Redundancy Strategies for Distribution Protection

Michael Thompson, Bernard Matta, and Ray Connolly, *Schweitzer Engineering Laboratories, Inc.*

***Abstract*—Redundancy of protection and control systems is very common at transmission levels of the electric power system. Redundancy is considered critical for networked electric power systems because, among other reasons, the ability of remote backup to ensure reliable fault detection in adjacent zones is often inadequate. At distribution levels, the system is often operated radially where the ability of upstream relays to back up feeder zones is considered less of a challenge. However, because the distribution system serves customers directly along every segment of the feeder, reliability can be even more important than for transmission circuits as outages have a direct impact on quality of service for individual customers. Distribution also has the attribute that, by its nature, it is in close proximity to the public and to public and private property. For this reason, failure to clear faults can have significant safety and property damage consequences. Further, multifunction relays provide much higher levels of functionality much more economically relative to previous technologies, making the old paradigm driving practices obsolete. For these reasons, designing redundancy into distribution protection and control systems is becoming much more common. This paper discusses the complexities of not designing in redundancy and examines strategies to design redundancy of critical functions into distribution protection and control systems.**

I. Introduction

Electromechanical (EM) relay systems of old, protecting distribution equipment, had some degree of redundant protection because of the discrete relay packaging. For example, if one of the four overcurrent relays that typically protected a feeder failed, at least one of the other three relays provided some degree of protection for multiphase faults and phase-to-ground faults. The redundancy was not complete though, as a phase relay may not provide the same sensitivity to in-zone ground faults as a ground relay. Redundant protection could be less for bus and transformer zones. Breaker failure schemes were often not applied. Upstream overcurrent relays were relied on to fill in holes in protection upon a relay or breaker failure. These overcurrent relays were not always easy to set and their operation removed many more customers from service than necessary. Improved selectivity could have been achieved with better redundancy built into the protection.

When EM relays were replaced with microprocessor-based relays, some utilities improved the protection redundancy in their new designs. For example, using two relays to protect a feeder. However, this is not a universal practice across distribution systems. In many systems, the EM relays for a zone of protection were replaced with a single microprocessor-based relay. The new relays offered an improvement: an alarm for failure. But upstream backup protection was relied on even more to protect distribution equipment exposed to frequent fault activity until the failed relay was replaced. Utilities often tried to perform field switching of load feeds until the relay could be replaced.

Some inexpensive and simple ways to apply protective designs that add redundant protection to distribution transformers, buses, and feeders are discussed in this paper. The added redundancy improves protection, reduces fault clearing times, and minimizes the number and duration of customer outages compared to protection that relies on upstream relays to cover relay failures. Application of these designs reduces engineering cost in determining relay settings because the need for bus or transformer overcurrent relays to back up feeder protection is eliminated. Overcurrent coordination studies between feeder relays and upstream relays are no longer needed when relays are initially installed or in the future when feeder relay settings are changed.

II. Redundancy Practices for Distribution

This paper focuses on typical North American utility distribution system applications. However, many of the considerations and recommendations are transferable to industrial distribution systems. The typical distribution system consists of:

- A distribution substation transformer that is fed by the transmission or sub-transmission system.
- The medium-voltage bus.
- Feeders that distribute power to residential, commercial, and industrial consumers.

Often, for reliability of service, there may be two distribution transformers and two medium-voltage buses with a bus-tie within a substation to provide diversity of sources. While the feeders are typically operated radially, the distribution system can be quite complex with means to transfer segments of load to other feeders at multiple normally open points throughout the system. The number of feeders on a given bus is typically limited to no more than four or five to provide less impact to customers upon loss of a bus or transformer. Of course, in dense urban distribution systems, this number may be higher.

Reliability of service is critical because, in many cases, the ability to supply individual loads from multiple sources is limited along the distribution system. Outages directly affect quality of service and restoration often takes time to isolate the affected line section and reconfigure feeders to restore loads to those not on the affected segment. While new technologies such as fault location, isolation, and service restoration (FLISR) systems are being deployed to reduce outage duration for as many customers as possible, in many cases manual processes are still required [1]. Another technology being deployed is a concept called high-density coordination (HDC). The feeder is divided into many more smaller blocks of load to reduce outages to as few customers as possible. HDC allows the many reclosers to be coordinated without stacking coordination intervals too severely [2] [3]. FLISR and HDC are evidence of new thinking in improving distribution reliability. This paper is another.

Reliability of protection for distribution systems is important because distribution lines are, by their nature, in close proximity to the public and to public and private property. For this reason, failure to clear faults can have significant safety and property damage consequences.

While redundant protection is commonly applied for transmission and sub-transmission circuits, often very little redundancy is applied in distribution protection system design. Several historical reasons exist for this approach.

- Delayed fault clearing does not affect system stability, as can be the case at transmission levels.
- The number of distribution circuits is much greater than the number of transmission circuits, so adding redundant protection might be considered to have more cost impact.
- The system is operated radially, so the ability of upstream relays to detect faults in the zones that must be backed up is considered less challenging.

The last point is discussed in more detail in Section IV of this paper. Applying upstream relays to provide backup protection at the distribution level can be difficult. Greater sectionalization to reduce customer count per section reduces the difficulty. However, relying on upstream devices to provide backup results in tripping multiple zones of protection. This result goes against the purpose of greater sectionalization.

A. Distribution Transformer Protection Redundancy

1) Use of Relaying Systems

Historical practice has been to apply redundant protection systems to the distribution transformer zone. System A is typically differential protection that provides high-set, 87U and low-set, 87R differential elements to detect faults in the transformer and its associated zone. System B is typically overcurrent protection that provides overcurrent elements to detect faults in the buswork of the zone and high-grade faults in the transformer. The overcurrent elements also provide protection coordinated with the transformer damage curve for uncleared external through faults. System B also includes a sudden pressure relay (63SPR) to detect both high- and low-grade faults in the transformer. This method provides hardware and protection principle diversity to ensure all fault types can be detected. Independent tripping, typically separate lockout relays, is used to ensure no single-point-of-failure between System A and System B. Ideally, the two systems use independent current transformers (CTs) and voltage transformer (VT) secondaries, as well.

Designing for full dual-primary protection using two differential relays is very common today because of the relatively low cost and capability of multifunction transformer differential relays. A second multifunction transformer differential relay provides much better protection than an overcurrent relay. Using two multifunction transformer differential relays can simplify the design for redundancy and settings of the protection system; this is the recommended approach.

Redundant protection for the distribution transformer is necessary given the inability of upstream relaying on the transmission or sub-transmission system to see all faults in the distribution transformer zone. Sensitive line-ground relaying cannot see past the typical delta high-side of the distribution transformer. Phase relaying often cannot see through the significant impedance of the distribution transformer. In many cases, it is even considered undesirable for the transmission system relaying to see distribution faults to simplify coordination and improve reliability of the transmission system. Further, transmission line protection cannot be set sensitive enough to see low-level, partial winding faults in the transformer itself. Highly sensitive 87R and 63SPR relaying is required to see these faults [4].

2) Use of High-Voltage Fuses

In many cases, distribution transformers may not have sensitive relaying and are protected by fuses. The high-voltage fuses are very reliable and can detect faults in the buswork of the transformer zone and coordinate with the transformer damage curve, but their sensitivity to low-grade winding faults is limited. Failure of a fuse to interrupt typically results in the fuse burning up and causing a high-side flashover that can be reliably detected by the transmission system protection; but, as stated earlier, transmission protection operation is an undesirable backup operation that may create a more widespread outage. For these applications, the transformer is typically smaller and considered replaceable should it fail internally.

B. Distribution Bus Protection Redundancy

The practices for distribution bus protection vary widely. In some cases, no selective high-speed protection is applied at distribution levels. Faults on the bus are simply cleared by overcurrent relaying associated with the main breaker (or with the transformer CTs in substations without a main breaker) that is time-coordinated with the feeder protection. Historical thinking was that there is relatively little exposure to bus faults compared to the significant exposure for faults on distribution lines; utility experience has since shown that animal-induced faults, water intrusion, and condensation do occur and generate significant damage and long restore times. Further, slow clearing of a distribution bus fault has no impact on system stability. This approach is becoming less common as the industry has a better appreciation for the safety consequences of delayed clearing due to arc-flash hazards.

Single high-speed protection systems are common, with time-delayed backup protection from upstream relays that overlap the bus zone. However, providing fully redundant high-speed bus protection schemes is easily achievable in most applications today. Doing so can improve and simplify protection of distribution buses and feeders, as will be discussed throughout this paper.

Reference [5] provides detailed information on bus protection schemes. This paper does not discuss these in any depth. Section III of [6] provides a thorough discussion on strategies for providing redundant high-speed protection systems for buses. While that discussion is focused on a transmission application, many of the concepts are applicable to distribution as well. In this subsection, we cover the following options at a high level:

- 87B, bus differential protection.
- 50ZI, zone interlock protection (also known as fast bus overcurrent scheme).
- 50AF, time-over-light elements supervised by high-speed overcurrent that responds to the arc flash inside metal clad switchgear.

In the following discussion we mention using non-traditional zone boundaries for some of the bus protection options. This is because protection engineers are, rightfully, careful about ensuring proper overlapping of zones of protection to guarantee that no credible fault can be outside the zone of protection of at least one relay. Most breakers separate two zones of the primary system. Typical practice is to overlap the protection zones as well as the tripping zones such that a fault inside the breaker itself is inside both zones of protection and both zones are tripped to isolate the faulted breaker. In the redundant schemes proposed, there is no fault that is not inside at least one zone of protection. In many cases where the tripping zone and protection zone do not overlap, the breaker failure scheme mitigates delayed clearing.

1) 87B Bus Differential Protection

Differential protection is the classic solution for selective, high-speed protection of buses. Implementing a bus differential scheme requires availability of CTs on the main, tie, and feeder breakers to define the zone of protection. This may not be possible in a retrofit application if the medium-voltage breakers were not originally purchased with the required CTs, or if cabling was not installed to access the CTs.

High-impedance bus differential relays (87Z) are suitable for applications where CTs of the same ratio are available to be dedicated to the bus differential scheme. The number of branch circuits on a bus that can be protected by an 87Z scheme has very high practical limits and, therefore, is scalable for expansions of the bus. The 87Z relays cannot provide additional functions such as branch circuit overcurrent and breaker failure functions.

Percentage-restrained relays (87B) are also used. These relays measure the current flowing in each branch circuit and develop a restraint signal that is a measure of the current flowing through the zone of protection. This restraint signal is compared to the operate signal, which is the sum of the currents flowing into the bus per Kirchhoff's Current Law. The operate signal must be greater than a percentage (or a variable percentage) of the restraint signal to declare an internal fault.

Modern percentage-restrained differential relays are a significant game changer over EM technology. Modern percentage-restrained relays do not need a dedicated CT circuit to galvanically sum the currents to develop the operate signal. They mathematically sum the currents and can appropriately scale the currents such that there is no need to have matched CTs. They can be built with enough restraint inputs to accommodate CT inputs for each feeder independently, making the bus relay available to provide feeder backup as detailed in Section VI.B. Relays with fewer restraint inputs may still require paralleling of CTs and cannot provide independent feeder backup. Modern relays also have negligible burden, so wiring multiple devices in series on an available CT circuit is not a concern. For this reason, CTs used for other purposes can be shared to create a differential zone where none existed before. Reference [6] talks about considerations for protection zone overlap if the bus zone and feeder zone do not have the traditional overlap when they share a CT.

2) 50ZI, Zone Interlock Protection

Zone interlock schemes use signaling between the feeder and bus main relays to make an unselective overcurrent relay selective. In radial systems, this can be a simple blocking scheme sometimes called a fast bus overcurrent scheme. The bus main overcurrent relay sees the fault and waits for a short interval to receive a blocking signal that indicates the fault is on a feeder and not on a bus. If no block is received, the relay trips the bus.

This scheme is desirable because it does not require additional relays to implement. For this reason, it is an option to provide high-speed tripping in distribution bus applications that do not have CTs and cabling available to implement an 87B scheme. It is also a desirable way to provide a redundant high-speed scheme in parallel with a differential scheme at minimal expense. This scheme is easily scalable to buses with many feeder circuits.

This scheme has some less desirable issues as well. The scheme is not quite as fast as a differential scheme that is inherently selective. Additionally, the 50ZI scheme tends to be less reliable than a bus differential scheme because many more devices are required to work together for the scheme to function properly. Failure of any one of the blocking relays or the blocking signal can cause a security failure. Failure of the bus main relay (that typically also provides the time-delayed backup function for bus faults) can cause a dependability failure. Complication increases because the engineer must determine if the preferred outcome is to fail secure or fail dependable. That is, do you:

- Disable the scheme if it can overtrip for a feeder fault due to a blocking relay being out of service, or
- Leave the scheme in service and keep high-speed tripping, but allow the potential for an overtrip should a fault occur on the feeder whose relay has failed?

If the 50ZI scheme is being implemented to provide a redundant high-speed bus protection scheme, the slightly slower operation is probably acceptable and the choice to design the scheme to fail secure upon any self-test alarm is easier to make.

The 50ZI scheme relies on relays at the feeder zone boundary (typically CTs on the bus side of the feeder breaker) so the bus zone and feeder zone do not overlap at the breaker. This is generally of small consequence—especially if the 50ZI scheme is providing a high-speed scheme that is redundant to an 87B scheme. But it does mean there is a small zone between the CT and breaker where a fault can occur for which the 50ZI will be blocked to allow the feeder breaker to trip, yet the feeder breaker will not interrupt the fault.

If 50ZI is the only high-speed bus protection, such a fault will have to be cleared by a breaker failure scheme (as we recommend in Section II.D) or by upstream time-delayed overcurrent. Alternatively, a better solution is to connect the feeder relays in the non-traditional location on the feeder breaker line-side CTs in such designs. That way, a fault inside the breaker between the interrupter and the CT is in the bus zone and the faulted breaker is properly isolated by the bus protection.

3) 50AF, Arc-Flash Protection

Similar to a 50ZI scheme, arc-flash sensing can be used to make an inherently unselective overcurrent relay selective. Sensing light from the arc flash inside the switchgear enclosure ensures that the scheme only trips for faults in the bus and not on the feeders.

4) Summary

Any of the selective, high-speed bus protection schemes described here can be used in any combination to provide redundancy for distribution bus protection. Ensuring selective high-speed protection is important to improve the reliability of the distribution system.

Relying on time-delayed backup protection instead of dedicated primary protection should not be tolerated for normal clearing, and high-speed redundancy for N-1 clearing is highly desirable. Fast and selective bus protection improves arc-flash safety, reduces stresses on the distribution transformer, and reduces damage to faulted equipment. The last point is important because it is often the case in distribution systems that alternate sources for many customers are not available. Service cannot be restored until repairs are made. Reduction in damage by high-speed protection can significantly speed up service restoration in those cases.

In applications where CTs are available for bus differential protection, 87B is preferred for System A. If CTs are not available for 87B, 50ZI and 50AF are possible solutions. The choice of the System B high-speed, selective protection is dependent on several factors. Some System B options are:

- A second 87B relay sharing the same zone boundary CTs as the System A 87B relay (not recommended if 87Z is used [6]).
- A second 87B relay sharing the CTs with the feeder zone boundary CTs (requires using a percentage-restrained 87B relay).
- A 50ZI scheme (this scheme uses the feeder zone boundary CTs for the bus zone similar to the previous option).
- A 50AF scheme (switchgear that has arc-flash sensing or can be retrofitted with arc-flash sensing).

C. Distribution Feeder Protection Redundancy

It is common to apply a single multifunction relay on each distribution feeder and rely on upstream relays to provide feeder backup protection. There are several disadvantages to this approach that are discussed in this paper.

Redundancy for feeder protection is the central topic in this paper. While the previous sections covered redundancy for the transformer and bus protection, redundancy for the feeder protection is covered as follows:

- This subsection mentions operational and maintenance considerations regarding adding redundancy for feeder protection.
- Section III discusses organizational considerations regarding relying on upstream backup.
- Section IV discusses the protection ramifications of using upstream backup.
- Section V discusses what functions should be redundant.
- Section VI discusses ways to provide redundancy.

When a single multifunction relay on the feeder fails, that feeder breaker should be taken out of service quickly after the condition is discovered (ideally by monitoring the self-test fail status). Removing the breaker from service until repairs can be made typically means extensive switching to transfer the loads to alternate sources if possible. There can be increased danger to operations personnel during such switching activities because a fault induced by a failed switching operation can take significant time to clear if the only protection available is the bus main backup. Opening the feeder breaker and dropping the load before switching to pick it back up from an alternate source may be advised. If the distribution system topology cannot support switching to re-feed the load, operators may be reluctant to drop customers until the protection can be restored.

Similarly, periodic maintenance and testing of the feeder protection can be difficult to schedule if an outage of the feeder breaker is required to accomplish the work. If there is redundant protection on the feeder, these concerns are eliminated. One protection system can be isolated and tested or repaired with no fears about failing to clear a fault on the feeder, or about tripping the bus main should a fault occur and causing a wider outage than necessary.

Urgency and the possible human performance issues that come with it are reduced when feeder protection redundancy is applied, leading to better outcomes.

D. Breaker Failure Protection

In a protection system, we use relays to detect faults on the protected circuit and we use circuit breakers to interrupt those faults. Both systems have to work properly for a fault to be cleared. To ensure dependability for failure of any one system, we use redundancy. Redundancy for detecting faults is typically accomplished by using two relatively independent protection systems for each power system circuit. Redundancy for clearing a fault is not accomplished by using two circuit breakers in series (except in rare cases). System B for interrupting a fault is the use of a breaker failure protection system.

In non-redundant systems, we have to treat failure of the relay to detect a fault and failure of a breaker to interrupt the fault as the same contingency. Both failures are covered by having a relay on an upstream breaker that can sense all faults in the zone being backed up, which trips an independent upstream circuit breaker. Once we provide redundancy for the fault detection function, we still need to provide redundancy for the fault interruption function by applying breaker failure relaying.

Regardless of whether we use redundancy for fault detection at distribution levels, enabling breaker failure relaying has benefits. For example, if the feeder breakers have a breaker failure function, it is immediately clear that the cause of the bus trip is not a bus fault but a failed feeder breaker. Restoration of customer loads can be expedited considerably with this simple bit of extra targeting. Breaker failure relaying also clears failed breaker conditions faster than upstream overcurrent backup relaying because there is no need to wait through the coordination interval that is applied to provide otherwise selective coordination. Some bus overcurrent settings practices, as discussed in Section IV.A, can result in very long protection response times that are unnecessary if a feeder relay has already declared a need to trip and a subsequent breaker failure occurs.

Historically, the barrier to installing breaker failure was the cost of installing additional relays and the added complexity of the circuits. With multifunction relays, it is usually a simple matter of enabling available functions and relatively simple added wiring or inter-relay communication programming. We advocate that breaker failure relaying should be universally applied at all power system levels—not just transmission.

III. Organizational Considerations

Organizational structures and boundaries of responsibility can come into play when relying on the bus main relaying to back up the feeders. Often, different engineering and operations organizations are responsible for the distribution substation and the distribution system. In some cases, the settings for the bus main relay are the responsibility of the substation department relay engineers and the settings for the feeder relay are the responsibility of the distribution engineers. In other cases, settings for both the bus main and the feeder relays are the responsibility of the substation relay engineers and only the settings for the fuses and reclosers on the line are the responsibility of the distribution engineers. Of course, there are many other organizational arrangements. These arrangements are mentioned to make the reader aware to question if there are organizational issues with ensuring reliable protection for the distribution system.

Handoffs between organizations are a potential point of disconnect where communication can fail. Information about the criticality of the upstream backup to cover for a feeder relay or feeder breaker failure can be missed. Often, it is difficult for the substation engineer to know enough about the distribution system to be able to verify adequate backup when making the bus main relay settings. A design that incorporates redundancy for detecting feeder faults makes miscommunication and oversights significantly less likely.

IV. Common Feeder Backup Protection

To establish an appreciation of the value in eliminating the need of traditional bus overcurrent elements backing up feeder relays, next we will discuss complications that can arise when trying to apply the backup elements.

Fig. 1 shows a common way feeder protection is backed up when one relay is installed per feeder. Phase and ground inverse-time overcurrent elements (51P and 51G) in the bus main relay (51-BL) that measure the low-side currents of the transformer, or the sum of the currents into the bus if there is a bus-tie circuit breaker, are set to coordinate with the feeder relays and trip the transformer low-side and bus-tie circuit breakers. The 51P and 51G elements could be in a relay that also controls the low-side circuit breaker or in a transformer differential relay. The small implementation cost of 51P and 51G in a transformer differential relay makes this feeder backup method attractive to many protection engineers, and may be more common in substations that do not have a main breaker.

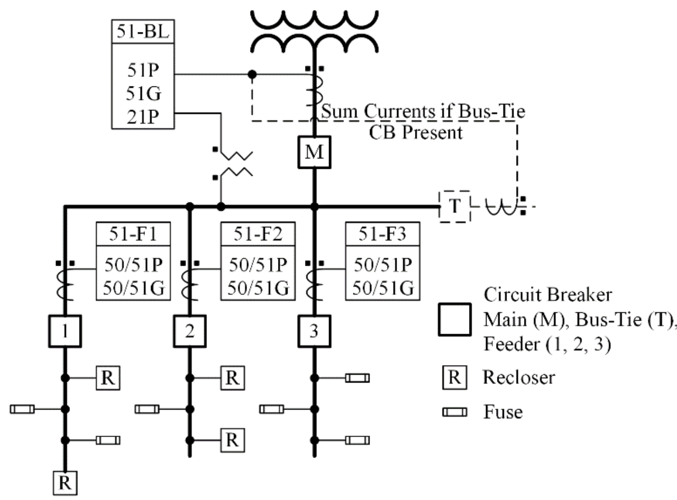


Fig. 1. Traditional feeder backup protection.

In this paper, we assume that 51-BL operates on the sum of the bus source currents (sometimes referred to as a partial differential). This ensures coordination of the bus main overcurrent elements with the feeder relays regardless of how the bus is being fed. These overcurrent elements are separate from the overcurrent relays that respond to the transformer winding currents coordinated with the transformer damage curve.

Considering a relay failure on a faulted feeder and compared to having redundant feeder protection, the most significant disadvantage of the overcurrent backup scheme is loss of service to customers on the healthy feeders. The outage duration can be long because the bus source circuit breakers typically do not have reclosing. Such an outage would leave customers dissatisfied and service reliability numbers reduced. Because 51-BL must coordinate with the feeder relays, the slower tripping of the former expose the transformer to the fault currents for a longer time. Close-in feeder fault current magnitudes approach those of bus faults.

A. *Setting 51P and 51G Pickups in the 51-BL Relay*

Referring to Fig. 1, 51P and 51G in the 51-BL relay measure transformer low-side currents that are equal to bus currents in the absence of a bus-tie circuit breaker. The 51P and 51G elements are typically connected as partial differential elements when a bus-tie circuit breaker is present, and the elements measure the bus currents. As a security limit, 51P in the 51-BL relay must carry the emergency loading of the bus. Instead of obtaining estimated bus loading from distribution planning or system operations departments, some engineers equate the emergency bus loading to the emergency transformer loading rating even if a bus-tie circuit breaker is present, and the engineers use this rating as the load 51P must carry. This practice can result in very slow protection response to bus faults. For accuracy, the emergency bus loading is referred to in this paper as the load 51P must carry.

To completely back up a feeder relay failure, 51-BL must be capable of sensing faults at the end of the feeder trunk or any portion of the feeder not protected by a downstream recloser, fuse, or other protective device. See Fig. 2.

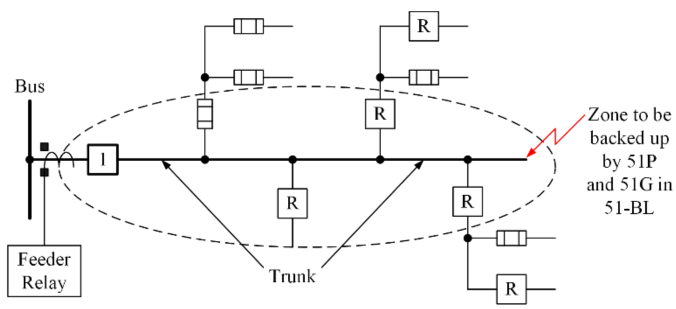


Fig. 2. Feeder portion that 51P and 51G in 51-BL relay must back up.

Setting the pickup of this 51P element can be challenging. For security, the element must be set high enough to carry the emergency loading of the bus and high enough to coordinate with the phase overcurrent elements of all feeder relays. For dependability, the element must be set low enough to detect multiphase faults at the end of the trunk of all feeders. That is, if there is no redundancy of relays on the individual feeders, the main bus backup relays must be capable of dependably detecting faults out to the ends of the feeder trunks.

These loading and sensitivity requirements can conflict. Typically, resolutions to this conflict between security limits and dependability limits could include the option of installing main line reclosers or fuses on feeder trunks to shorten the zones of the feeders the 51-BL relay must back up, or employing additional relay elements and logic to supervise 51P operation to make the element less sensitive to load.

Various methods can be used when there is a conflict between the security limit of setting the pickup above maximum loadability, with a security margin, and the dependability limit of setting the pickup below minimum fault conditions on the trunks of the feeders that must be backed up, with a dependability margin. When it is necessary to set the 51P element pickup where it does not have adequate margin above expected load, the relay needs more information to differentiate between a fault condition and load. Three solutions can be used to accomplish this:

- Impedance element supervision
- Undervoltage element supervision
- Load encroachment (LE) element supervision

Explanations for how these elements improve the loadability of 51P are given in Appendix A. The solutions require VTs on the bus and, to varying degrees, more sophisticated relays than simple overcurrent relays. Setting the 51P supervising elements can be complicated.

Because all of these solutions require voltage information, the engineer must decide on the degree of security and dependability that the bus main 51P provides under LOP conditions. Further, use of switch-on-to-fault schemes may also need to be evaluated depending on the method used, the arrangement of the VTs, and operating scenarios. These considerations are discussed in detail in Appendix A.

The complexity of properly applying these loadability enhancement features is removed when feeder protection redundancy eliminates the need for the bus main overcurrent relay to cover 100 percent of all of the downstream zones.

B. Time Coordinating 51P and 51G in the 51-BL Relay

The pickup, time characteristic, and time dial of 51P and 51G are set to coordinate with the feeder protection. For an unloaded system and feeders having separate poles, the coordination is usually simple to achieve. More effort could be needed to coordinate 51P with the feeder phase overcurrent elements at low-magnitude fault currents if load is considered. The 51P measures the vector sum of the bus load current and the fault current, whereas the feeder phase protection measures the vector sum of the feeder load current and the fault current. At low fault current levels, such as for a fault toward the end of a feeder or faults with much resistance, the difference in operating current between the bus main 51P and the feeder phase element becomes more pronounced. The effect is a relative shift of the 51P curve toward the feeder phase element curve, and if not considered could result in the two elements miscoordinating. This curve shifting has been identified as causing 51P to trip before feeder phase elements for low-magnitude faults on feeders [7].

If the feeders are configured as double-circuit lines sharing the same electric poles, a greater concern is simultaneous faults on two feeders. The fault currents measured by the 51-BL relay can be approximately twice the currents measured by the individual feeder relays. Unless special schemes are implemented to instantaneously trip the feeder breakers for simultaneous faults, coordinating the bus main 51P with the feeder protection can be difficult to impossible [8].

C. Other Disadvantages of 51-BL Providing Feeder Relay Backup Protection

Another disadvantage of upstream overcurrent elements backing up feeder protection is that the coordination needs to be checked every time the settings of a feeder relay are changed, and these changes can occur fairly often. Because resetting bus or transformer relays in the field can be risky or require an outage of a transformer, engineers might bend coordination criteria if feeder relay settings are changed.

A trip from 51-BL will not provide immediate fault location or indication of the problem.

D. Improvements With Redundant Feeder Protection

The different ways of adding redundant protection to feeders that are presented in this paper could eliminate the need for upstream overcurrent backup protection. The redundant protection improves selectivity, which in turn improves customer satisfaction and service reliability numbers. Feeder protection redundancy reduces feeder fault durations for feeder relay failures. Faster fault clearing improves public safety, improves service to the customers fed from the healthy feeders, reduces damage to public and private property, and lessens damage and wear to equipment of the electric system including the transformer and substation bus. Procedures for setting relays are simplified initially when the redundant protection is added, and in the future if feeder relay setting changes are needed.

V. Feeder Protection and Control Functions That Need to Be Redundant

Most importantly, 51P, 51G, and high-set 50P and 50G protection must be redundant. These elements provide the basic protection needed and the optimum selectivity and fault clearing times for the feeders. A hot-line tag function should be redundant because line work could become necessary at any time.

Only one reclosing element (79) for a feeder circuit breaker should be active at any time. Having two 79 elements in separate relays for the same circuit breaker, with the second 79 element becoming active if the first relay fails, might be ideal in some applications but would come with added complexity. If dual 79 elements are required, two multifunction feeder relays per feeder are required. However, if SCADA close is acceptable as a temporary backup to the 79 element until the failed relay is replaced, options other than dual feeder relays become available to provide feeder protection redundancy. SCADA close must be independent of automatic reclosing; therefore, SCADA close must be in a device or relay separate from the relay with the 79 element. The relay without the 79 element provides a reclose initiate output to the relay that has the 79 element.

The need for a redundant 27 element is determined by the user. Considering the strategy of having a 79 element in one relay and SCADA close in another relay, a 27 element is needed in the latter if SCADA close is only to be permitted after the status of the feeder voltage is checked. If the utility practice is to allow SCADA close for all conditions, a 27 element does not need to be redundant. A redundant 27 element requires two multifunction feeder relays per feeder. The other methods presented in Section VI for providing redundancy can be used if a 27 element is not needed in both relays.

Some utilities set the high-set 50P and 50G to protect underground cables in substations that make up a feeder from the circuit breaker to the overhead riser pole outside the substation. Reclosing is canceled when 50P or 50G trips because faults in underground cables are usually permanent. This reclose-cancel scheme should be redundant, and the redundancy is simple to implement by excluding 50P and 50G trips from the reclose initiate output of the relay without the 79 element.

Feeder protection that includes a fuse-saving scheme uses dedicated, fast operating 50 or 51 elements that are typically in service when the 79 element is in the reset state or, in some cases, after the first shot of reclosing. A redundant fuse-saving scheme is difficult to implement with two multifunction relays per feeder and not possible with the other redundancy options presented in this paper because of the 79 element dependency. Converting to a fuse-blowing scheme until a failed relay is replaced should not be a problem for most applications; therefore, redundancy is typically not needed for fuse-saving schemes.

Long feeders could require LE in the protection. The option of having the redundant feeder protection in a bus differential relay presented in Section VI does have 27 elements that could be used to increase the loadability of 51P in the redundant relay. However, if the 27 element cannot be set so that 51P is secure under load and dependable under fault conditions, two multifunction feeder relays with LE per feeder are required.

A breaker failure scheme is backup to the associated circuit breaker interrupting faults; so, only one breaker failure scheme is needed for a feeder. The scheme can be in either relay in the redundancy modules presented in Section VI, with the other relay providing contact outputs as breaker failure initiates (BFIs). Alternatively, each relay providing feeder protection can have a breaker failure scheme that is initiated by internal BFIs only. This approach can reduce wiring between relays and be beneficial in other ways that are discussed in detail in [9].

There must be redundant manual control of the feeder circuit breaker. That is, we cannot have one relay through which all manual (local/remote) breaker operations are issued or we risk a single-point-of-failure. Local manual control should be performed in one relay while SCADA manual control is performed in another device; or, local manual operations can be implemented by 01 switches or pushbuttons that are separate from both relays. The open and close pushbuttons on some relays that are isolated from the rest of the relay are considered to be separate from the relay. Local manual control and SCADA manual control are separated in the redundancy solutions presented in Section VI.

VI. Options for Providing Redundancy

We have made the case that designing for protection system redundancy and breaker failure for distribution applications is very desirable. In this section, we offer ideas on how to economically design for redundancy at the feeder level. Section II discussed redundancy for the medium-voltage bus. This discussion assumes that redundant bus protection is included.

Here we offer three solutions and discuss the pros and cons of each option. Decisions on which solution is right for a given application are dependent on many factors.

- Apply two multifunction feeder relays per feeder.
- Apply a multifunction percentage-restrained bus differential relay on the bus. Use 50/51 elements in the bus relay for each feeder.
- Apply a feeder backup relay on each panel that provides 50/51 protection for all feeders on that panel.

There are many approaches to the physical arrangement of protection and control equipment. Typically, feeder protection and control can be associated with each individual breaker (on the door of the breaker compartment or in the control compartment of an outdoor free-standing breaker). Alternatively, the equipment is located in protection and control panels. In the following conceptual sketches, we show panels with as many as four relays in each. These are easily transferable to other physical arrangements.

Breaker failure protection is assumed to be implemented in all three proposed solutions. The decision of whether the breaker failure function should reside in the primary protection or in the redundant protection, or both, depends on many factors [9]. For this reason, 50BF is not shown in the function list box in Fig. 3 and Fig. 4.

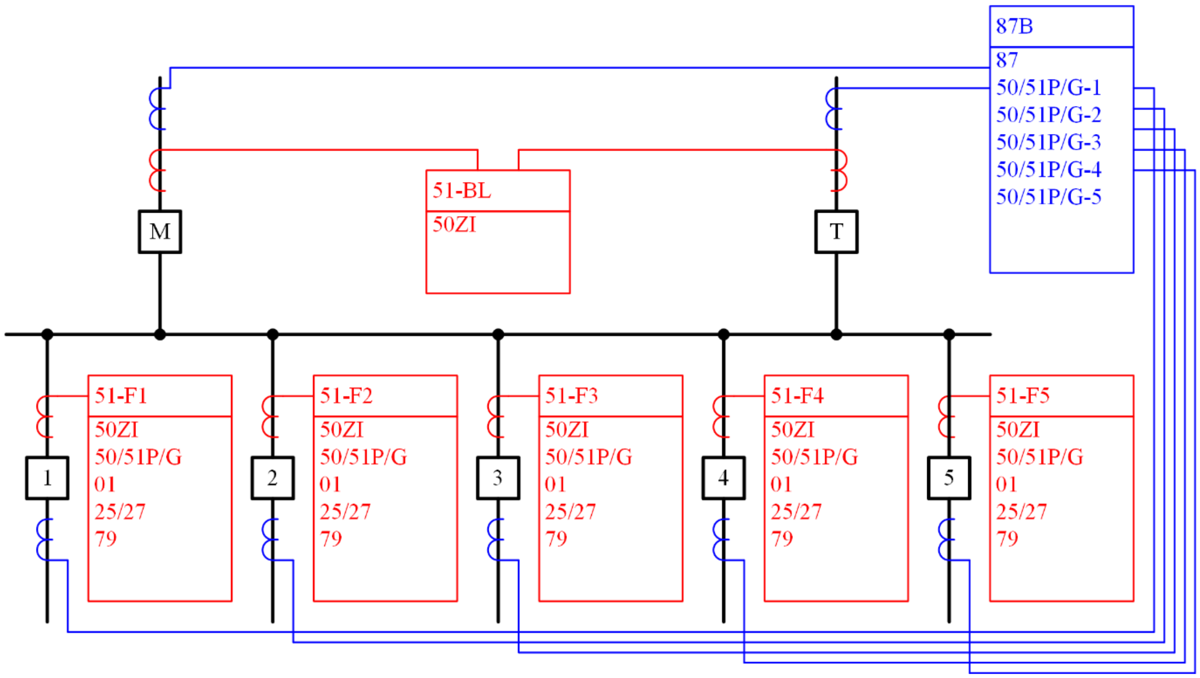


Fig. 3. Example using the bus differential relay to provide redundant overcurrent protection.

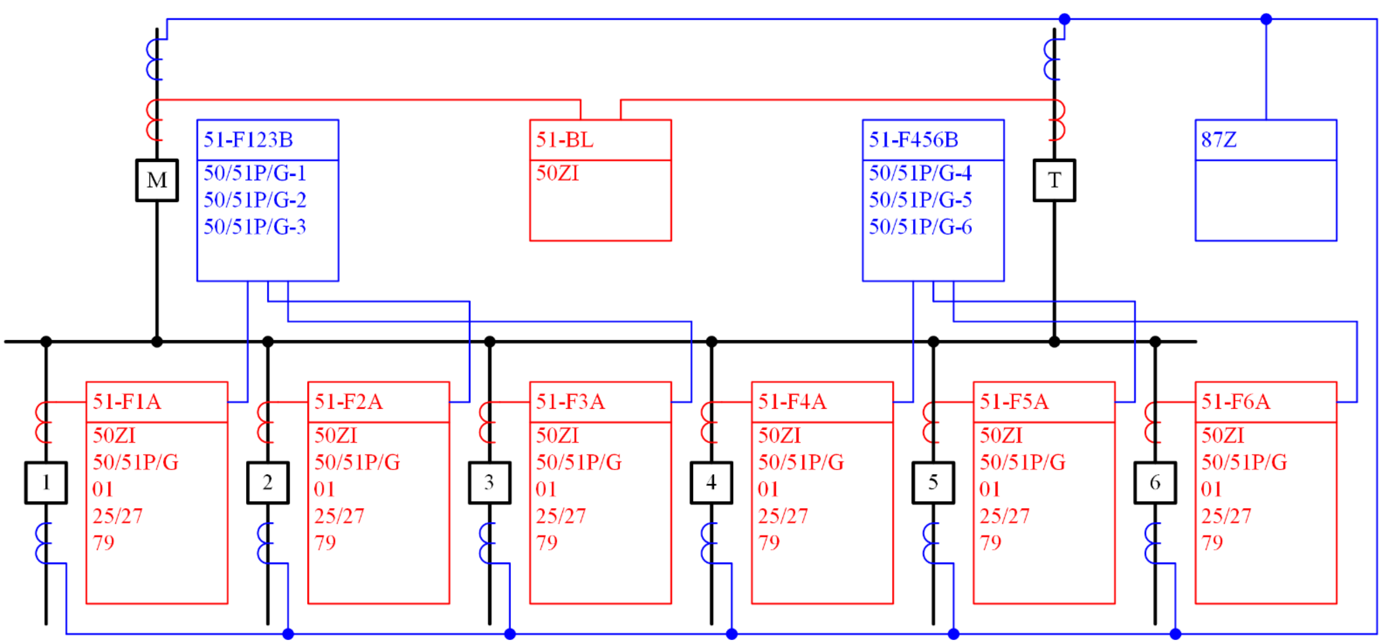


Fig. 4. Single-line diagram using a multirestraint transformer relay for three feeders.

A. *Redundant Multifunction Feeder Relays*

Simply installing two multifunction feeder relays on each feeder is probably the simplest and most flexible solution. Designing for dual relays on transmission lines is well established and using the same design philosophy for distribution lines can follow these well-developed approaches. Design standards such as using two like relays, two different relays, or even relays from two different vendors are easily accommodated. Fig. 5 shows some examples. Fig. 5a and Fig. 5b show using identical relays for the redundant systems. Fig. 5c shows mixing relay platforms between the two redundant systems. In the figure, one system is designated with an “A” in the device identifier code and the redundant system is designated with a “B.”

This design is simple for operators as well because all controls and indications for a feeder are in one location. The operator interface controls can be clearly labeled so there is no confusion as to which relay has local control functions implemented. The approach can be similar and the arrangement similar regardless of whether the feeder protection and control are located in a panel, on a switchgear door, or in an outdoor free-standing breaker cabinet.

Both relays can give redundancy between local manual control and remote SCADA manual control functions, such as 25/27 closing supervision, if the feeder requires it. Similarly, both full-featured multifunction relays can provide directional control as well. These greater functional requirements are becoming more common with the proliferation of distribution-connected DERs.

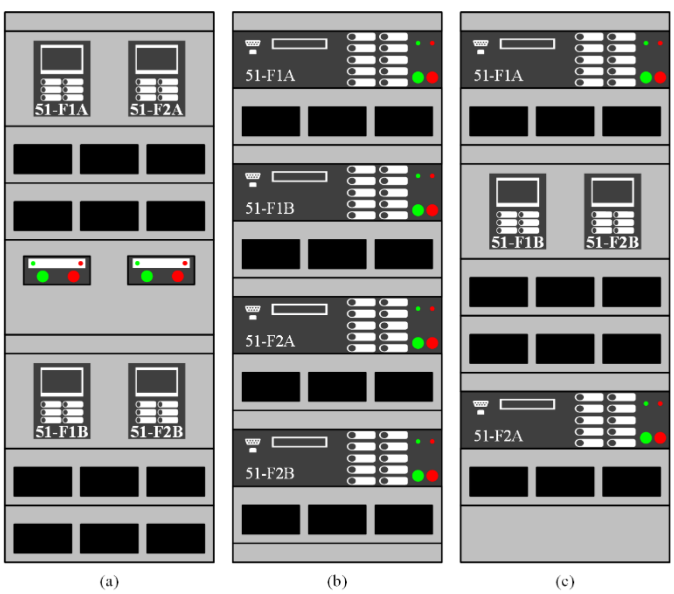


Fig. 5. Examples of using two relays per feeder.

B. *Locate Redundant Protection in the 87B Relay*

If redundancy is desired for only the 50/51 fault detection functions, providing redundant protection can be easily accomplished by simply enabling these elements in the multifunction percentage-restrained bus differential relay, if the bus differential relay applies independent restraint inputs for each feeder. Fig. 3 shows this configuration. Note that the figure is highly simplified; to reduce clutter, VT signals and control signals are not shown.

System A is shown in red. The bus is protected by a 50ZI scheme with signaling between the feeder and the bus main relay. The bus main relay responds to the sum of the currents in the two source breakers. The multifunction feeder relay provides nearly all protection and control for the feeder breakers. System B is shown in blue. The bus redundant protection is percentage-restrained 87B. The feeder redundant protection is phase and ground 50/51 protection.

The bus differential relay should already be wired to direct trip each feeder breaker for a bus fault; so, tripping for a feeder fault requires no additional wiring. Direct tripping (often in parallel with the traditional lockout path) is a best practice with programmable multifunction relays [10] [11].

The schematic design would require 79RI signals from the 87B relay to the 51-F relays to ensure initiation of the reclosing sequence if the 51 element in the redundant relay times out before the one in the feeder relay. If a ground relay cutoff function to facilitate single-pole switching operations is implemented in the feeder relay, the 51G cutoff status would be wired to the 87B relay.

This alternative is attractive because it provides dependable and selective tripping for failure of the feeder relay while not requiring any additional relays. The additional wiring required is minimal. The elements are simply set the same as they are in the feeder relays, so no additional engineering effort is needed. The main limitation of this option is that typical 87B relays limit this solution to a distribution bus with five feeders.

One drawback of this approach is that targets for feeder tripping functions are located on the bus protection panel and not on the feeder panel. There are methods to easily mitigate this concern if desired.

There is some additional complication to this option if the multifunction percentage-restrained differential relay does not provide residual time overcurrent elements. However, this is easily addressed by implementing 51G elements in programmable logic that runs at protection speeds. Appendix B provides an example of the programming.

C. *Add a Multifeeder Redundant Relay to Each Panel*

Similar to the previous option, if redundancy is desired for the 50/51 fault detection functions only, redundant protection can be economically added to each feeder relay panel. A multifunction transformer relay with three restraint inputs can provide redundant protection for as many as three feeders. See Fig. 6 and Fig. 4 for an example. Again, note that Fig. 4 is highly simplified and does not show VT signals or control signals.

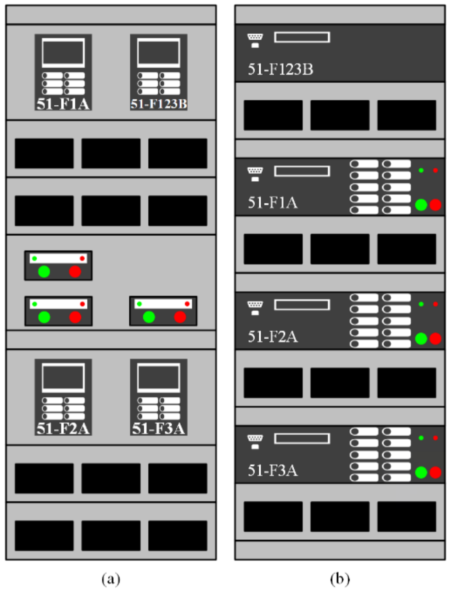


Fig. 6. Examples of using multirestraint transformer relay for three feeders.

In this example, System A is again shown in red in Fig. 4. It is unchanged from the scheme shown in Fig. 3. System B is shown in blue. In this case, the example includes a bus with six feeders. A high-impedance bus differential relay is used for redundant protection for the bus zone. One multifunction transformer relay is added to each panel. Each panel now can protect as many as three feeders with redundant phase and ground 50/51 protection.

This alternative is attractive because it provides dependable and selective tripping for failure of the feeder relay while only requiring one additional relay per three feeders. The additional wiring required is minimal because the current and dc logic circuits just require some additional intra-panel wiring. The elements are simply set the same as they are in the feeder relays, which involves no additional engineering effort. Another advantage of this approach is that targets for feeder tripping functions are located on the feeder panel. Further, the scheme is easily scalable.

VII. Conclusions

Multifunction relays provide a lot of features and capability for relatively lower cost than previous technologies. Cost may have been a traditional barrier to building distribution protection with full redundancy as is the common practice for transmission circuits. There are a number of technical reasons that the level of redundancy used at distribution has been less as well. Traditional drivers at transmission were the consequences of dependability failures such as large-area blackouts, widespread power quality issues for slowly cleared faults, and the near infeasibility of relying on remote backup to detect and clear faults on the networked transmission system with many sources of infeed. These technical problems simply do not have as much impact at distribution.

However, many of these same issues apply to distribution except perhaps on a smaller scale. To the individual consumer, an outage that affects only their town or neighborhood is no less impactful than one that affects the region. With ever increasing loads on existing distribution infrastructure, providing backup for distribution systems from the bus main relaying is becoming more difficult. Inability to reliably provide backup for transmission circuits from relaying upstream, and adjacent circuits due to loadability limitations, was a significant driver for deploying protection redundancy and breaker failure on transmission. We would assert the same is true for distribution in many cases.

Distribution is much messier than transmission. The circuits can be very complex with many different wire sizes, lateral taps, load characteristics, alternate configurations of ties and normally open points, etc. Engineering the protection system for these chaotic applications can be extremely complex. The critical resource today is not the cost of the relays, it is the cost and availability of the technical personnel to design, maintain, test, and set the relays. Designing for redundancy is a great way to simplify these tasks. Redundancy also removes the urgency to marshal scarce resources to address problems when a single-point-of-failure happens.

In transmission, with its long history of designing for full redundancy, the primary protection equipment is designed to support the practice. Usually, multiple CT cores are on each side of each breaker. VTs include multiple secondary windings to improve isolation of the redundant protection systems. Breakers have two isolated trip circuits to further improve isolation of the redundant protection systems. In distribution, this level of redundancy is often unavailable. That should not preclude designing with redundant protection. CTs and VTs are very reliable. Test switches can provide easy means to isolate the redundant systems when it becomes necessary to troubleshoot, test, or repair one of the redundant systems.

One concern is that, with typical distribution breakers having a single trip circuit, loss of one fuse or one trip coil still represents a single-point-of-failure so redundant protection systems still have this single-point-of-failure. While this is true, trip circuit monitoring means that a blown trip circuit fuse or failed trip coil is no longer a hidden failure. Use of a breaker failure protection scheme means that, if a fault should occur before the trip circuit alarm can be addressed, the fault is cleared and the wider outage caused by tripping the bus main and bus tie only happens in that case. Even in breakers with dual trip circuits, a failure of the mechanical mechanism or interrupter could still happen so it is impossible to eliminate all single-points-of-failure from the design.

The critical protection functions used on distribution are usually phase and ground 50/51 protection. If we design for redundancy of only these functions, the most improvements in reliability (both dependability and security) are achieved. If the full-featured multifunction feeder relay is out of service, there may be some operational inconvenience such as having to manually close a breaker instead of relying on automatic reclosing; however, urgency to remove the feeder from service to affect repairs is usually eliminated. Urgency adds to operational costs and can lead to human performance issues, so this is a huge benefit to designing for redundancy.

The simplest, most flexible, and most obvious solution is to apply redundant protection on each feeder. But as was just reiterated, the critical protection functions used on distribution are usually phase and ground 50/51 protection. Such elements are ubiquitous and available in multifunction relays.

One solution worthy of consideration is using a multifunction percentage-restrained bus differential relay for bus protection and enabling the overcurrent elements on the branch circuits to provide dependable protection. This solution does not require any additional relays at all and only minor added wiring.

Another solution is to add a multifunction multirestraint transformer relay to each panel wired to provide phase and ground 50/51 protection to three feeders. This solution requires a minimum number of added relays and only minor added wiring.

Distribution systems are the critical link to serving individual customers. Because the distribution system serves customers directly along every segment of the feeder, reliability has a direct impact on quality of service for individual customers. Distribution, by its nature, is in close proximity to the public and to public and private property. Failure to clear faults can have significant safety and property damage consequences. Multifunction protection technology is an enabling technology to remove historical barriers to designing redundancy into the distribution protection system.

VIII. Appendix A – Improving Loadability of 51P Elements

Three solutions to improve loadability of phase overcurrent elements are described in this appendix:

- Impedance elements supervision
- Undervoltage elements supervision
- Load encroachment (LE) element supervision

A. Phase Distance Supervision

An impedance element can be used to improve the loadability of a 51P element. A line-distance relay naturally has a greater reach along the line angle and reduced reach near the resistive axis in the RX plane where high loading would appear. See Fig. 7. The distance element must be set to dependably detect all faults in the zone it is backing up as the logic to produce a trip is the AND combination of 21P AND 51PT. This may require evaluation of several impedance paths on feeders with multiple branches and conductor types. The 21P reach must be greater than the largest of the feeder trunk impedances by a dependability margin, with the different angles of the feeder impedances considered. The 21P reach must also restrict 51P tripping at the expected power factor of the load, with margin.

Typically, the 21P element is used to torque control the 51P element. Torque control is an antiquated term that comes from EM induction disk technology. The induction disk included a shading coil to develop torque to cause the disk to rotate. A contact in the shading coil circuit must be closed for the disk to be able to rotate. To allow the 51P element to time, the torque control equation must be asserted.

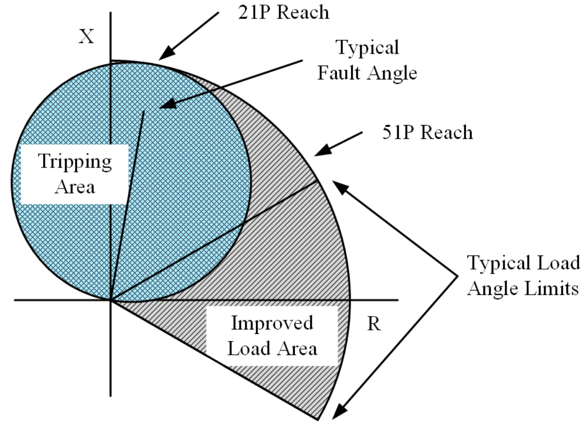


Fig. 7. Using a 21P element to increase 51P loadability.

This solution was in common usage prior to the advent of multifunction relays with dedicated LE elements. This method was used with electo-mechanical technology. There were also some early multifunction overcurrent relays that included a mho distance element that supervised the 51P elements to improve loadability [12].

The 21P element should be blocked for an LOP condition, and most modern relays have provisions for this block. A decision must be made whether 51P should in turn be completely blocked during an LOP condition or allowed to operate for certain current magnitudes. The torque control of 51P in the 51-BL relay is typically similar to (1):

$$51\text{PTC} = 21\text{P OR } (50\text{P AND LOP}) \qquad (1)$$

where:

21P is the output of the impedance element.

50P is the output of an instantaneous phase overcurrent element.

LOP is the output of the loss-of-potential logic.

The relay setting engineer must decide on the degree of security and dependability that 51P provides under LOP conditions with the pickup setting of 50P. The pickup setting could be equal to the emergency loading of the bus, making 51P secure for LOP conditions but with limited feeder coverage. The 50P could be set to detect faults at the ends of the feeder trunks, making 51P dependable but susceptible to tripping under load. A switch-onto-fault scheme is needed if the main circuit breaker recloses for 51P trips and the 21P is not offset.

B. Phase-to-Phase Undervoltage Supervision

Supervising 51P with phase-to-phase undervoltage elements allows the relay to differentiate between a fault and load because of the angle of the voltage drop across the system source impedance for the two conditions. When the current flow is inductive, as is characteristic of a short circuit, a large voltage drop occurs. When the current flow is at higher power factor, as is characteristic of load, a small voltage drop occurs. See Fig. 8 for a Kirchhoff's voltage law diagram that illustrates the concept. The diagram is simplified assuming the source impedance is purely reactive such that the voltage drop is lagging the current angle by 90°. The magnitude of the current is the same in both illustrations—only the angle of the current and resulting voltage drop are changed.

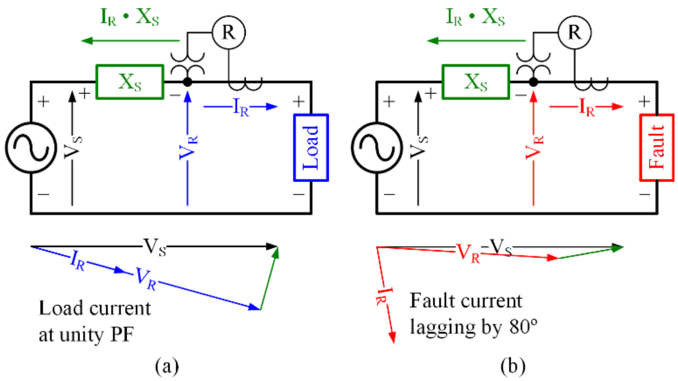


Fig. 8. Relay voltage during load and fault conditions.

Voltage-controlled 51P elements are a traditional method for allowing the phase overcurrent pickup to be set below load. Similar to using an impedance element, the logic to produce a trip is the AND combination of 27PP AND 51P.

Impedances of the feeders must be known so the bus voltages can be calculated for feeder faults, but a typical cookbook value is 0.8 to 0.85 times VLL nominal. The torque control equation for 51P in the 51 BL relay in (2) is similar to the equation when 21P is used, and the decisions about how 51P should operate under LOP conditions are the same.

$$\begin{aligned}51\text{PTC} &= (27\text{PP AND NOT LOP}) \\ &\quad \text{OR } (50\text{P AND LOP})\end{aligned} \tag{2}$$

C. Load Encroachment Supervision

Most multifunction relays include LE elements. LE differentiates between a fault and load by looking at two attributes: power factor angle and balance. The logic establishes a load blocking area bounded by a minimum load impedance and a user-specified range of angles around the R-axis that are limits to the expected power factor of load. Any conditions outside that load region are not blocked so that the 51P element can clear the fault. See Fig. 9. The gray area in the figure is the load-blocking region that asserts a logic bit ZLOAD. Although this region is shown bounded by the 51P reach circle, it actually extends out to infinity to the right.

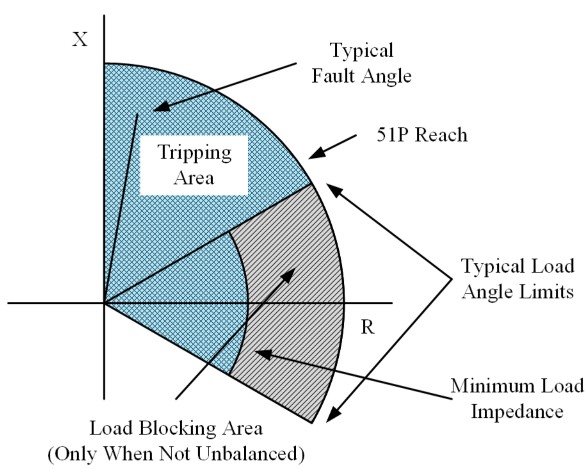


Fig. 9. Typical load encroachment element.

The second criterion that helps an LE scheme differentiate between load and faults is detection of unbalance. Faults, more often than not, are unbalanced while load is usually relatively balanced. We only want to allow the load impedance power factor angle check to block the 51P element during balanced conditions. The LE element should include logic to bypass the load impedance check if significant unbalance is detected.

In some implementations, this feature is built into the directional element logic. To get access to this function in radial applications, it is still necessary to enable the directional function even though it will not be used to control the overcurrent elements. Reference [13] details why Relay Word bit (RWB) ZLOAD should not solely be used for LE supervision. The blocking logic should have logic like that in Fig. 10 added to unblock the element when the overcurrent condition is unbalanced.

32QE is used to detect unbalanced faults because of the logic shown in Fig. 10. Logic bit 32QE is a logic function built into a directional element to allow it to determine whether to use negative- or positive-sequence quantities to make a directional decision.

Detecting an unbalanced fault by comparing the negative-sequence current (I_2) to a fraction (a2) of the positive-sequence current (I_1) is a better method than comparing I_2 against a static threshold that would be difficult to set. The relay setting engineer sets a2 for the application. The default is typically 0.10 and suitable for transmission applications. Distribution load can have greater levels of normal load unbalance, so this setting can be raised to 0.15–0.25 [14]. The negative-sequence fault detector elements 50QFP and 50QRP are typically set for the minimum pickup of 0.5 ampere.

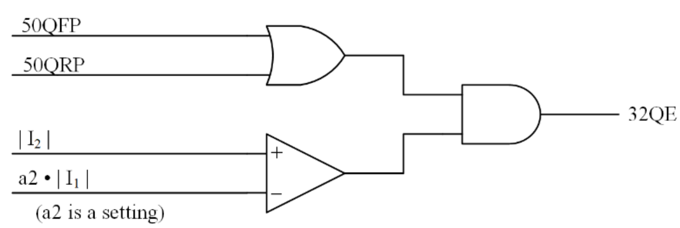


Fig. 10. Logic to detect unbalanced conditions.

To control the 51P element we use the two logic bits, ZLOAD and 32QE, in the element torque control equation. The OR combination of NOT ZLOAD OR 32QE allows the element to trip if the overcurrent condition is unbalanced, or if it is balanced and not in the load-blocking region:

$$51\text{PTC} = \text{NOT ZLOAD OR 32QE} \tag{3}$$

The logic for LE supervision is not an AND condition as with the previous two methods, but a NOT AND condition 51P AND NOT ZLOAD. This subtle difference makes use of LE to improve loadability, theoretically more dependable over the other methods. Plus, because the load power factor angle limits are precisely set, LE typically gives more loadability than an impedance element can. This is because the reach setting has to meet both dependability margin (i.e., must see any in-zone fault that the 51P can pick up for) and security margin (i.e., must not assert for emergency loading).

When the pickup of 51P must be set below expected maximum load levels, the relay setting engineer must decide the degree of protection, if any, that 51P should provide under LOP conditions. Generally, the risk of tripping on load has to be balanced with the risk of not tripping for a fault in the zone being backed up. The need for the bus main relay to back up the feeder relay during an LOP condition can be considered an N-2 contingency. If the 51P element is blocked for LOP, the VT signal and the faulted feeder relay must have failed for a failure to trip to occur. The following three choices are described in ascending order from most secure to most dependable:

- Block 51P tripping for balanced faults.
- Allow 51P tripping for balanced faults if the current is above emergency load limits with margin.
- Allow 51P tripping for all faults with no LE supervision.

Logic equation (4) will allow tripping if the fault is unbalanced, but will block 51P tripping for balanced conditions on detection of an LOP condition:

$$51PTC = NOT\ LOP\ AND\ NOT\ ZLOAD\ OR\ 32QE \quad (4)$$

Logic equation (5) will allow tripping if the fault current is above emergency load (a separate phase overcurrent element, 50P5, is set above emergency load), OR if the fault is unbalanced. It will block 51P tripping for balanced conditions below emergency load on detection of an LOP condition:

$$\begin{aligned} 51PTC = NOT\ LOP\ AND\ NOT\ ZLOAD \\ OR\ 32QE\ OR\ 50P5 \end{aligned} \quad (5)$$

Logic equation (6) will allow tripping with no load encroachment supervision on detection of an LOP condition:

$$51PTC = NOT\ ZLOAD\ OR\ 32QE\ OR\ LOP \quad (6)$$

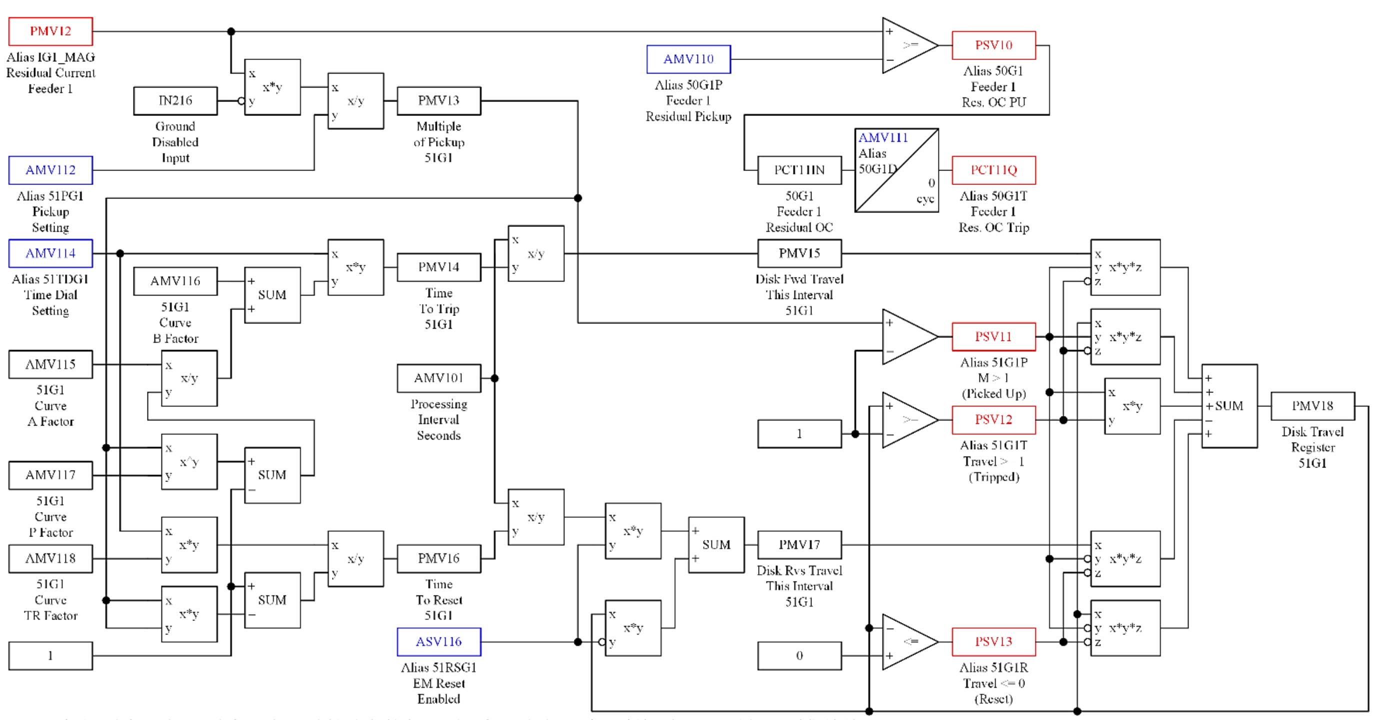
IX. Appendix B – 51N Element Logic Example

This appendix shows programmable logic code to implement ground time overcurrent elements in a relay that does not natively include these elements. This logic provides residual 50 (with optional definite time) and 51 (inverse time) overcurrent elements with five selectable curves and optional EM reset characteristics. A ground 51 enable function is also included. When Boolean input IN216 is asserted, 51G inverse timing is blocked.

The logic variables used in the code are labeled as follows:

- # designates a comment or annotation.
- PSVnn is a Boolean variable number *nn*.
- PMVnn is a math variable number *nn*.
- ASVnnn is a Boolean setting parameter number *nnn*.
- AMVnnn is an analog setting parameter number *nnn*.
- InnFIR is the real component of the filtered phasor current for input nn. 07=IA, 08=IB, 09=IC.
- InnFII is the imaginary component of the filtered phasor current for input nn. 07=IA, 08=IB, 09=IC.

Critical variables for settings and operational logic use aliases to rename them. The code would be replicated for as many as five feeder relays by substituting different logic variables for each element implemented. Fig. 11 shows a graphical representation of the programmable logic.



Note 1: Logic shown is for Feeder 1. Logic for Feeders 2–5 is identical with the exception of protection/automation variable assignments and the ground disabled input.

Note 2: Variables highlighted blue are aliased setting variables. Variables highlighted red are aliased logic variables.

Fig. 11. Logic to implement ground 50/51 overcurrent elements.

A. Set Point Variable Alias Settings

```
AMV110 → 50G1P
AMV111 → 50G1D
AMV112 → 51PG1
AMV113 → 51CG1
AMV114 → 51TDG1
ASV116 → 51RSG1
```

B. 50/51 Element Settings Code

```
# NOMINAL FREQUENCY SETTING
AMV100 := 60.000000 # ENTER FNOM SETTING
# RESIDUAL GROUND ELEMENT SETTINGS
# CALCULATE PROTECTION LOGIC PROCESSING INTERVAL
AMV101 := 1.000000 / (12.000000 * AMV100) # PROCESSING INTERVAL, IN SECONDS
#
# FEEDER 1, I07, I08, I09
50G1P := 10.000000 # INST PICKUP, SECONDARY AMPS
50G1D := 0.000000 # DEFINITE DELAY, CYCLES
51PG1 := 1.000000 # INVERSE TIME OC (TOC) PICKUP, SECONDARY AMPS
51CG1 := 1.000000 # TOC CURVE, U1, 2, 3, 4, 5
51TDG1 := 2.000000 # TOC TIME DIAL
51RSG1 := 1 # TOC EM RESET, 1 = ENABLED, 0 = DISABLED
#
# FIND CURVE CONSTANTS 51G1
ASV111 := 51CG1 = 1.000000 # CURVE U1 SELECTED
ASV112 := 51CG1 = 2.000000 # CURVE U2 SELECTED
ASV113 := 51CG1 = 3.000000 # CURVE U3 SELECTED
ASV114 := 51CG1 = 4.000000 # CURVE U4 SELECTED
ASV115 := 51CG1 = 5.000000 # CURVE U5 SELECTED
AMV115 := ASV111 * 0.010400 + ASV112 * 5.950000 + ASV113 * 3.880000 + ASV114 * 5.640000 + ASV115 * 0.003420
       # FEEDER 1 TOC CURVE CONSTANT A
AMV116 := ASV111 * 0.022600 + ASV112 * 0.180000 + ASV113 * 0.096300 + ASV114 * 0.024340 + ASV115 * 0.002620
       # FEEDER 1 TOC CURVE CONSTANT B
AMV117 := ASV111 * 0.020000 + ASV112 * 2.000000 + ASV113 * 2.000000 + ASV114 * 2.000000 + ASV115 * 0.020000
       # FEEDER 1 TOC CURVE CONSTANT P
AMV118 := ASV111 * 1.080000 + ASV112 * 5.950000 + ASV113 * 3.880000 + ASV114 * 5.640000 + ASV115 * 0.323000
       # FEEDER 1 TOC CURVE CONSTANT TR
```

C. Logic Variable Alias Settings

```
PMV12 → IG1_MAG
PSV10 → 50G1
PCT11Q → 50G1T
PSV11 → 51G1P
PSV12 → 51G1T
PSV13 → 51G1R
```

D. 50/51 Element Logic Code

```
### FEEDER CIRCUIT 1, I07, I08, I09, RESIDUAL OC ELEMENTS
PMV10 := I07FIR + I08FIR + I09FIR # IG1 REAL
PMV11 := I07FII + I08FII + I09FII # IG1 IMG
IG1_MAG := SQRT(PMV10 * PMV10 + PMV11 * PMV11) # IG1 MAG
50G1 := IG1_MAG >= 50G1P # 50G1 ASSERTED
PCT11PU := 50G1D
PCT11DO := 0.000000
PCT11IN := 50G1 # PCT11Q, 50G1T TRIPPED
# 51G1
PMV13 := (IG1_MAG * NOT IN216) / 51PG1 # M, MULTIPLE OF PU
PMV14 := 51TDG1 * (AMV116 + AMV115 / (EXP(AMV117 * LN(PMV13)) - 1.000000)) # TT=TD*(B+A/(M^P-1))
PMV15 := AMV101 / PMV14 # DISK TRAVEL TO TRIP THIS INTERVAL
PMV16 := 51TDG1 * AMV118 / (1.000000 - PMV13 * PMV13) # RESET TIME=TD*TR/(1-M^2)
PMV17 := (AMV101 / PMV16) * 51RSG1 + PMV18 * NOT 51RSG1 # DISK TRAVEL TO RESET THIS INTERVAL
51G1P := PMV13 > 1.000000 # M IS GREATER THAN 1, 51G1PU
51G1T := (PMV18 >= 1.000000) # 51G1 TIMED OUT (TRIPPED)
51G1R := (PMV18 <= 0.000000) # 51G1 RESET
PMV18 := PMV15 * 51G1P * NOT 51G1T + PMV18 * 51G1P * NOT 51G1T + 51G1P * 51G1T - PMV17 * NOT 51G1P * NOT
       51G1R + PMV18 * NOT 51G1P * NOT 51G1R # DISK TRAVEL INTEGRATER
```

X. References

[1] G. P. Juvekar, E Atienza, C. Kelley, and N. Malla, "Power System Contingencies to Evaluate FLISR Systems," proceedings of the 75th Annual Conference for Protective Relay Engineers, College Station, TX, March 2022.

[2] R. M. Chaney, J. T. Thorne, R. V. Singel, A. Hanson, C. Anderson, and J. Hughes, "Case Study: High-Density Distribution Coordination Using High-Speed Communications," proceedings of the 74th Annual Georgia Tech Protective Relaying Conference, Virtual Format, April 2021.

[3] J. Thorne, D. Nahay, C. Salo, J. Blair, and G. Ashokkumar, "Improving Distribution System Reliability With High-Density Coordination and Automatic System Restoration," proceedings of the 49th Annual Western Protective Relay Conference, Spokane, WA, October 2022.

[4] S. Uddin, A. Bapary, M. Thompson, R. McDaniel, and K. Salunkhe, "Application Considerations for Protecting Transformers With Dual Breaker Terminals," proceedings of the 73rd Annual Georgia Tech Protective Relaying Conference, Atlanta, GA, May 2019.

[5] IEEE C37.234-2021, *IEEE Guide for Protective Relay Applications to Power System Buses*, 2021.

[6] J. LaBlanc and M. J. Thompson, "Redundant Bus Protection Using High-Impedance Differential Relays," *71st Annual Conference for Protective Relay Engineers (CPRE)*, 2018, pp. 1–13, doi: 10.1109/CPRE.2018.8349818.

[7] C. F. Henville, M. Nagpal, and A. F. Elneweihi, "The Evolution of Backup Protection in BC Hydro," proceedings of the 37th Western Protective Relay Conference, Spokane, WA, October 2010.

[8] M. R. Duff, P. Gupta, D. Prajapati, and A. Langseth, "Utility Implements Communications-Assisted Special Protection and Control Schemes for Distribution Substations," proceedings of the 70th Annual Conference for Protective Relay Engineers, College Station, TX, March 2017.

[9] B. Kasztenny and M. J. Thompson, "Breaker Failure Protection – Standalone or Integrated With Zone Protection Relays?" *64th Annual Conference for Protective Relay Engineers*, 2011, pp. 385–395, doi: 10.1109/CPRE.2011.6035639.

[10] Thompson, "The Power of Modern Relays Enables Fundamental Changes in Protection and Control System Design," *60th Annual Conference for Protective Relay Engineers*, 2007, pp. 71–84, doi: 10.1109/CPRE.2007.359892.

[11] C16 Working Group, "Relay Scheme Design Using Microprocessor Relays – A Supplement to Relay Trip Circuit Design by IEEE PSRC 1999," June 2014, Available: https://www.pes-psrc.org/kb/report/105.pdf.

[12] *SEL-251C Distribution Bus Relay Instruction Manual*. Available: selinc.com.

[13] G. E. Alexander, "Guidelines for Applying Load-Encroachment Element for Overcurrent Supervision," SEL Application Guide Volume III (AG2005-07). Available: https://selinc.com.

[14] R. McDaniel and M. Thompson, "Impedance-Based Directional Elements – Why Have a Threshold Setting?" proceedings of the 48th Annual Western Protective Relay Conference, Spokane, WA, October 2021.

XI. Biographies

Michael J. Thompson received his B.S., magna cum laude, from Bradley University in 1981 and an M.B.A. 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 Engineering Services, Inc. (SEL ES). He is a senior member of the IEEE, Chairman of the IEEE PES Power System Relaying and Control Committee, past chairman of the Substation Protection Subcommittee of the PSRC, and received the Standards Medallion from the IEEE Standards Association in 2016. He is also a subject matter expert advising the System Protection and Control Working Group of the North American Electric Reliability Corporation. Michael is a registered professional engineer in six jurisdictions, was a contributor to the reference book *Modern Solutions for the Protection Control and Monitoring of Electric Power Systems*, has published numerous technical papers and magazine articles, and holds three patents associated with power system protection and control.

Bernard Matta received his B.S. in electrical engineering from Pennsylvania State University. He joined Virginia Power (presently Dominion Energy) in 1986 and worked in the system protection department calculating relay settings, performing system studies, testing protection systems, and writing standard procedures. He was on a team that evaluated and implemented microprocessor-based relays to replace electromechanical equipment. Bernard joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2000. He has served many electric utilities and customers throughout the U.S. by providing relay settings to protect transmission, distribution, and generation equipment. Bernard is an IEEE member.

Ray Connolly received his B.S. in electrical engineering from Drexel University and his MBA from Saint Joseph's University. Prior to joining Schweitzer Engineering Laboratories, Inc. (SEL) in 2020 as a director for SEL Engineering Services, Inc. (SEL ES), he spent 36 years in the utility sector with Exelon Corporation (PECO Energy, Commonwealth Edison, and Exelon Nuclear) and PPL Corporation (PPL Electric Utilities and LGE-KU), where his various roles included director of transmission operations and planning, director of transmission and substations, and director of distribution engineering. Ray has extensive experience in transmission and distribution system operations, protective relaying and communication systems, transmission and substation design, SCADA, energy management systems, and advanced distribution management system deployments. He is a Licensed Professional Engineer in Kentucky, Illinois, Pennsylvania, and Florida.

20230303 • TP7086-02