TEXAS RE

Ensuring electric reliability for Texans

2017 Assessment of Reliability Performance

Summary Report

April 2018

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Introduction

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 will 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.

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.

Data sources for this report include:

1. Transmission Availability Data System (TADS)
2. Generation Availability Data System (GADS)
3. Demand Response Availability Data System (DADS)
4. Misoperation Information Data Analysis System (MIDAS)
5. Events Analysis Process

Texas RE's Mission

To assure efficient and effective reduction of risks to the reliability and security of the bulk power system within the ERCOT Interconnection.

Registration

Through the Compliance Monitoring and Enforcement Program (CMEP), NERC and Regional Entities, including Texas RE, assure reliability by holding entities in the Interconnection accountable for compliance with Reliability Standards.

Approximately 15 percent of all registered entities in the United States are under Texas RE's jurisdiction. As of January 1, 2018, there were 215 unique U.S. entities registered with NERC through Texas RE.

Reliability Function	Texas RE	NERC
Balancing Authority	1	105
Distribution Provider	33	362
Distribution Provider-UFLS	8	45
Generator Operator	128	875
Generator Owner	146	920
Planning Authority	1	70
Reliability Coordinator	1	15
Resource Planner	1	171
Transmission Operator	19	184
Transmission Owner	29	331
Transmission Planner	26	186
Transmission Service Provider	1	82
Unique Entities	**215**	**1,394**

Summary of 2017 Key Findings and Observations

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. 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 54% 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.**

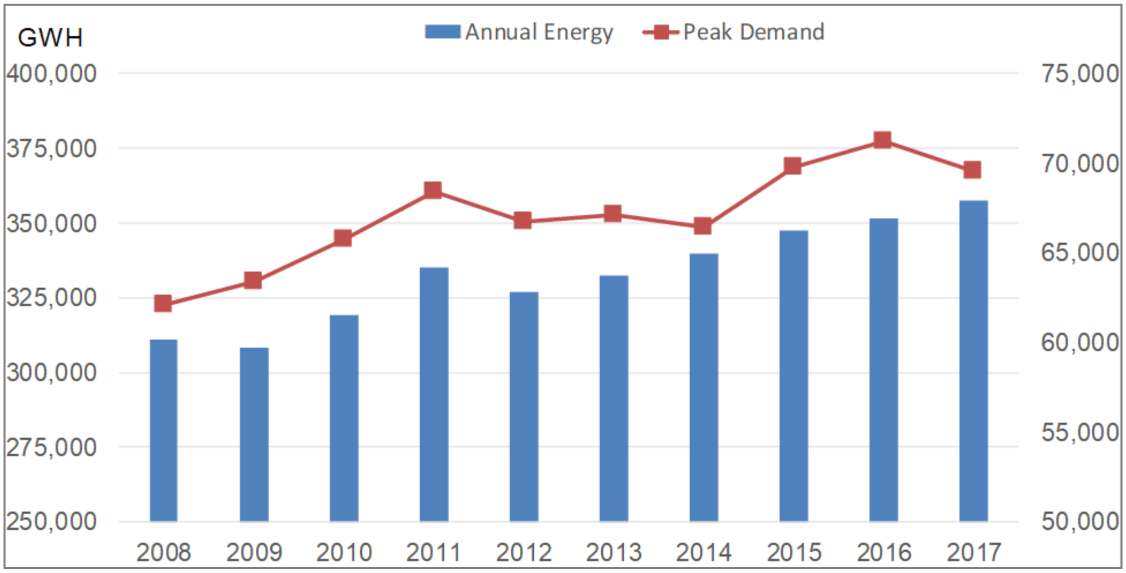
   The outage rate per circuit and outage rate per 100 miles of line in 2017 remained stable when compared to previous years. For the 138 kV system, failed substation equipment and failed transmission circuit equipment continued to dominate the sustained outages, accounting for 85% of the outage duration.

5. **Protection System Misoperation rates increased in 2017.**

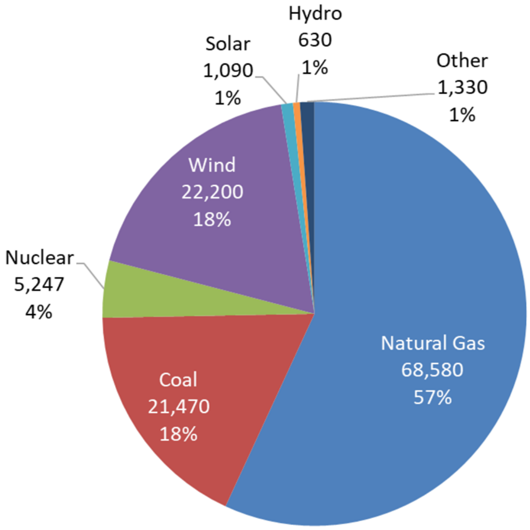
   The overall percent misoperation rate increased from 5.4% in 2016 to 7.3% in 2017, but remains within historical averages.

2017 at a Glance

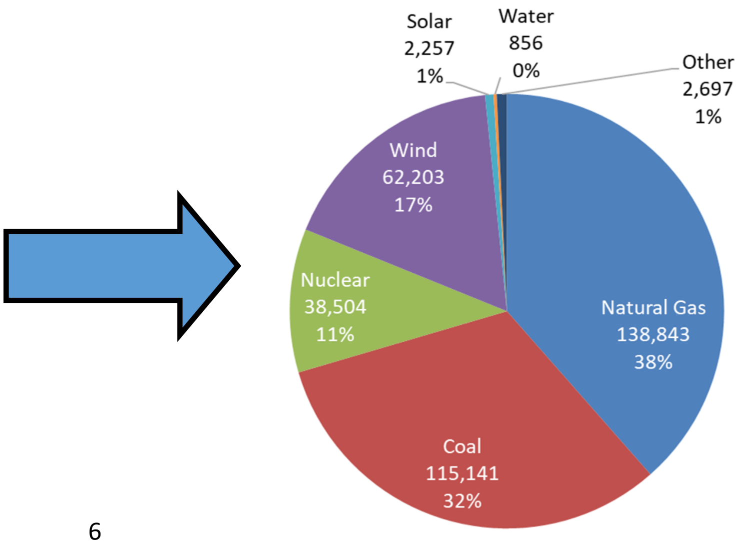
- Peak hourly demand: 69,531 MW on July 28, 2017 versus record of 71,193 MW
- Peak hourly wind generation: 16,035 MW on November 17, 2017 at 10:00 p.m.
- Peak hourly renewable penetration: 53.7% on October 27, 2017 at 3:00 a.m.
- Renewable energy percentage: 18.7% of total energy for calendar year 2017
- 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



2017 Generation Nameplate Capacity (MW)



2017 Energy (GWH) by Fuel Type



2018 Focus Areas

1. **Resource adequacy**

    a. Impact of generation retirements and resource mix changes on system inertia, ramping, and 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.

2. **Weak grid areas on 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.

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, but also on infrastructure that operation of the BPS depends on.

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.

5. **Situational awareness**

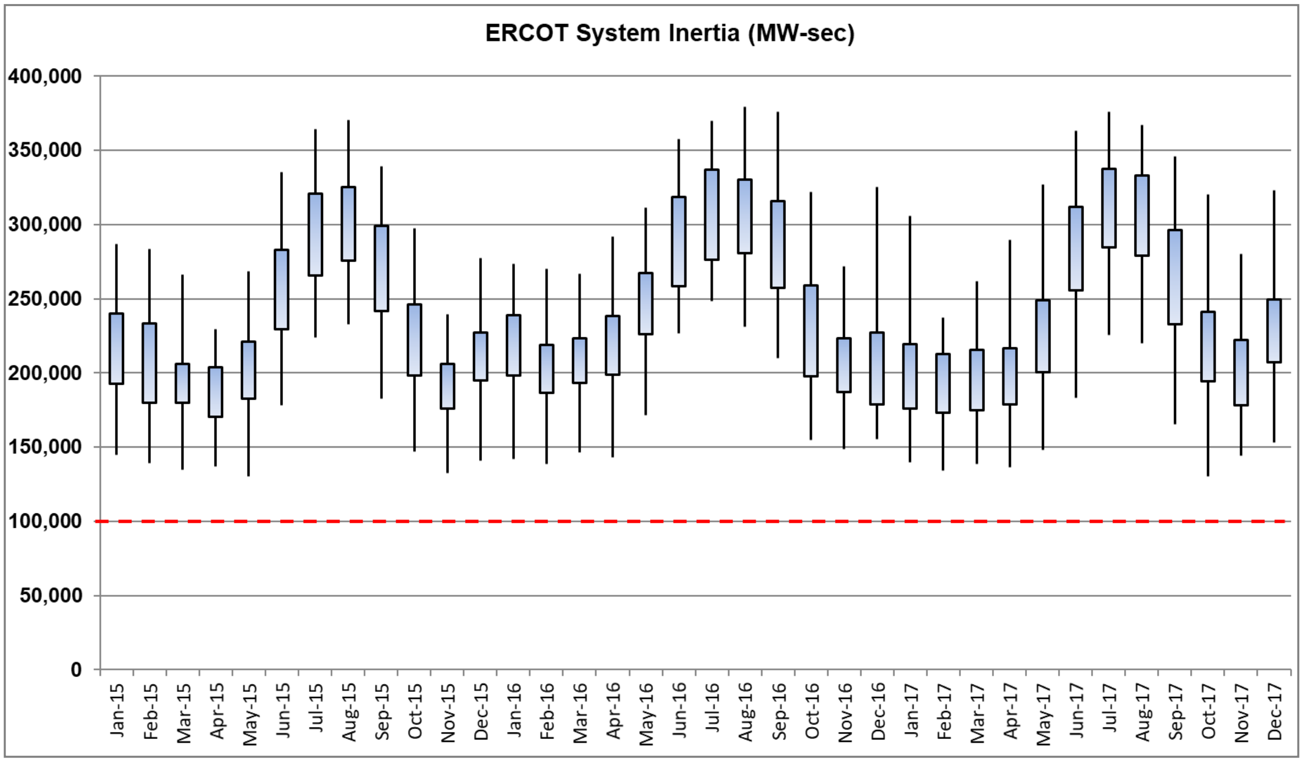
    From 2013-2017, there were a total of 24 loss of EMS/SCADA events reported in the Texas RE Region. Loss of EMS or SCADA events will continue to be of concern due to their impact on visibility and situational awareness for System Operators.

6. **Human performance and skilled workforce**

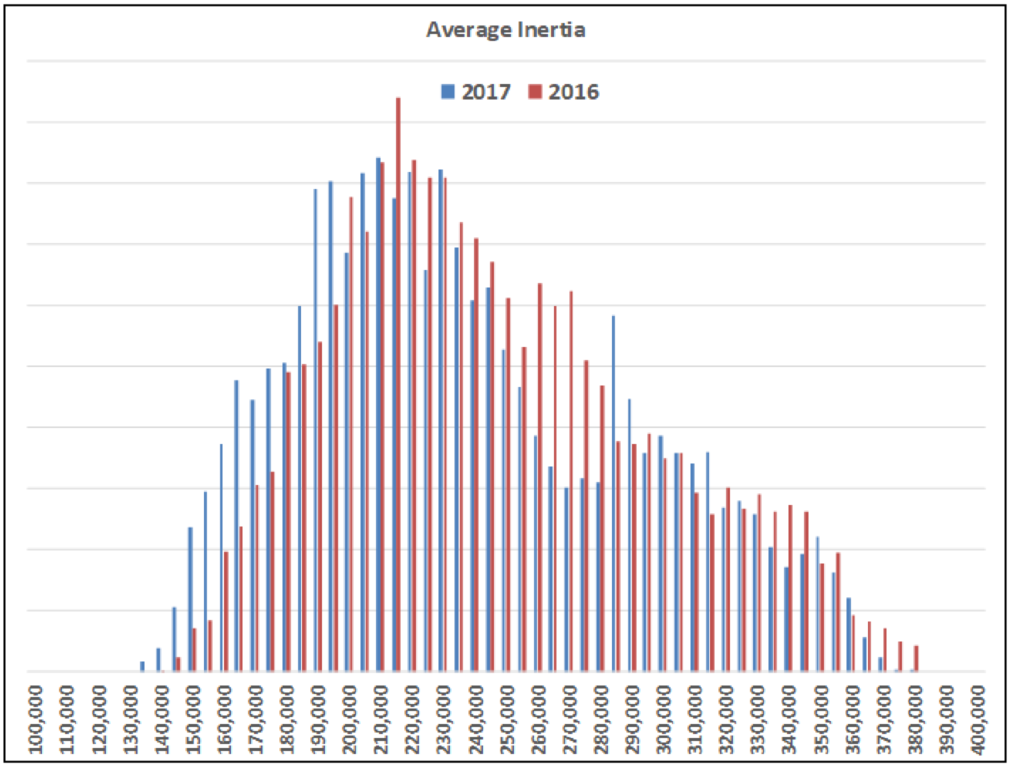
    Skilled workers and technical expertise are vital to the reliable operation of the BPS. Human performance issues manifest themselves in a number of ways, particularly in the areas of Protection System Misoperations, loss of EMS events, asset management and maintenance.

Emerging Issue—Inertia

ERCOT began calculating synchronous inertia in July 2014 in order to better understand and manage the growth in wind generation.



Inertia data indicates a decline in inertia levels in 2017 when compared to 2016.

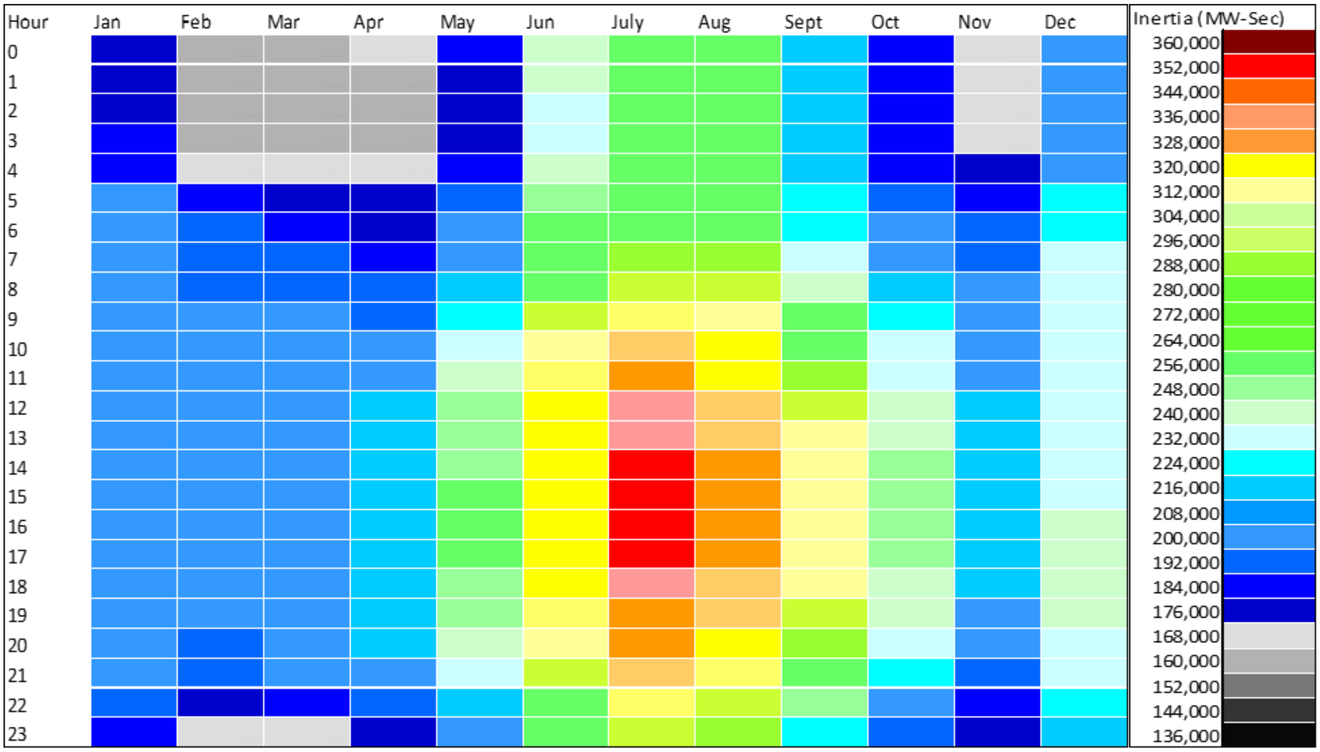


Emerging Issue—Inertia

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).

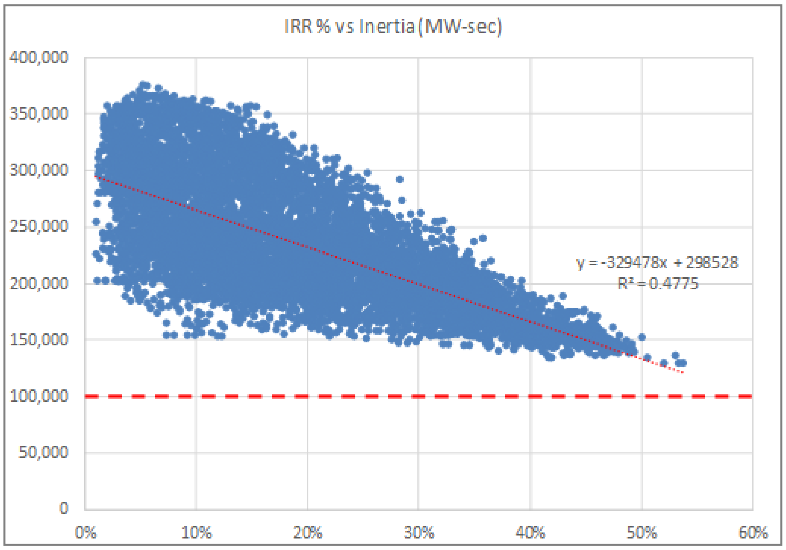
Year	Minimum Inertia (GW-s)	Load (MW)	Net Load (MW)	IRR %
2015	130.3	27,798	20,569	26.1%
2016	138.4	26,839	14,797	44.9%
2017	130.0	28,443	13,178	53.7%

The heat map graph of 2017 inertia levels below shows the weakest inertia time periods are HE 01, 02, 03, and 04 during the shoulder months of February, March, April, and November.

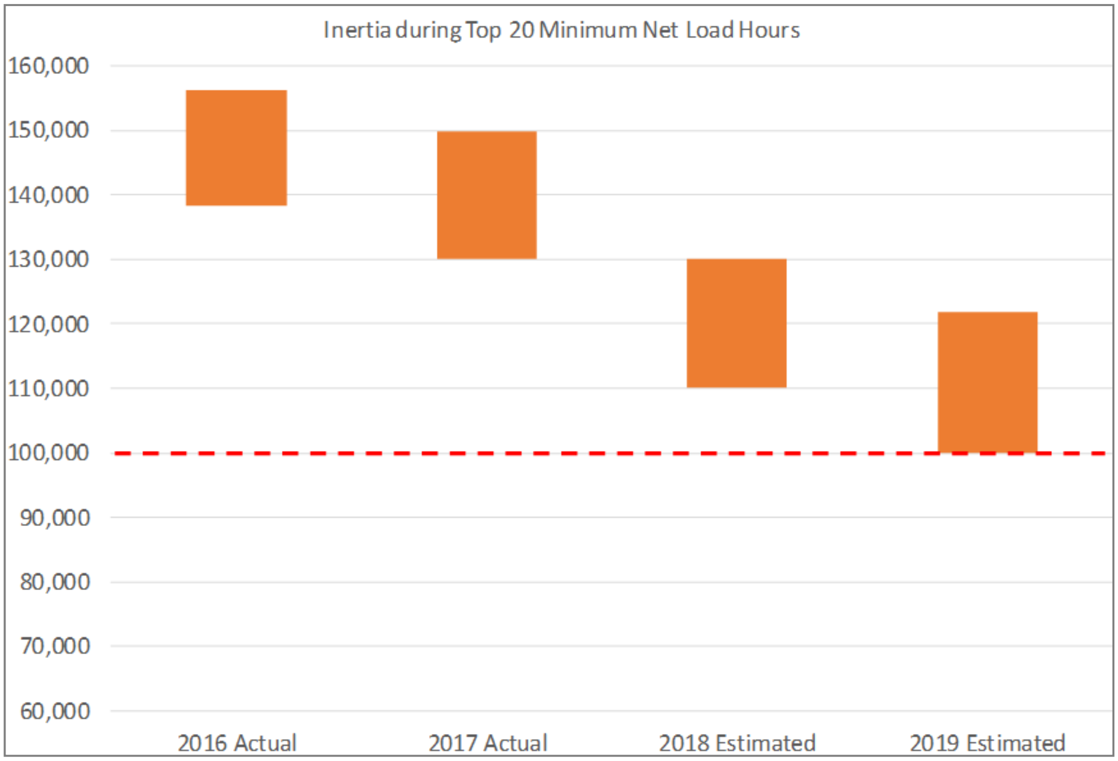


Emerging Issue—Inertia

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



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. This 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).

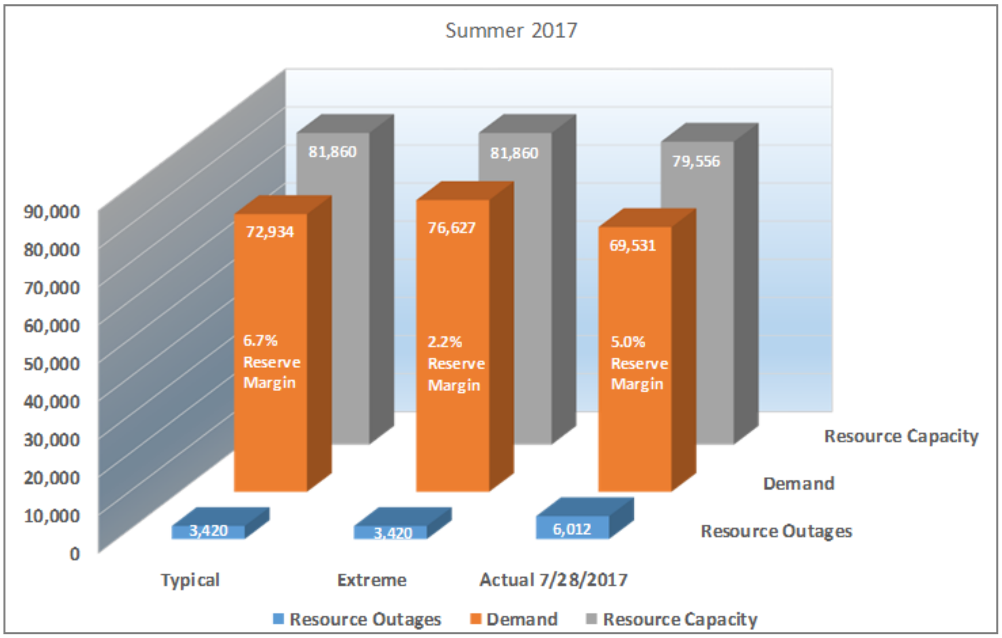


Resource Adequacy

Sufficient operating reserves were maintained during the summer and winter peak hours.

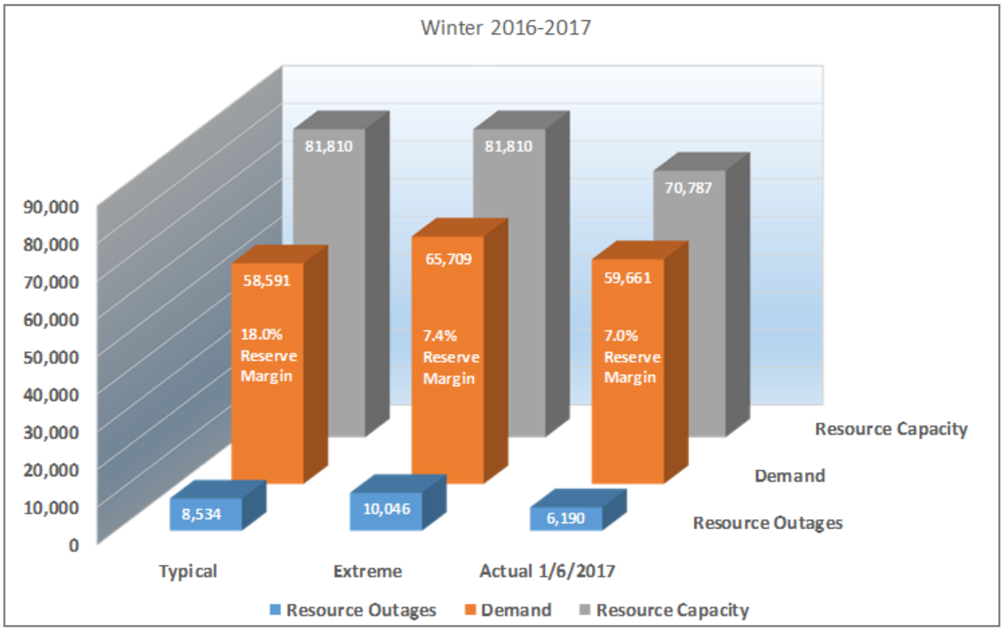
Summer 2017

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.



Disturbances and Events

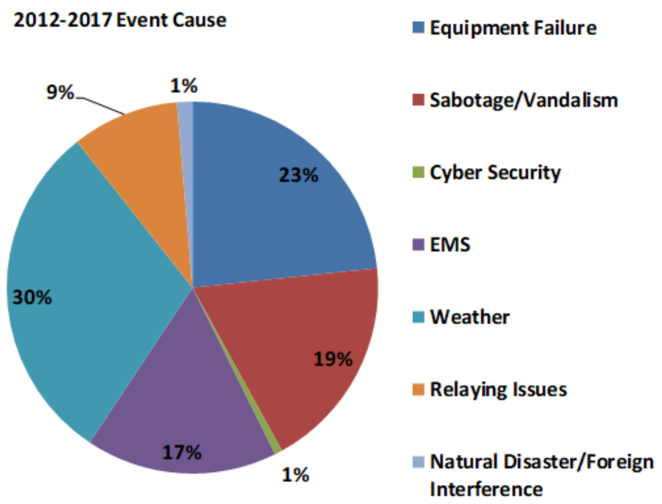
Entities report disturbances affecting the BPS and other events that meet certain criteria through multiple channels. The types that must be reported and the criteria they must meet depend on the channel. This report covers six types of disturbances:

- **Loss of generation or transmission:** Loss of three or more BES facilities from a common cause or loss of ≥ 1,000 MW of generation
- **Loss of load:** Loss of firm load for 15 minutes or more exceeding 300 MW for entities with previous year's demand ≥ 3,000 MW, or 200 MW for all other entities
- **Loss of monitoring or control:** Loss of monitoring capability, control capability, communications, or operator tools for 30 minutes or more that affects an entity's ability to make operating decisions
- **RAS misoperation:** Failed or unnecessary operation of a Remedial Action Scheme
- **Islanding:** Unintentional system separation resulting in an electrical island ≥ 100 MW
- **Facility Damage:** Damage, destruction, or physical threats to a BES Facility from actual or suspected intentional human action, or results in actions to avoid an Emergency.

These disturbances are reported to Texas RE through the Event Analysis Process, Reliability Standard EOP-004, and Department of Energy Form OE-417.

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

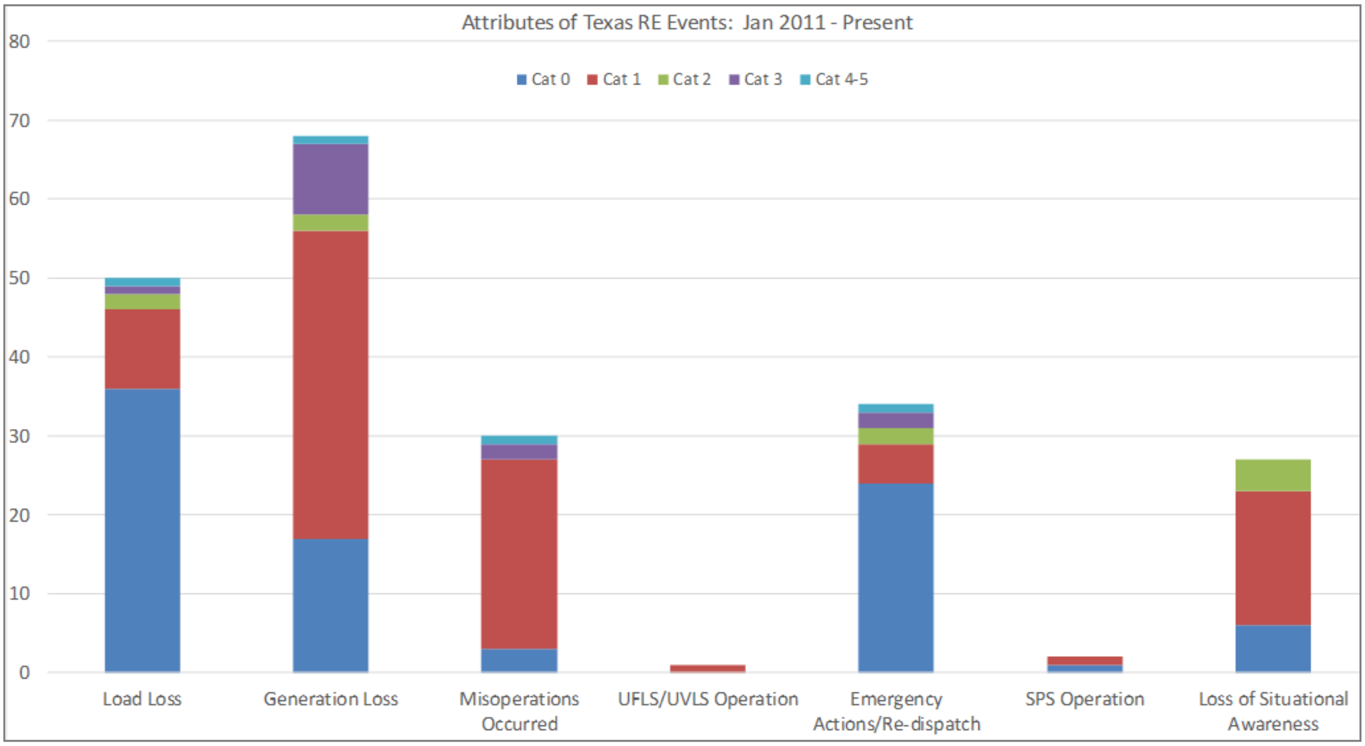
Event Category	2013	2014	2015	2016	2017	5-Yr Avg
Non-Qualified	92	77	90	65	52	75
1	7	11	9	5	11	9
2	2	2	1	0	0	1
3	1	1	1	2	0	1
4 and 5	0	0	0	0	1	0
Total	102	91	101	72	64	86

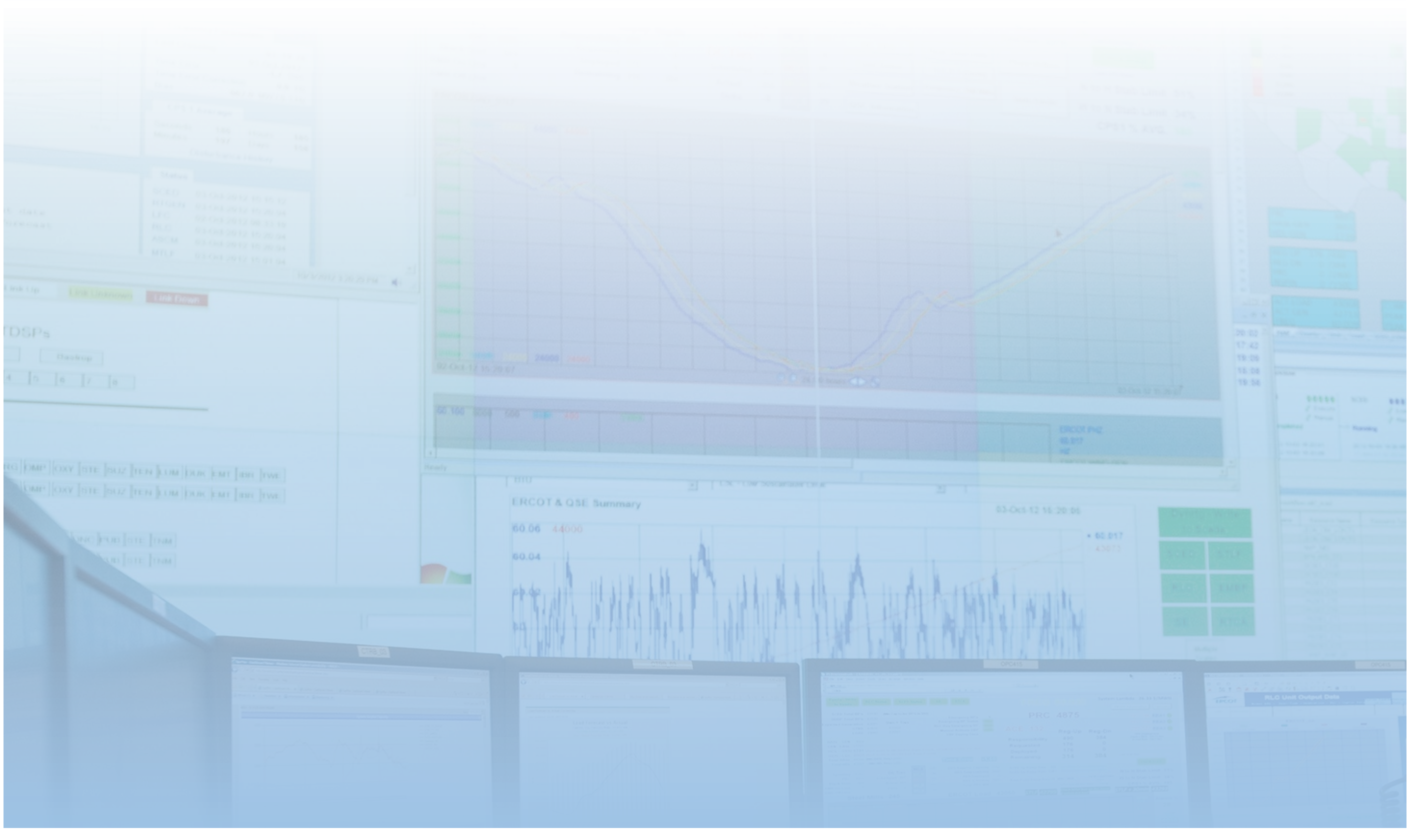


NERC Events Analysis Process, including category definitions

Disturbances and Events

Event severity is determined by a number of key attributes, including load lost, MW of generation lost, protection system misoperations, emergency actions taken, etc.





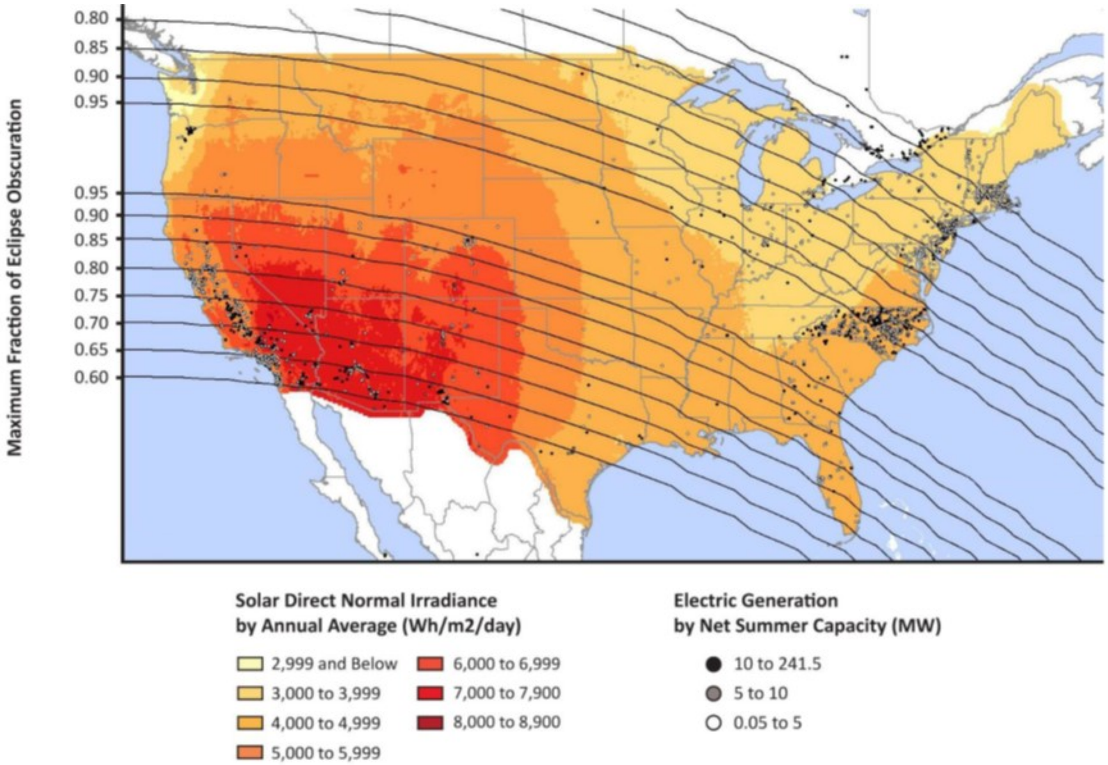
2017 Major Events

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.

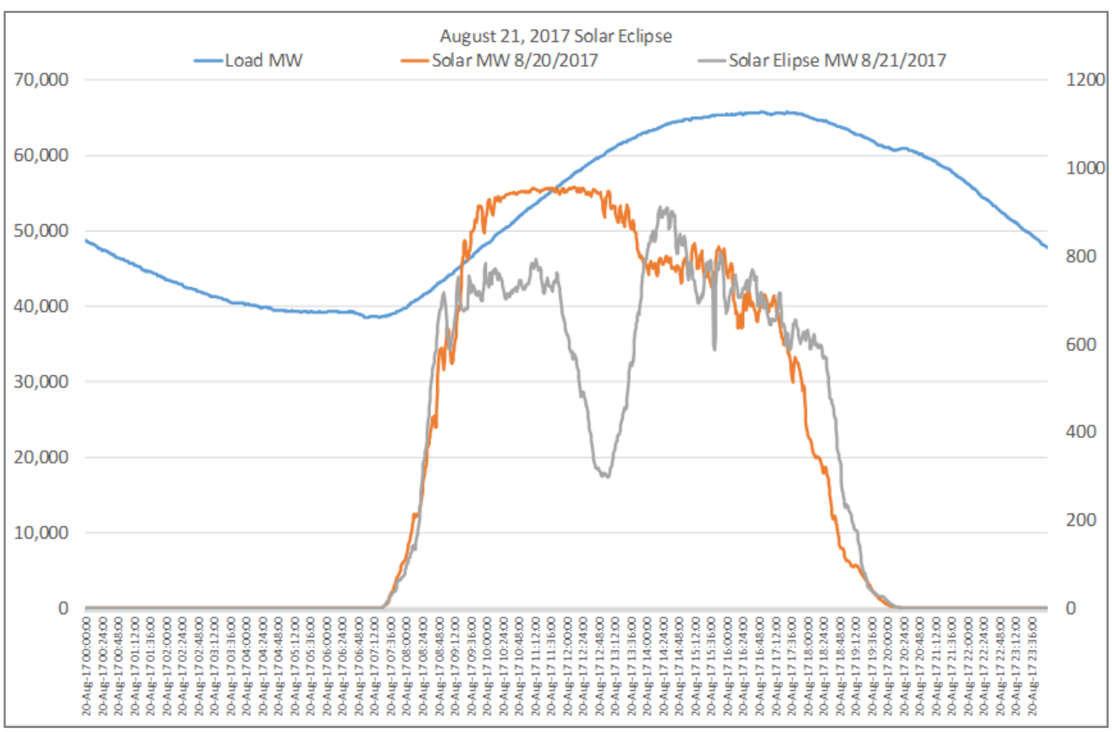
2. **Loss of EMS event on May 4, 2017**
   A large transmission entity lost its primary and backup EMS systems on May 4, 2017 for over seven hours. During a routine update of the EMS, new database elements were added to represent installed field equipment and these additions exceeded a specific size 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 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%.



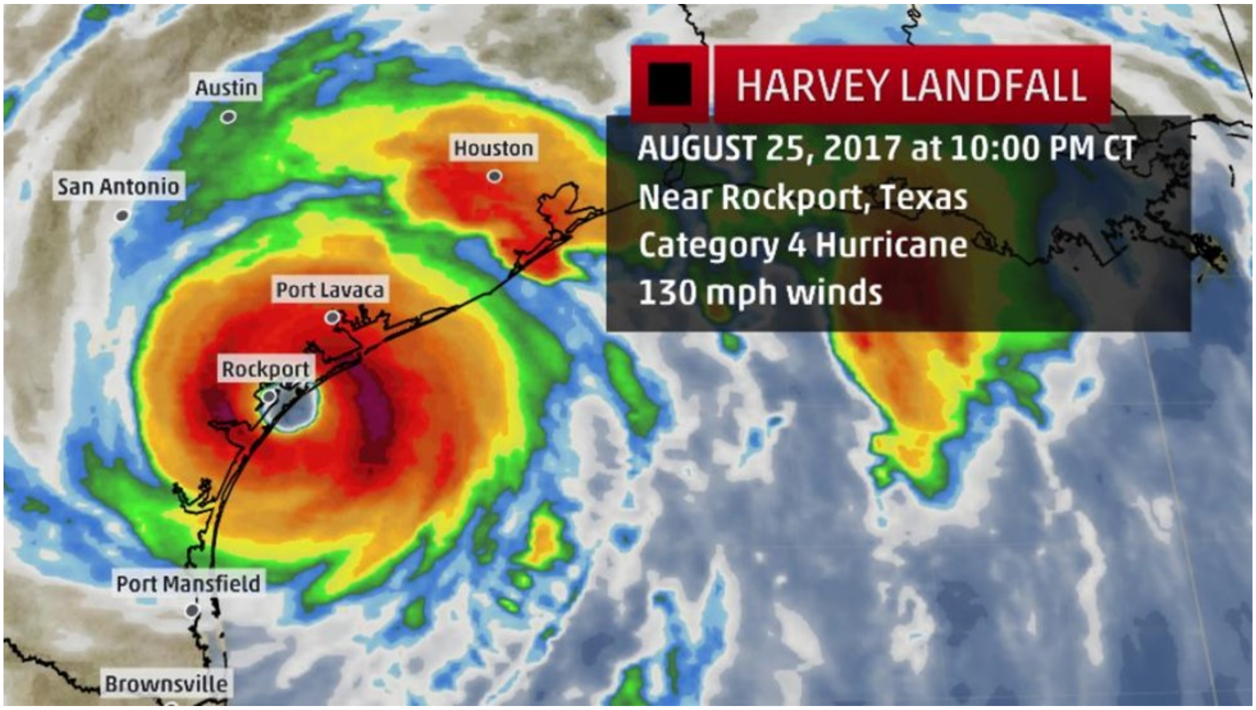
Solar Eclipse Estimated Obstruction



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. 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. Low-lying stations were flooded and became completely inoperable, and 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.



Hurricane Harvey Landfall

Transmission Performance

2017 Transmission Performance in Brief, based on TADS data.

345 kV

Circuits: 433

Circuit miles: 15,263

Circuit Automatic Outages: 407

Circuit Outage Duration: 5,840 hrs

Transformer Automatic Outages: 31

Transformer Outage Duration: 12,818 hrs

138 kV

Circuits: 1,856

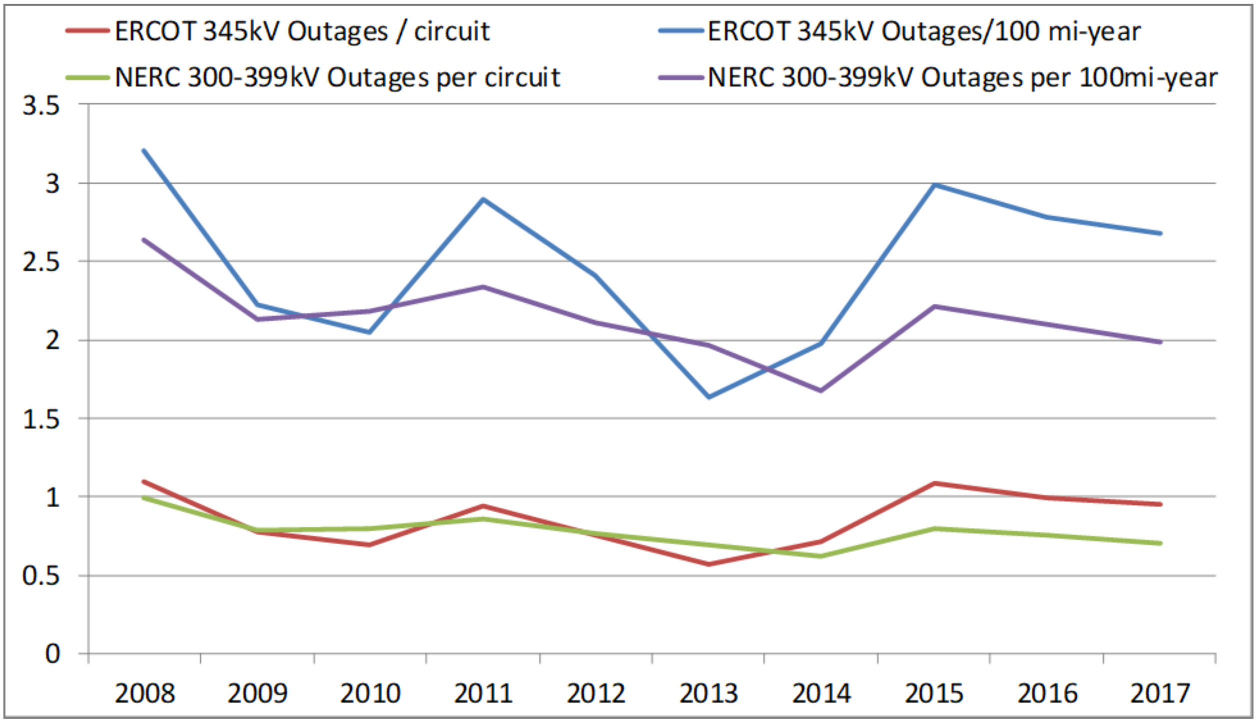
Circuit miles: 21,516

Circuit Automatic Outages: 406

Circuit Outage Duration: 10,875 hrs

- 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.

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. 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.



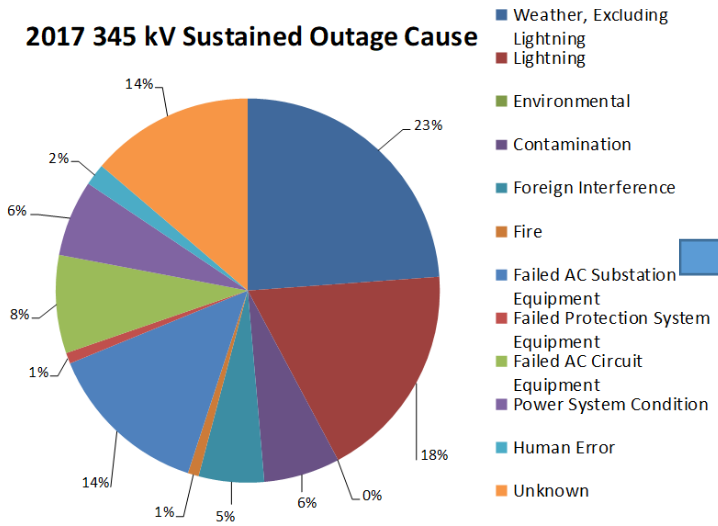
Transmission Performance

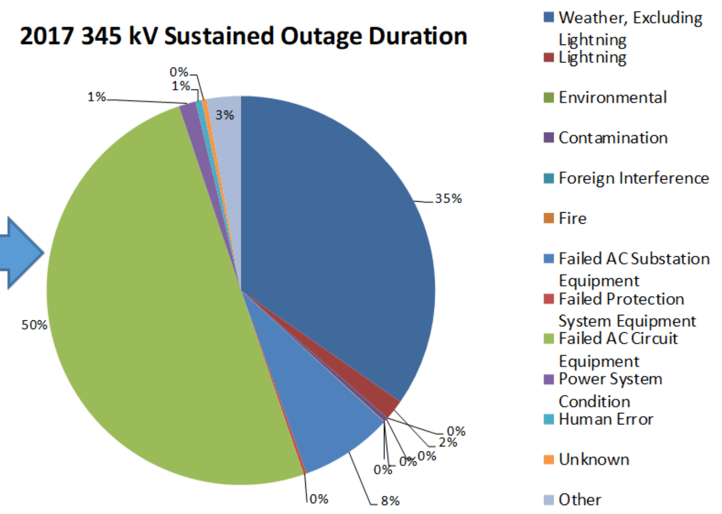
TADS Automatic Outage Historical Data for ERCOT

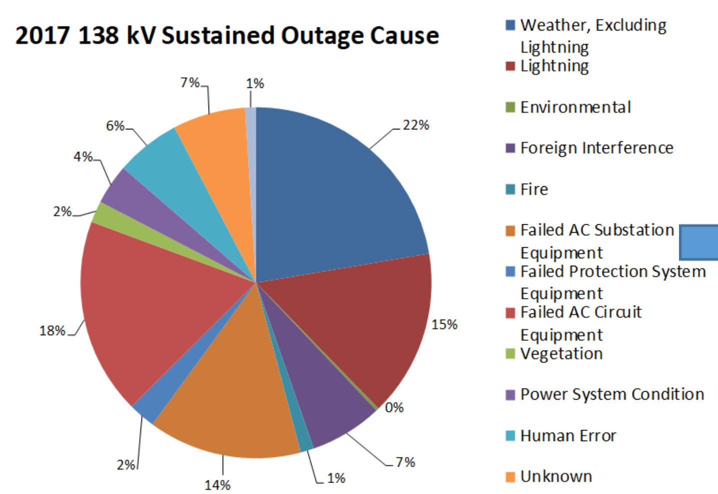
Voltage Class Name	Metric	2013	2014	2015*	2016	2017	5-Yr Avg
AC Circuit 300-399 kV	Automatic Outages per Circuit	0.57	0.71	1.08	0.99	0.95	0.86
AC Circuit 300-399 kV	Automatic Outages per 100 miles	1.63	1.97	3.00	2.78	2.68	2.41
AC Circuit 100-199 kV	Sustained Automatic Outages per Circuit			0.25	0.19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

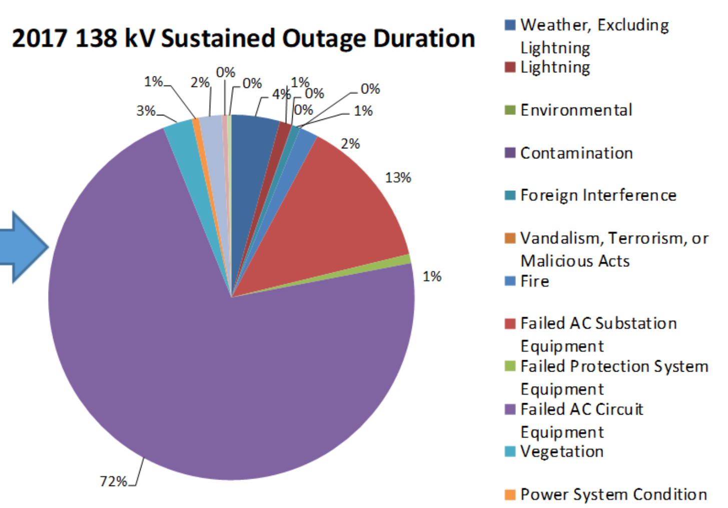
*2015 was the first year of TADS reporting for 138 kV circuits

2017 Transmission Circuit Sustained Outages by Cause and Duration









Generation Performance

Unplanned outages of generating units can undermine reliability by reducing capacity available to meet demand. They can also introduce instability by reducing frequency and depriving the system of voltage support and ramping capability to match changes in load. In some cases, the loss of a large unit in one part of the Interconnection can cause units in other parts of the system to trip, further impacting reliability.

2017 Generation Performance in Brief:

- 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.
- Generation forced outages (from GADS data): 1,849
- Equivalent Forced Outage Rate (EFOR), MW Weighted from GADS data: 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.

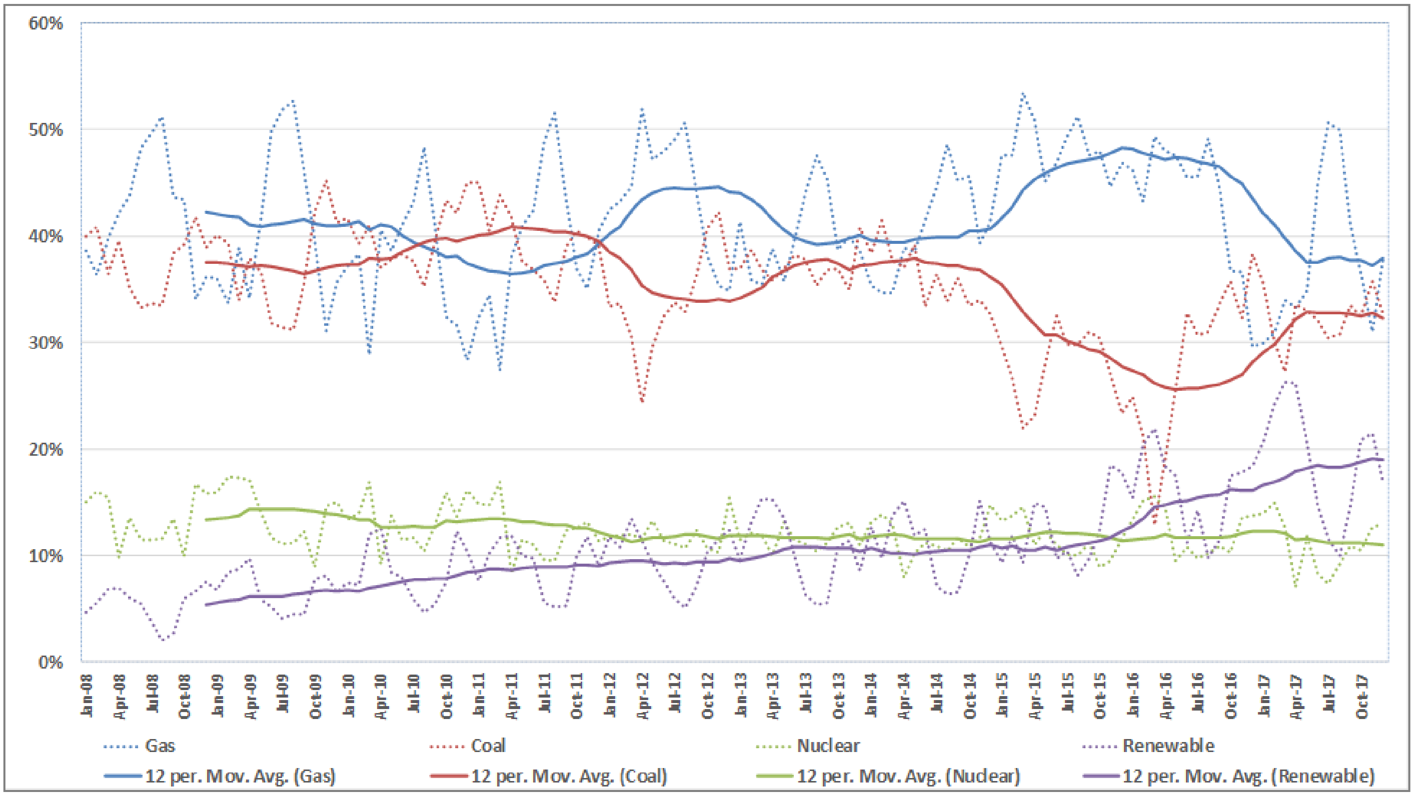
The portion of total energy supplied by natural gas continued to decline in 2017, from 48% in 2015, to 44% in 2016 and down to 38% in 2017 as wind energy continued to increase. The portion of total energy supplied by coal increased slightly by 3%, from 29% in 2016 to 32% in 2017. However, the portion 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.

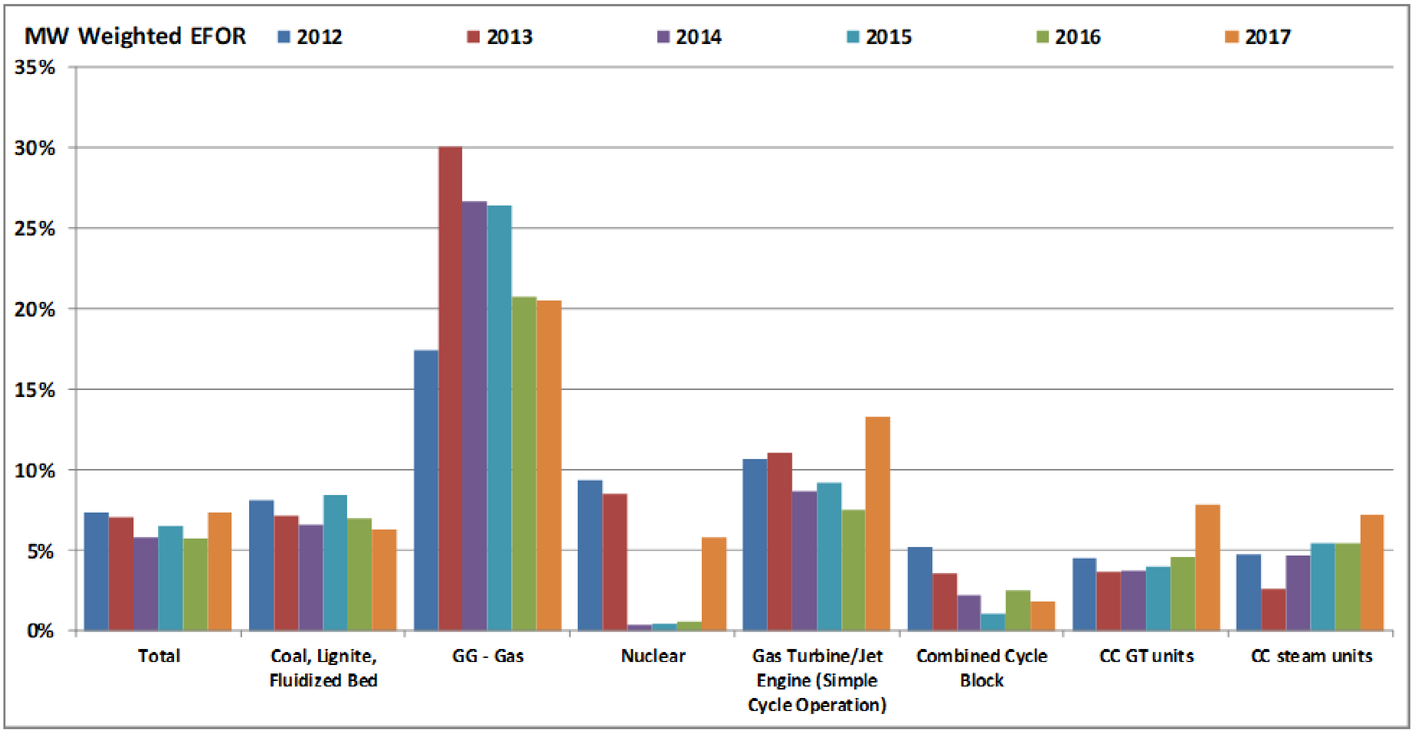
2017 Performance Metrics, based on GADS Data

Metric	Texas RE Region 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%	

Generation Performance

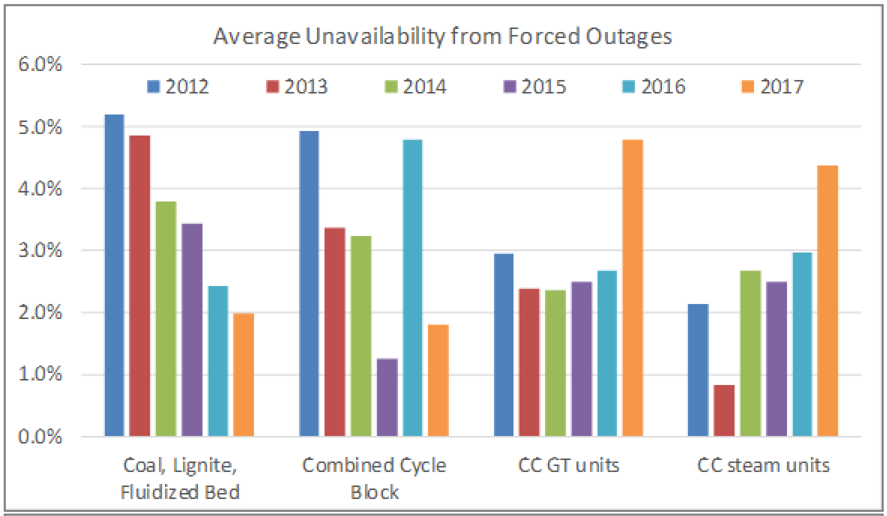
Fuel Type as a % of Total Energy

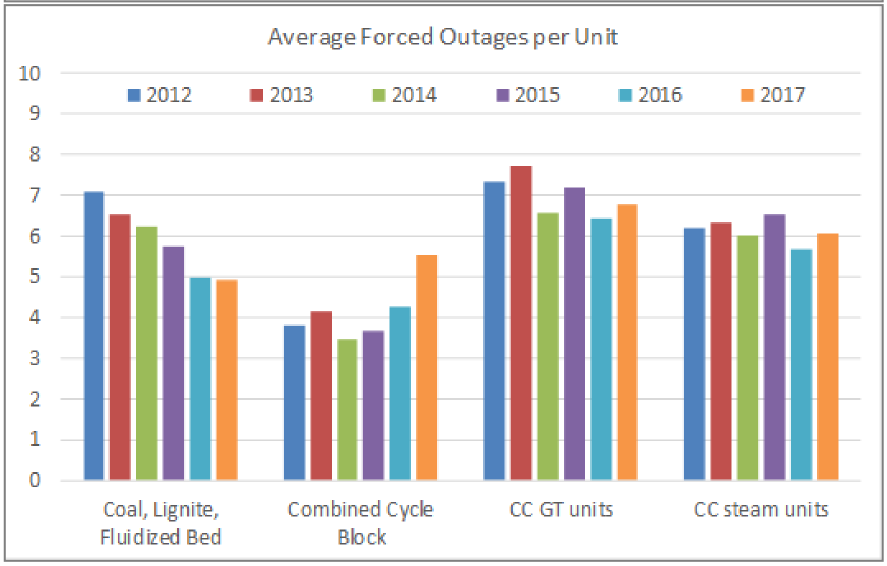


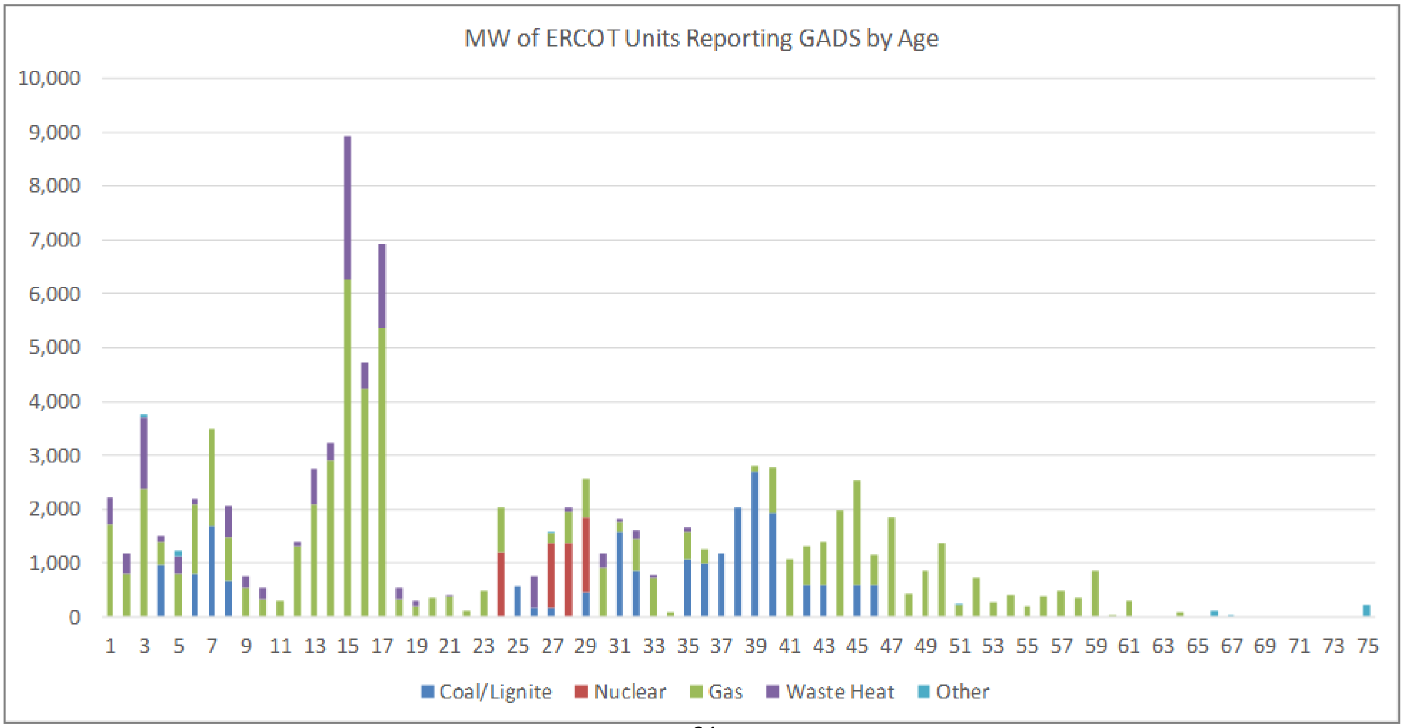


Generation Performance

The age of the generating fleet is sometimes used as an indicator for increasing outage rates. The age characteristics of the fleet reported to GADS shows an age bubble around 35–39 years, driven by coal and some gas units and second age bubble around 12–18 years comprised almost exclusively of gas and combined cycle units.

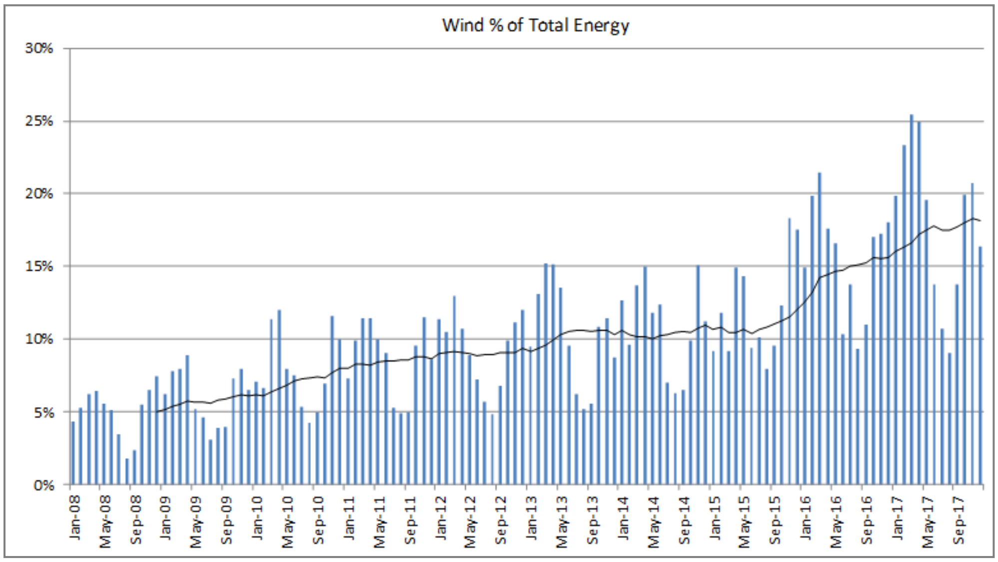




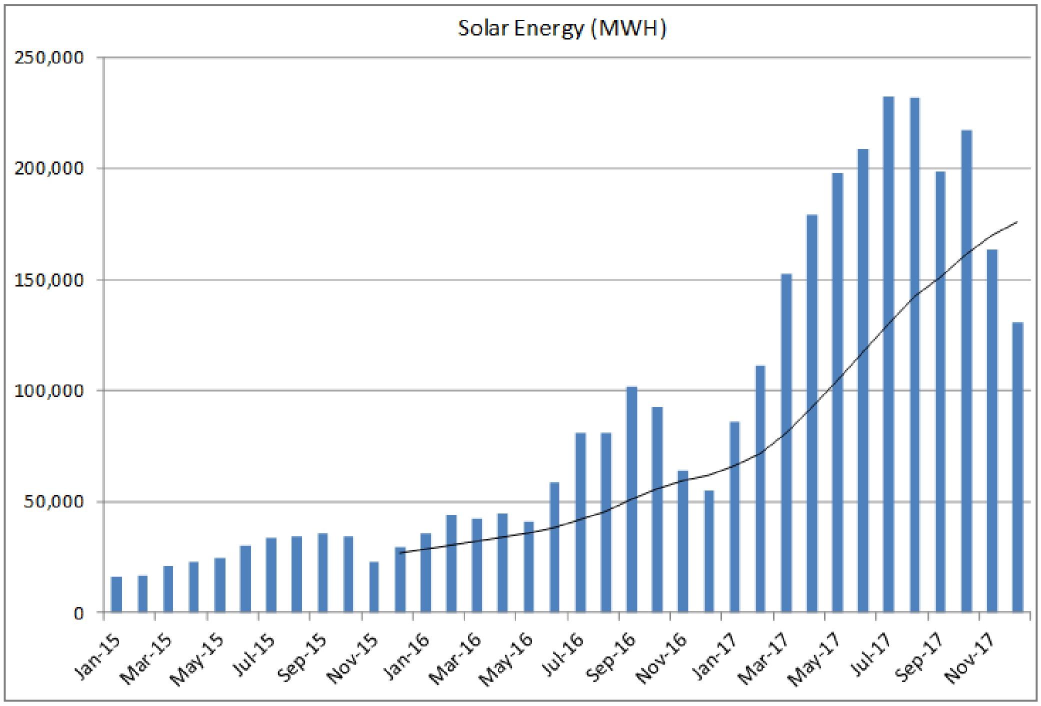


Renewable Generation

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.



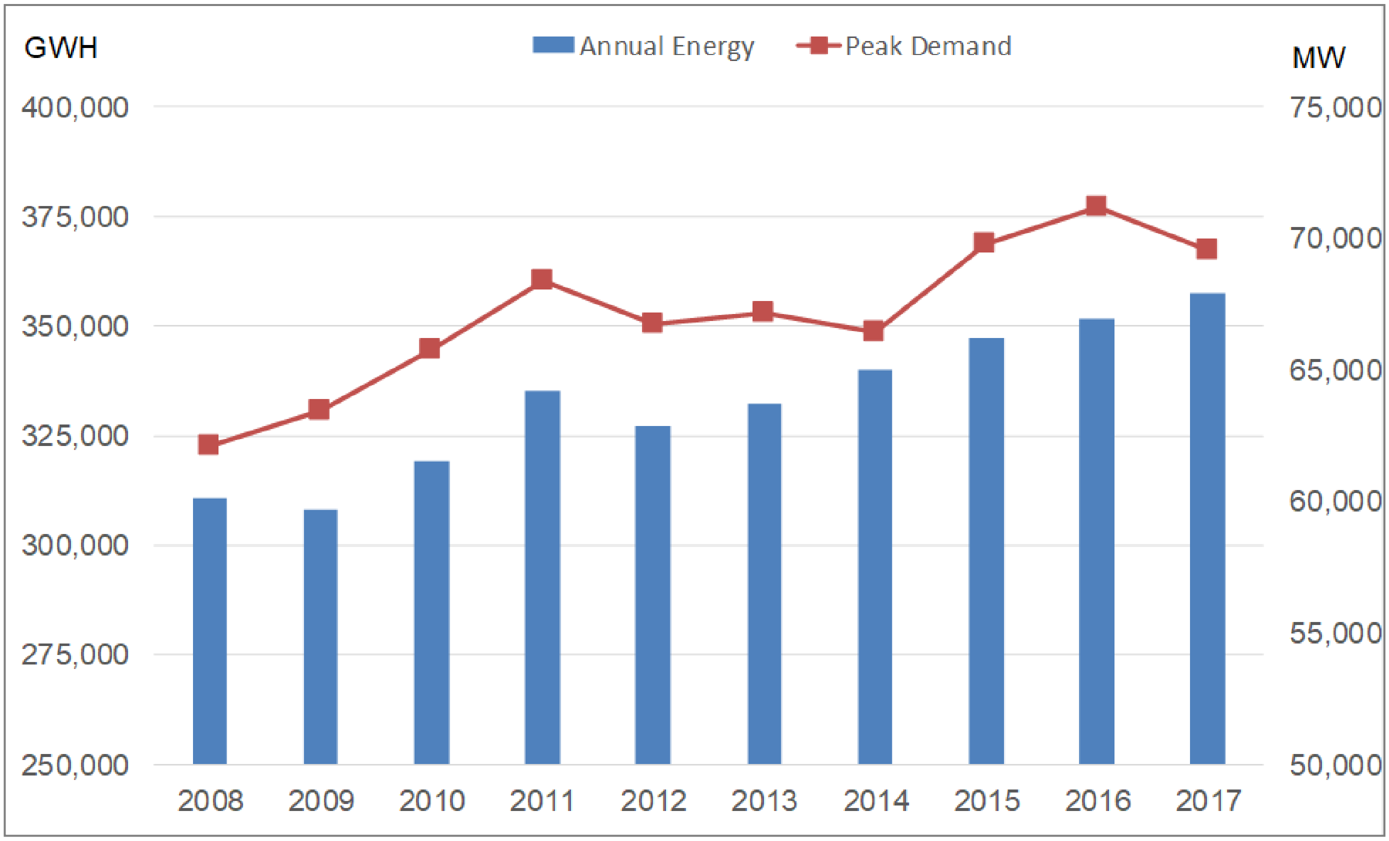
Utility-scale solar generation within the region nearly doubled during 2017, from 560 MW in January 2017 to almost 1,000 MW by December. The amount of energy provided by solar generation increased by 185% versus 2016.



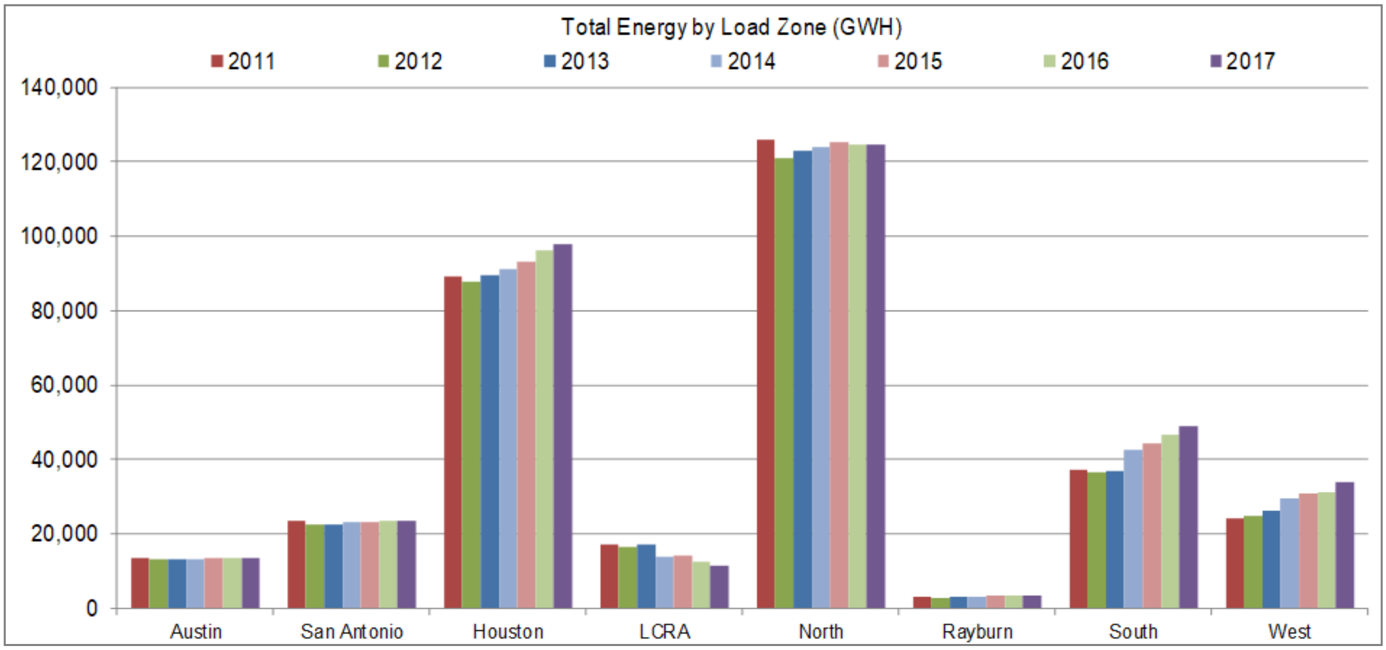
Load

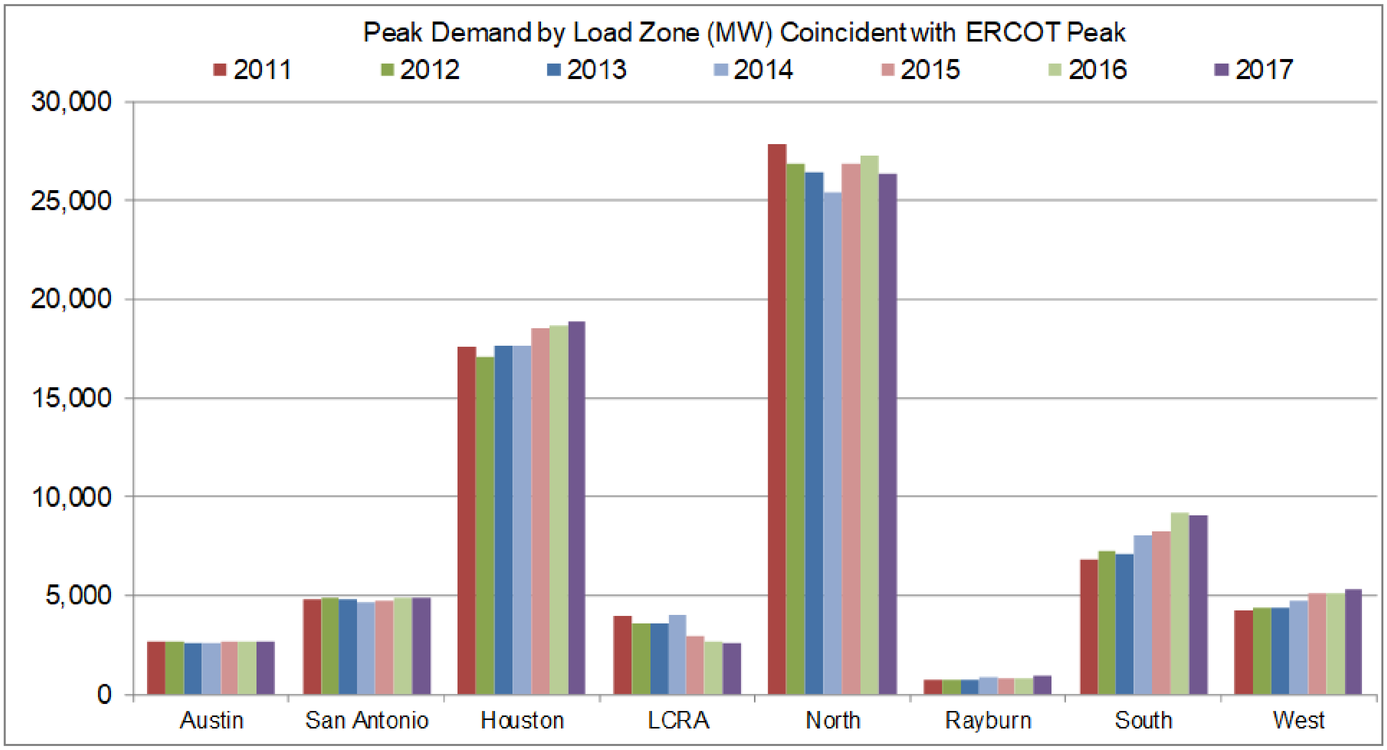
Total energy consumption increased by 1.7% in 2017 versus 2016, to over 357,370 GHW. Peak demand declined in 2017 to 69,531 MW, compared to the all-time record of 71,193 MW reached on August 11, 2016. Areas with load growth continue to be led by the Houston, South and West load zones (Coast, Far West,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

- 2017 Summer Hourly Peak Demand: 69,531 MW on July 28, 2017 at HE17
- 2017 Winter Hourly Peak Demand: 59,661 MW on January 6, 2017 at HE19



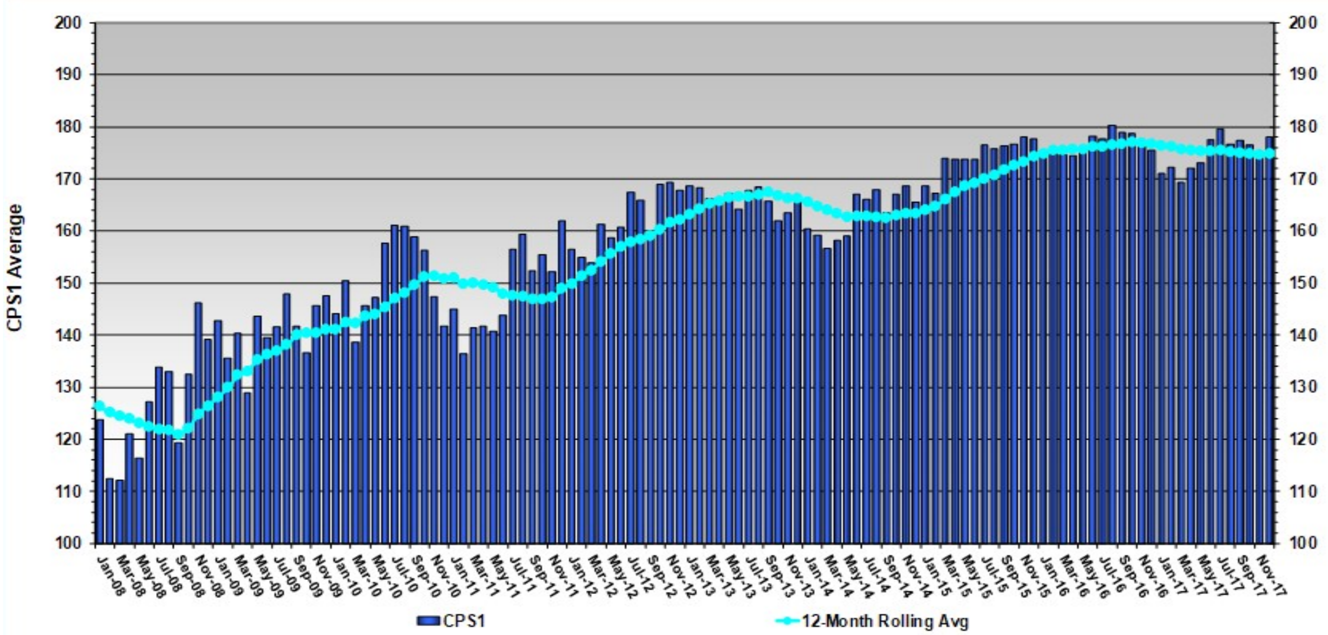
Load


Total Energy by Load Zone (GWH)
2011
2012
2013
2014
2015
2016
2017
140,000
120,000
100,000
80,000
60,000
40,000
20,000
0
Austin
San Antonio
Houston
LCRA
North
Rayburn
South
West

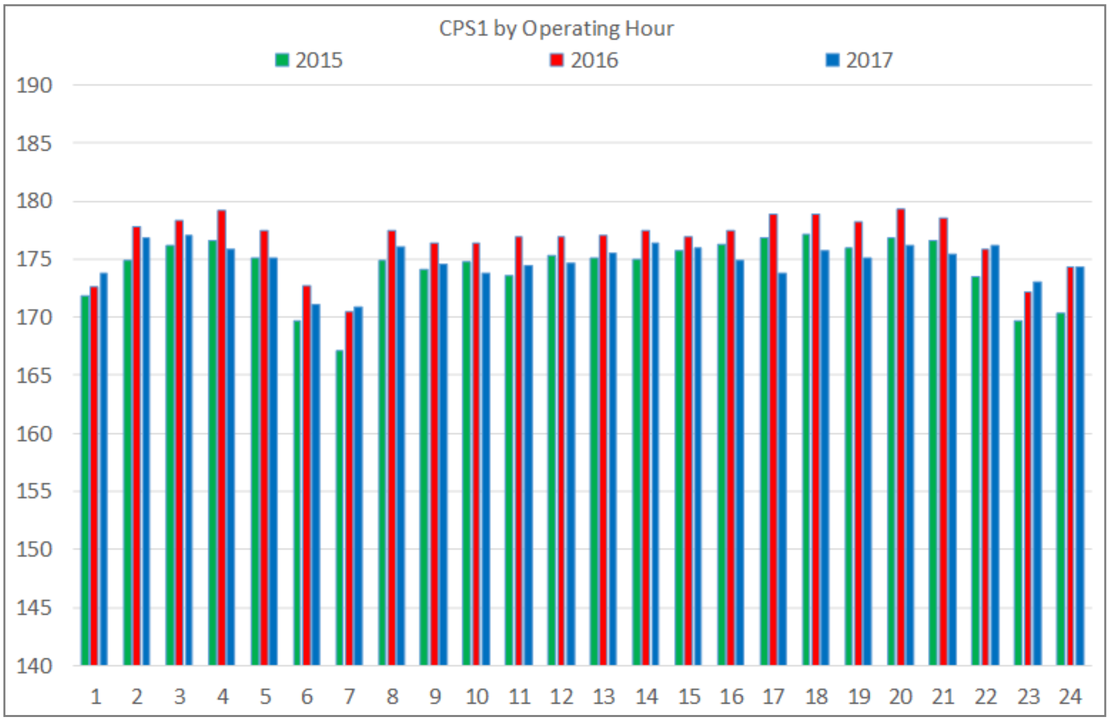

Peak Demand by Load Zone (MW) Coincident with ERCOT Peak
2011
2012
2013
2014
2015
2016
2017
30,000
25,000
20,000
15,000
10,000
5,000
0
Austin
San Antonio
Houston
LCRA
North
Rayburn
South
West

Frequency Control

- 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

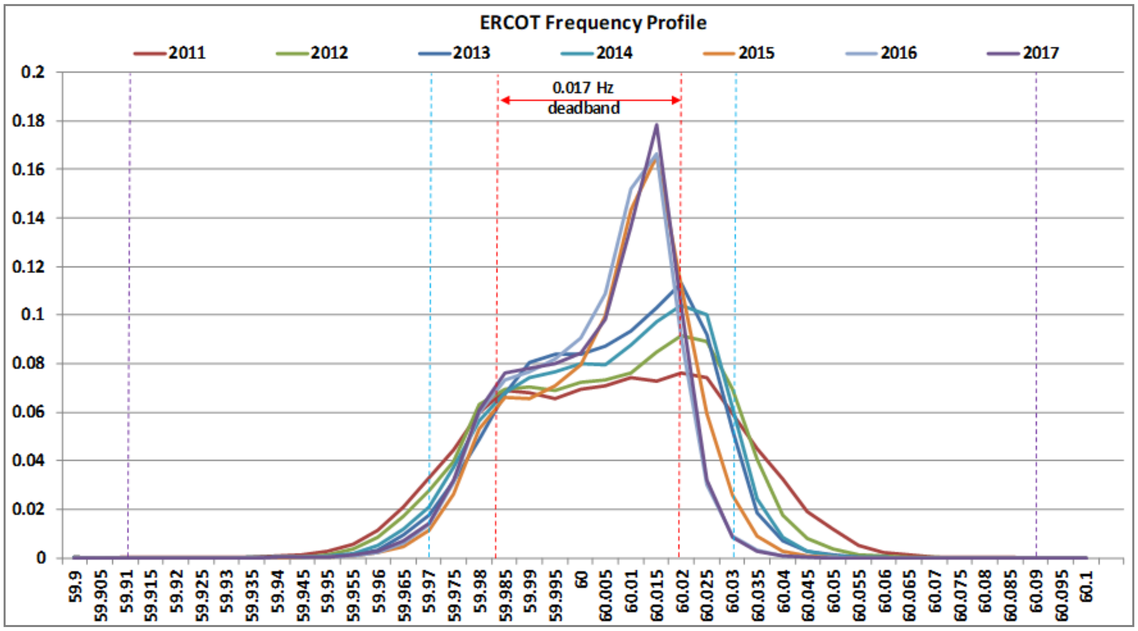


The CPS1 score by operating hour continues to indicate possible issues for hour-ending (HE) 06, HE07, and HE23. These issues are related to the load ramps during these hours and procedures used by generation resource entities during unit startup and shutdown.

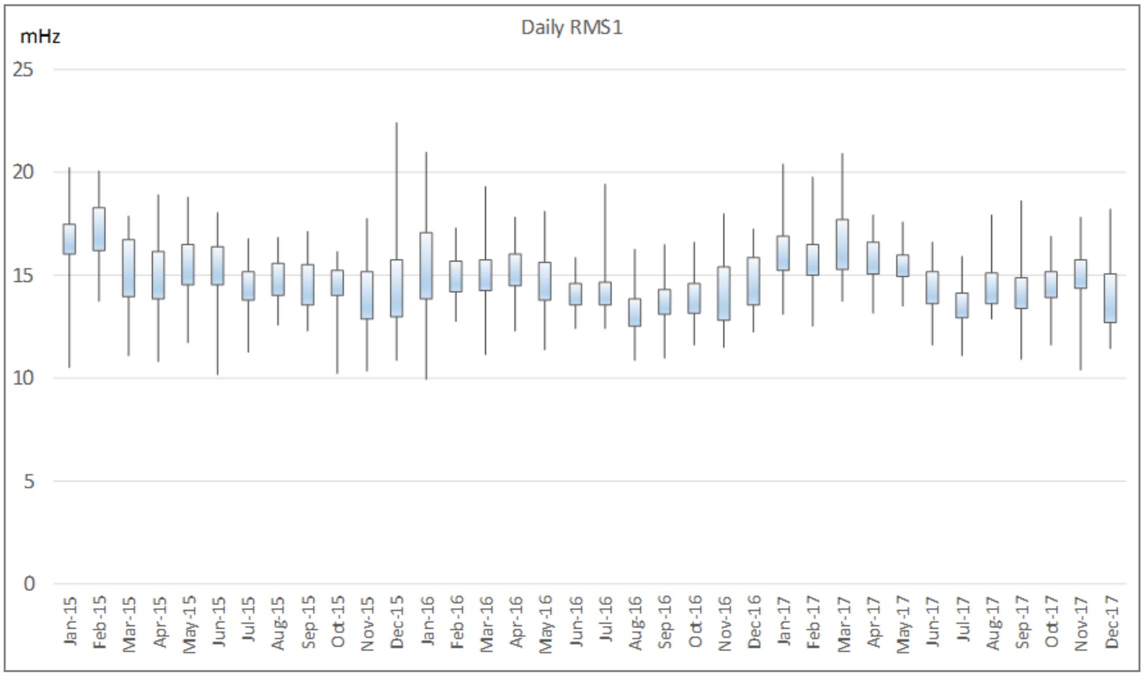


Frequency Control

The ERCOT frequency profile 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.

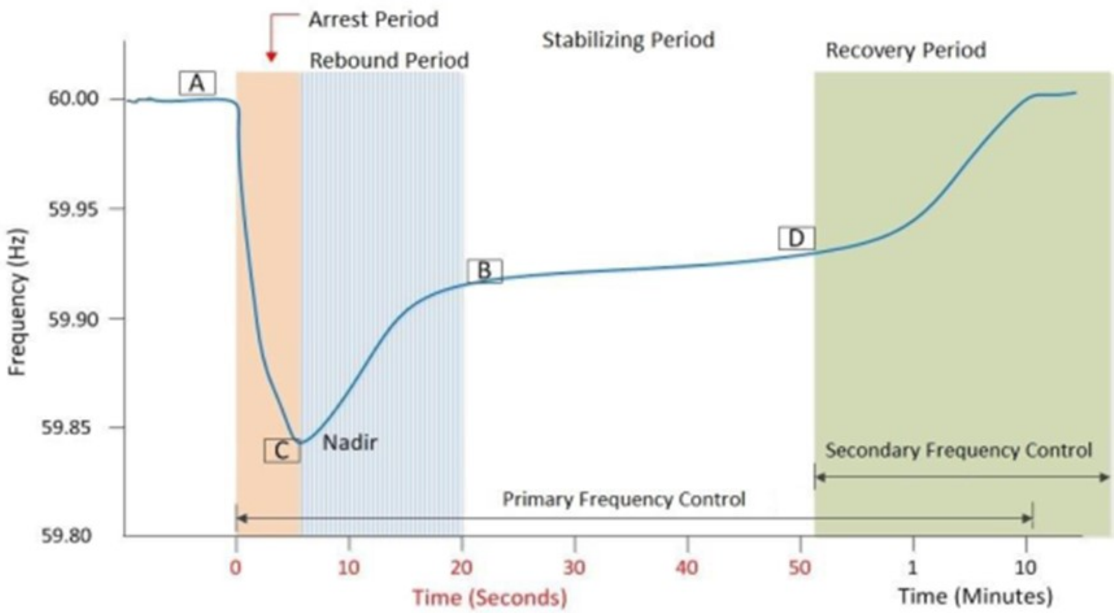


The daily RMS1 chart shows the average root-mean-square of the frequency error based on one-minute frequency data. The long-term trend continues to show excellent control of frequency error.



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.



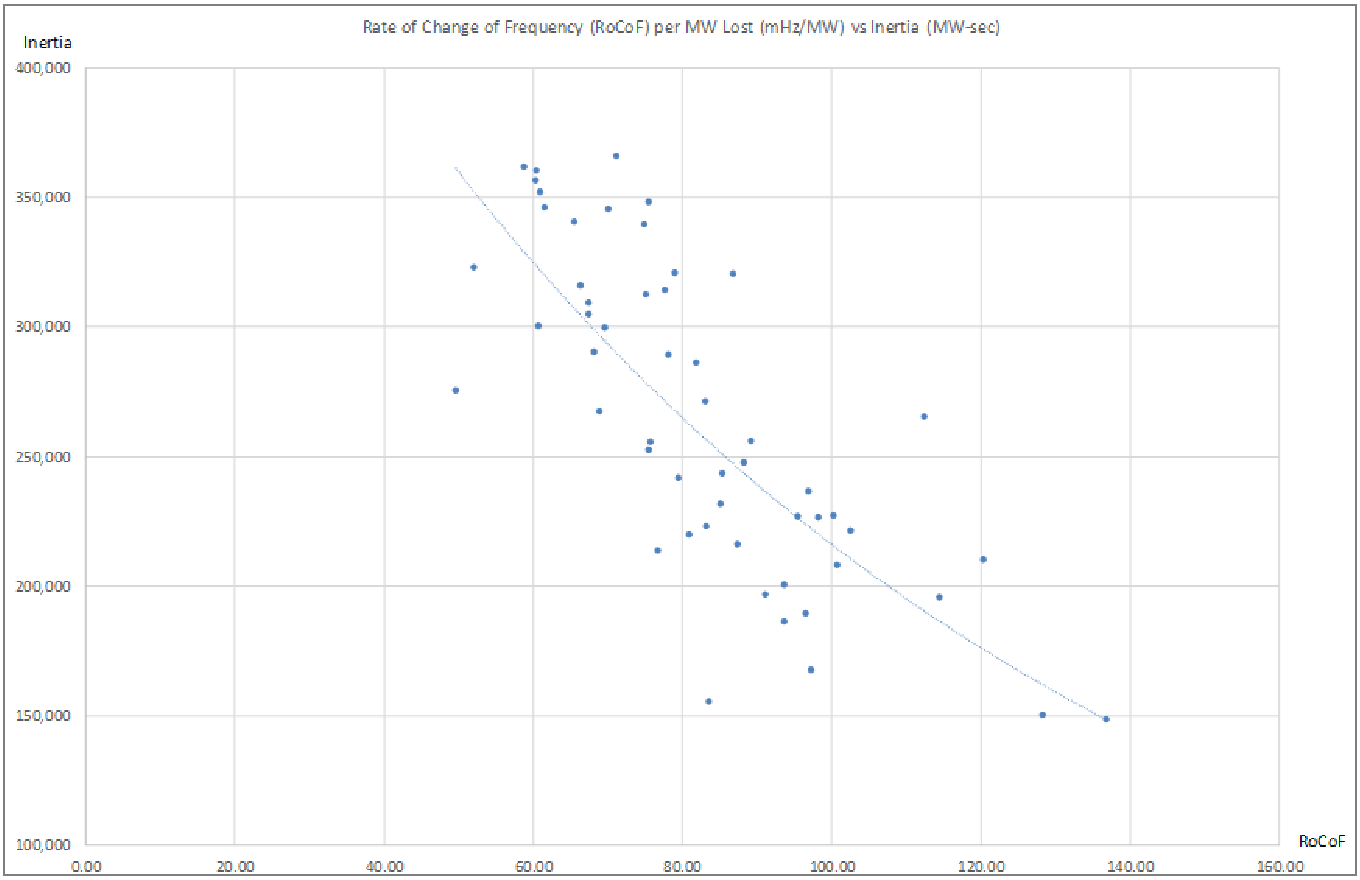
Typical Frequency Disturbance

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

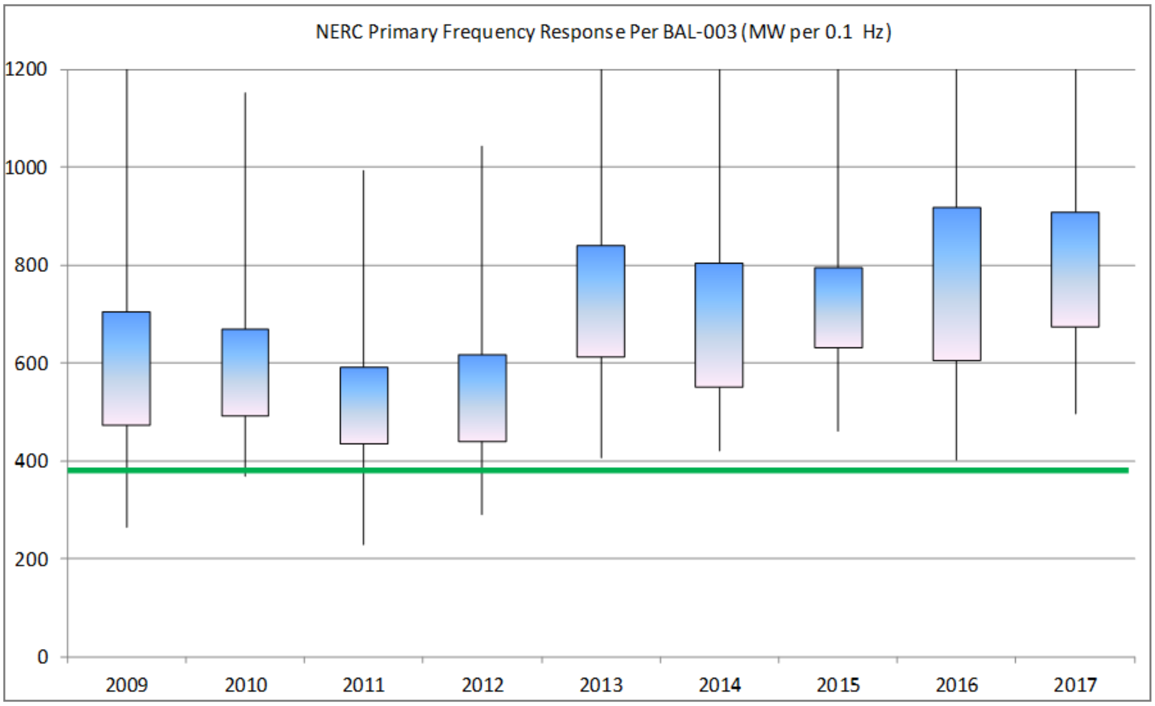
Period	Time Frame	Reliability Requirement	Metric(s)
Arrest Period	T0 to T+5 sec-onds	Arrest C-point at or above 59.3 Hz for loss of 2,750 MW (BAL-003)	• RoCoF/MW Loss • T0 to Tc • Nadir Frequency Margin
Rebound/ Stabilizing Period	T+6 to T+60 seconds	Achieve Interconnection frequen-cy response at or 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

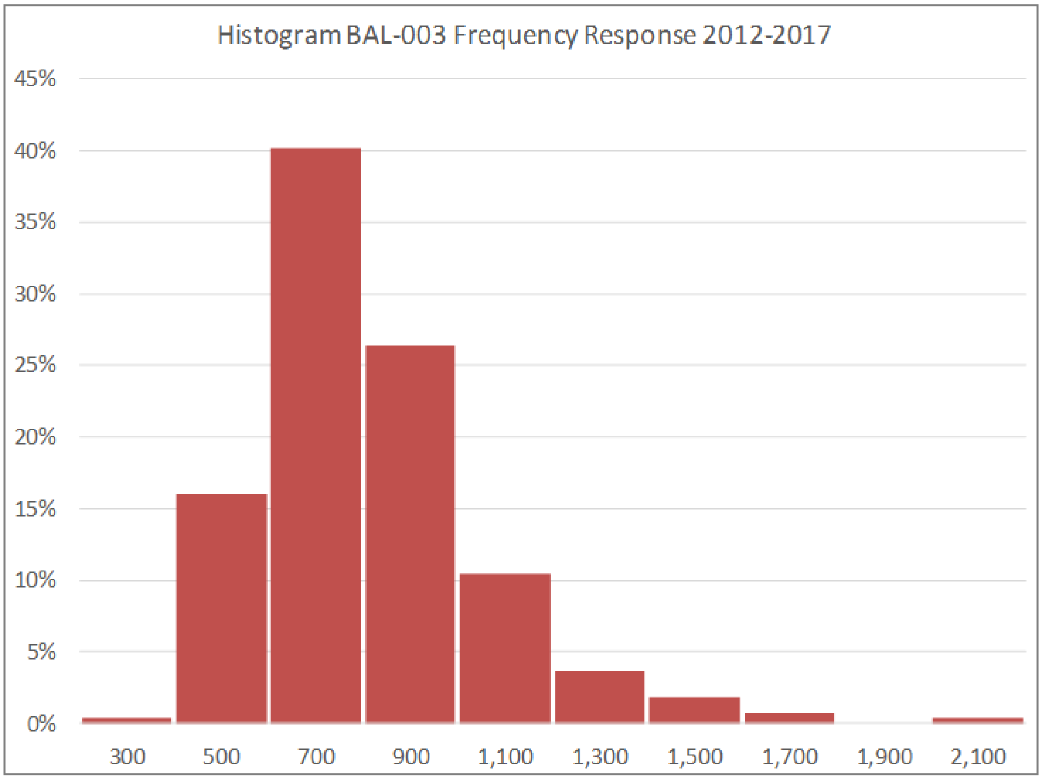
The Rate of Change of Frequency (RoCoF) during the initial frequency decline is largely driven by system inertia.

Primary Frequency Response

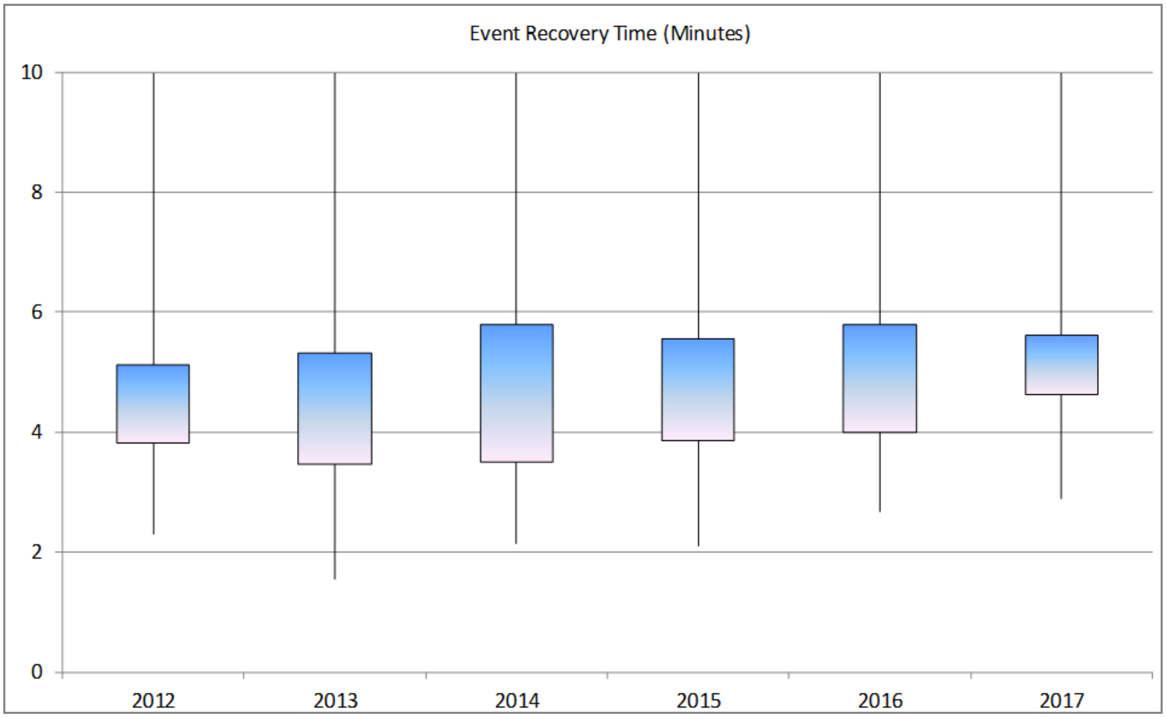


In 2017, the average frequency response was 844 MW per 0.1 Hz and the median frequency response was 759 MW per 0.1 Hz as calculated per NERC Standard BAL-003 for the 37 events that were evaluated during the period. The frequency response obligation for the Interconnection is 381 MW per 0.1 Hz.





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.

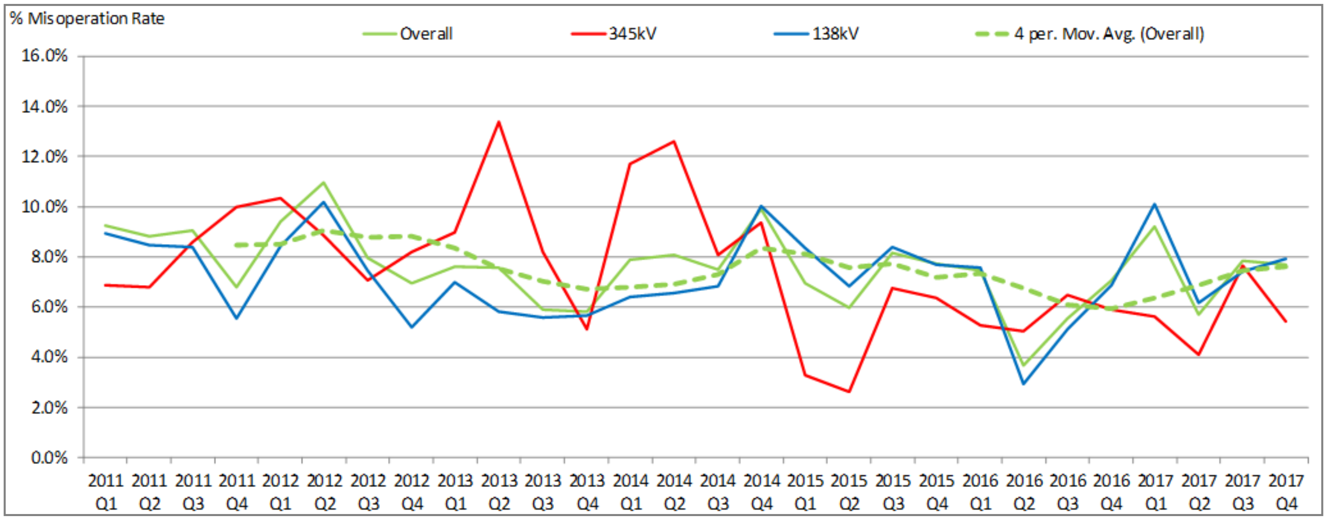


Protection System Performance

Protection systems protect sensitive equipment and help support overall system reliability. A protection system element (e.g., a relay device) misoperates when it either fails to operate as designed, or operates unintentionally or outside of its zone of protection. Misoperations contribute to outages of generation and transmission facilities. When a protection system misoperates, the system is in a less reliable state.

One measurement of the incidence of misoperations is the misoperation rate, the ratio of misoperations to correct operations. NERC has set a target of a nationwide misoperation rate of 8% by 2020.

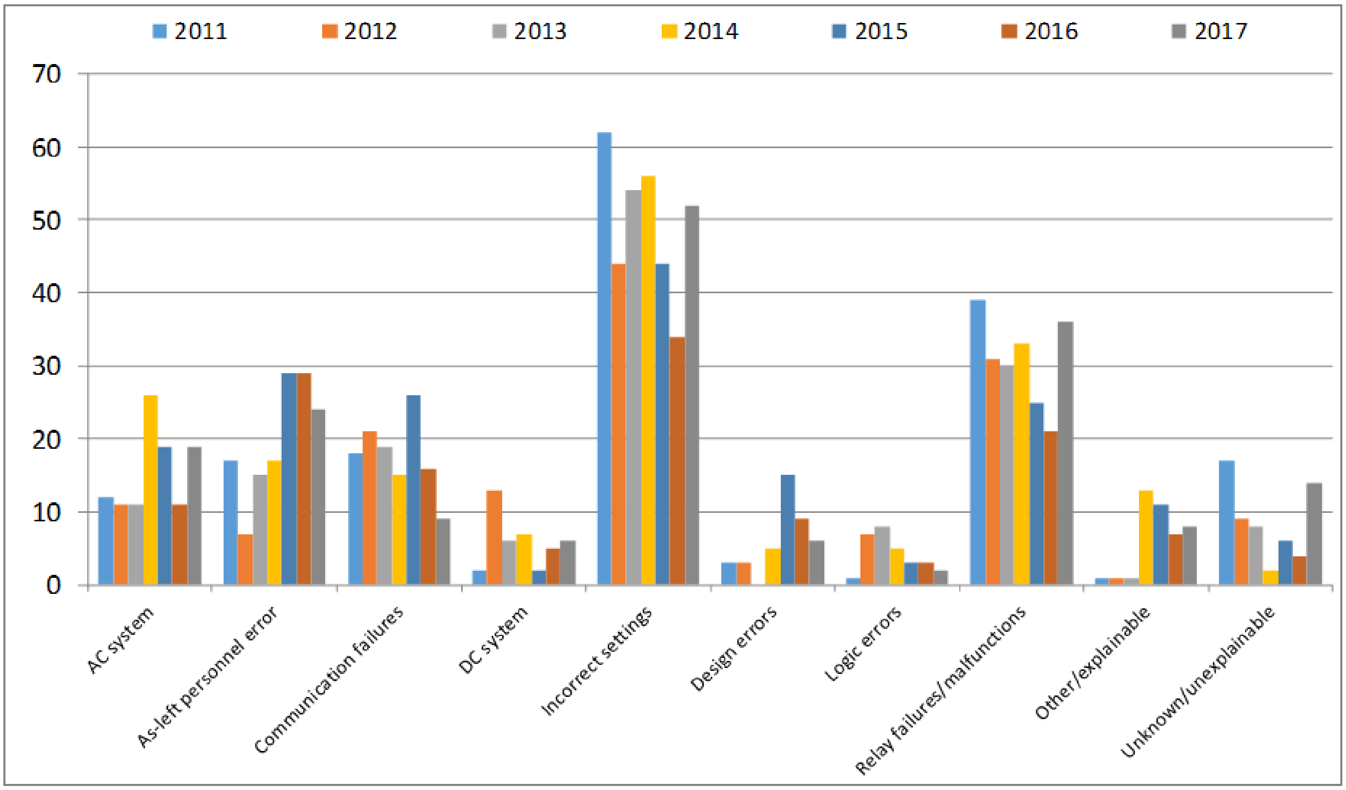
- Overall Protection system misoperation rate increased in 2017 to 7.3% versus 5.4% for 2016
- Incorrect settings, logic, and design errors remained the largest cause of misoperations, accounting for 34% of misoperations in 2017
- 2017 345 kV misoperation rate: 5.9%
- 2017 138 kV misoperation rate: 8.1%
- 2017 345 kV misoperations: 37
- 2017 138 kV misoperations: 136



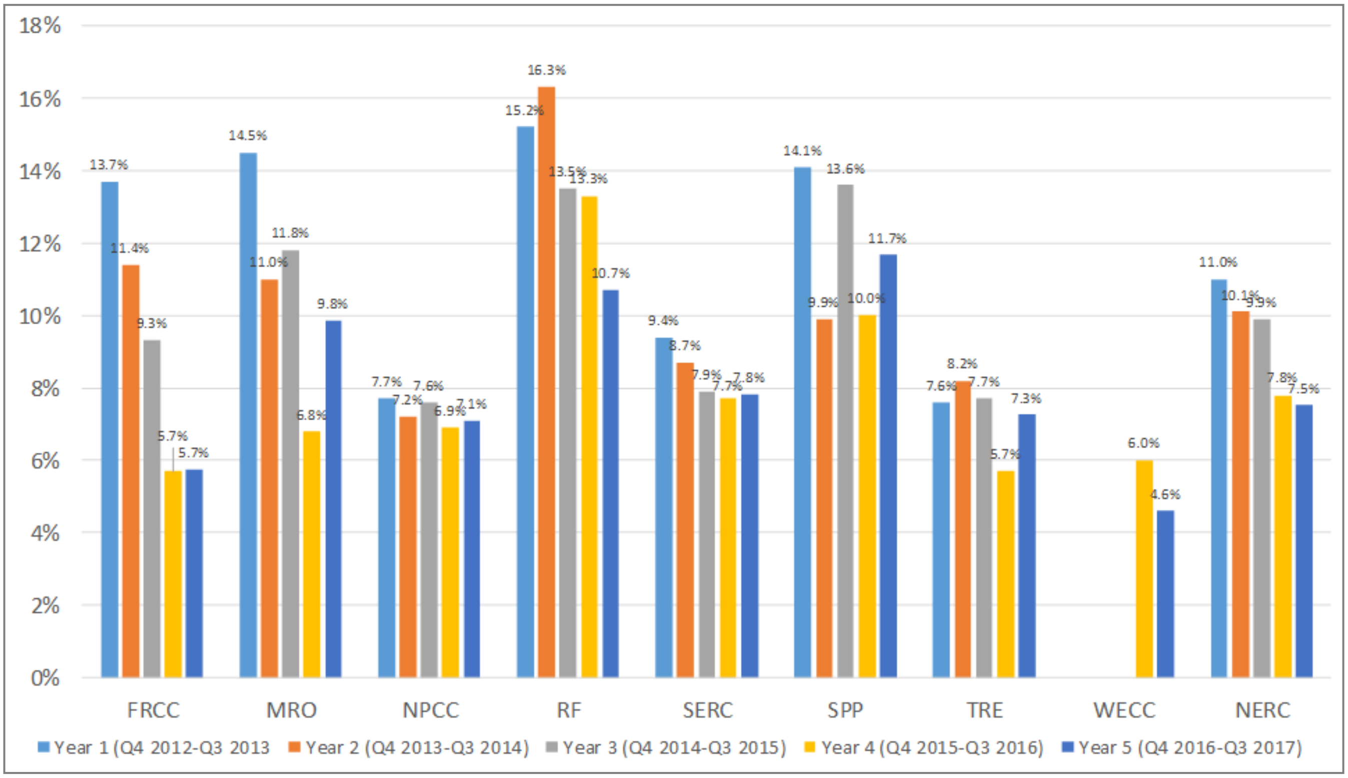
In 2017, three main categories account for 68% of the total misoperations: incorrect settings/logic/design (34%), as-left personnel errors (14%), and relay failures (20%).

Protection System Performance

Historical Misoperation Counts by Cause



Regional Misoperation Rates



Infrastructure Protection

Critical infrastructure protection will continue to remain a priority for NERC, the Department of Homeland Security, and Texas RE. Since September 2011, substation intrusions and copper theft have ranged from three to 28 in any one month.

For the purposes of this chart, physical/cyber security issues include bomb threats, sabotage, and cyber security issues.