2022 ASSESSMENT OF RELIABILITY PERFORMANCE APPENDICES

MAY 2023

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Introduction

TEXAS RE
Ensuring electric reliability for Texans

Appendix A – Resource Adequacy Detailed Analysis

A. Generator Performance Background (from NERC GADS and GADS-Wind)

For this analysis, generation performance data is based on required reports submitted in the Generation Availability Data System (GADS) and GADS-Wind systems under NERC Section 1600 of the Rules of Procedure. The number of generators reporting ERCOT GADS and GADS-Wind data is shown in the following tables.

Units Reporting	2018	2019	2020	2021	2022
Total	407	402	407	458	471
Coal/Lignite	26	21	20	19	19
Gas	45	43	43	40	40
Nuclear	4	4	4	4	4
Gas Turbine/Jet Engine	87	90	92	109	122
Reciprocating Engine				42	42
Hydro	8	8	8	8	8
Fluidized Bed	5	5	5	5	5
Combined Cycle (Block)	18	18	18	18	18
Combined Cycle GT	149	149	149	149	149
Combined Cycle ST	61	61	61	61	61
Other	3	3	7	3	3
Total Thermal MW Reporting	78,898	77,388	77,395	78,549	79,562
Total Thermal GWh Reporting	320,376	315,746	300,223	298,155	312,787
Wind (>200 MW)	47	55	61	64	70
Wind (100<MW<200)	35	72	77	76	81
Wind (< 100 MW)	58	82	110	118	110
Number of Wind Turbines	9,466	13,735	15,349	15,282	15,865
Total Wind MW Reporting	17,955	26,451	29,796	31,651	33,683

Table A.1 – 2018-2022 GADS and GADS-Wind Units Reporting

B. Analysis of Planned versus Actual Seasonal Operating Reserves

For the summer of 2022, peak hourly demand was 79,830 MW, approximately 1,946 MW higher than the typical scenario estimate of 77,884 MW from ERCOT's summer 2022 Seasonal Assessment of Resource Adequacy (SARA), and in line with the high peak load estimate of 79,806 MW. Actual reserve margin was approximately 6.2 percent. Sufficient operating reserves were maintained during the summer peak hours.

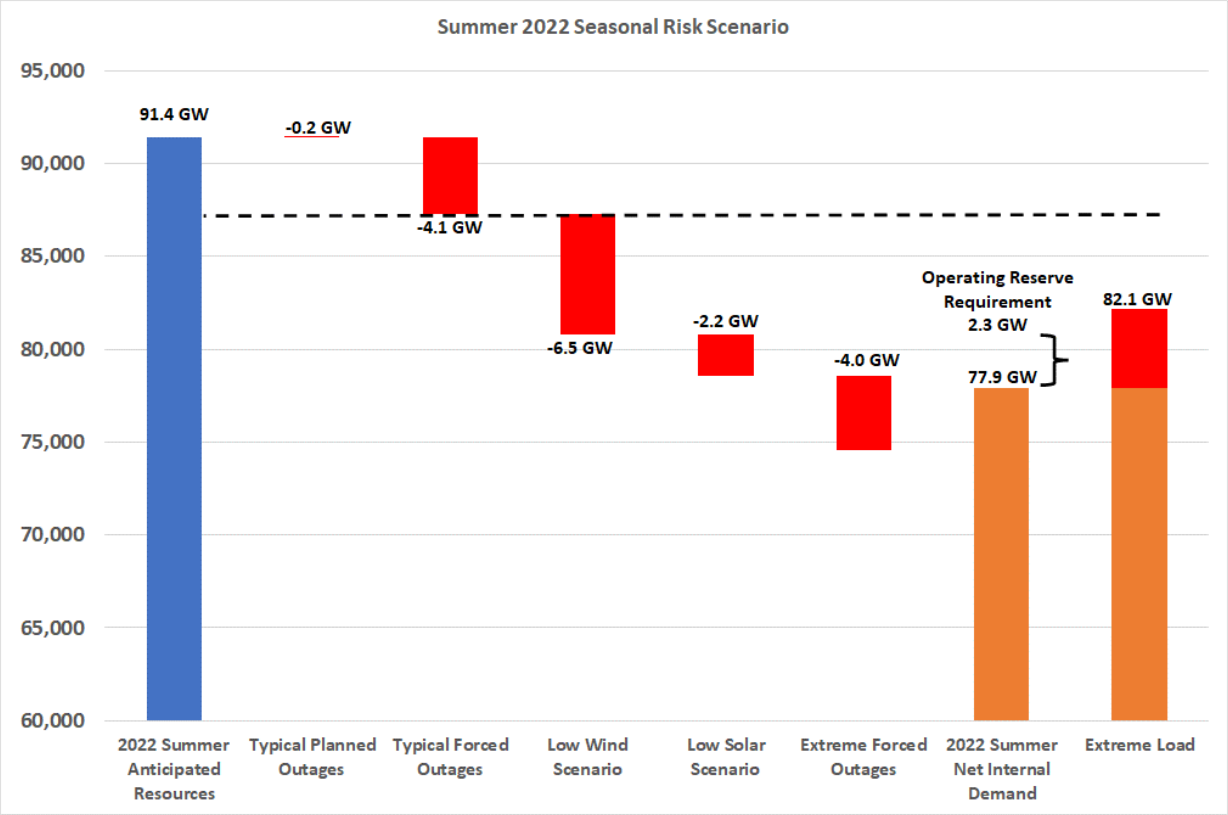


Figure A.1 – Summer 2022 Risk Scenarios

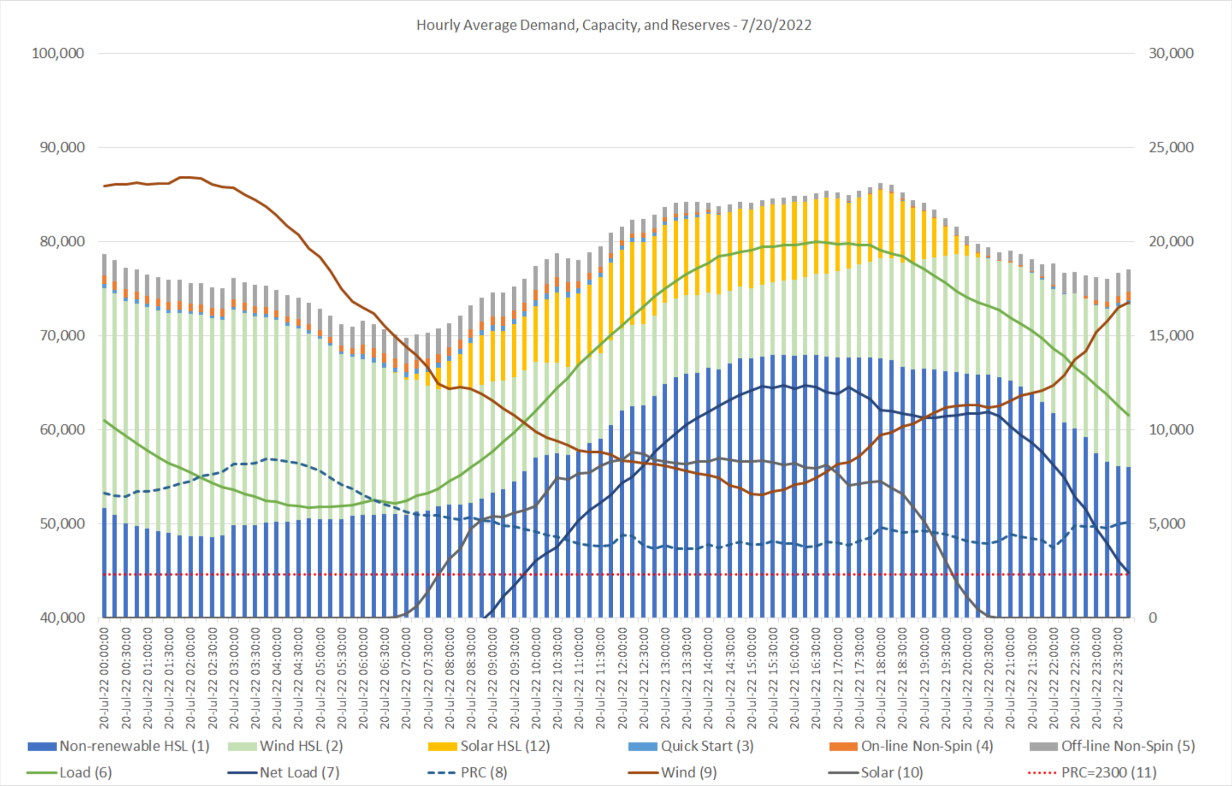


Figure A.2 – July 20, 2022, Capacity, Demand, and Reserves

The final ERCOT SARA for summer 2022 estimated typical thermal maintenance outages of 24 MW and typical forced outages of 4,081 MW with an extreme case of 13,676 MW. Combined actual planned and forced thermal outages for summer 2022 ranged from a low of 3,023 MW to a maximum of 11,490 MW.

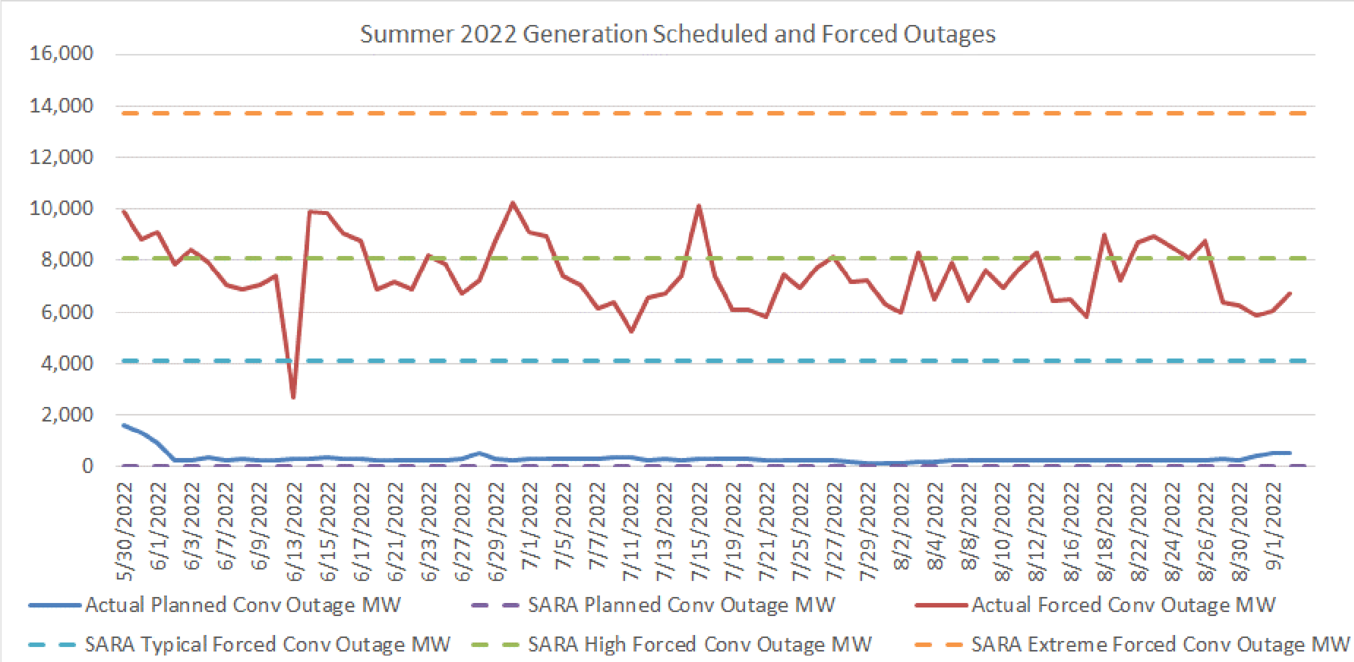


Figure A.3 – Summer 2022 Generation Scheduled and Forced Outages

For winter 2022, peak hourly demand was 73,976 MW, approximately 6,580 MW above the typical load scenario estimate of 67,398 MW from the winter SARA, but approximately 3,400 MW less than the high load estimate. Actual reserve margin was approximately 5.8 percent. Sufficient operating reserves were maintained during the winter peak hours.

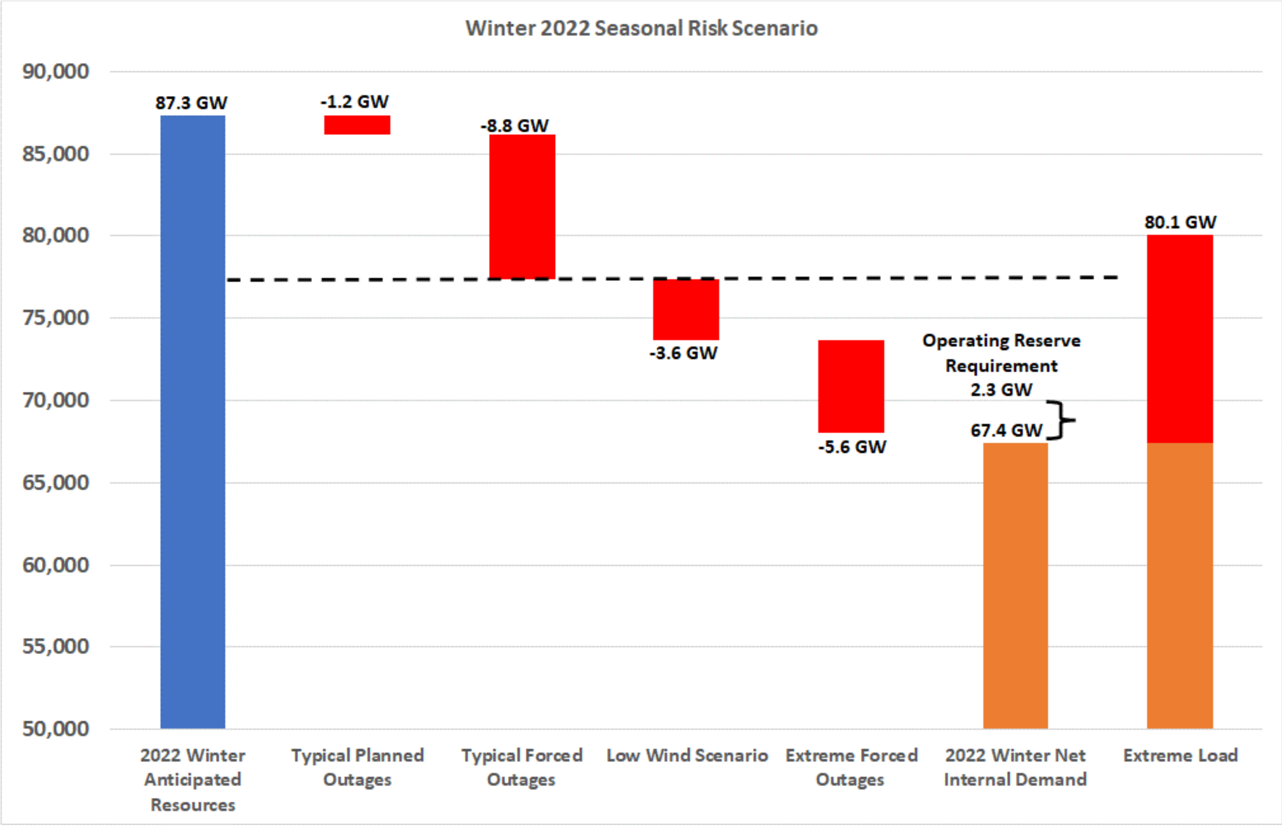


Figure A.4 – Winter 2022 Risk Scenarios

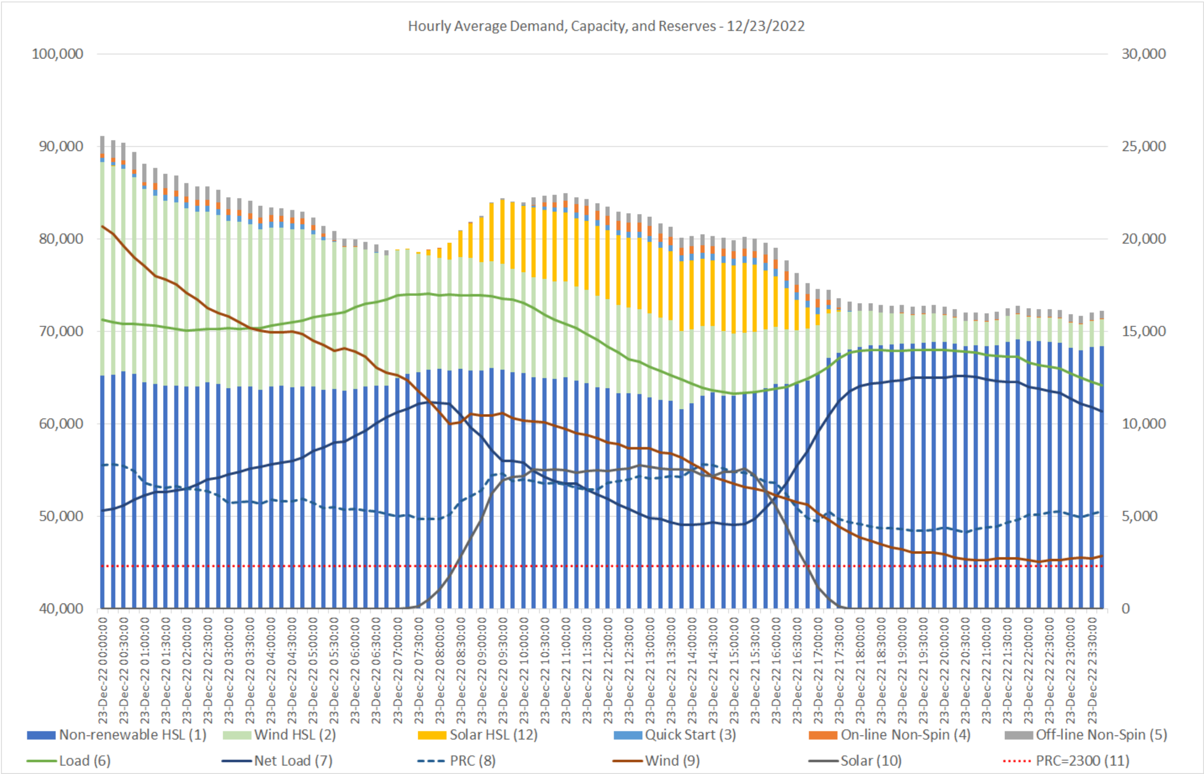


Figure A.5 – December 23, 2022, Capacity, Demand, and Reserves

The final ERCOT SARA for winter 2022-2023 estimated typical thermal maintenance outages of 1,183 MW and typical forced outages of 8,783 MW with an extreme case of 14,425 MW. Combined actual planned and forced outages for the winter ranged from a low of 8,122 MW to a maximum of 21,924 MW.

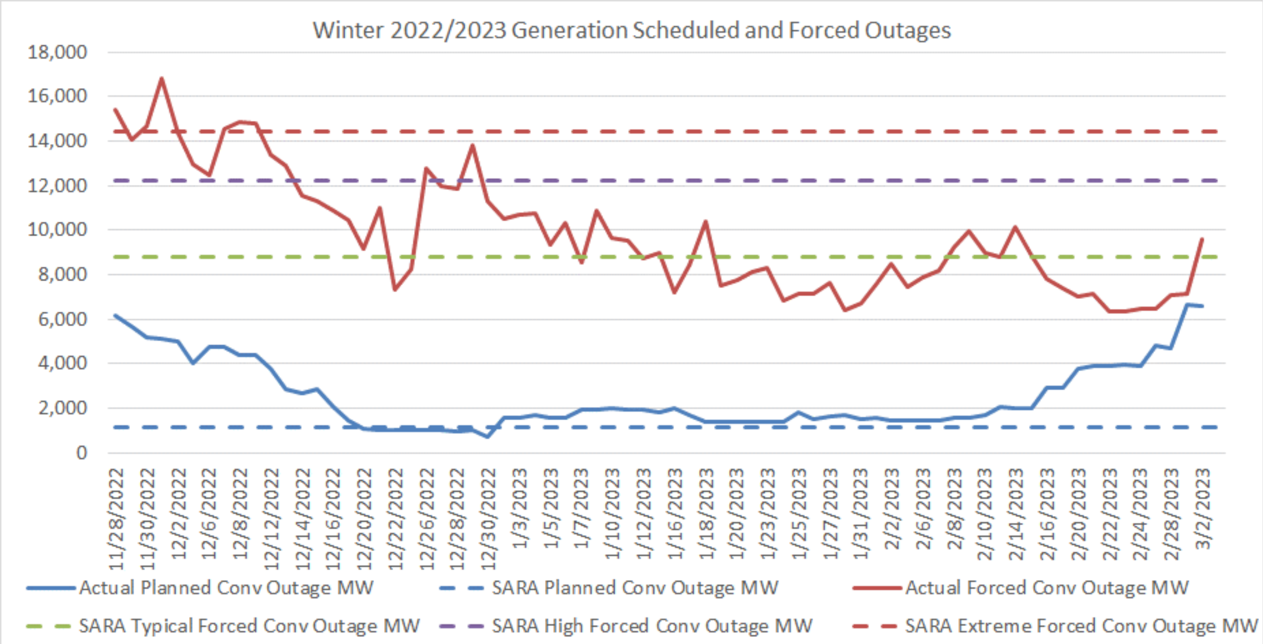


Figure A.6 – Winter 2022-2023 Generation Scheduled and Forced Outages

C. Primary Frequency Response

Primary frequency response is defined as the immediate proportional increase or decrease in real power output provided by generating units/generating facilities and the natural real power dampening response provided by load in response to system Frequency Deviations. This response is in the direction that stabilizes frequency. Figure A.7 shows a typical frequency disturbance broken down into several periods.

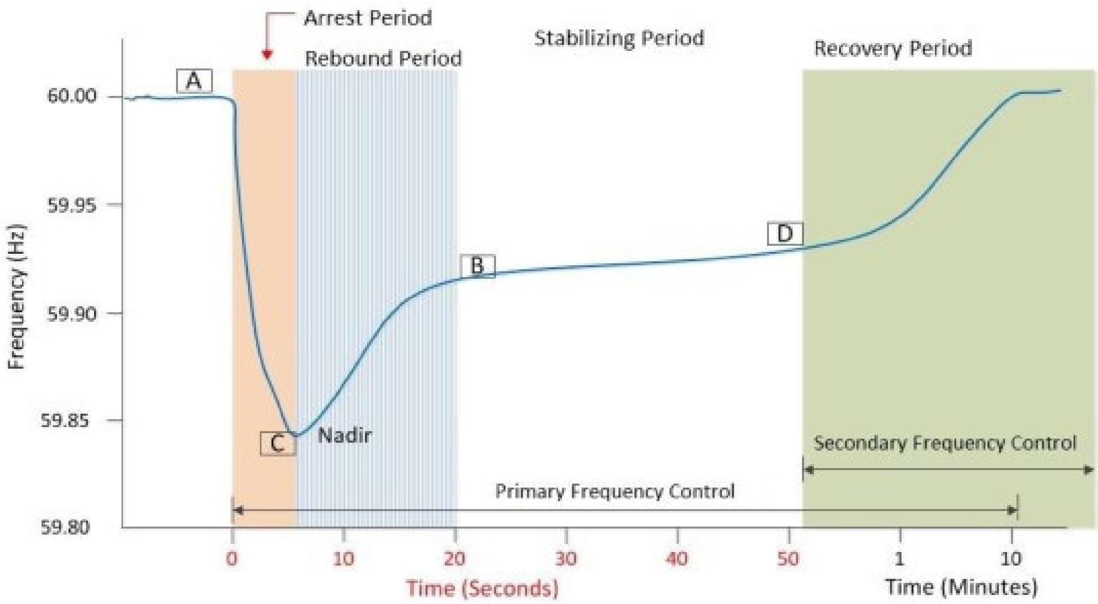


Figure A.7 – Typical Frequency Disturbance

Each of the periods of the frequency disturbance is analyzed by different metrics and performance indicators. Two of the key performance indicators are based on requirements in the BAL-002 and BAL-003 Standards. These are recovery of the Area Control Error (ACE) within 15 minutes following a Reportable Balancing Contingency Event and maintaining the Interconnection frequency response at or above the Interconnection Frequency Response Obligation (IFRO).

Period	Time Frame	Reliability Requirement	Metric(s)
Arrest Period	T0 to T+6 seconds	Arrest C-point at or above 59.3 Hz for loss of 2750 MW (BAL-003)	- RoCoF/MW Loss - T0 to Tc - Nadir Frequency Margin
Rebound/Stabilizing Period	T+6 to T+60 seconds	Achieve Interconnection frequency response at or above IFRO (412 MW per 0.1 Hz) (BAL-003)	- Primary Frequency Response
Recovery Period	T+1 to T+15 minutes	Recover ACE within 15 minutes (BAL-002)	- Event recovery time

Table A.2 – Frequency Event Requirements and Metrics

Rotating turbine generators and motors synchronously interconnected to the system store kinetic energy during contingency events that is released to the system (also called inertial response). Inertial response provides an important contribution in the initial moments following a generation or load trip event and determines the initial rate of change of frequency (RoCoF).Kinetic energy will automatically be extracted from the rotating synchronized machines on the interconnection in response to a sudden loss of generation, causing them to slow down and frequency to decline. The amount of inertia depends on the number and size of generators and motors synchronized to the system, and it determines the rate of frequency decline. Greater inertia reduces the rate of change of frequency, giving more time for primary frequency response to fully deploy and arrest frequency decay above under-frequency load shed set points. Therefore, with potential wide variations in inertia conditions with increasing use of IBRs, there is a need to monitor and trend inertia and RoCoF.

The nadir, or C-Point frequency, is an indicator of the system imbalance created by the unit trip and is a combination of synchronous inertial response and governor response. Normalizing the unit MW loss by inertia can provide insight into how the nadir can vary under different inertia conditions for the same MW loss value. Figure A.8 shows the nadir plotted against the generation MW loss value normalized for inertia, and shows the inverse relationship between historic performance for how the nadir was affected by different MW loss and inertia conditions. The graph shows a comparison of two three-year periods: 2016-2018 and 2020-2022. The graph shows very little change in the nadir frequency versus the normalized MW values over time.

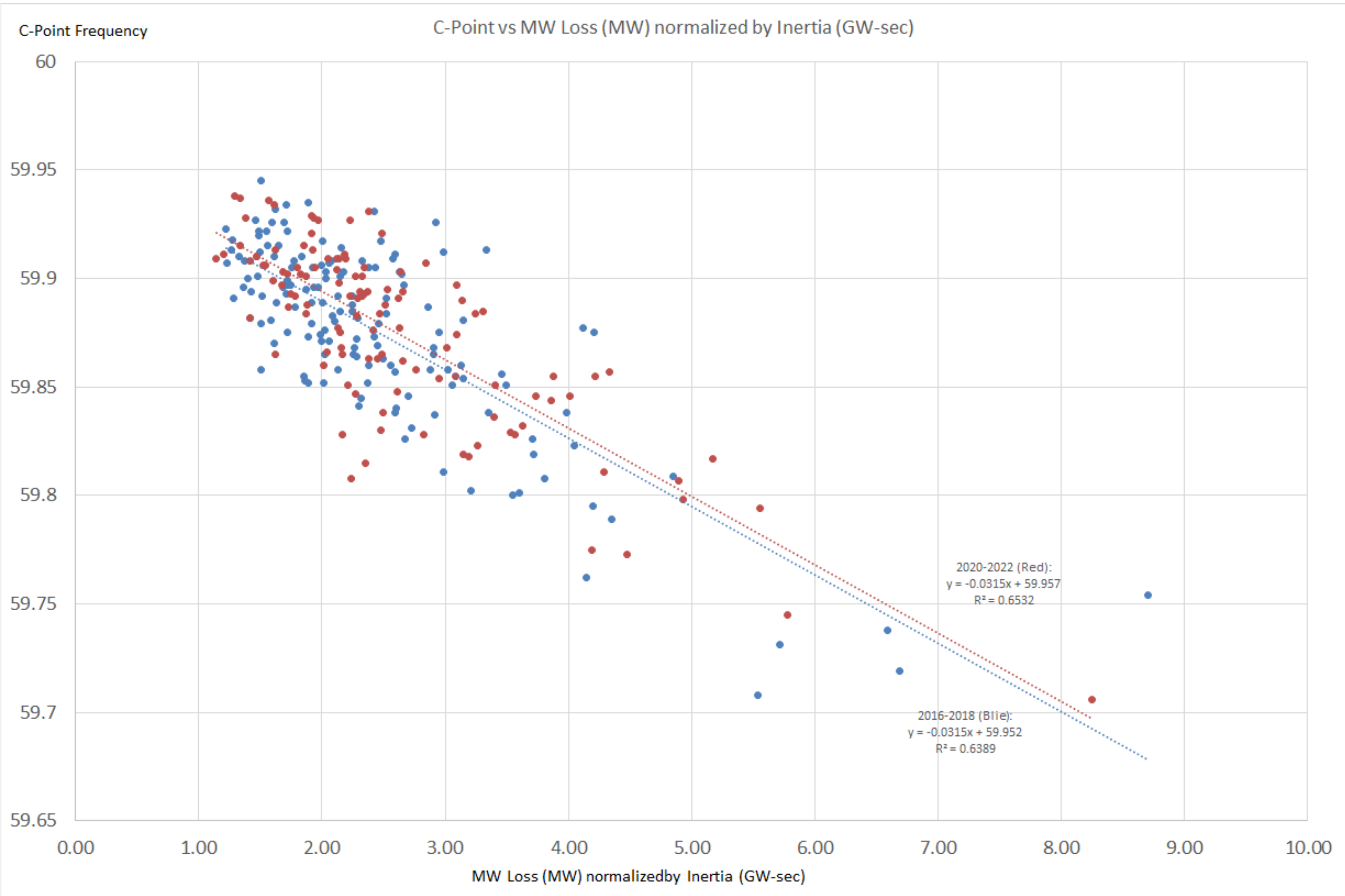


Figure A.8 – Frequency Disturbance Nadir versus Gen Loss MW/Inertia

The RoCoF during the initial frequency decline in the first 0.5 sec is largely driven by system inertia, therefore it is prudent to use the same analysis technique to plot the RoCoF against the generation MW loss normalized by system inertia. Figure A.9 shows this relationship, with a straight-line approximation. The graph shows a comparison of two three-year periods: 2016-2018 and 2020-2022. The steeper slope of the regression line for 2020-2022 indicates that RoCoF rates are increasing due to gradually declining inertia levels.

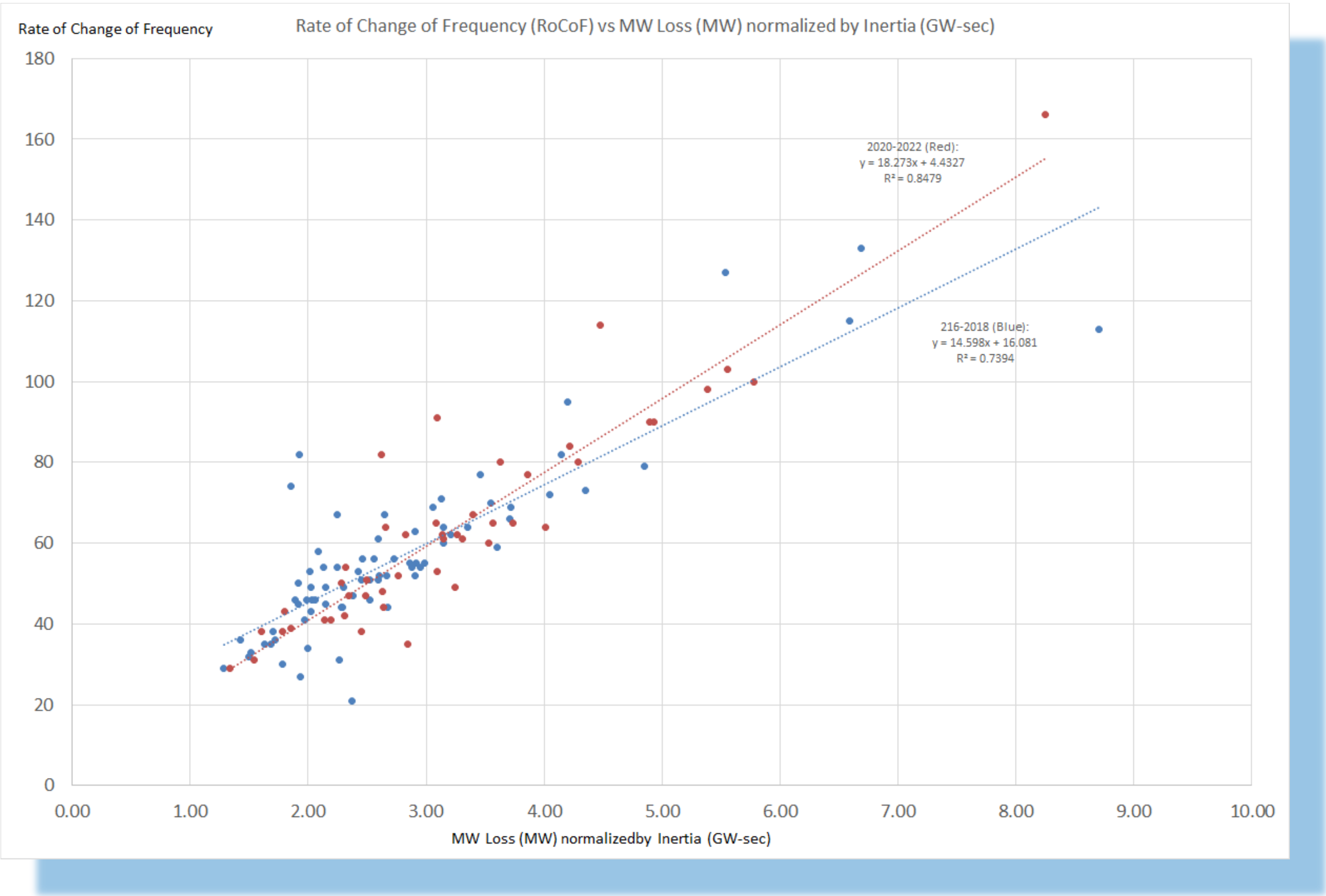


Figure A.9 – Rate of Change of Frequency versus Normalized Generation Loss

Figure A.10 shows the trend in primary frequency response for the Texas RE Region. In 2022, the average frequency response was 1,313 MW per 0.1 Hz and the median frequency response was 1,199 MW per 0.1 Hz as calculated per BAL-001-TRE for the events that were evaluated during the period.

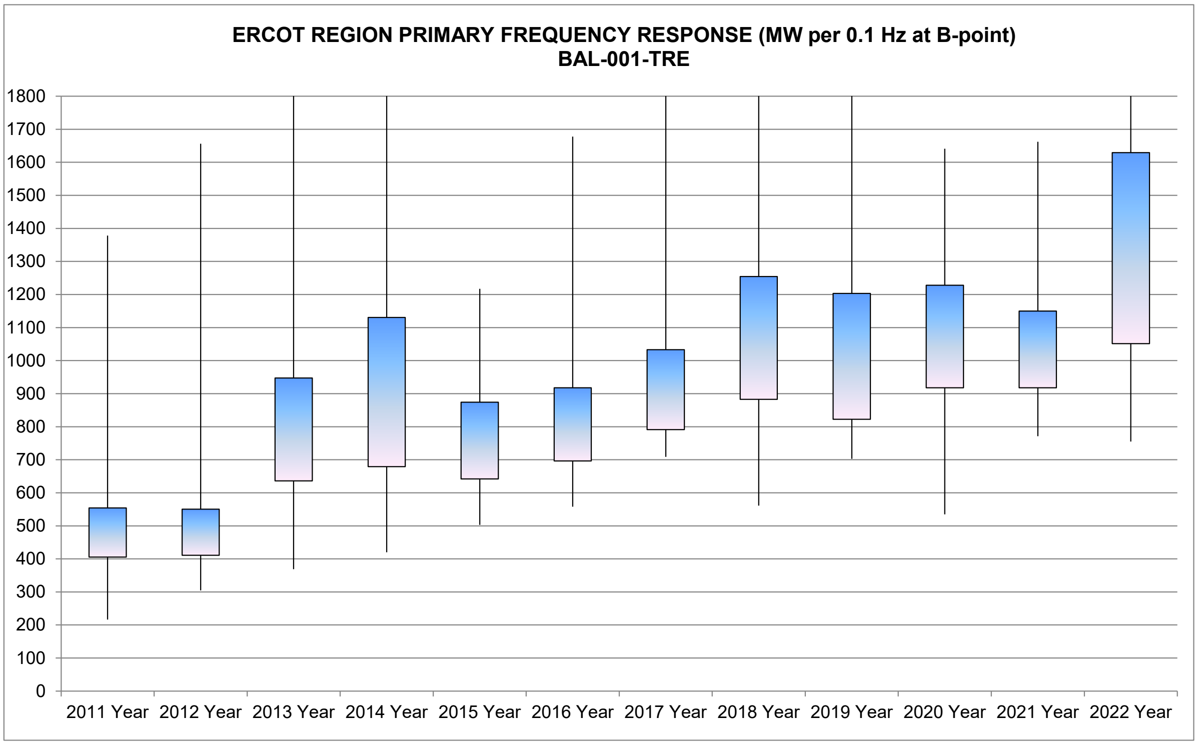


Figure A.10 – Annual Primary (B-Point) Frequency Response Trend for ERCOT Region

Figure A.11 shows the trend in frequency response in the inertial response zone between the A and C points in the Region. In 2022, the average frequency response was 579 MW per 0.1 Hz and the median frequency response was 552 MW per 0.1 Hz as calculated per BAL-001-TRE for the events that were evaluated during the period. The long-term trend shows a gradually increasing inertial response.

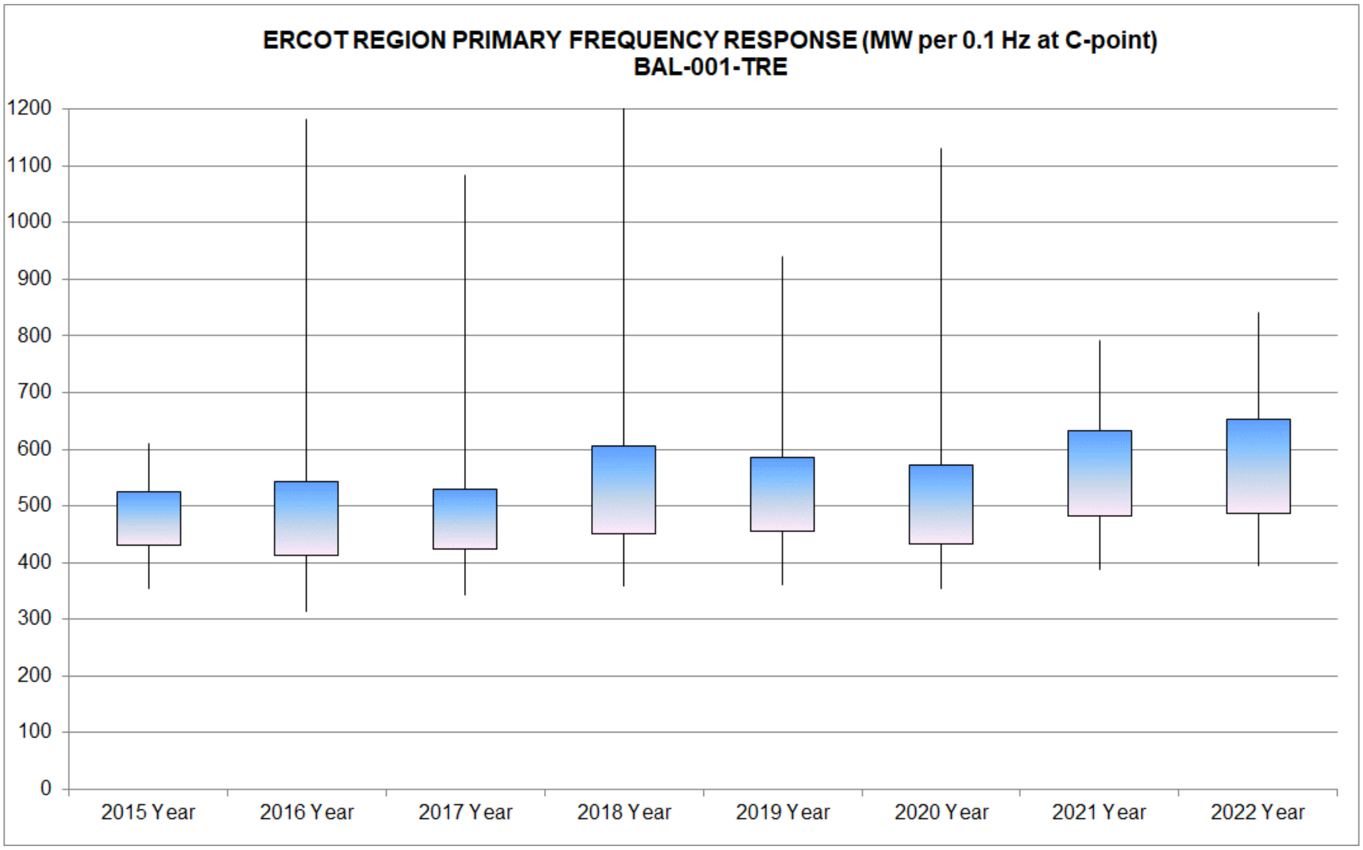


Figure A.11 – Annual Inertial (C-Point) Frequency Response Trend for ERCOT Region

D. Secondary Frequency Response

NERC Reliability Standards require a maximum ACE recovery time of 15 minutes for reportable disturbances. Average recovery time from generation loss events was 5.3 minutes in 2022.

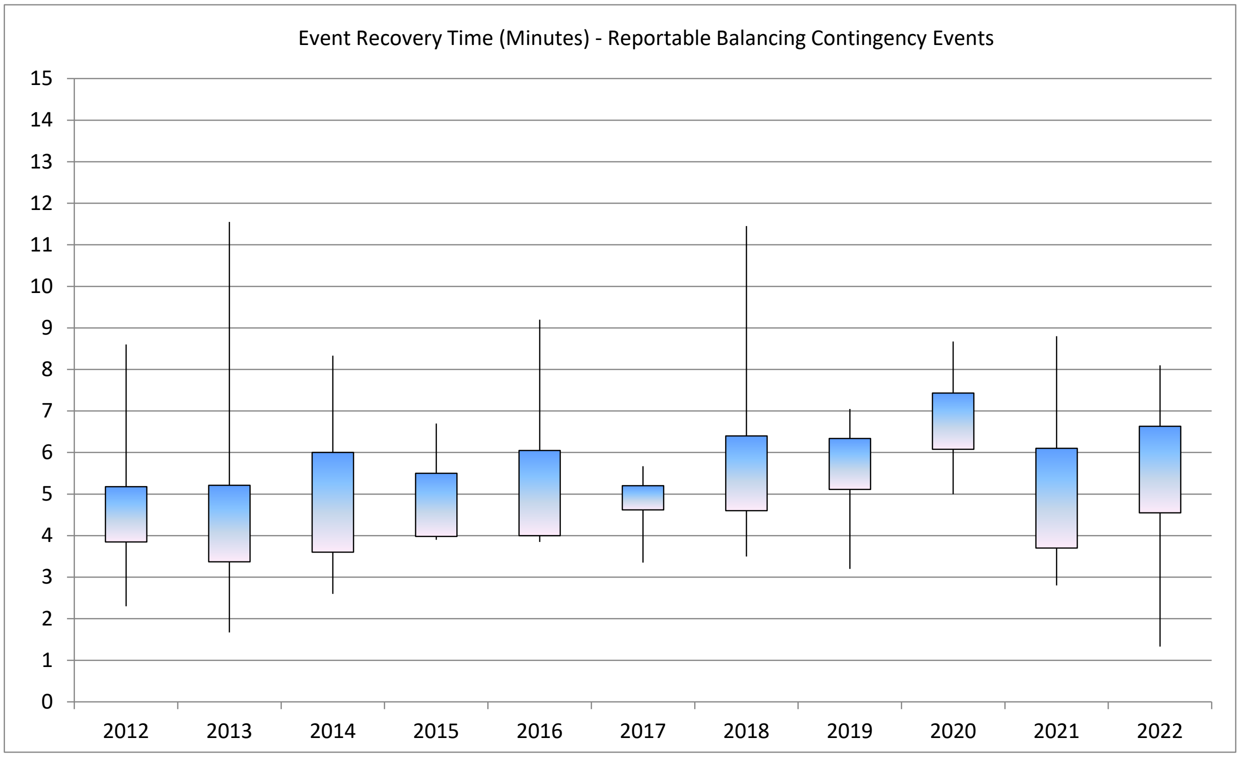


Figure A.12 – Event Recovery Time 2012-2022

E. 2022 Fossil-fueled Generator Performance Metrics

ERCOT fossil generation reporting in GADS produced a gross total of 326,750 GWh in 2022 (73 percent of total generation)

GADS provides various metrics to compare unit performance. Two of these methods are unweighted (time-based) and weighted (based on unit MW size). A summary of key unweighted performance metrics for the ERCOT generation fleet for 2018-2022 is provided in the following table.

ERCOT Region GADS Data Metric	2018	2019	2020	2021	2022	5-Yr Avg
	Unweighted	Unweighted	Unweighted	Unweighted	Unweighted	Unweighted
# Units Reporting	407	402	407	458	471	429
Total Unit-Months	4768	4803	4880	5478	5514	5089
Net Capacity Factor (NCF)	46.7%	46.8%	44.5%	44.4%	46.5%	45.8%
Service Factor (SF)	50.9%	51.7%	48.8%	45.7%	45.8%	48.6%
Equivalent Availability Factor (EAF)	85.2%	86.1%	84.1%	83.8%	84.1%	84.7%
Scheduled Outage Factor (SOF)	8.7%	9.3%	9.5%	9.4%	9.1%	9.2%
Forced Outage Factor (FOF)	3.9%	4.2%	3.9%	4.3%	4.5%	4.2%
EFOR	7.9%	8.3%	8.4%	10.1%	10.4%	9.0%

Equivalent Forced Outage Rate Demand (EFORd)	5.7%	6.1%	5.9%	6.7%	6.8%	6.2%

Table A.3 – ERCOT Generation Performance Metrics 2018 through 2022

- Net Capacity Factor: Percent of maximum net energy produced for the period
- Service Factor: Percent of time on-line
- Equivalent Availability Factor: Percent of time available without outages or de-rates
- Scheduled Outage Factor: Percent of time on scheduled outage or de-rate
- Forced Outage Factor: Percent of time on forced outage or de-rate
- Equivalent Forced Outage Rate: Probability of being on a forced outage or de-rate
- Equivalent Forced Outage Rate Demand: Probability that units will not meet generating requirements for demand periods due to forced outages or de-rates.

The following table shows the same metrics for 2022 by fuel type.

ERCOT Region GADS Data Metric	Coal/Lignite	Gas	Jet Engine	CC Block	CC GT	CC ST
	Unweighted	Unweighted	Unweighted	Unweighted	Unweighted	Unweighted
# Units Reporting	19	40	122	18	149	61
Total Unit-Months	228	462	1344	216	1788	732
Net Capacity Factor (NCF)	59.5%	12.4%	10.4%	47.1%	55.9%	47.0%
Service Factor (SF)	80.5%	28.5%	12.5%	52.4%	66.4%	65.5%
Equivalent Availability Factor (EAF)	76.2%	73.3%	90.7%	76.6%	82.2%	80.1%
Scheduled Outage Factor (SOF)	9.2%	14.9%	4.3%	11.0%	11.8%	11.7%
Forced Outage Factor (FOF)	9.1%	6.7%	4.2%	4.0%	3.6%	6.0%
EFOR	15.1%	29.9%	26.3%	8.8%	5.4%	10.1%
EFORd	10.1%	20.3%	9.5%	5.7%	4.5%	7.5%

Table A.4 – ERCOT Generation Performance Metrics by Fuel Type for 2022

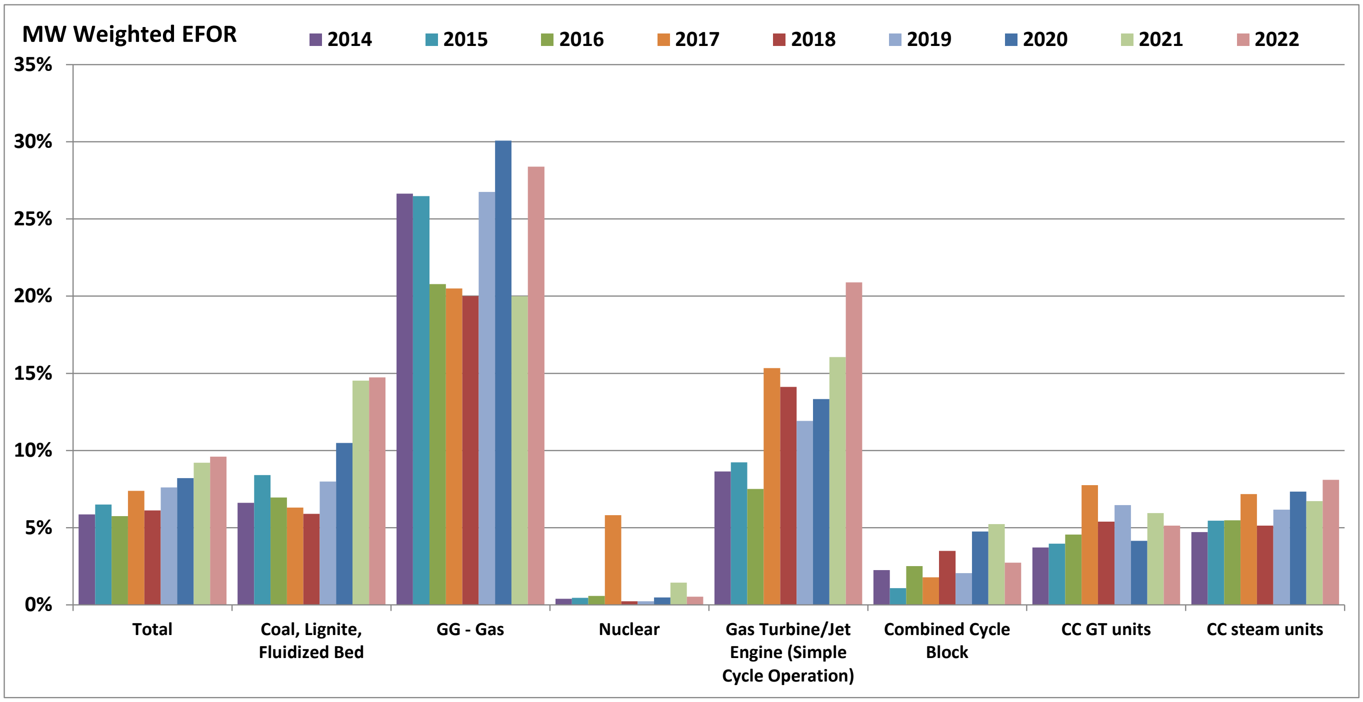


Figure A.13 – MW-Weighted EFOR Metric by Fuel Type and Year

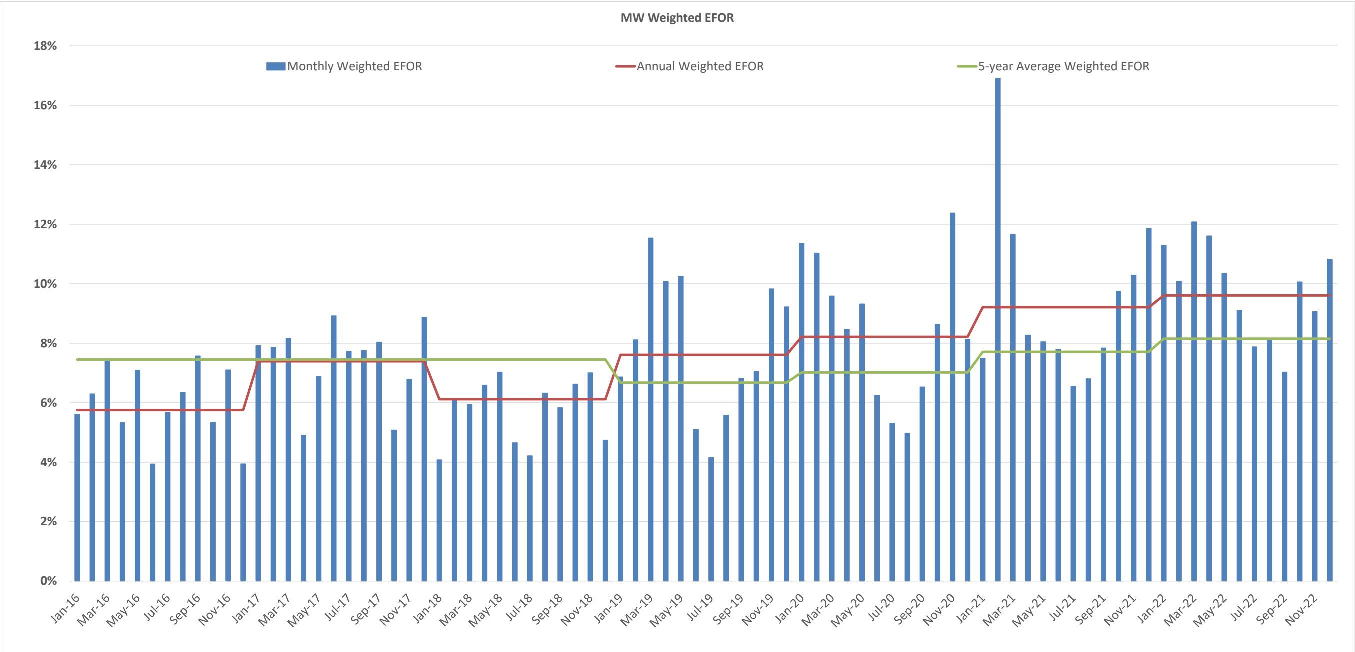


Figure A.14 – Time Trend for MW-Weighted EFOR

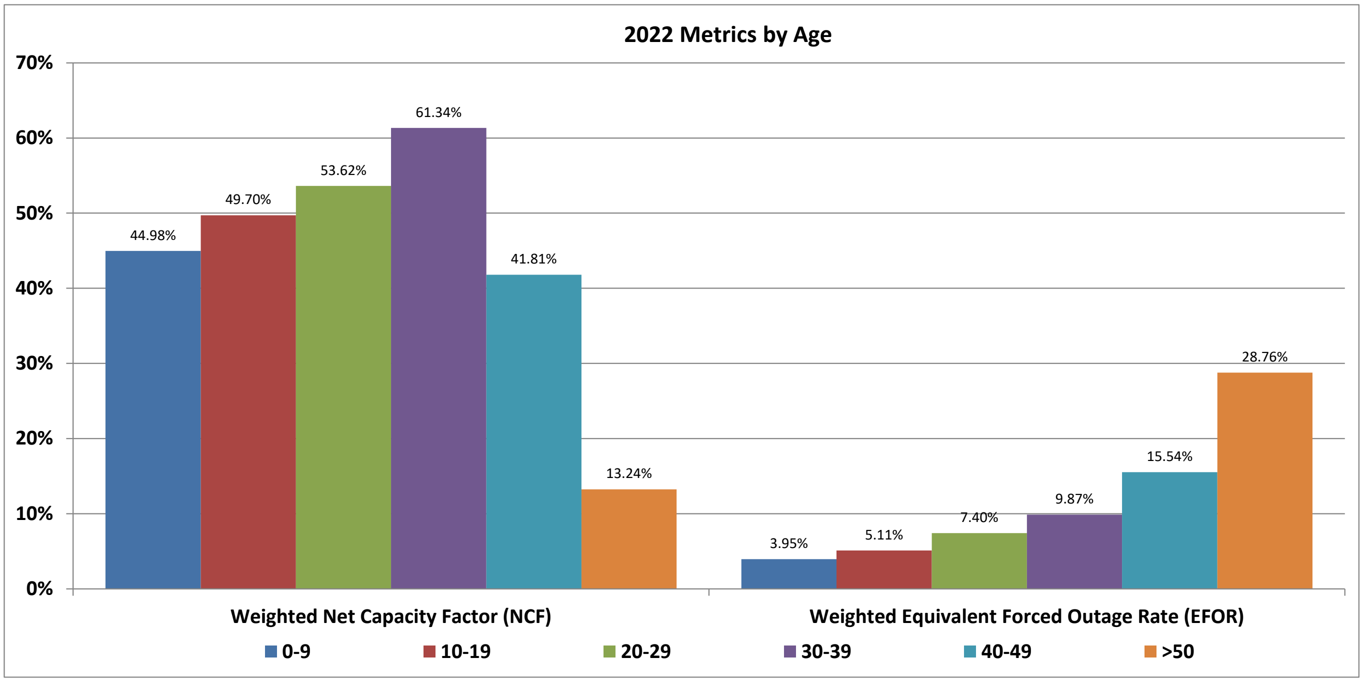


Figure A.15 – 2022 GADS Metrics by Unit Age (Years)

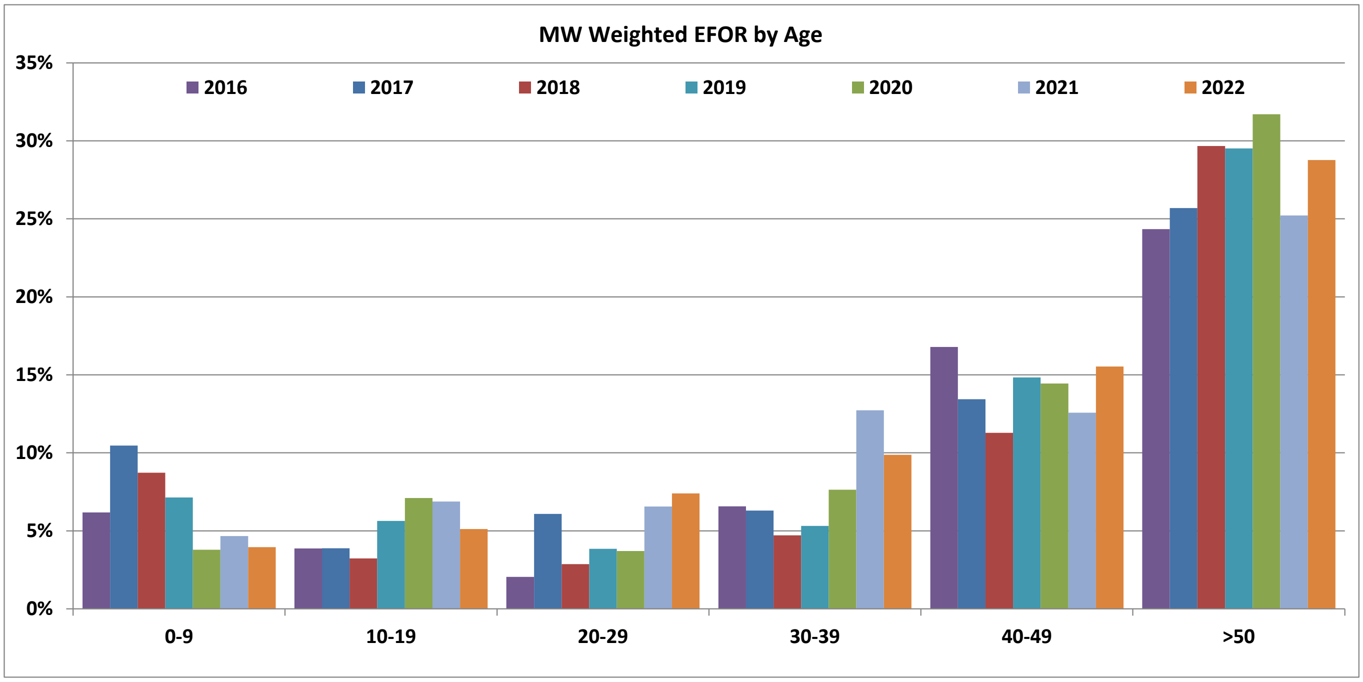


Figure A.16 – 2016-2022 GADS EFOR by Unit Age (Years)

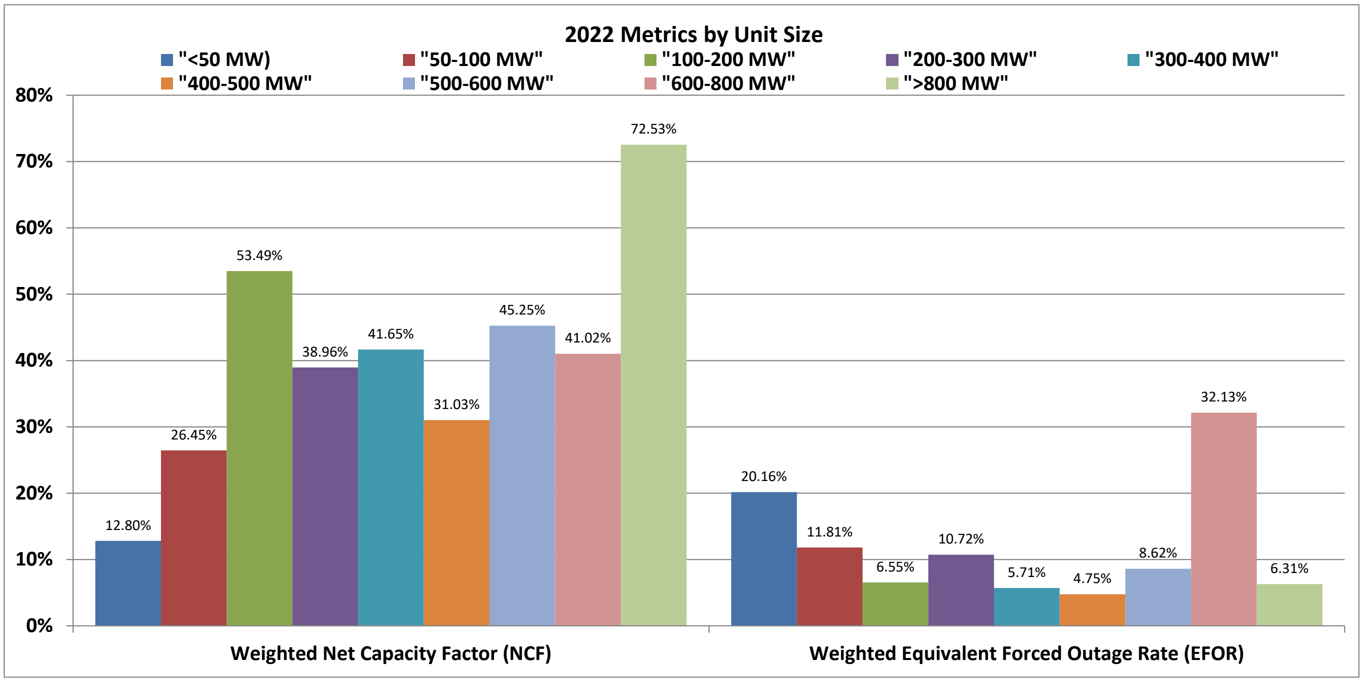


Figure A.17 – 2022 GADS Metrics by Unit Size

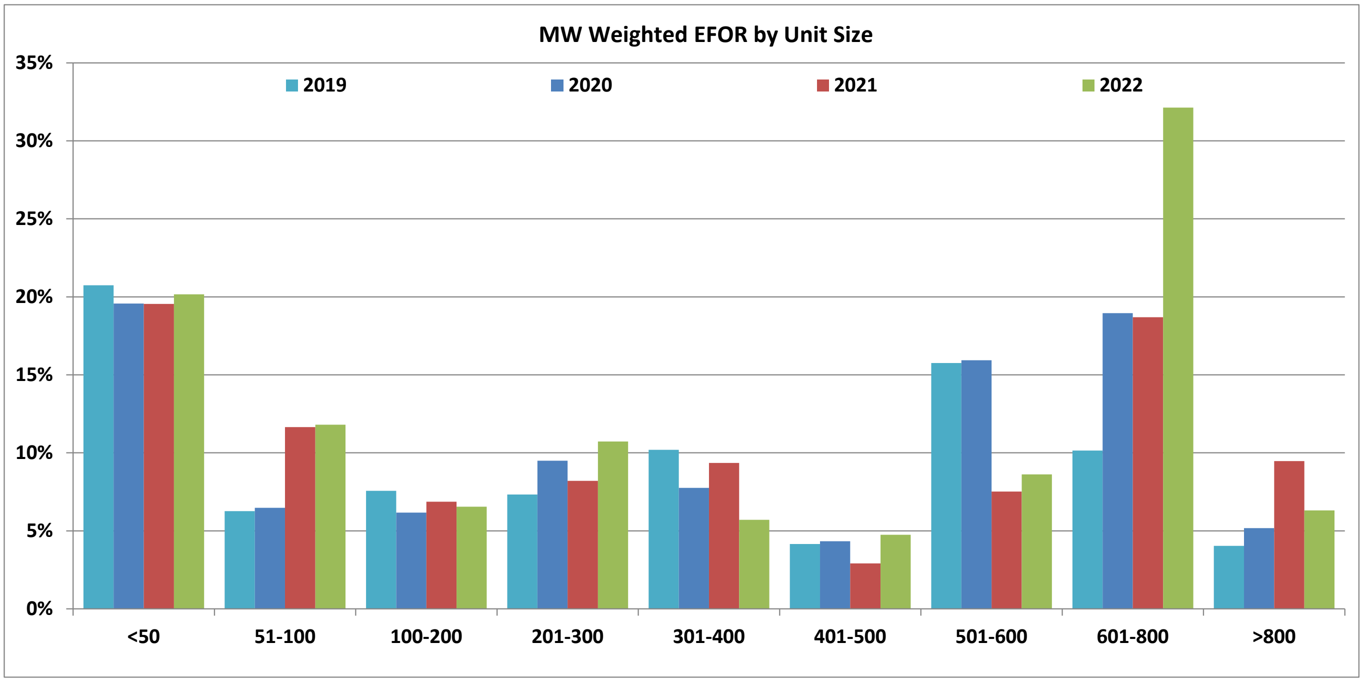


Figure A.18 – 2019-2022 GADS EFOR by Unit Size

2022 Fossil-fueled Generator Outages and De-rates

Table A.5 provides a summary of immediate de-rates and forced outages for conventional generation from January 2022 through December 2022. The 2,636 immediate forced outage events are equal to the number of forced outage events in 2021, with a median capacity of 181 MW per event nearly identical to last year's, as were the top three systems affected.

2022	Immediate De-rates	Immediate Forced Outages
Number of Events	2,366	2,636
Total Duration (hrs)	262,411.1	169,263.7
Total Capacity (MW)	257,969.9	477,574.5
Avg Duration per Event (hrs)	110.9	64.2
Median Duration per Event (hrs)	5.1	4.7
Avg Capacity per Event (MW)	109.0	181.2
Median Capacity per Event (MW)	78.0	151.0

Table A.5 – Generator Immediate De-rate and Forced Outage Data (Jan. – Dec. 2022)

The cause of the immediate forced outage events can also be further broken down into major categories based on the GADS data.

Major System	Number of Forced Outage Events	Total Duration (hours)	Total Capacity (MW)	Avg Duration per Event (hours)	Avg Capacity per Event (MW)
Boiler System	312	17,033.6	105,640.6	54.6	338.6
Balance of Plant	592	25,071.0	108,869.9	42.3	183.9
Steam Turbine/Generator	1394	92,262.5	210,091.7	66.2	150.7
Heat Recovery Steam Generator	67	9,935.6	10,301.1	148.3	153.7
Pollution Control Equipment	31	1,860.1	4,975.0	60.0	160.5
External	165	13,450.1	24,477.3	81.5	148.3
Regulatory, Safety, Environmental	20	651.7	2,143.7	32.6	107.2
Personnel/ Procedure Errors	50	181.4	10,850.7	3.6	217.0
Other	5	8818	224	1763.5	44.9

Table A.6 – 2022 Major Category Cause of Immediate Forced Outage Events from GADS

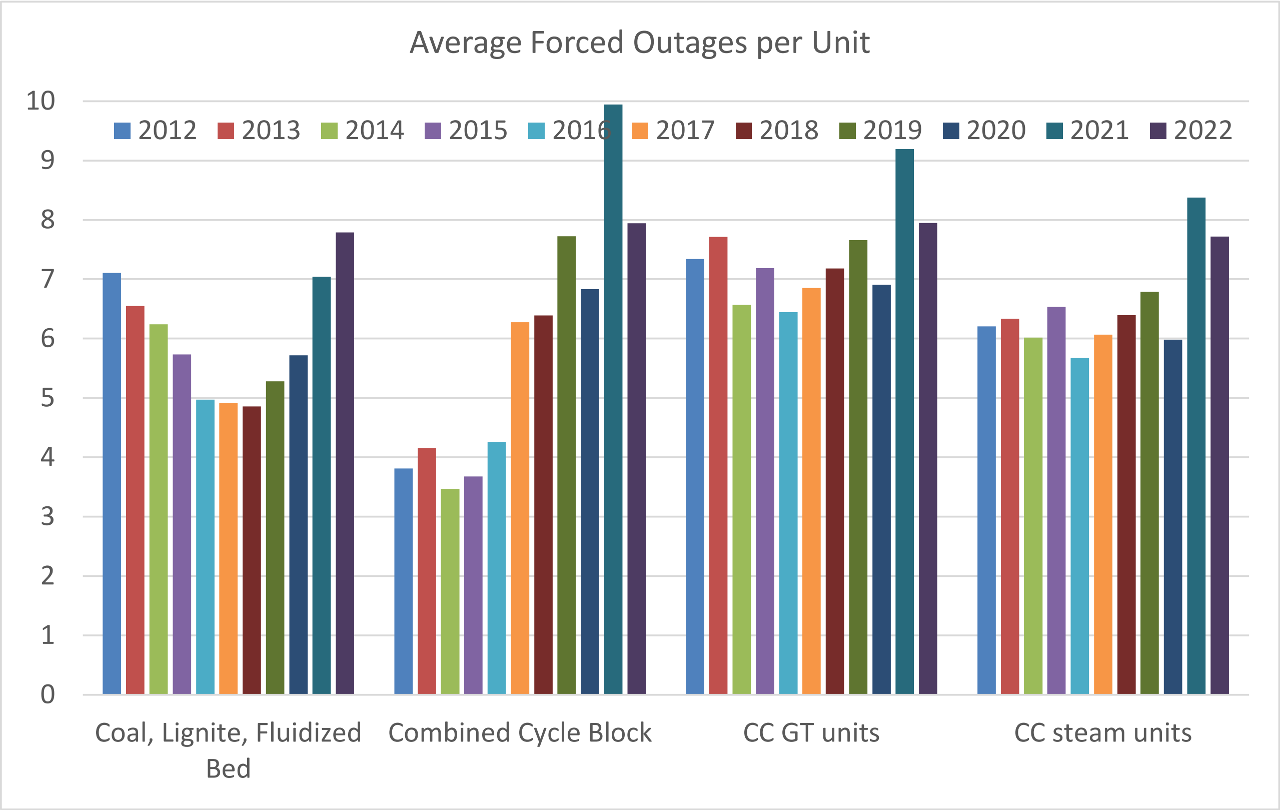


Figure A.19 – 2022 Average Forced Outages per Unit

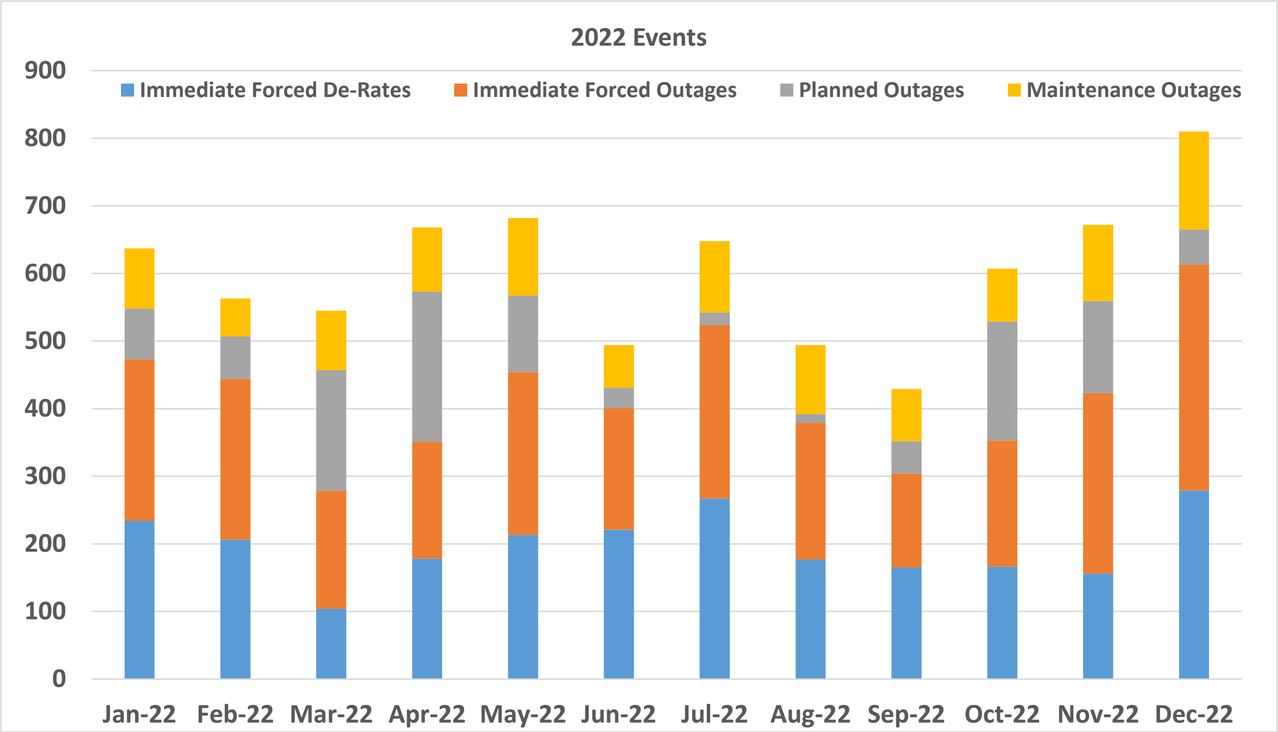


Figure A.20 –2022 Count of Generation Events by Month

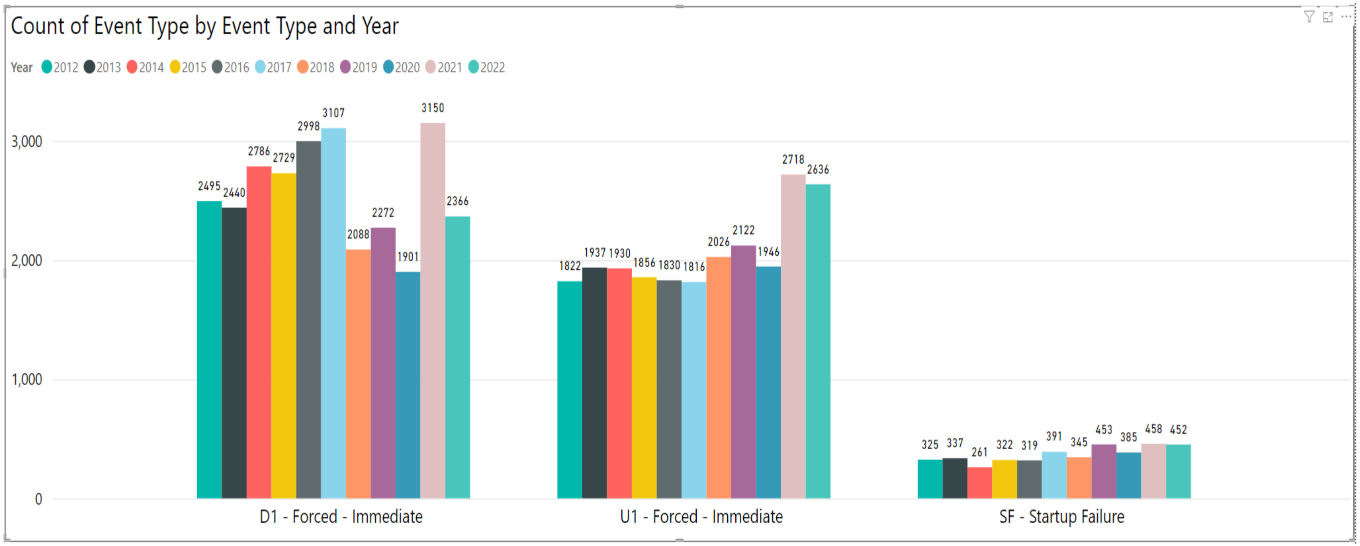


Figure A.21 – 2012-2022 Count of Events by Year

F. 2022 Renewable Generator Performance Metrics

Wind facilities greater than 200 MW began mandatory reporting in GADS-Wind in 2018. Wind facilities greater than 100 MW began mandatory reporting in GADS-Wind in 2019. All units began mandatory reporting in 2020. GADS-Wind provides similar metrics as GADS to compare unit-level and fleet-level performance. Two of these methods provide resource-level and equipment-level performance rates. In 2022, 261 ERCOT wind facilities and sub-groups submitted a total of 2,851 unit-months of data in GADS-Wind. Resource-level metrics look at the resource as a whole. Pooled equipment metrics provide a mechanism to look at sub-group performance of turbines of similar capacity. A summary of key performance metrics based on resource versus pooled equipment values for the ERCOT wind generators for 2019-2022 is provided in the following table.

Metric: ERCOT Region GADS-Wind Data	2019		2020		2021		2022	
	Resource	Equipment	Resource	Equipment	Resource	Equipment	Resource	Equipment
Net Capacity Factor (PRNCF and PENCF)	37.5%	39.7%	36.6%	39.6%	34.6%	38.1%	36.1%	39.4%
Equivalent Forced Outage Rate (PREFOR and PEEFOR)	12.1%	5.8%	14.7%	6.5%	16.6%	6.9%	17.1%	7.8%
Equivalent Scheduled Outage Rate (RESOR and PEESOR)	1.6%	1.5%	1.4%	1.3%	1.4%	1.3%	1.6%	1.4%
Equivalent Availability Factor (REAF and PEEAF)	87.0%	91.8%	84.7%	91.0%	82.9%	90.2%	82.2%	88.9%

Table A.7 – ERCOT Wind Generation Performance Metrics, 2019-2022

- Pooled Resource Equivalent Forced Outage Rate (PREFOR): Probability of forced plant downtime when needed for load.
- Resource Equivalent Scheduled Outage Rate (RESOR): Probability of maintenance or planned plant downtime when needed for load.
- Resource Equivalent Availability Factor (REAF): Percent of time the plant was available.
- Pooled Resource Net Capacity Factor (PRNCF): Percent of actual plant generation versus capacity.
- Pooled Equipment Equivalent Forced Outage Rate (PEEFOR): Probability of forced WTG equipment downtime when needed for load.
- Pooled Equipment Equivalent Scheduled Outage Rate (PEESOR): Probability of maintenance or planned WTG equipment downtime when needed for load.
- Pooled Equipment Net Capacity Factor (PENCF): Percent of actual WTG equipment generation while on-line versus capacity.
- Pooled Equipment Equivalent Availability Factor (PEEAF): Percent of time the WTG equipment was available.

GADS-Wind voluntary turbine outage data reporting for 2022 included 7,158 component outage reports totaling 939,444 turbine-hours of forced, planned, and maintenance outage duration.

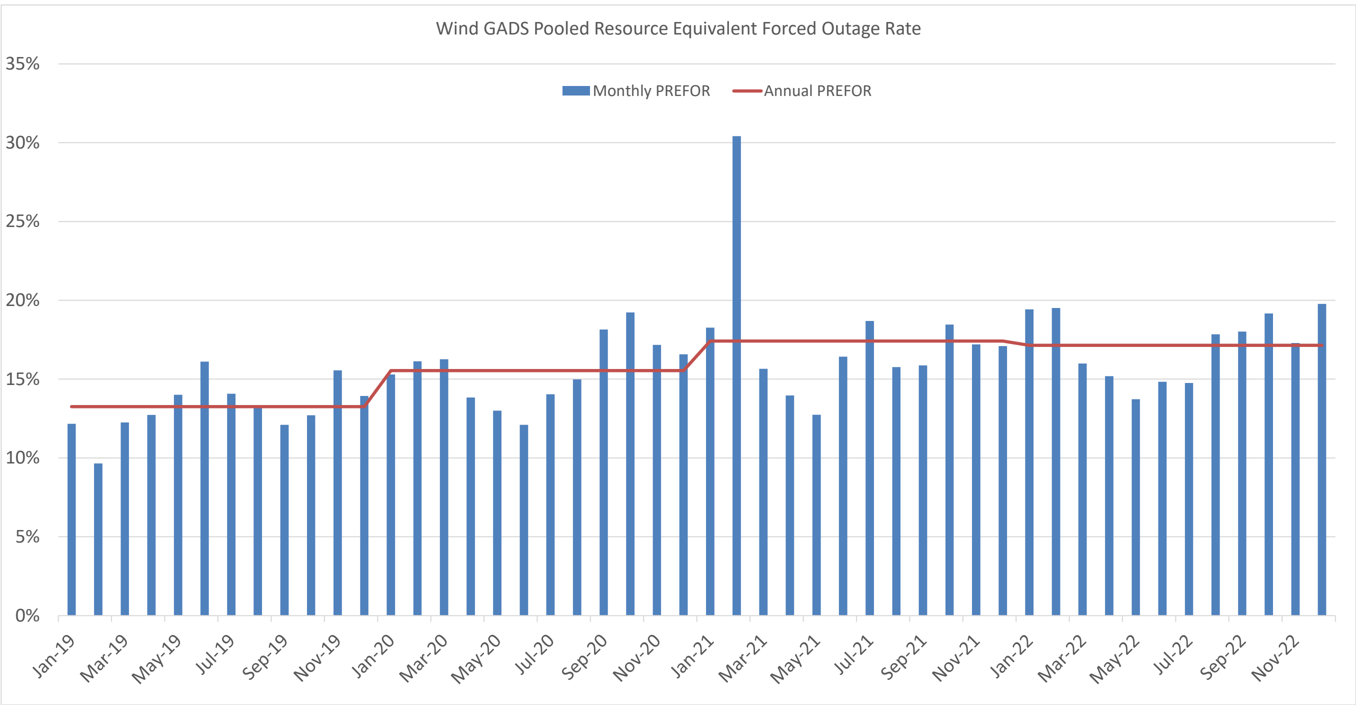


Figure A.22 – GADS-Wind Time Trend for MW-Weighted EFOR

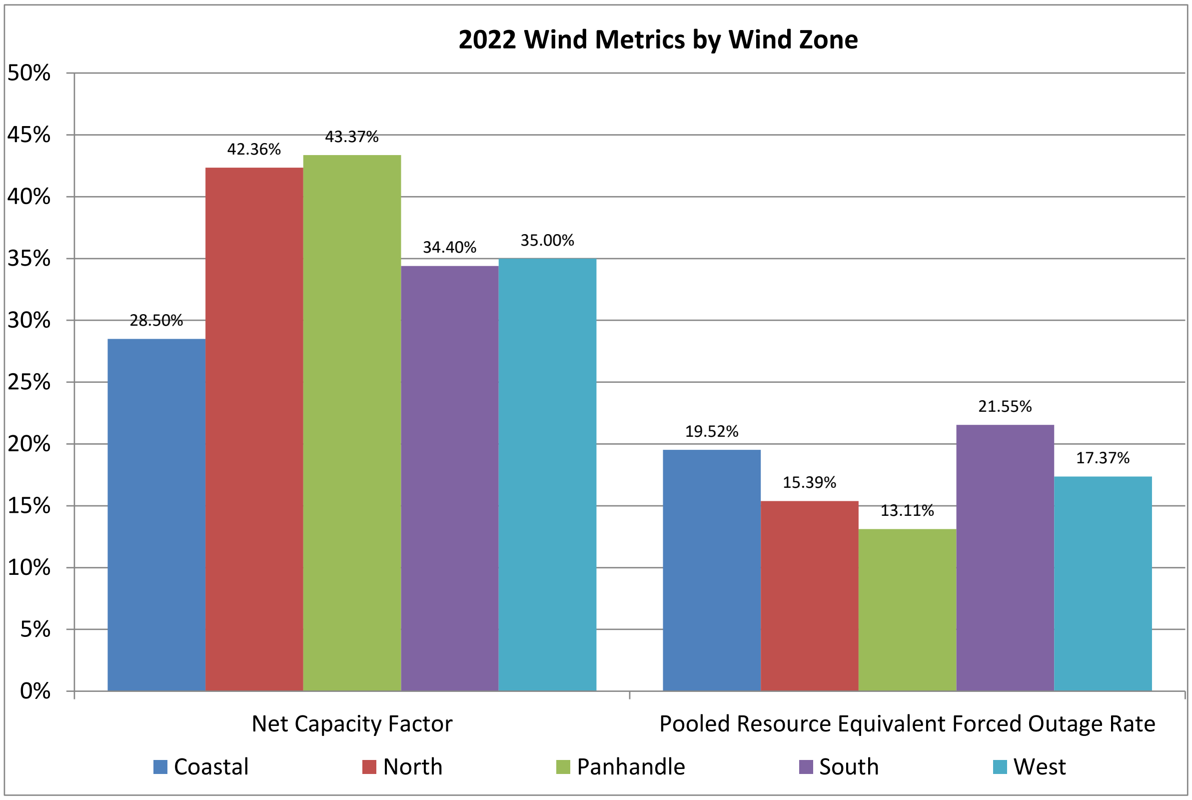


Figure A.23 – 2022 GADS-Wind Metrics by Wind Zone

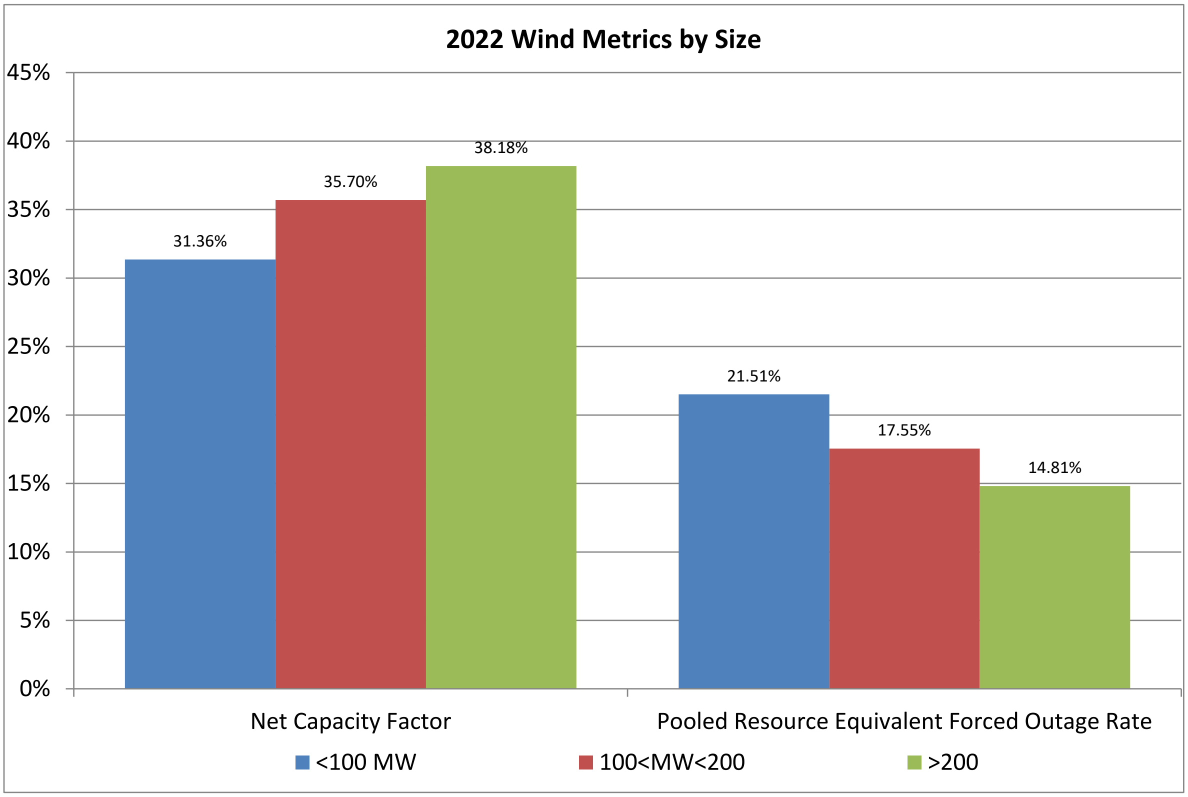


Figure A.24 – 2022 GADS-Wind Metrics by Unit Size

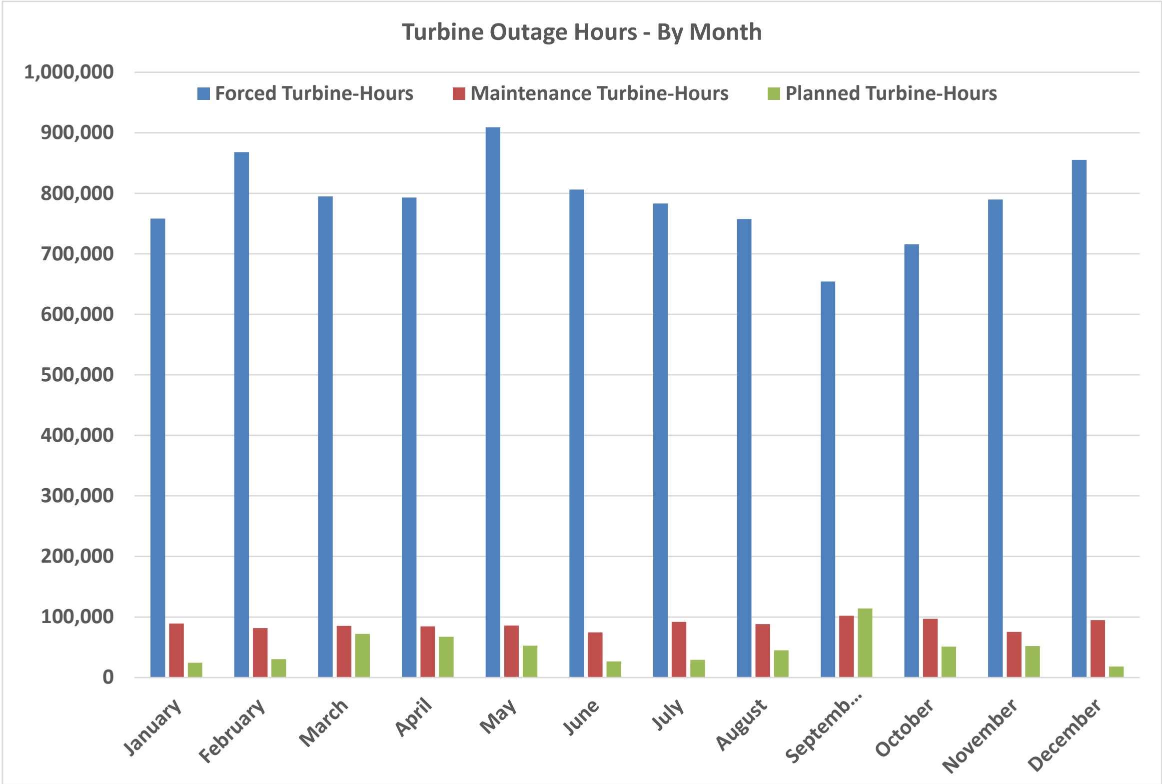


Figure A.25 – 2022 GADS-Wind Turbine Outage Hours by Month

G. Balancing Contingency Event Performance

Texas RE tracks the number of Balancing Contingency Events and recovery time within the Region to provide any potential adverse reliability indications. Per the NERC BAL-002-2 Disturbance Control Standard, a Reportable Disturbance is defined as any event which causes a change in Area Control Error greater than or equal to 800 MW. Note that the BAL-002 definition for a Reportable Balancing Contingency Event changed from 1,100 MW to 800 MW for ERCOT in January 2018 when BAL-002-2 went into effect.

As part of the Event Analysis process, Texas RE investigates the cause and relative effect on reliability of Balancing Contingency Events within the Region. Balancing Contingency Events greater than the MSSC (1,375 MW) typically do not create a significant reliability problem for the Region since ERCOT carries contingency reserves greater than the MSSC; however, these events warrant special consideration for review of system frequency response and recovery.

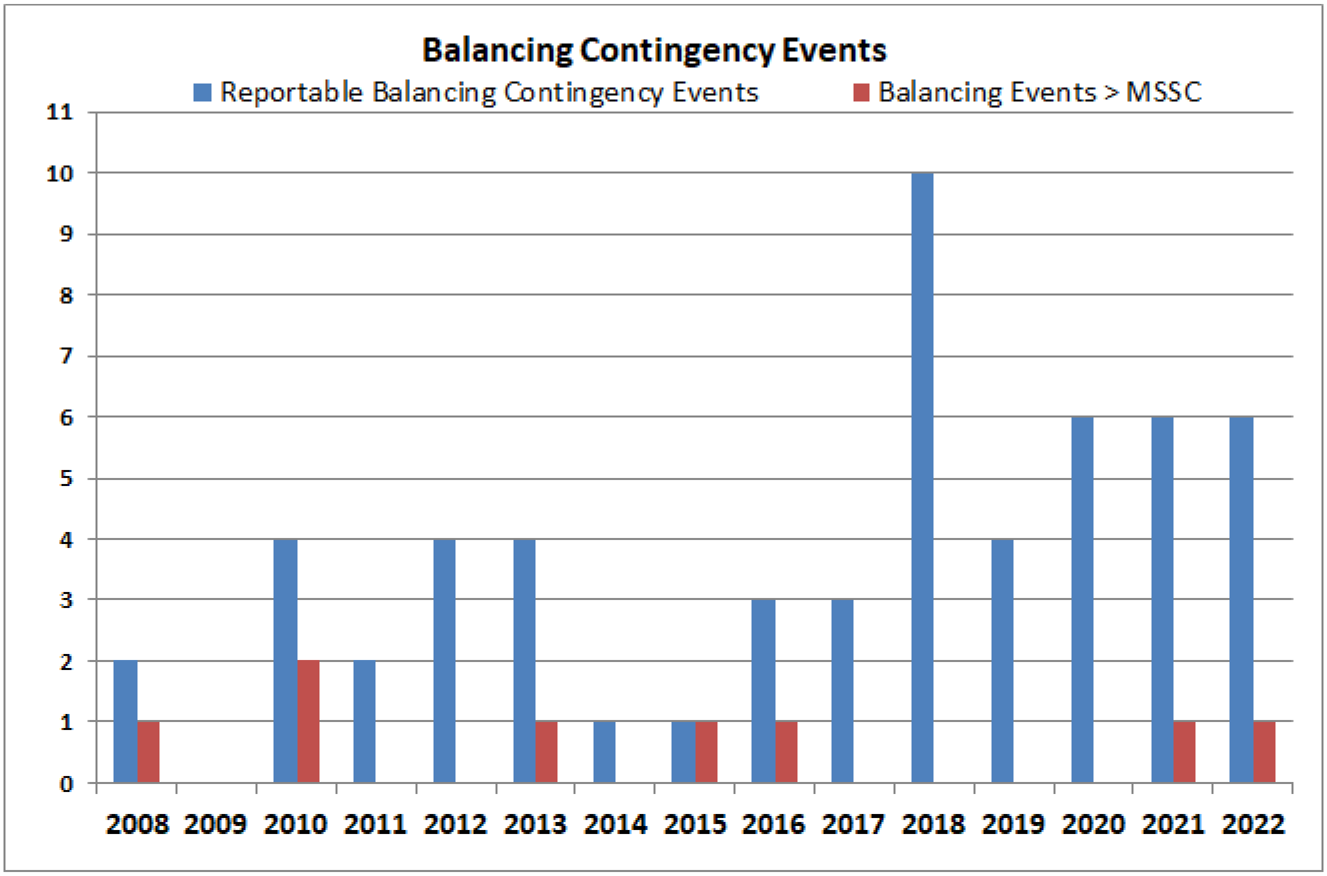


Figure A.26 – Reportable Balancing Contingency Events by Year

H. Fuel Constraints

There was a decrease in the unavailable generation capacity due to natural gas fuel curtailments in 2022 compared to 2021. The cumulative impact of gas curtailments for 2022 was comparable to 2014 and 2018, which also had severe winter weather events.

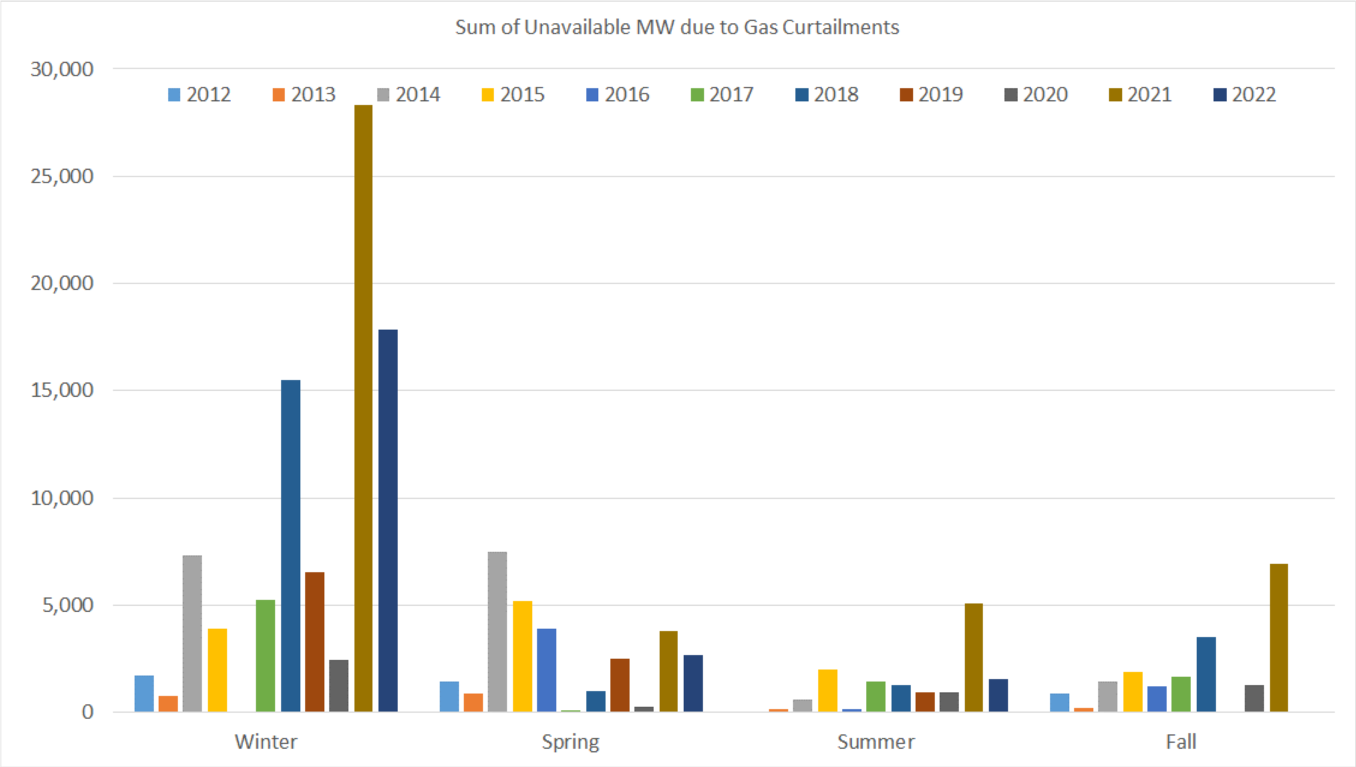


Figure A.27 – Cumulative Unavailable MW Due to Natural Gas Curtailments By Season

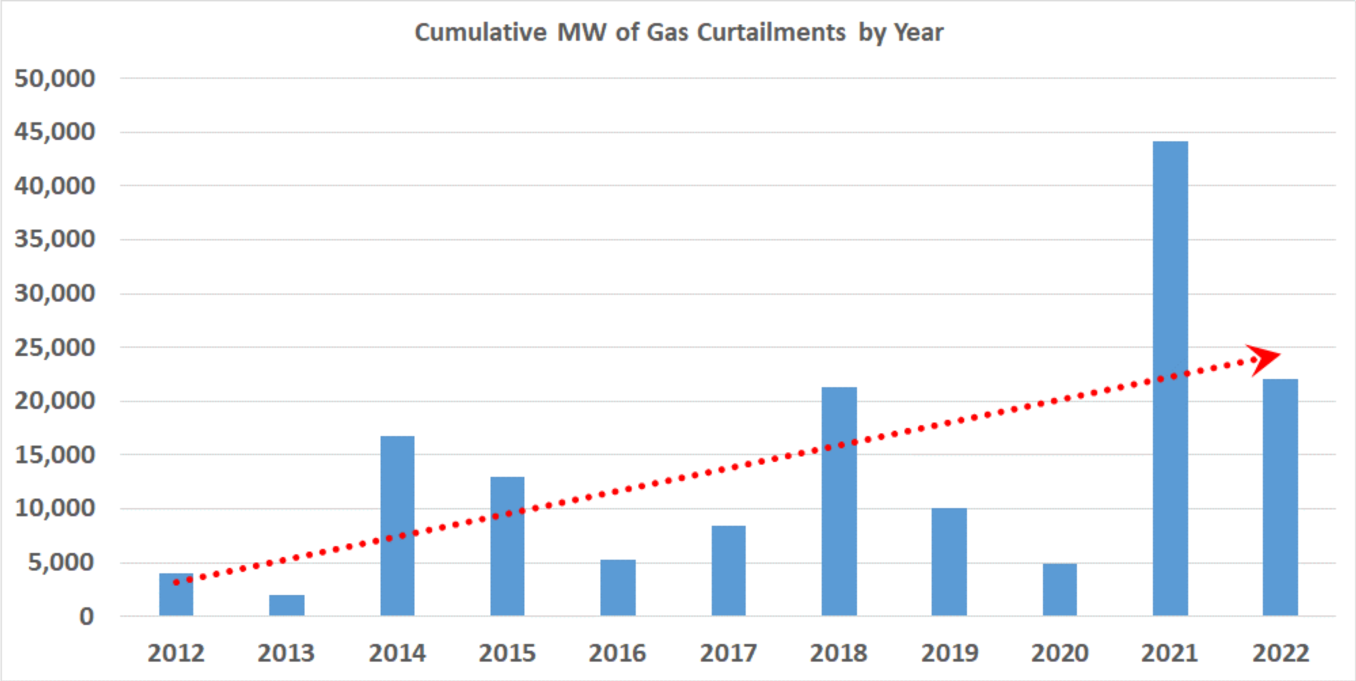


Figure A.28 – Cumulative Unavailable MW Due to Natural Gas Curtailments by Year

I. Demand Response

Three types of demand response are employed in the ERCOT region.

1. Load Resources (LR) providing Responsive Reserve Service (RRS) that are automatically interrupted by underfrequency relays when system frequency decreases to 59.7 Hz or below. These resources can also be manually deployed within 10 minutes by ERCOT in response to energy emergencies.

   Total registered capacity for Summer 2022 was 8,005 MW.

2. Emergency Response Service (ERS) is a service designed to be deployed by ERCOT as an operational tool under an EEA. ERS is designed to decrease the likelihood of ERCOT operating reserve depletion and the need for ERCOT to direct firm load shedding. Three types of ERS are procured, ERS-10 (ERS with a 10-minute ramp period), ERS-30 (ERS with a 30-minute ramp period), and weather-sensitive ERS.

   Total registered capacity for Summer 2022 was 890 MW.

3. Economic demand response is employed by non-opt-in entities (NOIEs), such as municipalities, for economic purposes in the form of commercial-industrial programs, smart thermostat programs, peak shaving programs, etc.

   Total registered capacity for Summer 2022 was 227 MW.

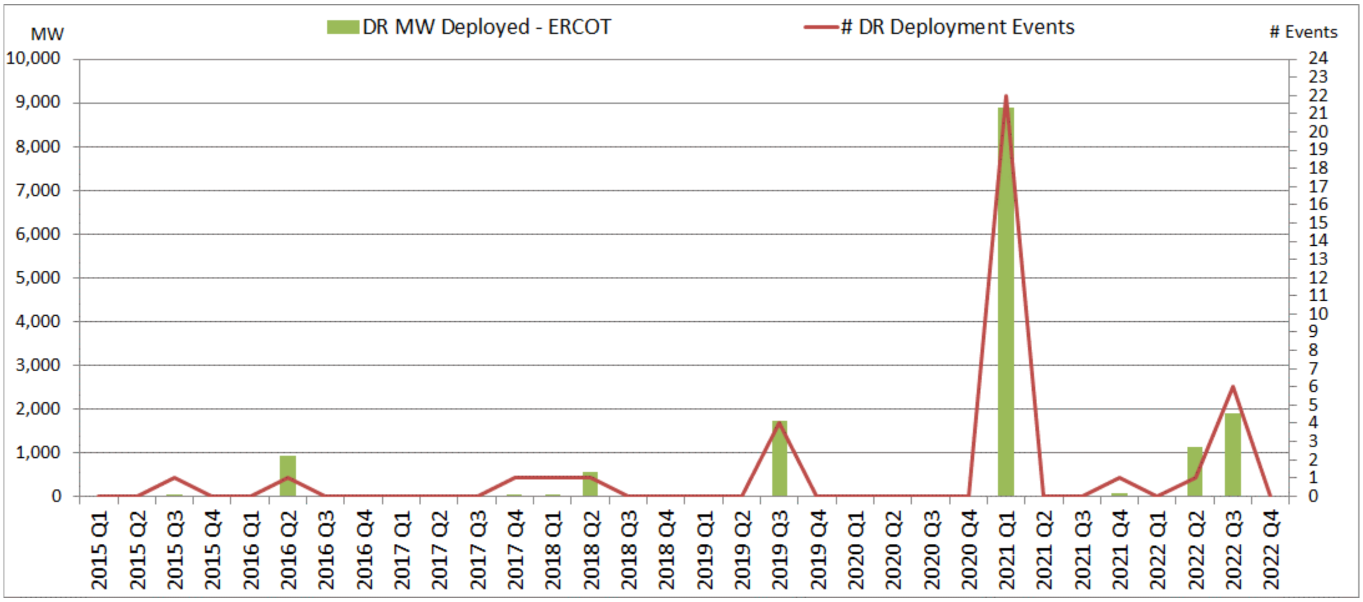


Figure A.29 – History of Demand Response Deployed by ERCOT

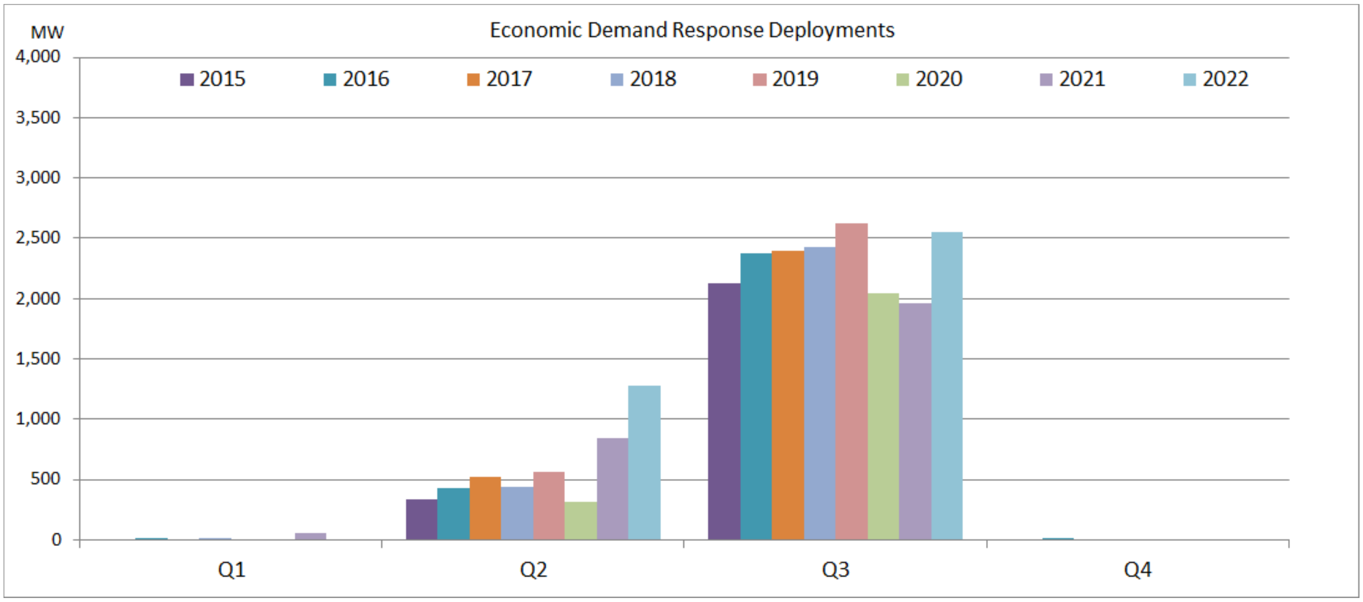


Figure A.30 – Cumulative MW of Economic Demand Response Deployments

Appendix B – System Resilience Detailed Analysis

A. Transmission Inventory Data (from NERC TADS)

For this analysis, transmission performance data is based on required reports submitted in the Transmission Availability Data System (TADS) under NERC Section 1600 of the Rules of Procedure. A summary of the aggregated ERCOT TADS elements, circuit miles, and outage data is shown in the following tables.

Year	Circuits (300-399 kV)	Circuit Miles (300-399 kV)	Transformers (300-399 kV)
2010	287	9384.7	
2011	307	9679.1	
2012	313	9884.0	
2013	370	13,071.6	
2014	394	13,976.1	
2015	408	14,605.0	206
2016	438	15,460.4	213
2017	456	15,886.3	217
2018	490	16,322.9	221
2019	514	17,357.7	223
2020	567	18,221.4	242
2021	604	18,808.3	252
2022	719	20,737.5	252

Table B.1 – 2010-2022 End of Year Circuit Data

	Automatic		Non-Automatic Operational	
Outage Information	Count	Duration (hours)	Count	Duration (hours)
2010	195	1,090.0	24	1,167.9
2011	276	1,908.6	66	7,096.1
2012	226	682.6	45	4,264.6
2013	197	1,935.6	32	7,877.4
2014	276	2,917.3	69	6,001.3
2015[1]	477	10,806.9	44	2,821.8
2016	436	6,446.1	43	3,645.6
2017	438	18,657.8	18	345.9
2018	334	22,619.0	27	3,472.9
2019	523	7,398.8	82	14,591.1
2020	471	6,103.8	137	28,351.5
2021	505	17,804.4	167	29,794.5
2022	441	9,155.3	195	14,128.9
5-Yr Average	455	12,616.3	122	18,067.8

Table B.2 – 2010-2022 345 kV Circuit and Transformer Outage Data

[1] Outage count and duration for 2015-2022 includes 345 kV transformers which began reporting in 2015

B. Event Analysis

The following significant events occurred in 2022:

- Loss of multiple elements on January 8, 2022: A fault occurred on a 345 kV transmission line combined with protective relay misoperations, causing the loss of two additional 345 kV lines.
- Loss of multiple elements on February 4, 2022: A 138 kV disconnect switch failed creating a system fault, combined with protective relay misoperations, causing the loss of multiple 138 kV and 69 kV elements and approximately 1,200 MW of generation, which impacted over 23,000 customers.
- Multiple solar unit loss on June 4, 2022: A fault occurred on a 345 kV transmission bus, causing the loss of over 1,700 MW of solar generation and over 850 MW of conventional generation.
- Loss of multiple elements on June 27, 2022: A fault occurred on a 138 kV disconnect switch creating a system fault, combined with protective relay misoperations, causing the loss of approximately 320 MW of generation and multiple 138 kV and 69 kV lines.
- Loss of multiple elements on July 26, 2022: A fault occurred on a 345 kV transmission line combined with protective relay misoperations, causing the loss of two additional 345 kV lines and a generation facility.
- Loss of multiple elements on September 6, September 11, and September 15, 2022: Multiple relay failure events at the same 138kV substation caused the loss of 138kV transmission lines and a generation facility.
- Loss of multiple elements on October 21, 2022: A fault occurred on a 345 kV transmission line causing the non-consequential loss of over 540 MW of wind generation.
- Loss of multiple elements on October 31, 2022: A fault occurred on a 345 kV autotransformer combined with protective relay misoperations, causing the loss of four 138 kV lines, approximately 680 MW of generation, and 500 MW of load.
- Loss of multiple elements on December 7, 2022: A 138 kV potential transformer failed, combined with 138 kV circuit breaker failure, causing the loss of multiple138 kV lines and approximately 1,600 MW of voltage-sensitive load reduction.

  Historical Disturbance Data: In 2022, the number of events reported remained steady when compared to the average number of events from 2018 through 2022.

Event Category[2]	2018	2019	2020	2021	2022	5-Yr Avg
Non-Qualified	78	73	84	74	70	76
1	13	11	8	14	11	11
2	0	0	0	0	1	0
3	0	0	0	0	1	0
4 and 5	0	0	0	1	0	0
Total	91	84	92	89	83	88

[2] Link to NERC Events Analysis Process with category definitions: https://www.nerc.com/pa/rrm/ea/ERO_EAP_Documents%20DL/ERO_EAP_v4.0_final.pdf

Table B.3 – Summary of Event Analyses

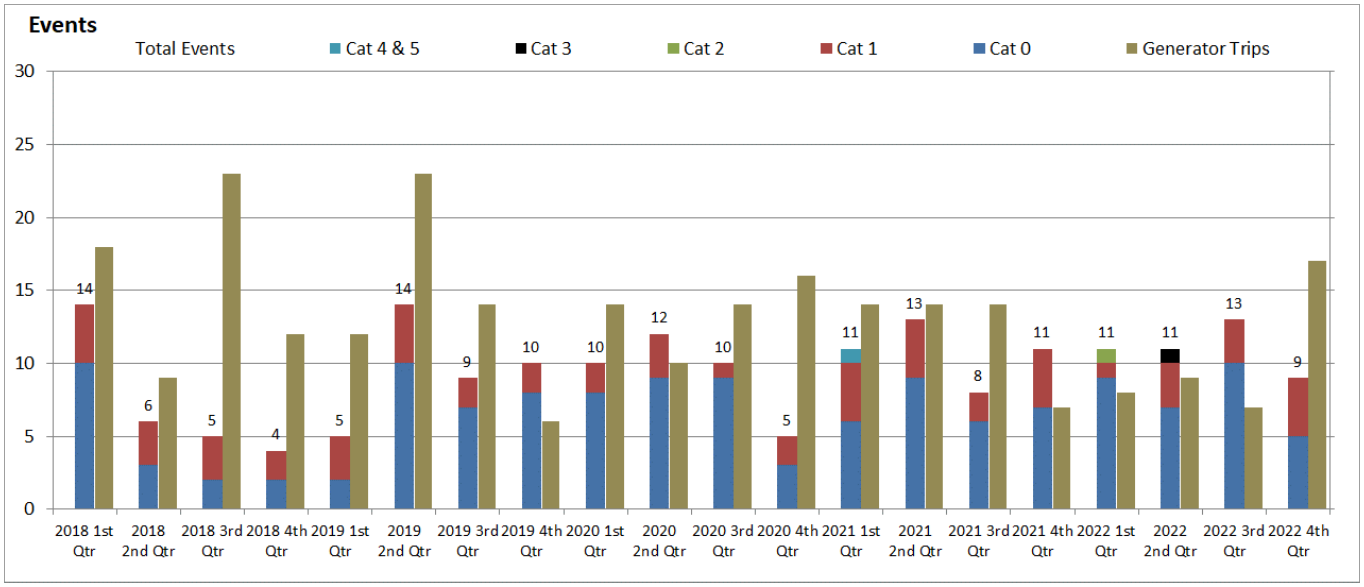


Figure B.1 – Events Reported by Quarter

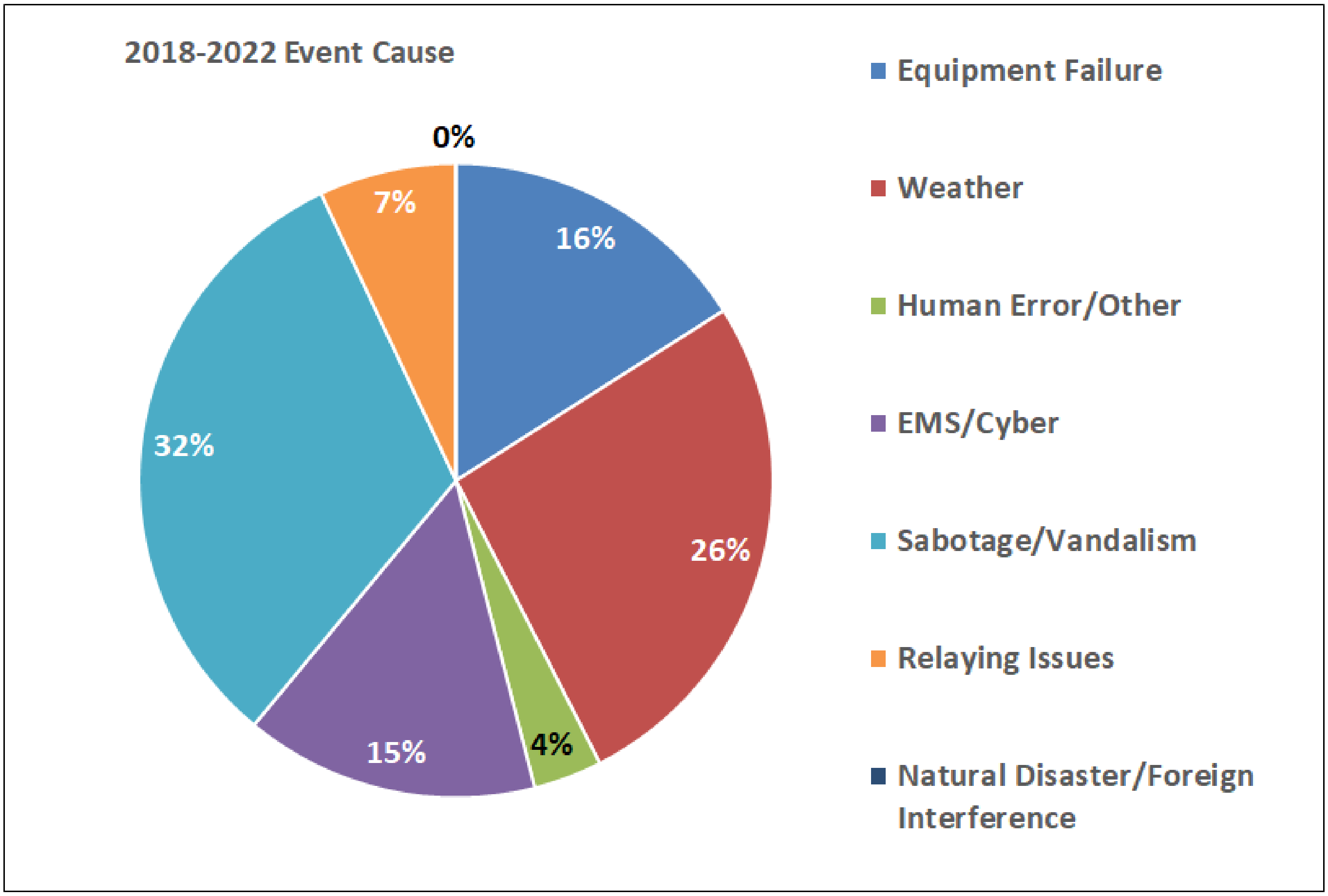


Figure B.2 – 2018-2022 Event Cause Summary

C. Transmission Circuit Outage Data

Long-term trends are indicating stable trends in outage rates per circuit and per 100 miles of line for the 345 kV and 138 kV systems.

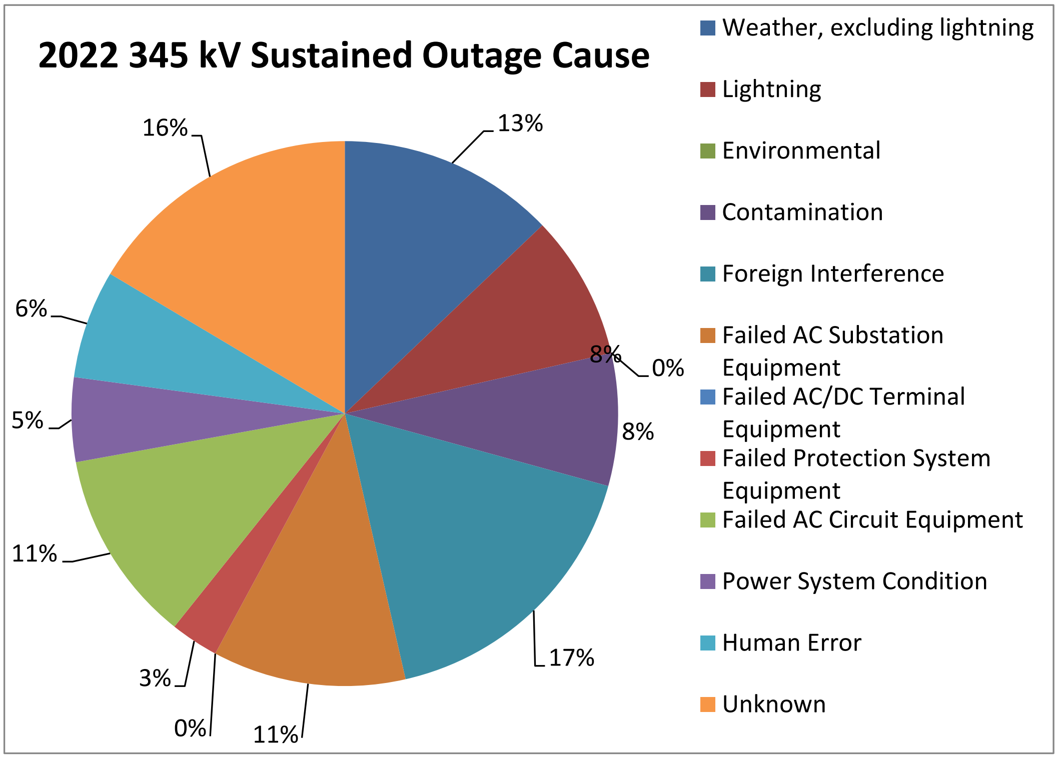
Voltage Class Name	Metric	2018	2019	2020	2021	2022	5-Yr Avg
AC Circuit 300-399 kV	Automatic Outages per Circuit	0.66	1.02	0.82	0.80	0.62	0.78
AC Circuit 300-399 kV	Automatic Outages per 100 miles	1.98	2.97	2.45	2.52	2.04	2.39
AC Circuit 100-199 kV	Sustained Automatic Outages per Circuit	0.22	0.19	0.19	0.29	0.25	0.23
AC Circuit 100-199 kV	Sustained Automatic Outages per 100 miles	1.87	1.65	1.61	2.50	2.25	1.98
Transformer 300-399 kV	Automatic Outages per Element	0.13	0.16	0.10	0.13	0.08	0.12

Table B.4 – TADS Circuit and Automatic Outage Historical Data for ERCOT Region

Automatic Outage Data

For 345 kV transmission circuits, predominant causes for sustained outages in 2022 were weather (excluding lightning), unknown, and foreign interference, representing 45 percent of the total sustained outages. Failed transmission circuit equipment accounted for 61 percent of the outage duration.

For 138 kV transmission circuits, predominant causes for sustained outages in 2022 were foreign interference, unknown, failed circuit equipment, and failed substation equipment, representing 61 percent of the total sustained outages. Failed transmission circuit equipment and foreign interference accounted for 60 percent of the outage duration.



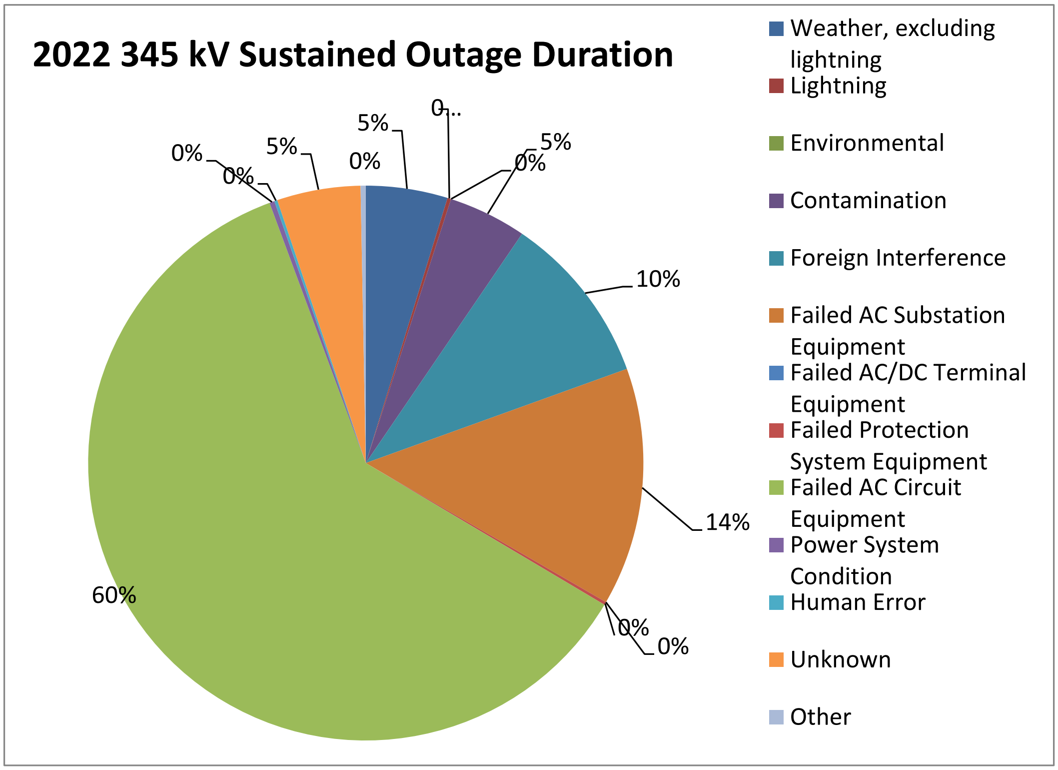
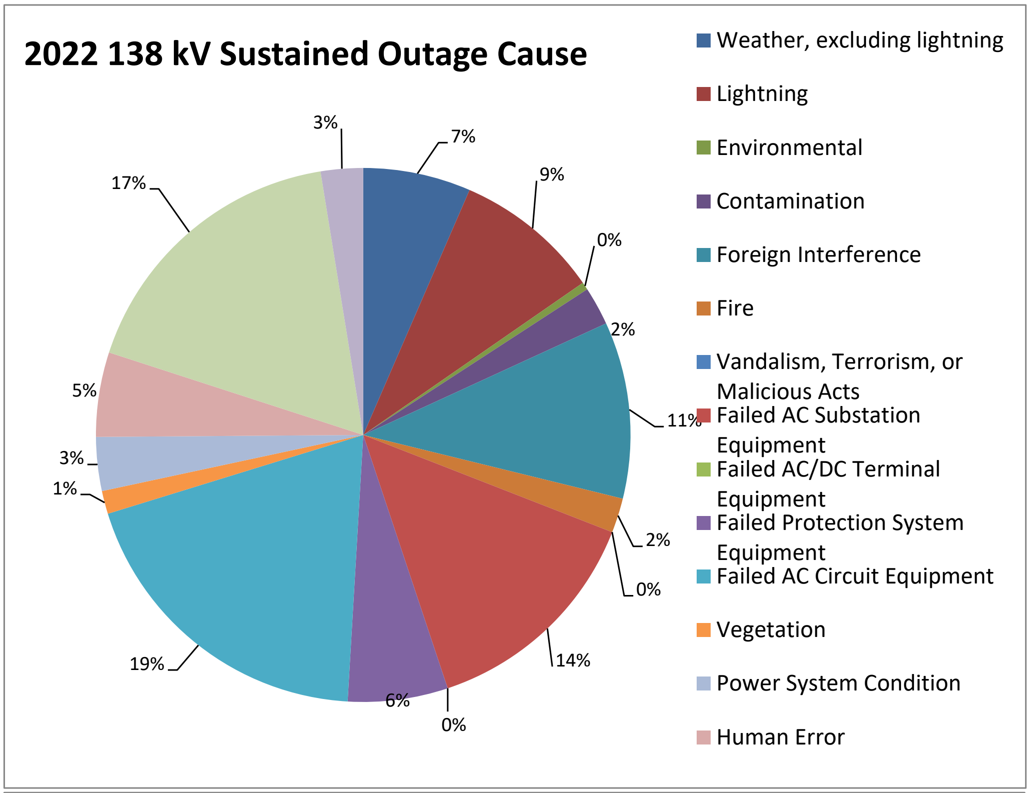


Figure B.3 – 2022 345 kV Sustained Outage Cause versus Duration



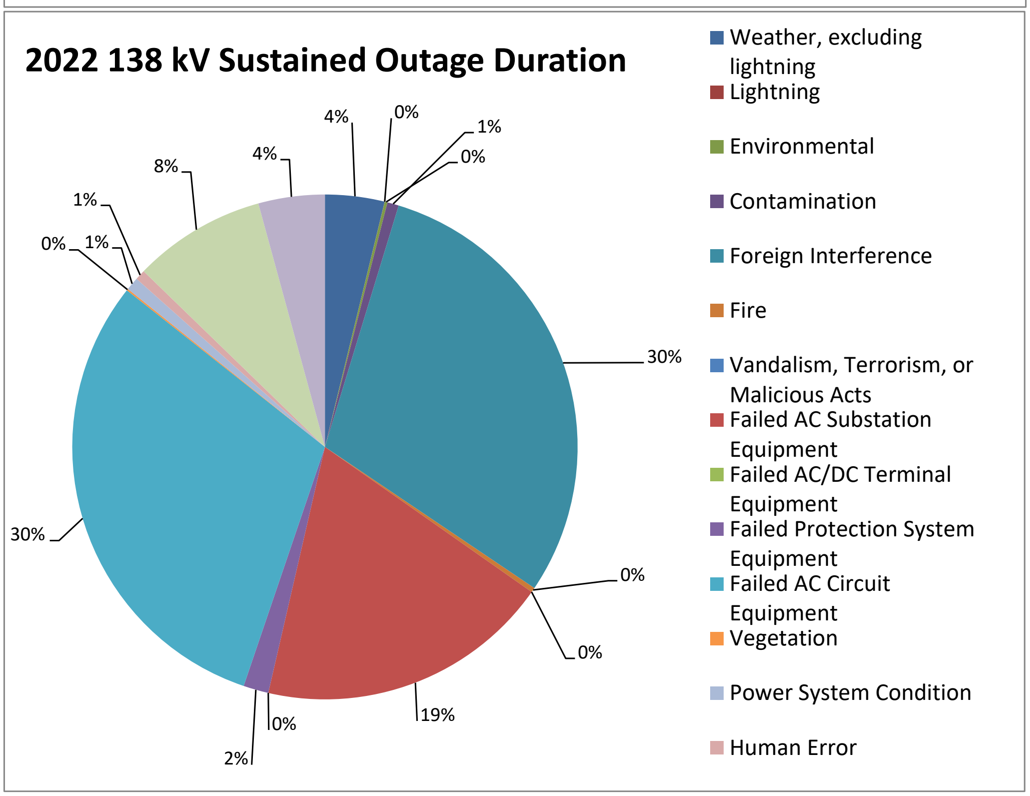


Figure B.4 – 2022 138 kV Sustained Outage Cause versus Duration

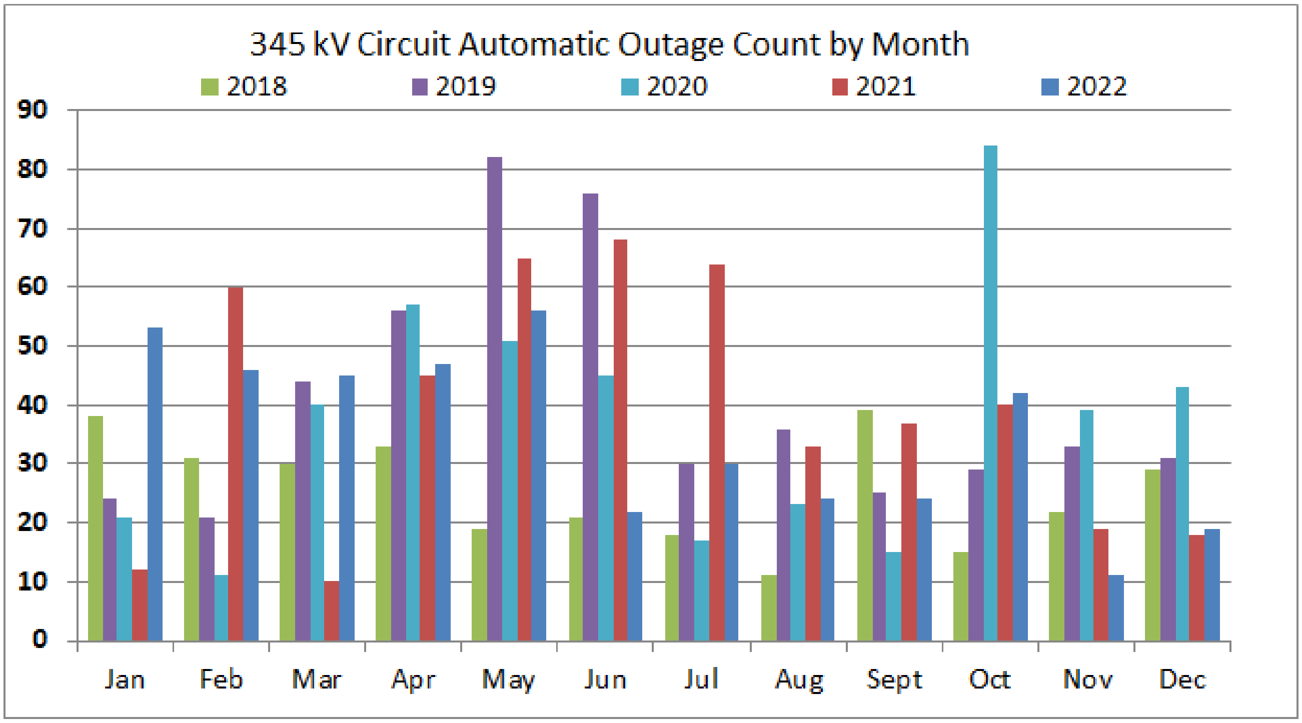


Figure B.5 – 345 kV Circuit Automatic Outages by Month

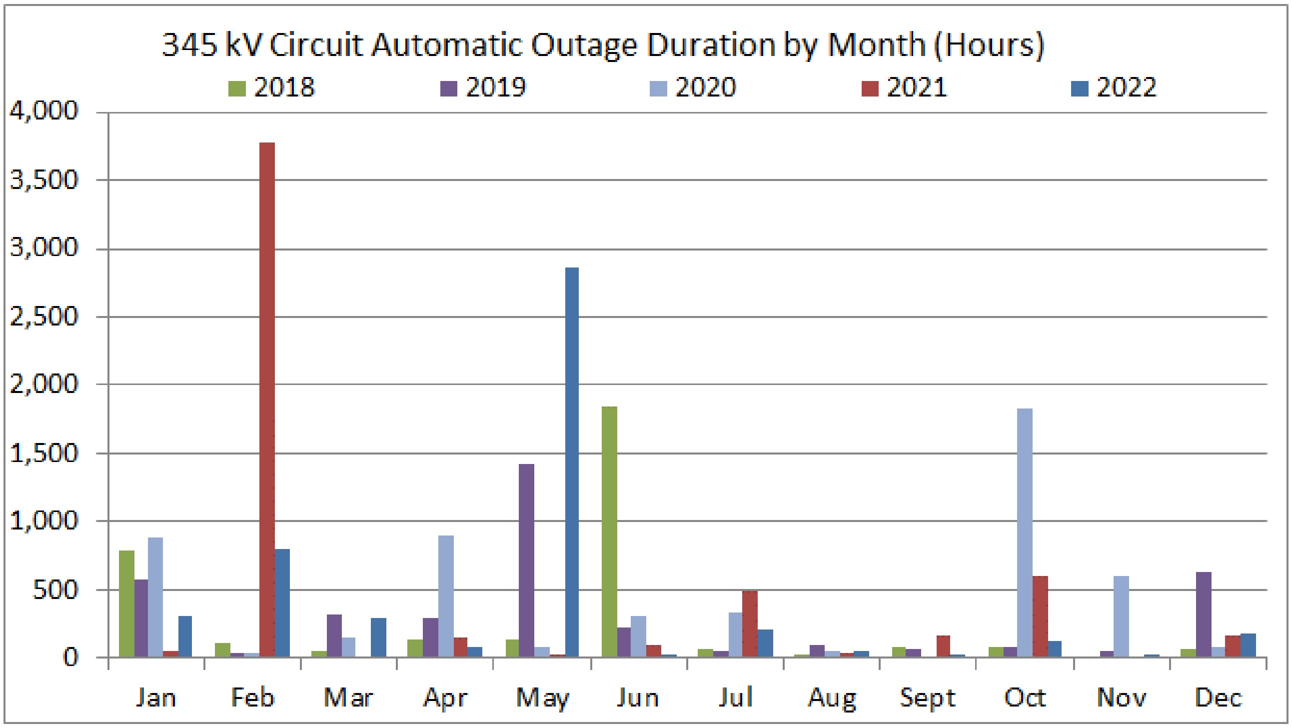


Figure B.6 – Multi-Year Comparison of TADS Outages and Duration by Month (> 200 kV)

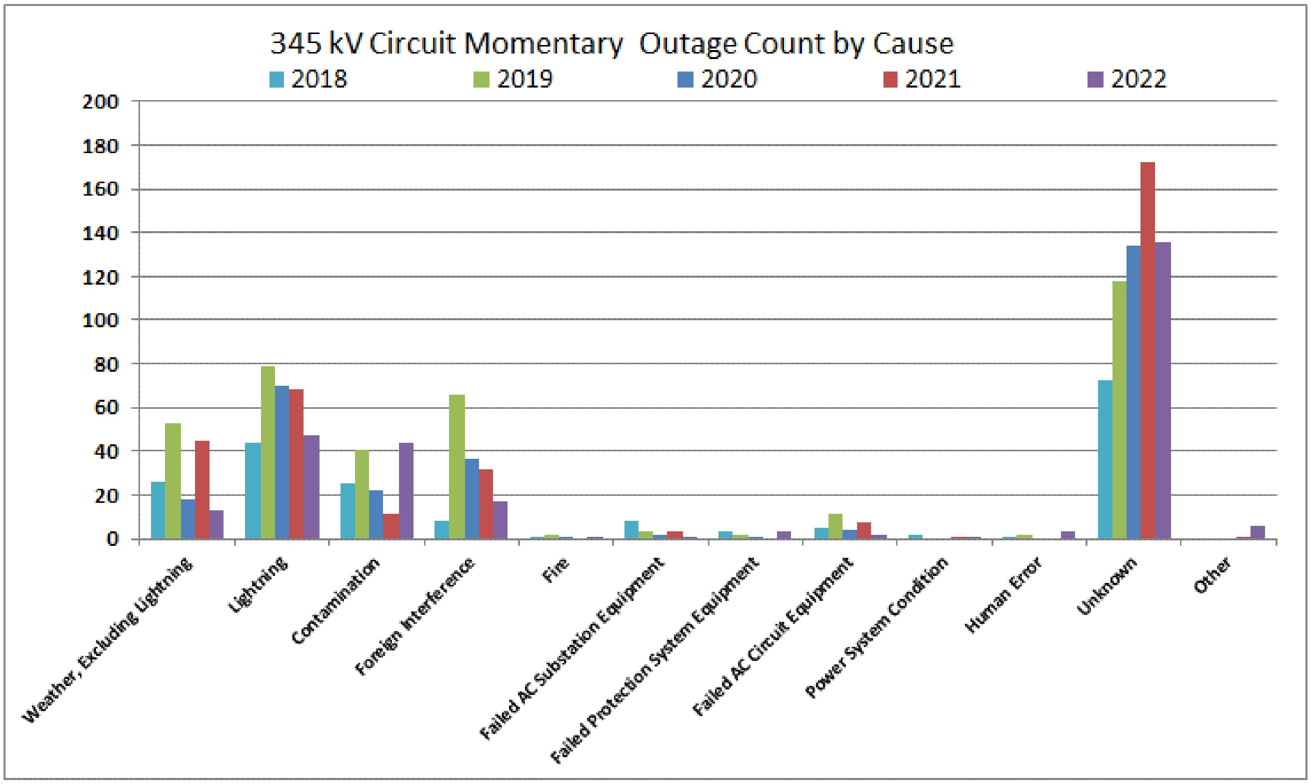


Figure B.7 – 345 kV Circuit Momentary Outage Count by Cause

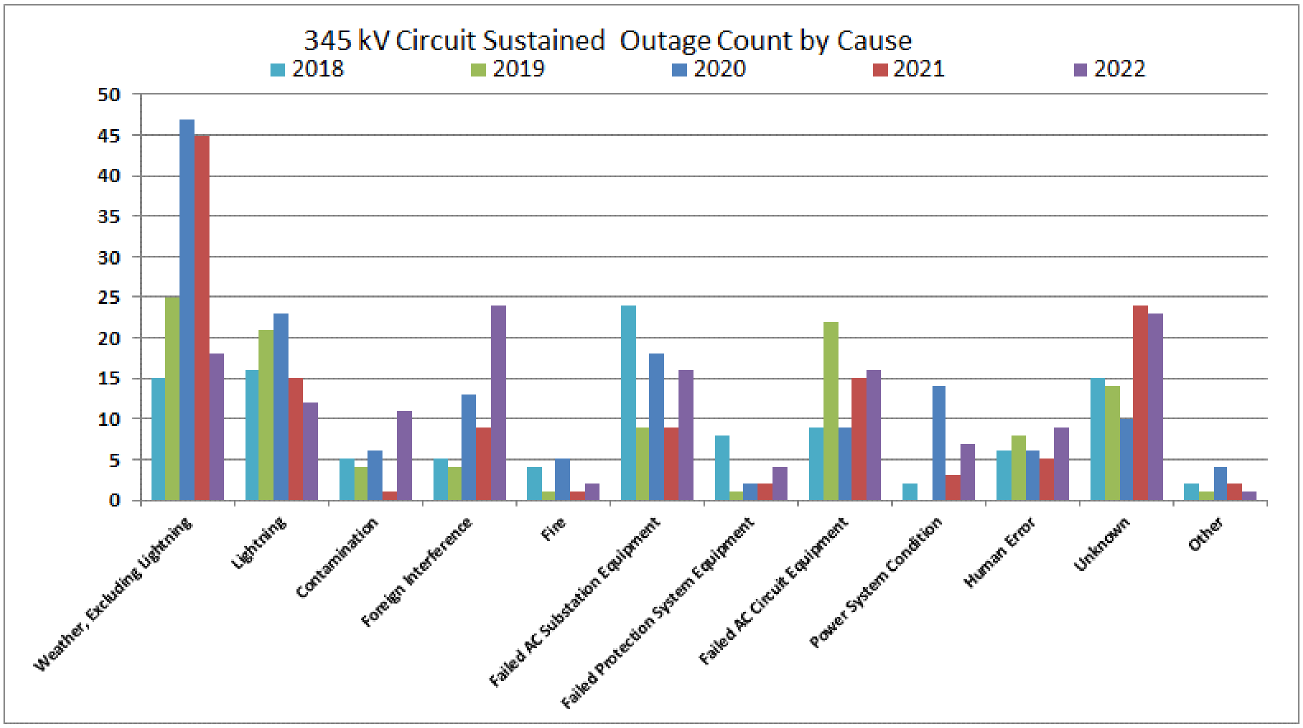


Figure B.8 – 345 kV Circuit Sustained Outage Count by Cause

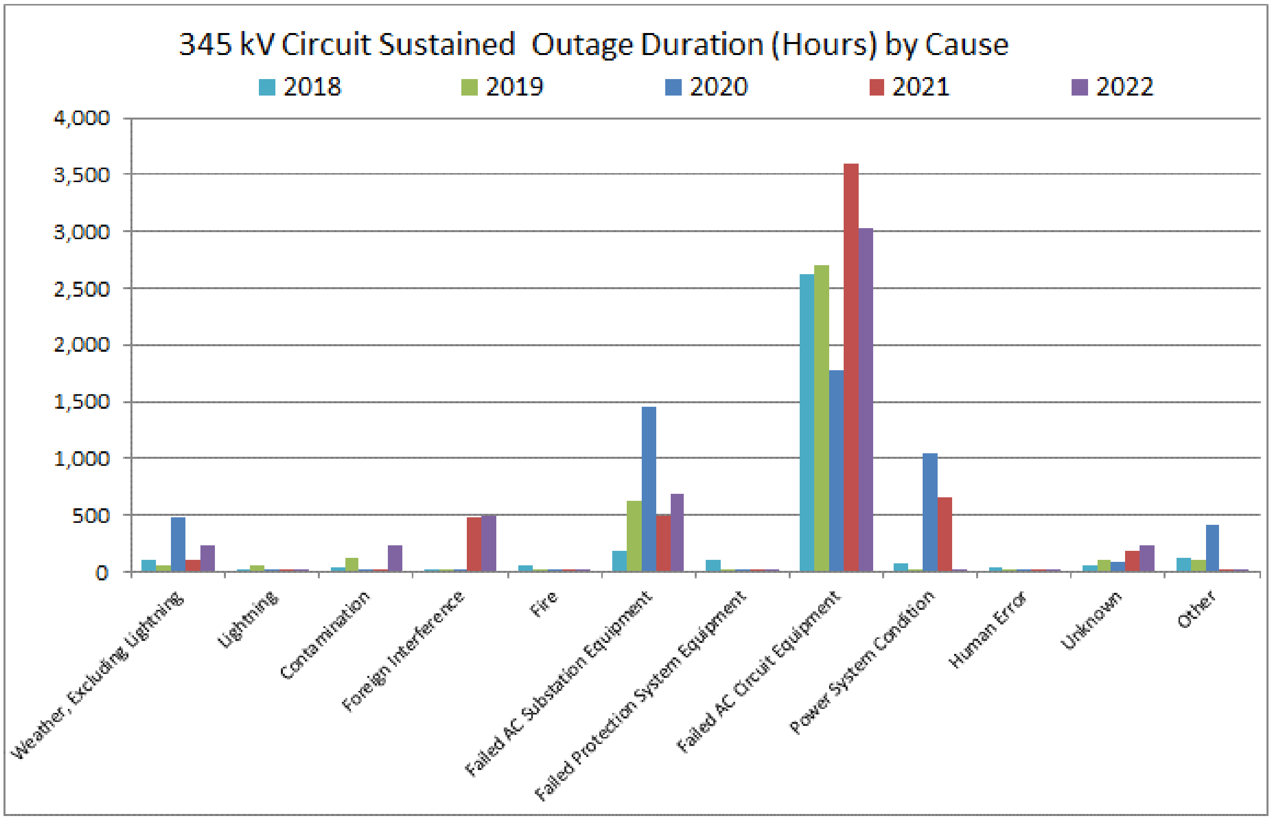


Figure B.9 – 345 kV Circuit Sustained Outage Duration (Hours) by Cause

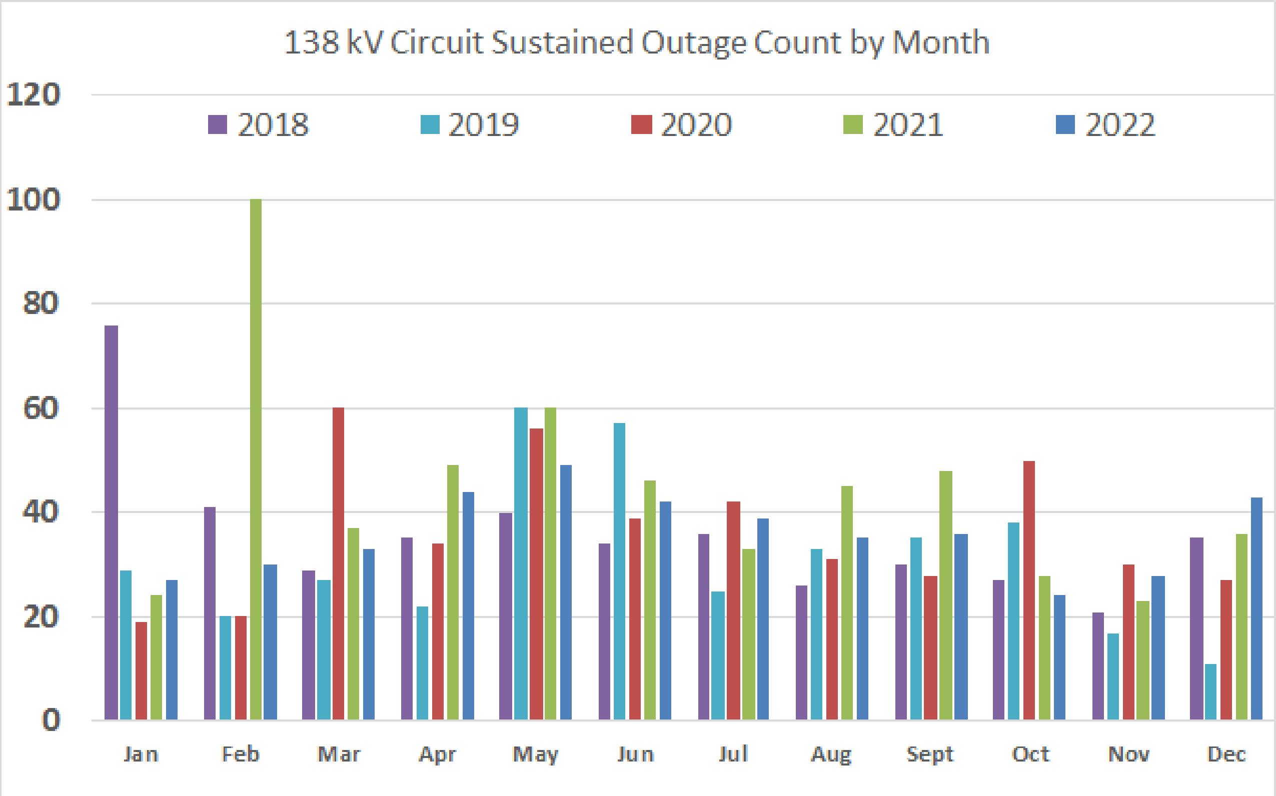


Figure B.10 – 138 kV Circuit Sustained Outage Counts by Month

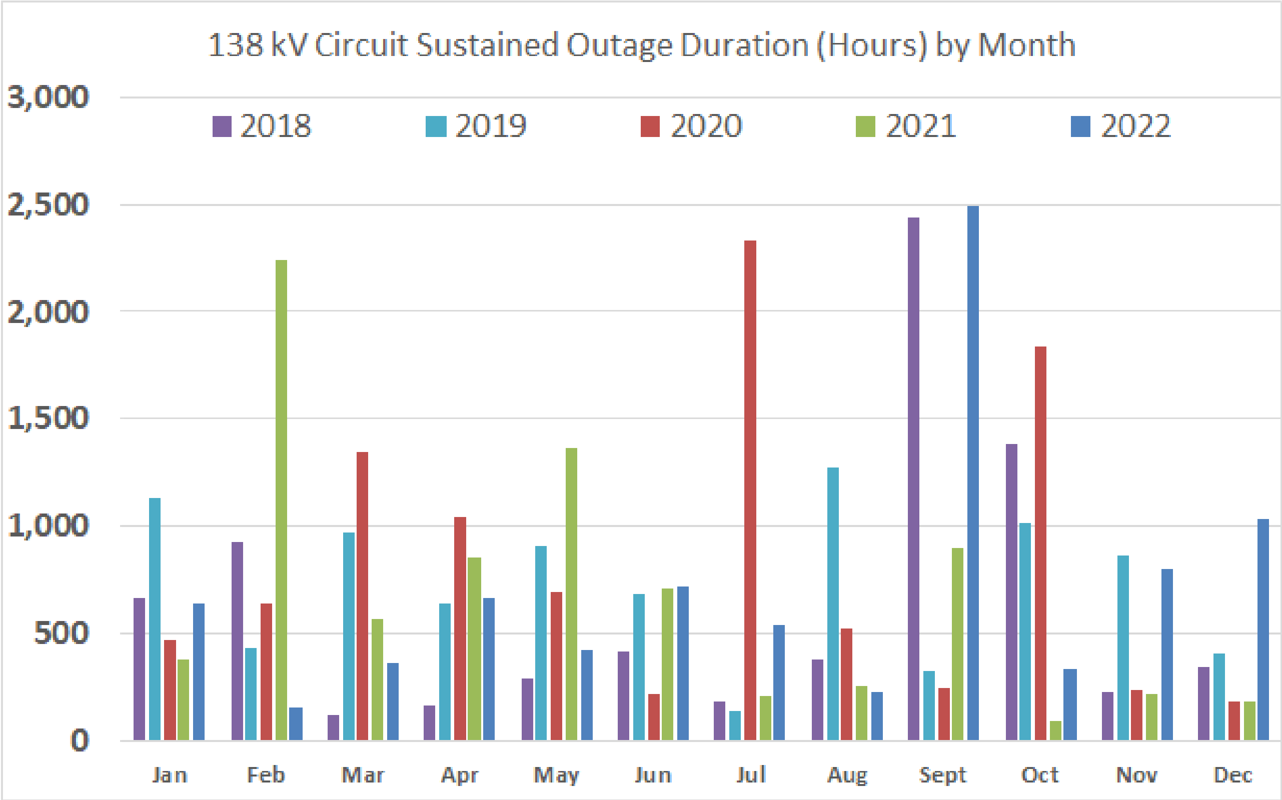


Figure B.11 – 138 kV Circuit Sustained Outage Duration (Hours) by Month

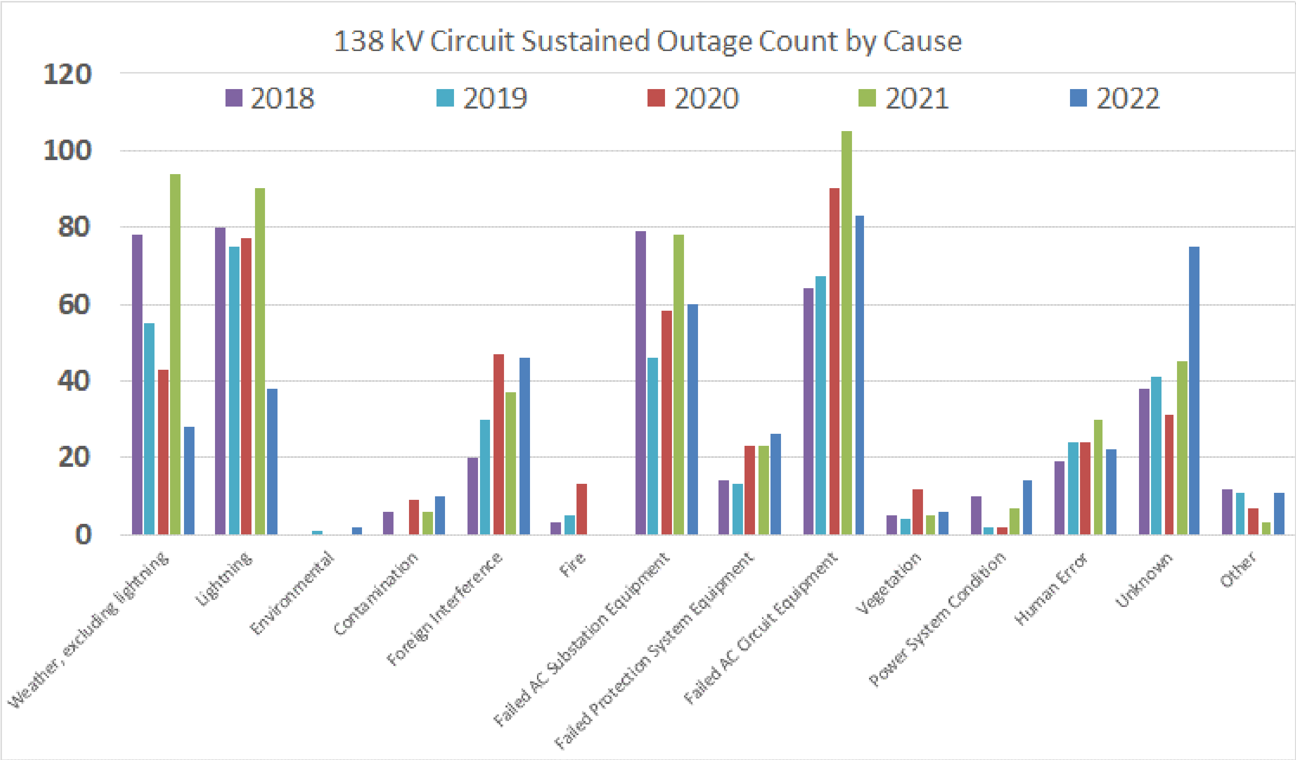


Figure B.12 – 138 kV Circuit Sustained Outage Count by Cause

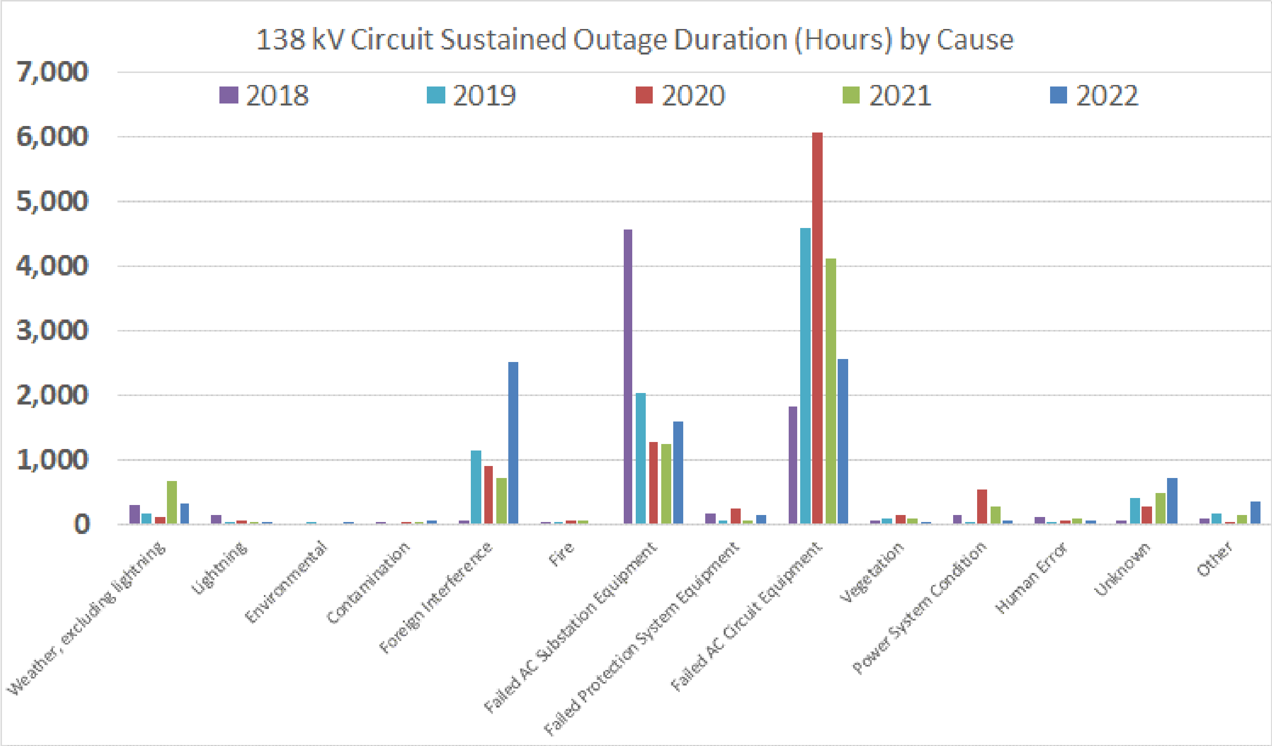


Figure B.13 – 138 kV Circuit Sustained Outage Duration by Cause

<u>Extreme Event Periods</u>

For transmission, "extreme days" are based on the most impactful days as determined by the number of transmission line and transformer outages as well as duration of outages. For generation, "extreme days" are based on the most impactful days as determined by the number of generation immediate forced outages, de-rates, as well as the cumulative MW impact of the outages. The following tables shows a comparison of the extreme transmission event days and extreme generation event days for 2017-2022. Extreme outage days for both generation and transmission in 2021 occurred during Winter Storm Uri.

Date	Number of Sustained Transmission Outage Events on Extreme Day	Leading Causes for Extreme Day	Average Sustained Outage Duration on Extreme Day	Longest Sustained Outage on Extreme Day	Average Sustained Outage Duration for Year	Longest Sustained Outage Duration for Year
8/26/2017	40	Weather	80 hours	257 hours	54 hours	7,594 hours
1/16/2018	50	Weather	10 Hours	72 hours	53 hours	6,403 hours
5/18/2019	19	Weather	85 hours	332 hours	31 hours	1,657 hours
10/28/2020	50	Weather	18 hours	63 hours	7 hours	99 hours
2/14/2021	43	Weather	64 hours	817 hours	20 hours	7,589 hours
3/21/2022	24	Weather	15 hours	146 hours	29 hours	1,971 hours

Table B.5 – Extreme Transmission Event Day Analyses

Date	Number of Generation Outage Events on Extreme Day	Leading Causes for Extreme Day	Cumulative Outage Duration on Extreme Day	Cumulative MW Impact on Extreme Day	Cumulative GWh Impact on Extreme Day
8/27/2017	41	Weather	22,798 hours	10,107 MW	2,917.5 GWH
1/16/2018	84	Balance of Plant/Fuel	2,891 hours	11,893 MW	517.8 GWh
5/11/2019	36	Turbine Generator	1,626 hours	6,449 MW	282.5 GWh
7/1/2020	44	Auxiliary systems	3,352 hours	8,251 MW	247.9 GWh
2/15/2021	187	Weather	6,937 hours	35,241 MW	1,204.1 GWh
12/23/2022	164	Weather	2,180 hours	23,163 MW	321.8 GWh

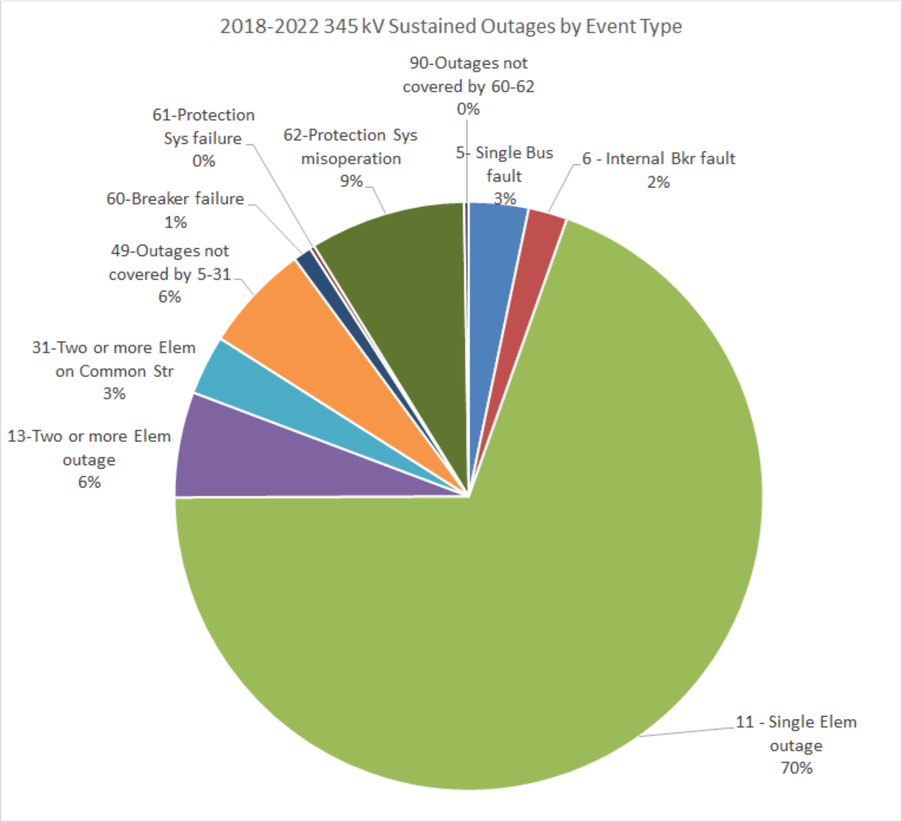
Table B.6 – Extreme Generation Event Day Analyses

D. Multiple Element Outages

For 345 kV circuits in 2022, 32 of the 419 reported automatic outage events involved two or more circuit elements. Dependent Mode outages (defined as an automatic outage of an element that occurred as a result of another outage) and Common Mode outages (defined as two or more automatic outages with the same initiating cause and occurring nearly simultaneously) represented eight percent of all outages and 57 percent of sustained outage duration for the 345 kV system.

For 138 kV circuits in 2022, 102 of the 430 reported automatic sustained outage events involved two or more circuit elements. Dependent Mode and Common Mode outages represented 24 percent of all sustained outages and 25 percent of sustained outage duration.

Over the five-year period from 2018-2022, multiple element outages represented 35 percent of sustained outages and 38 percent of the sustained outage duration for the 345 kV system.



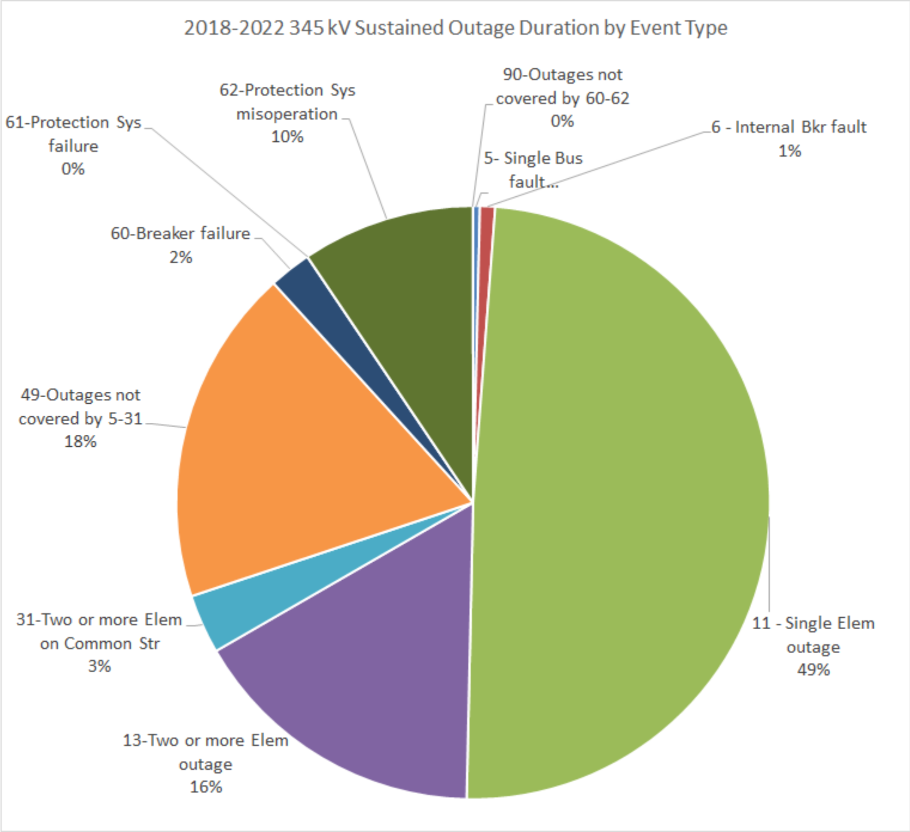


Figure B.14 – 2018-2022 345 kV Sustained Outages by Event Type

E. System Operating Limit Performance

A System Operating Limit (SOL) is the value (such as MW, MVar, amperes, frequency, or voltage) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. SOLs are based upon certain operating criteria. These include, but are not limited to:

- Facility Ratings (applicable pre- and post-Contingency equipment or Facility Ratings)
- Transient stability ratings (applicable pre- and post-Contingency stability limits)
- Voltage stability ratings (applicable pre- and post-Contingency voltage stability)
- System voltage limits (applicable pre- and post-Contingency voltage limits)

An Interconnection Reliability Operating Limit (IROL) is an SOL that, if violated, could lead to instability, uncontrolled separation, or Cascading outages. There are currently five IROLs in the Region, based on ERCOT's System Operating Limit methodology.

Voltage stability limits, transient and control stability limits, and stability issues for interfaces or in areas with low weight short circuit ratios are monitored and managed using Generic Transmission Limits (GTLs).

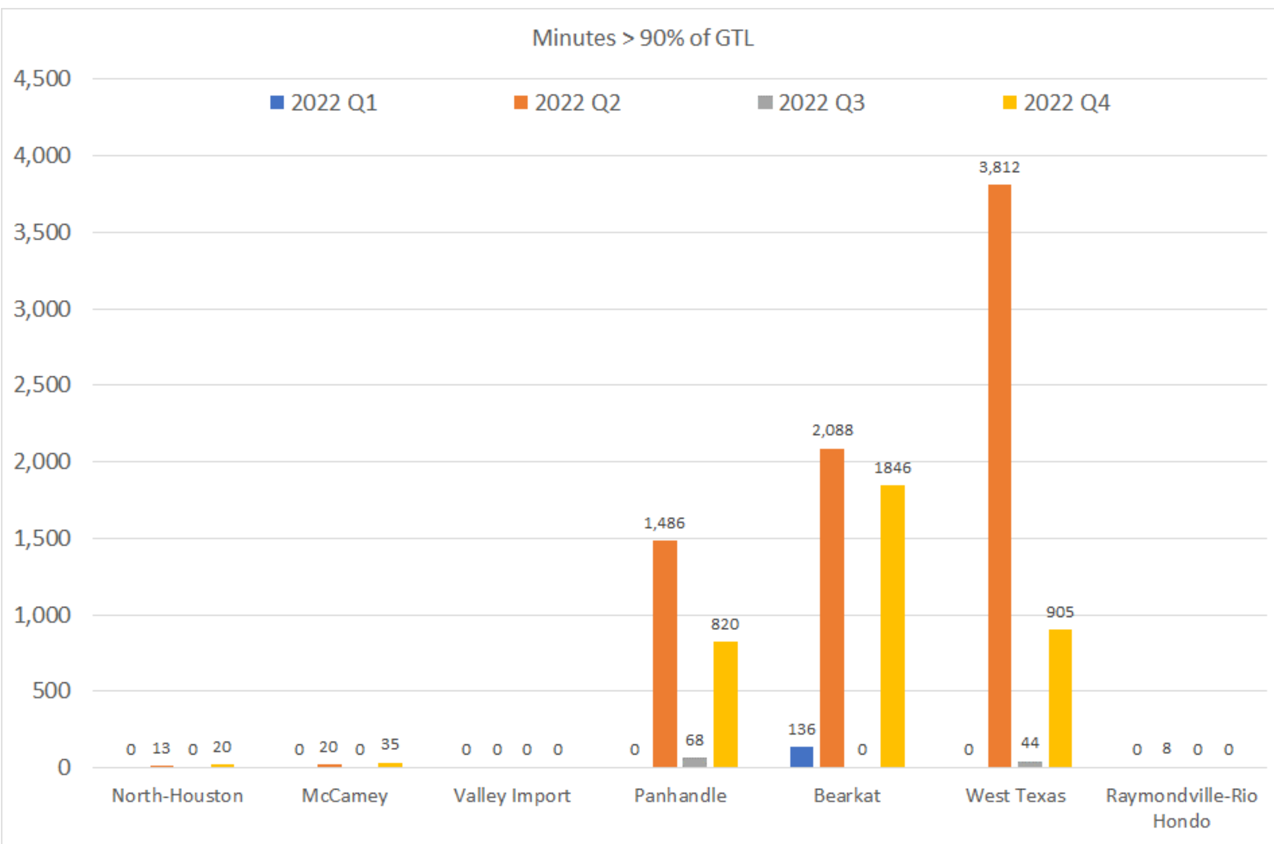


Figure B.15 – Interface Operation Minutes Greater Than 90 Percent of GTL

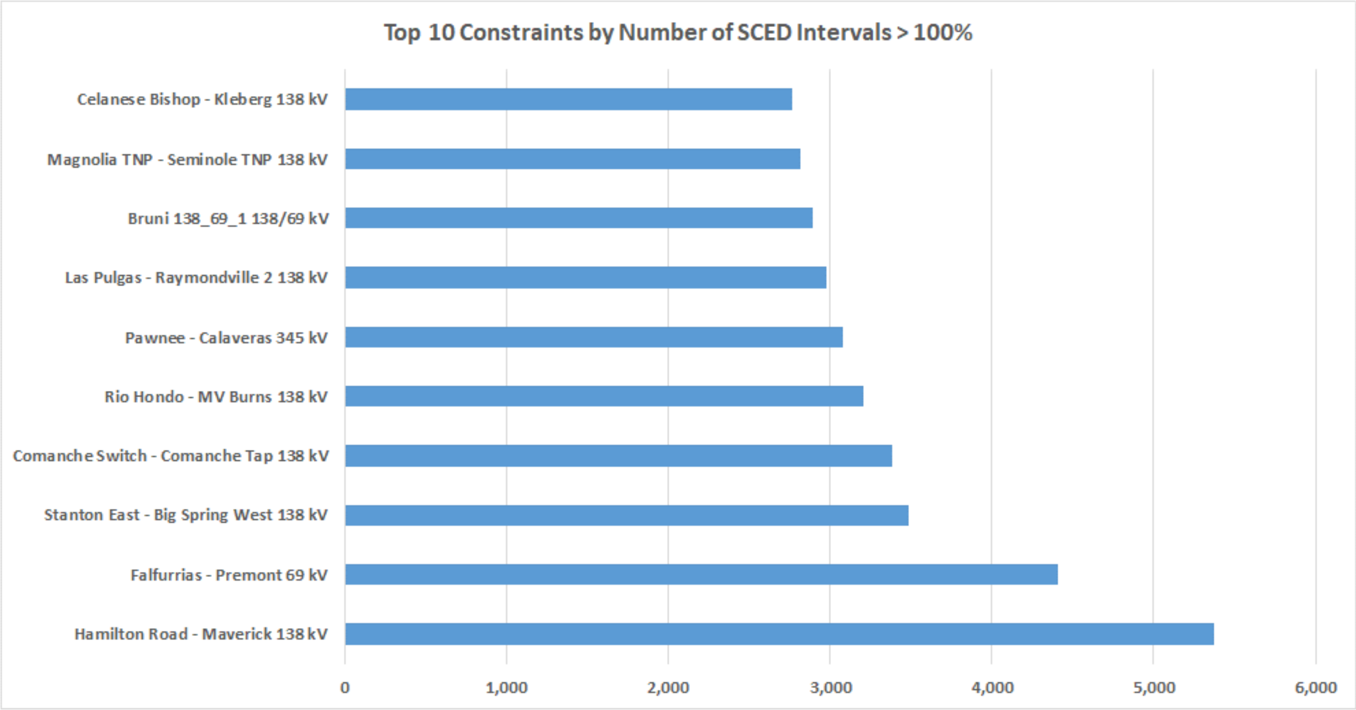


Figure B.16 – 2022 Top Constraints by Duration

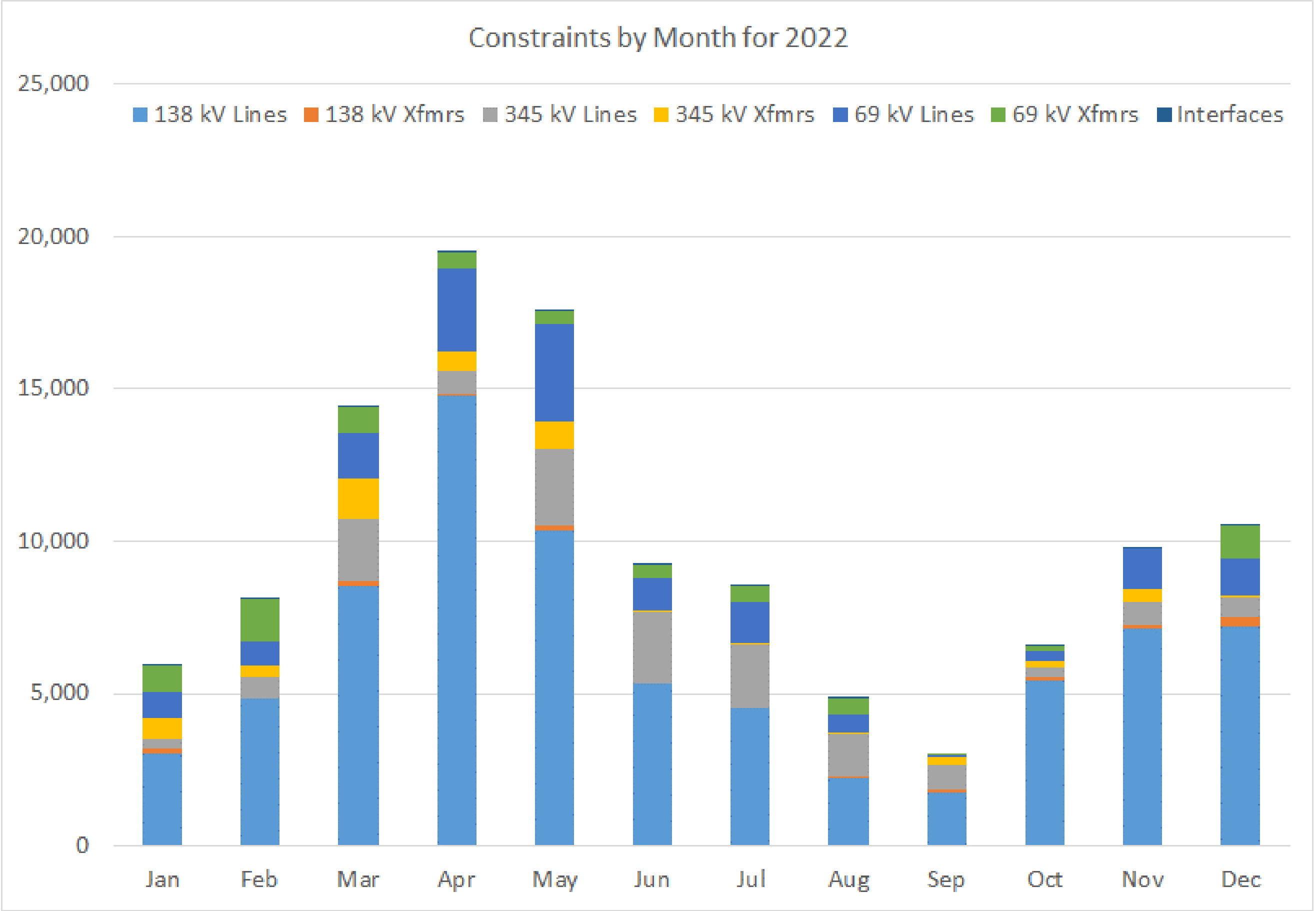


Figure B.17 – Constraints by Month for 2022

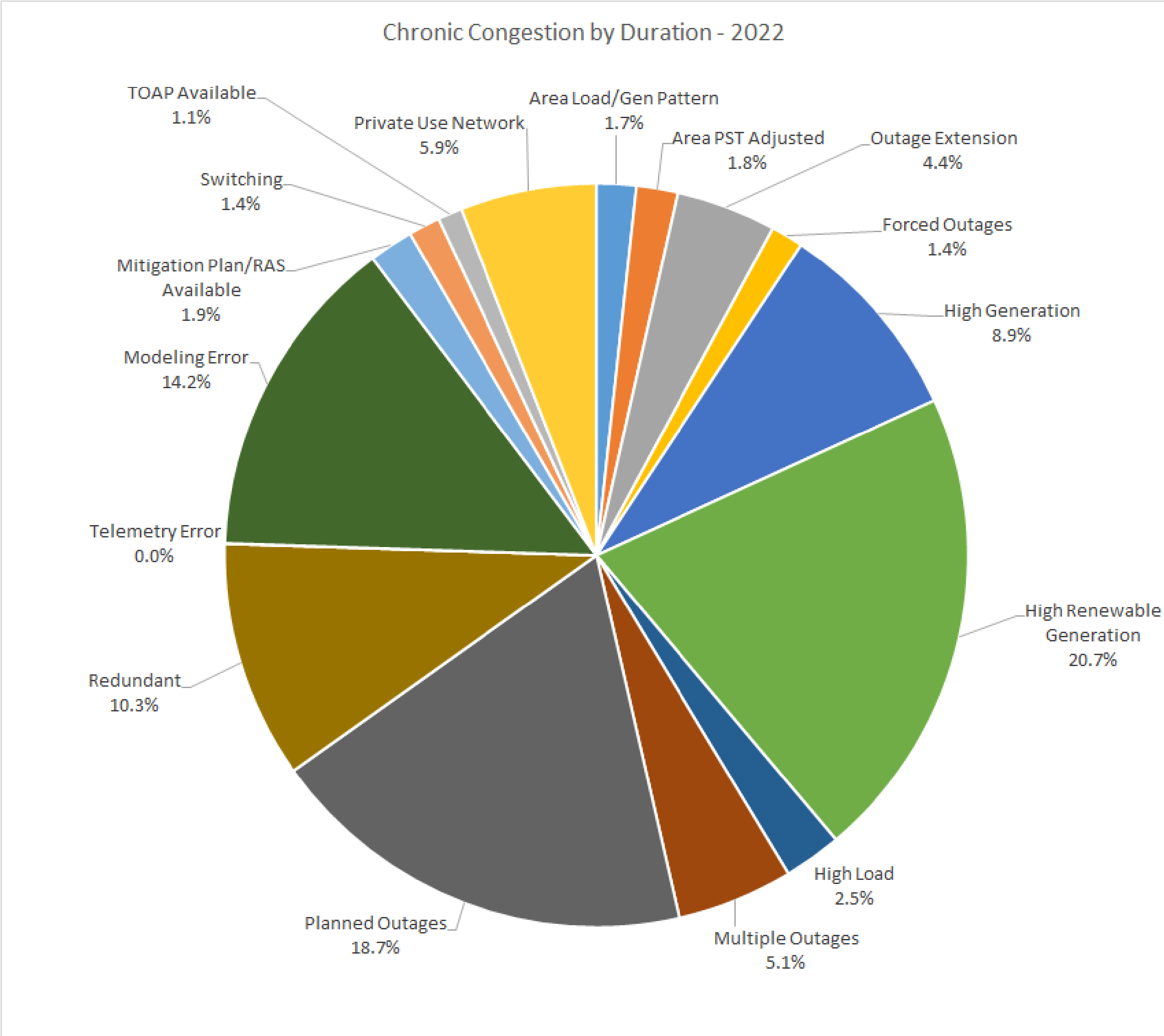


Figure B.18 – 2022 Chronic Constraint Causes by Duration

F. Reliability Unit Commitments

The Reliability Unit Commitment (RUC) process ensures that there is adequate Resource capacity and Ancillary Services capacity committed in the proper locations to serve ERCOT's forecasted load. Day-ahead RUC (DRUC) commitments are made for the next operating day. Hour-ahead (HRUC) commitments are made for a specific operating hour(s) after the DRUC process is completed.

HRUC commitments saw a dramatic increase in 2021 due to a change in ERCOT's methodology. RUC commitments totaled 115 units for 8,336 commitment hours. The primary reason for HRUC commitments was capacity, which accounted for approximately 80 percent of all HRUC hours.

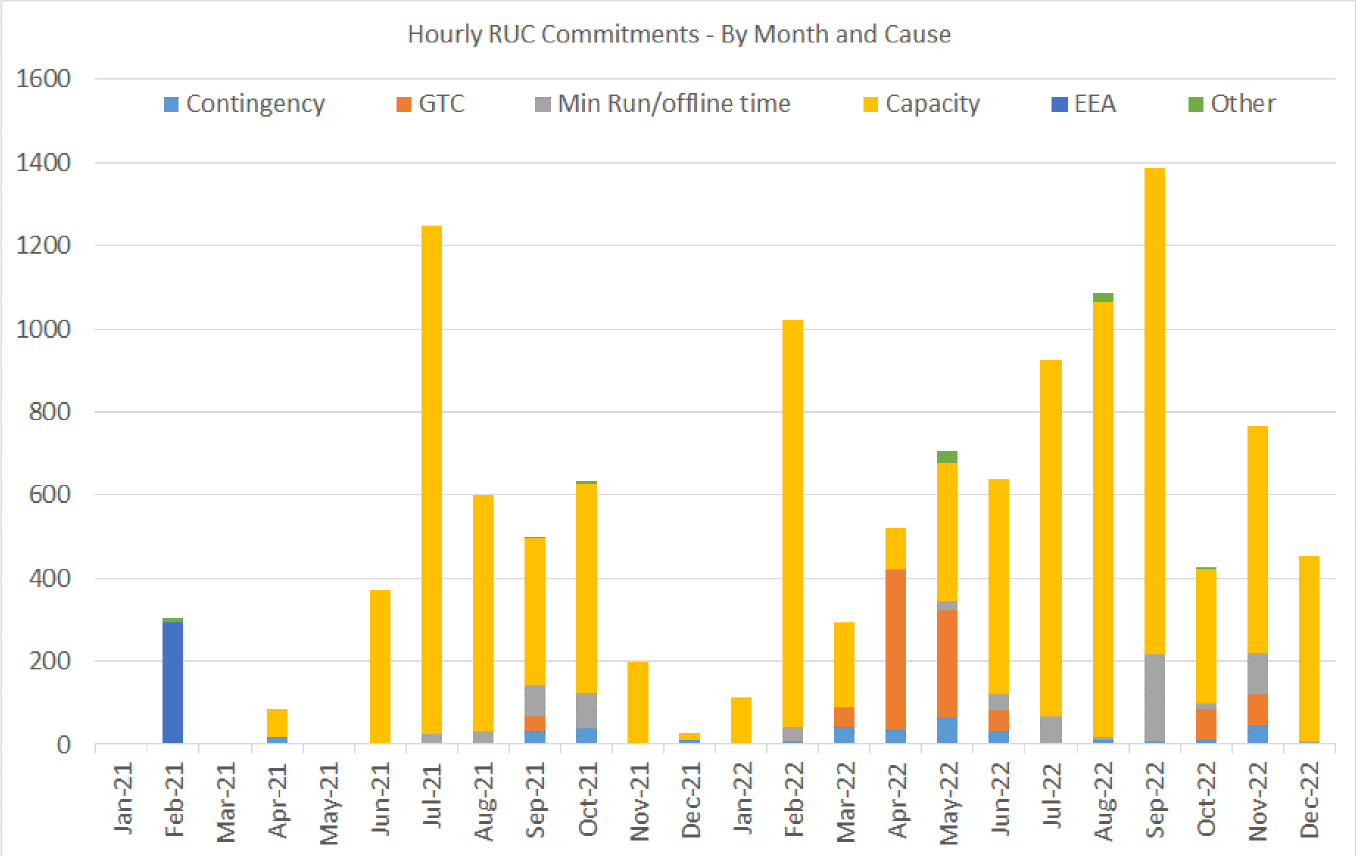


Figure B.19 – Hourly Reliability Unit Commitments by Month and Cause

Appendix C – Grid Transformation Detailed Analysis

A. Unit Additions and Retirements

Retirements and Mothball Status – 1202 MW

Unit	Date	Status	MW	Fuel Type
Olinger 1	4/5/2022	Mothball	78	Gas
Decker G2	3/31/2022	Retired	420	Gas
OCI Alamo 1	11/17/2022	Retired	1	Solar
GEUS Steam 1A	10/1/2022	Seasonal Mothball	17.5	Gas
Spencer #4	12/1/2022	Seasonal Mothball	57	Gas
Spencer #5	12/1/2022	Seasonal Mothball	61	Gas
Mountain Creek #8	3/1/2023	Seasonal Mothball	568	Gas

New Resources Approved for Commercial Operation – 6,288 MW

Unit	Date	MW	Fuel Type
Panther Creek III Repower	01/05/2022	15.96	Wind
Old Bloomington Road	01/12/2022	100	Gas
Anson Solar 1	01/20/2022	201.53	Solar
Ajax Wind	01/26/2022	366.6	Wind
Cranel Wind	01/27/2022	220	Wind
BRP Lopeno BESS	02/02/2022	9.95	Other
BRP Zapata II BESS	02/04/2022	9.95	Other
BRP Pueblo I BESS	02/07/2022	9.95	Other
BRP Zapata I BESS	02/07/2022	9.95	Other
BRP Pueblo II BESS	03/08/2022	9.95	Other
Elara Solar	03/17/2022	132.40	Solar
Flower Valley II Batt	03/28/2022	100.98	Other
Maverick Creek I Wind	03/29/2022	373.20	Wind
Maverick Creek II Wind	03/29/2022	118.80	Wind
Rabbs Power Station	05/02/2022	153.00	Gas
Sage Draw Wind	05/04/2022	338.00	Wind
Saddleback BESS	05/05/2022	9.95	Other
El Algodon Alto W	05/11/2022	201.00	Wind
Azure Sky BESS	05/12/2022	77.60	Other
Brightside Solar	05/16/2022	50.00	Solar
Faulkner BESS	05/19/2022	9.95	Other
Crossett Power Batt	05/26/2022	203.00	Other
Cactus Flats Wind	06/13/2022	148.40	Wind
Coyote Springs BESS	06/14/2022	9.95	Other
Republic Road Storage	06/15/2022	51.75	Other
Cedarvale BESS	06/17/2022	9.95	Other
LIGNIN (SJRR)	06/20/2022	100.00	Gas
RABBS U6 Power Station	06/23/2022	51.00	Gas
Rattlesnake BESS	06/23/2022	9.95	Other
RABBS U7 U8 Power Station	06/23/2022	102.00	Gas
Colorado Bend 2 repower	06/30/2022	45.00	Gas
RABBS U2 Power Station	07/12/2022	51.00	Gas

DeCordova BESS addition	07/12/2022	263.08	Other
Saragosa BESS1 (Matta Power Station)	07/22/2022	9.95	Other
Bastrop Energy Center AGP repower Phase I	08/02/2022	21.00	Gas
Bastrop Energy Center AGP repower Phase II	08/02/2022	21.00	Gas
Reloj Del Sol Wind	08/03/2022	209.40	Wind
Swoose II	08/15/2022	100.98	Other
Catarina BESS (La Huerta BESS)	08/25/2022	9.95	Other
Wolf Hollow 2 repower	08/25/2022	44.00	Gas
Lonestar BESS	08/25/2022	9.95	Other
White Mesa Wind	09/01/2022	152.30	Wind
RABBS U1 Power Station	09/12/2022	51.00	Gas
White Mesa 2 Wind	09/13/2022	348.00	Wind
Noble Solar	09/19/2022	279.00	Solar
Roughneck Storage	09/30/2022	50.00	Other
Noble Storage	10/11/2022	62.50	Other
NASA	10/14/2022	12.00	Gas
Byrd Ranch Energy Storage Plant	10/21/2022	50.60	Other
Nebula Solar	10/25/2022	137.45	Solar
Odessa-Ector Unit 2 (Block 2) Uprate Repower	10/26/2022	83.00	Gas
Noble Storage (BESS1)	10/27/2022	62.50	Other
Westoria Solar	11/01/2022	203.35	Solar
Beachwood Power Station (Mark One)	11/09/2022	153.00	Gas
TG East Wind	12/08/2022	336.00	Wind
Endurance Park Storage	12/28/2022	51.50	Other
Strategic Solar 1	12/29/2022	136.85	Solar
Vision Solar 1	12/29/2022	129.24	Solar

Table C.1 – 2022 Unit Additions and Retirements

B. Fuel Mix Analysis

Wind generation reporting in GADS-Wind produced a net total of 92,892 GWh in 2022, or 86.68 percent of the total ERCOT wind generation for 2022. Wind generation, as a percentage of total ERCOT energy produced, increased to 24.9 percent in 2022, up from 24.3 percent in 2021. In 2022, hourly wind generation reached a maximum of 26,871 MW on May 29, 2022, at 10:00 p.m., and hourly renewable generation served a maximum of 70.5 percent of system demand on April 10, 2022, at HE09.

Utility-scale solar generation within the region continued its significant growth in 2022. The amount of energy provided by solar generation increased 55 percent versus 2021.

Wind energy curtailments totaled 5,329 GWh in 2022. Solar energy curtailments totaled 2,266 GWh in 2022.

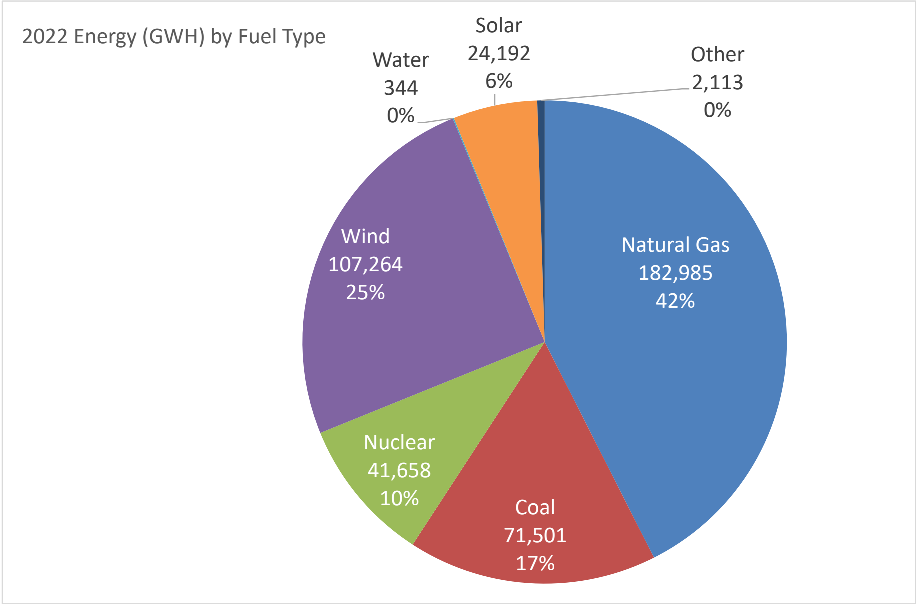


Figure C.1 – 2022 Energy by Fuel Type

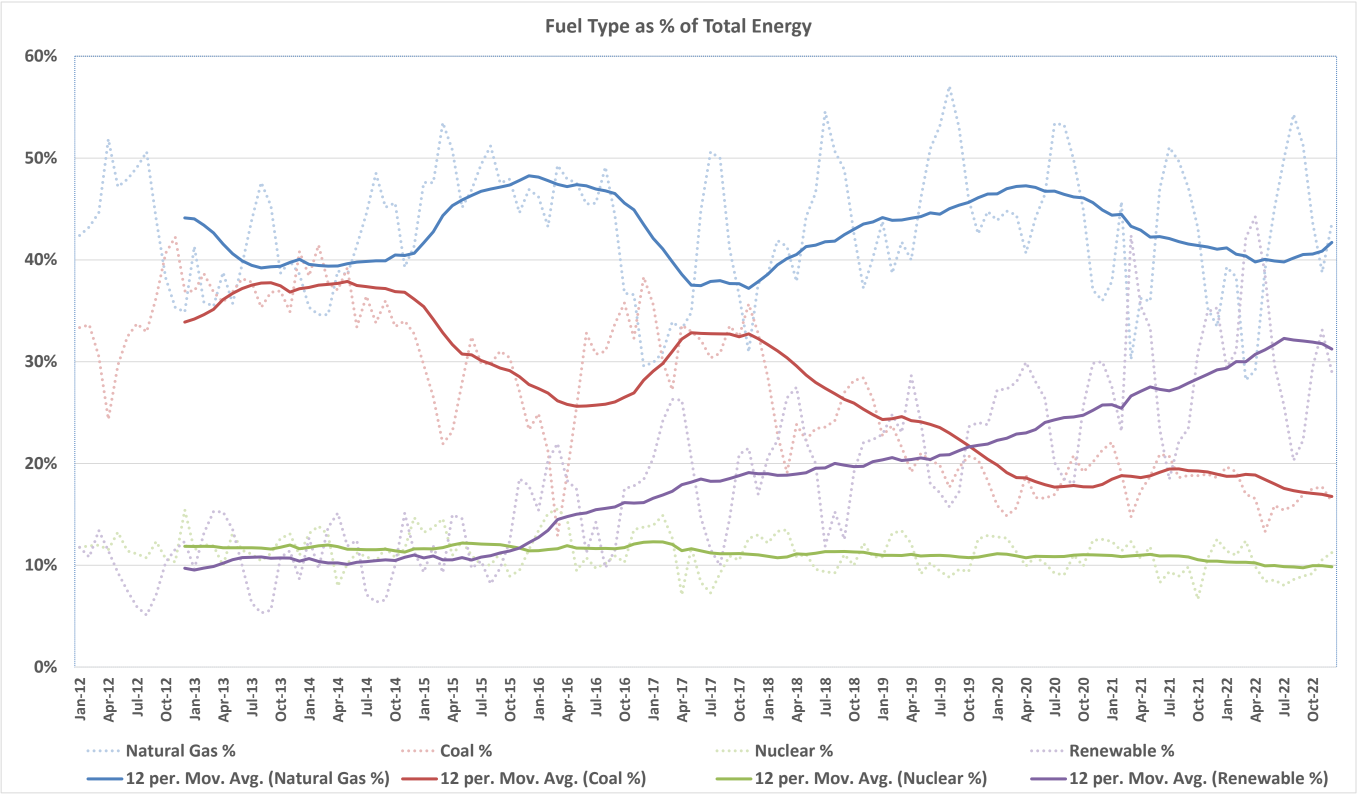


Figure C.2 – Energy by Fuel Type Trend

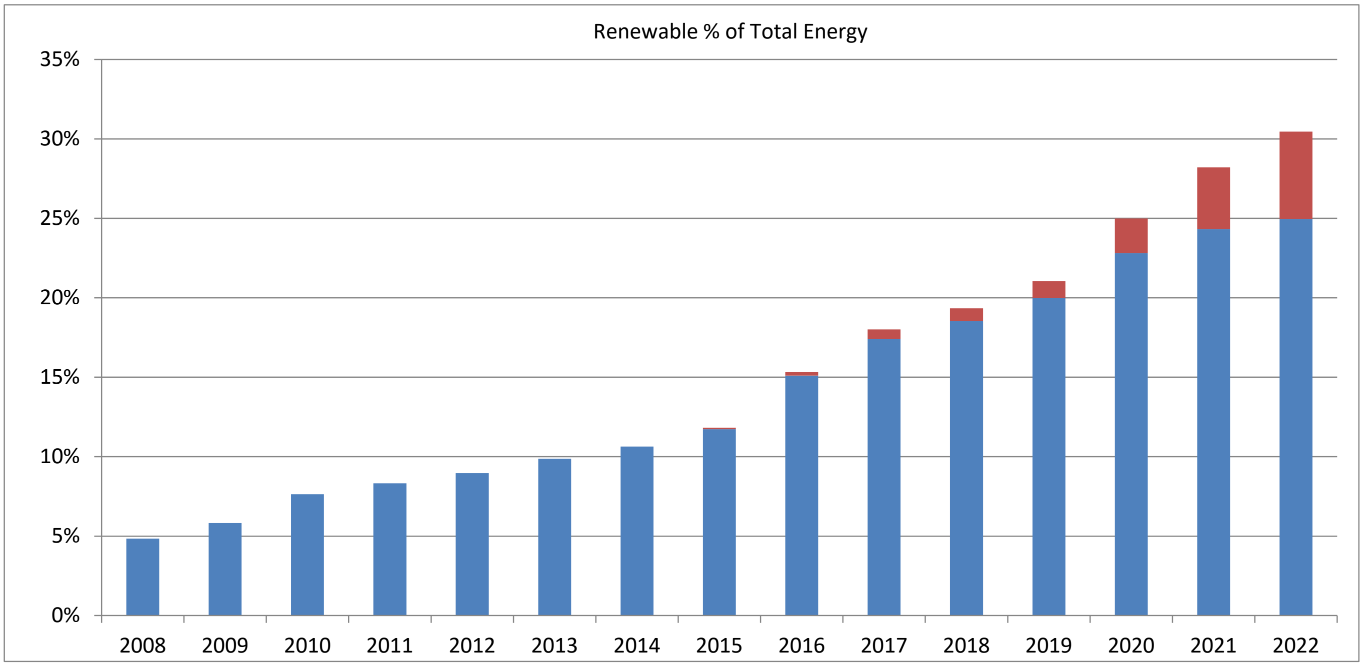


Figure C.3 – Renewable Energy Percentage of Total Load Time Trend

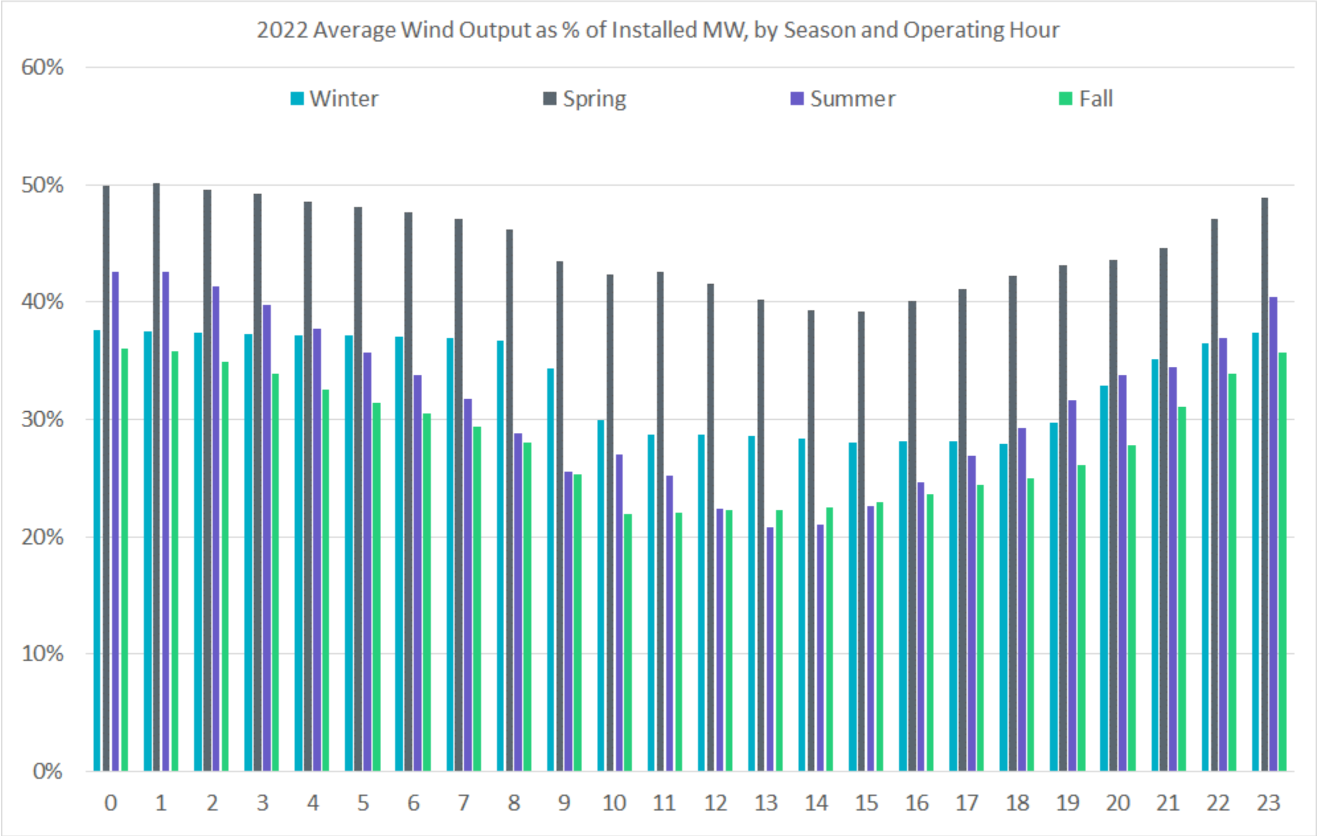


Figure C.4 – Average Wind Output as a Percentage of Installed Wind MW by Season/ Hour

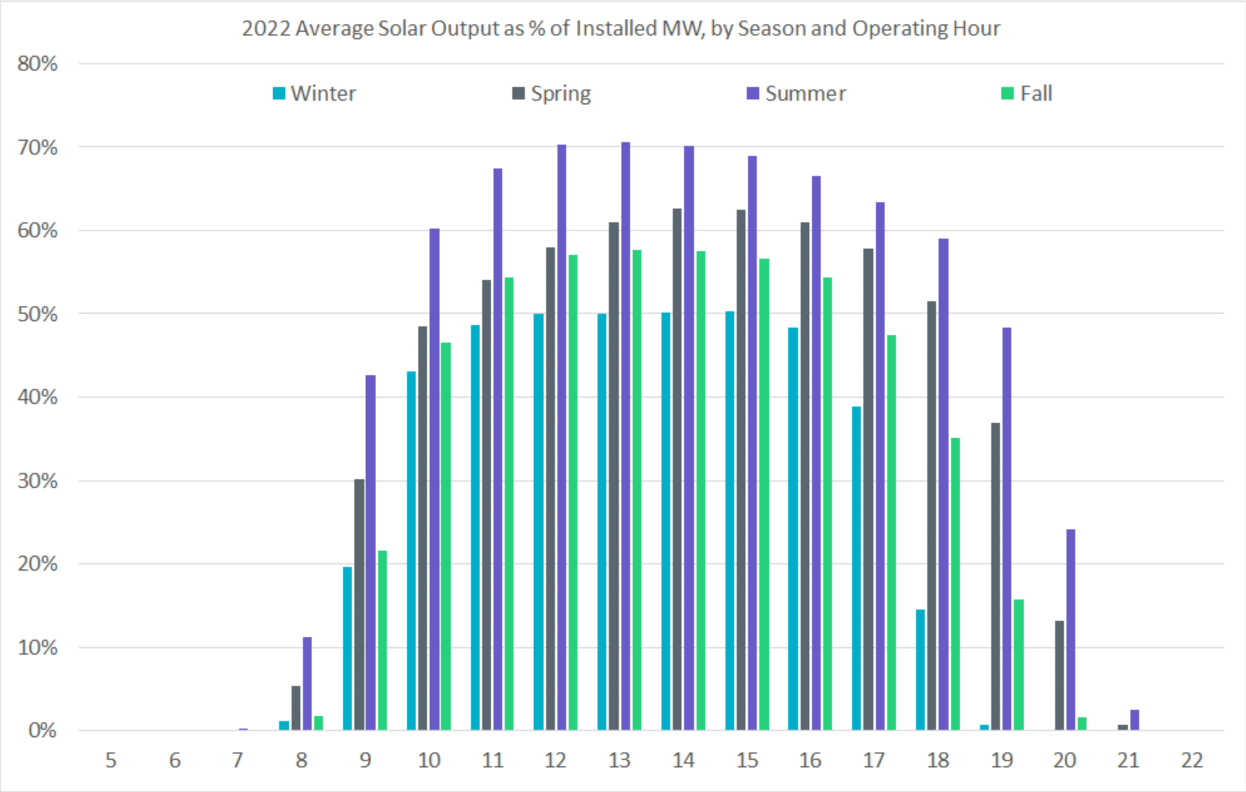


Figure C.5 – Average Solar Output as a Percentage of Installed Solar MW by Season/ Hour

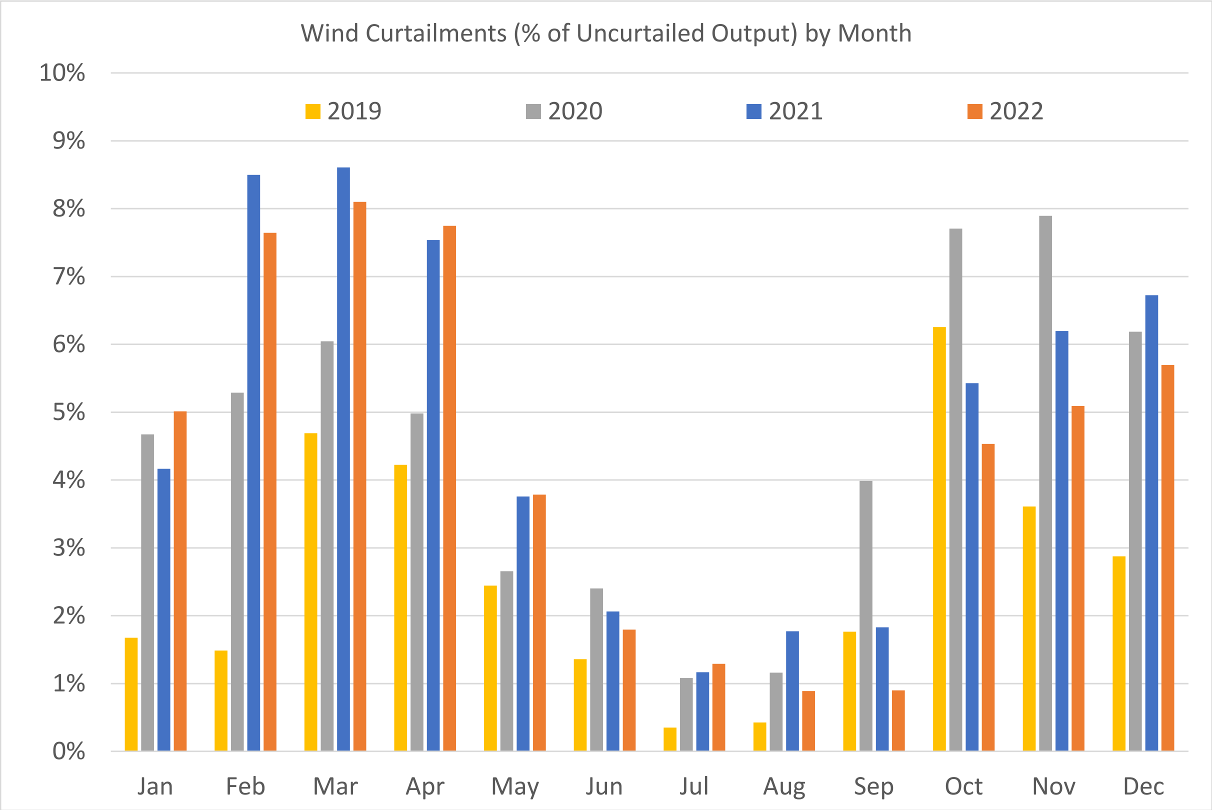


Figure C.6 – Wind Curtailments as a Percentage of Uncurtailed Output

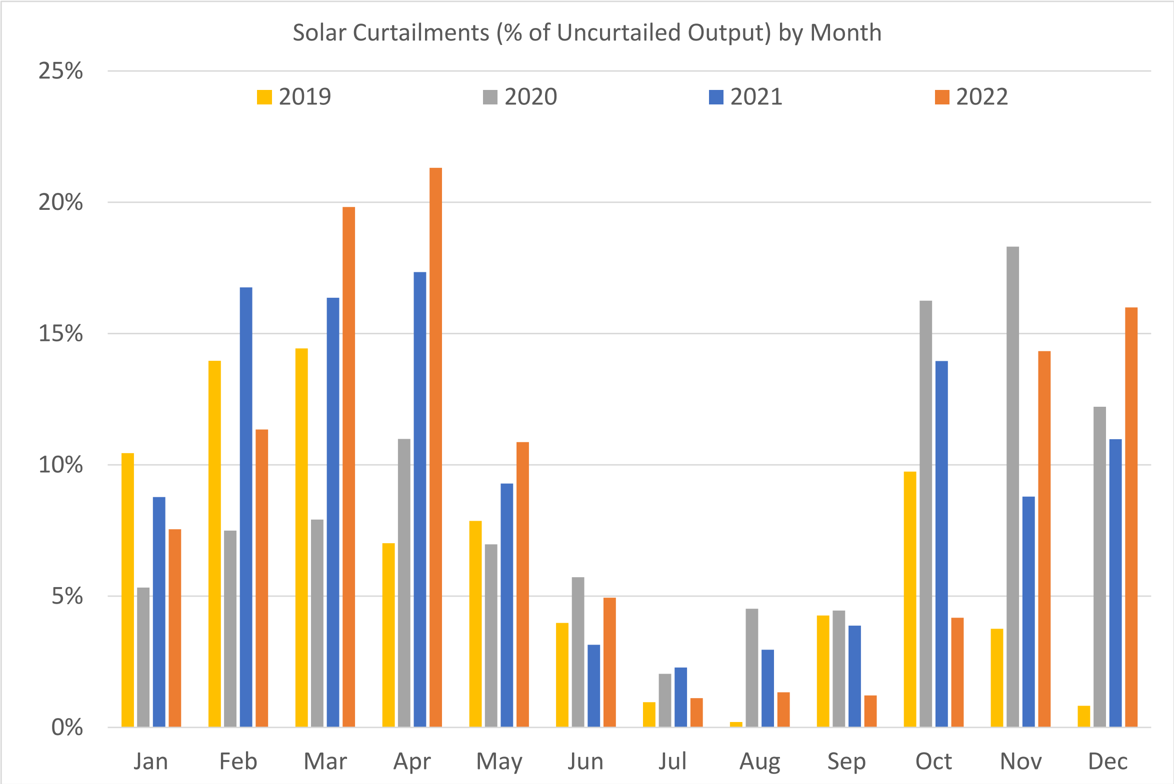


Figure C.7 – Solar Curtailments as a Percentage of Uncurtailed Output

C. Synchronous Inertia

ERCOT calculated that the critical inertia level for the Interconnection is approximately 94 Gigawatt-seconds (GW-s). ERCOT uses a critical inertia level of 100 GW-s for its operating procedures and in particular its forward projections for ancillary services procurement of responsive reserves in the day-ahead market.

The minimum hourly inertia level in 2022 was 115.0 GWs, on March 21, 2022, at HE02, when the IRR penetration level was 65.7 percent and system load was 33,365 MW (net load of 11,445 MW).

Year	Minimum Inertia (GW-s)	Load (MW)	Net Load (MW)	IRR %
2015	130.3	27,798	20,569	26.1%
2016	138.4	26,839	14,797	44.9%
2017	130.0	28,443	13,178	53.7%
2018	128.8	28,412	13,452	52.7%
2019	134.6	29,426	14,645	50.2%
2020	131.1	31,505	13,541	57.0%
2021	109.6	31,904	10,905	65.8%
2022	115.0	33,365	11,445	65.7%

Table C.2 – Minimum Inertia for 2015-2022

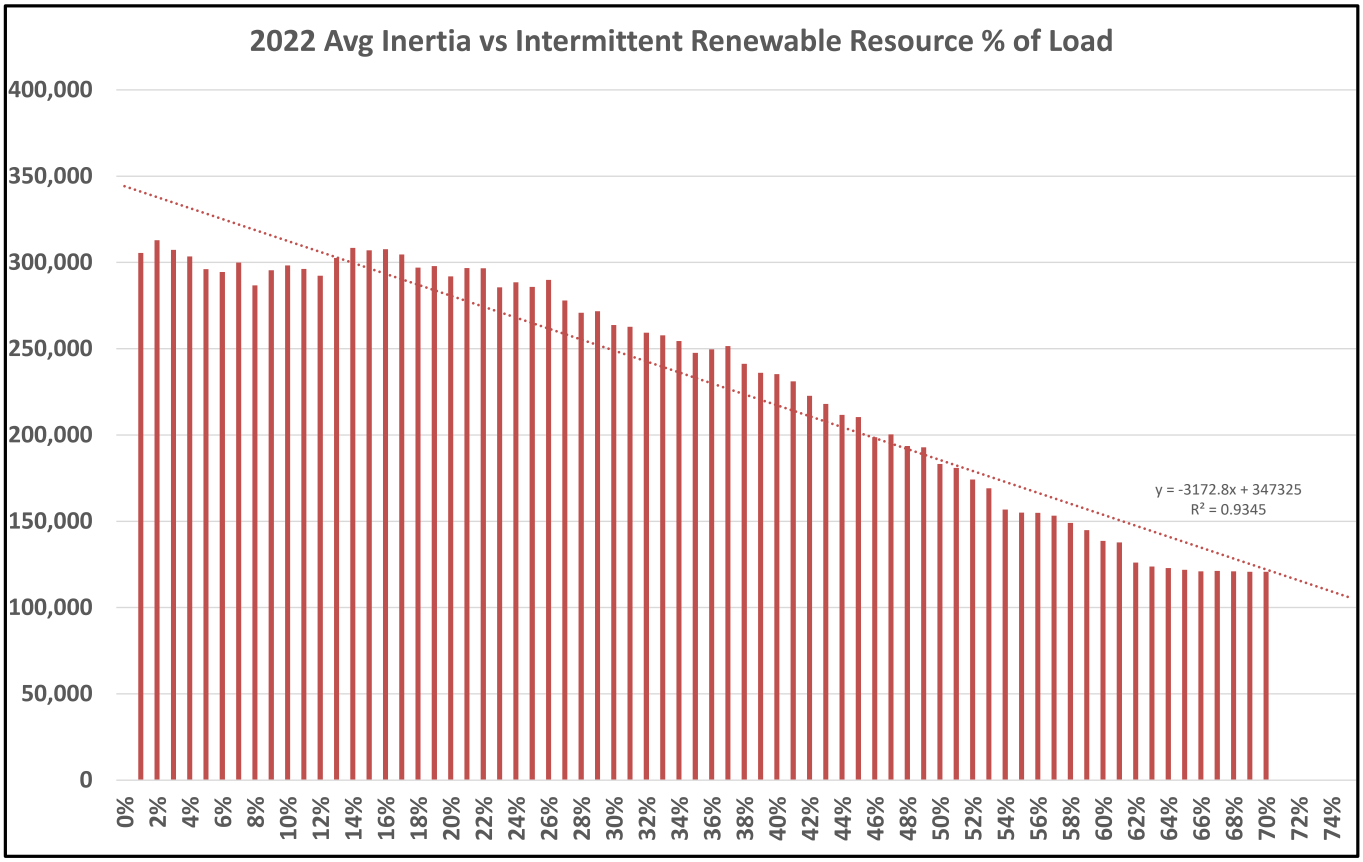


Figure C.8 – 2022 Average Inertia versus Renewable Percentage of Load

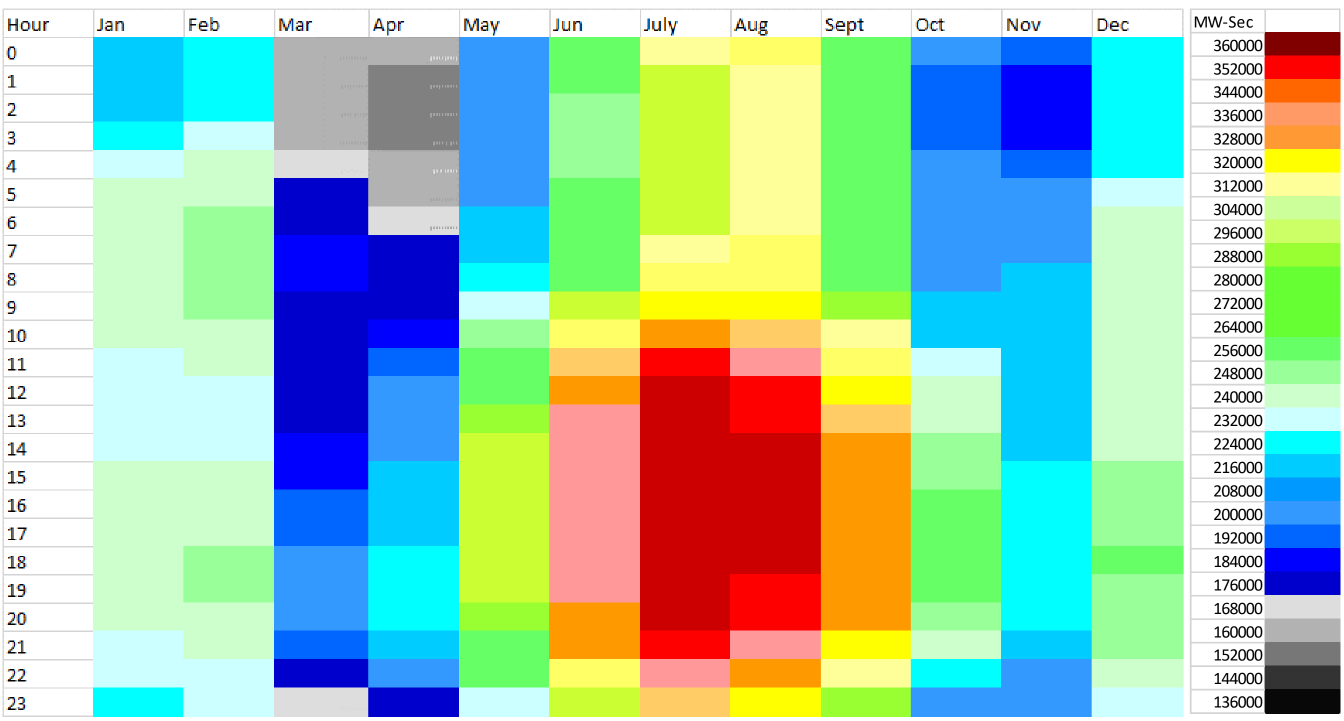


Figure C.9 – 2022 Average Inertia by Month and Operating Hour

D. Net Demand Ramping Variability

Changes in the amount of non-dispatchable resources, system constraints, load behaviors, and the generation mix can affect the ramp rates needed to keep the system in balance. Conventional resources must have sufficient ramping capability to maintain the generation-load balance when intermittent renewables have large up or down ramps. ERCOT calculates the system ramp capability in real-time to ensure that this ramping variability can be met. If insufficient ramping capability is not available, ERCOT will bring additional quick start resources online.

Ramping Variability	Load	Wind Gen	Solar Gen	Net Load
Maximum One-Hour Increase	5,066 MW	4,862 MW	5,707	9,894
Maximum One-Hour Decrease	-5,298 MW	-5,304 MW	-5,659	-5,298

Table C.3 – Maximum and Minimum Load, Wind, Solar, and Net-Load Ramps for 2022

There continues to be a long-term increasing trend in the maximum one-hour up ramps for net load and solar. Figure C.10 shows a comparison of the maximum one-hour load, net load, and wind ramps for 2022 compared to previous years.

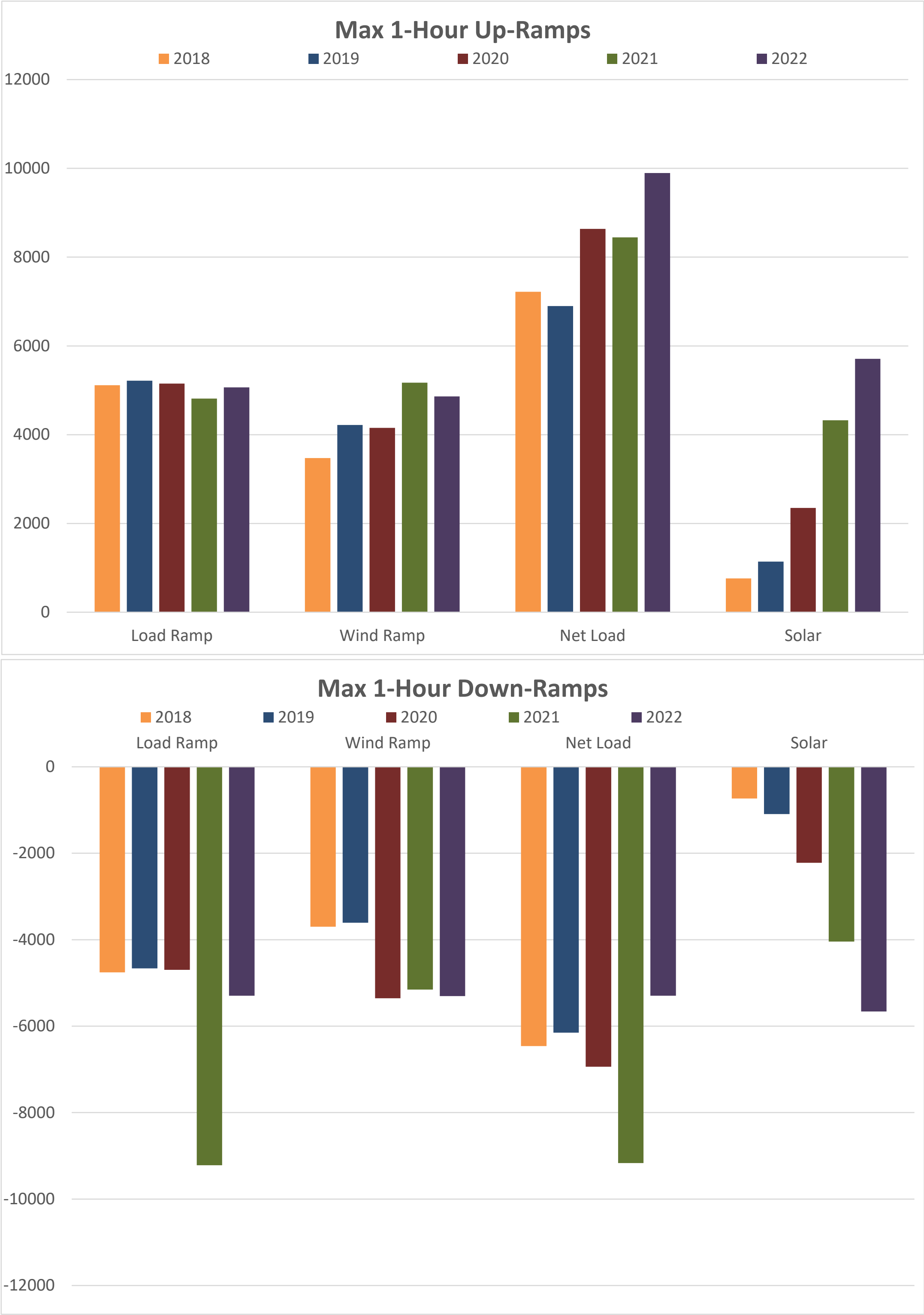


Figure C.10 – Maximum One-Hour Ramps for 2018-2022

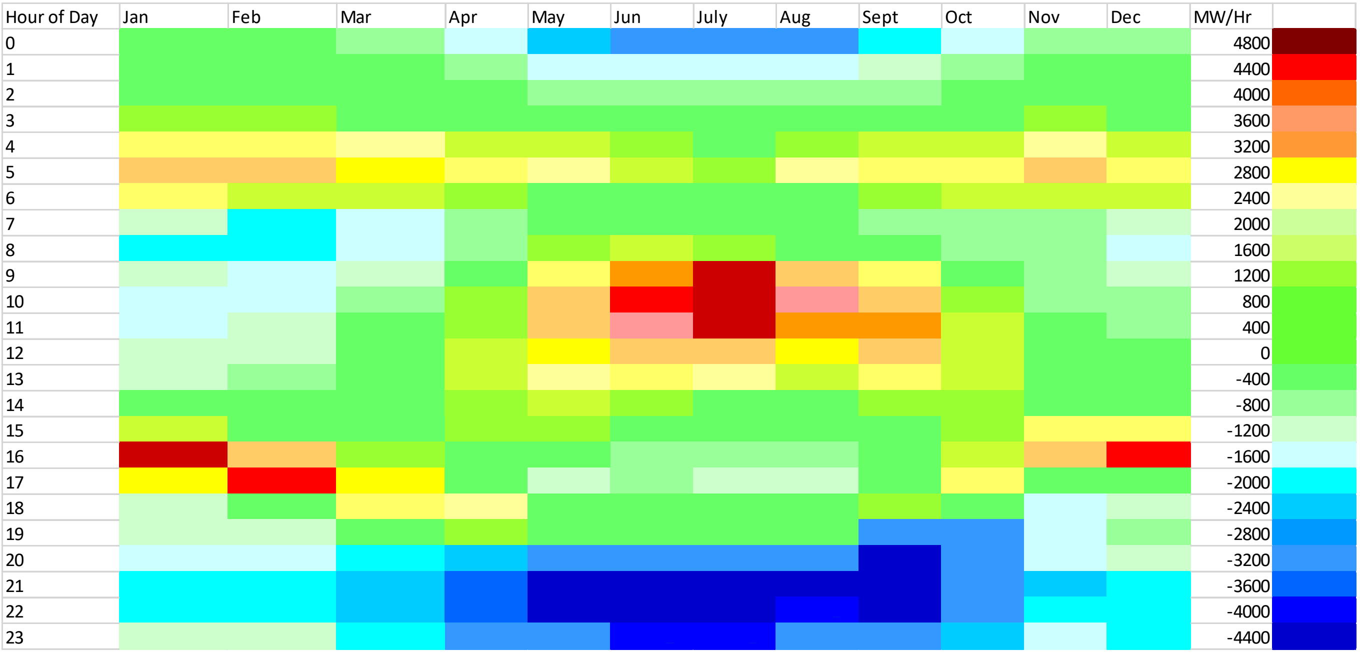


Figure C.11 – 2022 Heat Map of Net Load Ramp by Month and Operating Hour

Appendix D – Human Performance Detailed Analysis

A. Outages Initiated by Human Error

Outage rates for Protection System Misoperations and 345 kV circuit outages caused by human error showed an increase in 2022 compared to prior years. Generator outages caused by human error showed a noticeable decrease.

Element Type	Metric	2018	2019	2020	2021	2022	5-Yr Avg
AC Circuit 300-399 kV	Outages per Element Initiated by Human Error	1.5%	1.2%	1.1%	0.8%	1.7%	1.3%
AC Circuit 100-199 kV	Outages per Element Initiated by Human Error	1.1%	2.1%	1.0%	1.2%	0.9%	1.3%
Transformer 300-399 kV	Outages per Element Initiated by Human Error	0.5%	0.5%	0.8%	0.0%	1.2%	0.6%
Generator	Immediate Forced Outages Initiated by Human Error	3.9%	2.4%	2.6%	3.2%	1.9%	2.8%
Protection Systems	Misoperation Rate Caused by Human Error	2.9%	2.7%	2.7%	2.0%	3.2%	2.7%

Table D.1 – Outages Rates Caused by Human Error

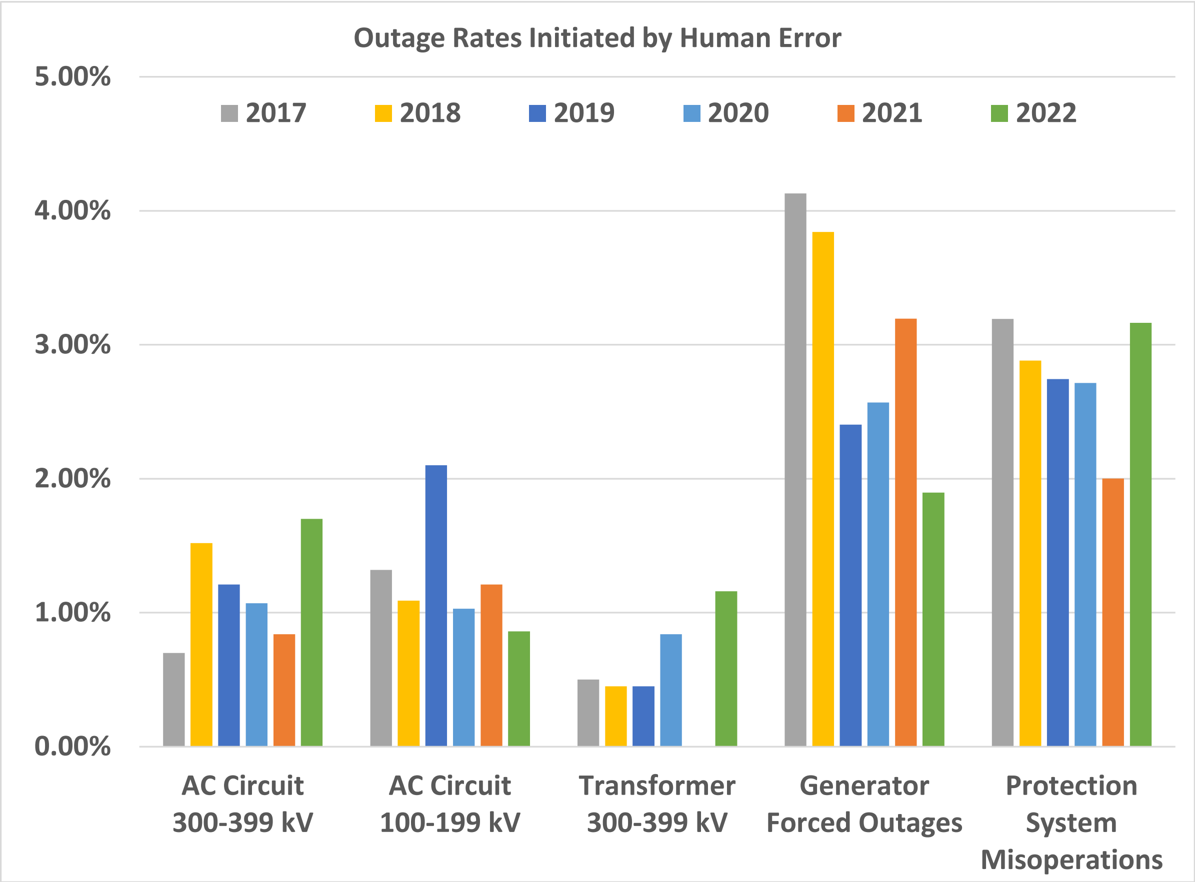
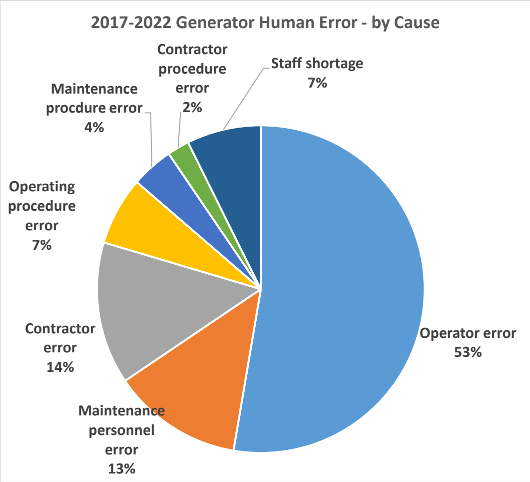


Figure D.1 – Outage Rates Caused by Human Error

Since 2017, there have been 505 generation immediate forced outages, de-rates, and startup failures caused by human error in the Region. The breakdown and impact of the causes is shown below.



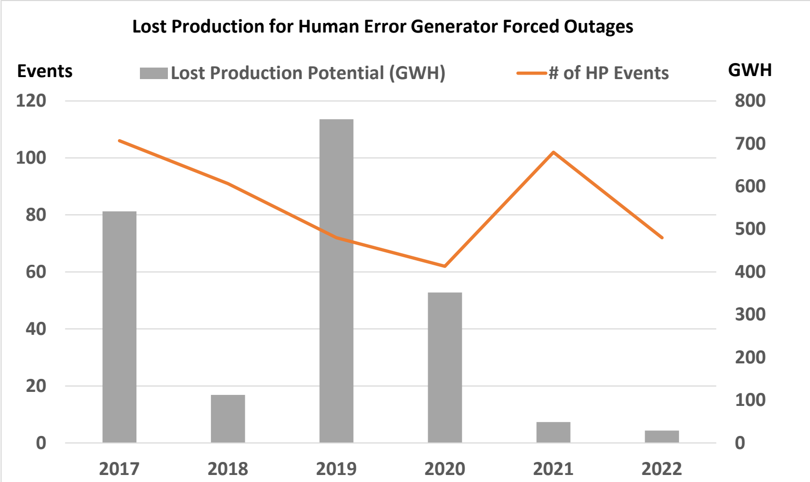


Figure D.2 – Generator Forced Outage Human Errors

B. Human Performance in System Events

The NERC Cause Code process provides a systematic approach to assigning cause code(s) after an event on the BPS is analyzed. Appropriate use of this method after event analysis will result in effective labeling, collection, and trending of causes. It will also lead to the proper application of risk management procedures to develop and implement appropriate corrective and proactive actions.

Human performance remains the primary causal factor in misoperations, primarily due to incorrect settings and/or as-left errors.

Since 2018, 54 events in ERCOT have been analyzed using this cause code process, with 429 root cause and contributing cause codes assigned. Approximately 53 percent of the assigned root and contributing cause codes are related to potential human performance issues (shown in red below in Figure D.3).

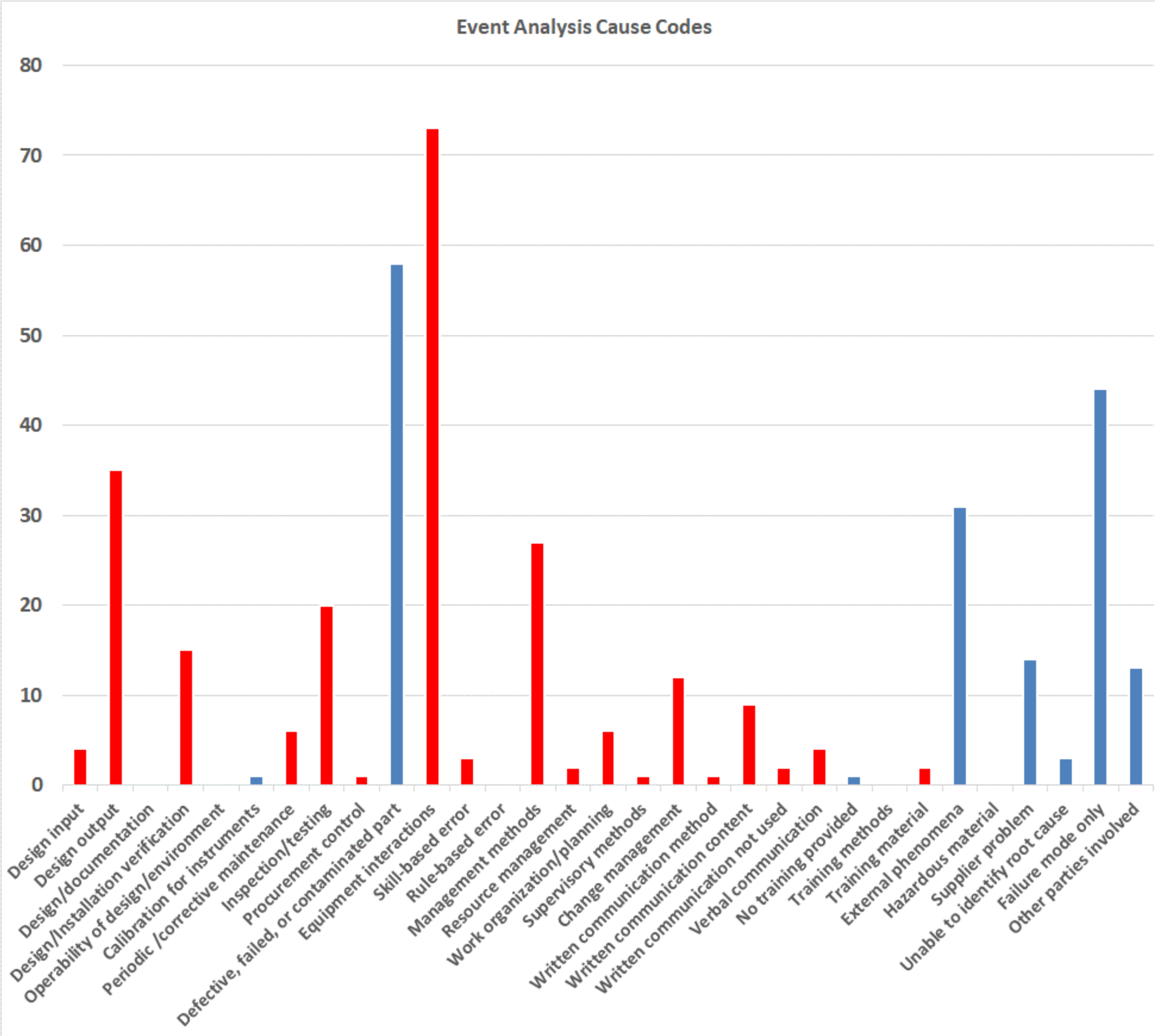


Figure D.3 – Event Analysis Human Performance Cause Coding

Appendix E – Bulk Power System Planning Analysis

A. Net Energy for Load

In 2022, total annual energy usage was roughly 430,000 GWh, an increase of 13.1 percent from 2021. Peak hourly demand was 79,830 MW on July 20, 2022. The West Load Zone has seen the largest load energy usage increase (6.5 percent per year since 2018).

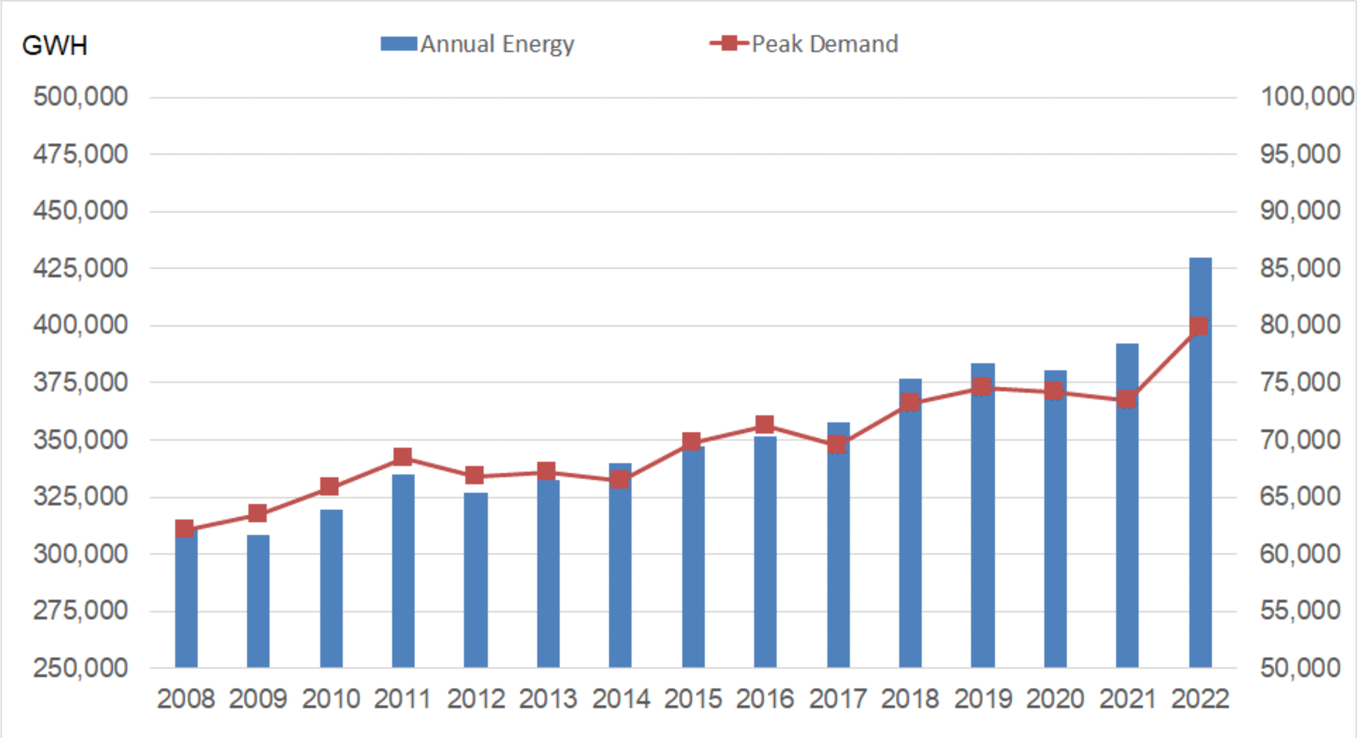


Figure E.1 – Annual Energy and Peak Demand

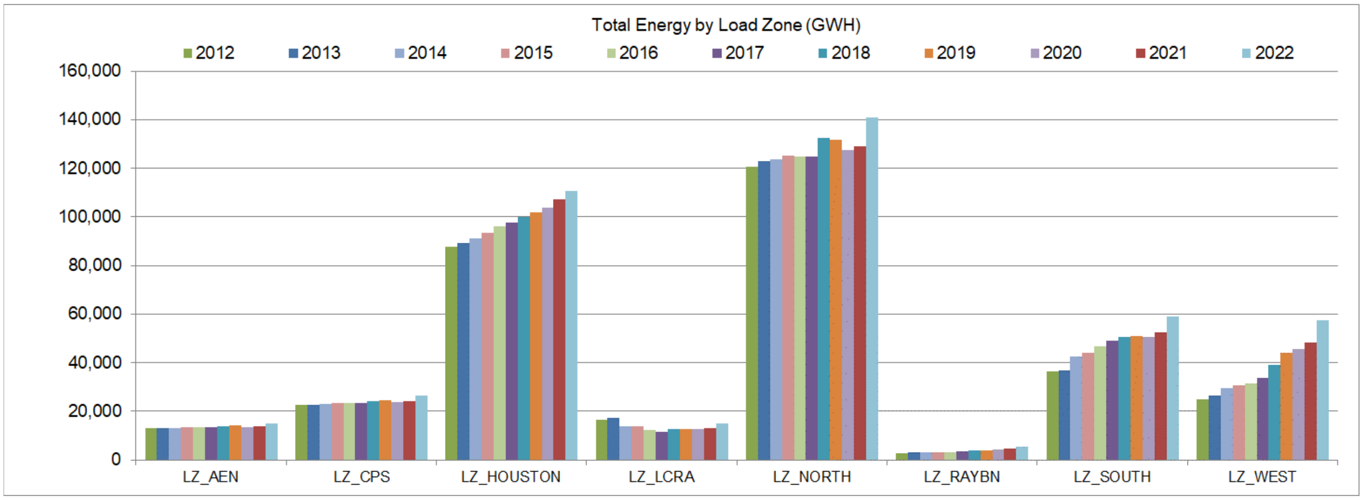


Figure E.2 – Energy by Load Zone

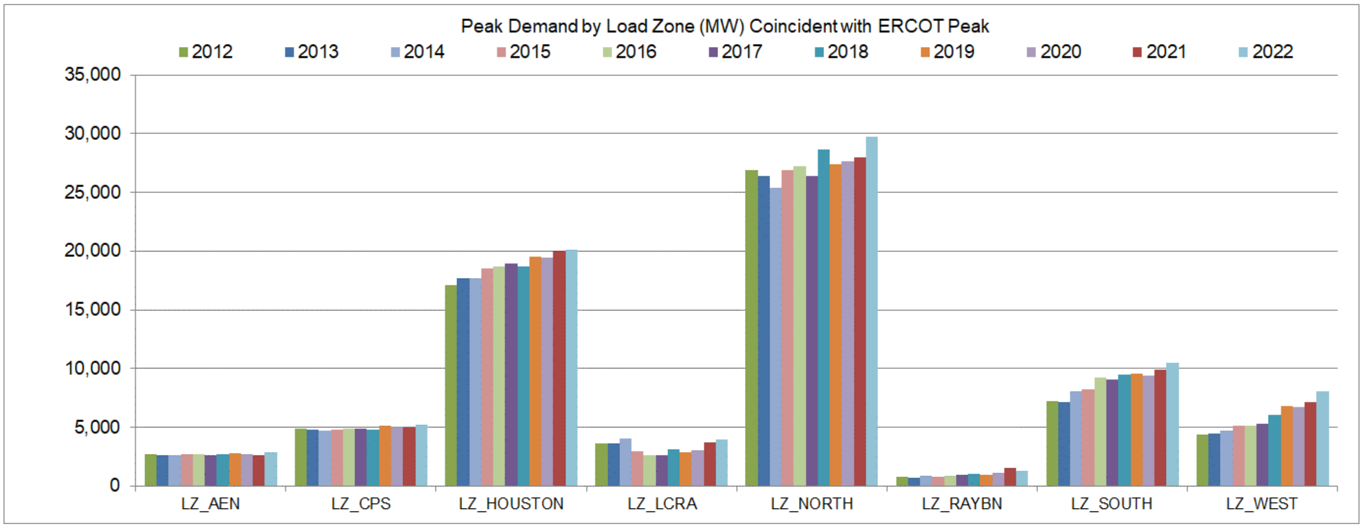


Figure E.3 – Peak Demand by Load Zone

The weather zone with the largest load energy usage increase was the Far West (7.9 percent per year since 2018).

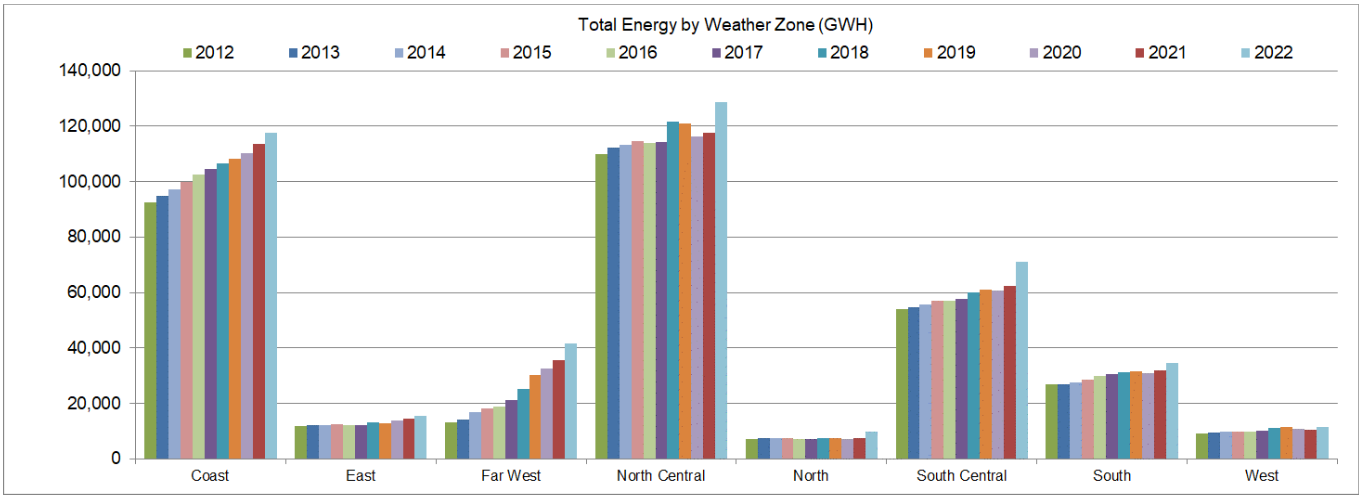


Figure E.4 – Energy by Weather Zone

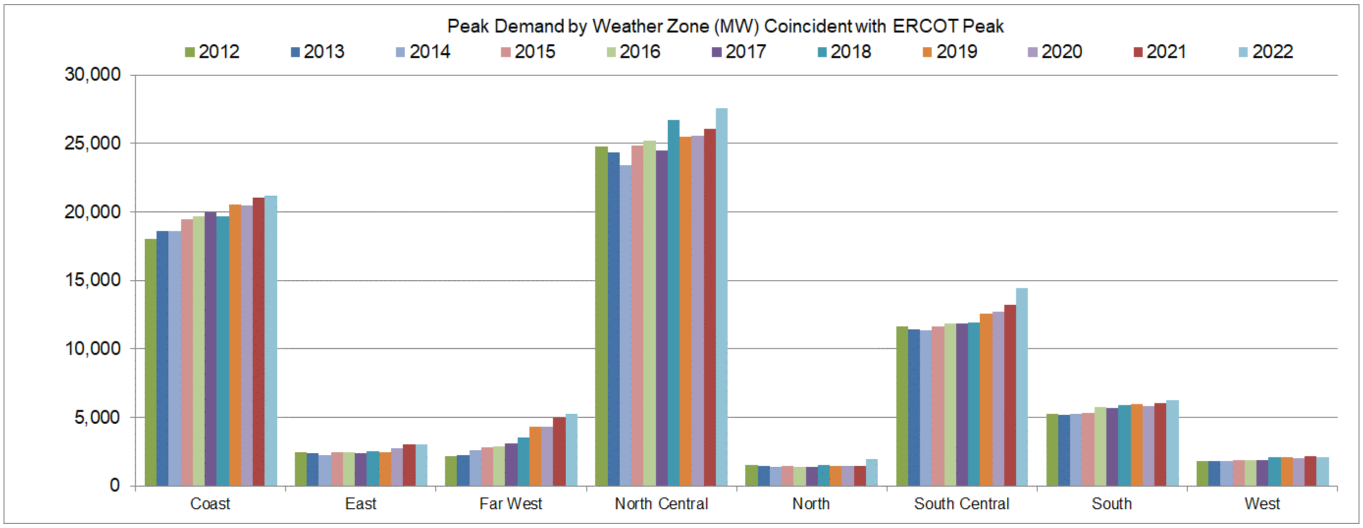


Figure E.5 – Peak Demand by Weather Zone

Overall energy growth rate has averaged 2.5 percent per year and demand growth rate has averaged 1.8 percent per year since 2018.

B. Reserve Margin

NERC develops and publishes its Long-Term Reliability Assessment (LTRA) each December to independently assess each region in an effort to identify trends, emerging issues, and potential risks during the 10-year horizon. A key component of the LTRA is an evaluation of the peak demand and planning reserve margins, which are based on average weather conditions and the forecasted economic growth conditions at the time of the assessment.

ERCOT publishes its Capacity, Demand and Reserves (CDR) report twice each year, in December and May. The purpose of the CDR is to provide updates to the planning reserve margins based on current load forecasts and resource availability.

While both of these reports are focused on the long-term planning reserve margins, the results will differ due to multiple factors such as data collection dates and forecasting of load.

In the LTRA, NERC uses a reference planning reserve margin of 13.75 percent, based on a one event in 10-year loss of load probability. Both assessments show the planning reserve margin to be above the reference margin for the next five years.

ERCOT also publishes its Seasonal Assessment of Resource Adequacy (SARA) four times each year. The SARA report serves as an early indicator of the risk that ERCOT may need to call an Energy Emergency Alert Level 1 (EEA1) due to having insufficient operating reserves during seasonal peak electric demand periods. It uses a scenario approach to illustrate a range of resource adequacy outcomes based on extreme system conditions. The SARA report relies on projected resource capabilities and peak demand forecasts similar to the CDR report. However, unlike the CDR, it incorporates generator outage trends to determine the expected amount of resource capacity available for operating reserves.

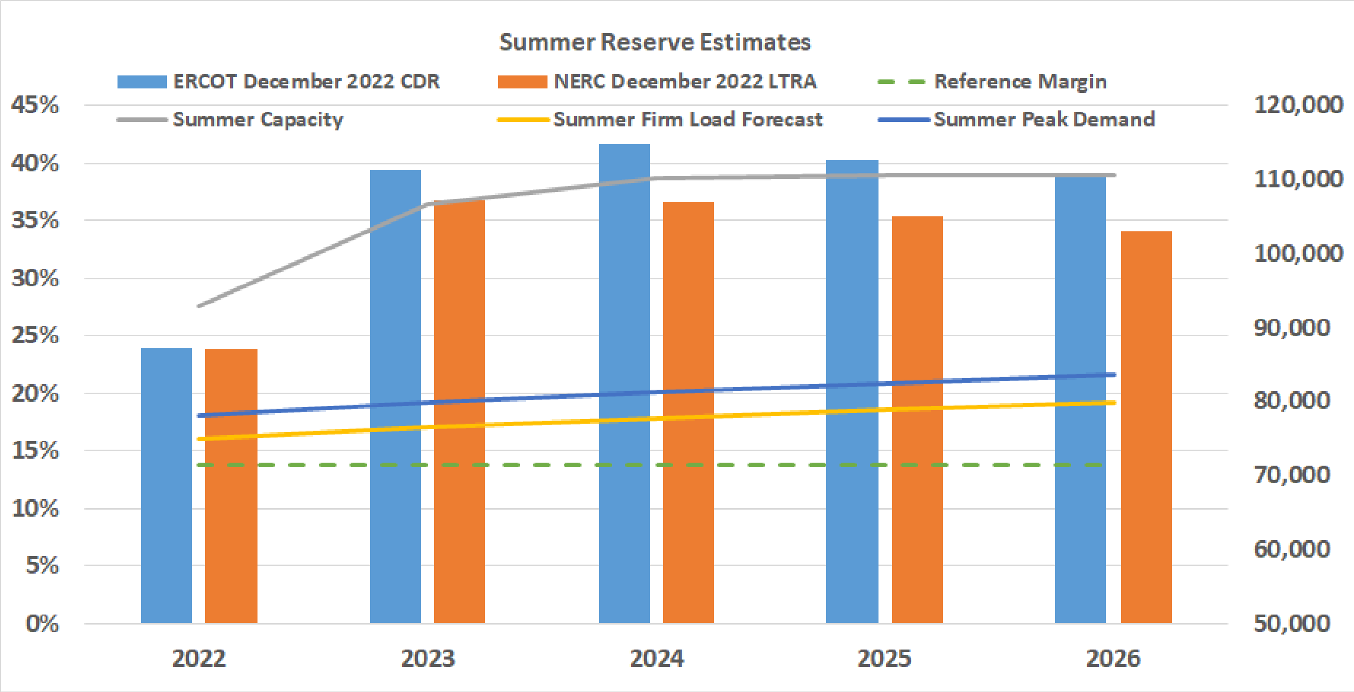


Figure E.6 – Summer Peak Reserve Margins

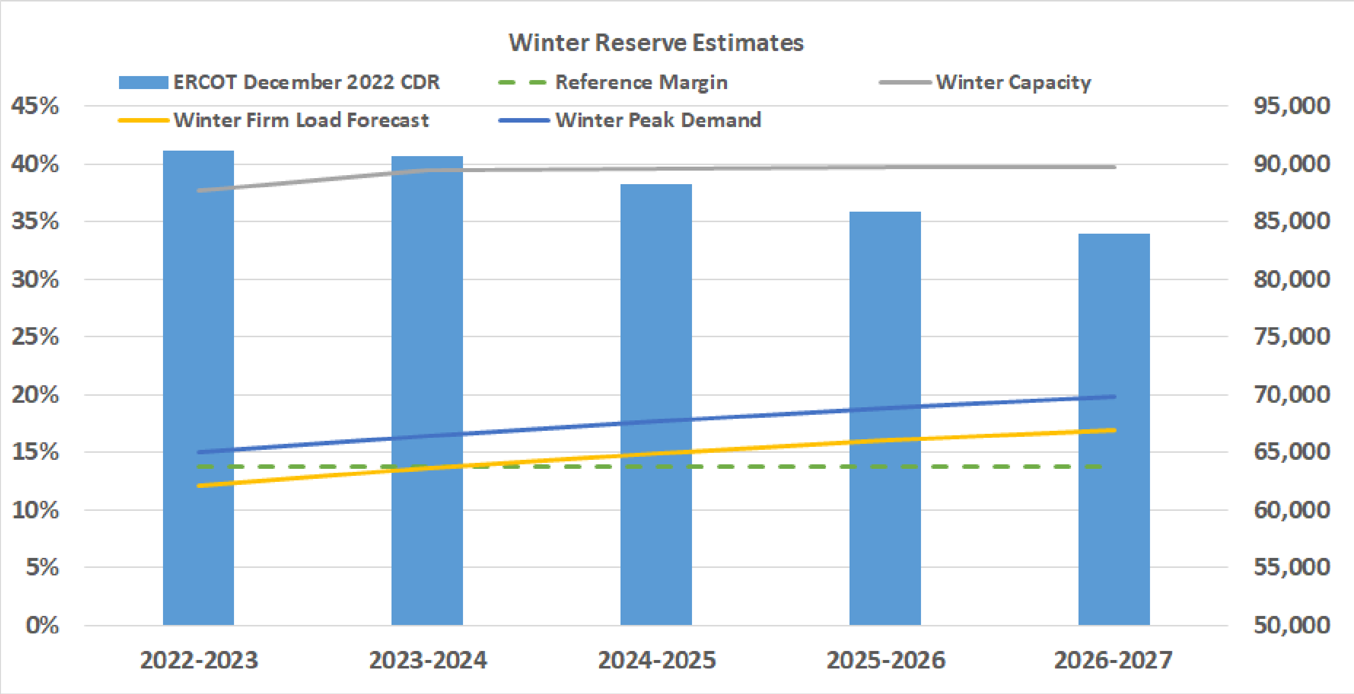


Figure E.7 – Winter Peak Reserve Margins

C. Distributed Energy Resources and Non-Modeled Generation

Distributed Energy Resources (DER) include any non-BES resource located solely within the boundary of the distribution utility, such as:

- Distribution and behind-the-meter generation
- Energy storage facilities
- Microgrids
- Cogeneration
- Stand-by or back-up generation

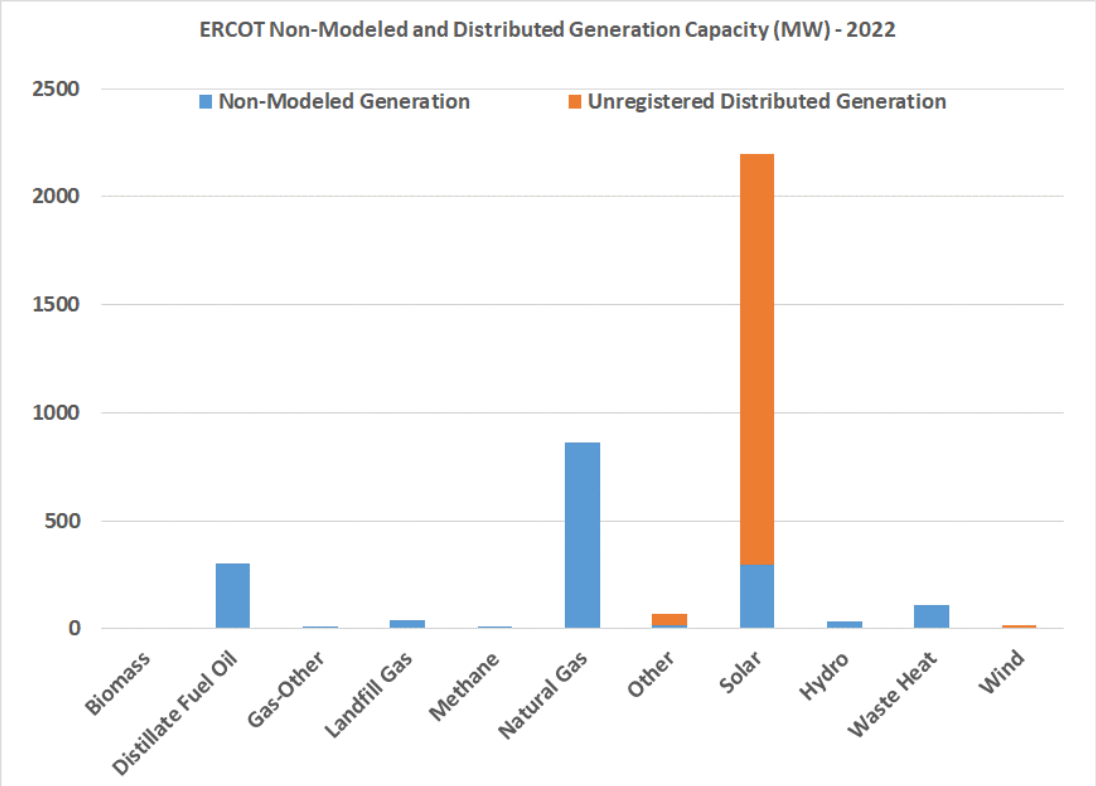
Increasing amounts of DER will change how the distribution system interacts with the BPS by transforming the distribution system into an active energy source. Currently, the aggregated effect of DER is not fully represented in BPS models or real-time operating tools. There are also differing expectations for DER performance between current Public Utility Commission of Texas (PUCT) rules and the Institute of Electrical and Electronics Engineers (IEEE) standards.

Issues with DER include:

- Modeling (both steady-state and dynamic)
- Ramping and energy-load balance
- Reactive power and voltage stability
- Frequency ride-through
- System protection and islanding protection
- Visibility and control
- Unanticipated power flows
- Load forecast errors

Currently under ERCOT Protocols, distributed generation resources greater than 1 MW must register with ERCOT and provide resource registration data per Protocol 16.5(5) and Planning Guide 6.8.2. Additionally, P.U.C. SUBST. R. 25.211(n) requires every electric utility to file (by March 30 of each year) a distributed generation interconnection report with the commission for the preceding calendar year that identifies each distributed generation facility interconnected with the utility's distribution system, including ownership, capacity, and whether it is a renewable energy resource.

At the end of 2022, ERCOT had approximately 1,688 MW of non-modeled generation capacity and 1,972 MW of unregistered distributed generation resources (DGR) that has provided data for mapping capacity to their modeled loads.



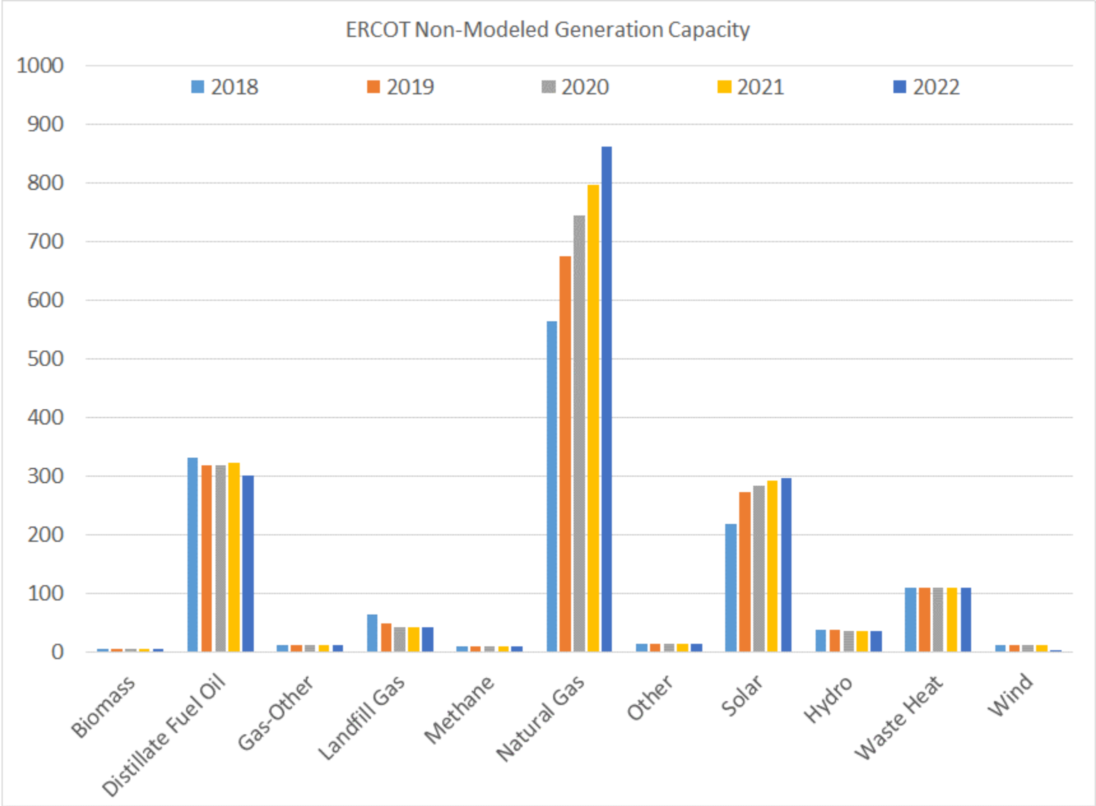


Figure E.8 – Non-Modeled Generation Capacity by Fuel Type

Appendix F – Loss of Situational Awareness Analysis

A. Loss of EMS and Loss of SCADA Events

Loss of Energy Management System (EMS) and System Control and Data Acquisition (SCADA) events continue to be a focus area for NERC and the Regions. Category 1 events include loss of operator ability to remotely monitor and control BES elements, loss of communications from SCADA Remote Terminal Units (RTU), unavailability of Inter-Control Center Communications Protocol (ICCP) links, loss of the ability to remotely monitor and control generating units via Automatic Generation Control (AGC), and unacceptable State Estimator or Contingency Analysis solutions for more than 30 minutes.

Loss of SCADA or EMS events reviewed in 2022 include the following:

- A TOP had a malfunction of a network switch which caused a complete loss of monitoring and control.
- A TOP lost the ability to monitor and control when a third-party contractor performing preventive maintenance turned off the wrong circuit breaker which fed critical power to servers, firewalls, and communications at the primary Control Center.
- A TOP experienced a loss of communications between the primary Control Center and substation RTUs due to a firmware bug within the firewall operating system.
- A TOP experienced a complete loss of monitoring and control while performing maintenance on the EMS.

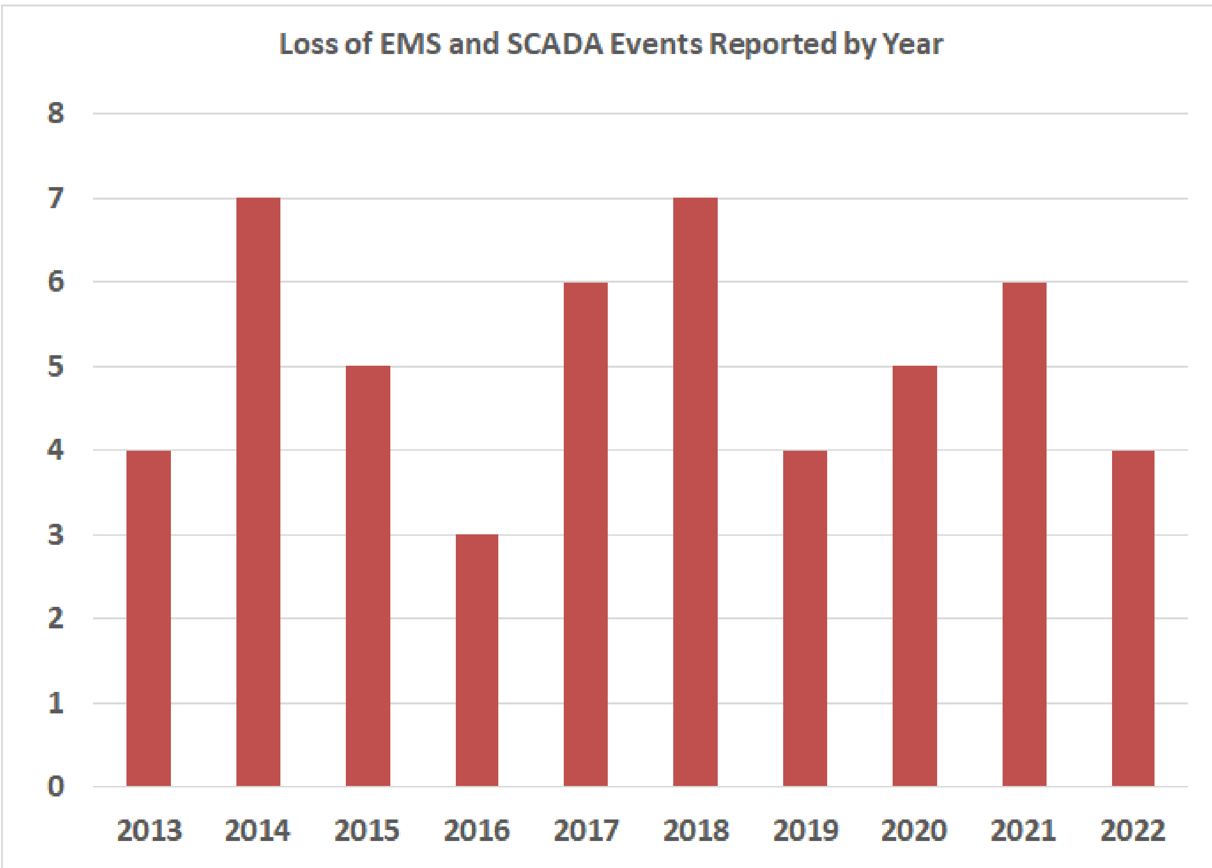


Figure F.1 – Loss of EMS and SCADA Events by Year

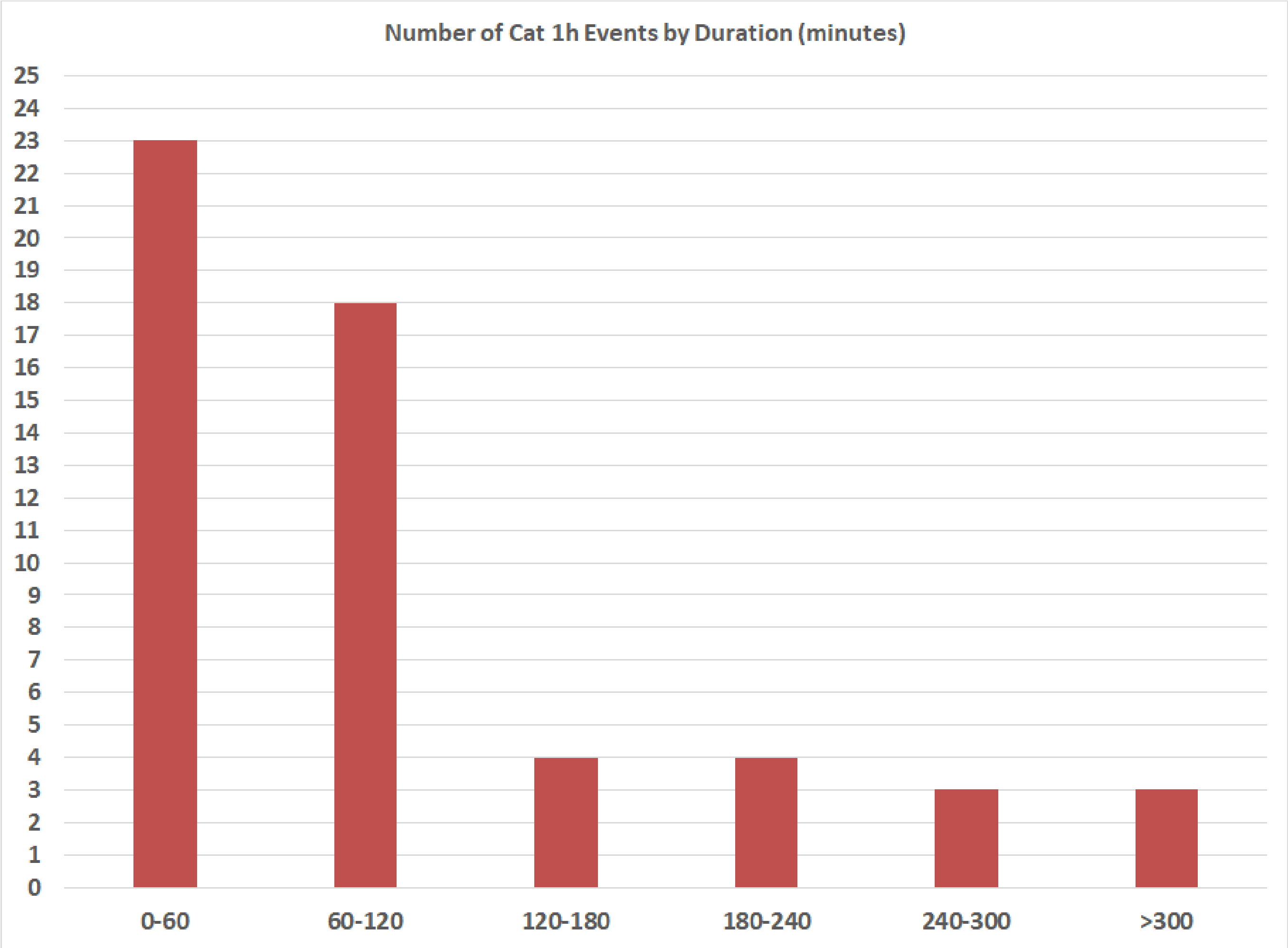


Figure F.2 – Loss of EMS and SCADA Events by Duration Since 2011

B. State Estimator Convergence

ERCOT's goal for State Estimator convergence is 97 percent or higher. In 2022, the convergence rate was 99.99 percent.

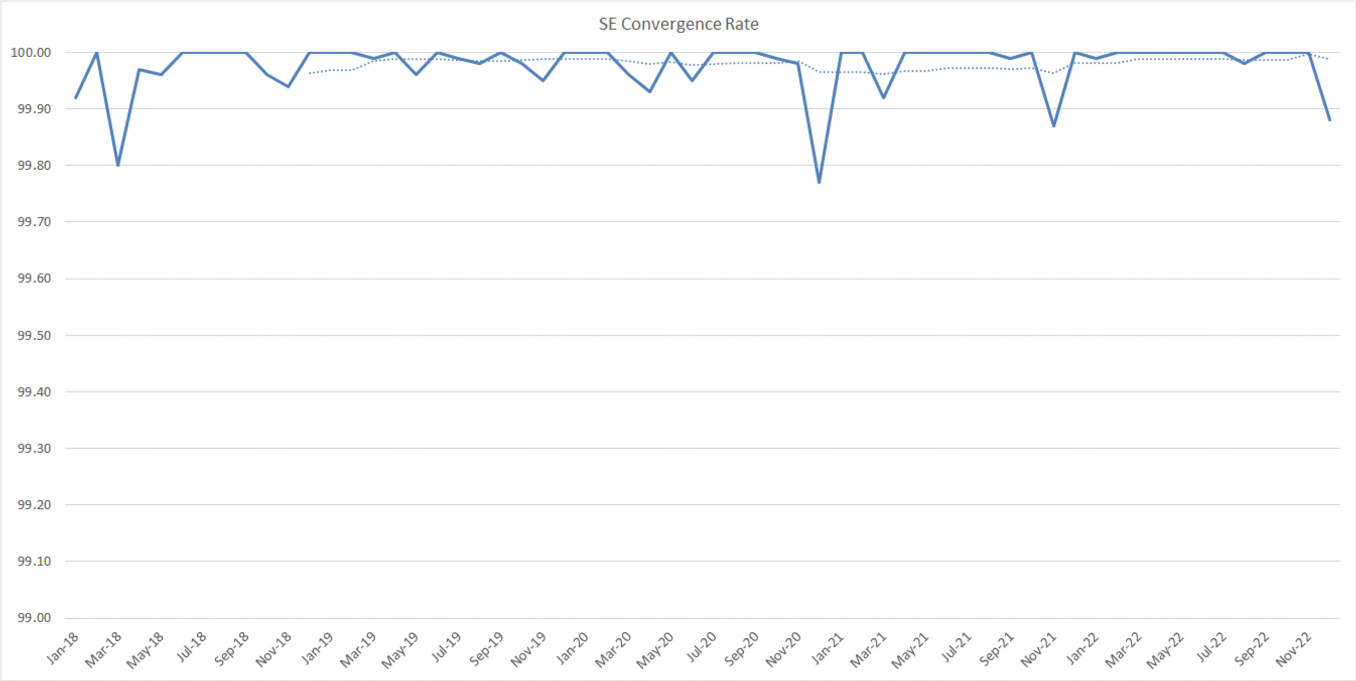


Figure F.3 – State Estimator Convergence Rate

C. Telemetry Availability Metrics

ERCOT telemetry performance criteria states that 92 percent of all telemetry provided to ERCOT must achieve a quarterly availability of 80 percent. Figure F.4 shows the telemetry availability metric per the ERCOT telemetry standard. For 2022, the total number of telemetry points failing the availability metric averaged 4,678 each month, or 3.41 percent of the total system telemetry points.

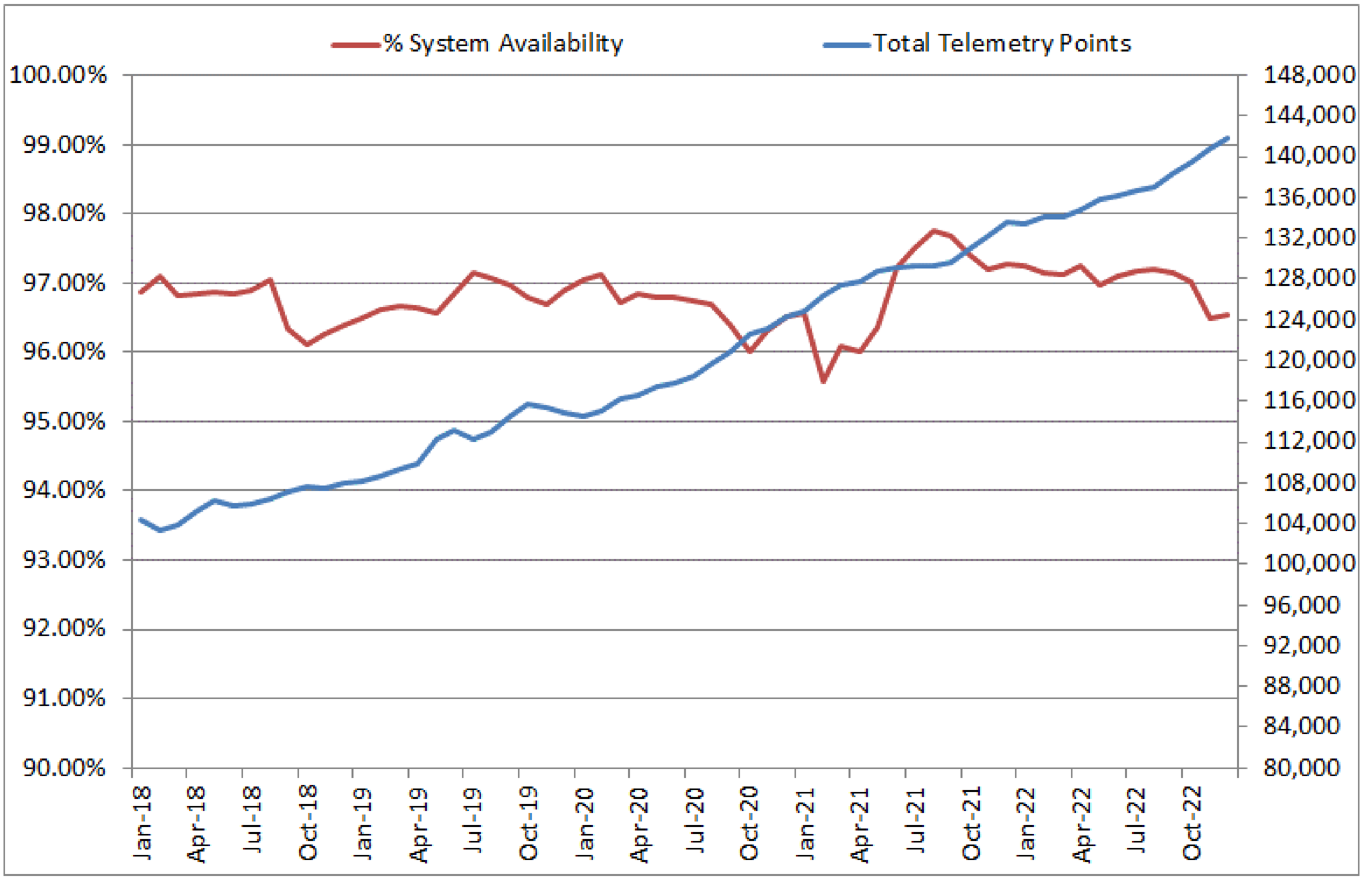


Figure F.4 – ERCOT Telemetry System Availability

D. Telemetry Accuracy Metrics

ERCOT uses several processes to verify the accuracy of telemetry when compared to State Estimator solutions. These include:

1. Residual difference between telemetered value and State Estimator value on Transmission Elements over 100 kV is <10 percent of emergency rating or < 10 MW (whichever is greater) on 99.5 percent of all samples during a month period.
2. The sum of flows into any telemetered bus is less than the greater of five MW or five percent of the largest Normal line rating at each bus.
3. The telemetered bus voltage minus state estimator voltage shall be within the greater of two percent or the accuracy of the telemetered voltage measurement involved for at least 95 percent of samples measured.

The following figures show the historic performance for these metrics.

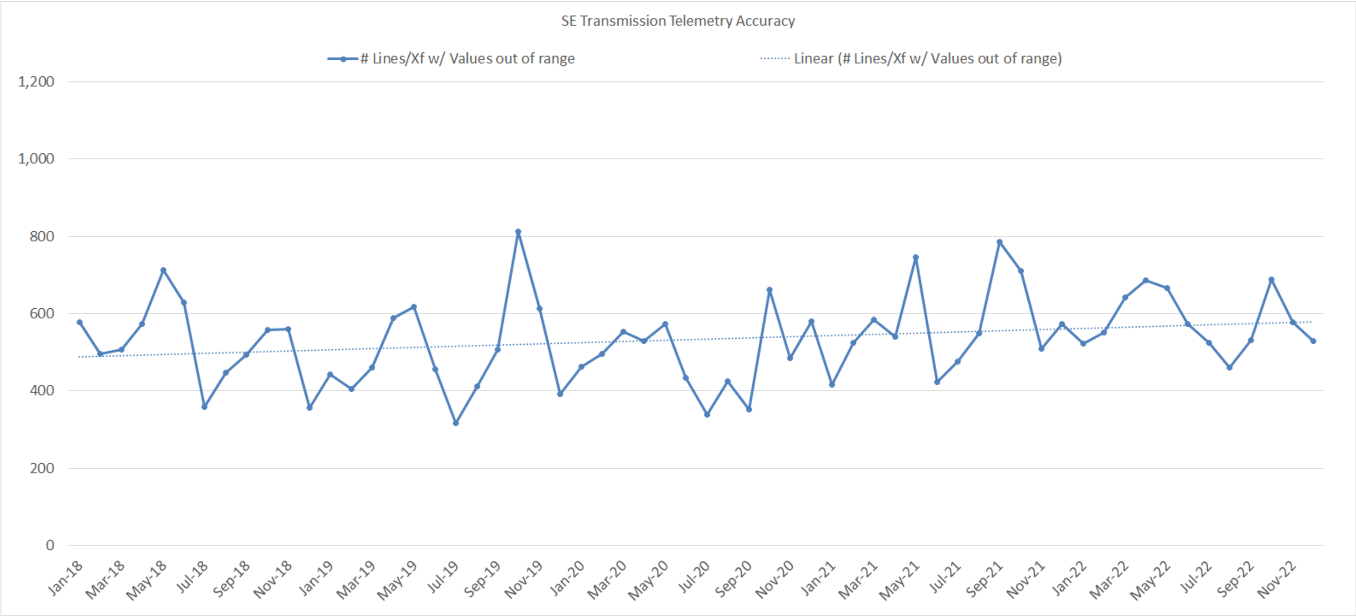


Figure F.5 – State Estimator versus Transmission Telemetry Accuracy

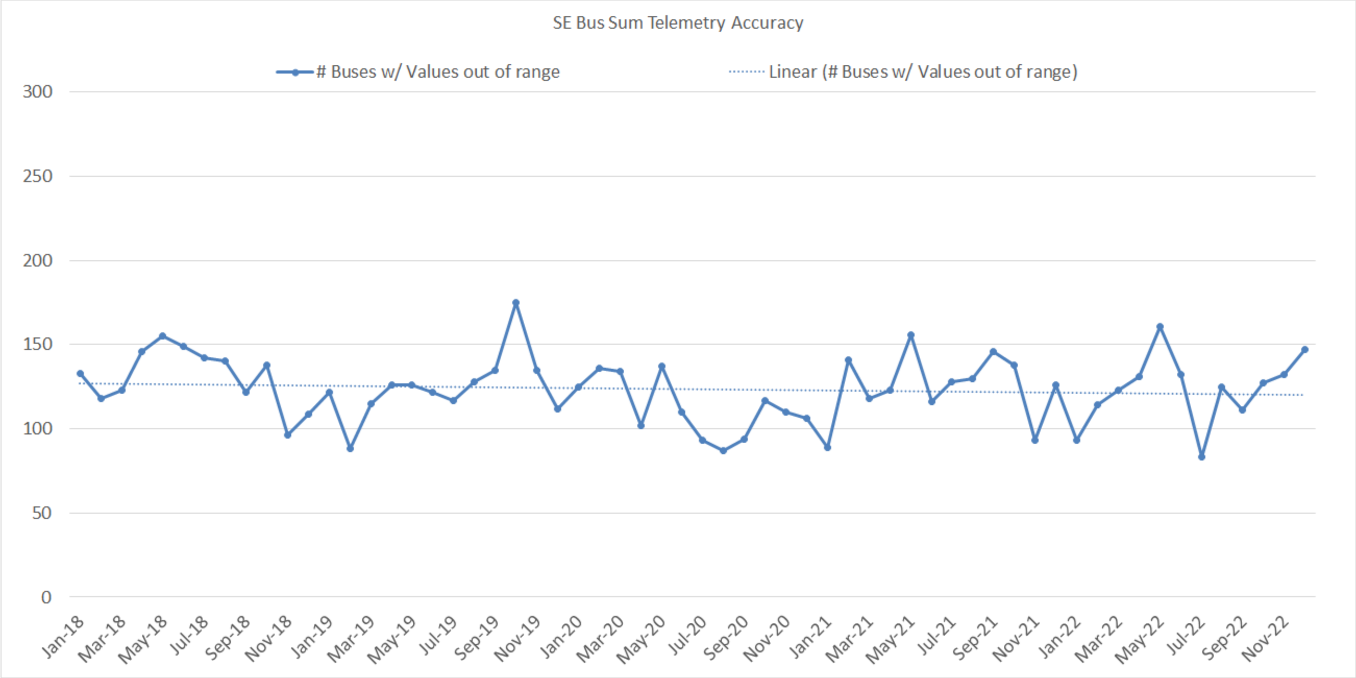


Figure F.6 – Bus Summation Telemetry Accuracy

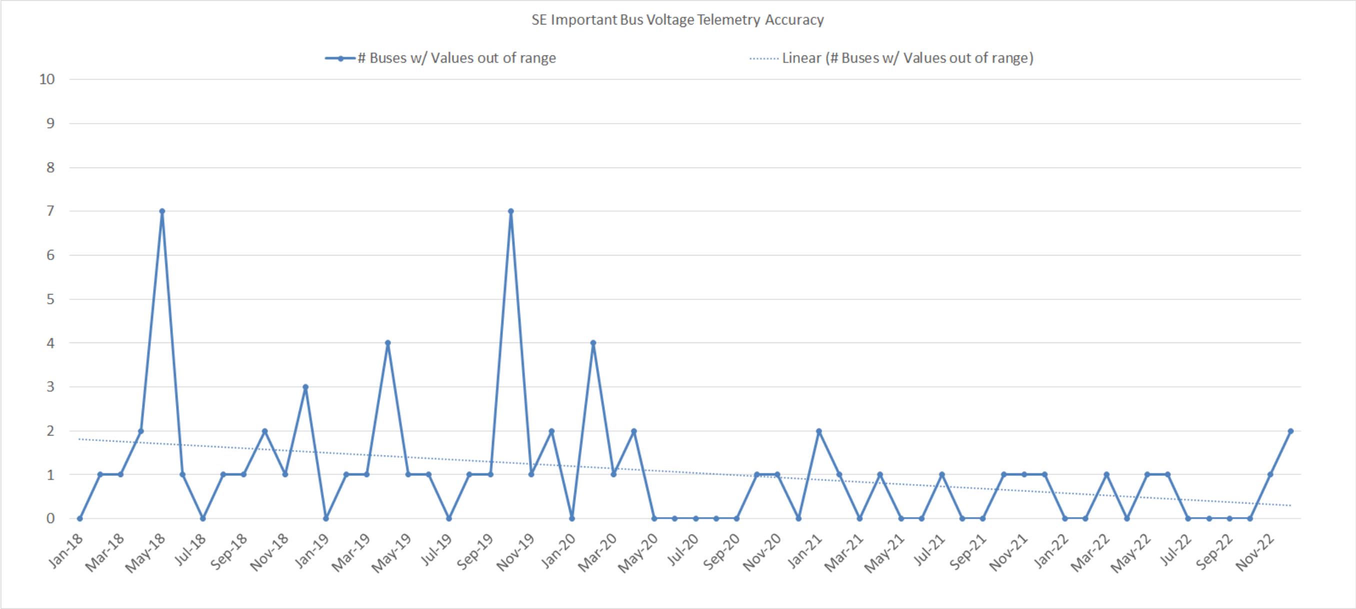


Figure F.7 – Bus Voltage Telemetry Accuracy

Appendix G – Protection System Detailed Analysis

A. Protection System Misoperations

Since January 2018, the overall transmission system Protection System Misoperation rate has been essentially flat, at 7.2 percent in 2018 to 7.3 percent in 2022. The five-year misoperation rate from 2018-2022 was 6.3 percent.

138 kV	2018	2019	2020	2021	2022	5-Yr Avg
Number of Misoperations	101	115	72	102	94	97
Number of Events	1639	1852	1305	1805	1297	1580
Percentage of Misoperations	6.2%	6.3%	5.5%	5.6%	7.3%	6.1%
345 kV	**2018**	**2019**	**2020**	**2021**	**2022**	**5-Yr Avg**
Number of Misoperations	48	40	43	33	41	41
Number of Events	548	715	629	717	612	644
Percentage of Misoperations	8.8%	5.6%	6.8%	4.6%	6.7%	6.4%
< 100 kV	**2018**	**2019**	**2020**	**2021**	**2022**	**5-Yr Avg**
Number of Misoperations	5	1	1	0	11	4
Number of Events	44	55	62	76	81	64
Percentage of Misoperations	11.4%	1.9%	1.6%	0.0	13.6%	6.3%

Table G.1 – Protection System Misoperation Data

In 2022, three main categories account for 58 percent of the total misoperations: incorrect settings/logic/design (32 percent), relay failures (12 percent), and other (14 percent).

Misoperations due to incorrect settings, communication failures, and relay failures increased in 2022 compared to 2021.

Misoperations due to AC systems and As-left personnel error are showing a positive downward trend.

However, unknown errors and other/explainable errors continue to show negative upward trends.

Entities have completed corrective actions on approximately 75 percent of misoperations.

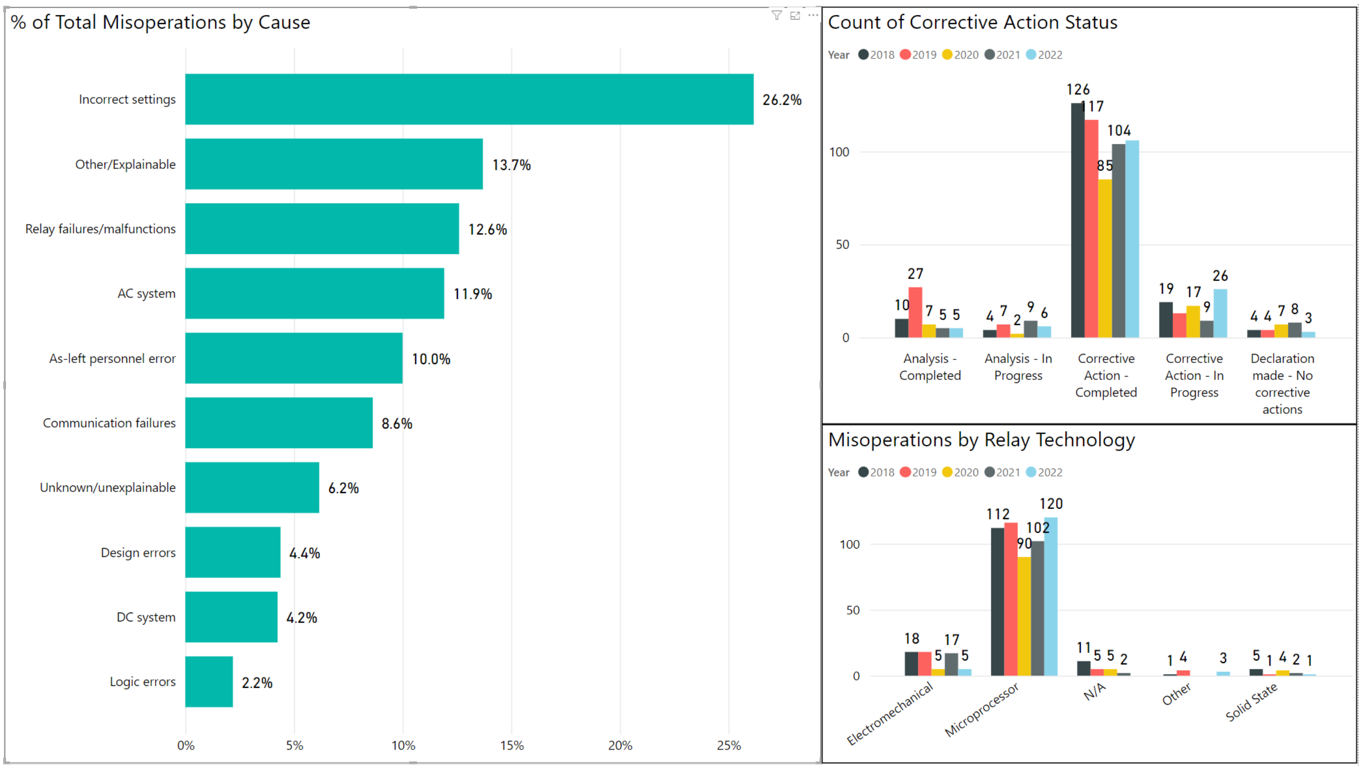


Figure G.1 – Protection System Misoperation Count 2018-2022

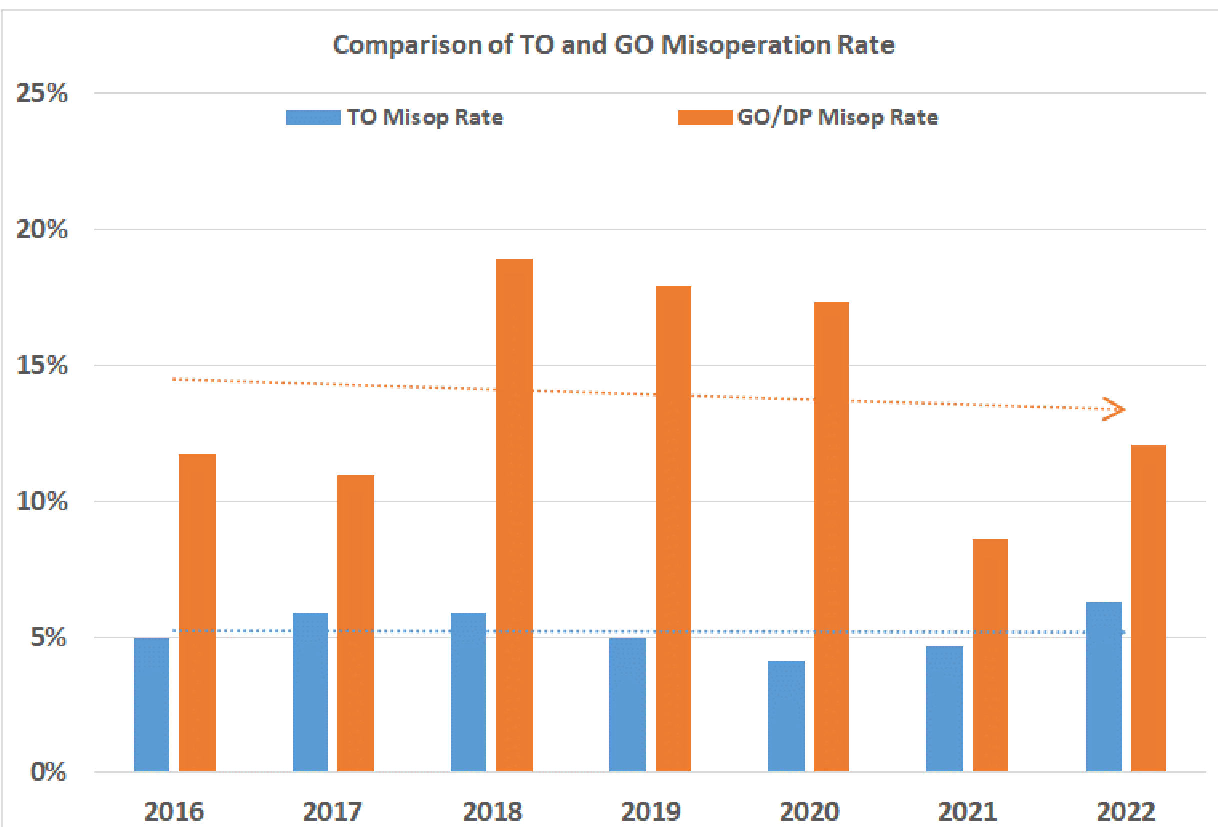


Figure G.2 – Protection System Misoperation Rate by Entity Type

B. Transmission Outages Initiated by Failed Protection System Equipment

From TADS data, the outage rate per element initiated by failed Protection System equipment for 345 kV transmission circuits and 138 kV circuits remained stable. The outage rates per element initiated by failed Protection System equipment for 345 kV transformers showed a significant decrease.

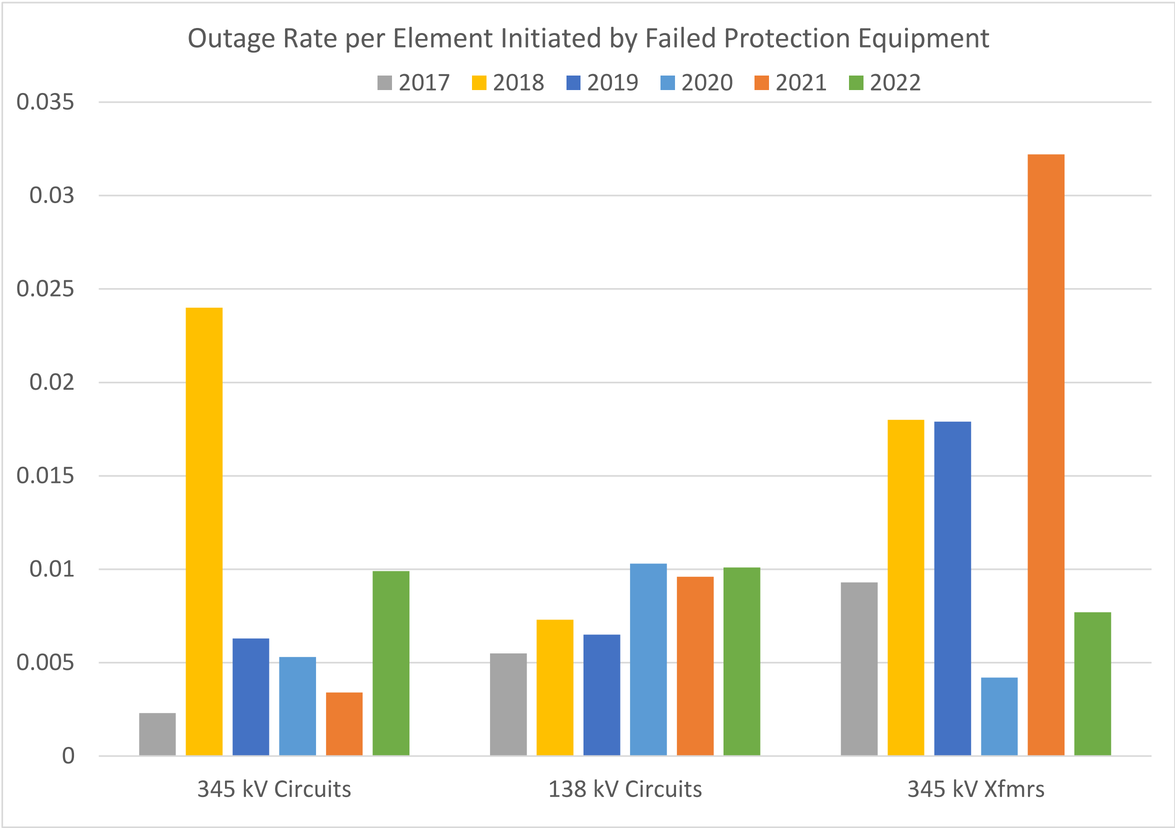


Figure G.3 – Outage Rates Caused by Failed Protection Equipment

Appendix H – Frequency Control Detailed Analysis

Appendix H – Frequency Control Detailed Analysis

A. CPS1 Performance

Control Performance Standard 1 (CPS1): 173.4 for calendar year 2022 versus 169.3 for calendar year 2021.

NERC Reliability Standard BAL-001-2 requires each Balancing Authority (BA) to operate such that the 12-month rolling average of the clock-minute ACE divided by the clock-minute average BA Frequency Bias times the corresponding clock-minute average frequency error is less than a specific limit. This is referred to as Control Performance Standard 1 (CPS1). The NERC CPS1 Standard requires rolling 12-month average performance of at least 100 percent. Figure H.1 shows the ERCOT region CPS1 trend since January 2017. For 2022, the annualized CPS1 score was 173.4.

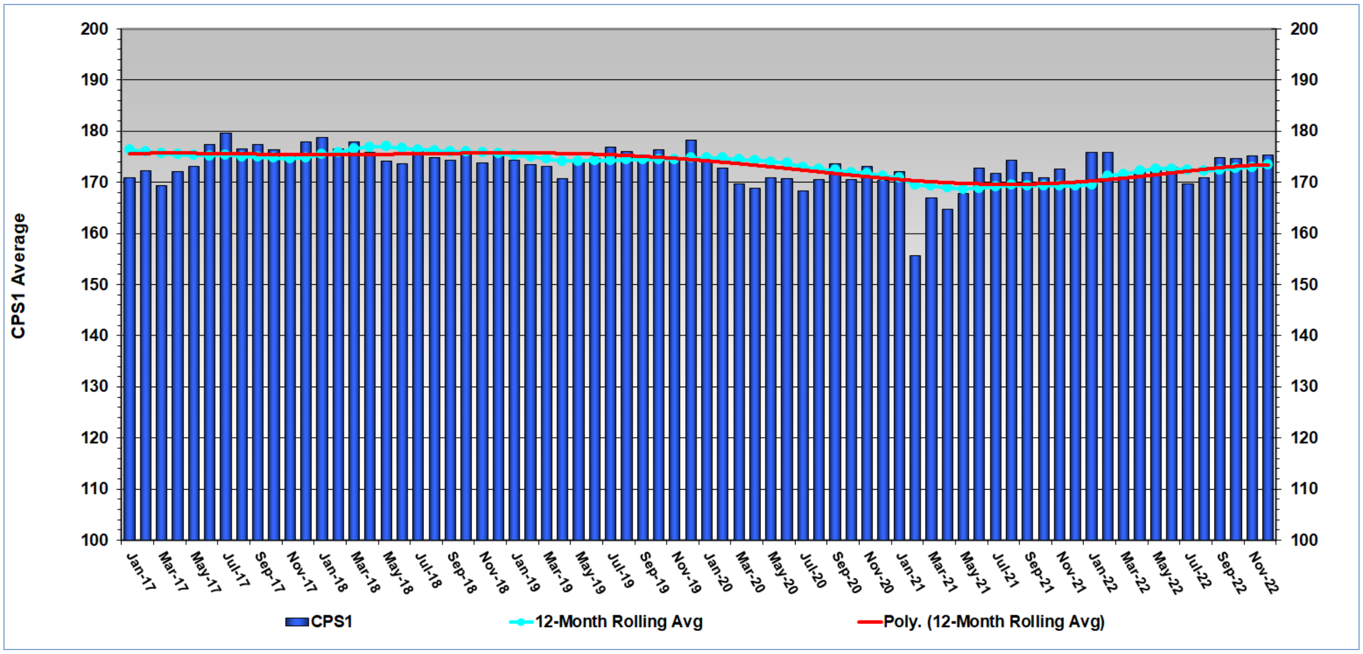


Figure H.1 – CPS1 Average January 2017 to December 2022

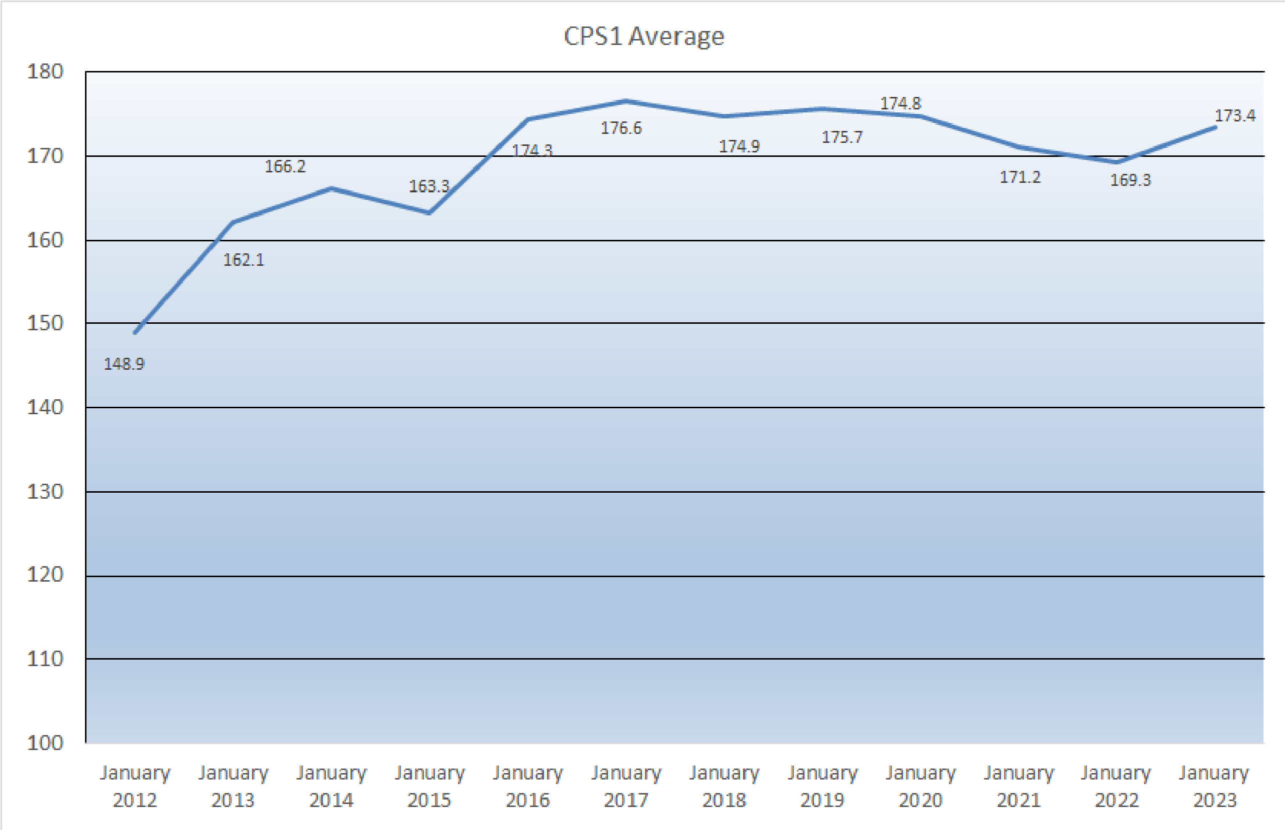


Figure H.2 – ERCOT CPS1 Annual Trend since January 2012

Figure H.3 shows bell curves of the ERCOT frequency profile, comparing 2017 through 2022. The shape of the bell curve in 2022 was virtually identical to 2021.

The blue dashed lines on the figure represent the Epsilon-1 (ε1) value of 0.030 Hz which is used for calculation of the CPS-1 score. The red dashed lines represent governor deadband settings of 0.017 Hz. The purple dashed lines represent three times the ε1 value which is used for Balancing Authority Ace Limit (BAAL) exceedances per NERC Standard BAL-001-2.

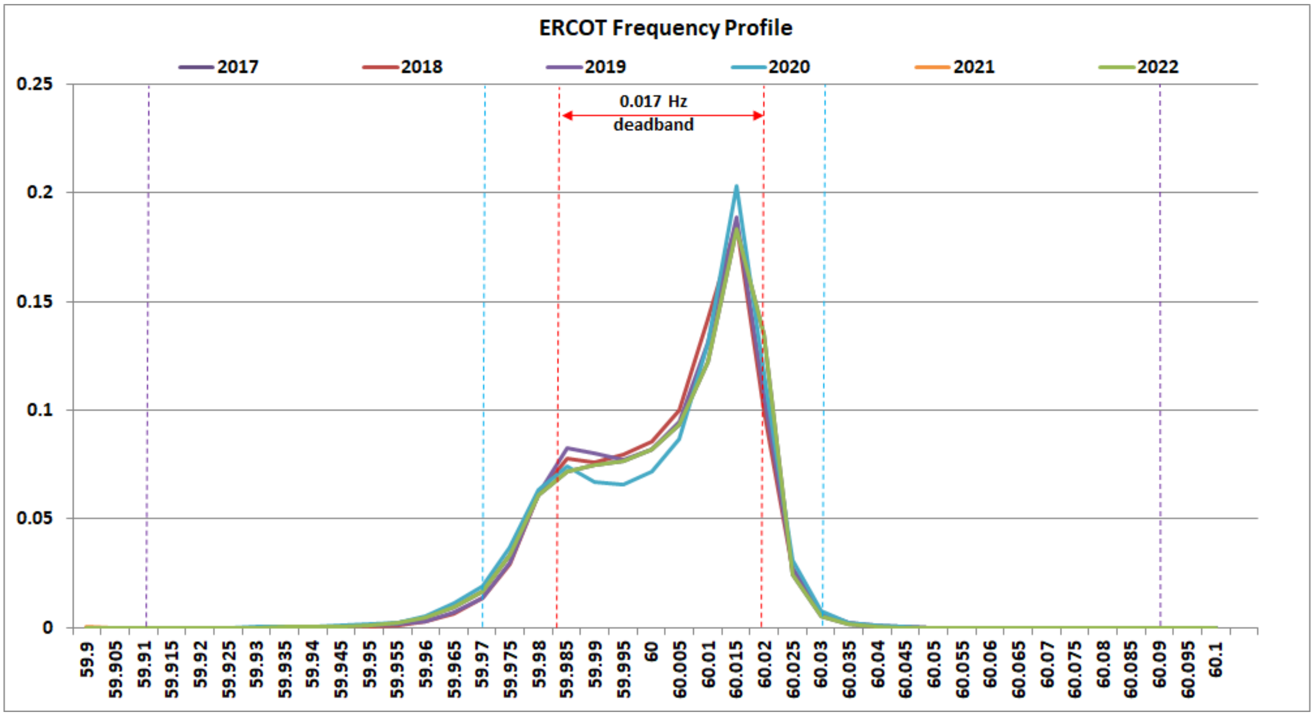


Figure H.3 – Frequency Profile Comparison

Figure H.4 shows the 2022 CPS1 scores by month compared to previous years. The February 2021 CPS1 score shows a sharp reduction compared to other months due to the impact of Winter Storm Uri.

The daily RMS1 figure shows the average root-mean-square of the frequency error based on one-minute frequency data. The long-term trend continues to show excellent control of frequency error. The red dashed line on the figure shows the 17 mHz governor deadband required by BAL-001-TRE in relation to the daily RMS1.

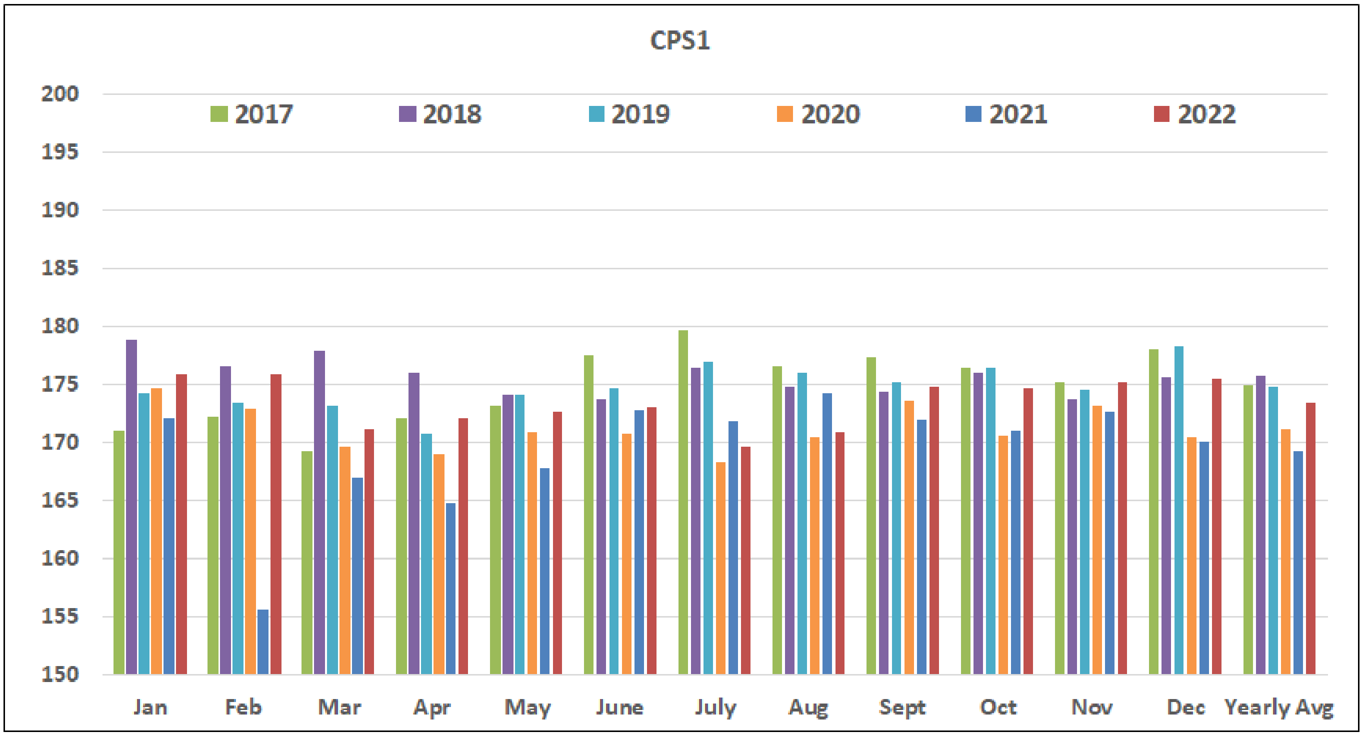


Figure H.4 – CPS1 Score by Month for 2017 through 2022

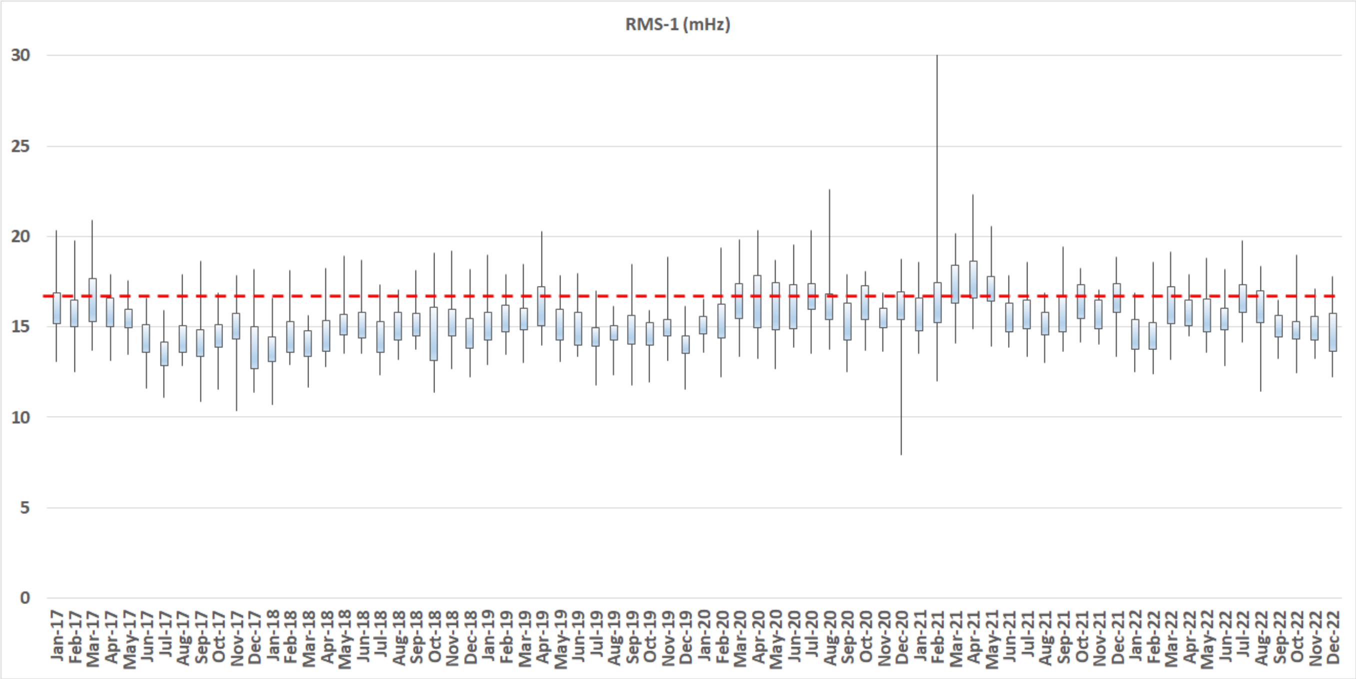


Figure H.5 – Daily RMS1 for 2017 through 2022

B. Time Error Correction Performance

In 2022, there were no manual Time Error Corrections. In December 2016, ERCOT added an ACE Integral term to the Generation-To-Be-Dispatched (GTBD) calculation. This term corrected longer-term errors in generation basepoint deviation rather than depending on regulation. Since implementation of the ACE Integral into the GTBD, ERCOT is controlling frequency to zero average time error.

C. Balancing Authority ACE Limit (BAAL) Performance

The Frequency Trigger Limits (FTLs) are defined as ranges for the BAAL high and low values per NERC Standard BAL-001-2 which became enforceable in July 2016. The FTL-Low value is calculated as 60 Hz – 3 x Epsilon-1 (ε1) value of 0.030 Hz, or 59.910 Hz for the ERCOT region. The FTL-High value is calculated as 60 Hz + 3 x Epsilon-1 (ε1) value, or 60.090 Hz for the ERCOT region.

The following table shows the total one-minute intervals where frequency was above the FTL-High alarm level or below the FTL-Low alarm level.

In 2021, 54 of the 79 BAAL exceedances were associated with Winter Storm Uri.

High/Low Frequency	2018 Total Minutes	2019 Total Minutes	2020 Total Minutes	2021 Total Minutes	2022 Total Minutes	Five-year Avg
Low (<59.91 Hz)	17	16	29	78	1	28
High (>60.09 Hz)	0	0	0	1	0	0

Table H.1 – BAAL Exceedance Performance