Analysis and Troubleshooting of 500kV line operation with Unit feeder differential misoperation

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***Abstract*—TVA experienced a tree-caused fault on one of the 500kV lines connected to a large generating plant. A feeder differential scheme on the high side of a generator step-up transformer (GSU) for an 1100MW generating unit misoperated 3 cycles after fault inception, followed by slow fault clearing at both 500kV line terminals (16 cycles and 18.5 cycles, respectively). This paper intends to provide analysis of the cause of slow clearing by the 500kV line protection, as well as the cause of the misoperation of the feeder differential. The reason for the slow clearing of the line fault was determined to be the insensitivity of the pilot ground protection for resistive faults. The reason for the misoperation of the feeder differential protection was much more difficult to determine. After some difficult and unsuccessful troubleshooting, a disconnected residual wire on one of the breaker CTs was found to be the cause. The reason why secondary injection testing was unsuccessful in pointing to the actual cause is discussed.**

Keywords—feeder differential; open neutral; dynamic mho expansion; resistive ground fault; resistive coverage; sensitivity secondary injection test

I. INTRODUCTION

The Tennessee Valley Authority (TVA) is a corporate agency of the United States that provides electricity for business customers and local power companies serving 10 million people in parts of seven southeastern states. The TVA system consists of over 16,000 circuit miles of transmission lines and over 500 substations, with operating voltages primarily at 500kV and 161kV.

One such 500kV line, connecting Plant W to Substation R, is 40 miles long and is one of five connections for a large generating plant (see Figure 1). Protection for 500kV lines presently calls for dual primary pilot protection, but originally the philosophy was two sets of pilot relays with a third set of non-pilot relaying. The latter was the scheme on the line from Substation R to Plant W.

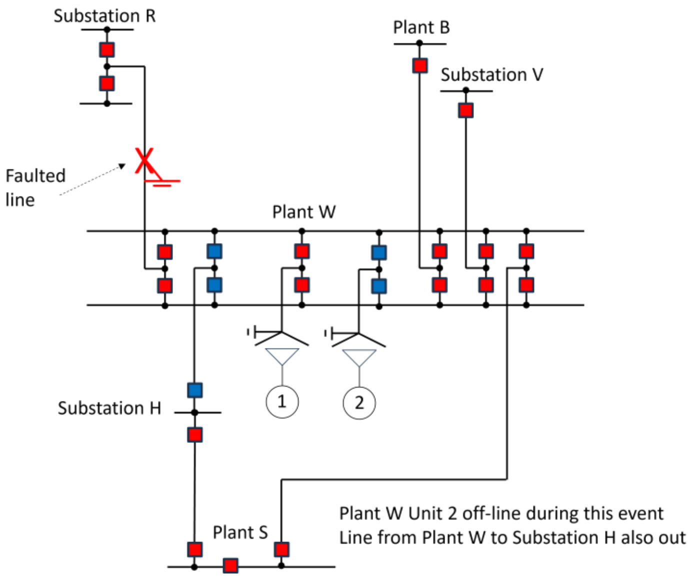

Figure 1. Area one-line diagram

II. Protection Details

A. *500kV transmission line relays*

As mentioned above, the 500kV transmission line was protected by three sets of relaying, each terminal having two sets of static/electronic relays in a directional-comparison cross-blocking scheme, with a set of non-pilot electromechanical backup relays (see Figure 2). Tripping was configured so that any tripping element that asserted would trip the terminal.

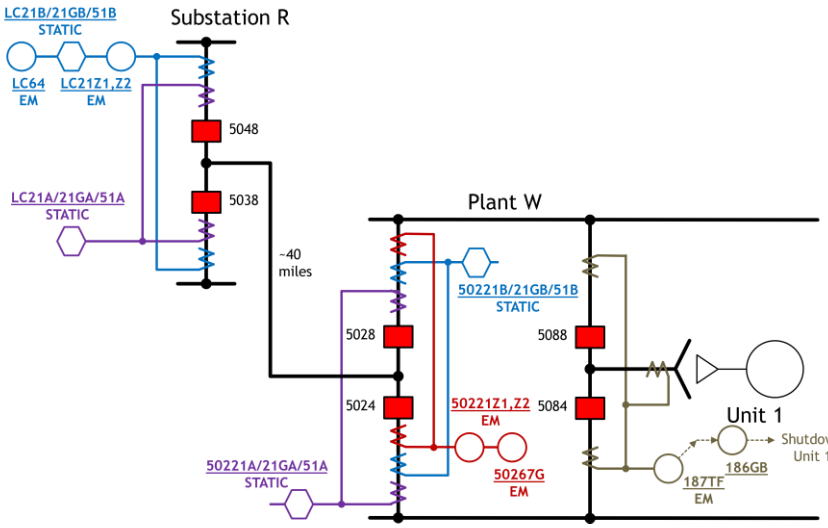

Figure 2. Protection one-line

1) *Static relays in cross-blocking (dual primary)*

Phase fault protection in the static package was provided by an overreaching pilot zone (mho element MT) supervised by a fault detector overcurrent element (I3ph element). Ground fault protection included an overreaching pilot zone (mho element MTG) supervised by a ground fault detector (G2 element), along with an instantaneous ground overcurrent element (G4). Carrier blocking was initiated for phase faults by an offset reverse mho element (MB), and for ground faults by a ground overcurrent element (G1).

It should be noted there were no underreaching instantaneous distance elements (neither phase nor ground) included in this static relay package.

There were two sets of static relays at each terminal. Each set keyed its own carrier blocking signal. Receipt of a blocking signal by either set was configured to block both overreaching zones (MT and MTG) in both relay sets ("cross-blocking").

2) *Electromechanical relays (backup)*

The electromechanical relays were non-pilot, step distance. Phase fault protection was provided by an instantaneous underreaching zone 1 and a time-delayed overreaching zone 2. Both distance zones at both terminals were cross-polarized mho elements. Ground fault protection was provided by a directional ground relay having an instantaneous element and a very inverse time overcurrent element. The directional elements at both terminals were dual-polarized zero-sequence.

B. *Unit feeder differential relays*

The unit was protected by a single set of three electromechanical overcurrent relays, one per-phase, configured in summation differential. The relays had a short-inverse-time characteristic. An instantaneous element was also included in each relay.

C. *Sources of fault data*

1) *Plant W*

Plant W had two digital fault recorders (DFR), with DFR 1 monitoring the Unit 1 and the lines to Substations R and H, while DFR 2 monitored lines to Substations B and R and the line to Plant S. DFR 1 triggered a record for the initial fault, but not for the subsequent fault, so the clearing time for the subsequent fault was determined by DFR 2.

The available fault data from DFR 1 included:

- Three-phase voltages on the Substation R line

- Three-phase voltages on the Unit 1 feeder
- Three-phase currents, sum of 5024+5028
- Three-phase currents for 5028
- Three-phase currents, sum of 5084+5088
- Three-phase currents for 5084
- 500kV neutral current from GSU 1

We could thus determine individual breaker currents for 5024 by subtracting the 5028 current from the total Substation R line current, and for 5088 by subtracting the 5084 current from the total Unit 1 feeder current.

2) Substation R

Substation R had two DFRs, one for the 500kV system, the other for the 161kV system (there is a 500/161kV transformer bank at the site). The 500kV DFR at Substation R was off-line, but the 161kV DFR was on-line. We could thus determine clearing time from the 161kV DFR but had no information on the 500kV fault currents or voltages.

III. Event Sequence

The initial state is shown in Figure 3. The Unit was on-line generating 1100MW. The line W-R was carrying 400MW flowing from Plant W to Station R.

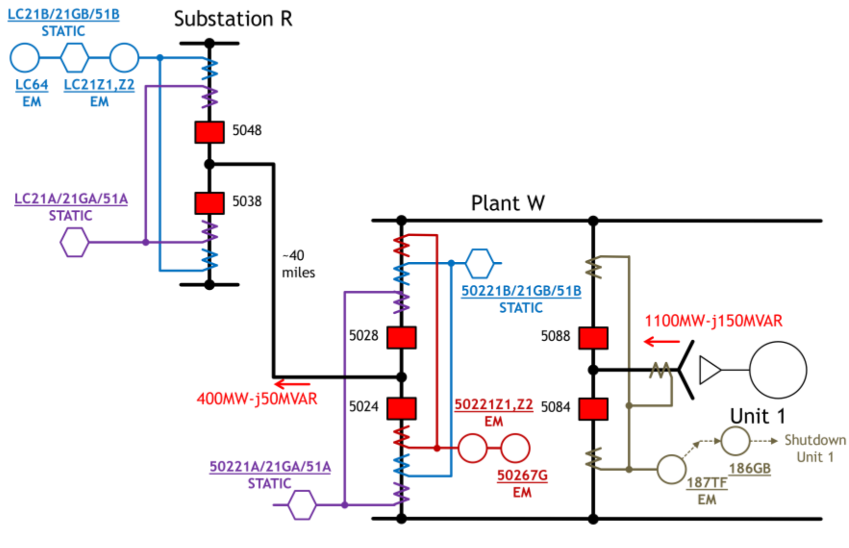

Figure 3. Initial state (red breakers=closed)

A. Initial fault

A phase-to-ground fault occurred on the line. The fault was subsequently determined to have been caused by a tree off the right-of-way that was cut by a landowner; the tree contacted the line as it fell (see Figure 4). Using single-ended data from DFR 1 and Plant W, the fault location was estimated to be roughly 55% of the line from Plant W to Substation R, with an approximate resistance of 19 ohms. Because of the fault location, we still expected the fault to clear instantaneously, even considering fault resistance and especially with dual pilot relaying.

However, the protection operation sequence clearly showed that we had experienced significantly delayed clearing.

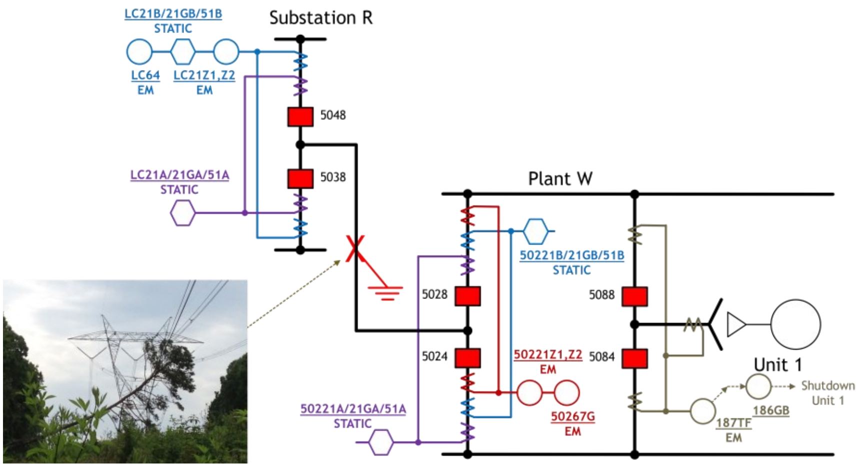

Figure 4. Phase-ground fault on the line from Plant W to Substation R

B. Protection operation sequence

Time t=0: Fault inception

Time t=13 cycles: Unit 1 feeder differential trips breakers 5084/5088 at Plant W

Time t=16 cycles: Plant W breakers 5024/5028 trip by static relay ground distance

Time t=18.5 cycles: Substation R breakers 5038/5048 trip by electromechanical backup ground IOC

Time t=17 seconds: Substation R breaker 5038 automatically recloses (dead-line)

Time t=17s+10 cycles: Plant W breaker 5028 automatically recloses (sync-check)

Time t=17s+13 cycles: Plant W breaker 5024 automatically recloses (sync-check)

Time t=17s+41 cycles: Substation R breaker 5048 automatically recloses (sync-check)

Time t=20 seconds: Fault recurs (same tree, same location)

Time t=20s+2.5 cyc: Substation R breakers 5038/5048 trip by electromechanical backup ground IOC

Time t=20s+10 cyc: Plant W breakers 5024/5028 trip by static relay ground distance

The final state is shown in Figure 5:

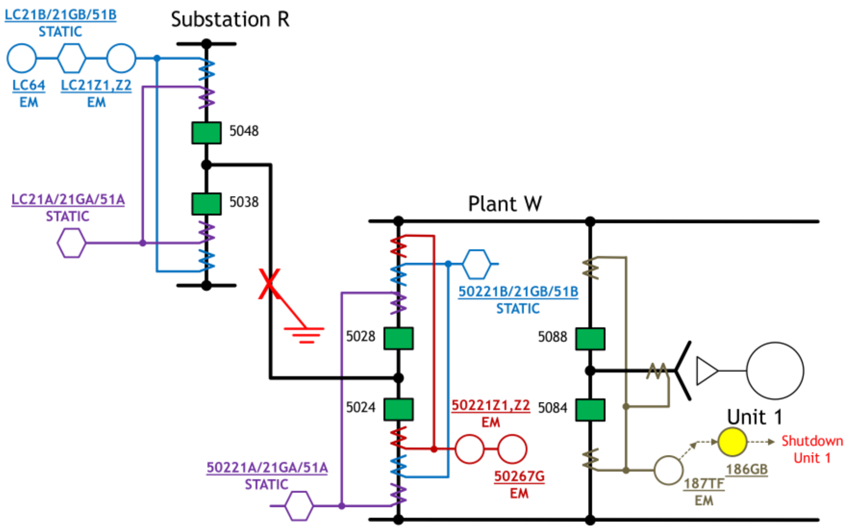

Figure 5. Final state (green breakers=open)

IV. Protection System Operation Analysis

There were several questions about the protection system performance for this event, which included:

1. The unit 1 feeder differential should not have operated for this fault which was clearly external to its zone.
2. Plant W 5024/5028 terminal was slow to clear on the initial fault (16 cycles)
3. Substation R 5038/5048 terminal was also slow to clear on the initial fault (18.5 cycles).

A. Unit 1 feeder differential misoperation

The feeder differential should normally see zero current on load and for external faults since it is a summation differential, so Unit 1 should not have tripped for this event. But Unit 1 did trip in 13 cycles, with a feeder differential A-phase relay target (time, not instantaneous). The relay was set with a pickup of 900A primary (1.5A secondary) with a #2-time dial. (NOTE: The instantaneous attachment was set for 14000A primary (23A secondary), but information indicated that element did not operate.)

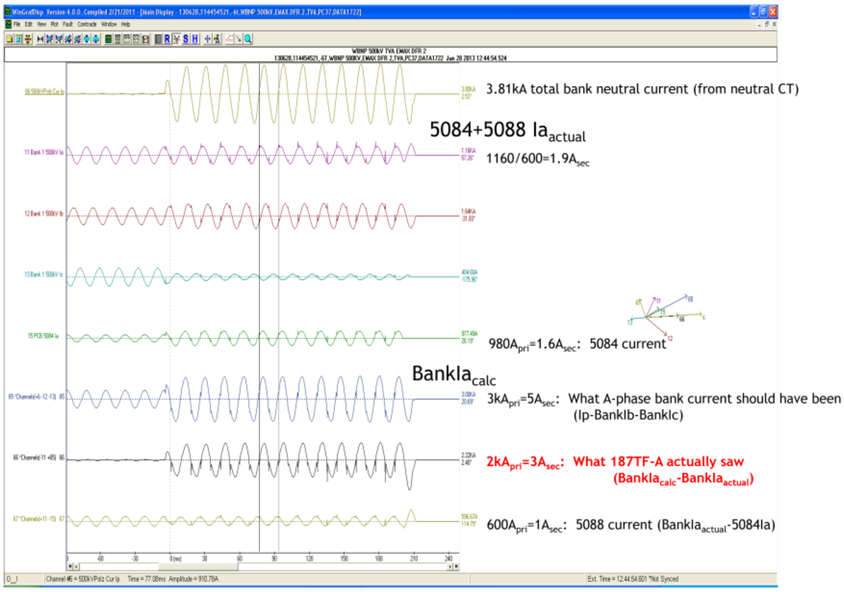

Figure 6. Initial fault DFR shot at Plant W, Unit 1 feeder quantities

We used the DFR information (Figure 6) available at Plant W in an attempt to calculate the current seen by the A-phase feeder differential relay, with the following comments:

- Sum of 5084/5088 phase currents from DFR (labeled “Bank 1”); (A-phase current phase angle is the reference for all phase angles shown)
  - Ia = 1160∠0° A primary = 1.9∠0° A secondary
  - Ib = 1660∠-88° A primary = 2.8∠-88° A secondary
  - Ic = 392∠129° A primary = 0.7∠129° A secondary
- 5084 phase currents from DFR, confirmed by SEL351 event record:
  - Ia = 982∠-31° A primary = 1.6∠-31° A secondary
  - Ib = 833∠-82° A primary = 1.4∠-82° A secondary
  - Ic = 77∠-153° A primary = 0.1∠-153° A secondary
- GSU residual magnitude & phase angle taken from DFR shot (adjusted phase angles to be relative to A-phase current reference instead of 500kV bus voltage); GSU phase current magnitudes taken from fault study including prefault load; GSU phase current angles calculated using relative angles from the calculated phase currents relative to the residual (GSU neutral). Results:
  - Ia = 2700∠-33° A primary = 4.5∠-33° A secondary

- Ib = 1700∠-90° A primary = 2.8∠-90° A secondary
- Ic = 200∠141° A primary = 0.3∠141° A secondary

- Calculating the 5088 currents as (5084+5088) - 5084, we obtain the actual secondary currents:
  - Ia = 1160∠0° - 982∠-31° = 600∠58° A primary = 1∠58° A secondary
  - Ib = 1660∠-88° - 833∠-82° = 836∠-93° A primary = 1.4∠-93° A secondary
  - Ic = 392∠129° - 77∠-153° = 383∠118° A primary = 0.6∠118° A secondary
- Calculating 5088 currents as GSU - 5084, <u>what the 5088 currents should have been</u>:
  - Ia = 2700∠-33° - 982∠-31° = 1719∠-34° A primary = 2.9∠-34° A secondary
  - Ib = 1700∠-90° - 833∠-82° = 882∠-98° A primary = 1.5∠-98° A secondary
  - Ic = 200∠141° - 77∠-153° = 183∠118° A primary = 0.3∠118° A secondary

Now, calculating the secondary currents seen by the feeder differential relays, GSU-5084-5088:

- Using 5088 currents <u>as they should have been</u> (no feeder differential operation):
  - Ia = 4.5∠-33° - 1.6∠-31° - 2.9∠-34° = -0- A secondary
  - Ib = 2.8∠-90° - 1.4∠-82° - 1.5∠-98° = -0- A secondary
  - Ic = 0.33∠141° - 0.1∠-153° - 0.3∠118° A = -0- A secondary
- Using 5088 currents <u>as they actually were</u> (A-phase feeder differential operation):
  - <u>Ia = 4.5∠-33° - 1.6∠-31° - 1∠58° = 3.1∠53° A secondary</u>
  - Ib = 2.8∠-90° - 1.4∠-82° - 1.4∠-93° = 0.1∠-173° A secondary
  - Ic = 0.33∠141° - 0.1∠-153° - 0.6∠118° A = 0.3∠-68° A secondary

So, the relay saw 3.1A secondary. This is 3.1/1.5 =200% of pickup which for time dial 2 results in an operating time of about 10 cycles, which agrees with the clearing time of 13 cycles including lockout relay and breaker interrupting time.

B. Troubleshooting

All CTs contributing to the differential scheme were individually tested with no problems found.

In addition, a secondary injection test was performed by passing current (1A secondary) from each current contribution to the differential relays, including 5084 CTs, 5088 CTs, and GSU 500kV bushing CTs. Each test "passed" (injected 1A by test set and measure 1A in relay) for each phase, so we concluded there was no open circuit.

There were a couple different incorrect theories that were set forth before the true cause was discovered, which were raised due to "spikes" seen in the waveforms of the currents in the DFR (see Figure 7).

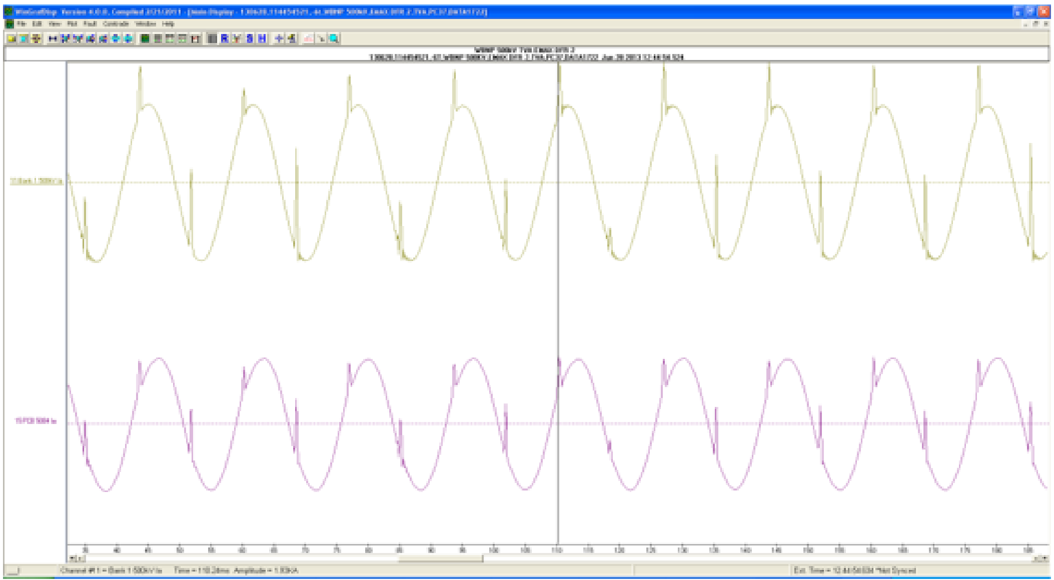

Figure 7. “Spikes” in 5084 CT circuit

The first was a loose connection at a test fixture in the 5084 CT circuit, which was raised because we suspected a possible open circuit somewhere in the CT circuit. However, the “success” of the secondary injection testing seemed to rule that out.

The second was surge arresters across 5088 CT secondaries. We had previously not seen such arresters in CT secondaries and suspected they may have fired possibly resulting in lost current to the differential summation.

However, the third, which proved to be correct, was the discovery of a lifted residual wire in the 5088 CT circuit connected to the unit 1 feeder differential relays. This was found by visual inspection of the terminal blocks where the CT cables first terminated in the control building. See Figure 8.

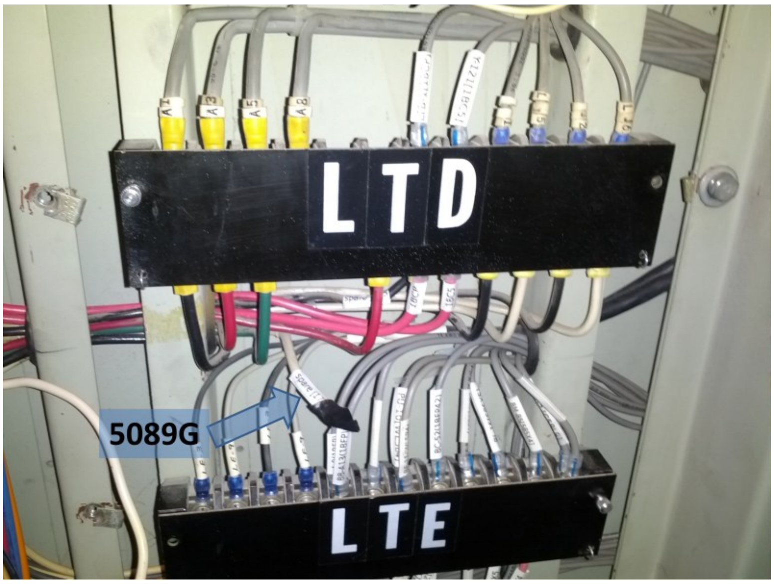

Figure 8. Lifted residual wire in 5088 CT circuit to feeder differential circuit (first terminal block in control building).

This lifted wire was figured in to the analysis of the secondary circuits, and which produced a current of just over 3A secondary to the A-phase differential relay. See Figure 9. This is about 200% of pickup which for time dial 2 results in an operating time of about 10 cycles, which agrees with the clearing time of 13 cycles including lockout relay and breaker interrupting time. Note the 5088 A-phase secondary current should have been 2.9∠-34°A (1716/600) but was only 1∠58°A (remaining 3.1∠-52°A forced thru CT magnetizing branch, due to the open residual wire). Compare Figure 9 with Figure 10 which shows what the differential relays would have seen if the residual wire had not been lifted.

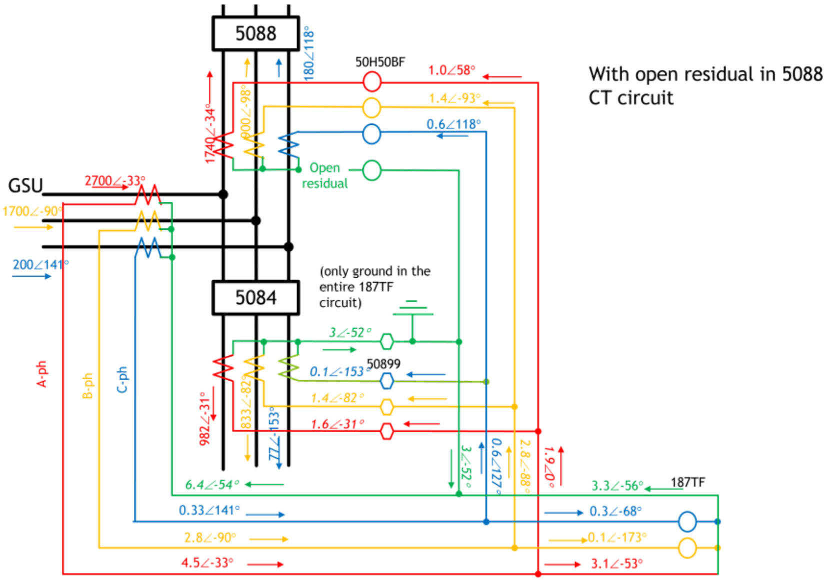

Figure 9. Unit 1 feeder differential relay currents during initial fault - with lifted 5088 residual wire

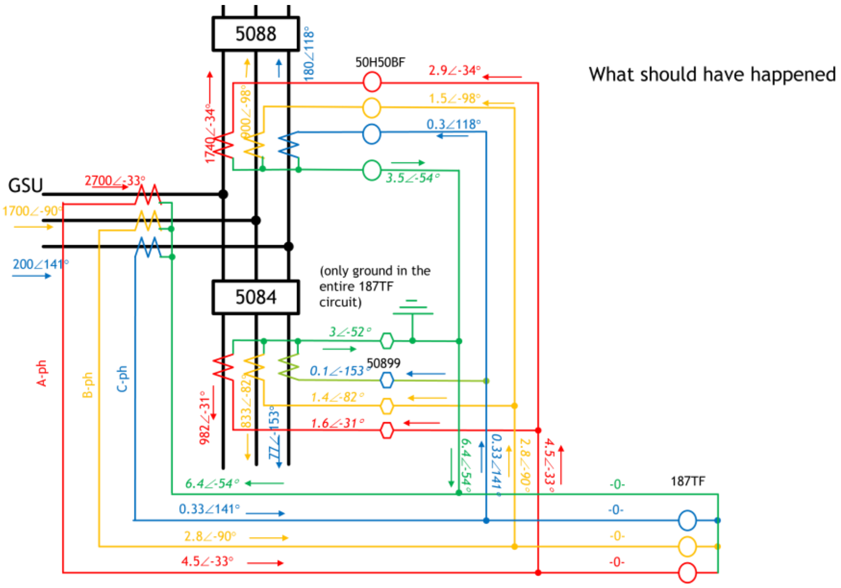

Figure 10. Unit 1 feeder differential relay currents during initial fault - with no lifted 5088 residual wire

An attempt was made to analyze the CT circuit to see if there was any possibility of CT saturation due to the open residual circuit (see Figure 11). It can be seen from the currents shown that a potential path for the relay current was possibly through the magnetizing branch of the A-phase CT in 5088. So instead of 2.9A reaching the relay, only 1A from 5088 was sent to the relay, contributing to a false differential current and the subsequent misoperation.

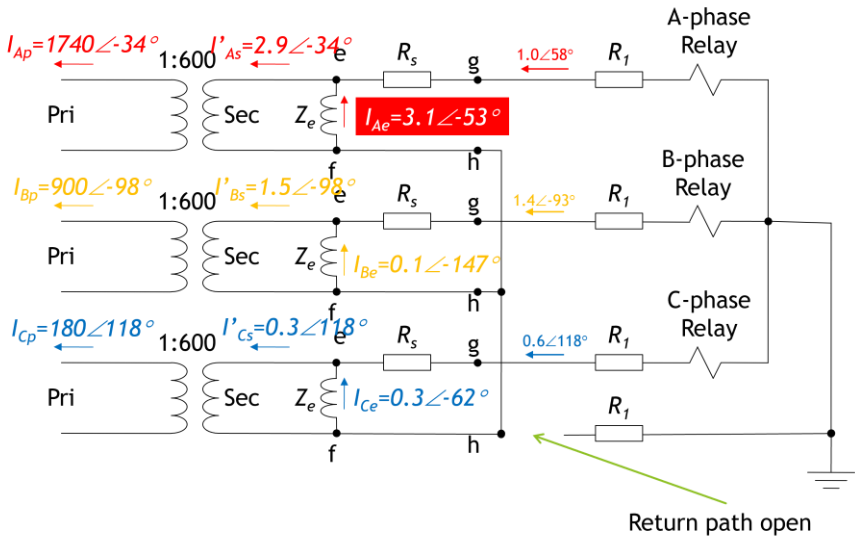

Figure 11. Effect of open residual circuit (NOTE: Contribution of 5088 only to the differential relays shown)

The reason this was not caught during the secondary injection test is that the non-polarity terminal of the current test source is connected to chassis ground which is tied to the station ground mat through the three-prong power supply plug of the test set. See Figure 12. When current was injected in A-phase of the 5088 CT secondary circuit, the current passed from the yard through the cable to the control building, through the A-phase relay, returning through the single house ground to the station ground mat. So, the test set return ground was a false path.

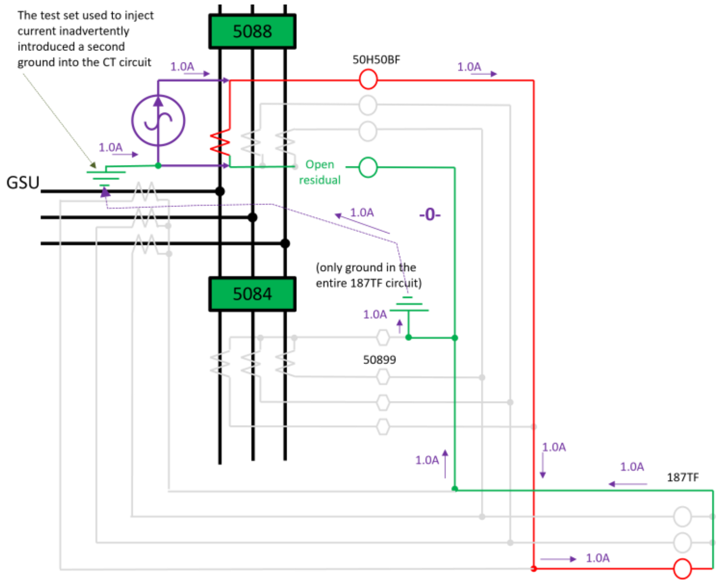

Figure 12. Secondary injection test that "passed"

C. Plant W 5024/5028 terminal slow clear

The Plant W 5024/5028 terminal took 16 cycles to clear the initial fault and took 9 cycles to clear the subsequent fault. Both sets of static relays had targets (PH/G/T1/T2/T3/T4). Fault data was available from the station digital fault recorder, which revealed the faulted phase voltage sagged to about 71% of nominal, with faulted phase current of 4690A and residual current of 4500A. The fault angle was 26 degrees, indicative of the 19-ohm resistive fault.

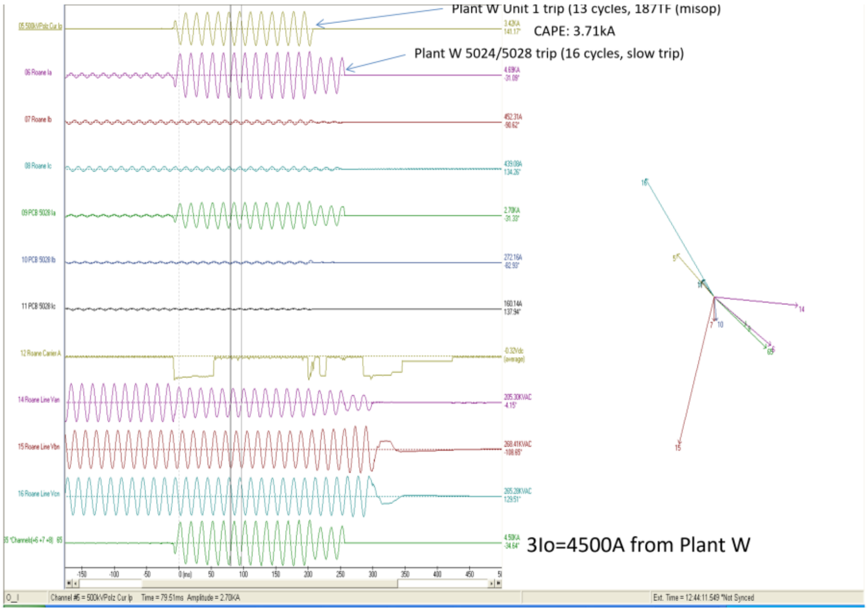

Figure 13. Initial fault DFR shot at Plant W, Substation R line quantities

Recall that primary ground fault protection is provided by the overreaching ground distance MTG mho elements (set for 32 ohms primary with 75-degree maximum torque angle (MTA)) supervised by the G2 ground fault detector (set for 300A primary 3Io), along with the G4 instantaneous ground overcurrent element (set for 10400A primary 3Io). The backup element in the electromechanical ground relay was set for 7200A.

With the residual current being 4500A, neither the G4 nor the backup ground IOC could have operated.

But it was expected the ground distance element should have. It should be noted that the G2 element is a residual ground fault detector only; it is NOT a sensitive ground directional overcurrent element. The only remaining tripping element is the MTG mho ground distance element. And it can be seen from Figure 14 that the resistive reach of the static mho characteristic is about 20 ohms primary.

The fault information was used in the short-circuit program and the apparent impedance seen by the ground distance was plotted (see Figure 14, left plot). Even with dynamic expansion of the mho element, the measured impedance is initially just outside the characteristic.

However, after the misoperation of the Unit 1 feeder and subsequent loss of fault current contribution from that source, the apparent impedance DID fall just inside the expanded mho characteristic (see Figure 14, right plot).

Thus, it was concluded that the limited resistive coverage of the MTG ground distance element was the reason for the slow trip.

If Unit 1 had not tripped (erroneously), the only remaining protection would have been the ground time overcurrent element in the electromechanically backup ground relays. At Plant W, the ground time overcurrent element was set for 480A primary (0.8A secondary) with a 2.5-time dial and a very inverse characteristic; 4500A of 3Io is almost 950% of pickup for an operating time of about 25 cycles.

Finally, note that the trip time of 10 cycles on the 2nd fault was likely slow due to the apparent impedance being just inside the expanded mho characteristic.

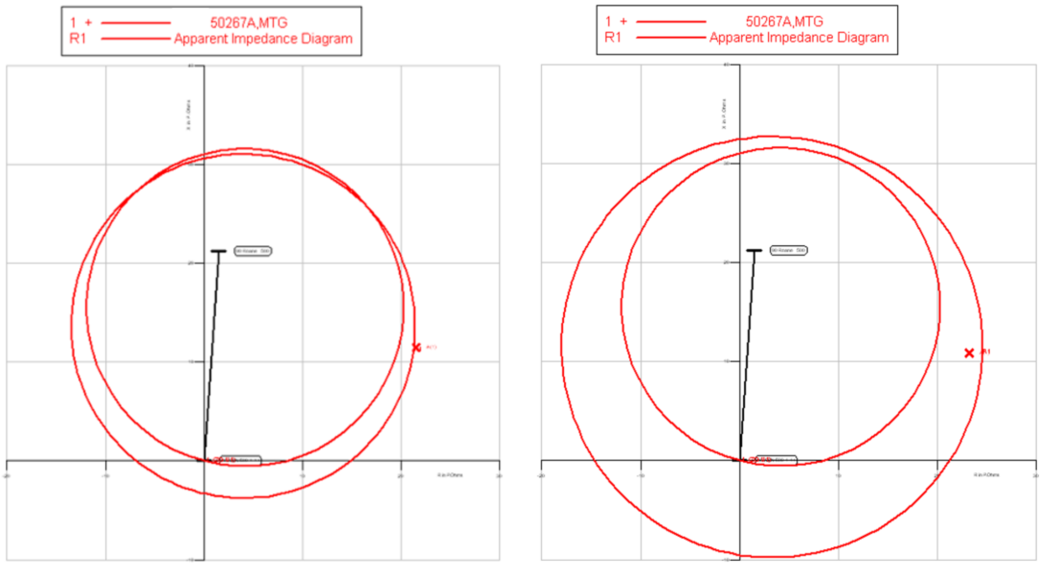

Figure 14. R-X plot, SLYG ground distance element, Initial fault, Plant W terminal (each major division = 10 ohms primary) (left=Initial fault, right=after Unit 1 trip)

D. Substation R 5038/5048 terminal slow clear

The Substation R 5038/5048 terminal cleared in 18.5 cycles on the initial fault (2.5 cycles after the Plant W terminal operated) but took only 2.5 cycles on the subsequent fault. The only target was directional ground instantaneous overcurrent (electromechanical). Neither set of static relays had targets. As previously stated, the 500kV DFR at Substation R was off-line for this event, so the contribution from this terminal was estimated using the short circuit program (about 4100A primary 3Io).

At this terminal, the MTG mho elements are also set for 32 ohms primary with 75-degree MTA supervised by the G2 ground fault detector also set for 300A primary 3Io, with the G4 instantaneous ground overcurrent element set for 24000A primary 3Io. The backup element in the electromechanical ground relay was set for 4200A.

Given the single-ended fault information, the apparent impedance seen by the ground distance at this terminal was plotted. Once again, even with dynamic expansion of the mho element, the measured impedance is initially just on the edge of the characteristic (Figure 15).

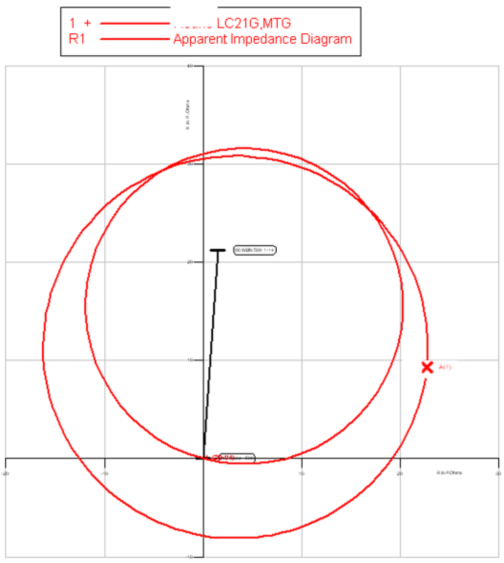

Figure 15. R-X plot, SLYG ground distance element, Initial fault, Substation R terminal

Even after Unit 1 tripped at Plant W, the apparent impedance was only slightly inside the expanded mho characteristic. But after the Plant W line terminal tripped, the apparent impedance was well within the characteristic. See Figure 16.

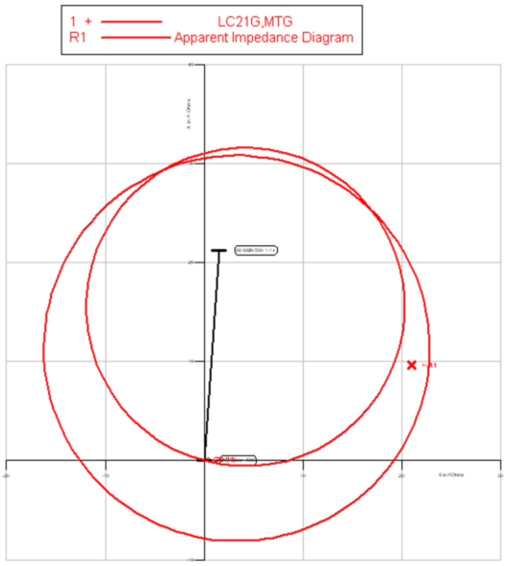

Figure 16. R-X plot, SLYG ground distance element, Initial fault, Substation R terminal (left=after Unit 1 trip, right=after Plant W terminal trip)

With no targets on the static relays at Substation R, and only the backup ground IOC target, we concluded that the SLYG ground distance element would have operated after Plant W terminal opened but the ground IOC element beat it. We had no record of the actual current contribution from this terminal, but the short circuit program estimated 5600A which was over the 4200A pickup.

Similarly with the Plant W terminal, if Unit 1 had not misoperated, the backup ground time overcurrent element would have likely had to operate at Substation R. At that terminal, the ground time overcurrent element was set for 360A primary (0.6A secondary) with a 2.5-time dial and a very inverse characteristic; 4100A of 3Io is over 1100% of pickup for an operating time of about 25 cycles.

So total clearing without the Unit 1 misoperation would have been roughly 25 cycles at each terminal.

Finally, note that the trip time of 2.5 cycles on the 2nd fault was due to the fact that Unit 1 at Plant W had tripped and locked out. The estimated fault current in this configuration was only about 4500A, which is only 108% of the 4200A pickup. So, it is either a case of the ground IOC element having a slightly lower actual pickup, or the static relays at Substation R actually operated but did not drop a target.

V. Philosophy of Resistive Ground Fault Coverage

TVA philosophy for ground faults calls protection elements with sensitivity that can detect up to 40 ohms of fault resistance. This is based on years of experience.

The actual practice for setting ground time overcurrent and carrier ground overcurrent element pickups starts with 1000% sensitivity for a bolted ground fault at the remote bus, then checking that pickup to provide at least 200% sensitivity for a remote line-end open 40-ohm ground fault.

The ground time overcurrent elements at both terminals of the Substation R-Plant W line followed this practice, but there was no sensitive carrier ground trip element in the static relays in the pilot scheme, only a supervisory overcurrent element (G2). The ground distance reaches were mho elements simply set to overreach the positive sequence line impedance by about 125%, which provided a maximum resistive reach of about 20 ohms (not including dynamic mho expansion).

This is something to consider when using ground distance mho elements exclusively for transmission line ground fault protection.

Present TVA practice continues to implement the overreaching ground distance mho elements in pilot schemes, with the addition of a low set carrier ground overcurrent trip element providing the 40 ohms of resistive coverage.

VI. Conclusion

Based on analysis, the transmission line protection on the 500kV line operated properly, albeit in a non-preferred manner, for the high-resistance fault, assisted by dynamic mho element expansion.

The misoperation during this event was the trip of the GSU 1 500kV feeder differential, which was due to an open neutral (residual/return) wire in the CT circuit for one of the 500kV breakers.

It is interesting to note that if the 500kV line relaying had performed as expected with high-speed tripping (3 to 4 cycles) rather than the slow clearing, we may not have discovered the problem with the feeder differential, since it took 13 cycles to clear.

When performing secondary injection testing, the presence of test set grounds must be accounted for in the circuit analysis.

A philosophy of resistive ground fault coverage must be implemented understanding the available protection elements and ensuring they are set with adequate sensitivity.

References

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Biography

Gary Kobet is an Electrical Engineer for the Tennessee Valley Authority (TVA) in Chattanooga, Tennessee. His responsibilities include developing and maintaining operating guides and advising operators on system and equipment protection issues. He has performed stability studies and post-event disturbance analysis, and also provided oversight of TVA’s Phasor Measurement system and applications. He has also worked in the System Protection department scoping relaying schemes for transmission and generation projects, as well as developing relay set point calculations and performing electromagnetic transient studies. Previously he worked as a field engineer and as power quality specialist. Mr. Kobet earned the B.S.E. (electrical) from the University of Alabama in Huntsville in 1989 and the M.S.E.E. from Mississippi State University in 1996. He is a member of the IEEE/PES Power System Relaying and Control Committee and is a registered Professional Engineer in the state of Alabama.

George Pitts is an Electrical Engineer for the Tennessee Valley Authority (TVA) in Chattanooga, Tennessee. His responsibilities include program management of TVA’s system interconnection process with emphasis on solar and batteries at utility scale. George validates models using PSCAD. Previously he has worked in Operations Engineering performing outage analysis, nuclear offsite power, black start, and disturbance analysis. He has worked in Transmission Planning as a protection system specialist scoping transmission protection schemes. He has participated with NATF, NERC and SERC as an SME on protection systems. George has worked in the pulp and paper industry as a maintenance electrical engineer and a process control engineer. He also worked in the oil and gas pipeline industry as a project engineer. Mr. Pitts earned the B.S.E.E. degree from Mississippi State in 1993. He is a registered professional engineer in TN and a senior member of IEEE.