Analysis of POTT Operation Failure on Complicated Simultaneous Inter-Circuit Faults

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Introduction:

In modern society, electricity is indispensible to our daily life. A fault occurred in the power system could result in power quality and stability issues, and even blackouts to a large area. Therefore, power system faults should be isolated properly by the protection system in a timely, effective, and selective manner.

Simultaneous or inter-circuit faults can be a challenging task to analyze and would have some unexpected impacts on protection system. When a protection improper operation occurs, the event should be investigated to find out the root cause and thus prevent reoccurrence.

The permissive overreaching transfer trip (POTT) scheme is one of commonly used communication-aided pilot schemes for transmission line protections. With the assistance of a communication channel, the scheme provides hi-speed operation at all terminals of the line for faults anywhere along the line or within the protected zone.

Based on a disturbance investigation, this paper examines the non-operation of POTT scheme when a complicated inter-circuit open phase fault was developed. Fault records from IEDs were utilized to determine what happened. The fault records captured by fault and Sequence of Events (SOE) recording equipment provided valuable information which gave an insight into the nature of this disturbance. The analog and digital data of fault records facilitate an efficient investigation and accurate analysis of these events. The findings and recommendations are introduced to the readers.

System Overview:

The simplified regional system one line is shown in Figure 1. L substation, an 115kV in-line breaker station with tapped step-down transformers on both sides of the line breaker, is in Boston area of the state of Massachusetts and it is one of the key substations in the region. L station is connected to remote station W and R through 115kV line Q6 & A7 respectively. 23kV sub-transmission system is connected to 115kV lines through two tapped step-down transformers at L station.

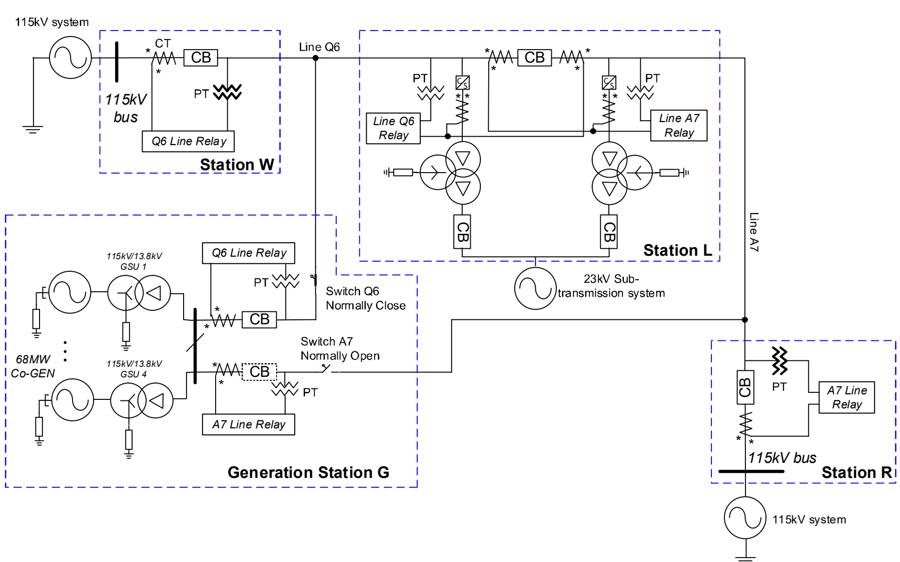

Figure 1: the simplified regional system one line

Independent generation facility G with total installation capacity of 68MW can be configured to connect to either line Q6 or A7. The incoming lines Q6 & A7 to generating facility yard are carried on the same line structure. The normal operational configuration of G is connected to line Q6.

115kV line Q6 and A7 are provided with dual protection systems at National Grid owned station L, W & R. System 1 protection is POTT scheme while system 2 is step distance. In addition, direct underreaching transfer trip (DUTT) and breaker failure direct transfer trip (BF DTT) are provided between terminal stations. A special DTT runs between station L, W, R, and generation yard G to ensure that the tapped generation facility is tripped once either line Q6 or A7 is opened from both line terminals. This DTT prevents the generation plant from islanding operation as well as out of synchronization when the line is solely energized by the generator and will be connected to the system by closing station breakers.

At in-line breaker station L, the secondary current from bushing CT on the breaker one side is subtracted from the secondary current of tapped transformer HV bushing CT on another side of the breaker; thus, the line relays fed from such wiring would sense the "pure" current on the line. In case of 115kV line fault, the in-line breaker and the same line side tapped transformer LV side 23kV breaker would be tripped to ensure 115kV and 23kV power sources would be isolated.

<u>Protective relay trip targets and records:</u>

At 07:00:23AM of 12/17/2021, both 115kV line Q6 and A7 were tripped from all line terminals. At generation station G, surveillance camera captured bright glares at their yard at the time of 115kV breaker trip. Damaged post insulator was identified on Q6 line disconnect switch and arcing marks were found on 115kV equipment under take-off structure.

1) At station W:

Line Q6 breaker was opened after receiving a DUTT signal from station L. Both system 1 and 2 relays triggered with event records, however, neither relay operated. The relay record from system 1 relay of POTT scheme was shown in Figure 2 below.

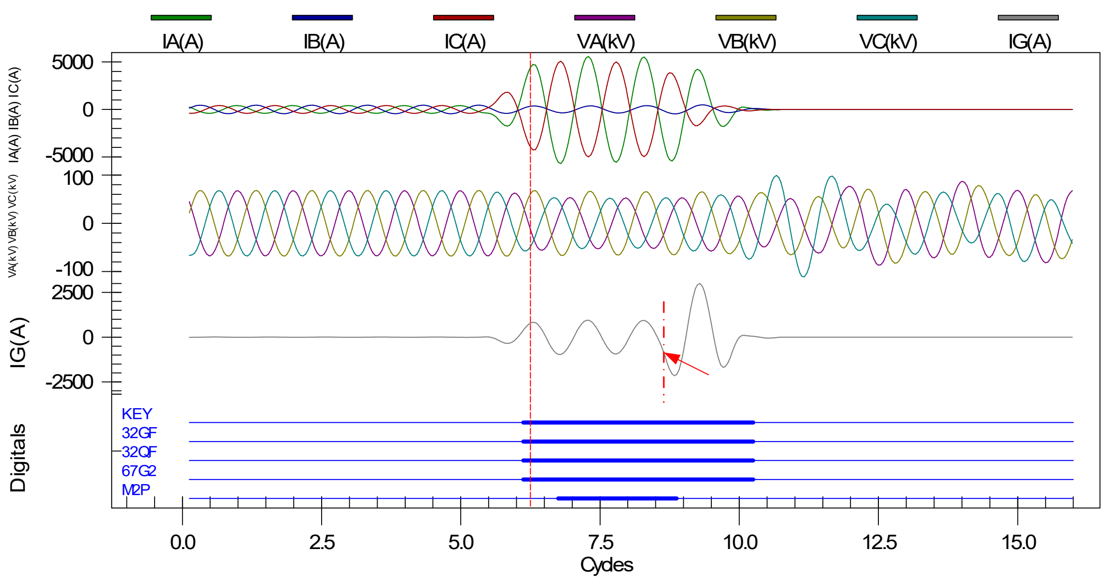

Figure 2: system 1 relay record of line Q6 from station W

From the relay record, a forward phase to phase to ground fault occurred in the system. Phase to phase distance element (M2P) and directional ground OC element 2 (67G2) of the pilot zone asserted, a trip permissive signal was sent to remote station L. At the time stamp of 8.5-cycle, the remote terminal (i.e., breakers at station L) must have opened as the change of fault current magnitude and the drop-out of M2P element. Even after Q6 line breaker was opened from station W, the line side voltage didn't disappear, indicating the slow fault isolation from generation terminal G. The system 2 relay, used for step-distance, had the similar oscillograph and will not be shown here.

2) Relays at station L:

115kV in-line breaker and 23kV breaker of tapped transformer on line Q6 side were opened after receiving trip command from line Q6 system 2 step distance relay by zone 1 ground distance element (21N1).

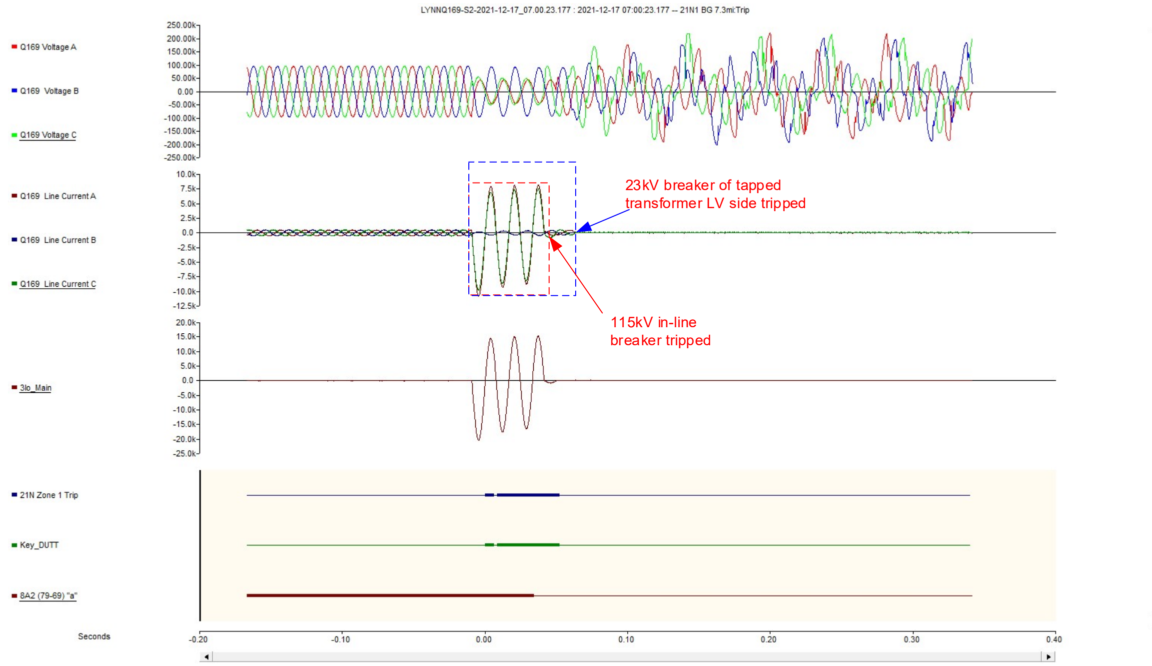

Figure 3: System 2 relay record of line Q6 at station L

Per line relay record, instantaneous ground distance zone 1 element (21N1) asserted in half cycle after the fault inception and trip command was send to isolate 115kV & 23kV power sources. 23kV breaker was opened 1.5-cycle after 115kV breaker was opened, which was normal as the standard interruption of 23kV breaker is 5-cycle while 115kV breaker is 3-cycle interruption device. The fault was of phase A-C to ground type. However, the faulted A & C phase current were almost in phase with the same magnitude, which was uncommon. The magnitude of 11.5kA ground current was detected by the relay. After station L was isolated from line Q6, the line was still energized from generation facility G. This should not have happened as DTT was sent to generation G after line terminals were opened from station W & L.

System 1 relay of POTT scheme for line Q6 didn't pick-up. Both system 1 & 2 relays for line A7 at station L didn't trip during the fault. However, a DUTT for line A7 was received from remote station R, which would trip in-line breaker and 23kV breaker of tapped transformer on line A7 side.

3) Relays at station R:

115kV breaker for line A7 was tripped from station R by zone 1 ground distance element of both system 1 & 2 relays. Since zone 1 elements picked-up, DUTT was sent over to remote station L to open both 115kV & 23kV breakers. In the meantime, the trip permissive signal (PT) was also sent to remote station L. However, POTT scheme of line A7 at station R did not operate as the permissive trip signal was not received from remote station L. The relay record from system 1 relay of POTT scheme was shown in Figure 4 below.

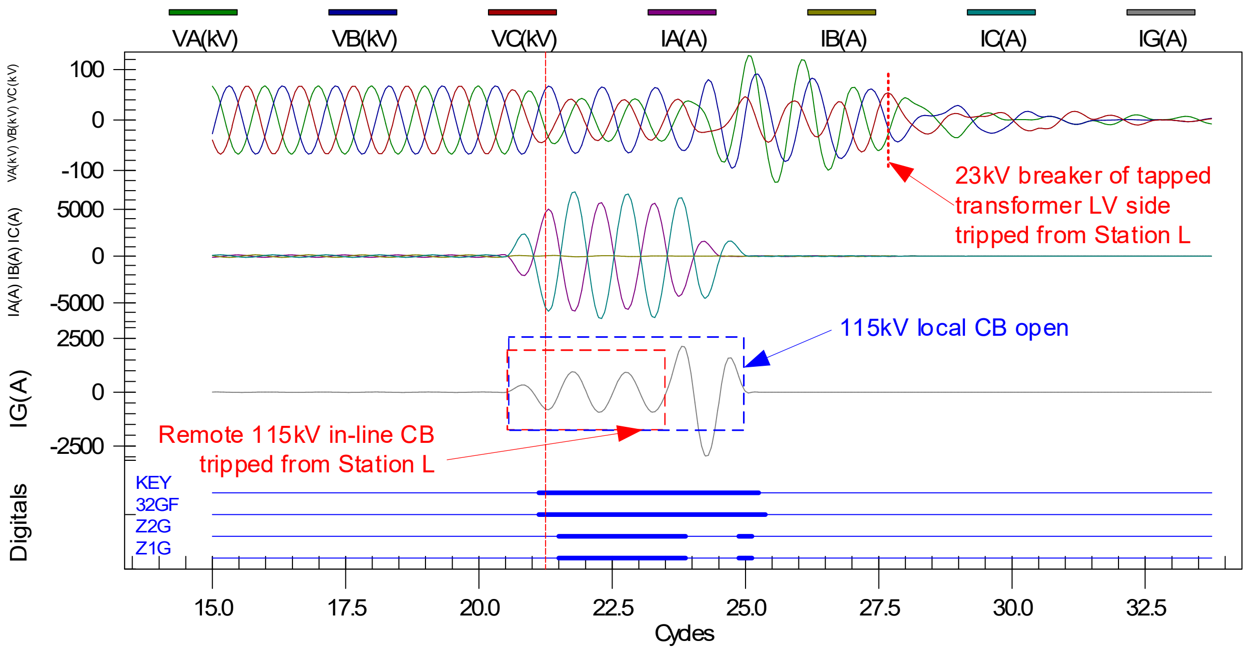

Figure 4: System 1 relay record of line A7 at station R

The record from line A7 system 1 relay at station R is shown in Figure 4. It can be seen:

Phase A-C to ground fault was present on 115kV line A7, instantaneous ground distance element zone 1 of the relay asserted and POTT permissive signal was sent to the remote.

The remote in-line breaker from station L was opened 1.5-cycle faster than local 115kV breaker , this can be verified by the ground current magnitude increment.

Line A7 was still alive for approximately 2.5-cycle after the line current disappeared. The was resulted from the trip process of 23kV breakers of the tapped transformer on line A7 side at station L, i.e., the line was back-feed from 23kV sub-transmission system via tapped transformer.

Once 115kV breakers were opened from station R & L, line A7 lost the ground source as the tapped transformer HV side at station L is Delta winding configured. During the station L 23kV breaker trip, phase A & B voltage of the line was elevated to some extent, indicating that a non-bolted C-phase to ground fault still existed on the line.

The system 2 relay, used for step-distance, had the similar oscillograph.

4) Relay targets at generation facility station G:

Prior to the event, generation was connected to 115kV line Q6. Damages were identified on 115kV line switch in the yard. Q6 line relay trip and breaker failure target were found. After 115kV line Q6 was tripped from both station W & L, DTT was also received at generation G. As indicated in line Q6 relay records from station W & L (Figure 2 & 3 respectively), line Q6 voltages did not disappear after the line was isolated at both terminals. This indicates that the line was back sourced from the generation yard.

Protective relay performance review:

115kV lines are provided with dual protection systems from different manufacturers. For any fault on the line, the relay should detect the fault and open the corresponding breaker(s). Parallel circuits are sometimes installed in the same right of way due to spacing constraints. To eliminate the mutual coupling effects, only negative sequence polarization is enabled on directional control for ground distance and overcurrent elements of the digital relays.

As seen in the previous section, system 1 relay for line Q6 and both system 1 & 2 relays for line A7 failed to operate for the fault at station L. The ground current magnitude on line Q6 from station L was 11.5 kA. There must be something on the directional control element of Q6 system 1 relay. Let's look at those in details.

1) 115kV line Q6 relays:

The settings of negative sequence polarized directional control elements of system 1 relay are given in the table below:

Setting	Value	Unit	Notes
Z1MG	2.73	Ω	Positive sequence line impedance magnitude
Z1ANG	82.22	Degree	Positive sequence line impedance angle
Order	Q	-	Ground directional element priority
Z2F	-1.21	Ω	Forward directional Z2 threshold
Z2R	0.79	Ω	Reverse directional Z2 threshold
a2	0.12	-	Positive sequence restraint factor, I2/I1
k2	0.2	-	Zero sequence restraint factor, I2/I0

System 1 relay has unique algorithm for negative sequence voltage polarized directional control element, in which the thresholds of forward and reverse negative sequence impedances (Z2FT & Z2RT) are dynamic in the negative sequence impedance plane. The real time calculated negative sequence impedance (Z2C) will be compared with the threshold, then the forward or reverse direction will be determined together with k2 supervision. If the calculated negative sequence impedance value is greater than forward threshold and less than reverse threshold, the directional control element would be in non-operational status (Z2C>Z2FT and Z2C<Z2RT). The characteristics of the directional control element is shown in Figure 6.

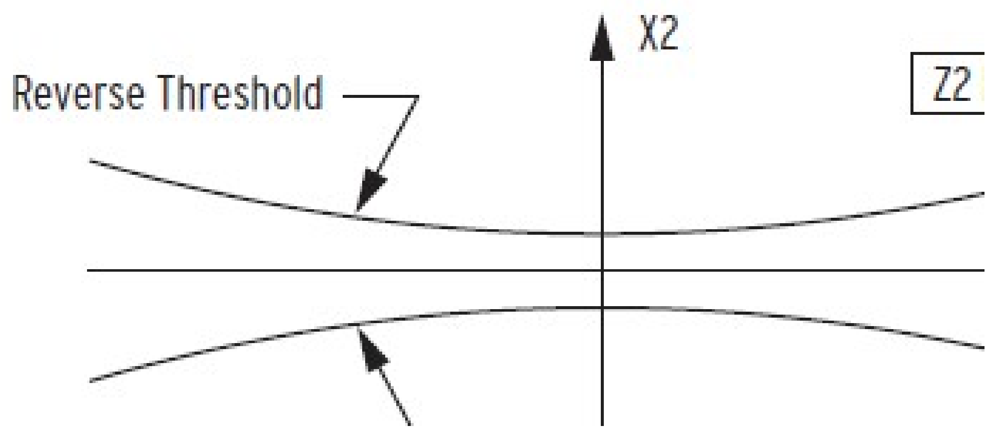

Figure 6: the characteristic of negative sequence voltage polarized directional control element.

The voltage and current information during the fault is given in the table below:

	Va	Vb	Vc	V1	V2	V0
Magnitude [V Secondary]	31.48	66.057	35.66	37.25	28.64	0.80
/_Angle [DEG]	0	-168.4	25.63	-49.48	74.54	116.68
	Ia	**Ib**	**Ic**	**I1**	**I2**	**I0**
Magnitude [A Secondary]	15.49	0.606	14.237	5.45	4.87	9.70
/_Angle [DEG]	-156.3	15.31	-152.37	149.01	-99.10	-154.21

With the voltage and current information, the calculations of the negative sequence voltage polarized directional control element are below:

a2/k2 logic	Z2C	Z2FT	Z2RT	F32QG	R32QG	Direction
OK	-0.146	-2.377	2.062	De-assert	De-assert	N/A

Where:

Z2C is calculated negative sequence impedance.

Z2FT is threshold of forward negative sequence impedance.

Z2RT is threshold of reverse negative sequence impedance.

F32QG is forward negative-sequence voltage-polarized directional element.

R32QG is reverse negative-sequence voltage-polarized directional element.

It should be noted that Z2F & Z2R settings were from fault simulation calculation methods, which was mentioned in the manufacturer's manual, see [1]. The calculated directional element is in the interim region, i.e., Z2C >Z2FT and Z2C < Z2RT, between the forward and reverse threshold boundary curves as shown in Figure 6. This explains the non-operation of system 1 relay for line Q6 during the fault. Furthermore, two different methods for Z2F & Z2R settings recommended by the manufacturer will be used to see the behavior of directional control element as follows:

- Auto 2 setting: Z2F=-0.3 & Z2R =0.3

a2/k2 logic	Z2C	Z2FT	Z2RT	F32QG	R32QG	Direction
OK	-0.146	-1.694	1.694	De-assert	De-assert	N/A

The calculated directional element is still in the interim region between the forward and reverse threshold boundary curves and can't decide.

- Auto setting based on half of the line positive sequence impedance: Z2F=1.37 & Z2R =1.47

a2/k2 logic	Z2C	Z2FT	Z2RT	F32QG	R32QG	Direction
OK	-0.146	0.243	2.572	Assert	De-assert	Forward

With auto settings for Z2F & Z2R, the relay would make a forward direction judgment. However, based on previous lessons learnt protection operations in National Grid system, normally, auto setting for Z2F & Z2R are not recommended. The directional settings were either based on fault simulation calculation method or auto2 (Z2F=-0.3 & Z2R=0.3) when inverter-based resource (IBR) is connected to the station or tapped to the line.

System 2 relay utilizes conventional negative sequence polarized directional control algorithm. The relay characteristic angle (RCA), the center of the directional characteristic, would always lag the inverted negative sequence voltage (-V2) by a certain angle and is determined by the negative sequence source impedance of the system. Then the angle of negative sequence current (I2) is compared with RCA. The directional element declares a forward fault when the angle difference between RCA line and I2 within 90° of limit angle. The conventional negative-sequence directional characteristic is shown in Figure 7.

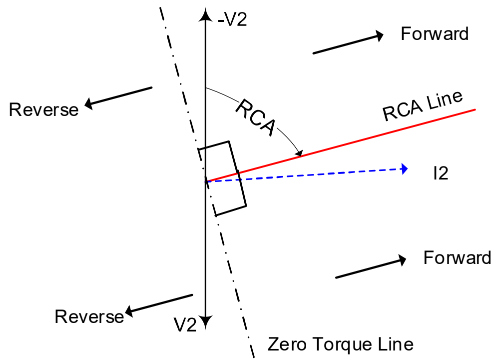

Figure 7: negative-sequence directional characteristic of system 2 relay

In the mathematical expression, the negative sequence polarized directional supervisory element would declare a forward fault if the value of COS[(∠-V2 -∠RCA) -∠I2] is positive.

Per relay records captured during Q6 fault, the angle of -V2, I2 were 254.54° and 260.9° respectively. The RCA is the line positive sequence impedance angle with the value of 82.22°. Now I2 would lead RCA line by 88.57°, which was close to the upper zero torque line in Figure 7 or forward directional region boundary. Therefore, the directional control element still identified forward fault and allowed the ground distance zone 1 element to make a trip.

2) 115kV line A7 relay performance review:

There was no triggered record from both A7 line relays. Since station L is in-line breaker configured, the current of Q6 and A7 can be assumed with same magnitude but with inverted phase angle during the fault. The relay performance would be explored below.

The settings of associated negative sequence polarized directional control elements of system 1 relay are given in the table below:

Setting	Value	Unit	Notes
Z1MG	1.49	Ω	Positive sequence line impedance magnitude
Z1ANG	80.65	Degree	Positive sequence line impedance angle
Order	Q	-	Ground directional element priority
Z2F	-0.79	Ω	Forward directional Z2 threshold
Z2R	1.21	Ω	Reverse directional Z2 threshold
a2	0.12	-	Positive sequence restraint factor, I2/I1
k2	0.2	-	Zero sequence restraint factor, I2/I0

It should be noted Z2F &Z2R setting were based on fault simulation methods.

The voltage and current information during the fault is given in the table below:

	Va	Vb	Vc	V1	V2	V0
Magnitude [V Secondary]	31.48	66.057	35.66	37.25	28.64	0.80
/_Angle [DEG]	0	-168.4	25.63	-49.48	74.54	116.68
	Ia	**Ib**	**Ic**	**I1**	**I2**	**I0**
Magnitude [A Secondary]	15.49	0.606	14.237	5.45	4.87	9.70
/_Angle [DEG]	23.7	195.31	27.63	-30.99	80.9	25.79

With the voltage and current information, the calculations of the negative sequence voltage polarized directional control element are below:

a2/k2 logic	Z2C	Z2FT	Z2RT	F32QG	R32QG	Direction
OK	0.307	-2.062	2.377	De-assert	De-assert	N/A

Therefore, the directional element of the relay was unable to make a judgement during the fault.

System 2 relay utilizes conventional negative sequence polarized directional control algorithm. The relay characteristic angle (RCA) is 80.65°. The angle of -V2, I2 were 254.54° and 80.9° respectively. The angle of RCA line is 173.89° & I2 lags RCA line by 93°. Therefore, system 2 relay identified the fault as reverse direction and didn't respond.

Generation Facility yard review:

As mentioned in the previous relay operation section, there was phase A-C to ground fault on 115kV line Q6. In the meantime, the same phase A-C to ground fault happened on 115kV line A7. After 115kV A7 line breakers were opened from station L & R with the ground source and isolated. Line A7 was still energized for approximately additional 2.5 cycles by line A7 tapped transformer at station L from 23kV sub-transmission system. During the 2.5-cycle period, phase A & B voltages of line A7 were elevated, and C-phase voltage still sagged, indicating a C-phase to ground fault presence on the line.

At generation yard, the generators were connected to line Q6 prior the event. Let's look at the top view of the generation station yard in Figure 8 (by courtesy of Google Map) and review the fault.

Figure 8: A bird view of generation facility yard by courtesy of Google map

Generators in the plant are connected to 115kV rigid bus via GSUs though the overhead MV feeders. Q6 and A7 line breaker & associated switch are connected to main 115kV station rigid bus. 115kV line switches were installed under line take-off structure in the yard. Line Q6 & A7 has independent line structures in the transition from the yard to the final shared Q6/A7 line structure. The electrical clearance between energized phase to phase and phase to ground in the yard is standard design. It should be noted C-phase of line A7 is next to A-phase line Q6 in the line take-off structure and underneath line switch.

Line Q6 protection trip, breaker failure and received DTT targets were found at generation yard. Post fault inspection at the yard verified Q6 line switch had blown open and the post insulator failed. There were other arcing marks were found on the primary equipment of 115kV A7 circuit in the vicinity of take-off structure, indicating non-bolted fault presence on line A7. The yard surveillance camera captured the bright glares near 115kV line take-off structures.

Based on the field findings, it was most likely the original fault occurred on Q6 line switch first. When the arcing & burning happened on the switch, the highly conductive plasma from the arc flash in Q6 circuit promptly propagated to the C-phase of A7 circuit in vicinity. The illustration of the fault is shown in Figure 9.

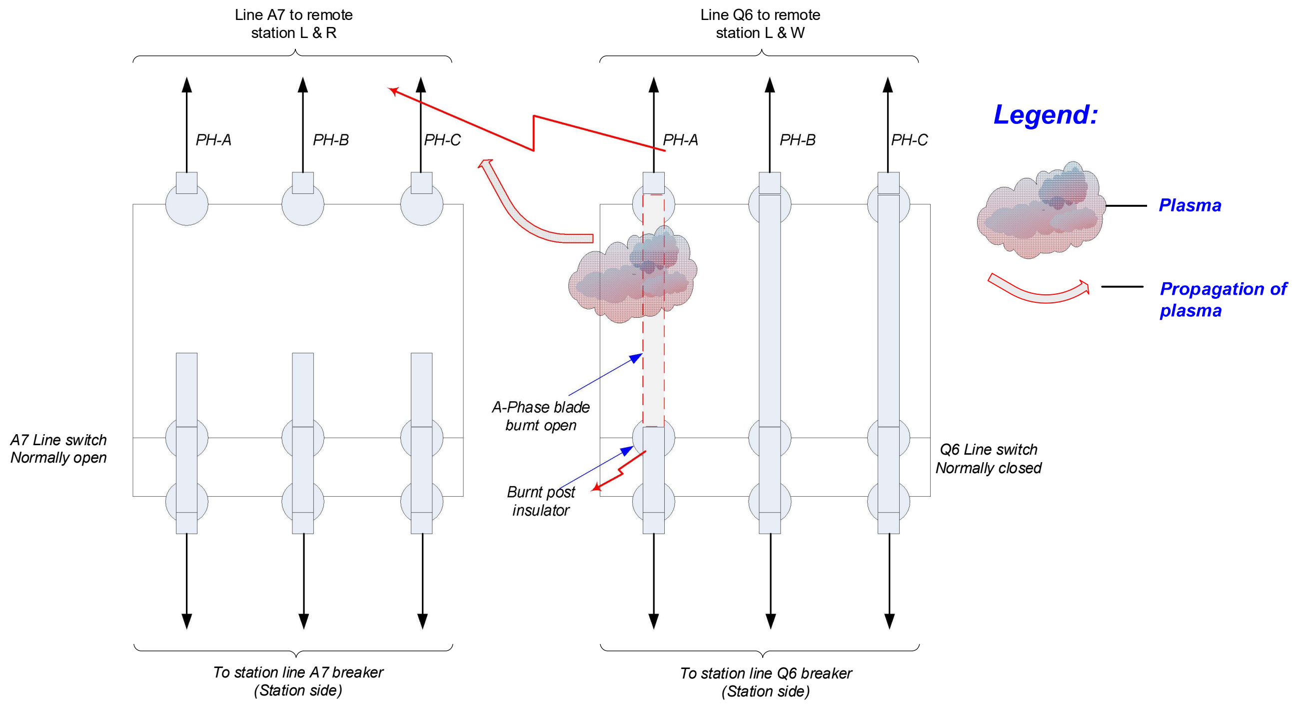

Figure 9: 115kV circuit fault illustration at generation yard

The burnt blade of Q6 switch resulted in open phase and failed post insulator caused A-phase to ground fault on Q6 circuit on the bus side. The arc flash plasma produced the temporary inter-circuit fault between phase A of Q6 to phase C of A7 circuit. The arc flash caused inter-circuit fault didn't disappear until A7 line was finally isolated from 23kV sub-transmission at station L.

Simultaneous inter-circuit fault simulation:

To verify the above-mentioned suspect, simultaneous inter-circuit fault simulations were performed in a short-circuit program. A-phase to ground fault with 1Ω resistance was applied on generation facility 115kV bus. Line Q6 was open A-phase from generation facility 115kV bus toward remote bus. The inter-circuit fault with 2Ω fault resistance between phase A of line Q6 to phase C of line A7 circuit out of generation 115kV bus was also applied. The snapshot of simulation results is shown in Figure 10.

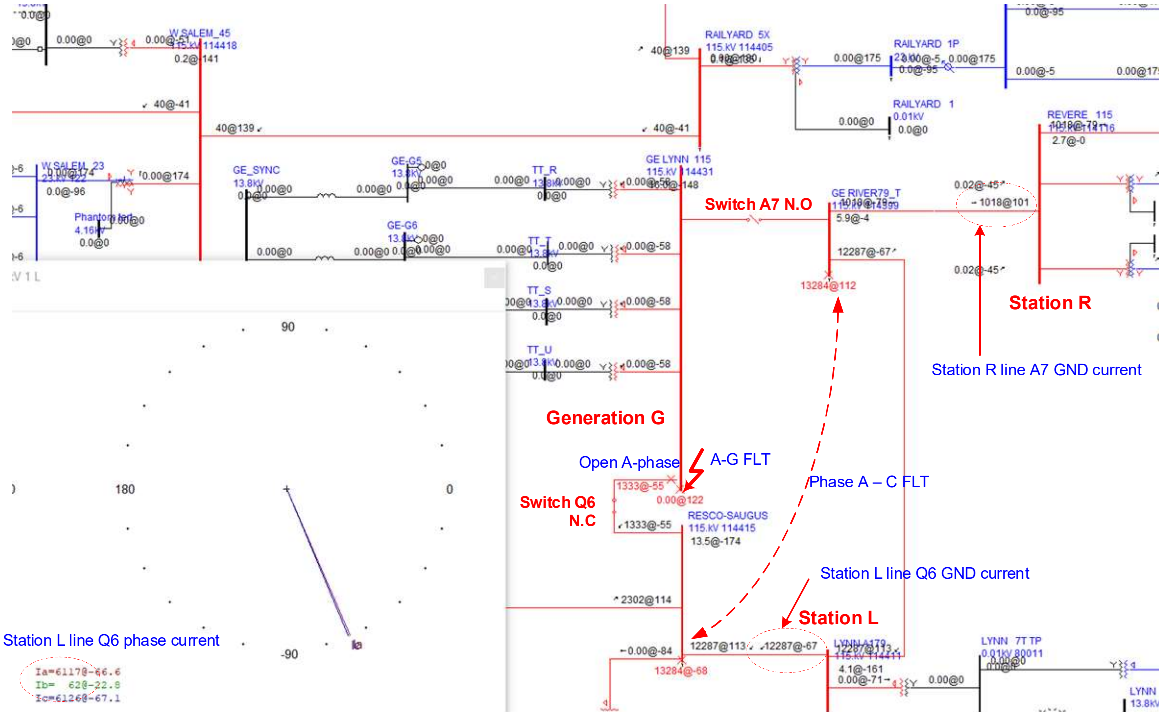

Figure 9: Simultaneous inter-circuit fault simulation from short-circuit study

Per the simulation, the magnitude A & C phase current on line Q6 from station L is 6.1 kA and the ground current on Q6 line is 12.28 kA. The phase A & C current are in phase, which matches the relay record. The phase A & C and ground current from system 2 relay of line Q6 at station L (in Figure 2) were 6.2 kA, 5.7 kA & 11.67 kA respectively. The simulated ground current on line A7 from station R is 1018A while the ground current captured by line A7 relay from station R (in Figure 4) is 970A. Considering the imperfect of simulation models, the simulated results basically match the relay records and confirm the fault analysis.

Summary & lessons learned:

1) The likelihood of the inter-circuit faults is rare, but it could happen. This misoperation or non-operation of the relay under more than N-1 contingency or inter-circuit faults was considered as an explainable event.

2) Transmission line nowadays is typically provided with dual protection systems. Engineers would always think it would be fine when the relays were selected from different product lines or hardware platform from the same manufacturer. Based on this event in the paper and other operational experience in National Grid system, it would be highly recommended that system 1 & 2 protective relays are diversified from different manufacturers because of potential latent design or hardware deficiencies.

3) Short-circuit program is a useful tool for fault simulations, advances in short circuit program allows for the modeling of simultaneous faults. In addition, fault records captured by protective relays provide valuable insight as to the nature of the fault.

4) Much freedom was given to the user on how to set the negative-sequence voltage polarized directional element of system 1 relay. It's recommended that the user check "auto", "auto2" and calculation generated values in directional element settings and select the settings based on the engineering judgement.

References:

1. SEL-321 Relay instruction manual - Date Code: 20080909

2. SEL-421 Relay instruction manual - Date Code: 20050805

3. LPRO-2100 Relay instruction manual

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