Texas Reliability Entity
Event Analysis

Event:
December 11, 2010 Loss of Multiple Generators
Category 3 Event

Texas Reliability Entity
July 2011

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Executive Summary

On December 11, 2010, Unit B at Generation Station A tripped causing the loss of 823 MW of generation. Within the next 30 seconds, Unit D and E at Generation Station C tripped causing the loss of 149 MW of generation and Unit G at Generation Station F tripped causing the loss of 99 MW of generation. A total of 1071 MW tripped within the first minute of the event. 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 23:38:34 on December 11, 2010, Unit B at Generation Station A tripped dropping 823 MW of generation in the ERCOT Region. The trip was due to a Master Fuel Trip, initiated by a loss of primary air pressure indication.

Eighteen seconds later (23:38:52), Unit D and E at Generation Station C tripped causing the loss of 89 MW and 60 MW of generation respectively. The trip was due to high exhaust temperature spread.

Ten seconds later (23:39:02), Unit G at Generation Station F tripped causing the loss of 99 MW of generation. The trip was due to a flameout caused by combustion instability.

1071 MW tripped within the first minute of the event.

System frequency dropped from 60.009 Hz to 59.749 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 hydro generation responsive reserve of 290 MW. These actions led to system frequency recovery within 6 minutes and 56 seconds to the pre-disturbance value of 60 Hz (at 23:45:30). BA Adjusted Responsive Reserves (ARR) remained above minimum target of 2300 MW set by ERCOT Protocols for the duration of the event. Physical Responsive Capability dropped to 3655 MW.

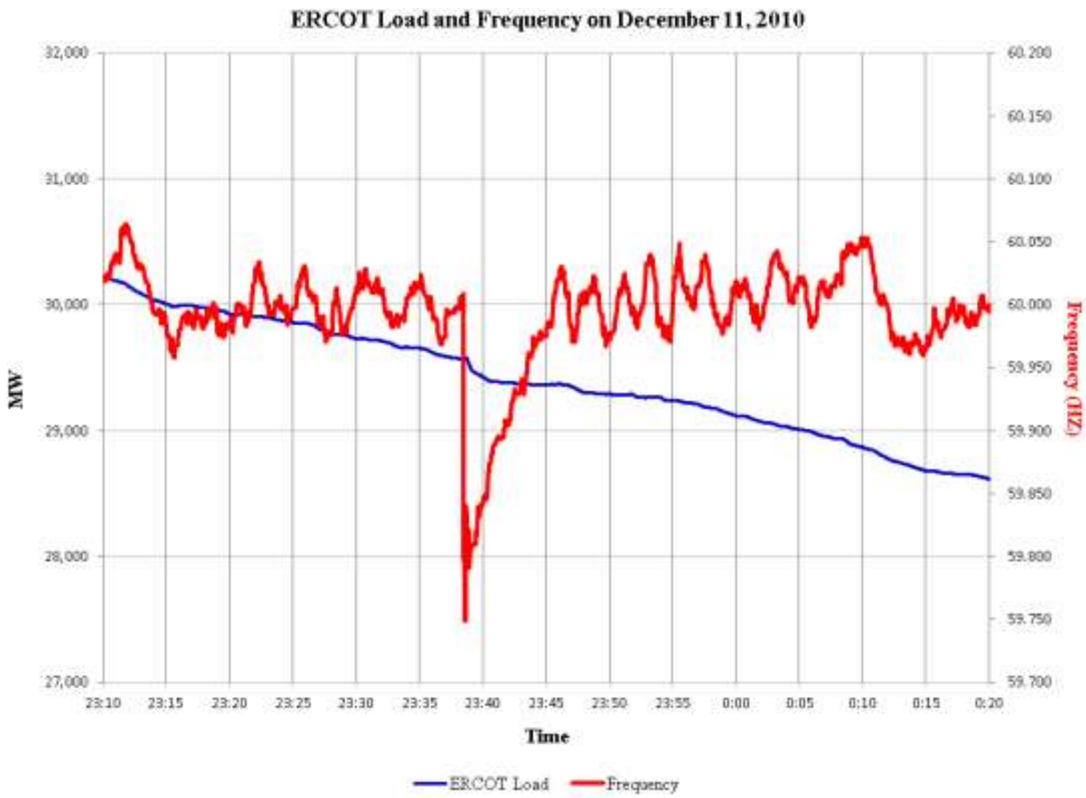
This event did not meet the criteria as a NERC Disturbance Control Standard (DCS) event since the loss of generation was below the 1083 MW threshold for the ERCOT region. The event met the definition of a Category 3a event (loss of load or generation of 1,000 MW or more in the ERCOT Region) under NERC's Event Analysis Working Group (EAWG) procedure.

II. Initial System Conditions Prior to Event

<u>*Initial system conditions just before the event of December 11, 2010 were*</u>:

System Load:	29574 MW
System Frequency:	60.009 Hz
Adjusted Responsive Reserves:	~4200 MW

At 23:38:34 ERCOT Region load was 29,574 MW and total wind generation was 4933 MW.



ERCOT Region Load and Frequency on December 11, 2010.

III. Sequence of Events on 12/11/2010

- 23:38:28 ERCOT Region frequency prior to disturbance was 60.009 Hz.
- 23:38:34 Unit B at Generation Station A operating at 823 MW, tripped to zero.
- 23:38:34 ERCOT Region frequency dropped to approximately 59.749 Hz immediately after the trip. Decay was stopped by governor action.

- 23:38:52 Unit D and E at Generation Station C operating at 89 MW and 60 MW respectively, tripped to zero.

- 23:39:02 Unit G at Generation Station F operating at 99 MW, tripped to zero.

- 23:40:00 290 MW of Hydro supplying Responsive Reserve begin deploying automatically in response to the frequency spike. ERCOT Region frequency was 59.841 Hz.

- 23:45:30 ERCOT Region frequency recovered to 60 Hz.

IV. Analysis of Unit Trips

A. Unit B at Generation Station A

Unit B at Generation Station A tripped offline on 12/11/2010 at 23:38 due to a Master Fuel Trip (MFT). The unit was loaded at 823 MW, versus a nameplate rating of 917 MW (90% of nameplate). The MFT trip was initiated due to the loss of primary air (PA) pressure indication. Primary air transports fuel from the coal mills to the boiler. The MFT initiated a subsequent trip of the generating unit.

Upon investigation, the Generator Operator determined that the loss of PA pressure signal was due to a faulty control indication. The pressure indication is supplied by three separate redundant transmitters (#1, #2 and #3) with the median value of the three used for control and trip purposes. Leaks on the transmitter sensing lines caused the #3 and #2 transmitters to indicate less than actual PA pressure. These two false readings caused the PA indication to fall below the trip indication threshold. The root cause of the unit trip was false PA indications caused by leakage on the transmitter sensing lines.

The trip did not cause any damage to the unit. The unit was returned to service on 12/12/2010 at 07:07.

B. Unit D and E at Generation Station C

The Generator Operator identified the cause of the Unit D at Generation Station C trip due to high exhaust temperature spread. The unit was loaded at 89 MW, versus a nameplate rating of 208 MW (43% of nameplate). The Generation Station C was operating in a 1x1 configuration at minimum load under local plant setpoint, not under AGC control. This trip was initiated when exhaust thermocouples indicated a high spread in temperature between different points in the exhaust stream, indicating a problem with combustion in one or more the combustion cans arranged in a can-annular arrangement. Standard control system logic evaluates the temperature differences and determines whether the temperature spread requires an automatic turbine trip. In this case, the combustion trouble was determined to be due to loss of flame in the combustion can. Unit E tripped automatically as a result of the loss of Unit D.

Units D and E did not suffer any damage as a result of the trips. Both units were placed in service without incident when next dispatched.

The Generator Operator provided the following analysis and follow-on actions for the unit trips:

1. Review indicates Unit D automatically responded to the change in system conditions by raising load approximately 10 MWs. Unit D was not operating on AGC at the time of the

trip. In the past, the unit has responded without tripping during frequency disturbances of a similar magnitude.

2. The manufacturer indicated that some units have experienced single chamber lean blow-outs (flameouts) due to cracking at the forward (round) end of the impingement sleeve of the transition piece.
3. Recent changes in ambient conditions may have contributed to unstable air/flow control (tuning). The controller tuning parameters were reviewed and adjusted to ensure proper operation.
4. After the trip on 12/11/2010, a borescope inspection was performed on Unit D to inspect the combustion system. No damage to the combustion hardware was observed and the cause of the loss of flame could not be determined.

Lean combustion flameout is a known and documented characteristic of certain manufacturer combustion turbines due to their lean fuel/air mixture ratio design operating parameter. While this lean fuel/air mixture ratio design contributes to very low emissions the risk of lean flameouts increases. Per the Generator Operator, their ongoing efforts to address this characteristic include tuning modifications and varying fuel schedules.

C. Unit G at Generation Station F

The Generator Operator identified the cause of the Unit G at Generation Station F trip due to flameout caused by combustion instability. The unit was loaded to 99 MW, versus a nameplate rating of 207 MW (48% of nameplate). The flameout was the result of the unit experiencing revolutions per minute (RPM) losses (between 15 and 20 RPM) and increasing load at ramp rates of approximately 1 megawatt per second. The unit lost RPMs and increased load in response to the grid frequency excursion.

The unit returned to service at approximately 03:46 on 12/12/2010. As a result of the initial investigation, the unit was re-tuned to increase margin from susceptibility to grid instabilities.

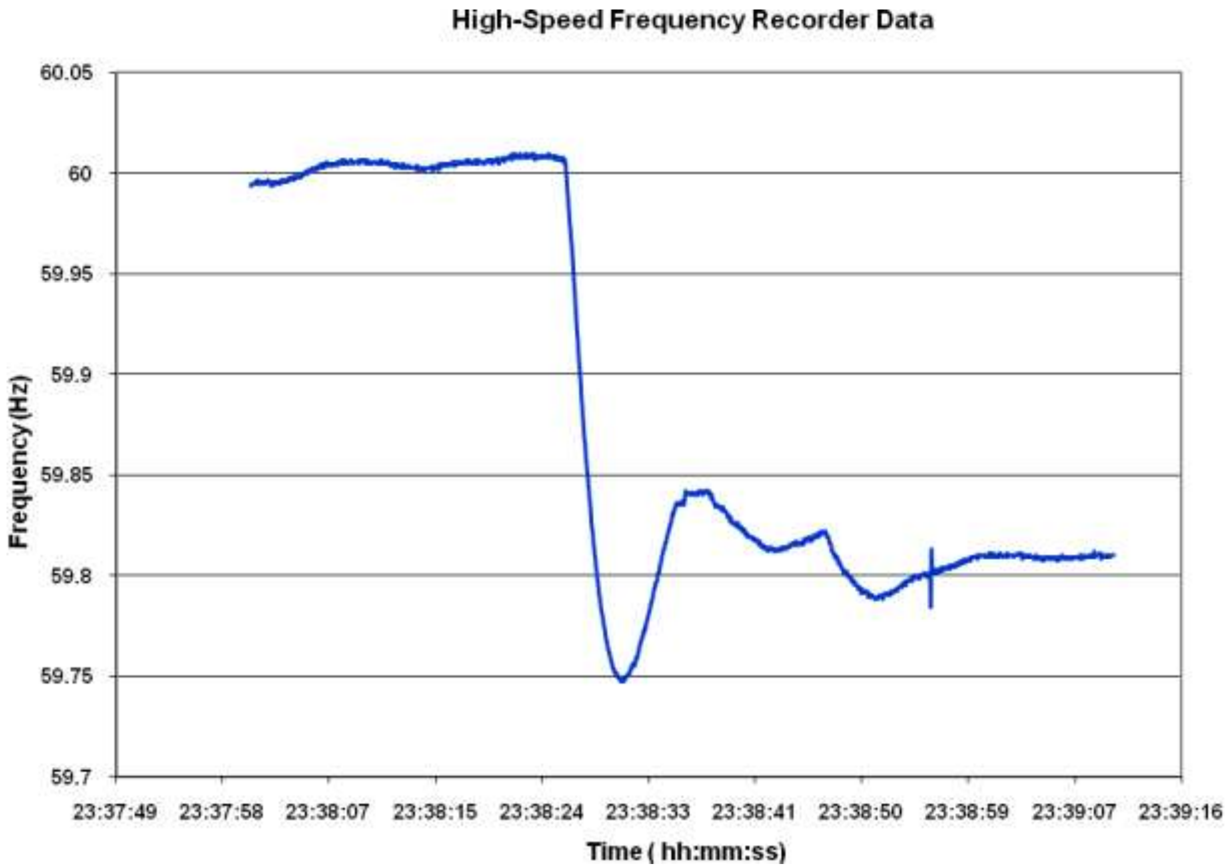
Breakers involved operated as per design during this event. No personnel injuries or equipment damage were identified.

V. Response Analysis

A. Initial Response

The loss of 1071 MW of generation in the ERCOT Region on December 11, 2010 constituted a significant disturbance to grid operations (generation loss represented 3.6% 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 60.009 Hz immediately prior to the disturbance. Immediately after the disturbance, system frequency dropped to 59.749 Hz. The following are among the actions that registered entities initially took to stabilize the system:

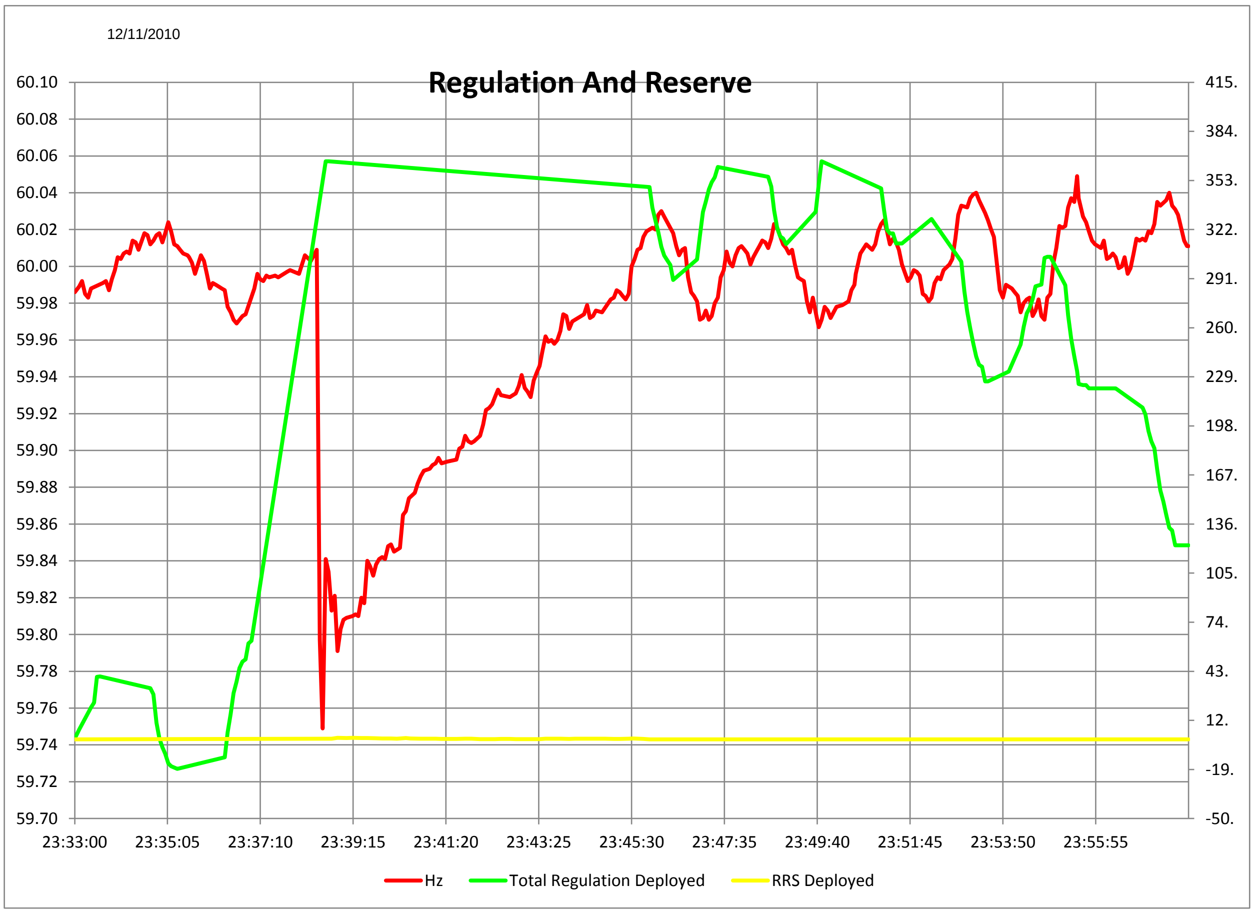


High-Speed Frequency Recorder Data on December 11, 2010.

- 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 468.34 MW/0.1 Hz, which met the target of 420 established in ERCOT Protocols. 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 336.18 MW/0.1 Hz, which failed to meet the minimum response level. The PDCWG also noted the following concerns:
    - 107 out of 151 units (units running that were not excluded) (70.9%) sustained governor response for this event.

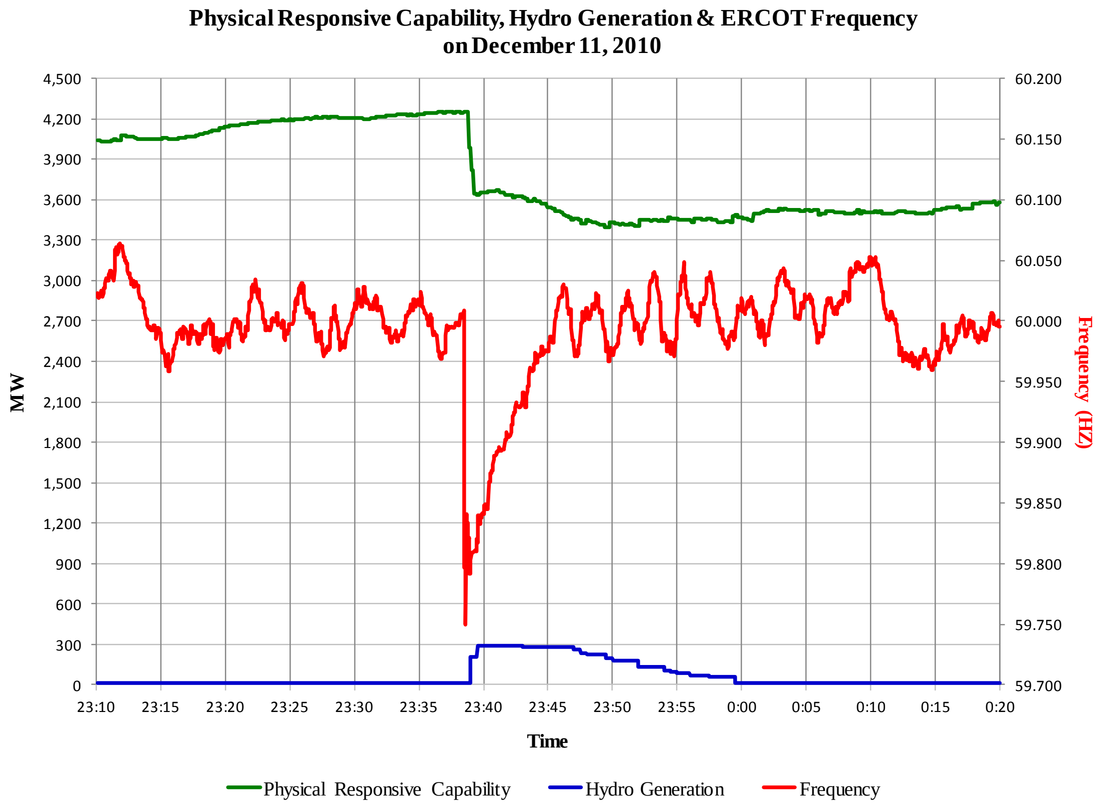
- The BA control center computer made a step deployment of 290 MW of hydro generation RRS, within 90 seconds of the frequency bottom. Per the RC, hydro generation was made available as Responsive Reserve Service (RRS) deployed when frequency dropped below 59.90 Hz. This was independent of Nodal RRS deployment calculations and criteria. At 59.91 RRS was activated to determine if RRS was required. RRS action assessed SCED (Security Constrained Economic Dispatch) to determine if adequate capacity was available. Since SCED had sufficient capacity, RRS was not deployed. Texas Reliability Entity (Texas RE) did not identify any problems with this automatic deployment by the BA or the response from Qualified Scheduling Entity's (QSEs) to ramp their generators output up within 10 minutes as required.

The result of these actions was that system frequency returned to its pre-disturbance value of 60 Hz within 6 minutes and 56 seconds.



B. Reserves

The recovery from the initial disturbance did not take ARR below 3000 MW, the point at which an "Advisory" is called for in ERCOT Protocols. The Physical Responsive Reserve remained above 3400 MW during the event and recovery.



Physical Responsive Capability, Hydro Generation and Frequency on December 11, 2010.

C. Registered Entity Corrective Actions

Equipment owners have taken the following actions to address the problems noted:

- The Generator Operator for Generation Station A inspected all of the primary air pressure transmitters and their associated sensing lines have been repaired and checked for leakage.
- The Generator Operator for Generation Station C completed a borescope inspection to inspect the combustion system. Inspection of the transition pieces recommended by the turbine manufacturer will be made the next scheduled outage.
- The Generator Operator for Generation Station F re-tuned Unit G to increase margin from susceptibility to grid instabilities.

VI. Conclusions

In general, the steps taken in the recovery from this event achieved the desired results. Given the number (4) of unit trips during the event, and the high volume of incoming communications, RC and BA operators handled the situation effectively.

While frequency response from generators performed to effectively address the initial frequency response, the ERCOT Region was short on the “B+30” calculation of system frequency response.

- 107 out of 151 units (running that were not excluded) (70.9%) provided the ‘sustained’ governor response for this event. 44 units did not contribute to system response for the event.
- The ‘sustained’ governor response rate has been slowly improving across the last four large generation loss events (> 1000 MW) in the ERCOT system this year; 6/23/2010 – 62.1%, 8/20/2010 – 66.6%, 11/3/2010 – 70.4%, 12/11/2010 – 70.9%.
- This was the first disturbance involving a generation loss greater than 1000 MW in the ERCOT Region under the new nodal market design.