Lesson Learned

Incorrect Field Modification and RAS Operation Lead to Partial System Collapse

Primary Interest Groups

Balancing Authorities (BAs)
Reliability Coordinators (RCs)
Transmission Operators (TOPs)
Transmission Owners (TOs)
Generator Operators (GOPs)
Generator Owners (GOs)

Problem Statement

During an outage to isolate a 500 kV line disconnect switch and install a temporary bypass to facilitate its replacement, the position of an auxiliary contact multiplier relay was incorrectly modified by field staff. This incorrect multiplier position enabled line stub bus protection, which misoperated due to the increase in flow despite there being no actual line fault. This incorrect multiplier position also prevented the remedial action scheme (RAS) from operating as designed for the loss of the respective 500 kV circuit. The actuations resulted in separation of a large portion of the entity's system, load losses, generator trips, and islanding of a small pocket sustained by local generation.

Details

On August 9, 2017, planned work was underway to replace the 500 kV Line A disconnect switch at Station A. As part of this project, a temporary bypass was installed to keep the circuit in-service during the replacement (see Figure 1).

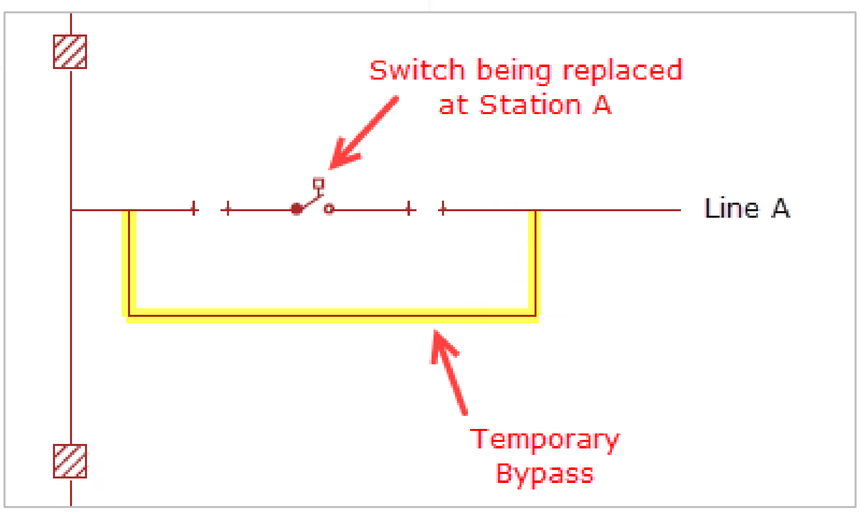

Figure 1: Schematic of Disconnect Switch and Bypass at Station A

Believing that the Line A disconnect switch was in the open position (as is typical for line outages), the Field Protection & Control (P&C) staff member toggled the position of an auxiliary contact multiplier relay to maintain protection adequacy of Line A with the bypass circuit in-service. The intention was to simulate the switch in the closed position to the protection relays during the month-long line disconnect replacement. The P&C personnel was not aware that the disconnect switch was requested closed during this period to facilitate its removal due to clearance issues. During this modification, the physical position of the disconnect switch was not verified and neither was the OPEN & CLOSED labeling on the auxiliary multiplier relays to confirm the current line switch position. Due to this incorrect assumption, this action resulted in the auxiliary contact multiplier being placed in the opposite position, indicating to the protective relays that the disconnect switch was open. The circuit, along with the bypass, was then placed back in-service in the early hours on August 10.

With the circuit in-service and the line disconnect switch being indicated as open to the protection relays, the line stub bus protection was enabled and the detection of a Line A contingency in the RAS became disabled as designed after one second. The TO does not normally receive any indication when a RAS contingency becomes disabled. By mid-day, as generation and flows in the region increased, the power flow on Line A exceeded the stub bus protection pickup threshold; this, combined with the perceived open disconnect switch, looked exactly like a major fault to the protection system and resulted in the undesirable trip of the Line A terminal breakers at Station A.

When the Line A contingency occurred, the RAS was armed to trip Line B, Line C, Line D, some generation, and large industrial loads in the region (see Figure 2). An assessment by the RC indicated that the arming of the RAS was correct based on the system conditions at the time. However, the RAS did not trip as expected (Line B remained in service) due to the detection of a Line A contingency being previously disabled. Instead, Line B tripped from overvoltage protection 58 seconds after the initial contingency. A security feature of the RAS prevents it from detecting the Line A contingency after one second following its initiation.

With the significant imbalance of the generation and load in the area, Line E and Line F protections operated during load swings into the relay trip settings. Line G “B” line protection was an intelligent electronic device (IED) type with an older firmware version that operated at about 61.7 hertz. Line H and I “B” line protections operated at above 65 hertz.

The actuations resulted in separation of a large portion of the entity’s system, load losses, generator trips, and islanding of a small pocket sustained by local generation as indicated on the following diagram.

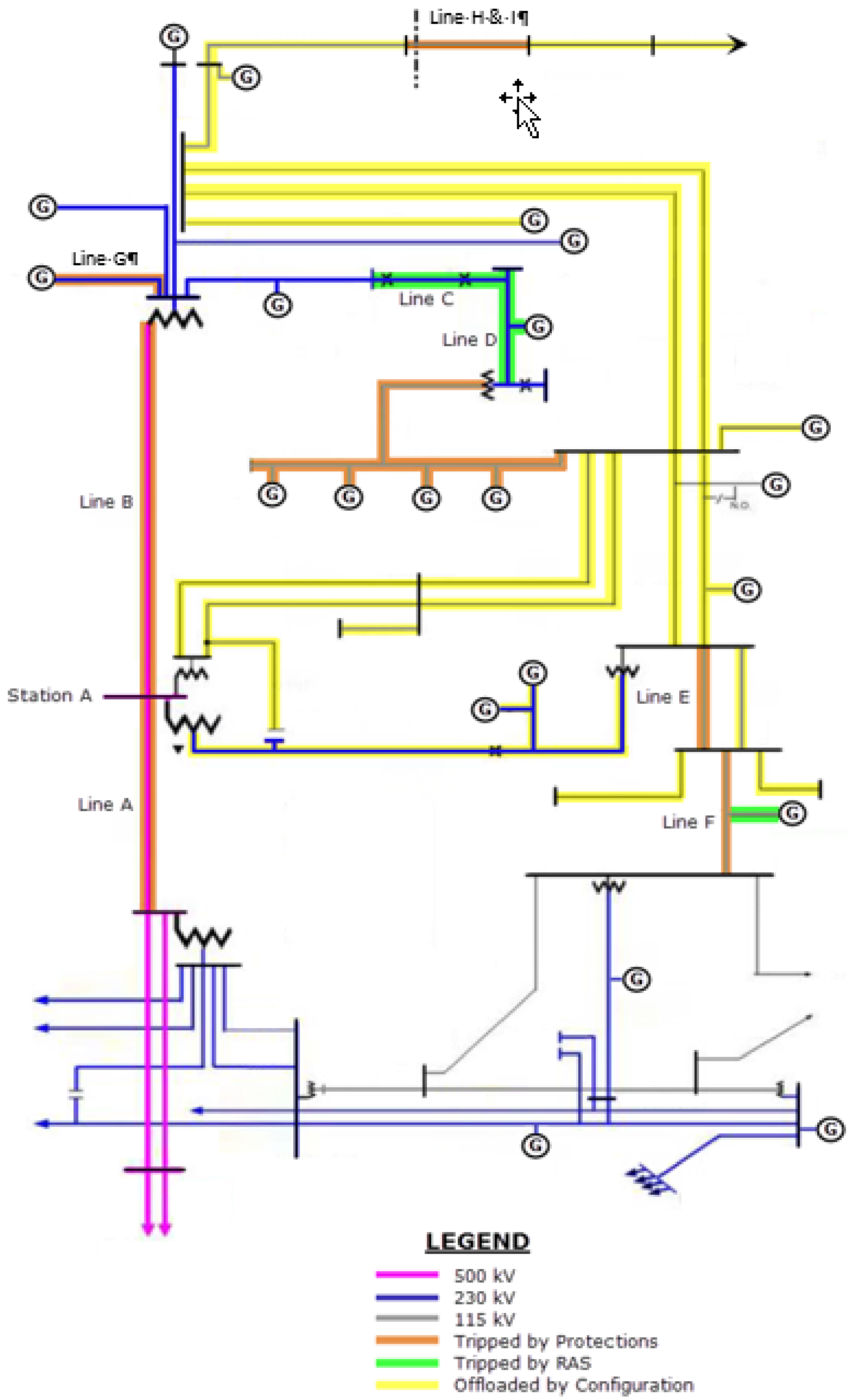

Figure 2: Single Line Diagram of the Affected Region

Corrective Actions (as performed by the entity)

- The position of the auxiliary multiplier was corrected for the Line A disconnect switch.
- Although it is common practice to verify the status of equipment when performing auxiliary isolation/switching, it was not clearly stated in the process documents. These documents will be revised to clearly state that a status check (both primary and auxiliary devices) must be performed prior to operating auxiliary devices.
- The event was reviewed with all control room staff and field staff to re-enforce the importance of clear communication and verifying device status during switching.
- The functionality of the Line B cross-trip scheme was tested to verify that it works within acceptable timings.
- Line E and Line F protections operated during a power swing for which a study will be done to verify the possibility of improving immunity during a similar event.
- For one of the relay misoperations (Line G), the issue was determined to be a limitation of the relay design associated with an older firmware version which may cause misoperation during frequency excursions. The relay manufacturer advised that newer firmware versions provide a user settable parameter that, if set correctly, could have avoided this misoperation.
- For the other misoperation on a different relay type (Line H & I), a setting modification was suggested by the vendor and is being incorporated by the TO. This is the only location where these relays were set in this manner and new protection relay settings have been issued to the field.
- The viability of adding an alarm point to monitor RAS contingency status for critical BES elements will be explored.

Lessons Learned

- Ensure field staff always verify the status of the equipment prior to making changes on an auxiliary contact multiplier and include this in your procedures if it doesn’t already exist.
- Reinforce proper communications between control room staff and field P&C staff so that both parties understand the purpose of the auxiliary switching.
- Consider adding an alarm or status change when a RAS Contingency is inadvertently blocked by any means other than the “Master Block” control point.

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