# Applying Radio Communication in Distribution Generation Teleprotection Schemes

Edmund O. Schweitzer, III, Dale Finney, and Mangapathirao V. Mynam
*Schweitzer Engineering Laboratories, Inc.*



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# Applying Radio Communication in Distribution Generation Teleprotection Schemes

Edmund O. Schweitzer, III, Dale Finney, and Mangapathirao V. Mynam,
*Schweitzer Engineering Laboratories, Inc.*

***Abstract*—The value of teleprotection schemes at the transmission level has been well established. Varieties of channels have been employed as communications technologies advanced. The associated schemes have been tailored to both the function served and the available channel characteristics. The use of communication at the distribution level was considered unnecessary until recently because conventional distribution networks have been comprised of radial feeders without generation sources, where time-coordinated overcurrent schemes have provided adequate protection. The advent of distributed generation (DG) introduces several new challenges.**

**A high penetration of DG can result in a loss of sensitivity and/or coordination of the existing feeder ground fault protection. Another concern is effective islanding protection. Passive anti-islanding schemes can fail if the generation output approaches the level of load within the island. Direct transfer tripping schemes solve this challenge but are typically complex if there are multiple upstream devices that can open to form an island or if the DG can be transferred among feeders.**

**Conventional communications channels usually prove to be cost-prohibitive for applications at the distribution level. However, new technologies for wireless communication have become available recently, which are much more cost-effective but have characteristics that can differ from more traditional channels.**

**This paper illustrates how teleprotection schemes can be designed to suit both the new challenges in distribution networks and the characteristics of the wireless channel. These schemes provide reliable and cost-effective solutions, allowing DG to be integrated without compromising the operation of the distribution network.**

## I. Introduction

### *A. Distributed Generation*

A distributed generator is defined as an energy source that is connected directly to the distribution network. Distributed energy resources include both distributed generators and energy storage devices. Recently, renewable energy sources have been developed, such as solar, wind, and biofuels. Because of the scale of these sources, there is a tendency towards their integration at the distribution level. Distributed generation (DG) is gaining momentum, with governments all over the world pushing towards clean energy and carbon footprint reduction, causing a paradigm shift in the conventional generation, transmission, and distribution of electrical energy.

Distribution systems, which are conventionally radial, may now be equipped with energy sources, making them low-voltage transmission networks. There is a definite need to revisit the protection and operational philosophies associated with this new distribution network, along with available communications technologies.

### *B. Pertinent Characteristics of Distributed Generators*

While virtually all generators connected into the transmission system are synchronous, DG systems can be synchronous, induction, or inverter based. A synchronous generator relies on the interaction of the rotor and stator fields to deliver real and reactive power to the system. An excitation system is used to create the rotor field, and as a result, a synchronous generator can produce stable power when islanded. Consequently, synchronous generators require synchronizing facilities and are at risk of severe damage due to out-of-phase reclosing. The initial fault current produced by a synchronous generator is a function of the subtransient reactance and typically is several times the rated current.

An induction generator differs from a synchronous generator in that it absorbs reactive power from the system in order to maintain the rotor field. Soft starters, rather than synchronizing facilities, are employed for bringing an induction generator online. An induction generator is, however, still subject to damage due to out-of-phase reclosing. Islanded operation of an induction generator is possible if the island can supply sufficient reactive power to maintain the field of the machine. This is known as self-excitation. An induction generator can supply significant fault current as long as there is reactive compensation available from the system.

An inverter-based distributed generator converts dc electricity from a power source to ac electricity. Inverters can be classified by their method of commutation. Most inverters used in DG applications are self-commutated. Self-commutated inverters require synchronizing facilities and can be damaged during out-of-phase reclosing. In contrast to synchronous and induction generators, the fault current of an inverter-based distributed generator is intentionally limited by its control system and may only marginally exceed the rated current.

## II. Challenges Associated With DG Integration

This section reviews known issues that can occur on feeders with distributed generators [1] [2]. Systematic procedures have been developed to determine the extent of the impact, if any, for a particular DG installation [3].

## A. Protection

### 1) Fuse Blowing Due to Slow DG Clearing

The percentage of transient faults can be as high as 80 percent in a distribution network. For many years, utilities have successfully employed fuse-saving schemes to achieve a high level of service availability for their customers [3]. However, increased fault contributions and slow fault clearing from the DG may result in fuses blowing for faults otherwise cleared by the fuse-saving scheme. This leads to extended customer outages. As a result, one major utility specifies a maximum DG clearing time based on a typical fuse melt time of 200 milliseconds [4]. This issue is unique to synchronous and induction distributed generators. Inverter fault contribution is typically limited to 150 to 200 percent of the thyristor rated current in magnitude and one-half cycle in duration.

### 2) Loss of Fuse/Recloser Coordination

Reclosers are typically coordinated with fuses, as shown in Fig. 1. In this example, a transformer is located on a branch circuit, as shown in Fig. 2. The branch circuit is downstream of a recloser. The fast recloser curve is set to be between the branch and transformer fuse curves. Under normal operation, the fast curve is active. A fault downstream of the branch fuse is interrupted by the recloser. Automatic reclosing is delayed to allow transient faults to extinguish. Upon reclosing, the fast curve is deactivated. If the fault is permanent, it will be cleared by the branch fuse. Effectively, the slow curve acts to back up the fuse.

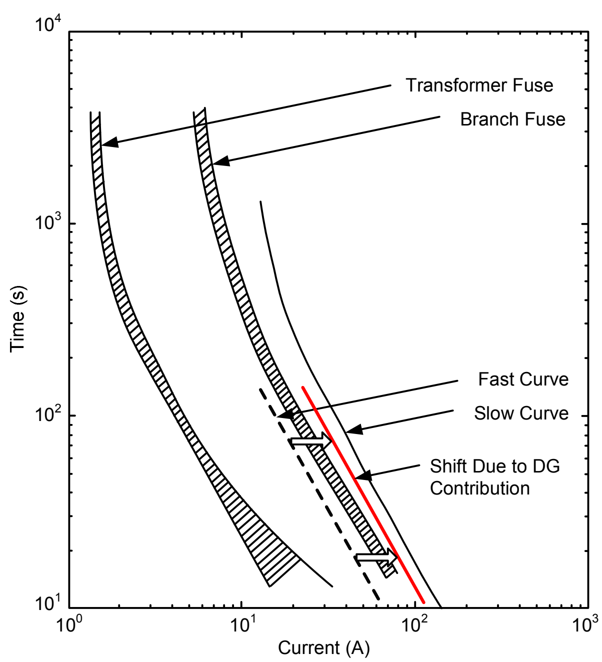


Fig. 1. DG may cause loss of coordination

Fuse-saving schemes depend on the coordination of inverse-time characteristics between the fuse and recloser. The fundamental premise is that both see the same current. Fig. 1 illustrates the issue introduced by DG. The fuse will always see more current when the DG is connected. This will have the effect of moving the fast curve to the right. The result is that the fuse can operate before the recloser. The curves respond to the current squared, amplifying the effect of shrinking coordination time margins. As DG penetration increases, the discrepancy between the recloser and fuse currents increases, and the potential for loss of coordination grows as DG penetration grows.

### 3) Loss of Protection Sensitivity

The addition of a distributed generator to the feeder can lead to a reduction in the available fault current contribution from the system. Fig. 2 shows a feeder with a connected synchronous or induction distributed generator. The equivalent source representing the power system (SYS) feeds the distribution network. The circuit breakers (CBs) represent switching elements that are capable of interrupting fault current. Adding impedances and redrawing yield the circuit in Fig. 3. The variable $x$ represents the location of the DG expressed as a percentage of feeder length. Inspection of this equivalent circuit shows that Fault 1 current splits between the two sources.

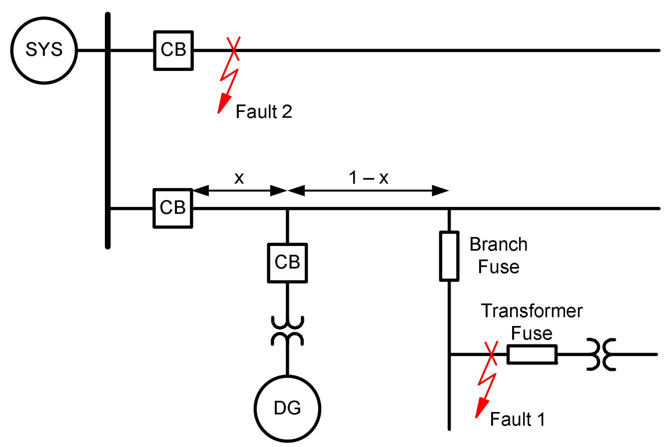


Fig. 2. A faulted feeder with DG

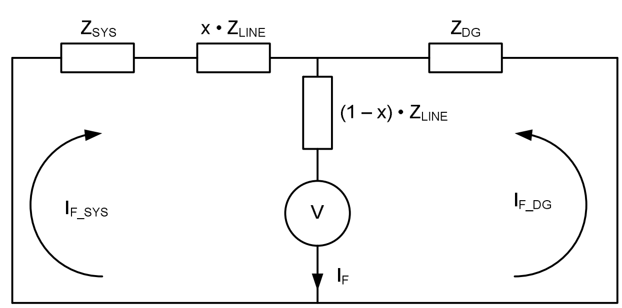


Fig. 3. Faulted feeder equivalent circuit

We can apply circuit analysis to develop expressions for the fault currents both with and without the generator. Using these expressions, a plot can be produced that shows the available fault current at the feeder end expressed as a ratio of fault current without DG (see Fig. 4). Inspection of this plot shows that fault current varies as a function of DG penetration and location (*x* in Fig. 3). For this example, the circuit parameters have been arbitrarily selected. The penetration level is defined as the ratio of (capacity factor • DG rated kVA)/(peak load on the feeder). Note that for high levels of DG penetration, the reduction in fault current is significant.

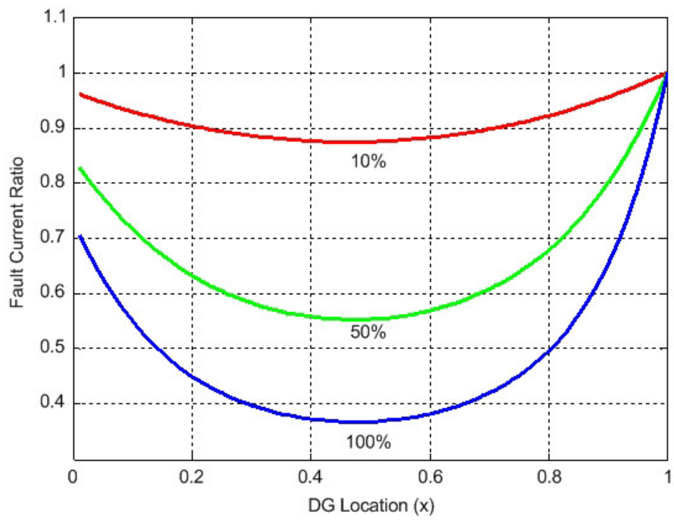


Fig. 4. Feeder fault current contribution expressed as a ratio of available fault current without DG for various DG penetration levels and locations (sample feeder and DG data used)

Ground fault current levels at the end of a feeder may be less than the load current. Ground fault protection must be set greater than the maximum current unbalance under normal operation. As a consequence of the reduction in fault current due to DG being online, feeder protection may be unable to detect ground faults over the entire feeder.

#### 4) *DG Step-Up Transformer Grounding*

The DG transformer connection must be compatible with the distribution network to which it is connected, and therefore, the method of transformer grounding is typically mandated by the utility. Both the three-wire network and the four-wire multigrounded network are commonly used.

A four-wire network can supply single-phase loads, so transient overvoltages are a concern. In a four-wire network, the DG step-up transformer will be effectively grounded on the high side to limit overvoltages to a safe value. A solidly grounded connection is often avoided because it may produce excessive ground fault levels. Conversely, three-wire networks feed phase-to-phase and three-phase loads. Equipment may be rated for full phase-to-phase voltage, alleviating overvoltage concerns. Sensitive ground fault protection may be applied. In some systems, a grounded DG transformer high-side connection is not permitted, and as a result, current-based ground fault protection cannot be applied at the DG. In other distribution systems, the available ground fault current at the DG is restricted. Fig. 5 shows the sequence network for a single-line-to-ground fault for a feeder with connected DG. The DG transformer has a grounded-wye connection on the system side and a delta connection on the generator side. The transformer impedances that appear in the zero-sequence network act to shunt the available ground fault current. Consequently, on an effectively grounded system, increasing the penetration of DG can adversely impact the sensitivity of feeder ground fault protection.

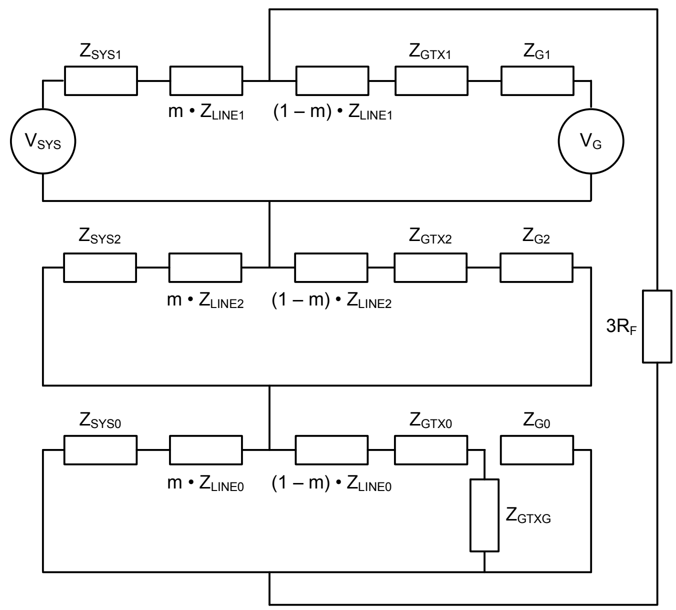


Fig. 5. Sequence network diagram for a ground fault with a grounded DG interconnect

#### 5) *Nuisance Tripping*

The addition of DG creates a contribution to upstream faults, as is evident for Fault 2 in Fig. 2. This creates a possibility that upstream reclosers and feeder protection that are typically nondirectional could operate for faults on the adjacent circuit. In addition, the DG interconnect protection (in particular, the voltage elements or the DG transformer fuses) could operate for faults on adjacent feeders.

#### 6) *Increased Fault Duty*

Inspection of Fig. 2 also reveals that, with the addition of DG, the available fault current seen by downstream equipment increases. At high levels of DG penetration, the interrupting rating of downstream devices may be compromised.

### B. DG Islanding

An island is a section of the distribution network that has been isolated from the remainder of the network. Stable islanding requires that load and generation be matched within the island. Islanding is not new to power system operators; transmission networks operate in islanding conditions during contingencies. Load- or generation-shedding schemes are typically triggered following island conditions to balance load to generation. However, for systems with DG, it is not recommended to operate networks in an islanded state for the following reasons:

- Personnel safety concern
- Possibility of subsequent out-of-synchronism reclose
- Power quality concerns

IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems recommends disconnecting or tripping the DG within 2 seconds following an islanding condition. However, utilities prefer to trip the DG prior to the autoreclose time of the reclosing relay, which is in the order of 0.4 to 0.5 seconds. Various anti-islanding schemes exist that detect islanding conditions and send a trip command to disconnect the distributed generator. The operating quantities in these schemes are typically frequency, rate of change of frequency (df/dt), phase angle, and voltage magnitude. The performance of the operating quantities depends on the power mismatch between the generation and the load in the island at the time of islanding.

#### 1) Existing Anti-Islanding Schemes

Anti-islanding schemes can be mainly categorized as passive, active, and communications-based. Passive schemes use the measured voltage and/or current quantities at the interconnect to detect the islanding condition. One type of active scheme injects signals at the DG location and detects the islanding condition by measuring the system response to the injected signal or modulation. Another type of active scheme introduces an intentional positive feedback into the inverter controls. As a result, the inverter is intentionally unable to regulate voltage or frequency when islanded, allowing detection of the islanding condition.

#### 2) Performance of Anti-Islanding Schemes

The performance of the passive schemes that are based on frequency is dependent on the real power mismatch between the local generation and the load. Higher mismatches typically result in faster response times. Lower mismatches can result in restraining the operation of the scheme or slower responses. This zone of lower mismatch is termed a nondetection zone. Because the power output of the DG is typically constant, the load requirement prior to the island dictates the performance of the frequency-based islanding schemes. Fig. 6 shows an example of the operating times of frequency elements for a specific distribution system with different load-to-generation ratios.

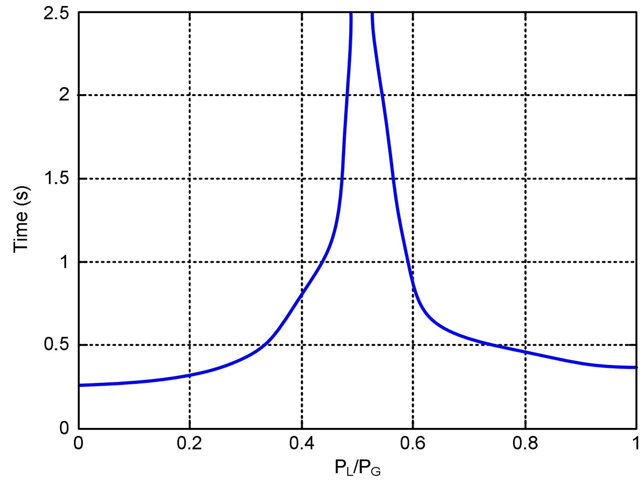


Fig. 6. Islanding detection time when using frequency elements increases as the power exchange decreases

Similarly, islanding schemes based on the voltage magnitude depend on the reactive power mismatch in the island. Load characteristics also play a role in the performance of the passive elements.

There are typically three load categories:

- Constant impedance—power varies with the square of the voltage magnitude.
- Constant power—power does not vary with the voltage magnitude.
- Constant current—power varies directly with the voltage magnitude.

Depending on the load characteristics, power mismatch in the island can vary significantly from the mismatch prior to the islanded state. For example, power consumption associated with constant impedance changes with the square of the voltage magnitude. This causes the power mismatch levels to be different before and after the island, dictating the performance of the islanding algorithm.

The possibility of nondetection of the island condition has led many utilities to adopt a two-to-one rule—meaning that the minimum islanded load must be twice as large as the total available DG within the island. If this limit cannot be guaranteed, passive schemes are not permitted.

The performance of the active schemes is not dependent on the power mismatch in the island. However, one of the main concerns with the active injection-based schemes is the interference introduced when multiple distributed generators are connected with the injection systems to detect islanding.

## III. Teleprotection

We can define teleprotection as the use of communication to improve the performance of protection schemes. In transmission networks, teleprotection has been used for many years to achieve improvements in speed, selectivity, and sensitivity.

The following teleprotection methods have been applied in transmission systems:

- Direct transfer trip (DTT). In this scheme, remote breakers are tripped upon reception of the trip command. Breaker failure protection is a typical example.
- Direct underreaching transfer trip (DUTT). In this scheme, an underreaching element sends a DTT. A trip is issued upon reception of the transfer trip signal.
- Permissive underreaching transfer trip (PUTT). In this scheme, an underreaching element keys a permissive transfer trip. A trip is issued for operation of an underreaching element and reception of the permissive transfer trip.
- Permissive overreaching transfer trip (POTT). In this scheme, an overreaching element keys a permissive transfer trip. A trip is issued for operation of an overreaching element and reception of the permissive transfer trip.
- Directional comparison blocking (DCB). In this scheme, a reverse-looking element keys a block. A trip is issued for operation of an overreaching element without reception of a block.
- Directional comparison unblocking (DCUB). In this scheme, a block is keyed during normal operation. An unblock is keyed when the overreaching element operates. A trip is issued for operation of the overreaching element and reception of the unblock. In addition, the overreaching element is allowed to trip if neither the block nor unblock is received for a finite period. DCUB is therefore a form of POTT that allows a trip for a simultaneous occurrence of a forward fault and a loss of communication.

These schemes require a communications channel. In the following discussion, we refer to a channel as the physical medium used to convey a signal. Terminal equipment is the hardware connected at the ends of the channel. Examples of terminal equipment include modems, fiber-optic transceivers, and radios. We use the term *link* to refer to the channel together with its terminal equipment.

Varieties of communications links have been used for teleprotection at the transmission level. These links include power line carrier, leased phone lines, microwave radio, and fiber-optic cable. These links may be dedicated or, when bandwidth permits, be multiplexed to allow other applications to share the link.

In the following discussion, we review the characteristics of a communications link that are important when applied for teleprotection. We focus on unlicensed spread-spectrum radio and compare this link with two others that may also be considered as candidates in a distribution network—namely the leased telephone link and the fiber-optic link.

### *A. Security*

Security is a measure of the ability of a link to not operate when it is not required to operate. The security of a link is a function of the channel characteristics and the error correction methods employed by the terminal equipment.

The signal-to-noise ratio (SNR) is one measure of channel quality. The SNR goes down when channel noise increases but also goes down when the signal level decreases. A decrease in signal level can result from increased path loss, weather, or a failing hardware component.

The bit error rate (BER) is the ratio of erroneous bits to total bits transmitted on a digital channel. BER is related to SNR and is also dependent on the modulation scheme and type of noise. In general, as SNR drops, BER goes up.

The attenuation of a radio channel increases with length. This property is known as path loss. The basic relationship for the path loss between two antennas in free space is given by the following equation.

$$\text{LP(db)} = 20\log \bullet \left( \frac{4 \bullet \text{d}}{\lambda} \right) \tag{1}$$

where:

LP is the path loss in db.

d is the distance between the transmitter and receiver.

$\lambda$ is the carrier wavelength in the same units as *d*.

The receiver sensitivity is the signal level at which a receiver can reliably recover data. Manufacturers will typically specify the receiver sensitivity for a specified value of BER, which may range from $10^{-3}$ to $10^{-6}$.

Radio channels share an important advantage with fiber-optic channels in that they are unaffected by the electrical transients or ground potential rise (GPR) associated with a power system fault. The same cannot be said for leased telephone channels, which may be forced out of service during a fault.

Terminal equipment typically employs error control coding to improve the security of a communications link. Some error control coding methods may detect and correct errors where others may simply detect errors. The cyclic redundancy check (CRC) is a commonly used method. During encoding, extra (check) bits are added to the payload. When the message is received, the CRC is recalculated from the received payload and compared to the received check bits. A discrepancy indicates that the payload (or the CRC) has been corrupted. The check bits are redundant because they add no additional information to the message. The effectiveness of error control coding is a function of the relative number of check bits as compared to the payload. Increasing the number of check bits makes for a more secure message at the expense of message length, thus bandwidth.

Relays can also add additional security in the form of duplicate messages and parity checks. The resulting level of security provided approaches the level required for transmission applications [5].

### *B. Speed*

The speed of a communications channel depends on the data rate of the channel, the size of the message, and the existence of any additional latency in the equipment at each terminal. Routing the communication directly from the terminal equipment to the relay avoids any delays associated with auxiliary teleprotection equipment.

Currently, point-to-point spread-spectrum radios are available with data rates as high as 38400 bps. Assuming a message size of 36 bits, the transmission time for a message at 38400 bps is approximately 1 millisecond. This assumes that the radio does not add any overhead for error control. Transmission times in the range of 4 to 5 milliseconds are typical when error control is taken into account.

Unlicensed radios operate primarily in the 915 MHz frequency band and have a range of around 10 to 20 miles with line-of-sight operation. A repeater is required when line of sight between the ends of the link is obscured or when the length of the path exceeds the range of the radio. The addition of a repeater effectively doubles the latency of the radio link.

Radios are available that can also apply data encryption. Encryption adds overhead to the message and, as a result, can add up to 10 milliseconds of additional latency. Note that the purpose of encryption is to protect the privacy of data, whereas error control coding addresses security. Encryption is therefore not considered necessary on a teleprotection link.

Finally, delays associated with the relay itself must be considered. Depending on the relay, the rate at which messages are processed can vary from two to eight times per power system cycle.

The data rates and error control on leased telephone circuits are similar to that of radio, so we can expect similar channel latencies on these links.

Optical fiber has the lowest latency of any of the links due to its immunity to electrical interference and high bandwidth. The delay on a fiber-optic channel can be less than 1 millisecond [6].

## C. Availability

The availability of a link can be defined as the amount of time that the link is capable of successfully transmitting data expressed as a percentage of total time. A link will become unavailable if either its terminal equipment or channel fails. Assuming similar reliability of terminal equipment, the difference in availability of various links depends mainly on the channel characteristics.

The availability of a radio channel can be degraded because of such issues as weather, growth of trees, or erection of structures within the path of the radio link. Additionally, because the band is unlicensed, there is always the possibility of interference of another radio in the vicinity.

Spread-spectrum radios deliberately distribute their signals across a wide frequency band. As a result, these radios have very good immunity to interference and are difficult to jam. Spread-spectrum radios generally do a very good job of rejecting narrowband sources of interference; however, degradation can occur when multiple spread-spectrum systems are operating in the same vicinity.

Radios are available that can synchronize their frequency hopping behavior to allow the placement of multiple radios at a location without interference (Fig. 7).

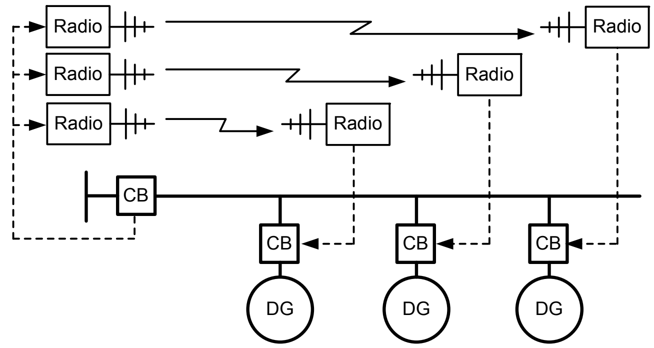


Fig. 7. Collocated radios

The availability of leased telephone channels can be characterized by long periods of operation interrupted by brief bursts of noise [5]. Other causes of failure include reconfiguration of circuits at the telephone company central office or damage of a buried cable through inadvertent excavation.

Fiber-optic cable is expected to have the highest level of availability because it is immune to electrical interference. However, buried fiber is also subject to inadvertent excavation.

Protective relays are now designed to interface directly with terminal equipment. These relays are capable of measuring the availability and the current status of the link. This creates the ability to design better protection schemes, which adapt according to the status of the channel.

## D. Cost

As previously mentioned, 915 MHz spread-spectrum radio can operate at distances of up to 20 miles if there is an unobstructed electromagnetic line of sight between antennas (electromagnetic line of sight is more generous than optical line of sight). Installed cost is now on the order of a few thousand dollars per terminal. If the terrain is not adequately flat, towers and/or repeaters will be required, and this can result in a significant escalation in cost. On the plus side, there are no additional recurring licensing or leasing costs.

The terminal equipment cost for leased telephone links is similar to that of radio. These links will have additional costs associated with GPR isolation. In addition, leasing costs in the United States can be upwards of several hundred dollars per month.

Fiber-optic transceiver costs range from several hundred dollars for multimode transceivers to over one thousand dollars for single-mode transceivers. By far, the largest cost is to buy and install the fiber. This cost can run into thousands of dollars per mile [7].

# IV. Communications-Based Feeder Protection Schemes

Some of the issues identified in Section II may be dealt with during the project planning phase through selection of the optimum location and/or size of the DG. Coordination studies can resolve other issues [3] [8]. The use of communication is not seen as a replacement for good engineering practices. Instead, it can be considered for issues that cannot be resolved by a simpler approach or for a higher level of DG penetration than might otherwise be possible.

Tripping the DG instantaneously has the potential to address coordination issues. IEEE 1547 requires that the DG be taken offline for all faults on the circuit to which it is connected. However, this can likely lead to DG trips for faults on adjacent feeders. Assuming that faults must be cleared within 200 milliseconds (see Section II, Subsection A) and the DG breaker takes 5 cycles or 83 milliseconds to operate, the DG protection must operate in less than 117 milliseconds. Assuming that it will take a minimum of 6 cycles or 100 milliseconds to clear a fault on an adjacent feeder (1 cycle for protection plus 5 cycles for the breaker), it becomes unlikely that fuse saving can be retained without tripping DG for faults on adjacent feeders.

A teleprotection scheme may be implemented to address DG overtripping. The teleprotection schemes in Section III do not strictly apply for protection of feeders with DG. These schemes were designed for transmission lines. However, the underlying principles are applicable.

*A. DG POTT Scheme*

A permissive scheme can be implemented as shown in Fig. 8. Substation directional elements are set to pick up for a fault on the feeder and send trip permission. Instantaneous elements at the DG are set to pick up for faults anywhere on the feeder. The DG trips for a pickup of local protection associated with receipt of trip permission. Instantaneous DG tripping is permitted in the case of a channel failure. In this contingency, overtripping of the DG is possible and acceptable for a fault on an adjacent feeder. This allows the use of channels of lesser availability as compared with DTT DG schemes.

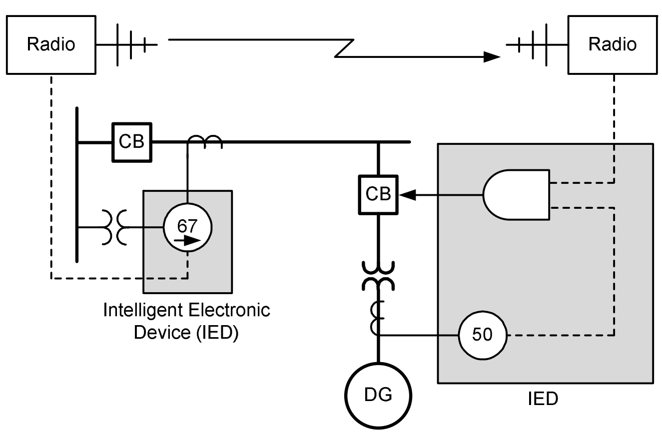


Fig. 8. DG POTT scheme

Reclosers on the feeder do not need to participate in the scheme as long as the substation directional elements can see all feeder faults. This avoids the need for electronic reclosers with communications capabilities. Distributed generators are tripped for faults anywhere on the feeder, including those that may be isolated via downstream reclosers.

Clearly, the upstream feeder protection does not require trip permission from the DG. However, this protection may require local directional supervision to ensure that it does not trip because of the contribution from the DG.

The POTT scheme can produce the fastest clearing time at the DG, thereby mitigating fuse coordination issues. Given an arbitrary maximum DG fault-clearing time, it is evident that the interruption time requirement of the DG breaker is a function of the speed of the teleprotection link (i.e., a faster teleprotection link allows the use of a slower, less expensive breaker).

The effectiveness of the scheme rests on the ability of the substation directional element to see all faults on the feeder. It is possible that directional elements that are polarized from zero- or negative-sequence voltage may not have a sufficient polarizing signal to operate for feeder-end faults. Transformer neutral current may also be considered for the polarizing signal.

*B. DG DCB Scheme*

An alternative to the POTT scheme is the DCB scheme, as shown in Fig. 9. Directional elements in the substation are set to see upstream faults and transmit a blocking signal to the DG. The blocking signal is inverted and connected by an AND gate to the local protection. This reverse-looking element is also necessary to prevent tripping of the substation breaker.

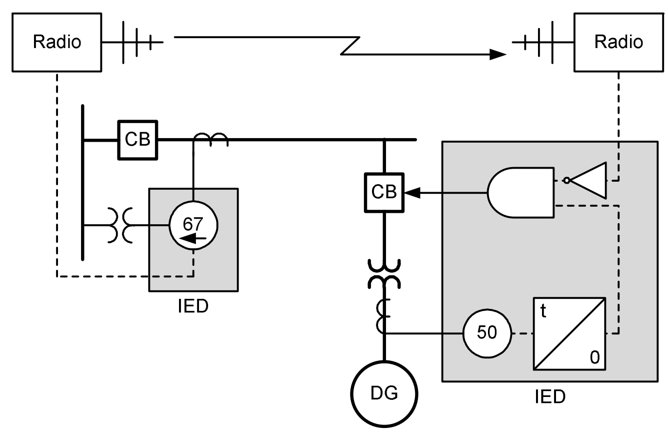


Fig. 9. DG DCB scheme

Local protection is delayed to account for channel latency, and the time delay must be set longer than the longest anticipated delay of the channel. Thus particular radio links that have low average channel latency but high maximum channel latency should be avoided for use in DCB schemes.

DCB schemes that employ channels with deterministic latency can deliver DG clearing times that approach those of POTT. In addition, the DCB scheme is not dependent on the ability of a forward-looking directional element to see all feeder faults.

Overtripping of the DG is possible for a channel failure or for a failure of the substation directional elements to pick up for a reverse fault. Again, this weakness demonstrates itself only under contingency conditions while allowing the use of a lesser performance channel, making the solution very attractive.

A common cause of DG overtripping is the operation of the intertie voltage element. This protection is specified in IEEE 1547 for detection of feeder problems [9]. However, it has been known to operate for faults on adjacent feeders. It is feasible to also supervise this function with the same blocking signal.

*C. Adaptive Protection Coordination*

The potential for loss of fuse/recloser coordination due to the contribution of the DG was explained and illustrated in Section II. In many cases, the fast curve may be adjusted to account for the DG contribution [1] [8]. However, the result of a permanent adjustment may be that the recloser is too fast when the DG is offline, resulting in recloser tripping for faults downstream of the transformer fuse. An alternative is the communications-based approach shown in Fig. 10. The DG transmits its online indication to the upstream recloser. The recloser implements a settings group change whenever the DG is online. In the alternate settings group, the time dial of the fast curve is reduced to account for the difference between the recloser current and the fuse current. Adjustment of the slow curve is unnecessary because the DG will be offline after the first reclose operation. A fault study is required to determine the appropriate value for the multiplier setting. When the impedance of the feeder is not significant as compared with the impedance of either source, the recloser current expressed as a percentage of the fuse current is:

$$\frac{I_{RECL}}{I_{FUSE}} \approx \frac{X_{DG}}{X_{DG} + X_{SYS}} \tag{2}$$

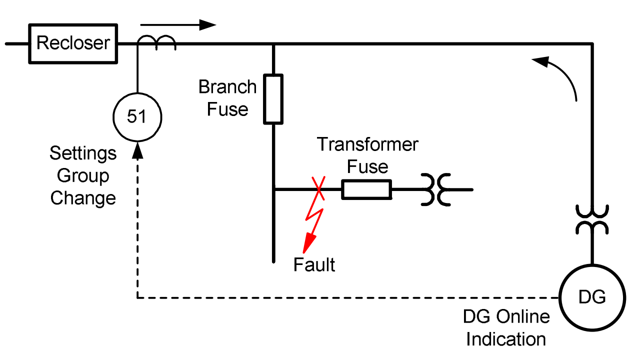


Fig. 10. Adaptive protection coordination scheme

This scheme requires communications between the DG and the recloser and a recloser that supports multiple settings groups.

The scheme is not dependent on the speed of the communications channel because the DG online indication will be present prior to the fault.

Protection is not lost in the event of a communications failure, although fuse/recloser coordination will be lost. This response under the contingency of lost communication is acceptable.

The proposed scheme may also be used to desensitize recloser protection, if necessary, during energization of the DG transformer.

*D. Direct Transfer Trip for Ground Faults*

An ungrounded DG transformer connection is advantageous in the sense that it does not provide a ground fault source. Therefore, the sensitivity of the feeder protection is not degraded, and loss of coordination is not a concern for ground faults. However, current-based ground fault protection cannot be employed to trip the DG. Tripping at the DG from voltage elements may result in overtripping. In three-wire systems where feeder equipment is rated for full phase-to-phase voltage, it may be acceptable to allow the DG to trip from voltage elements after the feeder breaker has opened. This would require potential transformers (PTs) on the DG transformer high side.

Alternatively, a DTT could be keyed from sensitive ground fault protection located in the substation, as shown in Fig. 11.

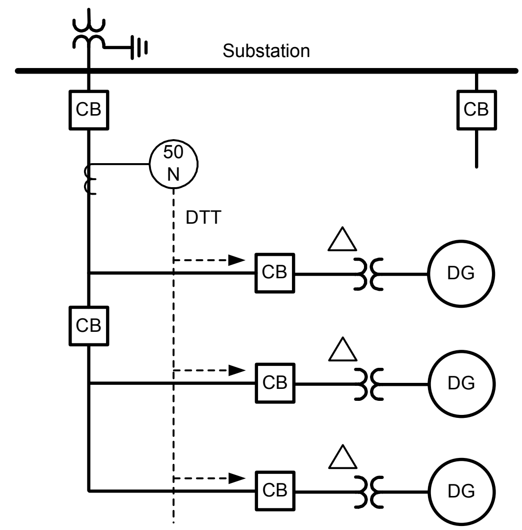


Fig. 11. Direct transfer trip

A sensitive overcurrent element is set to detect all feeder ground faults. All DG on the feeder trips from DTT. Existing ground fault protection provides time-coordinated tripping of the feeder breaker and reclosers, but curves are adjusted to allow all DG to trip first. Once the DG is disconnected, the fault can be cleared without risk of overvoltage. After the fault, distributed generators that measure feeder voltage reconnect automatically. DG is disconnected if communication is lost. Large distributed generators may employ redundant communication for higher availability. Inverter-based distributed generators may not require DTT if tripping can be guaranteed by their design.

## V. Communications-Based Anti-Islanding Schemes

### *A. Transfer Tripping*

DTT is one of the conceptually simple islanding schemes. In these schemes, islanding is typically detected based on breaker status or open phase detection logic by the upstream feeder relays or reclosers. Typically, there may be multiple breakers at different locations, any of which, when tripped, could create an island. Fig. 12 shows a programmable logic controller (PLC) receiving breaker statuses from feeder relays and reclosers.

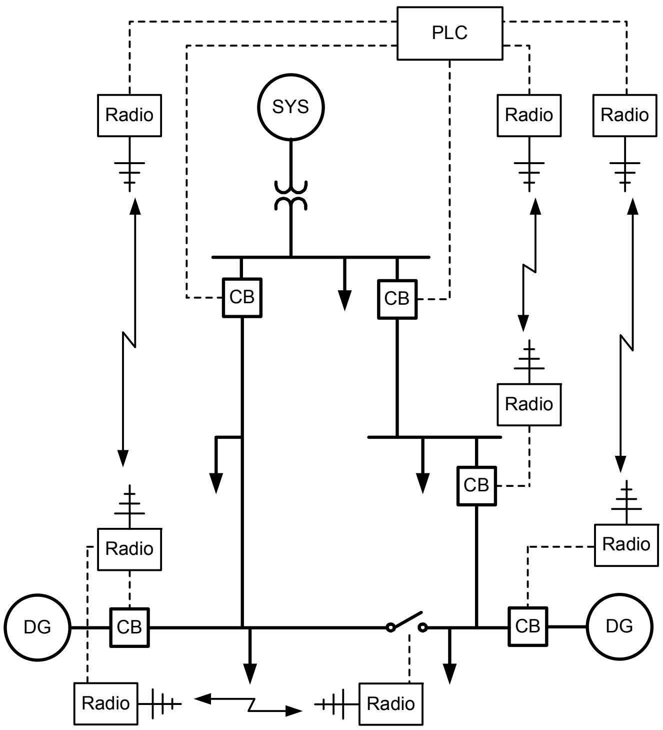


Fig. 12. DTT anti-islanding using a PLC and radios

Based on preprogrammed logic, the PLC sends a trip command to the DG breaker. Radio communication and leased telephone lines are typically used as economical communications media for transfer tripping schemes. A radio at each monitoring location communicates the breaker status to the radio at the central location where the PLC is installed. It is recommended to use radios with collocation functionality to provide deterministic and dependable communication.

Utilities prefer to disconnect the DG when communication fails. This practice is acceptable to both the DG owner and the utility when highly reliable communication is in place. Spread-spectrum-based ISM band communication offers low-cost communication with lower availability. However, by performing path studies and implementing appropriate design practices, it is possible to take advantage of low-cost communication and achieve high availability. Tripping DG for communications failures is not appealing to DG owners. Therefore, DG protection designs must include logic to address communications failures without sacrificing protection for out-of-phase reclosing. It is recommended to supervise the feeder reclosing using standard practices; one such practice is dead line/live bus. Phase voltage on the line side of the breaker is required for this reclose supervision logic. Alternate schemes need to be implemented to prevent out-of-phase reclose when the line-side potential is not available.

Fig. 13a shows logic that can be implemented in the feeder relay to inhibit reclose if the communications link is down for more than 8 milliseconds. Reclosing is enabled if the communication is restored for longer than 1 second. This assumes that the autoreclose open interval delay expires before 1 second and drives the scheme to lockout.

Fig. 13b shows the logic to trip the DG if communication fails for over 5 seconds. This logic can be implemented in the protective relay at the DG site. The T1 and T2 timers in Fig. 13 are arbitrarily selected and can be changed per application requirements or practice. The communications okay (COMMOK) signal can be generated by using a watchdog mechanism, where the protective relay at the DG site periodically sends a digital bit to the upstream feeder relay. A communications failure is declared and the autoreclose is blocked by the feeder relay if the watchdog bit does not arrive for a programmable period of time.

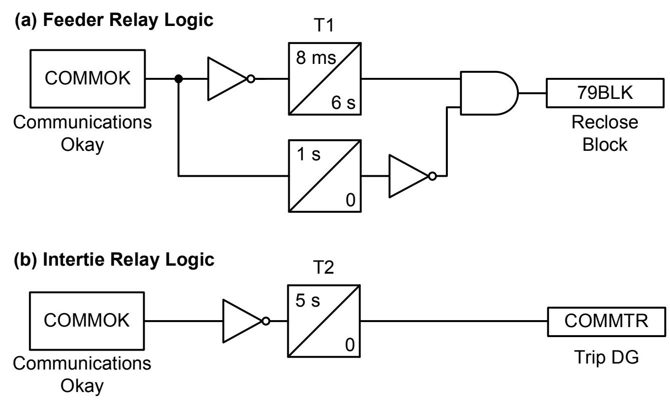


Fig. 13. Communications failure logic

Implementation of transfer trip schemes is challenging when feeder reconfiguration and multiple distributed generators need to be considered.

### *B. Supervised Passive Anti-Islanding Scheme*

Passive anti-islanding schemes can detect an island from local measurements of voltage and frequency. However, these schemes, specifically vector shift and df/dt, are subject to nuisance tripping during disturbances. A communications channel can be used to supervise these schemes in order to improve security. An example is shown in Fig. 14.

The scheme requires df/dt elements located at the DG and substation using bus-side PTs. If an islanding event occurs by opening the substation breaker, the element at the DG will operate but the element at the substation will not. The DG will subsequently be disconnected. During a system disturbance, both elements may operate. The substation IED sends a block to the DG IED, preventing the DG from tripping. A short time delay at the DG is required to account for channel latency. Because islanding detection is carried out locally using passive protection elements, this scheme can still operate if the communications channel is unavailable, although false operations are more likely. A second advantage is that it does not require communications with midline reclosers. Because it is a passive scheme, it requires a power mismatch for guaranteed operation, as described in Section II, Subsection B.

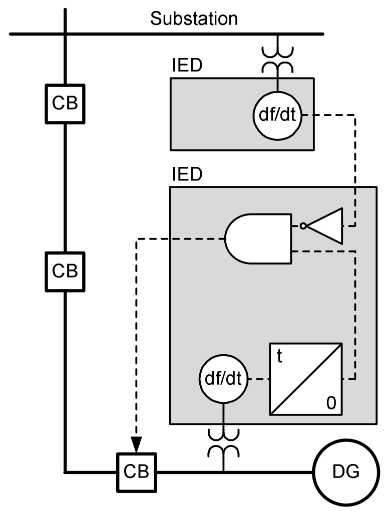


Fig. 14. Supervised df/dt scheme

With cost being an important factor for DG projects, spread-spectrum-based ISM communication offers a great solution to provide security for passive islanding detection schemes. A low-cost communications channel to minimize nuisance tripping is a viable option that DG owners could implement. As the DG penetration increases, dedicated fiber communication might be justifiable.

*C. Synchrophasor-Based Anti-Islanding*

A wide-area measurement-based scheme that uses time-synchronized measurements from a remote source and the DG to detect an islanding event is discussed here and in [10]. The voltage angle difference between the two locations is provided as an input to the islanding detection logic. Islanding is detected based on the slip frequency (rate of change of angle difference with respect to time) and acceleration (rate of change of slip frequency). Fig. 15 shows the islanding detection characteristic.

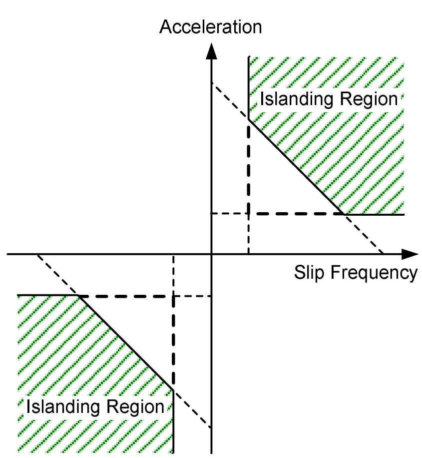


Fig. 15. Synchrophasor-based islanding detection characteristic

The transmission format used in this scheme is defined by IEEE C37.118 for reporting synchrophasors in power systems. The maximum data rate used is 60 messages per second. To optimize the required bandwidth, integer data format is used for the data. Table I shows the data items and size.

TABLE I
SYNCHROPHASOR MESSAGE BANDWIDTH REQUIREMENTS

| Data Item | Bytes |
|---|---|
| Overhead | 18 |
| Positive-sequence voltage phasor | 4 |
| Frequency and df/dt | 4 |
| Digital status (16 digital bits) | 2 |
| Total | 28 |

Based on the bytes required and message rate, a data rate of 19200 bps is required for this scheme. Spread-spectrum-based ISM communication is a viable, cost-effective option to implement the synchrophasor-based islanding scheme. Fig. 16 shows a phasor measurement unit (PMU) installed at the DG location and the substation breaker monitoring phase voltages. A phasor data concentrator (PDC) capable of processing the synchrophasor data using a programmable logic engine and sending control commands to the PMU is installed at the substation. The PDC receives synchrophasor messages from the DG location via radio communication and from the substation PMU via direct copper. Synchrophasor-based islanding detection logic is implemented in the PDC, and the trip output from the PDC is sent to the PMU at the DG site. Passive islanding schemes are implemented in the PMU at the DG site to offer backup protection.

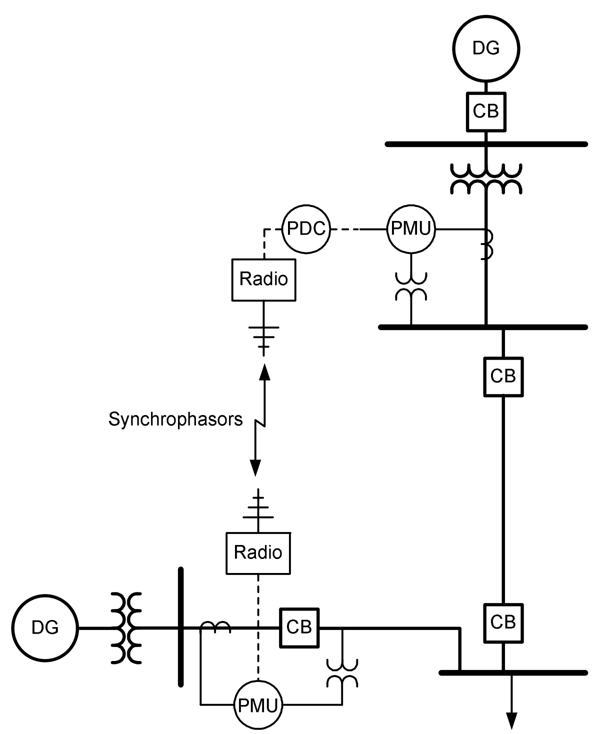


Fig. 16. Synchrophasor-based anti-islanding scheme

The logic presented in Fig. 13a is also implemented in the PDC to prevent an out-of-synchronism close during a communications failure. In contrast with the DTT scheme, the synchrophasor-based scheme does not require communication with midline reclosers or disconnects.

## VI. Conclusion

This paper reviews the challenges of integrating generation at the distribution level. It presents several schemes that use communication to improve protection and anti-islanding performance in distribution networks with distributed generation but are not completely dependent on the availability of the communication. The schemes are well-suited to the characteristics of a radio link. Specifically, the security of a radio link approaches that of links used in transmission applications. Radio links also compare very well in terms of speed, which is more than adequate for the schemes presented in this paper. The availability of a radio link can be more difficult to quantify. As a result, schemes that are biased towards dependability are favored whenever radio links are employed.

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## VIII. Biographies

**Dr. Edmund O. Schweitzer, III** is recognized as a pioneer in digital protection and holds the grade of Fellow of the IEEE, a title bestowed on less than one percent of IEEE members. In 2002, he was elected a member of the National Academy of Engineering. Dr. Schweitzer received his BSEE and MSEE from Purdue University, and his PhD from Washington State University. He served on the electrical engineering faculties of Ohio University and Washington State University, and in 1982 he founded Schweitzer Engineering Laboratories, Inc. (SEL) to develop and manufacture digital protective relays and related products and services. Today, SEL is an employee-owned company, which serves the electric power industry worldwide, and is certified to the international quality standard ISO-9001.

**Dale Finney** received his Bachelor's degree from Lakehead University and Master's degree from the University of Toronto, both in electrical engineering. He began his career with Ontario Hydro, where he worked as a protection and control engineer. Currently, Mr. Finney is employed as a senior power engineer with Schweitzer Engineering Laboratories, Inc. His areas of interest include generator protection, line protection, and substation automation. Mr. Finney holds several patents and has authored more than a dozen papers in the area of power system protection. He is a member of the main committee of the IEEE PSRC, a member of the rotating machinery subcommittee, and a registered professional engineer in the province of Ontario.

**Mangapathirao (Venkat) Mynam** received his MSEE from the University of Idaho in 2003 and his BE in electrical and electronics engineering from Andhra University College of Engineering, India, in 2000. He joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2003 as an associate protection engineer in the engineering services division. He is presently working as a lead research engineer in SEL research and development. He was selected to participate in the U.S. National Academy of Engineering (NAE) 15th Annual U.S. Frontiers of Engineering Symposium. He is a member of IEEE.

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