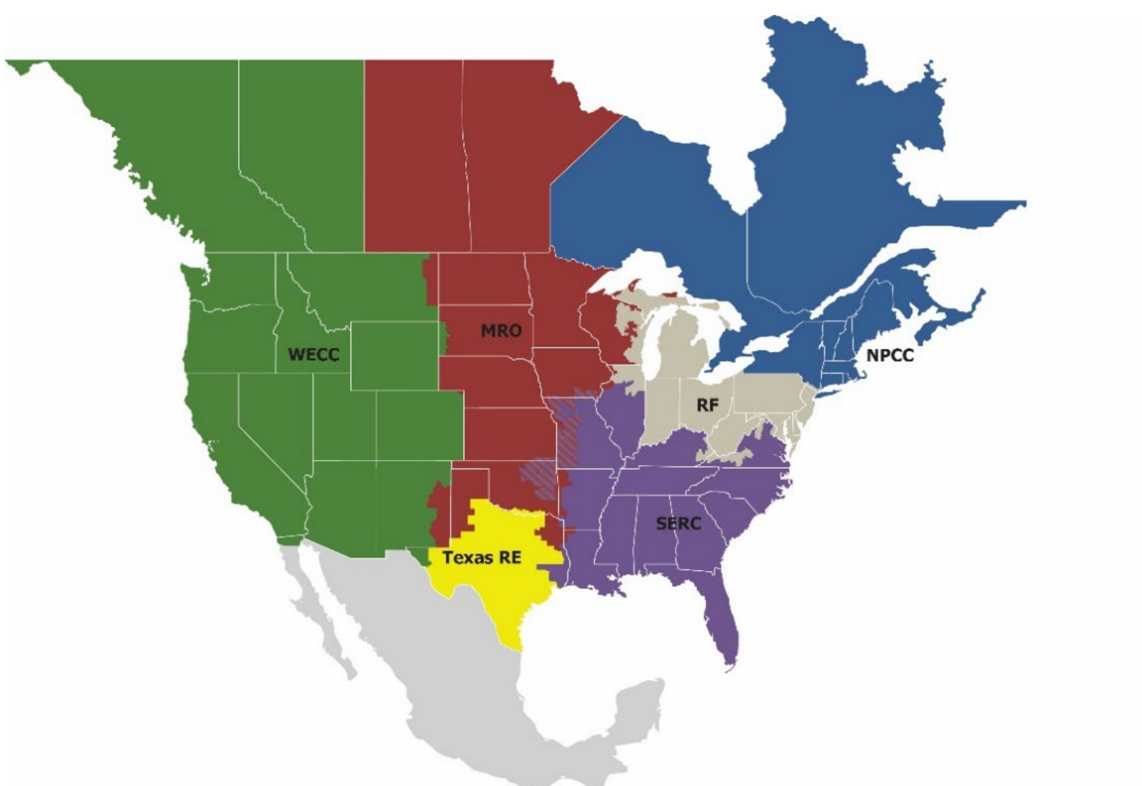


Figure 1.2: Regional Entity Boundaries

CHAPTER 2: 2024 SUMMER OUTLOOK

The growing complexity and increasing uncertainty in seasonal load forecasting adds to summer reliability risks. Extreme hot temperatures and severe weather can cause demand for electricity to deviate significantly from historical forecasts. Underestimating electricity demand can lead to ineffective operations planning and insufficient resources being scheduled. Relatedly, generator performance and fuel supply issues are more likely to occur when generators are called upon with short notice, exposing Balancing Authorities to potential resource shortfalls.

In coordination with the ERO Enterprise and industry, MRO performs seasonal generation and load forecasts to determine reliability risk as part of this assessment. Details from the 2024 Seasonal Summer Forecast can be found in Appendix B.

Based on this information, the projected reliability conditions for each assessment area in the MRO region for the 2024 summer season is described below.

Manitoba Hydro

MH's Anticipated Reserve Margin (ARM) has been reduced to 16 percent for this summer compared to the prior summer of 29 percent due to increased peak demand projections and capacity exports and a forced outage of a hydro plant. There were no changes to MH's Installed Capacity (ICAP) Planning Reserve Margin Requirements (PRMR) of 12 percent.

MH does not anticipate any emerging reliability issues from the reduced reserve margin for the 2024 summer season. Although MH experienced unanticipated higher than normal summer load conditions last summer, no changes are required to seasonal resource planning for the upcoming summer season because anticipated reserve margins exceed the reference margin level. Manitoba Hydro is experiencing below average water supply conditions; however late winter snowfall has been above average, which favorably impacts spring runoff. Manitoba Hydro expects to reliably supply its internal demand and export obligations, even if drought continues through 2024 or 2025. Manitoba Hydro continues to monitor several issues such as extreme weather events, drought, decarbonization-driven changes to supply and demand, and asset health.

Midcontinent Independent System Operator

MISO projects sufficient capacity available for the upcoming 2024 summer season based on normal weather with typical outage conditions. The risk of being unable to meet reserve requirements at peak demand this summer is lower than in 2023 due to additional resource availability and slightly lower peak demand forecast. MISO may need to utilize Load Modifying Resources (LMRs) or demand response during extreme conditions as LMRs become an increasingly important segment of MISO's resource mix. Low wind conditions during extreme conditions could further exacerbate capacity deficiencies.

MISO's ICAP PRMR increased from 15.9 percent last summer to 17.7 percent for this summer based on the 2024 summer seasonal capacity construct changes in resource capability. Seasonal based Generation Verification Test Capacity (GVTC) output updated annualized planned maintenance, retirement suspensions, and changes in the resource mix contributed to nearly 9 percent increase in reserve margin from 23 percent last summer to 31.6 percent this summer.

Though risk has been identified for extreme summer season scenarios, MISO operators anticipate that system reliability can be maintained using Load Modifying Resources (LMRs) and scheduling non-firm transfers into the system when necessary and available.

Saskatchewan Power Corporation

Saskatchewan is a winter peaking region, but also experiences high load in summer during extreme hot weather as occurred last summer. The risk of operating reserve shortages during summer peak load periods or EEAs could increase if significant generation forced outages happen at the same time as planned maintenance outages during the high-demand months of June through September. If extreme demand from high temperatures aligns with significant generation outages as observed last summer, SPC will deploy available demand response programs and short-term power transfers from neighboring utilities as necessary to mitigate the situation.

SPC's 2024 summer PRMR is 15 percent and is unchanged from the previous summer. Similarly, SPC's anticipated reserve margins remained the same for this summer at 30 percent.

Southwest Power Pool

SPP is projecting a low likelihood of emerging reliability issues impacting the area for the upcoming summer season under normal conditions. The risk of being unable to meet reserve requirements at peak demand this summer is lower than in 2023 due to additional resources and firm imports. SPP's resources are projected to be higher this summer by nearly 7 percent as compared to a reserve margin of 24.6 percent last summer. SPP's ICAP PRMR remained unchanged at 19 percent coincident peak (15 percent non-coincident peak). Tight energy conditions on peak summer days with high demand and low wind generation could result in capacity deficiency during extreme conditions.

Though risk has been identified for extreme summer season scenarios, SPP operators anticipate that system reliability can be maintained using the current operational processes and procedures. SPP will continue to assess the needs for the 2024 summer season and will adjust as needed to ensure that real time reliability is maintained throughout the summer timeframe.

CHAPTER 3: SEASONAL TRENDS

The following data was used to analyze system performance during the 2023 summer season to identify seasonal trends:

- Bulk Electric System (BES)[2] Event Analysis
- Energy Emergency Alerts
- Generation Availability Database System
- Transmission Availability Database System
- Misoperation Information Data Analysis System
- Historical Summer Load Forecast

Performance analysis information (GADS, TADS, MIDAS) and Event Analysis (EA) data is collected and analyzed by staff for MRO's regional footprint, while the resource and transmission system adequacy reviews are conducted by the Planning Coordinators within each respective area.

BES Event Analysis

MRO staff analyzes major events and system disturbances per the NERC Rules of Procedure Section 800. Using the Event Analysis Process established by the ERO Enterprise (collectively NERC and the Regional Entities), MRO works with registered entities to perform a root cause analysis of the event, develop a brief report, and document recommendations or lessons learned that can be shared with electric power industry stakeholders.

Transmission System Events

Eighteen transmission events occurred on the system in MRO's region from January through December 2023, with five occurring during the 2023 summer months. Equipment failure and protection system misoperations were identified as contributing causes. Protection system misoperations is a leading cause of events across the ERO Enterprise.

To mitigate this risk, MRO published lessons learned and two white papers that address issues related to protection system misoperations identified through the performance analysis and event analysis programs. MRO staff continue to collaborate with industry subject matter experts that serve on the Protective Relay Subgroup (PRS) to reduce protection system misoperations.

Energy Management System Events

There were four Category 1h (loss of monitoring or control at a control center) Energy Management System (EMS) events within the MRO region in 2023, with no event occurring in the summer season. The average duration of 1h events for the year was 48 minutes. A Category 1h event is described as: An event that results in the loss of monitoring or control at a control center such that it significantly affects the entity's ability to make operating decisions for 30 continuous minutes or more. (The NERC Reference Guideline for 1h events can be found at Reference Guideline for Category 1h Events.)

A common factor identified among the EMS events is that they occurred either during or shortly after a routine

[2] Bulk Electric System Definition Reference Document Version 3 August 2018

maintenance procedure.

Figure 3.1 compares the loss of EMS events that took place during the last five years. Each section of the blue bar represents the duration of each event in minutes. The green bar is the average duration of all the events for each year.

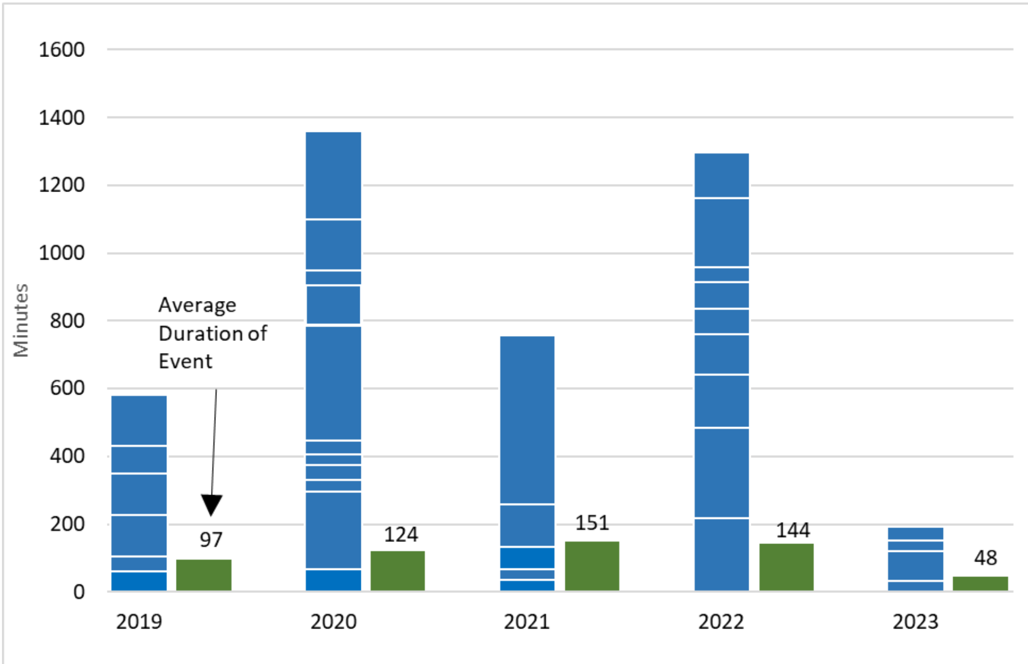


Figure 3.1: Loss of EMS Event Time Duration

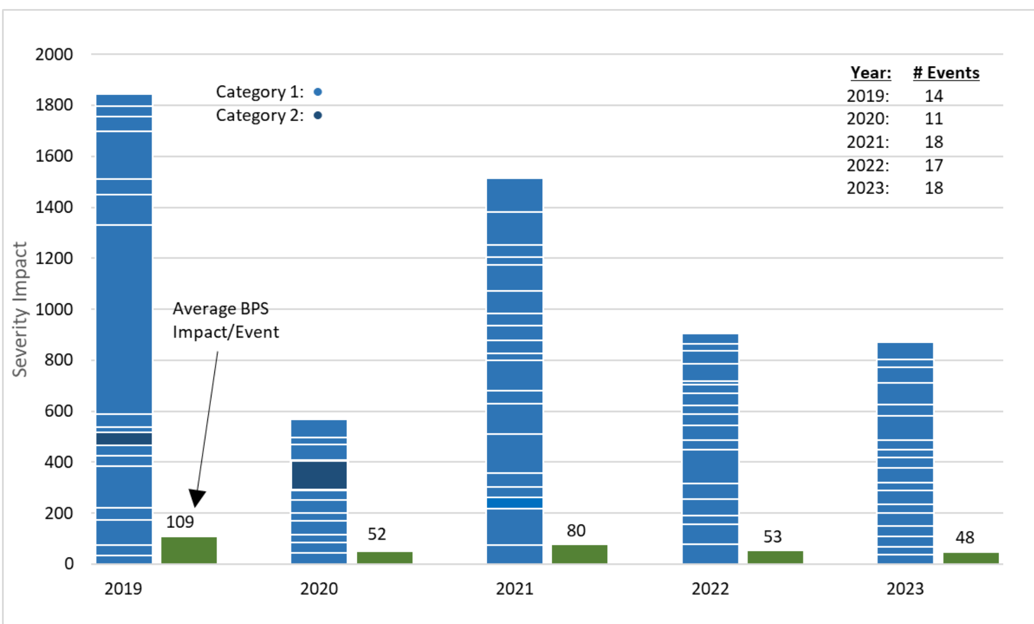


Figure 3.2: MRO Event Severity Index

Figure 3.2 illustrates MRO's Event Severity Index that includes all BES events and allows for comparison of the impact that each event had on the BES. Each section of the bar represents the calculated impact of the event using the number of elements lost, amount of generation lost, and amount of load lost. The green bar is the average annual impact of all events, which MRO uses as a general indicator of how entities are limiting the impacts of events on the BES. MRO's primary focus is to limit large impact events, especially those that may lead to a cascading event or outage.

Below are the event categories included in the Event Severity Index (note the [NERC Addendum for Determining Event Categories] is on NERC's website):

- **Category 1a**: An event that results in an unexpected outage, contrary to design, of three or more BES Facilities caused by a common disturbance.
- **Category 2d:** An event that results in complete loss of off-site power (LOOP) to a nuclear generating station per the Nuclear Plant Interface Requirement.
- **Category 2f**: An event that results in an unintended loss of 300 MW or more of firm load for more than 15 minutes.

A summary of BES events that occurred during the 2023 summer season in MRO's region, including the event category, number of BES facilities lost, MW of generation lost, and MW of load lost, is included in Appendix C.

Historical Event Causes

Figure 3.3 shows the top ten event causes from January 2019 through December 2023 for the MRO region. These causes include event characteristics and attributes associated with BES events, as well as EMS events. This chart indicates that Protection System Misoperation continues to be the top event cause in the MRO region.

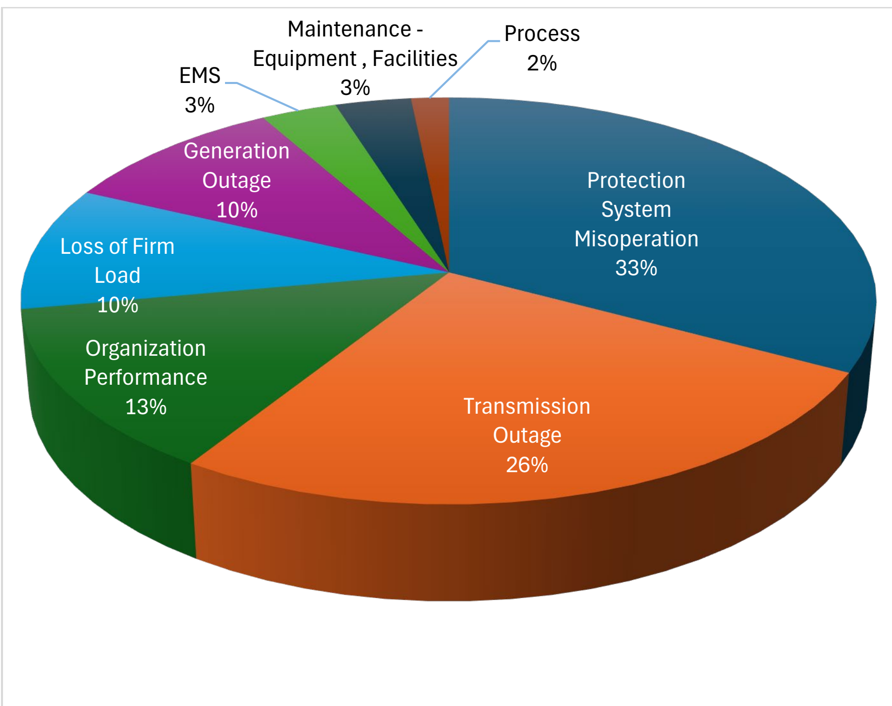


Figure 3.3: Top Event Causes 2019 - 2023

Energy Emergency Alerts

An energy emergency occurs when a load serving entity or Balancing Authority (BA) has exhausted all the resource options and can no longer meet its expected load and operating reserves. Energy Emergency Alerts (EEAs) are issued by the Reliability Coordinator (RC). The current enforceable version of NERC Reliability Standard EOP-011-4 addresses the effects of operating emergencies by ensuring each Transmission Operator (TOP) and BA has developed an operating plan(s) to mitigate operating emergencies, and those plans are coordinated within an RC area. NERC has established three levels of EEAs to ensure all RCs clearly understand potential and actual energy emergencies. More information on EEAs and energy emergency response can be found in the current NERC Reliability Standard EOP-011-4 Emergency Preparedness and Operations.

The MRO region experienced seven EEA level 3 events during the summer of 2023. More detail on these EEA events is included in Appendix C.

Generator Availability

Generating Availability Data System (GADS) is a program that collects information about the performance of electric generating equipment to assist with analyzing generation outages. GADS reporting became mandatory on January 1, 2013, and includes data on more than 8,000 conventional generation units across North America. It is a valuable source of information related to reliability, availability, and maintainability and includes unit design data, monthly performance data (including hours of availability and power produced), and events data. The ERO Enterprise has been capturing wind generation performance data in a separate GADS Wind application since submission became mandatory on January 1, 2018. Beginning in 2024, the wind performance data will move to a new platform that will also capture wind event, as well as solar performance and event data as of the mandatory reporting date of January 1, 2024. Wind turbine outage information and solar data will be included in this report when mandatory and representative data sets are available.

Generation unavailability can have a substantial impact on reliability. Useful metrics for generator unavailability are the equivalent forced outage rates (EFOR)[3] and megawatt Weighted EFOR or (WEFOR)[4]. Long-term trends continue to indicate increasing WEFOR rates due to component fatigue and an aging fleet. Given higher penetrations of intermittent resources, conventional generation is being cycled (ramping up and down) to follow load and operating at minimum output more often, increasing the number of forced outages due to component failures. Additional findings include:

- Increase in 2023 WEFOR was driven in part by difficulties in spring and fall maintenance in 2023 and 2022.

- Event impact decreased substantially year over year, but the summer season was an improvement from the previous year.

- Fossil Steam and Hydro contributed to higher event impacts and increased WEFOR percentages for 2023 summer season but overall have lower impact to the BES.

[3] The hours of unit failure (unplanned outage hours and equivalent unplanned derated hours) given as a percentage of the total hours of the availability of that unit (unplanned outage, unplanned derated, and service hours) - Alexander Eydeland and Krzysztof Wolyniec (2003). *Energy and Power Risk Management*. John Wiley and Sons. p. 109. ISBN 9780471455875

[4] WEFOR measures the probability that a group of units will not meet their generating requirements because of forced outages or forced derates. The weighting gives larger units more impact to the metric than smaller units.

Based on forced outage rates for fossil-steam and simple cycle gas turbines, MRO is closely monitoring the performance (and identifying the failure risk) of these types of resources. Higher forced outage rates of fossil-steam and simple cycle gas could impact generation resource availability during extreme summer peak demand and increase the number and duration of EEA events. Maintaining a robust and reliable fleet of balancing resources is critical to meeting energy needs at all hours and integrating renewable resources.

More details on generation event impacts and summer season forced outage, forced derate, and startup failure causes for certain types of generation are provided in Appendix D.

Transmission Availability

Transmission Availability Data System (TADS) is a program that collects information regarding the availability of AC and DC transmission circuits and transformers operating at 100kV and above. TADS also collects detailed information about individual outage events, that when analyzed both regionally and North American-wide, provides useful data in reliability analyses. An automatic outage results from the automatic operation of a switching device, such as a circuit breaker, causing an element to change from being in-service to not being in-service. Sustained outages for one minute or greater are reported for outages to elements that are operated at 100kV and above. Momentary outages of less than one minute are only reported for elements operated at or above 200kV.

The following summarizes the transmission outages experienced during the summer of 2023.

- TADS-reportable outages were up almost 30 percent from 2022 and are attributed to storms that went through the southern portion of MRO's region, however they were only 2 percent over the 5-year average.
- Lightning was the cause of 38 percent of the momentary outages reported in the summer of 2023.
- Thirty percent of the momentary outages reported in 2023 have an unknown cause, suggesting that thorough line inspections after transient faults are not typically performed after clear weather operations or an inspection is performed, but a definitive cause for the transient faults cannot be determined.
- Failed AC Circuit Equipment was the leading cause of sustained outages at 28 percent for the summer of 2023. Followed by the Other category at 23 percent and Failed AC Substation Equipment at 11 percent.
- A four-day period in the middle of June accounted for 12 percent of the total reported operations for the summer of 2023 as storms went through the southern portion of MRO's region.

Additional information on summer seasonal automatic outages, momentary outages, sustained outages, and historical summer transmission outages per 100 circuit miles are provided in Appendix E.

Protection System Misoperations

A properly functioning protection system is critical for maintaining reliability of the BES. Proper operation of protection systems is instrumental in preventing cascading events and large disturbances. A protection system misoperation is summarized as a failure of a composite protection system to operate as intended for protection purposes (the full definition can be found in the NERC Glossary). The reporting of misoperations allows for causal analysis, overall trending across North America, and an opportunity to improve the effectiveness of mitigation measures. TOs, GOs, and Distribution Providers are required, per the NERC Rules of Procedure Section 1600 data request process, to report protection system operations and misoperations. Reporting is accomplished through the Misoperation Information Data Analysis System (MIDAS). A common measure using MIDAS data is a misoperation rate [(misoperations)/(total operations)], which provides an industry measurement of protection system performance. The annual ERO Enterprise misoperation rate is shown below in Figure 3.4 from the 2023 NERC State of Reliability report.

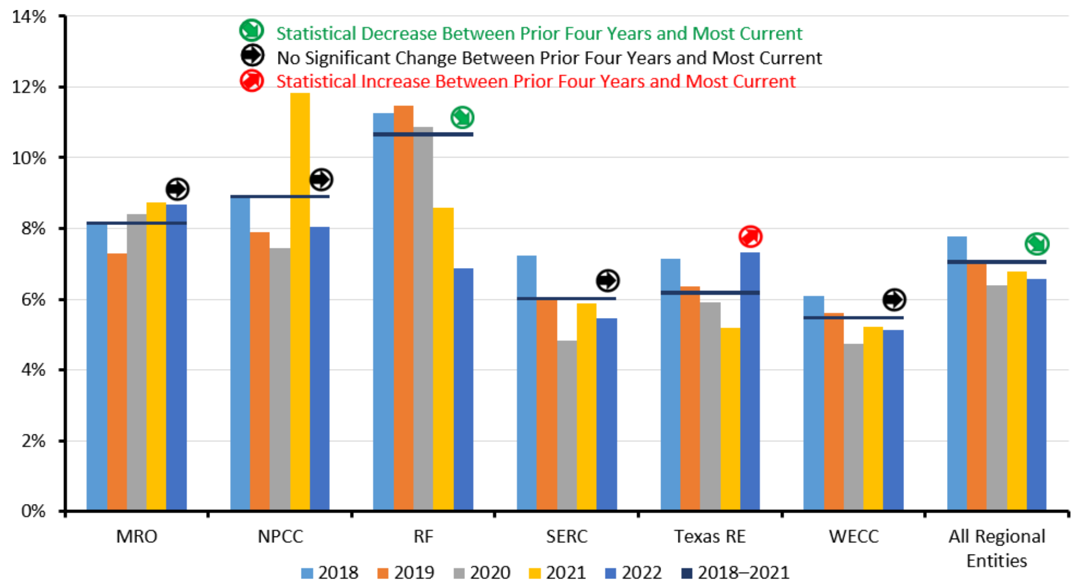


Figure 3.4: Changes and Trends in the Annual Misoperations Rate by Regional Entity

There were 2,920 operations and 240 misoperations reported within the MRO region in 2023 for a misoperation rate of 8.46 percent. Figure 3.5 shows the misoperation rate trending upward until 2021. Since then, the misoperation rate has seen marginal downward improvements each year.

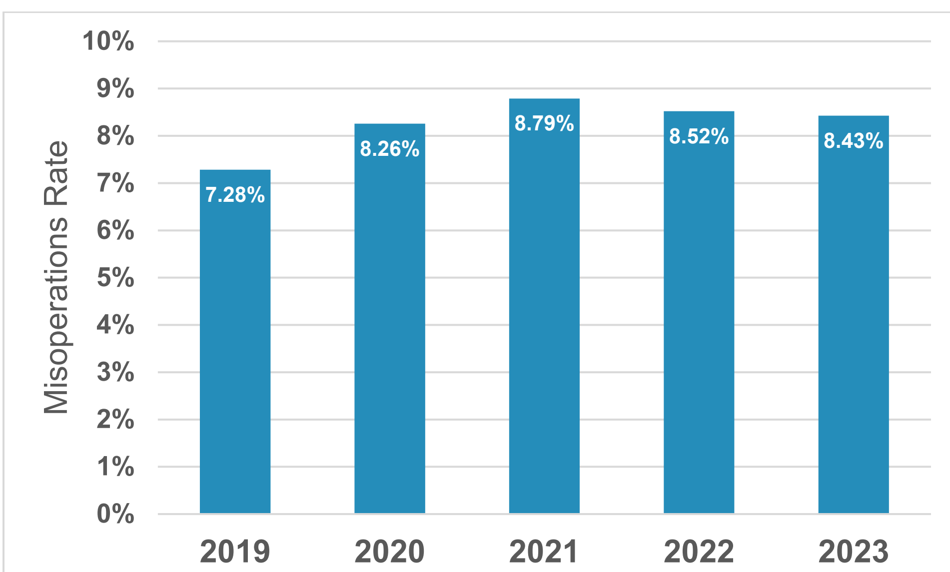


Figure 3.5: MRO Misoperation Rate by Year

Figures 3.6 and 3.7 provide context for the misoperation rate for 2023. Total protection system operations decreased by approximately 11.5 percent in 2023 from the previous year and total misoperations decreased by approximately 12 percent, resulting in a slightly lower misoperation rate. Overall, Figures 3.6 and 3.7 show that 2023 was slightly below the 5-year average for both total operations and misoperations.

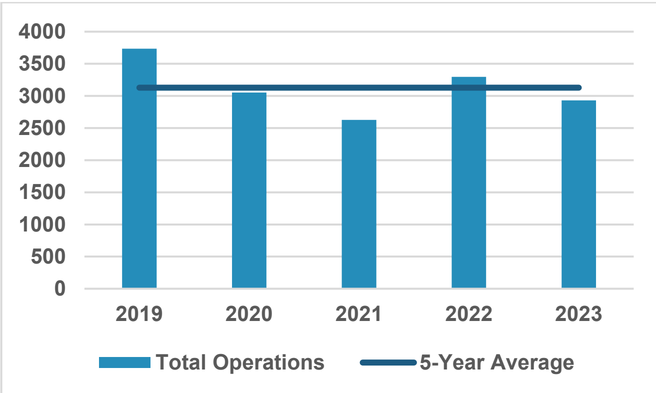


Figure 3.6: Protection System Operations by Year

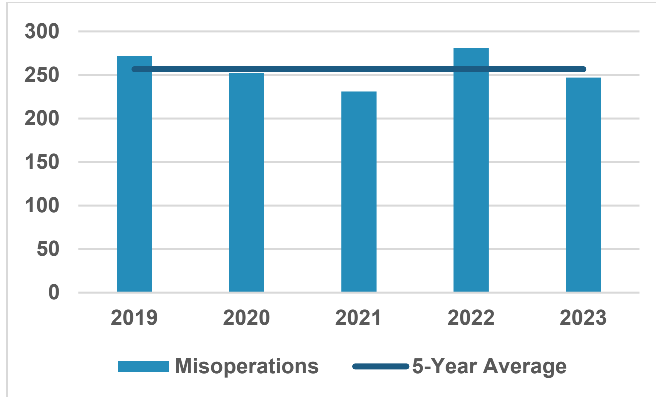


Figure 3.7: Misoperations by Year

MIDAS reports are completed and reported by entities quarterly. The second and third quarters of the year (April 1 through September 30) align closest to the summer season (June 1 through September 30) for this assessment. As shown in Figure 3.8 below, more relay system operations occur on the MRO system in the spring/summer vs. the fall/winter. MRO attributes this disparity to more BES faults caused by stronger and more frequent summer weather events when compared to winter weather.

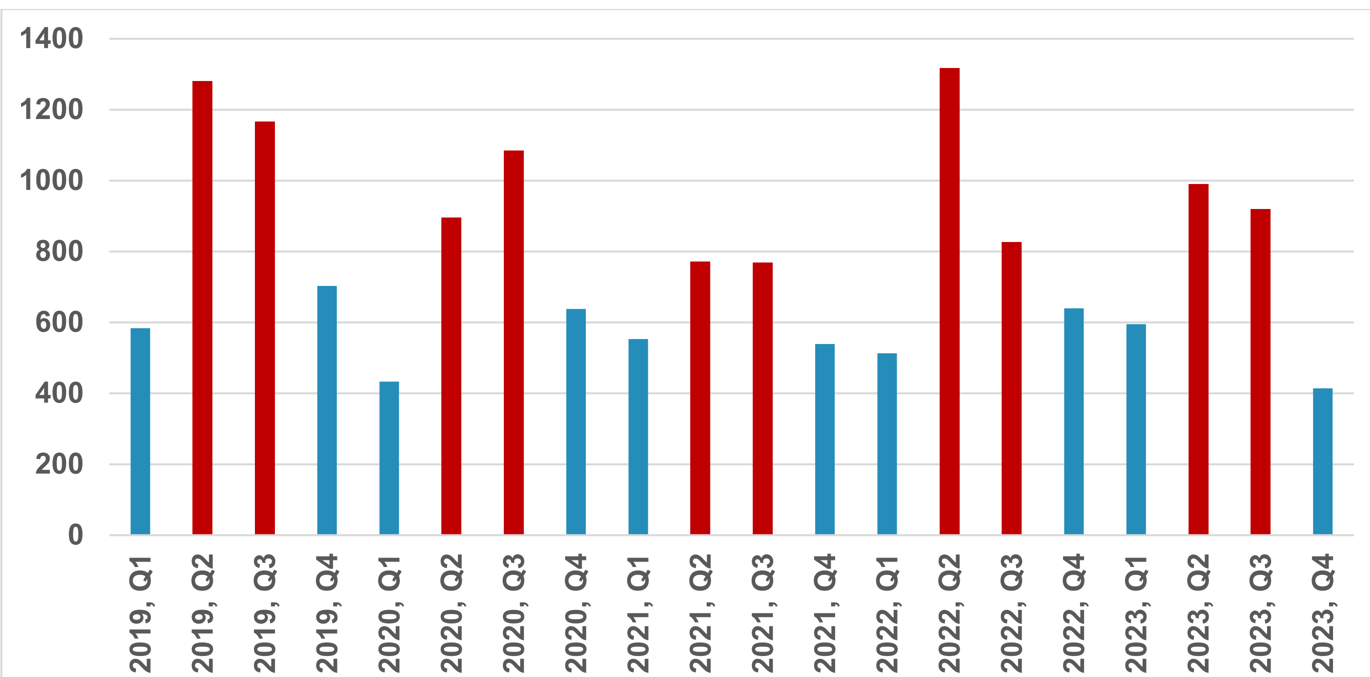


Figure 3.8: Total Operations (Spring/Summer vs. Autumn/Winter)

As shown in Figure 3.9, many misoperations are not associated with a fault. Non-fault associated misoperations have a smaller variance than misoperations associated with a fault and do not vary with the number of correct protection system operations. Therefore, these misoperations would have a larger impact on the overall misoperation rate if the total number of protection system operations is low.

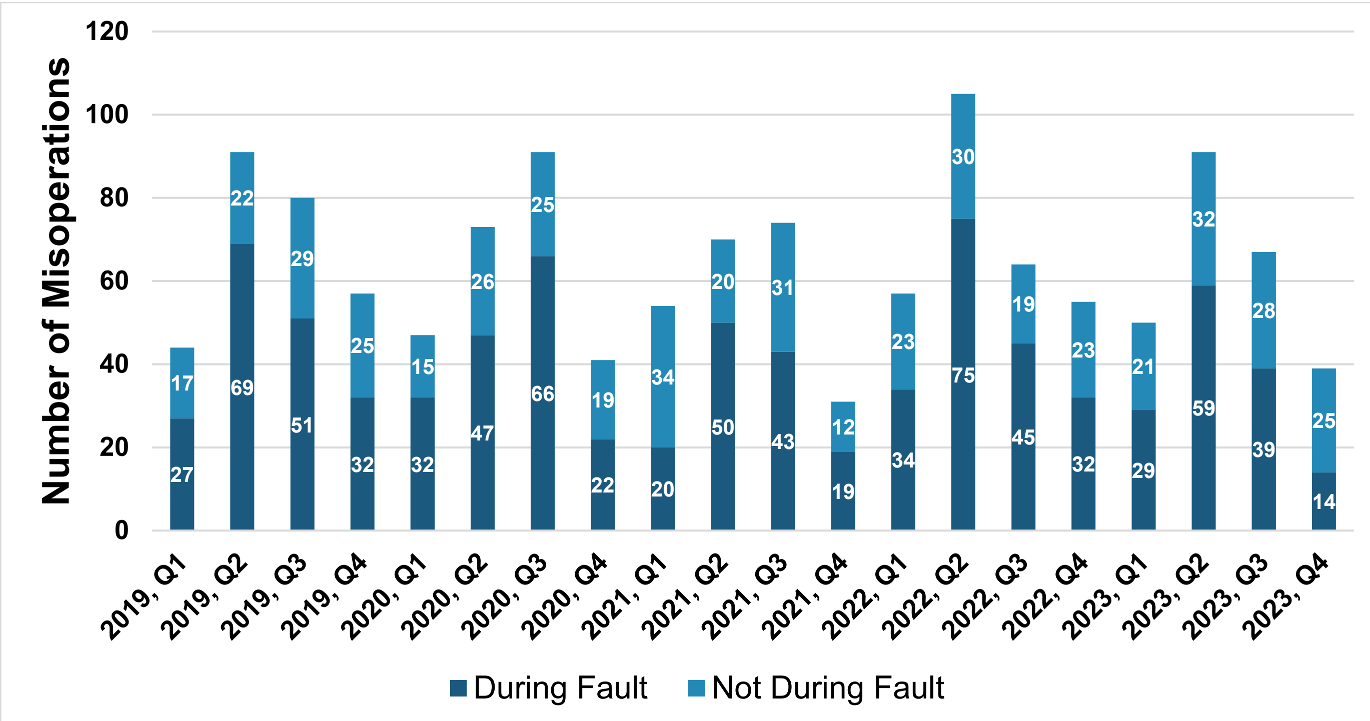


Figure 3.9: Fault Associated and Non-Fault Associated Misoperations

There was a total of 117 misoperations that occurred in the MRO region between June 1, 2023, and September 30, 2023. Examining these misoperations reveals several areas for improvement.

As illustrated in Figure 3.10, of the 117 misoperations that occurred during this timeframe, 44 percent were attributed to human errors (i.e., as-left personnel errors, design errors, incorrect settings, and logic errors) as opposed to equipment failures. Nearly one quarter of misoperations were attributable to incorrect settings alone. This highlights the importance of utilizing a robust system of controls throughout a project lifecycle (design, production, construction, commissioning, and maintenance) to ensure that any human errors are mitigated as much as possible through human performance tools.

Misoperations due to human error was identified as a medium risk in the 2024 MRO Regional Risk Assessment to promote awareness across the region. To address human error-related misoperations, the following actions have been taken or continue to take place:

- Commissioning best practices and challenges are being discussed by MRO's Protective Relay Subgroup, which is an industry-led group comprised of utility companies and MRO staff.

- NERC will host a second annual BES Protection System Misoperation Reduction Workshop at WECC's headquarters on October 1-2, 2024.

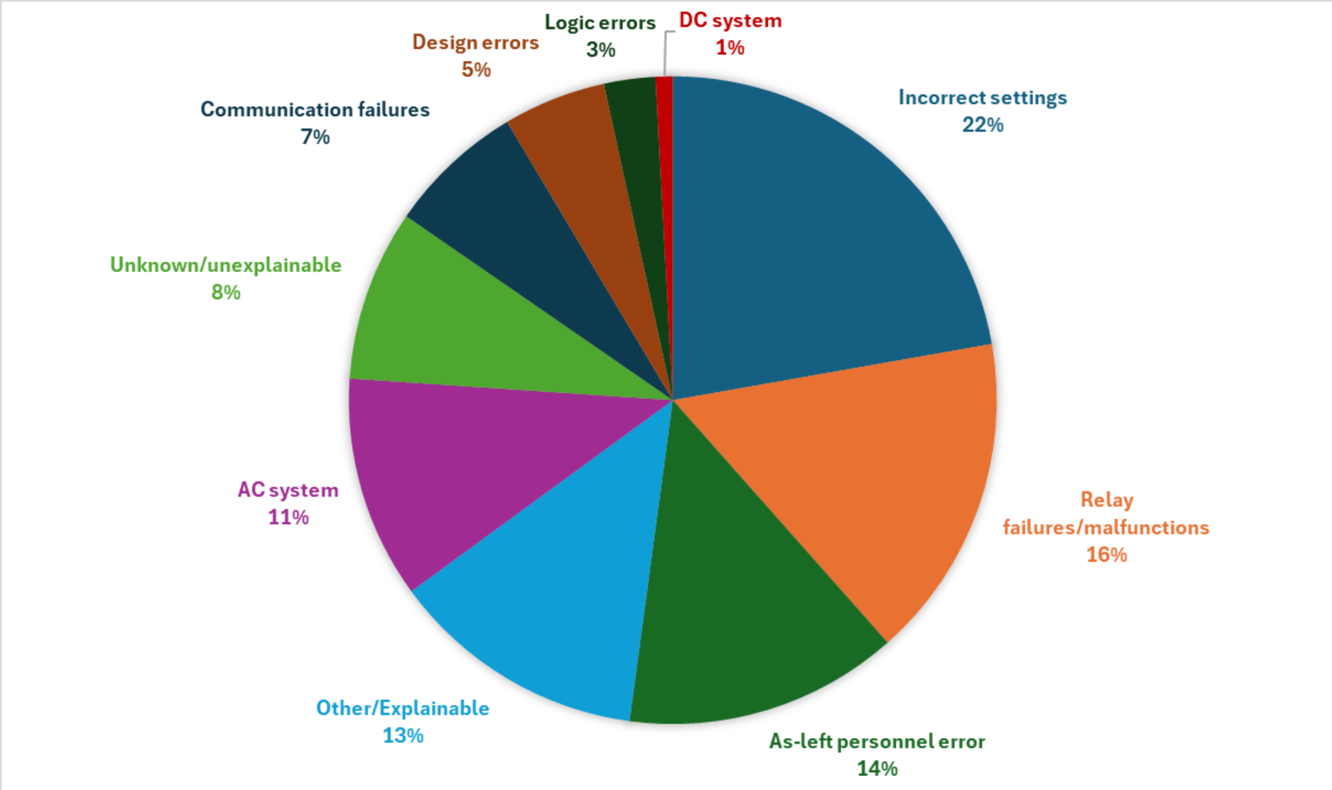


Figure 3.10: Summer 2023 Misoperations by Cause

Historical Summer Load Forecast

To account for weather effects as accurately as possible, entities provide a forecast based on normal weather, or assumed temperatures consistent with approximately the past 30 years of meteorological data. This is also referred to as the 50/50 forecast, which means that each year, the probability of the projected peak load being exceeded is 50 percent, while the probability that the actual peak load would be less than predicted is also 50 percent. A 90/10 forecast is a worst-case, extreme weather scenario that can be reasonably anticipated. It means there is only a 10 percent probability of the projected peak load being exceeded and there is a 90 percent chance that the actual peak load would be less than predicted. In other words, the forecast would be exceeded, on average, only once every ten years.

Figure 3.11 shows the five-year historical summer normal (50/50) and extreme (90/10) forecasts, along with actual and all-time summer peak load for each assessment area in the MRO region.

Figure 3.11: 5-Year Historical Summer Load Forecast

All assessment areas recorded a new all-time summer peak load in 2023, with MISO and SPC entering emergency procedures to manage conditions during extreme heat. MH, MISO, SPC and SPP actual peak demand exceeded the normal and extreme forecast last summer and so these entities are forecasting extreme peak load of 3,333 MW, 125,817 MW, 3,736 MW and 56,344 MW respectively for the upcoming summer peak season. The historical five-year all-time highest summer hourly average demand recorded for each of the MRO assessment areas are as follows:

- MH: 3,529 MW in June 2023
- MISO: 124,900 MW in August 2023
- SPC: 3,669 MW in July 2023
- SPP: 56,184 MW in August 2023

Actual weather conditions that occurred at the time of peak load can then be compared to the forecast weather prediction to determine if any adjustments may be warranted in the forecast peak. This is particularly important for MISO and SPP, whose single BA footprints span from the Canadian border to the Gulf of Mexico and can result in significant weather diversity on any given day.

CHAPTER 4: EMERGING RISKS

Generation Resource Mix

A diverse mix of fuel types is reflected in MRO's 2024 summer peak installed and accredited capacity as shown in Figure 4.1. The largest single contributor of generation by peak capacity in the region is natural gas. Approximately 70 percent of gas plants are in the southern portion of the region. Coal plants and wind turbine generators make up the next largest portions of the generation mix. Conventional generation with large rotating mass (i.e., steam, hydro, and combustion turbine technologies) capable of providing essential reliability services like frequency and voltage support continues to be retired and replaced with renewable generation that either cannot, or has limited capability, to provide these essential reliability services because of design constraints.

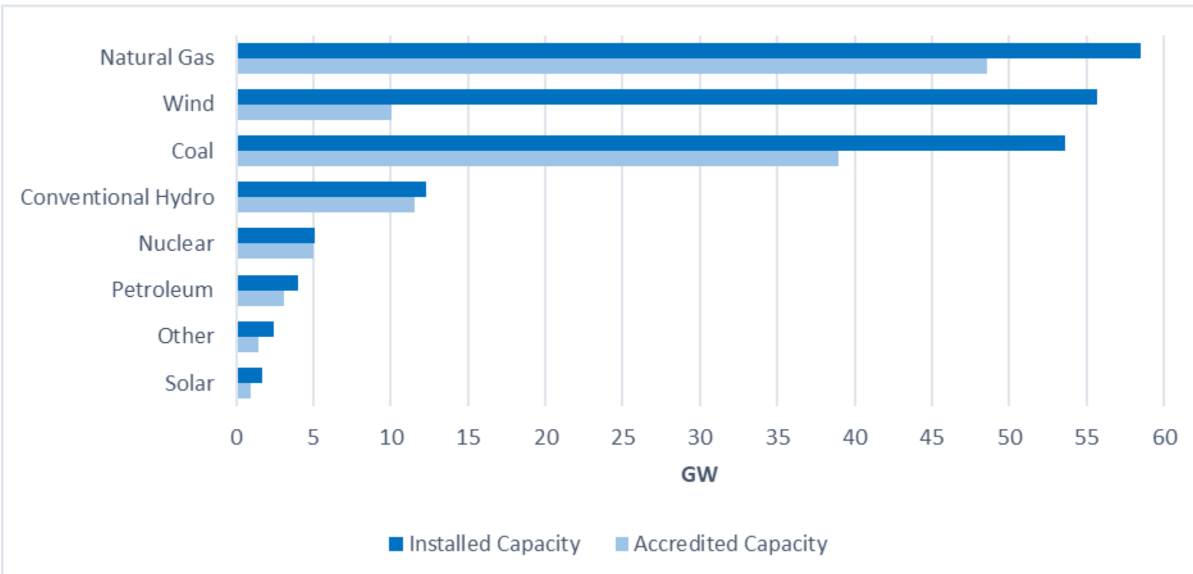


Figure 4.1: MRO 2024 Summer Peak Installed and Accredited Capacity by Fuel Types

Increases in intermittent resources, such as wind and solar, are also contributing to operational complexity in terms of resource commitment and dispatch. Forecasting inaccuracy can result in larger, unanticipated shortfalls or exceedances in real-time operations and ramping changes are also hard to accurately predict.

Wind

There are approximately 56 GW of installed wind capacity in the MRO region, of which 10 GW (18 percent) is accredited for the 2024 summer peak. Multiple proposed projects in the MISO and SPP generation interconnection queue will add approximately 37 GW of installed wind capacity in the MRO region by summer 2033. Operational challenges associated with large amounts of wind include accurately forecasting the output of wind resources, maintenance impacts of conventional resource cycling, and in some older wind turbines, less reactive support capability than comparable conventional generation resources.

Solar

The installation of utility scale solar photovoltaics (PV) generation is accelerating in the MRO region and is projected to become the second most prominent renewable source after wind. Approximately 36 GW of proposed solar projects exist in the MISO and SPP generation interconnection queue for installation by summer 2033 in the MRO region. Solar resources create additional operational challenges while preparing for daily ramping changes at sunrise and sunset. It is important to note that not every wind and solar project in the interconnection queue will be built, as some requests may be withdrawn after a system impact study. A system impact study establishes necessary transmission upgrades that may be needed before a project can connect to the bulk power system.

Summary of Risk

The move away from conventional generation to intermittent resources requires BAs to have capacity available that can ramp quickly and respond to change in output from intermittent resources. Existing steam units do not typically have high ramp rates, especially those that were designed as base load units. Furthermore, the units were not designed to be cycled to the extent they are today, which can lead to higher forced outage rates and additional maintenance requirements. These factors increase the risk of having insufficient resources to serve load during periods when the actual output of renewables is significantly less than forecasted. This creates a challenge for control room operator awareness and decision-making processes, especially during periods of high uncertainty in intermittent resource output and significant ramping. It also forces BAs to carry additional operating reserves to account for forecast uncertainty associated with wind and solar resources and load forecasting errors.

With increased penetration of intermittent resources and retirement of conventional resources, planned outages of conventional generating units are more difficult to schedule. With the higher uncertainty of output of intermittent resources, a BA is more dependent upon conventional resources to be available to respond during more of the off-peak periods. This reduces the number of resources that can perform planned outage work while at the same time reliably serving load. This, coupled with the increased maintenance requirements driven by more frequent ramping of conventional units, makes it more challenging to serve load.

CHAPTER 5: SUMMARY

Focus Areas for 2024 Summer

The following focus areas represent MRO's independent evaluation of the generation and transmission system for the 2024 summer season, as well as potential operational concerns that should be considered during this same timeframe:

- MISO and SPC are at risk of implementing Energy Emergency Alerts (EEAs) if above-normal summer peak load coincides with unplanned outages conditions like those observed last summer.

- MISO and SPP face risks of electricity supply shortfalls during periods of more extreme summer conditions with historic high outage rates and low wind resource output.

- With increased penetration of wind and solar in the MRO region, performance of wind and solar generation during periods of high demand is a key factor in determining whether there is sufficient electricity supply on the system.

- Conventional generation Weighted Equivalent Forced Outage Rates (WEFOR) for 2023 were once again higher than the five-year moving average. Long-term trends continue to indicate increasing generation forced outage rates due in part to higher penetrations of intermittent resources that result in conventional generation cycling more than originally designed, causing component failures.

- Protection system misoperation continues to drive major events in the MRO region. Human error-related misoperations accounted for nearly half of last summer's total misoperations, and nearly one quarter of this was attributable to incorrect relay settings.

APPENDIX A: REGISTRATION AND CERTIFICATION

Registration

There are approximately 245 entities registered in the MRO region (NERC Compliance Registry (NCR)) as of the date of this publication. These users, owners and operators of the bulk power system are deemed material to reliability because they meet specific criteria or perform certain functions. The number of registered entities on the NCR fluctuates with the addition of new entities and/or changes to existing entities' operational structure and functions. Which mandatory NERC Reliability Standards and requirements are applicable depends on how an entity is registered and the functions it performs. This information is also fundamental to reliability assessments in that certain functions pose greater risk to reliability of the bulk power system.

The functional relationships identified in the NERC Rules of Procedure, Reliability Standards, and important entity relationships are part of an entity's registration record. All Balancing Authorities (BA) and Transmission Operators (TOP) are required to be under the responsibility of one Reliability Coordinator (RC). Transmission facilities must be the responsibility of one Transmission Planner (TP), Planning Coordinator (PC) and TOP. Loads and generators shall be the responsibility of one BA. RCs, BAs, TOPs, along with Generator Owners (GOs) and Generator Operators (GOPs), have an important role in maintaining reliability during normal and complex weather operations. These entities provide accurate operational data for ERO event analysis. Generator modeling data provided by GOs and GOPs utilized by TOPs, BAs and RCs is critical for use in operations planning and real-time analysis of the bulk power system.

There has been little registration growth over the past five years in all functions except GO and GOP. The increase in entities registered as GOs and GOPs is due to the decline of vertically integrated utilities and the deregulation of the supply side of the industry, combined with an increase in renewable resources. With the increasing integration of Inverter Based Resources (IBRs), new NERC registration criteria have been established to register owners and operators of BPS-connected IBRs with a nameplate rating of 20MVA or more. The registration of candidates is scheduled to begin in May 2025 per the NERC Inverter Based Resources Work Plan, IBR Registration milestones. NERC's analysis of the 2022 U.S. Energy Information Administration (EIA) data identified over 80 BPS-connected IBR assets meeting the proposed criteria in the MRO region.

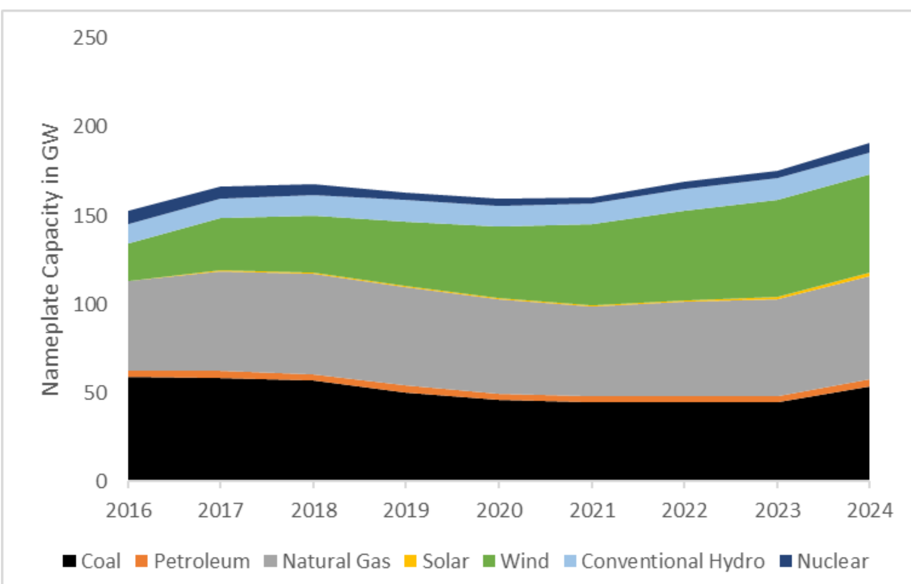


Figure AA1: MRO Historical Resource Mix by Fuel Types

Certification

Real-time actions of RCs, TOPs, and BAs impact the reliable operation of the bulk power system. ERO Enterprise Certification activities provide regional assurance that the processes, procedures, tools, and training a registered entity uses to perform its functions have the capacity to meet the reliability obligations of its registration. Material changes to already certified and operational registered entities require a certification review by the Regional Entity. The decision to certify changes to an already operating and certified registered entity is a collaborative decision between MRO and NERC. MRO averages five certification review activities per year and anticipates one certification, initiated in 2024/early 2025. This seasonal reliability assessment directly focuses on RCs, TOPs, and BAs, and was developed based on data collected during performance analysis, event analysis, and situational awareness activities, providing insights on the performance of BES elements.

APPENDIX B: 2024 SUMMER SEASONAL FORECAST

The 2024 summer seasonal forecast includes the months of June 2024 through September 2024.

Anticipated Summer Resource and Peak Demand Scenario

Peak demand (or load) is the highest electrical power demand that occurs over a specific period and is typically characterized as daily, seasonal, or annual. The changes in demand levels are generally predictable and have daily, weekly, and seasonal patterns. The annual peak of hourly, daily, and monthly demand typically occurs during the summer or winter due to higher cooling or heating needs. Figure AB1 illustrates the 2024 anticipated, and the eight-year historical, generation by fuel type at the time of summer peak for each of the PCs in the MRO region:

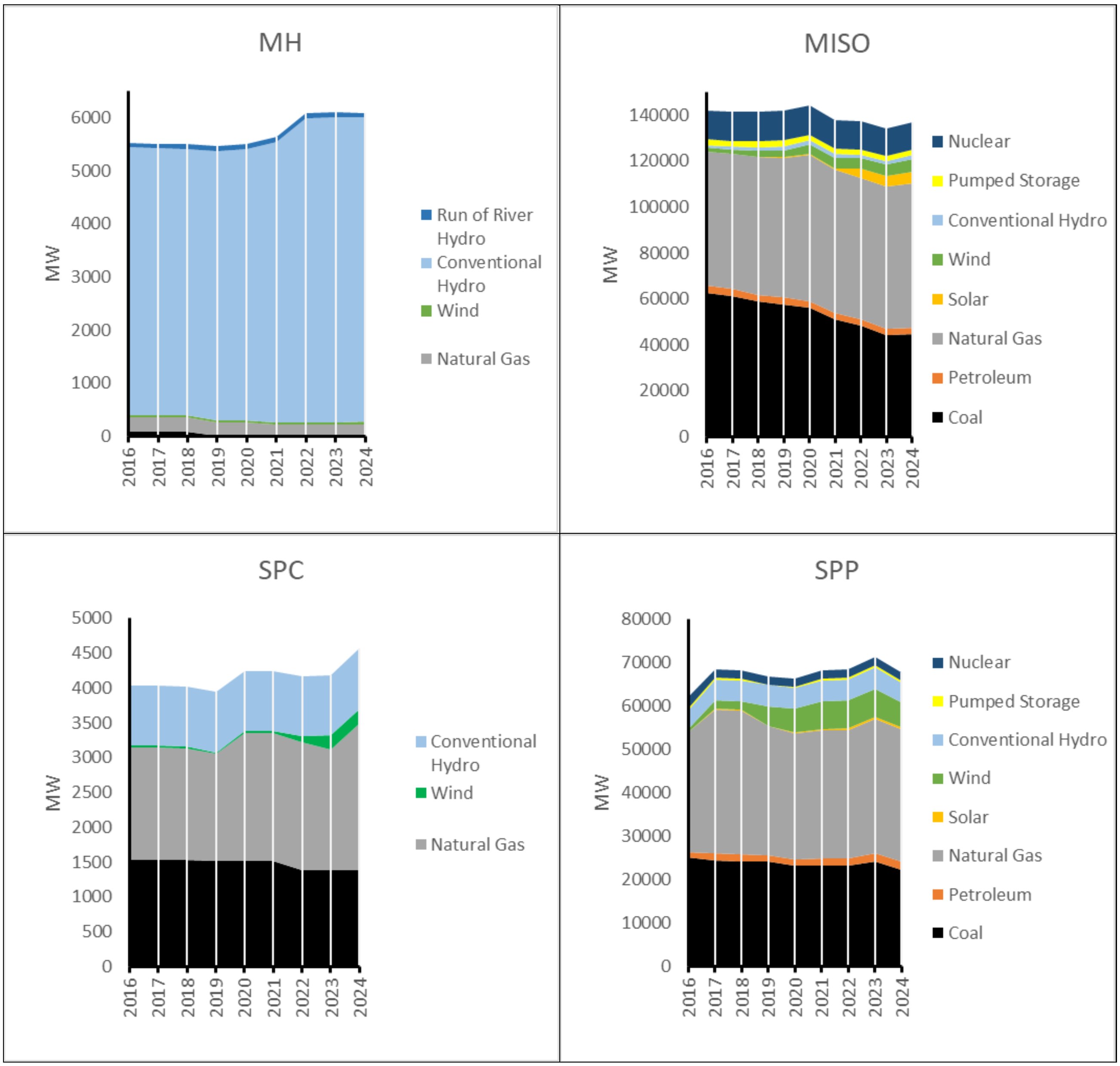


Figure AB1: Generation by Fuel Type at Time of Summer Peak

Each PC has a different resource mix. While MH is predominantly conventional hydro, the resource mix in MISO, SPC, and SPP consists primarily of coal and natural gas with increasing amounts of wind in MISO and SPP. Because intermittent resources like wind and solar are weather dependent, forecasted on-peak wind and solar capacity contributions are based on historic average values and can be substantially less than Installed Capacity[5] (ICAP). MISO and SPP wind and solar capacity accreditation is significantly lower than the total existing ICAP values for this reason. As penetration of intermittent resources increases, forecast errors in the output of intermittent resources available in the short-term (hours or days) can have greater impact. Balancing Authorities may need to increase operating reserves to account for the uncertainty in short-term resource output.

Rooftop solar, battery storage, and other distributed, behind-the-meter generation resources are having a dramatic impact on the load shape and the ability to forecast net demand (total demand less behind the meter resource output). When coupled with the anticipated increase in demand (e.g., electric vehicle charging, cryptocurrency, hydrogen production, and other electrification efforts), future load forecasts and patterns will likely change dramatically from what they are today.

Fossil-steam, gas, and petroleum generating plant cooling systems are less effective when cooling water input temperatures are higher. This can lead to reduced output in the summer months. The increase in cooling water temperatures and low river water levels that can occur in summer may impact generators with once-through cooling, thereby reducing output capability. Environmental limitations on discharge temperatures can lead to similar restrictions. The extreme peak demand scenarios in Tables AB3 and AB4 examine how extreme or prolonged hot temperatures over a large area could impact the generation resource adequacy. Resources throughout the extreme scenarios are compared against expected reserve margin requirements based on peak load and normal weather. The effects from low-probability events are also factored in through additional resource derates. For example, maximum historical outages minus the average of both maintenance and forced outages for non-intermittent resources or low-output scenarios (such as a wind resource output adjustment due to low-wind), and additional load based on extreme weather conditions.

The 90/10 peak load weather forecast methodology is used to model the reliability risk of the actual system peak exceeding the forecasted 50/50 peak load due to load forecast uncertainty. This traditional methodology and assumption are used by the industry to ensure energy availability through increased dispatchable resources capacity, and to assure adequate resources during higher than anticipated peak demand. However, recent increases in extreme weather events and unavailability of energy during off-peak hours (e.g., low wind production) present new challenges, in part due to the retirement of dispatchable resources and the rapid growth of fuel sources that are weather dependent and inherently less predictable (like wind and solar). As a result, a new ERO Enterprise energy availability initiative is underway to review existing forecast methodology and assumptions and identify metrics and criteria for adequate energy assessments. The Energy Reliability Assessment Working Group (ERAWG) will assess the risks associated with unassured energy supplies, including the timing and inconsistent output from intermittent resources, fuel location, and volatility in forecasted load that can result in insufficient amounts of energy on the system to serve electrical demand. The electric power industry needs to develop new and enhanced forecasting methods and new metrics to evaluate energy availability that provides reliable and secure operations of the bulk power system at all times.

The summer seasonal risk scenario, which includes the cumulative impact of the occurrence of multiple low-probability events, is lower than the winter season due to better predictability of load and generation availability

[5] The maximum amount of capacity a generator can produce. ICAP can be considered in two different ways: Nameplate capacity rating in MW or seasonal net dependable capacity rating that accounts for ambient temperatures and humidity during the season.

during the summer season. The following definitions are used for the risk scenario analysis:

- **Anticipated Resources**: Existing resources plus Net Firm Transfers plus Planned resources.
- **Typical Maintenance Outages:** Historical average of generator maintenance outages for specified period/conditions, (e.g., average of maintenance outages for June through September weekdays, over the past three years) or area-specific methodology for determining anticipated maintenance outages.
- **Typical Forced Outages:** Historical average of forced generator outages for a specified period/conditions (e.g., average of forced outages for June through September weekdays, over the past three years), or area-specific methodology for determining anticipated forced outages for non-intermittent resources (e.g., thermal, hydro).
- **Normal Peak Load**: Peak hour demand forecast based on normal weather. This is also referred to as the 50/50 peak load forecast.
- **Reserve Margin**: The amount of generation capacity available above projected load to reliably meet expected demand.
- **Extreme Resource Derates:** Reduced capacity contribution due to generator resource performance in extreme conditions (e.g., temperature-based derates; or based on severe historical events).
- **Extreme Peak Load:** Sum of Normal Peak Load and seasonal load adjustment on extreme weather conditions (e.g., 90/10 peak load forecast; or based on severe historical events).
- **Extreme Low Generation**: Anticipated Resource minus Typical Forced Outages and Extreme Derates.

Several risk factors and criteria are used when determining the risk levels (low, medium, and high) if an assessment area is likely to issue EEAs. This includes meeting the reference margin levels, the loss of load expectation and the availability of sufficient operating reserve under normal and extreme peak demand.

The anticipated resources for conventional generators are based on the ICAP, which represents physical generating capacity adjusted for ambient weather conditions while intermittent renewables, such as wind and solar, capacity contributions are based on historic average values. Table AB2 displays anticipated reserve margins with normal peak load projections for each assessment area. The normal peak load projections are based on 50/50 weather forecasts and are provided on a coincident[6] basis for the assessment areas. MH, MISO, SPP and SPC have sufficient resources to meet their PRMR under normal peak summer conditions.

Assessment Area	Anticipated Resources	Normal Peak Load	Anticipated Reserve Margin	PRMR	Likelihood to issue EEAs
MH	3,637	3,143	**15.7%**	12.0%	**Low**
MISO	146,337	116,079	**26.1%**	17.7%	**Low**
SPC	4,613	3,540	**30.3%**	15.0%	**Low**
SPP	70,698	55,337	**27.8%**	19.0%	**Low**

Table AB2: Anticipated Reserve Margin Percentage with Normal Peak Load

While MISO, SPC and SPP anticipate reserve margins that reflect robust amounts of excess capacity, there is still potential risk of energy shortfall based on past performance during extreme weather events. Based on the

[6] Sum of two or more peak loads that occur in the same hour.

normal peak load forecast with typical maintenance and forced outage scenario shown in Table AB3, MH, MISO, SPC and SPP have sufficient resources to meet their operating reserve requirements under normal peak summer conditions with typical maintenance and forced outages.

Assessment Area	Anticipated Resources	Typical Maintenance and Forced Outages	Anticipated Resources with Typical Outages	Normal Peak Load	Anticipated Reserve Margin with Typical Outages	Likelihood to issue EEAs
MH	3,637	125	3,512	3,143	**11.7%**	**Low**
MISO	146,337	20,175	126,162	116,079	**8.7%**	**Low**
SPC	4,613	134	4,479	3,540	**26.5%**	**Low**
SPP	70,698	5.640	65,058	55,337	**17.6%**	**Low**

Table AB3: Reserve Margin Percentage with Typical Outages and Normal Peak Load

The scenario shown in Table AB4 considers typical maintenance and forced outages combined with extreme summer peak load forecast. For this scenario, MH, MISO, SPC and SPP have sufficient resources to meet operating reserve requirements under extreme peak summer conditions with typical maintenance and forced outages. Even though SPC has sufficient resources to meet operating reserve requirements under extreme peak summer conditions with typical maintenance and forced outages, SPC is likely to issue EEAs due to conditions like those observed during the 2023 extreme hot weather. SPC's anticipated reserve margins remained the same for this summer to that of last year. While MH reserve margin is more than 50 percent below its PRMR, it is still above the operating reserve requirements.

Assessment Area	Anticipated Resources with Typical Outages	Extreme Peak Load	Reserve Margin Under Extreme Peak Load	Likelihood to issue EEAs
MH	3,512	3,333	**5.4%**	**Low**
MISO	126,162	125,817	**0.3%**	**Medium**
SPC	4,479	3,736	**19.9%**	**Medium**
SPP	65,058	57,537	**13.1%**	**Low**

Table AB4: Reserve Margin Percentage with Typical Outages and Extreme Peak Load

The worst-case scenario for summer 2024 considers increased resource outages and derates combined with an extreme peak load forecast as shown in Table AB5.

Assessment Area	Anticipated Resources with Typical Outages	Extreme Resource Derates	Extreme Low Generation	Extreme Peak Load	Reserve Margin Under Extreme Resource Derates and Extreme Peak Load	Likelihood to issue EEAs
MH	3,512	10	3,502	3,333	**5.1%**	**Low**
MISO	126,162	8,228	117,934	125,817	**-6.3%**	**High**
SPC	4,479	359	4,120	3,736	**10.3%**	**High**
SPP	65,058	8,975	56,083	57,537	**-2.5%**	**High**

Table AB5: Reserve Margin Percentage with Extreme Resource Derates and Extreme Peak Load

The extreme low generation in Table AB5 shows that MISO and SPP resources fall below the extreme peak load, due to extreme hot weather-related generation outages and derates. Under the extreme summer peak demand and high generation outage scenario studied, MISO, SPC and SPP would likely need to issue EEAs for operational procedures and/or emergency procedures, which may include demand response, non-firm purchases, and/or short-term load interruption. This worst-case scenario has much higher than expected generation outages and derates when combined with prolonged hot weather.

Wind and Solar Resources

MISO and SPP continue to see an increase in wind and utility scale solar photovoltaic penetration in the region. Figure AB6 reflects the summer season wind and solar photovoltaic ICAP and peak capacity for each of the assessment areas. The peak capacity value is the accredited Effective Load Carrying Capability (ELCC) amount of wind or solar available during the period of peak demand. ELCC is defined as the amount of incremental load a particular type of resource, such as wind or solar, can dependably and reliably serve, while also considering the probabilistic nature of generation shortfalls and random forced outages. The ELCC amount also varies with the resource mix of the system being evaluated. This results in decreasing ELCC values as renewable penetration becomes higher and conventional resources are retired, at times much lower than the ICAP value.

MISO's seasonal capacity construct has resulted in slightly lower wind availability and higher solar peak capacity for the upcoming summer peak season. With all solar units having a 50 percent accreditation, the individual ICAP values are also slightly higher than in years past.

SPP is calculating wind and solar based on accredited capacity of SPP balancing authority areas during peaks and is assuming 5,875 MW wind and 486 MW solar availability for the 2024 summer.

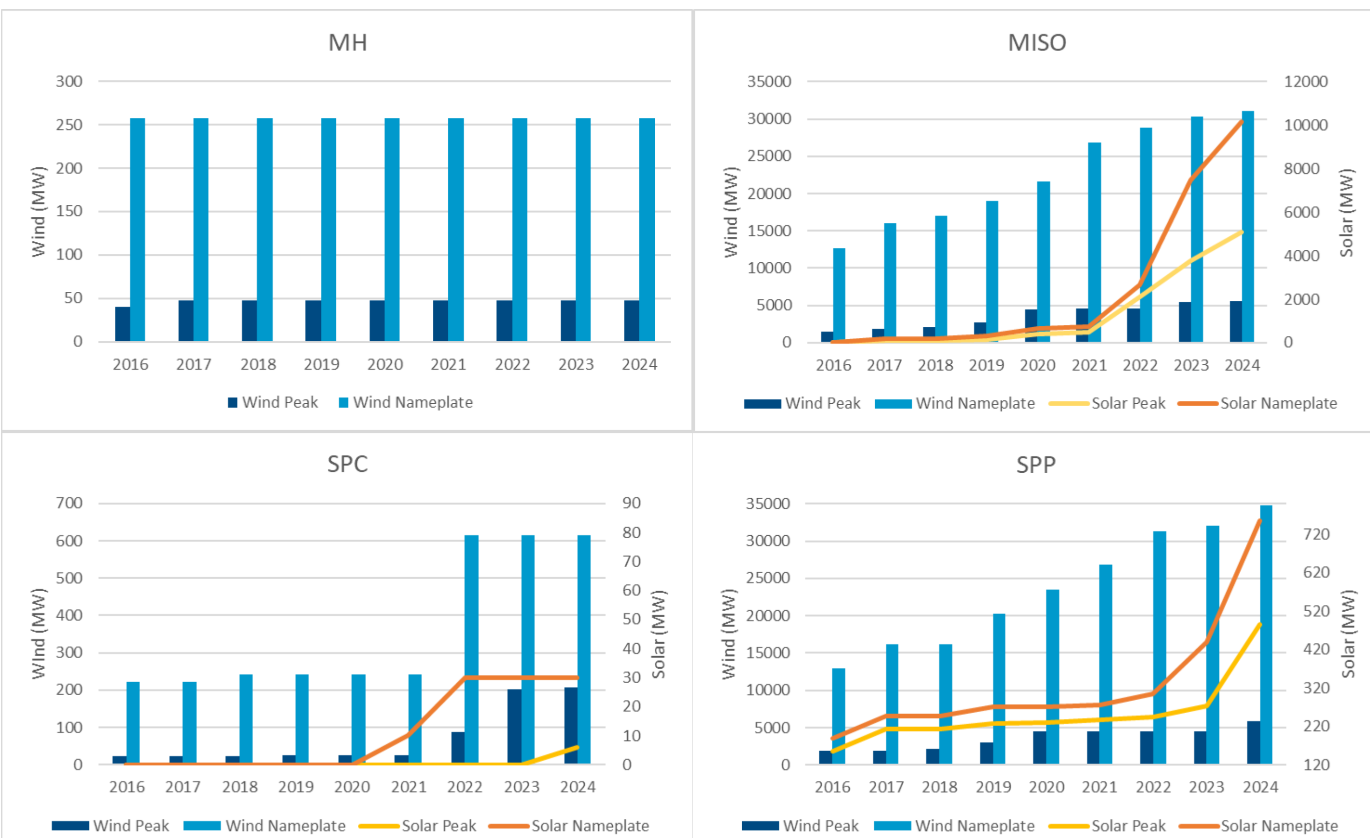


Figure AB6: Wind and Solar Photovoltaic Summer ICAP and Peak Capacity

The rapid growth of inverter-based resources (IBR) is the most significant driver of grid transformation and poses a high risk to bulk power system reliability. Currently there are approximately 56 GW of installed wind and 2 GW of solar capacity registered in the MRO region based on the existing NERC registration criteria of 75 MVA and above. With the new NERC registration criteria for IBRs with nameplate rating of 20 MVA or more will result an increase in existing and future wind and solar capacity in the MRO region. Bulk power system-connected wind and solar are growing at an unprecedented rate in the MRO region and could reach as much as 127 GW combined by 2033 and continues to challenge grid planners and operators.

When implemented correctly, inverter technology can provide significant benefits for reliability of the power grid. However, the new technology can introduce significant risks if not integrated properly. IBR performance issues, such as momentary cessation, unwarranted inverter or plant-level tripping issues, controller interactions and instabilities, and other critical performance risks such as low wind or cloud covers can have significant impact to reliability of the bulk power system.

APPENDIX C: 2023 BES EVENT AND EEA DETAILS

July 7, 2023, Transmission Event

Event Category: 1.a

- 3 BES Facilities Interrupted
- 10 MW of Generation Lost
- No MW of Load Lost

While a severe thunderstorm was rolling through the area, a transmission line fault occurred on the entity's 345kV system locking out the line at both ends due to a structure on the ground.

At the same time, a 345/230kV transformer and a 161 MW wind farm tripped out of service due to a logic settings issue in the breaker failure scheme on the faulted 345kV line.

Relay settings were corrected to mitigate this issue.

July 28, 2023, Transmission Event

Event Category: 1.a

- 6 BES Facilities Interrupted
- No MW of Generation Lost
- No MW of Load Lost

A 230kV line relayed and failed to reclose. The event occurred following manual open command to a 230kV breaker during maintenance activities. One of the phases on the breaker failed to open due to mechanical failure. This created exceedingly high voltages at the facility, tripping out four 230kV transmission lines, a 230/345kV transformer and a 230kV/115kV transformer.

The damaged equipment was isolated, and the system was restored in under five hours.

August 2, 2023, Transmission Event

Event Category: 1.a

- 3 BES Facilities Interrupted
- No MW of Generation Lost
- No MW of Load Lost

A 230kV bus tripped via overvoltage relay causing multiple 230kV BES outages. The overvoltage relay had been tested and calibrated the previous day, but misoperated on the day of the event causing the initiating trip. Three 230kV transmission lines and 230kV bus were de-energized during this event.

The relay was taken out of service and replaced.

<u>August 23, 2023, Transmission Event</u>

Event Category: 1.a

- 3 BES Facilities Interrupted
- No MW of Generation Lost
- No MW of Load Lost

During a severe thunderstorm, an entity converter station began automatically switching reactive devices, going from absorbing megavars (MVARs) to supplying MVARs in a short span of time. This resulted in several protection operations and multiple BES outages. Two 230kV transmission lines, a 230kV bus a 230/115kV transformer and a 115kV bus were all de-energized during this event.

The cause of the event was not yet determined at the time of this publication.

<u>August 29, 2023, Transmission Event</u>

Event Category: 1.a

- 6 BES Facilities Interrupted
- No MW of Generation Lost
- 19 MW of Load Lost

A 115kV breaker tripped out of service during switching due to an incorrect relay setting. With the parallel path removed by the opened breaker, the opening of a 115kV switch caused an arc. Relay protection operated correctly to clear this fault, de-energizing four 115kV lines, a 115 kV bus, a 115kV GSU transformer and 19 MW of load.

Lack of coordination created by the switching program was identified as a root cause and appropriate relay settings were corrected to mitigate the issue.

<u>June 7, 2023 – EEA Level 3 Event</u>

A 630 MW coal fired power plant was offline due to cooling water flooding that occurred on June 2. The system was experiencing higher than expected system loading due to the hot and humid temperatures. These high temperatures meant that some of the gas and coal fired power plants were experiencing higher than anticipated derates and there were additional, unexpected, forced outages for a total of approximately 754 MW. The RC's wind production was low, approximately 37 MW, and they were importing 261 MW and 86 MW from their neighbors. The RC's peak load was 3,395 MW.

The RC notified several customers to curtail their production (approximately 24 MW of total load relief). The RC also notified a gas power plant to begin 'duct burn' which allowed approximately 5 MW more power to be produced. Wind power did increase approximately 50 MW which helped increase the operating reserves. With these load curtailments, their operating reserves were able to recover.

No firm load was shed during this event.

June 12, 2023 – EEA Level 3 Event

A 630 MW coal fired power plant was offline due to cooling water flooding that occurred on June 2. The system was experiencing higher than expected system loading due to the hot and humid temperatures. These high temperatures meant that some of the gas and coal fired power plants were experiencing higher than anticipated derates. There were additional, unexpected, forced outages for a total of approximately 734 MW as well as an additional 42 MW of unplanned generation offline. The RC's wind production was very low, approximately 10 MW, and they were importing 241 MW and 90 MW from their neighbors. The RC's peak load was 3,498 MW.

The RC notified several customers to curtail their production (approximately 114 MW of total load relief). With these load curtailments, their operating reserves were able to recover. No Firm load was shed during this event.

July 24, 2023 – EEA Level 3 Event

A 630 MW coal fired power plant was offline due to cooling water flooding that occurred on June 2. The system was experiencing higher than expected system loading due to the hot and humid temperatures. These high temperatures meant that some of the power and coal fired power plants were experiencing higher than anticipated derates. There were additional, unexpected, forced outages for a total of approximately 1,527 MW as well as an additional 42 MW of unplanned generation offline. The RC's wind production was very low, approximately 33 MW, and they were importing 280 MW and 90 MW from their neighbors. The RC's peak load was 3,777 MW.

The RC notified several customers to curtail their production (approximately 122 MW of total load relief). With these load curtailments, their operating reserves were able to recover. No Firm load was shed during this event.

July 31, 2023 – EEA Level 3 Event

A 630 MW coal fired power plant was offline due to cooling water flooding that occurred on June 2. The system was experiencing higher than expected system loading due to the hot and humid temperatures. These high temperatures meant that some of the gas and coal fired power plants were experiencing higher than anticipated derates and there were additional, unexpected, forced outages for a total of approximately 1,593 MW. The RC's wind production was low, approximately 33 MW, and they were importing 319 MW and 89 MW from neighboring RCs. The RC's peak load was 3,360 MW.

The RC notified several customers to curtail their production (approximately 43 MW of total load relief). With these load curtailments, their operating reserves were able to recover.

No Firm load was shed during this event.

August 2, 2023 – EEA Level 3 Event

A 630 MW coal fired power plant was offline due to cooling water flooding that occurred on June 2. The system was experiencing higher than expected system loading due to the hot and humid temperatures. These high temperatures meant that some of the gas and coal fired power plants were experiencing higher than anticipated derates and there were additional, unexpected, forced outages for a total of approximately 1,571 MW. The RC's wind production was low, approximately 43 MW, and they were importing 276 MW and 89 MW from neighboring RCs. The RC's peak load was 3,360 MW.

The RC notified several customers to curtail their production (approximately 43 MW of total load relief). With these load curtailments, their operating reserves were able to recover.

No Firm load was shed during this event.

August 4, 2023 – EEA Level 3 Event

With two generators offline due to the forced outage (approximately 600 MW) that occurred on June 3, and with the high ambient temperatures that the RC's system was experiencing, an EEA3 was declared because operating reserves were forecasted to be lower than the required limit. The forecasted load was 3,490 MW, but the actual load was 3,404 MW. The RC had approximately 1,605 MW of generation unavailable due to planned or unplanned maintenance. Additionally, their wind generation was only 24 MW (615 MW is the installed capacity).

The RC curtailed approximately 35 MW from their Demand Response customers. The RC also called on some generators to initiate burning of more gas at certain plants to gain more MW's while requesting and receiving emergency energy from their neighbors (90 MW). All these actions helped to restore their operating reserves.

No Firm load was shed during this event.

August 14, 2024 – EEA Level 3 Event

With two generators offline due to the forced outage (approximately 600 MW) that occurred on June 3, and with the high ambient temperatures that the RC's system was experiencing, an EEA3 was declared because operating reserves were forecasted to be lower than the required limit. The forecasted load was 3,430 MW, but the actual load was 3,491 MW. The RC had approximately 1,425 MW of generation unavailable due to planned or unplanned maintenance. Additionally, their wind generation was only 146 MW (615 MW is the installed capacity).

The RC curtailed approximately 43 MW from their Demand Response customers and some industrial customers who voluntarily reduced load. All these actions helped to restore their operating reserves.

No Firm load was shed during this event.

APPENDIX D: GENERATION AVAILABILITY DETAILS

Generation unavailability can have a substantial impact on reliability. Useful metrics for generator unavailability are the EFOR (Equivalent Forced Outage RATE) and WEFOR (Weighted Equivalent Forced Outage RATE). For the MRO region, the historical annual conventional generator WEFOR for all seasons is shown in Figure AD1 and is on an upward trend over the five-year span. 2020 had the lowest rate due to a reduction in both total demand and reductions in forced outages and derates in simple cycle generation. The steep increase in 2022 WEFOR was driven in part by extreme outage events in the winter season at the beginning (January and February) and end of the year (December - Winter Storm Elliott). This was also driven by high levels of outages in the fall primarily led by simple cycle gas turbines and a small, but heavily MW weighted increase in WEFOR of fossil steam plants. WEFOR has held relatively steady until 2022, which saw a notable increase in the last year along with event impact, attributable almost entirely to fossil steam and simple cycle gas turbines. 2023 had poor WEFOR performance across the year, starting slightly elevated from a difficult 2022 fall maintenance season and subsequent challenging winter. The fleet did not rebound from this elevated WEFOR rate with the spring maintenance window leading to several long term and high impact outages that helped elevate summer WEFOR well above the seasonal average. The forced outage rate increase was attributed to the increase in yearly WEFOR in Fossil-Steam, Hydro, and Combined Cycle Gas Turbines over the 5-year average. The details of the 5-year monthly outage changes are explored below in Figure AD2.

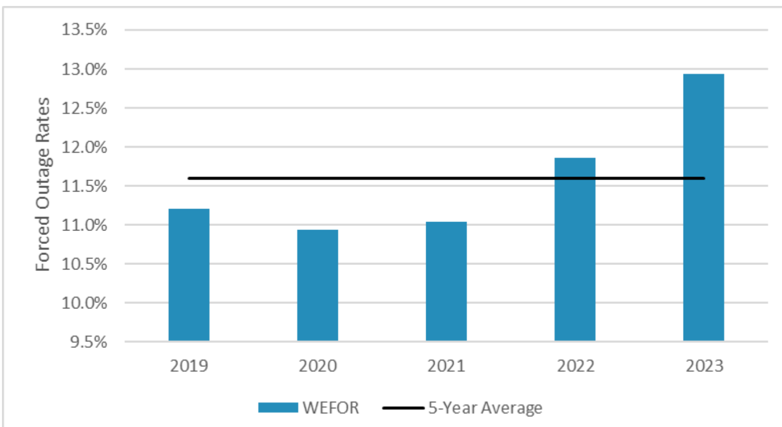


Figure AD1: MRO Annual Generator MW-Weighted EFOR

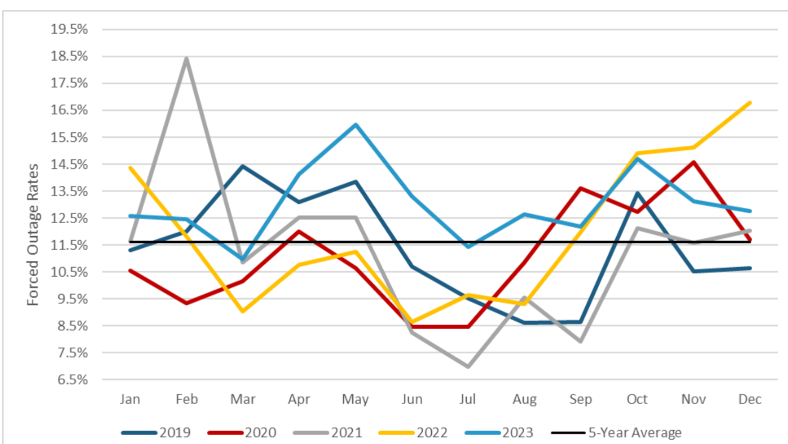


Figure AD2: MW-Weighted EFOR By Month

Figure AD3 shows the total event impact in gigawatt hours (GWh) and the number of impactful events due to forced outage, forced derate, or startup failure for each conventional unit type. The total event impact is a measure of total energy unavailable or lost due to a forced outage, forced derate, or start-up failure presented alongside a simple count of impactful events.

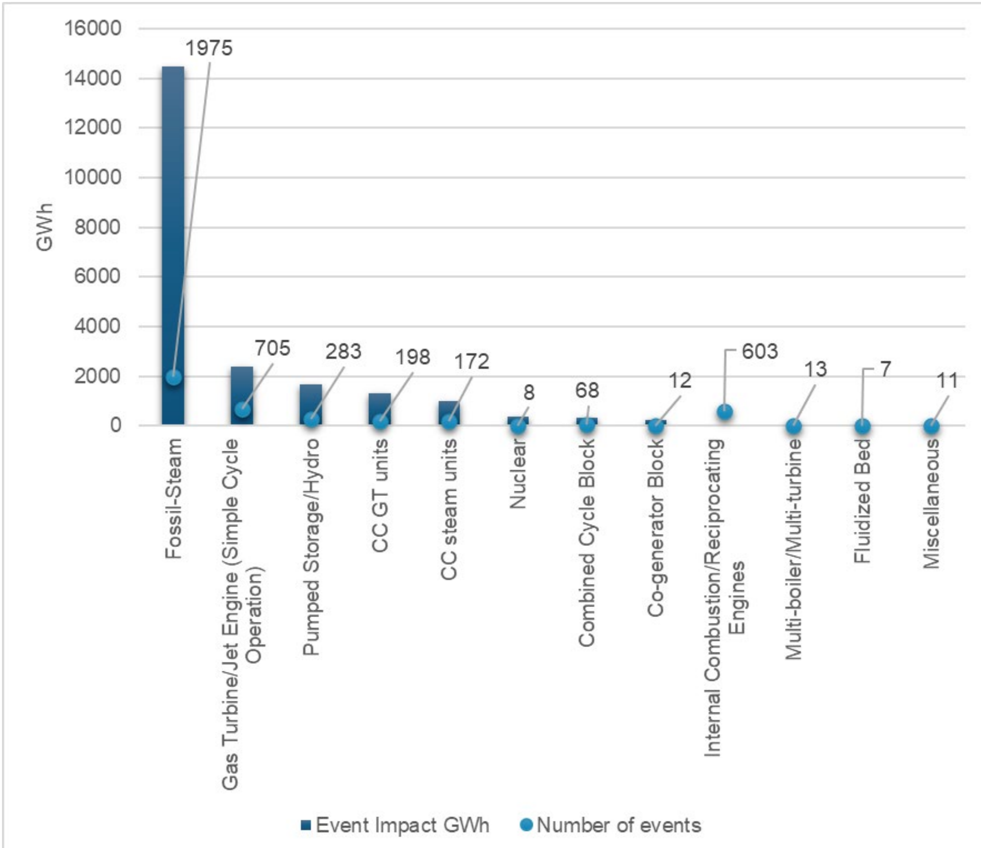


Figure AD3: Total Event Impact (GWh) and Number of Events for Summer 2023

The GADS data presented in Figure AD3 is a summary of 2023 summer season and five-year historical event impact in the MRO footprint over the summer months. In this chart, even though fossil-steam generation shows a high event impact of 14,470 GWh and a total event impact of 21,904 GWh for all generation types, this is not a concurrent impact, nor does it represent generation inadequacy. It simply demonstrates the energy lost in generation events. There was an approximate 9.8% decrease in event impact in 2023 from the previous summer season. This seasonal improvement is not reflected in the monthly WEFOR rates due to generally long-running outages and derates that peaked during the final months of spring.

Table AD4 shows the top causes of forced outages, forced derates, and startup failures by MWh lost for fossil-steam plants in Summer 2023. Table AD5 shows the same information for the five-year historical summer season period.

Cause Type	Portion of lost MWh
Operator error – 10 events	7.85%
SCR NOx Soot blowers – 1 event	7.19%
Scrubber/absorber tower or module – 36 events	6.32%
Waterwall (Furnace wall) – 29 Events	5.11%
Forced draft fans – 19 Events	4.02%

Table AD4: Fossil-Steam 2023 Summer Outage Causes

Cause Type	Portion of lost MWh
Waterwall (furnace wall) – 135 events	6.02%
Plant Modifications Strictly for Compliance with new or changed regulatory requirements – 2 events	3.07%
Air heater (regenerative) – 23 events	2.80%
Forced draft Fans – 173 events	2.71%
Other Boiler Tube Leaks – 57 events	2.70%

Table AD5: Fossil-Steam 2019-2023 Summer Outage Causes

Fossil steam cause codes were more concentrated during the 2023 Summer season than the 5-year annual or 5-year seasonal averages, in part due to the relative decrease of impactful events. Waterwall is often responsible for the most event impact in fossil-steam units and is prevalent due to the frequency and ubiquity of the somewhat broad cause code. For this reason, it often acts as a litmus test for truly impactful events in each assessment period. Three cause codes making up larger portions of lost MWhs is concerning initially and the more prevalent seasonal codes for 2023 will be discussed below, but waterwall event impact was noticeably decreased in 2023 overall and specifically in the summer season. Operator error events are impactful. These events took place over several units, but one extreme duration event accounts for over 90% of this event's impact. Human performance, and human management oversight on generation maintenance is critical especially on aging equipment. Though the total impact was largely attributable to the summer and is not a larger scale issue in 2023 or the 5-year span. Scrubber/Absorber events are concentrated in three units which make up over 95% of event impact for the cause code. Among these, one unit makes up over 80% of the total impact, largely due to lengthy but not immediate derates. This is a point of concern for aging fossil steam plants for peak availability, however the immediate threat to the grid is less than event impact would imply. These codes save Forced Draft fans are all among the top ten most impactful cause codes for 2023, but not the most impactful. The divergence demonstrates primarily that high impact events both in pulverizers and main transformers in early 2023 set the stage for high yearlong WEFOR.

The 5-season span more closely matches historical performance for fossil steam. Summer has generally had less impactful events occur across the MRO fleet, and fossil steam fits that trend well. Events in the 5-summer span are less impactful than the winter and the annual average. The top cause codes also are largely the same with only Air Heater (regenerative) diverging from the 5-year top cause codes. This reinforces that 2023 was in line with expectations and that summers are lower risk periods for fossil steam plants.

Table AD6 shows the top causes of forced outage, forced derate, and startup failure by MWh lost for simple cycle gas turbines in the 2023 summer season. Table AD7 shows the same data for the five-year historical summer period.

Cause Type	Portion of lost MWh
High Pressure Shaft B – 1 event	7.29%
Generator Vibration (Excluding vibration due to failed bearing) – 5 events	6.33%
Lube oil pumps B – 7 events	6.13%
Main Transformer – 5 events	5.87%
Blade Path Temperature Spread A – 46 events	5.79%

Table AD6: Simple Cycle Gas Turbine 2023 Summer Outage Causes

Cause Type	Portion of lost MWh
Engine Vibration – 28 events	5.60%
High pressure blades/buckets B – 4 events	4.64%
Other Compressor problems – 6 events	4.46%
Other DCS problems – 10 events	4.08%
Other miscellaneous gas turbine problems – 24 events	2.91%

Table AD7: Simple Cycle Gas Turbine 2019-2023 Summer Outage Causes

Simple Cycle Gas turbines worked against the 2023 increase in WEFOR, performing substantially better than the 5-year average, in line with 2020 and 2021 WEFOR, though still high in comparison to the rest of the fleet. The summer event impact mirrored this change, with total event impact numbers slightly elevated over 2020 and 2021. The top four summer 2023 cause codes are all low event counts that have one or two events that are extremely long lasting. These are not indicative of seasonal concerns, but of the relative total energy impact of sizable component failure. Blade path temperature spread on the other hand may constitute a potential summer vulnerability. This is more common during winter months due to increased fuel oil burning leading to uneven heating. However, the units most affected in the summer used only natural gas. This implies that these are not intrinsically seasonal weather or market effects, but a result of issues in spring maintenance. Notably there is no overlap between the five most impactful cause codes for 2023 and summer 2023. This alongside the low number of events in these top seasonal cause codes suggests that these are not larger trends that the generation class should be wary of, and that summer was mild for these units.

In the 5-season cause codes there is substantially less concentration of impact in the top cause codes than in the 5-year span or in the summer of 2023. This spread of failure mechanisms suggests that more abstract issues drive summer events like age, maintenance, and random component failures. The cause codes are consistent with top cause codes for the 5-year span as well with the notable lack of any fuel availability cause codes in the summer.

Summer season forced outage, forced derate, and startup failure causes for other types of generation is provided below.

Cause Type	Portion of lost MWh
Gas turbine vibration – 1 event	42.98%
Fuel piping and valves A – 6 events	11.81%
Exciter transformer – 1 event	8.94%
Unit auxiliaries transformer– 2 events	8.02%
Other fuel quality problems – 6 events	3.06%

Table AD8: Combined Cycle Gas Turbine 2023 Summer Outage Causes

Cause Type	Portion of lost MWh
Stator windings; bushings; and terminals – 4 events	24.35%
Gas turbine vibration – 8 events	10.00%
Fuel piping and valves A – 22 events	6.50%
Stator core iron – 2 events	4.03%
Exciter commutator and brushes – 5 events	3.82%

Table AD9: Combined Cycle Gas Turbine 2019-2023 Summer Outage Causes

Cause Type	Portion of lost MWh
Gas turbine vibration - 2 events	34.08%
Exciter transformer – 1 event	11.96%
Condenser tube fouling tube side – 28 events	11.82%
Fuel piping and valves A – 5 events	10.15%
Unit auxiliaries transformer – 2 events	6.52%

Table AD10: Combined Cycle Steam 2023 Summer Outage Causes

Cause Type	Portion of lost MWh
Stator windings; bushings; and terminals – 3 events	19.63%
Gas turbine vibration – 3 events	6.27%
Reheat steam relief/safety valves – 6 events	8.90%
Stator core iron – 2 events	4.82%
Stator; general – 3 events	4.36%

Table AD11: Combined Cycle Steam 2019-2023 Summer Outage Causes

Cause Type	Portion of lost MWh
Switchyard circuit breakers - (not outside management control) – 2 events	27.84%
Other miscellaneous external problems – 82 events	19.46%
Rotor; General – 11 events	14.68%
Stator windings; bushings; and terminals - 2 events	8.34%
Bearing cooling system A – 2 events	7.31%

Table AD12: Hydro 2023 Summer Outage Causes

Cause Type	Portion of lost MWh
Switchyard circuit breakers - (not outside management control) – 2 events	11.61%
Other miscellaneous external problems – 110 events	8.77%
Governor Oil System – 49 events	7.74%
Other turbine control problems – 52 events	6.81%
Other turbine problems – 37 events	6.70%

Table AD13: Hydro 2019-2023 Summer Outage Causes

APPENDIX E: TRANSMISSION AVAILABILITY DETAILS

Table AE1 shows the number of circuits and circuit miles for overhead 100-599kV AC transmission lines within the MRO region. DC transmission circuit miles were not included since there are so few outages.

100-199-kV		200-299-kV		300-399-kV		400-599-kV	
Circuits	Miles	Circuits	Miles	Circuits	Miles	Circuits	Miles
3,414	47,329	419	14,251	515	18,584	9	1,001

Table AE1: AC Transmission Circuit Miles

Figure AE2 shows the number of 100kV and above automatic outages that include both momentary (for 200kV and above) and sustained outages for the 2019 through 2023 summer seasons. There were only seven 400-599kV outages for the 2023 summer season.

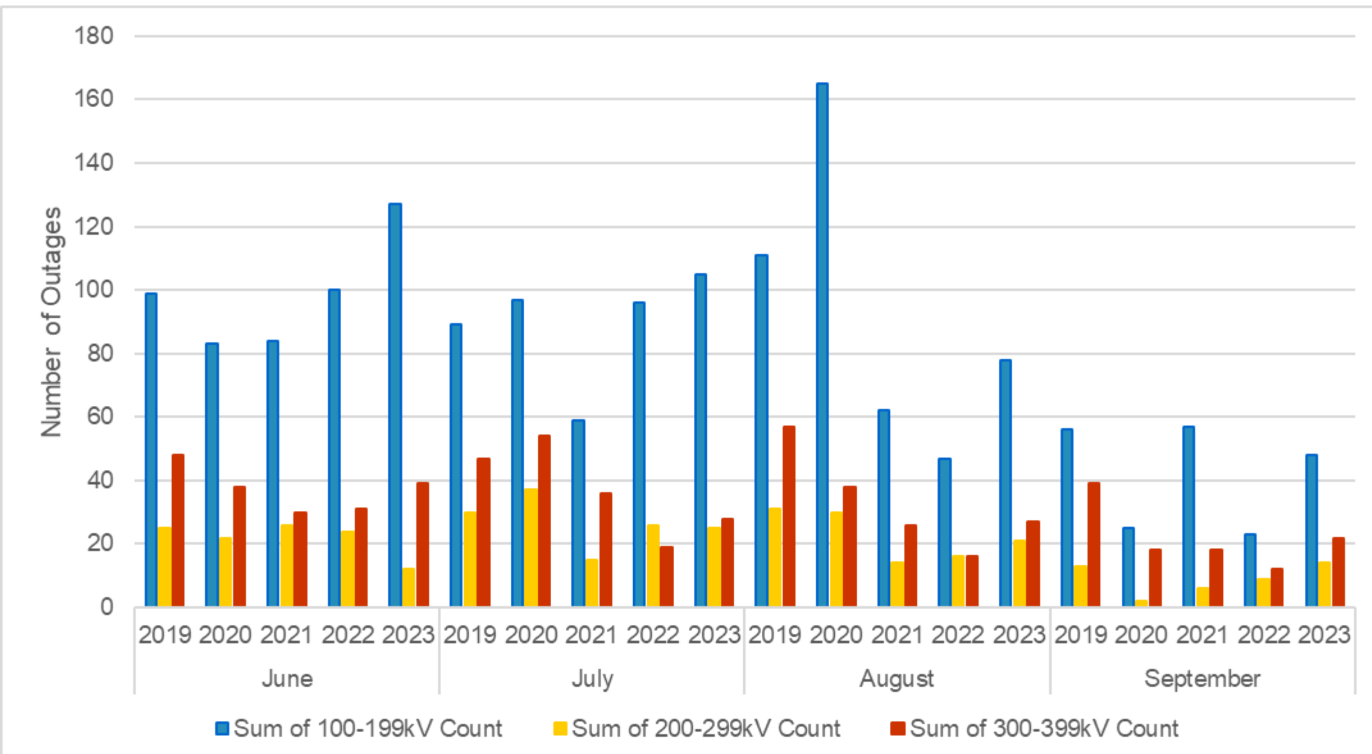


Figure AE2: Summer Automatic Outages by Month

Figure AE3 shows the causes of momentary outages for the past five summer seasons. The chart does not include momentary automatic outages for circuits 100-199kV because causes are not reported for momentary outages on circuits less than 200kV. The chart shows that lightning was the leading cause of momentary outages for the summer season of 2023, as well as the previous two summer seasons. The chart also illustrates a significant number of momentary outages have an unknown cause. This suggests that thorough line inspections after transient faults are not typically performed after clear weather operations. It may also suggest that even if an inspection is performed, a definitive cause for many transient faults cannot be determined.

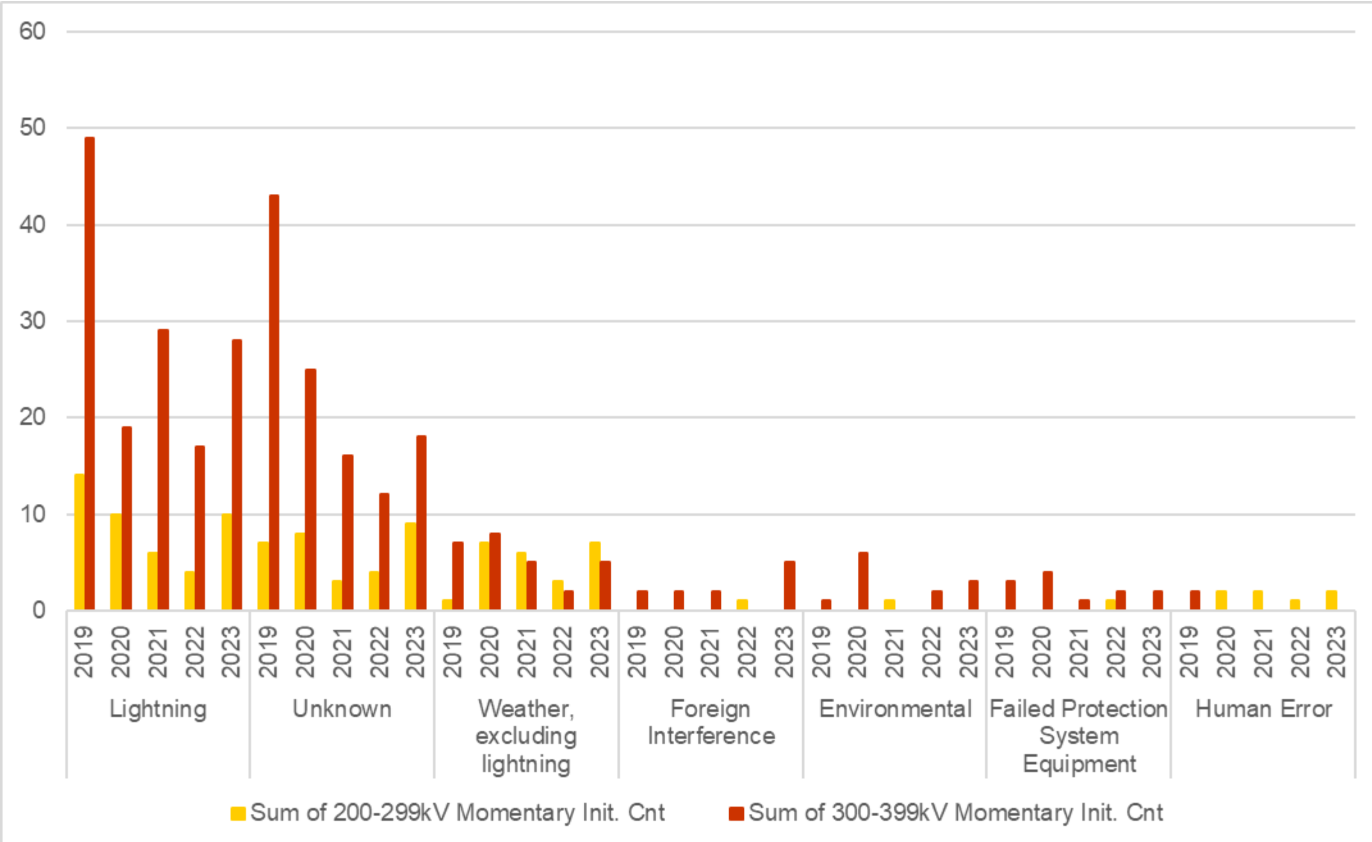


Figure AE3: Summer Momentary Outages by Cause

Figure AE4 shows the causes of sustained outages for the 2019 through 2023 summer seasons. The chart shows that failed AC circuit equipment, other, and failed AC substation equipment continue to be major contributors to sustained outages during the summer seasons. The graph shows that for the 2023 summer season, the top two sustained outage causes, failed AC circuit equipment, and other are higher than any of the other previous summer seasons for the 100-199kV voltage range.

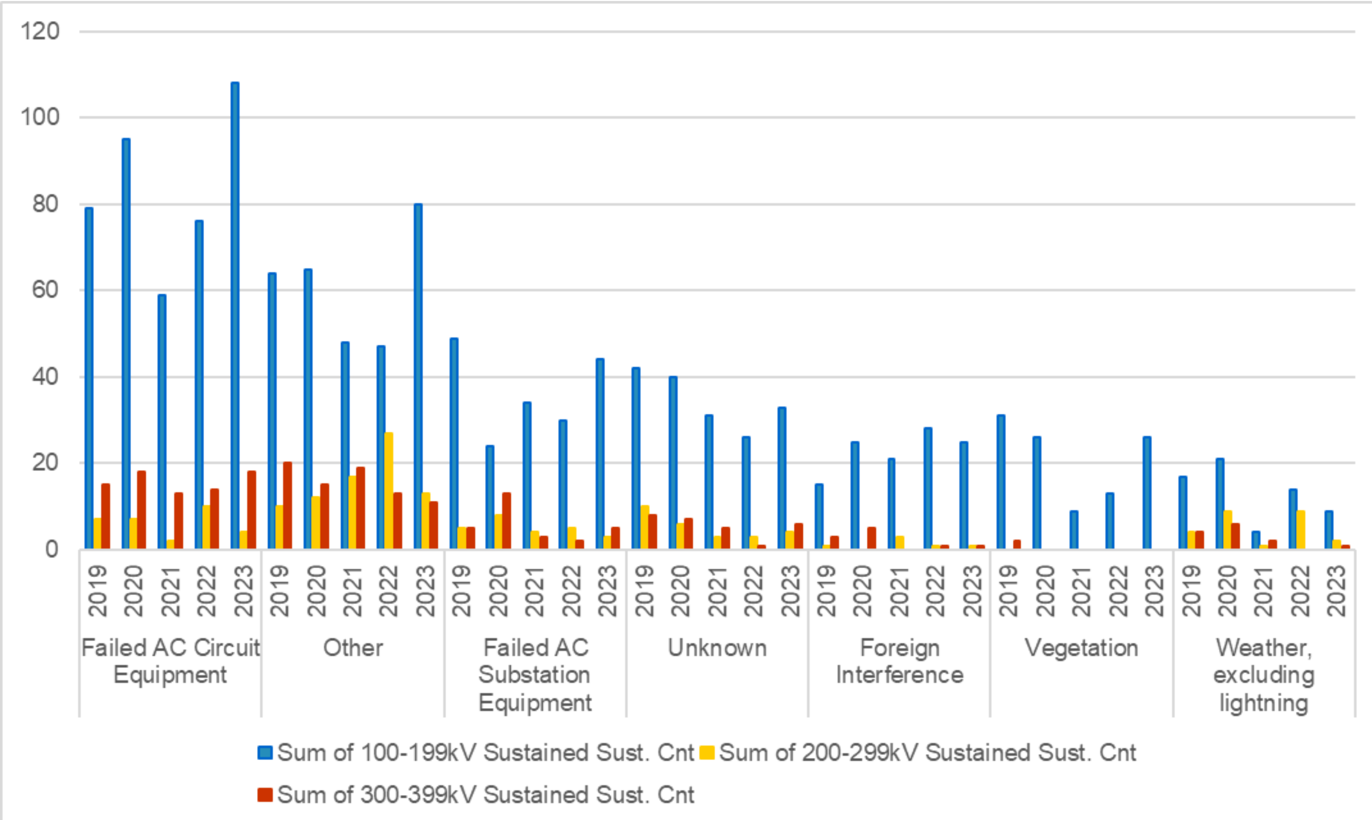


Figure AE4: Summer Sustained Outages by Cause

Figure AE5 reflects the yearly summer total outages per 100 circuit miles for 100-399kV circuits. The chart clearly shows an increase in outages during the 2023 summer season in the 100-199kV and 300-399kV voltages. TADS reportable outages were up almost 30 percent from the previous year; however, they were only 2 percent over the 5-year average. A four-day period in the middle of June accounted for 12 percent of the total reported operations for the summer of 2023 as storms went through the southern portion of MRO. This is the only period in the 2023 summer season that had an increase in outages over multiple days.

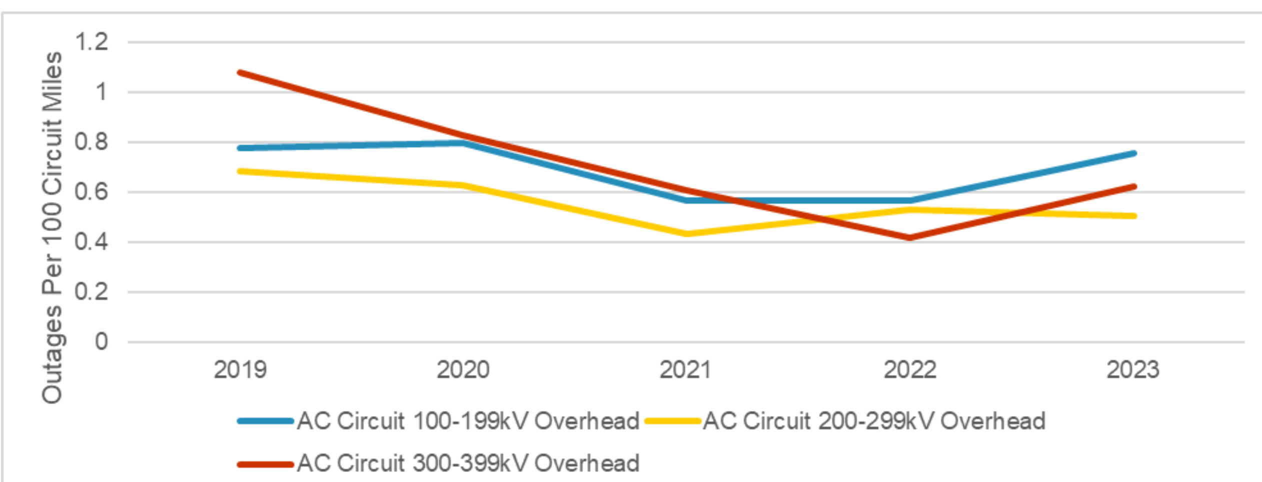


Figure AE5: Total Transmission Outages per 100 Circuit Miles