Application of Current Differential Protection to Tapped Transmission Lines

APPLICATION OF CURRENT DIFFERENTIAL PROTECTION TO TAPPED TRANSMISSION LINES

B. Kasztenny **I. Voloh** **M. Adamiak** **J. Zeek**

GE Power Management
215 Anderson Avenue
Markham, Ontario
Canada L6E 1B3

GE Power Management
640 Freedom Buss. Cntr.
King of Prussia, PA 19406
USA

AEP
825 Tech Center Drive
Gahanna, OH 43230-8250
USA

1. Introduction

Microprocessor-based current differential relays offer superior protection for power transmission lines. The key advantages over distance relays include better sensitivity for high resistance faults, 100% line protection, and better performance in the single-pole-tripping mode, particularly during evolving and cross-country faults.

Besides the well-known requirements of high-speed communication and sampling synchronization, a microprocessor-based differential relay requires – as per principle of differential protection – that the currents are monitored on all the circuits connected to a protected line including tapped transformers and lines. This may create a problem as the tapped connections are meant to provide a cost-effective alternative to actual substations. The taps are made outside the main substations and may not be equipped with proper protection means such a Circuit Breakers (CBs) and Current Transformers (CTs). Also, high-speed communication from the tap site may be a problem. This either limits the application of line current differential relays or makes the tapped connections economically less attractive.

This paper discusses application problems and solutions permitting the application of current differential protection to tapped transmission lines without measurements at the tap point (-s).

2. Problems Caused by Tapped Transformers

Figure 1 presents a sample system configuration with two parallel lines and several transformers tapped. The low voltage busbars may be interconnected although in most applications, the tap feeds a radial load. Note that if the LV busbars are networked, some means of isolating a fault on the LV side must be provided so as to prevent backfeed for a fault on the differentially protected line. It is assumed that the current differential protection system monitors the currents only in the main substations. Currents at the taps, either transformers or lines, are not available to the relays.

One possible solution to the problem of protecting such configurations is to use directional elements on the tapped transformers to send a blocking signal to the line differential protection system. This approach actually combines the differential protection principle yielding good sensitivity but requiring high-bandwidth communications, with the directional blocking scheme that may be accomplished using more traditional signaling channels. Depending on the availability of the CBs at the tap, the blocking signal should be sent for transformer and downstream faults (when the CBs are installed at the tap and a faulty transformer may be isolated from the tap) or only for faults at the low voltage bus and downstream (when the CBs are not available and a faulty transformer requires tripping the entire line). As the line differential system is not sensitive enough to provide sufficient protection for the transformer, a direct transfer trip must be actually sent by the transformer protection to the relays in the main substations. In any case, reliable communication is required from the tap (-s) to the main substations.

This paper presents a solution that assumes that high-speed communication from the taps facilitating digital current differential protection is not available. It is assumed that the protection zone must cover the entire line including taps and a portion of the high voltage windings of the

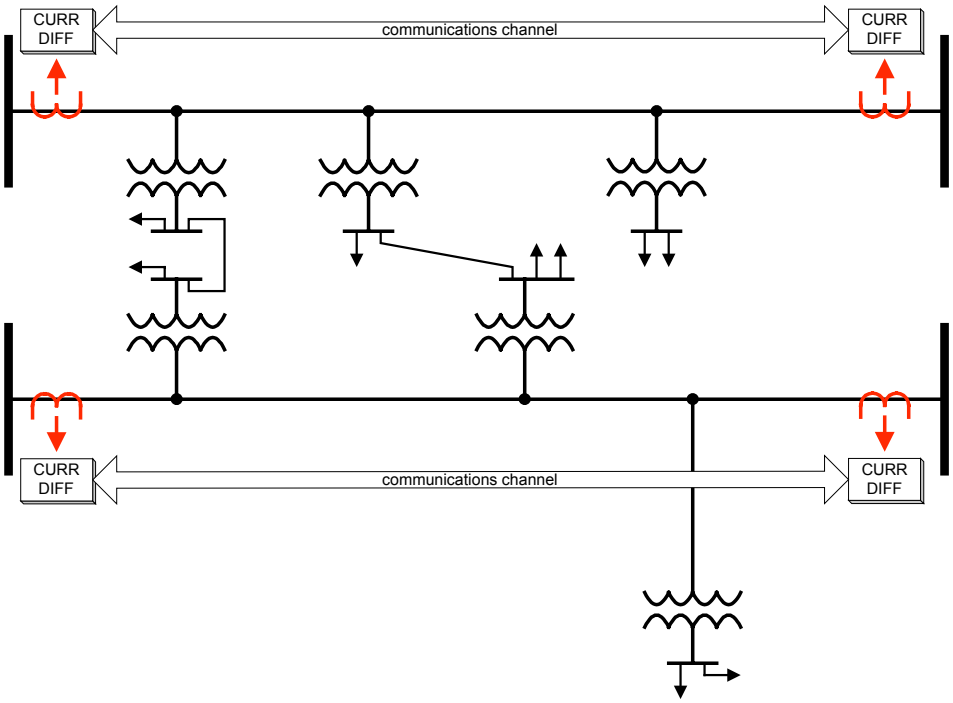

Figure 1. Sample system with two parallel lines and several tapped transformers.

transformers. It is to be noted that the ability to protect a tapped power line without measuring all the currents in the zone will cost the user in terms of sensitivity and speed of performance.

The following sources of differential error signals need to be addressed to make the application possible:

- Total load current of the tapped transformers and lines.
- Faults on the low voltage side of the transformers.
- Magnetizing inrush of the tapped transformers on top of the line capacitive inrush current.
- External ground faults on the high voltage system causing a zero-sequence infeed from the line-side windings of the tapped transformers when connected in a grounded wye.

The following sections discuss these problems and proposed solutions.

3. Application of Differential Relays to Lines with Tapped Transformers

3.1. Unbalance Caused by the Load Current

During normal operation the tapped transformer (-s) will draw some load current. The total load current would appear to the line differential system as an error signal. Typically, the amount of load drawn from tapped connections is low as compared with the power transferred between the main substations. This provides the opportunity to restrain the differential relay by the bias current. However, as the number of taps increases (as high as five), the total load current leaking from the differential zone may become quite high. Also, when the line is initially energized, the

entire load current is supplied from a single terminal and the differential error current will be equal to the restraining current and, as such, the biased characteristic does not help.

One solution to the problem is to raise the pickup setting above the sum of the maximum total load current and the line charging current. It should be noted that the penalty for raising the pickup setting is loss of sensitivity.

As far as the charging current is concerned, the following should be taken into account. For long lines, the compensating reactors may be used, therefore the pickup setting should accommodate only the uncompensated portion of the charging current. Modern digital relays can apply an adaptive pickup setting based on the connection status of the shunt reactors. Alternatively, the shunt reactor current can be input directly to the relay and digitally subtracted from the total current. Digital relays can also directly compensate for the charging current by virtually calculating the charging current on-line using the terminal voltage and line parameters. Such compensation can attenuate the differential error current due to capacitive charging by a factor of ten.

The charging current that is seen by the differential relay – regardless of the compensation by the shunt reactors and/or relay compensating algorithms – is shifted by 90 degrees or more as compared with the load current drawn by the tapped transformers. This allows for lower pickup setting because the net current is lower than the sum of magnitudes of the charging and total load currents.

When a line differential relay uses a traditional characteristic with separate boundaries created by slope and pickup settings, then only the pickup setting can prevent misoperation due to the leaking load current - increasing the slope does not help in single infeed situation. Some relays, however, combine the pickup and slope settings when creating the restraining current (for a given restraint level the higher the slope, the lower the pickup). This gives a chance for better sensitivity even when the relay is set to restraint on the total tap load current.

Another solution to the differential error signal caused by the unmonitored load current is to apply distance supervision. The setting requirement is to overreach all the line terminals but avoid picking up on the load current. The overreaching distance elements will, however, pickup on close external faults on the HV system. Under such conditions, however, the differential system would see increased restraint current due to the through fault current. In addition, the large restraining current may be present only in the faulted phases while the differential error current due to the load is present in all three phases. All this may endanger security and the higher pickup/slope settings may be required despite the distance supervision.

3.2. Faults on LV Side of the Tapped Transformers

As the tapped currents are not included into the current balance monitored by the differential relays, faults on the low voltage side of the taped transformers would create a differential signal and, most likely, result in a misoperation.

Distance supervision can be used to cope with this problem. The distance element should be set to overreach securely all the line terminals including tapped lines. But at the same time, they should not reach to the low voltage terminals of the transformers (Figure 2). This may create a problem, particularity if the transformers have a large power rating, are located very close to the substations, and at the same time the line is very long (Figure 3). In this difficult situation it would be recommended to include this tapped transformer into the differential scheme. How-

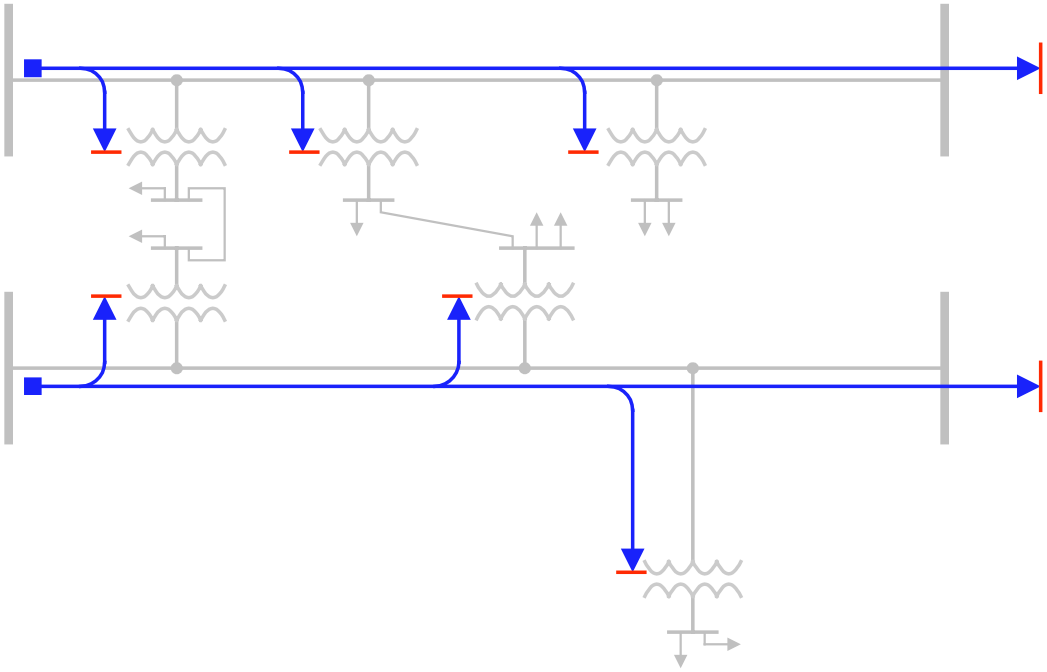

Figure 2. Illustration of the reach requirement for the distance supervising functions.

ever, if inclusion was impossible, a decision could be made to allow the nearest terminal to the tapped transformer to operate for low side faults. Note that the far terminal can be set not to operate and maintain connection to the line and any other load transformers on the line. Automatic reclosing can be coordinated to allow the near circuit breaker to reclose after the distribution fault is cleared and return the line to full service. Typically, however, the tapped transformers are of relatively small power rating and the reach setting that meets the above requirements is often possible.

If the considered line is a parallel line and/or has more than one tap and/or there are interconnections between the low voltage sides of the transformers, then detailed short circuit studies are required to set the distance supervising functions as well as a means of disconnecting any positive sequence source

In most cases, the tapped transformer is delta on the high side and grounded wye on the low side. This configuration provides a natural differentiation for internal versus external ground faults as transformer low side ground faults will not present any zero sequence current to the differential relay. As such, a ground overcurrent element in the differential can be used to enable differential operation on the line.

When the tapped transformer is grounded wye on the high side, the zero-sequence compensating factor for the ground distance elements should be approached carefully. On both internal and external faults the tapped transformers would feed the zero sequence currents. These currents are not measured by the relays, but they will cause extra zero-sequence voltage drops along certain segments of the line (Figure 4). In other words, the zero-sequence impedances of the transformers would appear as shunt elements in the zero-sequence equivalent network thereby decreasing the zero-sequence impedance as seen from the fault location. Again, detailed short circuit studies

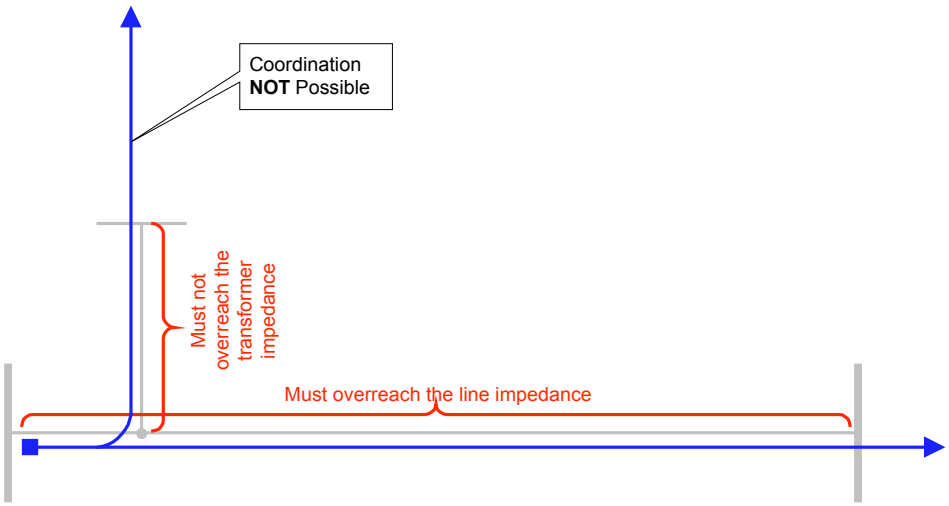

Figure 3. Potential coordination problem for large transformers and long lines.

for both internal and external fault would help to select an adequate value of the zero-sequence compensating factor.

Modern microprocessor-based line current differential relays can provide at least one zone of distance protection. This suits the application well as no extra cost is generated and the trip time is not increased by the output and input contacts activation times as it would be when using an external relay.

Another solution is to utilize a pickup signal of a microprocessor-based backup distance relay – if installed – and send the permission via fast communications, if possible. This, however, would endanger the very concept of backup protection.

3.3. Magnetizing Inrush Currents

Transformer magnetizing inrush current during line energization may cause the differential elements to pickup. In order to ensure security of the protection system, the distance supervising functions must not pickup on the magnetizing inrush.

For this purpose it is justified to consider the initial inrush due to energization since the recovery inrush after an external fault would generate much lower inrush currents because the voltage at the transformer location is not going to drop dramatically during external faults.

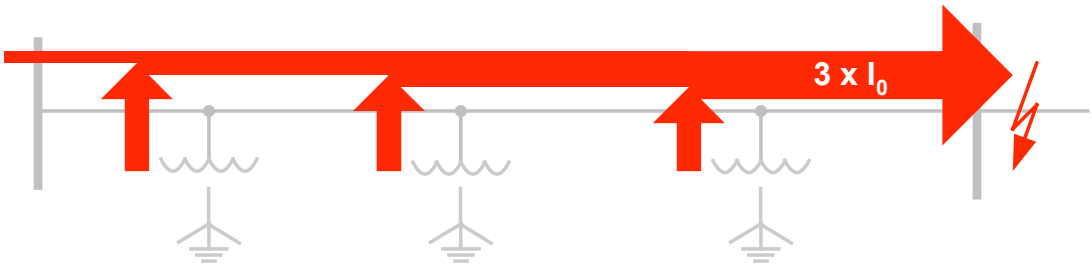

Figure 4. Illustration of the uncertainty as to the zero-sequence compensating factor.

It may be further assumed that the voltage signal will not drop during the energization inrush conditions because of the line impedance between the transformer tap and the energizing high voltage busbar.

For a given distance relay it may be approximated how much of a typical inrush waveform is seen by a relay circuit or algorithm as the operating signal. Based on that approximation, the maximum secure reach may be calculated.

One may test, or get the required information from the vendor, as to the maximum allowable reach of a distance element that would not be picked up on transformer inrush current.

An example of an impedance estimate during inrush might look like:

$$Z_{\max} = 2.5\frac{V_n}{I_{peak_inrush}} \tag{1}$$

Assuming the transformer is very close to the substation, the reach of the distance element should not be higher than some 0.75 of the transformer impedance. If the peak inrush current is K times the transformers rated current, one obtains the following equation for the K, guaranteeing that while set to 75% of the transformer impedance, the distance relay will not pickup on the magnetizing inrush current:

$$Z_{\max} = 0.75 \cdot Z_T = 0.75 \cdot X_{\%} \cdot \frac{V_n}{\sqrt{3} I_n} < 2.5\frac{V_n}{K \cdot I_n} \quad \rightarrow \quad K < \frac{2.5 \cdot \sqrt{3}}{0.75 \cdot X_{\%}} = \frac{5.77}{X_{\%}} \tag{2}$$

Assuming a 10% short circuit voltage for the transformer, one would get K = 57.7. This means that as long as the maximum peak inrush current is less than some 57 times the rated current, the considered distance relay set to reach up to 75% of the transformer impedance will not pickup during the inrush conditions. This is a pretty good security margin, as a typical magnetizing current will be significantly lower than 50 times rated.

It must be kept in mind that this example is valid for the assumed distance characteristic of (1).

Another factor to consider is a combination of the magnetizing inrush current (inductive) and the line inrush current (capacitive). The net current appearing at the energizing substation will be lower as the two components compensate mutually. Also, the harmonic content may be different as compared with energizing a transformer directly from a busbar. This, however, is of a secondary importance for the supervising distance functions.

Another alternative to prevent differential operation during line energization is the use of harmonic restraint. Harmonic restraint can be provided either internally if a given current differential relay provides it or externally by means of a separate relay. This approach must be approached with caution as the harmonic content may be too low to inhibit the protection during magnetizing inrush conditions. In addition, a harmonic restraint jeopardizes dependability on internal faults accompanied by CT saturation.

3.4. External Faults on HV System

The distance supervising elements overreach the line terminals and will pickup on close external faults. This may create an extra problem if the transformers have grounded windings on the line side. The neutral current supplied by the transformers will be measured by one terminal of the line only (Figure 5) and will create an unbalance of the differential signal causing a false trip.

In order to ensure security, the differential relays must not respond to the zero-sequence current. As a digital differential relay may be designed to operate on a per-phase basis, they will respond to the neutral current. One solution is to set the mode of operation of the differential to operate either on positive or negative-sequence currents or a combination of thereof.

Another solution is to remove the zero-sequence current from the phase currents prior to forming a differential signal. Several design options are possible with respect to this:

- Removing the zero-sequence current entirely, or just a net (unbalance) zero-sequence current. The first alternative is theoretically sufficient, but the second one brings more security. On internal faults the two options are equivalent.
- Removing the zero-sequence current from the differential signal only, or from both differential and restraining signals. The first option brings more security, but deteriorates, to certain extent, sensitivity on internal faults.

Another tempting idea is to remove the zero-sequence current conditionally – only for external faults: Only upon detecting a reverse direction of the neutral current, the removal of the net zero-sequence current takes place. This approach would keep the original sensitivity of a phase-segregated relay for internal faults. The major weakness is that only the relay close to an external fault would sense the fault in the reverse direction. Subsequently, this relay will have to share the information with its peers to ensure compensation at the remaining terminals. Because of its complexity, this approach is not recommended.

3.5. Internal Faults

Removal of the zero-sequence current would desensitize the protection on single-line-to-ground internal faults: the differential current would be reduced to 2/3rd of the original value. Other sensitivity limitations are caused by distance supervision and less sensitive settings of the differential element.

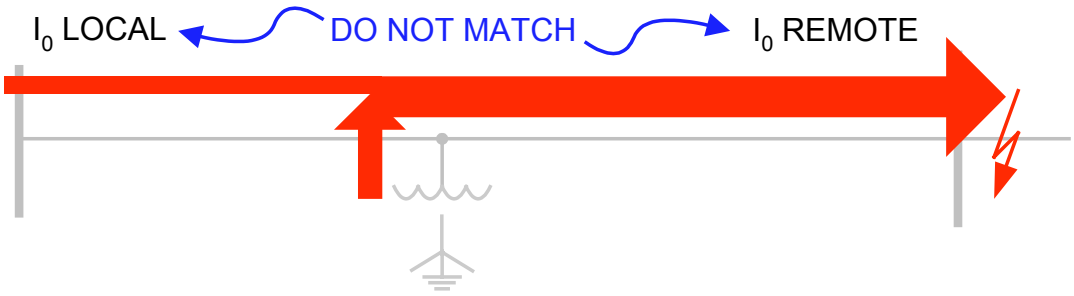

Figure 5. Ground current fed by the transformers with grounded wye connections.

Another problem caused by the removal of the zero-sequence current is a differential error signal created in the healthy phases. As a consequence, the healthy phases will overtrip on internal faults. This is a straightforward consequence of the fact that the relay, although phase-segregated, responds to the negative- and positive-sequence currents only and as such is not capable of proper fault type identification based on the current differential element.

The fault type identification is not, however, of a primary importance as the single-pole tripping should not be applied to lines with tapped transformers.

4. Example

Figure 6 shows a sample 220 kV system with two circuits between the ALPHA and BETA substations and number of tapped transformers. A SLG fault has been considered at the ALPHA busbar. Current differential protection on both the circuits is analyzed for this sample fault.

4.1. Simplified Model of the Current Differential Relay

A generic approach to the line current differential protection has been adopted.

The differential signal is formed internally as a vector sum of the local and remote currents:

$$I_D = \left| \underline{I}_{LOCAL} + \underline{I}_{REMOTE} \right| \tag{3}$$

The restraining signal is created internally as an average of the magnitudes:

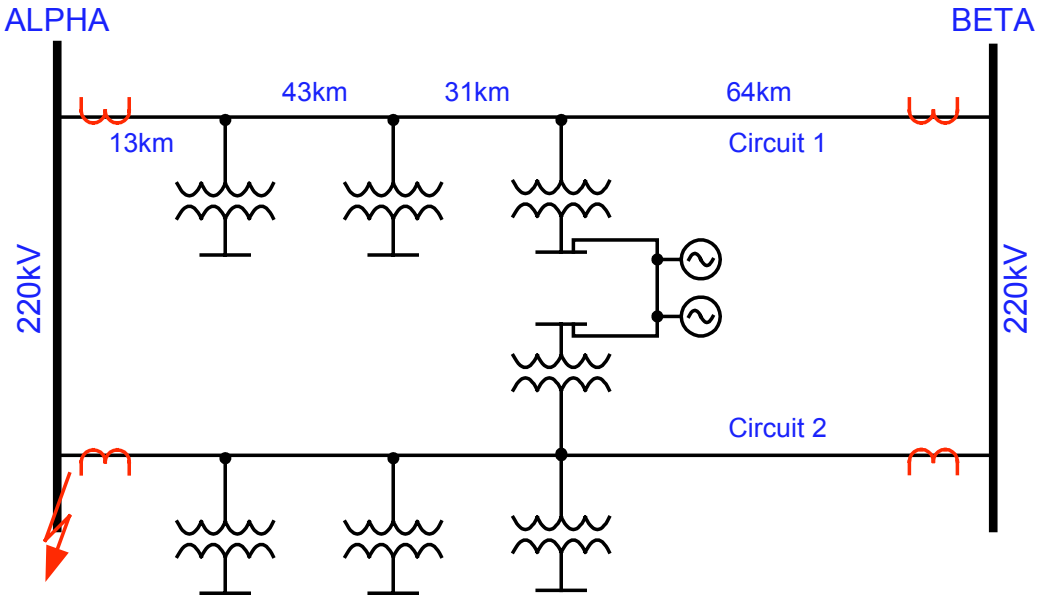

Figure 6. Sample system.

$$I_R = \frac{\left|\underline{I}_{LOCAL}\right| + \left|\underline{I}_{REMOTE}\right|}{2} \quad (4)$$

Pickup and slope are the settings.

4.2. An External AG Fault at ALPHA

The following phasors are measured by the relays (from the short-circuit studies):

Circuit 1:

ALPHA Substation		BETA Substation	
IA = 1203.8 A	@ -81.9 deg	IA = 840.3 A	@ 99.1 deg
IB = 136.9 A	@ 97.1 deg	IB = 376.5 A	@ -82.5 deg
IC = 136.9 A	@ 97.1 deg	IC = 376.5 A	@ -82.5 deg

Circuit 2:

ALPHA Substation		BETA Substation	
IA = 1214.9 A	@ -81.9 deg	IA = 822.6 A	@ 98.9 deg
IB = 126.6 A	@ 96.4 deg	IB = 393.0 A	@ -82.2 deg
IC = 126.6 A	@ 96.4 deg	IC = 393.0 A	@ -82.2 deg

The differential currents calculated by a traditional phase-segregated current differential relay are:

Circuit 1:

IDA = 363.9 A	IRA = 1022.0 A
IDB = 239.6 A	IRB = 256.7 A
IDC = 239.6 A	IRC = 256.7 A

Circuit 2:

IDA = 392.6 A	IRA = 1018.8 A
IDB = 266.5 A	IRB = 259.8 A
IDC = 266.5 A	IRC = 259.8 A

If, however, the zero-sequence currents are removed from the differential signal then the spurious differential error signals are significantly reduced:

Circuit 1:

IDA = 83.15 A

IDB = 41.6 A

IDC = 41.6 A

Circuit 2:

IDA = 84.5 A

IDB = 42.2 A

IDC = 42.2 A

As seen from the example, removal of the zero-sequence current brings the currents almost to a perfect balance on this external fault. The remaining spurious differential signal results from line charging currents and the positive- and negative-sequence infeed coming from the low voltage side of the tapped transformers.

In order to cope with the differential error signal, a version of the relay without the zero-sequence current removal would have to use:

- either a pickup of 364 A or a slope of 93% (239.6/256.7*100%) for the circuit 1 protection, and
- a pickup of 393 A or a slope of 103% (266.5/259.8*100%) for the circuit 2 protection.

Such large values of a slope are not acceptable, and practically, the pickup setting would have to take care of the differential error currents.

If the zero-sequence current is removed from the differential signal the required settings are as follows:

- a pickup of 83.2 A or a slope of 16 % 41.6/256.7*100%) for the circuit 1 protection, and
- a pickup of 84.5 A or a slope of 16% (42.2/259.8*100%) for the circuit 2 protection.

This example shows that sensitive settings can be preserved if the zero-sequence current is removed from the differential currents.

5. Conclusions

The application of line current differential protection to lines with tapped transformers has been presented. The approach taken does not require measurements at the taps, and therefore, is economically attractive.

The presented application uses distance supervision to prevent misoperation for faults on low voltage sides of the tapped transformers and zero-sequence removal to cope with external ground faults on the high voltage system.

❖ ❖ ❖

Biographies

Bogdan Kasztenny received his M.Sc. and Ph.D. degrees from the Wroclaw University of Technology (WUT), Poland. He joined the Department of Electrical Engineering of WUT after his graduation. Later he was with the Southern Illinois and Texas A&M Universities. Currently, Dr. Kasztenny works for GE Power Management as a Chief Application Engineer. Bogdan is a Senior Member of IEEE and has published more than 100 papers on protection and control.

Ilia Voloh graduated from Ivanovo State Power University, Soviet Union. He then was for many years with Moldova Power Company in various roles in the Protection and Control area. Currently Ilia is a Protection and Control Advisor with GE Power Management. His areas of interest are current differential and phase comparison line protection, and communications for protective relaying. Ilia is a Member of IEEE.

Mark Adamiak received his Bachelor of Science and Master of Engineering degrees from Cornell University in Electrical Engineering and an MS-EE degree from the Polytechnic Institute of New York. From 1976 through 1990, Mark worked for American Electric Power (AEP) in the System Protection and Control section where his assignments included R&D in Digital Protection and Control, relay and fault analysis, and system responsibility for Power Line Carrier and Fault Recorders. In 1990, Mark joined General Electric where his activities have ranged from algorithm development, simulator design, substation automation, and advanced technology development. In addition, Mr. Adamiak has been actively involved in developing the framework for the implementation of the MMS/Ethernet peer-to-peer communication solutions for next generation relay communications. In 1986, Mark was the winner of the Eta Kappa Nu (HKN) society's "Outstanding Young Electrical Engineer" award. Mark is a member of HKN, a Senior Member of IEEE, past Chairman of the IEEE Relay Communication Sub Committee, a US member on IEC TC57 - Working Group 11 on Substation Communication, and a registered Professional Engineer in the State of Ohio.

Jay Zeek received his Bachelor of Science in Electrical Engineering degree from The Ohio State University. From 1981 to the present Jay has worked at American Electric Power starting in the System Protection and Control section. Now a Senior Engineer in the Protection Measurements Engineering and Standards section, Jay is responsible for relay settings in the AEP areas in Indiana, Michigan, and western Ohio. Jay also assists in developing AEP policy in protection systems and providing direction in standards development.

GE Power Management

215 Anderson Avenue
Markham, Ontario
Canada L6E 1B3
Tel: (905) 294-6222
Fax: (905) 201-2098
www.GEindustrial.com/pm