Lessons Learned: Protecting Lines without Communication-Assisted Tripping

Stephen Marx, P.E.
System Protection Engineer, Bonneville Power Administration

Brianne Young
Lead Electrical Engineer, ICF

With modern communication, relays on transmission lines can clear nearly all types of faults instantaneously. However, there are many lines that do not have communication. Because of this, the need to understand and protect lines without the additional aid of communication is still a major requirement. An initial understanding of basic protection – step distance, overcurrent protection, and residual ground current – is required. For parallel lines, the concept of Mutual Coupling will have to be considered. For three-terminal lines, the effect of apparent impedance will also be examined for impedance reach and current flow.

Section 1: Basic Protection

All transmission lines are terminated at substations, where the relays are located. A relay's zone of protection is from the relay location up to the next substation. It is desirable for the relay to operate as fast as possible for all faults between the two substations. For faults on the remote bus and further, delayed clearing would be required to allow for the remote relays to operate first for their zone of protection.

Phase distance relays use positive-sequence impedance to protect for three-phase or phase-to-phase faults on transmission lines. Similarly, ground distance relays use a combination of positive- and zero-sequence impedance calculations to protect for phase-ground faults. Overcurrent relays use current measurements to protect transmission lines, generators, and transformers based on expected fault currents. This paper focuses on the use of overcurrent and impedance distance relays for transmission lines.

1.A: Step Distance Protection

Distance relays use measured voltage and current to calculate the impedance of a fault. The impedance setting pickup, or reach, is based upon the percentage of the total impedance of the protected line, or the apparent impedance, as defined below, to the end of the desired protected zone. When the impedance to the fault is less than the reach setting of the relay, the distance relay will pick up and trip the breaker. There are typically two or three zones of protection set to the forward direction to trip for faults on the line and coordinate with, or back up for, faults on downstream lines. Figure 1 shows a simplified drawing using only two zones to protect the local line, while not tripping for faults on adjacent lines. Zone 1 is set such that it will not overreach the remote bus. This first zone of protection is set to trip as fast as possible for as much of the line as possible and must not overreach into the next line section. Zone 2 is set to cover the entire line with a short time delay to clear faults on the entire line, while coordinating with downstream relays. A check should be made to be sure that this Zone 2 setting does not overreach the Zone 1

setting of the next line section. If it does, Zone 2 will need to be time coordinated with the next line section Zone 2 [1]. In some cases, where Zone 2 cannot adequately overreach the end of the zone of protection, or where additional backup protection is desired, Zone 3 may be set for a longer forward reach and increased time delay. This third zone is common, and can be critical, in areas on lines where there is no communication tripping.

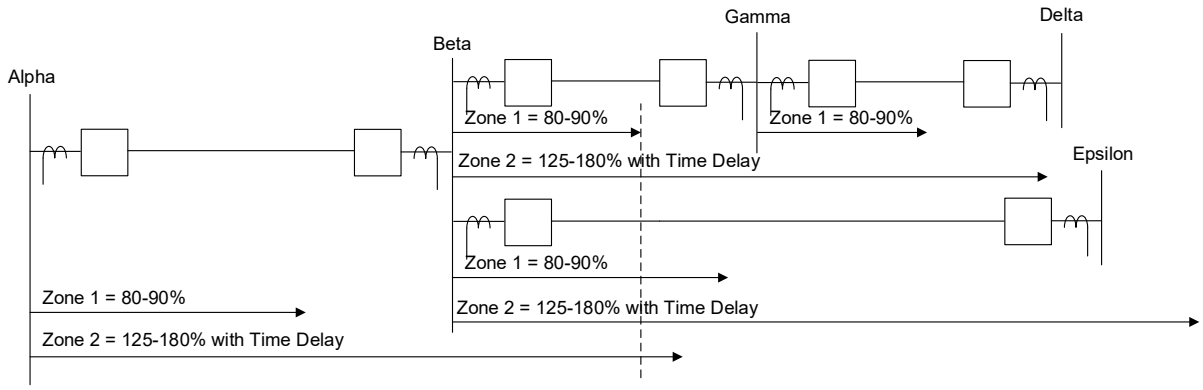

Figure 1 Step distance reach with two zones of protection

1.B: Current Protection

Faults or short circuits on a transmission line show excess current and low voltage. Short circuits near the generator end of the line cause heavy flow of current and a big dip in voltage, while faults some distance away have less of an effect. Protection of the transmission line can be accomplished by using either impedance protection or over-current protection, or by using a combination of the two.

1.C: Directional Overcurrent Ground

Under balanced three-phase conditions, the three phase currents sum to zero. However, with line to ground faults, the faulted phase current will be higher than the unfaulted phases, creating a current imbalance. The overcurrent ground relay operates on this residual current. Directional ground overcurrent protection uses zero-sequence quantities, usually supervised by directional elements. The current element is more sensitive than the ground distance element. From [1], coordination is typically based upon the maximum current contribution to the remote bus fault. The fault study to obtain this maximum coordinating fault current may resemble a remote bus fault with the two 'strongest' lines out. That is a line out for maintenance, and the faulted line opened at the other end with the fault being close in, on the line side of the remote bus breaker.

Section 2: Line parameters that affect protection

2.A: Apparent Impedance

The actual impedance of a line is calculated based on the parameters and configuration of the conductor. The impedance to a fault, calculated by the relay, is based upon voltage and current measured by the relay. For a three-terminal line, as shown in Figure 2 or a line with taps, the impedance to one of the remote buses, may not match the actual line impedance due to the voltage and currents affected by infeed from taps between the relay and the fault. This impedance as seen by the relay is called the "Apparent Impedance". The impedance "seen" by a

distance relay is not always the actual line impedance from a relay terminal to the point of fault [2]. For a two terminal line the actual impedance will equal the apparent impedance.

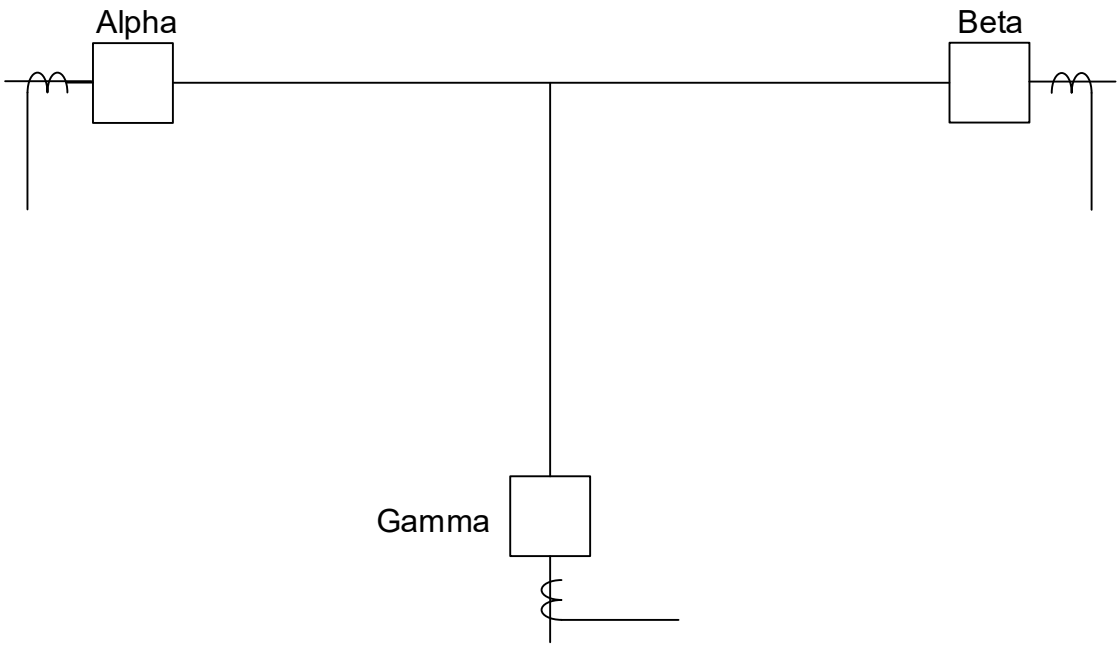

Figure 2 Sample drawing of a three-terminal line

The setting of Zone 1 and Zone 2 of a three-terminal line requires several calculations to determine the apparent impedance to each remote terminal as seen by the relay. Using the 3-terminal line shown in Figure 2, to determine the Zone 1 and Zone 2 settings at substation Alpha, four separate impedance calculations are required. The four calculations are: the apparent impedance to a bus fault at Beta, the apparent impedance to a line end fault at Beta, the apparent impedance to a fault at Gamma, and the apparent impedance to a line end fault at Gamma. The apparent impedance to Beta with Gamma breaker open should be equivalent to the actual impedance from Alpha to Beta. The Zone 1 setting must be set to the lowest calculated impedance to ensure that Zone 1 does not overreach either remote bus. On a three-terminal line, the actual impedance is usually lower than the apparent impedance. The apparent impedance will be used to ensure Zone 2 will overreach both remote buses. It is recommended that Zone 2 setting should not be less than 130% of the largest of the four above calculations. Verification also needs to be made that Zone 2 does not overreach any Zone 1 setting of lines leaving Beta when Gamma terminal is opened.

Zone 1 and Zone 2 settings at station Beta and Gamma would be made in the same manner. Therefore, no less than 12 calculations may be required for a three-terminal line.

According to [3], apparent impedance is defined as the ratio between the voltage and current in the injection point. The apparent impedance at the relay can be calculated two ways:

The apparent impedance is equal to the impedance of the Alpha line to the tap, plus the impedance of the Beta line to the tap multiplied by the current from Alpha and Gamma summed and divided by the current from Alpha.

$$Z_{apparent} = Z_{AlphaTap} + Z_{BetaTap}\frac{(I_{Alpha}+I_{Gamma})}{I_{Alpha}} \quad \text{Eq 1}$$

or

Calculate a three-phase fault at Beta. The apparent impedance is equal to the phase-ground voltage, divided by the phase current at the relay.

$$Z_{apparent} = \frac{E_{phase-ground}}{I_{Phase}} \quad \text{Eq 2}$$

Looking at the example for Figure 3 and using equation 1, the authors would like to propose two different scenarios.

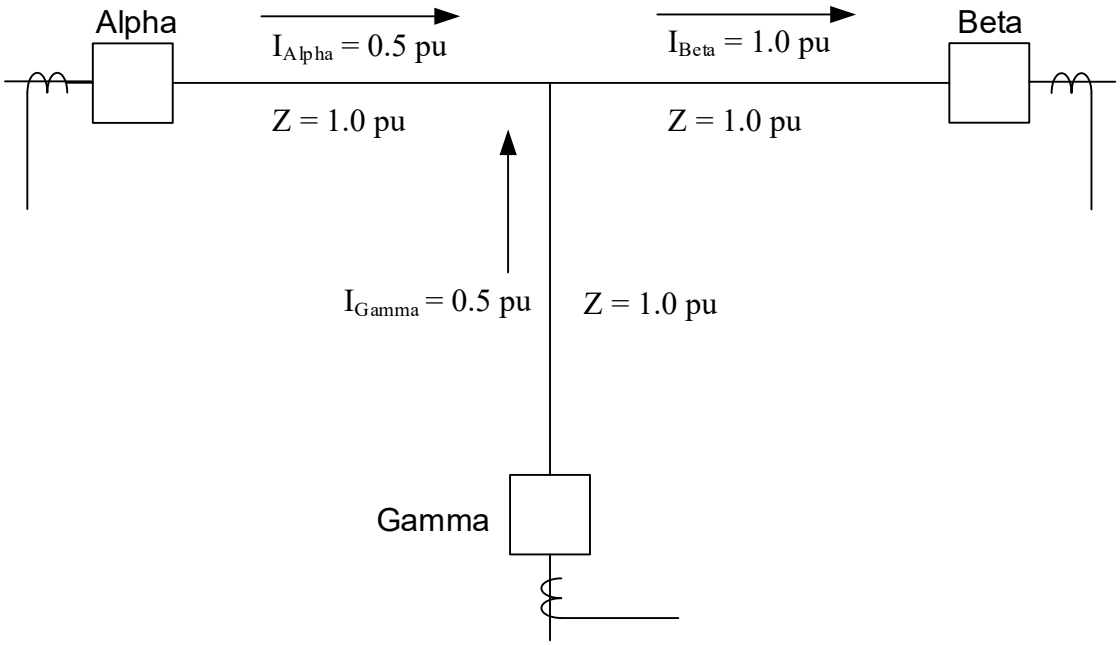

Figure 3 Example of current infeed from a three-terminal line with the system normal

Scenario 1: Apparent impedance seen at Alpha to a bus fault at Beta

For a setting example, set the Zone 1 and Zone 2 to 85% to not overreach the next line section, and 130% to ensure overreach of next line section, respectively, to Beta using the actual per unit line impedance from Alpha.

$$Z_{zone1} = 85\% * Z_{Actual}$$

$$Z_{zone1} = 85\% * 2.0pu = 1.7\ \Omega pu$$

$$Z_{zone2} = 130\% * Z_{Actual}$$

$$Z_{zone2} = 130\% * 2.0pu = 2.6\ \Omega pu$$

Using equation #1, calculate the apparent impedance at Alpha substation.

$$Z_{apparent} = Z_{AlphaTap} + Z_{BetaTap}\frac{(I_{Alpha}+I_{Gamma})}{I_{Alpha}} \text{ Eq 1}$$

$$Z_{apparent} = \left[1.0 + 1.0\frac{(0.5+0.5)}{0.5}\right]pu$$

$$Z_{apparent} = 3.0pu$$

Setting the reach based on actual line impedance, then comparing the reach to the apparent impedance, Zone 1 and Zone 2 will reach 56% and 86% respectively. Therefore, Zone 2 will underreach Beta substation.

From scenario 1 above, it is shown that apparent impedance needs to be considered and not overlooked. Using the recommended setting reach above, the new Zone 1 and Zone 2 are given in equation 2 and 3:

$$Z_{zone1} = 85\% * Z_{Actual}$$

$$Z_{zone1} = 85\% * 2.0pu = 1.7\ \Omega pu \text{ Eq 2}$$

$$Z_{zone2} = 130\% * Z_{apparent}$$

$$Z_{zone2} = 130\% * 3.0pu = 3.97\ \Omega pu \text{ Eq 3}$$

When the breaker at Gamma is open, the Zone 1 and Zone 2 relays at Alpha will reach 85% and 195% respectively to Beta. A check needs to be made on the Zone 2 setting to verify that it does not overreach the Zone 1 settings leaving Beta station. If it does, the Zone 2 element will need to be time coordinated with the next line sections Zone 2.

The relays at Gamma will be set the same as Alpha.

$Z_{zone1} = 1.7\ \Omega pu$ and $Z_{zone2} = 3.97\ \Omega pu$.

Scenario 2: Apparent impedance to a line end fault

The next comparison will be for a line end fault at Beta station, as illustrated in Figure 4. In this case, a close-in fault to Beta will cause the Zone 1 impedance relay at Beta to operate

instantaneously. Then assume the current from Alpha stays the same at 0.5 pu, and the current contribution at Gamma increases by 0.5 pu from current redistribution.

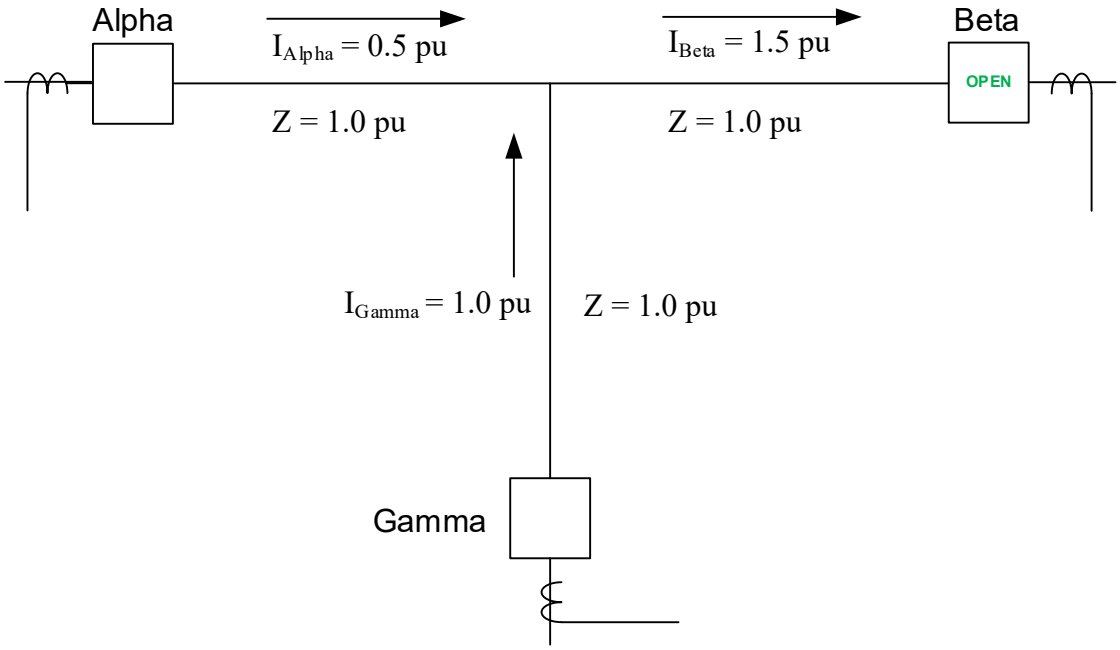

Figure 4 Example of current infeed from a three-terminal line with the line end breaker open

The apparent impedance at Alpha towards Beta with the new current distribution is calculated in equation 4:

$$Z_{apparent} = Z_{AlphaTap} + Z_{BetaTap}\frac{(I_{Alpha}+I_{Gamma})}{I_{Alpha}} \quad \text{Eq 1}$$

$$Z_{apparent} = \left[1.0 + 1.0\frac{(0.5 + 1.0)}{0.5}\right]pu$$

$$Z_{apparent} = 4.0pu \text{ Eq 4}$$

The apparent impedance at Gamma, using the same contribution to Beta, for a line end fault at Beta is calculated in equation 5:

$$Z_{apparent} = Z_{GammaTap} + Z_{BetaTap}\frac{(I_{Gamma}+I_{Alpha})}{I_{Gamma}} \quad \text{Eq 1}$$

$$Z_{apparent} = \left[1.0 + 1.0\frac{(1.0 + 0.5)}{1.0}\right]pu$$

$$Z_{apparent} = 2.5pu \quad \text{Eq .5}$$

With the Alpha relay set to $Z_{zone1} = 1.7\ \Omega pu$ and $Z_{zone2} = 3.97\ \Omega pu$, for the initial fault, Zone 2 will pick up and start timing. When the breaker at Beta opens, the apparent impedance at Alpha will increase, and Zone 2 will drop out and stop identifying the fault. The relay at Gamma will time out after 0.5 seconds and open the breaker. After Gamma opens, the apparent impedance at Alpha will change to 2.0 ohms. Zone 2 will pick up again, start timing and trip in 0.5 seconds, or 1.0 seconds from the initial fault.

2.B: Mutual coupling

Parallel transmission lines, where two or more lines share a common corridor, either on separate towers or a double-circuit on one tower, are common globally. Parallel lines are mutually coupled together because of the alternating magnetic flux generated by the other parallel circuit, or by the self-generated magnetic flux [4].

There are many books and papers written on mutual coupling which explain the math behind the magnetic mutual coupling, or the electromagnetic flux linkage equations. Many papers also cover how zero-sequence current depends on factors such as earth return, tower footing, and fault impedances all by sharing the same transmission right of way [4]. This paper will not cover these details but will introduce mutual coupling and give two examples of what can happen when it is ignored.

As mentioned in [1] and [5], magnetic mutual coupling affects the zero-sequence network. Ground directional overcurrent elements respond to zero-sequence quantities and can be affected by mutual coupling. One solution to this problem is using line current differential schemes [3]. When the line does not have communication aided tripping, then other considerations are required.

Transmission lines start and stop at a substation. Figure 5 shows examples of different configurations of parallel lines. The set of lines can start at the same substation and end at the same substation (Figure 5), start at the same substation and end at different substations (Figure 6), or start at different substations and end at different substations (Figure 7). The parallel path may be the entire length of both lines as shown in Figure 5, or partially parallel as shown in Figures 6 or 7.

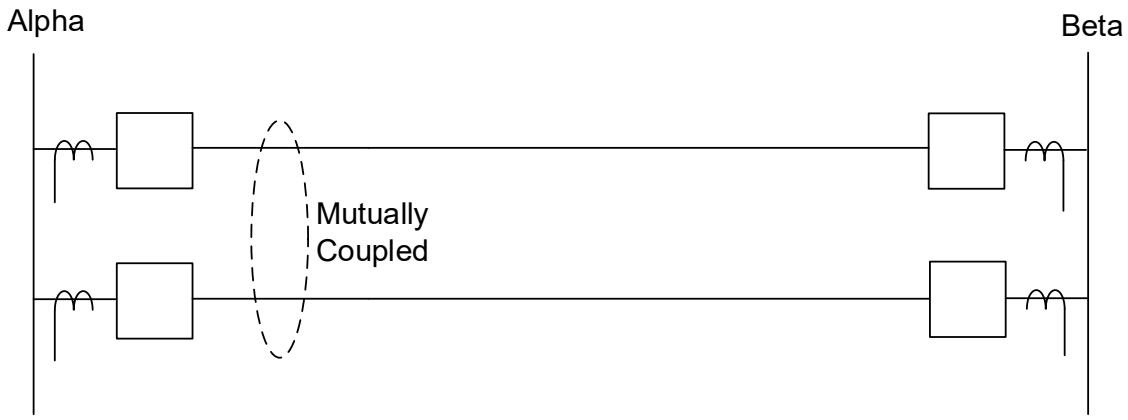

Figure 5 Mutually coupled lines that start and end at the same substations

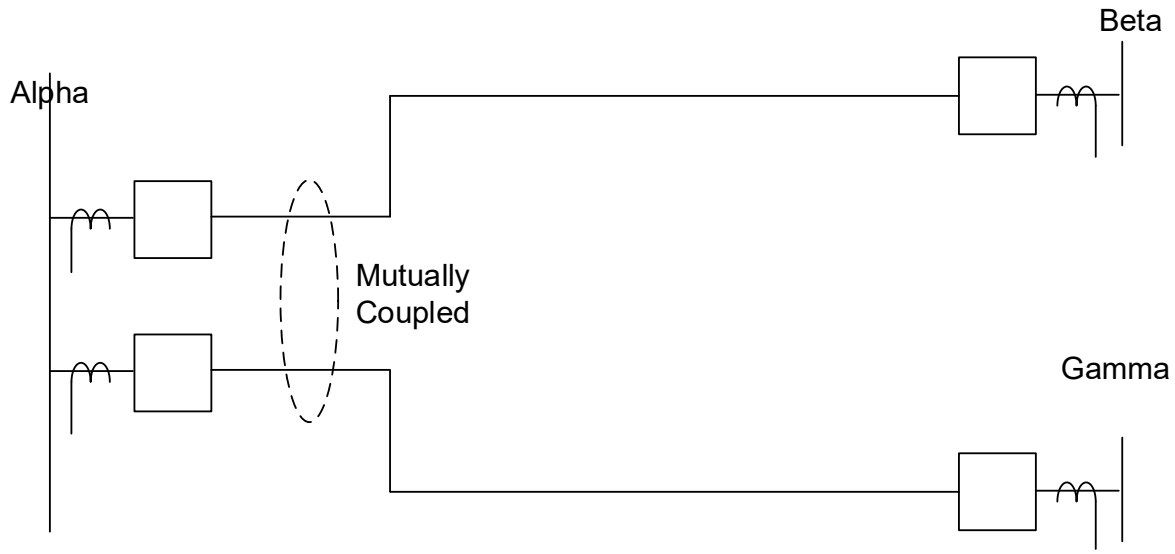

Figure 6 Mutually coupled lines that start at one substation and end at different substations

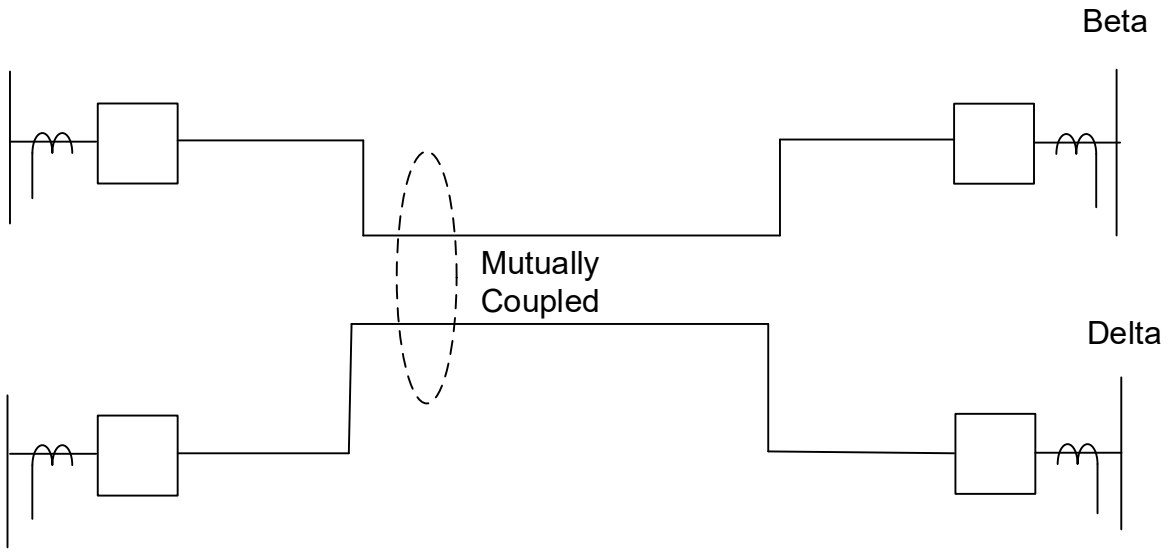

Figure 7 Mutually coupled lines can start at different substations and end at different substations

The ground overcurrent pickup should be set based on the maximum external fault current. Typically, this value would be for a fault at the remote bus, with a line removed out of the remote bus. The lessons learned examples reviewed below will show that this value could be found several miles down a mutually coupled line.

Section 3: Lessons Learned

3.A: Faults on Lines with Apparent Impedance

Three-phase fault on the Swan Valley – Teton #1 Aug 6, 2023

On August 6, 2023, there was a three-phase fault on Swan Valley – Teton #1 line, which has a tapped line to Targhee, as shown in Figure 8.

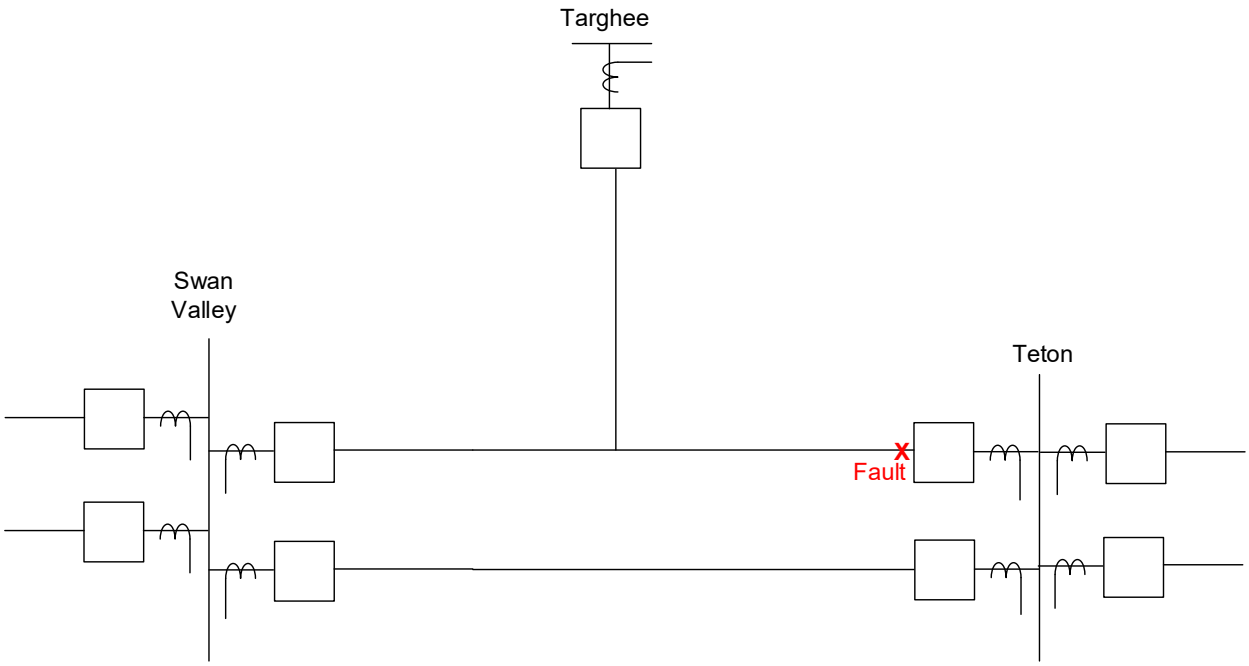

Figure 8 System configuration for location of three-phase fault

The settings on this line at the time of the fault were as follows:

Table 1 Setting for Teton, Swan Valley and Targhee

	Teton		Swan Valley		Targhee		
	Zone 1	Zone 2	Zone 1	Zone 2	Zone 1	Zone 2	Zone 3
Impedance Reach	2.43 Ω	6.18 Ω	2.38 Ω	5.89 Ω	1.51 Ω	4.10 Ω	5.33 Ω
Time Delay	0 cycles	30 cycles	0 cycles	30 cycles	0 cycles	30 cycles	60 cycles

The location of the fault was 2.07 miles from Teton. The initial fault impedance at each station is referenced in table 2, along with each change of impedance following the sequence of events below.

The initial impedance values place the fault within the Zone 1 protection of Teton and Zone 2 protection of Swan Valley and Targhee. When the fault occurred, the Teton Zone 1 instantaneous element picked up. Swan Valley's Zone 2 picked up and initiated the Zone 2-time delay of 30 cycles. Targhee picked up Zone 2 and Zone 3, set for 30 cycles and 60 cycles delays for tripping, respectively.

Teton tripped instantaneously and cleared the fault in under three cycles (Figure 9). The fault current shifted, causing an increase in current at Swan Valley (Figure 10) and a decrease in current at Targhee (Figure 7.3). The change in current at Swan Valley and Targhee changed the apparent impedance seen by the relay at both stations.

With the change in impedance, Swan Valley tripped in 30 cycles from the initial fault. However, the increased impedance at Targhee dropped out the Zone 2 element.

After Swan Valley opened, the fault current shifted to the Targhee bus (Figure 11). The increase in current lowered the apparent impedance, picking up Zone 2 a second time. The relay tripped for a Zone 2 and Zone 3 fault 60 cycles after the initial fault.

Table 2 Breaker opening time and apparent fault impedance

Time	Teton	Swan Valley	Targhee
t=0, initial fault	0.20 Ω	4.23 Ω	3.24 Ω
t=3cyc, Teton opens	open	3.76 Ω	4.17 Ω
t=30cyc, Swan Valley opens	open	open	2.09 Ω
t=60cyc, Targhee opens	open	open	open

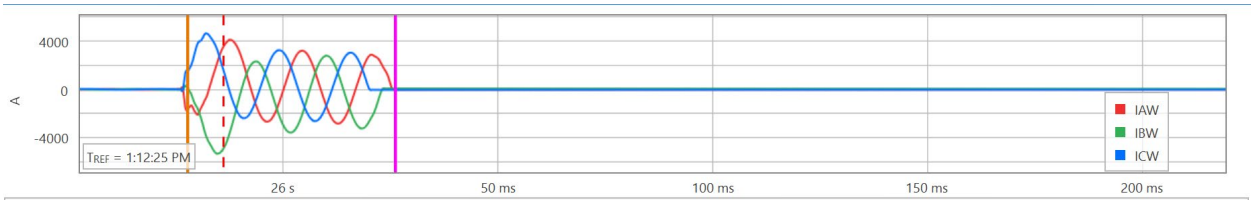

Figure 9 Teton substation event oscillography

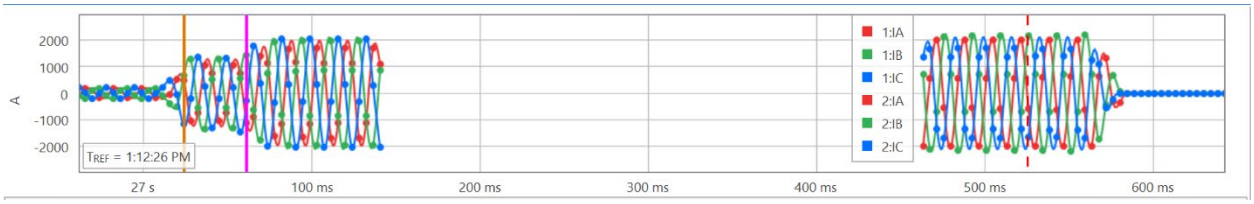

Figure 10 Swan Valley substation event oscillography

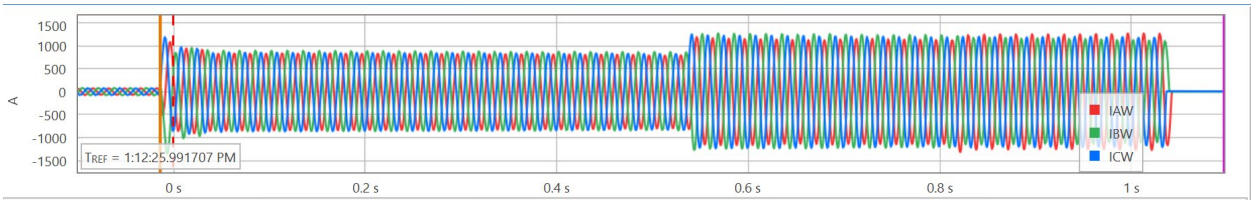

Figure 11 Targhee substation event oscillography

In summary, the relays operated as explained in the theory of apparent impedance and described above. Teton tripped Zone 1 instantaneously in 3 cycles. Swan Valley tripped Zone 2 within 30 cycles. Targhee tripped Zone 2 and Zone 3 within 60 cycles.

3.B: Faults for Mutual Coupling

Fault #1

On December 17, 2013, there was a single-line to ground fault on the Goshen – Drummond line. The fault location was at 29% of the line from Goshen, which is illustrated in Figure 12. The sequence of events was as follows: Drummond opened first; then, 36 milliseconds later, Swan

Valley opened; followed by Goshen opening 2 milliseconds after Swan Valley. The fault should have been isolated between Goshen and Drummond. The question to consider is why did Swan Valley trip?

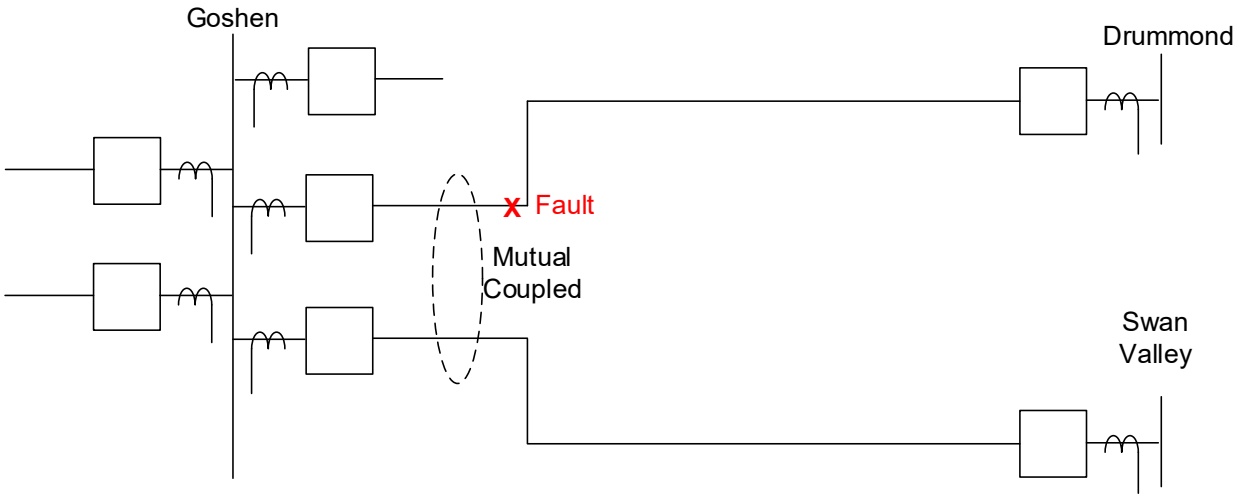

Figure 12 Fault on a mutually coupled line

The fault analysis started by looking at the data from the relays and comparing the known values to the predicted fault current from the fault simulator program. Table 3 shows both sets of fault current.

Table 3 Ground fault current for fault on mutually coupled line

Ground Fault Current	Goshen	Swan Valley
Measured by relay during fault	2645 A	539 A
Calculated using short circuit program	2850 A	653 A

In the original settings, Swan Valley was set to 150% of a bus fault at Goshen all lines normal. The short circuit fault current was 347 A, setting the relay to 520 A. The fault current at the time of the fault was 539 A, which is above the pickup of the relay.

After analyzing the fault event, it was discovered that the Goshen – Drummond line and Goshen – Swan Valley line are mutually coupled. Figure 13 shows the percentage of coupling along the two lines. The figure shows a reference from Drummond to Goshen being mutually coupled from 70.861% to 100% of the line. The study for faults from the Goshen bus equates to 0% to 29.139% from Goshen to Drummond.

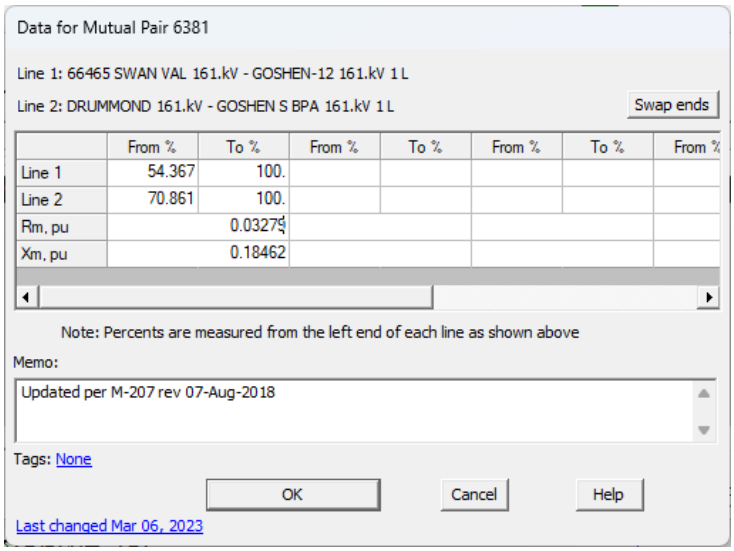

Figure 13 Percentage of mutual coupling

Considering mutual coupling, the current change for faults along the line was evaluated and it was shown that the current dropped as the distance increased from Swan Valley to Goshen. However, on the mutually coupled line, the fault current increased as the short circuit fault was moved from Goshen towards Drummond. Table 4 shows faults run at 5% increments from Goshen towards Drummond in the short circuit program. The fault current from Swan Valley to a Goshen bus fault is the same as a close in fault on the Goshen – Drummond line. The fault current then increases to a maximum at 29% of the Goshen – Drummond line. This point was the ending point where Goshen – Swan Valley and Goshen to Drummond is mutually coupled.

Table 4 Single line to ground fault current on Goshen – Drummond line in 5% increments

Fault on Goshen to Drummond line	Fault current at Swan Valley
Close-in to Goshen	359
5%	456
10%	517
15%	563
20%	603
25%	641
30%	653
35%	553
40%	477
45%	417
50%	367
55%	326
60%	291
65%	261
70%	234

75%	209
80%	187
85%	166
90%	147
95%	128
Drummond Bus	109

It is interesting to observe that the maximum current on the Goshen – Drummond mutually coupled line is at the end of where the two lines are mutually coupled, or approximately 29%.

Because of the mutual coupling, the coordinating fault for the instantaneous overcurrent ground element should be set for 135% of the maximum external fault current, which is found to be at 29% of the adjacent, mutually coupled line, rather than the fault current at the remote end bus. The new setting should be 135% of 653 A, or 881 A. As a follow up, the short circuit fault value in 2024 is now calculated to 1100 A.

As part of the lesson learned from this fault, similar evaluations were performed for the lines mutually coupled looking from the other direction, as well as other mutually coupled lines in this area. Other relays needed adjustments to their ground overcurrent instantaneous pickups, as well.

Fault #2

Three years later, on July 4, 2016, there was a single line to ground fault on the Swan Valley – Teton #2 line. The relays at Swan Valley and Teton tripped on the Swan Valley – Teton #2 line as expected. The relays at Targhee on the Swan Valley – Teton # 1 line also tripped. Figure 14 shows the unique configuration of these lines. Again, the question to consider is why did Targhee trip outside of its zone of protection?

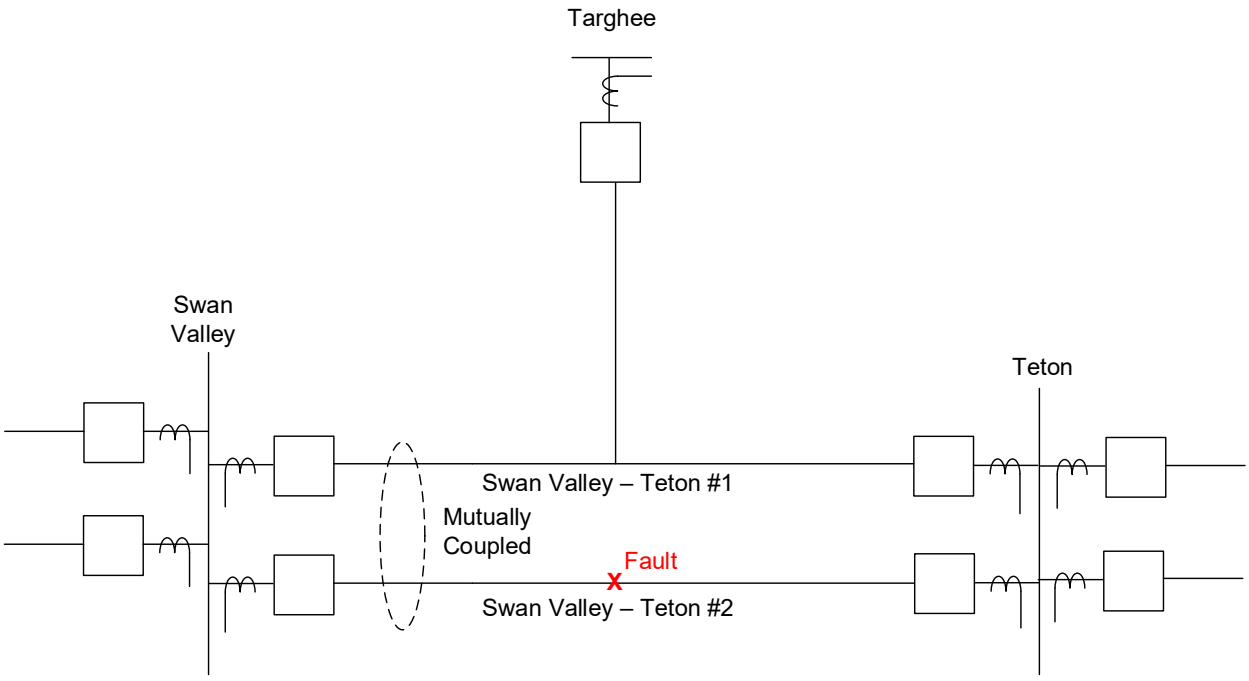

Figure 14 Fault on line parallel to three-terminal line

Under normal practice, the instantaneous overcurrent ground element at Targhee would be set based on the higher bus fault for either Swan Valley or Teton. The fault simulator program calculates the maximum fault current at the Swan Valley and Teton bus to 268 A and 325 A respectively. The pickup was set to 135% of the maximum fault current, for an N-1 fault or 438 A. The relay at Targhee measured a fault current of 445 A.

The Swan Valley – Teton #1 line is mutually coupled for 100% of the Swan Valley – Teton #2 line. The Targhee tap is location at 49.36% from Teton on the #1 line. Even though the Targhee tap portion of the line is not mutually coupled to any other line, mutual coupling between the main lines should have been considered when running the fault study to find the maximum external fault.

Table 5 shows faults run at 5% increments from Swan Valley towards Teton, on the #2 line, in the short circuit program.

The maximum short circuit fault current at Targhee is 389 A for a fault 50% from Swan Valley on the Swan Valley – Teton #2 line. This number does not exactly match the actual fault current of 445 A. Studies were required to adjust the short circuit program. The coordinating fault current at Targhee should have been set to 135% of 389 A, or 525 A. It is interesting to observe that instead of the maximum fault being at the end of the mutually coupled sections of the line, it is at the same location as the tap.

Table 5 Single line to ground faults current on Swan Valley – Teton line in 5% increments

Fault on Swan Valley to Teton line	Fault current at Swan Valley
Swan Valley Bus fault	228
5%	245
10%	260
15%	275
20%	290
25%	305
30%	320
35%	337
40%	355
45%	374
(Targhee Tap point) 50%	389
55%	370
60%	354
65%	341
70%	330
75%	321
80%	314
85%	308
90%	305
95%	302
Teton Bus fault	301

Section 4: Conclusion

While communication aided tripping can help in solving the issues discussed in this paper, understanding fundamental coordination concepts is necessary for addressing scenarios where communication between line relays is unavailable or existing communication is lost.

Multiple terminal lines will be affected by apparent impedance. As shown above, the apparent impedance may not equal the actual line impedance of the conductors. From the example, it was revealed that for a close in fault at the remote substation, the other two terminals were impacted differently. Depending upon current flow after the first breaker opens, the current and voltage at the remaining terminals will shift, potentially causing protection elements to change state.

Ground faults will be affected by mutual coupling between lines. As described in the paper, mutual coupling can cause the maximum coordinating fault to be found several miles away on the mutually coupled line. It was observed in the examples that the maximum coordinating fault was found at the end of where the two lines were mutually coupled and on the line opposite the tap point of the third terminal. Given the dynamics of different line configurations, it would be diligent to check for mutual coupling and run short circuit fault study along entire length of mutually coupled portions of lines.

Section 5: References

[1] A. D. Cathcart, BPA Relay Setting Guidelines
[2] G. E. Alexander, J. G. Andrichak, "Application of Phase and Ground Distance Relays to Three Terminal Lines' GE Protection & Control"
[3] Atle Rygg, Mohammad Amin and Marta Molinas, "Apparent impedance analysis: A new method for power system stability analysis.
[4] A. Brahman, "Analytical Technique to Evaluate Impact of Mutual Coupling on Transmission Line Protection Schemes", Presented to the faculty of graduate school of The University of Texas at Arlington in Partial Fulfilment of the Requirements for the degree of Master of Science November 2017.
[5] D. A. Tziouvaras, H. J. Altuve and F. Calero, Protecting Mutually Coupled Transmission Lines: Challenges and Solutions.

Section 6: Biographies

Stephen Marx received his BSEE from the University of Utah in 1988. He joined Bonneville Power Administration (BPA) in 1988 where he is presently the District Engineer in Idaho Falls, Idaho. He has over 35 years of experience in power system protection and metering and has been a lecturer at the Hands-On Relay School in the state of Washington since 2007. He has authored and coauthored several technical papers. He is a registered professional engineer in the state of Oregon and a member of the IEEE.

Brianne Young is a Lead Electrical Engineer at ICF, as part of the Grid Engineering & Analytics, Protection & Compliance team. She coordinates projects for Utilities, specializing in transmission line protection and fault analysis. She mentors junior engineers, overseeing relay settings development and deliverables. Prior to joining ICF, she worked for Bonneville Power Administration (BPA) as a Field Engineer responsible for protective relay settings and fault analysis. She received her BSEE from the University of Washington.