# Useful Applications for Differential Relays With Both KCL and ATB 87 Elements

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***Abstract*—Differential protection elements can be classified into two main categories, Kirchhoff's current law (KCL) and ampere-turn balance (ATB). KCL differential elements sum the currents into a power system zone where all terminals are connected by a current carrying connection, such as with a power system bus or a rotating machine stator. ATB differential elements sum the ATB around a magnetic circuit, such as with a power transformer where power transfer through the differential zone relies mainly on magnetic coupling between windings on a magnetic core.**

**The protection requirements are often quite different for an electrical apparatus that requires KCL differential elements versus ATB differential elements; but often, both types of apparatus exist in the same tripping zone. There are many applications in which having both a KCL and an ATB differential element in the same protective relay can optimize protection, providing an optimal balance of security and dependability and an optimal balance of sensitivity and speed. This paper identifies examples of these applications and how such a relay can be applied.**

## I. Introduction

Current differential protection is used to protect many types of critical equipment in the power system: transformers, buses, transmission lines, generators, etc. Current differential elements are very selective and fast because the zone of protection is determined by the location of the current transformers (CTs), and no coordination with external devices is necessary. Current differential elements measure the current going in and out of a protected zone, as shown in Fig. 1. The concept is simple: a difference in currents across the zone of protection can indicate a fault inside the zone.

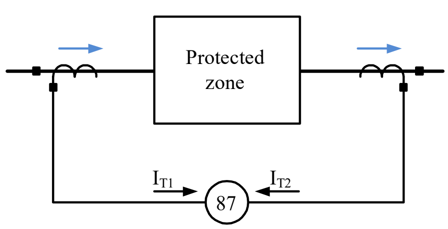


Fig. 1. Current differential protection

Some system conditions exist where a difference in currents across the zone of protection should be tolerated (i.e., in-zone surge arrestors, capacitive charging current, and energization of a magnetic core). The algorithms that modern relays use to secure differential elements during these conditions are discussed in the following sections.

Different principles can be used to implement current differential protection. The principle that is required depends on the type of power system equipment being protected. Two of the most common principles of current differential protection are Kirchhoff's current law (KCL) and ampere-turn balance (ATB) current differential protection. Most microprocessor relays are purpose-built for a given application and provide either KCL or ATB current differential elements, depending on the type of apparatus they are designed to protect (e.g., a bus relay has a KCL-based current differential element, and a transformer relay has an ATB-based current differential element).

Relays with a single differential element can result in engineers using one current differential element to protect what are actually two differential zones. An example of this practice is one ATB-based element protecting a transformer as well as the bus area between the dual breakers at one of the terminals. Using a single element to protect two differential zones in this way often results in compromises to sensitivity, security, speed, and selectivity of one of the zones [1]. This paper shows how having both a KCL-based and ATB-based current differential element inside the same relay allows us to protect each zone in the proper way, therefore, removing the need for compromises and allowing for better protection.

## II. KCL vs. ATB Current Differential Protection

Because both KCL and ATB current differential protection are typically realized through a percentage-restrained differential element, many engineers may not understand that there is a fundamental difference between them. This section describes how these two principles of current differential protection work and how they are implemented in modern microprocessor relays. In general, many ATB differential elements can be converted to a KCL type by turning off features, but most KCL-type differential elements cannot be converted to ATB type. This section explains the difference.

### *A. KCL-Based Current Differential Elements*

The current differential protection discussed in this section is based on KCL. The current entering a zone of protection must equal the current leaving the zone of protection; otherwise, there must be another path (such as a fault) inside the zone for current to flow through. In Fig. 1, this means that under normal load conditions, $I_{T1}$ equals $-I_{T2}$. Because KCL requires an electrical connection for current to flow, this principle is used to protect buses, generators, reactors, and lines.

Fig. 2 shows how KCL-based current differential protection is implemented in a modern relay. The currents measured by the CTs are first scaled by TAP settings to adjust for any magnitude differences caused by unequal CT ratios. The resulting currents ($I_{T1C}$ and $I_{T2C}$) should be equal in magnitude during normal load conditions. They should also be opposite in angle (180 degrees apart) due to the standard convention of wiring CTs in opposite polarity for current differential applications. These currents are used to calculate operate (IOP) and restraint (IRT) quantities. The operate and restraint quantities are compared to a minimum operate threshold and a slope characteristic to determine if the relay should trip. For more information about this process, see [2].

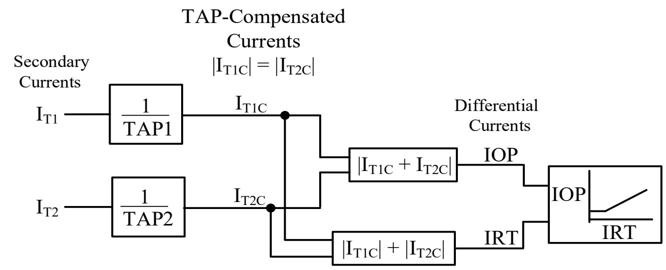


Fig. 2. KCL-based current differential protection

When KCL-based elements are applied to lines, the charging current associated with a long cable or line segment can be modeled electrically as a capacitive shunt path to ground. To a KCL-based element, this will appear as operate current. Additional security must be added for this case, as discussed in Appendix A. Operate current is also generated from conducting in-zone surge arrestors; however, modern relays are designed to mitigate this with additional security delays and do not typically require setting considerations.

### B. *ATB-Based Current Differential Elements*

Current differential protection for transformers does not use the KCL principle because there is not always an electrical connection between the windings of the transformer for current to flow through. Instead, it uses ATB, the principle that the number of amperes multiplied by the number of winding turns on each core loop of a transformer will always sum to zero. This principle accounts for the three challenges that exist when using current differential protection on transformer windings. First, the transformer itself, along with its winding connections and CT ratios, often results in the current magnitudes not matching across the transformer. Second, the transformer winding connections may result in a phase shift between the currents on either side. Third, some transformer winding connections (e.g., delta) prevent zero-sequence currents from being measured by the CTs on that side, while other connections (e.g., wye) allow it.

Reference [3] teaches engineers how to develop ATB equations for each core loop of an ideal transformer. The equations are then modified to account for the fact that CTs typically measure current on the terminal side of a transformer's delta winding. Knowing that the total of ampere turns on each core loop of the transformer must sum to zero, the ATB equations for a simple wye-delta transformer in Fig. 3 are given in (1).

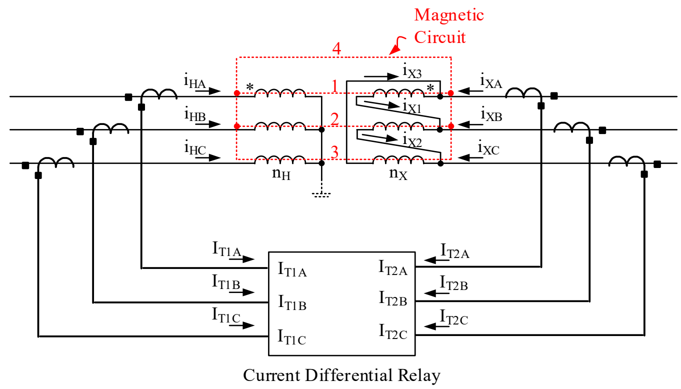


Fig. 3. Simple wye-delta transformer

$$
\begin{aligned}
i_{XA} + \frac{n_H}{n_X}\left(i_{HA} - i_{HC}\right) &= 0 \\
i_{XB} + \frac{n_H}{n_X}\left(i_{HB} - i_{HA}\right) &= 0 \\
i_{XC} + \frac{n_H}{n_X}\left(i_{HC} - i_{HB}\right) &= 0
\end{aligned}
\tag{1}
$$

We can write the turns ratio of the transformer in Fig. 3 in terms of voltage (phase-to-neutral at the terminals) and current, as shown in (2):

$$
\frac{n_H}{n_X} = \frac{V_H / \sqrt{3}}{V_X}
\tag{2}
$$

Substituting (2) into (1), we get (3):

$$
\begin{aligned}
i_{XA} + \frac{V_H}{V_X} \bullet \frac{1}{\sqrt{3}}\left(i_{HA} - i_{HC}\right) &= 0 \\
i_{XB} + \frac{V_H}{V_X} \bullet \frac{1}{\sqrt{3}}\left(i_{HB} - i_{HA}\right) &= 0 \\
i_{XC} + \frac{V_H}{V_X} \bullet \frac{1}{\sqrt{3}}\left(i_{HC} - i_{HB}\right) &= 0
\end{aligned}
\tag{3}
$$

Rearranging and substituting the relay terminal names ($H = T1$, $X = T2$), we can write (4). Here, we are assuming wye-connected CTs and that the phase currents have already been scaled in magnitude to account for any differences in CT ratios.

$$
\begin{aligned}
I_{T2A} &= -\frac{V_{T1}}{V_{T2}} \bullet \frac{1}{\sqrt{3}}\left(I_{T1A} - I_{T1C}\right) \\
I_{T2B} &= -\frac{V_{T1}}{V_{T2}} \bullet \frac{1}{\sqrt{3}}\left(I_{T1B} - I_{T1A}\right) \\
I_{T2C} &= -\frac{V_{T1}}{V_{T2}} \bullet \frac{1}{\sqrt{3}}\left(I_{T1C} - I_{T1B}\right)
\end{aligned}
\tag{4}
$$

As we can see in (4), we are not just comparing current on one side of the zone of protection ($I_{T2A}$) to current on the other side of the zone of protection ($I_{T1A}$), as we do with the KCL principle. Following the ATB principle for this transformer requires calculating phase-to-phase (delta) currents on the wye-side of the transformer ($I_{T1A} - I_{T1C}$). These currents are then scaled by a factor of the voltage ratio across the transformer ($V_{T1} / V_{T2}$) and an extra $1 / \sqrt{3}$. Before we calculate the IOP and IRT quantities, we must perform those functions.

The way this is commonly done in modern ATB relays is shown in Fig. 4. The TAP compensation block looks the same as in Fig. 2, but the TAP setting now includes the voltage ratios across the transformer in addition to the CT ratios [4]. This takes care of the $V_{T1} / V_{T2}$ terms in (4). The new block, matrix compensation, takes care of the rest. This block applies a matrix to each winding that performs the ATB equations required by (4). The relay settings engineer must make sure to select the correct matrix for the application to ensure proper operation. References [5] and [6] describe this process in detail.

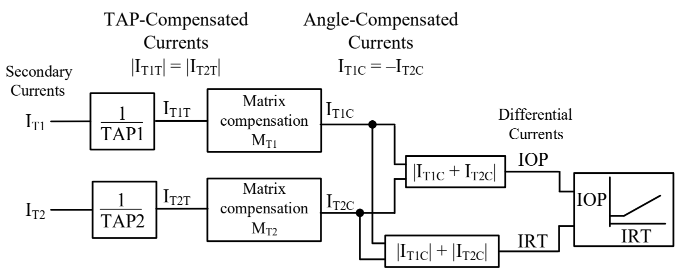


Fig. 4. Simplified ATB-based current differential protection

We can now determine the matrices that must be selected to satisfy the ATB equations for the transformer in Fig. 3. For Terminal 2 (the delta winding), the identity matrix must be used ($M_{T2}$, as follows).

$$M_{T2} = \begin{bmatrix} 1 & 0 & 0 \\ 0 & 1 & 0 \\ 0 & 0 & 1 \end{bmatrix}$$

Multiplying this matrix by the Terminal 2 phase currents gives us (5). This matrix satisfies the left side of the ATB equations in (4) because it results in the $I_{T2A}$, $I_{T2B}$, and $I_{T2C}$ currents being unmodified.

$$\begin{bmatrix} 1 & 0 & 0 \\ 0 & 1 & 0 \\ 0 & 0 & 1 \end{bmatrix} \bullet \begin{bmatrix} I_{T2A} \\ I_{T2B} \\ I_{T2C} \end{bmatrix} = \begin{bmatrix} I_{T2A} \\ I_{T2B} \\ I_{T2A} \end{bmatrix} \tag{5}$$

For Terminal 1 (the wye winding), the matrix that must be used to satisfy the ATB equations is $M_{T1}$, as follows.

$$M_{T1} = \frac{1}{\sqrt{3}} \bullet \begin{bmatrix} 1 & 0 & -1 \\ -1 & 1 & 0 \\ 0 & -1 & 1 \end{bmatrix}$$

Multiplying this matrix by the Terminal 1 phase currents gives us (6). This matrix satisfies the right side of the ATB equations in (4). The voltage ratio was already handled by the TAP scaling in Fig. 4.

$$\frac{1}{\sqrt{3}} \bullet \begin{bmatrix} 1 & 0 & -1 \\ -1 & 1 & 0 \\ 0 & -1 & 1 \end{bmatrix} \bullet \begin{bmatrix} I_{T1A} \\ I_{T1B} \\ I_{T1C} \end{bmatrix} = \begin{bmatrix} \frac{1}{\sqrt{3}} \bullet \left( I_{T1A} - I_{T1C} \right) \\ \frac{1}{\sqrt{3}} \bullet \left( I_{T1B} - I_{T1A} \right) \\ \frac{1}{\sqrt{3}} \bullet \left( I_{T1C} - I_{T1B} \right) \end{bmatrix} \tag{6}$$

This example shows how the TAP scaling, along with the matrix compensation provided by (5) and (6), performs the ATB equations that are required to balance the differential element that is derived in (4). After the TAP scaling and matrix compensation are applied, the resulting currents ($I_{T1C}$ and $I_{T2C}$ in Fig. 4) should be equal and 180 degrees out of phase during load conditions. These currents are used to calculate the operate IOP and IRT quantities, which are compared to a slope characteristic to determine if the relay should trip.

An ATB type differential element also requires two additional features after compensation is complete. Because the balance between zone boundaries relies on coupling through a magnetic core, it requires some means to deal with core saturation effects, such as inrush and overexcitation. This is typically done through harmonic restraint, harmonic blocking, or waveshape-recognition techniques. These techniques introduce delays in tripping to ensure that the ATB differential element does not misoperate during inrush or overexcitation conditions [7]. In the examples in this paper, we illustrate how using the proper type of differential element can eliminate this compromise in some applications.

The second feature required for an ATB element is a high-set unrestrained differential element (87U) that allows fast tripping for severe internal faults. This element ignores any inrush supervision and, therefore, trips at high-speed. Because this element must be set above inrush current to maintain security, it lacks sensitivity to certain internal faults. Examples in this paper show that using this element in place of a KCL element when it is not required ends up limiting speed.

## III. Organizational Benefits of Using KCL and ATB Elements in the Same Relay

This section summarizes the organizational benefits of having KCL and ATB elements in the same physical device. The organizational benefits are very similar to the benefits of using centralized protection and control (CPC) in a substation, which is discussed in [8]. CPC, the practice of using a single device to replace an entire substation of relays, is simply an extension of having KCL and ATB elements in the same relay.

### A. *Improved Availability*

At first glance, it may not be intuitive how combining KCL and ATB elements in the same relay affects availability. On one hand, having fewer relays means a lower chance for a failure to occur. On the other hand, a failure of that single relay causes protection to be lost for both the KCL and ATB zones.

Fault tree analyses can be used to determine the unavailability of a system when one or more of its components fail. [8] shows a detailed example of doing this for a CPC distribution system compared to using individual relays for each zone of protection. We can follow this same method to determine the difference in unavailability for a combined KCL/ATB relay compared to separate KCL and ATB relays to protect the system shown later in Fig. 7. Using the same unavailability numbers for each component (as in [8]), the fault tree analysis results in the unavailability numbers given in Table I. Unavailability numbers are given for two different failure modes. "Any protection" means any part of the protection system is lost, and "all protection" means the entire protection system is lost.

TABLE I UNAVAILABILITY SUMMARY

| **Failure mode** | **Unavailability (• $10^{-6}$)** | |
|---|---|---|
| | **Separate relays** | **Combined relay** |
| All protection | 0.162 | 382 |
| Any protection | 810 | 562 |
| All protection with redundancy | ~0 | 0.1459 |
| Any protection with redundancy | 1,620 | 1,124 |

Unavailability is the probability or fraction of time a device or system is unable to perform its intended function [9]. Unavailability ranges from 0 to 1, where 0 indicates the system is always able to perform its intended function and 1 indicates the system can never perform its intended function. To relate this to real time, we can use (7) to determine how many days in a year the protection system could be down. An unavailability of 810 • $10^{-6}$ means the system could be down for 0.296 days per year. Similarly, we can use (8) to determine how many years it takes (on average) for a given protection system to experience a failure. An unavailability of 810 • $10^{-6}$ means that it will take 3.38 years to experience a failure.

$$U_{dpy} = U \cdot 365 \tag{7}$$

$$YTF = \frac{1}{U \cdot 365} = \frac{1}{U_{dpy}} \tag{8}$$

where:

$U$ = unavailability in the range of 0 to 1

$U_{dpy}$ = unavailability in days per year

YTF = years to failure

Table I shows that a combined relay has a lower chance of losing any protection but a higher chance of losing all protection because everything is in one box. This risk can and should be mitigated by installing redundant relays. Once this is done, the availability of a combined relay becomes better than or nearly equal to separate relays for both failure modes.

State of Reliability reports from the North American Electric Reliability Corporation (NERC) consistently rank human error as a leading cause of protection system misoperations [10]. Modern relays can be complicated, with many settings to set correctly and many elements to test. Each additional setting on the system introduces another place for an error to occur. Having KCL and ATB elements in the same relay eliminates redundant settings between these two applications. Because settings like CT ratio, PT ratio, phase sequence, etc., only need to be entered once, the chance for human error is reduced.

### *B. Reduced Maintenance Costs*

In the USA and Canada, bulk electric system owners must comply with NERC Standard PRC-005, which covers all assets over a certain voltage level (mainly 100 kV and above). The standard requires that transmission and generation asset owners create a protection system maintenance program that includes the testing of relay communications systems, control circuitry, settings integrity, and measurement accuracy. One of these requirements is that periodic maintenance and testing of relay systems be performed every 6 or 12 years, depending on the ability of the relay to self-monitor and report problems.

For traditional installations that require both KCL and ATB elements for different zones of protection, two relays are required: one with a KCL element and one with an ATB element. If a single relay can perform both of these functions, the PRC-005 maintenance costs are reduced. A single relay also simplifies tracking relay firmware updates, settings files, cybersecurity patches, and service bulletins.

### *C. Simplified Stock*

One relay with both KCL and ATB elements allows users to stock one device for multiple applications, instead of having to manage two different relay models. Even if a power system asset owner wishes to keep protection functions segregated, the same relay part number can be used for transformer protection as well as bus protection applications. This allows for simpler standards as well as fewer spares required in case of a failure.

### *D. Simplified Training*

The protection system is complicated, and it can be difficult for utilities to ensure that their staff is adequately trained on every device on their system. The ability to use a single relay for multiple applications reduces the number of relays that engineers and technicians need to learn, which reduces training costs as well as the chance for human error.

### *E. Reduced Panel Sizes*

Microprocessor relay panels are typically designed for a specific application (e.g., bus protection or transformer protection). Using a relay with both KCL and ATB elements can allow for a single panel to serve both applications. This reduces the total number of required panels, the footprint of the control house, and all associated costs. It also eliminates any interpanel wiring that may exist to serve auxiliary functions (breaker failure, etc.).

## IV. Considerations When Using KCL and ATB Elements in the Same Relay

This section discusses several considerations that apply to many applications in which ATB and KCL current differential elements are used in the same relay.

### *A. Zone Overlap*

If a breaker exists at the zone boundary, the ATB and KCL elements each control their own tripping zone. This allows for selectivity in tripping so that only the affected section of the power system is de-energized after a fault. For a fault on the breaker at the zone boundary, both zones trip.

When designing a protection system, it is critical to ensure that no part of the power system is left unprotected. Traditionally, this was done by overlapping the zones of protection around the circuit breaker at the zone boundary, as shown in Fig. 5. This was done by wiring CTs on one side of the breaker to the ATB relay and wiring CTs on the other side of the breaker to the KCL relay. In the case of a relay with both KCL and ATB elements, only one CT is required to measure current at the zone boundary. This CT defines the boundary between the KCL and ATB zones, as shown in Fig. 6. Either CT can be chosen without leaving any part of the power system unprotected. Although the zones no longer overlap, no portion of the power system is not inside a protection zone—a fault is always in either the ATB or KCL zone, but now the tripping zones do not overlap. We discuss this in the following section. The situation illustrated in Fig. 6 is similar to the common application with a freestanding CT on one side of a live tank circuit breaker. Addressing the configuration in Fig. 6 is well established in protective relaying practices.

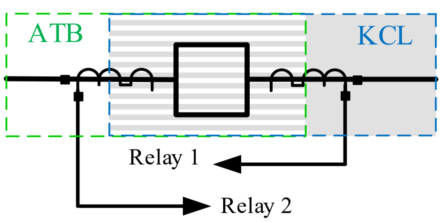


Fig. 5. Traditional zone overlap across a circuit breaker

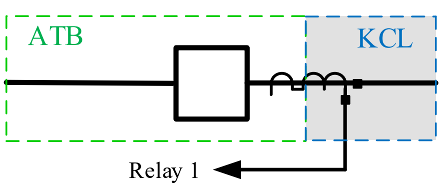


Fig. 6. Zones of protection with a single CT at the zone boundary

Due to the need for zone overlap with traditional relays, the breaker at the zone boundary is included in both tripping zones. With only one CT at the zone boundary, we must decide which CT to select—this determines which tripping zone the breaker is included in. In distribution applications, it is preferred to include the zone boundary breaker in the zone closest to the source. This way, if there is a fault in the breaker, the fault current coming from the source will be removed when the primary relay trips, without having to wait on backup protection or breaker failure delays. Faster tripping is always desired, as it reduces unnecessary through-fault stress to power system equipment. For more information on considerations for selecting the CT to use in applications with the configuration depicted in Fig. 6, see [11].

If a breaker does not exist at the zone boundary, both the ATB and KCL elements control the same tripping zone. As described previously, having only one CT at the zone boundary for these applications does not leave a gap in protection.

### *B. CT Polarity*

When using a single set of CTs to separate two zones, the engineer needs to determine how the polarity of the CT at the zone boundary should be wired. This likely results in a compromise somewhere, as the polarity of the zone boundary CT may only be "correct" (standard differential polarity) for one of the zones of protection. The polarity of that CT for the other zone of protection needs to be inverted. CT polarity in modern KCL relays can often be inverted via a polarity setting. CT polarity in modern ATB relays can often be inverted using the compensation matrix setting. Adding 6 multiples of 30 degrees to any matrix effectively inverts the polarity by shifting the phase angle 180 degrees [6]. Note that in addition to inverting the polarity, compensation matrices may also remove zero-sequence current. It is important to be aware of this, as incorrectly removing zero-sequence current can result in misoperation of the differential element [5].

When using a combined relay, we recommend wiring the CTs in traditional differential polarity for the ATB zone and inverting the polarity for the KCL zone. This is because transformer compensation settings are complicated enough as they are and mistakes here are a common cause of misoperations. It is also important to note that changing polarity through differential settings only inverts currents used by the differential element and does not impact any other function in the relay that relies on proper current direction (e.g., restricted earth fault, directional overcurrent, or distance).

### *C. CT Ratio Selection at the Zone Boundary and TAP Spread Ratio*

Using a single relay for ATB and KCL protection allows for more freedom in selecting the CT ratio for the CT at the zone boundary. Most modern relays can accommodate a very wide TAP spread ratio (the ratio between the largest and smallest TAP setting). This allows us to select CT ratios for each zone that are optimized for the application. In the example of KCL and ATB zones that protect a bus and transformer, this allows us to use lower CT ratios for the ATB zone to gain the desired high sensitivity. For single-breaker applications, this lower ratio is acceptable for the KCL zone because all faults external to that zone are limited by the impedance of the transformer. For dual-breaker applications, two of the CTs in the KCL zone may need to be tapped at a higher ratio, but the CT at the zone boundary with the ATB zone can remain at a lower ratio for extra sensitivity. In this case, the KCL zone must be set securely.

## V. Optimizing Protection With KCL and ATB Elements in the Same Relay

In addition to the organizational benefits that were introduced in Section III, some of the greatest benefits of having KCL and ATB elements in the same relay are on the technical side. This section uses application examples to describe many ways that protection systems can be optimized when KCL and ATB elements are available in the same relay.

### *A. Centralized Protection of a Distribution Substation*

Using a relay that supports both KCL and ATB differential elements in a CPC application results in many of the organizational benefits described in Section III. The example shown in Fig. 7 uses a CPC relay to provide protection to a small distribution substation.

An ATB differential element is used for transformer protection (87T) and a KCL differential element provides the low-voltage busbar protection (87B). The common CT used for both differential zones is chosen so that the breaker at the zone boundary is included in the ATB (transformer) differential zone for the reasons described in Section IV. Note that if the CPC relay has enough inputs, it is also possible to gain better selectivity by bringing in the CTs on the transformer side of the zone boundary breaker and overlapping the ATB and KCL zones (not shown in Fig. 7). This trips both the ATB and KCL zones for a fault in the zone boundary breaker, allowing for more precise fault location.

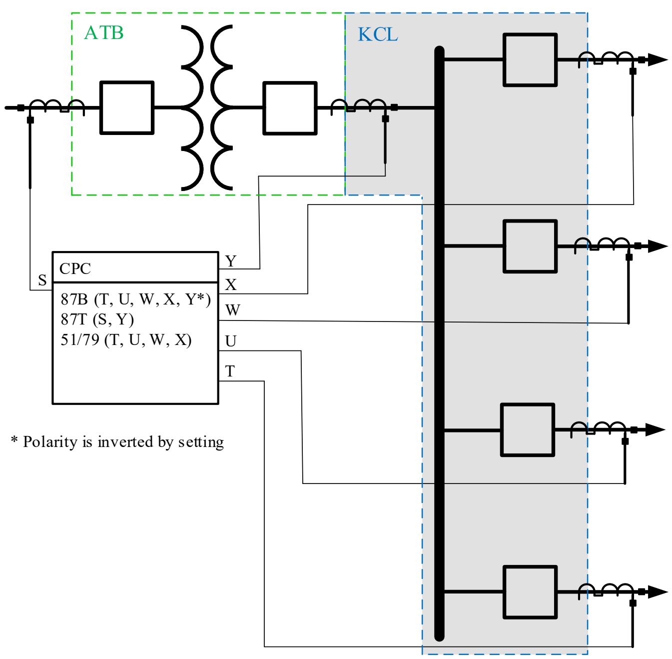


Fig. 7. CPC protection of a distribution substation

Similarly, we must decide if the feeder breakers should be included in the KCL differential zone or in the feeder protection zone. Consider that a fault inside the circuit breaker requires tripping the bus to clear. If we use the line-side CT for the zone boundary between the feeder zone and the bus zone, as shown in Fig. 7, the scheme automatically has the desired selectivity. The speed advantage that helped drive the zone boundary decision between the ATB and KCL zones is similar.

If we choose the CT on the bus side of the feeder breaker for the zone boundary a fault in the breaker is detected by the feeder relay, but tripping the feeder breaker does not necessarily clear the fault. So, the time delayed upstream backup protection or breaker failure must be relied on—again subjecting the transformer to unnecessary additional through-fault stress.

Having an ATB differential element (87T), KCL differential element (87B), plenty of overcurrent elements, distance elements, and directional elements and reclosing all within a single device enable one relay to provide complete protection for an entire substation. Reference [8] details a similar substation to the one shown in Fig. 7, where the primary protection, backup protection, automation, and communications needs for the entire substation are located on a single panel, minimizing not only the equipment and panel requirements but also the control house footprint. Combining CPC with digital secondary system (DSS) technology can result in construction cost savings of up to 12 percent, material costs savings of up 13 percent, with total savings approaching $600,000 for a greenfield distribution substation with a similar topology [8]. See [8] for a thorough discussion on DSS technology and its benefits.

### *B. Pad-Mounted Switchgear Protection*

Pad-mounted switchgear applications can benefit from having multiple differential elements in the same relay. An increasingly popular topology for pad-mounted switchgear is to arrange them in a loop [12], as shown in Fig. 8. This topology enables a remedial action scheme to quickly isolate a faulted switchgear bus or source-way cable segment.

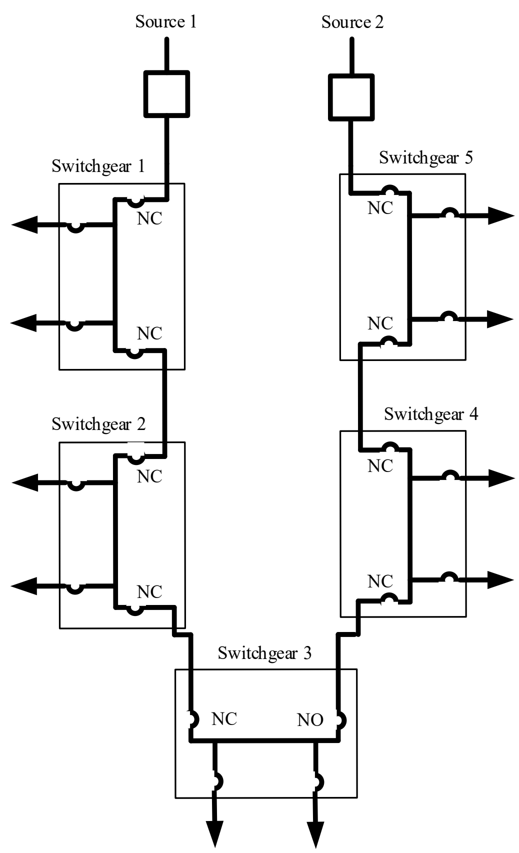


Fig. 8. Looped switchgear topology

By taking advantage of a DSS, a simple KCL-based differential zone can be established to provide sensitive and secure cable protection between each of the switchgear. The example shown in Fig. 9 is using a point-to-point technology that does not require a network switch or an external clock for synchronization. The distance limitations of DSS technology vary between the relay manufacturer and fiber-optic link options but is assumed in this paper to be a maximum of 2 km.

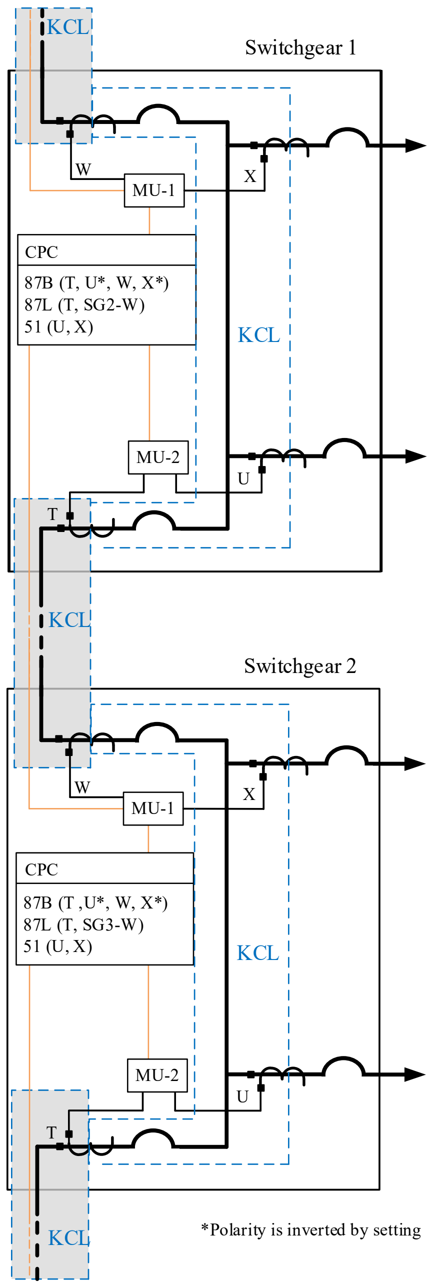


Fig. 9. Switchgear differential zones

As shown in Fig. 9, two merging units (MU-1 and MU-2) within each switchgear publish the load-way (X and U) and source-way (W and T) currents to the local CPC relay to provide KCL-based differential bus protection (87B) and nondirectional time-overcurrent protection for the load ways [51(U, X)]. The same CPC relay is also receiving the current measurement on the remote source way W from the adjacent switchgear's MU-1. A KCL-based cable differential is formed between the remote source-way current (W from the adjacent switchgear, SG2-W or SG3-W) and the local source-way current (T).

In this example, the CPC relay in Switchgear 1 is providing bus differential protection for Switchgear 1 and cable differential protection for the cable connecting Switchgears 1 and 2. In the event of a cable fault between Switchgears 1 and 2, the CPC relay in Switchgear 1 issues a trip command to the local MU-2 as well as MU-1 in Switchgear 2 to isolate the fault. The cable connecting Switchgears 2 and 3 is protected by the CPC relay's cable differential zone in Switchgear 2. In this configuration, each CPC relay is providing a KCL zone for their local bus and one of their source-way cables. This scheme is repeated for all switchgear within the loop. This enables a differential zone to be used on the bus and both source-way cables using only two differential zones per relay.

In this application, both the zones are using KCL differential elements instead of one KCL and one ATB differential element. While slightly off the theme of this paper, a relay with both KCL and ATB differential elements can be applied. The ATB differential element in the relay can be configured as a second KCL differential element by setting the harmonic blocking/restraint functions and the internal phase and zero-sequence compensation functions to OFF. In pad-mounted switchgear applications, it is also common for the load-way cables to feed nearby transformers. If desired, a transformer on a single load way can be incorporated into the bus zone by using an ATB differential element instead of a KCL element.

Although the cable lengths for this application are relatively short, the amount of charging current should be evaluated to ensure the minimum operate current setting for the 87L element is secure. See Appendix A on how this can be done. For most KCL zones, raising the minimum operate current setting to account for charging current does not result in a practical loss of sensitivity.

### *C. Protection of Transformers With Dual-Breaker Terminals*

Substations with dual-breaker terminals for each network branch are common. When the network element is a power transformer, functionally, a bus zone (KCL), and a transformer zone (ATB) are formed, as illustrated in Fig. 10. Proper protection practices provide a KCL differential element for the bus zone and an ATB differential element for the transformer zone.

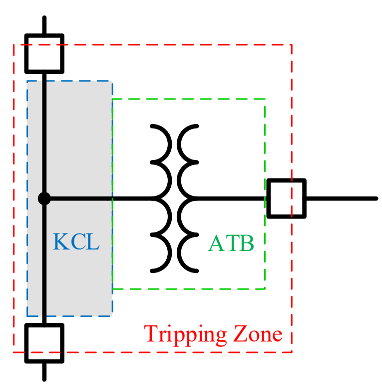


Fig. 10. Transformer dual-breaker functional zones

These two zones have very different sensitivity, speed, and security requirements. They also have very different security and dependability requirements. Performance and reliability are related such that efforts to improve performance may reduce reliability and vice versa. An example is provided to illustrate such compromises. Designing a protection system that is secure from transformer inrush (security is a reliability criterion) inherently sacrifices speed (a performance criterion). In designing a protection system, it is necessary to balance these requirements [1].

Reference [1] provides a thorough discussion of application considerations for protecting transformers with dual-breaker terminals. The important points are summarized here. A transformer relay with both a KCL and an ATB differential element makes optimizing protection using these concepts more economical because a lower number of relays is required.

For security, the protection of a bus zone must have tolerance for high through faults that challenge the performance of the CTs making up the zone boundaries. A bus zone is typically made up of high-capacity conductors with close spacing and a low-impedance ground grid. Faults that occur in the bus zone generally produce very high currents so that security is of greater concern than sensitivity. For this reason, security is often obtained by setting the 87B element with relatively high pickup and slope.

Compare this to a transformer zone. Transformers require very high sensitivity because they can have extremely damaging partial-winding faults [3]. High sensitivity is required to detect and clear these faults quickly to prevent tank rupture and core damage [7]. Security for through faults is not as challenging because the maximum through-fault magnitude is limited by the impedance of the transformer.

The fastest possible speed of protection is critical in both zones to reduce equipment damage. In the bus zone, speed is even more critical to improve system stability, through-fault damage on adjacent equipment, and wide-spread power quality issues.

Using a single ATB element to cover both the transformer and bus leads to compromises. For example, issues that are traditionally concerns for bus protection security now need to be considered when setting the ATB element. If the 87U pickup is not set high enough, misoperations may occur when CTs saturate during external faults. In applications with a large disparity between the capacity of the bus and the transformer, the unrestrained differential element often cannot be set high enough in per unit of TAP to be secure, so it must be turned off.

Reference [1] outlines three criteria to evaluate if using a single ATB element in an overall transformer/bus differential zone is acceptable. The evaluation may reveal that the protection has unacceptable compromises, such as:

- Inadequate security for through faults, not limited by the impedance of the transformer.
- Inadequate loadability of the bus.
- Inadequate sensitivity for transformer faults.

In most applications, protecting the tripping zone shown in Fig. 10 with separate KCL and ATB zones is the optimal solution. While [1] describes two-, three-, and four-relay solutions, that terminology is obsolete when a transformer relay with both KCL and ATB differential zones is available. It becomes much easier to optimize protection if the selected transformer relay has this capability, and all that is required is some additional wiring and configuration. The additional benefit is that the protection is selective such that operators can easily determine if it is safe to isolate the transformer using a switch and restore the bus section in the event of a transformer zone target and no bus zone target.

Fig. 11 shows recommended protection for a typical autotransformer application with dual breakers on the high-side terminals. The relay provides KCL and ATB zones in addition to 51P (through-fault protection), 51N (ground backup protection), and REF to provide all recommended protection in a single relay.

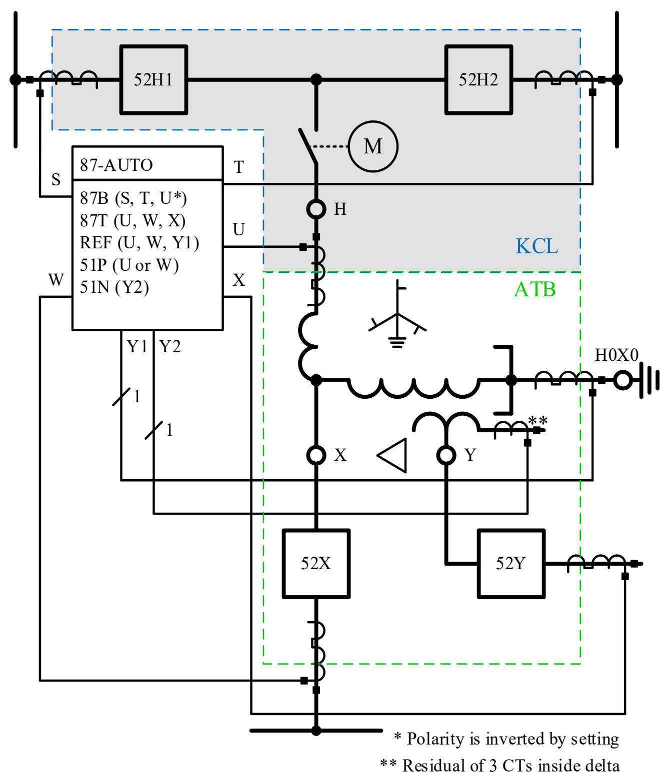


Fig. 11. Transformer dual-breaker application with recommended protection

The zone boundary between the two differential zones is the H bushing CT wired to the CT input U. This application differs from the one in Section V.A. in that we have one tripping zone and two protection zones, so there is no need to determine if the zone boundary breaker should be included in the KCL or ATB zone. As described in Section IV, most modern transformer relays can accommodate a very wide TAP spread ratio so the breaker CTs and the transformer CTs can have significantly different ratings—each optimized for their application. This allows us to use a low CT ratio for the zone boundary CT to gain sensitivity for the ATB zone. This should not be a security issue for the KCL zone, as the transformer impedance limits the fault current contribution for downstream external bus faults.

The H bushing CT is shown wired with differential polarity for the transformer zone. There are two reasons for this. ATB differential requires transformer angle and zero-sequence compensation, which often challenges engineers. While the relay can invert the polarity of the input by using a compensation matrix that is 6 clock positions away (180 degrees) [6], this approach is less intuitive than simply telling the KCL differential element to invert the polarity of the U input for its zone. Specifically for this application, note that the ATB compensation settings do not affect the REF element. We are using the sum of the 3I0 measured by the CT wired to the U and W inputs as reference for the angle checks against the ground CT wired to the Y1 input. Thus, the polarity of U and W current signals must be the same and opposite that of the Y1 input for the REF element to work properly.

The Y2 input is connected to the residual of the three CTs inside the delta tertiary winding. The application shows a tertiary bus with the assumption that it is likely loaded, such as with a shunt reactor for voltage control. The residual connection removes the positive and negative-sequence components such that the ground backup element only responds to ground fault current contributed by the autotransformer.

Winding through-fault protection, 51P, that is coordinated with the transformer through-fault damage curve can be accomplished with either the high- or low-side phase CT signals, depending on the requirements of the application.

### D. Protection of Banks of Three Single-Phase Transformers

In some facilities, a transformer installation may be made up of three single-phase transformers. These are often called transformer banks. Using single-phase transformers may be required to facilitate the construction and transport of very large-capacity transformers, in which a three-phase transformer of the required capacity may be too large and heavy. In other applications, a fourth single-phase transformer is provided to improve resiliency of a critical transmission link. Should a transformer fail, the spare can be quickly inserted in its place to restore the transmission path. In either of these situations, transformer banks are usually extremely critical to the operation of the grid and warrant the best protection system design possible.

The nature of three single-phase transformers makes possible several improved protection practices not possible with three-phase transformers. The last two bullets in the following list relate directly to the theme of this paper.

- Precise identification of the faulted tank to speed restoration of a critical transmission link
- Improved speed, sensitivity, and selectivity for high-grade faults
- Improved speed, sensitivity, and selectivity for winding to ground faults

#### 1) Ability to Provide Precise Faulted Tank Selectivity

This protection improvement is covered here to provide background on the recommended protection shown in Fig. 12. A three-phase transformer requires the protection to sum ampere turns around the three loops in the magnetic core. This usually requires use of delta compensation on some of the terminals. The delta compensation combines currents from two phases to make up the zone boundary signal, as explained in Section II.B. This makes normal transformer differential protection practices unable to precisely identify the faulted tank. So, applying the same protection to a transformer bank as applied to a three-phase transformer is not best practice.

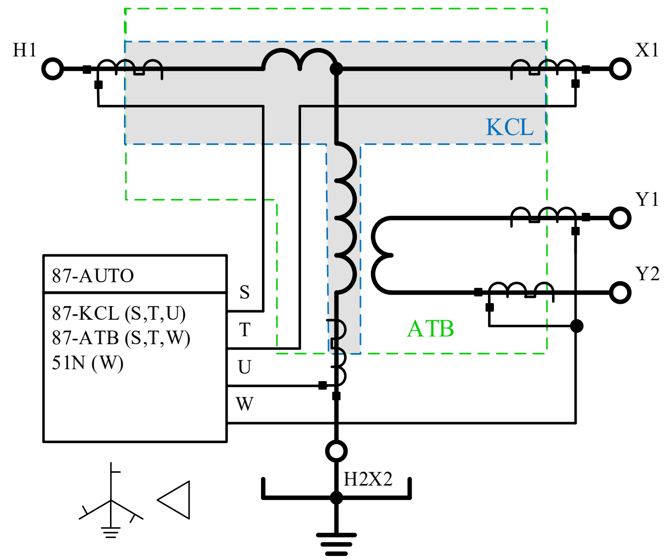


Fig. 12. Bank of single-phase autotransformers with recommended protection

A single-phase transformer has a closed magnetic core, making it possible to configure the differential element to sum the ATB for each magnetic core and, therefore, provide faulted tank identification [13]. A single-phase transformer also has the advantage that CTs can be located on each of the bushings of the transformer, which makes directly measuring each of the winding currents easily possible.

The Y bushing CTs provide the tertiary currents inside the delta. Fig. 12 shows connecting the CTs on both Y bushings of the transformer in additive polarity. See [13] for details on the advantage of this configuration and how to account for it in the TAP compensation settings.

Fig. 12 also assumes that the buswork in the zone is protected by separate bus differential relays for the reasons discussed in Section V.C. and [1]. In this case, the desire to identify if a fault is external to one of the transformer tanks is further justification for this practice.

It can also be noted that sudden pressure protection is also able to provide positive faulted tank identification.

#### 2) Advantages of Using Both a KCL and an ATB Differential for a Transformer Bank

Adding a KCL differential element to the protection system design replaces and improves upon two supplemental protective elements applied to transformers. These are the unrestrained differential element (87U) and the REF [13] [14].

##### a) Unrestrained Differential Element, 87U

As discussed in Section II.B., an ATB differential element requires some means to mitigate the effects of the nonlinear magnetic core, which inherently slows tripping. For this reason, a transformer differential relay always includes a high-set, unrestrained differential element (87U) in addition to the sensitive percentage-restrained differential element (87R). The 87U element provides fast tripping for severe faults that could result in catastrophic damage and tank rupture, but its sensitivity is extremely limited.

Ideally, we set the 87U element below minimum fault conditions. But to maintain security, the unrestrained element must be set above the worst-case estimate of inrush current and above the worst-case estimate of false differential current during a through fault [1]. This results in a lack of sensitivity to certain internal faults.

Referring back to Fig. 12, we can see that the zone boundary for the 87-KCL element is provided by the CTs connected to the inputs S, T, and U of the relay. The 87-KCL scheme is possible because phase CTs above the neutral star point on the grounded H2X2 bushing are easily available in a bank of three single-phase transformers.

The constraints for setting the sensitivity of the 87U element are eliminated or relaxed for the 87-KCL element. The limitation to set the element above inrush is eliminated because this differential element does not rely on the principle of ATB on the magnetic core. Further, the percentage-restraint principle provides security for false differential current from CT saturation that the high-set unrestrained element cannot provide. The only way to secure an unrestrained differential element is to set it above worst-case false differential current. To provide contrast between the sensitivity of the two elements, we observe that the minimum pickup for the 87-KCL element can be securely set below 1 per unit of the transformer rating while the 87U element must be set to 8 to 10 per unit or even higher to obtain security.

To summarize, the 87-KCL element is superior to the 87U element in that it improves sensitivity, speed, and security. Applying a relay with both KCL and ATB elements allows this improvement in protection at little added expense.

##### *b) Phase-Segregated REF*

REF protection works on the principle of KCL [3]. There are two common schemes.

- Current-polarized directional ground element
- High-impedance differential element

For faults near the grounded neutral terminal of any wye-connected winding, the phase currents measured at the terminals of the transformer can be quite low, while the current in the shorted turns can be very high, quickly damaging the transformer. REF schemes take advantage of the fact that the current in the fault loop can be measured directly by the neutral bushing CT. The current in the winding ground connection is very high—even for only a few faulted turns above the grounded terminal of the winding [15].

The main challenge with applying REF to a transformer bank is obtaining the ground current. A fundamental attribute of a current-polarized directional based REF element is that it requires the ground current to be measured by a single CT on the grounded neutral bushing. The signal is, therefore, immune from false residual that is a concern when summing three CTs. In a transformer bank, this fundamental principle is usually violated unless the bank is constructed with an insulated neutral bus with a single connection to ground where a single neutral CT can be applied. Using the 87-KCL element, as shown in Fig. 12, in place of an REF element uses the ground CT current in the zone of protection. This allows it to have the same advantage as an REF scheme in sensing partial-winding faults to ground near the neutral of the winding, without requiring an isolated neutral bus.

There are several more advantages of using a KCL element over a current-polarized directional REF element for transformer banks. First, a set of three-phase KCL elements provides selective faulted tank identification, while an REF element does not. This is because the operating signal of an REF element is a zero-sequence quantity, so there is no way for the element to know which transformer the fault is in. Second, a KCL element requires no intentional delay for security and can provide faster tripping for potentially severe faults. An REF element typically requires a minimum security delay of a cycle or more.

When compared to a high-impedance differential REF element, a KCL element is still the best choice. A KCL element can use the same set of CTs for protection that are used for other relay functions and does not require special secondary wiring that is required for the REF element [13] [14].

### *E. Additional Applications With Two Protection Zones Inside a Tripping Zone*

There are a number of additional applications that can benefit from segregating the tripping zone into two separate zones. The following subsections talk about these briefly.

#### *1) Transformer With Tertiary Bus*

In many transformer applications, the tertiary winding is connected to a bus to connect station service transformers or to connect shunt reactive power compensation equipment to the transmission system. Often, the fault current level on a large transformer's tertiary bus is too high for breakers to interrupt. In such applications, a fault on the tertiary bus must be cleared by tripping the transformer zone. This creates the two protection zones, one tripping zone scenario we have discussed in Sections V.C. and V.D.

A relay with both ATB and KCL differential elements can be applied to create the two protection zones, as shown in Fig. 13. Protection is improved because the ultra-high fault currents can be cleared without the delay caused by the harmonic or waveshape features required to keep the ATB differential element secure, thus reducing the possibility of a tertiary winding through-fault failure. The precise indication of whether the transformer or the bus is faulted can aid troubleshooting and restoration.

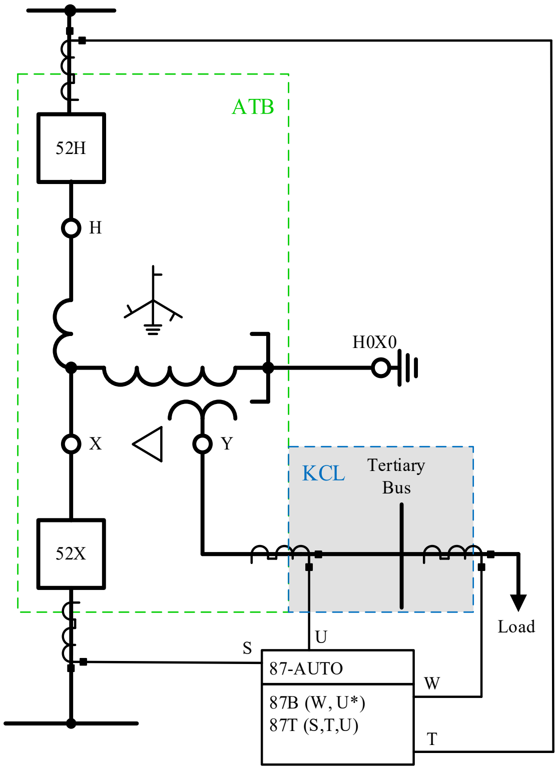


Fig. 13. Transformer with loaded tertiary bus

### 2) *Transformer With Long Lead Bus*

There is an occasional need to protect installations where the transformer is located somewhat remote from the source substation. This is shown in Fig. 14, with possible examples being:

- Connections between a transmission and a distribution substation perhaps separately owned.
- Connections between a green energy facility and a transmission interconnect substation.
- Connections between a utility tie substation and utilization substations in an industrial facility.

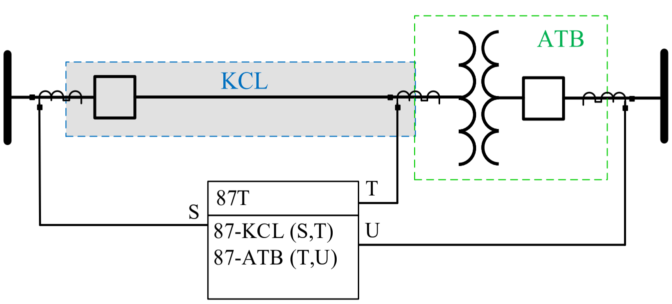


Fig. 14. Transformer with long lead bus

One approach is to protect the lead bus using line current differential relays at the source and transformer ends. A separate transformer relay is used at the transformer substation.

If the distances are not excessive, it is possible to consider running CT leads from the source breakers to the transformer substation by properly evaluating and specifying the CTs to perform adequately given the extra-long lead length. The ability to meet adequate performance is much enhanced if a relay with both KCL and ATB elements is specified.

For faults in the KCL zone, the performance requirements for the remote CTs are relaxed because the KCL element can be set with higher pickup and slope to maintain security for the expected poor performance. There is no need to compromise trying to select settings that are sensitive enough for faults in the transformer but secure for faults not limited by the impedance of the transformer.

Relays that support DSS technologies, as described in Section V.B., can also be used. This approach has a lot of the advantages of using line current differential relays in this application with one additional benefit: one CPC/DSS relay could serve the functions of three traditional relays.

### 3) *Extra-High-Voltage (EHV) Reactor With a Dedicated Reactor Breaker*

In many applications of high-voltage shunt reactors—including both line-connected and bus-connected—a reactor breaker is applied for switching and for selective fault clearing. In most cases, the current rating of the reactor is at least an order of magnitude lower than the rating of the associated circuit. The CTs used for the reactor protection must be rated based on the reactor rating to provide adequate sensitivity for the reactor protection.

It is desirable for purchasing and spare equipment that the circuit breaker used for reactor switching be similar to standard breakers used elsewhere in the utility system. Thus, it is desirable to not have to specify a reactor breaker with low-ratio CTs if possible. One solution to this problem is to segregate the tripping zone into a lead-bus zone and a reactor zone.

Fig. 15 shows recommended protection for a typical EHV shunt reactor [16] [17]. Note that this section focuses on the 87B and 87RX elements. See Appendix B for discussion of some of the other protection shown in Fig. 15.

In this example, the three breakers are rated 3,000 A while the reactor is rated 100 A. This discrepancy in equipment ratings is not unusual. To get adequate sensitivity for the reactor differential element, the engineer's choice is to specify that the 52RX breaker should be purchased with low-ratio CTs or try to tap the multiratio CTs to a low number of turns. Attempting to tap the multiratio CTs down to get the required sensitivity with the standard breaker CTs is discouraged due to the extremely high X/R ratio of the reactor, causing the CTs to saturate on direct current (dc) switching transients. A better solution is to design the protection system to use the matched CTs at each end of the reactor winding (the inputs T and U) for both terminals of the sensitive reactor differential. Using CTs with matching saturation characteristics can reduce the false differential current presented to the differential element when the reactor CTs inevitably saturate, improving security. This allows the reactor zone to be set more sensitively.

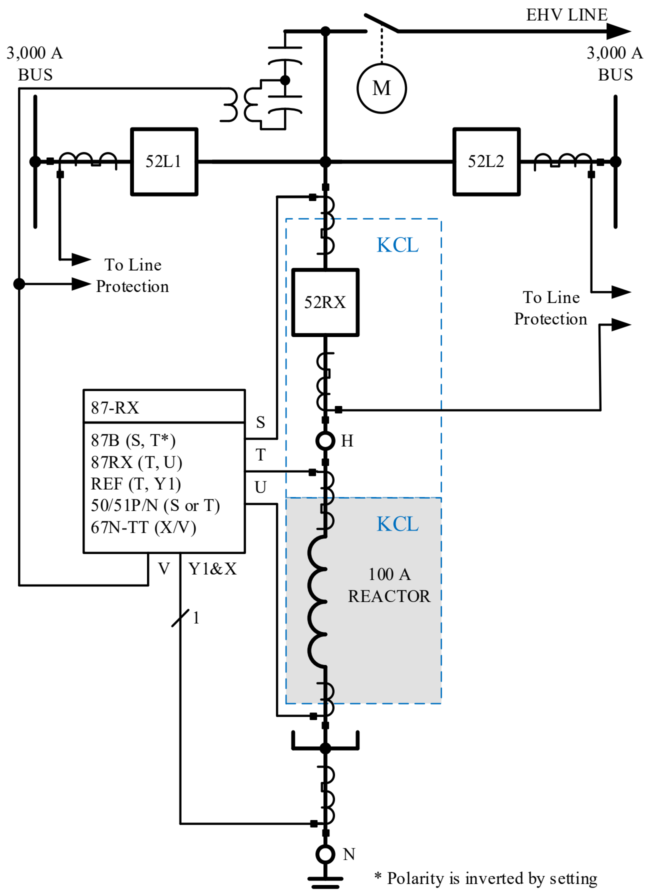


Fig. 15. EHV shunt reactor with recommended protection

Similar to the pad-mounted switchgear example in Section V.B., both the lead-bus zone and the reactor zone require a KCL-type differential element. This requires converting the ATB element into a KCL element by setting the harmonic blocking/restraint functions and the internal phase and zero-sequence compensation functions to OFF. The lead-bus zone needs to be set more securely to account for the fact that the CTs bounding the zone saturate differently since they do not match.

Similar to the dual-breaker autotransformer example in Section V.C., the CTs on the reactor bushings are wired polarity into the reactor to facilitate application of REF protection on the reactor and to allow the phase and zero-sequence compensation functions to be turned OFF. In this example, the 87B zone uses the high-ratio breaker CTs wired to the S input and the low-ratio CTs on the reactor bushings wired to the T input (with the T currents inverted by a setting in the KCL differential element).

In the autotransformer application, the TAP spread ratio between the bus breaker CT ratings and the apparatus CT ratings is typically within the range for a capable relay to accommodate. However, in this application, it is recommended to evaluate the TAP spread ratio required prior to finalizing any reactor specifications. The difference in CT ratios may challenge even the most capable differential relay. Compromises may be required.

### *F. Generator Step-Up (GSU) and Generator Stator Protection*

#### *1) Generator and GSU Protection in a Single Device*

A common method of providing redundant differential protection for the generator stator is to include the stator in the GSU transformer differential zone as an overall differential zone, as shown in Fig. 16. With the wide adoption of multifunction relays, it is common practice to have dual primary schemes on both the generator and the GSU. The use of an overall differential zone can save one differential element in the redundant protection design. The choice to have the GSU zone boundary on the neutral side of the stator is convenient because the neutral-side phase CTs are in proper polarity. So, no special consideration for CT polarity is necessary. Unlike the dual-breaker terminal application discussed in Section V.C., there is no security or performance compromise in letting the GSU zone overlap the stator zone.

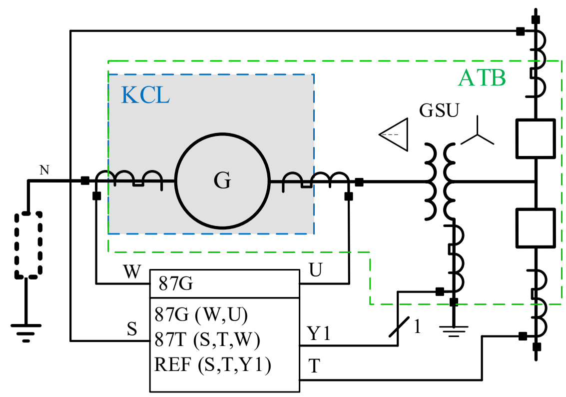


Fig. 16. Overall generator and GSU zone

A different philosophy for ATB/KCL zone boundaries is shown in Fig. 17. This approach shows segregating the generator and GSU zones, where the generator terminal CTs mark the boundary between them. Segregating the two zones provides precise information on the location of the fault, which can aid in troubleshooting. Notice that the shared CT circuit is connected with differential polarity on the ATB zone and not on the KCL zone. This follows the guidance from Section IV to simply invert the polarity for a KCL zone as opposed to inverting the polarity using compensation settings for an ATB zone.

It is preferred to install a breaker between the generator and the GSU, segregating the two zones. One reason is because selectivity can be improved by only tripping the affected area. The second reason is because when a breaker exists, the GSU can be energized from the high-voltage side (with the low side of the transformer open) to eliminate any possible generator differential element misoperation due to unequal CT saturation during inrush current.

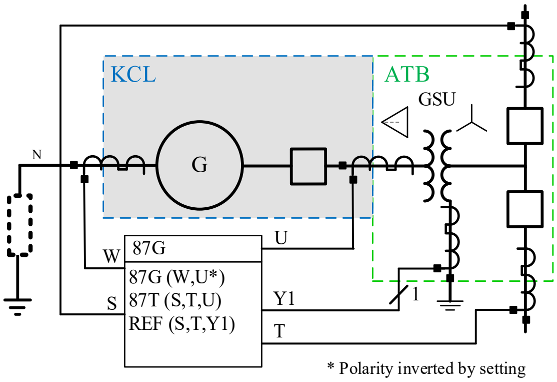


Fig. 17. Segregated generator and GSU zones

The breaker between the generator and the GSU also creates two different frequency zones, while the generator is building up to nominal frequency. An overall differential element in this scenario can unintentionally combine these current measurements at different frequencies if a load exists on the generator side of the breaker. This will result in false operating current that may far exceed any percent slope thresholds and result in a misoperation.

### 2) *Split-Phase Protection for Turn-to-Turn Stator Faults*

KCL-based differential elements can reliably detect stator phase-to-phase, phase-to-ground, and three-phase faults in most conditions for low-impedance grounded machines. To detect phase-to-ground faults near the neutral, a current-polarized directional based REF or neutral overcurrent element can be used.

For high-impedance grounded machines a KCL-based differential element is not effective at detecting phase-to-ground faults. In these systems, 100 percent stator coverage for ground faults is achieved using a combination of a fundamental neutral overvoltage element with a third-harmonic voltage differential element [18]. These elements are outside the scope of this paper but are required in most applications and should not be overlooked.

Regardless of the grounding method, a KCL-based differential element with CTs on the terminals of the machine cannot detect turn-to-turn faults. During a turn-to-turn fault, the phase current entering and leaving is unchanged, as seen by the phase differential element. There are several methods used for detecting this fault type, including negative-sequence directional elements, fundamental unbalance overvoltage, and split-phase (i.e., transverse differential) protection [19].

Due to the relatively low rotational speed of hydraulic turbines, it is common for these generators to be designed with paralleled branch stator windings per phase [20]. For simplicity, the example in Fig. 18 shows a single-phase stator winding with two parallel paths. Under normal operating conditions, the total current through each phase winding should be divided evenly between the two branches, with a difference in current being between 0.5 to 2 percent of the rated current [21]. The split phase measures the difference in current between the parallel windings to provide protection for turn-to-turn faults, phase faults, and an open circuit in one of the windings.

There are several CT and relay arrangements that can be used for split-phase protection. Fig. 18 illustrates a bushing CT connection in which the difference in current between the two branches is monitored by the generator relay's split-phase protection element (60P). 60P is an overcurrent element with a dynamic pickup threshold and a timer that is extended if an external fault is detected [20]. The pickup value is typically set to 150 percent of the maximum standing differential current during a heavy load. It is recommended that split-phase current be monitored periodically to ensure difference current due to load is not higher than expected [18]. The time dial should be long enough to allow false operating current due to unequal CT saturation to subside following an external fault [21].

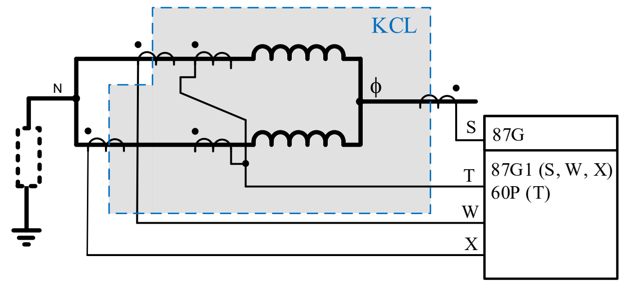


Fig. 18. Generator and split-phase (60P)

A KCL-based differential element (87) can also be used as a method for split-phase protection, as shown in Fig. 19. This scheme is really an approximation of KCL, since we are not directly measuring the two parallel currents and summing to a third measurement. Instead, we assume the current in the parallel paths are approximately equal based on the winding construction. If the difference between the two paths is outside the allowed error tolerance, we assume a fault has occurred somewhere in one of the windings.

Using an 87 element for split-phase protection is an attractive option for several reasons. The element uses the same CTs as the overall generator phase differential element, the element is easy to set, and the element is very secure during heavy loading (since load current is seen as a restraining quantity).

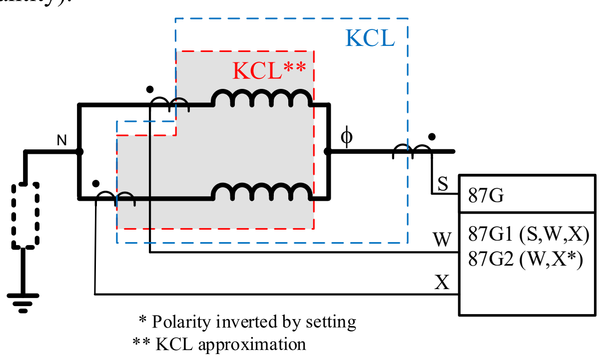


Fig. 19. Generator and split-phase (87)

The main limitation to using an 87 element for split-phase protection is a lack of sensitivity. A turn-to-turn fault likely does not generate enough operate current to overcome the restraint during heavy loading, making the 87 element not sensitive enough to detect a single turn-to-turn fault in many cases. Although the 87 element can often be more convenient, the 60P method of split-phase protection with adequate security considerations is preferred due to the 87 element's lack of sensitivity during a heavy load [20].

## *G. Phase-Shifting Transformer (PST) Protection*

PSTs are used to control power flow on the transmission system. They create a phase shift between source and load terminals by inserting a variable magnitude quadrature voltage into each phase. These transformers can be constructed with either a single magnetic core or two magnetic cores. The recommended protection varies depending on whether the PST is a two- or single-core configuration [22] [23]. Fig. 20 shows a common configuration of a two-core PST and its recommended protection. Fig. 21 shows a delta-hexagonal PST, which is one of the common configurations for a single-core PST, and its recommended protection. These diagrams assume that a differential relay with both KCL and ATB differential elements is used.

Many of the protection elements shown in Fig. 20 and Fig. 21 are outside of the scope of this paper, and some are discussed in Appendix C. Here, we focus on the elements labeled 87P, 87S, 87-REG, and 87-EXC.

### *1) Two-Core PST Protection*

A two-core PST, as its name implies, is actually two interconnected transformers—the series transformer (core) and the excitation transformer (core). Traditional protection for a two-core PST requires two differential elements to fully cover the PST—designated 87P and 87S [22] [23]. In a two-core PST application, the P and S do not stand for primary and secondary protection as we often see used for a redundant protection system. 87P stands for primary winding differential, and 87S stands for secondary winding differential. Both elements are required. In the past, that typically meant four relays were required to provide a redundant protection system.

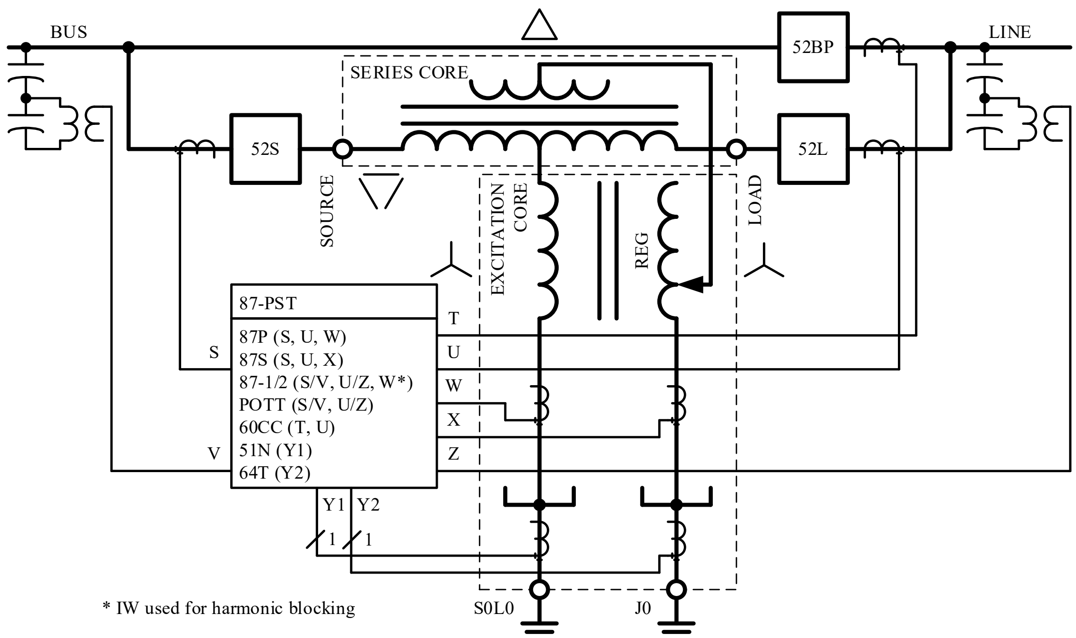


Fig. 20. Two-core PST with recommended protection

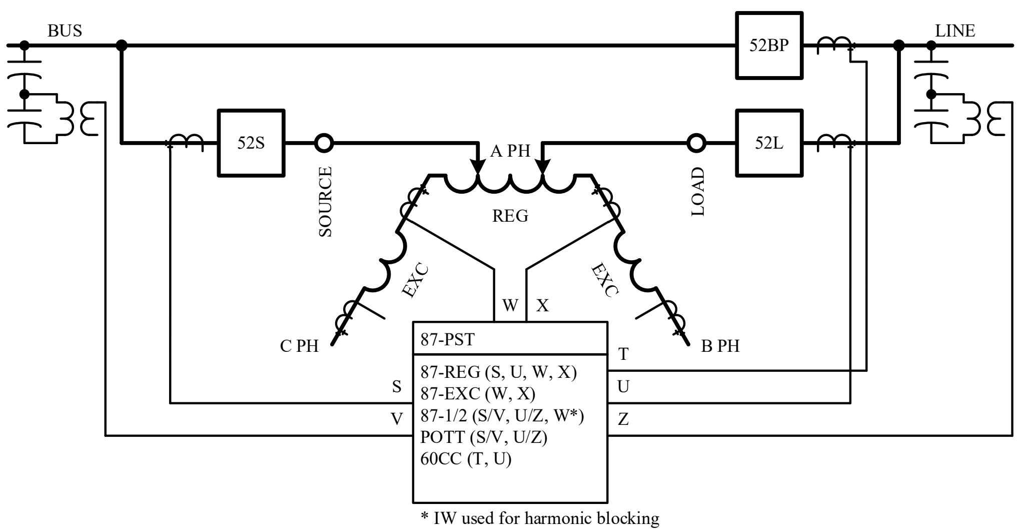


Fig. 21. Single-core PST with recommended protection

The 87P element is a KCL-type differential element that wraps the primary windings of the two transformers, as shown in Fig. 22. Referring back to Fig. 20, we can see that the zone boundary for the 87P element is provided by the CTs connected to the inputs S, U, and W of the 87-PST relay. Because the terminals of the zone of protection are galvanically connected and do not rely on the principle of ATB, this protection has historically been provided by a KCL differential type relay. The secondary windings, colored in green in Fig. 22, are not protected by the 87P element.

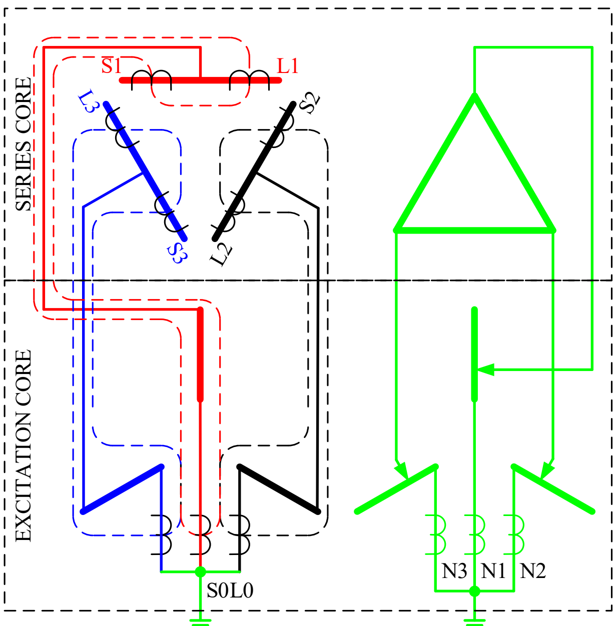


Fig. 22. Primary winding KCL differential element, 87P

The 87S element is an ATB type differential element that uses the CTs at the source and load terminals of the primary windings of the series transformer and the phase CTs at the base of the secondary (regulating) winding of the excitation transformer. Referring back to Fig. 20, we can see that the zone boundary for the 87S element is provided by the CTs connected to input S, U, and X of the 87-PST relay. By using the principle of ATB on the series core of the PST, faults in the secondary windings can be detected, as well as turn-to-turn faults in the series transformer.

Fig. 23 is used to illustrate the zone of protection covered by the 87S element. This diagram looks much different than the more detailed diagram of Fig. 22. The PST has been simplified to only show the windings that balance ATBs on the series core. The windings of the excitation transformer are reduced to simple lines. From this diagram that focuses on only the series core windings, we can see that the 87S is set up like it is protecting a three-winding transformer.

A transformer type differential element (ATB) is required for the 87S scheme because phase-shift and zero-sequence compensation are required. The wye (primary) windings lead and lag the delta (secondary) winding by 90 degrees. This is expected because the PST injects a quadrature voltage to provide the phase shift between source and load terminals. Zero-sequence compensation is required because zero-sequence currents can flow in the primary winding of the series transformer during a through fault. The secondary winding CT inputs do not see this zero-sequence current because it circulates in the delta secondary winding of the series transformer.

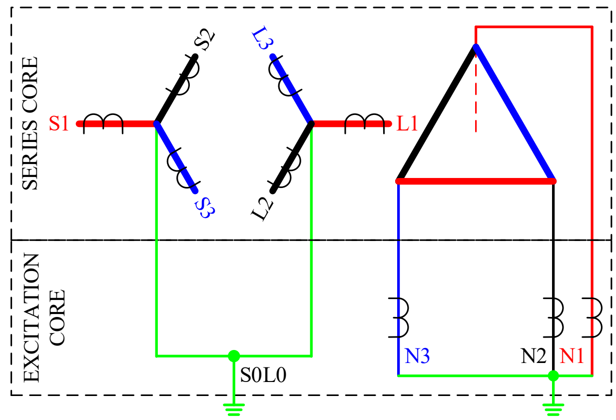


Fig. 23. Secondary winding ATB differential element, 87S

The primary windings of the excitation transformer, the simplified lines shown in green, are not protected by the 87S element.

### 2) *Single-Core PST Protection*

A single-core PST has a set of regulating windings and a set of excitation windings on one, three-phase magnetic core. The quadrature voltage is derived by inserting the regulating winding associated with the excitation winding connected across the opposite phases between the source and load terminals. Fig. 21 and Fig. 24 illustrate a delta-hexagonal configuration. Other configurations are common as well. It is not possible to apply the principle of ATB to a single-core PST [22]. The traditional protection for this type of PST is to provide KCL differential elements for each of the six windings, as shown in Fig. 24 [22] [23]. 87-EXC zones are the shaded differential zones, and the 87-REG zones are the unshaded differential zones.

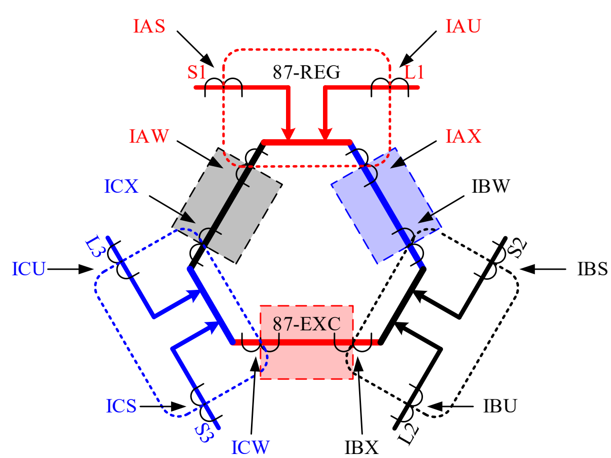


Fig. 24. Single-core KCL differential, 87-REG and 87-EXC

A relay with both KCL and ATB differential elements can be applied to provide full protection using a single relay. The KCL differential element in the relay is used to provide the

87-REG differential elements. The ATB differential element is used to provide the 87-EXC differential elements. This is a KCL-type zone, so the inrush and overexcitation security features are turned off to convert the element to a KCL element.

As shown in Fig. 21 and Fig. 24, we can see that the zone boundary for the 87-REG element is provided by the CTs connected to the inputs S, U, W, and X of the relay. The CT circuits are all wired polarity into the 87-REG zone, so there is no need to invert polarity on any CT inputs for this zone.

Fig. 21 and Fig. 24 show that the zone boundary for the 87-EXC element is provided by the CTs connected to the inputs W and X of the relay. There is no need to invert the polarity for either CT in the 87-EXC zone because each CT is reversed relative to the zone of protection. This still results in the currents being 180 degrees out of phase for external faults and through currents. However, we do need to use the angle compensation features available in the ATB element. The examination of Fig. 24 reveals that the CTs bounding each 87-EXC zone are on different phases. For example, IAW and ICX bind the black excitation winding in Fig. 24.

Table D1 of [24] or Table VIII of [6] shows the various compensation matrices. In this application, we could select the identity matrix (wye matrix in Row 0) for the IW CT inputs. Then, we select a wye compensation matrix for the IX CT inputs that has “0 0 1” in the first row. This means that it uses zero times the A- and B-phase and one times the C-phase current in the A-phase differential calculations. The examination of the tables shows that the required compensation is the wye matrix in Row 4. This is logical as C-phase leads A-phase by 120 degrees, so a matrix that provides 4 • 30 = 120 degrees of compensation offsets this phase difference. The resulting differential calculation for the 87-EXC zones is shown in (9).

$$1 \bullet \begin{bmatrix} 1 & 0 & 0 \\ 0 & 1 & 0 \\ 0 & 0 & 1 \end{bmatrix} \bullet \begin{bmatrix} I_{AW} \\ I_{BW} \\ I_{CW} \end{bmatrix} = 1 \bullet \begin{bmatrix} 0 & 0 & 1 \\ 1 & 0 & 0 \\ 0 & 1 & 0 \end{bmatrix} \bullet \begin{bmatrix} I_{AX} \\ I_{BX} \\ I_{CX} \end{bmatrix} \tag{9}$$

## VI. Conclusion

Two common principles of current differential protection are used to protect the power system apparatus: KCL-based and ATB-based current differential protection. Most microprocessor relays are purpose-built for a given application and provide either KCL or ATB elements, depending on the type of apparatus they are designed to protect. These relays often result in engineers using one current differential element to protect what are actually two differential zones. This practice often results in compromises of the sensitivity, security, speed, and selectivity of one or both of the zones. This paper showed how having both a KCL-based and ATB-based current differential element available inside the same relay allows us to protect each zone in the proper way, therefore, removing the need for compromises and allowing for better protection.

In addition to allowing for improved protection schemes, there are many organizational benefits of having a KCL and ATB-based current differential element in the same relay. These include improved availability, reduced maintenance costs, simplified stock and training, and reduced panel sizes.

## VII. Appendix A: Additional Information on Line-Charging Current

Charging current is the amount of current that flows to the shield (ground) through the distributed capacitance that is formed between the phase conductor, dielectric material, and ground. This has the same differential characteristics as a permanent, high-impedance, internal fault. Charging current is relatively constant regardless of current magnitude, so increasing slope settings to improve security is not needed. Ensuring the minimum operating current setting is at least 120 percent of the estimated charging current is sufficient to provide security for cable differential protection.

The cable shunt capacitive reactance is a per-unit length commonly specified by the cable manufacturer. The charging current per phase can then be calculated and converted to a differential per-unit value using (10). The minimum operate current setting for the cable differential element needs to be set higher than $I_{CH\_PU}$ to ensure proper security.

$$I_{CH\_PU} = \frac{\left( X_C \bullet \frac{V_{LL}}{\sqrt{3}} \bullet L \right)}{TAP_{min}} \tag{10}$$

where:

$X_C$ = cable shunt capacitive reactance per-unit length
$L$ = length of the cable
$V_{LL}$ = line-to-line voltage
$TAP_{min}$ = minimum TAP setting in cable differential zone

## VIII. Appendix B: Additional Information on Reactor Applications

The sensitive turn-to-turn fault protection scheme is implemented using the zero-sequence voltage-polarized directional element 67N-TT. This is the protection scheme requiring sensitive settings in the range of 10 percent of the reactor rating [16]. The reactor is constructed with little natural asymmetry. Any unbalance in the currents in the reactor can be attributed to either system voltage unbalance or a turn-to-turn fault in the windings. An impedance-based zero-sequence voltage-polarized directional element with forward and reverse boundary offset into the reactor (typically half of the reactor impedance) can easily determine if the source of the unbalance is internal to the reactor (turn fault) or due to a ground unbalance on the transmission network [16] [25]. Because the unbalance current pickup threshold is so sensitive, the directional element must be able to trip with zero-polarizing voltage. The current at pickup is too small to cause any voltage drop across the source impedance of the system. That is why an impedance-based directional element is suitable for this application [25].

Fig. 15 shows that the neutral bushing CT is wired to both the Y1 input for REF protection and the X input for 67N-TT protection. Both the REF and the 67N-TT scheme benefit from the fact that their operating signal comes from a single CT on the ground lead. Using a single ground CT makes the schemes immune from false residual current from unequal performance of three phase CTs. This is especially important for reactors, given that CT performance issues cannot be avoided due to the high X/R ratio and resultant long dc time constant of the reactor.

As shown in Fig. 15, the polarity of the ground CT circuit is wired towards the reactor. This is to accommodate the application of the REF element. The result is that system faults are forward and reactor turn-to-turn faults are reverse. Because the purpose of the 67-TT element is specifically to detect turn-to-turn faults that the 87RX is blind to, measuring the zero-sequence unbalance current at the neutral end is as equally valid as if it were measured at the terminals of the reactor.

For an impedance element, the location of the voltage transformer (VT) signal determines the point of reach. In this case, the VT signal is connected to the terminals of the reactor. For the impedance thresholds that determine the zone boundary between forward and reverse to be inside the reactor and not out on the system, they are set with a negative sign. The scheme trips when the unbalance current is above the current threshold and the directional element declares reverse.

The reactor neutral ground CT can be an even lower ratio than the reactor phase CTs, making sensitive turn-to-turn fault protection easier to implement. The single CT is wired in series to the A, B, and C terminals of the X CT input such that it measures only zero-sequence current for use by the zero-sequence voltage-polarized impedance-based directional element. If wired to one phase CT input, the relay correctly measures I0 but falsely measures I1 and I2 in the ground CT. When connected this way, the effective CTR is the primary rating to 15 A (assuming a 5 A nominal CT). For the Y1 input used by the REF, the CTR is the actual turns ratio without multiplying the secondary rating by a factor of three.

## IX. Appendix C: Additional Information on PST Applications

Fig. 20 and Fig. 21 show the complete suite of protective elements required to protect a two-core and a single-core PST, respectively. References [22] and [23] can provide additional details on these additional elements that are available in a special application for PSTs. The following provides a brief explanation of the less common function codes shown for the reader's convenience.

As shown in Fig. 20 and Fig. 21, the third set of differential elements, 87-1/2, is the sequence component differential elements with variable phase compensation that can detect turn-to-turn faults that the traditional differential elements applied to a PST are blind to.

The 60CC element, also available as a special application, is provided to detect the extremely high circulating current that can occur if the PST is bypassed off neutral. The differential elements are blind to this condition as well. Typically, the circulating current loop is broken by tripping the load-side breaker to leave the transmission circuit in service on the bypass branch. Some papers describing this element have used the device code 32CC.

The 64T element is a simple overcurrent element that responds to any current flowing from the ground into the delta-connected secondary circuit.

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## XI. Biographies

**John Hostetler** received his BS from Washington State University in 2011 and his Master of Engineering degree from the University of Idaho in 2020. He joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2011, where he works as a lead product engineer in the research and development division.

**Michael J. Thompson** received his BS, magna cum laude, from Bradley University in 1981 and an MBA from Eastern Illinois University in 1991. Upon graduating, he served nearly 15 years at Central Illinois Public Service (now AMEREN). Prior to joining Schweitzer Engineering Laboratories, Inc. (SEL) in 2001, he worked at Basler Electric. He is presently a distinguished engineer at SEL. He is a senior member of the IEEE, the Chairman of the IEEE PES Power System Relaying and Control Committee, the past chairman of the Substation Protection Subcommittee of the PSRC, and he received the Standards Medallion from the IEEE Standards Association in 2016. Michael is a registered professional engineer in six jurisdictions and was a contributor to the reference book, Modern Solutions for the Protection Control and Monitoring of Electric Power Systems. He has published numerous technical papers and magazine articles and holds four patents associated with power system protection and control.

**Ariana Hargrave** earned her BSEE, magna cum laude, from St. Mary's University in San Antonio, Texas, in 2007. She graduated with a Master of Engineering in electrical engineering from Texas A&M University in 2009, specializing in power systems. Ariana joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2009 and works as a principal application engineer in Boerne, Texas. She has published over 30 application guides and technical papers and was honored to receive the Walter A. Elmore Best Paper Award from the Georgia Institute of Technology Protective Relaying Conference in 2017, 2018, and 2023. She also authored the chapter on system protection in the book *Women in Power: Research and Development Advances in Electric Power Systems*. She is a senior IEEE member and a registered professional engineer in the state of Texas.


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