Lessons Learned Through Commissioning, Livening, and Operating Switchgear

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LESSONS LEARNED THROUGH COMMISSIONING, LIVENING, AND OPERATING SWITCHGEAR

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Abstract — During commissioning, verifying the functionality of protective relays and wiring prior to livening is standard practice in the oil and gas industry. For protective relays, verification is complex due to their increased capabilities and the sophisticated control schemes that use them. This paper presents lessons learned from an industrial project of approximately 12 000 protective relays in a 110, 35, 10, 6, and 0.38 kV power generation, transmission, and distribution system.

The paper discusses power-system-related events from commissioning to after handover. Some events involve a single relay; others include complex schemes involving multiple electronic devices, communication protocols, and their impact on overall power system performance. Each event includes detailed analysis using relay waveform captures, sequential event reports, logic diagrams, instruction manuals, and functional design specifications to determine the root cause and corrective action.

Index Terms — Event Reports, Relay Protection, Generator Control, Root Cause.

I. INTRODUCTION

This paper highlights six different events that occurred during commissioning or just after system handover to the client. These events include a generator slow-response control event where a zero MW reading resulted in offloading of generation and how a failed surge arrester led to the field engineers finding an 87L line current differential relay disabled. A transformer compensation matrix setting error that resulted in a transformer differential trip for an external fault is also described, along with how mysterious feeder trips revised line construction practices. The remaining events include how a loss of 52A status resulted in two different trips for similar reasons, and how a load bank commissioning test uncovered an incorrect directional relay setting error. In sharing these events, the authors shall teach about the issues found during commissioning, describe how to use event reports to determine root cause, and illustrate how to avoid similar issues in the future.

II. SLOW-RESPONSE CONTROL SYSTEM EVENT

The commissioning team was tasked with updating relay communications settings for an in-service primary line protective relay. The protection scheme consisted of redundant line relays protecting a 110 kV line running from the utility. To follow the best-practice method for modifying relay settings for an in-service relay, the approved procedure included the team isolating the relay trip outputs by inserting a test plug and relying on the redundant relay to protect the line. Upon isolating the in-service relay, the facility's slow-response generator control system detected an unexpected dip in utility power import from 6 MW to 0 MW due to a loss of voltage in the relay and the relay being used as the control system's source of line megawatts. This resulted in the gradual offloading of the facility generation in an attempt to increase the utility import back to the desired tie-flow set point. The slow-response generator control system drove up the utility import from 6 MW to 73 MW until the system operators could get the situation under control. Fig. 1 depicts the power import from the utility during this incident, which was measured by another relay sensing the utility currents and voltages.

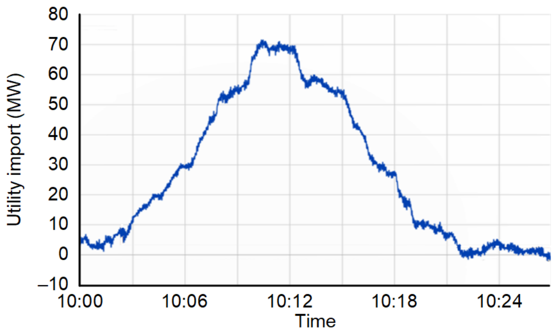

Fig. 1 Utility power import during the incident

The trip output contacts and voltage transformer inputs to the primary line Relay A were wired to the relay sharing the same 14-pole test block. All 14 poles of the test block were isolated by inserting the test plug in the test block socket, resulting in a loss-of-voltage measurement by the primary relay. The desired system response to a loss-of-voltage measurement is to switch the power-flow measurement source to the redundant backup Relay B, as described in the data-flow diagram in Fig. 2.

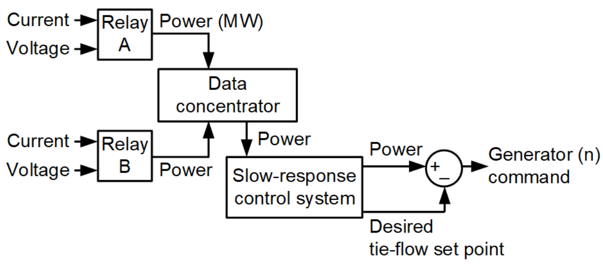

Fig. 2 Data-flow diagram

As shown in the data-flow diagram in Fig. 2, relay power measurements are communicated to the slow-response generator control system through a data concentrator. This is also shown in the process diagram in Fig. 3. The logic flow depicted in the process diagram is performed by the data concentrator.

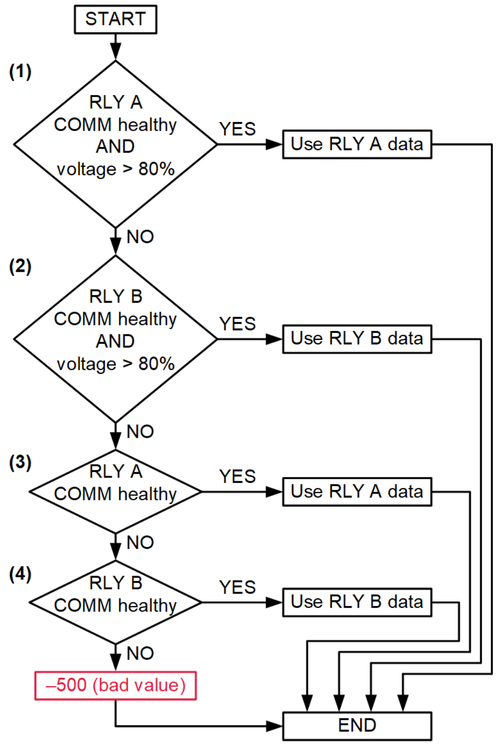

Fig. 3 Process diagram

As mentioned, the desired system response to a loss-of-voltage measurement is to switch the power-flow measurement source to the redundant relay. Decision Gate 1 in the process diagram evaluated to NO because of the loss of voltage in Relay A. Decision Gate 2 evaluated YES because Relay B communications were healthy and its voltage inputs were unaffected. Therefore, the power-flow measurement should have switched to Relay B as the source, and the slow-response generator control system should have taken no action.

In investigating the issue, the field engineers found that although communication between the data concentrator and Relay B appeared to be healthy to the electrical control system, the data received by the slow-response control system's data concentrator were flagged with having bad data quality. The active IEC 61850 configuration file was retrieved from Relay B; it confirmed that the data set being polled by the slow-response control system's data concentrator was set as a spare data set with blank data. Therefore, the Decision Gate 2 result in the process diagram was NO, and Relay A remained as the primary power-flow measurement source, which provided a reading of 0 MW to the slow-response control system. The corrective action to address the bad data quality was to update the IEC 61850 configuration, perform laboratory testing to verify correct functionality, and load the configuration file into Relay B.

If the sudden rise in the utility power import and facility generation offloading had gone unnoticed by the system operators, this condition could have caused power system instability, leading to potential islanding of the facility and frequency load-shedding to restore system stability. The process diagram also shows that even with healthy communications with both devices, the same outcome would have been expected for a simultaneous loss-of-potential condition on both relays caused by a blown voltage transformer (VT) fuse, because both relays are connected to the same VT.

To solve this problem, the team recommended sending a value of –500, which is identified by the slow-response control system as a bad value, if Decision Gates 3 and 4 evaluate to YES. The expected action of the slow-response control system when receiving that bad value is to take no action, which addresses the concern about the loss-of-potential condition. This recommendation is currently under review.

III. FAILED 110 KV SURGE ARRESTER REVEALS DISABLED LINE RELAY

In this event, a line current differential (87L) relay detected a line fault and tripped both line terminals. Power system operators quickly identified the root cause as a failed surge arrester. Fig. 4 is a photo of the failed surge arrester counter. Although this was a correct trip event, further analysis found that both the primary and backup 87L relay detected the fault, but only the backup 87L relay tripped. Fig. 5 and Fig. 6 show the backup and primary relay performances, respectively. Fig. 5 shows a trip issued by the backup relay and Fig. 6 shows that the primary relay did not trip.

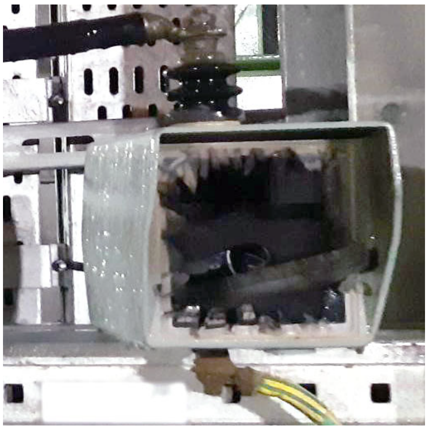

Fig. 4 Failed surge arrester counter

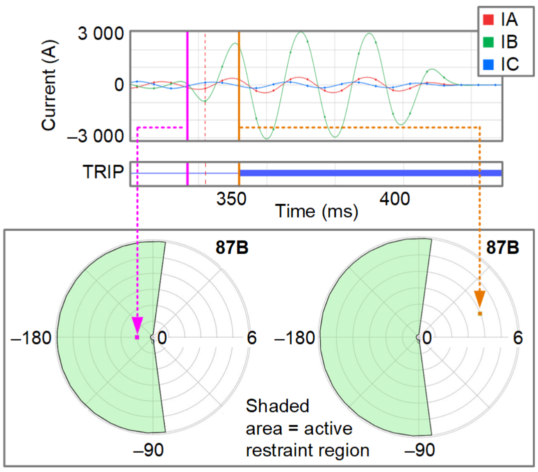

Fig. 5 Backup relay performance

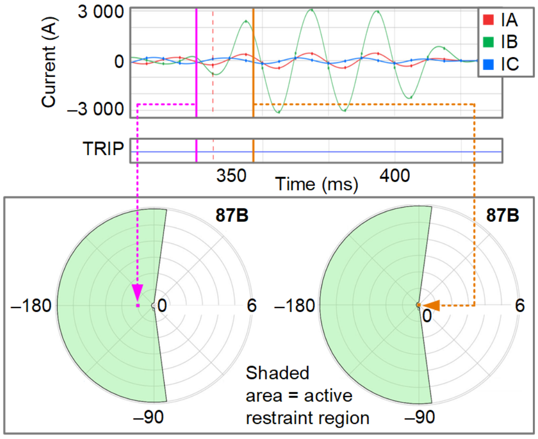

Fig. 6 Primary relay performance

Reference [1] describes the current-based alpha plane characteristic. In both Fig. 5 and Fig. 6, the pre-fault condition accurately plots at –1, indicating that the relay is secure (no trip condition). However, during the fault condition, both relays plot in the tripping region of the alpha plane, yet only the backup relay issued a trip.

After further investigation, the relay technician found that a communications channel watchdog alarm disabled the primary relay 87L protection. The communications channel watchdog alarm warns the user when an 87L protection element operation is repeatedly avoided by the disturbance detector or if the relay repeatedly receives an 87L direct transfer trip without an accompanying pickup of the disturbance detector. This alarm can occur during local or remote relay testing and, if not reset, can result in a disabled 87L relay element. The addition of the communications watchdog alarm is a security improvement in the relay design to help prevent undesired operations that can occur from communications-channel-based single event upsets (SEUs), as detailed in [1].

As a result of this event, the engineering team implemented several report changes to monitor the alarm counters and watchdog alarm status. Relay test engineers now include this report in the relay test documentation and verify proper operation prior to putting a relay into service.

Several months later, commissioning engineers used these updated reports and correctly identified a need to reset the 87L watchdog alarms prior to putting a line into service. Power system operators removed a 110 kV line from service and powered down the relays for a change in current transformer (CT) wiring. Local relay testing for the change in CT ratio occurred 11 days later. When this occurred, the watchdog alarm status (87ERR2) correctly asserted and disabled the 87L relay element. Fig. 7 shows an example report.

```
=>tar 87err2
87ROCTB 87ROCTC 87TOUT  87ALARM 87ERR1  87ERR2  87LSP   *
0       0       0       0       0       1       0       0

=>
=>pro 10
xxxxxxxxxxxxx                              Date: 23/09/2021  Time: 10:17:48.192
110KV xxxxxxxxx                            Serial Number: 1190560471

#       DATE       TIME     87WDCT1    87WDCT2    87CH1LX    87CH1LD     87CH1RT
00010  10/09/2021 08:00:00     0.000      0.000      0.000      0.000      0.107
00009  10/09/2021 09:00:00     0.000      0.000      0.000      0.000      0.131
00008  10/09/2021 10:00:00     0.000      0.000      0.000      0.000  9.713E-02
00007  10/09/2021 11:00:00     0.000      0.000   9984.000  .369E+05      0.000
00006  21/09/2021 16:00:00     0.000     11.000      0.000      0.000      0.107
00005  22/09/2021 10:00:00     0.000     11.000      0.000      0.000  7.124E-02
00004  22/09/2021 11:00:00     0.000     11.000      0.000      0.000  4.798E-02
00003  22/09/2021 12:00:00     0.000     11.000      0.000      0.000  6.912E-02
00002  22/09/2021 13:00:00     0.000     11.000      0.000      0.000  4.798E-02
00001  22/09/2021 14:00:00     0.000     11.000      0.000      0.000      0.105
```

Fig. 7 Example report

Commissioning engineers reviewed the relay's sequential event report, verifying the test activity that occurred and resulted in an assertion of the 87L watchdog alarm. Then, they cleared the watchdog alarm before putting the relay back into service, and made sure that 87L protection was enabled.

IV. TRANSFORMER TRIP

The transformers in this system are protected using microprocessor-based protective relays. These relays have advanced calculation methods that can accommodate any transformer arrangement. The user-configurable set points of the protective relays were programmed according to the protection study report, and the user-configurable logic was programmed according to the logic diagrams issued by the engineering team. In addition, the protective relay has embedded logic with predefined algorithms for certain functions to ensure the correct operation of the relays. Verifying the correct implementation of the engineering design is part of the precommissioning and commissioning processes.

The main protection scheme used to protect transformers at this installation is transformer differential protection. It was important to set the current transformer phase-angle compensation setting [2] correctly to match the physical construction of the transformer, the phase-to-bushing connections, and the CT connections. Incorrect settings could lead to undesired operations. It was also important to verify the settings and wiring during commissioning and to properly record and manage changes until the system went into service.

The event described in this section includes an undesired operation of the transformer differential relay for an out-of-zone fault and an incomer relay trip for a feeder fault during the livening process. As shown in Fig. 8, the system is comprised of a step-up delta-wye transformer from a 10.5 kV brownfield feeder to a 35 kV greenfield substation. The transformer is protected with a transformer protective relay that provides differential and restricted earth fault protection. The incomer protective relay provides inverse-time overcurrent protection.

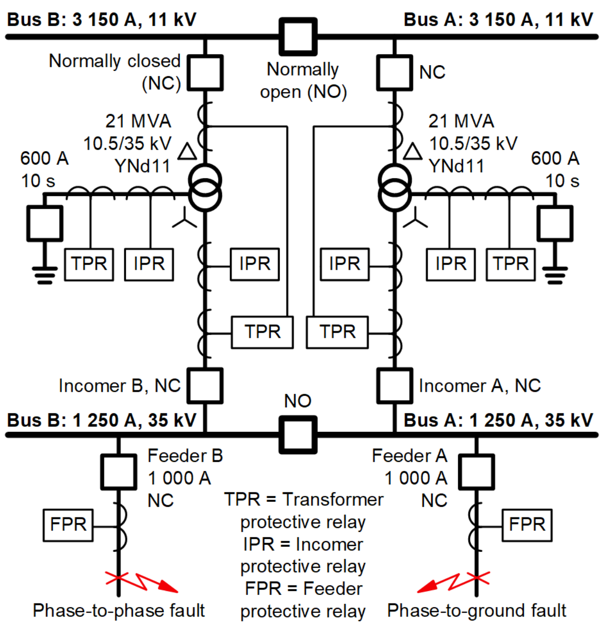

Fig. 8 System where transformer protection trip occurred

The 35 kV switchboard was energized using standard livening procedures after the precommissioning and commissioning procedures were completed. As the next step, the feeders were precommissioned and commissioned. The first feeder energized was reconductored because it used part of an existing line. During the livening process of that feeder in Bus B, multiple events were recorded and the protection tripped the Incomer B breaker.

Preliminary investigation found a BC phase-to-phase fault at the 35 kV Feeder B. Although the expectation was that the feeder would be tripped, the Incomer B breaker was tripped by both the transformer protective relay, for differential protection, and the incomer protective relay, for instantaneous overcurrent protection.

Event reports for each relay were extracted by the commissioning team to further understand the event. Fig. 9 shows the fault current waveform recorded at the feeder. It clearly shows the magnitude of the fault current around 1 500 A in Phase B and Phase C, lasting for five cycles. However, the trip (TR) Relay Word bit was not asserted either from 51P (600 A pickup) or 50P (2 700 A pickup). Instead, the incomer cleared the fault, suggesting a discrimination issue between Incomer B and Feeder B.

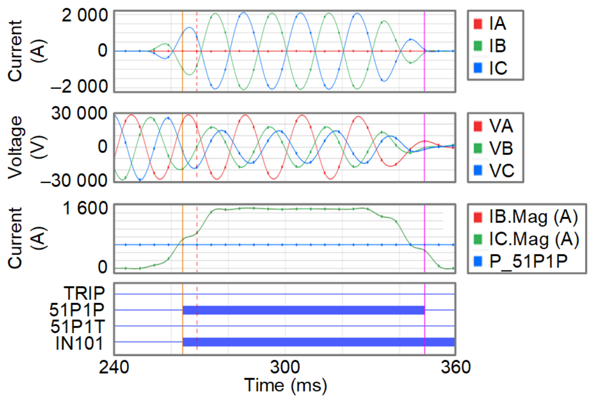

Fig. 9 Feeder event report

Fig. 10 shows the waveform recorded at the 35 kV Incomer B relay, where fault current with a magnitude of 1 500 A was seen on Phase B and Phase C, lasting close to five cycles. The 50P1P element picked up as soon as it hit the set point (1 000 A) and triggered a trip on 50P1T after 15 ms. The breaker opened (52A deasserted) 50 ms later.

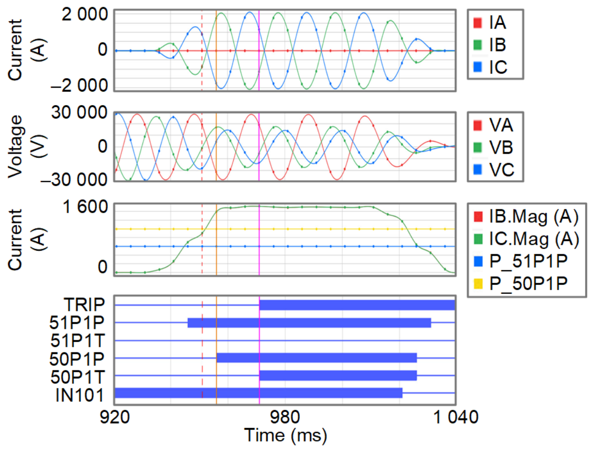

Fig. 10 Incomer B event report

A similar pattern can be seen when reviewing the event record on the transformer protective relay. The fault current was experienced in both the primary and secondary windings, and it was cleared within 60 ms after the Phase A restrained differential element (87RA) Relay Word bit was asserted, as shown in Fig. 11.

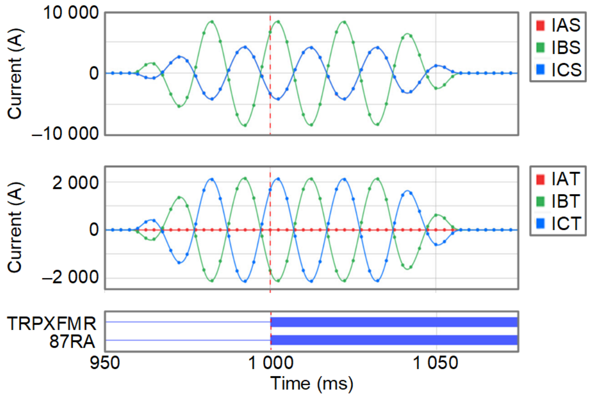

Fig. 11 Transformer relay event report

Fig. 12 explores further the operating current (IOP) and restraint current (IRT) measured during the event with the 87RA element assertion. Equation (1) shows the method of calculating operating (differential into the zone) and restraint (through the zone) current. Based on relay design, the "k" coefficient in (1) can vary. In the case of the relay in question, k = 1, and for an external fault, IOP should be zero. For an internal fault, IOP should ideally be equal to the IRT. As per (1) and Fig. 12, the fault impacts all three phases in the delta winding, and Phase B and Phase C experience fault current for the wye-connected secondary.

$$IRT = \frac{|\mathbf{I_1}| + |\mathbf{I_2}|}{k} \qquad IOP = |\mathbf{I_1} + \mathbf{I_2}| \qquad (1)$$

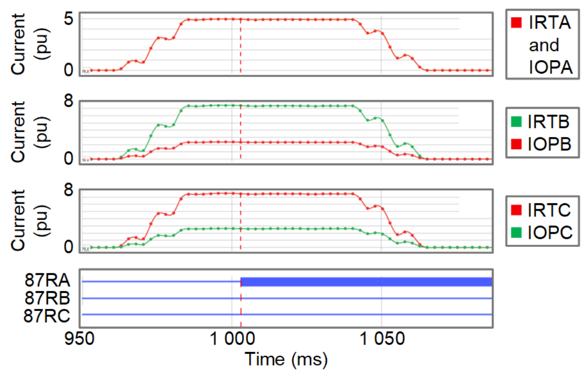

Fig. 12 Further exploration of 87RA assertion

Detailed analysis of this fault showed that the transformer protective relay determined an in-zone fault where Phase A operated, as the operating and restraint current pair plotted in the trip region of the percentage differential element. After performing basic tests, the team confirmed that the transformer was fault-free. Simultaneously, a detailed review of the set points was performed on the transformer protective relay.

It is important to set the compensation settings to match the transformer nameplate (an example nameplate is shown in Fig. 13), taking into account the phase-to-bushing connections and the CT connections. These settings define the amount of compensation that the relay applies to each set of winding currents. For example, this correction is needed if both wye and delta power transformer windings are present but both sets of CTs are connected in wye. The effect of the compensation is to create phase shift and to remove zero-sequence current components [3].

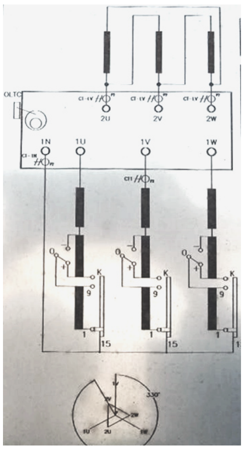

Fig. 13 Internal connection and vector arrangement taken from the transformer nameplate (21 MVA)

After the review, it was found that the compensation settings were set to TSCTC = 0 (Winding 1 S input, 10.5 kV) and TTCTC = 11 (Winding 2 T input, 35 kV) to compensate for a YNd11 arrangement. According to Fig. 14 and Fig. 15, the set points were incorrect [2]. The commissioning engineers concluded that the settings should have been TSCTC = 0 (S input, 10.5 kV) and TTCTC = 1 (T input, 35 kV) to correctly compensate the differential currents for the step-up transformer.

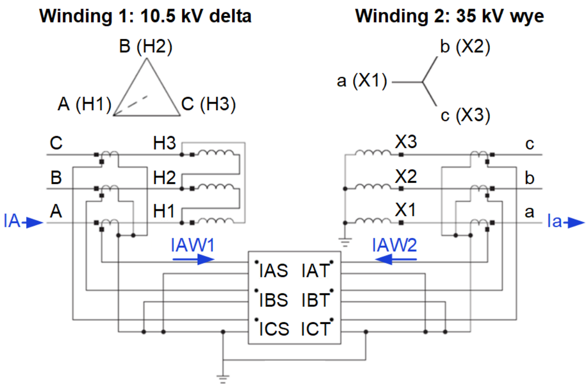

Fig. 14 Delta-wye transformer

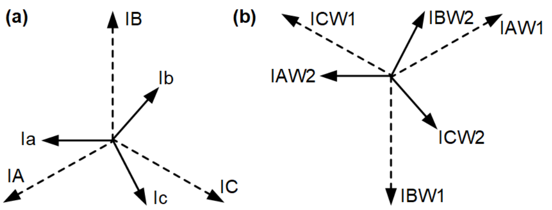

Fig. 15 Phase currents a) on system and b) at relay

A recalculation of IOP and IRT with correct settings was performed to verify the correct operation of the relay. If TTCTC = 1 for this fault, a replay of the event using the modified compensation settings, shown in Fig. 16, proves that the relay would have been secure (all operate current would be approximately 0 and restraint current would be 5 to 10 pu on all phases) for this operation [4].

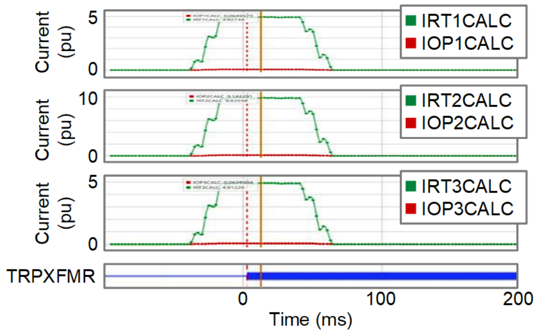

Fig. 16 IOP and IRT based on custom calculations using modified compensation setting TTCTC =1

Further analysis concluded that this error was detected on the protection study report during transformer primary injection testing and that the relay settings were then corrected; however, during the precheck phase of the livening process, the settings were reverted to match the latest protection study report, which failed to capture the red-line markup of the protection study made earlier.

Fig. 10, the Incomer B relay event report, shows a trip triggered from the instantaneous overcurrent (50P1T) set point. The incomer relay should not clear a downstream feeder fault; instead, the downstream feeder protection should clear the fault to maintain trip discrimination and allow the remaining feeders to continue to supply their load.

Fig. 17 shows the trip curve for both the incomer and feeder relays on this switchboard (not to scale). The instantaneous pickup (1 000 A) was mapped incorrectly to the trip equation of the incomer relay. The Feeder B instantaneous protection pickup (50P) was set at 2 700 A with a 400 ms time delay; however, the fault current seen in this scenario would not trigger a trip for 50P. Instead, a 51P element set at a standard inverse curve (IEC Class A) would have triggered in approximately one second to maintain discrimination between the upstream and downstream feeders with no changes to the set points.

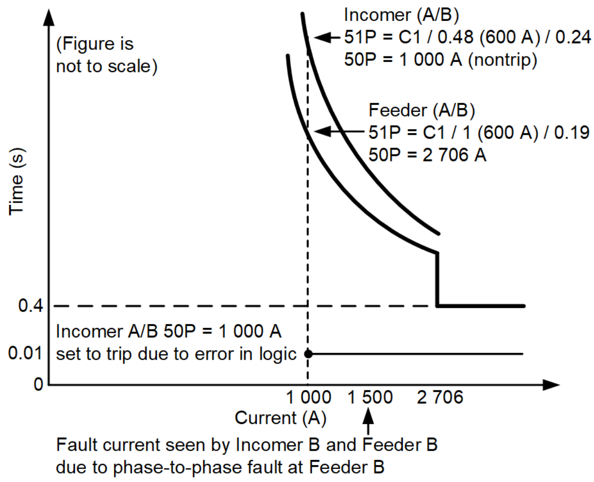

Fig. 17 Trip curve for incomer and feeder relays

After a design review, the team confirmed that the instantaneous element was supposed to block the automatic transfer scheme operation. However, the element was mapped to the trip equation incorrectly in the logic diagram. It was subsequently removed from the trip equation and the logic diagrams were updated.

Thorough review of the final set points and the logic diagram as part of the overall design can identify errors like this in commissioning activities while safe energizing practices are still maintained. In addition, it is important to carefully control changes made after commissioning to avoid overriding the corrections made during commissioning activities.

V. MYSTERIOUS TRIPS ON 35 KV FEEDER A

During the investigation of the 35 kV Incomer B (trip-logic error) and Incomer B transformer protective relay (compensation error), the team observed that the same errors were made for Incomer A and the Incomer A transformer relay. At this time, Incomer B was isolated and all feeders were energized only through Incomer A. This increased the overall load on Incomer A and elevated the operate and restraint current in the Incomer A transformer protective relay. A trip would isolate all power flow for all critical downstream feeders.

Prior to the implementation of changes to the transformer protective Relay A and the Incomer A relay, the Incomer A breaker tripped while it was single-ended, and power to all downstream feeders was lost. However, unlike the previous event on Incomer B, ground current was observed in this scenario. Analysis of the transformer relay event record shown in Fig. 18 revealed a through fault on the ground. The 35 kV wye-winding zero-sequence current and the transformer neutral current were 180 degrees apart with identical magnitudes, confirming that the fault was out-of-zone.

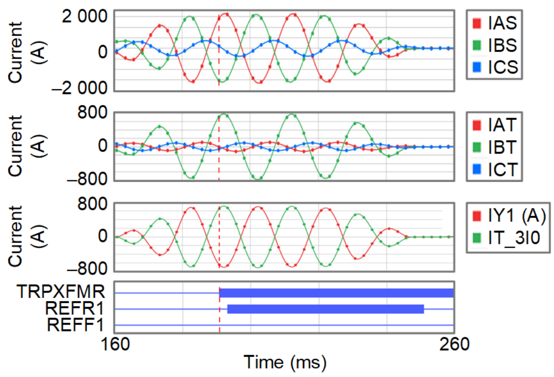

Fig. 18 Transformer relay event report

Analysis of the event report shown in Fig. 19 further confirmed that a downstream Phase-B-to-ground fault was experienced by the incomer relay. The incomer relay 50N1 protection picked up without issuing a trip. No trip was recorded in the feeder relay for the first trip event. This was due to the 600 ms time delay set on the ground protection; the fault was cleared by the transformer protective relay before 600 ms elapsed. Further investigation showed that the sequential event recorder feature in the protective relay used in this project to record the event was not set correctly to record ground fault pickups.

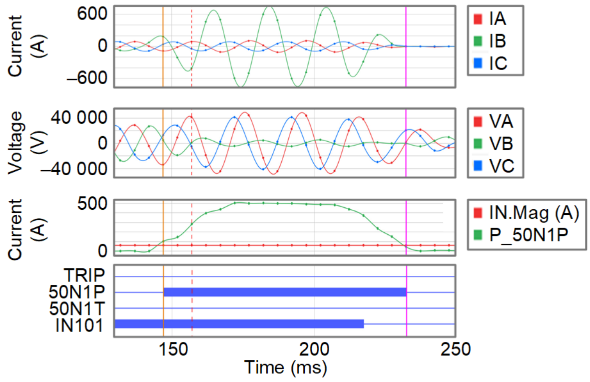

Fig. 19 Incomer A trip event report

Because of the criticality of the downstream loads, and the cause of the trip was established in the previous event, the 35 kV switchgear was livened using Incomer A and Incomer B. The bus tie was opened under normal operating conditions after correcting the transformer protection settings on both transformer relays and correcting the trip logic on both incomer relays. However, following the Phase-B-to-ground fault where the operations team did not find conclusive evidence for the cause of the trip events, power was restored to Feeder A, and the protection subsequently tripped two more times.

Fig. 8 shows the switchgear arrangement and the possible fault location on Feeder A. Fig. 20 shows the fault current recorded at the feeder relay for the first of the two Feeder A trips. The fault current gradually declined, then increased and remained stable until the fault was cleared. The fault was cleared soon after the 600 ms time delay included for discrimination purposes.

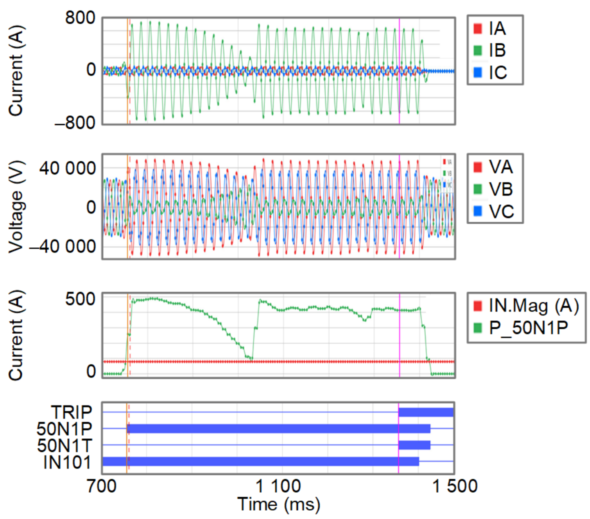

Fig. 20 Fault current recorded for first Feeder A trip

Fig. 21 shows the fault current recorded at the feeder relay for the second Feeder A trip.

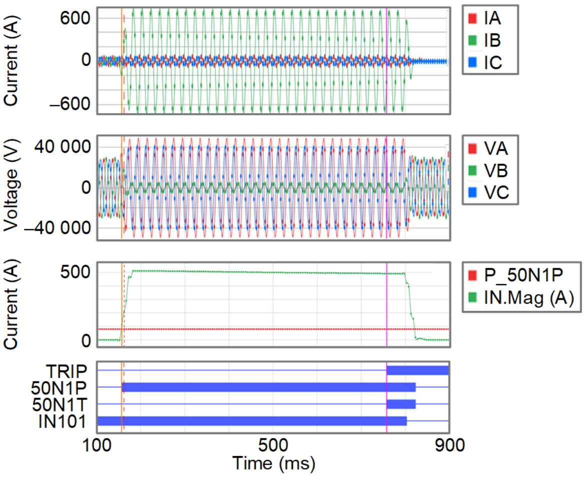

Fig. 21 Fault current recorded for second Feeder A trip

Unfolding the cause of the trips was not an easy task with the protective relays set incorrectly and with a fault that was not present all the time. An elimination method was used to pinpoint the fault location. After the initial trip on Incomer B, the major equipment was tested for insulation resistance and the engineers ran procedural tests prior to reenergization. (The details of these tests are not included here because they are tangential to the event analysis of the protective relay records.)

After the first trip on Feeder A, the team concluded that the fault was still present. However, without conclusive evidence, and because the load feeding the line was critical, the line was re-energized.

Similarly, the second trip on Feeder A was cleared soon after the 600 ms time delay. Because there was no conclusive evidence of equipment failure, the team walked the overhead line span to observe any physical damage. Initial investigation found nothing. After another walk of the line on a windy day (with westerly winds moving from west to east), the team observed that the separation between the overhead line for Phase B and the concrete poles was minimal, as shown in Fig. 22.

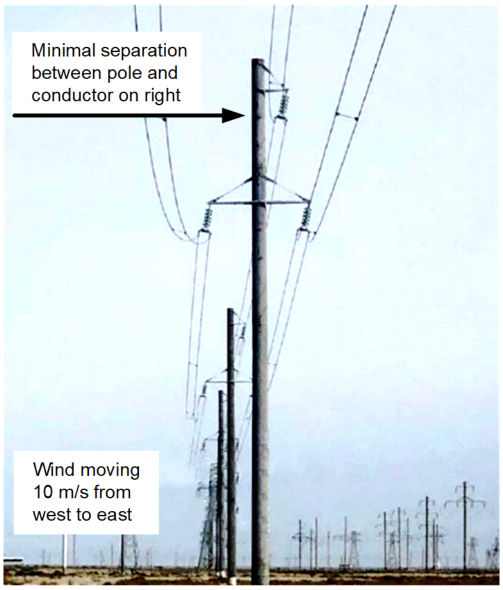

Fig. 22 Concrete pole with minimal conductor separation

The minimal separation meant that it was possible for the Phase B line to flashover to the pole. Analysis of wind data also confirmed that this geographical location is prone to receiving high-speed winds. With this information in hand, the operations team walked the line again and visually inspected poles using binoculars. They found signs of flashover damage on a couple of the concrete poles. Fig. 23 shows one example.

Fig. 23 Flashover damage on concrete pole

Because the operations team observed the overhead line during a westerly wind, their observations of the minimal line separation prompted them to investigate this issue in detail. They concluded that the repeated trips on Feeder A (after the initial trip due to incorrect settings) occurred with the transformer protective relay set correctly for transformer differential protection. They further concluded that the incomer relay was set correctly (as per the lessons learned from the previous event), with the instantaneous protection trip removed from the trip equation and instead used to block the automatic transfer scheme.

The feeder relay's sequential event recorder feature was updated to identify pickup fault current prior to trips, to help investigate any future trips. The team concluded that a combination of short crossarm length on the concrete poles and high westerly winds was the cause of the trip, although the existing installation did meet the project specifications. The construction team replaced the crossarms of the concrete poles with longer lengths to resolve the issue.

VI. PEER-TO-PEER COMMUNICATION TRIP EVENTS

This section discusses the lessons learned from two separate events that occurred on in-service feeder protective relays installed on a 35 kV switchgear. The system, which consists of a 35 kV switchgear with a main-tie-main bus configuration, a 380 V station service switchgear with a main-tie-main bus configuration (located in the same substation), and multiple 6 kV switchgears located downstream of the substation that also have main-tie-main bus configurations. All three main-tie-main switchgears are equipped with transfer controllers for automatic and manual source transfer. These controllers are labeled 35kV_ATS, 6kV_ATS, and 380V_ATS in the single-line diagram. At the time of the event, only a single 6 kV switchgear was in service; therefore, only one 6 kV switchgear is depicted in the simplified diagram in Fig. 24.

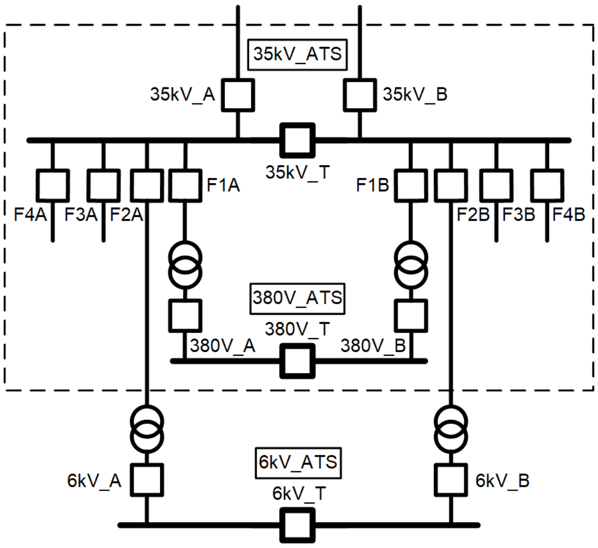

Fig. 24 Simplified single-line system diagram

The interlocking and an intertripping scheme between the relays used a peer-to-peer communication protocol. There is a peer-to-peer communication link between each pair of upstream and downstream relays; for example, the relays at Breakers F1A and 380V_A transmit data over a dedicated communications channel. One bit transmitted from upstream to downstream that is significant in the two events discussed in this section is the upstream breaker's status. Opening of the upstream breaker (e.g., F1A) results in the opening of the downstream incomer breaker (e.g., 380V_A) and the initiating of fast automatic transfer to the opposite source through the closing of the bus-tie breaker (e.g., 380V_T).

Event 1 occurred when new approved settings changes were being uploaded to the F1A relay. During the process of uploading new settings to the relay, the engineer loading the settings noticed switching operation in the 380 V switchgear located in the same substation. Once the settings upload to the F1A relay was successful, the engineer retrieved the sequence of events from the F1A, 380V_A, 380V_B, and 380V_T relays, as well as the 35kV_ATS and 380V_ATS controllers, for analysis. Examination of the sequence of events reports showed that a fast source transfer was initiated by 380V_A as the relay detected a momentary opening of the upstream F1A breaker.

Event 2 occurred during the replacement of the relays at F3B and F4B. The construction contractor accidentally created a short circuit on the control circuit, which caused the miniature circuit breaker (MCB) supplying control voltage to all Bus B relays to trip. There were reports of switching operation at both the local downstream 380 V switchgear and the remote downstream 6 kV switchgear shortly after the MCB tripped. Interrogation of the relays and controller at both the 380 V and 6 kV switchgears showed fast transfer initiation by the 380_B Incomer B relay due to the detection of the upstream Breaker 35kV_F1B opening.

In both Event 1 and Event 2, the root cause was determined to be an incorrect declaration of breaker-open logic in the upstream relay that was then transmitted downstream. Fig. 25 shows an excerpt from the F1A relay sequence of events from Event 1.

#	DATE	TIME	ELEMENT	STATE
31	02/10/20	14:39:27.870	Software Alarm	1
28	02/10/20	14:39:28.875	Software Alarm	0
27	02/10/20	14:40:45.231	Relay Settings Changed	
23	02/10/20	14:40:45.231	Communication Fail (Downstream)	1
19	02/10/20	14:40:45.231	F1A Breaker Closed Status	0
18	02/10/20	14:40:45.231	F1A Disconnector Closed Status	0
17	02/10/20	14:40:45.231	F1A Ground Switch Open Status	0
16	02/10/20	14:40:45.231	Open Command to Downstream (F1A CB Open)	1
15	02/10/20	14:40:45.251	Communication Fail (Downstream)	0
10	02/10/20	14:40:45.256	F1A Breaker Closed Status	1
9	02/10/20	14:40:45.256	F1A Disconnector Closed Status	1
8	02/10/20	14:40:45.256	F1A Ground Switch Open Status	1
7	02/10/20	14:40:45.256	Open Command to Downstream (F1A CB Open)	0

Fig. 25 F1A relay report excerpt for Event 1

Line 31 corresponds to the relay engineer logging into the relay write-access level, which triggered a software alarm and then self-reset after one second. New relay settings were uploaded to the relay in Line 27, which caused the relay to disable temporarily while accepting the new settings. Peer-to-peer communication with the downstream relay was also temporarily lost during this period for a total duration of 20 ms (Lines 23 to 15).

In this application, a second peer-to-peer channel was also enabled to communicate with an input/output (I/O) module to transmit and receive additional I/O, including breaker open (52b) status, breaker closed (52a) status, disconnect switch open/close status, and ground switch open/close contacts. As with the peer-to-peer communications channel with the downstream relay, the channel with the remote I/O module was also lost temporarily. During a period of time when the relay has poor peer-to-peer communication, it does not process any received bits on this channel, and instead maps these bits to user-defined default values, which in this case were all zeros. The 52a status deasserted for the duration of the communications channel failure (Line 19) and then reasserted (Line 10). During this time, both the 52a and 52b statuses were logically zero as seen by the relay. There is a period between Lines 15 and 7 when the communication with the downstream relay returned as healthy while the upstream relay was also sending an unexpected active-open command to the downstream relay.

Fig. 26 shows an excerpt from the 380V_A relay sequence of events. The command to trip the 380 V incomer breaker was issued in Line 51, which corresponds to the same time that the peer-to-peer communications became healthy again between the two relays.

#	DATE	TIME	ELEMENT	STATE
53	2/10/20	14:40:42.495	Communication OK (Upstream)	0
51	2/10/20	14:40:45.245	Breaker Open Command Output	1
47	2/10/20	14:40:45.245	Communication OK (Upstream)	1
46	2/10/20	14:40:45.245	Open Command from Upstream (F1A CB Open)	1
44	2/10/20	14:40:45.250	Inititate Automatic Transfer	1
40	2/10/20	14:40:45.265	Open Command from Upstream (F1A CB Open)	0

Fig. 26 380V_A relay report excerpt for Event 1

The open-command-to-downstream (F1A circuit breaker [CB] open) logic programmed in the F1A relay is shown in Fig. 27. This is not a fail-safe logic, because the scenario described above would result in a false open command being issued to the downstream relay. Additionally, a failure of an I/O module, or a failure of the communications media between the relay and the I/O module, would also result in a false open command being issued to the downstream relay. The logic needs to be improved to remain secure for such conditions.

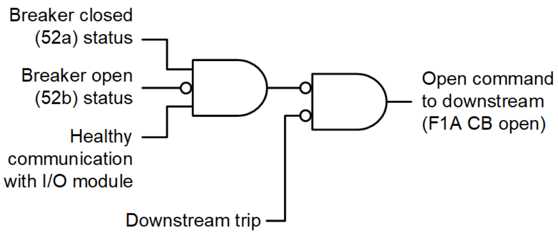

Fig. 27 F1A relay open-command-to-downstream logic

The loss of control voltage supply that occurred in Event 2 caused all relay and I/O module inputs to evaluate to logical zero (similar to what was experienced in Event 1). As a result, the upstream relays issued a false open command to the downstream relay, and in Event 2 this affected all relays on Bus B. All feeder relays on the 35 kV switchgear are programmed with open-command-to-downstream logic similar to that programmed in the F1A relay. Fig. 28 and Fig. 29 are sequence of events excerpts from the F1B and F2B relays, respectively. These reports show that both relays sent false open commands to the downstream relay after the 52a status deasserted.

#	DATE	TIME	ELEMENT	STATE
40	05/10/20	09:21:40.921	Spring Charge Failure Alarm	0
39	05/10/20	09:21:40.921	Remote Mode	0
			…	
29	05/10/20	09:21:40.921	F1B Breaker Closed Status	0
28	05/10/20	09:21:40.921	F1B Disconnector Closed Status	0
27	05/10/20	09:21:40.921	F1B Ground Switch Open Status	0
26	05/10/20	09:21:40.921	Open Command to Downstream (F1B CB Open)	1
			…	
20	05/10/20	09:32:16.212	Spring Charge Failure Alarm	1
19	05/10/20	09:32:16.212	Remote Mode	1
			…	
12	05/10/20	09:32:16.212	F1B Breaker Closed Status	1
11	05/10/20	09:32:16.212	F1B Disconnector Closed Status	1
10	05/10/20	09:32:16.212	F1B Ground Switch Open Status	1
9	05/10/20	09:32:16.212	Open Command to Downstream (F1B CB Open)	0
			…	

Fig. 28 F1B relay report excerpt for Event 2

#	DATE	TIME	ELEMENT	STATE
40	10/05/20	09:21:40.917	F2B Breaker Closed Status	0
39	10/05/20	09:21:40.917	F2B Disconnector Closed Status	0
38	10/05/20	09:21:40.917	F2B Ground Switch Open Status	0
			…	
34	10/05/20	09:21:40.917	Spring Charge Failure Alarm	0
33	10/05/20	09:21:40.917	Remote Mode	0
			…	
26	10/05/20	09:21:40.927	Open Command to Downstream (F2B CB Open)	1
			…	
17	10/05/20	09:32:16.209	F2B Breaker Closed Status	1
16	10/05/20	09:32:16.209	F2B Disconnector Closed Status	1
15	10/05/20	09:32:16.209	F2B Ground Switch Open Status	1
14	10/05/20	09:32:16.209	Open Command to Downstream (F2B CB Open)	0
			…	
10	10/05/20	09:32:16.209	Spring Charge Failure Alarm	1
9	10/05/20	09:32:16.209	Remote Mode	1
			…	

Fig. 29 F2B relay report excerpt for Event 2

The desired relay operation for both Event 1 and Event 2 was for the relays to remain secure and not issue an open command on either end of the feeder. The corrective action was to make this logic fail-safe for the scenarios described: sending settings to the relay, the failure of an I/O module, the failure of communications between a relay and I/O module, and the loss of control voltage supply. The logic depicted in Fig. 30 was implemented to address this. The logic does not use the inverted 52a status, and the total number of logical operators is significantly reduced to simplify the logic. The inverted downstream trip-received signal is used to supervise the logic to avoid sending the trip command back to the downstream relay where it originated.

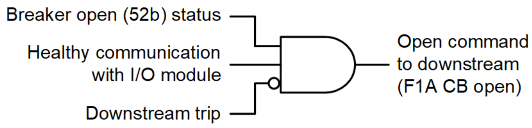

Fig. 30 Updated logic that addresses listed scenarios

VII. 380 V LOAD BANK TESTING

A 1 MW load bank test was performed by commissioning engineers on a new 380 V switchgear with a connected standby diesel generator (SDG). Fig. 31 shows a simple one-line diagram.

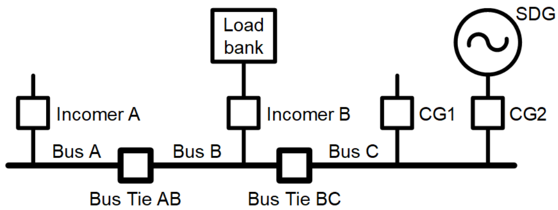

Fig. 31 One-line diagram for 380 V switchgear setup

The test required the SDG to energize Bus C and feed through a connected load bank on Incomer B. At the start of the test, both Bus Tie AB and Bus Tie BC were open. Bus A was isolated and energized by temporary generation to power auxiliary loads. When the test began, test engineers closed Bus Tie BC to connect the SDG to the load bank.

After the engineers closed the Bus Tie BC breaker, Breaker CG2 immediately tripped on a relay's directional phase overcurrent element. Fig. 32 shows the event report retrieved from one of the relays protecting Breaker CG2.

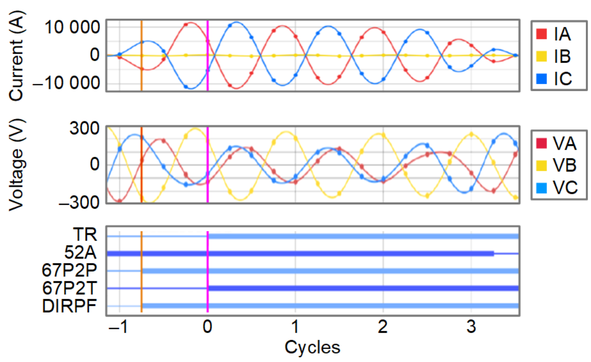

Fig. 32 Breaker CG2 relay event report

After analyzing the event report, commissioning engineers reviewed the cable connections from the load bank to Incomer B. Due to the temporary 1 MW load bank test connections to the motor control center (MCC), the commissioning contractor used two cables per phase to connect the load bank to the incomer. Two cables were correctly connected from the load bank Phase B to the incomer Phase B. However, when the four remaining cables for Phase A and Phase C were connected, two of the cables were swapped, creating a 10 000 A phase-to-phase fault upon energization. Although this was the root cause of the trip, further analysis of the tripping times revealed another problem.

The protection for Breaker CG2 consists of two relays: a generator protective relay and a directional relay designed to trip for faults on the SDG side of the breaker. According to the event report, the directional relay asserted a trip in 15 ms. The directional element was set to the forward direction and based on the phase-to-phase fault on the Incomer B load bank; the directional relay should not have tripped. For this specific fault, Bus Tie BC should have tripped. Although the Bus Tie BC relay did pick up, the definite time (50) element of the CG2 backup directional relay was faster than the 51 element in the Bus Tie BC relay.

Upon review of the drawings, the engineering team found a discrepancy: the side (bus or generator) to which the CT star point was connected changed between design revisions (typical drawings, versus as-built). The relay settings engineer developed the settings based on the relay typical drawings and not the as-built drawings. Following this event and a review of the CT wiring, the commissioning team updated the settings to match the relay's intended zone of operation.

VIII. CONCLUSIONS

This paper detailed multiple events covering a wide range of applications in a 110, 35, 10, 6, and 0.38 kV power generation, transmission, and distribution system. The lessons learned from each event were described, as well as the solutions that the engineers applied.

In summary, proper settings management of as-left settings is critical. Engineering teams should clear any 87L communication watchdog alarms after local relay testing that might result in a blocking of the protection when a relay is placed in service. Microprocessor-based relay reporting functionalities should be used to their full advantage to continuously monitor for communication watchdog alarms.

For system design, it is important to document the basis for each relay set point change made during commissioning and to manage changes for all affected design documentation (such as protection settings studies). An example fail-safe intertripping logic design for peer-to-peer communications was shown in this paper. Engineers should also review CT-polarity-sensitive protection elements against as-built drawings to confirm the intended design.

The lessons learned by the teams working on this particular system can be applied to future projects by other engineers working on switchgear commissioning, livening, and operation.

IX. REFERENCES

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