Texas Reliability Entity
Event Analysis

Event:
November 3, 2010 DCS Event
Category 3 Event

Texas Reliability Entity
July 2011

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Executive Summary

On November 3, 2010, an electrical failure of a 13.8 kV switchgear tripped Unit B at the Generation Station A, removing 1351 MW of generation from the ERCOT Region. In conjunction with the Unit B trip, the Generation Station C Unit D tripped removing an additional 83 MW. Another unit trip approximately 10 minutes later removed an additional 503 MW of generation. Reliability Coordinator (RC) and Balancing Authority (BA) personnel and systems operated effectively to restore system frequency by deploying reserves, and then afterwards restored those reserves. 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 10:21:10 on November 03, 2010, Unit B at Generation Station A tripped dropping 1353 MW of generation in the ERCOT Region. The trip was due to a failure within the 13.8 kV circuit breaker cubicle for the startup feed pump during routine feedwater system testing.

Twenty seconds later (10:21:30), Unit D at Generation Station C tripped offline removing 83 MW from the system. 1434 MW tripped within the first minute of the event.

Roughly ten minutes after the loss of Generation Station A Unit B and Generation Station C Unit D, a second event occurred at Generation Station E. Generation Station E unit F tripped with 503 MW at 10:31:00.

System frequency dropped from 60.012 Hz to 59.714 Hz as a consequence of the loss of generation. The drop was arrested by governor action of ERCOT Region generators, aided by automatic deployment of generation responsive reserve of 571 MW as well as automatic deployment of 680 MW of Load Acting as Resources (LaaR) by underfrequency relay action. BA operators responded to this event and issued directives at 10:26:02 to deploy remaining LaaR (603 MW) to assist frequency recovery within 15 minutes. These actions led to system frequency recovery within 5 minutes and 10 seconds to the pre-disturbance value of 60 Hz (at 10:26:20).

After the frequency recovery, the BA had to contend with depletion of its reserves, particularly the Adjusted Responsive Reserve (ARR) which forms the basis for emergency notifications and actions. The recovery from the initial disturbance (using automatic LaaR deployment and automatic deployment of Responsive Reserve Service (RRS)) took ARR near 3000 MW. At 10:29 (5 minutes after the initial disturbance), the BA issued directives to Generation Entity A and Generation Entity B to lower fleet

generation by a total of 500 MW due to high frequency. At 10:31 (10 minutes after the initial disturbance), the loss of Generation Station E unit F removed an additional 503 MW of generation from the ERCOT Region and resulted in dropping the ARR level to approximately 2600 MW . An “Advisory” was issued at 11:00 for ARR below 3000 MW. BA operators made Hot-line calls and issued Verbal Dispatch Instructions (VDIs) to restore LaaRs and lower fleet generation due to high frequency caused by the LaaR deployment. By 11:42:26, ARR was above 3000 MW and the “Advisory” was cancelled at 12:45.

The RC responded to the first event as a NERC Disturbance Control Standard (DCS) event due to the loss of generation above 1000 MW in the ERCOT Region. The event also met the definition of a Category 3a event (loss of load or generation of 1,000 MW or more in the ERCOT Region) under NERC’s Event Analysis Working Group (EAWG) procedure and also exceeded the most severe single contingency event for the ERCOT Region. The second event with Generation Station E unit F did not approach 80% of the single largest contingency and is thus not being treated as a DCS event. The second event did impact the recovery and for this reason, it is discussed in the response.

II. Forecasts and Initial System Conditions Prior to Event

11/03/2010 PUCT Current Day Report forecast reflecting 20:00 Peak (Pk):

Forecasted Pk HR Demand:	31,693 MW @ 1100 HR
Generation for Pk HR Demand	41,195 MW @ 1100 HR
Schedule Gen for Pk HR Demand	35,182MW @ 1100 HR
Pk Hour load served by Balancing Energy	-3489 MW @ 1100 HR

Potential for Capacity Emergency (EEA1)	Low @ 1100 HR
Potential for Deploying LaaR (EEA2A)	Low @ 1100 HR
Potential for Deploying IEL (EEA2B)	Low @ 1100 HR
Potential for Firm Load Shed (EEA3)	Low @ 1100 HR

Initial system conditions just before the event of November 3, 2010 were:

System Load:	31,477 MW
Net Scheduled Generation:	31,797 MW
Capacity on Line:	31,005 MW
Balancing Energy:	-1597 MW
System Frequency:	60.012 Hz
Schedule Control Error (Total):	11 MW
Net Spin Reserves:	5354 MW
Adjusted Responsive Reserves:	~4714 MW

III. Sequence of Events on 11/03/2010

- 10:21:06 ERCOT Region frequency prior to disturbance was 60.012 Hz.
- 10:21:10 Generation Station A unit B operating at 1353 MW, tripped to zero.
- 10:21:10 ERCOT Region frequency dropped to approximately 59.714 Hz immediately after the trip.
- 10:21:10 680 MW of Load acting as Resources (LaaRs) were deployed by under frequency relay action.
- 10:21:20 571 MW of Generation Responsive Reserve was deployed automatically in response to the frequency spike.
- 10:21:30 Generation Station C unit D operating at 83 MW, tripped to zero.
- 10:26:02 A Hotline call was made to all Qualified Scheduled Entities (QSE) to deploy the remaining LaaRs providing Responsive Reserve Service (RRS). This resulted in an additional 603 MW of LaaRs being deployed. QSEs had a total LaaR obligation of 1150 MW providing RRS at the time of the event. A total of 1283 MW of LaaRs were deployed within 10 minutes of the Verbal Dispatch Instruction (VDI) being issued.
- 10:26:20 ERCOT Region frequency recovered to 60 Hz.
- 10:29 BA directed Generation Entity A to lower fleet generation by 300 MW due to high frequency.
- 10:29 BA directed Generation Entity B to lower fleet generation by 200 MW due to high frequency.
- 10:31:00 Generation Station E unit F operating at 503 MW, tripped to zero.
- 11:00 Advisory issued for Adjusted Responsive Reserve (ARR) below 3000 MW.
- 11:08:11 A Hotline call was made to all QSEs to restore LaaRs and Hydros in synchronous condenser mode that were supplying RRS.
- 12:45 Advisory issued for ARR below 3000 MW was cancelled.

IV. Analysis of Initial Unit Trips

A. Generation Station A unit B

The Generator Operator reported that shortly after closing the breaker for Startup Feed Pump (SUFP)-24 in 13.8 kV Standby Switchgear 2H/Cubicle 1A, the breaker tripped back open. Approximately eight seconds later, an electrical fault occurred in the cubicle causing a lockout of Standby Bus 2H and an undervoltage condition on Auxiliary Buses 2H and 2F. This resulted in a Reactor Coolant Pump (RCP) undervoltage condition on each bus and a subsequent STP Unit 2 reactor trip.

The cause of the breaker failure in 13.8 kV Standby Switchgear 2H/Cubicle 1A (SUFP 24) was due to an arc restrike, or re-ignition, across the open contacts of the supply breaker after the breaker tripped. This caused damage to the arc chutes and caused plasma (ionized air) in the cubicle. Eventually, the plasma created a conductive path in the cubicle for the three phases to ground. The grounding of the three phases caused the voltage on the associated buses (Auxiliary Buses 2H and 2F) to drop to zero and resulted in an explosion that caused physical damage to the cubicle. The voltage drop caused the STP Unit 2 reactor to trip on RCP undervoltage.

Although arc restrikes and the resulting breaker damage are rare and require the alignment of several contributing factors to occur, corrective actions to minimize the probability of these factors from occurring are warranted. Currently, it is not known why the arc restrikes occurred. The most likely scenario is that the SUFP 24 breaker tripped four seconds after closing due to the 51B Time Overcurrent Relay being actuated by the overcurrent condition caused by the event; however, there may be other possible causes that led to the breaker tripping, including particulate contamination of the arc chutes, moisture contamination in the arc chutes, etc. The failed SUFP 24 breaker and additional components were sent to a lab for failure analysis. The root cause investigation report and the associated corrective action plan will be completed when the failure analysis is concluded.

There is evidence that the breaker in the Startup Feed Pump 13.8 kV 2H breaker cubicle failed to clear an electrical fault while attempting to start the startup feed pump. The breaker's failure to clear the electrical fault is a protection system misoperation.

The Generation Station A unit B main generator output breaker operated as per design. There was no equipment damage due to the trip of Generation Station A unit B.

B. Generation Station C unit D

The Generator Operator identified the cause of the Generation Station C unit D trip while loaded at 83 MW (versus nameplate rating of 234 MW or 35% of nameplate) due

to exhaust temperature spread. The unit was operating in a 2x1 combined cycle mode with both combustion turbines operating near minimum load on AGC. The Generator Operator noted that this type of machine operates with a lean combustion to maintain low emissions. Due to the lean combustion operation, the turbines may experience lean combustion blow out incidents. Post-event analysis by the Generator Operator indicates that the Generation Station C unit D trip was caused by a confluence of three factors:

1. Review of control system data indicates that the Unit D turbine fuel temperature control valve was operating erratically in the hours prior to the trip. This erratic operation contributed to unstable fuel/air flow control. The fuel temperature control operation operated normally upon re-start and has continued to operate without incident. The underlying cause of the erratic valve operation prior to the trip could not be determined. The controller tuning parameters were reviewed and adjusted to ensure proper operation.
2. Recent changes in ambient conditions contributed to unstable air/flow control.
3. The frequency disturbance caused by the Generation Station A unit B trip introduced additional instability into the fuel/air flow control as the unit's speed changed a lot more than normal which changed the actual airflow to the unit.

C. Generation Station E unit F

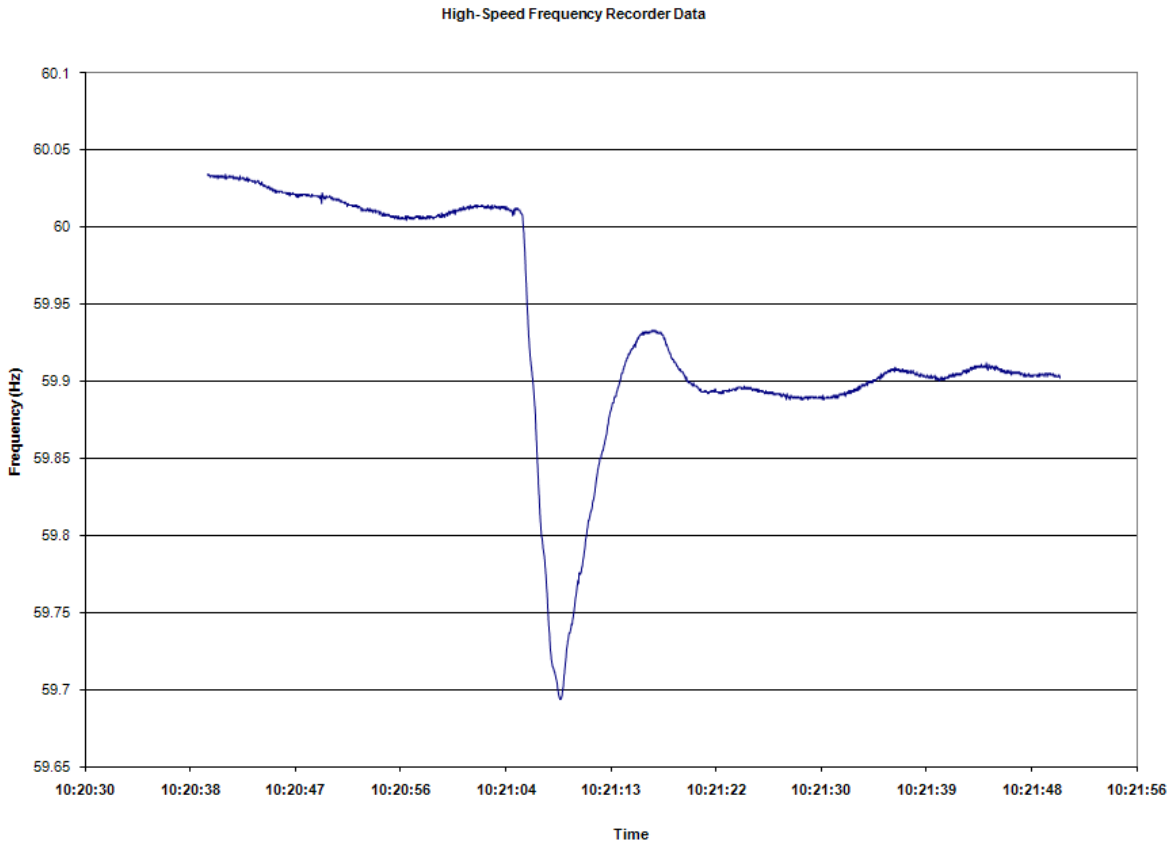
Approximately 10 minutes after the initial disturbance, the Generation Station E unit F tripped while loaded at 503 MW. A needle valve failed and sprayed steam on the 'B' boiler water circulating pump (BWCP) differential pressure transmitter, causing the transmitter reading to fail. The average calculated BWCP differential pressure then dropped below 11", and because the unit was at less than 60% feedwater flow, a boiler trip was initiated by the unit control system. The boiler trip initiated a turbine trip, which closed the turbine valves. This resulted in detection of reverse power, triggering operation of the reverse power relay which ultimately opened the Generation Station E unit F generator breaker. Although the Generation Station E unit F trip occurred in a time frame associated with the DCS event, the root cause of the trip was the failure of the needle valve and was not related to the system frequency deviation.

V. Response Analysis

A. Initial Response

The loss of 1434 MW of generation in the ERCOT Region during the morning of November 3, 2010 constituted a significant disturbance to grid operations (generation loss represented 4.5% of ERCOT Region load). The BA 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 (measured at the RC control center) was at 60.012 Hz immediately prior to the disturbance. Immediately after the disturbance, system frequency dropped to 59.714 Hz. The following are among the actions that registered entities initially took to stabilize the system:

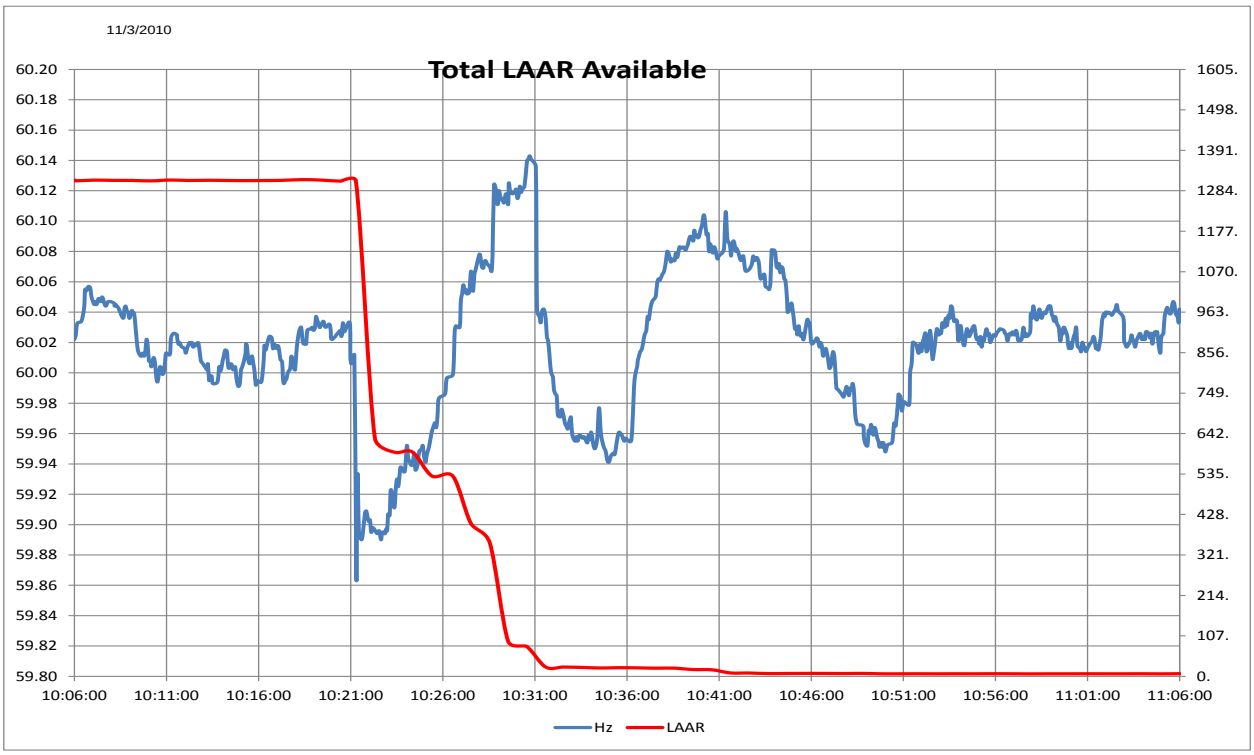


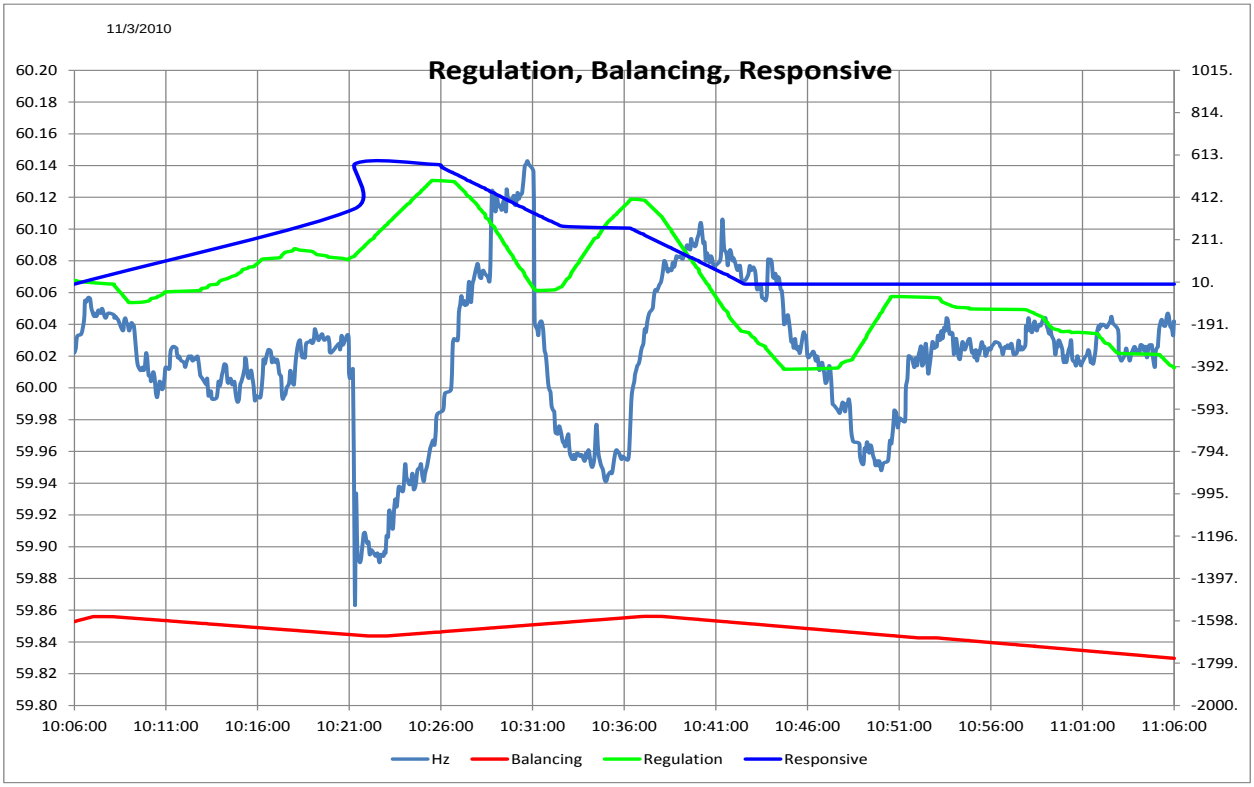
High-Speed Frequency Recorder Data on November 03, 2010.

- Generator governor response arrested the frequency decline, as analyzed by the Performance, Disturbance, Compliance Working Group (PDCWG) in its draft report. The initial calculated system frequency response, termed the "B" point, was 153.76 MW/0.1 Hz, which failed to meet the target of 420 established in ERCOT Protocols 5.9.2. The second calculated response point, termed "B+30" to denote that it measures how well response is sustained 30 seconds after the event, declined to 19.8 MW/0.1 Hz, which also failed to meet the minimum response level. The PDCWG also noted the following concerns:
    - 293 out of 416 units (units running that were not excluded) (70.4%) sustained governor response for this event.
- The BA control center computer made a step deployment of 571 MW of generation RRS, within 10 seconds of the frequency bottom, modifying the setpoint sent to QSEs to accomplish this deployment. Texas RE did not identify any problems with this automatic deployment by the BA or the response from QSEs to ramp their generators output up within 10 minutes as required.

- Automatic deployment of 680 MW of LaaR by underfrequency relay action aided the frequency recovery.
- Manual deployment of LaaR reduced load by another 603 MW within 10 minutes of the BA Verbal Dispatch Instruction (VDI) which was issued at 10:26:02, approximately 5 minutes after the initial disturbance. One LaaR provider with two resources with approximately 5 MW of load failed to deploy within the required 10 minute time frame. One LaaR provider with approximately 42 MW of load experienced a Remote Terminal Unit (RTU) failure but still deployed.

The result of these actions was that system frequency returned to its pre-disturbance value of 60 Hz within 5 minutes and 10 seconds.





B. Reserves and Declaration of Advisory

After the frequency recovery, the BA had to contend with depletion of its reserves, particularly the ARR that forms the basis for emergency notifications and actions. The recovery from the initial disturbance (automatic/manual LaaR deployment and automatic RRS deployment) did not take ARR below 3000 MW, the point at which an "Advisory" is called for in ERCOT Protocols 5.6.4, until the Generation Station E unit F trip at 10:31, at which time the ARR level dropped to approximately 2600 MW. The RC did not issue an Advisory until 11:00, or 29 minutes after the 3000 MW ARR level was breached. At 11:08:11, all QSEs were instructed via Hot-line calls to restore LaaRs and Hydros in synchronous condenser mode that were supplying RRS. By 11:42:26, ARR was above 3000 MW and the Advisory was cancelled at 12:45.

The result of these actions was that the ARR remained above the BA minimum level of 2300 MW.

VI. Conclusions

In general, the steps taken in the recovery from this event achieved the desired results. Given the number (3) of unit trips during the event, and the high volume of incoming communications, RC and BA operators handled the situation effectively.

Equipment owners have taken actions to address problems as noted:

- Generation Entity A's analysis indicates that the Unit D trip that occurred during a system disturbance was caused by an unusual combination of combustion system control issues in addition to the frequency disturbance. It is worth noting that the same unit has operated through more severe frequency excursions without incident. The controls have been re-tuned on November 8, 2010 to minimize the probability of future events of this type.

In conclusion, while frequency response from generators and LaaR performed to effectively address the initial frequency response, the ERCOT Region was short on the "B" and "B+30" calculation of system frequency response. 293 out of 416 units (running that were not excluded) provided the 'sustained' governor response for this event. A third of the units did not contribute or actually reduced output instead of increasing it.