2017 Assessment of Reliability Performance of the Texas RE Region
By Texas Reliability Entity, Inc.
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Executive Summary

The goals of the 2017 Assessment of Reliability Performance report for the Electric Reliability Council of Texas (ERCOT) bulk power system (BPS) are to illuminate the historical and overall BPS reliability picture, to help identify risk areas, and to prioritize and create actionable results for reliability improvement.

This report represents an ongoing effort by Texas Reliability Entity, Inc. (Texas RE) to provide a view of risks to reliability based on historic performance. By integrating many ongoing efforts and addressing key measurable components of BPS reliability, this report seeks to provide insight, guidance, and direction to those areas in which reliability goals can be more effectively achieved. Additionally, this report seeks to streamline and align the data and information reported from multiple sources, thereby providing efficient data and information transparency. The key findings and observations can serve as inputs to process improvements, event analysis, reliability assessments, and critical infrastructure protection.

For 2017, the overall BPS reliability performed within the defined acceptable performance metrics. The following are key observations made for 2017:

- System inertia is showing a downward trend during low Net Load conditions.
- Growth in renewable generation continues to be managed well by ERCOT.
- Frequency control and primary frequency response metrics continue to be maintained at high levels.
- Protection System Misoperation rates increased in 2017, but remain within historical averages.
- Transmission availability, outages per circuit, and outages per 100 miles of line remained stable in 2017 when compared to previous years.

Major focus areas for 2018 will be:

- Resource adequacy
  - Impact of generation unit retirements and resource mix changes
    - System inertia
    - System ramping capability
    - Frequency response
  - Distributed energy resource effects on demand, ramping, and voltage control
- Weak grid areas in the Interconnection
  - Panhandle
  - West Texas
  - Lower Rio Grande Valley
- Resilience and recovery
- Cyber and physical security
- Situational awareness
- Human performance and skilled workforce

Introduction

Texas RE is the Federal Energy Regulatory Commission (FERC)-approved Regional Entity for the Texas RE Region, as authorized by the Energy Policy Act of 2005. Texas RE is authorized in the Texas RE Region through its Delegation Agreement with the North American Electric Reliability Corporation (NERC) to:

- Develop, monitor, assess and enforce compliance with NERC Reliability Standards.
- Assess and periodically report on the reliability and adequacy of the BPS.

The Texas RE Region, also known as the ERCOT Interconnection or Texas Interconnection, is a separate electric Interconnection located entirely within the state of Texas and operates as a single Balancing Authority (BA) and Reliability Coordinator (RC) area. It provides power to more than 24 million Texas customers—representing 90% of the state's electric load—and covers approximately 200,000 square miles. The ERCOT BPS connects more than 46,500 miles of transmission lines and 570 generation units. The Texas RE Region is projected to have more than 78,000 MW of expected generation capacity for the 2018 summer peak demand. Installed renewable generation capacity totals more than 20,000 MW of wind and 1,000 MW of solar. ERCOT Interconnection members include consumers, cooperatives, generators, power marketers, retail electric providers, investor-owned electric utilities (transmission and distribution providers), and municipal-owned electric utilities.

Figure 1 – Texas RE Region Map

Texas RE collects reliability data from multiple sources in its role as the Regional Entity. Data sources include, but are not limited to, the following:

- Transmission Availability Data System (TADS) (NERC Rules of Procedure (ROP) Section 1600)
- Generation Availability Data System (GADS) (NERC ROP Section 1600)
- Demand Response Availability Data System (DADS) (NERC ROP Section 1600)
- Misoperation Information Data Analysis System (MIDAS) (NERC ROP Section 1600)
- Event Reports (NERC Reliability Standards and NERC Events Analysis Process)
- Frequency Control Performance and Primary Frequency Response (NERC Reliability Standards and ERCOT Operating Guides)

Texas RE continually evaluates risks to system reliability within the Texas RE Region through long-term and seasonal reliability assessments, events analysis, situational awareness, tracking reliability indicators, real-time performance monitoring, and planning observations. Texas RE developed the 2017 Assessment of Reliability Performance report to provide a high-level overview of the data collected in the Texas RE Region. This report is intended to provide:

- 2017 data at a high level;
- Associated historical data;
- An analysis of the 2017 and other historical data as an indicator of the current state of the Texas RE Region; and
- Observations that help connect the state of the region today to the future.

This report describes Texas RE's assessment of reliability data and historical trends in nine focus areas:

1. Emerging Reliability Issues
2. Resource Adequacy
3. Disturbances and Events
4. Transmission
5. Generation
6. Load and Demand Response
7. Frequency Control and Primary Frequency Response
8. Protection System Performance
9. Infrastructure Protection

Each section provides a brief description of the data that is collected and the reliability area being addressed, historical trends, analysis and observations of the historical data, and conclusions.

2017 At A Glance

- Peak hourly demand: 69,531 MW on July 28, 2017 versus record of 71,193 MW
- Peak hourly wind generation: 16,035 MW on November 17, 2017 at 10:00 p.m.
- Peak hourly renewable penetration: 53.7% on October 27, 2017 at 3:00 a.m.
- Renewable energy percentage: 18.7% of total energy for calendar year 2017
- Control Performance Standard 1 (CPS1): 174.9 for calendar year 2017 versus 176.6 for calendar year 2016
- Primary Frequency Response: 759 MW/0.1 Hz versus NERC obligation of 381 MW/0.1 Hz
- Protection system misoperation rate: 7.3% for 2017 versus 5.4% for 2016
- TADS 345 kV circuit automatic outage rate per 100 miles: 2.68 for 2017 versus 2.78 for 2016
- GADS EFOR (MW Weighted): 7.33% for 2017 versus 5.75 % for 2016

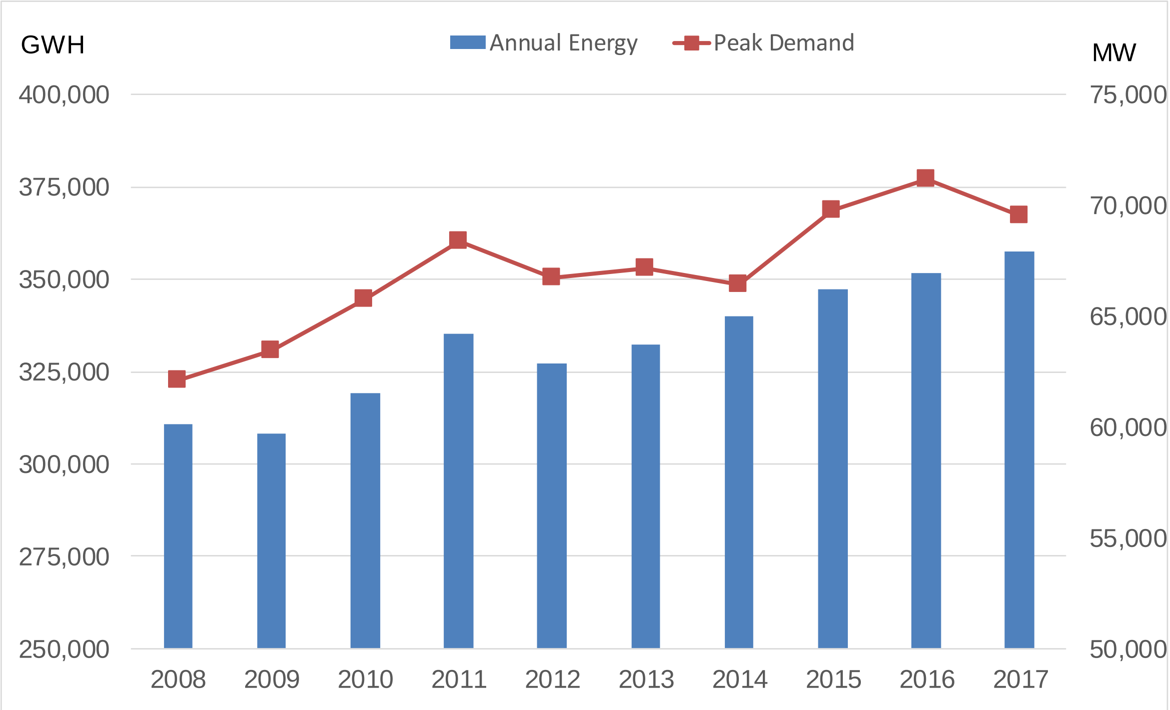

Figure 2 – Annual Energy and Peak Demand

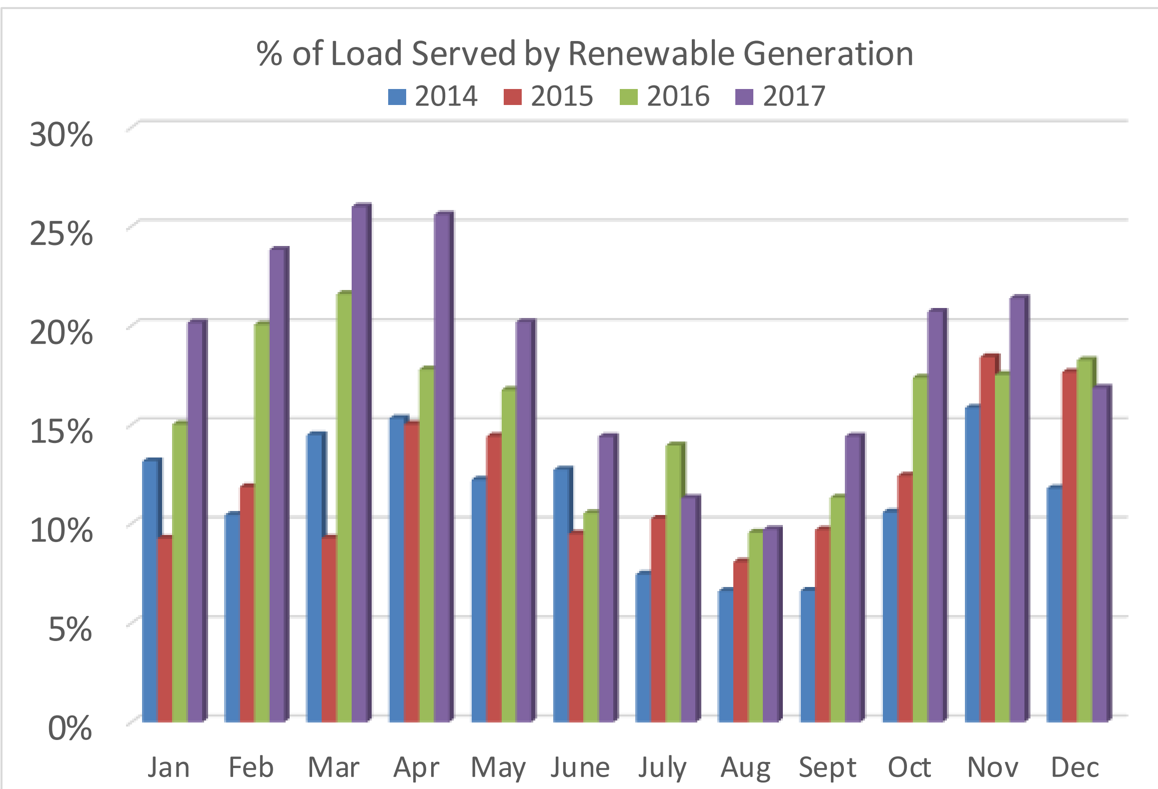

Figure 3 – Percentage of Load Served by Renewable Generation

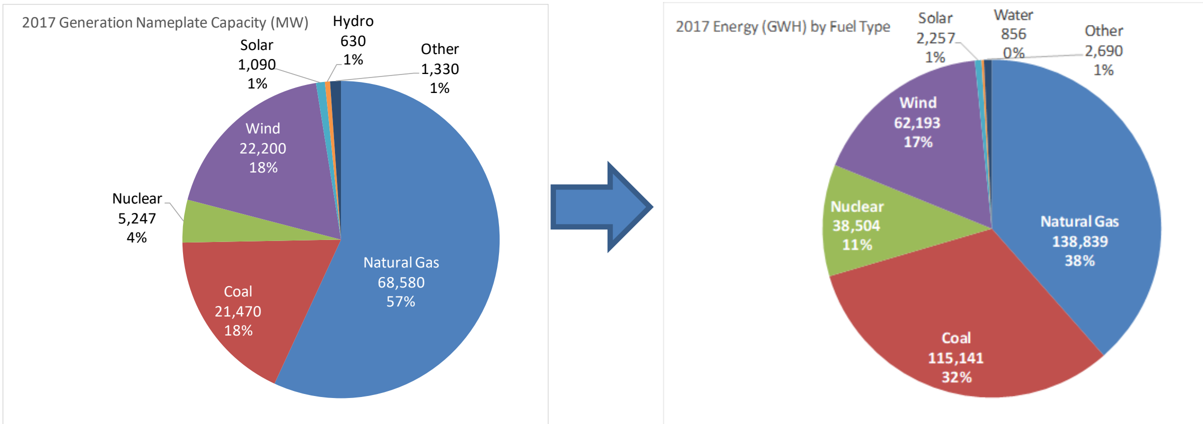

Figure 4 – 2017 Generation Capacity and Energy by Fuel Type

Summary of Key Findings and Observations

Overall BPS reliability in the Texas RE Region continues to perform within acceptable performance levels. The following are key findings:

1. **System inertia is showing a downward trend during low Net Load conditions.**

   Overall system inertia declined slightly in 2017 compared to 2016 as renewable generation provided an increasing percentage of total energy. As of December 2017, ERCOT projections indicate utility-scale solar generation will increase to over 2,300 MW and wind generation will increase to over 25,900 MW during the next two years based on current signed generation interconnect agreements with financial security. The declining trend in inertia is expected to continue in 2018.

2. **Frequency control and primary frequency response metrics continue to be maintained at high levels.**

   The frequency Control Performance Standard (CPS) metrics for the Texas RE Region continue to be among the highest of all the NERC regions. Addition of the Integral Area Control Error (ACE) term to the Generation-To-Be-Dispatched (GTBD) calculation in December 2016 had a positive impact in correcting time error, longer-term errors in generation basepoint deviation, and regulation deployments. Further changes are being codified to address wind ramps in the GTBD formula. The effect of this modification will be evaluated throughout 2018.

3. **Growth in Renewable Generation continues to be managed well.**

   Total energy produced by wind generation increased by almost 53% over 2016. Wind generation, as a percentage of total ERCOT energy produced, increased to 17.4% in 2017, up from 15.1% in 2016. Wind generation served a peak of 53.7% of system demand on October 27, 2017 at 3:00 a.m. Utility-scale solar generation within the region more than doubled during 2017. The amount of energy provided by solar generation increased by 185% versus 2016, but remains a very small percentage of total energy (0.6%).

4. Transmission outage rates remain stable.

The outage rate per circuit and outage rate per 100 miles of line in 2017 remained stable when compared to previous years. For the 138 kV system, failed substation equipment and failed transmission circuit equipment continued to dominate the sustained outages, accounting for 85% of the outage duration.

Voltage stability limits, transient and control stability limits, and stability issues in areas with low weight short circuit ratios are monitored by Generic Transmission Limits (GTLs) and managed through the use of Generic Transmission Constraints (GTCs). In 2017, there were 4,873 basecase exceedances of GTLs for at least one SCED interval, compared to 5,703 basecase exceedances in 2016. Approximately 80% of the exceedances were due to increased wind penetration in Panhandle (Panhandle Interface).

Reporting and trending of chronic congestion began in October 2016. The reporting includes the following:

(1) Exceedances that were 125% or greater of the Emergency Rating for a single SCED interval;
(2) Exceedances greater than 100% of the Emergency Rating for 30 consecutive minutes or more; and
(3) The number of occurrences and congestion rent associated with each of the constraints.

Total estimated congestion rent (defined as the difference between congestion payments to generators and the congestion charges to loads) for 2017 exceeded $756 million. Planned/forced outages and the North-Houston import accounted for 31% of the constraint intervals and 69% of the congestion rent.

5. Protection System Misoperation rates increased in 2017.

The overall percent misoperation rate increased from 5.4% in 2016 to 7.3% in 2017, but remains within historical averages. Incorrect settings, logic, and design errors were 34% of misoperations in 2017 compared to 33% in 2016. As-left personnel errors (14%) and relay failures (20%) were the next two largest causes for misoperations in 2017. Human error/human performance issues continue to be the root cause for the majority of misoperations, accounting for 54% in 2017. This trend, as well as other human performance issues that result in misoperations, will continue to be monitored.

Recommended Focus Areas for 2018

The NERC Board approved the Reliability Issues Steering Committee (RISC) ERO Reliability Risk Priorities report in February 2018.[1] The priorities and recommendations from that report are the basis for the recommended focus areas for the upcoming year.

1. **Resource adequacy**
   a. **Impact of generation unit retirements and resource mix changes**
      i. **System inertia**
      ii. **System ramping capability**
      iii. **Frequency response**
   b. **Distributed energy resource effects on demand, ramping, and voltage control**

   The rate of change of the resource mix is increasing. There are potentially increasing risks to the BPS as conventional synchronous generation is retired and replaced with renewable, distributed, or asynchronous resources. Uncoordinated integration of inverter-based technology may result in unforeseen common-mode failures that may not have been anticipated (as demonstrated during the Blue Cut fire event).

   Resource adequacy needs to look beyond the calculation of reserve margins and utilize probabilistic analysis to accommodate the energy limitation of resources, such as variable renewable resources.

   The increased dependency on natural gas as the predominant fuel source will begin to present more challenges to real-time operations. Natural gas fuel supplies and deliverability can have a significant impact on reliability and must be studied to identify necessary mitigation strategies. Situational awareness should now include gas sources, pipeline status, gas compressor station locations and failures, and other deliverability issues.

   Limited data availability is impacting the ability to integrate Distributed Energy Resources (DER) into planning models.

2. **Weak grid areas in the Interconnection**
   a. **Panhandle**
   b. **West Texas**
   c. **Lower Rio Grande Valley**

   Weak grid characteristics include lack of local synchronous generation combined with a lack of local load. These characteristics can lead to grid strength challenges due to low short-circuit strength and voltage stability issues.

   Several projects are currently planned to increase the transmission import capability into the Rio Grande Valley by 2019.

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[1] ERO Reliability Risk Priorities report: http://www.nerc.com/comm/RISC/Related%20Files%20DL/ERO-Reliability-_Risk_Priorities-Report_Board_Accepted_February_2018.pdf

The generation modeling information necessary to perform transient and small-signal stability studies is incomplete. Proper models for wind plant control systems in the Panhandle and Valley areas have limited the accuracy of dynamic models used for instability studies as well as studies for the interaction and performance of the control systems. The modeling of large-scale solar inverter systems is also lacking.

3. **Resilience and recovery**

Hurricane Harvey highlighted the impact of extreme natural events on the resilience of the BPS, not only from the equipment damage sustained due to high winds and flooding, but also on infrastructure that operation of the BPS depends on. The BPS is becoming more dependent on other sectors such as telecommunications for visibility and control. Coordination between sectors should be enhanced to mitigate vulnerabilities that significantly impact the reliability and resilience of the BPS, therefore system resilience not only includes the electric infrastructure, but fuel sources and fuel delivery infrastructure, data and voice communications systems, water supplies, etc.

FERC currently views resilience to be “[t]he ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event.” FERC Docket AD18-7-000 launched an information gathering effort with the RTOs and ISOs to develop a common understanding of what resilience of the BPS means and requires and to understand how each RTO and ISO assesses and mitigates threats to resilience in its footprint. FERC will use this information to evaluate whether Commission action regarding resilience is necessary.

4. **Cyber and physical security**

Critical Infrastructure Protection (CIP) will continue to remain a priority for NERC, the Department of Homeland Security, and Texas RE for the foreseeable future. Cyber threats are becoming more sophisticated and increasing in number. Exploitation of cyber vulnerabilities can result in loss of control or damage to utility voice communications, data, monitoring, protection and control systems, and tools. The potential for cyber or physical attack on natural gas infrastructure highlights the need for increased coordination among pertinent ISACs and the industry to improve response and recovery times due to the interdependency of the gas and electric system. Interdependency and increased reliance on third-party service providers, cloud-based services, and the supply chain expands the attack surface and associated risk for potential cyber vulnerabilities.

5. **Situational awareness**

Data is needed to understand the performance of and risks to the BPS. This includes information regarding DER. Data is needed from multiple sources and larger areas to identify and manage risks. It is important that data requirements include: (1) the data needed from DER, including any necessary aggregated forms of data; (2) status of infrastructure on which operators rely (e.g., gas infrastructure, data and voice telecommunications systems, DER); (3) logistics for how the data will be exchanged; (4)

the frequency of the data updates; and (5) security and confidentiality measures for protecting necessary data.

From 2013-2017, there were a total of 24 loss of EMS/SCADA events reported in the Texas RE Region. Loss of EMS or SCADA events will continue to be of concern due to their impact on visibility and situational awareness for System Operators. Accuracy and availability of telemetry is a key issue for situational awareness for System Operators as well as the proper functioning of Real-Time Assessment tools.

6. Human performance and skilled workforce

Skilled workers and technical expertise are vital to the reliable operation of the BPS. Human performance issues manifest themselves in a number of ways, particularly in the areas of Protection System Misoperations, loss of EMS events, asset management and maintenance. Turnover of experienced workers, lack of adequate training programs, inadequate management oversight and controls, and ineffective corrective actions can lead to severe events or disruptions on the BPS.

I. Emerging Reliability Issues

Introduction

In December 2015, the NERC Essential Reliability Services Working Group published a report detailing important directional measures to help the industry understand and prepare for the increased deployment of variable energy resources, retirement of conventional coal units, advances in demand response technologies, and other changes to the traditional characteristics of generation and load resources. The recommendations focused on the broad areas of managing frequency, load ramping, voltage control, and dispatchability. Specific recommendations included development of industry practices and measures for synchronous inertia at the Balancing Authority and Interconnection level, frequency response at the Interconnection level, real time inertial models, net demand ramping variability, system reactive capability, overall reactive performance, and system short circuit strength.

Data and Trends

A. Synchronous Inertia at the Balancing Authority and Interconnection level

ERCOT began calculating synchronous inertia in July 2014 in order to better understand and manage the growth in wind generation. The calculated synchronous inertia versus the system net load for 2017 continues to show a strong linear relationship. The graph of average inertia shows a decline in inertia levels in 2017 when compared to 2016. Finally, the heat map graph of 2017 inertia levels shows the weakest inertia time periods are HE 01, 02, 03, and 04 during the shoulder months of February, March, April, and November.

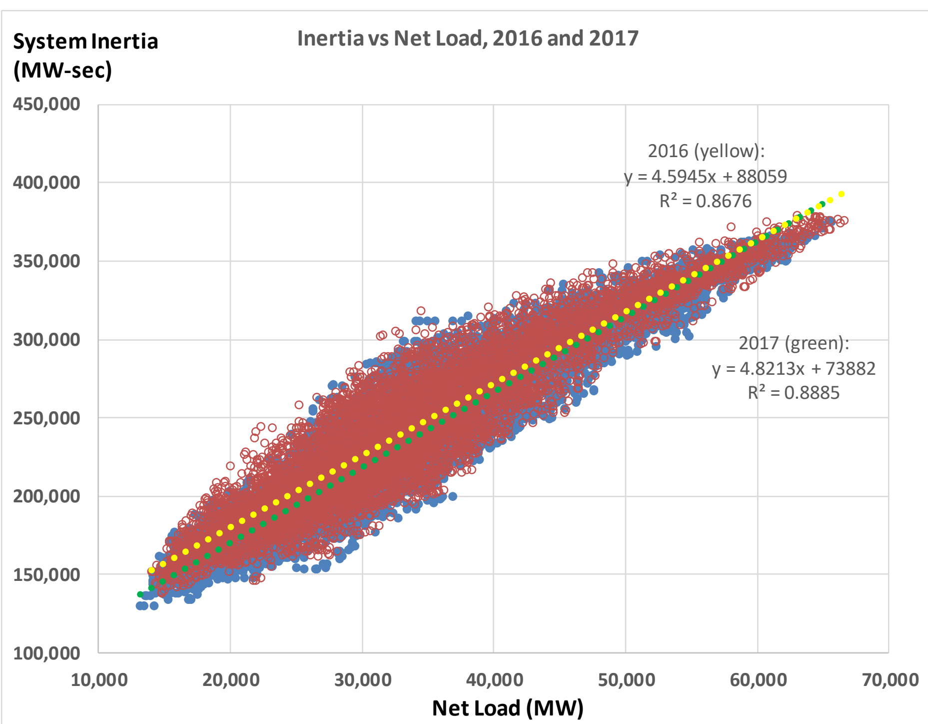


Figure 5 – Inertia versus Net Load, 2016 versus 2017

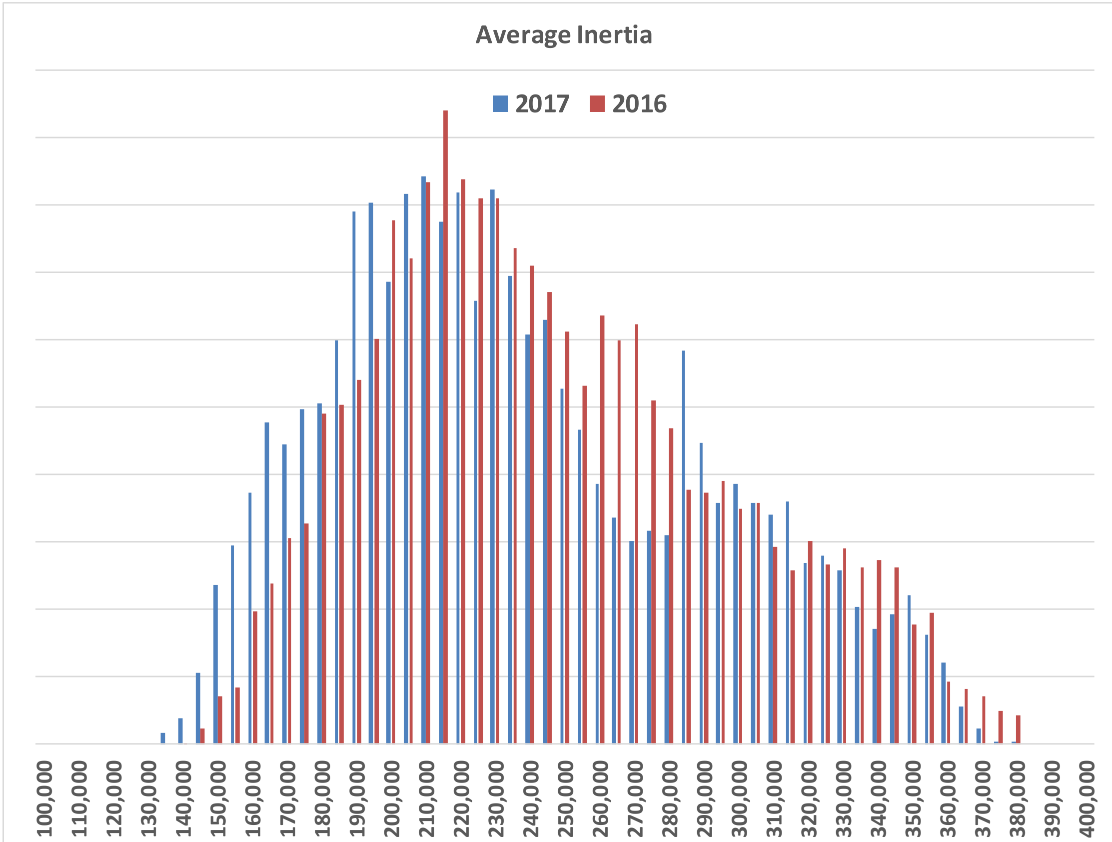


Figure 6 – Average Inertia for 2016 and 2017

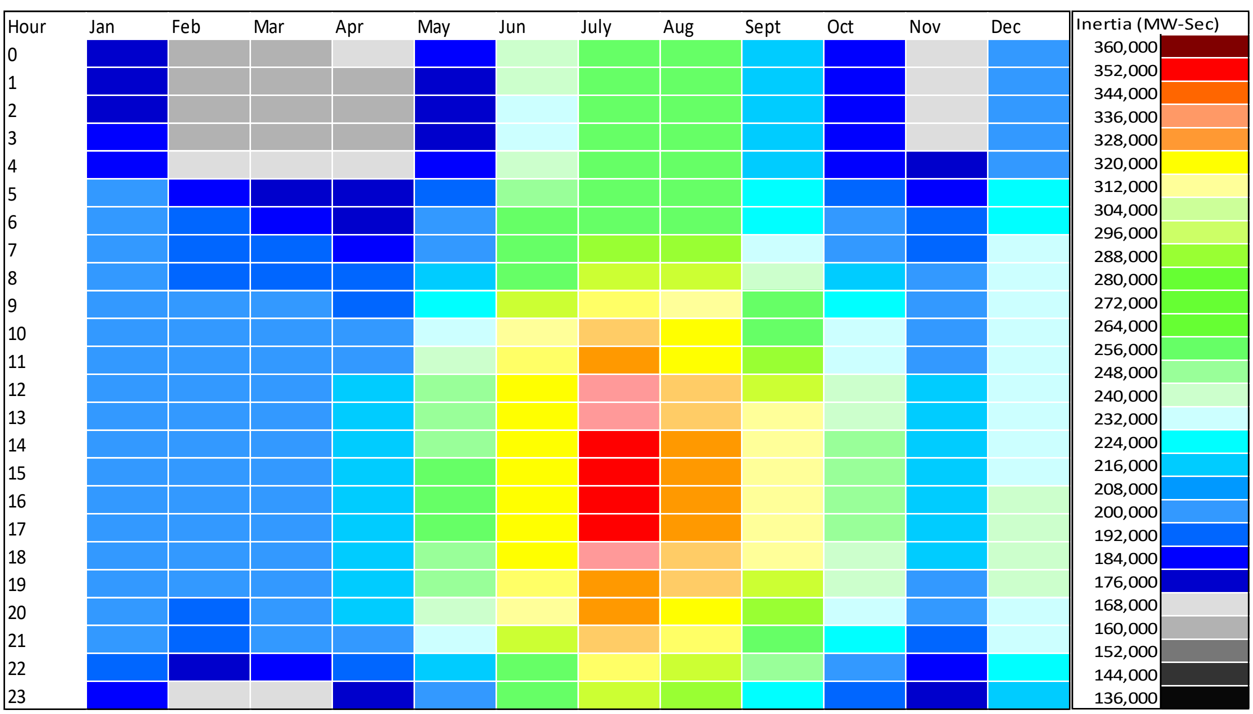


Figure 7 – 2017 Inertia by Month and Operating Hour

This chart shows the calculated synchronous inertia versus the percentage of load served by intermittent renewable resources (IRR), i.e., wind and solar generation. This chart also indicates a fairly linear relationship between the inertia and the IRR percentage.

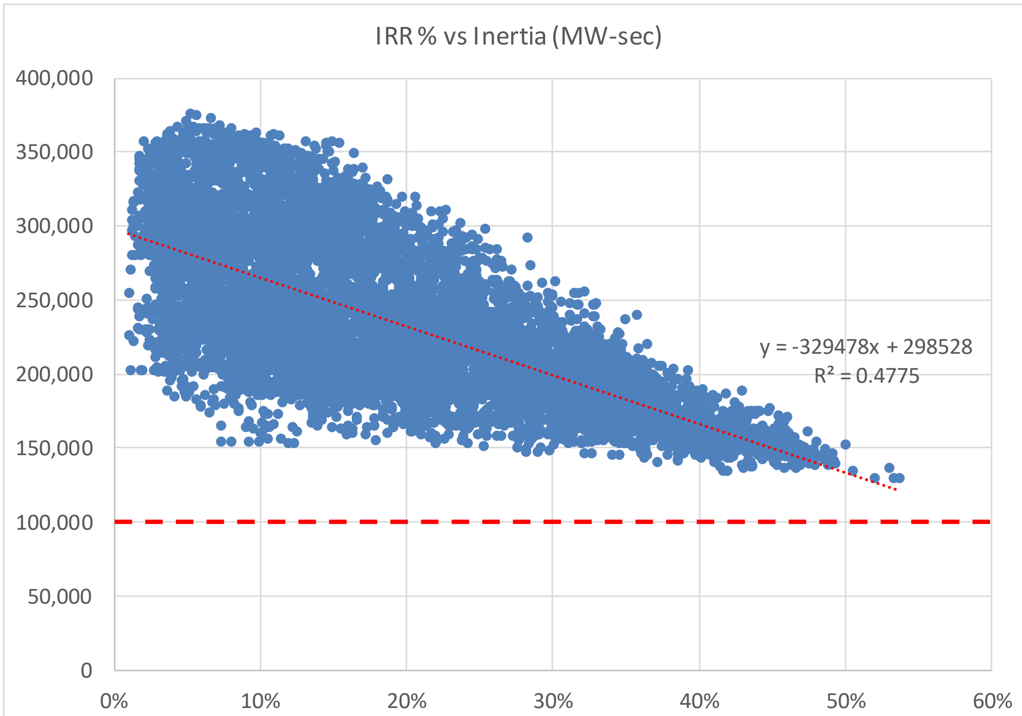


Figure 8 – Inertia versus Percentage of Load Served by IRRs for 2017

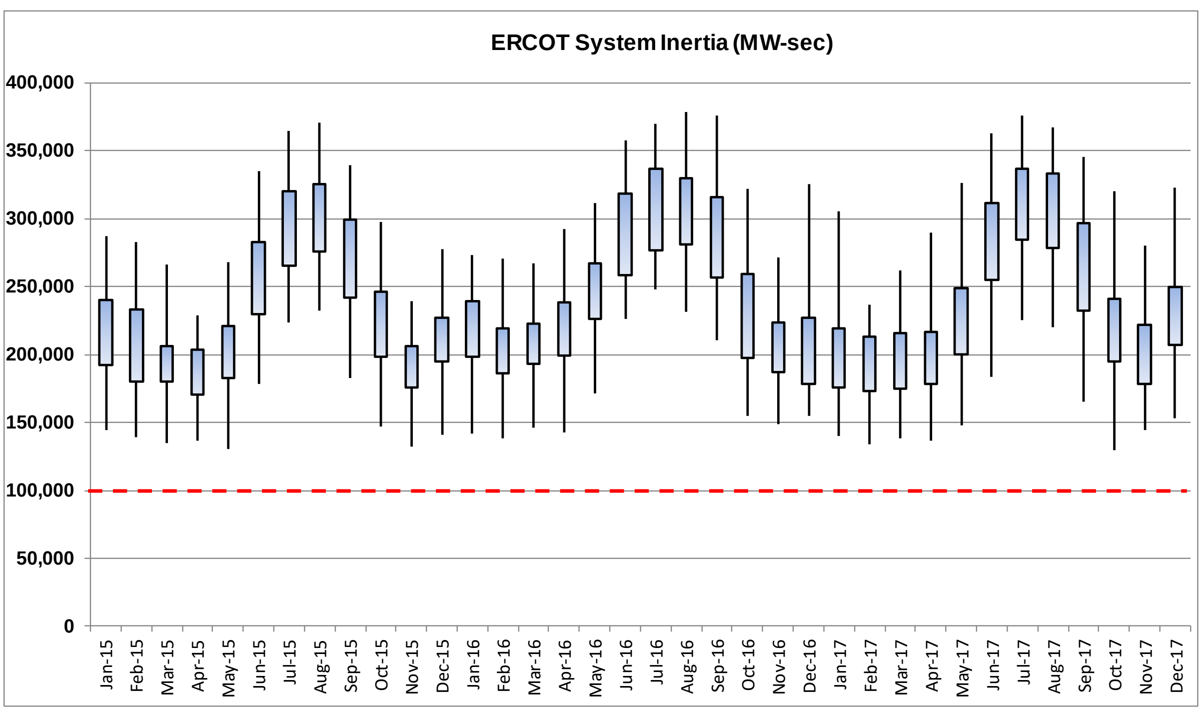


Figure 9 – Historical System Inertia Type

The Performance Disturbance Compliance Working Group (PDCWG) uses high-speed frequency data to look at the Rate of Change of Frequency (RoCoF) during generation loss events. The purpose is to look at the correlation of RoCoF versus system inertia at the time of the event. The following chart shows the data collected to date. The RoCoF is normalized by the MW loss during the event on this chart. At lower values of inertia, the RoCoF increases substantially.

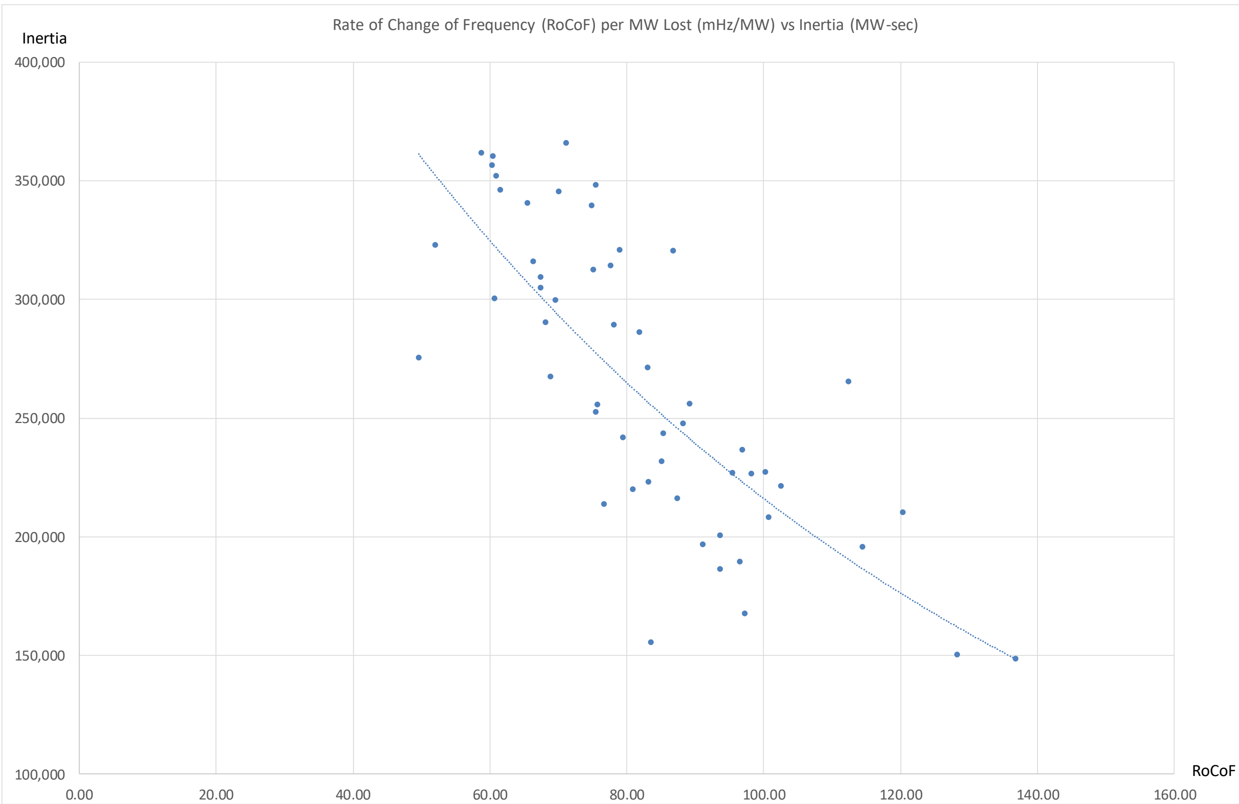


Figure 10 – Rate of Change of Frequency versus Inertia

ERCOT has 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 in its operating procedures and its forward projections for ancillary services, in particular, the procurement of responsive reserves in the day-ahead market.

The minimum hourly inertia level in 2017 was 130.0 GW-s, on October 27, 2017 at 3:00 a.m., when the intermittent renewable resources (IRR) penetration level was 53.7% and system load was 28,443 MW (net load of 13,178 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%

The number and types of units on-line and providing synchronous inertia is a significant factor in the overall inertia of the Interconnection. ERCOT is calculating system inertia in real-time based on the number and type of generation resources that are on-line. Each different resource type has a different inertia constant. As coal units begin to retire in 2018, the inertia for the Interconnection could vary significantly, depending on new generation mix that replaces the retired coal units. The following chart shows the actual range of inertia during the Top-20 minimum net load hours for 2016 and 2017. The 2018 and 2019 estimated ranges are based on replacing the retired coal units with either all gas generation (top end of the range) or all renewable (lower end of the range).

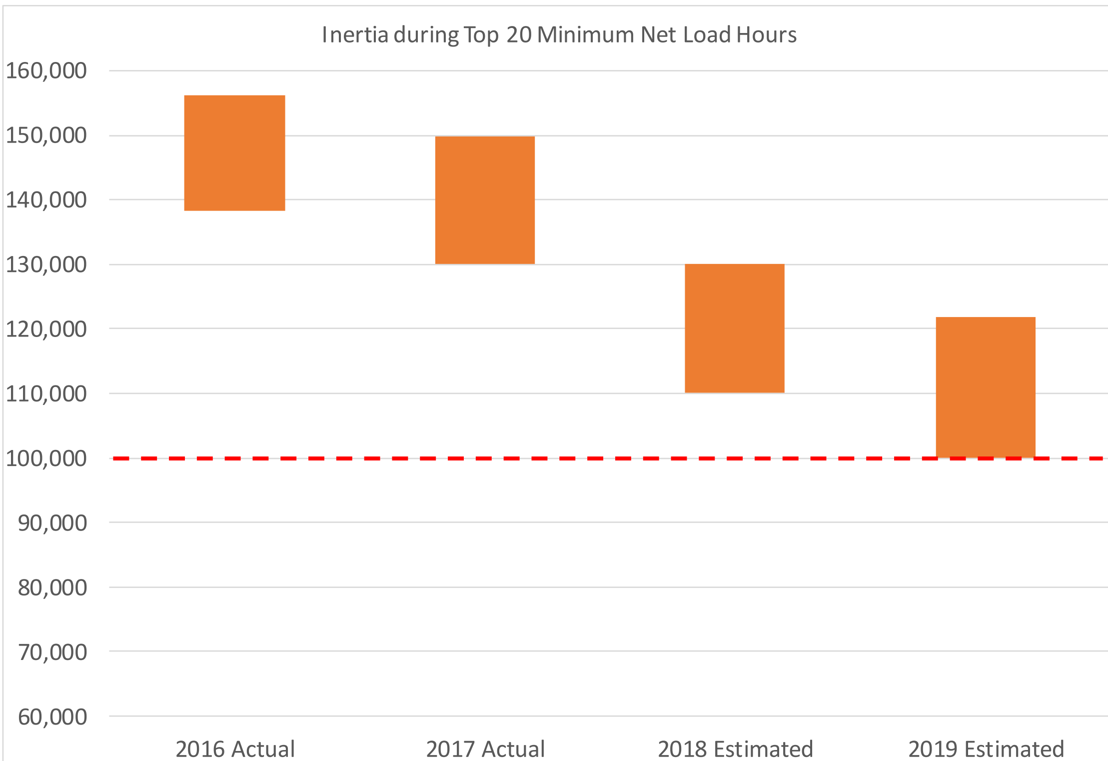


Figure 11 – Inertia During Top 20 Minimum Net Load Hours

B. Net Demand Ramping Variability

Changes in the amount of non-dispatchable resources, system constraints, load behaviors and the generation mix can impact 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. The Essential Reliability Services Working Group recommended that each Balancing Authority calculate the historical and projected maximum one-hour-up, one-hour-down, three-hour-up, and three-hour-down net demand ramps.

Ramping Variability	Load	Wind Generation	Net Load
Maximum One-Hour Increase	4,801 MW	4,471 MW	5,687
Maximum One-Hour Decrease	-4,636 MW	-4,619 MW	-7,553

Table 1 – Maximum and Minimum One-Hour Load and Wind Ramp for 2017

The following charts show the one-hour wind and net load ramp frequency plots for 2017 versus 2016.

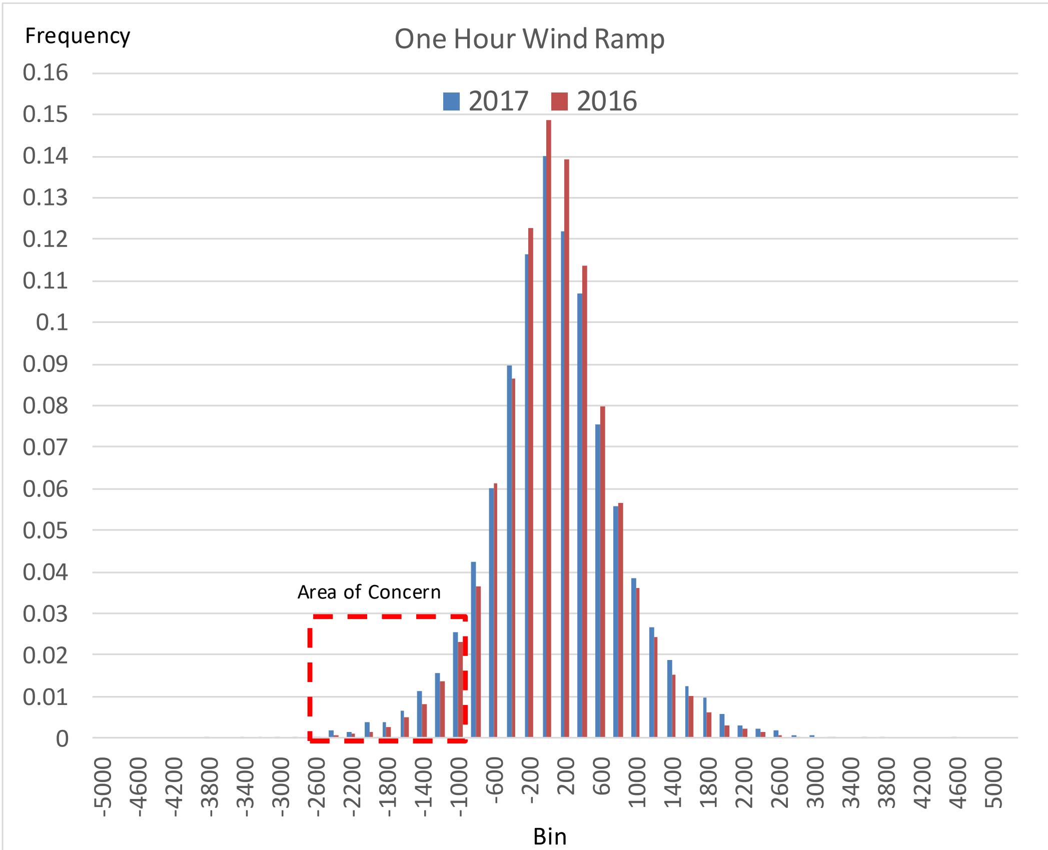


Figure 12 – One Hour Wind Ramp Frequency Plot for 2016-2017

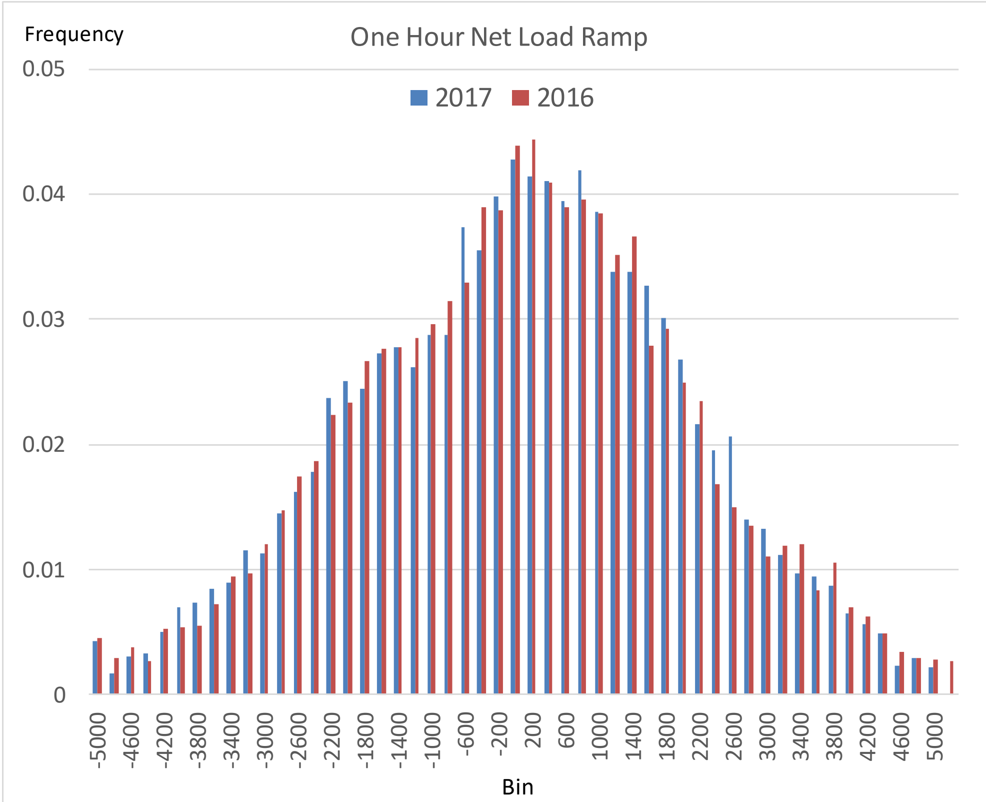


Figure 13 – One Hour Net-Load Ramp Frequency Plot for 2017

The following chart shows a comparison of the maximum one-hour load, net load, and wind ramps for 2017 compared to previous years.

Figure 14 – Maximum One-Hour Ramps for 2013-2017

The following chart shows the average variability by season and operating hour for 2017.

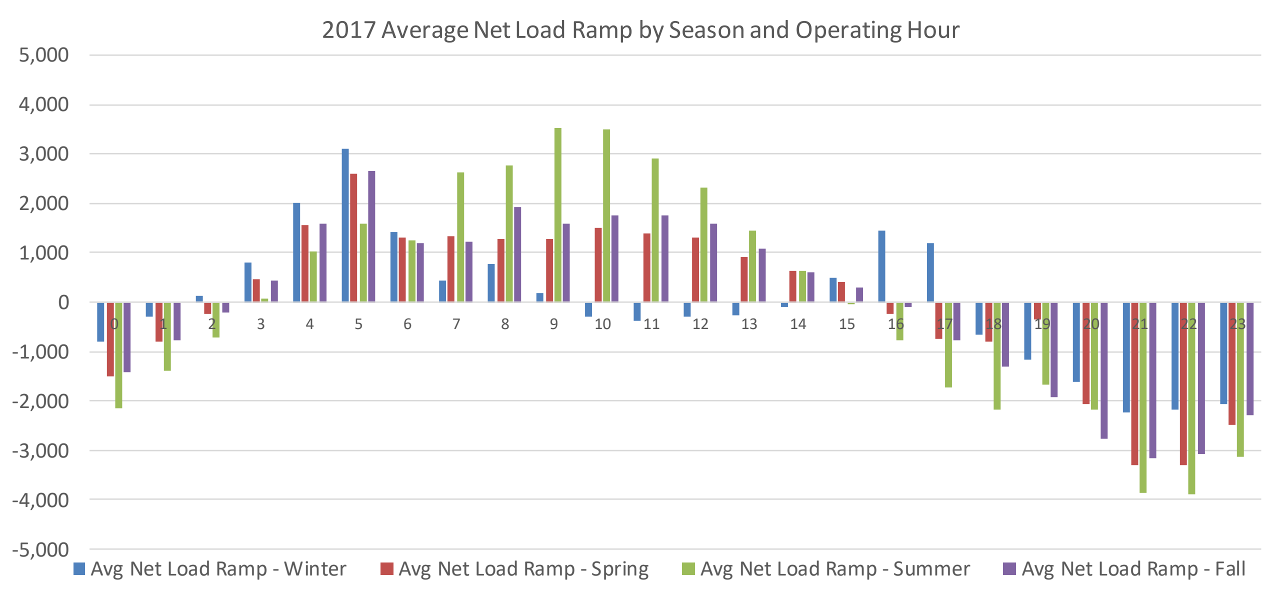


Figure 15 – Average Net Load Ramp by Season and Operating Hour for 2017

C. Distributed Energy Resources

Distributed Energy Resources (DERs) 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. This can result in unanticipated power flows, load forecast errors, ramping issues, system protection issues, or other issues. There are also differing standards for DER between current PUCT rules and IEEE standards.

Issues with DERs 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; and
- Visibility and control.

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. P.U.C. SUBST. R. 25.211(n) also 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.

ERCOT stakeholders are currently working on changes to market rules to develop standardized methods for collecting and providing data for mapping current and future registered DER capacity to their modeled loads, and to develop a process for competitive and non-competitive distribution providers to monitor the accumulation of unregistered DER units connected to their modeled loads.

II. Resource Adequacy

Introduction

Short-term assessments of resource adequacy are conducted on a seasonal basis to focus on the availability of sufficient operating reserves to meet the anticipated peak electrical demand. The seasonal assessments consider a range of possible variables and scenarios, such as normal versus extreme weather, normal versus extreme resource outages, low wind conditions, etc.

2017 Resource Adequacy in Brief

Summer Peak: Actual 69,531 MW vs. projected 72,934 MW
Winter Peak: Actual 59,661 MW vs. projected 58,591 MW

Observations

- Summer 2017: Peak demand was less than anticipated for the typical scenario, but resource outages were higher than expected. Actual reserve margin was approximately 5% compared to the 6.7% reserve margin calculated for the typical scenario.
- Winter 2017: Peak demand was higher than anticipated for the typical scenario, but resource outages were lower than expected. Actual reserve margin was approximately 7% compared to the 18% reserve margin calculated for the typical scenario due to lower than anticipated resource capacity.
- Sufficient operating reserves were maintained during the summer and winter peak hours.

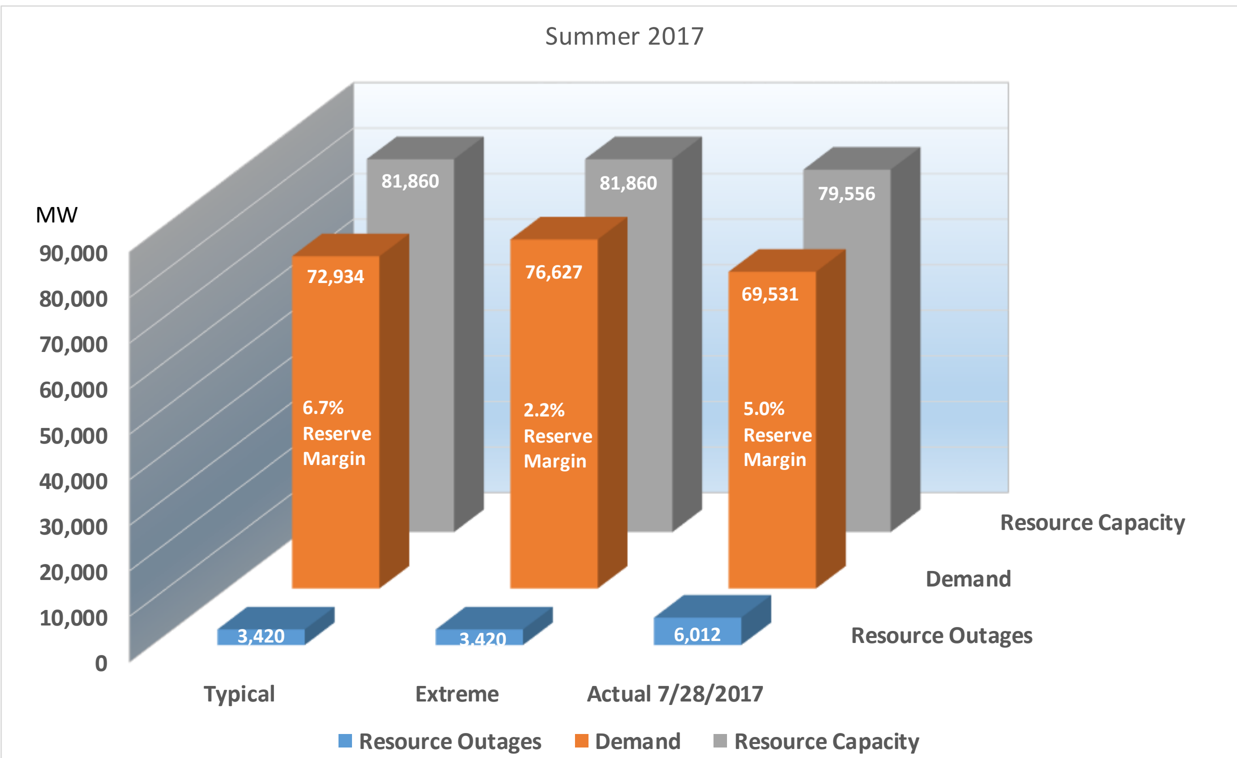


Figure 16 – Summer 2017 SARA versus Actual at Peak

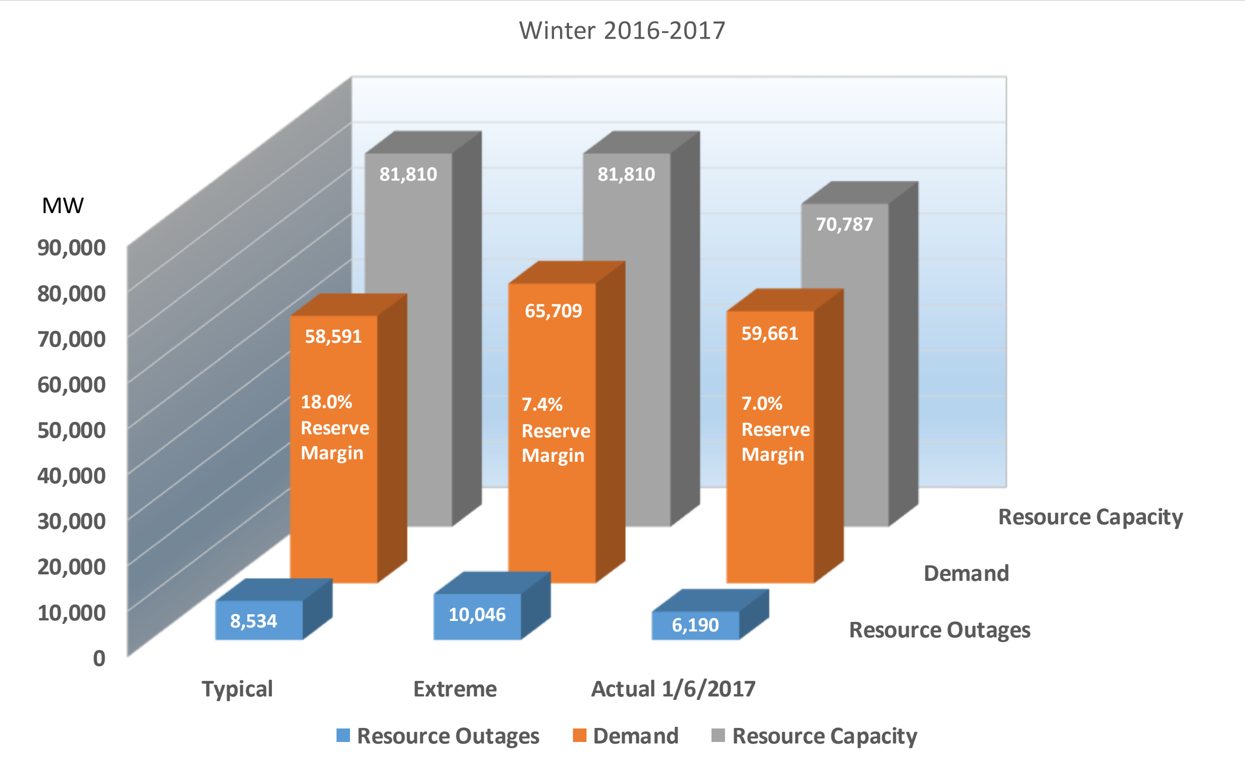


Figure 17 – Winter 2016-2017 SARA versus Actual at Peak

The following tables and charts show a comparison of the assumptions for peak load, scheduled outages, and forced outages for the Seasonal Assessment of Resource Adequacy (SARA) for Winter 2016-2017 and Summer 2017 versus the actual conditions that occurred during those periods. During Summer 2017, ERCOT issued twenty-two Advisories for Physical Responsive Capacity (PRC) less than 3,000 MW. During the Winter 2016-2017, ERCOT issued four Advisories for PRC less than 3,000 MW. The assumptions for scheduled and forced outages for Winter 2016-2017 were higher than actual conditions, while the forced/scheduled outage assumptions for Summer 2017 were higher than actual conditions, in part, due to the effects of Hurricane Harvey.

Case	Estimated	Actual
Peak Load (MW)	58,591	59,661
Extreme Load (MW)	65,709	
Typical Forced Outages (MW)	4,243	2,919
Extreme Forced Outages (MW)	9,998	6,111
Typical Maintenance Outages (MW)	4,291	5,644

Table 2 – Winter 2016-2017 Resource Adequacy, Estimated versus Actual

Case	Estimated	Actual
Peak Load (MW)	72,934	69,531
Extreme Load (MW)	76,627	
Typical Forced Outages (MW)	3,004	6,063

Extreme Forced Outages (MW)	4,878	11,147[2]
Typical Maintenance Outages (MW)	416	918

Table 3 – Summer 2017 Resource Adequacy, Estimated versus Actual

The following charts show the generation MW out of service for scheduled and forced outages for Summer 2017 and Winter 2016-2017.

For Summer 2017, the average scheduled generation outage MW was 918 MW with a maximum of 2,589 MW. This is in comparison to the Seasonal Assessment of Resource Adequacy (SARA) for Summer 2017 that estimated typical maintenance outages of 416 MW. For Summer 2017, the average forced generation outage MW was 6,063 MW with a maximum of 11,147 MW, which occurred during Hurricane Harvey. This is in comparison to Summer 2017 SARA that estimated typical forced outages of 3,004 MW with an extreme case of 4,878 MW.

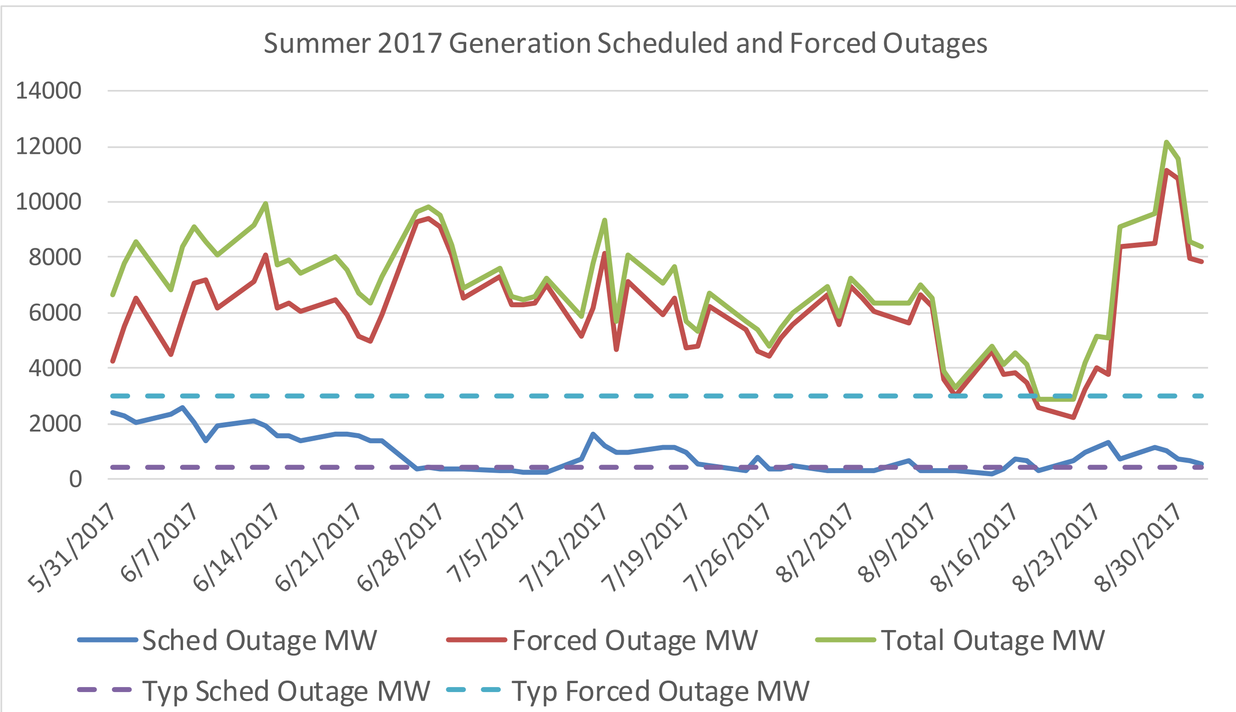


Figure 18 – Summer 2017 Generation Scheduled and Forced Outages

For Winter 2016-2017, the average scheduled generation outage MW was 5,644 MW with a maximum of 10,456 MW. This is in comparison to the SARA that estimated typical maintenance outages of 4,291 MW. For Winter 2016-2017, the average forced generation outage MW was 2,919 MW with a maximum of 6,111 MW. This is in comparison to Winter 2016-2017 SARA that estimated typical forced outages of 4,243 MW with an extreme case of 9,998 MW.

[2] During Hurricane Harvey

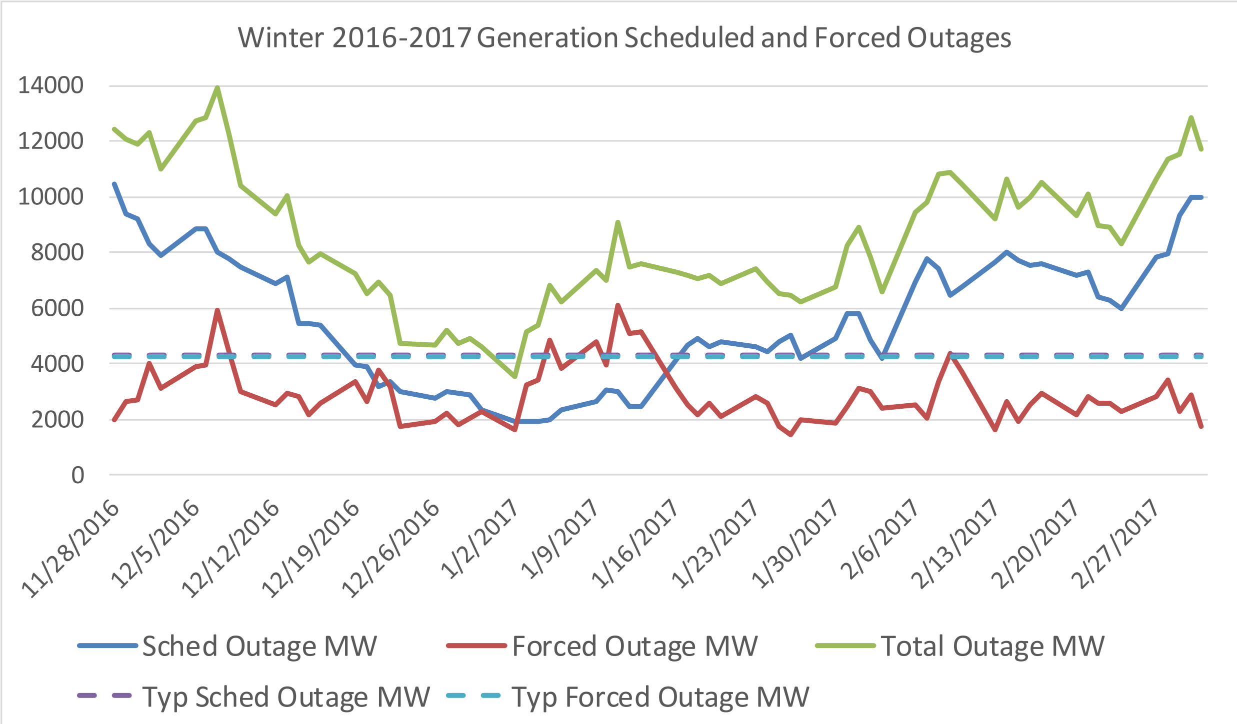


Figure 19 – Winter 2016-2017 Generation Scheduled and Forced Outages

III. Disturbances and Events

Introduction

While major outages of the BES are rare, minor events and outages are a common occurrence in a system as complex as ERCOT. Many factors contribute to these disturbances, including line exposure over large geographic areas, misoperations of protective devices, and the multitude of elements that are required to operate and monitor a system as complex as the electrical grid.

2017 Events in Brief

Events Reported: 64
Protection System Misoperations: 183
Generation Forced Outages: 1,816
345 kV Circuit Automatic Outages: 407

Using automated tools, mandatory reports, voluntary reports, and other public third-party information, Texas RE analyzes grid disturbances and categorizes them by the severity of their impact on the BPS.

This section provides information about disturbance events in the region.

Additional data on events analysis is presented in Appendix B.

Observations

- Hurricane Harvey was the most significant event in the region since the February 2011 winter storm. This devastating storm caused extensive damage to the BPS and affected over 1.67 million customers. ERCOT and utilities exhibited outstanding coordination, working together to restore power to customers and protect the reliability of the grid.
- Weather remains the number one cause of disturbances identified from the event analyses, followed by equipment failures, vandalism/sabotage/theft, and protection system misoperations.

Historical Data and Trends

A. Key Events in 2017

(1) Multiple generator loss event on March 15, 2017

On March 15, 2017, two large generators carrying a combined total of 1,353 MWs tripped within one minute of each other. System frequency dipped to 59.753 Hz and recovered to pre-disturbance levels in 9 minutes, 54 seconds. The initial unit trip was caused by low DC voltage to protective relays when a battery charger was inadvertently left out of service. The second unit trip was initiated by boiler controls that responded to the frequency disturbance and tripped the unit on low induced draft fan duct pressure.

(2) Loss of EMS event on May 4, 2017

A large transmission entity lost its primary and backup EMS systems on May 4, 2017 for over seven hours. During a routine update of the EMS, new database elements were added to represent installed field equipment and these additions exceeded a specific size limitation within the EMS. This loss of the EMS caused erroneous telemetry values to be sent to ERCOT, impacting ERCOT's State Estimator, Real-Time Contingency Analysis (RTCA), and Voltage Security Assessment Tool (VSAT) for over four hours.

(3) Solar Eclipse on August 21, 2017

The solar eclipse event of August 21 was planned and prepared for months in advance. Projections based on available data indicated a solar reduction of 60-75% during the event. Actual reduction in solar generation was on the order of 67%.

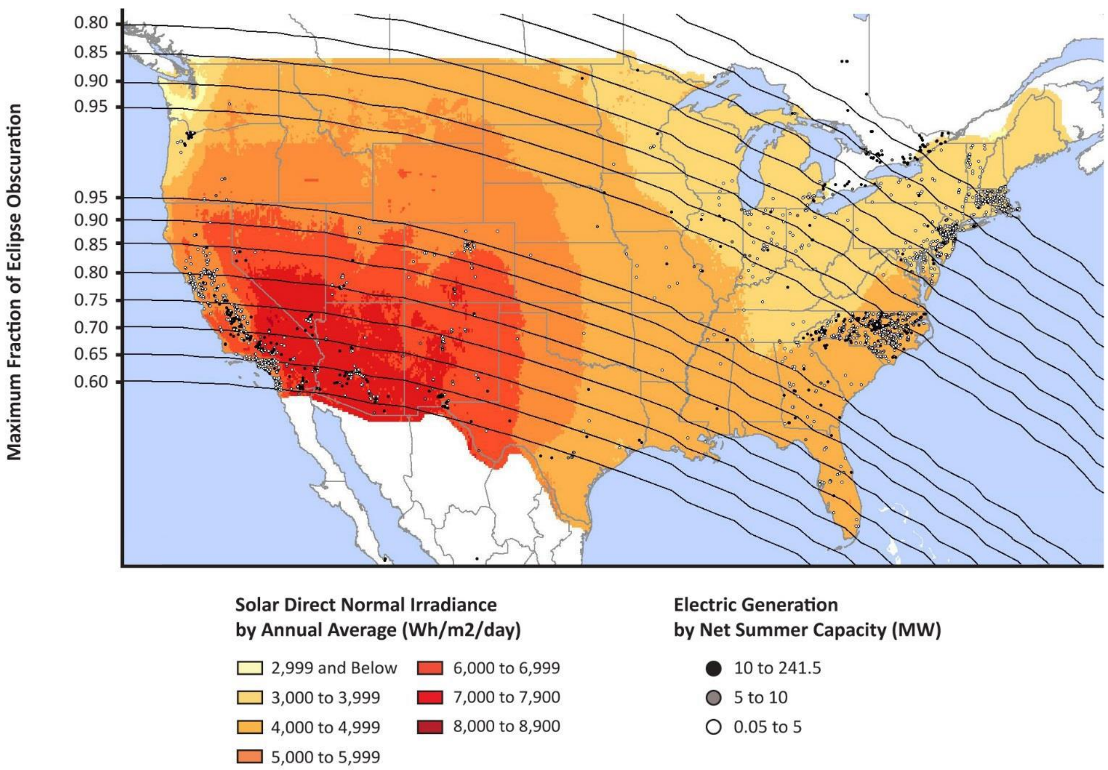


Figure 20 – Solar Eclipse Estimated Obstruction

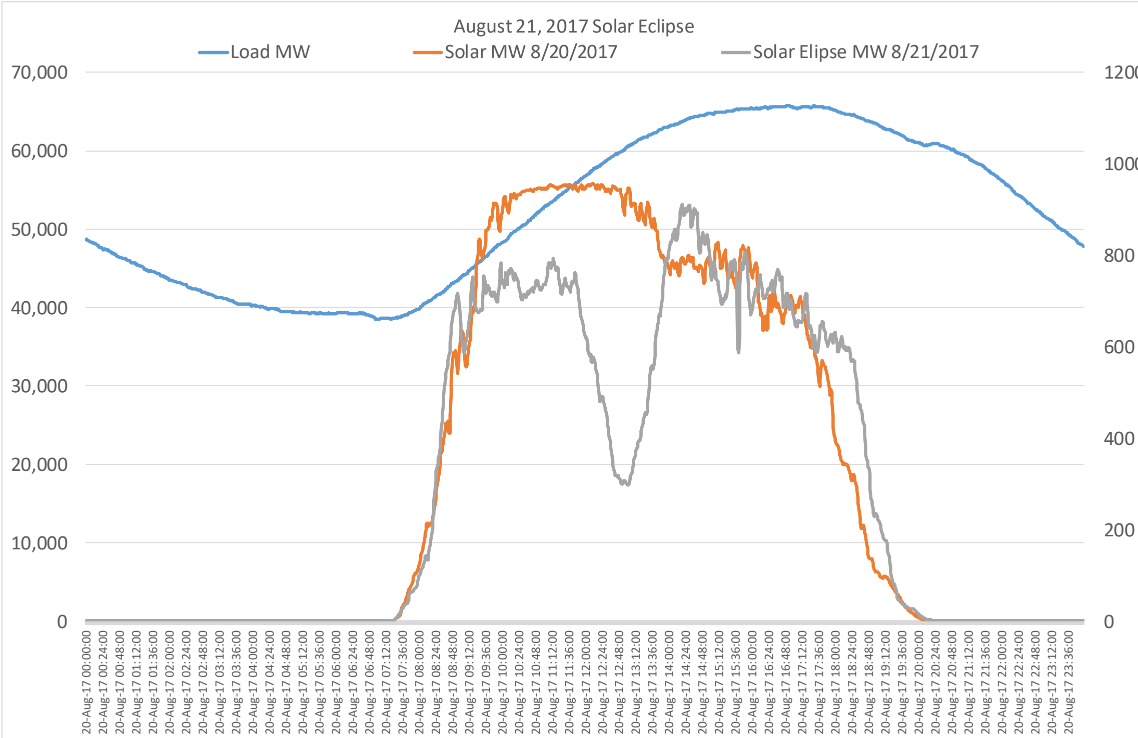


Figure 21 – Solar Eclipse Actual Impact

(4) Hurricane Harvey, August 25 through September 8, 2017

Hurricane Harvey made landfall as a Category 4 hurricane on August 25, 2017 at 10:00 p.m. Central Daylight Time (CDT), with winds in excess of 130 MPH and record-breaking storm surge. The storm inflicted massive disruptions on the electric power system in the Corpus Christi, Houston/Galveston, and Beaumont/Port Arthur areas of Texas. As Harvey moved inland, the storm stalled, causing excessive rain (40-50 inches) in parts of southeastern Texas, flooding large areas of Houston and inland as far as Austin. The leading edge of the storm began to inflict transmission system outages on the BPS as early as 4:00 p.m. on August 25. As the main body of the storm progressed over the Texas power system from August 25 through August 30, approximately 225 transmission assets were impacted. These included 345, 138, and 69 kilovolt (kV) transmission lines and transformer banks. Transmission Operators reported that several low-lying stations were flooded and became completely inoperable, and that high winds damaged transmission and substation equipment. Generating facilities over a very wide footprint were either forced or tripped off-line, and some generators were rendered unavailable due to the loss of interconnecting transmission. During the event, a maximum of 10,992 MW of generation capacity was rendered unavailable. The distribution system was also severely damaged. By late Saturday, August 26, a peak 338,000 electric customer outages were reported across the impacted area. The total number of reported customer outages exceeded 1.67 million.

B. Historical Disturbance Data

In 2017, the number of events reported decreased when compared to 2013-2016.

Event Category[3]	2013	2014	2015	2016	2017	5-Yr Avg
Non-Qualified	92	77	90	65	52	75
1	7	11	9	5	11	9
2	2	2	1	0	0	1
3	1	1	1	2	0	1
4 and 5	0	0	0	0	1	0
Total	102	91	101	72	64	86

Table 4 – Summary of Events Analysis

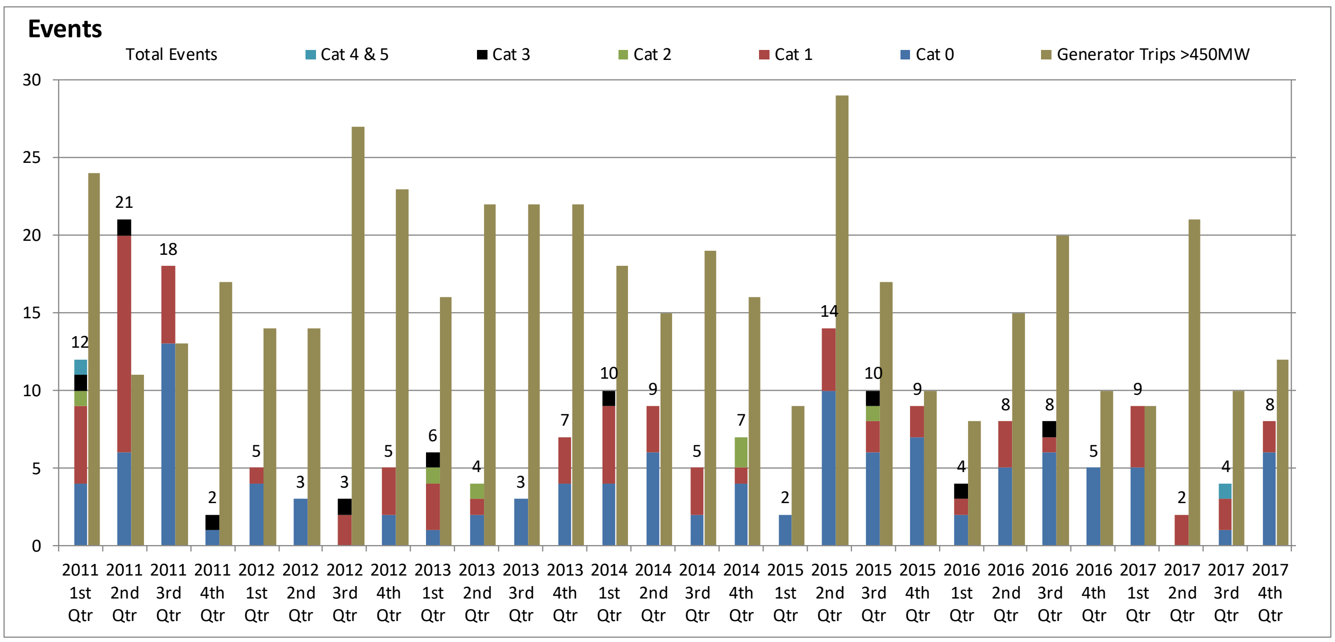


Figure 22 – Events Reported by Quarter

[3] Link to NERC Events Analysis Process with category definitions: http://www.nerc.com/pa/rrm/ea/ERO_EAP_Documents%20DL/ERO_EAP_v3.1.pdf

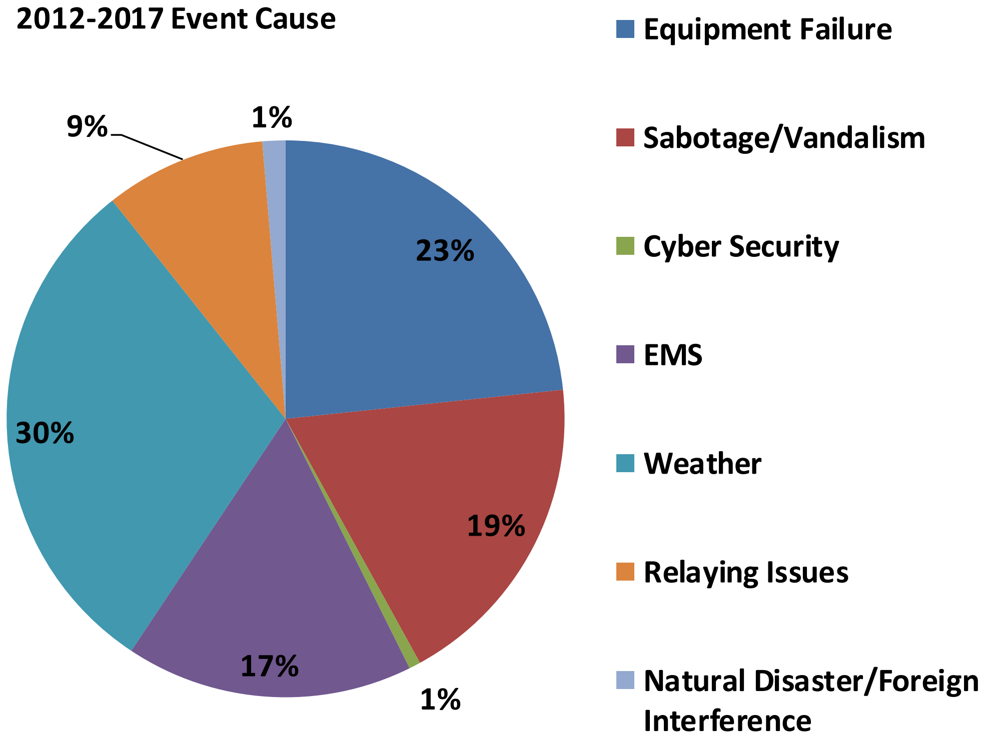


Figure 23 – 2012-2017 Event Cause Summary

Registered Entities are required to report loss of load to 50,000 customers or more for one hour or more to the Department of Energy using OE-417 reports. 2017 showed a sharp increase in the customer impact from these events due to Hurricane Harvey. The trend in these reports is included in the following figure.

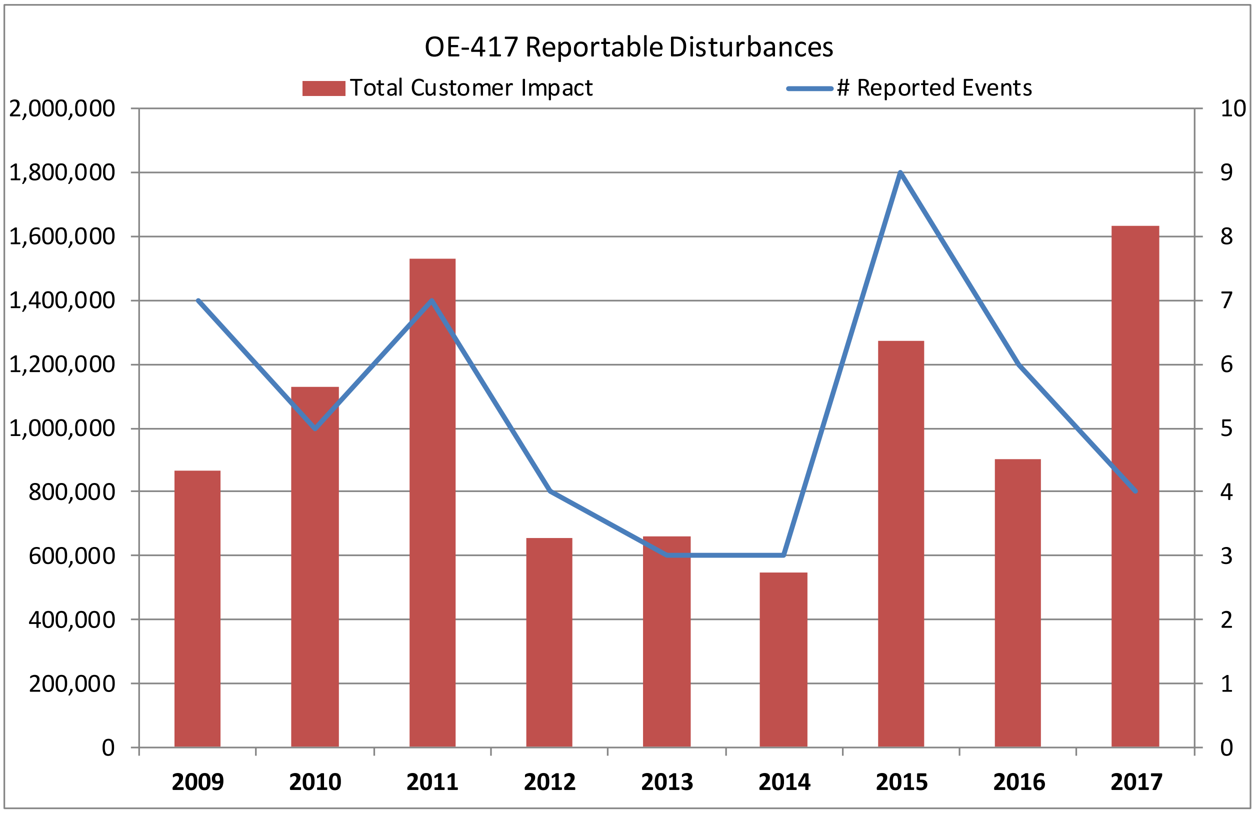


Figure 24 – OE-417 Reports of Lost Load

Event severity is determined by a number of key attributes, including load lost, MW of generation lost, protection system misoperations, emergency actions taken, etc. The following chart shows the breakdown of event attributes by event category.

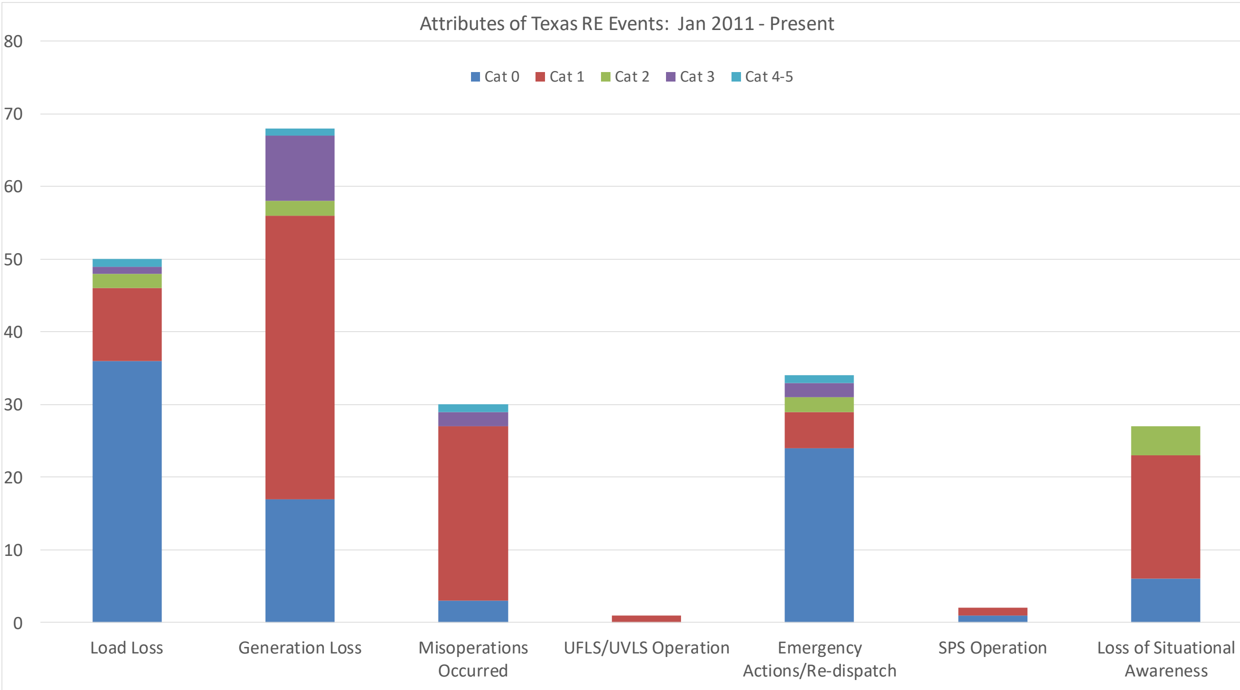


Figure 25 – Event Attributes by Category

C. Generation Loss Events

Texas RE staff also review each loss of generation greater than 450 MW and frequency deviations less than 59.91 Hz within the Texas RE Region. These events are reported to NERC Situational Awareness staff, but are not tracked or reported under the NERC Events Analysis Process. There were 50 of these in 2017 that were reviewed by Texas RE. The trend in generator unit trips is shown in Figure 13.

The unit trip events greater than 450 MW that occurred in 2017 can be broken down to indicate the major categories and causes of the unit trips based on GADS data.

Major System	Sub-System	Number of Trips	
	Burner Management/Controls	1	
	Induced/Forced Draft Fans	5	
	Other	3	
Boiler System			9
Nuclear			1
	Feedwater System	5	
	Electrical/Instrumentation	2	
	Power Station Switchyard	1	
	Distributed Control System	1	
	Other	4	
Balance of Plant			13
	Valves/Piping/Lube Oil	1	
	Controls	3	

	Exciter	2	
	Generator	4	
	Other	1	
Steam Turbine/Generator			11
Pollution Control Equipment			2
External to Plant			3
Other			1

Table 5 – Major Causes of Generator Trips > 450 MW

Several key items of focus have been the identification of events where multiple generators trip at the same site, generator units trip due to faults or system conditions outside the generator's protection system zones, or where it is not necessary to trip the unit in order to clear the fault condition. Tracking these types of events provides an indication of issues with generator protective relaying, generator excitation system issues, and control system issues. These events also go beyond normal single contingency planning criteria. In 2017, there were two occurrences of multiple generator trips. Since 2011, issues that have resulted in multiple unit trips include:

- Loss of plant instrument air system which was common to multiple units at the same site
- Protection system misoperations
- Sympathetic trips on combined cycle units due to exhaust temperature spread
- Fuel supply lines to gas plants (low gas pressure, control valve problems, etc.)
- Failures in the plant auxiliary power system which was common to multiple units at the same site

Date	Event Description
1/10/2017	Eight wind facilities ran back with losses of multiple turbines due to a fault on a remote 138 kV transmission line.
6/11/2017	Three wind facilities ran back with losses of multiple turbines due to a fault on a remote 138 kV transmission line.
6/19/2017	Two generators at the same site tripped due to a bus fault at the facility substation.
11/6/2017	Two generators at the same site tripped due to a bus fault at the facility substation.
12/7/2017	Two combined cycles units at the same site tripped due to a bus fault at the facility substation.

Table 6 – 2017 Events with Multiple Generator Trips

D. EMS/SCADA Events

Loss of EMS/SCADA events continue to be a focal point at the NERC and regional levels. Category 1 events include loss of operator ability to remotely monitor and control BPS 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.

For 2013-2017, there were 24 loss of EMS/SCADA events that lasted 30 minutes or more reported in the Texas RE Region. The most significant 2017 event occurred on May 4, when a large transmission entity lost its primary and backup EMS systems for over seven hours. During a routine update of the EMS, new database elements were added to represent installed field equipment and these additions exceeded a specific size limitation within the EMS. This loss of the EMS caused erroneous telemetry values to be sent to ERCOT, impacting ERCOT's State Estimator, Real-Time Contingency Analysis (RTCA), and Voltage Security Assessment Tool (VSAT) for over four hours.

IV. Transmission

Introduction

Texas RE collects transmission outage and inventory data annually each February from Transmission Owners throughout the Texas RE Region for transmission elements operated at 100 kV and above using TADS. The outage data is separated into voltage classes, outage duration (momentary or sustained), and outage cause. These categories illustrate the types of outages occurring on the BES.

This section provides information summarizing the data collected from TADS, as well as transmission performance data from other sources for the region. Additional data on TADS analysis is presented in Appendix C.

2017 Transmission Performance in Brief

345 kV Circuits: 433
345 kV Circuit miles: 15,263
345 kV Circuit Outages: 407
345 kV Circuit Outage Duration: 5,840 hrs
345 kV Transformer Outages: 31
345 kV Xfmr Outage Duration: 12,818 hrs

138 kV Circuits: 1,856
138 kV Circuit miles: 21,516
138 kV Circuit Sustained Outages: 406
138 kV Circuit Outage Duration: 10,785 hrs

Observations

- There were no ERCOT IROL exceedances in 2017.
- For the 345 kV circuit outages, approximately 25% of total transmission outages in 2017 were due to unknown causes.
- For the 345 kV circuit outages in 2017, 21% of the sustained automatic outage events and 87% of the sustained outage duration involved two or more circuit elements. Outages of two or more circuits on common structures represented 66% of these outages.
- For the 138 kV circuit outages in 2017, failed substation equipment and failed transmission circuit equipment dominated the sustained outages, accounting for 46% of the outage events and 85% of the outage duration.

Historical Data and Trends

A. 2017 TADS Metrics for Texas RE Region

Compared to 2016 data, 2017 outage rates per 100 miles of line per year for the 345 kV system decreased slightly, from 2.78 to 2.68 and the total outage duration from automatic outages increased from 2,617 hours to 5,840 hours.

	Momentary Outages		Sustained Outages	
Voltage Range	Per Circuit	Per 100 Miles	Per Circuit	Per 100 Miles
300-399 kV	0.69	1.95	0.26	0.73
100-199 kV	Not reportable	Not reportable	0.22	1.91

Table 7 – 2017 Momentary and Sustained Outages

Long term trends continue to show a fairly stable trend in outage rates per circuit and per 100 miles of line. Texas RE Region outage rates are also comparable to NERC-wide outage rates for the 300-399 kV overhead voltage class. See the following figure and table.

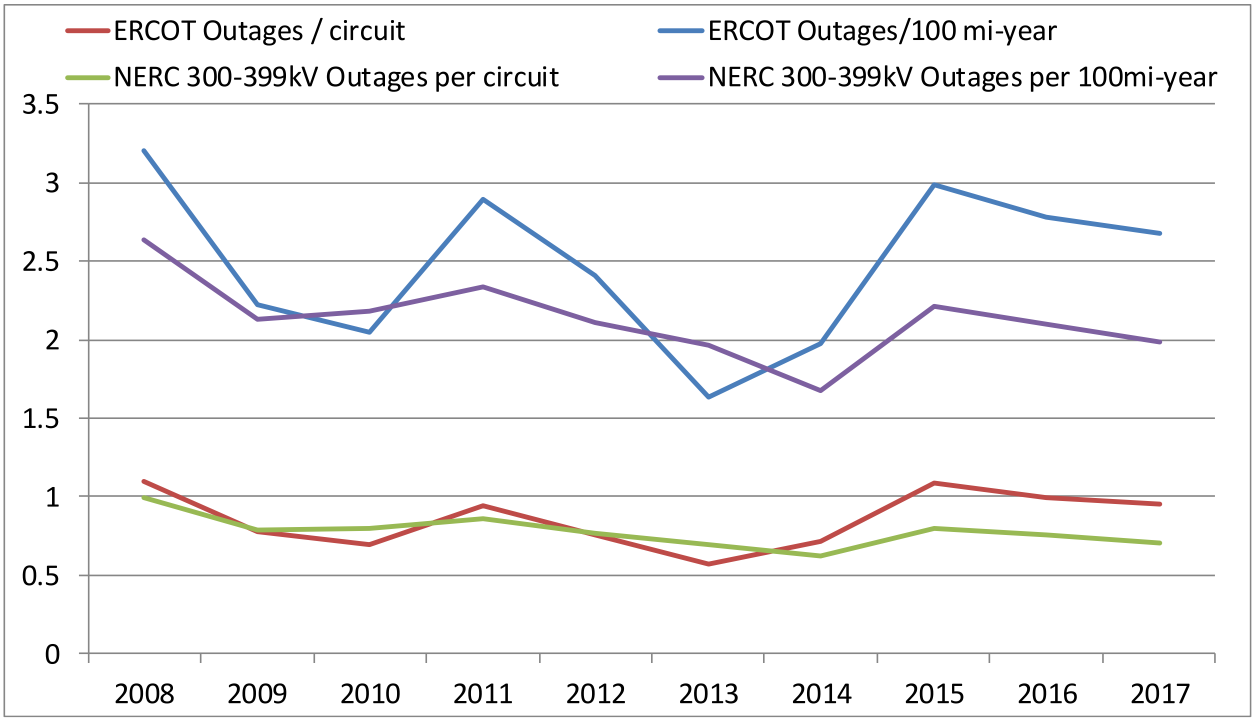


Figure 26 – 2008-2017 345 kV Automatic Outage Metrics

Voltage Class Name	Metric	2013	2014	2015	2016	2017	5-Yr Avg
AC Circuit 300-399 kV	Automatic Outages per Circuit	0.57	0.71	1.08	0.99	0.95	0.86
AC Circuit 300-399 kV	Automatic Outages per 100 miles	1.63	1.97	3.00	2.78	2.68	2.41
AC Circuit 100-199 kV	Sustained Automatic Outages per Circuit			0.25[4]	0.19	0.22	0.22
AC Circuit 100-199 kV	Sustained Automatic Outages per 100 miles			2.12	1.57	1.91	1.87

Table 8 – TADS Circuit and Automatic Outage Historical Data for ERCOT Region

B. Automatic Outage Data

For the 345 kV system, predominant causes for momentary outages in 2017 were lightning, contamination, and unknown, representing 75% of the total momentary outages. Predominant causes for sustained outages in 2017 were weather, lightning, failed substation/circuit equipment, and unknown, representing 77% of the total sustained

[4] 2015 was the first year of TADS reporting for 138 kV circuits.

outages. Failed transmission circuit equipment dominated the sustained outage duration, accounting for 50% of the outage duration.

For the 138 kV system, predominant causes for sustained outages in 2017 were weather, lightning, and failed substation/circuit equipment, representing 69% of the total sustained outages. Failed substation/transmission circuit equipment dominated the sustained outage duration, accounting for 85% of the outage duration.

Reference Figures 27 through 33.

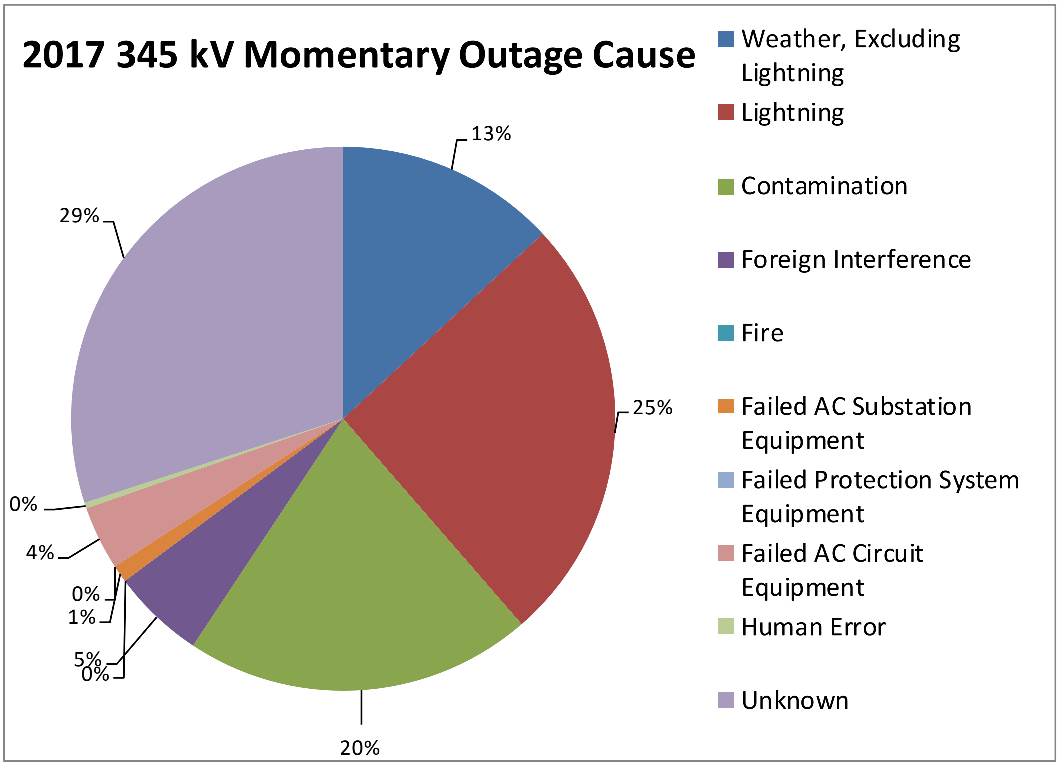


Figure 27 – 2017 345 kV Momentary Outage Cause

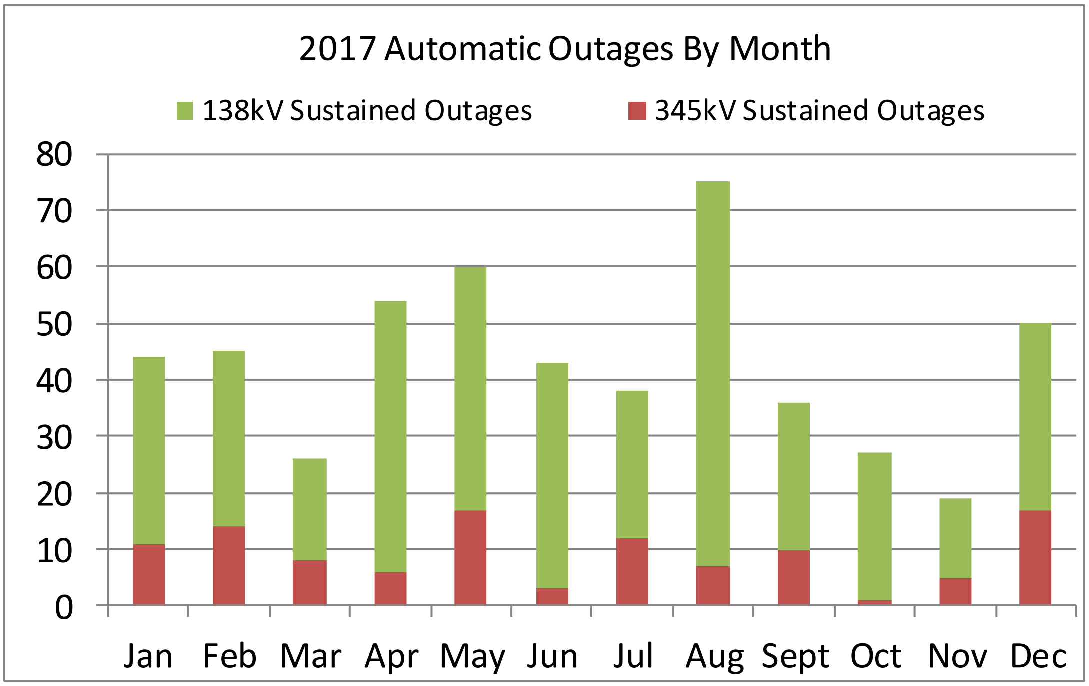


Figure 28 – 2017 Automatic Outages by Month

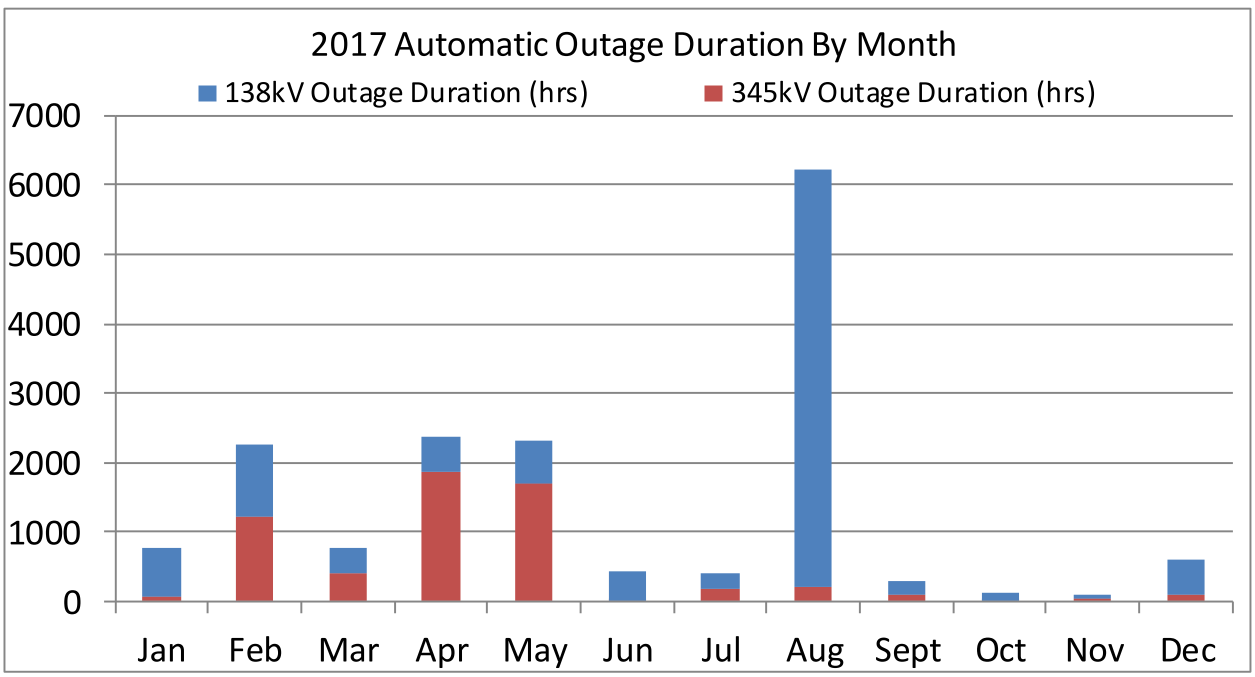


Figure 29 – 2017 Automatic Outage Duration by Month

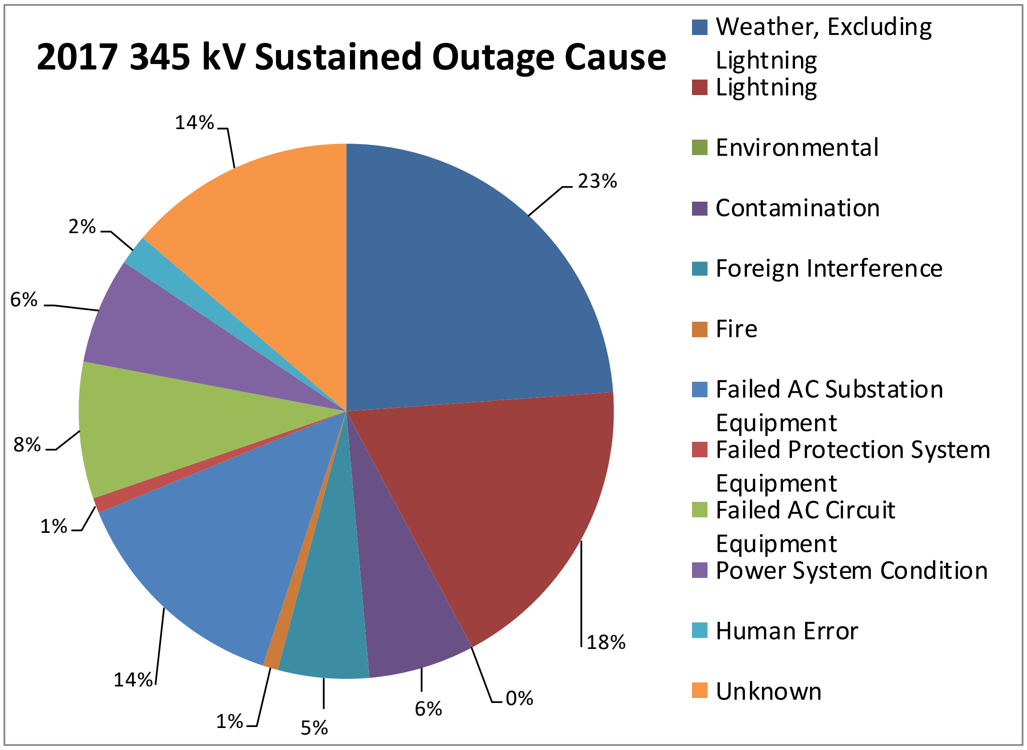


Figure 30 – 2017 345 kV Sustained Outage Cause

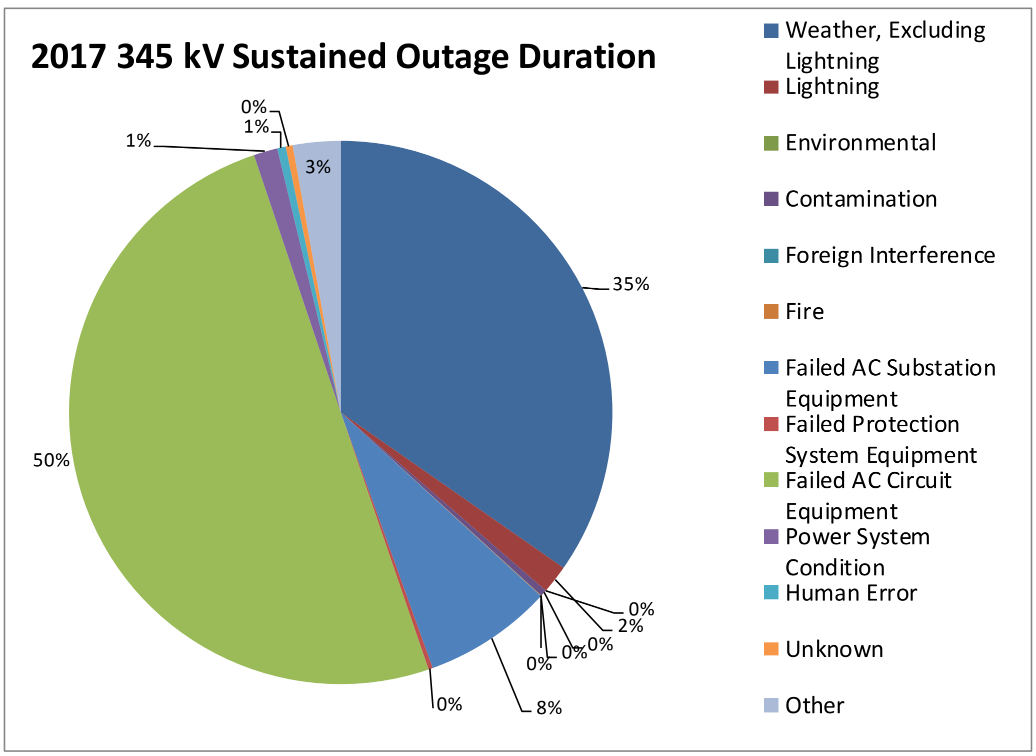


Figure 31 – 2017 345 kV Sustained Outage Duration

The following table shows the 345 kV circuit sustained outage data by average duration for 2013-2017 combined, 138 kV circuit sustained outage data for 2015-2017 combined, and the 345 kV transformer sustained outage data for 2015-2017 combined.

345 kV Circuits Sustained Cause Code	Number of Sustained Outages	Average Outage Duration (Hours)
Failed AC Circuit Equipment	84	147.4
Weather, Excluding Lightning	72	72.7
Failed AC Substation Equipment	76	31.3
Foreign Interference	21	17.3
Lightning	50	10.6
Power System Condition	26	6.6
Contamination	36	6.1
Fire	2	5.6
Unknown	35	5.2
Failed Protection System Equipment	38	4.6
Other	53	3.8
Human Error	38	3.7
Vegetation	2	0.0
2013-2017 345 kV Circuits	**533**	**41.3**
138 kV Circuits Sustained Cause Code	**Number of Sustained Outages**	**Average Outage Duration (Hours)**
Fire	10	112.5
Failed AC Circuit Equipment	312	60.7
Failed AC Substation Equipment	187	40.8
Environmental	16	14.5
Vegetation	40	14.2
Weather, Excluding Lightning	93	13.7
Lightning	84	13.4
Contamination	3	13.3
Failed Protection System Equipment	63	6.3
Human Error	107	5.2
Foreign Interference	72	4.2
Power System Condition	41	4.0
Unknown	57	2.8
Other	70	2.3
2015-2017 138 kV Circuits	**1155**	**28.3**
345 kV Transformers Sustained Cause Code	**Number of Sustained Outages**	**Average Outage Duration (Hours)**
Failed AC Substation Equipment	33	534.6
Failed Protection System Equipment	4	93.3
Human Error	5	61.5
Power System Condition	7	37.3
Other	6	16.2

Failed AC Circuit Equipment	3	9.0
Lightning	6	5.2
Foreign Interference	1	4.1
Unknown	1	4.0
Weather, Excluding Lightning	5	3.8
Environmental	1	3.5
Contamination	2	2.2
2015-2017 345 kV Transformers	**75**	**250.3**

Table 9 – Sustained Outage Data by Average Outage Duration

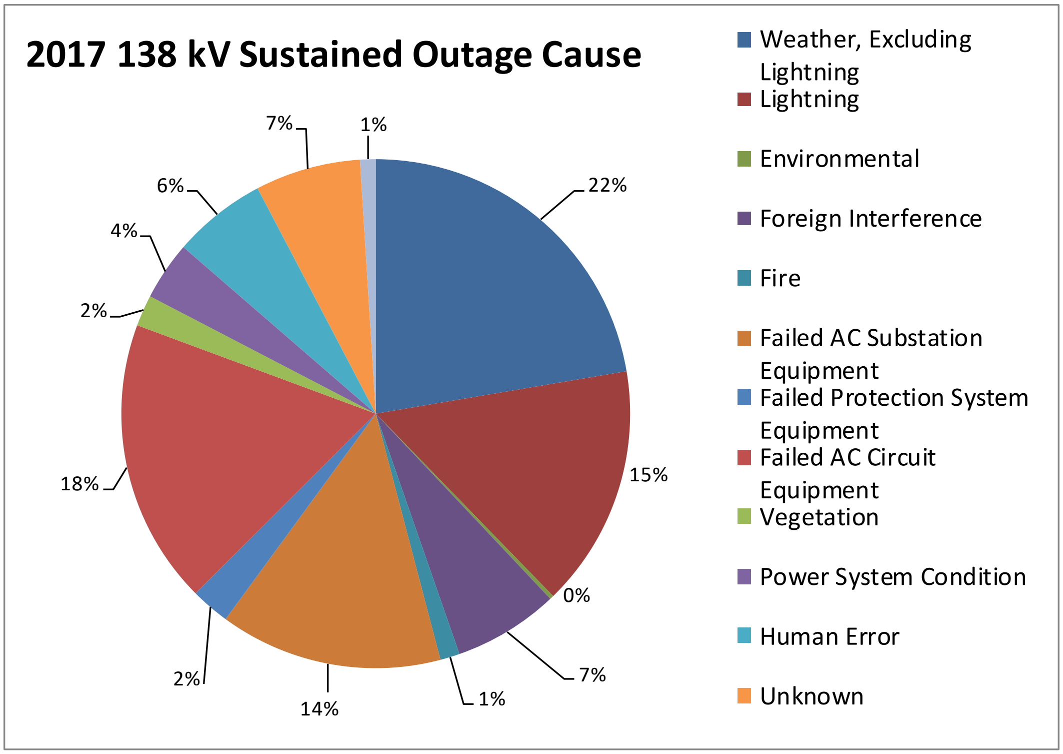


Figure 32 – 2017 138 kV Sustained Outage Cause

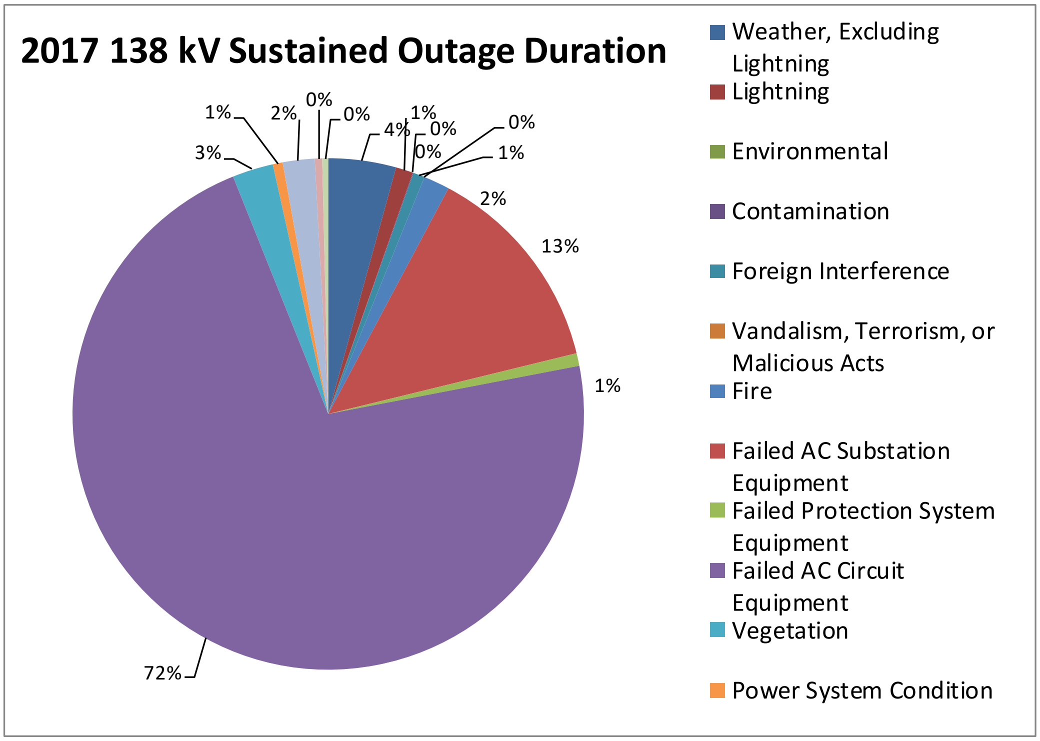


Figure 33 – 2017 138 kV Sustained Outage Duration

The following figure shows a comparison of 2017 automatic outage rates per circuit and per 100 miles of line between different ERCOT Transmission Owners compared to the aggregated region performance.

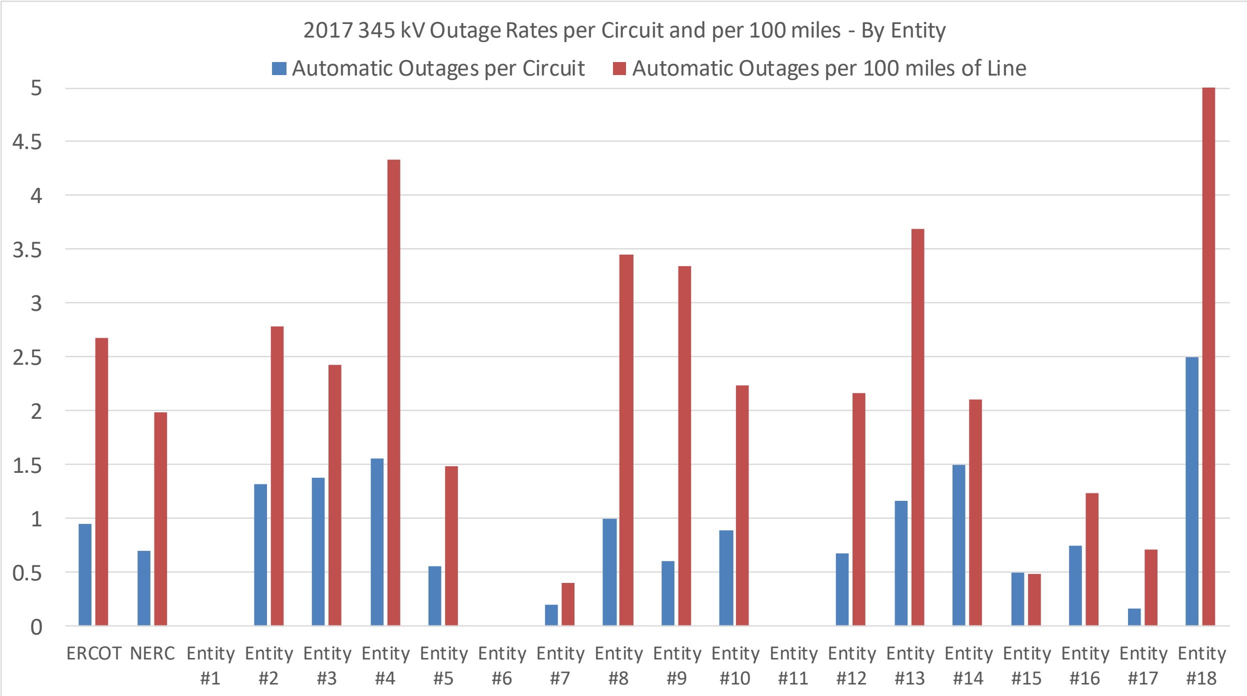


Figure 34 – 2017 345 kV Outage Rates by Entity

C. Common Mode and Dependent Mode Outage Data

For 345 kV circuits in 2017, 29 of the 407 reported automatic outage events involved two or more circuit elements. Dependent Mode outages (defined as an automatic outage of an element which 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 7% of all outages and 87% of sustained outage duration for the 345 kV system.

For 138 kV circuits in 2017, 84 of the 406 reported automatic sustained outage events involved two or more circuit elements. Dependent Mode and Common Mode outages represented 21% of all sustained outages and 9% of sustained outage duration.

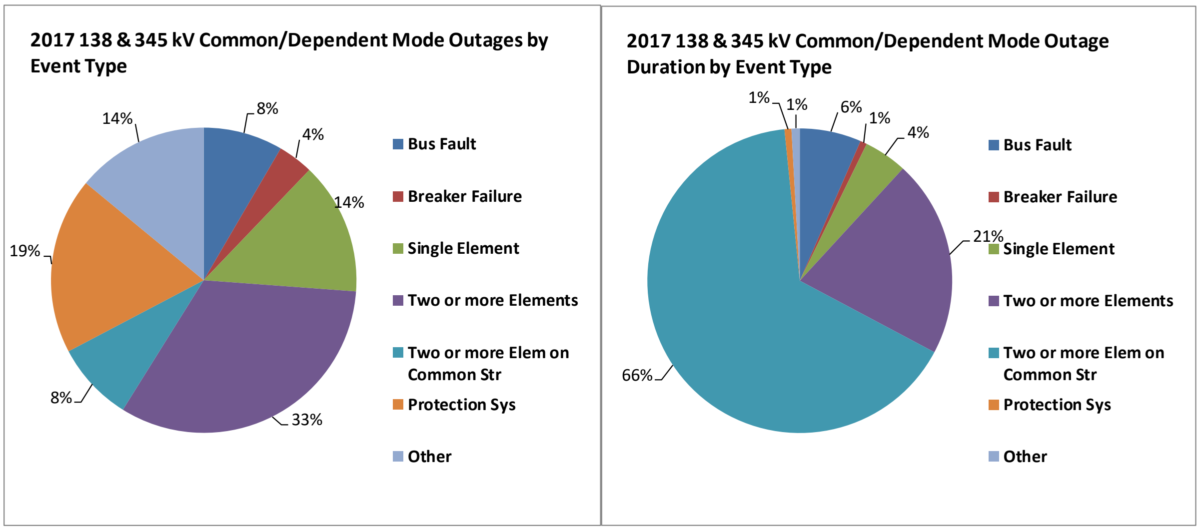


Figure 35 – 2017 345 kV & 138 kV Common/Dependent Mode Outages by Event Type

D. Vegetation Management

Conductor contact with trees has been an initiating trigger and a contributing factor in several major system disturbances since 1965, including the August 14, 2003, Northeast blackout. Tree contact caused the loss of multiple transmission circuits in several of the outages, causing multiple contingencies and further weakening of the system.

NERC began collecting vegetation-related outage information in 2004 as a result of the Northeast blackout. Initiatives to reduce vegetation-related outages include quarterly vegetation management reports and self-certification of vegetation-related outages by Registered Entities through the enforcement of the FAC-003 Standard.

In the Texas RE Region in 2017, there were no vegetation-related outages reported in the TADS system for 345 kV circuits and 12 reported vegetation-related sustained outages for 138 kV circuits.

E. System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Performance

A System Operating Limit 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 IROL is an SOL that, if violated, could lead to instability, uncontrolled separation, or cascading outages. There is currently one defined IROL in the Texas RE Region, the North-Houston stability limit.

In 2017, there were no exceedances of the North-Houston stability limit.

ERCOT utilizes Constraint Management Plans (CMPs) as a set of pre-defined actions executed in response to system conditions to prevent or resolve one or more thermal or non-thermal transmission security violations SOLs. CMPs include, but are not limited to the following:

- Re-dispatch of generation from Security-Constrained Economic Dispatch (SCED)
- Remedial Action Plans (RAPs)
- Pre-Contingency Action Plans (PCAPs)
- Temporary Outage Action Plans (TOAPs)
- Mitigation Plans (MPs)

When developing CMPs, ERCOT typically utilizes the 15-minute rating of the impacted transmission Facility(ies), if available, as the limit. The following charts show the monthly trend in transmission facility constraints where the thermal rating of the facility was exceeded post-contingency (i.e., an SOL exceedance).

Voltage stability limits, transient and control stability limits, and stability issues in areas with low weight short circuit ratios are monitored and managed through the use of Generic Transmission Constraints (GTCs).

In 2017, there were 6,323 basecase exceedances for at least one SCED 5-minute interval where the element load exceeded 100% of the limit (normal rating). There were approximately 81,400 post-contingency exceedances for at least one SCED 5-minute interval where the element post-contingency calculated load exceeded 100% of the limit (15-minute rating). Table 8 shows the list of the top constraints for 2017 by duration based on this criteria.

Constraint (Binding Element)	Approx. Number of Hours
Holder Auto 138/69 kV	541.9
Twin Oak Switch – BTU Jack Creek 345 kV	493.7
Solstice – Pig Creek 138 kV	401.8
Singleton – Zenith 345 kV (SngZen99)	338.4
Panhandle Interface	324.9
Hamilton Road – Maverick 138 kV	251.6
Singleton – Zenith 345 kV (SngZen98)	250.3
Bruni Auto 138/69 kV	197.3
Blue Mound – Wagley Robertson 138 kV	194.8
Loyola Auto 138/69 kV	172.5

Table 10 – 2017 Top Constraints by Duration

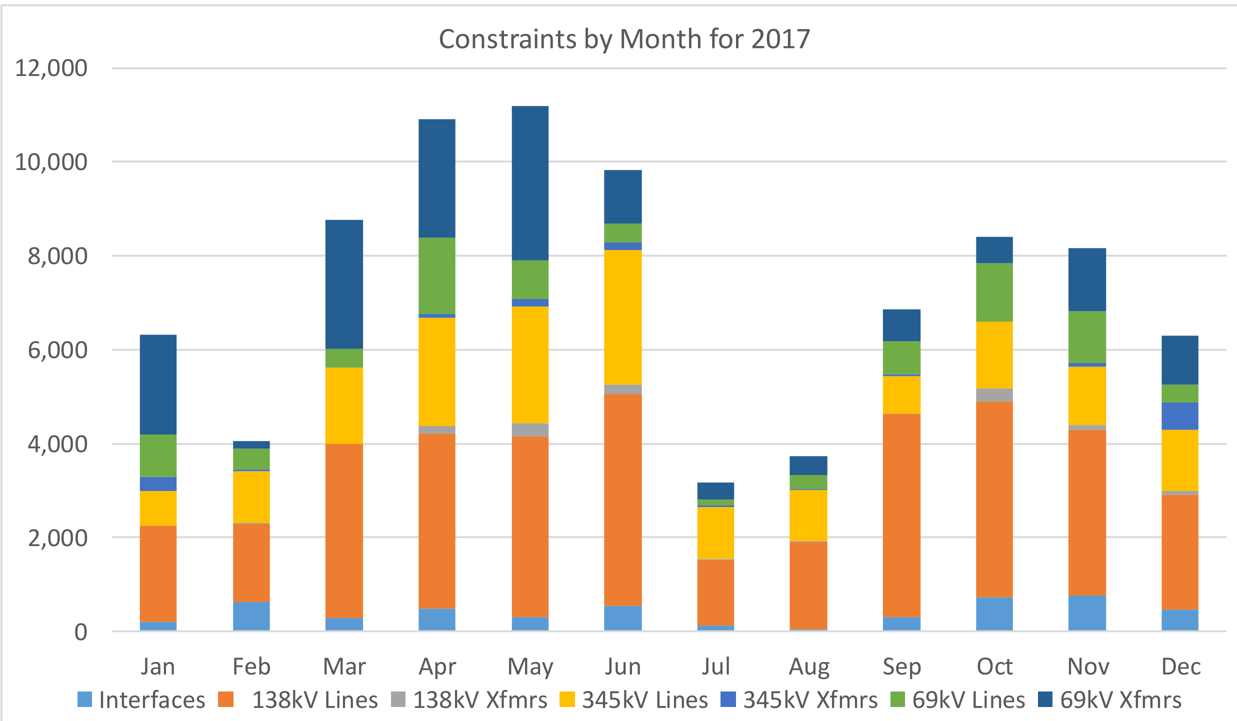


Figure 36 – Constraint by Month for 2017

ERCOT also posts a Chronic Congestion Summary report each month. This report provides the following:

(1) All security violations that were 125% or greater of the Emergency Rating for a single SCED interval or greater than 100% of the Emergency Rating for a duration of 30 minutes or more during the prior reporting month and the number of occurrences and congestion cost associated with each of the constraints causing the security violations on a rolling 12-month basis.

(2) Operating conditions on the ERCOT System that contributed to each security violation reported in paragraph (1) above.

The table below shows a summary of the Chronic Congestion for 2017, by the cause of the congestion. Total estimated congestion rent for 2017 exceeded $756 million. Double circuit contingencies were responsible for 64% ($482,280,000) of the total congestion rent.

Chronic Constraint Cause	Sum of # Intervals > 100% for 30 Min or more	Sum of Congestion Rent ($)
Area Load/Generation pattern.	106	25,699,040
Multiple outages in the area	113	47,275,613
Planned outages in the area	1032	293,198,953
High North-Houston (N-H) Import	236	95,455,884
Redundant	204	545,975
Incorrect telemetry	40	5,440,006
TOAP available	1196	80,276,878
Forced outages in the area	265	80,626,203
PCAP/RAP/RAS/MP available	2021	76,760,959
High DC export	8	7,078,549
High generation in the area	277	37,196,887
Low voltage in the area	1	1,152,676
Area phase-shifter adjusted	26	2,329,999
High load in the area	4	3,604,347
Total	5529	756,641,969

Table 11 – 2017 Chronic Constraint Causes

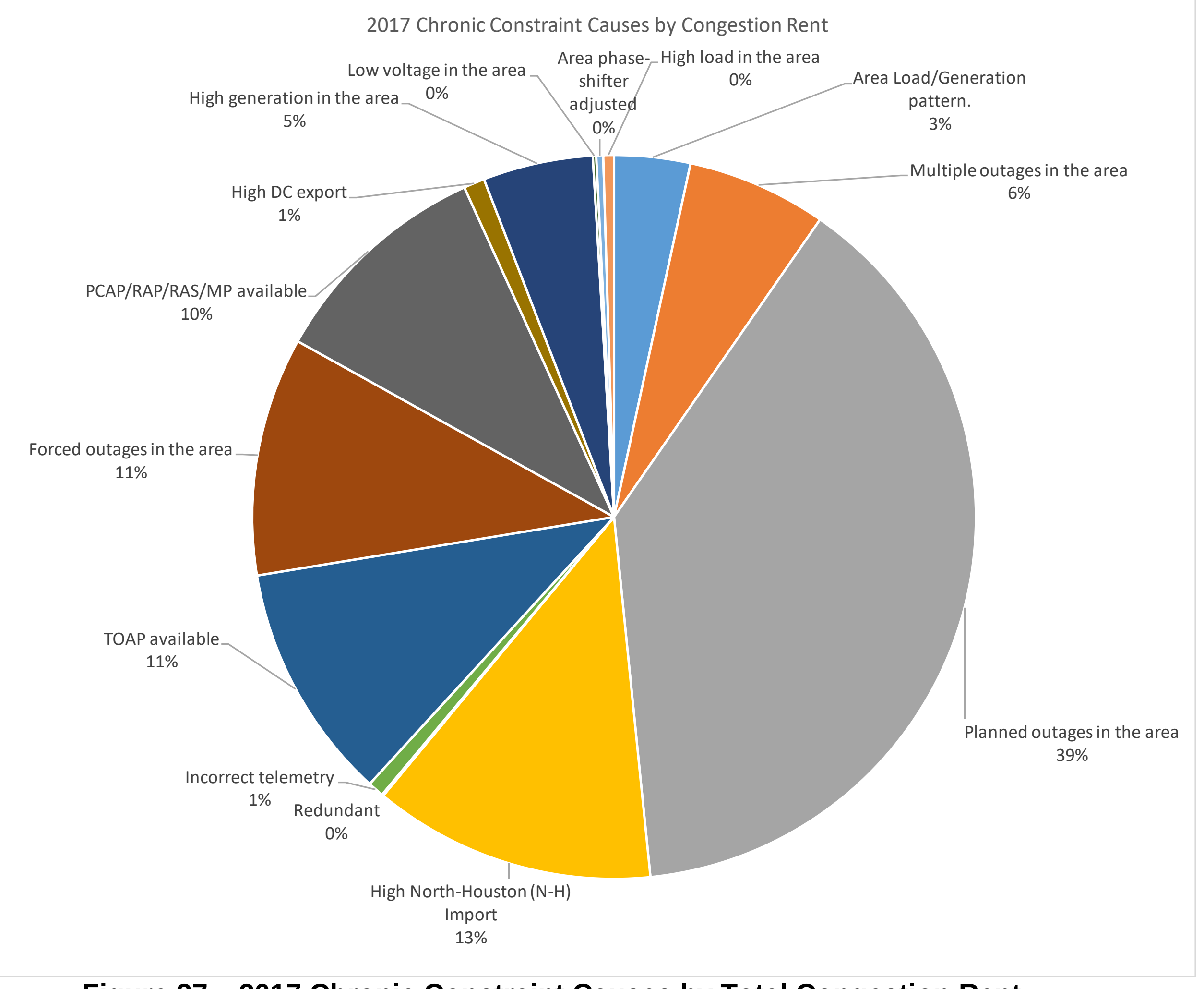


Figure 37 – 2017 Chronic Constraint Causes by Total Congestion Rent

F. Voltage Control

ERCOT Operating Guides require a generation resource to provide either leading or lagging reactive power up to the required capability of the unit upon request from a transmission operator or ERCOT ISO. The guides also require a generation resource to maintain the transmission system voltage at the point of Interconnection with the transmission system within 2% of the voltage profile while operating at less than the maximum reactive capability of the generation resource. ERCOT voltage control procedures also require the transmission operators to maintain bus voltages between 95% and 105% of nominal during normal operating conditions and between 90% and 110% of nominal post-contingency. The following chart shows the 2017 voltage control analysis for twenty 345 kV buses defined by ERCOT as being important for State Estimator to converge to a correct solution. This chart is based on one-hour telemetry data. The red lines indicate the +/- 5% operational voltage limits.

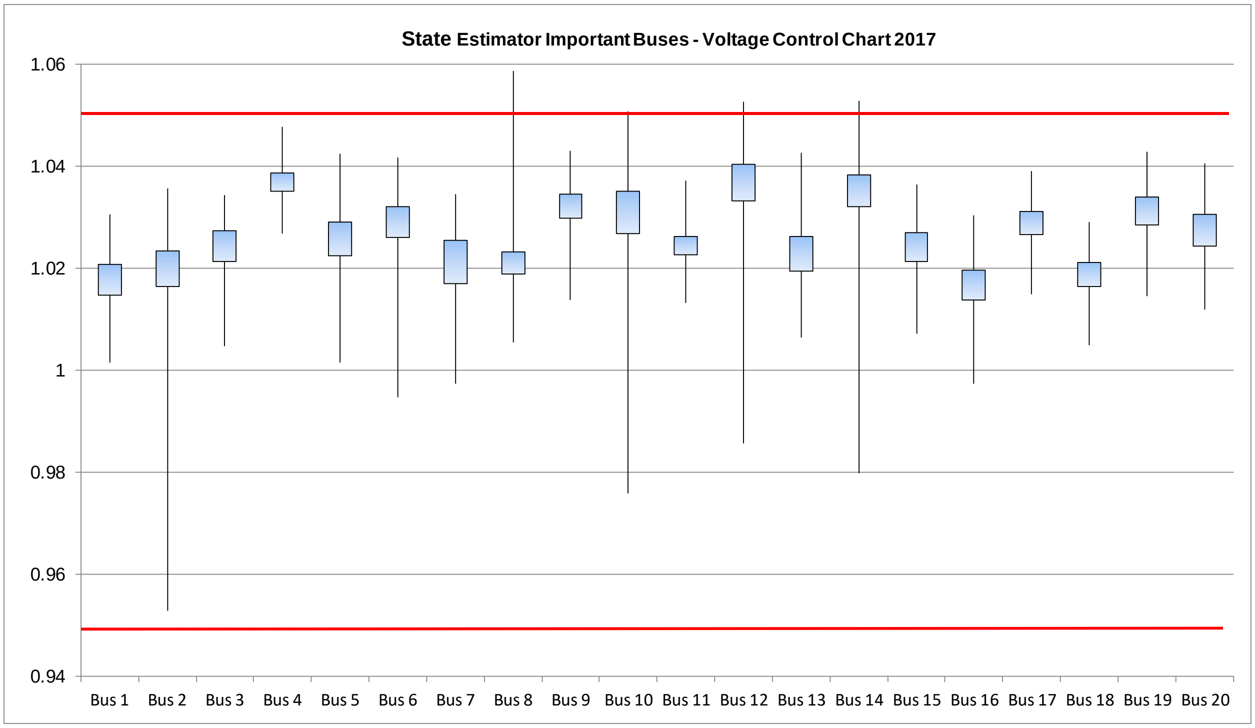


Figure 38 – 345 kV Bus Voltage Chart for Important State Estimator Buses 2017

G. Remedial Action Schemes

Remedial Action Schemes (RAS's) are protective relay systems designed to detect abnormal ERCOT system conditions such as transmission contingency overloads and take automatic pre-planned corrective actions to maintain a secure system. The following chart shows the trend in RAS's in service, as well as operating procedures and guides used congestion management, since 2011 reported by Texas RE to NERC. Operating procedures and guides include Remedial Action Plans, Mitigation Plans, and Pre-Contingency Action Plans as defined in ERCOT Protocols and Operating Guides. For the purposes of this chart, "economic" RAS's were removed since these types of RAS's are not necessary to meet the NERC Transmission Planning standards.

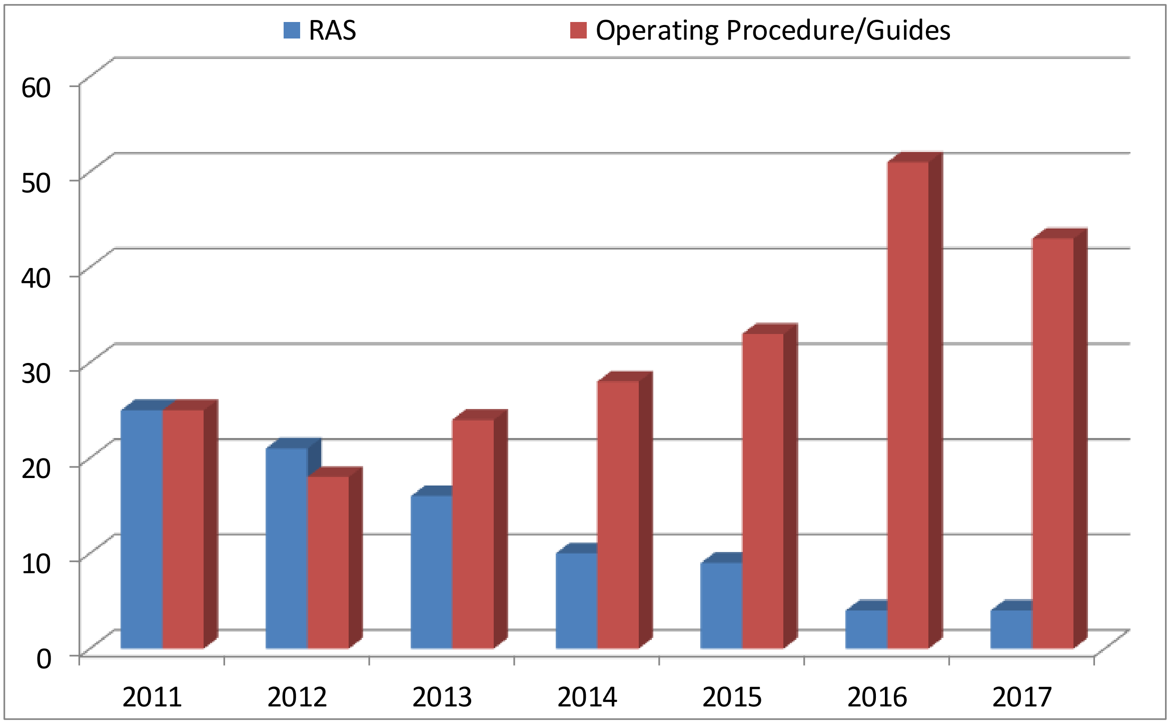


Figure 39 – RAS and Operating Procedure Trends

ERCOT Operating Guides require owners of RAS's to report operations of these systems to Texas RE on a quarterly basis. The following figure shows the trend in arming/disarming operations and activation of the RAS. Since 2011 Q3, there has only been one reported misoperation of a RAS in the Texas RE Region (shown by the yellow dot in 2012 Q4 on the chart).

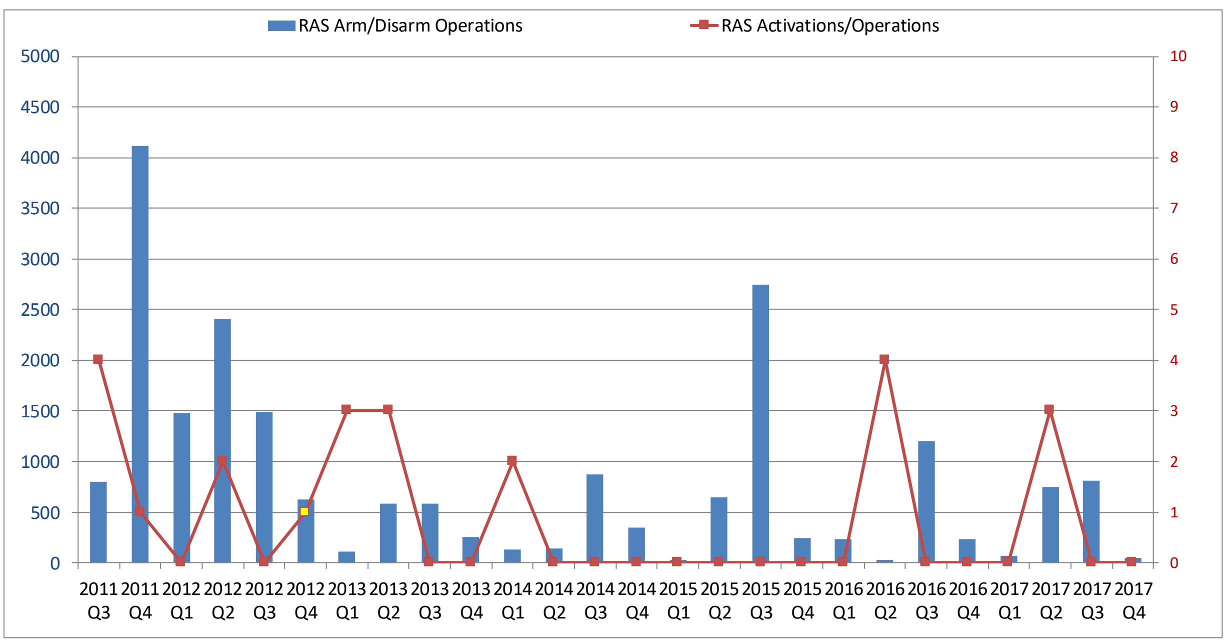


Figure 40 – Remedial Action Scheme Operation Trend

V. Generation

Introduction

Texas RE collects generation outage information for units 20 MW and larger through the Generation Availability Data System (GADS). Starting in January 2017, wind generations units will begin voluntary reporting in GADS with mandatory reporting beginning in 2018. The GADS data is used to calculate various generation metrics, including gross and net capacity factors, scheduled and forced outage rates, availability factors, seasonal de-rating factors, and starting reliability and average run times. ERCOT generators providing GADS data represent approximately 73% of the installed nameplate capacity within the region.

2017 Generation Performance in Brief

Nameplate Capacity: 119,436 MW
Net Generation
  From Nuclear: 38,504 GWH
  From Renewable: 63,059 GWH
  From Natural Gas: 138,844 GWH
  From Coal/Lignite: 115,141 GWH
  From Other: 1,849 GWH
Forced Outages (GADS): 1,816
GADS MW Weighted EFOR: 7.4%

Additional data on GADS analysis is presented in Appendix D.

Observations

- Peak hourly wind generation: 16,035 MW on November 17, 2017 at 10:00 p.m.
- Record hourly wind penetration: 53.7% of total energy on October 27, 2017 at 3:00 a.m.
- GADS EFOR (MW Weighted): 7.4% for 2017 versus 5.8% for 2016
- The portion of total energy supplied by natural gas declined in 2017 by approximately 6% compared to 2016 as wind generation continued to supply a greater portion of total energy. The portion of total energy supplied by coal in 2017 increased by approximately 3% compared to 2016.
- As of December 2017, ERCOT projections indicate utility-scale solar generation will increase to over 2,300 MW and wind generation will increase to over 25,900 MW during the next two years, based on current signed generation interconnect agreements with financial security.

Historical Data and Trends

A. Resource Mix

In 2017, the reported nameplate capacity was 119,436 MW of all types of generators. Coal, natural gas, and wind each comprise more than 18.6% of the nameplate capacity.

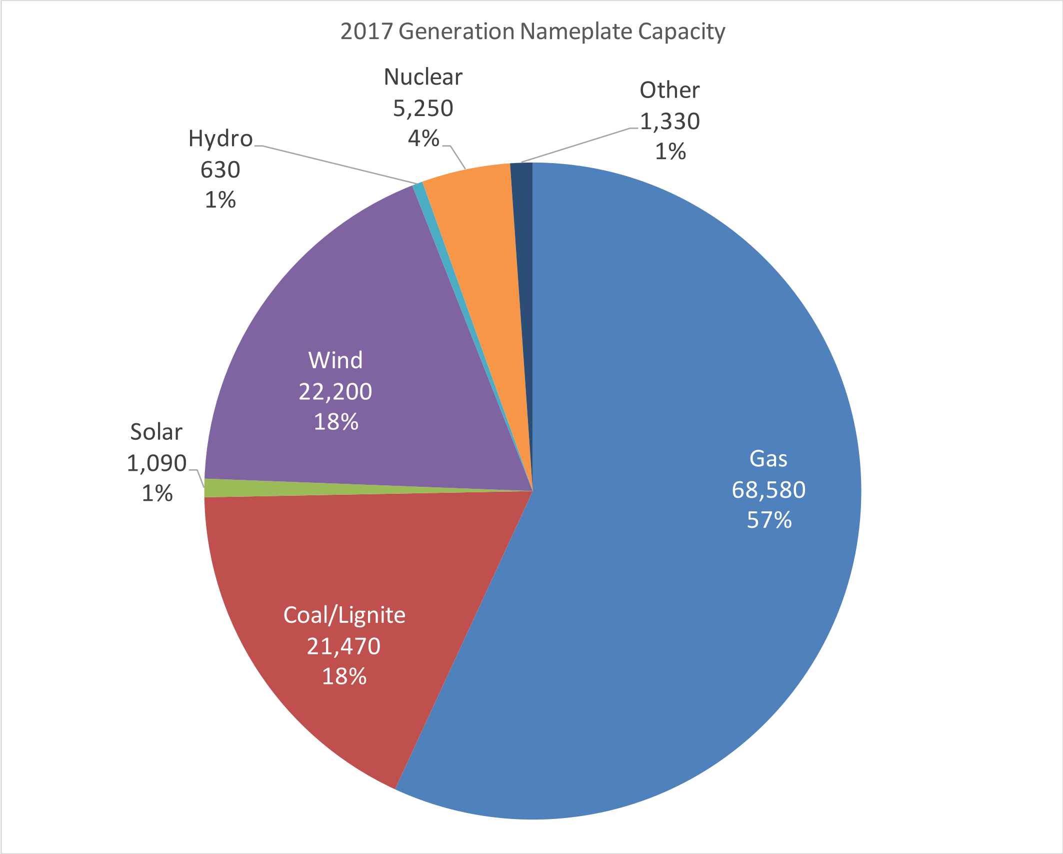


Figure 41 – 2017 Generation Nameplate Capacity

The portion of total energy supplied by natural gas continued to decline in 2017, from 48% in 2015, to 44% in 2016 and down to 38% in 2017 as wind energy continued to increase. The portion of total energy supplied by coal increased slightly by 3%, from 29% in 2016 to 32% in 2017. However, the portion of total energy supplied by coal is expected to decline dramatically in 2018, by 20% or more, due to the planned retirements of seven units and the extended mothball status of one other unit.

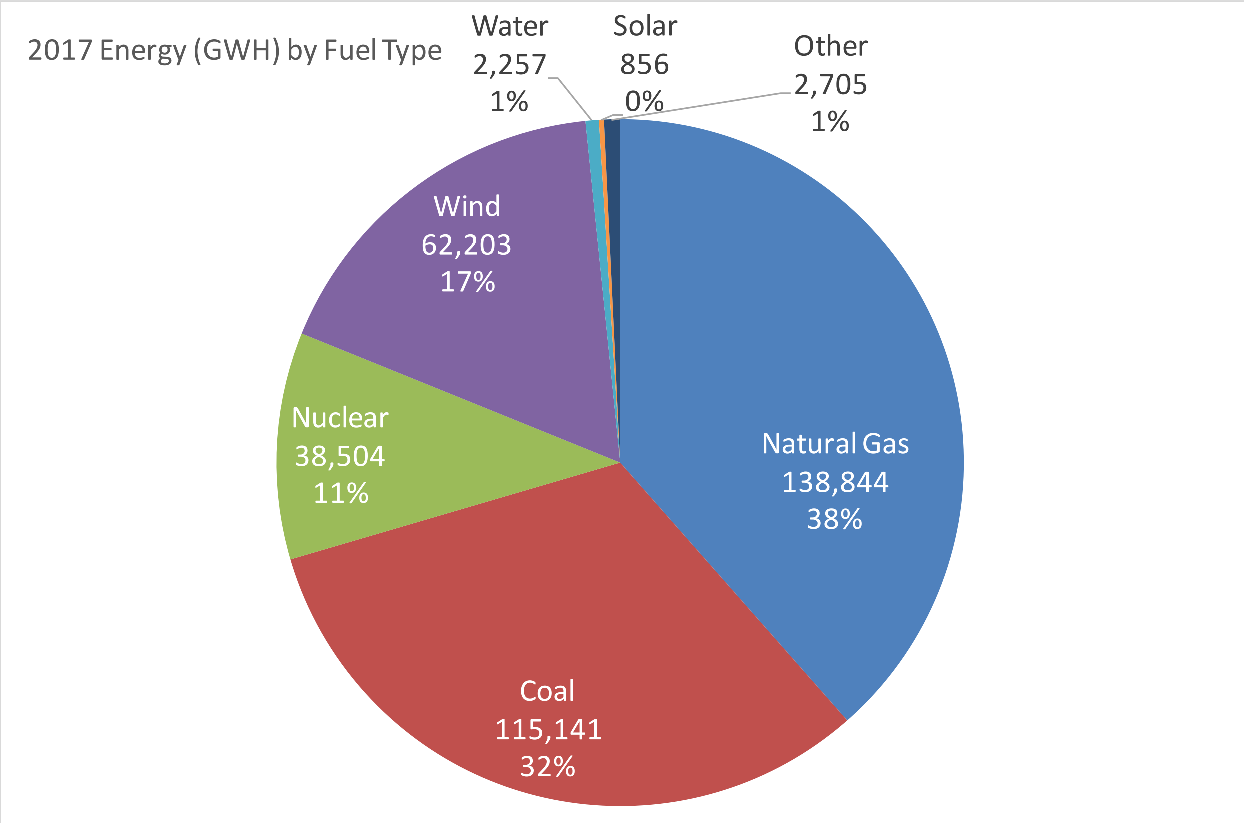


Figure 42 – 2017 Energy by Fuel Type

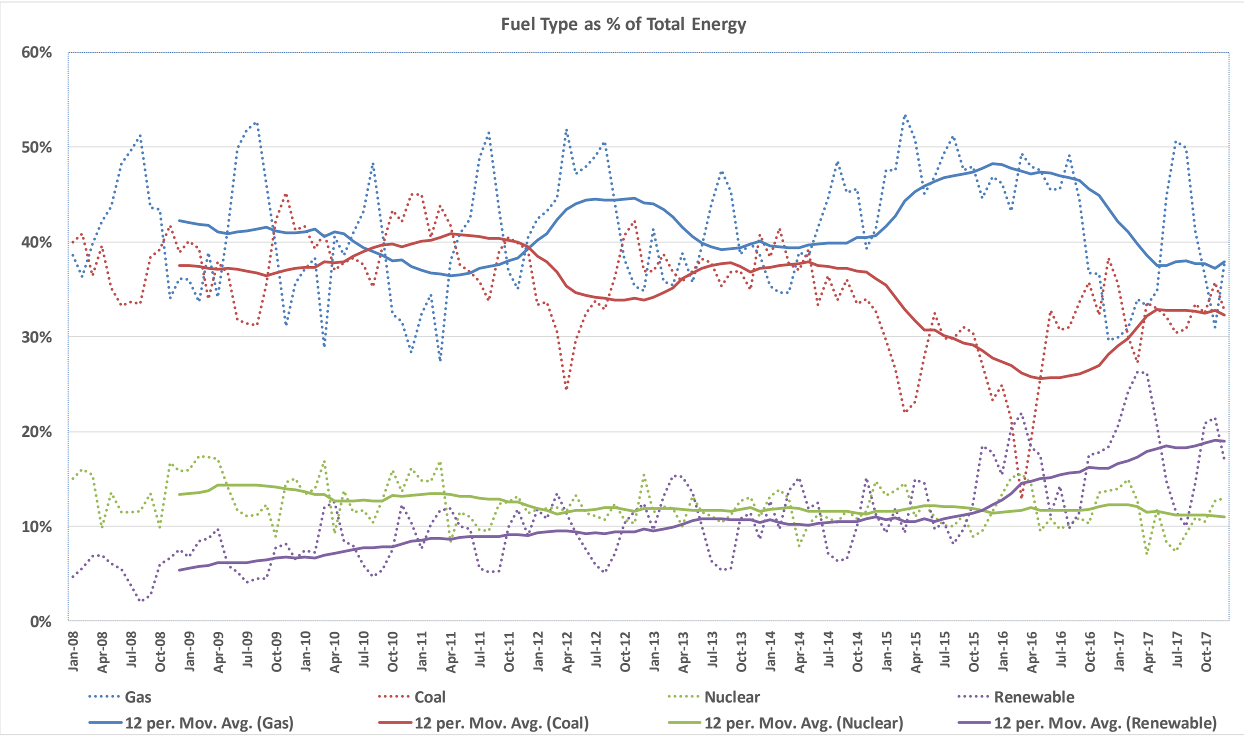


Figure 43 – Energy by Fuel Type Trend

B. 2017 Performance Metrics

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 performance metrics based on unweighted versus weighted values for the ERCOT generation fleet for 2017 is provided in the following table.

Metric	Texas RE Region GADS Data 2017		NERC Fleet Average 2012-2016	
	Unweighted	Weighted	Unweighted	Weighted
Net Capacity Factor (NCF)	43.3%		34.2%	
Service Factor (SF)	46.1%	59.7%	43.4%	48.0%
Equivalent Availability Factor (EAF)	85.3%	85.6%	83.5%	83.1%
Scheduled Outage Factor (SOF)	8.3%	8.5%	10.1%	11.2%
Forced Outage Factor (FOF)	4.1%	3.3%	4.6%	3.9%
Equivalent Forced Outage Rate (EFOR)	9.6%	7.4%	18.1%	14.0%
Equivalent Forced Outage Rate Demand (EFORd)	6.6%		8.4%	

Table 12 – ERCOT Generation Performance Metrics January through December 2017

- Net Capacity Factor: NCF = Σ (Net Actual Generation) / Σ (NMC x PH)
- Service Factor: SF = Σ SH / Σ PH
- Availability Factor: AF = Σ AH / Σ PH
- Scheduled Outage Factor: SOF = Σ (POH + MOH) / Σ PH
- Forced Outage Factor: FOF = Σ FOH / Σ PH
- Equivalent Forced Outage Rate: EFOR = Σ (FOH + EFDH) / Σ (FOH + SH + Synch Hours + Pump Hours + EFDH)

Where:

Forced Outage Hours (FOH)
Equivalent Forced De-rate Hours (EFDH)
Period Hours (PH)
Planned Outage Hours (POH)
Maintenance Outage Hours (MOH)
Availability Hours (AH)
Service Hours (SH)
Net Maximum Capability (NMC)

GADS metrics in Table 12 for the Texas RE Region in 2017 were in-line or better than the NERC fleet average for 2012-2016, the latest years that data is available. The Equivalent Forced Outage Rate (EFOR), which measures the rate of forced outage events on generating units, was lower for Texas RE Region units in comparison to the NERC fleet average, indicating a lower risk that a unit may be unavailable to meet generating requirements due to forced outages or de-ratings.

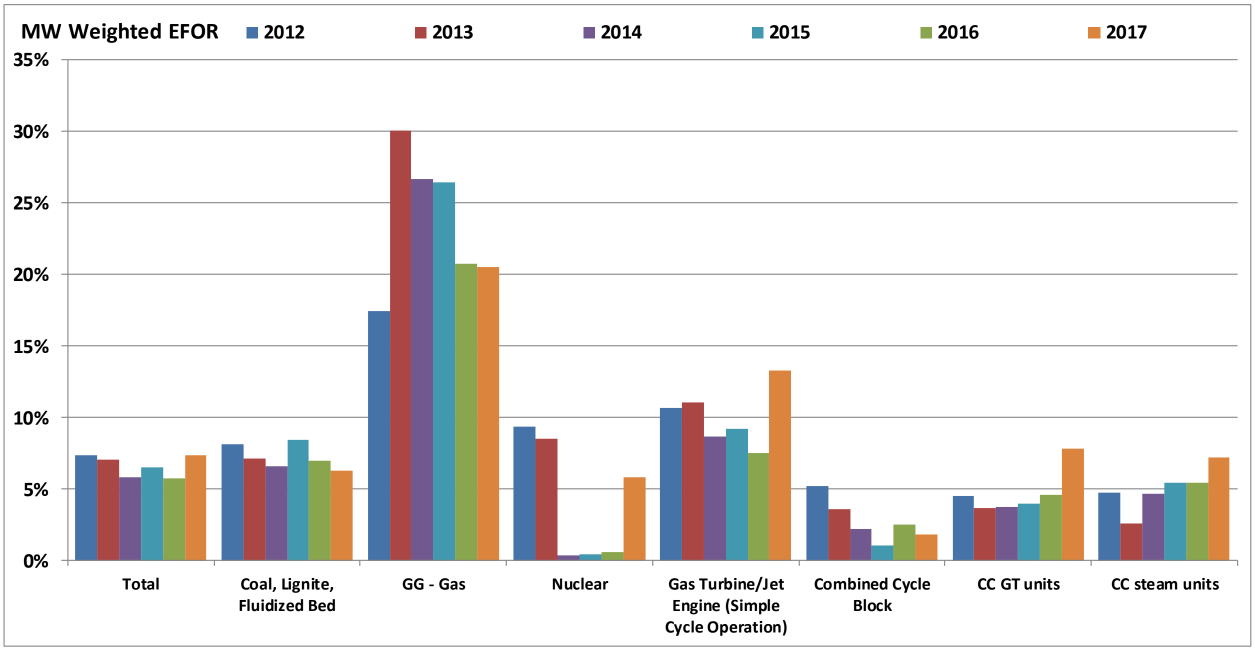


Figure 44 – GADS Generation Performance Metrics by Fuel Type and Year

The age of the generating fleet is sometimes used as an indicator for increasing outage rates. The following figure uses GADS data to plot fleet capacity by age and fuel type. It shows two characteristics of the fleet reported to GADS: (1) there is an age bubble around 35–39 years, driven by coal and some gas units; and (2) there is a significant age bubble around 12–18 years, comprised almost exclusively of gas and combined cycle units.

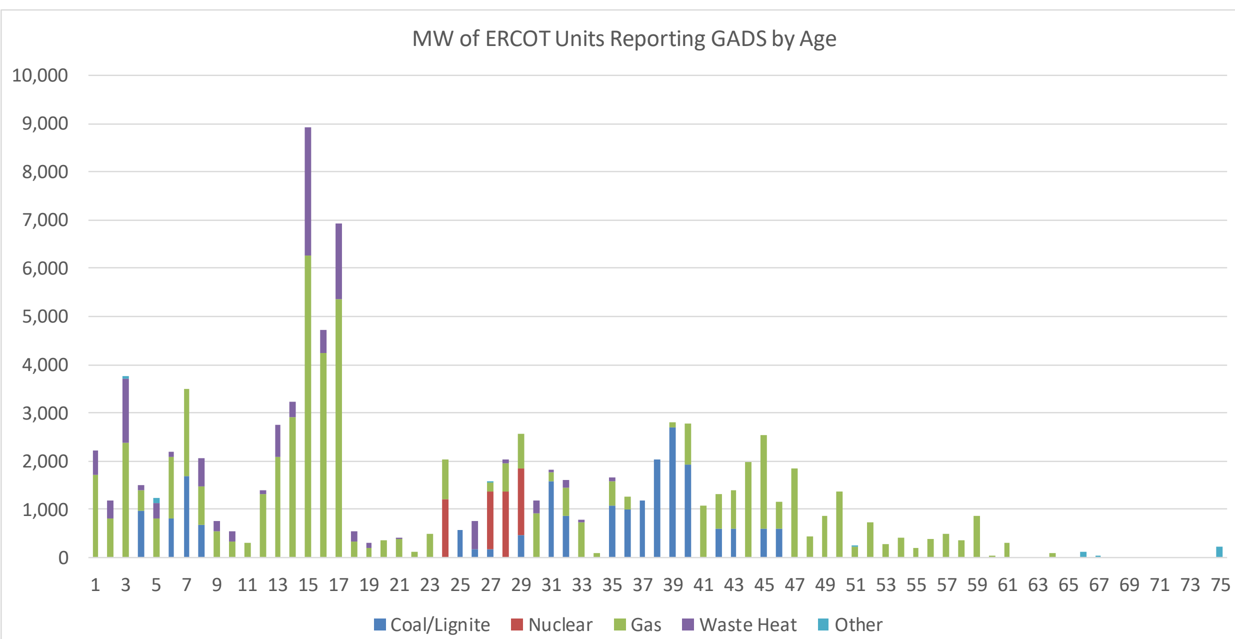


Figure 45 – GADS Generation in ERCOT by Age and Fuel Type

During the period from January 2017 through December 2017, the average FOH was 349.7 hours. This was a significant increase from previous years, in part due to the impact of Hurricane Harvey. The average MOH (including extensions to MO) was 154.4 hours, and the average POH (with extensions of PO) was 546.9 hours.

Metric (per unit)	Texas RE Region 2013	Texas RE Region 2014	Texas RE Region 2015	Texas RE Region 2016	Texas RE Region 2017	5-Year Average
Avg Forced Outage Hours	256.2	248.9	263.9	246.1	349.7	272.9
Avg Maintenance Outage Hours	149.0	134.7	131.3	138.8	154.4	141.6
Avg Planned Outage Hours	511.6	594.7	634.7	570.4	546.9	571.7

Table 13 – Average GADS Generation Unit Outage Hours

C. 2017 Outages and De-rates

From January 2017 through December 2017, there were 1,816 immediate forced outage events, totaling 130,745 hours, with a total outage capacity of 383,272 MW, or an average of 211 MW per event. The majority of the immediate forced outage events occurred due to boiler control or other control system issues, blade path temperature spreads, main transformer or other high voltage substation events, human error, and vibration issues.

During the same period, there were 3,107 immediate de-rate events, totaling 166,155 hours, with a total de-rate capacity of 362,034 MW, or an average of 116 MW per de-rate event. The majority of the immediate de-rate events occurred due to low BTU or wet coal and pulverizer feeder and mill issues, and baghouse failures. Reference the following chart and graphics.

	Immediate De-Rates	Immediate Forced Outages
Number of Events	3,107	1,816
Total Duration	166,155.8 hours	130,745.0 hours
Total Capacity	362,034 MW	383,272 MW
Avg Duration per Event	53.5 hours	72.0 hours
Avg Capacity per Event	116.5 MW	211.1 MW

Table 14 – Generator Immediate De-rate and Forced Outage Data (Jan. – Dec. 2017)

The cause of the immediate de-rate events can be further broken down into major categories based on the GADS data.

Major System	Number of De-rate Events	Total Duration (hours)	Total Capacity (MW)	Average Duration per Event (hours)	Average Capacity per Event (MW)
Boiler System	1,071	50,568.0	101,158.6	47.2	94.5
Balance of Plant	322	42,268.5	47,892.3	131.3	148.7
Steam Turbine/Generator	585	35,936.4	73,960.0	61.4	126.4

Heat Recovery Steam Generator	43	1,242.7	5,906.6	28.9	137.4
Pollution Control Equipment	203	4,726.6	18,282.6	23.3	90.1
External	436	7,593.9	38,567.8	17.4	88.5
Regulatory, Safety, Environmental	240	10,852.6	25,364.6	45.2	105.7
Personnel/Procedure Errors	19	482.3	2,470.1	25.4	130.0
Other	187	12,457.0	47,787.0	66.6	255.5

Table 15 – 2017 Major Category Cause of Immediate De-rate Events from GADS

The following charts show the 2017 GADS data for immediate forced outages and immediate de-rate events broken down by fuel type and cause.

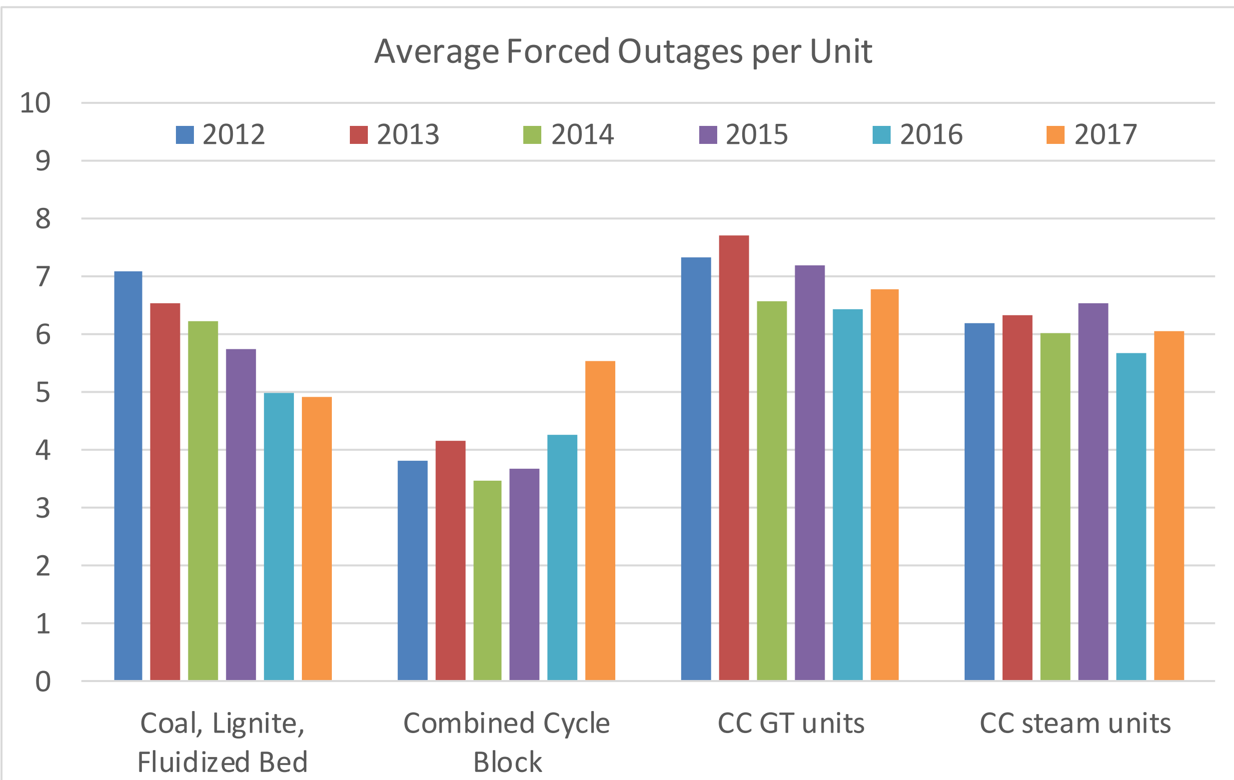


Figure 46 – 2017 Average Forced Outages per Unit

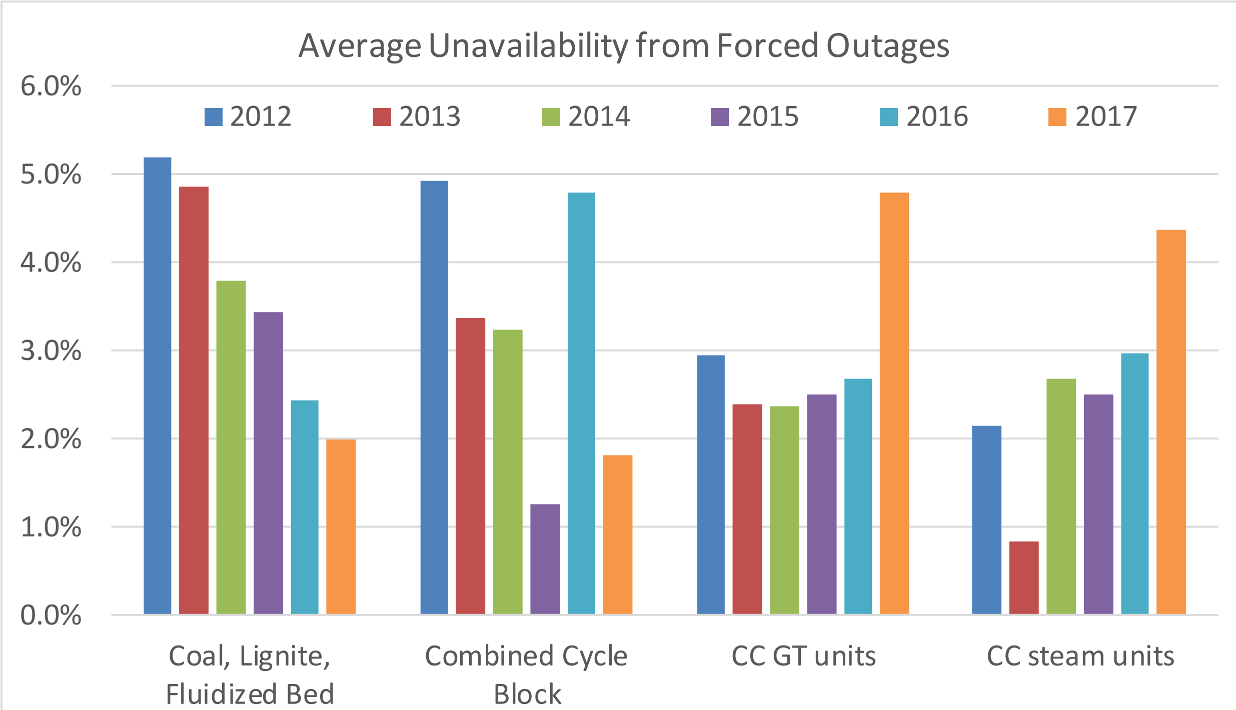


Figure 47 – 2017 Average Unavailability from Forced Outages per Unit

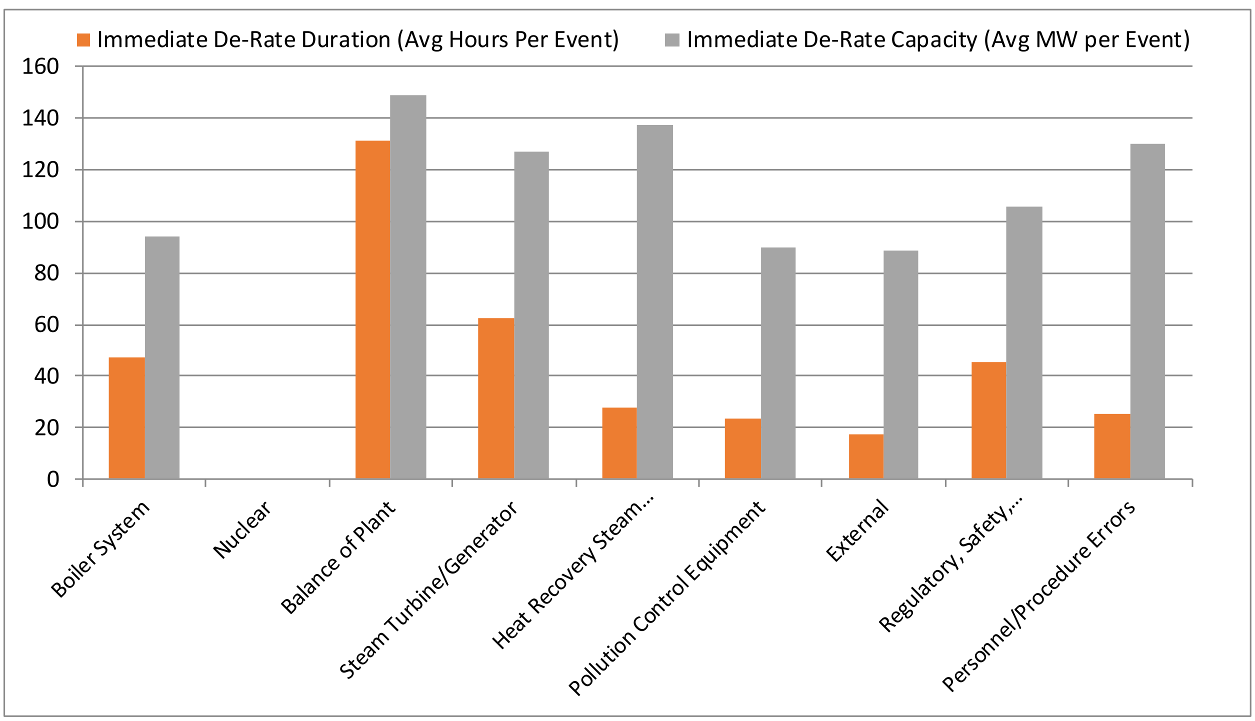


Figure 48 – 2017 Generator Immediate De-rate Events/Duration by Cause

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)	Average Duration per Event (hours)	Average Capacity per Event (MW)
Boiler System	173	9,148.9	62,127.9	52.9	359.1
Balance of Plant	332	8,316.5	72,958.3	25.0	219.8
Steam Turbine/Generator	852	36,403.1	146,013.9	42.7	171.4
Heat Recovery Steam Generator	63	5,410.0	11,450.8	85.9	181.8
Pollution Control Equipment	20	415.6	2,987.2	20.8	149.4
External	84	28,658.9	15,325.9	341.2	182.5
Regulatory, Safety, Environmental	12	484.9	1,465.0	40.4	122.1
Personnel/Procedure Errors	77	2,272.7	16,514.9	29.5	214.5
Other	202	39,563.0	53,213.0	195.9	263.4

Table 16 – 2017 Major Category Cause of Immediate Forced Outage Events from GADS

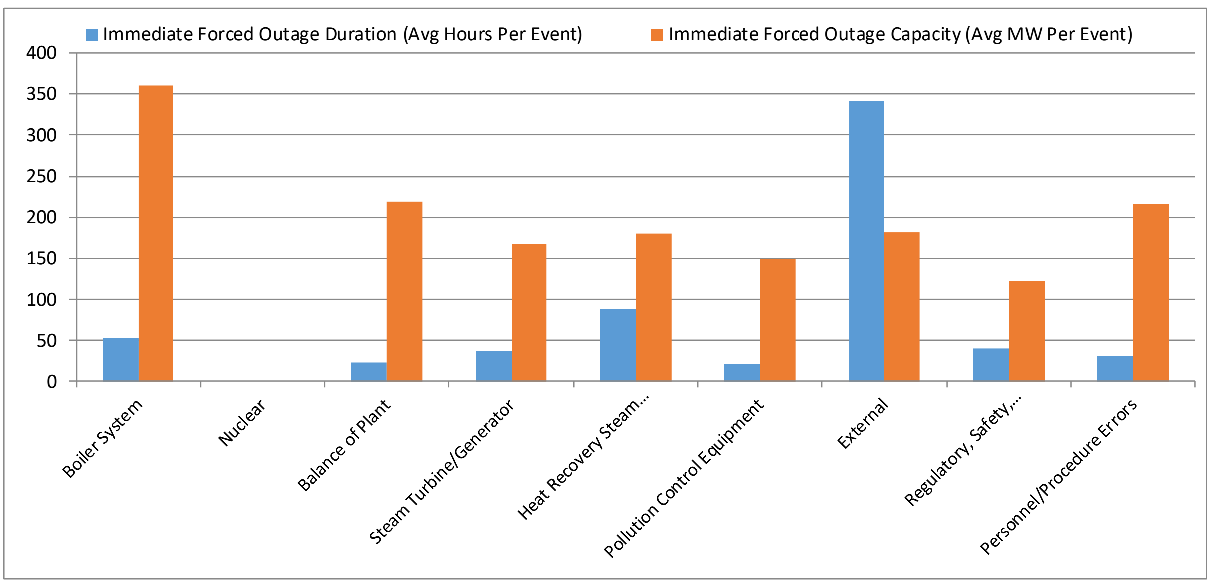


Figure 49 – 2017 Generator Immediate Forced Outage Events/Duration by Cause

D. Renewable Generation

Wind generation produced a total of 62,192 GWH in 2017, an increase of 17% from 2016. Wind generation, as a percentage of total ERCOT energy produced, increased to 17.4% in 2017, up from 15.1% in 2016. In 2017, hourly wind generation reached a maximum of 16,035 MW on November 17, 2017 at 10:00 p.m., and hourly wind generation served a maximum of 53.7% of system demand on October 27, 2017 at 3:00 a.m.

The following graphs show the historical trends for wind generation growth in the region. The blue bars represent the wind generation for the month and the black line represents the 12-month moving average.

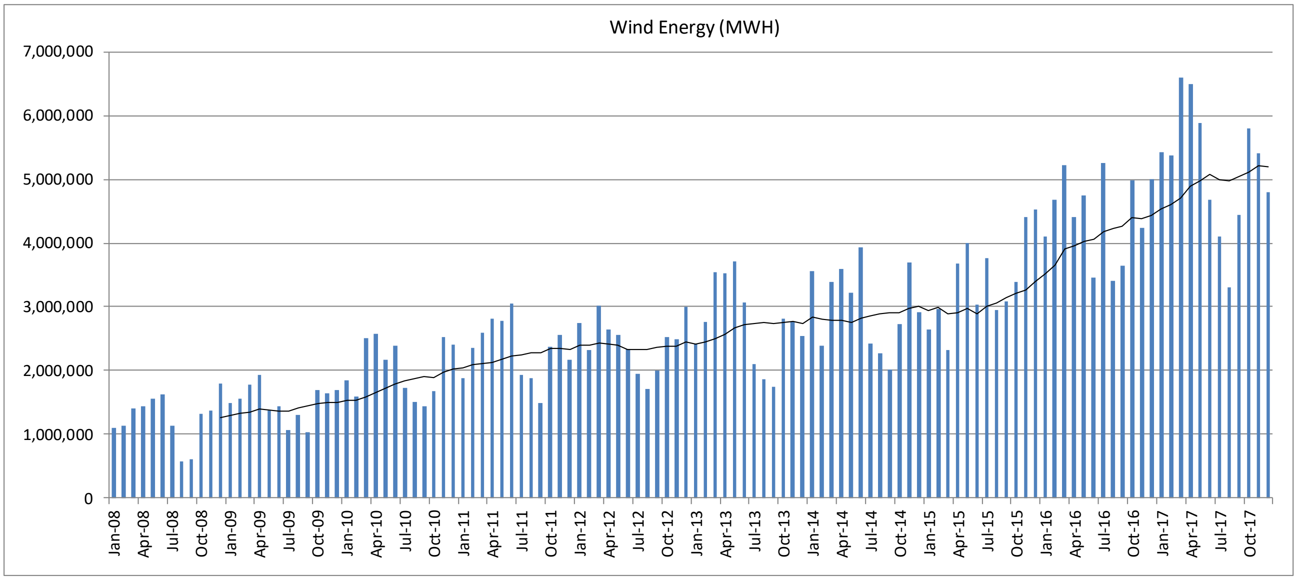


Figure 50 – 2008-2017 Wind Generation MWh

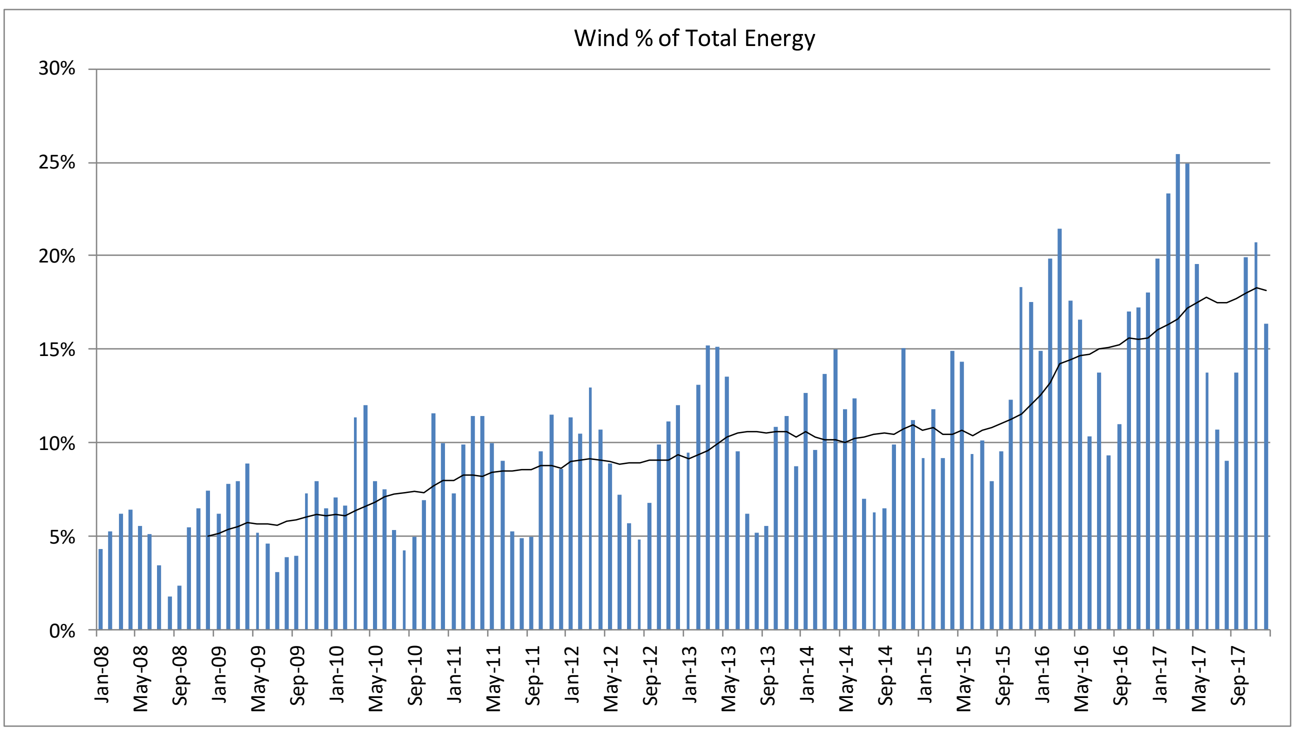


Figure 51 – 2008-2017 Wind Generation as a Percentage of ERCOT Total Energy

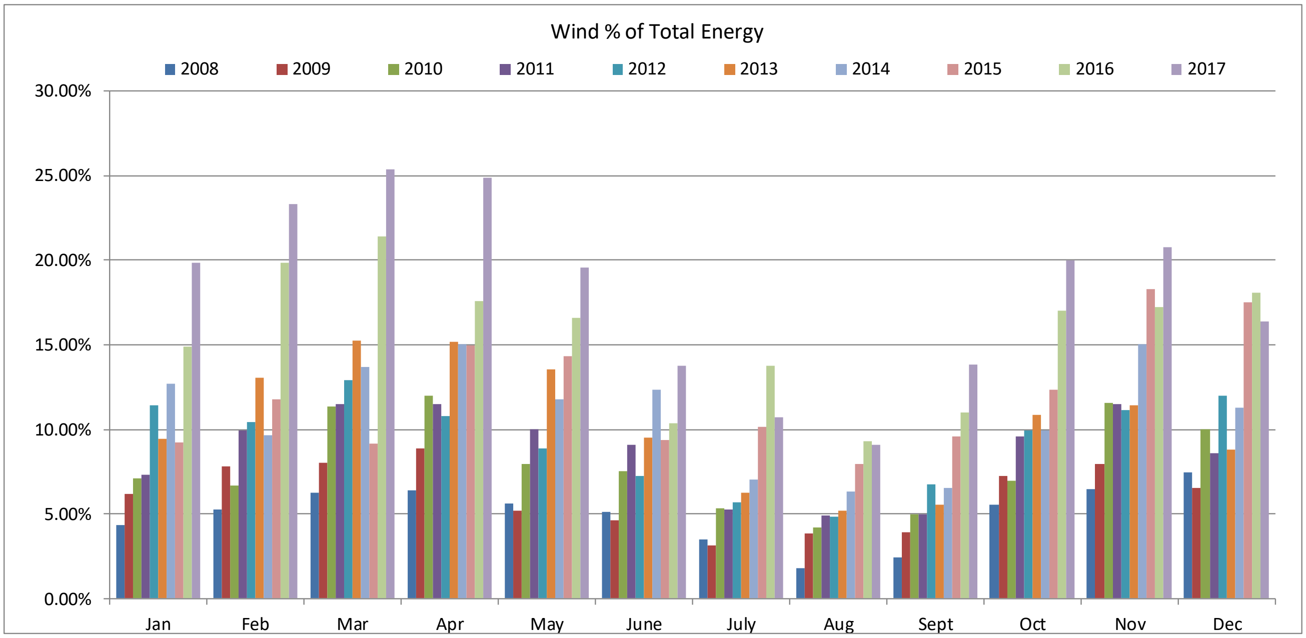


Figure 52 – 2008-2017 Wind Generation as Percentage of ERCOT Total Energy by Month

The following graph shows the distribution of capacity factor for all wind generation for the summer peak hours-ending of 15:00-19:00 for 2017. The average wind capacity factor for HE 15:00-19:00 was 26.2% for Summer 2017.

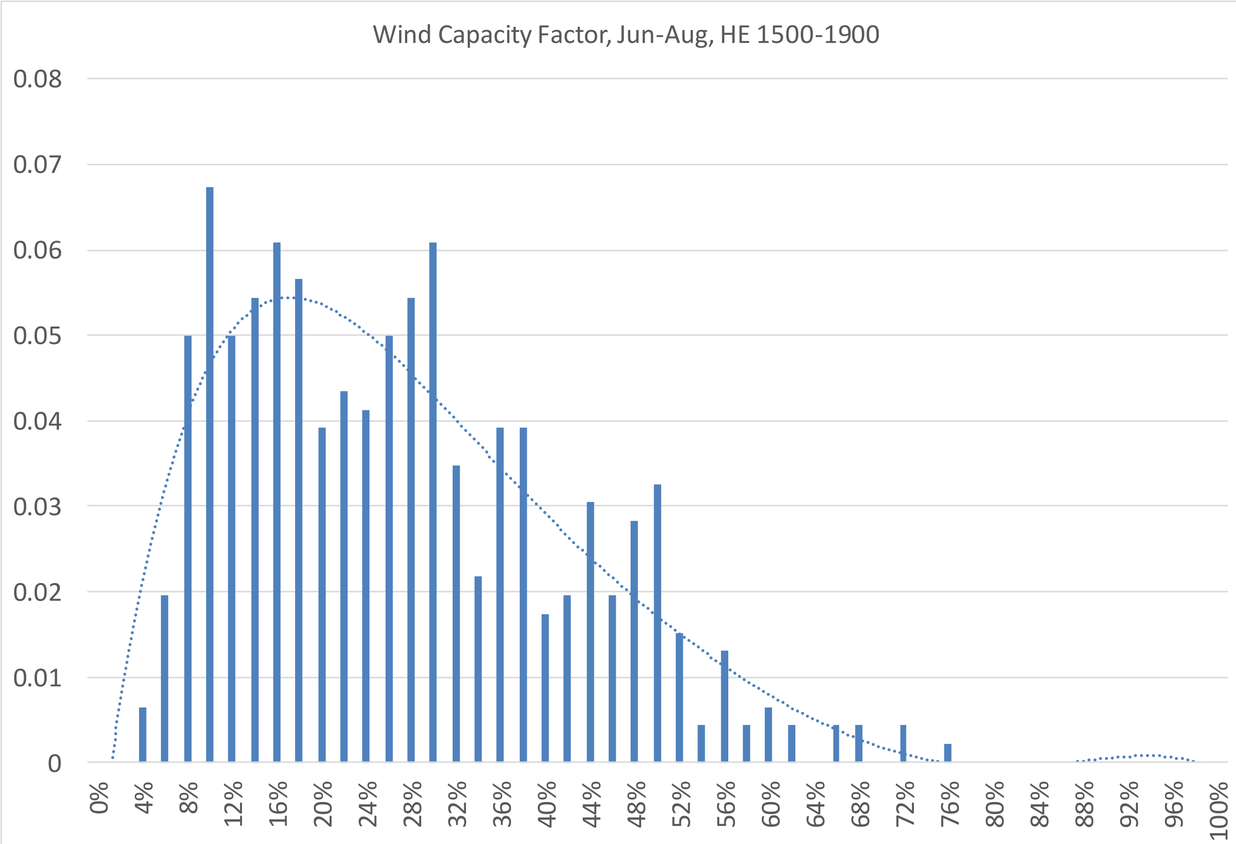


Figure 53 – 2017 Wind Capacity Factor for Summer Peak Hours

Wind facilities began voluntary reporting in WindGADS in 2017. Wind facilities greater than 200 MW will begin mandatory reporting in WindGADS in 2018. WindGADS 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 2017, 13 ERCOT wind facilities submitted a total of 53 unit-months of data in WindGADS. A summary of key performance metrics based on resource versus equipment values for the ERCOT wind generators for 2017 is provided in the following table.

Metric	Texas RE Region GADS Data 2017	
	Resource	Equipment
Net Capacity Factor (PRNCF and PENCF)	28.8%	29.8%
Equivalent Forced Outage Rate (PREFOR and PEEFOR)	7.5%	4.4%
Equivalent Scheduled Outage Rate (RESOR and PEESOR)	2.7%	2.6%
Equivalent Availability Factor (REAF and PEEAF)	90.3%	92.5%

Table 17 – ERCOT Wind Generation Performance Metrics, 2017 (Partial)

- 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): % of time the plant was available.
- Pooled Resource Net Capacity Factor (PRNCF): % of actual plant generation.
- 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): % of actual WTG equipment generation while on line.
- Pooled Equipment Equivalent Availability Factor (PEEAF): % of time the WTG equipment was available.

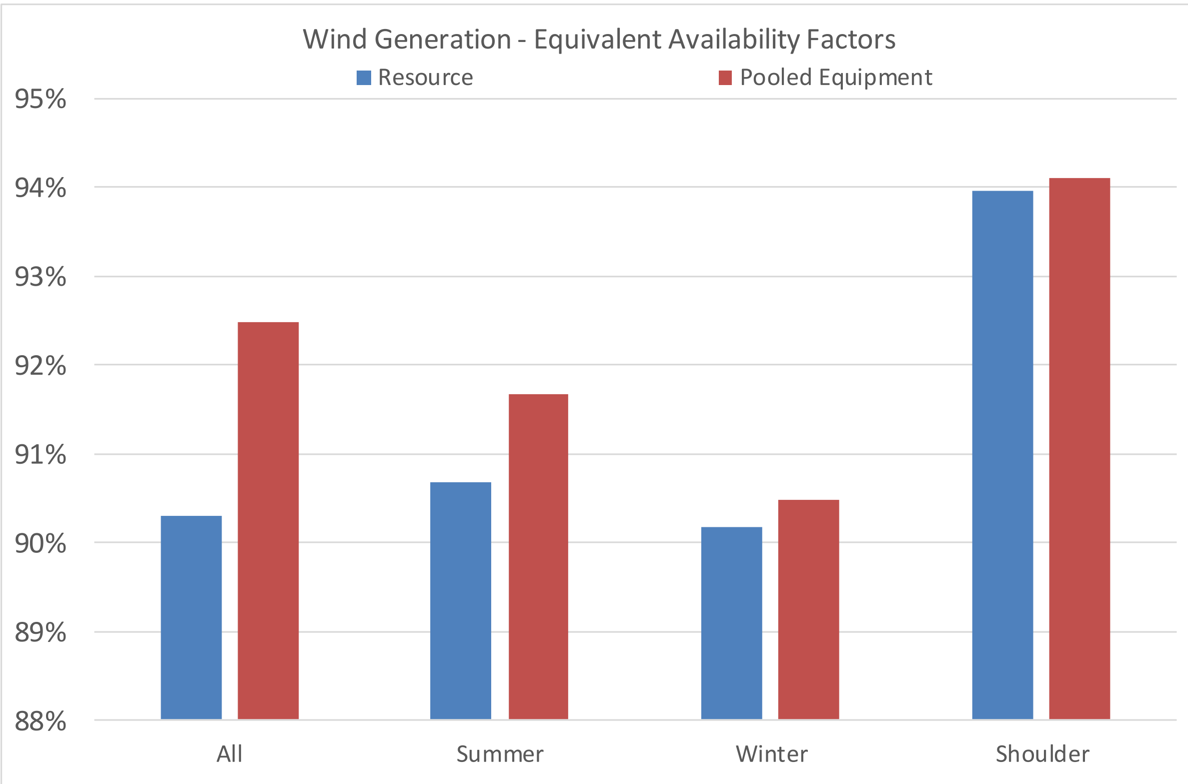


Figure 54 – 2017 WindGADS Equivalent Availability Factors

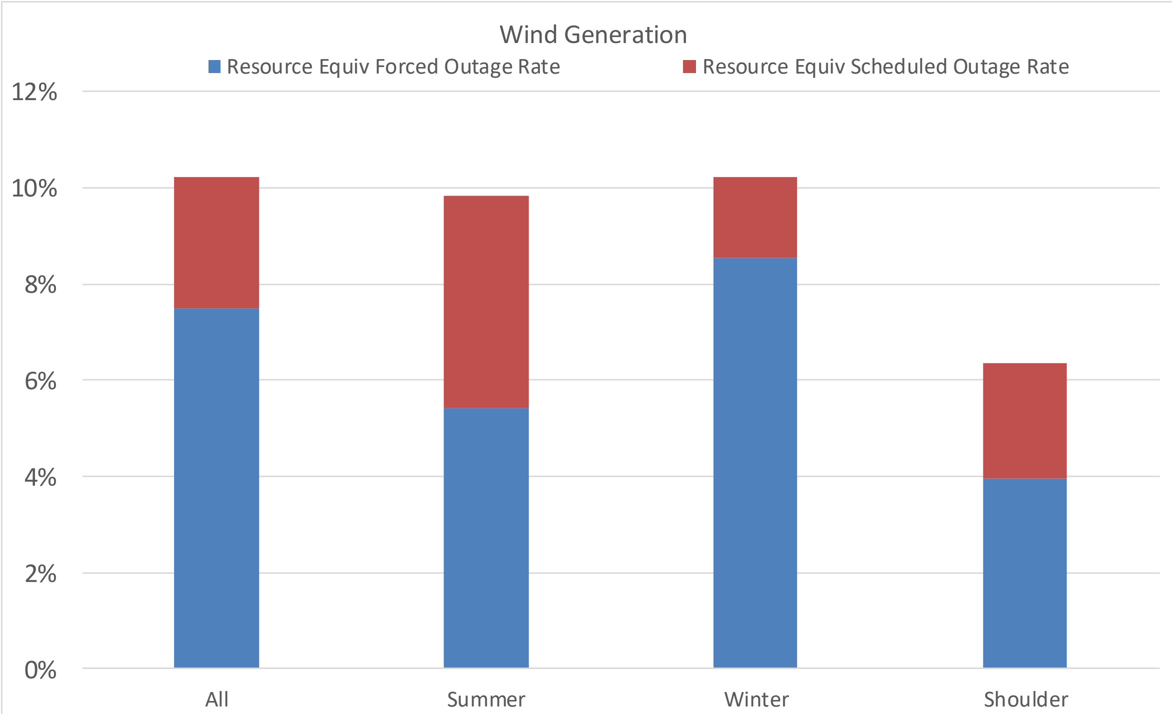


Figure 55 – 2017 WindGADS Equivalent Outage Rates

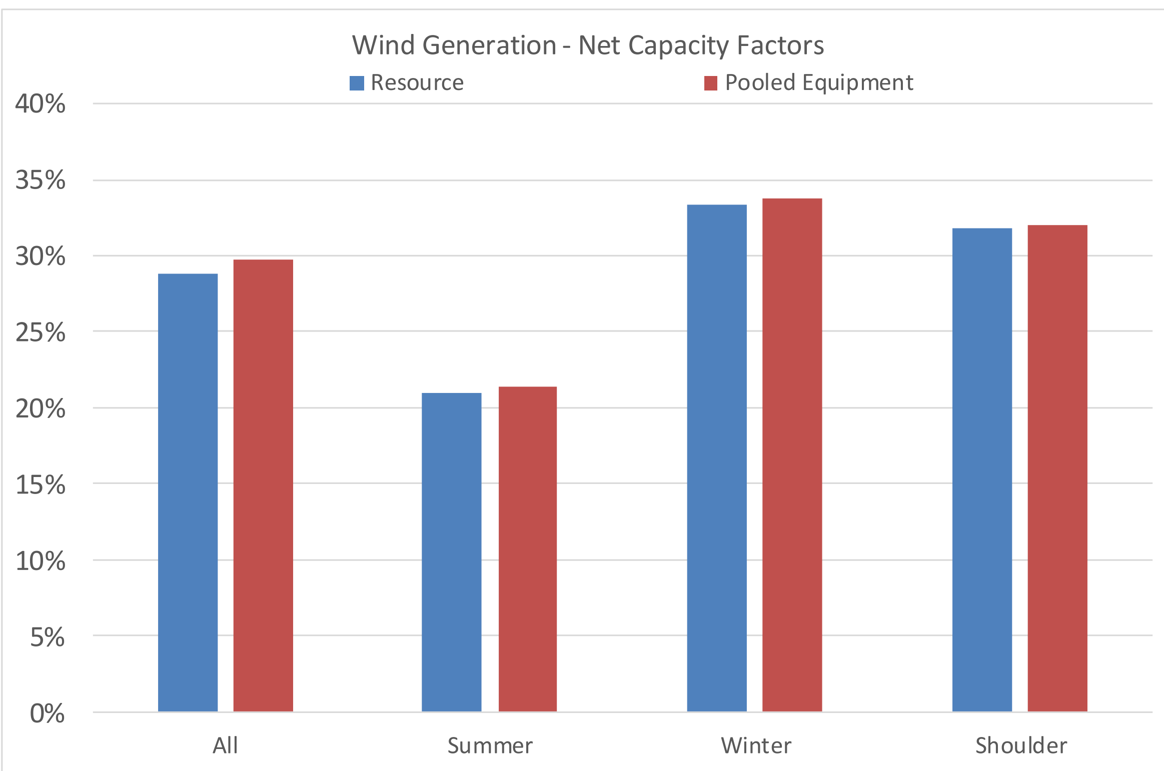


Figure 56 – 2017 WindGADS Net Capacity Factors

Utility-scale solar generation within the region nearly doubled during 2017, from 560 MW in January 2017 to almost 1,000 MW by December. The amount of energy provided by solar generation increased by 185% versus 2016. The following graphs show the historical trends for solar generation growth in the region. The blue bars represent the solar generation for the month and the black line represents the 12-month moving average.

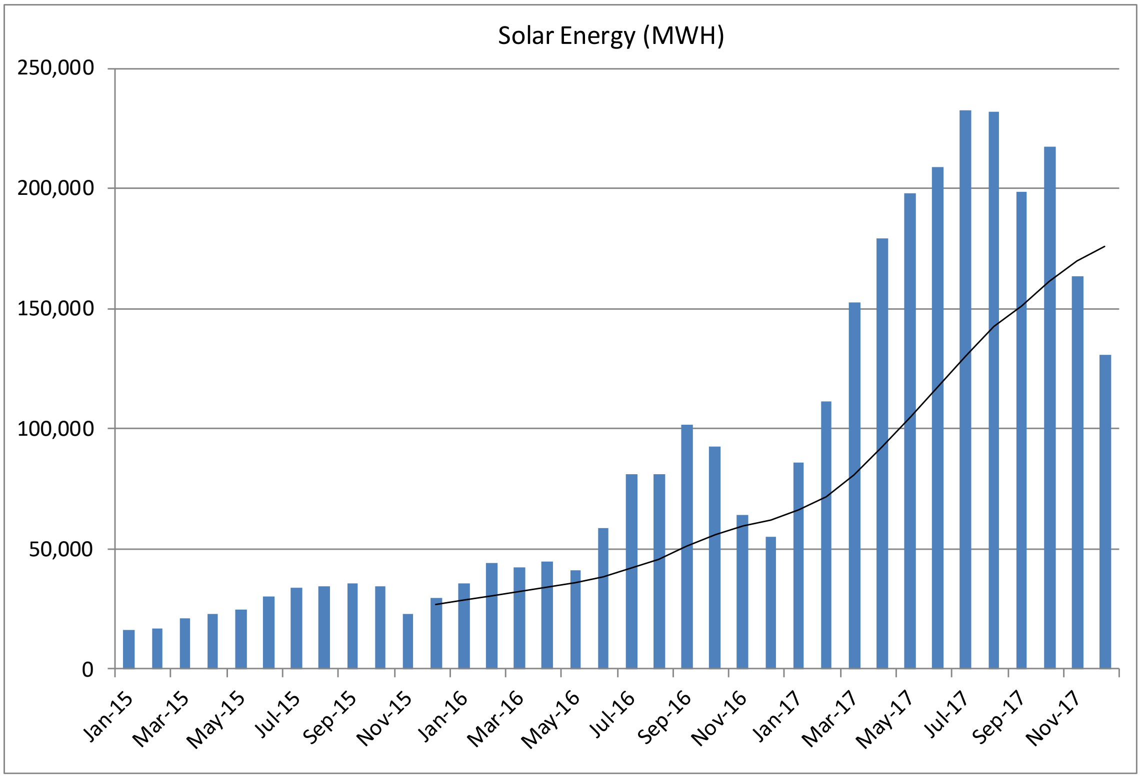


Figure 57 – 2015-2017 Solar Generation MWH

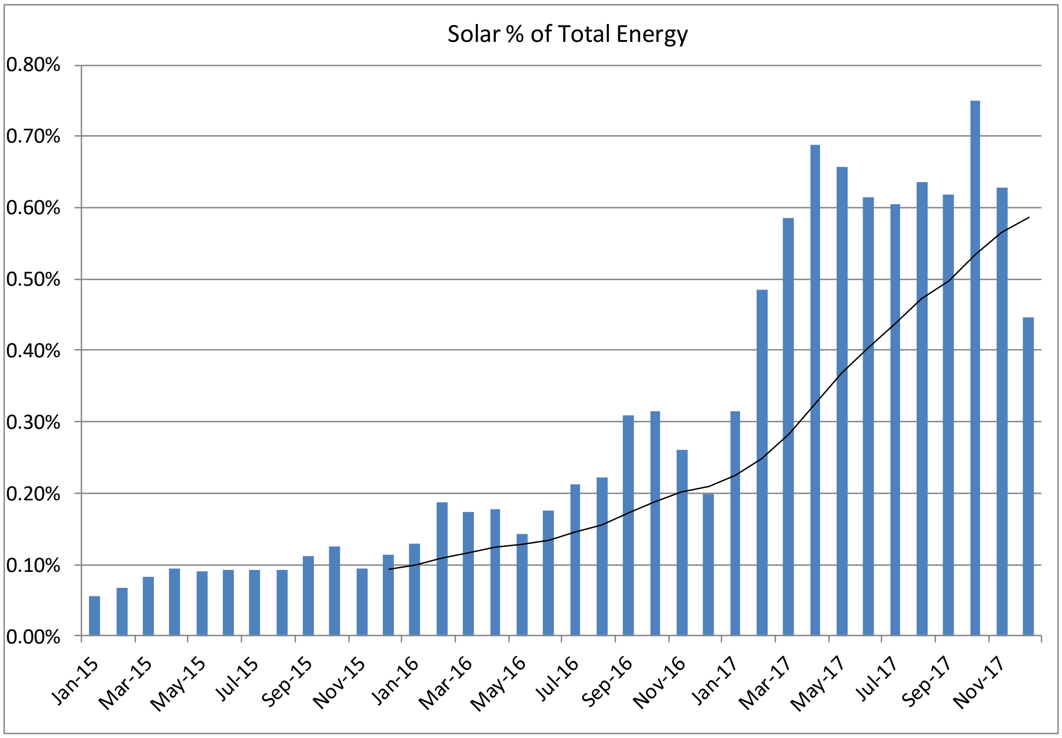


Figure 58 – 2015-2017 Solar Generation as a Percentage of ERCOT Total Energy

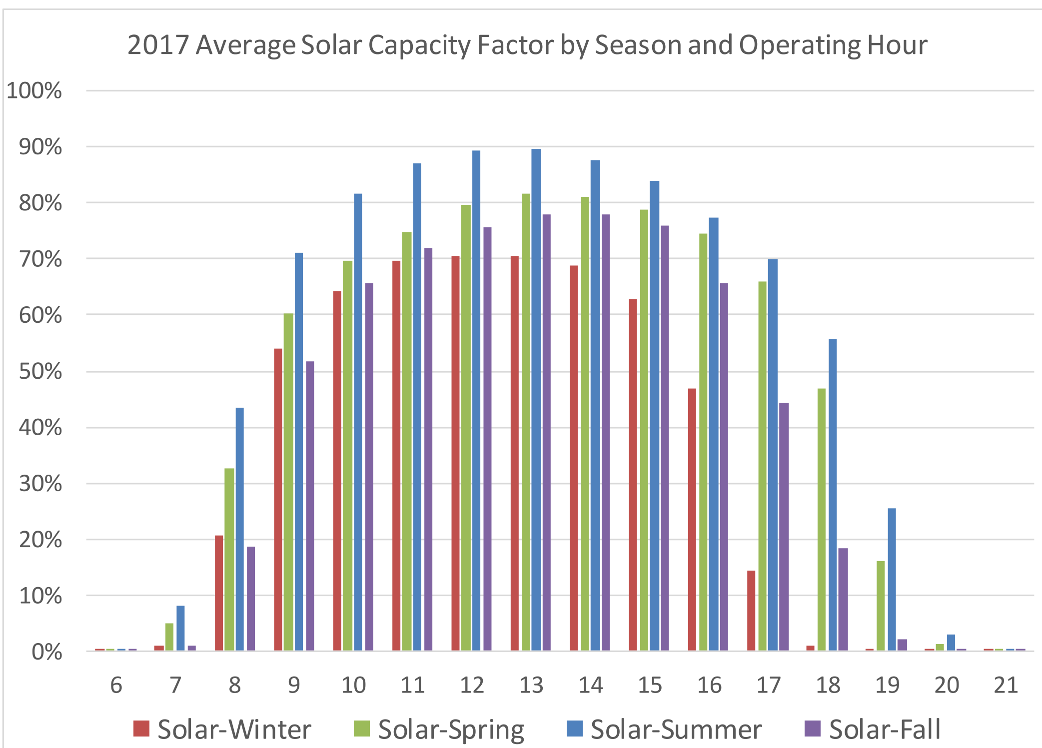


Figure 59 – 2017 Solar Capacity Factor by Season and Operating Hour

VI. Load and Demand Response

Introduction

2017 Load and Demand Response in Brief

Summer hourly Peak Demand: 69,531
Winter hourly Peak Demand: 59,661
Total Energy GWH: 357,370
Load Resource Deployments: 0
Demand Response Deployments: 96

Demand Response (DR) is one of many resources needed to manage the increasing demand for electricity and lack of resource adequacy. In addition to providing capacity for resource adequacy purposes, capacity and ancillary services provided by DR help to ensure resource adequacy while providing operators with additional flexibility in maintaining operating reliability.

The NERC DADS collects DR enrollment and event information to measure its actual performance, including its contribution to improved reliability. Ultimately, this analysis can provide industry with a basis for projecting contributions of dispatchable and non-dispatchable DR to support forecast adequacy and operational reliability.

Observations

- Summer hourly peak demand: 69,531 MW on July 28, 2017 at HE 17:00
- Winter 2017 hourly peak demand: 59,661 MW on January 6, 2017 at HE 19:00
- Demand response deployments in 2017: 96

Historical Data and Trends

Total energy consumption increased by 1.7% in 2017 versus 2016, to over 357,370 GHW. Peak demand declined in 2017 to 69,531 MW, compared to the all-time record of 71,193 MW reached on August 11, 2016. Areas with load growth continue to be led by the Houston, South and West load zones (Coast, Far West, and South weather zones).

The long-term average increase in total energy consumption is approximately 1.7% per year since 2008.

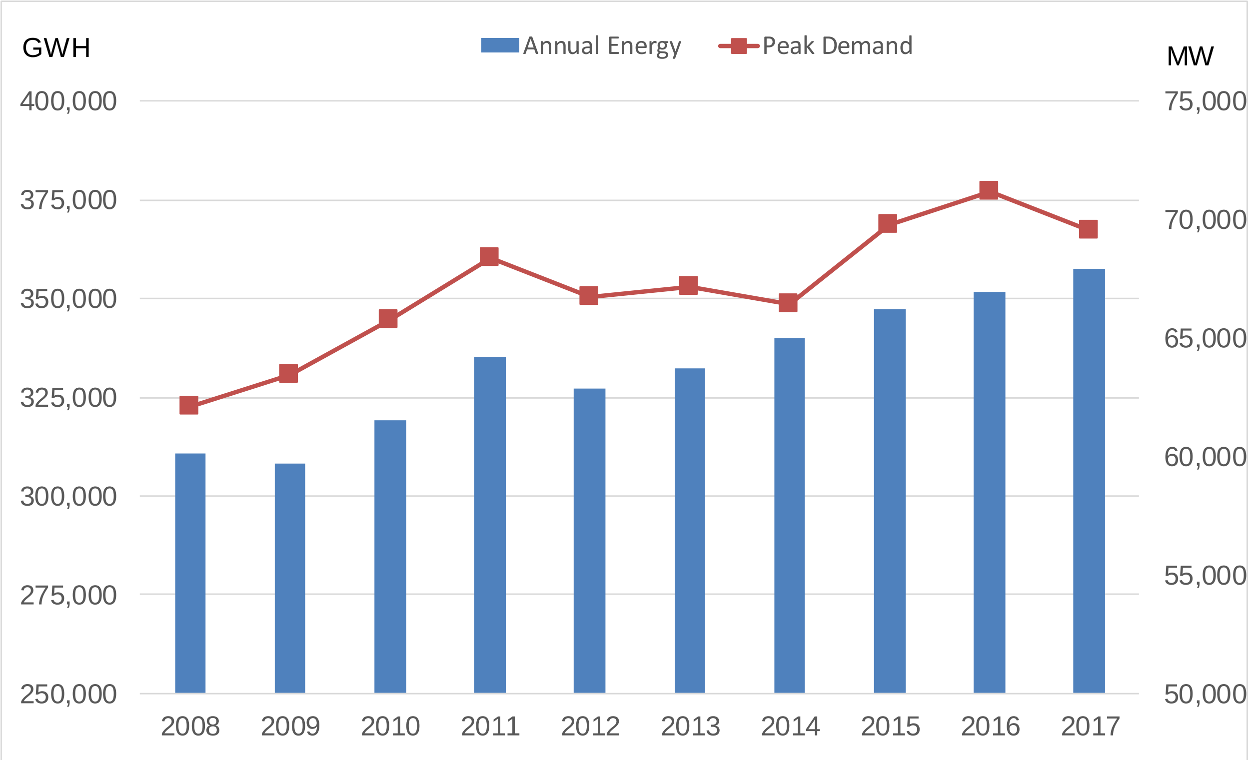


Figure 60 – Annual Energy and Peak Demand

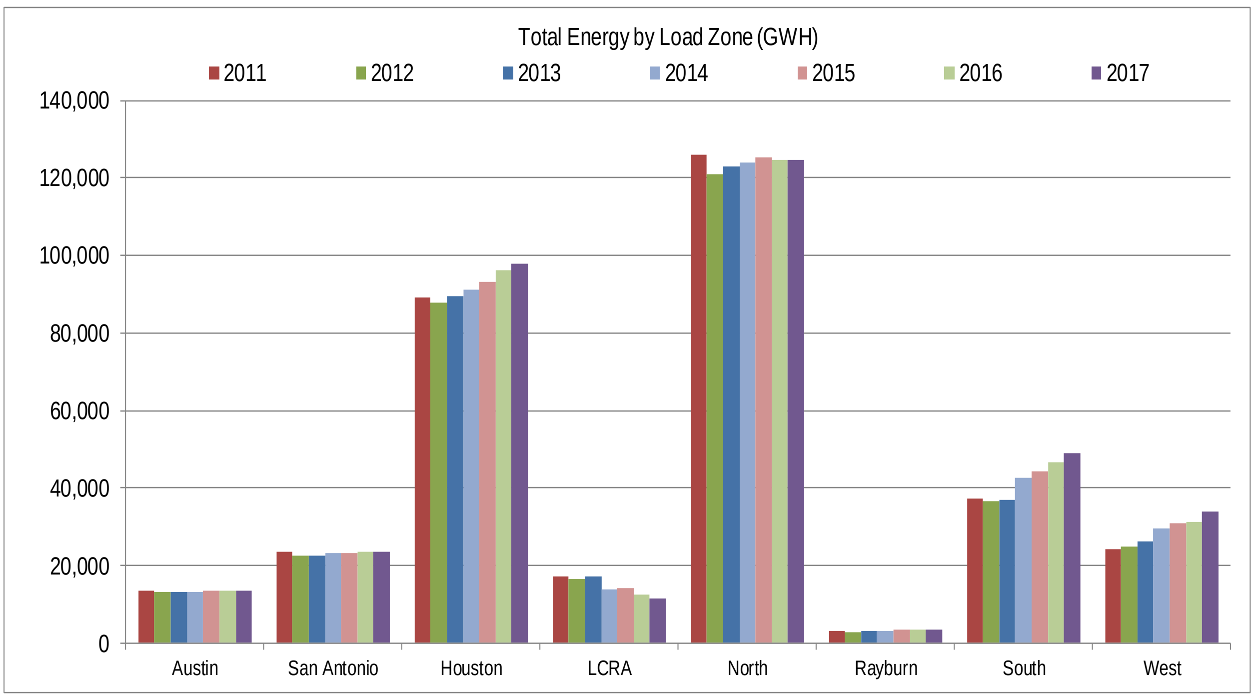


Figure 61 – Energy by Load Zone

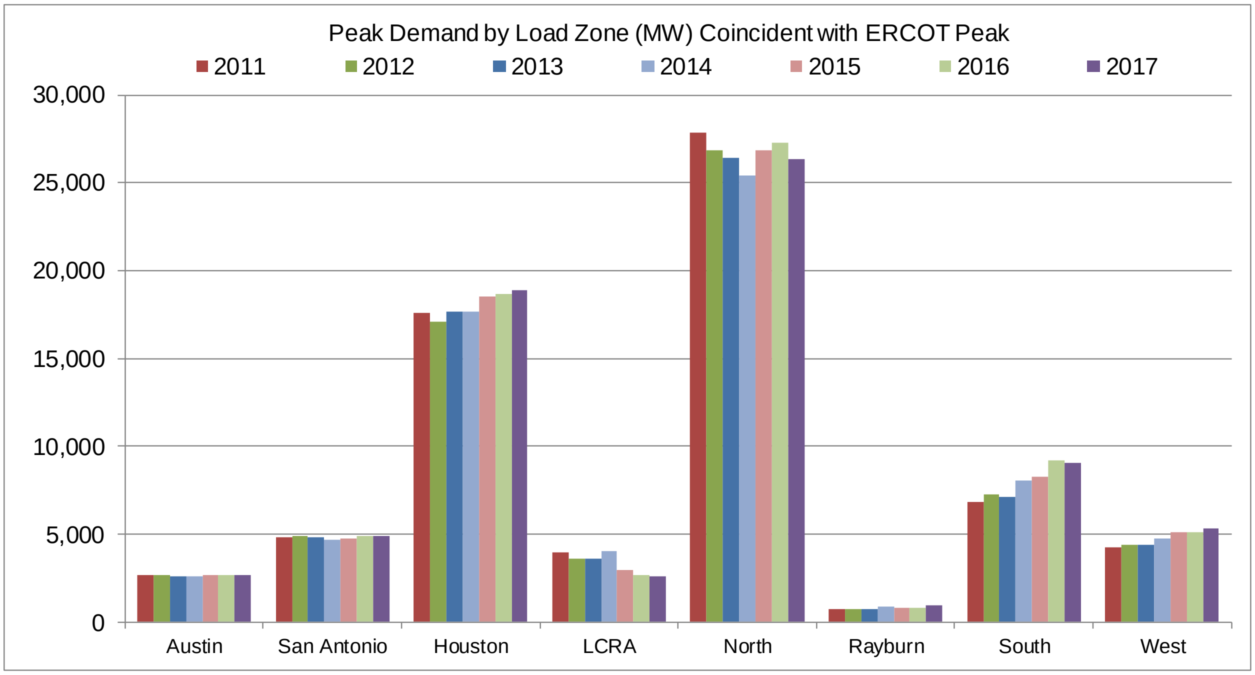


Figure 62 – Peak Demand by Load Zone

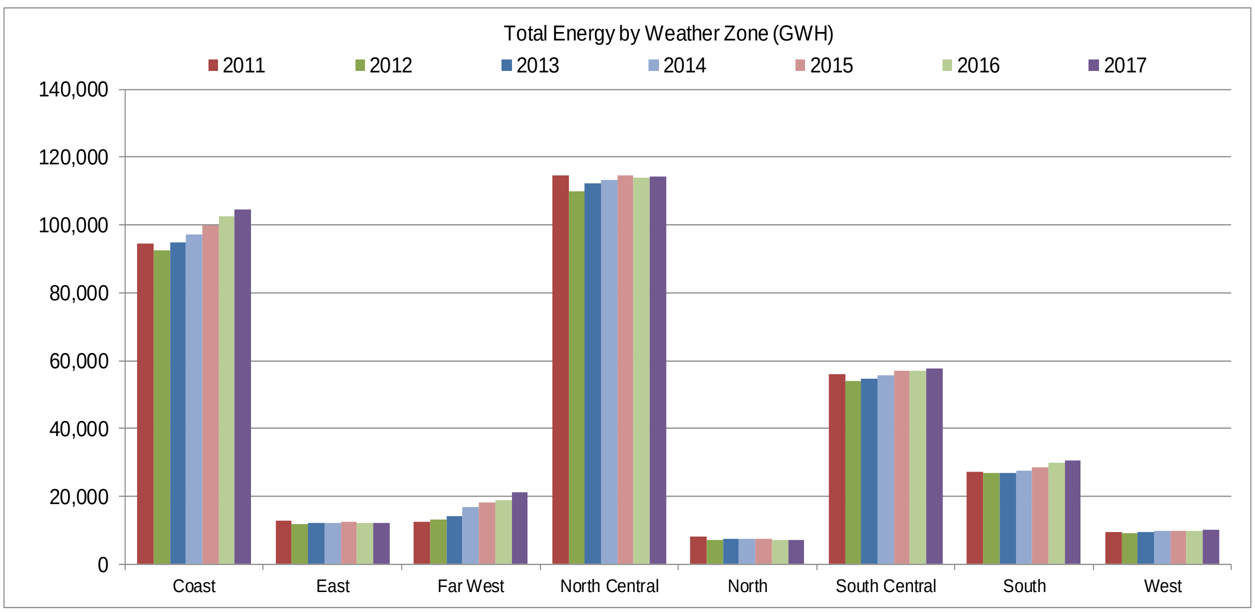


Figure 63 – Energy by Weather Zone

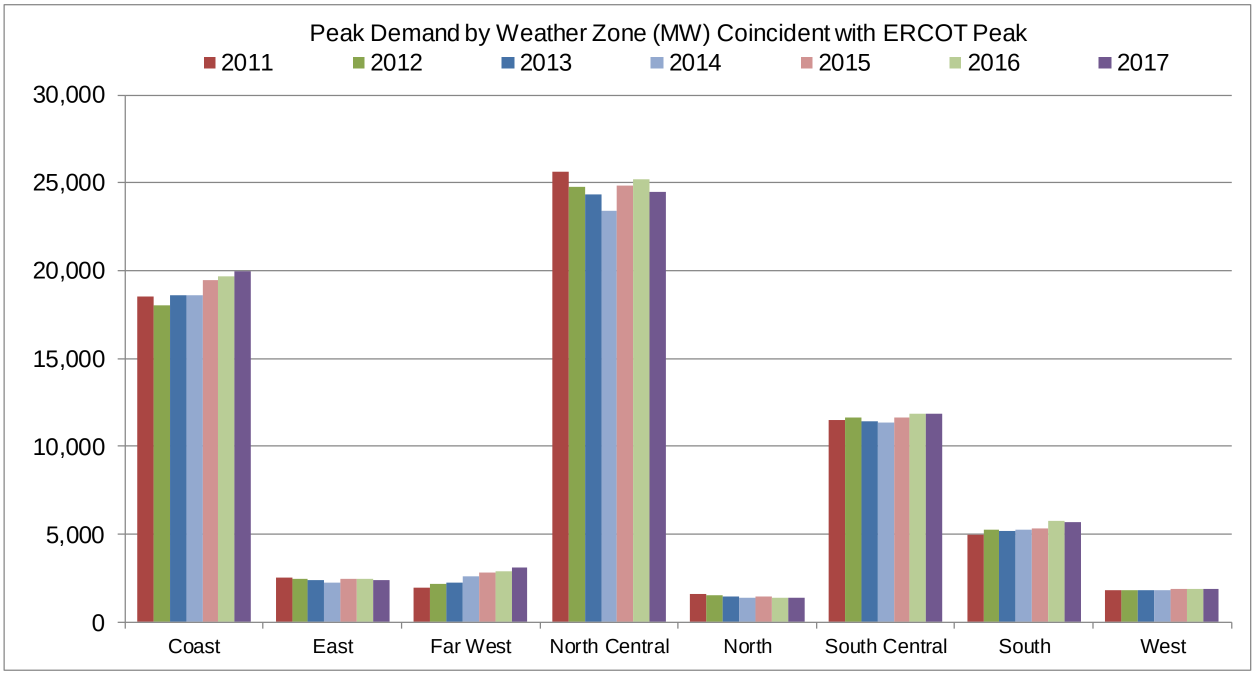


Figure 64 – Peak Demand by Weather Zone

Three types of demand response are employed in the Texas RE 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.
2. 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. Two types of ERS are procured, ERS-10 (ERS with a 10 minute ramp period) and ERS-30 (ERS with a 30 minute ramp period).
3. Demand response that 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.

The following chart shows the registered capacity and average hourly committed capacity for demand response since April 2014.

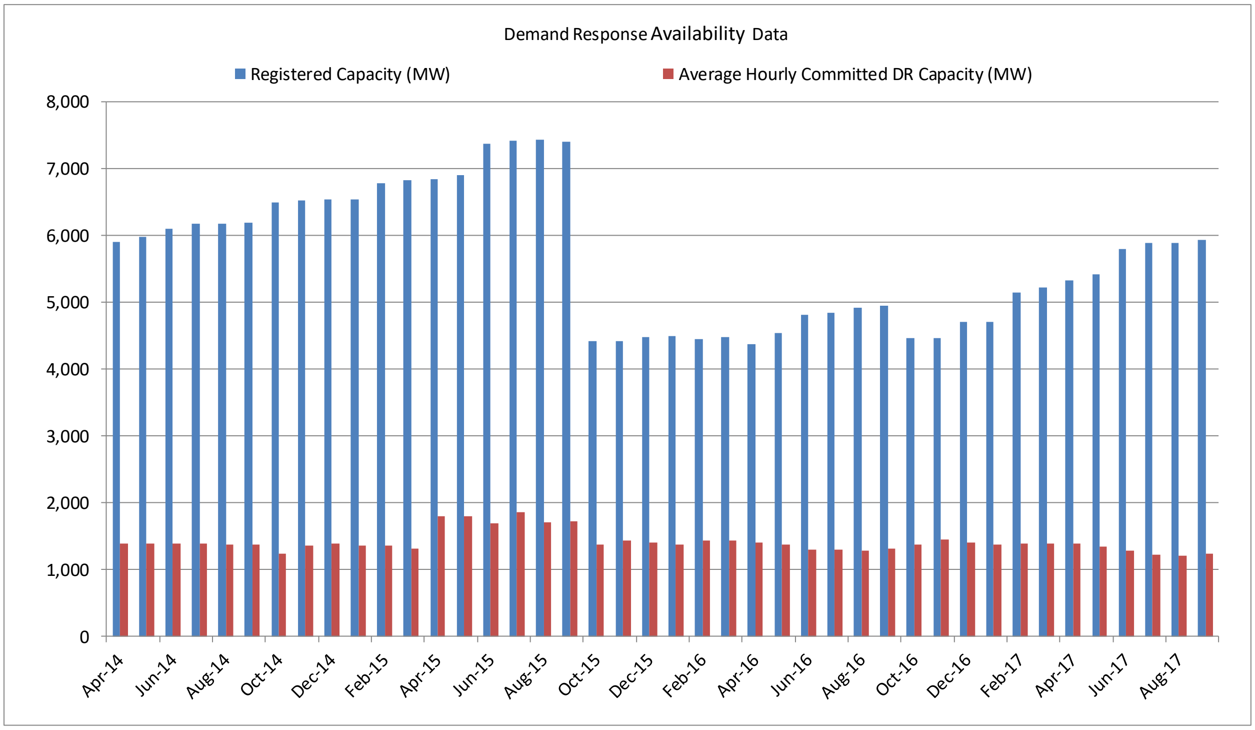
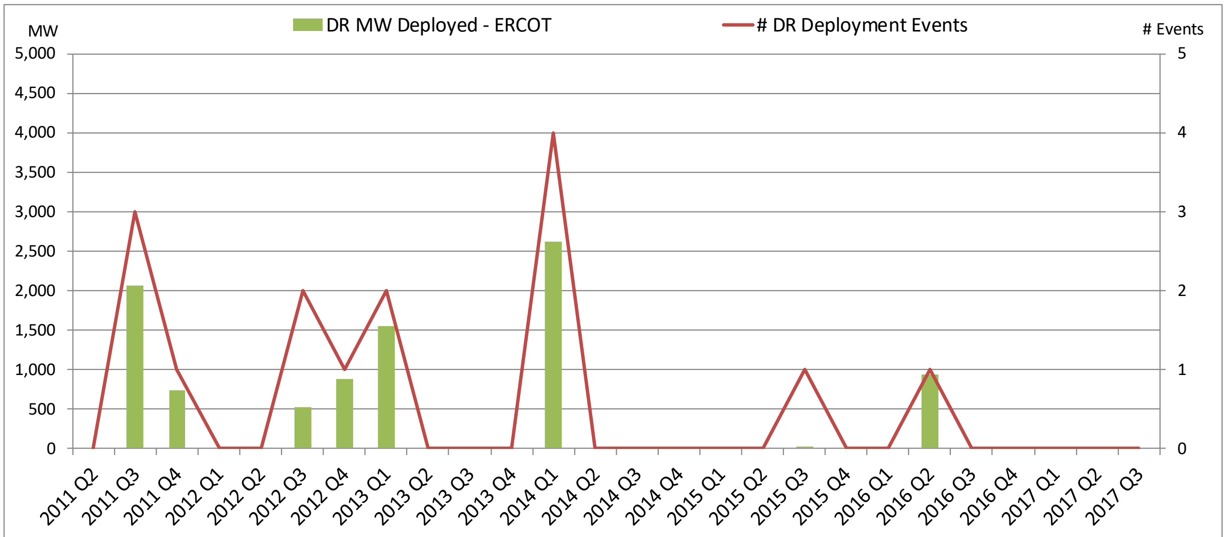


Figure 65 – Demand Response Registered and Committed Capacity

There were no Load Resource or ERS deployments in 2017. Reference Appendix E for additional historical information on Load Resource and ERS deployments.

The DR MW Deployed-ERCOT represents Load Resource and ERS deployments by ERCOT. The DR MW Deployed-Other represents demand response deployed by NOIEs for economic purposes.



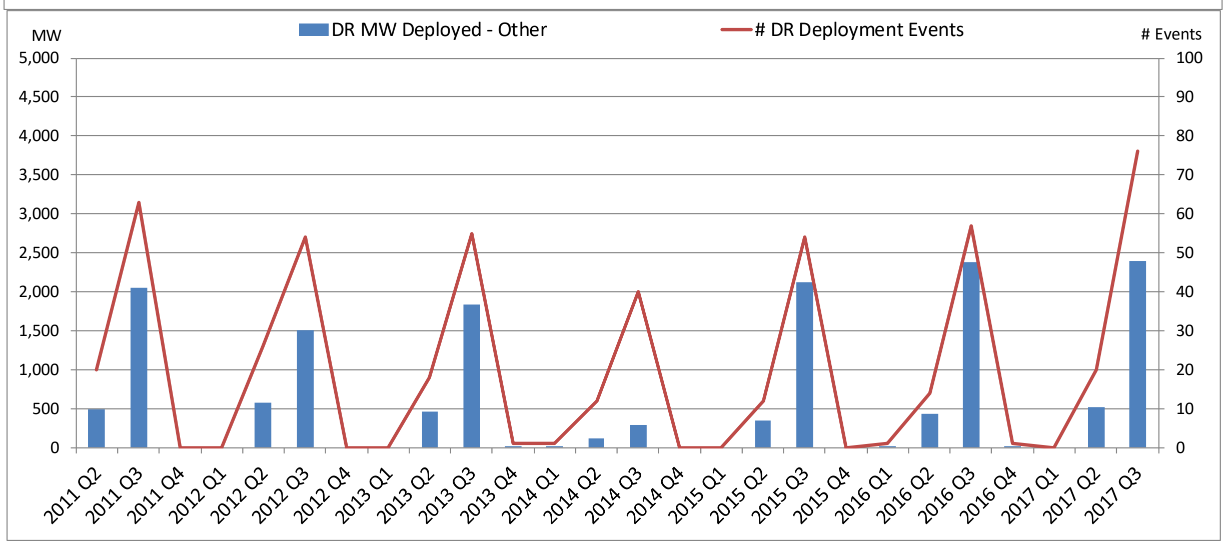


Figure 66 – Texas RE Region Demand Response Availability and Deployments

From May-September 2017, there were a total 96 deployments of DR by NOIEs, or an average of 36.2 MW dispatched per deployment. The average response rate was 84% based on the MW reduction divided by the MW dispatched, or 30.4 MW per deployment.

Month	# of Events	Sum of MW Dispatched	Sum of Realized MW	Average Event Duration (Hours)	Response Rate Based on Maximum Hour of Response
May	2	31.3	12.7	0.5	41%
June	18	619.6	505.9	1.7	89%
July	26	981.9	887.8	1.9	83%
August	22	807.5	680.2	1.7	84%
September	28	1031.5	828.2	2.0	75%
Total	**96**	**3471.8**	**2914.9**	**1.5**	**84%**

Table 18 – Demand Response Deployments by Non-Opt-In Entities for 2017

VII. Frequency Control and Primary Frequency Response

Introduction

The ERCOT Performance, Disturbance, Compliance Working Group (PDCWG) is responsible for reviewing, analyzing, and evaluating the frequency control performance of the Texas RE Region. On a monthly basis, the group reviews various metrics and trends, and makes recommendations as needed for improvements to ERCOT's frequency control process.

2017 Frequency Control in Brief

Annual CPS-1: 174.9
BAAL exceedances: 18 clock-minutes
Frequency Response: 759 MW/0.1 Hz
Average recovery time: 5.7 minutes

Observations

- CPS1: 174.9 for calendar year 2017 versus 176.6 for calendar year 2016
- Balancing Authority ACE Limit (BAAL) exceedances: 18 clock-minutes for calendar year 2017 versus 26 clock-minutes for 2016
- Frequency Response: 759 MW/0.1 Hz versus NERC obligation of 381 MW/0.1 Hz
- Average recovery time from generation loss events: 5.7 minutes versus 5.3 minutes for calendar year 2016

Historical Data and Trends

A. CPS1 Performance

NERC Reliability Standard BAL-001-2 requires each BA to operate such that the 12-month rolling average of the clock-minute Area Control Error (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%. The following figure shows the Texas RE Region CPS1 trend since January 2008. Since the start of the Nodal Market in December 2010, the region has made steady improvement in the CPS1 trend. For 2017, the annualized CPS1 score was 174.9.

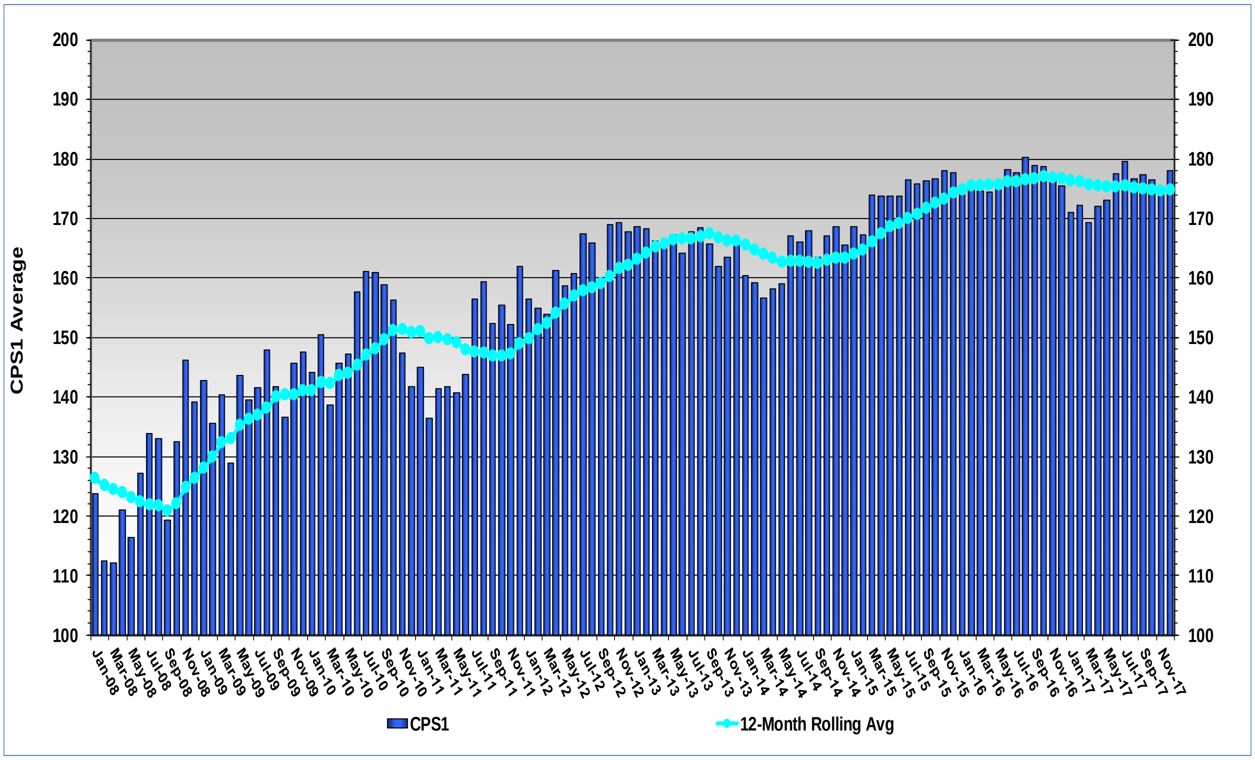


Figure 67 – CPS1 Average January 2008 to December 2017

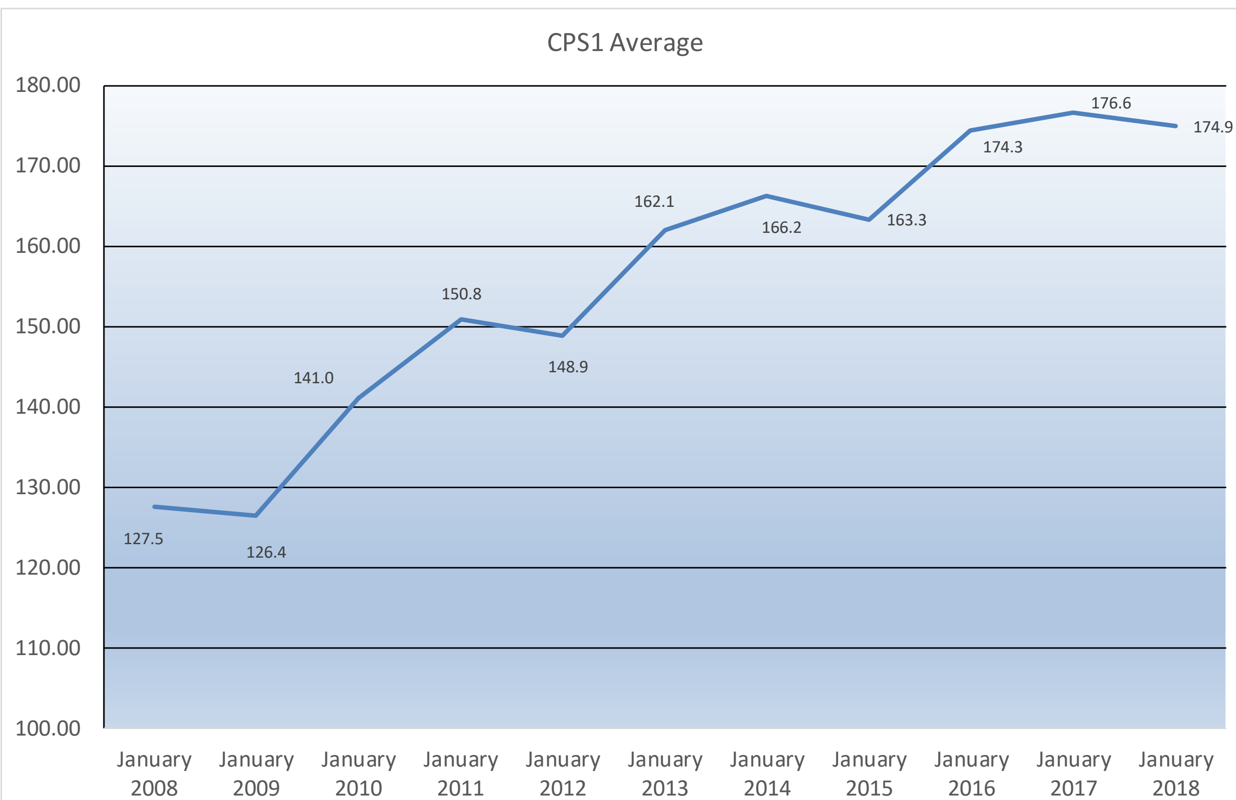


Figure 68 – ERCOT CPS1 Annual Trend since January 2008

As of October 2015, all generation units are required to set their governor deadbands at 0.017 Hz per Regional Standard BAL-001-TRE.

Figure 54 shows Bell curves of the ERCOT frequency profile, comparing 2011 through 2017. The shape of the Bell curve in 2017 continued the pattern started in 2015 due, in part, to the percentage of generation units that have reduced turbine governor deadband settings from 0.036 Hz to 0.017 Hz and the effect of governors on wind turbines providing primary frequency response for high frequency excursions.

The blue dashed lines on the chart 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 BAAL exceedances per NERC Standard BAL-001-2.

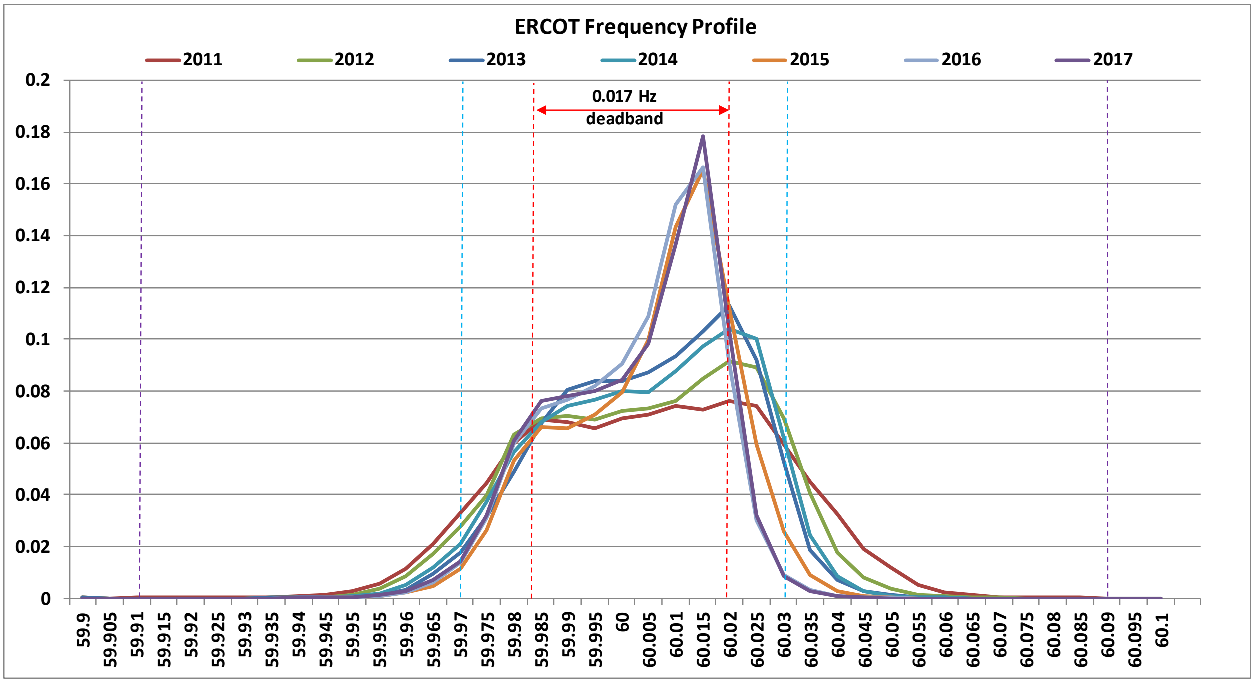


Figure 69 – Frequency Profile Comparison

The following figure shows the 2017 CPS1 scores by operating hour compared to 2015 and 2016.

The CPS1 score by operating hour continues to indicate possible issues for hour-ending (HE) 06:00, HE 07:00, and HE 23:00. These issues are related to the load ramps during these hours and procedures used by generation resource entities during unit startup and shutdown.

The daily RMS1 chart 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.

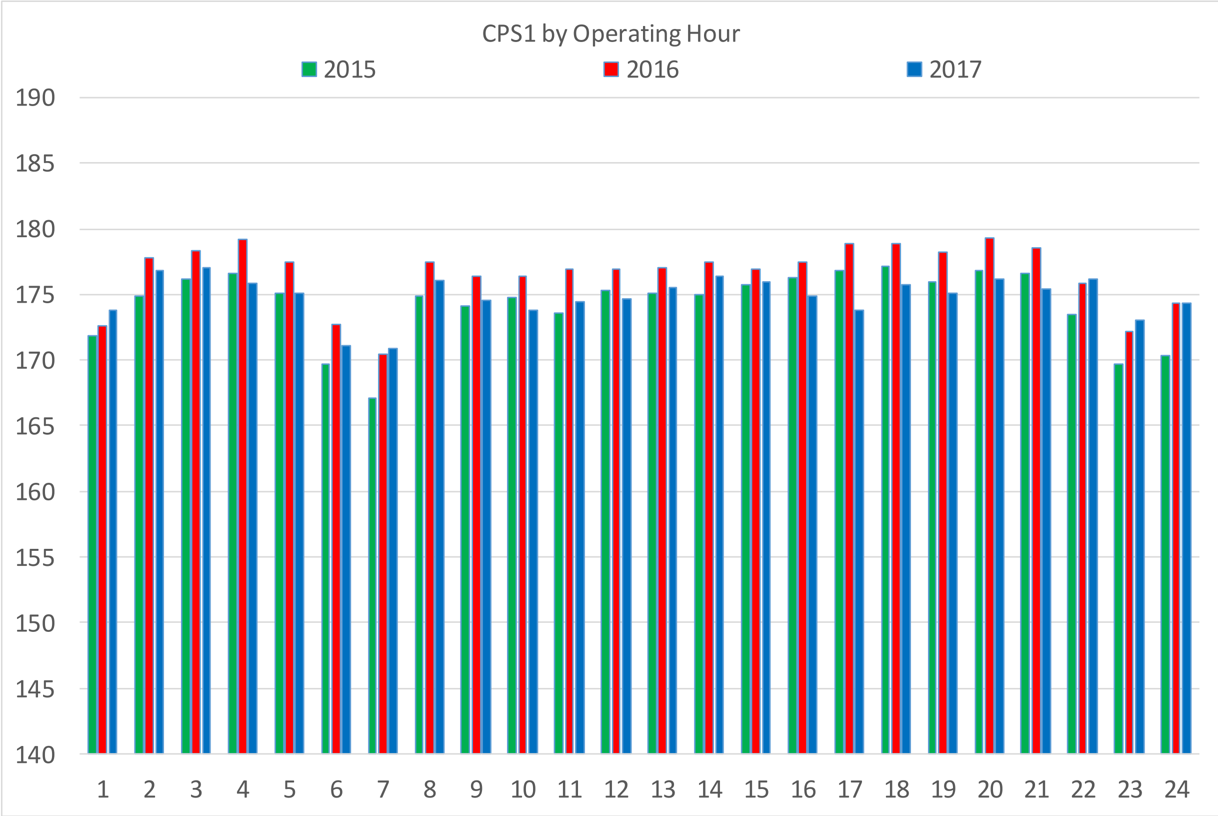


Figure 70 – CPS1 Score by Operating Hour for 2015 through 2017

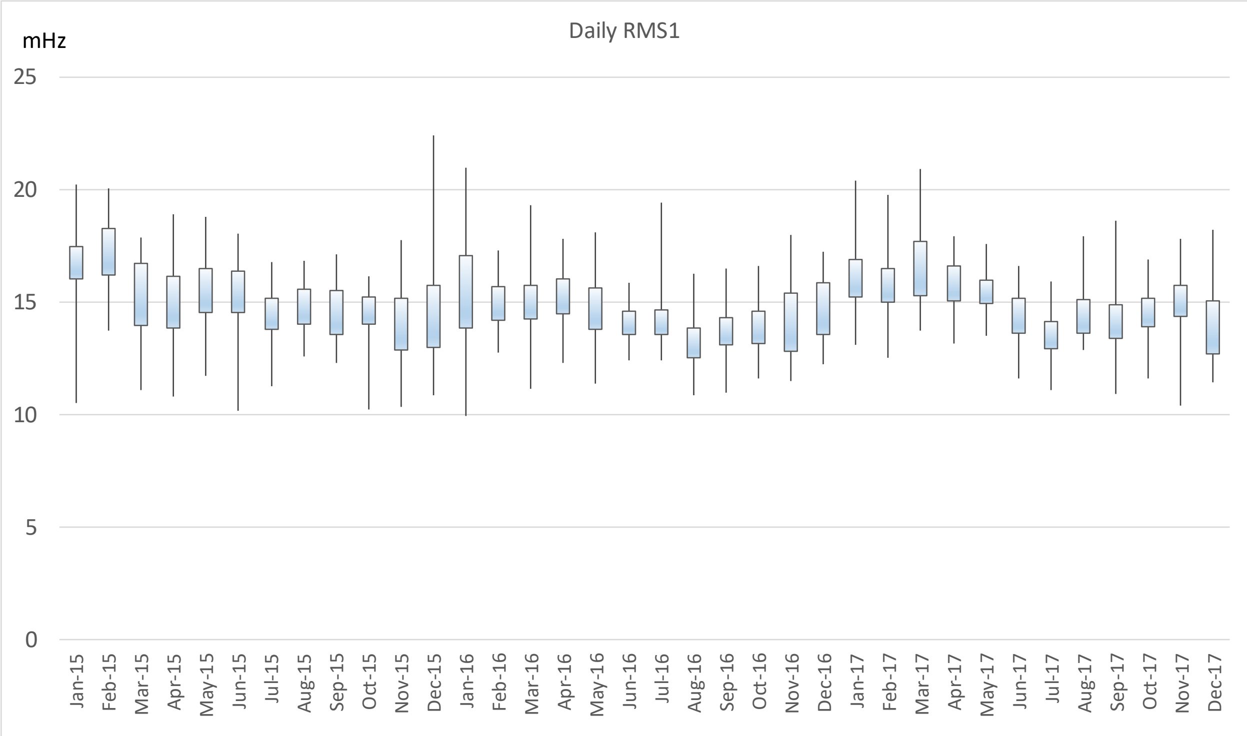


Figure 71 – Daily RMS1 for 2015 through 2017

B. Time Error Correction Performance

In 2017, there were no Time Error Corrections. In December 2016, ERCOT added an Area Control Error (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 Balancing Authority ACE Limit 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 Texas RE Region. The FTL-High value is calculated as 60 Hz + 3 x Epsilon-1 (ε1) value, or 60.090 Hz for the Texas RE 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.

High/Low Frequency	2012 Total Minutes	2013 Total Minutes	2014 Total Minutes	2015 Total Minutes	2016 Total Minutes	2017 Total Minutes
Low (<59.91 Hz)	131	82	63	13	26	18
High (>60.09 Hz)	26	9	7	1	0	0

Table 19 – Frequency Trigger Limit Performance

D. 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. The following figure shows a typical frequency disturbance, broken down into several periods.

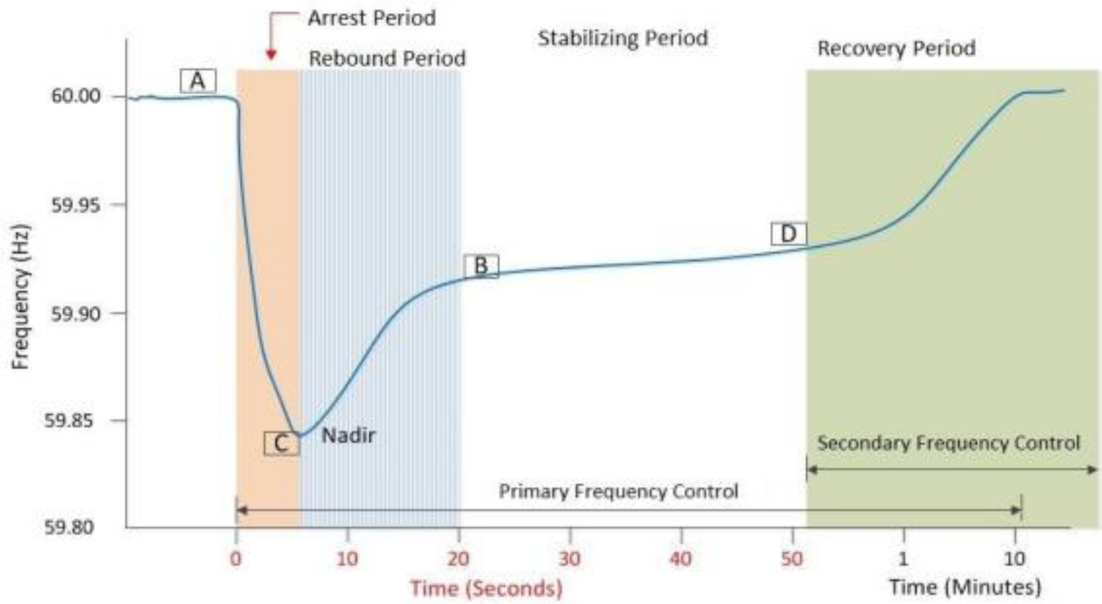


Figure 72 – Typical Frequency Disturbance

Each of the periods of the frequency disturbance is analyzed by different metrics and performance indicators.

Period	Time Frame	Reliability Requirement	Metric(s)
Arrest Period	T0 to T+5 seconds	Arrest C-point at or above 59.3 Hz for loss of 2,750 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 (381 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 20 – Frequency Event Requirements and Metrics

The RoCoF during the initial frequency decline is largely driven by system inertia. The Nadir, or C-Point, is an indicator of the system imbalance created by the unit trip and is combination of inertial response and governor response. It can be measured by the size of the unit trip in proportion to the system load at the time of the event.

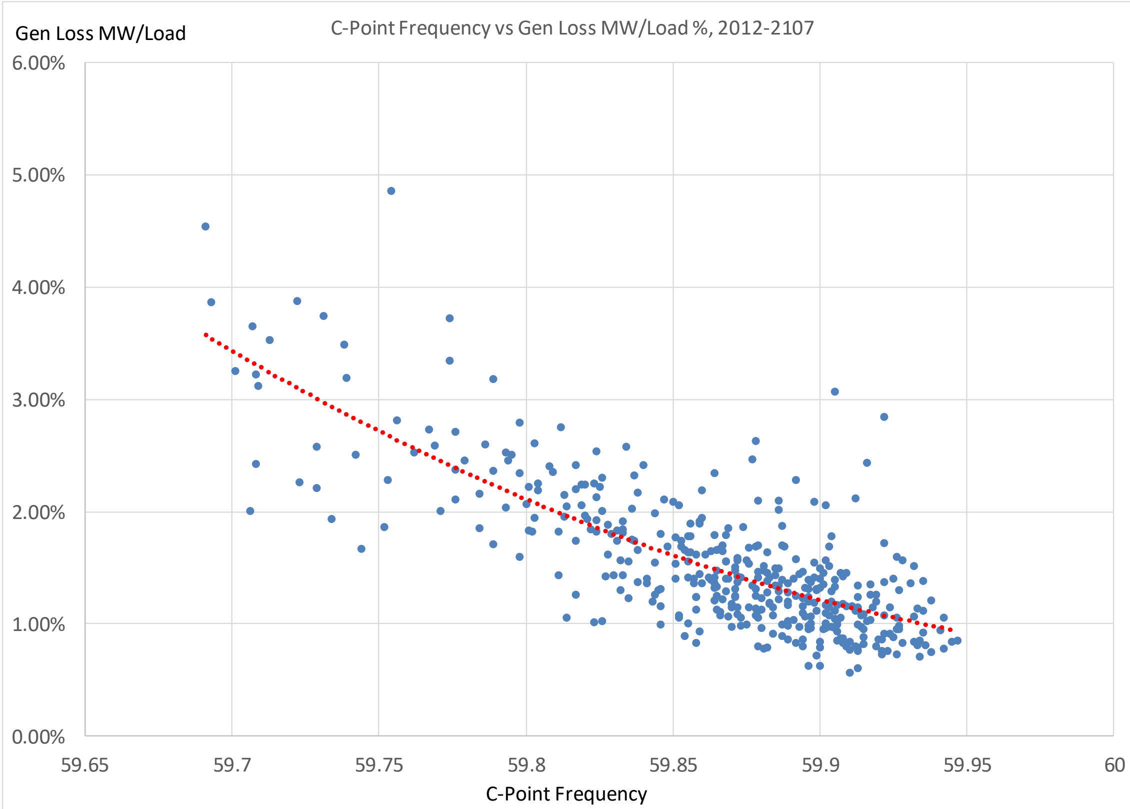


Figure 73 – Frequency Disturbance Nadir vs. Gen Lost MW/System Load

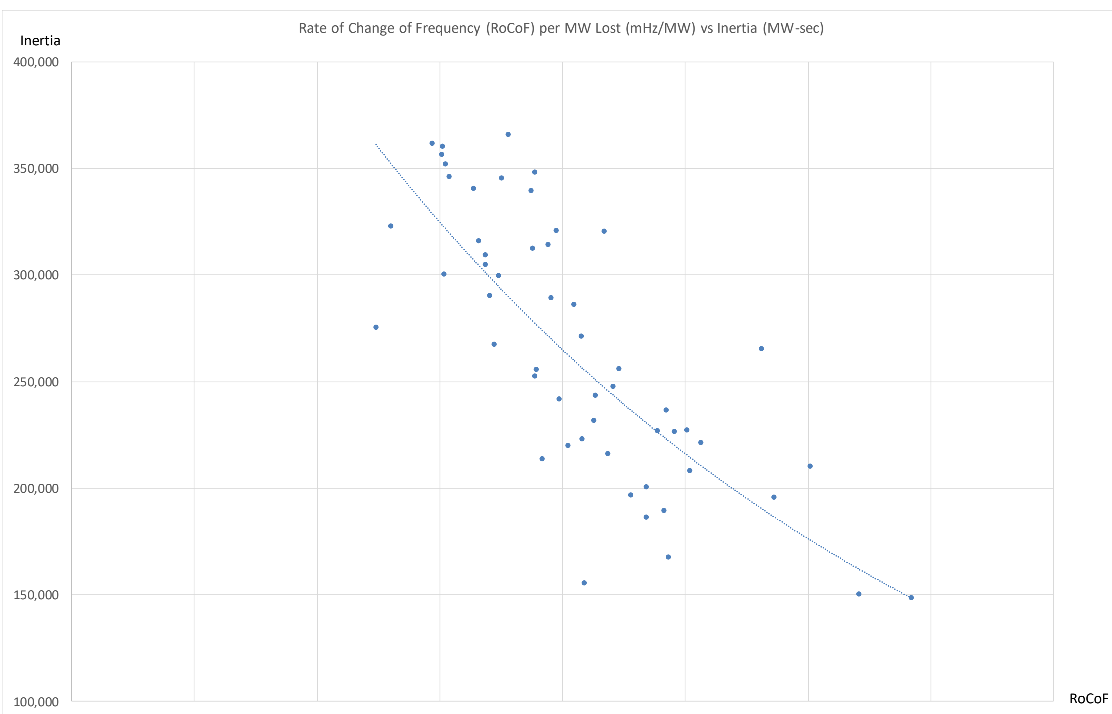


Figure 74 – Rate of Change of Frequency vs. Inertia

Similar to the RoCoF, the time between the start of the frequency disturbance (To) and the Nadir point (Tc) is also an indicator of system inertia. The following figure shows this metric for 2015-2017. The average time shows a decline over the period, indicating the average system inertia is decreasing.

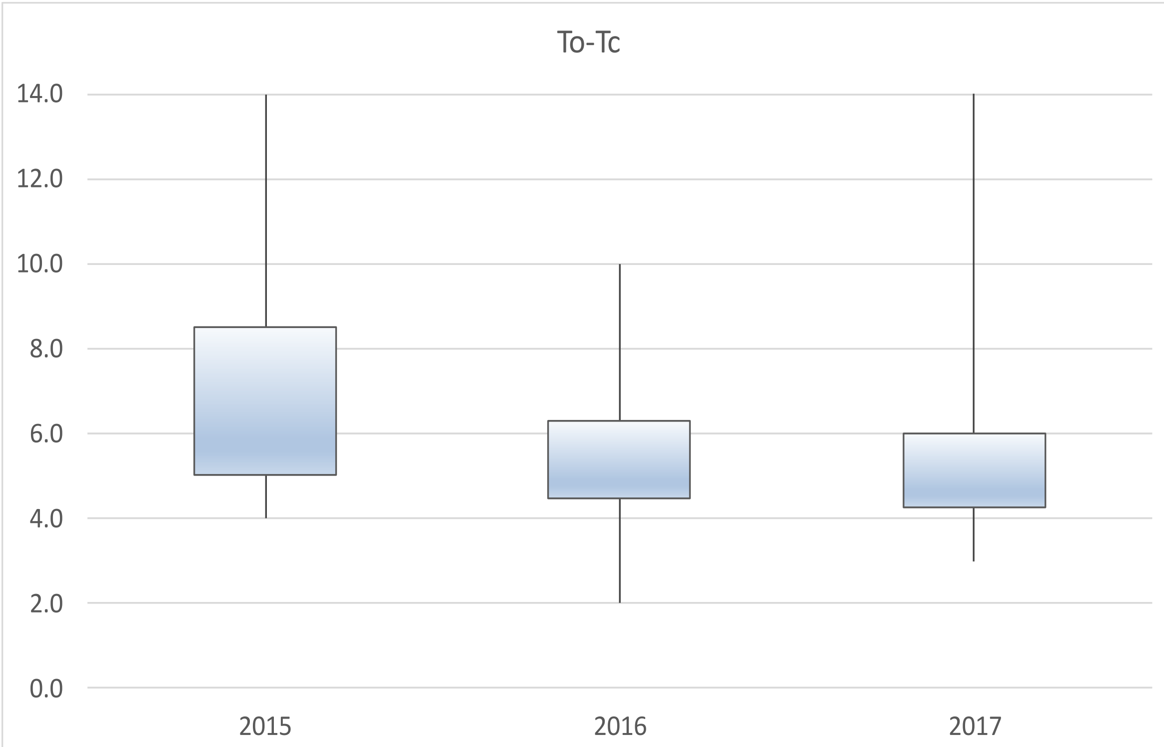


Figure 75 – Time between To (Start of Frequency Disturbance) to Nadir

The following figure shows the trend in primary frequency response for the Texas RE Region. In 2017, the average frequency response was 844 MW per 0.1 Hz and the median frequency response was 759 MW per 0.1 Hz as calculated per NERC Standard BAL-003 for the 37 events that were evaluated during the period. The following graphs show the annualized primary frequency response trend per NERC Reliability Standard BAL-003 and the detailed frequency response data since 2010 for the region.

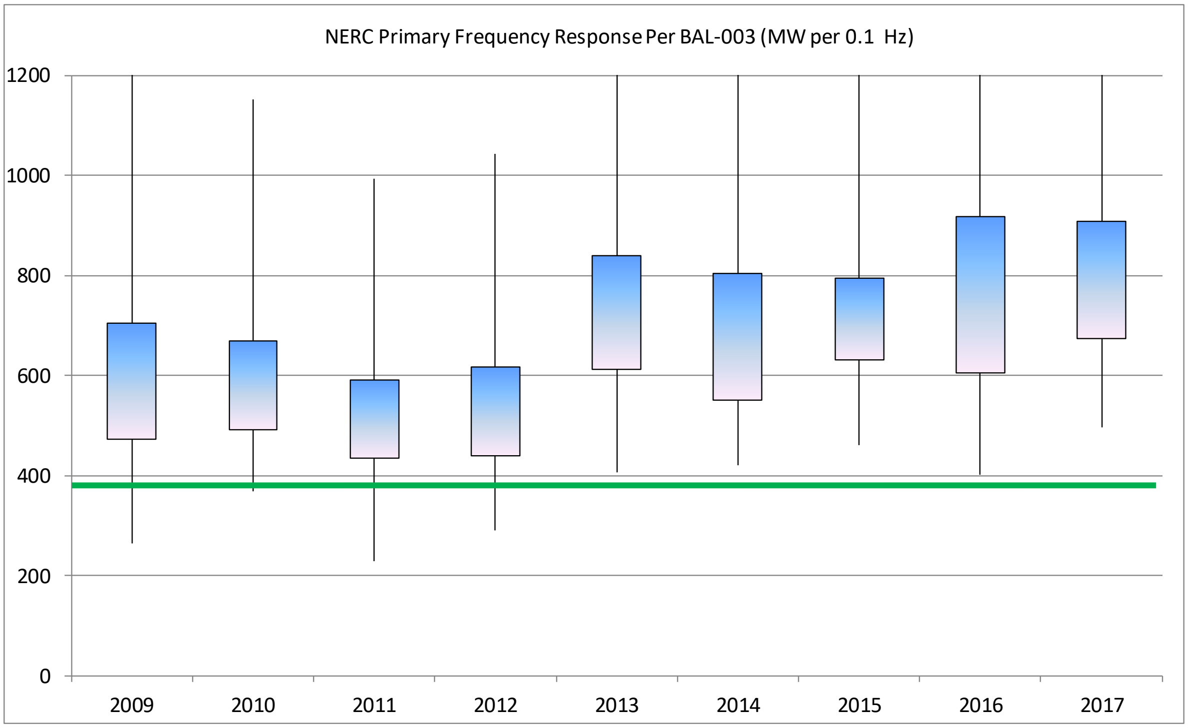


Figure 76 – Annual Primary Frequency Response Trend for Texas RE Region

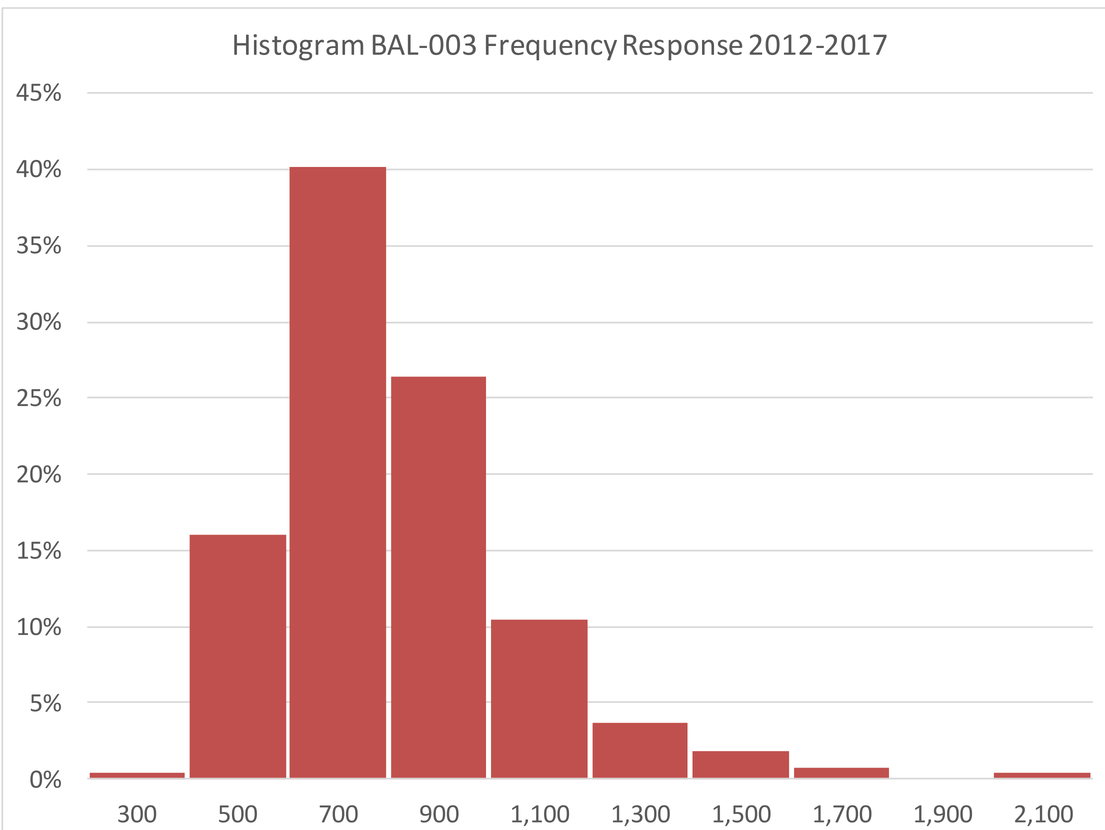


Figure 77 – Histogram of ERCOT Frequency Response 2012-2017

The NERC Reliability Standards require a maximum recovery time of 15 minutes for reportable disturbances. Average recovery time from generation loss events was 5.7 minutes in 2017 versus 5.3 minutes for calendar year 2016. The average event recovery is showing a long-term gradual upward trend since 2012.

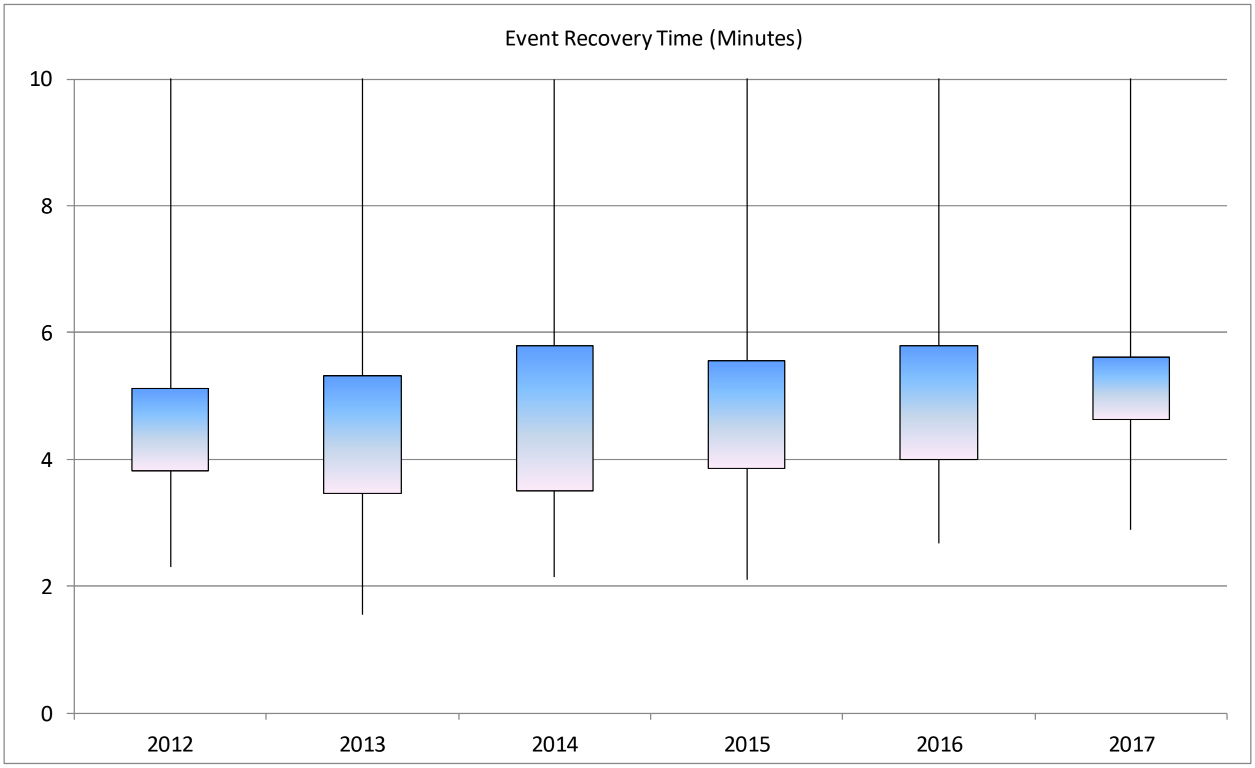


Figure 78 – Event Recovery Time 2012-2017

In the Texas RE Region, a 450 MW generation loss threshold and/or a frequency change of 0.09 Hz is typically used as the event threshold for review and analysis.

In 2017, the average unit failures per event was nine, compared to eight for 2016.

Failures of PDCWG Metrics	2015 (* Note)		2016		2017	
	Events	Unit Failures	Events	Unit Failures	Events	Unit Failures
Events	25	275	30	236	29	268
Median Frequency Response	720 MW		764 MW		759 MW	

Table 21 – Failures of PDCWG Metrics

- NOTE: 2015 data is valid for period April 1, 2015 through December 31, 2015, which correlates with the implementation of Regional Standard BAL-001-TRE.

VIII. Protection System Performance

Introduction

Texas RE collects Protection System Misoperation data quarterly from registered Transmission Owners, Generation Owners, and Distribution Providers that own transmission throughout the Texas RE Region for transmission elements operated at 100 kV and above. The Protection System Misoperation data is separated into voltage classes, category of Misoperation, element protected, relay system type, and Misoperation cause to illustrate the types of Protection System Misoperations occurring on the BES.

2017 Misoperations in Brief

2017 345 kV misoperation rate: 5.9%
2017 138 kV misoperation rate: 8.1%
2017 345 kV misoperations: 37
2017 138 kV misoperations: 136

Protection System Misoperations create multiple reliability issues for the BPS. If no system fault is present, a misoperation can unexpectedly remove facilities, load, and/or generation from the system creating a condition which must be mitigated by system operators. If a misoperation occurs during a system fault, more facilities may be removed from service than expected, which could lead to cascading or voltage collapse. These events, which may go beyond applicable planning criteria, may represent a tangible threat to reliability.

Additional data on misoperations analysis is presented in Appendix F.

Observations

- Protection system misoperation rate increased in 2017 to 7.3% versus 5.4% for 2016
- Incorrect settings, logic, and design errors remained the largest cause of misoperations, accounting for 34% of misoperations in 2017

Historical Data and Trends

A. Protection System Misoperation Statistics

Since January 2011, the overall transmission system Protection System Misoperation rate has a slight downward trend, from 8.8% in 2012 to 7.3% in 2017.

138 kV	2013	2014	2015	2016	2017	5-Yr Avg
Number of Misoperations	98	112	140	95	136	116
Number of Events	1545	1421	1712	1820	1678	1634
Percentage of Misoperations	6.3%	7.9%	8.2%	5.2%	8.1%	7.1%

345 kV	2013	2014	2015	2016	2017	5-Yr Avg
Number of Misoperations	32	53	33	35	37	38
Number of Events	317	456	678	593	621	533
Percentage of Misoperations	10.1%	11.6%	4.9%	5.9%	5.9%	7.1%
< 100 kV	2013	2014	2015	2016	2017	5-Yr Avg
Number of Misoperations	4	2	2	4	0	2
Number of Events	121	139	101	79	77	104
Percentage of Misoperations	3.3%	1.4%	2.0%	5.1%	0.0%	1.9%

Table 22 – Protection System Misoperation Data

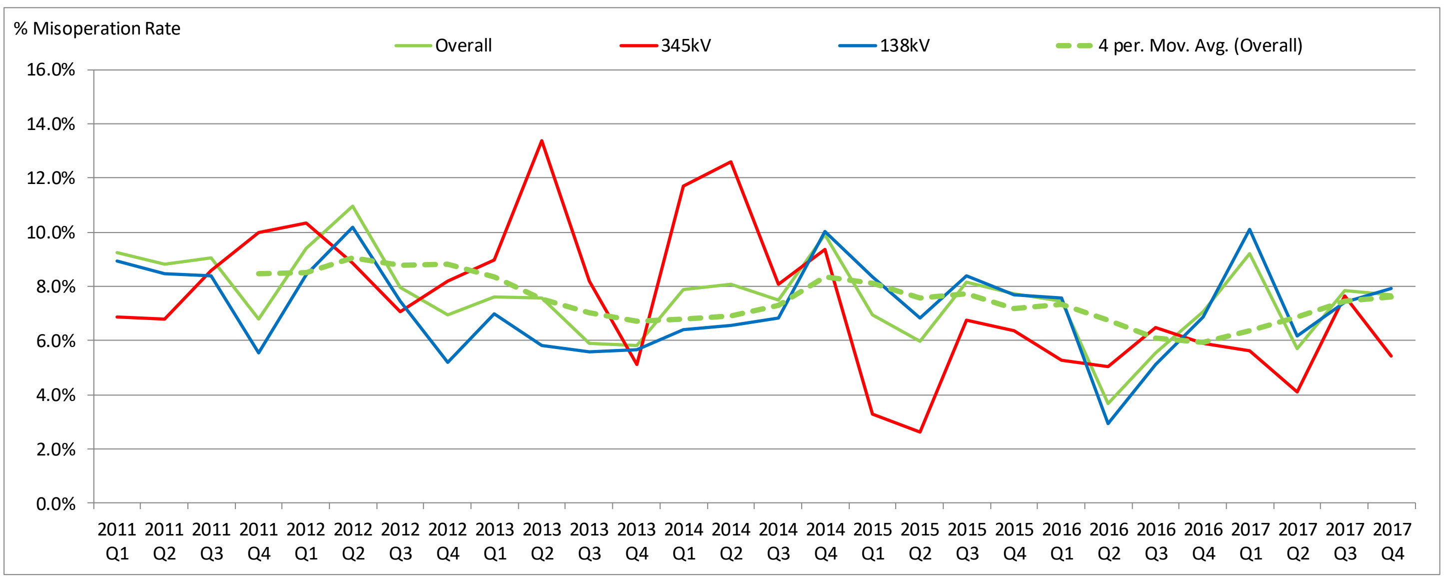


Figure 79 – Protection System Misoperation Trends

In 2017, three main categories account for 68% of the total misoperations: incorrect settings/logic/design (34%), as-left personnel errors (14%), and relay failures (20%).

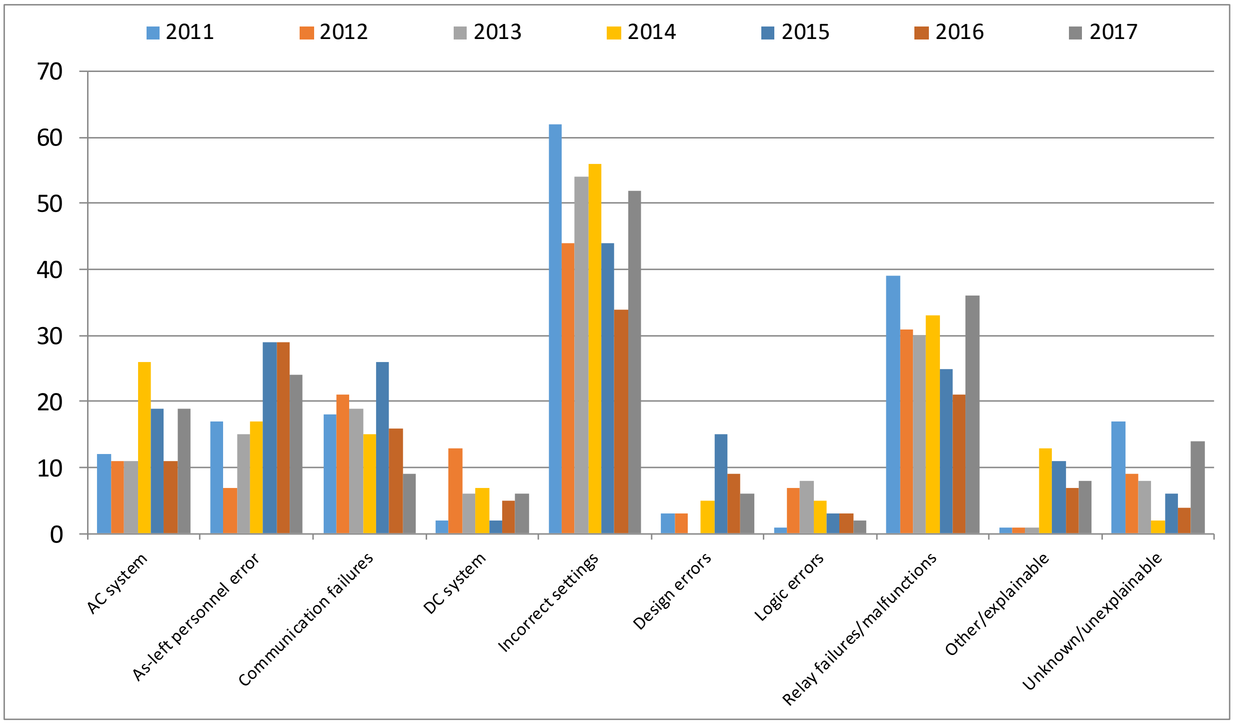


Figure 80 – Protection System Misoperations by Cause 2011-2017

Seventy-eight percent of the misoperations occurred at the 138 kV voltage level.

The following figures show a comparison of protection system misoperation rates between a sample of different ERCOT Transmission Owners compared to the aggregated region performance, and a comparison of protection system misoperation rates between the different NERC regions for the period of October 2012 through August 2017.

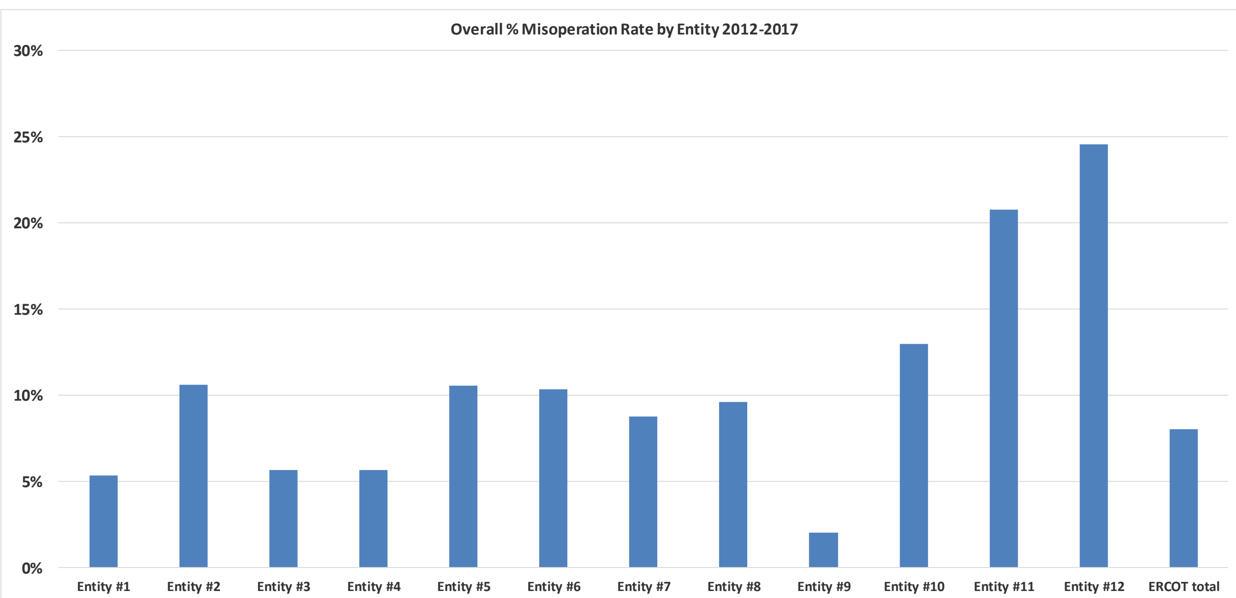


Figure 81 – Protection System Misoperation Rates by Entity 2012-2017

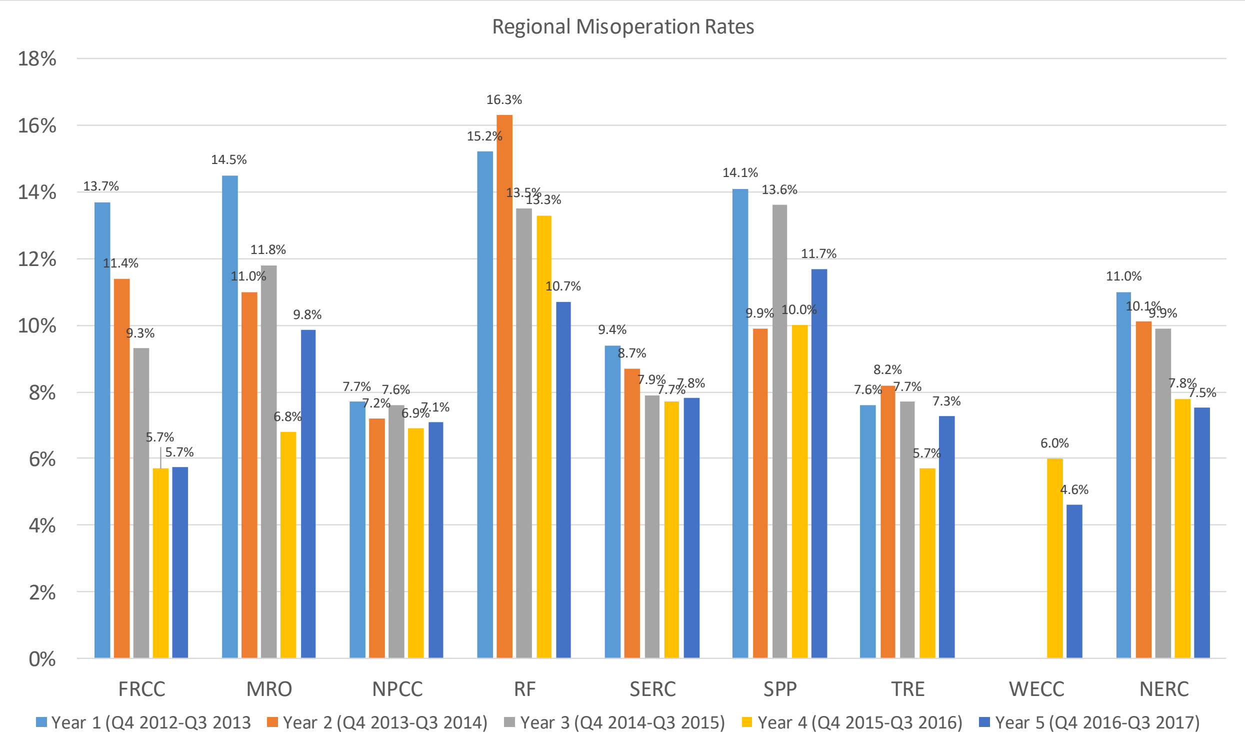


Figure 82 – Protection System Misoperation Rates by Region Q4 2012-Q3 2017

B. Human Performance Misoperations

Human error remains the primary causal factor in misoperations, primarily due to incorrect settings and/or as-left errors. The following list provides examples of actual human error-related misoperations in 2017 in the Texas RE Region.

- Generator tripped due to low DC supply voltage. Battery charger was turned off for maintenance but not returned to service.
- 138 kV line overtrip due to a partially open CT shorting switch caused by construction activity during the prior week.
- 138 kV line overtrip due to incorrect trip equation which did not match the issued setting.
- 138 kV line trip due to a jumper inadvertently left in place from a previous project which tied the ground and external trip inputs of the SEL relays.
- 138 kV line trip due to construction activity. Breaker failure transfer trip inadvertently placed in service without applying settings.
- Generator tripped due to incorrect breaker failure timer setting.
- 138 kV line overtrip. Previously issued relay settings had not been implemented in the relays.
- Wind plant GSU trip due to incorrect CT polarity on differential relay.
- Wind plant GSU trip due to CTs left shorted following maintenance on the transformer.
- 138 kV line overtrip due to error in communication logic associated with breaker failure scheme.

- 138 kV GSU trip due to instantaneous ground overcurrent element. Setting was programmed as part of protection scheme at 69 kV, but was not removed as part of 138 kV upgrade.
- 138 kV line overtrip due to BF logic setting, left incorrect by field technicians.
- 138 kV bus misoperation due to differential equation in B30 relay, left incorrect by field technicians.
- 138 kV line overtrip due to carrier start logic error, left incorrect by field technicians.
- Two 138 kV breakers tripped due to incorrect SOTF logic
- 138 kV line tripped due to miswired polarity to the backup relay
- 345 kV GSU tripped due to a CT shorting screw left in place.
- 138 kV line overtripped for an external fault. DCB scheme was disabled on one end of the line.
- 138 kV breaker overtripped due to CT left open-circuited by field technicians.
- 138 kV bus differential did not trip properly for a 138 kV PT failure. An incorrect relay setting template was used.
- Transformer relays failed to trip high side breaker due to test switches being left open.
- 345 kV line differential protections failed to trip due to relays being left disabled following commissioning tests.
- 345 kV breaker failure misoperation due to incorrect labeling of relay outputs on the drawings.
- 138 kV line overtrip. Relay settings not updated following completion of construction project.

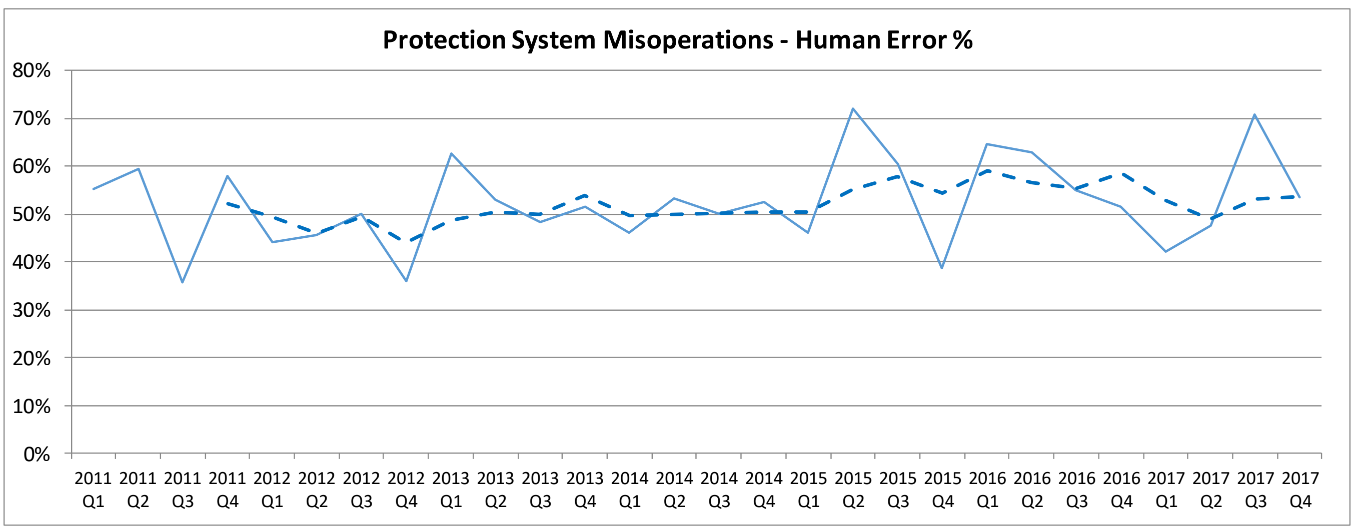


Figure 83 – Protection System Misoperations Trend Caused by Human Performance

IX. Infrastructure Protection

Introduction

Texas RE monitors infrastructure protection issues as part of its situational awareness effort. These issues primarily consist of substation intrusions and copper theft that are typically dealt with by local law enforcement. However, if the issue involves critical infrastructure, cyber intrusions, or possible sabotage, then it is elevated to NERC and the Department of Energy under the reporting requirements in NERC Reliability Standard EOP-004.

Observations

Critical infrastructure protection will continue to remain a priority for NERC, the Department of Homeland Security, and Texas RE. Additional data should be monitored to analyze possible locational trends in intrusions, theft, or other physical security issues.

Historical Data and Trends

Since September 2011, substation intrusions and copper theft have ranged from three to 28 in any one month, averaging seven per month. For the purposes of this chart, physical/cyber security issues include bomb threats, sabotage, and cyber security issues.

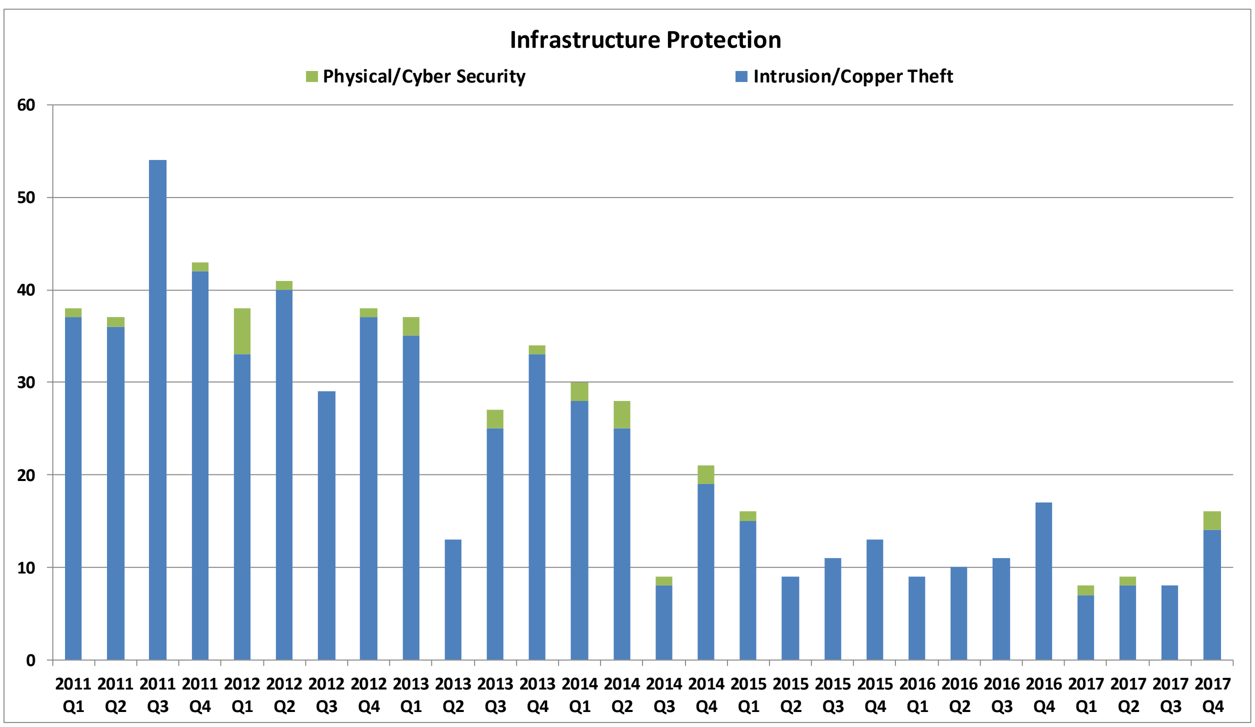


Figure 84 – ERCOT Trend in Substation Intrusions/Copper Theft/Cyber Security Issues

Appendix A – References

1) NERC 2017 Long-Term Reliability Assessment
2) NERC 2016 Long-Term Reliability Assessment
3) NERC 2017 Summer Assessment
4) NERC 2016 Summer Assessment
5) NERC 2017/2018 Winter Assessment
6) NERC 2016/2017 Winter Assessment
7) NERC 2017 State of Reliability Report
8) NERC 2016 State of Reliability Report
9) NERC Distributed Energy Resources – Connection, Modeling, and Reliability Considerations
10) NERC Operational Risk Assessment with High Penetration of Natural Gas-Fired Generation
11) Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System
12) ERO Event Analysis Process Document

Appendix B – Disturbance Events Analysis

The 2011-2017 Event Analysis is summarized by category and cause code in the following figures:

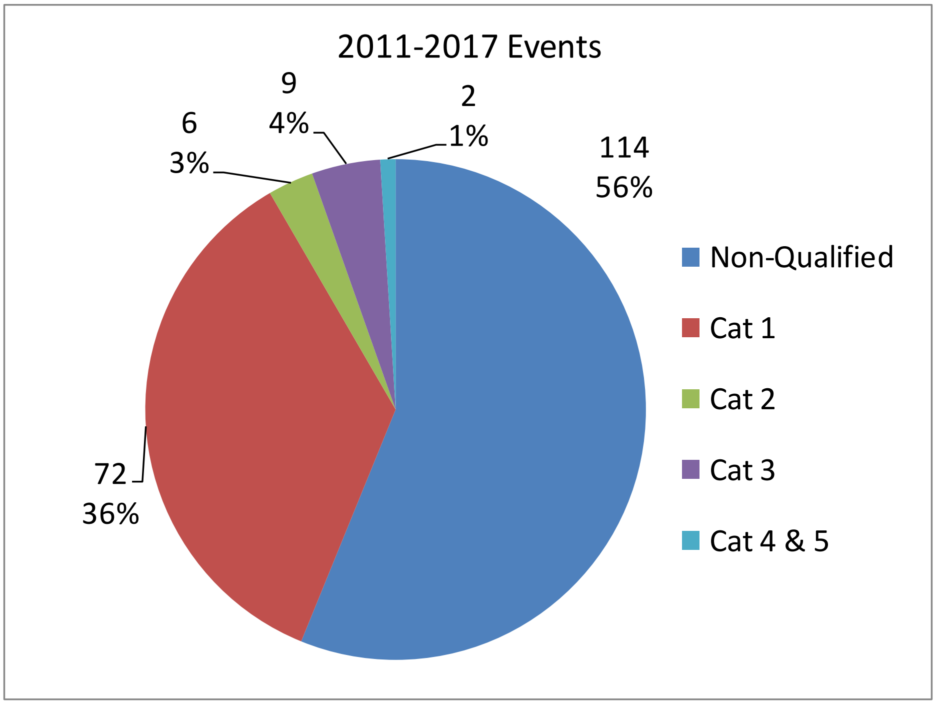


Figure B.1 – 2011-2017 ERCOT Events by Category

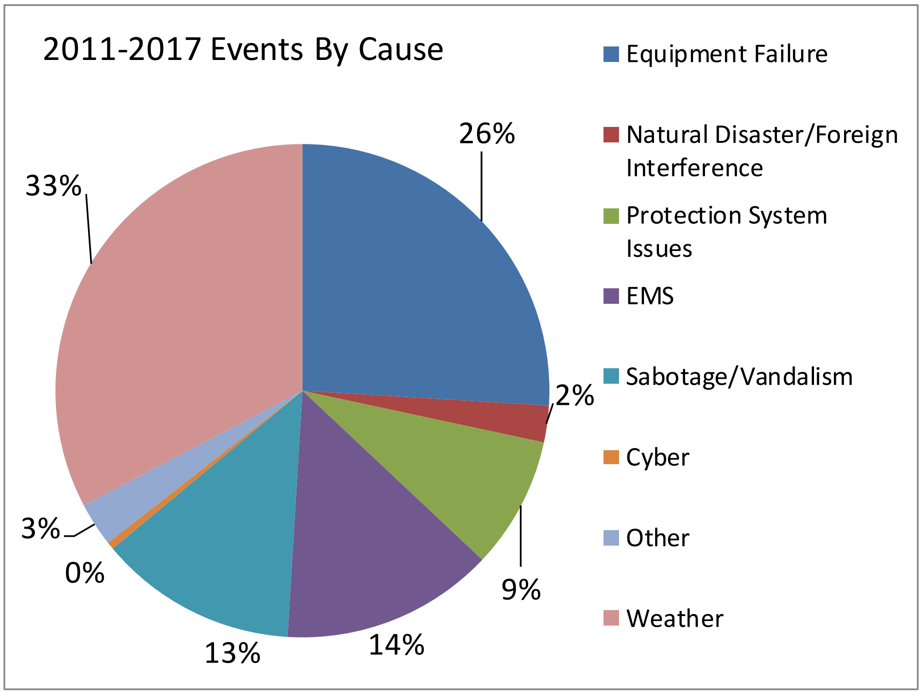


Figure B.2 – 2011-2017 ERCOT Events by Cause

Texas RE tracks the number of Disturbance Control Standards (DCS) events and recovery time for DCS events as well as DCS events greater than the Most Severe Single Contingency (MSSC) within the region to provide any potential adverse reliability indications. Per the NERC BAL-002 Disturbance Control Standard, a Reportable Disturbance is defined as any event which causes a change in area control error greater than or equal to 80% of the MSSC, or approximately 1,100 MW for the Texas RE Region. As part of the Event Analysis process, Texas RE investigates the cause and relative effect on reliability of DCS events within the region. DCS events greater than the MSSC typically do not create a reliability problem for the Texas RE Region since ERCOT carries contingency reserves greater than the MSSC; however, these events warrant special consideration for review of system frequency response and recovery.

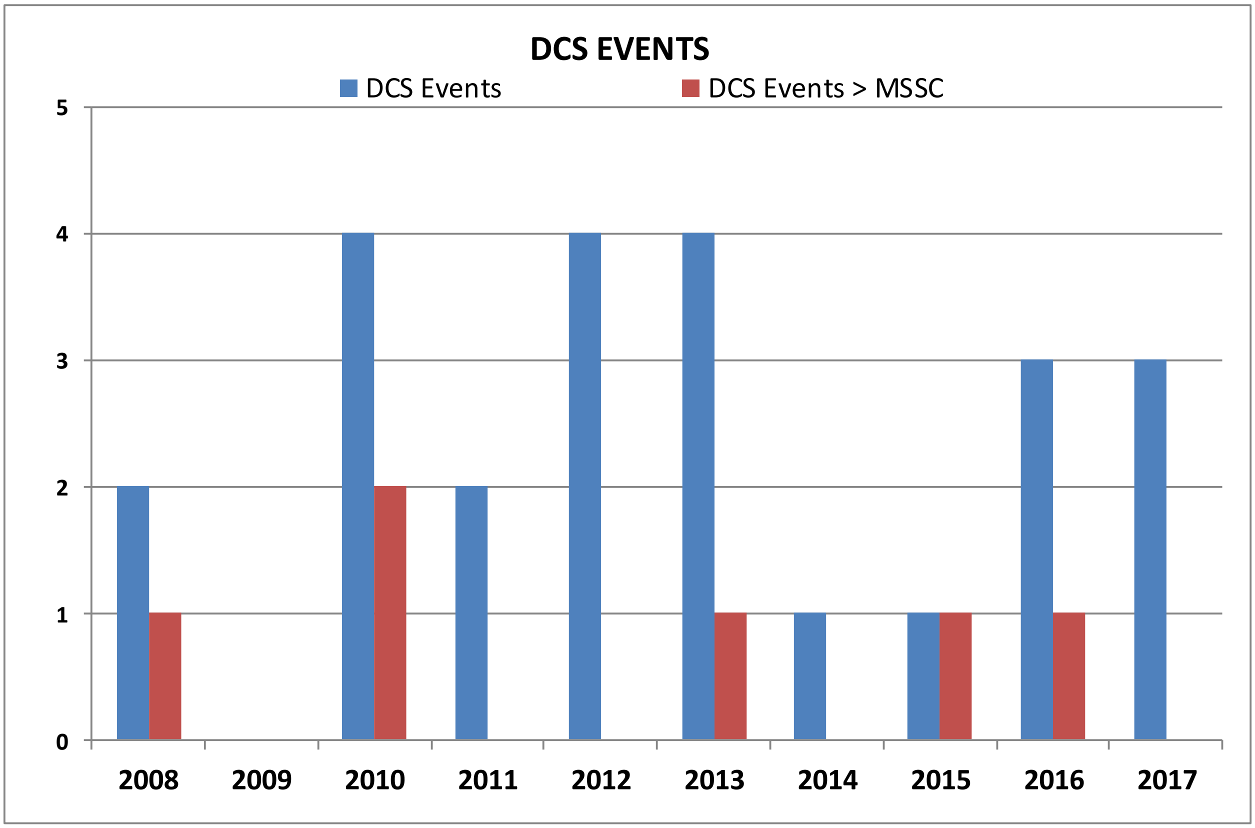


Figure B.3 – DCS Events by Year

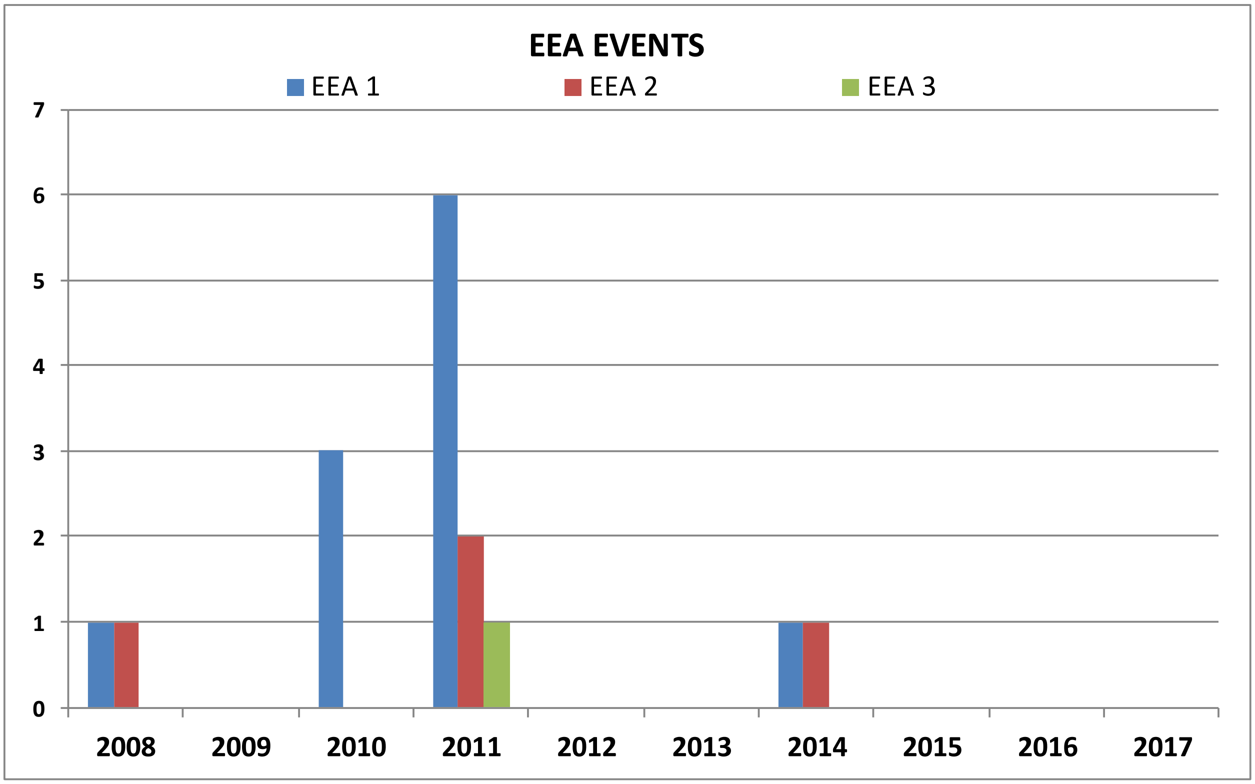


Figure B.4 –EEA Events by Year

Texas RE also tracks the number of EEA2 events and EEA3 events within the region to provide any potential reliability indicators. EEA events occur infrequently within the region, with the exception of 2011. Two EEA2 events occurred (August 4 and August 24, 2011) due to extreme temperatures combined with generation resource unavailability. Another EEA2 event occurred on January 6, 2014 (Polar Vortex) due to similar issues with extreme temperatures combined with resource unavailability. One EEA3 event (Southwest Cold Weather Event) occurred on February 1-5, 2011. There were no EEA3 events in 2012-2017.

EEA Date and Level	Minimum Reserve Level During EEA (based on 2,300 MW minimum)	Duration of EEA Event
2/2/2011 – EEA2	447 MW	28.7 hours (total duration)
2/2/2011 – EEA3	447 MW	498 minutes (EEA3 only)
6/27/2011 – EEA1	2,275 MW	85 minutes
8/2/2011 – EEA1	2,123 MW	207 minutes
8/3/2011 – EEA1	1,722 MW	205 minutes
8/4/2011 – EEA2	984 MW	307 minutes
8/5/2011 – EEA1	2,122 MW	175 minutes
8/23/2011 – EEA1	2,160 MW	91 minutes
8/24/2011 – EEA2	1,192 MW	230 minutes
1/6/2014 – EEA2	1,345 MW	140 minutes

Table B.1 – EEA Event Magnitude and Duration

E. EMS/SCADA Events

Loss of EMS/SCADA events continue to be a focus point at the NERC and regional levels. Category 1 events include loss of operator ability to remotely monitor, 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.

For 2013-2017, there were 24 loss of EMS/SCADA events reported in the Texas RE Region. Events reported in 2017 include the following:

- A TOP lost its primary and backup EMS systems for 50 minutes during a maintenance update when the vendor mistakenly entered an incorrect timing parameter
- A TOP lost its primary and backup EMS systems for over seven hours. During a routine update of the EMS, new database elements were added to represent installed field equipment and these additions exceeded a specific size limitation within the EMS. This loss of the EMS caused erroneous telemetry values to be sent to ERCOT, impacting ERCOT's State Estimator, Real-Time Contingency Analysis (RTCA), and Voltage Security Assessment Tool (VSAT) for over four hours.
- A TOP lost SCADA for approximately three hours during an update to its firewalls.

Telemetry Availability

ERCOT telemetry performance criteria states that 92% of all telemetry provided to ERCOT must achieve a quarterly availability of 80%. The following chart shows the telemetry availability metric per the ERCOT telemetry standard. For 2017, the total number of telemetry points failing the availability metric averaged approximately 3,438 each month, or approximately 3.4% of the total system telemetry points.

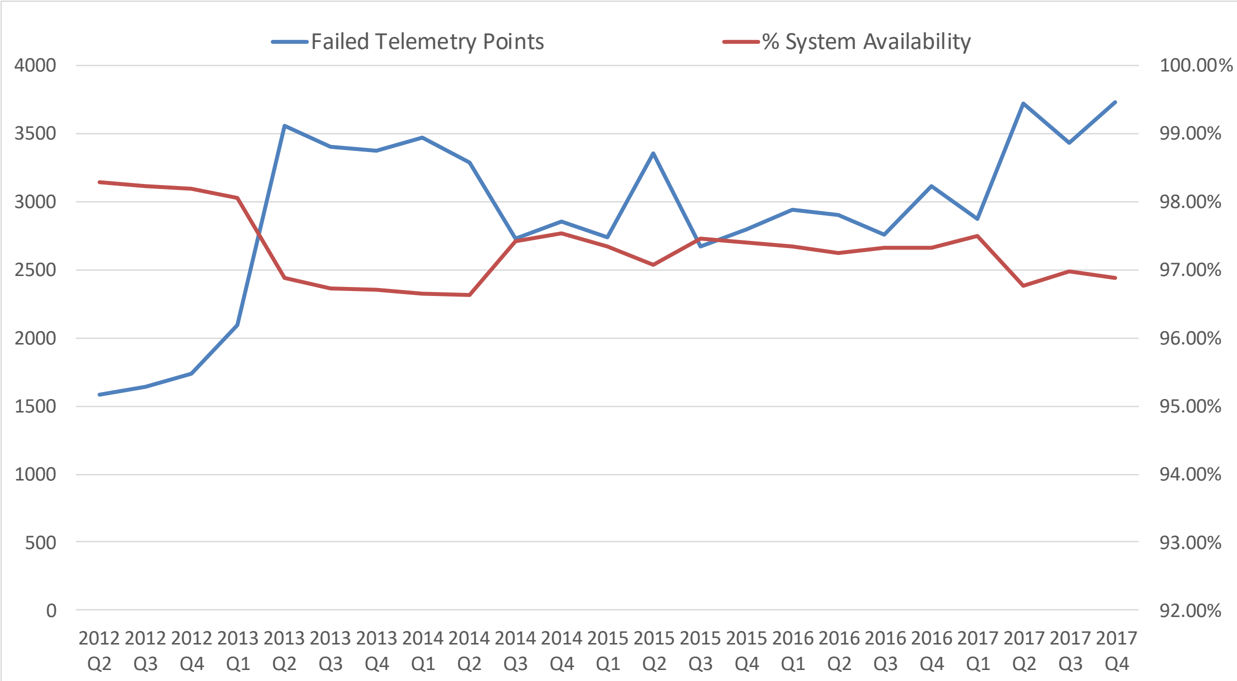


Figure B.5 – ERCOT Telemetry System Availability

Appendix C – Transmission Availability Analysis

TADS Element and Outage Data

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)
2008	258	8,917.8	
2009	274	9,312.5	
2010	290	9,601.0	
2011	310	9,845.6	
2012	316	10,049.4	
2013	371	13,285.6	
2014	397	14,193.2	
2015	413	14,832.0	206
2016	424	15,024.9	216
2017	433	15,263.5	221

Table C.1 – 2008-2017 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[5]	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
5-Yr Average	365	8,152.7	41	4,138.4

Table C.2 – 2010-2017 345 kV Circuit and Transformer Outage Data

Automatic Outage Data

For 2013-2017 for 345 kV circuits, Failed AC Circuit Equipment represented 9% of sustained outage cause and 57% of sustained outage duration.

[5] Outage count and duration for 2015-2017 includes 345 kV transformers which began reporting in 2015

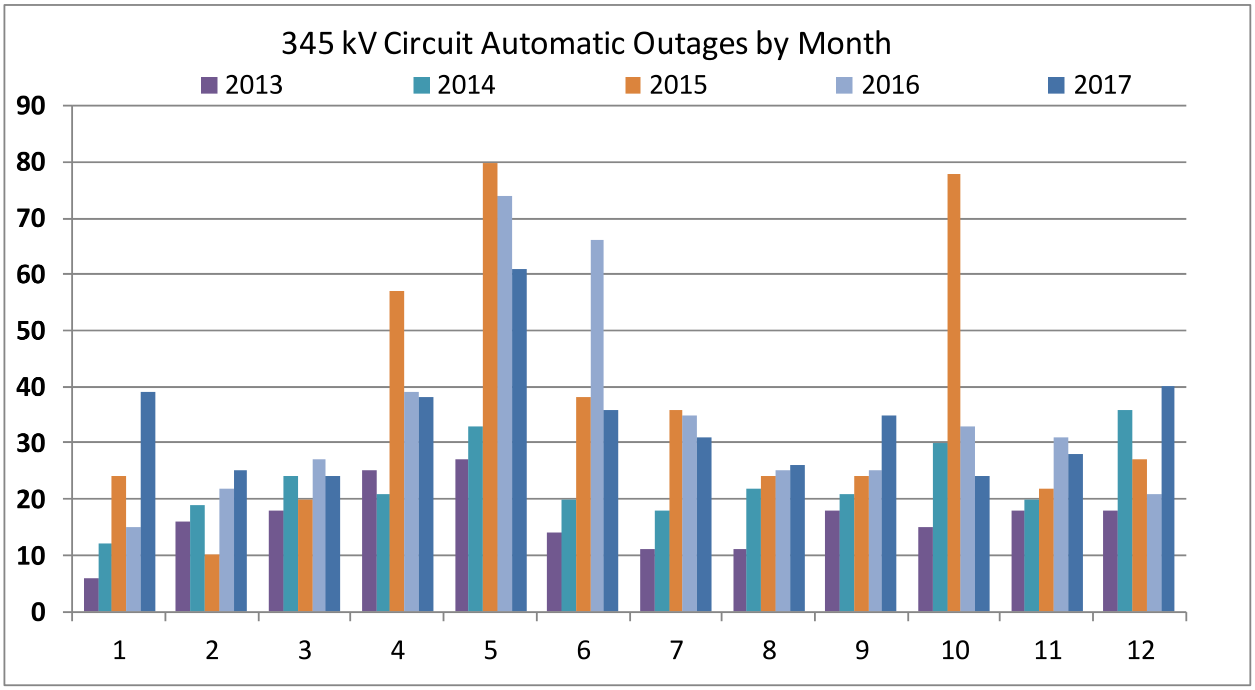


Figure C.1 – 345 kV Circuit Automatic Outages by Month

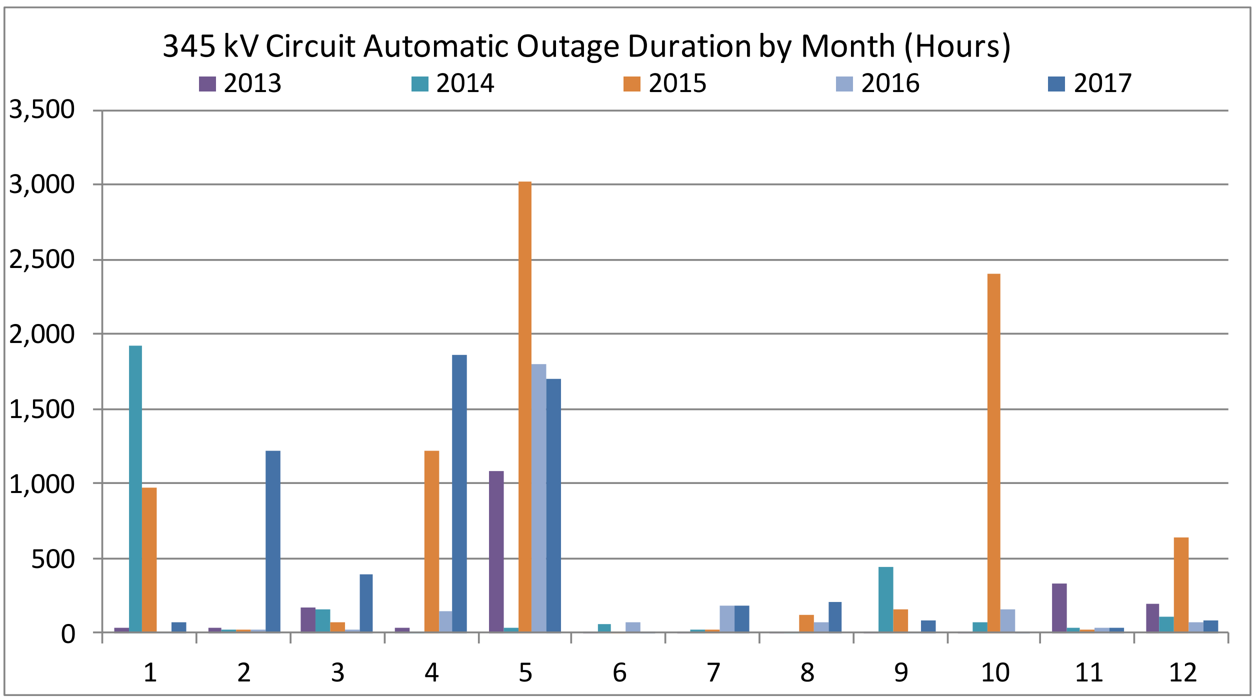


Figure C.2 – Multi-Year Comparison of TADS Outages and Duration by Month (> 200 kV)

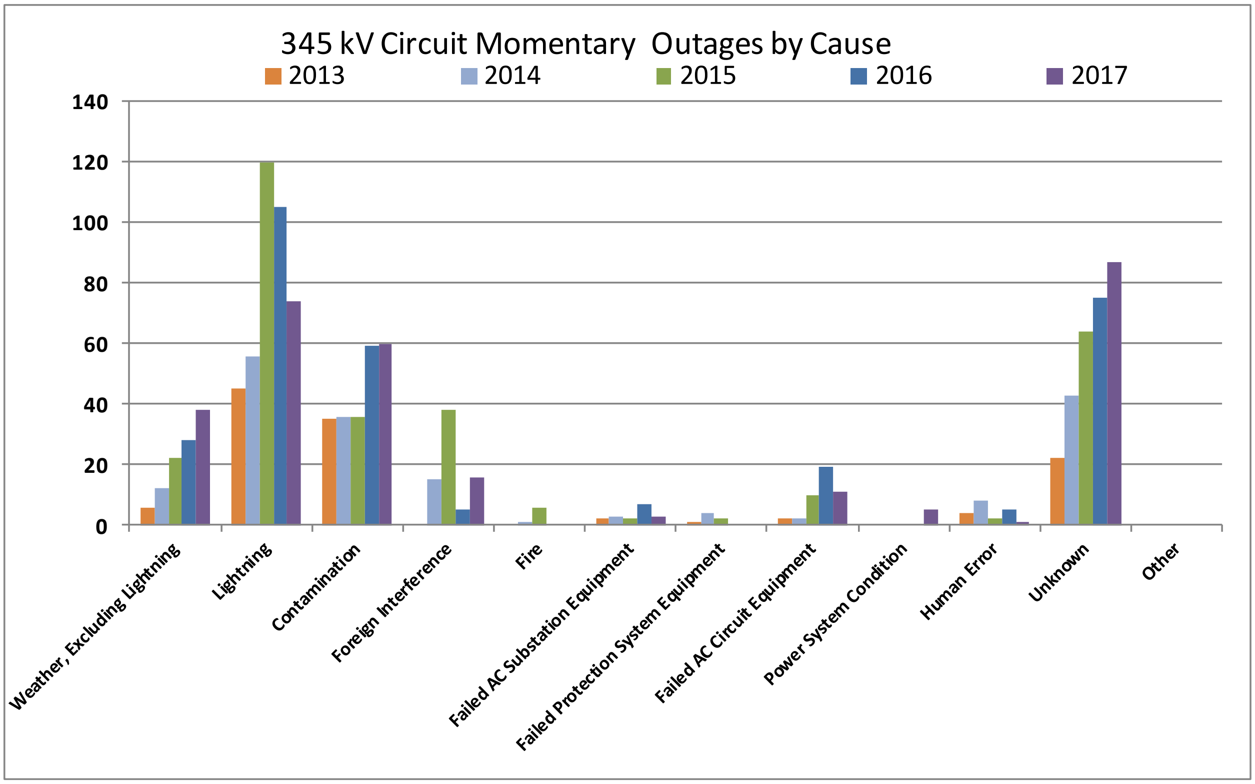


Figure C.3 – 345 kV Circuit Momentary Outages by Cause

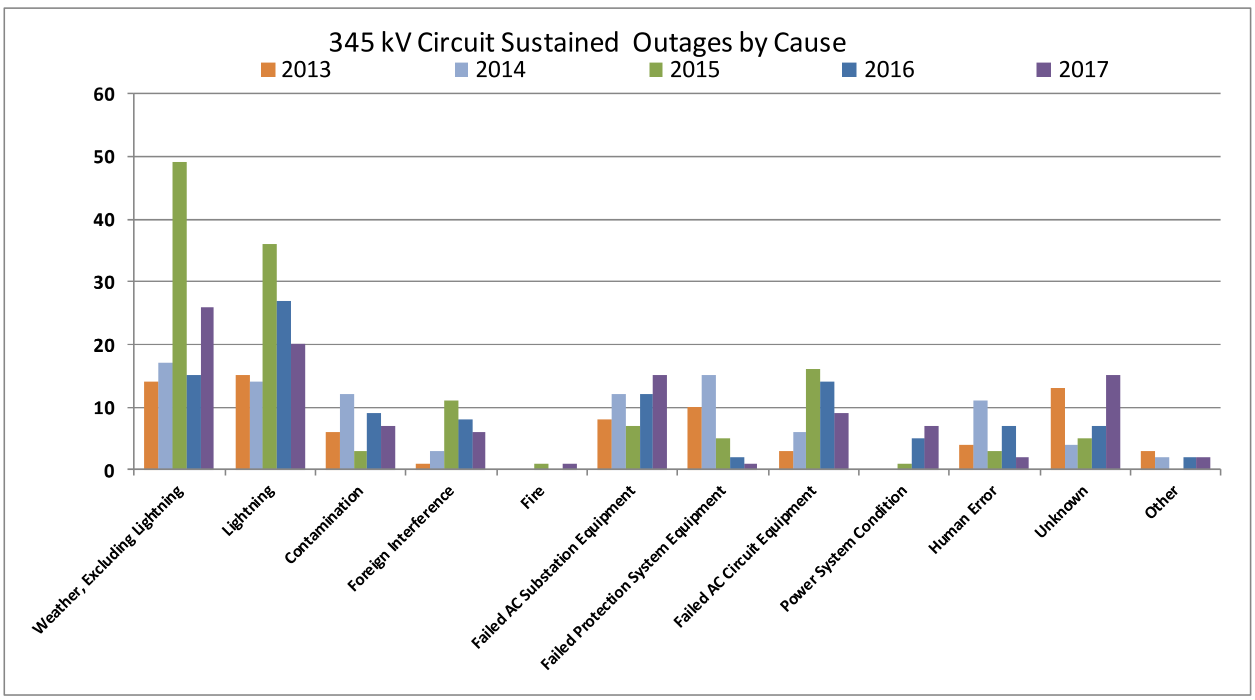


Figure C.4 – 345 kV Circuit Sustained Outages by Cause

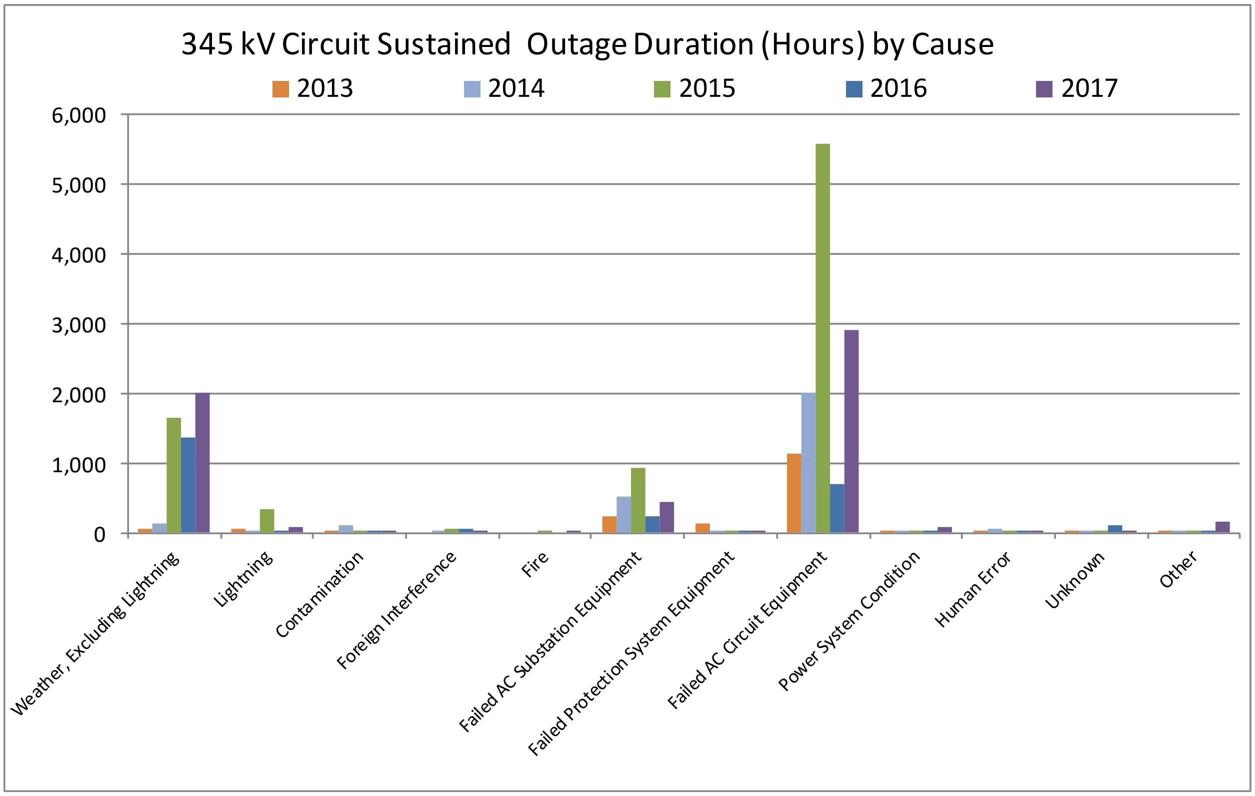


Figure C.5 – 345 kV Circuit Sustained Outage Duration (hours) by Cause

Common and Dependent Mode Outage Data

For 2013-2017 combined, Dependent Mode outages and Common Mode outages for 345 kV circuits represented 7% of all momentary outages, 23% of all sustained outages and 60% of sustained outage duration.

For 2013-2017 combined, Failed AC Circuit equipment represented 13% of the Common Mode and Dependent Mode outages, but resulted in over 75% of the Common Mode and Dependent Mode outage duration.

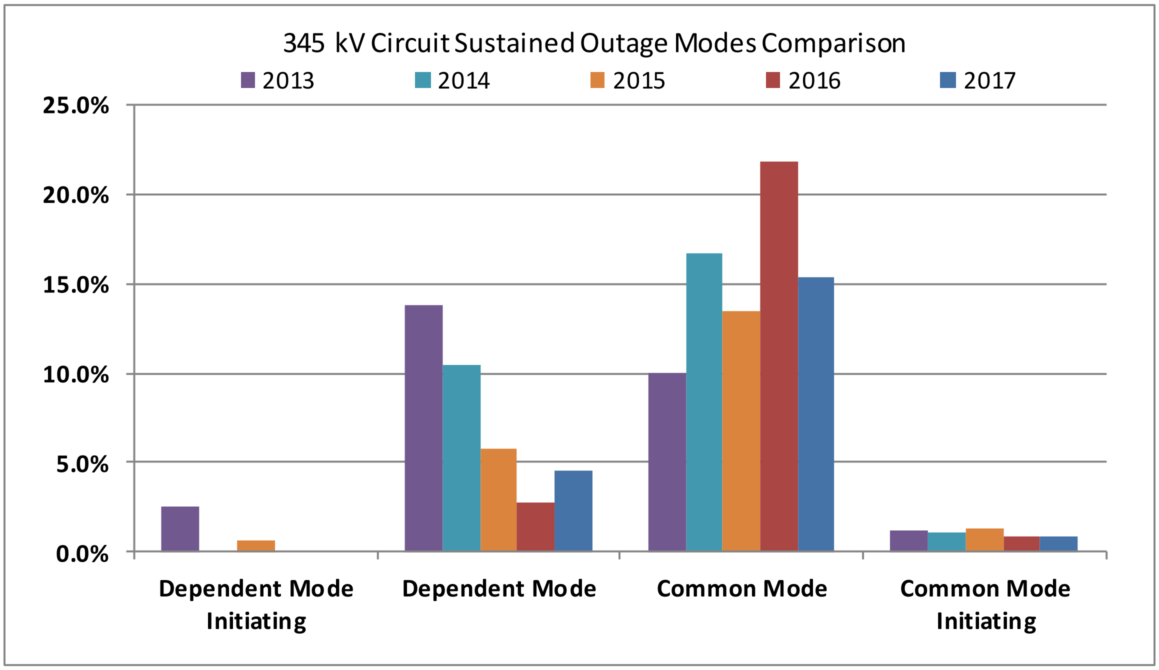


Figure C.6 – 345 kV Circuit Sustained Outage Modes Comparison

The following charts show the 2013-2017 Dependent Mode outages and Common Mode outage data broken down by cause and duration.

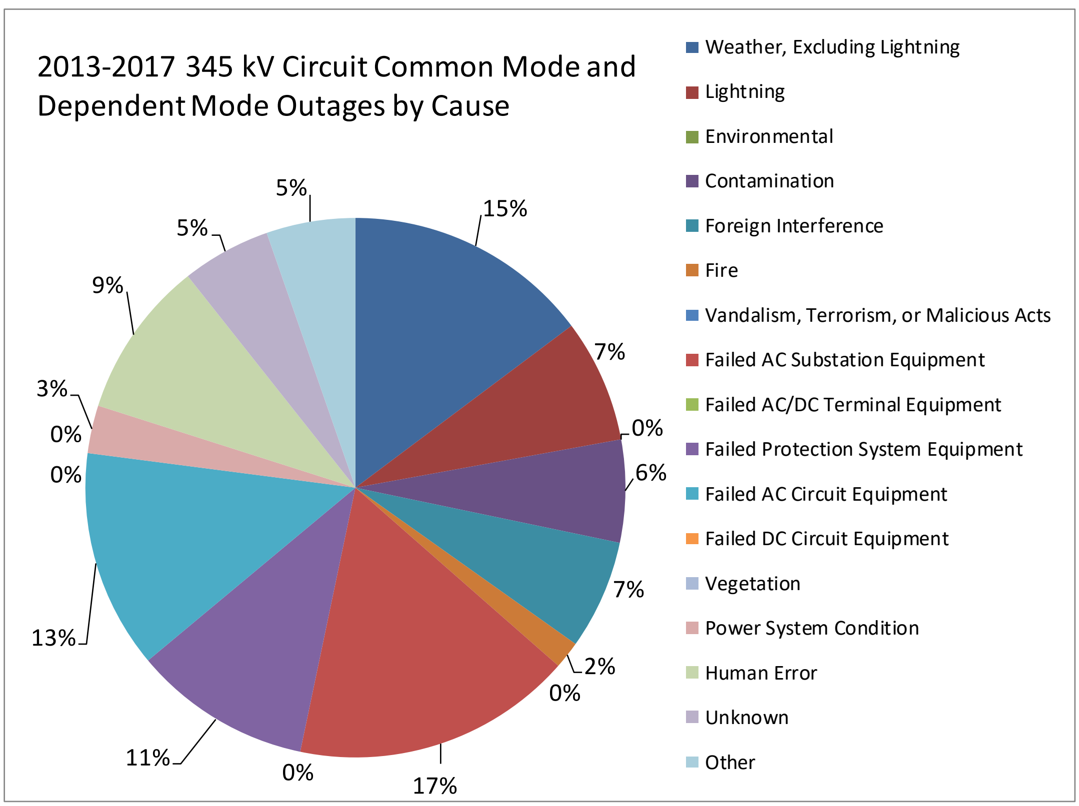


Figure C.7 – 2013-2017 345 kV Circuit Common/Dependent Mode Outages by Cause

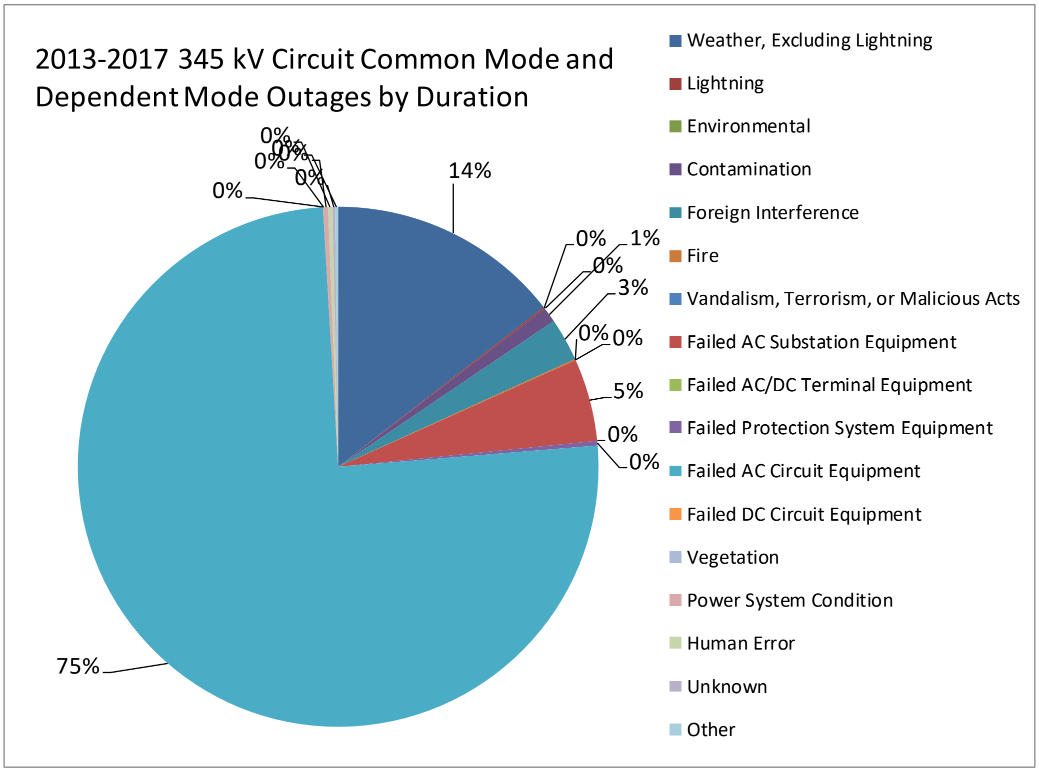


Figure C.8 – 2013-2017 345 kV Circuit Common/Dependent Mode Outages by Duration

Appendix D – Generation Availability Analysis

GADS provides and also permits comparison of unit performance by fuel type. A summary of key performance metrics for the entire ERCOT generation fleet is provided in the following figures.

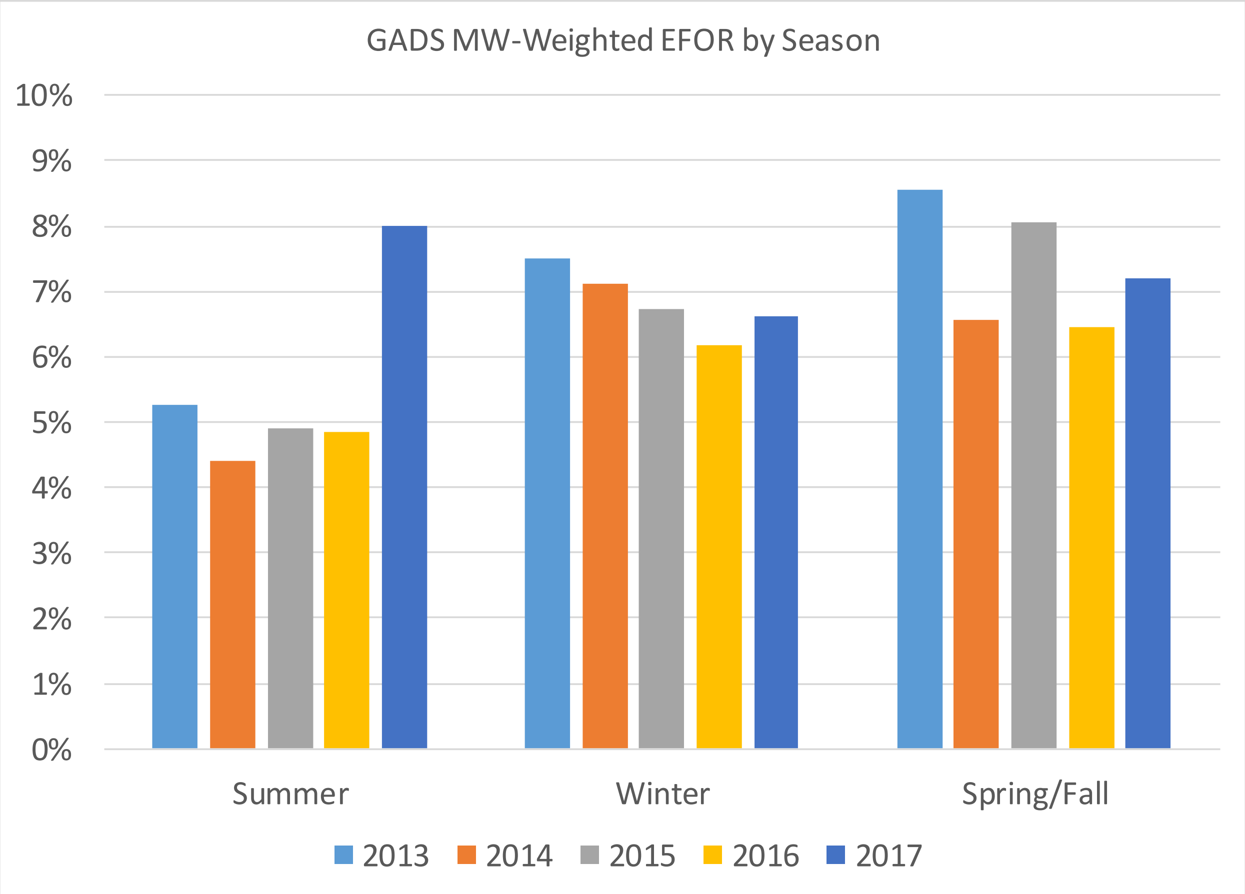


Figure D.1 – GADS Weighted EFOR by Season for the ERCOT Generation Fleet

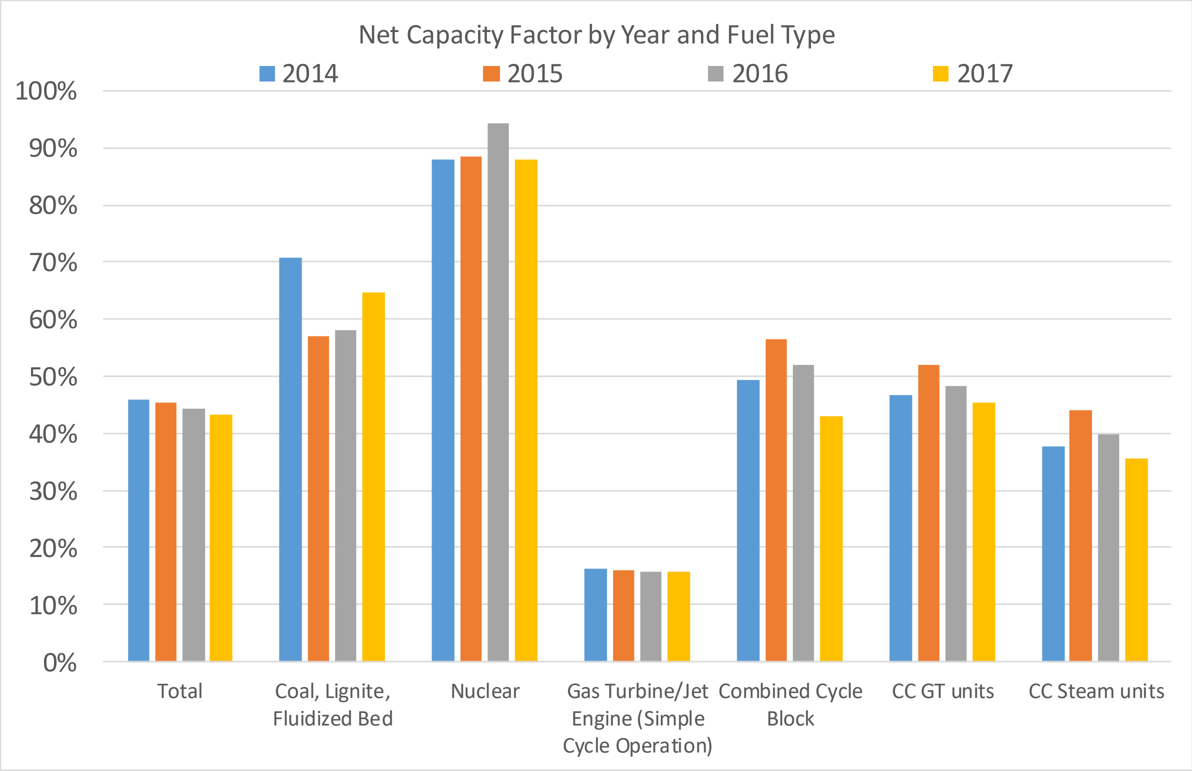


Figure D.2 – Net Capacity Factor by Year and Unit Type

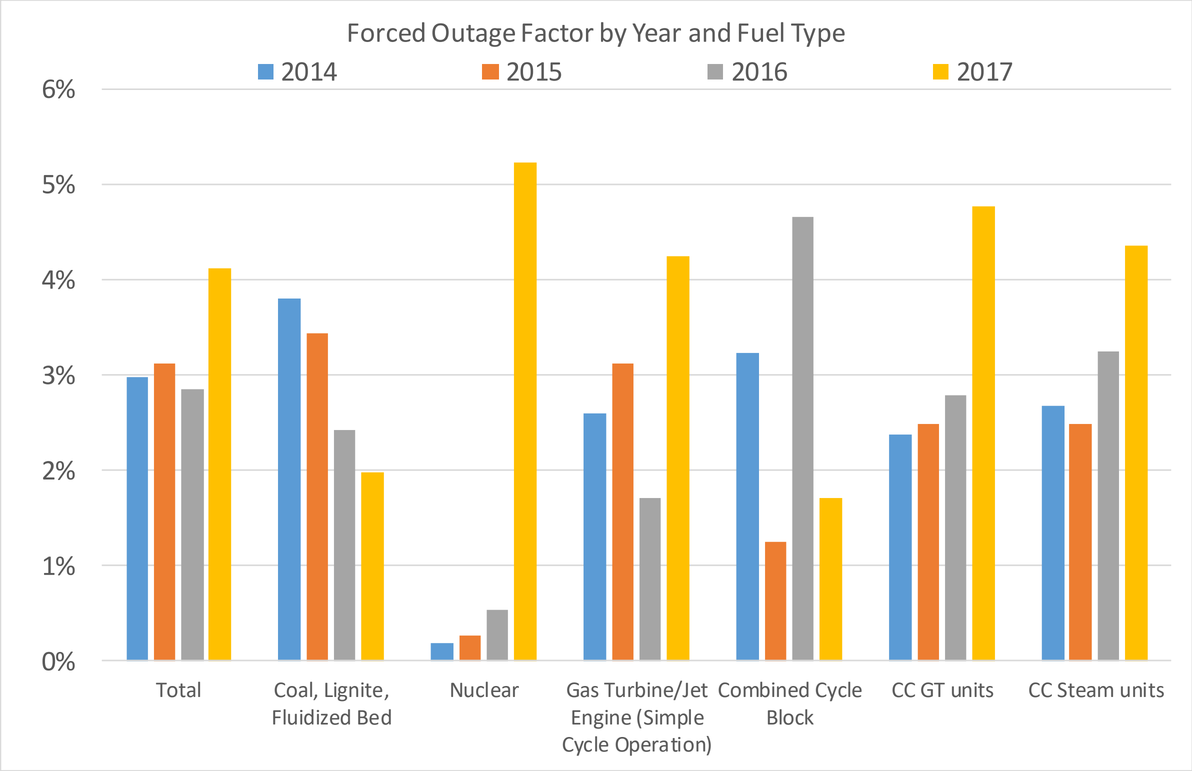


Figure D.3 – Forced Outage Factor by Year and Unit Type

For 2012 through 2017, there was an average of 230 immediate de-rate events each month, with an average duration of 10,748 hours each month and an average capacity of 101 MW per de-rate event.

For 2012 through 2017, there was an average of 155 immediate forced outage events each month, with an average duration of 7,273 hours each month and an average capacity of 221 MW per outage event.

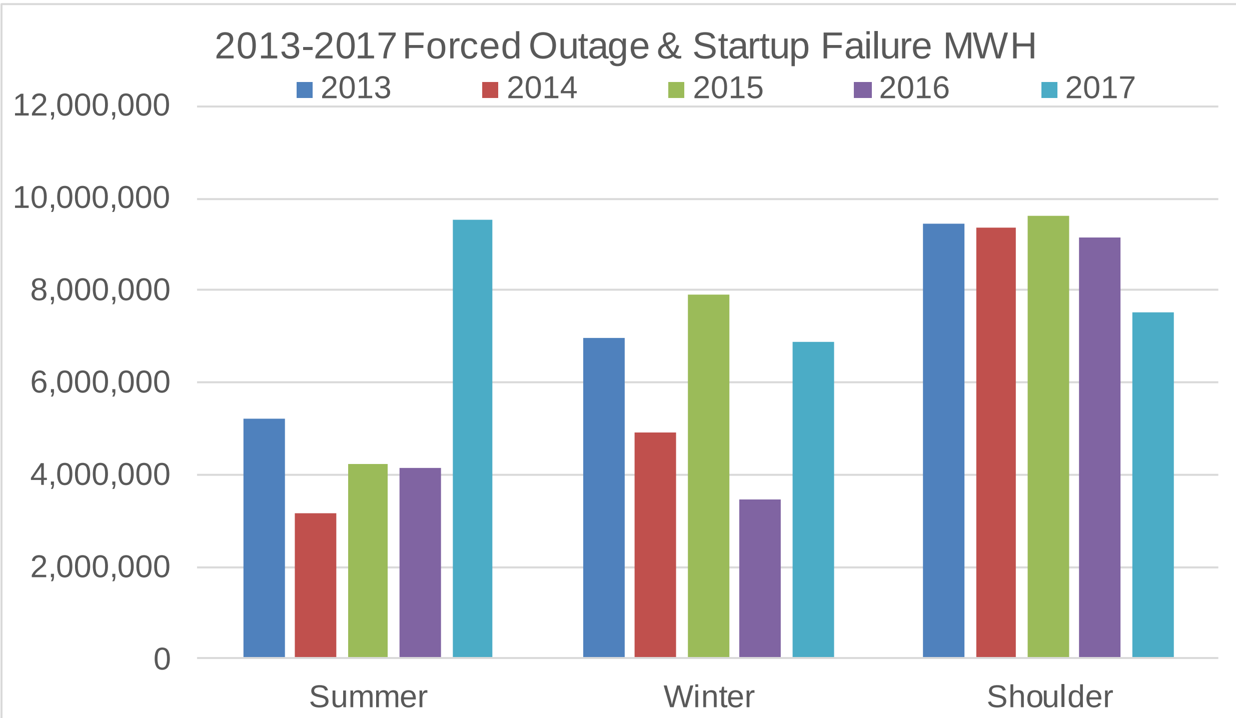


Figure D.4 – 2013-2017 Lost MWH from Forced Outages

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

Major System	2013 Number of Forced Outage Events	2014 Number of Forced Outage Events	2015 Number of Forced Outage Events	2016 Number of Forced Outage Events	2017 Number of Forced Outage Events	5-Year Average
Boiler System	237	249	206	203	273	234
Balance of Plant	434	431	404	355	332	391
Steam Turbine/Generator	1,019	934	1,007	819	852	926
Heat Recovery Steam Generator	69	69	65	96	63	72
Pollution Control Equipment	20	25	23	20	20	22
External	68	126	90	77	84	89
Regulatory, Safety, Environmental	10	17	12	11	12	12
Personnel/Procedure Errors	57	88	74	72	77	74

Table D.1 – 2013-2017 Category Cause of Immediate Forced Outage Events from GADS

Appendix E – Demand Response Historical Data

The following table provides a list of load resource deployments greater than 100 MW since 2011.

Date	Event Description
2/2/2011	887 MW of Load Resources and 468 MW of EILS were deployed manually by System Operators due to the loss of multiple generators. System Operators issued directives to shed 4,000 MW of firm load due to EEA3 conditions. Deployment time: 33.5 hours for LR and EILS, 7.4 hours for firm load shed
3/23/2011	393 MW of Load Resources deployed automatically by underfrequency relay due to the trip of multiple generators. Deployment time: 37 minutes
5/19/2011	113 MW of Load Resources deployed automatically by underfrequency relay due to the trip of a large generator. Deployment time: 9 minutes
8/4/2011	881 MW of Load Resources and 514 MW of EILS were deployed by System Operators due to EEA2 conditions. Deployment time: 3 hours 4 minutes
8/24/2011	634 MW of Load Resources were deployed by System Operators due to EEA2 conditions. Deployment time: 2 hours 13 minutes
11/29/2011	730 MW of Load Resources deployed automatically by underfrequency relay due to the trip of a large generator. Deployment time: 6 minutes
7/10/2012	195 MW of Load Resources deployed automatically by underfrequency relay due to the trip of multiple large generators. Deployment time: 14 minutes
7/30/2012	317 MW of Load Resources deployed automatically by underfrequency relay due to the trip of multiple large generators. Deployment time: 14 minutes
11/02/2012	882 MW of Load Resources deployed automatically by underfrequency relay due to the trip of a large generator. Deployment time: 11 minutes
1/4/2013	572 MW of Load Resources deployed automatically by underfrequency relay due to the trip of a large generator. Deployment time: 20 minutes
1/8/2013	974 MW of Load Resources deployed automatically by underfrequency relay due to the trip of a large generator. Deployment time: 11 minutes
11/1/2013	463 MW of Load Resources deployed automatically by underfrequency relay due to the trip of a large generator. Deployment time: 11 minutes
1/6/2014	1,085 MW of Load Resources and 607 MW of ERS deployed manually by System Operators due to EEA2 conditions. Deployment time: 56 minutes
5/1/2016	Approximately 927 MW of Load Resources deployed automatically by underfrequency relay due to a large generation trip event.

Table E.1 – Demand Response Deployments since 1/1/2011

Appendix F – Protection System Misoperations Analysis

The following graphs show historical protection system misoperation data for 2011-2017, broken down by voltage, misoperation category, relay system type, equipment protected, and cause.

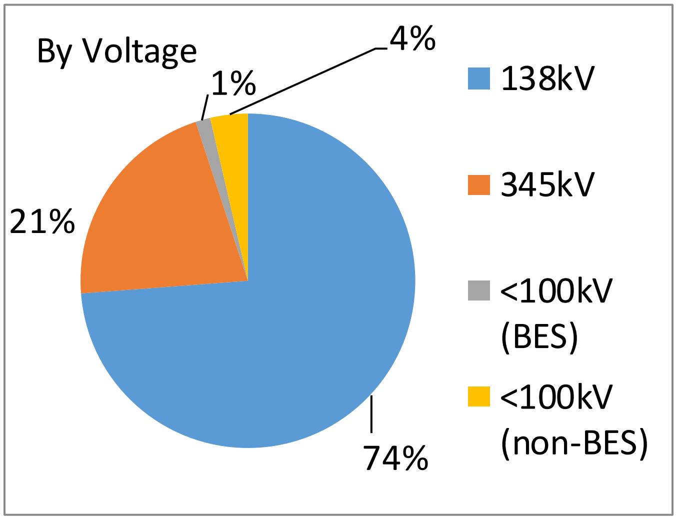


Figure F.1 – Protection System Misoperation Data for 2011-2017 by Voltage

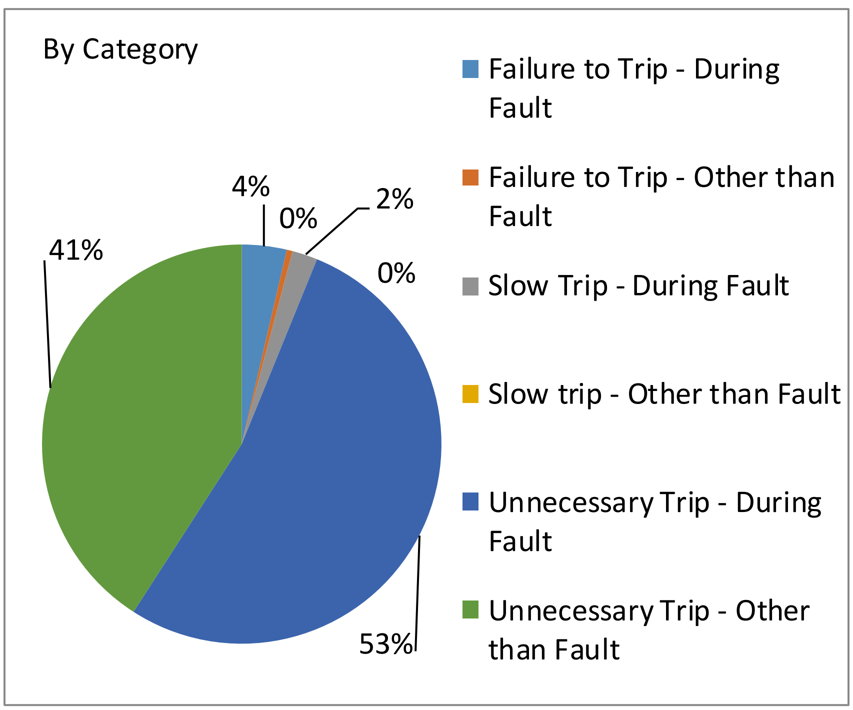


Figure F.2 – Protection System Misoperation Data for 2011-2017 by Category

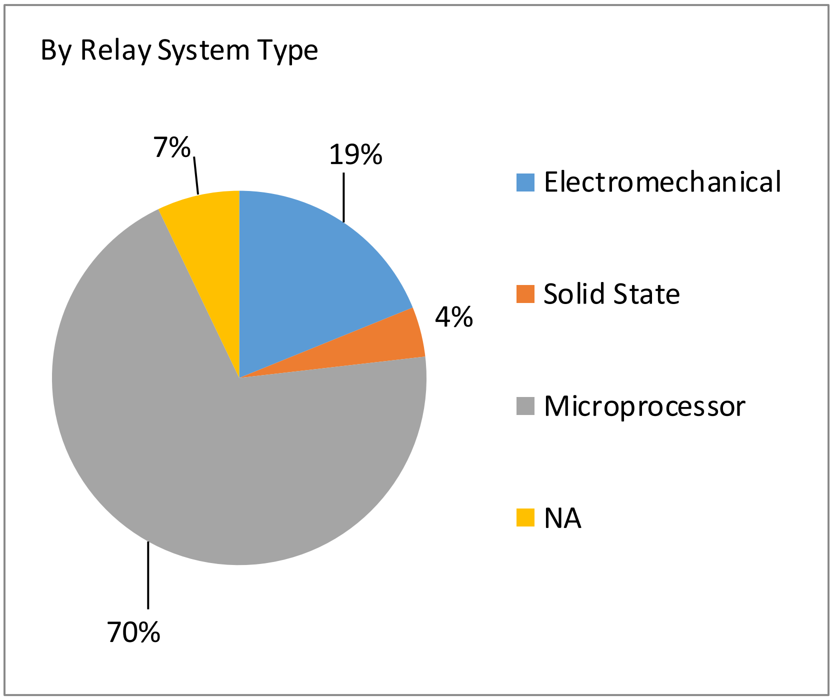


Figure F.3 – Protection System Misoperation Data for 2011-2017 by Relay System Type

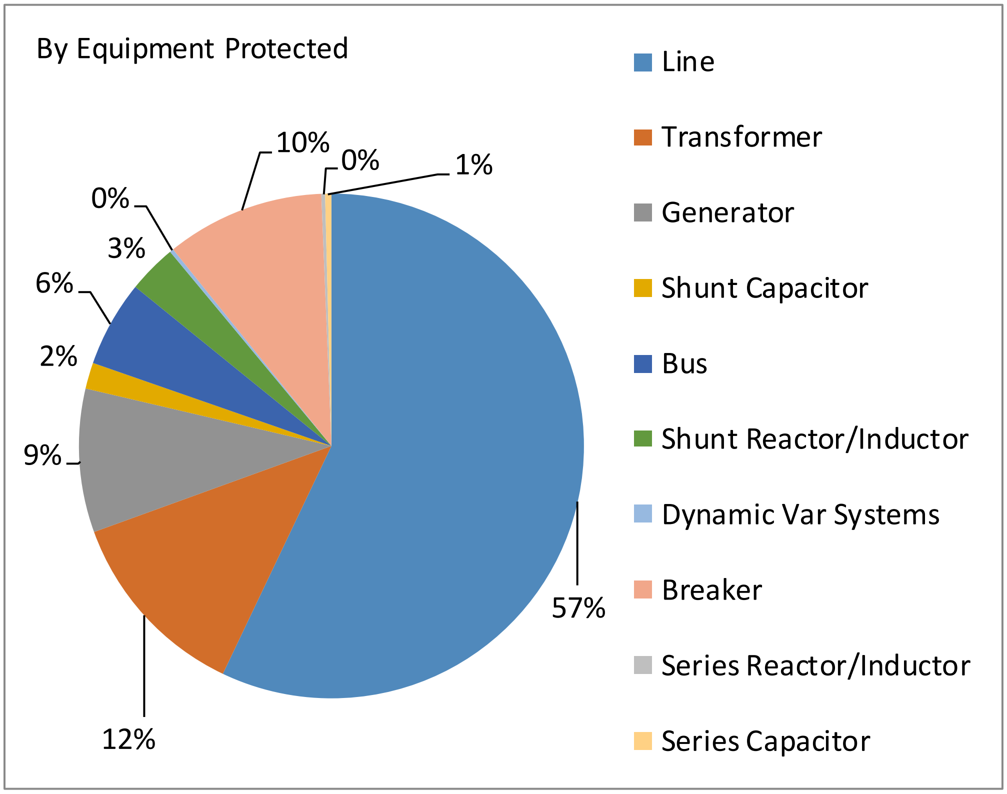


Figure F.4 – Protection System Misoperation Data for 2011-2017 by Equipment Protected

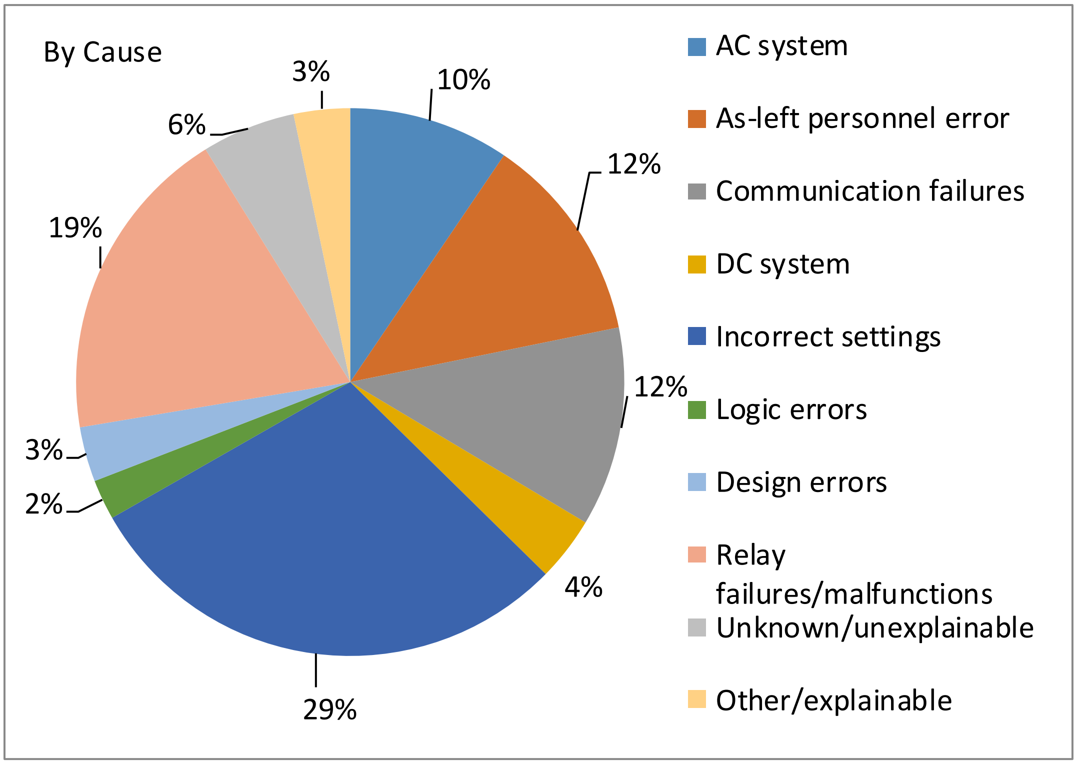


Figure F.5 – Protection System Misoperation Data for 2011-2017 by Cause

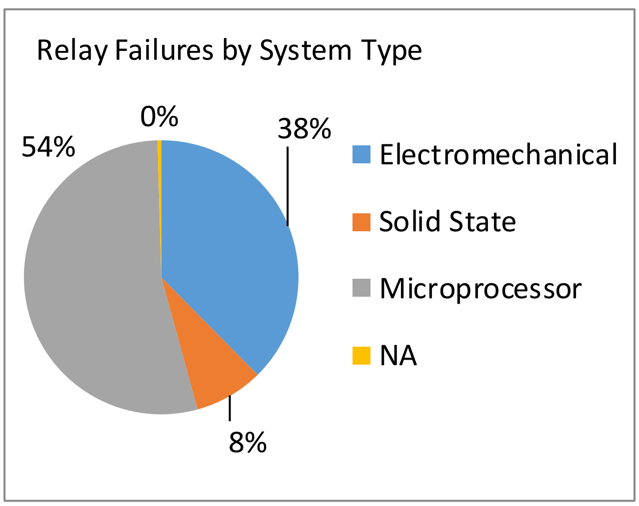


Figure F.6 – Protection System Misoperations 2011-2017 Relay Failures by System Type

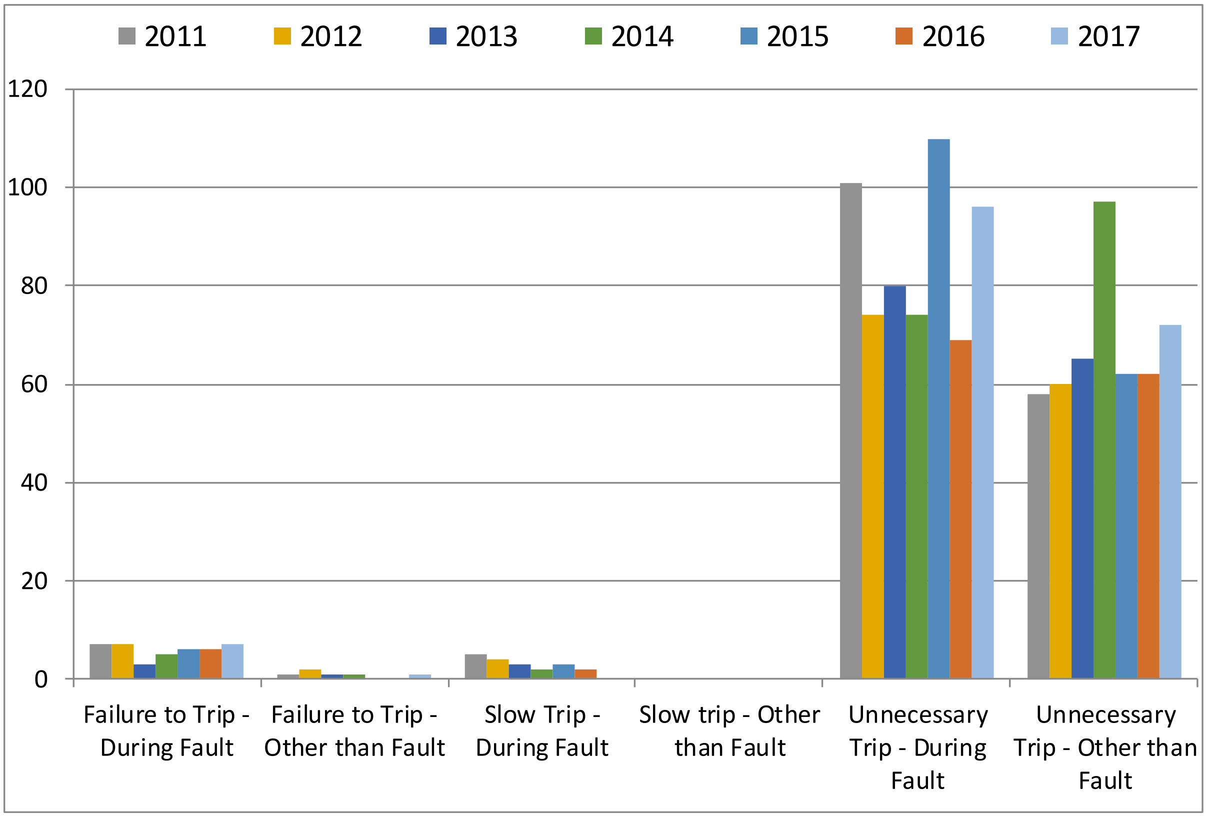


Figure F.7 – Protection System Misoperations by Misoperation Type 2011-2017

Unnecessary trips during a fault on transmission lines remain the main type of misoperation, accounting for 39% of the total number of misoperations.

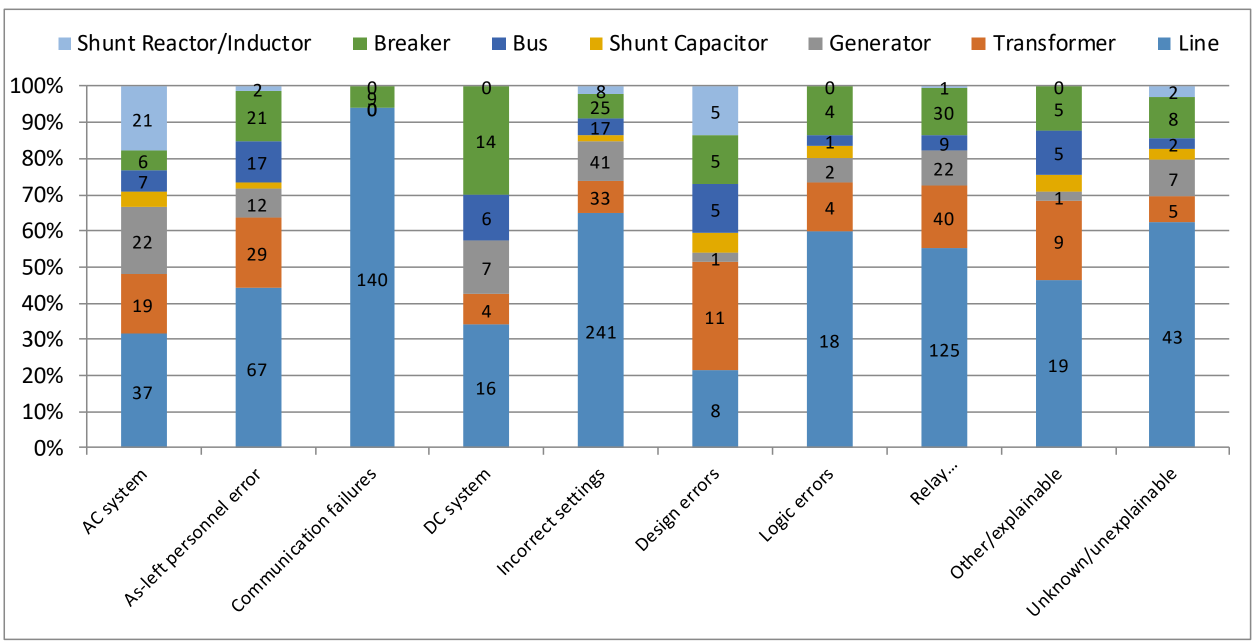


Figure F.8 – Protection System Misoperation Data by Cause and Element

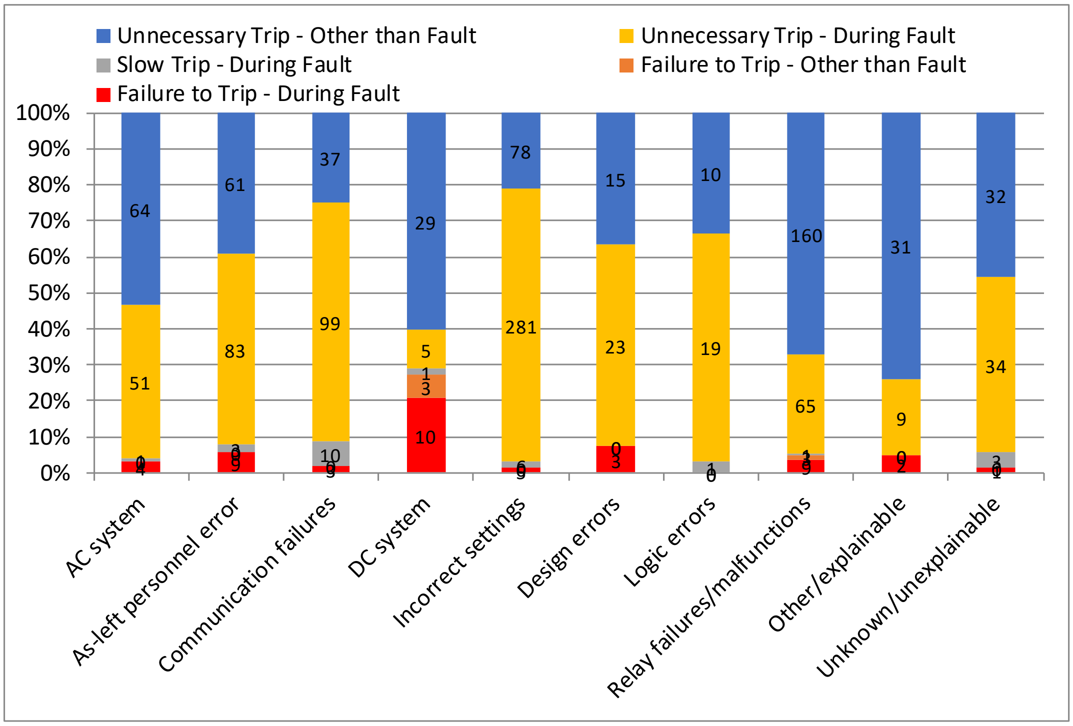


Figure F.9 – Protection System Misoperation Data by Cause 2011-2017

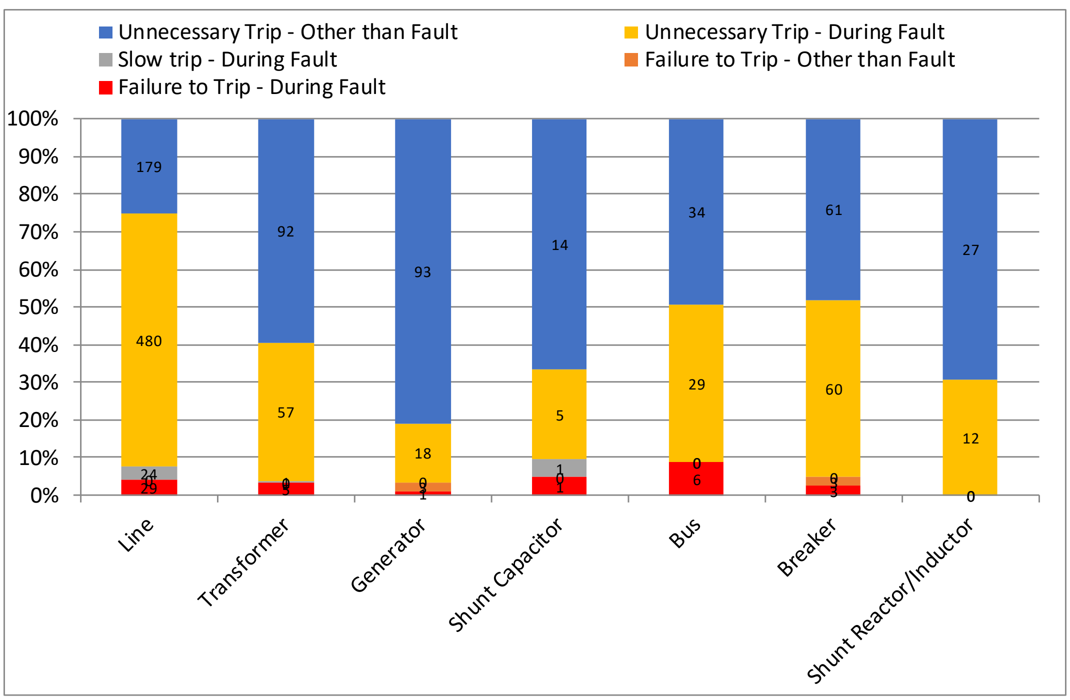


Figure F.10 – Protection System Misoperations by Category 2011-2017