TEXAS RELIABILITY ENTITY

Ensuring electric reliability for Texans

Review of Reliability Performance Data

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Introduction

- **This purpose of the presentation is to review the performance data for the Electric Reliability Council of Texas (ERCOT) region.**
  - Overview of the reliability areas of interest
  - Review of key metrics for each area
  - Review of key observations
- **Data is collected under Section 800, 1000 or 1600 of the North American Electric Reliability Corporation (NERC) Rules of Procedure, not under Section 400 (compliance and enforcement).**

Texas RE Review of Reliability Performance

- **Texas Reliability Entity, Inc. (Texas RE) Assessment of Reliability Performance report for 2013 was published in April 2014:**
  - High-level 2013 data;
  - Associated historical data;
  - Analysis of 2013 and other historical data as indicators of current state of ERCOT region;
  - Observations that help connect the state of the region today to the future; and
  - Recommendations, where possible, for addressing threats to reliability and gaps in data and analysis process.
    - 2013 Texas RE Assessment of Reliability Performance (April 2014): http://www.texasre.org/CPDL/2013%20Texas%20RE%20Assessment%20of%20Reliability%20Performance.pdf
    - NERC 2014 State of Reliability Report (May 2014): http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/2014_SOR_Final.pdf

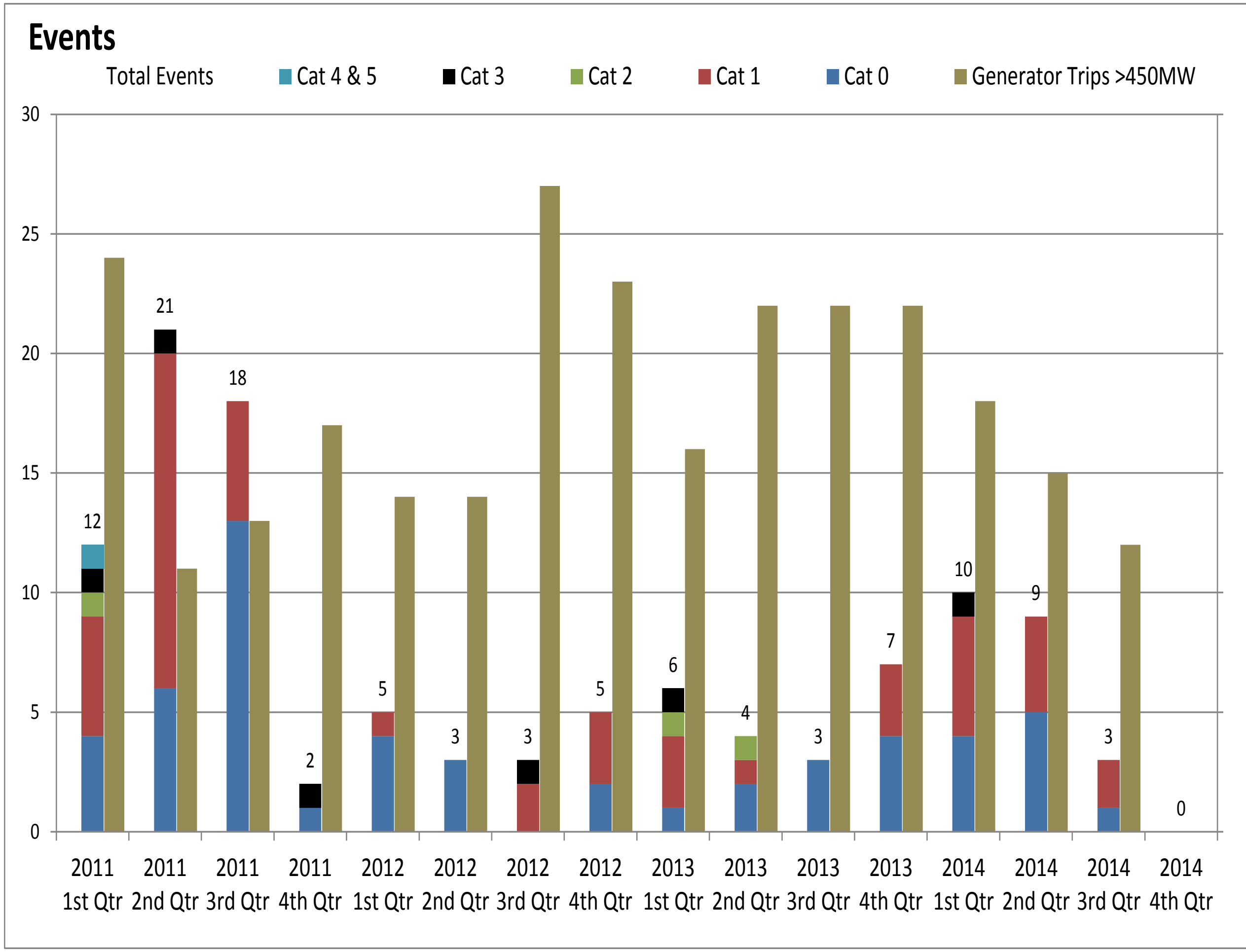
Reliability Areas with Associated Data

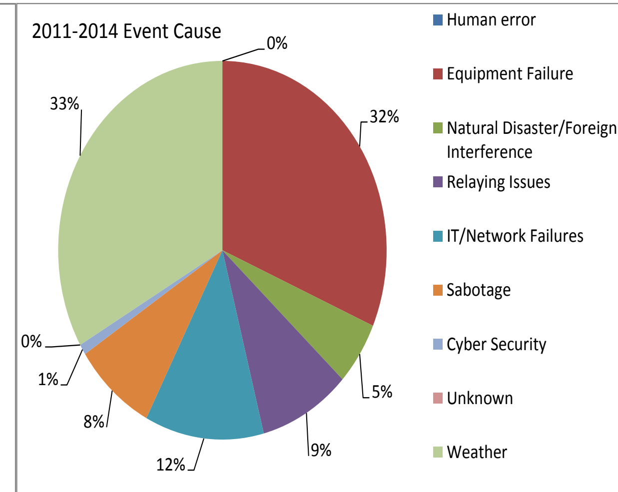
- Event Analysis
- Transmission Reliability Analysis (TADS)
- Generation Reliability Analysis (GADS)
- Protection System Misoperations
- Frequency Control
- Primary Frequency Response
- Demand Response
- Infrastructure Protection
- Other Performance Trends

Event Analysis – Key Observations 2011-2014 YTD

- **111 reportable events**
  - 101 events classified as Category 0 or Category 1 (little or minimal follow-up per Events Analysis Program)
  - 315 event reports received
- **Weather (33%), Equipment Failure (32%), and Energy Management System (EMS) Issues (12%) are the main causes**
- **21 events in 2011-2014 YTD involved multiple generator trips**
- **Generation trips > 450 MW average 18 per quarter**
- **Increasing trend in loss of EMS events noted by NERC**

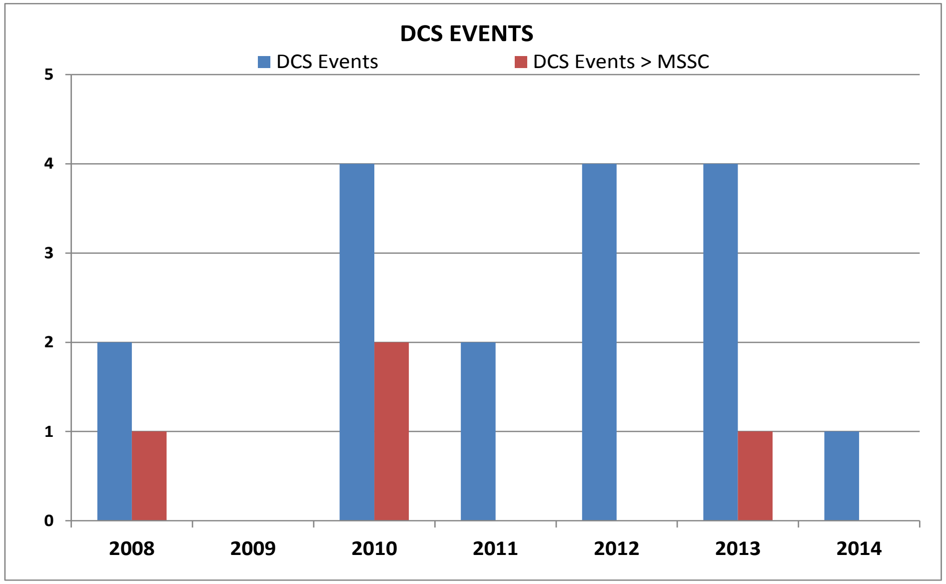
Event Analysis – Summary Data

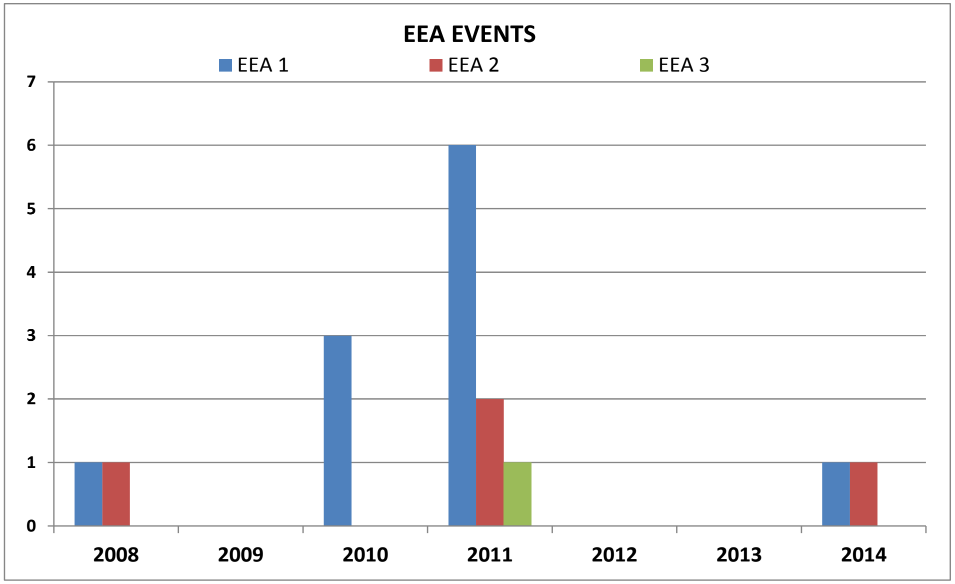




- **Weather (33%)**
- **Equipment Failure (32%)**
- **EMS Issues (12%)**

Event Analysis – Summary Data





Year	# of Multiple Generation Unit Trip Events
2011	5
2012	2
2013	7
2014 YTD	7

Multiple generator trip event count includes trips due to faults or system conditions outside the generator's protection system zones, or multiple unit trips at the same site due to a single point of failure.

Event Analysis – Loss of EMS Events

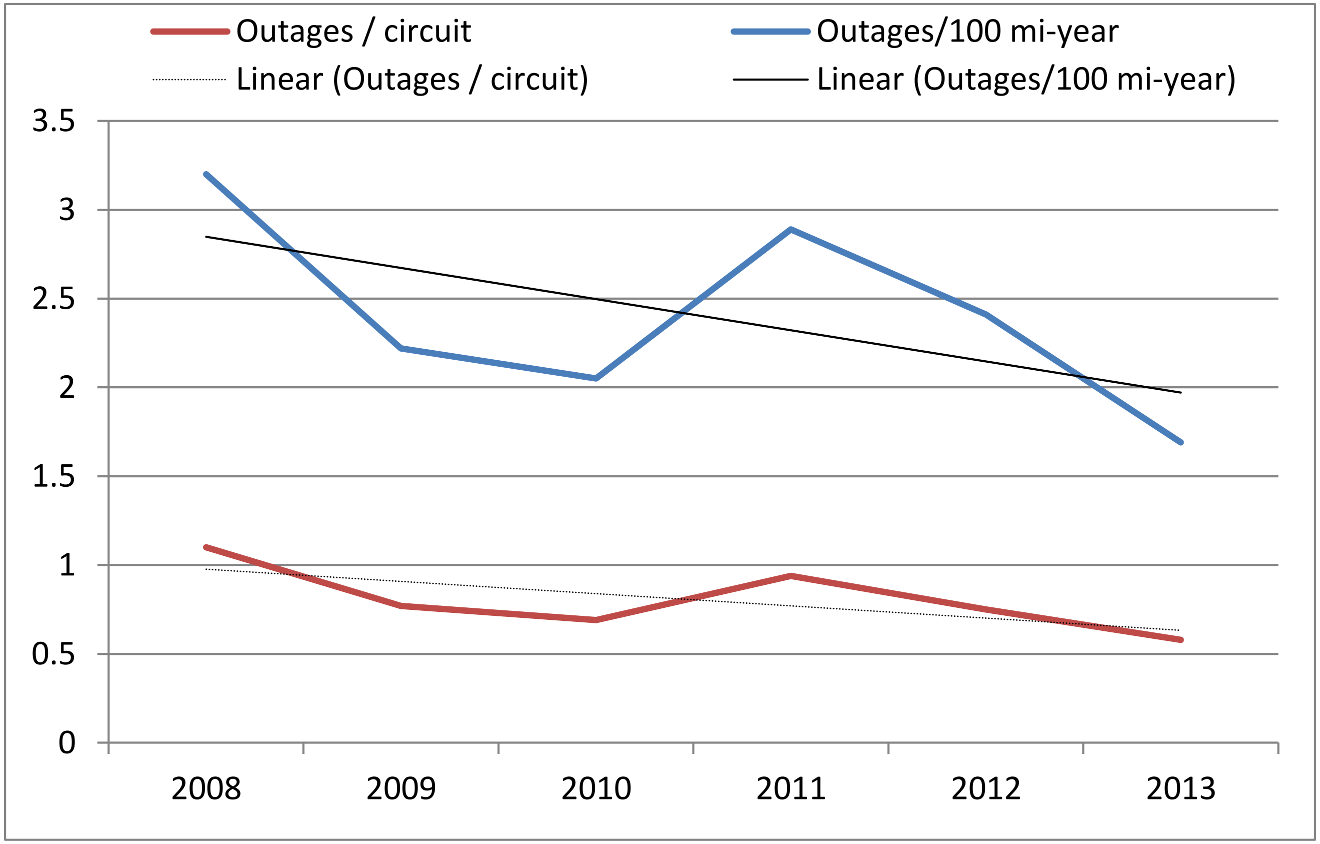
- **NERC EMS Task Force has noticed an increasing trend in loss of EMS events.**
- **2013 and 2014 YTD – eight loss of EMS/SCADA events reported in the ERCOT region.**
- **Common themes include:**
  - Improper sizing setting of parameters
  - Incorrect application parameter settings
  - Improper patch management
  - Incorrect recovery procedures
  - Missing documentation for programs, procedures, etc.
  - Improper configuration of security tools
  - Improper Local/Wide Area Network (LAN/WAN) configuration
  - Improper disk/memory sizing
  - Improper settings, procedures, or design requirements for failover
  - Improper user/application permission issues
  - Incorrect database settings/configuration
  - Incorrect recovery procedures
  - External program configuration issues (anti-virus, etc.)
  - Improper server redundancy set up
  - Improper power sources redundancy
  - Incorrect communication network settings
  - Improper settings on routers, switches, etc.
  - Improper server clustering
  - Inadequate testing

Transmission Reliability – Key Observations

- **902 automatic outages and 2574 planned outages of 345kV lines reported in Transmission Data Availability System (TADS) for 2010-2013.**
  - Overall average circuit availability remained above 98.3%.
  - Lightning, Contamination, and Unknown caused 73% of momentary outages.
  - Lightning, Failed Substation Equipment, and Human Error caused 77% of sustained outage duration.
  - "Unknown" represents 20% of momentary outages.
    - More accurate cause coding is needed.
  - "Failed AC Substation Equipment" represented 18% of sustained outage events and 26% of outage duration.
  - Failed AC Circuit Equipment" represented 7% of sustained outage events vs. 38% of outage duration.
  - No Interconnection Reliability Operating Limit (IROL) violations for 5 consecutive quarters.
  - NERC AC Substation Equipment Task Force working on white paper to review AC Substation Equipment failure modes and trends.

ERCOT Region TADS Data for 2008-2013

- **Outage rate per circuit and Outage rate per 100 mi-year showing a decreasing trend.**

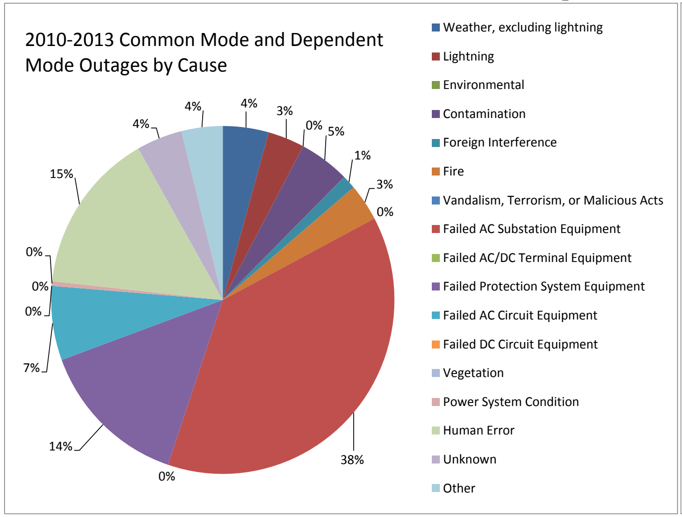


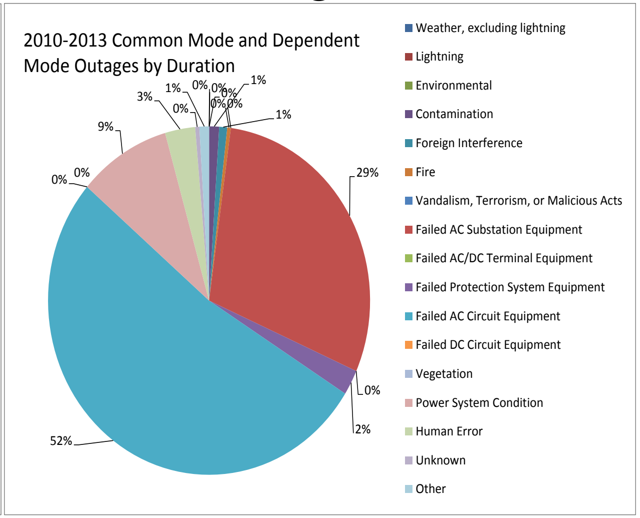
Outage Type	Percentage of Automatic Outages
Single element	81%
Bus faults (normal clearing)	3%
Breaker faults (normal clearing)	1%
Multiple elements (normal clearing)	1%
Multiple elements (common structures)	3%
Breaker failures (delayed clearing)	3%
Protection system failures	5%
Other	3%

Voltage Class Name	Metric	2008	2009	2010	2011	2012	2013
AC Circuit 300-399 kV	Outages per Circuit	1.10	0.77	0.69	0.94	0.75	0.56
AC Circuit 300-399 kV	Outages per 100 miles per year	3.20	2.22	2.05	2.89	2.41	1.63

Transmission Outages – Common/Dependent Mode

Common Mode and Dependent Mode Outage Statistics





- Dependent Mode outages (defined as an automatic outage of an element which occurred as a result of another outage).
- Common Mode outages (defined as one or more automatic outages with the same initiating cause and occur nearly simultaneously).

Cause	Percentage of Common/Dependent Mode Outages by Cause	Percentage of Common/Dependent Mode Outages by Duration
Failed Substation Equipment	38%	29%
Failed Protection System Equipment	14%	2%
Human Error	15%	3%
Failed AC Circuit Equipment	7%	52%

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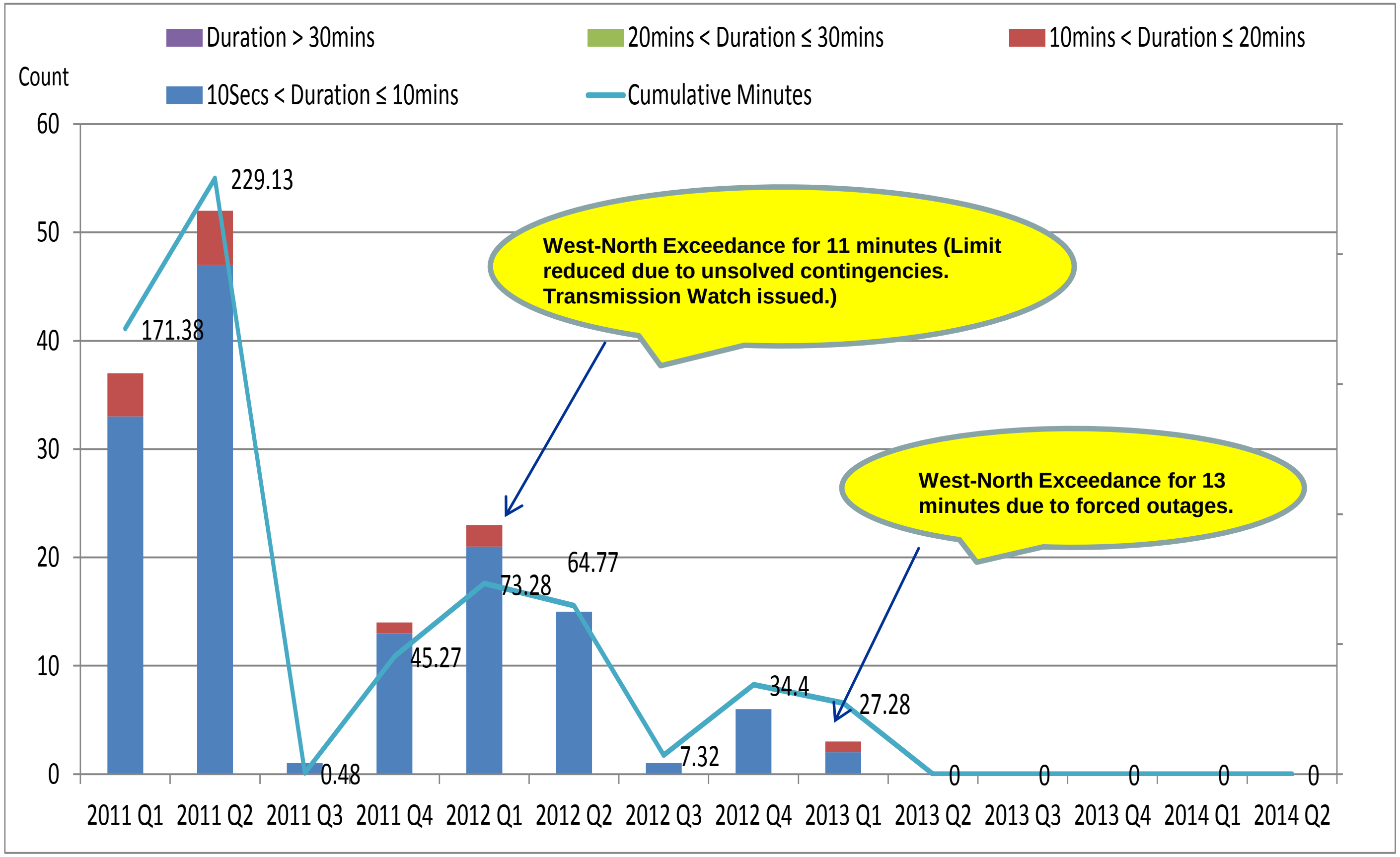
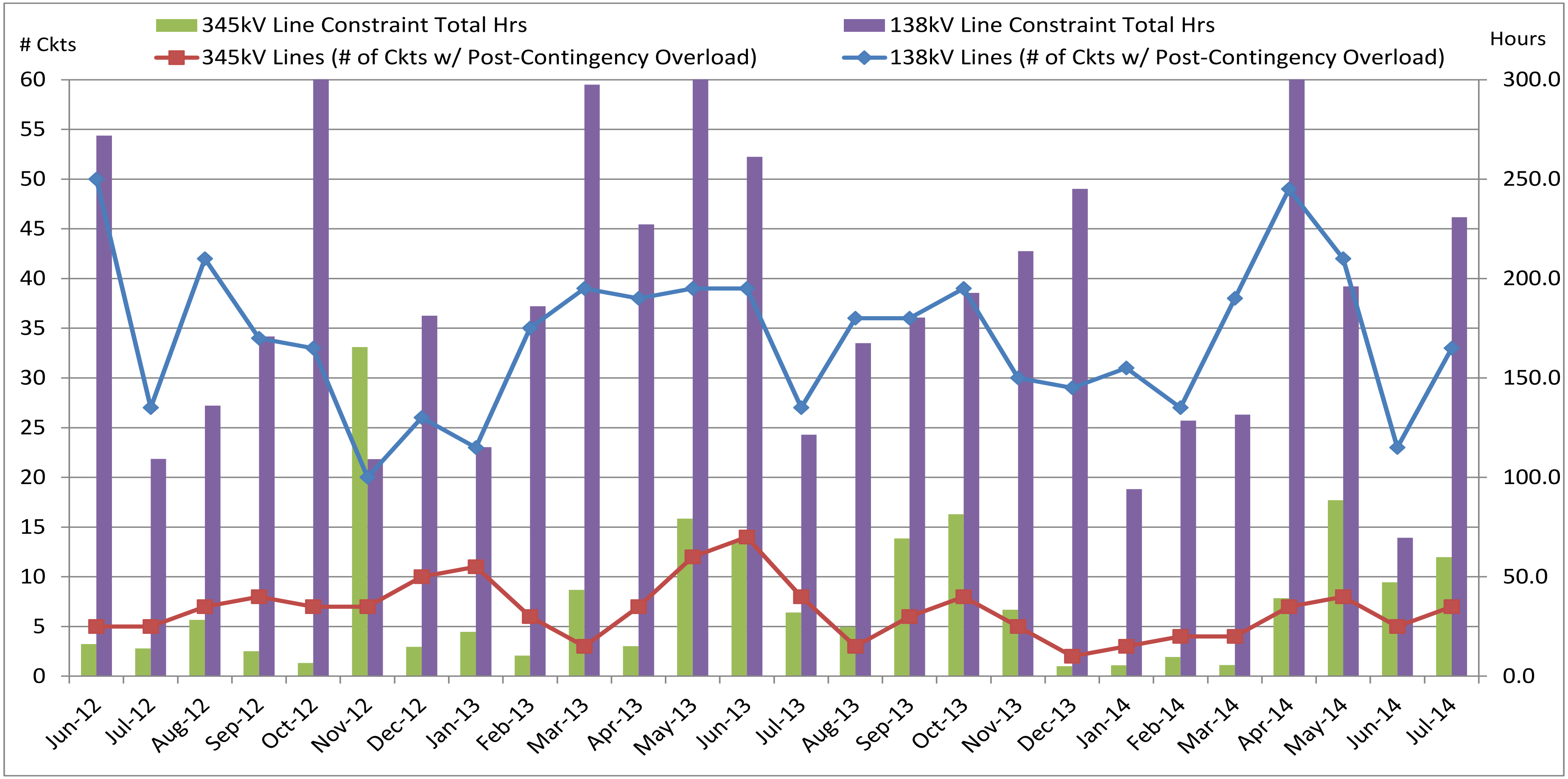
Transmission Limits – IROL Exceedances



NERC ALR 3-5 IROL/SOL Exceedances (< 30 minutes)			
Region	2011	2012	2013
EI	194	172	137
WECC	734	927	955
TRE	103	82	3
Note: IROL/SOL violations from 10 sec to < 30 minutes			

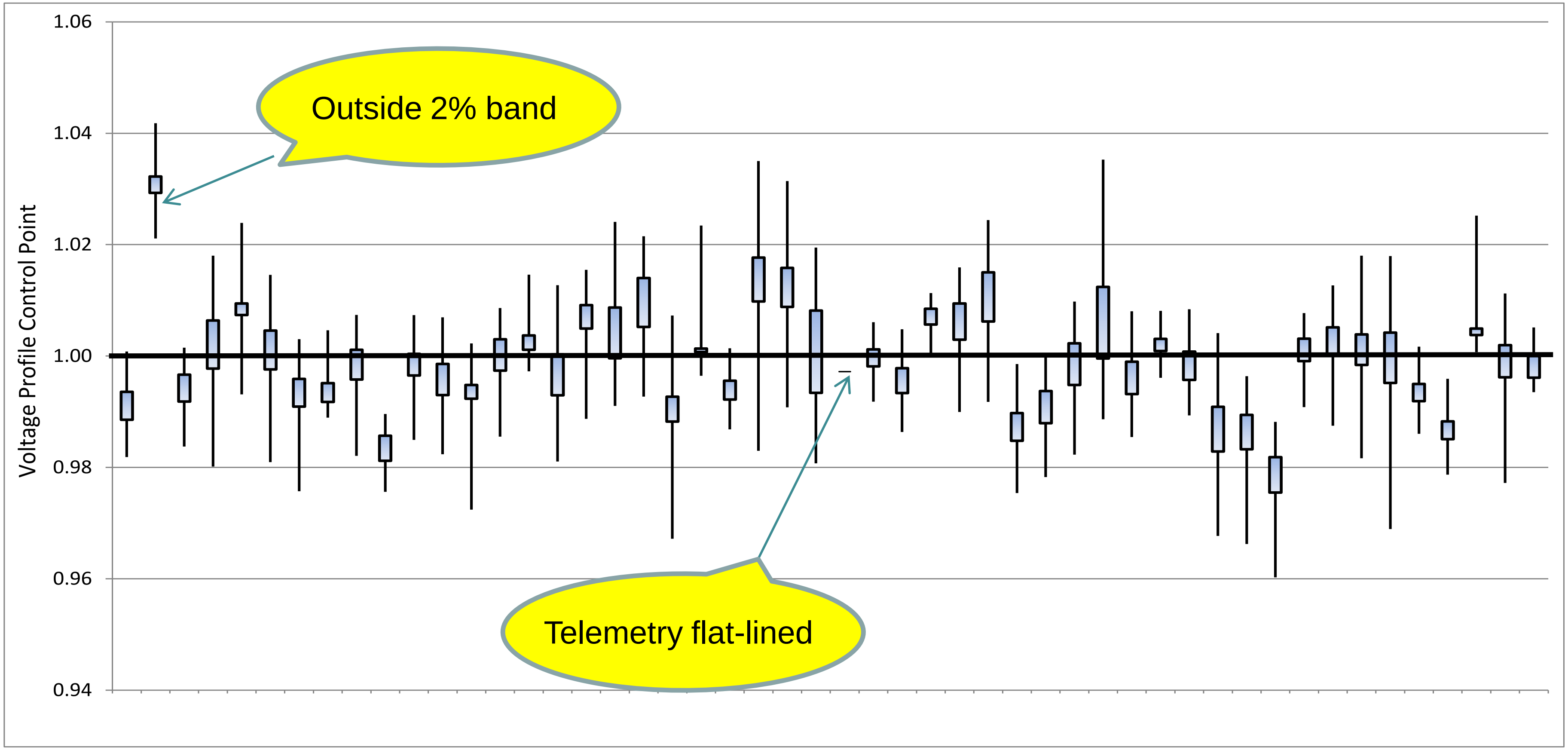
- **Count of IROL exceedances, categorized by duration**

Transmission Limits (Post-Contingency Overloads)



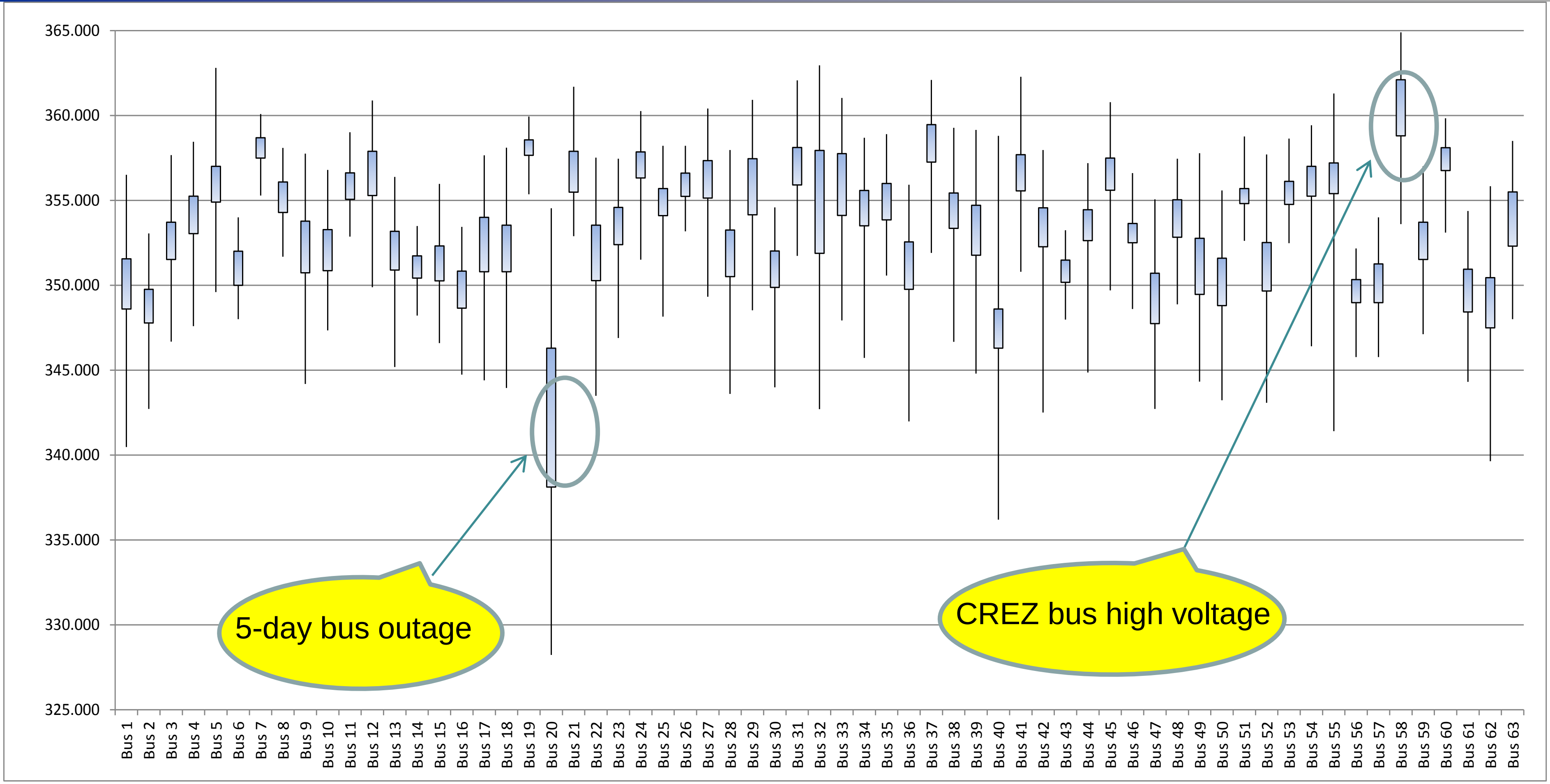
- **Lines represent the total number of lines which are a constraint during the month (i.e., a post-contingency overload > 100%).**
- **Bars represent the total hours during the month that the line constraints occurred.**

Voltage Control (Generation Buses) – July 2014



- One-minute PI data from 52 generation buses (138kV and 345kV). Includes both fossil and wind generation.
- Boxes represent the 25%/75% percentiles. Leader lines show the min/max voltage during the period.
- Data is normalized so that the 1.0 per-unit value represents the control point from the seasonal voltage profile.

Voltage Control (Transmission Buses) – July 2014

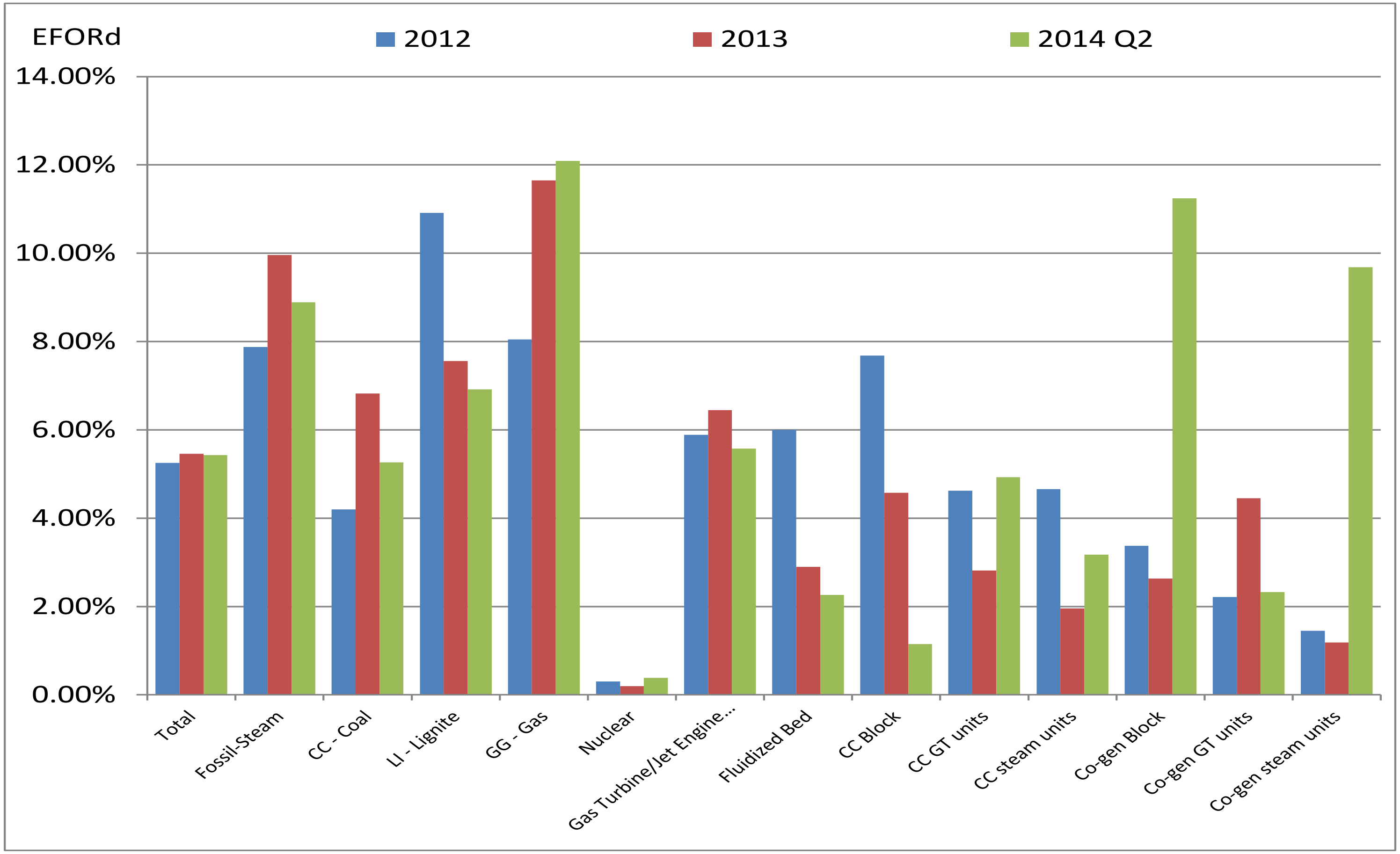


- **One-minute PI data from 63 345kV transmission buses.**
- **Boxes represent the 25%/75% percentiles. Leader lines show the min/max voltage during the period.**

Generation Reliability – Key Observations

- Mandatory GADS reporting for units > 50 MW began in January 2012
- Mandatory GADS reporting for units > 20 MW (excluding wind) began January 2013
- ERCOT-region GADS metrics continue to compare favorably with NERC fleet-wide metrics in most cases
- Immediate forced outage and forced derate events were reviewed for common failure modes
- Immediate forced outage and forced derate events were reviewed for summer/winter trends

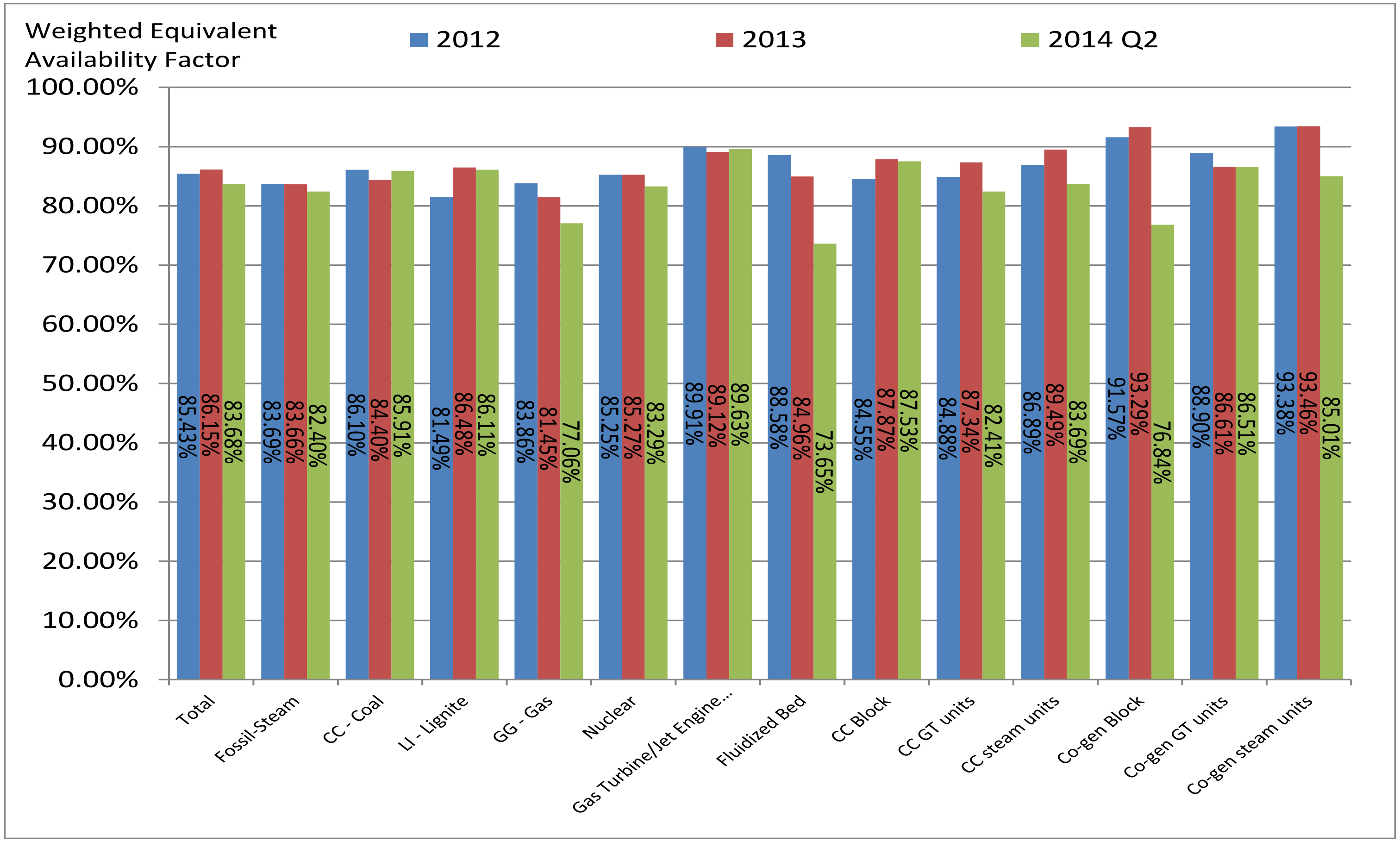
Review of ERCOT Region GADS Data



NERC 2008-2012 Fleet Avg EFORd	
Fossil	9.71
Coal	8.29
Gas	16.63
Lignite	6.99
Nuclear	3.94
Jet Engine	9.87
Gas Turbine	10.49
CC Block	4.57

- **Equivalent Forced Outage Rate Demand (EFORd) measures the probability that a unit will not meet its demand periods for generating requirements because of forced outages or derates.**
- **ERCOT units only, based on GADS submittal data (no wind, or units under 50 MW in 2012).**

Review of ERCOT Region GADS Data



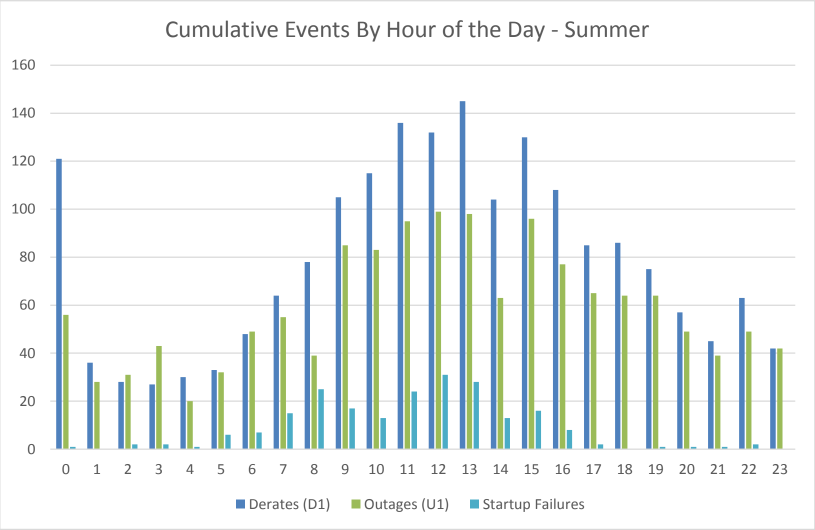
NERC 2008-2012 Fleet Avg WEAF	
Fossil	82.90
Coal	83.08
Gas	82.82
Lignite	84.80
Nuclear	87.66
Jet Engine	89.14
Gas Turbine	90.15
CC Block	86.63

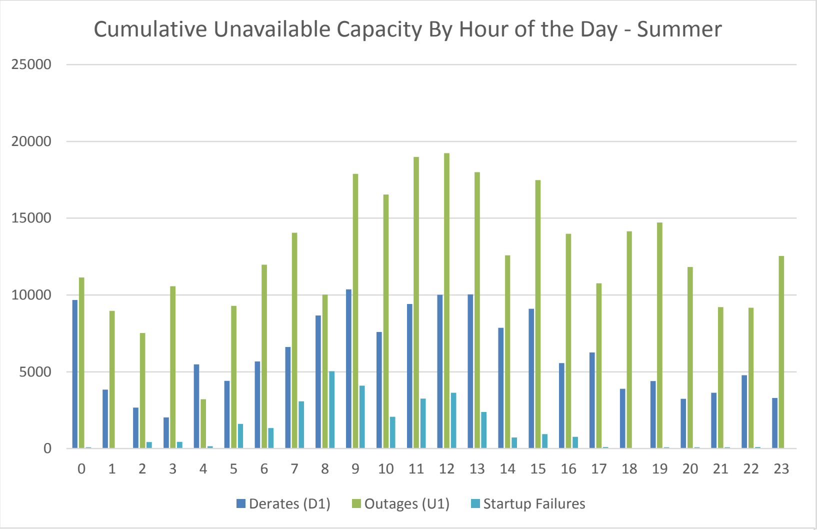
- **Equivalent Availability Factor: Measures the percentage of net maximum generation that could be provided after all types of outages are taken into account. Weighted by unit MW capacity.**
- **ERCOT units only, based on GADS submittal data (no wind, or units under 50 MW in 2012).**

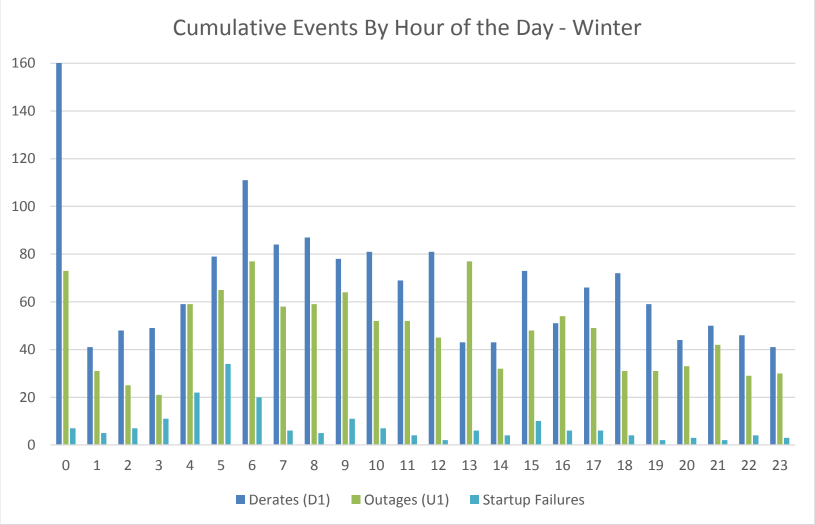
Review of ERCOT-Region GADS Data 2012-2014Q2

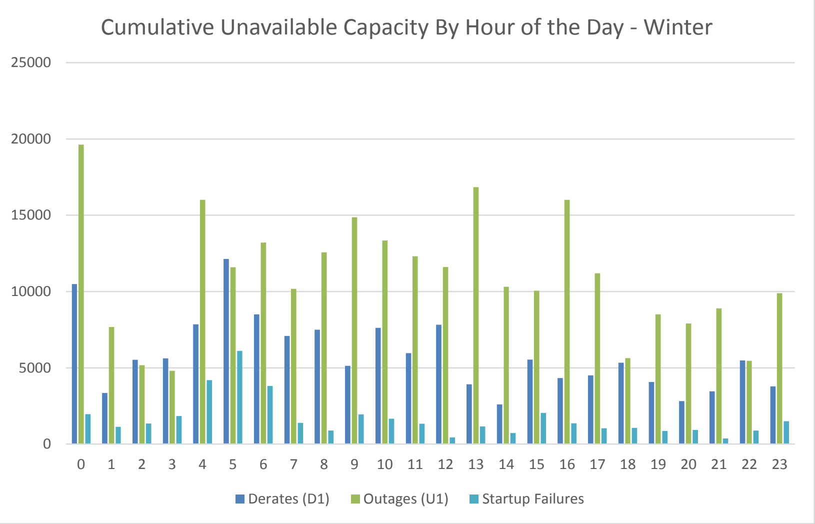
	Net Capacity Factor (NCF)	Average Run Time (ART)	Starting Reliability (SR)	Scheduled Outage Factor (SOF)	Forced Outage Factor (FOF)	Mean Forced Outage Duration (MFOD)	Service Factor (SF)	Equivalent Availability Factor (EAF)	Equivalent Forced Outage Rate demand (EFORd)
OVERALL	45.08%	59.32	98.82%	8.57%	3.13%	43.64	48.09%	86.47%	5.37%
100 - Fossil-Steam	43.50%	92.7	98.85%	9.36%	4.77%	67.4	40.96%	84.41%	8.91%
Coal	70.74%	964.0	96.60%	9.07%	4.33%	78.4	84.24%	85.18%	5.75%
Lignite	69.27%	754.7	94.76%	7.60%	5.43%	48.3	81.99%	83.89%	8.94%
Gas	6.66%	29.8	99.09%	9.69%	4.83%	73.1	18.58%	84.53%	10.25%
200 - Nuclear	69.23%	3790.9	100.00%	6.26%	6.43%	803.6	86.60%	85.21%	0.28%
300 - Gas Turbine/Jet Engine (Simple Cycle Operation)	17.08%	18.3	98.57%	7.03%	2.80%	41.8	17.21%	89.65%	6.21%
650 - Fluidized Bed	63.21%	1256.5	98.48%	13.83%	2.48%	46.8	78.83%	82.62%	4.30%
850 - Combined Cycle Block	45.88%	79.0	99.31%	10.31%	3.67%	88.9	60.15%	84.49%	4.97%
851 - CC GT units	48.02%	48.2	98.94%	8.98%	2.76%	30.6	55.31%	85.69%	3.95%
852 - CC steam units	42.06%	56.4	99.52%	7.85%	1.74%	21.2	60.84%	88.02%	3.28%
860 - Co-generator Block	63.05%	338.1	99.69%	6.82%	3.73%	59.8	83.33%	88.85%	4.13%
861 - CoG GT units	54.03%	123.0	96.94%	8.09%	2.67%	34.6	75.33%	86.98%	3.17%
862 - CoG steam units	32.17%	62.5	99.56%	4.13%	1.96%	39.6	69.36%	93.06%	3.04%

Summer/Winter Forced Outage, Failed Start and Derate Data 2012-2014









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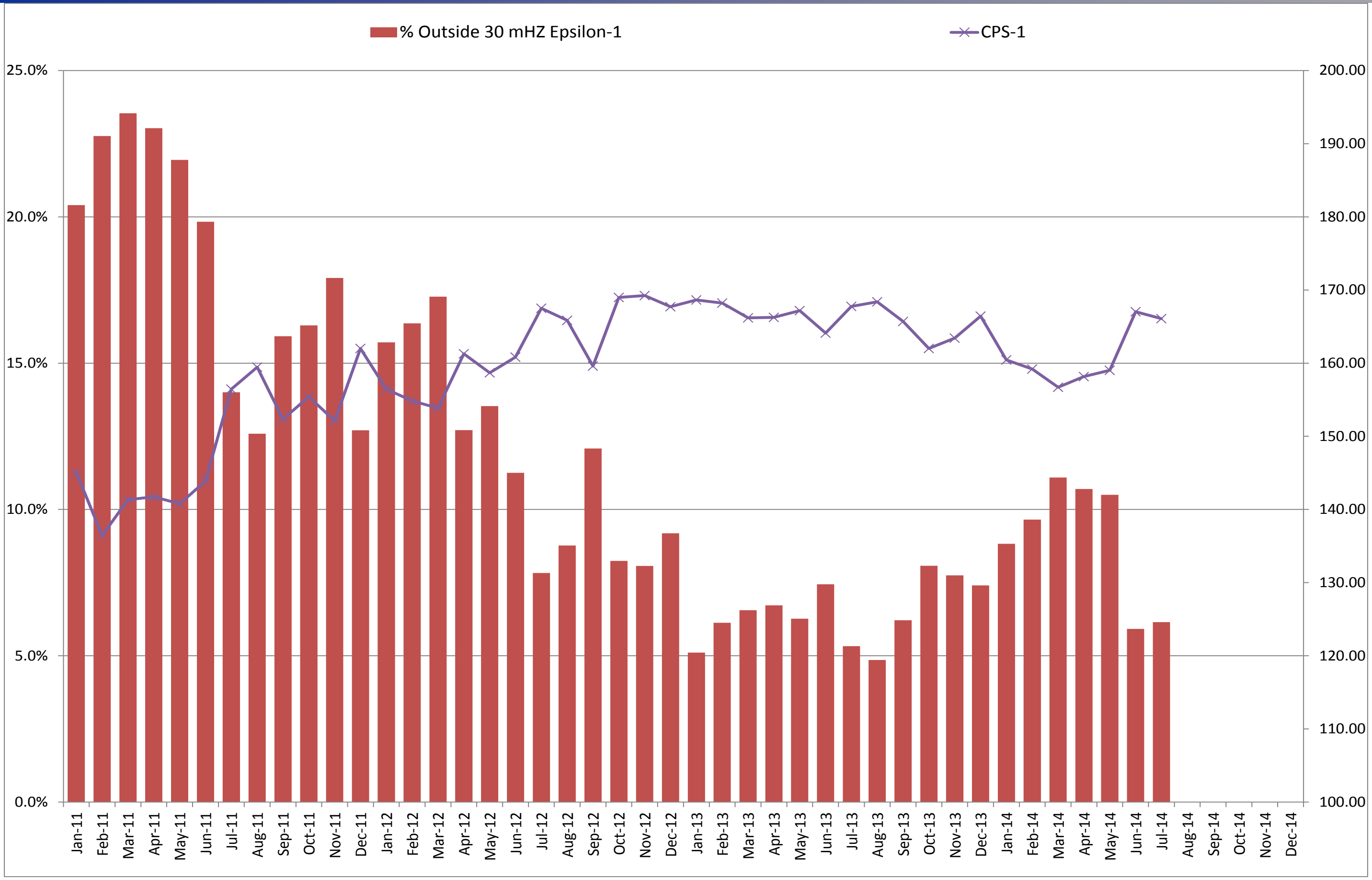
Frequency Control and Primary Frequency Response – Key Observations

- **For 2014 YTD, time error corrections averaged seven per month (or an average of 0.8 second of per day), always for slow time error.**
  - Correlation noted between aggregated basepoint deviation, time error, load ramps periods, and dependency on Reg-Up.
- **Long term trends for primary frequency response continue to show improvement. Improvement noted with non-frequency responsive units providing Responsive Reserve Service.**

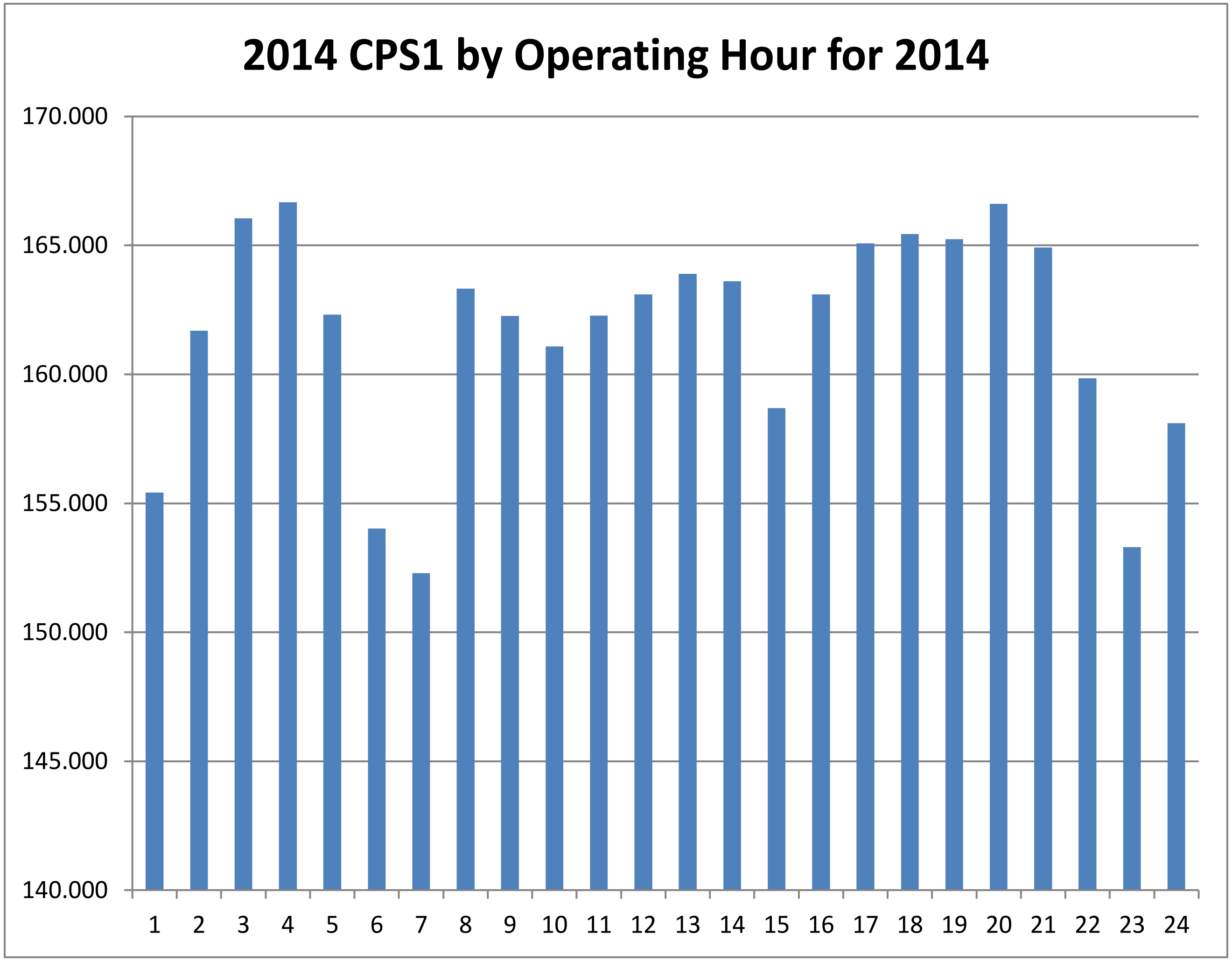
Frequency Control



- LFC tuning changes made May 27, 2014
- Approx 8 pt. improvement noted in CPS1

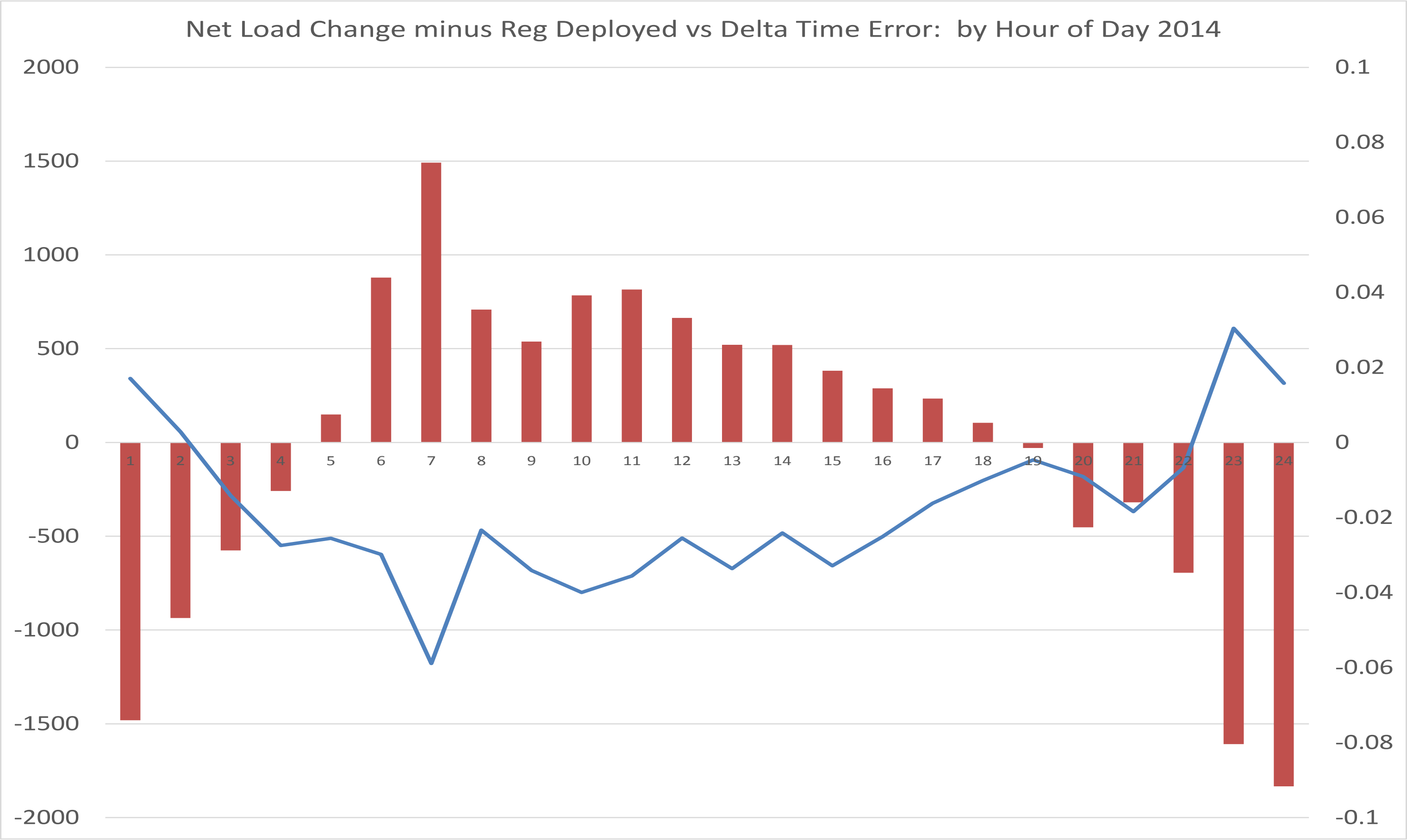
- **Bars represent % of time that frequency is outside 30 mHz Epsilon-1 (ε1) value which is used in calculation of CPS1 for the ERCOT region per BAL-001 (i.e. < 59.97 Hz or > 60.03 Hz).**
- **Based on one-minute PI data.**

Frequency Control



- **Effect of unit start-up and shutdown on CPS1 is still apparent.**

Net Load Change vs. Time Error



- Bars represent the average net load change between operating hours minus net regulation deployed.
- Line represents the average net time error between operating hours.
- Graph clearly indicates that net positive load ramp periods result in negative time errors.

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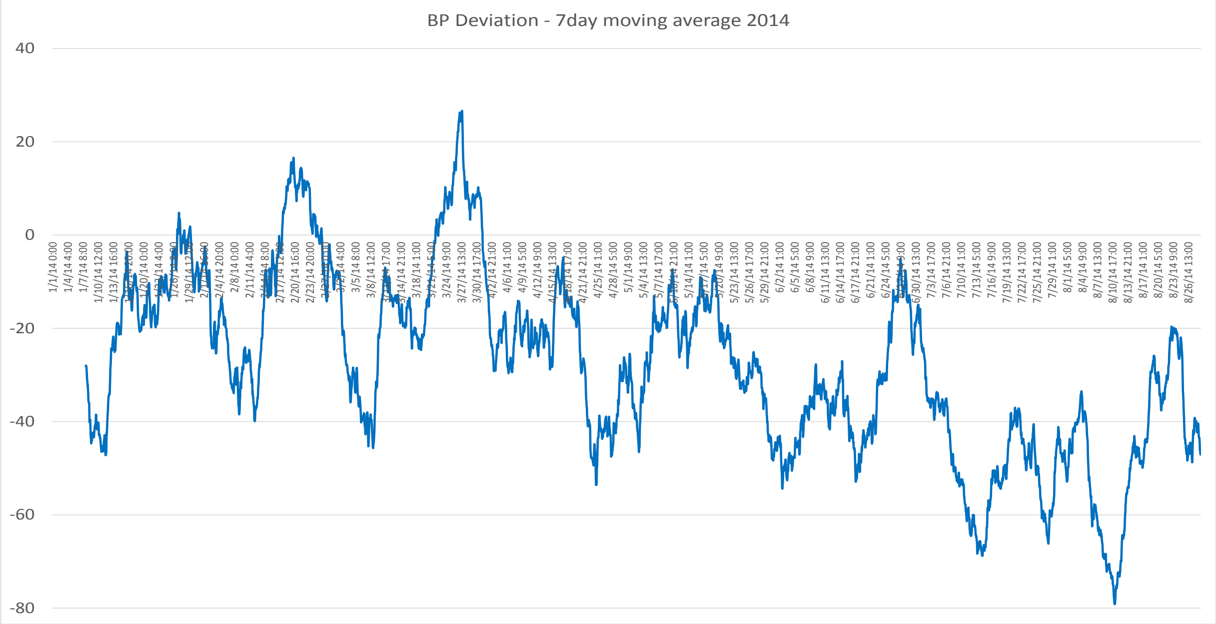
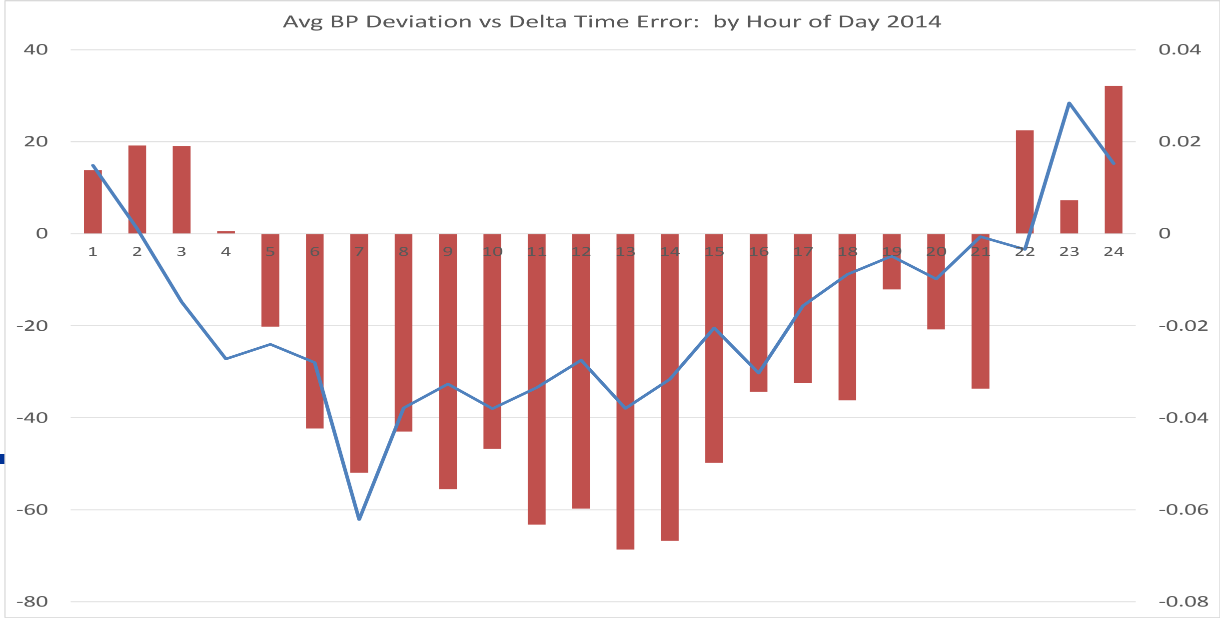
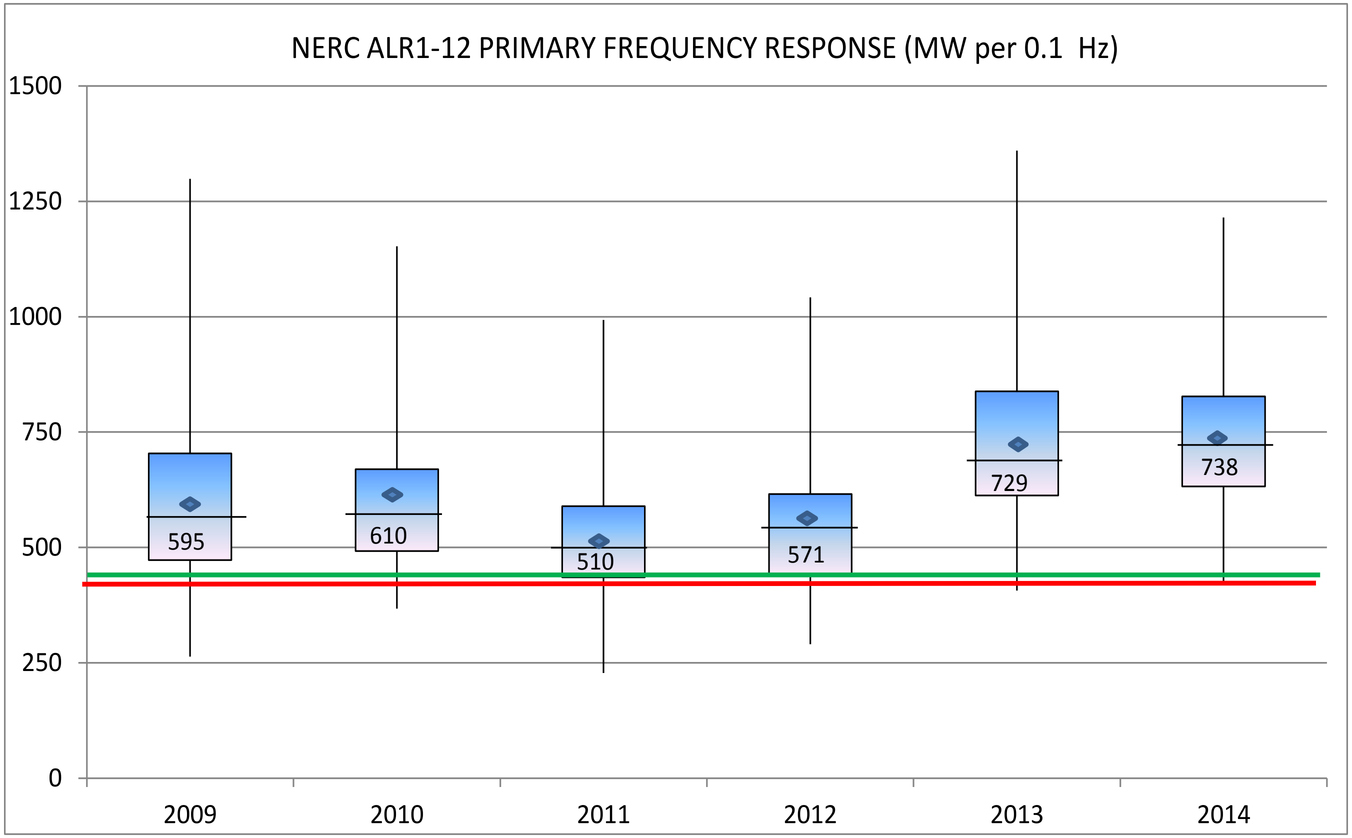
Basepoint Deviation vs. Time Error





- 7-day moving average of aggregated hourly generation basepoint deviations
- Average aggregated basepoint deviation of -28 MW across all operating hours
- Maximum of -510 MW in one hour
- Average aggregate basepoint deviation versus net time error for each operating hour

Primary Frequency Response Performance



- Primary Frequency Response provided by generating units during loss of generation events is continuing to show an improving trend since 2011.
- ERCOT target is 420 MW per 0.1 Hz (red line). NERC minimum is 413 MW per 0.1 Hz (green line) per BAL-003.
  - Leader lines show min/max for the quarter.
  - Boxes indicate 25%/75% quartiles.

	2012	2013	2014 YTD
Number of Events Analyzed	54	56	29
Average number of units per event failing PDCWG metric at B-Point	28	21	18

Primary Frequency Response Performance

	2012	2013	2014 YTD
Number of Events Analyzed	54	56	29
Average Number of Units per Event with RRS Obligation	39	36	37
Average Number of RRS Units per event failing PDCWG Metric at B-Point	13	6	5
Percentage of RRS Unit Failures	34%	17%	14%

- **Improvement noted with non-frequency responsive units providing Responsive Reserve Service**

Year	# Events < 413 MW per 0.1 Hz
2009	5
2010	3
2011	15
2012	9
2013	2
2014 YTD	0

- **Number of events below NERC BAL-003 threshold continues to decline**

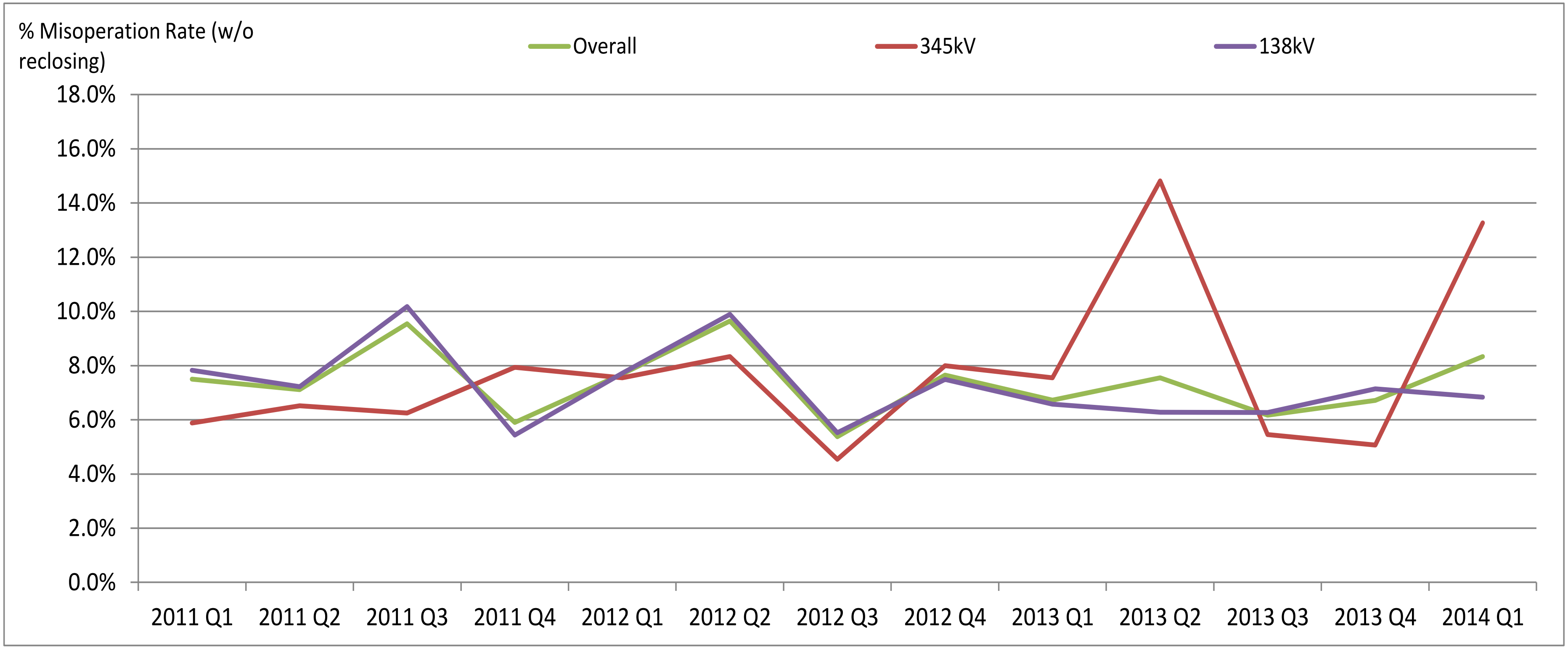
Year	Average Event Recovery Time
2012	4 min, 58 sec
2013	5 min, 05 sec
2014 YTD	4 min, 59 sec

- **Event recovery time remains consistent and well-within NERC requirements**

Protection Systems – Key Observations

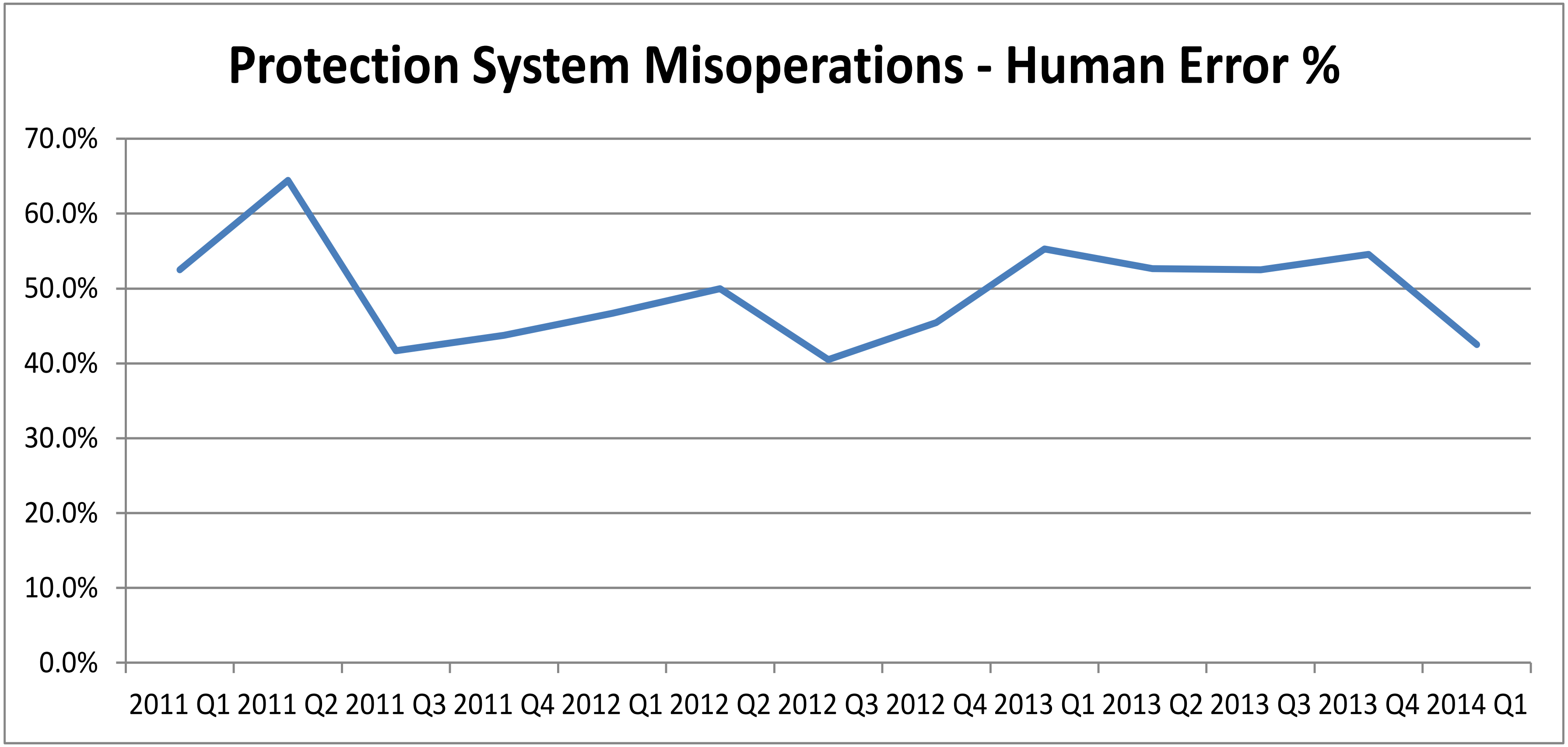
- **Relatively flat trend in overall misoperation rate since January 2011 (Note: Percentages do not include Failure to Reclose)**
  - 2011 overall rate of 7.5% compared to 2012 overall rate of 7.6% and 2013 rate of 6.8%.
  - Slight upward trend in 345kV rate of 6.6% in 2011 compared to 2012 345kV rate of 7.2% and 2013 rate of 8.6%.
  - ERCOT overall misoperation rates are second lowest of all regions.
- **Incorrect Settings/Logic (42%), Relay Failure (21%), and Communications failure (10%) are the main causes of misoperations. This is similar to NERC-wide trend.**
  - Relay failures evenly split between electromechanical and microprocessor-based relay systems.
- **Transmission lines (61%), Transformers (11%), and Generators (10%) are the main facilities affected by misoperations**
  - 86% of generator misoperations occur with no system fault.
- **50% of misoperations are attributable to "human" performance.**
- **FERC Order 754 data request for single points of failure of protection systems. Submittal for buses > 100kV due October 2014.**

ERCOT Region Protection System Misoperations



- **Failure to Reclose removed from historical misoperation data.**
- **Lines show percentage of protection system operations that are misoperations.**
- **Percent Misoperation Rate is normalized based on number of system events.**

ERCOT Region “Human Error” Misoperation Reports



- **Percentage of Protection System Misoperations due to human factors, i.e., settings errors, wiring errors, design errors, etc.**

ERCOT Region – FERC Order 754

ERCOT 300-399 kV Systems	Number of Locations Evaluated	Number of Locations at which Protection System Did Not Meet All Attributes for Redundancy
Transmission lines	400	24
Transmission transformers	117	53
Generator step-up transformers	9	3
Step-down transformer	2	0
Shunt devices	19	1
Buses	115	74
DC supplies	121	8

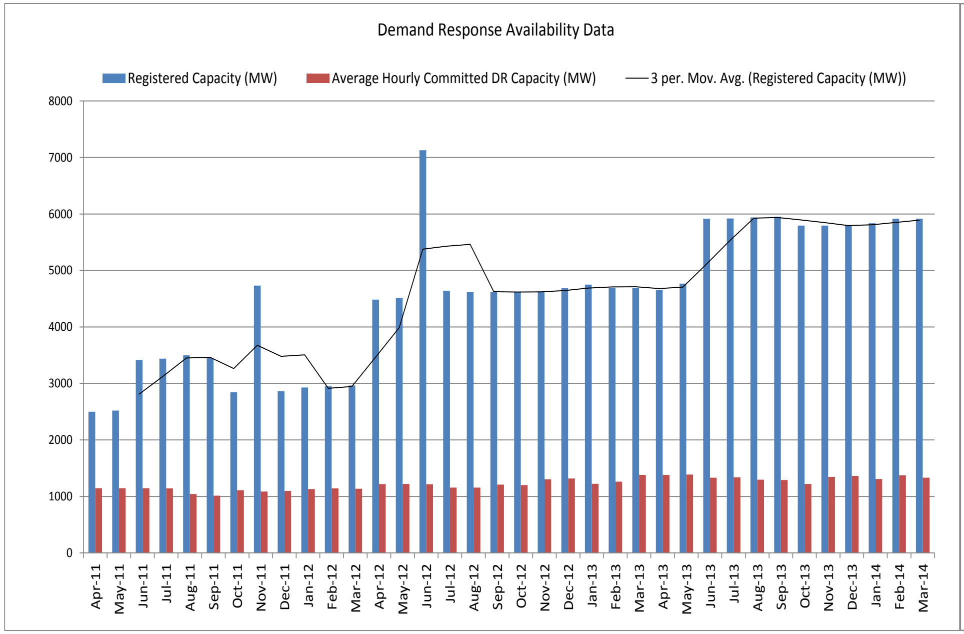
- **The most common issue noted was transformers and buses with a single, non-redundant, bus or transformer differential scheme.**
- **In FERC Order 754, the Commission expressed a concern about single point of failure of protection systems and issued a directive for further investigation. The Order stated that "the Commission believes that there is an issue concerning the study of the non-operation of non-redundant primary protection systems; e.g., the study of a single point of failure on protection systems." NERC issued a Data Request to collect information regarding locations where a single point of failure in a Protection System could result in a reliability risk.**

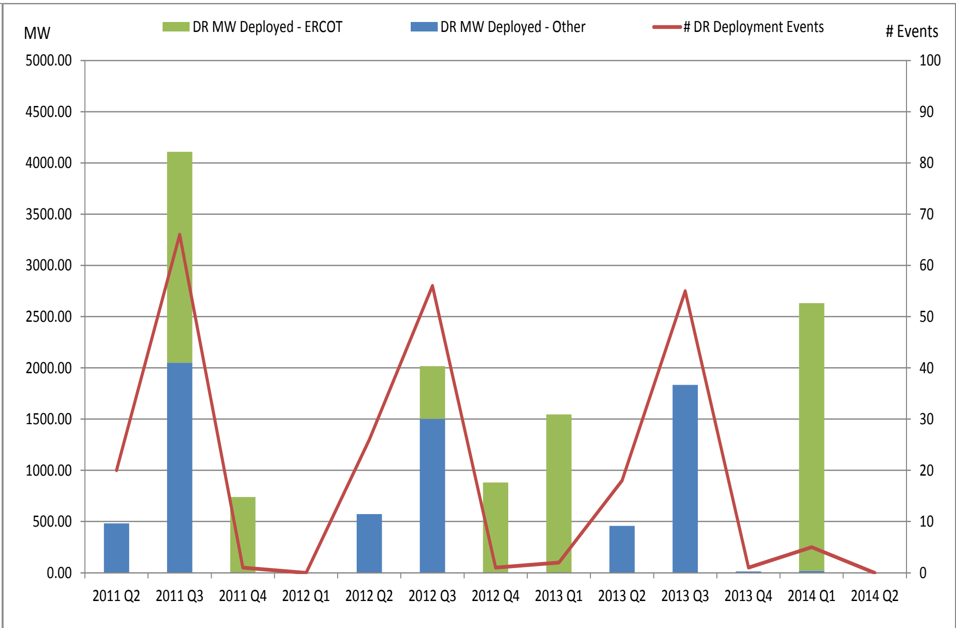
Demand Response, Infrastructure Protection, and Other Performance Observations

- **Demand Response**
  - Reported demand response capacity increased by 25% since January 2013, to ~ 6000 MW as of March 2014.
- **Infrastructure Protection**
  - Since January 2011, reports of copper theft and substation intrusion have averaged 12 per month, with a maximum of 28 in one month.
- **Other Performance issues noted:**
  - Telemetry availability and accuracy requirements
  - Entities failing to maintain adequate capacity to cover ancillary service obligations
  - Entities not current with required reactive tests
  - Entities not current with required governor tests

Demand Response – Observations

- Reported demand response capacity increased by 25% since January 2013, to ~ 6000 MW as of March 2014.

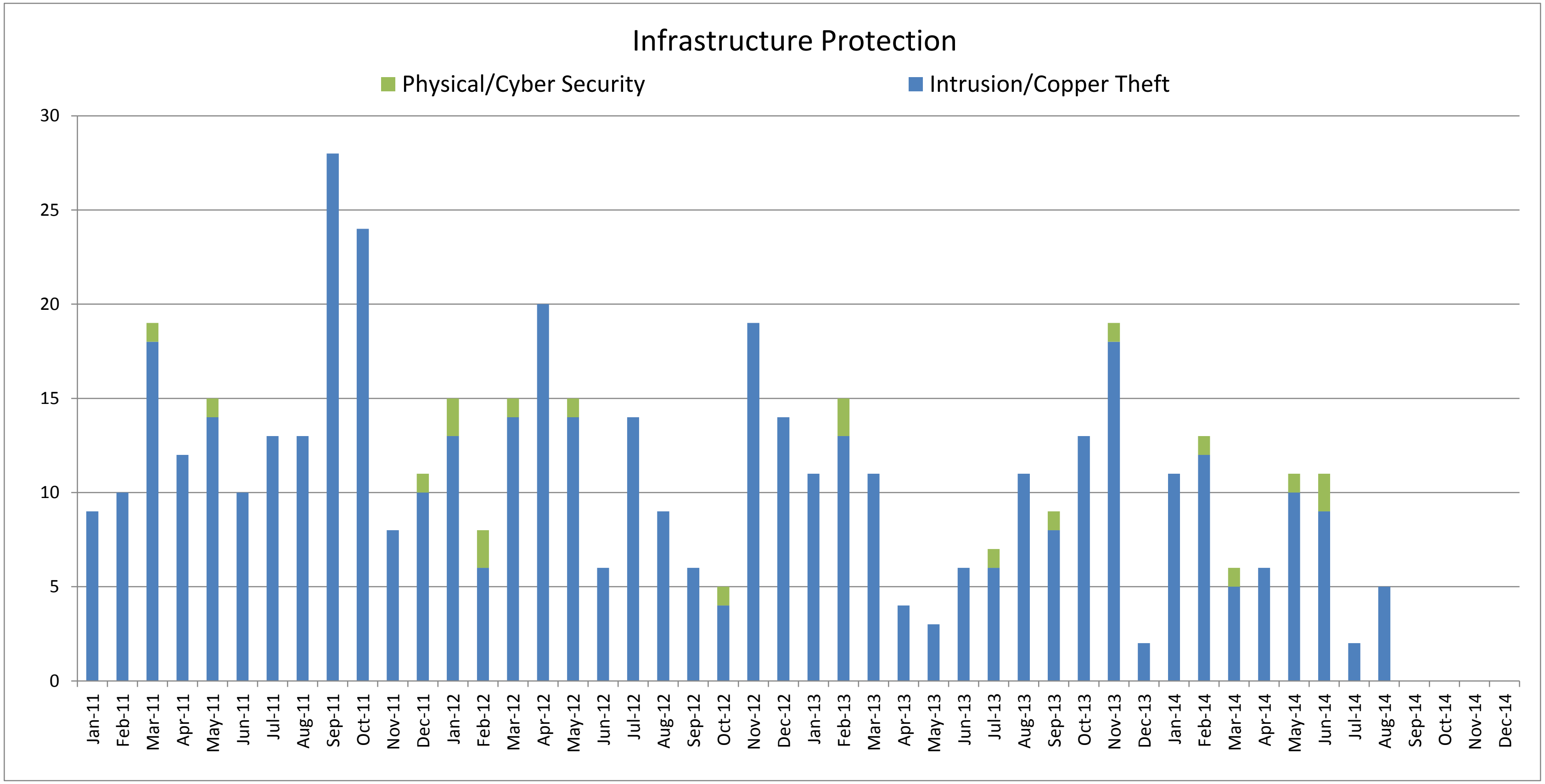




- Since April 2011, average DR event deployment
- ERCOT: 13 deployments – Average of 643 MW and 1.94 hours per deployment
- NOIE: 238 deployments – Average of 29 MW and 2.44 hours per deployment

Infrastructure Protection – Observations

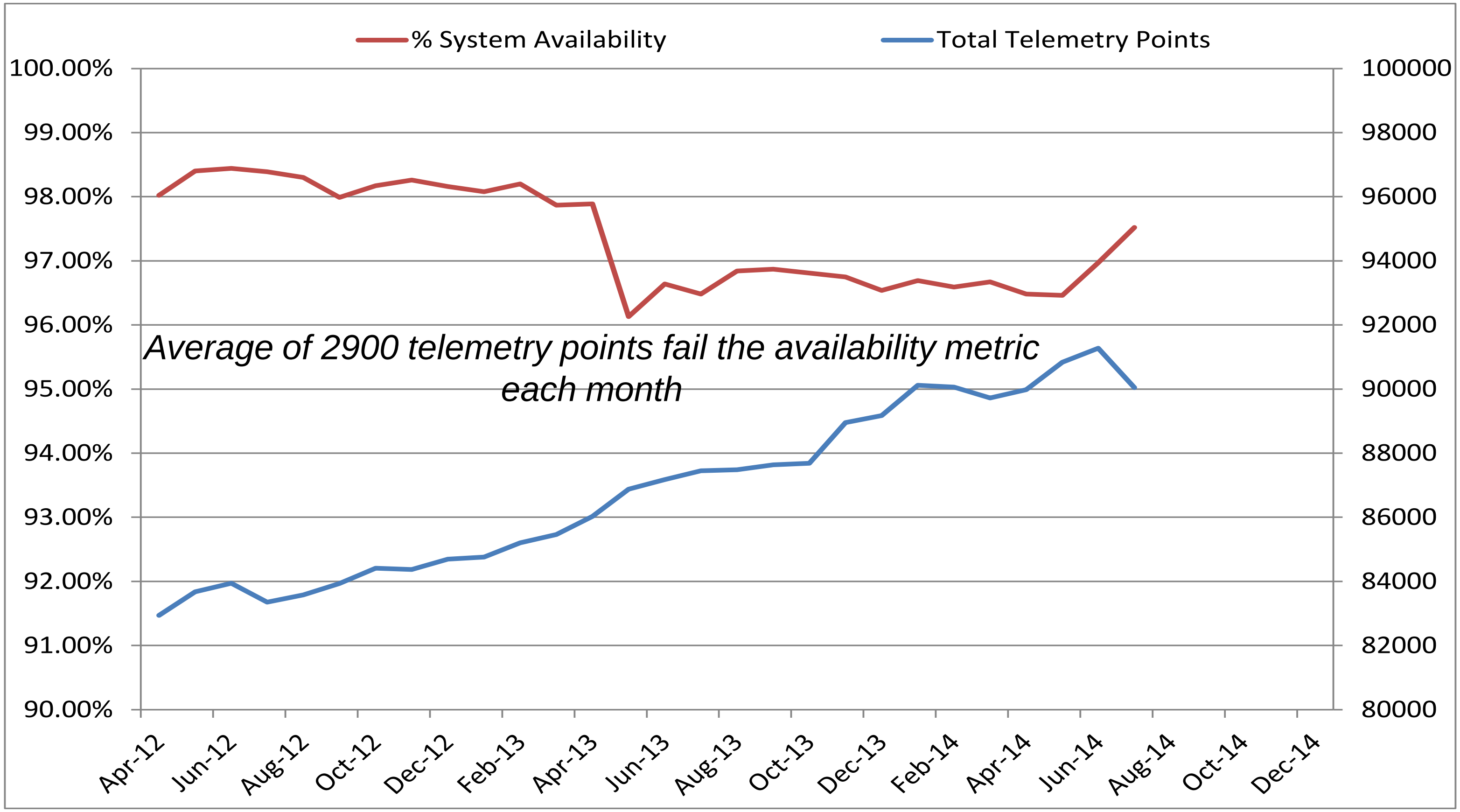
- Texas RE monitors reports from the System Security Response Group (SSRG).
- Since September 2011, substation intrusions and copper theft have ranged from three to 28 in any one month, averaging 12 each month. Four issues required reporting under the DOE-417 requirements in EOP-004.



Telemetry Performance – Observations

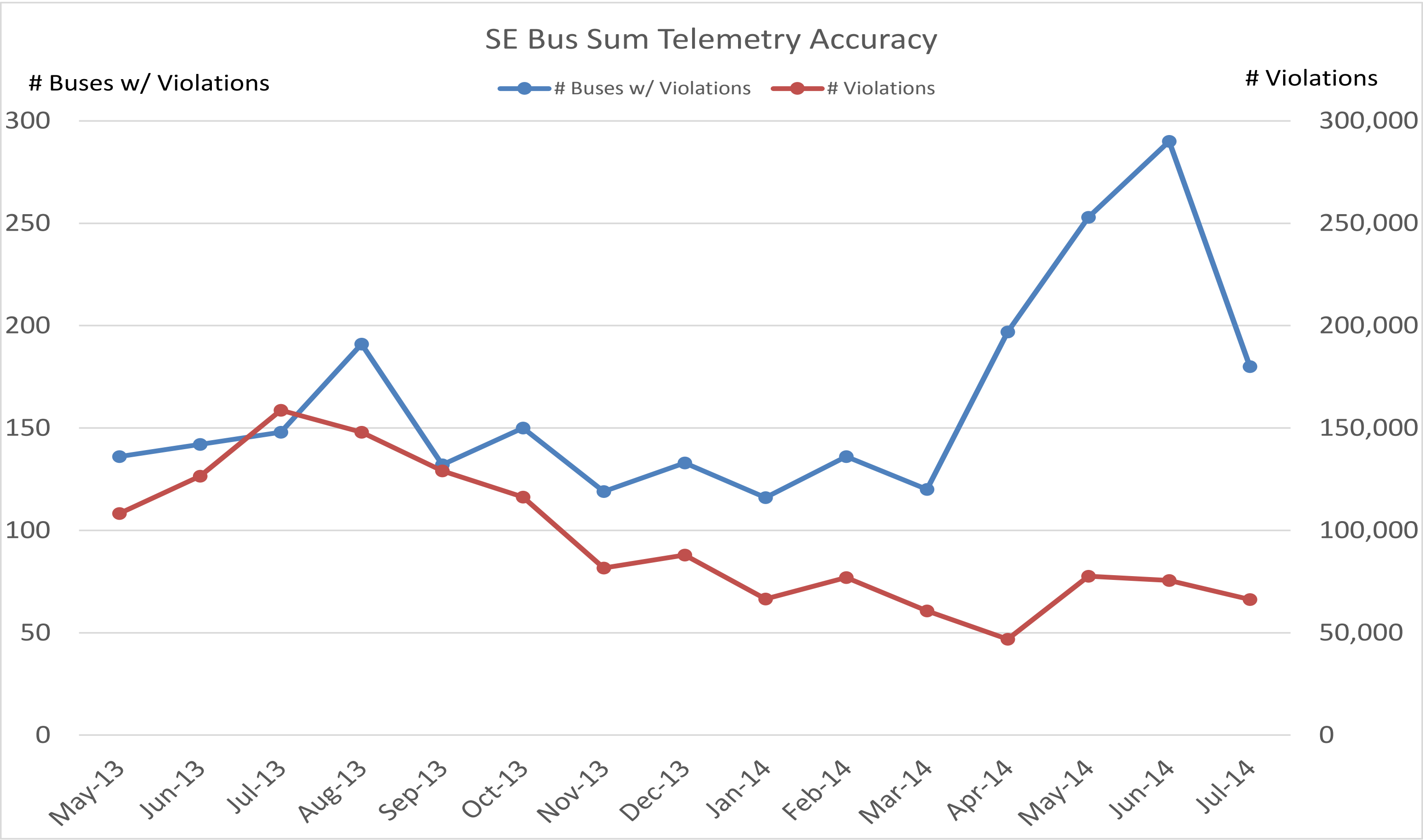
- **TAC Telemetry Standard**
  - Ninety two (92%) percent of all telemetry provided to ERCOT must achieve a quarterly availability of eighty (80%) percent. Availability will be measured based on end-to-end connectivity of the communications path and the passing of Real-Time data with a Valid, Manual, or Calculated quality code at the scheduled periodicity.
- **State Estimator (SE) Standard (partial list)**
  - **Bus MW telemetry accuracy:** sum of flows into any telemetered bus should be less than the greater of 5 MW or 5% of the largest Normal line rating at each bus. When there is no incident line at the bus, 5 MW will be the threshold value.
  - **SE vs. telemetry for major transmission elements:** residuals on transmission elements over 100kV should be <10% of emergency rating or <10 MW (whichever is greater) on 99.5% of all samples during a month period.
  - **Bus voltage telemetry accuracy:** on the 20 most important voltage buses for the State Estimator, the telemetered bus voltage minus state estimator voltage shall be within the greater of 2% or the accuracy of the telemetered voltage measurement involved for at least 95% of samples.
  - **SE vs. telemetry for congested transmission elements:** differences between the MW telemetry values and MW SE values should be within <3% of the largest associated Emergency Rating on at least 95% of samples measured in a one month period for predetermined congestion elements. Congested elements are those transmission elements causing 80% of congestion in the latest year for which data is available.

Telemetry Availability Performance



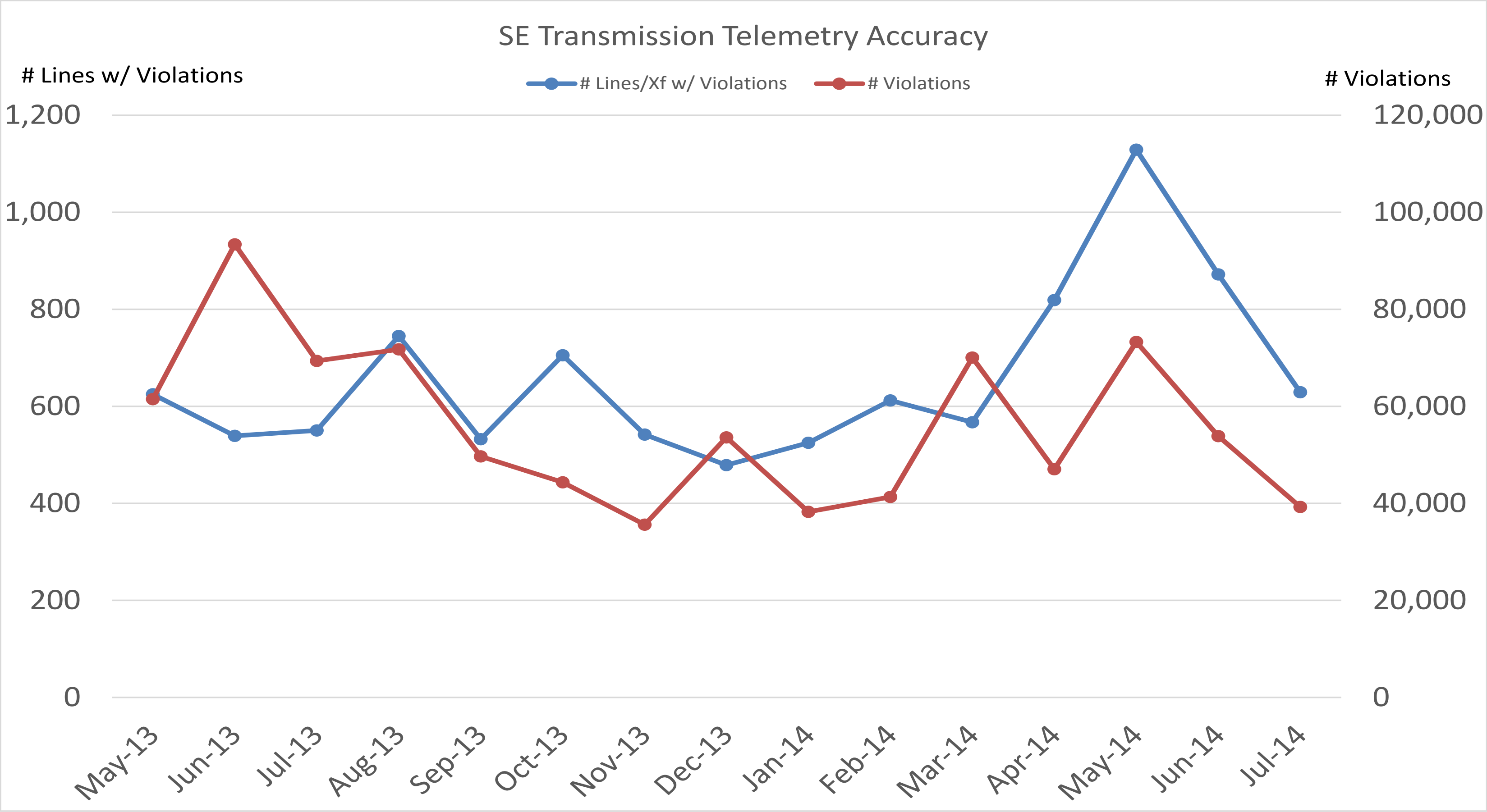
- **"Ninety two percent of all telemetry provided to ERCOT must achieve a quarterly availability of 80% percent. Availability will be measured based on end-to-end connectivity of the communications path and the passing of Real-Time data with a Valid, Manual, or Calculated quality code at the scheduled periodicity." - TAC0706060-Telemetry_Standards.doc**

Bus Summation Telemetry Accuracy



- **State Estimator Bus Telemetry Accuracy: the sum of flows into any telemetered bus to be less than the greater of 5 MW or 5% of the largest Normal line rating at each bus. When there is no incident line at the bus, 5 MW will be the threshold value.**

State Estimator vs. Telemetry for Transmission



- **SE vs. Telemetry for Major Transmission Elements: residuals on Transmission Elements over 100kV are <10% of emergency rating or <10MW (whichever is greater) on 99.5% of all samples during a month period.**

Questions?

Ensuring electric reliability for Texans