Texas Reliability Entity
Event Analysis

Event:
June 23, 2010 DCS Event
Category 3 Event

Texas Reliability Entity
July 2011

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Executive Summary

On June 23, 2010, failure of a transformer disconnect switch created a fault condition at a 138kV substation, and incorrect relay operations compounded the fault's effects, removing 1253 MW of generation from the ERCOT Region near peak load. 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. However, recovery revealed issues with governor response, relay coordination and operational communications. 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 three concerns that arose in this event; and (5) recommendations for follow-up action.

I. Event Overview

Shortly before 15:20 on June 23, 2010, during peak load conditions, an equipment failure and two relay misoperations reduced ERCOT Region generation by approximately 1253 MW. Generating Station A generating unit B was operating at 732 MW but tripped off-line due to mechanical failure of a disconnect switch on the unit's 138kV step-up transformer. As the ensuing ground fault was cleared by protection systems to effectively prevent damage to the transformer, two circuit breakers at the 345kV Generating Station A substation tripped due to a relay misoperation and opened the transmission line from Generating Station A to Generating Station C. This in turn tripped additional generation units (D, E and F) carrying 482 MW. Another small unit, Generator Unit G, tripped due to misoperation of its backup relaying while generating 38 MW. Total generation lost due to the event was approximately 1253 MW, including the noncommissioned Unit G.

System frequency dropped from 59.98 Hz to 59.709 Hz as a consequence of the loss of generation. The drop was arrested by governor action of ERCOT Region generators, aided by automatic removal of 246 MW of Load Acting as Resources (LaaR), as well as the modest contribution to recovery due to natural frequency response of system load. These LaaR were a subset of the 1150 MW total procurement by the BA that was configured to trip by underfrequency relay action at 59.7 Hz. The BA's Energy Management System also deployed 1150 MW of generation providing Responsive Reserve Service (RRS) at 15:20:00. The BA operators responded to this event and procured additional generation to assist frequency recovery within 15 minutes. BA Operators issued instructions to Generator Operator H to deploy 400 MW of additional generation (at 15:22:52) and to Generator Operator N to deploy 100 MW (at 15:26:34). These actions led to system frequency recovery within 6 minutes and 32 seconds to the pre-disturbance value of 59.98 Hz (at 15:26:34). The BA then began efforts to stabilize frequency and recover its reserves.

The BA's reserves, particularly the key parameter, Adjusted Responsive Reserves (ARR) had steadily been reduced as resources were deployed. (ARR indicates the amount of resource capacity available for deployment for disturbance recovery; ARR includes a seasonal derating factor.) The BA issued a "watch" notice at 15:28 once the ARR dropped below 2500 MW, but saw that its actions to increase generation offset by a runback in generation elsewhere in one of Generator Operator J's gas turbines. The ARR level fell below 2300 by 15:30:55, breaching the threshold for an emergency condition. Also, after the recovery to pre-disturbance levels, frequency oscillated and began to trend downward again. BA operators next ordered the manual deployment of an additional 571 MW of LaaRs between 15:32 and 15:34. Frequency increased and continued upward until reaching 60 Hz at 15:34:16.

At 15:34:58, the RC declared an Energy Emergency Alert (EEA), Level 1, since ARR had remained below the 2300 MW threshold. ARR promptly began to increase, but starting at 15:39, the RC was notified of three unit trips. Generator Unit K (380 MW), Generator Unit L (96 MW) and Generator Unit M (attempting restart, and capable of producing 104 MW) tripped within a minute of each other, due to unrelated mechanical or fuel issues. This reversed the improvement and dragged ARR levels down to 1957 MW; nevertheless, system frequency remained well above 60 Hz due to deployment of LaaR and additional generation. The BA ordered deployment of 522 MW of Non-Spin Reserve Service (NSRS) at 15:45:09 to replace generation lost as a result of these unit trips, as well as to offset the generation recalled from RRS automatically. (The BA's control system issues a recall to generation deployed for RRS as the system frequency recovers.) By 15:48:12, ARR rose back above 2300 MW and the BA's control system had begun to issue balancing energy instructions to reduce generation for the next interval. At 16:00, all Qualified Scheduling Entities (QSEs) were instructed to restore all deployed LaaRs, and BA operators dispatched an additional 525 MW of NSRS, for a total of 1047 MW NSRS deployed following the disturbance. EEA Level 1 was cancelled at 16:03, with the watch cancelled at 18:45 and the advisory level withdrawn 30 minutes later.

This event was considered reportable to NERC due to the loss of generation above 1000 MW in the ERCOT Region, and it met the definition of a Category 3.a. event under NERC's Event Analysis Working Group procedure. The RC provided a preliminary operations report, a more detailed event report, and responded to two Requests For Information on July 16 and August 20 to assist in this effort. Transmission Operator A and Generator Operator N also provided requested information to Texas RE. The ERCOT Region Performance, Disturbance, Compliance Working Group (PDCWG) provided a review of generator response to the event and its draft report provides insights from their analysis.

II. Forecasts and Initial System Conditions Prior to Event

6/23/2010 PUCT Current Day Report forecast reflecting 17:00 Peak (Pk):

Forecasted Pk HR Demand:	59195 MW @ 1100 HR	59368 MW @ 1500 HR
Generation for Pk HR Demand	63695 MW @ 1100 HR	63634 MW @ 1500 HR
Schedule Gen for Pk HR Demand	54994 MW@ 1100 HR	54609 MW @ 1500 HR
Balancing Energy at Pk HR Load	4201 MW@ 1100 HR	4759 MW @ 1500 HR

Potential for (EEA1)	Low @ 1100 HR	Low @ 1500 HR
Potential for Deploying LaaR (EEA2A)	Low @ 1100 HR	Low @ 1500 HR
Potential for Deploying IEL (EEA2B)	Low @ 1100 HR	Low @ 1500 HR
Potential for Firm Load Shed (EEA3)	Low @ 1100 HR	Low @ 1500 HR

Initial system conditions just before the event of June 23, 2010 were:

System Frequency:	59.980 Hz
Net Scheduled Generation:	60052 MW
Capacity on Line:	60697 MW
System Load:	58803 MW
Responsive Reserves:	3627 MW
Adjusted Responsive Reserves:	3286 MW
Net Spin Reserves:	3154 MW
Schedule Control Error (Total):	-527 MW
Schedule Control Error (Wind Only)	-265 MW

Weather in the major cities around the ERCOT Region just before the event:

City	Temp (F)	Pressure (psi)	Conditions
Austin	93.1	29.44	Clear
DFW	101.6	29.94	Clear
Houston	86.0	30.06	Thunder Storms in Area
San Antonio	91.9	29.97	Mostly Cloudy
Waco	96.3	30.00	Clear

III. Sequence of Events on 6/23/2010

- 15:18:26 - RC was informed that Generator Unit M tripped earlier while carrying 100 MW, and Generator Operator intended to restart it. Loss of this unit depressed system frequency from 60 Hz prior to the start of the event.

- 15:19:46 - Generating Station A Unit B was operating at 732 MW and tripped to zero. ERCOT Region frequency was 59.98 Hz at the time of this trip.

- 15:19:55 through 15:20:03 - Two circuit breakers tripped at the 345 kV Generating Station A, opening one end of a 345 kV line between Generating Station A and Generating Station C, causing three generating units to trip at Generating Station C. At Generating Station C, Unit D was operating at 157 MW, Unit E was operating at 157 MW, and Unit F was operating at 168 MW when they tripped off. Unit G a few miles away was generating 38 MW and also tripped off. A total of 1215 MW tripped off, excluding Unit G which was undergoing testing for commissioning.

- 15:20:00 - BA automatically deployed 1150 MW of Generation Responsive Reserve (from 3286 MW of ARR available at the beginning of the event).

- 15:20:47 - Telemetry indicated approximately 246 MW of LaaRs were deployed by under frequency relay action since the start of the event.

- 15:20:49 - BA called Generator Operator H, Generator Operator N and Generator Operator J to inquire if they could provide additional generation. Generator Operator H agreed to provide an additional 400 MW (at 15:22:52), Generator Operator N agreed to provide an additional 100 MW of hydro (at 15:26:34), and Generator Operator J reported that its units were running at maximums and could not produce more.

- 15:22:52 - ARR dropped below 2500 MW.

- 15:26:34 - ERCOT Region frequency returned to pre-disturbance value to 59.98 Hz.

- 15:28:39 - RC issued a Watch for ARR below 2500 MW. Generator Operator J informed BA that one of its units experienced an automatic runback that reduced output by 100 MW.

- 15:30:23 - BA issued an Out of Merit Energy instruction for two gas turbine units to go to their maximums, 91 MW each. These units were going off-line at the end of their schedules.

- 15:30:55 - ARR dropped below 2300 MW.

- 15:32:37 though 15:33:45 - RC ordered deployment of an additional 571 MW of LaaRs, bringing the total deployed following the initial disturbance to 817 MW.

- 15:34:16 - ERCOT Region frequency recovered to 60 Hz and continues to increase. Frequency remains above 60 Hz for over 41 minutes starting at 15:35.

- 15:34:58 - RC declared EEA Level 1; ARR was below 2300 MW. RC made Hotline calls to the Qualified Scheduling Entities (QSEs) to notify them of RC's declared EEA Level 1 for Adjusted Responsive Reserve below 2300 MW.

- 15:39:03 - Generator Unit K tripped carrying 380 MW due to mechanical issues (blown seal); RC notified at 15:40:49.

- 15:39:23 - RC notified of Generator Unit L trip due to gas pressure issues while carrying 96 MW.

- 15:39:58 - RC notified of Generator Unit L trip while attempting to restart, unit capability 104 MW.

- 15:40:03 - ARR fell to its lowest point of 1957 MW following unit trips.

- 15:45:09 - BA deployed 522 MW of Non-Spin Reserve Service (NSRS).

- 15:47:00 - During the next minute, Regulation down service was fully deployed by BA's computer to system frequency above 60.1 Hz.

- 15:48:12 - ARR rose back above 2300 MW.

- 15:48:54 - RC notified of Generator Unit P trip at 40 MW.

- 15:49:12 - ARR returned above 2500 MW.

- 15:49:26 - BA issued 300 MW Fleet Down instruction to Generator Operator H due to high frequency and full deployment of down regulation service.

- 15:50:48 - Frequency exceeded 60.1 Hz and remains at this level or above for 10 minutes.

- 15:52:00 - BA terminated 400 MW Fleet Up instruction given to Generator Operator H.

- 15:53:00 - BA terminates 100 MW Fleet Up instruction given to Generator Operator N.

- 15:54:46 - RC notified adjacent Reliability Coordinator of EEA Level 1 status and asked if there was Emergency Transmission Availability across the DC Ties.

- 15:55:46 Peak frequency of the event recorded, 60.125 Hz.

- 16:00 - BA made Hotline call to all QSEs instructing them to restore LaaRs. 226 MW additional down regulation available at the start of the hour is deployed to lower frequency within the next 7 minutes.

- 16:00:07 - Instruction issued for additional 525 MW of NSRS to deploy within the next 30 minutes, for a total of 1047 MW NSRS.

- 16:03 - RC canceled EEA Level 1. Generator Unit L returned to service.

- 16:03 - RC made a Hotline call to QSEs notifying them of cancellation of EEA Level 1 for ARR below 2300 MW.

- 16:06 – Generator Unit P returned to service.

- 16:09:52 - RC notified adjacent Reliability Coordinator that EEA Level 1 had been canceled.

- 16:16:10 - System frequency returned to 60 Hz.

- 17:15 - BA extended NSRS from interval ending (IE) 18:15-18:30.

- 18:45 - RC canceled Watch issued for ARR below 2500 MW.

- 19:15 - RC canceled Advisory issued for ARR below 3000 MW.

IV. Analysis of Initial Unit Trips

A. Generating Station A Unit B

The root cause of the trip of Generating Station A Unit B was the failure of the main power transformer high-side 'C' phase disconnect switch. On June 23, 2010 at 15:19:46, a phase-to-ground fault occurred on the disconnect switch and lasted for 5.5 cycles before being isolated from generation and transmission systems. The amount of fault current measured by the Digital Fault Recorder (DFR) on the high-side was 16332 Amps rms. At the time of the fault, Generating Station A Unit B was producing 732 MW or roughly 1021 Amps per phase. The continuous rating of the 138kV switch was 4000 Amps per phase.

The high-side disconnect switch was installed in 1992, replacing the original switch installed when the plant first commenced operations in 1972. The switch was a vertical-break single-ended gang switch. Generator Operator N reported that the switch operated successfully a few days prior to the event. It appears that the connection point broke off the switch just before the jaw (see pictures in Appendix 1). The top portion of the standoff post insulator disintegrated due to the fault (see pictures in Appendix 1). The fault destroyed the switch and with it any evidence of metal fatigue, although that appears to be a likely cause of failure. Contamination was also a possible source given the plant's location in an industrial environment near saltwater.

Generator Operator N's procedures required the company to inspect the switches every two years, from 1992 to 2007. In 2007, Generator Operator N changed its inspection interval to every 18 months. Recently, Generator Operator N stated it would now conduct switch inspections, testing, and cleaning on an annual basis during unit maintenance outages. They also plan to conduct monthly infrared inspections of these switches

B. Generating Station C Units D, E, and F

The generation plant that includes Generating Station A Unit B is connected to a 138 kV/345 kV auto-transformer that is also connected to Generating Station C. When the phase-to-ground fault involving Generating Station A Unit B occurred, the transmission line between Generating Station A and Generating Station C opened, tripping Generating Station C Units D, E, and F. Generating Station C units were generating 482 MW when they tripped.

As reported by Transmission Operator A, the phase-to-ground fault at Generating Station A Unit B may have caused a phase-to-phase voltage wave distortion between the A and C phases of circuit breakers XXX-1 and XXX-2 at Generating Station A. A phase Capacitor Voltage Transformer (CVT) used by the backup protective relay function experienced a distorted voltage waveform, causing the SEL-311L relay to incorrectly identify the direction of the fault. The CVT was manufactured in 2006. After the event, Transmission Operator A performed a relay misoperation analysis and determined that the intended SEL-311L settings should have included a time delay of 15 cycles (the relay tripped the breaker in 3 cycles). Transmission Operator A filed a misoperation report with the RC, and it corrected the time delay settings on June 24, 2010. Transmission Operator A also conducted a system-wide review of time delay settings on its similar protective system applications and found no additional changes were needed. Transmission Operator A is no longer using the CVTs involved in this event for relaying.

C. Generator Unit G

At about the same time the three Generating Station C units tripped off, a generating unit (G) 20 miles away tripped, causing the loss of 38 MW of generation. This generating unit was undergoing commission testing and was not released for operation at the time of the event. Analysis by the Generator Operator indicated that an element in the transmission line differential protection relay thought to be disabled was asserted and led to the unit trip through its interaction with other protective relays. The Generator Operator has disabled the element to prevent a recurrence.

V. Response Analysis

A. Initial Response

The loss of 1,253 MW of generation in the ERCOT Region during the afternoon of June 23, 2010 constituted a significant disturbance to grid operations as well as qualifying as a NERC DCS event. 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 Standard's 15 minute target, but other aspects of the recovery merit discussion.

ERCOT Region frequency (measured at the RC control center) was at 59.98 Hz immediately prior to the disturbance, likely due to the loss of Generator Unit M shortly before this much larger disturbance. Immediately after the disturbance, system frequency dropped to 59.709 Hz. The following are among the actions that registered entities initially took to stabilize the system:

- Automatic deployment of LaaR immediately reduced load by 246 MW through underfrequency relay action. Most LaaR did not automatically trip, however because the RC's control center frequency measurement only fell to 59.709 Hz, above the target of 59.7. It is likely that most LaaR did not detect a frequency drop of sufficient duration and magnitude to trigger their relays.

- 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 425.38 MW/0.1 Hz, which met the target of 420 established in ERCOT Protocols 5.9.2. However, 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 312.85 MW/0.1 Hz. The PDCWG report pointed out that many of the combined cycle units actually lowered their output with a frequency decline, rather than increased it, due to the operating characteristics of these types of plants. Also, with many units operating near their peak, little response could be expected, as units are not required to provide a reserve capacity for governor response unless they are meeting portfolio requirements for regulation service or RRS obligations. The PDCWG suggested that the ERCOT Region's "energy-only" market design, by encouraging combined cycle plant operation at full capability with its attendant limitations to governor response, will likely cause system frequency response to decline further over time. The impact of intermittent renewable resources may further aggravate this decline. The PDCWG recommended close monitoring of future disturbances to track the ratio and behaviors of generators to determine whether this situation continues.
- The BA's control center computer made a step deployment of the entire amount of generation RRS, 1150 MW, within 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.
- BA operators, when faced with a NERC DCS event, typically request additional resource deployment to ensure meeting the 15 minute compliance target. Within 1 minute of the disturbance, the BA sought available generation from three QSEs and ordered deployment of 500 MW from two of them through Fleet Verbal Dispatch Instructions (VDIs).
- The BA requested available hydro capacity in accord with this procedure, issuing a VDI for 100 MW to Generator Operator N. This course of action was within the operator's discretion and the initial deployment of LaaR by underfrequency relay provided a reason to consider alternatives. A total of 176 MW had responded to either the bid in RRS or by the issued VDI.

The result of these actions was that system frequency returned to its pre-disturbance value of 59.98 Hz within 6 minutes and 32 seconds. Although the frequency did not stabilize for several minutes afterwards and nearly 15 minutes passed from the beginning of the disturbance until frequency rose to 60 Hz, the NERC DCS target was met.

B. Reserves and Declaration of Emergency Energy Alert

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 initial disturbance took ARR below 3000 MW, the point at which an “Advisory” is called for in ERCOT Protocols 5.6.4. The RC did not issue an Advisory. By the time RC operators made their initial notification via a Hotline call, 5 minutes and 47 seconds had passed since ARR dropped below the next notification threshold for a “Watch” at 2500 MW. At the time of this “Watch” notice frequency had recovered but reserves declined further. BA operators had been responding to calls from QSEs with LaaR owners, as well as making requests for additional generation and issuing instructions.

About 11 minutes after the initial disturbance (at 15:30:55), ARR dropped below the emergency threshold, 2300 MW. During the next four minutes, BA operators observed that frequency had not stabilized above the initial disturbance point, recall of generator RRS had begun, and one unit reported a runback. The BA continued to deploy LaaR during this timeframe. After completing the LaaR VDIs, the BA made a Hotline Call for EEA1 first to the QSEs and 3 minutes later to transmission companies (the Transmission Desk operator had logged the EEA entry and made required MIS posting while the QSE call was made). Deployment of LaaR helped assure frequency stability and this effort was successful, as less than a minute later, system frequency recovered to 60 Hz.

After EEA1 was declared, 476 MW of generation tripped, and this further reduced ARR. Frequency dipped but stayed above 60 Hz, which meant that the BA’s computer systems continued to automatically recall generator responsive reserve as well as issue down regulation deployment signals, both of which would improve ARR by unloading generators. Non-spin was deployed and frequency continued to rise, enabling the BA to begin recalling Fleet VDIs issued to QSEs with generators. The ARR exceeded its emergency threshold just over 17 minutes after first falling below 2300 MW. BA operators continued to allow ARR to increase and system frequency remained high as well. EEA1 was not terminated until more than 15 minutes after the 2300 MW level had been exceeded and 5 minutes after LaaR recall instructions, to assure that the recovery would be sustained.

C. Notification of EEA to adjacent Reliability Coordinator

During an EEA, one of the options that the RC must consider in EEA Step 1 is whether to obtain power through a DC tie. To obtain power through a DC tie, the RC must go through an involved process of obtaining transmission reservations from an adjacent Reliability Coordinator and then locating a source for the generation through the DC tie operator. ERCOT Protocol 5.6.7 calls for utilizing available DC tie capability, but this is not always feasible and requires cooperation of other parties. In this case, the RC made notification to the adjacent RC about the EEA-1 only 8 minutes before its cancellation, based on telephone records and log entries. Per procedures, the RC operator attempted to contact the adjacent RC and left a message with an operator requesting a return call, but the adjacent RC did not return the call before the RC notified the adjacent RC that the EEA1 was cancelled. The timing of such calls is left to the discretion of the operators per the Frequency Desk Procedure. The RC shift supervisor also provided messaging to the adjacent RC and other NERC Regions through the NERC Reliability Coordinator Information System (RCIS).

VI. Conclusions

In general, despite the issues with equipment, steps taken in the recovery from this event achieved the desired results. Given the large number ten (10) of unit trips and runbacks 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:

- After replacing the failed disconnect switch on its step-up transformer, Generator Operator N attempted to analyze the disconnect switch failure but in the end determined that it would increase its monitoring intervals to annual reviews along with monthly infrared camera inspections.

- Transmission Operator A identified issues with its relaying at Generating Station A, an omitted time delay in the trip equation and incorrect identification of the direction of the fault in the SEL-311L relay. Transmission Operator A corrected these relay settings issues the next day and conducted a review of similar relays across its system. Further review of the training of personnel and coordination practices for these devices may be of benefit to understand how the settings issues occurred in the first place.

- The Generator Operator identified an issue with its relaying and made changes to eliminate a component that caused its Unit G to trip while undergoing testing. Additional follow-up to clarify details that led to the misoperation and to review coordination between the Generator Operator, the Generation Owner, and Transmission Operator A, their transmission provider, is recommended.

- Generator Operator J identified the cause of runback at their unit: high temperature differential between the unit's combustor temperature and its shell temperature near full loading of the unit. A turbine controls engineer was able to successfully retune the combustion system the following day.

Lastly, while frequency response from generators and LaaR performed to effectively address the initial frequency response, ERCOT Region was short on the B+30 calculation of system frequency response as a consequence of high loading on units in general and the negative response obtained from combined-cycle plants in particular when fully loaded.

Appendix 1

Disconnect Switch "C" Phase After Fault