Autotransformer Protection Case Studies: Going Above and Beyond the Traditional Cookbook

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Autotransformer Protection Case Studies: Going Above and Beyond the Traditional Cookbook

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Abstract—**Autotransformers are vital components of transmission power systems; they are applied to interconnect extra-high voltage (EHV) power network systems and are responsible for transferring large amounts of energy between them. Reliable protection systems for autotransformers are an important part of the dependability and security of electrical power systems.**

Applying autotransformer banks that are built with single-phase units is common and requires specific features of a protection system. These specific features ensure quick identification of fault location and faulted units to quickly replace the faulted tank with the spare one.

This paper presents a theory related to differential protection based on the ampere-turn-balance (ATB) principle and Kirchhoff's current law (KCL), and it discusses the requirements for their application for autotransformer bank protection and their performance for different fault conditions. This paper also discusses different protection schemes available for autotransformer banks and points out the pros and cons of each scheme and how they can complement each other.

I. Introduction

Autotransformers are important pieces of equipment that make a major contribution to preserve the security of power systems and energy delivery, since they interconnect extra-high voltage (EHV) power network systems and are responsible for transferring large amounts of energy. Therefore, dependable and secure protection systems are required for autotransformers. Autotransformers have electrical and magnetic connections between the primary and secondary sides, which means only part of the energy is transmitted via magnetic coupling. This saves iron material and allows for a more compact design. Usually, a tertiary delta winding is included and can be used to feed the substation auxiliary service. The unit protection schemes of autotransformers can be applied in different arrangements, as follows:

- Differential protection based on Kirchhoff's current law (KCL) for electrically connected windings.
- Differential protection based on the ampere-turn-balance (ATB) principle for all windings.
- Differential or directional protection based on zero-sequence currents and restricted earth fault (REF) protection.
- Dedicated differential protection schemes for tertiary delta-connected windings.
- Distance elements applied with directional comparison logic.

Differential protection based on KCL for the electrically connected windings, which can be either high- or low-impedance-based, can be applied if current transformers (CTs) are available in each phase at the neutral end of the windings. This provides high-speed sensitive protection against phase and earth faults and remains unaffected by ratio changes due to the load tap changer (LTC). It is also immune to the effects of magnetizing inrush current and overexcitation. However, it does not detect turn-to-turn faults, which can be detected by negative-sequence differential current protection based on the ATB principle.

Internal transformer faults disrupt the ATB. Differential protection based on the ATB principle detects internal autotransformer faults, including turn-to-turn faults. However, it is affected by inrush, overexcitation, LTC, CT steady-state errors, and saturation, so additional algorithms are required to keep the element dependable and secure.

REF protection is beneficial in transformer applications. Because it does not respond to load current, it offers a significant improvement in sensitivity over differential protection based on the ATB. However, the neutral current flow direction and magnitude can be affected by the autotransformer's winding impedance values and power system topology, which changes according to operational requirements. This characteristic has the potential to affect the reliability of the REF element, but the analysis of the reliability of the protection scheme must consider the whole protection system that is applied to the autotransformer.

II. Autotransformer Basics

Fig. 1(a) shows a transformer with two windings. N_H represents the number of primary terminal (high-voltage) turns, while N_X represents the number of secondary terminal (low-voltage) turns. When the V_H voltage is applied to the transformer's primary terminal, the secondary terminal is open (i.e., unloaded), the excitation current is ignored, the I_H and I_X currents are zero, and the V_X voltage induced in the secondary side is equal to V_H divided by the transformation rate (N_H / N_L). The same result is obtained when the transformer is built according to Fig. 1(b), which is an autotransformer with the same primary and secondary winding voltages of the transformer in Fig. 1(a). The secondary winding has been eliminated and the secondary terminal (A_2) is electrically connected to the primary winding at the point X. This way, N_C equals N_X and B_1 is connected to B_2, which becomes a common terminal between the primary and secondary sides. In the autotransformer there are two main windings, which are called common and series windings. The total number of turns (N_T) is equal to the sum of the turns of the series winding (N_S) and the common winding (N_C), which is equal to N_H in Fig. 1(a).

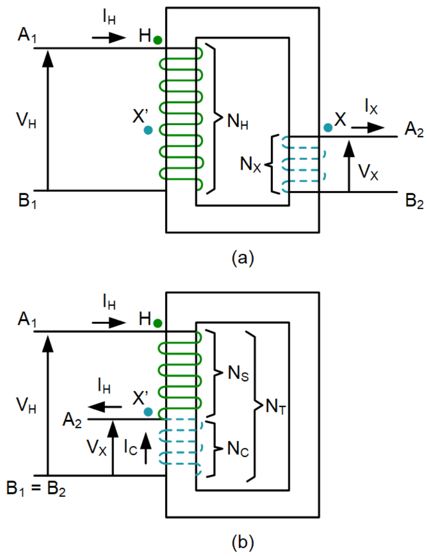

Fig. 1. (a) Example of a two-winding transformer and (b) an autotransformer.

The high-voltage current (I_H) flows through the series winding. The current flowing in the common winding (I_C) is the difference between the low-and high-voltage current, according to (1). The current in the common winding flows in the opposite direction to the current in the series winding.

$$I_C = I_X - I_H \tag{1}$$

The common winding and the series winding have equal ampere-turn values, but the magnetic fluxes are in opposite directions.

Some of the advantages of using autotransformers are below [1].

- For a transformation ratio of 2, the size of the autotransformer would be approximately 50 percent of the corresponding size of a two-winding transformer. In contrast, when the transformation ratio is 20 the size difference is just 5 percent and is considered insignificant. The material cost savings are appreciable when the transformation ratio of the autotransformer is low, about 2.
- An autotransformer has higher efficiency than a two-winding transformer. This is due to the lower ohmic and core loss from the reduced material used.
- An autotransformer has better voltage regulation because it has a single winding, which means lower percentage impedance.

On the other hand, the low impedance in the autotransformer makes the system's fault current so high that the mechanical forces in the autotransformer may exceed its withstand capability. A solution is to install current-limiting reactors in series with the autotransformer.

Another inconvenience of autotransformers is that due to the electrical connection between the high-voltage (H) and low-voltage (X) sides, a disturbance in one of them also involves the other. For example, if a single-line-to-ground (SLG) fault occurs on Side H, a voltage surge to earth will also occur on the healthy phases of Side X. Direct grounding from neutral will weaken this effect.

Autotransformers are widely used in high-voltage systems, where the neutral of the system is directly grounded. In constructing these autotransformers, it is common to have a tertiary winding connected in a delta winding, which may be used to feed the substation protection and control system loads. This tertiary winding also provides low zero-sequence impedance and triple harmonic magnetizing currents to prevent triple harmonics in the magnetic flux and induced voltages.

This tertiary winding is called the stabilizer winding as it also stabilizes the neutral point voltage and reduces the third harmonic voltages on the line. To reduce fault currents under certain conditions, the reactors are installed in series with the tertiary winding inside the delta [2], see Fig. 2.

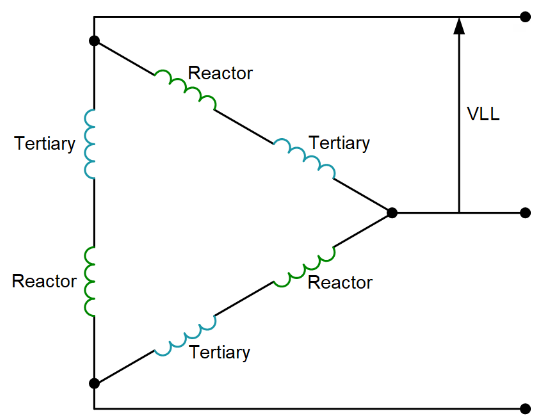

Fig. 2. Example of a tertiary autotransformer winding connection, with a high-reactance reactor connected inside the delta.

A stabilizing tertiary winding with low apparent power, low current, and high-reactance reactors are used to limit ground fault currents on the primary and secondary side of the autotransformer. Current flow through the grounded neutral is limited by the additional impedance of the series-connected reactors within the delta winding [2]. Phase fault currents in the tertiary side are also limited by the presence of a reactor inside the delta.

Reactors, connected externally to the delta, as shown in Fig. 3, can only influence currents external to the tertiary circuit, for example, faults on the tertiary bus. SLG faults on the primary or secondary autotransformers will not be limited by these reactors, because the zero-sequence current flowing inside the delta for SLG faults on the primary or secondary sides will not be limited by the reactor's impedance.

This application is not as common as having reactors inside the delta winding of autotransformers. Still, it can be applied when high impedance is required in the tertiary circuit, for example, to limit the fault current to a value at which the tertiary circuit breaker can interrupt, as seen in Fig. 3. In some cases, the fault current in the tertiary is extremely high. For example,

Fig. 3 shows a field case where a fault current-limiting reactor was applied to reduce the fault current from 124 kA to 18 kA in the 13.8 kV bus.

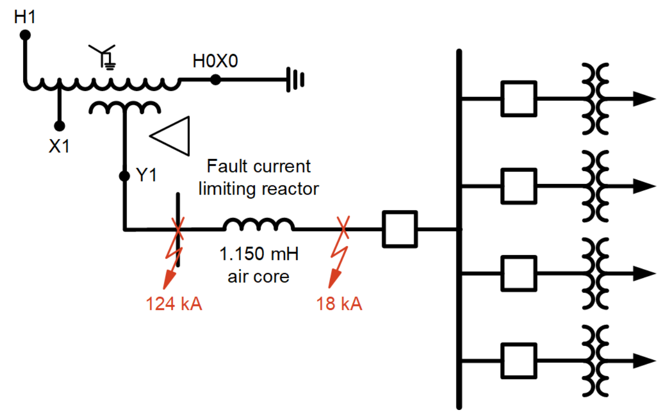

Fig. 3. A fault current-limiting reactor installed outside the delta-connected tertiary winding to reduce extremely high fault current.

If the tertiary winding is not used to feed loads from the auxiliary substation service, one of the winding terminals must be solidly grounded to stabilize the potential of the winding.

A. Bank Configuration (Made of Single-Phase Units and Spare Unit)

Nowadays, life is increasingly connected and dependent on equipment that uses electrical energy to function.

This great demand for energy calls for larger and more powerful autotransformers.

It is common to facilitate these large autotransformers' construction, transportation, and maintenance using autotransformer banks built of three single-phase units and a spare unit.

After a fault in one of the phase units, the spare unit is put in service in place of the failed phase unit to put the bank in service again as fast as possible.

III. Types of Faults

In autotransformers, there are normally three different types of electrical faults. These electrical faults include winding-to-ground faults, which can be divided into faults far from the neutral point and near to the neutral, interwinding faults, and interturn faults of the same winding [3].

A. Winding-to-Ground Faults

Winding-to-ground faults are the most common internal faults for autotransformer banks. In addition, there are two types of partial winding-to- ground faults, faults whose location in the winding is far from the neutral point and faults close to the neutral point.

Faults far from the neutral point produce large phase current variations. Protection functions, which use phase currents as operating quantities, can be used effectively to monitor this type of fault. This is the case with phase differential protection.

Faults close to the neutral point are characterized by small changes in the differential current and large currents in the neutral of the autotransformer. It is possible to measure this neutral current with a CT installed in the connection from the neutral point to the ground, with the polarity facing the ground connection.

B. Turn-to-Turn Faults

Turn-to-turn faults are characterized by small changes in the differential currents and large fault currents in the loops. These faults can be detected more easily by applying the negative-sequence differential element [4].

C. Winding-to-Winding Faults

Winding-to-winding faults are characterized by large variations in the currents of the windings involved in the fault. This means that protection elements that use phase currents as operating quantities can readily detect these faults. Typically, phase differential elements are used to detect and isolate these types of faults.

IV. Autotransformer Bank Protection Requirements

Considering that autotransformers are critical assets in the power systems, their protection schemes must be secure and dependable. For internal faults in an autotransformer bank, normal operating conditions, and external events, it is expected that the protection scheme applied is capable of covering the following requirements:

- Provide reliable faulted phase indication to allow the quick replacement of the failed unit with the spare unit in the case of an internal fault. Quick replacement is vital to increase autotransformer availability and reduce transmission grid companies (TGCs) loss of revenue and penalties.
- Be sensitive to all internal faults, including partial winding faults, as turn-to-turn faults and turn-to-ground faults near the neutral point, especially during high-load conditions.
- Provide protection for the primary, secondary, and tertiary windings.
- Provide high security for inrush currents, but also trip quickly when energizing a faulted autotransformer.
- Be secure for external faults with CT saturation and dependable for internal faults with CT saturation.

Provide a fast trip decision for all internal faults in the autotransformer units and lead buses. Proper signaling indicates the fault location, whether in the lead buses or internal to the tank. Autotransformers require high-speed protection to mitigate catastrophic consequences of internal faults, such as tank rupture and the melting of core steel. Fig. 4 shows the protected areas that the autotransformer protection system should cover in a bank composed of three single-phase and one spare unit and have dual circuit breaker configuration in the primary and secondary sides. BHT, BXT, and BYT are the lead buses of the high-voltage, medium-voltage, and low-voltage sides, respectively. ATR is the autotransformer.

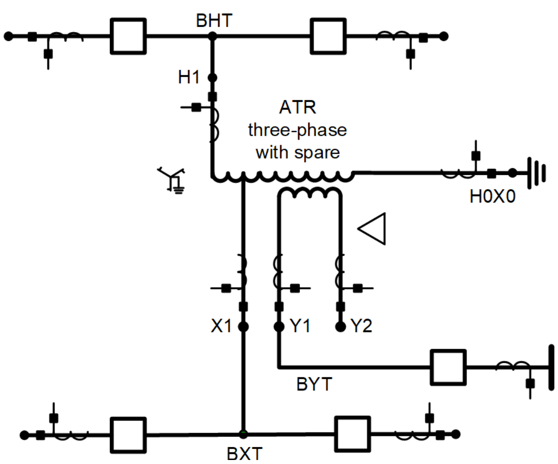

Fig. 4. Autotransformer protection area in a topology with dual circuit breakers on the H and X sides.

The selective fault region indicator is important for autotransformer banks made of three single-phase autotransformer units and a spare unit. The proper indication of the faulted unit and the fault region allows the quick replacement of this unit with the spare unit, reducing the autotransformer bank unavailability.

V. Unit Protection

Several protection schemes can protect power autotransformer units against internal faults. Each of these schemes can detect one or more autotransformer types of faults. Likewise, each has its advantages and drawbacks. This section briefly reviews the main protection elements applied for the autotransformer unit protection.

A. Differential Protection Elements

1) KCL Differential Element (KCL 87t) Principle

In autotransformers where in addition to the primary (H) and secondary (X) bushing CTs, there are CTs available in the common-winding star point, a differential scheme based on KCL can be deployed, as shown in Fig. 5.

Given the galvanic connection between the high-voltage, medium-voltage, and common windings, it is possible to apply a differential scheme based on the KCL, which says that the sum of the currents flowing into a node shall be zero. This is always true if there is no internal fault between the three CT sets shown in Fig. 5.

In such a scheme, there is no need to compensate for the tertiary delta current, resulting in a phase-selective element. In addition, it is not affected by the autotransformer inrush current. However, it is sensitive to partial turn-to-ground faults as the high fault current passes through the common-winding CT. On the other hand, it cannot detect turn-to-turn faults, given that this fault does not result in a differential current in the node.

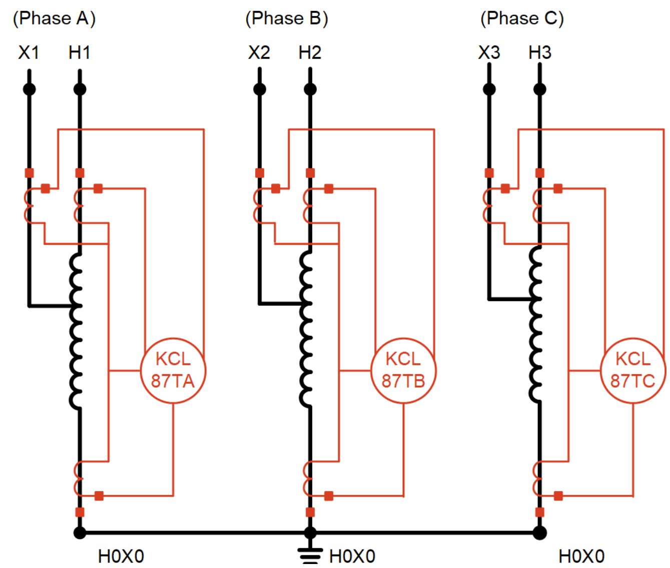

Fig. 5. Autotransformer KCL-based low-impedance differential element principle (tertiary winding not shown for simplicity).

The KLC-based differential scheme can be deployed in a low-impedance differential element fashion or a high-impedance differential element fashion [5].

For the low-impedance differential implementation, the secondary currents received by the relay need to be converted into primary values before composing the phase differential (I_{OP}) quantity and phase restraint quantity (I_{RST}). These quantities are then used to implement a percentage-restraint differential characteristic.

For the high-impedance differential implementation, dedicated CTs with the same ratio are required.

2) ATB Differential Element (ATB 87T) Principle

In an autotransformer bank, each phase has its magnetic circuit, allowing ATB equations to be written for each phase individually [6]. For example, the ampere-turn (AT) equation for a three-winding autotransformer phase can be expressed as in (2), considering the tertiary CTs are internal to the delta:

$$N_H \cdot I_H + N_X \cdot I_X + N_Y \cdot I_Y = 0 \tag{2}$$

A single-phase basis tap equation can be used to calculate the normalization tap factor for each winding [5], as show in (3).

$$\text{TAPn} = \frac{\text{MVA} \cdot 1{,}000}{\text{kVn} \cdot \text{CTRn}} \tag{3}$$

where:

TAPn is the magnitude normalization factor and n is the winding designation.

MVA is the single-phase rating of the autotransformer.

kVn is the voltage rating of the winding n in kilovolts.

CTRn is the CT ratio for Winding n.

The way an ATB-based differential element is applied in autotransformers is impacted mainly by the availability and location of CTs in the tertiary winding.

a) Autotransformer Without CTs at Tertiary Winding

In applications of three-phase autotransformers with a single tank, when the delta tertiary winding is buried in the autotransformer tank, CTs are not usually available inside the delta winding and only the CTs at the H and X windings are available for the ATB 87T element, as shown in Fig. 6. In these applications, the delta winding is not loaded and used as a stabilizing winding.

As the tertiary-winding CTs are unavailable and zero-sequence currents circulate inside the delta for unbalanced faults involving ground, the ATB 87T element must compensate for zero-sequence current in both primary and secondary windings. However, the need to compensate does not allow a proper faulted phase identification by the ATB 87T element operation in case of SLG faults.

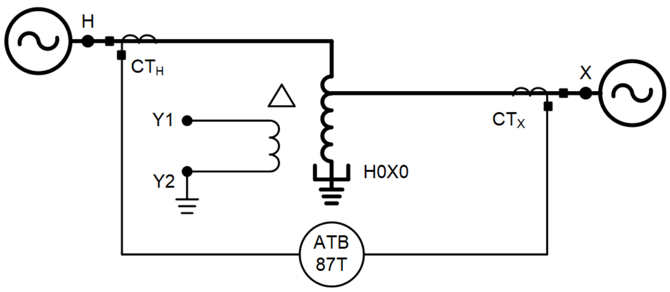

Fig. 6. ATB-based differential element applied in an autotransformer without CTs at tertiary winding.

b) Autotransformer With CT Available in Tertiary Winding

In applications of autotransformer banks, each phase has its closed magnetic circuit, and the tertiary delta winding is connected outside the autotransformer tank. As the CT is normally located on the phase unit bushing and the tertiary delta connection is made through the connection of external cables and buswork, the current inside the delta winding is easily available to be used by the protection system [5].

With at least one CT available at each tertiary winding, the inclusion of the tertiary-winding current in the ATB differential scheme is possible, as shown in Fig. 7. The main advantage of this configuration is that there is no need to compensate for zero-sequence current in the primary and secondary windings. This scheme can be used regardless of whether the tertiary winding is loaded or not.

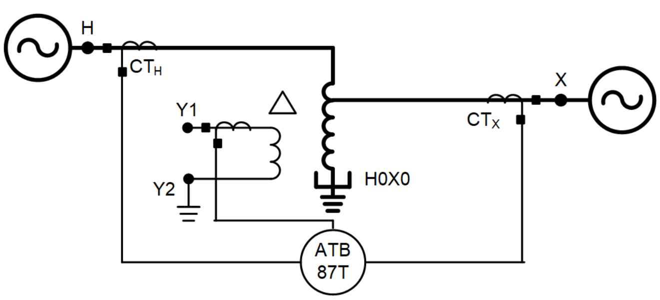

Fig. 7 ATB differential element with CT available at the tertiary winding.

Some autotransformers have two CTs available on each side of the tertiary windings, as shown in Fig. 8. In this configuration, the CTs can be paralleled with additive polarity, resulting in a measured current twice the current inside the delta winding. This is important to guarantee the detection of phase-to-ground faults anywhere inside the delta winding when a grounding transformer is located on the tertiary-winding network [7] [8].

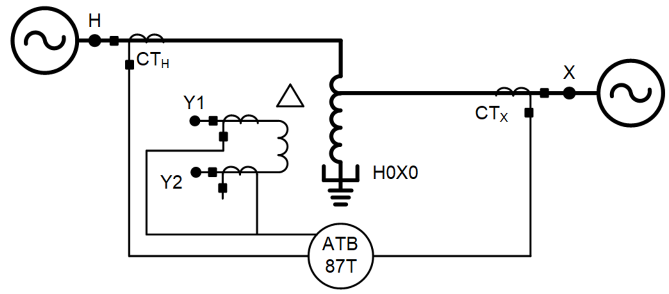

Fig. 8. ATB differential element with CTs available at both sides of the tertiary winding.

3) Negative-Sequence Differential Element (87Q) Principle

The main reason to apply negative-sequence differential elements in autotransformers is the increased sensitivity this element provides for low-phase current faults, such as turn-to-turn faults. In addition, the negative-sequence restraint (I_{2RST}) current is low even during high balanced load conditions, allowing the 87Q elements to have increased sensitivity compared with the phase differential element [4].

Turn-to-turn faults do not generate differential current for KCL-based implementations. On the other hand, they do generate negative-sequence differential current for the ATB-based implementations [4]. For this reason, applying the 87Q element in an ATB-based protection scheme is recommended.

The ATB-based 87Q element calculates the negative-sequence currents from the phase current in each monitored winding of the autotransformer to compose the negative-sequence differential current ($I2_{OP}$) and the negative-sequence restraint ($I2_{RST}$) [4].

As the negative-sequence current calculation involves the three-phase currents, its operation does not directly indicate which is the faulted tank, and further analysis is required to identify it.

B. REF Protection Elements

REF elements are intended to provide coverage for partial winding-to-ground faults. These faults near the neutral point result in a small change in the phase current; however, high current flows between the faulted turns.

The small change in the primary and secondary phase currents makes the partial winding-to-ground faults challenging to be detected by the ATB-based phase differential element, especially during high-load conditions. However, as the path for this fault includes the ground, the high fault current also flows through the transformer neutral point, and a protective relay can measure it. Using the neutral current (I_N) and the zero-sequence currents at the high-voltage side ($I0_H$) and medium-voltage side ($I0_X$), an REF element can be implemented in a directional-based REF (32 REF) or differential-based (87N REF) fashion.

Fig. 9 illustrates the currents I_N, $I0_H$, and $I0_X$ for two different fault locations, an external fault (F1), represented by the red arrows, and for an internal fault (F2), represented by the green arrows.

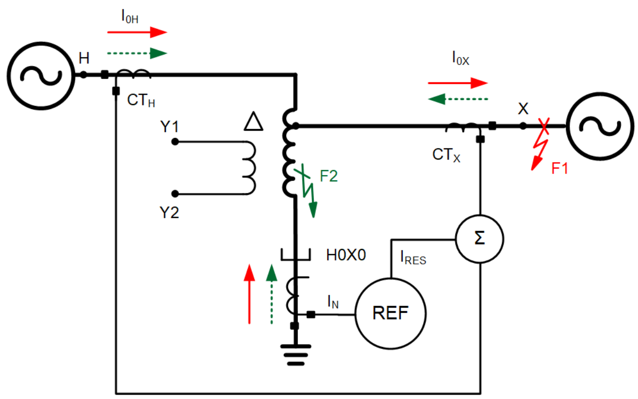

Fig. 9. Example of autotransformer expected zero-sequence currents for external (F1, solid arrows) and internal (F2, dashed arrows) faults.

Directionally, the currents I_{0H} and I_{0X} are added to compose the residual current (I_{RES}), and I_N is the operating current [9]. I_{RES} and I_N are expected to be in opposite polarity for external faults and in-phase for internal faults near the autotransformer neutral point.

In the differential fashion, I_{RES} and I_N compose a zero-sequence differential quantity ($I0_{OP}$) and a zero-sequence restraint quantity ($I0_{RST}$) These quantities are used to implement a percentage-restraint differential characteristic.

Heavy phase-to-phase external faults, including ground or not, can give rise to false zero-sequence differential current due to phase CT saturation. Therefore, to avoid the undesired operation of the 87N REF element, some implementations include directional supervision for 87N REF. This directional supervision principle of operation is similar to the 32 REF element described before.

C. *Tertiary—Dedicated Differential*

For autotransformers with CTs available on each side of the delta tertiary winding, like the configuration shown in Fig. 10, it is also possible to implement a dedicated differential element.

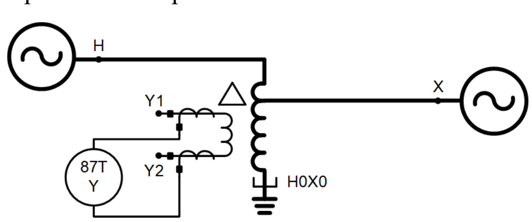

Fig. 10. Delta-dedicated differential element when CTs are available at both sides of the tertiary winding.

The tertiary delta winding dedicated differential element is based on the KCL principle, so there is no need to compensate for zero-sequence current. However, as this element operates based only on the delta currents, it can be set according to the delta winding rating and not the whole autotransformer rating, which results in an element more sensitive to faults in the delta winding.

In applications where the delta winding is loaded and a grounding transformer is used, this element can provide coverage for ground faults in the delta winding. A final advantage of this scheme is that it only operates for faults in the delta winding and is phase-based, providing a clear indication of the faulted unit and location.

As this differential element is based on the KCL principle, it cannot detect turn-to-turn faults in the delta winding.

D. *Distance Elements With Directional Comparison Logic*

Distance elements can be applied as primary or backup protection for autotransformers. Instantaneous Zone 1 elements have a typical maximum setting of 70 percent of the autotransformer impedance, and the Zone 2 distance elements have a typical maximum setting of 200 percent of the transformer impedance. This is because the tertiary delta winding provides a low-impedance path for the zero-sequence current during external ground faults. For this reason, in autotransformers with this configuration, the Zone 2 setting must consider this [8]. Instantaneous-phase and ground-distance overreaching elements can be applied with a directional comparison logic, like a permissive overreaching transfer trip (POTT) scheme, to provide internal fault detection, as shown in Fig. 11.

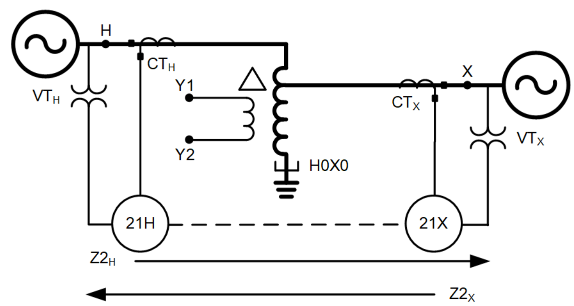

Fig. 11. Overreaching distance elements applied with a directional comparison scheme to detect internal faults in an autotransformer.

The 21H and 21X elements shown in Fig. 11 can be implemented in a single relay or in two different distance relays, according to the project details and relay capabilities. If they are in two different relays, the permissive signal (keying) must be transmitted over a wired connection or a local communication, as both are located in the same substation.

VI. Low-Impedance Directional-Based REF

As discussed in the previous section, REF sensitivity to ground faults is better than the phase differential element at identifying internal faults close to the neutral point [9]. The phase current is low when the fault is close to the neutral. Differential elements, which respond to phase current, have low sensitivity for ground faults close to the transformer neutral. On the other hand, the neutral current is very high for these faults. Therefore, REF protection, which responds to neutral current, can detect ground faults close to the transformer neutral.

One of the methods to implement an REF element is using directional elements; such an option has advantages in terms of security when residual current (I_{RES}) derived from phase CTs and current from a neutral current transformer (I_N) are used to implement the REF protection, as shown in Fig. 9.

In the case of an external fault, the phase CTs can saturate. Therefore, the REF is implemented using a low-impedance differential element. In that case, a misoperation can occur due to the false differential current caused by the phase CT saturation since the restraint current may not be high enough. Therefore, directional-based REF elements and high-impedance differential elements are more secure for external faults with CT saturation [3] [9].

A. Principle of Operation

The low-impedance directional-based REF element measures the phase angle between the transformer neutral current (I_N) and the residual current at the transformer terminals (I_{RES}), see Fig. 1. The element uses I_{RES} as a reference current and compares its direction with the operating current obtained from the neutral CT, which is I_N. The characteristic of the directional-based REF element is shown in Fig. 12, with the lined area indicating the tripping area. Because the REF element employs a neutral CT at one end of the winding and one or more sets of three CTs at the line end of the winding, the element can detect only ground faults within that particular wye-connected winding. The element is restricted because protection is limited to ground faults within a zone defined by neutral and line CT placement.

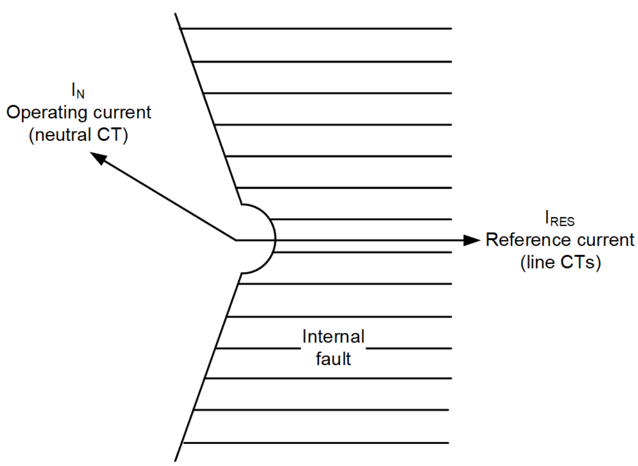

Fig. 12. Characteristic of operation of directional-based REF element.

For external faults, as shown in Fig. 13, the operating and reference currents will be in opposite directions, and the element declares an external fault. For internal faults, it is expected that both currents have the same direction, and an internal fault is declared. The transformer circuit breakers will be tripped to isolate the faulted transformer.

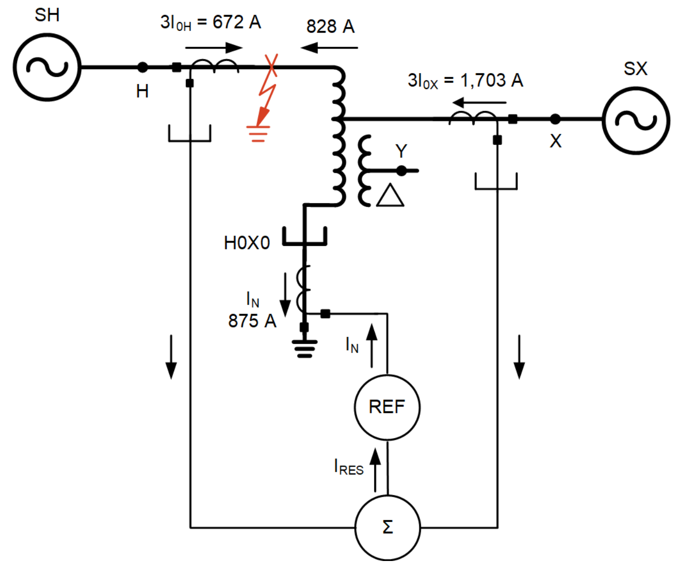

Fig. 13. Example of fault currents for a fault in the high-voltage side of an autotransformer.

The advantages of using directional-based REF are:

- Different ratios can be used for the neutral and line CTs, and the currents can be normalized numerically in the relay.
- It is unnecessary to have dedicated CTs, as in the case of high-impedance REF, so other protection elements can share the same CTs.

B. Application With Autotransformers

It is known that the neutral current direction can be towards the transformer or away from the autotransformer for faults on the high-voltage side [9]. Fig. 13 shows an example from [9] where the neutral current is flowing away from the autotransformer for the in-zone fault in the H so the directional-based REF element will declare an external fault and will not trip since the residual currents from the line CTs are flowing toward the autotransformer, in the opposite direction to the neutral current.

The neutral current will not always flow away from the autotransformer for a fault in the high-voltage side. It depends on the tertiary impedance and the strength of the secondary winding source impedance, Z_{0SX} in Fig. 14.

Fig. 14 shows the zero-sequence network for an SLG fault in the high-voltage side of the autotransformer from Fig. 13, where:

Z_H, Z_X, and Z_Y are the primary, secondary, and tertiary autotransformer impedances, respectively.

Z_{0SH} and Z_{0SX} are the equivalent source impedances from the primary and secondary sides, respectively.

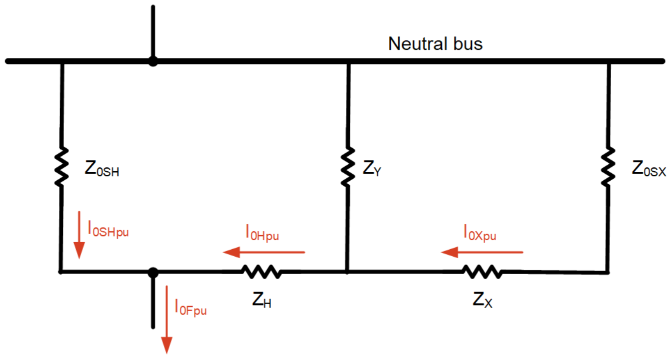

Fig. 14. Autotransformer zero-sequence network for an SLG fault in the high-voltage side.

The per-unit zero-sequence current in the secondary side of the autotransformer can be written as shown in (4).

$$I_{0Xpu} = \frac{Z_Y}{Z_Y + Z_X + Z_{0SX}} \cdot I_{0Hpu} \qquad (4)$$

One can see that if Z_Y is much greater than ($Z_X + Z_{0SX}$), the primary current (I_{0Hpu}) will be almost equal to the autotransformer secondary current (I_{0Xpu}) per unit. Consequently, the secondary current (I_{0X}) in amperes will be greater than the primary current (I_{0H}) in amperes, so the neutral current (I_N) will flow away from the autotransformer, as shown in Fig. 13.

As discussed in previous sections, it is common practice to use fault-current-limiting reactors installed in series with the tertiary winding inside the delta, see Fig. 2. The total impedance for the tertiary will be the sum of the winding and reactor impedances. So, it is not uncommon to have a tertiary impedance much larger than the primary and secondary impedances for autotransformers in the transmission system. Table I shows the Z_H, Z_X, and Z_Y values for different autotransformer banks. The tertiary impedance is much larger for the units with a reactor installed inside the tertiary delta winding.

TABLE I
IMPEDANCES AUTOTRANSFORMER BANKS (S_{BASE} = 100 MVA)

Equipment	Reactor Inside Delta	Z_H (%)	Z_X (%)	Z_Y (%)
500/230/13.8 kV 3 • 200 MVA	Yes	2.13	–0.27	22.93
525/440/13.8 kV 3 • 500 MVA	Yes	0.42	0.27	20.58
500/230/13.8 kV 3 • 150 MVA	Yes	3.1	–0.27	23.09
500/230/13.8 kV 3 • 200 MVA	No	1.46	0.13	2.64
500/230/13.8 kV 3 • 100 MVA	Yes	3.45	–0.04	77.37
525/230/13.8 3 • 100 MVA	No	2.48	–0.11	6.38

The natural question that arises before this situation: is this a problem for the autotransformer protection system when the directional-based REF element is applied? Let us answer such a question in the next section with a field case study.

C. Directional-Based REF Field Case Study

The 500/230 kV system shown in Fig. 15 experienced a fault in the high-voltage side of autotransformer ATR 1, 600 MVA. The protective relay includes the phase differential and directional-based REF elements, among other protection elements. The protective relay is connected to the circuit breaker CTs. An SLG fault happened between the circuit breaker and ATR 1, so inside the zone of unit protection.

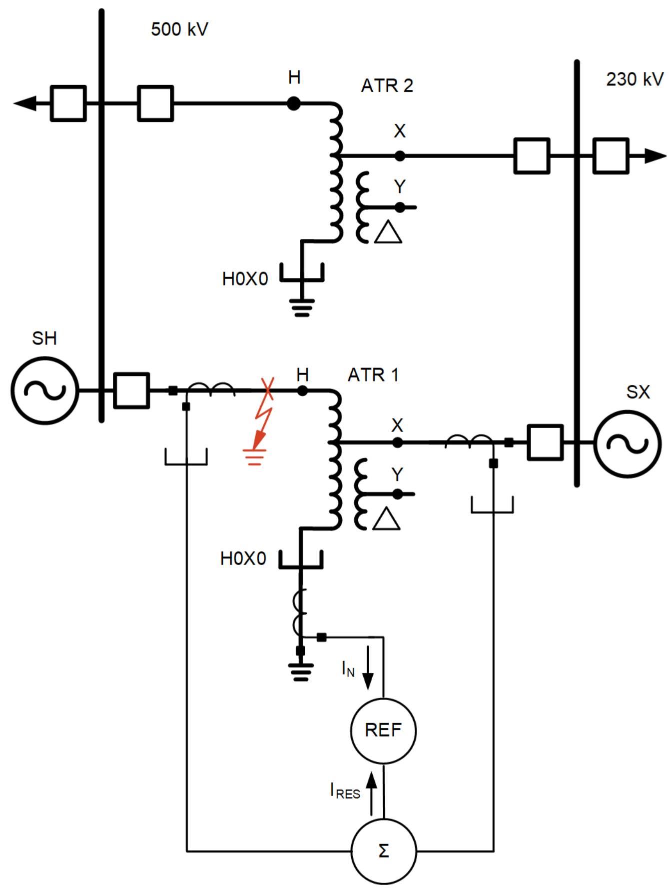

Fig. 15. Field case study–fault in the high-voltage side of ATR 1.

Fig. 16 shows the event report for the in-zone SLG fault for ATR 1. It is possible to see that the currents I_N and I_{RES} are flowing in opposite directions, so the REF element declares an external fault, as can be seen in the digital chart of Fig. 16, REF_EXT asserted and REF_INT did not assert. However, the differential element (87T) detected the fault reliably, and the total fault was cleared in 3.5 cycles. As mentioned previously, the REF element is intended to detect faults that the differential element may not be sensitive enough to, like faults close to the neutral point. The performance of the protection system for the fault discussed cannot be considered unsatisfactory since the protection system could detect the fault and trip the circuit breakers to isolate the faulted equipment.

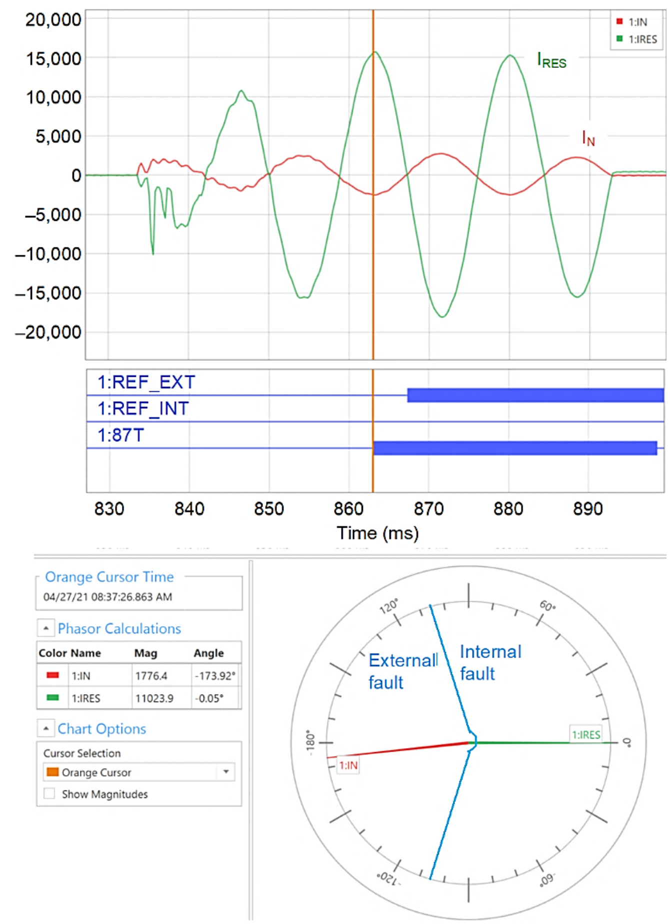

Fig. 16. Field case study–event report for the fault in the H side of ATR 1.

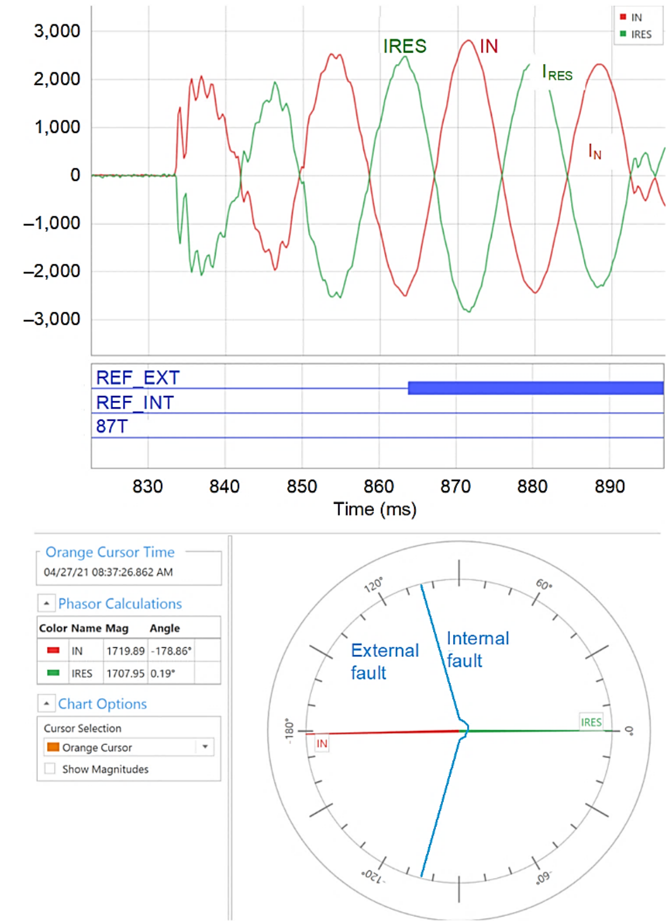

Fig. 17. Field case study–event report from the ATR 2 protection system for the fault in the H side of ATR 1.

We can now ask if the directional-based REF will misoperate for an external fault on the H side when the neutral current experiences the same behavior, i.e., flowing away from the autotransformer. This question is answered by analyzing the currents for the ATR 2 bank that is connected in parallel to ATR 1 bank, so the same fault is external to the ATR 2 protection system. Fig. 17 shows the event report from the ATR 2 protection system. It can be seen that the currents I_N and I_{RES} are flowing in opposite directions, so the REF element declared an external fault, REF_EXT asserted, and REF_INT did not assert, and the 87T did not assert, as expected, because it is an out-of-zone fault. The directional-based REF remains secure for external faults even when the neutral current flows away from the autotransformer. This is because when the neutral current presents such behavior for a fault on the H side, the zero-sequence current entering the Winding X is higher them the zero-sequence current leaving the Winding H, so I_N and I_{RES} will always be in opposite directions for such an external fault.

As previously mentioned, the REF is supposed to detect internal faults close to the neutral point where the phase differential element does not have good sensitivity. So, let's check the REF sensitivity for internal faults in the autotransformer of the field case study. To do so, a simulation program calculates the expected currents for such faults.

The autotransformer data are as follows:

- 500/230/13.8 kV, 600 MVA.
- Z_{HX} = 11.20 percent on 200 MVA.
- Z_{HY} = 150.4 percent on 200 MVA.
- Z_{XY} = 136.0 percent on 200 MVA.

Table II shows the calculated currents I_N and I_{RES} for internal partial winding faults in different locations. The percentage location is measured from the neutral point, and the currents are in primary values, angles are given in reference to I_{RES}, and the load current is 100 percent of autotransformer rated power, for a 30 percent load current the result is quite similar. The REF element is configured with a pickup value of 150 A_{PRI}.

TABLE II
SENSITIVITY FOR THE REF ELEMENT

Fault Location (%)	I_N (APRI)	IRES (APRI)	REF Sensitivity	87T Sensitivity
1	27,700∠0.8°	410∠0.0°	TRIP	NO TRIP
2	19,790∠–0.5°	711∠0°	TRIP	NO TRIP
3	14,686∠–0.5°	806∠0°	TRIP	NO TRIP
4	11,728∠–0.6°	875∠0°	TRIP	NO TRIP
5	9,991∠–0.6°	943∠0°	TRIP	NO TRIP
6	8,710∠–0.6°	1,015∠0°	TRIP	NO TRIP
7	7,866∠–0.6°	1,091∠0°	TRIP	TRIP
8	7,250∠–0.6°	1,173∠0°	TRIP	TRIP
9	6,786∠–0.6°	1,263∠0°	TRIP	TRIP
10	6,439∠–0.7°	1,361∠0°	TRIP	TRIP
15	5.527∠–0.7°	1,967∠0°	TRIP	TRIP
20	5,273∠–0.8°	2,847∠0°	TRIP	TRIP
40	3,180∠–1.8°	7,512∠0°	TRIP	TRIP
60	1,362∠–1.3°	12,680∠0°	TRIP	TRIP
70	401∠4.4°	13,590∠0°	TRIP	TRIP
75	98∠145.63°	13,510∠0°	NO TRIP	TRIP

Table II shows that the REF is sensitive enough to detect partial-winding faults up to 70 percent from the neutral point, for the specific load configuration. Table II also shows that, for this specific application, the phase differential element, configured as shown in Table III, is not capable of detecting faults under 7 percent of the winding when the autotransformer is loaded at 100 percent of the rated power, showing that there is an overlap in the protection coverage between the directional-based REF and the differential element.

TABLE III
ATB-BASED DIFFERENTIAL ELEMENT SETTINGS

Setting	Value
CTR 500 kV	2,000
CTR 230 kV	1,600
CTR 13.8 kV	4,000
TAP 500 kV (A)	0.35
TAP 230 kV (A)	0.94
TAP 13.8 kV (A)	6.28
Pickup restrained element (PU)	0.30
Slope 1 (%)	25
Slope 2, adaptive (%)	50
Pickup unrestrained element (PU)	10

The tests show that for this application, there are no concerns about the performance of the directional-based REF, since the element works in a complementary way with the 87T element.

D. Directional-Based REF Applied to Autotransformer Banks

Autotransformer banks made of three singe-phase units have CTs available on the line sides (H and X bushings) and on the neutral side (H0X0 bushing) of the windings, see Fig. 18. Faults in the tertiary winding are not detected by the REF element, so it is not shown in the figure for simplicity. The application with the residual connection of the H0X0 bushing CTs to measure I_N, as shown in Fig. 18, may jeopardize the security of the directional-based REF scheme because of the possibility of false zero-sequence current for external faults when one of the H0X0 CTs saturates.

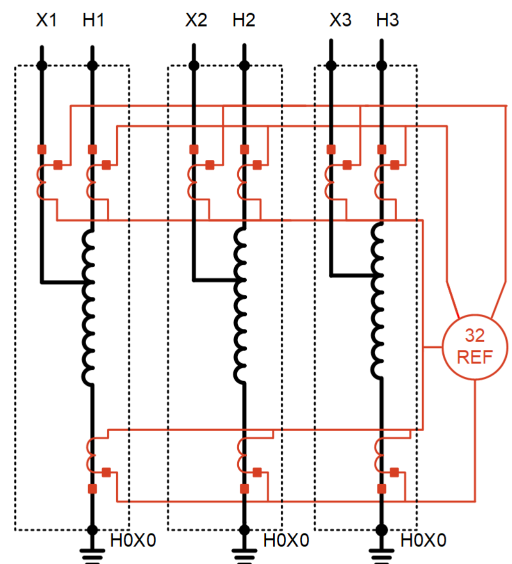

Fig. 18. Not recommended application of directional-based REF using residual connection of H0X0 bushing CTs.

The application of the directional-based REF element must be considered only when there is a single external CT to measure the neutral current, as shown in Fig. 19. However, such a scheme, when applied to autotransformer banks consisting of three single-phase units, typically does not give a positive indication of the faulted phase tank [4], which will impose additional time to the task of replacing the faulted phase tank with the spare tank. As discussed later, this fact can impose penalties on the transmission company owning the autotransformer bank.

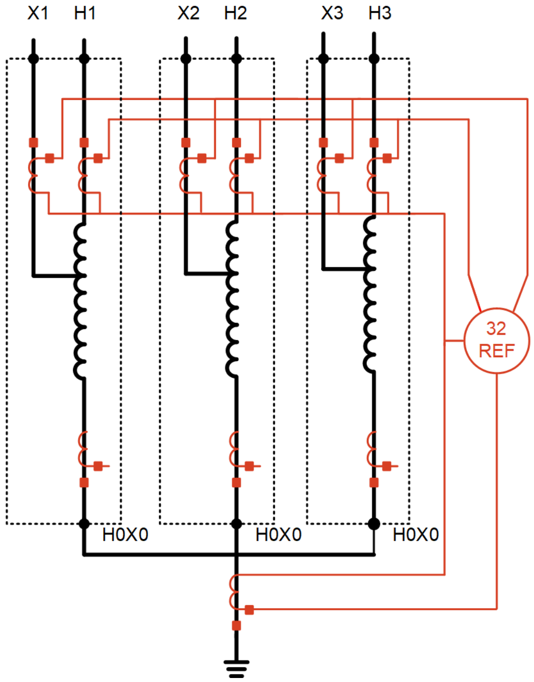

Fig. 19. Directional-based REF applied to an autotransformer bank with a single neutral CT.

Two other protection schemes that can be applied to reliably detect faults close to the neutral point and provide a positive indication of faulted phase tank in autotransformer banks are:

- Per-phase high-impedance differential element, Fig. 20. This scheme is inherently secure for CT saturation and provides great sensitivity for partial-winding SLG faults. However, the drawback of such a scheme is that it requires dedicated CT cores with equal ratios and magnetizing characteristics.
- Per-phase percentage low-impedance differential element based on KCL for electrically connected windings as shown in Fig. 5.

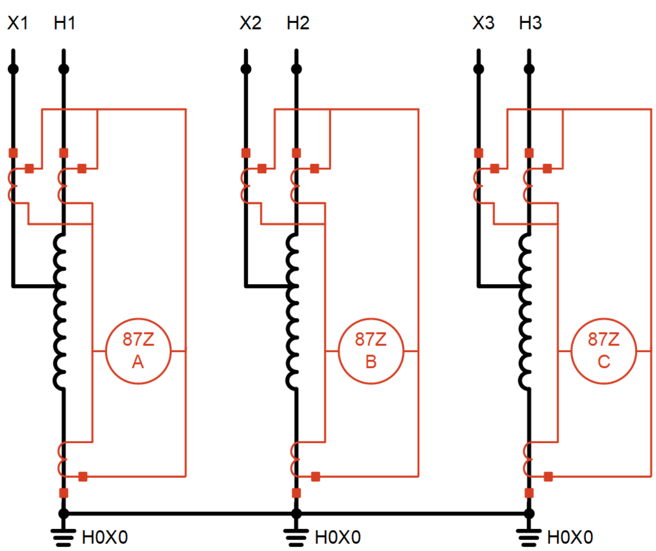

Fig. 20. Three-phase high-impedance differential element scheme (tertiary winding not shown for simplicity).

VII. Differential Protection

A differential element is used as unit protection for important equipment in the transmission power system, e.g., transformers, autotransformers, phase-shifting transformers, reactors, busbars, cables, etc.

Differential relays have been applied for autotransformer protection for many decades. They are easy to configure, have good sensitivity, and the protected zone is limited by the location of the CTs to which the relay is connected, providing excellent selectivity.

A. ATB-Based Differential Element

As mentioned in previous sections, a differential element can be implemented based on the ATB principle, ATB-based differential element. This principle responds to the magnetic transformer circuit's AT balance. The ATB-based differential element monitors the transformer's electric and magnetic circuits. Internal transformer faults disrupt the AT balance, which allows ATB-based differential elements to detect internal transformer faults, including turn-to-turn faults.

To securely apply an ATB-based differential element in an autotransformer, it is mandatory to include proper compensations for the following possible situations that can cause the relay to measure a differential current:

1. Current magnitude mismatch among the windings.
2. Steady-state CT ratio error.
3. Unequal CT saturation.
4. On-LTC.
5. Current phase shift across the transformer.
6. Zero-sequence current sources.
7. Magnetizing inrush currents.
8. High excitation current on overexcitation.

1) Current Mismatch and Errors Compensation

To compensate for the current magnitude mismatch, the selected CT ratios for different windings must exactly match the inverse of the transformer turns ratio; however, this is an ideal situation that cannot be accomplished in all applications because the available CT ratios typically do not provide exact ratio matching. For this reason, the differential relays have taps for scaling the currents. In the case of digital differential relays, the user can select the tap value in a continuous range, allowing full compensation for the current amplitude differences resulting from the mismatch between the CT ratios and connections and the power transformer turns ratios and connections [10]. Autotransformers usually have different rated power for the tertiary winding compared to the primary and secondary windings; however, the base power to calculate the tap for all windings must be the same.

To compensate for steady-state CT ratio errors, CT saturation, and LTC, a percentage restrained differential element is applied. In this case, the differential element has an adaptive pickup proportional to a quantity derived from the currents measured at each winding, called restraint current (I_{RST}) or through current. A common method uses the sum of current magnitudes measured from each transformer winding as the restraint current. The proportionality constant is called slope. The slope characteristic provides good sensitivity for low through currents (light load), but the increase in the required differential current to cause operation when high levels of current are flowing increases security, and this is a desirable behavior because CTs are more prone to saturation when they have to reproduce high levels of current in the primary circuits. Modern differential relays use an adaptive-slope percentage differential characteristic for increased security and sensitivity. The algorithm implements an internal and external fault detection logic, which uses the unfiltered currents to switch from a low values slope (SLP1) to a higher value slope (SLP2) when an external fault is detected. This increases security in case of CT saturation for that external fault while keeping a more sensitive slope for all other operating conditions, see Fig. 21 [11].

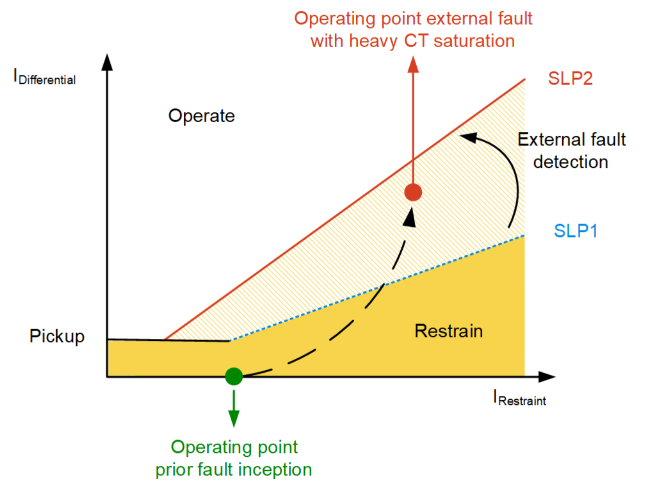

Fig. 21. Adaptive percentage restrained differential characteristic.

With modern digital differential relays, the current phase shift compensation and the zero-sequence removal, when required, are performed in the relay algorithm. Typically, matrix equations are used to calculate compensated currents for each winding using the measured currents, and the CTs can be connected in wye [10].

2) ATB-Based Differential Element With Harmonic Security

Transformer energization is a typical cause of inrush currents, which are seen as operating quantities by the differential element and can cause undesirable operations. Therefore, many differential relays use the even harmonic content (the second harmonic in particular) to prevent misoperation on inrush current.

The harmonic content of the differential current serves to differentiate faults from inrush and overexcitation conditions. In addition, harmonics can be used to restrain or block the transformer differential element.

Harmonic-restraint methods use harmonic components of the differential current to provide additional differential element restraint, basically boosting the restraint current with the addition of a certain portion of the second and fourth harmonic present in the differential current and consequently desensitizing the differential element. Conversely, harmonic-blocking methods block the differential element when the ratio of the harmonic content to the fundamental component of the differential current is above a preset threshold [10].

One of the issues with the use of harmonic content to secure the ATB-based differential element is that during the inception of an internal fault, the digital filtering will measure harmonic content during the rise of the differential current, which will delay the operation of the restrained differential element. For example, Fig. 22 shows that the second harmonic content takes about one cycle (16.67 millisecond) to reach zero after the rise of the differential current.

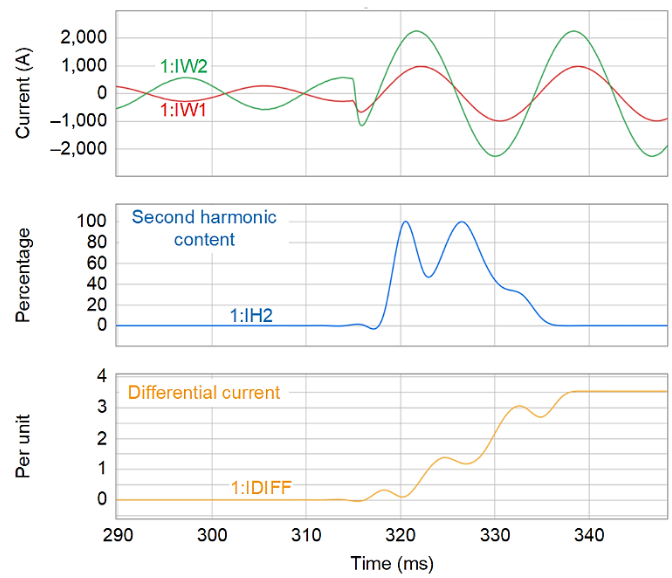

Fig. 22. Second harmonic content after fault inception.

The consequences of such behavior of the ATB-based differential protection secured with harmonic content can be clearly seen in a field case where a fault happened in the overlapping area of the autotransformer ATR protection (87T) and the busbar protection (87B) zones as shown in Fig. 23. Actually, the fault was in the free-standing CT connected to both protection systems.

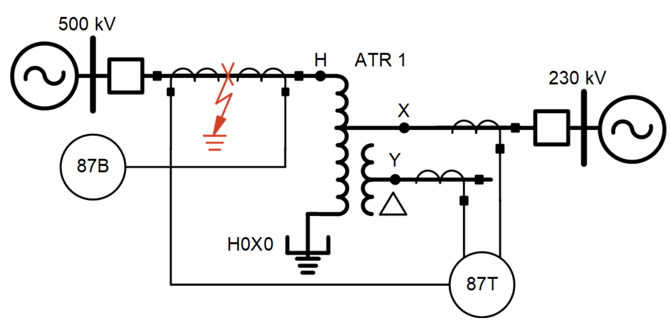

Fig. 23. Field case study, fault in the overlapping of the autotransformer differential (87T) and the busbar differential (87B).

It is evident in Fig. 24 that the tripping time of the busbar differential element, which employs the KCL principle and does not have and does not need harmonic security, is lower than the autotransformer protection, which is an ATB-based element and has harmonic restraint, 14 milliseconds versus 35 milliseconds, respectively. This field case has the particularity that the fault current included distortions for a longer time than usual after the fault inception, which made the second harmonic content take longer to fall below the threshold to release the autotransformer restrained differential element. Still, it is a good example of how the KCL-based element can be faster than the ATB-based one.

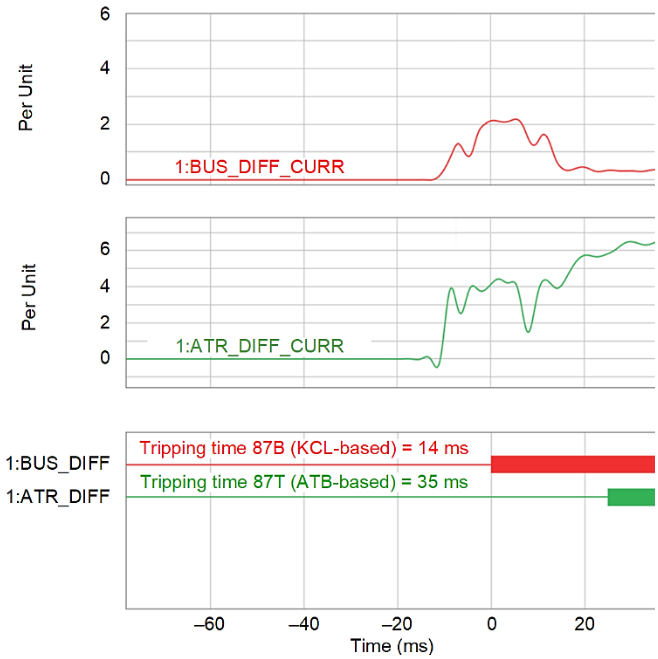

Fig. 24. Field case study, fault in the overlapping of the autotransformer differential (87T) and the busbar differential (87B).

Some transformers with high-permeability core steel can experience ultrasaturation during inrush, which translates into much less distortion in the inrush current and lower harmonic content [12], which challenges the effectiveness of traditional harmonic-blocking and harmonic-restraint schemes. Suppose a decision is made to lower harmonic-blocking thresholds or increase harmonic-restraint percentage. In that case, the consequence is a reduction in dependability and speed for heavy internal faults with CT saturation and internal faults during inrush. Modern digital relays implement time-domain algorithms to differentiate between inrush and internal fault, which will be discussed later.

3) ATB-Based Unrestrained Differential Element

In ATB-based autotransformer differential protection, the CTs can saturate for internal faults, and the harmonics caused by CT saturation can delay the operation of differential elements with harmonic-restraint or blocking principles. For this reason, to complement the restrained element, it is common to implement an unrestrained differential element, which is intended to rapidly detect very high magnitude currents that indicate an internal fault and trip faster than the restrained differential element.

Recommendations found in the instruction manuals of some transformer relays say that if the relay is applied in a dual breaker terminal. The circuit breaker CTs are used for the differential element. Spurious differential current may occur from CT saturation during an external fault, and this must be considered as the limiting factor in setting the unrestrained differential element. In this case, it is recommended to take the maximum bus fault per unit of the TAP value, multiply by the estimated CT saturation (e.g., 50 percent), and round up to the nearest integer value. This practice can impose a very large value for the unrestrained differential pickup, which will clearly cause a reduction in the sensitivity and, consequently, dependability of the protection scheme. So, it is not a good practice to use the circuit breaker CTs for the transformer differential protection in applications with dual breakers, like breaker-and-a-half arrangements. In such applications, it is recommended to have a dedicated protection element to detect faults in the lead bus and connect the autotransformer differential element to the bushing CTs.

4) Time-Domain-Based Transformer Protection

To improve the performance of the ATB-based differential element, modern relays include methods based on time-domain to increase the speed of the ATB-based protection while maintaining security. In [12], some of these methods are described and listed following:

- Waveshape-based inrush detection and blocking logic
- Waveshape-based bipolar unblocking logic
- Waveshape-based bipolar high-set unrestrained element logic

a) Waveshape-Based Inrush Detection Logic

One of the methods to detect inrush conditions is based on the waveshape of the differential current, which presents repeating periods of small and flat differential current ("dwell-time" periods). At the same time, such behavior is not present in a fault current. The algorithm uses this small and flat interval to detect transformer inrush and supervise the percentage restrained differential elements, blocking the element in case of a transformer energization. Furthermore, the algorithm addresses autotransformer banks built from single-phase units with a specific method that monitors each phase individually since the dwell times still exist in each phase but do not necessarily coincide like the three-legged three-phase transformers.

b) Waveshape-Based Bipolar Logic

The use of waveshape-based inrush detection and blocking logic to increase security during transformer energization does not inherently improve the transformer differential protection speed.

An opportunity for improving speed is based on the fact that the inrush current, when high, is asymmetrical, i.e., unipolar. It becomes more symmetrical over time as the inrush current decays into a steady-state excitation current. A waveshape-based bipolar differential overcurrent element allows for improvements in the operation of the restrained and unrestrained differential elements.

The differential currents for an internal fault that happens during transformer energization are shown in Fig. 25. The first part of the figure, from 0 to 72 milliseconds, shows the unipolar characteristic of the differential currents during an inrush condition. When the internal fault occurs, at 72 milliseconds, in Phase C, the resulting waveform has a bipolar characteristic, as shown in in Fig. 25.

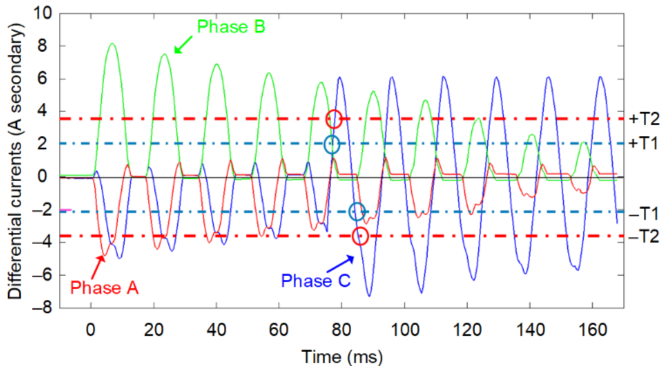

Fig. 25. Differential currents for an internal fault during transformer energization.

The dashed lines +T1 and –T1 in Fig. 25 represent the positive and negative thresholds of a low-set bipolar differential overcurrent element to reset the inrush blocking (the even harmonic blocking and the waveshape inrush blocking). During the inrush condition, the first 72 milliseconds, the differential current from the faulted phase, represented by the blue waveshape, is negative and repeatedly crosses the negative threshold –T1. At the same time, however, it does not cross the symmetrically placed positive threshold +T1. However, when the internal fault happens, the current crosses the positive threshold +T1; shortly afterward, it crosses the negative threshold –T1, and so on. This indicates that an internal fault has occurred, and the blocking signals are reset. This approach allows a faster trip during the energization of a faulted transformer compared to the traditional methods discussed in previous sections.

Also, the high-set bipolar differential overcurrent element is used as an unrestrained differential element. The traditional unrestrained differential element must be set above maximum inrush and maximum spurious differential current for a through fault. The high-set bipolar differential overcurrent element, operating as a new unrestrained differential element, is effectively insensitive to differential current from inrush. Fig. 25 illustrates the operation of the bipolar unrestrained differential element for a fault during an inrush condition. The dashed lines +T2 and –T2 represent the positive and negative thresholds for the high-set bipolar differential overcurrent element. Similar to the low-set bipolar element, when the internal fault with a high current level happens, the current crosses the positive threshold +T2; shortly afterward, it crosses the negative threshold –T2, an unambiguous indication of an internal fault.

B. KCL-Based Differential Element

As discussed, the KCL-based differential element shown in Fig. 5 can be applied to electrically connected windings. This scheme is not affected by situations that can adversely affect the ATB-based differential element and consequently do not require compensation for:

1. Current magnitude mismatch among the windings
2. On-LTC
3. Current phase shift across the transformer
4. Zero-sequence current sources
5. Magnetizing inrush currents
6. High excitation current on overexcitation

This makes the scheme very fast, sensitive, secure, and simple. It is much more sensitive to partial-winding SLG faults, which have the highest probability of happening in autotransformer transformer banks. Faults close to the neutral point will produce large currents flowing in the H0X0 terminal, and such current is being measured directly by the protection scheme. In the case of external faults, the current from the H0X0 terminal is an additional restraining for the scheme, making the system more secure.

The stabilizing or tertiary winding is not integrated into the KCL-based differential protection, so such an element does not protect it.

Turn-to-turn fault detection is also not provided by the KCL-based differential element.

VIII. Tertiary Protection

In a bank of single-phase autotransformers with tertiary winding, it is common to make the delta connections of the tertiary through a busbar. Therefore, when designing the auxiliary system to be connected to the tertiary, it is important to consider the best practices to reduce the probability of faults, paying attention to possible weak points that could cause a failure in the insulation, for instance.

For an ungrounded system, or for a system grounded through a high impedance, the residual voltage magnitude, that is, the sum of the three-phase-to-ground voltages, is large for SLG faults and zero for three-phase balanced conditions. See Fig. 26. So, to provide detection of SLG faults, it is common to use zero-sequence overvoltage elements, 59N or 64, using calculated 3V0 from the measured phase voltages or measured from a broken delta-connected voltage transformers (VTs). Measures must be taken to avoid ferroresonance. When a broken delta connection is used, a resistor can be connected to the series-connected secondary winding of the VTs.

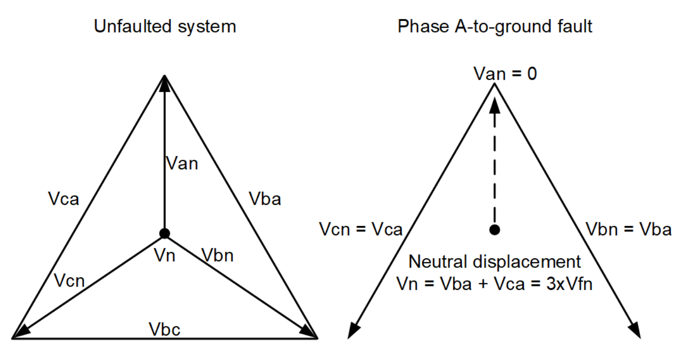

Fig. 26. Phasor diagram for tertiary-winding delta with short circuit and without short circuit.

The zero-sequence overvoltage element is not selective, so in an auxiliary service with multiple feeders it may be difficult to identify which sector is experiencing the SLG fault. For such a situation, it is recommended that the application of directional overcurrent elements is properly designed to work with ungrounded or high-impedance grounded networks [13].

A time-delayed overcurrent element (51G) can be used to avoid damage to the tertiary winding of a transformer bank caused by the zero-sequence current that flows inside the delta for faults in the primary and secondary networks. To implement such protection, the CTs from each leg of the delta are connected in parallel to sum the I_0 from each leg to produce the $3I_0$, which is measured by the relay. Fig. 27 shows the connections. In a modern digital relay, the CTs on each leg can be connected individually to the relay's phase current inputs, and the relay calculates the $3I_0$ current internally. This connection filters out the positive- and negative-sequence load currents and allows the 51G relay to respond to ground fault current (which is three times the zero-sequence current) to provide ground backup overcurrent protection. This scheme will not respond to phase faults in the tertiary network.

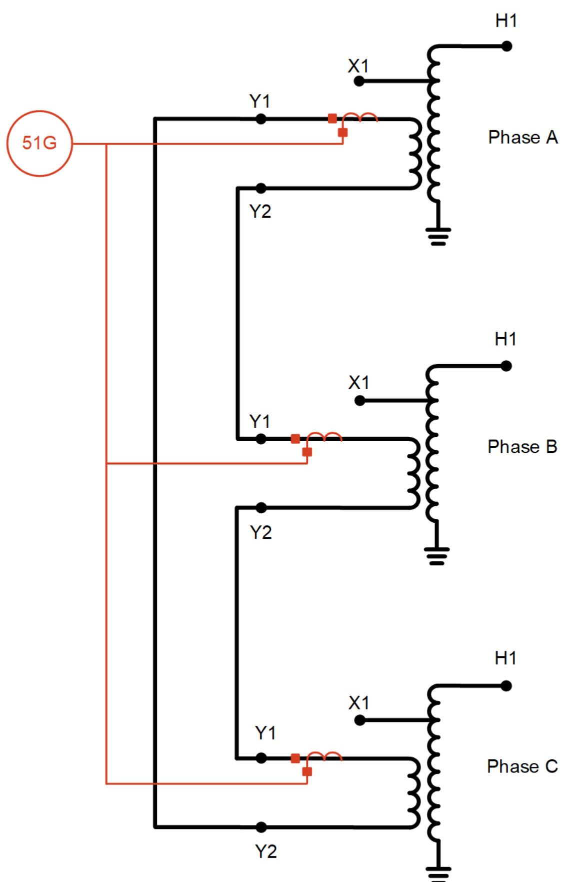

Fig. 27. 51G element connection for the tertiary-winding protection.

IX. Penalties For Unexpected Outages

As mentioned previously, the autotransformer protection system must be designed to help TGCs quickly identify the failed unit of a bank and replace it as quickly as possible to avoid penalties, which are discussed in this section.

In some countries, the earnings of TGCs are based on the amount of time the assets are made available and not on the amount of energy that is transmitted. In the case of an autotransformer in the Brazilian transmission system, earnings are based on the operational availability of such assets. The methodology to calculate the penalties, and consequently reduction in the earnings, due to unexpected outages is discussed in [14].

As an example, according to the rule in the Brazilian system, one hour of an unexpected outage of a specific autotransformer 500/440/13.8 kV is about $50,000, considering that the annual revenue for this asset is about $3,000,000. Monetary values are in U.S. dollars (USD) and account for the exchange rate from Brazilian Reais (BRL) to USD in July 2022.

X. Faulted Unit Replacement

One of the advantages of an autotransformer bank made of single-phase units is the possibility to replace any faulted phase unit with a spare unit, which increases the availability of the autotransformer. However, replacing the failed unit may involve hard electromechanical work of disconnecting the failed unit from the busbars and connecting the spare to the busbars. Another difficult task, which needs a lot of care, is rewiring and testing the protection, control, and supervision systems.

Considering that the interruption of equipment, such as a bank of autotransformers, can generate high costs for TGCs, operation and maintenance engineers have designed resources to quickly replace a failed unit. In the past, it was common to take several hours of work to replace one unit of an autotransformer bank.

To achieve the desired reduction in outage times, with a consequent improvement in the quality of service and avoidance of financial penalties, operation and maintenance engineers developed new electromechanical arrangements in the substation, allowing a significant reduction in time for the mentioned tasks to replace a failed unit. The new arrangements may be implemented with motorized disconnecting switches that allow the disconnection of the failed phase unit and the connection of the spare unit, basically with remote control of the switches.

Fig. 28 shows the three-line diagram of an installation with a designated spare transformer with motorized disconnecting switches for unit replacement. In red dashed lines are the components to enable fast replacement of a faulted unit. For instance, in the Phase A unit (T1) that fails, it is necessary to open the 89AH and 89AX switches and close 89SAH and 89SAX. In this way, the spare unit (T4) replaces T1. The tertiary buswork is not shown for simplicity.

Based on field experience, the new arrangement with motorized transfer switches reduces the time to replace phase units from about 7 hours to 15 minutes. However, severe penalties for outage equipment, such as an autotransformer, have justified changes in substation arrangements to the point of investing heavily in the development of projects that include an entire duplicated electromechanical structure, such as buses and switches.

One of the first steps of an occurrence involving a unit failing in a single-phase autotransformer bank is identifying the failed unit. To identify the failed unit, the maintenance team must inspect the field and analyze the oscillography of the operated protection relays. Depending on the fault in the autotransformer, the damage caused may not be visible, leaving only the possibility of identifying the failed unit by analyzing the oscillography, which must be done by an expert professional and not by the operator.

Retrieving oscillography records may involve the mobilization of a specialized maintenance team to the location of the occurrence, and the oscillography analysis still depends on a protection engineer.

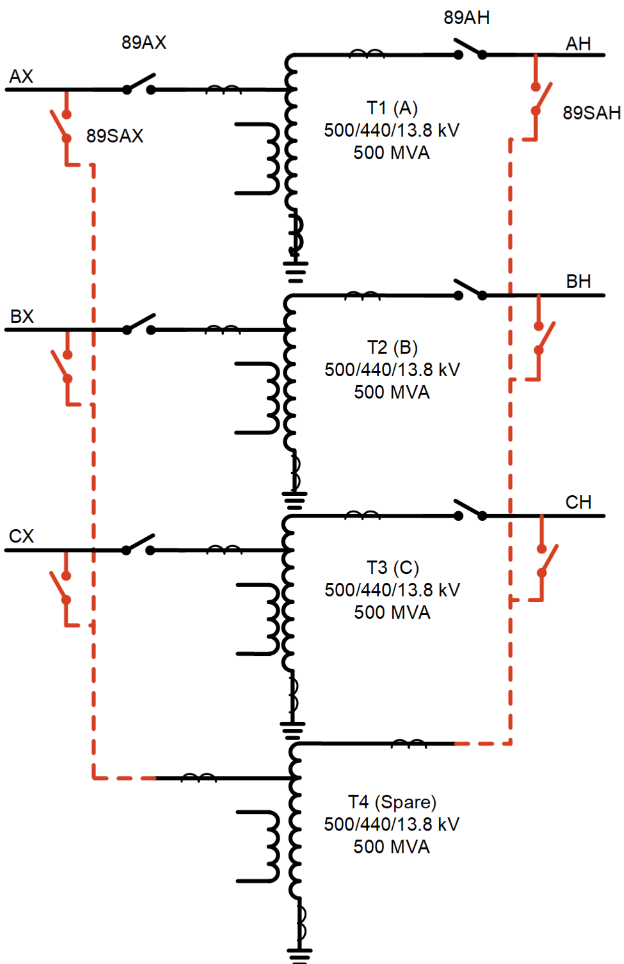

Fig. 28. A three-line diagram of an installation with a designated spare autotransformer with motorized disconnecting switches for unit replacement (tertiary buswork not shown for simplicity).

This process of collecting and analyzing oscillography can take hours. According to Brazilian regulations, for the autotransformer 500/440/13.8 kV used as an example, if there is a delay of four hours to identify the faulted phase unit plus six hours to replace the unit, the penalty applied can be nearly $270,000 for a single occurrence. When comparing the cost of the financial penalty to the cost of implementing an optimized protection system that can reduce the outage times considerably, it is clear that there are advantages in investing in the modernization of the protection system, not to mention the additional consequences and limitations to the operation of transmission power systems that a prolonged outage of important autotransformers can cause.

Just as the electromechanical designs of substations were rethought to allow quick replacement with motorized transfer switches to increase availability, protection design engineers must also rethink the design of protection systems. One of the goals of this paper is to propose a protection system for autotransformer banks made of single-phase units that are capable of properly and quickly identifying the faulted phase unit and promptly reconfiguring the protection system to include the spare unit, reducing the time to adapt the protection system to the new bank configuration from hours to minutes.

It is important to mention that the spare unit is also used during the regular programmed maintenance on the phase units, so a reduction in the maintenance time is also expected and will translate into a reduction in the operating expenses (OPEX).

XI. Panel of Plugs

Another point that must be taken into account is the transfer of the connections of bushing CTs and autotransformer control and supervision signals to keep the protection and control system working properly with the new configuration of the autotransformer bank, which must also be carried out when replacing the failed phase unit. This task can be accomplished quickly and securely by using a panel of plugs discussed in this section.

All CTs and protection and control wiring from the four units, phases, and spare of the autotransformer bank, are connected to the panel of plugs, which is installed in the switchyard, close to the autotransformer bank. Such a panel is the interface between the autotransformer bank and the control and protection panel in the relay room, see Fig. 29.

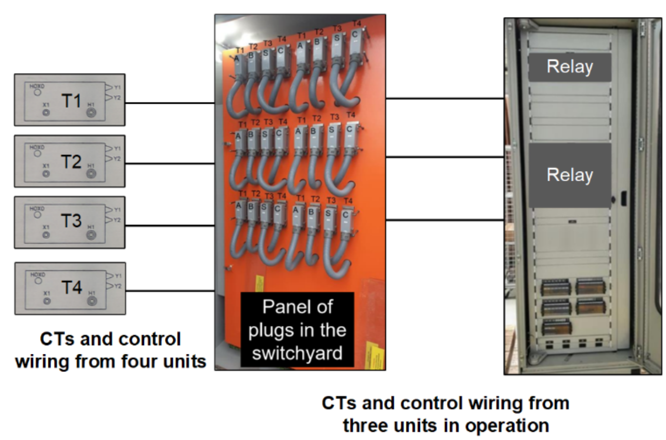

Fig. 29. Panel of plugs showing autotransformer units T1, T2, and T4 selected as phases A, B, and C, respectively, T3 selected as spare unit (not in scale).

Through the panel of plugs, it is possible to securely select the wiring of which three units from the four units available will be connected to the protection and control panels inside the control house. The panel of plugs makes it possible to do a very quick change of the wiring from bushing CTs and autotransformer control and supervision connected to the relays when the bank is reconfigured because of a failed unit or maintenance, without disconnecting and reconnecting several cables, that takes several hours to do. With the panel of plugs, it is possible to configure the protection and control system to the new configuration of the bank in minutes. Another advantage of the panel of plugs is to prevent human errors that can occur when disconnecting and reconnecting cables.

The cost of installing the panel of plugs is fairly compensated by the reduced time and increased security in the replacement procedure of a unit of the autotransformer.

Fig. 29 shows the panel of plugs with autotransformer units T1, T2, and T4 selected as phases A, B, and C, respectively, and T3 selected as a spare unit.

It is important to perform tests to validate and confirm the proper connection of the plugs every time a new configuration is set.

XII. Proposed Protection Scheme

This section discusses a proposition for optimized autotransformer protection, considering the configuration shown in Fig. 4, i.e., a breaker-and-half bus arrangement in the H side and X side, three single-phase units plus a spare unit. The available CT locations for the protection system are also shown in Fig. 4.

As mentioned in previous sections, the protection system must be capable of signaling the faulted unit and the location of the fault, internal to the tank or in the buswork, to allow fast replacement of the faulted unit. With that, the quality of service can be improved and financial penalties and loss of revenue to the TGCs can be avoided.

A. Protection Scheme Main 1

Fig. 30 shows an enhanced protection scheme for autotransformer banks that applies two relays for the main system one.

1) Relay 87T-Main 1

Relay 87T is a transformer relay with five sets of three-phase current and two sets of three-phase voltage inputs. This protection device is connected to the autotransformer bushing CTs, so the trip of the unit protection elements enabled in this relay will be a positive indication that the fault is internal to the tank. The following unit protection elements are enabled:

- 87T-ATB-P: This regular ATB-based phase differential element protects the series, common, and tertiary windings. The protection includes percentage restrained and unrestrained phasor-based elements and time-domain improvements to enhance reliability and speed, as discussed in previous sections. As bushing CTs are used, so there is no phase current shifting and the differential element will indicate the faulted phase quickly and properly. Reference [15] provides guidelines for setting this protection.
- 87T-ATB-Q: The negative-sequence differential element enhances the sensitivity for turn-to-turn faults that the other differential elements do not have enough sensitivity to detect.
- 87T-KCL: This is a KCL-based differential element that provides very sensitive, secure, and fast protection for the common and series windings, including for partial-winding faults close to the neutral point to clear the faults before they can evolve and cause more serious damage to the autotransformer, so a dedicated REF element based only on zero-sequence current is

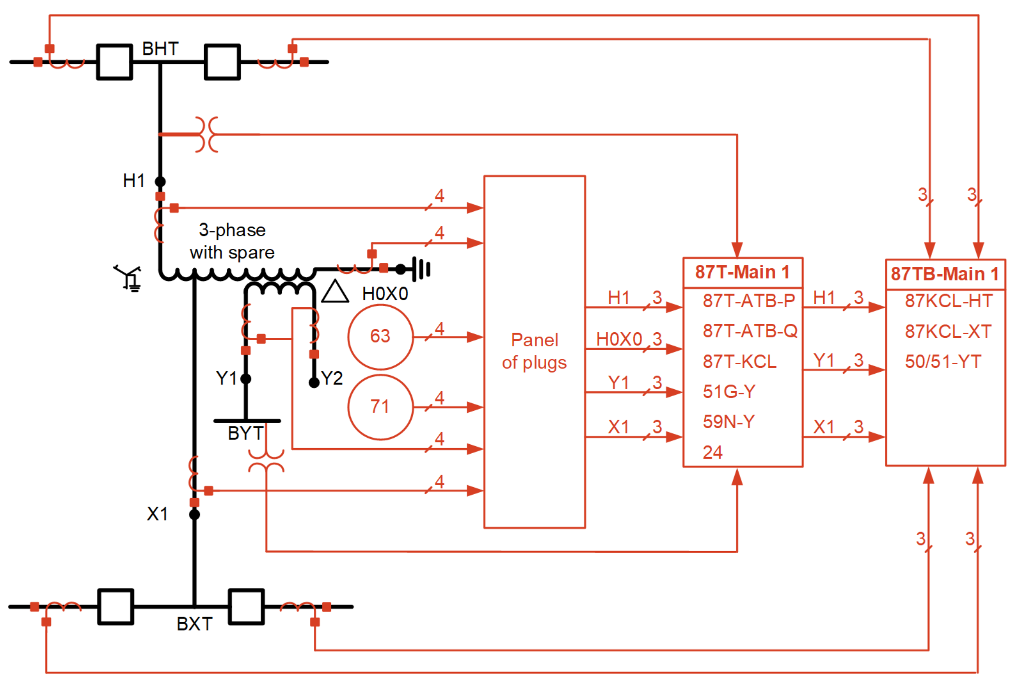

Fig. 30. Autotransformer protection scheme–Main Relay 87T-Main 1.

not required. This is an additional differential element in the same relay. Some modern relays allow the configuration of such an element using the custom logic described in [15].

To quickly switch the control and monitoring signals and bushing CTs connected to the relay when replacing phase units with the spare unit, a panel of plugs is used, as previously discussed.

Fig. 31 and Fig. 32 highlight the bushing CTs used for each unit protection element and the zone of protection.

Using the autotransformer bushing CTs allows a proper selection of CT ratios to optimize the differential protection, as explained in [15].

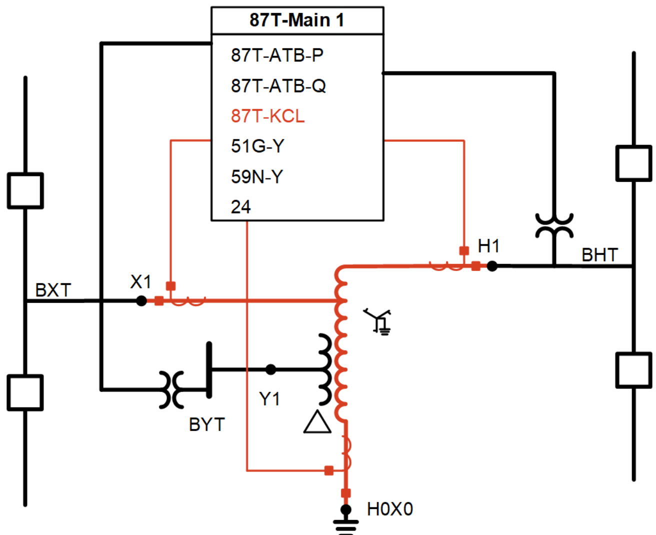

Fig. 31. 87KCL zone of protection highlighted in red (solid line).

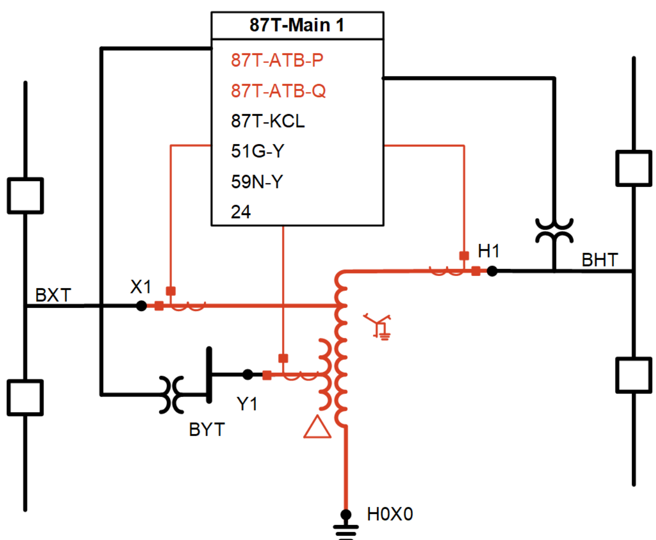

Fig. 32. 87ATB-P and 87ATB-Q zone of protection highlighted in red (solid line).

The relay also includes other protection elements like:

- Overexcitation element (24): To avoid damage caused by overvoltage or underfrequency or a combination of both in the transmission system.
- Zero-sequence overvoltage (59N-Y): In cases where the tertiary is ungrounded, this element will provide detection of SLG faults.
- Zero-sequence time overcurrent (51G-Y): This element avoids damage to the tertiary winding for SLG faults not cleared promptly on the primary or secondary sides.

2) Relay 87TB-Main 1

The Relay 87TB-Main 1 is intended to provide protection for the lead buses in the primary (BHT), secondary (BXT), and tertiary (BYT) buses.

This device is a busbar protective relay with 21 current inputs, which can be grouped into seven sets of three-phase current inputs. It is connected to bushing CTs, in series with the relay 87T-Main 1, and to the circuit breaker CTs. The connections to later ones do not need to be switched using the panel of plugs, see Fig. 30.

Fig. 33 highlights the CTs used for each unit protection element and the zone of protection.

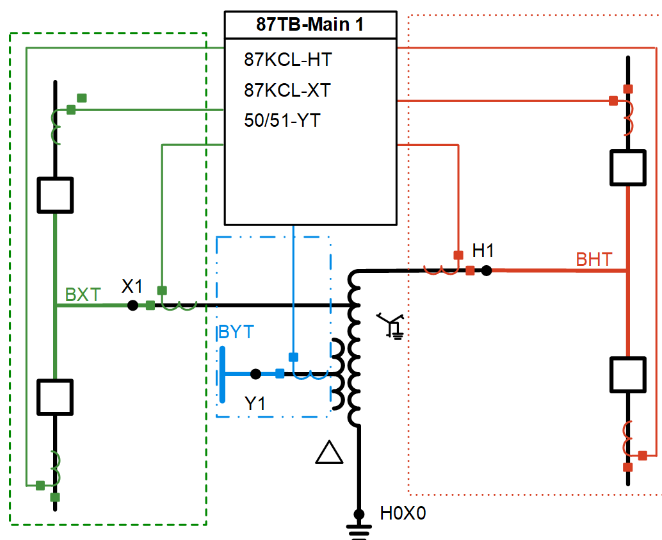

Fig. 33. 87KCL-HT, 87KCL-XT, and 50/51-YT zones of protection are highlighted in red dots, green dashes, and the blue dot-dash pattern, respectively.

The elements 87KCL-HT and 87KCL-XT are KCL-based differential elements. Therefore, they will provide a positive indication that the fault is located in the lead buses and not internally to the phase units, indicating that a replacement by the spare is not needed.

The overcurrent element 50/51-YT protects the tertiary bus. As the currents are being measured inside the delta, the currents outside the deltas are calculated using the custom logic in the relay, as the difference between two-phase currents measured inside the delta for each phase. For an unloaded tertiary, there is no need to coordinate this element with other protection elements because it does not measure any current for external faults. However, in cases where a load is connected to the tertiary, a fast bus tripping scheme, also known as logic selectivity, can be applied to improve speed.

B. Protection Scheme Main 2

The Main 2 protection system is identical to the Main 1.

There are several benefits to applying identical dual primary protection systems, such as:

- Lower engineering costs.
- Common human-machine interfaces (HMIs) for operators.
- Common integration architecture.
- Easier protection coordination because operating times and sensitivities are the same.
- Analysis of data with the same skills and tools.
- Fewer spares to stock.
- Optimized training and maintenance.
- Troubleshooting and monitoring are made easier by a side-by-side comparison.

XIII. Proposed Scheme With IEC 61850 Protocols

The proposed protection scheme can be implemented using IEC 61850 Sampled Values (SV) messaging to receive digitized analog quantity measurements. Such an approach allows the reduction of copper cables and the suppression of the panel of plugs from the protection scheme. Merging units (MUs) are installed inside outdoor cabinets in the switchyard [16]. Fig. 34 shows the required MUs and the connections to the CTs.

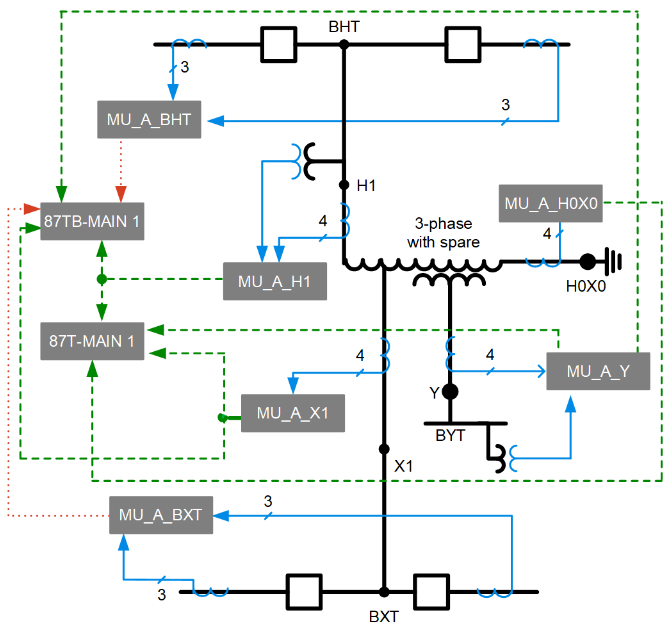

Fig. 34. Proposed protection scheme with IEC 61850 protocols to reduce copper cables and eliminate the panel of plugs.

Each MU has six current and six voltage inputs, which are connected to the conventional CTs through copper, but the analog quantities are sent to the protection relays 87T-MAIN 1 and 87TB-MAIN 1 through the Ethernet network, not shown in Fig. 34, with the use of the SV protocol. The dashed lines in Fig. 34 do not represent physical connections; they represent logical connections for the SV messages that are published by the MUs and subscribed to by the relays.

Instead of using a panel of plugs to switch the control and monitoring signals and bushing CTs connected to the relays, it is necessary to change the configured intelligent electronic device (IED) Description (CID) files loaded in the relays 87T-MAIN 1 and 87TB-MAIN 1 to adapt their subscription to the current autotransformer bank configuration, i.e., T1T2T3, T1T2T4, T1T4T3, or T4T2T3. To do so, it is possible to have the CID files for each bank configuration stored in the substation local HMI so the operator can select the bank configuration in operation by pushing a button and the proper CID file will be sent automatically to the relays through File Transfer Protocol (FTP), see Fig. 35. The information of which CID file is in effect sent back by the relays to the HMI, so the operator can confirm that the scheme has the correct configuration, and no further tests are necessary.

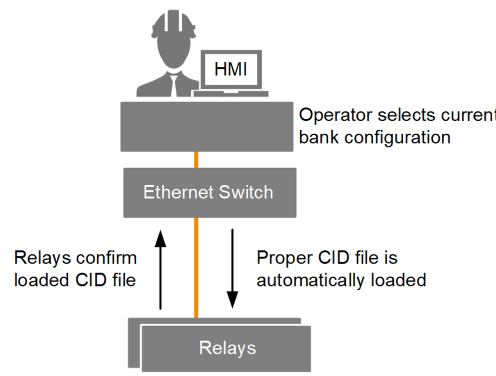

Fig. 35. Loading the proper CID file according to the operator's selection.

XIV. Conclusion

Optimum protection of the autotransformers means the security of investment for valuable operating equipment and therefore contributes to maximizing the power system security.

From a technical point of view, the proposed protection scheme for autotransformer banks offers extensive and reliable detection of all faults and maximizes the speed to clear faults, which translates into minimizing damages to the autotransformer. Furthermore, the prompt positive indication of fault location and failed phase unit allows for replacing the failed phase unit faster, with a consequent reduction in the time to restore service, contributing to maximizing the availability of the bank and avoiding financial penalties to TGCs.

Partial-winding faults can evolve and become more serious, causing extensive damage to the autotransformer. The protection scheme presented has the sensitivity and security to provide reliable protection and fast tripping time, minimizing the consequences of the internal fault.

The time to replace a failed unit can be reduced considerably when the electromechanical and protection systems are designed properly.

When comparing the cost of the multifunction relays required to implement the proposed protection scheme to the cost of the assets being protected and the cost of the unavailability of these assets, the proposed scheme is easily justified.

The application of IEC 61850 SV eliminates the complexity of the panel of plugs and reduces the amount of copper cables considerably; however, it increases the number of devices used in the solution.

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XVI. Biographies

Ronald Jogaib received his BSEE degree in electrical engineering from Rio de Janeiro State University, Brazil, in 2011. In 2011, he joined TAESA as an associate engineer, working on acceptance tests and inspection of EHV substation equipment. In 2013, he took a new role as a protection engineer, working on the analysis of the protection system performance for disturbances in the transmission systems, performing studies of coordination, selectivity, and configuration of protection systems, and site acceptance tests of new protection systems. In 2017, he became protection specialist engineer, being responsible for providing training to the protection team. He received his M.Sc. in electrical engineering from Fluminense Federal University, Brazil, in 2022.

Rodrigo Lehnemann Agostinho is a professional with 23 years of experience in commissioning transmission functions belonging to the Brazilian National Interconnected System—SIN, with 18 years dedicated to power systems protection. For 2 years, he has been part of the engineering team at Evoltz Participações, with the objective of offering support in the areas of protection, control and automation of O&M projects.

Ricardo Abboud received his BSEE degree in electrical engineering from Universidade Federal de Uberlândia, Brazil, in 1992. In 1993, he joined CPFL Energia as a protection engineer. In 2000, he joined Schweitzer Engineering Laboratories, Inc. (SEL) as a field application engineer in Brazil, assisting customers in substation protection and automation. In 2005, he became the field engineering manager, and in 2014, he became the engineering services manager. In 2016, he transferred to SEL headquarters in Pullman as an international technical manager. In 2019, he joined SEL University as a professor, and he is currently a fellow engineer with SEL Engineering Services, Inc. (SEL ES). He is a senior member of IEEE.

Paulo Lima received his BSEE in electrical engineering from Federal University of Itajubá, Brazil, in 2012. In 2013, he joined Schweitzer Engineering Laboratories, Inc. (SEL) as a protection application engineer in Brazil. In 2018, he became an application engineering group coordinator, and he has been the regional technical manager for Brazil since 2020. He has experience in application, training, integration, and testing of digital protective relays. He also provides technical writing and training associated with SEL products and SEL University.

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