Texas Reliability Entity
Event Analysis

Event:
July 29, 2015 Loss of Multiple Generators
Category 3 Event

September 17, 2015

Table of Contents

Executive Summary

On July 29, 2015 at 18:16:40, two combined cycle trains (CC1 and CC2) at a generation facility tripped offline carrying a combined total of about 953 MW. A nearby coal unit also tripped carrying 554 MW. One of the 345 kV transmission lines serving the combined cycle facility also tripped due to a misoperation of the protection system. System frequency dropped to a minimum frequency of 59.723 Hz and recovered to 60 Hz in approximately 6 minutes, 6 seconds. After the loss of generation, an advisory was issued for Physical Responsive Capability (PRC) being below 3000 MW. The advisory was cancelled at 18:50. This report provides: (1) an overview of the event; (2) background on system conditions just prior to the event; (3) the detailed sequence of events; (4) an analysis of the causal and contributing factors for concerns that arose in this event; and (5) recommendations for follow-up action.

I. Event Overview

At approximately 18:16:41 a flashover occurred on a surge arrester on the generator step-up transformer (GSU) for one of the gas turbines at a combined cycle generation facility. The fault was correctly identified by the GSU differential protection and a trip command was issued to the unit breaker. Due to the magnitude of the fault, the saturation in the current transformers was great enough to make the fault appear as though it was inside the bus differential zone of protection, and a trip command was issued by the bus differential relays. The operation of the bus differential relay tripped the remaining bus circuit breakers, isolating all three units of combined cycle train #1 from the system.

The line differential relay for one of the 345 kV lines serving the facility is estimated to have operated at the same time as when the gas turbine circuit breaker opened. The backup line differential relay protection did not operate. The operation of the line differential relay tripped additional circuit breakers at the combined cycle generation facility as well as circuit breakers at the transmission substation serving the facility. This had the effect of isolating all three units of combined cycle train #2 at the facility. The incorrect operation of the line differential relay is still under investigation.

A nearby coal generation unit tripped coincident with the loss of the combined cycle units. The coal generation unit was tripped by the incorrect operation of the generator step-up (GSU) transformer differential relay for the A-phase to ground fault. The generator owner reported current transformer (CT) ratios on the 345 kV side CTs for the transformer differential protection were not correct per the relay setting sheets and drawings.

System frequency measured at ERCOT's control center dropped from 60.017 Hz to 59.723 Hz, based on 4-second scans, as a consequence of the loss of generation. The drop was arrested by governor action of ERCOT region generators, aided by automatic deployment of 1341 MW of generation responsive reserve as well as 317 MW of regulation. These actions led to system frequency recovery within 6 minutes and 6 seconds to 60 Hz (at 18:22:46).

The loss of both 345 kV buses at the combined cycle generation facility caused additional issues at the plant. Real-time telemetry from the plant “froze” at pre-event values following the event until values were over-ridden by operators. Voice communications were also temporarily lost with the plant due to the loss of AC power.

The event met the criteria for North American Electric Reliability Corporation (NERC) Event Reporting under NERC Reliability Standard EOP-004-2 as well as a Category 3a reportable event under the ERO Events Analysis process due to the loss of generation greater than 1400 MW in the ERCOT region.

II. Initial System Conditions Prior to Event

<u>*7/29/2015 at 18:15*</u>:

System Demand:	66,277 MW
System Frequency:	59.995 Hz
Area Control Error (Total):	~ -45 MW
Physical Responsive Capability:	~3365 MW

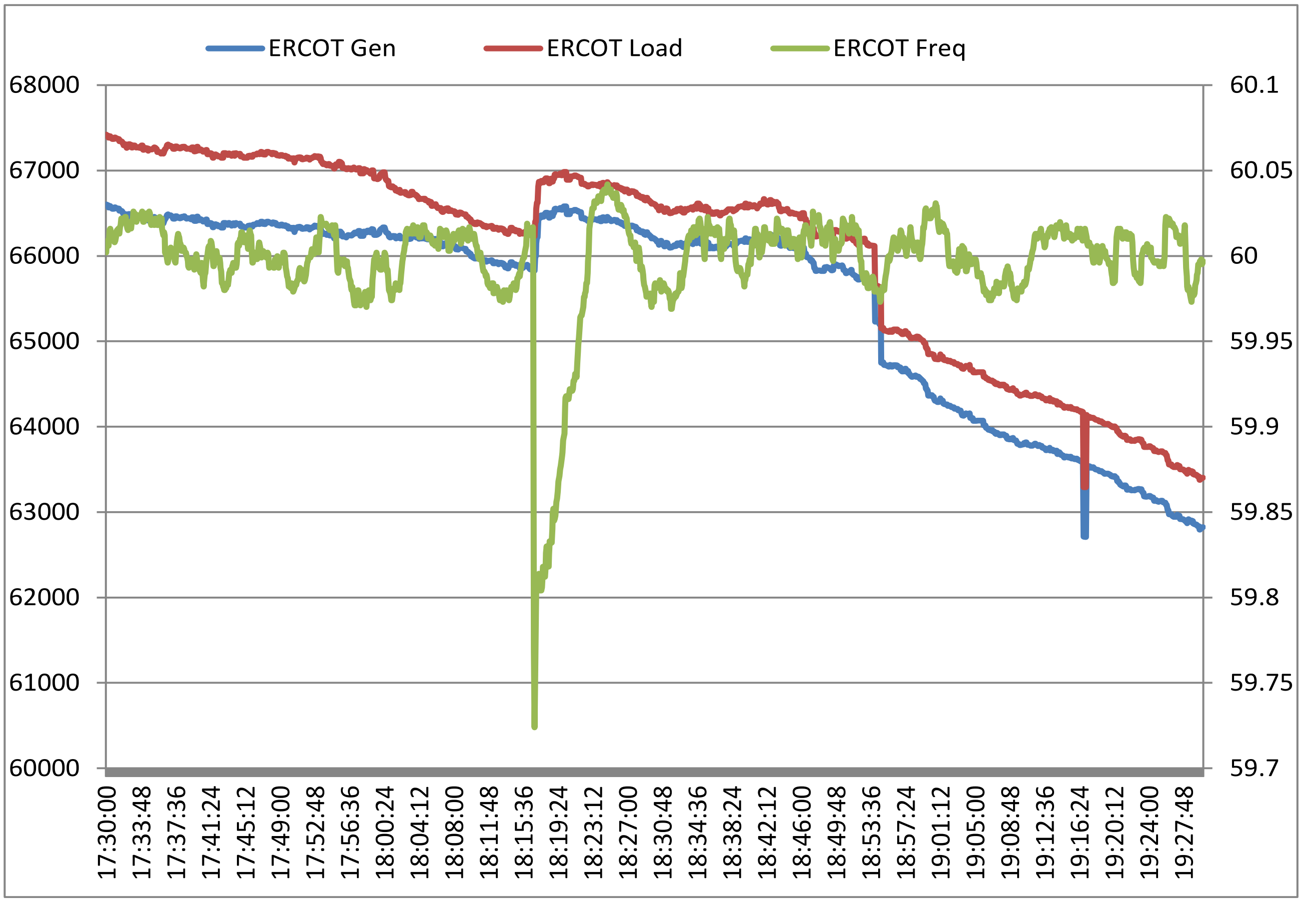

Figure 2: ERCOT System Generation, Load, and Frequency 7/29/2015

III. Analysis of Unit Trips

A. Combined Cycle Generation Facility

At approximately 18:16:41 a flashover occurred on the phase A surge arrester of the GSU for gas turbine #1 of combined cycle train #1. The fault was correctly identified by the GSU differential protection and a trip command was issued to the gas turbine unit circuit breaker within 8 ms of the fault initiation. Due to the magnitude of the fault, the saturation in the current transformers (CTs) was great enough to make the fault appear as though it was inside the bus differential zone of protection, and a trip command was issued by the bus differential relay at almost the same instant as the gas turbine unit circuit breaker opened to clear the fault. The operation of the bus differential relay tripped the remaining circuit breakers on the bus, isolating all three units of combined cycle train #1 from the system.

The line differential relay for one of the 345 kV lines serving the facility is estimated to have operated at the same time as when the gas turbine unit circuit breaker opened with a Differential Current A Phase target. The backup line differential relay protection did not operate. The operation of the line differential relay tripped additional circuit breakers at the generation facility as well as circuit breakers at the transmission substation serving the site. This had the effect of isolating all three units of combined cycle train #2. The incorrect operation of the line differential relay is still under investigation, but saturation of the CTs is suspected. The primary and backup line differential relays do not capture event oscillography or other post-event data in the same manner as modern digital relays. Event data is limited to front panel relay targets.

The local transmission owner noted the following in its review of the event data:

a. No CT saturation was noted on the relay records obtained from the breaker failure relays at the generation site.
b. The backup line differential relaying scheme restrained, which indicates a problem isolated to the primary line differential relaying scheme.
c. The fault current is split through two breakers at transmission substation, versus a single tie line terminal breaker at generation site. This leads to a higher probability of saturation at the generation site.
d. The primary line differential relay front panel target at the transmission substation indicated a trip signal was received via the plant terminal.
e. Generation plant engineering staff indicated a current waveform with a high peak value, indicative of CT saturation.

The loss of both 345 kV buses at the combined cycle facility caused additional issues at the plant. The two most notable were the loss of plant telemetry and the loss of voice communications with the plant.

1) The loss of the 345 kV buses caused a power loss to the plant Administration building, and substation control building. AC-powered 4-20 mA transducers for several individual gas turbines lost power, causing the transducer outputs to read

0 milliamps, which is treated as "Bad Quality". When this occurred, the plant Distributed Control System (DCS) maintains the last good value.

2) The Remote Terminal Unit (RTU) housed in the substation control house uses a serial connection via modems to transmit data to the plant DCS. The modem in the substation control house utilizes AC power. Attempts to poll the RTU from the DCS got no response due to the modem power issue.
3) The loss of power to the Administration building caused a loss of power to the VOIP telephone system. The VOIP system has a UPS that provides backup power for 20 to 30 minutes when offsite power is lost. It is believed that this backup power system performed as designed; however, the offsite power outage lasted longer than 20 to 30 minutes.
4) Backup communications capability through a satellite phone was unable to get reception inside the control building. A contributing factor to the lack of reception in the Control Room was that the handset was removed from the base station. Had the phone remained on the base station when the operator attempted to establish contact with the desk, it is likely that the antennae attached to the base station would have provided the necessary reception to the satellite phone system.

Corrective Actions Taken or In-Progress:

a) Engineers from the relay manufacturers are currently investigating the oscillography from the relays to understand the cause of the bus differential relay operation.
b) The generator owner is working with its transmission provider and has made plans to replace the substation RTU in the fall. The generator owner is investigating changing the power source of this RTU from AC to DC.
c) The generator owner is taking the following actions to ensure voice communications are not lost during similar events in the future:
    1) Purchasing an analog backup line at the facility that will be less dependent on offsite power.
    2) Evaluating the purchase of a plant cell phone for use as a backup in the control room.
    3) Providing additional training to plant personnel regarding voice communications.
    4) Updating contact information at the dispatch desk and plant.
    5) IT personnel have since tested the satellite phone system with plant personnel and verified proper operation

B. Coal Unit Generation Facility

A nearby coal generation unit tripped coincident with the fault at the combined cycle generation facility. The unit was tripped by the A-phase transformer differential relay on the generator step-up transformer. It was determined that the CT ratios were found to have an incorrect setting on the 345 kV side of the GSU.

The generator owner concluded the following:

a. The owner recently completed commissioning a new GSU and incorrectly set the 345 kV side transformer differential CTs.
b. The technician received setting changes on 3/19/2015 and looked at an incorrect setting that led him to believe the ratio of the 345 kV side CT should have been 2000/5. The setting sheet did not require a change to the CT ratio and the setting should have been set at 1200/5.
c. The technician performed relay acceptance of the 345 kV side CT with a ratio of 2000/5 on 3/24/2015.
d. The technician's commissioning paper work was filled out and listed the ratio as 2000/5 on two separate sheets.
e. The same technician re-verified the CT ratio (this is required as part of the commissioning checklist). He again verified it against the incorrect CT ratio.
f. The transformer was energized on 4/22/2015.
g. The owner implemented a corrective action plan to mitigate incorrect CT settings by requiring an additional CT verification process into the existing practice. This will require a second qualified technician or supervisor to double-check/re-verify the lead technician's work and sign off that it is correct. This process would include re-verifying CT ratios and settings, as well as requiring in service reads.

IV. Response Analysis

A. Primary Frequency Response

The loss of 1507 MW of net generation in the ERCOT region during the afternoon of July 29, 2015 constituted a significant disturbance to grid. ERCOT used the Region's resources and reserves to balance resources and demand and return system frequency to pre-disturbance frequency well within the 15 minute target set by NERC Standards.

ERCOT region frequency was at 60.014 Hz immediately prior to the disturbance. Immediately after the disturbance, system frequency dropped to 59.723 Hz, based on 4-second scans. The following are among the actions that registered entities initially took to stabilize the system:

- Generator governor response arrested the frequency decline, as analyzed by the Performance, Disturbance, Compliance Working Group (PDCWG) in the Frequency Measureable Event (FME) report. The initial calculated system frequency response was 789 MW/0.1 Hz, which exceeds the target of 471 MW/0.1 Hz established in NERC Reliability Standards. The response was due to the governor action from the on-line generation resources. The FME report also noted that 41 out of 60 units (units running that were not excluded) (68.3%) passed the initial governor response measurement and 45 out of 60 (75.0% passed the sustained governor response measurement for this event.

The result of these actions was that system frequency returned to its pre-disturbance value of 60 Hz within 6 minutes and 6 seconds.

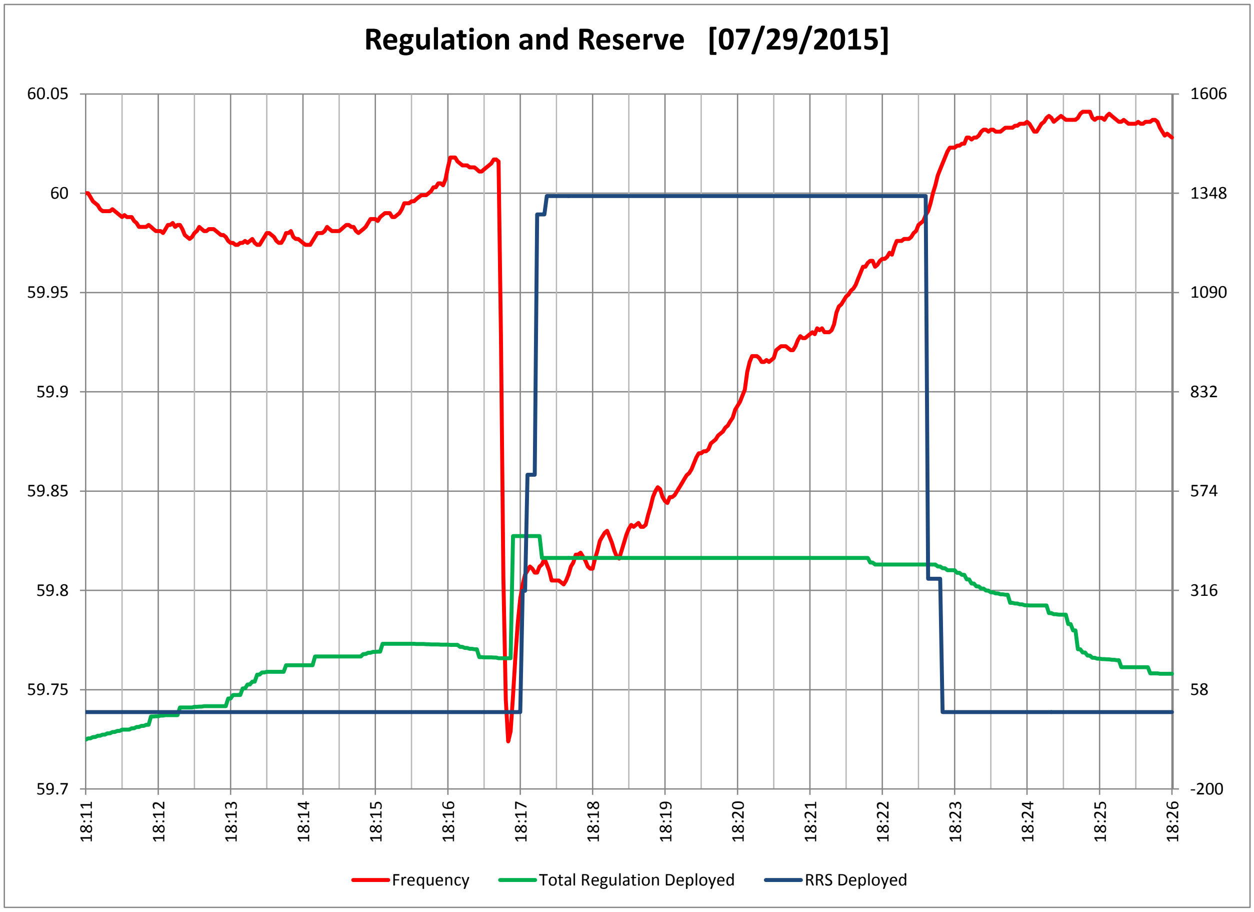

Figure 5: ERCOT Responsive Reserves and Regulation Deployments

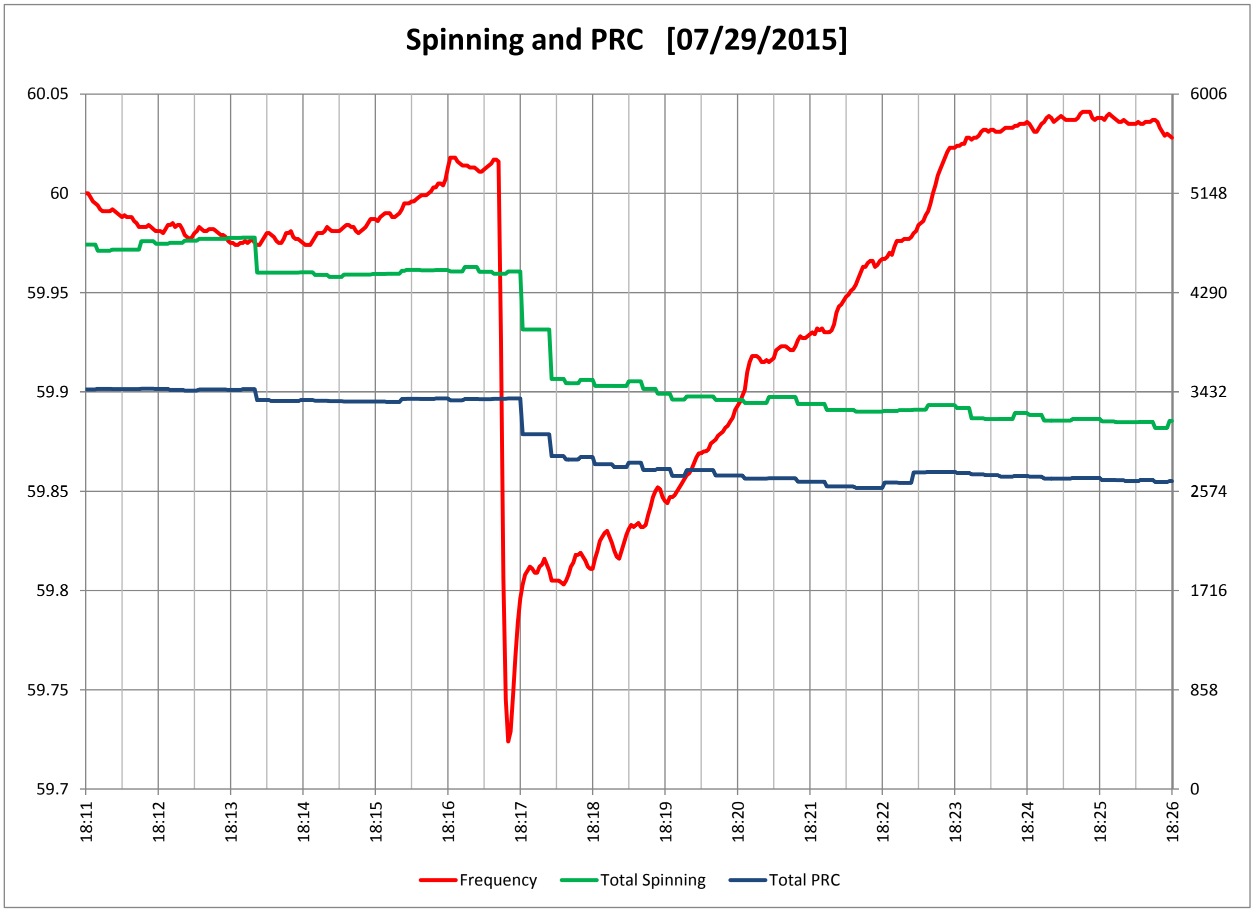

Figure 6: ERCOT Spinning Reserves and Physical Responsive Capability

B. Reserves

The Physical Responsive Capability (PRC) dropped to a low point of 2603 MW at 18:21:48. After the loss of generation, an advisory was issued for PRC being below 3000 MW. The advisory was cancelled at 18:50.

V. Conclusions

In general, the steps taken in the recovery from this event achieved the desired results. System Operators handled the situation effectively.

The magnitude of the generation loss was preventable, in light of the three protection system misoperations that occurred during the event. Proper follow-up and completion of the proposed corrective actions will help to prevent a similar occurrence at these facilities.