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Analysis of Directional Protection on distribution feeders for DER interconnection and its performance during Multi-Fault Events

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SUMMARY

While the increased penetration of distributed energy resources (DERs) brings many benefits to electrical grids and customers, it can lead to some technical challenges in protection systems. Impacts of DERs on the protection schemes in distribution networks have been reported in the literature. This paper aims to introduce and discuss a new case in which overcurrent protection directional elements are challenged during a combination of unique (rather rare) system events.

One such event occurred on the Alberta system in 2021, in which multiple faults occurred on a distribution system. Suspected lightning activity caused simultaneous faults on three separate feeders which were all connected back to the same substation. One of the three feeders was equipped with directional overcurrent protection to accommodate a DER connection on the feeder. While the two feeders with no DER connection had their faults successfully cleared by their respective protection devices, the protection relay for the feeder with the DER connection failed to detect the downstream fault which fell within its zone of protection. The cause of this was determined to be unanticipated declarations by the directional element on the relay. The failure of this relay to operate and clear the fault resulted in backup protection being forced to operate and trip off all load at the substation, creating a more significant customer interruption than otherwise would have been necessary. In addition, the complex nature of the event created initial uncertainty as to whether the unexpected operation was due to a failure of the relay to operate correctly, or due to some other cause.

In this paper the event above will be described in detail and the behavior of the protection devices involved will be reviewed. A determination as to whether the relays performed as expected is made, and a discussion ensues as to whether the performance is considered to be acceptable given the unique circumstances of the event and probability of re-occurrence. Possible changes to settings philosophies in the backdrop of increasingly widespread DER penetration are discussed.

KEYWORDS

directional element, feeder fault, negative sequence impedance

1. Introduction

Integration of distributed energy resources (DERs) in distribution networks has dramatically increased in recent years. While high penetration of DERs brings many benefits to electrical grids and customers, it can lead to some technical challenges in protection systems. Adverse impacts of DERs on the protection schemes of distribution networks have been reported in the literature. For example, reduction of substation feeder protection reach when DERs are present are discussed in [1]–[2]. Desensitization of feeder overcurrent protection in presence of DERs that can lead to blindness of protection to faults on a portion of the feeder is discussed in [3]-[5]. This paper aims to introduce and discuss a new case of overcurrent protection desensitization due to use of directional element.

When a DER is connected to a conventional radial feeder, it is a common practice to utilize directional protection to avoid undesirable operation of the feeder breaker when the generator supplies fault current to an external fault. Negative and zero sequence components are utilized in the determination of fault direction. The negative sequence element will be focused on in this paper, as this was the priority element in the event under discussion. The operating principle for this element is based on the circuit shown in Figure 1, which is described in detail in [8].

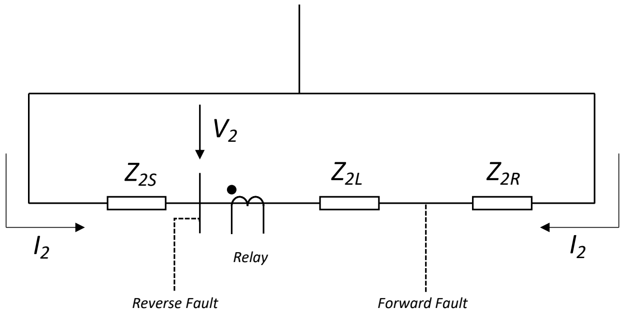

Figure 1 - Negative Sequence Circuit for a L-G fault

Z_{2S} is the negative sequence source impedance

Z_{2L} is the negative sequence impedance of the protected line

Z_{2R} is the negative sequence impedance of the remote source if present

V_2 is the negative sequence voltage measured at the relay

I_2 is the negative sequence current measured at the relay

The fault location will determine the direction and magnitude of negative sequence current seen by the relay. For a forward fault, the impedance seen by the relay should be equal to $-|Z_{2S}|$. For a reverse fault, the impedance should be $Z_{2L}+Z_{2R}$. The relay calculates an operating quantity according to equation (1), which is the negative sequence impedance with a phase shift included for the maximum torque angle set by the user. Threshold levels Z2F (forward) and Z2R (reverse) are established on the Z2 plane, and the relay will make a directional decision depending on where the operating quantity lies with respect to these thresholds on the Z2 plane [8].

$$z2 = \frac{Re[\overline{V_2}(\overline{I_2} * 1\angle\varphi_{MT1})^*]}{I_2^{\,2}} \qquad (1)$$

where φ_{MT1} is the maximum torque angle and usually corresponds to the line angle.

In order to boost dependability for this type of application, the relay is typically biased in the forward direction by raising the forward threshold value (Z2F) to one half the impedance of the protected line (between the substation and the DER). The reverse threshold (Z2R) is set 0.2 Ohms above this, so the no decision band between these thresholds is very small. Various approaches for setting these thresholds are described in [6].

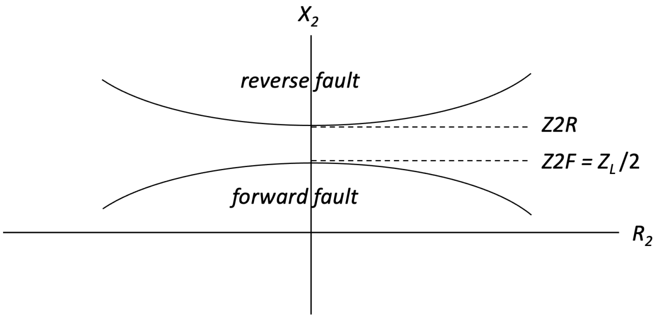

Figure 2 – Z_2 Plane with Directional Thresholds

2. Event Description

Figure 3 shows the configuration of the substation under consideration. There are five feeders supplied by two 138/25kV transformers. Only one feeder, designated 153L, includes a connected DER.

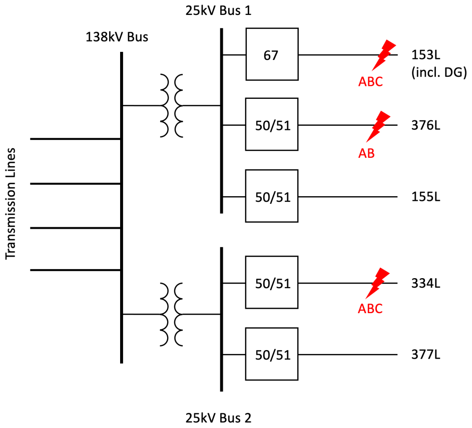

Figure 3 - Substation Configuration

The event under study started with a suspected lightning strike that led to the development of a three phase fault simultaneously on 153L and 334L, which are double circuited on the distribution poles. After approximately 140ms (8.4 cycles) an A-B fault also developed on 376L. The exact mechanism by which this second fault occurred is not known, however this line is also double circuited with 153L close to the suspected location of the incipient fault.

The non-directional time overcurrent relays for 334L and 376L tripped their respective feeder breakers as designed in approximately 1.17 and 1.65 seconds respectively. However, the directional equipped 153L relay failed to issue a trip to clear the fault, and as a result the substation transformer overcurrent protection operated as backup after 2.06 seconds. This caused the entire substation to trip off (the transformer does not have a high side breaker) and created significant customer interruptions. This behavior was initially considered contrary to expectations, as the forward fault current on 153L was more than adequate to operate the overcurrent element in a similar timeframe as the other two feeders. The various feeder currents recorded by their respective relays are shown in Figure 4.

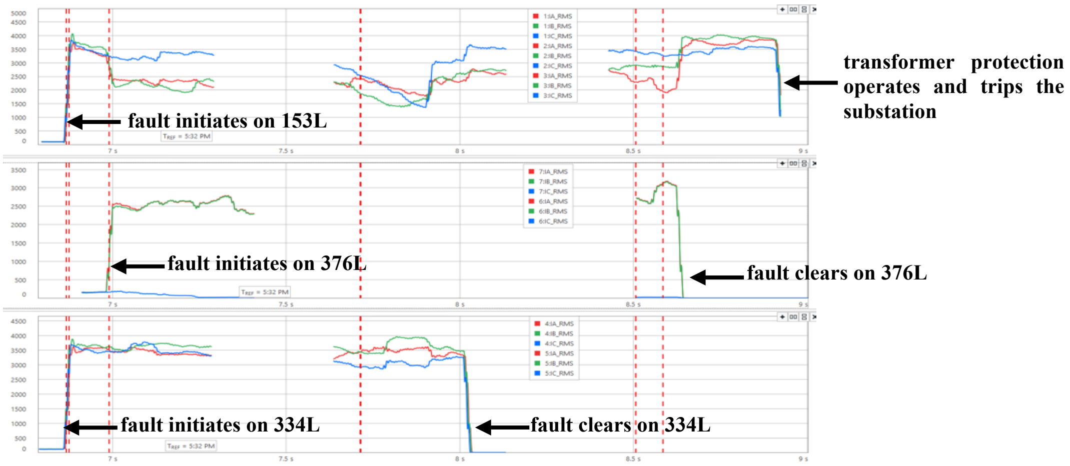

Figure 4 – RMS Currents on 153L, 376L, and 334L (top to bottom)

Upon examination of the relay records, it was observed that the 153L relay saw enough negative sequence current to enable the directional element after the fault on 376L initiated, however the directional declarations began to cycle repeatedly between forward and reverse. This condition lasted until the fault on 376L had cleared, at which point the 153L directional element dropped out and the overcurrent element began its cycle. By this point it was too late for the relay to complete its cycle before the transformer protection backed it up and tripped the substation.

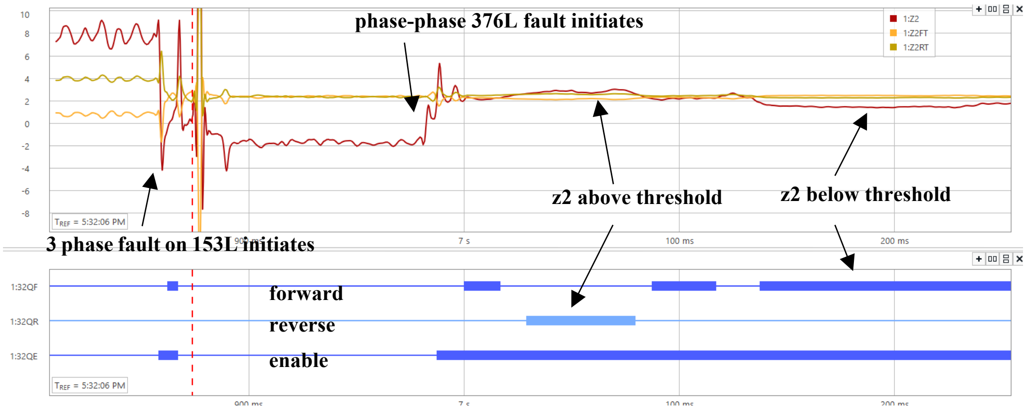

Figure 5 – 153L relay directional declarations during the initial period of the fault

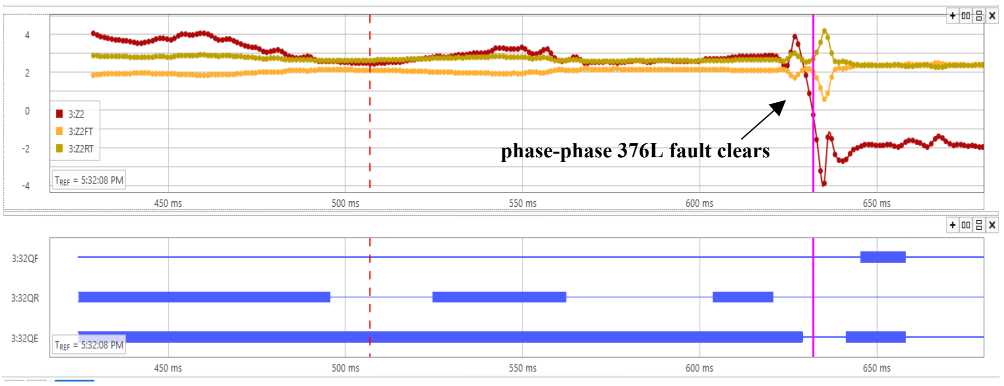

Figure 6 - 153L relay directional declarations during the latter period of the fault

3. Event Analysis

We focus on the latter portion of the event subsequent to the 334L fault being cleared, as it did not have a major influence on the behavior of the 153L relay. A simplified diagram of the system at this stage is shown in Figure 7. The three phase fault on 153L is considered as a solid grounding point. The sequence network is then drawn assuming boundary conditions for the 376L phase to phase fault as shown in Figure 8. Relay CTs are included for both feeders with polarity indicated.

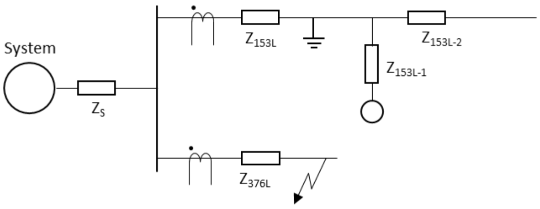

Figure 7 – Equivalent circuit for the event

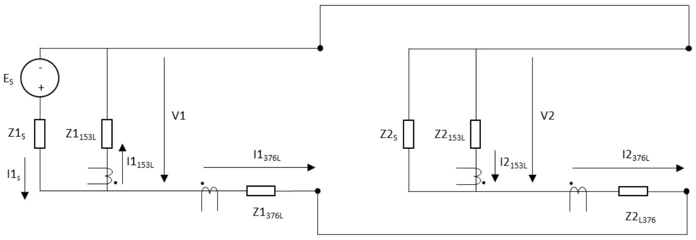

Figure 8 – Sequence network for the event

Using this circuit, the positive and negative sequence voltages and currents that are expected to be seen by the relays during this event are calculated. The following assumptions are used in the circuit calculations:

- Positive and Negative sequence impedances are assumed equal.
- 153L line impedances were assumed based on system models and the estimated fault location. The fault was determined to be closer to the substation than the DER, therefore the DER facility impedance is shorted out and irrelevant.
- 376L impedances were estimated based on the voltages and currents recorded by the relay, as the actual fault location is unknown and did not appear to be identical to the 153L fault location.
- Source voltage is set at 1.05pu

In order to validate the reasonableness of the assumptions, a comparison is performed between the circuit calculations and actual measured values provided by the relays. Results of the comparison are shown in Table 1.

Table 1 – Measured vs Calculated Sequence Quantities

Quantity	Measured	Calculated
376L		
I1	1583 A	1341 A
I2	1563 A	1341 A
V1	6455 V	6149 V

V2	1998 V	1661 V
153L		
I1	2842 A	2426 A
I2	653 A	656 A
V1	6453 V	6149 V
V2	1991 V	1661 V

The measured and calculated values show general agreement with some margin of error in certain quantities, which may be due to measurement and/or modelling inaccuracies. The measured values are constantly in flux, so depending on the exact moment chosen they may show better or worse agreement with calculations.

Proceeding with the circuit analysis, the negative sequence impedances are calculated for both relays as follows:

For the 153L Relay

$$Z_2 = \left|\frac{\overline{V}_2}{-\overline{I}_2}\right| = \left|\frac{-\overline{I2}_{153L} * \overline{Z}2_{153L}}{-\overline{I2}_{153L}}\right| = \overline{Z2}_{153L} \qquad (2)$$

For the 376L Relay

$$Z_2 = \left|\frac{\overline{V}_2}{\overline{I}_2}\right| = \left|\frac{-\overline{I2}_{376L} * \overline{Z}2_{153L}//\overline{Z}2_s}{\overline{I2}_{376L}}\right| = -\left|\overline{Z2}_{153L}//\overline{Z2}_s\right| \qquad (3)$$

The Z_2 that should be calculated by the 153L relay is equal in magnitude to the impedance of the shorted section of 153L and is a positive quantity. The 376L relay should calculate a Z_2 that is equal to the negative sequence source impedance paralleled with the shorted segment of 153L and is a negative quantity. Since the 376L relay calculates a negative quantity, it would correctly declare a forward direction (if enabled). Since the 153L quantity is positive, the directional declaration depends on the threshold settings. Per the relay manual [10] these settings are calculated in the relay as follows:

Z2FT = 1.25*Z2F-0.25*$|\mathbf{V}_2/\mathbf{I}_2|$

Z2RT = 0.75*Z2R+0.25*$|\mathbf{V}_2/\mathbf{I}_2|$

where:

Z2FT = forward direction threshold
Z2RT = reverse direction threshold
Z2F is a user entered setting and in our case is set at one half the line impedance, $Z_L/2$
Z2R is a user entered setting and in our case is set at Z2F + 0.2

The operating quantity z2 is calculated according to Equation (1). The measured and calculated values for these quantities are compared for the 153L relay in Table 2.

Table 2 – Measured vs Calculated values for thresholds and operating quantities

Quantity	Measured	Calculated
Z2RT	2.64	2.51
Z2FT	2.11	2.24
z2	2.46	2.51

The measured and calculated quantities show generally good agreement. The important point is that the operating quantity z2 falls close to or in between the threshold quantities. Since these thresholds are quite close together, and the z2 quantity would have been fluctuating over the course of the fault, it is unsurprising that z2 crossed above and below the thresholds as the fault progressed, rendering the relay incapable of making a determination as to the fault direction.

The fact that z2 happened to be close to the threshold quantities is a consequence of the location of the fault on 153L. The z2 value seen by the relay was equivalent to the line impedance between the substation and the 153L fault location, which happened to be about halfway down the line. Since the threshold setting is equal to half the line impedance, this meant that the operating quantity developed a similar value to the threshold settings. Had it been a close-in fault, then the z2 quantity would have been close to zero and the relay would have declared a forward fault. Had it been close to the end of the line then the impedance would have been higher, and it would have declared a reverse fault. Incidentally, the reverse declaration is more “correct” in this case, as the source of negative sequence current is in the reverse direction (on 376L). Notwithstanding the fact that a forward declaration would have been more desirable in this case, the calculations show that the 153L relay behaved as expected given the conditions, and therefore this was not considered a mis-operation.

4. Discussion on Mitigation Requirement

In order to gauge the realistic risk level which this event presents and its need for mitigation, the following conditions that needed to come together in order for the “failure” to occur must be taken into account.

1. There were simultaneous faults on multiple feeders at the same time. While simultaneous feeder faults are relatively rare (in our experience, typically one or two per year where an impact to the transmission system was recorded), when they do occur they tend to be either two phase or three phase faults. This is not unexpected, as an event of sufficient severity to create a fault condition across multiple circuits is unlikely to be limited to a single phase on either of the circuits.
2. The feeder equipped with directional protection experienced a balanced fault whereas the other feeder experienced an unbalanced fault. This specific configuration was necessary for the failure to occur. Had the faults been reversed, or had they both been of the same type (either balanced or unbalanced), then the directional element on 153L would have performed as desired. Given the propensity for simultaneous faults to also be multi-phase, this condition may not be as unusual as it seems at first glance, particularly as certain areas of the system become increasingly saturated with DERs. If this type of event occurred where both feeders had DERs connected (and therefore both equipped with directional protection) then it would not matter which feeder had the balanced, and which the unbalanced faults. The one with the balanced fault would be at risk of defeating the directional element and failing to trip.
3. The location of the balanced fault on 153L played a role in confusing the relay, as it established the negative sequence impedance at a level which was close to the threshold settings. Had the fault been further away the result would have been the same, but had it been slightly closer, the outcome likely would have been different.

Considering the above points, the risk that is revealed by this event may not be negligible, but it is still quite small. The risk would be higher in areas with extensive DER penetration, where there are numerous instances of multiple DER feeders connected to the same substation, and where these feeders contain double-circuited sections.

Potential Mitigations

One possible mitigation would be to increase the bias of the forward threshold Z2F. For this event, a higher Z2F value would have caused the z2 operating quantity to fall within the forward zone and issue a trip. However, making this change would also increase the risk that the line would trip for external faults. As the thresholds are increased, the margin between the reverse threshold and the expected impedance for a reverse fault condition is reduced, which in turn reduces the security. Considering that an individual external fault occurs much more frequently than any simultaneous fault, this would seem to be a poor trade-off of security for dependability.

Another option would be to connect the feeder relays together and incorporate logic such that each relay is made aware of fault conditions on its neighbors and be able to respond accordingly. This would require additional wiring and logic but could be viable if the need arose.

Generally it is not required for transformer protection to coordinate with a simultaneous feeder fault condition. The infrequency of such events would not normally justify the extra costs of implementing solutions. In this particular case no recommendation was made to change the settings or implement other mitigations. The combination of factors leading to the event were considered rare enough such that changes to settings would likely produce more harm than good. Nonetheless, protection and operations engineers should be aware of the possibility for this type of event to occur, so that when they do occur they can be readily understood and addressed as required.

5. Conclusions

When a DER is connected to a conventional radial feeder, it is a common practice to utilize directional protection to avoid undesirable operation of the feeder breaker when the generator supplies fault current to an external fault. This paper presented a technical difficulty that this type of protection can introduce using a real event. This event involved a simultaneous fault on three feeders where one feeder was equipped with directional overcurrent protection to accommodate a DER connection on the feeder. While the two feeders with no directional protection had their faults successfully cleared by their respective protection devices, the directional protection of the feeder with the DER connection failed to detect a downstream fault on the distribution feeder, and consequently resulted in backup protection being forced to operate and trip off all load at the substation, creating a more significant customer interruption than otherwise would have been necessary.

The event was described in detail in this paper and the behavior of the protection devices involved were reviewed. Sequence network of the faulted circuits was derived and the negative sequence impedance seen by the relay was calculated and compared with the relay thresholds which showed why the directional element failed to detect the fault. The analysis revealed that this was not a protection mis-operation as the relays performed as designed, indicating that similar events can occur if certain conditions are met. Discussions were provided in the paper to clarify how likely those conditions could exist, leading to fault detection failure in directional protection. Potential mitigation measures were presented as well and their benefits and risks were discussed.

6. References

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