# Summary of C37.230-2007, IEEE Guide for Protective Relay Applications to Distribution Lines


By Line Protection Subcommittee Working Group D5
Of the IEEE Power Engineering Society - Power System Relaying Committee

Gustavo Brunello
Randy Crellin
Fredric A. Friend
Rafael Garcia
Roger A. Hedding
Raluca Lascu
Michael J. McDonald
Dean H. Miller
Tony Seegers
William P. Waudby
Inma Zamora


## I. Abstract


A new IEEE Guide for Protective Relay Applications to Distribution Lines has been written to aid in the application and coordination of protective devices on radial power system distribution lines. As the Guide is 95 pages long, this summary paper is not intended to be a substitute to the guide.


## II. Objectives of the Guide

The Guide begins with a discussion of distribution fundamentals, line configurations and schemes. Advantages and disadvantages to some schemes are listed. Solutions to identified problems are discussed. The Guide also includes protection criteria and provides useful examples for illustrative purposes. This Guide will provide the user the rationale for determining the best approach for protecting a radial electric power distribution system.

The Guide contains a number of figures and graphs to aid in the understanding of the protection concepts explained in the text. Tables illustrating calculation results are also included to further clarify some key concepts.

## III. Key Clauses of the Guide

The Guide has several key clauses, including: fundamentals, system configuration and components, protective schemes, and criteria and examples. Also in the Guide is a special applications clause that includes important topics that were not addressed up to that time in the Guide. These include practices and considerations that impact relay protection, but may not be common in every distribution system. Highlights of the main clauses of the Guide follow.

### A. Fundamentals

Clause 4 of the Guide discusses the fundamentals of the various types of faults that can occur on distribution systems. Understanding the nature of these faults and the fault's impedance are important in determining the protective device application. In some cases the fault impedance will limit the fault current to values that are not detectable or that are comparable to load current values. This clause also discusses load characteristics, harmonics and the effects of transients on distribution line protection. The importance of the interrupt rating of circuit breakers, reclosers and fuses is also discussed in this clause.

Most faults are temporary in nature. Common causes of temporary faults are wildlife, wind and lightning. Some faults are permanent, such as those caused by equipment failures or dig-ins. Often, on distribution systems, faults can evolve from one type to another, such as a phase-to-ground fault flashing over and involving another phase. In some cases the fault current magnitude will change through the course of the fault event as a fault arc is established or the item initiating the fault burns away. Simultaneous faults involving different distribution circuits, sometimes of different voltages or phase relationships, can also occur.

Calculations of the system fault currents used to select, apply, and set protective devices on distribution systems are typically accomplished through the use of the symmetrical components methodology. Most fault studies utilizing symmetrical components are performed through the use of computers and software tools that allow protection specialists to model three-phase power system impedance characteristics, and calculate short circuit currents or 'sequence components' for various types of fault conditions. These currents can then be used to select and apply protective devices such as relays, reclosers, and fuses.

It is important to have the knowledge of load characteristics at various points in a power system for various studies like load flow, short circuit, stability and electromagnetic transients. Complex models to represent the load exist; however, the main problem to include adequate representation of loads is obtaining proper data for use in a model.

Non-linear loads and power electronic devices are the largest source of the harmonics that appear in power systems. Other power electronic devices such as diodes, silicon controlled rectifiers (SCR), gate-turn-off thyristors (GTO) and insulated gate bipolar transistors (IGBT) chop the supply waveforms. This chopping effect produces non-sinusoidal waveforms, which contain harmonics. The harmonic producing device will act as a current source and inject harmonic current back into the system. This is counter-intuitive since we typically think of loads as absorbing power.

Like fundamental frequency currents, harmonic currents tend to flow towards the path of least impedance. This causes them to show up in the most unexpected places such as power system neutrals. Other problems such as series and parallel resonance can occur, but those problems were not addressed. These harmonics will affect the performance of some protection devices that are applied on distribution circuits. The third harmonic current and other triplen harmonics can affect the performance of neutral or ground overcurrent relays. Where as the second and fifth harmonics can affect the performance of negative sequence relays. Relays that are tuned to the fundamental frequency are not affected by harmonics. Devices that respond to the rms value of the current, like electromechanical relays and fuses, are affected by the composite of all frequencies in the current flow. Since the harmonic content of the current will contribute to the heating of the power system equipment; the inclusion of the harmonics in the sensitivity of protection devices is sometimes beneficial.

Distribution line protective relays can be negatively affected by power transients and their effect should always be evaluated when applying settings. For example, if a large capacitor bank is installed at the substation bus, "close in" faults can cause large capacitor discharge currents to flow resulting in the possible misoperation of instantaneous overcurrent relays. Additional examples of transients are transformer energization inrush and system switching. Typically, time overcurrent relays are not affected by transients since the transient will be dampened out much faster than the relay operating time.

## B. System configuration and components

Clause 5 includes a discussion of the three main methods of system grounding used around the world, which are solidly grounded, ungrounded and impedance grounded. Each type of grounding method is described in significant detail in the Guide. For example: the solidly grounded method can be uni-grounded or multi-grounded, impedance grounded can be resistive grounded, reactive grounded or resonant grounded. The grounding method used is only important during single-phase-to-ground faults, where the operational and safety aspects strongly depend on the grounding method chosen.

The following short description of each method is discussed in greater detail in the Guide: A multi-grounded system is described as a four wire system with a neutral wire that is grounded at multiple locations along the length of the feeder, and is commonly used in the U.S. and in some other countries. An ungrounded system is simply a three conductor system whose neutral is not grounded and is therefore free to shift; this scheme is still widely used. Uni-grounded systems, as the name implies, are grounded at only one location with a solid connection to ground. Uni-grounded systems are either three wire systems or four wire systems with an insulated neutral. In a resonant-grounded system the transformer neutral is grounded through a reactance, commonly called a Petersen coil. This scheme is commonly used in Europe. The reactance is tuned to the fundamental frequency with the stray capacitance of all feeders connected to the same transformer. Impedance grounded systems use resistors or reactors to connect the substation transformer's neutral to ground to limit ground fault currents and to reduce dynamic and thermal stress on equipment.

Fault impedance ($Z_f$) is defined as the impedance involved in the fault. The impedance of a fault can be affected by a tree getting into a line or a conductor falling on the ground or many other factors. Because the fault impedance can vary widely, different practices are used to determine minimum ground fault settings.

The Guide includes a clause that describes various bus configuration designs taking into consideration requirements such as load characteristics, the necessity for maintaining continuity of service, flexibility of operation, maintenance, and cost. The designs vary from the simplest single-circuit layout to the involved duplicate systems installed for metropolitan service. Along with each bus description relay settings criteria and coordination considerations are discussed.

For example Figure 1 shows a fused transformer with a main secondary breaker and three feeder breakers. The setting criteria and coordination considerations between the transformer fuses, transformer overcurrent relays, the feeder overcurrent relays and the transformer damage curves are discussed.

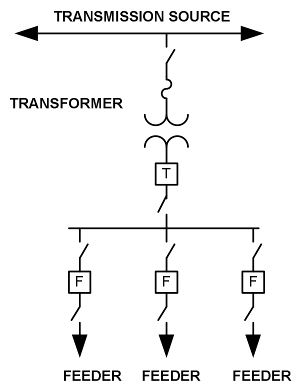


Figure 1–Single transformer distribution bus

The impact of distributed resources (DR) connected to a substation bus or feeder and their impact on protective relaying, as available fault current increases, is discussed. Also discussed is the practice of installing current-limiting reactors in series with each DR generator to control fault currents. Sketches of various substation low voltage bus configurations are presented with examples of how each is used.

The change in ground current sensitivity when using residual current compared to using current from a CT connected in the neutral of a four wire system is discussed. One of the differences pointed out is that residual connected CTs can cause nuisance operations due to errors arising from CT saturation and unmatched characteristics. When a ground reference is needed, for example, on a delta connected transformer, additional transformers are commonly used to provide the ground source. Zigzag and grounded-wye with a closed delta connection are two commonly used arrangements. Although the zigzag transformer connection is more widely used to provide a ground source both have been used successfully. Both arrangements have the ability to provide high positive sequence impedance while providing a low zero sequence source impedance. The level of available fault current can be controlled by adding a resistor between the primary neutral and ground of the grounding transformer.

The required coordination of distribution system overcurrent protective relays with the conductor damage curve is also discussed. The concern of overheating insulated power cables that can lead to damage to their dielectric, sheath, extruded jacket, splices and PVC conduit systems is discussed. Parameters to consider in the evaluation are the available fault current, relay time-current curve, conductor $I^2t$ curve, and effects of reclosing.

Relays are defined as “devices that respond to signals from sensors (voltage, current, temperature...), and operate contacts based upon predetermined criteria.” Relays are used for many purposes from operating breaker trip and close coils to controlling the operation of lockout and timing devices.

A recloser is defined as a “protective device that combines the sensing, relaying, fault interrupting and reclosing functions in one integrated unit.” Reclosers are generally installed in substations or along a feeder to provide fault detection, isolation, and service restoration. Reclosers use either oil or vacuum as the fault interrupting medium. Besides the interrupting medium, reclosers come in two forms hydraulic or electronic control. With a hydraulic type controller, a trip coil is connected in series with the line to sense an overcurrent condition. The viscosity of the hydraulic fluid has some impact on the timing of the overcurrent function since it is subject to change with changes in temperature. Electronic controllers are used with shunt trip coil reclosers and use either a separately mounted electronic control or a set of relays to provide time overcurrent tripping and reclosing. Reclosers with electronic control are more flexible, have advanced programming, and provide protection, and an operations counter.

The simplest form of overcurrent protection is provided by a fuse. Clause 5 explores the differences between the two fundamental types of fuses most often used in distribution systems, which are expulsion and current limiting fuses. Expulsion fuses are defined as “fuses that use gas generation and exhaust to remove conducting particles from the arc column and allow the fuse to interrupt current at current zero.” Since expulsion fuses interrupt currents at the current zero, therefore they will let through up to a half cycle of the full fault current before current interruption. On the other hand, current limiting fuses introduce high resistance into the circuit to reduce the magnitude and duration of the fault current. The $I^2t$ value will therefore generally be significantly lower for a current limiting fuse in comparison to an expulsion fuse.

Instrument transformers, both voltage and current transformers, are used to provide reduced magnitudes of available primary voltages and currents that can be safely used in relays and at the same time provide isolation from the primary system. When three voltage transformers are used they are generally connected wye and provide three phase-to-phase and phase-to-neutral voltages. The open delta VT connection is also commonly used and it provides three phase-to-phase voltage measurements using two VTs. CTs used for feeder relaying are generally located on the bus side of a distribution substation feeder circuit breaker when used for primary feeder protection. By connecting the relay at this location the breaker is able to isolate all faults that are detected beyond the location of the breaker.

Current transformer saturation as a result of the DC component of an asymmetrical fault current is also discussed in Clause 5. A couple of examples of CTs exhibiting saturation are provided. This clause also discusses the impact on the timing of time over-current relays.

## C. Protective schemes

Overcurrent protection is the simplest scheme used to protect distribution lines. There are three types of overcurrent relays applied on distribution systems:

- Phase overcurrent
- Ground overcurrent
- Negative sequence overcurrent

These relays can be directional or non-directional depending on relay type, system configuration, and protection requirements. For radial distribution, non-directional overcurrent relays are adequate; for network or looped systems directional overcurrent relays may be necessary.

Phase overcurrent relays respond to line currents. They must have minimum response or pick up settings greater than the expected maximum of their feeder load current. This current may be as high as the maximum load capability of the line.

Other factors to consider when calculating the pick up setting are the cold load characteristics of the feeder and any significant transformer magnetizing inrush current. Most utilities establish cold load pickup guidelines specific to their own systems. Typically, magnetizing inrush is not severe enough or will decay quickly before the feeder time overcurrent relay can respond.

To avoid misoperation, the phase overcurrent relay pickup settings are generally 1.5 to 3.0 times the maximum expected feeder load current.

Ground overcurrent relay pickup must be greater than the ground current expected on the feeder due to unbalances. Since much distribution load is single phase, it is possible to have substantial residual or zero sequence current flow in the feeder. Even when phases are well balanced under normal conditions, sectionalizing of a single phase lateral or load transfer to another feeder can significantly affect feeder balance. As a result, most ground relays are set with a pickup range from 25 to 50 percent of the phase relay pick up, providing better sensitivity for phase-to-ground faults while not operating for load imbalance.

Similar to ground overcurrent relays, negative sequence relays can be set below load current levels and be set more sensitively than phase overcurrent relays for phase-to-phase fault detection. In many applications this allows a higher phase overcurrent relay pickup setting, permitting more feeder load capability.

Negative sequence current caused by feeder load unbalance must be considered when setting negative sequence relays. Transformer magnetizing inrush, cold load pickup, and expected maximum feeder loads are to be considered as well when calculating relay settings.

Negative sequence relays can also be applied to detect open phase conditions and low side phase-to-ground faults on delta grounded-wye transformers. The ability to detect ground faults on the low side of delta grounded-wye transformers allows the feeder relays to source protect numerous tapped delta-wye transformers, saving the cost of local protection if one chooses to do so. Where local protection is installed, the negative sequence relaying provides backup at the distribution substation for failure of the local protection.

Overcurrent protection schemes for distribution feeders generally fall in two types;

- Fuse saving schemes
- Fuse blowing schemes

Distribution fuses require physical replacement after a fault clearing operation. In a fuse saving scheme, breakers or reclosers are set such that they trip before the fuse operates and then automatically reclose. In many cases, faults are only temporary and the line will successfully reclose, causing only a momentary disruption. This type of scheme is effective on long multi-tapped rural distribution feeders with primarily residential load that is not as sensitive to momentary outages. Fuse saving for this scheme requires that a recloser's fast curve, or a "low set instantaneous element" in the case of a station breaker, be set below the minimum melt curves of those fuses that are not to operate on temporary faults. After one or two operations on the "fast" curves, the next trip is set such that, if the fault is downstream of the fuse, it will operate first, clearing the persistent fault before the breaker or recloser trips again. This provides one or two opportunities for a temporary fault to be cleared before the fuse is allowed to operate. Permanent faults need to be located and physically removed before the line can be put back in service so replacement of the fuse does not seriously extend the outage duration. Application of fuse saving schemes is only applicable to in-line or tap fuses.

For distribution feeders where loads are sensitive to momentary outages and significant disruption occurs if the line is momentarily de-energized, a fuse blowing scheme is used to limit the number of main feeder trip-reclose cycles. This scheme is often used on feeders serving industrial plants and urban load centers where a number of trip-reclose cycles could result in equipment damage or added risk of personnel injury. In this type of scheme, the overcurrent relay or recloser control curves are set above fuse curves such that fuses operate first to clear the faulted line section. The substation device (circuit breaker or recloser) serves as a backup in case the fuse fails, in addition to its function of operating for faults on the main feeder trunk.

Voltage sensing relays are used in a wide variety of applications. Some of these are to protect equipment (e.g. power transformers) from damage, to determine if a supply source is healthy or not (i.e. source transfer schemes), to detect ground faults on normally ungrounded systems, to supervise automatic or manual closing of circuit breakers, to determine whether a single breaker pole is open or closed undesirably, to detect unbalanced voltage due to a blown fuse or to supervise or restrain overcurrent elements for fault detection near generation sources.

The voltage elements can be over or under voltage depending on the specific application. Elements are designed to either measure phase-to-phase or phase-to-ground voltage. It is also possible to measure sequence quantities using special transformer connections or with microprocessor relays designed with this feature. As with many overcurrent relays a time delay is often included as part of the application.

## D. Criteria and examples

The goal of the utility is to deliver electric energy to the customers in a safe, reliable, and economical manner. The goals in applying protective relaying to a distribution system are to detect all possible types of fault conditions that could occur, respond to the fault conditions by disconnecting the fault from the source as fast as possible while affecting the minimum number of customers, and not limiting the capability of the system to carry load current. Since attempting to accomplish some of these goals makes it impossible to accomplish others, compromises are made. The limits of these compromises are the criteria that are used to determine locations for the fault interrupting devices, and the sensitivity and operating speed of the fault detecting devices.

At least one fault detecting device should be set to operate for phase-to-phase or three-phase faults on the distribution line. Since the source impedance to the origin of the distribution line can vary in most situations, the maximum reasonable source impedance is normally used. Using this maximum source impedance and the impedance of the distribution line, the expected currents for a phase-to-phase fault at the most remote location can be calculated. The phase-to-phase fault current will be 0.87 times the three-phase fault at the same location. A margin can be applied to account for unforeseen operating conditions like arc resistance, fault impedance and CT error.

If the relay being used to detect phase-to-phase and three-phase fault conditions is a phase overcurrent relay, its pickup value is set higher than the maximum load current for the feeder. The maximum load current is not just the maximum steady state load current, it also includes the cold load pickup current.

Usually when a distribution circuit is restored after an outage the power draw is greater than the power draw before the outage because the initial load demand after an outage can exceed the load demand that would have been observed at any time before the outage. This phenomenon is referred to as cold load pickup if the outage was extended because the power supply has been unavailable for a period of time so that the load has reached a "cold" state before being re-energized. Cold load pickup is a composite of two conditions: inrush and loss of load diversity. The inrush part is a composite of several contributing factors. One factor is magnetizing inrush current which is the current required to satisfy the instantaneous flux requirements when energizing transformers. The magnitude of the initial peak magnetizing current, which is a function of residual flux and energizing voltage, can have an equivalent rms value many times greater than the full-load rating of the transformers. The inrush portion of the cold load pickup could be substantial in magnitude but short in duration and will be of a factor for energization of the circuit after a short outage as well after an extended outage.

A significant portion of a distribution feeder's load will be intermittent loads, such as air conditioners, electric heaters, and refrigerators. These loads will cycle on and off at differing intervals, so that, under normal conditions, only a portion are on at any given time. After extended feeder outages, however, this load diversity is lost. Consequently, when the feeder is re-energized, all (or most) of these loads will be switched on. This is the loss of load diversity part of cold load pickup. This additional load, which will contribute to the magnitude of the inrush, will also maintain higher that normal current on the circuit for an extended time- 30 minutes or more. The phase overcurrent relay settings will need to be designed to handle both the inrush and the loss of load diversity parts of cold load pickup.

Although it is desirable to have at least one fault detecting device operate for any phase-to-ground fault on the distribution line it is not always possible to accomplish this because the amount of resistance in the fault can range from zero to almost infinity. A fault caused by the breakdown of the insulation on a feeder pole that conducts through the line hardware and the pole's ground wire will have very low fault resistance, but a phase wire lying on asphalt, concrete or some other non-conductive material will have very high fault resistance. It is not unusual for the amount of fault resistance to change if a fault is not detected for a period of time.

It is impossible to detect all ground faults and not cause tripping on unbalanced load currents. Therefore, some common methods for designing the ground fault detection system for a feeder are: establish a fault resistance target value, establish a maximum clearing time for ground faults with zero fault resistance (bolted faults), or set the overcurrent relay pickup to some fraction of the bolted fault current at the end of the protection zone.

Being able to detect faults and still being able to carry the load current in many cases cannot be achieved with only protection devices at the substation. Locating fault sensing and interrupting devices out on the distribution line at some distance from the substation will reduce the amount of fault detection coverage that needs to be provided from the substation. Most distribution lines do not have single point loads but have the loads distributed along the length of the line so these remote fault sensing devices will not be required to permit as much load current to flow as the protection back at the substation. The distribution feeder configuration most often will not be a single line, but a series of line branches with a structure resembling a tree. Because of this structure, it is typical that the same size conductors will not be used throughout the distribution feeder system. To protect the smaller conductors on the branches and to minimize the amount of customers disconnected for a fault, fault-interrupting devices can be installed at the branching locations.

To achieve the desired results of sectionalizing the faulted branches of the distribution feeder, while keeping the unfaulted parts energized, requires the time coordination of the protective devices-which are operating in series.

While the criteria for sensitivity of the protective devices are based on having one device detect any fault condition, it is preferable to have two independent devices detecting each fault. By delaying the operation of the device closest to the source the more remote device can time out and clear the fault. In this type of arrangement the device closer to the source will back up the failure of the remote device.

Most of the devices applied to protect distribution lines have inverse time characteristics. This is true for fuses, time overcurrent relays and reclosers. To time coordinate overcurrent devices the critical condition to check is normally the response of the two devices for a fault condition that produces the maximum current through the remote device. By comparing the response of both devices for the same fault condition one can determine if the desired coordination will occur. The remote device should detect and clear the fault before the device nearer the source times out. The two devices may not be monitoring the same magnitude of current if there are multiple sources to the fault or if there are transformers between the devices.

Long fault clearing times will adversely impact the power quality of the customers whose services are electrically close to the fault location, but are not actually interrupted. Customer equipment may be designed to conform to published standards concerning the ability of the equipment to properly operate during the voltage sag or swell that may be experienced during a distribution system fault clearing operation. These standards may provide the relaying engineer some insight into the impact that long fault clearing times may have on a customer. For power quality issues, and minimizing human exposure and equipment damage issues, the line faults should be cleared as fast as possible. By setting the device closest to the fault location to operate as fast as possible the two issues of speed of fault clearing and coordination for selectivity can reach an acceptable balance.

**Feeder coordination considerations**

Figure 2 (below) shows an example of the coordination between three devices where 0.35 seconds has been used as the coordination margin. Device C is a line fuse, Device B is a line recloser, and Device A is a relay with a circuit breaker in the substation. Maintaining 0.35 seconds between the minimum melt time of the line fuse and the response time of the controls on the recloser for fault location 1 and maintaining 0.35 seconds between the response time of the recloser and the response time of the relay for fault location 2 establishes the coordination for this system. Both the time and the current axes on the graph are shown using logarithmic scales. The one-line diagram of the distribution line at the bottom of the graph is shown in a scale proportional to the magnitudes of faults along the line.

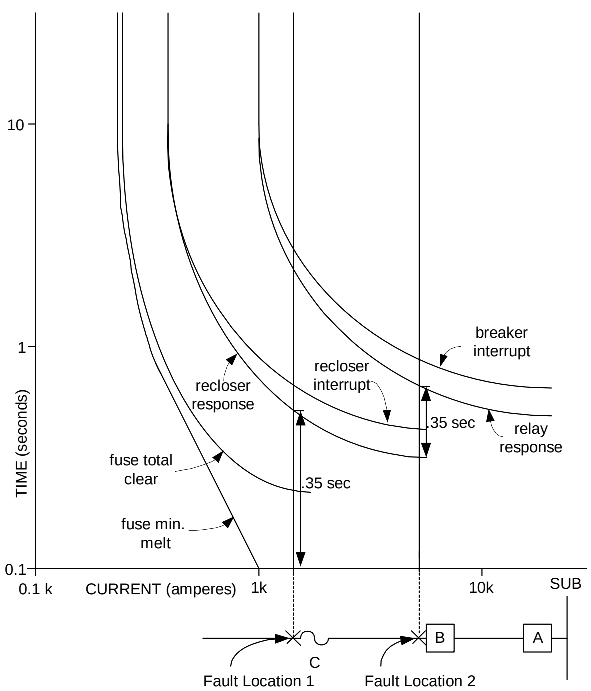


Figure 2–Three device coordination

When coordinating overcurrent devices for phase-to-phase or three phase faults the phase overcurrent devices are time coordinated with other phase overcurrent devices only; but when coordinating overcurrent devices for phase-to-ground faults, both the phase and the ground elements of the protection device should be included in the coordination. The phase element on the faulted phase will be monitoring the same current magnitude as the ground element if there are no other sources for either positive or zero sequence current other than the substation source. The response characteristic for one fault interrupter is the composite of both the phase and the ground element's response to the fault. The critical coordination point is the faster of the two responses at each current level.

**Transformer high side to low side coordination**

One common coordination situation that occurs on distribution systems is the coordination between the feeder relays and the substation transformer overcurrent protection. The overcurrent protection on the high side of the substation transformer will not see the same magnitude of current for a feeder fault as the feeder relays do because of the turns ratio and winding configuration of the transformer. A common distribution substation transformer in North America has a high side delta winding and a low side wye winding with the neutral grounded. For this type of transformer, the high side phase overcurrent protection will see only the positive and negative sequence current for a line-to-ground fault on the low side feeder circuit. For the same line-to-ground fault, the feeder relay will see the total of the positive, negative and zero sequence current on the basis of the low side voltage. To coordinate these two overcurrent protection devices for the ground fault requires comparing the response times of the two devices for the magnitude of current each will see for the same fault case.

The tightest coordination for this configuration occurs for a phase-to-phase fault close in on the feeder. The ratio between the current that the feeder phase relay will see compared to the current the transformer high side phase overcurrent device will see is smallest for this fault condition. For the phase-to-phase fault two phases on the feeder side will see 87% of the current for a three-phase fault in that location. But for the same fault one phase on the high side of the transformer would see the same magnitude current as for the three-phase fault. If the phase overcurrent relays coordinate for the phase-to–phase fault on the feeder, the relays will coordinate for all fault conditions.

**Reclosing coordination**

Reclosing relays automatically reclose circuit breakers after being tripped by fault detecting relays. Automatic reclosing is applied because the majority of faults on overhead distribution systems are temporary in nature. These faults may be caused by factors such as lightning induced insulator flashovers, animal or tree contact to the energized line, or by wind causing conductors to move together and flashover. These feeders can be effectively restored after de-energizing the fault long enough to allow the fault arc to extinguish and the gases to de-ionize. Reclosing elements automatically reclose the feeder breakers to attempt to restore the feeder after these temporary faults.

When automatic reclosing is applied the reset characteristic of the time delayed overcurrent tripping devices should be considered. Once the current through a time delay overcurrent device exceeds the pickup value for the device, it will start timing to the point at which the device will trigger the interruption of the current. If the current drops below the pickup value before the time delay is exceeded, the device will start resetting. Not all overcurrent devices reset at the same rate. Electromechanical relays reset at a rate based on the tension of the reset spring and the level of the current after the current drops below the pickup level. The longer the setting for the time delay to trip the longer it will take for the relay to reset. Fuses store heat produced by the current passing through the fusible element. Once the current drops below the minimum operate value of the fuse it will start cooling. If the fault is still present at the time of the automatic reclosing, the current is increased above the pickup value again. And if the reclose occurs before the relay has reset or the fuse has cooled to the initial state, the overcurrent devices have a biased condition toward operating. The relay will trip the circuit breaker and the fuse will blow in less time than if the devices had reset to the normal starting state. Since the reset characteristic is different for different overcurrent devices; the original time/current coordination between the devices will be modified. This can lead to undesirable protection equipment operations after the reclose.

## E. Special applications

Clause 8 contains important topics which have not been covered in earlier clauses of the guide. These topics deal with practices and considerations that impact relay protection but may not be common in every distribution system. Brief introductions of these topics follow which include: parallel lines, load shedding, adaptive relaying, sympathetic tripping, distributed resources, communication, multiple sources configurations, breaker failure, single-phase tripping and ground fault protection of ungrounded and resonant systems.

**Parallel lines**

Often adjacent circuits leave a substation in close proximity or even share common structures. Faults of sufficient duration may evolve to the point where multiple circuits are involved. This is especially true if instantaneous relaying is not applied. The consequence of this situation is that the circuits will share portions of the total fault current which will affect relay coordination. The single point source detects the entire fault current for the entire duration. Each feeder breaker only sees a portion of the fault current only for the time that the particular feeder breaker is closed. To ensure proper coordination, either sufficient coordination margin should be obtained or higher order relay integration employed. Additionally, distribution protection application should consider multiple faults occurring nearly simultaneously as this often occurs during major wind, lightning, or ice storms.

**Load shedding**

The objective of underfrequency load shedding is to arrest system-wide frequency decay after a disturbance to the system. The objective of undervoltage load shedding is to unload a system that is on the verge of collapse due to a shortage of reactive or real power support. If the frequency is decaying rapidly, the objective of the underfrequency load-shed scheme is to quickly drop sufficient load automatically to balance load with generation. In extreme cases, the load-shed relaying may need to match load with generation in an islanded system. In other cases, islanding the utility from its interconnections, if it has sufficient internal generation capacity, may be the only way to protect it from collapse. Setpoints for tripping vary from utility to utility or for the requirements of the control area's council. Some modern underfrequency schemes utilize rate of frequency change rather than frequency magnitude for the setpoints.

**Adaptive relaying**

Adaptive relaying is the ability to automatically make real-time adjustments to power system protection schemes in response to changing system conditions. Traditional distribution protective schemes have used fairly basic adaptive relaying. However, numerical distribution protection relays with multiple settings groups provide the capability to adapt protection settings, control schemes, reclosing schemes, and protection elements by changing settings groups and tripping matrices automatically due to changing system conditions. The relays adapt based on decisions made by internal logic, by analog quantities that it measures, by communication with other relays or intelligent electronic devices (IEDs), and/or by monitoring the status of switches and/or circuit breakers.

**Sympathetic tripping**

Sympathetic tripping problems are primarily dependent on the characteristics of the loads connected to a distribution system. As faults occur on a distribution line, the magnitudes of the voltages on the faulted phases are depressed at the source substation bus. Additionally, the voltage phasors may swing to a different phase angle relationship compared to the pre-fault voltage phasors. As the fault is cleared and the bus voltages are restored to normal, the load currents tend to increase on the phases that experienced the voltage depression. This increase in current relative to the pre-fault load current magnitudes can persist for several cycles.

A feeder that shares its source bus with the faulted feeder may experience high enough post-fault load currents to trip sensitive protective device overcurrent elements. On heavily loaded systems, this sympathetic tripping may also include the relaying associated with the source transformer bank. Maintaining a margin between the maximum loads a feeder is anticipated to carry and the sensitivity of protective elements is the best solution to avoid sympathetic tripping of unfaulted feeders and transformer relaying.

**Distributed resources**

Technological advances have been coupled with a favorable economic environment resulting in a number of small generators or Distributed Resources (DR) being installed on distribution systems. When DRs are integrated on radial or networked power systems originally designed to only serve load, they may require modification of the feeder protection. Thus, the main issues for DR and utility distribution system protective relaying are:

- *Protective device coordination.* The most obvious concern is for the coordination of upstream devices on the radial circuits containing the DR. The coordination of downstream devices, coordination on adjacent circuits and substation transformer backup protection should also be considered. The type of connection used to attach the DR to the system will determine whether the distribution coordination is affected.
- *Auto-reclosing.* Installing a DR on the circuit may require added delays to reclosing that affect other customer loads on the circuit. It is desirable to minimize this impact.

- *Issues of islanding DR with local loads.* Because of operational and safety issues, intentional islanding is rarely permitted by the utility without extensive analysis. Where direct transfer trip is to be used for protection against unintentional islanding, some utilities may require the addition of voltage-check and synch-check to the substation reclosing as redundancy to the transfer trip. Transfer tripping the DR needs to be coordinated between the DR and the utility and that may help shorten the duration of the circuit reclosing delay.
- *Grounding.* For most of the protection issues concerning DR, it is appropriate to consider the grounded wye connection to the system. If the DR connection is ungrounded wye or delta and the utility (grounded) source is opened; then the circuit will become ungrounded. If this occurs during a line-to-ground fault, then the DR interface may not detect the fault and respond correctly. If islanding occurs, then serious overvoltages may result

**Communications**

Historically, the use of communications channels in protective relay schemes on distribution circuits has been limited to applications such as direct transfer trip or remote control. As the design of distribution circuits has changed in response to increased reliability and power quality requirements, the use of communications channels to enhance the speed and dependability of the relay protection schemes has also increased. Relay communications channels for distribution circuit protection have been successfully implemented via direct connection to copper or fiber optic cables, leased telephone circuits, distribution carrier or other power system communications, and point-to-point radio. Selection of the communications channel and medium depends on the speed, security, and dependability requirements of the proposed protection scheme in addition to the type and cost of the locally available communications infrastructure. For example, a microprocessor-based relay with the ability to communicate with other relays or intelligent electronic devices can be applied to improve the speed and selectivity of tripping and the continuity of service to customers served from radial or looped-radial distribution circuits.

**Multiple source configurations**

Radial feeders are the most common types of distribution feeder. However, there are cases where the protection on such lines would not accommodate a line with multiple sources. If the line is a two or three terminal line, a line with distributed resources, or a line networked with other adjacent stations on the low voltage side; then the protection may be inadequate. Also cases where a line switch may be closed to energize a second line or distribution lines that are mostly cable and have substations that can provide backfeed through a line side delta connected transformer should be taken into account. Through the use of settings groups, various line switching configurations may be accommodated. SCADA or Distribution Automation systems may be used to automate the settings group changes.

**Breaker failure protection**

Traditionally, breaker failure protection has not been applied on distribution feeder circuits. This is due both to the cost of the breaker failure relay relative to the improved dependability of the feeder circuit, as well as concerns over the secure operation of the breaker failure relay. Instead of specific breaker failure detection, most feeder circuits rely on backup protection, such as bus overcurrent relays, high-side transformer overcurrent relays, or transformer ground overcurrent relays, to clear feeder faults during a breaker failure condition. These backup protection functions typically have pickup set to a high level for secure operation during maximum load conditions, so these functions may not have the sensitivity necessary to operate for some feeder faults during a breaker failure condition.
Breaker failure relays, applied to distribution feeder circuits, can improve dependability by clearing feeder faults during a breaker failure condition. In particular, multi-function numerical feeder protection relays that include breaker failure elements allow the application of breaker failure protection at low cost. Breaker failure elements can be used to re-trip the feeder breaker, and to trip upstream breakers, such as the bus breaker/transformer low-side breaker (if existing), or the transformer high-side interrupting device.

**Single phase tripping**

With the increasing interest in power quality and minimizing interruptions, single-phase tripping offers an alternative to three-phase tripping when the loads are single phase. Rather than tripping all three phases for the fault, the recloser can trip only the phase that has experienced a phase-to-ground permanent fault. Customers connected to the other 2 phases do not experience a service interruption due to the fault.

However, care should be taken using single-phase tripping in conjunction with floating wye or delta connected capacitor banks. This combination can result in overvoltages on the phase-to-neutral connected load on the open phase and cause failure in customer equipment.

Single-phase tripping can also produce another negative effect if used on a circuit with three-phase motor loads. Single-phase tripping on three-phase motors can damage these motors, as the current in the motor increases. Also, when single-phase interrupters are used in three-phase circuits, with a grounded-wye capacitor bank and a floating wye-delta connected transformer bank, ferroresonance is possible during ungrounded faults.

**Ungrounded and resonant grounding in distribution systems**

The consequences of ground faults on the system depend largely on the grounding method chosen. Faults on systems with low-impedance grounding, exhibit high levels of fault current. This sometimes requires the addition of complex grounding facilities. However, these large currents allow the faults to be easily detected and cleared quickly. In the case of grounding systems with isolated neutral, the fault current is reduced to a low value. Since these currents are based on line capacitance to ground, the current magnitude may be in the range of milliamps of secondary current, significantly less than load current. Grounding systems using a resonant coil also result in the fault current being reduced to a low value. The capacitive reactance of the system is compensated by the inductive reactance of the coil.

Using resonant-grounded systems, transient outages are automatically eliminated with no necessity to actuate on the switches or fuses. Therefore, service is not interrupted and the power supply may be maintained during the fault. Some advantages include:

- The number of high-speed automatic reclosures caused by grounding faults is reduced by 70% to 90%.
- The voltage increase after extinction of the arc is slow.
- For a single line-to-ground fault on the system, it is possible to operate for several hours, even when the fault persists.

However, these methods of grounding also involve some drawbacks:

- Protection systems using traditional technology, experience reduced reliability and sensitivity of the relays.
- The difficulty of locating faults is increased.
- During a single-line-to-ground fault, the line-to-ground voltages of each unfaulted phase increase by a factor approaching the $\sqrt{3}$ and can trigger insulator flashover.

Due to the last drawback, in order to make it possible to adopt these grounding systems, a preliminary analysis will have to be made of effects that the voltage surges in sound phases might have on insulation in the electrical system.

There are two methods commonly used to selectively detect ground faults on ungrounded systems. Varmetric relays are applied on isolated neutral systems, where wattmetric relays are applied on resonant neutral systems. Both methods use a component of the residual current that is perpendicular to the direction of the system displacement voltage. Therefore, these methods require the use of three voltage transformers to provide displacement voltage to the relay. Varmetric relays respond to the quadrature (imaginary) component of the zero sequence current compared to the displacement voltage. In an isolated neutral system, capacitive current flows from the healthy lines via the relay location to the fault. Therefore, the residual current contains a strong capacitive component that can be used to determine fault direction.

Wattmetric relays use the in-phase (real) component of zero sequence current as compared to the displacement voltage. In a compensated neutral system, the arc suppression coil superimposes an inductive current on the capacitive ground fault current, when a ground fault occurs. The resulting fault current at the relay location may be inductive or capacitive, depending on the size of the arc suppression coil versus the capacitance. Therefore, only the resistive residual current from the arc suppression coil provides a consistent value for determining fault direction.

## IV. Conclusion

A new Guide, C37.230, has been developed to assist the user in the application of protective relays on radial distribution lines. Advantages and disadvantages of various protective schemes are discussed as they apply to elements of common distribution systems. Examples and criteria are given to aid in concept understanding. The Guide includes improvements to distribution line protection made possible by the capabilities of microprocessor based relays. A special application clause is also included to address less common practices.